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August 1, 2016

- VIA ELECTRONIC FILING -

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket Nos. 160021-EI and 160062-EI

Dear Ms. Stauffer:

Enclosed for filing on behalf of Florida Power & Light Company ("FPL") are the rebuttal testimony and exhibits for the following FPL witnesses:

1. Ned Allis
2. Bob Barrett
3. Tiffany Cohen
4. Terry Deason
5. Renae Deaton
6. Moray Dewhurst
7. Keith Ferguson
8. Sam Forrest
9. Robert Hevert
10. Roxane Kennedy
11. Tom Koch
12. Jeffrey Kopp
13. Manny Miranda
14. Rosemary Morley
15. Kim Ousdahl
16. Kathleen Slattery

If you should have any questions about this filing, please do not hesitate to contact me.

Sincerely,

/s/ John T. Butler

John T. Butler

Enclosures

cc: Parties of record in Docket Nos. 160021-EI and 160062-EI

CERTIFICATE OF SERVICE
Docket Nos. 160021-EI and 160062-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail this 1st day of August 2016, to the following parties:

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF NED W. ALLIS

DOCKET NOS. 160021-EI; 160062-EI

AUGUST 1, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ned W. Allis. My business address is 207 Senate Ave., Camp Hill, PA 17011.

Q. Did you previously submit testimony in the proceeding?

A. Yes.

Q. Are you sponsoring or co-sponsoring any exhibits as part of your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

- NWA-3 – Mass Property Service Lives – Account Specific
- NWA-4 – Mass Property Net Salvage – Account Specific
- NWA-5 – Interrogatory Responses

I am also co-sponsoring Exhibit KO-19, specifically the supplemental schedules included as Attachment 2 to FPL's Second Notice of Identified Adjustments

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to the testimonies of the Office of Public Counsel ("OPC") witness Jacob Pous, Federal Executive Agencies ("FEA") witness Brian Andrews and South Florida Hospitals and Healthcare Association ("SFHHA") witness Lane Kollen. Specifically, I will respond to the portions of their testimony related to depreciation.

Q. Please summarize your rebuttal testimony.

A. My testimony demonstrates that the adjustments proposed for FPL's 2016 Depreciation Study by witnesses Pous, Andrews and Kollen are unfounded and inappropriate. The 2016 Depreciation Study, using either the original 2017 year-end plant and reserve balances or the 2016 year-end plant and reserve balances reflected in FPL's Second Notice of Identified Adjustments, appropriately represents the depreciation rates that should be applied to FPL's plant in service. The depreciation rates proposed in the 2016 Depreciation Study are based on widely accepted depreciation methods, incorporate FPL's actual experience and outlook, and properly balance the interests of current and future generations of customers. In contrast, the proposals by the intervenor witnesses do not meet these standards. Among the most prominent issues that I will explain and address in my rebuttal testimony are:

- Contrary to the implications of intervenor witnesses, the service life and net salvage recommendations in the 2016 Depreciation Study actually result in a significant decrease in depreciation expense of $563 million, when compared to the depreciation rates resulting from the service life and net salvage estimates that were approved in 2009.
- The 2016 Depreciation Study incorporates FPL-specific data and plans in support of the recommended service lives and net salvage. In contrast, the recommendations of the intervenor witnesses are not consistent with FPL's actual experience. OPC's and SFHHA's proposals are most notably flawed in this regard. As an example, both witness Pous and

witness Kollen ignore over $2 billion in historical retirement activity related to the Company's combined cycle power plants.

- In my professional judgment, the recommendations of the intervenor witnesses produce depreciation rates that do not adequately balance the interests of current and future customers. OPC's recommendations are particularly extreme, and result in a decrease of depreciation expense of more than $1 billion when compared to the depreciation rates that result from the currently approved service life and net salvage estimates.
- SFHHA's proposal to reject the 2016 Depreciation Study in its entirety and instead retain the existing depreciation rates is inappropriate and ill-advised. The 2016 Depreciation Study provides clear evidence that, independent of the calculation date used for the study, FPL's service life and net salvage parameters must be updated to incorporate current information. The study also demonstrates that updated plant and reserve balances must be used to calculate updated depreciation rates. Further, the basis for SFHHA's objection – FPL's use of December 31, 2017 balances for the 2016 Depreciation Study – has already been addressed with the depreciation rates provided in FPL's Second Notice of Identified Adjustment filed on June 16, 2016, which provides depreciation rates as of December 31, 2016. SFHHA's proposal to rely on the 2009 depreciation study would hurt current customers. As noted above, the recommended service life and net salvage parameters in the 2016 Depreciation Study reduce depreciation expense by $563 million. Applying depreciation rates

resulting from applying the service life and net salvage estimates approved in 2009 to current balances would increase depreciation expense by much more than the depreciation rates resulting from the 2016 Deprecation Study.

II. RESULTS OF THE 2016 DEPRECIATION STUDY

Q. On page 29 of his testimony, witness Pous states that for the 2016 Depreciation Study "it appears that both the utility and the depreciation analyst are in lock step as it relates to an aggressive depreciation proposal." Please address this accusation.

A. Witness Pous's accusation is simply incorrect, and the facts do not support his contention. Instead, the facts support that the 2016 Depreciation Study is fair, balanced and results in significant reductions to depreciation expense for many types of assets. As I explained in my direct testimony, the increase in depreciation expense is due primarily to the current plant and reserve balances used for the depreciation calculations, and not due to the service life and net salvage estimates in the depreciation study. That is, the increase in depreciation expense is not the result of the proposed changes I have made to lives and net salvage, but is instead the mathematical result of changes in plant and reserve balances since FPL's last depreciation study.

Instead, in the 2016 Depreciation Study I have made a number of recommendations that result in significant decreases in depreciation expense. These include the following:

- I have increased the life span for combined cycle plants from 30 to 40 years, resulting in a decrease in depreciation expense of $114.2 million
- I have changed the net salvage estimate for capital spare parts from 0% to 35%, resulting in a decrease in depreciation expense of $155.8 million.
- I have increased the average service life for capital spare parts from approximately 3.2 years to 9 years, resulting in a decrease in depreciation expense of $291.4 million.
- I have increased the service lives for twenty-one transmission, distribution and general plant accounts. These changes have been somewhat offset by a clear trend in FPL's data to more negative net salvage estimates. The total impact of my transmission, distribution and general plant recommendations is to decrease depreciation by a further $26.7 million.

In total, my recommended changes to service life and net salvage estimates result in a combined decrease in depreciation expense of approximately $563 million when compared to the depreciation rates that would result from the current, Commission-approved service life and net salvage parameters. The service life and net salvage estimates I have recommended therefore result in a substantial decrease in depreciation expense, which cannot by any objective measure be considered "aggressive," as witness Pous inaccurately characterizes them.

Q. You indicated that the increase in depreciation rates is primarily due to the change in plant and reserve balances, not the recommended service lives and net salvage estimates in the 2016 Depreciation Study. Please explain this concept further.

A. Depreciation rates for a given depreciable group can change for a number of reasons. One broad category of reasons for a change in depreciation expense is the estimates made in a depreciation study -- changes to average service lives, survivor curves, estimated retirement dates or net salvage. Changes to these estimates will result in a change in depreciation rates, all else equal. I will refer to the impact of depreciation expense due to these reasons as "changes in lives and net salvage."

However, depreciation rates will also change from study to study even if there are no changes in lives and net salvage. This occurs because plant balances, accumulated depreciation balances, and remaining life spans change from study to study. As a result, if depreciation is calculated at a different point in time, depreciation rates will automatically change with updated plant and accumulated depreciation balances. I will refer to the impact of these factors on depreciation rates to this as the "change in calculation time period."

For the 2016 Depreciation Study, the increase in depreciation expense is due primarily to the change in calculation time period, not the changes in lives and net salvage. In fact, viewed in isolation, the changes in lives and net salvage

recommended in the 2016 Depreciation Study result in a significant *reduction* in depreciation expense.

Q. Can you quantify the impact on depreciation rates of the change in calculation time period, as compared to the changes in lives and net salvage?

A. Yes. In Docket No. 090130-EI, the Commission approved specific survivor curves, interim retirement rates, life spans and net salvage estimates. Using these parameters, I have calculated the depreciation rates and expense that result if the same approved parameters are applied to the December 31, 2016 balances used for the 2016 Depreciation Study (as updated in FPL's Second Notice of Identified Adjustments provided in Exhibit KO-19).

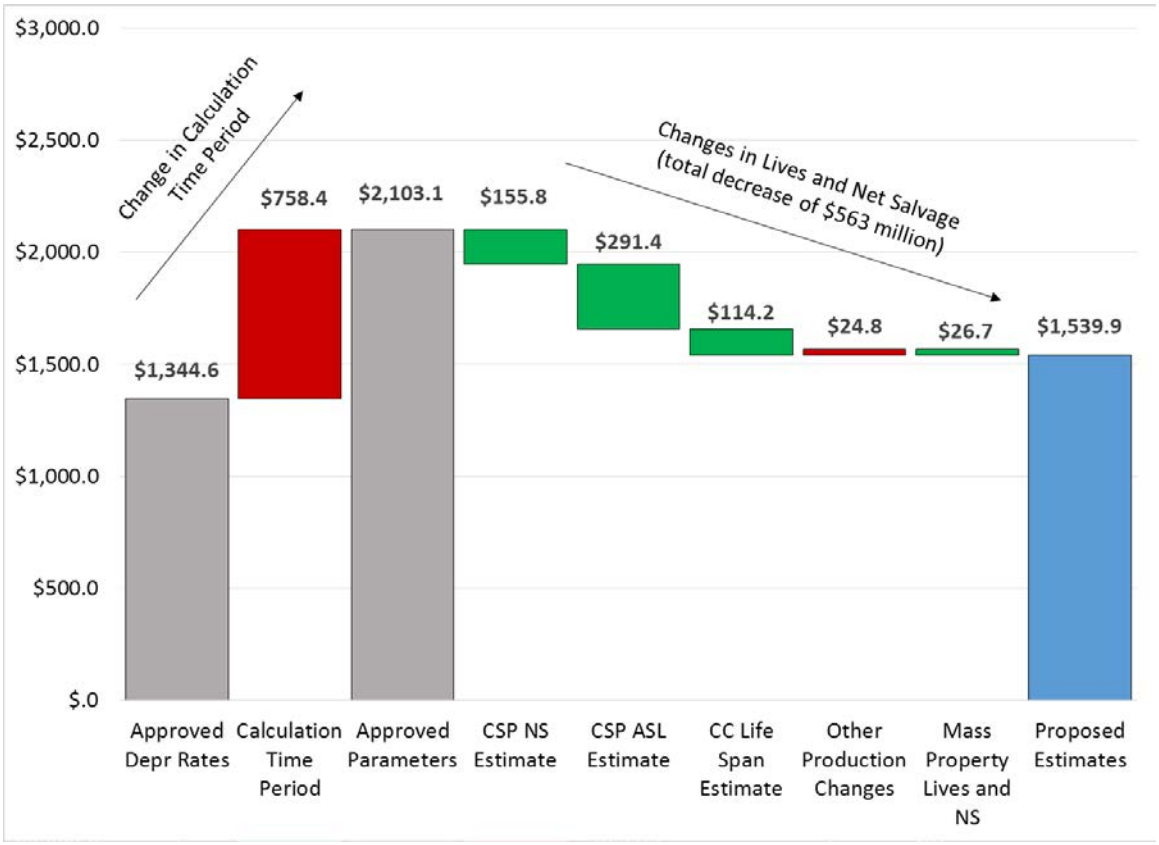
Q. What is the result of this calculation?

A. The result of this calculation is annual depreciation expense as of December 31, 2016 of $2,103.1 million. This is an increase of approximately $758.4 million over the $1,344.6 million in depreciation expense that would result from simply applying the approved depreciation rates (unadjusted for the change in calculation time period) to the December 31, 2016 plant and reserve balances. That is, the result of the "change in calculation time period" is an increase in depreciation expense of approximately $758.4 million.

In Figure 1 below, I have shown the impact of the "change in calculation time period" on depreciation expense for 2016 balances. I have also shown the impact of the "changes in life and net salvage" resulting from my depreciation

study: a reduction of $563 million. To help further illustrate the impact of specific life or net salvage estimates, I have also quantified the impact of certain changes to service lives and net salvage estimates.

Figure 1: Impact on Depreciation Expense of Change in Calculation Time Period and Changes in Life and Net Salvage



Q. What is the primary reason for the increase that occurs due to the change in calculation time period?

A. The increase is due primarily to additions to production plant accounts, which I have explained in more detail in my direct testimony.[1] For example, nuclear production plant represents $150 million of the $758 million increase due to the

[1] See pages 48 and 49 of my direct testimony for an explanation of how additions to life span property typically results in an increase in depreciation rates.

change in calculation time period. While nuclear plants have an overall 60-year life span, new assets added at the Company's nuclear facilities will have a shorter life than 60 years. As a result, for these accounts and other life span accounts, the depreciation rate tends to increase as new assets are added – otherwise the full cost of these plants would not be recovered.

Q. Given the large increase that occurs automatically from simply recalculating depreciation rates with current balances, what is the actual impact of the service life and net salvage estimates you have recommended in the depreciation study?

A. As noted above, and as can be seen in Figure 1, the actual impact of the changes in estimates proposed in the 2016 Depreciation Study – that is, the changes that actually result from my recommendations as opposed to changes that would occur anyway due to the change in calculation time period – is a significant decrease in depreciation expense of $563 million. It is incorrect and completely misleading to characterize this significant decrease in depreciation expense as an "aggressive depreciation proposal."

III. GENERAL DISCUSSION OF THE DEPRECIATION PROPOSALS

A. OPC'S DEPRECIATION PROPOSALS

Q. How would you characterize OPC's depreciation proposal?

A. OPC's recommendation is nothing short of extreme, in the sense that it consistently underestimates the actual, current cost of depreciation. In Section

II of my testimony, I explained that my service life and net salvage recommendations reduce depreciation expense by approximately $563 million when compared to the depreciation rates resulting from the currently approved depreciation parameters. Witness Pous proposes a further reduction in depreciation expense of $533 million. Combined with the large decrease I have recommended when compared to the depreciation rates resulting from the currently approved service life and net salvage estimates, this means that OPC's service life and net salvage proposals, combined with OPC's proposal regarding the theoretical reserve imbalance, result in a decrease in depreciation expense of over $1 billion. Witness Pous is effectively proposing to cut depreciation expense in half, an obviously extreme outcome owing to its sheer magnitude. Moreover, when one analyzes his recommendations further it is quite clear that they are not supported and are often the result of ignoring the Company's experience and data. For example, witness Pous has:

- Proposed to increase the life span for combined cycle plants significantly, and recommends a life span that is almost 10 years longer than FPL's actual experience.
- Ignored over $2 billion in interim retirements for production plant accounts that have occurred since the last depreciation study.
- Ignored over $2 billion in retirements of capital spare parts.
- Failed to properly calculate interim net salvage for production plant accounts, resulting in an error of approximately $21 million.
- Used the incorrect interim retirement rate for one nuclear account,

resulting in an additional error of approximately $13 million.[2]

- Proposed unusual survivor curve types for mass property that are not representative of the types of property in these accounts. OPC witness Pous's estimates are not consistent with the Company's actual experience. The result of his selection of these types of curves is to artificially reduce depreciation expense and artificially increase the theoretical reserve imbalance.
- For mass property accounts, witness Pous has also proposed net salvage estimates that are significantly less negative than the Company's actual experience – in some cases barely half of what the Company has actually experienced.
- Based on these various inappropriate adjustments, witness Pous has then used the theoretical reserve imbalance resulting from his proposals to further reduce depreciation expense by an additional $231 million by amortizing his calculated reserve imbalance over a 4-year period. This is in stark contrast to the theoretical reserve imbalance resulting from my 2016 Depreciation Study, which indicates that there is actually a minimal theoretical reserve imbalance.

One consistent theme that emerges when reviewing witness Pous's testimony is that he has repeatedly ignored or discarded the Company's actual experience and data. As a result, his recommendations result in depreciation

[2] See OPC's response to FPL's Fifth Request for Production of Documents, No. 17. OPC has included in the response to that request a corrected version of Exhibit JP-1.

expense that is far below what is supported by the Company's actual operations.

Q. In addition to the Company's data, are there other important components of a depreciation study?

A. Yes. In order to properly understand the service life characteristics of the assets included in a depreciation study, it is important to both observe representative portions of the property studied and to meet with personnel from the company in order to gain an understanding of the assets and the outlook for the property studied.

Q. Please provide an example of how site visits and meetings with management are important.

A. One of the larger dollar impact aspects of the current study is related to the Company's combined cycle fleet. I have toured the Company's Turkey Point, Lauderdale, West County, Martin and Riviera Beach combined cycle plants. In addition, I have met with many representatives from FPL who actually operate these facilities. These site visits and meetings have provided a more in depth understanding of the outlook and operations of the facilities.

In addition, I have toured combined cycle facilities in other states. I have also discussed these types of facilities with operators of combined cycle plants in additional states. This experience provides both a deeper understanding of these types of assets at combined cycle facilities as well as an understanding of the differences between facilities in different parts of the country.

Based on these site visits and meetings with FPL representatives, I recognize that the operating environment for FPL's combined cycle plants is harsher than many other locations, in particular due to the impact of salt in the air on components of the plants. The result is that FPL's combined cycle plants may have shorter lives than a plant located in a drier climate such as west Texas. FPL's experience with its Putnam plant, which has recently been retired, provides further justification for this concept. Additionally, while FPL has made investments to mitigate corrosion issues for some components, FPL's harsh operating environment still exists and will continue to impact the Company's fleet of combined cycle plants.

I have also gained an understanding of how the operations of these types of facilities results in a need to replace capital spare parts at regular intervals in order to operate the plants safely and efficiently.

Q. Has OPC witness Pous conducted similar site visits?

A. No. Witness Pous has not toured a single FPL facility for either this study or the previous study, and has never toured an FPL combined cycle facility.[3]

[3] See OPC's response to FPL's Second Set of Interrogatories No. 34.

B. INTERGENERATIONAL EQUITY AND APPROACH TO DEPRECIATION STUDY

Q. What is "intergenerational equity"?

A. The term "intergenerational equity" as it pertains to depreciation is a term used to describe the concept that customers should pay the cost of the consumption of capital assets from which they receive service, during the period when they are receiving that service. For example, the current generation of customers should not have to pay for depreciation of assets that have already been retired; nor should they pay for depreciation of assets that will not be placed into service for many years. As a corollary, future generations of customers should not have to pay for depreciation of assets from which they did not receive a benefit because current customers did not pay a sufficient amount to cover the cost of their service. Such situations would be described as "intergenerational inequity."

In addition to the concept that customers should not pay for assets from which they do not receive service, it is also desirable from an intergenerational equity standpoint to establish depreciation rates that allocate costs in an equitable manner over the service life of a Company's assets. It is not equitable for customers who receive service early in an asset's life to pay much more than customers who receive service later in that asset's life, nor is it equitable for the opposite to occur. In utility ratemaking, an equitable

allocation of costs is generally considered to mean that costs are allocated equally over an asset's service life. This is referred to as the straight-line method of depreciation.

Q. Does witness Pous discuss the concept of intergenerational equity?

A. Yes. For example, he discusses the concept in the introductory section of his testimony on page 8. Witness Pous's various explanations of this concept might present the reader with the incorrect impression that intergenerational inequity can only result from depreciation rates that are too high (whether from service lives that are too short or from net salvage estimates that are too negative). But the opposite is also true. Depreciation rates that are too low – whether due to service lives that are too long, net salvage estimates that are insufficiently negative, or both – also can result in intergenerational inequity. This can both result in future generations paying more for an asset than current customers, but also can result in a situation in which plant will not be fully depreciated when it is retired. In such a situation, customers at the time will have to pay (through capital recovery schedules or other mechanisms) for plant no longer providing service.

Q. Has witness Pous proposed recommendations in this proceeding that will produce intergenerational inequity?

A. Yes. The clearest example is witness Pous's approach and recommendation to the Company's capital spare parts.

Q. Please explain.

A. As I discuss in my direct testimony and have presented in the 2016 Depreciation Study, many of the Company's combined cycle assets referred to as "capital spare parts" have significantly shorter service lives than the other assets at the plants. As I will explain further in Section V.B, this fact is well supported by the Company's actual historical experience and the expectations for the future. It is therefore both appropriate and necessary that these assets should have a shorter service life estimate than the balance of the plant, a fact that has been recognized by the Commission in previous depreciation orders.[4]

Q. Does witness Pous recognize that there should be shorter lives for capital spare parts?

A. No. Witness Pous has instead inappropriately applied the life estimate from a completely different set of assets to capital spare parts. Any reasonable depreciation professional would recognize that this approach is fundamentally flawed. Witness Pous's approach is akin to saying that because the average annual temperature in Miami is 77 degrees, the average annual temperature in Fairbanks, Alaska must also be 77 degrees because both cities are within the United States. Clearly, this is a fallacy, as is witness Pous's life estimate for capital spare parts.

Just as striking, witness Pous also ignores overwhelming evidence of a shorter service life for capital spare parts in the form of FPL's actual historical data.

[4] See Section V.B for further discussion of the estimates for capital spare parts used in previous studies.

Since the last depreciation study, FPL has retired over $1.3 billion of capital spare parts. These are normal retirements that are necessary in order to operate the plants efficiently and safely. Witness Pous has chosen to completely ignore this evidence.

Q. How will witness Pous's proposal for capital spare parts produce intergenerational inequity?

A. As noted above, the Company has retired over $1.3 billion in capital spare parts over the last 7 years (about $190 million per year). The Company will continue to make retirements at a similar level in order to continue to operate these facilities.[5] However, witness Pous's estimate projects that only about $10 million in interim retirements would have occurred per year over the last 7 years. His estimate is therefore far too low on an annual basis. As a result, his proposal guarantees that the most of the costs of the $150 million to $200 million that will retire each year will not be recovered over their service lives. Instead, future customers will have to pay hundreds of millions of dollars for already retired assets – on top of the fact that they will also have to pay for the parts that replace the retired capital spare parts. Witness Pous's proposal would therefore result in intergenerational inequity.

[5] My estimate in the 2016 Depreciatoin Study is that the annual level of retirements for capital spare parts will occur at a lower rate going forward than in the past for reasons I discuss in more detail in Section V.B. However, the Company also has a larger fleet of combined cycles now than it did seven years ago. Thus, it is reasonable to expect that there will be on average at least $150 million to $200 million retirements of capital spare parts per year.

Q. Witness Pous also makes multiple references in which he states that the Company has "over-collected" from current customers.[6] Do you have any observations regarding the share that current customers have paid?

A. Yes. Witness Pous notes that since the early 2000s customer rates have included a total credit to, or reduction to, depreciation that have totaled approximately $2 billion. This means that current customers – those receiving service since the early 2000s – have paid in the order of $2 billion less than would result from the depreciation rates determined to be equitable and reasonable based on the Commission approved depreciation parameters. While witness Pous's testimony implies that current customers have "overpaid," if anything the opposite is true. By no objective measure should receiving a credit of $2 billion be considered "overpaying."

C. COMPARISONS TO OTHER UTILITIES

Q. In support of his recommendations, does witness Pous rely excessively on comparisons to service life and net salvage estimates for other electric utilities?

A. Yes, he does. Witness Pous makes a number of such comparisons, citing industry averages in support of his service life estimates[7] and net salvage estimates.[8] Indeed, because witness Pous's approach is generally to deviate

[6] See for example the direct testimony of Jacob Pous, page 19, lines 5 through 6 and page 43, lines 12 through14.
[7] See for example page 80, lines 22 through 23 of the direct testimony of Jacob Pous.
[8] See for example page 171, lines 5 through 6 of the direct testimony of Jacob Pous.

from the Company's actual historical data, comparisons to industry are one of the primary quantitative bases for many of witness Pous's proposals.

Q. Is it reasonable to use industry comparisons in the manner in which witness Pous does?

A. No, it is not. Industry comparisons should not be used as a substitute for Company-specific data. Further, witness Pous's use of industry comparisons is particularly inappropriate because he provides no evidence that the companies to which he makes comparisons are in any way similar to FPL. Comparing companies without establishing similar operating conditions, climates, accounting policies and other factors can, and often will, produce inappropriate results.

Q. What does witness Pous use for most of his industry comparisons?

A. Witness Pous uses a listing of average service life, survivor curve and net salvage estimates that my firm, Gannett Fleming, has made for other utilities. This was provided in discovery.[9] Witness Pous uses this document to make references to both service life and net salvage estimates for other utilities.[10] As noted above, specific uses of this industry information for witness Pous include comparisons of FPL estimates to industry averages of average service life or net salvage estimates made for other utilities.

[9] See Attachment 1 of FPL's response to OPC's First Request for Production of Documents No. 41. I note that although this information was provided to witness Pous in discovery, he also makes reference to similar industry databases provided in discovery in other cases.

[10] See for example pages 80, 89, 95, 119, 187, and 189 of the direct testimony of Jacob Pous.

Q. For service lives, should FPL be expected to have similar average service lives to other utilities or to an industry average?

A. No. To the contrary, for many types of assets FPL should be expected to have shorter service lives than other utilities. FPL's service territory is hot, humid and located in a coastal region that experiences frequent storms. Based on these factors, it should be expected that assets would experience much higher rates of corrosion (e.g., for transformers or conductor) or deterioration (e.g., for wood poles) than would be experienced by most other utilities.

Further, retirements also occur for many types of assets due to capacity reasons (e.g., a line needs to be replaced to increase capacity). Capacity is in part a function of population growth. FPL's service territory has experienced (and is likely to continue to experience) a higher rate of growth than many other regions of the country. This is another reason why one should expect FPL to have shorter service lives than many other utilities. Additionally, based on my experience visiting and observing utility property and discussing management approaches for many utilities across the country, FPL in general has a more proactive approach to replacing assets than many utilities. This has the obvious benefits of a more robust and reliable electric system, but can in general result in somewhat shorter overall service lives than would be the case for a company whose mode of operations is "run to failure."

By making comparisons to average and median values of the average service life estimates for other utilities, witness Pous inappropriately compares "apples to oranges." For example, the industry database to which witness Pous refers includes many utilities in much drier climates and that experience lower population growth, such as northern Nevada. A reasonable expectation is that service lives would be longer in those regions than they are for FPL.

Q. Is it well understood in the depreciation field that industry comparisons should not be used in the manner that witness Pous has used them?

A. Yes. In fact, witness Pous has said so himself. For example, in a recent case for Oklahoma Gas & Electric, witness Pous testified as follows:

> Q. Are typical industry estimates an appropriate or adequate basis for ignoring or significantly discounting statistical results based on Company specific information?
>
> A. No, not in this case. Industry range should only be used for confirmational purposes when adequate and credible utility specific data is available, as is the situation in this case as it relates to life analysis. Absent other meaningful support, values based on Company specific data that are reasonably within or near industry ranges should be given significant credence.[11]

[11] Oklahoma Docket PUD 201500273, direct testimony of Jacob Pous, page 59, lines 13 through 21. (Emphasis added)

Q. Is "adequate and credible utility specific data" available for FPL?

A. Yes. In fact, FPL has an extensive and well-documented database available for the depreciation study, far better than the data that was available for the Oklahoma Gas & Electric case cited above.[12] Thus, if witness Pous were consistent and objective in his approach to estimating service lives, he would not rely on industry ranges, much less industry averages, as the primary support for his estimates for FPL.

Q. Witness Pous also makes comparisons to other utilities for net salvage. Are there similar concerns with these industry comparisons?

A. Yes. Similar to service lives, net salvage can vary across the country and from utility to utility. A large portion of FPL's service territory is located in urban or developed areas. It is more expensive to do work in these areas, as factors such as work requirements and traffic control add to the expense of replacing or removing assets. For example, municipalities may require work during off-peak hours, which can add to the cost of projects. Similarly, communities in FPL's service territory may have more stringent requirements to repair streets or landscaping subsequent to completing work, which can add to removal costs. Additionally, environmental and other requirements may be higher in more populated or coastal parts of the country, which can also increase removal costs.

[12] For example, while FPL has data available from 1941 through 2014, for the Oklahoma Gas and Electric accounts challenged by witness Pous, data was only available from 1997 through 2014.

Given all of these considerations, it is not reasonable to directly compare FPL's net salvage estimates to those in more rural or less densely populated areas of the country. Similar to witness Pous's statement above regarding service lives, if a utility has sufficient data for the net salvage analyses then industry averages or ranges are not appropriate as a basis for net salvage estimates.

Q. If you compare FPL's net salvage estimates to other utilities that have a more similar operating environment, are FPL's net salvage estimates in line with these types of facilities?

A. Yes. In fact, for many accounts witness Pous has actually estimated more negative net salvage estimates for other comparable utilities than the estimates I have made for FPL. As an example, two accounts for which witness Pous makes industry comparisons are for distribution poles and distribution overhead conductors and devices. Estimates for these types of assets for utilities such as Southern California Edison ("SCE") and Pacific Gas & Electric ("PG&E") are more negative for these accounts than the estimates I have made for FPL. Not only are the estimates currently used for these utilities more negative, but also witness Pous has testified on depreciation for both PG&E and SCE. His estimates in those cases for Accounts 364 and 365 were either the same as or more negative than the estimates I have made for FPL.

The service areas for these utilities all include large metropolitan and developed areas and are located within proximity to the coast. They therefore provide more reasonable comparisons than witness Pous's reliance on simple industry averages, and support that FPL's net salvage estimates are consistent with other comparable utilities and that FPL's data provides a reasonable basis for net salvage estimates.

D. SUPPORT FOR THE DEPRECIATION STUDY

Q. Beginning on page 19 of his testimony, witness Pous argues that you have not sufficiently supported your depreciation study. Please address his claims.

A. Witness Pous devotes about twelve pages of his testimony to criticizing the study for what he alleges is a lack of support. The problem as it relates to FPL's 2016 Depreciation Study is that his criticisms do not accurately describe what is actually included in the depreciation study, much less what has been provided in numerous discovery responses.

Q. Are there any critical components of the 2016 Depreciation Study that are missing from witness Pous's discussion?

A. Yes. Throughout his discussion, witness Pous consistently neglects to mention the Company's actual historical data, which – consistent with widely accepted depreciation practices - form the primary statistical support for the depreciation study. This is a critical component, and is particularly important when reviewing the actual estimates witness Pous recommends. Indeed, for

most of the estimates he makes, he deviates from the Company's actual experience and from what is actually supported by the Company's data.

Q. Is your approach to the 2016 Depreciation Study consistent with widely accepted practices in the field of depreciation?

A. Yes. For the estimation of service lives, I have used the widely accepted retirement rate method and have analyzed the historical data and selected survivor curves in a manner consistent with classic depreciation theory. In contrast, as I explain in Section VI.B.ii, witness Pous's approach to curve fitting is not consistent with accepted practices and he ignores significant portions of the historical data.

Similarly, for the estimation of net salvage (which is discussed further in Section VII of my rebuttal testimony), I have followed widely accepted practices for the analysis of historical data. I have also provided additional supporting information explaining trends in the data and reasons for the estimates I have made. Witness Pous's approach is instead to ignore the historical data. Despite clear trends and support for more negative net salvage, he does not propose a more negative estimate than the currently approved estimate for a single account for which he has recommended an adjustment.

Q. Witness Pous criticizes what he refers to as your "underlying threshold assumption" for your net salvage proposals and claims that this assumption is not valid. Please address his claim.

A. What witness Pous refers to as an "underlying threshold assumption"[13] is actually the industry standard method for estimating net salvage. Any implication that I have not used accepted depreciation practices is simply incorrect. While witness Pous's discussion is intended to provide support for his decision to ignore the Company's actual historical data, as I will explain in Section VII and in Exhibit NWA-4, his various rationalizations and analyses do not provide support to ignore the data and are often incorrect.

I should also be clear that witness Pous's criticisms and overall approach to the net salvage analysis is not consistent with the standard approach in the industry; nor is it supported by authoritative depreciation texts. For example, the National Association of Regulatory Utility Commissioners in its 1996 publication *Public Utility Depreciation Practices* (referred to as the "NARUC Manual"), explains that

> "[m]ost analysts are of the opinion that reasonable salvage and cost of removal estimates and forecasts can be made by trending experience and applying informed judgment," and that "in any case it would not be economically justifiable for any

[13] See page 23 of the direct testimony of Jacob Pous.

utility, regardless of size, to produce indepth salvage forecasts for all categories of plant."[14]

Again, I would like to make clear that I have investigated the historical data to determine whether past experience is a reasonable predictor of the future. That is, I have incorporated more information than "simply trending experience and applying informed judgment." This information has been provided in discovery[15] and has been discussed in the narratives explaining my estimates provided in Parts X and XI of Exhibit NWA-1. In order to gain a better understanding of FPL's assets and operations, I have also met with FPL representatives who are knowledgeable of the Company's property. Notes from these meetings have also been provided in discovery.[16]

I should further note that witness Pous's criticisms of the use of the word "judgment"[17] are not an accurate description of what has been presented in FPL's 2016 Depreciation Study and in responses to discovery. In addition to the historical data presented in the study, Parts X and XI of Exhibit NWA-1 present 136 pages of explanations of the service life and net salvage estimate for every account and generating station. I have also provided further explanations of my estimates in discovery.

[14] NARUC Manual, pp. 159-160.
[15] See FPL's response to OPC's First Set of Interrogatories No. 51 provided in Exhibit NWA-5.
[16] See Attachments 1 and 2 to FPL's response to OPC's First Request for Production of Documents No. 38.
[17] See for example page 21, lines 2 through 3 of the direct testimony of Jacob Pous.

IV. LIFE SPANS

Q. What is "life span" property?

A. Life span property is a depreciation term used to refer to facilities such as power plants for which all components of the assets at the site will be retired concurrently. For example, when a power plant reaches the end of its useful life all assets at the facility will be retired at the same time. This may include structures that were originally constructed with the facility as well as assets such as pumps or motors that may be relatively new.

The retirement of the entire facility is referred to as a "terminal retirement" or a "final retirement." Additionally, in order to operate the facility, many assets will need to be replaced throughout the life of the plant. Retirements such as these that occur prior to the final retirement are referred to as "interim retirements."

Q. How is depreciation determined for life span property?

A. In order to properly determine depreciation rates and expense for life span property, one must make estimates of both final retirements and interim retirements. This is referred to as the "life span method." Final retirements are typically estimated for each production plant or generating unit by determining the most likely date at which the facility will retire. This date is referred to as an "economic recovery date," a "final retirement date" or a "probable retirement date." A related concept is the "life span" of the facility,

which is the period of time from the original installation of the facility to the final retirement date of the facility. Thus, if a power plant is constructed in 1990 and retires in 2030, it will have a 40-year life span.

It should be noted that the life span of a facility is different from the average service life of the facility. The average service life of the facility is normally shorter than the life span, for two reasons. One is that any additions that occur subsequent to the original installation of the facility will have a shorter life than the original additions. For example, for a facility with a final retirement date of 2030, assets installed in 2010 will have a shorter life than those installed in 1990. The second reason is there will typically be interim retirements that occur throughout the life of the facility. These interim retirements are most commonly and most accurately estimated using survivor curves, similar to the approach for mass property.

Once estimates of both final retirement dates and interim retirements are determined (as well as net salvage for each type of retirements), these estimates are combined to develop overall depreciation rates. For FPL, these depreciation rates have been determined for each account for each production plant unit.

Q. Do all parties agree with the use of the life span method?

A. Yes. While OPC and SFHHA propose changes to some of the estimates made in the 2016 Depreciation Study, each has used the life span method. FEA has not proposed any changes to the estimates in the study for life span accounts.

Q. What changes have been proposed by OPC and SFHHA?

A. Both have recommended different life span estimates for certain types of facilities. Both have also recommended different estimates for interim retirements.

In this section, I will discuss the proposed changes to life span estimates made by OPC and SFHHA and explain why each is inappropriate. In Section V, I will explain why their interim retirement estimates are inappropriate, which is in no small part due to the fact that each has elected to ignore over two billion dollars of retirements from FPL's actual historical experience.

Q. Has FPL retired any of its power plants in recent years?

A. Yes. As I discuss in my direct testimony, FPL has retired a number of power plants. These include steam-fired power plants as well as the two units at the Putnam combined cycle plant.

Q. What are some of the lessons learned from FPL's experience with these plants?

A. In addition to providing evidence of the life spans FPL's plants have actually experienced, the retirements of these plants illustrate one of the primary causes of the final retirement of power plants. Specifically, a power plant is

often retired as the result of an economic decision. As a plant ages and becomes more expensive to operate, and as new technologies become more efficient and economical relative to existing generation, it eventually becomes economical to replace the existing plant. The retired plant may be able to physically operate for a longer period of time, but it would be more costly option to keep the plant in service.

Thus, the process of estimating the life spans of the Company's power plants is not to determine how long a plant could physically last, but instead estimating when the economic decision will be to replace the plant with newer generation. Fortunately, for FPL the Company has experience replacing its facilities in recent years that provides evidence as to the overall economic life spans of the Company's facilities.

Q. What are the specific changes to life span estimates that each party has proposed?

A. OPC has proposed a 45-year life span for the Company's combined cycle facilities. For coal-fired facilities, SFHHA has proposed a 63-year life span for Scherer and a 65-year life span for the St. Johns River Power Park ("SJRPP").

Q. What are the current, Commission approved life spans for these facilities?

A. The currently approved life span estimate for combined cycle facilities is 30 years. OPC has therefore proposed to increase this life span estimate by 15

years, or 50%. The currently approved life span estimate for coal-fired generation is 50 years. SFHHA has proposed to increase this life span by 13 years for Scherer and 15 years for SJRPP.

Q. How do your estimates for these types of plants compare to the currently approved estimates?

A. For reasons set forth in my direct testimony, I have recommended an increase in the life span for combined cycle facilities to 40 years. Thus, I have already recommended a fairly significant increase in the life span for combined cycle facilities. A further increase, as proposed by OPC, is both inappropriate and is inconsistent with the Company's actual experience operating these facilities.

For coal-fired production facilities, I have proposed to continue to use the 50-year life span previously approved by the Commission. Given the industry-wide outlook for coal, it is reasonable to continue to use the previously approved estimate. Witness Kollen's proposal to significantly increase the life span by 15 years is particularly inexplicable given the fact that the outlook for coal-fired generation is worse today than it was in 2009 when the Commission approved a 50-year life span for these facilities.

I will explain the specific reasons why OPC's recommended life span for combined cycle plants should be rejected in the following section. I will then briefly discuss SFHHA's proposal for coal-fired generation. However, because SFHHA's witness Kollen's proposal is related to both depreciation

and dismantlement, and because many of his comments related to FPL's operating agreements with the co-owners of Scherer and SJRPP, FPL witness Ferguson will address SFHHA's proposal for the life spans of coal-fired generation in more detail in his rebuttal testimony.

A. COMBINED CYCLE

Q. What are the life span estimates for combined cycle facilities?

A. The currently approved estimate is for a 30-year life span. I have recommended an increase to a 40 year life span. OPC has recommended an increase to a 45-year life span.

Q. Please explain the reason for your recommendation to increase the life span for combined cycle production?

A. As I discuss in my direct testimony,[18] the Company has made significant investments in its combined cycle fleet. These investments have both helped to mitigate corrosion of certain components and have increased the efficiency of the plants. For both reasons, these investments have improved the economics of operating the facilities and a longer life span is now attainable.

Q. Witness Pous has proposed to increase the life span for these facilities even further. Do you agree with his recommendation?

A. No. A longer 45-year life span is neither realistic nor appropriate. FPL's experience indicates a much shorter life span than 45 years. I should also note that although witness Pous notes two examples of combined cycle plants with

[18] Direct testimony of Ned W. Allis, page 30, lines 5 through13.

45-year life spans, there are also many estimates for combined cycle facilities in the 35 to 40-year range. Additionally, FPL's operating environment and operating profile provides reason to expect that, if anything, FPL's combined cycle fleet will have shorter life spans than others in the industry.

Q. Has FPL retired any combined cycle plants?

A. Yes. As I discuss on pages 30 through 31 of my direct testimony, FPL retired the Putnam facility in 2014. The actual experienced life spans of the two units at Putnam were 36 and 37 years. These life spans are therefore much shorter than witness Pous's proposed 45-year life span. They are also somewhat shorter than the 40-year life span I have proposed.

Q. In his discussion of his estimated life spans does witness Pous mention FPL's actual experience with Putnam?

A. No.

Q. You indicated that FPL has made significant investments to its current fleet. Did FPL also make significant investments to the Putnam facility?

A. Yes. There were significant investments made to Putnam in the early 1990s, which included the replacement of the heat recovery steam generators.[19] Absent these investments Putnam likely would have had an even shorter service life.

[19] See Attachment 1 to OPC's First Request to Production of Documents No. 38, page 42.

Q. What was FPL's operating experience with Putnam?

A. As has been provided in discovery,[20] FPL's experience was that as the plant aged it became both more expensive to operate and less available to provide power. At the same time, newer combined cycle facilities became more efficient. Eventually the combination of these factors meant that it was more economical to replace Putnam's generation than to continue to operate the plant.

Q. What does OPC witness Pous provide as support for his estimated life spans?

A. Despite the fact that he has proposed to increase the life span by 50% over the approved life span, witness Pous actually provides little evidence in support of his proposal. He claims that, despite the significant increase in life span FPL has proposed compared to the Commission approved 30-year estimate, that a 40-year life span is still somehow "artificially short."[21] He argues that "standard economic theory" supports a longer life span and supports this claim by presenting a discussion of a trend towards increasing life spans for steam production facilities.[22] As I will explain, witness Pous's discussion of the economics of combined cycle facilities is incorrect, and his discussion of a trend towards increasing life spans is misleading and incomplete. Specifically, his discussion omits the more recent trend to shorter life spans and the fact that many power plants have retired earlier than estimated.

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[20] See Attachment 3 to OPC's First Request to Production of Documents No. 38.
[21] Direct testimony of Jacob Pous page 49, lines 10-11.
[22] See pages 50 through 51 of the direct testimony of Jacob Pous.

Witness Pous also cites two combined cycle facilities in other parts of the country for which a 45-year life span was estimated. As I will explain, these two facilities are much less relevant to FPL than FPL's actual experience, as these plants are located in regions of the country that is quite different from FPL's service territory.

Q. Please respond to witness Pous's discussion on page 49 of his testimony, in which he states that "standard economic theory" dictates that "large capital investments should be operated to maximum levels in order to deliver the economic worth that such facilities are capable of obtaining."

A. Witness Pous's discussion of what he refers to as "standard economic theory" is incorrect and is inconsistent with FPL's actual experience and operations of its facilities. Specifically, his implication is that a facility should be operated for as long as possible, apparently without any consideration of alternative forms of generation (e.g., more economical replacement generation) that may be less expensive.

It is fundamentally incorrect that the economics of operating a fleet of power plants dictates that these facilities should be operated for as long as is possible. Witness Pous's statement to this effect ignores the fact that in addition to the initial capital investment, there are significant costs – including fuel, maintenance and major capital investments – required to operate a plant throughout its life. While operating a plant as long as possible may maximize the initial capital investment, it is very often not economical once these other

costs are considered. This is particularly true because, as was the case with Putnam, the cost trend of operating a plant tends to increase over time. As a result, the economical option is often to replace an older, less efficient plant with a newer, more efficient plant.

Q. What has FPL's actual experience been with regard to the economics of its power plants?

A. FPL's actual experience demonstrates quite clearly that it has been more economical to replace older, less efficient power plants with newer facilities. As witness Pous himself notes,[23] FPL has retired a number of steam-fired power plants since the last depreciation study. It would have been possible from a physical standpoint to operate these plants for a longer period of time, thereby operating the plants to "maximum levels" in witness Pous's words. However, it would not have been economical to do so because these plants had become more expensive than the alternative of replacing them with newer, more efficient facilities. The same is true of the Putnam combined cycle facility. While it may have been possible to operate the plant longer from a physical standpoint, it was not economical to do so and it was more economical to retire the facility and construct newer, more efficient combined cycles.

Thus, FPL's actual experience makes clear that witness Pous's has stood "standard economic theory" on its head. It does not make economic sense to

[23] Direct testimony of Jacob Pous, page 49, lines 14 through 15.

operate a power plant for as long as possible – this is often an expensive way to produce power. Instead, it is often more economical to replace older, less efficient and less available generation with newer technology.

Q. On pages 50 and 51 of his testimony, witness Pous describes what he refers to as the "expansion of life spans" in the industry for steam-fired, nuclear, hydroelectric simple cycle and other production power plants. Please address his discussion.

A. Witness Pous's presentation is intended to give the impression that because life span estimates trended longer over time for steam-fired power plants, the same will be true for all types of facilities. However, his discussion omits important details about the capital expenditures required to attain longer life spans for steam-fired power plants. He also conspicuously omits the experience from recent years, in which the opposite trend has occurred and many power plants have retired earlier than expected – resulting in significant levels of unrecovered costs in many cases.

Q. Please explain further.

A. Witness Pous states that "[i]n the last several years utilities and regulators are recognizing that 50 and 60-year life spans are more appropriate for steam-fired generation."[24] This statement is only partially true at best, and the trend in life spans for steam-fired power plants is certainly not increasing. While the life spans of many steam-fired power plants may have been estimated at 50 or 60 years, witness Pous omits the fact that many facilities were recently

[24] Direct testimony of Jacob Pous, page 50, line 23 to page 51, line 2.

retired earlier than expected and many more such early retirements are planned.

What actually occurred is that life span estimates for many facilities had been pushed out too far. The result has been many power plants have retired prior to being fully depreciated (this situation is made worse by the fact that for many plants, there had also not been adequate recovery of dismantlement costs), leaving unrecovered costs to be paid by customers that do not receive service from the retired plants.

Q. In support of his estimate, witness Pous mentions two combined cycle facilities for which a 45-year life span was estimated. Please address these facilities.

A. Witness Pous cites combined cycle facilities for Oklahoma Gas & Electric and for El Paso Electric Company for which a 45-year life span was used. In Section III.C I have explained that these two utilities operate in a less harsh environment and have different operating profiles than FPL. It would therefore be reasonable to expect that FPL would have a shorter life span for combined cycles than those operated in Texas or Oklahoma. Further, other utilities use the same or shorter life spans than FPL. For example, Nevada Power uses a 35-year life span and Pacific Gas & Electric uses a 30-year life span.

Thus, comparisons to other utilities does not support witness Pous's 45-year life span estimate over my 40-year life span estimate. More important though is that, as I have explained, FPL has actual experience retiring combined cycle units at life spans much shorter than his proposed 45-year estimate.

Q. Witness Pous also discusses FPL's mitigation of corrosion issues with certain components. Is corrosion still a concern for FPL's plants as compared to those in other parts of the country?

A. Yes. While FPL is addressing corrosion issues wherever possible, this does not mean that FPL's harsh operating environment has disappeared. Witness Pous's statement that "FPL is already addressing the corrosion issue identified as a problem associated with operating in a harsh environment"[25] is not an accurate characterization FPL's operating environment. FPL has addressed corrosion issues that impacted some components, primarily capital spare parts, and had resulted in earlier than expected retirements of these components and as a result contributed to a shorter life span for the Company's combined cycle plants. After addressing these issues, a longer 40-year life span is attainable. However, this does not mean that the harsh operating environment no longer impacts components at FPL's combined cycle plants. The Company's combined cycle plants continue to operate in a harsh environment, which will impact the lives of many of the components of its plants. This will also impact the cost of operating the facilities as they age and parts corrode and need to be replaced. For these reasons, FPL should be expected to – if

[25] Direct testimony of Jacob Pous, page 52, lines 4 through 5.

anything – have a shorter life span for combined cycles than those of other utilities.

B. COAL-FIRED PRODUCTION

Q. Please address witness Kollen's proposal for the life spans of coal fired power plants.

A. As noted earlier, for the 2016 Depreciation Study I have recommended to continue to use the 50-year life span estimated previously adopted by the Commission. Given that the outlook for coal-fired generation is even less favorable today than was the case in 2009 when the 50-year life span was established, it would not be appropriate to increase the life span further. FPL witness Ferguson addresses the life spans of coal-fired power plants in more detail in his rebuttal testimony.

V. INTERIM RETIREMENTS AND CAPITAL SPARE PARTS

Q. What are the issues related to interim retirements in this case?

A. There are two issues. One relates to the method used to estimate interim retirements. OPC witness Pous argues against the widely accepted method I have used for estimating interim retirements based on survivor curves. I will explain that not only are his criticisms unfounded, but that witness Pous has not even bothered to perform a study using the Company's current data to make estimates using his favored method. Instead, he has simply used the

same estimates that were approved 7 years ago – and are now 7 years out of date. As a result, witness Pous has ignored more than $2 billion in interim retirements that have occurred since the last depreciation study.

The second issue relates to capital spare parts. Witnesses Pous and Kollen have made recommendations that in effect ignore the extensive historical activity related to capital spare parts. Specifically, the Company has made over $2 billion in interim retirements for capital spare parts and has made approximately $1.3 billion in retirements for these assets in the last 7 years alone. Further, an understanding of the types of assets included in the proposed capital spare parts subaccount makes clear that the Company will continue to experience high levels of retirements of these types of assets. Both witnesses Pous and Kollen have proposed to use estimates of interim retirements based on a completely different set of assets and have therefore ignored the data related to capital spare parts. This produces unreasonable results. For example, OPC's proposal for capital spare parts implies an expectation that these assets would have an average service life that is approximately 1,250% longer than the Company has actually experienced for these assets.

Q. Have either OPC or SFHHA proposed estimates of interim retirements based on current, FPL account-specific data?

A. No. I would like to make clear that FPL is the only party in this case that has recommended estimates of interim retirements based on a study of currently available data. Estimates in FPL's 2016 Depreciation Study are based on the

analysis of historical data through the most recent year available (i.e., 2014), while the interveners' estimates are not. For all accounts except capital spare parts, witness Pous has simply used the approved estimates from the 2009 Depreciation Study, and therefore he has not incorporated the data from the last 7 years subsequent to that study. Further, he has inappropriately used the estimate from an entirely different group of assets and applied them to capital spare parts. He therefore does not incorporate any data related to FPL's capital spare parts. Witness Kollen has not challenged most of my estimates, but similar to witness Pous has used the estimate from an entirely different group of assets and applied them to capital spare parts.

Thus, the only estimates that are based on current, Company-specific and account-specific data are those set forth in FPL's 2016 Depreciation Study. This alone should cast serious doubt on OPC's and SFHHA's proposals.

Q. How will you address the issues related to interim retirements?

A. There are multiple issues with both OPC's and SFHHA's proposals as they relate to interim retirements. I will first address the method of estimating interim retirements, and explain that the widely accepted method I have used is more appropriate than that of OPC. I will then specifically discuss capital spare parts, as the recommendations of both OPC and SFHHA are particularly inappropriate for these assets. I then discuss the impact of interim retirement estimates on the net salvage for production plant. Neither witness Pous nor witness Kollen has adjusted the overall composite net salvage estimates for

production plants to account for their changes in net salvage. The result is that both have erroneously understated depreciation expense. Finally, I will address two other issues related to interim retirements – the allocation of accumulated depreciation for the new subaccount for capital spare parts and the appropriateness and necessity of including estimates of interim retirements for the Okeechobee combined cycle plant.

A. INTERIM RETIREMENT METHOD

Q. Please explain the method you have used to estimate interim retirements.

A. To estimate interim retirements, I have used survivor curves based in part on the statistical analysis of historical interim retirements. These are referred to as interim survivor curves. The use of interim survivor curves is a widely accepted method to estimate interim retirements for life span property. It is also considered to be the most accurate approach.

Q. Does witness Pous agree that interim retirements should be estimated and incorporated into depreciation rates for life span property?

A. Generally, yes. Witness Pous's normal practice is to include an estimate for interim retirements, and he does include estimates of interim retirements for his recommendations in this case. However, he did not update the analysis to incorporate more recent data.

Q. Witness Pous has not recommended estimates based on current data available?

A. No, he has not. He has instead proposed to continue using the currently approved interim retirement rates, with the notable exception that he completely ignores both the approved estimate and the actual history of interim retirements for capital spare parts. That is, not only is he recommending a less accurate methodology, but he also failed to update his estimates from a study performed 7 years ago to incorporate current information.

Q. Has the Company experienced interim retirements subsequent to the last depreciation study?

A. Yes. For the historical data that has been recorded since the last study (i.e., from 2008 to 2014), the Company has experienced over $2 billion in interim retirements. By opting to simply use the existing interim retirement estimates witness Pous has therefore ignored over $2 billion in interim retirements.

Q. Please explain the difference between your proposed method for accounting for interim retirements and the method proposed by OPC.

A. In the 2016 Depreciation Study, I have utilized the proposed retirement date for each generating unit. In addition, I have estimated an Iowa-type survivor curve for each production plant account, which takes into account the fact that some of the property at these plants will be retired before the final date of retirement. Witness Pous also proposes using the life span method and adjusting for interim retirements. However, instead of using an Iowa curve

with a distinct retirement dispersion pattern that matches the type of property in each plant account, he estimates an "interim retirement rate" and adjusts the remaining life for each generating unit within each plant account based on this interim retirement rate.

Q. How is this method different from using an interim survivor curve?

A. Although he claims there to be a difference, in actuality witness Pous simply uses an approximation of my method. That is, he also effectively selects a curve that represents interim retirement activity for each account. The difference is that instead of selecting a curve with variable retirement dispersion pattern, such as the Iowa R, S or L type curves that I have proposed, witness Pous has instead chosen a curve that assumes a constant level of interim retirements each year. As I will explain, this is an unrealistic assumption.

Q. On pages 54 through 59 witness Pous discusses his concerns with your method. Are his concerns valid?

A. No, they are not. Witness Pous's main criticism of my approach, both in this case and in FPL's previous depreciation case, is that the use of actuarial analysis for interim retirements is inappropriate. For example, he states that "[a]ctuarial analyses are normally performed on more homogeneous-type investments that are not generally dependent on one another, such as poles or wires. In particular, the varying types of investments within each of the major production plant accounts do not reasonably lend themselves to actuarial

analyses."[26] As I will show, this criticism is unfounded. Not only are actuarial analyses of interim retirements widely accepted in the utility industry and supported by authoritative depreciation texts, but the source that witness Pous claimed to "sponsor"[27] his approach in FPL's previous case specifically states that an actuarial analysis is the more accurate method.

I should note that many of witness Pous's specific criticisms are related to capital spare parts, which I will address in more detail in the next section. In this section, I will address his criticisms that relate to the method used to estimate interim retirements.

Q. Do you agree with witness Pous's assertion that actuarial analysis is not appropriate for production plant accounts?

A. No, I do not. The use of Iowa curves for interim retirements for this type of property has been widely accepted in the U.S. and Canada and is supported by authoritative depreciation texts.

Q. Does witness Pous cite any sources that recognize his methodology for interim retirements?

A. No, in this proceeding he does not. However, in other proceedings in which both witness Pous and Gannett Fleming have testified, including FPL's 2009 case, he asserted that two sources recognize his methodology. He previously purported that his method is "sponsored by the California Public Utilities Commission in its publication entitled 'Determination of Straight-Line

[26] Direct testimony of Jacob Pous, page 54, lines 18 through 22.
[27] See page 65 of witness Pous's direct testimony in Docket No. 090130-EI.

Remaining Life Depreciation Accruals Standard Practice U-4."[28] He has also testified that the NARUC Manual recognizes his methodology.[29]

Q. Do either of these sources support witness Pous's contention that your method is inappropriate for life span property?

A. No, they do not. In fact, the opposite is true. Standard Practice U-4, which witness Pous has claimed "sponsors" his approach, makes it clear that my method is in fact superior to his method. The method witness Pous employs is presented on page 28 of Standard Practice U-4. The actual passage reads as follows (for brevity the description of the calculations has been excluded):

> Interim retirements and additions include such items as changes within a building or changes at an electrical generating station not altering the basic structures, etc. As an approximation the assumption can be made that future annual interim retirements will occur at a consistent ratio to the present plant balance…In more accurate applications, this correction may be developed from an actuarial analysis of mortality data for the interim retirements. (Emphasis added).

Witness Pous's main source for his methodology clearly states not only that his method is an "approximation," but also the method I have proposed to develop interim survivor curves (i.e., from actuarial analysis of interim retirements) is "more accurate." In 1961, when Standard Practice U-4 was written, there may have been a need to rely on an approximation that was

[28] See page 65 of witness Pous's direct testimony in Docket No. 090130-EI.
[29] See page 42 of the direct testimony of Jacob Pous in Docket No. 090130-EI.

simpler from a computational standpoint. However, today with the help of modern computer software these computational considerations are not an issue any longer.

Q. Does the NARUC Manual recognize your method?

A. Yes. According to NARUC, developing an observed life table from historical data, which "can be fitted to generalize life curves, e.g., Iowa curves or curves based on the Gompertz-Makeham formula,"[30] and using the fitted curve to account for interim retirements is appropriate for life span property. This is precisely the method I have employed.

Q. Witness Pous also states that your method was "challenged and not accepted in the last rate case" for FPL.[31] Please address this claim.

A. Witness Pous is actually referring to Docket No. 090130-EI. While it is true that the Commission adopted the methodology proposed by witness Pous, it did not reject my methodology. To the contrary, the Commission specifically noted "that both FPL's method and OPC's method are industry accepted practices."[32] In other words, the Commission accepted that my method was appropriate, but instead opted to use a different method for its own depreciation calculations. It should also be noted that the Commission specifically stated that it "agrees with FPL's criticism that OPC's use of a

[30] NARUC Manual, page 153.
[31] Direct testimony of Jacob Pous, page 54, lines 3 through 6.
[32] Order No. PSC-10-0153-FOF-EI, page 31.

constant retirement rate assumes that retirements in the future will mirror those of the past."[33]

Q. Has witness Pous challenged your methodology for interim retirements in any other jurisdictions?

A. Yes. One example is a similar challenge to this methodology in Nevada in the 2004 rate proceeding of Sierra Pacific Power Company (Docket No. 05-10004). The Commission agreed with Gannett Fleming in that case and specifically agreed with Gannett's industry-established method of calculating interim retirements in its Order for Dockets No. 05-10003 & 05-10004. Specifically, the Order states:

> "The Commission is convinced that Sierra's [my] proposed methodology for calculating interim retirements is adequate and widely accepted in the industry. The Commission accepts Sierra's approach to calculating interim retirements."[34]

Gannett Fleming has also proposed the same approach for interim retirements in the vast majority of depreciation studies for which there are life span accounts. To the best of my knowledge, this approach has been accepted or acknowledged to be appropriate in each of the jurisdictions where interim retirements are used for the life span method.

[33] Ibid.
[34] Nevada Public Utilities Commission Order, Docket Nos. 05-10003 & 05-10004 at page 85.

Q. Witness Pous claims that because the property in production plant accounts is not homogeneous, using an interim survivor curve to estimate interim retirements is inappropriate. Is this concern valid?

A. No. Witness Pous is incorrect. Property in these accounts is grouped according to the Uniform System of Accounts, just as is the case for transmission, distribution and general plant property. Witness Pous has not objected to Iowa survivor curves for transmission, distribution or general plant accounts, despite the fact that some Transmission and Distribution plant accounts, such as Accounts 353 and 362 - Station Equipment (which include assets as diverse as transformers and digital relays) also do not include homogenous-type investments. Indeed, witness Pous has made his own recommendation for Accounts 353 and 362 using actuarial analyses even though the assets in this account are not homogeneous.

It is also important to recognize that the actuarial life analysis I have used for interim survivor curves is only related to interim retirements. Final retirements are instead based on estimates of the retirement date for an entire generating unit. The assets in production plant accounts subject to interim retirements are therefore more homogeneous than witness Pous's testimony suggests.

Q. Could you provide an example to illustrate the difference between witness Pous's proposal and the Company's proposal?

A. Yes. The difference is perhaps best illustrated by drawing an analogy between using the life span technique for power plants and using the life span technique for a car. This is the same analogy witness Pous uses on pages 52 and 53 of his testimony to explain the concept of interim retirements. A typical car might have a service life of 10 years, and during the life of the car various components will have to be replaced such as batteries, tires, etc. Thus, the car itself will have a life span of 10 years, the actual average service life of the car will be shorter once you take into account the interim retirements that occur due to the replacing each of the components.

Q. In this example, how would witness Pous estimate the interim retirements that a car would experience?

A. Using witness Pous's method of adjusting for interim retirements, one would estimate the percentage of the car's cost that would be retired each year and adjust the average service life based on this estimate.

Q. Does this method accurately estimate interim activity?

A. No. His method would not produce an accurate method for the life of the car; nor does it for production plant accounts. As car owners know from their own experience, a method that forecasts the same amount of retirements in each year does not accurately reflect of how car repairs are spread out over the life of a car. Reality dictates that there will likely be few retirements in the early years of the car's life, but as the car and its components age, the level of

retirements increase. So, while in the first few years only minor items will need to be replaced, as the car gets older the owner will have to replace the tires, the brakes and possibly even major items such as the transmission. These items are all more expensive, so it is clear that retirements will increase in the later stages of the life of the car. The pattern of retirements throughout the life of the car is referred to as the "dispersion pattern."

Q. Does witness Pous's proposal account for a dispersion pattern reflecting the fact that interim retirements tend to increase as property gets older?

A. No.

Q. Does your interim survivor curve method take into account this sort of retirement dispersion?

A. Yes, it does. Instead of assuming a constant level of interim retirements, one should use the Company's method and estimate these interim retirements with a survivor curve that better mirrors actual interim retirement experience taking into account the dispersion pattern. This is exactly what I have done in the depreciation study.

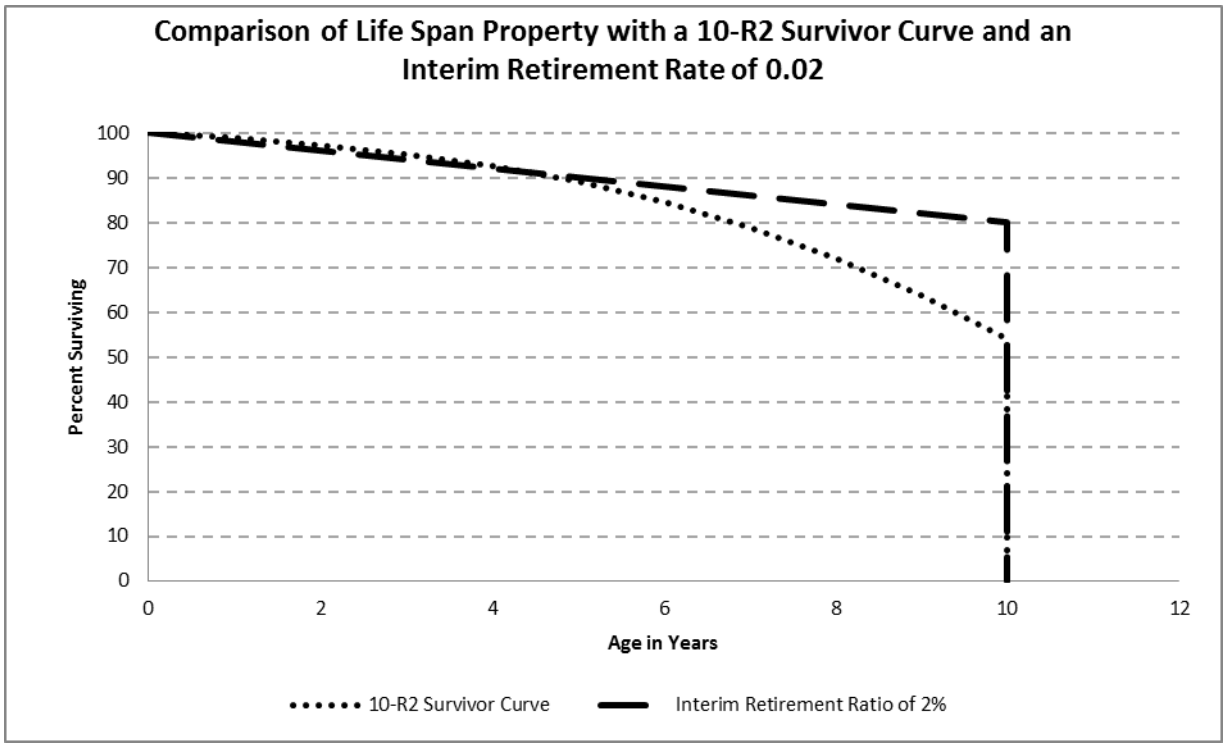
Q. Can you use the example of a car to help explain the difference between the two methods and your criticism of witness Pous's method?

A. Figure 2 below, graphically shows the results of using these two methods. The dashed line illustrates witness Pous's method assuming an interim retirement rate of 0.02, which means that 2% of the original cost of the car will be retired each year. The dotted line illustrates the company's method using a 10-R2 survivor curve. As the graph illustrates, witness Pous's method

results in a constant level of retirements for each year until the final retirement at age 10. As discussed earlier, this is not an accurate estimate of actual replacement expenditures throughout the life of the car. Instead, the 10-R2 curve is a better reflection of actual interim retirements. There are very few retirements in the early years but retirements increase as more expensive parts need to be replaced.

The average service life for each estimate is the area under the curve. As expected, in each case the average service life is less than 10 years. However, each method leads to different results. The average service life using witness Pous's method is 9 years, but using the Company's method and a 10-R2 survivor curve results in a more accurate average service life of 8.5 years. For FPL's property the impact of witness Pous's proposal is even more pronounced. As I will discuss in the next section, his recommendations understate interim retirements by more than $100 million per year.

Figure 2



As discussed previously, witness Pous's method fails to account for an increase in retirements as the property ages (e.g., brakes on a car). Thus, the average service life resulting from his method is too long, as it assumes that the level of interim retirements for the final 5 years of the life of the car will be the same as for the first five. This is of course an unreasonable assumption. Witness Pous's estimates in this proceeding apply the same unreasonable assumption to FPL's power plants.

Q. Are there other issues with witness Pous's proposed method for interim retirements?

A. Yes. Witness Pous has not explained or provided calculations supporting how the theoretical reserve is calculated using his method. He also did not do so in

Docket No. 090130-EI. As FPL witness Clarke explained in that case, witness Pous incorrectly excluded his estimated interim retirement rates from his theoretical reserve calculations.[35] Witness Pous has not rectified this issue in the instant proceeding, as he has not even bothered to calculate the theoretical reserve for production plant. He further declined to explain how the theoretical reserve is calculated when using his method in discovery.[36]

Q. Please address witness Pous's criticism regarding what he calls the "level of change in life spans between studies."[37]

A. This concept actually supports the opposite conclusion of the one witness Pous makes. Namely, an increase in life spans supports that my method is more appropriate than witness Pous's. Consider again the car example. If a car were to remain in service for 20 years instead of 10 years, then it would require much more significant investments. Indeed, even the engine and other major components may need to be replaced. Thus, this concept is more supportive of using interim survivor curves than witness Pous's method, because interim survivor curves recognize dispersion. The same is true of power plants. To operate plant longer, more components will need to be replaced, which favors my method as being more appropriate. Witness Pous instead doubles down on his erroneous assumption – significantly increasing the life for capital spare parts while proposing an even longer life span for combined cycle plants.

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[35] See the direct testimony of C. Richard Clarke in Docket No. 090130-EI, page 73, lines 5 through 9.
[36] See OPC's response to FPL's First Set of Interrogatories, No. 4.
[37] Direct testimony of Jacob Pous, page 58, lines 5 through 6.

Q. Please address witness Pous's concern regarding "the change in historical data between studies."[38]

A. Witness Pous references plant balances for capital spare parts and argues that we have presented changes in historical data therefore, without historical consistency, the study is flawed. His testimony is an attempt to get the Commission to discount the improved analysis in the instant case on the basis that if it is different, it must be wrong. In an effort to be sure we delivered as much insight as possible into the capital spare parts recommendation, FPL and Gannet Fleming spent considerable time investigating and analyzing the historical data for capital spare parts to better distinguish the capital spares assets from those that should be in the balance of plant. As a result, this study refines the historical data for capital spare parts. I should note that witness Pous also makes a similar generalization with regard to changes to interim survivor curves between studies. Again, he has no argument on the merits – he rejects the study simply because it has changed.

It is important in each depreciation study to update the results with current information. I have done so with the data for capital spare parts and with interim retirements in general. In stark contrast is the recommendation of witness Pous in this case, which is to simply ignore the data from the past 7 years and continue to use the stale results from the Company's previous study.

[38] Direct testimony of Jacob Pous, page 58, lines 17 through18.

Q. What is your conclusion in regards to estimates of interim retirements for production plant?

A. The interim survivor curve estimates I have proposed in the 2016 Depreciation Study are based on widely accepted methods for life span property. This methodology is supported by authoritative depreciation texts and has been accepted by jurisdictions across the United States and Canada. In contrast, witness Pous has proposed a methodology that is merely an approximation of the use of Iowa curves for interim survivor curves, and he has not even updated his estimates based on current data. His proposals are less accurate, fail to incorporate any informed judgment, produce unusual results, and are based on unrealistic assumptions for this type of property. As a result, his estimates should be rejected by the Commission.

In the next section, I will address the most significant issue related to OPC's proposal for interim retirements, which is OPC witness Pous's proposal for capital spare parts.

B. INTERIM RETIREMENTS FOR CAPITAL SPARE PARTS

Q. What is a "capital spare part" for the Company's combined cycle fleet of power plants?

A. As I explain on page 34 of my direct testimony, the term "capital spare part" is used to describe types of assets associated with the combustion turbines of combined cycle plants that typically have a shorter life than the overall

facility. Capital spare parts include assets such as turbine blades, rotor blades and transition nozzles that are removed from the plant and either refurbished or retired at regular intervals.

Q. Please explain further the life cycle of these types of assets.

A. Combined cycle plants are highly efficient machines that require regular maintenance and capital expenditures in order to operate reliably and efficiently. The manufacturers of these types of plants recommend regular outage intervals at which the plants are serviced. During these outages, many assets are replaced. At the time of replacement, FPL retires the asset and records salvage that is associated with either refurbishing or scrapping the asset.

Q. How often do these outage intervals occur?

A. The outage intervals for combined cycle plants are specified to occur based on the number of operating hours and the number of starts for the plant (i.e., the number of times the plant is turned off and turned back on). For example, in Docket No. 160088-EI, FPL witness Kennedy has provided the combustion turbine outage schedules for FPL plants using Mitsubishi technology. As can be seen in Exhibit RRK-1 of witness Kennedy's rebuttal testimony in Docket No. 160088-EI, inspections and outages are typically scheduled to occur at the following intervals:

- 12,000 hours – combustor inspection
- 24,000 hours – turbine inspection
- 48,000 hours – major inspection

Similarly, other equipment manufacturers, along with FPL equipment fleet teams, have service hour based recommendations. At each of these intervals, various capital spare parts are inspected and replaced as needed, and many replacements of components typically occur for the turbine inspection and major inspection. Because a typical combined cycle plant operates for around 8,000 hours per year, it is therefore normal and to be expected that there will be the retirements of many capital spare parts after about 3 years and more retirements after about 6 years (i.e., for a major inspection and for a hot gas path inspection).

Q. Does the Company's historical data support that retirements of capital spare parts occur at these ages?

A. Yes. The Company has a large fleet of modern combined cycles and has data that extends back as far as 1993 for its current fleet of combined cycle plants. These data were used for the statistical analyses for the depreciation study, and demonstrate exactly what one would expect based on the operating characteristics described above. Figure 3 below graphs the percentage of capital spare parts that have historically survived to a given age. For example, the graph shows approximately 70% surviving at age 3.5. This means that approximately 30% of capital spare parts have historically retired by this age. Again, this is consistent with what should be expected given the operation of these units, as the turbine inspection occurs at 24,000 operating hours. Figure 3 further shows that there have been many retirements of these assets in the three to 6-year range, just as would be expected based on the operation of

these units. Figure 4, which follows Figure 3, shows that the 6.5-L0 survivor curve represents a very good fit of the representative data points for capital spare parts.

Figure 3: Historical Data for Capital Spare Parts

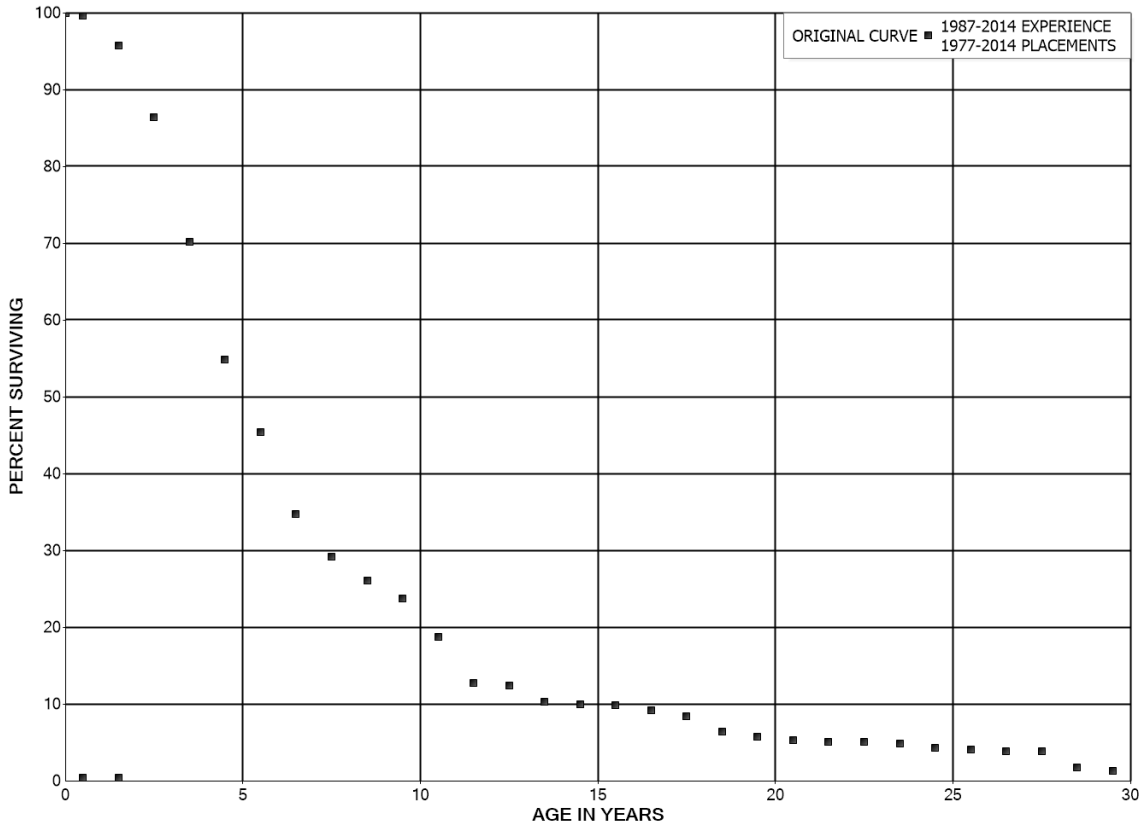
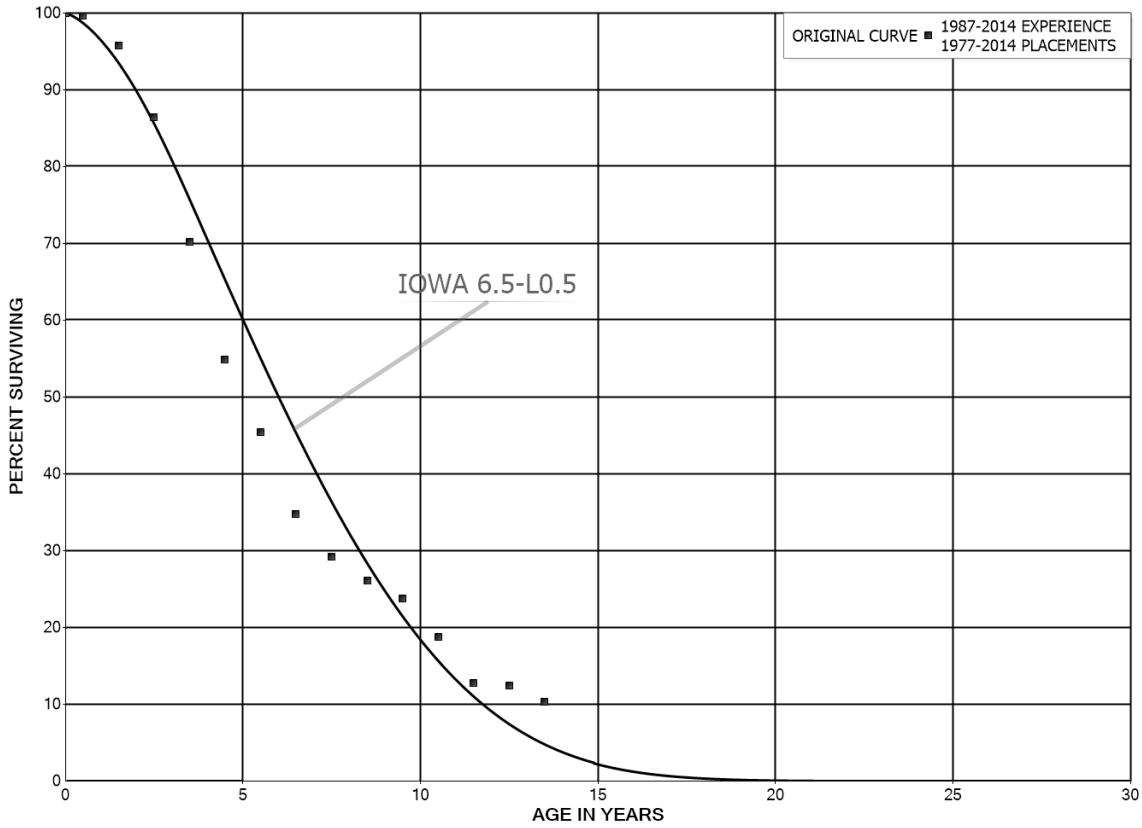


Figure 4: Historical Best Fitting Survivor Curve for Capital Spare Parts

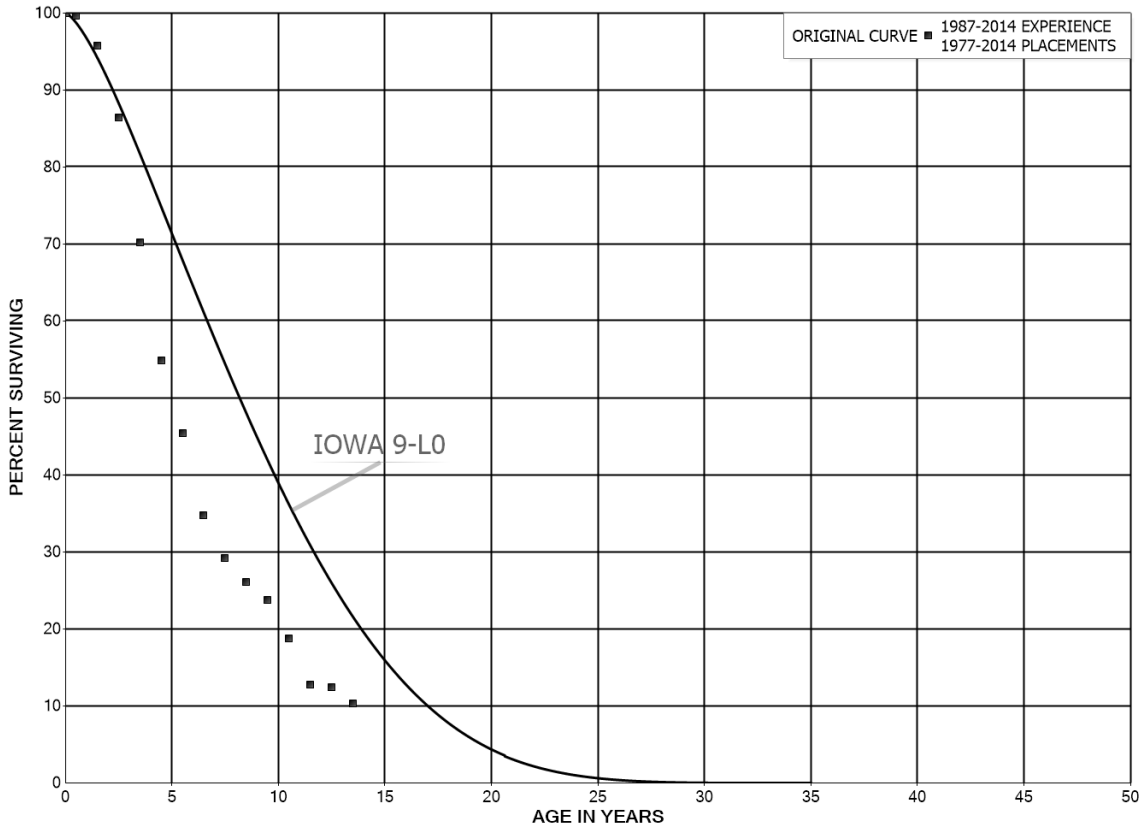


Q. In light of this historical data, did you estimate a 6.5-year average service life for capital spare parts?

A. No. For my estimates, I incorporated other factors than just the statistical analysis, and in particular have incorporated the operations and outlook for capital spare parts. As discussed on pages 693 and 694 of Exhibit NWA-1, based both on upgrades FPL has made to more robust capital spare parts and on the expected operating hours for FPL's combined cycle fleet, I have recommended to increase the average service life by about 30% compared to

what the Company has historically experienced.[39] The 9-L0 survivor curve I have estimated is shown below. As the chart illustrates, my estimate is for a longer service life than FPL has actually experienced historically.

Figure 5: 2016 Depreciation Study Estimate for Capital Spare Parts



[39] See the discussion of the estimate for capital spare parts on pages 693 and 694 of Exhibit NWA-1. I have also provided workpapers supporting this estimate in confidential Attachment 4 provided in FPL's response to OPC's First Request for Production of Documents No. 38.

Q. You have explained the support and reasons for the 9-L0 survivor curve, and have demonstrated that the Company's actual experience supports a relatively short life for capital spare parts. Have previous depreciation studies recognized a shorter life for capital spare parts?

A. Yes. In the 2009 Depreciation Study, FPL proposed a 5-year average service life for capital spare parts. In that case, the Commission Staff performed their own analysis and the Commission adopted Staff's 0.1565 interim retirement rate, which corresponds to an average service life of about 3.2 years. The currently approved depreciation rates therefore incorporate a shorter life for capital spare parts.

In the 2005 Depreciation Study, FPL had proposed average service lives for each account for each generating unit that were based on estimates for each component of the plant. In that study, the lives for capital spare parts were also much shorter than the overall life of the plant. For example, transition nozzles were estimated to have a 5-year life and turbine blades were estimated to have a 7 or 8-year life.[40] The estimates from the 2005 Study for production plant were adopted by the Commission in a settlement. Thus, shorter lives for capital spare parts for combined cycle plants have been approved and used since at least 2005.

[40] See for example pages 3 and 4 of 12 of Schedule V for Martin Combined Cycle – CC Unit 3 of Volume 5 of the 2005 Depreciation Study.

Q. Both witness Pous and witness Kollen allege that your proposal for a separate subaccount for capital spare parts "increases" depreciation expense. Please address this claim.

A. This claim is completely false and neither witness Kollen nor Pous offer any evidence or calculations to support their claim. By contrast, Figure 1 in Section II demonstrates that my estimates for capital spare parts significantly decrease depreciation expense by approximately $450 million. It should also be noted that the currently approved estimates are based on witness Pous's interim retirement rate methodology, and thus the use of my more appropriate interim survivor curves actually results in a significant decrease compared to estimates based on witness Pous's preferred methodology.

Q. What have OPC and SFHHA proposed for capital spare parts?

A. Both have proposed to use the estimates from the other assets in Account 343 for capital spare parts. That is, both propose that the Commission inappropriately ignore data demonstrating more than $2 billion of historical capital spare parts retirements and instead apply estimates derived from an entirely different set of assets with much longer lives.

Q. You have demonstrated that witness Pous and witness Kollen's allegations are false. What would be the consequence of adopting their recommendations?

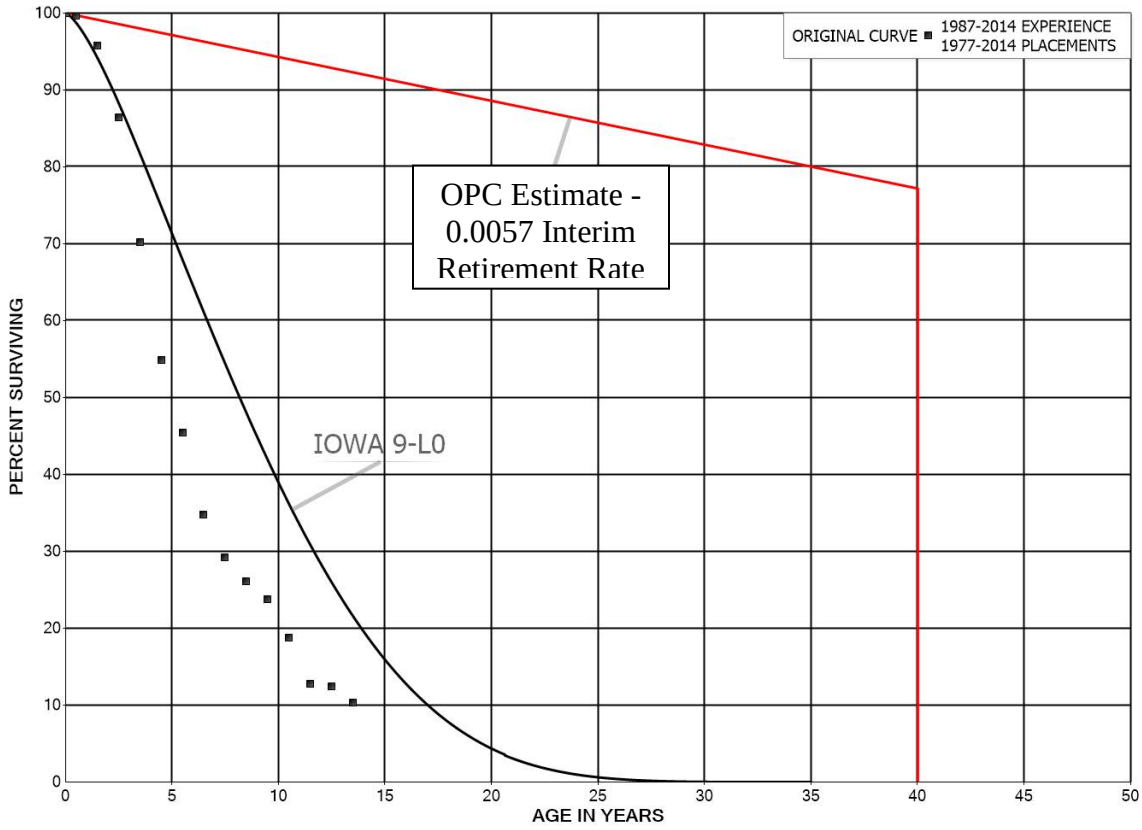
A. The result of both witness Pous and witness Kollen's recommendations for capital spare parts is to artificially reduce depreciation expense to a level far below what is actually supported by the historical data. As a result, the costs

of capital spare parts will not be recovered over their service lives. Instead, customers will have to pay for these assets after they are retired.

Q. To further illustrate the results of their proposals, please provide a comparison of OPC or SFHHA's estimate for capital spare parts to the Company's actual experience.

A. Figure 6 below compares my estimate and that of witness Pous (who has estimated that FPL will retire 0.57% of its capital spare parts per year) to FPL's actual experience. The figure demonstrates quite clearly that witness Pous's estimate is completely divorced from the reality of FPL's actual operations. The curve labeled as "OPC Estimate" is radically different from the Company's actual data, which is shown as the black squares in the chart. This provides convincing evidence that witness Pous's recommendation is not at all consistent with FPL's actual experience operating combined cycle power plants.

Figure 6: Comparison of FPL and OPC Estimates to Historical Data for Capital Spare Parts



Q. Is there any other evidence that OPC's estimate is inappropriate?

A. Yes. One way to test the reasonableness of an estimate is to compare the retirements that would be predicted by the estimate to the Company's actual experience. For example, for the 7 years of data available since the 2009 Depreciation Study (i.e., from 2008-2014) the Company has made approximately $1.3 billion in retirements for capital spare parts. This is actual, historical evidence of the level of retirements that typically occurs for this account.

Q. What would witness Pous's estimate predict for this time period?

A. Again, witness Pous's estimate is a 0.0057 interim retirement rate, which predicts that 0.57% of the account will retire each year. If this rate is applied to the 2014 balance for combined cycle capital spare parts of $1.8 billion, then the resulting prediction based on witness Pous's estimate would be that the Company would retire around $10.4 million per year. Thus, witness Pous's estimate would have predicted that the Company would have only retired about $73 million of capital spare parts over the most recent 7 years,[41] which is only about 5.5% of the Company's actual experienced retirements of $1.3 billion. Witness Pous's prediction was therefore off by a factor of 18.[42]

Q. Would you please respond to specific criticisms of your estimate for capital spare parts on pages 56 and 57 of witness Pous's testimony?

A. Yes. Witness Pous's criticisms only serve to demonstrate that he does not understand the Company's operations. First, he states, "[a] more realistic view of the information would recognize the dramatic changes in the dollar level of exposures from age 0 and age 7, and the dramatic levels of retirements between ages 0.5 and 5.5."[43] I have already explained that the levels of retirements are appropriate and consistent with an understanding of the Company's capital spare parts. The level of exposures (effectively the balance of investment that has historically been in service at a given age)

[41] This calculation is actually quite generous to witness Pous. The Company had fewer combined cycle plants in 2008 and therefore witness Pous's estimate would have actually projected fewer retirements for the 2008-2014 timeframe.
[42] $1.3 billion divided by $73 million is 17.8.
[43] Direct testimony of Jacob Pous, page 56, lines 17 through 19.

makes perfect sense as well. The Company added the West County, Riviera Beach and Cape Canaveral combined cycle plants in the six most recent years for which the historical data were available (i.e., from 2009 to 2014). Because all of these plants have reached age zero, but none have reached age 7, and because capital spare parts should be expected to experience a number of retirements between age 0 and age 7, it should be expected that the dollar level of exposures will drop considerably from age 0 to age 7.

Witness Pous also states that "given the fact that FPL's depreciation studies are separated by a 7-year period (2007-2014), an experienced depreciation analyst would recognize the statistical instability of the historical results and not rely on such relationships of being predictive of the future without significant and meaningful support."[44] Witness Pous does not explain what he means by the "statistical instability of the historical results," but his desire to disbelieve the historical data does not render it inaccurate. Indeed, the statistical analysis for capital spare parts has been fairly stable from study to study. In the 2009 Depreciation Study the statistical indications were for a 5-year average service life and in the current study the statistical indications are for a 6.5-year average service life – both are similar. Further, I analyzed numerous experience and placement bands, and each resulted in similar statistical indications. I should also note that witness Pous's discussion of $140 million that retires within a year of being purchased also does not

[44] Direct testimony of Jacob Pous, page 56, lines 19-23.

provide a reason to doubt the historical data. The $140 million he cites is for retirements that occur between 0.5 years and 1.5 years. This should not be considered abnormal. It is both a relatively small amount when compared to the over $3 billion in exposures for this age and is also consistent with the 12,000 hour combustor inspection, which would occur at about one and a half years of age. Further, as demonstrated above, the full account has experienced an average life of about 6.5 years, and therefore capital spare parts assets are not expense items (which would be in service for less than a year).

Finally, witness Pous notes my comments regarding the upgrade of components to newer, more robust capital spare parts. I have already explained in detail, and supported, that the result of these upgrades should be a service life about 30% longer than what the Company has historically experienced. Witness Pous's estimate is for capital spare parts to have a service life that is about 1,250% longer[45] than the Company has actually experienced. This is clearly unreasonable, especially because witness Pous has provided no analysis or support for such a large deviation from the Company's actual experience.

[45] Witness Pous's estimate of a 0.0057 interim retirement rate corresponds to an average service life of capital spare parts of approximately 87.7 years. This is 13.5 times (or 1,250% longer than) the experienced average service life of 6.5 years.

Q. What has witness Kollen proposed?

A. Witness Kollen has proposed to use the remaining life calculated for Account 343 Prime Movers – General and apply this remaining life to Account 343.2 Prime Movers – Capital Spare Parts. This is incorrect on a number of levels. First, just as witness Pous does, witness Kollen completely ignores the historical data specific to capital spare parts, and instead uses the estimates for a completely different set of assets. Second, he does not even calculate the remaining life for capital spare parts based on these (incorrect) estimates. He instead uses the remaining lives calculated for a completely different set of assets.

Q. Would you please address witness Kollen's criticisms of your capital spare parts recommendations?

A. Yes. Witness Kollen first states, "the shorter lives of certain components are already addressed in the average service lives and retirement survivor curves reflected in the present depreciation rates."[46] While this may be true of many of the existing depreciation rates,[47] it is most certainly not true of witness Kollen's estimates. His proposal therefore does not meet this criterion. Witness Kollen then states that "the interim net salvage is already addressed in the net salvage rates reflected in the present depreciation rates."[48] This is also incorrect, as the existing depreciation rates do not include a separate interim net salvage estimate for capital spare parts.

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[46] Direct testimony of Lane Kollen, page 25, lines 18 through 20.
[47] The currently approved depreciation rates for West County, Cape Canaveral, Riviera, and Port Everglades do not include estimates for capital spare parts.
[48] Direct testimony of Lane Kollen, page 25, lines 20 through 21.

Witness Kollen then states that "the depreciation study fails to properly separate the historical data between the two new subaccounts. Instead, it assumes that the historic interim retirements and net salvage that have applied generally will continue to apply to account 343 *General*, which is incorrect, and assumes that a different and more aggressive interim retirement curve and different net salvage apply for account 343.2 *Capital Spare Parts*, which is also incorrect due to the Company's accounting for Capital Spare Parts, which overstates both parameters."[49] Witness Kollen is completely incorrect in his assessment. I have separated both the historical life analysis and the historical net salvage analysis data into the two separate subaccounts and have studied both subaccounts separately based on the Company's actual experience for each subaccount. This can be seen quite clearly in the statistical life analysis for the two accounts presented on pages 183 through 188 of Exhibit NWA-1 and in the statistical net salvage analysis presented on pages 327 through 331 of Exhibit NWA-1. The two subaccounts correctly have different survivor curve and net salvage estimates because they have historically experienced and will continue to experience different survivor curve and different net salvage characteristics. Further, as I have explained in detail, my estimate for capital spare parts reflects that future service lives will be longer than the Company has historically experienced. This estimate is certainly not "aggressive," and in fact, the opposite is true.

[49] Direct testimony of Lane Kollen, pages 25 through 26.

Q. What do you conclude regarding witness Pous and Kollen's proposals for depreciating capital spare parts?

A. The proposals by both OPC and SFHHA are perhaps the most inappropriate recommendation either party makes. One cannot simply ignore over $2 billion in historical activity in order to artificially reduce depreciation expense – which is exactly what both witness Pous and witness Kollen have done. In contrast, my estimates for capital spare parts are most appropriate for these assets, and take into consideration both the historical experience and the outlook for capital spare parts.

Further, as I have demonstrated in this testimony, in my direct testimony, and in the 2016 Depreciation Study, capital spare parts have significantly different service lives than the other assets in Account 343. For this reason, it is most appropriate to create a separate subaccount for capital spare parts.

C. INTERIM NET SALVAGE

Q. Witnesses Pous and Kollen have both proposed to change interim retirement estimates for certain accounts. Have they correctly adjusted the net salvage estimates for production plants to incorporate these changes to interim retirements?

A. No. I have explained that their estimates of interim retirements are inappropriate. However, even if one were to accept their flawed estimates both have made errors in their calculations. Neither witness has adjusted the

net salvage for production plant to account for their interim retirement estimates.

Q. Please explain this error.

A. As I have discussed on page 44 of Exhibit NWA-1, the net salvage included for production plant in the depreciation study is only for interim retirements and not final retirements.[50] Thus, the net salvage percentages in the depreciation study for production plant accounts must be adjusted so as to apply only to interim retirements. For example, if the net salvage estimate for interim retirements is negative 10%, and 20% of the assets in the account are estimated to be retired as interim retirements, then the net salvage estimate that should be used in the depreciation calculations to be applied to the entire account is negative 2% (negative 10% multiplied by 20%). If instead 50% of the assets are estimated to be retired as interim retirements, then the net salvage used for the depreciation calculations will be different – namely, negative 5% and not negative 2%.

Q. Do either witness Pous or witness Kollen recognize this fact?

A. No. Neither makes the appropriate adjustment in their recommendations. This is most egregious as it relates to capital spare parts.

Q. How does this concept relate to capital spare parts?

A. By ignoring this concept, both have significantly - and erroneously - reduced depreciation expense. The Company experiences positive salvage for capital

[50] I should note that because dismantlement for FPL is handled through a different recovery mechanism, there is no final net salvage for FPL's production plants. For studies in which dismantlement is included in depreciation rates, then the final net salvage estimate must also be included in this calculation.

parts. When the parts are removed from the plant they are either refurbished or scrapped, and in either case the Company records gross salvage. The estimate in the study for interim retirements is positive 35%. Neither witness Pous nor witness Kollen disputes this estimate in their testimony.

Because the positive 35% estimate applies only to interim retirements, it must be adjusted in order to develop a net salvage percentage that applies to the entire plant balance. I have done so in the 2016 Depreciation Study, and my calculations are presented on page 302 of Exhibit NWA-1.

Q. Has either witness Pous or witness Kollen adjusted the interim net salvage estimates so as to only apply to interim retirements?

A. No. Instead they have inappropriately continued to apply the 35% net salvage estimate to the entire capital spare parts subaccount despite the fact that they both estimate that only a fraction of the balance of capital spare parts will be retired as interim retirements. For example, based on witness Pous's estimate of interim retirements for capital spare parts he forecasts that approximately 19% of the account will be retired as interim retirements. The 35% interim net salvage estimate should therefore only be applied to 19% of the account, and witness Pous should have adjusted his net salvage estimate to 7% to be used for his depreciation calculations. As can be seen quite clearly on Exhibit JP-1, he fails to do so.

Q. What is the result of this error?

A. The result of this significant oversight is an artificial reduction in depreciation expense of $21 million. Thus, witness Pous compounds his inappropriate decision to ignore over a billion dollars in interim retirements by failing to properly consider the impact on net salvage. Witness Kollen makes a similar mistake.

D. ALLOCATION OF ACCUMULATED DEPRECIATION FOR A NEW CAPITAL SPARE PARTS SUBACCOUNT

Q. Please explain the allocation of accumulated depreciation for new subaccounts.

A. Because FPL has not historically had a subaccount for capital spare parts, it has maintained accumulated depreciation (also referred to as the "book reserve") at the account level for Account 343. For the recommended new capital spare parts subaccount, there is therefore the need to allocate the book reserve between capital spare parts and non-capital spare parts. The standard method in the industry for doing so is to use the theoretical reserve for each subaccount to allocate the book reserve. I have used this approach for both capital spare parts and for the separation of distribution poles into wood and concrete subaccounts.

Q. What has SFHHA proposed?

A. SFHHA witness Kollen has proposed to use the plant balance instead of theoretical reserve. This is an inappropriate method because it fails to

recognize that accumulated depreciation is a function of age. That is, a brand new asset will have less accumulated depreciation than a 20-year old asset, all else equal, regardless of its plant balance.

Q. Do authoritative depreciation texts support that the theoretical reserve is an appropriate method of allocating the book reserve?

A. Yes. Page 188 of the NARUC Manual states:

> Theoretical reserve studies also have been conducted for the purpose of allocating an existing reserve among operating units or accounts.

Q. Please explain why witness Kollen's approach is incorrect.

A. The main issue with witness Kollen's approach is that it does not take into consideration the age of the assets when allocating the reserve. Because the reserve is a function of age, this must be considered when allocating the book reserve.

This issue with witness Kollen's approach can easily be explained with a simple example. Consider an account that has two units, each with an original cost of $100. Both units have a 20-year life. One unit is 10 years old and the other is brand new (i.e., 0 years old). The accumulated depreciation for the account is $50. Using witness Kollen's method, the book reserve would be allocated equally to the two units, because each represents one half of the plant balance for the account. This would of course be incorrect – the brand new asset should have a reserve balance of $0 because it is brand new and

therefore has experienced no depreciation. The 10-year old asset should have a reserve balance of $50.

Q. Would using the theoretical reserve correct this approach?

A. Yes. Using the same example, the theoretical reserve for the brand new asset is $0, and the theoretical reserve for the 10-year old asset is $50. Thus, an allocation in proportion to the theoretical reserve would correct the issue with witness Kollen's approach.

Q. Witness Kollen states that your method of allocation results "results in an excessive allocation of the depreciation reserve to subaccount 343, which has a longer service life, and an inadequate allocation to subaccount 343.2, which has a shorter service life."[51] Please address this claim.

A. First, I should be clear that any implication by witness Kollen that there was an attempt to increase depreciation expense based on an allocation methodology is simply incorrect. As explained above, I have used the industry standard method of allocating the book reserve to subaccounts. Second, I have explained that witness Kollen's proposed alternative is fundamentally incorrect and inappropriate. Finally, if anything my method actually results in allocating too much of the depreciation reserve to Account 343.2. If one were to retrospectively construct the book reserve for each account by applying historical depreciation rates to the respective subaccount plant balances, then the result would be a lower book reserve for capital spare parts than the result of my methodology.

[51] Direct testimony of Lane Kollen, page 27, lines 9-11.

For example, for West County Unit 1 the book reserve is a negative amount for Account 343.[52] This is due to retirements of capital spare parts, not retirements for the other types of assets in the account. Thus, a retrospective method of allocating the book reserve would assign a negative book reserve to capital spare parts and a positive book reserve to the rest of Account 343. The book reserve would therefore be lower for capital spare parts than occurred based on my allocation method, which would increase depreciation expense because the life of capital spare parts is shorter than for the other assets in the account. As a result, my method actually produces lower depreciation expense than the alternative.

E. OKEECHOBEE DEPRECIATION RATES

Q. What has FPL recommended for the Okeechobee combined cycle plant?

A. As discussed on page 11 of FPL witness Ferguson's direct testimony, FPL proposes to use the depreciation rates for the Port Everglades combined cycle plant as a proxy for the depreciation rates for Okeechobee. This represents a 3.66% composite depreciation rate using the depreciation rates calculated as of December 31, 2016 that have been provided in FPL's Second Notice of Identified Adjustments. By using Port Everglades as a proxy, the depreciation rates for Okeechobee properly incorporate estimates of interim retirements and interim net salvage.

[52] See page 62 of Exhibit NWA-1.

Q. What has SFHHA proposed?

A. SFHHA witness Kollen has proposed to assume that the Okeechobee plant will experience no interim retirements and has simply recommended a 2.50% depreciation rate based on the 40-year life span for combined cycle facilities.

Q. Witness Kollen states that "the Okeechobee depreciation rate should reflect a service life of 40 years."[53] Do FPL's recommended depreciation rates for Okeechobee reflect a service life of 40 years?

A. FPL's recommended depreciation rates reflect a life span of 40 years. They also correctly reflect the impact of interim retirements, which means that the overall average service life for all assets at the plant will be less than 40 years.

Q. Will Okeechobee experience interim retirements?

A. Yes. As has been the case with all of FPL's combined cycle plants, various components of the Okeechobee plant will need to be replaced in order to operate the plant reliably and efficiently. In order to determine equitable and fair depreciation rates, estimates of interim retirements therefore must be incorporated into the depreciation rates for Okeechobee.

Q. What would be the consequence of not including interim retirements in the depreciation rates for Okeechobee as witness Kollen has proposed?

A. The result would be that assets retired as interim retirements would not be recovered over their service life. This would be particularly true for capital spare parts.

[53] Direct testimony of Lane Kollen, page 66, lines 16-17.

VI. MASS PROPERTY SERVICE LIFE ESTIMATES

A. INTRODUCTION

Q. What is mass property?

A. The term "mass property" refers to accounts such as poles or substation equipment for which assets are continually added and replaced. Mass property contrasts with life span property, which as I explained in Section IV is property for which all assets at a facility will be retired concurrently. The Company's transmission, distribution and general plant accounts are mass property accounts.

Q. How are service lives estimated for mass property?

A. A mass property account is typically a group of assets for which there will be a range of service lives. For example, some poles will retire at early ages (for example, if hit by a car) and some will survive for much longer. The range of lives for a group of assets is referred to as the "dispersion" of lives or dispersion of retirements. Service lives are estimated for mass property accounts using established survivor curves, which provide an estimate of both an average service life and a dispersion of lives around the average. This concept is discussed in more detail in Part II of Exhibit NWA-1.

Q. In general, how do your estimated average service lives compare to the current, Commission-approved estimates?

A. For mass property accounts, I have proposed to increase the average service lives for 21 accounts, retain the currently approved average service life for 11

accounts, and to reduce the average service life for 1 account. Because all else equal a longer average service life results in lower depreciation expense, my service life estimates result in a decrease in depreciation expense when compared to the Commission approved estimates.

Q. Please summarize the survivor curve estimates proposed by each party in the case.

A. Table 1 below provides a summary of the currently approved, FPL proposed, OPC proposed and FEA proposed survivor curves for each account for which OPC or FEA has recommended a different estimate than my estimate. The table shows the average service life as well as the Iowa survivor curve type. For example, a 40-R1 survivor curve has a 40-year average service life and a dispersion pattern consistent with the R1 survivor curve type.

Table 1: Comparison of Approved, FPL, OPC and FEA Survivor Curve Estimates for Mass Property Accounts

Account		Approved	FPL	OPC	FEA
350.2	Easements	75-S4	75-S4	100-R4	75-S4
353	Station Equipment	40-R1.5	40-R1	44-L1	40-R1
353.1	Station Equipment – Step-Up Transformers	35-R2	30-R1	38-R1	30-R1
354	Towers and Fixtures	52-R5	60-R4	70-R4	60-R4
355	Poles and Fixtures	44-R2	50-R2	55-S0	50-R2
356	Overhead Conductors and Devices	47-R1.5	51-R1	55-S0	51-R1
362	Station Equipment	43-R1.5	45-R1.5	48-S0.5	51-S0.5
364.1	Poles, Towers and Fixtures - Wood	39-R2	40-R2	44-R2.5	40-R2
364.2	Poles, Towers and Fixtures - Concrete	39-R2	50-R1.5	56-S0	50-R1.5
365	Overhead Conductors and Devices	41-S0	48-R1	53-R1	57-R1
367.6	Underground Conductors and Devices – Duct System	38-S0	42-S0	46-L0.5	42-S0
367.7	Underground Conductors and Devices – Direct Buried	35-R2	35-R2	45-L1	35-R2
369.1	Services – Overhead	48-R1	53-R1	53-R1	56-R1.5
373	Street Lighting and Signal Systems	30-R0.5	35-O1	39-L0	35-O1
392.3	Heavy Trucks	12-S3	12-S3	13-S3	12-S3

As can be seen in the table, for the 15 accounts that have been challenged by an intervenor witness, I have increased the average service lives for ten (when compared to the currently approved estimates). For four of the accounts challenged I have recommended to keep the average service life unchanged. For one account (Account 353.01), I have decreased the average service life consistent with the Company's experience and outlook for that account. The overall result has been to reduce depreciation expense for these accounts, as a result of the increases in average service life.

Q. What have OPC and FEA proposed?

A. For each adjustment they have made, they have recommended to increase the average service life when compared to both the approved estimate and to my estimate.

Q. You have discussed the changes in average service lives. Have you also changed the survivor curve types?

A. For some accounts I have, and for others I have retained the existing Iowa curve types. In general most of my changes in curve types have been relatively minor (e.g., a R1.5 to R1).

Q. Have OPC or FEA changed curve types from the Commission approved estimates?

A. Yes. OPC in particular proposes significant changes in curve types for many accounts. Indeed, it is the change in curve type that is the primary reason for witness Pous's proposed increase in average service lives for many accounts. As I will explain, for many accounts he has used curve types that are not typically used for the assets in these accounts. The curve types he has selected, such as L-type curves, are not common for most types of mass property accounts because they indicate dispersion patterns that are not a good reflection mortality characteristics of the property studied. As a result of these changes in curve types, witness Pous has artificially increased the average service lives for many accounts.

Q. How will you address the mass property service life estimates from each party?

A. I will first explain the process for the statistical life analysis – that is, for fitting survivor curves to the Company's data. This will include a general discussion of the process, a discussion of the issues with witness Pous's approach to curve fitting, a discussion of the problems with the types of curves witness Pous has selected for many accounts, and issues related to the selection of bands. I will then explain the life estimation portion of determining service lives and how the statistical analysis is combined with other information to determine the proper service life.

Finally, for each account for which OPC or FEA has proposed a different service life estimate I will provide an explanation as to why FPL's proposed estimates are most reasonable and most appropriate. This discussion is provided as Exhibit NWA-3 to my rebuttal testimony.

B. STATISTICAL LIFE ANALYSIS

i. Introduction

Q. Please explain the process for the statistical life analysis.

A. All parties in this proceeding agree with the use of a statistical analysis based on aged retirements known as the retirement rate method for assets in the transmission, distribution, and general classes of plant. I have described this method on pages 16 through 25 of my direct testimony and in Part II of

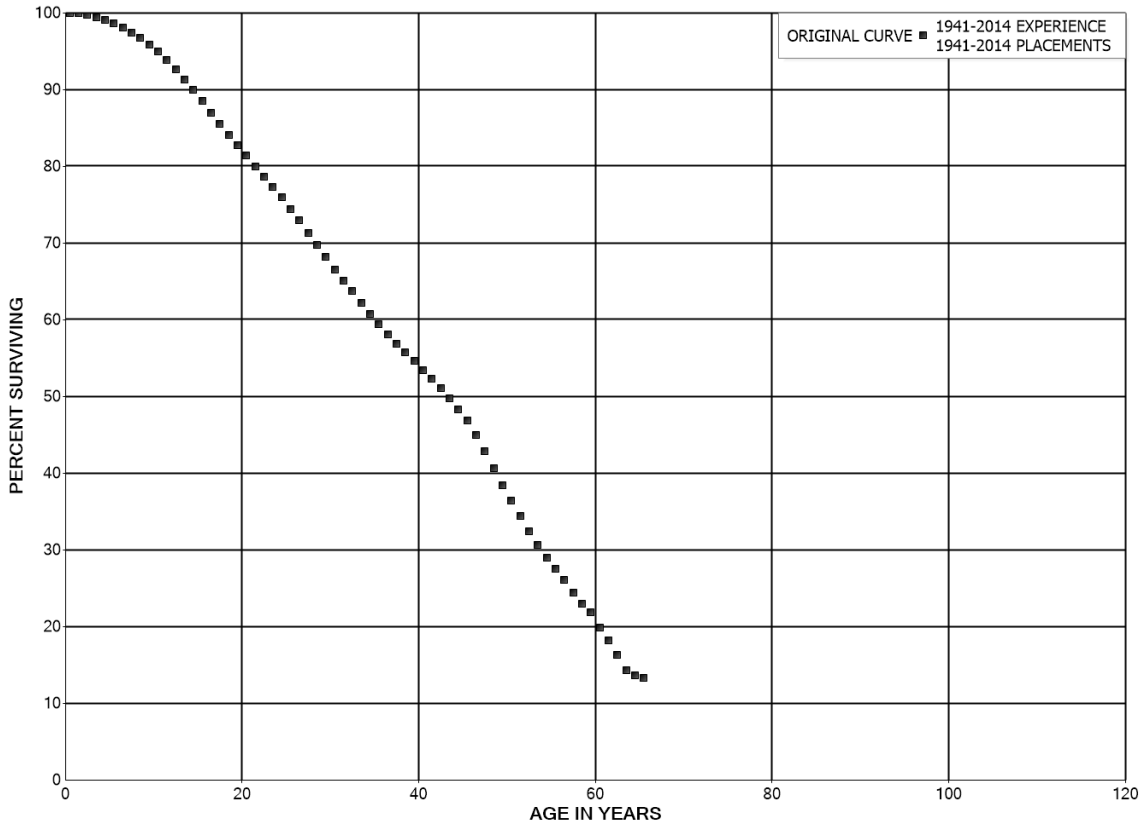
Exhibit NWA-1. When using the retirement rate method, original life tables are developed from the Company's historical accounting data. The original life tables provide an indication of the percentage of assets that have historically survived to each age for which data is available.

Q. Please provide an example of this analysis for an FPL account.

A. As an example, I will use Account 367.6 Underground Conductors and Devices – Duct System. The original life table for the overall experience band for this account can be found on pages 254 and 255 of Exhibit NWA-1. The table develops the percentage of installations that have historically survived to each age (the age is shown in the left-most column of the table and the percent surviving is shown in the right-most column).

I have presented all of the data points from the original life table for this account in Figure 7 below. The graph shows the percentage of assets that have historically survived to each age. The percent surviving from the life table is shown on the Y-Axis and the age is shown on the X-Axis. For example, the chart shows that the original life table indicates that about half of the assets have historically survived to about age 40, and that by age 60 only about 20% have survived.

Figure 7: Historical Data for Account 367.6 Underground Conductors and Devices - Duct System



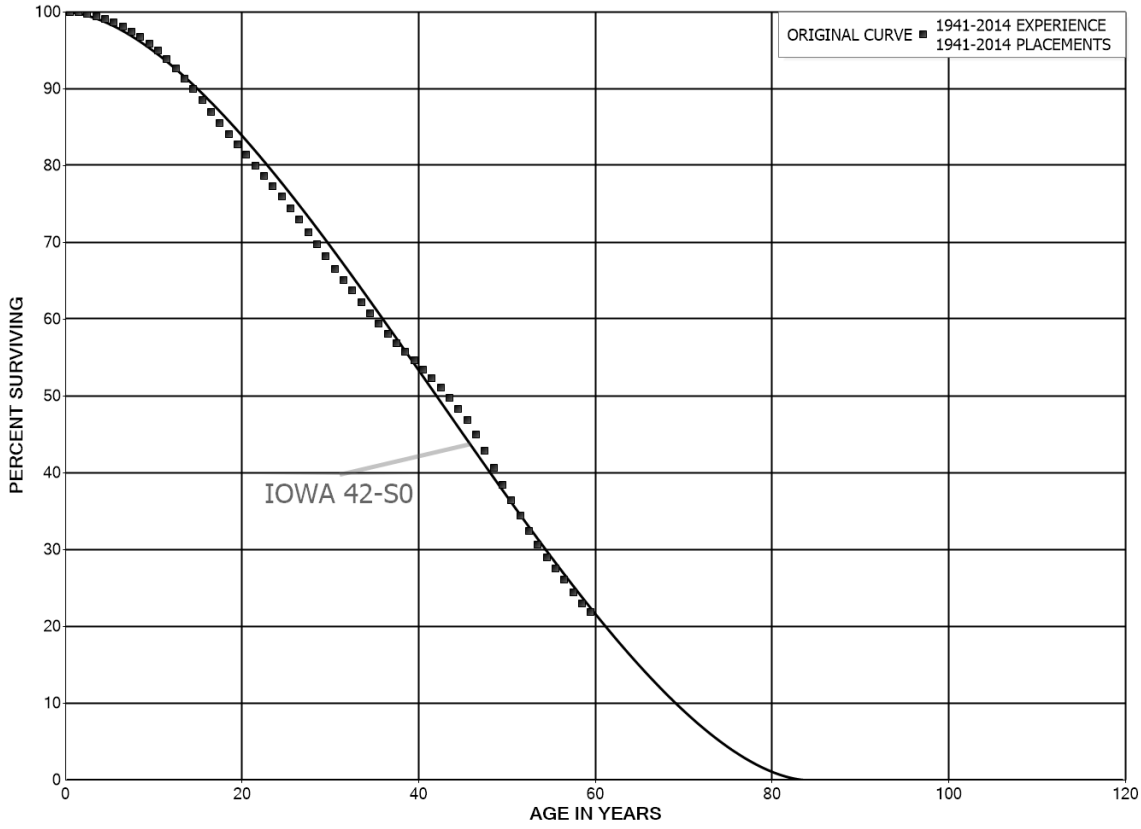
Q. How are original life tables used to forecast service lives?

A. Iowa survivor curves can be fit to the original life tables developed from the Company's actual experience. Iowa survivor curves provide a complete indication of the percentage of assets forecast to survive to each age, and average service lives and remaining lives can be derived from a given Iowa curve in order to calculate depreciation expense.

Curve fitting or curve matching of Iowa curves to an original life table can be performed either visually or mathematically. Figure 8 below provides a

comparison of the 42-S0 survivor curve to the original data.[54] The 42-S0 survivor curve is the estimate I have recommended in the 2016 Depreciation Study, and the chart below is the same as presented on page 253 of Exhibit NWA-1.

Figure 8: Comparison of FPL Estimate and Historical Data for Account 367.6 Underground Conductors and Devices - Duct System



Q. What is "visual curve matching"?

A. For visual curve matching, smooth survivor curves (normally Iowa survivor curves) are charted on the same graph as the original curve. By graphing the

[54] For reasons I will explain, I have not shown every data point in the original life table for Figure 8.

curves on the same graph, one can visually make a determination as to how close of a match the smooth curve is to the original curve.

Q. What is "mathematical curve matching"?

A. When performing mathematical curve matching, the difference between the smooth survivor curve and the original survivor curve is compared mathematically. This matching is typically performed using computer software. For mathematical curve matching I have used a measure of fit called the "residual measure."[55] A lower residual measure indicates a better mathematical fit of the data (and a residual measure of 0.00 would indicate that every data point perfectly matches the fitted Iowa curve).

Q. Is the 42-S0 survivor curve a good match to the historical data?

A. Yes. As can be seen in Figure 8 above, the line shown for the 42-S0 survivor curve is close to the original life table for each age. It is therefore a good visual fit of the data. It is also an excellent mathematical fit of the data, and has a residual measure of 0.71.

Q. In Figure 8, you have not plotted all of the data points from the original life table. Please explain.

A. The data points in an original life table are not all based on the same level of historical activity. For example, as can be seen on pages 254 and 255 of Exhibit NWA-1, for this account the level of investment that has been in

[55] The residual measure is based on the sum of squared difference between the original and smooth curve, which is a widely accepted statistical technique. The residual measure I have used normalizes the sum of squared differences for the number of data points included in the fitting process, and is equal to the square root of the total sum of the squares of differences between points on the original and smooth curves divided by the number of data points.

service for each age (referred to as "Exposures" and shown in the second column of the original life table) varies from over $1 billion to less than $10,000. The different data points therefore have different statistical significance and should not be given the same consideration in the curve fitting process. In part due to this reason,[56] some data points therefore should be emphasized less than others and some should be excluded entirely. Figure 8 only includes data points based on $1 million or more in exposures. For the types of assets in this account – underground conductors and related devices - $1 million of assets represents fairly large number of assets and is a significant enough level of exposures to be included in the analysis for this account.

Q. For both visual and mathematical curve matching, can the selection of data points impact the results of the analysis?

A. Yes, it can. It is important to determine which data points from the original survivor curve should be included in the analysis, and which should be emphasized more than others. Depending on the data points included, the curve fitting process can yield different results. As I explain in the next section, for many accounts witness Pous has excluded too many data points, which has resulted in inappropriate survivor curves.

[56] There are other factors to consider as well, such as trends in the data and the level of retirements.

ii. OPC Witness Pous's Curve Fitting Approach Is Inappropriate

Q. Witness Pous claims that your estimates are often "not the best fitting results for the actuarial analyses, even when the final proposal established in the life estimation phase of the study is based on actuarial results."[57] Is this true?

A. No. Witness Pous's assertion is the result of the fact that he has continued to use an inappropriate approach to curve fitting, in which he excludes important information from both the Company's historical data and from the actual curves he has selected. He makes this claim despite the fact that in FPL's previous depreciation study the Commission confirmed that my approach to curve fitting is more appropriate.

Q. Has witness Pous explained his approach to curve fitting in this proceeding?

A. No. However, a review of his presentation in his testimony makes clear that he continues to inappropriately use the same approach that he used in FPL's previous depreciation case.

Q. Please explain.

A. In Docket No. 090130-EI witness Pous stated that he emphasized the earlier data points in the analysis and excluded many later – but relevant ages. For example, witness Pous stated that "matching the 'head' of the observed life table is more important than matching the 'tail.'"[58] Further, from a review of the presentations of survivor curves in his testimony in both Docket No.

[57] Direct testimony of Jacob Pous, page 64, lines 11-13.
[58] Docket No. 090130-EI, direct testimony of Jacob Pous, page 99, lines 21-23.

090130-EI and in this case, it is clear that witness Pous ignored far more than just the "tail" of the survivor curve and instead has excluded important information about the survivor curve for each account.

Q. Did the Commission adopt witness Pous's approach to curve matching?

A. No. The Commission correctly adopted Gannett Fleming and FPL's approach, stating:

> The disagreement on curve fitting between FPL and OPC only serves to emphasize the need for judgment. Based on the evidence, we believe that FPL's method of curve estimation, as described in the record, is appropriate because it relied on visual and mathematical curve fitting, as well as classic depreciation theory.[59]

Q. Have you used the same general approach as adopted by the Commission in Docket No. 090130-EI?

A. Yes.

Q. Has witness Pous?

A. No. Witness Pous continues to use the same approach he used in Docket No. 090130-EI.

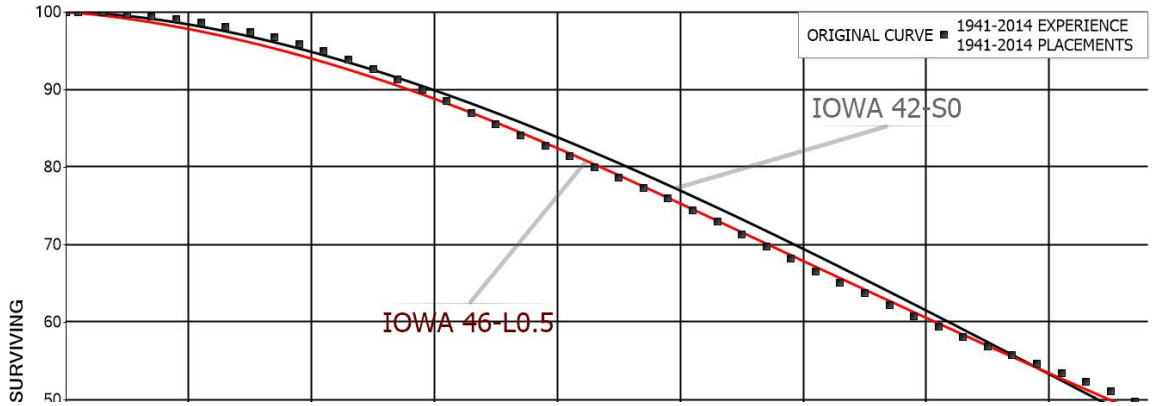
Q. Please explain the consequences of witness Pous continuing to use an inappropriate approach to curve matching.

A. A good example is Account 367.6, which I have discussed above. Witness Pous makes the statement that "[f]rom a purely mechanical life analysis standpoint, my recommendation of a 46L0.5 life-curve combination is a

[59] Order No. PSC-10-0153-FOF-EI, page 60.

similar but superior fit to the meaningful portion of the actuarially derived OLT than is witness Allis' proposal."[60] Witness Pous then presents a graph similar to what I show in Figure 9 below.

Figure 9: OPC's Presentation of Survivor Curves for Account 367.6 Underground Conductors and Devices - Duct System



When one compares this graph to Figure 8, it is quite clear that witness Pous's presentation excludes a significant amount of information. The last data point shown in Figure 9 above is for age 43.5 (each of the vertical lines in the graph represents 5 years of age). Witness Pous therefore shows no ages beyond age 44 and no percent surviving values below age 50%. As I will explain, this is a misleading presentation that obscures two important details – 1) that his estimate is an inferior fit to the data than mine; and 2) that his estimate projects unrealistic lives for many assets that are directly contradicted by the Company's actual experience.

[60] Direct testimony of Jacob Pous, page 119, line 22 to page 120 line 1.

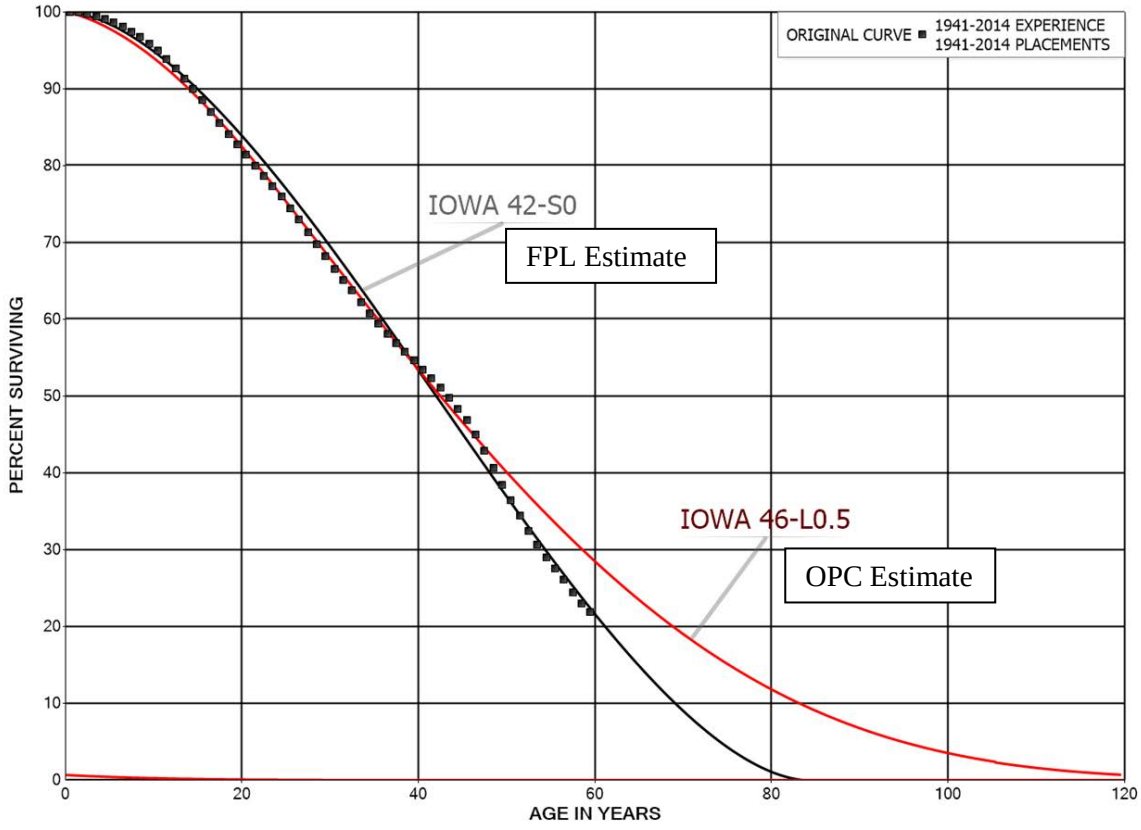
Q. Why do you say that witness Pous's presentation is misleading?

A. Witness Pous's presentation is misleading because it excludes relevant data points from the historical data. It also fails to show the actual difference between my estimate and his. By obscuring this information, he hides the fact that his estimate results in unrealistically long lives for many of the assets in this account.

Q. Please provide a better comparison of your estimate and that of witness Pous with the Company's historical data.

A. A better comparison is presented in Figure 10 below.

Figure 10: Comparison of FPL and OPC Estimates to Historical Data for Account 367.6 Underground Conductors and Devices - Duct System



Q. How do FPL's and OPC's estimates compare in Figure 10?

A. There are two main observations to make from a comparison of these estimates. First, witness Pous's estimate is an inferior fit of the data shown in Figure 10 when compared to mine. This is particularly true for data points from approximately age 50 through age 60, which fall between about 40% and 20% surviving. As I will explain, classic depreciation theory supports that these are important data points that should not be excluded from the statistical analysis for this account. Witness Pous has hidden this difference in his presentation in his testimony.

The second observation is related to the difference between the two Iowa curves (the curves labeled IOWA 42-S0, which is my estimate, and IOWA 46-L0.5, which is witness Pous's estimate). As can be seen in the graph, the two curves are very similar through about age 44 (i.e., the ages witness Pous actually shows in his graph). However, the curves begin to deviate significantly after age 44. Specifically, witness Pous's curve remains elevated above my estimate for all remaining ages and eventually extends beyond 120 years of age.

Both of these observations are hidden by witness Pous's presentation in his testimony. Yet both are critical to properly interpreting the data and selecting the best survivor curve.

Q. Your first observation is that your estimate is a much better fit than witness Pous's for ages 50 to 60. Should witness Pous have excluded these data points?

A. No. As I noted above, these data points are based on at least $1 million in exposures, and therefore are based on data that is statistically robust enough to be included in the life analysis. Just as important, because these data points range from about 40% to 20% surviving they fall within the most representative portion of the survivor curve. Witness Pous therefore should not have excluded these data points

Q. Please explain.

A. As the Commission recognized in Docket No. 090130-EI, the portion of the curve from 80% to 20% surviving is most representative of the survivor characteristics for a life table. That is, contrary to witness Pous's assertion in previous cases, the academic literature on survivor curves indicates that the most representative portion of the survivor curve is the middle portion of the curve, generally the portion between 80% and 20% surviving. This is because the middle portion of the curve is where the majority of retirements occur. There are relatively few retirements at the "head" of the curve, and relatively few at the "tail."

In the development of survivor curves in Bulletin 125 of the Iowa Engineering Experiment Station, Robley Winfrey (who developed the Iowa Survivor curves) provides analysis showing that when performing curve fitting, the

emphasis should be placed not on the first 20% of the curve or the last 20%, but rather on the information in the middle years. Mr. Winfrey's analysis is based on the probable error involved in fitting a smooth survivor curve to an observed life table with varying percentages surviving. He concludes:

> When survivor curves are to be classified according to the 18 types and the probable average life to be determined, it is recommended that more weight be given to the middle portion of the survivor curve, say that between 80 and 20 percent surviving, than to the forepart or extreme lower end of the curve. This inner section is the result of greater numbers of retirements and also it covers the period of most likely the normal operation of the property.[61]

Q. Please address your second observation, regarding the difference between the two survivor curves shown in Figure 10.

A. As noted above, the primary difference between my 42-S0 survivor curve estimate and witness Pous's 46-L0.5 survivor curve estimate is that witness Pous's survivor curve projects a much lower rate of retirements beyond age 50. This can be seen by the fact that his estimate declines to 0% surviving at a much slower rate than my estimate. He also projects that many assets will have much longer lives.

[61] Bulletin 125, Iowa Engineering Experiment Station, Winfrey, Robley, 1935, page 91.

Q. Does the data support this projection made by witness Pous?

A. No. The data shown in Figure 10 only extends to about 60 years of age. The portion of the survivor curve beyond this age is therefore an extrapolation of the data, as both witness Pous and I have not considered the data beyond age 60 to be meaningful. That is, the significant decline in the rate of retirements projected by witness Pous is not based on actual data. I should also note that witness Pous is actually extrapolating a larger portion of the curve than I have done, since he excludes data beyond about age 44.

Q. Is the portion of the curve extrapolated by witness Pous reasonable?

A. No. As can be seen in Figure 10, for the last data point on the graph (age 59.5) the percent surviving is approximately 20%. Thus, FPL's actual data indicates that approximately 80% of the account retires by age 60. My estimate extrapolates a trend in which retirements continue at a similar rate to what has actually occurred based on FPL's data. In contrast, witness Pous has extrapolated a completely different pattern of retirements. His estimate extrapolates that some of the remaining assets will be in service for 120 years or more, as his curve extends beyond 120 years of age. This is not a reasonable projection as FPL's actual data indicates that most of the assets in this account will retire by age 60. Further, there is no experience in the data of assets lasting longer than 73 years. Yet witness Pous projects that some of the remaining assets will live for 120 years.

Q. Can you explain further why witness Pous's estimate is unrealistic?

A. For this account, as with many accounts, witness Pous has selected L type survivor curves. L type curves are not common for most types of utility property, and for good reason. L type curves have "long tails," such as can be seen in Figure 10. This means that a portion of the assets live much longer than the average service life – for lower mode L curves, some assets will survive more than three times the average service life. Very few types of transmission and distribution plant have this characteristic.

This is not a reasonable expectation for the assets in this account, in particular for assets in Florida. As underground conductor ages, the cable will deteriorate and corrode over time. This is particularly true for FPL, as salt water and a high water table will impact these types of cable more so than in other drier climates. For this reason, the expectation should be that retirements will tend to increase with age. Witness Pous has projected the opposite. As Figure 10 shows, his 46-L0.5 survivor curve results in a significant slowing in retirements for older ages.

Q. What can you conclude about witness Pous's curve fitting approach?

A. As I have demonstrated in this section, witness Pous's approach is inappropriate and is not consistent with the Commission's order in Docket No. 090130-EI. Further, witness Pous has for this account selected an unusual and unrealistic Iowa survivor curve that only serves to artificially extend the average service life and reduce depreciation expense. As I will explain in the

next section, witness Pous has taken a similar approach for many other accounts, changing the curve type to unusual and unrealistic L type curves. Thus, even when his estimate and mine are similar fits to the data, his estimate is not appropriate for the assets studied.

iii. OPC Witness Pous Has Artificially Extended Service Lives by Selecting Uncommon Curve Types

Q. In the previous section, you explained how witness Pous artificially increased the service life by selecting a low mode L type curve. Has he made similar adjustments for other accounts?

A. Yes. A review of witness Pous's estimate for Account 367.6 shown in Figure 10 above illustrates how his changes are due at least in part to a change in the type of survivor curve. The same is true for other accounts. For example, he has changed to L type curves for four accounts and to an S0 type curve for three accounts. In each of these instances witness Pous has changed the curve types from those last approved by the Commission as well as from what I have proposed.

Q. Are these changes in curve types appropriate?

A. No. This is especially true because, as I will explain in the account specific discussion in Exhibit NWA-3, for these accounts a more common and realistic curve type usually represents a similar or better fit of the historical data.

Q. Why are witness Pous's selected curve types are unrealistic for FPL's property?

A. The reason is that for many types of assets, the level of retirements should be expected to increase with age. For example, as many types of assets age they tend to corrode or deteriorate, which leads to an increasing probability of retirement due to failure or proactive replacement. R type curves exhibit this type of retirement pattern, as do higher mode S type curves. Lower mode S type curves tend to have a fairly constant level of retirement. L type curves project a decreasing level of retirements as assets get older.

For most types of assets, R type curves or S type curves are far more realistic than L type curves based on the forces of retirement that act upon the assets. I would expect this to particularly be the case in Florida, which as I have explained has a harsh environment for many types of assets due to factors such as heat, humidity and salt in the air.

Q. Are the curve types that witness Pous recommends for these accounts consistent with curve types typically made for other utilities?

A. No. This is a point that witness Pous has acknowledged in his testimony.[62] As further support for this concept, the industry database witness Pous has relied on (which is based on estimates made by Gannett Fleming for other electric utilities) confirms that the curve types I have selected are generally much more common than the curve types he has used.

[62] For example, on page 122 of his testimony witness Pous acknowledges that the L0.5 curve he has selected for Account 367.6 is "not common."

Q. How do the curve types that witness Pous has recommended for these accounts compare to those you have recommended?

A. For accounts in which witness Pous has recommended L type curves, R and S type curves are typically more common. Additionally, for the accounts in which he has changed the curve type from an R type curve to a low mode S type curves, R type curves are more common.

Q. What is the result of these changes in curve types made by witness Pous?

A. The result is similar to the example I provided in the previous section for Account 367.6. By changing the curve type, witness Pous is extending the portion of the curve extrapolated beyond the Company's data. That is, he is projecting a longer "tail" to the survivor curve. Because both the average service life and the average remaining life are calculated as the area under the survivor curve, the result of changing the curve type is that witness Pous projects artificially long service lives and lower depreciation expense. It also has the result of artificially creating a larger theoretical reserve imbalance.

Q. What can you conclude regarding the curve types witness Pous has selected?

A. It is important as part of the judgment process of estimating service lives to consider the assets studied and the forces of retirements acting upon these assets. Proper consideration of these factors means that an R type curve is often the better estimate than a low mode S type curve or L type curve – even if they are similar fits of the historical data. As I have explained, in many cases witness Pous has selected unrealistic and unusual curve types for the

assets studied. This provides another reason why his estimates are not reasonable for these accounts.

iv. Selection of Bands

Q. Please explain the term "band" as it is used for life analysis.

A. The term band generally refers to the range of years of historical data that are included when developing an original life table. The term "experience band" refers to the range of transaction years for data included in an original life table. The term "placement band" refers to the range of vintage years included in an original life table.

Q. How does the selection of bands impact the life analysis process?

A. Typically for a depreciation study multiple bands will be analyzed and considered for each account. For example, for most accounts I have analyzed the "overall band," meaning a band with all years of data available, as well as more recent experience and placement bands (e.g., the most recent 20 or 30-year bands). The overall band incorporates the largest sample size because it incorporates all of the data available. It also typically incorporates the period of time closest to the life cycle of the assets studied. More recent bands can help to identify trends that may have changed over time, and if analyzed carefully they can provide insight about changes to the mortality characteristics of the property studied. However, they are also based on a smaller sample size and a shorter time period – often only a fraction of the average service life and a smaller fraction of the full life cycle of the property

studied. For this reason shorter bands can overemphasize trends and overreact to short term, but non-recurring activity.

Q. Is there a difference between your approach and those of the intervenors?

A. Yes, at least for some accounts. For the three accounts for which FEA witness Andrews proposes adjustments, he has relied on the most recent 20-year experience band. Witness Pous likewise has also relied on or significantly emphasized more recent bands for some of his recommendations.

Q. Both have criticized you for failing to recognize trends towards longer service lives.[63] Are their criticisms valid?

A. No. As noted previously, I have increased the average service lives for ten of the fifteen accounts challenged by either witness Andrews or witness Pous. These include the accounts for which either witness Andrews or witness Pous claim I have not recognized trends. Thus, I have indeed recognized trends towards longer service lives. What I have not done is overemphasize short term changes that can be the result of the natural variability in annual activity.

Q. Do you agree with witness Andrews and witness Pous's approach to rely on more recent bands?

A. No. Both have relied on bands that contain too short a period of experience to be relied on for the final survivor curve estimate. For example, witness Andrews relies on a 20-year experience band, with activity that has occurred from 1995 through 2014. Twenty years is, in my judgment, too short a period of time to rely on when a longer historical record is available. The accounts

[63] See for example page 105, lines 19-21 of the direct testimony of Jacob Pous and page 13, lines 20-21 of the direct testimony of Brian Andrews.

for which witness Andrews has proposed an adjustment to the recommended service life have average service lives of 40 or more years, which means that a portion of the accounts will remain in service for 70 or 80 years, if not longer. A 20-year period therefore is only a fraction of this overall life cycle, and as a result is not statistically robust enough of a period of time to be relied on for the final estimate. Further, a more recent band only observes a portion of the life cycle of different ranges of vintages. That is, for each vintage of property the retirements experienced in a 20-year band only range for 20 years. A 20-year band therefore does not include a full life cycle – or even close to a full life cycle – of any vintage.

Q. Are there any reasons to expect that using only the most recent 20 years of activity may not be appropriate for FPL?

A. Yes. In real-world utility operations the level of capital spending (and therefore the level of retirements) for a single group of assets can vary over time, increasing in some years and decreasing in others. This is the result of changing capital budget cycles (e.g., the Company may focus capital dollars on new power plants for some years and then target transmission or distribution lines in other years), as well as external factors such as the overall state of the economy. As noted above, witness Andrews, and to a lesser extent witness Pous, have both relied on the most recent 20-year experience band, which includes transactions recorded from 1995 through 2014. However, this period of time includes unusual events that are unlikely to

reoccur – at least with the same frequency as has happened in the last 20 years.

One is the recession in the late 2000s. While recessions will occur periodically over the full life cycle of utility property, it is unlikely that there will be many recurrences of a recession as severe as the recent "Great Recession." Florida was especially hard hit by this recession. Another occurrence that may not be recurring was in the late 1990s. As the Company's data shows, there was a pronounced decline in both additions and retirements for many accounts.

Q. What is the impact of these events on the most recent 20-year experience band?

A. An event such as the Great Recession is unlikely to occur again with much frequency, and at a minimum will be less frequent than in the last 20 years. By relying on a 20-year band, witness Andrews and witness Pous have given undue consideration to an event such as this.

Q. Please provide an example to demonstrate the impact on the most recent 20-year experience band?

A. As a part of the depreciation study, it is common to review the historical levels of additions and retirements. In my workpapers, I have provided a review of this information.[64] For many of FPL's accounts, there is a drop in the overall level of both additions and retirements in the mid to late 1990s.

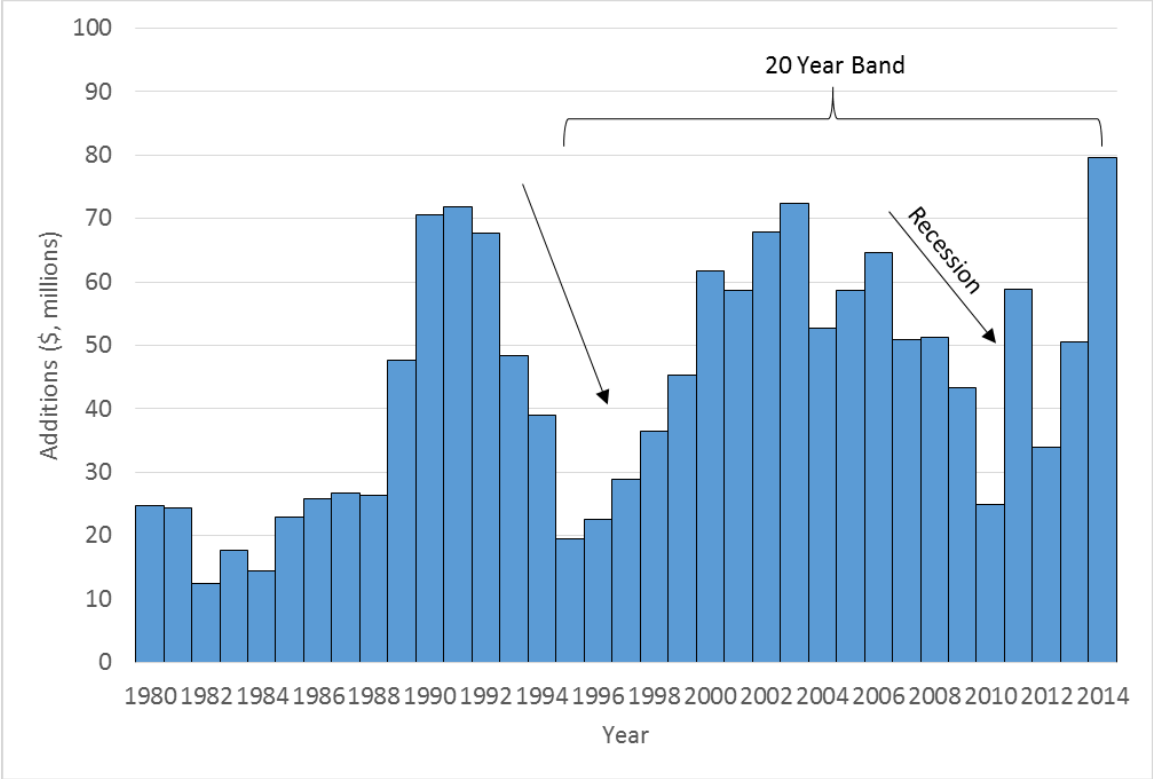
[64] See the response to OPC's First Request for Production of Documents No. 2.

Similarly, in the late 2000s there is also a drop in both types of activity, corresponding with the Great Recession.

Figure 11 below provides a graph of annual additions for Account 362 Station Equipment. This is one of the accounts for which witness Andrews relies on a 20-year experience band, ranging from 1995 through 2014. One item to note from this figure is that activity varies over time. This is consistent with my comments above regarding capital spending cycles.

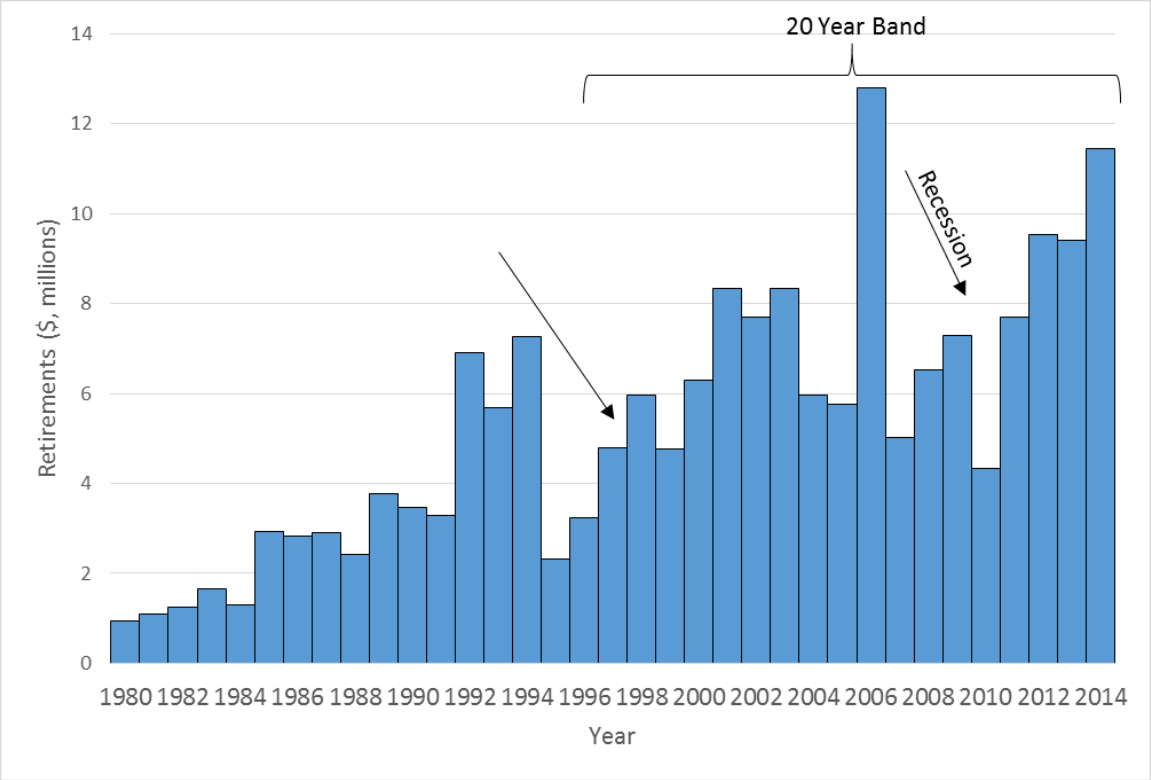
Additionally, as the figure illustrates, there is a noticeable decline in additions in both the mid-1990s and in the late 2000s. The figure also shows the range of years included in the most recent 20-year experience bands. This shows that the most recent 20-year band, which includes data from 1995 through 2014, includes two periods that have lower levels of activity. This confirms my statement above that the most recent 20-year band over-emphasizes what are likely to be unusual events.

Figure 11: Annual Additions for Account 362 Station Equipment



A similar pattern of activity can be seen in the retirements for this account, which are presented in Figure 12 below.

Figure 12: Annual Retirements for Account 362 Station Equipment



Q. Do other accounts exhibit a similar pattern?

A. Yes. For each of the accounts for which witness Andrews has recommended an adjustment to the service life there is a similar pattern of additions and retirements.

Q. Do you have any other comments regarding the selection of bands?

A. Yes. The overall approach to the selection of bands should be applied consistently. That is, one should not select shorter bands only when they increase the average service life, but not use shorter bands when they would support a shorter service life. I have used a consistent approach. For the

reasons set forth above, I have generally relied on the overall band unless there are specific reasons to deviate from the longer range of experience.

OPC witness Pous, in contrast, appears to use shorter bands when they support a longer service life, but gives much less emphasis to shorter bands when they would support a shorter service life. For example, for Account 367.7, which contains direct buried underground conductors, more recent placement bands indicate a shorter service life than the overall band. Yet witness Pous has proposed to increase the average service life by 10 years for this account. Additionally, for Account 367.6, which contains underground conductors that are not direct buried, witness Pous proposes a longer service life than indicated by the data, which he justifies by arguing that newer cable will have a longer service life. Yet his expectation is not supported by the data – more recent placement bands indicate similar service lives as those indicated by the overall band.

Q. Witness Andrews cites two depreciation texts in support of his decision to rely on the most recent 20-year bands. Please address his discussion.

A. I should first note that one of the quotes, from NARUC, is more supportive of my approach than that of witness Andrews. The NARUC Manual states:

> In general, historical data used to forecast future retirements should not contain events that are either anomalous or unlikely to recur.[65]

[65] NARUC Manual, page 112.

As noted above, witness Andrews's approach gives too much emphasis to events such as the Great Recession and the decline of activity in the 1990s, which are not likely to recur (at least not with the same frequency as in the most recent 20-year experience band).

Additionally, a closer look at the passage cited by witness Andrews from Wolf and Fitch reveals that the authors' criticism of the overall band is more focused on placement bands, not experience bands. Although he has relied on a shorter experience band, Witness Andrews has relied on the overall placement band for each account. Specifically, the second portion of the section of Wolf and Fitch cited by witness Andrews reads:

> Each individual retirement ratio is based on a different group of property. The first retirement ratio will include observations from all vintages and the second retirement ratio from all but the most recent. This pattern continues until the final point is based on observations from only one vintage. It is difficult to figure out the exact meaning of the overall band, and, in spite of the fact it does include all the data points, it should be given limited significance.[66]

Thus, a more detailed reading of this passage reveals that the discussion of the overall band is related to vintages, not transaction years. I have explained

[66] Frank Wolf and Chester Fitch, *Depreciation Systems*, 1994, pages 186-187. (Emphasis added)

above why I believe the overall band is in fact appropriate to use for FPL. However, because placement bands, not experience bands, are associated with vintages, this passage from *Depreciation Systems* is in fact not supportive of witness Andrews's approach.

Q. Please explain.

A. Again, witness Andrews's approach is to use the overall placement band, but only a 20-year experience band. His approach therefore actually compounds the criticism of the overall band made in *Depreciation Systems*. Because the 20-year experience band only contains 20 years of history for each vintage, it incorporates only a fraction of the life cycle for each vintage – and incorporates the full history of no vintages except those installed within the past 20 years. As a result, the most recent 20-year experience band is even more "difficult to interpret" than the overall band, because it is effectively pieced together from relatively small portions of the experience for each vintage.

C. RELEVANT CONSIDERATIONS IN LIFE ESTIMATION

Q. Should the service life estimates be based only on the statistical analysis?

A. No. The process of estimating service life should also take into consideration other factors regarding the outlook of the Company's assets. These factors include specific information based on Company plans and the operation of the electric system, as well as general knowledge about the property studied. Both witness Pous and I agree with this concept. However, there are important differences in his approach. As I explain in the account specific

discussion provided in Exhibit NWA-3, his approach in this case is to typically focus only on factors that he argues will increase the service life, while giving little to no consideration to factors that would have the opposite effect. Additionally, many of the statements he makes in support of his proposals are in fact incorrect.

Q. Please provide an example as to how information external from the statistical analysis should be interpreted.

A. One example that witness Pous discusses for multiple accounts is the Company's pole inspection program, which has been in place for about a decade. For the pole inspection program, each pole on FPL's system is inspected and tested on a periodic basis. If a pole fails (e.g., has deteriorated to the point that it does not have adequate strength), one of two main options are available. If the deterioration is not too pronounced, then there may be options to treat the pole or add structural support to the pole and it will not need to be retired. However, if the deterioration is more significant, particularly for older poles, the pole will be retired.

Witness Pous's opinion is that the pole inspection program will simply increase the service lives of the Company's poles. This is a one-sided approach to interpreting the impact of the pole inspection program, as he emphasizes the portion of the program that has the effect of increasing the life of poles but de-emphasizes the portion that would have the effect of decreasing the life of poles.

Q. When both factors are considered, what do you expect to be the impact of the pole inspection program over time?

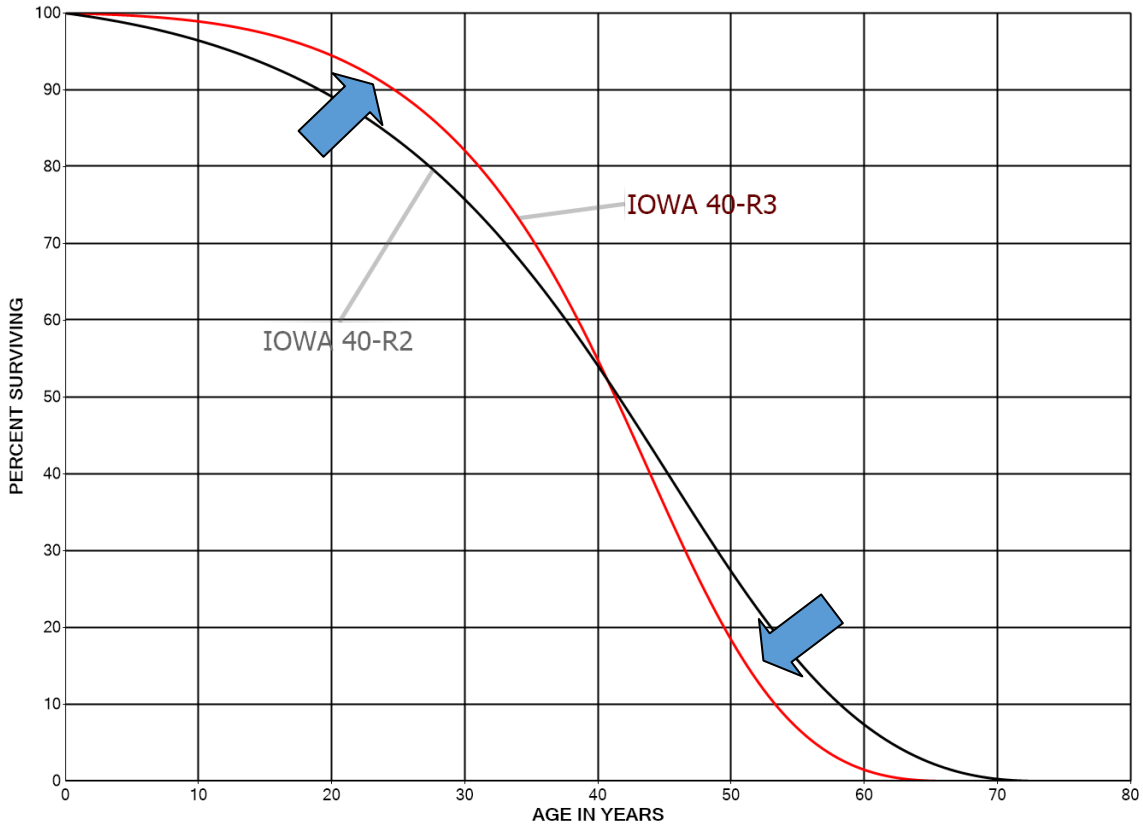
A. I expect that the pole inspection program will both reduce retirements at early ages while increasing retirements of assets at older ages compared to a situation in which the program did not exist. Prior to a pole inspection program, older deteriorated poles would typically not be retired until they failed because poles were not inspected on as regular of a basis. As a result, some poles may have remained in service for a long time. With the inspection program, these poles will be identified earlier and replaced proactively. This has obvious benefits for reliability, but does not necessarily result in an increase in life as witness Pous suggests. Instead, it will decrease the life for many poles. For these reasons, the actual impact of the pole inspection program may be that it will impact the mode of the curve more than the average service life.

Q. Please explain further what you mean by impacting the mode of the survivor curve?

A. The term "mode" is used to describe the general dispersion pattern of the survivor curve. Effectively, the mode describes the steepness of a survivor curve. For a curve with a lower mode, retirements are more spread out – fewer occur relatively close to the average service life. This produces a fairly flat survivor curve. For a higher mode curve, a higher percentage of retirements will occur relatively close to the average service life. This produces a steeper survivor curve.

As an example, two survivor curves are shown below, both with a 40-year average service life. The curve labeled 40-R2 has a lower mode than the curve labeled 40-R3. For the lower mode curve there are a higher rate of retirements earlier in the assets' lives (as can be seen by the 40-R2 being below the 40-R3 through about age 40), but a lower rate later in the assets' lives. Further, older assets remain in service a bit longer for the 40-R2 than the 40-R3, as the 40-R2 curve declines to 0% surviving at a later age.

Figure 13: Comparison of Higher Mode R3 Curve to Lower Mode R2 Curve with Average Service Life of 40 Years



Q. Please explain further how you expect the pole inspection to impact the mode of the survivor curve.

A. The two arrows shown in Figure 13 above show how the pole inspection program should be expected to impact the lives of FPL's poles. The top arrow illustrates the impact of factors such as pole treatment, which can have the effect of reducing the rate of retirements for earlier ages. The bottom arrow represents the impact of the inspection program on older assets. Older assets are more likely to be retired if they fail the inspection, both because older assets are more likely to be deteriorated and because it is less economical to repair an older pole that is close to the end of its useful life. Thus, the overall impact of the inspection program is likely to have the impact of increasing the mode of the survivor curve.

Q. Why do you emphasize here the impact on the mode of the curve?

A. For both transmission poles and concrete distribution poles, witness Pous has proposed the opposite of what one should expect for the result of the pole inspection program. His recommendation is to decrease the mode of the curve for both of these accounts. I note that he did increase the mode for wood distribution poles, but as I will explain in Exhibit NWA-3 he has improperly fit his curve to the historical data. A better fit actually produces a very similar average service life to my estimate (and a shorter remaining life).

Q. Does storm hardening also have an impact on the life of poles?

A. Yes. In addition to the fairly obvious fact that storm hardening (which is expected to continue for some time) increases the number of retirements of

poles, storm hardening will also interact with the pole inspection program to impact the life of poles. The result is that the bottom arrow on the graph – the impact of increased retirements of older assets – is likely to be more pronounced.

Q. Please explain.

A. As FPL constructs a stronger, more resilient system through its storm hardening program, one result is a lower tolerance for older, weaker poles. By this I mean that because the standard is now for a stronger pole than was the case prior to storm hardening, the result will be that older, weaker poles are more likely to be replaced now and in the future than was the case in the past. This factor will have the result of increasing the rate of retirements of older poles.

Q. Have you explained these concepts previously?

A. Yes. OPC asked discovery questions regarding the impact of both storm hardening and pole inspections on the service lives of poles. I have explained these concepts in the responses to these interrogatories.[67]

D. ACCOUNT SPECIFIC

Q. Do you also have specific responses to the estimates made by witness Pous and witness Andrews?

A. Yes. Exhibit NWA-3 provides a discussion of each account for which either OPC or FEA has proposed a different survivor curve estimate than what has

[67] See FPL's responses to OPC's Tenth Set of Interrogatories No. 253 and 256 provided in Exhibit NWA-5.

been recommended in the 2016 Depreciation Study. The discussion in Exhibit NWA-3 responds to specific assertions made by OPC or FEA and also includes graphical comparisons of recommended survivor curves. These discussions explain in more detail why FPL's proposed survivor curves are the most appropriate estimates for each account.

VII. MASS PROPERTY NET SALVAGE ESTIMATES

A. INTRODUCTION

Q. What is mass property net salvage?

A. Net salvage as used in depreciation is defined as gross salvage less cost of removal. When an asset is retired it may have scrap or reuse value, which is gross salvage. There is also a cost to retire the asset. For example, the retirement of a distribution pole typically requires a multiple person crew and heavy equipment to remove the pole from the ground and cut the pole for disposal. There may also be disposal costs for the pole. All of these costs associated with the retirement are cost of removal.

Most types of utility property typically experience negative net salvage, meaning that cost of removal exceeds gross salvage. This is true of many of FPL's assets. FPL's actual experience demonstrates that for many types of transmission and distribution assets there are significant costs to retire the assets and that these costs generally exceed any gross salvage value.

Q. How is net salvage estimated?

A. Net salvage is expressed as a percentage of the original cost retired. For example, if an account has a net salvage estimate of negative 50%, then a $1,000 asset would be expected to, on average, cost $500 to retire, net of any gross salvage. Similar to the service life estimates described in Section VI, net salvage estimates are based on a combination of statistical analysis of historical data as well as informed judgment that incorporates other factors.

Q. How is the statistical analysis performed?

A. The statistical analysis is performed by comparing historical cost of removal and gross salvage to historical retirements as recorded in a utility's property records. By analyzing both annual activity and longer and shorter term averages of the experienced net salvage expressed as a percent of retirements, these data provide a statistical basis for estimates of net salvage.

Q. In general, how do your net salvage estimates compare to the current, Commission-approved estimates?

A. For twelve mass property accounts I have recommended a more negative (or less positive) net salvage estimate. For fifteen accounts, I have recommended the same net salvage estimate as is currently approved. For five accounts, I have recommended a less negative net salvage estimate. In light of the trend to more negative net salvage for many accounts, my recommendations represent a balanced approach. Some estimates produce higher depreciation expense and some produce lower depreciation expense. Either way, my estimates are supported by the Company's actual historical data.

Q. Please summarize the net salvage estimates of each party.

A. The only intervenor witness who has challenged my net salvage estimates is OPC witness Pous. A summary of the currently approved net salvage estimates as well as my estimates and those of witness Pous are summarized in the table below. The table also summarizes the statistical analysis of the Company's historical data, and shows the overall average net salvage experienced by FPL for the full range of available data as well as the most recent 5-year average of net salvage experienced by FPL. That is, the table provides a comparison of the net salvage estimates to the Company's actual experience.

Table 2: Comparison of Approved, FPL and OPC Net Salvage Estimates with Historical Net Salvage Data

Account		Approved Estimate	FPL Estimate	OPC Estimate	1986-2014 Experience	Most Recent 5-Year Experience
353	Station Equipment	(2)	(2)	0	(1)	0
354	Towers and Fixtures	(15)	(25)	(15)	(50)	(69)
355	Poles and Fixtures	(50)	(50)	(40)	(55)	(45)
356	Overhead Conductors and Devices	(50)	(55)	(45)	(57)	(59)
362	Station Equipment	(10)	(10)	(5)	(10)	(8)
364.1	Poles, Towers and Fixtures - Wood	(60)	(100)	(60)	(116)	(179)
364.2	Poles, Towers and Fixtures - Concrete	(60)	(100)	(60)	(116)	(179)
365	Overhead Conductors and Devices	(60)	(80)	(60)	(76)	(108)
367.6	Underground Conductors and Devices – Duct System	0	(5)	0	(6)	(10)
369.1	Overhead Services	(85)	(125)	(85)	(133)	(104)
370	Meters	(30)	(30)	(20)	(20)	(25)
370.1	Meters – AMI	(30)	(30)	(20)	(38)	(38)
390	Structures and Improvements	(5)	(10)	10	(11)	(15)

Q. How do the currently approved net salvage estimates compare to the Company's actual experience?

A. As can be seen in the table above, for many accounts the currently approved estimates are much less negative than the Company's actual experience. For example, for Accounts 364.1 and 364.2 (wood and concrete poles, which were studied together for the net salvage analysis), the Company's actual experienced net salvage for the full range of data available was negative 116% net salvage. More recent experience has been even more negative, and the Company has experienced negative 179% net salvage in the last 5 years. However, the currently approved estimate for these accounts is only negative 60% - almost half the overall average and about a third of the Company's more recent experience. Thus, it should be quite clear that the Company's actual experience is supportive of a more negative net salvage estimate than the currently approved estimate.

Q. Is there more data available for the current study than was available when the current estimates were determined?

A. Yes. For the current study there are seven additional years of data available for the statistical net salvage analysis. For many accounts the additional data provides further support for the fact that more negative net salvage estimates are appropriate. That is, just based on the data alone the case for more negative net salvage estimates is stronger for the 2016 Depreciation Study than the 2009 Depreciation Study because more data is available.

Q. Please discuss how your estimates compare to the Company's data.

A. My estimates are generally consistent with the Company's historical data, and for some accounts are actually quite conservative when compared to the historical data. For example, for Accounts 364.1 and 364.2 I have estimated a negative 100% net salvage estimate. This is less negative than the overall average of negative 116% and much less negative than the more recent average of negative 176%. Further, for those accounts for which my estimates are different from the Company's data I have explained and supported the reasons why in Part XI of Exhibit NWA-1.

Q. How do witness Pous's estimates compare to the Company's historical data?

A. Out of the thirteen accounts for which witness Pous has recommended different net salvage estimates than mine, he has proposed less negative estimates than the currently approved estimates for seven. He has proposed to keep the approved net salvage estimates for the other six. He has not proposed a more negative net salvage estimate for a single one of these accounts, despite the fact that the data indicates more negative estimates for many accounts.

Indeed, for many accounts witness Pous's estimates are much less negative than the Company's actual experience. Further, his estimates often fail to recognize trends in the data or even move in the opposite direction of clearly established trends. For example, for Accounts 364.1 and 364.2, despite the

data providing a clear indication of more negative net salvage, witness Pous has proposed no change to the currently approved estimate.

B. FPL'S HISTORICAL DATA

Q. In general, what are the reasons provided by witness Pous for proposing different estimates from those you have made and the fact that his estimates deviate significantly for the historical data?

A. While witness Pous devotes a number of pages to criticizing the methods and support for my estimates, a detailed review of his testimony reveals that he actually provides very little in terms of actual, supported evidence for his estimates. Thus, the most clear contrast between my estimates and his are that mine are supported by actual, FPL-specific data and widely accepted methods for estimating net salvage, whereas witness Pous's estimates are instead primarily supported by speculative justifications for ignoring the Company's actual experience.

Q. Please explain.

A. Once one gets past the general criticisms he makes – which I will explain are unfounded – a review of his discussions of the actual estimates for each account reveals that there is in fact little support for his decision to propose estimates that are often very different from what is actually indicated by the data. While he claims that his estimates are based "upon data, assumptions, and rationales that I develop and support in detail",[68] his estimates have very

[68] Direct testimony of Jacob Pous, page 11, lines 18-19.

little support from the Company's data. Instead his actual support is typically the result of either cherry-picking individual years of activity that support less negative estimates while ignoring more meaningful overall trends, or simply ignoring the results of the statistical analysis altogether by offering a variety of rationalizations for disregarding FPL's actual experience. As I will show, his justifications are rarely supported by actual analysis and are often incorrect. Further, to the extent he has provided calculations or analyses that he purports to support his overall approach of ignoring the Company's data, a more detailed review of his arguments reveal that his analysis is often incorrect.

Q. Witness Pous criticizes your approach for what he refers to as relying on "mechanical averaging" or "simplistic averaging."[69] Please address these criticisms.

A. I should first make clear that witness Pous has mischaracterized what I have actually done. While the analysis of averages was appropriately considered in my estimates, contrary to witness Pous's implication there was much more involved in my net salvage estimates than "simplistic averaging." I have investigated the historical data, determined the causes and reasons for trends, met with knowledgeable FPL personnel to understand historical and future practices, and observed actual FPL property, including a pole replacement project. Thus, any assertion that I have only relied on mechanical averaging is simply incorrect.

[69] See for example page 138, lines 6-9 and page 164, lines 16-17 of the direct testimony of Jacob Pous.

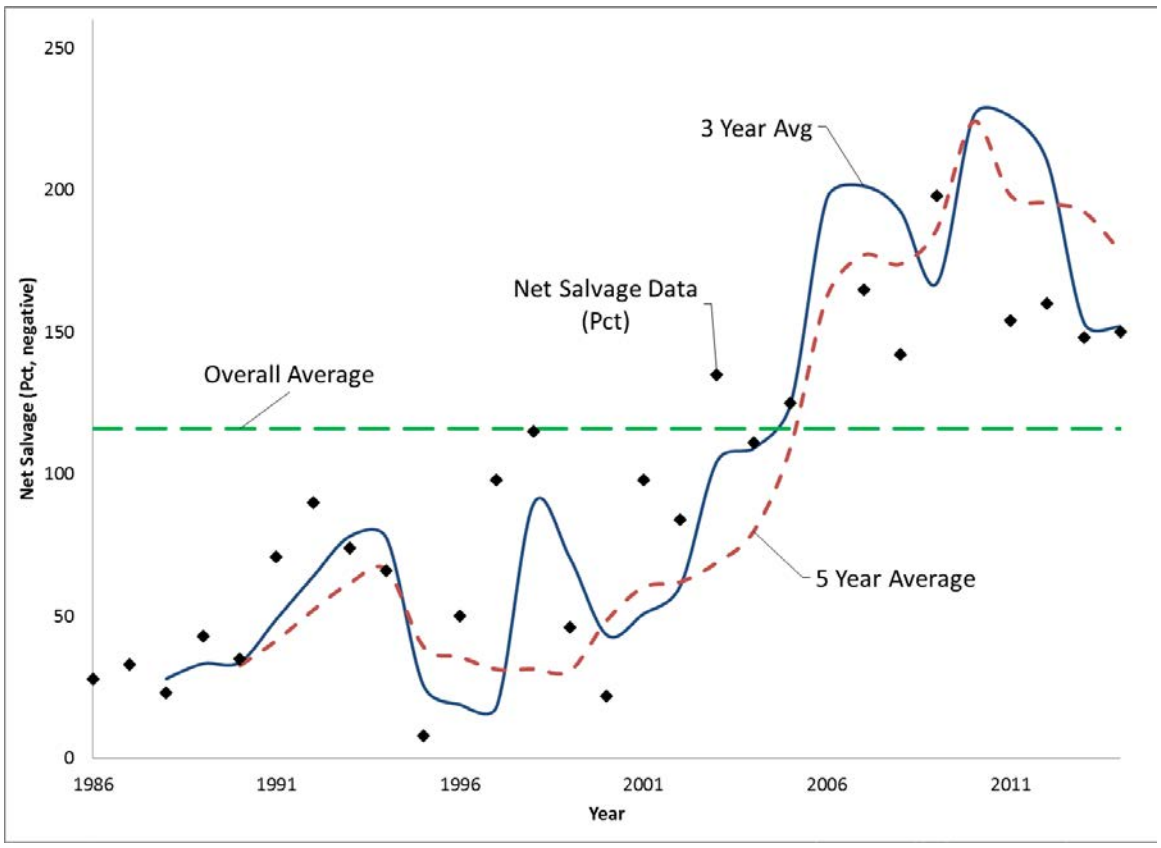
Moreover, while witness Pous disparages the use of averages for net salvage analyses, he is in fact disparaging what depreciation professionals widely consider to be the proper method of estimating net salvage. Further, much of witness Pous's analysis is instead to cherry-pick individual years of data, which he claims without any actual support to be more indicative of the future experience for a given account. For example, he may speculate – without actual support – that individual years may represent "economies of scale" or "emergency replacements," when in fact differences between years are just the result of timing differences or the natural variation between the work performed in different years.

Q. Why are averages of years of historical net salvage experience used instead of individual years?

A. Averages of years are used in the net salvage analysis because they tend to smooth fluctuations that naturally occur in the data. As an example, Figure 14 below provides a graph of the net salvage data for Accounts 364.1 and 364.2[70]. The black diamonds in the chart show the net salvage percentages that have occurred for each year in which the data is available. These tend to show an overall increasing trend, but are fairly volatile and vary from year to year. Further, because different levels of work are performed in each year, the dollar values from which these percentages are derived also vary from year to year.

[70] Please note that for the purposes of illustrating the net salvage data graphically, I have changed the sign of the net salvage for this and other charts. That is, negative net salvage percentages are shown as positive in these charts. The actual net salvage percentage would look exactly the same, except would be "upside down" when compared to the charts in my testimony.

Figure 14: Historical Net Salvage Data for Accounts 364.1 and 364.2 Poles Towers and Fixtures



Moving 3-year averages are shown in the blue line on the chart. These smooth the fluctuations in the individual years. However, there is still some degree of volatility in the 3-year averages, because 3 years is still a relatively short period of time when compared to the full range of data available (from 1986 through 2014).

The dashed red line shows moving 5-year averages of the same data. Although there is still some volatility in the 5-year averages, because they are based on longer time periods the 5-year averages provide a smoother trend in

the data. The 5-year averages also make clear that there is a pronounced trend to more negative net salvage in the historical data over the past 20 years.

Finally, I have graphed the overall level of net salvage for this account, which is negative 116%. This is shown in the green dashed line in the chart. The overall average includes all of the data in the analysis and therefore provides the largest available sample size. However, it does not provide any indications of trends.

Further, I should note that witness Pous makes a variety of references to concepts such as the "mix of investment" reflected in the historical data.[71] The use of averages actually alleviates this concern. By averaging the experience that has occurred over almost three decades, the overall average net salvage incorporates a wide range of types of projects and mixes of investments.

Q. You indicated the term "sample size." How much activity is reflected in the Company's historical data for these accounts?

A. The historical data for this account includes $131 million in retirements that have occurred from 1986 through 2014. Given that these are the retirements of poles that are often decades old, the data incorporates the actual experience for a very large number of poles. For many of the accounts that are challenged by witness Pous, the data incorporates a similar, if not higher level

[71] See for example page 175, lines 1-5 and page 176, lines 17-20 of the direct testimony of Jacob Pous.

of retirements. This provides a reason to be confident in the ability of the data to provide a meaningful basis for net salvage estimates. Indeed, FPL has much more historical data than many other utilities, due in part to the fact that FPL is a bigger company. For this reason, FPL's data should be considered more reliable than is the case with many other utilities.

Q. Do authoritative depreciation texts support the use of averages as opposed to the analysis of individual years?

A. Yes. The NARUC Manual explains that "it is common to look at data for bands of years," and these bands should be "broad enough so a fairly smooth trend can be detected." The NARUC Manual also notes that there can be timing differences in the historical data (i.e., cost of removal and retirements can be recorded in different calendar years), stating that "the impact of this timing mismatch can be largely negated by analyzing a band of years."[72] Wolf and Fitch's *Depreciation Systems* also explain that "statistics based on a single year are often erratic, making an underlying pattern difficult to detect" and that the process of using moving averages "smooths the pattern of the ratios."[73]

[72] The NARUC Manual, page 159.
[73] *Depreciation Systems*, W.C. Fitch and Frank. K. Wolf, 1994, page 261.

Q. You have indicated that the Company's actual experience supports your estimates. Please provide an example of how the Company's data supports your estimate.

A. Consider again Accounts 364.1 and 364.2 (wood and concrete distribution poles). In Figure 14 above I provided a chart of the historical net salvage data.

Q. What does this chart demonstrate regarding FPL's actual experience?

A. The chart makes quite clear that the negative net salvage has trended towards a more negative level for many years. This can be seen clearly by the 3-year averages and 5-year averages, which show a consistent trend to more negative net salvage over the past 20 years.

Q. You have demonstrated a trend in the data towards more negative net salvage. Have you investigated the causes of this trend?

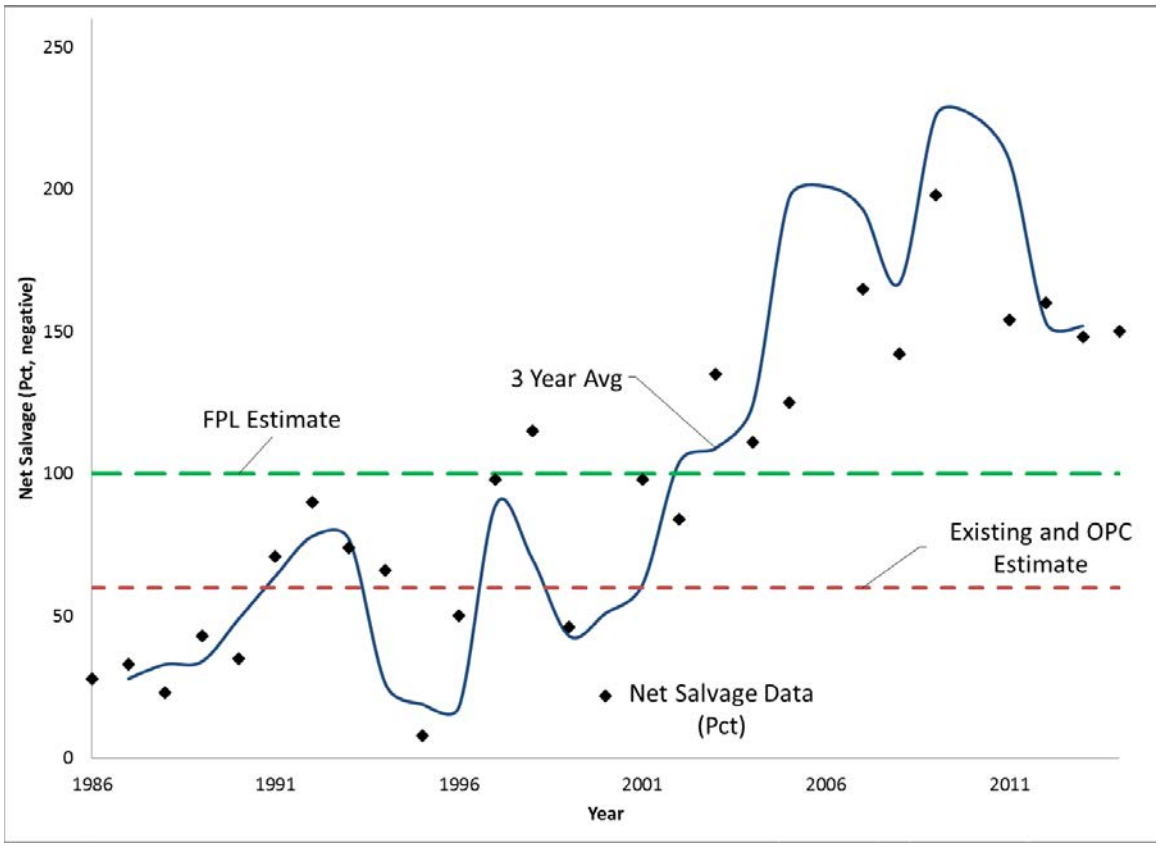
A. Yes, I have. I met multiple times with FPL representatives who are knowledgeable with the operations of the Company. The trend exhibited in the data is consistent with their experience, and they have consistently explained the reasons for increasing cost of removal.[74] Further, the experience for FPL is consistent with what I have seen for other utilities.

Q. Please compare FPL's actual experience as shown in Figure 14 with the net salvage estimates.

A. Yes. In Figure 15 below I have added to the chart the currently approved estimate of negative 60%, my estimate and witness Pous's estimate.

[74] The reasons for the trend of increasing removal costs is discussed in more detail in the next section.

Figure 15: Comparison of Existing, FPL Proposed and OPC Proposed Net Salvage Estimates with Historical Data for Accounts 364.1 and 364.2 Poles, Towers and Fixtures



Q. What can you conclude based on this data?

A. The data provides a clear indication that an estimate more negative than the currently approved negative 60% estimate is appropriate. Indeed, the 3-year moving averages have not been at the level of the currently approved negative 60% net salvage estimate since the early 2000s. I have recognized this trend, the causes of which have been explained and verified, by recommending a more negative net salvage estimate of negative 100%. However, this is still a conservative estimate in that it is less negative than the overall average of negative 116% and the even more negative more recent experience.

Q. What is witness Pous's response to the trend that can clearly be seen in the data?

A. His response for this account is to not change the estimate at all. Despite the clear trend in the data, witness Pous has elected to ignore it. While he provides a variety of rationalizations for his decision to completely ignore the data, his reasons do not stand up to scrutiny.

Q. Is there data available to test witness Pous's theories as to why the cost of removal should be lower than indicated by the data?

A. Yes. As I will explain, witness Pous made many of the same arguments to ignore the data 7 years ago for the 2009 Depreciation Study, when as an example he predicted that economies of scale would result in decreasing costs of removal. With seven more years of experience we now can test his justifications in the previous case. For example, FPL has undergone a large scale replacement project for this account for its storm hardening program – that is, precisely the kind of program that might produce economies of scale. The result was not a significant decrease in cost of removal. Instead, since the implementation of the storm hardening program cost of removal has remained high and net salvage has been much more negative than my conservative estimate. Given that we now have evidence that the predictions he made in the last case do not produce his expected results, there is little reason to believe witness Pous's justifications for ignoring the data in the instant case.

C. REASONS FOR INCREASING REMOVAL COSTS

Q. Have you investigated the reasons for increasing removal costs?

A. Yes. As I explained in both my Direct Testimony[75] and in Exhibit NWA-1,[76] there are a number of reasons why removal costs have increased. The Company has also performed additional analyses of the reasons for increasing costs. Additionally, as FPL witness Miranda explains, the Company has also made efforts to mitigate costs when possible.

Q. Why have removal costs increased?

A. There are multiple, and sometimes inter-related, reasons for increasing removal costs. Many of these reasons are outside of the Company's control. Environmental rules have increased removal costs. As an example, disposal requirements for treated wood poles have increased, increasing the cost to dispose of wood poles (and therefore increasing removal costs). Permitting requirements have become more restrictive and burdensome, which increases costs.[77] As an example, municipalities or counties may require work to only be performed at certain hours of the day, increasing project costs. Another example is the requirements for restoring the site after a pole is removed. Municipalities have required restoration of sidewalks or landscaping, which increases removal costs. Increasing requirements for traffic control has also added to costs.

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[75] See pages 38 through 40 of my direct testimony.
[76] See for example pages 728 and 729 of Exhibit NWA-1.
[77] Note that "permitting requirements" does not necessarily mean the cost of permits, but instead can mean the actual work requirements dictated by the permit.

In addition to these factors, labor costs in general tend to increase over time. The impact of labor costs can be compounded by various other work requirements – as work requirements have increased, both the number of hours required to complete a project and the hourly costs have increased as well.

Given all of these factors, the experience of FPL's operating and management personnel confirm what has been apparent in the Company's data for some time. However, I should again emphasize that FPL's data is quite clear that, for example, cost of removal has increased significantly for poles over the past 20 years. These various factors, confirmed by FPL personnel knowledgeable of the assets, add additional support and explanation for what we already know has occurred based on the data.

D. OPC'S REASONS FOR IGNORING THE DATA ARE INCORRECT

Q. You indicated that witness Pous provides a number of rationalizations or "analyses" that he claims to support effectively ignoring standard methods of estimating net salvage. Please discuss.

A. As discussed in the previous sections, witness Pous's estimate are not consistent with FPL's actual data. In order to attempt to support his estimates, he has instead provided a variety of rationalizations for ignoring the results of

the statistical net salvage analysis. In general, his justifications often do not stand up to scrutiny.

Q. Please provide an example of a problem with the reasons witness Pous provides to ignore the data.

A. One example provided by witness Pous is related to hurricane retirements. For example, for Account 365 Overhead Conductors and Devices he effectively argues that the experience related to hurricane retirements provides a more reasonable indication of the future net salvage for this account than the Company's data related to normal transactions. He states:

> It defies credibility to recognize that the Company can retire and remove millions of linear feet of conductor under hurricane circumstances at a cost rate of 59%, but wants the Commission to believe that the a net 100% cost rate is "conservative" because it was obtained from a simplistic averaging of the overall historical database.[78]

In other words, witness Pous ignores the overall results of the statistical analysis based on the extensive data available for normal retirements and instead bases his proposal on the experience for hurricane related retirements.

[78] Direct testimony of Jacob Pous, page 178, lines 5-8.

Q. Is witness Pous's assertion that "retirement activity under hurricane-related conditions would have to be some of the more costly activity that the utility could perform"[79] correct?

A. No. While the factors he lists to support his opinion that hurricane-related activity would be more costly may impact the overall cost to restore power after a hurricane, this does not mean that cost of removal will necessarily be higher. Indeed, it is logical to expect the opposite to be true. The effort involved to remove conductor after a hurricane would typically be less than under normal conditions. After a hurricane the wires are often already on the ground and do not need to be removed from poles. That is, the hurricane does most of the work removing the assets in this account. Further, for hurricane work there are often not the same traffic control costs or permitting requirements, which would offset many of the factors discussed by witness Pous.

Q. Given these considerations, would it be appropriate to ignore the data for normal retirements and instead rely on the experience for hurricane related retirements?

A. Of course not. In OPC witness Pous's analysis for this account he has relied on the experience for hurricane retirements and then applied this experience to the entire account – ignoring the extensive data available for normal retirements that are much more indicative to the level of cost of removal that will be incurred for the vast majority of the Company's overhead conductor.

[79] Direct testimony of Jacob Pous, page 178, lines 1-2.

Witness Pous's approach is in no way an acceptable method for estimating net salvage, particularly when the Company has an extensive database of normal retirement activity.

Q. Please provide an example of an issue with the types of analyses witness Pous has performed in support of his recommendation to ignore the historical data.

A. An example is presented on page 156 of witness Pous's testimony, in which he performed an analysis that he claims implies that concrete transmission poles have lower cost of removal than wood transmission poles. Witness Pous did not actually provide this analysis in his testimony or his workpapers, but did eventually provide the details behind his analysis in discovery.[80] As I will explain in the more detailed discussion for this account, a more detailed review of his analysis reveals that the data supports the opposite conclusion he has made. Concrete poles have historically had a higher – not lower – cost of removal percentage than wood poles, as can be seen in Table 3 below.

Table 3: Historical Cost of Removal Percentage for Account 355 Transmission Poles by Pole Type

		Cost of Removal	
Type	**Retirements**	**Amount**	**Pct.**
Wood	9,133,688	9,332,312	102%
Concrete	7,574,259	10,285,176	136%

[80] See OPC's Response to FPL's Second Set of Interrogatories No. 40.

Q. Does witness Pous also use comparisons to the estimates for other utilities to support ignoring the historical data?

A. Yes. For example he states:

> Mr. Allis makes no meaningful attempt to explain why the historical values relied upon sometimes produce negative net salvage values that are the most negative or among the most negative in the industry.[81]

This comment is incorrect on multiple levels. First, and again, I have investigated the data in a meaningful manner. However, witness Pous's premise that FPL's cost of removal is "unusually high" is incorrect. I have discussed in Section III.B reasons that his comparisons of net salvage estimates to those of many other utilities are inappropriate. I should again point out that witness Pous has actually recommended net salvage estimates that are as or more negative than mine in other jurisdictions. For example, witness Pous devotes a large portion of his discussions to Accounts 364.1, 364.2 and Account 365. I have demonstrated that FPL's data supports my estimate for Accounts 364.1 and 364.2, and the same is true of Account 365. I have estimated negative 100% for Accounts 364.1 and 364.2 and negative 80% for Account 365. In recent cases in California for SCE and PG&E, witness Pous proposed net salvage estimates that were similar or more negative estimates than mine. For Account 364 (which were not separated by pole type for either SCE or PG&E), witness Pous recommended an estimate of negative 132% for SCE and negative 100% for PG&E. For Account 365

[81] Direct testimony of Jacob Pous, page 135, lines 16-18.

he recommended estimates of negative 85% for SCE and negative 110% for PG&E.

Thus, because his estimates for more comparable utilities were as negative as or more negative than my estimates for FPL for these accounts, witness Pous should recognize that the estimates for FPL are not "unusually high."

Q. Witness Pous also presents various discussions regarding the dollar impact of your proposal. Please address these criticisms.

A. Witness Pous presents various calculations of the dollar level of net salvage that result from my estimates. For example, for Account 365 Overhead Conductors and Devices he states on page 132 of his direct testimony that "the Company's proposed net salvage figure would result in approximately $1.8 billion of depreciation expense over the life of the investment above the recovery of the original $2.2 billion investment."

This and similar statements made elsewhere by witness Pous are what I would refer to as "misleading through large numbers." They are particularly misleading because, as an example, for the same account witness Pous has proposed a net salvage estimate that corresponds to well over $1 billion over the life of the investment.

Q. Please explain this concept further.

A. FPL is a very large company, and owns a large number of assets. It will therefore cost a lot of money to remove these assets. For example, the

Company has a plant balance of almost $1.8 billion for distribution poles (wood and concrete).[82] It should be expected that it will cost a significant amount to remove these assets over the next 100 years (which is roughly the amount of time my estimates forecast the last of these poles to be retired).

Further, for many of the numbers witness Pous cites he compares the net salvage estimates I have made to what would result from zero net salvage. This is a completely irrelevant comparison – no one estimates zero net salvage, including witness Pous. Indeed, his net salvage estimates predict approximately $5 billion in net salvage costs for transmission and distribution plant accounts.

Finally, FPL's data makes clear that the Company will incur significant costs to retire its assets. For the period of available data (from 1986 through 2014), the Company has expended over $880 million to remove transmission and distribution assets. Given that in the future the Company will have to retire many more assets than it has over the last 29 years, and that these assets will cost more to remove over the next 100 years than they did in the past 29 years, it is perfectly reasonable to expect that FPL will experience billions of dollars in net salvage over the remaining lives of its assets.

[82] FPL's Second Notice of Identified Adjustment, Appendix 2.

E. CONSIDERATION OF ECONOMIES OF SCALE IN NET SALVAGE ANALYSIS

Q. What is the concept of economies of scale?

A. Economies of scale is a concept by which an increase in production (or an increase in the amount of activity) will result in a decreasing cost on a per unit basis. For example, when the Company replaced all of its existing meters with AMI meters, there were economies of scale in that costs such as travel time were reduced on a per unit basis because every meter on a street could be replaced at the same time. Similarly, if FPL were to replace every pole on a street, the per-unit cost might be cheaper than if only a handful of poles were replaced.

Q. Have you considered this concept in your net salvage analysis?

A. Yes. I have also recognized that witness Pous has significantly overstated the impact of this concept.

Q. What argument does witness Pous make regarding the concept of economies of scale?

A. Witness Pous makes the same argument he has made in many jurisdictions for many years that economies of scale will dramatically reduce the cost of removal for many accounts. For example, for transmission poles he speculates that because FPL will retire more poles in the future then "this increase in annual retirements must by necessity reflect economies of scale to be gained in the future when larger numbers of poles are retired in close

proximity to each other compared to the removal of one or a few poles at a time as is more realistically reflected in the historical data."[83]

Q. Is witness Pous's argument regarding economies of scale reasonable?

A. No. Instead he significantly overstates any impact that would occur due to economies of scale. It is highly unlikely that for most of its assets FPL will have a program similar to its meter replacement program, in which significant economies would be realized. Just because more retirements will occur in the future does not mean that there will be economies of scale. For example, retiring six transformers at six different substations rather than two transformers at two substations will not result in any economies of scale. Indeed, the amount of retirements has increased over time and net salvage for many accounts has trended more negative – the opposite of what witness Pous would predict.

Further, as mentioned above, witness Pous has made similar arguments about economies of scale for many years. In fact, he made essentially the same argument in FPL's last depreciation case.[84] In the time since that depreciation study, we now have actual data to test witness Pous's hypothesis. The actual data since the 2009 Depreciation Study does not support what witness Pous claims.

[83] Direct testimony of Jacob Pous, page 167, line 22, to page 168, line 2.
[84] See pages 146 and 147 of the direct testimony of Jacob Pous in Docket No. 090130-EI.

Q. Has FPL implemented any programs since the last case that would result in economies of scale?

A. Yes. FPL has implemented a large scale storm hardening program, as the Commission is well aware. For this program, FPL has replaced a large number of transmission and distribution poles. Further, these projects have typically involved replacing most, if not all, poles along a line. Thus, any potential economies of scale have been achieved with the storm hardening program. This therefore provides actual data to test witness Pous's theory.

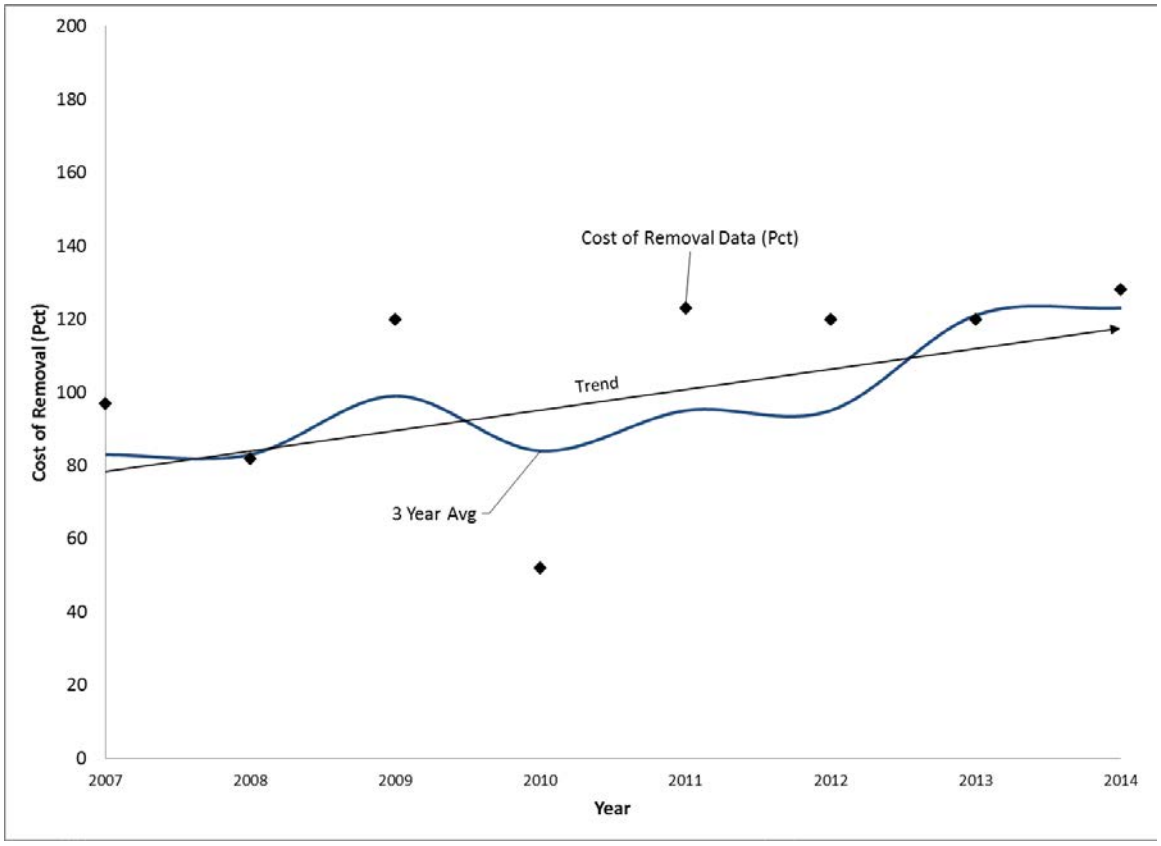
Q. Has cost of removal declined significantly as witness Pous predicted in 2009?

A. No. For example, for Account 355 (transmission poles), cost of removal percentages have increased. Thus, there has not been a dramatic decline in cost of removal on either a total or a per unit basis as witness Pous has predicted.

Q. Please explain.

A. For example, as noted above witness Pous discusses economies of scale for transmission poles. I have graphed the annual and 3-year average cost of removal percentages from 2007 through 2014 for Account 355 (transmission poles). The data shows the opposite of what witness Pous has predicted. Cost of removal has increased, not decreased.

Figure 16: Cost of Removal for Account 355 Poles and Fixtures Subsequent to Implementation of Storm Hardening Program



Similarly, previously in Figure 14 I showed the net salvage data for distribution poles. Subsequent to the storm hardening program, net salvage has remained much more negative than the overall average and much more negative than my estimate. Witness Pous's predictions of dramatic reductions in removal costs due to economies of scale have therefore failed to materialize.

Q. Are there other factors related to storm hardening work that have tended to offset economies of scale?

A. Yes. For example, the increase in the volume of work has impacted labor costs, in particular for contractors. These cost increases have offsets gains

that might have occurred from economies of scale. Additionally, work requirements can be more significant for large-scale projects than smaller projects, which also offsets any gains from economies of scale. For example, requirements for a project along a major road that takes many weeks or months to complete will often have stricter requirements than a project to replace only a few poles that may only take a few days. Municipalities have a higher tolerance for a lane of traffic being closed for a day or two, but will have less tolerance for a lane of traffic being closed for a month. Thus, the requirements for a larger project can include higher traffic control costs and are also more likely to require work to be done at off-peak hours. Both increase costs.

Q. What can you conclude regarding witness Pous's arguments regarding economies of scale?

A. Witness Pous has used this argument to effectively ignore the results of the statistical analysis of FPL's historical data. As I have explained, and as FPL's actual experience demonstrates, the impact of witness Pous's concept of economies of scale is exaggerated. Instead, the Company's data provides a reasonable basis for estimating future net salvage.

F. WITNESS POUS'S FALSE ALLEGATIONS OF MANIPULATING THE DATA

Q. What does witness Pous claim regarding adjustments to the historical data?

A. Witness Pous makes a false allegation that I have "manipulated" the historical data. What I have actually done is to review the Company's historical data and remove transactions that are abnormal or non-recurring. This is a common and appropriate practice for depreciation studies. It is also the same practice that was used in the previous depreciation study and was accepted by the Commission as appropriate. It would be inappropriate to include the transactions that have been excluded because they would skew the analysis and result in incorrect net salvage estimates.

Q. What types of transactions have been excluded?

A. Consistent with prior, Commission-approved practices for FPL I have removed reimbursed retirements that are not expected to recur. I have also removed hurricane retirements, which are relatively rare events and for which FPL has a separate recovery mechanism. These are the two primary types of transactions that witness Pous incorrectly argues to be "manipulation."

I have also removed other abnormal events that are not expected to recur. Examples include early failures of transformers, nuclear uprate retirements, and sales of buildings prior to the end of their useful life. I have also excluded final retirements of power plants from the analyses of interim retirements.

Q. Have you used a consistent approach for both the service life and net salvage analysis?

A. Yes. For example, the reimbursed retirements and hurricane retirements that were excluded were removed from both the service life and net salvage analyses.

Q. Has witness Pous used a consistent approach?

A. No. He adjusts the net salvage data for these non-recurring transactions in order to support less negative net salvage and therefore lower depreciation expense. But he does not do the same for life analysis, which would result in shorter service lives and therefore higher depreciation expense.

Q. You indicated that the Commission had previously approved your approach to adjusting the data for these types of transactions. Please explain.

A. Witness Pous made very similar arguments in Docket No. 090130-EI, which the Commission correctly did not consider persuasive. Specifically the Commission stated:

> In our opinion, it is reasonable to remove data related to nonrecurring events, such as hurricane effects and nonrecurring reimbursed retirements, from the analysis because the data can skew the results of the analysis. At the same time, we feel it is reasonable to include recurring data.[85]

[85] Order No. PSC-10-0153-FOF-EI, page 60.

The Commission further affirmed they agreed with FPL's approach to these types of transactions, later stating:

> As discussed above, we believe that FPL's approach with regard to reimbursed retirements and the effects of hurricanes is reasonable.[86]

And again:

> We believe that FPL's removal of nonrecurring reimbursed retirements and hurricane data is appropriate; otherwise, this data might skew the results.[87]

There are similar statements throughout the order.[88] It should be quite clear that the Commission agreed with FPL's approach and did not find witness Pous's arguments convincing.

Q. Have you used the same approach for these transactions as was used in the 2009 Depreciation Study?

A. Yes.

Q. Has witness Pous provided any new arguments that would suggest this approach is no longer appropriate?

A. No.

[86] Order No. PSC-10-0153-FOF-EI, page 64.
[87] Ibid.
[88] See for example pages 65, 67, 68 and 69 of Order No. PSC-10-0153-FOF-EI.

Q. Much of witness Pous's criticism is related to reimbursed retirements. Is your approach consistent with authoritative depreciation texts?

A. Yes. On page 31 of the NARUC Manual, in the section titled "Depreciation Study Data" NARUC states:

> A reimbursement is a retirement of property for which the company is compensated at the time of retirement through insurance because of the occurrence of a covered incident, or by public authority, customer, or other party as a result of negotiations wherein the property will be removed or relocated for the convenience of the entity desiring the retirement. In the case of insured losses, the payment received may be different from the original cost of the equipment. Thus, treating the reimbursement as normal gross salvage data in studies may give results that are not typical of the account as a whole because the insurance payment is not a characteristic of the account in general. Therefore, such retirements and the corresponding salvage should either both be included or excluded from the depreciation study. The accounting for removals should be analyzed to identify the apportionment of monies received among an offset to new construction, gross salvage, and cost of removal.

The removal of reimbursed amounts from the historical service life and net salvage database is also consistent with *Depreciation Systems*. For example,

on pages 16 and 17 of Wolf and Fitch's Depreciation Systems, in the Chapter on "Data" the authors explain reimbursed retirements:

> Reimbursed retirement – code 1. A reimbursed retirement is one for which the company is fully compensated at the time of retirement, usually because the retirement occurred earlier than normal as the result of an unusual event. Compensation may be from insurance, from the party who damaged the utility by causing the retirement, or from an individual or public authority who desired or required the relocation or abandonment of the retired property. Usually reimbursed retirements should not be included in analysis to estimate the life and salvage of property whose original investment is recovered through depreciation accruals.

Q. Can you explain how reimbursed retirements would skew the net salvage data?

A. Yes. Consider for example in witness Pous's discussion of reimbursed retirements, in which he states:

> Mr. Allis excluded $86.4 million of reimbursed retirements and $70 million of positive net salvage, which corresponds to an 81% level of positive net salvage.[89]

Witness Pous clarified in discovery that the numbers cited above were incorrect, and the historical reimbursed retirements actually experienced

[89] Direct testimony of Jacob Pous, page 144, lines 12-13.

positive net salvage of 90%.[90] A level of 90% positive net salvage would mean that when FPL retires its assets, it would receive from a third party 90% of the original cost of these assets. As I would expect any experienced analyst to recognize, there is no way that FPL will be routinely paid by a third party for 90% of the cost of its assets. To the extent there will be reimbursements in the future they will only be a tiny fraction of the actual costs FPL will incur to retire its assets.

FPL has approximately $1.8 billion of distribution poles. If the 90% positive salvage were at all a reasonable predictor of the future, this would mean FPL would receive more than to $1.6 billion in payments from a third party to remove its poles. Quite clearly, FPL will not recover this amount from third parties to remove its poles. To the contrary, FPL will not be compensated at all for the removal of the vast majority of its poles. Indeed, as witness Pous notes, the total amount of salvage for reimbursed retirements removed from the database is $90 million[91] – for all accounts. This is only about 6% of the $1.6 billion implied by a 90% positive salvage amount only for only a single account. Further, the $90 million amount is the total in salvage for reimbursed retirements for the past 29 years, and as the Commission noted includes large projects such as the Metrorail line that are obviously non-recurring.

[90] See OPC's response to FPL's Sixth Set of Interrogatories No. 59.
[91] Witness Pous clarified that the $70 million in the quote above should actually be $90 million.

Thus, it should be quite clear that reimbursed retirements are not likely to recur, at least not to anywhere near the frequency as they are represented in the historical activity. As a result, their inclusion would heavily skew the results of the net salvage analysis and would be inappropriate.

Q. Witness Pous also criticizes the Company's accounting for reimbursed retirements. Is his discussion accurate?

A. No. I should first note that his statement that the Company contends that it should categorize "amounts received from third parties" as "a contribution in aid of construction"[92] is incorrect. The Company has historically recorded a portion of amounts received from third parties to salvage, as evidenced by the mere fact that there is a disagreement related to the exclusion of many of these transactions from the net salvage data.

Additionally, it is both logical and consistent with the Uniform System of Accounts, the portion of the NARUC Manual cited above, and with the NARUC interpretation cited by witness Pous on page 145 of his testimony that if money received from a third party is related to the construction of a new asset then it should be recorded as a contribution in aid of construction and be recorded as an offset of the addition of that new asset.

[92] Direct testimony of Jacob Pous, page 144, line 21 to page 143, line 3.

G. ACCOUNT SPECIFIC

Q. Do you also have specific responses to the estimates made by witness Pous?

A. Yes. Similar to for service lives, I have provided a discussion of each account for which OPC has proposed a different net salvage estimate than what has been recommended in the 2016 Depreciation Study. This discussion is provided in Exhibit NWA-4 and explains in more detail why FPL's proposed net salvage estimates are the most appropriate estimates for each account.

VIII. THEORETICAL RESERVE IMBALANCE

Q. What is the theoretical reserve imbalance calculated in the 2016 Depreciation Study?

A. As noted in my direct testimony, and acknowledged by OPC, the theoretical reserve imbalance ("TRI") resulting from the 2016 Depreciation Study is negative $99 million (a negative TRI is also sometimes referred to as a "reserve deficit") as of December 31, 2017.[93] If the TRI is instead calculated as of December 31, 2016 the estimates in the 2016 Depreciation Study produce a TRI of a positive $80 million. At either calculation date, the theoretical reserve imbalance is very small, as evidenced by the fact that both amounts are less than 1% of the theoretical reserve and by the fact that in the

[93] Direct testimony of Ned W. Allis, page 53, lines 16-17.

span of one year (i.e., from 2016 to 2017) the TRI changes from a positive to a negative amount.

Q. What have you proposed regarding the TRI?

A. As noted in my Direct Testimony, I recommend the use of remaining life depreciation rates based on the remaining life technique. No adjustments to the reserve are needed, especially for small imbalances, and an amortization of the reserve imbalance over a shorter period would be inappropriate. If the Commission uses the December 31, 2016 balances provided in FPL's Second Notice of Identified Adjustment my recommendation is the same.

Q. What has witness Pous proposed?

A. Witness Pous proposes a reduction in depreciation expense of approximately $231 million based on what he calculates to be the TRI for only a portion of FPL's assets. Again, as I noted above, the actual TRI is in fact very small. In order to artificially inflate the TRI on which to base a significant reduction in depreciation expense, witness Pous does the following:

- First, he completely ignores the TRI for production plant, which accounts for over half of the Company's plant in service. Production plant actually has a large negative TRI.
- Next, he makes a number of adjustments to service lives and net salvage for transmission, distribution and general plant accounts which artificially increase the TRI. Previously in my rebuttal testimony, I have explained in detail why these adjustments would be inappropriate.

- Then, he uses the calculated TRI based on his estimates for only transmission, distribution and general plant as the basis for his conclusion that there is a large positive TRI (also referred to as a "reserve surplus") of approximately $1.5 billion.
- Finally, he recommends that a portion of this artificial TRI be amortized over 4 years, as a $231 million reduction to depreciation expense.

By ignoring the portion of the Company's assets that have a large negative reserve imbalance, and only focusing on the portion that has a positive reserve imbalance, witness Pous is clearly taking a results-driven approach as opposed to a systematic and rational approach to depreciation. Further, as I have explained in detail throughout my testimony, his recommended service lives and net salvage are inappropriate. Thus, there is in fact a minimal TRI and witness Pous's proposed adjustment is inappropriate.

Q. In Docket No. 090130-EI, did witness Pous recommend an adjustment based on the TRI?

A. Yes, he did.

Q. Was his adjustment based on the TRI that he calculated based on his estimates in that case?

A. No. His recommendation was based on the TRI calculated in FPL's depreciation study in that case. This is an important distinction. In the 2009 case all parties, including FPL, had calculated a fairly sizeable positive TRI. In contrast, in the current case the 2016 Depreciation Study I have conducted

results in a very small TRI. Only by artificially inflating the TRI can witness Pous justify his proposal to accelerate its amortization.

Q. How will you address witness Pous's recommendation related to the TRI?

A. While I disagree with witness Pous's proposal and much of his testimony on a conceptual basis, and in general believe that the remaining life technique is the proper approach for reserve imbalances, there is little need to address these concepts in my rebuttal testimony. This is because witness Pous's proposal is based entirely on the inappropriate adjustments he has made to service life and net salvage estimates, as well as the fact that he has completely ignored the negative TRI for production plant.

For this reason, my testimony on this issue will focus on 1) explaining the various problems with witness Pous's calculations; 2) explaining why it is inappropriate to cherry pick portions of the TRI for which to make adjustments; and 3) correct the record in regards to a number of inaccurate statements and citations witness Pous makes in his testimony. However, to the extent I have not addressed various statements in witness Pous's testimony does not mean that they are correct or that I agree with them.

Q. Please first explain the TRI for production plant.

A. In the 2016 Depreciation Study the TRI calculated for production plant is negative $738 million.[94]

[94] See page 114 of Exhibit NWA-1. I should note that for this discussion I will use 2017 balances in order to be consistent with witness Pous's testimony. However, the discussion is similar when using 2016 balnaces.

Q. Has witness Pous calculated a TRI for production plant?

A. No. In fact, he has not even explained how a theoretical reserve would be calculated using his method for estimating interim retirements.

Q. Witness Pous states that "[t]he surplus reserve would be even higher were I to incorporate the impact of my production plant recommendations."[95] Is this true?

A. There is no way to know whether this is correct, because witness Pous has not even calculated a TRI for production plant based on his estimates. Indeed, he has declined to even explain how a theoretical reserve would be calculated when using his proposed method for interim retirements.[96] However, I have estimated the resulting TRI from his production plant recommendations and determined that his recommendations still result in a negative TRI for production plant.

Q. Would it be appropriate to only consider the transmission, distribution and general plant theoretical reserve imbalances and ignore production plant?

A. Absolutely not. It is inappropriate and clearly results driven for witness Pous to cherry pick certain functions of plant to use as the basis of a TRI amortization with the goal of reducing depreciation expense.

[95] Direct testimony of Jacob Pous, page 11, lines 20-22.
[96] See OPC's response to FPL's Second Set of Interrogatories, No. 25.

Q. Has witness Pous proposed to amortize the entire transmission, distribution and general plant TRI that he calculates in this case?

A. No. Witness Pous has proposed to amortize the portion of the TRI that exceeds 10% of the theoretical reserve.

Q. Has witness Pous based his calculation of 10% of the theoretical reserve on the full theoretical reserve for all of the Company's depreciable assets?

A. No. In addition to the fact that he has not bothered to calculate a theoretical reserve imbalance for production plant, he has also overstated the percentage value of the TRI by excluding production plant. When he calculates 10% of the theoretical reserve he only uses the transmission, distribution and general plant theoretical reserve. He therefore significantly understates the denominator to be used when determining the percentage of the theoretical reserve in that he ignores half of the Company's investment (i.e., production plant). Including production plant would make the TRI a significantly smaller percentage of the theoretical reserve and would result in a significantly smaller amortization than witness Pous's proposal.

Q. In support of his use of a 10% threshold witness Pous states that "Mr. Allis has testified regarding addressing a reserve imbalance in a New York case based on a 10% threshold of the theoretical reserve level."[97] Please address this claim.

A. Witness Pous has mischaracterized my testimony in New York. The case cited is for Consolidated Edison Company of New York. First, I should be clear that the 10% threshold was calculated for the whole Company. It did not cherry-pick functions of plant as witness Pous does. Second, my recommendation in that case was to recover the TRI for Consolidated Edison over the remaining life, not over a 4-year period as witness Pous proposes. Third, I should be clear that New York uses whole life depreciation rates, not remaining life depreciation rates. This is an important distinction that I will explain in more detail. Fourth, New York has for many years established a 10% threshold to address theoretical reserve imbalances. While the study I performed in New York was consistent with this New York-specific practice, I explained in my testimony for Consolidated Edison that it was not a typical practice in the industry and that the remaining life technique was a better approach.

[97] Direct testimony of Jacob Pous, page 44, lines 3-5.

Q. Witness Pous also cites another jurisdiction in which a 5% criterion is used. Is the experience of this jurisdiction applicable to FPL?

A. No. The jurisdiction referenced by witness Pous is Alberta, Canada. Alberta also uses whole life depreciation rates. Therefore its approach is not applicable to FPL for which remaining life depreciation rates are used.

Q. You used the term "whole life depreciation rates" when discussing your testimony in New York and the practice in Alberta. Please explain this concept further.

A. When the whole life technique is used, there is no consideration of the book reserve when calculating depreciation rates. Instead, depreciation rates for an account are simply calculated using the estimated average service life and net salvage estimate. For this reason, whole life depreciation rates will not recover the full cost of the Company's assets without a TRI adjustment. This is in contrast to the much more widely used remaining life technique, which ensures the full recovery – no more, no less.

Because an adjustment based on the theoretical reserve is necessary when using the whole life technique in order to ensure full recovery but is not needed under the remaining life technique, any reasonable depreciation professional would know that it makes little sense to compare practices in a state that uses whole life depreciation rates with those in a state such as Florida that uses remaining life depreciation rates.

IX. FPL'S SECOND NOTICE OF IDENTIFIED ADJUSTMENTS

Q. Please explain FPL's Second Notice of Identified Adjustments as it relates to the 2016 Depreciation Study.

A. For FPL's Second Notice of Identified Adjustments, which was filed on June 16, 2016, the calculated depreciation rates and accruals were updated to reflect estimated December 31, 2016 plant and reserve balances instead of the estimated December 31, 2017 plant balances originally used in the 2016 Depreciation Study.

Q. Did this change in calculation date impact any of the service life or net salvage estimates in the 2016 Depreciation Study?

A. No. The service life and net salvage estimates are the same. All that was changed was the calculation date and the corresponding plant and reserve balances.[98]

Q. Why did FPL provide these updated depreciation calculations based on 2016 plant and reserve balances?

A. Based on discovery from Staff and other parties, it appeared that the use of 2017 plant and reserve balances instead of 2016 balances was a point of concern for other parties. In particular, because the December 31, 2017 originally filed in the 2016 Depreciation Study is subsequent to the January 1, 2017 implementation date of the proposed depreciation rates, FPL's

[98] I should note that changing the calculation date changes the calculation of composite net salvage percents for production plant, which can result in slight changes to the composite net salvage percents used for the depreciation calculations. However, this does not result in a change of estimates, but instead automatically occurs with a change in the calculation date.

understanding was that other parties were concerned that the use of December 31, 2017 balances may not be consistent with FPSC Rule 25.6.0436(4)(d) Depreciation, Florida Administrative Code ("F.A.C.").

Q. Why did you use December 31, 2017 plant and reserve balances in the originally filed 2016 Depreciation Study?

A. In preparing the 2016 Depreciation Study, we faced a challenging circumstance: FPL is replacing a number of assets through the end of 2017 for which the new assets are expected to have a longer service life than those that they are replacing. This is true for both concrete transmission and distribution poles and the Company's capital spare parts for its combined cycle fleet, but is most pronounced for capital spare parts. Specifically, FPL's upgrade to the GE 7FA.05 components is scheduled to be completed by the end of 2017, and a large portion of the GE 7FA.05 components will be added in 2017 – that is, subsequent to the January 1, 2017 effective date of the depreciation study.

This presents a situation in which a number of assets will be retired within a year of the effective date of the proposed depreciation rates and will be replaced with assets that will have longer service lives. For this reason, in my judgment it was appropriate to use December 31, 2017 balances so that the calculated service lives would be most representative of the plant that would actually be in service by the end of the test year.

Q. On page 23 of his testimony SFHHA witness Kollen recommends that the Commission reject the 2016 Depreciation Study and continue to use the current depreciation rates because that Study original used December 31, 2017 balances. Do you agree?

A. No. First, as I have explained, the Company filed depreciation rates based on December 31, 2016 in its Second Notice of Identified Adjustment on June 16, 2016. These depreciation rates alleviate any criticism witness Kollen makes. Second, it would clearly be inappropriate to continue to use the currently approved depreciation rates. As the 2016 Depreciation Study demonstrates, the approved depreciation rates are no longer appropriate – whether calculated with 2016 or 2017 balances.

I should again make clear that even if there were no changes to the service life and net salvage estimates, the depreciation rates would still change when calculated based on more recent balances than the December 31, 2009 balances used to calculate the currently approved depreciation rates. As I demonstrated on Figure 1 in Section II of my rebuttal testimony, the depreciation expense based on the service life and net salvage estimates approved in 2009 updated to the recent plant balances would be $563.3 million higher than the results of my 2016 Depreciation Study. Thus, if one were to apply witness Kollen's proposal in a manner that adequately reflected the reality of FPL's current plant in service instead of arbitrarily freezing

things in time as of 2009, the result would be a very large additional depreciation expense that customers would have to bear.

Q. Witness Kollen claims that "[a] new comprehensive depreciation study would have to be performed using plant, accumulated depreciation, and related net salvage, as of the effective date of the new rates, or January 1, 2017" in order overcome the use of December 31, 2017 plant balances. Please address this criticism.

A. While witness Kollen does not define what he means by "comprehensive depreciation study," he is incorrect that calculating depreciation rates using 2016 instead of 2017 plant and reserve balances would require a comprehensive change to the entire study. The change from 2017 to 2016 balances, which was provided to all interveners with all supporting workpapers on June 16, 2016, does not result in changes to any of the service or net salvage estimates in the 2016 Depreciation Study. Instead, it is simply a change to the mathematical calculations of depreciation rates using these estimates, which the interveners had ample opportunity to confirm. In short, the Commission has everything it needs to set depreciation rates based on December 31, 2016 plant and reserve balances.

Q. Does this conclude your rebuttal testimony?

A. Yes.

i. Account 350.2 Land Rights

The currently approved survivor curve for this account is the 75-S4. There have been few retirements and therefore there is limited data for the statistical analysis for this account. I have recommended to continue to use the approved estimate. OPC Witness Pous has recommended to increase the average service life by 25 years and has proposed the 100-R4 survivor curve.

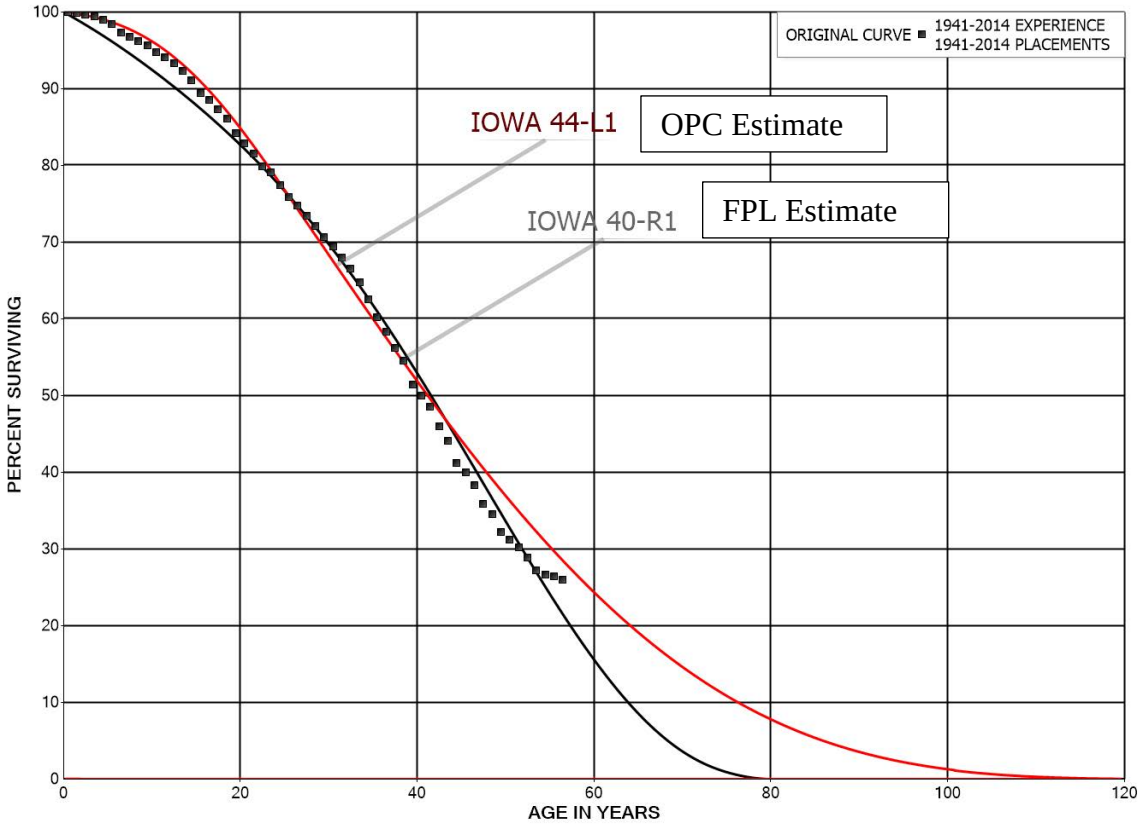
Witness Pous's arguments in this case are very similar to those he made in Docket No. 090130-EI. His proposal was not adopted by the Commission in that case. Further, because the data does not provide definitive results, the statistical analysis does not support his estimate over the approved estimate. The upper end of the industry range of estimates is 80 years, based on the Gannett Fleming industry database Witness Pous has cited in his testimony. Further, as I have explained in Section III.C, many of FPL's assets have shorter service lives than other utilities. It therefore does not make sense to have a much longer average service life for this account than the typical industry range for other utilities.

ii. Account 353 Station Equipment

The currently approved estimate for this account is the 40-R1.5 survivor curve. I have recommended the 40-R1 survivor curve, which has the same average service life as the currently approved estimate, but a slightly different curve shape. OPC Witness Pous has recommended the 44-L1 survivor curve.

Figure 1 below provides a comparison of each estimate to the representative data points. While witness Pous's estimate (shown in red in Figure 1) is a somewhat better fit of the historical data for early years, my estimate (shown in black) is a superior fit for the more important portion of the curve from 80% surviving to 20% surviving. In particular, the biggest difference between OPC's estimate and both my estimate and the historical data occurs beginning at about age 45. OPC's estimate begins to deviate from the data and forecasts a lower rate of retirements for these ages than the Company has actually experienced. Further, these ages are when many of the larger dollar items in this account, such as transformers and circuit breakers, will retire. It therefore makes sense to expect a higher level of retirements from age 30 through age 60. OPC's estimate predicts the opposite.

Figure 1



OPC's estimate is also not a common curve type for this account. OPC has proposed an L1 curve type. In the industry database witness Pous cites throughout his testimony there is only one L-type curve (of any mode) used for this account – out of a population of close to 80. The vast majority of estimates are R-type curves, and there are some S-type curves. L-type curves are rarely used for this account is for the reasons I explained above. Retirements of the larger dollar assets tend to occur in the 30 to 60 year range, and tend to accelerate as they approach 60 years of age because these types of assets reach the end of their useful lives. This retirement pattern is consistent with the retirement pattern shown in the 40-R1 survivor curve in Figure 1. It is not consistent with the 44-L1 estimate witness Pous has made.

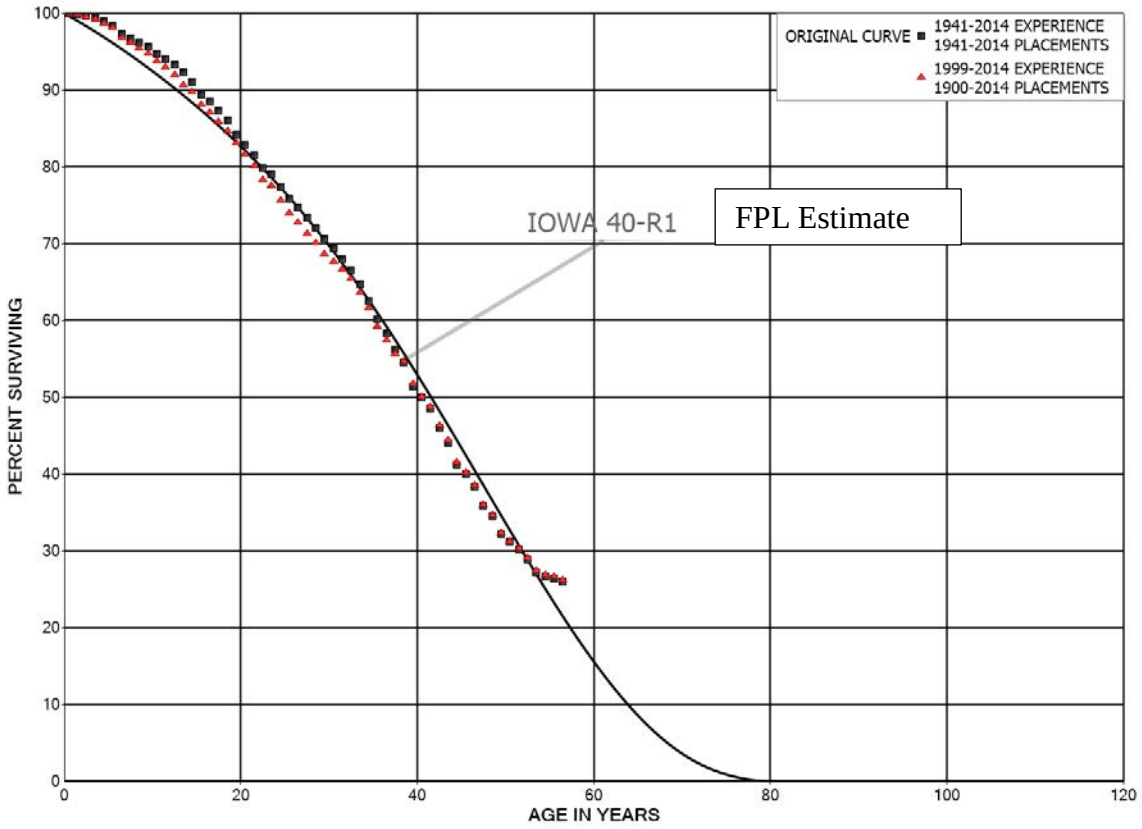
In addition to his presentation of the statistical results, witness Pous cites additional information in support of his estimate. On pages 77 and 78 of his testimony he cites the testimony of my colleague John Spanos. However, the cited testimony does not actually support OPC's 44-L1 curve. I agree with Mr. Spanos's comments in general that the survivor pattern projected by similar fitting survivor curves should be considered in order to assess the best estimate. As I explained above, these considerations support my estimate and not the L1 curve selected by witness Pous. I also will note that FPL's data generally results in more complete indications of survivor curves than was the case in the Massachusetts case cited by witness Pous. FPL's data therefore provides a better indication of the survivor curve, which as can be seen in Figure 1 demonstrates that my estimate is a superior fit to OPC's.

Witness Pous also presents a discussion on page 75 of his testimony with regard to what he calls the "variance in the types of investments in this account." Actuarial analysis was developed in part to address the issues witness Pous discusses. The fact that transformers are a smaller portion of historical retirements than the current investment balance is not surprising and does not affect the actuarial results as he implies it does. The data points in an original life table are developed by comparing retirements to the balances in service at each age. Thus, components that retire at earlier ages such as lightning arrestors are compared to a very large balance at earlier ages and have a limited impact on the life table. Retirements of transformers that occur at later ages are compared to the balances that survive to those ages. Indeed, if anything witness Pous's discussion supports my estimate over the survivor curve he has selected. As larger dollar items such as transformers age and reach the end of their useful lives they will be need to be replaced. Again, this will typically occur in the 30 to 60 year range and the level of retirements will increase with age. For this reason, as transformers age and are retired with more frequency the result should be a retirement pattern that is more similar to the R1 curve that I have estimated than the L1 estimated by witness Pous.

Witness Pous also argues that the impact of the removal of PCB's would increase the service life. I should first point out that the removal of PCB's did not always result in retirements, as in many cases in order to address PCB issues FPL removed oil from transformers and circuit breakers but the assets remained in service. Second, the implication in witness Pous' testimony that "many transformers

were retired early" is not necessarily correct. Transformers that had PCB oil were often older assets. Finally, the data does not support witness Pous's conclusion. The removal of PCB's was completed in 1998. Figure 2 below compares an experience band with data subsequent to 1998 to the overall band and my estimate. The 1999-2014 experience band (shown in red in the graph) actually indicates a somewhat shorter life than the overall band and my estimate.

Figure 2



Witness Pous also discusses the impact of tighter design tolerances on the life of transformers. This concept is one that I have discussed with engineers not only at FPL but with many other utilities around the country, and this concept supported by experts on transformers across the country. Decades ago, when materials were less expensive and manufacturing technology did not allow for the precision in designs available today, transformers and other assets were designed with more materials. Today transformers can be designed with "tighter tolerances" and do not need the same extent of material. This has the obvious benefit of reducing the cost of transformers (which are expensive equipment), but can also impact the life of transformers.

One impact of tighter design tolerances could be an overall shorter average service life, although I have not decreased the service life for this account related to this concept. However, where tighter

design tolerances are likely to have the most impact is for later ages beyond the design life of this equipment. While many older transformers were able to be pushed well beyond the design life, this will likely occur less frequently for newer transformers. As a result, the most pronounced impact will be for later ages where the rates of retirement will likely be higher than was the case for older transformers. Thus, this concept favors a higher mode curve than a lower mode curve and an R curve over an L curve. This provides another reason that the R1 curve type is a better selection than the L1 curve type used by witness Pous.

Witness Pous also states that "actual evidence provided by FPL demonstrates that it has investment in transformers that exceed 74 years of service."[1] However, his statement is incorrect, at least as it refers to the large dollar types of transformers that are the subject of witness Pous's discussion on pages 78 and 79 of his testimony. Referring to witness Pous's source for this statement,[2] the investments in transformers that "exceed 74 years of service" are potential transformers, not autotransformers. Further, the "investment" to which he refers is very small - there is only about $39,000 of investment that exceeds age 74. Potential transformers are a different type of asset from the larger transformers witness Pous discusses, and potential transformers are a relatively small dollar component of this account. The large dollar assets that witness Pous is actually referring to in his discussion are autotransformers, not potential transformers. FPL does not have investment in this account for autotransformers that exceeds 74 years of age. Instead, almost all of these types of assets are 50 years of age or less. Thus, a review of the "actual evidence" cited by witness Pous does not support his estimate and is more supportive of my estimate.

Finally, on page 74 of his testimony witness Pous also discusses the impact of a retirement that occurred at age 5.5. However, because the exposures are very large at this age (over $1 billion), the retirements at this age, which were in part due to warranty transactions, has a minimal impact on the original life table. I should also note that witness Pous has not incorporated this activity consistently for both the life and net salvage analyses. While he raises the issue here for life analysis, he gives undue consideration to this activity in the net salvage analysis. I have considered the impact of this transaction in both the life and net salvage analyses.

[1] Direct Testimony of Jacob Pous, p. 79, lines 8-9.

[2] Attachment 1 of FPL's response to OPC's First Set of Interrogatories No. 69 provided in Exhibit NWA-5.

iii. Account 353.01 Station Equipment – Step Up Transformers

The currently approved estimate for this account is the 35-R2. I have recommended a decrease in the average service life for this account. I have recommended the 30-R1 survivor curve. This is well supported by the historical data, which actually indicates an even shorter service life. A decrease in service life also makes sense because the life spans of the Company's power plants are on average shorter than was the case for the 2009 Depreciation Study. One of the main causes of retirements for step-up transformers, which are located at the Company's power plants, is the retirement of the power plant. The Company has retired a number of steam-fire power plants in recent years, which had life spans that were on average approximately 50 years. The combined cycle plants that have replaced these facilities have life spans of 40 years. It is therefore reasonable to expect a shorter life for step up transformers.

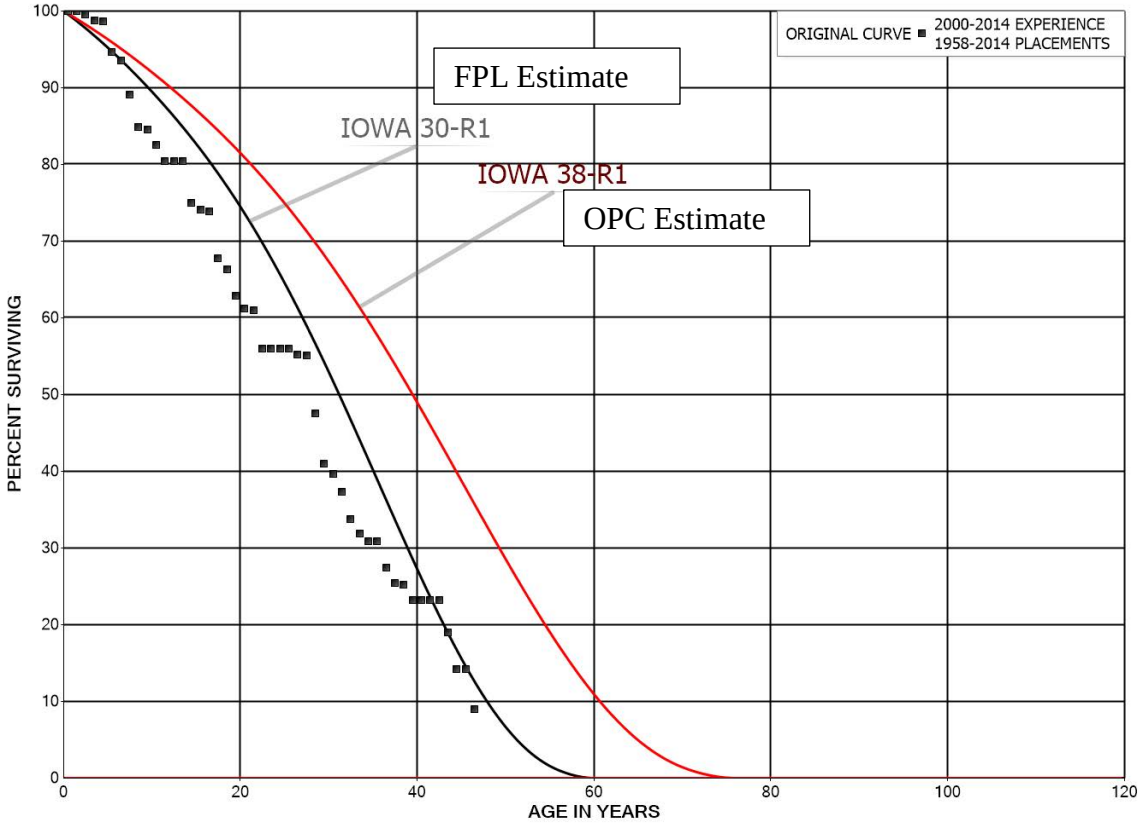
However, it is important to point out that not all retirements of these assets occur due to the retirement of power plants. Step-up transformers, which are critical components and are typically run to full capacity, are often replaced prior to the end of the life of the power plant. For example, FPL has replaced all of the step-up transformers at its nuclear power plants.

Despite the fact that both the data and other considerations indicate that a shorter life is appropriate, witness Pous has proposed to increase the average service life for this account. He has proposed the 38-R1 survivor curve. While witness Pous states that his estimate is "based on recognition of both the type of asset at issue for this subaccount as well as the key driver of useful life,"[3] he provides little support for deviating from the data. Further, not only is his estimate inconsistent with the data but it makes little sense based on what witness Pous calls "key driver of the useful life" – the life spans of the facilities where the Company's step-up transformers are located.

I should first note that witness Pous does not even show a chart of his estimate in his testimony. Had he done so, it would become quite clear that his estimate makes little sense. I have provided a comparison of my estimate (shown in black) and his (shown in red) to the historical data in Figure 3 below.

[3] Direct Testimony of Jacob Pous, p. 82, lines 6-7.

Figure 3



The first observation one can make from the chart is that OPC's estimate is a very poor fit of the historical data. However, it is also clear that witness Pous's estimate does not even match the justification he sets forth in his testimony. As can be seen in the chart, witness Pous's estimated survivor curve extends beyond 60 years of age. The longest life span for any of the Company's power plants is 60 years. As a result, the survivor curve for this account should not predict that any assets will remain in service for more than 60 years. Further, the step-up transformers the Company's nuclear plants (the only plants with 60 year life spans) have already been replaced. The step up transformers at these plants will therefore have an average life that is no longer than 30 years.[4] Witness Pous's estimate is therefore inconsistent with reality – none of the Company's step-up transformers will have lives of 50 years or more.[5]

As can be seen in the graph, witness Pous's estimate extends to about 70 years of age. This alone should be disqualifying – at a minimum, the survivor curve for this account should not predict any

[4] This is because there will be at least two transformers over the 60 year life spans of the nuclear plants. As a result the average lives of step up transformers at these sites cannot exceed 30 years.

[5] 50 years is the longest life span for any non-nuclear plant.

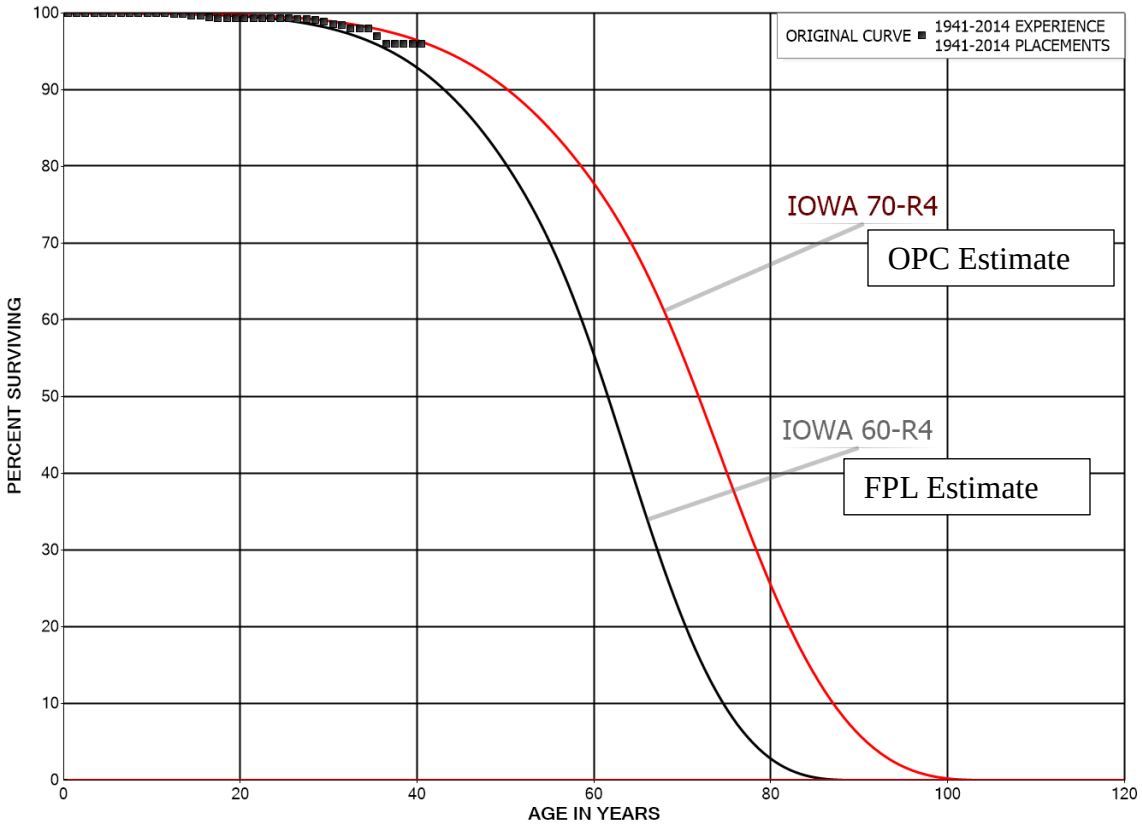
assets to last longer than 60 years. Further, his estimate projects that around 30% of the assets will remain in service for longer than 50 years. This is also illogical, especially given that many of the step up transformers at the Company's nuclear plants have already been replaced. Given that step up transformers are critical assets it would be unreasonable to run such a large number for 50 years or more.

iv. Account 354 Towers and Fixtures

The currently approved estimate for this account is the 52-R4 survivor curve. I have recommended an increase in the average service life to the 60-R4 survivor curve. Most of the assets in this account are relatively new when compared to the overall life cycle of transmission towers. Over 99% of the assets have been installed since 1974. As would be expected given the age of the assets, there have been relatively few retirements in the account and therefore the statistical analysis does not provide conclusive results. OPC has recommended a 70-R4 survivor curve for this account. The primary bases of witness Pous's estimate is the statistical analysis as well as a comparison to estimates for other utilities. He also makes a comment related to the mix of investment in the account.

Given that almost all of the assets in this account are younger than the average service life I have proposed (and much younger what witness Pous has proposed), the historical data should not be expected to provide definitive indications for this account. Witness Pous therefore relies too much on the statistical analysis. Further, witness Pous's analysis is improper. In the chart he presents on page 86 of his testimony, he includes a number of data points that should not be considered given the size of the exposures. As I noted above, more than 99% of the account was added since 1974. For this reason, the data beyond age 40.5 in the original life table provides limited value in the statistical life analysis. In Figure 4 below I provide a comparison of our estimates based on the representative data points (i.e., those through age 40.5). As can be seen in the chart, none of the data points extend below 80% surviving. Both curves are similar fits of the limited data, as might be expected given that the data is not definitive due to the age of the assets in the account. However, my estimate (shown in black) does a better job of incorporating the retirements that have occurred from age 30 through age 40.

Figure 4



Witness Pous also uses comparisons to estimates of other utilities to support his estimate for this account. However, when properly considered, such comparisons to the industry do not support his estimate over mine. Both the 60-R4 and the 70-R4 estimates are within the typical industry range of 50 to 75 years. However, his average service life estimate for this account of 70 years would be near the upper end of the industry range. As I have explained in Section III.C, due to the harsher conditions in Florida than many other parts of the country, FPL should be expected to have service lives on the shorter end of the industry range. This is true for metal transmission towers. Additionally, FPL's transmission towers are typically steel tubular towers on concrete caisson foundations. This may differ from many other utilities for which steel lattice towers are more common. As a result, a direct comparison to the average service lives for transmission towers for other utilities would not be as meaningful. Given all of these considerations, my estimated 60 year average service life is therefore more consistent with industry comparisons than witness Pous's estimate once the specifics of FPL's assets are considered.

Witness Pous also discusses the "mix of investment" in this account on page 85 of his testimony, and specifically discusses foundations. He states that "foundations are normally assumed to have very

long life expectations."[6] Witness Pous's implication appears to be that foundations would last much longer than the actual towers that are set upon these foundations. I would not necessarily expect this to be the case. When a tower is retired the foundation will typically be retired as well. This is true if the tower is replaced with another structure on the same footprint as well as if the transmission line were retired because it was no longer required (i.e., if it were replaced with a new line elsewhere on the system).

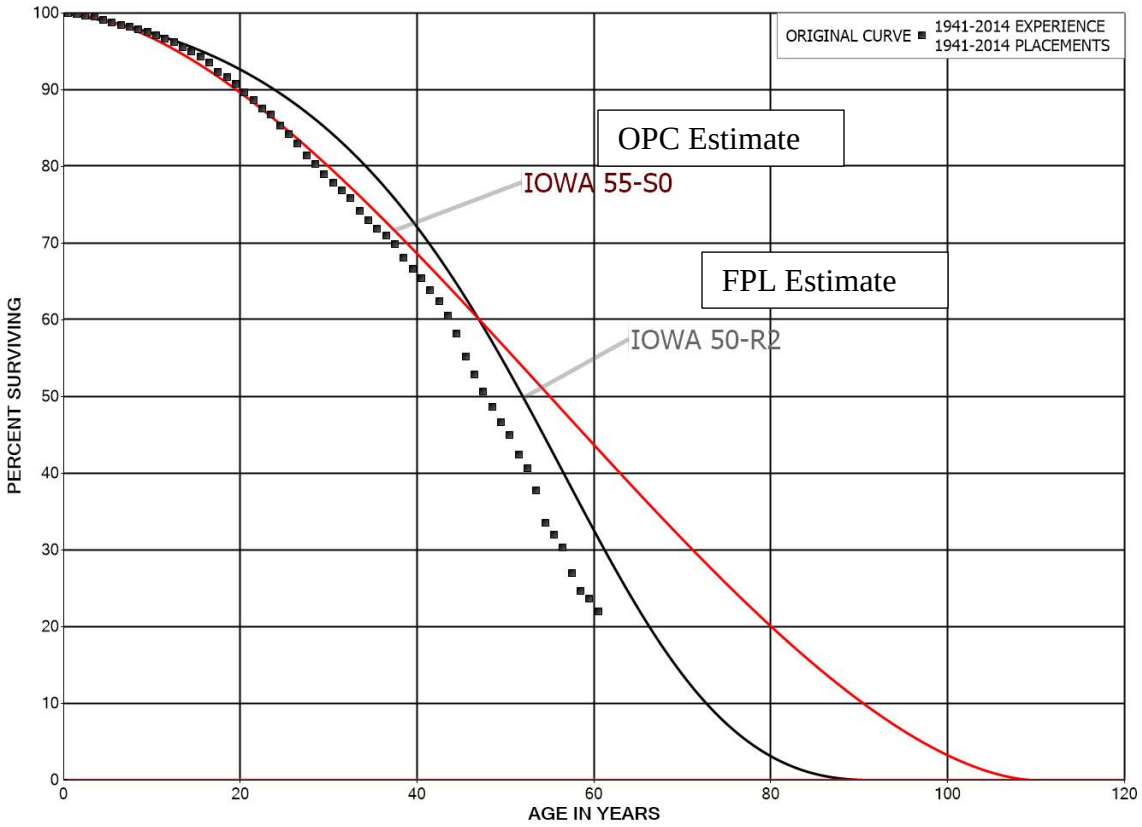
[6] Direct Testimony of Jacob Pous, p. 85, line 13.

v. Account 355 Poles and Fixtures

The currently approved estimate for this account is the 44-R2. I have recommended the 50-R2 survivor curve. This estimate is longer than indicated by the historical data, which takes into consideration that the mix of investment in this account has changed and that most transmission poles are now concrete. OPC has proposed the 55-S0 survivor curve. Witness Pous' estimate has an average service life that is more than ten years longer than the Company's actual experience for this account. While the increase in the percentage of this account that is concrete poles may support a somewhat longer service life than the Company has experienced historically, OPC's recommendation is too significant of a change.

Figure 5 below provides a comparison of my estimate (shown in black) and OPC's estimate (shown in red) to the historical data. Both are elevated above the historical data, and therefore both my estimate and OPC's estimate expect a longer service life than has occurred historically due to longer life expectations for concrete poles. The main difference between our estimates, which can also be seen in the figure, is that OPC has estimated a lower mode curve than has occurred historically, which increases the average service life. As I will explain, OPC's expectation is not reasonable for the assets in this account.

Figure 5



First, I should point out when one analyzes the vintages that are primarily comprised of concrete poles, the data does not support a dramatically longer service life for concrete poles; nor does it support a much lower mode curve. For example, in Figure 6 below I compare the 1985 through 2014 placement band (shown in green in Figure 6) with the overall band. The data for placements from 1985 through 2014 is generally comprised of a high percentage of newer concrete poles than wood poles. As can be seen in the figure, this placement band supports neither a significantly longer life nor a much lower mode when compared to the overall experience band. The concept can also be seen in Figure 7, which follows. The 40-R2 survivor curve, which actually has a shorter average service life than the best fitting curve from the overall band, is a very good fit of the available data for 1985 through 2014 vintages.

Figure 6

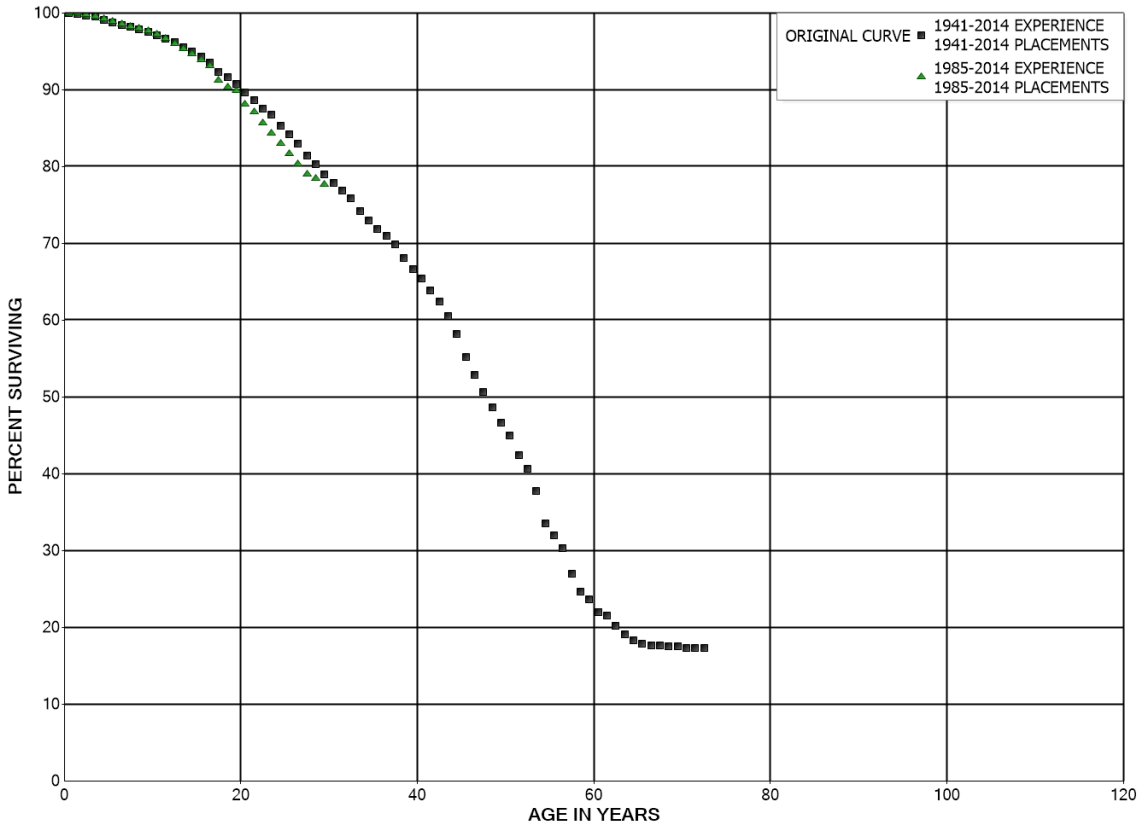
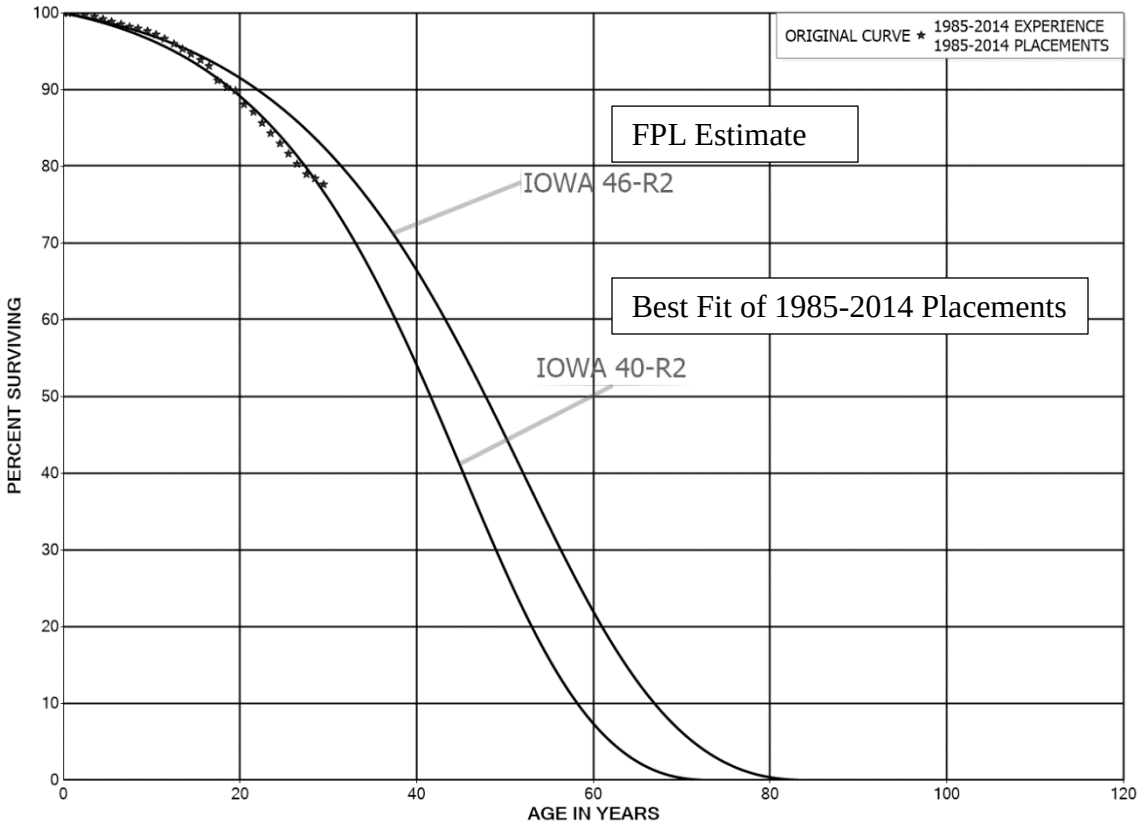


Figure 7



Witness Pous also references the pole inspection program on page 93 of his testimony. I have discussed the impact of the pole inspection program on the service life of poles in Section VI.C of my rebuttal testimony. I have explained that one likely impact of the pole inspection program is a higher mode curve. I should also point out that while the formal inspection program began in 2006, FPL had inspected transmission poles for many years prior to that date. Further, because there are not necessarily the same remediation options for concrete poles than wood poles (e.g., concrete poles cannot be treated in the way wood poles can), the pole inspection program may have the impact of both increasing the mode without lengthening the average service life. OPC has recommended a much lower mode curve than both my estimate and the approved estimate. This recommendation does not actually make sense in light of the pole inspection program.

On pages 89 and 90 of his testimony witness Pous criticizes my estimate for not recognizing what he calls the "more normal service life relationship between transmission and distribution poles." I first note that I do recognize that it is often the case that distribution poles have a shorter service life than transmission poles. This actually is the case for FPL once one considers that wood poles have a shorter life than transmission poles. However, FPL's concrete distribution poles historically have not had a shorter life than transmission poles. Witness Pous offers no reason why the historical relationship would

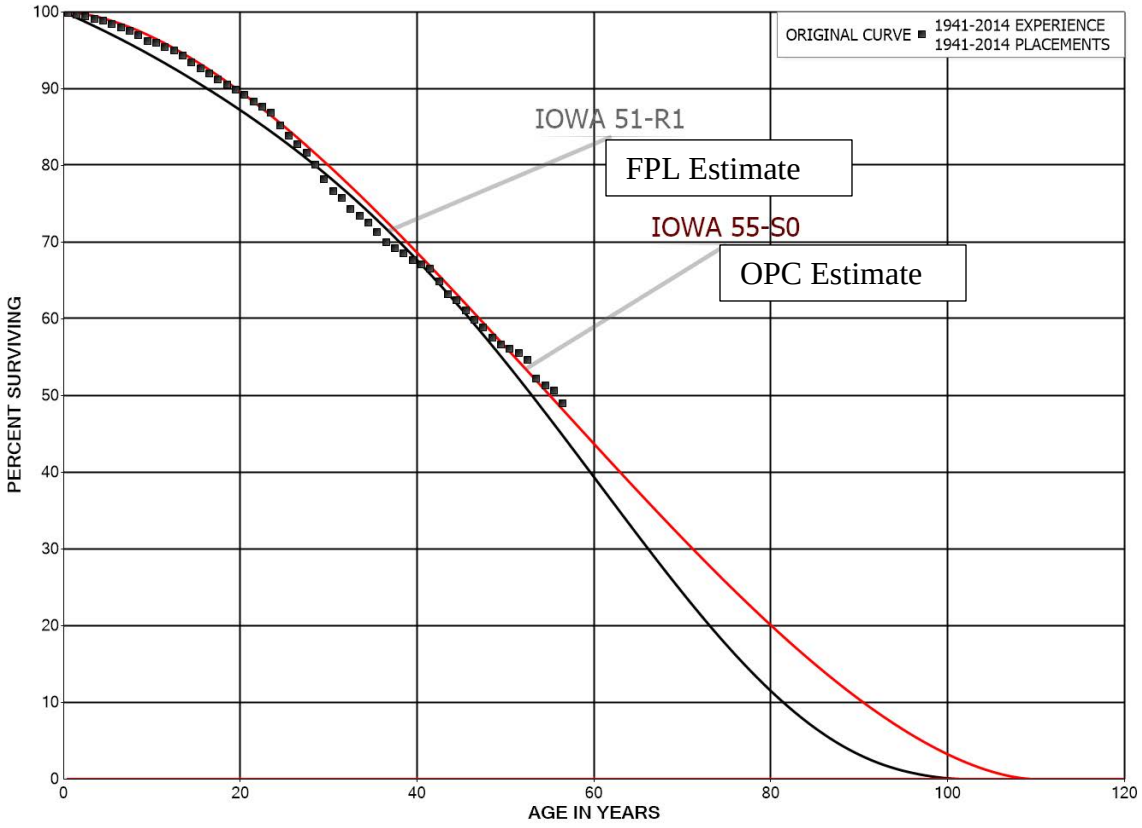
not be the same in the future. His argument is made even more bizarre by the fact that his estimate for concrete distribution poles is actually longer than for transmission poles. Thus, any criticisms he makes on the relationship of transmission and distribution poles are actually more applicable to his estimates than they are to mine.

vi. Account 356 Overhead Conductors and Devices

The currently approved estimate for this account is the 47-R1.5 survivor curve. I have recommended the 51-R1 survivor curve, which represents a longer average service life than the currently approved estimate and a moderate change to the curve type. Witness Pous recommends the 55-S0 survivor curve, which represents an even larger increase in the average service life and a more significant change in curve type to a lower mode S-type curve. As with many accounts, the primary driver of witness Pous's recommendation is that he has changed the mode of the curve to a lower mode curve type. As I will explain, his change in curve type is not reasonable for the type of property studied.

Figure 8 below provides a comparison of my estimate (shown in black), OPC's estimate (shown in red) and the Company's historical data. Both curves are relatively similar, and as can be seen in the figure the main differences occur after about age 50 and become more pronounced beyond age 60 (i.e., beyond the end of the data shown in the graph). As a result, the primary difference between the two estimates occurs beyond the end of the data in Figure 8. The primary difference is therefore due to differences in how witness Pous and I extrapolate the historical data.

Figure 8



As I have discussed for many accounts, R type curves generally predict an increasing level of retirements with age. In contrast, the S0 type curve used by witness Pous is a fairly straight line and therefore predicts a constant to somewhat declining level of retirements beyond age 60. The expectation implied by the S0 curve type is not as reasonable for this account as is the dispersion pattern for R type curves such as the R1 curve I have used. As I discuss on page 715 of Exhibit NWA-1, two of the causes of retirements for the conductor in this account are for capacity reasons and due to damage and failure, often as the result of metal fatigue that occurs due to wind loading. The need to upgrade conductor for capacity reasons tends to increase in probability with age, and therefore favors an R type curve over an S0 curve. Similarly, the probability of the need to replace conductor due to damage or failure tends to increase with age. Further, as I also discuss on page 715 of Exhibit NWA-1, the storm hardening program could have the result of increasing the probability of these latter types of retirements for older ages. This is because with stronger structures (i.e., poles and towers), more of the force of winds and storms[7] is transferred to the conductor. Over time, this will produce more metal fatigue for conductor and could increase the probability of retirements for this reason.

For these reasons, an R1 survivor curve type is more reasonable than the S0 curve type that witness Pous has selected. It is also true that R type curves are much more common for this account in the industry than the S0 curve type witness Pous has selected. Based on the industry data witness Pous cites in his testimony, almost all estimates for this account are based on R type curves. Further, most are actually for a higher mode than the R1 curve type I have used, which further supports the concepts I have discussed above. The S0 curve type was not used for any of the studies included in the industry database that witness Pous has cited.

Witness Pous also provides a number of reasons that he claims will result in longer lives for this account. In general, he does not present valid reasons for his decision to select an uncommon curve type. His discussion of the impact of the storm hardening program, in which he argues that the result of the storm hardening program could result in longer lives for conductor, is incorrect. Witness Pous states that "[t]o the extent transmission poles were knocked down due to severe winds in the past, those events may also have resulted in retirement of transmission overhead conductors in certain instances. To the extent transmission towers and poles are now being constructed to withstand greater storm forces, then that particular aspect of retirements attributable to overhead conductors should also diminish since fewer towers and poles will be knocked over during storms."[8] There are multiple problems with this statement. First, hurricane retirements have been excluded from the life analysis. Thus, the scenario witness Pous describes has no impact on the life analysis. Second, he is also wrong that hurricanes or strong storms are likely to result in fewer retirements of conductor. Hurricane strength winds are still

[7] Note that winds and storms does not necessarily mean hurricanes and major storms, but also the long term impact of more normal storms and weather such as thunderstorms.

[8] Direct Testimony of Jacob Pous, p. 99, lines 8-13.

likely to result in retirements of conductor, no matter the type of pole to which they are affixed. Instead, as I discuss above the more likely impact of the storm hardening program is that the strength of winds will have more of an impact on conductor now than in the past, due to increased stress on conductor over time.

Witness Pous also argues that the force of retirement due to upgrading lines will be less likely in the future because the Company has a "sizeable dollar level of investment in higher voltage transmission lines."[9] However, FPL has had higher voltage transmission lines for many years. The impact of having higher voltage lines on capacity retirements is therefore incorporated into the historical data. Witness Pous provides no evidence that the future will be any different. He also discusses the impact of installing dampers on the system. However, as witness Pous notes, dampers have been installed since 1974. The impact of dampers is therefore also already incorporated into the historical data.

[9] Direct Testimony of Jacob Pous, p. 99, lines 16-17.

vii. Account 362 Station Equipment

The currently approved estimate for this account is the 43-R1.5 survivor curve. I have recommended the 45-R1.5 survivor curve, which recognizes a moderate trend in the data towards a longer service life. OPC has proposed the 48-S0.5 survivor curve. As with many accounts, OPC Witness Pous's estimate is primarily due to a change to a lower mode curve. FEA has also recommended an adjustment to the survivor curve for this account and has proposed the 51-S0.5 survivor curve. Similar to OPC, FEA witness Andrews's estimate is also due in part to a change to a lower mode curve. In addition, witness Andrews's change in estimate is due to his reliance on the most recent 20 year experience band. I have addressed the issues with witness Andrews's approach in Section VI.B.iv of my rebuttal testimony and will not repeat that discussion here.

Figure 9 below shows a comparison of my estimate (shown in black) and that of OPC (shown in red) to the overall band. This presents a better illustration of the two estimates than witness Pous's graph shown on page 105 of his testimony, in which he omits a large portion of each curve. Both curves are similar through about age 50. The portion of the curve through about age 50 is the portion of the curve for which representative data is available. As the chart below illustrates, the biggest difference between the two curves is what both witness Pous and I project beyond the data (i.e., beyond about age 50 after the black squares stop on the graph). The 45-R1.5 represents a more reasonable projection beyond the end of the data in Figure 9 for the same reasons I have discussed for Account 353 in Section ii of this exhibit. Retirements of the larger dollar items in the account such as transformers and circuit breakers should be expected to increase in frequency as they age, consistent with the R1.5 curve type.

Figure 9

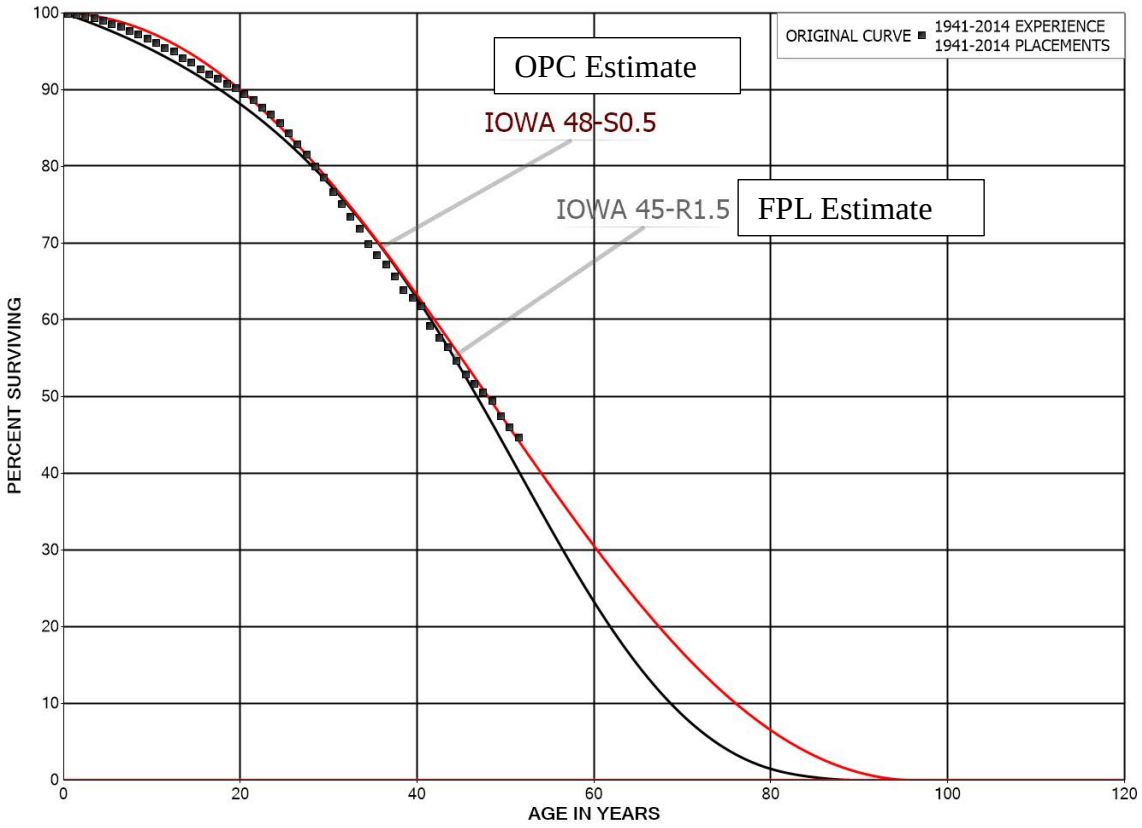
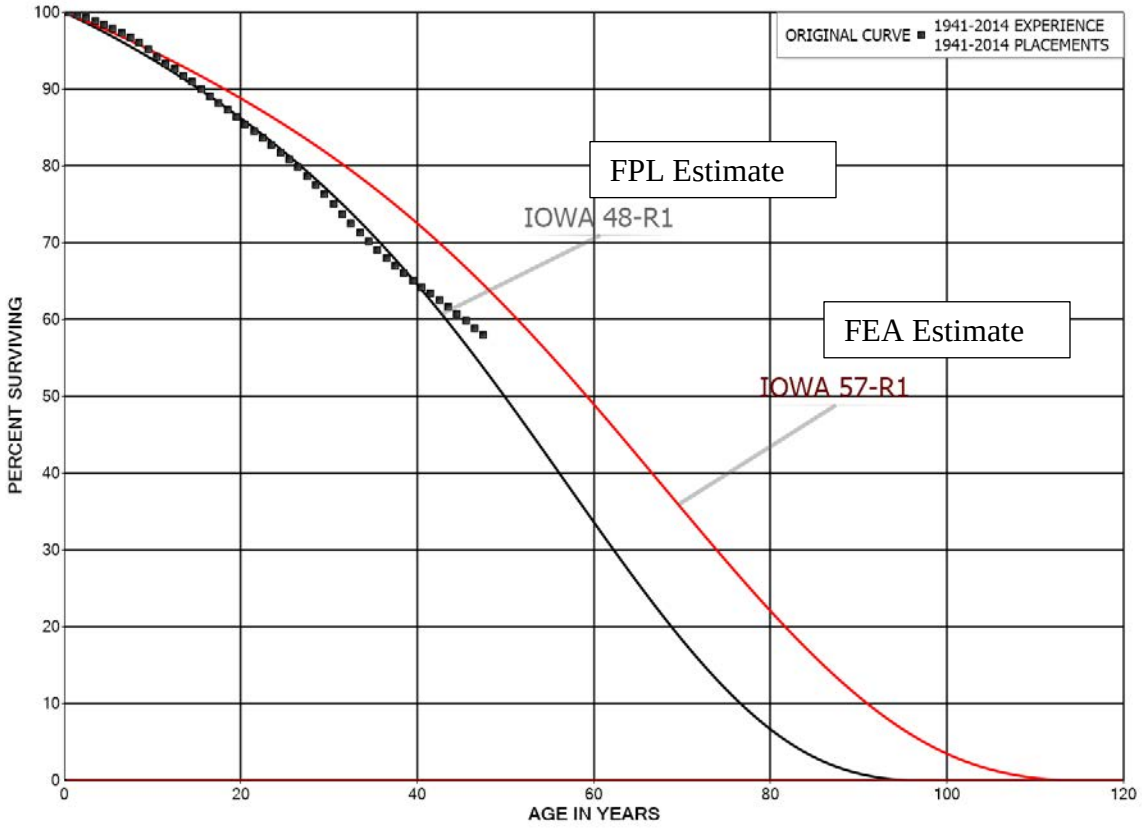

ORIGINAL CURVE
1941-2014 EXPERIENCE
1941-2014 PLACEMENTS
OPC Estimate
IOWA 48-S0.5
IOWA 45-R1.5
FPL Estimate
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120

Figure 10 below provides a similar comparison of my estimate (shown in black) and that of FEA (shown in red) with the overall band. As the chart shows, FEA's estimate is a poor fit of the overall band.

Figure 10



The S0.5 survivor curve selected by both OPC and FEA is not as common of a curve type as the R1.5 I have used in the 2016 Depreciation Study. Referring to the industry database witness Pous cites in his testimony, one can see that while S0.5 curves have occasionally been used for this account, R1.5 curves are much more common by about a 5 to 1 margin. Further, R type curves in general are far more common than S type curves. As was discussed for Account 353 Station Equipment, the larger dollar assets in the account such as transformers and circuit breakers will tend to retire in the middle portion of the curve. For this reason, it is reasonable to expect an increasing level of retirements in the middle portion of the curve (say from 30 to 60 years), which is consistent with the R type curves.

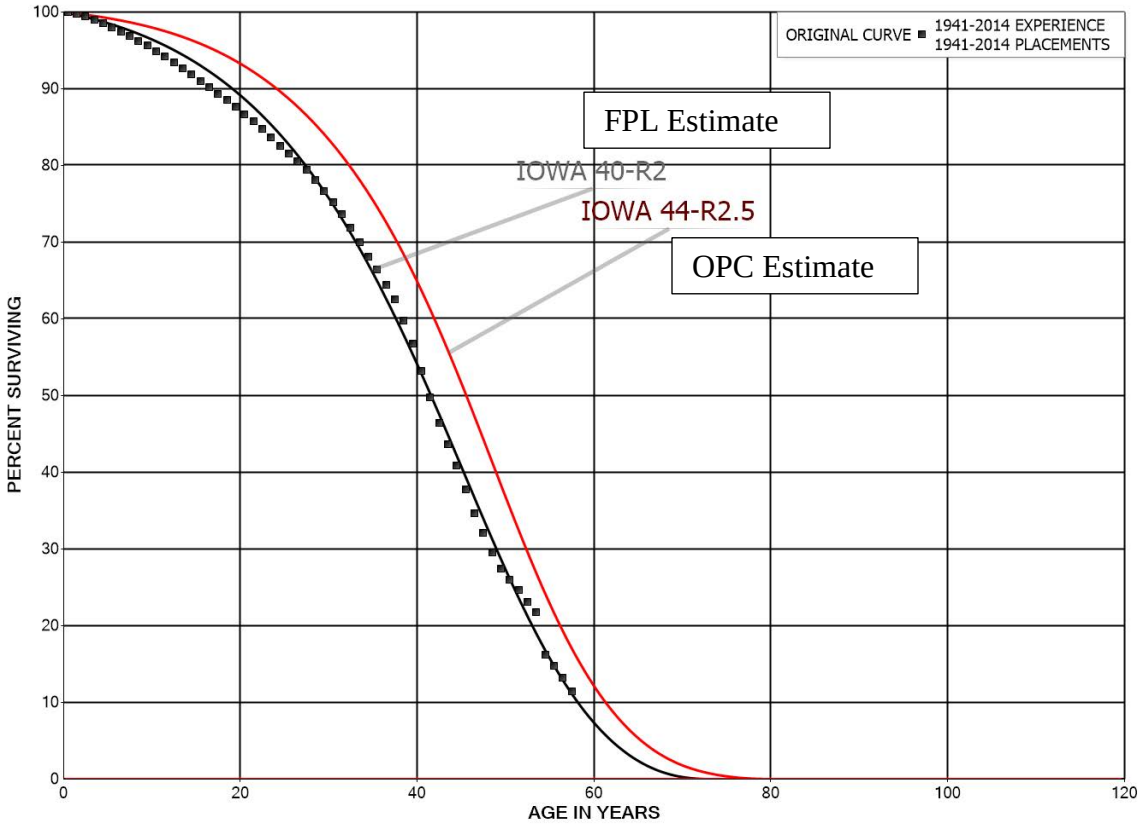
Witness Pous also discusses the impact of tighter design tolerances on the life of transformers. I have addressed his comments on this topic in the discussion for Account 353 in Section ii of this exhibit. The same concepts apply to this account. The concept of tighter design tolerances favors a higher mode curve than a lower mode curve, and provides another reason that the R1.5 curve type is a better selection than the S0.5 curve type used by both witness Pous and witness Andrews

viii. Account 364.1 Poles, Towers and Fixtures – Wood

Prior to the 2016 Depreciation Study, wood and concrete poles were studied together. The currently approved estimate for both types of poles is the 39-R2 survivor curve. Because wood poles have historically had a shorter service life on average than concrete poles, this implies that the currently approved average service life for wood poles is somewhat shorter than 39 years. For the 2016 Depreciation Study, I have proposed to sub-divide wood and concrete poles into separate subaccounts. For this account, which includes wood poles, I have proposed the 40-R2 survivor curve. This represents a moderate increase over the existing service life. OPC's proposal is to increase the service life to the 44-R2.5 survivor curve. OPC's estimate is a poor fit of the historical data, both for the overall experience and for the more recent experience OPC witness Pous relies on. OPC's estimate also represents a fairly sizeable increase in light of the Company's ongoing storm hardening program in which wood poles will be replaced at higher rates than was the case historically.

I have provided a comparison of my estimate (shown in black) and OPC's estimate (shown in red) to the overall experience band in Figure 11 below. As the chart illustrates, my estimate is a much better fit of the overall band.

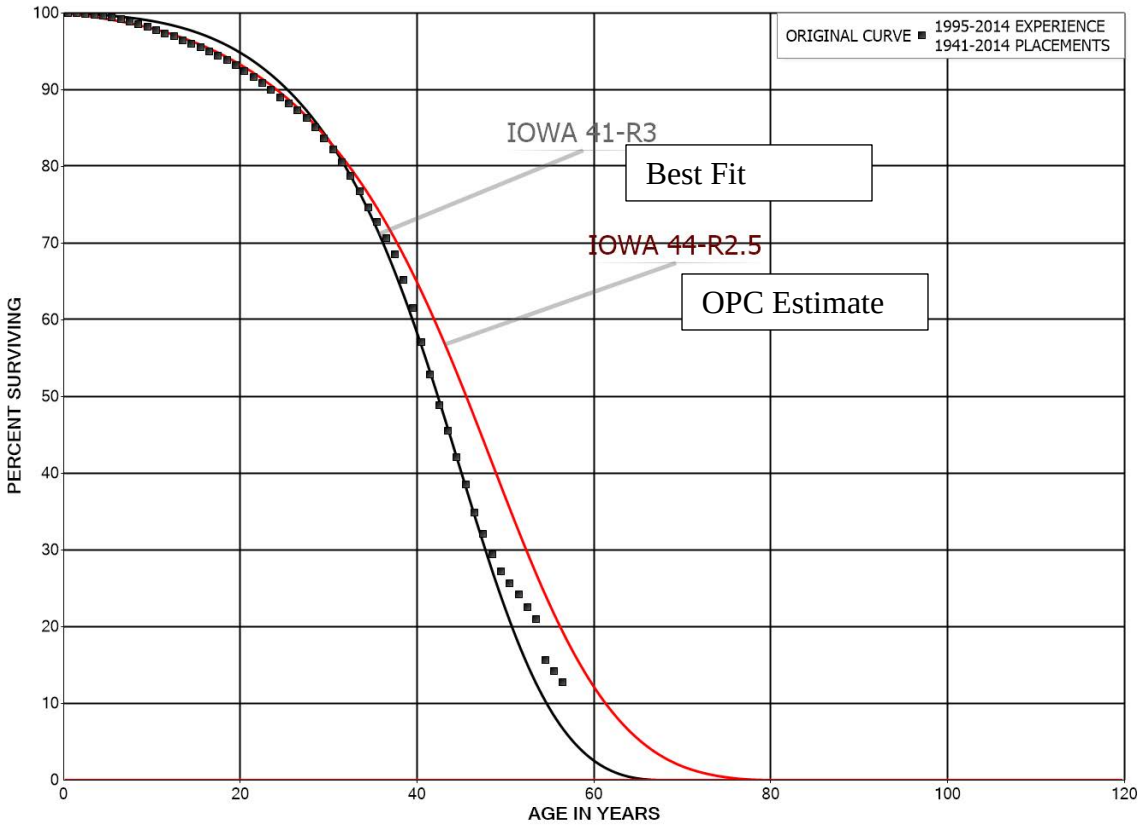
Figure 11



While witness Pous makes a handful of general statements in his discussion of this account, the only actual evidence he presents in support of his proposal is to use a more recent experience band instead of the overall experience band. His implication on pages 107 and 108 is that I did not consider the analyses of more recent experience bands. This is incorrect. I did consider more recent bands for this account. However, unlike witness Pous, when I considered these bands I used proper curve fitting techniques that did not ignore the most meaningful portion of the survivor curve.

When proper curve fitting techniques are used, more recent bands provide similar statistical indications to the estimate I have proposed. For example, Figure 12 below presents the 1995-2014 experience band relied on by witness Pous. The graph also shows in red the 44-R2.5 survivor curve recommended by witness Pous. In contrast to witness Pous's estimate, I have also presented a graph of the 41-R3 survivor curve (shown in black), which is a much better fit of the data. The chart illustrates that witness Pous's estimate is a similarly poor a fit for the more recent experience band as it is for the overall experience band. I should also note that the 43-R2.5 survivor curve witness Pous shows in his graph on page 110 of his testimony, but did not select as his final estimate, is also a poor fit of the historical data. The 41-R3, which has a similar average service life to the estimate that I recommend, is a superior fit of the data. In particular it is a much better fit for the most meaningful portion of the curve from 80% to 20% surviving. I should note that while I did not select the 41-R3 survivor curve, it would actually produce a shorter remaining life and somewhat higher depreciation expense than the 40-R2 survivor curve I have estimated.

Figure 12



Witness Pous also claims that I "skipped the life estimation phase"[10] for this account. This is untrue. I have explained the life estimation phase on pages 727 and 728 of Exhibit NWA and have specifically explained the impacts of the pole inspection and storm hardening program in the responses to discovery.[11] I have explained that information external to the statistical analysis supports that, if anything, the service life should be shorter in the future than represented by the historical data. The first and most meaningful piece of information is the storm hardening program. Since the program's inception, the Company's focus has been on replacing wood poles on feeder lines, which is ongoing. The Company then plans to move to replacing wood poles on many lateral lines. Storm hardening is planned to continue through at least 2024. Thus, the expectation should be that a higher level of retirements will continue for some time and the result will be that, if anything, the service life for this account will decline. Further, the impact of storm hardening should at a minimum offset any other factors witness Pous discusses that may result in a longer life.

[10] Direct Testimony of Jacob Pous, p. 107, line 14.

[11] See FPL's responses to OPC's Tenth Set of Interrogatories No. 253 provided in Exhibit NWA-5.

The second piece of information to consider is the pole inspection program. I have discussed the impact of the pole inspection program in Section VI.C of my rebuttal testimony. Indeed, the fact that more recent bands show higher mode curves for this account supports the concepts I set forth in that section. Further, as I explained, combined with standards for a stronger and resilient system, it is quite possible that the pole inspection program will result in more retirements and a shorter average service than occurred in the past.

Finally, witness Pous discusses "changing chemical treatments for wood poles."[12] I should first note that FPL has treated poles for many years, and so the impact of using treated poles is already incorporated into the data. This certainly does not provide a reason to ignore the most meaningful portion of the survivor curve, as witness Pous choses to do. Further, I should note that newer types of pole treatments do not necessarily result in longer lives than older types of pole treatment. For example, one reason pole treatments have changed over time is for environmental reasons. Newer treatments may be more environmentally friendly but do not necessarily result in an appreciably longer life (and the opposite could in fact be true).

[12] Direct Testimony of Jacob Pous, p. 107, line 18.

ix. Account 364.2 Poles, Towers and Fixtures - Concrete

Similar to Account 364.1, the approved estimate for the assets in this account was estimated for both wood and concrete poles. The approved estimate is the 39-R2 survivor curve. I have recommended the 50-R1.5 survivor curve. This estimate is for a longer service life than the Company has historically experienced for concrete poles, which is due in part to the expectation that the current investment in this account will experience a somewhat longer service life than has occurred historically due to newer concrete poles being stronger. As noted in my Direct Testimony, my estimate is for an average service life that is six years longer than the historical average service life for this account based on FPL's actual experience.

OPC has proposed the 56-S0 survivor curve. This estimate is more than ten years longer than the Company's actual experience for this type of assets. As with many accounts, OPC's estimate is primarily the result of lowering the mode of the curve. OPC's only real support for lowering the mode for this account is an analysis of a more recent placement band. As I will explain, OPC's analysis does not actually provide support for witness Pous's conclusion.

I should first point out that the best fitting curve for the overall band is the 44-R1.5 survivor curve. This can be seen in Figure 13 below. The chart also shows more recent placement bands (the 1975-2014 placement band is shown in green and the 1985-2014 placement band is shown in blue). The available data for more recent placement bands indicate a somewhat longer average service life, although these bands also indicate a somewhat higher mode curve. A comparison of more recent bands to the overall band can also be seen in the figure below.

Figure 13

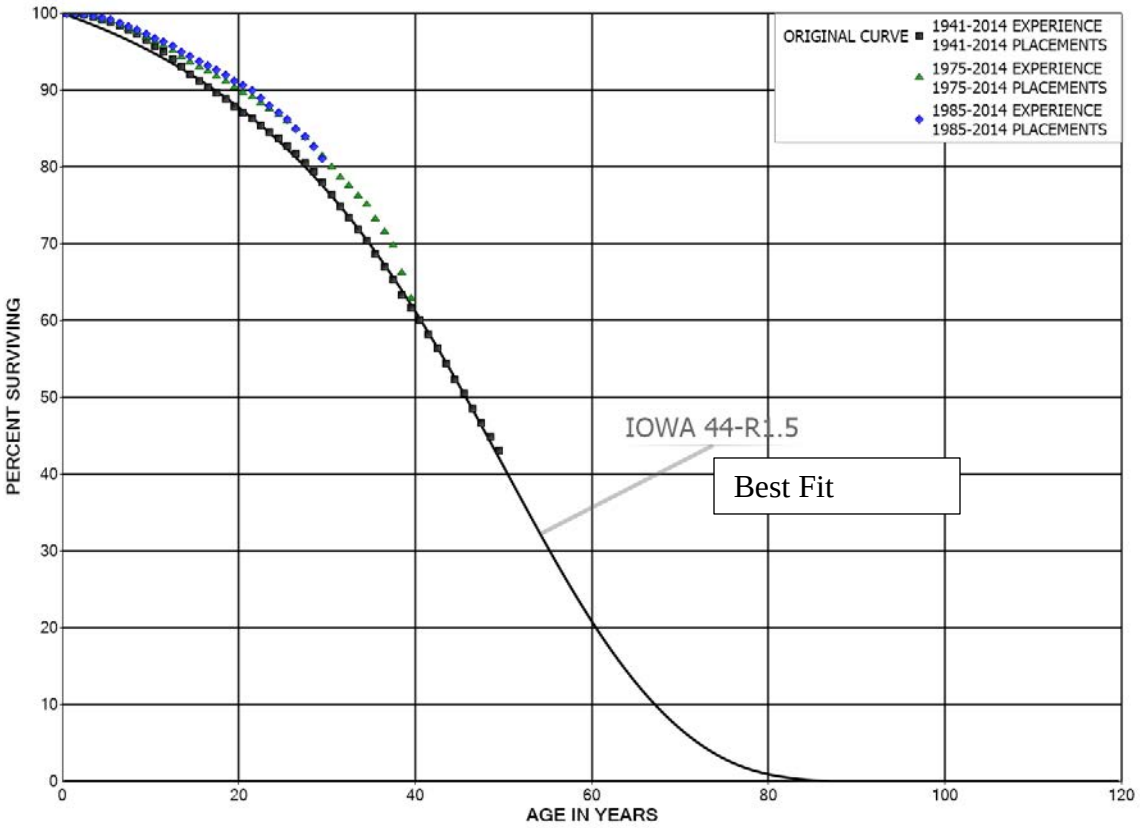
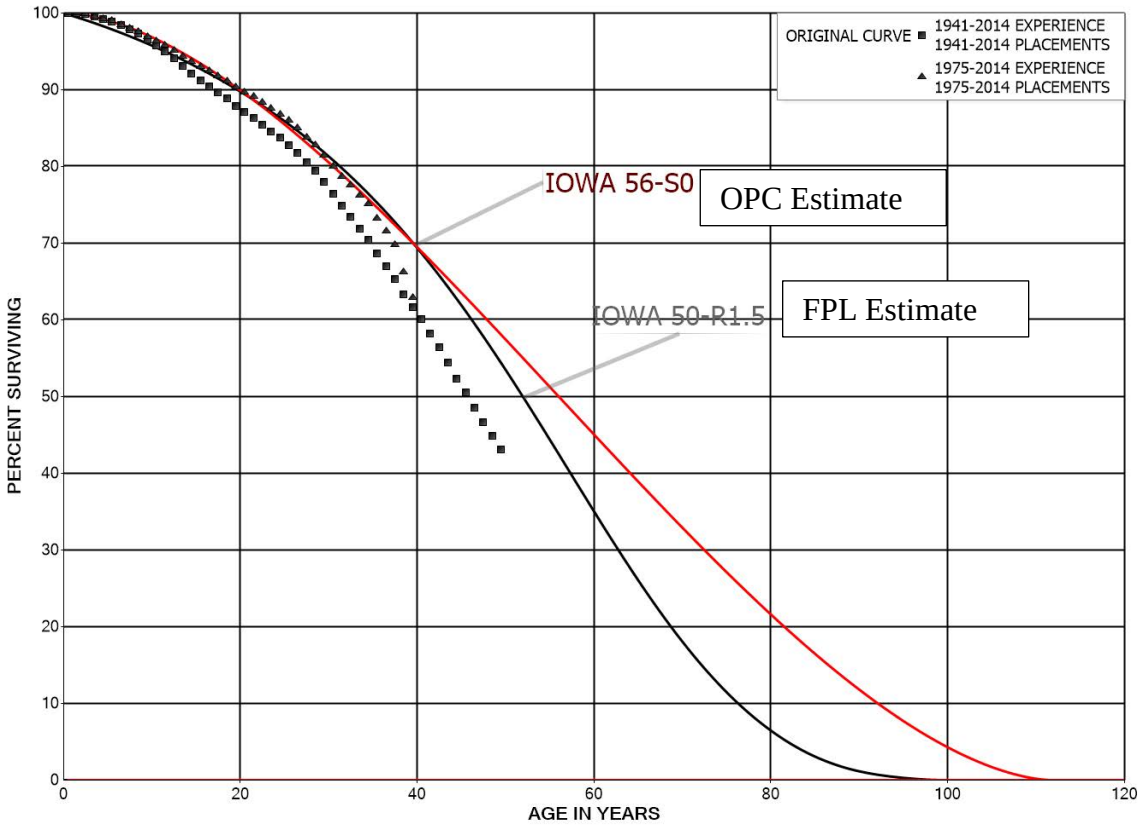

ORIGINAL CURVE
1941-2014 EXPERIENCE
1941-2014 PLACEMENTS
1975-2014 EXPERIENCE
1975-2014 PLACEMENTS
1985-2014 EXPERIENCE
1985-2014 PLACEMENTS
IOWA 44-R1.5
Best Fit
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120

Figure 14 below provides a comparison of my estimate (shown in black) and OPC's estimate (shown in red) to the overall band as well as the 1975-2014 placement band (as can be seen in Figure 13 above the 1985-2014 placement band is similar to the 1975-2014 placement band, but includes fewer data points).

Figure 14



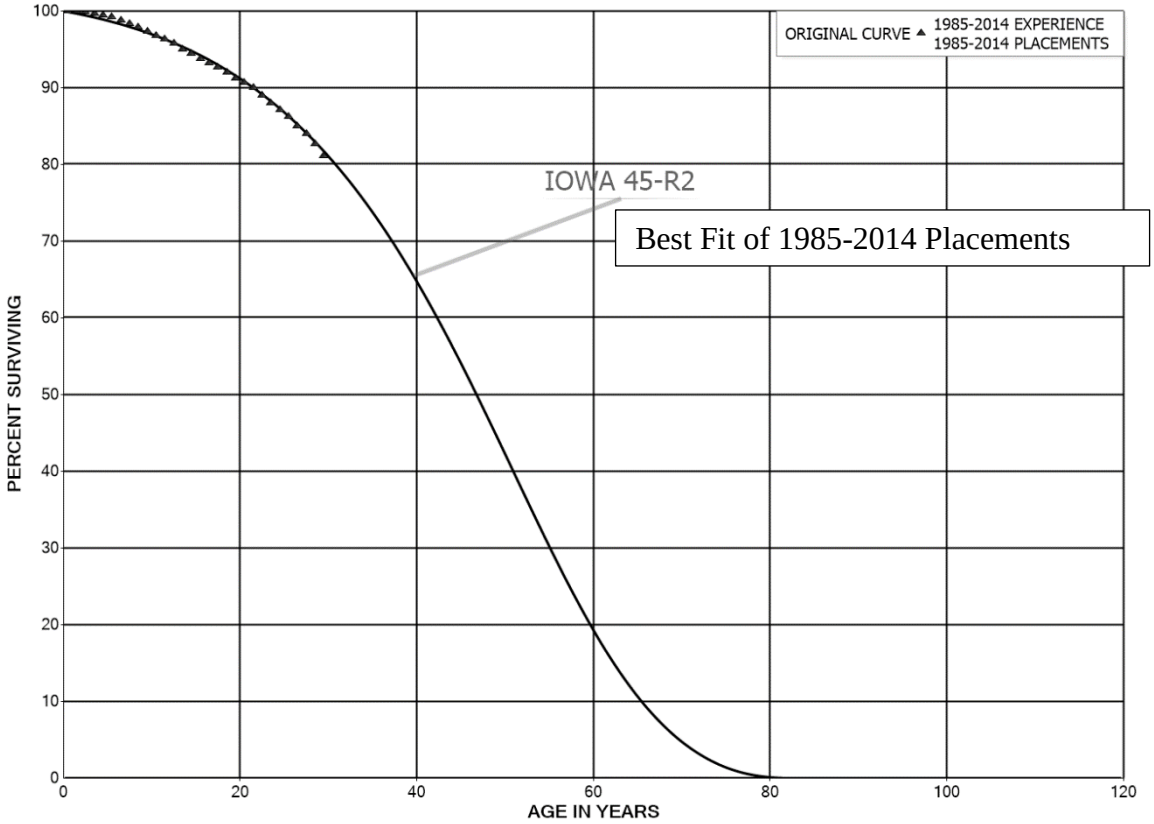
As can be seen in the graph, both my estimate and that of witness Pous predict a longer service life than FPL has historically experienced, since both of our curves are above the historical data on the graph. Further, both of our estimates give more consideration to more recent placement bands, which can be seen by the fact that both estimates are closer to the more recent placement bands. As can be seen in Figure 14, the main difference is that witness Pous projects a slower rate of retirements beyond age 40. This is the result of his selection of a lower mode curve. Importantly, he has selected a lower mode curve than what the Company has experienced historically.

A lower more curve should not be considered to be reasonable for this account. First, the Company has not historically experienced a low mode curve for this account. Second, witness Pous notes the pole inspection program on page 113 of his testimony. As I have explained in Section VI.C, of my rebuttal testimony, the pole inspection program should result in a higher – not lower – mode curve. Finally, witness Pous's analysis of more recent placement bands does not support his selection of a

lower mode curve. If anything more recent placement bands support the opposite. Witness Pous's estimate is based primarily on the 1985-2014 placement band. However, as with most of his presentations of survivor curves in his testimony, the chart he shows on page 113 of his testimony omits a significant amount of information. In fact, for this account witness Pous does not present any information below 80% surviving.

In fact, the 1985-2014 placement band does not support witness Pous's selection of a lower mode curve. In fact, the best fitting curve has a slightly higher mode than my estimate (and therefore a higher mode than OPC's estimate), as can be seen in Figure 15 below.

Figure 15



Witness Pous provides little other support for his estimate. He provides a comparison to industry averages, which I have explained is not meaningful given the different operating environment for FPL than for many other utilities. He also compares the maximum lives of his estimate and my estimate. I disagree with his assessment that a maximum life longer than 100 years is reasonable. Given the Company's approach to storm hardening, I would not expect poles that are older than 100 years of age to be of sufficient strength and reliability from a storm hardening perspective – particularly in light of the harsh conditions in FPL's service territory.

x. Account 365 Overhead Conductors and Devices

The currently approved estimate for this account is the 41-S0 survivor curve. The historical data indicates a longer service life than the approved estimate. I have estimated the 48-R1 survivor curve, which incorporates the trend to a longer service life and represents an increase in average service life of seven years. My estimate also represents a change in the mode of the curve. The R1 curve I have selected is a good fit of the representative data points for the historical data. However, it is also more reasonable for the assets in this account. The existing S0 survivor curve projects a fairly constant level of retirements as the assets in the account age, whereas the R1 projects an increasing level of retirements with age. Given the harsh operating environment in FPL's service territory, corrosion and stress on conductor due to exposure to winds and storms should be expected to increase the probability of retirement with age. The R1 survivor curve is therefore a better representation of these forces of retirements.

OPC has proposed the 53-R1 survivor curve for this account. FEA has proposed the 51-R1 survivor curve. OPC's estimate is therefore for an increase in average service life of twelve years when compared to the approved estimate. FEA's estimate is an increase in average service life of ten years. I should note both OPC and FEA have also proposed the same R1 type survivor curve that I have recommended.

One of the bases of OPC and FEA's proposals is their reliance on shorter bands. I have explained the problems with their approach in Section VI.B.iv of my rebuttal testimony. Neither party has provided a compelling explanation as to why to deviate from the overall band. As a result both have over-emphasized short-term experience that may not be representative of the future. Further, as I have explained on page 731 Exhibit NWA-1 and discussed further for Account 355 in Section v of this Exhibit, while the impact of the storm hardening is unknown at the present time, it could result in a shorter life for conductor due to increased stress on wires. This provides another reason for caution in terms of both increasing the life too much and in over-relying on recent bands.

Figure 16 below provides a comparison of OPC's estimate (shown in red) and my estimate (shown in black) to the overall band. As can be seen in the chart, my estimate is a much better fit. Similarly, Figure 17, which follows, compares my estimate (shown in black) and FEA's estimate (shown in red) to the overall band. Again, my estimate is the better fit.

Figure 16

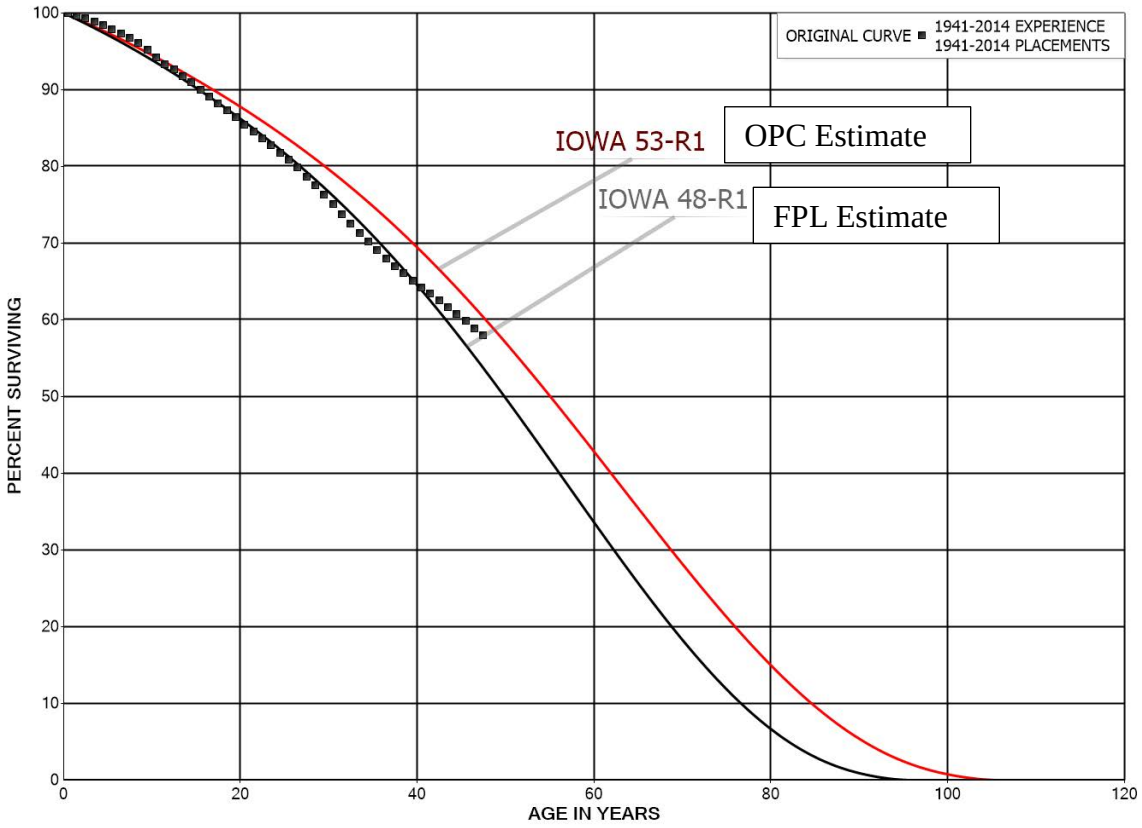
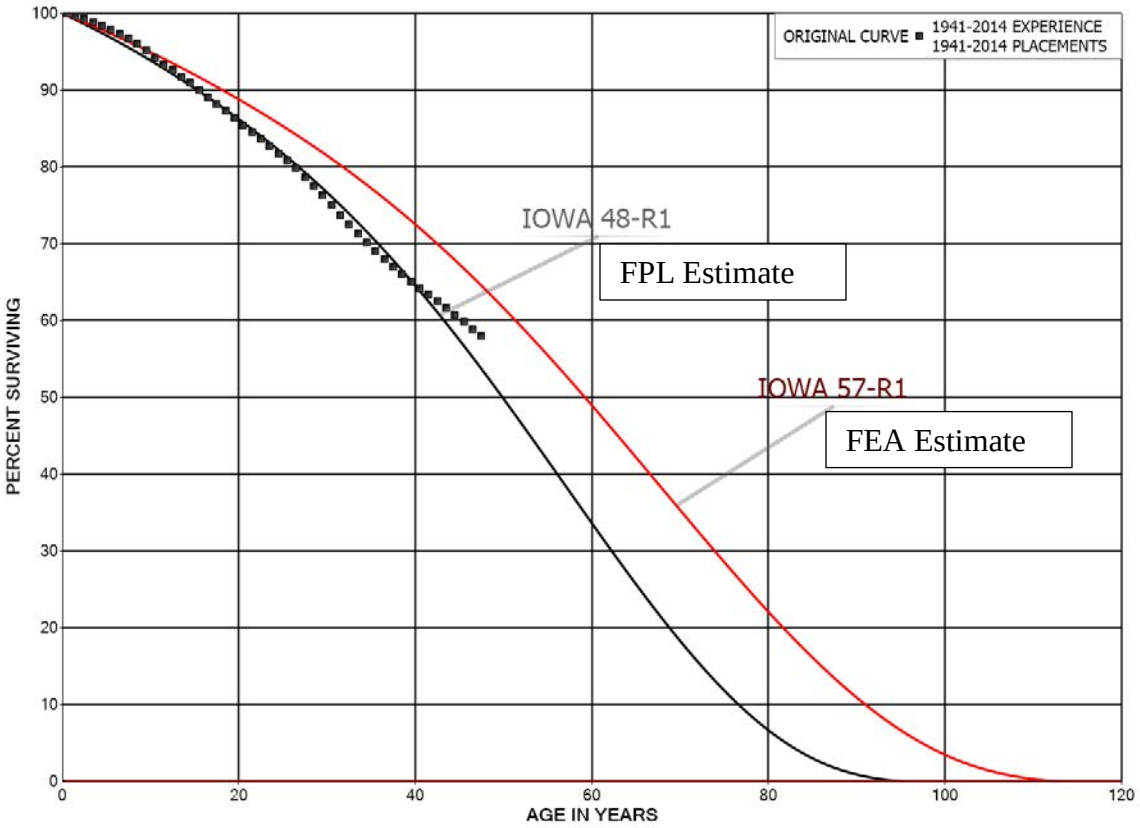

ORIGINAL CURVE
1941-2014 EXPERIENCE
1941-2014 PLACEMENTS
IOWA 53-R1
OPC Estimate
IOWA 48-R1
FPL Estimate
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120

Figure 17

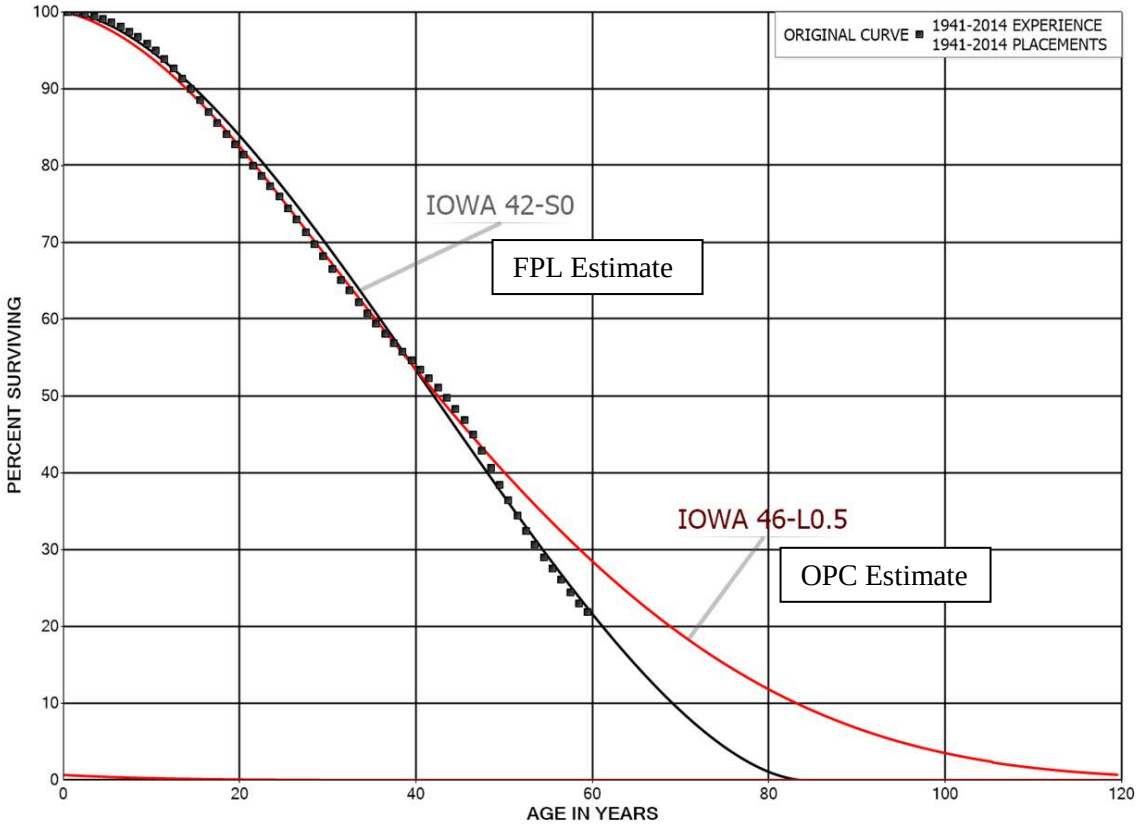


FEA does not provide any additional support for witness Andrews's estimate. OPC provides very little support other than the statistical analysis, which I have addressed above. Witness Pous does not agree with the impact of the storm hardening program on conductor, but I have already addressed this point in Section vi of this exhibit. Witness Pous also compares the maximum lives forecast by both of our estimates to maximum lives for estimates of other utilities. As I have explained in Section III.C of my rebuttal testimony, FPL should be expected to have shorter lives than many other utilities due to the harsh conditions in FPL's service territory. This would also be true of maximum lives. I would expect the maximum lives for FPL's conductor to be quite a bit shorter than many other utilities due to the impact of corrosion and stress on the Company's conductor. Given these factors, a maximum life longer than 100 years (as witness Pous projects) is not as reasonable as is the maximum life resulting from my estimate.

xi. Account 376.6 Underground Conductors and Devices – Duct System

The currently approved estimate for this account is the 38-S0 survivor curve. I have recommended to increase the service life and retain the existing curve type. The 42-S0 is my proposed estimate for this account. OPC has proposed the 46-L0.5 survivor curve for this account. I have discussed the curve fitting for this account in detail in Section VI.B of my rebuttal testimony and have demonstrated both that my estimate is a better fit of the historical data and that witness Pous's selection of an L0.5 curve type is inappropriate. I will not repeat these arguments here, but present again a comparison of our estimates to the Company's data in Figure 18 below. As can be seen in the chart, my estimate (shown in black) is a better fit of the data, and in particular is a better fit from ages 50 to 60.

Figure 18



Witness Pous's primary basis for a longer service life, other than his inappropriate approach to curve fitting, is a discussion of the impact of newer types of underground cable that are less subject to early retirements as was the case with older types of cable. There are a couple of issues with witness Pous's discussion as it relates to his recommendation. I should first note that I have considered the impact of newer types of cable in my estimate, as is discussed on page 737 of Exhibit NWA-1. Second,

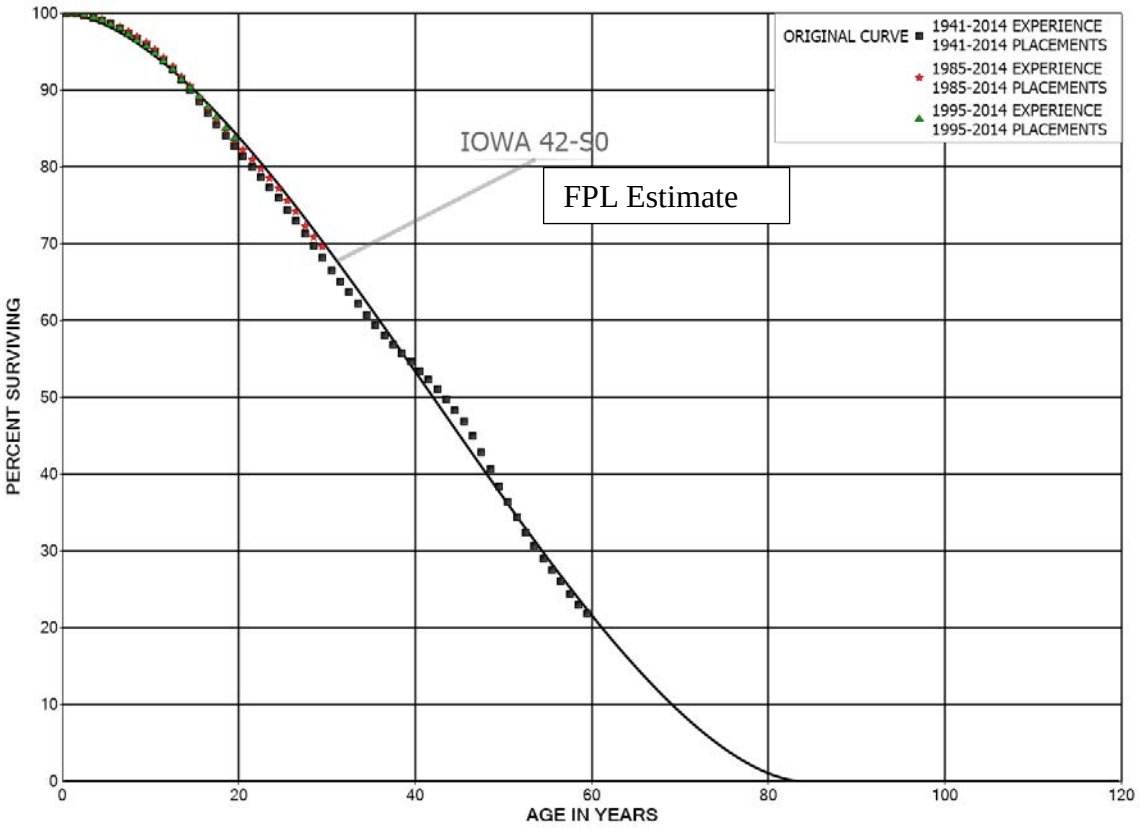
FPL has divided Account 367 into two different types of underground conductor – direct buried and duct system. The issue with high failure rates for older cable is more pronounced for direct buried cable, which is in a different subaccount (Account 367.7) than this account (Account 367.6). Thus, his discussion is more pertinent to the other subaccount. However, as I will discuss in Section xi of this exhibit for Account 367.7, he has taken the opposite approach for that subaccount, proposing a significant increase in the average service life and a curve type that forecasts that some of the older types of cable with last longer than 100 years of age. Unlike my approach, witness Pous has therefore not consistently considered the impact of newer types of underground cable.

In addition to the fact that witness Pous has taken an inconsistent approach to the impact of improvements in cable quality, the Company's data does not support his conclusion as it relates to this account, which does not contain direct buried cable. As I have already explained in discovery,[13] an analysis of more recent placement bands (i.e., newer vintages which represent newer types of underground cable) provides similar service life indications as the overall experience band. Further, my estimate is a very good fit of these more recent bands, and if anything my estimate actually reflects a somewhat longer service life than is indicated by more recent placement bands.

Figure 19 below provides a comparison of the most recent 20 year (shown in green) and 30 year (shown in red) placement bands to the overall experience band. As the chart shows, there is not a material difference between the more recent placement bands and the overall band. Further, my estimate is a very good fit of the more recent placements, and is actually slightly elevated when compared to these bands. Thus, FPL's data does not support witness Pous's conclusion that there will be a significant longer life for the newer cable in this account.

[13] See FPL's response to OPC's Seventh Set of Interrogatories, No. 201(h) (provided in Exhibit NWA-5), in which I have already explained many of the reasons set forth here why witness Pous's estimate is a poor choice for this account.

Figure 19



Witness Pous also cites a statement from FPL representatives that "life of cable for overhead and underground [conductor] is similar."[14] This does not contradict anything I have recommended. My estimates for the two accounts are relatively similar 42 years for underground conductor compared to 48 years for overhead. The Company's data supports a shorter life for underground conductor, which is recognized by both my estimate and by that of OPC. In fact, witness Pous has proposed a larger differential between underground and overhead conductor (46 years vs. 56 years) than I have. Further, more recent notes from my meetings with FPL representatives clarify that it would be reasonable to expect a shorter life for underground conductor than overhead conductor for a number of reasons, including that for underground cable the insulator is built into the cable, failures occur more frequently than for overhead conductor, and water can impact the life of underground cable.[15]

[14] This statement is from my notes provided in Attachment 2 of FPL's response to OPC's First Request for Production of Documents No. 38.

[15] See page 11 of Attachment 1 of FPL's response to OPC's First Request for Production of Documents No. 38.

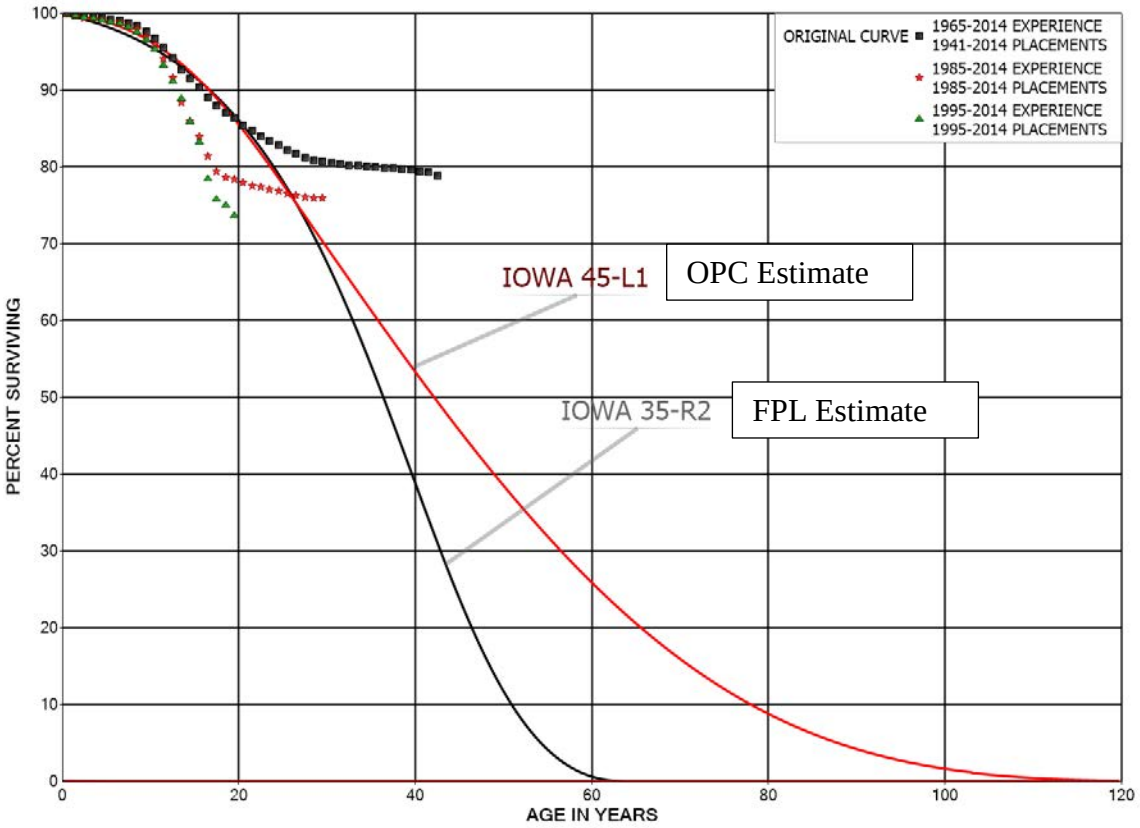
xii. Account 367.7 Underground Conductors and Devices – Direct Buried

The currently approved estimate for this account is the 35-R2 survivor curve. The historical data does not provide materially different indications from the 2009 Depreciation Study. Further, FPL is proactively replacing older direct buried cable. For this reason the expectation going forward is, if anything, for a shorter average service life than has historically been experienced. Further, there are also river crossings in this account, which comprise most of the more recent vintages (since the late 1980s). More recent placement bands indicate a shorter service life than the overall band. For these reasons, my recommendation is to continue to use the approved 35-R2 survivor curve.

Witness Pous has proposed a fairly significant increase in the service life for this account, and has recommended the 45-L1 survivor curve. His estimate is based primarily on the statistical analysis. However, based on his testimony, he does not appear to consider the types of assets in the account, more recent placement bands, or Company plans. This is particularly surprising considering his discussion for Account 367.6 of higher failure rates for older types of underground cable, which again will impact direct buried cable in this account more than the assets in Account 367.6.

A comparison of my estimate (shown in black) and that of witness Pous (shown in red) to the historical data is presented below. As can be seen in the chart, more recent placement bands (shown in green and red) indicate a shorter service life than the overall band.

Figure 20



The chart also helps to illustrate the inappropriateness of witness Pous's estimate. As he discusses for Account 367.6 but fails to mention for this account, older types of cable have higher failure rates than newer types of cable. This is particularly true for direct buried cable. As a result, the dispersion pattern indicated by the R2 type curve is much more reasonable than the L1 type curve, in particular because the Company plans to proactively replace older direct buried cable. Retirements for the assets in this account should be expected to increase significantly with age and few should be expected to survive for a very long time. Witness Pous's estimate predicts the opposite, forecasting a slowing level of retirements with age and predicting that some direct buried cable will remain in service for more than 100 years. His estimate is therefore not a reasonable expectation for the assets in this account. Additionally, his estimates for both this account and Account 367.6 are almost the same (45-L1 for this account vs. a 46-L0.5), which makes little sense given that this account has a higher percentage of older cable than Account 367.6.

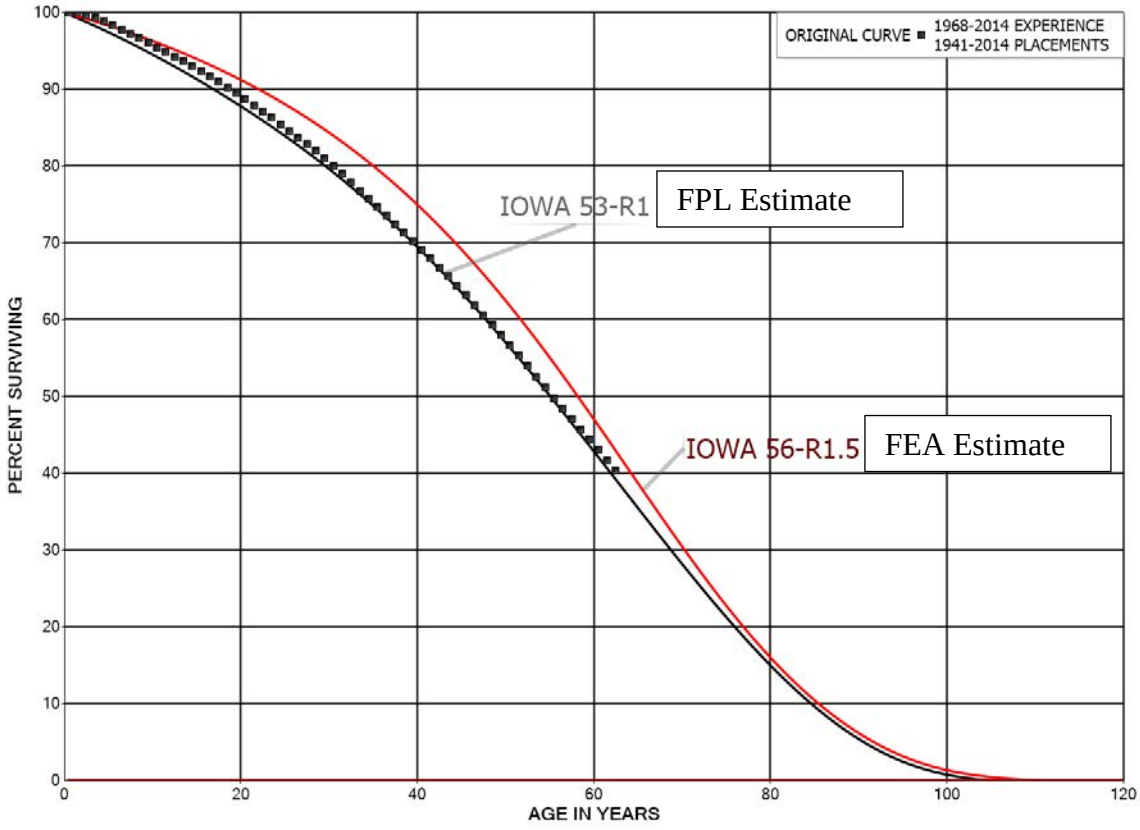
In addition to the statistical analysis, the only other support for witness Pous's estimate is a comparison to estimates for other utilities. Yet the comparison witness Pous makes for this account is even less reasonable than the comparisons he makes for many other accounts. Most utilities do not have separate subaccounts for direct buried cable, and as a result the service life estimates in industry

database he cites on pages 125 and 126 of his testimony are for all types of underground conductor, not just direct buried cable. Further, many utilities operate in different climates than Florida. It is not appropriate to make a comparison of all types of underground conductor from utilities in entirely different regions of the country to only direct buried cable in Florida.

xiii. Account 369.1 Services – Overhead

The currently approved survivor curve estimate for this account is the 48-R1 survivor curve. Consistent with the historical data and for the reasons discussed on page 743 of Exhibit NWA-1, I have recommended the 53-R1 survivor curve. OPC has not proposed an adjustment for this account. FEA has recommended a 56-R1.5 survivor curve. FEA's estimate is based on the most recent 20 year experience band. I have addressed the issues with FEA's approach in Section VI.B.iv of my rebuttal testimony. A comparison of my estimate (shown in black) and FEA's estimate (shown in red) to the overall band is provided in Figure 21 below, which demonstrates that my estimate is a better fit of the overall band.

Figure 21

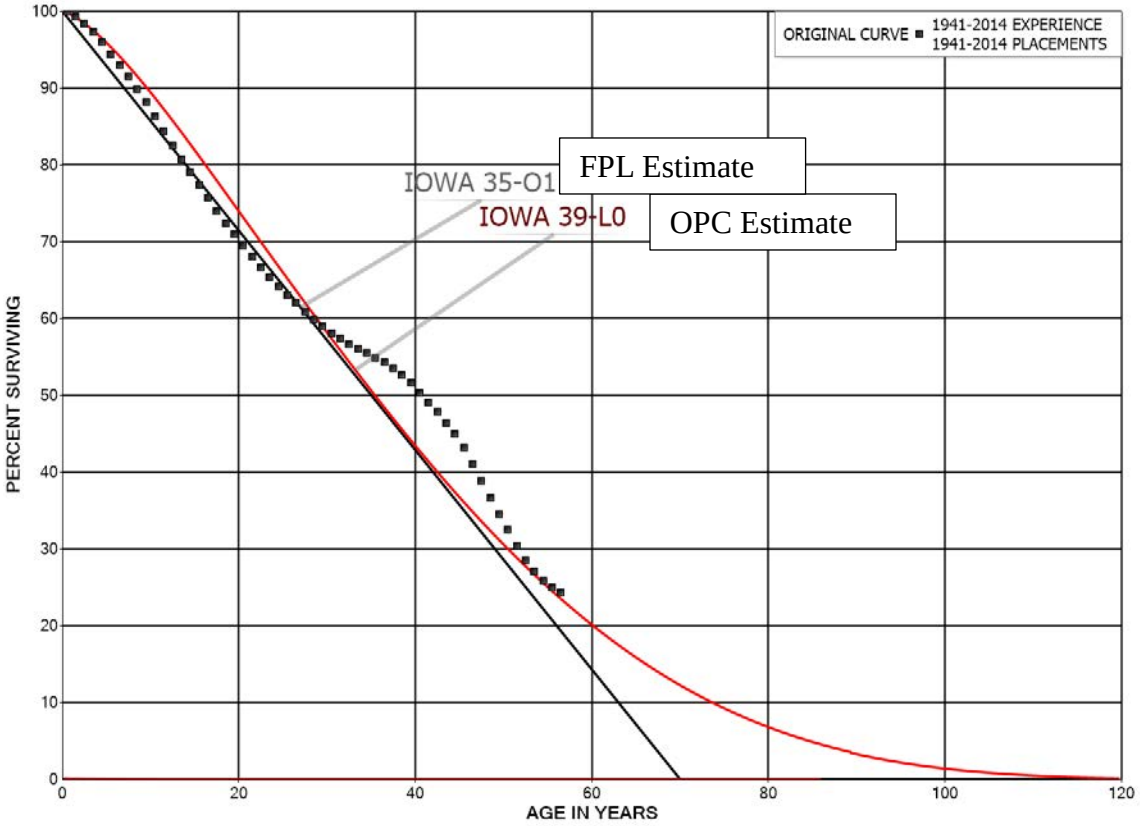


xiv. Account 373 Street Lighting and Signal Systems

The currently approved estimate for this account is the 30-R0.5. I have recommended an increase in average service life and change in curve type to the 35-O1 survivor curve. OPC has recommended an even longer service life, proposing the 39-L0 survivor curve. OPC witness Pous does not provide any support for estimate other than the statistical analysis.

There are a number of problems with OPC's witness Pous's statistical analysis. As with most of his graphs, his graphical presentation on page 127 of his testimony omits important information as he only shows the portion of the graph through age 48.5 and above 30% surviving. However, his presentation of the survivor curves for this account is also simply incorrect. Specifically, it shows a curve labeled as a "35O1" curve, but the actual graph does not show a 35-O1 survivor curve. A comparison of my 35-O1 survivor curve estimate (shown in black) to both OPC's estimate (shown in red) and the historical data is shown in Figure 22 below. As can be seen in the graph, the 35-O1 survivor curve is actually quite different from the curve labeled "35O1" on witness Pous's graph. For example, the 35-O1 is much closer to the historical data for ages 0 through 30 than the curve shown in witness Pous's graph on page 127 of his testimony. The O1 curve is also a straight line, yet the curve labeled "35O1" in witness Pous's graph curves and is not straight.

Figure 22



As a result of his presentation showing the wrong curve, the observations made by witness Pous comparing the 35-O1 and 39-L0 survivor curves are therefore also incorrect. His conclusion that the 39-L0 survivor curve estimate is a better estimate than mine based on the statistical analysis is therefore also incorrect. For example, he states "[a]s shown in the following graph, witness Allis' proposal is not the best fitting curve early on, but becomes a particularly poor fit after age 30."[16] As noted above, witness Pous has shown the wrong curve in his graph on page 127 of his testimony. As can be seen in Figure 22 above, the 35-O1 is in fact a much better fit of the data through age 30 than the 39-L0.

Witness Pous then states that "[w]hile [his] recommendation is also not a particularly great fit of the historical data, it is superior throughout the OLT. Moreover, it better captures the noticeable change in the annual retirement rate after age 30."[17] This too is incorrect. His estimate is not "superior throughout the OLT" when compared to my estimate, but is instead a much worse fit from age 0 through 30. Further, while witness Pous cites a "noticeable change in the annual retirement rate after age 30," a more complete look at the data shows that this "change" is not as pronounced as in his presentation in

[16] Direct Testimony of Jacob Pous, p. 127, lines 4-6.

[17] Direct Testimony of Jacob Pous, p. 127, lines 6-8. I should note that "OLT" is short for "original life table."

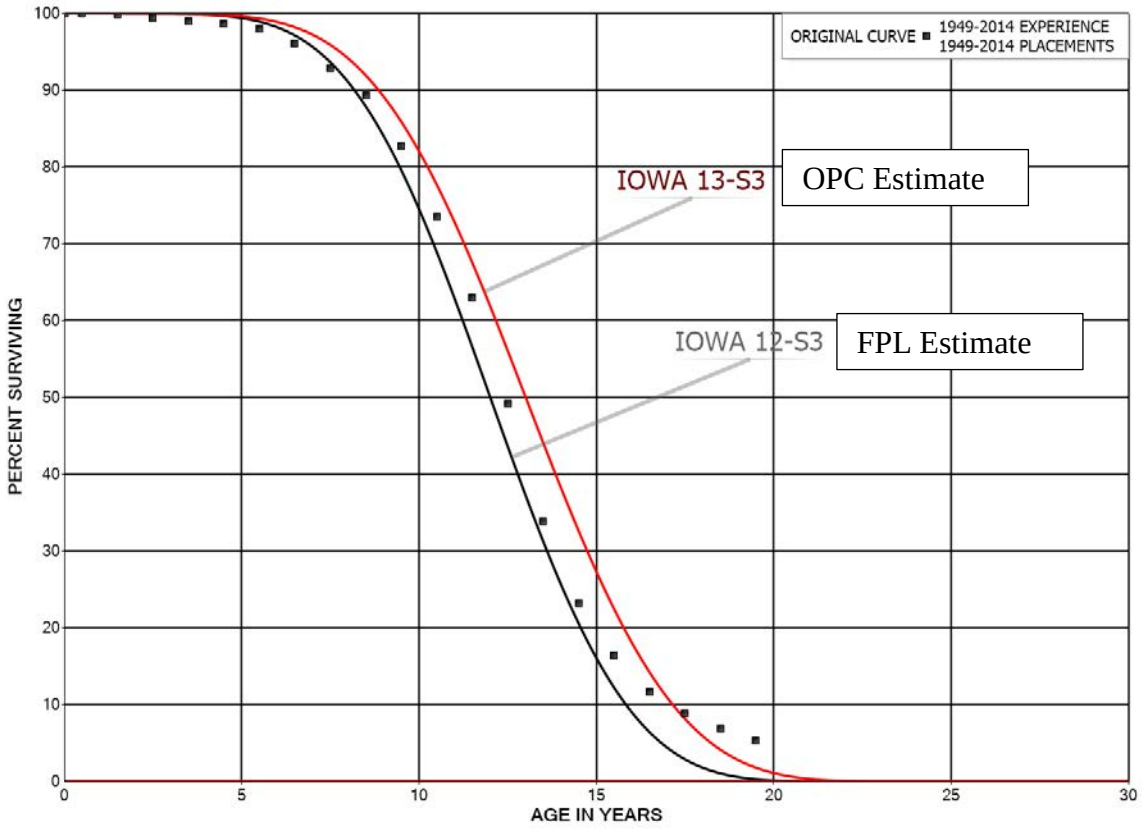
his testimony. As can be seen in Figure 22 above, the rate of retirement increases in the data again after age 40 and returns to percentages surviving that are close to the overall trend established by the 35-O1 curve by age 50. In any event, the data does not support the very long tail extrapolated by witness Pous's selected L0 type curve.

xv. Account 392.3 Heavy Trucks

The current estimate for this account is the 12-S3 survivor curve. The historical data provides similar indications to the previous study. I have recommended to continue to use the 12-S3 survivor curve. OPC has recommended to increase the average service life and has proposed a 13-S3 survivor curve. Witness Pous's recommendation is based on a more recent placement band and on a discussion of an early retirement in the historical data. While I agree with witness Pous that the early retirement he discusses is not likely to recur and should be given less consideration, this retirement activity does not have as much of an impact as his use of a more recent placement band.

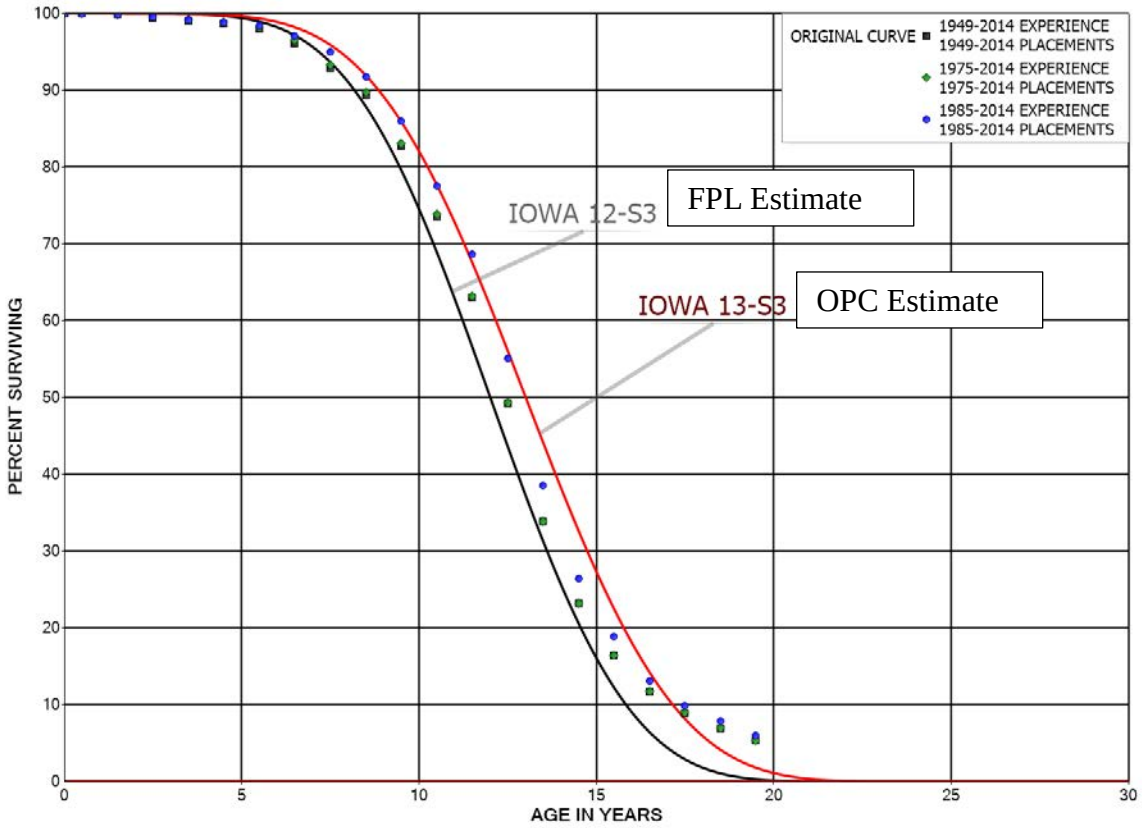
For example, in Figure 23 below I have removed the early retirement noted by witness Pous from the overall band. This graph compares my estimates (shown in black) and OPC's estimate (shown in red) to the data once this retirement is excluded. The overall band therefore does not provide a reason to change the estimate for this account, as the 12-S3 is at least a good of a visual fit as the 13-S3. It is also a better mathematical fit and is somewhat better fit for the portion between 80% and 20% surviving.

Figure 23



More recent placement bands are not necessarily supportive of witness Pous's estimate over mine. Figure 24 below provides a comparison of the overall band and more recent placement bands. While the 1985-2014 placement band (shown in blue) is slightly longer than the overall band, the 1975-2014 placement band (shown in green) is not.

Figure 24



When each of these bands are considered and compared to the 12-S3 and 13-S3 survivor curves, there is not enough support to favor witness Pous's estimate over mine and therefore not enough support to change the currently approved 12-S3 survivor curve. Indeed, the overall and 1975-2014 placement bands indicate that the 12-S3 survivor curve continues to be the better fit of the data.

i. Account 353 Station Equipment

The currently approved net salvage estimate for this account is negative 2%. I have recommended to continue to use the approved negative 2% estimate. OPC has proposed an estimate of 0 net salvage. OPC's estimate means that OPC witness Pous expects that assets at substations such as transformers and circuit breakers will be retired for a net cost of zero. Given the work involved to disconnect, remove and dispose of these assets, as well as the Company's historical data once properly considered, OPC's expectation of zero net salvage is not reasonable. Instead, negative net salvage should be expected for this account.

Witness Pous's criticisms of my estimate for this account are contradictory. In his discussion of this account witness Pous criticizes me for both employing "a simplistic averaging approach"[1] and for not using my "normal approach" to rely "on historical averages."[2] Neither criticism is accurate. As I have explained in Section VII.B of my rebuttal testimony, witness Pous has not accurately characterized my approach, which incorporates more than just reviewing historical averages of net salvage percentages. For example, I have also reviewed and investigated years of data and specific transactions to determine whether they are representative of future net salvage for each account. For this account there are many years for which the gross salvage is higher than should be expected for most of the investment in this account. As a result, the overall and recent averages do not provide the best indication of future experience.

The historical net salvage analysis is provided on pages 341 and 342 of Exhibit NWA-1. The overall net salvage is shown as negative 1%. However, one reason that the overall net salvage is not more negative is that the overall gross salvage is 11%, which offsets the overall cost of removal of 12%. A review of the gross salvage data reveals that the overall level of gross salvage in the historical data is not likely to be indicative of the actual experienced gross salvage for most of investment in the account. Instead, one would expect gross salvage to be lower on average going forward. There are two reasons for this. One is that in recent years the gross salvage includes warranty related transactions (for example in 2012). Most assets will not be retired under these types of circumstances and therefore will experience much lower gross salvage. The other reason is that the older years in the data, from about 1986 through 1997, experienced very high levels of gross salvage. Some individual years experienced gross salvage that was close to or exceeded 100% of the original cost of the assets retired and many of the moving averages were around 50% of the original cost of the assets retired or higher. Clearly FPL will not be compensated for 100%, or even 50%, of the value of most of its assets in this account when they are retired at the end of their useful lives. Instead, gross salvage closer to 5% is a more reasonable expectation. Indeed, the higher levels of gross salvage experienced in the 1980s and early 1990s have

[1] Direct Testimony of Jacob Pous, p. 149, lines 13-15.

[2] Direct Testimony of Jacob Pous, p. 148, line 22 to p. 149, line 1.

not continued since 1997. The overall average gross salvage since 1997 is 6%. Most moving averages of gross salvage since 1997 have been closer to the 5% range, with the exception of those influenced by warranty transactions in recent years. Additionally, as I note on page 709 of Exhibit NWA-1, the most recent 10 and 20 year average gross salvage percentages are 8% and 7%, respectively. The experienced gross salvage since 1997 is a more reasonable predictor of future gross salvage, and is likely still too high given the recent warranty transactions.

In contrast, the cost of removal has been relatively consistent. I should make clear that the full historical database studied includes over $259 million in retirements. The database therefore incorporates a large sample size and a wide variety of types of assets that have been retired and therefore provides a good basis for predicting future cost of removal. Witness Pous's concerns with regard to the mix of the types of investments in the retirements for this account are therefore at a minimum overstated. Additionally, witness Pous's analyses of the historical data focuses on individual years.[3] I have addressed the problems with this approach in Section VII.B of my rebuttal testimony and have explained that it is more appropriate to consider long term and moving averages.

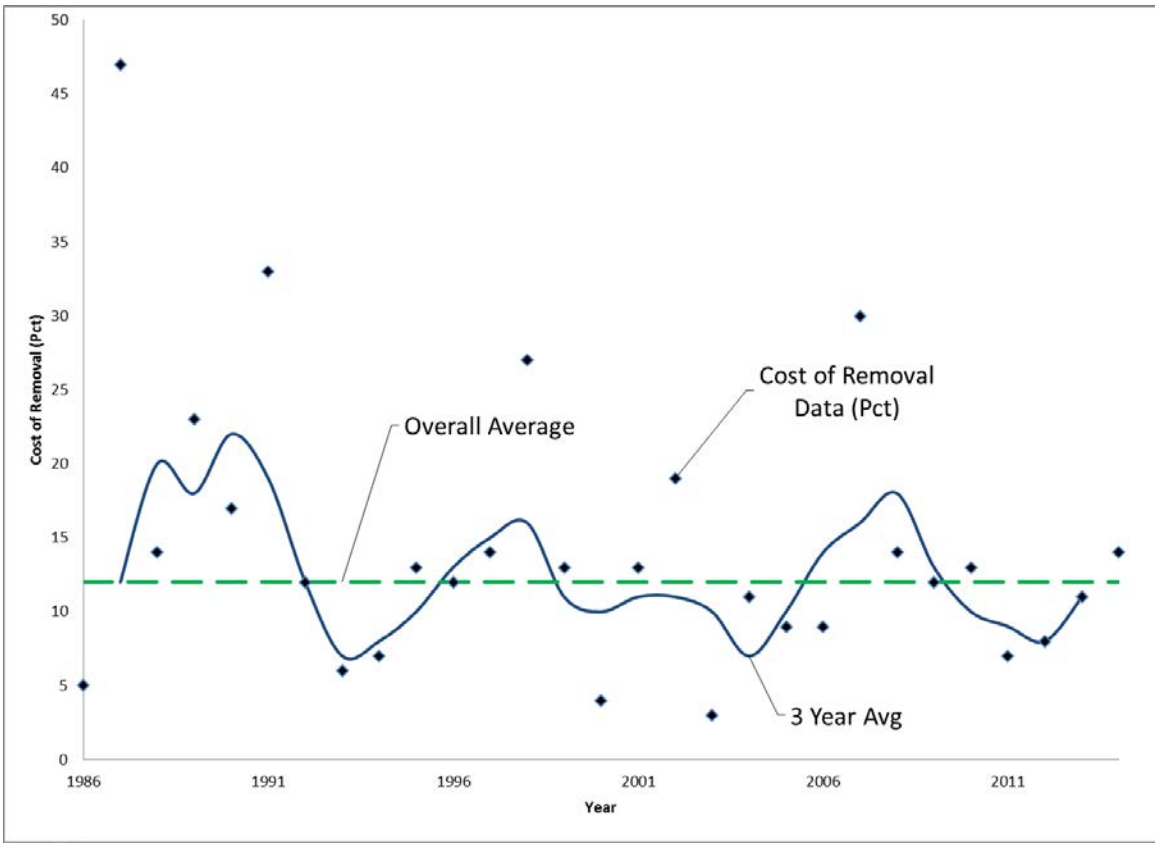
Additionally, much of the basis of OPC's estimate is witness Pous's expectation that "often can bring positive levels of net salvage due to copper content and the lower per-unit cost of removal associated with dollar concentrated large assets."[4] It is incorrect that transformers will often bring positive levels of net salvage once the full process of removing a transformer is considered. While the eventual disposal of a transformer may result in some level of positive salvage, Mr. Pous's statement ignores the fact that there are significant costs to disconnect the transformer, remove the oil from the transformer, and remove the transformer prior to disposal. This work typically involves heavy equipment such as a crane and therefore results in levels of cost of removal which typically offset or exceeds any gross salvage.

Figure 1 below provides a graph of the annual cost of removal percentages (shown as black diamonds), as well as three-year moving averages of cost of removal percentages (shown as the blue line) and the overall average cost of removal percentage (shown as the green dashed line). While the data varies from year to year, cost of removal has consistently been in a fairly similar range with an overall average cost of removal percentage of 12%. As a result, the data provides a sound basis to expect that cost of removal will be on average be around 10% to 15% for the assets in this account.

[3] Direct Testimony of Jacob Pous, p. 150, lines 8-11.

[4] Direct Testimony of Jacob Pous, p. 149, line 23 to p. 150, line 1.

Figure 1



Contrary to witness Pous's assertions that I have only relied on simplistic averaging, the methodology discussed above is a more accurate description of my approach to the estimation of net salvage. Given all of the considerations I have discussed, the most reasonable expectation of the future experience for this account is that cost of removal will be on average in the 10% to 15% going forward, with the 12% overall average being a reasonable expectation. Gross salvage should be expected to be less than has occurred historically. An expectation of about 5% gross salvage is reasonable. An expectation of 10% would be quite conservative, and would certainly address any concerns witness Pous has raised. However, even a conservative expectation of 10% gross salvage supports my estimate and not OPC's. The currently approved estimate of negative 2% (which corresponds to a conservative estimate of 10% gross salvage less a cost of removal estimate of 12%) is therefore, if anything, less negative than the Company will likely experience. My recommendation to retain the existing negative 2% net salvage estimate is therefore not only appropriate but is in fact a conservative estimate of negative net salvage.

ii. Account 354 Towers and Fixtures

The currently approved estimate for this account is negative 15% net salvage. While there have been fewer retirements for this account than for many other accounts (which is due to the fact that the assets in this account are fairly new relative to their expected service life), there has typically been cost of removal when there have been retirements. As can be seen on pages 344 and 345 of Exhibit NWA-1, the overall average cost of removal is 51%. There has been limited gross salvage, and the overall average net salvage is negative 50%. Cost of removal in more recent years, which have on average had a higher level of retirements than was the case in earlier years, has been higher. For example, the most recent five year average net salvage is negative 69%.

The data therefore indicates that a more negative net salvage estimate than negative 15% is appropriate. Further, other transmission line assets such as transmission poles incur more negative levels of net salvage, so a more negative net salvage estimate for this account is a reasonable expectation. I have proposed negative 25% for this account. This is consistent with the trend in the data and is conservative due to the fact that there is a smaller amount of historical activity available for this account than for other transmission and distribution accounts.

OPC witness Pous has ignored the trend in the data and has proposed to retain the currently approved estimate of negative 15%. Witness Pous provides two reasons for his decision to ignore the data – the mix of investment in the historical data and the impact of higher contractor costs in recent years. I should first point out that my estimate is very conservative when compared to the data – negative 25% is half of the overall average and even more less negative than the more recent data. Thus, my estimate is sufficiently conservative to alleviate any concerns he raises.

Witness Pous also discusses the impact of contractor costs for this account. My estimate for this and other accounts already incorporate the impact of higher costs for outside contractors in recent years. For example, as noted above one of the factors considered for this account is the net salvage estimate for transmission poles. I discuss the impact of contractor labor in the discussion on of the net salvage estimate for transmission poles on page 714 of Exhibit NWA-1. For this account, my estimate is also for a less negative level of net salvage than FPL's recent experience. Additionally, I should note that storm hardening work will continue for some time in the future, and therefore witness Pous overstates the impact of contractor costs.

Further, witness Pous's only other support for deviating from the data is incorrect. He discusses the cost of removal for foundations in recent years on page 153 of his direct testimony. There are a number of issues with his discussion. First, the percentage of foundations in the data (38%) is quite close to the percentage of foundations in the current plant balance (30%). Thus, witness Pous has not provided a reason to expect that the mix of investment in the data is not comparable to the mix of investment in the account. Second, foundations and towers are often retired at the same time, and thus

recent years that include foundation retirements would provide an indication of the cost of retiring an entire tower. The activity in recent years therefore demonstrates that the both current net salvage estimate and OPC's net salvage estimate are insufficient. Finally, the activity associated with towers that witness Pous cites is representative of FPL's normal practices. FPL has caisson concrete foundations for its towers, which are different from the foundations for lattice steel towers that are often used by other utilities. The typical practice for FPL's is that the top 2 to 3 feet of the foundation is chipped away until the remaining portion of the foundation is below grade. Subsequently, the steel reinforcements and anchor bolt cage are cut and removed. This process should be expected to have cost of removal, and is not necessarily comparable to the experience for other utilities.

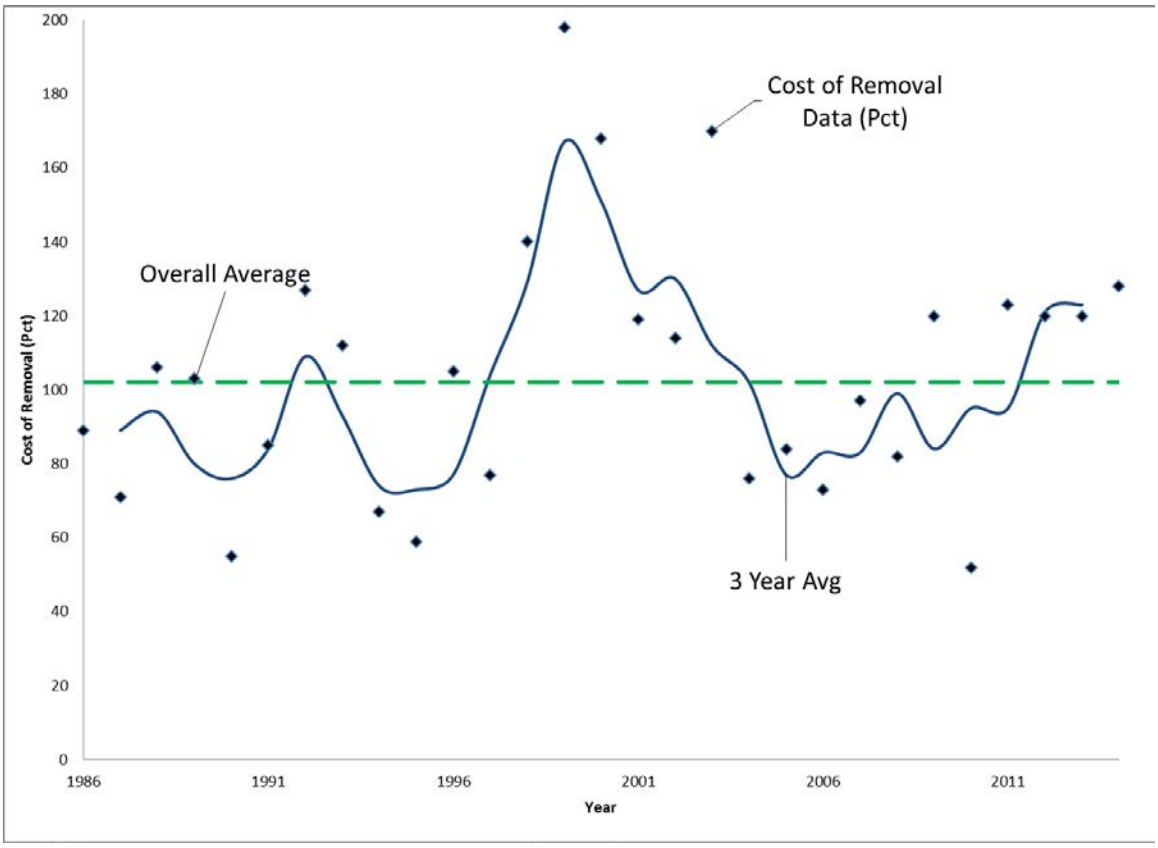
iii. Account 355 Poles and Fixtures

The currently approved net salvage estimate for this account is negative 50%. As can be seen on pages 346 and 347 of Exhibit NWA-1, the overall net salvage data is supportive of a similar estimate as the approved estimate for this account. The overall average net salvage is negative 55% and the most recent five year average is negative 46%. Further, as I will explain, a more detailed review of the data supports that an even more negative net salvage estimate could be appropriate. However, I have recommended to retain the currently approved net salvage estimate of negative 50%. OPC's estimate is for a less negative net salvage estimate of negative 40%, which would not be appropriate for this account. The data definitely supports an estimate of at least negative 50%, and witness Pous's support for his estimate does not stand up to scrutiny. In fact, witness Pous's "analysis" that provides the only quantitative support for his estimate actually supports that a more negative estimate net salvage may be appropriate.

As noted above, the overall average net salvage is negative 55%, which is equal to the overall average gross salvage of 47% less the overall average cost of removal of 102%. I should first note that gross salvage of 47% is higher than should be expected to occur on average for the types of assets in the account. Both wood and concrete poles should be expected to have minimal gross salvage. Chemically treated wood poles typically have no gross salvage and instead incur disposal costs. Concrete poles also do not experience much gross salvage. Thus, the overall gross salvage should not be considered to be indicative of the level of gross salvage that will be experienced by most assets in the account. Instead, a large portion of the gross salvage is instead related to reimbursements that were not excluded from the data, but should not be expected to recur at anywhere near the level as has occurred in the historical data. A more reasonable expectation for the gross salvage for most of the assets in this account is instead in the 5% to 10% range, and certainly no more than 20%.

In contrast, cost of removal has occurred regularly and should be expected to continue because there are significant costs involved with removing and retiring a pole. The experienced cost of removal for this account is presented in Figure 2 below. The figure provides a graph of the annual cost of removal percentages (shown as black diamonds) as well as three-year moving averages of cost of removal percentages (shown as the blue line) and the overall average cost of removal percentage (shown as the green dashed line). The three-year moving averages of these costs have consistently exceeded 70 percent and the overall average is 102 percent.

Figure 2



Given that gross salvage should be expected to be lower in the future, the historical level of cost of removal indicates that, if anything, a more negative net salvage estimate than the currently approved 50% may be appropriate. For example, even if FPL were to experience 20% gross salvage (which is a high expectation for gross salvage for the assets in this account), the historical level of cost of removal of about 100% would result in negative 80% net salvage. A more reasonable level of 5% to 10% gross salvage would result in even more negative net salvage than negative 80%.

On pages 156 and 157, witness Pous discusses the impact of contractor labor on cost of removal. As discussed on page 714 of Exhibit NWA-1, I have already taken this factor into consideration into my estimate. This is one reason why I have recommended negative 50% instead of the negative 80% discussed above.

Thus, once the data is properly considered, it is supportive of an estimate at least as negative as my estimate. The actual basis for Witness Pous's estimate of negative 40%, which is not supported by the Company's actual data, is an analysis he performed of historical net salvage in which wood poles and concrete poles were analyzed separately.[5] Based on his analysis, witness Pous concludes that

[5] Direct Testimony of Jacob Pous, p. 156, lines 1-19.

concrete poles will experience less negative net salvage than wood poles. However, his presentation of the analysis in his testimony is incomplete. Once the actual data is reviewed it demonstrates the opposite conclusion of the one reached by witness Pous – the actual data shows that cost of removal percentages for concrete poles have historically been higher than those for wood poles.

Table 1 below provides the overall retirements, cost of removal, gross salvage and net salvage for the period included in witness Pous's analysis.[6] The cost of removal, gross salvage and net salvage are also presented as percentages of retirements, consistent with the presentation of the net salvage analysis for this account found on page 346 of Exhibit NWA-1. Witness Pous cites the overall average net salvage for concrete poles of negative 39% as support for his expectation that the overall net salvage for the account will be negative 40%. This analysis provides the only actual quantitative basis for his proposal.

Table 1

Type of Pole		Cost of Removal		Gross Salvage		Net Salvage	
	Retirements	Amount	Pct.	Amount	Pct.	Amount	Pct.
Wood	9,133,688	9,332,312	102%	2,085,478	23%	(7,246,834)	-79%
Concrete	7,574,259	10,285,176	136%	7,320,220	97%	(2,964,956)	-39%

However, once the data is in Table 1 is reviewed in more detail it is apparent that witness Pous's conclusion is flawed. I should first note that the cost of removal percentage for concrete poles is 136%, compared to 102% for wood poles. Thus, this analysis actually demonstrates a higher level of cost of removal for concrete poles than for wood poles. This makes some logical sense as well. There are higher cutting costs for concrete poles once they are removed from the ground than is the case for wood poles.

However, the reason that the net salvage percentage, which is the number cited by witness Pous, is different from the cost of removal percentage is because witness Pous's analysis includes a very high level of gross salvage for concrete poles. This occurs because he has not excluded reimbursements from this analysis.[7] The gross salvage for concrete poles is largely due to reimbursements, which should not be expected to continue at a level anywhere close to the 97% that has historically occurred for concrete poles. As I have explained in Section VII.F of my rebuttal testimony, most of these reimbursements

[6] Witness Pous did not provide the actual analysis in his testimony or workpapers. These amounts were provided in discovery in OPC's response to FPL's Second Set of Interrogatories No. 40.

[7] For a further discussion of reimbursements and why they should be excluded from the net salvage analysis, please refer to Section VII.F of my rebuttal testimony.

should be excluded from the net salvage analysis. For this reason, a better comparison of whether concrete poles will be more costly to retire is to compare the cost of removal percentages in Table 1. Again, these demonstrate the opposite of witness Pous's conclusion and show that concrete poles have actually been more costly to remove.

Witness Pous appears to recognize that there is this flaw in his analysis, given that he states that "an experienced depreciation analyst would not try and claim that the gross salvage was due to reimbursable events that are not expected to reoccur in the future, given the continuous and significant annual level that has transpired."[8] However, the opposite is true. A reasonable analyst would recognize that the level of gross salvage for concrete poles in witness Pous's analysis, which is primarily due to reimbursements, is in no way representative of what will occur in the future for the majority of FPL's transmission poles. For witness Pous's analysis to make sense as a basis for the estimate for this account, then the 97% gross salvage experienced for concrete transmission poles (which again is primarily reimbursements) would have to be expected to apply to the full balance of assets in this account (as most are concrete poles). The 2016 plant balance for this account is $1.99 billion. If a 97% gross salvage were representative of the future experience for this account, then FPL would be expected to recover $1.93 billion ($1.99 billion multiplied by 97%) from third parties in order to retire its poles. This is not a reasonable expectation.

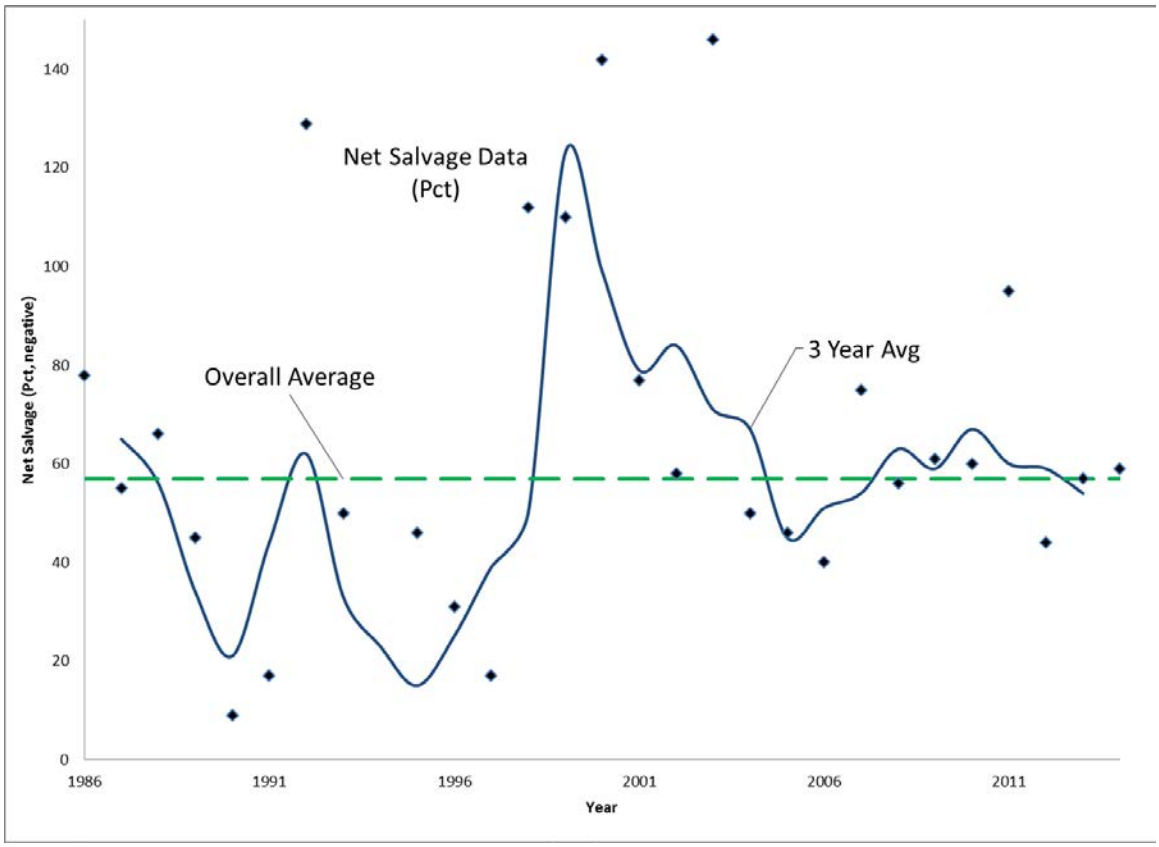
Thus, witness Pous's analysis in no way supports an estimate of negative 40% for this account. If anything, it provides support for a more negative net salvage estimate, because historically cost of removal percentages for concrete poles have been higher than for wood poles. The negative 50% net salvage estimate in the 2016 Depreciation Study, which is supported by the historical data, is the most appropriate estimate for this account.

[8] Direct Testimony of Jacob Pous, p. 156, lines 16-18.

iv. Account 356 Overhead Conductors and Devices.

The currently approved estimate for this account is negative 50%. The historical data, which is provided on pages 348 and 349 of Exhibit NWA-1, indicates a more negative net salvage estimate. The overall average is negative 57% and the most recent five-year average is negative 59%. I have recommended an estimate of negative 55%, which is consistent with trend in the data to a somewhat more negative level of net salvage than the currently approved estimate. Figure 3 below provides a graph of the net salvage data for this account. My estimate of negative 55% is consistent with the overall average shown in green and the more recent three-year averages shown in blue. I should note that for this graph, as well as other graphs of net salvage data in this exhibit, I have shown negative net salvage values as positive (that is, I have reversed the sign). This presents a better visual of the net salvage data, and is also consistent with the graphs I have presented of cost of removal values (which are positive values). The actual negative net salvage percentages would look exactly the same as shown in Figure 3, except they would be "upside down" if shown as negative values.

Figure 3



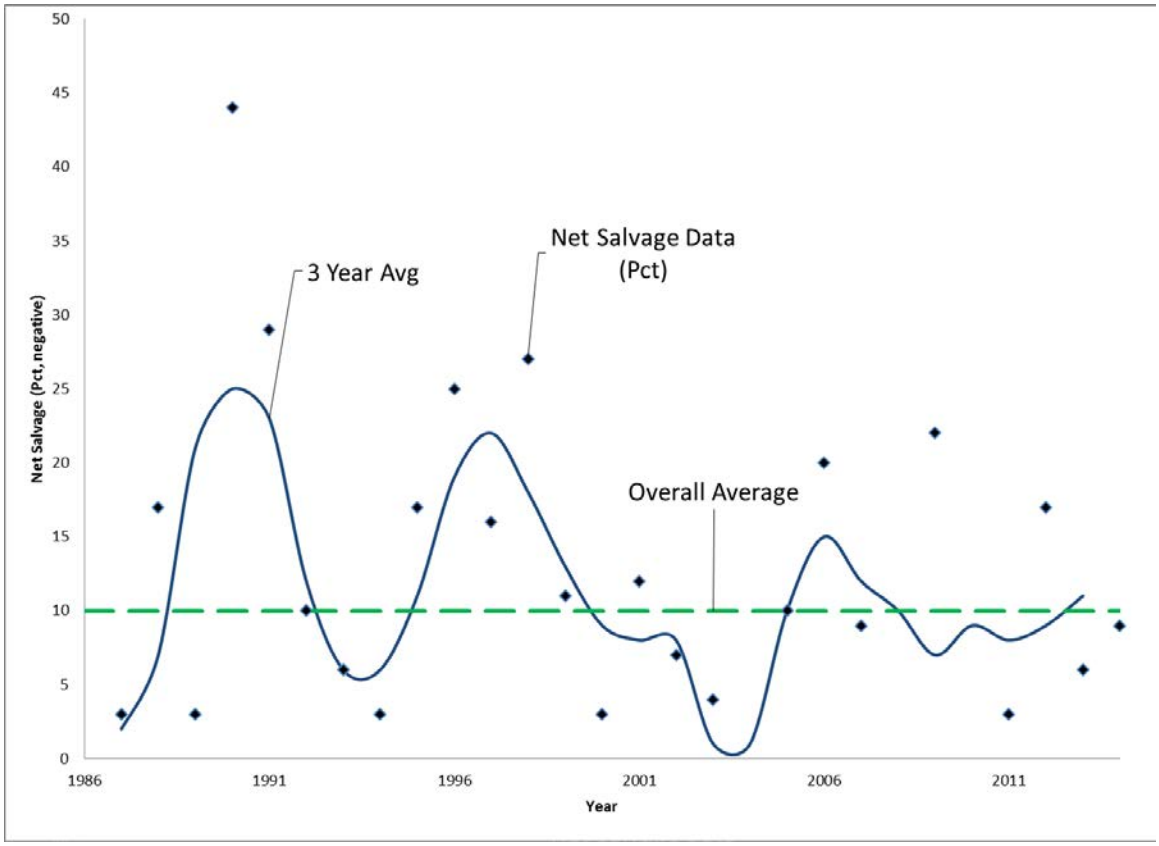
Witness Pous recommends the opposite of what is indicated by the data. Despite indications in the data for more negative net salvage than the currently approved estimate, he recommends a less negative net salvage estimate of negative 45%. His reasons for ignoring the Company's actual data do not stand up to scrutiny. One argument he presents is related to economies of scale. I have addressed the problems with this argument in Section VII.E of my rebuttal testimony. I should also note that the historical data included in the net salvage analysis for this account includes more than $100 million in retirements, and therefore provides a significant amount of experience for the net salvage analysis. Witness Pous also cites references to other utilities, which I have addressed in Section III.C to my rebuttal testimony.

The remaining support presented by witness Pous is related to hurricane related retirements. For this account as well as other accounts witness Pous argues that hurricane related activity is more representative of expectations for future net salvage than normal activity. I have discussed this topic in Section VII.D of my rebuttal testimony. Cost of removal for hurricane related retirements is much different than under normal conditions – both because the hurricane itself has done a large part of the work of removing the wire and because there are not the same costs for factors such traffic control and permitting requirements. It is inappropriate to base an estimate of net salvage on hurricane retirements while ignoring the data for normal retirements, as witness Pous does for this and other accounts.

v. Account 362 Station Equipment

The currently approved estimate for this account is negative 10%. The historical data recorded since the 2009 Depreciation Study continues to indicate that the approved negative 10% estimate is reasonable for this account. I have recommended to continue to use the currently approved negative 10% estimate. Figure 4 provides a graphical depiction of the net salvage data for this account.[9] The data for this account can also be found on pages 358 and 359 of Exhibit NWA-1. The overall average net salvage (shown in green below) is negative 10%, the same as the approved estimate. Further, Figure 4 shows that net salvage in recent years has also been similar to negative 10%, particularly when the three-year moving averages (in blue) are considered. As I explained in Section VII.B of my rebuttal testimony, averages should be given more consideration the analysis than the experience for individual years due to timing differences and differences in the types of activity each year.

Figure 4



[9] Please note that negative net salvage values are shown as positive in this graph.

Witness Pous has recommended a less negative estimate for this account than the approved estimate. His estimate is not supported by the historical data, and instead he attempts to provide a number of rationalizations for ignoring the data. His discussion for this account is very similar to for Account 353. I have previously addressed these concepts in Part i of this exhibit, which discusses Account 353, and will not repeat the discussion here. However, I will note that witness Pous's statement that "there has been a trend to a lower level of negative net salvage than existed when the prior depreciation study was performed" is not correct. As can be seen in the three-year averages in Figure 4 above the data since 2007 (i.e., 2008-2014) is consistent with the overall average of negative 10% and the three-year averages indicate a slight trend to more negative net salvage in the past couple of years. I also should point out that witness Pous relies on the analysis of an individual year of data for his support,[10] which as discussed above and in Section VII.B of my rebuttal testimony, is not the proper way to perform net salvage analysis.

[10] Direct Testimony of Jacob Pous, p. 163, lines 3-9.

vi. Accounts 364.1 and 364.2 Poles, Towers and Fixtures

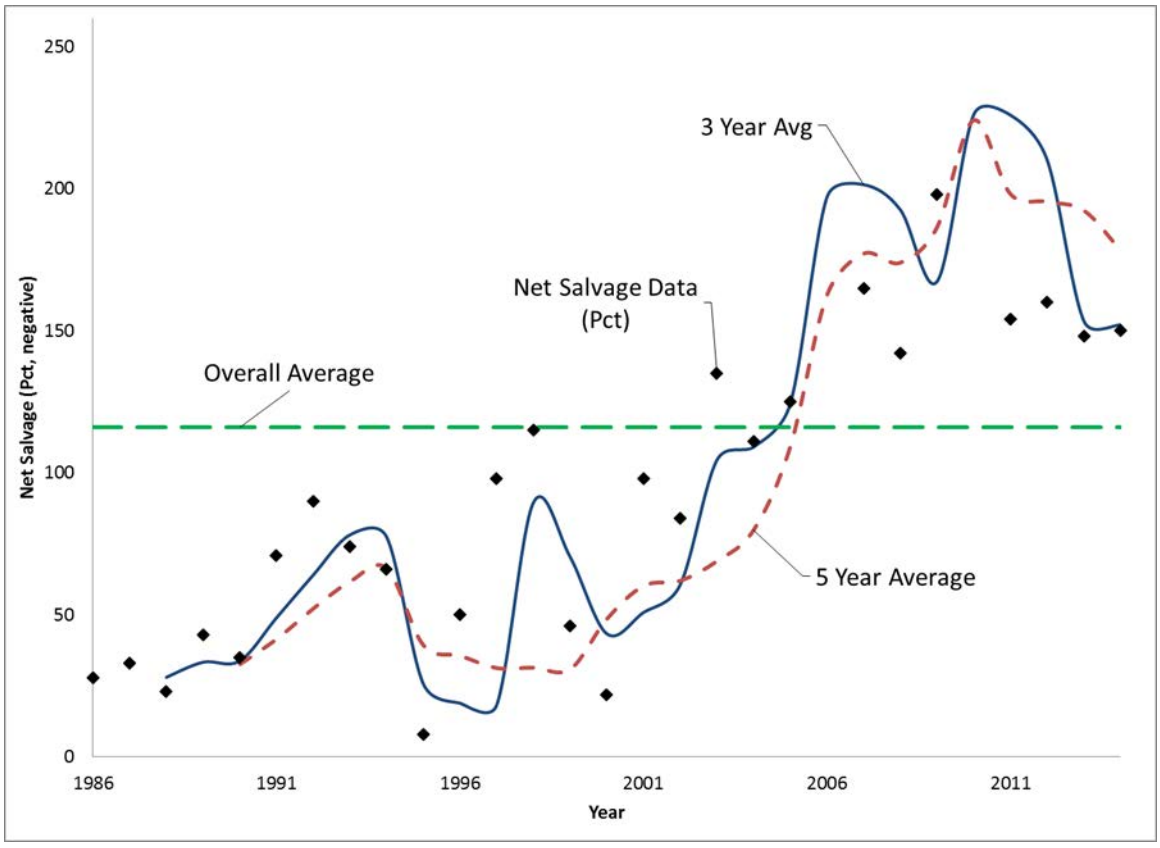
Account 364.1 Poles, Towers and Fixtures – Wood and Account 364.1 Poles, Towers and Fixtures – Concrete were studied together for the net salvage analysis, and the same estimate has been recommended for both accounts. One advantage of creating separate subaccounts for wood and concrete poles will be that the net salvage data can be maintained and analyzed separately for the two subaccounts. However, it is reasonable at this time to expect that on a percentage basis the net salvage will be similar for the two types of poles. The approved estimate for both accounts is negative 60% net salvage. However, the historical data demonstrates quite clearly that a more negative net salvage estimate is required. The overall average net salvage in the net salvage analysis, which is shown on pages 360 and 361 of Exhibit NWA-1, is negative 116% - almost double the approved net salvage estimate. More recent data indicates even more negative net salvage than is indicated by earlier years. For example, the most recent five year average is negative 179%. I have recommended an estimate of negative 100%. This is a conservative estimate in that it is less negative than the overall average in the data. It is an even more conservative estimate given the fact that, as I will explain, the historical data understates actual net salvage expectations due to high levels of gross salvage in the earlier years of the analysis that are not expected to continue.

Despite the fact that the data indicates a far more negative net salvage estimate than the currently approved estimate for this account, witness Pous proposes no change to the currently approved estimate of negative 60%. As is evidenced in both his recommendation and his testimony, witness Pous has elected to ignore the historical data for this account. His approach is therefore clearly inappropriate. However, a review of his arguments presented in his testimony provides further reason to demonstrate that there is no basis for witness Pous to cast aside the strong evidence provided by FPL's data that demonstrates that a more negative net salvage estimate is warranted for these accounts. I will first discuss the data for this account and then will address witness Pous's specific arguments.

I should note that I have discussed the historical net salvage data for this account in some detail in Section VII.B of my rebuttal testimony. Figure 5 below is the same as shown in my rebuttal testimony, and presents the net salvage percentages for each year (black diamonds on the graph), the three-year moving average net salvage percentages (shown in blue), the five-year moving average net salvage percentages (shown in red) and the overall average (shown in green).[11]

[11] Please note that negative net salvage values are shown as positive in this graph.

Figure 5



However, similar to the discussion of Account 355 presented in Section iii of this exhibit, the historical net salvage for this account likely understates the net salvage expectations for this account. As can be seen on page 360 of Exhibit NWA-1, the overall average gross salvage is 28 percent. This is higher than should be expected for the assets in this account. Wood poles should have no positive gross salvage (and instead typically will have disposal costs) and concrete poles should have minimal gross salvage, if any. A closer look at the gross salvage data shows that almost all the gross salvage occurred in the earlier years of the data, and that some years experienced 100% gross salvage or more. In more recent years, gross salvage has trended closer to a reasonable gross salvage expectation for the assets in this account of 5%. Further, many of the earlier years, such as those in the early 1990s, experienced very high gross salvage. Some years had gross salvage of 100% or more. Thus, the historical level of gross salvage should not be expected in the future for most of the assets in this account.

Instead, gross salvage should be expected to be more in the 5% to 10% range (and even that may be too high). The overall cost of removal is 144 percent, and thus the statistical indications, once the historical gross salvage is properly considered, are more in the negative 130% or 140% range. To help illustrate this concept, I have graphed just the historical cost of removal in Figure 6 below. Because the

historical gross salvage is higher than should be expected for this account, the graph below likely provides a better indication FPL's future level of net salvage than the net salvage data percentages shown in Figure 5.

Figure 6

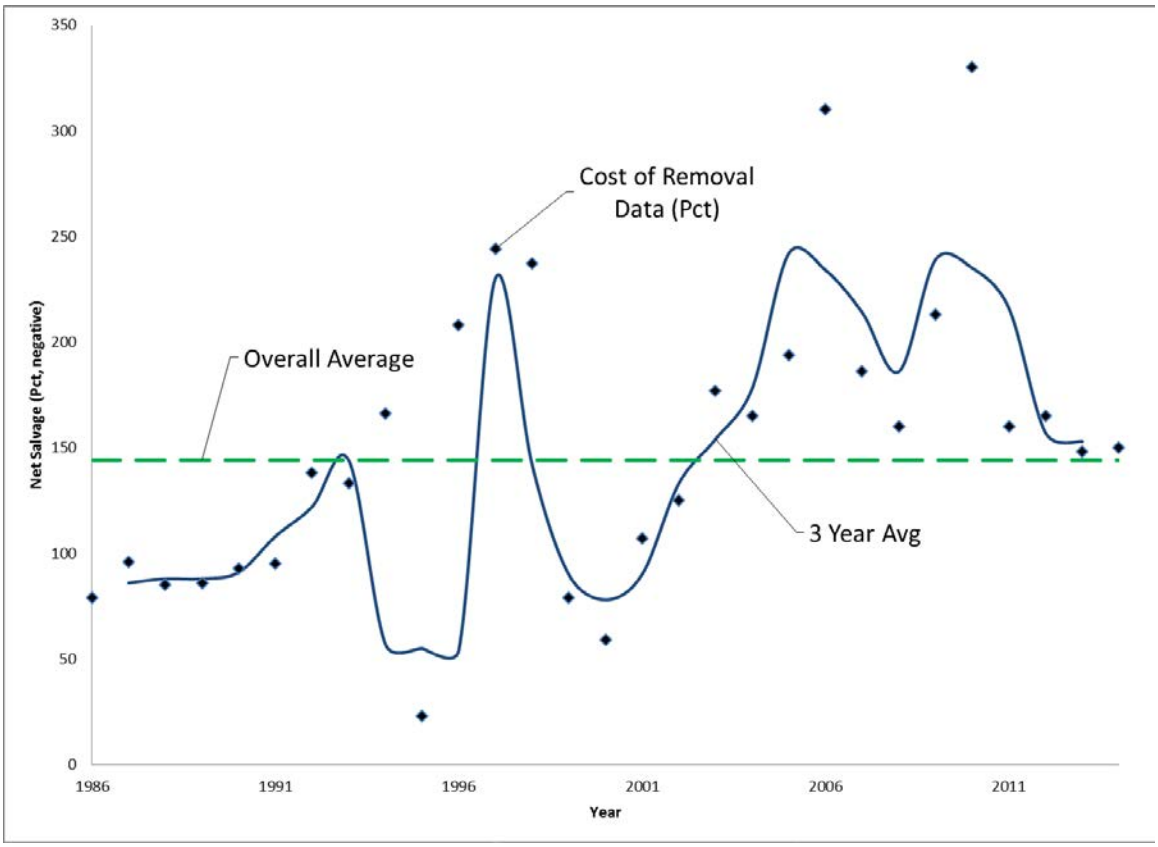


Figure 6 demonstrates further that the existing estimate of negative 60% is insufficient. It better illustrates the overall trend in removal costs and shows that cost of removal has been more negative than 60% for some time. In fact, for most years other than a few years in the mid and late 1990s, the three year averages are fairly close to or higher than 100%. Many years have experienced cost of removal that has been much higher than 100%. Thus, the analysis of historical cost of removal further supports that my estimate is in fact a conservative estimate of net salvage.

Given the clear support of my estimate in the historical data, witness Pous has no choice but to attempt to devise ways to ignore the data in order to support his estimate. His attempts are not convincing, and many have already been addressed in my rebuttal testimony. I should first note that the net salvage database includes more than $130 million in retirements. This is a significant amount of activity and provides good reason for confidence in the data. I have also explained in Section iii of this

exhibit that witness Pous's analysis of the historical net salvage for wood and concrete poles was incorrect, and demonstrated that if anything concrete poles should be expected to experience more negative net salvage than wood poles.

Finally, I have also addressed witness Pous's comments regarding economies of scale, which comprises most of his discussion for this account, in Section VII.E of my rebuttal testimony. I should again point out that his discussion of economies of scale is particularly unconvincing in light of the storm hardening program. The storm hardening program provides an example of exactly the type of situation that witness Pous discusses on page 169 of his testimony in which he provides a hypothetical example of "a section of line containing 30 poles that are to be retired at one time." This type of situation has been common for the storm hardening program. However, contrary to the implication in witness Pous's testimony, cost of removal for storm hardening work has not been significantly lower than in other years. In fact, the cost of removal since the implementation of the storm hardening program has been much more negative than my estimate of negative 100%, as can be seen in both Figure 5 and Figure 6. Witness Pous's expectation for economies of scale has not materialized (and should not be expected to materialize in the future). There are a number of other factors that are mostly outside of FPL's control that offset any gains from economies of scale, as I have discussed in Section VII.E of my rebuttal testimony.

vii. Account 365 Overhead Conductors and Devices

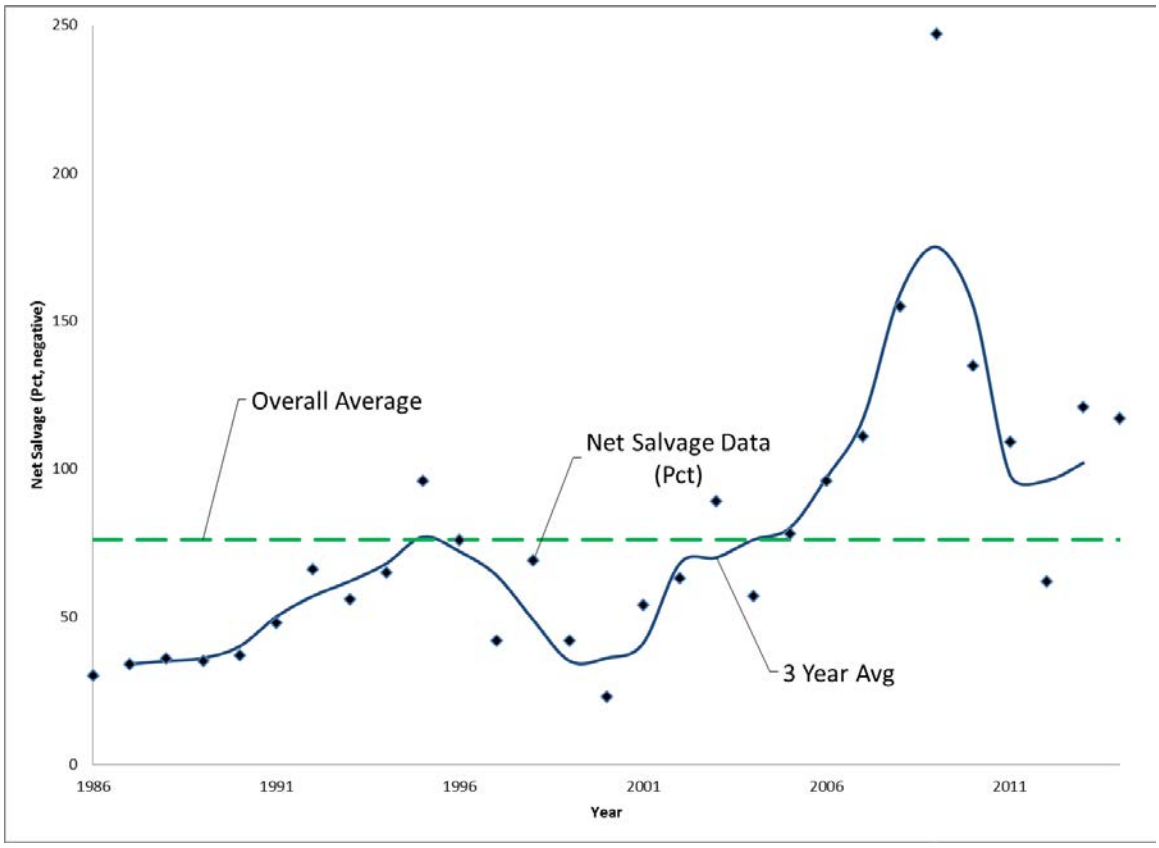
The currently approved estimate for this account is negative 60% net salvage. The historical data indicates that a more negative net salvage estimate is warranted. The historical data indicates an overall average net salvage of negative 76%. More recent data has been more negative. For example, the most recent five year average net salvage is negative 108%. I have recommended an estimate of negative 80%, which is consistent with the overall average net salvage but less negative than more recent data.

Witness Pous has recommended no change in the currently approved negative 60% net salvage. Similar to many accounts, he has opted to ignore the results of the statistical net salvage analysis based on the Company's recorded data. Instead, the primary statistical basis for witness Pous's estimate is an analysis of hurricane retirements, which as I have explained in Section VII.D of my rebuttal testimony are not a reasonable basis for determining net salvage.

The historical net salvage data for this account is presented in Figure 7 below.[12] As the figure illustrates, the net salvage has trended to be more negative. The three year averages have been more negative than the currently approved estimate of negative 60% since the early 2000s, and since the last study they have been even more negative than my estimate.

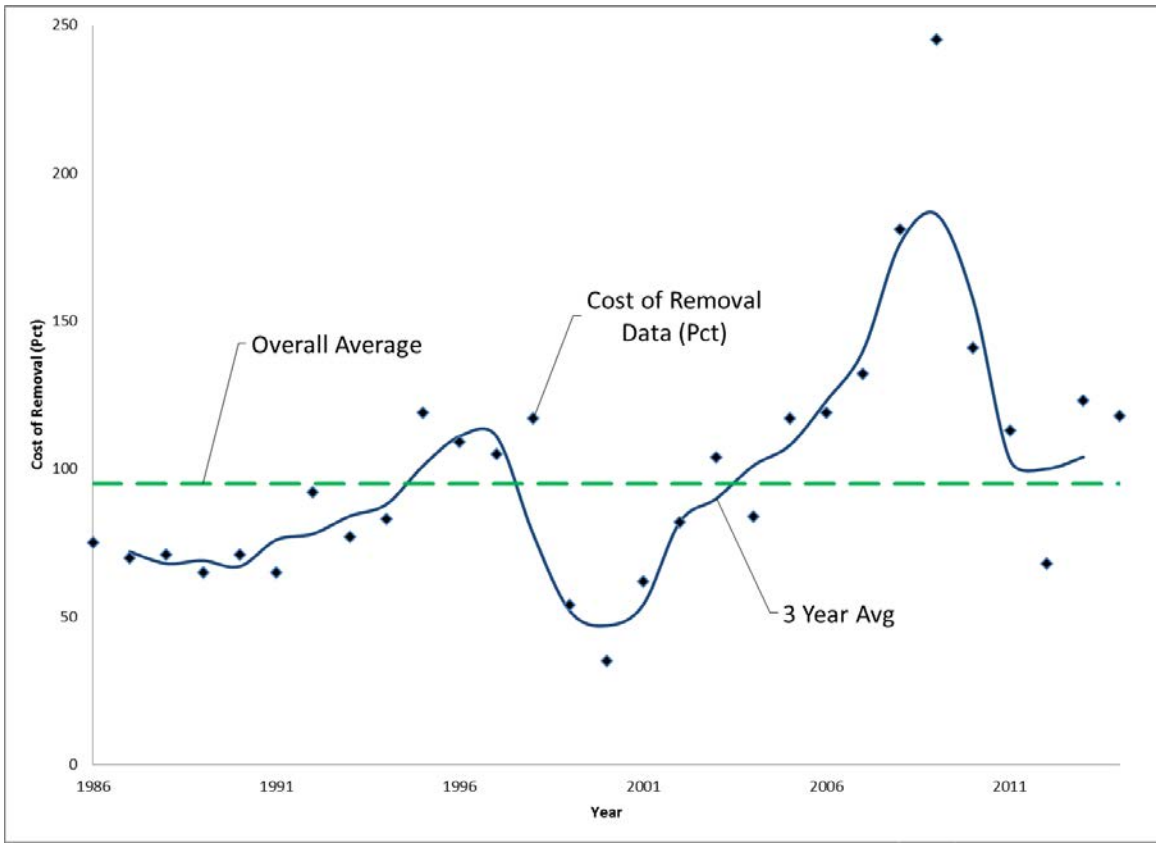
[12] Please note that negative net salvage values are shown as positive in this graph.

Figure 7



If just the cost of removal is reviewed, the data is further supportive of a more negative net salvage estimate. Gross salvage has trended lower in recent years. It is reasonable to expect that gross salvage may not be quite as high as in earlier years. The Company will retire less copper conductor than was the case in earlier years, and as a result will likely receive less scrap salvage on a per unit basis. The historical cost of removal is shown in Figure 8 below. While Figure 8 also shows a trend in historical cost of removal, it is not quite as pronounced as for the net salvage data shown in Figure 7. While cost of removal has increased over time, it has been relatively high for the full period of available data.

Figure 8



Much of witness Pous's criticism of this account is devoted to criticizing the explanations provided for increasing cost of removal for this account. I should first point out that his discussion is not an accurate representation of what has been provided. Many of the driving factors for increasing cost of removal for this account are similar to those for other accounts, such as Account 364. These factors, such as environmental, permitting and traffic control requirements, have all been explained in my direct testimony,[13] the 2016 Depreciation Study[14] and in discovery.[15] I have discussed these factors further in my rebuttal testimony in Section VII.C. On pages 173 and 174 of his testimony, witness Pous cites only a portion of a discovery response and presents it as if it is a full explanation of factors influencing this account. Thus, his testimony does not provide an accurate picture of what I have provided and discussed. Additionally, I should emphasize once again that the data is supportive of my estimate. The full database for the net salvage analysis is based on almost $180 million in retirements, and therefore

[13] Direct Testimony of Ned W. Allis, pp. 39-40.

[14] See for example the discussion on pages 728 and 729 of Exhibit NWA-1.

[15] See for example Attachments 1 and 2 of FPL's response to OPC's First Request for Production of Documents No. 38 and FPL's response to OPC's First Set of Interrogatories, No. 51.

FPL's extensive historical database provides a reasonable representation of the future experience for this account and should not be ignored.

Witness Pous has provided no valid reason to ignore the historical data. He again presents his argument related to economies of scale, which I have addressed in Section VII.E of my rebuttal testimony. He also argues that some of the factors that have driven higher costs of removal, such as higher labor costs, also increase the cost of new assets. I should first note that many of the assets in this account are older and will therefore be unaffected by this concept. Further, while there may be some impact on the net salvage percentage due to this factor, the fact that my estimate is more consistent with the overall average as opposed to more recent averages alleviates this concern. My estimate is much less negative than the more recent averages, and therefore witness Pous's argument does not provide any justification his approach, which completely ignores the trend to more negative net salvage.

The one actual quantitative argument witness Pous sets forth also has no validity. Witness Pous cites a historical net salvage percentage of negative 59% for hurricane retirements in support of his estimate of negative 60%.[16] That is, witness Pous's actual analysis of the historical data for this account consists of the following:

- The Company has almost $180 million in normal retirement activity that supports a more negative estimate than the currently approved estimate.
- Witness Pous chooses to not believe this data and therefore does not consider the data for his estimate.
- Instead, he relies on data for hurricane related retirements, which are not conducted under normal circumstances and are therefore not at all indicative of the future experience for the vast majority of this account.

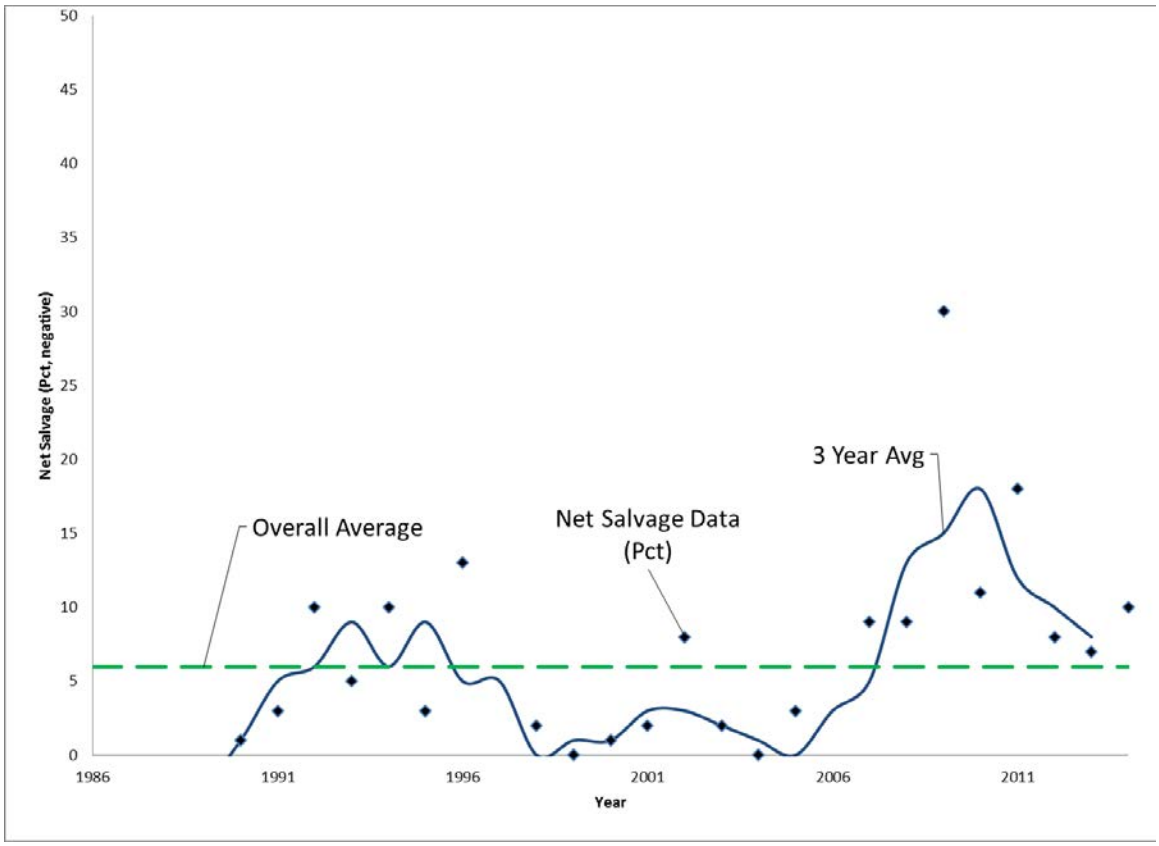
I have explained the problems with relying on hurricane retirements in Section VII.D of my rebuttal testimony. For a number of reasons, one of which is that the hurricane does much of the work to remove overhead conductor, hurricane related activity should not be considered to be indicative of the future net salvage for this account. Witness Pous's approach – ignoring the extensive actual net salvage data for normal retirements, and instead basing an estimate on limited activity for unusual circumstances – is not an accepted method of estimating net salvage, and does not provide reason to ignore the clear support in the historical data for a more negative net salvage estimate.

[16] Direct Testimony of Jacob Pous, p. 178, lines 2-8.

viii. Account 367.6 Underground Conductors and Devices – Duct System

The currently approved estimate for this account is 0%. The net salvage data indicates that a negative net salvage estimate is appropriate. The overall net salvage in the historical data is negative 6%. More recent data indicates more negative net salvage, with the most recent five year average being negative 10%. I have recommended an estimate of negative 5% net salvage. The historical net salvage data for this account is shown in Figure 9 below.[17] Since the early 1990s there has consistently been negative net salvage for this account.

Figure 9



One reason for the trend to more negative net salvage is that there has been lower gross salvage than was the case 15 or 20 years ago. FPL does not expect significant gross salvage for underground cable. Underground cable is different from overhead cable in that the insulator is built into the cable, and because underground cable needs to be cut in order to recover any scrap. As a result, scrap salvage should be expected to be lower than would be the case for overhead cable.

[17] Please note that negative net salvage values are shown as positive in this graph.

OPC witness Pous proposes 0% net salvage. As with most accounts, he again decides to ignore the historical data. Instead, his estimate is based on a discussion of two concepts, both of which are incorrect. First, he states that "the appropriate interpretation of actual transactions should be that conductor is not pulled from conduit unless it can receive positive salvage."[18] This is incorrect. Conductor is removed from conduit so that new conductor can be installed. Typically, this results in negative net salvage because the cost of removing the conductor exceeds any salvage.

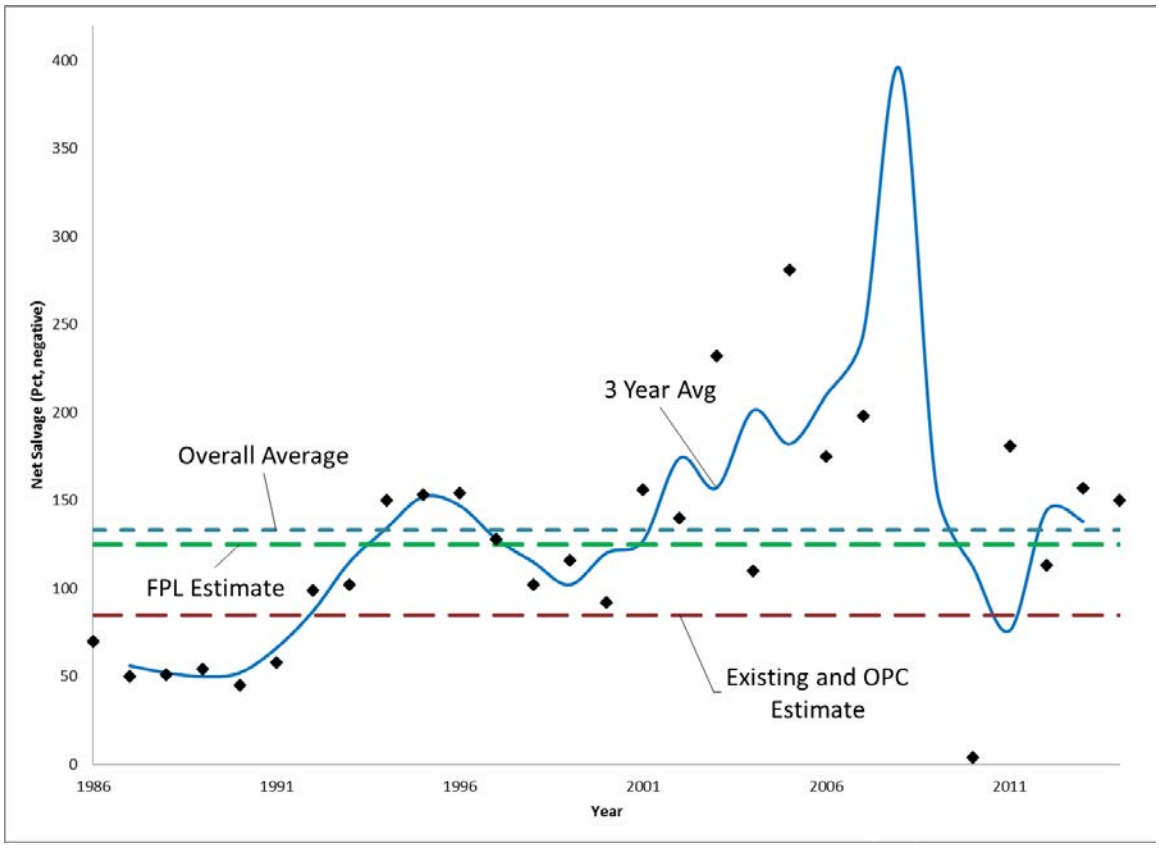
Witness Pous's second argument is that "when conductor is pulled and costs are incurred 'to make room for new conductor,' those costs should be assigned to the new installation rather than as cost of removal."[19] Thus, witness Pous argues against FPL's using net salvage data because he believes that the Company should account for the replacement of underground conductor in a fundamentally incorrect manner. When replacing an asset, the cost related to the new asset should be charged to the new asset and the cost related to removing or retiring the old asset should be charged to cost of removal. Pulling conductor from conduit is quite clearly a process of removing the old conductor and therefore should be charged to cost of removal.

Witness Pous's proposal to ignore the data is therefore based on a combination of an incorrect understanding of FPL's practices and a fundamentally incorrect approach to accounting for cost of removal. I should further note that witness Pous's statement that "[t]he Company's proposal is no different than what the Commission denied in the last proceeding"[20] is also incorrect. The data since the last study provides additional support for my estimate, which can be seen clearly in Figure 9 above. Additionally, in Docket No. 090130-EI the Commission stated "[w]e find that 0 percent net salvage is appropriate based on the data."[21] The data in this case is quite clearly supportive of my estimate and not that of OPC, and therefore the negative 5% net salvage estimate recommended in the 2016 Depreciation Study is most appropriate for this account.

[18] Direct Testimony of Jacob Pous, p. 181, lines 7-10.
[19] Direct Testimony of Jacob Pous, p. 181, lines 10-14.
[20] Direct Testimony of Jacob Pous, p. 180, lines 17-18.
[21] Order No. PSC-10-0153-FOF-EI, p. 69.

ix. Account 369.1 Services – Overhead

The currently approved net salvage estimate for this account is negative 85%. The approved estimate is less negative than indicated by the historical data. The overall average net salvage is negative 133% and most three-year moving averages in the last twenty years have been more negative than the overall average. Figure 10 below presents the historical net salvage data. The overall average is shown as a blue dashed line, and the three-year moving averages are shown as a solid blue line. To provide perspective as to how the existing estimate compares to the data, I have also included the existing estimate (the red dashed line) and my estimate (the green dashed line) in the graph. With the exception of one instance (which is due to timing differences), every three-year moving average since the early 1990s is more negative than the existing negative 85% net salvage estimate.



Cost of removal of 100% or more is a reasonable expectation for services. The actual physical service line is not a particularly expensive item has a lower unit cost than, say, a pole. Additionally, when replacing a service line the effort involved to remove the existing service is similar to the effort required to install the new service, and as a result the labor split between cost of removal and the new asset can be relatively close to 50-50. Considering these factors, as well as that service lines will be replaced on average more than 50 years after installation (the average service life estimate for this

account is 53 years) and that costs will increase over a 50 year period, it is not surprising that net salvage for this account is more negative than negative 100%.

Despite the historical data, which has not supported an estimate in the range of negative 85% in more than twenty years, witness Pous recommends no change to the existing negative 85% net salvage estimate. As with most accounts, his approach is to provide a number of reasons to ignore the data. His only quantitative support is, similar to the overhead conductor accounts, to inappropriately rely on hurricane retirements.

One item witness Pous criticizes is the explanations that have been provided for increasing cost of removal presented in the 2016 Depreciation Study. I should first make clear that many of the reasons for an overall increase in cost of removal for this account are consistent the reasons for increases in cost of removal with other accounts. Second, as can be seen in Figure 10, the trend to more negative net salvage is not a particularly recent occurrence for this account. Cost of removal has been consistently high and net salvage has consistently been more negative than negative 100% since the early 1990s. Finally, I have provided additional reasons that explain higher costs for services.[22] Service lines, which generally extend to the customer's property, are often more difficult to access than assets on FPL's land or rights-of-way. Additionally, disconnecting the service line requires care, as a service line often extends across a roadway or structure. Both of these factors can increase the effort involved in removing the service, and in fact the effort involved to remove the service line can exceed that of installing the new service as a result.

Witness Pous is incorrect in his attempt to argue that because there is variability in the types of tasks involved, the net salvage data cannot be relied on. I should note that because much of FPL's service territory is in developed areas, the challenges with replacing services are common because service lines typically extend to customer property in these developed areas. Additionally, the Company has almost thirty years of data, which provide clear support for a more negative net salvage estimate. If there were any validity to witness Pous's arguments regarding the variability in the data, it would support relying on longer term averages instead of individual years or short term averages. In part for this reason, I have given more consideration to longer term averages for my estimate.

Most of witness Pous's other arguments have been addressed previously. These include economies of scale, reimbursed retirements and witness Pous's reliance on hurricane retirement activity. I should make clear that similar to the overhead conductor accounts, hurricane related activity is not at all a reasonable basis for net salvage because the hurricane typically does much of the work to remove the conductor.

Finally, I should make clear that witness Pous's statement that "the Company has chosen not to provide any new specific data" for this account is simply incorrect. There are seven additional years of

[22] See for example page 744 of Exhibit NWA-1.

data for the study, which support that a more negative net salvage estimate than the approved negative 85% estimate is appropriate. As discussed above, I have also provided additional information and explanations to support a more negative net salvage. I should further point out that in Docket 090130-EI the Commission did in fact recognize the trend to more negative net salvage and approved a change from a negative 60% to a negative 85% net salvage estimate.[23] The data continues to support a more negative net salvage estimate – even more negative than the currently approved negative 85%. Therefore an additional move in the 2016 Depreciation Study to a more negative net salvage estimate is appropriate.

[23] Order No. PSC-10-0153-FOF-EI

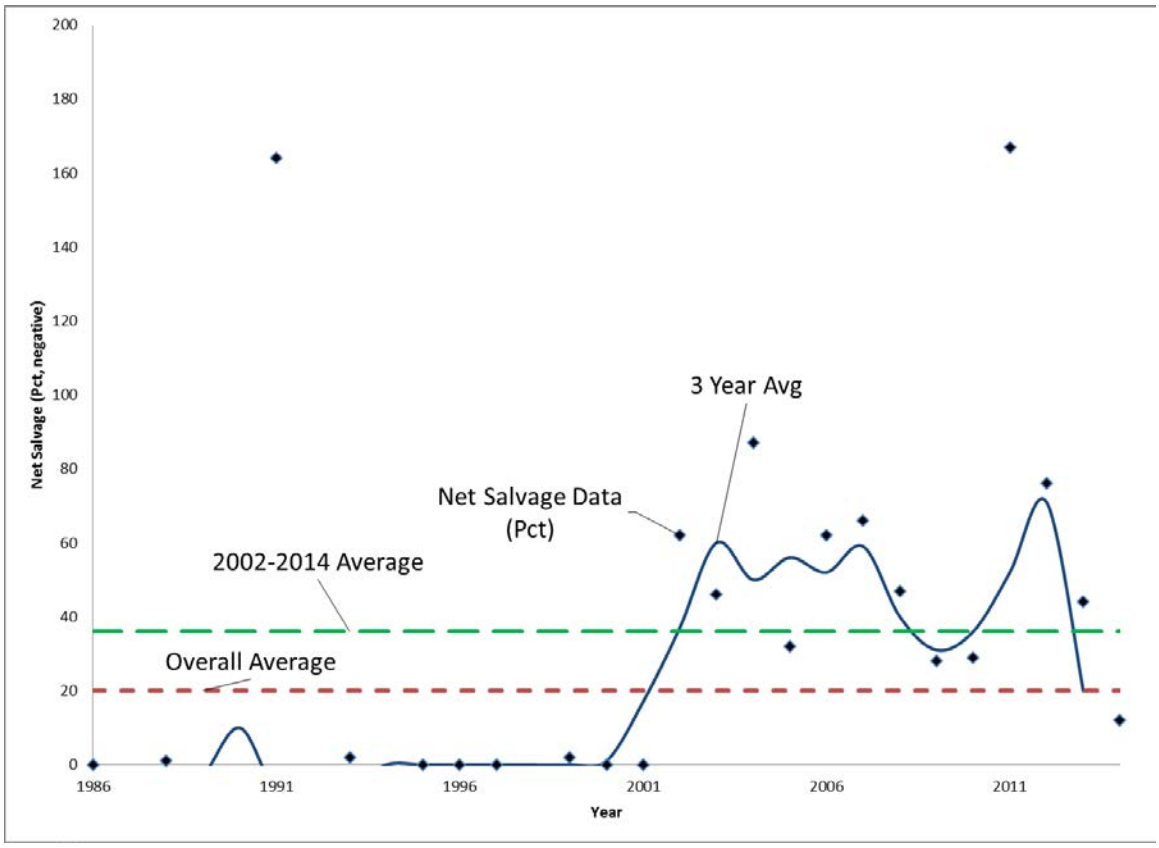
x. Accounts 370 and 370.1 Meters

The currently approved net salvage estimate for this account is negative 30%. The historical data continues to support an estimate that is at least as negative as the currently approved estimate, especially when it is properly considered. I have recommended to retain the existing negative 30% net salvage estimate. In contrast, witness Pous again recommends a less negative net salvage estimate than the currently approved estimate, and proposes a negative 20% net salvage estimate. I should note that despite witness Pous's numerous assertions throughout his testimony that the net salvage data should be investigated to determine whether it is representative of future experience, he ignores the various investigations that I have conducted for this account. Instead, witness Pous bases his estimate on data that is not representative for this account.

Accounts 370 and 370.1 are studied together for the net salvage analysis. Because there is limited historical data for Account 370.1 AMI Meters (because these are new assets), the data for Account 370 Meters is the primary statistical basis for the estimate for both meters accounts. It is reasonable to expect that the costs to remove an older type meter such as included in Account 370 would be the same as the cost to remove a newer AMI meter. This is a reasonable approach until more data specific to Account 370.1 is available. However, I should also point out that to the extent there is limited data available for Account 370.1, these data do support a negative net salvage estimate in the range of negative 30%, as can be seen on page 380 of Exhibit NWA-1.

The historical data for Account 370 is shown on pages 378 and 379 of Exhibit NWA-1. The data is also shown in Figure 10 below. The first observation that is apparent when reviewing the data is that recorded cost of removal changed significantly beginning in 2002. I will discuss this change in more detail, but the most important point is that the data from 2002 to the present is representative of FPL's current practices for recording cost of removal for meters. Thus, the data since 2002 is representative of what will occur in the future – the data prior to 2002 is not. The data prior to 2002 therefore has little value in the net salvage analysis and should be given minimal consideration for the net salvage estimate for this account. In Figure 10 below I have presented both the overall average net salvage of negative 20% as well as the average net salvage since 2002, which is negative 36%. The data prior to 2002 does not provide any indication of future experience, and therefore the 2002 to 2014 average is far more representative of future net salvage for this account.

Figure 10



In the early 2000s the Company implemented a new accounting system, at which time the process for recording cost of removal for this account was revised. Prior to 2002 there was very little recorded cost of removal for this account. I should note that this had been true for many other utilities as well. Many years ago when older-style electromechanical meters were the primary type of meter, when a meter was removed from service it was returned to a meter shop, tested, and repaired and refurbished if possible. As a result, meters were often reused at a different location after being refurbished. At that time, due to this practice it made sense that the cost involved with removing the meter from a customer location was not fully charged to cost of removal, because the meter may not have been retired but instead would be used elsewhere on the system.

This practice is no longer common. Meters are fairly inexpensive, and as a result it is typically no longer economical to refurbish meters. This is particularly true because meters today are generally either AMI meters or solid state or digital meters. While it may have been economical years ago to refurbish older-style electromechanical meters, the same is not true with newer meters (which also have a shorter service life than older-style meters and typically cannot be refurbished). As a result of these

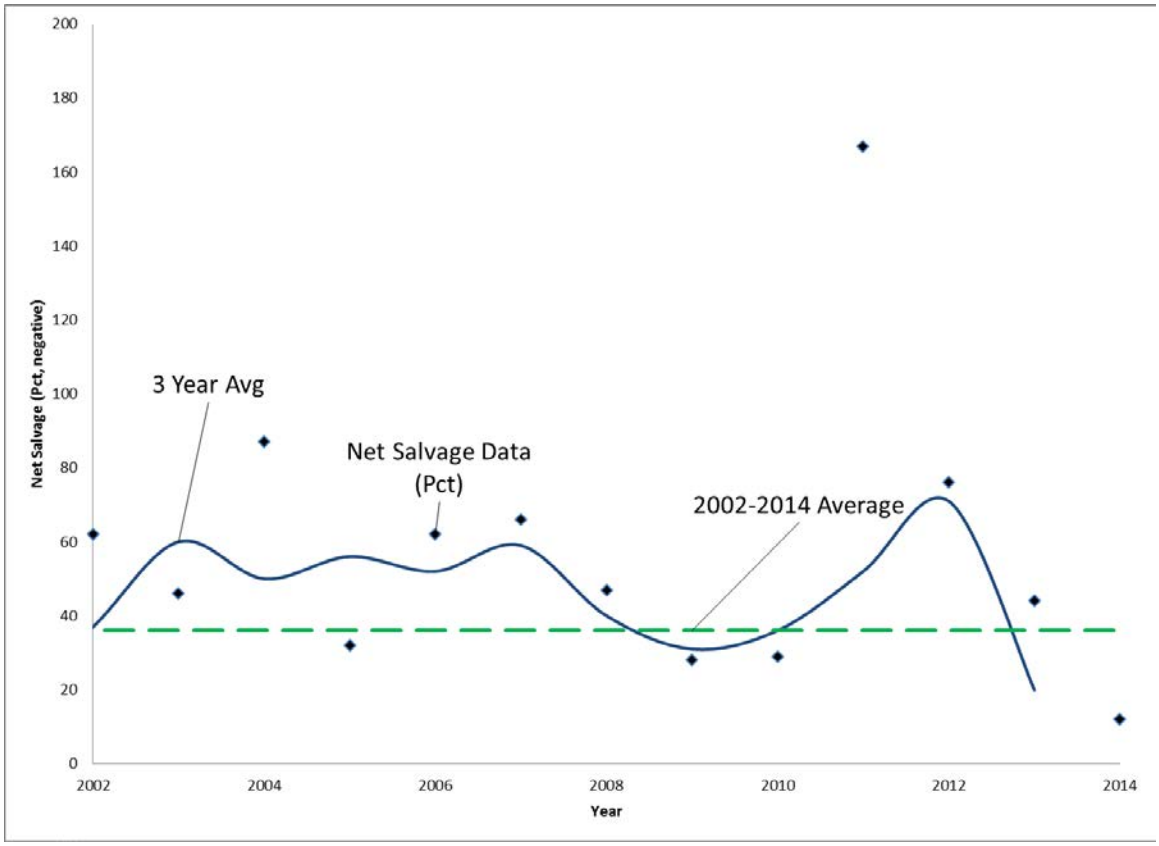
changes, when a meter is removed from a customer location it is generally retired. It therefore makes sense to charge the cost of removing the meter to cost of removal, as FPL has done since 2002.

While witness Pous characterizes FPL's data as an outlier in the industry, FPL's change to better recording cost of removal for meters is not the only instance of such a change. For example, Pacific Gas & Electric experienced a similar change in recorded cost of removal in 2004, and has experienced similar cost of removal to FPL since.

I should add that a relatively high level of cost of removal for meters makes intuitive sense as well. The actual meter is a relatively inexpensive piece of equipment. A meter also has little to no scrap value. Further, the effort involved to retire the old meter when replacing the meter is similar to that involved with installing the new meter. For these reasons, it is not surprising that the cost to remove a meter would be at least 30% of the cost of installing the meter.

For all of these reasons, once the data is investigated it should be clear that only the data since 2002 should be considered in the net salvage analysis. Figure 11 below provides a graph of the historical net salvage data from 2002 through 2014. These data provide clear support that the currently approved negative 30% net salvage continues to be appropriate. If anything, the data properly considered supports a more negative estimate.

Figure 11



Witness Pous cites both the overall average and most recent three-year average of negative 20% in support of his negative 20% net salvage estimate.[24] Neither is representative of the future experience once the data is investigated, as I have done. The overall average is skewed by the non-representative data prior to 2002, as explained above. Further, the most recent-three year average cited by witness Pous is skewed by a large retirement in 2014. I investigated this activity[25] and determined that the retirement in 2014 was primarily related to the deployment of AMI meters for commercial and industry customers. This activity is not likely to recur and therefore is not representative of the future experience for this account.

Witness Pous's other support for his estimate is primarily related to hurricane related retirements and reimbursed retirements. I have addressed this issues previously. Thus, given all of the considerations discussed here, the currently approved negative 30% net salvage estimate continues to be most appropriate for this account. If anything, the data, once properly considered, supports that a more negative net salvage estimate could be appropriate.

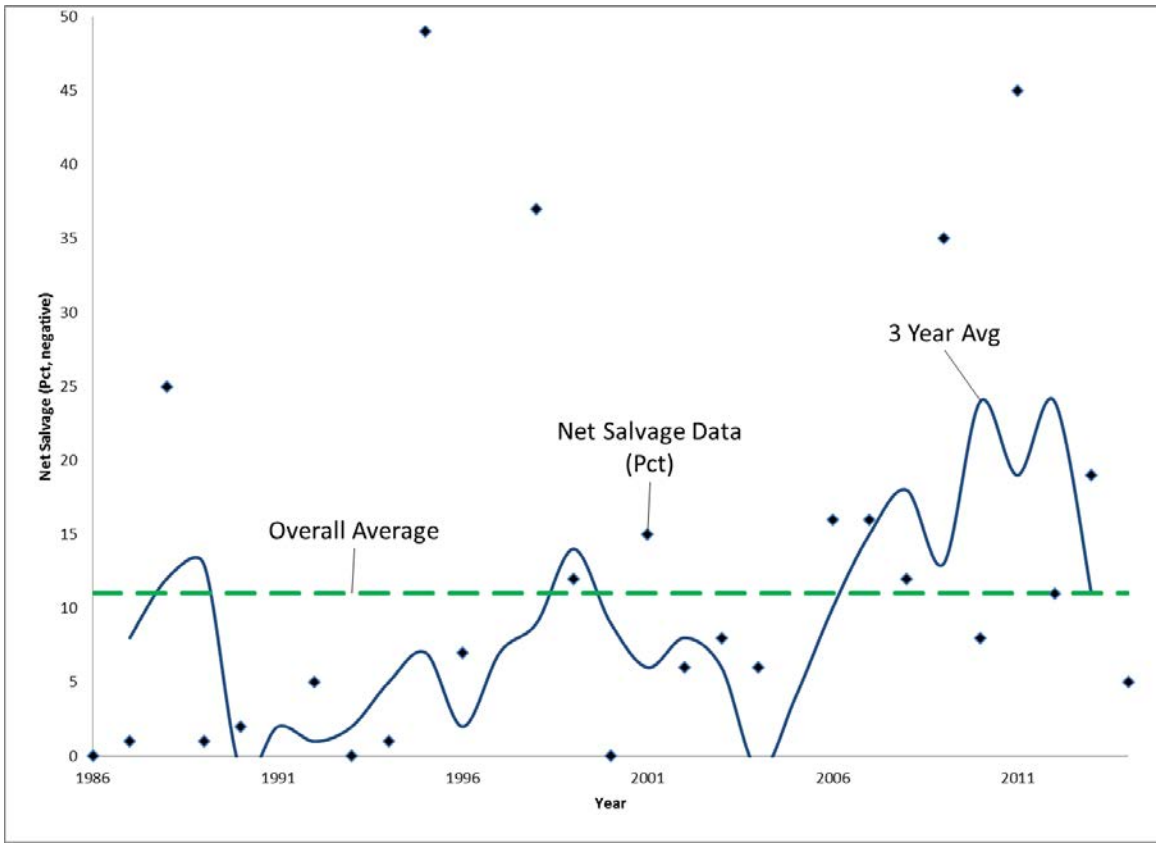
[24] Direct Testimony of Jacob Pous, p. 121, lines 5-6.

[25] This information was provided in discovery in FPL's response to OPC's First Set of Interrogatories, No. 51.

xi. Account 390 Structures and Improvements

The currently approved net salvage estimate for this account is negative 5%. The historical data, which is presented on pages 385 and 386 of Exhibit NWA-1, supports a more negative net salvage estimate than the currently approved estimate. I have recommended an estimate of negative 10%. The overall average net salvage is negative 11% and the most recent five year average is negative 15%. Figure 12 below shows the net salvage analysis for this account.[26]

Figure 12



While the data is supportive of my estimate, witness Pous has proposed a move in the opposite direction. He proposes a positive 10% net salvage estimate. Witness Pous's arguments in support of his estimate are very similar to his arguments in Docket No. 090130-EI. I should note that his arguments were not persuasive in that case and were not adopted by the Commission.[27] Witness Pous's primary argument is that the Company's buildings will have significant value after they reach the end of their useful lives. Specifically, he presents his "selection of a 10% positive net salvage as an initial step in

[26] It is reasonable to assume that the costs to remove an older type meter such as included in Account 370 would be the same as the cost to remove a new AMI meter.

[27] See page 74 of Order No. PSC-1O-Ol53-FOF-EI

this proceeding towards the recognition of the net salvage that large office buildings, service centers and general plant structures will have even after 50, 60, or 80 years of use or longer is appropriate."[28] This is the same argument he presented in Docket No. 090130-EI, which the Commission did not find persuasive. This argument is no more persuasive today than it was in that docket.

First, I should make clear that I did consider in my estimate any value that a building may have at the end of its useful life, as is discussed on page 755 of Exhibit NWA-1. However, unlike witness Pous, I did not overstate this impact and I did not rely on non-representative data. Further, I used a consistent and balanced approach for both the life and net salvage analysis. The service life estimate for this account is the 55-R1.5 survivor curve. The average service life for this account (which is 55 years) incorporates not only the lives of FPL's actual buildings but also the various components of buildings such as roofs and HVAC equipment that will be replaced over the course of a building's life. As a result, because the components of the Company's buildings will have shorter lives, the 55-R1.5 estimate implies that the buildings themselves will on average have a life longer than 55 years – 60 years or more. Additionally, this is just the average. Some buildings are therefore estimated to remain in service for 80 years or more.

Witness Pous is incorrect that there will be significant value in the buildings themselves after 60 or 80 years. There may be value to the site, but this is primarily related to the land. The building itself can actually have negative value. For example, if a new owner would need to demolish the building for the site to be used for a new purpose, then the net salvage for the actual building would be negative. This is because the land would be worth less than if there were no building on it due to the cost of removing the existing structure. I should also note that this account includes many service centers. These are utility specific buildings that may require significant modifications even if not demolished once they reach the end of their useful lives. This too implies minimal, if not negative, net salvage.

The data presented by witness Pous in support of his proposal is not at all representative of the net salvage of FPL's buildings once they reach the end of their useful lives. His primary data point is the sale of the Company's Miami general office in 2011, for which the Company did receive positive salvage.[29] However, this building was only 36 years old when it was sold.[30] It was therefore not at the end of its useful life, a point which can also be understood by the fact that the Company continues to use the building for its operations (it is just owned by a different owner). This is a very different situation than one in which a building will be retired at 60 to 80 years of age. While the land for the Miami general office will still have value in 30 to 40 years, the building will have much less value.

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[28] Direct Testimony of Jacob Pous, p. 193, lines 13-16.

[29] Direct Testimony of Jacob Pous, p. 193, lines 11-13.

[30] I should note that most of the other sales transactions witness Pous references were even younger, and therefore even less representative of the net salvage for this account.

For this reason, the proper approach is to exclude this sale from the historical data, as it is a non-recurring event. I have properly done so for both the service life and net salvage analyses. Witness Pous has not. While he gives this non-representative transaction undue consideration in the net salvage analysis, he continues to exclude the transaction (as well as the sales of other buildings) from the life analysis (as he proposes no change to my service life recommendation for this account). Thus, he has given undue consideration to sales buildings when they would lead to a higher level of positive net salvage (reducing depreciation expense) but ignores this activity if it would result in a shorter service life (and would therefore increase depreciation expense). He has therefore not taken a balanced approach as I have, but instead has used a results driven approach in order to reduce depreciation expense.

Witness Pous's discussion on page 195 of his testimony of the Uniform System of Accounts is similarly incorrect. I should first note that his comparison of the sales of buildings at early ages to the treatment for vehicles is inaccurate. The service life established for vehicles is the point in time from which they are installed to when they are retired from utility operations (when they are typically sold at auction). Both the service life and net salvage estimates for vehicles are handled consistently – the net salvage for vehicles is based on the end of their life for utility operations. In my approach for buildings, the same is true. The life established for buildings excludes early sales of buildings, as does the net salvage. Thus, the net salvage estimate I have made is based on the time and age at which the buildings are expected to be retired from utility operations. Witness Pous has not taken a consistent approach. He bases the life of buildings on data that excludes these early sales of buildings, but bases his net salvage estimate on data that includes these sales that occur prior to the end of the assets' useful lives.

My approach is therefore consistent with the Uniform System of Accounts. Both my service life and my net salvage estimates are based on the "the time between the date electric plant is includible in electric plant in service, or electric plant leased to others, and the date of its retirement."[31] In contrast, witness Pous's approach is not consistent with the Uniform System of Accounts. His net salvage estimate is based on sales that have occurred prior to the end of the estimated service life for buildings, and are therefore not representative of the service life for the assets in this account.

Finally, I should make clear that many of the retirements in this account are for components of buildings, not the entire buildings themselves. These retirements have and will continue to experience negative net salvage, a point on which witness Pous and I agree.[32] Thus, my estimate properly considers both these costs and the net salvage at the end of the useful lives of the Company's office buildings and service centers. As a result, my estimate of negative 10% is appropriate for this account.

[31] 18 C.F.R. 101 (FERC Uniform System of Accounts), Definition 36.

[32] Direct Testimony of Jacob Pous, p. 194, lines 10-11.

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QUESTION:
Depreciation Net Salvage. Please identify and provide by account the analyses performed, if any, that demonstrates that the mix of investment reflected in the historical net salvage analysis is representative of the current mix of investment still in service. If no specific analysis was performed, explain and justify if and why the Company believes that the historical events are representative of future retirements.

RESPONSE:
As part of the 2016 Depreciation Study, the net salvage data for each account was reviewed for trends, transactions that were outside of the typical experience for the account, and for the type of investment in each account. Certain transactions or trends in the data were analyzed in more detail to determine the proper consideration for the estimation of net salvage. Please refer to Attachment No. 1 of this response for the analyses performed related to historical data transactions which were used to determine whether the historical mix of investment in the net salvage analysis was representative of the current mix of investment that is still in service. Additionally, please refer to the narratives discussing the estimation of net salvage provided in Part X and Part XI of Exhibit NWA-1, as well as the information provided in FPL's response to OPC's First Set of Production of Documents No. 38, for further discussion of the considerations and judgment incorporated into the estimation of net salvage and for further information.

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Analysis of Investment Mix for Historical Data

Steam Production Plant

Account 312 Boiler Plant Equipment

Question: What has caused high gross salvage in recent years (for example, 2007, 2008, 2010 and 2013)?

Response: A review of work orders from these years reflects that the levels of gross salvage value is related to the increase in the level of Capital Spare Parts (CSP) components (resulting in greater non-cash salvage resulting from refurbishment). Primary drivers are Pt. Everglades U3&4 (2007), Scherer Coal Cars (2007, 2008), Martin U1&2 (2008, 2010, 2013).

For the study, the data was not adjusted. However, activity for CSPs and coal cars likely make up a higher percentage of historical retirements than the overall mix of investment for the account. As assets age CSPs may comprise a smaller percentage of interim retirements. Gross salvage may therefore be lower in the future as a percent of interim retirements.

Account 314, Turbogenerator Units

Question: What caused higher levels of gross salvage for this account in many years (for example, in 1992, 2003, 2004, 2010 and 2011)? Also, what caused the relatively young retirements in some of these years.

Response: Many of the retirements and gross salvage were related to capital spare parts. For the study, the data for these transactions was not adjusted. However, CSPs likely make up a higher percentage of historical retirements than the current mix of investment for the account. As assets age CSPs may comprise a smaller percentage of interim retirements. Gross salvage may therefore be lower in the future as a percent of interim retirements.

Certain transactions were considered to be outliers and adjusted to be excluded from the life and net salvage analyses, including a generator failure/rotor replacement at Martin U1 in 2002-2003; the replacement of U1 generator stator coil at Manatee in 2003-2004; and LP Turbine and Rotor replacements at Manatee in 1992.

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Nuclear Production Plant

Account 322 Reactor Plant Equipment

Question. Why are there higher levels of gross salvage in many years?

Response: High gross salvage resulted from the following drivers: St Lucie U1&2 (1995), Turkey Pt. U4 Equipment Reliability (2007, 2011, and 2013), Turkey Pt. U3 CDRM Insurance Settlement (2010), St. Lucie U2 RCP Motor Replacement (2011) and St. Lucie U1&2 Equipment Reliability (2013). Because the CDRM transactions were related to an insurance settlement and therefore not considered to be indicative of the future experience for most of the assets in the account, these transactions given less consideration in the net salvage analysis.

Question. What caused higher levels of retirements and cost of removal in 2011 and 2012?

Response: Much of the activity in these years is due to the EPU (uprate) projects. Retirement, salvage and cost of removal identified as uprate work were excluded from the life and net salvage analyses. Additionally, regular outage work was typically scheduled to coincide with the uprate activity and was not considered to be abnormal.

Question. What caused the gross salvage recorded in 2014?

Response: PTN U3: $8.9 million XFR from CE 5421100 WO P-121127 to 5959998 on refurbishment WO P-121128. PSL salvage XFR from P-111735, CE 5421100 to CE 5959998 on same WO – remove/refurb/re-install. Generally, many of the retirements and gross salvage recorded in 2014 were refurbishment work orders. For the study, the data for these transactions were not adjusted. However, these types of transactions likely make up a higher percentage of historical retirements than the overall mix of investment for the account. As assets age refurbishments may comprise a smaller percentage of interim retirements. Gross salvage may therefore be lower in the future as a percent of interim retirements.

Account 323 Turbogenerator Units

Question. What caused the relatively early retirements (i.e., ages 2 and less) in 2011?

Response. Retirements related to PSL LP Turbine Rotors, PSL U2 Turbine Valves, and PTN U4 Turbine Valves that were retired at age 2 or less in 2011 were excluded from the life and net salvage analyses and not considered to be indicative of future experience.

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Question. What caused the higher levels of gross salvage in this account (1994, 2005, 2006, 2007, 2009 and 2010 for example)?

Response. Retirement, cost of removal and/or salvage transactions related to turbine valves at PTN U4 recorded in 2009, LP rotors at St Lucie Units 1 and 2 recorded in 2005 and the replacement of LP Rotors at St Lucie Unit 2 recorded in 1994 were excluded from the life and net salvage analyses and not considered to be indicative of future experience for the full account. Additionally, many of the retirements and gross salvage in these years were related to capital spare parts. For the study, the data for these transactions was not adjusted. However, CSPs likely make up a higher percentage of historical retirements than the mix of investment for the account. As assets age CSPs may comprise a smaller percentage of interim retirements. Gross salvage may therefore be lower in the future as a percent of interim retirements.

Question. What caused higher levels of retirements and cost of removal in 2011, 2012 and 2013?

Response: Many of the activity in these years is due to the EPU projects. Costs identified as uprate work was excluded as retirements and cost of removal for the life and net salvage analyses. Additionally, regular outage work was typically scheduled to coincide with the uprate activity and was not considered to be abnormal.

Question. Cost of removal in 2014 was lower than in previous years. Why was cost of removal lower (while retirements were still at a high level)?

Response: Almost all of the difference in nuclear removal cost for UA 323 occurred Turkey Point Unit 4. The uprate project was completed in 2013 so 2014 removal cost for the uprate project was zero (actually slightly negative due almost certainly to a true-up in early 2014). Also, regular outage work for Unit 4 was scheduled to coincide with the uprate activity so that work also was completed in 2013 and therefore was minimal in 2014. Costs identified as uprate work was excluded as retirements and cost of removal for the life and net salvage analyses. Additionally, due to the timing of costs, overall and moving averages were given more consideration in the net salvage analysis.

Account 324 Accessory Electric Equipment

Question. What was retired 2011?

Response. Aux Transformer at TP U4. This was considered to be a normal retirement.

Other Production Plant

Account 341 Structures and Improvements

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Question. Why was there a higher level of cost of removal recorded in 2010?

Response: 2010 total cost of removal is $2.4M. $2.2M is attributed to piping replacement projects at Putnam Common. Underground piping replacement was completed through internal order 09377-070-0905-007 with a cost of removal of $1.3M and over ground piping replacement was completed through internal order 09378-070-0905-007 with a cost of removal of $909. No adjustment was made to exclude these amounts from the life or net salvage analyses. However, the cost of removal amount was given less consideration in the net salvage analysis because future interim retirements may consist of a smaller percentage of this type of retirement than is represented in the historical data.

Question. In 2005 what caused the higher level of cost of removal?

Response: The cost of removal is related to Martin U8 combined cycle conversion project. Retirements are due to Ft. Myers U2 replacement of discharge canal retaining wall and Martin U3 replacement of intake cooling pump. The cost of removal amount was given less consideration in the net salvage analysis because future interim retirements may consist of a smaller percentage of this type of retirement than is represented in the historical data.

Question. What was the large cost removal in 1994 (approximately $1.5 million)? Was this related to the retirement in 1995?

Response: The retirement in 1995 is related to Ft. Lauderdale Common demolition and backfill of service building and Putnam Common water treatment facilities. The large cost of removal in 1994 is also related to Ft. Lauderdale Common. No adjustment was made to exclude this from the analysis, but the cost of removal amount was given less consideration in the net salvage analysis.

Account 343.2 Prime Movers – Capitalized Spare Parts

Question. Gross salvage in 2010 and 2013 is higher than in other years. What caused the higher gross salvage in these years?

Response: Primary drivers for 2013 include Major Dot 04 Rotor Outages at Sanford Unit 4 and Unit 5 ($30.7M); Hot Gas Path Outages at West County Unit 1 and Unit 2 ($29.9M); and the sale of a rotor from Ft. Myer Unit 2 to Lamar ($10.4M). These drivers account for $71.0M of gross salvage. Primary drivers for 2010 include outage costs for Sanford U4 and Turkey Pt. U5. No adjustments were made to the data although this information was considered in the net salvage analysis. Generally, due in part to potential timing differences, long term and moving averages were given more consideration in the statistical analysis.

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Account 344 Generators

Question. What caused the gross salvage in 2013?

Response: Primary drivers include a generator rotor replacement at Ft. Myers Unit 2 (internal order G00000107223) and generator rotor rewind at Putnam Unit 1 (internal order G00000107173). No adjustment made to data for net salvage analysis.

Question. What was retired in 2012 and 2013?

Response: 2012 retirements at $4.1M and 2013 retirements at $4.7M; Activity related to the retirements include combustion turbine overhauls, rotor rewinds, and wedge replacements. These were not considered to be abnormal retirements and no adjustment was made to data for life or net salvage analysis.

Question. What caused the gross salvage amount in 2014?

Response: The gross salvage amounts for UA 344 in 2014 relate to Sanford Unit 4 and Unit 5 generator rewind work orders. Unit 4 (472,852) credited to CE 5421100 and debited to CE 5959998 for WO G-119988 in August, 2014 This was a remove/re-wind/replace work order so a separate work order for re-wind was not needed. Unit 5 (1,046,660) Unit 5 credited to CE 5421100 and debited to 5959998 for WO G-107404 on February, 2014. Again this was a remove/re-wind/replace work order so both sides of the entry are recorded to G-107404. No adjustment made to data for net salvage analysis.

Account 345 Accessory Electric Equipment

Question. What caused the retirements in 2012 and 2013?

Response: 2012 retirements at $3.4M and 2013 retirements at $3.6M; the primary driver is the combustion turbine exciter upgrades completed on Ft. Lauderdale Unit 4 and Unit 5. No adjustment made to data for life or net salvage analysis.

Transmission Plant

Account 352 Structures and Improvements

Question. What is the gross salvage recorded in 2009?

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Response: The large gross salvage is due to a lump sum reimbursable relocation payment which was recorded to account 35200 in October 2009 in the amount of $245,880.80 (WO 00279-009-0311-000). This was adjusted to be excluded from the net salvage analysis.

Account 353 Station Equipment

Question. What are the salvage amounts in 2008 and 2011?

Response: The majority of the gross salvage for 2008 is primarily is due to the recording of the Siemens Settlement ($4,350,000; other recoveries for material and labor cost), as a result of the failure of a Turkey Point Unit 4 GSU transformer after 10 days in service. An additional $2,900,000 was recorded to other recoveries in 2008 as a result of the sale of a transformer to FPLE Calhoun. The transactions related to the TP GSU and transformer sale were excluded from the life and net salvage analyses.

The major other recoveries in 2011 were : $762,000 associated with retirements of high voltage breakers and equipment at C-5 Complex substation (WO T00000000612); $346,000 associated with equipment retirements at Delta substation (WO T00000003208); and $291,549.00 related to the replacement of a GSU transformer at Manatee Unit 3 (WO T00000006034). The Manatee GSU was adjusted to Account 353.1. The other transactions were not adjusted and were not considered to be abnormal.

Question. What caused the gross salvage in 2012?

Response: Gross salvage in 2012 resulted primarily from a) warranty replacement of Gratigny Substation auto transformer, b) other recovery accrual processed under Duval Substation internal order to install the JEA tie line#4, and C) other recovery recorded for Delta Substation addition of mid span breaker and 2 disconnect switches. These amounts were not adjusted in the data. However, less consideration was given to the warranty replacement. The mix of investment retired in the future is likely to have less gross salvage than recorded in 2012.

Question. What types of transactions have resulted in the levels of gross salvage experienced in recent years?

Response: The last 10 years were analyzed. In summary, the types of salvage is primarily other recoveries associated with Storm Recovery transactions, Participation Accounting transactions, warranty replacements transactions, Reserve Equipment sales, junked reserve equipment sales, and reimbursable accruals. Due to the types of transactions recorded for this time period (e.g. reimbursable accruals, reserve equipment sales), it is likely that the mix of investment in retirements recorded during this time experienced a higher level of gross salvage than will occur for the mix of investment currently in service.

Account 353.1, Step Up Transformers

Question. What caused the gross salvage in 2009?

Response: Other recoveries of $5,999,188.80 were recorded to properly reflect warranty transactions for the GSU failure at Turkey Point Unit 4 (see response to Acct 353 for 2008) to utility

account 353.1. These other recoveries had been recorded to utility account 353. The transactions associated with the TP 4 GSU were excluded from the life and net salvage analyses.

Question. What caused the retirements in vintage 2007 ($5.9 million and $1.7 million) and vintage 2004 ($1.6 million) recorded in 2012?

Response: The 2007 vintage retirements for approximately $5.9M are related to retirements of 2 main transformers at Port Everglades Units 1 & 2. There are also 2007 vintage property retirements for approximately S1.7M associated with 2 main transformer cooling units at St. Lucie Unit 1. The vintage 2004 property retirement for approximately $1.6M retired main transformer from Manatee Unit 3. These were not adjusted in the data although consideration was given to the causes of retirement. One of the causes of retirement of step up transformers in this account is the retirement of the associated generating facility, which resulted in the retirement of the Pt Everglades GSUs. However, the level of retirements in this account over the fifteen year period of historical data that is available is likely higher on an annual basis than will be the case for the time remaining assets in this account will be in service. This factor was considered in the estimation of service life for this account.

Account 354 Towers and Fixtures

Question. What was the large gross salvage in 2011?

Response: The majority of the salvage amount is due to $453,834.47 of other recoveries recorded in June 2011 that were related to reimbursements. These transactions were excluded from the net salvage analysis.

Account 355 Poles and Fixtures

Question: Why was there negative gross salvage recorded in 2004 and 2009?

Response: These amounts offset positive gross salvage in prior years. The data was not adjusted, but was analyzed using averages.

Question. What caused higher levels of salvage for transmission poles in some years (for example what caused high gross salvage in 2007 or 2013)?

Response: Many of these transactions are related to reimbursements. The mix of reimbursements in the historical data is higher than the mix of assets that will have reimbursement amounts going forward. For this reason, gross salvage should be lower going forward than in recent years for this account, which was considered in the estimation of net salvage.

Question. Why has cost of removal increased in recent years?

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Response: Cost of removal has increased for many reasons that should be expected to continue, such as labor costs, equipment costs, permitting costs and environmental costs. However, a portion of the increase in costs is due to the volume of work performed for storm hardening, which has led to increases in contractor costs. For this reason, there could be some moderation of costs in future years, which was considered in the estimation of net salvage.

Account 356 Overhead Conductors and Devices

Question: What was the gross salvage recorded in recent years?

Response: Some of the transactions (for example $1,151,244 of other recoveries in 2011) were related to reimbursable relocation contractor accruals recorded in 2011. While these amounts were not adjusted in the historical data, the mix of reimbursements for these years is higher than the mix of assets that will have reimbursement amounts going forward. For this reason, gross salvage should be lower going forward than in recent years for this account, which was considered in the estimation of net salvage.

Account 357 Underground Conduit

Question. Why was there cost of removal but no retirements in many years?

Response: These were generally due to timing differences, and the retirements were recorded in different years.

Question. What were the gross salvage amounts recorded in 1997, 1999 and 2000?

Response: The 1997 gross salvage amount of $2,029,590 recorded to other recoveries under account 357 (WO 08068-009-0988-000) was related to a lawsuit settlement associated with the St. Lucie Unit 2 Participation Agreement. The 1999 gross salvage amount of $892,276 recorded to other recoveries under account 357 (WO 04101-009-0984-000) was related to the recording of a Loxahatchee River Crossing transmission project installed by FPL for the Town of Jupiter. In The 2000 gross salvage amount of $3,125,259.79 was recorded to other recoveries under account 357 related to the recording of a Venetian Causeway transmission project installed by FPL for the City of Miami Beach. These transactions are considered to be abnormal and were excluded from the net salvage analysis. There were no retirements associated with the Venetian Causeway project or WO 04101-009-0984-000.

Account 358 Underground Conductors and Devices

Question. What are the large gross salvage amounts in 1997, 1999 and 2000?

Response: Primary drivers include reimbursable relocations associated with Dade-Flagami #1 underground feed to Aviation, Hobe-Plumosus #2 Underground Cable, Miami-Miami Beach 69KV

loop to Lummus Substation, and a lawsuit settlement associated with Miami Beach Substation WO scope titled as "Repair work in Government Cut". These transactions were not adjusted in the historical data but were given less considerations as similar transactions are not expected to occur for most of current investment mix in the account.

Account 359 Roads and Trails

Question: What removal cost does FPL experience for Roads and Trails? What sorts of project have removal costs in this account?

Response: The replacement projects associated with account 359 are primarily related to the replacement of culverts, bridges, and gates. The mix of investment currently in the account has a lower percentage of these types of assets than is reflected in the historical retirements. This was considered in the estimation of net salvage.

Distribution Plant

Account 361 Structures and Improvements

Question: What were the gross salvage amounts recorded in 1997 and 2008?

Response: The majority of the $2,151,446.32 of 1997 other recoveries, 99.7% or $2,143,949.08 is from a contract with Aviation to build a new 138KV distribution substation. In 2008, the other recovery amount of $502,000 is related to a CIAC reimbursement for work performed. Both of these transactions were excluded from the net salvage analysis.

Account 364, Poles, Towers and Fixtures

Question. Why has cost of removal increased in recent years?

Response: Cost of removal has increased for many reasons, many of which should be expected to continue. These include factors such as labor costs, equipment costs, permitting costs and environmental costs. However, a portion of the increase in costs are due to the volume of work performed for storm hardening. Storm hardening work is more likely to occur near major roadways, which result in higher removal costs. For this reason, future cost of removal could moderate somewhat when compared to the more recent years. All of these factors were considered in the estimation of net salvage.

Question. Why has gross salvage decreased for this account?

Response: The decrease in gross salvage is likely due to two factors. The first is that stricter disposal requirements for wood poles can mean that there is less salvage value. This trend

should be expected to continue. The other reason is that the use of contractors has been higher in recent years, and contractor charges are typically net charges (i.e., net of salvage).

Account 365, Overhead Conductors and Devices

Question. Why has cost of removal increased in recent years?

Response: Cost of removal has increased for many reasons that should be expected to continue, such as labor costs, equipment costs, permitting costs and safety requirements. However, a portion of the increase in costs could also be due to the volume of work performed for storm hardening. Storm hardening work is more likely to occur near major roadways, which result in higher removal costs. For this reason, future cost of removal could moderate somewhat when compared to the more recent years. All of these factors were considered in the estimation of net salvage.

Question. Why has gross salvage decreased for this account?

Response: The decrease in gross salvage is likely due to multiple factors. One is that scrap prices have been lower in some years. Another is that there may be less copper in recent retirements. This trend should be expected to continue, as the overall historical database likely contains a higher percentage of copper than the current mix of investment. The other reason is that the use of contractors has been higher in recent years, and contractor charges are typically net charges (i.e., net of salvage).

Account 366.6 Underground Conduit – Duct System

Question: Why is there negative cost of removal in 2012 through 2014?

Response: The negative cost of removal recorded for Underground Conduit – Duct System, account 366.6 in 2012 through 2014 was primarily due to the classification of reimbursable jobs as non-reimbursable. These transactions are not expected to be reoccurring and were not considered to be indicative of the retirement experience for the current investment mix in this account.

Account 366.7 Underground Conduit – Direct Buried

Question: Why is there negative cost of removal in 2012 through 2014?

Response: The negative cost of removal recorded for Underground Conduit – Duct System, account 366.6 in 2012 through 2014 was primarily due to the classification of reimbursable jobs as non-reimbursable. These transactions are not expected to be reoccurring and were not considered to be indicative of the retirement experience for the current investment mix in this account.

Account 368 Line Transformers

Florida Power & Light Company
Docket No. 160021-EI
OPC's First Set of Interrogatories
Interrogatory No. 51
Attachment No. 1
Page 11 of 12

Question: What caused the large cost of removal in 2013?

Response: The large cost of removal in 2013 is primarily due to a true-up of transformer removal cost that actually occurred in prior periods. The data was not adjusted to prior periods, but averages were given more consideration in the net salvage analysis.

Account 369.1 Services – Overhead

Question. What was caused high cost of removal for this account relative to retirements?

Response: There are a number of factors that have influenced the cost of removal for this account. One of the reasons for high removal costs is the fact that overhead services are small in quantity but are often in hard to get at places with high safety factors involved. This is especially true around residential neighborhoods. Removal is often time consuming due to safety requirements. Often distribution services are stretched across roads in high residential areas and with the spring effect of conductor more manpower is required. Factors that have influenced cost of removal for other distribution line accounts, such as permitting requirements, have also influenced the cost of removal for this account. The material costs are also relatively small for services (when compared to other types of assets such as poles), and the labor costs when replacing a service are often about half the time for removal and half for the new asset. For these reasons, higher levels of cost of removal are expected to continue for this account.

Question. Why is cost of removal lower in 2010 than other years?

Response: Timing differences. Averages were given more consideration in the net salvage analysis than individual years.

Account 370 Meters

Question. Why has cost of removal been higher since 2002?

Response: The Company's process for recording cost of removal changed in 2002. Recording of cost of removal has improved since 2002 and many costs that had not been recorded to cost of removal are now reflected in the data. The accounting practices since 2002 are expected to be more indicative of the future experience for this account than those prior to 2002.

Question. What caused the higher level of retirements in 2014?

Response: The higher level of retirements in 2014 was primarily due to CI (Commercial/Industrial) Expansion Deployment (related to AMI Meters for commercial and industrial customers).

General Plant

Account 390 Structures and Improvements

Florida Power & Light Company
Docket No. 160021-EI
OPC's First Set of Interrogatories
Interrogatory No. 51
Attachment No. 1
Page 12 of 12

Question. What was retired in 2011?

Response: Most of the retirements recorded in 2011 are related to the sale of the General Office building (GO). The retirements and salvage for this sale were excluded from the service life and net salvage analyses, as the building was sold before the end of its life (a portion of the building is still leased to FPL).

Florida Power & Light Company
Docket No. 160021-EI
OPC's First Set of Interrogatories
Interrogatory No. 69
Page 1 of 1

QUESTION:
Depreciation Account 353. Please identify the size, year of installation and cost of each transformer in Account 353 on the Company system. The information should be provided on electronic medium in Excel readable format.

RESPONSE:
See Attachment No. 1 to this response for transformers by size, year of installation, and cost in Account 353 as of December 2014 and 2015.

Florida Power & Light Company
Docket No. 160021-EI
OPC's First Set of Interrogatories
Interrogatory No. 69
Attachment No. 1
Tab 1 of 1

Transformers as of December 2014

Utility Account	Short Description	1941	1947	1948	1950	1951	1952	
35300 - Station Equipment	TRANSFORMER, AUTO 1-120 MVA							
	TRANSFORMER, AUTO 1-20 MVA							
	TRANSFORMER, CURRENT 4-23KV		400.00		0.04			
	TRANSFORMER, POTENTIAL 230/500KV		4,620.00	1,636.00				
	TRANSFORMER, POTENTIAL 69KVA		34,121.00			15,643.00	2,700.00	327.01
	TRANSFORMER, POTENTIAL UNDER 69KV							
	TRANSFORMER, STEP DOWN 1 & 3ph 1 - 15 MVA							
	TRANSFORMER, CURRENT FREESTANDING 550K							
	METERING UNIT CT/PT 69-240KV							
	TRANSFORMER, AUTO 496-795 MVA							
	TRANSFORMER, AUTO 121-295 MVA							
	TRANSFORMER, CURRENT 138KV							
	TRANSFORMER, AUTO 296-495 MVA							
	TRANSFORMER, POTENTIAL 115/138KV - TRAN							
	TRANSFORMER, CURRENT 240KV							
	TRANSFORMER, CURRENT FREESTANDING 138KV							
	TRANSFORMER, CURRENT METERING							
	TRANSFORMER, AUTO 796-1500 MVA							
	TRANSFORMER, AUTO 795-1500 MVA							
	TRANSFORMER, CURRENT FREESTANDING 240K							
	TRANSFORMER, POWER VOLTAGE 69-500KV							
	TRANSFORMER, CURRENT 69K							
	TRANSFORMER, CURRENT 115KV - 600A							
	TRANSFORMER, PLANT MAIN							
	TRANSFORMER, PLANT MAIN INSTALLATION							
Grand Total			**39,141.00**	**1,636.00**	**0.04**	**15,643.00**	**2,700.00**	**327.01**

Transformers as of December 2015

Utility Account	Short Description	1941	1947	1948	1950	1951	1952	
35300 - Station Equipment	TRANSFORMER, AUTO 1-120 MVA							
	TRANSFORMER, AUTO 1-20 MVA							
	TRANSFORMER, CURRENT 4-23KV		400.00		0.04			
	TRANSFORMER, POTENTIAL 230/500KV		4,620.00	1,636.00				
	TRANSFORMER, POTENTIAL 69KVA		34,121.00			15,643.00	2,700.00	327.01
	TRANSFORMER, POTENTIAL UNDER 69KV							
	TRANSFORMER, STEP DOWN 1 & 3ph 1 - 15 MVA							
	TRANSFORMER, CURRENT FREESTANDING 550K							
	METERING UNIT CT/PT 69-240KV							
	TRANSFORMER, AUTO 496-795 MVA							
	TRANSFORMER, AUTO 121-295 MVA							
	TRANSFORMER, CURRENT 138KV							
	TRANSFORMER, AUTO 296-495 MVA							
	TRANSFORMER, POTENTIAL 115/138KV - TRAN							
	TRANSFORMER, CURRENT 240KV							
	TRANSFORMER, CURRENT FREESTANDING 138KV							
	TRANSFORMER, CURRENT METERING							
	TRANSFORMER, AUTO 796-1500 MVA							
	TRANSFORMER, AUTO 795-1500 MVA							
	TRANSFORMER, CURRENT FREESTANDING 240K							
	TRANSFORMER, POWER VOLTAGE 69-500KV							
	TRANSFORMER, CURRENT 69K							
	TRANSFORMER, CURRENT 115KV - 600A							
	TRANSFORMER, PLANT MAIN							
	TRANSFORMER, PLANT MAIN INSTALLATION							
Grand Total			**39,141.00**	**1,636.00**	**0.04**	**15,643.00**	**2,700.00**	**327.01**

1953	1954	1955	1956	1957	1958	1959	1961	1962	
							10,000.00		
							885.00		
					170.00	1,850.00	1,051.93	7,100.00	
	8,585.00	1,605.00	12,105.84		13,418.00	11,604.14	29,990.36		408.77
			1,144.83	225.00	7,055.00		16,680.00		
					4,860.00		5,250.00	9,456.27	
							6,600.00		1,750.00
	8,585.00	1,605.00	13,250.67	225.00	25,503.00	13,454.14	70,457.29	16,556.27	2,158.77

1953	1954	1955	1956	1957	1958	1959	1961	1962	
							10,000.00		
							885.00		
					170.00	1,850.00	1,051.93	7,100.00	
	8,585.00	1,605.00	12,105.84		13,418.00	11,604.14	29,990.36		408.77
			1,144.83	225.00	7,055.00		16,680.00		
					4,860.00		5,250.00	9,456.27	
							6,600.00		1,750.00
	8,585.00	1,605.00	13,250.67	225.00	25,503.00	13,454.14	70,457.29	16,556.27	2,158.77

1963	1964	1965	1966	1967	1968	1969	1970	1971	
			1,900.00		10,160.00		17,912.00	16,494.17	13,514.57
				549,229.45	1,367,402.29	276,072.81	138,095.10	1,125,611.40	383,045.13
		1,275.50				1,650.00		1,282.12	
	14,228.85		1,600.00				13,380.26	35,951.48	
	5,145.00		4,905.00			13,312.54			
		344.17	7,669.00			96.61			
							1,420.52		
				2,888,226.37	10,948.34	0.00		492,200.28	2,484,974.62
				632,232.86	1,036,360.00	1,019,079.73	85,900.11	293,950.50	3,279,565.52
	4,200.00								
								324,594.34	0.00
	8,400.00								
	31,973.85	**1,619.67**	**16,074.00**	**4,069,688.68**	**2,424,870.63**	**1,310,211.69**	**256,707.99**	**2,290,084.29**	**6,161,099.84**

1963	1964	1965	1966	1967	1968	1969	1970	1971	
			1,900.00		10,160.00		17,912.00	16,494.17	13,514.57
				549,229.45	1,367,402.29	276,072.81	138,095.10	1,125,611.40	383,045.13
		1,275.50				1,650.00		1,282.12	
	14,228.85		1,600.00				13,380.26	35,951.48	
	5,145.00		4,905.00			13,312.54			
		344.17	7,669.00			96.61			
							1,420.52		
				2,888,226.37	10,948.34	0.00		492,200.28	2,484,974.62
				632,232.86	1,036,360.00	1,019,079.73	85,900.11	293,950.50	3,279,565.52
	4,200.00								
								324,594.34	0.00
	8,400.00								
	31,973.85	**1,619.67**	**16,074.00**	**4,069,688.68**	**2,424,870.63**	**1,310,211.69**	**256,707.99**	**2,290,084.29**	**6,161,099.84**

1972	1973	1974	1975	1976	1977	1978	1979	1980	
82,049.87	26,536.46	27,131.44	32,059.68	13,264.39	9,576.00	45,092.55	7,378.96		
2,562,480.21	347,112.06	1,520,834.99	3,051,207.10	53,846.15	(275,475.08)	513,539.97	400,836.88	(281,215.04)	
1,140.00	7,614.77		2,351.12	1,922.01					
		91.30	41,025.19	1,751.51		36,118.46	45,218.67	2,457.63	
13,579.86			4,588.15	1,391.43		7,879.53	2,642.98	18,529.13	
							5,856.85	343.65	
8,088.05	0.00	(2,136.17)			161.52			12,064.70	
13,625.84		3,299.16	3,663.29	13,322.42					
1,530,225.65	940,856.50	20,124.66	10,693.78	1,728,586.36	928,960.46	90,290.60	4,459,556.41	569,954.10	
1,546,299.07	39,951.11	1,304,596.80	16,298.00	601,778.02	1,206,011.48	2,008,338.63	12,721.42	258,142.62	
							0.00		
1,667.12			1,897,477.72	2,748.62	8,616,173.82		10,267,143.29	196,067.07	
							20,392.59		
								1,364,787.01	
5,759,155.67	**1,362,070.90**	**2,873,942.18**	**5,059,364.03**	**2,418,610.91**	**10,485,408.20**	**2,701,259.74**	**15,221,748.05**	**2,141,130.87**	

1972	1973	1974	1975	1976	1977	1978	1979	1980	
82,049.87	26,536.46	27,131.44	32,059.68	13,264.39	9,576.00	45,092.55	7,378.96		
2,562,480.21	347,112.06	1,520,834.99	3,051,207.10	53,846.15	(275,475.08)	513,539.97	400,836.88	(281,215.04)	
1,140.00	7,614.77		2,351.12	1,922.01					
		91.30	41,025.19	1,751.51		36,118.46	45,218.67	2,457.63	
13,579.86			4,588.15	1,391.43		7,879.53	2,642.98	18,529.13	
							5,856.85	343.65	
8,088.05	0.00	(2,136.17)			161.52			12,064.70	
13,625.84		3,299.16	3,663.29	13,322.42					
1,530,225.65	940,856.50	20,124.66	10,693.78	1,728,586.36	928,960.46	90,290.60	4,459,556.41	569,954.10	
1,546,299.07	39,951.11	1,304,596.80	16,298.00	601,778.02	1,206,011.48	2,008,338.63	12,721.42	258,142.62	
							0.00		
1,667.12			1,897,477.72	2,748.62	8,616,173.82		10,267,143.29	196,067.07	
							20,392.59		
								1,364,787.01	
5,759,155.67	**1,362,070.90**	**2,873,942.18**	**5,059,364.03**	**2,418,610.91**	**10,485,408.20**	**2,701,259.74**	**15,221,748.05**	**2,141,130.87**	

1981	1982	1983	1984	1985	1986	1987	1988	1989	
53,029.55	47,138.22	81,596.81	32,157.05	89,464.91	30,161.70	19,435.30	40,567.48	7,841.06	
313,699.89	(274,963.98)	1,167,443.97	474,886.78	654,515.17	197,273.36	2,476,497.41	734,919.82	76,919.42	
	1,446.60	2,637.52					2,493.02		
	130,416.02	24,658.60	9,631.15	78,823.03	161,474.94		24,515.33	18,044.93	
	4,037.19	0.00		10,455.58		6,407.89	6,596.01	14,490.74	
			307.06						
(1,957.46)	38,101.86	0.00	20,652.51	117,202.48	212,041.49	21,088.14			
						225,000.00			
			103,006.64		820,707.27	62,181.97	11,582.99		
24,261.12	170,683.62	(694,506.31)	0.00	16,333.94	5,479,843.19	16,161,647.90	9,432,061.06	4,536,190.12	
48,839.81	3,248,854.43	273,810.23	1,331,637.55	1,352,886.10	4,766,633.48	(420,421.16)	869,871.93	1,998,965.81	
	3,228.03	0.00		794.71		30,784.07			
4,696,264.12	2,869,628.16	2,188,322.13	2,677,069.33	6,895.66	4,458,768.76	(2,058,312.83)	(6,924,834.98)	38,878.39	
			70,265.79				66,292.89	12,590.53	
	32,748.46								
						21,000.00			
4,509.75					0.00				
	5,603.37			47,764.64					
						210,000.00			
					(1,062.26)	39,509.68	(0.36)		
5,138,646.78	**6,276,921.98**	**3,043,962.95**	**4,719,613.86**	**2,375,136.22**	**16,125,841.93**	**16,794,818.37**	**4,264,065.19**	**6,703,921.00**	

1981	1982	1983	1984	1985	1986	1987	1988	1989	
53,029.55	47,138.22	81,596.81	32,157.05	89,464.91	30,161.70	19,435.30	40,567.48	7,841.06	
313,699.89	(274,963.98)	1,167,443.97	474,886.78	654,515.17	197,273.36	2,476,497.41	734,919.82	76,919.42	
	1,446.60	2,637.52					2,493.02		
	130,416.02	24,658.60	9,631.15	78,823.03	161,474.94		24,515.33	18,044.93	
	4,037.19	0.00		10,455.58		6,407.89	6,596.01	14,490.74	
			307.06						
(1,957.46)	38,101.86	0.00	20,652.51	117,202.48	212,041.49	21,088.14			
						225,000.00			
			103,006.64		820,707.27	62,181.97	11,582.99		
24,261.12	170,683.62	(694,506.31)	0.00	16,333.94	5,479,843.19	16,161,647.90	9,432,061.06	4,536,190.12	
48,839.81	3,248,854.43	273,810.23	1,331,637.55	1,352,886.10	4,766,633.48	(420,421.16)	869,871.93	1,998,965.81	
	3,228.03	0.00		794.71		30,784.07			
4,696,264.12	2,869,628.16	2,188,322.13	2,677,069.33	6,895.66	4,458,768.76	(2,058,312.83)	(6,924,834.98)	38,878.39	
			70,265.79				66,292.89	12,590.53	
	32,748.46								
						21,000.00			
4,509.75					0.00				
	5,603.37			47,764.64					
						210,000.00			
					(1,062.26)	39,509.68	(0.36)		
5,138,646.78	**6,276,921.98**	**3,043,962.95**	**4,719,613.86**	**2,375,136.22**	**16,125,841.93**	**16,794,818.37**	**4,264,065.19**	**6,703,921.00**	

1990	1991	1992	1993	1994	1995	1996	1997	1998	
		138,303.03	(893.53)	(83,578.87)	36,991.23	19,066.10		146,487.24	
	28,182.65	829,858.35	2,783,505.43	(6,080,434.27)	(296,708.16)	(14,918.08)	111,636.48		
			(6,243.90)	8,334.05	(10.31)	65.27	3,568.42		11,698.45
		(799.96)	51,335.55	73,960.11	(640.35)	107,748.66	76,311.85	(56,896.99)	118,864.17
		15,141.46	19,855.88	42,267.03	40,605.27	(78,156.73)			63,789.79
		1,528.65	(5,956.29)	3,151.12	33.26	46.28	1,349.23		15,687.53
						(12,064.70)			
	260,083.57					45,000.00		123,677.79	
				34,586.16	(22,787.85)	(132,316.43)	175,977.66	209,214.84	166,056.30
	6,580,666.49	2,865,938.61	3,930,682.27	2,874,699.36	(2,713,887.14)	62,398.16	2,353,264.31	7,331,533.45	4,967,187.60
	25,259.81	7,821,695.96	19,827,885.15	(8,572,898.91)	862,352.61	1,650,093.50	180,846.96	211,382.11	2,509,983.40
				362,748.96	(992.57)				
	10,780,389.39	27,602,206.29	3,034,411.25	(33,662,430.15)	25,643.10	2,014,429.36	3,800,687.21	(6,524,704.24)	0.00
		58,671.63	(42,996.06)	57,279.08	(97,318.76)	65,559.78			
				46,198.61					
						(144,468.93)			117,912.32
			1,557,393.18	(1,557,393.18)		(82,157.81)			
			146,703.50	(146,703.50)					
	83,124.37		91,148.65					(270,269.31)	269,571.32
	11,220.37					179,428.59	(9,383.29)		(11,733.41)
				52,885,685.75	614,919.33	1,637,339.94	6,432,215.70	7,409,986.07	2,758,814.29
				3,428,784.13		790,370.22	595,164.69	681,633.02	652,465.99
	17,768,926.65	**39,332,544.02**	**31,386,831.08**	**9,714,255.48**	**(1,551,800.34)**	**6,107,463.18**	**13,721,639.22**	**9,262,043.98**	**11,640,297.75**

1990	1991	1992	1993	1994	1995	1996	1997	1998	
		138,303.03	(893.53)	(83,578.87)	36,991.23	19,066.10		146,487.24	
	28,182.65	829,858.35	2,783,505.43	(6,080,434.27)	(296,708.16)	(14,918.08)	111,636.48		
			(6,243.90)	8,334.05	(10.31)	65.27	3,568.42		11,698.45
		(799.96)	51,335.55	73,960.11	(640.35)	107,748.66	76,311.85	(56,896.99)	118,864.17
		15,141.46	19,855.88	42,267.03	40,605.27	(78,156.73)			63,789.79
		1,528.65	(5,956.29)	3,151.12	33.26	46.28	1,349.23		15,687.53
						(12,064.70)			
	260,083.57					45,000.00		123,677.79	
				34,586.16	(22,787.85)	(132,316.43)	175,977.66	209,214.84	166,056.30
	6,580,666.49	2,865,938.61	3,930,682.27	2,874,699.36	(2,713,887.14)	62,398.16	2,353,264.31	7,331,533.45	4,967,187.60
	25,259.81	7,821,695.96	19,827,885.15	(8,572,898.91)	862,352.61	1,650,093.50	180,846.96	211,382.11	2,509,983.40
				362,748.96	(992.57)				
	10,780,389.39	27,602,206.29	3,034,411.25	(33,662,430.15)	25,643.10	2,014,429.36	3,800,687.21	(6,524,704.24)	0.00
		58,671.63	(42,996.06)	57,279.08	(97,318.76)	65,559.78			
				46,198.61					
						(144,468.93)			117,912.32
			1,557,393.18	(1,557,393.18)		(82,157.81)			
			146,703.50	(146,703.50)					
	83,124.37		91,148.65					(270,269.31)	269,571.32
	11,220.37					179,428.59	(9,383.29)		(11,733.41)
				52,885,685.75	614,919.33	1,637,339.94	6,432,215.70	7,409,986.07	2,758,814.29
				3,428,784.13		790,370.22	595,164.69	681,633.02	652,465.99
	17,768,926.65	**39,332,544.02**	**31,386,831.08**	**9,714,255.48**	**(1,551,800.34)**	**6,107,463.18**	**13,721,639.22**	**9,262,043.98**	**11,640,297.75**

1999	2000	2001	2002	2003	2004	2005	2006	
	(176,974.70)		5,749.65			(31,239.53)	123,080.99	
	(659,653.64)	0.00	0.00	0.00	0.00		0.00	1,210,043.21
		3,488.01	14,426.78	15,815.51	47,099.42			
					47,408.38	0.00		
	5,805.00	84,923.24	(27,842.90)		13,177.08	42,643.96	55,205.02	24,886.63
				3,977.57	20,993.90	234.34	0.00	
		198,905.87	149,431.78			280,272.06	145,792.83	
	2,750.00	210,652.46	(15,901.90)	(41.12)	207,242.39	192,447.88	1.36	45,863.73
	407,600.99	2,631,837.87	2,915,026.46	1,267,640.43	2,722,715.95	1,434,579.98	10,335,813.26	(574,845.36)
	(9,234,437.23)	1,147,685.50	(1,217,675.17)	2,686,631.65	465,380.75	7,112,973.89	2,223,922.01	3,551,715.05
		11,177.02	67,759.87				51,775.49	11,002.16
	3,282,823.88	(281,640.80)	0.00	0.00	0.00	251,192.94	148,768.79	5,004,734.60
		1,197.67						
						38,474.06	55,322.95	22,787.97
		91,634.91		8,832.49			24,562.80	107,794.49
						834.18		880.79
		0.00	33,355.02			61,879.37		
				4,669.74				
	19,782,612.38	(85,427,693.77)		2,917,812.72	(1,458,906.36)	(1,458,906.36)		2,965,777.39
	890,964.66	(5,665,837.78)		274,342.06	(137,171.03)	(137,171.03)		216,669.55
	14,301,491.34	**(86,993,669.80)**	**1,924,329.59**	**7,179,681.05**	**1,927,940.48**	**7,788,215.74**	**13,164,245.50**	**12,587,310.21**

1999	2000	2001	2002	2003	2004	2005	2006	
	(176,974.70)		5,749.65			(31,239.53)	123,080.99	
	(659,653.64)	0.00	0.00	0.00	0.00		0.00	1,210,043.21
		3,488.01	14,426.78	15,815.51	47,099.42			
					47,408.38	0.00		
	5,805.00	84,923.24	(27,842.90)		13,177.08	42,643.96	55,205.02	24,886.63
				3,977.57	20,993.90	234.34	0.00	
		198,905.87	149,431.78			280,272.06	145,792.83	
	2,750.00	210,652.46	(15,901.90)	(41.12)	207,242.39	192,447.88	1.36	45,863.73
	407,600.99	2,631,837.87	2,915,026.46	1,267,640.43	2,722,715.95	1,434,579.98	10,335,813.26	(574,845.36)
	(9,234,437.23)	1,147,685.50	(1,217,675.17)	2,686,631.65	465,380.75	7,112,973.89	2,223,922.01	3,551,715.05
		11,177.02	67,759.87				51,775.49	11,002.16
	3,282,823.88	(281,640.80)	0.00	0.00	0.00	251,192.94	148,768.79	5,004,734.60
		1,197.67						
						38,474.06	55,322.95	22,787.97
		91,634.91		8,832.49			24,562.80	107,794.49
						834.18		880.79
		0.00	33,355.02			61,879.37		
				4,669.74				
	19,782,612.38	(85,427,693.77)		2,917,812.72	(1,458,906.36)	(1,458,906.36)		2,965,777.39
	890,964.66	(5,665,837.78)		274,342.06	(137,171.03)	(137,171.03)		216,669.55
	14,301,491.34	**(86,993,669.80)**	**1,924,329.59**	**7,179,681.05**	**1,927,940.48**	**7,788,215.74**	**13,164,245.50**	**12,587,310.21**

2007	2008	2009	2010	2011	2012	2013	2014	Grand Total
	13,974.34		0.00					905,428.12
(733,516.19)	34,100.70	(634,268.71)	(356,620.16)				(761.24)	13,774,261.63
	11,330.00	42,344.11	13,209.64	4,962.24	26,377.42	42,961.34	31,222.68	295,746.83
		0.00	28,219.31					1,101,326.01
62,107.91	13,501.33	19,822.83	17,837.51	8,256.46	50,106.90	83,511.17	75,081.75	876,995.74
2,527.01			7,658.95			9,708.11	20,824.02	121,485.85
								413,242.42
371,356.83	153,191.30	739,118.90	636,276.37	135,000.00	566,914.47	750,106.42	777,757.23	5,557,885.42
112,531.07	97,735.50	127,084.18	306,333.43	0.00	997,851.99	133,794.28	99,407.51	4,000,859.81
(1,290,693.58)	246,164.23	(9,003,230.75)	5,717,271.43	10,282,305.77	12,167,338.86	(84,396.94)	24,428,321.86	143,138,046.34
(2,767,898.10)	6,467,552.03	(3,339,506.25)	5,968,129.76	12,273,129.35	(816,742.03)	(1,367,547.76)	(301,337.70)	74,180,880.39
41,654.25	34,806.90	212,585.05	0.00			1.59	(12,087.52)	827,788.01
(2,378,759.24)	8,894,560.75	(3,885,114.74)	4,733,674.19	166,753.47	(0.45)	262,712.12	5,250,513.72	57,779,402.16
	6,706.52		0.00					218,641.66
52,722.24	13,519.40							270,173.69
	238,269.01	53,537.53	31,239.60	23,351.99	56,947.76	158,949.43	135,661.04	925,224.44
								1,714.97
(83,664.03)			(1,203,474.92)					0.00
	10,889.77		(64,257.78)					0.00
	34,697.51			13,724.73		266,708.45	54,601.29	753,307.01
	9,166.67					(24,657.08)		287,723.30
				576.78				576.78
								4,669.74
(137,565.74)	5,183,214.87	(6,250,613.13)	(1,760,813.39)			0.00		6,093,879.69
130,666.47		(303,780.53)						1,417,100.42
(6,618,531.10)	**21,463,380.83**	**(22,222,021.51)**	**14,074,683.94**	**22,908,060.79**	**13,048,794.92**	**231,089.89**	**30,559,965.88**	**312,946,360.43**

2007	2008	2009	2010	2011	2012	2013	2014	2015	Grand Total
	13,974.34		0.00					296,410.60	1,201,838.72
(733,516.19)	34,100.70	(634,268.71)	(356,620.16)				(761.24)		13,774,261.63
	11,330.00	42,344.11	13,209.64	4,962.24	26,377.42	42,961.34	31,222.68	376.48	296,123.31
		0.00	28,219.31						1,101,326.01
62,107.91	13,501.33	19,822.83	17,837.51	8,256.46	50,106.90	83,511.17	75,081.75	143,907.62	1,020,903.36
2,527.01			7,658.95			9,708.11	20,824.02	22,059.70	143,545.55
									413,242.42
371,356.83	153,191.30	739,118.90	636,276.37	135,000.00	566,914.47	750,106.42	777,757.23	820,742.89	6,378,628.31
112,531.07	97,735.50	127,084.18	306,333.43	0.00	997,851.99	133,794.28	99,407.51	1,033,737.37	5,034,597.18
(1,290,693.58)	246,164.23	(9,003,230.75)	5,717,271.43	10,282,305.77	12,167,338.86	(84,396.94)	24,428,321.86	19,266,949.91	162,404,996.25
(2,767,898.10)	6,467,552.03	(3,339,506.25)	5,968,129.76	12,273,129.35	(816,742.03)	(1,367,547.76)	(301,337.70)	10,092,530.48	84,273,410.87
41,654.25	34,806.90	212,585.05	0.00			1.59	(12,087.52)		827,788.01
(2,378,759.24)	8,894,560.75	(3,885,114.74)	4,733,674.19	166,753.47	(0.45)	262,712.12	5,250,513.72	107,770.44	57,887,172.60
	6,706.52		0.00						218,641.66
52,722.24	13,519.40								270,173.69
	238,269.01	53,537.53	31,239.60	23,351.99	56,947.76	158,949.43	135,661.04	304,414.63	1,229,639.07
									1,714.97
(83,664.03)			(1,203,474.92)						0.00
	10,889.77		(64,257.78)						0.00
	34,697.51			13,724.73		266,708.45	54,601.29	20,207.72	773,514.73
	9,166.67					(24,657.08)		303,206.10	590,929.40
				576.78					576.78
								(4,669.74)	0.00
(137,565.74)	5,183,214.87	(6,250,613.13)	(1,760,813.39)			0.00			6,093,879.69
130,666.47		(303,780.53)							1,417,100.42
(6,618,531.10)	**21,463,380.83**	**(22,222,021.51)**	**14,074,683.94**	**22,908,060.79**	**13,048,794.92**	**231,089.89**	**30,559,965.88**	**32,407,644.20**	**345,354,004.63**

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QUESTION:
Depreciation Account 367.6. For Account 367.6 - Underground Conductors & Devices, please provide the following:

a. The different types of conductor and duct systems by linear footage and corresponding dollar amount.
b. When each type of conductor was first installed, the year when each type of conductor ceased to be installed, and the reasons for changing types of conductor.
c. The dollar level of retirement by year, by type of conductor and duct system for the period 2004-2015.
d. Whether it is FPL's policy to retire the investment in this sub account in place when possible.
e. The dollar level of retirements by year, for the period 2004-2015 that were abandoned in place rather than removed.
f. The linear footage and corresponding dollars of copper cable.
g. The corresponding linear footage and dollar level of copper retired by year, for the period 2004-215.
h. All reasons why FPL believes that an average service life of 45 years or longer would not also be a reasonable average service life.

RESPONSE:
a. See Attachment No. 1 to this response.

b. See Attachment No. 2 to this response. These conductors are still being installed.

c. See Attachment No. 3 to this response.

d. It is FPL's policy to retire the investment in this sub account in place when possible.

e. FPL does not track whether underground cable is abandoned rather than removed.

f. See Attachment No. 4 to this response.

g. See Attachment No. 5 to this response.

h. There are a number of reasons that support FPL's recommended 42-S0 survivor curve as a better estimate than a survivor curve estimate with an average service life of 45 years or more. The first is the statistical life analysis. The 42-S0 survivor curve represents a very good fit of the representative data points for the overall experience band (which are shown on page VII-109 of Exhibit NWA-1). Other experience and placement bands also provide similar statistical indications. S type survivor curves that have an average service life of 45 years or more are not good fits of the historical data. Similarly, R type survivor curves with an average service life of 45 years or more are not good fits of the historical data.

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There are some L type curves that represent relatively good fits of a portion of the historical data that have an average service life of around 45 years. However, there are multiple reasons as to why L type curves do not represent a good estimate for this account. The first is that these L curves do not fit the historical data as well as the S0. Second, the approved curve type is the S0 curve type (the same as recommended in the depreciation study). OPC had recommended an L type curve in the 2009 Depreciation Study, but the Commission did not adopt OPC's curve type recommendation in favor of the S0 survivor curve recommended by FPL. Third, L type survivor curves forecast a decreasing level of retirements as the assets age (e.g., for this account this effect would be most pronounced starting at age 50). This expectation inherent to the L type curves is not reasonable for this type of property, both because this pattern of retirements is not consistent with the historical data for the account and also because factors such as corrosion should result in an increasing, or at least consistent, level of retirements as the assets in this account age.

For these reasons, an average service life estimate of 45 years or more would have to deviate from the statistical indications from the historical data. There is not a convincing reason to do so for this account. As discussed on page XI-35 of Exhibit NWA-1, while there have been improvements in the quality underground conductor, the impact of these improvements is already supported by the historical data. The 42-S0 survivor curve represents an increase in service life over the approved 38-S0 survivor curve. Further, the 42-S0 survivor curve was favored by Mr. Allis over the 41-S0 survivor curve, which is also a very good fit of the historical data, for this reason. Additionally, more recent placement bands do not support that newer cable will experience a significantly longer service life than indicated by the overall experience band. The 42-S0 survivor curve is a very good fit of the most recent 30 and 20 year placement bands, and a 45-S0 or longer curve is not a good fit of these placement bands.

Finally, environmental factors in Florida may limit the impact on longer service lives for conductor in duct system or conduit. The proximity to the ocean and the frequency of thunderstorms means that water (and salt water) can enter conduit and ducts. While improved cable quality can help mitigate the impact of corrosion, newer cable is not immune to these factors. Cable failures in duct or conduit typically require replacement (i.e., the cable cannot be easily spliced), and thus the environment in Florida means that underground conductor will continue to need to be replaced.

For all of these reasons, the 42-S0 survivor curve, which is a very good fit of the historical data, represents a superior estimate than survivor curves with an average service life of 45 years or more.

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QUESTION:
Forecasting
Depreciation Account 364.1 - Please specifically state and demonstrate how the retirements due to the storm hardening and pole inspection programs were treated and considered in the life analysis and estimation process that resulted in a 40R2 life-curve combination proposal. Further, explain and justify how such treatment resulted in proper recognition of the future life characteristics for the remaining investment in Account 364.1.

RESPONSE:
Retirements related to the storm hardening and pole inspection programs were not coded as outliers and were not excluded from the statistical life analysis, for reasons that are discussed in this response. However, the impact of both of these programs – both in terms of historical retirements and in terms of the future outlook for the account – were considered in the recommended 40-R2 survivor curve for this account. The 40-R2 forecasts that FPL will experience a lower rate of retirements for earlier ages (e.g., until about age 30), but will experience a similar rate of retirements for later ages (e.g. from ages 40 to 60) as has occurred historically. Factors related to both the pole inspection and storm hardening program that inform the judgment used for this estimate are as follows.

First, it should be noted the service life estimate for this account represents an increase in service life over the estimate from the previous depreciation study. The currently approved estimate for this account is the 39-R2 survivor curve. The recommended 40-R2 survivor curve for this account is therefore an increase in service life over the approved estimate. However, the approved estimate applies to all distribution poles (including concrete poles). Since concrete poles have historically had a longer service life than wood poles, the change in service life for this proposed subaccount is actually longer than a change from a 39-R2 to a 40-R2. The 40-R2 survivor curve estimate therefore incorporates an expectation for a longer service life for wood poles than in previous depreciation studies.

Retirements specifically related to the pole inspection program should not be excluded from the statistical analysis because the pole inspection program will continue to result in retirements going forward. Under the pole inspection program, the Company inspects each pole in its service territory every eight years. If a pole has deteriorated or is in poor condition, the Company can either take action to mitigate deterioration, such as adding treatment to the pole, or the pole will be replaced. The impact of the inspection program on the service lives in this account is therefore mixed. For some assets, mitigation may improve the life of the poles, but for others assets will be replaced earlier than would have occurred prior to the inspection program (e.g., prior to the program poles might not be replaced until damaged and could no longer remain service, but now that the program is in place these poles will be identified sooner and replaced proactively). The overall impact on the service life for this account is therefore mixed, but the likely impact going forward is that there will be somewhat fewer retirements for earlier ages (e.g., through about age 30), but a higher rate of retirements for later ages. The impact therefore could affect the mode of the curve more than the average service life, producing a higher mode curve.

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Retirements for this account have increased since the implementation of the storm hardening program. However, while the storm hardening program resulted in the retirements of some assets earlier than would have occurred absent the program, a portion of the poles replaced were older and weaker poles that therefore would have to be replaced at some point absent the storm hardening program. Additionally, storm hardening is ongoing. FPL will continue to replace older wood poles going forward. For these reasons, excluding storm hardening transactions from the database would result in the exclusion of too much information and would result in indications of too long of service lives.

One aspect of the statistical data that supports that the storm hardening retirements should not be discounted too significantly is that the historical data for the current study through 2014 actually provides indications of longer service lives than prior to the implementation of the storm hardening program. That is, if replacements due to storm hardening were to dramatically impact the service life of the assets in this account, the expectation is that data that incorporates activity since the program began in 2007 would indicate a shorter service life than data that only included experiences prior to 2007. Instead, the opposite is true. As noted above, the recommendation in the 2016 Depreciation Study for this account is for an increase in the service life for this account. Data that excludes the years since the implementation of the storm hardening program (i.e., through 2006) indicates a shorter service life than is indicated for the full band in the 2016 Depreciation Study. This provides reason to expect that a portion of the wood poles retired for storm hardening were replaced at ages consistent with their overall life expectation (i.e., were not replaced prematurely), and therefore retirements associated with storm hardening should not be too aggressively discounted.

Storm hardening and the pole inspection program together may have an additional impact on service lives that would limit any further increases in the life of poles. In order to operate a more reliable system, FPL's standards for strength and loading of poles have increased. In the past, older poles may have remained in service for a relatively long period of time and would be retired when significantly deteriorated or damaged. Based on FPL's current outlook, poles will be retired when they do not meet strength or loading requirements that are more stringent than in the past. For example if an automated feeder switch or if foreign utility attachments (phone, cable, etc.) are added, a pole may have to be replaced with a stronger pole (or a concrete pole) due to loading. A stronger system also means less tolerance for deterioration of wood poles, which could also result in replacing poles more frequently. Additionally, because FPL now inspects each pole on an eight year cycle, these factors will be observed and addressed proactively, which could also result in more frequent replacements than in the past. Taken together, these factors provide further reason not to significantly discount retirements associated with either pole inspections or storm hardening in recent years.

Given these considerations, the expectation for this account is that the level of retirements at earlier ages (through about age 30) will occur at a lower rate than has occurred historically. However, the retirement pattern for later ages (about age 40 and beyond) should be similar to what has occurred historically. These expectations are incorporated into the recommended 40-R2 survivor curve, which is generally above the historical data for earlier ages and a good fit for later ages.

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QUESTION:
Forecasting
Depreciation Account 364.2 - Please state whether a 55S0 life-curve combination is also a reasonable and appropriate life-curve combination alternative to the Company's proposed 50R1.5 life-curve combination for Account 364.2. To the extent the response is other than fully affirmative, then provide all support and justification for a contrary position. The response should identify and justify the criteria relied upon for the position taken, and to the extent judgment is relied upon for the response include the specific input values or information that formed and supports the results of the asserted judgment process

RESPONSE:
The 55-S0 survivor curve is not a reasonable and appropriate survivor curve estimate for this account. As is discussed on pages XI-26 and XI-27 of Exhibit NWA-1, the statistical indications based on the historical data for concrete distribution poles indicated an average service life of about 45 years. A 55-S0 survivor curve estimate would represent an average service life that is 10 years longer than indicated by the historical data. This is too long of an increase over the statistical indications for this account.

As discussed on page XI-27, it is appropriate to estimate a service life that is somewhat longer than indicated by the historical data. One reason for this is because newer poles are stronger than those installed 30 or 40 years ago, which may result in a longer service life. The 50-R1.5 survivor curve, which represents an average service life that is five years longer than indicated by the historical data, incorporates this expectation. The 50-R1.5 is also a reasonable fit of more recent 30 and 40 year placement bands, although these placements have experienced a higher rate of retirement than represented by the 50-R1.5 survivor curve for ages in the middle portion of the curve (this can be seen by comparing the 50-R1.5 survivor curve to the 1975-2014 placement band on page VII-96 of Exhibit NWA-1). The impact of stronger poles therefore supports a longer service life than indicated by the historical data. In contrast, a 55-S0 survivor curve is too long of an increase given these considerations and is also a different curve type than is indicated by the historical data.

For most years, retirements for concrete poles have not been significantly higher since the storm hardening program began than was the case in higher years, with the exception of 2014. While storm hardening retirements were a consideration in recommending the 50-R1.5 survivor curve, the impact of storm hardening has not been significant enough to support the 55-S0 survivor curve, which again is a large increase over what is supported by the statistical data.

Another consideration that supports the 50-R1.5 survivor curve is the mortality characteristics of concrete poles. The primary difference between the 50-R1.5 and 55-S0 survivor curves is the level of retirements forecast by each curves for later ages (i.e., for ages 50 and beyond). The 50-R1.5 survivor curve forecasts the level of retirements to increase for these ages. This is consistent with both the historical experience for this account, and with the forces of retirements for concrete poles. While not subject to the same level of deterioration as wood poles (which is one reason a lower mode curve is recommended for concrete poles than for wood poles), deterioration does cause retirements of concrete poles and tends to increase with age. Concrete

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poles tend to deteriorate due to cracking in the concrete and corrosion of the rebar (which can accelerate due to cracking). Cracking of the concrete and corrosion are more pronounced in areas in proximity to the ocean due to salt in the air. In contrast to the 50-R1.5 survivor curve, the 55-S0 is a fairly straight curve beyond age 50, meaning that the 55-S0 forecasts a fairly constant level of retirements for later ages. This expectation would be inconsistent with the impact of deterioration described above and with FPL's actual experience (which indicates an increasing level of retirements with age).

Given all of these considerations, the 50-R1.5 survivor curve is more appropriate than the 55-S0.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF ROBERT E. BARRETT, JR.

DOCKET NO. 160021-EI

AUGUST 1, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert E. Barrett, Jr. My business address is Florida Power & Light Company ("FPL" or "the Company"), 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following rebuttal exhibit:

- Exhibit REB-15 Illustrative MFR C-37 with Revised Inflation Factor

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is: (1) to explain why the Florida Public Service Commission ("FPSC" or "Commission") should reject the arguments of AARP's witness Michael Brosch, Florida Industrial Power Users Group's ("FIPUG") witness Jeffry Pollock and the South Florida Hospitals and Healthcare Association's ("SFHHA") witness Lane Kollen that the 2017 and 2018 revenue requirements forecasts are unreliable; (2) to explain why the Commission should reject the recommendation of the OPC, AARP, FIPUG and SFHHA witnesses that the Commission should not approve the Company's proposed 2018 Subsequent Year Adjustment ("2018 SYA"); (3) to explain why the Commission should reject the arguments of the OPC, AARP and SFHHA witnesses against the need for the Okeechobee Limited Scope Adjustment

("Okeechobee LSA"); (4) to explain why the Commission should reject the arguments of OPC, AARP and SFHHA witnesses that FPL's four-year proposal is not in the best interest of customers; (5) to explain why the recommendation of OPC witness Helmuth Schultz to return the remaining reserve amortization to customers should be rejected; (6) to demonstrate that the recommendation of OPC witness Dismukes to update FPL's inflation factor for the benchmark O&M calculation does not produce a meaningful change in the results; (7) to rebut SFHHA witness Richard Baudino's claim that commitment fees for short term debt should be excluded from the cost rate for that debt and collected as O&M; (8) to address non-recurring costs identified in Staff witness Iliana Piedra's testimony and audit report; and (9) to explain why the Commission should approve the framework for the transfer of the Martin-Riviera ("MR-RV") Lateral to Florida Southeast Connection ("FSC").

Q. Please summarize your rebuttal testimony.

A. FPL filed two full sets of Minimum Filing Requirements ("MFRs"): one set for the 2017 Test Year and a separate set for the 2018 SYA. Both sets of MFRs were the result of the same rigorous forecasting process. The Company's forecasts of revenue requirements included in these MFRs are reasonable and reliable for setting base rates in 2017 and 2018 in this proceeding. The forecasts were based on work prepared by internal and external subject experts all of which was reviewed and approved by management using a thorough process. The forecasting process produces reasonable results that have proven to serve as a reliable basis for setting base rates in the past.

The Commission has approved the use of base rate adjustments in years subsequent to the test year on multiple occasions. Use of the Company's proposed 2018 Subsequent Year to approve a SYA in this proceeding is appropriate under the Commission's Rule 25-6.0425 and represents an efficient and reasonable basis upon which to establish rates for the Company. Moreover, the Company's forecast of revenue requirements for the 2018 Subsequent Year is sound and reasonable. The forecast of revenue requirements contained in the Company's 2018 SYA MFRs demonstrates that the level of revenue requirements for the 2017 Test Year are not reflective of the revenue requirements the Company will incur in 2018, demonstrating that the 2018 SYA is necessary and appropriate. The Company followed the same rigorous process for 2018 as it did for 2016 and 2017. The underlying work and support for each of these forecasts share a common platform and approach, equally appropriate for 2018 as for 2016 and 2017. Finally, the Commission's monthly surveillance of the Company's earnings ensures that customers are adequately protected. OPC's, AARP's, FIPUG's and SFHHA's opposition to the 2018 SYA should be rejected.

The Okeechobee LSA is an appropriate and effective way to implement the recovery of the base revenue requirements for the previously approved Okeechobee generating unit. The fuel benefits that the unit provides will be passed automatically to customers through the fuel clause, and it is appropriate for FPL to begin recovering the base revenue requirements for the unit at the

same time. The Okeechobee LSA functions in all material respects like the Generation Base Rate Adjustment ("GBRA") mechanism that the Company has successfully used in the past, including most recently for the modernizations of the Cape Canaveral Energy Center, Riviera Beach Energy Center and Port Everglades Energy Center. Like the GBRA, the Okeechobee LSA protects customers through: (1) its timing of the base rate increase to coincide with the commencement of commercial operations of the unit; (2) its cost true-up mechanism; and, (3) helping to reduce the need for lengthy base rate proceedings for all parties. The Commission should reject as unfounded OPC's and SFHHA's assertion that the Okeechobee LSA undermines the Commission's regulatory scrutiny.

FPL's four-year rate proposal offers customers base rate stability and certainty through at least January 2021. It is an asymmetric proposal that has the Company bearing the risk of revenue and cost uncertainties, while continuing to afford customers the protection of the Commission's oversight of the Company's earnings. Additionally, it provides a four-year period of regulatory certainty allowing management to continue its focus on improving the Company's performance in service delivery and realizing additional efficiencies in its operations to an extent that is unlikely if base rate filings are necessary every year. The Commission should reject as unfounded OPC's, AARP's and SFHHA's argument that the proposal is not in the best interest of customers.

FPL disputes the recommendation of OPC witnesses that adjustments proposed for 2017 should be applied to 2016 and that any remaining reserve amount should be refunded to customers over two years, as well as OPC's assertion that the Commission should utilize a different inflation factor in developing its forecast and the O&M benchmark analysis reflected in MFR C-37.

FPL disagrees with the recommendation of SFHHA witness Baudino to remove commitment fees from the cost of the debt and include in base O&M. Doing so would be inconsistent with the Commission's past practice and contrary to the Generally Accepted Accounting Principles ("GAAP"), which require that commitment fees be recorded to interest expense.

Finally, FPL's proposal to transfer the MR-RV lateral to FSC provides for customer savings and reduced operational risk over the life of the asset versus FPL maintaining ownership and recovery within base rates. The Commission should reject the recommendation of SFHHA's witness that the transaction be conditioned on FPL filing a NGA Section 5 rate case. FPL's proposal is already contingent upon a demonstration of customer benefits.

II. FINANCIAL FORECASTS

Q. Are the Company's forecasts for 2017 and 2018 reasonable and reliable for setting rates in this proceeding?

A. Yes. The bases and process used in developing the 2017 and 2018 forecasts are robust and reasonable, and the resulting forecasts of revenue requirements can be relied upon for rate setting. FPL's forecasts are the products of a rigorous process involving a multi-year planning horizon and have proven to be accurate in setting rates in the past.

Q. Witnesses Brosch, Kollen, and Pollock each contends that FPL has a strong incentive to over-estimate its forecast of expenses. Do you agree with that position?

A. No, I do not. Contrary to the assertions of these intervenor witnesses, FPL does not pessimistically forecast its operating costs nor does it have a strong incentive to do so. FPL must provide evidence sufficient to defend its cost projections to this Commission and presenting a pessimistic forecast would not serve that purpose. Witness Brosch points to FPL's forecast of O&M expenses in both the 2010 and 2013 test years compared to actual performance, noting that FPL's actual O&M performance was lower than the forecast and drawing the conclusion that the Company must have been pessimistically forecasting those expenses. However, this conclusion is unwarranted.

Q. What factors led to actual O&M expenses in 2010 being $97 million less than the amount included in the 2010 Test Year in Docket No. 080677-EI?

A. The variance in 2010 is primarily the result of FPL's response to the Great Recession that was officially declared by economists in December 2008 and was not determined to be over until the fall of 2010. The O&M forecast utilized in the 2009 Prior Year and the 2010 Test Year was prepared in late 2008, before FPL, or economists in general, had even determined we were in a recession or how severe the impact would be to the Florida economy. During this period of uncertainty in 2009 and 2010, FPL had a decline in customer count for the first time in its history and began to look for ways to manage down its costs in anticipation of softening revenues as the recession continued to deepen. Because the recession was not even declared to be over until late 2010, FPL operated in 2010 in a very uncertain cost and revenue environment. FPL's effective response to the extraordinary economic conditions at that time does not demonstrate that FPL's forecasting process was pessimistic.

Q. What factors led to the actual O&M in 2013 being $130 million less than the amount included in the 2013 Test Year?

A. After the 2012 Settlement Agreement was approved by the Commission, FPL significantly increased its efforts to create productive efficiencies in the business that would deliver sustainable value for customers. This was an important benefit of the 2012 Settlement Agreement, in that it allowed management to increase the Company's focus on finding ways to improve productivity rather than preparing, filing and defending rate cases annually.

This was made possible, in part, through a feature of the 2012 Settlement Agreement, the flexible amortization of the Reserve Amount, which allowed the Company to absorb near-term fluctuations in revenues and expenses while working to identify and implement longer-term productivity gains. The main catalyst for FPL's productivity improvement initiatives has been Project Momentum, which has become an important part of FPL's annual planning process. Project Momentum kicked off in early 2013. Through this process the Company was able to generate incremental productivity improvements that allowed for immediate cost reductions in 2013, and has generated additional savings in each successive planning cycle, savings that are reflected in FPL's forecasts for 2017 and 2018.

Thus, these cost reductions are now benefiting customers in the current rate case, with FPL having a test-year O&M significantly below the Commission benchmark in each of the cost categories. Again, this was a special opportunity that presented itself in 2013 but which cannot be realistically repeated year after year and which does not suggest pessimistic forecasting.

Q. Given the Company's actual performance in both 2010 and 2013 as compared to the test year forecast, can the Commission rely on the O&M forecast for the 2017 Test Year and 2018 Subsequent Year?

A. Yes. As with the O&M forecasts in both the 2010 and 2013 test years, FPL's 2017 Test Year and 2018 Subsequent Year represent FPL's best estimate of the resources required to run the business as the Company plans to run it. It is

unrealistic to expect that the circumstances leading to lower actual O&M expenses in 2010 and 2013 would repeat themselves in 2017 or 2018. Moreover, FPL's base O&M forecasts reflect only very modest growth over the 2016-2018 period: a decrease of 0.1% in 2016, and increases of only 2.2% in 2017 and 4.1% in 2018, for an average annual increase of only 2.0% for the three years that is well below the average annual expected inflation of 2.4% for the period. In addition, FPL's base O&M cost in 2017 is forecasted to be *lower* than the 2013 *actual* performance and in fact *lower* than actual base O&M cost incurred by the Company in 2010, clearly demonstrating that FPL has made unprecedented productivity gains and has included the results of its productivity discipline in its current forecast. This effective cost management has contributed to FPL being the best-in-class non-fuel O&M performer amongst its peers and saving customers nearly $2 billion annually versus average performance as explained by FPL witness Reed.

Q. Witness Brosch states that FPL's financial forecasts do not "include any assumed new future productivity gains." Is it appropriate to include incremental, unknown productivity improvements in the calculation of revenue requirements?

A. No. FPL included all productivity improvements in its financial forecasts for both 2017 and 2018 that were known and quantifiable at the time those forecasts were made. Despite witness Brosch's assertions, FPL has continued to look for opportunities to improve its cost position, but has experienced diminishing cost reductions with each annual review. Project Momentum has become an integral

part of our annual planning process and will continue to provide cost improvement opportunities. FPL has just completed its 2016 Project Momentum process and the preliminary FPL base O&M reductions to the 2017 Test Year revenue requirements are estimated to be $10.0 million and an incremental reduction of $7.3 million on the 2018 Subsequent Year revenue requirements. The FPSC-adjusted amounts of these reductions are estimated to be $9.7 million and $7.0 million in 2017 and 2018, respectively. Even though this represents an update to just one of many forecast assumptions, FPL is reducing its requested revenue increase in both years by those amounts. At this point, FPL has identified and quantified all known future efficiency gains affecting the Test Year and Subsequent Year.

III. 2018 SUBSEQUENT YEAR ADJUSTMENT

Q. Has the Commission previously approved the use of subsequent year adjustments?

A. Yes. Order Nos. 13537, PSC-92-1197-FOF-EI and PSC-93-0165-FOF-EI are examples of instances in which the Commission approved the use of "two fully projected test years" in rate cases for FPL, Florida Power Corporation and Tampa Electric Company, respectively.

Q. FIPUG witness Pollock states that it is not common practice for utility commissions to allow utilities to propose multi-year rate plans. What is your reaction to his assertion?

A. His assertion misses the point entirely. The real question is whether such a proposal is appropriate in Florida. The answer to that question is, yes. FPL's SYA is a necessary component of the proposal, as without rate relief in 2018, FPL's ROE is projected to decrease by greater than 100 basis points. In addition, as noted in my summary, the Commission has determined it has the ability to utilize a subsequent year adjustment.

Q. Witness Pollock further asserts that any changes made to FPL's 2017 revenue request, for example if the Commission reduces FPL's 2017 cost of capital, could cause the revenue need in 2018 to be minimal or non-existent. Do you agree with his assertion?

A. No, I do not. Witness Pollock is mistaken in his assertion that a reduction in the 2017 cost of capital would have a commensurate impact on the 2018 revenue need. On the contrary, FPL's revenue need in 2018 will not be materially different than it is currently projected to be if FPL were awarded a different cost of capital for 2017. It is important to understand that the 2018 SYA reflects the incremental revenue requirements for 2018, which are independent of those in 2017.

Q. Witnesses Kollen, Pollock and Brosch assert that the 2018 SYA should be rejected by the Commission and FPL can file another base rate proceeding in 2017 if it believes it has a revenue deficiency. Do you believe that would be an efficient and effective process?

A. No. Although the Company can indeed file another case in 2017 for rates to be effective in 2018 if the subsequent year increase is not granted, the Company will expend significant time and resources in developing and defending that filing – time that could be spent continuing to find additional ways to create value for FPL's customers. Furthermore, the cost in time and resources will not only be borne by FPL, but also the Commission, its staff, and all other interested parties.

The Company's forecast of 2018 is reliable, and intervener witnesses have not presented any credible reason why the 2018 forecast cannot reasonably be relied upon for setting rates, other than it is one year further out in time than 2017. More frequent proceedings are administratively burdensome and costly for all parties.

Additionally, FPL has been able to prepare, file and execute base rate proceedings occurring infrequently (every three or four years), in addition to its daily business operations. The Company has been able to do this without building a large permanent staff devoted to processing rate cases, in part because the filings have been infrequent. Moreover, a stable regulatory

environment has allowed FPL and its customers to benefit from a business model that is highly customer-focused and operationally driven. This has been a highly successful model generating significant customer value. If base rate proceedings were to become an annual requirement this business model undoubtedly would be altered, to the detriment of customers.

Q. Do you agree with the calculation presented on page 42, lines 5 through 7 of OPC witness Smith's testimony with regard to the revenue requirement for the 2018 SYA?

A. No, I do not. Witness Smith incorrectly estimates the incremental revenue requirements in 2018 and therefore incorrectly asserts that there is no need for a 2018 SYA. His Exhibit RCS-3, Schedule A-1 indicates a recommended revenue requirement reduction in 2018 of $604 million. However, witness Smith's calculation of the incremental need in 2018 is in error, even based on his own conclusions for 2017. If the OPC's recommended revenue reduction in 2017 were to be adopted ($807 million plus sales growth to get to $812 million, Page 43, Line 1), then the incremental need in 2018, using witness Smith's math, would be a $208 million *increase*.

Witness Smith argues, "the test year is supposed to be representative of rates on a going-forward basis. If the test year is chosen appropriately, there should be no reason for another rate adjustment so shortly after original test year." Once witness Smith's error is corrected, it is clear that even his own calculations, assuming all adjustments recommended by OPC's witness, show that the

proposed 2017 revenues are insufficient for 2018 resulting in a $208 million *deficiency*. Per the Company's filing, the deficiency is properly estimated to be $262 million. Thus OPC effectively concedes a significant *incremental revenue deficiency* in 2018 irrespective of the outcome for 2017.

Witness Smith refers to Order No. PSC-10-0153-FOF-EI, in which the Commission observed that "[i]f the test year is truly representative of the future, then the utility should earn within the allowed range for at least the first 12 months of new rates." However, the Commission went on to state, "[w]e believe that back-to-back rate increases should only be allowed in extraordinary cases." Thus the passage cited by witness Smith *does* allow for subsequent year adjustments in "extraordinary cases," which necessarily include circumstances when the Company is expected to earn outside of its allowed range in the year following the first 12 months of new rates even with the requested rate relief. That is exactly the case here where the Company projects its ROE in 2018 to be more than 100 basis points ("bps") lower than its ROE in 2017. Witness Smith's arguments are unfounded.

IV. OKEECHOBEE LIMITED SCOPE ADJUSTMENT

Q. Witnesses Kollen and Brosch assert that FPL's proposed Okeechobee LSA ignores the business environment that may exist in 2019 and is instead "piecemeal, single-issue ratemaking." Please comment on this assertion?

A. The assertion appears intended to create controversy where there should be none. Limited Proceedings, authorized in Section 366.076(1), Florida Statutes and implemented in Commission Rule 25-6.0431, are intended precisely to address even a single issue such as the Okeechobee LSA. The Okeechobee LSA deals with the single issue of appropriately matching the revenue collected with the underlying revenue requirements associated with the new power plant; therefore, it is exactly the appropriate application of a limited scope adjustment.

In 2012, witness Kollen testified in Docket 120015-EI that the requested step increase for the Cape Canaveral Energy Center -- which is substantially the same as the Okeechobee LSA -- is earnings neutral because the revenue increase is calculated to earn the authorized midpoint ROE. Further, the Okeechobee LSA matches the increased revenue requirements associated with the plant with the offsetting fuel savings generated by that plant. Thus, for the single issue the Okeechobee LSA addresses, it appropriately "considers the cost reductions that the Company" achieves with respect to that issue.

Q. Witness Smith recommends that the Okeechobee LSA not be approved as he is "skeptical of the accuracy and reasonableness of FPL's 2019-2020 projections." Do you agree with his assertion?

A. No, and Mr. Smith's skepticism regarding the Company's financial projections is an insufficient reason to deny the Company's requested recovery of the revenue requirements reflected in the Okeechobee LSA.

The Okeechobee LSA is calculated to earn the authorized ROE (i.e., the "mid-point" of the Commission's allowed range). It is mid-point seeking in that it will move the Company's overall earnings toward the mid-point irrespective of where those earnings would otherwise be before the addition of the revenue requirements and revenue increase for that given plant. If earnings prior to this are below the mid-point, the Okeechobee LSA will move earnings toward the midpoint but never exceed the mid-point. Likewise, if earnings prior to this are above the mid-point, this will move earnings toward the mid-point but not fall below the mid-point. As noted previously, SFHHA witness Kollen has previously testified before this Commission that this type of base rate adjustment is earnings neutral.

V. FOUR-YEAR PROPOSAL

Q. FIPUG witness Pollock, AARP witness Brosch and SFHHA witness Kollen all contend that the assumptions underlying FPL's four-year proposal are speculative and contain "massive uncertainties." Do you agree with that position?

A. No. In addition to the detailed forecasts for 2017 and 2018 included within its MFR filings, FPL has provided a high level base projection of 2019 and 2020. This projection was prepared utilizing the Company's detailed financial model and uses input assumptions that are consistent with this rate filing and all other official Company filings (i.e., TYSP). The base projection indicates that FPL will fall outside of the allowed ROE range during the four years even if each of the base rate requests contained in the Company's four-year proposal are granted in full, requiring the Company to find ways to manage the business to earn an acceptable ROE during that four-year period.

Additionally, whatever uncertainties exist will affect the parties asymmetrically. If the proposal is agreed to, FPL has offered to refrain from filing for new base rates to be effective until at least January 2021. Accordingly, FPL bears all of the risk of uncertain cost increases. On the other hand, if revenues and expenses deviate from those assumed by FPL, for instance if FPL continues to improve upon its best-in-class cost performance, such that earnings exceed the top of the approved range of ROE, the Commission or any party can seek a review of

FPL's rates for a potential reduction. This is the same protection afforded all parties without the four-year stay-out proposal. And of course, the Commission can, at any time, seek to review the Company's base rates.

Q. Do you agree with witness Brosch's assertion, in arguing against the four-year proposal, that one would expect fluctuating earnings under a balanced multi-year plan yet FPL's earnings have not fluctuated?

A. No. Witness Brosch misunderstands or misinterprets the features of the rate case settlement agreements specifically designed to mitigate volatility in earnings. A key component of the past settlement agreements, particularly the 2012 Settlement Agreement, has been the reserve amortization mechanism which has allowed the Company to manage uncertainty in revenues and expenses over the settlement period. This non-cash mechanism, designed to keep the Company within its authorized range of ROE, has benefitted customers by allowing the Company to refrain from base rate filings for four years. Without the reserve amortization contained in the 2010 and 2012 Settlement Agreements, earnings would have exhibited the variability expected by witness Brosch and FPL would not have committed to a multi-year base rate plan.

Q. Witness Brosch asserts that FPL's rate case expenses are less than half of one percent of FPL's cumulative revenue request and as such, it is more advantageous for customers to have annual rate cases as opposed to the Commission approving the four year proposal. Do you agree with that assertion?

A. No. Witness Brosch significantly understates the cost to customers of litigating

a rate case every year by focusing only on the incremental $4.9 million the Company has reported as the direct costs for this case. The bigger cost is the diversion of time and attention of management and employees to plan, prepare, file and defend annual rate cases. Customers have benefitted greatly from the multi-year settlements because they have allowed the Company to increase its focus on improving productive efficiency during the settlement period, instead of having to prepare, file and defend more frequent rate requests.

Q. Witness Brosch contends that the four-year proposal is not in the best interest of customers. Do you agree with that position?

A. No, I do not. Witness Brosch acknowledges the benefits of a multi-year plan (page 14, lines 1 through 20 of his testimony) and refers to a report, Future Test Years: Challenges Posed for State Utility Commissions. In discussing the positive side of regulatory lag, which is built into FPL's four-year proposal, the report states on page 33 that "[e]conomic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs....Commissions rely on regulatory lag as an effective tool for motivating utilities to act efficiently." Locking in the 2017 Test Year increase, the 2018 SYA and the Okeechobee LSA today, with no opportunity to reset base rates again until January 2021, constitutes significant regulatory lag, with its attendant incentive for FPL to control costs.

Accordingly, FPL's four-year proposal meets witness Brosch's own test that the customers "are better off under the plan" (page 10, lines 13 through 16),

securing no base rate increases other than those contained in the four-year proposal through at least 2021, while giving up none of the protections against over earning that FPL customers currently retain. FPL is willing to offer this asymmetric option fully understanding that it will need to manage rising cost pressure within a fixed base rate environment.

VI. RESERVE AMORTIZATION

Q. Do you agree with the recommendation of OPC witness Schultz that any unamortized Reserve Amount remaining at the end of 2016 be refunded to customers over a two-year period?

A. No. Witness Schultz suggests that his 2017 proposed adjustments imply an overstatement of FPL's expenses in 2016 and as such may result in some remaining unamortized Reserve Amount at December 2016. This suggestion is without merit because it is speculative, and any attempt to apply those 2017 adjustments to 2016 would violate the terms of the 2012 Settlement Agreement. The Reserve Amount is a mechanism of the 2012 Settlement Agreement and any unamortized amount should remain in the reserve where it serves as a reduction to rate base.

VII. INFLATION

Q. OPC witness Dismukes recommends a different inflation factor be utilized in developing forecasted cost increases and in preparing the Commission O&M benchmark calculation (MFR C-37). Do you agree with his recommendation?

A. No, I do not. As noted in the rebuttal testimony of FPL witness Morley, FPL utilized what it believed to be an appropriate measure of CPI for preparing its forecasts. However, even if FPL were to utilize the inflation factor recommended by witness Dismukes, it would have a negligible impact on FPL's forecasts. The Company does not use a formulaic process, such as the application of a specific rate of inflation across the board to its historical costs, to develop its forecasts, but rather utilizes CPI as a benchmark reference to assist with their preparation. In addition, it is worth noting that FPL's 2017 Test Year O&M would still be significantly below the Commission benchmark and no one category would exceed the benchmark if witness Dismukes recommended inflation factors were adopted. Exhibit REB-15 shows MFR C-37 using the inflation factors suggested by witness Dismukes.

VIII. COMMITMENT FEES

Q. Please respond to SFHHA witness Baudino's claim that commitment fees for short term debt should be excluded from the cost rate for that debt and collected as O&M.

A. FPL records the cost of commitment fees to interest expense to comply with the reporting requirements of GAAP. Therefore, it is more appropriate to treat the commitment fees as part of the cost rate of the debt rather than include within O&M consistent with the Commission's past practice. As noted in the testimony of witness Kollen (page 59, line 9), there is zero net effect on the revenue requirements associated with witness Baudino's proposal.

IX. FPSC STAFF AUDIT REPORT

Q. The audit report sponsored by Staff witness Piedra identifies specific expenses related to a cleanup of an oil spill in 2015 and states that they are non-recurring. The report goes on to state that Staff did not determine whether those expenses affected the 2017 Test Year or 2018 Subsequent Year forecasts. Were these expenses excluded from development of the 2017 Test Year and 2018 Subsequent Year forecasts?

A. Yes. The expenses identified by Staff witness Piedra were recognized by FPL as non-recurring costs and therefore were appropriately excluded from development of the 2017 Test Year and 2018 Subsequent Year forecasts.

X. TRANSFER OF MARTIN-RIVIERA LATERAL

Q. Do you agree with SFHHA witness Kollen's recommendation that the transfer of the MR-RV natural gas lateral be conditioned upon FPL filing a NGA Section 5 rate case against both FSC and Sabal Trail?

A. No. FPL's proposal is simple – the Commission should approve moving the ownership and operation of the MR-RV natural gas pipeline from FPL to FSC to lower the total cost and operational risks that today are approved as the responsibility of FPL's customers. Witness Kollen's suggestion that the transfer be conditioned upon a NGA Section 5 rate review at FERC ignores the fact that FPL's proposal contains a provision requiring that the Company file a petition with an updated transportation tariff reflecting any relevant assumptions decided in this rate proceeding. That petition will demonstrate that the costs to FPL customers of transportation on the MR-RV natural gas lateral are projected to be lower after the transfer to FSC than they would be under continued FPL base rate recovery or the Company will not seek approval. The Commission can determine, at the time of the petition for transfer, whether or not the savings to FPL customers are sufficient to justify the transaction.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Illustrative MFR C-37 with Revised Inflation Factor

Functional O&M	Adjusted 2013 Base Year O&M	Proposed Compound Multiplier	2017 Test Year Benchmark O&M	2017 Test Year O&M	Proposed 2017 Test Year Variance	As-Filed 2017 Test Year Variance	Difference
STEAM PRODUCTION	$ 85,366	1.052910	$ 89,883	$ 68,882	**$ (21,001)**	**$ (21,897)**	**$ 896**
NUCLEAR PRODUCTION	$ 406,557	1.052910	$ 428,068	$ 363,795	**$ (64,273)**	**$ (68,537)**	**$ 4,264**
OTHER PRODUCTION	$ 161,143	1.052910	$ 169,669	$ 165,581	**$ (4,088)**	**$ (5,778)**	**$ 1,690**
OTHER POWER SUPPLY	$ 6,299	1.052910	$ 6,632	$ 6,523	**$ (109)**	**$ (175)**	**$ 66**
TRANSMISSION	$ 47,189	1.118926	$ 52,801	$ 48,309	**$ (4,492)**	**$ (5,019)**	**$ 527**
DISTRIBUTION	$ 286,102	1.118926	$ 320,127	$ 294,260	**$ (25,867)**	**$ (29,057)**	**$ 3,190**
CUSTOMER ACCOUNTS	$ 149,954	1.118926	$ 167,787	$ 108,616	**$ (59,171)**	**$ (60,843)**	**$ 1,672**
CUSTOMER SERVICE	$ 12,851	1.118926	$ 14,379	$ 13,938	**$ (442)**	**$ (585)**	**$ 143**
SALES	$ 15,170	1.118926	$ 16,974	$ 14,242	**$ (2,732)**	**$ (2,901)**	**$ 169**
ADMINISTRATIVE & GENERAL	$ 388,309	1.118926	$ 434,489	$ 312,006	**$ (122,483)**	**$ (126,811)**	**$ 4,328**
TOTAL	**$ 1,558,940**		**$ 1,700,810**	**$ 1,396,151**	**$ (304,658)**	**$ (321,603)**	**$ 16,945**

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF TIFFANY C. COHEN

DOCKET NO. 160021-EI

AUGUST 1, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tiffany C. Cohen. My business address is Florida Power & Light Company ("FPL" or the "Company"), 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following rebuttal exhibits:

- TCC-7, Comments on Illustrative Baron Table 12
- TCC-8, Distribution Substation Interrogatory
- TCC-9, Major Southeastern Investor Owned Utility Bill Comparison 2006 - 2016

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut the testimony of the Florida Industrial Power Users Group's ("FIPUG") witness Pollock, the South Florida Hospital and Healthcare Association's ("SFHHA") witness Baron, the Federal Executive Agencies' ("FEA") witness Alderson, AARP's witness Brosch, the Wal-Mart Stores East, L.P. and Sam's East, Inc.'s ("Wal-mart") witness Chriss and the Office of Public Counsel's ("OPC") witness Lawton.

Specifically, I will address the Florida Public Service Commission's ("FPSC" or "the Commission") policy on gradualism and FPL's application of that policy, FPL's proposed rate design for demand and non-fuel energy charges for commercial and industrial rate classes, the proposed $2 increase in residential and non-demand commercial customer charges, the intervenors' testimony regarding the Commercial/ Industrial Load Control ("CILC") and the Commercial/Industrial Demand Reduction ("CDR") rider credits, and the testimony regarding the impact of natural gas prices on FPL's low bills.

II. SUMMARY

Q. Please summarize your rebuttal testimony.

A. My testimony shows that:

- FPL has correctly applied the Commission's policy regarding gradualism;
- FPL's method for developing commercial and industrial demand and energy rates is appropriate and reasonable and maintains the current relationship between energy and demand charges;
- FPL's proposed $2 customer charge increase is reasonable and represents a modest step in aligning fixed costs with fixed cost recovery;
- FPL has appropriately reset the CILC and CDR credits to the levels prior to the 2012 Settlement Agreement [adjusted for the Cape Canaveral, Riviera and Port Everglades generation base rate adjustments ("GBRAs")];

- FPL already offers customers the option to take transmission level service from a substation; and
- FPL's low bills today are not solely the result of low natural gas prices but also the result of management initiatives that have saved customers billions of dollars.

III. COMMISSION POLICY ON GRADUALISM AND INTERVENOR PROPOSALS FOR ALLOCATING THE REVENUE INCREASE

Q. Witnesses Baron, Pollock and Alderson each take issue with FPL's allocation of revenue increases and the application of gradualism. Please explain the concept of gradualism as it applies to the allocation of revenue increases for rate design.

A. The Commission has made clear its goal that rates should be based on the fully allocated cost-of-service ("COSS") method with the objective of achieving parity among rate classes. The Commission also has expressed concerns about any rate class receiving an overly-large revenue requirement increase and has created a guideline, referred to as gradualism, to address those concerns. The concept of gradualism, as applied in Florida, limits the revenue increase for each rate class to 1.5 times the system average increase in total operating revenues, including adjustment clauses, and provides that no rate class be decreased.

In the FPSC Order that first instituted the rate increase limit guideline (Order No. 10306 issued September 1981 in Docket No. 810002-EU), the Commission stated: "All parties in this proceeding agree that the revenue increase should be allocated between classes so as to move toward an equalized rate of return for all classes. While we embrace this concept, we feel the impact on customers' bills must be considered in allocating revenues." The Commission articulated its guideline for addressing bill impacts that "[n]o customer class shall receive a revenue increase greater than 1.5 times the system average increase as a result of this proceeding." (p. 106-107). In subsequent orders the Commission has made it clear that the calculated 1.5 times increase is based on *total* revenues.

Q. Has FPL applied the Commission's guidelines on revenue allocation and gradualism correctly?

A. Yes.

Q. Please explain.

A. The rates FPL has proposed in this case appropriately reflect the allocated costs by rate class, move all classes closer toward an equalized rate of return (i.e., parity) while limiting the increase to each class to no more than 1.5 times the system average based on total operating revenues including clause revenues. For 2017, FPL has requested an 8.2% increase in total revenues in this case. Under the gradualism guideline, any increase to a rate class is limited to 1.5 times 8.2%, or 12.3%. As shown on Minimum Filing

Requirement (MFR) E-8, under FPL's proposed rates, no class will receive an increase of more than 12.3% in total.

Q. Witnesses Pollock and Baron also assert that gradualism should be measured by excluding clause revenues in the calculation, and witness Alderson asserts that the calculation should exclude revenues from the fuel clause. Do you agree with those assertions?

A. No. The Commission has stated explicitly in other orders that revenues from adjustment clauses are to be included in the gradualism calculation. In FPL's most recent fully litigated rate case, Order No. PSC-10-0153-FOF-EI issued March 17, 2010, in Docket No. 080677-EI, the Commission stated: "Consistent with our decisions in more recent electric rate cases, we find that in this case no class shall receive an increase greater than 1.5 times the system average percentage increase in total, i.e., *with adjustment clauses*, and no class should receive a decrease." (Emphasis added) (p. 179).

Witness Pollock argues that clause revenues should not be used in the gradualism calculation and then quotes a Commission order that contradicts his argument. He quotes from a recent Tampa Electric Company case, Order No. PSC-09-0283-FOF-EI, which states unequivocally that: "No class should receive an increase greater than 1.5 times the system average percentage increase *in total*, and no class should receive a decrease." (Emphasis added) (p. 87).

Q. Has the Commission ever applied the concept of gradualism exclusive of clause revenue?

A. No, it has not, a fact that witness Baron acknowledges. Mr. Baron states that "it is true that the Commission required FPL to include all clause revenues in the application of the '1.5 times' adjustment in the 2009 FPL rate case." He goes on to recommend that the Commission "consider modifying this mitigation protocol to exclude clause revenues in the determination of whether the increase to any rate schedule is excessive and would constitute rate shock." His argument demonstrates that not including clauses would be in direct contradiction of Commission guidelines and to do as he suggests would require a change in policy; it also demonstrates that the guideline is broadly understood to include clause revenues. Excluding clause revenues would distort the proper application of gradualism, impede the movement of several rate classes toward parity (significantly reducing the likelihood of ever achieving parity for those classes) and continue inter-class subsidies that benefit one class of customers over another.

Q. Witness Pollock asserts on page 39 of his testimony that "gradualism is typically measured on the revenues generated from electricity sales, not revenues from other sources." Do you agree with his assertion?

A. No. Witness Pollock does not provide support for this statement and it is not supported by prior Commission orders. Furthermore, witness Pollock's calculations are incorrect. On page 36 of his testimony, witness Pollock states that only base sales revenues should be included in gradualism calculations by

referencing data from his exhibit JP-5. Exhibit JP-5 shows base revenue increases from sales and percentages as filed in FPL's MFR E-13A. MFR E-13A is not the appropriate source for the base revenue portion of gradualism calculations as the increases shown are not by rate class and do not include changes in other operating revenues such as miscellaneous service charges, unbilled revenues and CILC/CDR offset revenues and other revenues by rate class.

The proper source for total present base operating revenues by rate class is MFR E-5, line 25 and the proper source for proposed base revenue increases by rate class is MFR E-5, line 44. The final proposed base operating revenue increases from MFR E-5 include revenues from base rates, changes in miscellaneous service revenues, unbilled revenues and CILC/CDR offset revenues. FPL has consistently used and the Commission has accepted MFR E-5 as the source of total base revenues to be used in applying the gradualism guideline.

Q. Are there other Commission orders that support FPL's calculation of the gradualism guideline?

A. Yes. The Commission has consistently held that the gradualism guideline should be based on 1.5 times the system average percentage increase, in total, including adjustment clauses. (See Order No. PSC-08-0327-FOF-EI, issued May 2008 in Docket No. 070304-EI; Order No. PSC-09-0283-FOF-EI, issued April 2009 in Docket No. 080317-EI; Order No. PSC-10-0153-FOF-EI issued

March 2010 in Docket No. 080677-EI; and Order No. PSC-13-0443-FOF-EI issued September 2013 in Docket No. 130040-EI).

Q. Witnesses Pollock and Baron both assert that FPL has improperly applied the gradualism concept in this case because FPL has ignored the impact of resetting the CILC/CDR credits. Do you agree with their assertions?

A. No, I do not agree. The credit reset is entirely consistent with the Commission's guideline and also with how the credits and credit offset revenue reductions were treated in the 2012 Settlement Agreement. The current revenue recovery assigned to CILC/CDR customers includes both base rates paid by CILC/CDR customers and the credit offset revenues paid by all customers.

The Commission's gradualism guideline is assessed in terms of *revenues* required to be recovered from a rate class and resetting the credits does not change that revenue responsibility. The decrease in the credit offset revenues does not change the current revenue responsibility of the CILC/CDR customers. Rather, it changes the customers from whom that revenue is to be recovered. Therefore, a change in the *source* of the revenue recovered does not change the *method* of calculating gradualism.

It is appropriate to start with current class revenues from all sources in the calculation of gradualism to measure the 1.5 times system average limitation

on additional revenues. It would be incorrect to treat the reduction in CILC/CDR credits as a revenue increase and treating it as such unfairly allocates a larger portion of the overall increase to other customer classes.

Q. At page 42 of witness Pollock's testimony which references exhibit JP-8, Mr. Pollock proposes an alternative class revenue allocation. Is his proposal an appropriate application of the gradualism guideline?

A. No. Witness Pollock has improperly removed other revenues and not included the credit offsets to arrive at his revenue allocation. Witness Pollock included similar alternative revenue allocations in FIPUG's interrogatory numbers 21 and 88. FPL responded to those requests by pointing out that FIPUG's use of "Sales Revenue at Present Rates Including Clauses" for gradualism calculations "is incorrect because it only includes revenues from base rates and clauses and does not include unbilled revenues, revenues from service charges, and CILC/CDR credit offset revenues."

Further his calculation is inappropriate because he allocates all of the revenue shortfall to the remaining customers *equally* instead of following the COSS and addressing parity considerations.

Q. At page 44 of his testimony, witness Pollock states: "If however, the Commission approves less than 33% of FPL's proposed base revenue increase or decrease, it should be spread equally to all customer classes." Do you agree with witness Pollock's proposal?

A. No. Regardless of the amount of revenue increase, any increase should be spread to all customer classes based on COSS allocations while also considering the Commission's gradualism guidelines.

Q. On page 59 of SFHHA witness Baron's testimony, Table 12 presents an alternative calculation of percentage increases for the CILC-1D rate class. Do you agree with witness Baron's approach?

A. No. His chart is based on an improper application of the Commission's gradualism guideline. As previously stated, it is incorrect to treat the reduction in CILC/CDR credits as a revenue increase. Additionally, some of the items in witness Baron's Table 12 are misleading as explained in Exhibit TCC-7. Because Table 12 only shows amounts for the CILC-1D rate class, there should be no mention of the CDR credit as the CDR is not applicable to the CILC rate schedule.

IV. RATE DESIGN FOR DEMAND-BASED RATES

Q. Witnesses Pollock and Chriss each take issue with FPL's calculations for demand and energy charges for the GSLD(T)-1 rate classes. Please explain FPL's approach to rate design for demand and energy charges in this case.

A. FPL began with present demand and energy rates and increased those rates by the same percentage to maintain the current relationship between demand and energy rates. FPL then adjusted on-peak energy charges to ensure revenue

neutrality and to achieve target revenues. This approach was used in consideration of rate stability and the impact on customers with differing load factors with which this Commission has expressed concerns. In FPL's last fully litigated rate case, the Commission's order stated: "However, consideration of rate stability and rate shock are also important considerations in rate design. Increases in the demand charge impact low load factor customers to a greater extent than high load factor customers because they are less able to offset the higher demand costs with lower energy costs and are thus less able to affect their total bill." (Order No. PSC-10-0153-FOF-EI, issued March 2010 in Docket No. 080677-EI, page 189).

The approach FPL uses can be applied consistently across rate classes and it provides rate stability, avoids drastic changes in demand and/or energy charges, and maintains current price signals between on- and off-peak energy charges.

Q. Please comment on witness Pollock's and Chriss's assertions regarding the pricing of demand charges.

A. Both witnesses assert that demand charges should be set closer to unit cost. Following strict unit cost in setting demand rates would distort the relationships between the general service demand classes and make it difficult to achieve target revenues while maintaining time-of-use ("TOU") design goals and principles. Setting demand rates closer to unit cost would recover less cost from energy charges making it difficult to provide meaningful price

signals between on- and off-peak energy charges. Also, as noted in Order No. PSC-10-0153-FOF-EI, large increases in the demand rate would adversely impact low load factor customers.

Q. Please comment on intervenor assertions that FPL's proposed rate design differs from how FPL calculated demand and energy charges in past rate cases.

A. FPL's proposal is consistent with FPL's proposals in past rate cases; however, FPL refined the process for developing rates. In this case, FPL started with present demand charges and increased them by the same percentage as energy charges based on the target revenues needed from the rate class. In prior cases, FPL started with demand unit cost and adjusted them down to maintain the same relationship between demand and energy changes and to mitigate the impact to low load factor customers. The end result is the same, proposed demand charges remain lower than unit cost.

Also for energy charges, FPL began with present rates and applied the same percent increase to both the on-peak energy charge and the off-peak energy charge to maintain the TOU price signal embedded in TOU energy rates. This is consistent with past Commission guidance. In Order No. PSC-10-0153-FOF-EI, Docket No. 080677-EI, page 190, the Commission stated: "However, it is reasonable, as a proxy, to maintain the current differential between on- and off-peak ratios to prevent unexpected impacts on existing TOU customers who have adapted their usage to this ratio."

The percent increase methodology that FPL utilized mitigates the impact of rate increases on low load factor customers and is a reasonable and thoughtful approach to balance the needs of all customers. Additionally, FPL continues to offer High Load Factor Time of Use ("HLFT") rates for those customers that prefer a higher demand charge coupled with a lower energy charge.

Q. Why does FPL think it is appropriate to set off-peak energy charges higher than unit cost?

A. For the GSD(T) and GSLD(T) rate classes, FPL's current and proposed rate design uses the same demand charge for both the standard rate schedule and the corresponding TOU rate schedule, with the TOU demand charge only applying to demand occurring in the on-peak period. TOU customers pay no demand charge for demand occurring in off-peak periods. Consequently, customers with little or no on-peak usage only pay the off-peak energy charge for their energy usage, avoiding all demand charges. Florida's other investor-owned utilities include a maximum demand charge as part of their TOU rates to recover demand distribution costs. FPL does not have a maximum demand charge, and as a result has proposed a higher off-peak energy charge to recover a portion of demand distribution costs through the off-peak energy charge. By increasing on- and off-peak energy charges by the same percentage, the proposed rates maintain the current price signal between on- and off-peak energy rates.

Q. Witness Pollock provides a table on page 65 of his testimony comparing unit costs to present and proposed energy charges. Do you agree that his table is an accurate representation of unit costs and present rates?

A. No. Witness Pollock's table uses unit costs based on the 12CP and 1/13th COSS method. FPL used the 12CP and 25% COSS method for proposed rates. Witness Pollock's chart is misleading in that it shows a much lower energy unit cost than was included in MFR E-6b based on the proposed COSS.

Q. Can you comment on witness Pollock's recommendation that the current GSLD(T) and CILC energy charge increases should not exceed 50% of the increase in the demand charge?

A. As stated earlier, FPL maintained the current relationship between demand and energy rates to mitigate the impacts on lower load factor customers and offers the HLFT rates for customers who prefer a higher demand charge coupled with lower energy charges.

Q. Do you agree with witness Chriss's recommendation that GSLD-1 and GSLD(T)-1 demand charges should be set at 90% of the demand unit cost (as shown on page 28 of his testimony, Table 2) and that GSD-1 and GSD(T)-1 demand charges should be set at 85% of the demand unit cost (as shown on page 32 of his testimony, Table 4)?

A. No. For 2017, witness Chriss's recommendations would result in a $4.55 per kW (46%) increase in demand charges for GSLD(T)-1 customers and a $3.53 per kW (41%) increase in demand charges for GSD(T)-1 customers. FPL's

proposed rates would result in a $2.64 per kW (27%) increase in demand charges for GSLD(T)-1 and a $1.70 per kW (20%) increase in demand charges for GSD(T)-1. In contrast to witness Chriss's proposals regarding these rates, FPL's proposals consider the impact that higher demand charges have on low load factor customers. As stated previously, FPL's approach adheres to the Commission's decisions on this issue in past rate cases, and customers that prefer a higher demand charge can take service under the HLFT rate schedule.

Q. Witness Alderson states on page 29 of her testimony that "The Company's proposed base rate charges for the three CILC rate sub-classes for the 2017 Test Year and 2018 Subsequent Year are economically illogical, do not provide appropriate efficient price signals, and are not reflective of the Company's own COSS results." Do you agree with this assertion?

A. No. This statement is based on the inaccurate assumption that all CILC rates are derived from one revenue requirement that is allocated among three sub rate classes. In fact, there are three separate CILC rate classes each with a separate revenue requirement, a separate rate of return and a separate parity index. Additionally, each rate class is subject to the gradualism calculation, separately and independently of the other CILC rate classes.

At equalized revenue requirements, witness Alderson is correct that unit costs per MFR E-6b, 12CP and 25%, Attachment 1 of 2, page 1 of 6, line 14, are

lower for the CILC-1T rate class as compared to the CILC-1D rate class. However, proposed rates are based on revenue requirements adjusted for gradualism rules that limit rate class revenue increases to no more than 1.5 times the system average increase. After adjustments for gradualism, the CILC-1T rate class received the majority of its allocated revenue increase while the CILC-1D rate, because of gradualism, did not receive the full amount of the allocated revenue increase. This is demonstrated in FPL's filing on MFR-14, Attachment 2, page 31, columns 13 and 14 continued on page 32, columns 15 through 18. FPL then used the percent increase method to allocate the increases by rate class to demand and energy charges.

Additionally, setting demand rates to match CILC-1D and/or CILC-1T unit cost and moving the difference to energy rates, as suggested by witness Alderson, is not appropriate because it results in a significant increase to the energy rates in the CILC-1T rate class. Applying the same percentage increase to demand and energy maintains the current relationship between demand and energy rates and provides a consistent approach for applying increases.

Q. Do you have any other comments on her testimony?

A. Yes. There are inconsistencies between the data provided in witness Alderson's exhibits and FPL's filing. First, present rates as shown in witness Alderson's testimony on page 30 in Table 4, do not include the West County 3 adjustment included in present rates as filed in MFR E-13C, pages 2 – 4. Ms.

Alderson provides no explanation for why the rates used in Table 4 are different from FPL's proposed rates.

Second, Table 5 on page 32 of witness Alderson's testimony contains unit costs from the 12CP and 1/13th COSS method and not the 12CP and 25% COSS method on which FPL's proposed rates are based. These inconsistencies skew witness Alderson's comparisons of the COSS to proposed rates.

Q. Do you agree with witness Chriss's recommendation on page 33 of his testimony that "If the Commission approves the 2019 Okeechobee LSA, for rate schedules that contain demand charges, the increase to those schedules should only be applied to the demand charge"?

A. No. Witness Chriss's testimony appears to take issue with the rate design aspect of FPL's proposed approach to the Okeechobee LSA and not the allocation of the increase. The method proposed by witness Chriss once again increases demand charges disproportionately to energy charges and adversely impacts low load factor customers. FPL's proposed method for the Okeechobee LSA increases all rates by an equal percentage. The method used in FPL's filing is administratively efficient, and has been used and accepted by the Commission for Turkey Point 5, Canaveral, Riviera and Port Everglades modernizations.

V. RATE DESIGN FOR RESIDENTIAL CUSTOMER CHARGES

Q. Witness Brosch opposes the $2 increase in the customer charge for residential customers (RS-1) to recover a portion of fixed distribution costs and cites public policy reasons for keeping the customer charge low. Do you have any comments on those considerations?

A. Yes. First, a basic guideline of electric utility rate design is the idea that costs that do not vary with usage should be recovered through a fixed charge (e.g., customer or demand charge), and costs that vary with usage should be recovered through a variable charge. The costs of the distribution system needed to serve customers are largely fixed, in the sense that they do not vary with energy consumption. For customers other than residential and small commercial customers, these costs are generally recovered through a demand charge (to the extent practical considering all rate design goals) which more closely aligns with the fixed nature of these costs. For residential and small commercial customers, these fixed costs are recovered through a variable energy (kWh) charge.

As I stated in my direct testimony, the $2 increase in the customer charge represents approximately 10% of fixed distribution costs currently being recovered through a variable kWh charge. Moving this amount of fixed costs to a fixed charge is a modest step in aligning rates with costs, while minimizing bill impacts.

Regarding the policy considerations witness Brosch lists, those are certainly important considerations in developing rates, but they are not the only items that should be considered and they should not be considered in a vacuum. Other public policy considerations include costs to serve the class, consumption and load characteristics of the class, and revenue stability and continuity. The considerations Mr. Brosch specifies, i.e., affordability, control over monthly bills, the encouragement of energy conservation and the payback on energy efficiency investments, were considered in the proposal to add $2 to the customer charge.

Regarding affordability, FPL is always mindful of managing its business to ensure we deliver safe, efficient, reliable service at fair and reasonable prices. Further, FPL chose a modest increase in the customer charge in recognition of the impact proposing a full recovery of fixed costs through a fixed charge would have on lower usage customers.

Appropriate energy conservation and investments in energy efficiency will continue to be encouraged under FPL's proposed customer charge. Customers who use more energy will still pay a higher bill and the cost for energy usage above 1,000 kWh will still be higher, both of which will encourage energy conservation and efficiency.

VI. CILC & CDR RATES AND CREDITS

Q. Can you briefly describe the history of the CILC Rate Schedule and the CDR rider ("CILC/CDR credits")?

A. Yes. The CILC rate schedule was first implemented on a trial basis in 1986 (Order No. 18259, issued October 1987, Docket No. 861403-EG) and was made a permanent program in 1990 (Order No. 22747 issued March 1990, Docket No. 891045-EG). In 1995, participation in the rate was limited to existing customers and those who had entered into a CILC agreement (Order No. PSC-96-0468-FOF-EG issued April 1996, Docket No. 960130-EG) and the rate schedule was closed in 2000 (Order No. PSC-99-0505-PCO-EG issued March 1999, Docket No. 990002-EG).

The CDR credit was originally established by the Commission in 2000 (Order No. PSC-00-0915-PAA-EG, issued May 2000, Docket No. 991788-EG) and was continued through subsequent Demand Side Management ("DSM") proceedings. The CDR program is open to customers in the General Service Demand and Large Demand rate classes.

Q. Is it correct that these CILC/CDR credits are part of FPL's DSM program?

A. Yes. These rate schedules were approved and implemented under the authority of Section 366.82, F.S., and are part of FPL's DSM programs.

Q. When was the current level of CILC/CDR credits set?

A. The current level of credits were set as part of the 2012 Settlement Agreement approved by the Commission in Docket No. 120015-EI.

Q. Did FPL propose the current level of CILC/CDR credits as part of its petition in the 2012 rate case, Docket No. 120015-EI?

A. No. FPL did not propose any changes to the CILC/CDR credits.

Q. Why didn't FPL propose a change in the CILC/CDR credits as part of its 2012 rate case?

A. As stated in Ms. Deaton's testimony in the 2012 rate case, the CILC and CDR programs are conservation programs initiated as part of FPL's DSM plan, and the proper venue for addressing these programs is in a DSM plan docket.

Q. Would you explain how the current level of CILC/CDR credits came about?

A. Yes. The current level of the CILC/CDR credits were agreed to by FPL and approved by the Commission as one aspect of a multi-faceted 2012 Settlement Agreement.

Q. What is FPL proposing in this case with regard to the CILC/CDR credits?

A. As explained in my direct testimony, FPL proposes to reset the CILC/CDR credits to pre-settlement levels, adjusted for base rate increases for the Canaveral, Rivera, and Port Everglades modernizations. Simply resetting the credits to the levels that existed prior to the 2012 Settlement Agreement would not have taken into account the amount by which the credits would have

grown as a result of the base rate increase for the modernizations. This ensures equitable treatment for load control customers.

Q. Why is FPL proposing to reset the CILC/CDR credits in this case?

A. A key goal of rate design is to ensure fair and equitable rates. The revenues from the CILC/CDR credits, including the revenue from the increased level of these credits during the term of the 2012 Settlement Agreement are recovered through the Energy Conservation Cost Recovery ("ECCR") clause and are paid for by all customers. It would be inequitable to the other customers to extend the current level of credits beyond 2016. As shown in TCC-5, the customers receiving the CILC/CDR credits already pay rates that are well below their cost of service.

Q. How is proposing to reset the CILC/CDR credit level as part of this rate case consistent with FPL's position in prior cases that the appropriate venue for addressing the level of CILC/CDR credits is in a DSM Docket?

A. It is entirely consistent with FPL's position in prior cases. As I have explained, the current level of credits was not proposed in FPL's original filing, rather it was part of a multi-faceted settlement agreement. Any modification to the credit levels filed by FPL in this proceeding should be properly considered in the Commission's next DSM Goals/Plan proceeding along with all of FPL's demand response programs to determine the appropriate level of conservation to be paid for by all customers.

Q. Didn't the Commission approve the current level of CILC/CDR credits in the most recent DSM Docket?

A. Yes. In the 2014 DSM Plan docket, pursuant to the Final Order Approving the 2012 Rate Case Settlement, FPL requested and the Commission approved the use of the credit levels previously approved by the Commission for the four year term of the 2012 Settlement Agreement. For FPL not to request and the Commission not to approve the credits from the 2012 Settlement Agreement would have had the effect of not honoring the terms of the 2012 Settlement Agreement.

VII. PROPOSAL FOR DISTRIBUTION SUBSTATION SERVICE

Q. Witness Pollock states that FPL should offer distribution substation service. Do you agree?

A. No. As explained by witness Miranda in response to FIPUG's 4th Set of Interrogatory Requests, No. 85, (attached as Exhibit TCC-8) the primary distribution system is a network that functions to serve all distribution customers, therefore the costs are allocated to all distribution customers. In cases of a substation outage, customers may be served from alternate substations.

Q. What would be required to offer a distribution substation service tariff?

A. FPL would be required to incur significant administrative costs to set up such a tariff. A new customer class would need to be established for load research to support cost of service allocations. A new rate would require costly changes to FPL's systems for billing, accounting, and reporting purposes.

Q. Have any customers requested that FPL offer distribution substation service?

A. No. I am not aware of any customers requesting this service or any that would take such service if it were available.

Q. Do large primary demand customers served directly from a substation have alternatives that allow them to avoid distribution costs?

A. Yes. FPL offers these customers the option to take transmission level service and thereby avoid all distribution costs by entering into either (1) a Long-Term Rental Agreement for Distribution Substation Facilities ("Distribution Substation Rental Agreement"), FPL Tariff Sheet No. 9.730, or (2) a Facilities Rental Service Agreement, FPL Tariff Sheet No. 9.750.

The Distribution Substation Rental Agreement allows customers served directly from a substation to rent their portion of the substation through monthly payments. The Facilities Rental Service Agreement gives customers the option to make a lump sum payment for the substation in lieu of monthly payments. The rental agreements directly assign the customer's portion of the cost of the substation to the customer. In the cases of multiple customers served from a single substation, costs are allocated among those customers. FPL has eight distribution substation rental customers, and three customers that have contracted under the Facilities Rental Service Agreement.

Also in my direct testimony on page 23, FPL requested to remove the 2,000 kW demand requirement for transmission level service so that a customer of any size served directly from a substation may qualify for transmission level rates simply by entering into the Distribution Substation Rental Agreement. There is no reason to require the company to incur additional costs to develop a new class of service, new tariffs, and incur significant billing costs on the hypothetical assumption that a few customers may request this service when customers have two options that allow them to take service under transmission rates and avoid all distribution costs, other than their share of the substation costs.

VIII. FPL'S LOW RESIDENTIAL BILL

Q. What is the purpose of Exhibit TCC-2?

A. The purpose of Exhibit TCC-2 is to show a projection of residential and four typical Commercial and Industrial customer bills through the four years of FPL's rate proposal.

Q. Can you explain how the information for Exhibit TCC-2 was developed?

A. Yes. Exhibit TCC-2 uses the projected base rates as calculated in MFR E-13c and the projected clause rates from FPL's forecast.

Q. Do you have any comments on witness Brosch's and witness Lawton's claims that gas price trends from 2006 to 2016 contributed significantly to FPL's historically favorable bill impacts?

A. Yes. As explained by witnesses Forrest and Kennedy, lower gas prices alone do not account for FPL's low customer bills today. It is because of FPL's commitment to smart investments and modernization of our generating fleet that our customers are saving billions of dollars today and have electric bills that are among the lowest in the state of Florida. It is important to note that, if low natural gas prices were the main reason that FPL's bills are lower today than 2006, then many utilities around the country and in the Southeast should have experienced the same trend, i.e., lower bills in 2016 versus 2006. In fact, just the opposite is true. As stated in my direct testimony, since 2006, FPL's typical residential bill has actually ***decreased*** 14%, while the national average typical bill has increased by 29%. More recent data shows the national average typical residential bill has increased by 24% from 2006 to 2016 (EEI data published April 2016). As demonstrated in Exhibit TCC-9, compared to FPL's peer group of major Southeastern Investor-Owned Utilities, only 3 (including FPL) out of 15 utilities have lower rates today than 2006. FPL's residential bill is the lowest in the state of Florida, 20% below the Florida average and 30% below the national average. This is a significant accomplishment – one that has provided tremendous value for FPL's customers.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Table 12 - SFHAA witness Baron
Calculation of Percentage Increases for Rate Schedule CILC-1D

Line No.	Column	MFR E-14 - Base Rate	MFR E-8 As-Filed w/o Clauses	MFR E-8 As-Filed with Clauses	Baron Table 11 w/o and with Clauses	
		A	B	C	D	
1	**Present Revenues**				**w/o**	**with**
2	Rate Sched Revenue (before CDR credit)[1]	87,717,549	87,717,549	87,717,549	87,717,549	87,717,549
3	CDR Credit[1]	(27,075,627)	(27,075,627)	(27,075,627)	(27,075,627)	(27,075,627)
4	Net Base Rate Sched Revenue	60,641,923	60,641,923	60,641,923	60,641,923	60,641,923
5	CILC Credit Offset (add-back CDR credit)[1]		27,075,627	27,075,627	27,075,627	27,075,627
6			87,717,549	87,717,549	87,717,549	87,717,549
7	Unbilled and Other Revenues		1,708,169	1,708,169	1,708,169	1,708,169
8	Total Operating Revenues		89,425,718	89,425,718	89,425,718	89,425,718
9	Clauses		-	110,216,026	-	110,216,026
10	Total Revenue with Clauses		89,425,718	199,641,744	89,425,718	199,641,744
11						
12	**Proposed Revenues**					
13	Rate Sched Revenue (before CDR credit)[1]	112,346,055	112,346,055	112,346,055	112,346,055	112,346,055
14	CDR Credit[1]	(27,075,627)	(27,075,627)	(27,075,627)	(27,075,627)	(27,075,627)
15	**CDR Credit Reduction ("Reset" Increase)[1]**	**9,943,455**	**9,943,455**	**9,943,455**	**9 ,943,455**	**9,943,455**
16	Net Base Rate Sched Revenue	95,213,883	95,213,883	95,213,883	95,213,883	95,213,883
17	CILC Credit Offset		27,075,627	27,075,627	27,075,627	27,075,627
18	**Remove Effect of Credit Reduction[2, 3]**		**(9,943,455)**	**(9,943,455)**		
19	Unbilled and Other Revenues		1,713,077	1,713,077	1,713,077	1,713,077
20	Total Operating Revenues		114,059,132	114,059,132	124,002,587	124,002,587
21	Clauses		-	110,216,026	-	110,216,026
22	Total with Clauses		114,059,132	224,275,157	124,002,587	234,218,613
23	**Increase**	**34,571,961**	**24,633,413**	**24,633,413**	**34,576,869**	**34,576,869**
24	**% Increase**	**57.01%**	**27.55%**	**12.34%**	**38.67%**	**17.32%**

FPL Comments:

[1] The titles in lines 2,3,5,13, 14 and 15 should not reference CDR credits as this chart includes only credits built into CILC-1D base rates.

[2] Line 18 is titled "Remove Effect of Credit Reduction" which is misleading. This line would be more accurately described as "Decrease in Credit Offset Revenues Collected through the Conservation Clause."

[3] Line 18 does not include an amount for column D. To be correct, $9,943,455 should be subtracted to decrease the credit offset revenues collected through the conservation clause. Using the correct calculation results in the same numbers shown in columns B and C.

While witness Baron's treatment of the CILC credits and credit offset revenues are correct for Present Revenues, he does not apply the same calculation to Proposed Revenues. Witness Baron includes a $9,943,455 reduction in the credit in line 15, column D, but does not include the offsetting reduction in revenues to be received through the conservation clause in line 18, column D.

Florida Power & Light Company
Docket No. 160021-EI
FIPUG's Fourth Set of Interrogatories
Interrogatory No. 85
Page 1 of 1

QUESTION:
Referring to FPL's Response to FIPUG's Interrogatory No. 17, for those distribution level customers that are served directly from, or within, one span of an FPL-owned substation:

a. Does FPL allocate primary distribution plant downstream of the substation (e.g., poles, towers, fixtures and overhead conductors) to these customers?
b. If the response to part a is yes, please explain how this is consistent with cost causation.
c. Please explain why FPL does not track these customers.

RESPONSE:

a. Yes
b. The primary distribution system is a network that functions to serve all distribution customers, therefore the costs are allocated to all distribution customers. In cases of a substation outage, customers may be served from alternate sources.
c. FPL has not had a business need to track these customers.

Typical 1,000-kWh Residential Customer Bill Comparison 2006 - 2016

Major Southeastern Investor-Owned Utilities	January 1, 2006	July 1, 2015	% Change from 2006	January 1, 2016	% Change from 2006
Florida Power & Light (FL)	$108.61	$97.21	-10%	$93.38	-14%
Duke Energy Progress (SC)	$90.82	$102.53	13%	$106.10	17%
Entergy Mississippi (MS)	$127.98	$108.25	-15%	$99.89	-22%
Tampa Electric (FL)	$109.61	$108.47	-1%	$106.22	-3%
Duke Energy Carolinas (NC)	$80.86	$108.90	35%	$107.11	32%
Dominion Virginia Power (VA)	$85.28	$113.20	33%	$111.34	31%
Appalachian Power (VA)	$61.39	$113.40	85%	$114.83	87%
Duke Energy Carolinas (SC)	$74.71	$117.05	57%	$116.57	56%
Duke Energy Progress (NC)	$87.29	$118.18	35%	$106.81	22%
Duke Energy Florida (FL)	$109.56	$121.59	11%	$114.15	4%
Alabama Power (AL)	$88.76	$130.77	47%	$124.15	40%
Mississippi Power (MS)	$96.56	$136.18	41%	$132.34	37%
Georgia Power (GA)	$76.33	$136.76	79%	$109.24	43%
Gulf Power (FL)	$92.48	$139.29	51%	$135.58	47%
South Carolina Electric & Gas (SC)	$96.49	$148.41	54%	$148.27	54%
Average	$92.45	$120.01	30%	$115.07	24%
National Average	$106.19	$137.29	29%	$132.12	24%

Source: EEI Typical Bills and Average Rates Report

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF TERRY DEASON

DOCKET NOS. 160021-EI; 160062-EI

AUGUST 1, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Terry Deason. My business address is 301 S. Bronough Street, Suite 200, Tallahassee, Florida 32301.

Q. By whom are you employed and in what capacity?

A. I am employed by the Radey Law Firm as a Special Consultant specializing in the fields of energy, telecommunications, water and wastewater, and public utilities generally.

Q. Please describe your educational background and professional experience.

A. I have thirty-nine years of experience in the field of public utility regulation spanning a wide range of responsibilities and roles. I served as a consumer advocate in the Florida Office of Public Counsel ("OPC") on two separate occasions, for a total of seven years. In that role, I testified as an expert witness in numerous rate proceedings before the Florida Public Service Commission ("Commission" or "PSC"). My tenure of service at OPC was interrupted by six years as Chief Advisor to Florida Public Service Commissioner Gerald L. Gunter. I left OPC as its Chief Regulatory Analyst when I was first appointed to the Commission in 1991. I served as Commissioner on the Commission for sixteen years, serving as its chairman on two separate occasions. Since retiring from the Commission at the end of 2006, I have been providing consulting services and expert testimony on

behalf of various clients, including public service commission advocacy staff and regulated utility companies. I have also testified before various legislative committees on regulatory policy matters. I hold a Bachelor of Science Degree in Accounting, summa cum laude, and a Master of Accounting, both from Florida State University.

Q. Are you sponsoring an exhibit?

A. Yes. I am sponsoring the following rebuttal exhibit:

- TD-1, Biographical Information for Terry Deason

Q. For whom are you appearing as a rebuttal witness?

A. I am appearing as a rebuttal witness for Florida Power & Light Company ("FPL" or "the Company").

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to certain assertions and recommendations in the testimony of: South Florida Hospital and Health Care Association ("SFHHA") witnesses Baudino and Kollen, Office of Public Council ("OPC") witnesses Lawton, Schultz and Smith, Florida Industrial Power Users Group ("FIPUG") witness Pollock, Federal Executive Agencies ("FEA") witness Gorman, and AARP witness Brosch. The issues I address in rebuttal to these witnesses are: Construction Work In Progress ("CWIP"); Property Held for Future Use ("PHFFU"); Performance Based Compensation; Directors and Officers Liability ("DOL") Insurance; and the Return on Equity ("ROE") Performance Adder.

II. CONSTRUCTION WORK IN PROGRESS

Q. What is CWIP?

A. CWIP refers to assets that are recorded in the Federal Energy Regulatory Commission ("FERC") Account 107 of the Federal Energy Regulatory Commission Uniform System of Accounts ("USOA"). This account includes the total of work order balances for electric plant that is in the process of being constructed.

Q. Is CWIP a necessary part of providing quality utility service?

A. Yes, it is. A well-managed utility focused on providing quality and cost effective service will deploy capital to construct new and/or modernize existing facilities to meet these objectives.

Q. Recognizing that CWIP is a necessary part of providing quality utility service, should it be permitted to earn a return?

A. Yes, it should. Otherwise the utility will not be given an opportunity to realize a fair return on its investment in electric plant. By way of explanation, the return earned by a utility once a plant goes into service compensates the utility for its investment in that plant only from the in-service date forward. The return earned on plant in service does not – and is not intended – to provide any compensation to the utility for its investment in a plant before it goes into service.

Q. How should this be accomplished?

A. It should be accomplished in one of two ways. First, balances in CWIP could be allowed to accrue an Allowance for Funds Used During Construction ("AFUDC"). The Commission has adopted Rule 25-6.0141, Florida Administrative Code ("F.A.C."), which sets forth the calculation of AFUDC and the eligibility requirements of those construction projects which qualify. The second way is to allow CWIP to be included in rate base when rates are set.

Q. Is there a fundamental difference between the two approaches?

A. Yes, there is. Accruing AFUDC adds to the capital costs of a project. The return is an accounting entry only and is actually realized when the capital asset is included in rate base and is depreciated. Including CWIP in rate base avoids increasing the capital cost of the project through AFUDC and instead, provides a return in rates while the project is being constructed.

Q. What does Rule 25-6.0141, F.A.C., say about the return to be earned on CWIP?

A. The Rule recognizes that the return on CWIP can be earned in either of the two fundamental ways that I just described. Further, the Rule establishes the criteria for CWIP projects to be eligible for AFUDC. Generally, to be eligible for AFUDC, a CWIP project must be large in size (greater than 0.5 percent of all existing plant on the books of the utility) and have a long construction time (greater than one year from the project's commencement). CWIP projects not eligible for AFUDC under the rule are generally included in rate base rather

than accruing AFUDC.

Q. Why did the Commission require that CWIP projects be large in size and long in construction duration to be eligible for AFUDC?

A. The Commission recognized that most construction projects are relatively small in size and of short duration. The Commission further recognized that these projects were generally routine and recurring in nature. It was determined that it was not administratively efficient to require the accrual of AFUDC on such projects. Further, due to their routine, recurring nature, they were better addressed as a component of rate base. The overall reasonableness of these projects could then be reviewed in the context of rate cases and surveillance reports.

Q. What is the Commission's policy on the inclusion of CWIP in rate base?

A. The Commission recognizes that CWIP constitutes an investment upon which a return should be allowed. Construction projects ineligible for a return through the accrual of AFUDC are included in rate base. And in some situations, the Commission allows large projects otherwise eligible for AFUDC to be allowed in rate base instead of allowing AFUDC to be accrued. This is done in those situations where a utility's construction program is so large that reliance solely on AFUDC would harm the company's financial integrity.

Q. Does witness Smith recommend a disallowance of any of the CWIP that FPL is seeking to include in its rate base?

A. No. Witness Smith, on behalf of OPC, acknowledges the Commission's policy to provide a return on construction projects ineligible for AFUDC by means of rate base inclusion. While stating some philosophical differences with the Commission's policy, he makes no disallowance in his recommended revenue requirements calculation.

Q. Does witness Kollen recommend a disallowance of any of the CWIP that FPL is seeking to include in its rate base?

A. Yes. Witness Kollen, on behalf of SFHHA, recommends a disallowance of 100% of the amount of nuclear fuel in process ("NFIP"). Instead of including NFIP in rate base, witness Kollen recommends that it be allowed to accrue AFUDC.

Q. Is witness Kollen's recommendation consistent with Commission policy?

A. No. Witness Kollen's recommendation is inconsistent with Commission policy and Rule 25-6.0141, F.A.C. This Rule requires a minimum construction period of one year and a project threshold cost of 0.5 percent of total plant in service, which for FPL is a project threshold cost of approximately $246 million in the 2017 Test Year. The amounts of NFIP for each fuel cycle at each nuclear plant do not meet the Rule's threshold requirements.

Q. Do you agree with witness Kollen's recommendation?

A. No, I do not agree. It would be inappropriate to make such a significant unilateral change to Commission policy that has been adopted through the rulemaking process and codified by rule. At best, his proposal is an attempt to adopt a new policy without the benefit of a thorough evidentiary review and the due process protections of a rulemaking proceeding, a proceeding that would be open to all interested parties and not just those parties to this rate case. At worst, it is an attempt to unjustifiably reduce FPL's revenue requirement in this case and ill-advisedly defer cost recovery to the future.

Q. Witness Kollen argues that his proposal to defer cost recovery to the future is appropriate. Do you agree?

A. I do not agree with his conclusion. I do agree with his statement that "all costs associated with the construction or completion of an asset that is constructed or acquired to provide service should be recovered from customers over the period that the asset provides service to those customers." Witness Kollen has misapplied this concept to conclude that a return on nuclear fuel being processed to insure continuous service to customers should be disallowed in this rate case and deferred to the future. Customers expect and deserve to have sufficient quantities of nuclear fuel available when needed. It is the same as having sufficient quantities of coal in transit and coal located in inventory at a coal plant to assure continuous service to customers from that plant. And given the economics of nuclear generation, it is even more imperative that nuclear fuel be available to serve customers. FPL's

investment in NFIP is absolutely necessary to provide this assurance to customers.

Q. Witness Kollen alleges that allowing NFIP in rate base will result in intergenerational inequity. Is he correct?

A. No, there is no intergenerational inequity because the NFIP is needed to assure existing customers of continuous service from nuclear plants just like coal in transit and coal in inventory is needed to assure existing customers that generation will be available from a coal plant. Ironically, the only way that there would be intergenerational inequity would be for the Commission to adopt witness Kollen's recommendation.

Q. How would witness Kollen's recommendation result in intergenerational inequity?

A. The Commission's consistent application of its policy as stated in Rule 25-6.014 F.A.C. has resulted in an equilibrium of costs over time. Existing customers pay less in their fuel adjustment charges for nuclear fuel as it is consumed, because that fuel cost does not have to include a return on the accrual of AFUDC. At the same time, and again by virtue of the Commission's policy, existing customers' base rates reflect the *inclusion* of NFIP in rate base. Thus there is a balance and equilibrium. Witness Kollen's recommendation would destroy this equilibrium by giving existing customers the benefit of both lower fuel adjustment charges as the nuclear fuel is consumed and avoidance of the obligation of paying a return on NFIP in base rates. In essence, witness Kollen would have existing customers benefited to

the detriment of future customers, who would be obligated to pay higher fuel adjustment charges once the fuel that is accruing AFUDC starts to be consumed.

Q. Witness Kollen references paragraph (1)(g) of Rule 25-6.0141, F.A.C. Are you familiar with this provision?

A. Yes, I am. This provision was added to the Rule in 1996, while I was serving on the Commission. It gives the Commission limited discretion to exclude a portion of CWIP from rate base and allow it to accrue AFUDC instead.

Q. What was the context within which the Commission adopted this provision?

A. The Commission was considering a number of changes to the Rule. The overall purpose of the amendments was to increase the threshold of project qualification in order to limit AFUDC treatment to only those projects with a significant financial impact on any given utility.

Q. Why did the Commission believe this was needed?

A. The Commission was reviewing the thresholds in the context of possible industry restructuring. It was believed that limiting the amount of AFUDC would get regulated costs more comparable to true economic costs and more consistent with Generally Accepted Accounting Principles ("GAAP").

Q. Did the Commission consider the benefits for customers?

A. Yes, the Commission recognized that setting a higher threshold for AFUDC accrual would have the effect of lowering total project costs in rate base and

that this would ultimately lead to lower base rates and a lower likelihood of stranded costs.

Q. Did the Commission consider the possibility that the higher threshold could result in current customers paying for projects that would only benefit future customers?

A. Yes, the Commission considered this and determined that this would not likely be the result of the higher threshold. Commission Staff's recommendation dated April 18, 1996, in Docket No. 951535-EI, Proposed Revisions to Rule 25-6.0141, F.A.C., recognized that large long term construction projects would still accrue AFUDC and that other projects should be in rate base. Staff's recommendation stated:

> However, large, long term projects, such as power plants, will still accrue AFUDC unless the Commission specifically approves inclusion in rate base. Not all construction is solely for the benefit of future ratepayers. There are many projects which are built in order to increase the reliability of service or replace aging or obsolete equipment and facilities. In some cases, facilities in high growth areas reach capacity and must be expanded.

Q. Should paragraph (1)(g) of Rule 25-6.014, F.A.C., be used to approve witness Kollen's proposal to disallow NFIP in rate base?

A. No, it should not. This provision was enacted to give discretion to the Commission to exclude a portion of CWIP from rate base should the

Commission determine that the potential impact on base rates was such that the exclusion may be required. Therefore, before this provision is used to exclude NFIP, the Commission must make a finding that the resulting impact on rates of including the NFIP would be inappropriate or unduly burdensome. Exercising this provision should only be done in truly extraordinary situations.

Q. Has the Commission ever used this provision to disallow CWIP or NFIP projects from rate base?

A. No, not to my knowledge.

Q. Was NFIP allowed in rate base in FPL's last rate case?

A. Yes.

Q. What is the revenue impact of the disallowance suggested by witness Kollen?

A. Witness Kollen calculates the revenue requirements impact to be $40 million for the 2017 Test Year. I have not determined the exact impact of $40 million of FPL's rates, but believe it to be roughly 35-40 cents on a typical, 1,000 kWh residential bill. I do not believe that this would be considered extraordinary such that the utilization of paragraph (1)(g) would be justified.

Q. Does witness Pollock recommend exclusion of any of the CWIP that FPL is seeking to include in its rate base?

A. Yes. Based upon either a total disregard of Commission policy or a misapplication of Rule 25-6.0141 F.A.C., witness Pollock, on behalf of FIPUG, recommends that 100% of FPL's CWIP be excluded from rate base.

Q. What is the basis for witness Pollock's recommendation?

A. Despite the requirements of Rule 25-60141 F.A.C., witness Pollock declares that CWIP is not used and useful and should be included in rate base only in extraordinary circumstances, such as the company's financial integrity being threatened. And in an inexplicable inconsistency, he further opines that the amount of CWIP being sought by FPL is insufficient to create financial stress if it were disallowed, yet is large enough that it would significantly add to rate shock if it were allowed in rate base.

Q. Do you agree that CWIP is not used and useful?

A. No. As contemplated by Commission policy and Rule, CWIP is a necessary component of providing dependable and consistent service for customers. As such, it is used and useful and is entitled to earn a return either through AFUDC or inclusion in rate base. The Rule then establishes what is eligible for AFUDC, with ineligible CWIP being included in rate base. Contrary to witness Pollock's assertion, a showing of extraordinary financial harm is not a requirement to allow rate base inclusion of AFUDC ineligible CWIP.

Q. Does the Commission ever consider financial integrity when deciding the amount of CWIP to include in rate base?

A. Yes. In the relatively rare situation that the amount of AFUDC-eligible CWIP is so large in relation to a company's overall rate base that cash flows become insufficient to meet essential financial metrics, the Commission has allowed some AFUDC-eligible CWIP to be included in rate base. Contrary to witness Pollock's assertion, the Commission's standard is not and never has been one

of requiring a showing of financial harm before AFUDC-*ineligible* CWIP is allowed in rate base. It should be noted that FPL is not seeking the inclusion of any AFUDC-eligible CWIP in rate base. FPL is seeking only to include AFUDC-*ineligible* CWIP in rate base, consistent with Rule 25-6.0141 F.A.C.

III. PROPERTY HELD FOR FUTURE USE

Q. What is PHFFU?

A. PHFFU is the original cost of electric plant owned and held for future use in electric service under a definite plan for such use. It includes both property acquired but never previously used, as well as property used by the utility but retired from service pending its reuse in the future. The original cost amounts are booked in FERC Account 105 Electric plant held for future use, as prescribed by the USOA.

Q. Does FERC Account 105 also include land and land rights?

A. Yes, it does. The parameters for land and land rights are generally the same as those set forth for electric plant in the USOA, with one notable exception.

Q. What is the exception?

A. When describing the types of electric plant eligible for inclusion in FERC Account 105, the USOA includes the term "definite" when describing the plan for its use. In describing the types of land and land rights eligible for inclusion in FERC Account 105, the USOA does not use the term "definite." The USOA simply prescribes that land and land rights be planned for future

electric use.

Q. Why is this a significant distinction?

A. Electric plant is held to a higher standard for inclusion in PHFFU because of the USOA's requirement that there be a definite plan for its future use. In contrast, the USOA recognizes that land and land rights may need to be acquired for possible future use. In other words, the USOA does not prescribe that the land and land rights have a definite future use in order to be treated as PHFFU.

Q. Does this distinction have implications for regulatory policy?

A. Yes, it does. Appropriate and responsible regulatory policy recognizes that, unlike electric plant that usually would be acquired only a short time before it is to be placed into service, land and land rights may need to be acquired many years in advance of their designated use. It would be an inappropriate and unreasonable standard to require all land and land rights to have a "definite" plan for use at the time of initial acquisition. This is not to suggest that regulated utilities should be encouraged to acquire land and land rights in a speculative manner. Certainly all regulatory land acquisitions should be made consistent with a utility's plans to cost-effectively and reliably serve all future demands from its customers.

Q. Has the Commission recognized the need of regulated utilities to acquire property in advance of its designated use?

A. Yes, as early as 1971, the Commission articulated an expanding policy on the inclusion of PHFFU in a regulated utility's rate base. In Order No. 5278,

issued November 30, 1971, in Docket No. 70532-EU, in re: Petition of Tampa Electric Company for an increase in rates and charges and for approval of a fair and reasonable rate of return, the Commission stated:

> This Commission has long recognized that in Florida, public utilities cannot, in the exercise of good business judgment, indefinitely postpone the acquisitions of property necessary to future expansion. In many instances, a deferral of acquisition of necessary property would be very costly and imprudent and the management would be subject to criticism for delay… Until recently, this Commission allowed the inclusion of Property Held for Future Use if it were acquired as a result of a definite plan for its use, and its use was imminent. Since we last considered this matter, there has been a growing controversy over the locating of power plants, both nuclear and fossil fuel, which makes it imperative that we review our policies, practices, and procedures in this area…It is the conclusion of this Commission that so long as the acquisition of the property in question is considered a responsible and prudent investment and it appears that it will be used for utility purposes in the reasonably near future, in the light of prevailing conditions, such land should be included in the Company's rate base.

Q. Does witness Smith address PHFFU in his testimony?

A. Yes, he recommends the disallowance of $14.2 million of PHFFU from FPL's rate base. The majority of his recommended disallowance ($10.0 million) is the cost of sites to either expand existing distribution substations or build new distribution substations. The remaining $4.2 million is the cost of easements for four transmission projects scheduled to be completed in the 2027-2028 time frame.

Q. What is the basis for his recommended disallowances?

A. Witness Smith states, "Property held for future use that is beyond the ten-year planning horizon is not used and useful in providing service to ratepayers." He then tabulates the costs associated with all PHFFU projects with expected in-service dates beyond 2026 to determine the amount of his recommended disallowance. His recommendation is not based upon an individual study of each property to determine whether each is reasonably needed over the planning horizon.

Q. Do you agree with witness Smith's recommended disallowances?

A. I do not agree with his recommended disallowances. His use of an arbitrary and fixed time limitation on PHFFU projects is contrary to Commission precedent and contrary to good regulatory policy. If adopted, his recommended disallowances would be inconsistent with the long-range planning requirements which are necessary for the reliable and cost-effective provisioning of service to customers. Witness Smith's recommended disallowances would not be in the customers' best interest.

Q. What is the Commission's policy in regard to PHFFU?

A. The Commission has a policy that has evolved somewhat over time, but has consistently recognized the need for adequate long-term planning and the need to have property available to fulfill service commitments to customers reliably and cost effectively. This is clearly evident from the Commission's 1971 order involving Tampa Electric Company ("TECO") that I earlier cited. In that same order, regarding its decision to allow a future power plant site in rate base and the need for adequate planning, the Commission stated:

> In this regard, failure to provide for the long-range planning necessary for adequate and reliable power supply could well be considered an imprudent act and inconsistent with the public interest.

Q. What is the standard the Commission has applied to determine whether specific future use properties should be included in rate base?

A. The Commission's standard is one of reasonableness or what amount of PHFFU is reasonably needed to cost-effectively provide reliable service to existing and future customers. Applying this standard requires a review of specific properties to determine whether their acquisition and retention are reasonable to provide service over an adequate planning horizon. The Commission's reasonableness standard cannot be determined by arbitrary and rigid time limitations on the properties' ultimate use. To do so would be contrary to Commission policy and ultimately work to the disadvantage of utilities' customers.

Q. In testimony you filed in FPL's 2012 rate case you were asked this same question on the Commission's standard to judge PHFFU and you are giving the same answer now that you gave then, correct?

A. Yes.

Q. Witness Smith quotes your answer in his testimony. Does witness Smith's reliance on your answer change your conclusion?

A. No. The fact remains that witness Smith's recommended disallowance is based on the use of an arbitrary and rigid ten-year time limitation, which is not consistent with the Commission's standard and good regulatory policy. Further, witness Smith has made no review of the need and appropriateness of each individual project. Instead, he simply states that in his opinion FPL has made no showing that the projects "are reasonably needed to provide reliable service to existing and future customers." Whether FPL has made a sufficient showing will depend on the evidence in this record. I note that FPL witness Miranda addresses the need for these projects with greater specificity in his rebuttal testimony.

Q. Has the Commission spoken to the need to make an individual study of properties held for future use?

A. Yes, in Order No. 5619, in Docket No. 71370-EU, the Commission recognized that there is no hard and fast rule to determine the amount of PHFFU to include in rate base. The Commission stated:

> Under past Commission policy, we have recognized that the deferral of acquisition of property for future use to meet

foreseeable needs could be imprudent and costly. Thus, we have no hard and fast rule as to what should be or should not be included but must make an individual study for each tract so held.

Q. Has the Commission previously addressed a proposal to limit PHFFU to an arbitrary ten-year rule?

A. Yes, in a 1992 rate case involving TECO, there was a proposal to apply a ten-year rule to PHFFU. The Commission rejected this approach. In Order No. PSC-93-0165-FOF-EI, the Commission stated:

> Public counsel's witness, Mr. Schultz, applied a 10-year rule to plant held for future use, suggesting that property either owned by Tampa Electric for longer than ten years or whose projected in-service date is greater than ten years in the future should be removed from rate base. We disagree with this methodology because it arbitrarily disallows rate recovery for power plant distribution substation, and transmission substation sites that Tampa Electric plans to use to meet future growth beyond a point in time ten years from now. It is well known that, in Florida, these sites are becoming increasingly more difficult to find, purchase, and permit.

Q. Would the requirement to have a definite plan to use all PHFFU within a ten-year planning horizon be consistent with regulatory goals of reliable and cost efficient service to customers?

No. As I stated earlier, the USOA does not require there to be a definite plan of use with a definite time frame. But more importantly, requiring there to be a specific plan for development within ten years belies the purpose of acquiring property to cost-effectively and reliably provide service to existing and future customers. For a public utility to wait to acquire property, property that often times must possess very specific locational, geologic, hydrologic, and environmental attributes, until the utility has a firmly established plan of development within ten years, could prove costly and could threaten reliability. In fact, waiting could even be considered imprudent as stated by the Commission in Order No. 5619 which I just quoted.

A cardinal virtue of proper planning is not only to anticipate needs but also to maintain options to enable a utility to provide service in an ever changing environment. Requiring a definite plan of development within ten years would be short-sighted, would limit the ability of a utility to adapt to changing circumstances, and could ultimately lead to higher costs. This is why it is better to evaluate each property individually and make an informed judgment of its reasonableness.

Q. Has the Commission addressed the need for property to be acquired and retained prior to there being a specific plan for its use?

A. Yes, the Commission has. In Order No. 5619, the Commission recognized that deferring acquisition of property could be imprudent and costly. The Commission also addressed the growing amount of time lag between the study of a site and when construction begins. The Commission stated:

> In recent years, the lag time has been extended considerably from the time the first study is made until the final approval is given and construction begins. Obviously, it would be folly then to insist that the Company defer the purchase of land for future use until all doubts as to its use have been resolved.

(Emphasis added).

And in Order No. PSC-93-0165-FOF-EI, in Docket No 920324-EI, the Commission included TECO's Port Manatee plant site in rate base, even though there were no current plans for its use:

> Public Counsel argues that Tampa Electric has no current plans for the Port Manatee plant site. Staff agrees that, at the current time, the company has not identified a particular generating unit to be built at the site. However, as discussed before, it will be more difficult to find an alternate plant site in the future. By allowing the Port Manatee site to remain in rate base, Tampa

Electric will already have a viable generating site for future power plants.

Q. If the Commission were to adopt witness Smith's recommended disallowances, would there be consequences?

A. Yes, there would be. Disallowing the costs from rate base, as he recommends, would be tantamount to declaring the properties in question as being unneeded and imprudent to retain. As a consequence, FPL would have to evaluate whether the properties should be retained. While I cannot and do not speak for FPL in this regard, I would expect the properties would be sold. This would mean the properties would no longer be available to serve customers. FPL would then be in the position of acquiring similar properties at some time in the future; assuming similar properties with the same attributes would be available. There would also be a question of the price that would have to be paid at that time.

Q. Has the Commission previously addressed these potential consequences?

A. Yes, in the same order addressing TECO's Port Manatee plant site that I just cited, the Commission stated:

> Power plant sites in Florida are becoming increasingly more difficult to find, purchase, and permit. Tampa Electric has a potential power plant site at Port Manatee. Utilities purchase power plant sites in advance, because the value of the land will generally appreciate at a rate greater than the utility's overall rate of return. If the Commission found that the Port Manatee

site was an imprudent investment and did not allow Tampa Electric to earn a rate of return on the property, Tampa Electric would be encouraged to sell the site now. Tampa Electric would then have to search for, and purchase, another site for a future power plant, at much greater cost.

Q. The case you just referenced specifically addressed a generating plant site. Is it also relevant for transmission and distribution property?

A. Yes, the concepts and principles stated therein also apply to transmission and distribution properties.

Q. Would there be any other consequences of adopting witness Smith's recommended disallowances?

A. Yes, there would be. Aside from the immediate consequence of losing the properties in question as future sites, adopting witness Smith's recommendation would send a message to FPL and other Florida utilities to take a shorter look into the future and be less aggressive in actively seeking and acquiring properties that they believe are needed to cost-effectively and reliably serve their customers. By using either rigid time limitations or imposing a requirement for a definite plan of development, utilities would logically wait longer to acquire needed property and increase the risk of having to acquire less than optimal sites, pay more for the sites that are available, or both. This would not be in the customers' best long-term interest.

Q. Are there additional reasons the Commission should avoid sending such a message to FPL and Florida's other utilities?

A. Yes, there are. There are many dynamics in play which would call for even longer planning horizons, not shorter.

Q. What are these dynamics to which you refer?

A. Over my 39 years of experience in utility regulation, I have observed dynamics which make planning for future demand more difficult yet more essential for customers to be served cost-effectively and reliably. Perhaps most important is the rapid growth Florida has experienced and the reduction in the number of sites available for future development. This dynamic is further compounded by an increase in conservation areas in Florida, increased demands on Florida's limited water resources, an increase in environmental standards and requirements, an escalation of "not-in-my-backyard" concerns from citizens, and more litigation concerning the placement of utility facilities. On top of these dynamics is the fact that the time required to locate, acquire, and get all necessary permits has generally increased.

IV. PERFORMANCE BASED COMPENSATION

Q. What is the recommendation of witness Schultz regarding non-executive performance-based variable compensation?

A. Witness Schultz refers to performance-based variable compensation as incentive compensation and is recommending a disallowance of 100% of non-executive performance based compensation that is tied to what he considers

financial goals and 50% of such compensation that he considers to be tied to operational goals. FPL witness Slattery addresses why his categorization of financial goals as not customer-related is incorrect, as well as the overall reasonableness and necessity of the non-executive performance-based variable compensation. If accepted, the effect of his recommendation would be to deny cost recovery of these costs on a going forward basis.

Q. Do you agree with witness Schultz's recommendation?

A. No, I do not. His recommendation to disallow a significant part of non-executive performance-based variable compensation is inconsistent with sound regulatory policy and basic principles of ratemaking.

Q. How is witness Schultz's recommendation inconsistent with sound regulatory policy and basic principles of ratemaking?

A. A fundamental tenet of sound regulatory policy is to provide recovery of all reasonable and necessary costs incurred to provide service to customers. And a basic principle of ratemaking is to include all such costs as test year expenses in calculating a regulated company's net operating income. Only if the Commission finds that the expenses in question are unreasonable or unnecessary should they be disallowed in calculating the company's revenue requirement.

Another fundamental tenet of sound regulatory policy is to encourage regulated utilities to be efficient and provide high quality service to their customers over the long term. Sacrificing efficiency or quality of service in

the long run to achieve temporary rate reductions is not in the customers' interest. All regulatory decisions have consequences and good regulatory policy results when these consequences are adequately considered.

Witness Schultz's recommendation violates both of these tenets of sound regulatory policy.

Q. Please explain how witness Schultz's recommendation violates the tenet of recovery of reasonable and necessary costs.

A. Witness Schultz has made no allegations or presented any evidence that the total compensation paid to FPL employees, including performance-based variable compensation, is unnecessary or unreasonable. Neither he, nor any other OPC witness, has presented an analysis of the employment market to determine what amount of compensation is reasonable and necessary to attract the workforce needed to efficiently and reliably run an electric utility. This is in contrast to the testimony of FPL's witness Slattery who explains that the overall compensation is reasonable, that it is necessary to attract and retain a qualified workforce, and that it is at or near the median of employee compensation paid by other regulated utilities.

Witness Schultz's recommendation is further flawed because he makes no analysis of the reasonableness of the net amount of compensation that remains after incentive compensation is eliminated. He has not provided any evidence that shows the level of compensation that remains will ensure that FPL is

competitive in the market in terms of its ability to attract and retain qualified employees.

Consequently, witness Schultz's testimony is totally devoid of any consideration of reasonableness regarding either the overall amount of compensation or of the net amount he has recommended.

Q. Has the Commission addressed performance-based variable compensation for other Florida utilities?

A. Yes. A prior Florida Power Corporation rate case provided for cost recovery of incentive (performance-based variable) compensation finding that: "Incentive plans that are tied to achievement of corporate goals are appropriate and provide an incentive to control costs." Order No. PSC-92-1197-FOF-EI, issued October 22, 1992, in Docket No. 910890-EI, In Re: Petition for a rate increase by Florida Power Corporation. And in a TECO rate case, the Commission found that TECO's total compensation package, including the component contingent on achieving incentive goals, was set near the median level of benchmarked compensation and allowed recovery of incentive compensation that was directly tied to results of TECO:

> TECO's Success Sharing Plan has been in place since 1990 and its appropriateness was approved in the Company's last rate case in 1992. Lowering or eliminating the incentive compensation would mean TECO employees would be compensated below the employees at other Companies, which

> would adversely affect the Company's ability to compete in attracting and retaining a high quality and skilled workforce. We therefore decline to do so.

Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for a rate increase by Tampa Electric Company.

The Commission has also approved incentive compensation in three prior rate cases for Gulf Power Company ("Gulf Power"), the most recent of which resulted in an Order No. PSC-12-0179-FOF-EI, issued April 3, 2012, in Docket No. 110138-EI, In re: Petition for increase in rates by Gulf Power Company. The Commission's finding in the 2001 Gulf rate case contains language similar to the TECO case:

> To only receive a base salary would mean Gulf employees would be compensated at a lower level than employees at other companies. Therefore, an incentive pay plan is necessary for Gulf salaries to be competitive in the market. Another benefit of the plan is that 25% of an individual employee's salary must be re-earned each year. Therefore, each employee must excel to achieve a higher salary. When employees excel, we believe that the customers benefit from a higher quality of service.

Order No. PSC-02-0787-FOF-EI, in Docket 010949-EI, In re: Request for rate increase by Gulf Power Company, (page 45 of order).

In this case, FPL is seeking recovery of the same type of incentive compensation allowed in the above noted cases.

Q. Are there any Florida Court decisions relevant to the issue of Commission disallowance of compensation expenses?

A. Yes, two cases are instructive in this regard and both dealt with the Commission's disallowance of executive compensation.

In *Florida Bridge Company v. Bevis,* the Florida Supreme Court reversed a decision of the Commission disallowing a portion of the Company President's salary. The Court observed:

> Indeed, the Commission has made no attempt to determine whether the president's compensation is excessive in view of the services he provides. The arbitrary ratio by which the Commission reduced the salary and expense account[,] the ratio of days physically absent from the home office to the total number of workdays in the test year[,] has no support in logic, precedent, or policy.

363 So. 2d 799, 800-01 (Fla. 1978)

The Court found the Commission's action "was arbitrary and constitutes a substantial departure from the essential requirements of law." Id.

The First District Court of Appeal reached a similar conclusion in *Sunshine Utilities of Central Florida, Inc. v. Florida Public Service Commission*, in finding fault with the Commission's disallowance of a portion of the Company president's salary:

> In determining whether an executive's salary is reasonable compared to salaries paid to other company executives, the comparison must, at a minimum, be based on a showing of similar duties, activities, and responsibilities in the person receiving the salary.

624 So. 2d 306, 311 (Fla. 1st DCA 1993)

Q. How are these cases related to the disallowance of performance-based variable compensation recommended by Witness Schultz?

A. It relates to the point I made earlier in my testimony regarding Witness Schultz's failure to determine whether overall compensation expense is reasonable and necessary. The Florida Supreme Court and the First District Court of Appeal reversed Commission decisions because the basis for the disallowances did not address the reasonableness of the salaries as compared to the market.

Witness Schultz's analysis is similarly flawed because he has made no attempt to compare the total compensation paid to FPL employees to the market for similar services, duties, activities and responsibilities. Nor has he or any other witness, presented evidence that the salaries for any employee are excessive.

Instead he recommends a portion be disallowed based on how it is paid: Because it is performance-based variable pay, rather than base salary, it is subject to disallowance notwithstanding whether the total amount of compensation is reasonable. The focus of any disallowance should be how much is paid, not how it is paid.

Q. Is it your position that Commission precedent supports the recovery of all of the non-executive performance-based variable pay?

A. While the Commission reviews each utility's compensation costs on the facts specific to that utility, the Commission has consistently recognized that incentive compensation/performance-based variable pay is an accepted and desirable way to achieve corporate goals and to control costs for the benefit of customers. The Commission has also determined that incentive compensation is an appropriate component to include within overall compensation to judge whether the overall compensation paid to employees is reasonable.

I believe there are a number of reasons for this precedent. First, the Commission's policy is consistent with the basic tenets of sound regulatory policy that I described earlier. Second, the Commission has recognized that having good management at utilities is essential for regulators to achieve their mission of having safe, reliable and reasonably-priced service delivered to customers. Third, the Commission has further understood that management needs sufficient tools and incentives to achieve these goals and that regulators should not attempt to "micro-manage" their regulated utilities. Fourth, the

Commission has appropriately recognized that not all issues in a rate proceeding are a simple situation of "us vs. them," where every issue has a clear winner and a clear loser. While at-risk compensation has been and is currently being characterized as an "us vs. them" issue, in reality it is not. Incorporating performance-based variable pay as part of an overall compensation plan is a good example of aligning employee interests with customer interests.

Q. Mr. Deason, do you understand that witness Schultz is suggesting that FPL will continue pay the entire non-executive performance-based variable pay even if it is disallowed?

A. Yes, I understand his suggestion. That suggestion is an implicit acknowledgement that the total compensation, including 100% of performance-based variable pay, is a necessary and reasonable business expense.

Disallowing a reasonable and necessary business expense, or requiring the Company to share part of the expense, is nothing more than a backdoor approach to reducing the allowed ROE. Funds that should go to shareholders as a fair return on investment instead would be diverted to cover costs that should otherwise be recovered in rates

V. DIRECTORS AND OFFICERS LIABILITY INSURANCE

Q. What is the recommendation made by witness Schultz regarding DOL Insurance?

A. Witness Schultz, on behalf of OPC, recommends that the DOL insurance be reduced by $1.391 million. He indicates the costs should be shared equally between customers and shareholders.

Q. Do you agree with this recommendation?

A. No, I do not. The cost of DOL insurance is an ordinary and necessary cost of doing business, and as such the entire amount FPL has requested should be recovered in rates.

Q. Why are DOL insurance premiums an ordinary, necessary and beneficial cost of doing business?

A. DOL insurance is necessary to attract and retain knowledgeable, experienced and capable directors and officers. DOL insurance is purchased for the purpose of protecting the company and its directors and officers from normal risks associated with managing the Company. Qualified and capable directors and officers would be reluctant to assume the responsibilities of managing a company without the assurance that their personal assets would be shielded from legal expenses, settlements or judgments arising from lawsuits. The assets of the Company are likewise protected from lawsuits that could divert capital to cover any losses. Increasing scrutiny of corporate governance and the related risk exposure of directors and officers make insurance a necessity

in maintaining a high quality board and senior management team. Adequate liability coverage gives directors and officers the level of comfort necessary to enable them to make forward-looking decisions that will provide operational and cost-efficiency benefits for customers.

Q. Has the Commission previously allowed recovery of the cost of DOL insurance?

A. Yes. There are two good examples involving Peoples Gas System and TECO. In the Peoples Gas System's case the Commission stated:

> DOL Insurance has become a necessary part of conducting business for any company or organization and it would be difficult for companies to attract and retain competent directors and officers without it. Moreover, ratepayers receive benefits from being part of a large public company, including, among other things, access to capital. In addition, DOL Insurance is necessary to protect the ratepayers from allegations of corporate misdeeds.

Order No. PSC-09-0411-FOF-GU, page 37 issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System.

In the TECO case, the Commission stated:

> We find that DOL insurance is a part of doing business for a publicly-owned Company. It is necessary to attract and retain competent directors and officers. Corporate surveys indicate

that virtually all public entities maintain DOL insurance, including investor-owned electric utilities.

Order No. PSC-09-0283-FOF-EI, page 64 issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company.

Q. What is instructive from these two cases?

A. Both of these cases found that DOL insurance is, first, necessary and, second, beneficial to customers. In the Peoples Gas System's case in particular, the Commission found that DOL insurance benefits customers by enabling their service provider to be managed by competent directors and officers, by enabling service to be provided by a large public company with access to capital, and by protecting customers from allegations of corporate misdeeds.

Q. Why is this important?

A. It clearly places DOL insurance in the proper overall regulatory perspective for cost recovery. Any expense that is determined to be both necessary and prudent is typically provided full cost recovery in rates (assuming the amount spent is reasonable in amount, which does not appear to be at issue for the level of premiums paid by FPL). In the case of DOL insurance, the Commission has also found it to not only be necessary but to also be especially beneficial to customers. It would be extremely rare, if ever, that an expense that is determined to be both necessary and beneficial to customers to be denied cost recovery. However, DOL insurance costs are being characterized as an exception by witness Schultz because of his contention that DOL insurance primarily benefits stockholders.

Q. Do you agree with his characterization of the purpose of DOL insurance?

A. No, I do not. DOL insurance is not designed to protect shareholders. DOL insurance is designed to protect the officers and directors of the corporation from lawsuits alleging harm from decisions of the officers and directors acting in their official capacity. This is an important distinction for two reasons. First, without adequate DOL insurance, any corporation would find it difficult to attract the best qualified individuals to serve as officers and directors. Second, and perhaps more importantly, it allows officers and directors to make decisions based on their best judgment and not on the goal of minimizing exposure to potential lawsuits. And this second reason is especially applicable to officers and directors of regulated utilities.

Q. Why is this second reason especially applicable to officers and directors of regulated utilities?

A. A regulated utility is in a relatively unique position as compared to typical for-profit companies. To be successful, a regulated utility must meet all of its obligations required by virtue of being a state-sanctioned regulated monopoly and must also fulfill its commitments to all stakeholders, including its vendors, employees, creditors, stockholders, customers and regulators. Therefore, truly effective directors and officers must feel free to exercise their best independent judgment to balance all of those sometimes competing interests, without fear of lawsuits threatening their personal assets. It is both

good public policy and good regulatory policy to encourage such informed, objective decision making that is enabled to a great extent by DOL insurance.

Q. Why is it good regulatory policy to encourage DOL insurance?

A. It is good regulatory policy to encourage DOL insurance to enable officers and directors to engage in thoughtful, objective decision making that carefully weighs the outcomes and resulting impacts on all stakeholders.

Q. Is there a real-world example of this?

A. Yes, perhaps the best example of this is the Commission's policy of encouraging settlements among the parties on matters in dispute. The best settlements are those where all parties engage in meaningful discussion and agree on sometimes significant concessions. When these concessions are believed to be in the best interest of a regulated utility and its stakeholders, the officers and directors should feel free to exercise this judgment, without the fear of a lawsuit alleging the concessions were too great.

Q. In response to a previous question, you contrasted a regulated utility with a typical for-profit company. Are for-profit companies the only entities that find it necessary and appropriate to purchase DOL insurance?

A. No, many non-profit entities purchase DOL insurance for the same reasons, i.e., to enable them to have qualified officers and directors and to enable those officers and directors to engage in objective decision making. So entities that do not even have stockholders also find it necessary and appropriate to have DOL insurance. This fact is another reason why I disagree with witness

Schultz's characterization that DOL insurance is primarily to protect shareholders from the past decisions of officers and directors.

Q. What would be the result of accepting witness Schultz's recommendation to disallow half of the cost of FPL's DOL insurance?

A. Witness Schultz characterizes his recommendation as a sharing of costs based on who he believes benefits. As I just described, I believe his opinion on who benefits is incorrect. Nevertheless, the true effect of his recommendation is to disallow one-half of the cost of FPL's DOL insurance. This is tantamount to saying that one-half of the cost is unnecessary and imprudently incurred. If this is not the Commission's intended result, his recommendation violates one of the most basic tenets of regulatory theory, i.e., that all necessary and prudent costs should be allowed to be recovered in rates.

Q. From a policy perspective, what would be the effective message that would be sent by adopting witness Schultz' recommendation?

A. At least from a theoretical level, his recommendation would trigger three potential outcomes, none of which is desirable for a regulated utility and its customers. First, the company could simply decide to not have DOL insurance. This would result in the extremely undesirable consequences of which I earlier spoke. Second, the company could decide to not have DOL insurance and pay its officers and directors more to make-up for the greater risk exposure. Presumably the increased costs would then be borne fully by customers because they clearly would be prudent and necessary to attract and retain directors and officers and pay them a market level of compensation.

And third, the company could retain its DOL insurance and not recover one-half of the cost of doing so. Given that DOL is essential for a large publicly traded company to function and maintain access to capital on reasonable terms, this third outcome would almost be assured.

Q. What would be the bottom-line impact of the third potential outcome?

A. As I noted earlier, disallowing a reasonable and necessary business expense, or requiring the company to share part of the expense, is unfair and inconsistent with the basic tenets of regulatory theory that all necessary and prudent costs should be allowed to be recovered in rates. It would amount to nothing more than another backdoor approach to reducing the allowed ROE. Funds that should go to shareholders as a fair return on investment instead would be diverted to cover costs that should otherwise be recovered in base rates.

VI. ROE PERFORMANCE ADDER

Q. How is your testimony in this area organized?

A. I begin by describing how FPL's requested ROE adder fits within Florida's policy on ROE adjustments based on performance and cite to specific cases in which such adjustments have been made. I next respond to some of the more general themes contained in the recommendations of witnesses Baudino, Brosch, Gorman, Lawton, and Pollock. I continue by individually addressing

some of the more specific arguments made and positons taken by witnesses Brosch, Lawton, and Pollock. I end with some concluding observations.

Q. How does FPL's requested ROE adder fit within Florida's policy on performance based adjustments to ROE?

A. The possibility of setting rates at an ROE above or below the mid-point of the range is a well-established practice in the state of Florida. FPL's requested ROE performance adder is a request to set rates at a target ROE point above the mid-point to recognize exceptional performance. The reciprocal of this is to set rates at a target ROE point below the mid-point for less than satisfactory performance. Setting rates at a point above or below the mid-point is authorized by statute, is a regulatory tool historically used by the Commission, and has been upheld by the Florida Supreme Court. Further, the concept of recognizing superior management or penalizing unsatisfactory management is recognized by authoritative sources as an appropriate regulatory tool.

Q. What is the specific statutory provision to which you refer?

A. I am referring to Section 366.041(1), F.S., which authorizes the Commission when setting rates to consider "the efficiency, sufficiency, and adequacy of the facilities provided and the services rendered; the cost of providing such service and the value of such service to the public…"

Q. Has the Commission utilized its discretion to set rates at a target ROE above or below the mid-point?

A. Yes, the Commission has. In fact, the Commission has set rates at targets both higher and lower than the mid-point in three different cases involving the

same electric utility, Gulf Power Company.

Q. In what case did the Commission set rates at a target ROE below the mid-point for Gulf Power?

A. In a 1990 rate case the Commission authorized an ROE of 12.55% for Gulf Power. However, in recognition of mismanagement, the Commission set rates at 12.05%, a full 50 basis point reduction, for a period of two years.

Q. Was this decision appealed to the Florida Supreme Court?

A. Yes, it was. In *Gulf Power Co. v. Wilson*, 597 So. 2d 270 (Fla. 1992) ("Gulf Power Case"), the Court upheld the Commission's adjustment to ROE based on evidence of the utility's mismanagement, but explained that the discretion worked both ways:

> This Court has previously recognized that this authority includes the discretion to *reward,* within the reasonable rate of return range, for management efficiency. In fact, Gulf Power has in the past received a ten basis point reward for efficient management through its energy conservation efforts. *Gulf Power v. Cresse,* 410 So. 2d 492 (Fla. 1982). We find that, inherent in the authority to adjust for management efficiency is the authority to reduce the rate of return for mismanagement, as long as the resulting rate of return falls within the reasonable range set by the Commission. This concept of adjusting a utility's rate of return on equity based on performance of its

management is by no means new to Florida or other jurisdictions.

Q. In what cases did the Commission set rates at a target ROE above the mid-point for Gulf Power?

A. The first time was in Docket No. 800001-EU, where the Commission set rates at 10 basis points above the ROE mid-point. In denying a Petition for Reconsideration filed by OPC, the Commission stated:

> With regard to the ten basis points added to the return on equity capital used for ratemaking purposes, we believe that once we have identified an appropriate range for a fair rate of return consistent with the record, we have some discretion in fixing the point within the range to be used to determine revenue requirements. In this instance, we exercised our authority in this regard to reward Gulf Power Company's visible efforts in promoting conservation, an objective which we hope that management of all utilities will strive to achieve. The action in this case was within our discretion and reconsideration thereof will be denied.

This action was upheld by the Florida Supreme Court. In *Gulf Power Co. v. Cresse*, 410 So. 2d 492 (Fla 1982), the Court affirmed the Commission's authority to reward a utility for management efficiency with an upward adjustment in its rate of return.

Q. What was the second instance in which the Commission set Gulf Power's rates at a target above the ROE mid-point?

A. The second time was in a 2001 rate case, Docket No. 010949-EI. In this case, the Commission found the mid-point ROE to be 11.75%. However, in recognition of Gulf's high level of performance, the Commission set rates at 25 basis points above that level or 12.00%. In its Order No. PSC-02-0787-FOF-EI, the Commission stated:

> Gulf contends that it deserves an upward adjustment to its return on equity (ROE) as a reward for its continuing high level of performance in customer satisfaction, customer complaints, transmission and distribution reliability, and generating plant availability. Gulf's position is that increasing the ROE sends a message to the Company and the customers that superior performance is important. Furthermore, such an increase provides an incentive to continue to provide superior service…. The testimony of Gulf witnesses Labrato and Fisher demonstrates that Gulf's service is excellent. In addition, testimony of customers at the customer service hearings was very favorable. We find that Gulf's past performance has been superior and we expect that level of performance to continue into the future.

Q. What do witnesses Baudino, Brosch, Gorman, Lawton, and Pollock recommend for FPL's requested ROE performance adder?

A. All of these intervenor witnesses recommend denial of the ROE performance adder.

Q. What are the reasons given by these intervenor witnesses for their recommendations?

A. These intervenor witnesses give reasons which have common themes. Generally, these recurring themes are:

- An ROE adder is inconsistent with the regulation of a monopoly;
- An ROE adder is unneeded because monopolies enjoy a privileged position with an obligation to provide superior service;
- An ROE adder is unjustified because of FPL's capital expenditures;
- An ROE adder is unjustified because it is duplicative of GPIF; and
- An ROE adder leads to unjust rates.

Q. Do you agree that an ROE performance adder is inconsistent with the regulation of a monopoly?

A. No, I strongly disagree. To the contrary, a properly imposed performance-based ROE adjustment is an essential regulatory tool. It enables a regulatory authority to introduce elements of competition and incentives that otherwise

may be lacking in more traditional approaches to ratemaking and enables regulators to directly express priorities in terms of service quality, cost control, and customer satisfaction to management. This was expressly recognized by the Florida Supreme Court in the Gulf Power Case:

> In a competitive market environment, the market would provide the necessary incentives for management efficiency and corresponding disincentives for mismanagement. However, for a utility that operates as a monopoly, this discretionary authority to reward or reduce a utility's rate of return within a reasonable rate of return range is the only incentive available.

Q. Do you agree that an ROE performance adder is unneeded for monopolies?

A. I disagree for at least two reasons. First, as I just explained, the fact that utilities are regulated monopolies is the very reason that incentive based regulatory tools, like ROE adjustments, are necessary. And second, certain factual assertions presented by the intervenor witnesses do not give a complete picture. While there may indeed be some advantages to being a regulated utility, the intervenor witnesses fail to mention the corresponding obligations and disadvantages.

Q. What are some of the disadvantages of being a regulated utility?

A. Regulated utilities like FPL have an obligation to serve all customers when service is demanded. They do not have the option of not investing during

times of uncertainty or financial difficulty. Neither do they have the option of departing unprofitable markets or not serving certain customers. Regulated utilities must justify their prices, while competitive firms enjoy pricing flexibility and alacrity. Regulated utilities' earnings are set and closely monitored, while competitive firms such as Walmart do not have governmentally imposed restrictions on earnings. The fact that regulated utilities' earnings are set within a narrow range and actively monitored to insure that earning levels are not exceeded is the very reason that discretion in setting rates at a point other than the mid-point can be so very crucial to obtaining the goals of regulation.

Q. Do regulated utilities such as FPL have an obligation to provide superior performance?

A. Regulated utilities do have an obligation to serve, which I just described. In addition, regulated utilities in Florida have an obligation to provide "reasonably sufficient, adequate, and efficient service upon terms as required by the commission." This language is found in Section 366.03, F.S. Regulated utilities do <u>not</u> however, have an obligation to provide superior performance. It would be wholly unrealistic and perhaps mathematically impossible for everyone to be superior. It would be synonymous with setting an expectation that, as in the mythical town of Lake Wobegon, everyone is above average.

Q. Has the Commission ever required a utility to provide superior performance or found a utility to be in violation of a Commission rule or order for not providing superior performance?

A. No, not to my knowledge. The Commission has generally followed a standard of reasonably sufficient, adequate, and efficient, as prescribed in statute. When the Commission has imposed a lower ROE it has been for performance and a quality of service which was determined to be inadequate. Likewise, when the Commission has awarded a higher ROE it was for performance and a quality of service beyond that which would be considered merely adequate.

Q. Why has the Commission followed this practice?

A. It is the standard prescribed in statute. Beyond that, it constitutes good regulatory policy. Applying this standard and using its authority to adjust the ROE provides the Commission with a powerful and needed regulatory tool to get inadequate performance corrected and to have superior performance continue and even become a goal to which other utilities may aspire. This was certainly the intent of the Commission when it awarded Gulf Power a ten basis points higher ROE for its conservation efforts. Following the intervenor witnesses' opinions and recommendations would effectively take this tool out of the hands of the Commission.

Q. Do you agree that an FPL adder would be unjustified because FPL's capital expenditures have helped it achieve superior performance?

A. No, to the contrary, I believe FPL's capital expenditure history is a strong indicator that an ROE adder is indeed justified. While a robust capital

expenditure program is imperative to achieve the goals of regulation, merely deploying capital does not guarantee this result. In contrast, FPL's capital expenditures have not only met the requirements of regulation, but have exceeded them.

Q. What are the requirements of regulation to which you refer?

A. I am referring to the overarching requirement to have safe and reliable service provided to customers at reasonable rates.

Q. How are the intervenors incorrect in their assertions?

A. The intervenor witnesses are confusing what is a regulated utility's obligation and what constitutes superior service beyond its obligation. The intervenor witnesses' call for service at "at the lowest practical cost" (witness Brosch) or "lowest reasonable cost" (witness Pollock), as if it is the utility's obligation to have low costs and superior performance. The intervenor witnesses also fail to recognize that, if there is indeed to be a superior level of performance, it has to be a shared goal of both utility management and utility regulators. It is unrealistic to expect that utilities and their management will always have a robust capital expenditure program simply because it is their "obligation" to do so. This is a fundamental flaw in the approach that is being advanced by the intervenor witnesses who fail to fully appreciate the role of the regulator.

Q. What is the role of the regulator in this regard?

A. It is the role of the regulator to encourage capital expenditures which improve service and/or reduce costs. Florida has a history of implementing policies and making decisions which provide this needed encouragement. In fact, FPL

has responded appropriately and has not been hesitant to deploy capital that benefits its customers and is conducive to achieving the common goal of regulation. However, the successes of FPL's capital expenditures are now being used by the intervenor witnesses as a reason to deny an ROE adder – an irony that should not escape us. Generally, they focus on the rate base impacts of the capital expenditures and fail to appreciate the cost savings and efficiencies that have resulted. I would note that witness Pollock does recognize this: "However, FPL has lower costs because it has invested in cost saving measures, such as installing lower heat rate generation capacity and smart grid meters."

Q. Is an ROE adder duplicative of the Generating Performance Incentive Factor ("GPIF")?

A. While the GPIF is a good example of Commission authority to incent utility behavior, it is much more limited in scope than an ROE adder. As I understand the ROE adder proposal, it is designed to incentivize the utility to continue to provide superior performance and value to customers on a much broader range of performance than the GPIF. The GPIF is limited to certain measures of generating unit performance. FPL witness Kennedy addresses the Company's superior performance in a wide range of generating unit performance measures, a number of which are not captured in the GPIF. However, FPL's superior performance outlined in its direct case does not stop there. It extends to superior nuclear performance as outlined by FPL witness Goldstein. It extends to extraordinary transmission and distribution reliability

performance relative to other Florida utilities and the electric utility industry in total. It extends to customer satisfaction addressed by FPL witness Santos. It is addressed by a number of performance metrics addressed by FPL witness Reed. FPL's superior performance and the superior value FPL provides to its customers are much broader than the GPIF, and an ROE adder is an appropriate tool for the Commission to employ to incent such excellent performance into the future.

Q. Do you agree that an ROE adder will result in unjust rates?

A. No, for three reasons. First, by definition and function, the ROE adder will not set rates at an unjust level. To the contrary, rates will be set within the Commission's established range of reasonableness. This concept has been recognized and approved by the Florida Supreme Court. Second, a properly structured and implemented performance adder is not intended to unjustly enrich a company. To the contrary, it is intended to introduce incentives designed to continue or even enhance superior performance, such that the net cost paid by customers through rates is <u>less</u> than it would be had the superior performance not been achieved. And third, an ROE adder would mimic dynamics that would naturally occur in a competitive market.

Q. How would rates set using an ROE adder or penalty mimic competitive rates?

A. Economic theory holds that a competitive firm that provides greater customer value (through the quality of its products and services and the efficiency with which it provides them) can demand higher rates and revenues than a

competitor that provides less customer value. An ROE adder or penalty is consistent with this economic principle. The Florida Supreme Court, in the 1992 Gulf Power Case I earlier referenced, adopts this principle.

Q. Witness Gorman on behalf of FEA takes the position that the ROE adder is not justified because FPL has "been provided the privilege of providing a monopolistic or franchise service territory." Please respond.

A. The fact that FPL has the exclusive right to serve a particular geographic area and an obligation to serve within that area is irrelevant to the discussion. Nearly all electric utilities operate within an exclusive service area. The real question is whether the differences in performance among those utilities should be acknowledged. For reasons I have explained, I believe this represents good policy, and this Commission has elected to do so in the past.

Q. Has the Commission considered arguments before that competitive forces should be considered in setting rates?

A. Yes. In an application for increased rates by Aloha Utilities, Inc., Docket No. 010503-WU, OPC offered the testimony of Hugh Larkin in opposition to the requested increase. In advocating for a total rejection of the requested increase based on poor service, witness Larkin testified: "The competitive principle requiring that regulation be a substitute for competition would view both price and service from a competitive standpoint." Witness Larkin went on to quote James C. Bonbright's *Principles of Public Utility Rates ("Bonbright's Principles")*:

> Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation but subject to the market forces of competition. In short, regulation should be not only a substitute for competition, but a closely imitative substitute.

Q. What did the Commission decide in the Aloha case?

A. The Commission, in accordance with the Court's decision in the Gulf Power Case, set Aloha's ROE at the bottom of the range in recognition of its poor service.

Q. Witness Lawton asserts that an ROE adder would constitute retroactive ratemaking. Do you agree?

A. No, witness Lawton either does not understand the standard applicable to retroactive ratemaking applicable in Florida or is simply trying to confuse the issue.

Q. Please explain.

A. Retroactive ratemaking occurs when future rates are increased to make up for past earning deficiencies and/or past failures to recover approved costs. (On occasion, surcharges have been assessed when ordered by a court on remand.) Retroactive ratemaking would also occur if future rates were decreased to eliminate past overearnings and/or past over-recoveries of approved costs. Retroactive ratemaking is prohibited in Florida, but it would not occur through

the implementation of either an ROE adder or ROE penalty. This is because the ROE adder (or penalty) does not provide for future recovery of past underearnings (or past overearnings). An ROE adder simply uses historical data to determine the fair and reasonable level of rates applicable for service rendered in the future. It is the same as using a historical test year to set forward looking rates. It is interesting to note that witness Lawton sees no retroactivity with an ROE penalty: "A penalty involving managerial misconduct is not retroactive ratemaking." However, in his view, an ROE adder for exemplary management would be retroactive. These two positions are not reconcilable.

Q. Witness Brosch asserts that an ROE adder for FPL would be redundant to its employee compensation program to incent employees to obtain specified goals. Do you agree?

A. No, witness Brosch is mixing apples and oranges. FPL's employee compensation structure is a management tool to incent employees to be productive and hopefully obtain both operational and financial goals. It is designed to provide these incentives at market medians so that overall compensation is at competitive levels. It affects the manner in which employees are paid but is not designed to pay more than is reasonably necessary to attract and retain qualified employees. In contrast, an ROE adder is a regulatory tool to recognize superior performance and to incent continued superior performance. It is designed to reward shareholders at overall customer rates that are fair and competitive. It also acts as an incentive to

deploy capital on reasonable terms that results in even greater customer value through better service, reduced costs, or both.

Q. Witness Pollock asserts that there should be no ROE adder because of hedging losses. Do you agree?

A. No. It is Commission policy to have utilities engage in hedging to reduce the volatility of fuel costs. Hedging is not designed to be a tool to reduce the overall cost of fuel. In fact, given the purpose and construct for hedging by Florida utilities, if losses are incurred on hedges it means that natural gas prices have dropped. Where a portfolio is only partially hedged, such as FPL's, it means that all customers are enjoying lower prices that more than offset the hedging losses. For this reason, the focus of intervenors on the losses under the hedging program is very much misplaced in general, and completely inappropriate in this base rate case as a measure of performance. Losses and gains over time are to be expected and hedging losses during a specified period of time does not imply mismanagement any more than hedging gains during another period of time implies superior management. Therefore, hedging results should have no bearing on the question of an ROE adder. It should be noted that despite the hedging losses, FPL's rates are still among the lowest in Florida and low by national standards. That is a good indicator of superior management performance.

Q. Witness Pollock also asserts that the existence of a depreciation reserve deficit should be a reason to reject the ROE adder. Do you agree?

A. No. It is ironic that witness Pollock and FIPUG are taking exception to the natural consequence of positions they advocated (to rapidly flow back an earlier depreciation reserve surplus through the flexible use of depreciation surplus reserve) and endorsed as part of a comprehensive settlement. Nevertheless, the existence of a theoretical depreciation reserve deficit or surplus is not an indicator of either superior management or mismanagement. Therefore, the fact that FPL's current depreciation reserve is in a deficient position should have no bearing on the question of an ROE adder.

Q. In response to a previous question you indicated that an OPC witness referred to *Bonbright's Principles* as an authoritative source. Is there another passage from it that is instructive on the use of ROE adders and penalties?

A. Yes. This passage was also referenced by the Florida Supreme Court in the 1992 Gulf Power Case. The Court quoted pages 366-67 of *Bonbright's Principles*. The passage from which the Court quoted reads:

> While exceptional management is rarely explicitly rewarded, and mediocrity infrequently penalized, it suggests more systematic and deliberate efforts on the part of regulating agencies to distinguish, somewhat as competition is presumed to do, in favor of companies under superior management and against companies with substandard management. The

distinction might take the form of an explicit and publicly recognized differential in the allowed rate of return. There is ground for the conviction that the opportunity of a well-managed utility to earn a return *liberally* adequate to attract capital is in the public interest as encouraging rapid technological progress and long-run policies of operation.

Q. Do you have any concluding observations regarding FPL's requested ROE adder?

A. Based on my thirty-nine years of regulatory experience, utilities that provide exceptional value to customers are those that have allowed ROEs and capital structures that maintain their financial integrity and have a willingness to deploy capital to provide improved service and even greater value to customers. ROE levels and a willingness to deploy capital are directly related. To that end, the use of an ROE adder is a valuable and meaningful regulatory tool that can and should be used, where appropriate, to result in continued and even increasing value for customers.

While an ROE adder is discretionary, it should be based on the facts presented and not rejected on overly simplified philosophical arguments that it is not beneficial to customers. In the right situation, an ROE adder can be and should be enormously beneficial to customers. Too often we can lose sight of the potential for long term benefits when confronted with the prospect of increasing the calculated revenue requirement in a given rate proceeding.

However, low allowed ROEs and inefficient capital structures do not equate to customer benefits. They may temporarily lower revenue requirements in a given rate case, but this does not equate to exceptional customer value over the long-term.

Certainly a balance has to be reached with careful consideration and discretion. The same is true for ROE penalties, in that they should not be used to result in lower revenue requirements as an end objective. Rather, they should be used as a means to get reluctant management to cure past mismanagement and to focus on providing improved service and greater customer value.

Q. Does this conclude your testimony?

A. Yes, it does.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF RENAE B. DEATON

DOCKET NO. 160021-EI

AUGUST 1, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Renae B. Deaton. My business address is Florida Power & Light Company ("FPL" or the "Company"), 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following rebuttal exhibits:

- RBD-7 – FPL Generation Fleet 2015 vs. 1989
- RBD-8 – Comparison of CI Customer Fuel Savings To Additional Revenue Requirement Under 12CP & 25%
- RBD-9 – Impact of Proposed Production Cost Allocations
- RBD-10 – Impact of MDS and Proposed Production Cost Allocation Methods
- RBD-11 – Summary of Rate Class Impacts due to Proposed Alternative Allocation Methods
- RBD-12 – Prior Commission Orders Rejecting Use of MDS
- RBD-13 – Revised MFRs E-1 and E6b

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address cost of service study ("COSS") items and counter-proposals raised in the direct testimonies of South

Florida Hospital and Healthcare Association ("SFHHA") witness Baron, Florida Industrial Power Users Group ("FIPUG") witness Pollock, Federal Executive Agencies ("FEA") witness Alderson, and Wal-Mart Stores East, LP and Sam's East, Inc. ("Walmart") witness Chriss (collectively "Intervenor Witnesses"). My rebuttal testimony responds to the testimony of the Intervenor Witnesses regarding their: (1) opposition to the use of the 12CP and 25% cost allocation method for production plant, (2) proposals for alternative cost allocation methods for production plant, and (3) proposals for use of a Minimum Distribution System ("MDS") cost allocation method for distribution costs.

II. SUMMARY

Q. Please summarize your rebuttal testimony.

A. The Intervenor Witnesses' alternatives to the COSS allocation methods proposed by FPL either do not match cost causation with the cost causer and/or are inconsistent with FPL's planning and operations. FPL's proposal to move from using the 12CP and 1/13th method to the 12CP and 25% method of allocating production plant better matches cost causation with the cost causer and system benefits, and recognizes the importance that energy use plays in the selection of generation capacity. The efficiency improvements made to FPL's generation fleet have resulted in significant fuel savings, more than $500 million in 2015 alone. The large Commercial / Industrial ("CI") customers' share of the fuel savings is nine times more than the increase in base revenue requirements resulting from the

use of the 25% energy allocation method, i.e., over $200 million in fuel savings as compared to $22 million increase in revenue requirements.

Alternative proposals for production demand cost allocations proposed by the Intervenor Witnesses, likewise, do not recognize all three FPL planning requirements: (1) a minimum 20% summer reserve margin, (2) loss of load probability ("LOLP") of less than 0.1 days per year, and (3) a minimum 20% winter reserve margin.

Proposals to require the use of the MDS cost allocation method for distribution cost should continue to be rejected by the Florida Public Service Commission ("FPSC" or the "Commission"), as they have been in past cases. FPL's distribution system is planned and built to meet customer demand. FPL does not install distribution facilities in anticipation of connecting a customer that has no load.

III. OPPOSITION TO USE OF THE 12CP AND 25% COST ALLOCATION METHOD FOR PRODUCTION DEMAND COST

Q. Is the Intervenor Witnesses' opposition to FPL's proposal to use the 12CP and 25% method to classify and allocate production plant reasonable?

A. No. The Intervenor Witnesses oppose the use of the 12CP and 25% method to classify and allocate production plant and note that it would allocate a larger share

of production plant to their clients. As explained in direct testimony, and further below, it is appropriate to allocate a larger share of production costs to large CI customers to better align cost causation with cost causer and recognize the fuel savings these customers have and will continue to realize as a result of FPL's generation planning and operations.

Q. What are the primary reasons the witnesses cite for their objection to the use of the 12CP and 25% method?

A. The primary arguments cited by intervenors are:

- FPL has used the 12CP and 1/13th method for over 30 years and has not justified a change;
- No study was performed to determine the exact percentage that should be allocated based on energy;
- FPL would be the only Investor Owned Utility ("IOU") in Florida not using the 12CP and 1/13th method at this time;
- Combined cycle generation is less capital intensive than coal and nuclear, and natural gas prices have fallen; and
- The amount of energy use required for combined cycle generation to be more economic than peaking generation is small.

Q. Are the Intervenor Witnesses correct that there have been no significant changes in circumstances that warrant deviating from the 12CP and 1/13th method?

A. No. The Intervenor Witnesses note that FPL has used the 12CP & 1/13th method since 1983 and claim there have been no changes to support a change from this

allocation method (Pollock at page 46, lines 20-22; Barron at page 13, lines 8-10). On the contrary, much has changed in the last 32 years to warrant a change in the allocation method. As FPL witness Kennedy notes, FPL's system heat rates have improved drastically, 25% better than 1990, and 23% better than the fossil industry average. This improvement has saved customers more than $500 million in fuel costs in 2015 alone and $8 billion since 2001. Since 1990, FPL has added significant base and intermediate load generation, including replacing three fossil steam generation plants since 2012. The capital expenditures at the Cape Canaveral, Riviera and Port Everglades sites were used to replace older, more depreciated plants with state-of-the art, highly efficient combined cycle generation. Exhibit RBD-7 illustrates the changes to the generation portfolio mix since 1990. In 1989, 14% of installed summer capability was peaking generation, vs. 9% in 2015. These changes have resulted in significant energy cost savings for our customers, which is an important consideration in choosing the type of generating unit to fill a capacity need.

Exhibit RBD–8 illustrates the annual savings large CI customers (the groups SFHHA, FEA, Walmart, and FIPUG represent) receive as compared to the additional revenue requirements allocated to them as a result of using the 12CP and 25% method. This chart illustrates that in 2015 large CI customers' share of the $500 million in fuel savings was more than 9 times the additional base revenue requirement responsibility they would incur under a 12CP and 25%

allocation method, i.e., over $200 million in savings as compared to $22 million in additional revenue requirements.

Q. Witnesses Pollock and Baron assert that FPL has not adequately supported the change to the 12CP and 25% method because FPL has not filed an analysis or study showing that 25% is the proper amount of production plant to be classified as energy-related (Pollock at page 52, line 20 to page 53, line 1; Baron at page 14, lines 3-10). Do you agree with these assertions?

A. No. While it is correct that FPL did not conduct an analysis or study to determine the ***exact*** percentage of production plant that should be classified and allocated based on energy, an increase in the energy allocation to at least 25% is justified based on the rationale and precedent set in previous Commission orders and staff recommendations where allocations to energy of more than $1/13^{th}$ were approved.

As witness Chriss notes, the 25% energy allocation is a judgmental determination, as is the 12CP & $1/13^{th}$ method (Chriss at page 15, lines 8-15). Judgmental allocations are contemplated by the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") (p. 57-58) and have been part of this commission's decisions regarding the appropriate allocation method for over 30 years. The 12CP and 25% method is an appropriate and fair allocation method that has been previously approved by this Commission in Order No. PSC-09-0283-FOF-EI for Tampa Electric Company ("TECO"), and recommended by staff in Docket No. 090079-EI for Duke Energy Florida ("DEF").

Q. Does the rational used in recommending and approving the use of the 12CP and 25% method for DEF and TECO apply here?

A. Yes. In approving the use of the 12CP & 25% method for TECO, the Commission agreed with TECO:

> "Witness Ashburn testified that the proposed methodology provides a more appropriate allocation of production plant within the cost of service study when considering how power plants are planned and operated. Witness Ashburn stated that the Company has installed a significant amount of base and intermediate-load generation, which was more expensive to install than peaking generation, but less expensive to operate over time."
>
> "TECO noted in its brief that the selection of the appropriate cost allocation method is a matter of judgment upon which reasonable people can disagree, and it comes down to a judgment decision which affects how much of the revenue requirement should be allocated to each class. We agree with TECO on this point."
>
> "FIPUG argued that we have never embraced the 12 CP and 25 percent AD cost of service. We are not bound by any prior decisions in this matter, if we believe that circumstances warrant a change in cost methodology. While the 12 CP and 1/13 AD method has been relied upon frequently in the past, we have also deviated in the past from that method."

"Based on the record, we find that TECO's proposal for a 12 CP and 25 percent Average Demand Allocation is reasonable and therefore it shall be approved." (pages 82 – 85)

In recommending the 12CP and 25% method for DEF, the staff stated:

"Although there were several accepted cost allocation methodologies discussed, there is no one 'correct' cost allocation methodology. It is a matter of judgment." (page 298)

"Staff is persuaded by PEF's arguments that units being constructed today are more expensive because they provide benefits other than just additional capacity... Based on the record, staff believes a 12 CP and 25 percent Average Demand allocation is reasonable, balances the interests of the parties, is based on Commission precedent, and should be approved." (page 299)

Q. Is the fact that other Florida IOUs are currently using the 12CP and 1/13th method a valid reason to use it here?

A. No. Currently all the other Florida IOUs use that method; however, the use of the method is pursuant to a settlement or stipulation for Gulf Power Company ("Gulf"), TECO, and DEF. The use of the 12CP & 1/13th method pursuant to a settlement does not infer approval by this Commission. In the order approving the use of the 12CP and 25% method for TECO, the Commission noted as much

in reference to the use of the 12CP and 1/13th method in settlement agreements for DEF:

> "In its 2000 rate case,[1] Progress Energy Florida, Inc. (PEF) (then Progress Energy Florida) filed the MFR required study, and two additional studies: 12CP and 25 percent AD and 12CP and 50 percent AD. That rate case was settled among all the parties and the stipulation provided that the 12CP and 1/13 AD methodology would continue to be used during the term of the stipulation.[2] PEF again requested a 12CP and 25 percent AD cost allocation methodology in its 2005 rate case,[3] which was also settled by stipulation using the 12CP and 1/13 AD cost methodology. In both cases, the cost of service methodology was never formally reviewed or approved, but simply accepted as part of the stipulations."

What the intervenors failed to note is that while TECO and DEF agreed to use the 12CP and 1/13th method in settlement, both filed and supported the use of the 12CP *and 50%* method in their most recent rate case filings (see testimony of TECO witness Ashburn pages 31-32, lines 4-25 and 1-3 in Docket No. 130040-EI and testimony of DEF (then Progress Energy Florida) witness Slusser p. 18-19 in Lines 19-25 and 1-12, Docket No. 090079-EI).

[1] Docket No. 000824-EI, In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.
[2] Order No. PSC-02-0655-AS-EI, issued May 14, 2002, in Docket No. 000824-EI, In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.
[3] Docket No. 050078-EI, In re: Petition for a Rate Increase by Progress Energy Florida.

Q. Should the Commission should ignore the role energy plays in generation selection because FPL is installing combined cycle as opposed to nuclear or coal generation and gas prices have fallen as witnesses Alderson, Baron and Pollock all imply (Alderson at page 10, lines 1-22; Barron at page 14, lines 1-11; Pollock at page 51, lines 1-22)?

A. No. The type of generation is irrelevant as it pertains to the capital substitution justification for using an energy allocation for production plant, as fuel savings can be realized regardless of the generation type. As discussed above, FPL's capital expenditures have produced significant fuel savings and it is just and fair to allocate a larger share of production plant based on energy to better align cost causation with cost causer and recognize the fuel savings customers have and will continue to realize. I would also note that the proposed energy allocation is only 25% and not 70% that was previously approved for the St. Lucie plant (Order No. 12348).

Q. Witness Baron uses a screening curve to evaluate the appropriateness of the 12CP and 25% method. Do you agree with his analysis?

A. No. Witness Baron claims that any energy usage above the breakeven point, where the utility would be indifferent between the choice of a peaking gas turbine and combined cycle unit, does not cause the company to incur any additional capital cost and should be ignored for cost allocation purposes. Witness Baron fails to recognize that the base and intermediate load generation brings benefits to customers during all hours of use, not just those hours below the break-even point.

Q. Witness Baron cites increased unit costs for off-peak energy as a reason why the 12CP and 25% method should not be adopted. Do you agree?

A. No, as discussed above, the base and intermediate load generation brings benefits to customers during all hours of use, including off-peak use. If FPL had no off-peak use, there would be no need for base and intermediate load generation. It is appropriate that all customers share in the higher capital cost of combined cycle generation given the resulting overall lower system cost per megawatt hour.

IV. ALTERNATE PROPOSALS FOR ALLOCATION OF PRODUCTION PLANT

Q. What alternatives did the Intervenor Witnesses propose for allocation of production plant?

A. Witnesses Pollock and Baron advocated maintaining the 12CP and 1/13th method. I have previously discussed why it is appropriate to switch from 12CP and 1/13th to the 12CP and 25% method. Witnesses Alderson and Chriss both present other alternatives for allocation of production plant. These alternatives are:

- 4CP (or 6 CP)
- 4CP summer / 1CP winter
- Average and Excess ("A&E")

Q. Please describe the 4CP and 6 CP proposals.

A. The 4CP proposal advocated by witnesses Alderson and Chriss is a demand only allocation based on the four highest summer coincident peaks. 100% of production demand-related costs are allocated based on the sum of each rate class'

demand at the time of the system peak during the months of June through September, divided by the sum of the system peaks for June through September. Witness Chriss also stated that since historical data for May and October are within 90% of the summer peak, he would agree with a 6CP allocation (Chriss at page 5, lines 1-10). A 6CP allocation would be applied in a similar manner as the 4CP method using the rate class coincident peaks during the months of May through October, rather than June through September.

Q. Please describe the 4CP summer / 1CP winter proposal.

A. The 4CP summer / 1CP winter proposal advocated by witness Alderson is similar to the 4CP proposal, except it includes the winter peak demand (January) with the four summer peak demands. Production demand related costs are allocated based on the sum of the four summer peaks of June through September plus the January peak for each rate class as a percent of the sum of the system peaks in those same months.

Q. Is it appropriate for production plant to be allocated exclusively on the basis of contribution to system peaks, as would be the case under the 4CP, 6CP or the 4CP / 1CP proposals?

A. No. All of these demand-only allocation proposals fail to recognize important considerations that this commission has acknowledged in setting production plant allocations: (1) generation capacity is needed to serve load every month, not just four, five, or six months of the year, to meet the annual LOLP criteria in FPL's resource planning process; and (2) energy use has an influence on the type of generating units added, which drives capital expenditures on FPL's system.

Additionally, the summer only allocation methods fail to recognize that FPL's resource planning includes a winter reserve margin criteria.

While the decision to add additional generation capacity is driven by load requirements, the *type* of generation capacity added - and thus the total cost of the unit additions - is influenced by the number of hours the units are expected to run. As Dr. Steven R. Sim, FPL's Resource Assessment and Planning witness in Docket No. 060225-EI, In re: Florida Power & Light Company's Petition to Determine Need for West County Energy Center Units 1 and 2 Electric Power Plant, noted, "the type of resources that should be added is primarily based on a determination of the resources that result in the lowest average electric rates for FPL's customers" (Sim Direct Testimony, page 5, line 23 through page 6, line 2). If MW capacity were the only consideration in the generation plan, the Company's generation portfolio would consist solely of peaking units that have the lowest fixed costs. This is clearly not the case. Witness Pollock admits that generation is chosen based on the lowest overall cost: "[h]aving determined that capacity is needed, FPL has chosen the generation technology that would result in the lowest overall cost. CCGTs are the most efficient generating technology and thus are also the lowest cost source of capacity." (Pollock p. 51, lines 20-22)

Q. Are there other problems with demand-only allocations for production plant?

A. Yes. Methods such as the those proposed by intervenors, which do not recognize that generation is needed to serve load every month of the year and that do not

recognize the importance energy use plays in the generation selection process, can result in some rate classes, such as the street light rate class, being allocated little or no production plant even though all rate classes clearly benefit from, and rely on, the system's production resources.

Q. Witness Chriss states that if the Commission wishes to maintain an energy allocation, it should use an A&E method for allocation of production plant cost. Do you agree?

A. No. Under the A&E method a portion of production plant costs equal to FPL's annual system load factor would be allocated on average demand ("AD"). The remaining costs would be allocated on the difference between a rate class's group non-coincident peak demand ("GNCP") and its average, which is the "excess" demand component of the formula. FPL's average load factor projected for the 2017 Test Year is 56%. Therefore, under the A&E method, 56% of production plant would be allocated on average demand. The "excess" demand component, 44% for 2017, would be allocated to rate classes based on the difference between their GNCP and their average demand.

The A&E method uses the GNCP to determine the allocation of the "excess" demand component of the formula. As described above, that means that 44% of the total production costs for 2017 would be allocated utilizing the rate class GNCP as the basis. The class GNCP demand is rarely coincident with the peak demand on the system. Use of this non-coincident demand to allocate production plant is inconsistent with FPL's generation planning process described previously.

Moreover, use of the class non-coincident peak demand to allocate production plant does not reflect cost-causation and directly contradicts witness Chriss' direct testimony.

Q. Does the use of the class non-coincident demand in the A&E method proposed by Walmart witness Chriss contradict his direct testimony?

A. Yes. As stated in his direct testimony, Mr. Chriss correctly recognizes that "… the timing and size of a utility's production plant are made to meet the maximum demand placed on the system by all customer classes, also known as its **coincident** peak ("CP")" (emphasis added) (Chriss p. 16, lines 14 – 16). Using the class **non-coincident** peak demands to allocate production plant directly contradicts that statement.

Q. Have you prepared an exhibit identifying the cost shifts as a result of these alternate proposals?

A. Yes, Exhibit RBD-9 shows the impacts on rate class revenue requirements due to the various proposed allocation methods. Page 1 shows that under the 4CP method $73 million is shifted from larger CI customers to residential and small general service customers. The residential rate class would see an increase of $63 million and the small general service rate class would see an increase of $10 million.

Page 2 of RBD-9 shows the impact of the proposed 4CP summer & 1CP winter method. In this case, residential customers would be the only class negatively

impacted, as $91 million would be shifted from all other customer classes to residential.

Page 3 of RBD-9 shows the impact of the A&E method. In this proposal, several rate classes would see higher costs. The residential rate class increases $34 million; the small general service rate class increases $6 million; and lighting customers see a $17 million increase.

Q. Is there a method that uses system demand data to calculate the AD weighting as A&E does but uses the coincident peak to allocate production plant?

A. Yes, the NARUC Manual on pages 57 and 58 discusses the use of the 1CP and AD and the 12CP and AD methods. Under these methods, the percentage of production plant classified and allocated based on energy is calculated by the percentage of the AD to the sum of the system peak (either 1CP or 12CP) and the AD. For FPL the amount of production plant classified as energy-related would be 36% under the 1CP and AD method and 39% under the 12CP and AD method. Either of these methods would be more appropriate than witness Chriss' proposal to allocate production-related demand costs based on non-coincident peak demand. I also should note that both methods result in a greater portion of production costs being allocated on an energy basis than FPL's proposed 12CP and 25% method.

V. PROPOSALS FOR USE OF A MINIMUM DISTRIBUTION SYSTEM COST ALLOCATION METHOD FOR DISTRIBUTION COSTS

Q. Witnesses Baron, Pollock and Alderson advocate the use of the MDS method for allocating distribution costs. Do you agree with this proposal?

A. No. The Commission should reject the MDS method in this case for the following reasons:

- The MDS method presumes a type of electric system and a method of planning that is not reflective of FPL's distribution system;
- The MDS method arbitrarily shifts all benefits obtained from economies of scale to the larger customers and inherently ignores the impact of diversity and double-counting;
- Witnesses Baron and Pollock inappropriately rely on the use of the MDS classifications used by Gulf and TECO as part of a stipulation and settlement agreements as a proxy to re-classify FPL distribution costs; and
- Outside of stipulations and settlement agreements, the Commission has consistently rejected this method for IOUs.

Q. Please explain.

A. First, the MDS method assumes that a certain investment in transformers, conductors and poles is required solely as a result of connecting customers to the electric system. Thus, the MDS method is based on a set of theoretical distribution facilities designed to serve the zero or minimum load requirements of customers. This Commission has previously stated this type of system is purely fictitious and has no grounding in the way the utility designs its systems or incurs

costs because no utility builds to serve zero load (Order No. PSC-02-0787-FOF-EI, page 76, issued June 10, 2002, in Docket No. 010949-EI, In re: Request for rate increase by Gulf Power Company). Moreover, the Commission's analysis is consistent with FPL's approach to distribution planning, as the central criterion used in planning FPL's distribution system is kW load requirements, not the number of customers served.

Next, the MDS method arbitrarily shifts all benefits obtained from economies of scale to the larger customers even though there are economies of scale in serving residential customers. In dense urban areas, not only are multiple residential customers frequently served off the same transformer, but the size of such a transformer is frequently comparable to that used for commercial customers. For example, a high-rise residential condominium and a high-rise office building have very similar facility requirements of FPL, but MDS would inappropriately shift costs from the office building to the condominium.

The diversity of residential customers' loads also creates economies of scale. Because each residential customer's maximum demand will not coincide exactly with other customers on the same transformer, engineering procedures dictate that transformers serving multiple residential customers need not be sized to serve the sum of every customer's maximum demand. FPL's distribution planners can, and do, routinely add new customers to existing transformers because of the diversity

of residential loads. By contrast, no such diversity is applicable to a large commercial customer served from a single transformer.

The MDS method also double counts the kW loads of customers for the investment in transformers associated with their so-called minimal load requirements. This double counting occurs because customers would first be allocated their cost of the so-called minimum load transformers based on the number of customers. The remaining cost of transformers would then be allocated on the basis of their maximum individual customer non-coincident peaks ("NCP"), with no adjustment for that portion of the maximum customer peaks which is provided under the minimum load transformer. The impact of this double counting on the residential and the small commercial rate class customers is especially great because they represent 98% of secondary distribution customers and 88% of secondary customer NCP.

Q. Does the Company's proposed method of allocating distribution plant avoid these problems with the MDS method?

A. Yes. FPL's method classifies meters, service drops and primary pull-offs as customer-related and classifies the remaining balance of distribution plant as demand-related. Thus, under FPL's method substations, poles, conductors (excluding primary pull-offs) and transformers are classified as demand-related and are properly allocated among the rate classes using various measures of peak demand.

Q. If one were to use the MDS method, do witnesses Baron and Pollock properly determine the amount of distribution costs to classify as customer related for FPL?

A. No. Witnesses Baron and Pollock inappropriately rely on Gulf and TECO'S MDS classifications as proxies for FPL's distribution plant accounts. The Gulf and TECO systems are different than FPL's in terms of size (physical service area and number of customers), geography, and the diversity of customers being served.

Witness Pollock did not perform an analysis to compare FPL's distribution cost to either Gulf or TECO. Instead, he proposed that FPL simply use the average of Gulf and TECO's results to classify 26% of distribution costs as customer related.

Mr. Baron performed an analysis only of Account 364 – Poles, Towers and Fixtures to compare Gulf and TECO's costs to FPL's costs for the purpose of classifying plant under the MDS method (page 44-45, lines 9-20 and line 1-16). In his comparison, he states that Gulf used the cost of 35' poles and smaller as the basis for classifying 65% of costs in this account to the customer component. He also notes that TECO's study assigned 64% of Account 364 as customer related. For FPL, Mr. Baron used a subaccount that also includes more expensive 40' and 45' poles in addition to 35' poles to calculate a customer component percentage of 70%. He then concludes that these percentages are close enough to be able to declare that Gulf's and TECO's MDS classification results are a good proxy for

all of FPL's distribution costs, which is convenient for his argument, but unsuitable as a basis for allocating FPL's costs.

Q. Does the NARUC Manual support the use of the MDS method in this case as the Intervenor Witnesses claim?

A. No. Witnesses Baron, Pollock, and Alderson imply that the NARUC Manual endorses, if not requires, the use of the MDS method (Pollock at page 57-58, lines 15-21 and 1-16; Baron at page 35-36, lines 18-21 and lines 1-20; Alderson at page 24, lines 1-15). However, as the Commission has previously observed, the NARUC Manual states that the choice of method will depend on the unique circumstances of the case (Order No. PSC-02-0787-FOF-EI, page 75, in Docket No. 010949-EI).

It is important to note that the NARUC Manual was not intended to prescribe one allocation method over another. In fact, the preface states:

> "the writing style should be nonjudgmental; not advocating any one particular method, but trying to include all currently used methods with pros and cons."

The NARUC Manual further states:

> "In making this determination, *supporting data* may be more important than *theoretical considerations*. Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses" (page 89) (Emphasis added)

Moreover, the NARUC Manual also recognizes that MDS may not be an accurate way to segregate customer- and demand-related costs. Specifically, the NARUC Manual states:

> "Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost." (page 95)

In other words, the NARUC Manual itself does not endorse any particular cost allocation method. It also recognizes that the MDS method has an inherent flaw - that the so-called customer-related costs have a demand component to them.

Q. You previously indicated that the central criterion used in planning the FPL distribution system is kW load requirements, not the number of customers served. Does this mean that the need to serve individual customers never influences distribution plant additions?

A. No. There are certainly cases where line extensions are required to serve specific customers. This is where a strong and consistently enforced contribution-in-aid-of-construction ("CIAC") policy comes into play. As outlined in Rule 25-6.064, F.A.C., customers are required to pay for the cost of any line extension to the extent that the expected revenues do not offset the cost of the line extension. In this manner, customers with "minimum load requirements" must pay for the cost of any requested line extensions above that which would otherwise be required to

serve the expected load. This is a far more equitable outcome than the cost allocation resulting from the MDS method, because the specific customers necessitating the line extension bear the cost.

Q. Is the requirement to pay a line extension CIAC limited to large commercial/industrial customers?

A. No, not at all. A CIAC would be required in any case where the expected load and revenue does not offset the required investment. In fact, the CIAC line extension formula is routinely applied to new residential customers and subdivisions.

Q. Do the Intervenor Witnesses offer any other arguments for applying the MDS method in this case?

A. Yes. The Intervenor Witnesses cite the fact that the Commission has recently approved settlement agreements that provide for the use of the MDS method by Gulf and TECO as reasons to require MDS by FPL. As discussed previously, the approval by the Commission of a settlement agreement that includes MDS does not necessarily constitute endorsement or specific approval of that method as the most appropriate approach. I would also like to point out that, unlike the changes in the makeup of our generation system that has driven the decision to use a different allocation method for production plant, there have been no changes in the distribution system to justify moving to the MDS method.

Q. FIPUG witness Pollock states that the distribution storm hardening requirement is not needed to meet customer load, but instead is required to connect customers to the grid. Do you agree?

A. No. As Mr. Pollock noted, the storm hardening rule was implemented to "require the cost-effective strengthening of critical electric infrastructure to increase the ability of transmission and distribution facilities to withstand extreme weather conditions; and reduce restoration costs and **outage times** to end-use customers associated with extreme weather conditions" (emphasis added). Clearly if there is no load on the system then there is no outage. Storm hardening is required to serve customer's demand and energy needs, not to serve customers with no demand.

Mr. Pollock implies that only residential customers benefit from storm hardening, and should bear the majority of the cost. This is clearly not the case. Certainly commercial and industrial customers benefit from storm hardening at least as much, if not more than residential customers. Businesses cannot operate without electricity. Even those with backup generation will incur higher operating costs during an outage. It is fair and appropriate that all customers share the cost of the approved storm hardening plans.

Q. Witnesses Baron and Pollock use a pole per customer analysis to attempt to illustrate that FPL's demand only allocation is unreasonable. Is this analysis appropriate?

A. No. First of all, the cost of service study allocates costs, not poles. Second, FPL has a large percent of residential customers that are served from underground that do not require a pole beyond the feeder. FPL also has a large, dense urban population residing in multiple-occupancy buildings such as condominiums,

apartment complexes and high-rise buildings. As a result, it is not appropriate to use a pole per customer analysis to evaluate the cost of service allocation method.

Q. Have you performed a calculation of the cost shifts that would result from the proposed use of the MDS method?

A. Yes. I would first note that while 88% of FPL customers are residential and only 2% are CI demand customers, the residential customers account for only 59% of FPL's load while the CI demand customers account for 35%. As stated previously, FPL's system is designed on the basis of load, and CI customers have significantly higher loads per customer than residential. This is the reason that any attempt to change the cost allocation to a customer-based one, i.e., MDS, inappropriately shifts costs to residential customers. The Intervenor Witnesses' proposed use of the MDS method would shift costs away from medium and large commercial rate classes, classes in which the witnesses' clients take service, onto residential and small commercial rate classes.

Exhibit RBD-10 provides a comparison of the rate class revenue requirements as proposed by FPL and those that would result from the use of the proposed MDS method. As can be seen on page 1 of Exhibit RBD-10, the residential rate class would be allocated $66 million in additional costs using MDS than the amount in FPL's 2017 Test Year cost of service study. Likewise, the small general service rate class would be allocated $8 million more. In total, use of the MDS method would shift $74 million in costs away from larger CI rate classes represented by the Intervenor Witnesses and onto residential and small commercial rate classes.

Witnesses Baron, Pollock, and Alderson all support use of MDS, and they also support the use of alternatives to FPL's proposed 12CP and 25% production cost allocation method as discussed previously. The combined impact of the use of MDS with the use of the alternative production allocation methods supported by the Intervenor Witnesses is shown on pages 2 – 5 of Exhibit RBD-10. For the residential rate class, the impacts are:

- 12CP & 1/13th + MDS: $90 million
- 4CP + MDS: $128 million
- 4CP / 1CP + MDS: $157 million
- A&E + MDS: $99 million

Exhibit RBD-11 summarizes the impacts to the rate classes due to the alternative COSS allocation methods proposed by the Intervenor Witnesses.

Q. Are the reasons the Commission cited for rejecting the MDS method in prior cases still applicable?

A. Yes. The reasons cited in prior cases remain applicable in this case. Exhibit RBD-12 contains a list of Commission Orders rejecting the use of the MDS method. Further, the justifications the Intervenor Witnesses rely on, the stipulation and settlement agreements in the Gulf and TECO cases and the storm hardening requirement, do not provide a valid basis for the Commission to deviate from those prior decisions for FPL. FPL's methods of allocating distribution costs remain valid for FPL, and the MDS proposal should be rejected.

VI. IDENTIFIED ADJUSTMENTS

Q. Were there any items in the Notice of Adjustments ("NOA") impacting the COSS?

A. Yes. Item numbers 15 and 16 in Attachment 1 to the NOA filed on May 7, 2016 impacted the COSS. Item 15 identified an issue with the cost basis for transmission pull-offs that resulted in customer-related unit costs for the transmission rates (CILC-1T, GSLD(T)-3, and SST-TST) being about $1000 too high. Item 16 identified an issue with inclusion of $3.1 million of wholesale interchange revenue in revenues from sales of electricity that should have been reclassified to other operating revenues. The reclassification from sales revenues to other revenues is needed in order to not impact retail revenue reflected in MFR E-6. This had no impact on revenue recovered through base rates and only a minor impact on unit cost.

Q. Do you have any exhibits that reflect these adjustments?

A. Yes, Exhibit RBD-13 reflects the revised MFR E-1 and E-6b for items 15 and 16 in the NOA.

Q. Does this conclude your rebuttal testimony?

A. Yes.

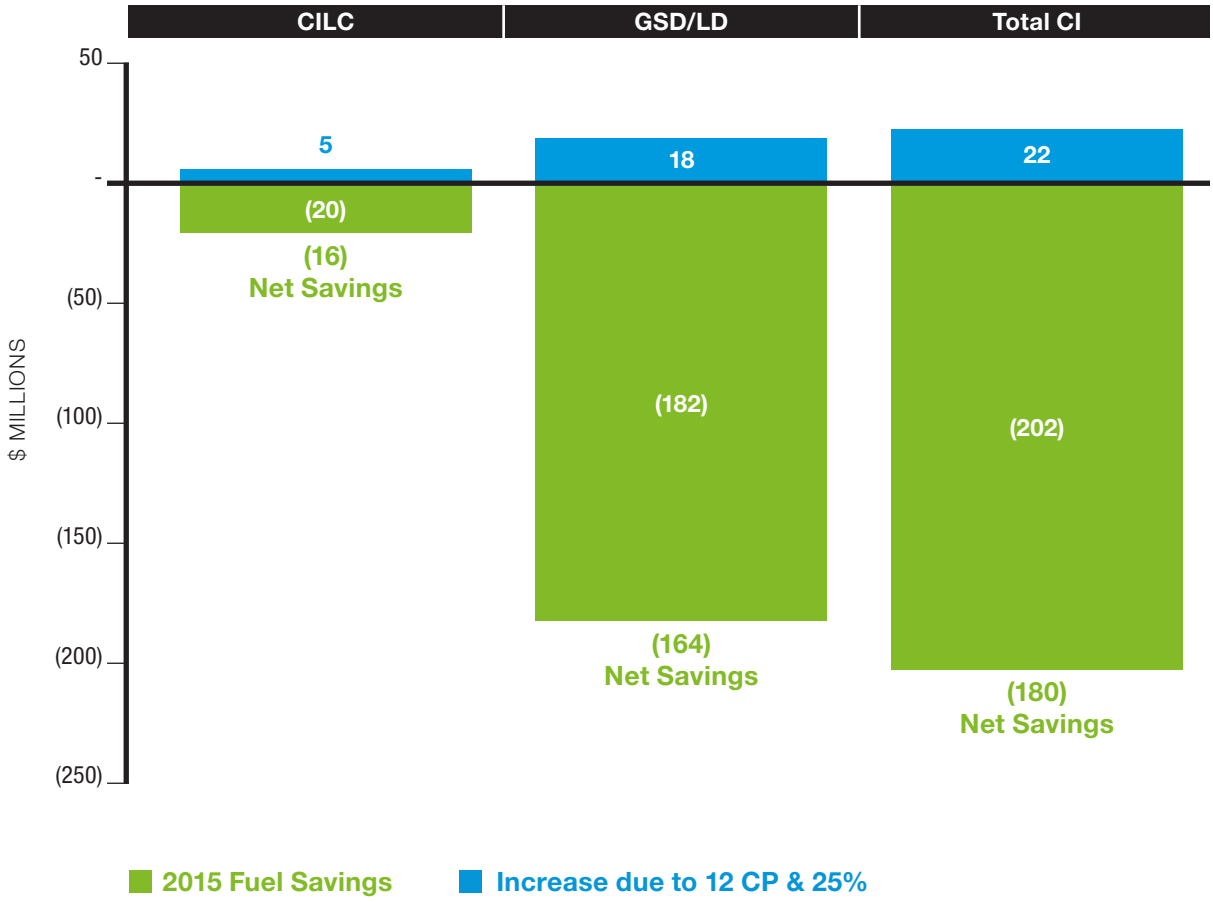
FPL Generation Fleet 2015 vs. 1989

	Firm Capability 2015 [1]		% Capability		Net Capability 1989 [2]		% Capability		Change in %	
Unit Type	Winter MW	Summer MW	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
ST	8,369	8,231	30.8%	32.6%	11,402	11,264	80.9%	82.7%	-50.0%	-50.1%
CC	16,411	14,844	60.5%	58.8%	468	448	3.3%	3.3%	57.2%	55.5%
GT/CT	2,350	2,143	8.7%	8.5%	2,228	1,910	15.8%	14.0%	-7.1%	-5.5%
PV	-	20	0.0%	0.1%					0%	0%
	27,130	25,238	100%	100%	14,098	13,622	100%	100%	0%	0%

(1) 2016 Ten Year Site Plan, p. 23 Schedule 1
(2) 1990 Ten Year Site Plan, p. 42 Form 1A

ST = Steam
CC = Combined Cycle
PV = Solar photovoltaic
GT = Gas Turbine
CT = Combustion Turbine

Comparison of CI Customer Fuel Savings* to Additional Revenue Requirements under 12CP & 25%



*Allocation of $500 million of 2015 fuel savings due to heat rate efficiency improvements

Impact of 4CP on Rate Class Revenue Requirements

For the Test Year 2017
($ Millions)

Line	(1) Rate Class	(2) As Filed Target Revenue Requirements (1)	(3) 4CP Target Revenue Requirements	(4) Increase (Decrease) in Revenue Requirements (3) - (2)	(5) Percent Increase (Decrease) (4) / (2)
1	RS(T)-1	3,924.2	3,986.7	62.6	1.6%
2	GS(T)-1	389.3	399.4	10.2	2.6%
3	GSCU-1	3.9	3.6	(0.3)	-7.0%
4	GSD(T)-1	1,341.9	1,318.1	(23.8)	-1.8%
5	GSLD(T)-1	535.1	515.4	(19.7)	-3.7%
6	GSLD(T)-2	108.7	100.8	(7.9)	-7.3%
7	GSLD(T)-3	5.8	5.2	(0.6)	-9.6%
8	CILC-1D	115.0	106.8	(8.1)	-7.1%
9	CILC-1G	4.6	4.3	(0.3)	-6.6%
10	CILC-1T	47.7	42.2	(5.5)	-11.4%
11	OL-1	12.9	12.1	(0.8)	-6.4%
12	OS-2	1.4	1.3	(0.1)	-6.6%
13	SL-1	98.2	93.4	(4.8)	-4.9%
14	SL-2	1.4	1.3	(0.1)	-9.0%
15	MET	4.6	4.5	(0.2)	-3.8%
16	SST-DST	0.9	0.9	(0.0)	-3.0%
17	SST-TST	3.0	2.5	(0.6)	-18.4%
	Total Revenues from Sa	**6,598.6**	**6,598.6**	**0.0**	**0.0%**
	Other Operating Revenu	190.0	190.0	-	0.0%
	Total Operating Revenu	6,788.6	6,788.6	0.0	0.0%

Notes:
(1) As provided in the direct testimony of Renae B. Deaton in Exhibit RBD-6, Column (2)

Totals may not add due to rounding.

Impact of 4CP and 1CP Winter on Rate Class Revenue Requirements

For the Test Year 2017
($ Millions)

Line	(1) Rate Class	(2) As Filed Target Revenue Requirements (1)	(3) 4CP and 1CP Winter Target Revenue Requirements	(4) Increase (Decrease) in Revenue Requirements (3) - (2)	(5) Percent Increase (Decrease) (4) / (2)
1	RS(T)-1	3,924.2	4,015.2	91.0	2.3%
2	GS(T)-1	389.3	388.0	(1.2)	-0.3%
3	GSCU-1	3.9	3.6	(0.2)	-6.4%
4	GSD(T)-1	1,341.9	1,300.8	(41.1)	-3.1%
5	GSLD(T)-1	535.1	512.6	(22.5)	-4.2%
6	GSLD(T)-2	108.7	100.9	(7.8)	-7.2%
7	GSLD(T)-3	5.8	5.3	(0.5)	-8.8%
8	CILC-1D	115.0	107.5	(7.5)	-6.5%
9	CILC-1G	4.6	4.3	(0.3)	-6.0%
10	CILC-1T	47.7	42.5	(5.2)	-10.9%
11	OL-1	12.9	12.3	(0.6)	-4.6%
12	OS-2	1.4	1.4	(0.1)	-3.7%
13	SL-1	98.2	94.9	(3.3)	-3.4%
14	SL-2	1.4	1.3	(0.1)	-8.2%
15	MET	4.6	4.5	(0.1)	-2.7%
16	SST-DST	0.9	0.9	(0.0)	-4.5%
17	SST-TST	3.0	2.6	(0.5)	-15.1%
	Total Revenues from Sa	**6,598.6**	**6,598.6**	**(0.0)**	**0.0%**
	Other Operating Revenu	190.0	190.0	-	0.0%
	Total Operating Revenu	6,788.6	6,788.6	(0.0)	0.0%

Notes:
(1) As provided in the direct testimony of Renae B. Deaton in Exhibit RBD-6, Column (2)

Totals may not add due to rounding.

Impact of Average & Excess Demand on Rate Class Revenue Requirements

For the Test Year 2017
($ Millions)

Line	(1) Rate Class	(2) As Filed Target Revenue Requirements (1)	(3) Average & Excess Demand Target Revenue Requirements	(4) Increase (Decrease) in Revenue Requirements (3) - (2)	(5) Percent Increase (Decrease) (4) / (2)
1	RS(T)-1	3,924.2	3,958.1	34.0	0.9%
2	GS(T)-1	389.3	395.0	5.7	1.5%
3	GSCU-1	3.9	3.6	(0.3)	-6.8%
4	GSD(T)-1	1,341.9	1,307.9	(34.1)	-2.5%
5	GSLD(T)-1	535.1	524.9	(10.1)	-1.9%
6	GSLD(T)-2	108.7	102.5	(6.2)	-5.7%
7	GSLD(T)-3	5.8	6.5	0.8	13.1%
8	CILC-1D	115.0	106.1	(8.9)	-7.8%
9	CILC-1G	4.6	4.3	(0.3)	-7.3%
10	CILC-1T	47.7	44.2	(3.5)	-7.3%
11	OL-1	12.9	15.3	2.4	18.3%
12	OS-2	1.4	2.6	1.1	79.4%
13	SL-1	98.2	112.1	13.9	14.1%
14	SL-2	1.4	1.3	(0.1)	-9.2%
15	MET	4.6	4.6	(0.1)	-1.6%
16	SST-DST	0.9	1.6	0.7	74.2%
17	SST-TST	3.0	8.1	5.0	165.4%
	Total Revenues from Sa	**6,598.6**	**6,598.6**	**0.0**	**0.0%**
	Other Operating Revenu	190.0	190.0	-	0.0%
	Total Operating Revenu	6,788.6	6,788.6	0.0	0.0%

Notes:
(1) As provided in the direct testimony of Renae B. Deaton in Exhibit RBD-6, Column (2)

Totals may not add due to rounding.

Impact of MDS on Rate Class Revenue Requirements

For the Test Year 2017
($ Millions)

Line	(1) Rate Class	(2) As Filed Target Revenue Requirements (1)	(3) MDS Target Revenue Requirements	(4) Increase (Decrease) in Revenue Requirements (3) - (2)	(5) Percent Increase (Decrease) (4) / (2)
1	RS(T)-1	3,924.2	3,989.6	65.5	1.7%
2	GS(T)-1	389.3	397.4	8.2	2.1%
3	GSCU-1	3.9	4.3	0.5	12.5%
4	GSD(T)-1	1,341.9	1,297.1	(44.8)	-3.3%
5	GSLD(T)-1	535.1	514.7	(20.3)	-3.8%
6	GSLD(T)-2	108.7	104.5	(4.2)	-3.9%
7	GSLD(T)-3	5.8	5.8	-	0.0%
8	CILC-1D	115.0	110.6	(4.3)	-3.8%
9	CILC-1G	4.6	4.4	(0.2)	-3.3%
10	CILC-1T	47.7	47.7	-	0.0%
11	OL-1	12.9	14.8	1.9	14.7%
12	OS-2	1.4	1.2	(0.2)	-14.8%
13	SL-1	98.2	96.6	(1.6)	-1.6%
14	SL-2	1.4	1.4	(0.0)	-3.0%
15	MET	4.6	4.4	(0.3)	-5.6%
16	SST-DST	0.9	0.8	(0.1)	-12.2%
17	SST-TST	3.0	3.0	-	0.0%
	Total Revenues from Sales	**6,598.6**	**6,598.6**	**0.0**	**0.0%**
	Other Operating Revenues	190.0	190.0	-	0.0%
	Total Operating Revenues	**6,788.6**	**6,788.6**	**0.0**	**0.0%**

Notes:

(1) As provided in the direct testimony of Renae B. Deaton in Exhibit RBD-6, Column (2)

Totals may not add due to rounding.

Impact of MDS and 12CP & 1/13th on Rate Class Revenue Requirements

For the Test Year 2017
($ Millions)

Line	(1) Rate Class	(2) As Filed Target Revenue Requirements (1)	(3) MDS and 12CP & 1/13thTarget Revenue Requirements	(4) Increase (Decrease) in Revenue Requirements (3) - (2)	(5) Percent Increase (Decrease) (4) / (2)
1	RS(T)-1	3,924.2	4,014.2	90.1	2.3%
2	GS(T)-1	389.3	397.6	8.3	2.1%
3	GSCU-1	3.9	4.3	0.4	10.2%
4	GSD(T)-1	1,341.9	1,286.8	(55.2)	-4.1%
5	GSLD(T)-1	535.1	510.2	(24.8)	-4.6%
6	GSLD(T)-2	108.7	101.9	(6.8)	-6.2%
7	GSLD(T)-3	5.8	5.6	(0.2)	-2.9%
8	CILC-1D	115.0	107.9	(7.1)	-6.1%
9	CILC-1G	4.6	4.3	(0.2)	-5.4%
10	CILC-1T	47.7	46.0	(1.7)	-3.6%
11	OL-1	12.9	14.5	1.5	12.0%
12	OS-2	1.4	1.2	(0.2)	-15.7%
13	SL-1	98.2	94.6	(3.6)	-3.6%
14	SL-2	1.4	1.3	(0.1)	-5.9%
15	MET	4.6	4.3	(0.3)	-6.3%
16	SST-DST	0.9	0.8	(0.1)	-13.0%
17	SST-TST	3.0	2.9	(0.1)	-4.6%
	Total Revenues from Sales	**6,598.6**	**6,598.6**	**0.0**	**0.0%**
	Other Operating Revenues	190.0	190.0	-	0.0%
	Total Operating Revenues	**6,788.6**	**6,788.6**	**0.0**	**0.0%**

Notes:

(1) As provided in the direct testimony of Renae B. Deaton in Exhibit RBD-6, Column (2)

Totals may not add due to rounding.

Impact of 4CP and MDS on Rate Class Revenue Requirements

For the Test Year 2017
($ Millions)

Line	(1) Rate Class	(2) As Filed Target Revenue Requirements [1]	(3) 4CP and MDS Target Revenue Requirements	(4) Increase (Decrease) in Revenue Requirements (3) - (2)	(5) Percent Increase (Decrease) (4) / (2)
1	RS(T)-1	3,924.2	4,052.2	128.0	3.3%
2	GS(T)-1	389.3	407.6	18.3	4.7%
3	GSCU-1	3.9	4.1	0.2	5.5%
4	GSD(T)-1	1,341.9	1,273.3	(68.6)	-5.1%
5	GSLD(T)-1	535.1	495.0	(40.0)	-7.5%
6	GSLD(T)-2	108.7	96.6	(12.1)	-11.1%
7	GSLD(T)-3	5.8	5.2	(0.6)	-9.6%
8	CILC-1D	115.0	102.5	(12.5)	-10.9%
9	CILC-1G	4.6	4.1	(0.5)	-9.9%
10	CILC-1T	47.7	42.2	(5.5)	-11.4%
11	OL-1	12.9	14.0	1.1	8.3%
12	OS-2	1.4	1.1	(0.3)	-21.4%
13	SL-1	98.2	91.8	(6.4)	-6.5%
14	SL-2	1.4	1.2	(0.2)	-12.0%
15	MET	4.6	4.2	(0.4)	-9.4%
16	SST-DST	0.9	0.8	(0.1)	-15.2%
17	SST-TST	3.0	2.5	(0.6)	-18.4%
	Total Revenues from Sales	**6,598.6**	**6,598.6**	**(0.0)**	**0.0%**
	Other Operating Revenues	190.0	190.0	-	0.0%
	Total Operating Revenues	**6,788.6**	**6,788.6**	**(0.0)**	**0.0%**

Notes:
[1] As provided in the direct testimony of Renae B. Deaton in Exhibit RBD-6, Column (2)

Totals may not add due to rounding.

Impact of 4CP, 1CP Winter, and MDS on Rate Class Revenue Requirements

For the Test Year 2017
($ Millions)

Line	(1) Rate Class	(2) As Filed Target Revenue Requirements [1]	(3) 4CP and 1CP Winter and MDS Target Revenue Requirements	(4) Increase (Decrease) in Revenue Requirements (3) - (2)	(5) Percent Increase (Decrease) (4) / (2)
1	RS(T)-1	3,924.2	4,080.7	156.5	4.0%
2	GS(T)-1	389.3	396.2	6.9	1.8%
3	GSCU-1	3.9	4.1	0.2	6.1%
4	GSD(T)-1	1,341.9	1,256.1	(85.9)	-6.4%
5	GSLD(T)-1	535.1	492.2	(42.8)	-8.0%
6	GSLD(T)-2	108.7	96.7	(12.0)	-11.1%
7	GSLD(T)-3	5.8	5.3	(0.5)	-8.8%
8	CILC-1D	115.0	103.2	(11.8)	-10.3%
9	CILC-1G	4.6	4.2	(0.4)	-9.3%
10	CILC-1T	47.7	42.5	(5.2)	-10.9%
11	OL-1	12.9	14.2	1.3	10.1%
12	OS-2	1.4	1.2	(0.3)	-18.5%
13	SL-1	98.2	93.3	(4.9)	-5.0%
14	SL-2	1.4	1.2	(0.2)	-11.2%
15	MET	4.6	4.2	(0.4)	-8.3%
16	SST-DST	0.9	0.8	(0.2)	-16.7%
17	SST-TST	3.0	2.6	(0.5)	-15.1%
	Total Revenues from Sales	**6,598.6**	**6,598.6**	**0.0**	**0.0%**
	Other Operating Revenues	190.0	190.0	-	0.0%
	Total Operating Revenues	**6,788.6**	**6,788.6**	**0.0**	**0.0%**

Notes:
[1] As provided in the direct testimony of Renae B. Deaton in Exhibit RBD-6, Column (2)

Totals may not add due to rounding.

Impact of A&E Demand and MDS on Rate Class Revenue Requirements

For the Test Year 2017
($ Millions)

Line	(1) Rate Class	(2) As Filed Target Revenue Requirements [1]	(3) A&E and MDS Target Revenue Requirements	(4) Increase (Decrease) in Revenue Requirements (3) - (2)	(5) Percent Increase (Decrease) (4) / (2)
1	RS(T)-1	3,924.2	4,023.6	99.4	2.5%
2	GS(T)-1	389.3	403.2	13.9	3.6%
3	GSCU-1	3.9	4.1	0.2	5.7%
4	GSD(T)-1	1,341.9	1,263.1	(78.9)	-5.9%
5	GSLD(T)-1	535.1	504.6	(30.5)	-5.7%
6	GSLD(T)-2	108.7	98.3	(10.4)	-9.6%
7	GSLD(T)-3	5.8	6.5	0.8	13.1%
8	CILC-1D	115.0	101.7	(13.3)	-11.5%
9	CILC-1G	4.6	4.1	(0.5)	-10.6%
10	CILC-1T	47.7	44.2	(3.5)	-7.3%
11	OL-1	12.9	17.2	4.3	33.0%
12	OS-2	1.4	2.4	0.9	64.5%
13	SL-1	98.2	110.5	12.3	12.5%
14	SL-2	1.4	1.2	(0.2)	-12.2%
15	MET	4.6	4.3	(0.3)	-7.3%
16	SST-DST	0.9	1.5	0.6	62.1%
17	SST-TST	3.0	8.1	5.0	165.4%
	Total Revenues from Sales	**6,598.6**	**6,598.6**	**0.0**	**0.0%**
	Other Operating Revenues	190.0	190.0	-	0.0%
	Total Operating Revenues	**6,788.6**	**6,788.6**	**0.0**	**0.0%**

Notes:
[1] As provided in the direct testimony of Renae B. Deaton in Exhibit RBD-6, Column (2)

Totals may not add due to rounding.

Summary of Rate Class Impact due to Proposed Alternative Allocation Methods ($MM)

Line	Rate Class	(1) 4CP	(2) 4CP and 1CP	(3) Average & Excess	(4) MDS Impact	(5) MDS and 12CP &	(6) 4CP and MDS	(7) 4CP, 1CP Winter,	(8) Average & Excess
1	RS(T)-1	62.6	91.0	34.0	65.5	90.1	128.0	156.5	99.4
2	GS(T)-1	10.2	(1.2)	5.7	8.2	8.3	18.3	6.9	13.9
3	GSCU-1	(0.3)	(0.2)	(0.3)	0.5	0.4	0.2	0.2	0.2
4	GSD(T)-1	(23.8)	(41.1)	(34.1)	(44.8)	(55.2)	(68.6)	(85.9)	(78.9)
5	GSLD(T)-1	(19.7)	(22.5)	(10.1)	(20.3)	(24.8)	(40.0)	(42.8)	(30.5)
6	GSLD(T)-2	(7.9)	(7.8)	(6.2)	(4.2)	(6.8)	(12.1)	(12.0)	(10.4)
7	GSLD(T)-3	(0.6)	(0.5)	0.8	-	(0.2)	(0.6)	(0.5)	0.8
8	CILC-1D	(8.1)	(7.5)	(8.9)	(4.3)	(7.1)	(12.5)	(11.8)	(13.3)
9	CILC-1G	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.5)	(0.4)	(0.5)
10	CILC-1T	(5.5)	(5.2)	(3.5)	-	(1.7)	(5.5)	(5.2)	(3.5)
11	OL-1	(0.8)	(0.6)	2.4	1.9	1.5	1.1	1.3	4.3
12	OS-2	(0.1)	(0.1)	1.1	(0.2)	(0.2)	(0.3)	(0.3)	0.9
13	SL-1	(4.8)	(3.3)	13.9	(1.6)	(3.6)	(6.4)	(4.9)	12.3
14	SL-2	(0.1)	(0.1)	(0.1)	(0.0)	(0.1)	(0.2)	(0.2)	(0.2)
15	MET	(0.2)	(0.1)	(0.1)	(0.3)	(0.3)	(0.4)	(0.4)	(0.3)
16	SST-DST	(0.0)	(0.0)	0.7	(0.1)	(0.1)	(0.1)	(0.2)	0.6
17	SST-TST	(0.6)	(0.5)	5.0	-	(0.1)	(0.6)	(0.5)	5.0

(1) 4CP method per Exhibit RBD-9, page 1 of 3
(2) 4CP and 1CP Winter method per Exhibit RBD-9, page 2 of 3
(3) Average & Excess Demand method per Exhibit RBD-9, page 3 of 3
(4) MDS method per Exhibit RBD-10, page 1 of 5
(5) MDS and 12CP and 1/13th. method per Exhibit RBD-10, page 2 of 5
(6) 4CP and MDS method per Exhibit RBD-10, page 3 of 5
(7) 4CP, 1CP Winter, and MDS method per Exhibit RBD-10, page 4 of 5
(8) Average & Excess Demand method per Exhibit RBD-10, page 5 of 5

Prior Commission Orders Rejecting Use of MDS

No.	Order No.	Issue Date	Docket No.	Company
1	9599	October 17, 1980	800011-EU	Tampa Electric Company
2	9628	November 10, 1980	800001-EU	Gulf Power Company
3	9864	March 11, 1980	800119-EU	Florida Power Corporation
4	10306	September 23, 1981	810002-EU	Florida Power & Light Company
5	10557	February 1, 1982	8100136-EU	Gulf Power Company
6	11307	November 10, 1982	820007-EU	Tampa Electric Company
7	11437	December 22, 1982	820097-EU	Florida Power & Light Company
8	11498	January 11, 1983	820150-EU	Gulf Power Company
9	11628	February 17, 1983	820100-EU	Florida Power Corporation
10	23573	October 3, 1990	891345-EI	Gulf Power Company
11	PSC-02-0787-FOF-EI	June 10, 2002	010949-EI	Gulf Power Company
12	PSC-10-0153-FOF-EI	March 17, 2010	080677-EI	Florida Power & Light Company

MFR E-1 - COST OF SERVICE STUDY
AT PRESENT RATES - December 2017
($000 WHERE APPLICABLE)

Method: 12CP and 25%	TOTAL RETAIL	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET
RATE BASE -											
Electric Plant In Service	43,122,297	733,617	29,415	287,358	2,500,403	22,995	8,727,503	3,488,258	697,104	35,364	29,763
Accum Depreciation & Amortization	(13,074,538)	(215,247)	(8,701)	(82,323)	(756,897)	(6,987)	(2,593,722)	(1,032,855)	(204,987)	(10,195)	(8,717)
Net Plant In Service	30,047,759	518,370	20,714	205,035	1,743,506	16,008	6,133,781	2,455,403	492,117	25,169	21,046
Plant Held For Future Use	233,315	4,327	169	1,876	13,432	118	49,954	20,185	4,089	238	174
Construction Work in Progress	747,987	13,078	518	5,786	43,437	417	152,801	61,251	12,374	729	517
Net Nuclear Fuel	630,075	15,678	597	8,603	35,101	413	151,865	61,743	14,687	987	525
Total Utility Plant	31,659,136	551,452	21,998	221,300	1,835,477	16,956	6,488,400	2,598,581	523,267	27,122	22,262
Working Capital - Assets	3,552,622	63,554	2,511	28,623	216,342	2,503	707,176	280,985	60,009	3,382	2,415
Working Capital - Liabilities	(2,675,642)	(46,361)	(1,835)	(20,352)	(164,467)	(1,905)	(523,311)	(207,419)	(43,824)	(2,410)	(1,776)
Working Capital - Net	876,981	17,193	676	8,271	51,874	598	183,865	73,566	16,185	972	639
Total Rate Base	32,536,116	568,645	22,674	229,572	1,887,351	17,554	6,672,265	2,672,147	539,452	28,094	22,902
REVENUES -											
Sales of Electricity	5,725,192	87,743	4,108	35,842	369,198	4,184	1,137,893	381,091	78,330	4,563	4,093
Other Operating Revenues	197,013	1,683	68	465	12,321	111	23,189	8,219	1,669	58	68
Total Operating Revenues	5,922,205	89,426	4,176	36,307	381,520	4,295	1,161,082	389,310	79,999	4,621	4,161
EXPENSES -											
Operating & Maintenance Expense	(1,354,606)	(22,234)	(885)	(9,338)	(84,823)	(1,007)	(255,814)	(100,855)	(21,054)	(1,109)	(862)
Depreciation Expense	(1,672,107)	(28,864)	(1,159)	(12,124)	(97,860)	(924)	(338,610)	(134,810)	(27,286)	(1,478)	(1,186)
Taxes Other Than Income Tax	(578,191)	(9,904)	(396)	(3,943)	(33,819)	(320)	(117,213)	(46,790)	(9,413)	(484)	(402)
Amortization of Property Losses	6,182	100	4	30	369	4	1,200	477	97	4	4
Gain or Loss on Sale of Plant	5,759	97	4		340	2	1,222	502	95		4
Total Operating Expenses	(3,592,963)	(60,805)	(2,432)	(25,375)	(215,793)	(2,245)	(709,216)	(281,476)	(57,561)	(3,067)	(2,442)
Net Operating Income Before Taxes	2,329,242	28,621	1,744	10,932	165,726	2,050	451,866	107,834	22,438	1,554	1,719
Income Taxes	(711,051)	(7,715)	(543)	(2,882)	(53,209)	(694)	(135,821)	(25,803)	(5,474)	(437)	(532)
NOI Before Curtailment Adjustment	1,618,192	20,906	1,201	8,049	112,518	1,356	316,045	82,031	16,963	1,117	1,187
Curtailment Credit Revenue	587							388	130	70	

MFR E-1 - COST OF SERVICE STUDY
AT PRESENT RATES - December 2017
($000 WHERE APPLICABLE)

Method: 12CP and 25%	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
RATE BASE -							
Electric Plant In Service	104,444	10,049	25,788,030	635,142	8,726	6,333	17,794
Accum Depreciation & Amortization	(41,364)	(3,151)	(7,868,871)	(230,804)	(2,587)	(1,883)	(5,247)
Net Plant In Service	63,080	6,899	17,919,159	404,338	6,139	4,451	12,547
Plant Held For Future Use	131	42	137,253	1,110	50	35	132
Construction Work in Progress	1,240	133	445,879	9,172	158	96	402
Net Nuclear Fuel	576	62	335,168	3,298	193	68	511
Total Utility Plant	65,027	7,135	18,837,459	417,918	6,541	4,650	13,593
Working Capital - Assets	4,799	658	2,122,938	53,777	821	447	1,680
Working Capital - Liabilities	(3,354)	(503)	(1,614,426)	(41,569)	(604)	(341)	(1,184)
Working Capital - Net	1,445	155	508,512	12,208	217	107	496
Total Rate Base	66,472	7,290	19,345,971	430,126	6,757	4,756	14,089
REVENUES -							
Sales of Electricity	14,051	992	3,505,124	91,271	1,508	801	4,400
Other Operating Revenues	680	35	147,117	1,254	21	21	33
Total Operating Revenues	14,730	1,027	3,652,241	92,526	1,529	823	4,433
EXPENSES -							
Operating & Maintenance Expense	(1,684)	(268)	(830,125)	(23,536)	(297)	(175)	(541)
Depreciation Expense	(4,261)	(371)	(996,003)	(25,877)	(345)	(227)	(722)
Taxes Other Than Income Tax	(1,180)	(131)	(345,721)	(8,028)	(119)	(84)	(243)
Amortization of Property Losses	21	2	3,725	141	1	1	2
Gain or Loss on Sale of Plant	7	3	3,440	40	1	2	
Total Operating Expenses	(7,096)	(764)	(2,164,684)	(57,259)	(759)	(484)	(1,503)
Net Operating Income Before Taxes	7,634	263	1,487,557	35,267	770	339	2,930
Income Taxes	(2,568)	(57)	(462,798)	(11,095)	(260)	(103)	(1,060)
NOI Before Curtailment Adjustment	5,066	205	1,024,759	24,172	510	236	1,870
Curtailment Credit Revenue							

MFR E-1 - COST OF SERVICE STUDY
AT PRESENT RATES - December 2017
($000 WHERE APPLICABLE)

Method: 12CP and 25%	TOTAL RETAIL	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET
Reassign Curtailment Credit Revenue	(587)	(11)	(0)	(6)	(33)	(0)	(127)	(51)	(10)	(1)	(0)
Net Curtailment Credit Revenue		(11)	(0)	(6)	(33)	(0)	(127)	336	119	69	(0)
Net Curtailment NOI Adjustment		(7)	(0)	(3)	(20)	(0)	(78)	206	73	42	(0)
Net Operating Income (NOI)	1,618,192	20,899	1,200	8,046	112,498	1,356	315,967	82,237	17,037	1,159	1,187
Rate of Return (ROR)	4.97%	3.68%	5.29%	3.50%	5.96%	7.72%	4.74%	3.08%	3.16%	4.13%	5.18%
Parity At Present Rates	1.00	0.74	1.06	0.70	1.20	1.55	0.95	0.62	0.63	0.83	1.04
EQUALIZED RATE OF RETURN (ROR) -											
Equalized Base Revenue Requirements	5,725,192	99,778	3,989	41,339	338,827	3,397	1,163,781	463,684	94,296	4,952	4,015
Other Operating Revenues	197,013	1,683	68	465	12,321	111	23,189	8,219	1,669	58	68
Total Equalized Revenue Requirements	5,922,205	101,461	4,058	41,804	351,149	3,507	1,186,970	471,903	95,965	5,009	4,083
Revenue Requirements Deficiency (Excess)	0	12,035	(119)	5,497	(30,371)	(787)	25,888	82,593	15,965	388	(78)
Revenue Requirements Index[(1)]	100.0%	88.1%	102.9%	86.9%	108.6%	122.4%	97.8%	82.5%	83.4%	92.2%	101.9%

[(1)] (Total Revenues divided by
Total Equalized Revenue Requirements)

Note: Totals may not add due to rounding.

MFR E-1 - COST OF SERVICE STUDY
AT PRESENT RATES - December 2017
($000 WHERE APPLICABLE)

Method: 12CP and 25%	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
Reassign Curtailment Credit Revenue	(0)	(0)	(346)	(0)	(0)	(0)	(0)
Net Curtailment Credit Revenue	(0)	(0)	(346)	(0)	(0)	(0)	(0)
Net Curtailment NOI Adjustment	(0)	(0)	(212)	(0)	(0)	(0)	(0)
Net Operating Income (NOI)	5,066	205	1,024,547	24,172	510	236	1,870
Rate of Return (ROR)	7.62%	2.82%	5.30%	5.62%	7.55%	4.96%	13.27%
Parity At Present Rates	1.53	0.57	1.06	1.13	1.52	1.00	2.67
EQUALIZED RATE OF RETURN (ROR) -							
Equalized Base Revenue Requirements	11,181	1,248	3,403,445	86,741	1,224	802	2,494
Other Operating Revenues	680	35	147,117	1,254	21	21	33
Total Equalized Revenue Requirements	11,860	1,284	3,550,562	87,995	1,245	824	2,527
Revenue Requirements Deficiency (Excess)	(2,870)	256	(101,679)	(4,531)	(284)	1	(1,906)
Revenue Requirements Index[(1)]	124.2%	80.0%	102.9%	105.1%	122.8%	99.8%	175.4%

[(1)] (Total Revenues divided by
Total Equalized Revenue Requirements)

Note: Totals may not add due to rounding.

MFR E-1 - COST OF SERVICE STUDY
EQUALIZED AT PROPOSED RETAIL ROR - December 2017
($000 WHERE APPLICABLE)

Method: 12CP and 25%	TOTAL RETAIL	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
RATE BASE -										
Electric Plant In Service	43,122,297	733,617	29,415	287,358	2,500,403	22,995	8,727,503	3,488,258	697,104	35,364
Accum Depreciation & Amortization	(13,074,538)	(215,247)	(8,701)	(82,323)	(756,897)	(6,987)	(2,593,722)	(1,032,855)	(204,987)	(10,195)
Net Plant In Service	30,047,759	518,370	20,714	205,035	1,743,506	16,008	6,133,781	2,455,403	492,117	25,169
Plant Held For Future Use	233,315	4,327	169	1,876	13,432	118	49,954	20,185	4,089	238
Construction Work in Progress	747,987	13,078	518	5,786	43,437	417	152,801	61,251	12,374	729
Net Nuclear Fuel	630,075	15,678	597	8,603	35,101	413	151,865	61,743	14,687	987
Total Utility Plant	31,659,136	551,452	21,998	221,300	1,835,477	16,956	6,488,400	2,598,581	523,267	27,122
Working Capital - Assets	3,552,622	63,554	2,511	28,623	216,342	2,503	707,176	280,985	60,009	3,382
Working Capital - Liabilities	(2,675,642)	(46,361)	(1,835)	(20,352)	(164,467)	(1,905)	(523,311)	(207,419)	(43,824)	(2,410)
Working Capital - Net	876,981	17,193	676	8,271	51,874	598	183,865	73,566	16,185	972
Total Rate Base	32,536,116	568,645	22,674	229,572	1,887,351	17,554	6,672,265	2,672,147	539,452	28,094
TARGET REVENUE REQUIREMENTS (EQUALIZED) -										
Equalized Base Revenue Requirements	6,595,430	114,917	4,593	47,452	389,111	3,862	1,341,341	534,821	108,656	5,700
Other Operating Revenues	193,129	1,685	68	465	12,293	113	23,294	8,234	1,672	58
Total Target Revenue Requirements	6,788,559	116,602	4,661	47,917	401,404	3,975	1,364,635	543,055	110,329	5,757
EXPENSES -										
Operating & Maintenance Expense	(1,355,173)	(22,252)	(885)	(9,346)	(84,836)	(1,007)	(255,947)	(100,955)	(21,074)	(1,109)
Depreciation Expense	(1,672,107)	(28,864)	(1,159)	(12,124)	(97,860)	(924)	(338,610)	(134,810)	(27,286)	(1,478)
Taxes Other Than Income Tax	(578,814)	(9,924)	(397)	(3,951)	(33,833)	(320)	(117,360)	(46,901)	(9,435)	(485)
Amortization of Property Losses	6,182	100	4	30	369	4	1,200	477	97	4
Gain or Loss on Sale of Plant	5,759	97	4		340	2	1,222	502	95	
Total Operating Expenses	(3,594,153)	(60,842)	(2,433)	(25,391)	(215,821)	(2,244)	(709,496)	(281,687)	(57,603)	(3,069)
Net Operating Income Before Taxes	3,194,406	55,760	2,228	22,526	185,583	1,730	655,140	261,368	52,726	2,689
Income Taxes	(1,044,788)	(18,184)	(730)	(7,355)	(60,868)	(570)	(214,234)	(85,029)	(17,158)	(875)
NOI Before Curtailment Adjustment	2,149,618	37,576	1,498	15,171	124,715	1,160	440,906	176,339	35,568	1,814
Curtailment Credit Revenue	587							388	130	70

MFR E-1 - COST OF SERVICE STUDY
EQUALIZED AT PROPOSED RETAIL ROR - December 2017
($000 WHERE APPLICABLE)

Method: 12CP and 25%	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
RATE BASE -								
Electric Plant In Service	29,763	104,444	10,049	25,788,030	635,142	8,726	6,333	17,794
Accum Depreciation & Amortization	(8,717)	(41,364)	(3,151)	(7,868,871)	(230,804)	(2,587)	(1,883)	(5,247)
Net Plant In Service	21,046	63,080	6,899	17,919,159	404,338	6,139	4,451	12,547
Plant Held For Future Use	174	131	42	137,253	1,110	50	35	132
Construction Work in Progress	517	1,240	133	445,879	9,172	158	96	402
Net Nuclear Fuel	525	576	62	335,168	3,298	193	68	511
Total Utility Plant	22,262	65,027	7,135	18,837,459	417,918	6,541	4,650	13,593
Working Capital - Assets	2,415	4,799	658	2,122,938	53,777	821	447	1,680
Working Capital - Liabilities	(1,776)	(3,354)	(503)	(1,614,426)	(41,569)	(604)	(341)	(1,184)
Working Capital - Net	639	1,445	155	508,512	12,208	217	107	496
Total Rate Base	22,902	66,472	7,290	19,345,971	430,126	6,757	4,756	14,089
TARGET REVENUE REQUIREMENTS (EQUALIZED) -								
Equalized Base Revenue Requirements	4,625	12,935	1,442	3,922,581	98,192	1,403	929	2,869
Other Operating Revenues	68	695	35	143,115	1,256	21	21	34
Total Target Revenue Requirements	4,693	13,630	1,478	4,065,696	99,448	1,425	951	2,903
EXPENSES -								
Operating & Maintenance Expense	(862)	(1,683)	(268)	(830,395)	(23,540)	(297)	(175)	(540)
Depreciation Expense	(1,186)	(4,261)	(371)	(996,003)	(25,877)	(345)	(227)	(722)
Taxes Other Than Income Tax	(403)	(1,179)	(131)	(346,018)	(8,033)	(119)	(85)	(242)
Amortization of Property Losses	4	21	2	3,725	141	1	1	2
Gain or Loss on Sale of Plant	4	7	3	3,440	40	1	2	
Total Operating Expenses	(2,443)	(7,095)	(765)	(2,165,252)	(57,269)	(759)	(484)	(1,501)
Net Operating Income Before Taxes	2,250	6,536	713	1,900,444	42,179	666	467	1,401
Income Taxes	(737)	(2,144)	(231)	(622,069)	(13,761)	(220)	(152)	(470)
NOI Before Curtailment Adjustment	1,513	4,392	482	1,278,375	28,418	447	314	931
Curtailment Credit Revenue								

MFR E-1 - COST OF SERVICE STUDY
EQUALIZED AT PROPOSED RETAIL ROR - December 2017
($000 WHERE APPLICABLE)

Method: 12CP and 25%	TOTAL RETAIL	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
Reassign Curtailment Credit Revenue	(587)	(11)	(0)	(6)	(33)	(0)	(127)	(51)	(10)	(1)
Net Curtailment Credit Revenue		(11)	(0)	(6)	(33)	(0)	(127)	336	119	69
Net Curtailment NOI Adjustment		(7)	(0)	(3)	(20)	(0)	(78)	206	73	42
Net Operating Income (NOI)	2,149,618	37,570	1,498	15,167	124,695	1,160	440,828	176,545	35,641	1,856
Equalized Rate of Return (ROR)	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%
TARGET REVENUE REQUIREMENTS DEFICIENCY - [1]										
Base Revenue Requirements	870,239	27,175	485	11,610	19,913	(322)	203,448	153,730	30,326	1,136
Other Operating Revenues - Misc Service Charges	(3,885)	2	0	0	(29)	2	105	15	3	0
Target Revenue Requirements Deficiency	866,354	27,177	485	11,610	19,884	(320)	203,553	153,745	30,330	1,137
TARGET REVENUE REQUIREMENTS INDEX [2]	87.2%	76.7%	89.6%	75.8%	95.0%	108.0%	85.1%	71.7%	72.5%	80.3%

[1] Target Revenue Requirements at proposed ROR less Total Revenues at present rates from Attachment # 1.
[2] Total Revenues at present rates from Attachment # 1 divided by Target Revenue Requirements.

Note: Totals may not add due to rounding.

MFR E-1 - COST OF SERVICE STUDY
EQUALIZED AT PROPOSED RETAIL ROR - December 2017
($000 WHERE APPLICABLE)

Method: 12CP and 25%	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
Reassign Curtailment Credit Revenue	(0)	(0)	(0)	(346)	(0)	(0)	(0)	(0)
Net Curtailment Credit Revenue	(0)	(0)	(0)	(346)	(0)	(0)	(0)	(0)
Net Curtailment NOI Adjustment	(0)	(0)	(0)	(212)	(0)	(0)	(0)	(0)
Net Operating Income (NOI)	1,513	4,392	482	1,278,163	28,418	446	314	931
Equalized Rate of Return (ROR)	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%
TARGET REVENUE REQUIREMENTS DEFICIENCY - [(1)]								
Base Revenue Requirements	532	(1,115)	450	417,457	6,920	(104)	128	(1,531)
Other Operating Revenues - Misc Service Charges	0	15	0	(4,002)	2	0	0	0
Target Revenue Requirements Deficiency	532	(1,100)	450	413,455	6,922	(104)	128	(1,531)
TARGET REVENUE REQUIREMENTS INDEX [(2)]	88.7%	108.1%	69.5%	89.8%	93.0%	107.3%	86.5%	152.7%

[(1)] Target Revenue Requirements at proposed ROR less Total Revenues at present rates from Attachment # 1.
[(2)] Total Revenues at present rates from Attachment # 1 divided by Target Revenue Requirements.

Note: Totals may not add due to rounding.

MFR E-6b - COST OF SERVICE STUDY - UNIT COSTS
PROPOSED RATES - EQUALIZED - SUMMARY - December 2017
($000 WHERE APPLICABLE)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	**Method: 12CP and 25%**	TOTAL RETAIL	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1
1	**Total Retail**								
2	**Revenue Requirements**								
3	Total Revenue Requirements	6,595,430	114,917	4,593	47,452	389,111	3,862	1,341,341	534,821
4									
5	**Demand**								
6	**Revenue Requirements**								
7	Total Revenue Requirements	4,781,775	82,513	3,300	29,689	271,523	2,037	1,014,148	408,732
8									
9	**Billing Units (Annual)**								
10	KW for Demand Classes	111,079,183	5,184,883	204,233	2,778,867			70,516,172	25,368,292
11	KWH for All Other Classes	63,734,975,328				5,968,792,122	70,241,818		
12									
13	**Unit Costs ($/Unit)**								
14	Total Unit Costs ($/Unit)		15.914075	16.157542	10.683925	0.045490	0.028998	14.381783	16.111909
15									
16	**Energy**								
17	**Revenue Requirements**								
18	Total Revenue Requirements	1,270,025	31,556	1,204	17,319	70,830	833	306,004	124,239
19									
20	**Billing Units (Annual)**								
21	KWH for All Rate Classes	107,246,477,186	2,687,420,391	101,623,502	1,508,335,314	5,968,792,122	70,241,818	25,825,428,784	10,507,497,706
22									
23	**Unit Costs ($/Unit)**								
24	Total Unit Costs ($/Unit)		0.011742	0.011844	0.011482	0.011867	0.011864	0.011849	0.011824
25									
26	**Customer**								
27	**Revenue Requirements**								
28	Total Revenue Requirements	455,553	848	89	444	46,759	992	21,189	1,851
29									
30	**Billing Units (Annual)**								
31	# of Bills for Metered Classes	58,819,235	3,336	744	204	5,165,476	130,561	1,281,531	37,126
32	KWH for Lighting Classes	691,469,568							
33									

MFR E-6b - COST OF SERVICE STUDY - UNIT COSTS
PROPOSED RATES - EQUALIZED - SUMMARY - December 2017
($000 WHERE APPLICABLE)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(2)	(3)
Line No.	**Method: 12CP and 25%**	GSLD(T)-2	GSLD(T)-3	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
1	**Total Retail**										
2	**Revenue Requirements**										
3	Total Revenue Requirements	108,656	5,700	4,625	12,935	1,442	3,922,581	98,192	1,403	929	2,869
4											
5	**Demand**										
6	**Revenue Requirements**										
7	Total Revenue Requirements	78,645	3,545	3,335	2,243	1,041	2,864,732	13,077	944	763	1,509
8											
9	**Billing Units (Annual)**										
10	KW for Demand Classes	5,230,120	426,632	230,384						54,706	1,084,895
11	KWH for All Other Classes				97,899,984	10,793,313	56,993,678,507	560,806,958	32,762,626		
12											
13	**Unit Costs ($/Unit)**										
14	Total Unit Costs ($/Unit)	15.036946	8.308214	14.477154	0.022909	0.096444	0.050264	0.023318	0.028824	13.941437	1.391147
15											
16	**Energy**										
17	**Revenue Requirements**										
18	Total Revenue Requirements	29,552	1,984	1,058	1,162	125	675,951	6,645	389	137	1,035
19											
20	**Billing Units (Annual)**										
21	KWH for All Rate Classes	2,515,470,925	172,992,260	91,208,296	97,899,984	10,793,313	56,993,678,507	560,806,958	32,762,626	11,856,926	89,667,754
22											
23	**Unit Costs ($/Unit)**										
24	Total Unit Costs ($/Unit)	0.011748	0.011470	0.011601	0.011873	0.011577	0.011860	0.011849	0.011865	0.011595	0.011547
25											
26	**Customer**										
27	**Revenue Requirements**										
28	Total Revenue Requirements	459	171	231	(346)	276	381,898	303	35	29	324
29											
30	**Billing Units (Annual)**										
31	# of Bills for Metered Classes	1,890	84	324		2,183	52,195,536			72	168
32	KWH for Lighting Classes				97,899,984			560,806,958	32,762,626		
33											

MFR E-6b - COST OF SERVICE STUDY - UNIT COSTS
PROPOSED RATES - EQUALIZED - SUMMARY - December 2017
($000 WHERE APPLICABLE)

Line No.	(1) Method: 12CP and 25%	(2) TOTAL RETAIL	(3) CILC-1D	(4) CILC-1G	(5) CILC-1T	(6) GS(T)-1	(7) GSCU-1	(8) GSD(T)-1	(9) GSLD(T)-1
1	**Unit Costs ($/Unit)**								
2	Total Unit Costs ($/Unit)		254.340313	120.006329	2,175.950449	9.052214	7.595216	16.533863	49.853622
3									
4	**Lighting**								
5	**Revenue Requirements**								
6	Total Revenue Requirements	88,078							
7									
8	**Billing Units (Annual)**								
9	Fixtures	9,535,124							
10									
11	**Unit Costs ($/Unit)**								
12	Total Unit Costs ($/Unit)								
13									
14									
15	Note: Totals may not add due to rounding.								
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32									
33									

MFR E-6b - COST OF SERVICE STUDY - UNIT COSTS
PROPOSED RATES - EQUALIZED - SUMMARY - December 2017
($000 WHERE APPLICABLE)

Line No.	(1) Method: 12CP and 25%	(2) GSLD(T)-2	(3) GSLD(T)-3	(4) MET	(5) OL-1	(6) OS-2	(7) RS(T)-1	(8) SL-1	(9) SL-2	(2) SST-DST	(3) SST-TST
1	**Unit Costs ($/Unit)**										
2	Total Unit Costs ($/Unit)	242.830420	2,035.969467	714.061870	(0.003531)	126.655855	7.316682	0.000540	0.001057	401.870683	1,930.411156
3											
4	**Lighting**										
5	**Revenue Requirements**										
6	Total Revenue Requirements				9,876			78,167	36		
7											
8	**Billing Units (Annual)**										
9	Fixtures				2,395,776			7,136,090	3,258		
10											
11	**Unit Costs ($/Unit)**										
12	Total Unit Costs ($/Unit)				4.122106			10.953760	10.958398		
13											
14											
15	Note: Totals may not add due to rounding.										
16											
17											
18											
19											
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MFR E-6b - COST OF SERVICE STUDY - UNIT COSTS
PROPOSED RATES - EQUALIZED - DETAIL - December 2017
($000 WHERE APPLICABLE)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	**Method: 12CP and 25%**	TOTAL RETAIL	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1
1	**Demand**								
2	**Revenue Requirements**								
3	Production - Steam	201,380	3,747	147	1,955	11,338	91	43,766	17,332
4	Production - Nuclear	955,530	17,738	694	9,255	53,675	431	207,174	83,520
5	Production - Other Production	1,345,422	24,973	977	13,032	75,589	608	291,710	117,567
6	Production - Other Power Supply	7,198	134	5	70	404	3	1,561	629
7	Production - Curtailment Credit	517	9	0	5	30	0	112	42
8	Transmission	554,684	10,295	403	5,373	31,165	251	120,265	48,466
9	Distribution - Land & Land Rights	10,360	174	7		612	4	2,196	899
10	Distribution - Structures & Improvements	22,561	379	15		1,333	9	4,783	1,962
11	Distribution - Station Equipment	242,702	4,076	159		14,334	98	51,456	21,112
12	Distribution - Poles, Towers & Fixtures	225,260	3,712	148		13,316	91	47,792	19,571
13	Distribution - Overhead Conductors & Devices	466,419	7,248	306		27,634	188	99,169	40,417
14	Distribution - Underground Conduit	210,669	3,446	138		12,459	85	44,709	18,293
15	Distribution - Underground Conductors & Devices	307,637	4,905	202		18,213	124	65,349	26,679
16	Distribution - Primary Capacitors and Regulators	25,128	422	17		1,484	10	5,328	2,186
17	Distribution - Secondary Transformers	206,307	1,254	81		9,937	43	28,779	10,058
18	**Sub-Total Revenue Requirements**	4,781,775	82,513	3,300	29,689	271,523	2,037	1,014,148	408,732
19									
20	**Billing Units (Annual)**								
21	KW for Demand Classes	111,079,183	5,184,883	204,233	2,778,867			70,516,172	25,368,292
22	KWH for All Other Classes	63,734,975,328				5,968,792,122	70,241,818		
23	**Sub-Total Billing Units (Annual)**	63,846,054,511	5,184,883	204,233	2,778,867	5,968,792,122	70,241,818	70,516,172	25,368,292
24									
25	**Unit Costs ($/Unit)**								
26	Production - Steam		0.722751	0.717882	0.703622	0.001900	0.001298	0.620656	0.683196
27	Production - Nuclear		3.421119	3.398334	3.330651	0.008993	0.006143	2.937967	3.292291
28	Production - Other Production		4.816531	4.785581	4.689506	0.012664	0.008653	4.136780	4.634396
29	Production - Other Power Supply		0.025776	0.025591	0.025091	0.000068	0.000046	0.022130	0.024814
30	Production - Curtailment Credit		0.001773	0.001866	0.001712	0.000005	0.000004	0.001589	0.001641

MFR E-6b - COST OF SERVICE STUDY - UNIT COSTS
PROPOSED RATES - EQUALIZED - DETAIL - December 2017
($000 WHERE APPLICABLE)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(2)	(3)
Line No.	**Method: 12CP and 25%**	GSLD(T)-2	GSLD(T)-3	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
1	**Demand**										
2	**Revenue Requirements**										
3	Production - Steam	3,397	178	153	20	14	118,964	118	42	18	99
4	Production - Nuclear	16,577	1,124	722	95	66	563,140	560	201	86	470
5	Production - Other Production	23,334	1,582	1,017	134	93	792,951	789	283	121	663
6	Production - Other Power Supply	125	8	5	1	0	4,242	4	2	1	4
7	Production - Curtailment Credit	8	1	0	0	0	309	0	0	0	0
8	Transmission	9,619	652	419	55	38	326,917	325	117	50	273
9	Distribution - Land & Land Rights	171		8	12	5	6,192	72	2	4	
10	Distribution - Structures & Improvements	373		17	27	12	13,482	157	4	8	
11	Distribution - Station Equipment	4,010		183	291	128	145,028	1,694	45	88	
12	Distribution - Poles, Towers & Fixtures	3,665		162	270	117	134,723	1,574	42	77	
13	Distribution - Overhead Conductors & Devices	7,238		282	561	235	279,652	3,269	87	135	
14	Distribution - Underground Conduit	3,406		148	253	109	126,041	1,472	39	71	
15	Distribution - Underground Conductors & Devices	4,872		201	370	157	184,260	2,153	57	96	
16	Distribution - Primary Capacitors and Regulators	415		19	30	13	15,016	175	5	9	
17	Distribution - Secondary Transformers	1,435			122	51	153,815	713	19		
18	**Sub-Total Revenue Requirements**	78,645	3,545	3,335	2,243	1,041	2,864,732	13,077	944	763	1,509
19											
20	**Billing Units (Annual)**										
21	KW for Demand Classes	5,230,120	426,632	230,384						54,706	1,084,895
22	KWH for All Other Classes				97,899,984	10,793,313	56,993,678,507	560,806,958	32,762,626		
23	**Sub-Total Billing Units (Annual)**	5,230,120	426,632	230,384	97,899,984	10,793,313	56,993,678,507	560,806,958	32,762,626	54,706	1,084,895
24											
25	**Unit Costs ($/Unit)**										
26	Production - Steam	0.649429	0.416983	0.662158	0.000206	0.001297	0.002087	0.000211	0.001297	0.331766	0.091485
27	Production - Nuclear	3.169460	2.634191	3.134518	0.000975	0.006140	0.009881	0.000999	0.006139	1.570434	0.433262
28	Production - Other Production	4.461541	3.707470	4.413949	0.001374	0.008641	0.013913	0.001406	0.008648	2.211115	0.610923
29	Production - Other Power Supply	0.023888	0.019861	0.023606	0.000007	0.000046	0.000074	0.000008	0.000046	0.011831	0.003253
30	Production - Curtailment Credit	0.001589	0.001389	0.001716	0.000001	0.000003	0.000005	0.000001	0.000003	0.000854	0.000255

MFR E-6b - COST OF SERVICE STUDY - UNIT COSTS
PROPOSED RATES - EQUALIZED - DETAIL - December 2017
($000 WHERE APPLICABLE)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	**Method: 12CP and 25%**	TOTAL RETAIL	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1
1	Transmission		1.985673	1.973046	1.933343	0.005221	0.003568	1.705494	1.910497
2	Distribution - Land & Land Rights		0.033526	0.033341		0.000103	0.000060	0.031147	0.035457
3	Distribution - Structures & Improvements		0.073061	0.072557		0.000223	0.000129	0.067831	0.077343
4	Distribution - Station Equipment		0.786041	0.780472		0.002401	0.001391	0.729700	0.832220
5	Distribution - Poles, Towers & Fixtures		0.716020	0.724543		0.002231	0.001293	0.677741	0.771467
6	Distribution - Overhead Conductors & Devices		1.397929	1.500479		0.004630	0.002681	1.406333	1.593194
7	Distribution - Underground Conduit		0.664607	0.677700		0.002087	0.001210	0.634020	0.721078
8	Distribution - Underground Conductors & Devices		0.946046	0.989753		0.003051	0.001768	0.926721	1.051666
9	Distribution - Primary Capacitors and Regulators		0.081383	0.080807		0.000249	0.000144	0.075550	0.086163
10	Distribution - Secondary Transformers		0.241838	0.395587		0.001665	0.000612	0.408123	0.396487
11	**Sub-Total Unit Costs ($/Unit)**		15.914075	16.157542	10.683925	0.045490	0.028998	14.381783	16.111909
12									
13	**Energy**								
14	**Revenue Requirements**								
15	Production - Steam	142,266	3,534	135	1,940	7,935	93	34,274	13,915
16	Production - Nuclear	578,877	14,381	549	7,893	32,287	380	139,460	56,621
17	Production - Other Production	549,111	13,641	520	7,487	30,629	360	132,290	53,704
18	Customer - Uncollectible Accounts	(229)				(21)		(20)	(1)
19	**Sub-Total Revenue Requirements**	1,270,025	31,556	1,204	17,319	70,830	833	306,004	124,239
20									
21	**Billing Units (Annual)**								
22	KWH for All Rate Classes	107,246,477,186	2,687,420,391	101,623,502	1,508,335,314	5,968,792,122	70,241,818	25,825,428,784	10,507,497,706
23	**Sub-Total Billing Units (Annual)**	107,246,477,186	2,687,420,391	101,623,502	1,508,335,314	5,968,792,122	70,241,818	25,825,428,784	10,507,497,706
24									
25	**Unit Costs ($/Unit)**								
26	Production - Steam		0.001315	0.001327	0.001286	0.001329	0.001329	0.001327	0.001324
27	Production - Nuclear		0.005351	0.005398	0.005233	0.005409	0.005406	0.005400	0.005389
28	Production - Other Production		0.005076	0.005120	0.004964	0.005131	0.005129	0.005122	0.005111
29	Customer - Uncollectible Accounts					(0.000003)		(0.000001)	(0.000000)
30	**Sub-Total Unit Costs ($/Unit)**		0.011742	0.011844	0.011482	0.011867	0.011864	0.011849	0.011824

MFR E-6b - COST OF SERVICE STUDY - UNIT COSTS
PROPOSED RATES - EQUALIZED - DETAIL - December 2017
($000 WHERE APPLICABLE)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(2)	(3)
Line No.	**Method: 12CP and 25%**	GSLD(T)-2	GSLD(T)-3	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
1	Transmission	1.839244	1.528321	1.819812	0.000566	0.003562	0.005736	0.000580	0.003566	0.911576	0.251968
2	Distribution - Land & Land Rights	0.032670		0.033934	0.000127	0.000505	0.000109	0.000129	0.000059	0.068268	
3	Distribution - Structures & Improvements	0.071258		0.073858	0.000276	0.001102	0.000237	0.000281	0.000127	0.148716	
4	Distribution - Station Equipment	0.766744		0.794483	0.002972	0.011862	0.002545	0.003022	0.001371	1.599908	
5	Distribution - Poles, Towers & Fixtures	0.700752		0.701051	0.002761	0.010880	0.002364	0.002807	0.001274	1.411643	
6	Distribution - Overhead Conductors & Devices	1.383845		1.222020	0.005728	0.021755	0.004907	0.005828	0.002641	2.461576	
7	Distribution - Underground Conduit	0.651272		0.642215	0.002583	0.010126	0.002211	0.002625	0.001192	1.293061	
8	Distribution - Underground Conductors & Devices	0.931586		0.871576	0.003776	0.014561	0.003233	0.003839	0.001742	1.755041	
9	Distribution - Primary Capacitors and Regulators	0.079385		0.082258	0.000308	0.001228	0.000263	0.000313	0.000142	0.165648	
10	Distribution - Secondary Transformers	0.274283			0.001250	0.004738	0.002699	0.001271	0.000577		
11	**Sub-Total Unit Costs ($/Unit)**	15.036946	8.308214	14.477154	0.022909	0.096444	0.050264	0.023318	0.028824	13.941437	1.391147
12											
13	**Energy**										
14	**Revenue Requirements**										
15	Production - Steam	3,310	222	119	130	14	75,725	745	44	15	116
16	Production - Nuclear	13,468	904	482	530	57	308,122	3,031	177	63	472
17	Production - Other Production	12,774	858	457	503	54	292,284	2,875	168	59	448
18	Customer - Uncollectible Accounts				(1)		(180)	(6)			
19	**Sub-Total Revenue Requirements**	29,552	1,984	1,058	1,162	125	675,951	6,645	389	137	1,035
20											
21	**Billing Units (Annual)**										
22	KWH for All Rate Classes	2,515,470,925	172,992,260	91,208,296	97,899,984	10,793,313	56,993,678,507	560,806,958	32,762,626	11,856,926	89,667,754
23	**Sub-Total Billing Units (Annual)**	2,515,470,925	172,992,260	91,208,296	97,899,984	10,793,313	56,993,678,507	560,806,958	32,762,626	11,856,926	89,667,754
24											
25	**Unit Costs ($/Unit)**										
26	Production - Steam	0.001316	0.001285	0.001299	0.001331	0.001297	0.001329	0.001328	0.001329	0.001299	0.001293
27	Production - Nuclear	0.005354	0.005228	0.005287	0.005417	0.005276	0.005406	0.005405	0.005407	0.005284	0.005260
28	Production - Other Production	0.005078	0.004958	0.005015	0.005139	0.005004	0.005128	0.005126	0.005130	0.005012	0.004993
29	Customer - Uncollectible Accounts				(0.000014)		(0.000003)	(0.000010)			
30	**Sub-Total Unit Costs ($/Unit)**	0.011748	0.011470	0.011601	0.011873	0.011577	0.011860	0.011849	0.011865	0.011595	0.011547

MFR E-6b - COST OF SERVICE STUDY - UNIT COSTS
PROPOSED RATES - EQUALIZED - DETAIL - December 2017
($000 WHERE APPLICABLE)

Line No.	(1) Method: 12CP and 25%	(2) TOTAL RETAIL	(3) CILC-1D	(4) CILC-1G	(5) CILC-1T	(6) GS(T)-1	(7) GSCU-1	(8) GSD(T)-1	(9) GSLD(T)-1
1									
2	**Customer**								
3	**Revenue Requirements**								
4	Transmission Pull-Offs	738			329				
5	Distribution - Meters	153,384	737	77	110	15,872	191	13,802	1,662
6	Distribution - Installation on Customer's Premises	2,265	0	0		197	5	49	1
7	Distribution - Services	180,252	108	3		15,785	399	4,102	236
8	Customer - Meter Reading	21,917	68	11	4	4,359	22	3,155	379
9	Customer - Collections, Service and Sales	194,306	11	2	1	17,015	430	4,216	122
10	Customer - Field Collection - Late Pay Charges	(61,644)	(72)	(5)		(4,443)	(53)	(3,809)	(534)
11	Customer - Initial Connection Charges	(1,687)	(0)			(452)		(51)	(1)
12	Customer - Connection of Existing Acct Charges	(14,186)	(0)	(0)		(720)		(83)	(1)
13	Customer - Reconnection Charges	(10,849)				(559)		(23)	
14	Customer - Returned Check Charges	(6,060)	(4)			(267)		(155)	(10)
15	Customer - Current Diversion Charges	(2,185)				(48)		(18)	(2)
16	Customer - Other Billings (Charges)	(2,126)	(0)	(0)	(0)	(186)	(5)	(46)	(1)
17	Customer - Reimbursements - Other Charges	1,429	0	0		208	3	50	1
18	**Sub-Total Revenue Requirements**	455,553	848	89	444	46,759	992	21,189	1,851
19									
20	**Billing Units (Annual)**								
21	# of Bills for Metered Classes	58,819,235	3,336	744	204	5,165,476	130,561	1,281,531	37,126
22	KWH for Lighting Classes	691,469,568							
23	**Sub-Total Billing Units (Annual)**	750,288,803	3,336	744	204	5,165,476	130,561	1,281,531	37,126
24									
25	**Unit Costs ($/Unit)**								
26	Transmission Pull-Offs				1,613.574094				
27	Distribution - Meters		220.910208	103.871609	537.734094	3.072742	1.465926	10.770118	44.754745
28	Distribution - Installation on Customer's Premises		0.038003	0.038001		0.038067	0.038001	0.038028	0.038017
29	Distribution - Services		32.233630	4.591774		3.055850	3.054902	3.201174	6.348537
30	Customer - Meter Reading		20.479287	14.521435	21.391162	0.843807	0.168700	2.461749	10.214023

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PROPOSED RATES - EQUALIZED - DETAIL - December 2017
($000 WHERE APPLICABLE)

Line No.	(1) Method: 12CP and 25%	(2) GSLD(T)-2	(3) GSLD(T)-3	(4) MET	(5) OL-1	(6) OS-2	(7) RS(T)-1	(8) SL-1	(9) SL-2	(2) SST-DST	(3) SST-TST
1											
2	**Customer**										
3	**Revenue Requirements**										
4	Transmission Pull-Offs		135								273
5	Distribution - Meters	451	36	177		152	120,042			20	55
6	Distribution - Installation on Customer's Premises	0		0	26	0	1,987			0	
7	Distribution - Services	71		45		97	159,396			10	
8	Customer - Meter Reading	61	2	8		20	13,824			1	2
9	Customer - Collections, Service and Sales	6	0	1	214	7	171,884	360	36	0	1
10	Customer - Field Collection - Late Pay Charges	(131)	(2)		(577)	(0)	(51,951)	(57)	(2)	(2)	(7)
11	Customer - Initial Connection Charges	(0)					(1,183)				
12	Customer - Connection of Existing Acct Charges	(0)					(13,381)				
13	Customer - Reconnection Charges						(10,267)				
14	Customer - Returned Check Charges				(9)		(5,614)	(0)			
15	Customer - Current Diversion Charges						(2,116)				
16	Customer - Other Billings (Charges)	(0)	(0)	(0)	(2)	(0)	(1,881)	(4)	(0)	(0)	(0)
17	Customer - Reimbursements - Other Charges	0			3	0	1,159	4	0		
18	**Sub-Total Revenue Requirements**	459	171	231	(346)	276	381,898	303	35	29	324
19											
20	**Billing Units (Annual)**										
21	# of Bills for Metered Classes	1,890	84	324		2,183	52,195,536			72	168
22	KWH for Lighting Classes				97,899,984			560,806,958	32,762,626		
23	**Sub-Total Billing Units (Annual)**	1,890	84	324	97,899,984	2,183	52,195,536	560,806,958	32,762,626	72	168
24											
25	**Unit Costs ($/Unit)**										
26	Transmission Pull-Offs		1,610.807777								1,626.569153
27	Distribution - Meters	238.620432	429.482576	547.530586		69.462526	2.299856			271.003227	329.076925
28	Distribution - Installation on Customer's Premises	0.038014		0.038008	0.000268	0.038019	0.038064			0.038011	
29	Distribution - Services	37.487666		138.987844		44.573629	3.053817			138.889430	
30	Customer - Meter Reading	32.535527	19.045485	24.252907		9.309451	0.264845			12.124561	14.745627

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PROPOSED RATES - EQUALIZED - DETAIL - December 2017
($000 WHERE APPLICABLE)

Line No.	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Method: 12CP and 25%	TOTAL RETAIL	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1
1	Customer - Collections, Service and Sales		3.287032	3.288006	3.287077	3.293910	3.289668	3.289796	3.287478
2	Customer - Field Collection - Late Pay Charges		(21.500985)	(6.303323)		(0.860096)	(0.405623)	(2.972237)	(14.386250)
3	Customer - Initial Connection Charges		(0.020359)			(0.087586)		(0.039686)	(0.027446)
4	Customer - Connection of Existing Acct Charges		(0.014302)	(0.032066)		(0.139415)		(0.064706)	(0.031496)
5	Customer - Reconnection Charges					(0.108305)		(0.017942)	
6	Customer - Returned Check Charges		(1.080962)			(0.051696)		(0.121246)	(0.273413)
7	Customer - Current Diversion Charges					(0.009375)		(0.014120)	(0.066421)
8	Customer - Other Billings (Charges)		(0.035979)	(0.035981)	(0.035977)	(0.036035)	(0.035987)	(0.036002)	(0.035988)
9	Customer - Reimbursements - Other Charges		0.044740	0.066874		0.040347	0.019629	0.038937	0.031836
10	**Sub-Total Unit Costs ($/Unit)**		254.340313	120.006329	2,175.950449	9.052214	7.595216	16.533863	49.853622
11									
12	**Lighting**								
13	**Revenue Requirements**								
14	Lighting - Street Lights & Traffic Signals	78,203							
15	Lighting - Outdoor	9,876							
16	**Sub-Total Revenue Requirements**	88,078							
17									
18	**Billing Units (Annual)**								
19	Fixtures	9,535,124							
20	**Sub-Total Billing Units (Annual)**	9,535,124							
21									
22	**Unit Costs ($/Unit)**								
23	Lighting - Street Lights & Traffic Signals								
24	Lighting - Outdoor								
25	**Sub-Total Unit Costs ($/Unit)**								
26									
27									
28	Note: Totals may not add due to rounding.								
29									
30									

MFR E-6b - COST OF SERVICE STUDY - UNIT COSTS
PROPOSED RATES - EQUALIZED - DETAIL - December 2017
($000 WHERE APPLICABLE)

Line No.	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(2)	(3)
	Method: 12CP and 25%	GSLD(T)-2	GSLD(T)-3	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
1	Customer - Collections, Service and Sales	3.287231	3.286828	3.288512	0.002186	3.286643	3.293082	0.000642	0.001102	3.288029	3.292850
2	Customer - Field Collection - Late Pay Charges	(69.117675)	(26.617212)		(0.005896)	(0.024018)	(0.995315)	(0.000102)	(0.000047)	(23.436588)	(43.237413)
3	Customer - Initial Connection Charges	(0.017970)					(0.022663)				
4	Customer - Connection of Existing Acct Charges	(0.006312)					(0.256372)				
5	Customer - Reconnection Charges						(0.196703)				
6	Customer - Returned Check Charges				(0.000095)		(0.107557)	(0.000001)			
7	Customer - Current Diversion Charges						(0.040549)				
8	Customer - Other Billings (Charges)	(0.035986)	(0.035987)	(0.035987)	(0.000024)	(0.035987)	(0.036031)	(0.000007)	(0.000012)	(0.035987)	(0.035987)
9	Customer - Reimbursements - Other Charges	0.039493			0.000030	0.045591	0.022207	0.000008	0.000013		
10	**Sub-Total Unit Costs ($/Unit)**	242.830420	2,035.969467	714.061870	(0.003531)	126.655855	7.316682	0.000540	0.001057	401.870683	1,930.411156
11											
12	**Lighting**										
13	**Revenue Requirements**										
14	Lighting - Street Lights & Traffic Signals							78,167	36		
15	Lighting - Outdoor				9,876						
16	**Sub-Total Revenue Requirements**				9,876			78,167	36		
17											
18	**Billing Units (Annual)**										
19	Fixtures				2,395,776			7,136,090	3,258		
20	**Sub-Total Billing Units (Annual)**				2,395,776			7,136,090	3,258		
21											
22	**Unit Costs ($/Unit)**										
23	Lighting - Street Lights & Traffic Signals							10.953760	10.958398		
24	Lighting - Outdoor				4.122106						
25	**Sub-Total Unit Costs ($/Unit)**				4.122106			10.953760	10.958398		
26											
27											
28	Note: Totals may not add due to rounding.										
29											
30											

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF MORAY P. DEWHURST

DOCKET NO. 160021-EI

AUGUST 1, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Moray P. Dewhurst. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Did you previously submit testimony in the proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to the following:

- PART 1: Financial Strength, Risk Profile, Capital Structure and ROE

  Financial strength and risk profile comments, as well as capital structure and return on equity ("ROE") arguments made by Office of Public Counsel's ("OPC") witnesses Randall Woolridge, Kevin O'Donnell and Daniel Lawton; Federal Executive Agency's ("FEA") witness Michael Gorman; AARP's witness Michael Brosch; Wal-Mart Stores East, LP and Sam's East, Inc.'s ("Wal-Mart") witness Steve Chriss; South Florida Hospital and Healthcare Association's ("SFHHA") witnesses Richard Baudino and Lane Kollen; and Florida Industrial Power Users Group's ("FIPUG") witness Jeffry Pollock;

- PART 2: ROE Performance Adder ("ROE Adder")

  ROE Adder arguments made by OPC's witness Lawton; SFHHA's witness Richard Baudino; FIPUG's witness Jeffry Pollock; FEA's witness

Michael Gorman; AARP's witness Michael Brosch; and Wal-Mart's witness Steve Chriss;

- PART 3: Storm Cost Recovery Mechanism

  Storm cost recovery arguments made by OPC's witness Helmuth Schultz and SFHHA's witness Lane Kollen; and

- PART 4: Cost of Debt and DOL Insurance

  Other arguments regarding FPL's cost of debt projections made by SFHHA's witness Richard Baudino; FEA's witness Michael Gorman; and FIPUG's witness Jeffry Pollock; and Directors' and Officers' Liability ("DOL") Insurance made by OPC's witness Helmuth Schultz.

Q. Please summarize your rebuttal testimony.

A. PART 1: Financial Strength, Risk Profile, Capital Structure and ROE

With respect to the linked issues of financial strength, risk profile, capital structure and return on equity, intervenor witnesses use flawed analyses, which ignore important practical considerations, to reach conclusions that, if acted upon, would seriously undermine FPL's strong financial position, deny investors the opportunity to earn a fair rate of return on the capital they have committed to the business, and over time erode FPL's ability to continue delivering superior value to its customers.

Intervenor witnesses err most fundamentally in presuming that it is possible to make significant changes to capital structure and allowed ROE without any damaging effects in terms of FPL's overall cost position and ability to execute

its business strategies. But undermining FPL's financial position will ultimately undermine its business position, to the detriment of long-term customer interests. Intervenors' positions incorrectly assume the way in which FPL has financed its operations over the years has had nothing to do with the benefits that customers realize today in the form of low bills and high reliability.

Intervenor witnesses ignore FPL's specific risk position and strategies, which call for and depend upon maintaining a "stronger-than-average" financial position. As a result, their recommendations are extreme, and their ROE recommendations in particular, if allowed, would result in the lowest authorized ROE for any vertically integrated electric utility in the U.S. in over two years.

FPL's financial policies are an integral part of its overall strategy to deliver value to customers, the results of which are readily visible in comparisons of cost, rates, reliability, overall customer service, etc. FPL's strategies are working for customers; intervenor witnesses' recommendations would thoroughly undermine those strategies. Their recommendations should be rejected.

PART 2: ROE Adder

With respect to FPL's requested ROE Adder, intervenor witnesses largely ignore the policy argument for this regulatory incentive tool. No witness has disputed FPL's superior performance as benchmarked against other electric utilities nationally by FPL witness Reed. Additionally, no witness has challenged FPL's performance against its duty to provide "reasonably sufficient, adequate, and efficient service" – the duty established by Florida law. Instead, each witness who testifies on this topic makes up a different standard of service and then claims either that FPL's performance is merely in line with it, or that FPL's performance is the result of factors outside of FPL's control, not as a result of anything FPL did. But the policy argument for the ROE Adder does not depend on *every* aspect of performance being controllable, and it is indisputable that the actions FPL has taken have resulted in today's superior competitive position. The fundamental point remains valid: acting as a surrogate for direct competition, regulation can provide a strong incentive for rate-regulated companies to improve the value they deliver to customers through the introduction of an ROE Adder.

PART 3: Storm Cost Recovery Mechanism

OPC supports continuation of the storm cost recovery mechanism currently in place, while SFHHA disputes it. SFHHA's witness Kollen fails to appreciate either FPL's real exposure to risk from tropical storms or the impact that adoption of his recommendation would have on FPL's risk profile – or both.

Witness Kollen's recommendation to leave FPL with no cost recovery mechanism in place would reflect a significant change to FPL's risk profile. As discussed in my direct testimony, absent the historical three-pronged approach to storm cost recovery, the Commission should continue the mechanism agreed upon in the 2010 and 2012 rate case settlements.

PART 4: Cost of Debt and DOL Insurance

As in prior cases, FPL has used reasonable, third-party forecasts to project its long- and short-term debt costs. Witnesses Baudino, Gorman and Pollock either engage in "cherry picking" by asking the Commission to selectively update these forecasts, or in some instances, create their own forecasts for the Commission to utilize. The bias in such exercises is evident and should result in rejection of intervenors' debt cost recommendations.

Finally, with respect to DOL insurance, the intervenors' recommendations would disallow recovery of a legitimate cost of providing electric service to our customers without demonstrating any imprudence on the part of FPL. Accordingly, their recommendations should be rejected.

PART 1: FINANCIAL STRENGTH, RISK PROFILE, CAPITAL STRUCTURE AND ROE

II. IMPLICATIONS OF INTERVENOR RECOMMENDATIONS

Q. What is your overall conclusion regarding intervenors' arguments related to FPL's financial strength, risk profile, capital structure and requested ROE?

A. My conclusion is that the testimonies provided by witnesses for OPC, SFHHA, FIPUG, AARP and FEA on these topics are all based on a fundamentally flawed premise and rely on either overly simplistic analytical frameworks that are known to be incomplete, or analyses that are inappropriate or embody 'non sequiturs.' Because their analyses are wrong, their recommendations, if adopted by the Commission, would seriously undermine FPL's financial strength and threaten its ability to continue the strategy that has helped it to become one of the best performing utilities in the country.

Q. What is the false premise that underlies each of these witnesses' recommendations?

A. Underlying the testimony of all the intervenor witnesses on these points is the belief that decisions concerning ROE, capital structure, and financial strength can be made independently of, and will have no impact on, a company's operational strategies and performance. This is wrong, and it is particularly

wrong when reviewing a company like FPL, whose strategy is based in part on maintaining a "stronger-than-average" financial position. FPL's financial policies are an integral part of its overall business strategy; they cannot be changed without an impact on its business position, its ability to support its capital investment program, and the way in which it serves its customers.

If the Commission wishes to judge the "cost" of those policies, it can readily do so by looking at the *total* cost of FPL's delivered service, which, as benchmarking shows, compares very favorably with other companies in its industry and with other utilities in the state. It would be both wrong and dangerous to take any one cost element in isolation, as intervenor witnesses seek to do here, and argue that it could be reduced without considering the effects that it would have on the overall delivery of customer value.

This false premise pervades the intervenor witnesses' testimony. In many cases it is implicit, but in some instances intervenor witnesses are quite direct about it. For example, witness Baudino states on page 50 that "[a] 60% common equity ratio imposes higher than necessary capital costs, when *the same productivity and output could be achieved* with a less costly set of inputs." (emphasis added). Witness Gorman makes the same point when he claims on page 18 that FPL's capital structure "increases its cost of service *with very little benefit to retail customers*" (emphasis added), referring then to

FPL's bond ratings as if those strong ratings were the only benefit. Neither witness attempts to justify his claim.

Intervenor witnesses appear to appreciate neither the general point that operating and financial strategies cannot be separated in the real world (in contrast to the way they are commonly treated in academic texts) nor the specific point that FPL's successful approach to delivering value is based on a stronger-than-average financial position.

Q. Please provide examples of problems you have observed in intervenor witnesses' analyses.

A. All of the intervenor witnesses who directly address capital structure rely on a simplistic framework that is known to be inconsistent with empirical evidence and cannot usefully be implemented. I will discuss this framework and its problems in much more detail later (beginning on page 35 of my rebuttal testimony).

Witnesses Woolridge (Exhibit JRW-4), Baudino (page 48) and Brosch (AARP Exhibit 1.5 and 1.6) all seek to draw inferences from comparisons between FPL's equity ratio and the average equity ratio of a group of utility holding companies. This is both inappropriate and unnecessary. While the use of a proxy group of holding companies is appropriate in estimating cost of equity, the use of such a group for risk or credit analysis is inappropriate unless adjustments are made, which intervenor witnesses do not do. Moreover, it is

quite unnecessary, as direct comparisons of FPL's capital structure can readily be made with those of other *operating* companies.

Witnesses O'Donnell (page 16), Woolridge (page 31), Baudino (page 49) and Brosch (page 49) seek to draw inferences by comparing FPL's equity ratio measured on a Generally Accepted Accounting Principles ("GAAP") basis with that of its parent company and/or those of FPL's affiliates. This is wholly inappropriate for reasons I explain in greater detail later (beginning on page 32 of my rebuttal testimony). Intervenor witnesses must surely be aware that without making certain critical adjustments, such comparisons are utterly meaningless.[1]

All intervenor witnesses concentrate their attention on investor sources of capital and set aside as fixed the other drivers of the overall cost of capital, including in particular deferred income taxes, which carry zero cost in the calculations. For example, a 59 percent equity ratio, as calculated based on investor sources, actually results in only 45 percent of FPL's rate base being financed with equity when its deferred income taxes are included as shown in MFR D-1A in the 2017 Test Year. This error illustrates the flawed premise that I have described: they are assuming that the deferred income tax component would remain unchanged if investor-supplied capital ratios or

[1] For example, Standard & Poor's, with whose reports the intervenor witnesses should be familiar, explicitly describe the types of adjustments they make in their credit analysis.

allowed ROEs were changed. But this is not the case, because the deferred income taxes derive from FPL's capital investment program, which would surely be affected if their recommendations were adopted, over time reducing the element of deferred income taxes and therefore *increasing*, all other things equal, the overall cost of capital.

While these may appear to be 'technical' points, they are important.

Q. Please provide examples of what you have termed "analyses that embody 'non sequiturs.'"

A. Witness Woolridge (pages 8-9) argues that FPL's earned ROE performance over the period 2011-2015 has been reflected in the outperformances of the stock of its parent since 2013. This is misleading, and it ignores all other factors, including in particular the significant improvement in the outlook for NextEra Energy Resources' ("NEER") renewables business, which has in fact been the principal driver of NEE's relative outperformance. In fact, during the period 2013 – early 2016, there was little change in equity investor expectations for FPL's earned ROE: they expected it to earn in the upper half of its authorized band and it did so. Accordingly, because changes in share price are generally agreed to be driven by changes in expectations, it is unlikely that much, if any, of NEE's outperformance is attributable to FPL.

As a second example, witness Baudino (page 15) and Woolridge (page 7) both note that Moody's Investors Service ("Moody's") upgraded FPL's credit

rating in January 2014, yet they fail to note that this was part of Moody's reevaluation of the entire U.S regulated utility sector. Without this important piece of context, a reader might be led to the view that FPL's relative position had changed, which was not the case.

A third example is provided by witness Baudino's discussion of NEE's announcement of its intention to increase its dividend payout ratio over time (page 15). Mr. Baudino's testimony implies that this decision signaled "increased confidence in FPL's ability to maintain or grow its earnings." This does not follow, however, and in fact the reasons for the increase in target payout ratio had very little to do with FPL and nothing at all to do with changes in confidence in FPL's earnings outlook.

I offer these examples as they indicate to me a tendency among some of the intervenor witnesses to oversimplify. Particularly when dealing with the complex technical issues surrounding capital structure and cost of capital, it is important to apply sensible, real-world perspectives to the data used in analysis.

Q. Please summarize intervenors' recommendations with respect to ROE and equity ratio.

A. OPC, SFHHA, FIPUG and AARP each recommend that the Commission decrease FPL's equity ratio, with recommendations ranging from 47 percent

to 55 percent; while OPC, SFHHA, FIPUG, AARP and FEA each recommend that the Commission establish an ROE for FPL that is well below 10 percent.

Intervenor	Witness	ROE	Equity Ratio
SFHHA	Baudino	recommends 9.00 percent	recommends 55 percent
AARP	Brosch	recommends a lower ROE than the approved ROE in the 2010 rate case	recommends 47 percent
Wal-Mart	Chriss	recommends the commission consider impact of approved ROE on customers	n/a
FEA	Gorman	recommends 9.25 percent[2]	n/a
OPC	Lawton	defers to Woolridge	defers to O'Donnell
OPC	O'Donnell	defers to Woolridge	recommends 50 percent
FIPUG	Pollock	recommends below the electric utility average	recommends 51.10 percent
OPC	Woolridge	recommends 8.75 percent	defers to O'Donnell

Q. What would be the consequences of implementing intervenors' recommendations?

A. The consequences of implementing the intervenors' recommendations would be numerous and include the following:

- Immediate negative reactions from equity investors, debt investors and the rating agencies, as the perception of regulatory risk would be radically increased. Ironically, this would promptly undermine the

[2] Assumes FPL's equity ratio of 59.6% is maintained.

very arguments intervenor witnesses have made for lowering ROE and increasing the equity ratio;

- Likely downgrades, whether immediate or over time;
- Restrictions on FPL's ability to support its liquidity needs;
- Erosion of FPL's relative cost position;
- Higher financing costs in the long-term; and
- Most importantly, over time, a serious erosion of FPL's ability to deliver value to customers.

These effects would not all occur immediately, but their impacts would compound over time. Intervenors cannot credibly conclude that the total cost of capital would decrease, as they claim, as there is no way of knowing just what the total impact of this degradation and heightened risk perception would be over the long term. And even if the cost of *capital* decreased it does not follow that FPL's *total* costs would be lower over the long term. Over time, however, we would surely witness reduced electric system investment and, in due course, lower customer value.

Q. What do the intervenors say about the consequences of their recommendations?

A. Witnesses seek to quantify the impact of their recommendations but they do so from the very narrow perspective of the potential impact on credit ratings; and even within this limited context their analyses are flawed and should not be relied upon. None of the intervenor witnesses acknowledges or addresses

the impacts on the business beyond possible credit ratings and cost of debt degradation.

Q. What does OPC witness O'Donnell claim would be the impact to FPL's credit ratings if the recommendations made by OPC were adopted?

A. OPC witness O'Donnell claims (page 25) that no downgrade would occur, basing his view on another error. He refers to FPL's requested capital structure as "hypothetical" which I will address in more detail on page 40 of my rebuttal. He then adds (page 26): "Assuming arguendo that FPL's bonds were downgraded, consumers may be asked to pay an additional 25 basis points in higher interest expense associated with the hypothetical downgrade." Mr. O'Donnell then applies this arbitrary 25 basis points to FPL's entire outstanding debt balance of $8 billion in determining that "the downgrade would cost consumers approximately $20 million per year in higher debt service costs."

This argument by OPC witness O'Donnell is incorrect on multiple premises: first is the assumption that a downgrade would translate to an arbitrary 25 basis point increase in the cost of debt; second is the application of this increase to FPL's current outstanding debt balance; and finally, the naïve presumption that the increase in debt cost is the only impact or increased cost of such downgrade. The presumption that FPL will remain as financially sound and competitive in the capital markets, and that FPL will continue to be

able to deliver the same superior service to customers with a significantly weakened balance sheet is wrong and should not be relied upon.

Q. What does OPC witness Lawton say with regard to the impact of OPC's recommendations on FPL's credit metrics?

A. Witness Lawton states (page 30) "the financials all fall within the benchmarks [for an A rated utility] except for the 50% debt ratio compared to the Moody's benchmark," the obvious implication being that FPL very likely *would* lose its rating. Specifically, his analysis (Exhibit DJL-5) purports to demonstrate that a decrease in the ROE to 8.75 percent, as OPC recommends, would produce a Cash Flow/Debt ratio of 22.52 percent which is at the bottom of Moody's range of 22 percent to 30 percent for the 'A' category. FPL certainly would not maintain its 'A1' rating if this metric, which is the most heavily weighted financial metric in Moody's financial analysis, was at the bottom of the range. Witness Lawton also states that his "recommended 50 percent debt capitalization is not out of line with the Moody's 'Baa' debt capitalization benchmark of 55 percent." This would imply a downgrade of at least three notches, not to mention that 55 percent is the high-end of the 'Baa' range, bordering on the 'Ba' or junk category. Additionally, his comment seems to completely ignore Moody's warning, as published in its most recent credit opinion for FPL (March 31, 2016), that "a downgrade could be considered if there [is]… an increase in debt-to-capitalization above the 40 percent range." Witness Lawton may view the possibility of FPL's position bordering on junk with equanimity; but the Commission should not.

Additionally, Witness Lawton on page 27 of his direct testimony states Standard & Poor's Ratings Services ("S&P") "employs three similar financial metrics in evaluating financial integrity and ratings of a company." He goes on to define these three metrics as funds from operations divided by total debt ("FFO/Debt"), total debt divided by earnings before interest, taxes, depreciation and amortization ("Debt/EBITDA") and total debt divided by total capitalization ("Debt/Capital"). In fact, when S&P revised its methodology in November 2013, it stopped using Debt/Capital as a financial benchmark.

Q. FEA witness Gorman also attempts to assess the impact of his recommendations on FPL's credit metrics. Please respond.

A. For his part, witness Gorman simply abandons the actual credit rating analyses for his own suggested approach. Stating on page 56 of his testimony, "I calculated each of S&P's financial ratios," he then goes on to acknowledge that his analysis, which indicates FPL's rating would not be adversely impacted by a decrease in ROE to 9.25 percent with the Company's current capital structure, "is not the same as S&P's." He makes no attempt to assess the impacts on Moody's ratios. It is not necessary for any of the witnesses to make up their own form of analysis when the agencies have been very clear.

Q. Is there other evidence the Commission can look to in considering the implications of FPL's request versus intervenors' recommendations?

A. Yes. The Commission can look at FPL's low cost position and its overall performance. If it were the case that FPL was high cost overall, their analysis

of capital costs might illustrate some contribution to that. But that is not the case. FPL is very low cost by comparison with most other utilities.

Accordingly, it follows that intervenor witnesses' arguments really all boil down to the idea that FPL's total cost position could be lower still if capital costs were arbitrarily slashed. But, to repeat, this assumes that the reduction in capital cost they recommend would have no adverse impact on the rest of FPL's business. Said differently, it assumes that the way in which FPL has financed its operations over many years has had nothing to do with benefits that customers realize today in the form of low bills and high reliability. This contention and the related implications are false.

The ultimate results of our financial policies are reflected in our overall performance. As an individual who has been intimately involved in the determination of FPL's strategies for roughly 15 years and who has had direct accountability for its financial policies, I can assure the Commission that FPL and its customers would not enjoy their current favorable situation if the recommendations of intervenor witnesses with respect to ROE and capital structure were followed.

III. FINANCIAL STRENGTH

Q. Please respond to the intervenor witnesses' discussion of financial strength.

A. Astonishingly, none of the intervenor witnesses directly addresses financial strength or recognizes that different companies may seek to maintain different degrees of financial strength in response to differences of situation or as a choice of strategy. Yet these points are fundamental: without understanding FPL's position and strategy it is impossible to appreciate why we seek to maintain financial strength, as I explained in my direct testimony.

To the extent that intervenor witnesses even acknowledge the importance of financial strength they generally do so simply from the perspective of capital access. For example, witness Lawton (pages 24-30) in a section headed "Financial Integrity" in which he acknowledges that customers have an interest in a utility maintaining adequate financial strength, states: "the term financial integrity is a term or concept that addresses a company's ability to access capital on reasonable terms." (page 24)

Financial strength certainly encompasses capital access, but it is much more than that. A company maintains financial strength to respond to 'shocks' (unexpected financing or liquidity needs driven by external events), to take advantage of opportunities that may arise, and in general to retain flexibility to

respond to changing circumstances. What degree of financial strength is appropriate is a function of individual circumstances and strategy and therefore must be a matter of considered judgment. Because intervenor witnesses nowhere address FPL's specific circumstances and seem to be unaware that its overall strategy for delivering value to customers depends on maintaining a higher degree of financial strength than is typical in the industry, their assessments of both capital structure and allowed ROE are fundamentally flawed.

IV. FPL'S RISK PROFILE

Q. Please summarize your response to intervenor witnesses' treatment of risk.

A. No intervenor witness specifically addresses the issue of FPL's unique risk profile, which is critical to understanding FPL's approach to financial policies in general and capital structure in particular. Overall, intervenor witnesses offer an over-simplified view of risk and implicitly argue that risk can be reduced to a unidimensional concept; but this is not representative of the real world. They compound this by confusing the views of risk taken by different classes of investors (debt versus equity, for example). And in one case, an intervenor witness appears not to understand the basic concept of risk.

As a consequence of their failure to appreciate either the complexities of risk overall or the specifics of FPL's unique situation, intervenor witnesses are led

to make analytical and conceptual errors that undermine their assessments of ROE and capital structure.

In practice, risk has many aspects and many dimensions and is realized by different parties (customers versus investors) and by different classes of investors (equity versus debt most particularly) in different ways. To offer just one simple example, while regulatory risk as a broad category is highly relevant both to debt and equity investors, it affects each in different ways. Debt investors will be concerned primarily with large impacts to liquidity and cash flow as well as general predictability and stability in regulation. Equity investors will be sensitive not only to these aspects but also to others with a finer impact, such as the risk of modest disallowances or asymmetrical treatment of costs. Because risk in the real world has many aspects, a company must respond to different risks in different ways, and because each company's situation is different its response is likely to be different.

In the case of FPL, as my direct testimony indicated at pages 17-22, we have risk exposures in certain areas that are markedly different from most utilities and we have chosen to respond to them in part by maintaining a stronger than typical capital structure. This has had clear benefits for customers, because it has been an integral part of our overall strategy for delivering superior value. Yet intervenor witnesses are completely silent on this point. They neither challenge my assessment of FPL's specific situation nor acknowledge that

there is value to financial strength. Instead, they focus solely on what they purport to be the "cost" of maintaining the position that FPL and its customers have enjoyed for well over a decade; or, even more simply, they assert that FPL's capital structure is excessive because it employs more equity than is common in the industry.

Q. Please describe what you mean by "reduc[ing] risk to a unidimensional concept."

A. Because intervenor witnesses do not appreciate the specific characteristics of FPL's situation they are led to make general statements that imply there is one overall type of risk, which they commonly sub-divide into "business" versus "financial" and occasionally, "liquidity." Witnesses Woolridge[3] and O'Donnell,[4] for example, separate investment risk into "business" and "financial" risk.

Within this overall view, one type of risk is seen as much like another, and risk is viewed as either 'higher' or 'lower' on a single scale.[5] Furthermore, this limited view of risk implies that the sub-types of risk may be traded off – an increase in business risk, for example, can be compensated for by an exactly offsetting decrease in financial risk.

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[3] See, for example, witness Woolridge (page 37, lines 3-4): "A firm's investment risk is often separated into business and financial risk."

[4] See, for example, witness O'Donnell (page 6, lines 11-12): "The risks that a regulated utility incurs can be stated as financial risk and business risk."

[5] See, for example, witness Baudino (page 3, lines 3-5), where he characterizes FPL as "a low-risk, financially robust electric company." *See also*, (page 22, line 14-21): "FPL remains a low cost and low risk electric utility… Overall FPL remains a low risk electric utility..." *See also*, (page 76, lines 18-20): "…a financially strong and low risk utility investment like FPL."

Q. What is wrong with this approach to risk?

A. If terms such as "low risk" are simply used to summarize more in-depth analysis, as they often are in a typical credit rating agency report, and if they are not taken out of context, no great harm is done. The danger, however, is that such simplistic generalizations invite faulty reasoning and do not take into account the multiple issues involved in determining appropriate ROEs and capital structures in the real world.

In practice, different risk exposures have different impacts on a business' return profile, and no single measure of risk is uniformly appropriate. As a consequence, it is not possible to make simple statements about the 'trade-off' between, for example, business and financial risk. It is not true that two companies with the same capital structure and the same debt rating face the same business risk profile, and the risk born by equity holders may be quite different in the two cases. Yet this is precisely the foundation for the conclusions and recommendations of certain intervenor witnesses.

The point to be stressed here is that we must be very careful in drawing inferences about underlying risk from simple comparisons of higher-level metrics (e.g., equity ratios, bond ratings, equity betas, etc.).

The assumption that risk is unidimensional is frequently utilized in finance theory because it allows for analytical simplicity, but it is well known to be

false. For example, the Capital Asset Pricing Model ("CAPM"), which is used in part in assessing cost of equity, depends upon the Markowitz mean-variance framework, in which an asset's returns can be completely described by the mean (expected return) and variance. As a consequence, the sole measure of risk that matters in the CAPM is so-called systematic risk, measured by beta.[6] This is analytically elegant, but it is known to be inconsistent with empirical data. Among several factors, actual equity returns are *not* normally distributed and *cannot* be completely described by their means and variances. That is why, as witness Hevert repeatedly notes, it (or any other model) must be used with great care as the input to a broader analysis.

In addition to all these considerations is a further distinction that is important in the real world but is nowhere recognized or acknowledged by the intervenor witnesses. Different risk factors can have very different impacts on a company's expected return profile and on its needs for liquidity. Again, FPL's geographical exposure has an impact on both, but it has a particular impact on our need for liquidity, especially when coupled with our capital investment program. We accommodate this through maintaining a strong financial position.

Q. Please explain what you mean by 'faulty reasoning.'

[6] See, for example, witness Woolridge (page 37, lines 16-18): "… an assessment of investment risk for 97 industries, as measured by beta, which according to modern capital market theory is the only relevant measure of investment risk."

A. As an example, witnesses Gorman, Woolridge and Baudino each claim that business risks are incorporated in a company's credit ratings, and since FPL's credit ratings are higher than the average for the proxy groups, then it must mean that FPL has less business risk than other utilities. This is not an accurate assessment. As I discuss in my direct testimony, FPL's risk profile is heavily influenced by its geographical position, which constrains the company's transmission system, generation mix, and fuel supply, and carries with it a high exposure to tropical storm damage. This coupled with a strong capital investment program and other factors all suggest that FPL needs to maintain a stronger financial position than most other U.S. utilities.

Moreover, on at least two occasions intervenor witnesses appear to conflate risk from an equity investor's perspective with risk from a credit perspective, employing selective quotes from rating agency reports in the context of discussing risk from an equity perspective. Witness Baudino (page 25) refers to bond and credit rating agencies within the context of discussing a "fair rate of return" and his ROE estimation models. Similarly, in assessing FPL's ROE, Witness Woolridge claims FPL's capital expenditure program, geography, and nuclear risk are already considered by *rating agencies.* While it is certainly true that debt and equity investors share exposures to many underlying risk factors, it does not follow that they share them equally or consistently, and therefore rating agency views cannot be taken as fully characterizing equity investors' risk exposure.

Q. Please explain your reference to an intervenor witness "misunderstanding" the concept of risk.

A. Witness O'Donnell on page 6 of his testimony states "[b]usiness risk is a measure of a company's ability to operate at a profit within its industry. Given that FPL operates in a monopoly industry with no retail competition, its business risk is relatively small."

His definition of risk is simply wrong. Academically, risk is typically defined as the variability around an expected value, but it is certainly *not* a measure of a company's ability to operate at a profit. A highly profitable company may have high risk, while one that is consistently unprofitable may well have lower risk.

Q. SFHHA witness Baudino refers to FPL as being a "low risk, financially robust electric company" (page 3). Do you agree with this characterization?

A. I agree that FPL is financially strong relative to most other companies in its industry. As I have explained, this reflects both FPL's specific risk profile and a strategic choice. However, whether FPL is "low risk" or not depends crucially both on perspective (i.e., who is bearing that risk) and the standard of relativity being applied. For instance, given the high rating of FPL's first mortgage bonds ("FMBs"), the risk of a fixed income investor in these instruments is low compared to the average utility mortgage bond. This is reflected in the fact that FPL generally enjoys a lower cost of debt than the

average utility. In contrast, from an equity investor's perspective, FPL is not "low risk" compared with the average utility. More important, in the real world it is not possible to reduce the risks that equity investors are exposed to in selecting among different utilities to a simple scale of "higher versus lower" whether measured by beta or any other single indicator. Each company has a different profile and its investors will have different exposures in different states of the world.[7] In practice, risk cannot be reduced to a single measure.

Q. Witness Chriss argues that (1) the use of a future or projected test year and (2) the amount of revenues collected or costs recovered through clause charges both lower FPL's financial risk, and should be key considerations for the Commission when examining the proposed revenue requirement and associated ROE. Does this reduce FPL's financial risk as compared to its peers?

A. No. Projected test years and cost recovery clauses are both aspects of FPL's overall risk profile but they are not uncommon in the industry. Moreover, the mere existence of a clause recovery mechanism by itself tells us little, because different companies will have different exposures to the risk factors that underlie the clauses (e.g., variations in fuel price).

Q. Witnesses Gorman and Woolridge note that FPL's risks are considered by the rating agencies that arrive at FPL's A- and A1 ratings, while witness Baudino comments that comparing bond and credit ratings

[7] This is one reason why the measurement of beta presents problems; betas are not stationary but vary in different states of the world.

provides "an objective assessment of how FPL's overall risk compares" (page 71). Please respond.

A. I agree that FPL's risks are considered by credit rating agencies, but they are considered alongside of FPL's financial policies. In other words, FPL's strong credit ratings are arrived at *despite* FPL's risk factors, thanks to the strong financial policies it has consistently employed.

Q. Several intervenor witnesses characterize the ratings outlook for FPL as "stable", citing credit rating agency reports. Do you agree?

A. I agree that today the three agencies all describe the outlook for FPL as stable. However, that is not the same as saying it would remain stable if the intervenor witnesses' recommendations were adopted. The stable outlook of all three agencies is predicated in significant measure on the continuation of what the agencies see as the currently constructive regulatory environment. As witness Gorman notes in his testimony, quoting Moody's: "The stable rating outlook reflects the our [sic] expectation that the current rate case will result in a constructive outcome that will maintain its existing credit supportive features… including CFO Pre-WC-to-debt in the low to mid 30% range."

Implementation of the intervenor witnesses' recommendations with respect to capital structure and equity ratio would clearly not meet this expectation. Because of this, witness Lawton's analysis (page 54-57) that purports to show that implementation of his proposed recommendation would "support an

investment grade bond rating for FPL" is incomplete and should be disregarded.

V. CAPITAL STRUCTURE

Q. How do intervenors propose that the Commission should consider capital structure?

A. Intervenor witnesses Baudino, Brosch, O'Donnell and Pollock all call upon a simple framework in which equity is "more expensive" than debt and debt should be added to the capital structure to lower the overall cost of capital up to some (unspecified) "optimal" point.[8] I will comment on the flaws in this approach later. However, because this conceptual framework is not actually operational, as I will also explain at page 35, they all immediately abandon it in favor of one or more of three more generalized arguments as follows:

(1) FPL's current equity ratio is too high because it exceeds the average of other utilities,[9] *without any consideration for the differences in situation and strategy;*

(2) FPL's current equity ratio is too high because it exceeds the generally accepted accounting principles ("GAAP") equity ratio of NextEra Energy and/or its other subsidiaries, *without any consideration for*

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[8] Pollock page 32; Baudino page 42, O'Donnell page 9; *see also* Brosch page 47.

[9] In the case of AARP witness Brosch, he bases his recommendation on a comparison of FPL's equity ratio to the average equity ratio of a group of utility *holding companies*. This is inappropriate for the reasons I described earlier at page 10.

differences in situation and strategy and ignoring the irrelevance of GAAP equity ratios to the financial profile of NEE's other businesses; and

(3) FPL's current equity ratio is too high because it results in higher revenue requirements that could be lower, *without any ill effect.*

Q. Please respond to the assertion that FPL's equity ratio is "too high" because it exceeds the average of other utilities.

A. As I explained earlier, naïve comparison of capital structures without regard for differences in situation and strategy can tell us nothing about how FPL should structure itself. Companies differ in their risk profiles, as I described both in my direct testimony and earlier in my rebuttal testimony, and they also differ in how they choose to seek to deliver value to their customers. These differences will logically lead to different decisions about financial policies in general and capital structure in particular.

In effect, by proposing that the Commission alter FPL's capital structure on the basis of these comparisons, intervenor witnesses are assuming that all utilities are alike and interchangeable in every other respect (or at least, so nearly similar as to make no practical difference), so that differences in capital structure can meaningfully serve as a measure of deviations from the purported 'optimal' capital structure. Such a view is not consistent with practical experience in this industry.

In focusing on purported 'optimal' capital structure, intervenor witnesses are seeking to undertake what is referred to academically as "sub-optimization" – i.e., to optimize one element of an integrated system without regard for its impact on other parts of the system. Even if it were the case that intervenor witnesses' capital structure recommendations in some fashion truly represented a lower cost of capital, which I dispute because they have ignored FPL's risk profile, it would still not follow that we should adopt them.

It is true that we have deliberately chosen to maintain a stronger-than-average financial position for FPL. We have done so both because of the unique risk profile to which FPL is exposed, which in my judgment requires a greater than average degree of financial strength, and because the strong financial position gives us real-world advantages in many areas, which I noted in my direct testimony starting on page 11, and which in turn improve our ability to deliver value to our customers. It would be both wrong as a matter of logic and dangerous as a matter of practice to assume, as intervenor witnesses do, that we are free to arbitrarily change FPL's capital structure without also affecting its operational performance.

Q. Please respond to the assertion that FPL's equity ratio is "too high" because it exceeds the GAAP equity ratio of NEE and/or its other subsidiaries.

A. This assertion contains all of the same errors as the prior point discussed above, as well as additional problems. The biggest source of additional error is

in the comparison of GAAP equity ratios for businesses with different economic structures and radically different financing structures. This is simply not proper and appears to reflect a lack of understanding in how companies capitalize themselves.

As a practical matter, NextEra Energy structures and finances its principal subsidiary other than FPL, a business named NEER, in a very different way and it does so because the businesses are quite different and the strategies employed by these businesses are quite different. In structuring and financing NEER, NEE makes use of a wide variety of instruments, including project debt, tax equity, so-called 'hybrid' debt, and equity units, which together result in GAAP debt ratios that are much higher than the effective economic leverage. Without going into detail here, anyone familiar with the kinds of adjustments that S&P, for example, explicitly discusses in its reports, would be aware of this large difference. That intervenor witnesses apparently chose to overlook this difference should cast doubt on their broader assertions.

Q. Please respond to the assertion that FPL's equity ratio is "too high" because it results in unnecessarily high revenue requirements and could be lowered without any ill effects.

A. There are two main problems with the approach used by each of the witnesses that espouse this position. First, as discussed above, the intervenor witnesses have failed to show that FPL's equity ratio is "too high" given FPL's position and strategy. Rather, they ignore both FPL's position and its strategy,

incorrectly assuming that there is no relation between how the Company capitalizes and how it has performed and can continue to perform. This is discussed above as the false premise that underlies intervenor's testimony in this proceeding.

Second, intervenor witnesses' attempt to show that there would be no ill effects from arbitrarily reducing FPL's equity ratio is flawed. One such example is witness O'Donnell's claim that FPL's credit rating would not be downgraded if the Commission were to approve an equity ratio of 50 percent because "the rating agencies are used to analyzing utilities with reasonable equity ratios." Even putting aside his view of what is "reasonable," a rating agency's previous guidance on FPL contradicts witness O'Donnell's claim. Employing a lower equity ratio would negatively affect FPL's credit metrics, including CFO Pre-WC-to-debt and debt-to-capitalization, critical metrics analyzed by Moody's. In Moody's most recent publication on FPL (March 31, 2016), it cites that "a downgrade could be considered if there are significant cost disallowances or other changes to Florida's credit-supportive regulatory and cost recovery framework, or if there is a sustained decline in cash flow coverage metrics, including CFO Pre-WC-to-debt below 25%, or an increase in debt-to-capitalization above the 40% range."

Q. Do you agree with witness O'Donnell that FPL's "unnecessarily expensive capital structure" or "excessively high 59.6 percent common equity ratio" costs the typical residential customer about $41 per year?

A. No. Witness O'Donnell bases his calculations on the hypothetical rate impact using a 50 percent equity ratio, which he states is "comparable to other electric utilities and is also comparable to what the state commissions across the country have deemed to be fair and reasonable." I have already explained why this is an inappropriate comparison and why it logically cannot demonstrate that FPL's capital structure is "unnecessarily expensive."

However, even if witness O'Donnell were correct in his assertion, the overall magnitude is subject to different interpretations. In my judgment, $41 per year, or about 3 percent of the typical residential bill is far more than offset by the advantages that a "stronger-than-average" capital structure brings, both in terms of flexibility and resilience to stress scenarios and in terms of direct support to the Company's operational strategies. Witness O'Donnell's hypothetical $41 per year should be compared with the very real roughly $480 per year typical bill savings that the FPL residential customer enjoys by comparison to national averages (or the more than $200 per year benefit derived from lower O&M as compared to national averages (Silagy page 6)).

Q. Please describe the framework for determining capital structure that intervenor witnesses use, and explain why you believe it is flawed.

A. Each of witnesses Baudino, Brosch, O'Donnell, Gorman, Kollen and Pollock employs some variation on a framework that argues the following:

- debt is "cheaper" than equity

- as debt is added to a hypothetical capital structure the weighted average cost of capital, or WACC, is gradually reduced…
- …until at some point the greater risks associated with using more debt cause debt rates to rise and equity required returns to rise at a faster rate such that WACC starts to increase…
- …and therefore firms should choose the point that minimizes the WACC.

This framework is commonly found in most first-year finance textbook, and as a starting point for teaching finance students it captures some important principles. However, the framework itself is known to be incomplete, and it clearly is not representative of real-world behavior. It is a pedagogical tool, and not a financial model to be algorithmically used in the development of capital structures by corporations. In addition, it is not operational – meaning that there is no practical way of applying it, which is why each of the intervenor witnesses immediately abandons it in favor of simplistic comparisons of equity ratios for companies in different situations.

It is flawed conceptually because the only direct economic benefit of debt is the tax deductibility of interest payments, but the theoretical magnitude of this benefit would drive "optimal" capital structures to levels that even academics have admitted make no sense. Brealey, Myers and Allen note in the textbook "Principles of Corporate Finance" (McGraw-Hill, 2011) that under this

theory, "[t]he optimal debt policy appears to be embarrassingly extreme. All firms should be 100% debt-financed." (page 444)

It clearly is not representative of the real world, and in the early 1980s, I personally undertook a detailed statistical analysis demonstrating that companies do not finance themselves with anywhere near the degree of leverage that the simple academic model would suggest.

This observation is well known. Since the 1980s more sophisticated work has been done to try and incorporate 'real-world' considerations, so that theoretically derived 'optimal' capital structures more closely approximate real-world observations.

Q. Please summarize the problems of the approach intervenor witnesses use to criticize FPL's capital structure.

A. There are two fundamental problems with the simple business school model that intervenor witnesses seek to call upon, one irremediable and the other pragmatic:

(1) to repeat a theme noted now several times, the framework assumes that changes to capital structure have no effect on the asset side of the balance sheet, i.e., on operational performance.[10] This is simply wrong and inconsistent with the real world; and

[10] It is clear that some academics appreciate this fundamental issue. For example, in their introduction to Chapter 5 ("Does Debt Policy Matter?") of their book "Financing and Risk

(2) the factors that are supposed to increase cost and limit the benefit of adding debt (bankruptcy costs, costs of financial distress, agency costs, etc.) are essentially impossible to estimate with any precision and therefore it is essentially impossible to tell, even with the limited confines of the model where the "optimal" capital structure is. This is why I characterized the model as not operational.

Q. If the approach to capital structure used by intervenor witnesses is fatally flawed, how should the Commission consider this topic?

A. Determining an appropriate capital structure is an important question that cannot be reduced to an arithmetic search for the "lowest" cost of capital. Instead, it must be determined using judgment and it must be based on consideration both of the overall strategy of the business and of the unique circumstances affecting the business, including in particular its unique risk profile. This is what we have done at FPL and the result is periodically reviewed for continuing applicability. Because FPL's situation and strategy have remained broadly the same for over a decade, it should not be surprising that we have maintained consistency in our approach to capital structure.

Additionally, the Commission can consider the results of the capital structure being employed. In addition to purely financial impacts, such as the fact that

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Management" (McGraw-Hill, 2003), professors Brealey and Myers note: "In Chapter 6 we will undertake a detailed analysis of the imperfections that are most likely to make a difference, including taxes, the costs of bankruptcy, and the costs of writing and enforcing complicated debt contracts. We will also argue that it is naïve to suppose that investment and financing decisions can be completely separated." (page 92)

FPL's cost rates for long term debt are generally amongst the lowest in the nation, FPL's overall cost of service and exemplary performance for customers should not be ignored. Intervenors have failed to present any compelling evidence to support a deviation from FPL's historic and current approach.

Q. Witness Baudino at pages 45 to 46 of his testimony notes that FPL in discovery produced no document responsive to certain questions around analyzing capital structure. How do you respond?

A. Witness Baudino's line of questions suggests that he does not appreciate how capital structure review and determination occurs in the real world. For example, his observation that "FPL has no documents regarding how increasing, decreasing, or maintaining FPL's equity ratio would affect its total cost of capital" (page 45, internal quotes omitted) illustrates well by implication the framework I described earlier. The fact is, however, that FPL has no such documents because such analyses are not useful in the real world. Capital structure is *not* a matter of choosing the equity ratio that minimizes cost of capital; and trying to determine the impact on cost of capital from changing equity ratios is so fraught with inherent uncertainties, as well as lack of useful needed input data, as to be worthless in the real world. Witness Baudino's framework may be useful for introducing finance students to a partial view of the issues surrounding capital structure, but as I have noted before, it is not operational and it does not reflect real world behavior.

Q. Is FPL's equity ratio "hypothetical" as asserted by witness O'Donnell?

A. No. FPL's requested capital structure reflects the actual capital structure that has been maintained by FPL for well over a decade. Our approach to capitalization has served our customers exceptionally well for years and will continue to be the foundation of our ability to provide the type of service we are currently providing and at affordable rates for years to come. Intervenors' recommendations would undermine the financial strength of arguably the best performing utility in Florida and the U.S., financial strength that we have worked hard to establish over many years.

Q. Witnesses Pollock (page 32), Brosch (pages 50 to 51) and O'Donnell (pages 25 to 26) all claim that FPL may maintain a different capital structure than the one used by the Commission in this docket for ratemaking purposes. Is this correct?

A. No. In practice, FPL could not reasonably continue operating the Company in a manner that is contrary to the Commission's determination on an appropriate equity ratio in this case. Accordingly, if intervenor witnesses' recommendations to employ an equity ratio or 47 percent to 55 percent were adopted, FPL would have to issue $1.2 to $3.2 billion in long-term debt and correspondingly reduce its equity by the same amount. FPL would thus become far more leveraged and financially risky. Adoption of this recommendation would also reduce FPL's cash flow significantly. As I have already discussed at length, these impacts most likely would translate into a credit rating downgrade and certainly would result in higher borrowing costs.

Q. SFHHA witness Baudino claims that FPL's capital structure in 2014 consisted of 55 percent equity, claiming that amount should therefore be sufficient. Please respond.

A. FPL carefully manages its capital structure so that it closely matches the capital structure last reviewed and approved by the Commission based on a 13-month rolling average. Witness Baudino, in referring to MFR D-2, which provides the year-end, investor-sources capital structure as measured at a point-in-time, identified that at December 31, 2014, FPL's equity ratio was 55 percent. This was a function of the fluctuating cash flows of the business and decisions on the timing of accessing the long-term debt markets, and not an indicator that we maintain a regulatory capital structure significantly below the level that was approved by the Commission. Note that the 13-month rolling average equity ratio at December 31, 2014 was 60.0 percent; this can be derived from the Earnings Surveillance Report that the Company filed with the Commission in February 2015.

Q. SFHHA witness Baudino suggests that FPL issue projected 2017 and 2018 long-term debt now to take advantage of current interest rates (page 55). Is this a reasonable financing strategy for FPL to pursue?

A. No, in my judgment this would be unwise. To do as witness Baudino suggests would imply either substantially increasing FPL's leverage or maintaining material cash balances. To increase the leverage at FPL, FPL would have to recapitalize its balance sheet through an issuance in the range of $1.2 to $3.2 billion of long-term debt. FPL would then dividend or distribute this same

amount to its parent, NEE, with a plan to revert that cash back to FPL at a time when a stronger financial position is needed. This would be exceedingly challenged and costly during adverse circumstances, which is most likely the time when FPL would be seeking to restore its financial strength under this example. I agree that short-term capital market conditions are comparatively benign, but we should not set capital structure on the assumption that benign conditions will always prevail. We maintain financial strength precisely so that we have flexibility when conditions are stressed, and no one can tell for sure when that flexibility will be required.

Alternatively, pre-funding FPL's future debt needs today and maintaining a cash balance with those proceeds would result in FPL incurring material carrying costs, and increased costs to customers, given that such issuances would occur far in advance of those expected operational cash needs.

Q. What is your reaction to witness O'Donnell's assertion that if the Commission continues to accept FPL's actual equity ratio "the big winners are the shareholders…the customers lose" (page 22)?

A. I disagree with the premise that there are 'winners' and 'losers.' FPL customers today enjoy all the benefits of low bills, high reliability and excellent customer service, and they will continue to do so if FPL's financial policies are maintained.

VI. RETURN ON EQUITY

Q. Do you agree with the return on equity recommendations made by Dr. Woolridge, Mr. Baudino or Mr. Gorman?

A. No. The analyses on which these recommendations are based are flawed or biased, as witness Hevert explains in his rebuttal testimony. And the recommendations themselves simply do not pass the common sense test of reasonableness. Specifically, each of these recommendations, if adopted, would represent the lowest authorized ROE decision for any vertically integrated electric utility in the U.S. since the beginning of 2014. In fact, each is at the low end of authorized ROEs for Transmission and Distribution-only electric utilities – businesses with clearly lower risk profiles. In the current environment, as my Exhibit MD-3 shows, the opportunities available to investors to commit capital to the utility business elsewhere offer returns well in excess of what each intervenor witness is recommending for FPL. In fact, OPC witness Woolridge's recommended 8.75 percent ROE would be less than the lowest ROE awarded in the U.S. since the beginning of 2013 of 9 percent - which reflected a performance penalty.

Q. How would investors and the rating agencies view a decrease in the allowed ROE to the levels recommended by intervenor witnesses?

A. Clearly, different participants would react in different ways. However, based on my interactions with them, all would view such a change as very negative to risk and as a significant change in the regulatory environment. Investors

and rating agencies all tend to view allowed ROE as an important indicator of the broader regulatory environment, and such a large discontinuity relative to past practice in Florida would cause great concern. Investors generally would become more reluctant to commit incremental capital to the business, and there would be substantial pressure from equity investors to decrease investment in the business and increase payout ratios, as in 2010. While these effects would be concentrated on FPL, they would likely not be limited to FPL, but would extend to other Florida utilities regulated by the PSC. Over time, this would constrain access to capital, increase the cost of capital, and limit FPL's ability to invest, ultimately resulting in poorer customer value.

Q. Witnesses Brosch, Chriss and Pollock all refer to FPL's ROE request as "excessive." Please respond.

A. Testimony reflects that none of these three witnesses has conducted any independent analysis. Witness Brosch argues on page 40 of his direct testimony that "current risk free capital cost rates are much lower today than [in 2010]" and that therefore the allowed ROE should be lower. Yet witness Hevert's analysis is based on today's capital market conditions and reflect the impact of today's "risk-free capital cost rates," which of course are not the only determinant of cost of equity. As I will discuss in more detail, it would be wrong to set an allowed ROE off today's distorted interest rates strictly through a lock-step application of the notion that 'if risk-free rates have come down ROEs must, too.'

Witness Chriss presents a comparison of authorized ROEs for vertically integrated utilities from 2013 to the present but he provides no direct evidence on FPL's specific situation, in contrast to witness Hevert. Witness Pollock follows a similar line and presents comparative data on currently authorized ROEs, but again he provides no direct evidence comparable to witness Hevert's.

Q. Please explain your reference to "today's distorted interest rates."

A. Witness Baudino (pages 6 to 12 and page 75) and witness Woolridge (pages 15 to 27), discuss current capital market conditions and argue in part, that current capital market conditions support their recommended ROEs. My concern with this is that their own assessment clearly demonstrates that historically unprecedented intervention by the Federal Reserve has led to distortions in the historical relationships between many of the variables that they use in their models. At the risk of simplifying, witnesses Baudino and Woolridge (and, implicitly, Witness Gorman, too) are all assuming that they can safely apply historical relationships to a currently distorted risk-free interest rate structure *and* that that distorted structure may be relied upon to continue indefinitely into the future. Both of these are dangerous assumptions, and should not be used in determining FPL's authorized ROE.

Q. How have the historical relationships between modelling variables been affected?

A. Witness Hevert explains this issue in more detail, and I defer to him on the specifics, but the principal point we should be aware of is that we should not

expect equity risk premia to remain independent of the overall level of interest rates: low interest rates generally imply higher risk premia and vice versa.

Q. Please explain your concern about relying on the continuation of today's distorted market conditions.

A. Witnesses Baudino and Woolridge both make clear that macroeconomic and political events, both domestically and internationally, have had a significant short-term impact on the U.S. Treasury yield curve and on equity market valuations, including sectoral effects such as the current relatively high price-to-earnings ("P/E") relationship for the U.S. utility sector relative to the S&P 500 or other broader market indexes.[11] These effects have little or nothing directly to do with FPL or other U.S. utility companies, yet Witnesses Baudino and Woolridge are reflecting this in their ROE analyses – arguing that FPL's cost of capital is lower as a result of them. But macro-events come and go, and they come and go very rapidly. At some point – and I concede no one can know when – it is highly likely that the current environment will revert, in which case, if intervenor witnesses' recommendations are followed, there will be massive capital flight away from U.S. utilities generally and FPL even more so, and FPL and its customers and investors will be at risk of being

[11] See, for example, witness Baudino (page 9, lines 26-27): "The Fed's monetary policy actions since 2007 were deliberately undertaken to lower interest rates and support economic recovery." *See also*, (page 57, lines 6-12): "The Federal Reserve considered raising interest rates this year, only to defer any such increases due to economic concerns relating to job creation, domestic economic growth, and the effect on exchange rates that would increase the value of the dollar abroad and potentially harm U. S. exports." *See also*, (page 12, lines 11-13) in which he quotes ValueLine "This is reflected in the high valuation of many electric company equities. Most are trading at a market premium…" *See also* witness Woolridge (page 75, line 11): "the P/E ratios of utility stocks have increased."

left 'high and dry.' I do not believe this is a sound policy basis for setting allowed ROEs.

Q. Witness Woolridge argues that forecasts of interest rates have been wrong. Please respond.

A. Mr. Woolridge ties himself into a logical knot when discussing the issue of forecasting capital market conditions generally and interest rates in particular. He goes to some lengths to argue that historical interest rate forecasts *have turned out to be* wrong, in order to discredit the use of a forecast of increasing interest rates (pages 16 to 17). Yet, having discredited the forecasting abilities of professional economists (pages 17, 11 to 13 and 19 to 22) he promptly asks the Commission to substitute his own professional *opinion* (page 26) that interest rates will remain low. This is a forecast like any other –extrapolating today's rates is by definition a forecast that rates will remain unchanged. Witness Woolridge (page 47) presents his forecast despite his own contention that "I suggest that the Commission set an equity cost rate based on current market cost rate indicators and not *speculate* on the future direction of interest rates" (emphasis added).

Though I understand that intervenor witnesses may not like the result, we have to use the best information available to us. In my judgment, setting an allowed ROE based on the assumption that current market conditions, distorted as Mr. Woolridge acknowledges by macro and international events that are not likely to endure, will continue indefinitely, would be unwise. Mr.

Hevert's analytical techniques accommodate this concern far better than those of any of the intervenor witnesses.

Q. Couldn't the Commission simply re-visit the cost of capital issue if and when capital market conditions change?

A. While this might seem like an attractive alternative, there are two core problems; one practical and one conceptual.

The practical problem is that capital market conditions are constantly changing and generally no one event will be sufficiently obvious to serve as a trigger. Coupled with the four-year stay-out proposed in FPL's application, this would make it difficult to re-visit within the next few years.

However, there is a more fundamental issue. The allowed ROE is not used simply as an anchor point around which FPL's actual earned returns are expected to move. It also serves as a critical input in long-term capital investment decisions. Utilizing an allowed ROE based on distorted capital market conditions would give rise to capital investments, some of which later on would be revealed to be unwise if or when macro events revert to more normal conditions.[12] Ironically, given some intervenor witnesses' expressed concern for utilities having an incentive to overinvest (O'Donnell, page 5)

[12] It should be noted that this concern is at the heart of many critiques of the Federal Reserve's unprecedented intervention in capital markets. Arguably, the failure of investment to respond as policymakers hoped in the face of 'cheap' capital is evidence that investors have not been convinced that the true opportunity cost of capital has actually come down.

setting too low an authorized ROE would make more capital investments appear attractive from a cumulative present value of revenue requirements ("CPVRR") perspective. This issue is of particular concern for a business like FPL where investments are commonly very long-lived and cannot easily be reversed or moved (e.g. generation or Transmission and Distribution ("T&D") assets) once completed.

PART 2

VII. ROE PERFORMANCE ADDER

Q. Please summarize your reaction to intervenor witness testimony as it relates to the ROE performance Adder.

A. I have two primary concerns with the testimonies of witnesses Brosch, Gorman, Pollock, Lawton, Baudino and Chriss with regard to the performance Adder. First, intervenor witnesses uniformly misstate the performance standard to which a Florida regulated utility should be held; and, second, intervenors witnesses appear to misunderstand or mischaracterize my testimony on this topic.

Q. Please explain how intervenor witnesses mistake the performance standard.

A. Intervenors' witnesses present varying formulations of FPL's service obligation or "duty" to its customers in an attempt to demonstrate that FPL's

service does not rise to the level of warranting the requested ROE Adder. For example:

- Mr. Pollock claims FPL has an "obligation to provide reliable service at the lowest reasonable cost." (page 4)
- Mr. Gorman claims FPL is "require[d] to provide high quality, reliable service at competitive rates." (page 4)
- Mr. Lawton claims all monopolies "have a duty to provide superior performance" (page 13)
- Mr. Brosch claims FPL is required "to constantly strive for the provision of safe and reliable service at the lowest practical cost" (page 51)
- Mr. Baudino claims FPL customers "should expect exemplary management from the company" (emphasis added; page 77, 14-15)

Each witness is mistaken. As Witness Deason describes, FPL's service obligation is clearly stated in the Florida Statutes – FPL is obligated to provide "reasonably sufficient, adequate, and efficient" service. FPL's service, including its cost of service, is clearly above and beyond that standard as discussed in my direct testimony as well as the direct testimonies of FPL witnesses Silagy, Santos, Cohen, Kennedy, Miranda and Reed.

Q. Does a general standard or expectation of "superior" performance make sense for utilities, regardless of the Florida-specific legal standard?

A. No. Any attempt to impose a general standard of "superior" performance, as witness Lawton does, or "exemplary" management, as witness Baudino does, immediately runs into a logical conundrum: it is logically impossible for the median or average of a group to be equal to the best ("exemplary") or even the upper half ("superior") where there is variation in performance (as there is in the real world), however hard we try and regardless of whatever penalties or rewards may be imposed. The only way out of this conundrum is to conclude that the majority of the industry is failing to deliver against witness Lawton's and Baudino's standard, which defies reasonable belief. Overall, the U.S. utility industry does a highly creditable job in delivering reliable service at an affordable cost, as anyone who has traveled broadly across the globe can attest. Relative to this U.S. average, and even excluding those utilities that face penalties for substandard performance, it is clear that FPL provides superior service – for example, higher reliability at a lower cost. FPL is not simply delivering to its required obligation, as intervenors witnesses would have us believe, but is clearly going above and beyond.

Moreover, if it were true, as Mr. Lawton claims on page 13 of his direct testimony, that all monopolies "have a duty to provide superior performance in exchange for cost recovery plus an opportunity to earn a fair and reasonable return," all below-average performing utilities would presumably be denied cost recovery and a return on their invested capital. Clearly that is not how utility regulation works. In effect, intervenor positions would conclude that

half or more of the utilities in the U.S. should be subject to penalties for poor performance.

Q. Please explain how intervenor witnesses have misunderstood or mischaracterized your testimony.

A. First, witnesses Lawton and Baudino either directly state or indirectly imply that my direct testimony argues that a performance adder is *necessary* for FPL to continue to deliver outstanding performance (for example, see Mr. Lawton's testimony at page 13). To be clear, this is not what I have said. Instead, I argue that it would be *good policy* to provide for a performance adder in this specific instance.

Second, as discussed further below, witnesses Brosch, Pollock, Lawton and Baudino seek to show that some aspects of FPL's current performance are due to factors having nothing to do with management. While they misappreciate the influence that management may have on total performance over time, as I will discuss, this argument misses the point. As long as management has *some meaningful influence* over performance, which no one with practical experience would deny, the concept of an incentive based on total delivered performance has merit. The purpose of the ROE Adder is not to reward effort or input but to reward output (i.e., customer value) and to offer an incentive to improve output.

Third, witness Lawton appears to misinterpret my testimony as asking to be rewarded for past accomplishments (page 11). When I testified that the incentive would "reflect what FPL has already accomplished" I was referring to the *current* exceptional value that FPL provides. While past actions are relevant because they have resulted in FPL's current position, it is the recognition of FPL's current superior customer value, in combination with an incentive for continued improvement, that I believe to be the purpose of the ROE Adder. FPL's current performance, which few would deny merits the modifier 'superior,' is the culmination of more than two decades of customer-focused decision making, efforts to improve efficiency and careful investments, but it is the current performance that I believe warrants recognition.

Fourth, witness Pollock and Lawton note correctly, that FPL customers have paid or are paying for the service levels that they enjoy today. But they miss the point with regard to observing differences in performance among electric service providers. In effect, they are simply arguing that differences in performance should have no impact on allowed ROE without providing any basis for their contention. In contrast, I argue that differentiating ROE on the basis of overall performance represents better public policy because over time it is likely to result in higher levels of performance.

Q. Why is the intervenor witnesses' policy position inferior?

A. It is important that some general relationship exist between a utility's allowed ROE and its relative performance in delivering value to its customers.

It is commonly understood that regulation is designed to act as a surrogate for competition. For example, in the publication "Principles of Utility Corporate Finance" (Public Utilities Reports, Inc. 2011), the authors state at page 7 the following:

> "the fundamental economic goal of regulation is straightforward: to mimic a competitive market outcome, even when the underlying market is not competitive. In other words, purely economic regulation strives to achieve outcomes that capture the benefits of purely competitive markets when those markets are themselves not competitive."

Competitive markets financially reward those companies with better products or services – companies that do the right thing for customers. Such companies generally earn higher returns. If regulation is intended to be a substitute for competition, rewarding those companies that do the right thing for customers is an appropriate incentive. Indeed, as I noted in my direct testimony, in my experience it is more important to offer a positive incentive in light of the bias towards conservatism inherent in a regulated industry.

The key test for deciding between these two competing visions of public policy is very clear: do you believe that over time the observed performance of a regulated industry in which allowed ROE is linked to customer value delivery will be better than one in which there is no linkage? I believe the answer is obvious, and it is obvious for the same reason that, on average, companies in competing markets delivering superior customer value earn higher returns: incentives matter.

Q. Please respond to the various claims that FPL's low bills are due to low gas prices.

A. I would first observe that low bills are just one aspect of FPL's superior performance, albeit a very important factor. It is noteworthy that not a single intervenor witness has challenged any aspect of Witness Reed's benchmarking analysis in which he concludes that FPL has out-performed similarly sized companies across an array of financial and operating metrics. Instead, Intervenor witnesses point to several factors that they claim contribute to FPL's low bills, as if those factors undercut FPL's request for an ROE Adder to incent continued exemplary performance. Mr. Lawton even goes as far as saying FPL's low rates "are a direct result of historically low natural gas prices more than superior managerial performance" (page 14), but does not provide any quantification or analysis to support such a statement.

As FPL witness Forrest explains, intervenor witnesses overlook the fact that FPL has taken proactive steps to improve the efficiency of the system which has resulted in significantly less fuel being used. Curiously, intervenors in

this case either outright opposed, or failed to support, many of those efficiency investments.

Q. Please respond to Mr. Baudino's claim that FPL's low bills are due to population growth.

A. Mr. Baudino credits population growth within FPL's service territory with creating the opportunity for FPL to invest in new natural gas fueled power plants and claims that other utilities "have not had the same opportunities" (page 78). But Mr. Baudino seems not to understand that FPL's fuel efficiency has improved for multiple reasons. Moreover, the opportunity to invest in new technology is not limited simply to capacity expansion, as FPL's modernizations and its earlier re-powerings illustrate. Finally, even if the opportunity is created by growth it requires a customer-focused management team to exploit that opportunity.

To illustrate that population growth by itself does not automatically lead to a favorable cost position, we have only to consider other industries in Florida, including the healthcare industry that Mr. Baudino represents in this proceeding. They too would be impacted by such demand-related efficiency opportunities. But if a rising population in Florida is allowing for efficiencies at hospitals, spreading their costs across a greater number of patients, FPL is certainly not seeing it in the costs that we pay for health care services for our employees.

Q. Please respond to Mr. Baudino's claim that FPL's low bills are due to economies of scale.

A. I agree that, overall, scale can offer opportunities for lower unit costs. However, scale curves in the U.S. utility industry are relatively shallow and there is significant variation among companies that is not explained by scale. Moreover, FPL witness Reed's testimony demonstrates that FPL's performance is excellent after adjusting for scale impacts. Mr. Baudino does not address this.

Scale may provide a conceptual opportunity for efficiency; however, that opportunity must be taken advantage of, which requires management action. That FPL outperforms other large utilities is evidence of real difference.

Finally, scale itself is not completely exogenous and outside of management's control. It is open to the management teams of smaller utilities to consider merging into a larger organization, for example, as some have done, in order to benefit from economies in important areas such as purchasing.

Q. Please respond to Mr. Baudino's claim that FPL's low bills are due to its low cost nuclear operations.

A. Mr. Baudino credits the depreciation of FPL's nuclear power plants and their low operating costs as contributors to FPL's low bills, while somewhat to the contrary, Mr. Lawton claims that the "vintage of equipment" (page 19) – presumably the newness of FPL's generators – reduces costs and has "little to

do with management performance." (page 20) Both Mr. Baudino and Mr. Lawton ignore the point that the decision to invest in nuclear power decades ago and the decision to invest in modernizing FPL's fleet more recently were both *management decisions*.

FPL has invested substantially in modernizing and uprating its nuclear fleet which, while good for customers in the long term, in fact puts upward pressure on its cost structure in the short term.

Inadvertently, perhaps, intervenor witnesses' selective arguments about individual elements of FPL's cost structure point the way to exactly the view expressed in my direct testimony (page 29): the right way to judge FPL's overall performance is on a broad array of measures that contribute to FPL's delivery of customer value. Customers care about the total package, not the individual components of cost.

Q. Witness Lawton states (page 22) his view that asking customers to pay for enhancements to the Turkey Point cooling canal system should by itself disqualify FPL from eligibility for any performance adder. Do you agree?

A. No. While I strongly disagree with Mr. Lawton's characterization of the cooling canal situation, he himself notes that the question of the treatment of costs associated with the enhancements is a separate legal issue that will be addressed in another docket. How FPL has managed and continues to manage

all its facilities, including its nuclear facilities, is certainly a part – but only one part – of FPL's overall performance record. We are asking the Commission to consider the totality of FPL's performance, which is reflected in its overall relative cost position, its low bills, its high reliability relative to industry norms, its strong record of customer service, and its relative position compared with others in the industry with respect to environmental risks. No company is immune from environmental risk, however strong its compliance record. However, FPL's overall record of delivering value to customers, including fair and reasonable assessment of the management of its nuclear facilities, is quite clearly meaningfully superior to industry norms. Accordingly, consideration of the policy merits of awarding the proposed ROE Adder in this specific instance remains fully warranted.

Q. Several intervenor witnesses quantify the requested ROE Adder in terms of revenue requirements and the impact on FPL's request in this docket. What is your response?

A. Without commenting on any of their estimates, FPL acknowledges that the performance adder contributes to its request made in this docket. If FPL were a smaller utility with a smaller rate base, the revenue requirements corresponding to a 50 basis point adder would be smaller, and if FPL were a larger utility with a larger rate base, the revenue requirements corresponding to a 50 basis point adder would be larger. In my judgment, 50 basis points represents a small component of the customer bill but is large enough from an investor perspective to serve as a meaningful incentive.

In pointing out these impacts, intervenors overlook that even if FPL's entire request is granted, including the ROE Adder, FPL's customer bills will continue to be comparatively low. In fact, as discussed in FPL witness Cohen's direct testimony, the typical residential customer bill is expected to remain among the lowest in the state through 2020. I do not believe the magnitude of the impact on revenue requirements should disqualify the concept from thoughtful consideration, and I am surprised that any witness would argue that it is bad public policy to provide regulatory incentives for companies to deliver superior value to their customers.

Q. Witness Brosch, on behalf of AARP, claims that FPL has not proposed ROE penalties when electric utilities perform poorly, concluding FPL's view of regulation is "unbalanced." Please respond.

A. In my direct testimony (page 31), I note that penalties may be appropriate in some circumstances, and penalties have in fact been applied in some jurisdictions, including Florida. However, as discussed in more detail by Witness Deason, it should be emphasized that FPL is not proposing a universally applicable rule; rather, FPL is proposing only what it believes is reasonably warranted by its specific performance, recognizing the positive public policy signals that such a performance-based ROE Adder would send.

Contrary to Mr. Brosch's claim, and based on Florida's regulatory history, it would be perfectly balanced to award FPL an ROE Adder, particularly given

the compelling performance metrics that have been presented in this case. In fact, under the circumstances presented by FPL, failing to acknowledge FPL's superior service appears to me to be "unbalanced."

Q. Mr. Brosch asserts that FPL's growing rate base, and request for base rate increases, "is an admission that the Company has limited control over its total cost of service." Mr. Lawton makes a similar claim. Please respond.

A. I disagree. These witnesses either inadvertently overlook, or seriously misunderstand, the crux of my direct testimony as well as the testimony of other FPL witnesses, including Witness Miranda, Witness Kennedy and Witness Goldstein. FPL has deliberately chosen to make select capital investments (i.e., rate based investments) to drive improvements in customer value. The total impact of such decisions is *lower* overall rates and bills for customers and better reliability. It is not surprising that the rate base portion of the bill is growing.

PART 3

VIII. STORM COST RECOVERY

Q. Do any intervenor witnesses support FPL's proposed continuation of the storm cost recovery framework agreed upon in 2010 and 2012 in FPL's rate case settlements?

A. Yes. OPC witness Schultz states that "[t]he current framework prescribed by the 2010 Rate Settlement and continued by the 2012 Rate Settlement is sufficient with some exceptions." His exceptions are really requests for clarifications.

Q. What are the exceptions that Mr. Schultz identifies?

A. First, Mr. Schultz is concerned with FPL's ability "to seek recovery of costs associated with any storms" (page 42), as phrased in the Commission's order approving the 2012 settlement of FPL's rate case, taking the position that cost recovery should be available for major storms only. However, the language of the 2012 Settlement Agreement itself limits the mechanism's availability to major storms named by the National Hurricane Center, and witness Schultz acknowledges that this was the intent. Accordingly, there should be no need for further clarification.

Second, Mr. Schultz is concerned with the language from the 2012 Settlement that "[t]he Parties expressly agree that any proceeding to recover costs

associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous ox current base rate earnings or level of theoretical depreciation reserve." (page 43). His stated concern is that this language would limit consideration of the prudence or reasonableness of FPL's actual storm-related costs. I disagree. Nothing in the language he cites precludes a review for prudence and reasonableness at the appropriate time and subject to the Commission's direction.

Q. Mr. Schultz also provides recommendations should the process utilized prior to the existing mechanism be reestablished. Please respond.

A. I disagree with many of witness Schultz's recommendations. Nonetheless, FPL has not asked the Commission to reinstitute the prior approach despite the fact that, as discussed in my direct testimony, I believe the prior approach is a better long-term policy. Accordingly, there is no need for me to rebut his specific suggestions in this testimony.

Q. Mr. Kollen claims there are eight problems with the existing storm cost recovery mechanism. Please respond.

A. Witness Kollen argues that no cost recovery should be allowed unless FPL's $120.5 million storm reserve is first exhausted, and that the appropriate reserve level is $0. This is inconsistent with many years of Commission consideration and ruling on this subject and ignores the high likelihood of major tropical storms in FPL's expansive, largely coastal service area. He

also argues that there is no need for the "self-executing" or "expedited" nature of the mechanism and that the 12-month recovery timeframe is unnecessarily short. These arguments ignore the importance of minimizing intergenerational inequities when possible. It is worth recalling that if this kind of exposure were insurable, as they once were, the cost of that insurance would be included in current rates.

Witness Kollen then claims that "premature recovery before costs are incurred imposes an income tax cost on the recovery… that harms customers" (page 73), but this seems to be a misunderstanding of the mechanism, as it does not allow recovery before costs are incurred.

Next, witness Kollen claims the mechanism is unnecessary in light of available storm cost securitization, or less cost-effective than securitization. As an initial matter, I dispute that securitization is necessarily cheaper. Moreover, securitization is far more complex, takes longer, and strains the utility's balance sheet in addition to contributing to intergenerational inequities.

Witness Kollen further asserts that earnings in excess of FPL's authorized ROE should be considered as offsets to the recovery of storm costs. This would be inequitable and inconsistent with the traditional cost of service framework. We know FPL will incur storm related costs. In fact, such cost

would most appropriately be "baked in" to electric rates on an annual basis, just as they would if FPL were able to purchase commercial insurance and consistent with the prior framework. Witness Kollen's recommendation would thus guarantee that FPL would not have a fair opportunity to earn its authorized ROE over time.

Finally, witness Kollen asserts that the Commission simply need not take any action at this time. Such an approach would represent a fundamental change to FPL's risk profile. For at least two decades, investors have had some risk mitigation framework governing recovery of storm damage costs. Leaving FPL with no mechanism at all would have a negative impact on investors' perception of risk.

Q. Mr. Kollen also asserts that FPL's storm hardening efforts, storm reserve balance of over $100 million, ability to seek deferral of costs from the Commission, access to short term credit facilities, and ability to securitize storm damage costs all reduce FPL's risk and eliminate the need for such a mechanism. Please respond.

A. Witness Kollen's position ignores the high likelihood of major tropical storms in FPL's expansive, largely coastal service area, which extends to both costs of Florida. We know that FPL's storm damage exposure is greater than any other utility in Florida, or indeed in the country. In my judgment, all parties, including customers, benefit from having a clear framework established in advance, that ensures that prudently incurred storm restoration costs can be

recovered in an efficient and timely manner. Simply relying on an approach that essentially amounts to "don't worry; we'll sort it out when it happens" would not represent good policy. If certainly would worsen FPL's risk profile and have negative financial implications.

We all wish that tropical storms would not affect us, and FPL has been working hard to reduce its exposure. But the exposure remains.

As I stated in my direct testimony, my personal preference would be at some point to revert to the prior framework. FPL chose to request the continuation of this mechanism, rather than to request the establishment of an accrual, only in favor of removing an issue from debate in this case.

Q. Do you agree with Mr. Kollen that FPL's storm damage reserve is "substantially funded" at just over $120 million?

A. Absolutely not. This balance would have been far from sufficient to cover a number of prior years' storm related costs. For example, FPL's service territory experienced an unusually high level of storm activity in 2004 and 2005 and incurred almost $1.9 billion in costs to restore the electric transmission and distribution system. While FPL is not suggesting that it should maintain a storm reserve ample enough to cover costs associated with such unusual activity, it does demonstrate just how small a $120 million reserve is in comparison to FPL's storm damage exposure.

Overall, witness Kollen's testimony ignores the fact that, in the absence of establishing a target reserve level and accrual, FPL needs to have some recovery mechanism clearly spelled out in advance, which FPL is proposing to continue in this instance.

PART 4

IX. COST OF DEBT PROJECTIONS

Q. Are there other topics you are addressing in this rebuttal testimony?

A. Yes. Because they were raised by intervenors, I am also addressing FPL's long and short term cost of debt projections and intervenors' recommended adjustments, as well as the appropriateness of FPL recovering DOL insurance costs.

Q. Do you agree with witnesses Baudino, Gorman and Pollock that the interest rates associated with FPL's other projected long term debt issuances should be reduced to reflect more updated forecasts and/or recent changes to global financial markets?

A. No. While it is appropriate to update FPL's debt costs for actual debt issuances that have occurred, it would be inappropriate to selectively update some of the forecasts that underlie FPL's filing. In doing so, intervenors are cherry picking which forecasts to update. Certainly intervenors would be

opposed to FPL doing the same thing for other elements of the filing or forecast that increase revenue requirements.

Q. Please respond to Mr. Baudino's claim that FPL's short term debt projections should not be based on forecast data, but rather, should reflect a "reasonable increase" over FPL's 2015 cost of short term debt.

A. FPL relies upon objective, third party forecasts that are subject to verification. Witness Baudino is merely asserting that his forecast should be substituted for these third party forecasts. Without any evidence that witness Baudino (a party to this docket interested in reducing FPL's revenue requirements to the maximum extent) is better at forecasting interest rates than FPL's sources (uninterested third parties), this recommendation should be denied.

Q. How does witness Baudino's recommended short term debt rate of 0.56 percent compare with those of FPL's current short-term, commercial paper borrowing program?

A. Witness Baudino's recommendation is markedly lower than FPL's 30-day commercial paper rates, which are currently 0.67 percent. Accordingly, if witness Baudino's recommendation were accepted, FPL would not recover the cost associated with its short term debt.

X. DIRECTORS & OFFICERS LIABILITY ("DOL") INSURANCE

Q. What does OPC's witness Schultz recommend for DOL insurance?

A. Witness Schultz recommends that the DOL insurance be reduced by $1.391 million. He indicates the costs should be shared equally between customers and shareholders.

Q. Do you agree with OPC's witness Schultz recommendation that the cost associated with DOL insurance should be shared equally between customers and shareholders?

A. No, I do not. DOL insurance is a necessary cost of providing service and as such should be reflected in FPL's base rates. Simply stated, by law a corporation must have directors and officers. In today's environment of increased scrutiny and exposure with respect to corporate governance, the risk of liability to directors and officers has increased substantially. A company could not attract competent, capable officers or directors without DOL insurance. Thus, DOL insurance is a cost of business for any corporation and no company of FPL's size would be without such coverage.

Q. Do you agree with OPC's witness Schultz's assertion that DOL costs should be disallowed since incurring DOL insurance is to protect shareholders?

A. No. The purpose of DOL insurance is to enable the Company to attract and retain qualified, capable directors and officers, without which FPL's performance would certainly not be as good as it is and without which it might

literally be unable to function over time. This ensures proper management and oversight of the Company, which in turn benefits customers. This is a prudently incurred cost of doing business and should be included to calculate a company's revenue requirement. This is discussed further by FPL witness Deason.

Q. OPC's witness Schultz asserts FPL did not provide amounts of its DOL insurance premium in its 2016 Rate Case. Is this an accurate statement?

A. No. FPL did provide a confidential response to OPC's 19th Set of Interrogatories No. 396 that provided DOL insurance premiums from 2011 through the 2017 test year.

Q. Should the Commission include FPL's requested expense for DOL insurance in its revenue requirement calculation?

A. Yes. DOL insurance directly benefits customers and is a necessary and reasonable expense for the FPL to provide service to its customers.

XI. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF KEITH FERGUSON

DOCKET NOS. 160021-EI; 160062-EI

AUGUST 1, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Keith Ferguson, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Did you previously submit testimony in the proceeding?

A. Yes.

Q. Are you sponsoring or co-sponsoring any exhibits as part of your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

- KF-2 (Updated) – Proposed Depreciation Company Adjustments by Year for Base vs. Clause for 2017 and 2018
- KF-7 – Dismantlement Reserve - Company Adj Impact – Rate Base Only
- KF-8 – Order Approving Capital Recovery of Port Everglades ESPs

I am co-sponsoring the following exhibit:

- KF-4 (Corrected) – FPL 2016 Dismantlement Study filed on May 3, 2016 with FPL's First Notice of Identified Adjustments

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to demonstrate that certain recommendations in the testimony of the South Florida Hospitals and Health Care Association ("SFHHA") witness Kollen are incorrect and should be rejected. Specifically I will address the following topics:

– Dismantlement accrual

– Depreciation study accrual

– Amortization period recommended for the capital recovery schedule

– End of life materials and supplies and last core nuclear fuel accruals

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony will demonstrate that the Company's request on the topics identified above is reasonable and that the intervenor recommendations are flawed and should be rejected by the Commission. Specifically, I will demonstrate that:

- Witness Kollen's recommendation to apply either zero or at best, 10% contingency is unsupported and unreasonable.
- Witness Kollen mischaracterized the dismantlement accrual calculation.
- Witness Kollen's proposed life spans suggested for Scherer Unit 4 and St. Johns River Power Park ("SJRPP") are not reasonable.
- Contrary to statements of witness Kollen, the Second Notice of Identified Adjustments filed by the Company applied the proposed depreciation rates to plant and reserve balances as of December 31, 2016.
- Commission precedent supports FPL's recommended four-year amortization period for its capital recovery schedule and there is no basis for the 10-year recovery period recommended by witness Kollen.

- Witness Kollen's proposal to eliminate the end of life ("EOL") materials and supplies ("M&S") and last core nuclear fuel accruals and flow back of these reserves to customers over a four-year period is not consistent with Commission precedent.

II. DISMANTLEMENT ACCRUAL

Application of a Contingency Factor

Q. Do you agree with page 32, line 16 of witness Kollen's testimony that the contingency reflected in the Company's estimated dismantlement costs are excessive?

A. No, I do not agree. FPL has always included contingency as a part of the estimation for future dismantlement and the Commission has previously approved the use of FPL's proposed contingency percentage. Historical dismantlement activities by FPL have resulted in costs that exceed the estimate even including the contingency. The estimates that Burns & McDonnell ("BMcD") developed reflect the Company's best estimates to dismantle each of FPL's fossil and solar generating facilities and were prepared in accordance with Rule 25-6.04364, Electric Utilities Dismantlement Studies, Florida Administrative Code ("F.A.C."). BMcD's experience led to the recommendation to increase the FPL contingency factor from 16% to 20%. FPL witness Kopp of BMcD explains the basis for the 20% contingency factor in greater detail.

Q. Does FPL's recent experience relative to dismantling generating facilities demonstrate the need for a contingency adjustment factor?

A. Yes. Since the 2009 Dismantlement Study was prepared, FPL has dismantled generating facilities at multiple sites. At several of these sites, FPL encountered conditions that were unknown at the time the estimates were prepared which resulted in additional costs being incurred that contributed to the total dismantlement costs being above the costs estimates in the 2009 Dismantlement Study, including the 16% contingency factor. For example, during dismantlement of the Cutler plant, FPL identified additional soil contamination, which will result in remediation costs in excess of the amount estimated in the 2009 Dismantlement Study.

Q. Are you aware of this Commission ordering any investor-owned utility to apply a zero percent contingency factor to its dismantlement cost estimates as recommended by witness Kollen?

A. No. That would be completely unreasonable and inconsistent with the Commission's dismantlement study rule.

Q. Are you aware of this Commission approving a 20% contingency factor consistent with FPL's 2016 Dismantlement Study?

A. Yes. In Order No. PSC-10-0131-FOF-EI, Docket No. 090079-EI, the Commission approved a 20% contingency factor for Duke Energy Florida's most recently filed dismantlement study, which was also prepared by BMcD. In that Order the Commission stated, "[f]irst, dismantlement studies typically

include a contingency factor. A contingency factor is designed to account for unknown expenses at the time the estimate is prepared, but expected to be expended on the project."

Calculation of Dismantlement Accrual

Q. Witness Kollen contends on page 36, lines 1 through 6, that FPL's methodology for calculating the dismantlement accrual is inappropriate. Do you agree?

A. No. FPL's calculation methodology for the dismantlement accrual is fully compliant with Subsection (4) of Rule 25-6.04364 which states that "[t]he dismantlement annual accrual shall be calculated using the current cost estimates escalated to the expected dates of actual dismantlement. The future costs less amounts recovered to date shall then be discounted in a manner that accrues the costs over the remaining life span of the unit." In addition, Subsection (7) of the same rule states that "[t]he annual dismantlement accrual shall be a fixed dollar amount and shall be based on a 4-year average of the accruals related to the years between the dismantlement study reviews." FPL's approach in its 2016 Dismantlement Study is consistent with these two subsections of Rule 25-6.04364 as well as the approach applied in FPL's last dismantlement study approved by this Commission in in Order No. PSC-10-0153-FOF-EI, Docket Nos. 080677-EI and 090130-EI.

Q. Do you agree with witness Kollen on page 36, lines 1 through 2, that FPL failed to reflect the increase in the accumulated dismantlement reserve over the four-year period?

A. No. FPL appropriately captured the effect of the change related to the dismantlement reserve in FPL's Company adjustment as reflected on MFR B-2. This can be seen on page 3 of 8, line 12 for both the 2017 Test Year and 2018 Subsequent Year, which reflects the 13-month average change in rate base associated with this adjustment. Additionally, when FPL filed its First Notice of Identified Adjustments on May 3, 2016, it provided a corrected 2016 Dismantlement Study and its associated Company adjustments, including the impact on the dismantlement reserve; refer to my Exhibit KF-7.

Q. Is there anything else about witness Kollen's testimony on FPL's 2016 Dismantlement Study which you would like to address?

A. Yes. The exhibits provided by witness Kollen make it clear that he performed his dismantlement analysis on the Company's originally filed dismantlement study and not the corrected 2016 Dismantlement Study submitted in conjunction with the Company's First Notice of Identified Adjustments filed on May 3, 2016. Additionally, please refer to Exhibit KF-4 (Corrected), which reflects the corrected 2016 Dismantlement Study.

Life Spans for Scherer Unit 4 and SJRPP

Q. Witness Kollen argues FPL should use a 63 year estimated life span for Scherer Unit 4 (page 31, lines 17 through 18) and a 65 year estimated life span for SJRPP (page 32, lines 6 through 8). Do you agree with such a significant change in plant life for these two plants as it relates to both the 2016 Depreciation and Dismantlement studies?

A. No. Not only do I disagree with his conclusion, I am concerned with the flawed logic and misrepresentation of facts related to Scherer, the lack of evidence presented by SFHHA related to SJRPP and the disregard for FPL witness Allis's life span recommendations for those two plants.

Q. Could you please elaborate?

A. First, in his argument for longer lives, witness Kollen disregards the fact that the current authorized life span for these units is 50 years, as approved by the Commission in Order No. PSC-10-0153-FOF-EI, and he offers absolutely no critiques to the merits of FPL witness Allis's findings that a 50-year life continues to be accurate for Scherer and SJRPP. Witness Kollen also misconstrues FPL's response to SFHHA's Seventh Set of Interrogatories No. 162. He implies that the 65-year life referenced in that response relates to the probable retirement date assumed by Georgia Power Company ("GPC") for *Scherer 4* (page 31, Lines 2 through 4) when in fact SFHHA's Seventh Set of Interrogatories No. 162 is clearly addressing "Scherer and SJRPP *common facilities.*" [Emphasis added]

Next, witness Kollen tries to justify longer lives by asserting that "[i]t is highly unlikely that Scherer 4… will be dismantled before the other three units at the site" (page 31, lines 21 through 22 and page 32 line 1). This statement lacks any validating evidence and is in direct contradiction to FPL's recent dismantlement experience with Sanford Unit 3 and Turkey Point Units 1 and 2, all of which had dismantlement activities commence prior to the retirement of all of the units at each site. Retired units pose a safety hazard if they are left in place and not maintained; therefore, they are typically dismantled upon retirement.

Q. Witness Kollen states FPL is a "minority owner" in Scherer to support his assertion that GPC's asset life should be used in the Depreciation and Dismantlement studies. Is this an accurate characterization?

A. No. Although FPL is a minority owner from the perspective of the entire Scherer plant, it overlooks the fact that FPL is the majority owner (76.36% ownership) of Unit 4, as to which GPC is simply the plant *operator* and has no ownership interest. Witness Kollen further clouds the facts by not disclosing the various other ownership interest in Plant Scherer, and using the all-encompassing general term "the facility" (page 32, lines 4 through 5).

Q. Witness Kollen implies (page 31, lines 6 through 9 and page 32, lines 2 through 5) that because FPL and GPC have "spent significant sums to achieve compliance with continually evolving environmental requirements," both companies would be inclined to run the plant longer. Is that necessarily the case?

A. No. On the contrary, costs that have already been incurred to comply with environmental regulations are sunk costs that should not influence future decisions on the when it is economically justified to retire a unit. Moreover, environmental compliance costs often do not increase plant life or efficiency. In fact, as compliance requirements "continually evolve," the economics of the plant begin to favor earlier retirement because advanced generation technology tends to become a more attractive compliance alternative. In addition, the U.S. Environmental Protection Agency ("EPA") has issued or implemented numerous regulations targeting coal-fired generating facilities and the general trend over time has been for even more stringent environmental regulations. Those regulations have resulted in a significant number of plant retirements across the industry in the last several years.

Exhibit KF-8 contains an excerpt from Order No. PSC-12-0613-FOF-EI, Docket No. 120007-EI, in which the Commission granted FPL the ability to collect the remaining unamortized costs associated with its Electrostatic Precipitators ("ESPs") installed during the period of April 2005 through May 2007 at Port Everglades within a four-year capital recovery period after FPL

retired the plant in the fourth quarter of 2012 to modernize the plant into a high-efficiency combined cycle natural gas energy center. These investments enabled Port Everglades to continue to operate through its useful life rather than being forced into early retirement.

III. DEPRECIATION STUDY ACCRUAL

Q. Witness Kollen objects to FPL's use of 2017 year-end plant balances in the 2016 Depreciation Study. Is the Company opposed to using year-end 2016 plant and reserve balances instead for the purpose of setting depreciation rates and determining FPL's base rates in this proceeding?

A. No. While FPL continues to believe that the use of year-end 2017 plant and reserve balances provides a good match with FPL's 2017 Test Year and 2018 Subsequent Year, FPL has no objection in using the results for year-end 2016 plant and reserve balances to set depreciation rates and determining FPL's base rates in this proceeding.

Q. Do you agree with witness Kollen's recommendation on page 22, lines 20 through 21, of his testimony that FPL's 2016 Depreciation Study should be rejected because it reflects year-end 2017 rather than year-end 2016 balances?

A. No. The Company's Second Notice of Identified Adjustments filed with the Commission on June 16, 2016, provided supplemental versions of Tables 1 through 8 that appear in Part VI of the 2016 Depreciation Study, which reflect all of the changes in parameters and depreciation rates resulting from the use of

the year-end 2016 plant and reserve balances. In addition, the Company contemporaneously provided all workpapers and supporting schedules for the supplemental tables as part of the supplemental response to OPC's Tenth Request for Production of Document No. 124. The parties have had more than ample time to evaluate the results of the 2016 Depreciation Study using the 2016 year-end balances; refer to Exhibit KF-2 (Updated) for the computation of the related Company adjustment.

IV. CAPITAL RECOVERY SCHEDULE AMORTIZATION PERIOD

Q. Do you agree with witness Kollen's recommendation on pages 39 through 40 of his testimony to use a ten-year amortization period for capital recovery of assets retired or nearing retirement?

A. No. FPL has requested a four-year amortization period related to the capital recovery schedule, which is based on and consistent with past Company practice and Commission precedent. For the last ten years, FPL has consistently requested, received and applied four-year amortization periods that coincide with either the setting of FPL's new base rates and/or the effective date of depreciation studies. While it may technically be the case the Commission "has greater discretion to determine the appropriate amortization and recovery period" (Kollen page 39, lines 10 through 11), the Company's request for a four-year amortization period in this instant case is reasonable, appropriate, and consistent with prior practice for FPL.

Q. What is the Commission's practice with respect to the recovery period on capital recovery schedules for assets that have been retired?

A. In Docket Nos. 080677-EI and 090130-EI, the Commission stated that its practice with respect to capital recovery schedules for assets that have been retired has been to provide for recovery as "fast as practicable to remedy the existing intergenerational inequity." (See page 23, Order No. PSC-10-0153-FOF-EI). That being said, the Commission has balanced the need to provide recovery as fast as practicable with the potential impact on rates over the short term. For instance, in Order No. PSC-93-1808-FOF-EI, Gulf Power had assets that were being retired in the next year and the Commission stated, "[w]hile, theoretically, these assets should be recovered over their associated remaining period in service, we find that a four year recovery period is appropriate in this instance as an effort to smooth the related expense impact." This approach is consistent with FPL's proposal in this docket.

Q. Has this Commission ever approved a ten-year amortization period for capital recovery schedules?

A. FPL is not aware of this Commission ever approving a ten-year amortization period for capital recovery schedules. Doing so would be inconsistent with the principle of intergenerational equity, especially as it relates to retired assets. In Order No. PSC-10-0153-FOF-EI, on page 23, the Commission stated "deferring recovery is simply mortgaging the future."

V. EOL M&S AND LAST CORE NUCLEAR FUEL

Q. What is witness Kollen proposing for the currently Commission approved EOL M&S and last core nuclear fuel accruals?

A. On pages 15 through 19 of his testimony, witness Kollen is asking the Commission to subsume the two accruals into FPL's nuclear decommissioning liability and, concurrently, return the entire balance of the unfunded reserves for those costs to customers over a period of four years.

Q. Do you agree with this proposal?

A. No. It is inconsistent with Commission precedent. In Order No. PSC-02-0055-PAA-EI, the Commission stated that, "[b]ecause nuclear M&S inventories represent unrecovered costs remaining at the end of the nuclear site's life, we agree with FPL that these costs should be amortized over the remaining life span of each site to ratably allocate the costs to those receiving the benefit of the generated power. However, *these costs do not relate to the removal or disposal of the nuclear plant*. For this reason, the Commission finds that the amortization expense associated with the EOL M&S inventories be accounted for as a debit to nuclear maintenance expense with a credit to an unfunded Account 228 reserve." [Emphasis added]

Similarly, concerning the last core nuclear fuel the Commission stated that "[w]e believe that the Last Core is similar to nuclear decommissioning in that both represent estimates of a future obligation that will not be incurred until

the nuclear unit ceases operation. *However, the cost of the Last Core does not meet the intent of nuclear decommissioning because it does not involve the removal of the plant facility.* As with EOL M&S inventories addressed in VI, we believe that EOL nuclear fuel is unique to the nuclear unit and represents costs remaining at the time of shut down." [Emphasis added]

Q. Has the Commission previously considered the funded status of the nuclear decommissioning reserve in determining proper recovery for EOL M&S and last core nuclear fuel?

A. No. As explained by this Commission in Order No. PSC-02-0055-PAA-EI, these two items are not considered part of the cost of nuclear decommissioning. These are distinct future obligations.

Q. Has the Commission approved the accruals proposed in this proceeding for EOL M&S and last core nuclear fuel?

A. Yes. The Commission approved FPL's proposed accruals for EOL M&S and last core nuclear fuel in Order No. PSC-16-0293-CO-EI, Docket No. 150265-EI.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Docket No. 160021-EI
Proposed Depreciation Company Adjustment
by Year for Base vs. Clause
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DEPRECIATION RECONCILIATION FROM FPL'S 2017 FORECAST TO PROPOSED DEPRECIATION EXPENSE
($000)

Line No.	Function	AS FILED 2017 Forecast (1)	AS FILED 2017 Depreciation Expense Related to Clauses (2)	AS FILED Subtotal (1) + (2) = (3)	UPDATED 2017 Calculated Expense Using Proposed Rates (4)	UPDATED 2017 Calculated Expense Using Proposed Rates Related to Clauses (5)	UPDATED 2017 Total Expense (4) + (5) = (6)	UPDATED 2017 Updated Company Adjustment (6) - (3) = (7)
1	STEAM	$ 79,410	$ (22,971)	$ 56,439	$ 117,441	$ (36,604)	$ 80,838	$ 24,399
2								
3	NUCLEAR	159,482	(2,984)	156,498	311,380	(5,664)	305,716	149,218
4								
5	OTHER PRODUCTION	453,064	(21,428)	431,636	498,196	(20,031)	478,165	46,529
6								
7	TRANSMISSION	143,028	(235)	142,793	134,580	(238)	134,342	(8,451)
8								
9	DISTRIBUTION	510,866	(3,559)	507,308	482,419	(575)	481,844	(25,463)
10								
11	GENERAL	36,257	(717)	35,540	32,791	(254)	32,537	(3,003)
12								
13	**TOTAL**	**$ 1,382,107**	**$ (51,894)**	**$ 1,330,213**	**$ 1,576,807**	**$ (63,365)**	**$ 1,513,442**	**$ 183,229**
14								
15		**(A)**			**(B)**			
16								
17								
18								

Notes:
(A) Excludes amounts related to asset retirement obligations, acquisition adjustment, dismantlement and amortizable property which are included in the total amount forecasted for depreciation expense.
(B) Calculated amounts are based on FPL's proposed depreciation rates utilizing December 31, 2016 balances as included in FPL's Second Notice of Identified Adjustments file
(C) After-tax amount of $126,550 is reflected as a Per Book company adjustment on MFR C-3 for the 2017 Test Year.

DEPRECIATION RECONCILIATION FROM FPL'S 2018 FORECAST TO PROPOSED DEPRECIATION EXPENSE
($000)

Line No.	Function	AS FILED 2018 Forecast (1)	AS FILED 2018 Depreciation Expense Related to Clauses (2)	AS FILED Subtotal (1) + (2) = (3)	UPDATED 2018 Calculated Expense Using Proposed Rates (4)	UPDATED 2018 Calculated Expense Using Proposed Rates Related to Clauses (5)	UPDATED 2018 Total Expense (4) + (5) = (6)	2018 Updated Company Adjustment (6) - (3) = (7)	2018 As Filed Company Adjustment [D] (8)	Difference [E] (7) - (8) = (9)
1	STEAM	$ 80,593	$ (23,247)	$ 57,345	$ 119,198	$ (36,985)	$ 82,214	$ 24,868	$ 28,060	$ (3,191)
2										
3	NUCLEAR	160,939	(3,403)	157,537	315,780	(6,471)	309,310	151,773	159,593	(7,820)
4										
5	OTHER PRODUCTION	472,410	(21,430)	450,980	517,113	(20,033)	497,080	46,100	51,924	(5,824)
6										
7	TRANSMISSION	154,627	(238)	154,389	144,100	(240)	143,859	(10,530)	(9,874)	(656)
8										
9	DISTRIBUTION	559,878	(5,677)	554,201	530,312	(825)	529,487	(24,713)	(18,265)	(6,448)
10										
11	GENERAL	38,938	(719)	38,219	35,277	(255)	35,022	(3,197)	(2,572)	(624)
12										
13	**TOTAL**	**$ 1,467,385**	**$ (54,714)**	**$ 1,412,671**	**$ 1,661,780**	**$ (64,807)**	**$ 1,596,972**	**$ 184,302**	**$ 208,865**	**$ (24,564)**
14										
15		(A)			(B)				(C)	
16										
17										
18										

19 **Notes:**
20 (A) Excludes amounts related to asset retirement obligations, acquisition adjustment, dismantlement and amortizable property which are included in the total amount
21 forecasted for depreciation expense.
22 (B) Calculated amounts are based on FPL's proposed depreciation rates utilizing December 31, 2016 balances as included in FPL's Second Notice of Identified Adjustments filed on June 16, 2016
23 (C) After-tax amount of $128,296 is reflected as a Per Book Company adjustment on MFR C-3 for the 2018 Subsequent Year.
24 (D) Represents "as filed" amounts per original Exhibit KF-2, column (7).
25 (E) Represents the difference between the "as filed" original Exhibit KF-2 and update filed in the Second Notice of Identified Adjustments filed on June 16, 2016.

Docket Nos. 160021-EI & 160062-EI
Proposed Depreciation Company Adjustment
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Updated Exhibit KF-2, Page 3 of 4

CHANGE IN FORECASTED ACCUMULATED DEPRECIATION
RESULTING FROM FPL'S PROPOSED CHANGE IN BASE DEPRECIATION EXPENSE
($000)

2017 - As Filed

Line No.	Function	Ending Balance 12/31/2016	Ending Balance 1/31/2017	Ending Balance 2/28/2017	Ending Balance 3/31/2017	Ending Balance 4/30/2017	Ending Balance 5/31/2017	Ending Balance 6/30/2017	Ending Balance 7/31/2017	Ending Balance 8/31/2017	Ending Balance 9/30/2017	Ending Balance 10/31/2017	Ending Balance 11/30/2017	Ending Balance 12/31/2017	13-Month Average 2017
1	STEAM	$ -	$ (2,284)	$ (4,568)	$ (6,854)	$ (9,143)	$ (11,435)	$ (13,731)	$ (16,032)	$ (18,335)	$ (20,642)	$ (22,951)	$ (25,262)	$ (27,574)	$ (13,755)
2															
3	NUCLEAR	-	(13,244)	(26,488)	(39,731)	(52,978)	(66,231)	(79,488)	(92,748)	(106,009)	(119,270)	(132,537)	(145,810)	(159,092)	(79,510)
4															
5	OTHER PRODUCTION	-	(4,275)	(8,531)	(12,803)	(17,092)	(21,414)	(25,773)	(30,131)	(34,477)	(38,811)	(43,136)	(47,451)	(51,786)	(25,822)
6															
7	TRANSMISSION	-	612	1,234	1,864	2,502	3,148	3,802	4,464	5,132	5,808	6,490	7,179	7,896	3,856
8															
9	DISTRIBUTION	-	1,951	3,882	5,790	7,675	9,535	11,372	13,186	14,975	16,738	18,475	20,187	21,875	11,203
10															
11	GENERAL	-	225	449	673	896	1,118	1,339	1,560	1,781	2,000	2,220	2,439	2,657	1,335
12															
13	**TOTAL**	**$ -**	**$ (17,015)**	**$ (34,022)**	**$ (51,062)**	**$ (68,141)**	**$ (85,279)**	**$ (102,477)**	**$ (119,700)**	**$ (136,933)**	**$ (154,177)**	**$ (171,439)**	**$ (188,717)**	**$ (206,023)**	**$ (102,691)**
14															(A)
15															

2017 - Updated - June 2016

Line No.	Function	Ending Balance 12/31/2016	Ending Balance 1/31/2017	Ending Balance 2/28/2017	Ending Balance 3/31/2017	Ending Balance 4/30/2017	Ending Balance 5/31/2017	Ending Balance 6/30/2017	Ending Balance 7/31/2017	Ending Balance 8/31/2017	Ending Balance 9/30/2017	Ending Balance 10/31/2017	Ending Balance 11/30/2017	Ending Balance 12/31/2017	13-Month Average 2017
16															
17															
18															
19															
20	**Function**														
21															
22	STEAM	-	$ (2,020)	$ (4,041)	$ (6,063)	$ (8,088)	$ (10,117)	$ (12,149)	$ (14,185)	$ (16,223)	$ (18,265)	$ (20,308)	$ (22,353)	$ (24,399)	$ (12,170)
23															
24	NUCLEAR	-	(12,387)	(24,774)	(37,163)	(49,566)	(61,985)	(74,417)	(86,862)	(99,311)	(111,766)	(124,233)	(136,713)	(149,218)	(74,492)
25															
26	OTHER PRODUCTION	-	(3,877)	(7,733)	(11,596)	(15,464)	(19,357)	(23,278)	(27,192)	(31,086)	(34,960)	(38,820)	(42,666)	(46,529)	(23,274)
27															
28	TRANSMISSION	-	656	1,322	1,997	2,680	3,372	4,072	4,780	5,495	6,218	6,948	7,685	8,451	4,129
29															
30	DISTRIBUTION	-	2,148	4,290	6,428	8,561	10,689	12,813	14,935	17,051	19,162	21,268	23,368	25,463	12,783
31															
32	GENERAL	-	242	486	732	979	1,227	1,476	1,727	1,979	2,233	2,488	2,745	3,003	1,486
33															
34	**TOTAL**	**$ -**	**$ (15,237)**	**$ (30,449)**	**$ (45,665)**	**$ (60,899)**	**$ (76,171)**	**$ (91,482)**	**$ (106,796)**	**$ (122,095)**	**$ (137,378)**	**$ (152,658)**	**$ (167,935)**	**$ (183,229)**	**$ (91,538)**
35															

Difference

Line No.	Function	Ending Balance 12/31/2016	Ending Balance 1/31/2017	Ending Balance 2/28/2017	Ending Balance 3/31/2017	Ending Balance 4/30/2017	Ending Balance 5/31/2017	Ending Balance 6/30/2017	Ending Balance 7/31/2017	Ending Balance 8/31/2017	Ending Balance 9/30/2017	Ending Balance 10/31/2017	Ending Balance 11/30/2017	Ending Balance 12/31/2017	13-Month Average 2017
36															
37															
38															
39															
40	**Function**														
41															
42	STEAM	-	$ 264	$ 527	$ 791	$ 1,054	$ 1,318	$ 1,582	$ 1,847	$ 2,112	$ 2,377	$ 2,643	$ 2,909	$ 3,175	$ 1,585
43															
44	NUCLEAR	-	858	1,714	2,568	3,412	4,246	5,071	5,886	6,698	7,504	8,303	9,097	9,874	5,018
45															
46	OTHER PRODUCTION	-	399	798	1,207	1,628	2,057	2,495	2,939	3,391	3,851	4,317	4,785	5,258	2,548
47															
48	TRANSMISSION	-	44	88	133	178	224	270	316	363	410	458	505	555	273
49															
50	DISTRIBUTION	-	196	409	639	887	1,154	1,441	1,749	2,076	2,424	2,793	3,181	3,588	1,580
51															
52	GENERAL	-	17	37	59	83	109	137	167	199	232	268	306	346	151
53															
54	**TOTAL**	**$ -**	**$ 1,778**	**$ 3,573**	**$ 5,397**	**$ 7,242**	**$ 9,107**	**$ 10,996**	**$ 12,904**	**$ 14,839**	**$ 16,798**	**$ 18,781**	**$ 20,782**	**$ 22,794**	**$ 11,153**
55															

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Proposed Depreciation Company Adjustment
by Year for Base vs. Clause
Updated Exhibit KF-2, Page 4 of 4

2018 - As Filed

Line No.	Function	Ending Balance 12/31/2017	Ending Balance 1/31/2018	Ending Balance 2/28/2018	Ending Balance 3/31/2018	Ending Balance 4/30/2018	Ending Balance 5/31/2018	Ending Balance 6/30/2018	Ending Balance 7/31/2018	Ending Balance 8/31/2018	Ending Balance 9/30/2018	Ending Balance 10/31/2018	Ending Balance 11/30/2018	Ending Balance 12/31/2018	13-Month Average 2018
2	STEAM	$ (27,574)	$ (29,886)	$ (32,200)	$ (34,515)	$ (36,835)	$ (39,163)	$ (41,499)	$ (43,843)	$ (46,193)	$ (48,548)	$ (50,908)	$ (53,269)	$ (55,633)	$ (41,544)
4	NUCLEAR	(159,092)	(172,384)	(185,678)	(198,974)	(212,272)	(225,573)	(238,874)	(252,175)	(265,476)	(278,777)	(292,080)	(305,382)	(318,686)	(238,879)
6	OTHER PRODUCTION	(51,786)	(56,135)	(60,486)	(64,832)	(69,159)	(73,487)	(77,809)	(82,125)	(86,439)	(90,757)	(95,083)	(99,399)	(103,710)	(77,785)
8	TRANSMISSION	7,896	8,641	9,392	10,151	10,917	11,716	12,555	13,407	14,265	15,130	16,001	16,878	17,770	12,671
10	DISTRIBUTION	21,875	23,540	25,181	26,798	28,389	29,952	31,489	32,998	34,481	35,937	37,365	38,766	40,141	31,301
12	GENERAL	2,657	2,875	3,093	3,310	3,527	3,742	3,957	4,171	4,385	4,597	4,809	5,020	5,230	3,952
14	**TOTAL**	**$ (206,023)**	**$ (223,349)**	**$ (240,698)**	**$ (258,062)**	**$ (275,433)**	**$ (292,812)**	**$ (310,181)**	**$ (327,567)**	**$ (344,978)**	**$ (362,419)**	**$ (379,896)**	**$ (397,387)**	**$ (414,888)**	**$ (310,284)**
15															(B)

2018 - Updated - June 2016

Function	Ending Balance 12/31/2017	Ending Balance 1/31/2018	Ending Balance 2/28/2018	Ending Balance 3/31/2018	Ending Balance 4/30/2018	Ending Balance 5/31/2018	Ending Balance 6/30/2018	Ending Balance 7/31/2018	Ending Balance 8/31/2018	Ending Balance 9/30/2018	Ending Balance 10/31/2018	Ending Balance 11/30/2018	Ending Balance 12/31/2018	13-Month Average 2018
STEAM	$ (24,399)	$ (26,446)	$ (28,493)	$ (30,542)	$ (32,597)	$ (34,660)	$ (36,730)	$ (38,808)	$ (40,893)	$ (42,982)	$ (45,074)	$ (47,170)	$ (49,267)	$ (36,774)
NUCLEAR	(149,218)	(161,749)	(174,287)	(186,832)	(199,383)	(211,943)	(224,513)	(237,093)	(249,678)	(262,269)	(274,873)	(287,777)	(300,992)	(224,662)
OTHER PRODUCTION	(46,529)	(50,401)	(54,274)	(58,140)	(61,985)	(65,830)	(69,667)	(73,497)	(77,325)	(81,153)	(84,987)	(88,810)	(92,629)	(69,633)
TRANSMISSION	8,451	9,246	10,049	10,859	11,676	12,529	13,423	14,331	15,246	16,168	17,096	18,031	18,981	13,545
DISTRIBUTION	25,463	27,553	29,637	31,716	33,789	35,857	37,918	39,975	42,026	44,073	46,113	48,148	50,177	37,880
GENERAL	3,003	3,263	3,524	3,786	4,050	4,315	4,581	4,848	5,116	5,385	5,656	5,927	6,200	4,589
TOTAL	**$ (183,229)**	**$ (198,534)**	**$ (213,844)**	**$ (229,153)**	**$ (244,450)**	**$ (259,732)**	**$ (274,988)**	**$ (290,245)**	**$ (305,507)**	**$ (320,778)**	**$ (336,070)**	**$ (351,651)**	**$ (367,531)**	**$ (275,055)**

Difference

Function	Ending Balance 12/31/2017	Ending Balance 1/31/2018	Ending Balance 2/28/2018	Ending Balance 3/31/2018	Ending Balance 4/30/2018	Ending Balance 5/31/2018	Ending Balance 6/30/2018	Ending Balance 7/31/2018	Ending Balance 8/31/2018	Ending Balance 9/30/2018	Ending Balance 10/31/2018	Ending Balance 11/30/2018	Ending Balance 12/31/2018	13-Month Average 2018
STEAM	$ 3,175	$ 3,441	$ 3,706	$ 3,972	$ 4,238	$ 4,504	$ 4,769	$ 5,035	$ 5,301	$ 5,567	$ 5,833	$ 6,100	$ 6,366	$ 4,770
NUCLEAR	9,874	10,635	11,391	12,143	12,889	13,630	14,361	15,082	15,798	16,509	17,207	17,606	17,694	14,217
OTHER PRODUCTION	5,258	5,734	6,213	6,692	7,173	7,657	8,142	8,627	9,115	9,605	10,096	10,589	11,081	8,152
TRANSMISSION	555	605	656	708	759	813	868	924	981	1,038	1,095	1,152	1,211	874
DISTRIBUTION	3,588	4,013	4,456	4,918	5,401	5,904	6,430	6,977	7,545	8,135	8,748	9,382	10,036	6,579
GENERAL	346	387	431	476	524	573	624	677	732	788	847	908	970	637
TOTAL	**$ 22,794**	**$ 24,815**	**$ 26,853**	**$ 28,909**	**$ 30,984**	**$ 33,081**	**$ 35,194**	**$ 37,322**	**$ 39,471**	**$ 41,641**	**$ 43,826**	**$ 45,736**	**$ 47,358**	**$ 35,229**

Notes:
(A) Reflected on MFR B-2 for the 2017 Test Year as the Per Book depreciation study company adjustment.
(B) Reflected on MFR B-2 for the 2018 Subsequent Year as the Per Book depreciation study company adjustment.

Florida Power & Light Company

2016 Dismantlement Study (Corrected)

Babcock Ranch Solar
Cape Canaveral
Cedar Bay
Citrus Solar
DeSoto Solar
Ft. Myers
Lauderdale
Manatee
Manatee Solar
Martin
Martin Solar
Okeechobee
Port Everglades
Riviera Beach
Sanford
Scherer
Space Coast Solar
St. Johns River
Turkey Point
West County

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5. Escalation Rates Used to Calculate Future Dismantlement Costs
6. Annual Accrual Calculation (By Unit)
7. Future Expenditures by Year
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Section 1
Executive Summary

FLORIDA POWER & LIGHT COMPANY
2016 DISMANTLEMENT STUDY
EXECUTIVE SUMMARY

Florida Power & Light Company ("FPL") engaged Burns & McDonnell Engineering Company, Inc. ("BMcD") to perform a site specific fossil plant dismantlement cost study in 2015, which estimated the cost to dismantle FPL's fossil and solar plants to be approximately $467.2 million in 2015 dollars. BMcD's study included all of FPL's existing plants as well as plants that FPL is projected to place in service through 2020, with the exception of the Cedar Bay cogeneration facility. FPL acquired the Cedar Bay cogeneration facility in September 2015 and engaged NorthStar Demolition and Remediation LP as part of the due diligence in that transaction to provide an estimate to dismantle the facility (which was approximately $4.5 million). That estimate did not provide a breakdown of the component costs. The total amount of FPL's dismantlement costs, including the Cedar Bay cogeneration facility, escalated through 2016 is $478.3 million, as follows:

	(in millions) 2016 $	% of Total
Material & Equipment	$ 298	62%
Labor	286	60%
Burial	26	5%
Cedar Bay	5	1%
Salvage	(137)	(28)%
Total	$ 478	100%

FPL's previous dismantlement study was filed in 2009 and was approved by the Florida Public Service Commission ("FPSC") in Order No. PSC-10-0153-FOF-EI (Docket No. 090130-EI). The current dismantlement study reflects the impact of the updated cost estimates, retirement and additions of several units since the last study and the amortization of a portion of the dismantlement reserve as approved by the FPSC as part of FPL's 2012 Rate Settlement in Order No. PSC-13-0023-S-EI (Docket No. 120015-EI). A comparative analysis of significant drivers of the change in the resulting accrual since the previous study is contained in Section 2.

Section 1
Executive Summary

PLANT RETIREMENTS

FPL has retired and dismantled the following generating units since the 2009 dismantlement study:

Generating Unit	Retirement Date
Repowered Units – Partial Dismantlement	
Cape Canaveral Unit 1	2010
Cape Canaveral Unit 2	2010
Pt. Everglades Unit 1	2012
Pt. Everglades Unit 2	2012
Pt. Everglades Unit 3	2013
Pt. Everglades Unit 4	2013
Riviera Unit 3	2011
Riviera Unit 4	2011
Final Retirement – Full Dismantlement	
Cutler Unit 5	2012
Cutler Unit 6	2012
Putnam Unit 1	2014
Putnam Unit 2	2014
Sanford Unit 3	2012

In addition, FPL plans to retire the following units during 2016 and begin dismantlement in 2017:

Generating Unit	Retirement Date
Cedar Bay	2016
Fort Myers Gas Turbines	2016
Lauderdale Gas Turbines	2016
Pt. Everglades Gas Turbines	2016

FPL has also converted Turkey Point Units 1 and 2 from steam generating units to synchronous condensers in 2016 and 2013, respectively. As part of the conversion, FPL has and will incur costs to partially dismantle these units, but ultimate dismantlement is assumed to occur following the retirement of Turkey Point Unit 5 estimated to be in 2047.

Section 1
Executive Summary

PLANT ADDITIONS

FPL has added or will add by 2020 the following generating units since the 2009 dismantlement study.

Generating Unit	In-Service
Babcock Ranch Solar	2016
Cape Canaveral Clean Energy Center	2012
Cedar Bay (purchase date)	2015
Citrus Solar	2016
Fort Myers Peaking Units	2016
Lauderdale Peaking Units	2016
Manatee Solar	2016
Okeechobee Clean Energy Center	2019
Pt. Everglades Clean Energy Center	2016
Riviera Clean Energy Center	2014

DISMANTLEMENT RESERVE AMORTIZATION

As part of the 2012 Rate Settlement approved by the FPSC in Order No. PSC-13-0023-S-EI (Docket No. 120015-EI), FPL was authorized to amortize up to $176 million of the dismantlement reserve, subject to certain conditions. This amount was reduced to $146 million as part of the Cedar Bay settlement approved by the FPSC in Order No. PSC-15-0401-AS-EI (Docket No. 150075-EI). The utilization of the entire $146 million of dismantlement reserve amortization has been reflected in the current dismantlement study.

RETIREMENT DATES

The estimated retirements dates contained in the current dismantlement study are based on the retirement dates estimated in the 2016 depreciation study prepared by Gannett Fleming, which has also been filed in this docket.

ESCALATION RATES

The future cost of dismantlement is forecast by analyzing the individual cost categories from BMcD's cost study as described above. The 2015 cost of each category is divided into components of labor, material and equipment, disposal and salvage. These components are escalated by the estimated inflationary rates for compensation per hour, Producer Price Index (Intermediate Material), Gross Domestic Product (Implicit Price Deflator) and Metal and Metal Products. Section 5 contains a schedule of the applicable escalation rates for each category. FPL used the same data vendor, Global Insight, to obtain the inflation forecast as was used in the previous study. Global Insight, a division of IHS Inc., is an economics organization and considered a leading provider of economic data and analytics, and serves over 3,800 clients in industry, finance and

government, employing more than 600 staff in 23 offices in 13 countries.

The cost estimate obtained by applying Global Insight rates yields the future cost of dismantlement using currently available technologies and procedures, as shown in Section 4. The methodology used to determine the escalation rate for converting the current estimated dismantlement cost to future estimated dismantlement cost is consistent with the guidance set out in FPSC Rule 25-6.04364 and that used in the preparation of the prior dismantlement.

CONTINGENCY ALLOWANCE

The overall contingency allowance of 16% used by the Company in its prior study and approved in Order No. PSC-10-0153-FOF-EI (Docket 090130-EI) was increased by BMcD to 20% in the 2016 study, which is consistent with BMcD's experience with actual costs relative to estimated costs.

CONCLUSION

The annual dismantlement accrual for FPL is $26.2 million, based on total dismantlement cost in 2016 dollars of $478.3 million. FPL requests that the annual accrual be effective January 1, 2017. Section 6 of this report provides the calculation of the annual accrual.

Section 2

Drivers of Change in Dismantlement Accrual

	2009 Study Annual Accrual [1]	Plant Retirements/Adj [1]	New Plants	Reserve Amortization [2]	Updated Costs and Escalation Rates [3]	2016 Study Annual Accrual	*dif*
Clause	$ 453,816	$ -	$ -	$ -	$ 339,786	$ 793,602	$ 339,786
Steam	9,711,696	(3,258,085)	1,130,063	2,736,264	2,384,534	12,704,472	2,992,776
Other	8,302,875	(769,136)	3,932,512	1,630,900	(414,006)	12,683,144	4,380,269
	$ 18,468,387	**$ (4,027,222)**	**$ 5,062,574**	**$ 4,367,164**	**$ 2,310,315**	**$ 26,181,218**	**$ 7,712,832**

Notes:

[1] Includes St. Lucie Wind which was not constructed

[2] Reflects amortization of $146 million of dismantlement reserve enabled by Order No. PSC-13-0023-S-EI (Docket No. 120015-EI).

[3] Includes $52 million reallocation of theoretical dismantlement reserve surplus

Section 3

Comparison of Current Accruals and Proposed Accruals

Plant Site	Per Docket No. 090130-EI Order No. PSC-10-0153-FOF-EI Annual Accrual	Proposed Annual Accrual Effective 1/1/2017	Increase / (Decrease) in Annual Dismantlement Accrual
Babcock Ranch Solar[1]	$ 0	$ 380,369	$ 380,369
Cape Canaveral[2]	252,203	826,866	574,663
Cedar Bay[1]	0	1,130,063	1,130,063
Citrus Solar[1]	0	380,369	380,369
Cutler[2]	333,801	0	(333,801)
Desoto Solar	72,712	146,241	73,529
Ft. Myers	1,317,305	1,488,098	170,792
Lauderdale	1,251,191	2,261,757	1,010,566
Manatee	2,559,415	3,125,649	566,235
Manatee Solar[1]	0	380,369	380,369
Martin	2,533,098	3,614,148	1,081,050
Martin Solar	346,160	594,662	248,502
Okeechobee[1]	0	312,960	312,960
Port Everglades[2]	2,802,360	1,058,639	(1,743,721)
Putnam[2]	405,297	0	(405,297)
Riviera[2]	89,182	695,313	606,131
Sanford[2]	1,493,396	1,020,440	(472,956)
Scherer	1,634,157	2,317,556	683,399
Space Coast Solar	34,944	52,699	17,754
St. Johns River	869,586	958,937	89,351
St. Lucie Wind[3]	30,038	0	(30,038)
Turkey Point[2]	1,111,193	3,258,891	2,147,698
West County	1,332,348	2,177,193	844,845
Total	**$ 18,468,387**	**$ 26,181,218**	**$ 7,712,832** [A]

[A] Total increase in dismantlement accrual	$ 7,712,832
Less accrual for solar units (DeSoto, Martin and Space Coast) recovered through clause	339,785
Increase in base rate dismantlement accrual	$ 7,373,047 [4]

Notes:

[1] Added since 2009 Dismantlement Study

[2] Plant was partially dismantled or fully dismantled since 2009 Dismantlement Study as a result of a repowering, final retirement of a unit or conversion to synchronous condenser (Turkey Point)

[3] Plant was not constructed

[4] After-tax amount is $4,528,894. This corrected amount is different than the after-tax amount of $5,419,038 reflected as a Per Book Company Adjustment on MFR C-3 for both the 2017 Test Year and 2018 Subsequent Year.

Section 4

Calculation of Current and Future Jurisdictional Dismantlement Costs

2017 Jurisdictional Factor: 95.05950%

Site/Unit	Dismantlement Cost in 2016 Dollars	Dismantlement Cost in Future Dollars	Jurisdictional Dismantlement Cost in 2016 Dollars	Jurisdictional Dismantlement Cost in Future Dollars
Babcock Ranch Solar	$ 6,601,101	$ 17,928,699	$ 6,274,973	$ 17,042,932
Cape Canaveral				
Common	8,745,382	28,861,856	8,313,316	27,435,936
Unit 1	7,122,444	28,452,355	6,770,560	27,046,667
Cedar Bay	4,520,250	4,520,250	4,296,927	4,296,927
Citrus Solar	6,601,101	17,928,699	6,274,973	17,042,932
DeSoto Solar	2,338,490	5,108,176	2,222,957	4,855,807
Ft. Myers				
Common	19,702,679	48,380,642	18,729,268	45,990,396
Unit 2	9,039,546	26,346,751	8,592,947	25,045,089
Unit 3	1,568,707	4,498,227	1,491,205	4,275,992
Unit 4 (Combustion Turbine Peakers)	1,727,318	7,691,861	1,641,980	7,311,844
Gas Turbines	297,386	1,522,405	282,694	1,447,191
Lauderdale				
Common	19,099,027	34,238,552	18,155,439	32,546,996
Unit 4	4,346,178	8,578,351	4,131,455	8,154,538
Unit 5	4,340,750	8,569,391	4,126,295	8,146,021
Unit 6 (Combustion Turbine Peakers)	4,226,112	18,894,765	4,017,320	17,961,269
Gas Turbines	281,335	1,458,950	267,435	1,386,871
Manatee				
Common	31,234,151	50,931,140	29,691,028	48,414,887
Unit 1	10,574,637	18,040,007	10,052,197	17,148,740
Unit 2	10,574,637	18,040,007	10,052,197	17,148,740
Unit 3	6,732,122	20,971,186	6,399,522	19,935,105
Manatee Solar	6,601,101	17,928,699	6,274,973	17,042,932
Martin				
Common	46,459,059	80,096,302	44,163,749	76,139,144
Unit 1	10,112,774	19,210,487	9,613,152	18,261,393
Unit 2	10,112,774	19,210,487	9,613,152	18,261,393
Unit 3	2,857,402	6,218,011	2,716,232	5,910,810
Unit 4	2,864,092	6,200,760	2,722,592	5,894,411
Unit 8	6,668,321	20,995,725	6,338,872	19,958,432
Martin Solar	10,856,697	28,672,889	10,320,322	27,256,305
Okeechobee				
Common	5,726,113	25,084,242	5,443,214	23,844,955
Unit 1	6,641,891	34,869,012	6,313,748	33,146,309
Port Everglades				
Common	6,426,572	25,097,705	6,109,067	23,857,753
Unit 5	6,079,219	28,862,811	5,778,875	27,436,844
Gas Turbines	1,935,975	2,069,493	1,840,328	1,967,250
Riviera Beach				
Common	6,452,457	21,761,919	6,133,673	20,686,772
Unit 5	7,051,684	29,015,737	6,703,296	27,582,214
Sanford				
Common	10,290,606	24,963,942	9,782,199	23,730,599
Unit 4	6,424,194	18,370,483	6,106,806	17,462,889
Unit 5	6,397,182	17,670,475	6,081,129	16,797,465
Scherer				
Common	33,972,828	80,197,672	32,294,400	76,235,506
Unit 4	1,028,362	2,298,020	977,555	2,184,486
Handling	15,403,424	34,564,384	14,642,418	32,856,730
Space Coast Solar	886,054	2,003,712	842,278	1,904,718
St. Johns River				
Common	14,532,336	33,148,871	13,814,366	31,511,151
Unit 1	3,258,795	7,356,102	3,097,794	6,992,674
Unit 2	3,258,795	7,356,102	3,097,794	6,992,674
Handling	1,137,429	2,406,861	1,081,235	2,287,950
Turkey Point				
Common	14,068,274	38,409,418	13,373,231	36,511,800
Unit 1	13,564,981	41,798,519	12,894,803	39,733,463
Unit 2	7,384,545	24,170,409	7,019,711	22,976,270
Unit 5	10,235,882	34,458,323	9,730,179	32,755,910
West County				
Common	20,101,515	59,631,111	19,108,400	56,685,036
Unit 1	6,576,917	23,791,257	6,251,984	22,615,850
Unit 2	6,603,614	23,882,502	6,277,362	22,702,587
Unit 3	6,631,175	25,774,470	6,303,562	24,501,083
Totals	**$ 478,276,387**	**$ 1,238,509,183**	**$ 454,647,143**	**$ 1,177,320,637**

Section 4

Calculation of Current and Future Jurisdictional Dismantlement Costs

2018 Jurisdictional Factor: 95.12840%

Site/Unit	Dismantlement Cost in 2016 Dollars	Dismantlement Cost in Future Dollars	Jurisdictional Dismantlement Cost in 2016 Dollars	Jurisdictional Dismantlement Cost in Future Dollars
Babcock Ranch Solar	$ 6,601,101	$ 17,928,699	$ 6,279,521	$ 17,055,285
Cape Canaveral				
Common	8,745,382	28,861,856	8,319,342	27,455,822
Unit 1	7,122,444	28,452,355	6,775,467	27,066,271
Cedar Bay	4,520,250	4,520,250	4,300,042	4,300,042
Citrus Solar	6,601,101	17,928,699	6,279,521	17,055,285
DeSoto Solar	2,338,490	5,108,176	2,224,568	4,859,326
Ft. Myers				
Common	19,702,679	48,380,642	18,742,843	46,023,731
Unit 2	9,039,546	26,346,751	8,599,175	25,063,242
Unit 3	1,568,707	4,498,227	1,492,286	4,279,091
Unit 4 (Combustion Turbine Peakers)	1,727,318	7,691,861	1,643,170	7,317,144
Gas Turbines	297,386	1,522,405	282,899	1,448,240
Lauderdale				
Common	19,099,027	34,238,552	18,168,598	32,570,586
Unit 4	4,346,178	8,578,351	4,134,449	8,160,448
Unit 5	4,340,750	8,569,391	4,129,286	8,151,925
Unit 6 (Combustion Turbine Peakers)	4,226,112	18,894,765	4,020,232	17,974,288
Gas Turbines	281,335	1,458,950	267,629	1,387,876
Manatee				
Common	31,234,151	50,931,140	29,712,549	48,449,979
Unit 1	10,574,637	18,040,007	10,059,483	17,161,170
Unit 2	10,574,637	18,040,007	10,059,483	17,161,170
Unit 3	6,732,122	20,971,186	6,404,160	19,949,554
Manatee Solar	6,601,101	17,928,699	6,279,521	17,055,285
Martin				
Common	46,459,059	80,096,302	44,195,760	76,194,330
Unit 1	10,112,774	19,210,487	9,620,120	18,274,629
Unit 2	10,112,774	19,210,487	9,620,120	18,274,629
Unit 3	2,857,402	6,218,011	2,718,201	5,915,094
Unit 4	2,864,092	6,200,760	2,724,565	5,898,684
Unit 8	6,668,321	20,995,725	6,343,467	19,972,898
Martin Solar	10,856,697	28,672,889	10,327,802	27,276,060
Okeechobee				
Common	5,726,113	25,084,242	5,447,159	23,862,238
Unit 1	6,641,891	34,869,012	6,318,325	33,170,333
Port Everglades				
Common	6,426,572	25,097,705	6,113,495	23,875,045
Unit 5	6,079,219	28,862,811	5,783,064	27,456,730
Gas Turbines	1,935,975	2,069,493	1,841,662	1,968,676
Riviera Beach				
Common	6,452,457	21,761,919	6,138,119	20,701,766
Unit 5	7,051,684	29,015,737	6,708,154	27,602,206
Sanford				
Common	10,290,606	24,963,942	9,789,289	23,747,799
Unit 4	6,424,194	18,370,483	6,111,233	17,475,546
Unit 5	6,397,182	17,670,475	6,085,537	16,809,640
Scherer				
Common	33,972,828	80,197,672	32,317,807	76,290,762
Unit 4	1,028,362	2,298,020	978,264	2,186,070
Handling	15,403,424	34,564,384	14,653,031	32,880,545
Space Coast Solar	886,054	2,003,712	842,889	1,906,099
St. Johns River				
Common	14,532,336	33,148,871	13,824,379	31,533,991
Unit 1	3,258,795	7,356,102	3,100,039	6,997,742
Unit 2	3,258,795	7,356,102	3,100,039	6,997,742
Handling	1,137,429	2,406,861	1,082,018	2,289,609
Turkey Point				
Common	14,068,274	38,409,418	13,382,924	36,538,265
Unit 1	13,564,981	41,798,519	12,904,150	39,762,262
Unit 2	7,384,545	24,170,409	7,024,799	22,992,923
Unit 5	10,235,882	34,458,323	9,737,231	32,779,652
West County				
Common	20,101,515	59,631,111	19,122,250	56,726,122
Unit 1	6,576,917	23,791,257	6,256,516	22,632,242
Unit 2	6,603,614	23,882,502	6,281,912	22,719,042
Unit 3	6,631,175	25,774,470	6,308,131	24,518,841
Totals	**$ 478,276,387**	**$ 1,238,509,183**	**$ 454,976,675**	**$ 1,178,173,970**

Section 5

Escalation Rates Used to Calculate Future Dismantlement Costs

INFLATION FORECAST

The U.S. Economy
GLOBAL INSIGHT
30 Year Outlook (May 2015)

	Compensation per Hour (Non-Farm)		Producer Price Index (Intermediate Materials)		GDP Deflator (Implicit)		METAL & METAL PRODUCTS	
YEAR	ANNUAL RATE OF CHANGE	COMPOUNDED MULTIPLIER FROM 2015	ANNUAL RATE OF CHANGE	COMPOUNDED MULTIPLIER FROM 2015	ANNUAL RATE OF CHANGE	COMPOUNDED MULTIPLIER FROM 2015	ANNUAL RATE OF CHANGE	COMPOUNDED MULTIPLIER FROM 2015
2015	2.7%	1.000	-7.3%	1.000	1.1%	1.000	-5.0%	1.000
2016	3.5%	1.035	0.9%	1.009	2.0%	1.020	-0.6%	0.994
2017	3.7%	1.073	2.6%	1.036	2.0%	1.040	1.8%	1.013
2018	3.9%	1.115	2.4%	1.061	1.9%	1.060	2.8%	1.041
2019	3.9%	1.158	2.0%	1.082	2.0%	1.081	1.7%	1.058
2020	3.9%	1.203	0.5%	1.088	1.9%	1.101	1.4%	1.073
2021	3.9%	1.249	1.1%	1.100	2.0%	1.124	1.4%	1.088
2022	3.9%	1.298	1.9%	1.121	2.1%	1.147	1.4%	1.103
2023	3.9%	1.349	2.0%	1.143	2.2%	1.172	1.4%	1.119
2024	4.0%	1.402	1.4%	1.160	2.1%	1.197	1.3%	1.133
2025	4.0%	1.458	0.9%	1.170	2.1%	1.222	1.4%	1.148
2026	3.9%	1.515	0.8%	1.179	2.1%	1.247	1.7%	1.168
2027	3.9%	1.573	1.0%	1.191	2.1%	1.273	2.1%	1.192
2028	3.9%	1.634	1.2%	1.205	2.1%	1.299	2.2%	1.218
2029	3.8%	1.697	1.1%	1.218	2.1%	1.327	2.2%	1.245
2030	3.8%	1.763	1.0%	1.230	2.1%	1.355	2.1%	1.272
2031	3.9%	1.831	1.2%	1.244	2.2%	1.385	2.2%	1.300
2032	3.9%	1.902	0.9%	1.256	2.2%	1.416	2.1%	1.327
2033	3.9%	1.975	1.0%	1.269	2.2%	1.447	2.1%	1.354
2034	3.9%	2.052	1.1%	1.283	2.2%	1.480	2.0%	1.382
2035	3.9%	2.131	1.0%	1.296	2.2%	1.513	2.0%	1.409
2036	3.9%	2.214	1.0%	1.309	2.2%	1.546	1.9%	1.437
2037	3.9%	2.300	1.1%	1.323	2.2%	1.580	1.9%	1.465
2038	3.9%	2.390	1.1%	1.338	2.2%	1.616	1.9%	1.493
2039	3.9%	2.482	1.2%	1.354	2.3%	1.653	1.9%	1.522
2040	3.9%	2.579	1.2%	1.370	2.3%	1.690	1.9%	1.550
2041	3.9%	2.680	1.2%	1.386	2.3%	1.729	1.9%	1.580
2042	3.9%	2.784	1.2%	1.402	2.3%	1.769	1.9%	1.609
2043	3.9%	2.893	1.2%	1.418	2.3%	1.811	1.8%	1.639
2044	3.9%	3.005	1.2%	1.436	2.4%	1.853	1.8%	1.668
2045	3.9%	3.123	1.2%	1.453	2.4%	1.897	1.8%	1.698
2046	3.9%	3.244	1.2%	1.470	2.4%	1.942	1.8%	1.728
2047	3.9%	3.371	1.2%	1.487	2.4%	1.987	1.8%	1.759
2048	3.9%	3.502	1.2%	1.505	2.4%	2.034	1.8%	1.791
2049	3.9%	3.639	1.2%	1.523	2.4%	2.082	1.8%	1.822
2050	3.9%	3.780	1.2%	1.541	2.4%	2.131	1.8%	1.855
2051	3.9%	3.928	1.2%	1.559	2.4%	2.182	1.8%	1.888
2052	3.9%	4.081	1.2%	1.578	2.4%	2.233	1.8%	1.921
2053	3.9%	4.240	1.2%	1.596	2.4%	2.286	1.8%	1.956
2054	3.9%	4.405	1.2%	1.615	2.4%	2.340	1.8%	1.991
2055	3.9%	4.577	1.2%	1.634	2.4%	2.395	1.8%	2.026
2056	3.9%	4.755	1.2%	1.654	2.4%	2.451	1.8%	2.062
2057	3.9%	4.941	1.2%	1.673	2.4%	2.509	1.8%	2.099
2058	3.9%	5.133	1.2%	1.693	2.4%	2.568	1.8%	2.136
2059	3.9%	5.333	1.2%	1.713	2.4%	2.629	1.8%	2.174
2060	3.9%	5.541	1.2%	1.734	2.4%	2.691	1.8%	2.213
2061	3.9%	5.757	1.2%	1.754	2.4%	2.754	1.8%	2.252
2062	3.9%	5.982	1.2%	1.775	2.4%	2.819	1.8%	2.292
2063	3.9%	6.215	1.2%	1.796	2.4%	2.885	1.8%	2.333
2064	3.9%	6.457	1.2%	1.817	2.4%	2.953	1.8%	2.375
2065	3.9%	6.709	1.2%	1.839	2.4%	3.023	1.8%	2.417
2066	3.9%	6.970	1.2%	1.861	2.4%	3.094	1.8%	2.460
2067	3.9%	7.242	1.2%	1.883	2.4%	3.167	1.8%	2.504
2068	3.9%	7.524	1.2%	1.905	2.4%	3.242	1.8%	2.548
2069	3.9%	7.817	1.2%	1.928	2.4%	3.318	1.8%	2.594
2070	3.9%	8.122	1.2%	1.951	2.4%	3.397	1.8%	2.640
2071	3.9%	8.438	1.2%	1.974	2.4%	3.477	1.8%	2.687
2072	3.9%	8.767	1.2%	1.997	2.4%	3.559	1.8%	2.735
2073	3.9%	9.109	1.2%	2.021	2.4%	3.643	1.8%	2.783
2074	3.9%	9.464	1.2%	2.045	2.4%	3.728	1.8%	2.833
2075	3.9%	9.833	1.2%	2.069	2.4%	3.816	1.8%	2.883

Section 6

Annual Accrual Calculation

		Year		Future Cost			Difference		Annual Accrual					
Unit	**Dismantlement Cost in 2016 Dollars**	**Economic Recovery Year**	**Recovery Period As of 1/1/2017**	**1st Yr Expense (Future $)**	**2nd Yr Expense (Future $)**	**Total Future $ Cost**	**Adj Reserve as of 12/31/2016**	**Amount To Accrue**	**2017**	**2018**	**2019**	**2020**	**4 Year Average**	**Monthly Accrual**
Babcock Ranch Solar	$ 6,601,101	2046	29	$ 5,262,957	$ 12,665,743	$ 17,928,699	$ -	$ 17,928,699	$ 360,396	$ 373,396	$ 386,865	$ 400,819	$ 380,369	$ 31,697
Cape Canaveral														
Common	8,745,382	2053	36	8,471,328	20,390,528	28,861,856	-	28,861,856	417,775	432,125	446,968	462,321	439,797	36,650
Unit 5	7,122,444	2053	36	8,325,217	20,127,139	28,452,355	-	28,452,355	364,446	379,130	394,406	410,297	387,069	32,256
Cedar Bay	4,520,250	2016	0	N/A	N/A	4,520,250	-	4,520,250	4,520,250	-	-	-	1,130,063	94,172
Citrus Solar	6,601,101	2046	29	5,262,957	12,665,743	17,928,699	-	17,928,699	360,396	373,396	386,865	400,819	380,369	31,697
DeSoto Solar	2,338,490	2039	22	1,500,707	3,607,469	5,108,176	508,956	4,599,220	138,272	143,454	148,830	154,407	146,241	12,187
Ft. Myers														
Common	19,702,679	2043	26	14,212,629	34,168,013	48,380,642	12,436,940	35,943,702	857,612	888,513	920,527	953,695	905,087	75,424
Unit 2	9,039,546	2043	26	7,709,606	18,637,145	26,346,751	9,455,820	16,890,930	361,854	377,657	394,150	411,364	386,256	32,188
Unit 3	1,568,707	2043	26	1,316,721	3,181,505	4,498,227	1,574,379	2,923,847	63,290	66,008	68,842	71,799	67,485	5,624
Unit 4 (Combustion Turbine Peakers)	1,727,318	2056	39	2,250,160	5,441,700	7,691,861	-	7,691,861	84,991	88,395	91,934	95,616	90,234	7,520
Gas Turbines	297,386	2056	39	444,571	1,077,834	1,522,405	-	1,522,405	39,036	39,036	39,036	39,036	39,036	3,253
Lauderdale														
Common	19,099,027	2033	16	10,077,652	24,160,900	34,238,552	-	34,238,552	1,587,535	1,648,682	1,712,184	1,778,131	1,681,633	140,136
Unit 4	4,346,178	2033	16	2,517,540	6,060,811	8,578,351	5,147,011	3,431,340	150,290	157,145	164,313	171,807	160,889	13,407
Unit 5	4,340,750	2033	16	2,514,895	6,054,496	8,569,391	5,141,635	3,427,757	150,114	156,963	164,124	171,613	160,703	13,392
Unit 6 (Combustion Turbine Peakers)	4,226,112	2056	39	5,527,120	13,367,645	18,894,765	-	18,894,765	208,240	216,603	225,301	234,348	221,123	18,427
Gas Turbines	281,335	2056	39	425,975	1,032,975	1,458,950	-	1,458,950	37,409	37,409	37,409	37,409	37,409	3,117
Manatee														
Common	31,234,151	2028	11	14,981,184	35,949,956	50,931,140	23,226,652	27,704,488	1,974,543	2,068,556	2,167,045	2,270,223	2,120,092	176,674
Unit 1	10,574,637	2028	11	5,300,607	12,739,400	18,040,007	14,223,852	3,816,155	264,345	278,372	293,144	308,699	286,140	23,845
Unit 2	10,574,637	2028	11	5,300,607	12,739,400	18,040,007	14,149,025	3,890,982	269,528	283,831	298,892	314,752	291,751	24,313
Unit 3	6,732,122	2045	28	6,136,191	14,834,995	20,971,186	-	20,971,186	401,089	418,310	436,269	455,000	427,667	35,639
Manatee Solar	6,601,101	2046	29	5,262,957	12,665,743	17,928,699	-	17,928,699	360,396	373,396	386,865	400,819	380,369	31,697
Martin														
Common	46,459,059	2031	14	23,576,573	56,519,729	80,096,302	38,788,133	41,308,169	2,238,725	2,331,109	2,427,306	2,527,473	2,381,153	198,429
Unit 1	10,112,774	2031	14	5,638,035	13,572,452	19,210,487	13,937,020	5,273,467	269,541	282,950	297,027	311,804	290,331	24,194
Unit 2	10,112,774	2031	14	5,638,035	13,572,452	19,210,487	13,831,551	5,378,936	274,931	288,609	302,968	318,040	296,137	24,678
Unit 3	2,857,402	2034	17	1,821,139	4,396,872	6,218,011	3,575,356	2,642,655	102,656	107,744	113,085	118,690	110,544	9,212
Unit 4	2,864,092	2034	17	1,816,341	4,384,418	6,200,760	3,565,437	2,635,323	102,705	107,758	113,058	118,620	110,535	9,211
Unit 8	6,668,321	2045	28	6,142,075	14,853,650	20,995,725	-	20,995,725	398,738	416,039	434,090	452,924	425,448	35,454
Martin Solar	10,856,697	2045	28	8,418,601	20,254,288	28,672,889	2,105,831	26,567,058	563,305	583,712	604,859	626,771	594,662	49,555
Okeechobee														
Common	5,726,113	2059	40	7,350,626	17,733,616	25,084,242	-	25,084,242	-	-	275,078	285,599	140,169	11,681
Unit 1	6,641,891	2059	40	10,191,598	24,677,414	34,869,012	-	34,869,012	-	-	338,236	352,927	172,791	14,399
Port Everglades														
Common	6,426,572	2056	39	7,357,448	17,740,257	25,097,705	-	25,097,705	302,732	313,686	325,037	336,798	319,563	26,630
Unit 5	6,079,219	2056	39	8,436,248	20,426,563	28,862,811	-	28,862,811	305,594	318,400	331,742	345,644	325,345	27,112
Gas Turbines	1,935,975	2016	0	606,287	1,463,206	2,069,493	414,572	1,654,921	1,654,921	-	-	-	413,730	34,478
Riviera Beach														
Common	6,452,457	2054	37	6,387,524	15,374,395	21,761,919	-	21,761,919	302,482	312,770	323,408	334,407	318,267	26,522
Unit 5	7,051,684	2054	37	8,490,214	20,525,523	29,015,737	-	29,015,737	355,164	369,370	384,143	399,508	377,046	31,421

Section 6

Annual Accrual Calculation

		Year		Future Cost			Difference		Annual Accrual					
Unit	**Dismantlement Cost in 2016 Dollars**	**Economic Recovery Year**	**Recovery Period As of 1/1/2017**	**1st Yr Expense (Future $)**	**2nd Yr Expense (Future $)**	**Total Future $ Cost**	**Adj Reserve as of 12/31/2016**	**Amount To Accrue**	**2017**	**2018**	**2019**	**2020**	**4 Year Average**	**Monthly Accrual**
Sanford														
Common	10,290,606	2043	26	7,335,246	17,628,696	24,963,942	8,737,380	16,226,562	389,795	403,650	417,998	432,856	411,075	34,256
Unit 4	6,424,194	2043	26	5,377,800	12,992,683	18,370,483	3,746,638	14,623,845	317,202	330,778	344,935	359,698	338,153	28,179
Unit 5	6,397,182	2042	25	5,173,325	12,497,151	17,670,475	6,626,428	11,044,047	254,293	265,254	276,687	288,614	271,212	22,601
Scherer														
Common	33,972,828	2039	22	23,527,858	56,669,814	80,197,672	21,556,477	58,641,196	1,693,362	1,762,715	1,834,908	1,910,058	1,800,261	150,022
Unit 4	15,403,424	2039	22	10,147,893	24,416,491	34,564,384	19,090,984	15,473,400	458,138	475,913	494,377	513,558	485,497	40,458
Handling	1,028,362	2039	22	674,769	1,623,251	2,298,020	1,286,891	1,011,129	30,017	31,175	32,377	33,626	31,799	2,650
Space Coast Solar	886,054	2040	23	588,530	1,415,181	2,003,712	235,872	1,767,840	49,833	51,697	53,630	55,636	52,699	4,392
St. Johns River														
Common	14,532,336	2038	21	9,726,004	23,422,867	33,148,871	11,109,095	22,039,776	680,071	708,117	737,320	767,726	723,308	60,276
Unit 1	3,258,795	2038	21	2,158,169	5,197,933	7,356,102	4,327,119	3,028,983	93,690	97,533	101,534	105,699	99,614	8,301
Unit 2	3,258,795	2038	21	2,158,169	5,197,933	7,356,102	4,266,539	3,089,563	95,564	99,484	103,565	107,813	101,607	8,467
Handling	1,137,429	2038	21	707,433	1,699,428	2,406,861	1,395,979	1,010,882	32,537	33,754	35,016	36,325	34,408	2,867
Turkey Point														
Common	14,068,274	2047	30	11,281,647	27,127,771	38,409,418	-	38,409,418	746,604	772,579	799,458	827,272	786,478	65,540
Unit 1	13,564,981	2047	30	12,249,225	29,549,294	41,798,519	-	41,798,519	770,814	800,087	830,472	862,010	815,846	67,987
Unit 2	7,384,545	2047	30	7,075,226	17,095,183	24,170,409	(15,923,728)	40,094,137	1,000,799	1,020,012	1,039,594	1,059,551	1,029,989	85,832
Unit 5	10,235,882	2047	30	10,081,384	24,376,939	34,458,323	-	34,458,323	587,906	612,967	639,097	666,341	626,578	52,215
West County														
Common	20,101,515	2051	34	17,518,230	42,112,881	59,631,111	-	59,631,111	973,764	1,006,025	1,039,355	1,073,790	1,023,234	85,269
Unit 1	6,576,917	2049	32	6,958,462	16,832,795	23,791,257	-	23,791,257	363,573	378,974	395,027	411,760	387,333	32,278
Unit 2	6,603,614	2049	32	6,985,176	16,897,326	23,882,502	-	23,882,502	365,022	380,481	396,595	413,391	388,872	32,406
Unit 3	6,631,175	2051	34	7,537,564	18,236,906	25,774,470	-	25,774,470	354,762	369,668	385,200	401,385	377,754	31,479
Grand Total	**$ 478,276,387**			**$ 361,934,435**	**$ 872,054,499**	**$ 1,238,509,183**	**$ 228,537,844**	**$ 1,009,971,339**	**$ 29,101,052**	**$ 23,833,386**	**$ 25,391,149**	**$ 26,399,287**	**$ 26,181,218**	**$ 2,181,768**

Section 7

Future Expenditures by Year

Future Dismantlement Expenditures by Year
(Per 2016 Dismantlement Study)

Year	Projected Dismantlement Expenditures
2017	$ 5,126,537
2018	1,463,206
2033	25,582,399
2034	61,428,755
2036	34,852,642
2037	83,664,634
2038	15,110,087
2039	39,913,688
2040	8,781,290
2043	14,749,774
2044	71,369,388
2045	86,905,556
2046	1,415,181
2047	5,173,325
2048	48,449,154
2049	86,608,041
2050	20,696,868
2051	65,731,803
2052	78,684,710
2053	98,149,187
2054	13,943,638
2055	33,730,121
2056	25,055,795
2057	60,349,787
2058	16,796,545
2059	55,395,405
2060	35,899,918
2061	24,441,522
2062	59,086,975
2064	17,542,224
2065	42,411,030
Grand Total	**$ 1,238,509,183**

Section 8

Dismantlement Cost Analysis Prepared by Burns & McDonnell

Fossil Dismantlement Study

Florida Power & Light Company

Fossil Dismantlement Study
Project No. 84400

Final
03/01/2016

Corrected
04/19/2016

Fossil Dismantlement Study

prepared for

Florida Power & Light Company
Fossil Dismantlement Study
Miami, Florida

Project No. 84400

Final
03/01/2016

Corrected
04/19/2016

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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BURNS McDONNELL

March 1, 2016

Jon-Paul Zabala
Asset Recovery & Analysis
Florida Power & Light Company
700 Universe Boulevard, Juno Beach, FL 33408

Re: FPL Decommissioning Cost Study

Dear Mr. Zabala,

Burns & McDonnell is pleased to present its report to Florida Power & Light Company (FPL) on the Decommissioning Cost Study (Study) for power generation assets in Florida and Georgia, excluding nuclear.

The objective of the Study was to review the facilities and to make a recommendation to FPL regarding the total cost in 2015 dollars to decommission the facilities at the end of their useful lives. The preparation of the cost estimates included in the Study were performed in accordance with Rule 25-6.04364, Electric Utilities Dismantlement Studies, Florida Administrative Code.

Burns & McDonnell appreciates the opportunity to provide our professional consulting services to FPL. Please feel free to contact me at any time to discuss questions that may arise during your review of the Study. You may reach me by phone at (816) 822- 4239 or via email at jkopp@burnsmcd.com. We look forward to working with you again on any future projects.

Respectfully Submitted,
BURNS & MCDONNELL

Jeff Kopp, PE
Project Manager

JTK/kps

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
Babcock Ranch Solar	Babcock Ranch Solar Energy Center
BMcD	Burns & McDonnell
C&D	Construction & Demolition
Citrus Solar	Citrus Solar Energy Center
Desoto Solar	DeSoto Next Generation Solar Energy Center
FPL	Florida Power & Light Company
GE	General Electric
HRSG	Heat recovery steam generator
kV	kilovolt
Manatee Solar	Manatee Solar Energy Center
MW	Megawatt
NO_x	Mono-nitrogen oxides
OCEC	Okeechobee Clean Energy Center
PCB	Polychlorinated Biphenyl
Plants	Fleet of gas, fuel oil, solar, and coal-fired generation facilities reviewed in this Study.
SCR	Selective catalytic reduction
Space Coast Solar	Space Coast Next Generation Solar Energy Center
Study	Fossil Dismantlement Study

1.0 EXECUTIVE SUMMARY

1.1 Introduction

Burns & McDonnell ("BMcD") was retained by Florida Power & Light ("FPL") to conduct a Decommissioning Cost Study ("Study") for power generation assets ("Plants") in Florida and Georgia, excluding nuclear units. The assets include natural gas, fuel oil, solar, and coal-fired generating facilities. Individuals from BMcD visited each of the existing Plants covered by the Study in May of 2015, along with a representative from Brandenburg, a demolition contractor who served as a sub-consultant to BMcD on the Study. The purpose of the Study was to review the facilities and to make a recommendation to FPL regarding the total cost in 2015 dollars to decommission the facilities at the end of their useful lives. The preparation of the cost estimates included in the Study were performed in accordance with Rule 25-6.04364, Electric Utilities Dismantlement Studies, Florida Administrative Code.

The decommissioning costs were developed using the information provided by FPL, in-house data available to BMcD, and information supplied by Brandenburg. Quantity take-offs were performed for major plant facilities and equipment based on observations from the site visits and review of drawings provided for each Plant. Decommissioning activities were determined and labor hours were estimated to complete each decommissioning activity. Current market pricing for labor rates and unit pricing were then developed for each task, and these rates were applied to the estimated quantities for the Plants to determine the total cost of decommissioning.

1.2 Results

When FPL determines that the Plants should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a salvage contractor to offset a portion of the decommissioning costs. FPL will incur costs in the demolition and restoration of the sites less the salvage value of equipment and bulk steel. BMcD has prepared estimates in current year dollars (2015$) for the decommissioning of the Plants, as summarized in Table 1-1. Further breakdowns of these costs are presented in Table A-1 through Table A-18 in Appendix A. BMcD has also prepared annual costs for groundwater monitoring associated with closed ash ponds and/or landfills, as presented in Table 1-2. Note that the regulatory requirement for groundwater monitoring extends over a 30 year period following the closure.

Table 1-1: Decommissioning Cost Summary (2015$)[1]

Plant	Decommissioning Costs	Credits	Net Project Cost
Cape Canaveral	$20,031,993	($4,616,199)	**$15,415,794**
DeSoto Solar	$3,009,309	($735,431)	**$2,273,878**
Ft. Myers	$41,516,932	($10,119,993)	**$31,396,939**
Lauderdale	$39,299,982	($7,864,398)	**$31,435,584**
Manatee	$73,789,541	($16,363,554)	**$57,425,987**
Martin	$113,594,115	($26,204,511)	**$87,389,603**
Port Everglades	$21,261,928	($7,317,093)	**$13,944,835**
Riviera	$17,500,262	($4,387,026)	**$13,113,236**
St. Johns River[2]	$119,600,000	($11,470,000)	**$108,130,000**
Sanford	$31,444,119	($9,043,912)	**$22,400,207**
Scherer[2,3]	$205,554,000	($9,629,000)	**$195,925,000**
Space Coast Solar	$1,150,000	($289,000)	**$861,000**
Turkey Point	$64,616,729	($13,677,173)	**$50,939,556**
West County	$54,842,211	($16,156,521)	**$38,685,690**
Babcock Ranch Solar[4]	$8,569,000	($2,152,000)	**$6,417,000**
Citrus Solar[4]	$8,569,000	($2,152,000)	**$6,417,000**
Manatee Solar[4]	$8,569,000	($2,152,000)	**$6,417,000**
Okeechobee[4]	$17,515,000	($5,560,000)	**$11,955,000**

[1] Cost estimates were rounded to the nearest $1,000 and then site inventory costs and recoverable scrap for inventory was added to the rounded estimate resulting in the values shown.
[2] Costs for Scherer and St. Johns River have not been adjusted for FPL's ownership percentage.
[3] Scherer estimate includes only Unit 4 and all common facilities.
[4] Proposed facility.

Table 1-2: Annual Groundwater Monitoring Costs (2015$)

Plant	Annual Cost
St. Johns River	$175,000
Scherer	$1,175,300

Monitoring installation costs included in decommissioning costs.

The total project costs presented above include the costs to return the sites to an industrial condition suitable for reuse for development of an industrial facility. Included are the costs to dismantle the power generating equipment owned by FPL as well as the costs to dismantle the FPL-owned balance of plant facilities and environmental site restoration activities.

1.3 Statement of Limitations

In preparation of this decommissioning study, BMcD has relied upon information provided by FPL. BMcD acknowledges that it has requested the information from FPL that it deemed necessary to complete this study. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of decommissioning costs are based on Engineer's experience, qualifications and judgment. Since Engineer has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors, Engineer does not guarantee the accuracy of its estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

2.0 INTRODUCTION

2.1 Background

Burns & McDonnell ("BMcD") was retained by Florida Power & Light ("FPL") to conduct a Decommissioning Cost Study ("Study") for power generation assets ("Plants") in Florida and Georgia, excluding nuclear units. The assets include natural gas, fuel oil, solar, and coal-fired generating facilities. Individuals from BMcD visited each of the existing Plants covered by the Study in May of 2015, along with a representative from Brandenburg, a demolition contractor who served as a sub-consultant to BMcD on the Study. The purpose of the Study was to review the facilities and to make a recommendation to FPL regarding the total cost in 2015 dollars to decommission the facilities at the end of their useful lives.

2.2 Study Methodology

The site decommissioning costs were developed using information provided by FPL, information developed by Brandenburg, and in-house data BMcD has collected from previous project experience. BMcD estimated quantities for equipment based on a visual inspection of the facilities, review of engineering drawings, BMcD's in house database of plant equipment quantities, and BMcD's professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each decommissioning effort. Current market pricing for labor rates, equipment, scrap materials, and unit pricing were then developed for each task. These pricing inputs were developed for each site based on costs specific to the area in which the work is to be performed. These rates were applied to the quantities for the Plants to determine the total cost of decommissioning for each site.

The decommissioning costs include the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility. Included are the costs to decommission all of the assets owned by FPL at the site, including power generating equipment and balance of plant facilities along with environmental site restoration activities.

2.3 Site Visits

Representatives from BMcD and Brandenburg visited the sites. The site visits consisted of a tour of each facility with plant personnel to review the equipment installed at each site.

Mr. Jon-Paul Zabala, served as the FPL representative throughout the site visits, along with plant personnel at each of the sites.

The following BMcD and Brandenburg representatives comprised the site visit team:

- Mr. Jeff Kopp, BMcD, Project Manager
- Mr. Kory Sandven, BMcD, Project Engineer
- Mr. Parker Hills, BMcD, Project Engineer
- Mr. Andy Debrowski, Brandenburg, Demolition Contractor Representative

The site visits were performed on the following dates.

Table 2-1: Site Visit Dates

Plant	Site Visit Date
Martin	14-May-15
DeSoto Solar	20-May-15
Ft. Myers	20-May-15
Riviera Beach	21-May-15
West County	21-May-15
Scherer	26-May-15
St. Johns River	27-May-15
Cape Canaveral	27-May-15
Sanford	28-May-15
Manatee	28-May-15
Turkey Point	29-May-15
Lauderdale	29-May-15
Port Everglades	29-May-15

Figure 2-1: FPL Facilities Visited

3.0 EXISTING PLANT DESCRIPTIONS

The fiollowing are plant descriptions for each of the existing power plants included in this Study.

3.1 Cape Canaveral

The Cape Canaveral plant is located in Cape Canaveral, Florida. Originally, the facility consisted of two (2) natural gas fired boilers, however, those units were fully demolished and removed from the site and replaced with a single 3-on-1 combined cycle unit (Unit 1). Unit 1 consists of three Siemens 8000H combustion turbines, three heat recovery steam generators ("HRSGs"), and one steam turbine. The total capacity is 1,210 megawatts ("MW") at the summer peak rating. Additionally, this unit includes a selective catalytic reduction ("SCR") for reducing mono-nitrogen oxides ("NO_x") emissions. The facility also includes a man-made cooling water intake and discharge canal which has a manatee heating station.

3.2 DeSoto Next Generation Solar Energy Center

The DeSoto Next Generation Solar Energy Center ("Desoto Solar") is a photovoltaic solar power facility located approximately 30 miles northeast of Port Charlotte, in Arcadia, Florida. The facility currently includes approximately 90,504 single axis tracking SunPower solar panels with a total plant capacity of 25 MW at the summer peak rating.

3.3 Fort Myers

The Fort Myers plant is located along the Caloosahatchee River approximately 7 miles northeast of downtown Fort Myers, Florida. The facility includes a single 6-on-2 combined cycle unit (Unit 2) which incorporates six General Electric ("GE") 7FA combustion turbines, six Foster Wheeler HRSGs, and two steam turbines with a capacity of 1,470 MW at the summer peak rating. The facility also includes 2 simple cycle GE 7FA combustion turbines (Units 3A and 3B) with a combined capacity of 314 MW at the summer peak rating and 12 small simple cycle combustion turbines. By the end of 2016, 10 of the 12 simple-cycle combustion turbines will be retired. Water for the facility's condensing cooling system is provided via Caloosahatchee River with water discharge from the cooling towers to a man-made canal that discharges to the Orange River.

3.4 Lauderdale

The Lauderdale plant is located in Fort Lauderdale, Florida. Originally, the facility included two conventional boiler steam units and associated steam turbines that were repowered in the mid 1990's to combined cycle units (Units 4 and 5). The repowered combined cycle units can each be fired with either natural gas or fuel oil and each include two Westinghouse 501F combustion turbines, two HRSGs, and

one steam turbine. These two combined cycle units have a combined capacity of 884 MW or 442 MW each at the peak summer rating. Unlike many of the other FPL combined cycle units, the combustion turbines and generators are completely enclosed within a building. In addition to the combined cycle units, the facility has 24 simple-cycle combustion turbines. By the end of 2016, 22 of the 24 simple-cycle combustion turbines will be retired. The brackish water used in the facility's condensing cooling system is provided by the Dania Cut-Off Canal and discharged into a man-made canal to the South Fork New River.

3.5 Manatee

The Manatee plant is located within Manatee County, approximately 5 miles east of Parrish, Florida. The facility includes two fuel oil-fired boilers (Unit 1 and Unit 2), rated at approximately 809 MW each at the summer peak rating, and a 4-on-1 combined cycle unit (Unit 3) which includes four GE 7FA combustion turbines, four HRSGs, and one steam turbine with a combined capacity of 1,140 MW at the summer peak rating. In its entirety, the plant is rated to produce over 2,700 MW. The facility also includes a cooling pond to the east of the generation units which encompasses approximately 3,700 acres. Fuel oil is provided to the facility via a fuel oil pipeline that interconnects with offsite fuel oil storage tanks located at the port in Manatee County, approximately 20 miles away.

3.6 Martin

The Martin plant is located within Martin County, along the northeastern side of Lake Okeechobee and approximately 4 miles west of Indiantown, Florida. The facility includes two fuel oil-fired boilers (Unit 1 and Unit 2), with a combined capacity of 1,626 MW at the summer peak rating. The plant also includes two 2-on-1 combined cycle units (Unit 3 and Unit 4) which consist of two GE 7FA combustion turbines, two HRSGs, and one steam turbine with a combined capacity of 469 MW at the summer peak rating for each of these units. The facility also features an integrated solar thermal station which integrates solar thermal energy with Unit 8, a 4-on-1 combined cycle unit. The solar unit is capable of supporting up to 75 MW worth of steam, the equivalent of excess steam produced by duct firing the HRSGs on Unit 8. Although the solar thermal station supports Unit 8, the HRSGs for this unit are capable of providing rated capacity of the steam turbine without the aid of the solar station. In its entirety, the plant is rated to produce over 3,500 MW. The facility also includes a cooling pond to the east of the generation units which encompasses approximately 6,500 acres.

3.7 Port Everglades

The Port Everglades plant is located within the boundaries of the Port Everglades port, in the City of Fort Lauderdale, Florida. Similar to the Cape Canaveral plant, originally the Port Everglades plant consisted

of two (2) natural gas fired boilers, however, those units were fully demolished and removed from the site and replaced with a single 3-on-1 combined cycle unit (Unit 5). Unit 5 consists of three Siemens 8000H combustion turbines, three heat recovery steam generators ("HRSGs"), and one steam turbine. The total capacity is 1,237 MW at the summer peak rating. Additionally, this unit includes an SCR for reducing NO_x emissions. The Port Everglades plant also includes 12 small simple cycle combustion turbines, all of which will be retired by the end of 2016.

3.8 Riviera

The Riviera plant is located on approximately 22 acres of land in Palm Beach County, approximately 10 miles north of the city of West Palm Beach, Florida. Similar to the Cape Canaveral and Port Everglades plants, originally the Riviera plant consisted of two (2) natural gas fired boilers, however, it was recently reconstructed as a single 3-on-1 combined cycle unit (Unit 5). Unit 5 consists of three Siemens 8000H combustion turbines, three HRSGs, and one steam turbine. The total capacity is 1,237 MW at the summer peak rating. Additionally, this unit includes an SCR for reducing NO_x emissions.

3.9 St. Johns River Power Park

The St. Johns River Power Park Plant is located in northeast area of Jacksonville, Florida. This facility is jointly owned between Jacksonville Electric Authority and FPL with ownership percentages of 80 and 20 percent, respectively. The facility includes two coal-fired steam turbine units (Units 1 and 2) with a combined capacity of 1,270 MW at the summer peak rating. The coal handling system for the facility includes a rotary rail car dumper equipped with a static weight scale, a train positioner, a receiving bin, four short belt feeders, a cross conveyor, two elevating conveyors, and two magnetic separators. In addition, the plant includes a coal unloading facility on Blount Island for coal delivered by barge, along with a system of coal conveyers from Blount Island to the plant. For cooling, the facility includes two hyperbolic natural draft cooling towers which are located in the northeast boundary of the site.

3.10 Sanford

The Sanford plant is located on approximately 1,718 acres of land in Volusia County, approximately 2.5 miles south of DeBary, Florida. Originally, the facility included two conventional boiler steam units which were repowered in the mid 1990's to two 4-on-1 combined cycle units (Units 4 and 5). During the retrofit process, the boilers and associated equipment were removed, however, the steam turbines remained and are currently used in combined cycle mode. Each combined cycle unit operates using natural gas as the primary fuel supply and includes four GE 7FA combustion turbines, four HRSGs, and one steam turbine. These two units have a combined capacity of 2,010 MW or 1,005 MW each at the

summer peak rating. Additionally, the site includes a 1,100 acre cooling pond to the north of the generation units which is connected via a 4,500 foot canal.

3.11 Scherer

The Scherer Steam Plant is located approximately 17 miles north of Macon, Georgia and includes four (4) coal-fired steam turbine units. The facility is jointly owned between Georgia Power Corporation, Jacksonville Electric Authority and FPL, with FPL having 76.36 percent ownership Unit 4 only. Unit 4 has a capacity of 990 MW at the summer peak rating and consists of a boiler, steam turbine generator, condenser, electrostatic precipitator, flue gas desulfurization unit, SCR, baghouse, one 530-foot tall natural draft-cooling tower, and a shared stack with Unit 3. Common facilities evaluated as part of this Study consist of the power house, the recycle pond, stormwater ponds, settling ponds, ash pond, ash settling landfill, coal storage yard, and limestone storage area.

3.12 Space Coast Next Generation Solar Energy Center

The Space Coast Next Generation Solar Energy Center ("Space Coast Solar") is a photovoltaic solar power facility located at the Kennedy Space Center in Cape Canaveral, Florida. The facility includes 35,000 single axis tracking SunPower solar panels with a total plant capacity of 10 MW at the summer peak rating. The Space Coast Solar facility uses the same panels as the Desoto Solar Center.

3.13 Turkey Point

The Turkey Point plant is located on the western coast of Biscayne Bay approximately 15 miles south of Miami, Florida. The facility includes two natural gas-fired boiler steam units (Units 1 and 2), two nuclear generating units (Units 3 and 4), and a 4-on-1 combined cycle unit (Unit 5). For the purpose of this study, the nuclear generating units and associated common facility equipment are excluded from the decommissioning estimates. Units 1 and 2 were originally designed with the plan for future conversion to burn coal, however, this conversion was never made. Unit 2 has been converted to a synchronous condenser and Unit 1 will be converted to a synchronous condenser in 2016. Unit 5 is a combined cycle unit which includes four 170-MW GE "F" Class combustion turbines with dry low NO_x combustors, four HRSGs, and one steam turbine with a combined capacity of 1,187 MW at the summer peak rating. The facility's condensing cooling system includes intake from the Biscayne Bay and discharges to a man-made series of canals that are associated with the nuclear unit. For purposes of this Study, the canal system was excluded from the decommissioning estimates, since it is a nuclear generation asset.

3.14 West County

The West County Energy Center is located approximately 15 miles west of West Palm Beach, in Palm Beach County, Florida. The facility includes three 3-on-1 combined cycle units, each configured with three Mitsubishi 501G1 combustion turbines, 3 Nooter Eriksen HRSGs, and one steam turbine with a combined capacity of 3,657 MW at the summer peak rating for the entire facility. Additionally, each unit has an SCR for reducing NO_x emissions. Each combined cycle unit includes a dedicated mechanical draft cooling tower.

4.0 PROPOSED PLANTS DESCRIPTIONS

FPL currently has several generation facilities under development which are anticipated to have a commercial operation date between 2016 and mid-2019 that were included for evaluation in the Study. Because these facilities are still in the development stage, as-built drawings of these facilities were unavailable. Instead, the decommissioning costs for these plants were estimated based on BMcD's experience with demolition of facilities similar to those proposed.

Following are plant descriptions for each of the proposed power plants included in this Study.

4.1 Babcock Ranch Solar Energy Center

The Babcock Ranch Solar Energy Center ("Babcock Ranch Solar") is proposed to be built by the end of 2016 as a photovoltaic solar power facility located near Babcock, Florida, with a proposed capacity of 74.5 MW at the summer peak rating and a facility size of approximately 440 acres. The facility is proposed to include approximately 229,000 panels in conjunction with 40 GE 2 MVA inverters and one 85 MVA step-up transformer.

4.2 Citrus Solar Energy Center

The Citrus Solar Energy Center ("Citrus Solar") is proposed to be built by the end of 2016 as a photovoltaic solar power facility located in DeSoto County, Florida, with a proposed nameplate capacity of 74.5 MW and a facility size of approximately 841 acres. The facility is proposed to include approximately 229,000 Hanwha 325 W panels in conjunction with 40 GE 2 MVA inverters and one 85 MVA step-up transformer.

4.3 Fort Myers

It is anticipated that by the end of 2016, the Fort Myers plant will replace 10 of the 12 simple-cycle combustion turbines with two GE 7FA.05 combustion turbines, each rated for 231 MW. For purposes of this Study, decommissioning estimates have been prepared based on the configuration of the plant after this replacement project occurs.

4.4 Lauderdale

It is anticipated that by the end of 2016, the Lauderdale plant will replace 22 of the 24 simple-cycle combustion turbines with five GE 7FA.05 combustion turbines, each rated for 231 MW. For purposes of this Study, decommissioning estimates have been prepared based on the configuration of the plant after this replacement project occurs.

4.5 Manatee Solar Energy Center

The Manatee Solar Energy Center ("Manatee Solar") is proposed to be built by 2016 as a photovoltaic solar power facility located in Manatee County, Florida, with a proposed capacity of 74.5 MW at the summer peak rating and a facility size of approximately 762 acres. The facility is proposed to include approximately 229,000 panels in conjunction with 40 GE 2 MVA inverters and one 85 MVA step-up transformer.

4.6 Okeechobee Clean Energy Center

The Okeechobee Clean Energy Center ("OCEC") is proposed to be built prior to June 2019 and will be located in northeast Okeechobee County, Florida, approximately 24 miles west of Vero Beach and 27 miles north-northeast of Okeechobee on the border with Indian River County. The OCEC will include approximately 189 acres and utilize three "H" Class combustion turbines, three HRSGs, and a steam turbine. The plant will have an approximate generating capability of 1,633 MW at the summer peak rating.. Additionally, each HRSG will have an SCR for reducing NO_x emissions. For cooling, Unit 1 is anticipated to have a 30-cell mechanical draft cooling tower and basin located at the site. The facility will use equipment similar to that at the Riviera Plant.

5.0 DECOMMISSIONING COSTS

BMcD has prepared decommissioning cost estimates for the Plants. When FPL determines that each site should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a demolition contractor to offset a portion of the site decommissioning costs. However, FPL will incur costs of decommissioning of the Plants and restoration of the site to the extent that those costs exceed the salvage value of equipment and bulk steel.

The decommissioning costs include the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility. Included are the costs to dismantle all of the assets owned by FPL at the site, including power generating equipment and balance of plant facilities, as well as environmental site restoration activities.

For purposes of this study, BMcD has assumed that each site will be decommissioned as a single project, allowing the most cost effective demolition methods to be utilized. It is BMcD's understanding, based on information provided by FPL, that this methodology was used for demolition of the other FPL facilities that were fully retired. A summary of several of the means and methods that could be employed is summarized in the following paragraphs; however, means and methods will not be dictated to the contractor by BMcD. It will be the contractor's responsibility to determine means and methods that result in safely decommissioning the Plants at the lowest possible cost.

Asbestos remediation would take place prior to commencement of any other demolition activities. Abatement would need to be performed in compliance with all state and federal regulations, including, but not limited to requirements for sealing off work areas and maintaining negative pressure throughout the removal process. Final clearances and approvals would need to be achieved prior to performing further demolition activities.

High grade assets would then be removed from the site, to the extent possible. This would include items such as transformers, transformer coils, circuit breakers, electrical wire, condenser plates and tubes, and heater tubes. High grade assets include precious alloys such as copper, aluminum, brass tubes, stainless steel tubes, and other high value metals occurring in plant systems. High grade asset removal would occur up-front in the schedule, to reduce the potential for vandalism, to increase cash flow, and for separation of recyclable materials, in order to increase scrap recovery. Methods of removal vary with the location and nature of the asset. Small transformers, small equipment, and wire would likely be removed and shipped as-is for processing at a scrap yard. Large transformers, combustion turbines, steam turbines, and condensers would likely require some on-site disassembly prior to being shipped to a scrap yard.

Construction and Demolition ("C&D") waste includes items such as non-asbestos insulation, roofing, wood, drywall, plastics, and other non-metallic materials. C&D waste would typically be segregated from scrap and concrete to avoid cross-contaminating of waste streams or recycle streams. C&D demolition crews could remove these materials with equipment such as excavators equipped with material handling attachments, skid steers, etc. This material would be consolidated and loaded into bulk containers for disposal.

In general, boilers and HRSGs could be felled and cut into manageable sized pieces on the ground. First the structures around the boilers would need to be removed using excavators equipped with shears and grapples. Stairs, grating, elevators, and other high structures would be removed using an "ultra-high reach" excavator, equipped with shears. Following removal of these structures, the boilers or HRSGs would be felled, using explosive blasts. The boilers would then be dismantled using equipment such as excavators equipped with shears and grapples, and the scrap metal loaded onto trailers for recycling.

After the surrounding structures and ductwork have been removed, the stacks would be imploded, using controlled blasts. Following implosion the stack liners and concrete would be reduced in size to allow for handling and removal.

Balance of plant structures and foundations would likely be demolished using excavators equipped with hydraulic shears, hydraulic grapples, and impact breakers, along with workers utilizing open flame cutting torches. Steel components would be separated, reduced in size, and loaded onto trailers for recycling. Concrete would be broken into manageable sized pieces and stockpiled for crushing on-site. Concrete pieces would ultimately be loaded in a hopper and fed through a crusher to be sized for on-site disposal.

The Turkey Point plant would likely be demolished utilizing "ultra-high reach" excavators equipped with shears and a concrete processor, excavators, and skid steers, since it cannot be felled, due to the proximity of the adjacent nuclear unit.

5.1 General Assumptions for All Sites

The following assumptions were made as the basis of all of the cost estimates.

1. Pricing for all estimates are in 2015 dollars.
2. Scrap values are based on the American Metals Market Monthly Report for October 2015.
3. All work will take place in a safe and cost efficient method.
4. Labor costs are based on a regular 40 hour workweek without overtime.

5. Labor rates are based on RS Means values for a demolition crew B-8 with rates adjusted based on the site cost indexes for Florida and Georgia.
6. The estimates are inclusive of all costs necessary to properly dismantle and decommission all sites to a marketable or usable condition. For purposes of this study and the included cost estimates, the facilities will be restored to a condition suitable for industrial use.
7. All facilities will be decommissioned to zero generating output. Existing utilities will remain in place for use by the contractor for the duration of the demolition activities.
8. It is assumed that all of the power stations will be dismantled after all units at a single site are taken out of service, allowing dismantlement of entire sites at once.
9. Soil testing and any other on-site testing has not been conducted for this study.
10. Transmission switchyards and substations within the boundaries of the plant are not part of the demolition scope. Switchyards that are associated with the facilities only and are not part of the transmission system are included for demolition. For purposes of this study, the division between generation assets and transmission assets is at the high side of the generator step-up transformers.
11. The costs for relocation of transmission lines, or other transmission assets, are specifically excluded from the decommissioning cost estimates. Any costs necessary to support on-going operations of adjacent or newly proposed units will be allocated to the operating costs of the units not being decommissioned.
12. Step-up transformers, auxiliary transformers, and spare transformers are included for demolition and scrap in all estimates.
13. Abatement of asbestos will precede any other work. After final air quality clearances have been obtained, demolition can proceed.
14. All demolition and abatement activities, including removal of asbestos, will be done in accordance with any and all applicable Federal, State and Local laws, rules and regulations.
15. Asbestos estimates were provided by FPL and escalated at 2.5 percent from 2014 to 2015 to represent 2015 year dollars unless noted otherwise in the site specific sections below.
16. FPL will remove or consume all burnable coal, fuel oil and chemicals prior to commencement of demolition activities.
17. Hazardous material abatement is included for all sites as necessary, including asbestos, mercury, and polychlorinated biphenyls (“PCBs”). Lead paint coated materials will be handled by certified personnel as necessary, but lead paint will not be removed prior to demolition.
18. Intake and discharge canals including any manatee heater equipment are assumed to remain at the site after demolition and thus have been excluded from decommissioning estimates.

19. No environmental costs have been included to address cleanup of contaminated soils, hazardous materials, or other conditions present on-site having a negative environmental impact, other than those specifically listed in these assumptions. No allowances are included for unforeseen environmental remediation activities.
20. Handling and disposal of hazardous material will be performed in compliance with the approved methods of FPL's Environmental Services Department.
21. Refractory brick on the coal fired boilers is handled and disposed of as hazardous waste, due to the likelihood of the presence of arsenic contamination.
22. Existing ash ponds will be pumped dry, filled with inert debris, capped with 40 mil geo-membrane, geo-net drainage layer, 24 inches of soil, and vegetated cover.
23. Stormwater ponds will be pumped dewatered, graded to drain to natural drainage patterns, and seeded.
24. Cooling lakes or ponds will remain as-is.
25. Site areas will be graded to achieve suitable site drainage to natural drainage patterns, but grading will be minimized to the extent possible.
26. All above grade structures will be demolished. All below grade structures, including foundations, will be removed to two (2) feet below grade. Additional structures and foundations greater than two (2) feet below grade will be abandoned in-place unless deemed hazardous by FPL or otherwise stated in the assumptions as being demolished.
27. Existing basements will be used to bury non-hazardous debris. Concrete in trenches and basements will be perforated to create drainage. Non-hazardous debris, such as concrete and brick, will be crushed and used as clean fill on-site once the capacity of all existing basements has been exceeded. All inert debris will be disposed of on-site. Costs for offsite disposal are included for materials not classified as inert debris.
28. Major equipment, structural steel, combustion turbines, generators, inlet filters, exhaust stacks, transformers, electrical equipment, cabling, wiring, pump skids, above ground piping, and equipment enclosures for the above equipment will be sold for scrap and removed from the Plant site by the demolition contractor. All other demolished materials are considered debris.
29. Except for the circulating water lines, underground piping will be abandoned in place. Circulating water system pipes will be capped, have the tops broken out, and backfilled with on-site soil.
30. Sewers, catch basins and ducts will be filled and sealed on the upstream side. Horizontal runs will be abandoned in place after being closed.

31. Costs are included to clean out the fuel oil tanks and lines. Costs have also been included to remove three (3) feet of soil directly below each of the fuel oil tanks to account for the potential for this soil to be contaminated during normal operations.
32. Disturbed site areas will be seeded or surfaced with crushed concrete after they are graded to provide a suitable ground cover to prevent soil erosion.
33. BMcD assumes that spare parts will be sold to the extent possible prior to decommissioning. Any remaining spare parts will be sold as scrap by the demolition contractor.
34. Rolling stock, including rail cars, dozers, plant vehicles, etc. is assumed to be removed by FPL prior to decommissioning.
35. Valuation and sale of land and all replacement generation costs are excluded from this scope.
36. For purposes of this study, it is assumed that none of the equipment will have a salvage value in excess of the scrap value of the materials in the equipment at the time of the decommissioning study. The decommissioning cost estimate is based on the end of useful life of each facility. All equipment, steel, copper, and other metals will be sold as scrap. Credits for salvage value are based on scrap value alone. Resale of equipment and materials is not included.
37. The scope of the costs included in this Study is limited to the decommissioning activities that will occur at the end of useful life of the facilities and groundwater monitoring activities associated with closure of ash ponds and landfills. Groundwater monitoring costs associated with the closed ash ponds and landfills are reported as the annual cost for one year, in 2015 dollars. These monitoring activities will be required for 30 years. Additional on-going costs may be required for maintenance of the site, depending on the condition of the site and ownership of the site. No additional ongoing costs have been included in the cost estimates provided in this Study.
38. Contingency is included in the cost estimate to cover expenses that are unknown at the time the estimate was prepared, but can reasonably be anticipated to be expended on the project. When preparing a cost estimate, there is always some uncertainty as to the precision of the quantities in the estimate, how work will be performed, and what work conditions will be like when the project is executed. Uncertainties are greater in a demolition project than in a construction project due to the nature of the drawings used for quantity takeoffs and the likelihood of encountering unknown conditions, such as hazardous materials, or environmental contamination. Other unknown conditions that could impact the costs include, but are not limited to, changing market conditions and weather delays. These uncertainties will impact the actual costs of the project relative to the estimated cost. The estimator is aware of these unknowns when preparing the cost estimate and includes contingency to cover these costs. A 20 percent contingency was included on the direct costs in the estimates prepared as part of this study to cover unknowns.

39. Indirect costs are included in the cost estimate to cover owner expenses such as management trailers, utilities, demolition oversight, and home office general and administrative costs. An indirect cost of 5 percent was included in the estimates to cover such costs.

Market conditions may result in cost variations at the time of contract execution.

5.2 Site Specific Decommissioning Assumptions

The following assumptions were made specific to each plant cost estimate.

5.2.1 Cape Canaveral

The following assumptions were made specific to the Cape Canaveral plant.

1. Intake and discharge canals including any manatee heater equipment are assumed to remain in place after demolition and have been excluded from the decommissioning estimate.
2. The laydown yard south of intake and discharge canals is assumed to be separate from the plant and is excluded from the demolition estimate.
3. Crushed concrete is assumed to be disposed of onsite and spread across the site.
4. The collector switchyard equipment, located west of the gas turbines, and the overhead transmission line from the onsite collector switchyard to the adjacent substation are included in the demolition estimate. The plant substation will remain in place and is not included in the decommissioning estimate.
5. The natural gas feeder station located north of the onsite switchyard is assumed to remain in place after demolition and has been excluded from the decommissioning estimate.
6. Cost estimate includes cost for importing topsoil, grading, and seeding the stormwater pond.

5.2.2 DeSoto Next Generation Solar Energy Center

The following assumptions were made specific to the DeSoto Next Generation Solar Center facility.

1. The cost estimate includes cost for grading, and seeding the site. No imported topsoil is assumed necessary for the solar facility due to the small footprint of the equipment foundations.

5.2.3 Space Coast Next Generation Solar Energy Center

The following assumptions were made specific to the Space Coast Solar Center facility.

1. The cost estimate includes cost for grading, and seeding the site. No imported topsoil is assumed necessary for the solar facility due to the small footprint of the equipment foundations.

5.2.4 Fort Myers

1. The property south of State Road 80 which is leased to the city for the manatee park is excluded from the decommissioning estimates.
2. The collector switchyard equipment immediately adjacent to the combustion turbines will be removed and all salvageable material will be scrapped including the overhead transmission lines to the plant substation. The plant substation and switchyard will remain and all access roads on the site that are specifically for the plant substation are not included in the decommissioning estimate.
3. The discharge canal located central to the plant site will remain and is excluded from the estimate.
4. Cooling water piping from intake and to discharge canals is assumed to be below two (2) feet and will be capped and left in place.
5. The estimate includes the proposed two (2) GE 7FA.05 combustion turbines in replacement of 10 of the existing simple-cycle combustion turbines, with two simple-cycle combustion turbines remaining at the site and included in the decommissioning estimate. For reference, the proposed GE 7FA.05 combustion turbines were classified as Unit 4.

5.2.5 Lauderdale

1. The discharge canal located north of the steam turbines site will remain and is excluded from the estimate.
2. The collector switchyard equipment immediately adjacent to the combustion turbines will be removed and all salvageable material will be scrapped including the overhead transmission lines to the plant substation. The plant substation and switchyard will remain in place and all access roads on the site that are specifically for the plant substation are not included in the decommissioning estimate.
3. The site includes a bridge to access the main entrance of the site. This bridge is assumed to remain after decommissioning of site and has been excluded from the decommissioning cost estimate.
4. The estimate includes the proposed five (5) GE 7FA.05 combustion turbines in replacement of 22 of the existing simple-cycle combustion turbines, with two simple-cycle combustion turbines remaining at site and included in decommissioning estimate. For reference, the proposed GE 7FA.05 combustion turbines were classified as Unit 6.

5.2.6 Manatee

1. The collector switchyard equipment immediately south of the combustion turbines will be removed and all salvageable material will be scrapped including the overhead transmission lines to the plant substation.
2. The plant substation and switchyard located south of the boilers will remain and all access roads on the site that are required for access to the plant substation are not included in the decommissioning estimate.
3. Units 1 and 2 have electrostatic precipitators for air quality controls which were included in the decommissioning estimate.
4. The cooling pond located northeast of site is assumed to remain after decommissioning of plant and all costs associated with pond have been excluded from the decommissioning estimate.
5. Condenser tube material for Units 1 and 2 are sea cure. Unit 3 condenser tube material is 316 stainless.
6. Fuel oil tanks at the nearby port are assumed to be separate from the plant and are excluded from the decommissioning estimate. The fuel pipeline from the port to the plant will be flushed, capped, and abandoned in place.
7. The soil contamination estimate was provided by FPL and performed by FPL's environmental team based on known contamination issues at the site. BMcD did not independently verify these estimates.

5.2.7 Martin

1. The site includes two substations, both of which are assumed to remain in place and are excluded from the decommissioning estimate.
2. The cooling pond located on the west side of the site is assumed to remain in place and all costs associated with the pond have been excluded from the decommissioning estimate.
3. Unit 8 includes a parabolic solar thermal facility. The parabolic troughs will be removed and disposed of in the onsite landfill. The structural framing for the parabolic troughs is made of aluminum and will be recycled, along with the steel columns that support the aluminum framing. The foundations below the columns will be removed to two (2) feet below grade.

5.2.8 Port Everglades

1. The Plant was under construction during the time of the Study. Estimates are based on the anticipated layout of the facility after construction is complete.

2. The two (2) plant substations and switchyards located south and southwest of the facility will remain and all access roads on the site that are required for access to the plant substations are not included in the decommissioning estimate.
3. The discharge canal is assumed to remain at site and was excluded from the decommissioning estimate.
4. The 12 CTs located north of Unit 5 are assumed to be removed, including foundation, equipment, and interconnection to plant substations.
5. The above ground piping at the natural gas metering area is included in the decommissioning estimate, however, all piping below ground is assumed to be two (2) feet below grade and is excluded from the estimate.

5.2.9 Riviera

1. The collector switchyard equipment immediately south of the combustion turbines will be removed and all salvageable material will be scrapped including the overhead transmission lines to the plant substation. The plant substation and switchyard located west of the combustion turbines will remain and all access roads on the site that are specifically for the plant substation are not included in the decommissioning estimate.

5.2.10 Sanford

1. The gazeebo and associated parking lot located in the southwest section of the site is assumed to remain and is excluded from the decommissioning estimate.
2. The collector switchyards immediately adjacent to the combustion turbines will be removed and all salvageable material will be scrapped including the overhead transmission lines to the plant substation. The plant substation will remain and all access roads on the site that are specifically for the plant substation are not included in the decommissioning estimate.
3. The plant includes two (2) condensate tanks within a containment area which were originally used for fuel oil storage. Soil remediation under these tanks is included.
4. The cooling pond and associated canal system are assumed to remain after decommissioning of plant and all costs associated with pond have been excluded from the decommissioning estimate.
5. The concrete separator between intake and discharge canal is assumed to remain in place and is excluded from decommissioning estimate.
6. The site includes ash landfills which were approved as closed prior to this Study. No costs are included in the current estimates for these landfills

5.2.11 Scherer

1. The decommissioning estimate includes the complete cost for demolition of Unit 4 and all common facilities. BMcD notes that FPL has percentage ownership of Unit 4 and common facilities; however, the costs presented in this Study are based on the full removal costs of each of these items, with no ownership percentages applied to these values. FPL will apply their ownership percentage to determine their portion of the cost obligations.
2. The plant substation will remain and all access roads on the site that are specifically for the plant substation are not included in the decommissioning estimate.
3. All railroad spurs from highway 87 to site are included in the decommissioning estimate. This includes the railroad tracks used for both limestone and coal transportation.
4. The coal pile area will have two (2) feet of soil excavated and replaced with clean fill, covered with imported topsoil, and seeded.
5. The powdered activated carbon ("PAC") and gypsum landfills located north of the Plant will be closed by rough grading of berms and sediment for cap base, importing material for cap base, installing geotextile over base soil, installing a 40-mil HDPE liner, installing geotextile on top of FML, importing and placing 24 inches of cover soil, grading cover soil, and hydroseeding.
6. The site includes an ash pond which will be closed by dewatering, rough grading of berms and sediment for cap base, importing material for cap base, installing geotextile over base soil, installing a 40-mil HDPE liner, installing geotextile on top of FML, importing and placing 24 inches of cover soil, grading cover soil, and hydroseeding.
7. The recycle pond will be closed by dewatering the pond, excavating ash residuals (estimated at 2 feet), transporting the residuals to the ash pond, removing the dam and transporting material the to the ash pond, grading the area, and hydroseeding.
8. The site includes a river pumping station located approximately five (5) miles southeast of the Plant and a water supply pipeline, which transports intake water from the river pumping station to the Plant. These pipes will be excavated to the top of pipe, have the tops broken out, and backfilled with soil.
9. Each unit includes a dedicated parabolic cooling tower.
10. There is a small and large dry stack, each of which is shared between two (2) units (i.e., Unit 4 shares stacks with Unit 3). Half of the costs associated with demolishing the Unit 3 and Unit 4 stacks has been included in the Unit 4 decommissioning costs.
11. The asbestos cost estimate was provided by FPL which included 20 percent for contingency and 5 percent for indirects in 2013 year-dollars. BMcD removed the contingency and indirects and then escalated value to represent 2015 year-dollars.

5.2.12 St. Johns River Power Park

1. BMcD notes that FPL has percentage ownership of the plant, however, the costs presented in this Study are based on the full removal costs for the plant, with no ownership percentages applied to these values. FPL will apply their ownership percentage to determine their portion of the cost obligations.
2. The plant substation will remain and all access roads on the site that are specifically for the plant substation are not included in the decommissioning estimate.
3. All railroad spurs surrounding the Plant are included for demolition up to the main railway located approximately 0.5 miles west of the Plant.
4. The coal pile area will have 2 feet of soil excavated and replaced with clean fill covered with imported topsoil, and seeded.
5. The limestone storage area located east of the boiler units will have 2 feet of soil excavated and replaced with clean fill, covered with imported topsoil, and seeded.
6. The site includes two (2) ash landfills which will be closed by rough grading of berms and sediment for cap base, importing material for cap base, installing geotextile over base soil, installing a 40-mil HDPE liner, installing geotextile on top of FML, importing and placing 24 inches of cover soil, grading cover soil, and hydroseeding.
7. The soil contamination estimate was provided by FPL and performed by FPL's environmental team based on known contamination issues at the site. BMcD did not independently verify these estimates.
8. North of the plant is the old city landfill that is assumed to be separate from the Plant. All costs associated with this landfill have been excluded from the decommissioning costs.
9. The site includes a telecommunication tower onsite which is not owned by the Plant. This tower is assumed to remain onsite after the decommissioning of the Plant.
10. The Plant includes an unloading dock located offsite. The coal is transported from the unloading dock to the Plant via a three (3) mile conveyor. The conveyor system is assumed to be removed at time of demolition, however, the unloading dock will remain in place, and was excluded from the decommissioning costs.

5.2.13 Turkey Point

1. Due to the proximity of the two nuclear units, this facility will require specialized dismantling to minimize vibrations which may impact the safety and operation of the nuclear facility. Since explosive blast to topple the boilers and stacks will not be allowed, the crew size was adjusted to

include two (2) additional iron workers and an upgraded crane to 90 ton load. This estimate was adjusted to account for selective equipment dismantlement methodology.

2. Unit 1 and 2 are natural gas-fired boiler units which burn low-sulfur fuel oil and have no air quality control equipment.
3. Several components of the two boiler units are shared with the nuclear units. The nuclear units were excluded from this decommissioning study and therefore, any components that are integrated were excluded from this study. Such components include:
   i) Discharge canal;
   ii) 6,500 acre cooling basin located south of Turkey Point;
   iii) Water treatment facility;
   iv) Project substation;
   v) All parking lots located south of Units 1 and 2;
   vi) Steam turbine crane track south of Unit 1 and 2 (crane is included); and
   vii) Boundary fence.
4. Decommissioning estimate includes a cost of $350,000 for the removal of the firewater protection surrounding the boiler units. This value was provided by FPL and was not independently evaluated by BMcD.
5. FPL has completed several studies regarding the method and cost for dismantling the stacks for Unit 1 and 2 in order to protect from impacting the nearby nuclear units. These studies include a vibrations study which evaluates the maximum size of sections which can be dropped off the stacks in order to be below the vibrations limit of the nuclear units. Based on the findings of the studies, and as described to BMcD by FPL, BMcD prepared an estimated cost for removing the stacks based on the removal process determined from these studies.

5.2.14 West County

1. The collector switchyard equipment adjacent to the combustion turbines will be removed and all salvageable material will be scrapped including the overhead transmission lines to the plant substation. The plant substation located north of the combustion turbines will remain and all access roads on the site that are specifically for the plant substation are not included in the decommissioning estimate.
2. Cooling water piping from the steam turbine to cooling towers is assumed to be below two (2) feet and will be capped and left in place at the steam turbine and at the cooling towers. All other cooling water piping will be removed and scrapped.

5.2.15 Babcock Ranch Solar Energy Center

The following assumptions were made specific to the Babcock Ranch Solar Energy Center facility.

2. The plant is currently in the development stage. Estimates were scaled based on the DeSoto Next Generation Solar Center facility.

5.2.16 Citrus Solar Energy Center

The following assumptions were made specific to the Citrus Solar Energy Center facility.

3. The plant is currently in the development stage. Estimates were scaled based on the DeSoto Next Generation Solar Center facility.

5.2.17 Manatee Solar Energy Center

The following assumptions were made specific to the Manatee Solar Energy Center facility.

4. The plant is currently in the development stage. Estimates were scaled based on the DeSoto Next Generation Solar Center facility.

5.2.18 Okeechobee

1. The plant is currently in the development stage. Estimates were based on a typical 3-on-1"H" Class combustion turbine combined cycle plant.

5.3 Results

Table 5-1 presents a summary of the decommissioning cost for each Plant. This summary provides a breakout of the major decommissioning activities and the scrap value for the Plant. Further breakdowns of these costs are presented in Table A-1 through Table A-18 in Appendix A. BMcD has also prepared annual costs for groundwater monitoring associated with closed ash ponds and/or landfills, as presented in Table 5-2. Note that the regulatory requirement for groundwater monitoring should be for a period of 30 years following the closure.

Table 5-1: Site Decommissioning Cost (2015$)[1]

Plant	Decommissioning Costs	Credits	Net Project Cost
Cape Canaveral	$20,031,993	($4,616,199)	**$15,415,794**
DeSoto Solar	$3,009,309	($735,431)	**$2,273,878**
Ft. Myers	$41,516,932	($10,119,993)	**$31,396,939**
Lauderdale	$39,299,982	($7,864,398)	**$31,435,584**
Manatee	$73,789,541	($16,363,554)	**$57,425,987**
Martin	$113,594,115	($26,204,511)	**$87,389,603**
Port Everglades	$21,261,928	($7,317,093)	**$13,944,835**
Riviera	$17,500,262	($4,387,026)	**$13,113,236**
St. Johns River[2]	$119,600,000	($11,470,000)	**$108,130,000**
Sanford	$31,444,119	($9,043,912)	**$22,400,207**
Scherer[2,3]	$205,554,000	($9,629,000)	**$195,925,000**
Space Coast Solar	$1,150,000	($289,000)	**$861,000**
Turkey Point	$64,616,729	($13,677,173)	**$50,939,556**
West County	$54,842,211	($16,156,521)	**$38,685,690**
Babcock Ranch Solar[4]	$8,569,000	($2,152,000)	**$6,417,000**
Citrus Solar[4]	$8,569,000	($2,152,000)	**$6,417,000**
Manatee Solar[4]	$8,569,000	($2,152,000)	**$6,417,000**
Okeechobee[4]	$17,515,000	($5,560,000)	**$11,955,000**

[1] Cost estimates were rounded to the nearest $1,000 and then site inventory costs and recoverable scrap for inventory was added to the rounded estimate resulting in the values shown.
[2] Costs for Scherer and St. Johns River have not been adjusted for FPL's ownership percentage.
[3] Scherer estimate includes only Unit 4 and all common facilities.
[4] Proposed facility.

Table 5-2: Annual Groundwater Monitoring Costs (2015$)

Plant	Annual Cost
St. Johns River	$175,000
Scherer	$1,175,300

Monitoring installation costs included in decommissioning costs.

6.0 LIMITATIONS

In preparation of this decommissioning study, BMcD has relied upon information provided by Florida Power & Light. BMcD acknowledges that it has requested the information from Florida Power & Light that it deemed necessary to complete this study. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of decommissioning costs are based on Engineer's experience, qualifications and judgment. Since Engineer has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors, Engineer does not guarantee the accuracy of its estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

APPENDIX A - COST BREAKDOWNS

Table A-1
Cape Canaveral Power Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Cape Canaveral Power Plant						
Unit 1						
GTs and HRSGs	$ 2,670,000	$ 2,917,000	$ -	$ -	$ 5,587,000	$ -
Steam Turbine & Pedestal	$ 1,174,000	$ 1,282,000	$ -	$ -	$ 2,456,000	$ -
SCR	$ 135,000	$ 147,000	$ -	$ -	$ 282,000	$ -
GSU & Electrical	$ 227,000	$ 248,000	$ 54,000	$ -	$ 529,000	$ -
Stack	$ 95,000	$ 103,000	$ -	$ -	$ 198,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 182,000	$ -	$ 182,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (4,218,000)
Subtotal	**$ 4,301,000**	**$ 4,697,000**	**$ 236,000**	**$ -**	**$ 9,234,000**	**$ (4,218,000)**
Common						
Auxiliary, Switchyard and Substation	$ 31,000	$ 34,000	$ -	$ -	$ 65,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 172,000	$ 188,000	$ -	$ -	$ 360,000	$ -
Roads	$ 193,000	$ 211,000	$ 212,000	$ -	$ 616,000	$ -
All BOP Buildings	$ 521,000	$ 569,000	$ -	$ -	$ 1,090,000	$ -
Fuel Oil Storage Tanks	$ 110,000	$ 121,000	$ -	$ -	$ 231,000	$ -
All Other Tanks	$ 113,000	$ 124,000	$ -	$ -	$ 237,000	$ -
Contaminated Soil Removal	$ -	$ -	$ -	$ 101,000	$ 101,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 1,504,000	$ 1,504,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 154,000	$ 154,000	$ -
Settling Pond Closure	$ -	$ -	$ -	$ 1,085,000	$ 1,085,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 65,000	$ -	$ 65,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 137,000	$ 137,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (255,000)
Subtotal	**$ 1,140,000**	**$ 1,247,000**	**$ 278,000**	**$ 2,981,000**	**$ 5,646,000**	**$ (255,000)**
Cape Canaveral Energy Center Subtotal	**$ 5,441,000**	**$ 5,944,000**	**$ 514,000**	**$ 2,981,000**	**$ 14,880,000**	**$ (4,473,000)**
TOTAL COST (CREDIT)					**$ 14,880,000**	**$ (4,473,000)**
PROJECT INDIRECTS (5%)					**$ 744,000**	
CONTINGENGY (20%)					**$ 2,976,000**	
SITE INVENTORY COST (CREDIT)[1]					**$ 1,431,993**	**$ (143,199)**
TOTAL PROJECT COST (CREDIT)					**$ 20,031,993**	**$ (4,616,199)**
TOTAL NET PROJECT COST (CREDIT)					**$ 15,415,794**	

[1] **Site inventory costs and recoverable scrap of inventory estimates (10%) were provided by FPL and were not independently reviewed by BMcD.**

Table A-2
DeSoto Next Generation Solar Energy Center
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
DeSoto Next Generation Solar Energy Center						
Unit 1						
Demolition	$ 564,000	$ 846,000	$ -	$ -	$ 1,410,000	$ -
Collector System	$ 44,000	$ 66,000	$ -	$ -	$ 110,000	$ -
Project Buildings	$ 6,000	$ 9,000	$ -	$ -	$ 15,000	$ -
Hazardous Material Disposal	$ -	$ -	$ 393,000	$ -	$ 393,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 25,000	$ -	$ 25,000	$ -
Site Restoration	$ -	$ -	$ -	$ 300,000	$ 300,000	$ -
Debris	$ -	$ -	$ 47,000	$ -	$ 47,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (722,000)
Subtotal	**$ 614,000**	**$ 921,000**	**$ 465,000**	**$ 300,000**	**$ 2,300,000**	**$ (722,000)**
Desoto Solar Energy Center Subtotal	**$ 614,000**	**$ 921,000**	**$ 465,000**	**$ 300,000**	**$ 2,300,000**	**$ (722,000)**
TOTAL COST (CREDIT)					**$ 2,300,000**	**$ (722,000)**
PROJECT INDIRECTS (5%)					**$ 115,000**	
CONTINGENGY (20%)					**$ 460,000**	
SITE INVENTORY COST (CREDIT)[1]					**$ 134,309**	**$ (13,431)**
TOTAL PROJECT COST (CREDIT)					**$ 3,009,309**	**$ (735,431)**
TOTAL NET PROJECT COST (CREDIT)					**$ 2,273,878**	

[1] **Site inventory costs and recoverable scrap of inventory estimates (10%) were provided by FPL and were not independently reviewed by BMcD.**

Table A-3
Ft. Myers Power Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Ft. Myers Power Plant						
Unit 2						
Asbestos Removal	$ -	$ -	$ -	$ -	$ -	$ -
GTs and HRSGs	$ 4,272,000	$ 4,668,000	$ -	$ -	$ 8,940,000	$ -
Steam Turbines & Pedestals	$ 1,079,000	$ 1,179,000	$ -	$ -	$ 2,258,000	$ -
SCR	$ 144,000	$ 158,000	$ -	$ -	$ 302,000	$ -
GSUs & Electrical	$ 174,000	$ 190,000	$ 64,000	$ -	$ 428,000	$ -
Stack	$ 174,000	$ 190,000	$ -	$ -	$ 364,000	$ -
Cooling Tower and Basin	$ 136,000	$ 149,000	$ -	$ -	$ 285,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 384,000	$ -	$ 384,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (6,883,000)
Subtotal	**$ 5,979,000**	**$ 6,534,000**	**$ 448,000**	**$ -**	**$ 12,961,000**	**$ (6,883,000)**
Unit 3						
Asbestos Removal	$ -	$ -	$ -	$ -	$ -	$ -
GTs	$ 750,000	$ 820,000	$ -	$ -	$ 1,570,000	$ -
SCR	$ 110,000	$ 121,000	$ -	$ -	$ 231,000	$ -
GSUs & Electrical	$ 67,000	$ 73,000	$ 27,000	$ -	$ 167,000	$ -
Stack	$ 62,000	$ 68,000	$ -	$ -	$ 130,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 66,000	$ -	$ 66,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,090,000)
Subtotal	**$ 989,000**	**$ 1,082,000**	**$ 93,000**	**$ -**	**$ 2,164,000**	**$ (1,090,000)**
Unit 4 (Proposed 2x GE 7FA.05s)						
Turbines & Foundations	$ 947,000	$ 1,035,000	$ -	$ -	$ 1,982,000	$ -
GSU	$ 87,000	$ 95,000	$ 23,000	$ -	$ 205,000	$ -
Stack	$ 6,000	$ 6,000	$ -	$ -	$ 12,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 75,000	$ -	$ 75,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,066,000)
Subtotal	**$ 1,040,000**	**$ 1,136,000**	**$ 98,000**	**$ -**	**$ 2,274,000**	**$ (1,066,000)**
GTs 1 & 2						
Asbestos Removal	$ -	$ -	$ -	$ -	$ -	$ -
GTs & Foundations	$ 218,000	$ 238,000	$ -	$ -	$ 456,000	$ -
GSUs & Electrical	$ 15,000	$ 16,000	$ 19,000	$ -	$ 50,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 11,000	$ -	$ 11,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (338,000)
Subtotal	**$ 233,000**	**$ 254,000**	**$ 30,000**	**$ -**	**$ 517,000**	**$ (338,000)**
Common Facilities						
Asbestos Removal[1]	$ -	$ -	$ -	$ 14,000	$ 14,000	$ -
Auxiliary, Switchyard and Substation	$ 4,000	$ 5,000	$ 17,000	$ -	$ 26,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 500,000	$ 547,000	$ -	$ -	$ 1,047,000	$ -
Roads	$ 734,000	$ 802,000	$ 805,000	$ -	$ 2,341,000	$ -
All BOP Buildings	$ 861,000	$ 940,000	$ -	$ -	$ 1,801,000	$ -
Fuel Oil Storage Tanks	$ 132,000	$ 144,000	$ -	$ -	$ 276,000	$ -
All Other Tanks	$ 198,000	$ 217,000	$ -	$ -	$ 415,000	$ -
Contaminated Soil Removal	$ -	$ -	$ -	$ 167,000	$ 167,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 4,854,000	$ 4,854,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 723,000	$ 723,000	$ -
Settling Pond Closure	$ -	$ -	$ -	$ 1,036,000	$ 1,036,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 114,000	$ -	$ 114,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 369,000	$ 369,000	$ -
Debris	$ -	$ -	$ 3,000	$ -	$ 3,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (479,000)
Subtotal	**$ 2,429,000**	**$ 2,655,000**	**$ 939,000**	**$ 7,163,000**	**$ 13,186,000**	**$ (479,000)**
Ft. Myers Power Plant Subtotal	**$ 10,670,000**	**$ 11,661,000**	**$ 1,608,000**	**$ 7,163,000**	**$ 31,102,000**	**$ (9,856,000)**
TOTAL COST (CREDIT)					**$ 31,102,000**	**$ (9,856,000)**
PROJECT INDIRECTS (5%)					**$ 1,555,000**	
CONTINGENGY (20%)					**$ 6,220,000**	
SITE INVENTORY COST (CREDIT)[2]					**$ 2,639,932**	**$ (263,993)**
TOTAL PROJECT COST (CREDIT)					**$ 41,516,932**	**$ (10,119,993)**
TOTAL NET PROJECT COST (CREDIT)					**$ 31,396,939**	

[1] **Asbestos removal estimates were provided by FPL and were not independently reviewed by BMcD.**
[2] **Site inventory costs and recoverable scrap of inventory estimates (10%) were provided by FPL and were not independently reviewed by BMcD.**

Table A-4
Lauderdale Power Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Lauderdale Power Plant						
Unit 4						
GTs and HRSGs	$ 1,374,000	$ 1,501,000	$ -	$ -	$ 2,875,000	$ -
Steam Turbine & Pedestal	$ 786,000	$ 859,000	$ -	$ -	$ 1,645,000	$ -
SCR	$ 50,000	$ 54,000	$ -	$ -	$ 104,000	$ -
GSU & Electrical	$ 128,000	$ 140,000	$ 46,000	$ -	$ 314,000	$ -
Stack	$ 58,000	$ 63,000	$ -	$ -	$ 121,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 136,000	$ -	$ 136,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (2,034,000)
Subtotal	**$ 2,396,000**	**$ 2,617,000**	**$ 183,000**	**$ -**	**$ 5,196,000**	**$ (2,034,000)**
Unit 5						
GTs and HRSGs	$ 1,374,000	$ 1,501,000	$ -	$ -	$ 2,875,000	$ -
Steam Turbine & Pedestal	$ 786,000	$ 859,000	$ -	$ -	$ 1,645,000	$ -
SCR	$ 48,000	$ 52,000	$ -	$ -	$ 100,000	$ -
GSU & Electrical	$ 129,000	$ 141,000	$ 48,000	$ -	$ 318,000	$ -
Stack	$ 58,000	$ 63,000	$ -	$ -	$ 121,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 136,000	$ -	$ 136,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (2,039,000)
Subtotal	**$ 2,395,000**	**$ 2,616,000**	**$ 185,000**	**$ -**	**$ 5,196,000**	**$ (2,039,000)**
Unit 6 (Proposed 5x GE 7FA.05s)						
Turbines & Foundations	$ 2,338,000	$ 2,554,000	$ -	$ -	$ 4,892,000	$ -
GSU	$ 218,000	$ 239,000	$ 23,000	$ -	$ 480,000	$ -
Stack	$ 15,000	$ 16,000	$ -	$ -	$ 31,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 188,000	$ -	$ 188,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (2,639,000)
Subtotal	**$ 2,571,000**	**$ 2,809,000**	**$ 211,000**	**$ -**	**$ 5,591,000**	**$ (2,639,000)**
GTs 1 & 2						
Turbines & Foundations	$ 210,000	$ 229,000	$ -	$ -	$ 439,000	$ -
GSUs	$ 17,000	$ 18,000	$ 16,000	$ -	$ 51,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 10,000	$ -	$ 10,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (332,000)
Subtotal	**$ 227,000**	**$ 247,000**	**$ 26,000**	**$ -**	**$ 500,000**	**$ (332,000)**
Common						
Asbestos Removal[1]	$ -	$ -	$ -	$ 195,000	$ 195,000	$ -
Auxiliary, Switchyard and Substation	$ 14,000	$ 15,000	$ 22,000	$ -	$ 51,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 448,000	$ 490,000	$ -	$ -	$ 938,000	$ -
Roads	$ 409,000	$ 447,000	$ 449,000	$ -	$ 1,305,000	$ -
All BOP Buildings	$ 569,000	$ 621,000	$ -	$ -	$ 1,190,000	$ -
Fuel Oil Storage Tanks	$ 162,000	$ 177,000	$ -	$ -	$ 339,000	$ -
All Other Tanks	$ 230,000	$ 252,000	$ -	$ -	$ 482,000	$ -
Contaminated Soil Removal	$ -	$ -	$ -	$ 201,000	$ 201,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 2,591,000	$ 2,591,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 2,734,000	$ 2,734,000	$ -
Settling Pond Closure	$ -	$ -	$ -	$ 1,127,000	$ 1,127,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 108,000	$ -	$ 108,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 163,000	$ 163,000	$ -
Debris	$ -	$ -	$ 2,000	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (379,000)
Subtotal	**$ 1,832,000**	**$ 2,002,000**	**$ 581,000**	**$ 7,011,000**	**$ 11,426,000**	**$ (379,000)**
Lauderdale Power Plant Subtotal	**$ 9,421,000**	**$ 10,291,000**	**$ 1,186,000**	**$ 7,011,000**	**$ 27,909,000**	**$ (7,423,000)**
TOTAL COST (CREDIT)					**$ 27,909,000**	**$ (7,423,000)**
PROJECT INDIRECTS (5%)					**$ 1,395,000**	
CONTINGENGY (20%)					**$ 5,582,000**	
SITE INVENTORY COST (CREDIT)[2]					**$ 4,413,982**	**$ (441,398)**
TOTAL PROJECT COST (CREDIT)					**$ 39,299,982**	**$ (7,864,398)**
TOTAL NET PROJECT COST (CREDIT)					**$ 31,435,584**	

[1] **Asbestos removal estimates were provided by FPL and were not independently reviewed by BMcD.**
[2] **Site inventory costs and recoverable scrap of inventory estimates (10%) were provided by FPL and were not independently reviewed by BMcD.**

Table A-5
Manatee Power Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Manatee Power Plant						
Unit 1						
Boiler	$ 3,532,000	$ 3,859,000	$ -	$ -	$ 7,391,000	$ -
Steam Turbine & Building	$ 1,274,000	$ 1,392,000	$ -	$ -	$ 2,666,000	$ -
Precipitator	$ 931,000	$ 1,017,000	$ -	$ -	$ 1,948,000	$ -
Stack	$ 189,000	$ 206,000	$ -	$ -	$ 395,000	$ -
GSU & Foundation	$ 63,000	$ 69,000	$ 67,000	$ -	$ 199,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 289,000	$ -	$ 289,000	$ -
Debris	$ -	$ -	$ 52,000	$ -	$ 52,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (5,313,000)
Subtotal	**$ 5,989,000**	**$ 6,543,000**	**$ 408,000**	**$ -**	**$ 12,940,000**	**$ (5,313,000)**
Unit 2						
Boiler	$ 3,532,000	$ 3,859,000	$ -	$ -	$ 7,391,000	$ -
Steam Turbine & Building	$ 1,274,000	$ 1,392,000	$ -	$ -	$ 2,666,000	$ -
Precipitator	$ 931,000	$ 1,017,000	$ -	$ -	$ 1,948,000	$ -
Stack	$ 189,000	$ 206,000	$ -	$ -	$ 395,000	$ -
GSU & Foundation	$ 63,000	$ 69,000	$ 67,000	$ -	$ 199,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 289,000	$ -	$ 289,000	$ -
Debris	$ -	$ -	$ 52,000	$ -	$ 52,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (5,313,000)
Subtotal	**$ 5,989,000**	**$ 6,543,000**	**$ 408,000**	**$ -**	**$ 12,940,000**	**$ (5,313,000)**
Unit 3						
GTs and HRSGs	$ 2,967,000	$ 3,242,000	$ -	$ -	$ 6,209,000	$ -
Steam Turbine & Pedestal	$ 1,002,000	$ 1,095,000	$ -	$ -	$ 2,097,000	$ -
SCR	$ 97,000	$ 106,000	$ -	$ -	$ 203,000	$ -
GSU & Electrical	$ 236,000	$ 258,000	$ 57,000	$ -	$ 551,000	$ -
Stack	$ 116,000	$ 127,000	$ -	$ -	$ 243,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 174,000	$ -	$ 174,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (4,909,000)
Subtotal	**$ 4,418,000**	**$ 4,828,000**	**$ 231,000**	**$ -**	**$ 9,477,000**	**$ (4,909,000)**
Common Facilities						
Asbestos Removal[1]	$ -	$ -	$ -	$ 15,000	$ 15,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 625,000	$ 682,000	$ -	$ -	$ 1,307,000	$ -
Roads	$ 389,000	$ 425,000	$ 426,000	$ -	$ 1,240,000	$ -
All BOP Buildings	$ 768,000	$ 839,000	$ -	$ -	$ 1,607,000	$ -
Fuel Oil Storage Tanks	$ 412,000	$ 450,000	$ -	$ -	$ 862,000	$ -
All Other Tanks	$ 58,000	$ 64,000	$ -	$ -	$ 122,000	$ -
Contaminated Soil Removal[2]	$ -	$ -	$ -	$ 1,004,000	$ 1,004,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 6,937,000	$ 6,937,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 7,034,000	$ 7,034,000	$ -
Settling Pond Closure	$ -	$ -	$ -	$ 484,000	$ 484,000	$ -
Cooling Pond Closure	$ -	$ -	$ -	$ -	$ -	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 127,000	$ -	$ 127,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 344,000	$ 344,000	$ -
Debris	$ -	$ -	$ 3,000	$ -	$ 3,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (505,000)
Subtotal	**$ 2,252,000**	**$ 2,460,000**	**$ 556,000**	**$ 15,818,000**	**$ 21,086,000**	**$ (505,000)**
Manatee Power Plant Subtotal	**$ 18,648,000**	**$ 20,374,000**	**$ 1,603,000**	**$ 15,818,000**	**$ 56,443,000**	**$ (16,040,000)**
TOTAL COST (CREDIT)					**$ 56,443,000**	**$ (16,040,000)**
PROJECT INDIRECTS (5%)					**$ 2,822,000**	
CONTINGENGY (20%)					**$ 11,289,000**	
SITE INVENTORY COST (CREDIT)[3]					**$ 3,235,541**	**$ (323,554)**
TOTAL PROJECT COST (CREDIT)					**$ 73,789,541**	**$ (16,363,554)**
TOTAL NET PROJECT COST (CREDIT)					**$ 57,425,987**	

[1] **Asbestos removal estimates were provided by FPL and were not independently reviewed by BMcD.**
[2] **As provided by FPL's from estimates prepared by their Environmental Group based on areas of known soil contamination that will require remediation at the time of project dismantlement.**
[3] **Site inventory costs and recoverable scrap of inventory estimates (10%) were provided by FPL and were not independently reviewed by BMcD.**

Table A-6
Martin Energy Center
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Martin Energy Center						
Unit 1						
Boiler	$ 3,553,000	$ 3,882,000	$ -	$ -	$ 7,435,000	$ -
Steam Turbine & Building	$ 1,482,000	$ 1,619,000	$ -	$ -	$ 3,101,000	$ -
Precipitator	$ 931,000	$ 1,017,000	$ -	$ -	$ 1,948,000	$ -
Stack	$ 189,000	$ 206,000	$ -	$ -	$ 395,000	$ -
GSU & Foundation	$ 53,000	$ 58,000	$ 66,000	$ -	$ 177,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 311,000	$ -	$ 311,000	$ -
Debris	$ -	$ -	$ 52,000	$ -	$ 52,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (6,369,000)
Subtotal	**$ 6,208,000**	**$ 6,782,000**	**$ 429,000**	**$ -**	**$ 13,419,000**	**$ (6,369,000)**
Unit 2						
Boiler	$ 3,553,000	$ 3,882,000	$ -	$ -	$ 7,435,000	$ -
Steam Turbine & Building	$ 1,482,000	$ 1,619,000	$ -	$ -	$ 3,101,000	$ -
Precipitator	$ 931,000	$ 1,017,000	$ -	$ -	$ 1,948,000	$ -
Stack	$ 189,000	$ 206,000	$ -	$ -	$ 395,000	$ -
GSU & Foundation	$ 53,000	$ 58,000	$ 66,000	$ -	$ 177,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 311,000	$ -	$ 311,000	$ -
Debris	$ -	$ -	$ 52,000	$ -	$ 52,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (6,369,000)
Subtotal	**$ 6,208,000**	**$ 6,782,000**	**$ 429,000**	**$ -**	**$ 13,419,000**	**$ (6,369,000)**
Unit 3						
GTs and HRSGs	$ 1,381,000	$ 1,509,000	$ -	$ -	$ 2,890,000	$ -
Steam Turbine & Pedestal	$ 420,000	$ 459,000	$ -	$ -	$ 879,000	$ -
SCR	$ 48,000	$ 53,000	$ -	$ -	$ 101,000	$ -
GSU & Electrical	$ 120,000	$ 132,000	$ 26,000	$ -	$ 278,000	$ -
Stack	$ 62,000	$ 67,000	$ -	$ -	$ 129,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 90,000	$ -	$ 90,000	$ -
Debris	$ -	$ -	$ -	$ -	$ -	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (2,508,000)
Subtotal	**$ 2,031,000**	**$ 2,220,000**	**$ 116,000**	**$ -**	**$ 4,367,000**	**$ (2,508,000)**
Unit 4						
GTs and HRSGs	$ 1,378,000	$ 1,506,000	$ -	$ -	$ 2,884,000	$ -
Steam Turbine & Pedestal	$ 406,000	$ 443,000	$ -	$ -	$ 849,000	$ -
SCR	$ 48,000	$ 53,000	$ -	$ -	$ 101,000	$ -
GSU & Electrical	$ 107,000	$ 117,000	$ 21,000	$ -	$ 245,000	$ -
Stack	$ 62,000	$ 67,000	$ -	$ -	$ 129,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 90,000	$ -	$ 90,000	$ -
Debris	$ -	$ -	$ -	$ -	$ -	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (2,415,000)
Subtotal	**$ 2,001,000**	**$ 2,186,000**	**$ 111,000**	**$ -**	**$ 4,298,000**	**$ (2,415,000)**
Unit 8						
GTs and HRSGs	$ 2,971,000	$ 3,246,000	$ -	$ -	$ 6,217,000	$ -
Steam Turbine & Pedestal	$ 887,000	$ 970,000	$ -	$ -	$ 1,857,000	$ -
SCR	$ 97,000	$ 106,000	$ -	$ -	$ 203,000	$ -
GSU & Electrical	$ 174,000	$ 190,000	$ 53,000	$ -	$ 417,000	$ -
Stack	$ 116,000	$ 127,000	$ -	$ -	$ 243,000	$ -
Cooling Tower and Basin	$ 240,000	$ 262,000	$ -	$ -	$ 502,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 232,000	$ -	$ 232,000	$ -
Debris	$ -	$ -	$ 14,000	$ -	$ 14,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (5,231,000)
Subtotal	**$ 4,485,000**	**$ 4,901,000**	**$ 299,000**	**$ -**	**$ 9,685,000**	**$ (5,231,000)**
ISCC						
Mirrors and Frames	$ 4,151,000	$ 4,535,000	$ -	$ -	$ 8,686,000	$ -
Hazardous Waste Disposal	$ -	$ -	$ 1,160,000	$ -	$ 1,160,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 278,000	$ -	$ 278,000	$ -
Debris	$ -	$ -	$ 205,000	$ -	$ 205,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,809,000)
Subtotal	**$ 4,151,000**	**$ 4,535,000**	**$ 1,643,000**	**$ -**	**$ 10,329,000**	**$ (1,809,000)**
Common						
Asbestos Removal[1]	$ -	$ -	$ -	$ 241,000	$ 241,000	$ -
Switchyard and Substation	$ 21,000	$ 23,000	$ 24,000	$ -	$ 68,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 1,188,000	$ 1,298,000	$ -	$ -	$ 2,486,000	$ -
Roads	$ 959,000	$ 1,048,000	$ 1,052,000	$ -	$ 3,059,000	$ -
All BOP Buildings	$ 1,154,000	$ 1,260,000	$ -	$ -	$ 2,414,000	$ -
Fuel Oil Storage Tanks	$ 2,001,000	$ 2,187,000	$ -	$ -	$ 4,188,000	$ -
All Other Tanks	$ 72,000	$ 78,000	$ -	$ -	$ 150,000	$ -
Contaminated Soil Removal	$ -	$ -	$ -	$ 619,000	$ 619,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 7,444,000	$ 7,444,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 4,537,000	$ 4,537,000	$ -
Settling Pond Closure	$ -	$ -	$ -	$ 2,676,000	$ 2,676,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 365,000	$ -	$ 365,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 886,000	$ 886,000	$ -
Debris	$ -	$ -	$ 5,000	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (726,000)
Subtotal	**$ 5,395,000**	**$ 5,894,000**	**$ 1,446,000**	**$ 16,403,000**	**$ 29,138,000**	**$ (726,000)**
Martin Energy Center Subtotal	**$ 30,479,000**	**$ 33,300,000**	**$ 4,473,000**	**$ 16,403,000**	**$ 84,655,000**	**$ (25,427,000)**
TOTAL COST (CREDIT)					**$ 84,655,000**	**$ (25,427,000)**
PROJECT INDIRECTS (5%)					**$ 4,233,000**	
CONTINGENGY (20%)					**$ 16,931,000**	
SITE INVENTORY COST (CREDIT)[2]					**$ 7,775,115**	**$ (777,511)**
TOTAL PROJECT COST (CREDIT)					**$ 113,594,115**	**$ (26,204,511)**
TOTAL NET PROJECT COST (CREDIT)					**$ 87,389,603**	

[1] Asbestos removal estimates were provided by FPL and were not independently reviewed by BMcD.

[2] Site inventory costs and recoverable scrap of inventory estimates (10%) were provided by FPL and were not independently reviewed by BMcD.

Table A-7
Port Everglades Power Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Port Everglades Power Plant						
Unit 5						
GTs and HRSGs	$ 2,646,000	$ 2,891,000	$ -	$ -	$ 5,537,000	$ -
Steam Turbine & Pedestal	$ 1,116,000	$ 1,219,000	$ -	$ -	$ 2,335,000	$ -
SCR	$ 135,000	$ 147,000	$ -	$ -	$ 282,000	$ -
GSU & Electrical	$ 191,000	$ 208,000	$ 79,000	$ -	$ 478,000	$ -
Stack	$ 95,000	$ 103,000	$ -	$ -	$ 198,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 179,000	$ -	$ 179,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (4,986,000)
Subtotal	**$ 4,183,000**	**$ 4,568,000**	**$ 258,000**	**$ -**	**$ 9,009,000**	**$ (4,986,000)**
GTs 1-12						
Turbines & Foundations	$ 1,377,000	$ 1,504,000	$ -	$ -	$ 2,881,000	$ -
GSUs	$ 75,000	$ 82,000	$ 12,000	$ -	$ 169,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 96,000	$ -	$ 96,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,931,000)
Subtotal	**$ 1,452,000**	**$ 1,586,000**	**$ 108,000**	**$ -**	**$ 3,146,000**	**$ (1,931,000)**
Common						
Auxiliary, Switchyard and Substation	$ 67,000	$ 73,000	$ 51,000	$ -	$ 191,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 144,000	$ 157,000	$ -	$ -	$ 301,000	$ -
Roads	$ 124,000	$ 135,000	$ 136,000	$ -	$ 395,000	$ -
All BOP Buildings	$ 110,000	$ 120,000	$ -	$ -	$ 230,000	$ -
Fuel Oil Storage Tanks	$ 521,000	$ 570,000	$ -	$ -	$ 1,091,000	$ -
All Other Tanks	$ 115,000	$ 125,000	$ -	$ -	$ 240,000	$ -
Contaminated Soil Removal	$ -	$ -	$ -	$ 147,000	$ 147,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 1,488,000	$ 1,488,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 288,000	$ 288,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 66,000	$ -	$ 66,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 228,000	$ 228,000	$ -
Debris	$ -	$ -	$ 5,000	$ -	$ 5,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (377,000)
Subtotal	**$ 1,081,000**	**$ 1,180,000**	**$ 258,000**	**$ 2,151,000**	**$ 4,670,000**	**$ (377,000)**
Port Everglades Subtotal	**$ 6,716,000**	**$ 7,334,000**	**$ 624,000**	**$ 2,151,000**	**$ 16,825,000**	**$ (7,294,000)**
TOTAL COST (CREDIT)					**$ 16,825,000**	**$ (7,294,000)**
PROJECT INDIRECTS (5%)					**$ 841,000**	
CONTINGENGY (20%)					**$ 3,365,000**	
SITE INVENTORY COST (CREDIT)[1]					**$ 230,928**	**$ (23,093)**
TOTAL PROJECT COST (CREDIT)					**$ 21,261,928**	**$ (7,317,093)**
TOTAL NET PROJECT COST (CREDIT)					**$ 13,944,835**	

[1] **Site inventory costs and recoverable scrap of inventory estimates (10%) were provided by FPL and were not independently reviewed by BMcD.**

Table A-8
Riviera Beach Power Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Riviera Beach Power Plant						
Unit 5						
GTs and HRSGs	$ 2,670,000	$ 2,917,000	$ -	$ -	$ 5,587,000	$ -
Steam Turbine & Pedestal	$ 1,124,000	$ 1,229,000	$ -	$ -	$ 2,353,000	$ -
SCR	$ 135,000	$ 147,000	$ -	$ -	$ 282,000	$ -
GSU & Electrical	$ 181,000	$ 197,000	$ 41,000	$ -	$ 419,000	$ -
Stack	$ 95,000	$ 103,000	$ -	$ -	$ 198,000	$ -
Cooling Tower and Basin	$ -	$ -	$ -	$ -	$ -	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 180,000	$ -	$ 180,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (4,024,000)
Subtotal	**$ 4,205,000**	**$ 4,593,000**	**$ 221,000**	**$ -**	**$ 9,019,000**	**$ (4,024,000)**
Common						
Auxiliary, Switchyard and Substation	$ 20,000	$ 22,000	$ -	$ -	$ 42,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 58,000	$ 63,000	$ -	$ -	$ 121,000	$ -
Roads	$ 126,000	$ 138,000	$ 138,000	$ -	$ 402,000	$ -
All BOP Buildings	$ 508,000	$ 555,000	$ -	$ -	$ 1,063,000	$ -
Fuel Oil Storage Tanks	$ 104,000	$ 114,000	$ -	$ -	$ 218,000	$ -
All Other Tanks	$ 112,000	$ 122,000	$ -	$ -	$ 234,000	$ -
Contaminated Soil Removal	$ -	$ -	$ -	$ 101,000	$ 101,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 1,504,000	$ 1,504,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 144,000	$ 144,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 51,000	$ -	$ 51,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 164,000	$ 164,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (246,000)
Subtotal	**$ 928,000**	**$ 1,014,000**	**$ 190,000**	**$ 1,913,000**	**$ 4,045,000**	**$ (246,000)**
Riviera Beach Power Plant Subtotal	**$ 5,133,000**	**$ 5,607,000**	**$ 411,000**	**$ 1,913,000**	**$ 13,064,000**	**$ (4,270,000)**
TOTAL COST (CREDIT)					**$ 13,064,000**	**$ (4,270,000)**
PROJECT INDIRECTS (5%)					**$ 653,000**	
CONTINGENGY (20%)					**$ 2,613,000**	
SITE INVENTORY COST (CREDIT)[1]					**$ 1,170,262**	**$ (117,026)**
TOTAL PROJECT COST (CREDIT)					**$ 17,500,262**	**$ (4,387,026)**
TOTAL NET PROJECT COST (CREDIT)					**$ 13,113,236**	

[1] **Site inventory costs and recoverable scrap of inventory estimates (10%) were provided by FPL and were not independently reviewed by BMcD.**

Table A-9
St. Johns River Power Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
St. Johns River Power Plant						
Unit 1						
Boiler	$ 3,620,000	$ 3,955,000	$ -	$ -	$ 7,575,000	$ -
Steam Turbine & Building	$ 1,518,000	$ 1,659,000	$ -	$ -	$ 3,177,000	$ -
Precipitator	$ 1,283,000	$ 1,402,000	$ -	$ -	$ 2,685,000	$ -
SCR/FGD	$ 1,059,000	$ 1,157,000	$ -	$ -	$ 2,216,000	$ -
Scrubbers	$ 219,000	$ 240,000	$ -	$ -	$ 459,000	$ -
Stack	$ 79,000	$ 86,000	$ -	$ -	$ 165,000	$ -
Cooling Tower & Basins	$ 244,000	$ 267,000	$ -	$ -	$ 511,000	$ -
GSU & Foundation	$ 143,000	$ 156,000	$ 78,000	$ -	$ 377,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 534,000	$ -	$ 534,000	$ -
Debris	$ -	$ -	$ 24,000	$ -	$ 24,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (5,455,000)
Subtotal	**$ 8,165,000**	**$ 8,922,000**	**$ 636,000**	**$ -**	**$ 17,723,000**	**$ (5,455,000)**
Unit 2						
Boiler	$ 3,620,000	$ 3,955,000	$ -	$ -	$ 7,575,000	$ -
Steam Turbine & Building	$ 1,518,000	$ 1,659,000	$ -	$ -	$ 3,177,000	$ -
Precipitator	$ 1,283,000	$ 1,402,000	$ -	$ -	$ 2,685,000	$ -
SCR/FGD	$ 1,059,000	$ 1,157,000	$ -	$ -	$ 2,216,000	$ -
Scrubbers	$ 219,000	$ 240,000	$ -	$ -	$ 459,000	$ -
Stack	$ 79,000	$ 86,000	$ -	$ -	$ 165,000	$ -
Cooling Tower & Basins	$ 244,000	$ 267,000	$ -	$ -	$ 511,000	$ -
GSU & Foundation	$ 143,000	$ 156,000	$ 78,000	$ -	$ 377,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 534,000	$ -	$ 534,000	$ -
Debris	$ -	$ -	$ 24,000	$ -	$ 24,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (5,455,000)
Subtotal	**$ 8,165,000**	**$ 8,922,000**	**$ 636,000**	**$ -**	**$ 17,723,000**	**$ (5,455,000)**
Handling						
Demolition	$ 1,613,000	$ 1,762,000	$ -	$ -	$ 3,375,000	$ -
Limestone Handling Facilities	$ 555,000	$ 606,000	$ -	$ -	$ 1,161,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 134,000	$ -	$ 134,000	$ -
Debris	$ -	$ -	$ 23,000	$ -	$ 23,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (64,000)
Subtotal	**$ 2,168,000**	**$ 2,368,000**	**$ 157,000**	**$ -**	**$ 4,693,000**	**$ (64,000)**
Common						
Auxiliary, Switchyard and Substation	$ 40,000	$ 44,000	$ 34,000	$ -	$ 118,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 127,000	$ 138,000	$ -	$ -	$ 265,000	$ -
Roads	$ 778,000	$ 850,000	$ 854,000	$ -	$ 2,482,000	$ -
All BOP Buildings	$ 1,092,000	$ 1,193,000	$ -	$ -	$ 2,285,000	$ -
Fuel Oil Storage Tanks	$ 89,000	$ 98,000	$ -	$ -	$ 187,000	$ -
All Other Tanks	$ 91,000	$ 99,000	$ -	$ -	$ 190,000	$ -
Contaminated Soil Removal[1]	$ -	$ -	$ -	$ 178,000	$ 178,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 92,000	$ 92,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 381,000	$ 381,000	$ -
Plant Washdown & Materials Disposal	$ -	$ -	$ -	$ 313,000	$ 313,000	$ -
Closure of Ash Landfill	$ -	$ -	$ -	$ 44,550,000	$ 44,550,000	$ -
Closure of Limestone Area	$ -	$ -	$ -	$ 153,000	$ 153,000	$ -
Closure of Stormwater and Wastewater Ponds	$ -	$ -	$ -	$ 733,000	$ 733,000	$ -
Closure of Other Ponds	$ -	$ -	$ -	$ 2,156,000	$ 2,156,000	$ -
Groundwater Monitoring Installation	$ -	$ -	$ -	$ 388,000	$ 388,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 105,000	$ -	$ 105,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 959,000	$ 959,000	$ -
Debris	$ -	$ -	$ 6,000	$ -	$ 6,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (496,000)
Subtotal	**$ 2,217,000**	**$ 2,422,000**	**$ 999,000**	**$ 49,903,000**	**$ 55,541,000**	**$ (496,000)**
St. Johns River Power Plant Subtotal	**$ 20,715,000**	**$ 22,634,000**	**$ 2,428,000**	**$ 49,903,000**	**$ 95,680,000**	**$ (11,470,000)**
TOTAL COST (CREDIT)					**$ 95,680,000**	**$ (11,470,000)**
PROJECT INDIRECTS (5%)					**$ 4,784,000**	
CONTINGENGY (20%)					**$ 19,136,000**	
TOTAL PROJECT COST (CREDIT)					**$ 119,600,000**	**$ (11,470,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 108,130,000**	

[1] As provided by FPL's from estimates prepared by their Environmental Group based on areas of known soil contamination that will require remediation at the time of project dismantlement.

Table A-10
Sanford Energy Center
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Sanford Energy Center						
Unit 4						
GTs and HRSGs	$ 2,739,000	$ 2,992,000	$ -	$ -	$ 5,731,000	$ -
Steam Turbine & Pedestal	$ 925,000	$ 1,010,000	$ -	$ -	$ 1,935,000	$ -
SCR	$ 97,000	$ 106,000	$ -	$ -	$ 203,000	$ -
GSU & Electrical	$ 154,000	$ 168,000	$ 37,000	$ -	$ 359,000	$ -
Stack	$ 116,000	$ 127,000	$ -	$ -	$ 243,000	$ -
Cooling Tower	$ 18,000	$ 20,000	$ -	$ -	$ 38,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 180,000	$ -	$ 180,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (4,248,000)
Subtotal	**$ 4,049,000**	**$ 4,423,000**	**$ 217,000**	**$ -**	**$ 8,689,000**	**$ (4,248,000)**
Unit 5						
GTs and HRSGs	$ 2,739,000	$ 2,992,000	$ -	$ -	$ 5,731,000	$ -
Steam Turbine & Pedestal	$ 914,000	$ 999,000	$ -	$ -	$ 1,913,000	$ -
SCR	$ 97,000	$ 106,000	$ -	$ -	$ 203,000	$ -
GSU & Electrical	$ 149,000	$ 163,000	$ 37,000	$ -	$ 349,000	$ -
Stack	$ 116,000	$ 127,000	$ -	$ -	$ 243,000	$ -
Cooling Tower	$ 18,000	$ 20,000	$ -	$ -	$ 38,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 180,000	$ -	$ 180,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (4,235,000)
Subtotal	**$ 4,033,000**	**$ 4,407,000**	**$ 217,000**	**$ -**	**$ 8,657,000**	**$ (4,235,000)**
Common						
Asbestos Removal[1]	$ -	$ -	$ -	$ 50,000	$ 50,000	$ -
Switchyard and Substation	$ 25,000	$ 27,000	$ 35,000	$ -	$ 87,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 34,000	$ 37,000	$ -	$ -	$ 71,000	$ -
Roads	$ 422,000	$ 461,000	$ 463,000	$ -	$ 1,346,000	$ -
All BOP Buildings	$ 166,000	$ 182,000	$ -	$ -	$ 348,000	$ -
Fuel Oil Storage Tanks	$ 329,000	$ 359,000	$ -	$ -	$ 688,000	$ -
All Other Tanks	$ 45,000	$ 49,000	$ -	$ -	$ 94,000	$ -
Contaminated Soil Removal	$ -	$ -	$ -	$ 167,000	$ 167,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 2,566,000	$ 2,566,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 282,000	$ 282,000	$ -
Settling Pond Closure	$ -	$ -	$ -	$ 244,000	$ 244,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 26,000	$ -	$ 26,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 351,000	$ 351,000	$ -
Debris	$ -	$ -	$ 2,000	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (375,000)
Subtotal	**$ 1,021,000**	**$ 1,115,000**	**$ 526,000**	**$ 3,660,000**	**$ 6,322,000**	**$ (375,000)**
Sanford Energy Center Subtotal	**$ 9,103,000**	**$ 9,945,000**	**$ 960,000**	**$ 3,660,000**	**$ 23,668,000**	**$ (8,858,000)**
TOTAL COST (CREDIT)					**$ 23,668,000**	**$ (8,858,000)**
PROJECT INDIRECTS (5%)					**$ 1,183,000**	
CONTINGENGY (20%)					**$ 4,734,000**	
SITE INVENTORY COST (CREDIT)[2]					**$ 1,859,119**	**$ (185,912)**
TOTAL PROJECT COST (CREDIT)					**$ 31,444,119**	**$ (9,043,912)**
TOTAL NET PROJECT COST (CREDIT)					**$ 22,400,207**	

[1] **Asbestos removal estimates were provided by FPL and were not independently reviewed by BMcD.**
[2] **Site inventory costs and recoverable scrap of inventory estimates (10%) were provided by FPL and were not independently reviewed by BMcD.**

Table A-11
Scherer Power Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Scherer Power Plant						
Unit 4						
Boiler	$ 4,520,000	$ 5,984,000	$ -	$ -	$ 10,504,000	$ -
Steam Turbine & Building	$ 1,564,000	$ 2,071,000	$ -	$ -	$ 3,635,000	$ -
Precipitator	$ 503,000	$ 666,000	$ -	$ -	$ 1,169,000	$ -
SCR	$ 1,590,000	$ 2,106,000	$ -	$ -	$ 3,696,000	$ -
FGD	$ 286,000	$ 379,000	$ -	$ -	$ 665,000	$ -
Baghouse	$ 339,000	$ 449,000	$ -	$ -	$ 788,000	$ -
Stacks	$ 174,000	$ 231,000	$ -	$ -	$ 405,000	$ -
Cooling Towers & Basin	$ 210,000	$ 278,000	$ -	$ -	$ 488,000	$ -
GSU & Foundation	$ 57,000	$ 75,000	$ 66,000	$ -	$ 198,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 802,000	$ -	$ 802,000	$ -
Debris	$ -	$ -	$ 37,000	$ -	$ 37,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (7,274,000)
Subtotal	**$ 9,243,000**	**$ 12,239,000**	**$ 905,000**	**$ -**	**$ 22,387,000**	**$ (7,274,000)**
Handling						
Demolition	$ 1,004,000	$ 1,329,000	$ -	$ -	$ 2,333,000	$ -
Limestone Handling Facilities	$ 212,000	$ 280,000	$ -	$ -	$ 492,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 33,000	$ -	$ 33,000	$ -
Debris	$ -	$ -	$ 70,000	$ -	$ 70,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (897,000)
Subtotal	**$ 1,216,000**	**$ 1,609,000**	**$ 103,000**	**$ -**	**$ 2,928,000**	**$ (897,000)**
Common						
Auxiliary, Switchyard and Substation	$ 164,000	$ 217,000	$ 62,000	$ -	$ 443,000	$ -
Asbestos Removal[1]	$ -	$ -	$ -	$ 14,571,000	$ 14,571,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 173,000	$ 229,000	$ -	$ -	$ 402,000	$ -
Roads	$ 1,133,000	$ 1,500,000	$ 1,506,000	$ -	$ 4,139,000	$ -
All BOP Buildings	$ 1,069,000	$ 1,415,000	$ -	$ -	$ 2,484,000	$ -
Fuel Oil Storage Tanks	$ 163,000	$ 216,000	$ -	$ -	$ 379,000	$ -
All Other Tanks	$ 153,000	$ 202,000	$ -	$ -	$ 355,000	$ -
Contaminated Soil Removal	$ -	$ -	$ -	$ 16,000	$ 16,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 119,000	$ 119,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 1,200,000	$ 1,200,000	$ -
Plant Washdown & Materials Disposal (Unit 4)	$ -	$ -	$ -	$ 248,000	$ 248,000	$ -
Closure of Ash Ponds and Landfills	$ -	$ -	$ -	$ 107,992,000	$ 107,992,000	$ -
Closure of Other Ponds	$ -	$ -	$ -	$ 2,514,000	$ 2,514,000	$ -
Limestone Area Closure	$ -	$ -	$ -	$ 167,000	$ 167,000	$ -
Groundwater Monitoring Installation	$ -	$ -	$ -	$ 1,823,000	$ 1,823,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 172,000	$ -	$ 172,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 2,097,000	$ 2,097,000	$ -
Debris	$ -	$ -	$ 7,000	$ -	$ 7,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,458,000)
Subtotal	**$ 2,855,000**	**$ 3,779,000**	**$ 1,747,000**	**$ 130,747,000**	**$ 139,128,000**	**$ (1,458,000)**
Scherer Power Plant Subtotal	**$ 13,314,000**	**$ 17,627,000**	**$ 2,755,000**	**$ 130,747,000**	**$ 164,443,000**	**$ (9,629,000)**
TOTAL COST (CREDIT)					**$ 164,443,000**	**$ (9,629,000)**
PROJECT INDIRECTS (5%)					**$ 8,222,000**	
CONTINGENGY (20%)					**$ 32,889,000**	
TOTAL PROJECT COST (CREDIT)					**$ 205,554,000**	**$ (9,629,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 195,925,000**	

[1] **Asbestos removal estimates were provided by FPL and were not independently reviewed by BMcD.**

Table A-12
Space Coast Next Generation Solar Energy Center
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Space Coast Next Generation Solar Energy Center						
Unit 1						
Demolition	$ 226,000	$ 338,000	$ -	$ -	$ 564,000	$ -
Collector System	$ 18,000	$ 26,000	$ -	$ -	$ 44,000	$ -
Project Buildings	$ 2,000	$ 4,000	$ -	$ -	$ 6,000	$ -
Hazardous Material Disposal	$ -	$ -	$ 157,000	$ -	$ 157,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 10,000	$ -	$ 10,000	$ -
Site Restoration	$ -	$ -	$ -	$ 120,000	$ 120,000	$ -
Debris	$ -	$ -	$ 19,000	$ -	$ 19,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (289,000)
Subtotal	**$ 246,000**	**$ 368,000**	**$ 186,000**	**$ 120,000**	**$ 920,000**	**$ (289,000)**
Space Coast Next Generation Solar Energy Center Subtotal	**$ 246,000**	**$ 368,000**	**$ 186,000**	**$ 120,000**	**$ 920,000**	**$ (289,000)**
TOTAL COST (CREDIT)					**$ 920,000**	**$ (289,000)**
PROJECT INDIRECTS (5%)					**$ 46,000**	
CONTINGENGY (20%)					**$ 184,000**	
TOTAL PROJECT COST (CREDIT)					**$ 1,150,000**	**$ (289,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 861,000**	

Table A-13
Turkey Point Power Plant
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Turkey Point Power Plant						
Unit 1						
Boiler	$ 5,038,000	$ 4,695,000	$ -	$ -	$ 9,733,000	$ -
Steam Turbine & Building	$ 801,000	$ 774,000	$ -	$ -	$ 1,575,000	$ -
Stack	$ 1,324,000	$ 1,278,000	$ -	$ -	$ 2,602,000	$ -
GSU & Foundation	$ 33,000	$ 32,000	$ 51,000	$ -	$ 116,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 228,000	$ -	$ 228,000	$ -
Debris	$ -	$ -	$ 38,000	$ -	$ 38,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (3,488,000)
Subtotal	**$ 7,196,000**	**$ 6,779,000**	**$ 317,000**	**$ -**	**$ 14,292,000**	**$ (3,488,000)**
Unit 2						
Boiler	$ 5,038,000	$ 4,695,000	$ -	$ -	$ 9,733,000	$ -
Steam Turbine & Building	$ 801,000	$ 774,000	$ -	$ -	$ 1,575,000	$ -
Stack	$ 1,324,000	$ 1,278,000	$ -	$ -	$ 2,602,000	$ -
GSU & Foundation	$ 33,000	$ 32,000	$ 51,000	$ -	$ 116,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 228,000	$ -	$ 228,000	$ -
Debris	$ -	$ -	$ 38,000	$ -	$ 38,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (3,488,000)
Subtotal	**$ 7,196,000**	**$ 6,779,000**	**$ 317,000**	**$ -**	**$ 14,292,000**	**$ (3,488,000)**
Unit 5						
GTs and HRSGs	$ 5,017,000	$ 4,844,000	$ -	$ -	$ 9,861,000	$ -
Steam Turbine & Pedestal	$ 1,001,000	$ 966,000	$ -	$ -	$ 1,967,000	$ -
SCR	$ 216,000	$ 209,000	$ -	$ -	$ 425,000	$ -
GSU & Electrical	$ 153,000	$ 148,000	$ 70,000	$ -	$ 371,000	$ -
Stack	$ 130,000	$ 125,000	$ -	$ -	$ 255,000	$ -
Cooling Tower and Basin	$ 137,000	$ 133,000	$ -	$ -	$ 270,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 167,000	$ -	$ 167,000	$ -
Debris	$ -	$ -	$ -	$ -	$ -	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (6,130,000)
Subtotal	**$ 6,654,000**	**$ 6,425,000**	**$ 237,000**	**$ -**	**$ 13,316,000**	**$ (6,130,000)**
Common						
Auxiliary, Switchyard and Substation	$ 14,000	$ 14,000	$ 33,000	$ -	$ 61,000	$ -
Asbestos Removal[1]	$ -	$ -	$ -	$ 859,000	$ 859,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 68,000	$ 66,000	$ -	$ -	$ 134,000	$ -
Cooling Water Discharge Canal	$ 73,000	$ 70,000	$ -	$ -	$ 143,000	$ -
Roads	$ 458,000	$ 442,000	$ 450,000	$ -	$ 1,350,000	$ -
All BOP Buildings	$ 426,000	$ 411,000	$ -	$ -	$ 837,000	$ -
Fuel Oil Storage Tanks	$ 683,000	$ 659,000	$ -	$ -	$ 1,342,000	$ -
All Other Tanks	$ 85,000	$ 82,000	$ -	$ -	$ 167,000	$ -
Contaminated Soil Removal	$ -	$ -	$ -	$ 228,000	$ 228,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 2,151,000	$ 2,151,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 60,000	$ 60,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 93,000	$ -	$ 93,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 293,000	$ 293,000	$ -
Debris	$ -	$ -	$ 2,000	$ -	$ 2,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (312,000)
Subtotal	**$ 1,807,000**	**$ 1,744,000**	**$ 578,000**	**$ 3,591,000**	**$ 7,720,000**	**$ (312,000)**
Turkey Point Subtotal	**$ 22,853,000**	**$ 21,727,000**	**$ 1,449,000**	**$ 3,591,000**	**$ 49,620,000**	**$ (13,418,000)**
TOTAL COST (CREDIT)					**$ 49,620,000**	**$ (13,418,000)**
PROJECT INDIRECTS (5%)					**$ 2,481,000**	
CONTINGENGY (20%)					**$ 9,924,000**	
SITE INVENTORY COST (CREDIT)[2]					**$ 2,591,729**	**$ (259,173)**
TOTAL PROJECT COST (CREDIT)					**$ 64,616,729**	**$ (13,677,173)**
TOTAL NET PROJECT COST (CREDIT)					**$ 50,939,556**	

[1] **Asbestos removal estimates were provided by FPL and were not independently reviewed by BMcD.**
[2] **Site inventory costs and recoverable scrap of inventory estimates (10%) were provided by FPL and were not independently reviewed by BMcD.**

Table A-14
West County Energy Center
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
West County Energy Center						
Unit 1						
GTs and HRSGs	$ 2,625,000	$ 2,869,000	$ -	$ -	$ 5,494,000	$ -
Steam Turbine & Pedestal	$ 990,000	$ 1,082,000	$ -	$ -	$ 2,072,000	$ -
SCR	$ 93,000	$ 101,000	$ -	$ -	$ 194,000	$ -
GSU & Electrical	$ 262,000	$ 286,000	$ 82,000	$ -	$ 630,000	$ -
Stack	$ 95,000	$ 103,000	$ -	$ -	$ 198,000	$ -
Cooling Tower and Basin	$ 302,000	$ 329,000	$ -	$ -	$ 631,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 242,000	$ -	$ 242,000	$ -
Debris	$ -	$ -	$ -	$ -	$ -	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (5,047,000)
Subtotal	**$ 4,367,000**	**$ 4,770,000**	**$ 324,000**	**$ -**	**$ 9,461,000**	**$ (5,047,000)**
Unit 2						
GTs and HRSGs	$ 2,625,000	$ 2,869,000	$ -	$ -	$ 5,494,000	$ -
Steam Turbine & Pedestal	$ 990,000	$ 1,082,000	$ -	$ -	$ 2,072,000	$ -
SCR	$ 93,000	$ 101,000	$ -	$ -	$ 194,000	$ -
GSU & Electrical	$ 278,000	$ 303,000	$ 82,000	$ -	$ 663,000	$ -
Stack	$ 95,000	$ 103,000	$ -	$ -	$ 198,000	$ -
Cooling Tower and Basin	$ 302,000	$ 329,000	$ -	$ -	$ 631,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 242,000	$ -	$ 242,000	$ -
Debris	$ -	$ -	$ -	$ -	$ -	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (5,060,000)
Subtotal	**$ 4,383,000**	**$ 4,787,000**	**$ 324,000**	**$ -**	**$ 9,494,000**	**$ (5,060,000)**
Unit 3						
GTs and HRSGs	$ 2,625,000	$ 2,869,000	$ -	$ -	$ 5,494,000	$ -
Steam Turbine & Pedestal	$ 990,000	$ 1,082,000	$ -	$ -	$ 2,072,000	$ -
SCR	$ 93,000	$ 101,000	$ -	$ -	$ 194,000	$ -
GSU & Electrical	$ 293,000	$ 320,000	$ 82,000	$ -	$ 695,000	$ -
Stack	$ 95,000	$ 103,000	$ -	$ -	$ 198,000	$ -
Cooling Tower and Basin	$ 302,000	$ 329,000	$ -	$ -	$ 631,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 242,000	$ -	$ 242,000	$ -
Debris	$ -	$ -	$ -	$ -	$ -	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (5,073,000)
Subtotal	**$ 4,398,000**	**$ 4,804,000**	**$ 324,000**	**$ -**	**$ 9,526,000**	**$ (5,073,000)**
Common						
Auxiliary, Switchyard and Substation	$ 134,000	$ 147,000	$ 31,000	$ -	$ 312,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 89,000	$ 98,000	$ -	$ -	$ 187,000	$ -
Roads	$ 535,000	$ 585,000	$ 587,000	$ -	$ 1,707,000	$ -
All BOP Buildings	$ 502,000	$ 548,000	$ -	$ -	$ 1,050,000	$ -
Fuel Oil Storage Tanks	$ 1,164,000	$ 1,271,000	$ -	$ -	$ 2,435,000	$ -
All Other Tanks	$ 138,000	$ 151,000	$ -	$ -	$ 289,000	$ -
Contaminated Soil Removal	$ -	$ -	$ -	$ 253,000	$ 253,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 2,835,000	$ 2,835,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 1,688,000	$ 1,688,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 156,000	$ -	$ 156,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 699,000	$ 699,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (504,000)
Subtotal	**$ 2,562,000**	**$ 2,800,000**	**$ 775,000**	**$ 5,475,000**	**$ 11,612,000**	**$ (504,000)**
West County Energy Center Subtotal	**$ 15,710,000**	**$ 17,161,000**	**$ 1,747,000**	**$ 5,475,000**	**$ 40,093,000**	**$ (15,684,000)**
TOTAL COST (CREDIT)					**$ 40,093,000**	**$ (15,684,000)**
PROJECT INDIRECTS (5%)					**$ 2,005,000**	
CONTINGENGY (20%)					**$ 8,019,000**	
SITE INVENTORY COST (CREDIT)[1]					**$ 4,725,211**	**$ (472,521)**
TOTAL PROJECT COST (CREDIT)					**$ 54,842,211**	**$ (16,156,521)**
TOTAL NET PROJECT COST (CREDIT)					**$ 38,685,690**	

[1] Site inventory costs and recoverable scrap of inventory estimates (10%) were provided by FPL and were not independently reviewed by BMcD.

Table A-15
Babcock Ranch Solar Energy Center
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Babcock Ranch Solar Energy Center						
Unit 1						
Demolition	$ 1,681,000	$ 2,521,000	$ -	$ -	$ 4,202,000	$ -
Collector System	$ 131,000	$ 197,000	$ -	$ -	$ 328,000	$ -
Project Buildings	$ 18,000	$ 27,000	$ -	$ -	$ 45,000	$ -
Hazardous Material Disposal	$ -	$ -	$ 1,171,000	$ -	$ 1,171,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 75,000	$ -	$ 75,000	$ -
Site Restoration	$ -	$ -	$ -	$ 894,000	$ 894,000	$ -
Debris	$ -	$ -	$ 140,000	$ -	$ 140,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (2,152,000)
Subtotal	**$ 1,830,000**	**$ 2,745,000**	**$ 1,386,000**	**$ 894,000**	**$ 6,855,000**	**$ (2,152,000)**
Babcock Ranch Solar Energy Center Subtotal	**$ 1,830,000**	**$ 2,745,000**	**$ 1,386,000**	**$ 894,000**	**$ 6,855,000**	**$ (2,152,000)**
TOTAL COST (CREDIT)					**$ 6,855,000**	**$ (2,152,000)**
PROJECT INDIREGTs (5%)					**$ 343,000**	
CONTINGENGY (20%)					**$ 1,371,000**	
TOTAL PROJECT COST (CREDIT)					**$ 8,569,000**	**$ (2,152,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 6,417,000**	

Table A-16
Citrus Solar Energy Center
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Citrus Solar Energy Center						
Unit 1						
Demolition	$ 1,681,000	$ 2,521,000	$ -	$ -	$ 4,202,000	$ -
Collector System	$ 131,000	$ 197,000	$ -	$ -	$ 328,000	$ -
Project Buildings	$ 18,000	$ 27,000	$ -	$ -	$ 45,000	$ -
Hazardous Material Disposal	$ -	$ -	$ 1,171,000	$ -	$ 1,171,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 75,000	$ -	$ 75,000	$ -
Site Restoration	$ -	$ -	$ -	$ 894,000	$ 894,000	$ -
Debris	$ -	$ -	$ 140,000	$ -	$ 140,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (2,152,000)
Subtotal	**$ 1,830,000**	**$ 2,745,000**	**$ 1,386,000**	**$ 894,000**	**$ 6,855,000**	**$ (2,152,000)**
Citrus Solar Energy Center Subtotal	**$ 1,830,000**	**$ 2,745,000**	**$ 1,386,000**	**$ 894,000**	**$ 6,855,000**	**$ (2,152,000)**
TOTAL COST (CREDIT)					**$ 6,855,000**	**$ (2,152,000)**
PROJECT INDIREGTs (5%)					**$ 343,000**	
CONTINGENGY (20%)					**$ 1,371,000**	
TOTAL PROJECT COST (CREDIT)					**$ 8,569,000**	**$ (2,152,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 6,417,000**	

Table A-17
Manatee Solar Energy Center
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Manatee Solar Energy Center						
Unit 1						
Demolition	$ 1,681,000	$ 2,521,000	$ -	$ -	$ 4,202,000	$ -
Collector Sytem	$ 131,000	$ 197,000	$ -	$ -	$ 328,000	$ -
Project Buildings	$ 18,000	$ 27,000	$ -	$ -	$ 45,000	$ -
Hazardous Material Disposal	$ -	$ -	$ 1,171,000	$ -	$ 1,171,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 75,000	$ -	$ 75,000	$ -
Site Restoration	$ -	$ -	$ -	$ 894,000	$ 894,000	$ -
Debris	$ -	$ -	$ 140,000	$ -	$ 140,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (2,152,000)
Subtotal	**$ 1,830,000**	**$ 2,745,000**	**$ 1,386,000**	**$ 894,000**	**$ 6,855,000**	**$ (2,152,000)**
Manatee Solar Energy Center Subtotal	**$ 1,830,000**	**$ 2,745,000**	**$ 1,386,000**	**$ 894,000**	**$ 6,855,000**	**$ (2,152,000)**
TOTAL COST (CREDIT)					**$ 6,855,000**	**$ (2,152,000)**
PROJECT INDIREGTs (5%)					**$ 343,000**	
CONTINGENGY (20%)					**$ 1,371,000**	
TOTAL PROJECT COST (CREDIT)					**$ 8,569,000**	**$ (2,152,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 6,417,000**	

Table A-18
Okeechobee Clean Energy Center
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Salvage
Okeechobee Clean Energy Center						
Unit 1						
GTs and HRSGs	$ 2,682,000	$ 2,930,000	$ -	$ -	$ 5,612,000	$ -
Steam Turbine & Pedestal	$ 1,045,000	$ 1,142,000	$ -	$ -	$ 2,187,000	$ -
SCR	$ 98,000	$ 107,000	$ -	$ -	$ 205,000	$ -
GSU & Electrical	$ 238,000	$ 260,000	$ 82,000	$ -	$ 580,000	$ -
Stack	$ 95,000	$ 104,000	$ -	$ -	$ 199,000	$ -
Cooling Tower and Basin	$ 311,000	$ 340,000	$ -	$ -	$ 651,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 247,000	$ -	$ 247,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (5,252,000)
Subtotal	**$ 4,469,000**	**$ 4,883,000**	**$ 329,000**	**$ -**	**$ 9,681,000**	**$ (5,252,000)**
Common						
Auxiliary, Switchyard and Substation	$ 16,000	$ 18,000	$ 13,000	$ -	$ 47,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 41,000	$ 45,000	$ -	$ -	$ 86,000	$ -
Roads	$ 161,000	$ 175,000	$ 176,000	$ -	$ 512,000	$ -
All BOP Buildings	$ 501,000	$ 548,000	$ -	$ -	$ 1,049,000	$ -
Fuel Oil Storage Tanks	$ 174,000	$ 190,000	$ -	$ -	$ 364,000	$ -
All Other Tanks	$ 107,000	$ 117,000	$ -	$ -	$ 224,000	$ -
Contaminated Soil Removal	$ -	$ -	$ -	$ 134,000	$ 134,000	$ -
Fuel Oil Storage Tank Cleaning	$ -	$ -	$ -	$ 1,498,000	$ 1,498,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 154,000	$ 154,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 52,000	$ -	$ 52,000	$ -
Seeding and Grading	$ -	$ -	$ -	$ 210,000	$ 210,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (308,000)
Subtotal	**$ 1,000,000**	**$ 1,093,000**	**$ 242,000**	**$ 1,996,000**	**$ 4,331,000**	**$ (308,000)**
Ockeechobee Clean Energy Center Subtotal	**$ 5,469,000**	**$ 5,976,000**	**$ 571,000**	**$ 1,996,000**	**$ 14,012,000**	**$ (5,560,000)**
TOTAL COST (CREDIT)					**$ 14,012,000**	**$ (5,560,000)**
PROJECT INDIRECTS (5%)					**$ 701,000**	
CONTINGENGY (20%)					**$ 2,802,000**	
TOTAL PROJECT COST (CREDIT)					**$ 17,515,000**	**$ (5,560,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 11,955,000**	

APPENDIX B - PLANT AERIALS

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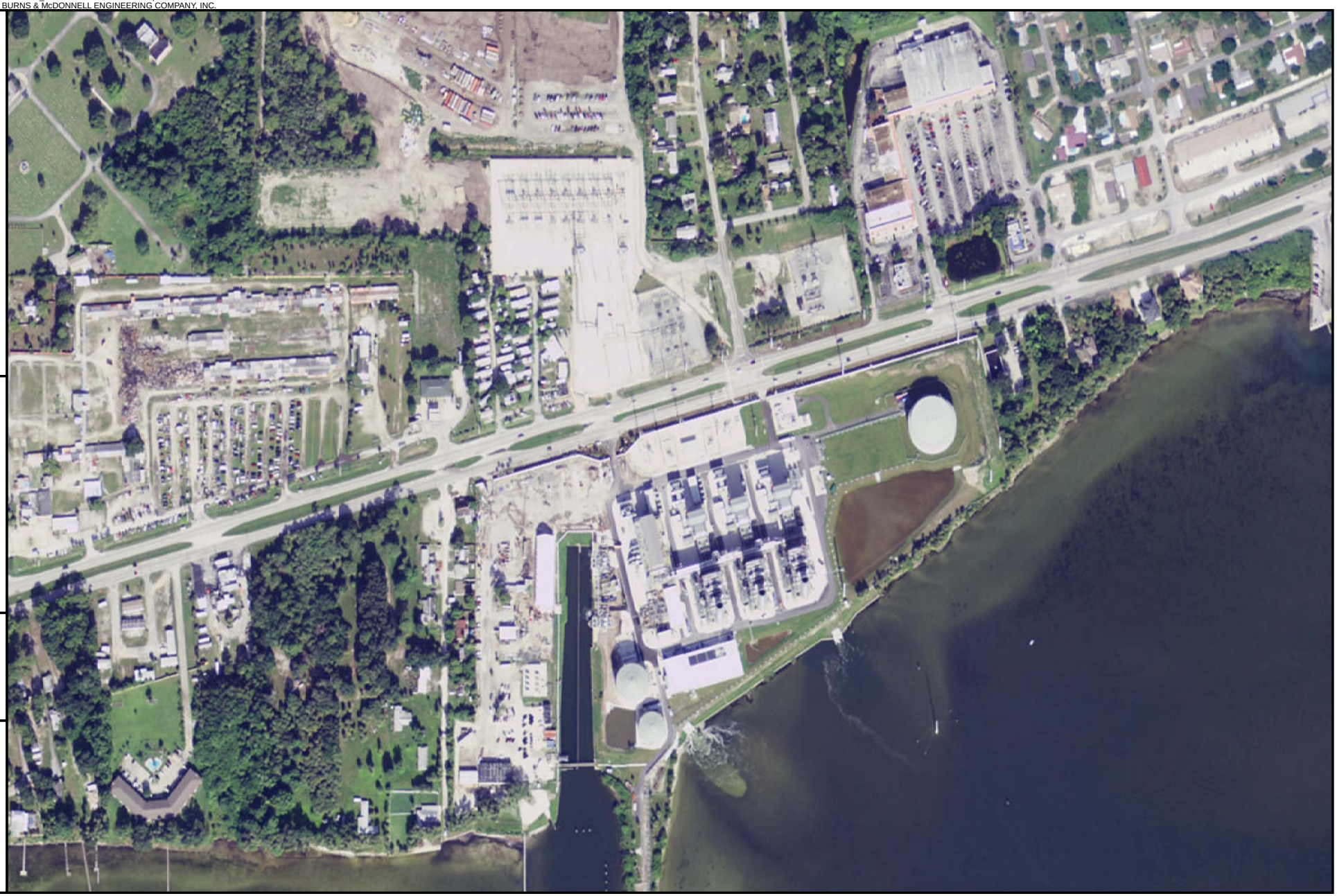

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Source: ESRI and Burns & McDonnell Engineering

BURNS McDONNELL

Cape Canaveral
Florida Power & Light

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Source: ESRI and Burns & McDonnell Engineering.

BURNS McDONNELL

DeSoto Next Generation Solar Energy Center
Florida Power & Light

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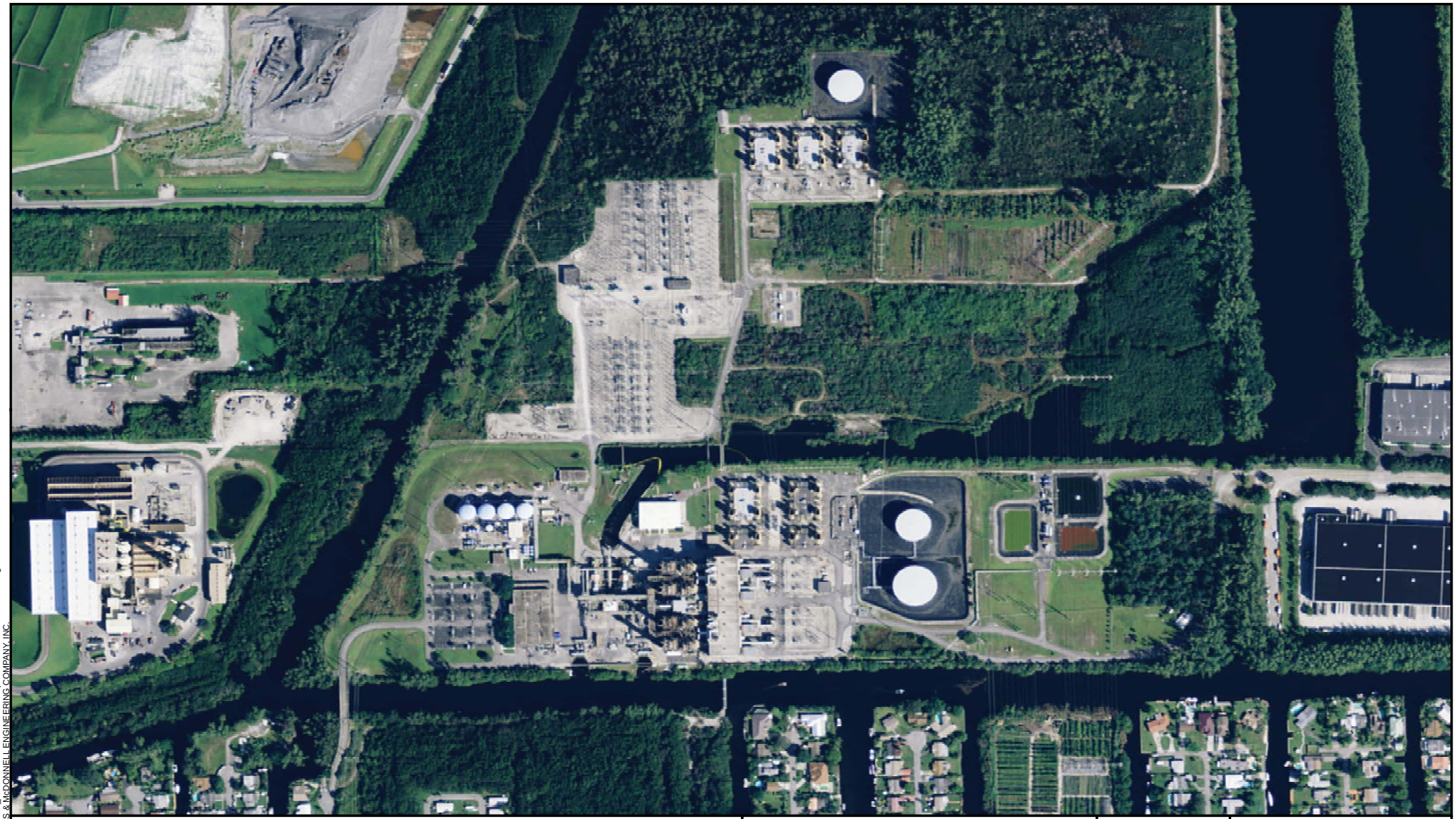

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Lauderdale Power Plant
Florida Power & Light

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BURNS McDONNELL

Fort Myers Power Plant
Florida Power & Light

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Source: ESRI and Burns & McDonnell Engineering.

BURNS McDONNELL

Manatee Power Plant
Florida Power & Light

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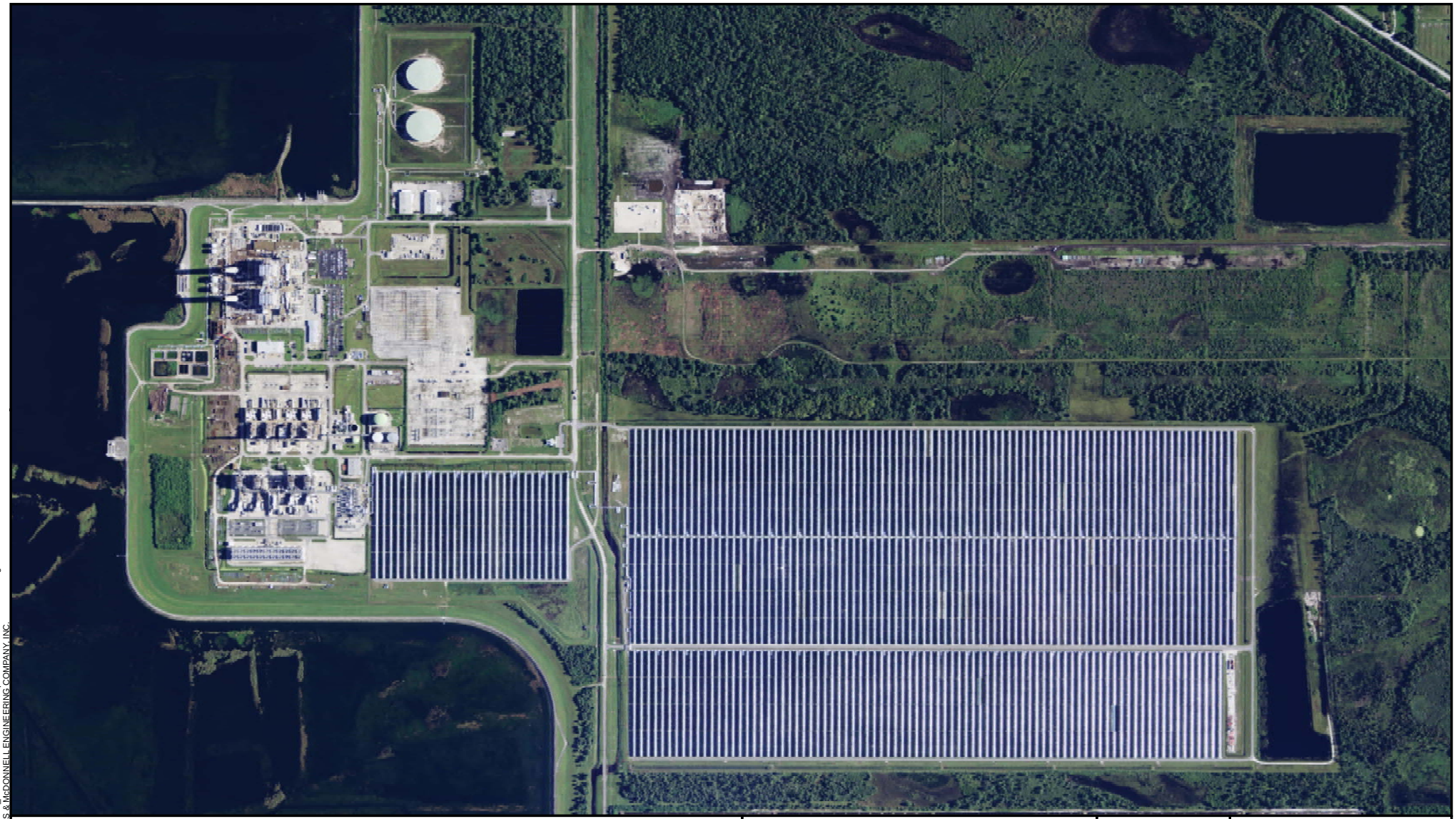

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Source: ESRI and Burns & McDonnell Engineering.

BURNS McDONNELL

Martin Power Plant
Florida Power & Light

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N

Source: ESRI and Burns & McDonnell Engineering.

BURNS McDONNELL

Port Everglades Power Plant
Florida Power & Light

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Riviera Power Plant
Florida Power & Light

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Sanford Power Plant
Florida Power & Light

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Miles

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Scherer Power Plant
Florida Power & Light

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St. John's River Power Park
Florida Power & Light

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Source: ESRI and Burns & McDonnell Engineering.

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Turkey Point Power Plant
Florida Power & Light

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Source: ESRI and Burns & McDonnell Engineering.

BURNS McDONNELL

West County Energy Center
Florida Power & Light

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Section 9

Dismantlement Cost Analysis for Cedar Bay Prepared by NorthStar Demolition & Remediation, LP

Cedar Bay:

Purpose and timing
On January 16, 2015, a walk down was conducted to determine a budgetary value to remove the assets from the site.

Attendees
Cedar Bay Generating Co LP site representatives – Operated by Cogentrix
Tracy Paterson II Plant GM
Mark R. Chaffee Chief Civil Structural Engineer
Steven J. Busbin Engineering Manager

FPL
Randal Voyles – FPL capital projects GM

Cedar Bay – Plant description
The Site is an existing coal fired power station producing a nominal 290 GMW and a net 260MW at maximum capability. This consists of 3 equal sized pyroflow circulating boiler firing a low surfer coal using limestone to capture the free sulfur materials. Prior to this decade was potentially a technology that could relatively environmentally friendly. Through a header system a consensual steam turbine produces the electrical power to the grid via step up transformers.

At a very high level the infrastructure in support of this is consists of the following:

Coal system

- Rail delivery system including diesel powered locomotive
- Coal Car dumping station
- Coal storage yard
- Coal crushing
- Tripper conveyor
- Paper refuge blending and drying area to
- Other coal handling equipment – conveyors, silos, gravimetric feeders, structures

Lime stone system

- Truck unloading
- Blowers
- Silo bughouses
- Williams heated Pulverizes
- Screw conveyors
- Distribution systems into the boiler

Boilers

- 3 pyroflow natural circulation boilers
- Cyclone separators
- Waterwalls, convection section, sonic soot removal system, Omega tubes
- Primary Fans
- Secondary air Fans
- ID fans
- Blowers

Ash capture removal and system

- Water cooled rotary screw conveyors
- Drag chains
- Baghouses
- Pneumatic fly ash conveyance system
- Stack

Power generation equipment

- Boiler Water treatment systems
- Clarifier
- Chlorinators
- Demonetization
- Cation and anion resin beds
- Feed pumps
- Low, medium and high feedwater heaters
- Steam condensers
- Condensate pumps

Steam Turbine/Generator

- Hydrogen cooled Generator
- Hydrogen recovery, cooling, and storage systems
- Oil lubrication
- Step up transformers
- Aux transformers
- Power distribution
- Motor Control cantors
- Transformers
- Cabling. Electrical manholes and safety systems
- Grounding
- Lightning protection
- Transmission lines (short~ ½ mile)

- Exciter

Other

- Control and protection
- Valves
- Gas systems
- Piping
- Storm water recovery systems
- Collection and storage basins
- Pumps
- Clean up system (very sophisticated)
- Tankage

Critical Spare Parts

A nominal number of spare parts are stored around the plant, this includes motors, tubing, pumps and so forth. Most are located on the Turbine Deck

Administration facilities

- Admin building
- Maintenance employee rooms
- Machine shops
- Electrical shops
- I&C maintenance facilities
- Mobile equipment as follows

Physical address:
9640 Eastport Road (32218)
Jacksonville, FL 32226
Located at 30.423581, -81.607984

The following is an aerial picture represents the general plant. The plant was designed by Black and Veatch and construction completed in 1991-1992

The Plant is very well operated and maintained resulting in a high level capacity factor/availability for circulating fluid bed boiler of this vintage. This will support the potential to reduce the cost of dismantlement of the facilities.

Basis of Estimate: Current Day Feb 2015

Exclusions:

No foundation removal

No hazardous waste removal

No Asbestos

No lead Paint

No Mercury devices

No PCP equipment
No removal of Major removal of coal, ash limestone, water, chemicals

Included:
All equipment, structures, hardware, lubrication oils, pumps, motors, skids, pipe, conduit, cabling as listed above. Fill in the coal unloading pit, removal of the residual layer of coal in the coal yard. Title would be transferred for everything at the site unless specifically excluded.

Execution strategy:
Market and Sell all equipment on the site to the extent possible first as systems and secondary at the component level. Followed by dismantlement activities using conventional methods. The ability to minimize the final cost of this effort is highly dependent upon the need of other similar power producers and the timing of their need, the value of the materials that can be scrapped, and the distance to the end users. We would actively auction or Bid the entire site as an EPC approach to support us in this effort. This has demonstrated to provide us with the lower risk and highest market value. Our experience stems from Cape, Rivera, port everglades, cutler, Sanford, and numerous ancillary supporting systems in the NEE portfolio.

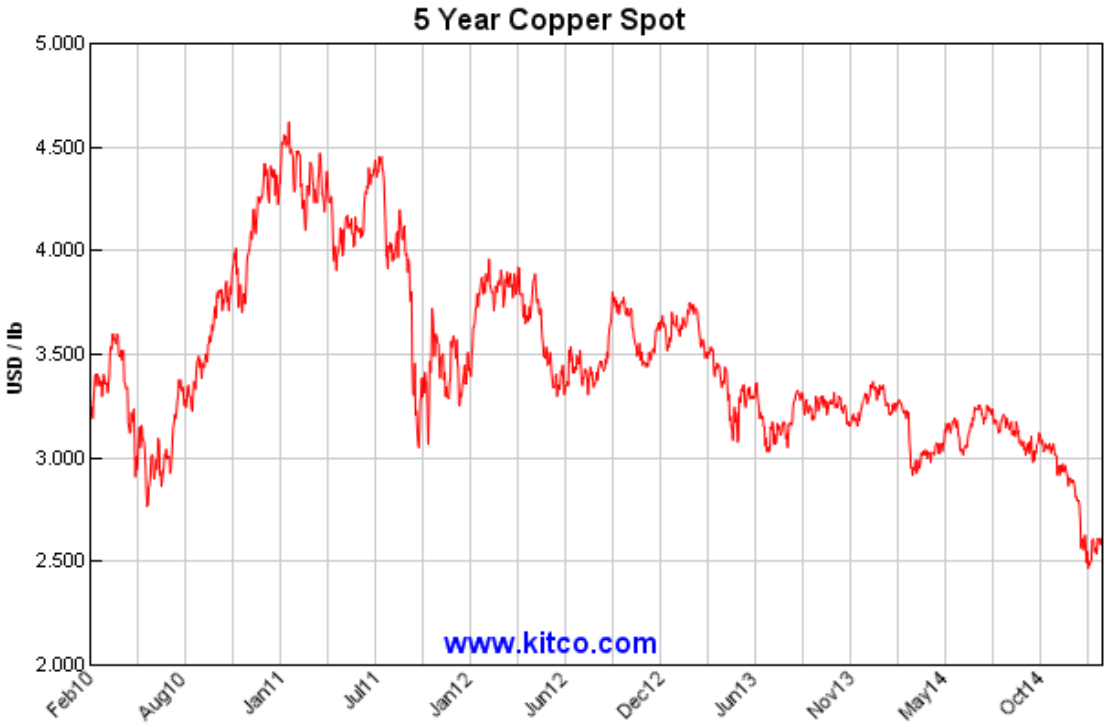
Schedule:
Recommended this effort take 24-30 months from notice to proceed to complete. Although this can be substantially shorter; time has shown that the longer durations typically result in a lower end cost. This works in two ways, it allows us to locate viable buyers in need, or time the salvage market to recover the highest salvage value attainable.

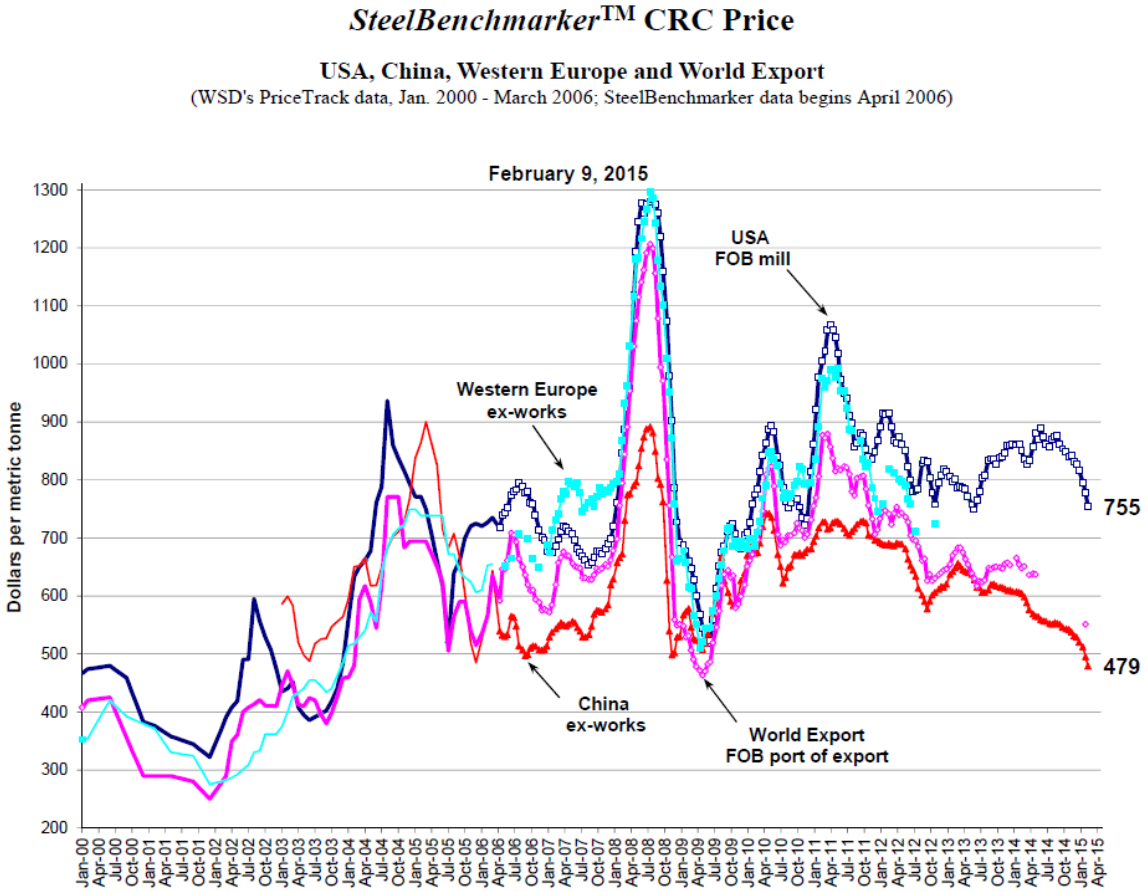
Budgetary cost:
The recommended cost of this effort is:

- **P90 cost of $4.5M** this is considered to be conservative due to the current timing the plant will continue to operate for several more years, cost of escalation of the resource pool, volatility of the salvage market, and the potential for whole sailing the equipment on the international market. There is of course equal potential for upside or down side. Dependent upon the level of upside there is potential that the marketability of the plant would result in a null cost or even some moneys being returned.
- **P50 cost of $1.0M** with a range of $0 to a cost of $2.0M

As an example the following salvage markets have trended downward since peaking in 2008-2010 time period. The majority of the savings values are in the steel, cooper, Stainless areas. Scrap Steel has somewhat returned to the higher level due to the reduction in inventory and the same trend is expected yet has not materialized yet for the other metals. Additionally, since this is a budgetary effort and not a great deal of effort was put forth to estimate the amount of materials the resulting weights may increase providing further savings.

Trend Charts for Metals Markets





Appendix supporting information:
Appendix A
Budgetary Vendor information

Appendix B
Pictures

Appendix C
Plant documentation

RELEASED FOR CONSTRUCTION
9-22-91

AES CEDAR BAY, INC.
CEDAR BAY COGENERATION PLANT
SITE - ARRANGEMENTS
OVERALL SITE - PLAN

BLACK & VEATCH

15637-1STU-S1000

REV	DATE	DESCRIPTION	BY
9	09-20-12	GENERAL REVISION - COAL PILE COVER/C LIMESTONE	RJE
8	07-16-03	GENERAL REVISION	MTA/PB/MAP
7	02-06-03	ADDED FGDR WASTE CONVEYOR	MTA/PB/MAP
6	05-06-02	ADDED ASH PELLETIZED AREA	MA/PB/MAP
5	03-06-02	GENERAL REVISIONS	MTA/PB/MAP
4	01-06-92	GENERAL REVISIONS	MTA/PB/MAP

NO	DATE	REVISIONS AND RECORD OF ISSUE	BY
3	10-04-91	GENERAL REVISIONS	MTA/PB/MAP
2	05-17-91	RELEASED FOR CONSTRUCTION	MTA/PB/MAP
1	03-27-91	GENERAL REVISIONS	MTA/PB/MAP
0	11-14-90	INITIAL ISSUE	MTA/PB/MAP

PLANT

SCALE: 1"=50'

11-05-90 RED MA

SURVEY DATA FOR PROPERTY BOUNDARY AND TOPOGRAPHY WAS PERFORMED BY CAMPBELL, CENTRY, INC. (WEST PALM BEACH, FLORIDA) DATED 10-26-90. SURVEY DATA FOR RAILROAD SPUR AND ROAD WAS PERFORMED BY BLACK & VEATCH DATED 11-05-90.

CHECKED: MDK DATE: 9-17-91
SPEC. NO. 1520
DRAWN: RJE DATE: 9-17-91
CHECKED: SPD DATE: 9-17-91

SHEET 9 OF 12SHEETS

PROJECT BOUNDARY

E 4500

E 5000

N 3000

N 2500

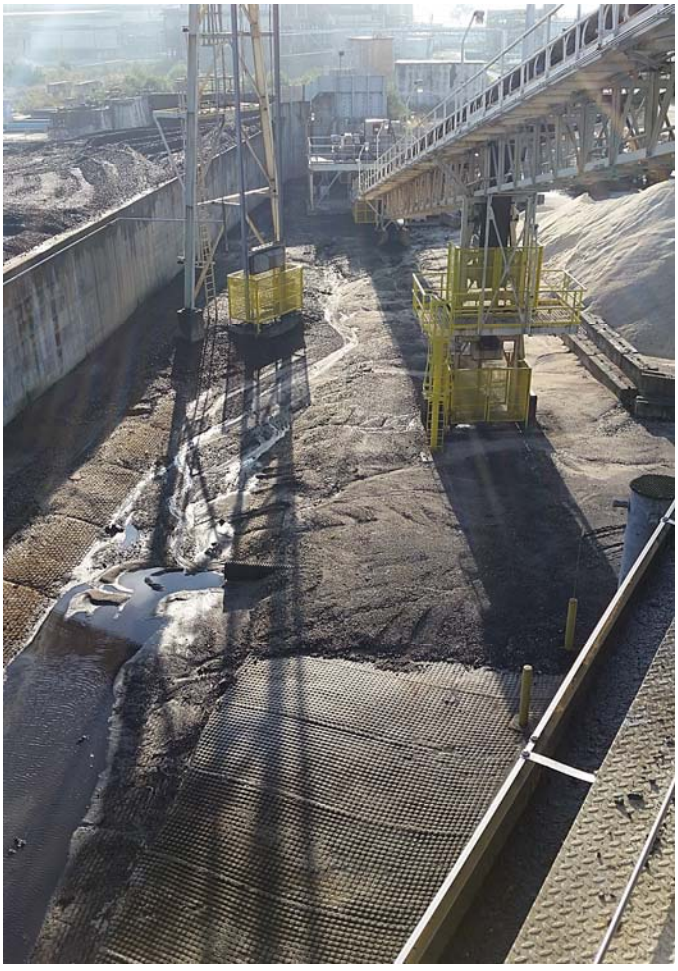
TO CASTPORT ROAD

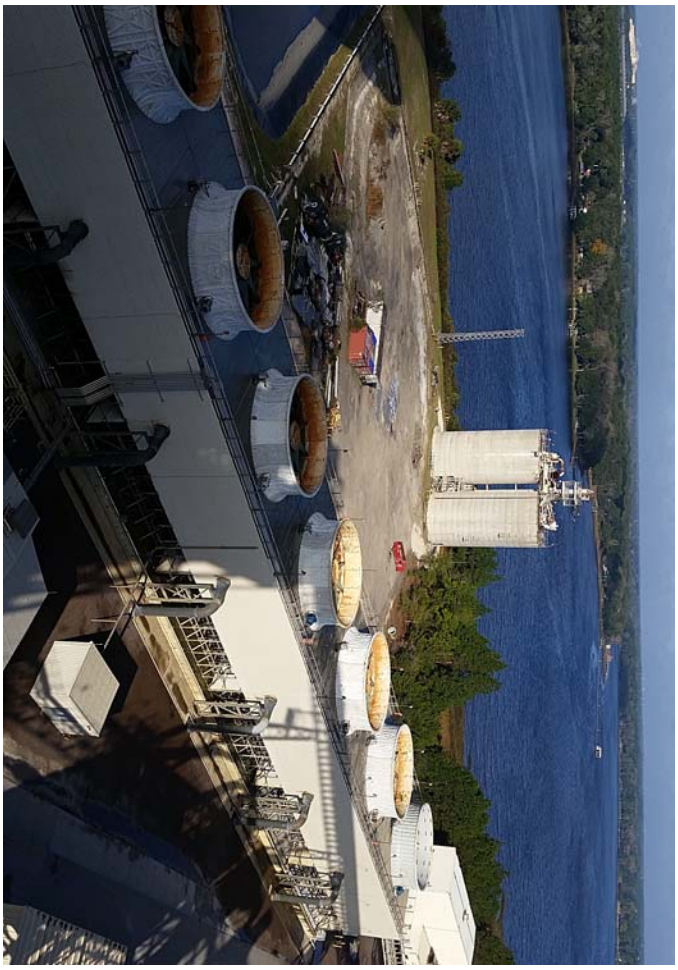
SITE ACCESS ROAD

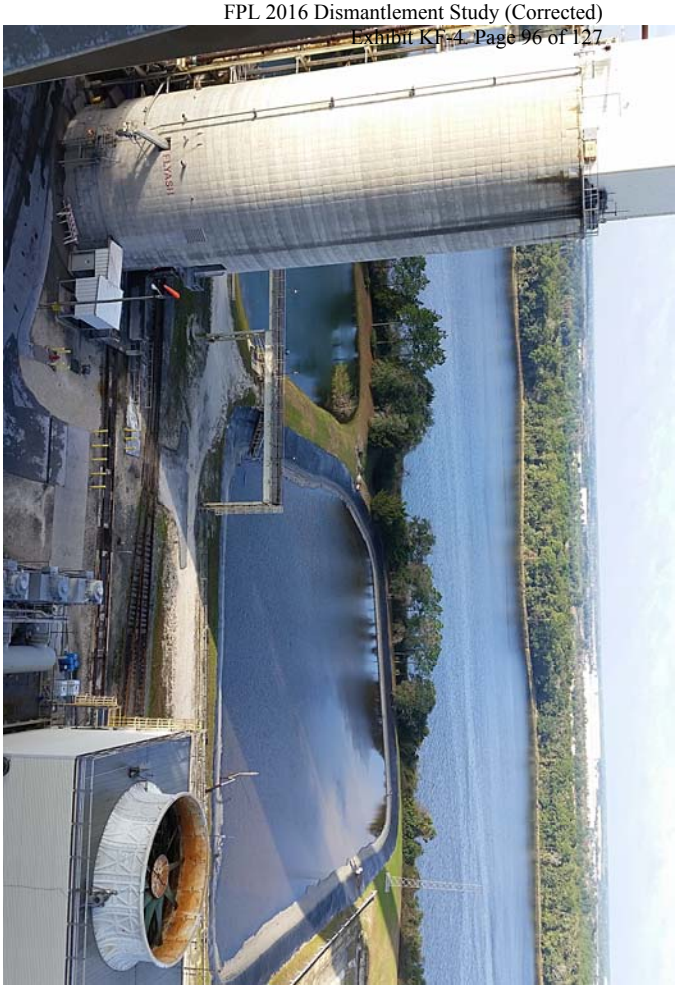
TRANSMISSION INTERCONNECTION TO JEA

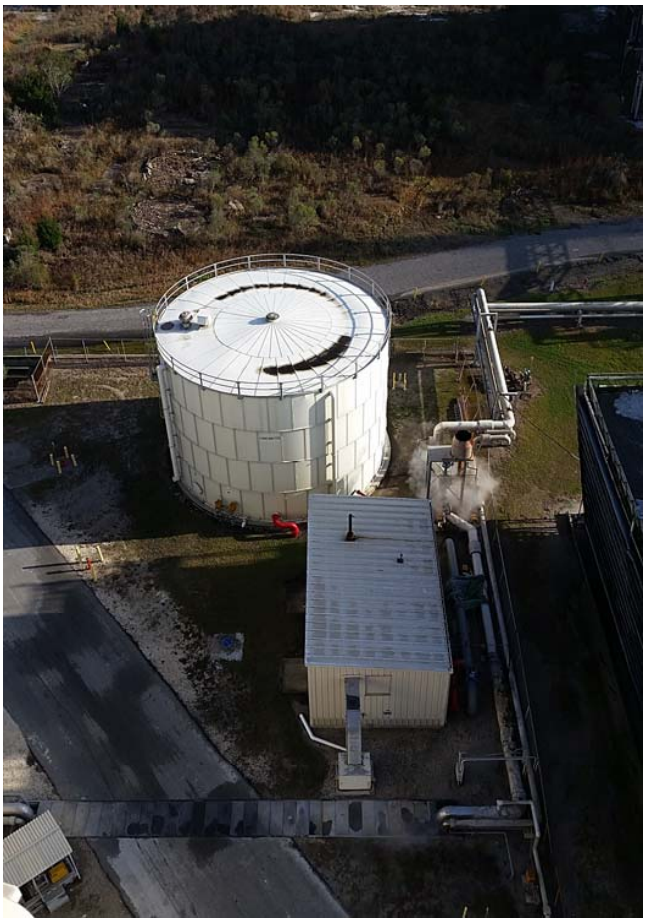
FACILITIES LEGEND

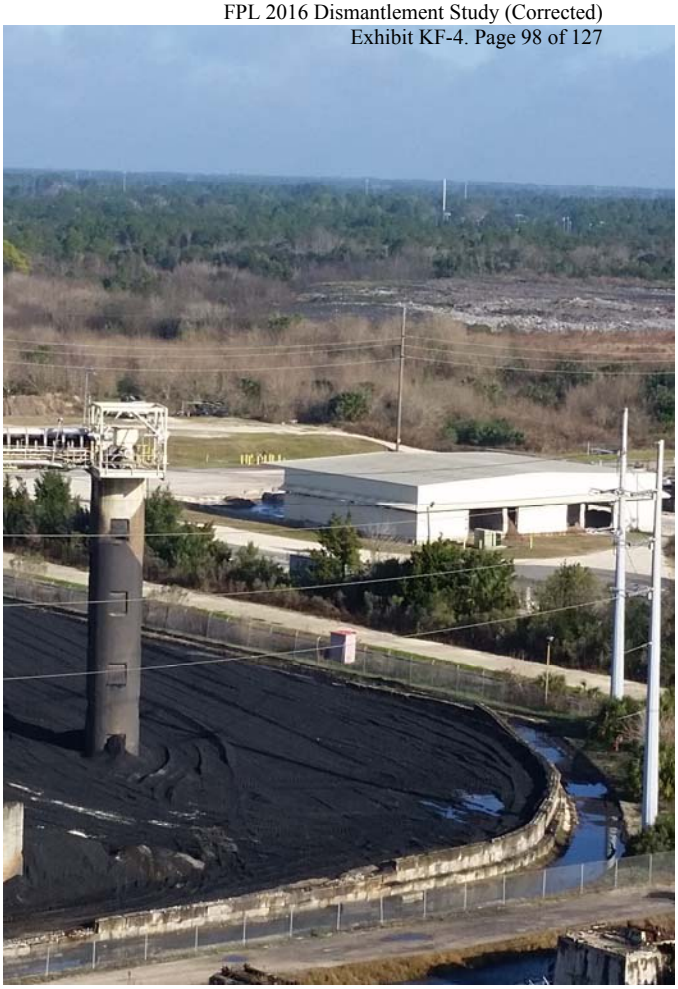
BLDG. ID	DESCRIPTION	LOCATION COORDINATES NORTH	LOCATION COORDINATES EAST	REFERENCE LOCATION
1	STEAM GENERATOR STRUCTURE	---	---	---
2	TURBINE GENERATOR BUILDING	5000.00	5000.00	NE COLUMN CL
3	TURBINE/DEMIN AREA	---	---	---
4	FUNNEL FLUE	---	---	---
5	ID FAN	---	---	---
6	CHIMNEY	4874.00	4982.87	CL
7	COOLING TOWER	3446.83	5020.00	NE FGN CORNER
8	CHEMICAL/MAU WATER PUMP STRUCTURE	---	---	---
9	FLY ASH SILO	3074.30	4634.36	CL
10	BED ASH SILO	3021.52	4568.30	CL
11	PRE RACK	---	---	---
12	BED ASH STORAGE HOPPER	---	---	---
13	ASH PELLETIZING BUILDING (REMOVED)	3432.87	4786.31	NE COLUMN CL
14	SCREEN STRUCTURE (REMOVED)	3536.31	4777.79	NE COLUMN CL
15	CURED PELLET STORAGE	---	---	---
16	ASH PELLET LOADOUT HOPPER	3521.80	4878.81	NE COLUMN CL
17	COAL UNLOADING STRUCTURE	---	---	---
18	COAL CONVEYOR BELT	3343.40	5330.30	CL
19/19A	COAL STORAGE WITH COVER	---	---	---
20	COAL CRUSHER BUILDING	---	---	SEE DWG 5160T
21	LIMESTONE STORAGE	---	---	---
22	LIMESTONE PULVERIZER BUILDING	3172.10	5032.80	SEE DWG 5360T
23	PRE PROTECTION COMPRESSOR ROOM	3528.78	5018.74	NE COLUMN CORNER
24	PELLET CURING SILOS	3668.89	4802.38	EAST CURING SILO
25	CHEMICAL/MAU WATER CHEMICAL FEED STRUCTURE	3183.83	4882.83	NE COLUMN CL
26	CHEMICAL/MAU WATER ADD AND RECIRCULATING WATER PUMPS	---	---	---
27	OAS STORAGE	4607.61	5083.30	NE FGN CORNER
28	RECEIVING STORAGE TANK	4771.00	5084.00	CL
29	RECEIVING PUMP STRUCTURE	4763.00	5064.00	NE COLUMN CL
30	WASTEWATER SUMP	4823.00	4807.00	NE FGN CORNER
31	CONDENSATE STORAGE TANK	4800.00	4868.00	CL
32	DEMINERALIZED WATER STORAGE TANK	4962.00	4831.00	CL
33	NEUTRALIZATION BASIN	4826.00	4934.00	CL
34	ADD STORAGE TANK	---	---	---
35	CAUSTIC STORAGE TANK	---	---	---
36/36A	WATER TREATMENT BUILDING #1/#2	4600.00	4873.00	NE COLUMN CL
37	SERVICES BUILDING	4650.00	4722.00	NE COLUMN CL
38/38A	FUEL OIL STORAGE TANK/DAY TANK	4688.00	4601.00	CL
39	STORAGE AREA SUMPF POND	---	---	---
40	YARD AREA SUMPF POND	---	---	---
41	PARKING	---	---	---
42	TRANSMISSION LINE	---	---	---
43	SITE ACCESS ROAD	---	---	---
44	NON-DESTRUCTIVE BEACON	---	---	---
45	FUEL UNLOADING STATION	4688.49	4529.34	NE FGN CORNER
46	LIME SLURRY COLLECTION BASIN	---	---	---
47	COOLING TOWER FIRE PROT. VALVE HOUSE	5240.79	4814.68	NE FGN CORNER
48	POND DISCHARGE STRUCTURE	---	---	SEE DWG 5370Z
49	COAL YARD AREA SUMP	---	---	---
50	EMERGENCY OVERFLOW	---	---	SEE DWG 5301I
51	COAL CONVEYOR 3	---	---	---
52	COAL CONVEYOR 2	---	---	---
53	COAL FEEDER 2	---	---	---
54	COAL CONVEYOR 4	---	---	---
55	COAL RECLAIM HOPPER 1	---	---	---
56	WATER PRE/POST TREATMENT AREA	---	---	---
57	WASTE FEED CONVEYOR	---	---	---
58	WASTE FEED LOADOUT HOPPER	---	---	---
59	DEMIN FACILITY	---	---	---
60	STORMWATER STORAGE TANK	---	---	---

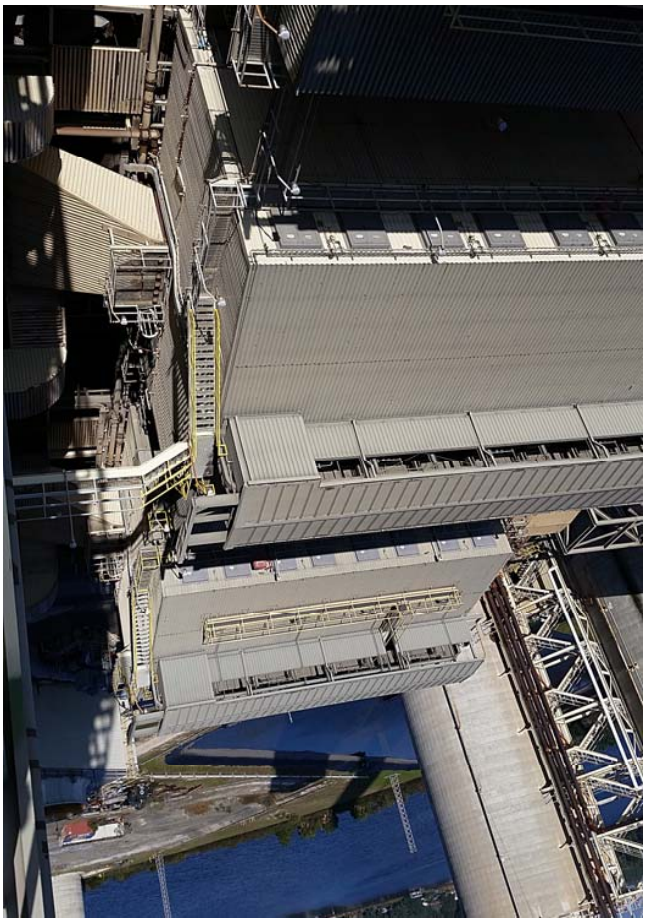




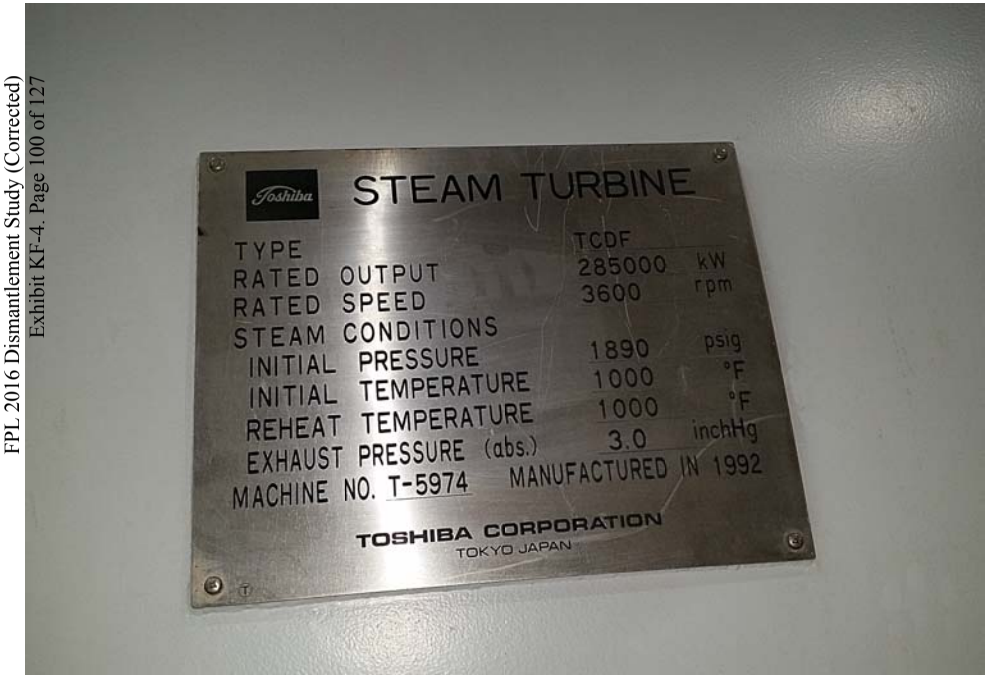








TOSHIBA
1TGA- TG- 1
TURBINE
GENERATOR 1


Toshiba
STEAM TURBINE
TYPE TCDF
RATED OUTPUT 285000 kW
RATED SPEED 3600 rpm
STEAM CONDITIONS
INITIAL PRESSURE 1890 psig
INITIAL TEMPERATURE 1000 °F
REHEAT TEMPERATURE 1000 °F
EXHAUST PRESSURE (abs.) 3.0 inchHg
MACHINE NO. T-5974 MANUFACTURED IN 1992
TOSHIBA CORPORATION
TOKYO JAPAN

Toshiba
A. C. GENERATOR
PHASE 3
POLES 2
VOLTS 20000
RATING CONT
POWER FACTOR 0.85
EXCITATION VOLTS 310
STATOR TEMP RISE 80°C
STATOR CONNECTION Y
STATOR INSULATION CLASS F
STANDARD SPECIFICATION
SERIAL NO. 9113124
TOSHIBA CORPORATION

February 12, 2015

Florida Power & Light
PGD Technical Services
700 Universe Blvd.
Juno Beach, FL 33408

Mr. Randal Voyles
Technical Services Manager

Re: Budget Estimate for Cedar Bay Plant
NorthStar Proposal No. 15-02-09

Dear Mr. Voyles,

NorthStar Demolition and Remediation LP is pleased to provide this budget estimate for the demolition of the Cedar Bay facility. The budget estimate was developed based on information gathered during a site inspection and drawings provided by the facility. This budget estimate includes the removal of the coal powered steam generator structure with 3 individual boiler units, one chimney stack, turbine generator building and condensers, all above ground structures listed on the Overall Site Plan (15637-1STU-S1000), such as transformers, cooling tower, fly and bed ash silos, cured pellet storage, coal storage, crushing and conveyance, limestone storage, pulverizing and conveyance, circulating water structure, misc. tanks and systems for water, fuel, acid and caustics, water treatment building, coal unloading structure, storage area runoff and yard area runoff ponds, misc. outbuildings, etc. All work will be to top of foundation or slab at or near grade.

Additionally, as this plant has only recently shut down and the equipment had been maintained to the highest level of quality, there are many items that potentially have a much greater value as a reusable asset rather than being sold as scrap. Because of the state of these materials, NorthStar feels that it would be of benefit to both FPL and NorthStar if we could partner in the marketing and sales of as much of this equipment as possible as this could increase our asset recovery well above $5.5 million.

In order to maximize FPL's return on its capital investment, we feel that additional marketing time is required to explore the international market on a piece by piece basis. NorthStar has relationships with many end user buyers and brokers that could be used for the liquidation of miscellaneous pieces and parts for this plant. They specialize in this type of equipment and have a vast client basis worldwide. Based on the extremely clean condition of the plant, we feel that this relationship would best serve FPL if we could spend time immediately marketing the equipment while it is still in place. This would allow us time to bring in our out-of-country clients to view and make "firm" offers on this equipment.

The assumptions made in the development of this estimate include the following;

- Work will be performed 5 days per week 10 hours per day
- The work can be completed within 12-14 months.
- FP&L will make all utility disconnects and relocations.
- All line break and hazardous material removal including universal wastes will be performed by FPL.
- Assumed no lead abatement besides employee protection during torch activities.
- Excludes any damage to existing concrete slabs and foundations to remain.
- Excludes any ash, coal, limestone and process waste cleanup and disposal.
- Asbestos is excluded from the pricing

Budget Estimate of Cost

Project Overhead	$650,000
Stack and Concrete Silos	$590,000
Boiler and ancillary structures	$3,250,000
Misc Buildings, cooling tower	$870,000
Water Treatment/Condensers	$650,000
Turbine	$350,000
Total Cost	**$6,360,000**
Scrap Recovery Credit	**($2,237,750)**
Net Cost to FPL	**$4,122,250**

Budget Estimate for Salvage Recovery

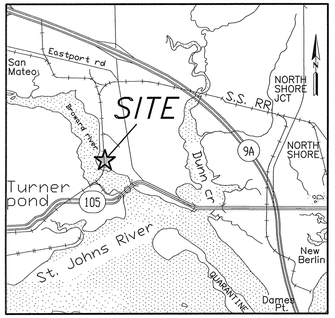
Steel Scrap	11000	Gross Tons	$140/ton	$1,540,000
Sales	Pumps/valves/motors			$300,000
Copper	140,000	Pounds	$1.95/lb.	$273,000
Stainless Tubes	115,000	Pounds	$0.65/lb.	$74,750
Misc.				$50,000
			Total Scrap	**$2,237,750**

Thank you for the opportunity to provide you with this budget estimate. Please feel free to call with any questions. Chris Schillesci 985-705-2641
Regards,

Chris Schillesci
Sr. Project Manager
NorthStar Demolition and Remediation LP

ALTA/ACSM LAND TITLE SURVEY

A PORTION OF WEBB PLACE, SUBDIVISION OF THE JOHN BROWARD GRANT, SECTION 46, TOWNSHIP 1 SOUTH, RANGE 27 EAST, DUVAL COUNTY, FLORIDA, AS DEPICTED IN PLAT BOOK 1, PAGES 7 AND 8, OF THE FORMER PUBLIC RECORDS OF SAID COUNTY, ALSO BEING A PORTION OF THOSE LANDS DESCRIBED AND RECORDED IN OFFICIAL RECORDS BOOK 6222, PAGE 504, TOGETHER WITH A PORTION OF THOSE LANDS DESCRIBED AND RECORDED IN OFFICIAL RECORDS BOOK 7101, PAGE 1756, OF THE CURRENT PUBLIC RECORDS OF SAID COUNTY.



VICINITY MAP

(NOT TO SCALE)

SURVEYOR'S DESCRIPTION (FACILITY SITE):

PARCEL A:
A portion of Webb Place, subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Duval County, Florida, as depicted in Plat Book 1, pages 7 and 8, of the former Public Records of said county, also being a portion of those lands described and recorded in Official Records Book 7101, page 1756, of the current Public Records of said county, being more particularly described as follows:

For a Point of Reference, commence at the corner common to the Easterly line of said Webb Place and Subsections 19 and 22, of said Section 46, said corner bearing South 89°58'16" West, 1325.83 feet from the Northeasterly corner of said Subsection 22; thence South 89°58'28" West, along the Westerly prolongation of the Northerly line of said Subsection 22, a distance of 578.30 feet to its intersection with the Westerly right of way line of Eastport Road, a 66 foot right of way as presently established; thence North 10°23'24" West, along said Westerly right of way line, a distance of 890.02 feet; thence South 79°36'36" West, departing said Westerly right of way line, 508.51 feet to a point lying on the Northerly line of those lands described and recorded in Official Records Book 6652, pages 2217 of said current Public Records; thence Westerly and Southerly along the Northerly and Westerly line of last said lands, the following 3 courses: Course 1, thence South 67°50'04" West, 316.23 feet; Course 2, thence South 49°14'16" West, 270.00 feet; Course 3, thence South 40°45'44" East, 644.88 feet to an intersection with said Westerly prolongation of the Northerly line of Subsection 22; thence South 89°58'28" West, departing said Westerly line and along said Westerly prolongation, 618.79 feet; thence North 40°49'07" West, 128.34 feet; thence South 49°11'36" West, 100.00 feet; thence North 40°49'07" West, 275.00 feet; thence South 49°10'53" West, 100.00 feet; thence South 40°49'07" East, 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Subsection 22; thence South 89°58'28" West, along said Westerly prolongation, 134.73 feet to the Northeasterly corner of those lands described in Exhibit "A", Parcel "A", as recorded in said Official Records Book 7101, page 1756 and the Point of Beginning.

From said Point of Beginning, thence Southerly along the Easterly line of said Parcel "A" the following 10 courses: Course 1, thence South 40°49'07" East, 427.65 feet; Course 2, thence South 03°45'51" West, 74.96 feet; Course 3, thence South 41°14'09" East, 54.38 feet; Course 4, thence South 49°10'10" West, 42.00 feet; Course 5, thence South 41°14'09" East, 10.00 feet; Course 6, thence South 49°10'10" West, 269.67 feet; Course 7, thence South 40°49'50" East, 485.00 feet; Course 8, thence South 49°10'10" West, 155.00 feet; Course 9, thence South 40°49'50" East, 220.00 feet; Course 10, thence South 49°10'10" West, 15.00 feet to the Northerly most corner of those lands described in Exhibit "A", Parcel "B", as recorded in said Official Records Book 7101, page 1756; thence South 40°49'50" East, departing said Easterly line and along the Northeasterly line of said Parcel "B", 191.10 feet to the Easterly most corner thereof, said corner lying on a curve concave Southeasterly having a radius of 118.15 feet; thence Southwesterly, along the Southeasterly line of said Parcel "B", and along the arc of said curve, through a central angle of 50°59'22", an arc length of 105.15 feet to a point on said curve, said arc being subtended by a chord bearing and distance of South 49°21'10" West, 101.71 feet; thence South 49°10'10" West, continuing along said Southeasterly line and along the Southerly line of said Parcel "A", 194.71 feet to a point hereinafter referred to as Reference Point "A"; thence continue South 49°10'10" West, along said Southerly line, 44 feet, more or less, to its intersection with the Easterly Mean High Water Line of the Broward River; thence along the meanderings of said Easterly Mean High Water Line the following 4 courses: Course 1, thence Westerly, departing said Southerly line, 490 feet, more or less; Course 2, thence Northwesterly, 1065 feet, more or less; Course 3, thence Northeasterly, 617 feet, more or less; Course 4, thence Northerly, 277 feet, more or less, to the Northwest corner of said Parcel "A"; thence North 89°58'28" East, departing said Easterly Mean High Water Line and along the Northerly line of said Parcel "A", said line also being the Westerly prolongation of the Northerly line of Subsection 22, a distance of 47 feet, more or less, to a point on said line, said point bearing North 21°01'01" West, 1748.17 feet from said Reference Point "A"; thence continue North 89°58'28" East, along last said line, 314.13 feet to the Point of Beginning.

Containing 30.4 acres, more or less.

TOGETHER WITH:

LEASE PARCEL 1:
A portion of Webb Place, subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Duval County, Florida, as depicted in Plat Book 1, pages 7 and 8, of the former Public Records of said county, also being a portion of those lands described and recorded in Official Records Book 6222, page 504, of the current Public Records of said county, being more particularly described as follows:

For a Point of Reference, commence at the corner common to the Easterly line of said Webb Place and Subsections 19 and 22, of said Section 46, said corner bearing South 89°58'16" West, 1325.83 feet from the Northeasterly corner of said Subsection 22; thence South 89°58'28" West, along the Westerly prolongation of the Northerly line of said Subsection 22, a distance of 578.30 feet to its intersection with the Westerly right of way line of Eastport Road, a 66 foot right of way as presently established; thence North 10°23'24" West, along said Westerly right of way line, a distance of 890.02 feet; thence South 79°36'36" West, departing said Westerly right of way line, 508.51 feet to a point lying on the Northerly line of those lands described and recorded in Official Records Book 6652, pages 2217 of said current Public Records; thence Westerly and Southerly along the Northerly and Westerly line of last said lands, the following 3 courses: Course 1, thence South 67°50'04" West, 316.23 feet; Course 2, thence South 49°14'16" West, 270.00 feet; thence South 77°53'56" West, departing said Northerly line, 280.31 feet to the Point of Beginning.

From said Point of Beginning, thence South 41°06'50" East, 624.12 feet; thence South 48°53'10" West, 105.09 feet; thence South 45°49'59" West, 230.33 feet; thence South 54°07'43" West, 105.42 feet; thence North 40°42'13" West, 663.30 feet; thence North 52°59'04" East, 90.52 feet; thence North 53°53'30" East, 170.27 feet; thence North 53°50'15" East, 176.06 feet to the Point of Beginning.

Containing 6.51 acres, more or less

LEASE PARCEL 2:
A portion of Webb Place, subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Duval County, Florida, as depicted in Plat Book 1, pages 7 and 8, of the former Public Records of said county, also being a portion of those lands described and recorded in Official Records Book 6222, page 504, of the current Public Records of said county, being more particularly described as follows:

For a Point of Reference, commence at the corner common to the Easterly line of said Webb Place and Subsections 19 and 22, of said Section 46, said corner bearing South 89°58'16" West, 1325.83 feet from the Northeasterly corner of said Subsection 22; thence South 89°58'28" West, along the Westerly prolongation of the Northerly line of said Subsection 22, a distance of 578.30 feet to its intersection with the Westerly right of way line of Eastport Road, a 66 foot right of way as presently established; thence North 10°23'24" West, along said Westerly right of way line, a distance of 890.02 feet; thence South 79°36'36" West, departing said Westerly right of way line, 508.51 feet to a point lying on the Northerly line of those lands described and recorded in Official Records Book 6652, pages 2217 of said current Public Records; thence Westerly along said Northerly line the following 2 courses: Course 1, thence South 67°50'04" West, 316.23 feet; Course 2, thence South 49°14'16" West, 270.00 feet; thence South 77°53'56" West, departing said Northerly line, 280.31 feet; thence North 38°45'00" West, 102.45 feet to the Point of Beginning.

From said Point of Beginning, thence South 55°49'01" West, 441.86 feet to a point on a curve concave Northeasterly having a radius of 665.76 feet; thence Northwesterly along the arc of said curve, through a central angle of 22°29'35", an arc length of 261.36 feet to a point on said curve, said arc being subtended by a chord bearing and distance of North 35°23'40" West, 259.69 feet; thence North 09°48'40" West, 84.68 feet; thence North 49°11'08" East, 370.75 feet; thence South 40°48'52" East, 382.13 feet to the Point of Beginning.

Containing 3.49 acres, more or less.

EXHIBIT A (FACILITY SITE) (Official Records Book 7101, Page 1756):

PARCEL A:
A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 and said subdivision (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot Public Right of Way as now established); run thence North 10° 23' 56" West along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217–2228, the following three courses and distances: First Course; South 67°49'32" West, a distance of 316.23 feet to a point; Second Course; South 49° 13' 44" West, a distance of 270.00 feet to a point; Third Course; South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11' 04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along said line, a distance of 134.73 feet to the Point of Beginning.

From the Point of Beginning thus described, run South 40°49'39" East, a distance of 427.65 feet to a point; run thence South 03°45'19" West, a distance of 74.96 feet to a point; run thence South 41°14'41" East, a distance of 54.38 feet to a point; run thence South 49°09'38" West, a distance of 42.00 feet to a point; run thence South 41°14'41" East, a distance of 10.00 feet to a point; run thence South 49°09'38" West, a distance of 269.67 feet to a point; run thence South 40°50'22" East, a distance of 485.00 feet to a point; run thence South 49°09'38" West, a distance of 155.00 feet to a point; run thence South 40°50'22" East, a distance of 220.00 feet to a point; run thence South 49°09'38" West, a distance of 210.00 feet to a point; run thence South 40°50'22" East, a distance of 188.96 feet to a point; run thence South 49°09'38" West, a distance of 175 feet, more or less, to the Mean High Water Line of the Broward River; run thence in a general Northwesterly and Northeasterly direction, along said Mean High Water Line, a distance of 2,350 feet, more or less, to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision, said point lying South 89°57'56" West, a distance of 395 feet, more or less, from the Point of Beginning; run thence North 89°57'56" East, along aforementioned line, a distance of 395 feet, more or less to the Point of Beginning.

TOGETHER WITH:

PARCEL B:
A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For a Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot Public Right of Way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217–2228 of the Current Public Records of said Duval County, Florida; run thence along the Northerly and Westerly line of said lands recorded in Official Records Volume 6652, Pages 2217–2228, the following three courses and distances: First Course; South 67°49'32" West, a distance of 316.23 feet to a point; Second Course; South 49°13'44" West, a distance of 270.00 feet to a point; Third Course, South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 134.73 feet to a point; run thence South 40°49'39" East, a distance of 427.65 feet to a point; run thence South 03°45'19" West, a distance of 74.96 feet to a point; run thence South 41°14'41" East, a distance of 54.38 feet to a point; run thence South 49°09'38" West, a distance of 42.00 feet to a point; run thence South 41°14'41" East, a distance of 10.00 feet to a point; run thence South 49°09'38" West, a distance of 269.67 feet to a point; run thence South 40°50'22" East, a distance of 485.00 feet to a point; run thence South 49°09'38" West, a distance of 155.00 feet to a point; run thence South 40°50'22" East, a distance of 220.00 feet to a point; run thence South 49°09'38" West, a distance of 210.00 feet to a point; run thence South 40°50'22" East, a distance of 188.96 feet to a point; run thence South 49°09'38" West, a distance of 175 feet, more or less, to the Mean High Water Line of the Broward River; run thence in a general Northwesterly and Northeasterly direction, along said Mean High Water Line, a distance of 2,350 feet, more or less, to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision, said point lying South 89°57'56" West, a distance of 395 feet, more or less, from the Point of Beginning; run thence North 89°57'56" East, along aforementioned line, a distance of 395 feet, more or less to the Point of Beginning.

From the Point of Beginning thus described, run South 40°49'39" East, a distance of 195.00 feet to a point; run thence South 40°50'22" East, a distance of 188.96 feet to a point; run thence North 49°09'38" East, a distance of 93.32 feet to a point on a curve, concave Southeasterly; run thence Northeasterly, along and around the arc of a curve, concave Southeasterly and having a radius of 118.15 feet, an arc distance of 105.15 feet, said arc being subtended by a chord bearing of North 50°21'58" East, a distance of 101.71 feet; run thence North 40°50'22" West, a distance of 191.10 feet to the Point of Beginning.

Those lands of Parcel "A" and Parcel "B" as described above and in the Title Commitment are the same lands described in Surveyor's Description Parcel A without gap, gore or overlap.

EXHIBIT B (MILL SITE) (Official Records Book 7101, Page 1756):

PARCEL A:
Portions of Sections 19, 22, 24, and Webb Place, subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, according to Plat recorded in Plat Book 1, Pages 7 and 8, former Public Records of Jacksonville, Duval County, Florida, being more particularly described as follows:

For point of reference, commence at a concrete monument located at the point of intersection of the North line of said Section 22 of said subdivision, with the East line of Webb Place of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeast corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of said Northerly line of Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot right of way, as now established), along said Westerly right of way line, a distance of 3,231.34 feet to a point; run thence South 89°21'22" West, parallel with the Southerly right of way line of Kraft Road (a 60 foot right of way, as now established), a distance of 1,639.56 feet to a point; run thence South 2°51'06" East, a distance of 1,845.0 feet to a point for the Point of Beginning.

From the Point of Beginning thus described, run North 2°51'06" West, a distance of 1,845.0 feet to a point; run thence North 89°21'22" East, parallel with said Southerly right of way line of Kraft Road, a distance of 1,639.56 feet to a point on said Westerly right of way line of Eastport Road; run thence South 10°23'56" East, along said Westerly right of way line, a distance of 4,786.00 feet to a concrete monument at the point of curvature; run thence in a Southeasterly direction, along the arc of a curve in the Southwesterly right of way line of said Eastport Road, said curve being concave to the Northeast and having a radius of 592.89 feet, an arc distance of 317.83 feet to a concrete monument at the point of tangency, the aforementioned arc having a chord bearing and distance of South 25°45'21" East, 314.04 feet; run thence South 41°06'46" East, along said Southwesterly right of way line, a distance of 806.21 feet to a concrete monument; run thence in a Southwesterly direction, along the arc of a curve in said Westerly right of way line, not tangent to last described line, said curve being concave to the Northwest and having a radius of 113.24 feet, an arc distance of 201.17 feet to a concrete monument at the point of tangency, the aforementioned arc having a chord bearing and distance of South 22°59'46" West, 175.74 feet; run thence South 73°53'14" West, along the Northerly right of way line of said Eastport Road, a distance of 166.73 feet to a concrete monument at the intersection of said Northerly line, with the Northerly right of way line of Heckscher Drive, as now established; run thence in a Westerly direction, along the arc of a curve in last mentioned Northerly right of way line, said curve not being tangent to last described line, said curve being concave to the South and having a radius of 766.78 feet, an arc distance of 387.82 feet to a concrete monument at a point on a second non–tangent curve, the aforementioned arc having a chord bearing and distance of South 72°37'12" West, 383.70 feet; run thence in a Southwesterly direction, along the arc of a curve in the Northwesterly right of way line of said Heckscher Drive, said curve being concave to the Southeast and having a radius of 483.06 feet, an arc distance of 275.68 feet to the point of tangency, the aforementioned arc having a chord bearing and distance of South 59°21'27" West, 271.95 feet; run thence South 43°05'30" West, along said Northwesterly right of way line, a distance of 129.62 feet to a point on the Southerly line of lands described in deed recorded in Official Records Volume 1344, Page 261, Public Records of said County; run thence North 56°55'00" West, along said Southwesterly line, a distance of 2,485.40 feet to the point of curvature; run thence in a Northwesterly direction, along the arc of a curve in said Southwesterly deed line, said curve being concave to the Northeast and having a radius of 1000.00 feet, an arc distance of 122.00 feet to the Westerly corner of said deed, the aforementioned arc having a chord bearing and distance of North 53°25'18" West, 121.92 feet; run thence in a Northerly direction, along the waters of the Broward River, following the meanderings of same, a distance of 1,150 feet, more or less, to a point which bears South 87°08'54" West from the Point of Beginning; run thence North 87°08'54" East, a distance of 40 feet, more or less, to the Point of Beginning.

TOGETHER WITH:

PARCEL B:
Portions of Sections 18, 19, 22, 23, and Webb Place, subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, according to plat recorded in Plat Book 1, Page 7 and 8, former Public Records of Jacksonville, Duval County, Florida, being more particularly described as follows:
For a Point of Reference, commence at a concrete monument located at the point of intersection of the North line of said Section 22 of said subdivision, with the East line of Webb Place of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeast corner of said Section 22; run thence North 89°57'56" East, along said North line, a distance of 1,325.83 feet to said concrete monument located at the Northeast corner of said Section 22; run thence South 76°37'10" West, a distance of 146.58 feet to a point for Point of Beginning.
From the Point of Beginning thus described, run North 00°24'12" West, a distance of 682.91 feet to a point; run thence North 53°56'47" East, a distance of 1,076.13 feet to a point; run thence South 60°07'28" East, a distance of 417.67 feet to a point; run thence South 36°36'37" East, a distance of 454.27 feet to a point; run thence South 43°25'48" West, a distance of 871.81 feet to a point; run thence South 35°36'59" East, a distance of 1,515.38 feet to a point; run thence South 54°38'17" West, a distance of 1,833.10 feet to a point lying on the Easterly prolongation of the Northerly line of lands described in Official Records Volume 365, Page 583, Public Records of said County; run thence South 89°57'39" West, along said Easterly prolongation and along said Northerly line, a distance of 742.41 feet to the Northwesterly corner of said lands; run thence South 01°22'21" East, along the Westerly line of said lands, a distance of 202.96 feet to the Easterly corner of lands described in Official Records Volume 3204, Page 401, Public Records of said County; run thence South 54°56'50" West, along the Southeasterly line of said lands, a distance of 210.95 feet to a point lying on the Northeasterly right of way line of Eastport Road (a 66 foot right of way, as now established); run thence North 41°06'46" West, along said Northeasterly right of way line, a distance of 200.02 feet to a point lying on the Northwesterly line of said lands described in Official Records Volume 3204, Page 401; run thence North 54°56'50" East, along said Northwesterly line, a distance of 211.16 feet to the Northerly corner thereof; run thence North 51°36'05" West, a distance of 346.25 feet to a point; run thence North 26°44'44" West, a distance of 905.69 feet to a point; run thence North 10°06'08" West, a distance of 778.33 feet to a point; run thence South 79°36'04" West, perpendicular to the Easterly right of way line of said Eastport Road, a distance of 200.85 feet to a point lying on said Easterly right of way line; run thence North 10°23'56" West, along said Easterly right of way line, a distance of 434.92 feet to a point; run thence North 79°36'04" East, perpendicular to said Easterly right of way line, a distance of 418.59 feet to a point; run thence South 10°23'56" East, parallel to said Easterly right of way line, a distance of 432.27 feet to a point; run thence North 79°28'07" East, a distance of 751.68 feet to a point; run thence North 53°38'14" East, a distance of 226.55 feet to a point; run thence North 63°51'10" East, a distance of 297.92 feet to the Point of Beginning.

LESS AND EXCEPT:

A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 and said subdivision (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot Public Right of Way as now established); run thence North 10° 23' 56" West along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217–2228 of the Current Public Records of said Duval County, Florida; run thence along the Northerly and Westerly line of said lands recorded in Official Records Volume 6652, Pages 2217–2228, the following three courses and distances: First Course; South 67°49'32" West, a distance of 316.23 feet to a point; Second Course; South 49° 13' 44" West, a distance of 270.00 feet to a point; Third Course, South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 134.73 feet to a point; run thence South 40°49'39" East, a distance of 427.65 feet to a point; run thence South 03°45'19" West, a distance of 74.96 feet to a point; run thence South 41°14'41" East, a distance of 54.38 feet to a point; run thence South 49°09'38" West, a distance of 42.00 feet to a point; run thence South 41°14'41" East, a distance of 10.00 feet to a point; run thence South 49°09'38" West, a distance of 269.67 feet to a point; run thence South 40°50'22" East, a distance of 485.00 feet to a point; run thence South 49°09'38" West, a distance of 155.00 feet to a point; run thence South 40°50'22" East, a distance of 220.00 feet to a point; run thence South 49°09'38" West, a distance of 210.00 feet to a point; run thence South 40°50'22" East, a distance of 188.96 feet to a point; run thence North 49°09'38" East, a distance of 93.32 feet to a point on a curve, concave Southeasterly; run thence Northeasterly, along and around the arc of a curve, concave Southeasterly and having a radius of 118.15 feet, an arc distance of 105.15 feet, said arc being subtended by a chord bearing of North 50°21'58" East, a distance of 101.71 feet; run thence North 40°50'22" West, a distance of 191.10 feet to the Point of Beginning.

From the Point of Beginning thus described, run South 40°49'39" West, a distance of 195.00 feet to a point; run thence South 40°50'22" East, a distance of 188.96 feet to a point; run thence North 49°09'38" East, a distance of 93.32 feet to a point on a curve, concave Southeasterly; run thence Northeasterly, along and around the arc of a curve, concave Southeasterly and having a radius of 118.15 feet, an arc distance of 105.15 feet, said arc being subtended by a chord bearing of North 50°21'58" East, a distance of 101.71 feet; run thence North 40°50'22" West, a distance of 191.10 feet to the Point of Beginning.

CERTIFIED TO:
Barclays Bank PLC, a Public Limited Company as Administrative and Collateral Agent;
Cedar Bay Generating Company LP, a Delaware Limited Partnership; and
Fidelity National Title Insurance Company, a California Corporation.

THIS IS TO CERTIFY THAT THIS MAP AND THE SURVEY ON WHICH IT IS BASED WERE MADE IN ACCORDANCE WITH 2011 MINIMUM STANDARD DETAIL REQUIREMENTS FOR ALTA/ACSM LAND TITLE SURVEYS, JOINTLY ESTABLISHED AND ADOPTED BY ALTA AND NSPS, AND INCLUDES ITEMS 1, 2, 3, 4, 6(b), 8, 9, 11(b), 13, 14, 15, 16, 17, 18, 20(a) AND 21 OF TABLE A THEREOF. THE FIELDWORK WAS COMPLETED ON JANUARY 24, 2013.

NOT VALID WITHOUT THE SIGNATURE AND THE ORIGINAL RAISED SEAL OF A FLORIDA LICENSED SURVEYOR AND MAPPER.

ROBERT M. ANGAS ASSOCIATES, INC.
SURVEYORS • PLANNERS • CIVIL ENGINEERS
14775 Old St. Augustine Road, Jacksonville, FL. 32258
Tel: (904) 642–8550 Fax: (904) 642–4163
Certificate of Authorization No.: LB 3624

DATE JANUARY 24, 2013

DAMON J. KELLY
PROFESSIONAL SURVEYOR AND MAPPER
STATE of FLORIDA LS No. 6284
KellyD@rmaalnc.com

REVISED MARCH 17, 2013 TO DEPICT ALL LANDS DESCRIBED IN REVISED TITLE COMMITMENT. (WO No. 12–146.01)

SHEET 1 OF 9
SEE SHEET 5 FOR GENERAL NOTES.

CAD FILE: I:\Survey\RMAproj\Cogentrix Cedar Bay\Bndy\Generating Site Sup 2013 Alta.dwg FIELD BOOK: EFB 'ZION' DRAWN BY: DMS CHECKED BY: DJK

COUNTY: DUVAL ORDER NO.: 12–146.00 FILE NO.: 122C–38.00A

ALTA/ACSM LAND TITLE SURVEY

A PORTION OF WEBB PLACE, SUBDIVISION OF THE JOHN BROWARD GRANT, SECTION 46, TOWNSHIP 1 SOUTH, RANGE 27 EAST, DUVAL COUNTY, FLORIDA, AS DEPICTED IN PLAT BOOK 1, PAGES 7 AND 8, OF THE FORMER PUBLIC RECORDS OF SAID COUNTY, ALSO BEING A PORTION OF THOSE LANDS DESCRIBED AND RECORDED IN OFFICIAL RECORDS BOOK 6222, PAGE 504, TOGETHER WITH A PORTION OF THOSE LANDS DESCRIBED AND RECORDED IN OFFICIAL RECORDS BOOK 7101, PAGE 1756, OF THE CURRENT PUBLIC RECORDS OF SAID COUNTY.

EASEMENT DESCRIPTIONS (per Title Commitment):

SOUTH RAILROAD EASEMENT (Official Records Book 7101, Page 1756):
A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Record Volume 6652, Pages 2217–2228 of the current Public Records of said Duval County, Florida; run thence along the Northerly and Westerly line of said lands recorded in Official Records Volume 6652, Pages 2217–2228, the following three courses and distances; First Course; South 67°49'32" West, a distance of 316.23 feet to a point; Second Course; South 49°13'44" West, a distance of 270.00 feet to a point, Third Course: South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 134.73 feet; run South 40°49'39" East, a distance of 427.65 feet to a point; run thence South 03°45'19" West, a distance of 74.96 feet to a point; run thence South 41°14'41" East, a distance of 54.38 feet to a point; run thence South 49°09'38" West, a distance of 42.00 feet to a point; run thence South 41°14'41" East, a distance of 10.00 feet to a point; run thence South 49°09'38" West, a distance of 269.67 feet to a point; run thence South 40°50'22" East, a distance of 485.00 feet to a point; run thence South 49°09'38" West, a distance of 155.00 feet to a point; run thence South 40°50'22" East, a distance of 220.00 feet to a point; run thence South 49°09'38" West, a distance of 210.00 feet to a point; run thence South 40°50'22" East, a distance of 188.96 feet to a point for Point of Beginning.

From the Point of Beginning thus described, run South 54°16'48" East, a distance of 103.22 feet to a point on a curve leading Southeasterly; run thence Southeasterly, along and around the arc of a curve, concave Easterly and having a radius of 118.15 feet, an arc distance of 70.04 feet, said arc being subtended by a chord bearing and distance of South 54°16'48" East, 69.02 feet; run thence South 54°16'48" East, a distance of 564.62 feet to a point; run thence South 33°14'16" West, a distance of 125 feet, more or less, to the Mean High Waterline of the Broward River; run thence along last said line in a general Northwesterly, Westerly and Easterly direction, a distance of 1,530 feet, more or less, to a point which lies South 49°09'38" West, a distance of 175 feet, more or less, from the Point of Beginning; run thence North 49°09'38" East, a distance of 175 feet, more or less, to the Point of Beginning.

TRANSMISSION RIGHT OF WAY EASEMENT (Official Records Book 7101, Page 1756):
A portion of Section 19 and Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 1,341.87 feet to the Point of Beginning.

From the Point of Beginning thus described, run South 59°21'07" West, a distance of 1,959.89 feet; run thence North 40°49'39" West, a distance of 53.60 feet; run thence South 87°08'54" West, a distance of 155 feet, more or less, to the Mean High Waterline of the Broward River; run thence in a general Southerly direction, along said Mean High Water Line of the Broward River, a distance of 360 feet, more or less, to an intersection with said Westerly prolongation of the Northerly line of said Section 22, of the subdivision of the John Broward Grant; run thence North 89°57'56" East, along last said line (also being the Northerly line of those lands known as the Cogeneration Plant Site), a distance of 395 feet, more or less, to the Easterly line of said lands known as the Cogeneration Plant Site, run thence along last said line, the following courses: First Course, South 40°49'39" East, a distance of 427.65 feet; Second Course, South 03°45'19" West, a distance of 74.96 feet; Third Course, South 41°14'41" East, a distance of 54.38 feet; Fourth Course, South 49°09'38" West, a distance of 42.00 feet; Fifth Course, South 41°14'41" East, a distance of 10.00 feet; Sixth Course, South 49°09'38" West, a distance of 269.67 feet; Seventh Course, South 40°50'22" East, a distance of 150.00 feet; run thence North 12°28'54" West, a distance of 125.00 feet to a point which lies 40.0 feet, when measured perpendicular to the line of those lands known as the Cogeneration Plant Site; run thence North 49°09'38" East, parallel to last said line, a distance of 233.19 feet; run thence North 03°45'19" East, a distance of 172.74 feet to a point which lies 50.0 feet when measured perpendicular to said Easterly line known as the Cogeneration Plant site; run thence North 40°49'39" West, parallel to last said line, a distance of 605.14 feet; run thence North 49°10'21" East, a distance of 127.00 feet; run thence South 40°49'39" East, a distance of 300.00 feet; run thence North 49°11'04" East, a distance of 50.00 feet; run thence North 40°49'39" West, a distance of 300.00 feet; run thence North 49°10'21" East, a distance of 196.55 feet; run thence North 59°21'07" East, a distance of 683.87 feet; run thence North 79°36'04" East, a distance of 791.45 feet to an intersection with said Westerly right of way line of Eastport Road; run thence North 10°23'56" West, along last said line, a distance of 40.00 feet; run thence South 79°36'04" West, a distance of 479.92 feet; run thence North 05°09'16" West, a distance of 122.19 feet; run thence North 59°21'07" East, a distance of 499.62 feet to an intersection with said Westerly right of way line of Eastport Road; run thence North 10°23'56" West, along last said line, a distance of 117.25 feet to the Point of Beginning.

PIPELINE EASEMENT (Official Records Book 7101, Page 1756):
A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at the concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217–2228 of the current Public Records of said Duval County, Florida, run thence along the Northerly and Westerly line of said lands recorded in Official Records Volume 6652, Pages 2217–2228, the following three courses and distances: First Course, South 67°49'32" West, a distance of 316.23 feet to a point; Second Course, South 49°13'44" West, a distance of 270.00 feet to a point; Third Course, South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 134.73 feet; run South 40°49'39" East, a distance of 427.65 feet to a point; run thence South 03°45'19" West, a distance of 74.96 feet to a point; run thence South 41°14'41" East, a distance of 54.38 feet to a point; run thence South 49°09'38" West, a distance of 42.00 feet to a point; run thence South 41°14'41" East, a distance of 10.00 feet to a point; run thence South 49°09'38" West, a distance of 269.67 feet to a point; run thence South 40°50'22" East, a distance of 485.00 feet to a point; run thence South 49°09'38" West, a distance of 155.00 feet to a point; run thence South 40°50'22" East, a distance of 220.00 feet to a point; run thence South 49°09'38" West, a distance of 210.00 feet to a point; run thence South 40°50'22" East, a distance of 188.96 feet to a point; run thence South 54°16'48" East, a distance of 103.22 feet to a point on the arc of a curve, leading Southeasterly; run thence Southeasterly, along and around the arc of a curve, concave Easterly and having a radius of 118.15 feet, an arc distance of 70.04 feet, said arc being subtended by a chord bearing and distance of South 54°16'48" East, 69.02 feet; run thence South 54°16'48" East, a distance of 516.34 feet to a point; run thence North 46°03'56" East, a distance of 75.72 feet to a point; run thence South 43°56'04" East, a distance of 105.22 feet to a point; run thence South 33°14'16" West, a distance of 5.06 feet to a point for the Point of Beginning.

From the Point of Beginning thus described continue South 33°14'16" West, a distance of 40.05 feet to a point; run thence South 53°57'14" East, a distance of 87.85 feet to a point; run thence North 85°18'30" East, a distance of 219.06 feet to a point of curvature of a curve, leading Southeasterly; run thence Southeasterly, along and around the arc of a curve, concave Southeasterly and having a radius of 569.94 feet, an arc distance of 471.19 feet to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of South 71°00'27" East, 457.89 feet; run thence South 47°19'24" East, along said tangency, a distance of 206.72 feet to the point of curvature, leading Southerly; run thence Southerly, along and around the arc of a curve concave Westerly and having a radius of 150.00 feet, an arc distance of 117.81 feet to the point of reverse curvature of a curve, leading Southerly, said arc being subtended by a chord bearing and distance of South 24°49'24" East, 114.81 feet; run thence Southerly, along and around the arc of said curve, an arc distance of 209.63 feet, said arc being subtended by a chord bearing and distance of South 18°24'04" East, 206.89 feet; run thence North 55°31'17" East, 179.60 feet to a point; run thence North 34°28'43" West, a distance of 12.50 feet to a point; run thence North 55°31'17" East, a distance of 6.26 feet to a point; run thence North 47°19'24" West, a distance of 790.54 feet to a point; run thence South 85° 18' 30" West, a distance of 471.75 feet to a point; run thence North 53°57'14" West, a distance of 74.96 feet to the Point of Beginning.

LIME MUD STORAGE PARCEL (Official Records Book 7101, Page 1756):
A portion of Section 19 of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217–2228 of the current Public Records of said Duval County, Florida, run thence along the Northerly and Westerly line of said lands recorded in Official Records Volume 6652, Pages 2217–2228, the following three courses and distances: First Course, South 67°49'32" West, a distance of 316.23 feet to a point; Second Course, South 49°13'44" West, a distance of 270.00 feet to a point; Third Course, South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 134.73 feet; run South 40°49'39" East, a distance of 427.65 feet to a point; run thence South 03°45'19" West, a distance of 74.96 feet to a point; run thence South 41°14'41" East, a distance of 54.38 feet to a point; run thence South 49°09'38" West, a distance of 42.00 feet to a point; run thence South 41°14'41" East, a distance of 10.00 feet to a point; run thence South 49°09'38" West, a distance of 269.67 feet to a point; run thence South 40°50'22" East, a distance of 485.00 feet to a point; run thence South 49°09'38" West, a distance of 155.00 feet to a point; run thence South 40°50'22" East, a distance of 220.00 feet to a point; run thence South 49°09'38" West, a distance of 210.00 feet to a point; run thence South 40°50'22" East, a distance of 188.96 feet to a point; run thence South 54°16'48" East, a distance of 103.22 feet to a point on the arc of a curve, leading Southeasterly; run thence Southeasterly, along and around the arc of a curve, concave Easterly and having a radius of 118.15 feet, an arc distance of 70.04 feet, said arc being subtended by a chord bearing and distance of South 54°16'48" East, 69.02 feet; run thence South 54°16'48" East, a distance of 516.34 feet to a point; run thence North 46°03'56" East, a distance of 75.72 feet to a point; run thence South 43°56'04" East, a distance of 105.22 feet to a point; run thence South 33°14'16" West, a distance of 5.06 feet to a point for the Point of Beginning.

From the Point of Beginning thus described, run South 49°09'38" West, a distance of 20.00 feet to a point; run thence South 40°50'22" East, a distance of 322.59 feet to a point; run thence South 49°25'03" West, a distance of 26.97 feet to a point; run thence South 40°34'57" East, a distance of 70.00 feet to a point; run thence North 49°25'07" East, a distance of 95.00 feet to a point; run thence South 40°34'57" East, a distance of 463.42 feet to a point; run thence South 21°23'12" East, a distance of 233.68 feet to a point; run thence North 46°03'56" East, a distance of 37.90 feet to a point; run thence South 43°56'04" East, a distance of 91.28 feet to a point; run thence North 21°23'12" West, a distance of 254.46 feet to a point; run thence North 40°34'57" West, a distance of 602.70 feet to a point; run thence South 49°25'03" West, a distance of 98.03 feet to a point; run thence North 40°50'22" West, a distance of 322.68 feet to the Point of Beginning.

PIPELINE EASEMENT No. 2 (Official Records Book 7101, Page 1756):
A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Page 2217–2228 of the current Public Records of said Duval County, Florida; run thence along the Northerly and Westerly line of said lands recorded in Official Records Volume 6652, Pages 2217–2228, the following three courses and distances; First Course, South 67°49'32" West, a distance of 316.23 feet to a point; Second Course, South 49°13'44" West, a distance of 270.00 feet to a point; Third Course, South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 134.73 feet to a point; run thence South 40°49'39" East, a distance of 427.65 feet to a point; run thence South 03°45'19" West, a distance of 74.96 feet to a point; run thence South 41°14'41" East, a distance of 54.38 feet to a point; run thence South 49°09'38" West, a distance of 42.00 feet to a point; run thence South 41°14'41" East, a distance of 10.00 feet to a point; run thence South 49°09'38" West, a distance of 269.67 feet to a point; run thence South 40°50'22" East, a distance of 485.00 feet to a point; run thence South 49°09'38" West, a distance of 155.00 feet to a point; run thence South 40°50'22" East, a distance of 135.00 feet to a point for the Point of Beginning.

From the Point of Beginning thus described, run South 54°16'48" West, a distance of 48.28 feet to a point; run thence North 46°03'56" East, a distance of 75.72 feet to a point; run thence South 43°56'04" East, a distance of 105.22 feet to a point; run thence South 33°14'16" West, 160 feet, more or less, to the Mean High Water Line of the Broward River (formerly known as Cedar Creek); run thence, in a general Northwesterly direction, along last said line, a distance of 80 feet, more or less, to a point which bears South 33°14'16" West, 125 feet, more or less, from the Point of Beginning; run thence North 33°14'16" East, a distance of 125 feet, more or less, to the Point of Beginning.

PUMP STATION EASEMENT (Official Records Book 7101, Page 1756):
A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217–2228 of the current Public Records of said Duval County, Florida; run thence along the Northerly and Westerly line of said lands recorded in Official Records Volume 6652, Pages 2217–2228, the following three courses and distances: First Course, South 67°49'32" West, a distance of 316.23 feet to a point; Second Course, South 49°13'44" West, a distance of 270.00 feet to a point; Third Course, South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point, run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 134.73 feet; run South 40°49'39" East, a distance of 427.65 feet to a point; run thence South 03°45'19" West, a distance of 74.96 feet to a point; run thence South 41°14'41" East, a distance of 54.38 feet to a point; run thence South 49°09'38" West, a distance of 42.00 feet to a point; run thence South 41°14'41" East, a distance of 10.00 feet to a point; run thence South 49°09'38" West, a distance of 269.67 feet to a point; run thence South 40°50'22" East, a distance of 485.00 feet to a point; run thence South 49°09'38" West, a distance of 155.00 feet to a point; run thence South 40°50'22" East, a distance of 220.00 feet to a point; run thence South 49°09'38" West, a distance of 210.00 feet to a point; run thence South 40°50'22" East, a distance of d188.96 feet to a point; run thence South 54°16'48" East, a distance of 103.22 feet to a point on the arc of a curve, leading Southeasterly; run thence Southeasterly, along and around the arc of a curve, concave Easterly and having a radius of 118.15 feet, an arc distance of 70.04 feet, said arc being subtended by a chord bearing and distance of South 54°16'48" East, 69.02 feet; run thence South 54°16'48" East, a distance of 516.34 feet to a point; run thence North 46°03'56" East, a distance of 75.72 feet to a point; run thence South 43°56'04" East, a distance of 105.22 feet to a point; run thence South 33°14'16" West, a distance of 5.06 feet to a point; run thence South 53°57'14" East, a distance of 87.85 feet to a point; run thence North 85°18'30" East, a distance of 219.06 feet to a point of curvature of a curve, leading Southeasterly; run thence Southeasterly, along and around the arc of a curve, concave Southeasterly and having a radius of 569.94 feet, an arc distance of 471.19 feet to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of South 71°00'27" East, 457.89 feet; run thence South 47°19'24" East, along said tangency, a distance of 206.72 feet to the point of curvature, leading Southerly; run thence Southerly, along and around the arc of a curve concave Westerly and having a radius of 150.00 feet, an arc distance of 117.81 feet to the point of reverse curvature of a curve, leading Southerly, said arc being subtended by a chord bearing and distance of South 24°49'24" East, 114.81 feet; run thence Southerly, along and around the arc of said curve, an arc distance of 209.63 feet, said arc being subtended by a chord bearing and distance of South 18°24'04" East, 206.89 feet; run thence North 55°31'17" East, 179.60 feet to a point; run thence North 34°28'43" West, a distance of 12.50 feet to a point; run thence North 55°31'17" East, a distance of 6.26 feet to a point; run thence North 47°19'24" West, a distance of 790.54 feet to a point; run thence South 85° 18' 30" West, a distance of 471.75 feet to a point; run thence North 53°57'14" West, a distance of 74.96 feet to the Point of Beginning.

LIFT STATION EASEMENT (Official Records Book 7101, Page 1756):
A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217–2228 of the current Public Records of said Duval County, Florida; run thence along the Northerly and Westerly line of said lands recorded in Official Records Volume 6652, Pages 2217–2228, the following three courses and distances: First Course, South 67°49'32" West, a distance of 316.23 feet to a point; Second Course, South 49°13'44" West, a distance of 270.00 feet to a point; Third Course, South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 134.73 feet; run South 40°49'39" East, a distance of 427.65 feet to a point; run thence South 03°45'19" West, a distance of 74.96 feet to a point; run thence South 41°14'41" East, a distance of 54.38 feet to a point; run thence South 49°09'38" West, a distance of 42.00 feet to a point; run thence South 41°14'41" East, a distance of 10.00 feet to a point; run thence South 49°09'38" West, a distance of 269.67 feet to a point; run thence South 40°50'22" East, a distance of 485.00 feet to a point; run thence South 49°09'38" West, a distance of 155.00 feet to a point; run thence South 40°50'22" East, a distance of 220.00 feet to a point; run thence South 49°09'38" West, a distance of 210.00 feet to a point; run thence South 40°50'22" East, a distance of 188.96 feet to a point; run thence South 54°16'48" East, a distance of 103.22 feet to a point on the arc of a curve, leading Southeasterly; run thence Southeasterly, along and around the arc of a curve, concave Easterly and having a radius of 118.15 feet, an arc distance of 70.04 feet, said arc being subtended by a chord bearing and distance of South 54°16'48" East, 69.02 feet; run thence South 54°16'48" East, a distance of 564.62 feet to the Point of Beginning.

From the Point of Beginning thus described, run North 54°16'48" West, a distance of 48.28 feet to a point; run thence North 46°03'56" East, a distance of 75.72 feet to a point; run thence South 43°56'04" East, a distance of 105.22 feet to a point; run thence South 33°14'16" West, 160 feet, more or less, to the Mean High Water Line of the Broward River (formerly known as Cedar Creek); run thence, in a general Northwesterly direction, along last said line, a distance of 80 feet, more or less, to a point which bears South 33°14'16" West, 125 feet, more or less, from the Point of Beginning; run thence North 33°14'16" East, a distance of 125 feet, more or less, to the Point of Beginning.

EASEMENT FOR ROAD (Official Records Book 7101, Page 1756):
A portion of Section 19 and Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 1,745.28 feet to the Point of Beginning.

From the Point of Beginning thus described, run South 29°53'29" West, a distance of 626.29 feet; run thence South 08°42'09" West, a distance of 15.66 feet; run South 05°09'16" East, a distance of 64.63 feet; run South 59°21'07" West, a distance of 88.63 feet; run North 05°09'16" West, a distance of 112.50 feet; run North 08°42'09" East, a distance of 163.84 feet; run North 02°24'20" West, a distance of 190.16 feet; run North 01°22'46" East, a distance of 54.12 feet; run North 10°03'24" West, a distance of 206.69 feet; run North 27°56'55" West, a distance of 610.19 feet; run North 34°15'20" East, a distance of 90.43 feet; run South 27°56'55" East, a distance of 500.27 feet; run North 35°01'15" East, a distance of 62.78 feet; run North 79°37'58" East, a distance of 321.43 feet to an intersection with said Westerly right of way line of Eastport Road; run South 10°23'56" East, along last said line, a distance of 80.00 feet; thence South 79°37'58" West, a distance of 288.65 feet; run South 35°01'15" West, a distance of 70.78 feet; run South 27°56'55" East, a distance of 74.88 feet; run South 10°03'24" East, a distance of 227.29 feet; run South 01°22'46" West, a distance of 59.49 feet; run South 02°24'20" East, a distance of 144.49 feet; run North 29°53'29" East, a distance of 541.37 feet to said Westerly right of line of Eastport Road; run South 10°23'56" East, along last said line, a distance of 123.71 feet to the Point of Beginning.

PREPARED BY:
ROBERT M. ANGAS ASSOCIATES, INC.
14775 OLD ST. AUGUSTINE ROAD
JACKSONVILLE, FL 32258 (904) 642-8550
CERTIFICATE OF AUTHORIZATION NO. LB 3624

CAD FILE: I:\Survey\RMApro\Cogentrix Cedar Bay\Bndy\Generating Site Sup 2013 Alta.dwg FIELD BOOK: EFB 'ZION' DRAWN BY: DMS CHECKED BY: DJK
COUNTY: DUVAL ORDER NO.: 12-146.00 FILE NO.: 122C-38.00A

FPL 2016 Dismantlement Study (Corrected)
Exhibit KF-1, Page 104 of 127
Docket No. 160021-EI

ALTA/ACSM LAND TITLE SURVEY

A PORTION OF WEBB PLACE, SUBDIVISION OF THE JOHN BROWARD GRANT, SECTION 46, TOWNSHIP 1 SOUTH, RANGE 27 EAST, DUVAL COUNTY, FLORIDA, AS DEPICTED IN PLAT BOOK 1, PAGES 7 AND 8, OF THE FORMER PUBLIC RECORDS OF SAID COUNTY, ALSO BEING A PORTION OF THOSE LANDS DESCRIBED AND RECORDED IN OFFICIAL RECORDS BOOK 6222, PAGE 504, TOGETHER WITH A PORTION OF THOSE LANDS DESCRIBED AND RECORDED IN OFFICIAL RECORDS BOOK 7101, PAGE 1756, OF THE CURRENT PUBLIC RECORDS OF SAID COUNTY.

EASEMENT DESCRIPTIONS (per Title Commitment) (continued):

CAUSEWAY EASEMENT (Official Records Book 7101, Page 1756):
A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217 thru 2228 of the current Public Records of said Duval County, Florida; run thence along the Northerly and Westerly line of said lands recorded in Official Records Volume 6652, Pages 2217 thru 2228, the following three courses and distances: First Course: South 67°49'32" West, a distance of 316.23 feet to a point; Second Course: South 49°13'44" West, a distance of 270.00 feet to a point, Third Course: South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 332.50 feet to the Point of Beginning.

From the Point of Beginning thus described, run North 02°51'06" West, a distance of 2,025.47 feet; run thence South 86°59'53" West, a distance of 112.66 feet to an intersection with the Westerly line of Parcel A, of those lands described and recorded in Official Records Volume 6222, Pages 511 thru 535, of the current Public Records of said county; run thence along last said line the following three courses and distances: first course, South 02°51'06" East, a distance of 699.63 feet to a point; second course, South 87°08'54" West, a distance of 40 feet, more or less, to the Mean High Water Line of the Broward River; third course, thence in a general Southerly direction, along said Mean High Water Line of the Broward River, a distance of 1,320 feet, more or less, to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said Subdivision, and lying South 87°57'56" West, a distance of 198 feet, more or less; from the Point of Beginning; run thence North 89°57'56" East, along said Westerly prolongation, a distance of 198 feet, more or less, to the Point of Beginning.

Less and Except those easements, right-of ways, and rights of easements recorded in the following instruments, in the current Public Records of said County:

A.) Deed Book 1769, Page 253 et seq
B.) Deed Book 190, Page 156 et seq
C.) Official Records Volume 452, Page 337 et seq
D.) Official Records Volume 2517, Page 291 et seq

CAUSEWAY EASEMENT No. 2 (Official Records Book 7101, Page 1756):
A portion of Section 19 and Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217 thru 2228 of the current Public Records of said Duval County, Florida; run thence along the Northerly and Westerly line of said lands recorded in Official Records Volume 6652, Pages 2217 thru 2228, the following three courses and distances: First Course: South 67°49'32" West, a distance of 316.23 feet to a point; Second Course: South 49°13'44" West, a distance of 270.00 feet to a point, Third Course: South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 1029.79 feet to the Point of Beginning.

From the Point of Beginning thus described, continue North 02°51'06" West, a distance of 600.00 feet to a point; run thence North 87°08'54" East, a distance of 150.00 feet to a point; run thence South 02°51'06" East, a distance of 600.00 feet to a point; run thence South 87°08'54" West, a distance of 150.00 feet to the Point of Beginning.

PERMANENT ACCESS ROAD EASEMENT (Official Records Book 7101, Page 1756):
A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence South 10°23'56" East, along said Westerly right of way line, a distance of 144.81 feet to the Point of Beginning.

From the Point of Beginning thus described, continue South 10°23'56" East, along said Westerly right of way line of Eastport Road, a distance of 40.04 feet; thence South 77°06'14" West, 158.21 feet; thence South 61°04'42" West, 416.47 feet to the point of curvature, of a curve leading Southwesterly; thence Southwesterly, along and around the arc of a curve, concave Northwesterly and having a radius of 469.48 feet, an arc distance of 162.33 feet, to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of South 70°59'02" West, 161.53 feet; thence South 80°53'23" West, along said tangency, a distance of 31.76 feet, to the point of curvature, of a curve leading Southwesterly; thence Southwesterly, along and around the arc of a curve, concave Southeasterly and having a radius of 249.08 feet, an arc distance of 126.46 feet, to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of South 66°20'43" West, 125.10; thence South 51°48'04" West, along said tangency, a distance of 42.83 feet, to the point of curvature, of a curve leading Northwesterly; thence Northwesterly, along and around the arc of a curve, concave Northerly, and having a radius of 100.00 feet, an arc distance of 152.46 feet, to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of North 84°31'18" West, 138.12 feet; thence North 40°50'41" West, along said tangency, a distance of 141.15 feet, to the point of curvature, of a curve leading Westerly; thence Westerly, along and around the arc of a curve, concave Southerly and having a radius of 20.11 feet, an arc distance of 29.56 feet, to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of North 82°56'42" West, 26.97 feet; thence South 54°57'18" West, along said tangency, a distance of 131.41 feet, to the point of curvature of a curve leading Northwesterly; thence Northwesterly, along and around the arc of a curve, concave Northeasterly and having a radius of 60 feet an arc distance of 88.19 feet, to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of North 82°56'11" West, 80.46 feet; thence South 40°49'39" West, along said tangency a distance of 653.03 feet, to an intersection with said Westerly prolongation of the Northerly line of said Section 22, of the subdivision of the John Broward Grant; thence North 89°57'56" East, along last said line, a distance of 52.83 feet, to a point; thence South 40°49'39" East, 618.51 feet to the point of curvature of a curve leading Southeasterly; thence Southeasterly along and around the arc of a curve, concave Northeasterly, and having a radius of 60.00 feet, an arc distance of 29.40 feet, to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of South 82°56'11" East, 26.82 feet; thence North 54°57'18" East, along said tangency, a distance of 131.41 feet, to the point of curvature of a curve, leading Southeasterly; thence Southeasterly, along and around the arc of a curve, concave Southerly, and having a radius 60.11 feet, an arc distance of 88.34 feet, to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of South 82°56'42" East, 80.60 feet; thence South 40°50'41" East, along said tangency, a distance of 141.15 feet, to the point of curvature of a curve leading Southeasterly; thence Southeasterly, along and around the arc of a curve, concave Northeasterly, having a radius of 89.48 feet, to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of South 84°31'18" East, 82.87 feet; thence North 51°48'04" East, along said tangency, a distance of 42.83 feet, to the point curvature of a curve leading Northeasterly; thence Northeasterly, along and around the arc of a curve, concave Southeasterly, and having a radius of 289.08 feet, an arc distance of 146.76 feet, to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of North 66°20'43" East, 145.19 feet; thence North 80°53'23" East, along said tangency, a distance of 31.76 feet, to the point of curvature, of a curve leading Northeasterly; thence Northeasterly, along and around the arc of a curve, being concave Northwesterly, and having a radius of 429.48 feet, an arc distance of 148.50 feet, to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of North 70°59'02" East, 147.76 feet; thence North 61°04'42" East, along said tangency, a distance of 422.10 feet, to a point; thence North 77°06'14" East, a distance of 165.58 feet, to an intersection with said Westerly right of way line of Eastport Road, and the Point of Beginning.

CONSTRUCTION WAREHOUSE AND OFFICE AREA (Official Records Book 7101, Page 1756):
A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217 thru 2228 of the current Public Records of said Duval County, Florida; run thence along the Northerly and Westerly line of said lands recorded in Official Records Volume 6652, Pages 2217 thru 2228, the following three courses and distances: First Course: South 67°49'32" West, a distance of 316.23 feet to a point; Second Course: South 49°13'44" West, a distance of 270.00 feet to a point, Third Course: South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to the Point of Beginning.

From the Point of Beginning thus described, run North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence South 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 688.13 feet to a point; run thence North 49°09'38" East, a distance of 200.00 feet to a point; run thence North 40°49'39" West, a distance of 284.73 feet to the Point of Beginning.

CONSTRUCTION LAYDOWN AREA 1 (Official Records Book 7101, Page 1756):
A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217 thru 2228, the following three courses and distances: First Course: South 67°49'32" West, a distance of 316.23 feet to a point; Second Course: South 49°13'44" West, a distance of 270.00 feet to a point, Third Course: South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 332.50 feet to the Point of Beginning.

From the Point of Beginning thus described, run North 02°51'06" West, a distance of 2,025.47 feet; run thence South 86°59'53" West, a distance of 112.66 feet to an intersection with the Westerly line of Parcel A, of those lands described and recorded in Official Records Volume 6222, Pages 511 thru 535, of the current Public Records of said county; run thence along last said line the following three courses and distances: first course, South 02°51'06" East, a distance of 699.63 feet to a point; second course, South 87°08'54" West, a distance of 40 feet, more or less, to the Mean High Water Line of the Broward River; third course, thence in a general Southerly direction, along said Mean High Water Line of the Broward River, a distance of 1,320 feet, more or less, to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said Subdivision, and lying South 87°57'56" West, a distance of 198 feet, more or less; from the Point of Beginning; run thence North 89°57'56" East, along said Westerly prolongation, a distance of 198 feet, more or less, to the Point of Beginning.

Less and Except those easements, right-of ways, and rights of easements recorded in the following instruments, in the current Public Records of said County:

A.) Deed Book 1769, Page 253 et seq
B.) Deed Book 190, Page 156 et seq
C.) Official Records Volume 452, Page 337 et seq
D.) Official Records Volume 2517, Page 291 et seq

CAUSEWAY EASEMENT No. 2 (Official Records Book 7101, Page 1756):
A portion of Section 19 and Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217 thru 2228 of the current Public Records of said Duval County, Florida; run thence along the Northerly and Westerly line of said lands recorded in Official Records Volume 6652, Pages 2217 thru 2228, the following three courses and distances: First Course: South 67°49'32" West, a distance of 316.23 feet to a point; Second Course: South 49°13'44" West, a distance of 270.00 feet to a point, Third Course: South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 1029.79 feet to the Point of Beginning.

From the Point of Beginning thus described, continue North 02°51'06" West, a distance of 600.00 feet to a point; run thence North 87°08'54" East, a distance of 150.00 feet to a point; run thence South 02°51'06" East, a distance of 600.00 feet to a point; run thence South 87°08'54" West, a distance of 150.00 feet to the Point of Beginning.

PERMANENT ACCESS ROAD EASEMENT (Official Records Book 7101, Page 1756):
A portion of Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 890.02 feet to a point on said Westerly right of way line; run thence South 79°36'04" West, a distance of 508.51 feet to a point at the Northeasterly corner of those lands described and recorded in Official Records Volume 6652, Pages 2217 thru 2228, the following three courses and distances: First Course: South 67°49'32" West, a distance of 316.23 feet to a point; Second Course: South 49°13'44" West, a distance of 270.00 feet to a point, Third Course: South 40°46'16" East, a distance of 644.88 feet to an intersection with said Westerly prolongation of said Northerly line of said Section 22; run thence South 89°57'56" West, along last said line, a distance of 618.79 feet to a point; run thence North 40°49'39" West, a distance of 128.34 feet to a point; run thence South 49°11'04" West, a distance of 100.00 feet to a point; run thence North 40°49'39" West, a distance of 275.00 feet to a point; run thence South 49°10'21" West, a distance of 100.00 feet to a point; run thence South 40°49'39" East, a distance of 230.77 feet to an intersection with said Westerly prolongation of the Northerly line of Section 22 of said subdivision; run thence South 89°57'56" West, along last said line, a distance of 1029.79 feet to the Point of Beginning.

From the Point of Beginning thus described, continue North 02°51'06" West, a distance of 600.00 feet to a point; run thence North 87°08'54" East, a distance of 150.00 feet to a point; run thence South 02°51'06" East, a distance of 600.00 feet to a point; run thence South 87°08'54" West, a distance of 150.00 feet to the Point of Beginning.

CONSTRUCTION LAYDOWN AREA 2 (Official Records Book 7101, Page 1756):
A portion of Section 19 and Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 1341.87 feet to a point; run thence South 59°21'07" West, a distance of 1493.54 feet to the Point of Beginning.

From the Point of Beginning thus described, run thence North 39°57'23" West, a distance of 330.35 feet; run thence North 70°51'19" West, a distance of 355.62 feet; run thence South 02°55'20" East, a distance of 435.27 feet to the point of curve, leading Southeasterly; run thence Southeasterly, along and around the arc of a curve, being concave Easterly and having a radius of 88.46 feet, an arc distance of 58.52 feet to the point of tangency of said curve, said arc being subtended by a chord bearing and distance of South 21°52'30" East, a distance of 57.46 feet; run thence along said tangent, South 40°49'39" East, a distance of 292.28 feet; run thence North 49°10'21" East, a distance of 351.77 feet; run thence North 59°21'07" East, a distance of 107.85 feet; run thence North 39°57'23" West, a distance of 70.93 feet to the Point of Beginning.

CONSTRUCTION LAYDOWN AREA 3 (Official Records Book 7101, Page 1756):
A portion of Section 19 and Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 1341.87 feet to a point; run thence South 59°21'07" West, a distance of 532.07 feet to the Point of Beginning.

From the Point of Beginning thus described, run thence South 05°09'16" East, a distance of 77.55 feet; run thence South 59°21'07" West, a distance of 458.07 feet; run thence North 17°54'38" West, a distance of 923.07 feet; run thence South 87°31'54" East, a distance of 676.01 feet; run thence South 10°03'24" East, a distance of 20.71 feet; run thence South 01°22'46" West, a distance of 54.12 feet; run thence South 02°24'20" East, a distance of 190.16 feet; run thence South 08°42'09" West, a distance of 163.84 feet; run thence South 05°09'16" East, a distance of 112.50 feet to the Point of Beginning.

CONSTRUCTION LAYDOWN AREA 4 (Official Records Book 7101, Page 1756):
A portion of Section 19 and Webb Place of the subdivision of the John Broward Grant, Section 46, Township 1 South, Range 27 East, Jacksonville, Duval County, Florida, as recorded in Plat Book 1, Pages 7 and 8, of the former Public Records of said Duval County, Florida, and being more particularly described as follows:

For Point of Reference, commence at a concrete monument located at the point of intersection of the Northerly line of Section 22 of said subdivision, (also being the Southerly line of Section 19 of said subdivision), with the Easterly line of said subdivision, said monument lying South 89°57'56" West, a distance of 1,325.83 feet from a concrete monument located at the Northeasterly corner of said Section 22; run thence South 89°57'56" West, along the Westerly prolongation of the Northerly line of said Section 22, a distance of 578.30 feet to a point on the Westerly right of way line of Eastport Road (a 66 foot public right of way, as now established); run thence North 10°23'56" West, along said Westerly right of way line, a distance of 1341.87 feet to a point; run thence South 59°21'07" West, a distance of 443.44 feet to the Point of Beginning.

From the Point of Beginning thus described, continue South 59°21'07" West, a distance of 44.31 feet; run thence South 05°09'16" East, a distance of 180.16 feet; run thence North 47°18'53" East, a distance of 122.13 feet; run thence North 03°53'21" West, a distance of 180.40 feet; run thence North 58°09'11" East, 153.94 feet; run thence North 10°55'34" West, a distance of 711.30 feet; run thence South 79°37'58" West, a distance of 75.01 feet; run thence South 35°01'15" West, a distance of 70.78 feet; run thence South 27°56'55" East, a distance of 74.88 feet; run thence South 10°03'24" East, a distance of 227.29 feet; run thence South 01°22'46" West, a distance of 59.49 feet; run thence South 02°24'20" East, a distance of 195.29 feet; run thence South 08°42'09" West, a distance of 161.89 feet; run thence South 05°09'16" East, a distance of 64.63 feet to the Point of Beginning.

PREPARED BY:
ROBERT M. ANGAS ASSOCIATES, INC.
14775 OLD ST. AUGUSTINE ROAD
JACKSONVILLE, FL 32258 (904) 642-8550
CERTIFICATE OF AUTHORIZATION NO. LB 3624

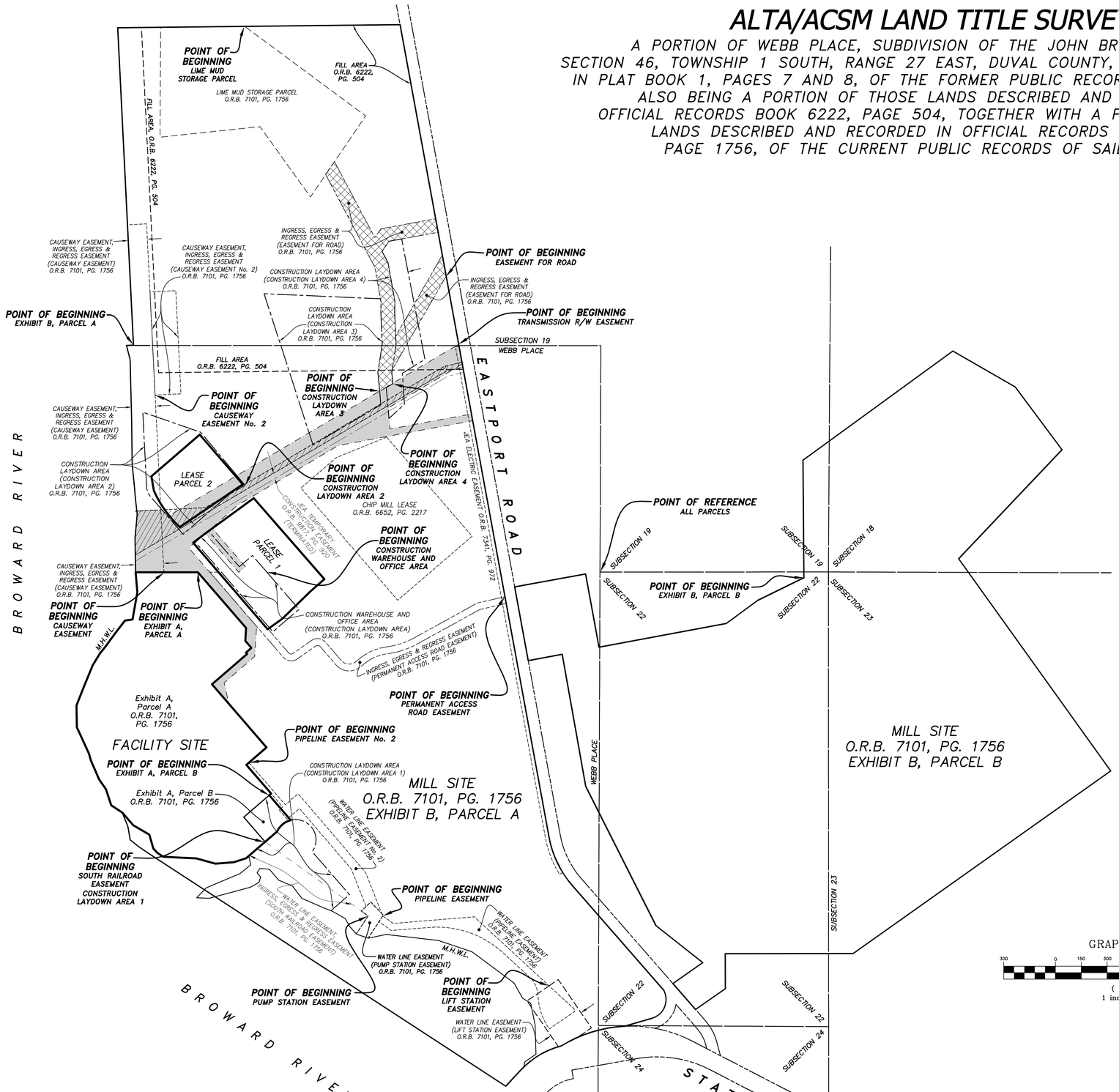
SHEET 3 OF 9
SEE SHEET 5 FOR GENERAL NOTES.

CAD FILE: I:\Survey\RMAproj\Cogentrix Cedar Bay\Bndy\Generating Site Sup 2013 Alta.dwg FIELD BOOK: EFB 'ZION' DRAWN BY: DMS CHECKED BY: DJK COUNTY: DUVAL ORDER NO.: 12-146.00 FILE NO.: 122C-38.00A

FPL 2016 Dismantlement Study (Corrected)
Exhibit KC-4, Page 105 of 127
Docket No. 160021-EI

ALTA/ACSM LAND TITLE SURVEY

A PORTION OF WEBB PLACE, SUBDIVISION OF THE JOHN BROWARD GRANT, SECTION 46, TOWNSHIP 1 SOUTH, RANGE 27 EAST, DUVAL COUNTY, FLORIDA, AS DEPICTED IN PLAT BOOK 1, PAGES 7 AND 8, OF THE FORMER PUBLIC RECORDS OF SAID COUNTY, ALSO BEING A PORTION OF THOSE LANDS DESCRIBED AND RECORDED IN OFFICIAL RECORDS BOOK 6222, PAGE 504, TOGETHER WITH A PORTION OF THOSE LANDS DESCRIBED AND RECORDED IN OFFICIAL RECORDS BOOK 7101, PAGE 1756, OF THE CURRENT PUBLIC RECORDS OF SAID COUNTY.



GRAPHIC SCALE

300 0 150 300 600 1200

(IN FEET)
1 inch = 300 ft.

LEGEND:

O.R.B.	OFFICIAL RECORDS BOOK
PG.	PAGE
R/W	RIGHT OF WAY
C/L	CENTERLINE
POC	POINT ON CURVE
M.H.W.L.	MEAN HIGH WATER LINE
LB	LICENSED BUSINESS
ID	IDENTIFICATION
(R)	DATA OF RECORD
(M)	MEASURED DATA
FND	FOUND
CM	CONCRETE MONUMENT
RB	REBAR
RB&C	REBAR AND CAP
IP	IRON PIPE
IP&C	IRON PIPE AND CAP
N&D	NAIL AND DISK
LT	TABULATED LINE DATA
CT	TABULATED CURVE DATA
R	RADIUS
Δ	CENTRAL ANGLE
L	ARC LENGTH
CB	CHORD BEARING
CH	CHORD DISTANCE
CONC	CONCRETE
CLF	CHAIN LINK FENCE
FWF	FIELD WIRE FENCE
TWPB	TELEPHONE WIRE PULL BOX
–OH–	OVERHEAD UTILITIES
MUP	METAL UTILITY POLE
WUP	WOOD UTILITY POLE
CUP	CONCRETE UTILITY POLE
WLP	WOOD LIGHT POLE
CLP	CONCRETE LIGHT POLE
GYA	GUY ANCHOR
WGP	WOOD GUY POLE
ELMK	ELECTRIC LINE MARKER
EWPB	ELECTRIC WIRE PULL BOX
RWV	RECLAIMED WATER VALVE
WV	WATER VALVE
FH	FIRE HYDRANT
BFP	BACK FLOW PREVENTER
SV	SANITARY SEWER VALVE
SMH	SANITARY MAN HOLE
RR	RAILROAD
XING	CROSSING
SLS	SPEED LIMIT SIGN
	SIGN
	RAILROAD TRACK

DENOTES TELEPHONE LINE EASEMENT, WATER LINE EASEMENT, INGRESS, EGRESS & REGRESS EASEMENT, POWER LINE EASEMENT (TRANSMISSION R/W EASEMENT), O.R.B. 7101, PG. 1756

DENOTES JEA EASEMENT O.R.B. 9817, PG. 916

DENOTES INGRESS, EGRESS & REGRESS EASEMENT (EASEMENT FOR ROAD) O.R.B. 7101, PG. 1756

SHEET 4 OF 9
EASEMENT DETAIL SHEET.
SEE SHEET 5 FOR GENERAL NOTES.
SEE SHEETS 1, 2 AND 3 FOR LEGAL DESCRIPTIONS.

PREPARED BY:
ROBERT M. ANGAS ASSOCIATES, INC.
14775 OLD ST. AUGUSTINE ROAD
JACKSONVILLE, FL 32258 (904) 642-8550
CERTIFICATE OF AUTHORIZATION NO. LB 3624

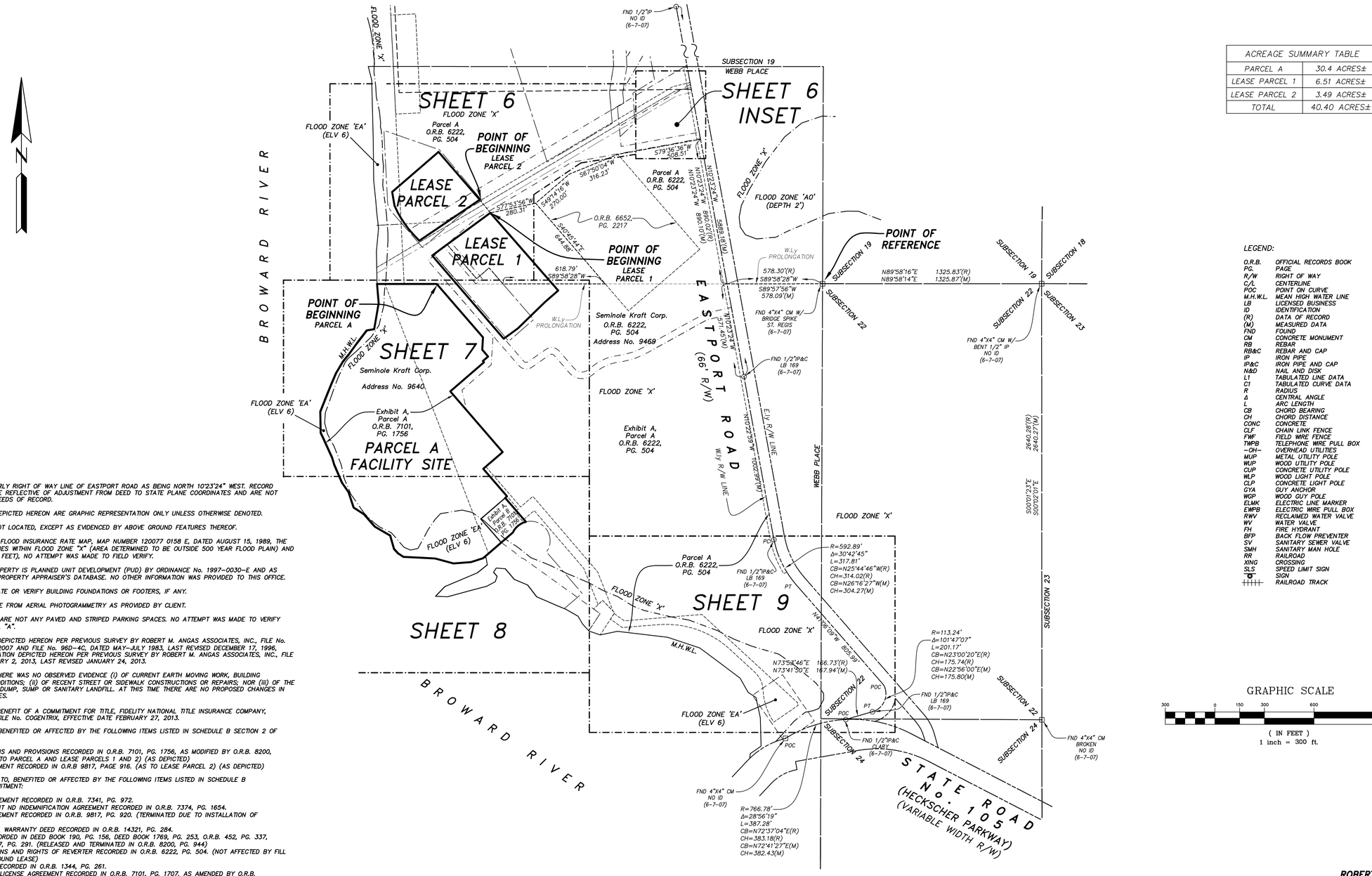
CAD FILE: I:\Survey\RMAproj\Cogentrix Cedar Bay\Bndy\Generating Site Sup 2013 Alta.dwg FIELD BOOK: EFB "ZION" DRAWN BY: DMS CHECKED BY: DJK

COUNTY: DUVAL ORDER NO.: 12-146.00 FILE NO.: 122C-38.00A

Docket No. 160021-EI
FPL 2016 Dismantlement Study (Corrected)
Exhibit KF-4, Page 106 of 127

ALTA/ACSM LAND TITLE SURVEY

A PORTION OF WEBB PLACE, SUBDIVISION OF THE JOHN BROWARD GRANT, SECTION 46, TOWNSHIP 1 SOUTH, RANGE 27 EAST, DUVAL COUNTY, FLORIDA, AS DEPICTED IN PLAT BOOK 1, PAGES 7 AND 8, OF THE FORMER PUBLIC RECORDS OF SAID COUNTY, ALSO BEING A PORTION OF THOSE LANDS DESCRIBED AND RECORDED IN OFFICIAL RECORDS BOOK 6222, PAGE 504, TOGETHER WITH A PORTION OF THOSE LANDS DESCRIBED AND RECORDED IN OFFICIAL RECORDS BOOK 7101, PAGE 1756, OF THE CURRENT PUBLIC RECORDS OF SAID COUNTY, BEING MORE PARTICULARLY DESCRIBED TO THE RIGHT.



ACREAGE SUMMARY TABLE	
PARCEL A	30.4 ACRES±
LEASE PARCEL 1	6.51 ACRES±
LEASE PARCEL 2	3.49 ACRES±
TOTAL	40.40 ACRES±

LEGEND:

O.R.B.	OFFICIAL RECORDS BOOK
PG.	PAGE
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C/L	CENTERLINE
POC	POINT ON CURVE
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LB	LICENSED BUSINESS
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XING	CROSSING
SLS	SPEED LIMIT SIGN
	SIGN
	RAILROAD TRACK

GRAPHIC SCALE

300 0 150 300 600 1200

(IN FEET)
1 inch = 300 ft.

GENERAL NOTES:

1) THIS IS A BOUNDARY SURVEY.

2) BEARINGS BASED ON THE WESTERLY RIGHT OF WAY LINE OF EASTPORT ROAD AS BEING NORTH 10°23'24" WEST. RECORD BEARINGS DEPICTED HEREON ARE REFLECTIVE OF ADJUSTMENT FROM DEED TO STATE PLANE COORDINATES AND ARE NOT TRANSCRIBED VERBATIM FROM DEEDS OF RECORD.

3) SECTION LINES AND LOT LINES DEPICTED HEREON ARE GRAPHIC REPRESENTATION ONLY UNLESS OTHERWISE DENOTED.

4) UNDERGROUND IMPROVEMENTS NOT LOCATED, EXCEPT AS EVIDENCED BY ABOVE GROUND FEATURES THEREOF.

5) EXAMINATION OF DUVAL COUNTY FLOOD INSURANCE RATE MAP, MAP NUMBER 120077 0158 E, DATED AUGUST 15, 1989, THE PROPERTY DESCRIBED HEREON LIES WITHIN FLOOD ZONE "X" (AREA DETERMINED TO BE OUTSIDE 500 YEAR FLOOD PLAIN) AND "AE" (BASE FLOOD ELEVATION 6 FEET), NO ATTEMPT WAS MADE TO FIELD VERIFY.

6) ZONING FOR THE DESCRIBED PROPERTY IS PLANNED UNIT DEVELOPMENT (PUD) BY ORDINANCE No. 1997-0030-E AND AS AMENDED, PER DUVAL COUNTY PROPERTY APPRAISER'S DATABASE. NO OTHER INFORMATION WAS PROVIDED TO THIS OFFICE.

7) NO ATTEMPT WAS MADE TO LOCATE OR VERIFY BUILDING FOUNDATIONS OR FOOTERS, IF ANY.

8) INTERIOR SITE IMPROVEMENTS ARE FROM AERIAL PHOTOGRAMMETRY AS PROVIDED BY CLIENT.

9) OUTSIDE PARCEL OF "A", THERE ARE NOT ANY PAVED AND STRIPED PARKING SPACES. NO ATTEMPT WAS MADE TO VERIFY PARKING SPACES WITHIN PARCEL "A".

10) SOME BOUNDARY INFORMATION DEPICTED HEREON PER PREVIOUS SURVEY BY ROBERT M. ANGAS ASSOCIATES, INC., FILE No. 119D-09(BND), DATED JUNE 7, 2007 AND FILE No. 96D-4C, DATED MAY-JULY 1983, LAST REVISED DECEMBER 17, 1996, MEAN HIGH WATER LINE INFORMATION DEPICTED HEREON PER PREVIOUS SURVEY BY ROBERT M. ANGAS ASSOCIATES, INC., FILE No. 122C-38.00B, DATED JANUARY 2, 2013, LAST REVISED JANUARY 24, 2013.

11) FOR THE DEPICTED PROPERTY THERE WAS NO OBSERVED EVIDENCE (I) OF CURRENT EARTH MOVING WORK, BUILDING CONSTRUCTION OR BUILDING ADDITIONS; (II) OF RECENT STREET OR SIDEWALK CONSTRUCTIONS OR REPAIRS; NOR (III) OF THE SITE USED AS A SOLID WASTE DUMP, SUMP OR SANITARY LANDFILL. AT THIS TIME THERE ARE NO PROPOSED CHANGES IN THE STREET RIGHT OF WAY LINES.

12) SURVEY PERFORMED WITH THE BENEFIT OF A COMMITMENT FOR TITLE, FIDELITY NATIONAL TITLE INSURANCE COMPANY, COMMITMENT No. NT12-3449, FILE No. COGENTRIX, EFFECTIVE DATE FEBRUARY 27, 2013.

THE PROPERTY IS SUBJECT TO, BENEFITED OR AFFECTED BY THE FOLLOWING ITEMS LISTED IN SCHEDULE B SECTION 2 OF SAID TITLE COMMITMENT:

ITEM 7) TERMS, CONDITIONS AND PROVISIONS RECORDED IN O.R.B. 7101, PG. 1756, AS MODIFIED BY O.R.B. 8200, PAGE 944. (AS TO PARCEL A AND LEASE PARCELS 1 AND 2) (AS DEPICTED)
ITEM 10) GRANT OF EASEMENT RECORDED IN O.R.B 9817, PAGE 916. (AS TO LEASE PARCEL 2) (AS DEPICTED)

THE PROPERTY IS NOT SUBJECT TO, BENEFITED OR AFFECTED BY THE FOLLOWING ITEMS LISTED IN SCHEDULE B SECTION 2 OF SAID TITLE COMMITMENT:

ITEM 8) JEA SPECIAL EASEMENT RECORDED IN O.R.B. 7341, PG. 972.
ITEM 9) REVOCABLE PERMIT ND INDEMNIFICATION AGREEMENT RECORDED IN O.R.B. 7374, PG. 1654.
ITEM 11) TEMPORARY EASEMENT RECORDED IN O.R.B. 9817, PG. 920. (TERMINATED DUE TO INSTALLATION OF IMPROVEMENTS)
ITEM 12) FLORIDA SPECIAL WARRANTY DEED RECORDED IN O.R.B. 14321, PG. 284.
ITEM 13) EASEMENTS RECORDED IN DEED BOOK 190, PG. 156, DEED BOOK 1769, PG. 253, O.R.B. 452, PG. 337, AND O.R.B. 2517, PG. 291. (RELEASED AND TERMINATED IN O.R.B. 8200, PG. 944)
ITEM 16) TERMS, CONDITIONS AND RIGHTS OF REVERTER RECORDED IN O.R.B. 6222, PG. 504. (NOT AFFECTED BY FILL LICENCE OF GROUND LEASE)
ITEM 17) RESERVATIONS RECORDED IN O.R.B. 1344, PG. 261.
ITEM 18) SIDETRACK AND LICENSE AGREEMENT RECORDED IN O.R.B. 7101, PG. 1707, AS AMENDED BY O.R.B. 7101, PG. 1746, AND SECOND AMENDMENT IN O.R.B. 8203, PG. 722. (SECOND AMENDMENT REPLACES EASEMENTS WHICH ARE SUBSEQUENTLY RELEASED AND TERMINATED BY O.R.B. 8200, PG. 944)

ALL THE ABOVE ITEMS RECORDED IN THE CURRENT PUBLIC RECORDS OF DUVAL COUNTY, FLORIDA.

SHEET 5 OF 9
SURVEY DETAIL SHEET.
SEE SHEETS 1, 2 AND 3 FOR LEGAL DESCRIPTIONS.

PREPARED BY:
ROBERT M. ANGAS ASSOCIATES, INC.
14775 OLD ST. AUGUSTINE ROAD
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CERTIFICATE OF AUTHORIZATION NO. LB 3624

CAD FILE: I:\Survey\RMAproj\Cogentrix Cedar Bay\Bnd\Generating Site Sup 2013 Alta.dwg FIELD BOOK: EFB "ZION" DRAWN BY: DMS CHECKED BY: DJK

COUNTY: DUVAL ORDER NO.: 12-146.00 FILE NO.: 122C-38.00A

Docket No. 160002-EI
FPL 2016 Ehanancement Study (Corrected)
Exhibit RT-4 Page 107 of 127

ALTA/ACSM LAND TITLE SURVEY

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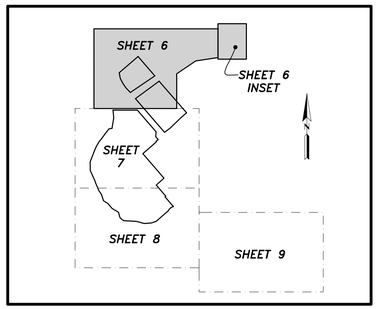

SHEET KEY
(NOT TO SCALE)

LEGEND:

O.R.B.	OFFICIAL RECORDS BOOK
PG.	PAGE
R/W	RIGHT OF WAY
C/L	CENTERLINE
POC	POINT ON CURVE
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XING	CROSSING
SLS	SPEED LIMIT SIGN
	SIGN
	RAILROAD TRACK

FACILITIES LEGEND	
BLDG. ID.	DESCRIPTION
1	STEAM GENERATOR STRUCTURE
2	TURBINE GENERATOR BUILDING
3	TRANSFORMER AREA
4	FABRIC FILTER
5	ID FAN
6	CHIMNEY
7	COOLING TOWER
8	CIRCULATING WATER PUMP STRUCTURE
9	FLY ASH SILO
10	BED ASH SILO
11	PIPE RACK
12	BED ASH STORAGE HOPPER
13	ASH PALLETIZING BUILDING (Foundation Only)
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15	CURED PELLET STORAGE
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50	EMERGENCY OVERFLOW
51	COAL CONVEYOR 2
52	COAL CONVEYOR 3
53	COAL FEEDER 2
54	COAL CONVEYOR 4
55	COAL RECLAIM HOPPER 1
56	WATER PRE/POST TREATMENT AREA
57	WASTE FIBER LOADING HOPPER
58	WASTE FIBER CONVEYOR
59	DENOX FACILITY
60	STORMWATER STORAGE TANK

GRAPHIC SCALE
60 0 30 60 120 240
(IN FEET)
1 inch = 60 ft.

FLOOD ZONE 'X'

FLOOD ZONE 'X', FLOOD ZONE 'EA' (ELV 6)

APPROXIMATE M.H.W.L.

BROWARD RIVER

CAUSEWAY EASEMENT, INGRESS, EGRESS & REGRESS EASEMENT (CAUSEWAY EASEMENT) O.R.B. 7101, PG. 1756

CAUSEWAY EASEMENT, INGRESS, EGRESS & REGRESS EASEMENT (CAUSEWAY EASEMENT No. 2) O.R.B. 7101, PG. 1756

MEAN HIGH WATER LINE PER PREVIOUS SURVEY BY ROBERT M. ANGAS ASSOCIATES, INC. FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION FILE No. 5160

Parcel A O.R.B. 6222, PG. 504

LEASE PARCEL 2

LEASE PARCEL 1

SET 5/8"RB&C LB 3624

POC

N49°11'08"E 370.75'

S40°48'52"E 382.13'

N09°48'40"W 84.68'

R=665.76'
Δ=22°29'35"
L=261.36'
CB=N35°23'40"W
CH=259.69'

S55°49'01"W 441.86'

N53°50'15"E 176.06'

N53°53'30"E 170.27'

N52°59'04"E 90.52'

S41°06'50"E 624.12'

N40°42'13"W 663.30'

S49°10'15"W 100.00'

N40°49'07"W 275.00'

S40°49'07"E 230.27'

S54°07'16"W 100.00'

N40°49'07"W 128.34'

CONSTRUCTION LAYDOWN AREA (CONSTRUCTION LAYDOWN AREA 2) O.R.B. 7101, PG. 1756

CONSTRUCTION LAYDOWN AREA (CONSTRUCTION LAYDOWN AREA 3) O.R.B. 7101, PG. 1756

CONSTRUCTION LAYDOWN AREA (CONSTRUCTION LAYDOWN AREA 4) O.R.B. 7101, PG. 1756

INGRESS, EGRESS & REGRESS EASEMENT (ROAD EASEMENT) O.R.B. 7101, PG. 1756

JEA EASEMENT O.R.B. 9817, PG. 916

JEA TEMPORARY CONSTRUCTION EASEMENT O.R.B. 9817, PG. 920 (TERMINATED)

TELEPHONE LINE EASEMENT, WATER LINE EASEMENT, INGRESS, EGRESS & REGRESS EASEMENT, POWER LINE EASEMENT (TRANSMISSION R/W EASEMENT) O.R.B. 7101, PG. 1756

TRANSMISSION INTERCONNECTION TO JEA

UNPAVED PARKING AREA

PAVED PARKING AREA

ASPHALT PAVEMENT

SITE ACCESS RAAD TO EASTPORT ROAD

ONE STORY METAL BUILDING

PUMP BOX

TANK PAD

CONC PAD

CONC PAD W/ TRANSFORMER

WELL

WALL

RR XING

UNDERGROUND UTILITY TRANS.

10"WATER LINE

10"WLP (SOLAR)

20"WUP

45"WUP

(2)TWPB

S49°41'16"W 270.00

S77°53'56"W 280.31'

S49°41'16"E 644.48'

W.l/y LINE OF O.R.B. 6652, PG. 2217

N.l/y LINE OF O.R.B. 6652, PG. 2217

316.23'

S67°50'04"W

O.R.B. 6652, PG. 2217

S79°36'36"W 508.51'

MATCHLINE SEE SHEET 5

MATCHLINE SEE SHEET 7

MATCHLINE SEE INSET BELOW

MATCHLINE SEE ABOVE

SHEET 6 INSET
(1"=60')

FILL AREA O.R.B. 6222, PG. 504

E.l/y R/W LINE

W.l/y R/W LINE

EASTPORT ROAD (66' R/W)

JEA ELECTRIC EASEMENT O.R.B. 7341, PG. 972

TELEPHONE LINE EASEMENT, WATER LINE EASEMENT, INGRESS, EGRESS & REGRESS EASEMENT, POWER LINE EASEMENT (TRANSMISSION R/W EASEMENT) O.R.B. 7101, PG. 1756

N02°23'24"W 890.02'(M)
N02°23'24"W 895.10'(R)

SHEET 6 OF 9
SURVEY DETAIL SHEET.
SEE SHEET 5 FOR GENERAL NOTES.
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PREPARED BY:
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Docket No. 160031-EI
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Exhibit KF-4, Page 106 of 127

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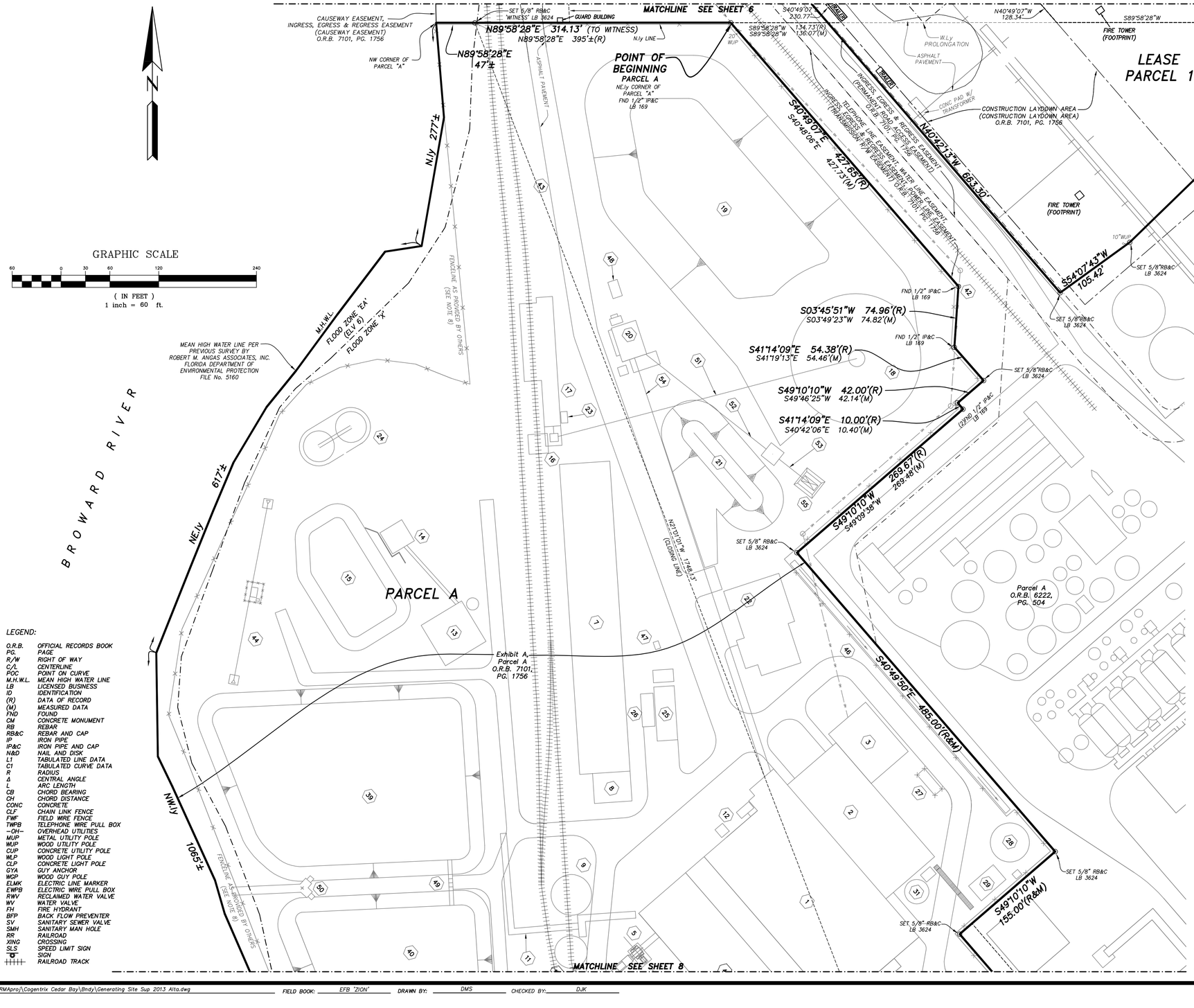

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SHEET 7 OF 9
SURVEY DETAIL SHEET.
SEE SHEET 5 FOR GENERAL NOTES.
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PREPARED BY:
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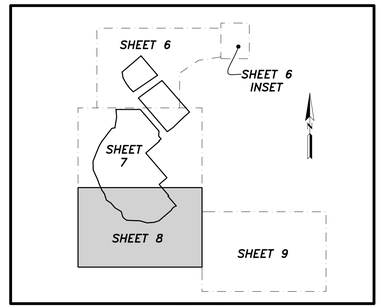
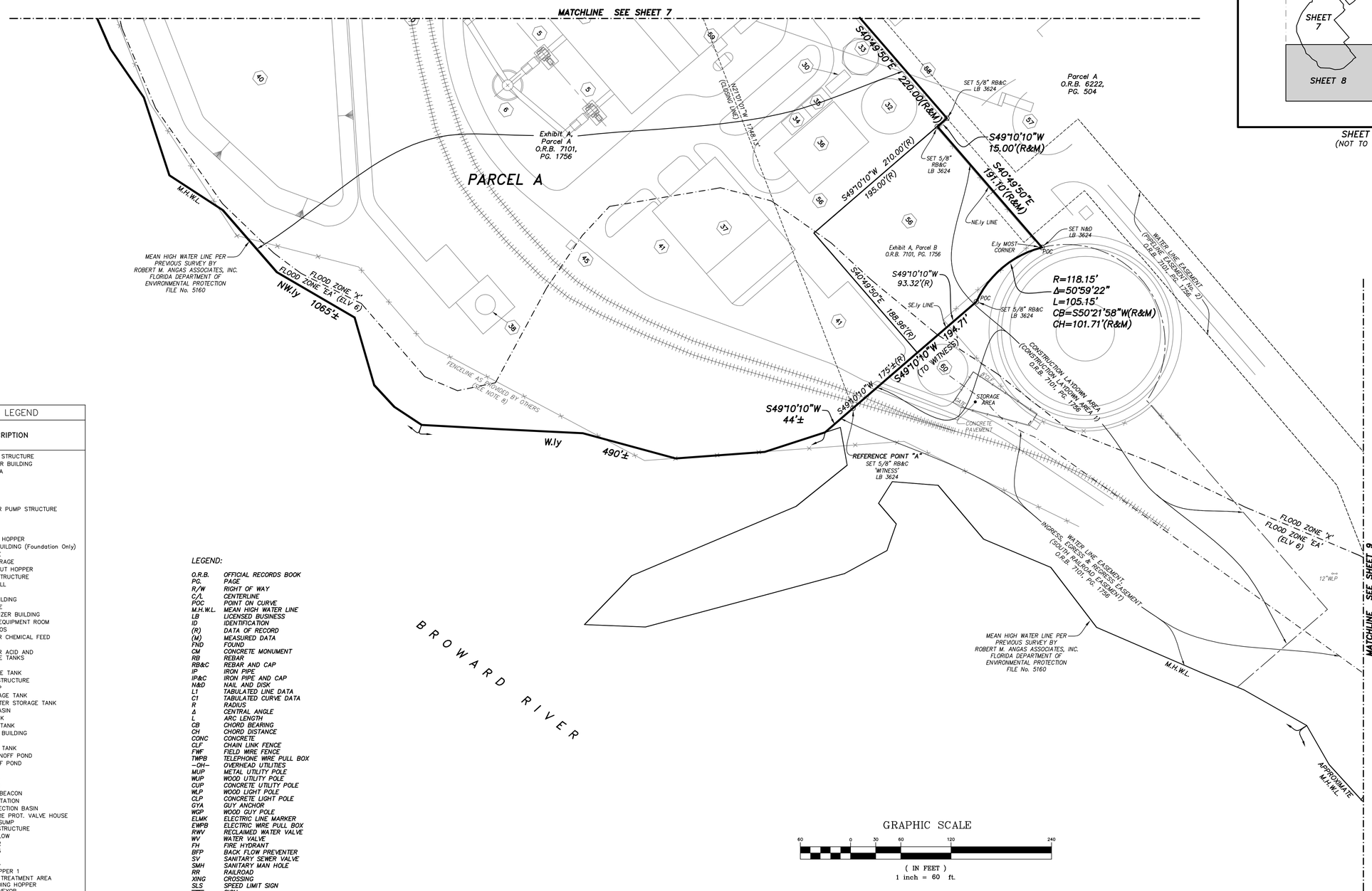
Exhibit KJ-4, Page 109 of 127

ALTA/ACSM LAND TITLE SURVEY

A PORTION OF WEBB PLACE, SUBDIVISION OF THE JOHN BROWARD GRANT, SECTION 46, TOWNSHIP 1 SOUTH, RANGE 27 EAST, DUVAL COUNTY, FLORIDA, AS DEPICTED IN PLAT BOOK 1, PAGES 7 AND 8, OF THE FORMER PUBLIC RECORDS OF SAID COUNTY, ALSO BEING A PORTION OF THOSE LANDS DESCRIBED AND RECORDED IN OFFICIAL RECORDS BOOK 6222, PAGE 504, TOGETHER WITH A PORTION OF THOSE LANDS DESCRIBED AND RECORDED IN OFFICIAL RECORDS BOOK 7101, PAGE 1756, OF THE CURRENT PUBLIC RECORDS OF SAID COUNTY.



SHEET KEY
(NOT TO SCALE)



FACILITIES LEGEND	
BLDG. ID.	DESCRIPTION
1	STEAM GENERATOR STRUCTURE
2	TURBINE GENERATOR BUILDING
3	TRANSFORMER AREA
4	FABRIC FILTER
5	ID FAN
6	CHIMNEY
7	COOLING TOWER
8	CIRCULATING WATER PUMP STRUCTURE
9	FLY ASH SILO
10	BED ASH SILO
11	PIPE RACK
12	BED ASH STORAGE HOPPER
13	ASH PALLETIZING BUILDING (Foundation Only)
14	SCREEN STRUCTURE
15	CURED PELLET STORAGE
16	ASH PELLET LOADOUT HOPPER
17	COAL UNLOADING STRUCTURE
18	COAL LOWERING WELL
19	COAL STORAGE
20	COAL CRUSHER BUILDING
21	LIMESTONE STORAGE
22	LIMESTONE PULVERIZER BUILDING
23	FIRE PROTECTION EQUIPMENT ROOM
24	PELLET CURING SILOS
25	CIRCULATING WATER CHEMICAL FEED STRUCTURE
26	CIRCULATING WATER ACID AND INHIBITOR STORAGE TANKS
27	GAS STORAGE
28	FIREWATER STORAGE TANK
29	FIREWATER PUMP STRUCTURE
30	WASTEWATER SUMP
31	CONDENSATE STORAGE TANK
32	DEMINERALIZED WATER STORAGE TANK
33	NEUTRALIZATION BASIN
34	ACID STORAGE TANK
35	CAUSTIC STORAGE TANK
36	WATER TREATMENT BUILDING
37	SERVICES BUILDING
38	FUEL OIL STORAGE TANK
39	STORAGE AREA RUNOFF POND
40	YARD AREA RUNOFF POND
41	PARKING
42	TRANSMISSION LINE
43	SITE ACCESS ROAD
44	NON-DIRECTIONAL BEACON
45	FUEL UNLOADING STATION
46	LIME SLURRY COLLECTION BASIN
47	COOLING TOWER FIRE PROT. VALVE HOUSE
48	COAL YARD AREA SUMP
49	POND DISCHARGE STRUCTURE
50	EMERGENCY OVERFLOW
51	COAL CONVEYOR 2
52	COAL CONVEYOR 3
53	COAL FEEDER 2
54	COAL CONVEYOR 4
55	COAL RECLAIM HOPPER 1
56	WATER PRE/POST TREATMENT AREA
57	WASTE FIBER LOADING HOPPER
58	WASTE FIBER CONVEYOR
59	DENOX FACILITY
60	STORMWATER STORAGE TANK

LEGEND:

O.R.B.	OFFICIAL RECORDS BOOK
PG.	PAGE
R/W	RIGHT OF WAY
C/L	CENTERLINE
POC	POINT ON CURVE
M.H.W.L.	MEAN HIGH WATER LINE
LB	LICENSED BUSINESS
ID	IDENTIFICATION
(R)	DATA OF RECORD
(M)	MEASURED DATA
FND	FOUND
CM	CONCRETE MONUMENT
RB	REBAR
RB&C	REBAR AND CAP
IP	IRON PIPE
IP&C	IRON PIPE AND CAP
N&D	NAIL AND DISK
L1	TABULATED LINE DATA
C1	TABULATED CURVE DATA
R	RADIUS
Δ	CENTRAL ANGLE
L	ARC LENGTH
CB	CHORD BEARING
CH	CHORD DISTANCE
CONC	CONCRETE
CLF	CHAIN LINK FENCE
FWF	FIELD WIRE FENCE
TMPB	TELEPHONE WIRE PULL BOX
--OH--	OVERHEAD UTILITIES
MUP	METAL UTILITY POLE
WUP	WOOD UTILITY POLE
CUP	CONCRETE UTILITY POLE
WLP	WOOD LIGHT POLE
CLP	CONCRETE LIGHT POLE
GYA	GUY ANCHOR
WGP	WOOD GUY POLE
ELMK	ELECTRIC LINE MARKER
EWPB	ELECTRIC WIRE PULL BOX
RWV	RECLAIMED WATER VALVE
WV	WATER VALVE
FH	FIRE HYDRANT
BFP	BACK FLOW PREVENTER
SV	SANITARY SEWER VALVE
SMH	SANITARY MAN HOLE
RR	RAILROAD
XING	CROSSING
SLS	SPEED LIMIT SIGN
	SIGN
	RAILROAD TRACK

GRAPHIC SCALE

60 0 30 60 120 240

(IN FEET)
1 inch = 60 ft.

SHEET 8 OF 9
SURVEY DETAIL SHEET.
SEE SHEET 5 FOR GENERAL NOTES.
SEE SHEETS 1, 2 AND 3 FOR LEGAL DESCRIPTIONS.

PREPARED BY:
ROBERT M. ANGAS ASSOCIATES, INC.
14775 OLD ST. AUGUSTINE ROAD
JACKSONVILLE, FL 32258 (904) 642-8550
CERTIFICATE OF AUTHORIZATION NO. LB 3624

CAD FILE: I:\Survey\RMAproj\Cogentrix Cedar Bay\Bndy\Generating Site Sup 2013 Alta.dwg FIELD BOOK: EFB "ZION" DRAWN BY: DMS CHECKED BY: DJK

COUNTY: DUVAL ORDER NO.: 12-146.00 FILE NO.: 122C-38.00A

ALTA/ACSM LAND TITLE SURVEY

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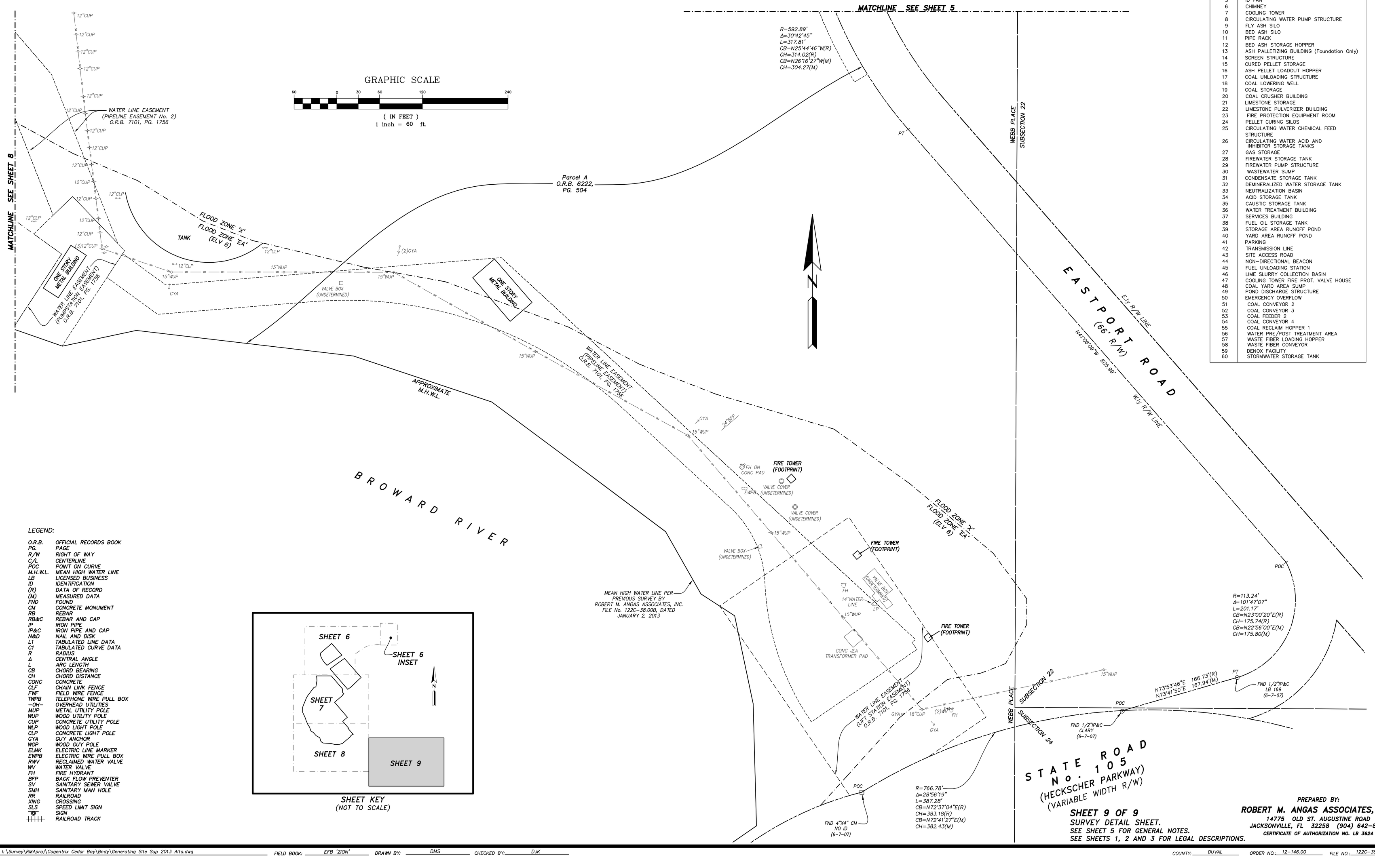

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SHEET 9 OF 9
SURVEY DETAIL SHEET.
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CAD FILE: I:\Survey\RMAproj\Cogentrix Cedar Bay\Bndy\Generating Site Sup 2013 Alta.dwg FIELD BOOK: EFB "ZION" DRAWN BY: DMS CHECKED BY: DJK
COUNTY: DUVAL ORDER NO.: 12-146.00 FILE NO.: 122C-38.00A

Docket No. 160021-EI
FPL 2016 Dismantlement Study (Corrected)
Exhibit KT-4, Page 111 of 127

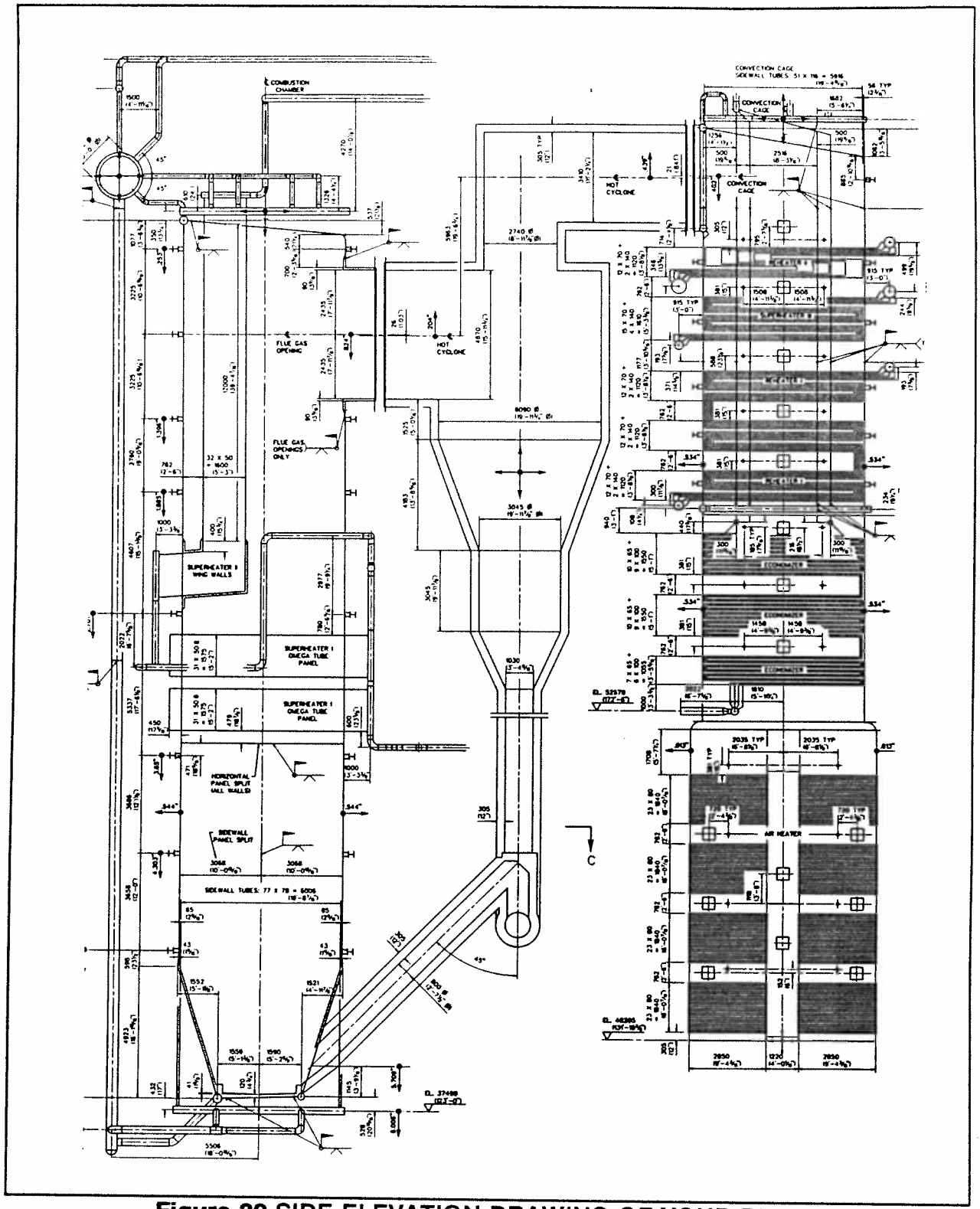


Figure 32 SIDE ELEVATION DRAWING OF YOUR PLANT

TOSHIBA

E- KC00478

INSTRUCTION MANUAL

DESIGN DATA AND CONSTRUCTION

FOR 343,000 kVA GENERATOR

TOSHIBA CORPORATION

KF2011

	Page
1.1 GENERAL DESCRIPTION	2
1.1.1 General	2
1.1.2 Design Data	3
1.2 DESCRIPTION OF EQUIPMENT	5
1.2.1 Generator Structure	5
1.2.2 Attachment Drawings	32

1.1 GENERAL DESCRIPTION

1.1.1 General

This instruction manual gives overall design data and descriptions of 343,000kVA generator and its auxiliary units installed at AES CEDAR BAY COGEN.PLANT

The electrical power output capability of a single generator is 291,550kW at a power factor of 0.85 lagging. The generator which is located in the power house at EL 132'-0", is mechanically driven by its associated steam turbine, electrically excited by the static thyristor rectifier excitation system and internally cooled by hydrogen gas and stator cooling water.

1.1.2 Design Data

a. Type

Three phase synchronous generator totally enclosed, direct coupled to steam turbine.

b. Cooling System

Stator winding : Direct water cooled

Stator core : Hydrogen cooled

Rotor winding : Direct hydrogen cooled

c. Rating

Rating	Continuous
Nominal rated capacity at 45Psi g hydrogen pressure	343 MVA
Power factor	0.85 (lagging)
Rated hydrogen pressure	45Psi g
Number of phases	3
Number of poles	2
Frequency	60 Hz
Rates speed	360 rpm
Terminal voltage	20 kV
Short circuit ratio at rated MVA	Not less than 0.58 (343 MVA base)
Insulation Class-Stator	Class F
-Rotor	Class F
Excitation	Static excitation system with thyristor

d. Cooling Gas

Cooling gas flow rate through generator : 1059 ^{Cf}/s(at 45psi g)

Cooling gas inlet temperature : 115 ° F

Cooling gas outlet temperature : 151 ° F

e. Water flow through stator winding : 174 g/min

f. Hydrogen Gas cooler

Quantity : 4 units/one generator

Cooling water flow rate per unit : 343 g/min

Total cooling water flow : 1372 g/min

Cooling water inlet temperature : 97 °F

Cooling water outlet temperature : 1106 °F

Head loss : Approx. 10.8 ft Aq

Cooling water quality : Fresh water

TOSHIBA

E-KS100195
-a

INSTRUCTION MANUAL

GENERAL DESCRIPTION

TOSHIBA CORPORATION

KF2011

92.5.11

92.5.12

E-KS100195-a

General Description

This turbine is a tandem-compound reheat unit with double-flow , low pressure stages. The design incorporates features which have proved their reliability and efficiency in a large number of units operting at comparable conditions.

This turbine has an opposed-flow, high-pressure reheat section and double-flow, low-pressure section. The high-pressure steam initially enters the turbine near the middle of the high pressure span and flows through the high-pressure stages toward the turbine end of the unit. The steam leaves the high-pressure section and returns to the reheat section of the boiler. Ihe reheated steam returns to the turbine through the combined reheat valves, and again enters the turbine near the middle of the high-pressure span. The steam then flows toward the generator through the reheat stages. After passing through the reheat stages, the steam enters the single crossover pipe from which steam enters the double-flow section. After passing through the low-pressure stages, the steam is exhaused downward into the condenser.

The exhaust hood is keyed to the foundation plates around its side of the hood to prevent axial movement.
The turbine expands axially from this point. The front standard is free to slide axially on its foundation plate, but the standard and hood are guided to prevent transverse movement.

All of the shells and hood are provided with bolted, horizontal joints for access to the steam path parts for inspection and maintenance. The joints of the shells and hood are accurately machined to give full metal-to metal contact and to assure a steam-tight joint.

TOSHIBA

E-KS200243α

INSTRUCTION MANUAL

RATING AND DESIGN DATA

TOSHIBA CORPORATION

KF2011

TOSHIBA

E-KS200243a
PAGE 1

Rating and Design Data

1. Type of Turbine	Tandem Compound 2 Cylinders 2 Flow Exhaust Reheat Turbine
2. Rated Output	285,000 kW
3. Rated Speed	3,600 rpm
4. Direction of Rotation	Counter-clock-wise (seeing from turbine end)

5. Steam Conditions

Main Steam Pressure at MSV inlet	1,890 psig
Main Steam Temperature at MSV inlet	1000 F
Reheat Steam Temperature at CRV inlet	1000 F

6. Exhaust Vacuum	3" Hg abs.
7. Number of Extractions	6

8. Number of Stages

HP Turbine	7 Stages
IP Turbine	4 Stages
LP Turbine	6 Stages x 2 Flows
Number of Wheels	23

Sec. 2

DWG.NO.4KA39752

SHIPPING DIMENSION AND WEIGHT

FOR

MAJOR ITEMS

FOR

AES CEDAR BAY INC.

CEDAR BAY COGENERATION

JUN 1992

TOSHIBA CORPORATION

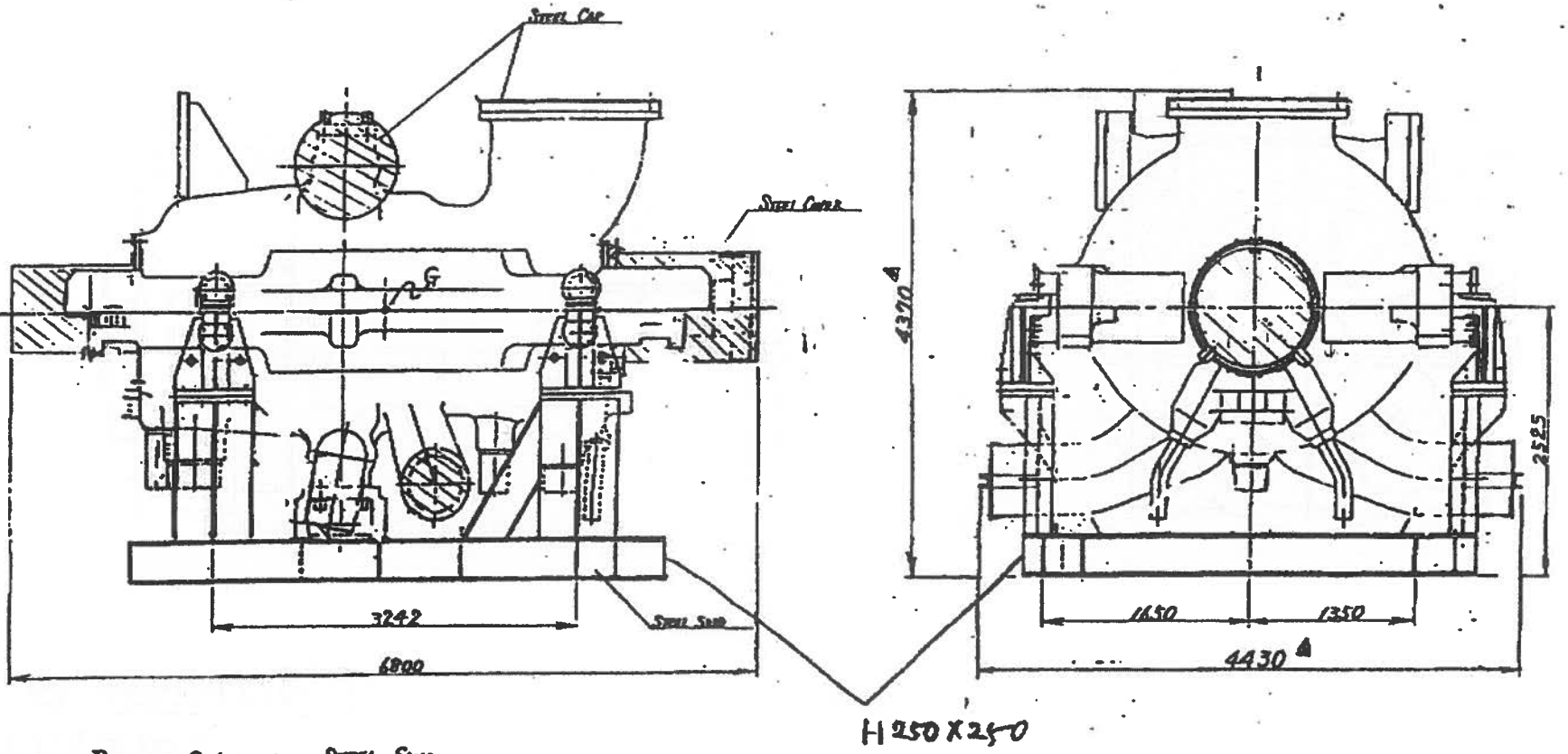
APPROVED BY	CHECKED BY	DRAFTED BY
15/Jun/92	15/Jun/92	12-JUN-'92
T. Kuba	T. Kuba	R. Ishiwaki

- I N D E X -

ITEM	DRG. No.	PAGE
1. SHIPPING DIMENSION AND WEIGHT OF HIP TURBINE ASSEMBLY --	PRELIMINALY	P 1
2. SHIPPING DIMENSION AND WEIGHT OF LP OUT CASING UPPER----	LATER	
3. SHIPPING DIMENSION AND WEIGHT OF LP OUT CASING LOWER----	LATER	
4. SHIPPING DIMENSION AND WEIGHT OF LP INNER CASING UPPER--	LATER	
5. SHIPPING DIMENSION AND WEIGHT OF LP INNER CASING LOWER--	LATER	
6. SHIPPING DIMENSION AND WEIGHT OF HIP TURBINE ROTOR------	LATER	
7. SHIPPING DIMENSION GENERATOR ----------	3KC000781REV.A	P 7

PRELIMINARY

SHIPPING DIMENSION AND WEIGHT OF HIP TURBINE ASSEMBLY



PACKING STYLE : STEEL SKID

DIMENSION : 6800 x 4430 x 4370 (mm)

WEIGHT : 120,000 (KG) APPROX

QUANTITY : 1

Docket No. 160021-EI
FPL 2016 Dismantlement Study (Corrected)
Exhibit KF-4. Page 124 of 127

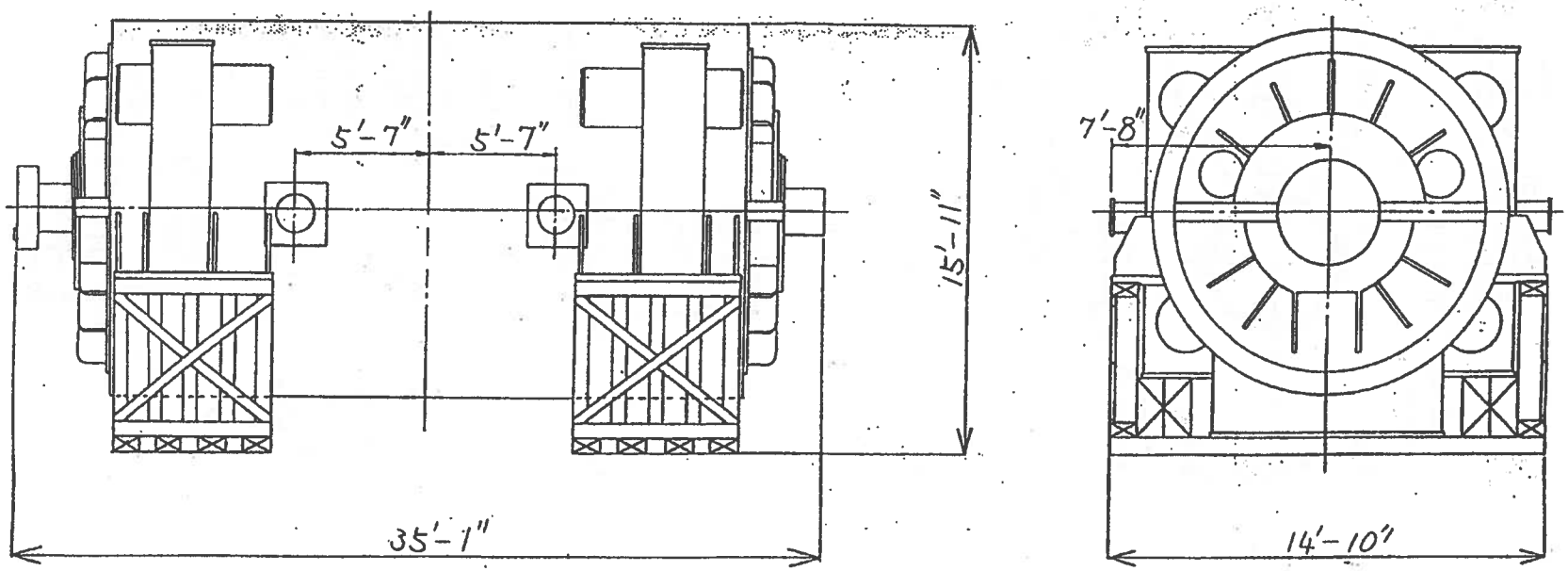
AES CEDAR BAY, INC.
CEDAR BAY COGENERATION PLANT
1X285MW TURBINE AND GENERATOR
SPECIFICATION 15637.62.1001
CONTRACT 15637.62.1001

C/H F1 | 図面 3 | DRAWING NO. C000781 | 変更 REV. | 組別 CIG. | 名称 TITLE (ABBR.) ABSHIPP.INC DIMENSION | 品質管理 REMARKS | 担当 PREP. EDY | M.F. 1 | 普通許容差ハ下記ニヨル
MODEL CODE ETA32A05 0040,343M,36R,L,XUCB1

CERTIFIED

FOR APPROVAL

APPROX WEIGHT 555500 LBS



図面番号 DRAWING NO. 3KC000781 ⊖ | REV. MARK A

承認 APPROVED BY	M. Fuzak May 15 '91	調査 REVIEWED BY	T. Yamadori May 15 '91	名称 TITLE	SHIPPING DIMENSION OF GENERATOR USA AES CEDAR BAY
調査 REVIEWED BY		担当 PREPARED BY	N. Miyakami May 15 '91		
担当 PREPARED BY					
REV. 箇所					
記事 CONTENTS					

REVISIONS 変更 | 尺度 SCALE | 単位 UNITS

株式会社 東芝 TOSHIBA CORPORATION TOKYO JAPAN

図面番号 DRAWING NO. 3KC000781 ⊖ | REV. MARK A | 変更回数

保管 REGISTERED T

記布先 PRESENT TO

Docket No. 160021-EI
FPL 2016 Dismantlement Study (Corrected)
Exhibit KF-4, Page 125 of 127

TOSHIBA

E-KS200244 2
PAGE 1

Weight List of Main Parts of Steam Turbine(lbs)

1. HIP Turbine

Outer Casing Upper	60,000
Outer Casing Lower	63,000
HP Inner Casing Upper	10,800
HP Inner Casing Lower	11,000
Rotor(with Blades)	33,800

2. LP Turbine

Outer Casing Upper	33,000
Outer Casing Lower	93,000
Inner Casing Upper	39,000
Inner Casing Lower	39,000
Rotor(with Blades)	78,100

3. Cross-over Pipe	16,600
4. Front Standard	42,000

5. Main Steam Valves

Main Stop Valve	22,000
Control Valves No.1 No.6	19,000
Combined Reheat Valve(per one set)	33,000

6. Oil Tank with AOP,TOP and EOP Motors	excluding lube oil	34,000
	including lube oil	67,700
7. Oil Conditioner	excluding lube oil	4,321
	including lube oil	8,179

KF2006

TOSHIBA

E-KS200244 2
PAGE 1

Weight List of Main Parts of Steam Turbine(lbs)

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KF 2006

Florida Power and Light Company
Dismantlement Reserve - Company Adjustment Impact - Rate Base Only
Exhibit KF-7

Line No.		2017			2018		
			Revised			Revised	
1		Beginning Balance	Accrual	Ending Balance	Beginning Balance	Accrual	Ending Balance
2		A	B	C	D	E	F
3							
4	December						($7,373,046)
5	January	$0	($614,421)	($614,421)	($7,373,046)	($614,421)	($7,987,467)
6	February	(614,421)	(614,421)	(1,228,841)	(7,987,467)	(614,421)	(8,601,887)
7	March	(1,228,841)	(614,421)	(1,843,262)	(8,601,887)	(614,421)	(9,216,308)
8	April	(1,843,262)	(614,421)	(2,457,682)	(9,216,308)	(614,421)	(9,830,728)
9	May	(2,457,682)	(614,421)	(3,072,103)	(9,830,728)	(614,421)	(10,445,149)
10	June	(3,072,103)	(614,421)	(3,686,523)	(10,445,149)	(614,421)	(11,059,569)
11	July	(3,686,523)	(614,421)	(4,300,944)	(11,059,569)	(614,421)	(11,673,990)
12	August	(4,300,944)	(614,421)	(4,915,364)	(11,673,990)	(614,421)	(12,288,410)
13	September	(4,915,364)	(614,421)	(5,529,785)	(12,288,410)	(614,421)	(12,902,831)
14	October	(5,529,785)	(614,421)	(6,144,205)	(12,902,831)	(614,421)	(13,517,251)
15	November	(6,144,205)	(614,421)	(6,758,626)	(13,517,251)	(614,421)	(14,131,672)
16	December	($6,758,626)	($614,421)	($7,373,046)	($14,131,672)	($614,421)	($14,746,092)
17							
18	13-Mo Avg			($3,686,523)			($11,059,569)
19							
20	Jurisd % [1]			0.950595			0.951284
21				($3,504,391) [2]			($10,520,788) [2]
22							

23 Notes:
24 [1] Jurisdictional factor per originally filed MFR B-2 for both 2017 Test Year and 2018 Subsequent Year (Page 3 of 8, Line 12)
25 [2] Represents rate base impact related to the corrected 2016 Dismantlement Study per the 1st Notice of Identified Adjustments

ORDER NO. PSC-12-0613-FOF-EI
DOCKET NO. 120007-EI
Page 15 and 16

M. Capital Cost Recovery Schedule:
Port Everglades Electrostatic Precipitators

FPL is currently recovering the costs associated with the Electrostatic Precipitators (ESPs) on the existing Units 1 through 4 at the Port Everglades Plant (PPE) through the ECRC. The Commission granted FPL an affirmative determination of need to modernize the PPE into a high-efficiency combined cycle natural gas energy center.[9] Assuming final approval of site certification for this modernization plan, all of the existing PPE units will be retired effective January 2013. FPL proposed to complete recovery of the PPE ESPs project in the ECRC through a capital recovery schedule.

The four ESPs at the PPE were placed in-service during the period April 2005 through May 2007. The original capital investment associated with the project is $81,901,169. As the year progressed, these capital expenditures have been recovered through the ECRC, leaving a net book value of $65,372,158, or 80% of the original investments, to be recovered as of March 31, 2012. The ESPs at PPE cannot be removed, modified, and reinstalled to serve other units, such as the 800 MW units at PMR and PMT for which new ESPs will be installed.[10] Therefore, FPL is requesting to include in its 2013 ECRC factors the recovery of the unrecovered net investment balance of the PPE ESPs at the time of the planned retirement.

FPL proposed a 4-year capital cost recovery schedule for the PPE ESPs beginning January 1, 2013. Given that the PPE ESPs were included in the overall plant-in-service and reserve balances used in establishing the depreciation rates currently approved at the generating unit and plant account level for the PPE,[11] and that the overall unrecovered plant investments at the PPE will be recovered in a 4-year schedule,[12] FPL's proposed 4-year capital cost recovery schedule in the ECRC for the PPE ESPs is appropriate.

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[9] Order No. PSC-12-0187-FOF-EI, in Docket No. 110309-EI, issued April 9, 2012, In re: Petition to determine need for modernization of Port Everglades Plant, by Florida Power & Light Company.

[10] his is due to their specific design and size for the 200 and 400 MW units at the PPE, which are significantly different from what would be required for the 800 MW units at PMR and PMT. The ESPs at PMR and PMT are retrofits into existing plants and are custom designed to fit in the limited and specific space between the boilers and stacks. Each ESP is sized for the specific exhaust gas volumes and flows of the specific unit.

[11] The depreciation rates FPL utilizes to depreciate the ESPs at PPE were approved in Order No. PSC-10-0153-FOF-EI, in Docket Nos. 080677-EI and 090130-EI (consolidated), issued March 17, 2010, In re: Petition for increase in rates by Florida Power & Light Company and In re: 2009 depreciation and dismantlement study by Florida Power & Light Company, at page 42.

[12] Addressed in Issue No. 23, stipulated, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light Company, which is currently before the Commission.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF SAM FORREST

DOCKET NO. 160021-EI

AUGUST 1, 2016

Q. Please state your name and business address.

A. My name is Sam Forrest. My business address is Florida Power & Light Company ("FPL"), 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science in Electrical Engineering from Texas A&M University and a Masters of Business Administration from the University of Houston. Prior to being named Vice President of EMT for FPL in 2007, I was employed by Constellation Energy Commodities Group as Vice President, Origination. In this capacity, I was responsible for managing a team of power originators marketing structured electric power products in Texas, the Western United States, and Canada. Prior to my responsibilities in the West, I was responsible for Constellation's business development activities in the Southeast U.S.

Before joining Constellation, from 2001 to 2004, I held a variety of energy marketing and trading management positions at Duke Energy North America ("DENA"). Prior to DENA, I was employed by Entergy Power Marketing Corp. ("EPMC") in several positions of increasing responsibility, including Vice President – Power Marketing following EMPC's entry into a joint venture with Koch Energy Trading.

Prior to my entry into the energy sector, I was involved with a successful start-up organization in the automotive industry from 1996 to 1998. From 1987 to 1996, I worked for AlliedSignal Aerospace at the Johnson Space Center in Houston, Texas, in increasing roles of responsibility.

Q. Please describe your duties and responsibilities in your current position.

A. I am responsible for the overall direction and management of the EMT Business Unit, which handles FPL's short-term and long-term fuel management and operations. These fuels include natural gas, residual and distillate fuel oils, and coal. Additionally, EMT is responsible for FPL's fuel hedging program, long-term fuel transportation and storage contracts, power origination activities and short-term power trading and operations. EMT is an active participant in the short-term and long-term natural gas markets throughout the Southeastern United States.

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony addresses the assertions of OPC witness Lawton that FPL's lower bills are a direct result of lower natural gas prices. I will demonstrate the investments made by FPL in more efficient generation have contributed significantly to the lower bills FPL's customers are experiencing today.

Q. On page 14 of his testimony, OPC witness Lawton states that FPL's "lower rates are a direct result of historically low natural gas prices." Would you like to address this comment?

A. Yes, I would. Lower gas prices certainly have had a positive effect on customer bills generally in electric utility industry, including FPL's. That appears to be the only conclusion that interests OPC witness Lawton, but it is far from the entire picture and completely ignores the fact that FPL has taken proactive steps to improve the efficiency of the system which has resulted in significantly less fuel being used – representing real savings for customers at whatever the cost of fuel. FPL had the foresight to expand our natural gas fleet with highly efficient generation, reducing the amount of fuel required for total generation, reducing our dependence on expensive foreign oil, and ultimately allowing us to take advantage of favorable gas prices which reduced bills to customers. Not all utilities have done so, and certainly few utilities initiated conversion projects as early and as consistently as FPL. Thus, even with lower natural gas prices, not all utilities are realizing the full range of customer savings that FPL has realized for customers, explaining in part the wide margin in FPL total bills relative to other utilities in Florida and compared to the national average, as FPL witness Cohen has described.

Q. Please reference testimony in this case that witness Lawton appears to have ignored in reaching his conclusion.

A. Page 8 of FPL witness Kennedy's direct testimony describes the dramatic 21% improvement in generating efficiency between 2001 and 2015 that FPL's fossil fleet has achieved as a result of the Company's investments. This efficiency improvement represents more than half a billion dollars of fuel cost savings in 2015 alone. Had 2015 fuel prices been higher, the savings would

have been even greater. Simply stated, no matter how fuel prices vary, FPL customers would logically always have lower fuel charges with FPL's generating efficiency improvements than they would without those improvements.

Q. Have lower natural gas prices led to lower bills for all utilities?

A. No. As demonstrated by Witness Cohen's Exhibit TCC-9, the typical 1000-kWh residential customer bill for FPL has gone from $108.61 in 2006 to $93.38 as of January 2016 - a 14% *reduction*. By contrast, the average of the Southeast comparison group in that exhibit has gone from $92.45 in 2006 to $115.07 - a 24% *increase*. Looking at it on a national basis provides similar results; with the national average up to $132.12 - a 24% *increase* since 2006. These same utilities are the beneficiaries of lower natural gas prices, just like FPL. As stated in the response to Staff's Fourth Set of Interrogatories, No. 133: "Other companies within the industry presumably had opportunities to make strategic investments in clean burning, natural-gas fired generation facilities, but did not. Others did, even if on a later timeline than FPL; however, most if not all of them would be reflected in the national and statewide metrics against which FPL still compares favorably. These comparisons confirm that not all utilities with similar fuel mixes are achieving the same results." It is because of FPL's commitment to smart investments and modernization of our generating fleet that our customers have saved billions of dollars and have electric bills that are among the lowest in the nation. FPL's typical residential bill is the lowest in the state of Florida, 20%

below the Florida average and 30% below the national average. This is a significant accomplishment – one that has provided tremendous value for our customers.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF ROBERT B. HEVERT

DOCKET NO. 160021-EI

AUGUST 1, 2016

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I. INTRODUCTION AND PURPOSE

Q. Please state your name, affiliation and business address.

A. My name is Robert B. Hevert. I am a Partner with ScottMadden, Inc. ("ScottMadden"), and my business address is 1900 West Park Drive, Suite 250, Westborough, MA 01581.

Q. Are you the same Robert B. Hevert who previously provided Direct Testimony in this proceeding?

A. Yes. At the time my Direct Testimony was filed, I was Managing Partner of Sussex Economic Advisors, LLC ("Sussex"). Effective June 1, 2016 Sussex became part of ScottMadden, and I assumed my current position as Partner.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to the direct testimonies of: (1) Dr. J. Randall Woolridge on behalf of Florida Office of Public Counsel ("OPC"); (2) Mr. Michael Gorman on behalf of the Federal Executive Agencies ("FEA"); (3) Mr. Richard A. Baudino on behalf of the South Florida Hospital and Health Care Association ("SFHHA"); (4) Mr. Steve Chriss on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"); (5) Mr. Michael Brosch on behalf of AARP; (6) Mr. Jeffry Pollock on behalf of the Florida Industrial Power Users Group ("FIPUG") (referred to herein, collectively, as the "opposing ROE witnesses"); (7) Mr. Kevin W. O'Donnell on behalf of OPC; and (8) Mr. Daniel Lawton on behalf of OPC, as their testimonies relate to the Company's Return on Equity ("ROE") or capital structure.

Q. Have you prepared any Rebuttal Exhibits?

A. Yes. My analyses and conclusions are supported by the data presented in Exhibits RBH-11 through RBH-44, which have been prepared by me or under my direct supervision.

Q. What are your conclusions regarding the appropriate Cost of Equity and capital structure for FPL?

A. In my Direct Testimony I recommended an ROE of 11.00 percent, within a range of 10.50 percent to 11.50 percent. As my Direct Testimony discussed, my ROE recommendation and the analytical results on which it is based consider a variety of factors, including certain risks faced by FPL such as vulnerability to severe weather conditions, exposure to new regulatory requirements associated with nuclear generation, and the risk of adverse capital market changes during the pendency of the Company's proposed four-year rate plan.

Because the application of financial models and the interpretation of their results are often sources of disagreement among analysts in regulatory proceedings, I believe it is important to review and consider a variety of data points; doing so enables us to put in context both quantitative analyses and the associated recommendations. As such, I have updated many of the analyses contained in my Direct Testimony, and I have provided several new analyses in response to issues raised by the opposing ROE witnesses. As discussed throughout the balance of

my Rebuttal Testimony, those analyses continue to support my ROE range and recommendation.

As to the capital structure, I continue to recommend the Company's existing capital structure of 40.40 percent long-term debt and 59.60 percent common equity. I further conclude that the Company's capital structure is within the range of equity ratios used by its peers, is consistent with rating agency criteria, and therefore, is reasonable.

Q. Please now provide an overview of your response to the ROE recommendations made by the opposing ROE witnesses.

A. It is important to keep in mind that no one financial model is more reliable than others at all times and under all market conditions; at times, certain model results simply do not make sense. Determining the Cost of Equity therefore is not always a strict mathematical exercise. Rather, it requires reasoned judgment in vetting the models and assumptions used by various analysts, and in assessing the reasonableness of their recommendations. That judgment may lead to the conclusion that the emphasis applied to a particular method in a prior proceeding or under prior market conditions is not appropriate in the current instance.

The opposing ROE witnesses have given considerable weight to a single method - the Discounted Cash Flow ("DCF") approach – even though their models produce ROE estimates that are 100 basis points, and more, below the returns authorized

for other electric utilities.[1] Given their dependence on a method that produces unduly low estimates, it is not surprising that their recommendations fall within a range that is far below the returns authorized for electric utilities in other jurisdictions.

The fact that the opposing ROE witnesses' recommendations are similar does not mean that their approaches are appropriate or that their conclusions are sound. For the reasons discussed throughout the balance of my Rebuttal Testimony, it is my view that, if adopted, the opposing ROE witnesses' recommendations would increase the Company's regulatory and financial risk, diminish its ability to compete for capital, and have the counter-productive effect of increasing FPL's overall cost of capital, ultimately to the detriment of its customers.

Q. Please now provide an overview of your response to the ROE recommendations made by the opposing ROE witnesses.

A. Although there are many areas in which I disagree with their methods and conclusions, there are certain issues that commonly serve to reduce the opposing ROE witnesses' recommendations:

- *Application of Discounted Cash Flow methods.* As a general matter, DCF based methods define the Cost of Equity as the discount rate that sets the current market price of a stock equal to the present value of the cash flows expected from owning that stock. In calculating expected cash flows, the

[1] Direct Testimony of J. Randall Woolridge, at 53 and Exhibit JRW-10, at 1. Direct Testimony of Michael P. Gorman, at 31, 33, Exhibit MPG-6 and Exhibit MPG-9. Direct Testimony of Richard A. Baudino, at 33 and Exhibit No.___(RAB-7).

opposing ROE witnesses rely on growth rates that are inappropriately low, or that are constrained by what they may consider to be "sustainable" levels of perpetual growth. Regardless of how they develop their models, DCF estimates as low as 8.15 percent[2] fail to meet the *Hope* and *Bluefield* "end result" standard, and should be given no weight in determining the Company's ROE.

- *Application of Risk Premium Models.* Risk Premium methods are based on the financial principle that equity investors assume greater risk than do debt investors and, therefore, require higher returns. The measure of that incremental return is the "Equity Risk Premium," or the difference between the required return on debt and the required Return on Equity. It is important to recognize that the Equity Risk Premium is not constant over time. Rather, as interest rates fall, the Equity Risk Premium increases, even when we consider additional measures of market risk. By not properly reflecting that well-documented relationship, certain of the opposing ROE witnesses have under-estimated FPL's Cost of Equity.
- *Application of the Capital Asset Pricing Model ("CAPM").* The CAPM, which also is a risk premium-based method, assumes that investors must be compensated for the time value of money, and for taking on additional risk. The time value of money is measured by long-term Treasury yields; compensation for additional risk is measured by the stock's Beta coefficient and the expected Market Risk Premium ("MRP"). The Market Risk Premium,

[2] Direct Testimony of Richard A. Baudino, at 41, and Exhibit RAB-7.

which weighs heavily in CAPM estimates, reflects the additional return that investors expect to receive by investing in the market as a whole over the return they would receive by investing only in long-term Treasury bonds. Certain of the opposing ROE witnesses have developed MRP estimates based on historical market returns and interest rates, and have assumed relationships between those two variables that do not reasonably reflect current or expected market conditions. As a result, their ROE estimates are unreasonably low.

- *Assessment of the Company's relative risk.* Determination of required ROE is a risk-comparable exercise. The opposing ROE witnesses do not fully consider the range of business risks and other factors when determining where FPL's required ROE falls within the range of analytical results.[3]

On balance, and after considering the issues summarized above, I have maintained the recommendations contained in my Direct Testimony.

Q. How is the remainder of your Rebuttal Testimony organized?

A. The remainder of my Rebuttal Testimony is organized as follows:

- Section II – Contains my response to OPC witness Woolridge;
- Section III – Contains my response to FEA witness Gorman;
- Section IV – Contains my response to SFHHA witness Baudino;
- Section V – Contains my response to Wal-Mart witness Chriss;

[3] *See*, Direct Testimony and Exhibits of Robert B. Hevert, at 37-50.

- Section VI – Contains my response to AARP witness Brosch and FIPUG witness Pollock;
- Section VII – Contains my response to OPC witness O'Donnell regarding the Company's capital structure;
- Section VIII – Contains my response to OPC witness Lawton regarding the Company's financial integrity;
- Section IX – Summarizes my updated analyses; and
- Section X – Summarizes my conclusions and recommendations.

II. RESPONSE TO THE TESTIMONY OF OPC WITNESS WOOLRIDGE

Q. Please provide a brief summary of Dr. Woolridge's testimony and ROE recommendation.

A. Dr. Woolridge recommends an ROE of 8.75 percent, which is near the upper end of his DCF and CAPM results. Dr. Woolridge makes clear, however, that his recommendation relies primarily on his Constant Growth DCF model results.[4]

Q. What are the principal areas of disagreement between you and Dr. Woolridge?

A. There are several areas in which I disagree with Dr. Woolridge. In general, those areas include: (1) the composition and selection of the proxy group companies; (2) the growth rates applied in the Constant Growth DCF model; (3) the application of the Multi-Stage DCF model; (4) the application of the CAPM; (5)

[4] Direct Testimony of J. Randall Woolridge, at 63.

the reasonableness of the Bond Yield Plus Risk Premium analysis; (6) the relevance of Market-to-Book ("M/B") ratios in excess of unity; (7) the relevance of flotation costs in determining the Company's Cost of Equity; and (8) the business risk of FPL relative to the proxy group. In addition, I disagree with Dr. Woolridge's presentation and interpretation of certain data relating to capital market conditions.

Regardless of how he arrived at his recommendation, it is very difficult to reconcile an ROE of 8.75 percent with past, current, and expected market environments.

A. Proxy Group Selection

Q. Please describe the screening criteria by which Dr. Woolridge developed his Proxy Group.

A. Dr. Woolridge relied on six screening criteria to develop his sample of 29 companies:

1. Proxy companies must derive at least 50.00 percent of revenues from regulated electric operations;
2. Each company selected must be listed as an Electric Utility by Value Line and as an Electric Utility or Combination Electric and Gas company by AUS Utilities Reports;
3. Selected companies must have an investment grade bond rating;
4. Companies must have a consistent dividend record with no cuts or omissions for the past six months;

5. Each company must not be involved in an acquisition, or be the target of an acquisition in the past six months; and
6. Proxy companies must have long-term Earnings Per Share ("EPS") growth forecasts available from Yahoo!, Reuters, or Zacks.[5]

Q. Do you agree with Dr. Woolridge's screening criteria?

A. Not entirely. Although we do have certain criteria in common (for example we both exclude companies that are party to a significant corporate transaction[6] or that do not consistently pay dividends), I do not believe that Dr. Woolridge's screens render a group of companies that is sufficiently comparable to FPL.

Q. Do any of Dr. Woolridge's proxy companies fail his proxy group screening criteria?

A. I believe so. Dr. Woolridge included in his proxy group Dominion Resources, Inc. ("Dominion"), Black Hills Corporation ("Black Hills"), Duke Energy Corporation ("Duke"), and Southern Company ("Southern"), all of which are party to significant acquisitions: Dominion announced its proposed acquisition of Questar Corporation on February 1, 2016;[7] Black Hills acquired SourceGas Holdings LLC on February 12, 2016;[8] Duke announced its proposed acquisition of Piedmont Natural Gas Company, Inc. on October 26, 2015;[9] and Southern

[5] Direct Testimony of J. Randall Woolridge, at 28.
[6] Subsequent to the filing of my Direct Testimony, Dominion Resources, Inc. entered into an agreement to acquire Questar Corp. on February 1, 2015 and Great Plains Energy Inc. entered into an agreement to acquire Westar Energy Inc. on May 29, 2016.
[7] Dominion Resources, Inc., SEC Form 8-K, January 31, 2016.
[8] Black Hills Corporation, SEC Form 8-K, July 12, 2015.
[9] Duke Energy Corporation, SEC Form 8-K, October 24, 2015.

completed its acquisition of AGL Resources Inc. on July 1, 2016.[10] As such, those companies should be removed from the proxy group.

Q. What is your concern with Dr. Woolridge's use of revenue, rather than income, as a screening criterion?

A. Measures of income are far more likely to be considered by the financial community in making credit assessments and investment decisions than are measures of revenue. From the perspective of credit markets, measures of financial strength and liquidity are focused on cash from operations, which is directly derivative of earnings, as opposed to revenue. For example, Moody's assigns a 40.00 percent weight to measures of financial strength and liquidity, of which 32.50 percent specifically relates to the ability to cover debt obligations with cash from operations.[11]

Just as rating agencies focus on measures of cash from operations, equity investors prefer measures of income in assessing equity valuation levels; common measures of relative equity valuation include the Price/Earnings ratio, and the ratio of Enterprise Value/EBITDA (Earnings Before Interest, Taxes, Depreciation, and Amortization). Revenue, however, may be several steps removed from the earnings and cash flows that that are the basis of equity valuations. Energy trading and marketing units, for example, often represent high

[10] Southern Company, SEC Form 8-K, August 23, 2015.

[11] *See*, Moody's Investors Service, Rating Methodology, *Regulated Electric and Gas Utilities*, December 23, 2013, at 10-14. I address the ratings process in more detail in my response to Mr. Lawton.

revenue but low margin operations. Those operations may generate a comparatively large proportion of the combined entity's revenue, but only a small percentage of its income. In such cases, focusing on revenue may mislead the analyst into assuming that a given operating unit is the primary driver of expected growth, when other business segments create the majority of earnings and cash flows. Here, we are considering whether the underlying utility is the principal source of long-term growth and as such, it could be misleading to focus on revenue rather than earnings for the purpose of identifying proxy companies.

Q. Have you made any changes to the proxy group used in your ROE analyses?

A. Yes, I have. Although I believe my proxy group reasonably reflects FPL's risk, I also recognize that in certain circumstances it is possible to have reasonable disagreements as to the definition and application of screening criteria. Consequently, I have developed a proxy group that contains all the companies used by Dr. Woolridge, Mr. Gorman, Mr. Baudino, and me in this proceeding, but for companies that: (1) have recently been party to mergers or significant transactions; (2) that do not have regulated generation assets; or (3) are affected by significant ongoing uncertainties that may be affecting their market data and investors' expectations of their future performance (I refer to that group as the "Combined Proxy Group"). Exhibit RBH-19 provides a comparison of the various proxy groups used by ROE witnesses in this proceeding and explains the reason certain companies were excluded from the Combined Proxy Group. As discussed in Section IX, the Cost of Equity estimates derived from the Combined Proxy Group support my ROE recommendation.

B. Application of the Constant Growth DCF Approach

Q. Please summarize your concerns with the Constant Growth DCF model and Dr. Woolridge's application of the model.

A. There are several aspects of Dr. Woolridge's DCF analyses and conclusions that are incompatible with market conditions, and inconsistent with the practical interpretation of the models' results. For example, the market data used in Dr. Woolridge's DCF analyses conflict with the models' underlying assumptions. In particular, the market prices used to calculate the dividend yield were taken from a period during which utilities in general, and the proxy companies in particular, traded at unusually high, and likely unsustainable, levels. In fact, during Dr. Woolridge's study period, utility Price/Earnings ("P/E") ratios exceeded their long-term average, and were similar to the market P/E ratio (as measured by the S&P 500).[12] The elevated P/E ratios are an important factor simply because the Constant Growth DCF model assumes constant P/E ratios in perpetuity. Consequently, the basis of Dr. Woolridge's recommendation – the Constant Growth DCF model – assumes data that are inconsistent with the model's fundamental assumptions.

Lastly, Dr. Woolridge's application of the Constant Growth DCF model includes a degree of subjectivity that prevents us from replicating his results. It is quite likely that analysts looking at the same data would come to different conclusions. For example, based on his review of historical and projected dividend, book

[12] Source: SNL Financial, Bloomberg Professional.

value, earnings and "sustainable" growth rates, Dr. Woolridge assumes a growth rate of 4.88 percent for the companies in his proxy group, although it is unclear how he calculates that estimate. Moreover, Dr. Woolridge's judgment is to give "primary weight"[13] to growth rate projections produced by equity analysts, despite his position that those analysts knowingly and persistently produce biased forecasts.

Q. What growth rates did Dr. Woolridge review in his Constant Growth DCF analysis?

A. Dr. Woolridge reviewed a number of growth rates, including historical and projected Dividends Per Share ("DPS"), Book Value Per Share ("BVPS"), and EPS growth rates as reported by Value Line; analysts' consensus EPS growth rate projections from Yahoo!, Reuters, and Zacks; and an estimate of "sustainable growth" derived from data provided by Value Line. Dr. Woolridge states that in arriving at his 8.75 percent DCF estimate, he gave more weight to projected EPS growth rates.[14]

[13] Direct Testimony of J. Randall Woolridge, at 52.
[14] *See*, Direct Testimony of J. Randall Woolridge, at 52.

Table 1: Summary of Dr. Woolridge's Growth Rate Estimates[15]

	Dr. Woolridge's Proxy Group
Value Line Historical Growth Rates (DPS, BVPS, EPS)	4.30%
Value Line Projected Growth Rates (DPS, BVPS, EPS)	4.80%
Sustainable Growth	3.90%
Analyst Projected EPS Growth Rates (excl. Value Line) – Mean/Median	4.80%/5.00%
Dr. Woolridge's Assumed DCF Growth Rate	4.88%

Q. Do you agree with Dr. Woolridge's sustainable growth rate estimate?

A. No, I do not. As discussed in more detail in my response to Mr. Baudino, the "sustainable growth" rate does not account for externally generated funds associated with issuances of new equity.

Q. Are there reasons to doubt the results of a DCF analysis that uses the sustainable growth rate for electric utilities in particular?

A. Yes. As noted below, the projected realized Return on Common Equity for many of the proxy companies is significantly diluted by recent or projected additions to net plant. The assumption that the Cost of Equity would materially decrease as capital investments increase, however, is contrary to market evidence.

[15] *See*, Direct Testimony of J. Randall Woolridge, Exhibit JRW-10, at 1 and 6.

Q. Have you conducted any analyses to demonstrate how the proxy companies' earned ROE projections are diluted by ongoing capital expenditures?

A. Yes, I have. As discussed in my Direct Testimony, I analyzed Value Line's earned ROE projections using the "DuPont" formula, which decomposes the Return on Common Equity into three components: (1) the Profit Margin (net income/revenues); (2) Asset Turnover (revenues/net plant); and (3) the Equity Multiplier (net plant/equity).[16] That analysis (see Exhibit RBH-8) showed that because the utility industry is going through a period of increased capital investment, the lag between the addition of net plant and revenue generated by those investments dilute the Asset Turnover ratio, at least in the near term. In the context of the sustainable growth model, the pressure on earned ROE would lead to the counter-intuitive conclusion that increased capital investments lead to decreased return requirements.

Q. Do Dr. Woolridge's analyses account for abnormally elevated P/E ratios?

A. Not on a consistent basis. As discussed throughout my Rebuttal Testimony, DCF-based methods, such as the Constant Growth model on which Dr. Woolridge (and the other opposing witnesses) relies, depend on recent stock prices as a principal input, and (in the case of the Constant Growth model) assume that Price/Earnings ratios, and resulting Cost of Equity will remain constant in perpetuity. As noted

[16] Direct Testimony of Robert B. Hevert, at 40.

above, an important analytical issue is that utility sector P/E ratios recently have been unstable and recently have been moved well above their historical levels.[17]

To support his Capital Asset Pricing Model analysis, Dr. Woolridge refers to "Building Block" approaches as part of the studies he uses to estimate the Market Risk Premium (*see* Exhibit JRW-11, pages 5 and 6). Among the "Building Block" studies included in that review are those produced by Ibbotson and Chen. The Morningstar 2015 Classic Yearbook also discusses the "Building Block" model.[18] In that discussion, Morningstar reviews the effect of increasing P/E ratios on the market return, and concludes that "reported earnings are affected not only by the long-term productivity, but also by 'one-time' items that do not necessarily have the same consistent impact year after year."[19] Morningstar therefore uses three-year average P/E ratios to develop its Supply-Side market return estimate.

Dr. Woolridge therefore recognized and adjusted his analyses to reflect the abnormal expansion in P/E ratios in his Building Blocks calculation, but did not acknowledge the same principle in his DCF analysis. That is, Dr. Woolridge relies on an analysis that adjusts abnormally high P/E ratios in a manner that reduces his CAPM estimate (the Building Blocks approach to developing the

[17] Since the beginning of 2000, the long-term average P/E ratio for Dr. Woolridge's proxy group was 17.08. The 30-day average P/E ratio for the period ending June 2016 was 21.63 for Dr. Woolridge's proxy group. Source: SNL Financial. Looking forward, indicators suggest that the industry's current valuation levels may not persist. Value Line, for example, expects a decline in the P/E ratio for all of the companies in Dr. Woolridge's proxy group over the coming three to five years (*see*, Exhibit RBH-20).

[18] Morningstar refers to the method as the "Supply Side" approach.

[19] Morningstar, Inc., 2015 Classic Yearbook, at 157.

Equity Risk Premium),[20] and at the same time relies on DCF estimates that do not recognize or adjust for the abnormal expansion in P/E ratios for his proxy companies.

Q. Please summarize Dr. Woolridge's reference to a March 2015 report by Moody's regarding the effect of ROEs on utilities' near-term credit profiles.

A. Dr. Woolridge points to the article and concludes (among other things) that lower authorized ROEs are not impairing utilities' credit profiles, and are not "deterring them from raising record amounts of capital."[21] Dr. Woolridge further states that the Moody's article "supports the prevailing/emerging belief that lower authorized ROEs are unlikely to hurt the financial integrity of utilities or their ability to attract capital."[22]

Q. What is your response to Dr. Woolridge in that regard?

A. The Moody's article makes clear that utilities' cash flow have benefited from increased deferred taxes, which are due to bonus depreciation. As Moody's noted, the rise in deferred taxes eventually will reverse.[23] That may be one reason that the Moody's study refers to "near-term credit profiles"; in the longer-term, utilities will not have the benefits of bonus depreciation to offset lower authorized returns.

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20 *See*, Direct Testimony of J. Randall Woolridge, Exhibit JRW-11, at 5-6 and Morningstar, Inc., 2015 Classic Yearbook, at 157.

21 Direct Testimony of J. Randall Woolridge, at 66.

22 *Ibid.*

23 Moody's Investors Service, *Lower Authorized Returns Will Not Hurt Near-Term Credit Profiles*, March 10, 2015, at 4.

Moody's also observed that although interest rates remain at relatively low levels, they "will go up, eventually." When they do, Moody's warns, "this could spell trouble for utilities." Moody's concludes, "[f]or now, utilities can enjoy their (historically) high equity valuations in terms of dividend yield and price-earnings ratios."[24] That is, in March 2015, Moody's observed that the then-current valuations were unusual, and that some degree of reversion toward long-term means was likely. For the electric utility sector, that was the case, as the S&P Electric Utility Index P/E ratio fell from 18.09 on February 1, 2015 to 15.40 on July 1, 2015.[25] That observation is consistent with a point made earlier in my Rebuttal Testimony: unusually high P/E ratios are unlikely to persist and, therefore, Dr. Woolridge's approach of giving primary weight to his Constant Growth DCF estimates should be viewed with considerable caution.

Dr. Woolridge further argues that the Moody's article supports the notion that elevated P/E ratios are a result of cost recovery mechanisms reducing utilities' risk.[26] As a preliminary matter, neither the article nor Dr. Woolridge provides any evidence or analysis to support the basis for the claim that cost recovery mechanisms have led to higher P/E multiples. To be clear, Moody's does not state that the cause of higher P/E multiples is cost recovery mechanisms. As stated in my Direct Testimony, the Federal Reserve's monetary policy actions intentionally lowered long-term interest rates (another of the factors cited in the

[24] Moody's Investors Service, *Lower Authorized Returns Will Not Hurt Near-Term Credit Profiles*, March 10, 2015, at 5.

[25] Source: Bloomberg Professional. Represents 30-day moving average.

[26] Direct Testimony of J. Randall Woolridge, at 75-76.

Moody's article) and have affected utility P/E ratios.[27] In any case, as noted above, electric utility P/E ratios declined by nearly 15.00 percent shortly after the Moody's article was published.

Nonetheless, if Dr. Woolridge is concerned that recovery mechanisms have supported, and will continue to support, elevated P/E ratios, one method of addressing that position is to assume that the terminal value in the Multi-Stage DCF analysis is calculated on the basis of current P/E ratios. As discussed later in my Rebuttal Testimony, I therefore included the current 30-day average proxy group P/E ratio in the updated Multi-Stage DCF results.[28]

Q. Do you have any concerns with Dr. Woolridge's belief that analysts' projections are consistently biased?

A. Yes, I do. Dr. Woolridge asserts that there is an upward bias in analysts' growth estimates and as such, "the DCF growth rate needs to be adjusted downward from the projected EPS growth rate."[29] Dr. Woolridge argues that analysts' earnings growth estimates are "overly optimistic and upwardly biased," and that relying on such estimates is a methodological error.[30] His position, however, is based on observations with respect to the broad market; Dr. Woolridge has provided no evidence that any of the growth rates used in our respective DCF analyses are the result of a consistent and pervasive bias on the part of the analysts providing those

27 Direct Testimony of Robert B. Hevert, at 55.
28 Exhibit RBH-14.
29 Direct Testimony of J. Randall Woolridge, at 50.
30 *Ibid.*, at 49.

projections. Despite his view that they are biased, Dr. Woolridge states that it was by "giving primary weight to the projected EPS growth rate of Wall Street analysts" that he arrived at his assumed growth rates.[31]

Q. What is your response to Dr. Woolridge in that regard?

A. There is no reason to believe that the analyst growth rates used in our respective DCF analyses are biased. As a practical matter, the October 2003 Global Research Analyst Settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows," and required the settling financial institutions to fund independent third-party research.[32] I have reviewed the Letters of Acceptance, Waiver and Consent signed by financial institutions that were party to the Global Settlement, and found no reference to misconduct by analysts following the utility sector.

Pursuant to Regulation AC, which became effective in April 2003, analysts must certify that "…the views expressed in the report accurately reflect his or her personal views, and disclose whether or not the analyst received compensation or other payments in connection with his or her specific recommendations or views."[33] I understand that industry practice is to avoid conflicts of interest by ensuring that compensation is not directly or indirectly linked to the opinions

31 *Ibid.*, at 52.

32 The 2002 Global Financial Settlement resolved an investigation by the U.S. Securities and Exchange Commission and the New York Attorney General's Office of a number of investment banks related to concerns about conflicts of interest that might influence the independence of investment research provided by equity analysts.

33 Securities and Exchange Commission, 17 CFR PART 242 [Release Nos. 33-8193; 34-47384; File No. S7-30-02], RIN 3235-AI60 Regulation Analyst Certification.

contained in those reports. Dr. Woolridge has not explained why any of the analysts covering our respective proxy companies would bias their projections in light of those certification requirements, or why investors would be more inclined to rely on his growth rate estimates than those of the analysts that base their projections on fundamental company-specific research.

Q. Is the use of analysts' earnings growth projections in the DCF model supported by financial literature?

A. Yes, it is. The relationship between various growth rates and stock valuation metrics has been the subject of much academic research.[34] As noted over 40 years ago by Charles Phillips in The Economics of Regulation:

> For many years, it was thought that investors bought utility stocks largely on the basis of dividends. More recently, however, studies indicate that the market is valuing utility stocks with reference to total per share earnings, so that the earnings-price ratio has assumed increased emphasis in rate cases.[35]

Subsequent academic research has clearly and consistently indicated that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[36] For example, Vander Weide and Carleton state that, "[our] results … are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock

[34] *See*, Harris, Robert, Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return, Financial Management (Spring 1986).

[35] Charles F. Phillips, Jr., The Economics of Regulation, at 285 (Rev. ed. 1969).

[36] *See*, *e.g.*, Christofi, Christofi, Lori and Moliver, Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate, Journal of Investing (Spring 1999); Harris and Marston, Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts, Financial Management, 21 (Summer 1992); and Vander Weide and Carleton, Investor Growth Expectations: Analysts vs. History, The Journal of Portfolio Management (Spring 1988).

buy-and-sell decisions."[37] Other research specifically notes the importance of analysts' growth estimates in determining the Cost of Equity, and in the valuation of equity securities. Dr. Robert Harris noted that "a growing body of knowledge shows that analysts' earnings forecast are indeed reflected in stock prices."[38] Citing Cragg and Malkiel, Dr. Harris notes that those authors "found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based."[39] Similarly, Brigham, Shome, and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data; and (ii) investors do rely on analysts' forecasts."[40]

In addition to the studies presented above, there have been other peer reviewed, published articles that specifically support the use of analysts' earnings growth projections in the DCF model.[41]

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37 Vander Weide and Carleton, Investor Growth Expectations: Analysts vs. History, The Journal of Portfolio Management (Spring 1988).

38 Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return, Financial Management (Spring 1986).

39 Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return, Financial Management (Spring 1986).

40 Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, The Risk Premium Approach to Measuring a Utility's Cost of Equity, Financial Management (Spring 1985).

41 *See*, for example, Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management, 1986; Robert S. Harris, Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992, at 63; and Advanced Research Center, *Investor Growth Expectations*, Summer, 2004.

Q. Do you agree with Dr. Woolridge's assertion that "the DCF growth rate needs to be adjusted downward from the projected EPS growth rate to reflect the upward bias"? [42]

A. No, I do not. First, if current stock prices (and therefore the dividend yield) already reflect analysts' bias, it is unclear why it is necessary to adjust the growth rate. In addition, although Dr. Woolridge asserts that "…long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased"[43] in general, he has not demonstrated that to be true for the electric companies in our proxy groups, in particular. To that point, I reviewed quarterly earnings presentations for several of the companies in Dr. Woolridge's proxy group and found that if anything, the analysts' growth rate projections were toward the lower end of the long-term growth rate ranges provided by the companies' management teams (*see* Table 2, below). I therefore disagree that the earnings projections included in our respective analyses are likely to be systemically biased.

[42] Direct Testimony of J. Randall Woolridge, at 50.
[43] *Ibid.*, at 76-77.

Table 2: Analysts' Earnings Growth Projections Relative to Management Presentations[44]

Company	Ticker	Zacks Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth	Investor Presentation Earnings Growth
Alliant Energy Corporation	LNT	6.10%	6.60%	6.00%	5.00% - 7.00%
Ameren Corporation	AEE	6.10%	5.20%	6.00%	5.00% - 8.00%
American Electric Power Company, Inc.	AEP	4.90%	4.10%	4.00%	4.00% - 6.00%
Avista Corporation	AVA	5.00%	5.00%	5.00%	4.00% - 5.00%
CMS Energy Corporation	CMS	6.40%	7.24%	6.00%	6.00% - 8.00%
Eversource Energy	ES	6.30%	5.49%	6.00%	5.00% - 7.00%
PNM Resources, Inc.	PNM	7.60%	8.76%	9.00%	7.00% - 9.00%
SCANA Corporation	SCG	5.30%	5.40%	4.50%	4.00% - 6.00%
Xcel Energy Inc.	XEL	5.30%	5.27%	5.50%	4.00% - 6.00%

Q. Do you agree with Dr. Woolridge that dividend and book value growth rates are appropriate measures of expected growth for the Constant Growth DCF model?[45]

A. No, I do not. Earnings growth is the fundamental driver of the ability to pay dividends. As noted in my Direct Testimony, to reduce growth to a single measure we assume a fixed payout ratio, and a constant growth rate for EPS, DPS, and BVPS.[46] Exhibit RBH-21 illustrates that under the strict assumptions of the Constant Growth DCF model, earnings, dividends, book value, and stock

[44] Source: Zacks, Yahoo Finance, Value Line, and individual company first quarter 2016 earnings presentations and investor presentations. *See*, also, Anup Agrawal and Mark A. Chen, *Do Analysts Conflicts Matter? Evidence from Stock Recommendations*, Journal of Law and Economics, August 2008, at 503-537.

[45] *See*, Direct Testimony of J. Randall Woolridge, at 45.

[46] *See* Direct Testimony of Robert B. Hevert, at 27-28.

prices all grow at the same, constant rate in perpetuity. Because earnings are the fundamental driver of dividends, and knowing that investors tend to value common equity on the basis of Price/Earnings ratios, the Cost of Equity is a function of the expected growth in earnings, not dividends. That is, earnings growth enables both dividend and book value growth. Book value can increase over time only through the addition of retained earnings, or with the issuance of new equity. Both of those factors are derivative of earnings: retained earnings increases with the amount of earnings not distributed as dividends; and the price at which new equity is issued is a function of the EPS and the then-current P/E ratio. Similarly, earnings are the fundamental driver of a company's ability to pay dividends.[47]

In addition, Value Line is the only service on which Dr. Woolridge relies that provides DPS, BVPS, or sustainable growth projections. To the extent that the earnings projections services such as Zacks and First Call represent consensus estimates, the results are less likely to be skewed in one direction or another as a result of an individual analyst.

[47] *See*, Direct Testimony of Robert B. Hevert, at 27-28; and Jing Liu, Doron Nissim, and Jacob Thomas, *Is Cash Flow King in Valuations?*, Financial Analysts Journal, Volume 63, Number 2, 2007.

Q. Do you agree with Dr. Woolridge that historical growth rates are appropriate measures of expected growth for the Constant Growth DCF model?[48]

A. No, I do not. The growth component of the Constant Growth DCF model is a *forward-looking* measure. To the extent historical growth influences investors' expectations of future growth, it already will be reflected in analysts' consensus earnings estimates. Carleton and Vander Weide, for example, found "overwhelming evidence that consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price."[49] Consequently, I do not believe that historical growth rates are appropriate for the Constant Growth DCF model.

Q. Have you conducted any analyses to determine which measures of growth are statistically related to the proxy companies' stock valuation levels?

A. Yes, I have. My analysis is based on the methodological approach used by Professors Carleton and Vander Weide, who compared the predictive capability of historical growth estimates and analysts' forecasts on the valuation levels of sixty-five utility companies.[50] I structured the analysis to assess whether earnings, dividend, book value, or sustainable growth rates best explain utility stock valuations. In particular, my analysis examined the statistical relationship between the P/E ratios of the companies included in Dr. Woolridge's proxy group,

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48 *See*, Direct Testimony of J. Randall Woolridge, at 45.

49 Vander Weide and Carleton, Investor Growth Expectations: Analysts vs. History, The Journal of Portfolio Management (Spring 1988).

50 James H. Vander Weide and Willard T. Carleton, *Investor Growth Expectations: Analysts vs. history*, The Journal of Portfolio Management, Spring 1988.

and the projected EPS, DPS, and BVPS reported by Value Line, and sustainable growth rate calculated using Value Line data. To determine which, if any, of those growth rates are statistically related to utility stock valuations, I performed a series of regression analyses in which the projected growth rates were explanatory variables and the P/E ratio was the dependent variable. The results of those analyses are presented in Table 3, below.

Table 3: Regression Results- Price to Earnings and Growth Rates[51]

	Intercept	Coefficient	Standard Error	T-Statistic	F-Statistic
Scenario 1- Projected EPS	13.736	34.462	15.108	2.281	5.203
Scenario 2- Projected DPS	16.778	-21.296	14.886	-1.431	2.047
Scenario 3- Projected BVPS	14.629	22.832	39.329	0.581	0.337
Scenario 4- BR+SV Sustainable Growth	15.138	11.442	40.453	0.283	0.080
Scenario 5- Projected EPS Projected DPS Projected BVPS BR+SV Sustainable Growth	15.283	41.198 -26.857 37.759 -50.037	17.400 14.974 42.387 44.299	2.368 -1.794 0.891 -1.130	2.454

In the first set of analyses (Scenarios 1-4), I considered each growth rate separately (*i.e.*, I performed four separate regressions with P/E as the dependent variable and projected EPS, DPS, BVPS and the sustainable growth rate, respectively, as the independent variable). I also performed a single regression analysis that included all five variables as potential explanatory variables

[51] *See*, Exhibit RBH-22.

(Scenario 5). I then reviewed the T- and F-Statistics to determine whether the variables and equations were statistically significant.[52]

Q. What did those analyses reveal?

A. The only growth rate that was statistically significant was Earnings Per Share. Because the DCF Model assumes that the current market value is a function of expected growth and, given that EPS growth is the only growth rate that is statistically related to electric utility valuation, earnings, not dividends or book value, is the proper measure of growth in the Constant Growth DCF Model.

Q. Is it possible to replicate Dr. Woolridge's DCF analysis?

A. No. As noted above, Dr. Woolridge's analysis is based on his personal view as to what constitutes a reasonable long-term growth rate. Because different analysts may well come to different conclusions based on their review of his growth rate data, we cannot replicate Dr. Woolridge's analyses.

Q. Do you have any concerns with the projected analysts' EPS growth rates relied on by Dr. Woolridge?

A. Yes. In determining his projected analysts' EPS growth rate, Dr. Woolridge includes negative growth projections. In doing so, Dr. Woolridge has implicitly assumed that investors would consider committing capital to a company that is expected to have negative growth, in perpetuity. As Exhibit RBH-23 demonstrates, eliminating negative growth rates from Dr. Woolridge's DCF

[52] In general, a T-Statistic of 2.00 or greater indicates that the variable is likely to be different than zero, or "statistically significant." The F-Statistic is used to determine whether the model as a whole has statistically significant predictive capability.

analysis increases the mean projected EPS growth rate by 52 basis points. However, given that Dr. Woolridge's 4.88 percent growth rate is based on his personal judgment, it is difficult to say how removing negative growth rates would affect his analyses and recommendation.

C. Application of Multi-Stage DCF Approach

Q. Please briefly summarize Dr. Woolridge's observations regarding your Multi-Stage DCF analysis.

A. First, Dr. Woolridge does not appear to disagree with the structure of the model itself. For example, in his Exhibit JRW-9, page 1 of 2, Dr. Woolridge describes the "dividend discount model", which takes the same structure as my Multi-Stage DCF model. At page 41 of his Testimony, Dr. Woolridge explains that in the second, or "Transition" stage, the dividend payout ratio increases because there are fewer investment opportunities. The assumption of increasing payout ratios as capital investments decline also is consistent with my Multi-Stage analysis. Although the dividend discount model is consistent in structure with my model, Dr. Woolridge argues that the terminal growth rate (that is, the long-term growth rate in the third, or "terminal period") applied in my model is overstated.[53]

Q. Before responding to those points, please describe the Multi-Stage DCF model, and explain how the terminal growth rate is derived and applied.

A. As discussed in my Direct Testimony, the Multi-Stage DCF model enables analysts to model growth in three stages, rather than a single growth rate in

[53] *See*, Direct Testimony of J. Randall Woolridge, at 77-82.

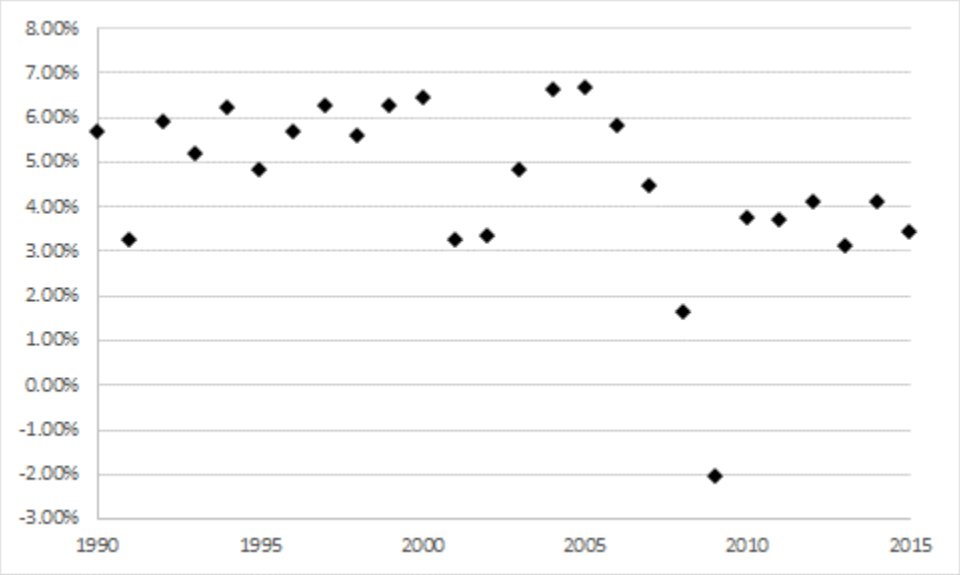
perpetuity (as the Constant Growth DCF model assumes).[54] The terminal, or third stage growth rate, represents investors' expectations for long-term (that is, perpetual) growth beginning in the third stage. Because the model assumes five-year periods for the first and second stage, the terminal stage (and, therefore, the terminal growth rate) begins in the eleventh year.

Q. What is the basis of Dr. Woolridge's concern with your assumed long-term growth rate based on expected GDP growth?

A. Dr. Woolridge states that "nominal GDP growth in recent decades has slowed and that a figure in the range of 4.0% to 5.0% is more appropriate today for the U.S. economy."[55] To support his position, Dr. Woolridge reviews average nominal GDP growth over periods of ten to 50 years, and concludes, "economic growth in the U.S. has slowed considerably in recent decades."[56] As shown on Chart 1 (below), however, since 1990 (*i.e.*, in "recent decades") the annual nominal growth rate in GDP has remained relatively stable, but for the period 2008 to 2012, which included the recent recession. Over that time, annual nominal GDP growth rates greater than 5.00 percent (the high end of Dr. Woolridge's suggested range) occurred in twelve of 26 years; growth rates of at least 5.35 percent occurred in eleven of 26 years.

54 *See*, Direct Testimony of Robert B. Hevert, at 31-32.
55 Direct Testimony of J. Randall Woolridge, at 80.
56 *Ibid.*, at 79.

Chart 1: Annual Nominal GDP Growth Rates[57]



Moreover, historical nominal GDP growth rates since 1960 reflect periods of differing inflation rates. For example, the real GDP growth rates in 1980 and 2008 were nearly identical at negative 0.24 percent and negative 0.29 percent, respectively. On a nominal basis, however, the growth rates were vastly different, at 8.75 percent and 1.66 percent. Knowing that inflation was significantly higher in the 1970s and early 1980s than it was in 2008, it is not surprising that nominal GDP rates are lower when viewed within the context of shorter term averages (*i.e.*, over the last ten or twenty years as Dr. Woolridge has done).

In addition, as shown in Table 4 (below), the recent economic downturn has had a significant effect on the real GDP growth rate calculated over shorter periods.

[57] Source: Bureau of Economic Analysis, June 28, 2016 update.

Table 4: Average Real GDP Growth Rates[58]

Average Length	As Of 2015	As Of 2007
10-Year Average	1.41%	3.04%
20-Year Average	2.41%	3.07%
30-Year Average	2.60%	3.12%
40-Year Average	2.83%	3.14%
50-Year Average	2.89%	3.38%

As Table 4 demonstrates, prior to the recent recession the difference between the average GDP growth rates measured over varying time periods was minimal. Subsequent to the recession the differences have been quite large. Because I apply the long-term growth rate beginning ten years in the future, it would be inappropriate to give undue weight to short-term trends in the time series, as Dr. Woolridge suggests.

As to the inflation portion of the expected nominal growth rate, Dr. Woolridge does not seem to disagree with my expected inflation rate of 2.00 percent, as he noted that the current inflation is "in the 2% to 3% range."[59] I also note that on page 85 of Dr. Woolridge's Direct Testimony, he provides the average growth rates (since 1960) for nominal GDP, the S&P 500 Index, the S&P 500 earnings per share, and the S&P 500 dividends per share. The average of those measures is 6.42 percent, which is 107 basis points above the 5.35 percent long-term GDP growth rate estimate included in my Direct Testimony. The 6.42 percent average

[58] Source: Bureau of Economic Analysis, June 28, 2016 update.

[59] Direct Testimony of J. Randall Woolridge, at 87. Note, the expected inflation rate has been updated to 2.02 percent in my Rebuttal Testimony Multi-Stage DCF analysis.

growth rate noted above also is 22 basis points greater than the approximately 6.20 percent long-term nominal GDP growth rate reported by the Bureau of Economic Analysis.[60] I therefore disagree with Dr. Woolridge's view that my assumed terminal growth rates are excessive.

Q. Are there examples in financial literature that support your calculation of the long-term growth rate based on GDP?

A. Yes. The use of expected long-term GDP growth in the terminal period is consistent with practice and financial literature.[61] Morningstar, a source on which Dr. Woolridge relies for Market Risk Premium estimates, describes an approach for calculating the long-term growth estimate that is similar to that which is included in my model.[62] As with my approach, Morningstar's method combines the historical average real GDP growth rate with a measure of inflation calculated using the TIPS spread.[63]

Q. Does Dr. Woolridge provide any other data that supports your terminal growth rate assumption?

A. Yes, Dr. Woolridge cites to certain research to support his view that analysts' earnings estimates are "overly optimistic and upwardly biased,"[64] including a

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60 Source: Bureau of Economic Analysis, June 28, 2016 update. Compound annual return from 1929 – 2015.

61 Dr. Roger Morin, for example, writes "[i]t is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy." *See*, Roger A. Morin, New Regulatory Finance, Public Utilities Report, Inc., 2006, at 308.

62 *See*, Ibbotson SBBI 2013 Valuation Yearbook, Morningstar, Inc., at 50-52.

63 Implied Expected Nominal GDP = ((1 + Historical Real GDP Growth) x (1 + Implied Forward Inflation)) – 1, or 5.32 percent = ((1 + 3.24 percent) x (1 + 2.02 percent)) - 1.

64 Testimony and Exhibits of J. Randall Woolridge, at 49.

2010 report by McKinsey & Company ("McKinsey").[65] The McKinsey report observes that "…long-term earnings growth for the market as a whole is unlikely to differ significantly from growth in GDP, as prior McKinsey research has shown."[66] In a footnote to that sentence, McKinsey further states that "[r]eal GDP has averaged 3 to 4 percent over past (*sic*) seven or eight decades, which would indeed be consistent with nominal growth of 5 to 7 percent given current inflation of 2 to 3 percent."[67] The McKinsey report therefore supports the terminal growth rate used in my Multi-Stage DCF model based on expected GDP; it represents the combination of historical real GDP growth and expected inflation, and is toward the lower end of the 5.00 percent to 7.00 percent range noted by McKinsey.[68]

Q. What is your response to Dr. Woolridge's reference to GDP forecasts provided by the *Survey of Professional Forecasters*, the Energy Information Administration ("EIA"), and the Congressional Budget Office ("CBO")?[69]

A. In the case of the *Survey of Professional Forecasters*, as Dr. Woolridge points out, it relates to the 2016 to 2026 period. That is, it does not apply to the terminal period, which begins in 2026. As to the CBO and EIA forecast, those projections cover only fifteen years of a perpetual period, and represent forecasts from single

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65 *Equity Analysts: Still too bullish*, McKinsey & Company, McKinsey on Finance, Number 35, Spring 2010.

66 *Ibid.*, at 16-17.

67 *Ibid.*, at 17.

68 Please also note that consistent with the McKinsey approach, the terminal growth rate used in my Multi-Stage DCF model (*see* Exhibit RBH-14) is the product of real GDP growth (3.24 percent) and expected inflation (2.02 percent).

69 *See*, Direct Testimony of J. Randall Woolridge, at 80-81.

entities. As such, I do not agree that those sources invalidate the growth rate used in my analysis.

In addition, the CBO provides updates regarding its forecasting record. In that context, the CBO discusses comparisons to other forecasts, and notes that "[d]espite their value, comparisons of forecasting errors can be misleading when forecasts are made for different purposes."[70] In essence, the CBO notes that comparisons to other forecasts are not always apt, at least in part because they may be based on different assumptions and used for different purposes. Moreover, the CBO states that it is required to assume that future fiscal policy will reflect current law, so that it may "provide a benchmark" against which proposed changes in law may be assessed.[71] Given that purpose and structure, I disagree that the CBO's forecast invalidates the growth rate used in my Multi-Stage DCF analysis.

The CBO also notes that among its two-year forecasts (since the early 1980's), the forecast error for "real output growth" and inflation (measured by the Consumer Price Index) has been 1.40 percentage points, and 0.80 percentage points,

70 *CBO's Economic Forecasting Record: 2015 Update*, February 2015, at 4-5.

71 "In particular, forecasters in the private sector attempt to predict the future stance of federal fiscal policy, and the Administration's forecasts assume the adoption of the fiscal policy reflected in the President's proposed budget. CBO, however, is required to assume that fiscal policy in the future will generally reflect the provisions in current law, an approach that derives from the agency's responsibility to provide a benchmark for lawmakers as they consider proposed changes in law. Forecasting errors may be driven by those different assumptions, particularly when policymakers are considering major changes in the fiscal policy embedded in current law."

respectively.[72] That range of error, if applied to the 4.30 percent long-term CBO forecast noted by Dr. Woolridge, suggests that the 5.35 percent rate applied in my Direct Testimony is within the range of the CBO's projections.[73]

Q. Do you have any other observations regarding Dr. Woolridge's position that you should rely on economists' forecasts of real GDP growth beginning ten years in the future?

A. Yes, I do. Dr. Woolridge is quite critical of economists' projections of interest rates, noting that in hindsight, they often are incorrect.[74] At the same time, he is critical of the fact that I do not rely on economists' real GDP growth rate projections.[75] Putting aside the fact that the Multi-Stage DCF model requires forecasts beginning ten years from now, not as of the present, Dr. Woolridge does not explain why economists' near-term interest rate projections are improper, but their long-term real GDP growth rate projections are sound.

Q. Did you perform any analyses in response to Dr. Woolridge's contention that the currently elevated P/E ratios are expected to continue?

A. In response to Dr. Woolridge's assumption that current P/E ratios will persist in perpetuity, I also have included a series of Multi-Stage DCF analyses that assume

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72 *CBO's Economic Forecasting Record: 2015 Update*, February 2015, at 1.

73 As to the use of expected inflation, I note that the TIPS spread has been affected by low levels of inflation, which likely are affected by recently low oil prices. As noted at page 30 of the Federal Reserve's February 2016 *Monetary Policy Report*, "Inflation is expected to remain low in the near term, in part because of recent further declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of declines in energy and import prices dissipate and the labor market strengthens further."

74 *See*, Direct Testimony of J. Randall Woolridge, at 16-18.

75 The Philadelphia Federal Reserve publishes the list of economists that provide forecasts with attribution. *See* http://www.frbsf.org/economic-research/publications.

that the current P/E ratio will remain in place by calculating the terminal value in the Multi-Stage DCF analysis on the basis of the Combined Proxy Group's current 30-day average P/E ratio. The results of my Multi-Stage DCF analyses are shown on Table 10 in Section IX (*see also*, Exhibit RBH-14).

D. Application of the CAPM

Q. Please briefly describe Dr. Woolridge's CAPM analysis and results.

A. Dr. Woolridge's CAPM analyses produce an estimated Cost of Equity of 7.90 percent to 8.10 percent.[76] Although Dr. Woolridge relies primarily on his DCF analysis, he also considers his CAPM results in determining what he considers an appropriate range of the Company's Cost of Equity.[77] As with Dr. Woolridge's DCF results, I strongly disagree that a CAPM result of 7.90 percent to 8.10 percent is a reasonable estimate of the Company's ROE. As discussed below, Dr. Woolridge's unduly low CAPM estimates primarily are the result of his estimated Market Risk Premium.

Q. Please describe how Dr. Woolridge calculates his Market Risk Premium estimate.

A. Dr. Woolridge reviews a series of studies that calculate the MRP using different methodologies; he also considers the results of his "Building Blocks" approach.

[76] *See*, Direct Testimony of J. Randall Woolridge, Exhibit JRW-11, at 1.
[77] *See*, Direct Testimony of J. Randall Woolridge, at 63.

Based on those reviews, Dr. Woolridge concludes that the MRP ranges from 4.00 percent to 6.00 percent and, within that range, 5.50 percent is reasonable.[78]

Q. Does Dr. Woolridge express any concerns regarding your CAPM analysis?

A. Dr. Woolridge's principal disagreement with my CAPM analysis involves the Market Risk Premium component of the model. As to my use of expected market returns, Dr. Woolridge states that the result is "inflated due to errors and bias in [my] study."[79] Dr. Woolridge also points to the long-term EPS growth rates for the S&P 500 based on the data from Bloomberg and Value Line, respectively,[80] and notes that they "are not consistent with historic or projected economic and earnings growth."[81] In support of his position that the expected market return included in my CAPM analysis is overstated, Dr. Woolridge cites two surveys: the Duke Chief Financial Officers ("CFO") survey, and the Philadelphia Federal Reserve Survey of Professional Forecasters.[82]

Q. What is your response to Dr. Woolridge on those points?

A. First, by referring to the survey by the Federal Reserve Bank of Philadelphia, Dr. Woolridge suggests that my estimated market return is inconsistent with those used by professional forecasters.[83] On reviewing that survey, I note that only 18 of 40 survey participants responded to the question regarding the expected return

78 *Ibid.*, at 61; Exhibit JRW-11, at 1, 5-6.
79 *Ibid.*, at 88. [Clarification added]
80 *Ibid.*, at 84.
81 *Ibid.*, at 85.
82 *Ibid.*, at 88.
83 *Ibid.*

for the S&P 500 over the next ten years.[84] Similarly, 26 of 40 responded to the question regarding expected return on ten-year Treasury bonds. Because a considerable portion of the survey respondents did not answer those questions, it is difficult to have confidence that the estimates represent the market's expected total return.

Even if all 40 economists provided expected market returns and Treasury yields, as noted earlier Dr. Woolridge gives economists' interest rate projections little weight, going so far as to note that in a Bloomberg survey, "100% of the economists were wrong."[85] Yet, Dr. Woolridge gives economists' forecasts of market returns and interest rates considerable weight in supporting his expected Market Risk Premium.

As to the Duke CFO survey, Dr. Woolridge's 8.75 percent ROE recommendation, which applies to a company that is less risky than the overall market,[86] is 245 basis points above the expected market return suggested by the survey results. If the survey were a reasonable method of determining the expected market return, Dr. Woolridge's ROE recommendation would be no higher than 6.30 percent.[87] Moreover, as shown in Table 5 below, the survey respondents have provided estimates that, on average, significantly underestimated actual market returns.

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84 *See*, Federal Reserve Bank of Philadelphia, Survey of Professional Forecasters, First Quarter of 2016, at 17.

85 Direct Testimony of J. Randall Woolridge, at 16. [emphasis included]

86 Dr. Woolridge and I agree that Beta coefficients for our proxy companies are less than 1.0.

87 6.30 percent equals the expected market return suggested by the Duke CFO survey.

Table 5: S&P 500 Market Return: Accuracy of Survey Estimates[88]

	Actual	Graham Harvey Estimate
2015	1.38%	6.07%
2014	13.69%	5.00%
2013	32.39%	3.40%
2012	16.00%	4.00%
2011	2.11%	5.30%
2010	15.06%	6.28%
Average	13.44%	5.01%

Further, the Duke CFO Survey authors have noted a distinction between the expected market return on one hand, and the hurdle rate on the other. In prior surveys, the hurdle rate was significantly higher than the expected market return. For example, the authors' survey showed that the reported average hurdle rate, which is the return required for capital investments, was above 13.00 percent.[89] The author further reported that the Weighted Average Cost of Capital ("WACC") exceeded the expected market return, even though the WACC includes the cost of debt. For example, in 2012 the reported WACC was 9.30 percent even though the expected market return was 6.00 percent.[90] Dr. Woolridge's reference to the 4.55 percent expected Market Risk Premium, which relies on the survey's expected market return, therefore should be given little weight.

88 Source: Morningstar, Inc., 2016 SBBI Appendix A, at 3-5, 21-23; http://www.cfosurvey.org (1-year return estimates as of fourth quarter of the previous year).

89 Graham, John R. and Harvey, Campbell R, *The Equity Risk Premium* in 2015 (June 25, 2015), at 8, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2611793. At page 9, the authors note that hurdle rates are "used for actual investment decisions."

90 Duke/CFO Magazine Global Business Outlook survey – U.S., Second Quarter 2012 at 139, 159.

Q. Do any of the authors cited in Woolridge's Equity Risk Premium survey provide support for your approach to estimating the current MRP?

A. Yes. A study by Pablo Fernandez titled "Market Risk Premium used in 71 countries in 2016: a survey with 6,932 answers" discusses how the required Equity Risk Premium is commonly calculated using a Constant Growth DCF approach.[91] That study states:

> [t]he [implied equity premium] is the implicit [required equity premium] used in the valuation of a stock (or market index) that matches the current market price. The most widely used model to calculate the [implied equity premium] is the dividend discount model: the current price (P0) is the present value of expected dividends discounted at the required rate of return (Ke). If d1 is the dividend per share expected to be received in year 1, and g the expected long term growth rate in dividends per share:
>
> $P_0 = d_1 / (Ke - g)$, which implies:
>
> [implied equity premium] = $d_1/P_0 + g - R_f$[92]

As discussed in my Direct Testimony, I calculated the *ex-ante* MRP in a similar manner using a market capitalization weighted Constant Growth DCF calculation on the individual companies in the S&P 500 Index.

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[91] Dr. Woolridge cites Pablo Fernandez's research; *see* Direct Testimony of J. Randall Woolridge, Exhibit JRW-11, at 5.

[92] Pablo Fernandez, Alberto Ortiz, and Isabel Fernandez Acín, *Market Risk Premium used in 71 countries in 2016: a survey with 6,932 answers*, IESE Business School, at 10.

Q. Do you have any other observations regarding Dr. Woolridge's Equity Risk Premium estimates?

A. Yes. Many of Dr. Woolridge's Equity Risk Premium estimates assume market returns nearly equal to, or below the Company's required return and as such, do not make either theoretical or practical sense. For example, Exhibit JRW-11, page 5 of 6 indicates that the average estimated Equity Risk Premium over all the articles included in the survey is 4.64 percent. Combining that estimate with Dr. Woolridge's 4.00 percent estimated Risk-Free Rate (Exhibit JRW-11, page 1 of 6) produces an estimated market return of 8.64 percent, which is 11 basis points below Dr. Woolridge's 8.75 percent recommendation.

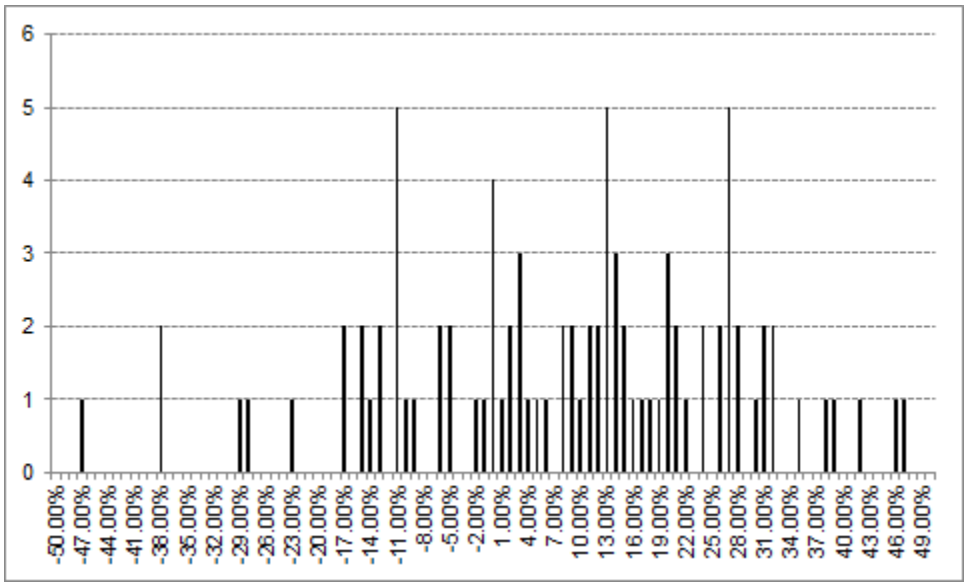
Dr. Woolridge observes that "…a regulated public utility is less risky than the market," and should have a Beta coefficient less than 1.0.[93] Because his implied 8.64 percent market return is below his 8.75 percent ROE recommendation, its relevance to investors' actual required returns is questionable. Even focusing on studies from the 2010 to 2015 period (Exhibit JRW-11, page 6 of 6), the expected market return would be approximately 8.92 percent, which is only 17 basis points above Dr. Woolridge's 8.75 recommendation for FPL. Because such important elements of his CAPM analyses contradict each other, Dr. Woolridge's CAPM results are not reliable.

[93] Direct Testimony of J. Randall Woolridge, at 56.

Q. Turning to Dr. Woolridge's position that the EPS growth rates used to develop your estimated market return are too high, did you consider where your estimates fall within the range of historical observations?

A. Yes, I gathered the annual capital appreciation return on Large Company Stocks reported by Morningstar for the years 1926 through 2015, produced a histogram of those observations, and calculated the probability that a given capital appreciation return estimate would be observed. The results of that analysis, which are presented in Chart 2 (below), demonstrate that capital appreciation rates of 9.87 percent to 10.68 percent and higher actually occurred quite often.[94]

Chart 2: Frequency Distribution of Observed Capital Appreciation Rates 1926 – 2015[95]



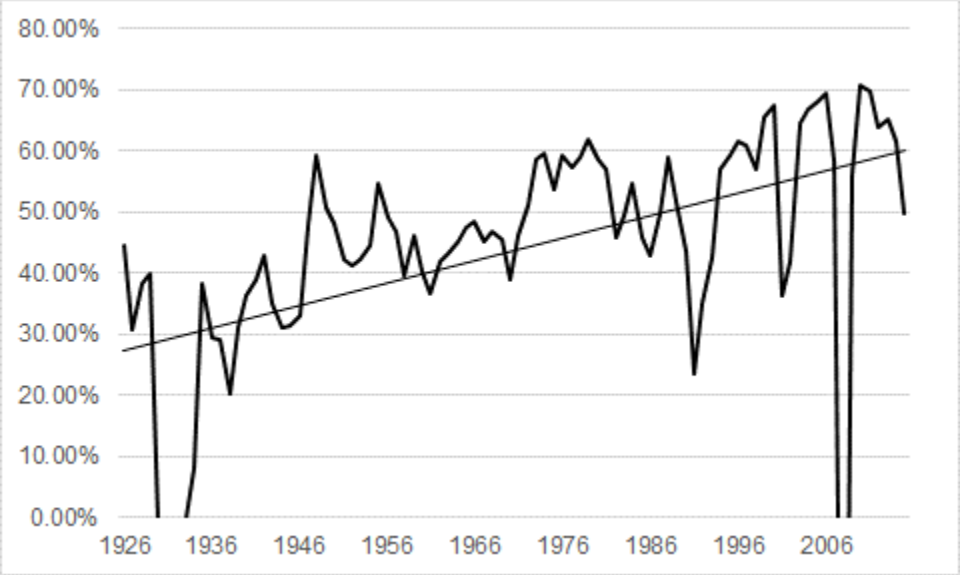
[94] Under the Constant Growth DCF model's assumptions, the growth rate equals the rate of capital appreciation.

[95] Source: Morningstar, Inc., 2016 Morningstar Stocks, Bonds, Bills and Inflation, Table A-3.

In fact, the growth rates Dr. Woolridge asserts are "overstated" by historical standards represent approximately the 49th to 51st percentile of the actual capital appreciation rates observed from 1926 to 2015.

Lastly, under the sustainable growth model, if the retention ratio is higher now than it historically has been, there would be reason to believe that expected growth rates would be higher than historical growth rates. To determine whether that has been the case, I calculated the annual retention ratio from 1926 to 2015 using earnings and dividends data published by Dr. Robert J. Shiller. As shown in Chart 3 (below), that data indicates the S&P 500 earnings retention has trended upward over time, and is currently well above its historical average. Consequently, the sustainable growth model included in Dr. Woolridge's DCF analysis suggests that the future growth of the S&P 500 could outpace its historical growth.

Chart 3: S&P 500 Annual Earnings Retention Ratio, 1926 - 2015[96]



E. Bond Yield Plus Risk Premium Analysis

Q. Please summarize Dr. Woolridge's response to your Bond Yield Plus Risk Premium analysis.

A. Dr. Woolridge believes that the Risk Premium derived from the analysis is "inflated" and "is a gauge of *commission* behavior and not *investor* behavior."[97] Dr. Woolridge further observes that my Risk Premium approach and results "reflect other factors used by utility commissions in authorizing ROEs in addition to capital costs."[98] In particular, Dr. Woolridge points to a potential discrepancy between settled and litigated cases.[99] In addition, Dr. Woolridge reasons that the analysis overstates the actual ROE, because the estimated risk premium is based

96 Source: http://www.econ.yale.edu/~shiller/data.htm.
97 Direct Testimony of J. Randall Woolridge, at 90. [emphasis included]
98 *Ibid.*, at 14.
99 *Ibid.*

on historical Treasury yields, whereas the model is applied to current and expected yields.[100]

Q. What is your response to Dr. Woolridge's position that the Risk Premium analysis is a study of utility commissions' behavior, rather than investor behavior?

A. Those cases, and their associated decisions, reflect the same type of market-based analyses at issue in this proceeding. Moreover, given that authorized returns are publicly available, it is difficult to imagine that such data is not reflected, at least to some degree, in investors' return expectations and requirements (American Electric Power, one of Dr. Woolridge's proxy companies, discloses authorized returns, by jurisdiction, in its 2015 SEC Form 10-K). Consequently, it is reasonable to assume that authorized returns are a reasonable (although not the only) measure of investor-required returns.

Q. What is your response to Dr. Woolridge's statement that your analysis applies an historical risk premium to projected rates and as such, overstates the Cost of Equity?[101]

A. I applied both historical and projected interest rates to the regression coefficients developed in my Risk Premium analysis, not to an average historical risk premium. As discussed in my Direct Testimony, the regression coefficients specifically recognize that as interest rates increase the Equity Risk Premium

100 *Ibid.*

101 Direct Testimony of J. Randall Woolridge, at 89-91.

decreases.[102] A consequence of that relationship is that interest rates and the Cost of Equity generally move in the same direction, although not on a one-to-one basis. As projected interest rates increase, the Cost of Equity also will increase, but not to the same degree. Dr. Woolridge's concern that I have applied projected interest rates to an historical risk premium is misplaced in that (1) my analysis does not rely on an historical risk premium; and (2) because the estimated risk premium does not increase in lock step with interest rates, the resulting ROE estimate does not overstate the Cost of Equity.

Q. What is your response to Dr. Woolridge's position that your Risk Premium analysis must take into consideration the specific aspects of this proceeding relative to all others?[103]

A. First, every case has its unique set of issues and circumstances; there is no disagreement on that point. Looking at over 1,000 cases over many economic cycles, and using that data to quantify the relationship between the Equity Risk Premium and interest rates, mitigates that concern. I do agree, however, that the Risk Premium model results should be considered an industry average ROE estimate. To the extent FPL equity investors face incremental risks, its ROE should be adjusted.

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102 *See*, Direct Testimony of Robert B. Hevert, Exhibit RBH-3.

103 Direct Testimony of J. Randall Woolridge, at 90-91.

Q. Do you believe that it is a concern, as Dr. Woolridge states, to include both fully litigated and settled rate cases in your Risk Premium analysis?[104]

A. No, I do not. Of the rate cases in my Risk Premium analysis, 373 were settled and 1,102 were fully litigated. More recently (from 2012 through June 2016), 75 cases were litigated and 84 were settled. The difference in average authorized returns between the two, however, was only three basis points. Equally importantly, and as illustrated on Exhibit RBH-24, the same inverse relationship between interest rates and the Equity Risk Premium is present whether the analysis includes fully litigated rate cases, settled rate cases, or both. I therefore disagree with Dr. Woolridge's concern that the distinction between settled and litigated cases is meaningful.

Q. Are authorized returns in other jurisdictions a relevant benchmark in assessing the reasonableness of ROE estimates and recommendations?

A. Yes, they are. It is important to recognize that in establishing their return requirements, investors consider a broad range of data, including returns authorized in other jurisdictions. Equity investors have many options available to them, and allocate their capital based on the expected risks and returns associated with those alternatives. Given that investors consider such data in framing their investment decisions, return recommendations that materially depart from observed industry norms – such as such as Dr. Woolridge's 8.75 percent recommendation – should be supported by clear and unambiguous reasons.

[104] *Ibid.*

I also disagree with Dr. Woolridge's position that authorized returns are not meaningful because they are measures of "commission behavior" as opposed to measures of investors' return expectations.[105] There is no reason to believe that other regulatory commissions do not consider the same type of market-related factors at issue in this proceeding. Nor is there reason to assume that investors dismiss authorized returns in establishing their return expectations. Rather, the fact that companies such as American Electric Power – one of Dr. Woolridge's proxy companies – report authorized returns in their annual Securities Exchange Commission Form 10-K indicates that they are quite relevant to investors.

The implications of not reconciling his ROE recommendation with authorized returns are particularly acute given that Dr. Woolridge's conclusion is based principally on his application of a single model for which his inputs are quite subjective, his results cannot be replicated, and whose underlying assumptions are incompatible with prevailing market conditions.

Q. What is your response to Dr. Woolridge's statement that the current norm is for utility commissions to authorize ROEs below 10.00 percent?

A. First, from January 2014 through June 2016, utility commissions have authorized ROEs of 10.00 percent or higher for 12 vertically integrated electric utilities. None, however, has authorized a return as low as 8.75 percent.[106] Second, although Dr. Woolridge acknowledges that his recommendation is "below the

[105] Direct Testimony of J. Randall Woolridge, at 90.

[106] Source: SNL Financial, excluding formula-based rate plans and limited issue riders.

average authorized ROEs for electric companies,"[107] the lowest authorized ROE for a vertically integrated electric utility since January 2014 was 55 basis points *above* Dr. Woolridge's 8.75 percent recommendation. Here again, Dr. Woolridge's conclusions are incompatible with observable market data.

F. Market-To-Book Ratios and the Cost of Equity

Q. Please briefly summarize Dr. Woolridge's position regarding the relationship between Market/Book ratios and the Cost of Equity.

A. Dr. Woolridge suggests that M/B ratios in excess of unity indicate that the subject company's earned Return on Equity exceeds its Cost of Equity.[108] In support of that position, Dr. Woolridge provides a series of three regression analyses reflecting the relationship between the Return on Equity and M/B ratios for electric, natural gas, and water utilities, respectively. Because the Coefficient of Determination (sometimes referred to as the "R^2") ranges from 77.00 percent in the case of electric utilities, to 56.00 percent in the case of natural gas utilities, Dr. Woolridge concludes that "there is a strong positive relationship" between M/B ratios and the ROE for utilities.[109]

Q. What is your response to Dr. Woolridge on those points?

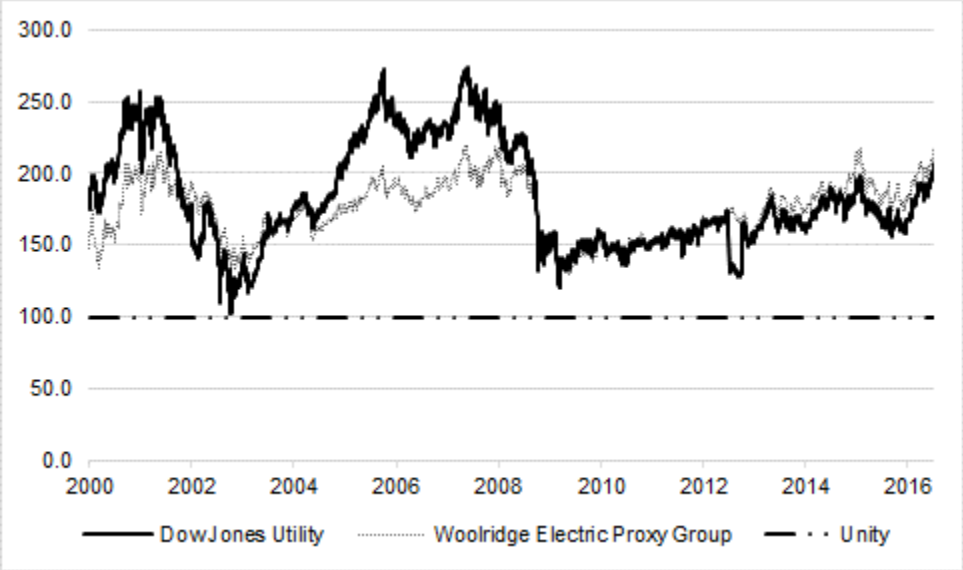
A. First, it is important to note that the M/B ratio equals the market value (or stock price) per share, divided by the total common equity (or the book equity) per share. Book value per share is an accounting construct, which reflects historical

[107] Direct Testimony of J. Randall Woolridge, at 67.
[108] *Ibid*., at 33.
[109] *See*, Direct Testimony of J. Randall Woolridge, at 35 and Exhibit JRW-6. Please note that there were only nine observations for the water group and twelve for the gas company group.

costs. In contrast, market value per share (*i.e.*, the stock price) is forward-looking, and a function of many variables, including (but not limited to) expected earnings and cash flow growth, expected payout ratios, measures of "earnings quality", the regulatory climate, the equity ratio, expected capital expenditures, and the earned return on common equity.[110] As discussed below, because the numerator (market value per share) and the denominator (book value per share) are a function of different variables, M/B ratios over 100.00 percent do not demonstrate that regulatory commissions have consistently authorized returns in excess of the true Cost of Equity. To put the issue in context, the M/B ratio for the companies in the Dow Jones Utility Index, as well as Dr. Woolridge's proxy group have been well in excess of 1.00 since at least 2000 (*see* Chart 4, below).

[110] *See*, for example, Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 366. Please note that Dr. Morin cites several academic articles that address the various factors that affect the M/B ratio for utilities. In addition, the notion that book values should be set at a value approaching unity by regulatory commissions has been refuted for many years. As noted by Stewart Myers in 1972: "In short, a straightforward application of the cost of capital to a book value rate base does not automatically imply that market and book values will be equal. This is an obvious but important point. If straightforward approaches did imply equality of market and book values, then there would be no need to estimate the cost of capital. It would suffice to lower (raise) allowed earnings whenever markets were above (below) book." Stewart C. Myers, *The Application of Finance Theory to Public Utility Rate Cases*, The Bell Journal of Economics and Management Science, Vol. 3, No. 1 (Spring 1972), at 76.

Chart 4: Market/Book Ratios Over Time[111]



In the context of rate-setting, the M/B ratio often is discussed relative to the Constant Growth DCF model. Under certain restrictive assumptions, that model can be rewritten to express the M/B ratio as follows:

$$\frac{M}{B} = \frac{ROE - G}{ke - G} \quad \text{Equation [1]}$$

where *ROE* is the return on book equity, k_e is the risk-adjusted discount rate, and *G* is the long-term growth rate in dividends per share. Taking Equation [1] at face value, if M/B exceeds unity, then ROE exceeds k_e. Branch *et al.* point out that M/B is generally greater than or equal to one because the value of the firm as a going concern (price per share) generally exceeds the liquidation value (book value per share) and "…firms having going concern values greater than their

[111] Source: SNL Financial and Bloomberg Professional.

liquidation values (most firms) and firms having finite prices (all firms) should have $ROE > k_e > G$."[112]

Any inferences drawn as to the relationship among M/B, *ROE*, and k_e from Equation [1] rely on the acceptance of all assumptions of the Constant Growth DCF model. Equally important, Equation [1] only can be solved from the Constant Growth DCF model if we further assume: (1) a constant dividend payout ratio in perpetuity; (2) no stock issuances or repurchases; and (3) that the firm is in a steady state, in which the book equity growth rate equals the dividend growth rate. Taken together, those assumptions are quite restrictive, and call into question a definitive linkage between M/B, *ROE*, and k_e.

As Dr. Morin states, it is rarely the case in cost of service-based regulation that M/B ratios equal 1.00:

> The third and perhaps most important reason for caution and skepticism is that application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the market-to-book (M/B) ratio of a given stock

[112] Ben Branch, Anurag Sharma, Chetan Chawla, and Feng Tu; *An Updated Model of Price-to-Book*, Journal of Applied Finance, November 1, 2014, at 78.

> exceeds unity. This was particularly relevant in the capital market environment of the 1990s and 2000s where utility stocks were trading at M/B ratios well above unity and have been for nearly two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base. [113]

Because the Constant Growth DCF model traditionally used in rate regulation assumes a M/B of unity, it would understate investors' required return rate when market value exceeds book value. It would do so because investors evaluate and receive their returns on the market value of a utility's equity, whereas regulators authorize returns on book common equity. Consequently, the market-based DCF model will result in a total annual dollar return on book common equity equal to the total annual dollar return expected by investors only when market and book values are equal, a rare and unlikely situation.

In essence, M/B ratios in excess of unity simply means that the firm is worth more as a going concern than the book value of its assets. If Dr. Woolridge is of the view that M/B ratios in excess of unity reflect earned returns in excess of the Cost of Equity, it would follow that he also is of the view that utility commissions have

[113] Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 434. [emphasis added]

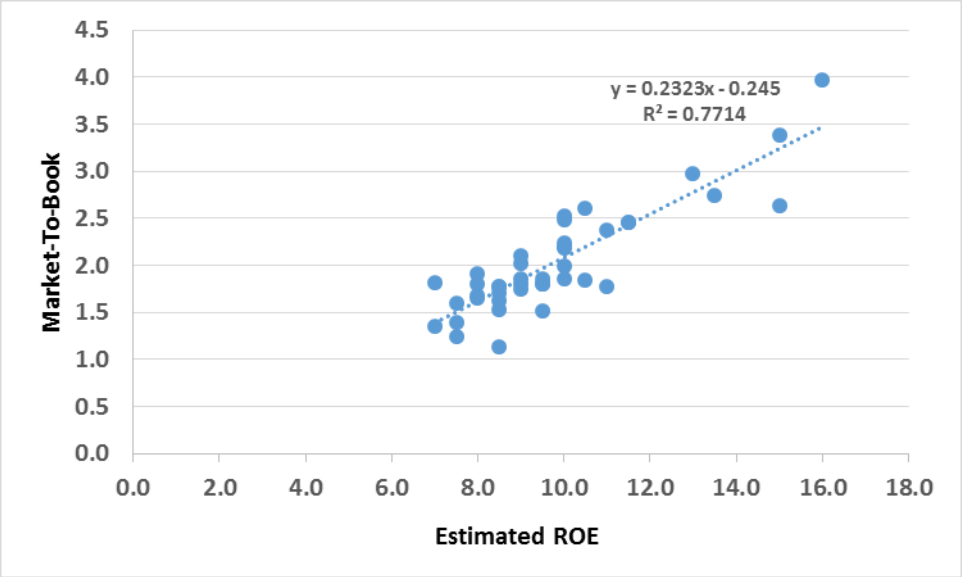
been consistently authorizing returns in excess of the Cost of Equity for at least the last fifteen years. Since Dr. Woolridge does not provide any additional support for his position beyond the general observation that M/B ratios for electric utilities have been greater than 100.00 percent, I disagree with that conclusion.

Lastly, although the earned Return on Equity may be one factor explaining M/B ratios, it is not the only factor. If it were, the regression equations presented in Exhibit JRW-6 would produce reasonable ROE estimates when the M/B ratio equals unity.

Q. In that regard, have you reviewed the ROE and M/B ratio data provided in Exhibit JRW-6?

A. Yes, I have reproduced the chart contained in Exhibit JRW-6, Panel A (Electric Companies), including the regression coefficients, in Chart 5 (below).

Chart 5: Exhibit JRW-6, Panel A, With Regression Coefficients[114]



Based on that data, an M/B ratio of 1.00 is associated with an ROE of 5.36 percent.[115] That estimate is only about 75 basis points above the Company's cost of debt (*i.e.*, 4.62 percent). In other words, for the M/B ratio to equal 1.00, the Cost of Equity would be nearly equal to the cost of debt, a condition that is highly improbable. Dr. Woolridge's own data therefore do not support his theory that ROEs in excess of unity indicate that the subject company's return exceeds investors' required returns.

[114] Source: Value Line. Note that as with Dr. Woolridge's Exhibit JRW-6, Panel A, my analyses include 42 observations and produce an R^2 of approximately 0.77.

[115] 1.00 = -0.245 + (5.36 percent x 0.232).

Q. Have you analyzed whether the actual earned Return on Equity explains the M/B ratios for Dr. Woolridge's proxy group?

A. Yes, I have. Based on data from SNL Financial, I performed a regression analysis in which the M/B ratio was the dependent variable, and the most recent twelve-month Return on Average Common Equity ("ROACE") was the explanatory variable. As shown in Exhibit RBH-25, the R^2 was approximately 48.00 percent (the coefficients and equation were statistically significant). Thus, other factors explain up to 52.00 percent of M/B ratios for Dr. Woolridge's proxy group.[116] Those results support the position that although the earned return on equity is a factor that explains M/B ratios, it is not the only factor. In any case, the regression equation indicates that a M/B ratio of 1.00 is associated with a Return on Common Equity of 2.29 percent; an M/B ratio of 1.10 relates to an ROACE of 3.27 percent. Because those estimates are far below the Company's 4.62 percent cost of debt, I do not agree that M/B ratios in excess of unity demonstrate earnings in excess of investors' requirements.

Q. Do you have any other points regarding this issue?

A. Yes. It is important to keep in mind that, like P/E multiples, M/B ratios tend to be used in practice as measures of relative, rather than absolute valuation. That is, investors often use M/B ratios to value an individual company based on the average M/B ratio of its peers. Such "market comparable" approaches to valuation are useful because no one financial model is accepted as the true measure of value at all times and under all conditions.

[116] 0.52 = (1 - 0.48).

G. Relative Risk

Q. Do you believe that credit ratings are an appropriate measure to determine the equity risk of FPL relative to the proxy group?

A. Although I agree that in general, credit ratings, and by extension credit spreads, are directionally related to the Cost of Equity, [117] I do not agree that changes in one is a direct measure of changes in the other. Debt and equity are different securities with different risk/return characteristics, different lives, and different investors. To that point, debt investors have a contractual, priority claim on cash flows not available to equity investors and as such, equity investors bear the residual risk of ownership. Moreover, because the life of debt is finite, debt investors' exposure to business and financial risk likewise is finite. Equity, on the other hand is perpetual and as such, equity investors are exposed to residual risk in perpetuity. Because debt and equity are distinct securities with different risk and return profiles, debt and equity investors themselves have different risk and return requirements. As such, any inferences drawn from credit ratings for the Company's Cost of Equity should be drawn with caution.

A visible measure of the distinction of the risks to which debt and equity investors are exposed is the difference in their respective Beta coefficients. Although I disagree with his application of the CAPM, Dr. Woolridge recommends average

[117] As noted by Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992, at 68, "equity risk premia... increased with the increases in the spread between corporate and government bond yields".

Beta coefficients of 0.70 and 0.75 for our respective proxy groups.[118] Duff & Phelps notes that as of December 2015, Beta coefficients for A-rated debt was negative .07[119]. That is, the Beta coefficients of A-rated debt are well below those of the equity Beta coefficients assumed by Dr. Woolridge. In fact, debt Beta coefficients in the range of .31 to .61 are associated with Ba and B rated debt, both of which are considered to be below investment grade.[120] Those differences are a clear indication that the risks assumed by debt investors are far different than those assumed by equity investors.

Q. Did you perform any analyses to determine whether Dr. Woolridge's data supports the assumption that there is a quantifiable difference in the Cost of Equity for companies with different bond credit ratings?

A. Yes, I did. I first produced Constant Growth DCF results for each of the comparison companies using the growth rates and dividend yields reported by Dr. Woolridge. I then applied "credit scores" to Dr. Woolridge's comparison companies by converting the S&P bond ratings reported in his Direct Testimony to a numerical value. If there is a quantifiable relationship between the proxy companies' credit ratings and Cost of Equity, there should be a positive, statistically significant relationship between the credit score and the DCF results. That is, as credit quality deteriorates (resulting in a higher score), the Cost of Equity should increase. I therefore performed a regression analysis, in which the

118 Exhibit JRW-11, at 3.
119 Duff & Phelps 2016 Valuation Handbook, John Wiley & Sons, Inc., 2016, at Appendix 3b.
120 Duff & Phelps 2016 Valuation Handbook, John Wiley & Sons, Inc., 2016, at Appendix 3b. Debt Beta coefficients for BBB-rated companies were .08.

dependent variable was the DCF result, and the explanatory variable was the credit score. As shown in Exhibit RBH-26, the regression analysis showed no statistically significant statistical relationship between the two. In fact, the R-squared of the regression was only about 2.20 percent, which indicates that credit ratings accounted for only 2.20 percent of the change in the DCF-estimated Cost of Equity.

H. Flotation Costs

Q. Did Dr. Woolridge address the issue of flotation costs in his direct testimony?

A. Yes, Dr. Woolridge devotes several pages of his testimony discussing various reasons why he believes such an adjustment is not necessary.[121] Dr. Woolridge does not account for flotation costs, reasoning that flotation costs for stock issuances are not out-of-pocket costs and, even if they were, current market conditions suggest that a *reduction* to the Cost of Equity is required to account for flotation costs.[122]

Q. Please respond to Dr. Woolridge in that regard.

A. First, I disagree with Dr. Woolridge's position that flotation costs for stock issuances are different than issuance costs associated with long-term debt. Companies pay the same types of fees (both direct and indirect) regardless of whether they are issuing equity or debt. As to Dr. Woolridge's observation that

[121] *See*, Direct Testimony of J. Randall Woolridge, at 91-93.
[122] *Ibid.*

underwriter fees are not "out-of-pocket" expenses,[123] I view that to be a distinction without a meaningful difference. Whether paid directly or via an underwriting discount, the cost results in net proceeds that are less than the gross proceeds.

I also disagree with Dr. Woolridge's position that flotation costs could represent a *reduction* in Cost of Equity. Flotation costs are true and necessary costs to the issuer, and represent funds that otherwise would be invested in long-lived assets. As explained in my Direct Testimony, to the extent flotation costs are not recovered, the issuing company is denied a portion of the opportunity to earn its expected (or required) return.[124]

I have provided an illustrative example of the effect of flotation costs on the ROE in Exhibit RBH-27.[125] As shown in that schedule, due to the effect of flotation costs, an authorized return of 11.15 percent would be required to realize an ROE of 11.00 percent (*i.e.*, a 15 basis point flotation cost adjustment). If flotation costs are not recovered, the growth rate falls and the ROE decreases to 10.85 percent (*i.e.*, below the required return).[126]

123 *Ibid.*, at 92.

124 *See*, Direct Testimony of Robert B. Hevert, at 47.

125 This example is based on an analysis performed by Dr. Roger Morin. *See*, Roger A. Morin, *New Regulatory Finance*, Public Utility Reports, Inc., 2006, at 330-332.

126 Exhibit RBH-27 is provided for illustrative purposes only. I have not relied on the results of the analysis in determining my recommended ROE and range.

I. Capital Structure

Q. Please summarize Dr. Woolridge's position on the Company's capital structure.

A. I disagree with Dr. Woolridge's conclusion that the Company's capital structure suggests less financial risk than the proxy companies.[127] To support his conclusion, Dr. Woolridge compares the Company's capital structure to the capital structures in place at the holding company level. As discussed in my Direct Testimony, I analyzed the actual capital structures in place at the operating companies held within my proxy group. Doing so reflects the nature of assets financed by vertically integrated utilities such as FPL. Based on that review, it is apparent that the Company's capital structure is generally consistent with the capital structures of the proxy companies.

Q. Is there a specific example that demonstrates the varied nature of a utility holding company's unregulated operations and capital structures?

A. Yes, there is. NextEra Energy Resources, ("NEER"), a wholly owned, indirect subsidiary of NEE, owns approximately 21,100MW of generating capacity across the U.S. and Canada.[128] As of 2015, approximately 66.00 percent of NEER's generating capacity was fully committed under long-term contracts, with a weighted average life of approximately fifteen years.[129] NEER's generating portfolio is diverse, with wind, natural gas and nuclear assets representing 91.00

127 *See*, Direct Testimony of J. Randall Woolridge, at 31.
128 NextEra Energy, Inc., SEC Form 10-K for the Fiscal Year Ended December 31, 2015, at 4.
129 *Ibid.*, at 16.

percent of the capacity.[130] In fact, NEER owns 2,721 MW of nuclear generating capacity, of which 1,621 MW is contracted.[131] NEER is responsible for the ultimate decommissioning of those plants.[132] Although Dr. Woolridge suggests that parent company capital structures are the better comparator of FPL's operating capital structure, he does not seem to have considered the effect of non-utility, project-financed assets at the consolidated parent level.

Lastly, and as discussed in my response to Mr. O'Donnell, my updated capital structure analysis continues to support the reasonableness of the Company's current capital structure.

III. RESPONSE TO THE TESTIMONY OF FEA WITNESS GORMAN

Q. Please briefly summarize Mr. Gorman's recommendation regarding the Company's Cost of Equity.

A. Mr. Gorman recommends an ROE of 9.25 percent, within a recommended range of 8.90 to 9.60 percent.[133] Mr. Gorman establishes his recommended ROE by reference to: (1) his constant growth DCF model using both consensus analyst growth rates and a sustainable growth rate (with median and average results ranging from 7.34 percent to 8.89 percent);[134] (2) his Multi-Stage DCF method (with mean and median results of 8.00 percent and 8.01 percent, respectively);[135]

130 *Ibid.*
131 *Ibid.*, at 16, 18.
132 *Ibid.*, at 18.
133 *See* Direct Testimony of Michael P. Gorman, at 2.
134 *Ibid.*, at 24, 41.
135 *Ibid.*

(3) his Risk Premium estimates (ranging 9.50 percent to 9.60 percent, with a point estimate of 9.55 percent);[136] and (4) his Capital Asset Pricing Model analyses (ranging from 7.90 percent to 9.25 percent).[137] In particular, Mr. Gorman's 9.25 percent recommendation represents the midpoint of his DCF (8.90 percent) and Risk Premium (9.60 percent) analyses.[138]

Q. What are the principal analytical areas in which you disagree with Mr. Gorman?

A. The principal analytical areas in which I disagree with Mr. Gorman include:

1. Proxy group composition;
2. The application of the Constant Growth DCF model, and interpretation of its results;
3. The Market Risk Premium component of his CAPM analysis, in particular the expected market return from which the MRP is calculated;
4. The assumptions and methods underlying Mr. Gorman's Risk Premium analyses;
5. The need for a flotation cost adjustment; and
6. Mr. Gorman's assessment of the Company's relative risk.

136 *Ibid.*, at 47.
137 *Ibid.*, at 53.
138 *Ibid.*, at 54.

A. Proxy Group Composition

Q. Do you agree with Mr. Gorman's exclusion of Dominion Resources, Great Plains Energy, Westar Energy, and Otter Tail Corporation from the proxy group?[139]

A. I agree with the exclusion of Dominion Resource, Great Plains Energy, and Westar Energy; as discussed in my response to Dr. Woolridge, I also have excluded those companies due to their recent merger and acquisition activity. However, I continue to include Otter Tail Corporation ("OTTR") in my analyses. Mr. Gorman excluded OTTR from his proxy group because analyst earnings growth rates estimates were not available from any of the data sources he relies on (Zacks, SNL Financial and Reuters). Because two of the data sources I rely on for earnings growth estimates (Yahoo and Value Line) report earnings growth rates for OTTR, I continue to include the company in my proxy group.

B. Constant Growth DCF Model

Q. As a preliminary matter, does Mr. Gorman give his Constant Growth DCF results any weight in arriving at his 9.25 percent ROE recommendation?

A. Yes, as noted earlier, Mr. Gorman's 9.25 percent recommendation represents the midpoint of his 8.90 percent to 9.60 percent recommended range. The bottom end of that range (8.90 percent) is based on Mr. Gorman's Constant Growth DCF

139 *Ibid.*, at 25.

median result of 8.89 percent,[140] and the upper bound (9.60 percent) represents the point estimate of his Risk Premium results.[141]

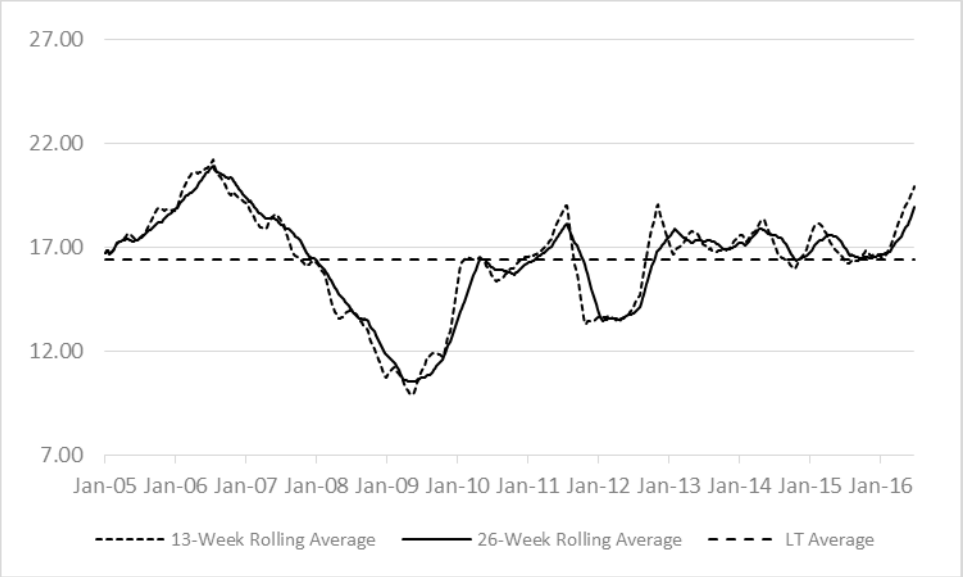
To arrive at his median DCF estimate, Mr. Gorman discards his Multi-Stage DCF results (8.01 percent), and his Constant Growth DCF model results based on the "sustainable growth" method (7.34 percent) in favor of his Constant Growth DCF results based on analysts' growth rate projections (8.89 percent).[142] Because Mr. Gorman does not rely on his Multi-Stage or sustainable growth DCF methods, I will not comment on his application of those approaches in my Rebuttal Testimony.

Q. Do you have any concerns with the Constant Growth DCF model in general, and the weight that Mr. Gorman applies to those results in particular?

A. Yes, I do. The Constant Growth DCF model is based on several underlying assumptions that combine to establish an inverse relationship between expected growth and the dividend yield. That is, as expected growth increases, the price would increase and the dividend yield would decrease. Conversely, as expected growth decreases, the price would decrease and the dividend yield would increase. Mr. Gorman's Constant Growth DCF analysis (as do Dr. Woolridge's and Mr. Baudino's), however, assumes P/E ratios that are high by historical standards, (*see* Chart 6, below), but growth rates that are relatively low.

140 *Ibid*., at 41, Table 4.
141 *Ibid*., at 47.
142 *Ibid*., at 41.

Chart 6: Proxy Group Rolling Average P/E Ratio[143]



Q. Are the growth rates assumed in Mr. Gorman's analysis consistent with historically high valuation levels?

A. No, they are not. Mr. Gorman's analysis assumes an average growth rate of 5.38 percent (*see* Exhibit MPG-5) which, he notes, is well below the long-term compound average growth rate for the economy as a whole (6.20 percent), and the long-term rate of stock market capital appreciation (on geometric average basis, 5.80 percent).[144] As discussed earlier, the Constant Growth DCF model assumes that low growth rates would be associated with low prices (and high dividend yields), yet the proxy group average P/E ratio is well above its long-term average. In the context of the Constant Growth DCF model, the two are not compatible.

[143] Sources: SNL Financial. Proxy Group P/E ratio calculated as an index.
[144] Direct Testimony of Michael P. Gorman at 37.

Mr. Gorman acknowledges that unsustainable expansions in P/E ratios create analytical concerns that should be addressed in determining the Cost of Equity. At page 52 of his direct testimony, Mr. Gorman discusses the Market Risk Premium component of his Capital Asset Pricing Model, and explains that Ibbotson & Chen found an "abnormal expansion" of P/E ratios relative to earnings and dividend growth. That is, Ibbotson & Chen found that because higher P/E ratios during the 1980 to 2001 period were not explained by higher growth in earnings or dividends, their analyses required adjustment.[145] Duff & Phelps, the source referenced by Mr. Gorman, calculates an adjustment using three-year average P/E ratios, rather than relying on the current year, because "the three-year average allows the adjustment to smooth out the volatility of extraordinary events and allows earnings to better reflect a normalized trend."[146] As did Ibbotson, Duff & Phelps recognized that abnormally high P/E ratios will produce questionable analytical results, and the long-term trend is important.

The same conditions hold here. The utility sector has undergone an "abnormal expansion" in P/E ratios; there is no dispute on that point. Whereas Duff & Phelps recognized and adjusted its analyses to reflect the abnormal expansion in P/E ratios, Mr. Gorman's DCF analyses, and his interpretation of their results, do not.

[145] *See* Direct Testimony of Michael P. Gorman at 52; Morningstar Inc., Ibbotson SBBI 2014 Classic Yearbook at 156 - 157. I also have addressed this issue in response to Dr. Woolridge's "Building Blocks" analysis.

[146] Duff & Phelps, 2016 Valuation Handbook: Guide to Cost of Capital, at 3-30.

Lastly, if Mr. Gorman's position is that the current P/E ratio will sustain itself over the long-run, as noted in my response to Dr. Woolridge, I have addressed that concern by calculating the terminal value portion of the Multi-Stage DCF model by reference to current P/E ratios.[147]

Q. Please summarize your concerns with Mr. Gorman's use of a sustainable long-term growth in his DCF analysis.

A. Although we agree that it is appropriate to rely on analyst earnings growth estimates in applying the Constant Growth DCF model, Mr. Gorman asserts that those estimates should be limited to what he considers to be a reasonable estimate of long-term "sustainable" growth. In that regard, because they are higher than the five- and ten-year nominal GDP growth estimates from Blue Chip *Financial Forecasts*, Mr. Gorman concludes that the mean analyst consensus earnings growth estimates in my Constant Growth DCF analysis produce elevated estimates of the Cost of Equity.[148]

As noted in my response to Dr. Woolridge, prior academic research (as well as the analyses presented in my response to Dr. Woolridge) indicates that investors rely on analysts' earnings growth projections. Those analyses demonstrate Value Line's "Retained to Common Equity", which is the product of the expected Return on Common Equity and the expected Retention Ratio (which are the two variables included in Mr. Gorman's assessment of what may constitute

147 *See* Exhibit RBH-14.
148 *See* Direct Testimony of Michael P. Gorman at 37-38.

"sustainable growth" on page 32 of his direct testimony) have no statistically significant ability to explain valuation levels (as measured by the P/E ratio, which Mr. Gorman presents in his Exhibit MPG-2).

Although Mr. Gorman may be of the view that analyst growth rates are not sustainable, the relevant issue is whether investors rely on those projections in making their investment decisions. That is, what matters is that analysts' projections reflect widely held expectations influencing investors at the time they make their pricing decisions, *i.e.*, the market prices investors are willing to pay. I am not aware of empirical evidence supporting the position that investors would disregard analysts' estimates of growth in Earnings Per Share for the companies in our respective proxy groups, nor has Mr. Gorman provided any such evidence. Rather, the empirical evidence discussed in my response to Dr. Woolridge supports the use of analysts' earnings growth projections. I therefore disagree with Mr. Gorman's conclusion that *his* view of sustainable growth, rather than analysts' projections, is the more relevant measure of investor expectations.

C. Application of Capital Asset Pricing Model

Q. Please briefly summarize Mr. Gorman's CAPM analysis and results.

A. Mr. Gorman's two CAPM estimates (9.25 and 7.90 percent) are based on two measures of principally historical Market Risk Premium estimates, Blue Chip's projected 30-year Treasury yield of 3.40 percent as the risk-free rate, and an

average Beta coefficient of 0.75, as reported by Value Line.[149] Based on his assessment of risk premiums in the current market, Mr. Gorman relies on the high-end 9.25 percent CAPM when estimating FPL's Cost of Equity.[150] Mr. Gorman's analyses assume Market Risk Premium estimates of 7.80 percent (based on the long-term historical arithmetic average real market return from 1926 through 2015 as reported by Duff & Phelps, adjusted for current inflation forecasts), and 6.00 percent (based on the historical difference between the average return on the S&P 500 and the average total return on long-term government bonds).[151] Combining those Market Risk Premium estimates with his projected long-term risk-free rate, Mr. Gorman develops expected market returns in the range of 9.40 to 11.20 percent.[152]

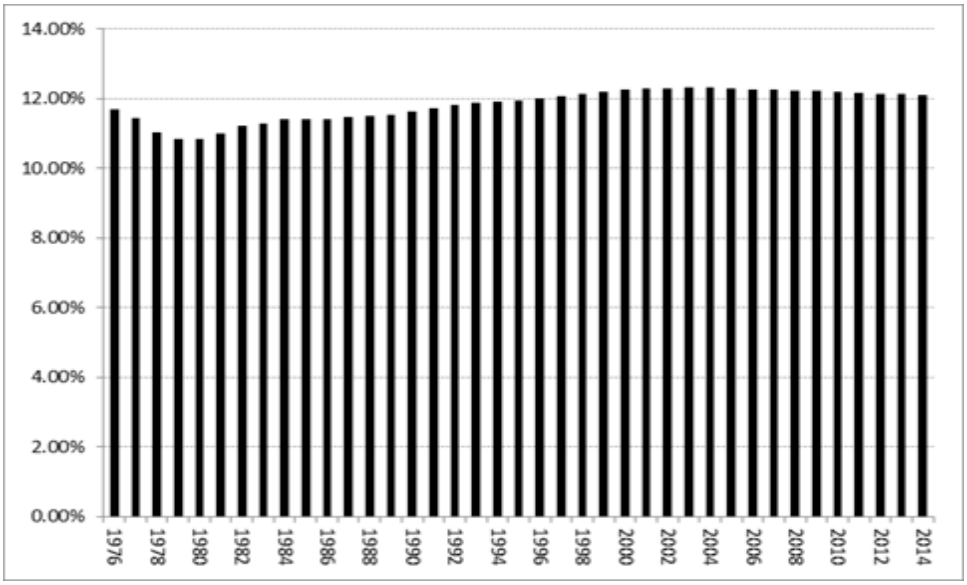
Q. Turning first to the expected total market return, do you agree with Mr. Gorman's 9.40 and 11.20 percent estimates?

A. No, I do not. As a practical matter, Mr. Gorman's 9.40 percent estimate, which is more than 250 basis points below the long-term average market return, falls in the bottom 10th percentile of the 90 annual returns reported by Morningstar.[153] His 11.20 percent estimate, which I believe is more reasonable, still falls in the bottom 24th percentile.

149 *Ibid.*, at 53 and Exhibit MPG-18.
150 *Ibid.*, at 53.
151 *Ibid*., at 51 and Exhibit MPG-18.
152 Mr. Gorman's low Market risk premium of 6.00 percent plus his projected risk-free rate of 3.40 percent equals an estimated market return of 9.40 percent. *See* Direct Testimony of Michael P. Gorman, 51; Exhibit MPG-18.
153 On a rolling average basis.

A helpful perspective on the historical market return is the rolling 50-year average annual market return. As Mr. Gorman points out, from 1926 through 2015 the arithmetic average market return was 12.00 percent.[154] Over the 50 years ended 2015, the average return was 12.10 percent, only ten basis points removed from the longer-term average that Mr. Gorman reports. Over time, the fifty-year average return has been quite consistent, in the range of approximately 12.00 percent (*see* Chart 7, below).

Chart 7: 50-Year Rolling Average Market Return (1976 – 2015)[155]



Taken from that perspective, Mr. Gorman's 9.40 percent expected market return is well below the long-term market experience, and, therefore, is not reasonable.

154 Direct Testimony of Michael P. Gorman, at 51.

155 Source: Morningstar, Inc., 2016 SBBI Appendix A Tables.

D. Application of the Risk Premium Model

Q. Please briefly describe Mr. Gorman's Risk Premium analyses.

A. Mr. Gorman defines the "Risk Premium" as the difference between average annual authorized equity returns for electric utilities, and a measure of long-term interest rates each year from 1986 through March 2016.[156] Mr. Gorman's first approach calculates the annual risk premium by reference to the 30-year Treasury yield, and his second approach considers the average A-rated utility bond yield.[157] In each case, Mr. Gorman establishes his risk premium estimate by reference to five-year and ten-year year rolling averages. The lower and upper bounds of Mr. Gorman's Risk Premium range are defined by the lowest and highest rolling average, respectively, regardless of the year in which those observations occurred.[158]

Regarding the period over which he gathers and analyzes his data, Mr. Gorman suggests that his 31-year horizon is a "generally accepted period to develop a risk premium study using 'expectational' data."[159] On page 44 of his direct testimony Mr. Gorman further states that "it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns," and concludes that his "risk premium study is based on expectational data, not actual investment returns, and, thus, need not encompass a

156 Direct Testimony of Michael P. Gorman, at 41-42.
157 *See* Direct Testimony of Michael P. Gorman, 42, Exhibit MPG-13 and MPG-14.
158 Direct Testimony of Michael P. Gorman at 41-42; Exhibit MPG-13 and MPG-14.
159 *Ibid.,* at 43.

very long historical time period."[160] Based on those assumptions, Mr. Gorman calculates a range of risk premium estimates of 4.25 percent to 6.71 percent using his Treasury bond analysis, and 2.88 percent to 5.53 percent using his A-rated utility bond analysis. Combined with a 3.40 percent projected Treasury yield and a 4.69 percent Baa-rated utility bond yield estimate, Mr. Gorman's Risk Premium analysis produces results ranging from 7.57 percent to 10.22 percent.[161] To calculate his Risk Premium-based ROE estimate, Mr. Gorman gives 75.00 percent weight to the high end of his risk premium estimates, and 25.00 percent to the low end, producing a range of 9.50 percent to 9.60 percent with a midpoint of 9.55 percent.[162]

Q. Do you have any general observations regarding Mr. Gorman's Risk Premium estimates and how they weigh in his overall ROE recommendation?

A. Yes, I do. In assessing his DCF analyses, Mr. Gorman decided to rely on his highest result and essentially discarded five of his six results, which ranged from 7.34 to 8.83 percent.[163] In his Risk Premium analysis, however, Mr. Gorman retained risk premiums that produced ROE estimates that were more than 100 basis points *below* the DCF estimates that he chose not to rely on. Despite their low levels, Mr. Gorman gave those risk premium estimates (producing ROE results of 7.57 and 7.65 percent) weights of 25.00 percent in aggregate. Mr.

160 *Ibid.,* at 44.
161 4.69% + 2.88% = 7.57%; 4.69% + 5.53% = 10.22%; 3.40% + 4.25% = 7.65%; 3.40% + 6.71% = 10.11%.
162 *Ibid.,* at 47.
163 *Ibid.,* at 41.

Gorman offers no explanation as to why he would exclude DCF results of 8.83 percent and lower, yet include Risk Premium results of 7.57 percent and 7.65 percent.

Q. What are your specific concerns with Mr. Gorman's Risk Premium analysis?

A. I have three concerns with his analysis: (1) Mr. Gorman's method understates the required risk premium in the current market because it ignores an important relationship confirmed by his own data, *i.e.*, that the risk premium is inversely related to the level of interest rates (whether measured by Treasury or utility bond yields); (2) the low end of Mr. Gorman's Risk Premium results is far lower than any ROE authorized since at least 1986 and as such, has no relevance in estimating the Company's Cost of Equity; and (3) Mr. Gorman suggests that a Market/Book of 1.00 is a relevant benchmark for assessing authorized ROEs.[164]

Q. Turning first to the issue of Market/Book ratios, as discussed on page 42 of his direct testimony, do you agree with Mr. Gorman that M/B ratios should be used to assess the reasonableness of ROE recommendations?

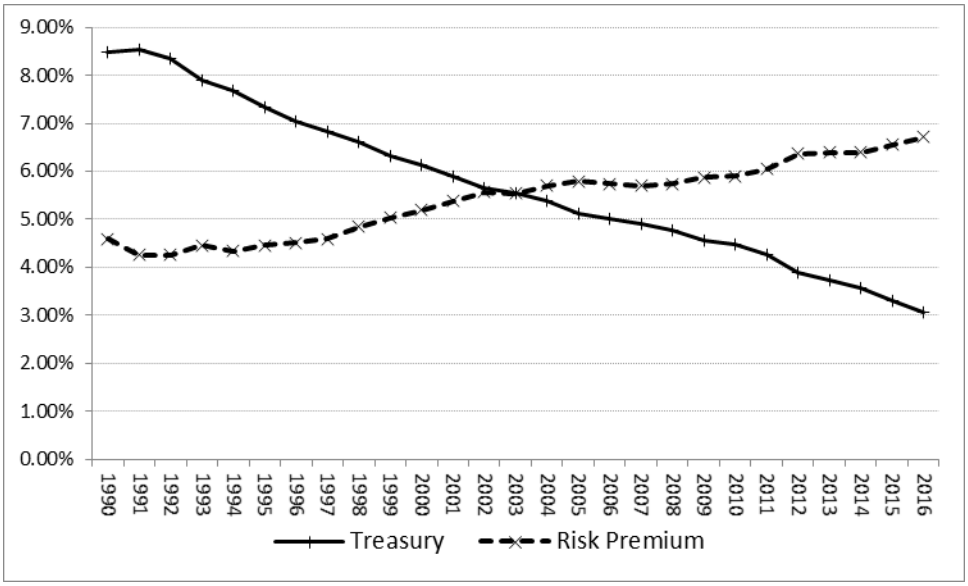
A. No, for the reasons discussed in my response to Dr. Woolridge, I do not.

Q. Have you reviewed Mr. Gorman's Risk Premium analyses?

A. Yes, I have. Considering first the Treasury yield-based analysis, I plotted the yields and Risk Premia over the 1986 to 2016 period included in Mr. Gorman's analysis. That graph, which is presented in Chart 8 (below), clearly indicates the inverse relationship between interest rates and the Equity Risk Premium.

[164] *Ibid.,* at 42.

Chart 8: Mr. Gorman's Treasury Yield-Based Risk Premium Data[165]



There are several other points made clear in Chart 8. First, the low end of Mr. Gorman's Risk Premium range, 4.25 percent, was observed in the five-year period ending 1991. There is little question that Risk Premium estimates associated with economic environments 25 years ago have little to do with current market conditions. A very visible measure of such differences is the fact that before 2002, Treasury yields exceeded the Risk Premium (on a five-year average basis). As Chart 8 (*see also* Exhibit RBH-28) demonstrates, however, since then the opposite has been true – the Risk Premium has consistently exceeded Treasury yields. By that measure alone, it is clear that the low end of Mr. Gorman's range has little, if any, relevance to the current market environment.

[165] Source: Direct Testimony of Michael P. Gorman, Exhibit MPG-13; based on five-year rolling average.

The high end of Mr. Gorman's range, 6.71 percent, occurred more recently (for the five year period ending March 2016). In fact, Exhibit MPG-13 indicates that his Equity Risk Premium averaged approximately 6.85 percent over the more recent period from 2015 through March 2016.[166] Adding that 6.85 percent Equity Risk Premium to Mr. Gorman's projected Treasury yield of 3.40 percent produces an ROE estimate of 10.25 percent.

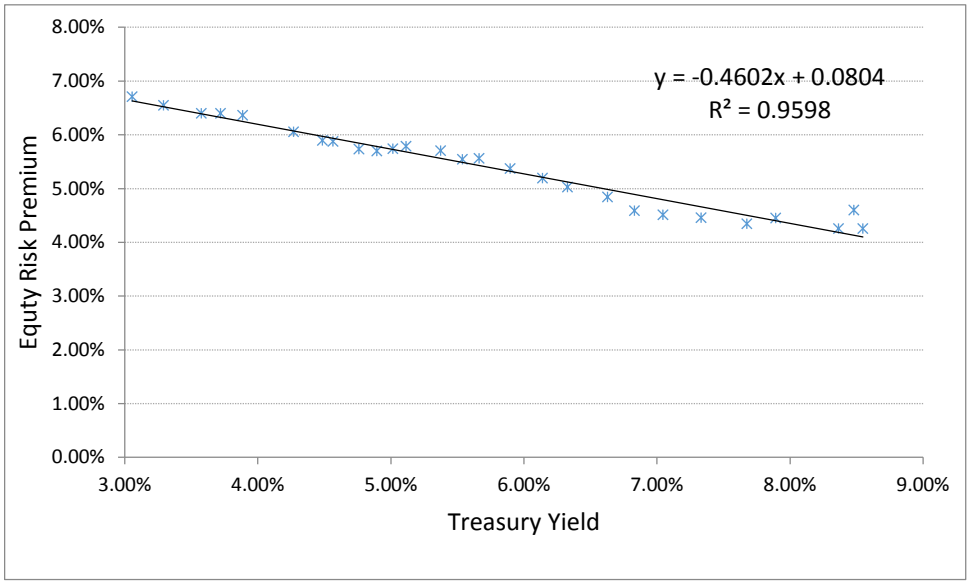
Q. Has the Risk Premium increased as Treasury yields have decreased?

A. Yes. The relationship between the five-year average Equity Risk Premium and Treasury yields is very clear. A simple linear regression demonstrates that the two are highly related, with a Coefficient of Determination (R-Square) of approximately 96.00 percent. That is, Mr. Gorman's data demonstrate that changes in Treasury yields account for 96.00 percent of the change in the Equity Risk Premium (*see* Chart 9, below).[167]

166 Based on Indicated Risk Premium.

167 Those findings are supported in academic studies. For example, Dr. Roger Morin notes that: "… [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates - rising when rates fell and declining when interest rates rose." Roger A: Morin, New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 128 [clarification added]

Chart 9: Treasury Yield vs. Equity Risk Premium (Five-Year Rolling Average)[168]



Turning back to Mr. Gorman's data, a simple linear regression analysis using annual (rather than the rolling average data) demonstrates that for every 100 basis point decrease in Treasury yields, the Equity Risk Premium increases by approximately 44 basis points (*see* Exhibit RBH-29).[169] Similarly, the Equity Risk Premium increases approximately 45 basis points for every 100 basis point decrease in utility bond yields. Those results are consistent with those reported by Maddox, Pippert, and Sullivan, who determined that the Risk Premium would increase by 37 basis points for every 100 basis point change in the 30-year Treasury yield.[170]

168 See Exhibit RBH-28. Source: Exhibit MPG-13.

169 Serial correlation is not present or is inconclusive.

170 *See* Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Vol. 24, No. 3, Autumn 1995, at 93.

I also have found that accounting for additional factors by incorporating the credit spread (taken from Mr. Gorman's exhibits) does not change the sign, statistical significance, or the magnitude of the slope coefficient.[171] In short, including Mr. Gorman's credit spreads do not change the finding that interest rates and the Equity Risk Premium are inversely related.

Q. What are your conclusions regarding Mr. Gorman's Risk Premium analysis?

A. Although Mr. Gorman includes rolling average estimates in his Risk Premium analysis, doing so does not negate the finding that his approach relies on data from markets that are so disconnected in time and substance from the current environment that there is no reasonable basis for his conclusion that 9.60 percent represents a proper Risk Premium-based estimate of the Company's Cost of Equity. Consequently, it is appropriate to apply methods that have been accepted in published literature, and which reflect the finding that interest rates and the Equity Risk Premium move in opposite directions.

E. Risk Factors and Market Sentiment

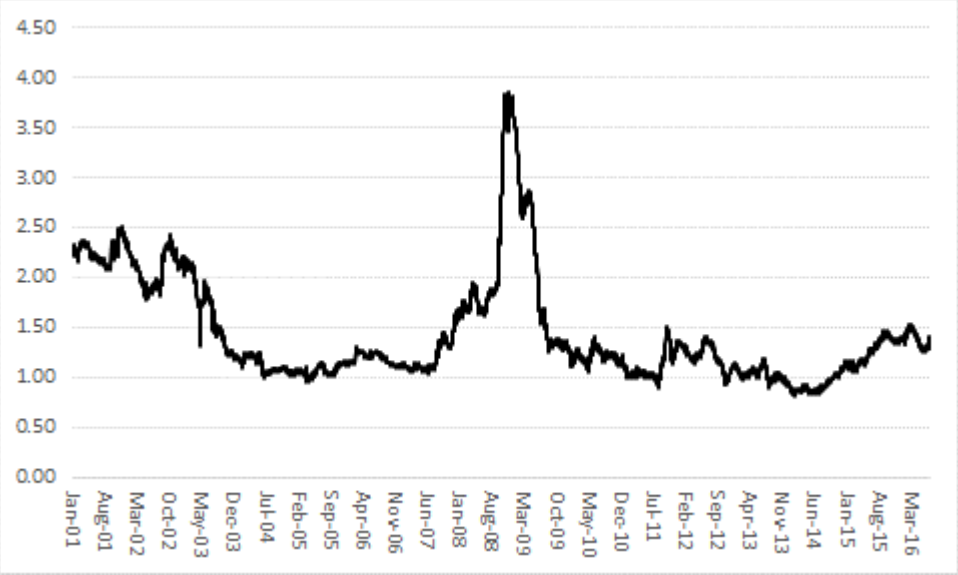
Q. Mr. Gorman suggests the market is placing a high value on utility stocks.[172] Have you considered the utility sector's recent equity market performance relative to the debt market?

A. Yes, I have. Because credit spreads, which represent the difference between the yields on debt and Treasury yields, can be directly observed, we can review the

[171] *See* Exhibit RBH-29.
[172] Direct Testimony of Michael P. Gorman, at 78.

change in spreads over time, and relative to other market sectors. Although credit spreads are not a full measure of equity risk, they reasonably can be seen to reflect, to some extent, investors' assessment of risk at a given point in time. As Chart 10 below indicates, but for the credit contraction that ended in 2003 and the financial crisis during 2008 and 2009, current credit spreads (for A-rated utilities) are near their highest level since the year 2000.

Chart 10: A-Rated Utility Credit Spreads[173]



Even considering the 2002 – 2003, and 2008 – 2009 market dislocations, the current utility credit spread (on a spot basis) is in the top 63rd percentile of spreads since January 2000; the thirty-day average is in the top 55th percentile. Looking to the period subsequent to the financial crisis (that is, since January 2010), the 30-day average credit spread is in the top 80th percentile (the spot spread is in the top 91st percentile). Taken from that perspective, it is apparent that investors

[173] Source: Bloomberg Professional

currently see the utility sector as relatively risky, and require higher returns as compensation for that risk.

As to the relationship between the level of Treasury yields and credit spreads, the level of explanatory value is rather low; Treasury yields explain only about 12.00 percent of the change in credit spreads.[174] Equity market volatility (as measured by the VIX), on the other hand, explains about 60.00 percent of the change in credit spreads.[175] That is, investors are concerned with market uncertainty, and require higher returns as uncertainty increases.

Q. Does any data presented by Mr. Gorman support the conclusion that credit spreads on A-rated utility debt are at historically elevated levels?

A. Yes. Mr. Gorman's Exhibit MPG-15 provides the spread between A-rated utility debt and Treasury bond yields. As shown in that exhibit, credit spreads on A-rated utility debt are higher than they have been in eight of the previous ten years. Credit spreads were only higher during the 2008-2009 financial crisis.

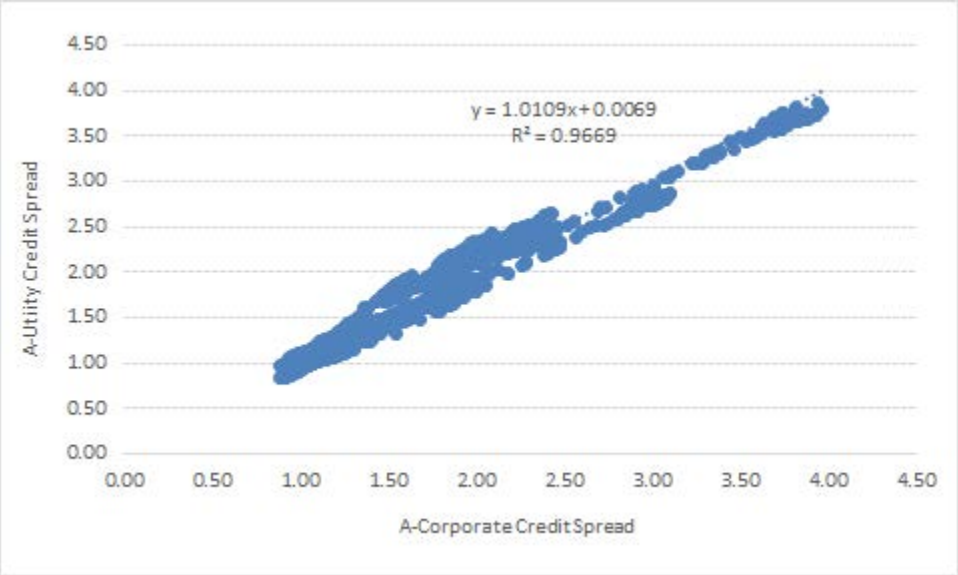
Q. Have you also reviewed the relationship between credit spreads for A-rated utility debt relative to A-rated corporate debt?

A. Yes, I have. Although Mr. Gorman suggests that utility debt is trading at a premium to corporate debt[176], I find the difference in yields to be only about two basis points. Given the historical volatility in the spread between corporate and

[174] Source: Bloomberg Professional.
[175] Source: Bloomberg Professional.
[176] Direct Testimony and Exhibits of Michael P. Gorman, at 78.

utility A-rated debt, there is no reason to conclude that utility yields are different than those of their corporate counterparts. That conclusion is consistent with the finding that over time, there has been a nearly one-to-one relationship between credit spreads on A-rated corporate and utility bonds. In fact, a regression analysis in which corporate credit spreads are the explanatory variable and utility credit spreads are the dependent variable shows that slope is approximately 1.00 and highly significant (*see* Chart 11, below). Because the intercept term is statistically insignificant, we can conclude that there has been no material difference between the two, and there certainly is no meaningful difference in the current market.

Chart 11: Corporate and Utility Credit Spreads (A-Rated)[177]



Q. What do you conclude from those analyses?

A. First, it is clear that A-rated utility credit spreads are at historically elevated levels. Second, the utility credit spreads are not measurably different than their corporate counterparts. Based on those two observations, we can conclude that investors do not consider utilities to be less risky than historical levels, nor are they requiring lower returns for utilities relative to similarly rated corporate bonds. Consequently, I do not believe we can conclude that the current level of utility equity valuation levels is due to lower levels of perceived risk. Rather, it is my view that the valuation levels are related to the "reach for yield" that sometimes occurs during periods of low Treasury yields.

[177] Source: Bloomberg Professional. Please note that for a univariate regression, the correlation coefficient equals the square root of the R-square. In this case, the square root of 0.9669 is approximately 0.98 (98.00 percent).

Q. Have there been other recent periods when utility equity valuation levels were high relative to both their long-term average and the market?

A. Yes. In early 2015, the utility sector (as measured by the S&P Electric Utility Index) traded at a Price/Earnings ratio of approximately 18.00. During the same period, the overall market (as measured by the S&P 500) traded at a P/E of approximately 18.00. Those levels were quite similar to the current market. In late January 2015, the utility sector began to lose value, and by the end of June 2015 it had lost approximately 15.50 percent of its value.[178] The point simply is that as investors see an increasing likelihood of higher interest rates, they will move out of sectors that provided relatively high current yields. As they do, valuations and P/E ratios fall. As discussed elsewhere in my Rebuttal Testimony, that degree of instability in P/E ratios is incompatible with the assumptions underlying the Constant Growth DCF model, rendering estimates from that model highly questionable.

Q. Have you also considered the effect of the United Kingdom's decision to exit the European Union (sometimes referred to as the "Brexit") on Treasury yields?

A. Yes, I have. What is clear is that in the one week following the Brexit vote (that is, from June 23 to June 30) Treasury yields fell by 25 basis points. As Treasury yields fell, utility valuations increased, as investors sought the relatively high dividend yields offered by the sector. Subsequent to June 30, the market appeared

[178] The Combined Proxy Group lost approximately 13.00 of its value between January 31, 2015 and the end of June 2015.

to have become more comfortable with the implications of the Brexit vote, interest rates began to increase, utility valuations fell, and the overall market increased to record levels.[179] The volatility observed during that two-week period demonstrates the importance of understanding the factors underlying market conditions, and how those factors and conditions comport, or not, with the methods used to estimate the Cost of Equity.

Q. What conclusions do you draw from those analyses?

A. In my view, we cannot conclude that the recent levels of utility valuations are due to a fundamental change in the risk perceptions of utility investors. Utility credit spreads are at historically elevated levels, and there is no measurable difference between credit spreads of A-rated utility debt, and A-rated corporate debt. That is, based on analyses of credit spreads, there is no reason to conclude that investors see utilities as less risky relative to either historical levels or to their corporate counterparts.

Q. Please briefly summarize Mr. Gorman's assessment of the Company's overall business risk.

A. Mr. Gorman summarizes certain rating agency reports and concludes that utilities in general are seen as a low-risk sector, which has provided utilities "strong access to capital."[180] Mr. Gorman also notes that 85.00 to 90.00 percent of regulated utilities have bond ratings in the range of A- to BBB, and FPL falls at

[179] Source: Bloomberg Professional

[180] Direct Testimony of Michael P. Gorman, at 11.

approximately the high-end of this range.[181] Lastly, Mr. Gorman suggests the implementation of a four year rate plan would not increase the Company's Cost of Equity.[182]

Q. Do the Company's current credit ratings distinguish it from other utilities?

A. No, they do not. As S&P notes, the vast majority of utility ratings fall within the BBB to A- range.[183] The Company's current credit rating falls within that range. In any event, as discussed in my response to Dr. Woolridge, credit ratings are not full measures of equity risk. And as discussed in my response to Mr. Chriss, investors' perceptions of regulatory supportiveness tend to be positively related to authorized equity returns.[184] Lastly, as Mr. Dewhurst explains, the Company's authorized capital structure and return have enabled it to access capital, maintain operating liquidity, and still have among the lowest retail rates in the region. In that important sense, Mr. Gorman's conclusion that the Company's credit rating somehow justifies an ROE that would be among the lowest authorized in the last 35 years for a vertically integrated electric utility is misplaced.

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181 *Ibid.*, at 19.

182 *Ibid.*, at 61-62.

183 Standard & Poor's RatingsDirect, *Industry Report Card: The Outlook For U.S. Regulated Utilities Remains Stable On Increasing Capital Spending And Robust Financial Performance*, December 16, 2014, at 6.

184 As noted in my response to Mr. O'Donnell, both Standard & Poors and Moody's consider the assessment of the regulatory environment a significant factor in determination of credit ratings.

Q. Mr. Gorman suggests there is insufficient evidence that interest rates will rise to conclude that a four year rate plan will increase risks for shareholders.[185] What is your response?

A. The principal issue is uncertainty, which represents risk to investors. As discussed in my Direct Testimony, with a multi-year rate plan FPL forgoes the option to seek rate relief as capital costs increase.[186] Should interest rates rise over the course of the proposed four year rate period, the Company would be exposed to increases in the costs of both debt and equity.[187] As reported by Blue Chip, the average consensus forecast is for the 30-year Treasury yield to rise to 3.40 percent (approximately 100 basis points) in 2017 and 4.40 percent (approximately 200 basis point) by the end of proposed four year rate period.[188] In addition, market expectations for increased long-term Treasury yields are apparent in the market prices to buy or sell at-the-money options in long-term Government bond funds. That is, the value of the option to sell the TLT (an exchange-traded fund of long-term Government bonds) in January 2018 at today's price is approximately one and a half times the value of the option to buy that fund.[189] Because bond prices fall as interest rates increase, investors see a greater likelihood of increases in long-term interest rates than decreases. As such, investors may require a premium to the allowed ROE for compensation for the additional risk associated with

185 Direct Testimony of Michael P. Gorman, at 61-62.
186 Direct Testimony of Robert B. Hevert, at 50-51.
187 *See* Direct Testimony of Robert B. Hevert, at 20 and 63.
188 *See*, Blue Chip Financial Forecast, Vol. 35 No. 6, June 1, 2016, at 2, 14.
189 http://www.nasdaq.com/symbol/tlt/option-chain?dateindex=7

foregoing the opportunity to seek rate relief in the event of increasing capital costs.

Q. Do you agree with Mr. Gorman's position that relying on projected Treasury yields is "problematic"?[190]

A. No, I do not. Mr. Gorman asserts that relying on projected yields does not consider "the highly likely outcome that current observable interest rates will prevail during the period rates determined in this proceeding will be in effect." Mr. Gorman then goes on to suggest that relative to projected interest rates, "current observable rates are just as likely to accurately predict future interest rates as are economists' projections."[191] He concludes that the accuracy of those projections are "highly problematic."[192]

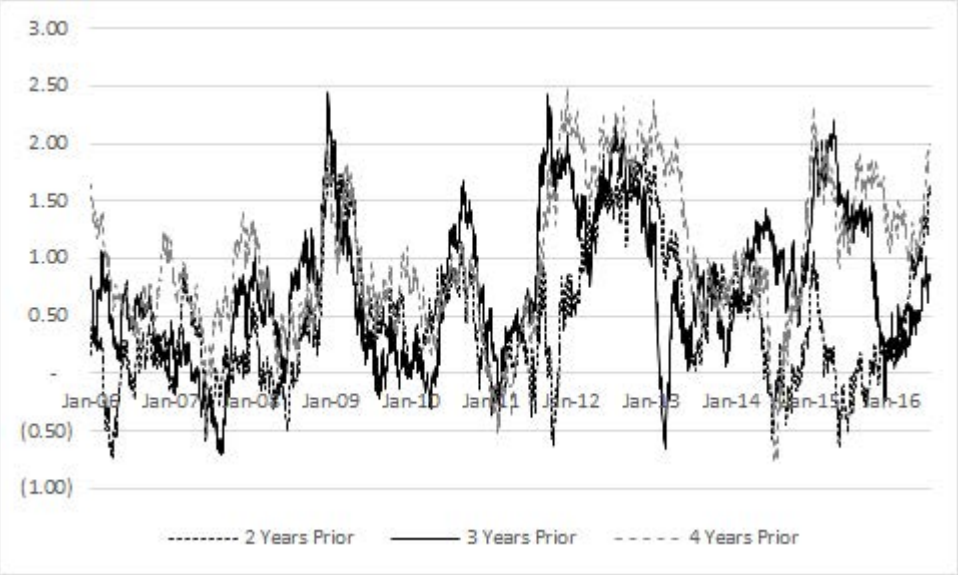
Q. What is your general response to Mr. Gorman's position?

A. First, the relevant question is whether investors view consensus forecasts as important information as they make their investment decisions. Mr. Gorman has provided no information to conclude that they do not. As to his position that it is highly likely that observable interest rates will prevail during the period in which rates will be in effect, that has not been the case historically; as Chart 12 below demonstrates, 30-year Treasury yields two, three and four yields lagged have not been very accurate predictors of spot yields. That is especially the case for the longer lag periods (three and four years), which would more closely reflect the

190 Direct Testimony of Michael P. Gorman, at 79 – 80.
191 *Ibid.*, at 79.
192 *Ibid.*, at 80.

term of the Company's proposed rate plan than does the roughly one-year lag reflected in Mr. Gorman's analysis (Exhibit MPG-21).

Chart 12: Difference in Spot vs. Lagged Treasury Yields[193]



In large measure, the inability of lagged yields to explain current yields relates to the decline in rates over time. As a practical matter, a simple trend variable has considerably greater explanatory value than do the lagged yields that Mr. Gorman favors. As shown in Exhibit RBH-30, the R-Square (which measures explanatory value of a given variable) increases from approximately 55.00 percent to approximately 82.00 percent. That is, a simple trend has a greater ability to explain current Treasury yields than do lagged observed Treasury yields.[194]

In my view, the relevant question becomes whether investors see that trend continuing over time. Simply extrapolating the trend, or even relying on prior

193 Source: Bloomberg Professional

194 It is interesting to note that including the Trend variable also changes the sign of the lagged Treasury yield variable from positive to negative.

Treasury yields as an estimate of future yields would assume that to be the case, even though central bank policy, which is a significant factor influencing interest rates, is changing. To that point, Mr. Gorman's observations include a highly unusual period in capital markets in which a number of central banks pursued a significant level of unconventional monetary stimulus (e.g., holding short-term rates near zero while also purchasing large quantities of long-term bonds), which led to long-term bond rates far below market estimates of normal rates. He has not explained, however, why such conditions will prevail two, three or four years in the future.

Regarding Mr. Gorman's observation that in the past, projected yields indicated interest rate increases even though actual yields did not increase, it is important to recognize that implied forward Treasury yields (which are based on observed interest rates) also indicated expectations of rate increases. Implied forward yields are based on the "Expectations" theory, which states that (for example) the current 30-year Treasury yield equals the combination of the current one-year Treasury yield, and the 29-year Treasury yield expected in one year. That is, an investor would be indifferent to (1) holding a 30-year Treasury to maturity, or (2) holding a one-year Treasury to maturity, then a 29-year Treasury bond, also to maturity.[195]

[195] In addition to the Expectations theory, there are other theories regarding the term structure of interest rates, including: the Liquidity Premium Theory, which asserts that investors require a premium for holding long term bonds; the Market Segmentation Theory, which states that securities of different terms are not substitutable and, as such, the supply of and demand for short-term and long-term instruments is developed independently; and the Preferred Habitat Theory,

As Chart 13 demonstrates, since 2006 the implied forward 29- and 28- year yields (one and two years hence, respectively) consistently exceeded the (interpolated) spot yields. That is, just as economists' projections implied increased interest rates, so did observable Treasury yields.

Chart 13: Forward vs. Interpolated Treasury Yields[196]

Q. What do you conclude from those analyses?

A. First, Mr. Gorman's assertion that spot yields are a reasonable measure of expected yields is inconsistent with observable data; there has been a considerable amount of dispersion between the two. Moreover, the ability of lagged yields to estimate current yields decreases as the lag period increases. In that regard, there

196 which states that in addition to interest rate expectations, certain investors have distinct investment horizons and will require a return premium for bonds with maturities outside of that preference. Source: Federal Reserve Schedule H.15

is no reason to conclude that current Treasury yields are a reasonable estimate of the yields that will prevail two, three or four years in the future.

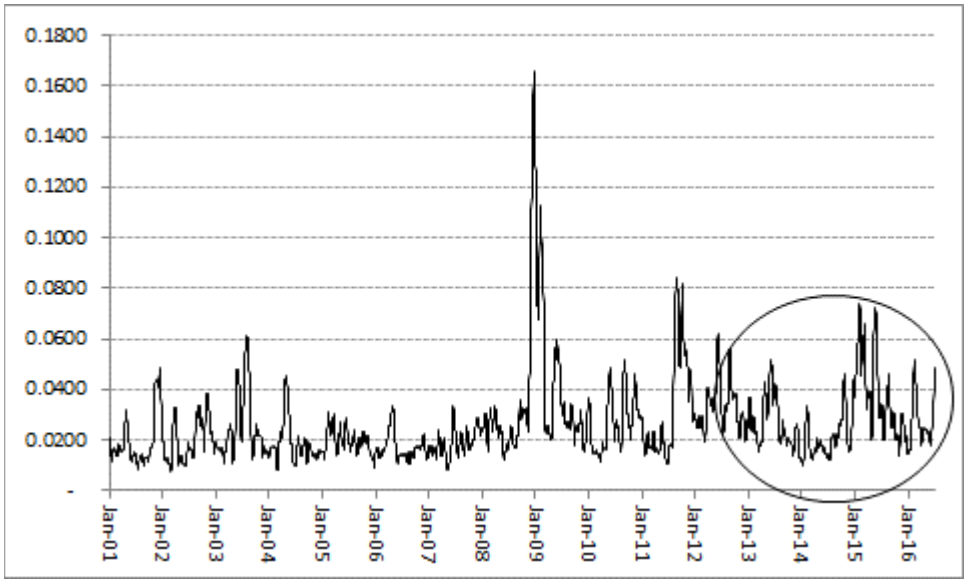
Second, a simple trend variable provides more explanatory value than do observed Treasury yields. But if we simply extrapolate that trend, by December 2018 the 30-year Treasury yield would be 0.58 percent (58 basis points; *see* Exhibit RBH-30). On the other hand, if we were to assume that the current 30-year Treasury yield will prevail for the next two to four years, we would have to assume no change in central bank policies, macroeconomic growth, or any of the other factors that recently have influenced Treasury yields.

Lastly, Mr. Gorman's conclusion that consensus projections exceeded observed yields does not seem to take into account the fact that implied forward yields also indicated interest rate increases. Because forward yields have been directionally consistent with economists' projections, and given that Mr. Gorman puts considerable weight on observed yields, there is no reason to believe that economists' projections are "highly problematic".

Q. Do you have any further observations regarding interest rates, and their effect on the Company's ROE?

A. Yes. Since 2012, the 30-year Treasury yield has been quite volatile, especially relative to its historical levels (*see* Chart 14, below).

Chart 14: 30-Year Treasury Yield Coefficient of Variation[197]



That variability represents an element of uncertainty for investors; uncertainty and risk increase investors' required returns. Further, as rates become more variable, the option to seek rate relief in future periods becomes more valuable. Foregoing that option, therefore, comes at a greater cost. Consequently, the increased variability of Treasury yields provides further support for my ROE range and recommendation.

F. Financial Integrity

Q. Please briefly summarize Mr. Gorman's assessment of his recommendation as it affects measures of the Company's financial integrity.

A. Mr. Gorman evaluates the reasonableness of his ROE recommendation by calculating the *pro forma* effect that his recommended ROE would have on two of

[197] Source: Bloomberg Professional. The Coefficient of Variation is calculated as the Standard Deviation divided by the Average. Calculations are based on 30-day moving periods.

the Company's key financial ratios with the goal of assessing whether those ratios would still fall within S&P's guideline ranges sufficient for an investment grade rating.[198] In that regard, Mr. Gorman develops the following *pro forma* ratios: (1) Debt to EBITDA; and (2) Funds From Operations ("FFO") to Total Debt. An important point is that Mr. Gorman's analysis assumes that the Company actually will earn the entirety of its authorized ROE on a going-forward basis.

In his Exhibit MPG-19, Mr. Gorman develops the *pro forma* financial ratios noted above based on the Company's retail cost of service, and his recommended ROE of 9.25 percent. Mr. Gorman notes that his *pro forma* financial analysis suggests that his recommended ROE of 9.25 percent would be sufficient to maintain "credit metrics at an investment grade utility level."[199]

Q. Do you agree with Mr. Gorman's analysis and conclusion?

A. No, I do not. First, simply maintaining an "investment grade" rating is an inappropriate standard. According to Standard & Poor's, only 6 of 221 utilities have had below investment grade ratings.[200] As Mr. Dewhurst explains, FPL must compete for capital within the utility sector in the first instance, and with companies beyond utilities, overall. If Mr. Gorman is of the view that simply maintaining an investment grade rating is sufficient for that purpose, I disagree. In my practical experience raising capital for a regulated utility, I can say

198 *See* Direct Testimony of Michael P. Gorman, at 56-57.
199 *Ibid.*, at 57.
200 See Standard & Poor's RatingsDirect, *The Outlook for U.S. Regulated Utilities Remains Stable on Increasing Capital Spending and Robust Financial Performance*, December 16, 2014, at 7-20.

firsthand that the competition for capital can be acute. Based on that practical experience, I also can say that Mr. Gorman's "investment grade" standard would frustrate the ability of FPL, or any other regulated utility, to raise capital under a variety of market conditions, and at reasonable costs and terms.

That fundamental concern aside, a wide range of ROE outcomes create *pro forma* coverage ratios that fall within S&P's guidelines for the Company's current rating. As shown in Exhibit RBH-31, using Mr. Gorman's analysis, an ROE of 6.55 percent creates coverage ratios that also fall within FPL's current range. There is little question that 6.55 percent is an unrealistic estimate of the Company's Cost of Equity.

Mr. Gorman concludes that his 9.25 percent recommendation produces *pro forma* ratios within S&P's "Intermediate" guideline and therefore supports an investment grade credit rating.[201] Again, using Mr. Gorman's analysis, an ROE of 6.55 percent produces coverage ratios that also fall within the "Intermediate" range. Again, I do not believe that 6.55 percent is a realistic estimate of the Company's Cost of Equity. My 11.00 percent ROE recommendation also produces coverage ratios that fall within the "Intermediate" range.[202]

In my view, the observation that that Mr. Gorman's 9.25 percent ROE produces *pro forma* ratios that fall within the same ratings band as the 6.55 percent ROE

[201] Direct Testimony of Michael P. Gorman, at 57.
[202] Exhibit RBH-31.

noted above does not support the conclusion that his recommendation would support the Company's financial integrity. As noted earlier, there are factors well beyond *pro forma* coverage ratios that weigh in rating determinations.

As noted above, Mr. Gorman's analysis also assumes that the Company actually will be able to earn its authorized return, and its Funds From Operations will not be diluted by regulatory lag, additional capital spending, or any of the other factors that may dilute earnings and cash flow.

Lastly, as Mr. Gorman recognizes, credit rating agencies consider a number of factors beyond coverage ratios. As noted in my response to Mr. O'Donnell, 50.00 percent of Moody's ratings factors relate to the regulatory environment. Mr. Gorman's ROE recommendation, which is far below the national average return for vertically integrated electric utilities, would introduce an element of regulatory risk that could put pressure on FPL's credit profile, potentially increasing its cost of capital. Because Mr. Gorman's analysis appears to be overly simplified, relying on its results may well lead to incorrect conclusions.

G. Flotation Costs

Q. What is Mr. Gorman's position with regard to flotation costs.

A. Mr. Gorman acknowledges that flotation costs are a legitimate cost of doing business, but suggests that the Commission only allow recovery if the actual costs

are demonstrated and proven to be reasonable. Mr. Gorman further asserts that because FPL does not issue common stock, it does not incur flotation costs.[203]

Q. What is your response to Mr. Gorman's position?

A. As explained in my direct testimony, flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and therefore are not reflected on the income statement. Rather, like investments in rate base or issuance costs of long-term debt, flotation costs are incurred over time, but remain part of the cost structure that exists during the test year and beyond.[204] Although FPL does not issue common stock, it still must compete for equity capital with other NextEra Energy affiliates and investment opportunities. The common stock that which has been issued by NextEra Energy, the parent holding company, includes flotation costs, which are passed through to FPL. As such, I continue to believe it is appropriate to consider flotation costs in the determination of where the Company's ROE falls within the range of results.

H. Response to Mr. Gorman's Criticisms

Q. Please summarize Mr. Gorman's criticisms of your Cost of Equity analyses.

A. Mr. Gorman asserts my estimated ROE is overstated and should be rejected because (1) my CAPM is based on inflated estimates of the Market Risk

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203 Direct Testimony of Michael P. Gorman, at 60-61.

204 Roger A. Morin, New Regulatory Finance, (Public Utilities Reports, Inc. 2006), at 321-322; Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221; and Cleveland S. Patterson, Flotation Cost Allowance in Rate of Return Regulation: Comment, The Journal of Finance Vol. XXXVIII, No. 4. September 1983, at 1337.

Premiums; (2) my Bond Yield Plus Risk Premium is based on inflated utility Equity Risk Premium; (3) my Risk Premium analyses rely on "stale" Treasury yields; (4) my Constant Growth DCF results are based on excessive, unsustainable growth rates; and (5) my Multi-Stage DCF is based on an unrealistic GDP growth estimate and unsustainable payout ratio assumptions.[205] I respond to each of those criticisms in turn, below.

Q. Please summarize Mr. Gorman's criticisms of your CAPM analysis.

A. Mr. Gorman's concern with my CAPM analysis lies primarily with my Market Risk Premium estimates.[206] In particular, Mr. Gorman states that my 12.82 percent and 13.63 percent projected returns on the market are "inflated."[207] To determine the reasonableness of my derived expected market returns, it is instructive to understand how often various ranges of total returns actually have occurred over the 1926 to 2015 period. In fact, the 12.82 percent and 13.63 percent estimates presented in my Direct Testimony, which Mr. Gorman asserts are "inflated,"[208] represent the approximately 49th percentile of the actual returns observed from 1926 to 2015. In other words, of the 90 annual observations, 46 were 13.63 percent or higher. Moreover, given the historical volatility in market returns (as noted by Morningstar, the long-term standard deviation is 19.99 percent), my total return estimates of 12.82 percent and 13.63 percent are

205 Direct Testimony of Michael P. Gorman, at 58.
206 *Ibid*., at 63.
207 *Ibid*., at 64.
208 *Ibid*.

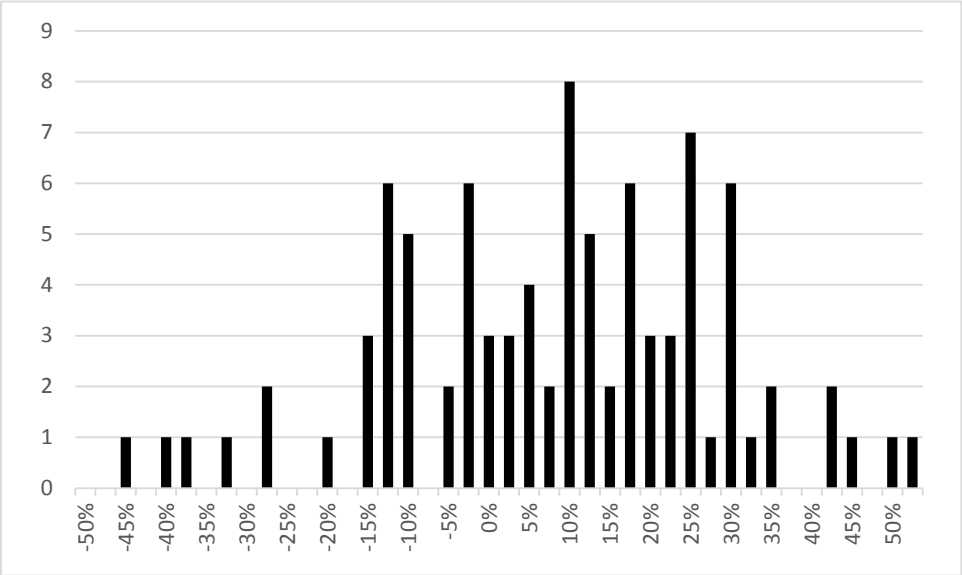
statistically indistinguishable from the long-term arithmetic average of 11.95 percent.[209]

Mr. Gorman further asserts that the Market Risk Premia estimated from my projected market returns are "inflated and not reliable."[210] I therefore performed a similar analysis using historical Market Risk Premia. I first gathered the annual Market Risk Premia reported by Morningstar, and produced a histogram of the observations (recall that Mr. Gorman includes historical data among the methods he uses to estimate the Market Risk Premium). The results of that analysis, which are presented in Chart 15 demonstrate that MRPs of at least 10.68 percent (the high end of the range of the MRP estimates in my Direct Testimony) will occur approximately half of the time.

[209] *See* Morningstar, Inc., 2016 Ibbotson Stocks, Bonds, Bills and Inflation Classic Yearbook, Appendix A, at 3-5; Exhibit RBH-32. Even if we were to look at the standard error, my estimate is well within one standard error of the long-term average.

[210] Direct Testimony of Michael P. Gorman, at 63.

Chart 15: Frequency Distribution of Observed Market Risk Premia, 1926 - 2015[211]



Q. Please summarize Mr. Gorman's criticisms of your Bond Yield Plus Risk Premium analysis.

A. Mr. Gorman's concern with my Bond Yield Plus Risk Premium analysis is my "contention" of a "simplistic inverse relationship" between the Equity Risk Premium and interest rates is not supported by academic research.[212] Mr. Gorman further argues that the relevant factor explaining changes in the Equity Risk Premiums is the change to equity risk relative to debt risk, not changes in interest rates, alone. He concludes that my analysis ignores such investment risk differentials.

[211] Exhibit RBH-32.
[212] Direct Testimony of Michael P. Gorman, at 66.

Q. What is your response to Mr. Gorman's critiques?

A. First, regarding the inverse relationship between the Equity Risk Premium and interest rates, I cited several academic studies in my Direct Testimony that support my findings.[213] Moreover, as explained above, Mr. Gorman's own data clearly demonstrate that the Equity Risk Premium moves inversely to interest rates (both Treasury Yields and Utility Bond Yields). Mr. Gorman may disagree with the premise, but empirical results based on his data support my position (*see* Exhibit RBH-29).

Q. Did you perform any additional analyses to address Mr. Gorman's concern regarding the effect of expected market volatility and other interest rate environments on your results?

A. Yes, I did. Although for the reasons discussed above I continue to believe the model is properly specified, I performed an additional analysis to specifically include the effect of equity market volatility, and credit spreads (*see* Exhibit RBH-33). As with my original Bond Yield Plus Risk Premium analysis, I defined the Risk Premium as the dependent variable, and the prevailing 30-year Treasury yield as an independent variable. I then included two additional explanatory variables: (1) the VIX (the Chicago Board Options Exchange's one-month volatility index, which is a common measure of volatility); and (2) the credit spread between the 30-year Treasury yield and the Moody's Baa Utility Index (as

[213] Direct Testimony of Robert B. Hevert, at 24-25.

a measure of incremental risk).[214] In both instances, the statistically significant inverse relationship between Treasury yields and the Risk Premium remains, and the resulting ROE estimates are generally consistent with those of my original Bond Yield Plus Risk Premium analysis.[215]

Lastly, I note that applying Mr. Gorman's projected 3.40 percent 30-year Treasury yield to the alternative Bond Yield Plus Risk Premium Analysis produces a more reasonable (although still low) ROE estimate of 9.95 percent relative to Mr. Gorman's 9.25 percent recommendation (*see*, Exhibit RBH-33).[216]

Q. What is your response to Mr. Gorman's concern that your CAPM and Bond Yield Plus Risk Premium analyses rely on "stale" Treasury yields?

A. The Treasury yield estimates used in my Direct Testimony corresponded with the timing of the data used in my ROE analysis. Updated Treasury yield estimates as of June 30, 2016 have been used in the analyses accompanying my Rebuttal Testimony. Consequently, my analyses do not rely on "stale" Treasury yields, as Mr. Gorman suggests.

[214] Mr. Gorman notes on page 27 of his testimony that his proxy group has an average Moody's credit rating of Baa1.

[215] *See* Exhibit RBH-3.

[216] Mr. Gorman uses a 3.40 percent projected Treasury yield in his risk premium analysis. *See*, Direct Testimony of Michael P. Gorman, at 47.

Q. Turning to your DCF analysis, do you agree with Mr. Gorman's assertion that the growth rates used in your constant growth DCF analysis are "excessive" and "unsustainable"?

A. No, I do not. Although Mr. Gorman argues that the consensus growth rates in my constant growth DCF model (averaging 5.39 percent) are high relative to his estimate of projected GDP growth and retention growth, he also notes that my mean results are similar to his own. Even though Mr. Gorman believes that my mean high Constant Growth DCF results of 10.08 percent, which are based on an average growth rate of 6.22 percent, are "not reasonable" estimates of the Company's Cost of Equity, those estimates are well within the prevailing range of authorized returns, a benchmark that Mr. Gorman appears to believe is relevant given that his Risk Premium method is predicated on authorized ROEs.[217]

Q. Please respond to Mr. Gorman's assertion your long-term growth rate is inconsistent with other consensus estimates of long-term GDP growth.

A. As noted in my response to Dr. Woolridge, the long-term growth rate in my multi-stage DCF analysis reflects growth expectations beginning ten years in the future, whereas Mr. Gorman's consensus GDP projections are only five or ten year projections. Because there are no consensus forecasts that begin in ten years, it is reasonable to assume that real growth will revert to its long-term average over time. Moreover, the terminal growth rate is intended to reflect expected growth in perpetuity and as such, the term of even the longest GDP forecast considered by

[217] Direct Testimony of Michael P. Gorman, at 68-69.

Mr. Gorman does not reflect the expected, perpetual nature of the terminal growth assumed in the DCF model.

In his Multi-Stage DCF analysis, Mr. Gorman cites to projections from the Energy Information Administration ("EIA"), Congressional Budget Office ("CBO"), and other sources including the Social Security Administration ("SSA"), and suggests that the terminal growth rate in my Multi-Stage DCF analysis is too high.[218] I address the EIA and CBO forecasts in my response to Dr. Woolridge. In the case of the SSA forecast, my long-term growth estimate falls well within the range of the "cases" that the SSA considers.[219] Moreover, Mr. Gorman's 4.35 percent long-term sustainable growth rate conflicts with market measures cited elsewhere in his testimony. For example, Mr. Gorman does not consider the use of long-term historical data for the purpose of developing his terminal growth rate, yet he relies on long-term historical data for the purposes of his CAPM analyses. According to Duff & Phelps (which provides the data Mr. Gorman relies on to estimate the historical Market Risk Premia), the arithmetic average historical capital appreciation rate is 7.70 percent, which is substantially higher than Mr. Gorman's 4.35 percent estimate of long-term GDP growth.[220]

[218] *Ibid*., at 39, 69.

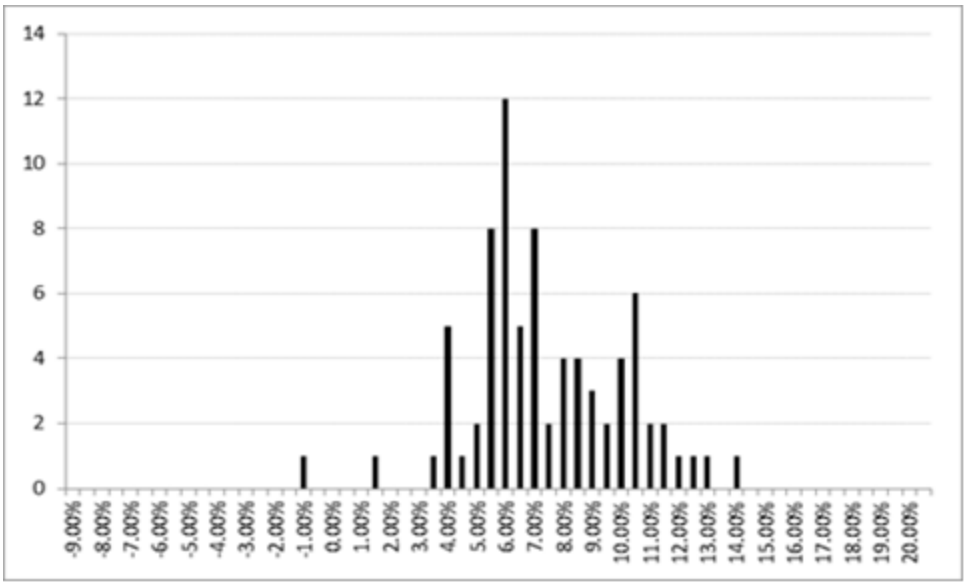
[219] Tables V.B1 and V.B2 of the 2016 *Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds* includes "Low Cost" scenario assumptions of 2.90 percent and 2.70 percent for the GDP Price Index, and Real GDP Growth, respectively, over the period 2025 through 2085. Combined, those projections indicate nominal GDP growth of approximately 5.70 percent.

[220] Duff & Phelps, 2016 Valuation Handbook: Guide to Cost of Capital at 2-4. Even if we were to consider the geometric mean, the historical capital appreciation rate exceeds Mr. Gorman's 4.35 percent estimate; Mr. Gorman notes on page 37 of his testimony that the long-term geometric average growth rate is 5.80 percent.

Aside from the inconsistency with his other analyses, Mr. Gorman's low growth rate has the effect of producing unduly low DCF estimates.

To assess whether my 5.35 percent nominal GDP growth estimate is reasonable within the context of historical observations, consistent with Mr. Gorman's approach to his risk premium study, I calculated the average five- and ten-year annual GDP growth rates from 1929 to 2015, an 87-year period. I then arranged that data in histograms to provide a perspective of how frequently various levels of growth have occurred. As Chart 16 demonstrates, average annual growth as low as 4.35 percent has been observed very infrequently. In fact, average annual growth *exceeded* 4.35 percent in 68 of 77 ten-year periods.

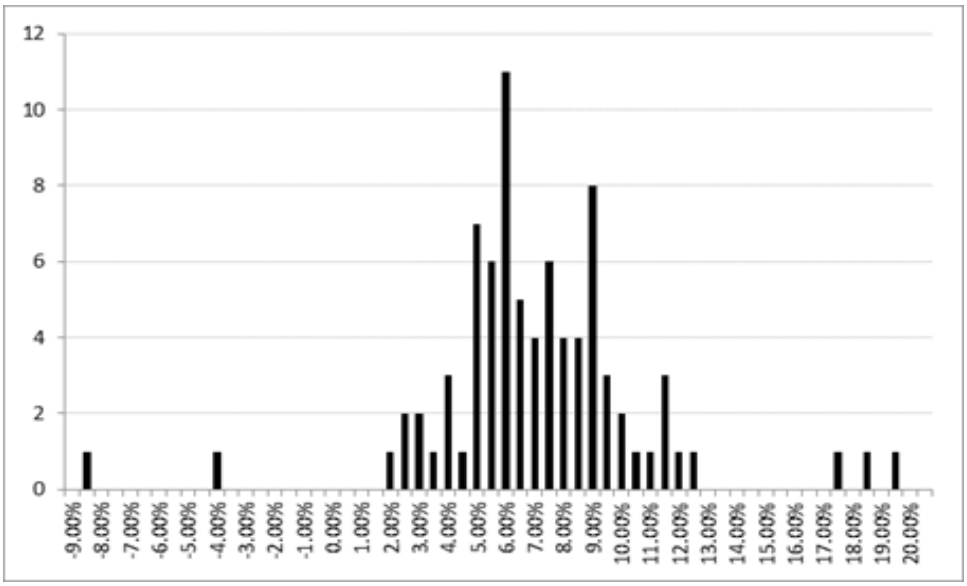
Chart 16: Average Annual GDP Growth Measured over Ten-Year Periods[221]



[221] Source: Bureau of Economic Analysis.

I also calculated average GDP growth over five year periods. In that case, average annual GDP growth rate was greater than 4.35 percent in 70 of 82 periods (*see* Chart 17).

Chart 17: Average Annual GDP Growth Measured over Five-Year Periods[222]



Q. What is your response to Mr. Gorman's assertion that your payout ratio assumption is "unreasonable"?

A. Mr. Gorman argues that there is "no reason" to expect the dividend payout ratio of the proxy group to increase or change between growth stages of the model.[223] However, as noted in my Direct Testimony there are several reasons why management may adjust dividend payments in the near term, such as increases or decreases in expected capital spending.[224] Over the long term, it is reasonable to assume that payout ratios will converge to the industry average; that is, the

222 *Ibid.*
223 Direct Testimony of Michael P. Gorman, at 72.
224 Direct Testimony of Robert B. Hevert, at 33.

analysis assumes that short-term trends in the payout ratio will not continue in perpetuity.

I also note that several of Mr. Gorman's proxy companies recently have discussed target payout ratios that are highly consistent with my 67.30 percent assumption. For example, in first and second quarter 2016 investor relations presentations, Alliant Energy, NorthWestern Corporation, and Xcel Energy all noted target payout ratios in the range of 60.00 percent to 70.00 percent.[225] Consequently, I disagree with Mr. Gorman's position that a long-term payout ratio of approximately 67.00 percent is unreasonable.

IV. RESPONSE TO SFHHA WITNESS BAUDINO

Q. Please summarize Mr. Baudino's ROE analyses and ROE recommendation in this proceeding.

A. Mr. Baudino recommends an ROE of 9.00 percent, which is based on the results of his Constant Growth DCF analyses.[226] Mr. Baudino also performs several CAPM analyses, but does not rely on them to set his recommended ROE.[227]

Mr. Baudino notes that interest rates declined from January 2008 through May 2016, and suggests that the required Return on Equity also is lower.[228] As to the Company's capital structure, Mr. Baudino proposes a hypothetical 55.00 percent

[225] In its June 2016 Investor Presentation at page 39, NextEra Energy noted its 2018 target payout ratio of 65.00 percent.
[226] Direct Testimony of Richard A. Baudino, at 2-3.
[227] *Ibid.*, at 41-42.
[228] *Ibid.*, at 6.

equity ratio.[229] Lastly, because he believes they are accounted for in the stock prices used in DCF analyses, Mr. Baudino suggests it is unnecessary to reflect flotation costs in his ROE estimate.[230]

Q. What are the principal areas in which you disagree with Mr. Baudino's ROE analyses?

A. The principal areas in which I disagree with Mr. Baudino include: (1) the composition and selection of the proxy group companies; (2) his reliance on the Constant Growth DCF model to determine the Company's Cost of Equity; (3) the growth rates applied in the Constant Growth DCF model; (4) the risk-free rate and Market Risk Premium used in the CAPM; (5) whether the Bond Yield Plus Risk Premium analysis provides reasonable estimates of the Company's Cost of Equity; (6) the recovery of flotation costs; (7) our respective assessments of the Company's level of business and financial risk; and (8) the reasonableness of the Company's capital structure.

A. Proxy Group Composition

Q. Please summarize the criteria by which Mr. Baudino selected his proxy group.

A. Mr. Baudino began with the electric utilities included in the June 2016 issue of AUS Utility Reports, and arrived at his proxy group by excluding companies that:

1. Were not rated at least "A" by Standard and Poor's or Moody's Investor Service;

229 *Ibid.*, at 50.
230 *Ibid.*, at 66-67.

2. Have less than 50.00 percent of their revenues from electric operations;
3. Do not have growth rates from Value Line and either Zacks or Thomson Financial;
4. Have recently cut or eliminated dividends; or
5. Were recently, or currently are involved in merger activities or significant restructuring.[231]

Based on those criteria, Mr. Baudino developed a group of twelve companies. Exhibit RBH-19 provides a comparison of the companies included in our respective proxy groups.

Q. Are the scope and definition of the screens applied by Mr. Baudino generally consistent with those used in your Direct Testimony?

A. Although certain of the screening criteria are common to our analyses, there are certain differences between our approaches.

Q. What are the primary differences between you and Mr. Baudino with respect to screening criteria?

A. The majority of the difference in our approaches relate to Mr. Baudino's use of proxy companies that: (1) receive less than 60.00 percent of their regulated net income from electric operations; (2) do not have meaningful amounts of regulated generating assets. In addition, seven companies included in my proxy group were excluded by Mr. Baudino because their bond credit ratings were below A from S&P or Moody's.

[231] *Ibid.*, at 28.

I also excluded Edison International ("EIX") from my proxy group based on recent financial information. EIX's merchant generation business unit was placed into Chapter 11 bankruptcy and subsequently sold to NRG Energy.[232] Although the sale of that segment was completed in April 2014,[233] there are continuing effects on the company's near-term financial outlook associated with a settlement agreement related to the business units' bankruptcy, including required payments of $204 million in 2015, and $214 million in 2016. Consequently, I excluded EIX from my proxy group.

Despite those differences, the composition of our respective proxy groups has little effect on the differences in our analytical results.[234] Consequently, the analyses accompanying my Rebuttal Testimony include results for a Combined Proxy Group that contains most of the proxy companies relied on by the ROE witnesses in this case.[235]

232 *See*, Edison International, SEC Form 10-K, for the Fiscal Year Ended December 31, 2013, at 35-36.

233 *See*, Edison International, SEC Form 10-K, for the Fiscal Year Ended December 31, 2014, at 104.

234 For example, Mr. Baudino reports an average Value Line Beta coefficient of 0.73 (*see* Exhibit No.___(RAB-9), while the average Value Line Beta coefficient for my proxy group, excluding recent mergers, is 0.75 as of June 30, 2016.

235 As discussed in my response to Dr. Woolridge, I continue to exclude companies that have been party to a merger or significant transaction, or that do not own generation assets.

B. Application of the Constant Growth DCF Analysis

Q. Please briefly describe Mr. Baudino's Constant Growth DCF analysis and results.

A. Mr. Baudino calculates an average dividend yield of 3.44 percent by dividing each proxy company's annualized dividend by its average monthly stock price for the six-month period ending May 2016.[236] For the expected growth rate, Mr. Baudino relies on Earnings Per Share growth rate projections from Value Line, Zacks, and Thomson Financial, as well as Dividend Per Share growth rate projections from Value Line.[237] Mr. Baudino then calculates DCF results based on the mean and median growth rate of the four sources noted above, producing eight ROE estimates, ranging from 8.15 percent to 9.54 percent.[238]

Mr. Baudino refers to the DCF results produced using mean growth rates as "Method 1", and DCF results produced using median growth rates as "Method 2". The mean DCF results of his Methods 1 and 2 were 8.64 percent and 8.87 percent, respectively.[239]

Lastly, Mr. Baudino considers a form of "sustainable growth", although he does not appear to include that estimate in his final DCF analyses.

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236 Direct Testimony of Richard A. Baudino, at 29.
237 *Ibid*., at 29.
238 *Ibid*., at 33, Exhibit No.___(RAB-7).
239 *Ibid*.

Q. What are your concerns with Mr. Baudino's selection of growth rates for the DCF models.

A. I disagree with Mr. Baudino's use of projected dividend growth rates in estimating the Cost of Equity and the form of "sustainable growth" described in Mr. Baudino's Direct Testimony. As discussed in my response to Dr. Woolridge, academic literature supports the use of earnings growth rates in the DCF model. As also discussed in my response to Dr. Woolridge, my analyses demonstrate that only earnings growth rates have a statistically significant ability to explain valuation levels.

Q. Please describe the sustainable growth rate estimate used by Mr. Baudino.

A. Mr. Baudino states that he "utilized the sustainable growth formula", which he appears to have taken from Value Line's projected "Retained to Common Equity" rate.[240] As Mr. Baudino explains, the estimate is calculated as the product of the expected earned return on common equity ("R"), and the retention ratio (i.e., the portion of earnings not paid out in dividends, or "B").

Q. Do you agree with Mr. Baudino's sustainable growth rate estimate?

A. No, I do not. As discussed in my response to Dr. Woolridge, the sustainable growth model assumes that growth is a function of expected earnings, and the extent to which those earnings are retained (that is, not paid out in dividends). Mr. Baudino relies on the simplest form of the sustainable growth model, which sometimes is referred to as the "B x R" approach (where "B" is the earnings

[240] *Ibid.*, at 31.

retention rate, and "R" is the expected Return on Common Equity). As Exhibit RBH-34 demonstrates, the B x R method is essentially equal to Value Line's "Retained to Common Equity" rate (differences are due to rounding).

If Mr. Baudino is going to consider a form of sustainable growth, he should use the "BR + SV" form of the model, which reflects growth from both internally generated funds (i.e., the "BR" term) and from issuances of equity (i.e., the "SV" term). As noted above, the first term is the product of the retention ratio (i.e., "B", or the portion of net income not paid in dividends) and the expected return on equity (i.e., "R"). The "SV" term can be represented as:

$$\left(\frac{m}{b} - 1\right) \times Growth\ Rate\ in\ Common\ Shares$$

Where:

$$\frac{m}{b} = The\ Market\ to\ Book\ Ratio$$

In this form, the "SV" term reflects an element of growth as the product of (1) the growth in shares outstanding and (2) that portion of the market-to-book ratio that exceeds unity.

In addition, it is important to realize that for the purpose of setting utility rates, sustainable growth requires an estimate of the expected earned Return on Common Equity. Since the "R" in the "B x R" approach refers to the equity return, Mr. Baudino effectively has pre-supposed the Return on Common Equity projected by Value Line for his proxy group companies. Notwithstanding that Mr. Baudino has assumed the reasonableness of Value Line's projections for the

purpose of his sustainable growth calculation, as demonstrated in Exhibit RBH-34, his recommended Cost of Equity of 9.00 percent is 108 basis points below the mean Return on Common Equity estimate (for his proxy group) of 10.08 percent.

Q. Putting aside those concerns, did Mr. Baudino use the sustainable growth estimate in arriving at his DCF estimate?

A. No, he did not. Exhibit No.___(RAB-7), page 2 provides the DCF calculations that support Mr. Baudino's ROE recommendation; that page does not reference the sustainable growth estimate. In addition, I have replicated Mr. Baudino's Exhibit No.___(RAB-7), page 2 (see Exhibit RBH-35), and confirmed that Mr. Baudino's DCF estimates do not include his sustainable growth estimate.

C. Multi-Stage DCF Analysis

Q. What are Mr. Baudino's concerns with your Multi-Stage DCF analysis?

A. Mr. Baudino considers it "highly unlikely" that investors consider Multi-Stage DCF analyses, and he is concerned I have provided no evidence that investors (1) use GDP growth in their evaluation, or (2) rely on payout ratio assumptions similar to those included in my Multi-Stage DCF analysis.[241]

Q. Do you agree with Mr. Baudino's suggestion that it is "highly unlikely" that investors use Multi-Stage DCF models?

A. No, I do not. As discussed in my Direct Testimony, the Constant Growth DCF Model requires a set of assumptions that can be quite limiting, and inconsistent

[241] Direct Testimony of Richard A. Baudino, at 68.

with prevailing and expected conditions. Mr. Baudino has provided no basis to assume that investors would prefer the limited structure of the Constant Growth DCF Model to the more flexible Multi-Stage form. As to the use of Multi-Stage models, D. Roger Morin notes that it is "consistent with current valuation practices of institutional investors and is a common estimation technique used by financial analysts."[242] For example, Morningstar describes a three-stage DCF approach (generally consistent with the model included in my Direct Testimony) in which the final stage assumes that long-run growth moves toward that of the overall economy.[243] In addition, while we disagree on certain aspects of the application of the Multi-Stage DCF model, I note both Dr. Woolridge and Mr. Gorman also consider Multi-Stage DCF analyses.

Q. Is GDP commonly used as a long-term growth rate assumption?

A. Yes, it is. As noted in my response to Dr. Woolridge, the use of expected long-term GDP growth in the terminal period is consistent with practice and financial literature. Morningstar's Multi-Stage DCF approach (noted above), for example, is similar to my methodology, including the use of GDP in the terminal growth period.[244] Nonetheless, if Mr. Baudino is of the view that (1) the Constant Growth DCF model is the better alternative, and (2) expected GDP growth is not a relevant measure of terminal growth, I have addressed those concerns by

242 Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 266.
243 *See*, Ibbotson SBBI 2013 Valuation Yearbook, Morningstar, Inc., at 50-52.
244 *Ibid*.

calculating the terminal value by reference to the proxy companies' recent P/E ratios.[245]

Q. What is your response to Mr. Baudino's concern with your assumption regarding payout ratios?[246]

A. I believe it is reasonable to assume that near-term payout ratios likely reflect downward pressure due to increased utility capital requirements, but will revert to the long-term industry average over the horizon of the DCF analysis. I note that assumption is consistent with the Value Line data presented in Mr. Baudino's Exhibit No.___(RAB-7), which indicates near-term dividend growth is expected to outpace earnings growth by approximately 130 basis points, on average, for Mr. Baudino's proxy group. In that regard, it is the Constant Growth DCF model relied on by Mr. Baudino (which assumes that payout ratios will remain unchanged in perpetuity) that is inconsistent with investor expectations.

Moreover, as discussed in more detail in my response to Mr. Gorman, a number of electric utility companies have indicated that their payout ratios likely will increase, and that they are targeting payout ratio ranges highly consistent with the long-term industry average used in my Multi-Stage DCF analysis.

[245] As noted earlier, the Constant Growth DCF model assumes a constant P/E ratio, in perpetuity.
[246] Direct Testimony of Richard A. Baudino, at 68.

D. Capital Asset Pricing Model

Q. Please summarize Mr. Baudino's CAPM analyses.

A. As noted earlier, Mr. Baudino performs two sets of CAPM analyses. His first set calculates two Market Risk Premium measures, which rely on the forecasted market total return as determined using Value Line projections, and five and 20-year Treasury security yields (i.e., 1.40 percent and 2.34 percent, respectively). Mr. Baudino calculates a total growth rate for the market of 10.44 percent, using the average of the book value and earnings growth forecasts (7.00 percent and 11.00 percent, respectively) for all companies covered by Value Line. Mr. Baudino combines that average growth rate with Value Line's average expected dividend yield of 0.84 percent for the same group of companies, and calculates an expected market return of 10.44 percent.[247]

Mr. Baudino's two Market Risk Premium measures represent the difference between (1) his calculated expected market total return, and (2) the current yield on five and 20-year Treasury securities. Mr. Baudino arrives at his CAPM results using the average Value Line Beta coefficient of 0.73 for his proxy companies.[248]

Mr. Baudino's second set of CAPM analyses calculate the geometric and arithmetic mean long-term annual returns on stocks, and long-term annual income returns on long-term government bonds, resulting in two historical measures of

[247] Exhibit No.___(RAB-8).
[248] Exhibit No.___(RAB-8).

the Market Risk Premium.[249] Mr. Baudino uses those two Market Risk Premium measures in combination with the current 20-year Treasury bond yield and the average Value Line Beta coefficient to calculate two additional CAPM results.

Although Mr. Baudino advises the Commission to consider only his DCF results in establishing the Company's ROE, he does report CAPM results ranging from 6.02 percent to 8.28 percent, reasoning that those results indicate that his 9.00 percent ROE recommendation is "generous".[250]

Q. Do you agree with Mr. Baudino's application of the CAPM and his interpretation of its results?

A. No, there are two areas in which I disagree with Mr. Baudino: (1) the term of the Treasury security used as the risk-free rate component of the model; and (2) the calculation of the Market Risk Premium. In addition, for the reasons discussed throughout my Rebuttal Testimony, I disagree that Mr. Baudino's 9.00 percent ROE recommendation is "generous".

Q. Turning first to the risk-free rate component, why do you disagree with Mr. Baudino's use of five and 20-year Treasury securities as the measure of the risk-free rate?

A. As discussed below, the tenor of the risk-free rate used in the CAPM should match the life (or duration) of the underlying investment. As noted by Morningstar:

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249 Direct Testimony of Richard A. Baudino, at 38 and Exhibit No.___(RAB-9).

250 *Ibid.*, at 41-42.

> The traditional thinking regarding the time horizon of the chosen Treasury security is that it should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.[251]

Pratt and Grabowski recommend a similar approach to selecting the risk-free rate: "In theory, when determining the risk-free rate and the matching ERP you should be matching the risk-free security and the ERP with the period in which the investment cash flows are expected."[252] To that point, a 2004 paper titled *Applying The Capital Asset Pricing Model* by Robert Harris reviews current practices for application of the CAPM and, when summarizing best current practices, concludes "[t]he risk-free rate should match the tenor of the cash flows being valued."[253] As a practical matter, equity securities represent a perpetual claim on cash flows; 30-year Treasury bonds are the longest-maturity securities available to match that perpetual claim.

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[251] Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 44.

[252] Shannon Pratt and Roger Gabrowski, Cost of Capital: Applications and Examples, 3rd Ed. (Hoboken, NJ: John Wiley & Sons, Inc., 2008), at 92. "ERP" is the Equity Risk Premium.

[253] Paper cited with permission of author.

One measure of the term of expected cash flows is Equity Duration. In finance, "duration" (whether for bonds or equity) typically refers to the present value weighted time to receive the security's cash flows. In terms of its practical application, duration is a measure of the percentage change in the market price of a given stock in response to a change in the implied long-term return of that stock. A common investment strategy is to "immunize" the portfolio by matching the duration of investments with the term of the underlying asset in which the funds are invested, or the term of a liability being funded.

As demonstrated in Exhibit RBH-36, the average Equity Duration of the companies in Mr. Baudino's proxy group is approximately 30.47 years. Given that relatively long Equity Duration, and knowing that utility assets are comparatively long-lived, I continue to believe that it is appropriate to use the long-term Treasury yield as the measure of the risk-free rate.

Q. Is Mr. Baudino's assumption that five and 20-year Treasury yields are equally valid measures of the risk-free rate supported by his data?

A. No, it is not. As discussed above, the mean Equity Duration of the companies in Mr. Baudino's proxy group is 30.47 years. In comparison, the current duration of five-year, 20-year and 30-year Treasuries are 4.88, 16.57, and 21.46 years respectively.[254] Although the duration of even the longest-term Treasury security falls short of the average Equity Duration for Mr. Baudino's proxy group, the 30-

[254] *See* Exhibit RBH-37.

year Treasury yield provides the longest available duration and, therefore, is the best available security for that purpose. The principle of duration is relevant to the electric utility stocks that comprise Mr. Baudino's proxy group, given that institutional investors own (on average) 75.75 percent of those companies' shares.[255]

Q. Putting aside the issue of Equity Duration, does Mr. Baudino's DCF model recognize the perpetual nature of equity?

A. Yes, it does. As Mr. Baudino correctly observes, the Constant-Growth DCF model assumes growth in perpetuity: "the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond)."[256]

Q. What would be the effect of assuming the companies in Mr. Baudino's proxy group only provided cash flows to equity investors over five or 20 years?

A. As shown in Exhibit RBH-38, assuming a 20-year holding period, the mean and median DCF would be 1.44 percent, and 1.69 percent, respectively. Interestingly, both of those ROE estimates are below Mr. Baudino's assumed 2.34 percent risk-free rate (*i.e.*, six month average of the 20-year Treasury yield). Assuming a holding period of five years produces mean and median ROE estimates of negative 36.93 percent and negative 36.50 percent, respectively. The only way Mr. Baudino's DCF results could be realized is if the shares were sold at the end of the five and 20-year holding periods, and the prices at which they are sold

[255] Source: SNL Financial.
[256] Direct Testimony of Richard A. Baudino, at 26.

reflect cash flows in perpetuity. Those results support the point made earlier in my testimony: The risk-free rate should reflect the perpetual nature of equity. Because the longest-dated Treasury security is 30 years, that is the appropriate term for this purpose.

Q. What is your response to Mr. Baudino's suggestion that "the risk-free rate should have no interest rate risk?"[257]

A. The process of duration matching mitigates interest rate risk. In any event, if Mr. Baudino is concerned with interest rate risk, he should focus exclusively on short-term Treasury Bills as the risk-free rate. Doing so, of course, would further decrease his already-low CAPM estimates. Consequently, I disagree with Mr. Baudino's position that interest rate risk disqualifies the 30-year Treasury yield as the appropriate measure of the risk-free rate.

Q. What concerns do you have with Mr. Baudino's *ex-ante* Market Risk Premium calculations?

A. In arriving at his *ex-ante* Market Risk Premium estimates, Mr. Baudino calculates the expected market return using an average of earnings growth projections (11.00 percent) and book value growth projections (7.00 percent). As noted above, academic research indicates investors rely on estimates of earnings growth in arriving at their investment decisions. The analysis presented in Exhibit RBH-22 (discussed in more detail in my response to Dr. Woolridge) also demonstrates book value growth rates are not a statistically significant indicator of electric

[257] *Ibid.*, at 62.

utility company valuations. In that regard, Mr. Baudino did not include book value growth projections in his proxy group-based DCF analysis. He has not explained, however, why it is reasonable to include those growth rates in his MRP analysis but exclude them from his proxy company DCF analyses. Excluding book value growth estimates from Mr. Baudino's market return calculation would increase his MRP estimate by 1.00 percentage points (100 basis points).

Q. Do you agree with Mr. Baudino's use of historical estimates of the MRP?

A. No, I do not. The MRP represents the additional return required by equity investors to assume the risks of owning the "market portfolio" of equity relative to long-term Treasury securities. As with other elements of Cost of Equity analyses, the MRP is meant to be a forward-looking parameter. As Morningstar observes:

> It is important to note that the expected equity risk premium, as it is used in discount rates and cost of capital analysis, is a forward looking concept. That is, the equity risk premium that is used in the discount rate should be reflective of what investors think the risk premium will be going forward.[258]

That is why the MRP estimates used in my CAPM analyses specifically rely on forward-looking, market-based estimates of the expected market return.

[258] Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook, at 53.

Q. Please briefly summarize Mr. Baudino's comments regarding your *ex-ante* CAPM analyses.

A. Mr. Baudino disagrees with my *ex-ante* Market Risk Premium, noting that the underlying growth rates "are by no means long-run sustainable growth rates."[259] Mr. Baudino further suggests that the forecasted Treasury bond yields relied upon in my CAPM analyses are "speculative at best and may or may not come to pass."[260]

Q. Do you agree with Mr. Baudino's concerns in that regard?

A. No, I do not. As discussed in my response to Mr. Gorman, my estimates of the Market Risk Premium and the growth rates underlying them are consistent with historical measures.

Regarding the use of projected interest rates, it is important to remember that, as Mr. Baudino states, "[r]eturn on equity analysis is a forward-looking process."[261] In that regard, Mr. Gorman, Dr. Woolridge, and I consider forward-looking estimates of the risk-free rate. Even if Mr. Baudino is concerned that the projections may not come to pass, the increases in forward long-term Treasury yields demonstrate that investors believe interest rates are likely to rise.[262] Because our analyses are predicated on market expectations, the expected

259 Direct Testimony of Richard A. Baudino, at 63.
260 *Ibid*., at 62.
261 *Ibid*., at 30.
262 *See*, Chart 13.

increase in Treasury yields (as reflected in increasing forward rates) is a measurable and relevant data point.

E. Bond Yield Plus Risk Premium Approach

Q. What concerns does Mr. Baudino express regarding your Bond Yield Plus Risk Premium analyses?

A. Mr. Baudino suggests that the Bond Yield Plus Risk Premium method is "imprecise and can only provide very general guidance," and notes that "[r]isk premiums can change substantially over time."[263] In summary, Mr. Baudino likens the approach to a "blunt instrument".[264] As to its application, Mr. Baudino disagrees with the use of projected Treasury yields in calculating the range of Risk Premium-based results.

Q. What is your response to Mr. Baudino's observations?

A. As to Mr. Baudino's point that the Risk Premium can change over time, I agree. As noted in my Direct Testimony (and as discussed in my response to Mr. Gorman), there is a statistically significant negative relationship between long-term Treasury yields and the Equity Risk Premium. Given Mr. Baudino's observation that interest rates have declined since 2008, the Bond Yield Plus Risk Premium analysis provides an empirically and theoretically sound method of quantifying the relationship between the Cost of Equity and interest rates. That is, it provides a method to quantify the change that Mr. Baudino has observed.

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263 Direct Testimony of Richard A. Baudino, at 65.

264 *Ibid.*

As to Mr. Baudino's notion that the approach is a "blunt instrument," I disagree. As shown in Exhibit RBH-12, the R-squared of the Bond Yield Plus Risk Premium regression analysis is 0.71, indicating a rather high degree of explanatory value. In comparison, Beta coefficients calculated based on the Value Line methodology have a mean R-squared of only 0.19 (see Exhibit RBH-39).

As Exhibit RBH-40 demonstrates, using the 95.00 percent confidence interval of the Bond Yield Plus Risk Premium regression's equation coefficient estimates, the ROE results range from 9.47 percent to 10.89 percent. That 142 basis point range is approximately equal to the range of DCF model results reported by Mr. Baudino (8.15 percent to 9.54 percent, or 139 basis points).[265] It also is considerably less than the range of CAPM results reported by Mr. Baudino (6.02 percent to 8.28 percent, or 226 basis points). Consequently, the Bond Yield Plus Risk Premium approach provides empirically and theoretically sound results that can be used, at minimum, to assess the wide range of ROE results produced by Mr. Baudino's analyses in general, and his 9.00 percent recommendation in particular.

[265] *Ibid.*, at 41.

F. Flotation Costs

Q. Please now summarize Mr. Baudino's response to your proposed flotation cost adjustment.

A. Mr. Baudino believes it is "likely that flotation costs are already accounted for in current stock prices" and that an adjustment to the DCF result would amount to "double counting."[266]

Q. Do you agree with Mr. Baudino's concerns?

A. No, I do not. Mr. Baudino states that "[m]ultiplying the dividend yield by a 4% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity."[267]

The flotation cost estimate used in my Direct Testimony, however, is well below 4.00 percent. Moreover, the adjustment is not calculated by "[m]ultiplying the dividend yield by a 4% flotation cost adjustment", as Mr. Baudino suggests. Rather, it is calculated by dividing the dividend yield by a factor of (1 – flotation costs).[268] Further, Mr. Baudino's suggestion that current prices "likely" account for flotation costs is misplaced. Because of direct issuance costs (such as those provided in Exhibit RBH-9 to my Direct Testimony), the net proceeds received by the Company were less than the market price of the offerings. Absent a direct

266 Direct Testimony of Richard A. Baudino, at 66.
267 *Ibid*., at 67.
268 *See*, Exhibit RBH-18.

recovery of those costs, the ROE should be adjusted to reflect that deficiency (which will persist in perpetuity).

I also note that although Mr. Baudino suggests that current prices "likely" account for flotation costs, he has provided no analyses as to what costs are reflected in prices, or how prices have adjusted in response to those costs. Conversely, my Direct Testimony provided a summary of direct costs incurred by the proxy companies to acquire the equity capital needed to fund the Company's rate base.

G. Relative Risk and Financial Integrity

Q. Has Mr. Baudino expressed any concerns with your consideration of the business risks associated with FPL?

A. Yes. Mr. Baudino suggests that the Company's credit rating already accounts for the risks discussed in my Direct Testimony.

Q. Do you believe that credit ratings are an appropriate measure to determine the relative risk of FPL relative to the proxy group?

A. Not entirely. As discussed in my response to Dr. Woolridge, credit ratings are directed toward the interests of debt investors. The view that differences in credit ratings "notches" among investment grade utilities can be used as a proxy for differences in the Cost of Equity fails to recognize the senior position that debt holders have relative to equity holders, and the investment horizon considered by equity holders. Moreover, Exhibit RBH-26 shows that there is not a quantifiable relationship between the proxy companies' credit ratings and Cost of Equity.

Q. Does the fact that Standard & Poor's ranks FPL as having an "Excellent" Business Risk Profile indicate they have less risk than other electric utilities?

A. No, it does not. A review of recent regulated electric utilities credit ratings from S&P Ratings Direct highlighted the prevalence of "Excellent" business risk profiles among electric utilities. Of 107 electric utility operating companies, S&P reported that 79 companies (i.e., approximately 75.00 percent) had "Excellent" business risk profiles (*see* Exhibit RBH-41). Among those with "Excellent" business risk profiles, S&P's credit ratings ranged from as high as AA- to as low as BB+ (i.e., below investment grade). As such, FPL's "Excellent" business risk profile from S&P does not distinguish the Company as being less risky than other electric utilities, nor does it insulate the Company from the detrimental effects of Mr. Baudino's ROE recommendation.

H. Capital Structure

Q. What is Mr. Baudino's position with regard to the Company's capital structure?

A. Mr. Baudino recommends an equity ratio of 55.00 percent if the Commission authorizes an ROE of 9.00 ROE, but an equity ratio of 53.00 percent if the allowed ROE is higher than 9.00 percent.[269] In support of his recommendation, Mr. Baudino notes the single highest equity ratio, at the holding company level, for his proxy group is approximately 55.00 percent and that the average equity

[269] Direct Testimony of Richard A. Baudino, at 4 and 53.

ratio for the proxy group used in my Direct Testimony was approximately 53.00 percent.

As discussed in my response to Dr. Woolridge, I believe the appropriate comparison is to the range of equity ratios in place at similar operating electric utilities. Reviewing the capital structures in place at the electric utility operating companies held within the Combined Proxy Group, it is apparent FPL's equity ratio is consistent with the proxy group's financing practices. I further discuss the Company's capital structure in response to Mr. O'Donnell.

V. RESPONSE TO WAL-MART WITNESS CHRISS

Q. Please summarize Mr. Chriss' testimony regarding the Company's ROE.

A. Mr. Chriss opposes my recommendation because it is higher than the average of authorized ROEs from regulatory commissions, both nationally and in Florida, since 2013.[270] Mr. Chriss also argues that the Commission should consider the Company's future test year and the percentage of revenues recovered through base rates versus cost recovery mechanisms.[271] Lastly, Mr. Chriss suggests that the Commission consider the effect of increases in rates on retailers. Chriss did not, however, undertake an independent, market-based analysis of the Company's Cost of Equity.

[270] *See*, Direct Testimony of Steve W. Chriss, at 10-11.
[271] *Ibid.*, at 9-10.

Q. Have you reviewed and updated the information contained in Mr. Chriss' Exhibit SWC-4?

A. Yes. As shown in Exhibit RBH-42, I have updated Mr. Chriss' Exhibit SWC-4 and added jurisdictional rankings from Regulatory Research Associates ("RRA"). RRA, which is the source of Mr. Chriss' rate case data, provides an assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives, or not. As RRA explains, less constructive environments are associated with higher levels of risk:

> RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate from an investor viewpoint. Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid range rating; and, 3, a weaker (less constructive) rating. We endeavor to maintain an approximately equal number of ratings above the average and below the average.[272]

Sorting the data relating to Mr. Chriss' Exhibit SWC-4 by RRA's ranking, two points become apparent. First, looking at all cases there is an approximately 45

[272] Source: Regulatory Research Associates, accessed May 18, 2015.

basis point difference between the average return for "Above Average" and "Average" jurisdictions (the higher-ranked jurisdictions providing the higher authorized returns), and a 25 basis point difference between "Average" and "Below Average" jurisdictions (see Table 6, below). As Table 6 indicates, ROEs for Vertically Integrated electric utilities in "Above Average" jurisdictions range from 9.70 percent to 10.95 percent, with a median of 10.20 percent.

Table 6: Average Authorized ROE by RRA Ranking

	AUTHORIZED ROE: VERTICALLY INTEGRATED		
RRA Ranking	Above Avg.	Avg.	Below Avg.
Total Cases	18	46	7
Minimum	9.70	9.00	9.48
Mean	10.17	9.79	9.70
Median	10.20	9.80	9.70
Maximum	10.95	10.30	9.96

Those observations are important since (as discussed in my response to Mr. O'Donnell, below) the authorized ROE is a very visible measure of the regulatory environment in which utilities operate. The regulatory environment, in turn, is important to utility analysts and investors.

Q. Please now summarize Mr. Chriss' concerns regarding the effect of a rate increase on retailers.

A. Mr. Chriss states that "electricity is a significant operating cost for retailers", and that "[w]hen electric rates increase, that increased cost to retailers can put pressure on consumer prices and on the other expenses required by a business to

operate."[273] Mr. Chriss suggests that the Commission "should thoroughly and carefully consider the impact to customers in examining the requested revenue requirement and ROE, in addition to all other facets of this case, to ensure that any increase in the Company's rates is only the minimum amount necessary to provide adequate and reliable service, while also providing an opportunity to earn a reasonable return."[274]

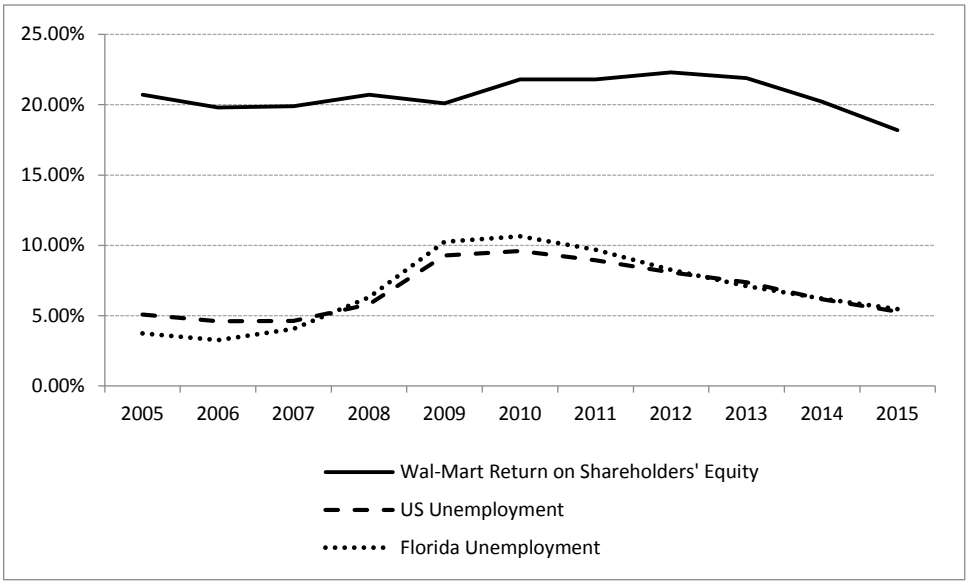
Although Mr. Chriss points out certain pressures that apply to retail businesses such as Wal-Mart, those companies have options not available to regulated utilities such as FPL. Wal-Mart has the option to choose whether, where, and when to open retail stores; what services or products will be offered; whether to invest in expansions, or whether to cease operations in a given location. Further, retail businesses may choose to increase their prices without gaining the approval of regulatory commissions. Quite simply, the options available to retailers such as Wal-Mart are not available to regulated utilities. Such options have value; forgoing those options comes at a cost.

Lastly, despite the pressures that Mr. Chriss discusses, since 200 Wal-Mart's Return on Shareholders' Equity has averaged over 20.00 percent.[275] Value Line currently estimates Wal-Mart's Beta coefficient to be 0.65, and assesses Wal-Mart's Financial Strength as A++. NextEra Energy, on the other hand, has a Beta

[273] Direct Testimony of Steve Chriss, at 7.
[274] Direct Testimony of Steve Chriss, at 7.
[275] Source: Value Line, as of April 29, 2016.

coefficient of 0.70, and a Financial Strength rating of A. By those measures, Wal-Mart is measurably less risky than NextEra Energy.[276]

Chart 18: Wal-Mart Return on Shareholders' Equity and Unemployment rates (2005-2015)[277]



Q. What is your response to Mr. Chriss' recommendation that the commission "examine" the proposed ROE in light of the company's future test year and cost recovery mechanisms?

A. Mr. Chriss asks the Commission to "examine" the proposed ROE in light of the company's future test year and percentage of revenue derived from cost recovery mechanisms, however he does not provide any explanation or analysis to support how these factors would affect FPL's ROE.[278]

[276] Source: Value Line, as of May 20, 2016. Please note that Value Line does not separately rate FPL.

[277] Sources: Value Line; Bureau of Labor Statistic (www.bls.gov).

[278] Direct Testimony of Steve Chriss, at 13-14.

In that regard, the position that a reduction in revenue volatility necessarily requires a reduction in the Cost of Equity runs counter to Modern Portfolio Theory, which is the fundamental basis of the Capital Asset Pricing Model. Under Modern Portfolio Theory, total risk is separated into two distinct components: non-diversifiable risk, which is that portion of risk that can be attributed to the market as a whole; and non-systematic (or diversifiable) risk, which is attributable to the idiosyncratic nature of the subject company itself and, therefore, can be diversified away. Any reduction in the Cost of Equity depends on the type of risk that is reduced. If the risk assumed to be mitigated by rate mechanisms is diversifiable, there would be no reduction in the Cost of Equity because investors could otherwise mitigate the risk through portfolio diversification. If, on the other hand, the risk is non-diversifiable (that is, systematic), it may be that the factors that drove the need to implement the mechanisms also are systematic. That is, if the factors that drove the implementation of rate structures reflected increased systematic risk, those structures would offset that incremental risk and there would be no reduction in the Cost of Equity. Either way, Mr. Chriss has not addressed that crucial issue.

Q. How common are revenue stabilization and cost recovery mechanisms?

A. There is little question that revenue stabilization and cost recovery structures are becoming increasingly common. The increased use of such mechanisms has generally resulted from the growing cost of maintaining system reliability, coupled with the flat or declining sales volume. Adjustment mechanisms to recover fuel costs, purchased power expenses, energy efficiency and demand-side

program costs, new plant investment, and other expenses are common.[279] In addition, decoupling has been implemented by electric utilities in 27 jurisdictions.[280] Consequently, the implementation of alternative regulation mechanisms has become an increasingly visible issue to investors.

Q. Are revenue stabilization mechanisms common among the proxy companies?

A. Yes, they are. Exhibit RBH-43 provides a summary of revenue stabilization mechanisms and cost trackers currently in effect at each electric utility subsidiary of the Combined Proxy Group companies. As Exhibit RBH-43 demonstrates, there are a substantial number of cost recovery mechanisms in place at the proxy companies. Although those mechanisms are diverse, they each address issues related to the timing or certainty of cost recovery. Exhibit RBH-43 also includes a summary of the alternative regulation and incentive plans currently in effect at the proxy companies. Those regulatory constructs include formula-based rate plans, which provide comprehensive adjustment mechanisms that automatically adjust rates in the event that the earned return is above or below an authorized range. Since revenue stabilization and cost recovery mechanisms are common among the proxy companies, I do not believe FPL is materially less risky than its peers by virtue of its recovery mechanisms.

[279] See Exhibit RBH-43.

[280] *See*, for example, *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, Edison Electric Institute, November 2015, at 4-5. Includes true-up plans, lost revenue adjustment mechanisms, and fixed/variable pricing.

Q. Has Mr. Chriss considered the effect of his recommendation on the Company's financial profile?

A. No, he has not. As discussed in my response to Mr. O'Donnell (below), it is important to recognize that both Moody's and Standard & Poor's put considerable weight on the nature of regulation. Here, Mr. Chriss suggests that the Commission should reduce the Company's ROE by some unspecified amount without the benefit of market-based, comparative analyses to support that recommendation. The consequence of such an action likely would indicate an increased degree of regulatory risk. In my view, therefore, Mr. Chriss has not reasonably considered the effect of his recommendation on the Company's financial profile and, therefore, its ability to attract capital on reasonable terms.

VI. RESPONSE TO OTHER ROE WITNESSES

Q. Please summarize Messrs. Brosch's and Pollock's testimony as they relate to the Company's Cost of Capital.

A. While they review recently authorized ROEs, neither Messrs. Brosch nor Pollock perform an independent analysis of the Company's cost of capital.

Based on his review of average authorized ROEs as well as changes in long-term Treasury yields, Mr. Brosch concludes capital market conditions are "very favorable" and recommends that the Commission therefore allow an ROE "that is significantly lower than the authorized ROE levels approved in recent FPL rate

orders."[281] With regard to capital structure, Mr. Brosch recommends an equity ratio of no more than 47.00 percent based on his review of the average equity ratio used by large electric utility holding companies, as reported by AUS, EEI and Y Charts.[282]

Mr. Pollock performs a similar review of authorized ROEs for vertically integrated electric utilities and concludes that average authorized ROEs have declined and notes that the most recent authorized ROEs in Florida ranged from 10.25 percent to 10.50 percent.[283] Based on that analysis Mr. Pollock concludes an 11.00 percent ROE is "excessive," and recommends the Commission authorize FPL an ROE below the average ROE allowed by other state regulatory commissions to reflect the lower risk associated with a 60.00 percent equity ratio.[284] With regard to capital structure, Mr. Pollock recommends an equity ratio of 51.10 percent based on the average authorized electric utility equity ratio since 2012.[285]

Q. What is your response to Messrs. Brosch and Pollock regarding the appropriate ROE for FPL in relation to recently authorized ROEs?

A. First, although both witnesses argue the average authorized ROE has recently been below 10.00 percent, as discussed in my response to Mr. Chriss, the median authorized ROE for vertically integrated utilities in credit supportive jurisdictions

281 *See*, Direct Testimony of Michael L. Brosch, at 38-39.
282 *See*, Direct Testimony of Michael L. Brosch, at 48, 50-51.
283 Direct Testimony of Jeffry Pollock, at 30.
284 *Ibid*., at 30-31.
285 *Ibid*., at 32.

has been 10.20 percent since January 2013. Of the 18 ROEs authorized for vertically integrated electric utilities by credit supportive jurisdictions since the beginning of 2013, 16 have been 10.00 percent or higher.[286]

Second, neither Mr. Brosch nor Mr. Pollock took in to consideration the Company's specific business risks when determining their ROE recommendations. As discussed in my Direct Testimony and discussed above, I believe the estimation of the Cost of Equity should take into consideration FPL's risk factors, including: (1) the Company's geographic risk, including its vulnerability to severe weather conditions; (2) the Company's need to access external capital; (3) the potential for new regulatory requirements associated with nuclear generation; and (4) the potential for an increase in the Cost of Equity over the Company's proposed four year rate period. Messrs. Brosch and Pollock's simple review of average authorized ROEs does not take into account those considerations.

Q. What is your response to Mr. Brosch's suggestion that the Company's ROE should be lowered to reflect the general decline in 30-year Treasury yields?

A. While the current 30-day average of the 30-year Treasury yield (2.50 percent as of June 30, 2016) is somewhat below the level seen at the time of the order in the Company's last rate case (2.81 percent as of December 13, 2012), Treasury yields have been rather volatile over the intervening period and spent much of the past few years at higher levels.

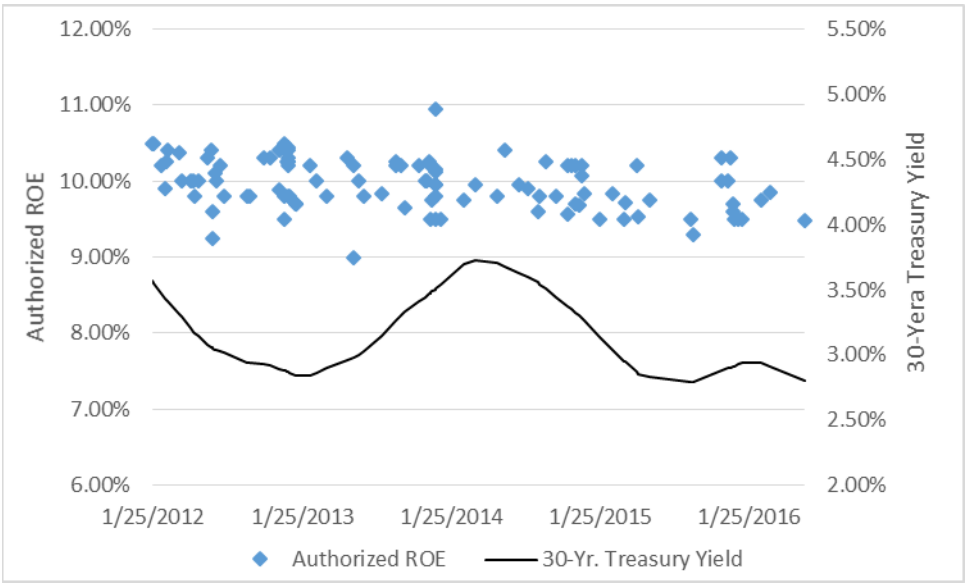
[286] *See* Exhibit RBH-42.

As discussed above, the recent lows in Treasury yields have been associated with a capital flight to safety associated with the "Brexit" and have recently begun to rise off the lows seen during that period. As discussed in my response to Mr. Gorman, consensus forecasts reported by Blue Chip continue to suggest investors expect rates to rise. Similarly, recent prices for options on the TLT index continue to show that investors are willing to pay a significant premium for protection against rising interest rates relative to declining interest rates. Importantly, the potential for rising rates represents risk for utility investors. For example, (as discussed above) the S&P Electric Utility Index lost approximately 15.00 percent of its value in the first half of 2015 as Treasury yields rose 86 basis points to 3.11 percent (from the end of January to the end of June).

Q. Have authorized ROEs changed in tandem with recent fluctuations in Treasury yields?

A. No, they have not. As shown in Chart 19 below, since January 2012 there has been no discernible relationship between the level of authorized ROEs for electric utilities and changes in long-term interest rates. The fact that authorized returns remained relatively stable over that period reflects the inverse relationship between interest rates and the Equity Risk Premium; it also may reflect the observation that utility commissions recognize that Federal policy – including "Quantitative Easing" – created unusual market conditions.

Chart 19: Authorized ROEs for Vertically Integrated Electric Utilities (January 2012 - June 2016) and 30-Year Treasury Yields[287]



Q. What is your response to Messrs. Brosch's and Pollock's recommendations regarding the Company's capital structure?

A. Mr. Brosch suggests higher debt leverage would be beneficial to ratepayers and recommends an equity ratio of 47.00 percent (or lower) based on his estimate of the industry average equity ratio.[288] To support his conclusion, Mr. Brosch compares the Company's existing capital structure to the reported investor owned holding company equity ratios reported by AUS, Edison Electric Institute and Y Charts.[289] As discussed in my response to Dr. Woolridge (above), my review of the actual capital structures in place at the operating companies held within my proxy group reflects the nature of assets financed by vertically integrated utilities

287 Source: Regulatory Research Associates and Federal Reserve Schedule H.15. Average 30-year Treasury over average lag period (200 days). Limited-issue riders are excluded.

288 *See*, Direct Testimony of Michael L. Brosch, at 51.

289 *Ibid.*

such as FPL. Based on that review, it is apparent that the Company's current capital structure is generally consistent with the capital structures of the proxy companies. As discussed in my response to Mr. O'Donnell (below), my updated capital structure analysis continues to support the reasonableness of the Company's capital structure.

Mr. Pollock recommends an equity ratio of 51.10 percent based on the average authorized equity ratio since 2012.[290] A review of the authorized equity ratios reported in Mr. Pollock's Exhibit___(JP-4), however, shows that the Company's 59.60 percent equity ratio is within the range of equity ratios authorized to other vertically integrated electric utilities and is consistent with the Company's most recently authorized equity ratio. Given FPL's specific operating risks and capital needs, I believe the Company's current capital structure is reasonable and Mr. Pollock's suggestion to rely on the average authorized equity ratio is misplaced.

VII. RESPONSE TO OPC WITNESS O'DONNELL

Q. Please summarize Mr. O'Donnell's recommendation regarding the Company's capital structure

A. Mr. O'Donnell recommends a capital structure of 46.93 percent long-term debt, 3.07 percent short-term debt, and 50.00 percent common equity. Mr. O'Donnell's recommendation is based on his review of other electric utility capital structures,

[290] Direct Testimony of Jeffry Pollock, at 32 and Exhibit___(JP-4).

authorized equity ratios reported by RRA, and the capital structure of NextEra Energy and its unregulated subsidiaries.[291]

Q. Do you agree with Mr. O'Donnell's recommended capital structure?

A. No I do not. As noted in my Direct Testimony, FPL is a separate corporate entity with its own capital structure and the Company's current capital structure is consistent with the range of capital structures in place at the operating utilities held by the proxy companies.[292] As discussed by Company witness Dewhurst, FPL has maintained a stable equity ratio over time, which has provided the financial support necessary to maintain FPL's credit rating and access to capital following severe storm damage and during turbulent economic conditions. As discussed below, adding debt to the capital structure (as Mr. O'Donnell recommends) increases financial risk and, therefore, the Cost of Equity.

Q. How does the capital structure affect the Cost of Equity?

A. In the practice of finance, we often speak of two general categories of risk: business risk and financial risk. Business risk generally includes operating, market, regulatory, and competitive uncertainties, whereas financial risk is associated with additional levels of debt in the capital structure (often referred to as "financial leverage"). As the degree of financial leverage increases, the risk of financial distress (*i.e.,* the risk of not meeting financial obligations as they become due) also increases. In essence, even if two firms face the same business risks, the

[291] Direct Testimony of Kevin W. O'Donnell, at 15, 21.
[292] Direct Testimony of Robert B. Hevert, at 67.

company with higher levels of debt in its capital structure is likely to have higher total risk and, therefore, higher costs of both debt and equity.

Business and financial risk are related in that financial leverage has the effect of concentrating business risk on equity investors. By way of example, if a firm were capitalized with 100.00 percent common equity, there would be no financial risk and individual equity holders would hold *pro rata* shares of business risk. If the firm were capitalized with 60.00 percent equity and 40.00 percent debt, the equity investors would continue to bear residual business risk, even though they represent only 60.00 percent of the capital structure. As Brigham and Gapenski point out, "…the use of debt, or financial leverage, concentrates the firm's business risk on its stockholders."[293]

It is also important to recognize both the complexity and the dynamic nature of the relationship between capital structure, financial integrity, cost of capital and maintaining ongoing access to capital at reasonable costs. In particular, financing costs go beyond coupon rates, and any measure of an "optimal" capital structure must consider the numerous objectives and constraints associated with financing decisions. In my practical experience raising capital for a publicly traded utility, I can say firsthand that capital structure "optimization" is an extremely complex notion. Simply reviewing holding company or authorized equity ratios without

[293] Eugene F. Brigham, Louis C. Gapenski, Financial Management, Theory and Practice, 1994, The Dryden Press, at 528.

considering differences in situations, constraints, or objectives is an overly simplistic approach that is likely to lead to flawed conclusions.

Q. Please describe your review of FPL's capital structure relative to industry practice.

A. In Exhibit RBH-10, I calculated the average capital structure for each of the utility operating companies held by the proxy companies over the most recent eight fiscal quarters (ending in the third calendar quarter of 2015). I have updated that analysis in Exhibit RBH-17 using the Combined Proxy Group. As that Exhibit demonstrates, for the period ending in the first quarter of 2016 the proxy group companies' average common equity ratios ranged from 45.95 percent to 61.00 percent. Based on that updated review, FPL's equity ratio remains within the range of those in place at the operating utilities of the proxy companies. Although this comparison is not specific to FPL, it does recognize that utility operating companies must finance long-lived assets, and must access capital regardless of market conditions. It also indicates that the Company's equity ratio is within the range of those in place at other vertically integrated electric utilities.

Q. Are there implications of increasing the debt component and reducing the common equity component of FPL's capital structure?

A. Yes, there are. Based on criteria established by Standard and Poor's ("S&P"), a credit rating reflects the combination of the company's "Business Risk" rating and its "Financial Risk" rating. With regard to business risk, Standard & Poor's ("S&P") has noted that:

> The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk. Each of the other four factors we examine--markets, operations, competitiveness, and management--can affect the quality of the regulation a utility experiences, but we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most.[294]

Similarly, Moody's considers the regulatory structure to be so important that 50.00 percent of the factors that weigh in a ratings determination are related to the nature of regulation.[295] Among the factors considered by Moody's in assessing the regulatory framework are the predictability and consistency of regulatory actions:

> As the revenues set by the regulator are a primary component of a utility's cash flow, the utility's ability to obtain predictable and supportive treatment within its regulatory framework is one of the most significant factors in assessing a utility's credit quality. The regulatory framework generally provides more certainty around a utility's cash flow and typically allows the company to operate

[294] Standard & Poor's, *Utilities: Assessing U.S. Utility Regulatory Environments*, updated November 15, 2011.

[295] Moody's Investors Service, Rating Methodology; Regulated Gas and Electric Utilities, at 6 (Dec. 23, 2013).

> with significantly less cushion in its cash flow metrics than comparably rated companies in other industrial sectors.
>
> ***
>
> In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly.[296]

A decision by the Commission to increase FPL's debt ratio (*i.e.*, increase FPL's financial leverage) therefore could adversely affect investors' perception of the regulatory environment in Florida.

Q. Please explain your concern with Mr. O'Donnell's recommendation relative to the financial community's view of Florida regulation.

A. As discussed in my response to Mr. Chriss, Florida is considered to be a credit-supportive jurisdiction. Any decrease in the perception of regulatory supportiveness in Florida may increase investors' assessment of FPL's regulatory risk (and therefore its business risk and Business Risk rating), increasing FPL's cost of capital. As noted earlier, Moody's considers the regulatory structure to be so important that 50.00 percent of the factors that weigh in a ratings determination are related to the nature of regulation.

As also discussed in Mr. Dewhurt's rebuttal testimony, if the Commission were to adopt Mr. O'Donnell's recommendation, it would represent a departure from

[296] Moody's Investors Service, Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, at 2 (June 18, 2010).

recent precedent. In light of Moody's focus on "predictable and supportive treatment," I strongly disagree with Mr. O'Donnell that his recommendation somehow would not have any impact on how credit rating agencies view FPL.[297] Such a dramatic change by the Commission from previous decisions would create an immediate and lasting concern for investors of the supportiveness of the regulation in Florida.

Q. What is your conclusion regarding the appropriate capital structure for FPL?

A. It is important for FPL's capital structure to reflect the Company's risks, and to provide sufficient financial support to maintain liquidity and access to capital. Considering that the proxy company average equity ratios range from 45.95 percent to 61.00 percent, I believe that FPL's 59.60 percent common equity ratio is reasonable. Increasing FPL's debt leverage would increase its Cost of Equity, and potentially reduce investor confidence in the regulatory support for its operations and increase its financial risk. I believe it is likely the increased financial and regulatory risk would increase investors' required returns.

[297] *See*, Direct Testimony of Kevin W. O'Donnell, at 25-26.

VIII. RESPONSE TO OPC WITNESS LAWTON

Q. Please summarize Mr. Lawton's testimony regarding the supportiveness of Dr. Woolridge's ROE recommendation and Mr. O'Donnell's capital structure recommendation for FPL's financial integrity.

A. Mr. Lawton suggests that Dr. Woolridge's 8.75 percent ROE recommendation and Mr. O'Donnell's 50.00 equity / 50.00 percent debt capitalization recommendation are sufficient to maintain FPL's financial integrity.[298] To support his position, Mr. Lawton notes that he reviewed credit rating agency commentary, and determined that FPL's credit quality is considered "strong," and "not threatened or under significant pressure of a downgrade."[299] Mr. Lawton also performs a *pro forma* analysis of certain financial metrics (including Cash From Operations to Interest, Cash From Operations to Debt, and Debt to Capital) to support his position and concludes that the results "indicate strong financial metrics, supporting FPL's current bond rating."[300]

Q. How do ratings agencies' view the use of credit metrics in ratings determinations?

A. Ratings agencies provide benchmark guidelines that associate credit metric ranges with different credit ratings, but credit ratings are not determined by mechanical application of financial ratios to a rating matrix. For example, On November 30, 2007, S&P released a statement announcing that electric, gas, and water utility

298 Direct Testimony of Daniel J. Lawton, at 30.
299 *Ibid.*, at 24.
300 *Ibid.*, at 26.

ratings would be "categorized under the business risk/financial risk matrix used by the Corporate Ratings group." [301] S&P also provided matrices of business and financial risk, based on "Financial Risk Indicative Ratios": FFO/Debt; FFO/Interest; and Total Debt/Capital. In that announcement, S&P noted that:

> …even after we assign a company business risk and financial risk, the committee does not arrive by rote at a rating based on the matrix. The matrix is a guide - - it is not intended to convey precision in the ratings process or reduce the decision to plotting intersections on a graph. Many small positives and negatives that affect credit quality can lead a committee to a different conclusion than what is indicated in the matrix.[302]

On May 27, 2009, S&P expanded its matrix, and noted the relative significance of credit metrics to the rating process:

> The rating matrix indicative outcomes are what we typically observe – but are not meant to be precise indications of guarantees of future rating opinions. Positive and negative nuances in our analysis may lead to a notch higher or lower than the outcomes indicated in the various cells of the matrix.

[301] Standard & Poor's Ratings Services, *U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix*, Nov. 30, 2007, at 2 – 3.

[302] *Ibid.*, at 3.

> Moreover, our assessment of financial risk is not as simplistic as looking at a few ratios. [303]

Later, on September 18, 2012, S&P further expanded its matrix, confirming that "[s]till, it is essential to realize that the financial benchmarks are guidelines, neither gospel nor guarantees."[304]

It is clear, therefore, that credit metrics are not relied on in a rote fashion, nor are individual metrics viewed in isolation, to the exclusion of other information. Rather, those reviews encompass broad assessments of business and financial risk, including factors that are extraneous to the standalone, mathematically derived financial metrics of the regulated utility, and which are often based on qualitative, not entirely quantitative, discussions with management.

It also should be remembered that metrics used by Mr. Lawton, (*i.e.*, Cash Flow to Interest, Cash Flow to Debt, and Debt to Capital ratios) are derived from financial statements, including the Income Statement, Balance Sheet and Cash Flow Statement. For regulated utilities, all three are influenced by the overall rate of return allowed by regulatory commissions, which is reflected in the revenue requirement. The metrics therefore are a result of the regulatory process, *i.e.*, the overall rate of return, which in turn is a function of the capital structure (debt and

[303] Standard & Poor's Ratings Services, *Criteria Methodology: Business Risk/Financial Risk Matrix Expanded*, May 27, 2009, at 4-5.

[304] Standard & Poor's Ratings Services, *Methodology: Business Risk/Financial Risk Matrix Expanded*, September 18, 2012, at 4.

equity ratios), debt cost rate and the allowed ROE. It is not the other way around. To set a component of the overall rate of return, such as the ROE and equity ratio, based on *pro forma* credit metrics therefore is a circular exercise, and one that in my experience is atypical of the regulatory process.

Assessing recommended equity ratios and ROEs on the basis of *pro forma* credit metrics therefore should be done with the explicit understanding that other, often qualitative factors weigh heavily in ratings determinations. Like so many other aspects of corporate finance, ratings determinations are an empirical, but not an entirely mathematical exercise. Because so many other factors are considered, a focused review of *pro forma* metrics is the type of partial analysis that practitioners avoid.

Q. Please describe Mr. Lawton's *pro forma* financial metric analysis.

A. Alternately assuming FPL and OPC's proposed ROE and capital structures, Mr. Lawton calculates the following ratios: Cash From Operation to Debt (CFO/Debt), Cash From Operations to Interest (CFO/Interest), and Debt to Total Capital (Debt/Capital).[305] Mr. Lawton then compares the results of those ratios to Moody's benchmark guidelines for "A" and "Baa" rated bonds.

[305] Direct Testimony of Daniel J. Lawton, Exhibit___(DJL-5). Mr. Lawton also varied certain revenue requirement assumptions based on the Company's and OPC's position, including rate base and depreciation & amortization.

Q. Does Mr. Lawton's analysis support his position that OPC's recommended 8.75 percent ROE and 50.00 equity / 50.00 percent debt capital structure would continue to support the Company's current bond rating?

A. No, I do not believe so. As Mr. Lawton notes, Mr. O'Donnell's proposed 50.00 percent equity ratio falls below Moody's benchmark for an A rating (55.00 percent to 65.00 percent equity).[306] In addition, Mr. Lawton's *pro forma* financial metric analysis shows OPC's ROE and capital structure recommendations would result in a 22.52 percent CFO/Debt ratio, which is at the bottom end of the 22.00 percent to 30.00 percent benchmark guideline for an "A" rating.[307] As noted above, although a given financial metric may be within a given benchmark range, other factors may affect the rating agency's actual rating assessment.

With regard to the CFO/Interest financial metric, I believe relying on Mr. Lawton's *pro forma* results to assess the credit supportiveness of any specific ROE or equity ratio is misplaced. In particular, I examined the robustness of using that measure as a threshold benchmark by recreating the analysis provided in Schedule (DJL-5) and testing variations in the assumed ROE. As shown in Table 7 (below) relying on the assumptions in the scenario in column "A" of Mr. Lawton's Schedule (DJL-5), including the Company's existing equity ratio of 59.60 percent, but adjusting the ROE to 0.00 percent (i.e., no return on equity) still produces a CFO/Interest in the "A" rating category. The assumption that the

306 Direct Testimony of Daniel J. Lawton, at 30. A 35.00 percent to 45.00 percent Debt/Capital ratio implies a 55.00 percent to 65.00 percent equity ratio.

307 *Ibid.*, Exhibit___(DJL-5).

Company could maintain an A-rating with a 0.00 percent allowed return on equity is clearly misplaced, and certainly does not provide a reasonable benchmark for determining an equity ratio that satisfies the *Hope* & *Bluefield* standards acknowledged by Mr. Lawton.[308] Assuming the scenario in column "B" of Mr. Lawton's schedule, including a 50.00 percent equity ratio, but adjusting the ROE to 6.25 percent also produces a CFO/Interest ratio in the A-rating category. Consequently, the CFO/Interest metric does not appear to be a good measure for assessing the reasonableness of ROE or capital structure proposals.

Table 7: CFO/Interest – Variations in Mr. Lawton's Analysis[309]

	Assumptions		**Moody's Guideline (4.5x – 6.0x = A rating)**	
Scenario	**ROE**	**Equity Ratio**	**CFO/ Interest**	**Implied Rating**
Scenario A – Original	11.50%	59.60%	8.6x	Aaa
Scenario A – with 0.00% ROE	**0.00%**	59.60%	4.8x	A
Scenario B – Original	8.75%	50.00%	5.1x	A
Scenario B – with 6.25% ROE	**6.25%**	50.00%	4.5x	A

I also note a similar test of the robustness of Mr. Lawton's CFO/Debt analysis produces similarly unlikely results. For example, assuming OPC's recommendations as provided in Schedule (DJL-5), but adjusting the ROE to negative 0.76 percent would still achieve a CFO/Debt ratio sufficient for a Baa rating (13.00 percent).

308 *Ibid.*, at 24.
309 See also, Exhibit RBH-44.

Lastly, I note that Moody's April 2015 Credit Opinion of FPL stated that a downgrade of the Company's rating would be considered "if there are significant cost disallowances or other changes to Florida's credit-supportive regulatory and cost recovery framework, or if there is a sustained decline in cash flow coverage metrics, including CFO Pre-WC-to-debt below 25%, or an increase in debt-to-capitalization above the 40% range." Mr. Lawton's *pro forma* analysis indicates OPC's recommendations result in financial metrics below the thresholds Moody's notes would trigger consideration of a downgrade.

Q. Are there other considerations that should be taken in to account when determining the credit supportiveness of OPC's ROE and capital structure recommendations?

A. Yes. As noted above, financial metrics are only one factor rating agencies take into consideration when assessing a company's credit rating. The assessment of the regulatory environment is another important factor. In that regard, Moody's notes that the regulatory "framework in which a regulated utility operates is typically one of its most significant credit considerations. The regulatory structure and its general framework is a primary consideration that differentiates the industry from most other corporate sectors."[310] Moody's further explains:

> As the revenues set by the regulator are a primary component of a utility's cash flow, the utility's ability to obtain predictable and supportive treatment within its

[310] *See* Moody's Investors Service, *Special Comment: Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities*, June 18, 2010, at 1.

> regulatory framework is one of the most significant factors in assessing a utility's credit quality. The regulatory framework generally provides more certainty around a utility's cash flow and typically allows the company to operate with significantly less cushion in its cash flow metrics than comparably rated companies in other industrial sectors. In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly.[311]

I believe the effect of (1) authorizing an equity ratio significantly below the ratio long used by FPL to successfully finance its operations (through a range of market and operating conditions); and (2) authorizing an ROE that is not only 175 basis points below the Company's currently authorized ROE, but is also below the lowest ROE authorized for a vertically integrated electric utility in at least the last 30-years, would be to reduce investors' assessment of the regulatory supportiveness for FPL. A perception of unsupportiveness, or regulatory inconsistency, could linger long into the future and affect FPL's ability to access the capital markets on favorable terms, especially during times of market unrest or operational strain from extensive weather related damage.

[311] *Ibid.*, at 2.

IX. UPDATED AND REVISED ANALYSES

Q. Have you updated the analyses presented in your Direct Testimony?

A. Yes. I have updated the Constant Growth DCF, Multi-Stage DCF, CAPM, and Risk Premium analyses presented in my Direct Testimony with data as of June 30, 2016. As noted in my response to Dr. Woolridge, I performed the analyses for a Combined Proxy Group comprised of the companies included by the opposing ROE witnesses and me in our respective proxy groups.

Q. Please summarize your updated CAPM analysis.

A. I have continued to use the same inputs used in my Direct Testimony, updated through June 30, 2016. For the risk-free rate, I continue to refer alternately to (1) the 30-day average of the 30-year Treasury yield; and (2) a consensus forecast of the average 30-year Treasury yield for 2017 and 2020. Likewise, I continue to rely on published Beta coefficients from Bloomberg and Value Line, and the *ex-ante* market risk premia described in my Direct Testimony (*i.e.*, the expected return on the S&P 500 Index less the current 30-year Treasury yield).

Q. What are your updated CAPM results?

A. As shown in Table 8 (below; see also, Exhibit RBH-11), based upon updated market information, my CAPM analyses produce a range of ROE estimates from 8.97 percent to 12.64 percent.

Table 8: CAPM Results

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.50%)	8.97%	9.29%
Blue Chip Forecast 2017 (3.40%)	9.86%	10.19%
Blue Chip Forecast 2020 (4.40%)	10.86%	11.19%
Value Line Beta Coefficient		
Current 30-Year Treasury (2.50%)	10.35%	10.75%
Blue Chip Forecast 2017 (3.40%)	11.25%	11.64%
Blue Chip Forecast 2020 (4.40%)	12.25%	12.64%

Q. Please summarize your updated Risk Premium analysis.

A. My updated Risk Premium analysis includes authorized ROEs as reported by Regulatory Research Associates through June 30, 2016. For the purpose of calculating the expected risk premium and ROE, I have used the current and projected 30-year Treasury yield. As shown in Table 9 (below; see also, Exhibit RBH-12), my updated results range from 10.04 percent to 10.37 percent.

Table 9: Bond Yield Plus Risk Premium Results

Assumed Treasury Yield	Implied ROE
Current 30-Year Treasury (2.50%)	10.04%
Blue Chip Forecast 2017 (3.40%)	10.08%
Blue Chip Forecast 2020 (4.40%)	10.37%

Q. Please summarize your updated Constant Growth DCF and Multi-Stage DCF analyses.

A. I have continued to use projected earnings growth rates from Zacks, First Call, and Value Line in developing my Constant Growth and Multi-Stage DCF models. The results are shown in Table 10 (below); *see also*, Exhibit RBH-13 to Exhibit RBH-14.

Table 10: Discounted Cash Flow Model Results

	Low Growth Rate	**Mean Growth Rate**	**High Growth Rate**
Mean Constant Growth DCF Results			
30-Day Average	8.32%	8.91%	9.41%
90-Day Average	8.41%	8.99%	9.49%
180-Day Average	8.60%	9.19%	9.69%
Mean Multi-Stage DCF Results			
	Low Growth Rate	**Mean Growth Rate**	**High Growth Rate**
30-Day Average	9.03%	9.16%	9.28%
90-Day Average	9.12%	9.26%	9.38%
180-Day Average	9.33%	9.48%	9.61%
Mean Multi-Stage DCF Results – Terminal P/E at 20.86			
	Low Growth Rate	**Mean Growth Rate**	**High Growth Rate**
30-Day Average	9.44%	9.79%	10.09%
90-Day Average	9.67%	10.03%	10.32%
180-Day Average	10.18%	10.54%	10.84%

X. SUMMARY AND CONCLUSION

Q. What are your overall conclusions and recommendations?

A. Based on the analyses discussed throughout my Rebuttal Testimony, I conclude that my recommended range of 10.50 percent to 11.50 percent, and within that range, 11.00 percent, remains a reasonable and appropriate estimate of FPL's Cost of Equity. The results of the updated DCF, CAPM, and Bond Yield Plus Risk Premium analyses, along with my analyses of capital market data, authorized returns in other regulatory jurisdictions, and assessment of rating agency concerns and criteria support the reasonableness of my range of ROE estimates and my recommendation. Furthermore, I do not support certain intervenors' recommendation to authorize a hypothetical capital structure below the Company's actual capital structure.

As discussed above, the period over which my analyses were performed included market data that were highly unusual and inconsistent with the DCF model's fundamental assumptions. In my view, therefore, Risk Premium-based methods should be given more weight than the DCF-based approaches. Doing so supports my recommended range of 10.50 percent to 11.50 percent, and my ROE recommendation of 11.00 percent.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Capital Asset Pricing Model Results
Bloomberg and Value Line Derived Market Risk Premium

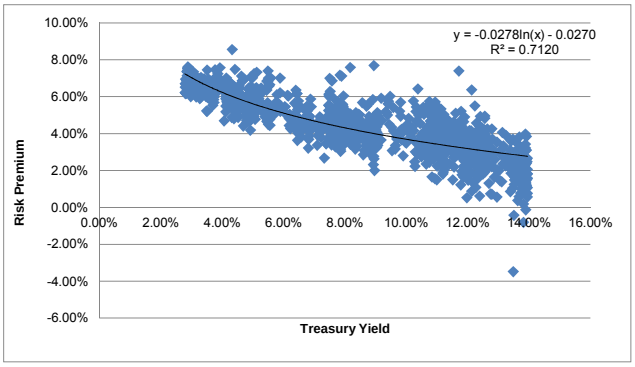
	[1]	[2]	[3]	[4]	[5]	[6]
			Ex-Ante Market Risk Premium		CAPM Result	
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP BLOOMBERG BETA COEFFICIENT						
Current 30-Year Treasury (30-day average) [7]	2.50%	0.610	10.59%	11.13%	8.97%	9.29%
Blue Chip Financial Forecast 2017 Projection [8]	3.40%	0.610	10.59%	11.13%	9.86%	10.19%
Blue Chip Financial Forecast 2020 Projection [9]	4.40%	0.610	10.59%	11.13%	10.86%	11.19%
Mean					9.90%	10.23%

			Ex-Ante Market Risk Premium		CAPM Result	
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP VALUE LINE AVERAGE BETA COEFFICIENT						
Current 30-Year Treasury (30-day average) [7]	2.50%	0.741	10.59%	11.13%	10.35%	10.75%
Blue Chip Financial Forecast 2017 Projection [8]	3.40%	0.741	10.59%	11.13%	11.25%	11.64%
Blue Chip Financial Forecast 2020 Projection [9]	4.40%	0.741	10.59%	11.13%	12.25%	12.64%
Mean					11.28%	11.68%

Notes:
[1] S*ee Notes [7] and [8]*
[2] Source: Schedule (RBH)-16
[3] Source: Schedule (RBH)-15
[4] Source: Schedule (RBH)-15
[5] Equals Col. [1] + (Col. [2] x Col. [3])
[6] Equals Col. [1] + (Col. [2] x Col. [4])
[7] Source: Bloomberg Professional
[8] Source: Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 2. Forecast for Q3 2017.
[9] Source: Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 14.

Bond Yield Plus Risk Premium

[1]	[2]	[3]	[4]	[5]
Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity
-2.70%	-2.78%			
Current 30-Year Treasury		2.50%	7.53%	10.04%
Blue Chip Financial Forecast 2017 Projection		3.40%	6.68%	10.08%
Blue Chip Financial Forecast 2020 Projection		4.40%	5.97%	10.37%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
Projected = Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 2. Forecast for Q3 2017.
Projected = Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 14.
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: SNL Financial
[7] Source: SNL Financial
[8] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/1/1980	14.50%	9.36%	5.14%
1/7/1980	14.39%	9.38%	5.01%
1/9/1980	15.00%	9.40%	5.60%
1/14/1980	15.17%	9.42%	5.75%
1/17/1980	13.93%	9.44%	4.49%
1/23/1980	15.50%	9.47%	6.03%
1/30/1980	13.86%	9.52%	4.34%
1/31/1980	12.61%	9.53%	3.08%
2/6/1980	13.71%	9.58%	4.13%
2/13/1980	12.80%	9.63%	3.17%
2/14/1980	13.00%	9.65%	3.35%
2/19/1980	13.50%	9.68%	3.82%
2/27/1980	13.75%	9.78%	3.97%
2/29/1980	13.75%	9.81%	3.94%
2/29/1980	14.00%	9.81%	4.19%
2/29/1980	14.77%	9.81%	4.96%
3/7/1980	12.70%	9.89%	2.81%
3/14/1980	13.50%	9.97%	3.53%
3/26/1980	14.16%	10.10%	4.06%
3/27/1980	14.24%	10.12%	4.12%
3/28/1980	14.50%	10.13%	4.37%
4/11/1980	12.75%	10.27%	2.48%
4/14/1980	13.85%	10.29%	3.56%
4/16/1980	15.50%	10.31%	5.19%
4/22/1980	13.25%	10.35%	2.90%
4/22/1980	13.90%	10.35%	3.55%
4/24/1980	16.80%	10.38%	6.43%
4/29/1980	15.50%	10.41%	5.09%
5/6/1980	13.70%	10.45%	3.25%
5/7/1980	15.00%	10.45%	4.55%
5/8/1980	13.75%	10.46%	3.29%
5/9/1980	14.35%	10.47%	3.88%
5/13/1980	13.60%	10.48%	3.12%

5/15/1980	13.25%	10.49%	2.76%
5/19/1980	13.75%	10.51%	3.24%
5/27/1980	13.62%	10.54%	3.08%
5/27/1980	14.60%	10.54%	4.06%
5/29/1980	16.00%	10.56%	5.44%
5/30/1980	13.80%	10.56%	3.24%
6/2/1980	15.63%	10.57%	5.06%
6/9/1980	15.90%	10.60%	5.30%
6/10/1980	13.78%	10.60%	3.18%
6/12/1980	14.25%	10.61%	3.64%
6/19/1980	13.40%	10.62%	2.78%
6/30/1980	13.00%	10.65%	2.35%
6/30/1980	13.40%	10.65%	2.75%
7/9/1980	14.75%	10.67%	4.08%
7/10/1980	15.00%	10.68%	4.32%
7/15/1980	15.80%	10.70%	5.10%
7/18/1980	13.80%	10.71%	3.09%
7/22/1980	14.10%	10.72%	3.38%
7/24/1980	15.00%	10.73%	4.27%
7/25/1980	13.48%	10.73%	2.75%
7/31/1980	14.58%	10.75%	3.83%
8/8/1980	13.50%	10.78%	2.72%
8/8/1980	14.00%	10.78%	3.22%
8/8/1980	15.45%	10.78%	4.67%
8/11/1980	14.85%	10.78%	4.07%
8/14/1980	14.00%	10.79%	3.21%
8/14/1980	16.25%	10.79%	5.46%
8/25/1980	13.75%	10.82%	2.93%
8/27/1980	13.80%	10.83%	2.97%
8/29/1980	12.50%	10.84%	1.66%
9/15/1980	13.50%	10.88%	2.62%
9/15/1980	13.93%	10.88%	3.05%
9/15/1980	15.80%	10.88%	4.92%
9/24/1980	12.50%	10.93%	1.57%
9/24/1980	15.00%	10.93%	4.07%
9/26/1980	13.75%	10.94%	2.81%
9/30/1980	14.10%	10.96%	3.14%
9/30/1980	14.20%	10.96%	3.24%
10/1/1980	13.90%	10.97%	2.93%
10/3/1980	15.50%	10.98%	4.52%
10/7/1980	12.50%	10.99%	1.51%
10/9/1980	13.25%	11.00%	2.25%
10/9/1980	14.50%	11.00%	3.50%
10/9/1980	14.50%	11.00%	3.50%
10/16/1980	16.10%	11.02%	5.08%
10/17/1980	14.50%	11.03%	3.47%
10/31/1980	13.75%	11.11%	2.64%
10/31/1980	14.25%	11.11%	3.14%
11/4/1980	15.00%	11.12%	3.88%
11/5/1980	13.75%	11.12%	2.63%
11/5/1980	14.00%	11.12%	2.88%
11/8/1980	13.75%	11.14%	2.61%
11/10/1980	14.85%	11.15%	3.70%
11/17/1980	14.00%	11.18%	2.82%
11/18/1980	14.00%	11.19%	2.81%
11/19/1980	13.00%	11.19%	1.81%
11/24/1980	14.00%	11.21%	2.79%
11/26/1980	14.00%	11.21%	2.79%
12/8/1980	14.15%	11.22%	2.93%
12/8/1980	15.10%	11.22%	3.88%
12/9/1980	15.35%	11.22%	4.13%
12/12/1980	15.45%	11.23%	4.22%
12/17/1980	13.25%	11.23%	2.02%
12/18/1980	15.80%	11.23%	4.57%
12/19/1980	14.50%	11.23%	3.27%
12/19/1980	14.64%	11.23%	3.41%
12/22/1980	13.45%	11.23%	2.22%
12/22/1980	15.00%	11.23%	3.77%
12/30/1980	14.50%	11.22%	3.28%
12/30/1980	14.95%	11.22%	3.73%
12/31/1980	13.39%	11.22%	2.17%
1/2/1981	15.25%	11.22%	4.03%
1/7/1981	14.30%	11.21%	3.09%
1/19/1981	15.25%	11.20%	4.05%
1/23/1981	13.10%	11.20%	1.90%
1/23/1981	14.40%	11.20%	3.20%
1/26/1981	15.25%	11.20%	4.05%
1/27/1981	15.00%	11.21%	3.79%
1/31/1981	13.47%	11.22%	2.25%
2/3/1981	15.25%	11.23%	4.02%
2/5/1981	15.75%	11.25%	4.50%
2/11/1981	15.60%	11.28%	4.32%
2/20/1981	15.25%	11.33%	3.92%

3/11/1981	15.40%	11.49%	3.91%
3/12/1981	14.51%	11.50%	3.01%
3/12/1981	16.00%	11.50%	4.50%
3/13/1981	13.02%	11.52%	1.50%
3/18/1981	16.19%	11.55%	4.64%
3/19/1981	13.75%	11.56%	2.19%
3/23/1981	14.30%	11.58%	2.72%
3/25/1981	15.30%	11.60%	3.70%
4/1/1981	14.53%	11.68%	2.85%
4/3/1981	19.10%	11.71%	7.39%
4/9/1981	15.00%	11.78%	3.22%
4/9/1981	15.30%	11.78%	3.52%
4/9/1981	16.50%	11.78%	4.72%
4/9/1981	17.00%	11.78%	5.22%
4/10/1981	13.75%	11.80%	1.95%
4/13/1981	13.57%	11.82%	1.75%
4/15/1981	15.30%	11.85%	3.45%
4/16/1981	13.50%	11.87%	1.63%
4/17/1981	14.10%	11.87%	2.23%
4/21/1981	14.00%	11.90%	2.10%
4/21/1981	16.80%	11.90%	4.90%
4/24/1981	16.00%	11.95%	4.05%
4/27/1981	12.50%	11.97%	0.53%
4/27/1981	13.61%	11.97%	1.64%
4/29/1981	13.65%	12.00%	1.65%
4/30/1981	13.50%	12.02%	1.48%
5/4/1981	16.22%	12.05%	4.17%
5/5/1981	14.40%	12.07%	2.33%
5/7/1981	16.25%	12.11%	4.14%
5/7/1981	16.27%	12.11%	4.16%
5/8/1981	13.00%	12.13%	0.87%
5/8/1981	16.00%	12.13%	3.87%
5/12/1981	13.50%	12.16%	1.34%
5/15/1981	15.75%	12.22%	3.53%
5/18/1981	14.88%	12.23%	2.65%
5/20/1981	16.00%	12.26%	3.74%
5/21/1981	14.00%	12.27%	1.73%
5/26/1981	14.90%	12.30%	2.60%
5/27/1981	15.00%	12.31%	2.69%
5/29/1981	15.50%	12.34%	3.16%
6/1/1981	16.50%	12.35%	4.15%
6/3/1981	14.67%	12.37%	2.30%
6/5/1981	13.00%	12.39%	0.61%
6/10/1981	16.75%	12.42%	4.33%
6/17/1981	14.40%	12.46%	1.94%
6/18/1981	16.33%	12.47%	3.86%
6/25/1981	14.75%	12.51%	2.24%
6/26/1981	16.00%	12.52%	3.48%
6/30/1981	15.25%	12.54%	2.71%
7/1/1981	15.50%	12.56%	2.94%
7/1/1981	17.50%	12.56%	4.94%
7/10/1981	16.00%	12.62%	3.38%
7/14/1981	16.90%	12.64%	4.26%
7/15/1981	16.00%	12.65%	3.35%
7/17/1981	15.00%	12.67%	2.33%
7/20/1981	15.00%	12.68%	2.32%
7/21/1981	14.00%	12.69%	1.31%
7/28/1981	13.48%	12.74%	0.74%
7/31/1981	13.50%	12.78%	0.72%
7/31/1981	15.00%	12.78%	2.22%
7/31/1981	16.00%	12.78%	3.22%
8/5/1981	15.71%	12.83%	2.88%
8/10/1981	14.50%	12.87%	1.63%
8/11/1981	15.00%	12.88%	2.12%
8/20/1981	13.50%	12.95%	0.55%
8/20/1981	16.50%	12.95%	3.55%
8/24/1981	15.00%	12.97%	2.03%
8/28/1981	15.00%	13.01%	1.99%
9/3/1981	14.50%	13.05%	1.45%
9/10/1981	14.50%	13.11%	1.39%
9/11/1981	16.00%	13.12%	2.88%
9/16/1981	16.00%	13.15%	2.85%
9/17/1981	16.50%	13.16%	3.34%
9/23/1981	15.85%	13.20%	2.65%
9/28/1981	15.50%	13.23%	2.27%
10/9/1981	15.75%	13.33%	2.42%
10/15/1981	16.25%	13.37%	2.88%
10/16/1981	15.50%	13.38%	2.12%
10/16/1981	16.50%	13.38%	3.12%
10/19/1981	14.25%	13.39%	0.86%
10/20/1981	15.25%	13.41%	1.84%
10/20/1981	17.00%	13.41%	3.59%
10/23/1981	16.00%	13.45%	2.55%

10/27/1981	10.00%	13.48%	-3.48%
10/29/1981	14.75%	13.51%	1.24%
10/29/1981	16.50%	13.51%	2.99%
11/3/1981	15.17%	13.53%	1.64%
11/5/1981	16.60%	13.55%	3.05%
11/6/1981	15.17%	13.56%	1.61%
11/24/1981	15.50%	13.61%	1.89%
11/25/1981	15.25%	13.61%	1.64%
11/25/1981	15.35%	13.61%	1.74%
11/25/1981	16.10%	13.61%	2.49%
11/25/1981	16.10%	13.61%	2.49%
12/1/1981	15.70%	13.61%	2.09%
12/1/1981	16.00%	13.61%	2.39%
12/1/1981	16.49%	13.61%	2.88%
12/1/1981	16.50%	13.61%	2.89%
12/4/1981	16.00%	13.61%	2.39%
12/11/1981	16.25%	13.63%	2.62%
12/14/1981	14.00%	13.63%	0.37%
12/15/1981	15.81%	13.63%	2.18%
12/15/1981	16.00%	13.63%	2.37%
12/16/1981	15.25%	13.63%	1.62%
12/17/1981	16.50%	13.63%	2.87%
12/18/1981	15.45%	13.63%	1.82%
12/30/1981	14.25%	13.67%	0.58%
12/30/1981	16.00%	13.67%	2.33%
12/30/1981	16.25%	13.67%	2.58%
12/31/1981	16.15%	13.67%	2.48%
1/4/1982	15.50%	13.67%	1.83%
1/11/1982	14.50%	13.72%	0.78%
1/11/1982	17.00%	13.72%	3.28%
1/13/1982	14.75%	13.74%	1.01%
1/14/1982	15.75%	13.75%	2.00%
1/15/1982	15.00%	13.76%	1.24%
1/15/1982	16.50%	13.76%	2.74%
1/22/1982	16.25%	13.79%	2.46%
1/27/1982	16.84%	13.81%	3.03%
1/28/1982	13.00%	13.81%	-0.81%
1/29/1982	15.50%	13.82%	1.68%
2/1/1982	15.85%	13.82%	2.03%
2/3/1982	16.44%	13.84%	2.60%
2/8/1982	15.50%	13.86%	1.64%
2/11/1982	16.00%	13.88%	2.12%
2/11/1982	16.20%	13.88%	2.32%
2/17/1982	15.00%	13.89%	1.11%
2/19/1982	15.17%	13.89%	1.28%
2/26/1982	15.25%	13.89%	1.36%
3/1/1982	15.03%	13.89%	1.14%
3/1/1982	16.00%	13.89%	2.11%
3/3/1982	15.00%	13.88%	1.12%
3/8/1982	17.10%	13.88%	3.22%
3/12/1982	16.25%	13.88%	2.37%
3/17/1982	17.30%	13.88%	3.42%
3/22/1982	15.10%	13.89%	1.21%
3/27/1982	15.40%	13.89%	1.51%
3/30/1982	15.50%	13.90%	1.60%
3/31/1982	17.00%	13.91%	3.09%
4/1/1982	14.70%	13.91%	0.79%
4/1/1982	16.50%	13.91%	2.59%
4/2/1982	15.50%	13.91%	1.59%
4/5/1982	15.50%	13.92%	1.58%
4/8/1982	16.40%	13.93%	2.47%
4/13/1982	14.50%	13.94%	0.56%
4/23/1982	15.75%	13.94%	1.81%
4/27/1982	15.00%	13.94%	1.06%
4/28/1982	15.75%	13.94%	1.81%
4/30/1982	14.70%	13.94%	0.76%
4/30/1982	15.50%	13.94%	1.56%
5/3/1982	16.60%	13.94%	2.66%
5/4/1982	16.00%	13.94%	2.06%
5/14/1982	15.50%	13.92%	1.58%
5/18/1982	15.42%	13.92%	1.50%
5/19/1982	14.69%	13.92%	0.77%
5/20/1982	15.00%	13.91%	1.09%
5/20/1982	15.10%	13.91%	1.19%
5/20/1982	15.50%	13.91%	1.59%
5/20/1982	16.30%	13.91%	2.39%
5/21/1982	17.75%	13.91%	3.84%
5/27/1982	15.00%	13.89%	1.11%
5/28/1982	15.50%	13.89%	1.61%
5/28/1982	17.00%	13.89%	3.11%
6/1/1982	13.75%	13.89%	-0.14%
6/1/1982	16.60%	13.89%	2.71%
6/9/1982	17.86%	13.88%	3.98%

6/14/1982	15.75%	13.88%	1.87%
6/15/1982	14.85%	13.88%	0.97%
6/18/1982	15.50%	13.87%	1.63%
6/21/1982	14.90%	13.87%	1.03%
6/23/1982	16.00%	13.86%	2.14%
6/23/1982	16.17%	13.86%	2.31%
6/24/1982	14.85%	13.86%	0.99%
6/25/1982	14.70%	13.86%	0.84%
7/1/1982	16.00%	13.84%	2.16%
7/2/1982	15.62%	13.84%	1.78%
7/2/1982	17.00%	13.84%	3.16%
7/13/1982	14.00%	13.82%	0.18%
7/13/1982	16.80%	13.82%	2.98%
7/14/1982	15.76%	13.82%	1.94%
7/14/1982	16.02%	13.82%	2.20%
7/19/1982	16.50%	13.80%	2.70%
7/22/1982	14.50%	13.77%	0.73%
7/22/1982	17.00%	13.77%	3.23%
7/27/1982	16.75%	13.75%	3.00%
7/29/1982	16.50%	13.74%	2.76%
8/11/1982	17.50%	13.68%	3.82%
8/18/1982	17.07%	13.63%	3.44%
8/20/1982	15.73%	13.60%	2.13%
8/25/1982	16.00%	13.57%	2.43%
8/26/1982	15.50%	13.56%	1.94%
8/30/1982	15.00%	13.55%	1.45%
9/3/1982	16.20%	13.53%	2.67%
9/8/1982	15.00%	13.52%	1.48%
9/15/1982	13.08%	13.50%	-0.42%
9/15/1982	16.25%	13.50%	2.75%
9/16/1982	16.00%	13.50%	2.50%
9/17/1982	15.25%	13.50%	1.75%
9/23/1982	17.17%	13.47%	3.70%
9/24/1982	14.50%	13.46%	1.04%
9/27/1982	15.25%	13.46%	1.79%
10/1/1982	15.50%	13.42%	2.08%
10/15/1982	15.90%	13.32%	2.58%
10/22/1982	15.75%	13.24%	2.51%
10/22/1982	17.15%	13.24%	3.91%
10/29/1982	15.54%	13.16%	2.38%
11/1/1982	15.50%	13.15%	2.35%
11/3/1982	17.20%	13.13%	4.07%
11/4/1982	16.25%	13.11%	3.14%
11/5/1982	16.20%	13.09%	3.11%
11/9/1982	16.00%	13.05%	2.95%
11/23/1982	15.50%	12.89%	2.61%
11/23/1982	15.85%	12.89%	2.96%
11/30/1982	16.50%	12.81%	3.69%
12/1/1982	17.04%	12.79%	4.25%
12/6/1982	15.00%	12.73%	2.27%
12/6/1982	16.35%	12.73%	3.62%
12/10/1982	15.50%	12.66%	2.84%
12/13/1982	16.00%	12.65%	3.35%
12/14/1982	15.30%	12.63%	2.67%
12/14/1982	16.40%	12.63%	3.77%
12/20/1982	16.00%	12.57%	3.43%
12/21/1982	14.75%	12.56%	2.19%
12/21/1982	15.85%	12.56%	3.29%
12/22/1982	16.25%	12.54%	3.71%
12/22/1982	16.58%	12.54%	4.04%
12/22/1982	16.75%	12.54%	4.21%
12/29/1982	14.90%	12.48%	2.42%
12/29/1982	16.25%	12.48%	3.77%
12/30/1982	16.00%	12.47%	3.53%
12/30/1982	16.35%	12.47%	3.88%
12/30/1982	16.77%	12.47%	4.30%
1/5/1983	17.33%	12.40%	4.93%
1/11/1983	15.90%	12.34%	3.56%
1/12/1983	14.63%	12.33%	2.30%
1/12/1983	15.50%	12.33%	3.17%
1/20/1983	17.75%	12.24%	5.51%
1/21/1983	15.00%	12.22%	2.78%
1/24/1983	14.50%	12.21%	2.29%
1/24/1983	15.50%	12.21%	3.29%
1/25/1983	15.85%	12.19%	3.66%
1/27/1983	16.14%	12.17%	3.97%
2/1/1983	18.50%	12.13%	6.37%
2/4/1983	14.00%	12.10%	1.90%
2/10/1983	15.00%	12.06%	2.94%
2/21/1983	15.50%	11.98%	3.52%
2/22/1983	15.50%	11.97%	3.53%
2/23/1983	15.10%	11.96%	3.14%
2/23/1983	16.00%	11.96%	4.04%

3/2/1983	15.25%	11.89%	3.36%
3/9/1983	15.20%	11.82%	3.38%
3/15/1983	13.00%	11.77%	1.23%
3/18/1983	15.25%	11.73%	3.52%
3/23/1983	15.40%	11.69%	3.71%
3/24/1983	15.00%	11.67%	3.33%
3/29/1983	15.50%	11.63%	3.87%
3/30/1983	16.71%	11.61%	5.10%
3/31/1983	15.00%	11.59%	3.41%
4/4/1983	15.20%	11.58%	3.62%
4/8/1983	15.50%	11.51%	3.99%
4/11/1983	14.81%	11.49%	3.32%
4/19/1983	14.50%	11.38%	3.12%
4/20/1983	16.00%	11.36%	4.64%
4/29/1983	16.00%	11.24%	4.76%
5/1/1983	14.50%	11.24%	3.26%
5/9/1983	15.50%	11.15%	4.35%
5/11/1983	16.46%	11.12%	5.34%
5/12/1983	14.14%	11.11%	3.03%
5/18/1983	15.00%	11.05%	3.95%
5/23/1983	14.90%	11.01%	3.89%
5/23/1983	15.50%	11.01%	4.49%
5/25/1983	15.50%	10.98%	4.52%
5/27/1983	15.00%	10.96%	4.04%
5/31/1983	14.00%	10.95%	3.05%
5/31/1983	15.50%	10.95%	4.55%
6/2/1983	14.50%	10.93%	3.57%
6/17/1983	15.03%	10.84%	4.19%
7/1/1983	14.80%	10.78%	4.02%
7/1/1983	14.90%	10.78%	4.12%
7/8/1983	16.25%	10.76%	5.49%
7/13/1983	13.20%	10.75%	2.45%
7/19/1983	15.00%	10.74%	4.26%
7/19/1983	15.10%	10.74%	4.36%
7/25/1983	16.25%	10.73%	5.52%
7/28/1983	15.90%	10.74%	5.16%
8/3/1983	16.34%	10.75%	5.59%
8/3/1983	16.50%	10.75%	5.75%
8/19/1983	15.00%	10.80%	4.20%
8/22/1983	15.50%	10.80%	4.70%
8/22/1983	16.40%	10.80%	5.60%
8/31/1983	14.75%	10.84%	3.91%
9/7/1983	15.00%	10.86%	4.14%
9/14/1983	15.78%	10.89%	4.89%
9/16/1983	15.00%	10.90%	4.10%
9/19/1983	14.50%	10.91%	3.59%
9/20/1983	16.50%	10.91%	5.59%
9/28/1983	14.50%	10.94%	3.56%
9/29/1983	15.50%	10.95%	4.55%
9/30/1983	15.25%	10.95%	4.30%
9/30/1983	16.15%	10.95%	5.20%
10/4/1983	14.80%	10.96%	3.84%
10/7/1983	16.00%	10.97%	5.03%
10/13/1983	15.52%	10.99%	4.53%
10/17/1983	15.50%	11.00%	4.50%
10/18/1983	14.50%	11.00%	3.50%
10/19/1983	16.25%	11.01%	5.24%
10/19/1983	16.50%	11.01%	5.49%
10/26/1983	15.00%	11.04%	3.96%
10/27/1983	15.20%	11.04%	4.16%
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2/1/1984	14.80%	11.38%	3.42%
2/6/1984	13.75%	11.40%	2.35%
2/6/1984	14.75%	11.40%	3.35%
2/9/1984	15.25%	11.42%	3.83%
2/15/1984	15.70%	11.44%	4.26%
2/20/1984	15.00%	11.46%	3.54%
2/20/1984	15.00%	11.46%	3.54%
2/22/1984	14.75%	11.47%	3.28%
2/28/1984	14.50%	11.51%	2.99%
3/2/1984	14.25%	11.54%	2.71%
3/20/1984	16.00%	11.64%	4.36%
3/23/1984	15.50%	11.67%	3.83%
3/26/1984	14.71%	11.68%	3.03%
4/2/1984	15.50%	11.71%	3.79%
4/6/1984	14.74%	11.75%	2.99%
4/11/1984	15.72%	11.78%	3.94%
4/17/1984	15.00%	11.81%	3.19%
4/18/1984	16.20%	11.82%	4.38%
4/25/1984	14.64%	11.85%	2.79%
4/30/1984	14.40%	11.87%	2.53%
5/16/1984	14.69%	11.98%	2.71%
5/16/1984	15.00%	11.98%	3.02%
5/22/1984	14.40%	12.02%	2.38%
5/29/1984	15.10%	12.06%	3.04%
6/13/1984	15.25%	12.15%	3.10%
6/15/1984	15.60%	12.17%	3.43%
6/22/1984	16.25%	12.21%	4.04%
6/29/1984	15.25%	12.26%	2.99%
7/2/1984	13.35%	12.27%	1.08%
7/10/1984	16.00%	12.31%	3.69%
7/12/1984	16.50%	12.32%	4.18%
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7/24/1984	16.79%	12.39%	4.40%
7/31/1984	16.00%	12.43%	3.57%
8/3/1984	14.25%	12.44%	1.81%
8/17/1984	14.30%	12.49%	1.81%
8/20/1984	15.00%	12.49%	2.51%
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11/14/1984	15.75%	12.58%	3.17%
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12/3/1984	15.80%	12.56%	3.24%
12/4/1984	16.50%	12.56%	3.94%
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12/19/1984	14.75%	12.53%	2.22%
12/19/1984	15.00%	12.53%	2.47%
12/20/1984	16.00%	12.53%	3.47%
12/28/1984	16.00%	12.50%	3.50%
1/3/1985	14.75%	12.49%	2.26%
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1/11/1985	16.30%	12.46%	3.84%
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1/25/1985	16.75%	12.42%	4.33%
1/30/1985	14.90%	12.40%	2.50%
1/31/1985	14.75%	12.39%	2.36%
2/8/1985	14.47%	12.35%	2.12%
3/1/1985	13.84%	12.31%	1.53%
3/8/1985	16.85%	12.28%	4.57%
3/14/1985	15.50%	12.25%	3.25%

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3/29/1985	15.62%	12.17%	3.45%
4/3/1985	14.60%	12.14%	2.46%
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7/26/1985	14.50%	11.33%	3.17%
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8/7/1985	15.00%	11.27%	3.73%
8/28/1985	14.25%	11.15%	3.10%
8/28/1985	15.50%	11.15%	4.35%
8/29/1985	14.50%	11.15%	3.35%
9/9/1985	14.60%	11.11%	3.49%
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9/27/1985	15.50%	11.05%	4.45%
9/27/1985	15.80%	11.05%	4.75%
10/2/1985	14.00%	11.03%	2.97%
10/2/1985	14.75%	11.03%	3.72%
10/3/1985	15.25%	11.03%	4.22%
10/24/1985	15.40%	10.96%	4.44%
10/24/1985	15.82%	10.96%	4.86%
10/24/1985	15.85%	10.96%	4.89%
10/28/1985	16.00%	10.95%	5.05%
10/29/1985	16.65%	10.94%	5.71%
10/31/1985	15.06%	10.93%	4.13%
11/4/1985	14.50%	10.92%	3.58%
11/7/1985	15.50%	10.90%	4.60%
11/8/1985	14.30%	10.89%	3.41%
12/12/1985	14.75%	10.73%	4.02%
12/18/1985	15.00%	10.69%	4.31%
12/20/1985	14.50%	10.67%	3.83%
12/20/1985	14.50%	10.67%	3.83%
12/20/1985	15.00%	10.67%	4.33%
1/24/1986	15.40%	10.41%	4.99%
1/31/1986	15.00%	10.35%	4.65%
2/5/1986	15.00%	10.32%	4.68%
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2/18/1986	16.00%	10.23%	5.77%
2/24/1986	14.50%	10.18%	4.32%
2/26/1986	14.00%	10.15%	3.85%
3/5/1986	14.90%	10.08%	4.82%
3/11/1986	14.50%	10.02%	4.48%
3/12/1986	13.50%	10.00%	3.50%
3/27/1986	14.10%	9.86%	4.24%
3/31/1986	13.50%	9.84%	3.66%
4/1/1986	14.00%	9.83%	4.17%
4/2/1986	15.50%	9.81%	5.69%
4/4/1986	15.00%	9.78%	5.22%
4/14/1986	13.40%	9.69%	3.71%
4/23/1986	15.00%	9.57%	5.43%
5/16/1986	14.50%	9.32%	5.18%
5/16/1986	14.50%	9.32%	5.18%
5/29/1986	13.90%	9.19%	4.71%
5/30/1986	15.10%	9.18%	5.92%
6/2/1986	12.81%	9.17%	3.64%
6/11/1986	14.00%	9.07%	4.93%
6/24/1986	16.63%	8.94%	7.69%
6/26/1986	12.00%	8.91%	3.09%
6/26/1986	14.75%	8.91%	5.84%
6/30/1986	13.00%	8.87%	4.13%
7/10/1986	14.34%	8.75%	5.59%
7/11/1986	12.75%	8.73%	4.02%
7/14/1986	12.60%	8.71%	3.89%
7/17/1986	12.40%	8.66%	3.74%
7/25/1986	14.25%	8.57%	5.68%
8/6/1986	13.50%	8.44%	5.06%
8/14/1986	13.50%	8.35%	5.15%
9/16/1986	12.75%	8.06%	4.69%

9/19/1986	13.25%	8.03%	5.22%
10/1/1986	14.00%	7.95%	6.05%
10/3/1986	13.40%	7.93%	5.47%
10/31/1986	13.50%	7.77%	5.73%
11/5/1986	13.00%	7.75%	5.25%
12/3/1986	12.90%	7.58%	5.32%
12/4/1986	14.44%	7.58%	6.86%
12/16/1986	13.60%	7.52%	6.08%
12/22/1986	13.80%	7.51%	6.29%
12/30/1986	13.00%	7.49%	5.51%
1/2/1987	13.00%	7.49%	5.51%
1/12/1987	12.40%	7.47%	4.93%
1/27/1987	12.71%	7.46%	5.25%
3/2/1987	12.47%	7.47%	5.00%
3/3/1987	13.60%	7.47%	6.13%
3/4/1987	12.38%	7.47%	4.91%
3/10/1987	13.50%	7.47%	6.03%
3/13/1987	13.00%	7.47%	5.53%
3/31/1987	13.00%	7.46%	5.54%
4/6/1987	13.00%	7.47%	5.53%
4/14/1987	12.50%	7.49%	5.01%
4/16/1987	14.50%	7.50%	7.00%
4/27/1987	12.00%	7.54%	4.46%
5/5/1987	12.85%	7.58%	5.27%
5/12/1987	12.65%	7.62%	5.03%
5/28/1987	13.50%	7.70%	5.80%
6/15/1987	13.20%	7.78%	5.42%
6/29/1987	15.00%	7.83%	7.17%
6/30/1987	12.50%	7.84%	4.66%
7/8/1987	12.00%	7.86%	4.14%
7/10/1987	12.90%	7.86%	5.04%
7/15/1987	13.50%	7.88%	5.62%
7/16/1987	13.50%	7.88%	5.62%
7/16/1987	15.00%	7.88%	7.12%
7/27/1987	13.00%	7.92%	5.08%
7/27/1987	13.40%	7.92%	5.48%
7/27/1987	13.50%	7.92%	5.58%
7/31/1987	12.98%	7.95%	5.03%
8/26/1987	12.63%	8.06%	4.57%
8/26/1987	12.75%	8.06%	4.69%
8/27/1987	13.25%	8.06%	5.19%
9/9/1987	13.00%	8.14%	4.86%
9/30/1987	12.75%	8.31%	4.44%
9/30/1987	13.00%	8.31%	4.69%
10/2/1987	11.50%	8.33%	3.17%
10/15/1987	13.00%	8.43%	4.57%
11/2/1987	13.00%	8.55%	4.45%
11/19/1987	13.00%	8.64%	4.36%
11/30/1987	12.00%	8.68%	3.32%
12/3/1987	14.20%	8.70%	5.50%
12/15/1987	13.25%	8.77%	4.48%
12/16/1987	13.50%	8.78%	4.72%
12/16/1987	13.72%	8.78%	4.94%
12/17/1987	11.75%	8.79%	2.96%
12/18/1987	13.50%	8.80%	4.70%
12/21/1987	12.01%	8.81%	3.20%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	12.75%	8.81%	3.94%
12/22/1987	13.00%	8.81%	4.19%
1/20/1988	13.80%	8.94%	4.86%
1/26/1988	13.90%	8.95%	4.95%
1/29/1988	13.20%	8.96%	4.24%
2/4/1988	12.60%	8.96%	3.64%
3/1/1988	11.56%	8.94%	2.62%
3/23/1988	12.87%	8.92%	3.95%
3/24/1988	11.24%	8.92%	2.32%
3/30/1988	12.72%	8.92%	3.80%
4/1/1988	12.50%	8.92%	3.58%
4/7/1988	13.25%	8.93%	4.32%
4/25/1988	10.96%	8.96%	2.00%
5/3/1988	12.91%	8.97%	3.94%
5/11/1988	13.50%	8.99%	4.51%
5/16/1988	13.00%	8.99%	4.01%
6/30/1988	12.75%	9.00%	3.75%
7/1/1988	12.75%	8.99%	3.76%
7/20/1988	13.40%	8.96%	4.44%
8/5/1988	12.75%	8.92%	3.83%
8/23/1988	11.70%	8.93%	2.77%
8/29/1988	12.75%	8.94%	3.81%
8/30/1988	13.50%	8.94%	4.56%
9/8/1988	12.60%	8.95%	3.65%
10/13/1988	13.10%	8.93%	4.17%

12/19/1988	13.00%	9.02%	3.98%
12/20/1988	12.25%	9.02%	3.23%
12/20/1988	13.00%	9.02%	3.98%
12/21/1988	12.90%	9.02%	3.88%
12/27/1988	13.00%	9.03%	3.97%
12/28/1988	13.10%	9.03%	4.07%
12/30/1988	13.40%	9.04%	4.36%
1/27/1989	13.00%	9.05%	3.95%
1/31/1989	13.00%	9.05%	3.95%
2/17/1989	13.00%	9.05%	3.95%
2/20/1989	12.40%	9.05%	3.35%
3/1/1989	12.76%	9.05%	3.71%
3/8/1989	13.00%	9.05%	3.95%
3/30/1989	14.00%	9.05%	4.95%
4/5/1989	14.20%	9.05%	5.15%
4/18/1989	13.00%	9.05%	3.95%
5/5/1989	12.40%	9.05%	3.35%
6/2/1989	13.20%	9.00%	4.20%
6/8/1989	13.50%	8.98%	4.52%
6/27/1989	13.25%	8.91%	4.34%
6/30/1989	13.00%	8.90%	4.10%
8/14/1989	12.50%	8.77%	3.73%
9/28/1989	12.25%	8.63%	3.62%
10/24/1989	12.50%	8.54%	3.96%
11/9/1989	13.00%	8.49%	4.51%
12/15/1989	13.00%	8.34%	4.66%
12/20/1989	12.90%	8.32%	4.58%
12/21/1989	12.90%	8.31%	4.59%
12/27/1989	12.50%	8.29%	4.21%
12/27/1989	13.00%	8.29%	4.71%
1/10/1990	12.80%	8.24%	4.56%
1/11/1990	12.90%	8.24%	4.66%
1/17/1990	12.80%	8.22%	4.58%
1/26/1990	12.00%	8.20%	3.80%
2/9/1990	12.10%	8.17%	3.93%
2/24/1990	12.86%	8.15%	4.71%
3/30/1990	12.90%	8.16%	4.74%
4/4/1990	15.76%	8.17%	7.59%
4/12/1990	12.52%	8.18%	4.34%
4/19/1990	12.75%	8.20%	4.55%
5/21/1990	12.10%	8.28%	3.82%
5/29/1990	12.40%	8.30%	4.10%
5/31/1990	12.00%	8.30%	3.70%
6/4/1990	12.90%	8.30%	4.60%
6/6/1990	12.25%	8.31%	3.94%
6/15/1990	13.20%	8.32%	4.88%
6/20/1990	12.92%	8.32%	4.60%
6/27/1990	12.90%	8.33%	4.57%
6/29/1990	12.50%	8.33%	4.17%
7/6/1990	12.10%	8.34%	3.76%
7/6/1990	12.35%	8.34%	4.01%
8/10/1990	12.55%	8.41%	4.14%
8/16/1990	13.21%	8.43%	4.78%
8/22/1990	13.10%	8.45%	4.65%
8/24/1990	13.00%	8.46%	4.54%
9/26/1990	11.45%	8.59%	2.86%
10/2/1990	13.00%	8.61%	4.39%
10/5/1990	12.84%	8.62%	4.22%
10/19/1990	13.00%	8.67%	4.33%
10/25/1990	12.30%	8.68%	3.62%
11/21/1990	12.70%	8.69%	4.01%
12/13/1990	12.30%	8.67%	3.63%
12/17/1990	12.87%	8.67%	4.20%
12/18/1990	13.10%	8.67%	4.43%
12/19/1990	12.00%	8.66%	3.34%
12/20/1990	12.75%	8.66%	4.09%
12/21/1990	12.50%	8.66%	3.84%
12/27/1990	12.79%	8.66%	4.13%
1/2/1991	13.10%	8.65%	4.45%
1/4/1991	12.50%	8.65%	3.85%
1/15/1991	12.75%	8.64%	4.11%
1/25/1991	11.70%	8.63%	3.07%
2/4/1991	12.50%	8.60%	3.90%
2/7/1991	12.50%	8.59%	3.91%
2/12/1991	13.00%	8.58%	4.43%
2/14/1991	12.72%	8.57%	4.15%
2/22/1991	12.80%	8.55%	4.25%
3/6/1991	13.10%	8.53%	4.57%
3/8/1991	12.30%	8.52%	3.78%
3/8/1991	13.00%	8.52%	4.48%
4/22/1991	13.00%	8.49%	4.51%
5/7/1991	13.50%	8.47%	5.03%
5/13/1991	13.25%	8.47%	4.78%

5/30/1991	12.75%	8.44%	4.31%
6/12/1991	12.00%	8.41%	3.59%
6/25/1991	11.70%	8.39%	3.31%
6/28/1991	12.50%	8.38%	4.12%
7/1/1991	12.00%	8.38%	3.62%
7/3/1991	12.50%	8.37%	4.13%
7/19/1991	12.10%	8.34%	3.76%
8/1/1991	12.90%	8.32%	4.58%
8/16/1991	13.20%	8.29%	4.91%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.25%	8.23%	4.02%
10/17/1991	13.00%	8.20%	4.80%
10/23/1991	12.50%	8.20%	4.30%
10/23/1991	12.55%	8.20%	4.35%
10/31/1991	11.80%	8.19%	3.61%
11/1/1991	12.00%	8.19%	3.81%
11/5/1991	12.25%	8.19%	4.06%
11/12/1991	12.50%	8.18%	4.32%
11/12/1991	13.25%	8.18%	5.07%
11/25/1991	12.40%	8.18%	4.22%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.50%	8.18%	4.32%
11/27/1991	12.10%	8.18%	3.92%
12/18/1991	12.25%	8.15%	4.10%
12/19/1991	12.60%	8.15%	4.45%
12/19/1991	12.80%	8.15%	4.65%
12/20/1991	12.65%	8.14%	4.51%
1/9/1992	12.80%	8.09%	4.71%
1/16/1992	12.75%	8.07%	4.68%
1/21/1992	12.00%	8.06%	3.94%
1/22/1992	13.00%	8.06%	4.94%
1/27/1992	12.65%	8.05%	4.60%
1/31/1992	12.00%	8.04%	3.96%
2/11/1992	12.40%	8.03%	4.37%
2/25/1992	12.50%	8.01%	4.49%
3/16/1992	11.43%	7.98%	3.45%
3/18/1992	12.28%	7.98%	4.30%
4/2/1992	12.10%	7.95%	4.15%
4/9/1992	11.45%	7.94%	3.51%
4/10/1992	11.50%	7.93%	3.57%
4/14/1992	11.50%	7.93%	3.57%
5/5/1992	11.50%	7.89%	3.61%
5/12/1992	11.87%	7.88%	3.99%
5/12/1992	12.46%	7.88%	4.58%
6/1/1992	12.30%	7.87%	4.43%
6/12/1992	10.90%	7.86%	3.04%
6/26/1992	12.35%	7.85%	4.50%
6/29/1992	11.00%	7.85%	3.15%
6/30/1992	13.00%	7.85%	5.15%
7/13/1992	11.90%	7.84%	4.06%
7/13/1992	13.50%	7.84%	5.66%
7/22/1992	11.20%	7.83%	3.37%
8/3/1992	12.00%	7.81%	4.19%
8/6/1992	12.50%	7.80%	4.70%
9/22/1992	12.00%	7.71%	4.29%
9/28/1992	11.40%	7.71%	3.69%
9/30/1992	11.75%	7.70%	4.05%
10/2/1992	13.00%	7.70%	5.30%
10/12/1992	12.20%	7.70%	4.50%
10/16/1992	13.16%	7.70%	5.46%
10/30/1992	11.75%	7.71%	4.04%
11/3/1992	12.00%	7.71%	4.29%
12/3/1992	11.85%	7.68%	4.17%
12/15/1992	11.00%	7.66%	3.34%
12/16/1992	11.90%	7.66%	4.24%
12/16/1992	12.40%	7.66%	4.74%
12/17/1992	12.00%	7.66%	4.34%
12/22/1992	12.30%	7.65%	4.65%
12/22/1992	12.40%	7.65%	4.75%
12/29/1992	12.25%	7.63%	4.62%
12/30/1992	12.00%	7.63%	4.37%
12/31/1992	11.90%	7.63%	4.27%
1/12/1993	12.00%	7.61%	4.39%
1/21/1993	11.25%	7.59%	3.66%
2/2/1993	11.40%	7.56%	3.84%
2/15/1993	12.30%	7.52%	4.78%
2/24/1993	11.90%	7.49%	4.41%
2/26/1993	11.80%	7.48%	4.32%
2/26/1993	12.20%	7.48%	4.72%
4/23/1993	11.75%	7.29%	4.46%
5/11/1993	11.75%	7.25%	4.50%
5/14/1993	11.50%	7.24%	4.26%
5/25/1993	11.50%	7.23%	4.27%

5/28/1993	11.00%	7.22%	3.78%
6/3/1993	12.00%	7.21%	4.79%
6/16/1993	11.50%	7.19%	4.31%
6/18/1993	12.10%	7.18%	4.92%
6/25/1993	11.67%	7.17%	4.50%
7/21/1993	11.38%	7.10%	4.28%
7/23/1993	10.46%	7.09%	3.37%
8/24/1993	11.50%	6.96%	4.54%
9/21/1993	10.50%	6.81%	3.69%
9/29/1993	11.47%	6.77%	4.70%
9/30/1993	11.60%	6.76%	4.84%
11/2/1993	10.80%	6.60%	4.20%
11/12/1993	12.00%	6.57%	5.43%
11/26/1993	11.00%	6.52%	4.48%
12/14/1993	10.55%	6.48%	4.07%
12/16/1993	10.60%	6.48%	4.12%
12/21/1993	11.30%	6.47%	4.83%
1/4/1994	10.07%	6.44%	3.63%
1/13/1994	11.00%	6.42%	4.58%
1/21/1994	11.00%	6.40%	4.60%
1/28/1994	11.35%	6.39%	4.96%
2/3/1994	11.40%	6.38%	5.02%
2/17/1994	10.60%	6.36%	4.24%
2/25/1994	11.25%	6.35%	4.90%
2/25/1994	12.00%	6.35%	5.65%
3/1/1994	11.00%	6.35%	4.65%
3/4/1994	11.00%	6.35%	4.65%
4/25/1994	11.00%	6.41%	4.59%
5/10/1994	11.75%	6.45%	5.30%
5/13/1994	10.50%	6.46%	4.04%
6/3/1994	11.00%	6.54%	4.46%
6/27/1994	11.40%	6.65%	4.75%
8/5/1994	12.75%	6.88%	5.87%
10/31/1994	10.00%	7.33%	2.67%
11/9/1994	10.85%	7.39%	3.46%
11/9/1994	10.85%	7.39%	3.46%
11/18/1994	11.20%	7.45%	3.75%
11/22/1994	11.60%	7.47%	4.13%
11/28/1994	11.06%	7.49%	3.57%
12/8/1994	11.50%	7.54%	3.96%
12/8/1994	11.70%	7.54%	4.16%
12/14/1994	10.95%	7.56%	3.39%
12/15/1994	11.50%	7.57%	3.93%
12/19/1994	11.50%	7.58%	3.92%
12/28/1994	12.15%	7.61%	4.54%
1/9/1995	12.28%	7.64%	4.64%
1/31/1995	11.00%	7.69%	3.31%
2/10/1995	12.60%	7.70%	4.90%
2/17/1995	11.90%	7.70%	4.20%
3/9/1995	11.50%	7.71%	3.79%
3/20/1995	12.00%	7.72%	4.28%
3/23/1995	12.81%	7.72%	5.09%
3/29/1995	11.60%	7.72%	3.88%
4/6/1995	11.10%	7.71%	3.39%
4/7/1995	11.00%	7.71%	3.29%
4/19/1995	11.00%	7.70%	3.30%
5/12/1995	11.63%	7.68%	3.95%
5/25/1995	11.20%	7.65%	3.55%
6/9/1995	11.25%	7.60%	3.65%
6/21/1995	12.25%	7.56%	4.69%
6/30/1995	11.10%	7.52%	3.58%
9/11/1995	11.30%	7.20%	4.10%
9/27/1995	11.30%	7.12%	4.18%
9/27/1995	11.50%	7.12%	4.38%
9/27/1995	11.75%	7.12%	4.63%
9/29/1995	11.00%	7.11%	3.89%
11/9/1995	11.38%	6.90%	4.48%
11/9/1995	12.36%	6.90%	5.46%
11/17/1995	11.00%	6.86%	4.14%
12/4/1995	11.35%	6.78%	4.57%
12/11/1995	11.40%	6.74%	4.66%
12/20/1995	11.60%	6.70%	4.90%
12/27/1995	12.00%	6.66%	5.34%
2/5/1996	12.25%	6.48%	5.77%
3/29/1996	10.67%	6.42%	4.25%
4/8/1996	11.00%	6.42%	4.58%
4/11/1996	12.59%	6.43%	6.16%
4/11/1996	12.59%	6.43%	6.16%
4/24/1996	11.25%	6.43%	4.82%
4/30/1996	11.00%	6.43%	4.57%
5/13/1996	11.00%	6.44%	4.56%
5/23/1996	11.25%	6.43%	4.82%
6/25/1996	11.25%	6.48%	4.77%

6/27/1996	11.20%	6.48%	4.72%
8/12/1996	10.40%	6.57%	3.83%
9/27/1996	11.00%	6.71%	4.29%
10/16/1996	12.25%	6.76%	5.49%
11/5/1996	11.00%	6.81%	4.19%
11/26/1996	11.30%	6.83%	4.47%
12/18/1996	11.75%	6.83%	4.92%
12/31/1996	11.50%	6.83%	4.67%
1/3/1997	10.70%	6.83%	3.87%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.82%	4.98%
3/31/1997	10.02%	6.80%	3.22%
4/2/1997	11.65%	6.80%	4.85%
4/28/1997	11.50%	6.81%	4.69%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
12/12/1997	11.00%	6.60%	4.40%
12/23/1997	11.12%	6.57%	4.55%
2/2/1998	12.75%	6.39%	6.36%
3/2/1998	11.25%	6.29%	4.96%
3/6/1998	10.75%	6.27%	4.48%
3/20/1998	10.50%	6.22%	4.28%
4/30/1998	12.20%	6.12%	6.08%
7/10/1998	11.40%	5.94%	5.46%
9/15/1998	11.90%	5.78%	6.12%
11/30/1998	12.60%	5.58%	7.02%
12/10/1998	12.20%	5.54%	6.66%
12/17/1998	12.10%	5.52%	6.58%
2/5/1999	10.30%	5.38%	4.92%
3/4/1999	10.50%	5.34%	5.16%
4/6/1999	10.94%	5.32%	5.62%
7/29/1999	10.75%	5.52%	5.23%
9/23/1999	10.75%	5.70%	5.05%
11/17/1999	11.10%	5.90%	5.20%
1/7/2000	11.50%	6.05%	5.45%
1/7/2000	11.50%	6.05%	5.45%
2/17/2000	10.60%	6.17%	4.43%
3/28/2000	11.25%	6.20%	5.05%
5/24/2000	11.00%	6.18%	4.82%
7/18/2000	12.20%	6.16%	6.04%
9/29/2000	11.16%	6.03%	5.13%
11/28/2000	12.90%	5.89%	7.01%
11/30/2000	12.10%	5.88%	6.22%
1/23/2001	11.25%	5.79%	5.46%
2/8/2001	11.50%	5.77%	5.73%
5/8/2001	10.75%	5.62%	5.13%
6/26/2001	11.00%	5.62%	5.38%
7/25/2001	11.02%	5.60%	5.42%
7/25/2001	11.02%	5.60%	5.42%
7/31/2001	11.00%	5.59%	5.41%
8/31/2001	10.50%	5.56%	4.94%
9/7/2001	10.75%	5.55%	5.20%
9/10/2001	11.00%	5.55%	5.45%
9/20/2001	10.00%	5.55%	4.45%
10/24/2001	10.30%	5.54%	4.76%
11/28/2001	10.60%	5.49%	5.11%
12/3/2001	12.88%	5.49%	7.39%
12/20/2001	12.50%	5.50%	7.00%
1/22/2002	10.00%	5.50%	4.50%
3/27/2002	10.10%	5.45%	4.65%
4/22/2002	11.80%	5.45%	6.35%
5/28/2002	10.17%	5.46%	4.71%
6/10/2002	12.00%	5.47%	6.53%
6/18/2002	11.16%	5.48%	5.68%
6/20/2002	11.00%	5.48%	5.52%
6/20/2002	12.30%	5.48%	6.82%
7/15/2002	11.00%	5.48%	5.52%
9/12/2002	12.30%	5.45%	6.85%
9/26/2002	10.45%	5.41%	5.04%
12/4/2002	11.55%	5.29%	6.26%
12/13/2002	11.75%	5.27%	6.48%
12/20/2002	11.40%	5.25%	6.15%
1/8/2003	11.10%	5.19%	5.91%
1/31/2003	12.45%	5.13%	7.32%
2/28/2003	12.30%	5.05%	7.25%
3/6/2003	10.75%	5.03%	5.72%
3/7/2003	9.96%	5.02%	4.94%
3/20/2003	12.00%	4.98%	7.02%
4/3/2003	12.00%	4.96%	7.04%
4/15/2003	11.15%	4.94%	6.21%
6/25/2003	10.75%	4.79%	5.96%
6/26/2003	10.75%	4.79%	5.96%
7/9/2003	9.75%	4.79%	4.96%

7/16/2003	9.75%	4.79%	4.96%
7/25/2003	9.50%	4.80%	4.70%
8/26/2003	10.50%	4.83%	5.67%
12/17/2003	9.85%	4.94%	4.91%
12/17/2003	10.70%	4.94%	5.76%
12/18/2003	11.50%	4.94%	6.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
12/23/2003	10.50%	4.94%	5.56%
1/13/2004	12.00%	4.95%	7.05%
3/2/2004	10.75%	4.99%	5.76%
3/26/2004	10.25%	5.02%	5.23%
4/5/2004	11.25%	5.03%	6.22%
5/18/2004	10.50%	5.07%	5.43%
5/25/2004	10.25%	5.08%	5.17%
5/27/2004	10.25%	5.08%	5.17%
6/2/2004	11.22%	5.08%	6.14%
6/30/2004	10.50%	5.10%	5.40%
6/30/2004	10.50%	5.10%	5.40%
7/16/2004	11.60%	5.11%	6.49%
8/25/2004	10.25%	5.10%	5.15%
9/9/2004	10.40%	5.10%	5.30%
11/9/2004	10.50%	5.07%	5.43%
11/23/2004	11.00%	5.06%	5.94%
12/14/2004	10.97%	5.07%	5.90%
12/21/2004	11.25%	5.07%	6.18%
12/21/2004	11.50%	5.07%	6.43%
12/22/2004	10.70%	5.07%	5.63%
12/22/2004	11.50%	5.07%	6.43%
12/29/2004	9.85%	5.07%	4.78%
1/6/2005	10.70%	5.08%	5.62%
2/18/2005	10.30%	4.98%	5.32%
2/25/2005	10.50%	4.96%	5.54%
3/10/2005	11.00%	4.93%	6.07%
3/24/2005	10.30%	4.90%	5.40%
4/4/2005	10.00%	4.88%	5.12%
4/7/2005	10.25%	4.87%	5.38%
5/18/2005	10.25%	4.78%	5.47%
5/25/2005	10.75%	4.76%	5.99%
5/26/2005	9.75%	4.76%	4.99%
6/1/2005	9.75%	4.75%	5.00%
7/19/2005	11.50%	4.64%	6.86%
8/5/2005	11.75%	4.62%	7.13%
8/15/2005	10.13%	4.61%	5.52%
9/28/2005	10.00%	4.54%	5.46%
10/4/2005	10.75%	4.54%	6.21%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6.20%
12/21/2005	10.29%	4.54%	5.75%
12/21/2005	10.40%	4.54%	5.86%
12/22/2005	11.00%	4.54%	6.46%
12/22/2005	11.15%	4.54%	6.61%
12/28/2005	10.00%	4.54%	5.46%
12/28/2005	10.00%	4.54%	5.46%
1/5/2006	11.00%	4.53%	6.47%
1/27/2006	9.75%	4.52%	5.23%
3/3/2006	10.39%	4.53%	5.86%
4/17/2006	10.20%	4.61%	5.59%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.74%	5.26%
6/27/2006	10.75%	4.80%	5.95%
7/6/2006	10.20%	4.83%	5.37%
7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4.86%	5.64%
7/28/2006	10.05%	4.86%	5.19%
8/23/2006	9.55%	4.89%	4.66%
9/1/2006	10.54%	4.90%	5.64%
9/14/2006	10.00%	4.91%	5.09%
10/6/2006	9.67%	4.92%	4.75%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.12%	4.95%	5.17%
12/1/2006	10.25%	4.95%	5.30%
12/1/2006	10.50%	4.95%	5.55%
12/7/2006	10.75%	4.95%	5.80%
12/21/2006	10.90%	4.95%	5.95%
12/21/2006	11.25%	4.95%	6.30%
12/22/2006	10.25%	4.95%	5.30%
1/5/2007	10.00%	4.95%	5.05%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.90%	4.95%	5.95%

1/12/2007	10.10%	4.95%	5.15%
1/13/2007	10.40%	4.95%	5.45%
1/19/2007	10.80%	4.94%	5.86%
3/21/2007	11.35%	4.87%	6.48%
3/22/2007	9.75%	4.86%	4.89%
5/15/2007	10.00%	4.81%	5.19%
5/17/2007	10.25%	4.81%	5.44%
5/17/2007	10.25%	4.81%	5.44%
5/22/2007	10.20%	4.80%	5.40%
5/22/2007	10.50%	4.80%	5.70%
5/23/2007	10.70%	4.80%	5.90%
5/25/2007	9.67%	4.80%	4.87%
6/15/2007	9.90%	4.82%	5.08%
6/21/2007	10.20%	4.83%	5.37%
6/22/2007	10.50%	4.83%	5.67%
6/28/2007	10.75%	4.84%	5.91%
7/12/2007	9.67%	4.86%	4.81%
7/19/2007	10.00%	4.87%	5.13%
7/19/2007	10.00%	4.87%	5.13%
8/15/2007	10.40%	4.88%	5.52%
10/9/2007	10.00%	4.91%	5.09%
10/17/2007	9.10%	4.91%	4.19%
10/31/2007	9.96%	4.90%	5.06%
11/29/2007	10.90%	4.87%	6.03%
12/6/2007	10.75%	4.86%	5.89%
12/13/2007	9.96%	4.86%	5.10%
12/14/2007	10.70%	4.86%	5.84%
12/14/2007	10.80%	4.86%	5.94%
12/19/2007	10.20%	4.86%	5.34%
12/20/2007	10.20%	4.85%	5.35%
12/20/2007	11.00%	4.85%	6.15%
12/28/2007	10.25%	4.85%	5.40%
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1/30/2008	10.00%	4.79%	5.21%
1/31/2008	10.71%	4.79%	5.92%
2/29/2008	10.25%	4.75%	5.50%
3/12/2008	10.25%	4.73%	5.52%
3/25/2008	9.10%	4.68%	4.42%
4/22/2008	10.25%	4.60%	5.65%
4/24/2008	10.10%	4.60%	5.50%
5/1/2008	10.70%	4.59%	6.11%
5/19/2008	11.00%	4.56%	6.44%
5/27/2008	10.00%	4.55%	5.45%
6/10/2008	10.70%	4.54%	6.16%
6/27/2008	10.50%	4.54%	5.96%
6/27/2008	11.04%	4.54%	6.50%
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7/16/2008	9.40%	4.52%	4.88%
7/30/2008	10.80%	4.51%	6.29%
7/31/2008	10.70%	4.51%	6.19%
8/11/2008	10.25%	4.51%	5.74%
8/26/2008	10.18%	4.50%	5.68%
9/10/2008	10.30%	4.50%	5.80%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/30/2008	10.20%	4.48%	5.72%
10/8/2008	10.15%	4.46%	5.69%
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12/29/2008	10.00%	4.24%	5.76%
12/29/2008	10.20%	4.24%	5.96%
12/31/2008	10.75%	4.22%	6.53%
1/14/2009	10.50%	4.15%	6.35%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/27/2009	10.76%	4.09%	6.67%
1/30/2009	10.50%	4.08%	6.42%
2/4/2009	8.75%	4.06%	4.69%
3/4/2009	10.50%	3.96%	6.54%
3/12/2009	11.50%	3.93%	7.57%
4/2/2009	11.10%	3.85%	7.25%
4/21/2009	10.61%	3.80%	6.81%
4/24/2009	10.00%	3.79%	6.21%
4/30/2009	11.25%	3.78%	7.47%
5/4/2009	10.74%	3.77%	6.97%
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6/24/2009	10.80%	3.77%	7.03%
7/8/2009	10.63%	3.77%	6.86%
7/17/2009	10.50%	3.78%	6.72%
8/31/2009	10.25%	3.82%	6.43%
10/14/2009	10.70%	4.01%	6.69%
10/23/2009	10.88%	4.06%	6.82%
11/2/2009	10.70%	4.09%	6.61%
11/3/2009	10.70%	4.10%	6.60%
11/24/2009	10.25%	4.15%	6.10%
11/25/2009	10.75%	4.16%	6.59%
11/30/2009	10.35%	4.17%	6.18%
12/3/2009	10.50%	4.18%	6.32%
12/7/2009	10.70%	4.18%	6.52%
12/16/2009	10.90%	4.21%	6.69%
12/16/2009	11.00%	4.21%	6.79%
12/18/2009	10.40%	4.22%	6.18%
12/18/2009	10.40%	4.22%	6.18%
12/22/2009	10.20%	4.23%	5.97%
12/22/2009	10.40%	4.23%	6.17%
12/22/2009	10.40%	4.23%	6.17%
12/30/2009	10.00%	4.26%	5.74%
1/4/2010	10.80%	4.28%	6.52%
1/11/2010	11.00%	4.30%	6.70%
1/26/2010	10.13%	4.35%	5.78%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.70%	4.35%	6.35%
2/9/2010	9.80%	4.38%	5.42%
2/18/2010	10.60%	4.40%	6.20%
2/24/2010	10.18%	4.41%	5.77%
3/2/2010	9.63%	4.41%	5.22%
3/4/2010	10.50%	4.41%	6.09%
3/5/2010	10.50%	4.41%	6.09%
3/11/2010	11.90%	4.42%	7.48%
3/17/2010	10.00%	4.41%	5.59%
3/25/2010	10.15%	4.42%	5.73%
4/2/2010	10.10%	4.43%	5.67%
4/27/2010	10.00%	4.46%	5.54%
4/29/2010	9.90%	4.46%	5.44%
4/29/2010	10.06%	4.46%	5.60%
4/29/2010	10.26%	4.46%	5.80%
5/12/2010	10.30%	4.45%	5.85%
5/12/2010	10.30%	4.45%	5.85%
5/28/2010	10.10%	4.44%	5.66%
5/28/2010	10.20%	4.44%	5.76%
6/7/2010	10.30%	4.44%	5.86%
6/16/2010	10.00%	4.44%	5.56%
6/28/2010	9.67%	4.43%	5.24%
6/28/2010	10.50%	4.43%	6.07%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.43%	5.82%
7/15/2010	10.53%	4.43%	6.10%
7/15/2010	10.70%	4.43%	6.27%
7/30/2010	10.70%	4.41%	6.29%
8/4/2010	10.50%	4.41%	6.09%
8/6/2010	9.83%	4.41%	5.42%
8/25/2010	9.90%	4.37%	5.53%
9/3/2010	10.60%	4.35%	6.25%
9/14/2010	10.70%	4.33%	6.37%
9/16/2010	10.00%	4.33%	5.67%
9/16/2010	10.00%	4.33%	5.67%
9/30/2010	9.75%	4.29%	5.46%
10/14/2010	10.35%	4.24%	6.11%
10/28/2010	10.70%	4.21%	6.49%
11/2/2010	10.38%	4.20%	6.18%
11/4/2010	10.70%	4.20%	6.50%
11/19/2010	10.20%	4.18%	6.02%
11/22/2010	10.00%	4.18%	5.82%
12/1/2010	10.13%	4.16%	5.97%
12/6/2010	9.86%	4.15%	5.71%
12/9/2010	10.25%	4.15%	6.10%
12/13/2010	10.70%	4.15%	6.55%
12/14/2010	10.13%	4.15%	5.98%
12/15/2010	10.44%	4.15%	6.29%
12/17/2010	10.00%	4.15%	5.85%
12/20/2010	10.60%	4.15%	6.45%
12/21/2010	10.30%	4.14%	6.16%
12/27/2010	9.90%	4.14%	5.76%
12/29/2010	11.15%	4.14%	7.01%
1/5/2011	10.15%	4.13%	6.02%
1/12/2011	10.30%	4.12%	6.18%

1/13/2011	10.30%	4.12%	6.18%
1/18/2011	10.00%	4.12%	5.88%
1/20/2011	9.30%	4.12%	5.18%
1/20/2011	10.13%	4.12%	6.01%
1/31/2011	9.60%	4.12%	5.48%
2/3/2011	10.00%	4.12%	5.88%
2/25/2011	10.00%	4.14%	5.86%
3/25/2011	9.80%	4.18%	5.62%
3/30/2011	10.00%	4.18%	5.82%
4/12/2011	10.00%	4.21%	5.79%
4/25/2011	10.74%	4.23%	6.51%
4/26/2011	9.67%	4.23%	5.44%
4/27/2011	10.40%	4.24%	6.16%
5/4/2011	10.00%	4.24%	5.76%
5/4/2011	10.00%	4.24%	5.76%
5/24/2011	10.50%	4.27%	6.23%
6/8/2011	10.75%	4.30%	6.45%
6/16/2011	9.20%	4.32%	4.88%
6/17/2011	9.95%	4.32%	5.63%
7/13/2011	10.20%	4.36%	5.84%
8/1/2011	9.20%	4.39%	4.81%
8/8/2011	10.00%	4.38%	5.62%
8/11/2011	10.00%	4.38%	5.62%
8/12/2011	10.35%	4.37%	5.98%
8/19/2011	10.25%	4.36%	5.89%
9/2/2011	12.88%	4.32%	8.56%
9/22/2011	10.00%	4.24%	5.76%
10/12/2011	10.30%	4.14%	6.16%
10/20/2011	10.50%	4.10%	6.40%
11/30/2011	10.90%	3.87%	7.03%
11/30/2011	10.90%	3.87%	7.03%
12/14/2011	10.00%	3.80%	6.20%
12/14/2011	10.30%	3.80%	6.50%
12/20/2011	10.20%	3.76%	6.44%
12/21/2011	10.20%	3.76%	6.44%
12/22/2011	9.90%	3.75%	6.15%
12/22/2011	10.40%	3.75%	6.65%
12/23/2011	10.19%	3.74%	6.45%
1/25/2012	10.50%	3.57%	6.93%
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2/27/2012	10.25%	3.43%	6.82%
2/29/2012	10.40%	3.41%	6.99%
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4/4/2012	10.00%	3.30%	6.70%
4/26/2012	10.00%	3.21%	6.79%
5/2/2012	10.00%	3.18%	6.82%
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5/29/2012	10.05%	3.11%	6.94%
6/7/2012	10.30%	3.08%	7.22%
6/14/2012	9.40%	3.06%	6.34%
6/15/2012	10.40%	3.06%	7.34%
6/18/2012	9.60%	3.06%	6.54%
6/19/2012	9.25%	3.05%	6.20%
6/26/2012	10.10%	3.04%	7.06%
6/29/2012	10.00%	3.04%	6.96%
7/9/2012	10.20%	3.03%	7.17%
7/16/2012	9.80%	3.02%	6.78%
7/20/2012	9.31%	3.01%	6.30%
7/20/2012	9.81%	3.01%	6.80%
9/13/2012	9.80%	2.94%	6.86%
9/19/2012	9.80%	2.94%	6.86%
9/19/2012	10.05%	2.94%	7.11%
9/26/2012	9.50%	2.94%	6.56%
10/12/2012	9.60%	2.93%	6.67%
10/23/2012	9.75%	2.93%	6.82%
10/24/2012	10.30%	2.93%	7.37%
11/9/2012	10.30%	2.92%	7.38%
11/28/2012	10.40%	2.90%	7.50%
11/29/2012	9.75%	2.89%	6.86%
11/29/2012	9.88%	2.89%	6.99%
12/5/2012	9.71%	2.89%	6.82%
12/5/2012	10.40%	2.89%	7.51%
12/12/2012	9.80%	2.88%	6.92%
12/13/2012	9.50%	2.88%	6.62%
12/13/2012	10.50%	2.88%	7.62%
12/14/2012	10.40%	2.88%	7.52%
12/19/2012	9.71%	2.87%	6.84%
12/19/2012	10.25%	2.87%	7.38%
12/20/2012	9.50%	2.87%	6.63%
12/20/2012	9.80%	2.87%	6.93%

12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.30%	2.87%	7.43%
12/20/2012	10.40%	2.87%	7.53%
12/20/2012	10.45%	2.87%	7.58%
12/21/2012	10.20%	2.87%	7.33%
12/26/2012	9.80%	2.86%	6.94%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/16/2013	9.60%	2.84%	6.76%
1/16/2013	9.60%	2.84%	6.76%
2/13/2013	10.20%	2.84%	7.36%
2/22/2013	9.75%	2.85%	6.90%
2/27/2013	10.00%	2.86%	7.14%
3/14/2013	9.30%	2.88%	6.42%
3/27/2013	9.80%	2.90%	6.90%
5/1/2013	9.84%	2.94%	6.90%
5/15/2013	10.30%	2.96%	7.34%
5/30/2013	10.20%	2.98%	7.22%
5/31/2013	9.00%	2.98%	6.02%
6/11/2013	10.00%	3.00%	7.00%
6/21/2013	9.75%	3.02%	6.73%
6/25/2013	9.80%	3.03%	6.77%
7/12/2013	9.36%	3.07%	6.29%
8/8/2013	9.83%	3.14%	6.69%
8/14/2013	9.15%	3.16%	5.99%
9/11/2013	10.20%	3.26%	6.94%
9/11/2013	10.25%	3.26%	6.99%
9/24/2013	10.20%	3.31%	6.89%
10/3/2013	9.65%	3.33%	6.32%
11/6/2013	10.20%	3.41%	6.79%
11/21/2013	10.00%	3.44%	6.56%
11/26/2013	10.00%	3.45%	6.55%
12/3/2013	10.25%	3.47%	6.78%
12/4/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.48%	6.72%
12/9/2013	8.72%	3.48%	5.24%
12/9/2013	9.75%	3.48%	6.27%
12/13/2013	9.75%	3.50%	6.25%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	10.12%	3.50%	6.62%
12/17/2013	9.50%	3.51%	5.99%
12/17/2013	10.95%	3.51%	7.44%
12/18/2013	8.72%	3.51%	5.21%
12/18/2013	9.80%	3.51%	6.29%
12/19/2013	10.15%	3.51%	6.64%
12/30/2013	9.50%	3.54%	5.96%
2/20/2014	9.20%	3.68%	5.52%
2/26/2014	9.75%	3.69%	6.06%
3/17/2014	9.55%	3.72%	5.83%
3/26/2014	9.40%	3.73%	5.67%
3/26/2014	9.96%	3.73%	6.23%
4/2/2014	9.70%	3.73%	5.97%
5/16/2014	9.80%	3.70%	6.10%
5/30/2014	9.70%	3.68%	6.02%
6/6/2014	10.40%	3.67%	6.73%
6/30/2014	9.55%	3.64%	5.91%
7/2/2014	9.62%	3.64%	5.98%
7/10/2014	9.95%	3.63%	6.32%
7/23/2014	9.75%	3.61%	6.14%
7/29/2014	9.45%	3.60%	5.85%
7/31/2014	9.90%	3.60%	6.30%
8/20/2014	9.75%	3.57%	6.18%
8/25/2014	9.60%	3.56%	6.04%
8/29/2014	9.80%	3.54%	6.26%
9/11/2014	9.60%	3.51%	6.09%
9/15/2014	10.25%	3.51%	6.74%
10/9/2014	9.80%	3.45%	6.35%
11/6/2014	9.56%	3.37%	6.19%
11/6/2014	10.20%	3.37%	6.83%
11/14/2014	10.20%	3.35%	6.85%
11/26/2014	9.70%	3.33%	6.37%
11/26/2014	10.20%	3.33%	6.87%
12/4/2014	9.68%	3.31%	6.37%
12/10/2014	9.25%	3.29%	5.96%
12/10/2014	9.25%	3.29%	5.96%
12/11/2014	10.07%	3.29%	6.78%
12/12/2014	10.20%	3.28%	6.92%
12/17/2014	9.17%	3.27%	5.90%
12/18/2014	9.83%	3.26%	6.57%
1/23/2015	9.50%	3.14%	6.36%

2/24/2015	9.83%	3.04%	6.79%
3/18/2015	9.75%	2.98%	6.77%
3/25/2015	9.50%	2.96%	6.54%
3/26/2015	9.72%	2.95%	6.77%
4/23/2015	10.20%	2.87%	7.33%
4/29/2015	9.53%	2.86%	6.67%
5/1/2015	9.60%	2.85%	6.75%
5/26/2015	9.75%	2.83%	6.92%
6/17/2015	9.00%	2.82%	6.18%
6/17/2015	9.00%	2.82%	6.18%
9/2/2015	9.50%	2.79%	6.71%
9/10/2015	9.30%	2.79%	6.51%
10/15/2015	9.00%	2.81%	6.19%
11/19/2015	10.00%	2.88%	7.12%
11/19/2015	10.30%	2.88%	7.42%
12/3/2015	10.00%	2.90%	7.10%
12/9/2015	9.14%	2.90%	6.24%
12/9/2015	9.14%	2.90%	6.24%
12/11/2015	10.30%	2.90%	7.40%
12/15/2015	9.60%	2.91%	6.69%
12/17/2015	9.70%	2.91%	6.79%
12/18/2015	9.50%	2.91%	6.59%
12/30/2015	9.50%	2.93%	6.57%
1/6/2016	9.50%	2.94%	6.56%
2/23/2016	9.75%	2.94%	6.81%
3/16/2016	9.85%	2.91%	6.94%
4/29/2016	9.80%	2.83%	6.97%
6/3/2016	9.75%	2.80%	6.95%
6/8/2016	9.48%	2.80%	6.68%
6/15/2016	9.00%	2.79%	6.21%
6/15/2016	9.00%	2.79%	6.21%
		# of Cases:	1,475
		Average:	4.51%

Constant Growth Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.08	$59.67	3.49%	3.57%	5.50%	5.00%	4.00%	4.83%	7.56%	8.40%	9.08%
Alliant Energy Corporation	LNT	$1.18	$38.20	3.08%	3.17%	6.10%	6.60%	6.00%	6.23%	9.17%	9.40%	9.78%
Ameren Corporation	AEE	$1.70	$50.12	3.39%	3.49%	6.10%	5.20%	6.00%	5.77%	8.68%	9.26%	9.60%
American Electric Power Company, Inc.	AEP	$2.24	$66.05	3.39%	3.47%	4.90%	4.10%	4.00%	4.33%	7.46%	7.80%	8.37%
Avista Corporation	AVA	$1.37	$41.65	3.29%	3.37%	5.00%	5.00%	5.00%	5.00%	8.37%	8.37%	8.37%
CMS Energy Corporation	CMS	$1.24	$42.95	2.89%	2.98%	6.40%	7.24%	6.00%	6.55%	8.97%	9.53%	10.23%
DTE Energy Company	DTE	$3.08	$92.91	3.32%	3.40%	5.80%	5.35%	5.00%	5.38%	8.40%	8.79%	9.21%
El Paso Electric Company	EE	$1.24	$45.30	2.74%	2.81%	6.70%	7.00%	2.50%	5.40%	5.27%	8.21%	9.83%
Entergy Corporation	ETR	$3.40	$77.45	4.39%	4.47%	NA	NA	3.50%	3.50%	7.97%	7.97%	7.97%
Eversource Energy	ES	$1.78	$56.36	3.16%	3.25%	6.30%	5.49%	6.00%	5.93%	8.73%	9.18%	9.56%
FirstEnergy Corp.	FE	$1.44	$33.34	4.32%	4.51%	NA	NA	9.00%	9.00%	13.51%	13.51%	13.51%
IDACORP, Inc.	IDA	$2.04	$74.50	2.74%	2.79%	4.00%	4.00%	3.00%	3.67%	5.78%	6.46%	6.79%
MGE Energy, Inc.	MGEE	$1.18	$53.30	2.21%	2.27%	NA	4.00%	7.00%	5.50%	6.26%	7.77%	9.29%
NorthWestern Corporation	NWE	$2.00	$59.68	3.35%	3.44%	5.00%	5.00%	6.50%	5.50%	8.43%	8.94%	9.96%
OGE Energy Corp.	OGE	$1.10	$30.95	3.55%	3.63%	5.20%	4.30%	3.00%	4.17%	6.61%	7.80%	8.85%
Otter Tail Corporation	OTTR	$1.25	$30.96	4.04%	4.16%	NA	6.00%	6.00%	6.00%	10.16%	10.16%	10.16%
Pinnacle West Capital Corporation	PNW	$2.50	$75.82	3.30%	3.36%	4.00%	3.73%	4.00%	3.91%	7.09%	7.27%	7.36%
PNM Resources, Inc.	PNM	$0.88	$33.49	2.63%	2.74%	7.60%	8.76%	9.00%	8.45%	10.33%	11.19%	11.75%
Portland General Electric Company	POR	$1.28	$41.86	3.06%	3.15%	6.40%	6.57%	5.50%	6.16%	8.64%	9.31%	9.73%
SCANA Corporation	SCG	$2.30	$71.01	3.24%	3.32%	5.30%	5.40%	4.50%	5.07%	7.81%	8.39%	8.73%
Wisconsin Energy Corporation	WEC	$1.98	$61.68	3.21%	3.31%	6.30%	6.77%	6.00%	6.36%	9.31%	9.67%	10.09%
Xcel Energy Inc.	XEL	$1.36	$42.20	3.22%	3.31%	5.30%	5.27%	5.50%	5.36%	8.58%	8.67%	8.81%
PROXY GROUP MEAN				3.27%	3.36%	5.66%	5.54%	5.32%	5.55%	8.32%	8.91%	9.41%
PROXY GROUP MEDIAN				3.26%	3.34%	5.65%	5.31%	5.50%	5.45%	8.42%	8.73%	9.42%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-trading day average as of June 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Combination Group
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.08	$57.08	3.64%	3.73%	5.50%	5.00%	4.00%	4.83%	7.72%	8.57%	9.24%
Alliant Energy Corporation	LNT	$1.18	$36.64	3.21%	3.31%	6.10%	6.60%	6.00%	6.23%	9.30%	9.54%	9.91%
Ameren Corporation	AEE	$1.70	$48.90	3.48%	3.58%	6.10%	5.20%	6.00%	5.77%	8.77%	9.34%	9.68%
American Electric Power Company, Inc.	AEP	$2.24	$65.03	3.44%	3.52%	4.90%	4.10%	4.00%	4.33%	7.51%	7.85%	8.43%
Avista Corporation	AVA	$1.37	$40.48	3.38%	3.47%	5.00%	5.00%	5.00%	5.00%	8.47%	8.47%	8.47%
CMS Energy Corporation	CMS	$1.24	$41.70	2.97%	3.07%	6.40%	7.24%	6.00%	6.55%	9.06%	9.62%	10.32%
DTE Energy Company	DTE	$3.08	$89.93	3.42%	3.52%	5.80%	5.35%	5.00%	5.38%	8.51%	8.90%	9.32%
El Paso Electric Company	EE	$1.24	$44.56	2.78%	2.86%	6.70%	7.00%	2.50%	5.40%	5.32%	8.26%	9.88%
Entergy Corporation	ETR	$3.40	$76.55	4.44%	4.52%	NA	NA	3.50%	3.50%	8.02%	8.02%	8.02%
Eversource Energy	ES	$1.78	$56.58	3.15%	3.24%	6.30%	5.49%	6.00%	5.93%	8.72%	9.17%	9.54%
FirstEnergy Corp.	FE	$1.44	$34.24	4.21%	4.40%	NA	NA	9.00%	9.00%	13.40%	13.40%	13.40%
IDACORP, Inc.	IDA	$2.04	$73.58	2.77%	2.82%	4.00%	4.00%	3.00%	3.67%	5.81%	6.49%	6.83%
MGE Energy, Inc.	MGEE	$1.18	$51.38	2.30%	2.36%	NA	4.00%	7.00%	5.50%	6.34%	7.86%	9.38%
NorthWestern Corporation	NWE	$2.00	$59.59	3.36%	3.45%	5.00%	5.00%	6.50%	5.50%	8.44%	8.95%	9.97%
OGE Energy Corp.	OGE	$1.10	$29.13	3.78%	3.86%	5.20%	4.30%	3.00%	4.17%	6.83%	8.02%	9.07%
Otter Tail Corporation	OTTR	$1.25	$29.44	4.25%	4.37%	NA	6.00%	6.00%	6.00%	10.37%	10.37%	10.37%
Pinnacle West Capital Corporation	PNW	$2.50	$73.65	3.39%	3.46%	4.00%	3.73%	4.00%	3.91%	7.19%	7.37%	7.46%
PNM Resources, Inc.	PNM	$0.88	$32.94	2.67%	2.78%	7.60%	8.76%	9.00%	8.45%	10.37%	11.24%	11.79%
Portland General Electric Company	POR	$1.28	$40.24	3.18%	3.28%	6.40%	6.57%	5.50%	6.16%	8.77%	9.44%	9.86%
SCANA Corporation	SCG	$2.30	$69.22	3.32%	3.41%	5.30%	5.40%	4.50%	5.07%	7.90%	8.47%	8.81%
Wisconsin Energy Corporation	WEC	$1.98	$59.53	3.33%	3.43%	6.30%	6.77%	6.00%	6.36%	9.43%	9.79%	10.21%
Xcel Energy Inc.	XEL	$1.36	$41.15	3.31%	3.39%	5.30%	5.27%	5.50%	5.36%	8.66%	8.75%	8.90%
PROXY GROUP MEAN				3.35%	3.45%	5.66%	5.54%	5.32%	5.55%	8.41%	8.99%	9.49%
PROXY GROUP MEDIAN				3.34%	3.44%	5.65%	5.31%	5.50%	5.45%	8.49%	8.83%	9.46%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-trading day average as of June 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Combination Group
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.08	$54.07	3.85%	3.94%	5.50%	5.00%	4.00%	4.83%	7.92%	8.77%	9.45%
Alliant Energy Corporation	LNT	$1.18	$33.83	3.47%	3.58%	6.10%	6.60%	6.00%	6.23%	9.58%	9.81%	10.19%
Ameren Corporation	AEE	$1.70	$46.40	3.66%	3.77%	6.10%	5.20%	6.00%	5.77%	8.96%	9.54%	9.88%
American Electric Power Company, Inc.	AEP	$2.24	$61.54	3.64%	3.72%	4.90%	4.10%	4.00%	4.33%	7.71%	8.05%	8.63%
Avista Corporation	AVA	$1.37	$37.83	3.62%	3.71%	5.00%	5.00%	5.00%	5.00%	8.71%	8.71%	8.71%
CMS Energy Corporation	CMS	$1.24	$39.10	3.17%	3.27%	6.40%	7.24%	6.00%	6.55%	9.27%	9.82%	10.53%
DTE Energy Company	DTE	$3.08	$85.80	3.59%	3.69%	5.80%	5.35%	5.00%	5.38%	8.68%	9.07%	9.49%
El Paso Electric Company	EE	$1.24	$41.72	2.97%	3.05%	6.70%	7.00%	2.50%	5.40%	5.51%	8.45%	10.08%
Entergy Corporation	ETR	$3.40	$72.44	4.69%	4.78%	NA	NA	3.50%	3.50%	8.28%	8.28%	8.28%
Eversource Energy	ES	$1.78	$54.15	3.29%	3.38%	6.30%	5.49%	6.00%	5.93%	8.87%	9.31%	9.69%
FirstEnergy Corp.	FE	$1.44	$33.04	4.36%	4.55%	NA	NA	9.00%	9.00%	13.55%	13.55%	13.55%
IDACORP, Inc.	IDA	$2.04	$70.82	2.88%	2.93%	4.00%	4.00%	3.00%	3.67%	5.92%	6.60%	6.94%
MGE Energy, Inc.	MGEE	$1.18	$48.29	2.44%	2.51%	NA	4.00%	7.00%	5.50%	6.49%	8.01%	9.53%
NorthWestern Corporation	NWE	$2.00	$57.21	3.50%	3.59%	5.00%	5.00%	6.50%	5.50%	8.58%	9.09%	10.11%
OGE Energy Corp.	OGE	$1.10	$27.72	3.97%	4.05%	5.20%	4.30%	3.00%	4.17%	7.03%	8.22%	9.27%
Otter Tail Corporation	OTTR	$1.25	$28.18	4.44%	4.57%	NA	6.00%	6.00%	6.00%	10.57%	10.57%	10.57%
Pinnacle West Capital Corporation	PNW	$2.50	$69.12	3.62%	3.69%	4.00%	3.73%	4.00%	3.91%	7.41%	7.60%	7.69%
PNM Resources, Inc.	PNM	$0.88	$31.32	2.81%	2.93%	7.60%	8.76%	9.00%	8.45%	10.52%	11.38%	11.94%
Portland General Electric Company	POR	$1.28	$38.74	3.30%	3.41%	6.40%	6.57%	5.50%	6.16%	8.90%	9.56%	9.98%
SCANA Corporation	SCG	$2.30	$64.86	3.55%	3.64%	5.30%	5.40%	4.50%	5.07%	8.13%	8.70%	9.04%
Wisconsin Energy Corporation	WEC	$1.98	$55.89	3.54%	3.66%	6.30%	6.77%	6.00%	6.36%	9.65%	10.01%	10.43%
Xcel Energy Inc.	XEL	$1.36	$38.85	3.50%	3.59%	5.30%	5.27%	5.50%	5.36%	8.86%	8.95%	9.10%
PROXY GROUP MEAN				3.54%	3.64%	5.66%	5.54%	5.32%	5.55%	8.60%	9.19%	9.69%
PROXY GROUP MEDIAN				3.54%	3.65%	5.65%	5.31%	5.50%	5.45%	8.70%	9.01%	9.61%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-trading day average as of June 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Multi-Stage Growth Discounted Cash Flow Model
30 Day Average Stock Price
Average EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$59.67	5.50%	5.00%	4.00%	4.83%	5.32%	66.00%	63.00%	66.88%	($0.00)	9.51%	16.83	3.16
Alliant Energy Corporation	LNT	$38.20	6.10%	6.60%	6.00%	6.23%	5.32%	64.00%	61.00%	66.88%	($0.00)	8.87%	19.84	3.73
Ameren Corporation	AEE	$50.12	6.10%	5.20%	6.00%	5.77%	5.32%	68.00%	64.00%	66.88%	($0.00)	9.06%	18.87	3.54
American Electric Power Company, Inc.	AEP	$66.05	4.90%	4.10%	4.00%	4.33%	5.32%	64.00%	67.00%	66.88%	($0.00)	9.23%	18.04	3.39
Avista Corporation	AVA	$41.65	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	($0.00)	8.70%	20.85	3.92
CMS Energy Corporation	CMS	$42.95	6.40%	7.24%	6.00%	6.55%	5.32%	63.00%	62.00%	66.88%	($0.00)	8.93%	19.51	3.67
DTE Energy Company	DTE	$92.91	5.80%	5.35%	5.00%	5.38%	5.32%	63.00%	61.00%	66.88%	($0.00)	8.96%	19.39	3.64
El Paso Electric Company	EE	$45.30	6.70%	7.00%	2.50%	5.40%	5.32%	59.00%	61.00%	66.88%	($0.00)	8.71%	20.78	3.90
Entergy Corporation	ETR	$77.45	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	$0.00	10.39%	13.90	2.61
Eversource Energy	ES	$56.36	6.30%	5.49%	6.00%	5.93%	5.32%	60.00%	58.00%	66.88%	($0.00)	9.14%	18.44	3.46
FirstEnergy Corp.	FE	$33.34	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	10.83%	12.79	2.40
IDACORP, Inc.	IDA	$74.50	4.00%	4.00%	3.00%	3.67%	5.32%	53.00%	60.00%	66.88%	($0.00)	8.80%	20.26	3.81
MGE Energy, Inc.	MGEE	$53.30	NA	4.00%	7.00%	5.50%	5.32%	56.00%	44.00%	66.88%	($0.00)	8.17%	24.70	4.64
NorthWestern Corporation	NWE	$59.68	5.00%	5.00%	6.50%	5.50%	5.32%	65.00%	59.00%	66.88%	($0.00)	9.03%	19.00	3.57
OGE Energy Corp.	OGE	$30.95	5.20%	4.30%	3.00%	4.17%	5.32%	67.00%	70.00%	66.88%	($0.00)	9.24%	17.98	3.38
Otter Tail Corporation	OTTR	$30.96	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	($0.00)	9.39%	17.32	3.26
Pinnacle West Capital Corporation	PNW	$75.82	4.00%	3.73%	4.00%	3.91%	5.32%	64.00%	65.00%	66.88%	($0.00)	8.91%	19.63	3.69
PNM Resources, Inc.	PNM	$33.49	7.60%	8.76%	9.00%	8.45%	5.32%	51.00%	55.00%	66.88%	($0.00)	9.75%	15.89	2.99
Portland General Electric Company	POR	$41.86	6.40%	6.57%	5.50%	6.16%	5.32%	56.00%	56.00%	66.88%	($0.00)	9.15%	18.40	3.46
SCANA Corporation	SCG	$71.01	5.30%	5.40%	4.50%	5.07%	5.32%	59.00%	60.00%	66.88%	($0.00)	9.29%	17.75	3.33
Wisconsin Energy Corporation	WEC	$61.68	6.30%	6.77%	6.00%	6.36%	5.32%	68.00%	67.00%	66.88%	($0.00)	8.43%	22.69	4.26
Xcel Energy Inc.	XEL	$42.20	5.30%	5.27%	5.50%	5.36%	5.32%	62.00%	63.00%	66.88%	($0.00)	9.11%	18.62	3.50
											MEAN	9.16%		
											MAX	10.83%		
											MIN	8.17%		

Projected Annual
Earnings per Share

		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2015	2016	2017	2018	2019	2020	**2021**	2022	2023	2024	2025	**2026**	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE	$3.38	$3.54	$3.71	$3.89	$4.08	$4.28	$4.49	$4.71	$4.95	$5.21	$5.48	$5.77	$6.08	$6.41	$6.75	$7.11	$7.48
Alliant Energy Corporation	LNT	$1.69	$1.80	$1.91	$2.03	$2.15	$2.29	$2.43	$2.57	$2.72	$2.87	$3.03	$3.19	$3.36	$3.54	$3.73	$3.92	$4.13
Ameren Corporation	AEE	$2.38	$2.52	$2.66	$2.82	$2.98	$3.15	$3.33	$3.52	$3.71	$3.91	$4.13	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63
American Electric Power Company, Inc.	AEP	$3.59	$3.75	$3.91	$4.08	$4.25	$4.44	$4.64	$4.85	$5.09	$5.34	$5.62	$5.92	$6.23	$6.56	$6.91	$7.28	$7.67
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.01	$2.15	$2.29	$2.44	$2.60	$2.76	$2.93	$3.10	$3.28	$3.46	$3.65	$3.84	$4.04	$4.26	$4.49	$4.73
DTE Energy Company	DTE	$4.45	$4.69	$4.94	$5.21	$5.49	$5.78	$6.09	$6.42	$6.77	$7.13	$7.51	$7.91	$8.33	$8.77	$9.24	$9.73	$10.25
El Paso Electric Company	EE	$2.03	$2.14	$2.26	$2.38	$2.51	$2.64	$2.78	$2.93	$3.09	$3.25	$3.43	$3.61	$3.80	$4.01	$4.22	$4.44	$4.68
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.92	$3.10	$3.28	$3.48	$3.68	$3.90	$4.12	$4.35	$4.59	$4.84	$5.10	$5.37	$5.65	$5.96	$6.27	$6.61
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$4.01	$4.16	$4.31	$4.47	$4.63	$4.82	$5.02	$5.24	$5.50	$5.77	$6.08	$6.40	$6.74	$7.10	$7.48	$7.88
MGE Energy, Inc.	MGEE	$2.06	$2.17	$2.29	$2.42	$2.55	$2.69	$2.84	$2.99	$3.16	$3.33	$3.50	$3.69	$3.89	$4.09	$4.31	$4.54	$4.78
NorthWestern Corporation	NWE	$2.90	$3.06	$3.23	$3.41	$3.59	$3.79	$4.00	$4.22	$4.44	$4.68	$4.93	$5.20	$5.47	$5.76	$6.07	$6.39	$6.73
OGE Energy Corp.	OGE	$1.69	$1.76	$1.83	$1.91	$1.99	$2.07	$2.16	$2.26	$2.37	$2.49	$2.61	$2.75	$2.90	$3.05	$3.22	$3.39	$3.57
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.07	$4.23	$4.40	$4.57	$4.75	$4.95	$5.16	$5.40	$5.66	$5.95	$6.27	$6.60	$6.95	$7.32	$7.71	$8.12
PNM Resources, Inc.	PNM	$1.64	$1.78	$1.93	$2.09	$2.27	$2.46	$2.66	$2.85	$3.05	$3.24	$3.43	$3.62	$3.81	$4.01	$4.22	$4.45	$4.69
Portland General Electric Company	POR	$2.04	$2.17	$2.30	$2.44	$2.59	$2.75	$2.92	$3.09	$3.26	$3.45	$3.64	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
SCANA Corporation	SCG	$3.81	$4.00	$4.21	$4.42	$4.64	$4.88	$5.13	$5.39	$5.67	$5.97	$6.28	$6.62	$6.97	$7.34	$7.73	$8.14	$8.58
Wisconsin Energy Corporation	WEC	$2.34	$2.49	$2.65	$2.82	$2.99	$3.18	$3.38	$3.58	$3.79	$4.01	$4.23	$4.45	$4.69	$4.94	$5.20	$5.48	$5.77
Xcel Energy Inc.	XEL	$2.10	$2.21	$2.33	$2.46	$2.59	$2.73	$2.87	$3.03	$3.19	$3.36	$3.54	$3.72	$3.92	$4.13	$4.35	$4.58	$4.83

Projected Annual
Dividend Payout Ratic

			[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE		66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT		64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE		68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP		64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA		68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS		63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE		63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE		59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR		67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES		60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE		55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA		53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE		56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE		65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE		67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR		80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW		64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM		51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR		56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG		59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC		68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL		62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.34	$2.42	$2.51	$2.60	$2.70	$2.86	$3.03	$3.22	$3.42	$3.63	$3.86	$4.07	$4.28	$4.51	$4.75	$5.00	$125.92
Alliant Energy Corporation	LNT	$1.15	$1.21	$1.27	$1.33	$1.39	$1.50	$1.62	$1.74	$1.86	$2.00	$2.13	$2.25	$2.37	$2.49	$2.62	$2.76	$82.00
Ameren Corporation	AEE	$1.71	$1.78	$1.86	$1.94	$2.02	$2.15	$2.28	$2.43	$2.58	$2.74	$2.91	$3.06	$3.22	$3.40	$3.58	$3.77	$106.24
American Electric Power Company, Inc.	AEP	$2.40	$2.53	$2.67	$2.82	$2.97	$3.11	$3.25	$3.41	$3.58	$3.76	$3.96	$4.17	$4.39	$4.62	$4.87	$5.13	$138.31
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.30
CMS Energy Corporation	CMS	$1.27	$1.35	$1.43	$1.52	$1.61	$1.73	$1.86	$2.00	$2.14	$2.29	$2.44	$2.57	$2.71	$2.85	$3.00	$3.16	$92.20
DTE Energy Company	DTE	$2.95	$3.09	$3.23	$3.38	$3.53	$3.78	$4.04	$4.33	$4.63	$4.95	$5.29	$5.57	$5.87	$6.18	$6.51	$6.85	$198.64
El Paso Electric Company	EE	$1.26	$1.34	$1.43	$1.52	$1.61	$1.72	$1.85	$1.98	$2.11	$2.26	$2.42	$2.54	$2.68	$2.82	$2.97	$3.13	$97.26
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$162.41
Eversource Energy	ES	$1.75	$1.84	$1.94	$2.03	$2.14	$2.32	$2.51	$2.72	$2.93	$3.17	$3.41	$3.59	$3.78	$3.98	$4.20	$4.42	$121.82
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$75.89
IDACORP, Inc.	IDA	$2.13	$2.28	$2.44	$2.60	$2.78	$2.94	$3.13	$3.33	$3.55	$3.79	$4.07	$4.28	$4.51	$4.75	$5.00	$5.27	$159.67
MGE Energy, Inc.	MGEE	$1.22	$1.22	$1.21	$1.20	$1.18	$1.36	$1.55	$1.75	$1.97	$2.21	$2.47	$2.60	$2.74	$2.88	$3.04	$3.20	$118.15
NorthWestern Corporation	NWE	$1.99	$2.05	$2.11	$2.17	$2.24	$2.41	$2.60	$2.80	$3.01	$3.23	$3.47	$3.66	$3.85	$4.06	$4.28	$4.50	$127.93
OGE Energy Corp.	OGE	$1.18	$1.24	$1.31	$1.38	$1.45	$1.50	$1.56	$1.62	$1.69	$1.76	$1.84	$1.94	$2.04	$2.15	$2.27	$2.39	$64.15
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$65.02
Pinnacle West Capital Corporation	PNW	$2.61	$2.72	$2.84	$2.96	$3.09	$3.23	$3.39	$3.56	$3.75	$3.96	$4.19	$4.41	$4.65	$4.90	$5.16	$5.43	$159.45
PNM Resources, Inc.	PNM	$0.91	$1.00	$1.11	$1.23	$1.35	$1.51	$1.68	$1.86	$2.04	$2.23	$2.42	$2.55	$2.68	$2.83	$2.98	$3.13	$74.46
Portland General Electric Company	POR	$1.21	$1.29	$1.37	$1.45	$1.54	$1.69	$1.84	$2.01	$2.18	$2.37	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$91.28
SCANA Corporation	SCG	$2.36	$2.49	$2.63	$2.77	$2.93	$3.14	$3.36	$3.60	$3.85	$4.13	$4.43	$4.66	$4.91	$5.17	$5.45	$5.74	$152.23
Wisconsin Energy Corporation	WEC	$1.69	$1.79	$1.90	$2.01	$2.13	$2.26	$2.40	$2.54	$2.68	$2.83	$2.98	$3.14	$3.30	$3.48	$3.67	$3.86	$130.97
Xcel Energy Inc.	XEL	$1.37	$1.45	$1.53	$1.62	$1.72	$1.83	$1.95	$2.07	$2.20	$2.34	$2.49	$2.62	$2.76	$2.91	$3.06	$3.23	$89.86

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($59.67)	$0.00	$1.18	$2.40	$2.60	$2.70	$2.86	$3.03	$3.22	$3.42	$3.63	$3.86	$4.07	$4.28	$4.51	$4.75	$5.00	$130.93
Alliant Energy Corporation	LNT	($38.20)	$0.00	$0.58	$1.18	$1.33	$1.39	$1.50	$1.62	$1.74	$1.86	$2.00	$2.13	$2.25	$2.37	$2.49	$2.62	$2.76	$84.76
Ameren Corporation	AEE	($50.12)	$0.00	$0.86	$1.76	$1.94	$2.02	$2.15	$2.28	$2.43	$2.58	$2.74	$2.91	$3.06	$3.22	$3.40	$3.58	$3.77	$110.01
American Electric Power Company, Inc.	AEP	($66.05)	$0.00	$1.21	$2.45	$2.82	$2.97	$3.11	$3.25	$3.41	$3.58	$3.76	$3.96	$4.17	$4.39	$4.62	$4.87	$5.13	$143.44
Avista Corporation	AVA	($41.65)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$91.13
CMS Energy Corporation	CMS	($42.95)	$0.00	$0.64	$1.31	$1.52	$1.61	$1.73	$1.86	$2.00	$2.14	$2.29	$2.44	$2.57	$2.71	$2.85	$3.00	$3.16	$95.36
DTE Energy Company	DTE	($92.91)	$0.00	$1.49	$3.03	$3.38	$3.53	$3.78	$4.04	$4.33	$4.63	$4.95	$5.29	$5.57	$5.87	$6.18	$6.51	$6.85	$205.49
El Paso Electric Company	EE	($45.30)	$0.00	$0.64	$1.30	$1.52	$1.61	$1.72	$1.85	$1.98	$2.11	$2.26	$2.42	$2.54	$2.68	$2.82	$2.97	$3.13	$100.39
Entergy Corporation	ETR	($77.45)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$170.22
Eversource Energy	ES	($56.36)	$0.00	$0.88	$1.81	$2.03	$2.14	$2.32	$2.51	$2.72	$2.93	$3.17	$3.41	$3.59	$3.78	$3.98	$4.20	$4.42	$126.24
FirstEnergy Corp.	FE	($33.34)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$79.86
IDACORP, Inc.	IDA	($74.50)	$0.00	$1.07	$2.17	$2.60	$2.78	$2.94	$3.13	$3.33	$3.55	$3.79	$4.07	$4.28	$4.51	$4.75	$5.00	$5.27	$164.94
MGE Energy, Inc.	MGEE	($53.30)	$0.00	$0.61	$1.25	$1.20	$1.18	$1.36	$1.55	$1.75	$1.97	$2.21	$2.47	$2.60	$2.74	$2.88	$3.04	$3.20	$121.34
NorthWestern Corporation	NWE	($59.68)	$0.00	$1.00	$2.04	$2.17	$2.24	$2.41	$2.60	$2.80	$3.01	$3.23	$3.47	$3.66	$3.85	$4.06	$4.28	$4.50	$132.44
OGE Energy Corp.	OGE	($30.95)	$0.00	$0.59	$1.20	$1.38	$1.45	$1.50	$1.56	$1.62	$1.69	$1.76	$1.84	$1.94	$2.04	$2.15	$2.27	$2.39	$66.54
Otter Tail Corporation	OTTR	($30.96)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$67.53
Pinnacle West Capital Corporation	PNW	($75.82)	$0.00	$1.31	$2.66	$2.96	$3.09	$3.23	$3.39	$3.56	$3.75	$3.96	$4.19	$4.41	$4.65	$4.90	$5.16	$5.43	$164.88
PNM Resources, Inc.	PNM	($33.49)	$0.00	$0.46	$0.95	$1.23	$1.35	$1.51	$1.68	$1.86	$2.04	$2.23	$2.42	$2.55	$2.68	$2.83	$2.98	$3.13	$77.60
Portland General Electric Company	POR	($41.86)	$0.00	$0.61	$1.25	$1.45	$1.54	$1.69	$1.84	$2.01	$2.18	$2.37	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$94.60
SCANA Corporation	SCG	($71.01)	$0.00	$1.19	$2.42	$2.77	$2.93	$3.14	$3.36	$3.60	$3.85	$4.13	$4.43	$4.66	$4.91	$5.17	$5.45	$5.74	$157.97
Wisconsin Energy Corporation	WEC	($61.68)	$0.00	$0.85	$1.75	$2.01	$2.13	$2.26	$2.40	$2.54	$2.68	$2.83	$2.98	$3.14	$3.30	$3.48	$3.67	$3.86	$134.83
Xcel Energy Inc.	XEL	($42.20)	$0.00	$0.69	$1.41	$1.62	$1.72	$1.83	$1.95	$2.07	$2.20	$2.34	$2.49	$2.62	$2.76	$2.91	$3.06	$3.23	$93.08

Multi-Stage Growth Discounted Cash Flow Model
90 Day Average Stock Price
Average EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$57.08	5.50%	5.00%	4.00%	4.83%	5.32%	66.00%	63.00%	66.88%	($0.00)	9.70%	16.08	3.02
Alliant Energy Corporation	LNT	$36.64	6.10%	6.60%	6.00%	6.23%	5.32%	64.00%	61.00%	66.88%	($0.00)	9.03%	19.01	3.57
Ameren Corporation	AEE	$48.90	6.10%	5.20%	6.00%	5.77%	5.32%	68.00%	64.00%	66.88%	($0.00)	9.15%	18.39	3.46
American Electric Power Company, Inc.	AEP	$65.03	4.90%	4.10%	4.00%	4.33%	5.32%	64.00%	67.00%	66.88%	($0.00)	9.29%	17.75	3.34
Avista Corporation	AVA	$40.48	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	($0.00)	8.80%	20.25	3.80
CMS Energy Corporation	CMS	$41.70	6.40%	7.24%	6.00%	6.55%	5.32%	63.00%	62.00%	66.88%	($0.00)	9.04%	18.94	3.56
DTE Energy Company	DTE	$89.93	5.80%	5.35%	5.00%	5.38%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.08%	18.75	3.52
El Paso Electric Company	EE	$44.56	6.70%	7.00%	2.50%	5.40%	5.32%	59.00%	61.00%	66.88%	($0.00)	8.77%	20.44	3.84
Entergy Corporation	ETR	$76.55	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	10.45%	13.73	2.58
Eversource Energy	ES	$56.58	6.30%	5.49%	6.00%	5.93%	5.32%	60.00%	58.00%	66.88%	($0.00)	9.13%	18.51	3.48
FirstEnergy Corp.	FE	$34.24	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	10.69%	13.12	2.46
IDACORP, Inc.	IDA	$73.58	4.00%	4.00%	3.00%	3.67%	5.32%	53.00%	60.00%	66.88%	($0.00)	8.84%	20.01	3.76
MGE Energy, Inc.	MGEE	$51.38	NA	4.00%	7.00%	5.50%	5.32%	56.00%	44.00%	66.88%	($0.00)	8.28%	23.83	4.48
NorthWestern Corporation	NWE	$59.59	5.00%	5.00%	6.50%	5.50%	5.32%	65.00%	59.00%	66.88%	($0.00)	9.04%	18.97	3.56
OGE Energy Corp.	OGE	$29.13	5.20%	4.30%	3.00%	4.17%	5.32%	67.00%	70.00%	66.88%	($0.00)	9.49%	16.88	3.17
Otter Tail Corporation	OTTR	$29.44	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	($0.00)	9.61%	16.45	3.09
Pinnacle West Capital Corporation	PNW	$73.65	4.00%	3.73%	4.00%	3.91%	5.32%	64.00%	65.00%	66.88%	($0.00)	9.02%	19.05	3.58
PNM Resources, Inc.	PNM	$32.94	7.60%	8.76%	9.00%	8.45%	5.32%	51.00%	55.00%	66.88%	($0.00)	9.83%	15.64	2.94
Portland General Electric Company	POR	$40.24	6.40%	6.57%	5.50%	6.16%	5.32%	56.00%	56.00%	66.88%	($0.00)	9.31%	17.68	3.32
SCANA Corporation	SCG	$69.22	5.30%	5.40%	4.50%	5.07%	5.32%	59.00%	60.00%	66.88%	($0.00)	9.40%	17.29	3.25
Wisconsin Energy Corporation	WEC	$59.53	6.30%	6.77%	6.00%	6.36%	5.32%	68.00%	67.00%	66.88%	($0.00)	8.54%	21.88	4.11
Xcel Energy Inc.	XEL	$41.15	5.30%	5.27%	5.50%	5.36%	5.32%	62.00%	63.00%	66.88%	($0.00)	9.20%	18.15	3.41
											MEAN	9.26%		
											MAX	10.69%		
											MIN	8.28%		

Projected Annual Earnings per Share		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2015	2016	2017	2018	2019	2020	**2021**	2022	2023	2024	2025	**2026**	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE	$3.38	$3.54	$3.71	$3.89	$4.08	$4.28	$4.49	$4.71	$4.95	$5.21	$5.48	$5.77	$6.08	$6.41	$6.75	$7.11	$7.48
Alliant Energy Corporation	LNT	$1.69	$1.80	$1.91	$2.03	$2.15	$2.29	$2.43	$2.57	$2.72	$2.87	$3.03	$3.19	$3.36	$3.54	$3.73	$3.92	$4.13
Ameren Corporation	AEE	$2.38	$2.52	$2.66	$2.82	$2.98	$3.15	$3.33	$3.52	$3.71	$3.91	$4.13	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63
American Electric Power Company, Inc.	AEP	$3.59	$3.75	$3.91	$4.08	$4.25	$4.44	$4.64	$4.85	$5.09	$5.34	$5.62	$5.92	$6.23	$6.56	$6.91	$7.28	$7.67
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.01	$2.15	$2.29	$2.44	$2.60	$2.76	$2.93	$3.10	$3.28	$3.46	$3.65	$3.84	$4.04	$4.26	$4.49	$4.73
DTE Energy Company	DTE	$4.45	$4.69	$4.94	$5.21	$5.49	$5.78	$6.09	$6.42	$6.77	$7.13	$7.51	$7.91	$8.33	$8.77	$9.24	$9.73	$10.25
El Paso Electric Company	EE	$2.03	$2.14	$2.26	$2.38	$2.51	$2.64	$2.78	$2.93	$3.09	$3.25	$3.43	$3.61	$3.80	$4.01	$4.22	$4.44	$4.68
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.92	$3.10	$3.28	$3.48	$3.68	$3.90	$4.12	$4.35	$4.59	$4.84	$5.10	$5.37	$5.65	$5.96	$6.27	$6.61
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$4.01	$4.16	$4.31	$4.47	$4.63	$4.82	$5.02	$5.24	$5.50	$5.77	$6.08	$6.40	$6.74	$7.10	$7.48	$7.88
MGE Energy, Inc.	MGEE	$2.06	$2.17	$2.29	$2.42	$2.55	$2.69	$2.84	$2.99	$3.16	$3.33	$3.50	$3.69	$3.89	$4.09	$4.31	$4.54	$4.78
NorthWestern Corporation	NWE	$2.90	$3.06	$3.23	$3.41	$3.59	$3.79	$4.00	$4.22	$4.44	$4.68	$4.93	$5.20	$5.47	$5.76	$6.07	$6.39	$6.73
OGE Energy Corp.	OGE	$1.69	$1.76	$1.83	$1.91	$1.99	$2.07	$2.16	$2.26	$2.37	$2.49	$2.61	$2.75	$2.90	$3.05	$3.22	$3.39	$3.57
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.07	$4.23	$4.40	$4.57	$4.75	$4.95	$5.16	$5.40	$5.66	$5.95	$6.27	$6.60	$6.95	$7.32	$7.71	$8.12
PNM Resources, Inc.	PNM	$1.64	$1.78	$1.93	$2.09	$2.27	$2.46	$2.66	$2.85	$3.05	$3.24	$3.43	$3.62	$3.81	$4.01	$4.22	$4.45	$4.69
Portland General Electric Company	POR	$2.04	$2.17	$2.30	$2.44	$2.59	$2.75	$2.92	$3.09	$3.26	$3.45	$3.64	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
SCANA Corporation	SCG	$3.81	$4.00	$4.21	$4.42	$4.64	$4.88	$5.13	$5.39	$5.67	$5.97	$6.28	$6.62	$6.97	$7.34	$7.73	$8.14	$8.58
Wisconsin Energy Corporation	WEC	$2.34	$2.49	$2.65	$2.82	$2.99	$3.18	$3.38	$3.58	$3.79	$4.01	$4.23	$4.45	$4.69	$4.94	$5.20	$5.48	$5.77
Xcel Energy Inc.	XEL	$2.10	$2.21	$2.33	$2.46	$2.59	$2.73	$2.87	$3.03	$3.19	$3.36	$3.54	$3.72	$3.92	$4.13	$4.35	$4.58	$4.83

Projected Annual Dividend Payout Ratic			[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE		66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT		64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE		68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP		64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA		68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS		63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE		63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE		59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR		67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES		60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE		55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA		53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE		56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE		65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE		67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR		80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW		64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM		51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR		56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG		59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC		68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL		62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.34	$2.42	$2.51	$2.60	$2.70	$2.86	$3.03	$3.22	$3.42	$3.63	$3.86	$4.07	$4.28	$4.51	$4.75	$5.00	$120.32
Alliant Energy Corporation	LNT	$1.15	$1.21	$1.27	$1.33	$1.39	$1.50	$1.62	$1.74	$1.86	$2.00	$2.13	$2.25	$2.37	$2.49	$2.62	$2.76	$78.59
Ameren Corporation	AEE	$1.71	$1.78	$1.86	$1.94	$2.02	$2.15	$2.28	$2.43	$2.58	$2.74	$2.91	$3.06	$3.22	$3.40	$3.58	$3.77	$103.59
American Electric Power Company, Inc.	AEP	$2.40	$2.53	$2.67	$2.82	$2.97	$3.11	$3.25	$3.41	$3.58	$3.76	$3.96	$4.17	$4.39	$4.62	$4.87	$5.13	$136.12
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$85.75
CMS Energy Corporation	CMS	$1.27	$1.35	$1.43	$1.52	$1.61	$1.73	$1.86	$2.00	$2.14	$2.29	$2.44	$2.57	$2.71	$2.85	$3.00	$3.16	$89.48
DTE Energy Company	DTE	$2.95	$3.09	$3.23	$3.38	$3.53	$3.78	$4.04	$4.33	$4.63	$4.95	$5.29	$5.57	$5.87	$6.18	$6.51	$6.85	$192.17
El Paso Electric Company	EE	$1.26	$1.34	$1.43	$1.52	$1.61	$1.72	$1.85	$1.98	$2.11	$2.26	$2.42	$2.54	$2.68	$2.82	$2.97	$3.13	$95.66
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$160.45
Eversource Energy	ES	$1.75	$1.84	$1.94	$2.03	$2.14	$2.32	$2.51	$2.72	$2.93	$3.17	$3.41	$3.59	$3.78	$3.98	$4.20	$4.42	$122.31
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$77.84
IDACORP, Inc.	IDA	$2.13	$2.28	$2.44	$2.60	$2.78	$2.94	$3.13	$3.33	$3.55	$3.79	$4.07	$4.28	$4.51	$4.75	$5.00	$5.27	$157.69
MGE Energy, Inc.	MGEE	$1.22	$1.22	$1.21	$1.20	$1.18	$1.36	$1.55	$1.75	$1.97	$2.21	$2.47	$2.60	$2.74	$2.88	$3.04	$3.20	$113.96
NorthWestern Corporation	NWE	$1.99	$2.05	$2.11	$2.17	$2.24	$2.41	$2.60	$2.80	$3.01	$3.23	$3.47	$3.66	$3.85	$4.06	$4.28	$4.50	$127.73
OGE Energy Corp.	OGE	$1.18	$1.24	$1.31	$1.38	$1.45	$1.50	$1.56	$1.62	$1.69	$1.76	$1.84	$1.94	$2.04	$2.15	$2.27	$2.39	$60.22
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$61.72
Pinnacle West Capital Corporation	PNW	$2.61	$2.72	$2.84	$2.96	$3.09	$3.23	$3.39	$3.56	$3.75	$3.96	$4.19	$4.41	$4.65	$4.90	$5.16	$5.43	$154.76
PNM Resources, Inc.	PNM	$0.91	$1.00	$1.11	$1.23	$1.35	$1.51	$1.68	$1.86	$2.04	$2.23	$2.42	$2.55	$2.68	$2.83	$2.98	$3.13	$73.27
Portland General Electric Company	POR	$1.21	$1.29	$1.37	$1.45	$1.54	$1.69	$1.84	$2.01	$2.18	$2.37	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$87.75
SCANA Corporation	SCG	$2.36	$2.49	$2.63	$2.77	$2.93	$3.14	$3.36	$3.60	$3.85	$4.13	$4.43	$4.66	$4.91	$5.17	$5.45	$5.74	$148.34
Wisconsin Energy Corporation	WEC	$1.69	$1.79	$1.90	$2.01	$2.13	$2.26	$2.40	$2.54	$2.68	$2.83	$2.98	$3.14	$3.30	$3.48	$3.67	$3.86	$126.29
Xcel Energy Inc.	XEL	$1.37	$1.45	$1.53	$1.62	$1.72	$1.83	$1.95	$2.07	$2.20	$2.34	$2.49	$2.62	$2.76	$2.91	$3.06	$3.23	$87.58

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($57.08)	$0.00	$1.18	$2.40	$2.60	$2.70	$2.86	$3.03	$3.22	$3.42	$3.63	$3.86	$4.07	$4.28	$4.51	$4.75	$5.00	$125.33
Alliant Energy Corporation	LNT	($36.64)	$0.00	$0.58	$1.18	$1.33	$1.39	$1.50	$1.62	$1.74	$1.86	$2.00	$2.13	$2.25	$2.37	$2.49	$2.62	$2.76	$81.36
Ameren Corporation	AEE	($48.90)	$0.00	$0.86	$1.76	$1.94	$2.02	$2.15	$2.28	$2.43	$2.58	$2.74	$2.91	$3.06	$3.22	$3.40	$3.58	$3.77	$107.35
American Electric Power Company, Inc.	AEP	($65.03)	$0.00	$1.21	$2.45	$2.82	$2.97	$3.11	$3.25	$3.41	$3.58	$3.76	$3.96	$4.17	$4.39	$4.62	$4.87	$5.13	$141.25
Avista Corporation	AVA	($40.48)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.58
CMS Energy Corporation	CMS	($41.70)	$0.00	$0.64	$1.31	$1.52	$1.61	$1.73	$1.86	$2.00	$2.14	$2.29	$2.44	$2.57	$2.71	$2.85	$3.00	$3.16	$92.64
DTE Energy Company	DTE	($89.93)	$0.00	$1.49	$3.03	$3.38	$3.53	$3.78	$4.04	$4.33	$4.63	$4.95	$5.29	$5.57	$5.87	$6.18	$6.51	$6.85	$199.02
El Paso Electric Company	EE	($44.56)	$0.00	$0.64	$1.30	$1.52	$1.61	$1.72	$1.85	$1.98	$2.11	$2.26	$2.42	$2.54	$2.68	$2.82	$2.97	$3.13	$98.79
Entergy Corporation	ETR	($76.55)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$168.27
Eversource Energy	ES	($56.58)	$0.00	$0.88	$1.81	$2.03	$2.14	$2.32	$2.51	$2.72	$2.93	$3.17	$3.41	$3.59	$3.78	$3.98	$4.20	$4.42	$126.72
FirstEnergy Corp.	FE	($34.24)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$81.81
IDACORP, Inc.	IDA	($73.58)	$0.00	$1.07	$2.17	$2.60	$2.78	$2.94	$3.13	$3.33	$3.55	$3.79	$4.07	$4.28	$4.51	$4.75	$5.00	$5.27	$162.96
MGE Energy, Inc.	MGEE	($51.38)	$0.00	$0.61	$1.25	$1.20	$1.18	$1.36	$1.55	$1.75	$1.97	$2.21	$2.47	$2.60	$2.74	$2.88	$3.04	$3.20	$117.16
NorthWestern Corporation	NWE	($59.59)	$0.00	$1.00	$2.04	$2.17	$2.24	$2.41	$2.60	$2.80	$3.01	$3.23	$3.47	$3.66	$3.85	$4.06	$4.28	$4.50	$132.23
OGE Energy Corp.	OGE	($29.13)	$0.00	$0.59	$1.20	$1.38	$1.45	$1.50	$1.56	$1.62	$1.69	$1.76	$1.84	$1.94	$2.04	$2.15	$2.27	$2.39	$62.60
Otter Tail Corporation	OTTR	($29.44)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$64.23
Pinnacle West Capital Corporation	PNW	($73.65)	$0.00	$1.31	$2.66	$2.96	$3.09	$3.23	$3.39	$3.56	$3.75	$3.96	$4.19	$4.41	$4.65	$4.90	$5.16	$5.43	$160.19
PNM Resources, Inc.	PNM	($32.94)	$0.00	$0.46	$0.95	$1.23	$1.35	$1.51	$1.68	$1.86	$2.04	$2.23	$2.42	$2.55	$2.68	$2.83	$2.98	$3.13	$76.40
Portland General Electric Company	POR	($40.24)	$0.00	$0.61	$1.25	$1.45	$1.54	$1.69	$1.84	$2.01	$2.18	$2.37	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$91.07
SCANA Corporation	SCG	($69.22)	$0.00	$1.19	$2.42	$2.77	$2.93	$3.14	$3.36	$3.60	$3.85	$4.13	$4.43	$4.66	$4.91	$5.17	$5.45	$5.74	$154.07
Wisconsin Energy Corporation	WEC	($59.53)	$0.00	$0.85	$1.75	$2.01	$2.13	$2.26	$2.40	$2.54	$2.68	$2.83	$2.98	$3.14	$3.30	$3.48	$3.67	$3.86	$130.15
Xcel Energy Inc.	XEL	($41.15)	$0.00	$0.69	$1.41	$1.62	$1.72	$1.83	$1.95	$2.07	$2.20	$2.34	$2.49	$2.62	$2.76	$2.91	$3.06	$3.23	$90.81

Multi-Stage Growth Discounted Cash Flow Model
180 Day Average Stock Price
Average EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$54.07	5.50%	5.00%	4.00%	4.83%	5.32%	66.00%	63.00%	66.88%	($0.00)	9.95%	15.21	2.86
Alliant Energy Corporation	LNT	$33.83	6.10%	6.60%	6.00%	6.23%	5.32%	64.00%	61.00%	66.88%	($0.00)	9.34%	17.54	3.30
Ameren Corporation	AEE	$46.40	6.10%	5.20%	6.00%	5.77%	5.32%	68.00%	64.00%	66.88%	($0.00)	9.36%	17.43	3.28
American Electric Power Company, Inc.	AEP	$61.54	4.90%	4.10%	4.00%	4.33%	5.32%	64.00%	67.00%	66.88%	($0.00)	9.52%	16.76	3.15
Avista Corporation	AVA	$37.83	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	($0.00)	9.05%	18.89	3.55
CMS Energy Corporation	CMS	$39.10	6.40%	7.24%	6.00%	6.55%	5.32%	63.00%	62.00%	66.88%	($0.00)	9.29%	17.74	3.33
DTE Energy Company	DTE	$85.80	5.80%	5.35%	5.00%	5.38%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.26%	17.88	3.36
El Paso Electric Company	EE	$41.72	6.70%	7.00%	2.50%	5.40%	5.32%	59.00%	61.00%	66.88%	($0.00)	9.01%	19.12	3.59
Entergy Corporation	ETR	$72.44	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	10.75%	12.97	2.44
Eversource Energy	ES	$54.15	6.30%	5.49%	6.00%	5.93%	5.32%	60.00%	58.00%	66.88%	($0.00)	9.30%	17.71	3.33
FirstEnergy Corp.	FE	$33.04	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	($0.00)	10.88%	12.67	2.38
IDACORP, Inc.	IDA	$70.82	4.00%	4.00%	3.00%	3.67%	5.32%	53.00%	60.00%	66.88%	($0.00)	8.98%	19.25	3.62
MGE Energy, Inc.	MGEE	$48.29	NA	4.00%	7.00%	5.50%	5.32%	56.00%	44.00%	66.88%	($0.00)	8.46%	22.42	4.21
NorthWestern Corporation	NWE	$57.21	5.00%	5.00%	6.50%	5.50%	5.32%	65.00%	59.00%	66.88%	($0.00)	9.19%	18.20	3.42
OGE Energy Corp.	OGE	$27.72	5.20%	4.30%	3.00%	4.17%	5.32%	67.00%	70.00%	66.88%	($0.00)	9.72%	16.03	3.01
Otter Tail Corporation	OTTR	$28.18	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	($0.00)	9.80%	15.72	2.95
Pinnacle West Capital Corporation	PNW	$69.12	4.00%	3.73%	4.00%	3.91%	5.32%	64.00%	65.00%	66.88%	($0.00)	9.27%	17.84	3.35
PNM Resources, Inc.	PNM	$31.32	7.60%	8.76%	9.00%	8.45%	5.32%	51.00%	55.00%	66.88%	($0.00)	10.05%	14.88	2.80
Portland General Electric Company	POR	$38.74	6.40%	6.57%	5.50%	6.16%	5.32%	56.00%	56.00%	66.88%	($0.00)	9.46%	17.03	3.20
SCANA Corporation	SCG	$64.86	5.30%	5.40%	4.50%	5.07%	5.32%	59.00%	60.00%	66.88%	($0.00)	9.67%	16.19	3.04
Wisconsin Energy Corporation	WEC	$55.89	6.30%	6.77%	6.00%	6.36%	5.32%	68.00%	67.00%	66.88%	($0.00)	8.76%	20.51	3.85
Xcel Energy Inc.	XEL	$38.85	5.30%	5.27%	5.50%	5.36%	5.32%	62.00%	63.00%	66.88%	($0.00)	9.44%	17.12	3.22
											MEAN	9.48%		
											MAX	10.88%		
											MIN	8.46%		

Projected Annual
Earnings per Share

		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2015	2016	2017	2018	2019	2020	**2021**	2022	2023	2024	2025	**2026**	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE	$3.38	$3.54	$3.71	$3.89	$4.08	$4.28	$4.49	$4.71	$4.95	$5.21	$5.48	$5.77	$6.08	$6.41	$6.75	$7.11	$7.48
Alliant Energy Corporation	LNT	$1.69	$1.80	$1.91	$2.03	$2.15	$2.29	$2.43	$2.57	$2.72	$2.87	$3.03	$3.19	$3.36	$3.54	$3.73	$3.92	$4.13
Ameren Corporation	AEE	$2.38	$2.52	$2.66	$2.82	$2.98	$3.15	$3.33	$3.52	$3.71	$3.91	$4.13	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63
American Electric Power Company, Inc.	AEP	$3.59	$3.75	$3.91	$4.08	$4.25	$4.44	$4.64	$4.85	$5.09	$5.34	$5.62	$5.92	$6.23	$6.56	$6.91	$7.28	$7.67
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.01	$2.15	$2.29	$2.44	$2.60	$2.76	$2.93	$3.10	$3.28	$3.46	$3.65	$3.84	$4.04	$4.26	$4.49	$4.73
DTE Energy Company	DTE	$4.45	$4.69	$4.94	$5.21	$5.49	$5.78	$6.09	$6.42	$6.77	$7.13	$7.51	$7.91	$8.33	$8.77	$9.24	$9.73	$10.25
El Paso Electric Company	EE	$2.03	$2.14	$2.26	$2.38	$2.51	$2.64	$2.78	$2.93	$3.09	$3.25	$3.43	$3.61	$3.80	$4.01	$4.22	$4.44	$4.68
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.92	$3.10	$3.28	$3.48	$3.68	$3.90	$4.12	$4.35	$4.59	$4.84	$5.10	$5.37	$5.65	$5.96	$6.27	$6.61
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$4.01	$4.16	$4.31	$4.47	$4.63	$4.82	$5.02	$5.24	$5.50	$5.77	$6.08	$6.40	$6.74	$7.10	$7.48	$7.88
MGE Energy, Inc.	MGEE	$2.06	$2.17	$2.29	$2.42	$2.55	$2.69	$2.84	$2.99	$3.16	$3.33	$3.50	$3.69	$3.89	$4.09	$4.31	$4.54	$4.78
NorthWestern Corporation	NWE	$2.90	$3.06	$3.23	$3.41	$3.59	$3.79	$4.00	$4.22	$4.44	$4.68	$4.93	$5.20	$5.47	$5.76	$6.07	$6.39	$6.73
OGE Energy Corp.	OGE	$1.69	$1.76	$1.83	$1.91	$1.99	$2.07	$2.16	$2.26	$2.37	$2.49	$2.61	$2.75	$2.90	$3.05	$3.22	$3.39	$3.57
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.07	$4.23	$4.40	$4.57	$4.75	$4.95	$5.16	$5.40	$5.66	$5.95	$6.27	$6.60	$6.95	$7.32	$7.71	$8.12
PNM Resources, Inc.	PNM	$1.64	$1.78	$1.93	$2.09	$2.27	$2.46	$2.66	$2.85	$3.05	$3.24	$3.43	$3.62	$3.81	$4.01	$4.22	$4.45	$4.69
Portland General Electric Company	POR	$2.04	$2.17	$2.30	$2.44	$2.59	$2.75	$2.92	$3.09	$3.26	$3.45	$3.64	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
SCANA Corporation	SCG	$3.81	$4.00	$4.21	$4.42	$4.64	$4.88	$5.13	$5.39	$5.67	$5.97	$6.28	$6.62	$6.97	$7.34	$7.73	$8.14	$8.58
Wisconsin Energy Corporation	WEC	$2.34	$2.49	$2.65	$2.82	$2.99	$3.18	$3.38	$3.58	$3.79	$4.01	$4.23	$4.45	$4.69	$4.94	$5.20	$5.48	$5.77
Xcel Energy Inc.	XEL	$2.10	$2.21	$2.33	$2.46	$2.59	$2.73	$2.87	$3.03	$3.19	$3.36	$3.54	$3.72	$3.92	$4.13	$4.35	$4.58	$4.83

Projected Annual
Dividend Payout Ratic

			[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE		66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT		64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE		68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP		64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA		68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS		63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE		63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE		59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR		67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES		60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE		55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA		53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE		56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE		65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE		67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR		80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW		64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM		51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR		56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG		59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC		68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL		62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.34	$2.42	$2.51	$2.60	$2.70	$2.86	$3.03	$3.22	$3.42	$3.63	$3.86	$4.07	$4.28	$4.51	$4.75	$5.00	$113.80
Alliant Energy Corporation	LNT	$1.15	$1.21	$1.27	$1.33	$1.39	$1.50	$1.62	$1.74	$1.86	$2.00	$2.13	$2.25	$2.37	$2.49	$2.62	$2.76	$72.50
Ameren Corporation	AEE	$1.71	$1.78	$1.86	$1.94	$2.02	$2.15	$2.28	$2.43	$2.58	$2.74	$2.91	$3.06	$3.22	$3.40	$3.58	$3.77	$98.17
American Electric Power Company, Inc.	AEP	$2.40	$2.53	$2.67	$2.82	$2.97	$3.11	$3.25	$3.41	$3.58	$3.76	$3.96	$4.17	$4.39	$4.62	$4.87	$5.13	$128.55
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$80.01
CMS Energy Corporation	CMS	$1.27	$1.35	$1.43	$1.52	$1.61	$1.73	$1.86	$2.00	$2.14	$2.29	$2.44	$2.57	$2.71	$2.85	$3.00	$3.16	$83.85
DTE Energy Company	DTE	$2.95	$3.09	$3.23	$3.38	$3.53	$3.78	$4.04	$4.33	$4.63	$4.95	$5.29	$5.57	$5.87	$6.18	$6.51	$6.85	$183.20
El Paso Electric Company	EE	$1.26	$1.34	$1.43	$1.52	$1.61	$1.72	$1.85	$1.98	$2.11	$2.26	$2.42	$2.54	$2.68	$2.82	$2.97	$3.13	$89.50
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$151.57
Eversource Energy	ES	$1.75	$1.84	$1.94	$2.03	$2.14	$2.32	$2.51	$2.72	$2.93	$3.17	$3.41	$3.59	$3.78	$3.98	$4.20	$4.42	$117.02
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$75.22
IDACORP, Inc.	IDA	$2.13	$2.28	$2.44	$2.60	$2.78	$2.94	$3.13	$3.33	$3.55	$3.79	$4.07	$4.28	$4.51	$4.75	$5.00	$5.27	$151.68
MGE Energy, Inc.	MGEE	$1.22	$1.22	$1.21	$1.20	$1.18	$1.36	$1.55	$1.75	$1.97	$2.21	$2.47	$2.60	$2.74	$2.88	$3.04	$3.20	$107.22
NorthWestern Corporation	NWE	$1.99	$2.05	$2.11	$2.17	$2.24	$2.41	$2.60	$2.80	$3.01	$3.23	$3.47	$3.66	$3.85	$4.06	$4.28	$4.50	$122.57
OGE Energy Corp.	OGE	$1.18	$1.24	$1.31	$1.38	$1.45	$1.50	$1.56	$1.62	$1.69	$1.76	$1.84	$1.94	$2.04	$2.15	$2.27	$2.39	$57.18
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$58.99
Pinnacle West Capital Corporation	PNW	$2.61	$2.72	$2.84	$2.96	$3.09	$3.23	$3.39	$3.56	$3.75	$3.96	$4.19	$4.41	$4.65	$4.90	$5.16	$5.43	$144.92
PNM Resources, Inc.	PNM	$0.91	$1.00	$1.11	$1.23	$1.35	$1.51	$1.68	$1.86	$2.04	$2.23	$2.42	$2.55	$2.68	$2.83	$2.98	$3.13	$69.74
Portland General Electric Company	POR	$1.21	$1.29	$1.37	$1.45	$1.54	$1.69	$1.84	$2.01	$2.18	$2.37	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$84.48
SCANA Corporation	SCG	$2.36	$2.49	$2.63	$2.77	$2.93	$3.14	$3.36	$3.60	$3.85	$4.13	$4.43	$4.66	$4.91	$5.17	$5.45	$5.74	$138.87
Wisconsin Energy Corporation	WEC	$1.69	$1.79	$1.90	$2.01	$2.13	$2.26	$2.40	$2.54	$2.68	$2.83	$2.98	$3.14	$3.30	$3.48	$3.67	$3.86	$118.39
Xcel Energy Inc.	XEL	$1.37	$1.45	$1.53	$1.62	$1.72	$1.83	$1.95	$2.07	$2.20	$2.34	$2.49	$2.62	$2.76	$2.91	$3.06	$3.23	$82.60

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($54.07)	$0.00	$1.18	$2.40	$2.60	$2.70	$2.86	$3.03	$3.22	$3.42	$3.63	$3.86	$4.07	$4.28	$4.51	$4.75	$5.00	$118.81
Alliant Energy Corporation	LNT	($33.83)	$0.00	$0.58	$1.18	$1.33	$1.39	$1.50	$1.62	$1.74	$1.86	$2.00	$2.13	$2.25	$2.37	$2.49	$2.62	$2.76	$75.27
Ameren Corporation	AEE	($46.40)	$0.00	$0.86	$1.76	$1.94	$2.02	$2.15	$2.28	$2.43	$2.58	$2.74	$2.91	$3.06	$3.22	$3.40	$3.58	$3.77	$101.93
American Electric Power Company, Inc.	AEP	($61.54)	$0.00	$1.21	$2.45	$2.82	$2.97	$3.11	$3.25	$3.41	$3.58	$3.76	$3.96	$4.17	$4.39	$4.62	$4.87	$5.13	$133.68
Avista Corporation	AVA	($37.83)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$82.84
CMS Energy Corporation	CMS	($39.10)	$0.00	$0.64	$1.31	$1.52	$1.61	$1.73	$1.86	$2.00	$2.14	$2.29	$2.44	$2.57	$2.71	$2.85	$3.00	$3.16	$87.01
DTE Energy Company	DTE	($85.80)	$0.00	$1.49	$3.03	$3.38	$3.53	$3.78	$4.04	$4.33	$4.63	$4.95	$5.29	$5.57	$5.87	$6.18	$6.51	$6.85	$190.06
El Paso Electric Company	EE	($41.72)	$0.00	$0.64	$1.30	$1.52	$1.61	$1.72	$1.85	$1.98	$2.11	$2.26	$2.42	$2.54	$2.68	$2.82	$2.97	$3.13	$92.63
Entergy Corporation	ETR	($72.44)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$159.39
Eversource Energy	ES	($54.15)	$0.00	$0.88	$1.81	$2.03	$2.14	$2.32	$2.51	$2.72	$2.93	$3.17	$3.41	$3.59	$3.78	$3.98	$4.20	$4.42	$121.44
FirstEnergy Corp.	FE	($33.04)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$79.19
IDACORP, Inc.	IDA	($70.82)	$0.00	$1.07	$2.17	$2.60	$2.78	$2.94	$3.13	$3.33	$3.55	$3.79	$4.07	$4.28	$4.51	$4.75	$5.00	$5.27	$156.95
MGE Energy, Inc.	MGEE	($48.29)	$0.00	$0.61	$1.25	$1.20	$1.18	$1.36	$1.55	$1.75	$1.97	$2.21	$2.47	$2.60	$2.74	$2.88	$3.04	$3.20	$110.42
NorthWestern Corporation	NWE	($57.21)	$0.00	$1.00	$2.04	$2.17	$2.24	$2.41	$2.60	$2.80	$3.01	$3.23	$3.47	$3.66	$3.85	$4.06	$4.28	$4.50	$127.07
OGE Energy Corp.	OGE	($27.72)	$0.00	$0.59	$1.20	$1.38	$1.45	$1.50	$1.56	$1.62	$1.69	$1.76	$1.84	$1.94	$2.04	$2.15	$2.27	$2.39	$59.56
Otter Tail Corporation	OTTR	($28.18)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$61.50
Pinnacle West Capital Corporation	PNW	($69.12)	$0.00	$1.31	$2.66	$2.96	$3.09	$3.23	$3.39	$3.56	$3.75	$3.96	$4.19	$4.41	$4.65	$4.90	$5.16	$5.43	$150.35
PNM Resources, Inc.	PNM	($31.32)	$0.00	$0.46	$0.95	$1.23	$1.35	$1.51	$1.68	$1.86	$2.04	$2.23	$2.42	$2.55	$2.68	$2.83	$2.98	$3.13	$72.88
Portland General Electric Company	POR	($38.74)	$0.00	$0.61	$1.25	$1.45	$1.54	$1.69	$1.84	$2.01	$2.18	$2.37	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$87.80
SCANA Corporation	SCG	($64.86)	$0.00	$1.19	$2.42	$2.77	$2.93	$3.14	$3.36	$3.60	$3.85	$4.13	$4.43	$4.66	$4.91	$5.17	$5.45	$5.74	$144.61
Wisconsin Energy Corporation	WEC	($55.89)	$0.00	$0.85	$1.75	$2.01	$2.13	$2.26	$2.40	$2.54	$2.68	$2.83	$2.98	$3.14	$3.30	$3.48	$3.67	$3.86	$122.25
Xcel Energy Inc.	XEL	($38.85)	$0.00	$0.69	$1.41	$1.62	$1.72	$1.83	$1.95	$2.07	$2.20	$2.34	$2.49	$2.62	$2.76	$2.91	$3.06	$3.23	$85.83

Multi-Stage Growth Discounted Cash Flow Model
30 Day Average Stock Price
Low EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Low Growth	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$59.67	5.50%	5.00%	4.00%	4.00%	5.32%	66.00%	63.00%	66.88%	($0.00)	9.28%	17.80	3.34
Alliant Energy Corporation	LNT	$38.20	6.10%	6.60%	6.00%	6.00%	5.32%	64.00%	61.00%	66.88%	($0.00)	8.82%	20.15	3.79
Ameren Corporation	AEE	$50.12	6.10%	5.20%	6.00%	5.20%	5.32%	68.00%	64.00%	66.88%	($0.00)	8.92%	19.60	3.68
American Electric Power Company, Inc.	AEP	$66.05	4.90%	4.10%	4.00%	4.00%	5.32%	64.00%	67.00%	66.88%	($0.00)	9.14%	18.45	3.47
Avista Corporation	AVA	$41.65	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	($0.00)	8.70%	20.85	3.92
CMS Energy Corporation	CMS	$42.95	6.40%	7.24%	6.00%	6.00%	5.32%	63.00%	62.00%	66.88%	($0.00)	8.80%	20.23	3.80
DTE Energy Company	DTE	$92.91	5.80%	5.35%	5.00%	5.00%	5.32%	63.00%	61.00%	66.88%	($0.00)	8.86%	19.89	3.74
El Paso Electric Company	EE	$45.30	6.70%	7.00%	2.50%	2.50%	5.32%	59.00%	61.00%	66.88%	($0.00)	8.10%	25.35	4.76
Entergy Corporation	ETR	$77.45	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	$0.00	10.39%	13.90	2.61
Eversource Energy	ES	$56.36	6.30%	5.49%	6.00%	5.49%	5.32%	60.00%	58.00%	66.88%	($0.00)	9.03%	18.98	3.57
FirstEnergy Corp.	FE	$33.34	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	10.83%	12.79	2.40
IDACORP, Inc.	IDA	$74.50	4.00%	4.00%	3.00%	3.00%	5.32%	53.00%	60.00%	66.88%	($0.00)	8.64%	21.21	3.99
MGE Energy, Inc.	MGEE	$53.30	NA	4.00%	7.00%	4.00%	5.32%	56.00%	44.00%	66.88%	($0.00)	7.90%	27.32	5.13
NorthWestern Corporation	NWE	$59.68	5.00%	5.00%	6.50%	5.00%	5.32%	65.00%	59.00%	66.88%	($0.00)	8.91%	19.65	3.69
OGE Energy Corp.	OGE	$30.95	5.20%	4.30%	3.00%	3.00%	5.32%	67.00%	70.00%	66.88%	($0.00)	8.94%	19.49	3.66
Otter Tail Corporation	OTTR	$30.96	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	($0.00)	9.39%	17.32	3.26
Pinnacle West Capital Corporation	PNW	$75.82	4.00%	3.73%	4.00%	3.73%	5.32%	64.00%	65.00%	66.88%	($0.00)	8.87%	19.87	3.73
PNM Resources, Inc.	PNM	$33.49	7.60%	8.76%	9.00%	7.60%	5.32%	51.00%	55.00%	66.88%	($0.00)	9.52%	16.78	3.15
Portland General Electric Company	POR	$41.86	6.40%	6.57%	5.50%	5.50%	5.32%	56.00%	56.00%	66.88%	($0.00)	8.99%	19.21	3.61
SCANA Corporation	SCG	$71.01	5.30%	5.40%	4.50%	4.50%	5.32%	59.00%	60.00%	66.88%	($0.00)	9.14%	18.43	3.46
Wisconsin Energy Corporation	WEC	$61.68	6.30%	6.77%	6.00%	6.00%	5.32%	68.00%	67.00%	66.88%	($0.00)	8.35%	23.24	4.37
Xcel Energy Inc.	XEL	$42.20	5.30%	5.27%	5.50%	5.27%	5.32%	62.00%	63.00%	66.88%	($0.00)	9.08%	18.73	3.52
											MEAN	9.03%		
											MAX	10.83%		
											MIN	7.90%		

Projected Annual
Earnings per Share

Company	Ticker	[14] 2015	[15] 2016	[16] 2017	[17] 2018	[18] 2019	[19] 2020	[20] **2021**	[21] 2022	[22] 2023	[23] 2024	[24] 2025	[25] **2026**	[26] 2027	[27] 2028	[28] 2029	[29] 2030	[30] 2031
ALLETE, Inc.	ALE	$3.38	$3.52	$3.66	$3.80	$3.95	$4.11	$4.29	$4.48	$4.68	$4.91	$5.16	$5.44	$5.73	$6.03	$6.35	$6.69	$7.05
Alliant Energy Corporation	LNT	$1.69	$1.79	$1.90	$2.01	$2.13	$2.26	$2.39	$2.53	$2.68	$2.82	$2.98	$3.14	$3.30	$3.48	$3.66	$3.86	$4.07
Ameren Corporation	AEE	$2.38	$2.50	$2.63	$2.77	$2.92	$3.07	$3.23	$3.40	$3.57	$3.76	$3.96	$4.17	$4.40	$4.63	$4.88	$5.14	$5.41
American Electric Power Company, Inc.	AEP	$3.59	$3.73	$3.88	$4.04	$4.20	$4.37	$4.55	$4.75	$4.98	$5.22	$5.49	$5.78	$6.08	$6.41	$6.75	$7.11	$7.49
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.00	$2.12	$2.25	$2.39	$2.53	$2.68	$2.83	$2.99	$3.16	$3.33	$3.51	$3.69	$3.89	$4.10	$4.32	$4.55
DTE Energy Company	DTE	$4.45	$4.67	$4.91	$5.15	$5.41	$5.68	$5.97	$6.27	$6.59	$6.94	$7.30	$7.69	$8.10	$8.53	$8.99	$9.47	$9.97
El Paso Electric Company	EE	$2.03	$2.08	$2.13	$2.19	$2.24	$2.30	$2.36	$2.45	$2.54	$2.65	$2.78	$2.93	$3.09	$3.25	$3.42	$3.61	$3.80
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.91	$3.07	$3.24	$3.42	$3.61	$3.80	$4.01	$4.23	$4.45	$4.69	$4.94	$5.20	$5.48	$5.77	$6.08	$6.40
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$3.99	$4.11	$4.23	$4.36	$4.49	$4.64	$4.81	$5.01	$5.24	$5.50	$5.79	$6.10	$6.43	$6.77	$7.13	$7.51
MGE Energy, Inc.	MGEE	$2.06	$2.14	$2.23	$2.32	$2.41	$2.51	$2.61	$2.73	$2.86	$2.99	$3.15	$3.31	$3.49	$3.68	$3.87	$4.08	$4.30
NorthWestern Corporation	NWE	$2.90	$3.05	$3.20	$3.36	$3.52	$3.70	$3.89	$4.09	$4.30	$4.52	$4.76	$5.01	$5.28	$5.56	$5.86	$6.17	$6.50
OGE Energy Corp.	OGE	$1.69	$1.74	$1.79	$1.85	$1.90	$1.96	$2.03	$2.10	$2.19	$2.29	$2.40	$2.53	$2.66	$2.81	$2.96	$3.11	$3.28
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.07	$4.22	$4.38	$4.54	$4.71	$4.90	$5.10	$5.34	$5.59	$5.87	$6.19	$6.52	$6.86	$7.23	$7.61	$8.02
PNM Resources, Inc.	PNM	$1.64	$1.76	$1.90	$2.04	$2.20	$2.37	$2.54	$2.71	$2.88	$3.06	$3.23	$3.41	$3.59	$3.78	$3.98	$4.19	$4.42
Portland General Electric Company	POR	$2.04	$2.15	$2.27	$2.40	$2.53	$2.67	$2.81	$2.97	$3.13	$3.29	$3.47	$3.65	$3.85	$4.05	$4.27	$4.50	$4.74
SCANA Corporation	SCG	$3.81	$3.98	$4.16	$4.35	$4.54	$4.75	$4.97	$5.21	$5.46	$5.74	$6.03	$6.36	$6.69	$7.05	$7.42	$7.82	$8.24
Wisconsin Energy Corporation	WEC	$2.34	$2.48	$2.63	$2.79	$2.95	$3.13	$3.32	$3.51	$3.71	$3.91	$4.12	$4.34	$4.57	$4.82	$5.07	$5.34	$5.63
Xcel Energy Inc.	XEL	$2.10	$2.21	$2.33	$2.45	$2.58	$2.71	$2.86	$3.01	$3.17	$3.34	$3.51	$3.70	$3.90	$4.11	$4.32	$4.55	$4.80

Projected Annual
Dividend Payout Ratic

Company	Ticker	[31] 2016	[32] 2017	[33] 2018	[34] 2019	[35] 2020	[36] 2021	[37] 2022	[38] 2023	[39] 2024	[40] 2025	[41] 2026	[42] 2027	[43] 2028	[44] 2029	[45] 2030	[46] 2031
ALLETE, Inc.	ALE	66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT	64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE	68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP	64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA	68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS	63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE	63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE	59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR	67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES	60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE	55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA	53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE	56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE	65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE	67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR	80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW	64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM	51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR	56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG	59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC	68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL	62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.32	$2.39	$2.45	$2.52	$2.59	$2.73	$2.88	$3.04	$3.22	$3.42	$3.64	$3.83	$4.04	$4.25	$4.48	$4.71	$125.46
Alliant Energy Corporation	LNT	$1.15	$1.20	$1.26	$1.32	$1.38	$1.48	$1.59	$1.71	$1.83	$1.96	$2.10	$2.21	$2.33	$2.45	$2.58	$2.72	$81.92
Ameren Corporation	AEE	$1.70	$1.76	$1.83	$1.89	$1.96	$2.08	$2.21	$2.34	$2.48	$2.63	$2.79	$2.94	$3.10	$3.26	$3.43	$3.62	$106.00
American Electric Power Company, Inc.	AEP	$2.39	$2.51	$2.65	$2.78	$2.93	$3.05	$3.18	$3.33	$3.49	$3.67	$3.86	$4.07	$4.29	$4.51	$4.75	$5.01	$138.14
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.30
CMS Energy Corporation	CMS	$1.26	$1.33	$1.41	$1.49	$1.57	$1.68	$1.80	$1.93	$2.06	$2.20	$2.35	$2.47	$2.60	$2.74	$2.89	$3.04	$91.99
DTE Energy Company	DTE	$2.94	$3.07	$3.19	$3.33	$3.46	$3.70	$3.95	$4.22	$4.50	$4.81	$5.15	$5.42	$5.71	$6.01	$6.33	$6.67	$198.32
El Paso Electric Company	EE	$1.23	$1.27	$1.31	$1.36	$1.40	$1.47	$1.54	$1.63	$1.72	$1.83	$1.96	$2.06	$2.17	$2.29	$2.41	$2.54	$96.28
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$162.41
Eversource Energy	ES	$1.75	$1.83	$1.91	$2.00	$2.09	$2.26	$2.44	$2.64	$2.85	$3.07	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28	$121.57
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$75.89
IDACORP, Inc.	IDA	$2.11	$2.25	$2.39	$2.54	$2.69	$2.84	$3.00	$3.18	$3.39	$3.62	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$159.25
MGE Energy, Inc.	MGEE	$1.20	$1.18	$1.16	$1.13	$1.10	$1.25	$1.41	$1.58	$1.77	$1.98	$2.22	$2.34	$2.46	$2.59	$2.73	$2.87	$117.36
NorthWestern Corporation	NWE	$1.98	$2.03	$2.08	$2.13	$2.18	$2.35	$2.52	$2.71	$2.91	$3.12	$3.35	$3.53	$3.72	$3.92	$4.13	$4.35	$127.65
OGE Energy Corp.	OGE	$1.17	$1.21	$1.26	$1.32	$1.37	$1.41	$1.45	$1.50	$1.55	$1.62	$1.69	$1.78	$1.88	$1.98	$2.08	$2.19	$63.91
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$65.02
Pinnacle West Capital Corporation	PNW	$2.60	$2.71	$2.82	$2.94	$3.06	$3.20	$3.35	$3.52	$3.70	$3.91	$4.14	$4.36	$4.59	$4.83	$5.09	$5.36	$159.34
PNM Resources, Inc.	PNM	$0.90	$0.99	$1.08	$1.19	$1.30	$1.45	$1.60	$1.76	$1.93	$2.10	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$74.08
Portland General Electric Company	POR	$1.21	$1.27	$1.34	$1.42	$1.49	$1.63	$1.77	$1.92	$2.08	$2.26	$2.44	$2.57	$2.71	$2.86	$3.01	$3.17	$90.98
SCANA Corporation	SCG	$2.35	$2.47	$2.59	$2.71	$2.85	$3.04	$3.24	$3.46	$3.71	$3.97	$4.25	$4.48	$4.71	$4.97	$5.23	$5.51	$151.84
Wisconsin Energy Corporation	WEC	$1.69	$1.78	$1.88	$1.99	$2.10	$2.22	$2.35	$2.48	$2.62	$2.76	$2.90	$3.06	$3.22	$3.39	$3.57	$3.76	$130.82
Xcel Energy Inc.	XEL	$1.37	$1.45	$1.53	$1.62	$1.71	$1.82	$1.93	$2.06	$2.19	$2.33	$2.48	$2.61	$2.75	$2.89	$3.05	$3.21	$89.82

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($59.67)	$0.00	$1.17	$2.37	$2.52	$2.59	$2.73	$2.88	$3.04	$3.22	$3.42	$3.64	$3.83	$4.04	$4.25	$4.48	$4.71	$130.17
Alliant Energy Corporation	LNT	($38.20)	$0.00	$0.58	$1.18	$1.32	$1.38	$1.48	$1.59	$1.71	$1.83	$1.96	$2.10	$2.21	$2.33	$2.45	$2.58	$2.72	$84.63
Ameren Corporation	AEE	($50.12)	$0.00	$0.86	$1.75	$1.89	$1.96	$2.08	$2.21	$2.34	$2.48	$2.63	$2.79	$2.94	$3.10	$3.26	$3.43	$3.62	$109.62
American Electric Power Company, Inc.	AEP	($66.05)	$0.00	$1.20	$2.44	$2.78	$2.93	$3.05	$3.18	$3.33	$3.49	$3.67	$3.86	$4.07	$4.29	$4.51	$4.75	$5.01	$143.14
Avista Corporation	AVA	($41.65)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$91.13
CMS Energy Corporation	CMS	($42.95)	$0.00	$0.64	$1.30	$1.49	$1.57	$1.68	$1.80	$1.93	$2.06	$2.20	$2.35	$2.47	$2.60	$2.74	$2.89	$3.04	$95.03
DTE Energy Company	DTE	($92.91)	$0.00	$1.48	$3.02	$3.33	$3.46	$3.70	$3.95	$4.22	$4.50	$4.81	$5.15	$5.42	$5.71	$6.01	$6.33	$6.67	$204.99
El Paso Electric Company	EE	($45.30)	$0.00	$0.62	$1.24	$1.36	$1.40	$1.47	$1.54	$1.63	$1.72	$1.83	$1.96	$2.06	$2.17	$2.29	$2.41	$2.54	$98.82
Entergy Corporation	ETR	($77.45)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$170.22
Eversource Energy	ES	($56.36)	$0.00	$0.88	$1.79	$2.00	$2.09	$2.26	$2.44	$2.64	$2.85	$3.07	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28	$125.85
FirstEnergy Corp.	FE	($33.34)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$79.86
IDACORP, Inc.	IDA	($74.50)	$0.00	$1.06	$2.14	$2.54	$2.69	$2.84	$3.00	$3.18	$3.39	$3.62	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$164.27
MGE Energy, Inc.	MGEE	($53.30)	$0.00	$0.60	$1.22	$1.13	$1.10	$1.25	$1.41	$1.58	$1.77	$1.98	$2.22	$2.34	$2.46	$2.59	$2.73	$2.87	$120.23
NorthWestern Corporation	NWE	($59.68)	$0.00	$1.00	$2.03	$2.13	$2.18	$2.35	$2.52	$2.71	$2.91	$3.12	$3.35	$3.53	$3.72	$3.92	$4.13	$4.35	$132.00
OGE Energy Corp.	OGE	($30.95)	$0.00	$0.59	$1.18	$1.32	$1.37	$1.41	$1.45	$1.50	$1.55	$1.62	$1.69	$1.78	$1.88	$1.98	$2.08	$2.19	$66.10
Otter Tail Corporation	OTTR	($30.96)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$67.53
Pinnacle West Capital Corporation	PNW	($75.82)	$0.00	$1.31	$2.65	$2.94	$3.06	$3.20	$3.35	$3.52	$3.70	$3.91	$4.14	$4.36	$4.59	$4.83	$5.09	$5.36	$164.71
PNM Resources, Inc.	PNM	($33.49)	$0.00	$0.45	$0.93	$1.19	$1.30	$1.45	$1.60	$1.76	$1.93	$2.10	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$77.03
Portland General Electric Company	POR	($41.86)	$0.00	$0.61	$1.24	$1.42	$1.49	$1.63	$1.77	$1.92	$2.08	$2.26	$2.44	$2.57	$2.71	$2.86	$3.01	$3.17	$94.15
SCANA Corporation	SCG	($71.01)	$0.00	$1.18	$2.40	$2.71	$2.85	$3.04	$3.24	$3.46	$3.71	$3.97	$4.25	$4.48	$4.71	$4.97	$5.23	$5.51	$157.34
Wisconsin Energy Corporation	WEC	($61.68)	$0.00	$0.85	$1.74	$1.99	$2.10	$2.22	$2.35	$2.48	$2.62	$2.76	$2.90	$3.06	$3.22	$3.39	$3.57	$3.76	$134.59
Xcel Energy Inc.	XEL	($42.20)	$0.00	$0.69	$1.41	$1.62	$1.71	$1.82	$1.93	$2.06	$2.19	$2.33	$2.48	$2.61	$2.75	$2.89	$3.05	$3.21	$93.03

Multi-Stage Growth Discounted Cash Flow Model
90 Day Average Stock Price
Low EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Low Growth	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$57.08	5.50%	5.00%	4.00%	4.00%	5.32%	66.00%	63.00%	66.88%	($0.00)	9.46%	17.00	3.19
Alliant Energy Corporation	LNT	$36.64	6.10%	6.60%	6.00%	6.00%	5.32%	64.00%	61.00%	66.88%	($0.00)	8.97%	19.31	3.63
Ameren Corporation	AEE	$48.90	6.10%	5.20%	6.00%	5.20%	5.32%	68.00%	64.00%	66.88%	($0.00)	9.01%	19.11	3.59
American Electric Power Company, Inc.	AEP	$65.03	4.90%	4.10%	4.00%	4.00%	5.32%	64.00%	67.00%	66.88%	($0.00)	9.20%	18.16	3.41
Avista Corporation	AVA	$40.48	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	($0.00)	8.80%	20.25	3.80
CMS Energy Corporation	CMS	$41.70	6.40%	7.24%	6.00%	6.00%	5.32%	63.00%	62.00%	66.88%	($0.00)	8.91%	19.63	3.69
DTE Energy Company	DTE	$89.93	5.80%	5.35%	5.00%	5.00%	5.32%	63.00%	61.00%	66.88%	($0.00)	8.98%	19.24	3.62
El Paso Electric Company	EE	$44.56	6.70%	7.00%	2.50%	2.50%	5.32%	59.00%	61.00%	66.88%	($0.00)	8.15%	24.93	4.68
Entergy Corporation	ETR	$76.55	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	10.45%	13.73	2.58
Eversource Energy	ES	$56.58	6.30%	5.49%	6.00%	5.49%	5.32%	60.00%	58.00%	66.88%	($0.00)	9.02%	19.06	3.58
FirstEnergy Corp.	FE	$34.24	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	10.69%	13.12	2.46
IDACORP, Inc.	IDA	$73.58	4.00%	4.00%	3.00%	3.00%	5.32%	53.00%	60.00%	66.88%	($0.00)	8.69%	20.95	3.94
MGE Energy, Inc.	MGEE	$51.38	NA	4.00%	7.00%	4.00%	5.32%	56.00%	44.00%	66.88%	($0.00)	8.00%	26.35	4.95
NorthWestern Corporation	NWE	$59.59	5.00%	5.00%	6.50%	5.00%	5.32%	65.00%	59.00%	66.88%	($0.00)	8.91%	19.61	3.69
OGE Energy Corp.	OGE	$29.13	5.20%	4.30%	3.00%	3.00%	5.32%	67.00%	70.00%	66.88%	($0.00)	9.17%	18.29	3.44
Otter Tail Corporation	OTTR	$29.44	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	($0.00)	9.61%	16.45	3.09
Pinnacle West Capital Corporation	PNW	$73.65	4.00%	3.73%	4.00%	3.73%	5.32%	64.00%	65.00%	66.88%	($0.00)	8.97%	19.29	3.62
PNM Resources, Inc.	PNM	$32.94	7.60%	8.76%	9.00%	7.60%	5.32%	51.00%	55.00%	66.88%	($0.00)	9.59%	16.51	3.10
Portland General Electric Company	POR	$40.24	6.40%	6.57%	5.50%	5.50%	5.32%	56.00%	56.00%	66.88%	($0.00)	9.14%	18.47	3.47
SCANA Corporation	SCG	$69.22	5.30%	5.40%	4.50%	4.50%	5.32%	59.00%	60.00%	66.88%	($0.00)	9.24%	17.96	3.37
Wisconsin Energy Corporation	WEC	$59.53	6.30%	6.77%	6.00%	6.00%	5.32%	68.00%	67.00%	66.88%	($0.00)	8.47%	22.41	4.21
Xcel Energy Inc.	XEL	$41.15	5.30%	5.27%	5.50%	5.27%	5.32%	62.00%	63.00%	66.88%	($0.00)	9.18%	18.25	3.43
											MEAN	9.12%		
											MAX	10.69%		
											MIN	8.00%		

Projected Annual
Earnings per Share

Company	Ticker	[14] 2015	[15] 2016	[16] 2017	[17] 2018	[18] 2019	[19] 2020	[20] **2021**	[21] 2022	[22] 2023	[23] 2024	[24] 2025	[25] **2026**	[26] 2027	[27] 2028	[28] 2029	[29] 2030	[30] 2031
ALLETE, Inc.	ALE	$3.38	$3.52	$3.66	$3.80	$3.95	$4.11	$4.29	$4.48	$4.68	$4.91	$5.16	$5.44	$5.73	$6.03	$6.35	$6.69	$7.05
Alliant Energy Corporation	LNT	$1.69	$1.79	$1.90	$2.01	$2.13	$2.26	$2.39	$2.53	$2.68	$2.82	$2.98	$3.14	$3.30	$3.48	$3.66	$3.86	$4.07
Ameren Corporation	AEE	$2.38	$2.50	$2.63	$2.77	$2.92	$3.07	$3.23	$3.40	$3.57	$3.76	$3.96	$4.17	$4.40	$4.63	$4.88	$5.14	$5.41
American Electric Power Company, Inc.	AEP	$3.59	$3.73	$3.88	$4.04	$4.20	$4.37	$4.55	$4.75	$4.98	$5.22	$5.49	$5.78	$6.08	$6.41	$6.75	$7.11	$7.49
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.00	$2.12	$2.25	$2.39	$2.53	$2.68	$2.83	$2.99	$3.16	$3.33	$3.51	$3.69	$3.89	$4.10	$4.32	$4.55
DTE Energy Company	DTE	$4.45	$4.67	$4.91	$5.15	$5.41	$5.68	$5.97	$6.27	$6.59	$6.94	$7.30	$7.69	$8.10	$8.53	$8.99	$9.47	$9.97
El Paso Electric Company	EE	$2.03	$2.08	$2.13	$2.19	$2.24	$2.30	$2.36	$2.45	$2.54	$2.65	$2.78	$2.93	$3.09	$3.25	$3.42	$3.61	$3.80
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.91	$3.07	$3.24	$3.42	$3.61	$3.80	$4.01	$4.23	$4.45	$4.69	$4.94	$5.20	$5.48	$5.77	$6.08	$6.40
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$3.99	$4.11	$4.23	$4.36	$4.49	$4.64	$4.81	$5.01	$5.24	$5.50	$5.79	$6.10	$6.43	$6.77	$7.13	$7.51
MGE Energy, Inc.	MGEE	$2.06	$2.14	$2.23	$2.32	$2.41	$2.51	$2.61	$2.73	$2.86	$2.99	$3.15	$3.31	$3.49	$3.68	$3.87	$4.08	$4.30
NorthWestern Corporation	NWE	$2.90	$3.05	$3.20	$3.36	$3.52	$3.70	$3.89	$4.09	$4.30	$4.52	$4.76	$5.01	$5.28	$5.56	$5.86	$6.17	$6.50
OGE Energy Corp.	OGE	$1.69	$1.74	$1.79	$1.85	$1.90	$1.96	$2.03	$2.10	$2.19	$2.29	$2.40	$2.53	$2.66	$2.81	$2.96	$3.11	$3.28
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.07	$4.22	$4.38	$4.54	$4.71	$4.90	$5.10	$5.34	$5.59	$5.87	$6.19	$6.52	$6.86	$7.23	$7.61	$8.02
PNM Resources, Inc.	PNM	$1.64	$1.76	$1.90	$2.04	$2.20	$2.37	$2.54	$2.71	$2.88	$3.06	$3.23	$3.41	$3.59	$3.78	$3.98	$4.19	$4.42
Portland General Electric Company	POR	$2.04	$2.15	$2.27	$2.40	$2.53	$2.67	$2.81	$2.97	$3.13	$3.29	$3.47	$3.65	$3.85	$4.05	$4.27	$4.50	$4.74
SCANA Corporation	SCG	$3.81	$3.98	$4.16	$4.35	$4.54	$4.75	$4.97	$5.21	$5.46	$5.74	$6.03	$6.36	$6.69	$7.05	$7.42	$7.82	$8.24
Wisconsin Energy Corporation	WEC	$2.34	$2.48	$2.63	$2.79	$2.95	$3.13	$3.32	$3.51	$3.71	$3.91	$4.12	$4.34	$4.57	$4.82	$5.07	$5.34	$5.63
Xcel Energy Inc.	XEL	$2.10	$2.21	$2.33	$2.45	$2.58	$2.71	$2.86	$3.01	$3.17	$3.34	$3.51	$3.70	$3.90	$4.11	$4.32	$4.55	$4.80

Projected Annual
Dividend Payout Ratic

Company	Ticker	[31] 2016	[32] 2017	[33] 2018	[34] 2019	[35] 2020	[36] 2021	[37] 2022	[38] 2023	[39] 2024	[40] 2025	[41] 2026	[42] 2027	[43] 2028	[44] 2029	[45] 2030	[46] 2031
ALLETE, Inc.	ALE	66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT	64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE	68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP	64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA	68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS	63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE	63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE	59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR	67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES	60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE	55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA	53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE	56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE	65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE	67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR	80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW	64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM	51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR	56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG	59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC	68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL	62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.32	$2.39	$2.45	$2.52	$2.59	$2.73	$2.88	$3.04	$3.22	$3.42	$3.64	$3.83	$4.04	$4.25	$4.48	$4.71	$119.86
Alliant Energy Corporation	LNT	$1.15	$1.20	$1.26	$1.32	$1.38	$1.48	$1.59	$1.71	$1.83	$1.96	$2.10	$2.21	$2.33	$2.45	$2.58	$2.72	$78.51
Ameren Corporation	AEE	$1.70	$1.76	$1.83	$1.89	$1.96	$2.08	$2.21	$2.34	$2.48	$2.63	$2.79	$2.94	$3.10	$3.26	$3.43	$3.62	$103.35
American Electric Power Company, Inc.	AEP	$2.39	$2.51	$2.65	$2.78	$2.93	$3.05	$3.18	$3.33	$3.49	$3.67	$3.86	$4.07	$4.29	$4.51	$4.75	$5.01	$135.94
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$85.75
CMS Energy Corporation	CMS	$1.26	$1.33	$1.41	$1.49	$1.57	$1.68	$1.80	$1.93	$2.06	$2.20	$2.35	$2.47	$2.60	$2.74	$2.89	$3.04	$89.27
DTE Energy Company	DTE	$2.94	$3.07	$3.19	$3.33	$3.46	$3.70	$3.95	$4.22	$4.50	$4.81	$5.15	$5.42	$5.71	$6.01	$6.33	$6.67	$191.85
El Paso Electric Company	EE	$1.23	$1.27	$1.31	$1.36	$1.40	$1.47	$1.54	$1.63	$1.72	$1.83	$1.96	$2.06	$2.17	$2.29	$2.41	$2.54	$94.68
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$160.45
Eversource Energy	ES	$1.75	$1.83	$1.91	$2.00	$2.09	$2.26	$2.44	$2.64	$2.85	$3.07	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28	$122.05
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$77.84
IDACORP, Inc.	IDA	$2.11	$2.25	$2.39	$2.54	$2.69	$2.84	$3.00	$3.18	$3.39	$3.62	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$157.26
MGE Energy, Inc.	MGEE	$1.20	$1.18	$1.16	$1.13	$1.10	$1.25	$1.41	$1.58	$1.77	$1.98	$2.22	$2.34	$2.46	$2.59	$2.73	$2.87	$113.18
NorthWestern Corporation	NWE	$1.98	$2.03	$2.08	$2.13	$2.18	$2.35	$2.52	$2.71	$2.91	$3.12	$3.35	$3.53	$3.72	$3.92	$4.13	$4.35	$127.44
OGE Energy Corp.	OGE	$1.17	$1.21	$1.26	$1.32	$1.37	$1.41	$1.45	$1.50	$1.55	$1.62	$1.69	$1.78	$1.88	$1.98	$2.08	$2.19	$59.97
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$61.72
Pinnacle West Capital Corporation	PNW	$2.60	$2.71	$2.82	$2.94	$3.06	$3.20	$3.35	$3.52	$3.70	$3.91	$4.14	$4.36	$4.59	$4.83	$5.09	$5.36	$154.65
PNM Resources, Inc.	PNM	$0.90	$0.99	$1.08	$1.19	$1.30	$1.45	$1.60	$1.76	$1.93	$2.10	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$72.88
Portland General Electric Company	POR	$1.21	$1.27	$1.34	$1.42	$1.49	$1.63	$1.77	$1.92	$2.08	$2.26	$2.44	$2.57	$2.71	$2.86	$3.01	$3.17	$87.46
SCANA Corporation	SCG	$2.35	$2.47	$2.59	$2.71	$2.85	$3.04	$3.24	$3.46	$3.71	$3.97	$4.25	$4.48	$4.71	$4.97	$5.23	$5.51	$147.94
Wisconsin Energy Corporation	WEC	$1.69	$1.78	$1.88	$1.99	$2.10	$2.22	$2.35	$2.48	$2.62	$2.76	$2.90	$3.06	$3.22	$3.39	$3.57	$3.76	$126.14
Xcel Energy Inc.	XEL	$1.37	$1.45	$1.53	$1.62	$1.71	$1.82	$1.93	$2.06	$2.19	$2.33	$2.48	$2.61	$2.75	$2.89	$3.05	$3.21	$87.55

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($57.08)	$0.00	$1.17	$2.37	$2.52	$2.59	$2.73	$2.88	$3.04	$3.22	$3.42	$3.64	$3.83	$4.04	$4.25	$4.48	$4.71	$124.58
Alliant Energy Corporation	LNT	($36.64)	$0.00	$0.58	$1.18	$1.32	$1.38	$1.48	$1.59	$1.71	$1.83	$1.96	$2.10	$2.21	$2.33	$2.45	$2.58	$2.72	$81.23
Ameren Corporation	AEE	($48.90)	$0.00	$0.86	$1.75	$1.89	$1.96	$2.08	$2.21	$2.34	$2.48	$2.63	$2.79	$2.94	$3.10	$3.26	$3.43	$3.62	$106.96
American Electric Power Company, Inc.	AEP	($65.03)	$0.00	$1.20	$2.44	$2.78	$2.93	$3.05	$3.18	$3.33	$3.49	$3.67	$3.86	$4.07	$4.29	$4.51	$4.75	$5.01	$140.95
Avista Corporation	AVA	($40.48)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.58
CMS Energy Corporation	CMS	($41.70)	$0.00	$0.64	$1.30	$1.49	$1.57	$1.68	$1.80	$1.93	$2.06	$2.20	$2.35	$2.47	$2.60	$2.74	$2.89	$3.04	$92.31
DTE Energy Company	DTE	($89.93)	$0.00	$1.48	$3.02	$3.33	$3.46	$3.70	$3.95	$4.22	$4.50	$4.81	$5.15	$5.42	$5.71	$6.01	$6.33	$6.67	$198.52
El Paso Electric Company	EE	($44.56)	$0.00	$0.62	$1.24	$1.36	$1.40	$1.47	$1.54	$1.63	$1.72	$1.83	$1.96	$2.06	$2.17	$2.29	$2.41	$2.54	$97.22
Entergy Corporation	ETR	($76.55)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$168.27
Eversource Energy	ES	($56.58)	$0.00	$0.88	$1.79	$2.00	$2.09	$2.26	$2.44	$2.64	$2.85	$3.07	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28	$126.33
FirstEnergy Corp.	FE	($34.24)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$81.81
IDACORP, Inc.	IDA	($73.58)	$0.00	$1.06	$2.14	$2.54	$2.69	$2.84	$3.00	$3.18	$3.39	$3.62	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$162.29
MGE Energy, Inc.	MGEE	($51.38)	$0.00	$0.60	$1.22	$1.13	$1.10	$1.25	$1.41	$1.58	$1.77	$1.98	$2.22	$2.34	$2.46	$2.59	$2.73	$2.87	$116.06
NorthWestern Corporation	NWE	($59.59)	$0.00	$1.00	$2.03	$2.13	$2.18	$2.35	$2.52	$2.71	$2.91	$3.12	$3.35	$3.53	$3.72	$3.92	$4.13	$4.35	$131.79
OGE Energy Corp.	OGE	($29.13)	$0.00	$0.59	$1.18	$1.32	$1.37	$1.41	$1.45	$1.50	$1.55	$1.62	$1.69	$1.78	$1.88	$1.98	$2.08	$2.19	$62.16
Otter Tail Corporation	OTTR	($29.44)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$64.23
Pinnacle West Capital Corporation	PNW	($73.65)	$0.00	$1.31	$2.65	$2.94	$3.06	$3.20	$3.35	$3.52	$3.70	$3.91	$4.14	$4.36	$4.59	$4.83	$5.09	$5.36	$160.01
PNM Resources, Inc.	PNM	($32.94)	$0.00	$0.45	$0.93	$1.19	$1.30	$1.45	$1.60	$1.76	$1.93	$2.10	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$75.84
Portland General Electric Company	POR	($40.24)	$0.00	$0.61	$1.24	$1.42	$1.49	$1.63	$1.77	$1.92	$2.08	$2.26	$2.44	$2.57	$2.71	$2.86	$3.01	$3.17	$90.63
SCANA Corporation	SCG	($69.22)	$0.00	$1.18	$2.40	$2.71	$2.85	$3.04	$3.24	$3.46	$3.71	$3.97	$4.25	$4.48	$4.71	$4.97	$5.23	$5.51	$153.45
Wisconsin Energy Corporation	WEC	($59.53)	$0.00	$0.85	$1.74	$1.99	$2.10	$2.22	$2.35	$2.48	$2.62	$2.76	$2.90	$3.06	$3.22	$3.39	$3.57	$3.76	$129.91
Xcel Energy Inc.	XEL	($41.15)	$0.00	$0.69	$1.41	$1.62	$1.71	$1.82	$1.93	$2.06	$2.19	$2.33	$2.48	$2.61	$2.75	$2.89	$3.05	$3.21	$90.76

Multi-Stage Growth Discounted Cash Flow Model
180 Day Average Stock Price
Low EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Low Growth	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$54.07	5.50%	5.00%	4.00%	4.00%	5.32%	66.00%	63.00%	66.88%	($0.00)	9.70%	16.08	3.02
Alliant Energy Corporation	LNT	$33.83	6.10%	6.60%	6.00%	6.00%	5.32%	64.00%	61.00%	66.88%	($0.00)	9.28%	17.81	3.35
Ameren Corporation	AEE	$46.40	6.10%	5.20%	6.00%	5.20%	5.32%	68.00%	64.00%	66.88%	($0.00)	9.21%	18.10	3.40
American Electric Power Company, Inc.	AEP	$61.54	4.90%	4.10%	4.00%	4.00%	5.32%	64.00%	67.00%	66.88%	($0.00)	9.43%	17.15	3.22
Avista Corporation	AVA	$37.83	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	($0.00)	9.05%	18.89	3.55
CMS Energy Corporation	CMS	$39.10	6.40%	7.24%	6.00%	6.00%	5.32%	63.00%	62.00%	66.88%	($0.00)	9.15%	18.40	3.46
DTE Energy Company	DTE	$85.80	5.80%	5.35%	5.00%	5.00%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.16%	18.34	3.45
El Paso Electric Company	EE	$41.72	6.70%	7.00%	2.50%	2.50%	5.32%	59.00%	61.00%	66.88%	($0.00)	8.34%	23.31	4.38
Entergy Corporation	ETR	$72.44	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	10.75%	12.97	2.44
Eversource Energy	ES	$54.15	6.30%	5.49%	6.00%	5.49%	5.32%	60.00%	58.00%	66.88%	($0.00)	9.19%	18.24	3.43
FirstEnergy Corp.	FE	$33.04	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	($0.00)	10.88%	12.67	2.38
IDACORP, Inc.	IDA	$70.82	4.00%	4.00%	3.00%	3.00%	5.32%	53.00%	60.00%	66.88%	($0.00)	8.82%	20.15	3.79
MGE Energy, Inc.	MGEE	$48.29	NA	4.00%	7.00%	4.00%	5.32%	56.00%	44.00%	66.88%	($0.00)	8.17%	24.78	4.66
NorthWestern Corporation	NWE	$57.21	5.00%	5.00%	6.50%	5.00%	5.32%	65.00%	59.00%	66.88%	($0.00)	9.07%	18.82	3.54
OGE Energy Corp.	OGE	$27.72	5.20%	4.30%	3.00%	3.00%	5.32%	67.00%	70.00%	66.88%	($0.00)	9.38%	17.36	3.26
Otter Tail Corporation	OTTR	$28.18	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	($0.00)	9.80%	15.72	2.95
Pinnacle West Capital Corporation	PNW	$69.12	4.00%	3.73%	4.00%	3.73%	5.32%	64.00%	65.00%	66.88%	($0.00)	9.22%	18.06	3.39
PNM Resources, Inc.	PNM	$31.32	7.60%	8.76%	9.00%	7.60%	5.32%	51.00%	55.00%	66.88%	($0.00)	9.81%	15.71	2.95
Portland General Electric Company	POR	$38.74	6.40%	6.57%	5.50%	5.50%	5.32%	56.00%	56.00%	66.88%	($0.00)	9.29%	17.77	3.34
SCANA Corporation	SCG	$64.86	5.30%	5.40%	4.50%	4.50%	5.32%	59.00%	60.00%	66.88%	($0.00)	9.51%	16.81	3.16
Wisconsin Energy Corporation	WEC	$55.89	6.30%	6.77%	6.00%	6.00%	5.32%	68.00%	67.00%	66.88%	($0.00)	8.68%	21.01	3.95
Xcel Energy Inc.	XEL	$38.85	5.30%	5.27%	5.50%	5.27%	5.32%	62.00%	63.00%	66.88%	($0.00)	9.41%	17.21	3.23
											MEAN	9.33%		
											MAX	10.88%		
											MIN	8.17%		

Projected Annual
Earnings per Share

		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2015	2016	2017	2018	2019	2020	**2021**	2022	2023	2024	2025	**2026**	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE	$3.38	$3.52	$3.66	$3.80	$3.95	$4.11	$4.29	$4.48	$4.68	$4.91	$5.16	$5.44	$5.73	$6.03	$6.35	$6.69	$7.05
Alliant Energy Corporation	LNT	$1.69	$1.79	$1.90	$2.01	$2.13	$2.26	$2.39	$2.53	$2.68	$2.82	$2.98	$3.14	$3.30	$3.48	$3.66	$3.86	$4.07
Ameren Corporation	AEE	$2.38	$2.50	$2.63	$2.77	$2.92	$3.07	$3.23	$3.40	$3.57	$3.76	$3.96	$4.17	$4.40	$4.63	$4.88	$5.14	$5.41
American Electric Power Company, Inc.	AEP	$3.59	$3.73	$3.88	$4.04	$4.20	$4.37	$4.55	$4.75	$4.98	$5.22	$5.49	$5.78	$6.08	$6.41	$6.75	$7.11	$7.49
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.00	$2.12	$2.25	$2.39	$2.53	$2.68	$2.83	$2.99	$3.16	$3.33	$3.51	$3.69	$3.89	$4.10	$4.32	$4.55
DTE Energy Company	DTE	$4.45	$4.67	$4.91	$5.15	$5.41	$5.68	$5.97	$6.27	$6.59	$6.94	$7.30	$7.69	$8.10	$8.53	$8.99	$9.47	$9.97
El Paso Electric Company	EE	$2.03	$2.08	$2.13	$2.19	$2.24	$2.30	$2.36	$2.45	$2.54	$2.65	$2.78	$2.93	$3.09	$3.25	$3.42	$3.61	$3.80
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.91	$3.07	$3.24	$3.42	$3.61	$3.80	$4.01	$4.23	$4.45	$4.69	$4.94	$5.20	$5.48	$5.77	$6.08	$6.40
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$3.99	$4.11	$4.23	$4.36	$4.49	$4.64	$4.81	$5.01	$5.24	$5.50	$5.79	$6.10	$6.43	$6.77	$7.13	$7.51
MGE Energy, Inc.	MGEE	$2.06	$2.14	$2.23	$2.32	$2.41	$2.51	$2.61	$2.73	$2.86	$2.99	$3.15	$3.31	$3.49	$3.68	$3.87	$4.08	$4.30
NorthWestern Corporation	NWE	$2.90	$3.05	$3.20	$3.36	$3.52	$3.70	$3.89	$4.09	$4.30	$4.52	$4.76	$5.01	$5.28	$5.56	$5.86	$6.17	$6.50
OGE Energy Corp.	OGE	$1.69	$1.74	$1.79	$1.85	$1.90	$1.96	$2.03	$2.10	$2.19	$2.29	$2.40	$2.53	$2.66	$2.81	$2.96	$3.11	$3.28
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.07	$4.22	$4.38	$4.54	$4.71	$4.90	$5.10	$5.34	$5.59	$5.87	$6.19	$6.52	$6.86	$7.23	$7.61	$8.02
PNM Resources, Inc.	PNM	$1.64	$1.76	$1.90	$2.04	$2.20	$2.37	$2.54	$2.71	$2.88	$3.06	$3.23	$3.41	$3.59	$3.78	$3.98	$4.19	$4.42
Portland General Electric Company	POR	$2.04	$2.15	$2.27	$2.40	$2.53	$2.67	$2.81	$2.97	$3.13	$3.29	$3.47	$3.65	$3.85	$4.05	$4.27	$4.50	$4.74
SCANA Corporation	SCG	$3.81	$3.98	$4.16	$4.35	$4.54	$4.75	$4.97	$5.21	$5.46	$5.74	$6.03	$6.36	$6.69	$7.05	$7.42	$7.82	$8.24
Wisconsin Energy Corporation	WEC	$2.34	$2.48	$2.63	$2.79	$2.95	$3.13	$3.32	$3.51	$3.71	$3.91	$4.12	$4.34	$4.57	$4.82	$5.07	$5.34	$5.63
Xcel Energy Inc.	XEL	$2.10	$2.21	$2.33	$2.45	$2.58	$2.71	$2.86	$3.01	$3.17	$3.34	$3.51	$3.70	$3.90	$4.11	$4.32	$4.55	$4.80

Projected Annual
Dividend Payout Ratic

		[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE	66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT	64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE	68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP	64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA	68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS	63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE	63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE	59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR	67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES	60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE	55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA	53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE	56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE	65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE	67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR	80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW	64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM	51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR	56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG	59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC	68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL	62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.32	$2.39	$2.45	$2.52	$2.59	$2.73	$2.88	$3.04	$3.22	$3.42	$3.64	$3.83	$4.04	$4.25	$4.48	$4.71	$113.34
Alliant Energy Corporation	LNT	$1.15	$1.20	$1.26	$1.32	$1.38	$1.48	$1.59	$1.71	$1.83	$1.96	$2.10	$2.21	$2.33	$2.45	$2.58	$2.72	$72.42
Ameren Corporation	AEE	$1.70	$1.76	$1.83	$1.89	$1.96	$2.08	$2.21	$2.34	$2.48	$2.63	$2.79	$2.94	$3.10	$3.26	$3.43	$3.62	$97.93
American Electric Power Company, Inc.	AEP	$2.39	$2.51	$2.65	$2.78	$2.93	$3.05	$3.18	$3.33	$3.49	$3.67	$3.86	$4.07	$4.29	$4.51	$4.75	$5.01	$128.37
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$80.01
CMS Energy Corporation	CMS	$1.26	$1.33	$1.41	$1.49	$1.57	$1.68	$1.80	$1.93	$2.06	$2.20	$2.35	$2.47	$2.60	$2.74	$2.89	$3.04	$83.65
DTE Energy Company	DTE	$2.94	$3.07	$3.19	$3.33	$3.46	$3.70	$3.95	$4.22	$4.50	$4.81	$5.15	$5.42	$5.71	$6.01	$6.33	$6.67	$182.89
El Paso Electric Company	EE	$1.23	$1.27	$1.31	$1.36	$1.40	$1.47	$1.54	$1.63	$1.72	$1.83	$1.96	$2.06	$2.17	$2.29	$2.41	$2.54	$88.51
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$151.57
Eversource Energy	ES	$1.75	$1.83	$1.91	$2.00	$2.09	$2.26	$2.44	$2.64	$2.85	$3.07	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28	$116.77
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$75.22
IDACORP, Inc.	IDA	$2.11	$2.25	$2.39	$2.54	$2.69	$2.84	$3.00	$3.18	$3.39	$3.62	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$151.26
MGE Energy, Inc.	MGEE	$1.20	$1.18	$1.16	$1.13	$1.10	$1.25	$1.41	$1.58	$1.77	$1.98	$2.22	$2.34	$2.46	$2.59	$2.73	$2.87	$106.44
NorthWestern Corporation	NWE	$1.98	$2.03	$2.08	$2.13	$2.18	$2.35	$2.52	$2.71	$2.91	$3.12	$3.35	$3.53	$3.72	$3.92	$4.13	$4.35	$122.29
OGE Energy Corp.	OGE	$1.17	$1.21	$1.26	$1.32	$1.37	$1.41	$1.45	$1.50	$1.55	$1.62	$1.69	$1.78	$1.88	$1.98	$2.08	$2.19	$56.93
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$58.99
Pinnacle West Capital Corporation	PNW	$2.60	$2.71	$2.82	$2.94	$3.06	$3.20	$3.35	$3.52	$3.70	$3.91	$4.14	$4.36	$4.59	$4.83	$5.09	$5.36	$144.82
PNM Resources, Inc.	PNM	$0.90	$0.99	$1.08	$1.19	$1.30	$1.45	$1.60	$1.76	$1.93	$2.10	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$69.36
Portland General Electric Company	POR	$1.21	$1.27	$1.34	$1.42	$1.49	$1.63	$1.77	$1.92	$2.08	$2.26	$2.44	$2.57	$2.71	$2.86	$3.01	$3.17	$84.19
SCANA Corporation	SCG	$2.35	$2.47	$2.59	$2.71	$2.85	$3.04	$3.24	$3.46	$3.71	$3.97	$4.25	$4.48	$4.71	$4.97	$5.23	$5.51	$138.47
Wisconsin Energy Corporation	WEC	$1.69	$1.78	$1.88	$1.99	$2.10	$2.22	$2.35	$2.48	$2.62	$2.76	$2.90	$3.06	$3.22	$3.39	$3.57	$3.76	$118.24
Xcel Energy Inc.	XEL	$1.37	$1.45	$1.53	$1.62	$1.71	$1.82	$1.93	$2.06	$2.19	$2.33	$2.48	$2.61	$2.75	$2.89	$3.05	$3.21	$82.57

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($54.07)	$0.00	$1.17	$2.37	$2.52	$2.59	$2.73	$2.88	$3.04	$3.22	$3.42	$3.64	$3.83	$4.04	$4.25	$4.48	$4.71	$118.05
Alliant Energy Corporation	LNT	($33.83)	$0.00	$0.58	$1.18	$1.32	$1.38	$1.48	$1.59	$1.71	$1.83	$1.96	$2.10	$2.21	$2.33	$2.45	$2.58	$2.72	$75.14
Ameren Corporation	AEE	($46.40)	$0.00	$0.86	$1.75	$1.89	$1.96	$2.08	$2.21	$2.34	$2.48	$2.63	$2.79	$2.94	$3.10	$3.26	$3.43	$3.62	$101.55
American Electric Power Company, Inc.	AEP	($61.54)	$0.00	$1.20	$2.44	$2.78	$2.93	$3.05	$3.18	$3.33	$3.49	$3.67	$3.86	$4.07	$4.29	$4.51	$4.75	$5.01	$133.38
Avista Corporation	AVA	($37.83)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$82.84
CMS Energy Corporation	CMS	($39.10)	$0.00	$0.64	$1.30	$1.49	$1.57	$1.68	$1.80	$1.93	$2.06	$2.20	$2.35	$2.47	$2.60	$2.74	$2.89	$3.04	$86.69
DTE Energy Company	DTE	($85.80)	$0.00	$1.48	$3.02	$3.33	$3.46	$3.70	$3.95	$4.22	$4.50	$4.81	$5.15	$5.42	$5.71	$6.01	$6.33	$6.67	$189.55
El Paso Electric Company	EE	($41.72)	$0.00	$0.62	$1.24	$1.36	$1.40	$1.47	$1.54	$1.63	$1.72	$1.83	$1.96	$2.06	$2.17	$2.29	$2.41	$2.54	$91.05
Entergy Corporation	ETR	($72.44)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$159.39
Eversource Energy	ES	($54.15)	$0.00	$0.88	$1.79	$2.00	$2.09	$2.26	$2.44	$2.64	$2.85	$3.07	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28	$121.05
FirstEnergy Corp.	FE	($33.04)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$79.19
IDACORP, Inc.	IDA	($70.82)	$0.00	$1.06	$2.14	$2.54	$2.69	$2.84	$3.00	$3.18	$3.39	$3.62	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$156.28
MGE Energy, Inc.	MGEE	($48.29)	$0.00	$0.60	$1.22	$1.13	$1.10	$1.25	$1.41	$1.58	$1.77	$1.98	$2.22	$2.34	$2.46	$2.59	$2.73	$2.87	$109.32
NorthWestern Corporation	NWE	($57.21)	$0.00	$1.00	$2.03	$2.13	$2.18	$2.35	$2.52	$2.71	$2.91	$3.12	$3.35	$3.53	$3.72	$3.92	$4.13	$4.35	$126.63
OGE Energy Corp.	OGE	($27.72)	$0.00	$0.59	$1.18	$1.32	$1.37	$1.41	$1.45	$1.50	$1.55	$1.62	$1.69	$1.78	$1.88	$1.98	$2.08	$2.19	$59.12
Otter Tail Corporation	OTTR	($28.18)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$61.50
Pinnacle West Capital Corporation	PNW	($69.12)	$0.00	$1.31	$2.65	$2.94	$3.06	$3.20	$3.35	$3.52	$3.70	$3.91	$4.14	$4.36	$4.59	$4.83	$5.09	$5.36	$150.18
PNM Resources, Inc.	PNM	($31.32)	$0.00	$0.45	$0.93	$1.19	$1.30	$1.45	$1.60	$1.76	$1.93	$2.10	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$72.32
Portland General Electric Company	POR	($38.74)	$0.00	$0.61	$1.24	$1.42	$1.49	$1.63	$1.77	$1.92	$2.08	$2.26	$2.44	$2.57	$2.71	$2.86	$3.01	$3.17	$87.35
SCANA Corporation	SCG	($64.86)	$0.00	$1.18	$2.40	$2.71	$2.85	$3.04	$3.24	$3.46	$3.71	$3.97	$4.25	$4.48	$4.71	$4.97	$5.23	$5.51	$143.98
Wisconsin Energy Corporation	WEC	($55.89)	$0.00	$0.85	$1.74	$1.99	$2.10	$2.22	$2.35	$2.48	$2.62	$2.76	$2.90	$3.06	$3.22	$3.39	$3.57	$3.76	$122.01
Xcel Energy Inc.	XEL	($38.85)	$0.00	$0.69	$1.41	$1.62	$1.71	$1.82	$1.93	$2.06	$2.19	$2.33	$2.48	$2.61	$2.75	$2.89	$3.05	$3.21	$85.78

Multi-Stage Growth Discounted Cash Flow Model
30 Day Average Stock Price
High EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	High Growth	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$59.67	5.50%	5.00%	4.00%	5.50%	5.32%	66.00%	63.00%	66.88%	($0.00)	9.70%	16.10	3.02
Alliant Energy Corporation	LNT	$38.20	6.10%	6.60%	6.00%	6.60%	5.32%	64.00%	61.00%	66.88%	($0.00)	8.96%	19.36	3.64
Ameren Corporation	AEE	$50.12	6.10%	5.20%	6.00%	6.10%	5.32%	68.00%	64.00%	66.88%	($0.00)	9.14%	18.45	3.47
American Electric Power Company, Inc.	AEP	$66.05	4.90%	4.10%	4.00%	4.90%	5.32%	64.00%	67.00%	66.88%	($0.00)	9.38%	17.36	3.26
Avista Corporation	AVA	$41.65	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	($0.00)	8.70%	20.85	3.92
CMS Energy Corporation	CMS	$42.95	6.40%	7.24%	6.00%	7.24%	5.32%	63.00%	62.00%	66.88%	($0.00)	9.10%	18.64	3.50
DTE Energy Company	DTE	$92.91	5.80%	5.35%	5.00%	5.80%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.06%	18.85	3.54
El Paso Electric Company	EE	$45.30	6.70%	7.00%	2.50%	7.00%	5.32%	59.00%	61.00%	66.88%	($0.00)	9.09%	18.69	3.51
Entergy Corporation	ETR	$77.45	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	$0.00	10.39%	13.90	2.61
Eversource Energy	ES	$56.36	6.30%	5.49%	6.00%	6.30%	5.32%	60.00%	58.00%	66.88%	($0.00)	9.24%	18.00	3.38
FirstEnergy Corp.	FE	$33.34	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	10.83%	12.79	2.40
IDACORP, Inc.	IDA	$74.50	4.00%	4.00%	3.00%	4.00%	5.32%	53.00%	60.00%	66.88%	($0.00)	8.88%	19.81	3.72
MGE Energy, Inc.	MGEE	$53.30	NA	4.00%	7.00%	7.00%	5.32%	56.00%	44.00%	66.88%	($0.00)	8.47%	22.38	4.21
NorthWestern Corporation	NWE	$59.68	5.00%	5.00%	6.50%	6.50%	5.32%	65.00%	59.00%	66.88%	($0.00)	9.28%	17.78	3.34
OGE Energy Corp.	OGE	$30.95	5.20%	4.30%	3.00%	5.20%	5.32%	67.00%	70.00%	66.88%	($0.00)	9.52%	16.77	3.15
Otter Tail Corporation	OTTR	$30.96	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	($0.00)	9.39%	17.32	3.26
Pinnacle West Capital Corporation	PNW	$75.82	4.00%	3.73%	4.00%	4.00%	5.32%	64.00%	65.00%	66.88%	($0.00)	8.93%	19.51	3.67
PNM Resources, Inc.	PNM	$33.49	7.60%	8.76%	9.00%	9.00%	5.32%	51.00%	55.00%	66.88%	($0.00)	9.91%	15.35	2.88
Portland General Electric Company	POR	$41.86	6.40%	6.57%	5.50%	6.57%	5.32%	56.00%	56.00%	66.88%	($0.00)	9.26%	17.90	3.36
SCANA Corporation	SCG	$71.01	5.30%	5.40%	4.50%	5.40%	5.32%	59.00%	60.00%	66.88%	($0.00)	9.38%	17.36	3.26
Wisconsin Energy Corporation	WEC	$61.68	6.30%	6.77%	6.00%	6.77%	5.32%	68.00%	67.00%	66.88%	($0.00)	8.51%	22.06	4.15
Xcel Energy Inc.	XEL	$42.20	5.30%	5.27%	5.50%	5.50%	5.32%	62.00%	63.00%	66.88%	($0.00)	9.14%	18.44	3.46
											MEAN	9.28%		
											MAX	10.83%		
											MIN	8.47%		

Projected Annual
Earnings per Share

		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2015	2016	2017	2018	2019	2020	**2021**	2022	2023	2024	2025	**2026**	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE	$3.38	$3.57	$3.76	$3.97	$4.19	$4.42	$4.66	$4.91	$5.18	$5.46	$5.75	$6.06	$6.38	$6.72	$7.07	$7.45	$7.85
Alliant Energy Corporation	LNT	$1.69	$1.80	$1.92	$2.05	$2.18	$2.33	$2.47	$2.63	$2.78	$2.94	$3.11	$3.27	$3.45	$3.63	$3.82	$4.03	$4.24
Ameren Corporation	AEE	$2.38	$2.53	$2.68	$2.84	$3.02	$3.20	$3.39	$3.59	$3.79	$4.01	$4.22	$4.45	$4.69	$4.94	$5.20	$5.47	$5.77
American Electric Power Company, Inc.	AEP	$3.59	$3.77	$3.95	$4.14	$4.35	$4.56	$4.79	$5.03	$5.29	$5.56	$5.85	$6.16	$6.49	$6.84	$7.20	$7.58	$7.99
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.03	$2.17	$2.33	$2.50	$2.68	$2.87	$3.06	$3.25	$3.44	$3.64	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
DTE Energy Company	DTE	$4.45	$4.71	$4.98	$5.27	$5.58	$5.90	$6.24	$6.59	$6.95	$7.34	$7.73	$8.14	$8.58	$9.03	$9.51	$10.02	$10.55
El Paso Electric Company	EE	$2.03	$2.17	$2.32	$2.49	$2.66	$2.85	$3.04	$3.23	$3.43	$3.64	$3.84	$4.04	$4.26	$4.49	$4.72	$4.98	$5.24
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.93	$3.12	$3.32	$3.52	$3.75	$3.98	$4.21	$4.46	$4.71	$4.97	$5.23	$5.51	$5.80	$6.11	$6.44	$6.78
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$4.02	$4.19	$4.35	$4.53	$4.71	$4.91	$5.13	$5.36	$5.63	$5.91	$6.23	$6.56	$6.91	$7.28	$7.66	$8.07
MGE Energy, Inc.	MGEE	$2.06	$2.20	$2.36	$2.52	$2.70	$2.89	$3.08	$3.28	$3.48	$3.69	$3.90	$4.10	$4.32	$4.55	$4.79	$5.05	$5.32
NorthWestern Corporation	NWE	$2.90	$3.09	$3.29	$3.50	$3.73	$3.97	$4.22	$4.48	$4.75	$5.02	$5.29	$5.58	$5.87	$6.19	$6.52	$6.86	$7.23
OGE Energy Corp.	OGE	$1.69	$1.78	$1.87	$1.97	$2.07	$2.18	$2.29	$2.41	$2.54	$2.67	$2.81	$2.96	$3.12	$3.29	$3.46	$3.65	$3.84
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.08	$4.24	$4.41	$4.59	$4.77	$4.97	$5.19	$5.43	$5.70	$5.99	$6.31	$6.64	$7.00	$7.37	$7.76	$8.18
PNM Resources, Inc.	PNM	$1.64	$1.79	$1.95	$2.12	$2.31	$2.52	$2.73	$2.95	$3.16	$3.37	$3.57	$3.76	$3.95	$4.17	$4.39	$4.62	$4.87
Portland General Electric Company	POR	$2.04	$2.17	$2.32	$2.47	$2.63	$2.80	$2.98	$3.17	$3.35	$3.55	$3.74	$3.94	$4.15	$4.37	$4.61	$4.85	$5.11
SCANA Corporation	SCG	$3.81	$4.02	$4.23	$4.46	$4.70	$4.96	$5.22	$5.50	$5.80	$6.11	$6.43	$6.78	$7.14	$7.52	$7.92	$8.34	$8.78
Wisconsin Energy Corporation	WEC	$2.34	$2.50	$2.67	$2.85	$3.04	$3.25	$3.46	$3.68	$3.90	$4.12	$4.35	$4.59	$4.83	$5.09	$5.36	$5.64	$5.94
Xcel Energy Inc.	XEL	$2.10	$2.22	$2.34	$2.47	$2.60	$2.74	$2.89	$3.05	$3.22	$3.39	$3.57	$3.76	$3.96	$4.17	$4.40	$4.63	$4.88

Projected Annual
Dividend Payout Ratic

			[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE		66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT		64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE		68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP		64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA		68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS		63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE		63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE		59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR		67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES		60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE		55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA		53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE		56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE		65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE		67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR		80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW		64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM		51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR		56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG		59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC		68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL		62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.35	$2.45	$2.56	$2.67	$2.78	$2.97	$3.16	$3.36	$3.58	$3.81	$4.05	$4.27	$4.49	$4.73	$4.98	$5.25	$126.32
Alliant Energy Corporation	LNT	$1.15	$1.21	$1.28	$1.35	$1.42	$1.53	$1.65	$1.78	$1.91	$2.05	$2.19	$2.31	$2.43	$2.56	$2.69	$2.84	$82.12
Ameren Corporation	AEE	$1.72	$1.80	$1.88	$1.96	$2.05	$2.19	$2.33	$2.48	$2.64	$2.80	$2.98	$3.13	$3.30	$3.48	$3.66	$3.86	$106.39
American Electric Power Company, Inc.	AEP	$2.41	$2.56	$2.71	$2.88	$3.06	$3.21	$3.37	$3.54	$3.72	$3.91	$4.12	$4.34	$4.57	$4.81	$5.07	$5.34	$138.62
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.30
CMS Energy Corporation	CMS	$1.28	$1.36	$1.46	$1.56	$1.66	$1.80	$1.94	$2.09	$2.25	$2.40	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$92.48
DTE Energy Company	DTE	$2.97	$3.11	$3.27	$3.43	$3.60	$3.87	$4.15	$4.45	$4.76	$5.10	$5.45	$5.74	$6.04	$6.36	$6.70	$7.06	$199.00
El Paso Electric Company	EE	$1.28	$1.38	$1.49	$1.61	$1.74	$1.88	$2.04	$2.20	$2.36	$2.53	$2.70	$2.85	$3.00	$3.16	$3.33	$3.50	$97.94
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$162.41
Eversource Energy	ES	$1.76	$1.86	$1.96	$2.06	$2.17	$2.36	$2.57	$2.78	$3.01	$3.25	$3.50	$3.69	$3.88	$4.09	$4.31	$4.54	$122.04
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$75.89
IDACORP, Inc.	IDA	$2.13	$2.29	$2.46	$2.64	$2.83	$3.00	$3.19	$3.40	$3.63	$3.89	$4.16	$4.39	$4.62	$4.87	$5.13	$5.40	$159.89
MGE Energy, Inc.	MGEE	$1.23	$1.25	$1.26	$1.27	$1.27	$1.47	$1.69	$1.93	$2.19	$2.46	$2.74	$2.89	$3.04	$3.21	$3.38	$3.56	$119.03
NorthWestern Corporation	NWE	$2.01	$2.09	$2.17	$2.26	$2.34	$2.55	$2.76	$2.99	$3.22	$3.47	$3.73	$3.93	$4.14	$4.36	$4.59	$4.83	$128.54
OGE Energy Corp.	OGE	$1.19	$1.27	$1.35	$1.43	$1.52	$1.59	$1.66	$1.74	$1.81	$1.90	$1.98	$2.09	$2.20	$2.32	$2.44	$2.57	$64.40
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$65.02
Pinnacle West Capital Corporation	PNW	$2.61	$2.72	$2.84	$2.97	$3.10	$3.25	$3.41	$3.58	$3.78	$3.99	$4.22	$4.44	$4.68	$4.93	$5.19	$5.47	$159.50
PNM Resources, Inc.	PNM	$0.91	$1.01	$1.13	$1.25	$1.39	$1.56	$1.74	$1.92	$2.12	$2.31	$2.51	$2.65	$2.79	$2.93	$3.09	$3.25	$74.72
Portland General Electric Company	POR	$1.22	$1.30	$1.38	$1.47	$1.57	$1.72	$1.89	$2.06	$2.24	$2.44	$2.64	$2.78	$2.92	$3.08	$3.24	$3.42	$91.48
SCANA Corporation	SCG	$2.37	$2.51	$2.65	$2.81	$2.97	$3.19	$3.43	$3.68	$3.95	$4.23	$4.53	$4.77	$5.03	$5.30	$5.58	$5.87	$152.48
Wisconsin Energy Corporation	WEC	$1.70	$1.81	$1.92	$2.05	$2.18	$2.32	$2.46	$2.61	$2.76	$2.91	$3.07	$3.23	$3.40	$3.58	$3.77	$3.98	$131.14
Xcel Energy Inc.	XEL	$1.37	$1.46	$1.54	$1.63	$1.73	$1.84	$1.96	$2.09	$2.22	$2.37	$2.52	$2.65	$2.79	$2.94	$3.10	$3.26	$89.91

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($59.67)	$0.00	$1.19	$2.42	$2.67	$2.78	$2.97	$3.16	$3.36	$3.58	$3.81	$4.05	$4.27	$4.49	$4.73	$4.98	$5.25	$131.57
Alliant Energy Corporation	LNT	($38.20)	$0.00	$0.58	$1.19	$1.35	$1.42	$1.53	$1.65	$1.78	$1.91	$2.05	$2.19	$2.31	$2.43	$2.56	$2.69	$2.84	$84.96
Ameren Corporation	AEE	($50.12)	$0.00	$0.87	$1.77	$1.96	$2.05	$2.19	$2.33	$2.48	$2.64	$2.80	$2.98	$3.13	$3.30	$3.48	$3.66	$3.86	$110.24
American Electric Power Company, Inc.	AEP	($66.05)	$0.00	$1.21	$2.47	$2.88	$3.06	$3.21	$3.37	$3.54	$3.72	$3.91	$4.12	$4.34	$4.57	$4.81	$5.07	$5.34	$143.96
Avista Corporation	AVA	($41.65)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$91.13
CMS Energy Corporation	CMS	($42.95)	$0.00	$0.64	$1.32	$1.56	$1.66	$1.80	$1.94	$2.09	$2.25	$2.40	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$95.80
DTE Energy Company	DTE	($92.91)	$0.00	$1.50	$3.05	$3.43	$3.60	$3.87	$4.15	$4.45	$4.76	$5.10	$5.45	$5.74	$6.04	$6.36	$6.70	$7.06	$206.05
El Paso Electric Company	EE	($45.30)	$0.00	$0.65	$1.33	$1.61	$1.74	$1.88	$2.04	$2.20	$2.36	$2.53	$2.70	$2.85	$3.00	$3.16	$3.33	$3.50	$101.44
Entergy Corporation	ETR	($77.45)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$170.22
Eversource Energy	ES	($56.36)	$0.00	$0.89	$1.82	$2.06	$2.17	$2.36	$2.57	$2.78	$3.01	$3.25	$3.50	$3.69	$3.88	$4.09	$4.31	$4.54	$126.58
FirstEnergy Corp.	FE	($33.34)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$79.86
IDACORP, Inc.	IDA	($74.50)	$0.00	$1.08	$2.18	$2.64	$2.83	$3.00	$3.19	$3.40	$3.63	$3.89	$4.16	$4.39	$4.62	$4.87	$5.13	$5.40	$165.29
MGE Energy, Inc.	MGEE	($53.30)	$0.00	$0.62	$1.28	$1.27	$1.27	$1.47	$1.69	$1.93	$2.19	$2.46	$2.74	$2.89	$3.04	$3.21	$3.38	$3.56	$122.58
NorthWestern Corporation	NWE	($59.68)	$0.00	$1.01	$2.07	$2.26	$2.34	$2.55	$2.76	$2.99	$3.22	$3.47	$3.73	$3.93	$4.14	$4.36	$4.59	$4.83	$133.37
OGE Energy Corp.	OGE	($30.95)	$0.00	$0.60	$1.22	$1.43	$1.52	$1.59	$1.66	$1.74	$1.81	$1.90	$1.98	$2.09	$2.20	$2.32	$2.44	$2.57	$66.97
Otter Tail Corporation	OTTR	($30.96)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$67.53
Pinnacle West Capital Corporation	PNW	($75.82)	$0.00	$1.32	$2.66	$2.97	$3.10	$3.25	$3.41	$3.58	$3.78	$3.99	$4.22	$4.44	$4.68	$4.93	$5.19	$5.47	$164.97
PNM Resources, Inc.	PNM	($33.49)	$0.00	$0.46	$0.95	$1.25	$1.39	$1.56	$1.74	$1.92	$2.12	$2.31	$2.51	$2.65	$2.79	$2.93	$3.09	$3.25	$77.98
Portland General Electric Company	POR	($41.86)	$0.00	$0.61	$1.26	$1.47	$1.57	$1.72	$1.89	$2.06	$2.24	$2.44	$2.64	$2.78	$2.92	$3.08	$3.24	$3.42	$94.89
SCANA Corporation	SCG	($71.01)	$0.00	$1.19	$2.43	$2.81	$2.97	$3.19	$3.43	$3.68	$3.95	$4.23	$4.53	$4.77	$5.03	$5.30	$5.58	$5.87	$158.35
Wisconsin Energy Corporation	WEC	($61.68)	$0.00	$0.86	$1.76	$2.05	$2.18	$2.32	$2.46	$2.61	$2.76	$2.91	$3.07	$3.23	$3.40	$3.58	$3.77	$3.98	$135.12
Xcel Energy Inc.	XEL	($42.20)	$0.00	$0.69	$1.41	$1.63	$1.73	$1.84	$1.96	$2.09	$2.22	$2.37	$2.52	$2.65	$2.79	$2.94	$3.10	$3.26	$93.17

Multi-Stage Growth Discounted Cash Flow Model
90 Day Average Stock Price
High EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	High Growth	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$57.08	5.50%	5.00%	4.00%	5.50%	5.32%	66.00%	63.00%	66.88%	($0.00)	9.90%	15.38	2.89
Alliant Energy Corporation	LNT	$36.64	6.10%	6.60%	6.00%	6.60%	5.32%	64.00%	61.00%	66.88%	($0.00)	9.12%	18.56	3.49
Ameren Corporation	AEE	$48.90	6.10%	5.20%	6.00%	6.10%	5.32%	68.00%	64.00%	66.88%	($0.00)	9.24%	17.99	3.38
American Electric Power Company, Inc.	AEP	$65.03	4.90%	4.10%	4.00%	4.90%	5.32%	64.00%	67.00%	66.88%	($0.00)	9.45%	17.08	3.21
Avista Corporation	AVA	$40.48	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	($0.00)	8.80%	20.25	3.80
CMS Energy Corporation	CMS	$41.70	6.40%	7.24%	6.00%	7.24%	5.32%	63.00%	62.00%	66.88%	($0.00)	9.22%	18.09	3.40
DTE Energy Company	DTE	$89.93	5.80%	5.35%	5.00%	5.80%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.18%	18.24	3.43
El Paso Electric Company	EE	$44.56	6.70%	7.00%	2.50%	7.00%	5.32%	59.00%	61.00%	66.88%	($0.00)	9.15%	18.38	3.45
Entergy Corporation	ETR	$76.55	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	10.45%	13.73	2.58
Eversource Energy	ES	$56.58	6.30%	5.49%	6.00%	6.30%	5.32%	60.00%	58.00%	66.88%	($0.00)	9.22%	18.07	3.39
FirstEnergy Corp.	FE	$34.24	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	10.69%	13.12	2.46
IDACORP, Inc.	IDA	$73.58	4.00%	4.00%	3.00%	4.00%	5.32%	53.00%	60.00%	66.88%	($0.00)	8.92%	19.57	3.68
MGE Energy, Inc.	MGEE	$51.38	NA	4.00%	7.00%	7.00%	5.32%	56.00%	44.00%	66.88%	($0.00)	8.58%	21.60	4.06
NorthWestern Corporation	NWE	$59.59	5.00%	5.00%	6.50%	6.50%	5.32%	65.00%	59.00%	66.88%	($0.00)	9.29%	17.76	3.34
OGE Energy Corp.	OGE	$29.13	5.20%	4.30%	3.00%	5.20%	5.32%	67.00%	70.00%	66.88%	($0.00)	9.80%	15.74	2.96
Otter Tail Corporation	OTTR	$29.44	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	($0.00)	9.61%	16.45	3.09
Pinnacle West Capital Corporation	PNW	$73.65	4.00%	3.73%	4.00%	4.00%	5.32%	64.00%	65.00%	66.88%	($0.00)	9.04%	18.94	3.56
PNM Resources, Inc.	PNM	$32.94	7.60%	8.76%	9.00%	9.00%	5.32%	51.00%	55.00%	66.88%	($0.00)	9.98%	15.11	2.84
Portland General Electric Company	POR	$40.24	6.40%	6.57%	5.50%	6.57%	5.32%	56.00%	56.00%	66.88%	($0.00)	9.41%	17.21	3.23
SCANA Corporation	SCG	$69.22	5.30%	5.40%	4.50%	5.40%	5.32%	59.00%	60.00%	66.88%	($0.00)	9.49%	16.92	3.18
Wisconsin Energy Corporation	WEC	$59.53	6.30%	6.77%	6.00%	6.77%	5.32%	68.00%	67.00%	66.88%	($0.00)	8.63%	21.28	4.00
Xcel Energy Inc.	XEL	$41.15	5.30%	5.27%	5.50%	5.50%	5.32%	62.00%	63.00%	66.88%	($0.00)	9.24%	17.97	3.38
											MEAN	9.38%		
											MAX	10.69%		
											MIN	8.58%		

Projected Annual
Earnings per Share

Company	Ticker	[14] 2015	[15] 2016	[16] 2017	[17] 2018	[18] 2019	[19] 2020	[20] **2021**	[21] 2022	[22] 2023	[23] 2024	[24] 2025	[25] **2026**	[26] 2027	[27] 2028	[28] 2029	[29] 2030	[30] 2031
ALLETE, Inc.	ALE	$3.38	$3.57	$3.76	$3.97	$4.19	$4.42	$4.66	$4.91	$5.18	$5.46	$5.75	$6.06	$6.38	$6.72	$7.07	$7.45	$7.85
Alliant Energy Corporation	LNT	$1.69	$1.80	$1.92	$2.05	$2.18	$2.33	$2.47	$2.63	$2.78	$2.94	$3.11	$3.27	$3.45	$3.63	$3.82	$4.03	$4.24
Ameren Corporation	AEE	$2.38	$2.53	$2.68	$2.84	$3.02	$3.20	$3.39	$3.59	$3.79	$4.01	$4.22	$4.45	$4.69	$4.94	$5.20	$5.47	$5.77
American Electric Power Company, Inc.	AEP	$3.59	$3.77	$3.95	$4.14	$4.35	$4.56	$4.79	$5.03	$5.29	$5.56	$5.85	$6.16	$6.49	$6.84	$7.20	$7.58	$7.99
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.03	$2.17	$2.33	$2.50	$2.68	$2.87	$3.06	$3.25	$3.44	$3.64	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
DTE Energy Company	DTE	$4.45	$4.71	$4.98	$5.27	$5.58	$5.90	$6.24	$6.59	$6.95	$7.34	$7.73	$8.14	$8.58	$9.03	$9.51	$10.02	$10.55
El Paso Electric Company	EE	$2.03	$2.17	$2.32	$2.49	$2.66	$2.85	$3.04	$3.23	$3.43	$3.64	$3.84	$4.04	$4.26	$4.49	$4.72	$4.98	$5.24
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.93	$3.12	$3.32	$3.52	$3.75	$3.98	$4.21	$4.46	$4.71	$4.97	$5.23	$5.51	$5.80	$6.11	$6.44	$6.78
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$4.02	$4.19	$4.35	$4.53	$4.71	$4.91	$5.13	$5.36	$5.63	$5.91	$6.23	$6.56	$6.91	$7.28	$7.66	$8.07
MGE Energy, Inc.	MGEE	$2.06	$2.20	$2.36	$2.52	$2.70	$2.89	$3.08	$3.28	$3.48	$3.69	$3.90	$4.10	$4.32	$4.55	$4.79	$5.05	$5.32
NorthWestern Corporation	NWE	$2.90	$3.09	$3.29	$3.50	$3.73	$3.97	$4.22	$4.48	$4.75	$5.02	$5.29	$5.58	$5.87	$6.19	$6.52	$6.86	$7.23
OGE Energy Corp.	OGE	$1.69	$1.78	$1.87	$1.97	$2.07	$2.18	$2.29	$2.41	$2.54	$2.67	$2.81	$2.96	$3.12	$3.29	$3.46	$3.65	$3.84
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.08	$4.24	$4.41	$4.59	$4.77	$4.97	$5.19	$5.43	$5.70	$5.99	$6.31	$6.64	$7.00	$7.37	$7.76	$8.18
PNM Resources, Inc.	PNM	$1.64	$1.79	$1.95	$2.12	$2.31	$2.52	$2.73	$2.95	$3.16	$3.37	$3.57	$3.76	$3.95	$4.17	$4.39	$4.62	$4.87
Portland General Electric Company	POR	$2.04	$2.17	$2.32	$2.47	$2.63	$2.80	$2.98	$3.17	$3.35	$3.55	$3.74	$3.94	$4.15	$4.37	$4.61	$4.85	$5.11
SCANA Corporation	SCG	$3.81	$4.02	$4.23	$4.46	$4.70	$4.96	$5.22	$5.50	$5.80	$6.11	$6.43	$6.78	$7.14	$7.52	$7.92	$8.34	$8.78
Wisconsin Energy Corporation	WEC	$2.34	$2.50	$2.67	$2.85	$3.04	$3.25	$3.46	$3.68	$3.90	$4.12	$4.35	$4.59	$4.83	$5.09	$5.36	$5.64	$5.94
Xcel Energy Inc.	XEL	$2.10	$2.22	$2.34	$2.47	$2.60	$2.74	$2.89	$3.05	$3.22	$3.39	$3.57	$3.76	$3.96	$4.17	$4.40	$4.63	$4.88

Projected Annual
Dividend Payout Ratic

Company	Ticker	[31] 2016	[32] 2017	[33] 2018	[34] 2019	[35] 2020	[36] 2021	[37] 2022	[38] 2023	[39] 2024	[40] 2025	[41] 2026	[42] 2027	[43] 2028	[44] 2029	[45] 2030	[46] 2031
ALLETE, Inc.	ALE	66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT	64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE	68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP	64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA	68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS	63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE	63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE	59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR	67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES	60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE	55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA	53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE	56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE	65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE	67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR	80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW	64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM	51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR	56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG	59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC	68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL	62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.35	$2.45	$2.56	$2.67	$2.78	$2.97	$3.16	$3.36	$3.58	$3.81	$4.05	$4.27	$4.49	$4.73	$4.98	$5.25	$120.72
Alliant Energy Corporation	LNT	$1.15	$1.21	$1.28	$1.35	$1.42	$1.53	$1.65	$1.78	$1.91	$2.05	$2.19	$2.31	$2.43	$2.56	$2.69	$2.84	$78.72
Ameren Corporation	AEE	$1.72	$1.80	$1.88	$1.96	$2.05	$2.19	$2.33	$2.48	$2.64	$2.80	$2.98	$3.13	$3.30	$3.48	$3.66	$3.86	$103.73
American Electric Power Company, Inc.	AEP	$2.41	$2.56	$2.71	$2.88	$3.06	$3.21	$3.37	$3.54	$3.72	$3.91	$4.12	$4.34	$4.57	$4.81	$5.07	$5.34	$136.43
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$85.75
CMS Energy Corporation	CMS	$1.28	$1.36	$1.46	$1.56	$1.66	$1.80	$1.94	$2.09	$2.25	$2.40	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$89.76
DTE Energy Company	DTE	$2.97	$3.11	$3.27	$3.43	$3.60	$3.87	$4.15	$4.45	$4.76	$5.10	$5.45	$5.74	$6.04	$6.36	$6.70	$7.06	$192.52
El Paso Electric Company	EE	$1.28	$1.38	$1.49	$1.61	$1.74	$1.88	$2.04	$2.20	$2.36	$2.53	$2.70	$2.85	$3.00	$3.16	$3.33	$3.50	$96.34
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$160.45
Eversource Energy	ES	$1.76	$1.86	$1.96	$2.06	$2.17	$2.36	$2.57	$2.78	$3.01	$3.25	$3.50	$3.69	$3.88	$4.09	$4.31	$4.54	$122.53
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$77.84
IDACORP, Inc.	IDA	$2.13	$2.29	$2.46	$2.64	$2.83	$3.00	$3.19	$3.40	$3.63	$3.89	$4.16	$4.39	$4.62	$4.87	$5.13	$5.40	$157.91
MGE Energy, Inc.	MGEE	$1.23	$1.25	$1.26	$1.27	$1.27	$1.47	$1.69	$1.93	$2.19	$2.46	$2.74	$2.89	$3.04	$3.21	$3.38	$3.56	$114.84
NorthWestern Corporation	NWE	$2.01	$2.09	$2.17	$2.26	$2.34	$2.55	$2.76	$2.99	$3.22	$3.47	$3.73	$3.93	$4.14	$4.36	$4.59	$4.83	$128.33
OGE Energy Corp.	OGE	$1.19	$1.27	$1.35	$1.43	$1.52	$1.59	$1.66	$1.74	$1.81	$1.90	$1.98	$2.09	$2.20	$2.32	$2.44	$2.57	$60.47
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$61.72
Pinnacle West Capital Corporation	PNW	$2.61	$2.72	$2.84	$2.97	$3.10	$3.25	$3.41	$3.58	$3.78	$3.99	$4.22	$4.44	$4.68	$4.93	$5.19	$5.47	$154.81
PNM Resources, Inc.	PNM	$0.91	$1.01	$1.13	$1.25	$1.39	$1.56	$1.74	$1.92	$2.12	$2.31	$2.51	$2.65	$2.79	$2.93	$3.09	$3.25	$73.52
Portland General Electric Company	POR	$1.22	$1.30	$1.38	$1.47	$1.57	$1.72	$1.89	$2.06	$2.24	$2.44	$2.64	$2.78	$2.92	$3.08	$3.24	$3.42	$87.95
SCANA Corporation	SCG	$2.37	$2.51	$2.65	$2.81	$2.97	$3.19	$3.43	$3.68	$3.95	$4.23	$4.53	$4.77	$5.03	$5.30	$5.58	$5.87	$148.58
Wisconsin Energy Corporation	WEC	$1.70	$1.81	$1.92	$2.05	$2.18	$2.32	$2.46	$2.61	$2.76	$2.91	$3.07	$3.23	$3.40	$3.58	$3.77	$3.98	$126.47
Xcel Energy Inc.	XEL	$1.37	$1.46	$1.54	$1.63	$1.73	$1.84	$1.96	$2.09	$2.22	$2.37	$2.52	$2.65	$2.79	$2.94	$3.10	$3.26	$87.64

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($57.08)	$0.00	$1.19	$2.42	$2.67	$2.78	$2.97	$3.16	$3.36	$3.58	$3.81	$4.05	$4.27	$4.49	$4.73	$4.98	$5.25	$125.97
Alliant Energy Corporation	LNT	($36.64)	$0.00	$0.58	$1.19	$1.35	$1.42	$1.53	$1.65	$1.78	$1.91	$2.05	$2.19	$2.31	$2.43	$2.56	$2.69	$2.84	$81.56
Ameren Corporation	AEE	($48.90)	$0.00	$0.87	$1.77	$1.96	$2.05	$2.19	$2.33	$2.48	$2.64	$2.80	$2.98	$3.13	$3.30	$3.48	$3.66	$3.86	$107.59
American Electric Power Company, Inc.	AEP	($65.03)	$0.00	$1.21	$2.47	$2.88	$3.06	$3.21	$3.37	$3.54	$3.72	$3.91	$4.12	$4.34	$4.57	$4.81	$5.07	$5.34	$141.77
Avista Corporation	AVA	($40.48)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.58
CMS Energy Corporation	CMS	($41.70)	$0.00	$0.64	$1.32	$1.56	$1.66	$1.80	$1.94	$2.09	$2.25	$2.40	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$93.08
DTE Energy Company	DTE	($89.93)	$0.00	$1.50	$3.05	$3.43	$3.60	$3.87	$4.15	$4.45	$4.76	$5.10	$5.45	$5.74	$6.04	$6.36	$6.70	$7.06	$199.58
El Paso Electric Company	EE	($44.56)	$0.00	$0.65	$1.33	$1.61	$1.74	$1.88	$2.04	$2.20	$2.36	$2.53	$2.70	$2.85	$3.00	$3.16	$3.33	$3.50	$99.84
Entergy Corporation	ETR	($76.55)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$168.27
Eversource Energy	ES	($56.58)	$0.00	$0.89	$1.82	$2.06	$2.17	$2.36	$2.57	$2.78	$3.01	$3.25	$3.50	$3.69	$3.88	$4.09	$4.31	$4.54	$127.06
FirstEnergy Corp.	FE	($34.24)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$81.81
IDACORP, Inc.	IDA	($73.58)	$0.00	$1.08	$2.18	$2.64	$2.83	$3.00	$3.19	$3.40	$3.63	$3.89	$4.16	$4.39	$4.62	$4.87	$5.13	$5.40	$163.30
MGE Energy, Inc.	MGEE	($51.38)	$0.00	$0.62	$1.28	$1.27	$1.27	$1.47	$1.69	$1.93	$2.19	$2.46	$2.74	$2.89	$3.04	$3.21	$3.38	$3.56	$118.40
NorthWestern Corporation	NWE	($59.59)	$0.00	$1.01	$2.07	$2.26	$2.34	$2.55	$2.76	$2.99	$3.22	$3.47	$3.73	$3.93	$4.14	$4.36	$4.59	$4.83	$133.16
OGE Energy Corp.	OGE	($29.13)	$0.00	$0.60	$1.22	$1.43	$1.52	$1.59	$1.66	$1.74	$1.81	$1.90	$1.98	$2.09	$2.20	$2.32	$2.44	$2.57	$63.04
Otter Tail Corporation	OTTR	($29.44)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$64.23
Pinnacle West Capital Corporation	PNW	($73.65)	$0.00	$1.32	$2.66	$2.97	$3.10	$3.25	$3.41	$3.58	$3.78	$3.99	$4.22	$4.44	$4.68	$4.93	$5.19	$5.47	$160.28
PNM Resources, Inc.	PNM	($32.94)	$0.00	$0.46	$0.95	$1.25	$1.39	$1.56	$1.74	$1.92	$2.12	$2.31	$2.51	$2.65	$2.79	$2.93	$3.09	$3.25	$76.78
Portland General Electric Company	POR	($40.24)	$0.00	$0.61	$1.26	$1.47	$1.57	$1.72	$1.89	$2.06	$2.24	$2.44	$2.64	$2.78	$2.92	$3.08	$3.24	$3.42	$91.37
SCANA Corporation	SCG	($69.22)	$0.00	$1.19	$2.43	$2.81	$2.97	$3.19	$3.43	$3.68	$3.95	$4.23	$4.53	$4.77	$5.03	$5.30	$5.58	$5.87	$154.46
Wisconsin Energy Corporation	WEC	($59.53)	$0.00	$0.86	$1.76	$2.05	$2.18	$2.32	$2.46	$2.61	$2.76	$2.91	$3.07	$3.23	$3.40	$3.58	$3.77	$3.98	$130.44
Xcel Energy Inc.	XEL	($41.15)	$0.00	$0.69	$1.41	$1.63	$1.73	$1.84	$1.96	$2.09	$2.22	$2.37	$2.52	$2.65	$2.79	$2.94	$3.10	$3.26	$90.90

Multi-Stage Growth Discounted Cash Flow Model
180 Day Average Stock Price
High EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	High Growth	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$54.07	5.50%	5.00%	4.00%	5.50%	5.32%	66.00%	63.00%	66.88%	$0.00	10.16%	14.55	2.73
Alliant Energy Corporation	LNT	$33.83	6.10%	6.60%	6.00%	6.60%	5.32%	64.00%	61.00%	66.88%	($0.00)	9.44%	17.12	3.22
Ameren Corporation	AEE	$46.40	6.10%	5.20%	6.00%	6.10%	5.32%	68.00%	64.00%	66.88%	($0.00)	9.45%	17.05	3.20
American Electric Power Company, Inc.	AEP	$61.54	4.90%	4.10%	4.00%	4.90%	5.32%	64.00%	67.00%	66.88%	($0.00)	9.69%	16.14	3.03
Avista Corporation	AVA	$37.83	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	($0.00)	9.05%	18.89	3.55
CMS Energy Corporation	CMS	$39.10	6.40%	7.24%	6.00%	7.24%	5.32%	63.00%	62.00%	66.88%	($0.00)	9.48%	16.96	3.19
DTE Energy Company	DTE	$85.80	5.80%	5.35%	5.00%	5.80%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.37%	17.39	3.27
El Paso Electric Company	EE	$41.72	6.70%	7.00%	2.50%	7.00%	5.32%	59.00%	61.00%	66.88%	($0.00)	9.42%	17.21	3.23
Entergy Corporation	ETR	$72.44	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	10.75%	12.97	2.44
Eversource Energy	ES	$54.15	6.30%	5.49%	6.00%	6.30%	5.32%	60.00%	58.00%	66.88%	($0.00)	9.40%	17.29	3.25
FirstEnergy Corp.	FE	$33.04	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	($0.00)	10.88%	12.67	2.38
IDACORP, Inc.	IDA	$70.82	4.00%	4.00%	3.00%	4.00%	5.32%	53.00%	60.00%	66.88%	($0.00)	9.06%	18.82	3.54
MGE Energy, Inc.	MGEE	$48.29	NA	4.00%	7.00%	7.00%	5.32%	56.00%	44.00%	66.88%	($0.00)	8.79%	20.33	3.82
NorthWestern Corporation	NWE	$57.21	5.00%	5.00%	6.50%	6.50%	5.32%	65.00%	59.00%	66.88%	($0.00)	9.46%	17.04	3.20
OGE Energy Corp.	OGE	$27.72	5.20%	4.30%	3.00%	5.20%	5.32%	67.00%	70.00%	66.88%	($0.00)	10.03%	14.95	2.81
Otter Tail Corporation	OTTR	$28.18	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	($0.00)	9.80%	15.72	2.95
Pinnacle West Capital Corporation	PNW	$69.12	4.00%	3.73%	4.00%	4.00%	5.32%	64.00%	65.00%	66.88%	($0.00)	9.29%	17.73	3.33
PNM Resources, Inc.	PNM	$31.32	7.60%	8.76%	9.00%	9.00%	5.32%	51.00%	55.00%	66.88%	$0.00	10.22%	14.38	2.70
Portland General Electric Company	POR	$38.74	6.40%	6.57%	5.50%	6.57%	5.32%	56.00%	56.00%	66.88%	($0.00)	9.57%	16.57	3.11
SCANA Corporation	SCG	$64.86	5.30%	5.40%	4.50%	5.40%	5.32%	59.00%	60.00%	66.88%	($0.00)	9.77%	15.84	2.98
Wisconsin Energy Corporation	WEC	$55.89	6.30%	6.77%	6.00%	6.77%	5.32%	68.00%	67.00%	66.88%	($0.00)	8.85%	19.95	3.75
Xcel Energy Inc.	XEL	$38.85	5.30%	5.27%	5.50%	5.50%	5.32%	62.00%	63.00%	66.88%	($0.00)	9.48%	16.95	3.19
											MEAN	9.61%		
											MAX	10.88%		
											MIN	8.79%		

Projected Annual
Earnings per Share

		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2015	2016	2017	2018	2019	2020	**2021**	2022	2023	2024	2025	**2026**	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE	$3.38	$3.57	$3.76	$3.97	$4.19	$4.42	$4.66	$4.91	$5.18	$5.46	$5.75	$6.06	$6.38	$6.72	$7.07	$7.45	$7.85
Alliant Energy Corporation	LNT	$1.69	$1.80	$1.92	$2.05	$2.18	$2.33	$2.47	$2.63	$2.78	$2.94	$3.11	$3.27	$3.45	$3.63	$3.82	$4.03	$4.24
Ameren Corporation	AEE	$2.38	$2.53	$2.68	$2.84	$3.02	$3.20	$3.39	$3.59	$3.79	$4.01	$4.22	$4.45	$4.69	$4.94	$5.20	$5.47	$5.77
American Electric Power Company, Inc.	AEP	$3.59	$3.77	$3.95	$4.14	$4.35	$4.56	$4.79	$5.03	$5.29	$5.56	$5.85	$6.16	$6.49	$6.84	$7.20	$7.58	$7.99
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.03	$2.17	$2.33	$2.50	$2.68	$2.87	$3.06	$3.25	$3.44	$3.64	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
DTE Energy Company	DTE	$4.45	$4.71	$4.98	$5.27	$5.58	$5.90	$6.24	$6.59	$6.95	$7.34	$7.73	$8.14	$8.58	$9.03	$9.51	$10.02	$10.55
El Paso Electric Company	EE	$2.03	$2.17	$2.32	$2.49	$2.66	$2.85	$3.04	$3.23	$3.43	$3.64	$3.84	$4.04	$4.26	$4.49	$4.72	$4.98	$5.24
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.93	$3.12	$3.32	$3.52	$3.75	$3.98	$4.21	$4.46	$4.71	$4.97	$5.23	$5.51	$5.80	$6.11	$6.44	$6.78
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$4.02	$4.19	$4.35	$4.53	$4.71	$4.91	$5.13	$5.36	$5.63	$5.91	$6.23	$6.56	$6.91	$7.28	$7.66	$8.07
MGE Energy, Inc.	MGEE	$2.06	$2.20	$2.36	$2.52	$2.70	$2.89	$3.08	$3.28	$3.48	$3.69	$3.90	$4.10	$4.32	$4.55	$4.79	$5.05	$5.32
NorthWestern Corporation	NWE	$2.90	$3.09	$3.29	$3.50	$3.73	$3.97	$4.22	$4.48	$4.75	$5.02	$5.29	$5.58	$5.87	$6.19	$6.52	$6.86	$7.23
OGE Energy Corp.	OGE	$1.69	$1.78	$1.87	$1.97	$2.07	$2.18	$2.29	$2.41	$2.54	$2.67	$2.81	$2.96	$3.12	$3.29	$3.46	$3.65	$3.84
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.08	$4.24	$4.41	$4.59	$4.77	$4.97	$5.19	$5.43	$5.70	$5.99	$6.31	$6.64	$7.00	$7.37	$7.76	$8.18
PNM Resources, Inc.	PNM	$1.64	$1.79	$1.95	$2.12	$2.31	$2.52	$2.73	$2.95	$3.16	$3.37	$3.57	$3.76	$3.95	$4.17	$4.39	$4.62	$4.87
Portland General Electric Company	POR	$2.04	$2.17	$2.32	$2.47	$2.63	$2.80	$2.98	$3.17	$3.35	$3.55	$3.74	$3.94	$4.15	$4.37	$4.61	$4.85	$5.11
SCANA Corporation	SCG	$3.81	$4.02	$4.23	$4.46	$4.70	$4.96	$5.22	$5.50	$5.80	$6.11	$6.43	$6.78	$7.14	$7.52	$7.92	$8.34	$8.78
Wisconsin Energy Corporation	WEC	$2.34	$2.50	$2.67	$2.85	$3.04	$3.25	$3.46	$3.68	$3.90	$4.12	$4.35	$4.59	$4.83	$5.09	$5.36	$5.64	$5.94
Xcel Energy Inc.	XEL	$2.10	$2.22	$2.34	$2.47	$2.60	$2.74	$2.89	$3.05	$3.22	$3.39	$3.57	$3.76	$3.96	$4.17	$4.40	$4.63	$4.88

Projected Annual
Dividend Payout Ratic

			[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE		66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT		64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE		68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP		64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA		68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS		63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE		63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE		59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR		67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES		60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE		55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA		53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE		56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE		65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE		67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR		80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW		64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM		51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR		56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG		59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC		68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL		62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.35	$2.45	$2.56	$2.67	$2.78	$2.97	$3.16	$3.36	$3.58	$3.81	$4.05	$4.27	$4.49	$4.73	$4.98	$5.25	$114.20
Alliant Energy Corporation	LNT	$1.15	$1.21	$1.28	$1.35	$1.42	$1.53	$1.65	$1.78	$1.91	$2.05	$2.19	$2.31	$2.43	$2.56	$2.69	$2.84	$72.63
Ameren Corporation	AEE	$1.72	$1.80	$1.88	$1.96	$2.05	$2.19	$2.33	$2.48	$2.64	$2.80	$2.98	$3.13	$3.30	$3.48	$3.66	$3.86	$98.31
American Electric Power Company, Inc.	AEP	$2.41	$2.56	$2.71	$2.88	$3.06	$3.21	$3.37	$3.54	$3.72	$3.91	$4.12	$4.34	$4.57	$4.81	$5.07	$5.34	$128.86
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$80.01
CMS Energy Corporation	CMS	$1.28	$1.36	$1.46	$1.56	$1.66	$1.80	$1.94	$2.09	$2.25	$2.40	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$84.13
DTE Energy Company	DTE	$2.97	$3.11	$3.27	$3.43	$3.60	$3.87	$4.15	$4.45	$4.76	$5.10	$5.45	$5.74	$6.04	$6.36	$6.70	$7.06	$183.56
El Paso Electric Company	EE	$1.28	$1.38	$1.49	$1.61	$1.74	$1.88	$2.04	$2.20	$2.36	$2.53	$2.70	$2.85	$3.00	$3.16	$3.33	$3.50	$90.17
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$151.57
Eversource Energy	ES	$1.76	$1.86	$1.96	$2.06	$2.17	$2.36	$2.57	$2.78	$3.01	$3.25	$3.50	$3.69	$3.88	$4.09	$4.31	$4.54	$117.24
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$75.22
IDACORP, Inc.	IDA	$2.13	$2.29	$2.46	$2.64	$2.83	$3.00	$3.19	$3.40	$3.63	$3.89	$4.16	$4.39	$4.62	$4.87	$5.13	$5.40	$151.91
MGE Energy, Inc.	MGEE	$1.23	$1.25	$1.26	$1.27	$1.27	$1.47	$1.69	$1.93	$2.19	$2.46	$2.74	$2.89	$3.04	$3.21	$3.38	$3.56	$108.10
NorthWestern Corporation	NWE	$2.01	$2.09	$2.17	$2.26	$2.34	$2.55	$2.76	$2.99	$3.22	$3.47	$3.73	$3.93	$4.14	$4.36	$4.59	$4.83	$123.17
OGE Energy Corp.	OGE	$1.19	$1.27	$1.35	$1.43	$1.52	$1.59	$1.66	$1.74	$1.81	$1.90	$1.98	$2.09	$2.20	$2.32	$2.44	$2.57	$57.42
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$58.99
Pinnacle West Capital Corporation	PNW	$2.61	$2.72	$2.84	$2.97	$3.10	$3.25	$3.41	$3.58	$3.78	$3.99	$4.22	$4.44	$4.68	$4.93	$5.19	$5.47	$144.97
PNM Resources, Inc.	PNM	$0.91	$1.01	$1.13	$1.25	$1.39	$1.56	$1.74	$1.92	$2.12	$2.31	$2.51	$2.65	$2.79	$2.93	$3.09	$3.25	$70.00
Portland General Electric Company	POR	$1.22	$1.30	$1.38	$1.47	$1.57	$1.72	$1.89	$2.06	$2.24	$2.44	$2.64	$2.78	$2.92	$3.08	$3.24	$3.42	$84.68
SCANA Corporation	SCG	$2.37	$2.51	$2.65	$2.81	$2.97	$3.19	$3.43	$3.68	$3.95	$4.23	$4.53	$4.77	$5.03	$5.30	$5.58	$5.87	$139.12
Wisconsin Energy Corporation	WEC	$1.70	$1.81	$1.92	$2.05	$2.18	$2.32	$2.46	$2.61	$2.76	$2.91	$3.07	$3.23	$3.40	$3.58	$3.77	$3.98	$118.57
Xcel Energy Inc.	XEL	$1.37	$1.46	$1.54	$1.63	$1.73	$1.84	$1.96	$2.09	$2.22	$2.37	$2.52	$2.65	$2.79	$2.94	$3.10	$3.26	$82.66

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($54.07)	$0.00	$1.19	$2.42	$2.67	$2.78	$2.97	$3.16	$3.36	$3.58	$3.81	$4.05	$4.27	$4.49	$4.73	$4.98	$5.25	$119.44
Alliant Energy Corporation	LNT	($33.83)	$0.00	$0.58	$1.19	$1.35	$1.42	$1.53	$1.65	$1.78	$1.91	$2.05	$2.19	$2.31	$2.43	$2.56	$2.69	$2.84	$75.47
Ameren Corporation	AEE	($46.40)	$0.00	$0.87	$1.77	$1.96	$2.05	$2.19	$2.33	$2.48	$2.64	$2.80	$2.98	$3.13	$3.30	$3.48	$3.66	$3.86	$102.17
American Electric Power Company, Inc.	AEP	($61.54)	$0.00	$1.21	$2.47	$2.88	$3.06	$3.21	$3.37	$3.54	$3.72	$3.91	$4.12	$4.34	$4.57	$4.81	$5.07	$5.34	$134.20
Avista Corporation	AVA	($37.83)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$82.84
CMS Energy Corporation	CMS	($39.10)	$0.00	$0.64	$1.32	$1.56	$1.66	$1.80	$1.94	$2.09	$2.25	$2.40	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$87.45
DTE Energy Company	DTE	($85.80)	$0.00	$1.50	$3.05	$3.43	$3.60	$3.87	$4.15	$4.45	$4.76	$5.10	$5.45	$5.74	$6.04	$6.36	$6.70	$7.06	$190.62
El Paso Electric Company	EE	($41.72)	$0.00	$0.65	$1.33	$1.61	$1.74	$1.88	$2.04	$2.20	$2.36	$2.53	$2.70	$2.85	$3.00	$3.16	$3.33	$3.50	$93.67
Entergy Corporation	ETR	($72.44)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$159.39
Eversource Energy	ES	($54.15)	$0.00	$0.89	$1.82	$2.06	$2.17	$2.36	$2.57	$2.78	$3.01	$3.25	$3.50	$3.69	$3.88	$4.09	$4.31	$4.54	$121.78
FirstEnergy Corp.	FE	($33.04)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$79.19
IDACORP, Inc.	IDA	($70.82)	$0.00	$1.08	$2.18	$2.64	$2.83	$3.00	$3.19	$3.40	$3.63	$3.89	$4.16	$4.39	$4.62	$4.87	$5.13	$5.40	$157.30
MGE Energy, Inc.	MGEE	($48.29)	$0.00	$0.62	$1.28	$1.27	$1.27	$1.47	$1.69	$1.93	$2.19	$2.46	$2.74	$2.89	$3.04	$3.21	$3.38	$3.56	$111.65
NorthWestern Corporation	NWE	($57.21)	$0.00	$1.01	$2.07	$2.26	$2.34	$2.55	$2.76	$2.99	$3.22	$3.47	$3.73	$3.93	$4.14	$4.36	$4.59	$4.83	$128.00
OGE Energy Corp.	OGE	($27.72)	$0.00	$0.60	$1.22	$1.43	$1.52	$1.59	$1.66	$1.74	$1.81	$1.90	$1.98	$2.09	$2.20	$2.32	$2.44	$2.57	$59.99
Otter Tail Corporation	OTTR	($28.18)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$61.50
Pinnacle West Capital Corporation	PNW	($69.12)	$0.00	$1.32	$2.66	$2.97	$3.10	$3.25	$3.41	$3.58	$3.78	$3.99	$4.22	$4.44	$4.68	$4.93	$5.19	$5.47	$150.44
PNM Resources, Inc.	PNM	($31.32)	$0.00	$0.46	$0.95	$1.25	$1.39	$1.56	$1.74	$1.92	$2.12	$2.31	$2.51	$2.65	$2.79	$2.93	$3.09	$3.25	$73.25
Portland General Electric Company	POR	($38.74)	$0.00	$0.61	$1.26	$1.47	$1.57	$1.72	$1.89	$2.06	$2.24	$2.44	$2.64	$2.78	$2.92	$3.08	$3.24	$3.42	$88.09
SCANA Corporation	SCG	($64.86)	$0.00	$1.19	$2.43	$2.81	$2.97	$3.19	$3.43	$3.68	$3.95	$4.23	$4.53	$4.77	$5.03	$5.30	$5.58	$5.87	$144.99
Wisconsin Energy Corporation	WEC	($55.89)	$0.00	$0.86	$1.76	$2.05	$2.18	$2.32	$2.46	$2.61	$2.76	$2.91	$3.07	$3.23	$3.40	$3.58	$3.77	$3.98	$122.54
Xcel Energy Inc.	XEL	($38.85)	$0.00	$0.69	$1.41	$1.63	$1.73	$1.84	$1.96	$2.09	$2.22	$2.37	$2.52	$2.65	$2.79	$2.94	$3.10	$3.26	$85.92

Multi-Stage Growth Discounted Cash Flow Model with Terminal P/E
30 Day Average Stock Price
Average EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$59.67	5.50%	5.00%	4.00%	4.83%	5.32%	66.00%	63.00%	66.88%	($0.00)	10.66%	20.86	3.92
Alliant Energy Corporation	LNT	$38.20	6.10%	6.60%	6.00%	6.23%	5.32%	64.00%	61.00%	66.88%	$0.00	9.15%	20.86	3.92
Ameren Corporation	AEE	$50.12	6.10%	5.20%	6.00%	5.77%	5.32%	68.00%	64.00%	66.88%	$0.00	9.60%	20.86	3.92
American Electric Power Company, Inc.	AEP	$66.05	4.90%	4.10%	4.00%	4.33%	5.32%	64.00%	67.00%	66.88%	$0.00	10.01%	20.86	3.92
Avista Corporation	AVA	$41.65	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	$0.00	8.70%	20.86	3.92
CMS Energy Corporation	CMS	$42.95	6.40%	7.24%	6.00%	6.55%	5.32%	63.00%	62.00%	66.88%	$0.00	9.30%	20.86	3.92
DTE Energy Company	DTE	$92.91	5.80%	5.35%	5.00%	5.38%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.36%	20.86	3.92
El Paso Electric Company	EE	$45.30	6.70%	7.00%	2.50%	5.40%	5.32%	59.00%	61.00%	66.88%	$0.00	8.73%	20.86	3.92
Entergy Corporation	ETR	$77.45	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	12.50%	20.86	3.92
Eversource Energy	ES	$56.36	6.30%	5.49%	6.00%	5.93%	5.32%	60.00%	58.00%	66.88%	$0.00	9.82%	20.86	3.92
FirstEnergy Corp.	FE	$33.34	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	13.37%	20.86	3.92
IDACORP, Inc.	IDA	$74.50	4.00%	4.00%	3.00%	3.67%	5.32%	53.00%	60.00%	66.88%	$0.00	8.96%	20.86	3.92
MGE Energy, Inc.	MGEE	$53.30	NA	4.00%	7.00%	5.50%	5.32%	56.00%	44.00%	66.88%	$0.00	7.21%	20.86	3.92
NorthWestern Corporation	NWE	$59.68	5.00%	5.00%	6.50%	5.50%	5.32%	65.00%	59.00%	66.88%	$0.00	9.54%	20.86	3.92
OGE Energy Corp.	OGE	$30.95	5.20%	4.30%	3.00%	4.17%	5.32%	67.00%	70.00%	66.88%	$0.00	10.04%	20.86	3.92
Otter Tail Corporation	OTTR	$30.96	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	$0.00	10.39%	20.86	3.92
Pinnacle West Capital Corporation	PNW	$75.82	4.00%	3.73%	4.00%	3.91%	5.32%	64.00%	65.00%	66.88%	$0.00	9.24%	20.86	3.92
PNM Resources, Inc.	PNM	$33.49	7.60%	8.76%	9.00%	8.45%	5.32%	51.00%	55.00%	66.88%	$0.00	11.21%	20.86	3.92
Portland General Electric Company	POR	$41.86	6.40%	6.57%	5.50%	6.16%	5.32%	56.00%	56.00%	66.88%	$0.00	9.84%	20.86	3.92
SCANA Corporation	SCG	$71.01	5.30%	5.40%	4.50%	5.07%	5.32%	59.00%	60.00%	66.88%	($0.00)	10.17%	20.86	3.92
Wisconsin Energy Corporation	WEC	$61.68	6.30%	6.77%	6.00%	6.36%	5.32%	68.00%	67.00%	66.88%	$0.00	7.96%	20.86	3.92
Xcel Energy Inc.	XEL	$42.20	5.30%	5.27%	5.50%	5.36%	5.32%	62.00%	63.00%	66.88%	$0.00	9.72%	20.86	3.92
											MEAN	9.79%		
											MAX	13.37%		
											MIN	7.21%		

Projected Annual
Earnings per Share

		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2015	2016	2017	2018	2019	2020	**2021**	2022	2023	2024	2025	**2026**	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE	$3.38	$3.54	$3.71	$3.89	$4.08	$4.28	$4.49	$4.71	$4.95	$5.21	$5.48	$5.77	$6.08	$6.41	$6.75	$7.11	$7.48
Alliant Energy Corporation	LNT	$1.69	$1.80	$1.91	$2.03	$2.15	$2.29	$2.43	$2.57	$2.72	$2.87	$3.03	$3.19	$3.36	$3.54	$3.73	$3.92	$4.13
Ameren Corporation	AEE	$2.38	$2.52	$2.66	$2.82	$2.98	$3.15	$3.33	$3.52	$3.71	$3.91	$4.13	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63
American Electric Power Company, Inc.	AEP	$3.59	$3.75	$3.91	$4.08	$4.25	$4.44	$4.64	$4.85	$5.09	$5.34	$5.62	$5.92	$6.23	$6.56	$6.91	$7.28	$7.67
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.01	$2.15	$2.29	$2.44	$2.60	$2.76	$2.93	$3.10	$3.28	$3.46	$3.65	$3.84	$4.04	$4.26	$4.49	$4.73
DTE Energy Company	DTE	$4.45	$4.69	$4.94	$5.21	$5.49	$5.78	$6.09	$6.42	$6.77	$7.13	$7.51	$7.91	$8.33	$8.77	$9.24	$9.73	$10.25
El Paso Electric Company	EE	$2.03	$2.14	$2.26	$2.38	$2.51	$2.64	$2.78	$2.93	$3.09	$3.25	$3.43	$3.61	$3.80	$4.01	$4.22	$4.44	$4.68
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.92	$3.10	$3.28	$3.48	$3.68	$3.90	$4.12	$4.35	$4.59	$4.84	$5.10	$5.37	$5.65	$5.96	$6.27	$6.61
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$4.01	$4.16	$4.31	$4.47	$4.63	$4.82	$5.02	$5.24	$5.50	$5.77	$6.08	$6.40	$6.74	$7.10	$7.48	$7.88
MGE Energy, Inc.	MGEE	$2.06	$2.17	$2.29	$2.42	$2.55	$2.69	$2.84	$2.99	$3.16	$3.33	$3.50	$3.69	$3.89	$4.09	$4.31	$4.54	$4.78
NorthWestern Corporation	NWE	$2.90	$3.06	$3.23	$3.41	$3.59	$3.79	$4.00	$4.22	$4.44	$4.68	$4.93	$5.20	$5.47	$5.76	$6.07	$6.39	$6.73
OGE Energy Corp.	OGE	$1.69	$1.76	$1.83	$1.91	$1.99	$2.07	$2.16	$2.26	$2.37	$2.49	$2.61	$2.75	$2.90	$3.05	$3.22	$3.39	$3.57
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.07	$4.23	$4.40	$4.57	$4.75	$4.95	$5.16	$5.40	$5.66	$5.95	$6.27	$6.60	$6.95	$7.32	$7.71	$8.12
PNM Resources, Inc.	PNM	$1.64	$1.78	$1.93	$2.09	$2.27	$2.46	$2.66	$2.85	$3.05	$3.24	$3.43	$3.62	$3.81	$4.01	$4.22	$4.45	$4.69
Portland General Electric Company	POR	$2.04	$2.17	$2.30	$2.44	$2.59	$2.75	$2.92	$3.09	$3.26	$3.45	$3.64	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
SCANA Corporation	SCG	$3.81	$4.00	$4.21	$4.42	$4.64	$4.88	$5.13	$5.39	$5.67	$5.97	$6.28	$6.62	$6.97	$7.34	$7.73	$8.14	$8.58
Wisconsin Energy Corporation	WEC	$2.34	$2.49	$2.65	$2.82	$2.99	$3.18	$3.38	$3.58	$3.79	$4.01	$4.23	$4.45	$4.69	$4.94	$5.20	$5.48	$5.77
Xcel Energy Inc.	XEL	$2.10	$2.21	$2.33	$2.46	$2.59	$2.73	$2.87	$3.03	$3.19	$3.36	$3.54	$3.72	$3.92	$4.13	$4.35	$4.58	$4.83

Projected Annual
Dividend Payout Ratic

			[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE		66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT		64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE		68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP		64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA		68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS		63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE		63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE		59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR		67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES		60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE		55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA		53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE		56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE		65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE		67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR		80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW		64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM		51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR		56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG		59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC		68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL		62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.34	$2.42	$2.51	$2.60	$2.70	$2.86	$3.03	$3.22	$3.42	$3.63	$3.86	$4.07	$4.28	$4.51	$4.75	$5.00	$156.10
Alliant Energy Corporation	LNT	$1.15	$1.21	$1.27	$1.33	$1.39	$1.50	$1.62	$1.74	$1.86	$2.00	$2.13	$2.25	$2.37	$2.49	$2.62	$2.76	$86.22
Ameren Corporation	AEE	$1.71	$1.78	$1.86	$1.94	$2.02	$2.15	$2.28	$2.43	$2.58	$2.74	$2.91	$3.06	$3.22	$3.40	$3.58	$3.77	$117.47
American Electric Power Company, Inc.	AEP	$2.40	$2.53	$2.67	$2.82	$2.97	$3.11	$3.25	$3.41	$3.58	$3.76	$3.96	$4.17	$4.39	$4.62	$4.87	$5.13	$159.96
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.33
CMS Energy Corporation	CMS	$1.27	$1.35	$1.43	$1.52	$1.61	$1.73	$1.86	$2.00	$2.14	$2.29	$2.44	$2.57	$2.71	$2.85	$3.00	$3.16	$98.58
DTE Energy Company	DTE	$2.95	$3.09	$3.23	$3.38	$3.53	$3.78	$4.04	$4.33	$4.63	$4.95	$5.29	$5.57	$5.87	$6.18	$6.51	$6.85	$213.74
El Paso Electric Company	EE	$1.26	$1.34	$1.43	$1.52	$1.61	$1.72	$1.85	$1.98	$2.11	$2.26	$2.42	$2.54	$2.68	$2.82	$2.97	$3.13	$97.62
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$243.80
Eversource Energy	ES	$1.75	$1.84	$1.94	$2.03	$2.14	$2.32	$2.51	$2.72	$2.93	$3.17	$3.41	$3.59	$3.78	$3.98	$4.20	$4.42	$137.81
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$123.80
IDACORP, Inc.	IDA	$2.13	$2.28	$2.44	$2.60	$2.78	$2.94	$3.13	$3.33	$3.55	$3.79	$4.07	$4.28	$4.51	$4.75	$5.00	$5.27	$164.36
MGE Energy, Inc.	MGEE	$1.22	$1.22	$1.21	$1.20	$1.18	$1.36	$1.55	$1.75	$1.97	$2.21	$2.47	$2.60	$2.74	$2.88	$3.04	$3.20	$99.77
NorthWestern Corporation	NWE	$1.99	$2.05	$2.11	$2.17	$2.24	$2.41	$2.60	$2.80	$3.01	$3.23	$3.47	$3.66	$3.85	$4.06	$4.28	$4.50	$140.45
OGE Energy Corp.	OGE	$1.18	$1.24	$1.31	$1.38	$1.45	$1.50	$1.56	$1.62	$1.69	$1.76	$1.84	$1.94	$2.04	$2.15	$2.27	$2.39	$74.41
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$78.28
Pinnacle West Capital Corporation	PNW	$2.61	$2.72	$2.84	$2.96	$3.09	$3.23	$3.39	$3.56	$3.75	$3.96	$4.19	$4.41	$4.65	$4.90	$5.16	$5.43	$169.43
PNM Resources, Inc.	PNM	$0.91	$1.00	$1.11	$1.23	$1.35	$1.51	$1.68	$1.86	$2.04	$2.23	$2.42	$2.55	$2.68	$2.83	$2.98	$3.13	$97.74
Portland General Electric Company	POR	$1.21	$1.29	$1.37	$1.45	$1.54	$1.69	$1.84	$2.01	$2.18	$2.37	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$103.51
SCANA Corporation	SCG	$2.36	$2.49	$2.63	$2.77	$2.93	$3.14	$3.36	$3.60	$3.85	$4.13	$4.43	$4.66	$4.91	$5.17	$5.45	$5.74	$178.92
Wisconsin Energy Corporation	WEC	$1.69	$1.79	$1.90	$2.01	$2.13	$2.26	$2.40	$2.54	$2.68	$2.83	$2.98	$3.14	$3.30	$3.48	$3.67	$3.86	$120.42
Xcel Energy Inc.	XEL	$1.37	$1.45	$1.53	$1.62	$1.72	$1.83	$1.95	$2.07	$2.20	$2.34	$2.49	$2.62	$2.76	$2.91	$3.06	$3.23	$100.68

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($59.67)	$0.00	$1.18	$2.40	$2.60	$2.70	$2.86	$3.03	$3.22	$3.42	$3.63	$3.86	$4.07	$4.28	$4.51	$4.75	$5.00	$161.11
Alliant Energy Corporation	LNT	($38.20)	$0.00	$0.58	$1.18	$1.33	$1.39	$1.50	$1.62	$1.74	$1.86	$2.00	$2.13	$2.25	$2.37	$2.49	$2.62	$2.76	$88.98
Ameren Corporation	AEE	($50.12)	$0.00	$0.86	$1.76	$1.94	$2.02	$2.15	$2.28	$2.43	$2.58	$2.74	$2.91	$3.06	$3.22	$3.40	$3.58	$3.77	$121.24
American Electric Power Company, Inc.	AEP	($66.05)	$0.00	$1.21	$2.45	$2.82	$2.97	$3.11	$3.25	$3.41	$3.58	$3.76	$3.96	$4.17	$4.39	$4.62	$4.87	$5.13	$165.09
Avista Corporation	AVA	($41.65)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$91.16
CMS Energy Corporation	CMS	($42.95)	$0.00	$0.64	$1.31	$1.52	$1.61	$1.73	$1.86	$2.00	$2.14	$2.29	$2.44	$2.57	$2.71	$2.85	$3.00	$3.16	$101.74
DTE Energy Company	DTE	($92.91)	$0.00	$1.49	$3.03	$3.38	$3.53	$3.78	$4.04	$4.33	$4.63	$4.95	$5.29	$5.57	$5.87	$6.18	$6.51	$6.85	$220.59
El Paso Electric Company	EE	($45.30)	$0.00	$0.64	$1.30	$1.52	$1.61	$1.72	$1.85	$1.98	$2.11	$2.26	$2.42	$2.54	$2.68	$2.82	$2.97	$3.13	$100.75
Entergy Corporation	ETR	($77.45)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$251.62
Eversource Energy	ES	($56.36)	$0.00	$0.88	$1.81	$2.03	$2.14	$2.32	$2.51	$2.72	$2.93	$3.17	$3.41	$3.59	$3.78	$3.98	$4.20	$4.42	$142.23
FirstEnergy Corp.	FE	($33.34)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$127.77
IDACORP, Inc.	IDA	($74.50)	$0.00	$1.07	$2.17	$2.60	$2.78	$2.94	$3.13	$3.33	$3.55	$3.79	$4.07	$4.28	$4.51	$4.75	$5.00	$5.27	$169.63
MGE Energy, Inc.	MGEE	($53.30)	$0.00	$0.61	$1.25	$1.20	$1.18	$1.36	$1.55	$1.75	$1.97	$2.21	$2.47	$2.60	$2.74	$2.88	$3.04	$3.20	$102.97
NorthWestern Corporation	NWE	($59.68)	$0.00	$1.00	$2.04	$2.17	$2.24	$2.41	$2.60	$2.80	$3.01	$3.23	$3.47	$3.66	$3.85	$4.06	$4.28	$4.50	$144.96
OGE Energy Corp.	OGE	($30.95)	$0.00	$0.59	$1.20	$1.38	$1.45	$1.50	$1.56	$1.62	$1.69	$1.76	$1.84	$1.94	$2.04	$2.15	$2.27	$2.39	$76.79
Otter Tail Corporation	OTTR	($30.96)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$80.79
Pinnacle West Capital Corporation	PNW	($75.82)	$0.00	$1.31	$2.66	$2.96	$3.09	$3.23	$3.39	$3.56	$3.75	$3.96	$4.19	$4.41	$4.65	$4.90	$5.16	$5.43	$174.86
PNM Resources, Inc.	PNM	($33.49)	$0.00	$0.46	$0.95	$1.23	$1.35	$1.51	$1.68	$1.86	$2.04	$2.23	$2.42	$2.55	$2.68	$2.83	$2.98	$3.13	$100.88
Portland General Electric Company	POR	($41.86)	$0.00	$0.61	$1.25	$1.45	$1.54	$1.69	$1.84	$2.01	$2.18	$2.37	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$106.83
SCANA Corporation	SCG	($71.01)	$0.00	$1.19	$2.42	$2.77	$2.93	$3.14	$3.36	$3.60	$3.85	$4.13	$4.43	$4.66	$4.91	$5.17	$5.45	$5.74	$184.65
Wisconsin Energy Corporation	WEC	($61.68)	$0.00	$0.85	$1.75	$2.01	$2.13	$2.26	$2.40	$2.54	$2.68	$2.83	$2.98	$3.14	$3.30	$3.48	$3.67	$3.86	$124.28
Xcel Energy Inc.	XEL	($42.19)	$0.00	$0.69	$1.41	$1.62	$1.72	$1.83	$1.95	$2.07	$2.20	$2.34	$2.49	$2.62	$2.76	$2.91	$3.06	$3.23	$103.90

Multi-Stage Growth Discounted Cash Flow Model with Terminal P/E
90 Day Average Stock Price
Average EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$57.08	5.50%	5.00%	4.00%	4.83%	5.32%	66.00%	63.00%	66.88%	($0.00)	11.09%	20.86	3.92
Alliant Energy Corporation	LNT	$36.64	6.10%	6.60%	6.00%	6.23%	5.32%	64.00%	61.00%	66.88%	$0.00	9.53%	20.86	3.92
Ameren Corporation	AEE	$48.90	6.10%	5.20%	6.00%	5.77%	5.32%	68.00%	64.00%	66.88%	$0.00	9.83%	20.86	3.92
American Electric Power Company, Inc.	AEP	$65.03	4.90%	4.10%	4.00%	4.33%	5.32%	64.00%	67.00%	66.88%	$0.00	10.16%	20.86	3.92
Avista Corporation	AVA	$40.48	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	$0.00	8.96%	20.86	3.92
CMS Energy Corporation	CMS	$41.70	6.40%	7.24%	6.00%	6.55%	5.32%	63.00%	62.00%	66.88%	$0.00	9.57%	20.86	3.92
DTE Energy Company	DTE	$89.93	5.80%	5.35%	5.00%	5.38%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.66%	20.86	3.92
El Paso Electric Company	EE	$44.56	6.70%	7.00%	2.50%	5.40%	5.32%	59.00%	61.00%	66.88%	$0.00	8.88%	20.86	3.92
Entergy Corporation	ETR	$76.55	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	12.62%	20.86	3.92
Eversource Energy	ES	$56.58	6.30%	5.49%	6.00%	5.93%	5.32%	60.00%	58.00%	66.88%	$0.00	9.78%	20.86	3.92
FirstEnergy Corp.	FE	$34.24	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	13.11%	20.86	3.92
IDACORP, Inc.	IDA	$73.58	4.00%	4.00%	3.00%	3.67%	5.32%	53.00%	60.00%	66.88%	$0.00	9.07%	20.86	3.92
MGE Energy, Inc.	MGEE	$51.38	NA	4.00%	7.00%	5.50%	5.32%	56.00%	44.00%	66.88%	$0.00	7.52%	20.86	3.92
NorthWestern Corporation	NWE	$59.59	5.00%	5.00%	6.50%	5.50%	5.32%	65.00%	59.00%	66.88%	$0.00	9.56%	20.86	3.92
OGE Energy Corp.	OGE	$29.13	5.20%	4.30%	3.00%	4.17%	5.32%	67.00%	70.00%	66.88%	$0.00	10.62%	20.86	3.92
Otter Tail Corporation	OTTR	$29.44	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	$0.00	10.87%	20.86	3.92
Pinnacle West Capital Corporation	PNW	$73.65	4.00%	3.73%	4.00%	3.91%	5.32%	64.00%	65.00%	66.88%	$0.00	9.51%	20.86	3.92
PNM Resources, Inc.	PNM	$32.94	7.60%	8.76%	9.00%	8.45%	5.32%	51.00%	55.00%	66.88%	$0.00	11.37%	20.86	3.92
Portland General Electric Company	POR	$40.24	6.40%	6.57%	5.50%	6.16%	5.32%	56.00%	56.00%	66.88%	$0.00	10.20%	20.86	3.92
SCANA Corporation	SCG	$69.22	5.30%	5.40%	4.50%	5.07%	5.32%	59.00%	60.00%	66.88%	($0.00)	10.41%	20.86	3.92
Wisconsin Energy Corporation	WEC	$59.53	6.30%	6.77%	6.00%	6.36%	5.32%	68.00%	67.00%	66.88%	$0.00	8.28%	20.86	3.92
Xcel Energy Inc.	XEL	$41.15	5.30%	5.27%	5.50%	5.36%	5.32%	62.00%	63.00%	66.88%	$0.00	9.96%	20.86	3.92
											MEAN	10.03%		
											MAX	13.11%		
											MIN	7.52%		

Projected Annual
Earnings per Share

Company	Ticker	[14] 2015	[15] 2016	[16] 2017	[17] 2018	[18] 2019	[19] 2020	[20] **2021**	[21] 2022	[22] 2023	[23] 2024	[24] 2025	[25] **2026**	[26] 2027	[27] 2028	[28] 2029	[29] 2030	[30] 2031
ALLETE, Inc.	ALE	$3.38	$3.54	$3.71	$3.89	$4.08	$4.28	$4.49	$4.71	$4.95	$5.21	$5.48	$5.77	$6.08	$6.41	$6.75	$7.11	$7.48
Alliant Energy Corporation	LNT	$1.69	$1.80	$1.91	$2.03	$2.15	$2.29	$2.43	$2.57	$2.72	$2.87	$3.03	$3.19	$3.36	$3.54	$3.73	$3.92	$4.13
Ameren Corporation	AEE	$2.38	$2.52	$2.66	$2.82	$2.98	$3.15	$3.33	$3.52	$3.71	$3.91	$4.13	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63
American Electric Power Company, Inc.	AEP	$3.59	$3.75	$3.91	$4.08	$4.25	$4.44	$4.64	$4.85	$5.09	$5.34	$5.62	$5.92	$6.23	$6.56	$6.91	$7.28	$7.67
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.01	$2.15	$2.29	$2.44	$2.60	$2.76	$2.93	$3.10	$3.28	$3.46	$3.65	$3.84	$4.04	$4.26	$4.49	$4.73
DTE Energy Company	DTE	$4.45	$4.69	$4.94	$5.21	$5.49	$5.78	$6.09	$6.42	$6.77	$7.13	$7.51	$7.91	$8.33	$8.77	$9.24	$9.73	$10.25
El Paso Electric Company	EE	$2.03	$2.14	$2.26	$2.38	$2.51	$2.64	$2.78	$2.93	$3.09	$3.25	$3.43	$3.61	$3.80	$4.01	$4.22	$4.44	$4.68
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.92	$3.10	$3.28	$3.48	$3.68	$3.90	$4.12	$4.35	$4.59	$4.84	$5.10	$5.37	$5.65	$5.96	$6.27	$6.61
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$4.01	$4.16	$4.31	$4.47	$4.63	$4.82	$5.02	$5.24	$5.50	$5.77	$6.08	$6.40	$6.74	$7.10	$7.48	$7.88
MGE Energy, Inc.	MGEE	$2.06	$2.17	$2.29	$2.42	$2.55	$2.69	$2.84	$2.99	$3.16	$3.33	$3.50	$3.69	$3.89	$4.09	$4.31	$4.54	$4.78
NorthWestern Corporation	NWE	$2.90	$3.06	$3.23	$3.41	$3.59	$3.79	$4.00	$4.22	$4.44	$4.68	$4.93	$5.20	$5.47	$5.76	$6.07	$6.39	$6.73
OGE Energy Corp.	OGE	$1.69	$1.76	$1.83	$1.91	$1.99	$2.07	$2.16	$2.26	$2.37	$2.49	$2.61	$2.75	$2.90	$3.05	$3.22	$3.39	$3.57
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.07	$4.23	$4.40	$4.57	$4.75	$4.95	$5.16	$5.40	$5.66	$5.95	$6.27	$6.60	$6.95	$7.32	$7.71	$8.12
PNM Resources, Inc.	PNM	$1.64	$1.78	$1.93	$2.09	$2.27	$2.46	$2.66	$2.85	$3.05	$3.24	$3.43	$3.62	$3.81	$4.01	$4.22	$4.45	$4.69
Portland General Electric Company	POR	$2.04	$2.17	$2.30	$2.44	$2.59	$2.75	$2.92	$3.09	$3.26	$3.45	$3.64	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
SCANA Corporation	SCG	$3.81	$4.00	$4.21	$4.42	$4.64	$4.88	$5.13	$5.39	$5.67	$5.97	$6.28	$6.62	$6.97	$7.34	$7.73	$8.14	$8.58
Wisconsin Energy Corporation	WEC	$2.34	$2.49	$2.65	$2.82	$2.99	$3.18	$3.38	$3.58	$3.79	$4.01	$4.23	$4.45	$4.69	$4.94	$5.20	$5.48	$5.77
Xcel Energy Inc.	XEL	$2.10	$2.21	$2.33	$2.46	$2.59	$2.73	$2.87	$3.03	$3.19	$3.36	$3.54	$3.72	$3.92	$4.13	$4.35	$4.58	$4.83

Projected Annual
Dividend Payout Ratic

Company	Ticker	[31] 2016	[32] 2017	[33] 2018	[34] 2019	[35] 2020	[36] 2021	[37] 2022	[38] 2023	[39] 2024	[40] 2025	[41] 2026	[42] 2027	[43] 2028	[44] 2029	[45] 2030	[46] 2031
ALLETE, Inc.	ALE	66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT	64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE	68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP	64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA	68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS	63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE	63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE	59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR	67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES	60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE	55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA	53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE	56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE	65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE	67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR	80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW	64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM	51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR	56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG	59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC	68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL	62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.34	$2.42	$2.51	$2.60	$2.70	$2.86	$3.03	$3.22	$3.42	$3.63	$3.86	$4.07	$4.28	$4.51	$4.75	$5.00	$156.10
Alliant Energy Corporation	LNT	$1.15	$1.21	$1.27	$1.33	$1.39	$1.50	$1.62	$1.74	$1.86	$2.00	$2.13	$2.25	$2.37	$2.49	$2.62	$2.76	$86.22
Ameren Corporation	AEE	$1.71	$1.78	$1.86	$1.94	$2.02	$2.15	$2.28	$2.43	$2.58	$2.74	$2.91	$3.06	$3.22	$3.40	$3.58	$3.77	$117.47
American Electric Power Company, Inc.	AEP	$2.40	$2.53	$2.67	$2.82	$2.97	$3.11	$3.25	$3.41	$3.58	$3.76	$3.96	$4.17	$4.39	$4.62	$4.87	$5.13	$159.96
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.33
CMS Energy Corporation	CMS	$1.27	$1.35	$1.43	$1.52	$1.61	$1.73	$1.86	$2.00	$2.14	$2.29	$2.44	$2.57	$2.71	$2.85	$3.00	$3.16	$98.58
DTE Energy Company	DTE	$2.95	$3.09	$3.23	$3.38	$3.53	$3.78	$4.04	$4.33	$4.63	$4.95	$5.29	$5.57	$5.87	$6.18	$6.51	$6.85	$213.74
El Paso Electric Company	EE	$1.26	$1.34	$1.43	$1.52	$1.61	$1.72	$1.85	$1.98	$2.11	$2.26	$2.42	$2.54	$2.68	$2.82	$2.97	$3.13	$97.62
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$243.80
Eversource Energy	ES	$1.75	$1.84	$1.94	$2.03	$2.14	$2.32	$2.51	$2.72	$2.93	$3.17	$3.41	$3.59	$3.78	$3.98	$4.20	$4.42	$137.81
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$123.80
IDACORP, Inc.	IDA	$2.13	$2.28	$2.44	$2.60	$2.78	$2.94	$3.13	$3.33	$3.55	$3.79	$4.07	$4.28	$4.51	$4.75	$5.00	$5.27	$164.36
MGE Energy, Inc.	MGEE	$1.22	$1.22	$1.21	$1.20	$1.18	$1.36	$1.55	$1.75	$1.97	$2.21	$2.47	$2.60	$2.74	$2.88	$3.04	$3.20	$99.77
NorthWestern Corporation	NWE	$1.99	$2.05	$2.11	$2.17	$2.24	$2.41	$2.60	$2.80	$3.01	$3.23	$3.47	$3.66	$3.85	$4.06	$4.28	$4.50	$140.45
OGE Energy Corp.	OGE	$1.18	$1.24	$1.31	$1.38	$1.45	$1.50	$1.56	$1.62	$1.69	$1.76	$1.84	$1.94	$2.04	$2.15	$2.27	$2.39	$74.41
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$78.28
Pinnacle West Capital Corporation	PNW	$2.61	$2.72	$2.84	$2.96	$3.09	$3.23	$3.39	$3.56	$3.75	$3.96	$4.19	$4.41	$4.65	$4.90	$5.16	$5.43	$169.43
PNM Resources, Inc.	PNM	$0.91	$1.00	$1.11	$1.23	$1.35	$1.51	$1.68	$1.86	$2.04	$2.23	$2.42	$2.55	$2.68	$2.83	$2.98	$3.13	$97.74
Portland General Electric Company	POR	$1.21	$1.29	$1.37	$1.45	$1.54	$1.69	$1.84	$2.01	$2.18	$2.37	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$103.51
SCANA Corporation	SCG	$2.36	$2.49	$2.63	$2.77	$2.93	$3.14	$3.36	$3.60	$3.85	$4.13	$4.43	$4.66	$4.91	$5.17	$5.45	$5.74	$178.92
Wisconsin Energy Corporation	WEC	$1.69	$1.79	$1.90	$2.01	$2.13	$2.26	$2.40	$2.54	$2.68	$2.83	$2.98	$3.14	$3.30	$3.48	$3.67	$3.86	$120.42
Xcel Energy Inc.	XEL	$1.37	$1.45	$1.53	$1.62	$1.72	$1.83	$1.95	$2.07	$2.20	$2.34	$2.49	$2.62	$2.76	$2.91	$3.06	$3.23	$100.68

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($57.08)	$0.00	$1.18	$2.40	$2.60	$2.70	$2.86	$3.03	$3.22	$3.42	$3.63	$3.86	$4.07	$4.28	$4.51	$4.75	$5.00	$161.11
Alliant Energy Corporation	LNT	($36.64)	$0.00	$0.58	$1.18	$1.33	$1.39	$1.50	$1.62	$1.74	$1.86	$2.00	$2.13	$2.25	$2.37	$2.49	$2.62	$2.76	$88.98
Ameren Corporation	AEE	($48.89)	$0.00	$0.86	$1.76	$1.94	$2.02	$2.15	$2.28	$2.43	$2.58	$2.74	$2.91	$3.06	$3.22	$3.40	$3.58	$3.77	$121.24
American Electric Power Company, Inc.	AEP	($65.03)	$0.00	$1.21	$2.45	$2.82	$2.97	$3.11	$3.25	$3.41	$3.58	$3.76	$3.96	$4.17	$4.39	$4.62	$4.87	$5.13	$165.09
Avista Corporation	AVA	($40.48)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$91.16
CMS Energy Corporation	CMS	($41.70)	$0.00	$0.64	$1.31	$1.52	$1.61	$1.73	$1.86	$2.00	$2.14	$2.29	$2.44	$2.57	$2.71	$2.85	$3.00	$3.16	$101.74
DTE Energy Company	DTE	($89.93)	$0.00	$1.49	$3.03	$3.38	$3.53	$3.78	$4.04	$4.33	$4.63	$4.95	$5.29	$5.57	$5.87	$6.18	$6.51	$6.85	$220.59
El Paso Electric Company	EE	($44.56)	$0.00	$0.64	$1.30	$1.52	$1.61	$1.72	$1.85	$1.98	$2.11	$2.26	$2.42	$2.54	$2.68	$2.82	$2.97	$3.13	$100.75
Entergy Corporation	ETR	($76.55)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$251.62
Eversource Energy	ES	($56.58)	$0.00	$0.88	$1.81	$2.03	$2.14	$2.32	$2.51	$2.72	$2.93	$3.17	$3.41	$3.59	$3.78	$3.98	$4.20	$4.42	$142.23
FirstEnergy Corp.	FE	($34.24)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$127.77
IDACORP, Inc.	IDA	($73.58)	$0.00	$1.07	$2.17	$2.60	$2.78	$2.94	$3.13	$3.33	$3.55	$3.79	$4.07	$4.28	$4.51	$4.75	$5.00	$5.27	$169.63
MGE Energy, Inc.	MGEE	($51.38)	$0.00	$0.61	$1.25	$1.20	$1.18	$1.36	$1.55	$1.75	$1.97	$2.21	$2.47	$2.60	$2.74	$2.88	$3.04	$3.20	$102.97
NorthWestern Corporation	NWE	($59.59)	$0.00	$1.00	$2.04	$2.17	$2.24	$2.41	$2.60	$2.80	$3.01	$3.23	$3.47	$3.66	$3.85	$4.06	$4.28	$4.50	$144.96
OGE Energy Corp.	OGE	($29.13)	$0.00	$0.59	$1.20	$1.38	$1.45	$1.50	$1.56	$1.62	$1.69	$1.76	$1.84	$1.94	$2.04	$2.15	$2.27	$2.39	$76.79
Otter Tail Corporation	OTTR	($29.44)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$80.79
Pinnacle West Capital Corporation	PNW	($73.65)	$0.00	$1.31	$2.66	$2.96	$3.09	$3.23	$3.39	$3.56	$3.75	$3.96	$4.19	$4.41	$4.65	$4.90	$5.16	$5.43	$174.86
PNM Resources, Inc.	PNM	($32.94)	$0.00	$0.46	$0.95	$1.23	$1.35	$1.51	$1.68	$1.86	$2.04	$2.23	$2.42	$2.55	$2.68	$2.83	$2.98	$3.13	$100.88
Portland General Electric Company	POR	($40.24)	$0.00	$0.61	$1.25	$1.45	$1.54	$1.69	$1.84	$2.01	$2.18	$2.37	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$106.83
SCANA Corporation	SCG	($69.22)	$0.00	$1.19	$2.42	$2.77	$2.93	$3.14	$3.36	$3.60	$3.85	$4.13	$4.43	$4.66	$4.91	$5.17	$5.45	$5.74	$184.65
Wisconsin Energy Corporation	WEC	($59.53)	$0.00	$0.85	$1.75	$2.01	$2.13	$2.26	$2.40	$2.54	$2.68	$2.83	$2.98	$3.14	$3.30	$3.48	$3.67	$3.86	$124.28
Xcel Energy Inc.	XEL	($41.15)	$0.00	$0.69	$1.41	$1.62	$1.72	$1.83	$1.95	$2.07	$2.20	$2.34	$2.49	$2.62	$2.76	$2.91	$3.06	$3.23	$103.90

Multi-Stage Growth Discounted Cash Flow Model with Terminal P/E
180 Day Average Stock Price
Average EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$54.07	5.50%	5.00%	4.00%	4.83%	5.32%	66.00%	63.00%	66.88%	($0.00)	11.62%	20.86	3.92
Alliant Energy Corporation	LNT	$33.83	6.10%	6.60%	6.00%	6.23%	5.32%	64.00%	61.00%	66.88%	$0.00	10.27%	20.86	3.92
Ameren Corporation	AEE	$46.40	6.10%	5.20%	6.00%	5.77%	5.32%	68.00%	64.00%	66.88%	$0.00	10.33%	20.86	3.92
American Electric Power Company, Inc.	AEP	$61.54	4.90%	4.10%	4.00%	4.33%	5.32%	64.00%	67.00%	66.88%	($0.00)	10.69%	20.86	3.92
Avista Corporation	AVA	$37.83	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	$0.00	9.59%	20.86	3.92
CMS Energy Corporation	CMS	$39.10	6.40%	7.24%	6.00%	6.55%	5.32%	63.00%	62.00%	66.88%	$0.00	10.17%	20.86	3.92
DTE Energy Company	DTE	$85.80	5.80%	5.35%	5.00%	5.38%	5.32%	63.00%	61.00%	66.88%	($0.00)	10.10%	20.86	3.92
El Paso Electric Company	EE	$41.72	6.70%	7.00%	2.50%	5.40%	5.32%	59.00%	61.00%	66.88%	$0.00	9.48%	20.86	3.92
Entergy Corporation	ETR	$72.44	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	13.18%	20.86	3.92
Eversource Energy	ES	$54.15	6.30%	5.49%	6.00%	5.93%	5.32%	60.00%	58.00%	66.88%	$0.00	10.19%	20.86	3.92
FirstEnergy Corp.	FE	$33.04	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	13.46%	20.86	3.92
IDACORP, Inc.	IDA	$70.82	4.00%	4.00%	3.00%	3.67%	5.32%	53.00%	60.00%	66.88%	$0.00	9.42%	20.86	3.92
MGE Energy, Inc.	MGEE	$48.29	NA	4.00%	7.00%	5.50%	5.32%	56.00%	44.00%	66.88%	$0.00	8.06%	20.86	3.92
NorthWestern Corporation	NWE	$57.21	5.00%	5.00%	6.50%	5.50%	5.32%	65.00%	59.00%	66.88%	$0.00	9.93%	20.86	3.92
OGE Energy Corp.	OGE	$27.72	5.20%	4.30%	3.00%	4.17%	5.32%	67.00%	70.00%	66.88%	$0.00	11.11%	20.86	3.92
Otter Tail Corporation	OTTR	$28.18	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	$0.00	11.30%	20.86	3.92
Pinnacle West Capital Corporation	PNW	$69.12	4.00%	3.73%	4.00%	3.91%	5.32%	64.00%	65.00%	66.88%	($0.00)	10.11%	20.86	3.92
PNM Resources, Inc.	PNM	$31.32	7.60%	8.76%	9.00%	8.45%	5.32%	51.00%	55.00%	66.88%	$0.00	11.85%	20.86	3.92
Portland General Electric Company	POR	$38.74	6.40%	6.57%	5.50%	6.16%	5.32%	56.00%	56.00%	66.88%	$0.00	10.56%	20.86	3.92
SCANA Corporation	SCG	$64.86	5.30%	5.40%	4.50%	5.07%	5.32%	59.00%	60.00%	66.88%	($0.00)	11.02%	20.86	3.92
Wisconsin Energy Corporation	WEC	$55.89	6.30%	6.77%	6.00%	6.36%	5.32%	68.00%	67.00%	66.88%	$0.00	8.85%	20.86	3.92
Xcel Energy Inc.	XEL	$38.85	5.30%	5.27%	5.50%	5.36%	5.32%	62.00%	63.00%	66.88%	$0.00	10.50%	20.86	3.92
											MEAN	10.54%		
											MAX	13.46%		
											MIN	8.06%		

Projected Annual
Earnings per Share

Company	Ticker	[14] 2015	[15] 2016	[16] 2017	[17] 2018	[18] 2019	[19] 2020	[20] **2021**	[21] 2022	[22] 2023	[23] 2024	[24] 2025	[25] **2026**	[26] 2027	[27] 2028	[28] 2029	[29] 2030	[30] 2031
ALLETE, Inc.	ALE	$3.38	$3.54	$3.71	$3.89	$4.08	$4.28	$4.49	$4.71	$4.95	$5.21	$5.48	$5.77	$6.08	$6.41	$6.75	$7.11	$7.48
Alliant Energy Corporation	LNT	$1.69	$1.80	$1.91	$2.03	$2.15	$2.29	$2.43	$2.57	$2.72	$2.87	$3.03	$3.19	$3.36	$3.54	$3.73	$3.92	$4.13
Ameren Corporation	AEE	$2.38	$2.52	$2.66	$2.82	$2.98	$3.15	$3.33	$3.52	$3.71	$3.91	$4.13	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63
American Electric Power Company, Inc.	AEP	$3.59	$3.75	$3.91	$4.08	$4.25	$4.44	$4.64	$4.85	$5.09	$5.34	$5.62	$5.92	$6.23	$6.56	$6.91	$7.28	$7.67
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.01	$2.15	$2.29	$2.44	$2.60	$2.76	$2.93	$3.10	$3.28	$3.46	$3.65	$3.84	$4.04	$4.26	$4.49	$4.73
DTE Energy Company	DTE	$4.45	$4.69	$4.94	$5.21	$5.49	$5.78	$6.09	$6.42	$6.77	$7.13	$7.51	$7.91	$8.33	$8.77	$9.24	$9.73	$10.25
El Paso Electric Company	EE	$2.03	$2.14	$2.26	$2.38	$2.51	$2.64	$2.78	$2.93	$3.09	$3.25	$3.43	$3.61	$3.80	$4.01	$4.22	$4.44	$4.68
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.92	$3.10	$3.28	$3.48	$3.68	$3.90	$4.12	$4.35	$4.59	$4.84	$5.10	$5.37	$5.65	$5.96	$6.27	$6.61
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$4.01	$4.16	$4.31	$4.47	$4.63	$4.82	$5.02	$5.24	$5.50	$5.77	$6.08	$6.40	$6.74	$7.10	$7.48	$7.88
MGE Energy, Inc.	MGEE	$2.06	$2.17	$2.29	$2.42	$2.55	$2.69	$2.84	$2.99	$3.16	$3.33	$3.50	$3.69	$3.89	$4.09	$4.31	$4.54	$4.78
NorthWestern Corporation	NWE	$2.90	$3.06	$3.23	$3.41	$3.59	$3.79	$4.00	$4.22	$4.44	$4.68	$4.93	$5.20	$5.47	$5.76	$6.07	$6.39	$6.73
OGE Energy Corp.	OGE	$1.69	$1.76	$1.83	$1.91	$1.99	$2.07	$2.16	$2.26	$2.37	$2.49	$2.61	$2.75	$2.90	$3.05	$3.22	$3.39	$3.57
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.07	$4.23	$4.40	$4.57	$4.75	$4.95	$5.16	$5.40	$5.66	$5.95	$6.27	$6.60	$6.95	$7.32	$7.71	$8.12
PNM Resources, Inc.	PNM	$1.64	$1.78	$1.93	$2.09	$2.27	$2.46	$2.66	$2.85	$3.05	$3.24	$3.43	$3.62	$3.81	$4.01	$4.22	$4.45	$4.69
Portland General Electric Company	POR	$2.04	$2.17	$2.30	$2.44	$2.59	$2.75	$2.92	$3.09	$3.26	$3.45	$3.64	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
SCANA Corporation	SCG	$3.81	$4.00	$4.21	$4.42	$4.64	$4.88	$5.13	$5.39	$5.67	$5.97	$6.28	$6.62	$6.97	$7.34	$7.73	$8.14	$8.58
Wisconsin Energy Corporation	WEC	$2.34	$2.49	$2.65	$2.82	$2.99	$3.18	$3.38	$3.58	$3.79	$4.01	$4.23	$4.45	$4.69	$4.94	$5.20	$5.48	$5.77
Xcel Energy Inc.	XEL	$2.10	$2.21	$2.33	$2.46	$2.59	$2.73	$2.87	$3.03	$3.19	$3.36	$3.54	$3.72	$3.92	$4.13	$4.35	$4.58	$4.83

Projected Annual
Dividend Payout Ratic

Company	Ticker	[31] 2016	[32] 2017	[33] 2018	[34] 2019	[35] 2020	[36] 2021	[37] 2022	[38] 2023	[39] 2024	[40] 2025	[41] 2026	[42] 2027	[43] 2028	[44] 2029	[45] 2030	[46] 2031
ALLETE, Inc.	ALE	66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT	64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE	68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP	64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA	68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS	63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE	63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE	59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR	67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES	60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE	55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA	53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE	56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE	65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE	67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR	80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW	64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM	51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR	56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG	59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC	68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL	62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.34	$2.42	$2.51	$2.60	$2.70	$2.86	$3.03	$3.22	$3.42	$3.63	$3.86	$4.07	$4.28	$4.51	$4.75	$5.00	$156.10
Alliant Energy Corporation	LNT	$1.15	$1.21	$1.27	$1.33	$1.39	$1.50	$1.62	$1.74	$1.86	$2.00	$2.13	$2.25	$2.37	$2.49	$2.62	$2.76	$86.22
Ameren Corporation	AEE	$1.71	$1.78	$1.86	$1.94	$2.02	$2.15	$2.28	$2.43	$2.58	$2.74	$2.91	$3.06	$3.22	$3.40	$3.58	$3.77	$117.47
American Electric Power Company, Inc.	AEP	$2.40	$2.53	$2.67	$2.82	$2.97	$3.11	$3.25	$3.41	$3.58	$3.76	$3.96	$4.17	$4.39	$4.62	$4.87	$5.13	$159.96
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.33
CMS Energy Corporation	CMS	$1.27	$1.35	$1.43	$1.52	$1.61	$1.73	$1.86	$2.00	$2.14	$2.29	$2.44	$2.57	$2.71	$2.85	$3.00	$3.16	$98.58
DTE Energy Company	DTE	$2.95	$3.09	$3.23	$3.38	$3.53	$3.78	$4.04	$4.33	$4.63	$4.95	$5.29	$5.57	$5.87	$6.18	$6.51	$6.85	$213.74
El Paso Electric Company	EE	$1.26	$1.34	$1.43	$1.52	$1.61	$1.72	$1.85	$1.98	$2.11	$2.26	$2.42	$2.54	$2.68	$2.82	$2.97	$3.13	$97.62
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$243.80
Eversource Energy	ES	$1.75	$1.84	$1.94	$2.03	$2.14	$2.32	$2.51	$2.72	$2.93	$3.17	$3.41	$3.59	$3.78	$3.98	$4.20	$4.42	$137.81
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$123.80
IDACORP, Inc.	IDA	$2.13	$2.28	$2.44	$2.60	$2.78	$2.94	$3.13	$3.33	$3.55	$3.79	$4.07	$4.28	$4.51	$4.75	$5.00	$5.27	$164.36
MGE Energy, Inc.	MGEE	$1.22	$1.22	$1.21	$1.20	$1.18	$1.36	$1.55	$1.75	$1.97	$2.21	$2.47	$2.60	$2.74	$2.88	$3.04	$3.20	$99.77
NorthWestern Corporation	NWE	$1.99	$2.05	$2.11	$2.17	$2.24	$2.41	$2.60	$2.80	$3.01	$3.23	$3.47	$3.66	$3.85	$4.06	$4.28	$4.50	$140.45
OGE Energy Corp.	OGE	$1.18	$1.24	$1.31	$1.38	$1.45	$1.50	$1.56	$1.62	$1.69	$1.76	$1.84	$1.94	$2.04	$2.15	$2.27	$2.39	$74.41
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$78.28
Pinnacle West Capital Corporation	PNW	$2.61	$2.72	$2.84	$2.96	$3.09	$3.23	$3.39	$3.56	$3.75	$3.96	$4.19	$4.41	$4.65	$4.90	$5.16	$5.43	$169.43
PNM Resources, Inc.	PNM	$0.91	$1.00	$1.11	$1.23	$1.35	$1.51	$1.68	$1.86	$2.04	$2.23	$2.42	$2.55	$2.68	$2.83	$2.98	$3.13	$97.74
Portland General Electric Company	POR	$1.21	$1.29	$1.37	$1.45	$1.54	$1.69	$1.84	$2.01	$2.18	$2.37	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$103.51
SCANA Corporation	SCG	$2.36	$2.49	$2.63	$2.77	$2.93	$3.14	$3.36	$3.60	$3.85	$4.13	$4.43	$4.66	$4.91	$5.17	$5.45	$5.74	$178.92
Wisconsin Energy Corporation	WEC	$1.69	$1.79	$1.90	$2.01	$2.13	$2.26	$2.40	$2.54	$2.68	$2.83	$2.98	$3.14	$3.30	$3.48	$3.67	$3.86	$120.42
Xcel Energy Inc.	XEL	$1.37	$1.45	$1.53	$1.62	$1.72	$1.83	$1.95	$2.07	$2.20	$2.34	$2.49	$2.62	$2.76	$2.91	$3.06	$3.23	$100.68

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($54.07)	$0.00	$1.18	$2.40	$2.60	$2.70	$2.86	$3.03	$3.22	$3.42	$3.63	$3.86	$4.07	$4.28	$4.51	$4.75	$5.00	$161.11
Alliant Energy Corporation	LNT	($33.83)	$0.00	$0.58	$1.18	$1.33	$1.39	$1.50	$1.62	$1.74	$1.86	$2.00	$2.13	$2.25	$2.37	$2.49	$2.62	$2.76	$88.98
Ameren Corporation	AEE	($46.40)	$0.00	$0.86	$1.76	$1.94	$2.02	$2.15	$2.28	$2.43	$2.58	$2.74	$2.91	$3.06	$3.22	$3.40	$3.58	$3.77	$121.24
American Electric Power Company, Inc.	AEP	($61.54)	$0.00	$1.21	$2.45	$2.82	$2.97	$3.11	$3.25	$3.41	$3.58	$3.76	$3.96	$4.17	$4.39	$4.62	$4.87	$5.13	$165.09
Avista Corporation	AVA	($37.83)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$91.16
CMS Energy Corporation	CMS	($39.10)	$0.00	$0.64	$1.31	$1.52	$1.61	$1.73	$1.86	$2.00	$2.14	$2.29	$2.44	$2.57	$2.71	$2.85	$3.00	$3.16	$101.74
DTE Energy Company	DTE	($85.80)	$0.00	$1.49	$3.03	$3.38	$3.53	$3.78	$4.04	$4.33	$4.63	$4.95	$5.29	$5.57	$5.87	$6.18	$6.51	$6.85	$220.59
El Paso Electric Company	EE	($41.72)	$0.00	$0.64	$1.30	$1.52	$1.61	$1.72	$1.85	$1.98	$2.11	$2.26	$2.42	$2.54	$2.68	$2.82	$2.97	$3.13	$100.75
Entergy Corporation	ETR	($72.44)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$251.62
Eversource Energy	ES	($54.15)	$0.00	$0.88	$1.81	$2.03	$2.14	$2.32	$2.51	$2.72	$2.93	$3.17	$3.41	$3.59	$3.78	$3.98	$4.20	$4.42	$142.23
FirstEnergy Corp.	FE	($33.04)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$127.77
IDACORP, Inc.	IDA	($70.82)	$0.00	$1.07	$2.17	$2.60	$2.78	$2.94	$3.13	$3.33	$3.55	$3.79	$4.07	$4.28	$4.51	$4.75	$5.00	$5.27	$169.63
MGE Energy, Inc.	MGEE	($48.29)	$0.00	$0.61	$1.25	$1.20	$1.18	$1.36	$1.55	$1.75	$1.97	$2.21	$2.47	$2.60	$2.74	$2.88	$3.04	$3.20	$102.97
NorthWestern Corporation	NWE	($57.21)	$0.00	$1.00	$2.04	$2.17	$2.24	$2.41	$2.60	$2.80	$3.01	$3.23	$3.47	$3.66	$3.85	$4.06	$4.28	$4.50	$144.96
OGE Energy Corp.	OGE	($27.72)	$0.00	$0.59	$1.20	$1.38	$1.45	$1.50	$1.56	$1.62	$1.69	$1.76	$1.84	$1.94	$2.04	$2.15	$2.27	$2.39	$76.79
Otter Tail Corporation	OTTR	($28.17)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$80.79
Pinnacle West Capital Corporation	PNW	($69.12)	$0.00	$1.31	$2.66	$2.96	$3.09	$3.23	$3.39	$3.56	$3.75	$3.96	$4.19	$4.41	$4.65	$4.90	$5.16	$5.43	$174.86
PNM Resources, Inc.	PNM	($31.32)	$0.00	$0.46	$0.95	$1.23	$1.35	$1.51	$1.68	$1.86	$2.04	$2.23	$2.42	$2.55	$2.68	$2.83	$2.98	$3.13	$100.88
Portland General Electric Company	POR	($38.74)	$0.00	$0.61	$1.25	$1.45	$1.54	$1.69	$1.84	$2.01	$2.18	$2.37	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$106.83
SCANA Corporation	SCG	($64.86)	$0.00	$1.19	$2.42	$2.77	$2.93	$3.14	$3.36	$3.60	$3.85	$4.13	$4.43	$4.66	$4.91	$5.17	$5.45	$5.74	$184.65
Wisconsin Energy Corporation	WEC	($55.89)	$0.00	$0.85	$1.75	$2.01	$2.13	$2.26	$2.40	$2.54	$2.68	$2.83	$2.98	$3.14	$3.30	$3.48	$3.67	$3.86	$124.28
Xcel Energy Inc.	XEL	($38.85)	$0.00	$0.69	$1.41	$1.62	$1.72	$1.83	$1.95	$2.07	$2.20	$2.34	$2.49	$2.62	$2.76	$2.91	$3.06	$3.23	$103.90

Multi-Stage Growth Discounted Cash Flow Model with Terminal P/E
30 Day Average Stock Price
Low EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Low Growth	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$59.67	5.50%	5.00%	4.00%	4.00%	5.32%	66.00%	63.00%	66.88%	$0.00	10.14%	20.86	3.92
Alliant Energy Corporation	LNT	$38.20	6.10%	6.60%	6.00%	6.00%	5.32%	64.00%	61.00%	66.88%	$0.00	9.01%	20.86	3.92
Ameren Corporation	AEE	$50.12	6.10%	5.20%	6.00%	5.20%	5.32%	68.00%	64.00%	66.88%	$0.00	9.26%	20.86	3.92
American Electric Power Company, Inc.	AEP	$66.05	4.90%	4.10%	4.00%	4.00%	5.32%	64.00%	67.00%	66.88%	$0.00	9.80%	20.86	3.92
Avista Corporation	AVA	$41.65	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	$0.00	8.70%	20.86	3.92
CMS Energy Corporation	CMS	$42.95	6.40%	7.24%	6.00%	6.00%	5.32%	63.00%	62.00%	66.88%	$0.00	8.97%	20.86	3.92
DTE Energy Company	DTE	$92.91	5.80%	5.35%	5.00%	5.00%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.13%	20.86	3.92
El Paso Electric Company	EE	$45.30	6.70%	7.00%	2.50%	2.50%	5.32%	59.00%	61.00%	66.88%	$0.00	7.00%	20.86	3.92
Entergy Corporation	ETR	$77.45	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	12.50%	20.86	3.92
Eversource Energy	ES	$56.36	6.30%	5.49%	6.00%	5.49%	5.32%	60.00%	58.00%	66.88%	$0.00	9.55%	20.86	3.92
FirstEnergy Corp.	FE	$33.34	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	13.37%	20.86	3.92
IDACORP, Inc.	IDA	$74.50	4.00%	4.00%	3.00%	3.00%	5.32%	53.00%	60.00%	66.88%	$0.00	8.55%	20.86	3.92
MGE Energy, Inc.	MGEE	$53.30	NA	4.00%	7.00%	4.00%	5.32%	56.00%	44.00%	66.88%	($0.00)	6.35%	20.86	3.92
NorthWestern Corporation	NWE	$59.68	5.00%	5.00%	6.50%	5.00%	5.32%	65.00%	59.00%	66.88%	$0.00	9.24%	20.86	3.92
OGE Energy Corp.	OGE	$30.95	5.20%	4.30%	3.00%	3.00%	5.32%	67.00%	70.00%	66.88%	$0.00	9.31%	20.86	3.92
Otter Tail Corporation	OTTR	$30.96	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	$0.00	10.39%	20.86	3.92
Pinnacle West Capital Corporation	PNW	$75.82	4.00%	3.73%	4.00%	3.73%	5.32%	64.00%	65.00%	66.88%	$0.00	9.13%	20.86	3.92
PNM Resources, Inc.	PNM	$33.49	7.60%	8.76%	9.00%	7.60%	5.32%	51.00%	55.00%	66.88%	$0.00	10.70%	20.86	3.92
Portland General Electric Company	POR	$41.86	6.40%	6.57%	5.50%	5.50%	5.32%	56.00%	56.00%	66.88%	$0.00	9.44%	20.86	3.92
SCANA Corporation	SCG	$71.01	5.30%	5.40%	4.50%	4.50%	5.32%	59.00%	60.00%	66.88%	$0.00	9.82%	20.86	3.92
Wisconsin Energy Corporation	WEC	$61.68	6.30%	6.77%	6.00%	6.00%	5.32%	68.00%	67.00%	66.88%	$0.00	7.75%	20.86	3.92
Xcel Energy Inc.	XEL	$42.20	5.30%	5.27%	5.50%	5.27%	5.32%	62.00%	63.00%	66.88%	$0.00	9.67%	20.86	3.92
											MEAN	9.44%		
											MAX	13.37%		
											MIN	6.35%		

Projected Annual Earnings per Share		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2015	2016	2017	2018	2019	2020	**2021**	2022	2023	2024	2025	**2026**	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE	$3.38	$3.52	$3.66	$3.80	$3.95	$4.11	$4.29	$4.48	$4.68	$4.91	$5.16	$5.44	$5.73	$6.03	$6.35	$6.69	$7.05
Alliant Energy Corporation	LNT	$1.69	$1.79	$1.90	$2.01	$2.13	$2.26	$2.39	$2.53	$2.68	$2.82	$2.98	$3.14	$3.30	$3.48	$3.66	$3.86	$4.07
Ameren Corporation	AEE	$2.38	$2.50	$2.63	$2.77	$2.92	$3.07	$3.23	$3.40	$3.57	$3.76	$3.96	$4.17	$4.40	$4.63	$4.88	$5.14	$5.41
American Electric Power Company, Inc.	AEP	$3.59	$3.73	$3.88	$4.04	$4.20	$4.37	$4.55	$4.75	$4.98	$5.22	$5.49	$5.78	$6.08	$6.41	$6.75	$7.11	$7.49
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.00	$2.12	$2.25	$2.39	$2.53	$2.68	$2.83	$2.99	$3.16	$3.33	$3.51	$3.69	$3.89	$4.10	$4.32	$4.55
DTE Energy Company	DTE	$4.45	$4.67	$4.91	$5.15	$5.41	$5.68	$5.97	$6.27	$6.59	$6.94	$7.30	$7.69	$8.10	$8.53	$8.99	$9.47	$9.97
El Paso Electric Company	EE	$2.03	$2.08	$2.13	$2.19	$2.24	$2.30	$2.36	$2.45	$2.54	$2.65	$2.78	$2.93	$3.09	$3.25	$3.42	$3.61	$3.80
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.91	$3.07	$3.24	$3.42	$3.61	$3.80	$4.01	$4.23	$4.45	$4.69	$4.94	$5.20	$5.48	$5.77	$6.08	$6.40
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$3.99	$4.11	$4.23	$4.36	$4.49	$4.64	$4.81	$5.01	$5.24	$5.50	$5.79	$6.10	$6.43	$6.77	$7.13	$7.51
MGE Energy, Inc.	MGEE	$2.06	$2.14	$2.23	$2.32	$2.41	$2.51	$2.61	$2.73	$2.86	$2.99	$3.15	$3.31	$3.49	$3.68	$3.87	$4.08	$4.30
NorthWestern Corporation	NWE	$2.90	$3.05	$3.20	$3.36	$3.52	$3.70	$3.89	$4.09	$4.30	$4.52	$4.76	$5.01	$5.28	$5.56	$5.86	$6.17	$6.50
OGE Energy Corp.	OGE	$1.69	$1.74	$1.79	$1.85	$1.90	$1.96	$2.03	$2.10	$2.19	$2.29	$2.40	$2.53	$2.66	$2.81	$2.96	$3.11	$3.28
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.07	$4.22	$4.38	$4.54	$4.71	$4.90	$5.10	$5.34	$5.59	$5.87	$6.19	$6.52	$6.86	$7.23	$7.61	$8.02
PNM Resources, Inc.	PNM	$1.64	$1.76	$1.90	$2.04	$2.20	$2.37	$2.54	$2.71	$2.88	$3.06	$3.23	$3.41	$3.59	$3.78	$3.98	$4.19	$4.42
Portland General Electric Company	POR	$2.04	$2.15	$2.27	$2.40	$2.53	$2.67	$2.81	$2.97	$3.13	$3.29	$3.47	$3.65	$3.85	$4.05	$4.27	$4.50	$4.74
SCANA Corporation	SCG	$3.81	$3.98	$4.16	$4.35	$4.54	$4.75	$4.97	$5.21	$5.46	$5.74	$6.03	$6.36	$6.69	$7.05	$7.42	$7.82	$8.24
Wisconsin Energy Corporation	WEC	$2.34	$2.48	$2.63	$2.79	$2.95	$3.13	$3.32	$3.51	$3.71	$3.91	$4.12	$4.34	$4.57	$4.82	$5.07	$5.34	$5.63
Xcel Energy Inc.	XEL	$2.10	$2.21	$2.33	$2.45	$2.58	$2.71	$2.86	$3.01	$3.17	$3.34	$3.51	$3.70	$3.90	$4.11	$4.32	$4.55	$4.80

Projected Annual Dividend Payout Ratic			[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE		66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT		64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE		68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP		64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA		68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS		63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE		63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE		59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR		67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES		60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE		55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA		53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE		56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE		65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE		67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR		80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW		64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM		51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR		56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG		59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC		68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL		62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.32	$2.39	$2.45	$2.52	$2.59	$2.73	$2.88	$3.04	$3.22	$3.42	$3.64	$3.83	$4.04	$4.25	$4.48	$4.71	$147.04
Alliant Energy Corporation	LNT	$1.15	$1.20	$1.26	$1.32	$1.38	$1.48	$1.59	$1.71	$1.83	$1.96	$2.10	$2.21	$2.33	$2.45	$2.58	$2.72	$84.81
Ameren Corporation	AEE	$1.70	$1.76	$1.83	$1.89	$1.96	$2.08	$2.21	$2.34	$2.48	$2.63	$2.79	$2.94	$3.10	$3.26	$3.43	$3.62	$112.83
American Electric Power Company, Inc.	AEP	$2.39	$2.51	$2.65	$2.78	$2.93	$3.05	$3.18	$3.33	$3.49	$3.67	$3.86	$4.07	$4.29	$4.51	$4.75	$5.01	$156.18
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.33
CMS Energy Corporation	CMS	$1.26	$1.33	$1.41	$1.49	$1.57	$1.68	$1.80	$1.93	$2.06	$2.20	$2.35	$2.47	$2.60	$2.74	$2.89	$3.04	$94.84
DTE Energy Company	DTE	$2.94	$3.07	$3.19	$3.33	$3.46	$3.70	$3.95	$4.22	$4.50	$4.81	$5.15	$5.42	$5.71	$6.01	$6.33	$6.67	$207.98
El Paso Electric Company	EE	$1.23	$1.27	$1.31	$1.36	$1.40	$1.47	$1.54	$1.63	$1.72	$1.83	$1.96	$2.06	$2.17	$2.29	$2.41	$2.54	$79.22
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$243.80
Eversource Energy	ES	$1.75	$1.83	$1.91	$2.00	$2.09	$2.26	$2.44	$2.64	$2.85	$3.07	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28	$133.58
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$123.80
IDACORP, Inc.	IDA	$2.11	$2.25	$2.39	$2.54	$2.69	$2.84	$3.00	$3.18	$3.39	$3.62	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$156.61
MGE Energy, Inc.	MGEE	$1.20	$1.18	$1.16	$1.13	$1.10	$1.25	$1.41	$1.58	$1.77	$1.98	$2.22	$2.34	$2.46	$2.59	$2.73	$2.87	$89.62
NorthWestern Corporation	NWE	$1.98	$2.03	$2.08	$2.13	$2.18	$2.35	$2.52	$2.71	$2.91	$3.12	$3.35	$3.53	$3.72	$3.92	$4.13	$4.35	$135.54
OGE Energy Corp.	OGE	$1.17	$1.21	$1.26	$1.32	$1.37	$1.41	$1.45	$1.50	$1.55	$1.62	$1.69	$1.78	$1.88	$1.98	$2.08	$2.19	$68.39
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$78.28
Pinnacle West Capital Corporation	PNW	$2.60	$2.71	$2.82	$2.94	$3.06	$3.20	$3.35	$3.52	$3.70	$3.91	$4.14	$4.36	$4.59	$4.83	$5.09	$5.36	$167.25
PNM Resources, Inc.	PNM	$0.90	$0.99	$1.08	$1.19	$1.30	$1.45	$1.60	$1.76	$1.93	$2.10	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$92.10
Portland General Electric Company	POR	$1.21	$1.27	$1.34	$1.42	$1.49	$1.63	$1.77	$1.92	$2.08	$2.26	$2.44	$2.57	$2.71	$2.86	$3.01	$3.17	$98.80
SCANA Corporation	SCG	$2.35	$2.47	$2.59	$2.71	$2.85	$3.04	$3.24	$3.46	$3.71	$3.97	$4.25	$4.48	$4.71	$4.97	$5.23	$5.51	$171.81
Wisconsin Energy Corporation	WEC	$1.69	$1.78	$1.88	$1.99	$2.10	$2.22	$2.35	$2.48	$2.62	$2.76	$2.90	$3.06	$3.22	$3.39	$3.57	$3.76	$117.42
Xcel Energy Inc.	XEL	$1.37	$1.45	$1.53	$1.62	$1.71	$1.82	$1.93	$2.06	$2.19	$2.33	$2.48	$2.61	$2.75	$2.89	$3.05	$3.21	$100.06

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($59.67)	$0.00	$1.17	$2.37	$2.52	$2.59	$2.73	$2.88	$3.04	$3.22	$3.42	$3.64	$3.83	$4.04	$4.25	$4.48	$4.71	$151.76
Alliant Energy Corporation	LNT	($38.20)	$0.00	$0.58	$1.18	$1.32	$1.38	$1.48	$1.59	$1.71	$1.83	$1.96	$2.10	$2.21	$2.33	$2.45	$2.58	$2.72	$87.53
Ameren Corporation	AEE	($50.12)	$0.00	$0.86	$1.75	$1.89	$1.96	$2.08	$2.21	$2.34	$2.48	$2.63	$2.79	$2.94	$3.10	$3.26	$3.43	$3.62	$116.45
American Electric Power Company, Inc.	AEP	($66.05)	$0.00	$1.20	$2.44	$2.78	$2.93	$3.05	$3.18	$3.33	$3.49	$3.67	$3.86	$4.07	$4.29	$4.51	$4.75	$5.01	$161.18
Avista Corporation	AVA	($41.65)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$91.16
CMS Energy Corporation	CMS	($42.95)	$0.00	$0.64	$1.30	$1.49	$1.57	$1.68	$1.80	$1.93	$2.06	$2.20	$2.35	$2.47	$2.60	$2.74	$2.89	$3.04	$97.88
DTE Energy Company	DTE	($92.91)	$0.00	$1.48	$3.02	$3.33	$3.46	$3.70	$3.95	$4.22	$4.50	$4.81	$5.15	$5.42	$5.71	$6.01	$6.33	$6.67	$214.65
El Paso Electric Company	EE	($45.30)	$0.00	$0.62	$1.24	$1.36	$1.40	$1.47	$1.54	$1.63	$1.72	$1.83	$1.96	$2.06	$2.17	$2.29	$2.41	$2.54	$81.76
Entergy Corporation	ETR	($77.45)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$251.62
Eversource Energy	ES	($56.36)	$0.00	$0.88	$1.79	$2.00	$2.09	$2.26	$2.44	$2.64	$2.85	$3.07	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28	$137.86
FirstEnergy Corp.	FE	($33.34)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$127.77
IDACORP, Inc.	IDA	($74.50)	$0.00	$1.06	$2.14	$2.54	$2.69	$2.84	$3.00	$3.18	$3.39	$3.62	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$161.64
MGE Energy, Inc.	MGEE	($53.30)	$0.00	$0.60	$1.22	$1.13	$1.10	$1.25	$1.41	$1.58	$1.77	$1.98	$2.22	$2.34	$2.46	$2.59	$2.73	$2.87	$92.49
NorthWestern Corporation	NWE	($59.68)	$0.00	$1.00	$2.03	$2.13	$2.18	$2.35	$2.52	$2.71	$2.91	$3.12	$3.35	$3.53	$3.72	$3.92	$4.13	$4.35	$139.88
OGE Energy Corp.	OGE	($30.95)	$0.00	$0.59	$1.18	$1.32	$1.37	$1.41	$1.45	$1.50	$1.55	$1.62	$1.69	$1.78	$1.88	$1.98	$2.08	$2.19	$70.59
Otter Tail Corporation	OTTR	($30.96)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$80.79
Pinnacle West Capital Corporation	PNW	($75.82)	$0.00	$1.31	$2.65	$2.94	$3.06	$3.20	$3.35	$3.52	$3.70	$3.91	$4.14	$4.36	$4.59	$4.83	$5.09	$5.36	$172.61
PNM Resources, Inc.	PNM	($33.49)	$0.00	$0.45	$0.93	$1.19	$1.30	$1.45	$1.60	$1.76	$1.93	$2.10	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$95.06
Portland General Electric Company	POR	($41.86)	$0.00	$0.61	$1.24	$1.42	$1.49	$1.63	$1.77	$1.92	$2.08	$2.26	$2.44	$2.57	$2.71	$2.86	$3.01	$3.17	$101.97
SCANA Corporation	SCG	($71.01)	$0.00	$1.18	$2.40	$2.71	$2.85	$3.04	$3.24	$3.46	$3.71	$3.97	$4.25	$4.48	$4.71	$4.97	$5.23	$5.51	$177.32
Wisconsin Energy Corporation	WEC	($61.68)	$0.00	$0.85	$1.74	$1.99	$2.10	$2.22	$2.35	$2.48	$2.62	$2.76	$2.90	$3.06	$3.22	$3.39	$3.57	$3.76	$121.19
Xcel Energy Inc.	XEL	($42.19)	$0.00	$0.69	$1.41	$1.62	$1.71	$1.82	$1.93	$2.06	$2.19	$2.33	$2.48	$2.61	$2.75	$2.89	$3.05	$3.21	$103.26

Multi-Stage Growth Discounted Cash Flow Model with Terminal P/E
90 Day Average Stock Price
Low EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Low Growth	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$57.08	5.50%	5.00%	4.00%	4.00%	5.32%	66.00%	63.00%	66.88%	$0.00	10.56%	20.86	3.92
Alliant Energy Corporation	LNT	$36.64	6.10%	6.60%	6.00%	6.00%	5.32%	64.00%	61.00%	66.88%	$0.00	9.39%	20.86	3.92
Ameren Corporation	AEE	$48.90	6.10%	5.20%	6.00%	5.20%	5.32%	68.00%	64.00%	66.88%	$0.00	9.49%	20.86	3.92
American Electric Power Company, Inc.	AEP	$65.03	4.90%	4.10%	4.00%	4.00%	5.32%	64.00%	67.00%	66.88%	$0.00	9.95%	20.86	3.92
Avista Corporation	AVA	$40.48	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	$0.00	8.96%	20.86	3.92
CMS Energy Corporation	CMS	$41.70	6.40%	7.24%	6.00%	6.00%	5.32%	63.00%	62.00%	66.88%	$0.00	9.24%	20.86	3.92
DTE Energy Company	DTE	$89.93	5.80%	5.35%	5.00%	5.00%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.42%	20.86	3.92
El Paso Electric Company	EE	$44.56	6.70%	7.00%	2.50%	2.50%	5.32%	59.00%	61.00%	66.88%	$0.00	7.14%	20.86	3.92
Entergy Corporation	ETR	$76.55	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	12.62%	20.86	3.92
Eversource Energy	ES	$56.58	6.30%	5.49%	6.00%	5.49%	5.32%	60.00%	58.00%	66.88%	$0.00	9.51%	20.86	3.92
FirstEnergy Corp.	FE	$34.24	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	13.11%	20.86	3.92
IDACORP, Inc.	IDA	$73.58	4.00%	4.00%	3.00%	3.00%	5.32%	53.00%	60.00%	66.88%	$0.00	8.66%	20.86	3.92
MGE Energy, Inc.	MGEE	$51.38	NA	4.00%	7.00%	4.00%	5.32%	56.00%	44.00%	66.88%	($0.00)	6.66%	20.86	3.92
NorthWestern Corporation	NWE	$59.59	5.00%	5.00%	6.50%	5.00%	5.32%	65.00%	59.00%	66.88%	$0.00	9.25%	20.86	3.92
OGE Energy Corp.	OGE	$29.13	5.20%	4.30%	3.00%	3.00%	5.32%	67.00%	70.00%	66.88%	$0.00	9.88%	20.86	3.92
Otter Tail Corporation	OTTR	$29.44	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	$0.00	10.87%	20.86	3.92
Pinnacle West Capital Corporation	PNW	$73.65	4.00%	3.73%	4.00%	3.73%	5.32%	64.00%	65.00%	66.88%	$0.00	9.40%	20.86	3.92
PNM Resources, Inc.	PNM	$32.94	7.60%	8.76%	9.00%	7.60%	5.32%	51.00%	55.00%	66.88%	$0.00	10.85%	20.86	3.92
Portland General Electric Company	POR	$40.24	6.40%	6.57%	5.50%	5.50%	5.32%	56.00%	56.00%	66.88%	$0.00	9.80%	20.86	3.92
SCANA Corporation	SCG	$69.22	5.30%	5.40%	4.50%	4.50%	5.32%	59.00%	60.00%	66.88%	($0.00)	10.05%	20.86	3.92
Wisconsin Energy Corporation	WEC	$59.53	6.30%	6.77%	6.00%	6.00%	5.32%	68.00%	67.00%	66.88%	$0.00	8.07%	20.86	3.92
Xcel Energy Inc.	XEL	$41.15	5.30%	5.27%	5.50%	5.27%	5.32%	62.00%	63.00%	66.88%	$0.00	9.91%	20.86	3.92
											MEAN	9.67%		
											MAX	13.11%		
											MIN	6.66%		

Projected Annual Earnings per Share		[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]
Company	Ticker	2015	2016	2017	2018	2019	2020	**2021**	2022	2023	2024	2025	**2026**	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE	$3.38	$3.52	$3.66	$3.80	$3.95	$4.11	$4.29	$4.48	$4.68	$4.91	$5.16	$5.44	$5.73	$6.03	$6.35	$6.69	$7.05
Alliant Energy Corporation	LNT	$1.69	$1.79	$1.90	$2.01	$2.13	$2.26	$2.39	$2.53	$2.68	$2.82	$2.98	$3.14	$3.30	$3.48	$3.66	$3.86	$4.07
Ameren Corporation	AEE	$2.38	$2.50	$2.63	$2.77	$2.92	$3.07	$3.23	$3.40	$3.57	$3.76	$3.96	$4.17	$4.40	$4.63	$4.88	$5.14	$5.41
American Electric Power Company, Inc.	AEP	$3.59	$3.73	$3.88	$4.04	$4.20	$4.37	$4.55	$4.75	$4.98	$5.22	$5.49	$5.78	$6.08	$6.41	$6.75	$7.11	$7.49
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.00	$2.12	$2.25	$2.39	$2.53	$2.68	$2.83	$2.99	$3.16	$3.33	$3.51	$3.69	$3.89	$4.10	$4.32	$4.55
DTE Energy Company	DTE	$4.45	$4.67	$4.91	$5.15	$5.41	$5.68	$5.97	$6.27	$6.59	$6.94	$7.30	$7.69	$8.10	$8.53	$8.99	$9.47	$9.97
El Paso Electric Company	EE	$2.03	$2.08	$2.13	$2.19	$2.24	$2.30	$2.36	$2.45	$2.54	$2.65	$2.78	$2.93	$3.09	$3.25	$3.42	$3.61	$3.80
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.91	$3.07	$3.24	$3.42	$3.61	$3.80	$4.01	$4.23	$4.45	$4.69	$4.94	$5.20	$5.48	$5.77	$6.08	$6.40
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$3.99	$4.11	$4.23	$4.36	$4.49	$4.64	$4.81	$5.01	$5.24	$5.50	$5.79	$6.10	$6.43	$6.77	$7.13	$7.51
MGE Energy, Inc.	MGEE	$2.06	$2.14	$2.23	$2.32	$2.41	$2.51	$2.61	$2.73	$2.86	$2.99	$3.15	$3.31	$3.49	$3.68	$3.87	$4.08	$4.30
NorthWestern Corporation	NWE	$2.90	$3.05	$3.20	$3.36	$3.52	$3.70	$3.89	$4.09	$4.30	$4.52	$4.76	$5.01	$5.28	$5.56	$5.86	$6.17	$6.50
OGE Energy Corp.	OGE	$1.69	$1.74	$1.79	$1.85	$1.90	$1.96	$2.03	$2.10	$2.19	$2.29	$2.40	$2.53	$2.66	$2.81	$2.96	$3.11	$3.28
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.07	$4.22	$4.38	$4.54	$4.71	$4.90	$5.10	$5.34	$5.59	$5.87	$6.19	$6.52	$6.86	$7.23	$7.61	$8.02
PNM Resources, Inc.	PNM	$1.64	$1.76	$1.90	$2.04	$2.20	$2.37	$2.54	$2.71	$2.88	$3.06	$3.23	$3.41	$3.59	$3.78	$3.98	$4.19	$4.42
Portland General Electric Company	POR	$2.04	$2.15	$2.27	$2.40	$2.53	$2.67	$2.81	$2.97	$3.13	$3.29	$3.47	$3.65	$3.85	$4.05	$4.27	$4.50	$4.74
SCANA Corporation	SCG	$3.81	$3.98	$4.16	$4.35	$4.54	$4.75	$4.97	$5.21	$5.46	$5.74	$6.03	$6.36	$6.69	$7.05	$7.42	$7.82	$8.24
Wisconsin Energy Corporation	WEC	$2.34	$2.48	$2.63	$2.79	$2.95	$3.13	$3.32	$3.51	$3.71	$3.91	$4.12	$4.34	$4.57	$4.82	$5.07	$5.34	$5.63
Xcel Energy Inc.	XEL	$2.10	$2.21	$2.33	$2.45	$2.58	$2.71	$2.86	$3.01	$3.17	$3.34	$3.51	$3.70	$3.90	$4.11	$4.32	$4.55	$4.80

Projected Annual Dividend Payout Ratic			[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
Company	Ticker		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ALLETE, Inc.	ALE		66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT		64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE		68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP		64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA		68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS		63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE		63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE		59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR		67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES		60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE		55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA		53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE		56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE		65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE		67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR		80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW		64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM		51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR		56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG		59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC		68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL		62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.32	$2.39	$2.45	$2.52	$2.59	$2.73	$2.88	$3.04	$3.22	$3.42	$3.64	$3.83	$4.04	$4.25	$4.48	$4.71	$147.04
Alliant Energy Corporation	LNT	$1.15	$1.20	$1.26	$1.32	$1.38	$1.48	$1.59	$1.71	$1.83	$1.96	$2.10	$2.21	$2.33	$2.45	$2.58	$2.72	$84.81
Ameren Corporation	AEE	$1.70	$1.76	$1.83	$1.89	$1.96	$2.08	$2.21	$2.34	$2.48	$2.63	$2.79	$2.94	$3.10	$3.26	$3.43	$3.62	$112.83
American Electric Power Company, Inc.	AEP	$2.39	$2.51	$2.65	$2.78	$2.93	$3.05	$3.18	$3.33	$3.49	$3.67	$3.86	$4.07	$4.29	$4.51	$4.75	$5.01	$156.18
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.33
CMS Energy Corporation	CMS	$1.26	$1.33	$1.41	$1.49	$1.57	$1.68	$1.80	$1.93	$2.06	$2.20	$2.35	$2.47	$2.60	$2.74	$2.89	$3.04	$94.84
DTE Energy Company	DTE	$2.94	$3.07	$3.19	$3.33	$3.46	$3.70	$3.95	$4.22	$4.50	$4.81	$5.15	$5.42	$5.71	$6.01	$6.33	$6.67	$207.98
El Paso Electric Company	EE	$1.23	$1.27	$1.31	$1.36	$1.40	$1.47	$1.54	$1.63	$1.72	$1.83	$1.96	$2.06	$2.17	$2.29	$2.41	$2.54	$79.22
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$243.80
Eversource Energy	ES	$1.75	$1.83	$1.91	$2.00	$2.09	$2.26	$2.44	$2.64	$2.85	$3.07	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28	$133.58
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$123.80
IDACORP, Inc.	IDA	$2.11	$2.25	$2.39	$2.54	$2.69	$2.84	$3.00	$3.18	$3.39	$3.62	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$156.61
MGE Energy, Inc.	MGEE	$1.20	$1.18	$1.16	$1.13	$1.10	$1.25	$1.41	$1.58	$1.77	$1.98	$2.22	$2.34	$2.46	$2.59	$2.73	$2.87	$89.62
NorthWestern Corporation	NWE	$1.98	$2.03	$2.08	$2.13	$2.18	$2.35	$2.52	$2.71	$2.91	$3.12	$3.35	$3.53	$3.72	$3.92	$4.13	$4.35	$135.54
OGE Energy Corp.	OGE	$1.17	$1.21	$1.26	$1.32	$1.37	$1.41	$1.45	$1.50	$1.55	$1.62	$1.69	$1.78	$1.88	$1.98	$2.08	$2.19	$68.39
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$78.28
Pinnacle West Capital Corporation	PNW	$2.60	$2.71	$2.82	$2.94	$3.06	$3.20	$3.35	$3.52	$3.70	$3.91	$4.14	$4.36	$4.59	$4.83	$5.09	$5.36	$167.25
PNM Resources, Inc.	PNM	$0.90	$0.99	$1.08	$1.19	$1.30	$1.45	$1.60	$1.76	$1.93	$2.10	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$92.10
Portland General Electric Company	POR	$1.21	$1.27	$1.34	$1.42	$1.49	$1.63	$1.77	$1.92	$2.08	$2.26	$2.44	$2.57	$2.71	$2.86	$3.01	$3.17	$98.80
SCANA Corporation	SCG	$2.35	$2.47	$2.59	$2.71	$2.85	$3.04	$3.24	$3.46	$3.71	$3.97	$4.25	$4.48	$4.71	$4.97	$5.23	$5.51	$171.81
Wisconsin Energy Corporation	WEC	$1.69	$1.78	$1.88	$1.99	$2.10	$2.22	$2.35	$2.48	$2.62	$2.76	$2.90	$3.06	$3.22	$3.39	$3.57	$3.76	$117.42
Xcel Energy Inc.	XEL	$1.37	$1.45	$1.53	$1.62	$1.71	$1.82	$1.93	$2.06	$2.19	$2.33	$2.48	$2.61	$2.75	$2.89	$3.05	$3.21	$100.06

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($57.08)	$0.00	$1.17	$2.37	$2.52	$2.59	$2.73	$2.88	$3.04	$3.22	$3.42	$3.64	$3.83	$4.04	$4.25	$4.48	$4.71	$151.76
Alliant Energy Corporation	LNT	($36.64)	$0.00	$0.58	$1.18	$1.32	$1.38	$1.48	$1.59	$1.71	$1.83	$1.96	$2.10	$2.21	$2.33	$2.45	$2.58	$2.72	$87.53
Ameren Corporation	AEE	($48.89)	$0.00	$0.86	$1.75	$1.89	$1.96	$2.08	$2.21	$2.34	$2.48	$2.63	$2.79	$2.94	$3.10	$3.26	$3.43	$3.62	$116.45
American Electric Power Company, Inc.	AEP	($65.03)	$0.00	$1.20	$2.44	$2.78	$2.93	$3.05	$3.18	$3.33	$3.49	$3.67	$3.86	$4.07	$4.29	$4.51	$4.75	$5.01	$161.18
Avista Corporation	AVA	($40.48)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$91.16
CMS Energy Corporation	CMS	($41.70)	$0.00	$0.64	$1.30	$1.49	$1.57	$1.68	$1.80	$1.93	$2.06	$2.20	$2.35	$2.47	$2.60	$2.74	$2.89	$3.04	$97.88
DTE Energy Company	DTE	($89.93)	$0.00	$1.48	$3.02	$3.33	$3.46	$3.70	$3.95	$4.22	$4.50	$4.81	$5.15	$5.42	$5.71	$6.01	$6.33	$6.67	$214.65
El Paso Electric Company	EE	($44.56)	$0.00	$0.62	$1.24	$1.36	$1.40	$1.47	$1.54	$1.63	$1.72	$1.83	$1.96	$2.06	$2.17	$2.29	$2.41	$2.54	$81.76
Entergy Corporation	ETR	($76.55)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$251.62
Eversource Energy	ES	($56.58)	$0.00	$0.88	$1.79	$2.00	$2.09	$2.26	$2.44	$2.64	$2.85	$3.07	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28	$137.86
FirstEnergy Corp.	FE	($34.24)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$127.77
IDACORP, Inc.	IDA	($73.58)	$0.00	$1.06	$2.14	$2.54	$2.69	$2.84	$3.00	$3.18	$3.39	$3.62	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$161.64
MGE Energy, Inc.	MGEE	($51.38)	$0.00	$0.60	$1.22	$1.13	$1.10	$1.25	$1.41	$1.58	$1.77	$1.98	$2.22	$2.34	$2.46	$2.59	$2.73	$2.87	$92.49
NorthWestern Corporation	NWE	($59.59)	$0.00	$1.00	$2.03	$2.13	$2.18	$2.35	$2.52	$2.71	$2.91	$3.12	$3.35	$3.53	$3.72	$3.92	$4.13	$4.35	$139.88
OGE Energy Corp.	OGE	($29.13)	$0.00	$0.59	$1.18	$1.32	$1.37	$1.41	$1.45	$1.50	$1.55	$1.62	$1.69	$1.78	$1.88	$1.98	$2.08	$2.19	$70.59
Otter Tail Corporation	OTTR	($29.44)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$80.79
Pinnacle West Capital Corporation	PNW	($73.65)	$0.00	$1.31	$2.65	$2.94	$3.06	$3.20	$3.35	$3.52	$3.70	$3.91	$4.14	$4.36	$4.59	$4.83	$5.09	$5.36	$172.61
PNM Resources, Inc.	PNM	($32.94)	$0.00	$0.45	$0.93	$1.19	$1.30	$1.45	$1.60	$1.76	$1.93	$2.10	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$95.06
Portland General Electric Company	POR	($40.24)	$0.00	$0.61	$1.24	$1.42	$1.49	$1.63	$1.77	$1.92	$2.08	$2.26	$2.44	$2.57	$2.71	$2.86	$3.01	$3.17	$101.97
SCANA Corporation	SCG	($69.22)	$0.00	$1.18	$2.40	$2.71	$2.85	$3.04	$3.24	$3.46	$3.71	$3.97	$4.25	$4.48	$4.71	$4.97	$5.23	$5.51	$177.32
Wisconsin Energy Corporation	WEC	($59.53)	$0.00	$0.85	$1.74	$1.99	$2.10	$2.22	$2.35	$2.48	$2.62	$2.76	$2.90	$3.06	$3.22	$3.39	$3.57	$3.76	$121.19
Xcel Energy Inc.	XEL	($41.15)	$0.00	$0.69	$1.41	$1.62	$1.71	$1.82	$1.93	$2.06	$2.19	$2.33	$2.48	$2.61	$2.75	$2.89	$3.05	$3.21	$103.26

Multi-Stage Growth Discounted Cash Flow Model with Terminal P/E
180 Day Average Stock Price
Low EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Low Growth	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$54.07	5.50%	5.00%	4.00%	4.00%	5.32%	66.00%	63.00%	66.88%	($0.00)	11.08%	20.86	3.92
Alliant Energy Corporation	LNT	$33.83	6.10%	6.60%	6.00%	6.00%	5.32%	64.00%	61.00%	66.88%	$0.00	10.13%	20.86	3.92
Ameren Corporation	AEE	$46.40	6.10%	5.20%	6.00%	5.20%	5.32%	68.00%	64.00%	66.88%	$0.00	9.98%	20.86	3.92
American Electric Power Company, Inc.	AEP	$61.54	4.90%	4.10%	4.00%	4.00%	5.32%	64.00%	67.00%	66.88%	($0.00)	10.48%	20.86	3.92
Avista Corporation	AVA	$37.83	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	$0.00	9.59%	20.86	3.92
CMS Energy Corporation	CMS	$39.10	6.40%	7.24%	6.00%	6.00%	5.32%	63.00%	62.00%	66.88%	$0.00	9.83%	20.86	3.92
DTE Energy Company	DTE	$85.80	5.80%	5.35%	5.00%	5.00%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.86%	20.86	3.92
El Paso Electric Company	EE	$41.72	6.70%	7.00%	2.50%	2.50%	5.32%	59.00%	61.00%	66.88%	$0.00	7.72%	20.86	3.92
Entergy Corporation	ETR	$72.44	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	13.18%	20.86	3.92
Eversource Energy	ES	$54.15	6.30%	5.49%	6.00%	5.49%	5.32%	60.00%	58.00%	66.88%	$0.00	9.92%	20.86	3.92
FirstEnergy Corp.	FE	$33.04	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	13.46%	20.86	3.92
IDACORP, Inc.	IDA	$70.82	4.00%	4.00%	3.00%	3.00%	5.32%	53.00%	60.00%	66.88%	$0.00	9.01%	20.86	3.92
MGE Energy, Inc.	MGEE	$48.29	NA	4.00%	7.00%	4.00%	5.32%	56.00%	44.00%	66.88%	$0.00	7.19%	20.86	3.92
NorthWestern Corporation	NWE	$57.21	5.00%	5.00%	6.50%	5.00%	5.32%	65.00%	59.00%	66.88%	$0.00	9.63%	20.86	3.92
OGE Energy Corp.	OGE	$27.72	5.20%	4.30%	3.00%	3.00%	5.32%	67.00%	70.00%	66.88%	$0.00	10.36%	20.86	3.92
Otter Tail Corporation	OTTR	$28.18	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	$0.00	11.30%	20.86	3.92
Pinnacle West Capital Corporation	PNW	$69.12	4.00%	3.73%	4.00%	3.73%	5.32%	64.00%	65.00%	66.88%	($0.00)	10.00%	20.86	3.92
PNM Resources, Inc.	PNM	$31.32	7.60%	8.76%	9.00%	7.60%	5.32%	51.00%	55.00%	66.88%	$0.00	11.32%	20.86	3.92
Portland General Electric Company	POR	$38.74	6.40%	6.57%	5.50%	5.50%	5.32%	56.00%	56.00%	66.88%	$0.00	10.16%	20.86	3.92
SCANA Corporation	SCG	$64.86	5.30%	5.40%	4.50%	4.50%	5.32%	59.00%	60.00%	66.88%	($0.00)	10.67%	20.86	3.92
Wisconsin Energy Corporation	WEC	$55.89	6.30%	6.77%	6.00%	6.00%	5.32%	68.00%	67.00%	66.88%	$0.00	8.64%	20.86	3.92
Xcel Energy Inc.	XEL	$38.85	5.30%	5.27%	5.50%	5.27%	5.32%	62.00%	63.00%	66.88%	$0.00	10.45%	20.86	3.92
											MEAN	10.18%		
											MAX	13.46%		
											MIN	7.19%		

Projected Annual
Earnings per Share

Company	Ticker	[14] 2015	[15] 2016	[16] 2017	[17] 2018	[18] 2019	[19] 2020	[20] **2021**	[21] 2022	[22] 2023	[23] 2024	[24] 2025	[25] **2026**	[26] 2027	[27] 2028	[28] 2029	[29] 2030	[30] 2031
ALLETE, Inc.	ALE	$3.38	$3.52	$3.66	$3.80	$3.95	$4.11	$4.29	$4.48	$4.68	$4.91	$5.16	$5.44	$5.73	$6.03	$6.35	$6.69	$7.05
Alliant Energy Corporation	LNT	$1.69	$1.79	$1.90	$2.01	$2.13	$2.26	$2.39	$2.53	$2.68	$2.82	$2.98	$3.14	$3.30	$3.48	$3.66	$3.86	$4.07
Ameren Corporation	AEE	$2.38	$2.50	$2.63	$2.77	$2.92	$3.07	$3.23	$3.40	$3.57	$3.76	$3.96	$4.17	$4.40	$4.63	$4.88	$5.14	$5.41
American Electric Power Company, Inc.	AEP	$3.59	$3.73	$3.88	$4.04	$4.20	$4.37	$4.55	$4.75	$4.98	$5.22	$5.49	$5.78	$6.08	$6.41	$6.75	$7.11	$7.49
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.00	$2.12	$2.25	$2.39	$2.53	$2.68	$2.83	$2.99	$3.16	$3.33	$3.51	$3.69	$3.89	$4.10	$4.32	$4.55
DTE Energy Company	DTE	$4.45	$4.67	$4.91	$5.15	$5.41	$5.68	$5.97	$6.27	$6.59	$6.94	$7.30	$7.69	$8.10	$8.53	$8.99	$9.47	$9.97
El Paso Electric Company	EE	$2.03	$2.08	$2.13	$2.19	$2.24	$2.30	$2.36	$2.45	$2.54	$2.65	$2.78	$2.93	$3.09	$3.25	$3.42	$3.61	$3.80
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.91	$3.07	$3.24	$3.42	$3.61	$3.80	$4.01	$4.23	$4.45	$4.69	$4.94	$5.20	$5.48	$5.77	$6.08	$6.40
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$3.99	$4.11	$4.23	$4.36	$4.49	$4.64	$4.81	$5.01	$5.24	$5.50	$5.79	$6.10	$6.43	$6.77	$7.13	$7.51
MGE Energy, Inc.	MGEE	$2.06	$2.14	$2.23	$2.32	$2.41	$2.51	$2.61	$2.73	$2.86	$2.99	$3.15	$3.31	$3.49	$3.68	$3.87	$4.08	$4.30
NorthWestern Corporation	NWE	$2.90	$3.05	$3.20	$3.36	$3.52	$3.70	$3.89	$4.09	$4.30	$4.52	$4.76	$5.01	$5.28	$5.56	$5.86	$6.17	$6.50
OGE Energy Corp.	OGE	$1.69	$1.74	$1.79	$1.85	$1.90	$1.96	$2.03	$2.10	$2.19	$2.29	$2.40	$2.53	$2.66	$2.81	$2.96	$3.11	$3.28
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.07	$4.22	$4.38	$4.54	$4.71	$4.90	$5.10	$5.34	$5.59	$5.87	$6.19	$6.52	$6.86	$7.23	$7.61	$8.02
PNM Resources, Inc.	PNM	$1.64	$1.76	$1.90	$2.04	$2.20	$2.37	$2.54	$2.71	$2.88	$3.06	$3.23	$3.41	$3.59	$3.78	$3.98	$4.19	$4.42
Portland General Electric Company	POR	$2.04	$2.15	$2.27	$2.40	$2.53	$2.67	$2.81	$2.97	$3.13	$3.29	$3.47	$3.65	$3.85	$4.05	$4.27	$4.50	$4.74
SCANA Corporation	SCG	$3.81	$3.98	$4.16	$4.35	$4.54	$4.75	$4.97	$5.21	$5.46	$5.74	$6.03	$6.36	$6.69	$7.05	$7.42	$7.82	$8.24
Wisconsin Energy Corporation	WEC	$2.34	$2.48	$2.63	$2.79	$2.95	$3.13	$3.32	$3.51	$3.71	$3.91	$4.12	$4.34	$4.57	$4.82	$5.07	$5.34	$5.63
Xcel Energy Inc.	XEL	$2.10	$2.21	$2.33	$2.45	$2.58	$2.71	$2.86	$3.01	$3.17	$3.34	$3.51	$3.70	$3.90	$4.11	$4.32	$4.55	$4.80

Projected Annual
Dividend Payout Ratic

Company	Ticker	[31] 2016	[32] 2017	[33] 2018	[34] 2019	[35] 2020	[36] 2021	[37] 2022	[38] 2023	[39] 2024	[40] 2025	[41] 2026	[42] 2027	[43] 2028	[44] 2029	[45] 2030	[46] 2031
ALLETE, Inc.	ALE	66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT	64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE	68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP	64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA	68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS	63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE	63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE	59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR	67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES	60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE	55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA	53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE	56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE	65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE	67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR	80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW	64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM	51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR	56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG	59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC	68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL	62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.32	$2.39	$2.45	$2.52	$2.59	$2.73	$2.88	$3.04	$3.22	$3.42	$3.64	$3.83	$4.04	$4.25	$4.48	$4.71	$147.04
Alliant Energy Corporation	LNT	$1.15	$1.20	$1.26	$1.32	$1.38	$1.48	$1.59	$1.71	$1.83	$1.96	$2.10	$2.21	$2.33	$2.45	$2.58	$2.72	$84.81
Ameren Corporation	AEE	$1.70	$1.76	$1.83	$1.89	$1.96	$2.08	$2.21	$2.34	$2.48	$2.63	$2.79	$2.94	$3.10	$3.26	$3.43	$3.62	$112.83
American Electric Power Company, Inc.	AEP	$2.39	$2.51	$2.65	$2.78	$2.93	$3.05	$3.18	$3.33	$3.49	$3.67	$3.86	$4.07	$4.29	$4.51	$4.75	$5.01	$156.18
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.33
CMS Energy Corporation	CMS	$1.26	$1.33	$1.41	$1.49	$1.57	$1.68	$1.80	$1.93	$2.06	$2.20	$2.35	$2.47	$2.60	$2.74	$2.89	$3.04	$94.84
DTE Energy Company	DTE	$2.94	$3.07	$3.19	$3.33	$3.46	$3.70	$3.95	$4.22	$4.50	$4.81	$5.15	$5.42	$5.71	$6.01	$6.33	$6.67	$207.98
El Paso Electric Company	EE	$1.23	$1.27	$1.31	$1.36	$1.40	$1.47	$1.54	$1.63	$1.72	$1.83	$1.96	$2.06	$2.17	$2.29	$2.41	$2.54	$79.22
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$243.80
Eversource Energy	ES	$1.75	$1.83	$1.91	$2.00	$2.09	$2.26	$2.44	$2.64	$2.85	$3.07	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28	$133.58
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$123.80
IDACORP, Inc.	IDA	$2.11	$2.25	$2.39	$2.54	$2.69	$2.84	$3.00	$3.18	$3.39	$3.62	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$156.61
MGE Energy, Inc.	MGEE	$1.20	$1.18	$1.16	$1.13	$1.10	$1.25	$1.41	$1.58	$1.77	$1.98	$2.22	$2.34	$2.46	$2.59	$2.73	$2.87	$89.62
NorthWestern Corporation	NWE	$1.98	$2.03	$2.08	$2.13	$2.18	$2.35	$2.52	$2.71	$2.91	$3.12	$3.35	$3.53	$3.72	$3.92	$4.13	$4.35	$135.54
OGE Energy Corp.	OGE	$1.17	$1.21	$1.26	$1.32	$1.37	$1.41	$1.45	$1.50	$1.55	$1.62	$1.69	$1.78	$1.88	$1.98	$2.08	$2.19	$68.39
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$78.28
Pinnacle West Capital Corporation	PNW	$2.60	$2.71	$2.82	$2.94	$3.06	$3.20	$3.35	$3.52	$3.70	$3.91	$4.14	$4.36	$4.59	$4.83	$5.09	$5.36	$167.25
PNM Resources, Inc.	PNM	$0.90	$0.99	$1.08	$1.19	$1.30	$1.45	$1.60	$1.76	$1.93	$2.10	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$92.10
Portland General Electric Company	POR	$1.21	$1.27	$1.34	$1.42	$1.49	$1.63	$1.77	$1.92	$2.08	$2.26	$2.44	$2.57	$2.71	$2.86	$3.01	$3.17	$98.80
SCANA Corporation	SCG	$2.35	$2.47	$2.59	$2.71	$2.85	$3.04	$3.24	$3.46	$3.71	$3.97	$4.25	$4.48	$4.71	$4.97	$5.23	$5.51	$171.81
Wisconsin Energy Corporation	WEC	$1.69	$1.78	$1.88	$1.99	$2.10	$2.22	$2.35	$2.48	$2.62	$2.76	$2.90	$3.06	$3.22	$3.39	$3.57	$3.76	$117.42
Xcel Energy Inc.	XEL	$1.37	$1.45	$1.53	$1.62	$1.71	$1.82	$1.93	$2.06	$2.19	$2.33	$2.48	$2.61	$2.75	$2.89	$3.05	$3.21	$100.06

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($54.07)	$0.00	$1.17	$2.37	$2.52	$2.59	$2.73	$2.88	$3.04	$3.22	$3.42	$3.64	$3.83	$4.04	$4.25	$4.48	$4.71	$151.76
Alliant Energy Corporation	LNT	($33.83)	$0.00	$0.58	$1.18	$1.32	$1.38	$1.48	$1.59	$1.71	$1.83	$1.96	$2.10	$2.21	$2.33	$2.45	$2.58	$2.72	$87.53
Ameren Corporation	AEE	($46.40)	$0.00	$0.86	$1.75	$1.89	$1.96	$2.08	$2.21	$2.34	$2.48	$2.63	$2.79	$2.94	$3.10	$3.26	$3.43	$3.62	$116.45
American Electric Power Company, Inc.	AEP	($61.54)	$0.00	$1.20	$2.44	$2.78	$2.93	$3.05	$3.18	$3.33	$3.49	$3.67	$3.86	$4.07	$4.29	$4.51	$4.75	$5.01	$161.18
Avista Corporation	AVA	($37.83)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$91.16
CMS Energy Corporation	CMS	($39.10)	$0.00	$0.64	$1.30	$1.49	$1.57	$1.68	$1.80	$1.93	$2.06	$2.20	$2.35	$2.47	$2.60	$2.74	$2.89	$3.04	$97.88
DTE Energy Company	DTE	($85.80)	$0.00	$1.48	$3.02	$3.33	$3.46	$3.70	$3.95	$4.22	$4.50	$4.81	$5.15	$5.42	$5.71	$6.01	$6.33	$6.67	$214.65
El Paso Electric Company	EE	($41.72)	$0.00	$0.62	$1.24	$1.36	$1.40	$1.47	$1.54	$1.63	$1.72	$1.83	$1.96	$2.06	$2.17	$2.29	$2.41	$2.54	$81.76
Entergy Corporation	ETR	($72.44)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$251.62
Eversource Energy	ES	($54.15)	$0.00	$0.88	$1.79	$2.00	$2.09	$2.26	$2.44	$2.64	$2.85	$3.07	$3.30	$3.48	$3.67	$3.86	$4.07	$4.28	$137.86
FirstEnergy Corp.	FE	($33.04)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$127.77
IDACORP, Inc.	IDA	($70.82)	$0.00	$1.06	$2.14	$2.54	$2.69	$2.84	$3.00	$3.18	$3.39	$3.62	$3.87	$4.08	$4.30	$4.53	$4.77	$5.02	$161.64
MGE Energy, Inc.	MGEE	($48.29)	$0.00	$0.60	$1.22	$1.13	$1.10	$1.25	$1.41	$1.58	$1.77	$1.98	$2.22	$2.34	$2.46	$2.59	$2.73	$2.87	$92.49
NorthWestern Corporation	NWE	($57.21)	$0.00	$1.00	$2.03	$2.13	$2.18	$2.35	$2.52	$2.71	$2.91	$3.12	$3.35	$3.53	$3.72	$3.92	$4.13	$4.35	$139.88
OGE Energy Corp.	OGE	($27.72)	$0.00	$0.59	$1.18	$1.32	$1.37	$1.41	$1.45	$1.50	$1.55	$1.62	$1.69	$1.78	$1.88	$1.98	$2.08	$2.19	$70.59
Otter Tail Corporation	OTTR	($28.17)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$80.79
Pinnacle West Capital Corporation	PNW	($69.12)	$0.00	$1.31	$2.65	$2.94	$3.06	$3.20	$3.35	$3.52	$3.70	$3.91	$4.14	$4.36	$4.59	$4.83	$5.09	$5.36	$172.61
PNM Resources, Inc.	PNM	($31.32)	$0.00	$0.45	$0.93	$1.19	$1.30	$1.45	$1.60	$1.76	$1.93	$2.10	$2.28	$2.40	$2.53	$2.66	$2.80	$2.95	$95.06
Portland General Electric Company	POR	($38.74)	$0.00	$0.61	$1.24	$1.42	$1.49	$1.63	$1.77	$1.92	$2.08	$2.26	$2.44	$2.57	$2.71	$2.86	$3.01	$3.17	$101.97
SCANA Corporation	SCG	($64.86)	$0.00	$1.18	$2.40	$2.71	$2.85	$3.04	$3.24	$3.46	$3.71	$3.97	$4.25	$4.48	$4.71	$4.97	$5.23	$5.51	$177.32
Wisconsin Energy Corporation	WEC	($55.89)	$0.00	$0.85	$1.74	$1.99	$2.10	$2.22	$2.35	$2.48	$2.62	$2.76	$2.90	$3.06	$3.22	$3.39	$3.57	$3.76	$121.19
Xcel Energy Inc.	XEL	($38.85)	$0.00	$0.69	$1.41	$1.62	$1.71	$1.82	$1.93	$2.06	$2.19	$2.33	$2.48	$2.61	$2.75	$2.89	$3.05	$3.21	$103.26

Multi-Stage Growth Discounted Cash Flow Model with Terminal P/E
30 Day Average Stock Price
High EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	High Growth	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$59.67	5.50%	5.00%	4.00%	5.50%	5.32%	66.00%	63.00%	66.88%	($0.00)	11.08%	20.86	3.92
Alliant Energy Corporation	LNT	$38.20	6.10%	6.60%	6.00%	6.60%	5.32%	64.00%	61.00%	66.88%	$0.00	9.37%	20.86	3.92
Ameren Corporation	AEE	$50.12	6.10%	5.20%	6.00%	6.10%	5.32%	68.00%	64.00%	66.88%	$0.00	9.81%	20.86	3.92
American Electric Power Company, Inc.	AEP	$66.05	4.90%	4.10%	4.00%	4.90%	5.32%	64.00%	67.00%	66.88%	($0.00)	10.37%	20.86	3.92
Avista Corporation	AVA	$41.65	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	$0.00	8.70%	20.86	3.92
CMS Energy Corporation	CMS	$42.95	6.40%	7.24%	6.00%	7.24%	5.32%	63.00%	62.00%	66.88%	$0.00	9.72%	20.86	3.92
DTE Energy Company	DTE	$92.91	5.80%	5.35%	5.00%	5.80%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.61%	20.86	3.92
El Paso Electric Company	EE	$45.30	6.70%	7.00%	2.50%	7.00%	5.32%	59.00%	61.00%	66.88%	$0.00	9.69%	20.86	3.92
Entergy Corporation	ETR	$77.45	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	12.50%	20.86	3.92
Eversource Energy	ES	$56.36	6.30%	5.49%	6.00%	6.30%	5.32%	60.00%	58.00%	66.88%	$0.00	10.04%	20.86	3.92
FirstEnergy Corp.	FE	$33.34	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	13.37%	20.86	3.92
IDACORP, Inc.	IDA	$74.50	4.00%	4.00%	3.00%	4.00%	5.32%	53.00%	60.00%	66.88%	$0.00	9.16%	20.86	3.92
MGE Energy, Inc.	MGEE	$53.30	NA	4.00%	7.00%	7.00%	5.32%	56.00%	44.00%	66.88%	$0.00	8.07%	20.86	3.92
NorthWestern Corporation	NWE	$59.68	5.00%	5.00%	6.50%	6.50%	5.32%	65.00%	59.00%	66.88%	$0.00	10.15%	20.86	3.92
OGE Energy Corp.	OGE	$30.95	5.20%	4.30%	3.00%	5.20%	5.32%	67.00%	70.00%	66.88%	$0.00	10.69%	20.86	3.92
Otter Tail Corporation	OTTR	$30.96	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	$0.00	10.39%	20.86	3.92
Pinnacle West Capital Corporation	PNW	$75.82	4.00%	3.73%	4.00%	4.00%	5.32%	64.00%	65.00%	66.88%	$0.00	9.30%	20.86	3.92
PNM Resources, Inc.	PNM	$33.49	7.60%	8.76%	9.00%	9.00%	5.32%	51.00%	55.00%	66.88%	$0.00	11.54%	20.86	3.92
Portland General Electric Company	POR	$41.86	6.40%	6.57%	5.50%	6.57%	5.32%	56.00%	56.00%	66.88%	$0.00	10.09%	20.86	3.92
SCANA Corporation	SCG	$71.01	5.30%	5.40%	4.50%	5.40%	5.32%	59.00%	60.00%	66.88%	($0.00)	10.37%	20.86	3.92
Wisconsin Energy Corporation	WEC	$61.68	6.30%	6.77%	6.00%	6.77%	5.32%	68.00%	67.00%	66.88%	$0.00	8.20%	20.86	3.92
Xcel Energy Inc.	XEL	$42.20	5.30%	5.27%	5.50%	5.50%	5.32%	62.00%	63.00%	66.88%	$0.00	9.81%	20.86	3.92
											MEAN	10.09%		
											MAX	13.37%		
											MIN	8.07%		

Projected Annual
Earnings per Share

Company	Ticker	[14] 2015	[15] 2016	[16] 2017	[17] 2018	[18] 2019	[19] 2020	[20] **2021**	[21] 2022	[22] 2023	[23] 2024	[24] 2025	[25] **2026**	[26] 2027	[27] 2028	[28] 2029	[29] 2030	[30] 2031
ALLETE, Inc.	ALE	$3.38	$3.57	$3.76	$3.97	$4.19	$4.42	$4.66	$4.91	$5.18	$5.46	$5.75	$6.06	$6.38	$6.72	$7.07	$7.45	$7.85
Alliant Energy Corporation	LNT	$1.69	$1.80	$1.92	$2.05	$2.18	$2.33	$2.47	$2.63	$2.78	$2.94	$3.11	$3.27	$3.45	$3.63	$3.82	$4.03	$4.24
Ameren Corporation	AEE	$2.38	$2.53	$2.68	$2.84	$3.02	$3.20	$3.39	$3.59	$3.79	$4.01	$4.22	$4.45	$4.69	$4.94	$5.20	$5.47	$5.77
American Electric Power Company, Inc.	AEP	$3.59	$3.77	$3.95	$4.14	$4.35	$4.56	$4.79	$5.03	$5.29	$5.56	$5.85	$6.16	$6.49	$6.84	$7.20	$7.58	$7.99
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.03	$2.17	$2.33	$2.50	$2.68	$2.87	$3.06	$3.25	$3.44	$3.64	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
DTE Energy Company	DTE	$4.45	$4.71	$4.98	$5.27	$5.58	$5.90	$6.24	$6.59	$6.95	$7.34	$7.73	$8.14	$8.58	$9.03	$9.51	$10.02	$10.55
El Paso Electric Company	EE	$2.03	$2.17	$2.32	$2.49	$2.66	$2.85	$3.04	$3.23	$3.43	$3.64	$3.84	$4.04	$4.26	$4.49	$4.72	$4.98	$5.24
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.93	$3.12	$3.32	$3.52	$3.75	$3.98	$4.21	$4.46	$4.71	$4.97	$5.23	$5.51	$5.80	$6.11	$6.44	$6.78
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$4.02	$4.19	$4.35	$4.53	$4.71	$4.91	$5.13	$5.36	$5.63	$5.91	$6.23	$6.56	$6.91	$7.28	$7.66	$8.07
MGE Energy, Inc.	MGEE	$2.06	$2.20	$2.36	$2.52	$2.70	$2.89	$3.08	$3.28	$3.48	$3.69	$3.90	$4.10	$4.32	$4.55	$4.79	$5.05	$5.32
NorthWestern Corporation	NWE	$2.90	$3.09	$3.29	$3.50	$3.73	$3.97	$4.22	$4.48	$4.75	$5.02	$5.29	$5.58	$5.87	$6.19	$6.52	$6.86	$7.23
OGE Energy Corp.	OGE	$1.69	$1.78	$1.87	$1.97	$2.07	$2.18	$2.29	$2.41	$2.54	$2.67	$2.81	$2.96	$3.12	$3.29	$3.46	$3.65	$3.84
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.08	$4.24	$4.41	$4.59	$4.77	$4.97	$5.19	$5.43	$5.70	$5.99	$6.31	$6.64	$7.00	$7.37	$7.76	$8.18
PNM Resources, Inc.	PNM	$1.64	$1.79	$1.95	$2.12	$2.31	$2.52	$2.73	$2.95	$3.16	$3.37	$3.57	$3.76	$3.95	$4.17	$4.39	$4.62	$4.87
Portland General Electric Company	POR	$2.04	$2.17	$2.32	$2.47	$2.63	$2.80	$2.98	$3.17	$3.35	$3.55	$3.74	$3.94	$4.15	$4.37	$4.61	$4.85	$5.11
SCANA Corporation	SCG	$3.81	$4.02	$4.23	$4.46	$4.70	$4.96	$5.22	$5.50	$5.80	$6.11	$6.43	$6.78	$7.14	$7.52	$7.92	$8.34	$8.78
Wisconsin Energy Corporation	WEC	$2.34	$2.50	$2.67	$2.85	$3.04	$3.25	$3.46	$3.68	$3.90	$4.12	$4.35	$4.59	$4.83	$5.09	$5.36	$5.64	$5.94
Xcel Energy Inc.	XEL	$2.10	$2.22	$2.34	$2.47	$2.60	$2.74	$2.89	$3.05	$3.22	$3.39	$3.57	$3.76	$3.96	$4.17	$4.40	$4.63	$4.88

Projected Annual
Dividend Payout Ratic

Company	Ticker	[31] 2016	[32] 2017	[33] 2018	[34] 2019	[35] 2020	[36] 2021	[37] 2022	[38] 2023	[39] 2024	[40] 2025	[41] 2026	[42] 2027	[43] 2028	[44] 2029	[45] 2030	[46] 2031
ALLETE, Inc.	ALE	66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT	64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE	68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP	64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA	68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS	63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE	63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE	59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR	67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES	60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE	55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA	53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE	56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE	65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE	67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR	80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW	64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM	51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR	56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG	59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC	68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL	62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.35	$2.45	$2.56	$2.67	$2.78	$2.97	$3.16	$3.36	$3.58	$3.81	$4.05	$4.27	$4.49	$4.73	$4.98	$5.25	$163.70
Alliant Energy Corporation	LNT	$1.15	$1.21	$1.28	$1.35	$1.42	$1.53	$1.65	$1.78	$1.91	$2.05	$2.19	$2.31	$2.43	$2.56	$2.69	$2.84	$88.48
Ameren Corporation	AEE	$1.72	$1.80	$1.88	$1.96	$2.05	$2.19	$2.33	$2.48	$2.64	$2.80	$2.98	$3.13	$3.30	$3.48	$3.66	$3.86	$120.28
American Electric Power Company, Inc.	AEP	$2.41	$2.56	$2.71	$2.88	$3.06	$3.21	$3.37	$3.54	$3.72	$3.91	$4.12	$4.34	$4.57	$4.81	$5.07	$5.34	$166.59
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.33
CMS Energy Corporation	CMS	$1.28	$1.36	$1.46	$1.56	$1.66	$1.80	$1.94	$2.09	$2.25	$2.40	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$103.50
DTE Energy Company	DTE	$2.97	$3.11	$3.27	$3.43	$3.60	$3.87	$4.15	$4.45	$4.76	$5.10	$5.45	$5.74	$6.04	$6.36	$6.70	$7.06	$220.16
El Paso Electric Company	EE	$1.28	$1.38	$1.49	$1.61	$1.74	$1.88	$2.04	$2.20	$2.36	$2.53	$2.70	$2.85	$3.00	$3.16	$3.33	$3.50	$109.31
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$243.80
Eversource Energy	ES	$1.76	$1.86	$1.96	$2.06	$2.17	$2.36	$2.57	$2.78	$3.01	$3.25	$3.50	$3.69	$3.88	$4.09	$4.31	$4.54	$141.47
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$123.80
IDACORP, Inc.	IDA	$2.13	$2.29	$2.46	$2.64	$2.83	$3.00	$3.19	$3.40	$3.63	$3.89	$4.16	$4.39	$4.62	$4.87	$5.13	$5.40	$168.36
MGE Energy, Inc.	MGEE	$1.23	$1.25	$1.26	$1.27	$1.27	$1.47	$1.69	$1.93	$2.19	$2.46	$2.74	$2.89	$3.04	$3.21	$3.38	$3.56	$110.93
NorthWestern Corporation	NWE	$2.01	$2.09	$2.17	$2.26	$2.34	$2.55	$2.76	$2.99	$3.22	$3.47	$3.73	$3.93	$4.14	$4.36	$4.59	$4.83	$150.76
OGE Energy Corp.	OGE	$1.19	$1.27	$1.35	$1.43	$1.52	$1.59	$1.66	$1.74	$1.81	$1.90	$1.98	$2.09	$2.20	$2.32	$2.44	$2.57	$80.12
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$78.28
Pinnacle West Capital Corporation	PNW	$2.61	$2.72	$2.84	$2.97	$3.10	$3.25	$3.41	$3.58	$3.78	$3.99	$4.22	$4.44	$4.68	$4.93	$5.19	$5.47	$170.53
PNM Resources, Inc.	PNM	$0.91	$1.01	$1.13	$1.25	$1.39	$1.56	$1.74	$1.92	$2.12	$2.31	$2.51	$2.65	$2.79	$2.93	$3.09	$3.25	$101.51
Portland General Electric Company	POR	$1.22	$1.30	$1.38	$1.47	$1.57	$1.72	$1.89	$2.06	$2.24	$2.44	$2.64	$2.78	$2.92	$3.08	$3.24	$3.42	$106.58
SCANA Corporation	SCG	$2.37	$2.51	$2.65	$2.81	$2.97	$3.19	$3.43	$3.68	$3.95	$4.23	$4.53	$4.77	$5.03	$5.30	$5.58	$5.87	$183.22
Wisconsin Energy Corporation	WEC	$1.70	$1.81	$1.92	$2.05	$2.18	$2.32	$2.46	$2.61	$2.76	$2.91	$3.07	$3.23	$3.40	$3.58	$3.77	$3.98	$123.98
Xcel Energy Inc.	XEL	$1.37	$1.46	$1.54	$1.63	$1.73	$1.84	$1.96	$2.09	$2.22	$2.37	$2.52	$2.65	$2.79	$2.94	$3.10	$3.26	$101.71

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($59.67)	$0.00	$1.19	$2.42	$2.67	$2.78	$2.97	$3.16	$3.36	$3.58	$3.81	$4.05	$4.27	$4.49	$4.73	$4.98	$5.25	$168.95
Alliant Energy Corporation	LNT	($38.20)	$0.00	$0.58	$1.19	$1.35	$1.42	$1.53	$1.65	$1.78	$1.91	$2.05	$2.19	$2.31	$2.43	$2.56	$2.69	$2.84	$91.31
Ameren Corporation	AEE	($50.12)	$0.00	$0.87	$1.77	$1.96	$2.05	$2.19	$2.33	$2.48	$2.64	$2.80	$2.98	$3.13	$3.30	$3.48	$3.66	$3.86	$124.14
American Electric Power Company, Inc.	AEP	($66.05)	$0.00	$1.21	$2.47	$2.88	$3.06	$3.21	$3.37	$3.54	$3.72	$3.91	$4.12	$4.34	$4.57	$4.81	$5.07	$5.34	$171.93
Avista Corporation	AVA	($41.65)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$91.16
CMS Energy Corporation	CMS	($42.95)	$0.00	$0.64	$1.32	$1.56	$1.66	$1.80	$1.94	$2.09	$2.25	$2.40	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$106.82
DTE Energy Company	DTE	($92.91)	$0.00	$1.50	$3.05	$3.43	$3.60	$3.87	$4.15	$4.45	$4.76	$5.10	$5.45	$5.74	$6.04	$6.36	$6.70	$7.06	$227.22
El Paso Electric Company	EE	($45.30)	$0.00	$0.65	$1.33	$1.61	$1.74	$1.88	$2.04	$2.20	$2.36	$2.53	$2.70	$2.85	$3.00	$3.16	$3.33	$3.50	$112.82
Entergy Corporation	ETR	($77.45)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$251.62
Eversource Energy	ES	($56.36)	$0.00	$0.89	$1.82	$2.06	$2.17	$2.36	$2.57	$2.78	$3.01	$3.25	$3.50	$3.69	$3.88	$4.09	$4.31	$4.54	$146.01
FirstEnergy Corp.	FE	($33.34)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$127.77
IDACORP, Inc.	IDA	($74.50)	$0.00	$1.08	$2.18	$2.64	$2.83	$3.00	$3.19	$3.40	$3.63	$3.89	$4.16	$4.39	$4.62	$4.87	$5.13	$5.40	$173.76
MGE Energy, Inc.	MGEE	($53.30)	$0.00	$0.62	$1.28	$1.27	$1.27	$1.47	$1.69	$1.93	$2.19	$2.46	$2.74	$2.89	$3.04	$3.21	$3.38	$3.56	$114.48
NorthWestern Corporation	NWE	($59.68)	$0.00	$1.01	$2.07	$2.26	$2.34	$2.55	$2.76	$2.99	$3.22	$3.47	$3.73	$3.93	$4.14	$4.36	$4.59	$4.83	$155.59
OGE Energy Corp.	OGE	($30.95)	$0.00	$0.60	$1.22	$1.43	$1.52	$1.59	$1.66	$1.74	$1.81	$1.90	$1.98	$2.09	$2.20	$2.32	$2.44	$2.57	$82.69
Otter Tail Corporation	OTTR	($30.96)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$80.79
Pinnacle West Capital Corporation	PNW	($75.82)	$0.00	$1.32	$2.66	$2.97	$3.10	$3.25	$3.41	$3.58	$3.78	$3.99	$4.22	$4.44	$4.68	$4.93	$5.19	$5.47	$176.00
PNM Resources, Inc.	PNM	($33.49)	$0.00	$0.46	$0.95	$1.25	$1.39	$1.56	$1.74	$1.92	$2.12	$2.31	$2.51	$2.65	$2.79	$2.93	$3.09	$3.25	$104.77
Portland General Electric Company	POR	($41.86)	$0.00	$0.61	$1.26	$1.47	$1.57	$1.72	$1.89	$2.06	$2.24	$2.44	$2.64	$2.78	$2.92	$3.08	$3.24	$3.42	$109.99
SCANA Corporation	SCG	($71.01)	$0.00	$1.19	$2.43	$2.81	$2.97	$3.19	$3.43	$3.68	$3.95	$4.23	$4.53	$4.77	$5.03	$5.30	$5.58	$5.87	$189.09
Wisconsin Energy Corporation	WEC	($61.68)	$0.00	$0.86	$1.76	$2.05	$2.18	$2.32	$2.46	$2.61	$2.76	$2.91	$3.07	$3.23	$3.40	$3.58	$3.77	$3.98	$127.96
Xcel Energy Inc.	XEL	($42.19)	$0.00	$0.69	$1.41	$1.63	$1.73	$1.84	$1.96	$2.09	$2.22	$2.37	$2.52	$2.65	$2.79	$2.94	$3.10	$3.26	$104.97

Multi-Stage Growth Discounted Cash Flow Model with Terminal P/E
90 Day Average Stock Price
High EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	High Growth	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$57.08	5.50%	5.00%	4.00%	5.50%	5.32%	66.00%	63.00%	66.88%	($0.00)	11.51%	20.86	3.92
Alliant Energy Corporation	LNT	$36.64	6.10%	6.60%	6.00%	6.60%	5.32%	64.00%	61.00%	66.88%	$0.00	9.75%	20.86	3.92
Ameren Corporation	AEE	$48.90	6.10%	5.20%	6.00%	6.10%	5.32%	68.00%	64.00%	66.88%	$0.00	10.04%	20.86	3.92
American Electric Power Company, Inc.	AEP	$65.03	4.90%	4.10%	4.00%	4.90%	5.32%	64.00%	67.00%	66.88%	($0.00)	10.51%	20.86	3.92
Avista Corporation	AVA	$40.48	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	$0.00	8.96%	20.86	3.92
CMS Energy Corporation	CMS	$41.70	6.40%	7.24%	6.00%	7.24%	5.32%	63.00%	62.00%	66.88%	$0.00	9.99%	20.86	3.92
DTE Energy Company	DTE	$89.93	5.80%	5.35%	5.00%	5.80%	5.32%	63.00%	61.00%	66.88%	($0.00)	9.91%	20.86	3.92
El Paso Electric Company	EE	$44.56	6.70%	7.00%	2.50%	7.00%	5.32%	59.00%	61.00%	66.88%	$0.00	9.84%	20.86	3.92
Entergy Corporation	ETR	$76.55	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	12.62%	20.86	3.92
Eversource Energy	ES	$56.58	6.30%	5.49%	6.00%	6.30%	5.32%	60.00%	58.00%	66.88%	$0.00	10.00%	20.86	3.92
FirstEnergy Corp.	FE	$34.24	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	13.11%	20.86	3.92
IDACORP, Inc.	IDA	$73.58	4.00%	4.00%	3.00%	4.00%	5.32%	53.00%	60.00%	66.88%	$0.00	9.27%	20.86	3.92
MGE Energy, Inc.	MGEE	$51.38	NA	4.00%	7.00%	7.00%	5.32%	56.00%	44.00%	66.88%	$0.00	8.39%	20.86	3.92
NorthWestern Corporation	NWE	$59.59	5.00%	5.00%	6.50%	6.50%	5.32%	65.00%	59.00%	66.88%	$0.00	10.16%	20.86	3.92
OGE Energy Corp.	OGE	$29.13	5.20%	4.30%	3.00%	5.20%	5.32%	67.00%	70.00%	66.88%	$0.00	11.28%	20.86	3.92
Otter Tail Corporation	OTTR	$29.44	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	$0.00	10.87%	20.86	3.92
Pinnacle West Capital Corporation	PNW	$73.65	4.00%	3.73%	4.00%	4.00%	5.32%	64.00%	65.00%	66.88%	$0.00	9.57%	20.86	3.92
PNM Resources, Inc.	PNM	$32.94	7.60%	8.76%	9.00%	9.00%	5.32%	51.00%	55.00%	66.88%	$0.00	11.70%	20.86	3.92
Portland General Electric Company	POR	$40.24	6.40%	6.57%	5.50%	6.57%	5.32%	56.00%	56.00%	66.88%	$0.00	10.45%	20.86	3.92
SCANA Corporation	SCG	$69.22	5.30%	5.40%	4.50%	5.40%	5.32%	59.00%	60.00%	66.88%	($0.00)	10.61%	20.86	3.92
Wisconsin Energy Corporation	WEC	$59.53	6.30%	6.77%	6.00%	6.77%	5.32%	68.00%	67.00%	66.88%	$0.00	8.52%	20.86	3.92
Xcel Energy Inc.	XEL	$41.15	5.30%	5.27%	5.50%	5.50%	5.32%	62.00%	63.00%	66.88%	$0.00	10.05%	20.86	3.92
											MEAN	10.32%		
											MAX	13.11%		
											MIN	8.39%		

Projected Annual
Earnings per Share

Company	Ticker	[14] 2015	[15] 2016	[16] 2017	[17] 2018	[18] 2019	[19] 2020	[20] **2021**	[21] 2022	[22] 2023	[23] 2024	[24] 2025	[25] **2026**	[26] 2027	[27] 2028	[28] 2029	[29] 2030	[30] 2031
ALLETE, Inc.	ALE	$3.38	$3.57	$3.76	$3.97	$4.19	$4.42	$4.66	$4.91	$5.18	$5.46	$5.75	$6.06	$6.38	$6.72	$7.07	$7.45	$7.85
Alliant Energy Corporation	LNT	$1.69	$1.80	$1.92	$2.05	$2.18	$2.33	$2.47	$2.63	$2.78	$2.94	$3.11	$3.27	$3.45	$3.63	$3.82	$4.03	$4.24
Ameren Corporation	AEE	$2.38	$2.53	$2.68	$2.84	$3.02	$3.20	$3.39	$3.59	$3.79	$4.01	$4.22	$4.45	$4.69	$4.94	$5.20	$5.47	$5.77
American Electric Power Company, Inc.	AEP	$3.59	$3.77	$3.95	$4.14	$4.35	$4.56	$4.79	$5.03	$5.29	$5.56	$5.85	$6.16	$6.49	$6.84	$7.20	$7.58	$7.99
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.03	$2.17	$2.33	$2.50	$2.68	$2.87	$3.06	$3.25	$3.44	$3.64	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
DTE Energy Company	DTE	$4.45	$4.71	$4.98	$5.27	$5.58	$5.90	$6.24	$6.59	$6.95	$7.34	$7.73	$8.14	$8.58	$9.03	$9.51	$10.02	$10.55
El Paso Electric Company	EE	$2.03	$2.17	$2.32	$2.49	$2.66	$2.85	$3.04	$3.23	$3.43	$3.64	$3.84	$4.04	$4.26	$4.49	$4.72	$4.98	$5.24
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.93	$3.12	$3.32	$3.52	$3.75	$3.98	$4.21	$4.46	$4.71	$4.97	$5.23	$5.51	$5.80	$6.11	$6.44	$6.78
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$4.02	$4.19	$4.35	$4.53	$4.71	$4.91	$5.13	$5.36	$5.63	$5.91	$6.23	$6.56	$6.91	$7.28	$7.66	$8.07
MGE Energy, Inc.	MGEE	$2.06	$2.20	$2.36	$2.52	$2.70	$2.89	$3.08	$3.28	$3.48	$3.69	$3.90	$4.10	$4.32	$4.55	$4.79	$5.05	$5.32
NorthWestern Corporation	NWE	$2.90	$3.09	$3.29	$3.50	$3.73	$3.97	$4.22	$4.48	$4.75	$5.02	$5.29	$5.58	$5.87	$6.19	$6.52	$6.86	$7.23
OGE Energy Corp.	OGE	$1.69	$1.78	$1.87	$1.97	$2.07	$2.18	$2.29	$2.41	$2.54	$2.67	$2.81	$2.96	$3.12	$3.29	$3.46	$3.65	$3.84
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.08	$4.24	$4.41	$4.59	$4.77	$4.97	$5.19	$5.43	$5.70	$5.99	$6.31	$6.64	$7.00	$7.37	$7.76	$8.18
PNM Resources, Inc.	PNM	$1.64	$1.79	$1.95	$2.12	$2.31	$2.52	$2.73	$2.95	$3.16	$3.37	$3.57	$3.76	$3.95	$4.17	$4.39	$4.62	$4.87
Portland General Electric Company	POR	$2.04	$2.17	$2.32	$2.47	$2.63	$2.80	$2.98	$3.17	$3.35	$3.55	$3.74	$3.94	$4.15	$4.37	$4.61	$4.85	$5.11
SCANA Corporation	SCG	$3.81	$4.02	$4.23	$4.46	$4.70	$4.96	$5.22	$5.50	$5.80	$6.11	$6.43	$6.78	$7.14	$7.52	$7.92	$8.34	$8.78
Wisconsin Energy Corporation	WEC	$2.34	$2.50	$2.67	$2.85	$3.04	$3.25	$3.46	$3.68	$3.90	$4.12	$4.35	$4.59	$4.83	$5.09	$5.36	$5.64	$5.94
Xcel Energy Inc.	XEL	$2.10	$2.22	$2.34	$2.47	$2.60	$2.74	$2.89	$3.05	$3.22	$3.39	$3.57	$3.76	$3.96	$4.17	$4.40	$4.63	$4.88

Projected Annual
Dividend Payout Ratic

Company	Ticker	[31] 2016	[32] 2017	[33] 2018	[34] 2019	[35] 2020	[36] 2021	[37] 2022	[38] 2023	[39] 2024	[40] 2025	[41] 2026	[42] 2027	[43] 2028	[44] 2029	[45] 2030	[46] 2031
ALLETE, Inc.	ALE	66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT	64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE	68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP	64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA	68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS	63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE	63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE	59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR	67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES	60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE	55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA	53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE	56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE	65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE	67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR	80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW	64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM	51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR	56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG	59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC	68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL	62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.35	$2.45	$2.56	$2.67	$2.78	$2.97	$3.16	$3.36	$3.58	$3.81	$4.05	$4.27	$4.49	$4.73	$4.98	$5.25	$163.70
Alliant Energy Corporation	LNT	$1.15	$1.21	$1.28	$1.35	$1.42	$1.53	$1.65	$1.78	$1.91	$2.05	$2.19	$2.31	$2.43	$2.56	$2.69	$2.84	$88.48
Ameren Corporation	AEE	$1.72	$1.80	$1.88	$1.96	$2.05	$2.19	$2.33	$2.48	$2.64	$2.80	$2.98	$3.13	$3.30	$3.48	$3.66	$3.86	$120.28
American Electric Power Company, Inc.	AEP	$2.41	$2.56	$2.71	$2.88	$3.06	$3.21	$3.37	$3.54	$3.72	$3.91	$4.12	$4.34	$4.57	$4.81	$5.07	$5.34	$166.59
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.33
CMS Energy Corporation	CMS	$1.28	$1.36	$1.46	$1.56	$1.66	$1.80	$1.94	$2.09	$2.25	$2.40	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$103.50
DTE Energy Company	DTE	$2.97	$3.11	$3.27	$3.43	$3.60	$3.87	$4.15	$4.45	$4.76	$5.10	$5.45	$5.74	$6.04	$6.36	$6.70	$7.06	$220.16
El Paso Electric Company	EE	$1.28	$1.38	$1.49	$1.61	$1.74	$1.88	$2.04	$2.20	$2.36	$2.53	$2.70	$2.85	$3.00	$3.16	$3.33	$3.50	$109.31
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$243.80
Eversource Energy	ES	$1.76	$1.86	$1.96	$2.06	$2.17	$2.36	$2.57	$2.78	$3.01	$3.25	$3.50	$3.69	$3.88	$4.09	$4.31	$4.54	$141.47
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$123.80
IDACORP, Inc.	IDA	$2.13	$2.29	$2.46	$2.64	$2.83	$3.00	$3.19	$3.40	$3.63	$3.89	$4.16	$4.39	$4.62	$4.87	$5.13	$5.40	$168.36
MGE Energy, Inc.	MGEE	$1.23	$1.25	$1.26	$1.27	$1.27	$1.47	$1.69	$1.93	$2.19	$2.46	$2.74	$2.89	$3.04	$3.21	$3.38	$3.56	$110.93
NorthWestern Corporation	NWE	$2.01	$2.09	$2.17	$2.26	$2.34	$2.55	$2.76	$2.99	$3.22	$3.47	$3.73	$3.93	$4.14	$4.36	$4.59	$4.83	$150.76
OGE Energy Corp.	OGE	$1.19	$1.27	$1.35	$1.43	$1.52	$1.59	$1.66	$1.74	$1.81	$1.90	$1.98	$2.09	$2.20	$2.32	$2.44	$2.57	$80.12
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$78.28
Pinnacle West Capital Corporation	PNW	$2.61	$2.72	$2.84	$2.97	$3.10	$3.25	$3.41	$3.58	$3.78	$3.99	$4.22	$4.44	$4.68	$4.93	$5.19	$5.47	$170.53
PNM Resources, Inc.	PNM	$0.91	$1.01	$1.13	$1.25	$1.39	$1.56	$1.74	$1.92	$2.12	$2.31	$2.51	$2.65	$2.79	$2.93	$3.09	$3.25	$101.51
Portland General Electric Company	POR	$1.22	$1.30	$1.38	$1.47	$1.57	$1.72	$1.89	$2.06	$2.24	$2.44	$2.64	$2.78	$2.92	$3.08	$3.24	$3.42	$106.58
SCANA Corporation	SCG	$2.37	$2.51	$2.65	$2.81	$2.97	$3.19	$3.43	$3.68	$3.95	$4.23	$4.53	$4.77	$5.03	$5.30	$5.58	$5.87	$183.22
Wisconsin Energy Corporation	WEC	$1.70	$1.81	$1.92	$2.05	$2.18	$2.32	$2.46	$2.61	$2.76	$2.91	$3.07	$3.23	$3.40	$3.58	$3.77	$3.98	$123.98
Xcel Energy Inc.	XEL	$1.37	$1.46	$1.54	$1.63	$1.73	$1.84	$1.96	$2.09	$2.22	$2.37	$2.52	$2.65	$2.79	$2.94	$3.10	$3.26	$101.71

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($57.08)	$0.00	$1.19	$2.42	$2.67	$2.78	$2.97	$3.16	$3.36	$3.58	$3.81	$4.05	$4.27	$4.49	$4.73	$4.98	$5.25	$168.95
Alliant Energy Corporation	LNT	($36.64)	$0.00	$0.58	$1.19	$1.35	$1.42	$1.53	$1.65	$1.78	$1.91	$2.05	$2.19	$2.31	$2.43	$2.56	$2.69	$2.84	$91.31
Ameren Corporation	AEE	($48.89)	$0.00	$0.87	$1.77	$1.96	$2.05	$2.19	$2.33	$2.48	$2.64	$2.80	$2.98	$3.13	$3.30	$3.48	$3.66	$3.86	$124.14
American Electric Power Company, Inc.	AEP	($65.03)	$0.00	$1.21	$2.47	$2.88	$3.06	$3.21	$3.37	$3.54	$3.72	$3.91	$4.12	$4.34	$4.57	$4.81	$5.07	$5.34	$171.93
Avista Corporation	AVA	($40.48)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$91.16
CMS Energy Corporation	CMS	($41.70)	$0.00	$0.64	$1.32	$1.56	$1.66	$1.80	$1.94	$2.09	$2.25	$2.40	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$106.82
DTE Energy Company	DTE	($89.93)	$0.00	$1.50	$3.05	$3.43	$3.60	$3.87	$4.15	$4.45	$4.76	$5.10	$5.45	$5.74	$6.04	$6.36	$6.70	$7.06	$227.22
El Paso Electric Company	EE	($44.56)	$0.00	$0.65	$1.33	$1.61	$1.74	$1.88	$2.04	$2.20	$2.36	$2.53	$2.70	$2.85	$3.00	$3.16	$3.33	$3.50	$112.82
Entergy Corporation	ETR	($76.55)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$251.62
Eversource Energy	ES	($56.58)	$0.00	$0.89	$1.82	$2.06	$2.17	$2.36	$2.57	$2.78	$3.01	$3.25	$3.50	$3.69	$3.88	$4.09	$4.31	$4.54	$146.01
FirstEnergy Corp.	FE	($34.24)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$127.77
IDACORP, Inc.	IDA	($73.58)	$0.00	$1.08	$2.18	$2.64	$2.83	$3.00	$3.19	$3.40	$3.63	$3.89	$4.16	$4.39	$4.62	$4.87	$5.13	$5.40	$173.76
MGE Energy, Inc.	MGEE	($51.38)	$0.00	$0.62	$1.28	$1.27	$1.27	$1.47	$1.69	$1.93	$2.19	$2.46	$2.74	$2.89	$3.04	$3.21	$3.38	$3.56	$114.48
NorthWestern Corporation	NWE	($59.59)	$0.00	$1.01	$2.07	$2.26	$2.34	$2.55	$2.76	$2.99	$3.22	$3.47	$3.73	$3.93	$4.14	$4.36	$4.59	$4.83	$155.59
OGE Energy Corp.	OGE	($29.13)	$0.00	$0.60	$1.22	$1.43	$1.52	$1.59	$1.66	$1.74	$1.81	$1.90	$1.98	$2.09	$2.20	$2.32	$2.44	$2.57	$82.69
Otter Tail Corporation	OTTR	($29.44)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$80.79
Pinnacle West Capital Corporation	PNW	($73.65)	$0.00	$1.32	$2.66	$2.97	$3.10	$3.25	$3.41	$3.58	$3.78	$3.99	$4.22	$4.44	$4.68	$4.93	$5.19	$5.47	$176.00
PNM Resources, Inc.	PNM	($32.94)	$0.00	$0.46	$0.95	$1.25	$1.39	$1.56	$1.74	$1.92	$2.12	$2.31	$2.51	$2.65	$2.79	$2.93	$3.09	$3.25	$104.77
Portland General Electric Company	POR	($40.24)	$0.00	$0.61	$1.26	$1.47	$1.57	$1.72	$1.89	$2.06	$2.24	$2.44	$2.64	$2.78	$2.92	$3.08	$3.24	$3.42	$109.99
SCANA Corporation	SCG	($69.22)	$0.00	$1.19	$2.43	$2.81	$2.97	$3.19	$3.43	$3.68	$3.95	$4.23	$4.53	$4.77	$5.03	$5.30	$5.58	$5.87	$189.09
Wisconsin Energy Corporation	WEC	($59.53)	$0.00	$0.86	$1.76	$2.05	$2.18	$2.32	$2.46	$2.61	$2.76	$2.91	$3.07	$3.23	$3.40	$3.58	$3.77	$3.98	$127.96
Xcel Energy Inc.	XEL	($41.15)	$0.00	$0.69	$1.41	$1.63	$1.73	$1.84	$1.96	$2.09	$2.22	$2.37	$2.52	$2.65	$2.79	$2.94	$3.10	$3.26	$104.97

Multi-Stage Growth Discounted Cash Flow Model with Terminal P/E
180 Day Average Stock Price
High EPS Growth Rate Estimate in First Stage

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	High Growth	Growth	2016	2020	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$54.07	5.50%	5.00%	4.00%	5.50%	5.32%	66.00%	63.00%	66.88%	($0.00)	12.04%	20.86	3.92
Alliant Energy Corporation	LNT	$33.83	6.10%	6.60%	6.00%	6.60%	5.32%	64.00%	61.00%	66.88%	$0.00	10.50%	20.86	3.92
Ameren Corporation	AEE	$46.40	6.10%	5.20%	6.00%	6.10%	5.32%	68.00%	64.00%	66.88%	$0.00	10.54%	20.86	3.92
American Electric Power Company, Inc.	AEP	$61.54	4.90%	4.10%	4.00%	4.90%	5.32%	64.00%	67.00%	66.88%	($0.00)	11.05%	20.86	3.92
Avista Corporation	AVA	$37.83	5.00%	5.00%	5.00%	5.00%	5.32%	68.00%	63.00%	66.88%	$0.00	9.59%	20.86	3.92
CMS Energy Corporation	CMS	$39.10	6.40%	7.24%	6.00%	7.24%	5.32%	63.00%	62.00%	66.88%	$0.00	10.59%	20.86	3.92
DTE Energy Company	DTE	$85.80	5.80%	5.35%	5.00%	5.80%	5.32%	63.00%	61.00%	66.88%	($0.00)	10.35%	20.86	3.92
El Paso Electric Company	EE	$41.72	6.70%	7.00%	2.50%	7.00%	5.32%	59.00%	61.00%	66.88%	$0.00	10.45%	20.86	3.92
Entergy Corporation	ETR	$72.44	NA	NA	3.50%	3.50%	5.32%	67.00%	59.00%	66.88%	($0.00)	13.18%	20.86	3.92
Eversource Energy	ES	$54.15	6.30%	5.49%	6.00%	6.30%	5.32%	60.00%	58.00%	66.88%	$0.00	10.41%	20.86	3.92
FirstEnergy Corp.	FE	$33.04	NA	NA	9.00%	9.00%	5.32%	55.00%	48.00%	66.88%	$0.00	13.46%	20.86	3.92
IDACORP, Inc.	IDA	$70.82	4.00%	4.00%	3.00%	4.00%	5.32%	53.00%	60.00%	66.88%	$0.00	9.63%	20.86	3.92
MGE Energy, Inc.	MGEE	$48.29	NA	4.00%	7.00%	7.00%	5.32%	56.00%	44.00%	66.88%	$0.00	8.93%	20.86	3.92
NorthWestern Corporation	NWE	$57.21	5.00%	5.00%	6.50%	6.50%	5.32%	65.00%	59.00%	66.88%	$0.00	10.54%	20.86	3.92
OGE Energy Corp.	OGE	$27.72	5.20%	4.30%	3.00%	5.20%	5.32%	67.00%	70.00%	66.88%	$0.00	11.77%	20.86	3.92
Otter Tail Corporation	OTTR	$28.18	NA	6.00%	6.00%	6.00%	5.32%	80.00%	63.00%	66.88%	$0.00	11.30%	20.86	3.92
Pinnacle West Capital Corporation	PNW	$69.12	4.00%	3.73%	4.00%	4.00%	5.32%	64.00%	65.00%	66.88%	($0.00)	10.17%	20.86	3.92
PNM Resources, Inc.	PNM	$31.32	7.60%	8.76%	9.00%	9.00%	5.32%	51.00%	55.00%	66.88%	$0.00	12.18%	20.86	3.92
Portland General Electric Company	POR	$38.74	6.40%	6.57%	5.50%	6.57%	5.32%	56.00%	56.00%	66.88%	$0.00	10.81%	20.86	3.92
SCANA Corporation	SCG	$64.86	5.30%	5.40%	4.50%	5.40%	5.32%	59.00%	60.00%	66.88%	($0.00)	11.23%	20.86	3.92
Wisconsin Energy Corporation	WEC	$55.89	6.30%	6.77%	6.00%	6.77%	5.32%	68.00%	67.00%	66.88%	$0.00	9.10%	20.86	3.92
Xcel Energy Inc.	XEL	$38.85	5.30%	5.27%	5.50%	5.50%	5.32%	62.00%	63.00%	66.88%	$0.00	10.59%	20.86	3.92
											MEAN	10.84%		
											MAX	13.46%		
											MIN	8.93%		

Projected Annual
Earnings per Share

Company	Ticker	[14] 2015	[15] 2016	[16] 2017	[17] 2018	[18] 2019	[19] 2020	[20] **2021**	[21] 2022	[22] 2023	[23] 2024	[24] 2025	[25] **2026**	[26] 2027	[27] 2028	[28] 2029	[29] 2030	[30] 2031
ALLETE, Inc.	ALE	$3.38	$3.57	$3.76	$3.97	$4.19	$4.42	$4.66	$4.91	$5.18	$5.46	$5.75	$6.06	$6.38	$6.72	$7.07	$7.45	$7.85
Alliant Energy Corporation	LNT	$1.69	$1.80	$1.92	$2.05	$2.18	$2.33	$2.47	$2.63	$2.78	$2.94	$3.11	$3.27	$3.45	$3.63	$3.82	$4.03	$4.24
Ameren Corporation	AEE	$2.38	$2.53	$2.68	$2.84	$3.02	$3.20	$3.39	$3.59	$3.79	$4.01	$4.22	$4.45	$4.69	$4.94	$5.20	$5.47	$5.77
American Electric Power Company, Inc.	AEP	$3.59	$3.77	$3.95	$4.14	$4.35	$4.56	$4.79	$5.03	$5.29	$5.56	$5.85	$6.16	$6.49	$6.84	$7.20	$7.58	$7.99
Avista Corporation	AVA	$1.89	$1.98	$2.08	$2.19	$2.30	$2.41	$2.53	$2.66	$2.80	$2.95	$3.10	$3.27	$3.44	$3.62	$3.82	$4.02	$4.23
CMS Energy Corporation	CMS	$1.89	$2.03	$2.17	$2.33	$2.50	$2.68	$2.87	$3.06	$3.25	$3.44	$3.64	$3.83	$4.03	$4.25	$4.47	$4.71	$4.96
DTE Energy Company	DTE	$4.45	$4.71	$4.98	$5.27	$5.58	$5.90	$6.24	$6.59	$6.95	$7.34	$7.73	$8.14	$8.58	$9.03	$9.51	$10.02	$10.55
El Paso Electric Company	EE	$2.03	$2.17	$2.32	$2.49	$2.66	$2.85	$3.04	$3.23	$3.43	$3.64	$3.84	$4.04	$4.26	$4.49	$4.72	$4.98	$5.24
Entergy Corporation	ETR	$5.81	$6.01	$6.22	$6.44	$6.67	$6.90	$7.16	$7.46	$7.79	$8.15	$8.56	$9.02	$9.50	$10.00	$10.54	$11.10	$11.69
Eversource Energy	ES	$2.76	$2.93	$3.12	$3.32	$3.52	$3.75	$3.98	$4.21	$4.46	$4.71	$4.97	$5.23	$5.51	$5.80	$6.11	$6.44	$6.78
FirstEnergy Corp.	FE	$2.00	$2.18	$2.38	$2.59	$2.82	$3.08	$3.34	$3.59	$3.85	$4.10	$4.35	$4.58	$4.82	$5.08	$5.35	$5.63	$5.93
IDACORP, Inc.	IDA	$3.87	$4.02	$4.19	$4.35	$4.53	$4.71	$4.91	$5.13	$5.36	$5.63	$5.91	$6.23	$6.56	$6.91	$7.28	$7.66	$8.07
MGE Energy, Inc.	MGEE	$2.06	$2.20	$2.36	$2.52	$2.70	$2.89	$3.08	$3.28	$3.48	$3.69	$3.90	$4.10	$4.32	$4.55	$4.79	$5.05	$5.32
NorthWestern Corporation	NWE	$2.90	$3.09	$3.29	$3.50	$3.73	$3.97	$4.22	$4.48	$4.75	$5.02	$5.29	$5.58	$5.87	$6.19	$6.52	$6.86	$7.23
OGE Energy Corp.	OGE	$1.69	$1.78	$1.87	$1.97	$2.07	$2.18	$2.29	$2.41	$2.54	$2.67	$2.81	$2.96	$3.12	$3.29	$3.46	$3.65	$3.84
Otter Tail Corporation	OTTR	$1.56	$1.65	$1.75	$1.86	$1.97	$2.09	$2.21	$2.34	$2.47	$2.61	$2.75	$2.90	$3.05	$3.21	$3.38	$3.56	$3.75
Pinnacle West Capital Corporation	PNW	$3.92	$4.08	$4.24	$4.41	$4.59	$4.77	$4.97	$5.19	$5.43	$5.70	$5.99	$6.31	$6.64	$7.00	$7.37	$7.76	$8.18
PNM Resources, Inc.	PNM	$1.64	$1.79	$1.95	$2.12	$2.31	$2.52	$2.73	$2.95	$3.16	$3.37	$3.57	$3.76	$3.95	$4.17	$4.39	$4.62	$4.87
Portland General Electric Company	POR	$2.04	$2.17	$2.32	$2.47	$2.63	$2.80	$2.98	$3.17	$3.35	$3.55	$3.74	$3.94	$4.15	$4.37	$4.61	$4.85	$5.11
SCANA Corporation	SCG	$3.81	$4.02	$4.23	$4.46	$4.70	$4.96	$5.22	$5.50	$5.80	$6.11	$6.43	$6.78	$7.14	$7.52	$7.92	$8.34	$8.78
Wisconsin Energy Corporation	WEC	$2.34	$2.50	$2.67	$2.85	$3.04	$3.25	$3.46	$3.68	$3.90	$4.12	$4.35	$4.59	$4.83	$5.09	$5.36	$5.64	$5.94
Xcel Energy Inc.	XEL	$2.10	$2.22	$2.34	$2.47	$2.60	$2.74	$2.89	$3.05	$3.22	$3.39	$3.57	$3.76	$3.96	$4.17	$4.40	$4.63	$4.88

Projected Annual
Dividend Payout Ratic

Company	Ticker	[31] 2016	[32] 2017	[33] 2018	[34] 2019	[35] 2020	[36] 2021	[37] 2022	[38] 2023	[39] 2024	[40] 2025	[41] 2026	[42] 2027	[43] 2028	[44] 2029	[45] 2030	[46] 2031
ALLETE, Inc.	ALE	66.00%	65.25%	64.50%	63.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Alliant Energy Corporation	LNT	64.00%	63.25%	62.50%	61.75%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Ameren Corporation	AEE	68.00%	67.00%	66.00%	65.00%	64.00%	64.48%	64.96%	65.44%	65.92%	66.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
American Electric Power Company, Inc.	AEP	64.00%	64.75%	65.50%	66.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Avista Corporation	AVA	68.00%	66.75%	65.50%	64.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
CMS Energy Corporation	CMS	63.00%	62.75%	62.50%	62.25%	62.00%	62.81%	63.63%	64.44%	65.25%	66.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
DTE Energy Company	DTE	63.00%	62.50%	62.00%	61.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
El Paso Electric Company	EE	59.00%	59.50%	60.00%	60.50%	61.00%	61.98%	62.96%	63.94%	64.92%	65.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Entergy Corporation	ETR	67.00%	65.00%	63.00%	61.00%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Eversource Energy	ES	60.00%	59.50%	59.00%	58.50%	58.00%	59.48%	60.96%	62.44%	63.92%	65.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
FirstEnergy Corp.	FE	55.00%	53.25%	51.50%	49.75%	48.00%	51.15%	54.29%	57.44%	60.59%	63.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
IDACORP, Inc.	IDA	53.00%	54.75%	56.50%	58.25%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
MGE Energy, Inc.	MGEE	56.00%	53.00%	50.00%	47.00%	44.00%	47.81%	51.63%	55.44%	59.25%	63.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
NorthWestern Corporation	NWE	65.00%	63.50%	62.00%	60.50%	59.00%	60.31%	61.63%	62.94%	64.25%	65.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
OGE Energy Corp.	OGE	67.00%	67.75%	68.50%	69.25%	70.00%	69.48%	68.96%	68.44%	67.92%	67.40%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Otter Tail Corporation	OTTR	80.00%	75.75%	71.50%	67.25%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Pinnacle West Capital Corporation	PNW	64.00%	64.25%	64.50%	64.75%	65.00%	65.31%	65.63%	65.94%	66.25%	66.57%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
PNM Resources, Inc.	PNM	51.00%	52.00%	53.00%	54.00%	55.00%	56.98%	58.96%	60.94%	62.92%	64.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Portland General Electric Company	POR	56.00%	56.00%	56.00%	56.00%	56.00%	57.81%	59.63%	61.44%	63.25%	65.07%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
SCANA Corporation	SCG	59.00%	59.25%	59.50%	59.75%	60.00%	61.15%	62.29%	63.44%	64.59%	65.73%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Wisconsin Energy Corporation	WEC	68.00%	67.75%	67.50%	67.25%	67.00%	66.98%	66.96%	66.94%	66.92%	66.90%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%
Xcel Energy Inc.	XEL	62.00%	62.25%	62.50%	62.75%	63.00%	63.65%	64.29%	64.94%	65.59%	66.23%	66.88%	66.88%	66.88%	66.88%	66.88%	66.88%

Projected Annual
Cash Flows

Company	Ticker	[47] 2016	[48] 2017	[49] 2018	[50] 2019	[51] 2020	[52] 2021	[53] 2022	[54] 2023	[55] 2024	[56] 2025	[57] 2026	[58] 2027	[59] 2028	[60] 2029	[61] 2030	[62] 2031	[63] Terminal Value
ALLETE, Inc.	ALE	$2.35	$2.45	$2.56	$2.67	$2.78	$2.97	$3.16	$3.36	$3.58	$3.81	$4.05	$4.27	$4.49	$4.73	$4.98	$5.25	$163.70
Alliant Energy Corporation	LNT	$1.15	$1.21	$1.28	$1.35	$1.42	$1.53	$1.65	$1.78	$1.91	$2.05	$2.19	$2.31	$2.43	$2.56	$2.69	$2.84	$88.48
Ameren Corporation	AEE	$1.72	$1.80	$1.88	$1.96	$2.05	$2.19	$2.33	$2.48	$2.64	$2.80	$2.98	$3.13	$3.30	$3.48	$3.66	$3.86	$120.28
American Electric Power Company, Inc.	AEP	$2.41	$2.56	$2.71	$2.88	$3.06	$3.21	$3.37	$3.54	$3.72	$3.91	$4.12	$4.34	$4.57	$4.81	$5.07	$5.34	$166.59
Avista Corporation	AVA	$1.35	$1.39	$1.43	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$88.33
CMS Energy Corporation	CMS	$1.28	$1.36	$1.46	$1.56	$1.66	$1.80	$1.94	$2.09	$2.25	$2.40	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$103.50
DTE Energy Company	DTE	$2.97	$3.11	$3.27	$3.43	$3.60	$3.87	$4.15	$4.45	$4.76	$5.10	$5.45	$5.74	$6.04	$6.36	$6.70	$7.06	$220.16
El Paso Electric Company	EE	$1.28	$1.38	$1.49	$1.61	$1.74	$1.88	$2.04	$2.20	$2.36	$2.53	$2.70	$2.85	$3.00	$3.16	$3.33	$3.50	$109.31
Entergy Corporation	ETR	$4.03	$4.05	$4.06	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$243.80
Eversource Energy	ES	$1.76	$1.86	$1.96	$2.06	$2.17	$2.36	$2.57	$2.78	$3.01	$3.25	$3.50	$3.69	$3.88	$4.09	$4.31	$4.54	$141.47
FirstEnergy Corp.	FE	$1.20	$1.27	$1.33	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$123.80
IDACORP, Inc.	IDA	$2.13	$2.29	$2.46	$2.64	$2.83	$3.00	$3.19	$3.40	$3.63	$3.89	$4.16	$4.39	$4.62	$4.87	$5.13	$5.40	$168.36
MGE Energy, Inc.	MGEE	$1.23	$1.25	$1.26	$1.27	$1.27	$1.47	$1.69	$1.93	$2.19	$2.46	$2.74	$2.89	$3.04	$3.21	$3.38	$3.56	$110.93
NorthWestern Corporation	NWE	$2.01	$2.09	$2.17	$2.26	$2.34	$2.55	$2.76	$2.99	$3.22	$3.47	$3.73	$3.93	$4.14	$4.36	$4.59	$4.83	$150.76
OGE Energy Corp.	OGE	$1.19	$1.27	$1.35	$1.43	$1.52	$1.59	$1.66	$1.74	$1.81	$1.90	$1.98	$2.09	$2.20	$2.32	$2.44	$2.57	$80.12
Otter Tail Corporation	OTTR	$1.32	$1.33	$1.33	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$78.28
Pinnacle West Capital Corporation	PNW	$2.61	$2.72	$2.84	$2.97	$3.10	$3.25	$3.41	$3.58	$3.78	$3.99	$4.22	$4.44	$4.68	$4.93	$5.19	$5.47	$170.53
PNM Resources, Inc.	PNM	$0.91	$1.01	$1.13	$1.25	$1.39	$1.56	$1.74	$1.92	$2.12	$2.31	$2.51	$2.65	$2.79	$2.93	$3.09	$3.25	$101.51
Portland General Electric Company	POR	$1.22	$1.30	$1.38	$1.47	$1.57	$1.72	$1.89	$2.06	$2.24	$2.44	$2.64	$2.78	$2.92	$3.08	$3.24	$3.42	$106.58
SCANA Corporation	SCG	$2.37	$2.51	$2.65	$2.81	$2.97	$3.19	$3.43	$3.68	$3.95	$4.23	$4.53	$4.77	$5.03	$5.30	$5.58	$5.87	$183.22
Wisconsin Energy Corporation	WEC	$1.70	$1.81	$1.92	$2.05	$2.18	$2.32	$2.46	$2.61	$2.76	$2.91	$3.07	$3.23	$3.40	$3.58	$3.77	$3.98	$123.98
Xcel Energy Inc.	XEL	$1.37	$1.46	$1.54	$1.63	$1.73	$1.84	$1.96	$2.09	$2.22	$2.37	$2.52	$2.65	$2.79	$2.94	$3.10	$3.26	$101.71

Projected Annual Data
Investor Cash Flows

Company	Ticker	[64] Initial Outflow	[65] 6/30/16	[66] 12/31/16	[67] 6/30/17	[68] 6/30/18	[69] 6/30/19	[70] 6/30/20	[71] 6/30/21	[72] 6/30/22	[73] 6/30/23	[74] 6/30/24	[75] 6/30/25	[76] 6/30/26	[77] 6/30/27	[78] 6/30/28	[79] 6/30/29	[80] 6/30/30	[81] 6/30/31
ALLETE, Inc.	ALE	($54.07)	$0.00	$1.19	$2.42	$2.67	$2.78	$2.97	$3.16	$3.36	$3.58	$3.81	$4.05	$4.27	$4.49	$4.73	$4.98	$5.25	$168.95
Alliant Energy Corporation	LNT	($33.83)	$0.00	$0.58	$1.19	$1.35	$1.42	$1.53	$1.65	$1.78	$1.91	$2.05	$2.19	$2.31	$2.43	$2.56	$2.69	$2.84	$91.31
Ameren Corporation	AEE	($46.40)	$0.00	$0.87	$1.77	$1.96	$2.05	$2.19	$2.33	$2.48	$2.64	$2.80	$2.98	$3.13	$3.30	$3.48	$3.66	$3.86	$124.14
American Electric Power Company, Inc.	AEP	($61.54)	$0.00	$1.21	$2.47	$2.88	$3.06	$3.21	$3.37	$3.54	$3.72	$3.91	$4.12	$4.34	$4.57	$4.81	$5.07	$5.34	$171.93
Avista Corporation	AVA	($37.83)	$0.00	$0.68	$1.38	$1.48	$1.52	$1.61	$1.71	$1.82	$1.93	$2.05	$2.19	$2.30	$2.42	$2.55	$2.69	$2.83	$91.16
CMS Energy Corporation	CMS	($39.10)	$0.00	$0.64	$1.32	$1.56	$1.66	$1.80	$1.94	$2.09	$2.25	$2.40	$2.56	$2.70	$2.84	$2.99	$3.15	$3.32	$106.82
DTE Energy Company	DTE	($85.80)	$0.00	$1.50	$3.05	$3.43	$3.60	$3.87	$4.15	$4.45	$4.76	$5.10	$5.45	$5.74	$6.04	$6.36	$6.70	$7.06	$227.22
El Paso Electric Company	EE	($41.72)	$0.00	$0.65	$1.33	$1.61	$1.74	$1.88	$2.04	$2.20	$2.36	$2.53	$2.70	$2.85	$3.00	$3.16	$3.33	$3.50	$112.82
Entergy Corporation	ETR	($72.44)	$0.00	$2.03	$4.10	$4.07	$4.07	$4.32	$4.60	$4.90	$5.24	$5.61	$6.03	$6.35	$6.69	$7.05	$7.42	$7.82	$251.62
Eversource Energy	ES	($54.15)	$0.00	$0.89	$1.82	$2.06	$2.17	$2.36	$2.57	$2.78	$3.01	$3.25	$3.50	$3.69	$3.88	$4.09	$4.31	$4.54	$146.01
FirstEnergy Corp.	FE	($33.04)	$0.00	$0.60	$1.25	$1.40	$1.48	$1.71	$1.95	$2.21	$2.49	$2.77	$3.06	$3.23	$3.40	$3.58	$3.77	$3.97	$127.77
IDACORP, Inc.	IDA	($70.82)	$0.00	$1.08	$2.18	$2.64	$2.83	$3.00	$3.19	$3.40	$3.63	$3.89	$4.16	$4.39	$4.62	$4.87	$5.13	$5.40	$173.76
MGE Energy, Inc.	MGEE	($48.29)	$0.00	$0.62	$1.28	$1.27	$1.27	$1.47	$1.69	$1.93	$2.19	$2.46	$2.74	$2.89	$3.04	$3.21	$3.38	$3.56	$114.48
NorthWestern Corporation	NWE	($57.21)	$0.00	$1.01	$2.07	$2.26	$2.34	$2.55	$2.76	$2.99	$3.22	$3.47	$3.73	$3.93	$4.14	$4.36	$4.59	$4.83	$155.59
OGE Energy Corp.	OGE	($27.72)	$0.00	$0.60	$1.22	$1.43	$1.52	$1.59	$1.66	$1.74	$1.81	$1.90	$1.98	$2.09	$2.20	$2.32	$2.44	$2.57	$82.69
Otter Tail Corporation	OTTR	($28.17)	$0.00	$0.67	$1.36	$1.32	$1.32	$1.41	$1.50	$1.60	$1.71	$1.82	$1.94	$2.04	$2.15	$2.26	$2.38	$2.51	$80.79
Pinnacle West Capital Corporation	PNW	($69.12)	$0.00	$1.32	$2.66	$2.97	$3.10	$3.25	$3.41	$3.58	$3.78	$3.99	$4.22	$4.44	$4.68	$4.93	$5.19	$5.47	$176.00
PNM Resources, Inc.	PNM	($31.32)	$0.00	$0.46	$0.95	$1.25	$1.39	$1.56	$1.74	$1.92	$2.12	$2.31	$2.51	$2.65	$2.79	$2.93	$3.09	$3.25	$104.77
Portland General Electric Company	POR	($38.74)	$0.00	$0.61	$1.26	$1.47	$1.57	$1.72	$1.89	$2.06	$2.24	$2.44	$2.64	$2.78	$2.92	$3.08	$3.24	$3.42	$109.99
SCANA Corporation	SCG	($64.86)	$0.00	$1.19	$2.43	$2.81	$2.97	$3.19	$3.43	$3.68	$3.95	$4.23	$4.53	$4.77	$5.03	$5.30	$5.58	$5.87	$189.09
Wisconsin Energy Corporation	WEC	($55.89)	$0.00	$0.86	$1.76	$2.05	$2.18	$2.32	$2.46	$2.61	$2.76	$2.91	$3.07	$3.23	$3.40	$3.58	$3.77	$3.98	$127.96
Xcel Energy Inc.	XEL	($38.85)	$0.00	$0.69	$1.41	$1.63	$1.73	$1.84	$1.96	$2.09	$2.22	$2.37	$2.52	$2.65	$2.79	$2.94	$3.10	$3.26	$104.97

Multi-Stage DCF Notes:

[1] Source: Bloomberg; based on 30-, 90-, and 180-day historical average as of June 30, 2016
[2] Source: Zacks
[3] Source: Yahoo! Finance
[4] Source: Value Line
[5] Equals indicated value (average, minimum, maximum) of Columns [2], [3], [4]
[6] Source: Federal Reserve, Bureau of Economic Analysis
[7] Source: Value Line
[8] Source: Value Line
[9] Source: Bloomberg Professional
[10] Equals Column [1] + Column [62]
[11] Equals result of Excel Solver function; goal: Column [10] equals $0.00
[12] Equals Column [61] / Column [30]
[13] Equals Column [12] / (Column [6] x 100)
[14] Source: Value Line
[15] Equals Column [14] x (1 + Column [5])
[16] Equals Column [15] x (1 + Column [5])
[17] Equals Column [16] x (1 + Column [5])
[18] Equals Column [17] x (1 + Column [5])
[19] Equals Column [18] x (1 + Column [5])
[20] Equals (1 + (Column [5] + (((Column [6] − Column [5]) / (2026 − 2021 + 1)) x (2021 − 2020)))) x Column [19]
[21] Equals (1 + (Column [5] + (((Column [6] − Column [5]) / (2026 − 2021 + 1)) x (2022 − 2020)))) x Column [20]
[22] Equals (1 + (Column [5] + (((Column [6] − Column [5]) / (2026 − 2021 + 1)) x (2023 − 2020)))) x Column [21]
[23] Equals (1 + (Column [5] + (((Column [6] − Column [5]) / (2026 − 2021 + 1)) x (2024 − 2020)))) x Column [22]
[24] Equals (1 + (Column [5] + (((Column [6] − Column [5]) / (2026 − 2021 + 1)) x (2025 − 2020)))) x Column [23]
[25] Equals Column [24] x (1 + Column [6])
[26] Equals Column [25] x (1 + Column [6])
[27] Equals Column [26] x (1 + Column [6])
[28] Equals Column [27] x (1 + Column [6])
[29] Equals Column [28] x (1 + Column [6])
[30] Equals Column [29] x (1 + Column [6])
[31] Equals Column [7]
[32] Equals Column [31] + ((Column [35] − Column [31]) / 4)
[33] Equals Column [32] + ((Column [35] − Column [31]) / 4)
[34] Equals Column [33] + ((Column [35] − Column [31]) / 4)
[35] Equals Column [8]
[36] Equals Column [35] + ((Column [42] − Column [35]) / 6)
[37] Equals Column [36] + ((Column [42] − Column [35]) / 6)
[38] Equals Column [37] + ((Column [42] − Column [35]) / 6)
[39] Equals Column [38] + ((Column [42] − Column [35]) / 6)
[40] Equals Column [39] + ((Column [42] − Column [35]) / 6)
[41] Equals Column [9]
[42] Equals Column [9]
[43] Equals Column [9]
[44] Equals Column [9]
[45] Equals Column [9]
[46] Equals Column [9]
[47] Equals Column [15] x Column [31]
[48] Equals Column [16] x Column [32]
[49] Equals Column [17] x Column [33]
[50] Equals Column [18] x Column [34]
[51] Equals Column [19] x Column [35]
[52] Equals Column [20] x Column [36]
[53] Equals Column [21] x Column [37]
[54] Equals Column [22] x Column [38]
[55] Equals Column [23] x Column [39]
[56] Equals Column [24] x Column [40]
[57] Equals Column [25] x Column [41]
[58] Equals Column [26] x Column [42]
[59] Equals Column [27] x Column [43]
[60] Equals Column [28] x Column [44]
[61] Equals Column [29] x Column [45]
[62] Equals Column [30] x Column [46]
[63] Equals (Column [62] x (1 + Column [6])) / (Column [11] − Column [6])
[64] Equals negative net present value; discount rate equals Column [11], cash flows equal Column [65] through Column [81]
[65] Equals $0.00
[66] Equals Column [47] x (12/31/2016 - 6/30/2016) / 365
[67] Equals Column [47] + (0.5 x Column [5])
[68] Equals Column [49]
[69] Equals Column [50]
[70] Equals Column [51]
[71] Equals Column [52]
[72] Equals Column [53]
[73] Equals Column [54]
[74] Equals Column [55]
[75] Equals Column [56]
[76] Equals Column [57]
[77] Equals Column [58]
[78] Equals Column [59]
[79] Equals Column [60]
[80] Equals Column [61]
[81] Equals Column [62] + [63]

Ex-Ante Market Risk Premium
Market DCF Method Based - Bloomberg

[1] S&P 500 Est. Required Market Return	[2] Current 30-Year Treasury (30-day average)	[3] Implied Market Risk Premium
13.09%	2.50%	10.59%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
AGILENT TECHNOLOGIES INC	A	14,440.14	0.08%	1.01%	10.13%	11.19%	0.0084%
ALCOA INC	AA	12,191.04	0.06%	1.31%	5.00%	6.34%	0.0040%
AMERICAN AIRLINES GROUP INC	AAL	16,368.04	0.09%	1.50%	-21.78%	-20.44%	-0.0174%
ADVANCE AUTO PARTS INC	AAP	11,888.86	0.06%	0.16%	12.01%	12.17%	0.0075%
APPLE INC	AAPL	523,641.83	2.72%	2.29%	11.56%	13.99%	0.3808%
ABBVIE INC	ABBV	100,130.67	0.52%	3.70%	13.51%	17.46%	0.0909%
AMERISOURCEBERGEN CORP	ABC	17,121.60	0.09%	1.70%	11.20%	12.99%	0.0116%
ABBOTT LABORATORIES	ABT	57,752.37	0.30%	2.66%	11.73%	14.55%	0.0437%
ACCENTURE PLC-CL A	ACN	73,850.67	0.38%	2.03%	9.82%	11.95%	0.0459%
ADOBE SYSTEMS INC	ADBE	47,731.28	0.25%	0.00%	20.26%	20.26%	0.0503%
ANALOG DEVICES INC	ADI	17,408.29	0.09%	2.93%	8.92%	11.98%	0.0108%
ARCHER-DANIELS-MIDLAND CO	ADM	25,201.40	0.13%	2.81%	7.15%	10.06%	0.0132%
AUTOMATIC DATA PROCESSING	ADP	41,849.98	0.22%	2.25%	10.29%	12.65%	0.0275%
ALLIANCE DATA SYSTEMS CORP	ADS	11,547.48	0.06%	0.00%	13.83%	13.83%	0.0083%
AUTODESK INC	ADSK	12,162.88	0.06%	0.00%	20.96%	20.96%	0.0133%
AMEREN CORPORATION	AEE	13,000.37	0.07%	3.25%	4.43%	7.75%	0.0052%
AMERICAN ELECTRIC POWER	AEP	34,436.15	0.18%	3.22%	5.05%	8.35%	0.0150%
AES CORP	AES	8,224.33	0.04%	3.53%	7.33%	10.99%	0.0047%
AETNA INC	AET	42,818.78	0.22%	0.82%	10.57%	11.44%	0.0255%
AFLAC INC	AFL	29,873.30	0.16%	2.31%	3.86%	6.22%	0.0097%
ALLERGAN PLC	AGN	91,409.25	0.48%	0.00%	12.32%	12.32%	0.0585%
AMERICAN INTERNATIONAL GROUP	AIG	59,185.62	0.31%	2.42%	9.50%	12.04%	0.0370%
APARTMENT INVT & MGMT CO -A	AIV	6,915.68	0.04%	2.99%	6.82%	9.92%	0.0036%
ASSURANT INC	AIZ	5,345.77	0.03%	2.27%	12.36%	14.77%	0.0041%
ARTHUR J GALLAGHER & CO	AJG	8,431.34	0.04%	3.19%	7.97%	11.29%	0.0050%
AKAMAI TECHNOLOGIES INC	AKAM	9,820.85	0.05%	0.00%	15.60%	15.60%	0.0080%
ALASKA AIR GROUP INC	ALK	7,184.39	0.04%	1.89%	2.65%	4.56%	0.0017%
ALLSTATE CORP	ALL	26,186.99	0.14%	1.89%	9.00%	10.97%	0.0149%
ALLEGION PLC	ALLE	6,646.79	0.03%	0.70%	13.10%	13.85%	0.0048%
ALEXION PHARMACEUTICALS INC	ALXN	26,156.59	0.14%	0.00%	27.12%	27.12%	0.0369%
APPLIED MATERIALS INC	AMAT	26,106.78	0.14%	1.70%	15.43%	17.26%	0.0234%
AMETEK INC	AME	10,790.55	0.06%	0.85%	10.30%	11.20%	0.0063%
AFFILIATED MANAGERS GROUP	AMG	7,979.77	0.04%	0.00%	13.73%	13.73%	0.0057%
AMGEN INC	AMGN	114,297.68	0.59%	2.61%	7.92%	10.64%	0.0632%
AMERIPRISE FINANCIAL INC	AMP	14,898.34	0.08%	3.16%	13.23%	16.60%	0.0129%
AMERICAN TOWER CORP	AMT	48,241.62	0.25%	1.91%	20.41%	22.52%	0.0565%
AMAZON.COM INC	AMZN	337,649.52	1.76%	0.00%	47.03%	47.03%	0.8256%
AUTONATION INC	AN	4,843.81	0.03%	0.00%	8.33%	8.33%	0.0021%
ANTHEM INC	ANTM	34,536.25	0.18%	1.98%	8.87%	10.93%	0.0196%
AON PLC	AON	28,937.41	0.15%	1.19%	12.08%	13.35%	0.0201%
APACHE CORP	APA	21,072.97	0.11%	1.79%	8.50%	10.37%	0.0114%
ANADARKO PETROLEUM CORP	APC	27,180.22	0.14%	0.38%	8.33%	8.72%	0.0123%
AIR PRODUCTS & CHEMICALS INC	APD	30,692.17	0.16%	2.36%	8.17%	10.63%	0.0170%
AMPHENOL CORP-CL A	APH	17,653.46	0.09%	1.01%	9.26%	10.31%	0.0095%
ACTIVISION BLIZZARD INC	ATVI	29,319.79	0.15%	0.66%	12.00%	12.70%	0.0194%
AVALONBAY COMMUNITIES INC	AVB	24,742.75	0.13%	2.98%	7.25%	10.34%	0.0133%
BROADCOM LTD	AVGO	61,463.59	0.32%	1.23%	15.70%	17.02%	0.0544%
AVERY DENNISON CORP	AVY	6,665.90	0.03%	2.21%	8.20%	10.50%	0.0036%
AMERICAN WATER WORKS CO INC	AWK	15,018.65	0.08%	1.75%	7.34%	9.16%	0.0072%
AMERICAN EXPRESS CO	AXP	57,784.77	0.30%	2.00%	9.00%	11.09%	0.0333%
ACUITY BRANDS INC	AYI	10,882.24	0.06%	0.21%	19.60%	19.83%	0.0112%
AUTOZONE INC	AZO	23,205.56	0.12%	0.00%	11.93%	11.93%	0.0144%
BOEING CO/THE	BA	82,728.64	0.43%	3.37%	12.08%	15.65%	0.0673%
BANK OF AMERICA CORP	BAC	136,308.32	0.71%	2.00%	7.50%	9.58%	0.0679%
BAXTER INTERNATIONAL INC	BAX	24,973.32	0.13%	1.09%	12.04%	13.20%	0.0171%
BED BATH & BEYOND INC	BBBY	6,671.73	0.03%	1.10%	6.83%	7.97%	0.0028%
BB&T CORP	BBT	28,917.04	0.15%	3.18%	5.27%	8.54%	0.0128%
BEST BUY CO INC	BBY	9,876.23	0.05%	4.17%	10.18%	14.57%	0.0075%
CR BARD INC	BCR	17,241.62	0.09%	0.42%	10.75%	11.19%	0.0100%
BECTON DICKINSON AND CO	BDX	35,987.34	0.19%	1.56%	11.38%	13.03%	0.0244%
FRANKLIN RESOURCES INC	BEN	19,519.16	0.10%	2.16%	4.88%	7.09%	0.0072%
BROWN-FORMAN CORP-CLASS B	BF/B	20,347.91	0.11%	1.42%	9.61%	11.09%	0.0117%
BAKER HUGHES INC	BHI	19,763.05	0.10%	1.51%	14.00%	15.62%	0.0160%
BIOGEN INC	BIIB	52,971.03	0.28%	0.00%	8.26%	8.26%	0.0228%
BANK OF NEW YORK MELLON CORP	BK	41,844.66	0.22%	1.89%	15.87%	17.90%	0.0390%
BLACKROCK INC	BLK	56,501.55	0.29%	2.67%	12.67%	15.52%	0.0456%
BALL CORP	BLL	10,250.51	0.05%	0.58%	4.40%	4.99%	0.0027%
BRISTOL-MYERS SQUIBB CO	BMY	122,777.55	0.64%	2.08%	20.56%	22.85%	0.1459%
BERKSHIRE HATHAWAY INC-CL B	BRK/B	356,822.76	1.86%	0.00%	7.10%	7.10%	0.1317%
BOSTON SCIENTIFIC CORP	BSX	31,709.98	0.16%	0.00%	11.73%	11.73%	0.0193%
BORGWARNER INC	BWA	6,424.12	0.03%	1.76%	11.60%	13.46%	0.0045%
BOSTON PROPERTIES INC	BXP	20,261.33	0.11%	2.25%	6.55%	8.88%	0.0094%
CITIGROUP INC	C	124,411.65	0.65%	0.92%	11.80%	12.78%	0.0827%
CA INC	CA	13,800.48	0.07%	3.15%	5.50%	8.73%	0.0063%
CONAGRA FOODS INC	CAG	20,865.00	0.11%	2.20%	8.00%	10.29%	0.0112%
CARDINAL HEALTH INC	CAH	25,416.85	0.13%	1.95%	11.90%	13.97%	0.0185%
CATERPILLAR INC	CAT	44,264.82	0.23%	4.10%	7.23%	11.47%	0.0264%
CHUBB LTD	CB	60,711.98	0.32%	2.10%	7.86%	10.04%	0.0317%
CBRE GROUP INC - A	CBG	8,882.34	0.05%	0.00%	12.50%	12.50%	0.0058%
CBS CORP-CLASS B NON VOTING	CBS	24,804.60	0.13%	1.20%	17.03%	18.33%	0.0236%
CROWN CASTLE INTL CORP	CCI	34,238.68	0.18%	3.54%	15.50%	19.32%	0.0344%
CARNIVAL CORP	CCL	33,238.05	0.17%	2.93%	16.58%	19.75%	0.0341%
CELGENE CORP	CELG	76,398.95	0.40%	0.00%	22.42%	22.42%	0.0891%
CERNER CORP	CERN	19,811.59	0.10%	0.00%	16.13%	16.13%	0.0166%
CF INDUSTRIES HOLDINGS INC	CF	5,617.56	0.03%	4.99%	17.15%	22.57%	0.0066%
CITIZENS FINANCIAL GROUP	CFG	10,569.02	0.05%	2.34%	9.00%	11.45%	0.0063%
CHURCH & DWIGHT CO INC	CHD	13,203.88	0.07%	1.38%	9.29%	10.73%	0.0074%
CHESAPEAKE ENERGY CORP	CHK	2,930.12	0.02%	0.00%	-3.48%	-3.48%	-0.0005%

C.H. ROBINSON WORLDWIDE INC	CHRW	10,600.42	0.06%	2.35%	10.28%	12.74%	0.0070%
CIGNA CORP	CI	32,831.11	0.17%	0.03%	8.62%	8.66%	0.0148%
CINCINNATI FINANCIAL CORP	CINF	12,317.88	0.06%	0.00%	16.30%	16.30%	0.0104%
COLGATE-PALMOLIVE CO	CL	65,368.89	0.34%	2.15%	8.38%	10.62%	0.0361%
CLOROX COMPANY	CLX	17,899.42	0.09%	2.24%	6.47%	8.78%	0.0082%
COMERICA INC	CMA	7,203.26	0.04%	2.12%	5.04%	7.22%	0.0027%
COMCAST CORP-CLASS A	CMCSA	158,228.88	0.82%	1.70%	11.32%	13.12%	0.1079%
CME GROUP INC	CME	32,983.82	0.17%	5.11%	12.78%	18.21%	0.0312%
CHIPOTLE MEXICAN GRILL INC	CMG	11,761.16	0.06%	0.00%	16.72%	16.72%	0.0102%
CUMMINS INC	CMI	19,155.23	0.10%	3.53%	4.26%	7.86%	0.0078%
CMS ENERGY CORP	CMS	12,839.04	0.07%	2.70%	6.00%	8.78%	0.0059%
CENTENE CORP	CNC	12,166.66	0.06%	0.00%	16.57%	16.57%	0.0105%
CENTERPOINT ENERGY INC	CNP	10,334.87	0.05%	4.30%	5.67%	10.09%	0.0054%
CAPITAL ONE FINANCIAL CORP	COF	32,523.44	0.17%	2.67%	6.57%	9.33%	0.0158%
CABOT OIL & GAS CORP	COG	11,969.11	0.06%	0.31%	40.79%	41.16%	0.0256%
COACH INC	COH	11,326.93	0.06%	3.31%	14.23%	17.78%	0.0105%
ROCKWELL COLLINS INC	COL	11,084.73	0.06%	1.58%	8.32%	9.97%	0.0057%
CONOCOPHILLIPS	COP	53,993.68	0.28%	2.30%	6.67%	9.04%	0.0254%
COSTCO WHOLESALE CORP	COST	68,793.82	0.36%	1.08%	10.55%	11.69%	0.0418%
CAMPBELL SOUP CO	CPB	20,534.29	0.11%	2.03%	7.32%	9.42%	0.0101%
COLUMBIA PIPELINE GROUP	CPGX	10,206.23	N/A	2.20%	N/A	N/A	N/A
SALESFORCE.COM INC	CRM	53,800.28	0.28%	0.00%	25.42%	25.42%	0.0711%
CISCO SYSTEMS INC	CSCO	144,302.44	0.75%	3.28%	8.77%	12.19%	0.0914%
CSRA INC	CSRA	3,829.02	0.02%	1.71%	10.00%	11.79%	0.0023%
CSX CORP	CSX	24,929.01	0.13%	2.85%	6.46%	9.40%	0.0122%
CINTAS CORP	CTAS	10,500.22	0.05%	1.08%	11.84%	12.98%	0.0071%
CENTURYLINK INC	CTL	15,840.97	0.08%	7.45%	-1.52%	5.87%	0.0048%
COGNIZANT TECH SOLUTIONS-A	CTSH	34,679.97	0.18%	0.00%	13.78%	13.78%	0.0249%
CITRIX SYSTEMS INC	CTXS	12,422.12	0.06%	0.00%	16.70%	16.70%	0.0108%
CVS HEALTH CORP	CVS	102,826.88	0.53%	1.73%	13.85%	15.70%	0.0840%
CHEVRON CORP	CVX	197,573.35	1.03%	4.10%	3.25%	7.42%	0.0762%
CONCHO RESOURCES INC	CXO	15,690.05	0.08%	0.00%	25.00%	25.00%	0.0204%
DOMINION RESOURCES INC/VA	D	48,021.89	0.25%	3.59%	6.25%	9.96%	0.0249%
DELTA AIR LINES INC	DAL	28,109.11	0.15%	1.67%	15.98%	17.77%	0.0260%
DU PONT (E.I.) DE NEMOURS	DD	56,632.99	0.29%	2.44%	8.25%	10.79%	0.0318%
DEERE & CO	DE	25,467.54	0.13%	2.98%	7.76%	10.85%	0.0144%
DISCOVER FINANCIAL SERVICES	DFS	22,091.15	0.11%	2.21%	8.13%	10.43%	0.0120%
DOLLAR GENERAL CORP	DG	26,675.16	0.14%	1.05%	13.89%	15.01%	0.0208%
QUEST DIAGNOSTICS INC	DGX	11,516.03	0.06%	1.95%	8.91%	10.94%	0.0066%
DR HORTON INC	DHI	11,676.73	0.06%	1.03%	14.71%	15.81%	0.0096%
DANAHER CORP	DHR	69,558.24	0.36%	0.63%	11.98%	12.64%	0.0457%
WALT DISNEY CO/THE	DIS	158,707.15	0.83%	1.49%	9.80%	11.36%	0.0938%
DISCOVERY COMMUNICATIONS-A	DISCA	15,147.86	0.08%	0.00%	13.45%	13.45%	0.0106%
DELPHI AUTOMOTIVE PLC	DLPH	17,088.36	0.09%	1.86%	9.88%	11.83%	0.0105%
DIGITAL REALTY TRUST INC	DLR	17,364.98	0.09%	3.23%	5.94%	9.26%	0.0084%
DOLLAR TREE INC	DLTR	22,209.17	0.12%	0.00%	17.67%	17.67%	0.0204%
DUN & BRADSTREET CORP	DNB	4,417.72	0.02%	1.58%	11.75%	13.43%	0.0031%
DIAMOND OFFSHORE DRILLING	DO	3,337.34	N/A	0.00%	N/A	N/A	N/A
DOVER CORP	DOV	10,754.91	0.06%	2.48%	10.48%	13.08%	0.0073%
DOW CHEMICAL CO/THE	DOW	55,963.47	0.29%	3.73%	6.00%	9.85%	0.0286%
DR PEPPER SNAPPLE GROUP INC	DPS	17,955.02	0.09%	2.18%	13.24%	15.57%	0.0145%
DARDEN RESTAURANTS INC	DRI	8,026.81	0.04%	3.46%	13.38%	17.08%	0.0071%
DTE ENERGY COMPANY	DTE	17,785.64	0.09%	3.02%	5.54%	8.65%	0.0080%
DUKE ENERGY CORP	DUK	59,091.55	0.31%	3.95%	4.71%	8.75%	0.0269%
DAVITA HEALTHCARE PARTNERS I	DVA	15,966.58	0.08%	0.00%	10.11%	10.11%	0.0084%
DEVON ENERGY CORP	DVN	18,995.00	0.10%	1.16%	7.97%	9.17%	0.0091%
ELECTRONIC ARTS INC	EA	22,832.80	0.12%	0.00%	11.27%	11.27%	0.0134%
EBAY INC	EBAY	26,895.85	0.14%	0.00%	8.89%	8.89%	0.0124%
ECOLAB INC	ECL	34,786.00	0.18%	1.20%	12.36%	13.63%	0.0247%
CONSOLIDATED EDISON INC	ED	24,466.66	0.13%	3.33%	3.07%	6.45%	0.0082%
EQUIFAX INC	EFX	15,281.39	0.08%	1.03%	9.21%	10.28%	0.0082%
EDISON INTERNATIONAL	EIX	25,305.76	0.13%	2.48%	5.44%	7.99%	0.0105%
ESTEE LAUDER COMPANIES-CL A	EL	33,608.03	0.17%	1.25%	11.73%	13.05%	0.0228%
EMC CORP/MA	EMC	53,108.30	0.28%	1.78%	10.58%	12.45%	0.0344%
EASTMAN CHEMICAL CO	EMN	10,038.11	0.05%	2.66%	5.50%	8.24%	0.0043%
EMERSON ELECTRIC CO	EMR	33,557.19	0.17%	3.64%	7.33%	11.10%	0.0194%
ENDO INTERNATIONAL PLC	ENDP	3,471.29	0.02%	0.00%	4.70%	4.70%	0.0008%
EOG RESOURCES INC	EOG	45,904.07	0.24%	0.78%	-9.66%	-8.92%	-0.0213%
EQUINIX INC	EQIX	26,919.74	0.14%	1.80%	22.05%	24.05%	0.0337%
EQUITY RESIDENTIAL	EQR	25,175.79	0.13%	18.91%	6.08%	25.56%	0.0335%
EQT CORP	EQT	13,375.03	0.07%	0.15%	25.00%	25.17%	0.0175%
EVERSOURCE ENERGY	ES	19,000.70	0.10%	2.97%	7.00%	10.07%	0.0100%
EXPRESS SCRIPTS HOLDING CO	ESRX	47,946.23	0.25%	0.00%	12.85%	12.85%	0.0320%
ESSEX PROPERTY TRUST INC	ESS	14,923.95	0.08%	2.79%	6.83%	9.72%	0.0075%
E*TRADE FINANCIAL CORP	ETFC	6,547.34	0.03%	0.03%	17.87%	17.90%	0.0061%
EATON CORP PLC	ETN	27,356.34	0.14%	3.83%	8.42%	12.41%	0.0176%
ENTERGY CORP	ETR	14,540.57	0.08%	4.22%	1.56%	5.82%	0.0044%
EDWARDS LIFESCIENCES CORP	EW	21,119.10	0.11%	0.00%	14.57%	14.57%	0.0160%
EXELON CORP	EXC	33,512.82	0.17%	3.47%	4.00%	7.53%	0.0131%
EXPEDITORS INTL WASH INC	EXPD	8,928.17	0.05%	1.56%	8.53%	10.16%	0.0047%
EXPEDIA INC	EXPE	15,849.71	0.08%	0.81%	22.29%	23.18%	0.0191%
EXTRA SPACE STORAGE INC	EXR	11,586.72	0.06%	2.98%	7.35%	10.44%	0.0063%
FORD MOTOR CO	F	49,938.54	0.26%	4.77%	6.72%	11.65%	0.0303%
FASTENAL CO	FAST	12,823.53	0.07%	2.71%	12.02%	14.89%	0.0099%
FACEBOOK INC-A	FB	326,875.71	1.70%	0.00%	31.69%	31.69%	0.5386%
FORTUNE BRANDS HOME & SECURI	FBHS	8,891.21	0.05%	1.11%	18.63%	19.84%	0.0092%
FREEPORT-MCMORAN INC	FCX	13,948.86	N/A	0.00%	N/A	N/A	N/A
FEDEX CORP	FDX	40,741.36	0.21%	1.03%	12.25%	13.34%	0.0283%
FIRSTENERGY CORP	FE	14,826.71	0.08%	4.12%	-1.55%	2.54%	0.0020%
F5 NETWORKS INC	FFIV	7,625.15	0.04%	0.00%	13.18%	13.18%	0.0052%
FIDELITY NATIONAL INFO SERV	FIS	24,053.13	0.13%	1.45%	12.13%	13.66%	0.0171%
FISERV INC	FISV	24,173.93	0.13%	0.00%	12.50%	12.50%	0.0157%
FIFTH THIRD BANCORP	FITB	13,504.16	0.07%	3.09%	3.83%	6.98%	0.0049%
FOOT LOCKER INC	FL	7,423.05	0.04%	2.05%	10.75%	12.91%	0.0050%
FLIR SYSTEMS INC	FLIR	4,259.71	0.02%	1.49%	15.00%	16.60%	0.0037%
FLUOR CORP	FLR	6,861.26	0.04%	1.71%	2.39%	4.12%	0.0015%
FLOWSERVE CORP	FLS	5,888.67	0.03%	1.68%	11.67%	13.45%	0.0041%
FMC CORP	FMC	6,194.03	0.03%	1.46%	9.53%	11.06%	0.0036%
TWENTY-FIRST CENTURY FOX-A	FOXA	51,399.08	0.27%	1.21%	13.84%	15.13%	0.0404%
FEDERAL REALTY INVS TRUST	FRT	11,738.17	0.06%	2.32%	6.26%	8.65%	0.0053%
FIRST SOLAR INC	FSLR	4,956.84	0.03%	0.00%	10.00%	10.00%	0.0026%
FMC TECHNOLOGIES INC	FTI	6,036.90	0.03%	0.00%	-8.10%	-8.10%	-0.0025%
FRONTIER COMMUNICATIONS CORP	FTR	5,795.00	0.03%	8.50%	11.55%	20.54%	0.0062%

AGL RESOURCES INC	GAS	7,961.26	0.04%	3.21%	6.50%	9.82%	0.0041%
GENERAL DYNAMICS CORP	GD	42,558.28	0.22%	2.14%	7.83%	10.05%	0.0222%
GENERAL ELECTRIC CO	GE	289,479.28	1.51%	2.96%	9.98%	13.09%	0.1970%
GENERAL GROWTH PROPERTIES	GGP	26,336.92	0.14%	2.59%	6.73%	9.40%	0.0129%
GILEAD SCIENCES INC	GILD	111,100.55	0.58%	2.21%	1.96%	4.20%	0.0242%
GENERAL MILLS INC	GIS	42,392.72	0.22%	2.64%	9.63%	12.40%	0.0273%
CORNING INC	GLW	22,023.14	0.11%	2.65%	12.34%	15.15%	0.0174%
GENERAL MOTORS CO	GM	43,577.06	0.23%	5.37%	9.44%	15.06%	0.0341%
ALPHABET INC-CL A	GOOGL	478,804.14	2.49%	0.00%	15.66%	15.66%	0.3899%
GENUINE PARTS CO	GPC	15,149.34	0.08%	2.60%	6.33%	9.01%	0.0071%
GLOBAL PAYMENTS INC	GPN	10,992.57	0.06%	0.06%	14.42%	14.48%	0.0083%
GAP INC/THE	GPS	8,444.80	0.04%	4.30%	6.91%	11.37%	0.0050%
GARMIN LTD	GRMN	8,019.66	0.04%	4.83%	5.68%	10.65%	0.0044%
GOLDMAN SACHS GROUP INC	GS	64,513.58	0.34%	1.81%	14.11%	16.05%	0.0538%
GOODYEAR TIRE & RUBBER CO	GT	6,824.13	0.04%	1.10%	7.00%	8.14%	0.0029%
WW GRAINGER INC	GWW	13,935.47	0.07%	2.15%	9.34%	11.59%	0.0084%
HALLIBURTON CO	HAL	38,916.11	0.20%	1.57%	12.53%	14.19%	0.0287%
HARMAN INTERNATIONAL	HAR	5,067.24	0.03%	1.97%	17.50%	19.64%	0.0052%
HASBRO INC	HAS	10,473.73	0.05%	2.43%	10.40%	12.96%	0.0071%
HUNTINGTON BANCSHARES INC	HBAN	7,141.87	0.04%	3.21%	5.32%	8.62%	0.0032%
HANESBRANDS INC	HBI	9,487.01	0.05%	1.74%	12.03%	13.88%	0.0068%
HCA HOLDINGS INC	HCA	30,115.06	0.16%	0.00%	11.00%	11.00%	0.0172%
WELLTOWER INC	HCN	27,192.32	0.14%	4.49%	4.67%	9.26%	0.0131%
HCP INC	HCP	16,525.56	0.09%	6.45%	2.81%	9.35%	0.0080%
HOME DEPOT INC	HD	158,847.29	0.83%	2.16%	13.47%	15.77%	0.1302%
HESS CORP	HES	19,034.83	0.10%	1.66%	-20.09%	-18.60%	-0.0184%
HARTFORD FINANCIAL SVCS GRP	HIG	17,458.42	0.09%	1.98%	9.33%	11.41%	0.0104%
HARLEY-DAVIDSON INC	HOG	8,203.38	0.04%	3.09%	10.35%	13.60%	0.0058%
HOLOGIC INC	HOLX	9,647.51	0.05%	0.00%	8.94%	8.94%	0.0045%
HONEYWELL INTERNATIONAL INC	HON	88,649.27	0.46%	2.11%	9.32%	11.53%	0.0531%
STARWOOD HOTELS & RESORTS	HOT	12,537.31	0.07%	2.03%	7.26%	9.36%	0.0061%
HELMERICH & PAYNE	HP	7,252.67	0.04%	4.12%	-1.40%	2.69%	0.0010%
HEWLETT PACKARD ENTERPRIS	HPE	30,359.53	0.16%	1.20%	6.42%	7.66%	0.0121%
HP INC	HPQ	21,468.11	0.11%	4.22%	2.83%	7.11%	0.0079%
H&R BLOCK INC	HRB	5,071.90	0.03%	3.83%	11.00%	15.04%	0.0040%
HORMEL FOODS CORP	HRL	19,392.89	0.10%	1.57%	5.90%	7.51%	0.0076%
HARRIS CORP	HRS	10,407.13	N/A	2.38%	N/A	N/A	N/A
HENRY SCHEIN INC	HSIC	14,509.34	0.08%	0.00%	11.43%	11.43%	0.0086%
HOST HOTELS & RESORTS INC	HST	12,113.98	0.06%	5.13%	5.00%	10.25%	0.0065%
HERSHEY CO/THE	HSY	24,215.69	0.13%	2.09%	9.18%	11.36%	0.0143%
HUMANA INC	HUM	26,808.71	0.14%	0.66%	13.14%	13.85%	0.0193%
INTL BUSINESS MACHINES CORP	IBM	145,703.01	0.76%	3.54%	3.54%	7.15%	0.0542%
INTERCONTINENTAL EXCHANGE IN	ICE	30,470.92	0.16%	1.33%	14.24%	15.66%	0.0248%
INTL FLAVORS & FRAGRANCES	IFF	10,049.53	0.05%	1.83%	11.00%	12.94%	0.0068%
ILLUMINA INC	ILMN	20,663.94	0.11%	0.00%	13.98%	13.98%	0.0150%
INTEL CORP	INTC	154,881.60	0.81%	3.16%	8.52%	11.81%	0.0951%
INTUIT INC	INTU	28,557.79	0.15%	1.08%	17.11%	18.28%	0.0271%
INTERNATIONAL PAPER CO	IP	17,425.57	0.09%	4.20%	7.50%	11.86%	0.0107%
INTERPUBLIC GROUP OF COS INC	IPG	9,295.56	0.05%	2.54%	8.00%	10.64%	0.0051%
INGERSOLL-RAND PLC	IR	16,395.29	0.09%	2.01%	10.71%	12.82%	0.0109%
IRON MOUNTAIN INC	IRM	10,461.09	N/A	4.77%	N/A	N/A	N/A
INTUITIVE SURGICAL INC	ISRG	25,173.51	0.13%	0.00%	13.07%	13.07%	0.0171%
ILLINOIS TOOL WORKS	ITW	37,432.02	0.19%	2.17%	6.65%	8.90%	0.0173%
INVESCO LTD	IVZ	10,656.98	0.06%	4.37%	9.55%	14.13%	0.0078%
HUNT (JB) TRANSPRT SVCS INC	JBHT	9,117.12	0.05%	1.08%	13.74%	14.90%	0.0071%
JOHNSON CONTROLS INC	JCI	28,696.86	0.15%	2.58%	9.20%	11.90%	0.0178%
JACOBS ENGINEERING GROUP INC	JEC	6,073.09	0.03%	0.00%	6.92%	6.92%	0.0022%
JOHNSON & JOHNSON	JNJ	333,653.15	1.73%	2.59%	6.29%	8.96%	0.1554%
JUNIPER NETWORKS INC	JNPR	8,634.92	0.04%	1.88%	9.56%	11.53%	0.0052%
JPMORGAN CHASE & CO	JPM	227,224.79	1.18%	3.04%	4.21%	7.31%	0.0863%
NORDSTROM INC	JWN	6,599.20	0.03%	4.05%	8.23%	12.45%	0.0043%
KELLOGG CO	K	28,581.44	0.15%	2.52%	5.82%	8.42%	0.0125%
KEYCORP	KEY	9,308.22	0.05%	3.05%	4.50%	7.62%	0.0037%
KRAFT HEINZ CO/THE	KHC	107,587.72	0.56%	2.65%	20.38%	23.30%	0.1303%
KIMCO REALTY CORP	KIM	13,168.58	0.07%	3.27%	5.67%	9.04%	0.0062%
KLA-TENCOR CORP	KLAC	11,405.64	0.06%	2.87%	5.55%	8.50%	0.0050%
KIMBERLY-CLARK CORP	KMB	49,510.37	0.26%	2.67%	7.64%	10.41%	0.0268%
KINDER MORGAN INC	KMI	41,774.73	0.22%	2.68%	14.65%	17.52%	0.0381%
CARMAX INC	KMX	9,486.29	0.05%	0.00%	12.92%	12.92%	0.0064%
COCA-COLA CO/THE	KO	196,106.59	1.02%	3.05%	5.72%	8.86%	0.0903%
MICHAEL KORS HOLDINGS LTD	KORS	8,730.68	0.05%	0.00%	5.35%	5.35%	0.0024%
KROGER CO	KR	34,913.43	0.18%	1.20%	9.44%	10.70%	0.0194%
KOHLS CORP	KSS	6,966.25	0.04%	5.33%	3.25%	8.67%	0.0031%
KANSAS CITY SOUTHERN	KSU	9,728.61	0.05%	1.50%	9.42%	10.99%	0.0056%
LOEWS CORP	L	13,930.18	N/A	0.61%	N/A	N/A	N/A
L BRANDS INC	LB	19,300.04	0.10%	6.58%	10.54%	17.47%	0.0175%
LEGGETT & PLATT INC	LEG	6,865.40	0.04%	2.56%	10.00%	12.69%	0.0045%
LENNAR CORP-A	LEN	9,621.04	0.05%	0.35%	11.68%	12.04%	0.0060%
LABORATORY CRP OF AMER HLDGS	LH	13,339.65	0.07%	0.00%	11.29%	11.29%	0.0078%
LKQ CORP	LKQ	9,721.73	0.05%	0.00%	16.13%	16.13%	0.0082%
L-3 COMMUNICATIONS HOLDINGS	LLL	11,288.20	0.06%	1.94%	9.94%	11.98%	0.0070%
LINEAR TECHNOLOGY CORP	LLTC	11,125.24	0.06%	2.65%	6.91%	9.65%	0.0056%
ELI LILLY & CO	LLY	86,927.16	0.45%	2.59%	11.85%	14.59%	0.0660%
LEGG MASON INC	LM	3,099.71	0.02%	2.98%	15.82%	19.04%	0.0031%
LOCKHEED MARTIN CORP	LMT	75,556.11	0.39%	2.71%	7.61%	10.42%	0.0409%
LINCOLN NATIONAL CORP	LNC	9,266.31	0.05%	2.62%	11.80%	14.58%	0.0070%
LOWE'S COS INC	LOW	70,152.91	0.36%	1.55%	16.39%	18.07%	0.0659%
LAM RESEARCH CORP	LRCX	13,415.78	0.07%	1.41%	9.72%	11.20%	0.0078%
LEUCADIA NATIONAL CORP	LUK	6,279.18	0.03%	1.44%	18.00%	19.57%	0.0064%
SOUTHWEST AIRLINES CO	LUV	25,042.91	0.13%	0.88%	8.46%	9.37%	0.0122%
LEVEL 3 COMMUNICATIONS INC	LVLT	18,429.96	0.10%	0.00%	-0.69%	-0.69%	-0.0007%
LYONDELLBASELL INDU-CL A	LYB	31,757.03	0.17%	4.49%	5.67%	10.28%	0.0170%
MACY'S INC	M	10,365.16	0.05%	4.50%	9.67%	14.38%	0.0078%
MASTERCARD INC-CLASS A	MA	96,751.30	0.50%	0.86%	14.60%	15.53%	0.0781%
MACERICH CO/THE	MAC	12,679.79	0.07%	5.05%	7.12%	12.35%	0.0081%
MARRIOTT INTERNATIONAL -CL A	MAR	16,896.24	0.09%	1.73%	11.96%	13.79%	0.0121%
MASCO CORP	MAS	10,295.17	0.05%	1.24%	14.68%	16.00%	0.0086%
MATTEL INC	MAT	10,652.55	0.06%	4.86%	10.15%	15.25%	0.0084%
MCDONALD'S CORP	MCD	105,641.38	0.55%	3.04%	10.31%	13.51%	0.0742%
MICROCHIP TECHNOLOGY INC	MCHP	10,904.02	0.06%	2.76%	9.64%	12.53%	0.0071%
MCKESSON CORP	MCK	42,125.74	0.22%	0.62%	12.00%	12.65%	0.0277%
MOODY'S CORP	MCO	18,207.85	0.09%	1.53%	11.00%	12.61%	0.0119%
MONDELEZ INTERNATIONAL INC-A	MDLZ	70,634.28	0.37%	1.50%	12.99%	14.58%	0.0535%

MEDTRONIC PLC	MDT	121,020.89	0.63%	1.96%	8.31%	10.35%	0.0651%
METLIFE INC	MET	43,759.89	0.23%	4.04%	5.10%	9.25%	0.0210%
MOHAWK INDUSTRIES INC	MHK	14,059.56	0.07%	0.00%	11.10%	11.10%	0.0081%
MEAD JOHNSON NUTRITION CO	MJN	16,939.75	0.09%	1.92%	9.84%	11.85%	0.0104%
MCCORMICK & CO-NON VTG SHRS	MKC	13,533.19	0.07%	1.60%	9.10%	10.77%	0.0076%
MARTIN MARIETTA MATERIALS	MLM	12,197.22	0.06%	0.83%	22.16%	23.08%	0.0146%
MARSH & MCLENNAN COS	MMC	35,683.62	0.19%	1.94%	11.62%	13.67%	0.0254%
3M CO	MMM	106,212.82	0.55%	2.54%	8.88%	11.53%	0.0637%
MALLINCKRODT PLC	MNK	6,644.80	0.03%	0.00%	9.35%	9.35%	0.0032%
MONSTER BEVERAGE CORP	MNST	32,630.99	0.17%	0.00%	18.96%	18.96%	0.0322%
ALTRIA GROUP INC	MO	134,915.06	0.70%	3.45%	7.67%	11.25%	0.0789%
MONSANTO CO	MON	45,249.69	0.24%	2.09%	7.85%	10.02%	0.0236%
MOSAIC CO/THE	MOS	9,158.19	0.05%	4.20%	0.85%	5.07%	0.0024%
MARATHON PETROLEUM CORP	MPC	20,112.53	0.10%	3.47%	5.63%	9.21%	0.0096%
MERCK & CO. INC.	MRK	159,465.94	0.83%	3.19%	5.08%	8.35%	0.0693%
MARATHON OIL CORP	MRO	12,723.20	0.07%	1.33%	-12.38%	-11.13%	-0.0074%
MORGAN STANLEY	MS	50,323.89	0.26%	2.68%	6.43%	9.20%	0.0241%
MICROSOFT CORP	MSFT	402,220.09	2.09%	2.76%	8.46%	11.33%	0.2370%
MOTOROLA SOLUTIONS INC	MSI	11,518.65	0.06%	2.50%	5.28%	7.84%	0.0047%
M & T BANK CORP	MTB	18,798.45	0.10%	2.41%	4.84%	7.30%	0.0071%
MICRON TECHNOLOGY INC	MU	14,269.71	0.07%	0.00%	6.10%	6.10%	0.0045%
MURPHY OIL CORP	MUR	5,467.20	N/A	4.38%	N/A	N/A	N/A
MYLAN NV	MYL	21,981.82	0.11%	0.00%	9.42%	9.42%	0.0108%
NAVIENT CORP	NAVI	3,949.64	N/A	5.41%	N/A	N/A	N/A
NOBLE ENERGY INC	NBL	15,409.47	0.08%	1.11%	7.03%	8.18%	0.0066%
NASDAQ INC	NDAQ	10,639.16	0.06%	1.90%	7.48%	9.45%	0.0052%
NEXTERA ENERGY INC	NEE	60,172.55	0.31%	2.67%	6.32%	9.07%	0.0284%
NEWMONT MINING CORP	NEM	20,754.37	0.11%	0.27%	6.13%	6.41%	0.0069%
NETFLIX INC	NFLX	39,180.77	0.20%	0.00%	35.50%	35.50%	0.0723%
NEWFIELD EXPLORATION CO	NFX	8,769.08	0.05%	0.00%	27.50%	27.50%	0.0125%
NISOURCE INC	NI	8,527.36	N/A	2.41%	N/A	N/A	N/A
NIKE INC -CL B	NKE	92,996.64	0.48%	1.34%	13.64%	15.07%	0.0729%
NIELSEN HOLDINGS PLC	NLSN	18,751.04	0.10%	2.34%	12.33%	14.81%	0.0144%
NORTHROP GRUMMAN CORP	NOC	40,110.79	0.21%	1.54%	7.54%	9.14%	0.0191%
NATIONAL OILWELL VARCO INC	NOV	12,688.10	0.07%	1.81%	-14.31%	-12.62%	-0.0083%
NRG ENERGY INC	NRG	4,720.47	N/A	1.60%	N/A	N/A	N/A
NORFOLK SOUTHERN CORP	NSC	25,176.16	0.13%	2.82%	12.44%	15.44%	0.0202%
NETAPP INC	NTAP	6,887.17	0.04%	3.09%	8.97%	12.19%	0.0044%
NORTHERN TRUST CORP	NTRS	15,118.13	0.08%	2.26%	11.45%	13.84%	0.0109%
NUCOR CORP	NUE	15,708.85	0.08%	3.04%	8.40%	11.57%	0.0094%
NVIDIA CORP	NVDA	25,103.34	0.13%	0.98%	9.67%	10.70%	0.0140%
NEWELL BRANDS INC	NWL	23,214.12	0.12%	1.55%	13.77%	15.43%	0.0186%
NEWS CORP - CLASS A	NWSA	6,646.70	0.03%	1.76%	8.80%	10.64%	0.0037%
REALTY INCOME CORP	O	17,869.29	0.09%	3.46%	3.67%	7.19%	0.0067%
OWENS-ILLINOIS INC	OI	2,916.16	0.02%	0.00%	7.37%	7.37%	0.0011%
ONEOK INC	OKE	9,969.46	0.05%	5.19%	7.30%	12.68%	0.0066%
OMNICOM GROUP	OMC	19,374.24	0.10%	2.64%	6.45%	9.17%	0.0092%
ORACLE CORP	ORCL	168,743.34	0.88%	1.45%	8.25%	9.76%	0.0857%
O'REILLY AUTOMOTIVE INC	ORLY	26,149.18	0.14%	0.00%	15.54%	15.54%	0.0211%
OCCIDENTAL PETROLEUM CORP	OXY	57,708.31	0.30%	3.99%	8.00%	12.15%	0.0365%
PAYCHEX INC	PAYX	21,427.20	N/A	2.82%	N/A	N/A	N/A
PEOPLE'S UNITED FINANCIAL	PBCT	4,557.22	N/A	4.62%	N/A	N/A	N/A
PITNEY BOWES INC	PBI	3,357.44	0.02%	4.21%	14.00%	18.51%	0.0032%
PACCAR INC	PCAR	18,178.51	0.09%	3.57%	7.83%	11.55%	0.0109%
P G & E CORP	PCG	31,707.02	0.16%	3.03%	4.98%	8.08%	0.0133%
PRICELINE GROUP INC/THE	PCLN	61,970.30	0.32%	0.00%	18.01%	18.01%	0.0580%
PATTERSON COS INC	PDCO	4,745.84	0.02%	2.10%	6.95%	9.12%	0.0023%
PUBLIC SERVICE ENTERPRISE GP	PEG	23,581.37	0.12%	3.52%	3.22%	6.80%	0.0083%
PEPSICO INC	PEP	153,021.54	0.80%	2.77%	6.41%	9.27%	0.0738%
PFIZER INC	PFE	213,543.35	1.11%	3.41%	5.80%	9.31%	0.1033%
PRINCIPAL FINANCIAL GROUP	PFG	11,915.84	0.06%	3.83%	9.03%	13.03%	0.0081%
PROCTER & GAMBLE CO/THE	PG	225,379.00	1.17%	3.14%	6.25%	9.49%	0.1112%
PROGRESSIVE CORP	PGR	19,530.38	0.10%	1.98%	8.37%	10.43%	0.0106%
PARKER HANNIFIN CORP	PH	14,552.33	0.08%	2.33%	8.21%	10.64%	0.0080%
PULTEGROUP INC	PHM	6,744.17	0.04%	1.85%	14.04%	16.02%	0.0056%
PERKINELMER INC	PKI	5,715.38	0.03%	0.54%	19.78%	20.37%	0.0061%
PROLOGIS INC	PLD	25,749.96	0.13%	3.43%	5.04%	8.55%	0.0114%
PHILIP MORRIS INTERNATIONAL	PM	157,794.61	0.82%	4.09%	8.24%	12.50%	0.1026%
PNC FINANCIAL SERVICES GROUP	PNC	40,639.96	0.21%	2.62%	6.03%	8.72%	0.0184%
PENTAIR PLC	PNR	10,533.96	0.05%	2.31%	8.66%	11.07%	0.0061%
PINNACLE WEST CAPITAL	PNW	9,009.01	0.05%	3.13%	4.64%	7.84%	0.0037%
PPG INDUSTRIES INC	PPG	27,710.50	0.14%	1.49%	8.50%	10.05%	0.0145%
PPL CORP	PPL	25,554.68	0.13%	4.03%	3.83%	7.93%	0.0105%
PERRIGO CO PLC	PRGO	12,986.00	0.07%	0.64%	9.68%	10.35%	0.0070%
PRUDENTIAL FINANCIAL INC	PRU	31,532.28	0.16%	3.95%	7.90%	12.01%	0.0197%
PUBLIC STORAGE	PSA	44,314.71	0.23%	2.78%	5.51%	8.37%	0.0193%
PHILLIPS 66	PSX	41,699.63	0.22%	3.01%	9.79%	12.94%	0.0281%
PVH CORP	PVH	7,619.10	0.04%	0.16%	6.36%	6.52%	0.0026%
QUANTA SERVICES INC	PWR	3,491.95	0.02%	0.00%	8.00%	8.00%	0.0015%
PRAXAIR INC	PX	32,060.92	0.17%	2.68%	7.11%	9.89%	0.0165%
PIONEER NATURAL RESOURCES CO	PXD	25,526.41	0.13%	0.05%	20.00%	20.06%	0.0266%
PAYPAL HOLDINGS INC	PYPL	44,251.09	0.23%	0.00%	15.50%	15.50%	0.0357%
QUALCOMM INC	QCOM	78,689.78	0.41%	3.66%	10.50%	14.35%	0.0587%
QORVO INC	QRVO	7,062.69	0.04%	0.00%	14.70%	14.70%	0.0054%
RYDER SYSTEM INC	R	3,283.43	0.02%	2.76%	9.92%	12.82%	0.0022%
REYNOLDS AMERICAN INC	RAI	76,976.51	0.40%	3.14%	9.44%	12.72%	0.0509%
ROYAL CARIBBEAN CRUISES LTD	RCL	14,453.46	0.08%	2.34%	24.87%	27.49%	0.0207%
REGENERON PHARMACEUTICALS	REGN	36,696.60	0.19%	0.00%	22.75%	22.75%	0.0434%
REGIONS FINANCIAL CORP	RF	10,779.73	0.06%	3.11%	5.26%	8.46%	0.0047%
ROBERT HALF INTL INC	RHI	5,011.12	0.03%	2.31%	11.63%	14.07%	0.0037%
RED HAT INC	RHT	13,147.06	0.07%	0.00%	17.70%	17.70%	0.0121%
TRANSOCEAN LTD	RIG	4,342.25	0.02%	0.00%	-6.20%	-6.20%	-0.0014%
RALPH LAUREN CORP	RL	7,451.16	0.04%	2.30%	7.46%	9.84%	0.0038%
ROCKWELL AUTOMATION INC	ROK	14,956.86	0.08%	2.66%	6.93%	9.68%	0.0075%
ROPER TECHNOLOGIES INC	ROP	17,260.82	0.09%	0.68%	11.43%	12.15%	0.0109%
ROSS STORES INC	ROST	22,648.21	0.12%	0.95%	12.46%	13.46%	0.0159%
RANGE RESOURCES CORP	RRC	7,322.82	0.04%	0.22%	-24.07%	-23.87%	-0.0091%
REPUBLIC SERVICES INC	RSG	17,645.41	0.09%	2.39%	8.11%	10.60%	0.0097%
RAYTHEON COMPANY	RTN	40,374.43	0.21%	2.12%	7.94%	10.14%	0.0213%
STARBUCKS CORP	SBUX	83,675.09	0.44%	1.43%	18.45%	20.01%	0.0871%
SCANA CORP	SCG	10,813.09	0.06%	3.03%	5.55%	8.66%	0.0049%
SCHWAB (CHARLES) CORP	SCHW	33,452.00	0.17%	1.02%	17.31%	18.42%	0.0320%
SPECTRA ENERGY CORP	SE	25,674.32	0.13%	4.46%	10.20%	14.88%	0.0199%

SEALED AIR CORP	SEE	9,062.66	0.05%	1.27%	4.27%	5.57%	0.0026%
SHERWIN-WILLIAMS CO/THE	SHW	27,163.04	0.14%	1.14%	15.80%	17.03%	0.0241%
SIGNET JEWELERS LTD	SIG	6,428.46	0.03%	1.26%	14.40%	15.75%	0.0053%
JM SMUCKER CO/THE	SJM	17,744.54	0.09%	1.88%	8.30%	10.26%	0.0095%
SCHLUMBERGER LTD	SLB	110,018.25	0.57%	2.53%	5.63%	8.23%	0.0471%
SL GREEN REALTY CORP	SLG	11,098.15	0.06%	2.79%	4.85%	7.71%	0.0044%
SNAP-ON INC	SNA	9,176.66	0.05%	2.03%	4.80%	6.88%	0.0033%
SCRIPPS NETWORKS INTER-CL A	SNI	8,030.06	0.04%	1.62%	11.73%	13.45%	0.0056%
SOUTHERN CO/THE	SO	50,334.56	0.26%	4.15%	4.12%	8.36%	0.0219%
SIMON PROPERTY GROUP INC	SPG	67,112.51	0.35%	3.01%	7.92%	11.05%	0.0386%
S&P GLOBAL INC	SPGI	28,402.45	0.15%	1.35%	10.00%	11.42%	0.0169%
STAPLES INC	SPLS	5,571.00	0.03%	5.57%	1.60%	7.22%	0.0021%
STERICYCLE INC	SRCL	8,841.10	0.05%	0.00%	14.28%	14.28%	0.0066%
SEMPRA ENERGY	SRE	28,447.62	0.15%	2.65%	6.88%	9.62%	0.0142%
SUNTRUST BANKS INC	STI	20,586.32	0.11%	2.46%	6.19%	8.73%	0.0093%
ST JUDE MEDICAL INC	STJ	22,173.64	0.12%	1.59%	10.63%	12.30%	0.0142%
STATE STREET CORP	STT	21,349.10	0.11%	2.65%	10.71%	13.50%	0.0150%
SEAGATE TECHNOLOGY	STX	7,271.06	0.04%	9.81%	1.43%	11.31%	0.0043%
CONSTELLATION BRANDS INC-A	STZ	33,177.89	0.17%	0.97%	14.80%	15.84%	0.0273%
STANLEY BLACK & DECKER INC	SWK	16,695.97	0.09%	2.03%	10.50%	12.64%	0.0110%
SKYWORKS SOLUTIONS INC	SWKS	12,038.27	0.06%	1.66%	17.77%	19.57%	0.0123%
SOUTHWESTERN ENERGY CO	SWN	6,021.63	0.03%	0.00%	-19.71%	-19.71%	-0.0062%
SYNCHRONY FINANCIAL	SYF	21,081.51	0.11%	1.09%	6.25%	7.37%	0.0081%
STRYKER CORP	SYK	44,814.15	0.23%	1.28%	10.41%	11.76%	0.0274%
SYMANTEC CORP	SYMC	12,576.48	0.07%	1.48%	8.69%	10.23%	0.0067%
SYSCO CORP	SYY	28,592.80	0.15%	2.41%	9.21%	11.73%	0.0174%
AT&T INC	T	266,000.76	1.38%	4.46%	3.92%	8.47%	0.1171%
MOLSON COORS BREWING CO -B	TAP	21,710.61	0.11%	1.62%	19.77%	21.55%	0.0243%
TERADATA CORP	TDC	3,259.10	0.02%	0.00%	9.67%	9.67%	0.0016%
TRANSDIGM GROUP INC	TDG	13,970.15	0.07%	0.00%	13.88%	13.88%	0.0101%
TECO ENERGY INC	TE	6,510.60	0.03%	3.35%	5.87%	9.32%	0.0032%
TE CONNECTIVITY LTD	TEL	20,423.46	0.11%	2.39%	12.20%	14.73%	0.0156%
TEGNA INC	TGNA	5,041.51	0.03%	2.42%	8.03%	10.55%	0.0028%
TARGET CORP	TGT	41,143.15	0.21%	3.30%	10.69%	14.17%	0.0303%
TIFFANY & CO	TIF	7,641.70	0.04%	2.73%	8.32%	11.16%	0.0044%
TJX COMPANIES INC	TJX	51,055.48	0.27%	1.33%	11.56%	12.97%	0.0344%
TORCHMARK CORP	TMK	7,458.63	0.04%	0.91%	7.98%	8.93%	0.0035%
THERMO FISHER SCIENTIFIC INC	TMO	58,145.37	0.30%	0.41%	11.83%	12.26%	0.0371%
TRIPADVISOR INC	TRIP	9,368.91	0.05%	0.00%	14.94%	14.94%	0.0073%
T ROWE PRICE GROUP INC	TROW	18,111.38	0.09%	2.96%	10.46%	13.57%	0.0128%
TRAVELERS COS INC/THE	TRV	34,806.66	0.18%	2.21%	8.04%	10.34%	0.0187%
TRACTOR SUPPLY COMPANY	TSCO	12,165.87	0.06%	0.96%	15.66%	16.70%	0.0106%
TYSON FOODS INC-CL A	TSN	26,879.48	0.14%	0.92%	12.30%	13.27%	0.0186%
TESORO CORP	TSO	8,988.59	0.05%	2.75%	-1.11%	1.63%	0.0008%
TOTAL SYSTEM SERVICES INC	TSS	9,751.64	0.05%	0.75%	11.00%	11.79%	0.0060%
TIME WARNER INC	TWX	57,831.44	0.30%	2.19%	14.38%	16.73%	0.0503%
TEXAS INSTRUMENTS INC	TXN	62,914.82	0.33%	2.45%	10.00%	12.58%	0.0411%
TEXTRON INC	TXT	9,828.49	0.05%	0.23%	7.31%	7.55%	0.0039%
TYCO INTERNATIONAL PLC	TYC	18,126.21	0.09%	2.02%	10.03%	12.15%	0.0115%
UNDER ARMOUR INC-CLASS A	UA	16,643.53	0.09%	0.00%	23.89%	23.89%	0.0207%
UNITED CONTINENTAL HOLDINGS	UAL	13,777.11	0.07%	0.00%	-12.07%	-12.07%	-0.0086%
UDR INC	UDR	9,862.71	0.05%	3.20%	6.73%	10.03%	0.0051%
UNIVERSAL HEALTH SERVICES-B	UHS	13,018.95	0.07%	0.30%	8.88%	9.19%	0.0062%
ULTA SALON COSMETICS & FRAGR	ULTA	15,216.45	0.08%	0.00%	21.00%	21.00%	0.0166%
UNITEDHEALTH GROUP INC	UNH	134,253.54	0.70%	1.43%	13.02%	14.54%	0.1015%
UNUM GROUP	UNM	7,558.35	0.04%	2.46%	7.60%	10.15%	0.0040%
UNION PACIFIC CORP	UNP	73,380.24	0.38%	2.57%	13.08%	15.83%	0.0604%
UNITED PARCEL SERVICE-CL B	UPS	95,081.12	0.49%	2.89%	10.04%	13.08%	0.0647%
URBAN OUTFITTERS INC	URBN	3,221.25	0.02%	0.00%	13.01%	13.01%	0.0022%
UNITED RENTALS INC	URI	5,938.51	0.03%	0.00%	14.13%	14.13%	0.0044%
US BANCORP	USB	69,625.84	0.36%	2.67%	5.86%	8.61%	0.0312%
UNITED TECHNOLOGIES CORP	UTX	85,820.58	0.45%	2.61%	9.56%	12.29%	0.0548%
VISA INC-CLASS A SHARES	V	176,888.54	0.92%	0.76%	17.45%	18.27%	0.1680%
VARIAN MEDICAL SYSTEMS INC	VAR	7,829.49	0.04%	0.00%	12.05%	12.05%	0.0049%
VF CORP	VFC	25,642.45	0.13%	2.46%	10.77%	13.36%	0.0178%
VIACOM INC-CLASS B	VIAB	16,668.47	0.09%	3.89%	5.81%	9.81%	0.0085%
VALERO ENERGY CORP	VLO	23,959.93	0.12%	4.74%	2.70%	7.50%	0.0093%
VULCAN MATERIALS CO	VMC	16,030.53	0.08%	0.67%	23.08%	23.82%	0.0199%
VORNADO REALTY TRUST	VNO	18,899.75	0.10%	2.59%	5.36%	8.02%	0.0079%
VERISK ANALYTICS INC	VRSK	13,634.93	0.07%	0.00%	12.00%	12.00%	0.0085%
VERISIGN INC	VRSN	9,378.79	0.05%	0.00%	9.85%	9.85%	0.0048%
VERTEX PHARMACEUTICALS INC	VRTX	21,277.04	0.11%	0.00%	50.53%	50.53%	0.0559%
VENTAS INC	VTR	24,622.78	0.13%	4.05%	1.93%	6.01%	0.0077%
VERIZON COMMUNICATIONS INC	VZ	227,619.92	1.18%	4.09%	3.95%	8.12%	0.0961%
WATERS CORP	WAT	11,384.42	0.06%	0.00%	8.92%	8.92%	0.0053%
WALGREENS BOOTS ALLIANCE INC	WBA	89,952.06	0.47%	1.75%	13.59%	15.46%	0.0723%
WESTERN DIGITAL CORP	WDC	13,300.73	0.07%	3.88%	1.90%	5.81%	0.0040%
WEC ENERGY GROUP INC	WEC	20,611.76	0.11%	3.03%	5.50%	8.62%	0.0092%
WELLS FARGO & CO	WFC	240,296.67	1.25%	3.27%	11.47%	14.93%	0.1866%
WHOLE FOODS MARKET INC	WFM	10,279.29	0.05%	1.69%	8.55%	10.31%	0.0055%
WHIRLPOOL CORP	WHR	12,659.12	0.07%	2.26%	15.17%	17.60%	0.0116%
WILLIS TOWERS WATSON PLC	WLTW	17,209.58	0.09%	1.54%	21.47%	23.18%	0.0207%
WASTE MANAGEMENT INC	WM	29,441.22	0.15%	2.47%	8.50%	11.08%	0.0170%
WILLIAMS COS INC	WMB	16,234.82	0.08%	10.29%	-2.07%	8.11%	0.0068%
WAL-MART STORES INC	WMT	227,577.54	1.18%	2.73%	2.87%	5.64%	0.0668%
WESTROCK CO	WRK	9,818.94	0.05%	3.86%	2.85%	6.76%	0.0035%
WESTERN UNION CO	WU	9,420.00	0.05%	3.34%	6.80%	10.25%	0.0050%
WEYERHAEUSER CO	WY	22,240.38	0.12%	4.26%	12.27%	16.78%	0.0194%
WYNDHAM WORLDWIDE CORP	WYN	7,974.32	0.04%	2.81%	7.65%	10.57%	0.0044%
WYNN RESORTS LTD	WYNN	9,226.33	0.05%	2.25%	10.00%	12.37%	0.0059%
CIMAREX ENERGY CO	XEC	11,313.33	0.06%	0.34%	-4.37%	-4.04%	-0.0024%
XCEL ENERGY INC	XEL	22,746.13	0.12%	3.04%	5.00%	8.12%	0.0096%
XL GROUP PLC	XL	9,439.01	0.05%	2.48%	9.00%	11.59%	0.0057%
XILINX INC	XLNX	11,684.36	0.06%	2.83%	8.23%	11.18%	0.0068%
EXXON MOBIL CORP	XOM	388,703.35	2.02%	3.18%	13.71%	17.11%	0.3457%
DENTSPLY SIRONA INC	XRAY	14,531.69	0.08%	0.47%	9.92%	10.42%	0.0079%
XEROX CORP	XRX	9,613.39	0.05%	3.30%	11.60%	15.09%	0.0075%
XYLEM INC	XYL	7,987.77	0.04%	1.39%	15.00%	16.49%	0.0068%
YAHOO! INC	YHOO	35,678.96	0.19%	0.00%	4.93%	4.93%	0.0091%
YUM! BRANDS INC	YUM	33,784.99	0.18%	2.28%	11.85%	14.26%	0.0251%
ZIMMER BIOMET HOLDINGS INC	ZBH	24,037.33	0.12%	0.78%	10.49%	11.31%	0.0141%
ZIONS BANCORPORATION	ZION	5,142.19	0.03%	1.18%	9.00%	10.24%	0.0027%
ZOETIS INC	ZTS	23,549.76	0.12%	0.80%	13.93%	14.79%	0.0181%

	19,232,690		13.09%

[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Bloomberg Professional
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional
[7] Source: Bloomberg Professional
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

19,343,630.12	99.43%	

Ex-Ante Market Risk Premium
Market DCF Method Based - Value Line

[1]	[2]	[3]
S&P 500 Est. Required Market Return	Current 30-Year Treasury (30-day average)	Implied Market Risk Premium
13.63%	2.50%	11.13%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
AGILENT TECHNOLOGIES INC	A	15,195.37	0.09%	0.99%	4.50%	5.51%	0.0048%
ALCOA INC	AA	13,348.34	0.08%	1.18%	11.50%	12.75%	0.0097%
AMERICAN AIRLINES GROUP INC	AAL	17,763.01	N/A	1.32%	N/A	N/A	N/A
ADVANCE AUTO PARTS INC	AAP	11,396.03	0.06%	0.16%	11.50%	11.67%	0.0076%
APPLE INC	AAPL	526,478.70	3.00%	2.43%	11.50%	14.07%	0.4218%
ABBVIE INC	ABBV	99,160.27	0.56%	3.72%	13.00%	16.96%	0.0958%
AMERISOURCEBERGEN CORP	ABC	17,371.28	0.10%	1.75%	11.00%	12.85%	0.0127%
ABBOTT LABORATORIES	ABT	58,222.49	0.33%	2.62%	7.50%	10.22%	0.0339%
ACCENTURE PLC-CL A	ACN	76,896.48	0.44%	1.97%	6.50%	8.53%	0.0374%
ADOBE SYSTEMS INC	ADBE	48,171.68	0.27%	0.00%	35.50%	35.50%	0.0974%
ANALOG DEVICES INC	ADI	17,860.11	0.10%	2.89%	11.00%	14.05%	0.0143%
ARCHER-DANIELS-MIDLAND CO	ADM	25,070.77	0.14%	2.81%	6.00%	8.89%	0.0127%
AUTOMATIC DATA PROCESSING	ADP	41,021.64	0.23%	2.52%	9.50%	12.14%	0.0284%
ALLIANCE DATA SYSTEMS CORP	ADS	11,894.99	0.07%	0.00%	10.50%	10.50%	0.0071%
AUTODESK INC	ADSK	13,268.18	N/A	0.00%	N/A	N/A	N/A
AMEREN CORPORATION	AEE	12,493.90	0.07%	3.40%	6.00%	9.50%	0.0068%
AMERICAN ELECTRIC POWER	AEP	32,711.87	0.19%	3.45%	4.00%	7.52%	0.0140%
AES CORP	AES	7,973.88	0.05%	3.64%	8.50%	12.29%	0.0056%
AETNA INC	AET	42,422.60	0.24%	0.83%	9.50%	10.37%	0.0250%
AFLAC INC	AFL	29,799.12	0.17%	2.34%	4.50%	6.89%	0.0117%
ALLERGAN PLC	AGN	92,329.86	0.53%	0.00%	15.00%	15.00%	0.0789%
AMERICAN INTERNATIONAL GROUP	AIG	61,862.68	0.35%	2.34%	5.00%	7.40%	0.0261%
APARTMENT INVT & MGMT CO -A	AIV	-	N/A	3.13%	N/A	N/A	N/A
ASSURANT INC	AIZ	5,423.63	0.03%	2.31%	7.00%	9.39%	0.0029%
ARTHUR J GALLAGHER & CO	AJG	8,422.88	0.05%	3.20%	15.00%	18.44%	0.0088%
AKAMAI TECHNOLOGIES INC	AKAM	10,064.78	0.06%	0.00%	13.00%	13.00%	0.0075%
ALASKA AIR GROUP INC	ALK	7,328.22	0.04%	1.86%	13.50%	15.49%	0.0065%
ALLSTATE CORP	ALL	25,447.50	0.14%	1.95%	6.50%	8.51%	0.0123%
ALLEGION PLC	ALLE	6,629.58	0.04%	0.69%	10.50%	11.23%	0.0042%
ALEXION PHARMACEUTICALS INC	ALXN	27,704.64	0.16%	0.00%	27.50%	27.50%	0.0434%
APPLIED MATERIALS INC	AMAT	26,705.81	0.15%	1.63%	18.00%	19.78%	0.0301%
AMETEK INC	AME	11,079.97	0.06%	0.76%	6.00%	6.78%	0.0043%
AFFILIATED MANAGERS GROUP	AMG	8,903.45	0.05%	0.00%	8.50%	8.50%	0.0043%
AMGEN INC	AMGN	114,400.40	0.65%	2.76%	8.50%	11.38%	0.0741%
AMERIPRISE FINANCIAL INC	AMP	16,965.64	0.10%	2.95%	11.00%	14.11%	0.0136%
AMERICAN TOWER CORP	AMT	47,326.04	0.27%	2.01%	15.50%	17.67%	0.0476%
AMAZON.COM INC	AMZN	340,821.80	1.94%	0.00%	90.00%	90.00%	1.7467%
AUTONATION INC	AN	5,024.11	0.03%	0.00%	9.00%	9.00%	0.0026%
ANTHEM INC	ANTM	33,819.75	0.19%	2.02%	7.50%	9.60%	0.0185%
AON PLC	AON	28,836.72	0.16%	1.21%	12.00%	13.28%	0.0218%
APACHE CORP	APA	22,015.42	0.13%	1.72%	5.00%	6.76%	0.0085%
ANADARKO PETROLEUM CORP	APC	28,337.41	N/A	0.36%	N/A	N/A	N/A
AIR PRODUCTS & CHEMICALS INC	APD	31,552.14	0.18%	2.36%	12.00%	14.50%	0.0261%
AMPHENOL CORP-CL A	APH	18,320.46	0.10%	0.94%	8.00%	8.98%	0.0094%
ACTIVISION BLIZZARD INC	ATVI	28,723.23	0.16%	0.72%	8.00%	8.75%	0.0143%
AVALONBAY COMMUNITIES INC	AVB	-	N/A	3.15%	N/A	N/A	N/A
BROADCOM LTD	AVGO	62,625.39	0.36%	1.26%	23.00%	24.40%	0.0870%
AVERY DENNISON CORP	AVY	6,884.97	0.04%	2.17%	9.50%	11.77%	0.0046%
AMERICAN WATER WORKS CO INC	AWK	14,030.40	0.08%	1.90%	8.00%	9.98%	0.0080%
AMERICAN EXPRESS CO	AXP	60,150.75	0.34%	2.02%	3.00%	5.05%	0.0173%
ACUITY BRANDS INC	AYI	11,091.79	0.06%	0.20%	19.50%	19.72%	0.0125%
AUTOZONE INC	AZO	22,502.48	0.13%	0.00%	11.50%	11.50%	0.0147%
BOEING CO/THE	BA	85,447.28	0.49%	3.44%	10.50%	14.12%	0.0687%
BANK OF AMERICA CORP	BAC	144,789.80	0.82%	1.71%	22.00%	23.90%	0.1970%
BAXTER INTERNATIONAL INC	BAX	25,334.21	0.14%	1.13%	-4.50%	-3.40%	-0.0049%
BED BATH & BEYOND INC	BBBY	7,170.02	0.04%	1.14%	3.00%	4.16%	0.0017%
BB&T CORP	BBT	28,908.90	0.16%	3.25%	7.50%	10.87%	0.0179%
BEST BUY CO INC	BBY	9,859.32	0.06%	3.68%	8.00%	11.83%	0.0066%
CR BARD INC	BCR	16,913.96	0.10%	0.45%	9.00%	9.47%	0.0091%
BECTON DICKINSON AND CO	BDX	36,539.06	0.21%	1.60%	9.50%	11.18%	0.0233%
FRANKLIN RESOURCES INC	BEN	20,268.52	0.12%	2.26%	4.50%	6.81%	0.0079%
BROWN-FORMAN CORP-CLASS B	BF/B	19,706.96	0.11%	1.41%	8.00%	9.47%	0.0106%
BAKER HUGHES INC	BHI	20,656.40	0.12%	1.44%	30.00%	31.66%	0.0372%
BIOGEN INC	BIIB	52,269.95	0.30%	0.00%	10.50%	10.50%	0.0313%
BANK OF NEW YORK MELLON CORP	BK	44,742.03	0.25%	1.64%	11.00%	12.73%	0.0324%
BLACKROCK INC	BLK	58,376.02	0.33%	2.57%	8.00%	10.67%	0.0355%
BALL CORP	BLL	10,410.45	0.06%	0.71%	11.00%	11.75%	0.0070%
BRISTOL-MYERS SQUIBB CO	BMY	120,655.00	0.69%	2.09%	17.50%	19.77%	0.1359%
BERKSHIRE HATHAWAY INC-CL B	BRK/B	359,874.30	N/A	0.00%	N/A	N/A	N/A
BOSTON SCIENTIFIC CORP	BSX	31,114.41	0.18%	0.00%	18.00%	18.00%	0.0319%
BORGWARNER INC	BWA	7,333.76	0.04%	1.54%	8.50%	10.11%	0.0042%
BOSTON PROPERTIES INC	BXP	-	N/A	2.00%	N/A	N/A	N/A
CITIGROUP INC	C	130,486.90	0.74%	0.45%	12.00%	12.48%	0.0927%
CA INC	CA	13,849.80	0.08%	3.04%	4.50%	7.61%	0.0060%
CONAGRA FOODS INC	CAG	20,908.64	0.12%	2.09%	6.00%	8.15%	0.0097%
CARDINAL HEALTH INC	CAH	25,467.12	0.15%	2.38%	14.00%	16.55%	0.0240%
CATERPILLAR INC	CAT	45,670.23	0.26%	3.94%	5.00%	9.04%	0.0235%

CHUBB LTD	CB	59,725.50	0.34%	2.15%	8.00%	10.24%	0.0348%
CBRE GROUP INC - A	CBG	10,062.14	0.06%	0.00%	10.00%	10.00%	0.0057%
CBS CORP-CLASS B NON VOTING	CBS	24,375.26	0.14%	1.12%	13.00%	14.19%	0.0197%
CROWN CASTLE INTL CORP	CCI	32,432.77	0.18%	3.87%	21.00%	25.28%	0.0467%
CARNIVAL CORP	CCL	37,266.80	0.21%	2.84%	15.50%	18.56%	0.0394%
CELGENE CORP	CELG	77,981.30	0.44%	0.00%	24.00%	24.00%	0.1066%
CERNER CORP	CERN	19,223.47	0.11%	0.00%	13.50%	13.50%	0.0148%
CF INDUSTRIES HOLDINGS INC	CF	6,442.30	0.04%	4.88%	8.00%	13.08%	0.0048%
CITIZENS FINANCIAL GROUP	CFG	11,700.02	N/A	2.17%	N/A	N/A	N/A
CHURCH & DWIGHT CO INC	CHD	12,882.26	0.07%	1.41%	7.00%	8.46%	0.0062%
CHESAPEAKE ENERGY CORP	CHK	3,169.94	N/A	0.00%	N/A	N/A	N/A
C.H. ROBINSON WORLDWIDE INC	CHRW	10,286.79	0.06%	2.39%	7.50%	9.98%	0.0058%
CIGNA CORP	CI	33,282.56	0.19%	0.03%	12.50%	12.53%	0.0238%
CINCINNATI FINANCIAL CORP	CINF	11,807.21	0.07%	2.67%	6.50%	9.26%	0.0062%
COLGATE-PALMOLIVE CO	CL	64,895.62	0.37%	2.15%	14.00%	16.30%	0.0602%
CLOROX COMPANY	CLX	17,355.54	0.10%	2.41%	8.50%	11.01%	0.0109%
COMERICA INC	CMA	7,787.47	0.04%	1.98%	6.50%	8.54%	0.0038%
COMCAST CORP-CLASS A	CMCSA	152,792.00	0.87%	1.75%	10.00%	11.84%	0.1030%
CME GROUP INC	CME	32,426.98	0.18%	2.50%	9.50%	12.12%	0.0224%
CHIPOTLE MEXICAN GRILL INC	CMG	12,000.10	0.07%	0.00%	13.50%	13.50%	0.0092%
CUMMINS INC	CMI	20,270.79	0.12%	3.28%	5.00%	8.36%	0.0097%
CMS ENERGY CORP	CMS	12,170.33	0.07%	2.94%	6.00%	9.03%	0.0063%
CENTENE CORP	CNC	11,904.16	0.07%	0.00%	19.50%	19.50%	0.0132%
CENTERPOINT ENERGY INC	CNP	10,115.12	0.06%	4.47%	2.00%	6.51%	0.0038%
CAPITAL ONE FINANCIAL CORP	COF	33,749.82	0.19%	2.44%	3.50%	5.98%	0.0115%
CABOT OIL & GAS CORP	COG	11,741.25	0.07%	0.32%	39.00%	39.38%	0.0263%
COACH INC	COH	11,235.50	0.06%	3.34%	4.50%	7.92%	0.0051%
ROCKWELL COLLINS INC	COL	11,320.02	0.06%	1.61%	8.00%	9.67%	0.0062%
CONOCOPHILLIPS	COP	56,507.59	0.32%	2.19%	6.50%	8.76%	0.0282%
COSTCO WHOLESALE CORP	COST	68,836.93	0.39%	1.15%	9.00%	10.20%	0.0400%
CAMPBELL SOUP CO	CPB	19,355.76	0.11%	2.00%	5.50%	7.56%	0.0083%
COLUMBIA PIPELINE GROUP	CPGX	10,201.76	N/A	2.12%	N/A	N/A	N/A
SALESFORCE.COM INC	CRM	55,744.70	N/A	0.00%	N/A	N/A	N/A
CISCO SYSTEMS INC	CSCO	147,093.50	0.84%	3.56%	6.00%	9.67%	0.0810%
CSRA INC	CSRA	4,002.10	N/A	1.63%	N/A	N/A	N/A
CSX CORP	CSX	25,808.41	0.15%	2.67%	7.00%	9.76%	0.0143%
CINTAS CORP	CTAS	10,244.95	0.06%	1.10%	11.00%	12.16%	0.0071%
CENTURYLINK INC	CTL	15,576.60	0.09%	7.57%	14.50%	22.62%	0.0201%
COGNIZANT TECH SOLUTIONS-A	CTSH	38,008.74	0.22%	0.00%	12.50%	12.50%	0.0271%
CITRIX SYSTEMS INC	CTXS	13,345.13	0.08%	0.00%	11.00%	11.00%	0.0084%
CVS HEALTH CORP	CVS	101,635.60	0.58%	1.81%	11.50%	13.41%	0.0776%
CHEVRON CORP	CVX	196,838.30	1.12%	4.10%	4.50%	8.69%	0.0974%
CONCHO RESOURCES INC	CXO	17,096.87	0.10%	0.00%	16.50%	16.50%	0.0161%
DOMINION RESOURCES INC/VA	D	44,148.15	0.25%	3.94%	8.00%	12.10%	0.0304%
DELTA AIR LINES INC	DAL	29,559.27	0.17%	2.09%	14.50%	16.74%	0.0282%
DU PONT (E.I.) DE NEMOURS	DD	60,448.64	0.34%	2.31%	7.00%	9.39%	0.0323%
DEERE & CO	DE	26,488.89	0.15%	2.85%	-1.50%	1.33%	0.0020%
DISCOVER FINANCIAL SERVICES	DFS	22,484.24	0.13%	2.06%	5.00%	7.11%	0.0091%
DOLLAR GENERAL CORP	DG	26,016.77	0.15%	1.15%	13.50%	14.73%	0.0218%
QUEST DIAGNOSTICS INC	DGX	11,354.73	0.06%	1.99%	10.00%	12.09%	0.0078%
DR HORTON INC	DHI	11,600.17	0.07%	1.02%	13.00%	14.09%	0.0093%
DANAHER CORP	DHR	N/A	N/A	0.00%	N/A	N/A	N/A
WALT DISNEY CO/THE	DIS	168,334.00	0.96%	1.43%	10.00%	11.50%	0.1102%
DISCOVERY COMMUNICATIONS-A	DISCA	10,698.84	0.06%	0.00%	17.00%	17.00%	0.0104%
DELPHI AUTOMOTIVE PLC	DLPH	19,348.80	0.11%	1.75%	14.50%	16.38%	0.0180%
DIGITAL REALTY TRUST INC	DLR	-	N/A	3.44%	N/A	N/A	N/A
DOLLAR TREE INC	DLTR	21,764.73	0.12%	0.00%	21.00%	21.00%	0.0260%
DUN & BRADSTREET CORP	DNB	4,631.43	0.03%	1.51%	5.00%	6.55%	0.0017%
DIAMOND OFFSHORE DRILLING	DO	3,547.22	0.02%	0.00%	11.50%	11.50%	0.0023%
DOVER CORP	DOV	11,117.98	0.06%	2.34%	2.00%	4.36%	0.0028%
DOW CHEMICAL CO/THE	DOW	60,273.41	0.34%	3.58%	9.50%	13.25%	0.0455%
DR PEPPER SNAPPLE GROUP INC	DPS	17,282.27	0.10%	2.31%	8.00%	10.40%	0.0102%
DARDEN RESTAURANTS INC	DRI	8,614.83	0.05%	2.94%	13.50%	16.64%	0.0082%
DTE ENERGY COMPANY	DTE	16,877.66	0.10%	3.28%	5.00%	8.36%	0.0080%
DUKE ENERGY CORP	DUK	56,532.45	0.32%	4.13%	4.50%	8.72%	0.0281%
DAVITA HEALTHCARE PARTNERS I	DVA	15,923.22	0.09%	0.00%	11.00%	11.00%	0.0100%
DEVON ENERGY CORP	DVN	20,331.20	0.12%	0.62%	1.00%	1.62%	0.0019%
ELECTRONIC ARTS INC	EA	22,860.78	0.13%	0.00%	17.00%	17.00%	0.0221%
EBAY INC	EBAY	28,403.55	0.16%	0.00%	3.50%	3.50%	0.0057%
ECOLAB INC	ECL	35,471.70	0.20%	1.16%	8.50%	9.71%	0.0196%
CONSOLIDATED EDISON INC	ED	22,596.84	0.13%	3.54%	1.50%	5.07%	0.0065%
EQUIFAX INC	EFX	15,108.24	0.09%	1.04%	9.50%	10.59%	0.0091%
EDISON INTERNATIONAL	EIX	24,106.76	0.14%	2.69%	3.50%	6.24%	0.0086%
ESTEE LAUDER COMPANIES-CL A	EL	35,052.88	0.20%	1.26%	8.00%	9.31%	0.0186%
EMC CORP/MA	EMC	54,410.58	0.31%	1.65%	3.50%	5.18%	0.0160%
EASTMAN CHEMICAL CO	EMN	10,789.86	0.06%	2.52%	9.50%	12.14%	0.0075%
EMERSON ELECTRIC CO	EMR	34,523.82	0.20%	3.54%	2.00%	5.58%	0.0110%
ENDO INTERNATIONAL PLC	ENDP	3,526.89	0.02%	0.00%	39.00%	39.00%	0.0078%
EOG RESOURCES INC	EOG	46,491.22	0.26%	0.91%	2.50%	3.42%	0.0091%
EQUINIX INC	EQIX	26,759.63	0.15%	1.82%	24.50%	26.54%	0.0404%
EQUITY RESIDENTIAL	EQR	-	N/A	3.10%	N/A	N/A	N/A
EQT CORP	EQT	12,648.38	0.07%	0.15%	12.00%	12.16%	0.0088%
EVERSOURCE ENERGY	ES	17,896.82	0.10%	3.26%	6.00%	9.36%	0.0095%
EXPRESS SCRIPTS HOLDING CO	ESRX	48,670.87	0.28%	0.00%	15.50%	15.50%	0.0430%
ESSEX PROPERTY TRUST INC	ESS	-	N/A	2.99%	N/A	N/A	N/A
E*TRADE FINANCIAL CORP	ETFC	7,320.79	0.04%	0.00%	17.50%	17.50%	0.0073%
EATON CORP PLC	ETN	28,771.56	0.16%	3.63%	5.00%	8.72%	0.0143%
ENTERGY CORP	ETR	13,966.07	0.08%	4.42%	3.50%	8.00%	0.0064%
EDWARDS LIFESCIENCES CORP	EW	20,995.05	0.12%	0.00%	17.00%	17.00%	0.0203%
EXELON CORP	EXC	32,223.90	0.18%	3.63%	7.00%	10.76%	0.0197%
EXPEDITORS INTL WASH INC	EXPD	8,898.35	0.05%	1.63%	11.00%	12.72%	0.0064%
EXPEDIA INC	EXPE	16,460.71	0.09%	0.87%	23.00%	23.97%	0.0225%
EXTRA SPACE STORAGE INC	EXR	-	N/A	3.59%	N/A	N/A	N/A

FORD MOTOR CO	F	53,235.99	0.30%	4.48%	7.00%	11.64%	0.0353%
FASTENAL CO	FAST	13,161.05	0.07%	2.63%	7.00%	9.72%	0.0073%
FACEBOOK INC-A	FB	329,128.80	1.87%	0.00%	34.00%	34.00%	0.6372%
FORTUNE BRANDS HOME & SECURI	FBHS	8,717.89	0.05%	1.13%	15.00%	16.21%	0.0080%
FREEPORT-MCMORAN INC	FCX	14,736.04	0.08%	0.00%	36.50%	36.50%	0.0306%
FEDEX CORP	FDX	50,209.02	0.29%	1.01%	12.50%	13.57%	0.0388%
FIRSTENERGY CORP	FE	14,083.45	0.08%	4.34%	9.00%	13.54%	0.0109%
F5 NETWORKS INC	FFIV	8,134.17	0.05%	0.00%	9.00%	9.00%	0.0042%
FIDELITY NATIONAL INFO SERV	FIS	24,020.75	0.14%	1.41%	13.50%	15.01%	0.0205%
FISERV INC	FISV	23,555.49	0.13%	0.00%	9.50%	9.50%	0.0127%
FIFTH THIRD BANCORP	FITB	14,723.70	0.08%	2.93%	3.00%	5.97%	0.0050%
FOOT LOCKER INC	FL	7,226.46	0.04%	2.07%	9.00%	11.16%	0.0046%
FLIR SYSTEMS INC	FLIR	4,342.20	0.02%	1.59%	8.00%	9.65%	0.0024%
FLUOR CORP	FLR	7,376.04	0.04%	1.59%	1.50%	3.10%	0.0013%
FLOWSERVE CORP	FLS	6,517.90	0.04%	1.51%	2.50%	4.03%	0.0015%
FMC CORP	FMC	6,593.97	0.04%	1.38%	4.50%	5.91%	0.0022%
TWENTY-FIRST CENTURY FOX-A	FOXA	31,995.17	0.18%	1.03%	10.50%	11.58%	0.0211%
FEDERAL REALTY INVS TRUST	FRT	-	N/A	2.52%	N/A	N/A	N/A
FIRST SOLAR INC	FSLR	4,972.96	0.03%	0.00%	8.50%	8.50%	0.0024%
FMC TECHNOLOGIES INC	FTI	6,358.48	0.04%	0.00%	-1.00%	-1.00%	-0.0004%
FRONTIER COMMUNICATIONS CORP	FTR	5,980.56	0.03%	8.24%	13.50%	22.30%	0.0076%
AGL RESOURCES INC	GAS	7,962.40	0.05%	3.21%	5.00%	8.29%	0.0038%
GENERAL DYNAMICS CORP	GD	42,723.34	0.24%	2.18%	7.00%	9.26%	0.0225%
GENERAL ELECTRIC CO	GE	286,812.50	1.63%	2.95%	9.50%	12.59%	0.2056%
GENERAL GROWTH PROPERTIES	GGP	-	N/A	2.69%	N/A	N/A	N/A
GILEAD SCIENCES INC	GILD	112,382.80	0.64%	2.26%	10.00%	12.37%	0.0792%
GENERAL MILLS INC	GIS	39,634.68	0.23%	2.76%	5.00%	7.83%	0.0177%
CORNING INC	GLW	22,349.25	0.13%	2.60%	6.00%	8.68%	0.0110%
GENERAL MOTORS CO	GM	45,917.58	0.26%	5.10%	11.00%	16.38%	0.0428%
ALPHABET INC-CL A	GOOGL	N/A	N/A	0.00%	N/A	N/A	N/A
GENUINE PARTS CO	GPC	14,874.02	0.08%	2.65%	7.00%	9.74%	0.0083%
GLOBAL PAYMENTS INC	GPN	9,809.47	0.06%	0.05%	14.00%	14.05%	0.0079%
GAP INC/THE	GPS	8,330.14	0.05%	4.44%	1.50%	5.97%	0.0028%
GARMIN LTD	GRMN	8,188.27	0.05%	4.76%	-1.00%	3.74%	0.0017%
GOLDMAN SACHS GROUP INC	GS	63,746.54	0.36%	1.70%	7.00%	8.76%	0.0318%
GOODYEAR TIRE & RUBBER CO	GT	7,291.06	0.04%	1.13%	8.50%	9.68%	0.0040%
WW GRAINGER INC	GWW	13,856.93	0.08%	2.16%	6.00%	8.22%	0.0065%
HALLIBURTON CO	HAL	39,330.72	0.22%	1.57%	8.00%	9.63%	0.0216%
HARMAN INTERNATIONAL	HAR	5,420.74	0.03%	1.82%	17.00%	18.97%	0.0059%
HASBRO INC	HAS	10,763.36	0.06%	2.37%	11.00%	13.50%	0.0083%
HUNTINGTON BANCSHARES INC	HBAN	7,512.78	0.04%	3.29%	9.00%	12.44%	0.0053%
HANESBRANDS INC	HBI	9,992.77	0.06%	1.66%	11.50%	13.26%	0.0075%
HCA HOLDINGS INC	HCA	31,393.59	0.18%	0.00%	11.00%	11.00%	0.0197%
WELLTOWER INC	HCN	-	N/A	4.78%	N/A	N/A	N/A
HCP INC	HCP	-	0.00%	6.74%	74.00%	83.23%	0.0000%
HOME DEPOT INC	HD	159,721.10	0.91%	2.15%	12.50%	14.78%	0.1345%
HESS CORP	HES	18,930.29	0.11%	1.67%	-1.00%	0.66%	0.0007%
HARTFORD FINANCIAL SVCS GRP	HIG	17,786.31	0.10%	1.87%	11.50%	13.48%	0.0137%
HARLEY-DAVIDSON INC	HOG	8,485.88	0.05%	2.99%	9.00%	12.12%	0.0059%
HOLOGIC INC	HOLX	9,965.05	0.06%	0.00%	21.00%	21.00%	0.0119%
HONEYWELL INTERNATIONAL INC	HON	89,411.34	0.51%	2.03%	8.50%	10.62%	0.0541%
STARWOOD HOTELS & RESORTS	HOT	12,871.33	0.07%	1.98%	5.50%	7.53%	0.0055%
HELMERICH & PAYNE	HP	7,473.06	0.04%	4.05%	-6.00%	-2.07%	-0.0009%
HEWLETT PACKARD ENTERPRIS	HPE	33,876.60	N/A	1.12%	N/A	N/A	N/A
HP INC	HPQ	22,157.45	N/A	3.86%	N/A	N/A	N/A
H&R BLOCK INC	HRB	5,127.65	0.03%	3.85%	8.00%	12.00%	0.0035%
HORMEL FOODS CORP	HRL	18,334.22	0.10%	1.79%	14.00%	15.92%	0.0166%
HARRIS CORP	HRS	10,473.83	0.06%	2.47%	7.50%	10.06%	0.0060%
HENRY SCHEIN INC	HSIC	14,574.67	0.08%	0.00%	9.00%	9.00%	0.0075%
HOST HOTELS & RESORTS INC	HST	-	N/A	4.72%	N/A	N/A	N/A
HERSHEY CO/THE	HSY	20,796.21	0.12%	2.40%	6.00%	8.47%	0.0100%
HUMANA INC	HUM	27,915.93	0.16%	0.62%	9.50%	10.15%	0.0161%
INTL BUSINESS MACHINES CORP	IBM	149,130.10	0.85%	3.64%	0.50%	4.15%	0.0352%
INTERCONTINENTAL EXCHANGE IN	ICE	30,469.95	0.17%	1.33%	14.00%	15.42%	0.0268%
INTL FLAVORS & FRAGRANCES	IFF	10,150.16	0.06%	1.76%	4.50%	6.30%	0.0036%
ILLUMINA INC	ILMN	21,578.05	0.12%	0.00%	22.50%	22.50%	0.0276%
INTEL CORP	INTC	155,580.80	0.89%	3.15%	9.50%	12.80%	0.1134%
INTUIT INC	INTU	28,378.53	0.16%	1.10%	13.00%	14.17%	0.0229%
INTERNATIONAL PAPER CO	IP	17,799.25	0.10%	4.07%	15.00%	19.38%	0.0196%
INTERPUBLIC GROUP OF COS INC	IPG	9,899.16	0.06%	2.56%	13.00%	15.73%	0.0089%
INGERSOLL-RAND PLC	IR	17,056.41	0.10%	1.93%	8.50%	10.51%	0.0102%
IRON MOUNTAIN INC	IRM	8,179.07	0.05%	5.03%	13.00%	18.36%	0.0085%
INTUITIVE SURGICAL INC	ISRG	25,196.29	0.14%	0.00%	11.50%	11.50%	0.0165%
ILLINOIS TOOL WORKS	ITW	38,387.91	0.22%	2.06%	10.00%	12.16%	0.0266%
INVESCO LTD	IVZ	14,525.65	0.08%	3.78%	7.00%	10.91%	0.0090%
HUNT (JB) TRANSPRT SVCS INC	JBHT	9,096.81	0.05%	1.09%	11.00%	12.15%	0.0063%
JOHNSON CONTROLS INC	JCI	29,170.16	0.17%	2.58%	9.50%	12.20%	0.0203%
JACOBS ENGINEERING GROUP INC	JEC	6,485.95	0.04%	0.00%	4.00%	4.00%	0.0015%
JOHNSON & JOHNSON	JNJ	322,995.20	1.84%	2.77%	8.50%	11.39%	0.2094%
JUNIPER NETWORKS INC	JNPR	9,286.65	0.05%	1.79%	10.00%	11.88%	0.0063%
JPMORGAN CHASE & CO	JPM	234,209.00	1.33%	3.00%	6.50%	9.60%	0.1280%
NORDSTROM INC	JWN	6,632.55	0.04%	3.92%	4.00%	8.00%	0.0030%
KELLOGG CO	K	27,240.50	0.16%	2.62%	5.00%	7.69%	0.0119%
KEYCORP	KEY	10,099.06	0.06%	2.84%	7.50%	10.45%	0.0060%
KRAFT HEINZ CO/THE	KHC	104,851.30	N/A	2.72%	N/A	N/A	N/A
KIMCO REALTY CORP	KIM	-	N/A	3.57%	N/A	N/A	N/A
KLA-TENCOR CORP	KLAC	11,654.75	0.07%	2.78%	12.50%	15.45%	0.0103%
KIMBERLY-CLARK CORP	KMB	48,242.74	0.27%	2.75%	10.00%	12.89%	0.0354%
KINDER MORGAN INC	KMI	42,132.49	0.24%	2.65%	13.00%	15.82%	0.0380%
CARMAX INC	KMX	9,147.57	0.05%	0.00%	12.50%	12.50%	0.0065%
COCA-COLA CO/THE	KO	195,286.60	1.11%	3.11%	4.00%	7.17%	0.0798%
MICHAEL KORS HOLDINGS LTD	KORS	9,117.41	0.05%	0.00%	9.00%	9.00%	0.0047%
KROGER CO	KR	33,525.89	0.19%	1.36%	10.50%	11.93%	0.0228%

KOHLS CORP	KSS	6,892.65	0.04%	5.44%	8.00%	13.66%	0.0054%
KANSAS CITY SOUTHERN	KSU	9,838.50	0.06%	1.45%	9.00%	10.52%	0.0059%
LOEWS CORP	L	13,763.21	0.08%	0.61%	12.50%	13.15%	0.0103%
L BRANDS INC	LB	19,915.20	0.11%	3.47%	8.00%	11.61%	0.0132%
LEGGETT & PLATT INC	LEG	6,865.40	0.04%	2.66%	11.00%	13.81%	0.0054%
LENNAR CORP-A	LEN	10,001.15	0.06%	0.34%	12.50%	12.86%	0.0073%
LABORATORY CRP OF AMER HLDGS	LH	13,393.48	0.08%	0.00%	9.50%	9.50%	0.0072%
LKQ CORP	LKQ	10,302.21	0.06%	0.00%	15.00%	15.00%	0.0088%
L-3 COMMUNICATIONS HOLDINGS	LLL	11,161.85	0.06%	1.94%	6.50%	8.50%	0.0054%
LINEAR TECHNOLOGY CORP	LLTC	11,399.80	0.06%	2.69%	5.50%	8.26%	0.0054%
ELI LILLY & CO	LLY	81,617.71	0.46%	2.76%	9.50%	12.39%	0.0576%
LEGG MASON INC	LM	3,512.10	0.02%	2.70%	10.50%	13.34%	0.0027%
LOCKHEED MARTIN CORP	LMT	73,068.72	0.42%	2.88%	8.00%	11.00%	0.0457%
LINCOLN NATIONAL CORP	LNC	10,604.65	0.06%	2.34%	7.00%	9.42%	0.0057%
LOWE'S COS INC	LOW	70,241.59	0.40%	1.78%	14.00%	15.90%	0.0636%
LAM RESEARCH CORP	LRCX	13,889.43	0.08%	1.38%	16.00%	17.49%	0.0138%
LEUCADIA NATIONAL CORP	LUK	N/A	N/A	0.00%	N/A	N/A	N/A
SOUTHWEST AIRLINES CO	LUV	26,473.32	0.15%	1.01%	17.50%	18.60%	0.0280%
LEVEL 3 COMMUNICATIONS INC	LVLT	18,724.91	0.11%	0.00%	38.00%	38.00%	0.0405%
LYONDELLBASELL INDU-CL A	LYB	33,845.89	0.19%	4.30%	6.50%	10.94%	0.0211%
MACY'S INC	M	10,294.22	0.06%	4.52%	3.00%	7.59%	0.0044%
MASTERCARD INC-CLASS A	MA	105,472.40	0.60%	0.79%	11.00%	11.83%	0.0711%
MACERICH CO/THE	MAC	-	N/A	3.39%	N/A	N/A	N/A
MARRIOTT INTERNATIONAL -CL A	MAR	17,529.30	0.10%	1.74%	12.50%	14.35%	0.0143%
MASCO CORP	MAS	10,347.48	0.06%	1.21%	14.50%	15.80%	0.0093%
MATTEL INC	MAT	11,022.15	0.06%	4.69%	6.50%	11.34%	0.0071%
MCDONALD'S CORP	MCD	106,398.10	0.61%	2.97%	6.00%	9.06%	0.0549%
MICROCHIP TECHNOLOGY INC	MCHP	10,752.89	0.06%	2.73%	8.00%	10.84%	0.0066%
MCKESSON CORP	MCK	42,060.01	0.24%	0.61%	12.00%	12.65%	0.0303%
MOODY'S CORP	MCO	19,763.05	0.11%	1.46%	7.50%	9.01%	0.0101%
MONDELEZ INTERNATIONAL INC-A	MDLZ	69,723.36	0.40%	1.65%	11.50%	13.24%	0.0526%
MEDTRONIC PLC	MDT	120,167.50	0.68%	1.84%	7.00%	8.90%	0.0609%
METLIFE INC	MET	48,521.94	0.28%	3.62%	6.50%	10.24%	0.0283%
MOHAWK INDUSTRIES INC	MHK	14,657.12	0.08%	0.00%	10.50%	10.50%	0.0088%
MEAD JOHNSON NUTRITION CO	MJN	16,543.49	0.09%	1.86%	6.50%	8.42%	0.0079%
MCCORMICK & CO-NON VTG SHRS	MKC	12,997.43	0.07%	1.68%	7.50%	9.24%	0.0068%
MARTIN MARIETTA MATERIALS	MLM	11,935.77	0.07%	0.85%	24.50%	25.45%	0.0173%
MARSH & MCLENNAN COS	MMC	35,416.49	0.20%	2.00%	9.00%	11.09%	0.0224%
3M CO	MMM	105,600.30	0.60%	2.55%	8.50%	11.16%	0.0671%
MALLINCKRODT PLC	MNK	6,417.92	N/A	0.00%	N/A	N/A	N/A
MONSTER BEVERAGE CORP	MNST	31,962.72	0.18%	0.00%	13.50%	13.50%	0.0246%
ALTRIA GROUP INC	MO	129,749.40	0.74%	3.44%	9.50%	13.10%	0.0968%
MONSANTO CO	MON	47,669.84	0.27%	1.98%	6.00%	8.04%	0.0218%
MOSAIC CO/THE	MOS	9,794.34	0.06%	4.29%	5.00%	9.40%	0.0052%
MARATHON PETROLEUM CORP	MPC	19,408.60	0.11%	3.55%	6.50%	10.17%	0.0112%
MERCK & CO. INC.	MRK	159,747.80	0.91%	3.19%	6.00%	9.29%	0.0845%
MARATHON OIL CORP	MRO	12,943.58	0.07%	1.31%	9.00%	10.37%	0.0076%
MORGAN STANLEY	MS	52,896.05	0.30%	2.20%	14.50%	16.86%	0.0508%
MICROSOFT CORP	MSFT	408,531.70	2.33%	2.77%	7.00%	9.87%	0.2295%
MOTOROLA SOLUTIONS INC	MSI	11,874.54	0.07%	2.54%	9.00%	11.65%	0.0079%
M & T BANK CORP	MTB	19,161.59	0.11%	2.33%	5.00%	7.39%	0.0081%
MICRON TECHNOLOGY INC	MU	15,314.50	0.09%	0.00%	1.00%	1.00%	0.0009%
MURPHY OIL CORP	MUR	5,580.84	N/A	4.32%	N/A	N/A	N/A
MYLAN NV	MYL	22,681.18	0.13%	0.00%	20.50%	20.50%	0.0265%
NAVIENT CORP	NAVI	4,075.50	N/A	5.18%	N/A	N/A	N/A
NOBLE ENERGY INC	NBL	15,999.35	N/A	1.08%	N/A	N/A	N/A
NASDAQ INC	NDAQ	10,595.64	0.06%	1.99%	10.00%	12.09%	0.0073%
NEXTERA ENERGY INC	NEE	57,076.41	0.33%	2.90%	6.00%	8.99%	0.0292%
NEWMONT MINING CORP	NEM	18,775.49	0.11%	0.28%	-1.00%	-0.72%	-0.0008%
NETFLIX INC	NFLX	39,256.97	0.22%	0.00%	35.00%	35.00%	0.0782%
NEWFIELD EXPLORATION CO	NFX	8,506.06	0.05%	0.00%	11.50%	11.50%	0.0056%
NISOURCE INC	NI	8,091.85	0.05%	2.62%	1.50%	4.14%	0.0019%
NIKE INC -CL B	NKE	91,192.20	0.52%	1.18%	15.00%	16.27%	0.0845%
NIELSEN HOLDINGS PLC	NLSN	19,388.05	0.11%	2.31%	9.00%	11.41%	0.0126%
NORTHROP GRUMMAN CORP	NOC	38,823.99	0.22%	1.68%	7.50%	9.24%	0.0204%
NATIONAL OILWELL VARCO INC	NOV	13,762.91	0.08%	0.55%	-9.00%	-8.47%	-0.0066%
NRG ENERGY INC	NRG	4,575.58	N/A	0.83%	N/A	N/A	N/A
NORFOLK SOUTHERN CORP	NSC	25,729.21	0.15%	2.71%	6.50%	9.30%	0.0136%
NETAPP INC	NTAP	7,571.82	N/A	2.92%	N/A	N/A	N/A
NORTHERN TRUST CORP	NTRS	16,322.85	0.09%	2.01%	7.50%	9.59%	0.0089%
NUCOR CORP	NUE	16,055.42	0.09%	2.97%	24.50%	27.83%	0.0254%
NVIDIA CORP	NVDA	25,893.66	0.15%	0.95%	11.50%	12.50%	0.0184%
NEWELL BRANDS INC	NWL	13,265.17	0.08%	1.54%	14.00%	15.65%	0.0118%
NEWS CORP - CLASS A	NWSA	6,877.82	0.04%	1.69%	27.50%	29.42%	0.0115%
REALTY INCOME CORP	O	-	N/A	3.72%	N/A	N/A	N/A
OWENS-ILLINOIS INC	OI	3,206.00	0.02%	0.00%	6.00%	6.00%	0.0011%
ONEOK INC	OKE	9,845.24	0.06%	5.36%	12.50%	18.20%	0.0102%
OMNICOM GROUP	OMC	20,199.24	0.12%	2.66%	9.00%	11.78%	0.0135%
ORACLE CORP	ORCL	169,439.00	0.96%	1.47%	4.50%	6.00%	0.0579%
O'REILLY AUTOMOTIVE INC	ORLY	25,560.11	0.15%	0.00%	11.00%	11.00%	0.0160%
OCCIDENTAL PETROLEUM CORP	OXY	59,816.31	0.34%	3.91%	4.00%	7.99%	0.0272%
PAYCHEX INC	PAYX	20,271.21	0.12%	3.20%	9.00%	12.34%	0.0142%
PEOPLE'S UNITED FINANCIAL	PBCT	4,940.06	0.03%	4.27%	10.50%	14.99%	0.0042%
PITNEY BOWES INC	PBI	3,498.79	0.02%	4.12%	4.00%	8.20%	0.0016%
PACCAR INC	PCAR	19,745.04	0.11%	3.90%	7.00%	11.04%	0.0124%
P G & E CORP	PCG	30,792.06	0.18%	3.16%	12.00%	15.35%	0.0269%
PRICELINE GROUP INC/THE	PCLN	69,006.74	0.39%	0.00%	15.50%	15.50%	0.0609%
PATTERSON COS INC	PDCO	4,801.85	0.03%	2.04%	9.50%	11.64%	0.0032%
PUBLIC SERVICE ENTERPRISE GP	PEG	22,371.50	0.13%	3.75%	3.00%	6.81%	0.0087%
PEPSICO INC	PEP	151,020.30	0.86%	2.88%	7.00%	9.98%	0.0858%
PFIZER INC	PFE	209,783.10	1.19%	3.47%	12.00%	15.68%	0.1873%
PRINCIPAL FINANCIAL GROUP	PFG	12,928.61	0.07%	3.50%	5.00%	8.59%	0.0063%
PROCTER & GAMBLE CO/THE	PG	224,154.60	1.28%	3.18%	6.50%	9.78%	0.1249%

PROGRESSIVE CORP	PGR	18,941.67	0.11%	2.74%	8.50%	11.36%	0.0122%
PARKER HANNIFIN CORP	PH	15,354.98	0.09%	2.21%	5.50%	7.77%	0.0068%
PULTEGROUP INC	PHM	7,001.58	0.04%	1.93%	11.00%	13.04%	0.0052%
PERKINELMER INC	PKI	5,911.88	0.03%	0.52%	6.50%	7.04%	0.0024%
PROLOGIS INC	PLD	-	N/A	3.35%	N/A	N/A	N/A
PHILIP MORRIS INTERNATIONAL	PM	158,073.20	0.90%	4.00%	5.00%	9.10%	0.0819%
PNC FINANCIAL SERVICES GROUP	PNC	43,248.33	0.25%	2.35%	4.00%	6.40%	0.0158%
PENTAIR PLC	PNR	11,114.86	0.06%	2.15%	12.50%	14.78%	0.0094%
PINNACLE WEST CAPITAL	PNW	8,592.23	0.05%	3.31%	4.00%	7.38%	0.0036%
PPG INDUSTRIES INC	PPG	29,591.53	0.17%	1.44%	9.50%	11.01%	0.0185%
PPL CORP	PPL	26,334.60	0.15%	3.93%	4.00%	8.01%	0.0120%
PERRIGO CO PLC	PRGO	13,937.28	0.08%	0.61%	15.00%	15.66%	0.0124%
PRUDENTIAL FINANCIAL INC	PRU	34,100.08	0.19%	3.64%	2.00%	5.68%	0.0110%
PUBLIC STORAGE	PSA	-	N/A	2.99%	N/A	N/A	N/A
PHILLIPS 66	PSX	42,503.73	0.24%	3.18%	2.50%	5.72%	0.0138%
PVH CORP	PVH	8,320.40	0.05%	0.15%	5.50%	5.65%	0.0027%
QUANTA SERVICES INC	PWR	3,702.43	0.02%	0.00%	8.50%	8.50%	0.0018%
PRAXAIR INC	PX	32,862.53	0.19%	2.69%	6.50%	9.28%	0.0174%
PIONEER NATURAL RESOURCES CO	PXD	26,265.62	0.15%	0.05%	18.50%	18.55%	0.0278%
PAYPAL HOLDINGS INC	PYPL	44,285.29	N/A	0.00%	N/A	N/A	N/A
QUALCOMM INC	QCOM	81,491.85	0.46%	3.82%	4.50%	8.41%	0.0390%
QORVO INC	QRVO	7,987.33	N/A	0.00%	N/A	N/A	N/A
RYDER SYSTEM INC	R	3,536.34	0.02%	2.49%	9.00%	11.60%	0.0023%
REYNOLDS AMERICAN INC	RAI	72,566.01	0.41%	3.30%	10.00%	13.47%	0.0556%
ROYAL CARIBBEAN CRUISES LTD	RCL	16,652.52	0.09%	1.94%	16.50%	18.60%	0.0176%
REGENERON PHARMACEUTICALS	REGN	36,813.99	0.21%	0.00%	23.00%	23.00%	0.0482%
REGIONS FINANCIAL CORP	RF	12,046.98	0.07%	2.86%	7.50%	10.47%	0.0072%
ROBERT HALF INTL INC	RHI	5,212.01	0.03%	2.24%	11.00%	13.36%	0.0040%
RED HAT INC	RHT	14,203.09	0.08%	0.00%	16.50%	16.50%	0.0133%
TRANSOCEAN LTD	RIG	4,391.94	0.03%	0.00%	-19.00%	-19.00%	-0.0048%
RALPH LAUREN CORP	RL	8,062.03	0.05%	2.16%	4.50%	6.71%	0.0031%
ROCKWELL AUTOMATION INC	ROK	15,699.42	0.09%	2.41%	3.00%	5.45%	0.0049%
ROPER TECHNOLOGIES INC	ROP	17,498.66	0.10%	0.69%	7.00%	7.71%	0.0077%
ROSS STORES INC	ROST	21,601.51	0.12%	1.04%	9.00%	10.09%	0.0124%
RANGE RESOURCES CORP	RRC	7,711.03	0.04%	0.18%	12.00%	12.19%	0.0054%
REPUBLIC SERVICES INC	RSG	17,173.32	0.10%	2.53%	8.50%	11.14%	0.0109%
RAYTHEON COMPANY	RTN	40,044.51	0.23%	2.17%	9.00%	11.27%	0.0257%
STARBUCKS CORP	SBUX	82,202.38	0.47%	1.59%	16.50%	18.22%	0.0853%
SCANA CORP	SCG	10,197.13	0.06%	3.27%	4.50%	7.84%	0.0046%
SCHWAB (CHARLES) CORP	SCHW	39,234.18	0.22%	0.94%	12.00%	13.00%	0.0290%
SPECTRA ENERGY CORP	SE	23,981.04	0.14%	4.62%	11.50%	16.39%	0.0224%
SEALED AIR CORP	SEE	9,433.96	0.05%	1.34%	16.00%	17.45%	0.0094%
SHERWIN-WILLIAMS CO/THE	SHW	26,724.58	0.15%	1.22%	11.00%	12.29%	0.0187%
SIGNET JEWELERS LTD	SIG	6,786.30	0.04%	1.20%	15.00%	16.29%	0.0063%
JM SMUCKER CO/THE	SJM	17,541.03	0.10%	1.89%	7.00%	8.96%	0.0089%
SCHLUMBERGER LTD	SLB	99,673.26	0.57%	2.51%	10.00%	12.64%	0.0717%
SL GREEN REALTY CORP	SLG	-	N/A	2.73%	N/A	N/A	N/A
SNAP-ON INC	SNA	9,047.59	0.05%	1.57%	10.00%	11.65%	0.0060%
SCRIPPS NETWORKS INTER-CL A	SNI	8,019.46	0.05%	1.61%	9.00%	10.68%	0.0049%
SOUTHERN CO/THE	SO	46,903.71	0.27%	4.43%	2.50%	6.99%	0.0187%
SIMON PROPERTY GROUP INC	SPG	-	N/A	3.06%	N/A	N/A	N/A
S&P GLOBAL INC	SPGI	29,258.99	0.17%	1.30%	11.00%	12.37%	0.0206%
STAPLES INC	SPLS	5,784.27	N/A	5.36%	N/A	N/A	N/A
STERICYCLE INC	SRCL	8,769.73	0.05%	0.00%	9.00%	9.00%	0.0045%
SEMPRA ENERGY	SRE	27,658.92	0.16%	2.77%	10.00%	12.91%	0.0203%
SUNTRUST BANKS INC	STI	21,840.19	0.12%	2.36%	7.00%	9.44%	0.0117%
ST JUDE MEDICAL INC	STJ	22,281.27	0.13%	1.63%	5.50%	7.17%	0.0091%
STATE STREET CORP	STT	23,840.58	0.14%	2.39%	5.50%	7.96%	0.0108%
SEAGATE TECHNOLOGY	STX	7,306.30	0.04%	10.29%	-2.00%	8.19%	0.0034%
CONSTELLATION BRANDS INC-A	STZ	31,077.11	0.18%	1.04%	16.50%	17.63%	0.0312%
STANLEY BLACK & DECKER INC	SWK	17,270.96	0.10%	1.91%	8.50%	10.49%	0.0103%
SKYWORKS SOLUTIONS INC	SWKS	12,783.34	0.07%	1.55%	17.50%	19.19%	0.0140%
SOUTHWESTERN ENERGY CO	SWN	5,287.44	0.03%	0.00%	-5.00%	-5.00%	-0.0015%
SYNCHRONY FINANCIAL	SYF	21,679.58	N/A	0.00%	N/A	N/A	N/A
STRYKER CORP	SYK	44,274.12	0.25%	1.28%	18.50%	19.90%	0.0502%
SYMANTEC CORP	SYMC	12,998.88	0.07%	1.41%	-1.00%	0.40%	0.0003%
SYSCO CORP	SYY	28,411.44	0.16%	2.51%	10.50%	13.14%	0.0213%
AT&T INC	T	257,822.60	1.47%	4.63%	6.50%	11.28%	0.1656%
MOLSON COORS BREWING CO -B	TAP	21,888.66	0.12%	1.61%	8.00%	9.67%	0.0121%
TERADATA CORP	TDC	3,695.66	0.02%	0.00%	3.50%	3.50%	0.0007%
TRANSDIGM GROUP INC	TDG	14,054.79	0.08%	0.00%	20.50%	20.50%	0.0164%
TECO ENERGY INC	TE	6,516.29	0.04%	3.36%	7.50%	10.99%	0.0041%
TE CONNECTIVITY LTD	TEL	22,522.56	0.13%	2.35%	9.00%	11.46%	0.0147%
TEGNA INC	TGNA	4,984.92	0.03%	2.44%	1.00%	3.45%	0.0010%
TARGET CORP	TGT	41,420.29	0.24%	3.44%	11.00%	14.63%	0.0345%
TIFFANY & CO	TIF	7,891.38	0.04%	2.87%	7.50%	10.48%	0.0047%
TJX COMPANIES INC	TJX	50,824.06	0.29%	1.35%	10.00%	11.42%	0.0330%
TORCHMARK CORP	TMK	7,554.99	0.04%	0.90%	7.00%	7.93%	0.0034%
THERMO FISHER SCIENTIFIC INC	TMO	59,868.92	0.34%	0.39%	9.00%	9.41%	0.0321%
TRIPADVISOR INC	TRIP	9,611.83	0.05%	0.00%	16.50%	16.50%	0.0090%
T ROWE PRICE GROUP INC	TROW	18,242.52	0.10%	2.98%	7.50%	10.59%	0.0110%
TRAVELERS COS INC/THE	TRV	33,289.74	0.19%	2.35%	1.50%	3.87%	0.0073%
TRACTOR SUPPLY COMPANY	TSCO	12,469.07	0.07%	1.06%	14.00%	15.13%	0.0107%
TYSON FOODS INC-CL A	TSN	23,443.20	0.13%	1.01%	12.50%	13.57%	0.0181%
TESORO CORP	TSO	9,327.92	0.05%	2.57%	5.50%	8.14%	0.0043%
TOTAL SYSTEM SERVICES INC	TSS	9,681.75	0.06%	0.76%	12.00%	12.81%	0.0071%
TIME WARNER INC	TWX	57,636.45	0.33%	2.20%	11.50%	13.83%	0.0454%
TEXAS INSTRUMENTS INC	TXN	63,715.95	0.36%	2.40%	7.50%	9.99%	0.0362%
TEXTRON INC	TXT	10,324.26	0.06%	0.21%	15.50%	15.73%	0.0092%
TYCO INTERNATIONAL PLC	TYC	18,682.19	0.11%	1.87%	9.50%	11.46%	0.0122%
UNDER ARMOUR INC-CLASS A	UA	16,676.17	0.09%	0.00%	24.50%	24.50%	0.0233%
UNITED CONTINENTAL HOLDINGS	UAL	15,326.41	0.09%	0.00%	7.00%	7.00%	0.0061%
UDR INC	UDR	-	N/A	3.35%	N/A	N/A	N/A

UNIVERSAL HEALTH SERVICES-B	UHS	13,419.52	0.08%	0.29%	11.50%	11.81%	0.0090%
ULTA SALON COSMETICS & FRAGR	ULTA	15,160.26	0.09%	0.00%	18.00%	18.00%	0.0155%
UNITEDHEALTH GROUP INC	UNH	132,787.30	0.76%	1.80%	14.00%	15.93%	0.1204%
UNUM GROUP	UNM	8,444.31	0.05%	2.08%	11.00%	13.19%	0.0063%
UNION PACIFIC CORP	UNP	74,456.73	0.42%	2.49%	7.00%	9.58%	0.0406%
UNITED PARCEL SERVICE-CL B	UPS	94,782.48	0.54%	2.95%	9.50%	12.59%	0.0680%
URBAN OUTFITTERS INC	URBN	3,150.45	0.02%	0.00%	13.50%	13.50%	0.0024%
UNITED RENTALS INC	URI	6,455.70	0.04%	0.00%	13.00%	13.00%	0.0048%
US BANCORP	USB	73,142.62	0.42%	2.51%	4.50%	7.07%	0.0294%
UNITED TECHNOLOGIES CORP	UTX	85,636.50	0.49%	2.58%	6.50%	9.16%	0.0447%
VISA INC-CLASS A SHARES	V	169,680.90	0.97%	0.77%	12.00%	12.82%	0.1238%
VARIAN MEDICAL SYSTEMS INC	VAR	8,055.82	0.05%	0.00%	7.50%	7.50%	0.0034%
VF CORP	VFC	27,117.84	0.15%	2.28%	11.00%	13.41%	0.0207%
VIACOM INC-CLASS B	VIAB	17,222.81	0.10%	3.68%	5.00%	8.77%	0.0086%
VALERO ENERGY CORP	VLO	25,232.42	0.14%	4.47%	5.50%	10.09%	0.0145%
VULCAN MATERIALS CO	VMC	15,873.75	0.09%	0.67%	33.50%	34.28%	0.0310%
VORNADO REALTY TRUST	VNO	18,675.11	0.11%	2.55%	22.50%	25.34%	0.0269%
VERISK ANALYTICS INC	VRSK	13,460.24	0.08%	0.00%	11.00%	11.00%	0.0084%
VERISIGN INC	VRSN	9,502.96	0.05%	0.00%	11.50%	11.50%	0.0062%
VERTEX PHARMACEUTICALS INC	VRTX	21,810.71	N/A	0.00%	N/A	N/A	N/A
VENTAS INC	VTR	-	N/A	4.27%	N/A	N/A	N/A
VERIZON COMMUNICATIONS INC	VZ	222,850.70	1.27%	4.13%	3.00%	7.19%	0.0913%
WATERS CORP	WAT	11,199.19	0.06%	0.00%	9.00%	9.00%	0.0057%
WALGREENS BOOTS ALLIANCE INC	WBA	91,835.88	0.52%	1.69%	13.00%	14.80%	0.0774%
WESTERN DIGITAL CORP	WDC	11,838.73	0.07%	3.94%	-0.50%	3.43%	0.0023%
WEC ENERGY GROUP INC	WEC	19,816.32	0.11%	3.23%	6.00%	9.33%	0.0105%
WELLS FARGO & CO	WFC	243,186.50	1.38%	3.17%	5.00%	8.25%	0.1142%
WHOLE FOODS MARKET INC	WFM	9,961.62	0.06%	1.83%	8.00%	9.90%	0.0056%
WHIRLPOOL CORP	WHR	13,588.80	0.08%	2.24%	11.50%	13.87%	0.0107%
WILLIS TOWERS WATSON PLC	WLTW	N/A	N/A	0.00%	N/A	N/A	N/A
WASTE MANAGEMENT INC	WM	28,217.74	0.16%	2.62%	7.50%	10.22%	0.0164%
WILLIAMS COS INC	WMB	16,335.00	0.09%	12.12%	16.50%	29.62%	0.0276%
WAL-MART STORES INC	WMT	225,312.50	1.28%	2.77%	2.00%	4.80%	0.0616%
WESTROCK CO	WRK	10,477.13	N/A	3.61%	N/A	N/A	N/A
WESTERN UNION CO	WU	9,529.15	0.05%	3.30%	8.00%	11.43%	0.0062%
WEYERHAEUSER CO	WY	22,406.98	0.13%	4.20%	10.50%	14.92%	0.0190%
WYNDHAM WORLDWIDE CORP	WYN	8,044.87	0.05%	2.78%	5.50%	8.36%	0.0038%
WYNN RESORTS LTD	WYNN	10,350.01	0.06%	1.97%	6.50%	8.53%	0.0050%
CIMAREX ENERGY CO	XEC	11,405.30	0.06%	0.27%	11.00%	11.28%	0.0073%
XCEL ENERGY INC	XEL	21,689.59	0.12%	3.23%	5.50%	8.82%	0.0109%
XL GROUP PLC	XL	9,809.11	0.06%	2.40%	9.00%	11.51%	0.0064%
XILINX INC	XLNX	12,034.91	0.07%	2.78%	6.00%	8.86%	0.0061%
EXXON MOBIL CORP	XOM	380,694.60	2.17%	3.27%	5.00%	8.35%	0.1811%
DENTSPLY SIRONA INC	XRAY	15,037.98	0.09%	0.48%	8.00%	8.50%	0.0073%
XEROX CORP	XRX	10,150.28	0.06%	3.19%	4.50%	7.76%	0.0045%
XYLEM INC	XYL	8,292.02	0.05%	1.34%	9.50%	10.90%	0.0051%
YAHOO! INC	YHOO	35,824.85	N/A	0.00%	N/A	N/A	N/A
YUM! BRANDS INC	YUM	34,961.30	0.20%	2.28%	10.00%	12.39%	0.0247%
ZIMMER BIOMET HOLDINGS INC	ZBH	24,075.17	0.14%	0.81%	13.00%	13.86%	0.0190%
ZIONS BANCORPORATION	ZION	5,759.96	0.03%	1.14%	11.00%	12.20%	0.0040%
ZOETIS INC	ZTS	23,778.38	0.14%	0.79%	11.00%	11.83%	0.0160%
		17,561,166					13.63%

[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Value Line
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Value Line
[7] Source: Value Line
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Bloomberg and Value Line Beta Coefficients

Company	Ticker	[1] Bloomberg	[2] Value Line
ALLETE, Inc.	ALE	0.612	0.750
Alliant Energy Corporation	LNT	0.612	0.750
Ameren Corporation	AEE	0.617	0.750
American Electric Power Company, Inc.	AEP	0.559	0.700
Avista Corporation	AVA	0.580	0.750
CMS Energy Corporation	CMS	0.542	0.700
DTE Energy Company	DTE	0.598	0.700
El Paso Electric Company	EE	0.735	0.750
Entergy Corporation	ETR	0.639	0.700
Eversource Energy	ES	0.589	0.750
FirstEnergy Corp.	FE	0.676	0.700
IDACORP, Inc.	IDA	0.672	0.800
MGE Energy, Inc.	MGEE	0.576	0.700
NorthWestern Corporation	NWE	0.607	0.700
OGE Energy Corp.	OGE	0.700	0.950
Otter Tail Corporation	OTTR	0.692	0.800
Pinnacle West Capital Corporation	PNW	0.599	0.750
PNM Resources, Inc.	PNM	0.638	0.800
Portland General Electric Company	POR	0.606	0.800
SCANA Corporation	SCG	0.589	0.700
Wisconsin Energy Corporation	WEC	0.512	0.650
Xcel Energy Inc.	XEL	0.479	0.650
Mean		0.610	0.74

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line

Proxy Group Capital Structure

		% Common Equity								
Company	Ticker	2016Q1	2015Q4	2015Q3	2015Q2	2015Q1	2014Q4	2014Q3	2014Q2	Average
ALLETE, Inc.	ALE	58.83%	58.04%	58.01%	58.93%	58.70%	56.98%	56.18%	55.83%	57.69%
Alliant Energy Corporation	LNT	51.65%	51.24%	51.27%	51.18%	50.32%	50.11%	54.23%	52.94%	51.62%
Ameren Corporation	AEE	52.82%	52.22%	53.40%	52.44%	52.88%	52.82%	54.54%	53.83%	53.12%
American Electric Power Company, Inc.	AEP	49.13%	48.82%	49.13%	49.63%	52.23%	52.11%	52.27%	52.31%	50.71%
Avista Corporation	AVA	55.13%	54.30%	54.95%	54.98%	54.81%	51.39%	52.62%	51.19%	53.67%
CMS Energy Corporation	CMS	51.42%	50.63%	51.44%	51.15%	51.35%	50.21%	49.99%	53.44%	51.20%
DTE Energy Company	DTE	50.53%	50.39%	50.32%	49.81%	48.42%	50.39%	49.32%	50.30%	49.93%
El Paso Electric Company	EE	45.95%	49.86%	49.94%	49.04%	48.79%	49.01%	53.63%	52.57%	49.85%
Entergy Corporation	ETR	48.59%	50.94%	49.01%	48.61%	48.37%	47.81%	48.73%	48.61%	48.83%
Eversource Energy	ES	54.51%	54.02%	54.83%	53.73%	53.84%	53.64%	53.44%	52.05%	53.76%
FirstEnergy Corp.	FE	52.97%	52.39%	52.12%	52.58%	52.26%	51.69%	51.49%	50.74%	52.03%
IDACORP, Inc.	IDA	50.70%	52.34%	52.25%	51.61%	49.38%	52.94%	52.92%	52.03%	51.77%
MGE Energy, Inc.	MGEE	62.00%	61.90%	61.88%	61.20%	61.12%	60.52%	59.93%	59.49%	61.00%
NorthWestern Corporation	NWE	47.54%	47.31%	46.01%	46.97%	47.54%	47.06%	47.78%	47.45%	47.21%
OGE Energy Corp.	OGE	55.17%	54.30%	54.38%	53.31%	52.98%	53.08%	55.43%	52.94%	53.95%
Otter Tail Corporation	OTTR	53.10%	52.75%	52.51%	52.32%	51.13%	49.80%	49.32%	47.60%	51.07%
Pinnacle West Capital Corporation	PNW	55.54%	55.50%	57.11%	55.72%	55.86%	57.54%	58.43%	57.32%	56.63%
PNM Resources, Inc.	PNM	45.35%	45.32%	44.76%	45.63%	46.11%	45.86%	47.43%	47.14%	45.95%
Portland General Electric Company	POR	50.89%	50.61%	50.31%	49.57%	44.11%	43.31%	44.86%	46.64%	47.54%
SCANA Corporation	SCG	52.77%	52.57%	52.55%	52.08%	53.72%	53.46%	53.47%	52.85%	52.93%
Wisconsin Energy Corporation	WEC	55.80%	55.39%	56.60%	55.65%	56.21%	55.93%	55.70%	55.55%	55.85%
Xcel Energy Inc.	XEL	54.68%	54.43%	53.02%	53.88%	54.97%	54.62%	54.54%	53.41%	54.19%
Mean		52.50%	52.51%	52.54%	52.27%	52.05%	51.83%	52.56%	52.10%	52.30%

Operating Company Capital Structure

		% Common Equity								
Operating Company	Parent	2016Q1	2015Q4	2015Q3	2015Q2	2015Q1	2014Q4	2014Q3	2014Q2	Average
Ameren Illinois Company	AEE	53.67%	53.42%	55.55%	54.67%	54.39%	53.90%	56.91%	56.19%	54.84%
Union Electric Company	AEE	51.97%	51.03%	51.25%	50.21%	51.37%	51.74%	52.17%	51.48%	51.40%
AEP Texas Central Company	AEP	44.18%	43.63%	43.32%	47.46%	45.01%	42.39%	43.93%	43.18%	44.14%
AEP Texas North Company	AEP	42.64%	42.36%	45.03%	48.87%	47.15%	46.96%	47.06%	46.79%	45.86%
Appalachian Power Company	AEP	47.20%	46.77%	46.66%	46.50%	46.52%	45.83%	46.29%	46.00%	46.47%
Indiana Michigan Power Company	AEP	48.26%	52.65%	52.41%	52.08%	51.94%	51.36%	51.45%	51.39%	51.44%
Kentucky Power Company	AEP	43.58%	43.26%	43.72%	43.87%	44.19%	44.74%	46.25%	48.23%	44.73%
Kingsport Power Company	AEP	65.21%	59.70%	59.76%	60.44%	60.77%	61.00%	60.55%	60.91%	61.04%
Ohio Power Company	AEP	50.03%	50.09%	50.36%	50.33%	49.30%	48.96%	46.03%	44.79%	48.74%
Public Service Company of Oklahoma	AEP	46.80%	46.45%	46.30%	45.29%	44.66%	49.69%	49.43%	48.30%	47.11%
Southwestern Electric Power Company	AEP	49.51%	49.59%	49.88%	47.62%	46.25%	50.46%	50.60%	51.26%	49.40%
Wheeling Power Company	AEP	53.90%	53.73%	53.89%	53.82%	86.56%	79.75%	81.14%	82.27%	68.13%
ALLETE (Minnesota Power)	ALE	56.60%	55.86%	55.62%	57.67%	57.56%	55.24%	53.98%	53.01%	55.69%
Superior Water, Light and Power Company	ALE	61.06%	60.23%	60.40%	60.19%	59.83%	58.72%	58.39%	58.65%	59.68%
Alaska Electric Light and Power Company	AVA	58.86%	58.18%	58.09%	58.07%	57.83%	NA	NA	NA	58.21%
Avista Corporation	AVA	51.39%	50.41%	51.80%	51.90%	51.78%	51.39%	52.62%	51.19%	51.56%
Consumers Energy Company	CMS	51.42%	50.63%	51.44%	51.15%	51.35%	50.21%	49.99%	53.44%	51.20%
DTE Electric Company	DTE	50.53%	50.39%	50.32%	49.81%	48.42%	50.39%	49.32%	50.30%	49.93%
El Paso Electric Company	EE	45.95%	49.86%	49.94%	49.04%	48.79%	49.01%	53.63%	52.57%	49.85%
Entergy Arkansas, Inc.	ETR	45.37%	44.18%	44.47%	43.76%	43.50%	43.29%	46.14%	45.30%	44.50%
Entergy Gulf States Louisiana, LLC	ETR	NA	52.85%	51.00%	50.47%	49.90%	48.96%	49.76%	51.50%	50.63%
Entergy Louisiana, LLC	ETR	47.60%	51.13%	48.89%	48.72%	48.09%	47.35%	48.02%	47.90%	48.46%
Entergy Mississippi, Inc.	ETR	49.27%	48.87%	48.86%	48.05%	48.23%	47.61%	47.71%	48.53%	48.39%
Entergy New Orleans, Inc.	ETR	53.42%	58.69%	50.76%	51.71%	50.62%	50.24%	50.58%	49.39%	51.93%
Entergy Texas, Inc.	ETR	47.29%	49.96%	50.09%	48.95%	49.86%	49.41%	50.14%	49.04%	49.34%
Connecticut Light and Power Company	ES	54.45%	53.05%	53.35%	52.25%	53.26%	53.11%	52.72%	50.52%	52.84%
NSTAR Electric Company	ES	55.76%	56.11%	59.18%	58.53%	58.22%	57.84%	57.17%	55.95%	57.34%
Public Service Company of New Hampshire	ES	54.04%	53.48%	53.56%	53.44%	53.40%	53.29%	53.92%	52.44%	53.45%
Western Massachusetts Electric Company	ES	53.78%	53.46%	53.25%	50.70%	50.48%	50.31%	49.97%	49.29%	51.40%
Cleveland Electric Illuminating Company	FE	45.05%	45.10%	44.89%	44.35%	45.44%	44.99%	45.28%	44.88%	45.00%
Jersey Central Power & Light Company	FE	52.37%	52.32%	52.77%	55.19%	54.99%	54.77%	55.24%	54.49%	54.02%
Monongahela Power Company	FE	49.61%	48.89%	48.79%	48.17%	47.92%	47.04%	46.86%	46.27%	47.94%
Ohio Edison Company	FE	64.08%	63.58%	65.73%	64.75%	64.01%	63.05%	57.70%	56.35%	62.40%
Pennsylvania Electric Company	FE	48.32%	47.70%	49.01%	48.46%	48.06%	47.66%	48.17%	47.74%	48.14%
Potomac Edison Company	FE	52.67%	51.59%	52.56%	51.73%	51.11%	51.05%	51.96%	51.17%	51.73%
Toledo Edison Company	FE	60.61%	60.41%	52.06%	51.72%	51.37%	50.74%	51.51%	50.70%	53.64%
West Penn Power Company	FE	51.06%	49.48%	51.14%	56.25%	55.18%	54.20%	55.21%	54.31%	53.35%
Idaho Power Co.	IDA	50.70%	52.34%	52.25%	51.61%	49.38%	52.94%	52.92%	52.03%	51.77%
Madison Gas and Electric Company	MGEE	62.00%	61.90%	61.88%	61.20%	61.12%	60.52%	59.93%	59.49%	61.00%
Interstate Power and Light Company	LNT	51.52%	50.91%	50.90%	51.72%	50.09%	49.90%	54.01%	52.05%	51.39%
Wisconsin Power and Light Company	LNT	51.78%	51.56%	51.63%	50.65%	50.54%	50.32%	54.45%	53.82%	51.84%
NorthWestern Corporation	NWE	47.54%	47.31%	46.01%	46.97%	47.54%	47.06%	47.78%	47.45%	47.21%
Oklahoma Gas and Electric Company	OGE	55.17%	54.30%	54.38%	53.31%	52.98%	53.08%	55.43%	52.94%	53.95%
Otter Tail Power Company	OTTR	53.10%	52.75%	52.51%	52.32%	51.13%	49.80%	49.32%	47.60%	51.07%
Public Service Company of New Mexico	PNM	45.35%	45.32%	44.76%	45.63%	46.11%	45.86%	47.43%	47.14%	45.95%
Texas-New Mexico Power Company	PNM	NA	NA	NA	NA	NA	NA	NA	NA	N/A
Arizona Public Service Company	PNW	55.54%	55.50%	57.11%	55.72%	55.86%	57.54%	58.43%	57.32%	56.63%
Portland General Electric Company	POR	50.89%	50.61%	50.31%	49.57%	44.11%	43.31%	44.86%	46.64%	47.54%
South Carolina Electric & Gas Co.	SCG	52.77%	52.57%	52.55%	52.08%	53.72%	53.46%	53.47%	52.85%	52.93%
Integrys Holding, Inc.	WEC	NA	NA	56.36%	55.10%	54.80%	54.61%	54.32%	54.05%	54.87%
Wisconsin Electric Power Company	WEC	56.95%	57.25%	57.07%	56.76%	59.02%	58.57%	58.45%	58.56%	57.83%
Wisconsin Public Service Corporation	WEC	54.65%	53.53%	56.36%	55.10%	54.80%	54.61%	54.32%	54.05%	54.68%
Northern States Power Company - MN	XEL	53.68%	53.26%	51.95%	53.34%	53.03%	52.89%	52.84%	52.49%	52.94%
Northern States Power Company - WI	XEL	54.43%	54.27%	52.92%	52.53%	56.36%	55.18%	55.01%	52.92%	54.20%
Public Service Company of Colorado	XEL	56.49%	56.34%	56.00%	55.55%	56.94%	56.79%	56.51%	56.12%	56.34%
Southwestern Public Service Company	XEL	54.13%	53.83%	51.20%	54.08%	53.54%	53.62%	53.81%	52.10%	53.29%
Mean		52.15%	52.09%	52.04%	51.99%	52.33%	51.98%	52.43%	51.95%	52.17%

Source: SNL Financial

Proxy Group Capital Structure

		% Long-Term Debt								
Company	Ticker	2016Q1	2015Q4	2015Q3	2015Q2	2015Q1	2014Q4	2014Q3	2014Q2	Average
ALLETE, Inc.	ALE	41.17%	41.96%	41.99%	41.07%	41.30%	43.02%	43.82%	44.17%	42.31%
Alliant Energy Corporation	LNT	48.35%	48.76%	48.73%	48.82%	49.68%	49.89%	45.77%	47.06%	48.38%
Ameren Corporation	AEE	47.18%	47.78%	46.60%	47.56%	47.12%	47.18%	45.46%	46.17%	46.88%
American Electric Power Company, Inc.	AEP	50.87%	51.18%	50.87%	50.37%	47.77%	47.89%	47.73%	47.69%	49.29%
Avista Corporation	AVA	44.87%	45.70%	45.05%	45.02%	45.19%	48.61%	47.38%	48.81%	46.33%
CMS Energy Corporation	CMS	48.58%	49.37%	48.56%	48.85%	48.65%	49.79%	50.01%	46.56%	48.80%
DTE Energy Company	DTE	49.47%	49.61%	49.68%	50.19%	51.58%	49.61%	50.68%	49.70%	50.07%
El Paso Electric Company	EE	54.05%	50.14%	50.06%	50.96%	51.21%	50.99%	46.37%	47.43%	50.15%
Entergy Corporation	ETR	51.41%	49.06%	50.99%	51.39%	51.63%	52.19%	51.27%	51.39%	51.17%
Eversource Energy	ES	45.49%	45.98%	45.17%	46.27%	46.16%	46.36%	46.56%	47.95%	46.24%
FirstEnergy Corp.	FE	47.03%	47.61%	47.88%	47.42%	47.74%	48.31%	48.51%	49.26%	47.97%
IDACORP, Inc.	IDA	49.30%	47.66%	47.75%	48.39%	50.62%	47.06%	47.08%	47.97%	48.23%
MGE Energy, Inc.	MGEE	38.00%	38.10%	38.12%	38.80%	38.88%	39.48%	40.07%	40.51%	39.00%
NorthWestern Corporation	NWE	52.46%	52.69%	53.99%	53.03%	52.46%	52.94%	52.22%	52.55%	52.79%
OGE Energy Corp.	OGE	44.83%	45.70%	45.62%	46.69%	47.02%	46.92%	44.57%	47.06%	46.05%
Otter Tail Corporation	OTTR	46.90%	47.25%	47.49%	47.68%	48.87%	50.20%	50.68%	52.40%	48.93%
Pinnacle West Capital Corporation	PNW	44.46%	44.50%	42.89%	44.28%	44.14%	42.46%	41.57%	42.68%	43.37%
PNM Resources, Inc.	PNM	54.65%	54.68%	55.24%	54.37%	53.89%	54.14%	52.57%	52.86%	54.05%
Portland General Electric Company	POR	49.11%	49.39%	49.69%	50.43%	55.89%	56.69%	55.14%	53.36%	52.46%
SCANA Corporation	SCG	47.23%	47.43%	47.45%	47.92%	46.28%	46.54%	46.53%	47.15%	47.07%
Wisconsin Energy Corporation	WEC	44.20%	44.61%	43.40%	44.35%	43.79%	44.07%	44.30%	44.45%	44.15%
Xcel Energy Inc.	XEL	45.32%	45.57%	46.98%	46.12%	45.03%	45.38%	45.46%	46.59%	45.81%
Mean		47.50%	47.49%	47.46%	47.73%	47.95%	48.17%	47.44%	47.90%	47.70%

Operating Company Capital Structure

		% Long-Term Debt								
Operating Company	Parent	2016Q1	2015Q4	2015Q3	2015Q2	2015Q1	2014Q4	2014Q3	2014Q2	Average
Ameren Illinois Company	AEE	46.33%	46.58%	44.45%	45.33%	45.61%	46.10%	43.09%	43.81%	45.16%
Union Electric Company	AEE	48.03%	48.97%	48.75%	49.79%	48.63%	48.26%	47.83%	48.52%	48.60%
AEP Texas Central Company	AEP	55.82%	56.37%	56.68%	52.54%	54.99%	57.61%	56.07%	56.82%	55.86%
AEP Texas North Company	AEP	57.36%	57.64%	54.97%	51.13%	52.85%	53.04%	52.94%	53.21%	54.14%
Appalachian Power Company	AEP	52.80%	53.23%	53.34%	53.50%	53.48%	54.17%	53.71%	54.00%	53.53%
Indiana Michigan Power Company	AEP	51.74%	47.35%	47.59%	47.92%	48.06%	48.64%	48.55%	48.61%	48.56%
Kentucky Power Company	AEP	56.42%	56.74%	56.28%	56.13%	55.81%	55.26%	53.75%	51.77%	55.27%
Kingsport Power Company	AEP	34.79%	40.30%	40.24%	39.56%	39.23%	39.00%	39.45%	39.09%	38.96%
Ohio Power Company	AEP	49.97%	49.91%	49.64%	49.67%	50.70%	51.04%	53.97%	55.21%	51.26%
Public Service Company of Oklahoma	AEP	53.20%	53.55%	53.70%	54.71%	55.34%	50.31%	50.57%	51.70%	52.89%
Southwestern Electric Power Company	AEP	50.49%	50.41%	50.12%	52.38%	53.75%	49.54%	49.40%	48.74%	50.60%
Wheeling Power Company	AEP	46.10%	46.27%	46.11%	46.18%	13.44%	20.25%	18.86%	17.73%	31.87%
ALLETE (Minnesota Power)	ALE	43.40%	44.14%	44.38%	42.33%	42.44%	44.76%	46.02%	46.99%	44.31%
Superior Water, Light and Power Company	ALE	38.94%	39.77%	39.60%	39.81%	40.17%	41.28%	41.61%	41.35%	40.32%
Alaska Electric Light and Power Company	AVA	41.14%	41.82%	41.91%	41.93%	42.17%	NA	NA	NA	41.79%
Avista Corporation	AVA	48.61%	49.59%	48.20%	48.10%	48.22%	48.61%	47.38%	48.81%	48.44%
Consumers Energy Company	CMS	48.58%	49.37%	48.56%	48.85%	48.65%	49.79%	50.01%	46.56%	48.80%
DTE Electric Company	DTE	49.47%	49.61%	49.68%	50.19%	51.58%	49.61%	50.68%	49.70%	50.07%
El Paso Electric Company	EE	54.05%	50.14%	50.06%	50.96%	51.21%	50.99%	46.37%	47.43%	50.15%
Entergy Arkansas, Inc.	ETR	54.63%	55.82%	55.53%	56.24%	56.50%	56.71%	53.86%	54.70%	55.50%
Entergy Gulf States Louisiana, LLC	ETR	NA	47.15%	49.00%	49.53%	50.10%	51.04%	50.24%	48.50%	49.37%
Entergy Louisiana, LLC	ETR	52.40%	48.87%	51.11%	51.28%	51.91%	52.65%	51.98%	52.10%	51.54%
Entergy Mississippi, Inc.	ETR	50.73%	51.13%	51.14%	51.95%	51.77%	52.39%	52.29%	51.47%	51.61%
Entergy New Orleans, Inc.	ETR	46.58%	41.31%	49.24%	48.29%	49.38%	49.76%	49.42%	50.61%	48.07%
Entergy Texas, Inc.	ETR	52.71%	50.04%	49.91%	51.05%	50.14%	50.59%	49.86%	50.96%	50.66%
Connecticut Light and Power Company	ES	45.55%	46.95%	46.65%	47.75%	46.74%	46.89%	47.28%	49.48%	47.16%
NSTAR Electric Company	ES	44.24%	43.89%	40.82%	41.47%	41.78%	42.16%	42.83%	44.05%	42.66%
Public Service Company of New Hampshire	ES	45.96%	46.52%	46.44%	46.56%	46.60%	46.71%	46.08%	47.56%	46.55%
Western Massachusetts Electric Company	ES	46.22%	46.54%	46.75%	49.30%	49.52%	49.69%	50.03%	50.71%	48.60%
Cleveland Electric Illuminating Company	FE	54.95%	54.90%	55.11%	55.65%	54.56%	55.01%	54.72%	55.12%	55.00%
Jersey Central Power & Light Company	FE	47.63%	47.68%	47.23%	44.81%	45.01%	45.23%	44.76%	45.51%	45.98%
Monongahela Power Company	FE	50.39%	51.11%	51.21%	51.83%	52.08%	52.96%	53.14%	53.73%	52.06%
Ohio Edison Company	FE	35.92%	36.42%	34.27%	35.25%	35.99%	36.95%	42.30%	43.65%	37.60%
Pennsylvania Electric Company	FE	51.68%	52.30%	50.99%	51.54%	51.94%	52.34%	51.83%	52.26%	51.86%
Potomac Edison Company	FE	47.33%	48.41%	47.44%	48.27%	48.89%	48.95%	48.04%	48.83%	48.27%
Toledo Edison Company	FE	39.39%	39.59%	47.94%	48.28%	48.63%	49.26%	48.49%	49.30%	46.36%
West Penn Power Company	FE	48.94%	50.52%	48.86%	43.75%	44.82%	45.80%	44.79%	45.69%	46.65%
Idaho Power Co.	IDA	49.30%	47.66%	47.75%	48.39%	50.62%	47.06%	47.08%	47.97%	48.23%
Madison Gas and Electric Company	MGEE	38.00%	38.10%	38.12%	38.80%	38.88%	39.48%	40.07%	40.51%	39.00%
Interstate Power and Light Company	LNT	48.48%	49.09%	49.10%	48.28%	49.91%	50.10%	45.99%	47.95%	48.61%
Wisconsin Power and Light Company	LNT	48.22%	48.44%	48.37%	49.35%	49.46%	49.68%	45.55%	46.18%	48.16%
NorthWestern Corporation	NWE	52.46%	52.69%	53.99%	53.03%	52.46%	52.94%	52.22%	52.55%	52.79%
Oklahoma Gas and Electric Company	OGE	44.83%	45.70%	45.62%	46.69%	47.02%	46.92%	44.57%	47.06%	46.05%
Otter Tail Power Company	OTTR	46.90%	47.25%	47.49%	47.68%	48.87%	50.20%	50.68%	52.40%	48.93%
Public Service Company of New Mexico	PNM	54.65%	54.68%	55.24%	54.37%	53.89%	54.14%	52.57%	52.86%	54.05%
Texas-New Mexico Power Company	PNM	NA	NA	NA	NA	NA	NA	NA	NA	NA
Arizona Public Service Company	PNW	44.46%	44.50%	42.89%	44.28%	44.14%	42.46%	41.57%	42.68%	43.37%
Portland General Electric Company	POR	49.11%	49.39%	49.69%	50.43%	55.89%	56.69%	55.14%	53.36%	52.46%
South Carolina Electric & Gas Co.	SCG	47.23%	47.43%	47.45%	47.92%	46.28%	46.54%	46.53%	47.15%	47.07%
Integrys Holding, Inc.	WEC	NA	NA	43.64%	44.90%	45.20%	45.39%	45.68%	45.95%	45.13%
Wisconsin Electric Power Company	WEC	43.05%	42.75%	42.93%	43.24%	40.98%	41.43%	41.55%	41.44%	42.17%
Wisconsin Public Service Corporation	WEC	45.35%	46.47%	43.64%	44.90%	45.20%	45.39%	45.68%	45.95%	45.32%
Northern States Power Company - MN	XEL	46.32%	46.74%	48.05%	46.66%	46.97%	47.11%	47.16%	47.51%	47.06%
Northern States Power Company - WI	XEL	45.57%	45.73%	47.08%	47.47%	43.64%	44.82%	44.99%	47.08%	45.80%
Public Service Company of Colorado	XEL	43.51%	43.66%	44.00%	44.45%	43.06%	43.21%	43.49%	43.88%	43.66%
Southwestern Public Service Company	XEL	45.87%	46.17%	48.80%	45.92%	46.46%	46.38%	46.19%	47.90%	46.71%
Mean		47.85%	47.91%	47.96%	48.01%	47.67%	48.02%	47.57%	48.05%	47.83%

Flotation Cost Adjustment - Combined Proxy Group

Two most recent open market common stock issuances per company, if available

Company	Date	Shares Issued	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds Per Share	Total Flotation Costs	Gross Equity Issue Before Costs	Net Proceeds	Flotation Cost Percentage
ALLETE, Inc.	2/26/2014	3,220,000	$49.75	$1.7413	$450,000	$47.87	$6,056,825	$160,195,000	$154,138,175	3.781%
ALLETE, Inc.	5/25/2001	7,475,000	$23.68	$0.9472	$350,000	$22.69	$7,430,320	$177,008,000	$169,577,680	4.198%
Alliant Energy Corporation	7/1/2003	17,250,000	$19.25	$0.7700	$370,000	$18.46	$13,652,500	$332,062,500	$318,410,000	4.111%
Alliant Energy Corporation	11/8/2001	9,775,000	$28.00	$1.0500	$425,000	$26.91	$10,688,750	$273,700,000	$263,011,250	3.905%
Ameren Corp.	9/9/2009	21,850,000	$25.25	$0.7575	$450,000	$24.47	$17,001,375	$551,712,500	$534,711,125	3.082%
Ameren Corp.	6/30/2004	10,925,000	$42.00	$1.2600	$400,000	$40.70	$14,165,500	$458,850,000	$444,684,500	3.087%
American Electric Power Company, Inc.	4/1/2009	69,000,000	$24.50	$0.7350	$400,000	$23.76	$51,115,000	$1,690,500,000	$1,639,385,000	3.024%
American Electric Power Company, Inc.	2/27/2003	57,500,000	$20.95	$0.6285	$550,000	$20.31	$36,688,750	$1,204,625,000	$1,167,936,250	3.046%
Avista Corporation	12/11/2006	3,162,500	$25.05	$0.4800	$300,000	$24.48	$1,818,000	$79,220,625	$77,402,625	2.295%
CMS Energy Corporation	3/30/2005	23,000,000	$12.25	$0.4288	$325,000	$11.81	$10,187,400	$281,750,000	$271,562,600	3.616%
CMS Energy Corporation	10/7/2004	32,775,000	$9.10	$0.3185	$325,000	$8.77	$10,763,838	$298,252,500	$287,488,663	3.609%
DTE Energy Company	6/19/2002	6,325,000	$43.25	$1.4056	$250,000	$41.80	$9,140,420	$273,556,250	$264,415,830	3.341%
Eversource Energy	3/16/2009	18,975,000	$20.20	$0.6565	$335,000	$19.53	$12,792,088	$383,295,000	$370,502,913	3.337%
Eversource Energy	12/6/2005	23,000,000	$19.09	$0.6200	$340,000	$18.46	$14,600,000	$439,070,000	$424,470,000	3.325%
FirstEnergy Corp.	9/11/2003	32,200,000	$30.00	$0.9750	$423,000	$29.01	$31,818,000	$966,000,000	$934,182,000	3.294%
IDACORP, Inc.	12/9/2004	4,025,000	$30.00	$1.2000	$300,000	$28.73	$5,130,000	$120,750,000	$115,620,000	4.248%
MGE Energy, Inc.	9/10/2004	1,265,000	$31.85	$1.0350	$125,000	$30.72	$1,434,275	$40,290,250	$38,855,975	3.560%
NorthWestern Corporation	9/29/2015	1,100,000	$51.81	$1.3300	$1,000,000	$49.57	$2,463,000	$56,991,000	$54,528,000	4.322%
NorthWestern Corporation	11/4/2014	7,766,990	$51.50	$1.8025	$1,000,000	$49.57	$14,999,999	$399,999,985	$384,999,986	3.750%
OGE Energy Corp.	8/21/2003	5,324,074	$21.60	$0.7900	$325,000	$20.75	$4,531,018	$114,999,998	$110,468,980	3.940%
Otter Tail Corporation	9/18/2008	5,175,000	$30.00	$1.0875	$400,000	$28.84	$6,027,813	$155,250,000	$149,222,188	3.883%
Otter Tail Corporation	12/7/2004	3,335,000	$25.45	$0.9500	$300,000	$24.41	$3,468,250	$84,875,750	$81,407,500	4.086%
Pinnacle West Capital Corporation	4/8/2010	6,900,000	$38.00	$1.3300	$190,000	$36.64	$9,367,000	$262,200,000	$252,833,000	3.572%
Pinnacle West Capital Corporation	4/27/2005	6,095,000	$42.00	$1.3650	$250,000	$40.59	$8,569,675	$255,990,000	$247,420,325	3.348%
PNM Resources, Inc.	12/6/2006	5,750,000	$30.79	$1.0780	$250,000	$29.67	$6,448,500	$177,042,500	$170,594,000	3.642%
PNM Resources, Inc.	3/23/2005	3,910,000	$26.76	$0.8697	$200,000	$25.84	$3,600,527	$104,631,600	$101,031,073	3.441%
Portland General Electric Company	6/11/2013	12,765,000	$29.50	$0.9588	$600,000	$28.49	$12,838,444	$376,567,500	$363,729,056	3.409%
Portland General Electric Company	3/5/2009	12,477,500	$14.10	$0.4935	$375,000	$13.58	$6,532,646	$175,932,750	$169,400,104	3.713%
SCANA Corporation	5/11/2010	8,222,500	$37.00	$1.2950	$350,000	$35.66	$10,998,138	$304,232,500	$293,234,363	3.615%
SCANA Corporation	12/31/2008	2,875,000	$35.50	$0.5325	$350,000	$34.85	$1,880,938	$102,062,500	$100,181,563	1.843%
Xcel Energy Inc.	8/3/2010	21,850,000	$21.50	$0.6450	$600,000	$20.83	$14,693,250	$469,775,000	$455,081,750	3.128%
Xcel Energy Inc.	9/9/2008	17,250,000	$20.25	$0.1500	$600,000	$20.07	$3,187,500	$349,312,500	$346,125,000	0.913%
Mean							$11,377,804	$347,521,913		
								WEIGHTED AVERAGE FLOTATION COSTS:		3.274%

Constant Growth Discounted Cash Flow Model Adjusted for Flotation Costs - 30 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
					Expected Dividend Yield							
Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Current	Adjusted for Flot. Costs	Zacks Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	DCF k(e)	Flotation Adjusted DCF k(e)
ALLETE, Inc.	ALE	$2.08	$59.67	3.49%	3.57%	3.69%	5.50%	5.00%	4.00%	4.83%	8.40%	8.52%
Alliant Energy Corporation	LNT	$1.18	$38.20	3.08%	3.17%	3.28%	6.10%	6.60%	6.00%	6.23%	9.40%	9.51%
Ameren Corporation	AEE	$1.70	$50.12	3.39%	3.49%	3.61%	6.10%	5.20%	6.00%	5.77%	9.26%	9.37%
American Electric Power Company, Inc.	AEP	$2.24	$66.05	3.39%	3.47%	3.58%	4.90%	4.10%	4.00%	4.33%	7.80%	7.92%
Avista Corporation	AVA	$1.37	$41.65	3.29%	3.37%	3.49%	5.00%	5.00%	5.00%	5.00%	8.37%	8.49%
CMS Energy Corporation	CMS	$1.24	$42.95	2.89%	2.98%	3.08%	6.40%	7.24%	6.00%	6.55%	9.53%	9.63%
DTE Energy Company	DTE	$3.08	$92.91	3.32%	3.40%	3.52%	5.80%	5.35%	5.00%	5.38%	8.79%	8.90%
El Paso Electric Company	EE	$1.24	$45.30	2.74%	2.81%	2.91%	6.70%	7.00%	2.50%	5.40%	8.21%	8.31%
Entergy Corporation	ETR	$3.40	$77.45	4.39%	4.47%	4.62%	NA	NA	3.50%	3.50%	7.97%	8.12%
Eversource Energy	ES	$1.78	$56.36	3.16%	3.25%	3.36%	6.30%	5.49%	6.00%	5.93%	9.18%	9.29%
FirstEnergy Corp.	FE	$1.44	$33.34	4.32%	4.51%	4.67%	NA	NA	9.00%	9.00%	13.51%	13.67%
IDACORP, Inc.	IDA	$2.04	$74.50	2.74%	2.79%	2.88%	4.00%	4.00%	3.00%	3.67%	6.46%	6.55%
MGE Energy, Inc.	MGEE	$1.18	$53.30	2.21%	2.27%	2.35%	NA	4.00%	7.00%	5.50%	7.77%	7.85%
NorthWestern Corporation	NWE	$2.00	$59.68	3.35%	3.44%	3.56%	5.00%	5.00%	6.50%	5.50%	8.94%	9.06%
OGE Energy Corp.	OGE	$1.10	$30.95	3.55%	3.63%	3.75%	5.20%	4.30%	3.00%	4.17%	7.80%	7.92%
Otter Tail Corporation	OTTR	$1.25	$30.96	4.04%	4.16%	4.30%	NA	6.00%	6.00%	6.00%	10.16%	10.30%
Pinnacle West Capital Corporation	PNW	$2.50	$75.82	3.30%	3.36%	3.48%	4.00%	3.73%	4.00%	3.91%	7.27%	7.39%
PNM Resources, Inc.	PNM	$0.88	$33.49	2.63%	2.74%	2.83%	7.60%	8.76%	9.00%	8.45%	11.19%	11.28%
Portland General Electric Company	POR	$1.28	$41.86	3.06%	3.15%	3.26%	6.40%	6.57%	5.50%	6.16%	9.31%	9.42%
SCANA Corporation	SCG	$2.30	$71.01	3.24%	3.32%	3.43%	5.30%	5.40%	4.50%	5.07%	8.39%	8.50%
Wisconsin Energy Corporation	WEC	$1.98	$61.68	3.21%	3.31%	3.42%	6.30%	6.77%	6.00%	6.36%	9.67%	9.78%
Xcel Energy Inc.	XEL	$1.36	$42.20	3.22%	3.31%	3.42%	5.30%	5.27%	5.50%	5.36%	8.67%	8.78%
PROXY GROUP MEAN											8.91%	9.02%

Notes:
The proxy group DCF result is adjusted for flotation costs by dividing each company's expected dividend yield by (flotation cost). The flotation cost adjustment is derived as the difference between the unadjusted DCF result and the DCF result adjusted for flotation costs.
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Equals [4] / (1 - 0.0327)
[6] Source: Zacks
[7] Source: Yahoo! Finance
[8] Source: Value Line
[9] Equals Average([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals Average [11] - Average [10]

DCF Result Adjusted For Flotation Costs:	9.02%
DCF Result Unadjusted For Flotation Costs:	8.91%
Difference (Flotation Cost Adjustment)	0.11% [12]

Proxy Group Comparison

Companies	Ticker	Hevert	Baudino	Gorman	Woolridge	Combined Group
ALLETE, Inc.	ALE	√	√	√	√	√
Alliant Energy Corporation	LNT	√	√	√	√	√
Ameren Corporation	AEE	√		√	√	√
American Electric Power Company	AEP	√		√	√	√
Avista Corporation	AVA	√	√	√	√	√
Black Hills Corporation	BKH				√	[1]
CMS Energy Corporation	CMS	√		√	√	√
Consolidated Edison, Inc.	ED		√		√	[2]
Dominion Resources, Inc.	D	√			√	[1]*
DTE Energy Corporation	DTE	√		√		√
Duke Energy Corporation	DUK				√	[1]
Edison International	EIX		√		√	[1]
El Paso Electric	EE				√	√
Entergy Corporation	ETR				√	√
Eversource Energy	ES		√		√	√
First Energy Corporation	FE				√	√
Great Plains Energy, Inc.	GXP	√				[1]*
IDACORP, Inc.	IDA	√	√	√	√	√
MGE Energy, Inc.	MGEE				√	√
NextEra Energy, Inc.	NEE				√	[1], [3]
NorthWestern Corporation	NWE	√	√	√	√	√
OGE Energy Corp.	OGE	√	√	√	√	√
Otter Tail Corporation	OTTR	√			√	√
PG&E Corporation	PCG				√	[1]
Pinnacle West Capital Corporation	PNW	√		√	√	√
PNM Resources	PNM	√		√	√	√
Portland General Electric Co.	POR	√	√	√	√	√
SCANA Corporation	SCG	√		√	√	√
Southern Company	SO				√	[1]
Westar Energy, Inc.	WR	√				[1]*
Wisconsin Energy Corporation	WEC		√		√	√
Xcel Energy, Inc.	XEL	√	√	√	√	√

√ Included in proxy group

* Originally included in Hevert proxy group, but removed for recent activity

[1] Removed for being party to a merger or significant transaction

Note: EIX is subject to onoing settlement payments associated with the bankruptcy of its merchant generation division

Note: PCG was subject to significant penalties from the San Bruno pipeline incident

[2] Removed for having no regulated generation

[3] Parent company; removed to avoid circular logic

Company	Ticker	Trailing P/E	P/E	Forecasted P/E	Percent Change Trailing to Forecast	Percent Change to Forecast
ALLETE, Inc.	ALE	17.30	18.70	14.00	-19%	-25%
Alliant Energy Corporation	LNT	22.90	20.80	15.00	-34%	-28%
Ameren Corporation	AEE	21.00	19.80	14.00	-33%	-29%
American Electric Power Company, Inc.	AEP	19.70	17.80	14.50	-26%	-19%
Avista Corporation	AVA	21.50	20.50	14.00	-35%	-32%
Black Hills Corporation	BKH	21.00	23.50	15.00	-29%	-36%
CMS Energy Corporation	CMS	24.30	21.30	14.00	-42%	-34%
Consolidated Edison, Inc.	ED	19.20	19.20	15.50	-19%	-19%
Dominion Resources, Inc.	D	22.50	20.10	18.00	-20%	-10%
Duke Energy Corporation	DUK	20.00	18.00	16.50	-18%	-8%
Edison International	EIX	17.20	17.70	15.00	-13%	-15%
El Paso Electric Company	EE	22.40	23.70	17.00	-24%	-28%
Entergy Corporation	ETR	14.40	15.40	13.00	-10%	-16%
Eversource Energy	ES	21.10	19.50	14.50	-31%	-26%
FirstEnergy Corp.	FE	15.10	13.00	11.50	-24%	-12%
IDACORP, Inc.	IDA	19.10	18.80	14.50	-24%	-23%
MGE Energy, Inc.	MGEE	26.20	24.10	15.00	-43%	-38%
NextEra Energy, Inc.	NEE	20.00	19.80	17.50	-13%	-12%
NorthWestern Corporation	NWE	23.30	21.20	13.50	-42%	-36%
OGE Energy Corp.	OGE	19.50	17.80	17.00	-13%	-4%
Otter Tail Corporation	OTTR	19.50	19.70	18.00	-8%	-9%
PG&E Corporation	PCG	29.80	21.10	12.00	-60%	-43%
Pinnacle West Capital Corporation	PNW	19.10	18.60	14.50	-24%	-22%
PNM Resources, Inc.	PNM	NMF	20.40	16.00	N/A	-22%
Portland General Electric Company	POR	19.50	18.30	13.00	-33%	-29%
SCANA Corporation	SCG	19.10	17.90	13.50	-29%	-25%
Southern Company	SO	17.50	17.90	15.00	-14%	-16%
Wisconsin Energy Corporation	WEC	23.50	21.00	15.00	-36%	-29%
Xcel Energy Inc.	XEL	19.60	18.80	14.50	-26%	-23%

Source: Value Line as of June 30, 2016

Proof Concept: Earnings, Dividends, Book Value and
Stock Price Growth Rate Equivalence in Constant Growth DCF

Line Description	IMPLIED GROWTH RATE AT ALLOWED ROE:	
Input	Dividend Yield	4.50% [1]
Assumes g = Allowed ROE - Div. Yield	Assumed Growth Rate	6.50%
Input	Total Return	11.00% [1]
Input	Payout Ratio	67.50% [2]
Input	Book Value/Share	20 [2]

		0	1	2	3	4	5	6	7	8	9	10	250
BV/S Escalates at Constant Growth g	Book Value/Share	$ 20.00	$ 21.30	$ 22.68	$ 24.16	$ 25.73	$ 27.40	$ 29.18	$ 31.08	$ 33.10	$ 35.25	$ 37.54	$ 137,540,924.55
Demonstrating Constant BV/S growth			6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Earnings based on ROE applied to BV/S	Earnings/share	$ 2.20	$ 2.34	$ 2.50	$ 2.66	$ 2.83	$ 3.01	$ 3.21	$ 3.42	$ 3.64	$ 3.88	$ 4.13	$ 15,129,501.70
Demonstrating Constant EPS growth			6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Demonstrating Constant Return Earned based on BV/S and EPS	Allowed ROE	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%
Div/S based on EPS and Constant Payout ratio	Dividends/Share	$ 1.49	$ 1.58	$ 1.68	$ 1.79	$ 1.91	$ 2.03	$ 2.17	$ 2.31	$ 2.46	$ 2.62	$ 2.79	$ 10,212,413.65
Demonstrating Constant Div/S growth			6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Retained Earnings based on difference between EPS and Div/S	Earnings retained to book value	$ 0.72	$ 0.76	$ 0.81	$ 0.86	$ 0.92	$ 0.98	$ 1.04	$ 1.11	$ 1.18	$ 1.26	$ 1.34	$ 4,917,088.05
Demonstrating Constant growth in Retained Earnings			6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
Demonstrating Constant Market/Book ratio	Market/Book Ratio	1.757	1.757	1.757	1.757	1.757	1.757	1.757	1.757	1.757	1.757	1.757	1.757
DCF calculation of market price = [Div/S]*[1+g]/[ROE-g]	Market Price	$ 35.15	$ 37.43	$ 39.86	$ 42.45	$ 45.21	$ 48.15	$ 51.28	$ 54.61	$ 58.16	$ 61.95	$ 65.97	$ 241,693,789.67
Demonstrating Price Appreciation equals Long Term Growth Rate	Price Appreciation	6.50%	OK	<== Price appreciation should equal long term growth rate									
Demonstrating Constant Price/Earnings Ratio	Price/Earnings	15.98	15.98	15.98	15.98	15.98	15.98	15.98	15.98	15.98	15.98	15.98	15.98
Present Value Factor calculated based upon the current period and the Constant ROE	Present Value Factor		0.9009	0.8116	0.7312	0.6587	0.5935	0.5346	0.4817	0.4339	0.3909	0.3522	0.0000

CASE 1	**DIVIDENDS IN PERPETUITY**												
Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period	Present Value Dividend		1.4248	1.3670	1.3116	1.2584	1.2074	1.1585	1.1115	1.0664	1.0232	0.9817	0.0000
Total Value of investment sum of all Present Value Dividends in perpetuity (250 instances for demonstration purposes)	Value of Investment		$ 35.14										

CASE 2	**10-YEAR HOLDING PERIOD**										
Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period	Present Value of Dividend	$ 1.42	$ 1.37	$ 1.31	$ 1.26	$ 1.21	$ 1.16	$ 1.11	$ 1.07	$ 1.02	$ 0.98
Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 10th Period (Terminal Value)	Present Value of Stock Price	--	--	--	--	--	--	--	--	--	23.23
Value of dividends = sum of all Present Value Dividends for periods 1-10	Value of Dividends	$ 11.91									
Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 10th Period (Terminal Value)	Value of Stock Price	$ 23.23									
Total Value of investment sum of all Present Value Dividends for periods 1-10 and Present Value of Stock in period 10 (Terminal Value)	Value of Investment	$ 35.15									

CASE 3	**5-YEAR HOLDING PERIOD**					
Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period	Present Value of Dividend	$ 1.42	$ 1.37	$ 1.31	$ 1.26	$ 1.21
Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 5th Period (Terminal Value)	Present Value of Stock Price	--	--	--	--	28.58
Value of dividends = sum of all Present Value Dividends for periods 1-5	Value of Dividends	$ 6.57				
Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 5th Period (Terminal Value)	Value of Stock Price	$ 28.58				
Total Value of investment sum of all Present Value Dividends for periods 1-5 and Present Value of Stock in period 5 (Terminal Value)	Value of Investment	$ 35.15				

[1] Source: Exhibit RBH-XX. Note, for purposes of this exhibit, these data are illustrative only.
[2] Note: Illustrative only.

Growth Rate Regression Analysis

Company	Ticker	[1] Median P/E Ratio	[2] Proj. Earnings Growth Rate	[3] Proj. Div Growth Rate	[4] Proj. BV Growth Rate	[5] Sustainable Growth Rate
ALLETE	ALE	16.00	4.00%	3.50%	4.00%	3.1%
Alliant Energy	LNT	15.00	6.00%	4.50%	4.00%	4.9%
Ameren Corp.	AEE	15.00	6.00%	4.00%	3.50%	3.4%
Amer. Elec. Power	AEP	14.00	4.00%	5.00%	4.00%	3.1%
Avista Corp.	AVA	16.00	5.00%	4.00%	3.50%	3.3%
Black Hills	BKH	17.00	6.50%	6.00%	5.00%	4.9%
CMS Energy Corp.	CMS	16.00	6.00%	6.50%	6.00%	5.1%
Consol. Edison	ED	15.00	1.50%	3.00%	3.50%	2.6%
Dominion Resources	D	18.00	8.00%	8.00%	5.00%	5.0%
Duke Energy	DUK	N/A	4.00%	3.50%	1.50%	2.0%
Edison Int'l	EIX	12.00	3.50%	9.00%	5.50%	5.3%
El Paso Electric	EE	15.00	2.50%	5.00%	3.50%	3.3%
Entergy Corp.	ETR	13.00	3.50%	3.00%	3.00%	4.5%
FirstEnergy Corp.	FE	16.00	9.00%	1.00%	3.50%	4.7%
IDACORP, Inc.	IDA	14.00	3.00%	7.50%	4.00%	3.6%
MGE Energy	MGEE	16.00	7.00%	4.00%	5.00%	7.3%
NextEra Energy	NEE	15.00	6.00%	11.00%	5.50%	3.9%
Eversource Energy	ES	17.00	6.00%	6.00%	4.00%	4.0%
NorthWestern Corp.	NWE	16.00	6.50%	5.50%	4.50%	4.1%
OGE Energy	OGE	14.00	3.00%	9.50%	3.50%	3.6%
Otter Tail Corp.	OTTR	23.00	6.00%	1.50%	4.50%	3.9%
PG&E Corp.	PCG	16.00	12.00%	4.50%	5.00%	4.8%
Pinnacle West Capital	PNW	15.00	4.00%	5.00%	3.50%	3.5%
PNM Resources	PNM	17.00	9.00%	10.00%	3.50%	4.3%
Portland General	POR	15.00	5.50%	6.00%	4.00%	4.0%
SCANA Corp.	SCG	14.00	4.50%	5.00%	5.00%	4.0%
Southern Co.	SO	16.00	2.50%	3.00%	3.00%	3.1%
Wisconsin Energy	WEC	16.00	6.00%	7.00%	7.00%	3.6%
Xcel Energy Inc.	XEL	15.00	5.50%	6.00%	4.00%	3.9%

Source: Value Line Investment Survey as of June 30, 2016; Exhibit JRW-10

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.408347
R Square	0.166747
Adjusted R Square	0.134699
Standard Error	1.796265
Observations	28.000000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	16.787844	16.787844	5.203006	0.030982
Residual	26	83.890728	3.226566		
Total	27	100.678571			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	13.736357	0.887633	15.475269	0.000000	11.911801	15.560912
Proj. Earnings Growth Rate	34.461849	15.108155	2.281010	0.030982	3.406592	65.517106

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.270143
R Square	0.072977
Adjusted R Square	0.037322
Standard Error	1.894642
Observations	28

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	7.347222	7.347222	2.046770	0.164439
Residual	26	93.331349	3.589667		
Total	27	100.678571			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	16.778439	0.893586	18.776533	0.000000	14.941648	18.615231
Proj. Div Growth Rate	-21.296296	14.885711	-1.430654	0.164439	-51.894314	9.301721

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.113124
R Square	0.012797
Adjusted R Square	-0.025172
Standard Error	1.955172
Observations	28

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1.288398	1.288398	0.337039	0.566542
Residual	26	99.390173	3.822699		
Total	27	100.678571			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	14.628613	1.725545	8.477675	0.000000	11.081703	18.175522
Proj. BV Growth Rate	22.832370	39.328829	0.580550	0.566542	-58.009196	103.673936

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.055388
R Square	0.003068
Adjusted R Square	-0.035276
Standard Error	1.964783
Observations	28

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.308861	0.308861	0.080008	0.779526
Residual	26	100.369710	3.860373		
Total	27	100.678571			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	15.137599	1.701026	8.899100	0.000000	11.641090	18.634107
Sustainable Growth Rate	11.442334	40.452702	0.282857	0.779526	-71.709386	94.594053

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.546922
R Square	0.299124
Adjusted R Square	0.177233
Standard Error	1.751561
Observations	28

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	30.115390	7.528847	2.454020	0.074516
Residual	23	70.563182	3.067964		
Total	27	100.678571			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	15.282894	1.828242	8.359341	0.000000	11.500889	19.064900
Proj. Earnings Growth Rate	41.198478	17.400325	2.367684	0.026688	5.203164	77.193792
Proj. Div Growth Rate	-26.857425	14.973545	-1.793658	0.086027	-57.832562	4.117713
Proj. BV Growth Rate	37.759099	42.386933	0.890819	0.382250	-49.924952	125.443150
Sustainable Growth Rate	-50.037609	44.298500	-1.129555	0.270307	-141.676039	41.600820

Analysts' Projected EPS Growth Rates - Woolridge Proxy Group as Filed

Company	Ticker	Yahoo	Reuters	Zacks	Mean
ALLETE, Inc.	ALE	3.00%	NA	4.50%	3.75%
Alliant Energy Corporation	LNT	6.60%	6.60%	6.10%	6.43%
Ameren Corporation	AEE	5.20%	5.20%	6.10%	5.50%
American Electric Power Company, Inc.	AEP	4.10%	4.10%	4.90%	4.37%
Avista Corporation	AVA	5.00%	NA	5.00%	5.00%
Black Hills Corporation	BKH	6.50%	NA	6.50%	6.50%
CMS Energy Corporation	CMS	7.20%	7.20%	6.40%	6.93%
Consolidated Edison, Inc.	ED	1.90%	1.90%	2.30%	2.03%
Dominion Resources, Inc.	D	5.90%	5.90%	6.80%	6.20%
Duke Energy Corporation	DUK	4.60%	4.60%	4.80%	4.67%
Edison International	EIX	2.50%	2.50%	4.90%	3.30%
El Paso Electric Company	EE	7.00%	NA	6.70%	6.85%
Entergy Corporation	ETR	-2.40%	-2.40%	-2.30%	-2.37%
Eversource Energy	ES	6.30%	6.30%	6.30%	6.30%
FirstEnergy Corp.	FE	-2.50%	-2.50%	-1.00%	-2.00%
IDACORP, Inc.	IDA	4.00%	4.00%	4.00%	4.00%
MGE Energy, Inc.	MGEE	4.00%	NA	NA	4.00%
NextEra Energy, Inc.	NEE	7.40%	7.40%	6.90%	7.23%
NorthWestern Corporation	NWE	5.00%	5.00%	5.00%	5.00%
OGE Energy Corp.	OGE	4.30%	4.30%	5.20%	4.60%
Otter Tail Corporation	OTTR	6.00%	NA	NA	6.00%
PG&E Corporation	PCG	6.10%	6.10%	5.10%	5.77%
Pinnacle West Capital Corporation	PNW	3.70%	3.70%	4.10%	3.83%
PNM Resources, Inc.	PNM	8.80%	8.80%	7.60%	8.40%
Portland General Electric Company	POR	6.60%	6.60%	6.40%	6.53%
SCANA Corporation	SCG	4.80%	4.80%	5.30%	4.97%
Southern Company	SO	3.30%	3.20%	4.10%	3.53%
WEC Energy Group, Inc.	WEC	6.80%	6.80%	6.30%	6.63%
Xcel Energy Inc.	XEL	5.30%	5.30%	5.30%	5.30%
Average		4.72%	4.58%	4.94%	4.80%
Median		5.00%	5.00%	5.20%	5.00%

Source: Exhibit JRW-10, Page 5 (Electronic version to two decimal places)

Analysts' Projected EPS Growth Rates - Woolridge Proxy Group Corrected

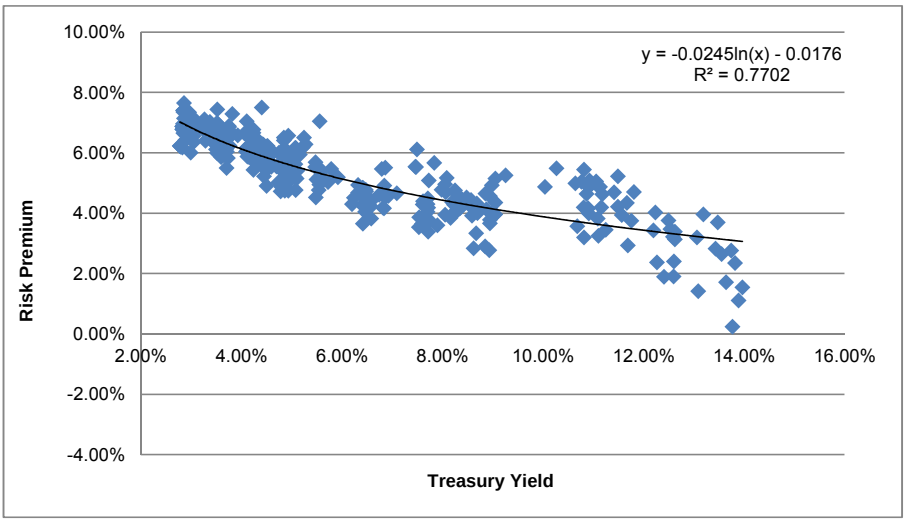
Company	Ticker	Yahoo	Reuters	Zacks	Mean
ALLETE, Inc.	ALE	3.00%	NA	4.50%	3.75%
Alliant Energy Corporation	LNT	6.60%	6.60%	6.10%	6.43%
Ameren Corporation	AEE	5.20%	5.20%	6.10%	5.50%
American Electric Power Company, Inc.	AEP	4.10%	4.10%	4.90%	4.37%
Avista Corporation	AVA	5.00%	NA	5.00%	5.00%
Black Hills Corporation	BKH	6.50%	NA	6.50%	6.50%
CMS Energy Corporation	CMS	7.20%	7.20%	6.40%	6.93%
Consolidated Edison, Inc.	ED	1.90%	1.90%	2.30%	2.03%
Dominion Resources, Inc.	D	5.90%	5.90%	6.80%	6.20%
Duke Energy Corporation	DUK	4.60%	4.60%	4.80%	4.67%
Edison International	EIX	2.50%	2.50%	4.90%	3.30%
El Paso Electric Company	EE	7.00%	NA	6.70%	6.85%
Entergy Corporation	ETR	NA	NA	NA	NA
Eversource Energy	ES	6.30%	6.30%	6.30%	6.30%
FirstEnergy Corp.	FE	NA	NA	NA	NA
IDACORP, Inc.	IDA	4.00%	4.00%	4.00%	4.00%
MGE Energy, Inc.	MGEE	4.00%	NA	NA	4.00%
NextEra Energy, Inc.	NEE	7.40%	7.40%	6.90%	7.23%
NorthWestern Corporation	NWE	5.00%	5.00%	5.00%	5.00%
OGE Energy Corp.	OGE	4.30%	4.30%	5.20%	4.60%
Otter Tail Corporation	OTTR	6.00%	NA	NA	6.00%
PG&E Corporation	PCG	6.10%	6.10%	5.10%	5.77%
Pinnacle West Capital Corporation	PNW	3.70%	3.70%	4.10%	3.83%
PNM Resources, Inc.	PNM	8.80%	8.80%	7.60%	8.40%
Portland General Electric Company	POR	6.60%	6.60%	6.40%	6.53%
SCANA Corporation	SCG	4.80%	4.80%	5.30%	4.97%
Southern Company	SO	3.30%	3.20%	4.10%	3.53%
WEC Energy Group, Inc.	WEC	6.80%	6.80%	6.30%	6.63%
Xcel Energy Inc.	XEL	5.30%	5.30%	5.30%	5.30%
Average		5.26%	5.25%	5.46%	5.32%
Median		5.20%	5.20%	5.30%	5.30%

Source: Exhibit JRW-10, Page 5

Difference: 0.52%

Bond Yield Plus Risk Premium - Settled Only

	[1]	[2]	[3]	[4]	[5]
	Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity
	-1.76%	-2.45%			
Current 30-Year Treasury			2.50%	7.28%	9.78%
Blue Chip Financial Forecast 2017Q3 Projection			3.40%	6.52%	9.92%
Blue Chip Financial Forecast 2020 Projection			4.40%	5.89%	10.29%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
[3] Projected = Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 2.
[3] Projected = Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 14.
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: SNL Financial
[7] Source: SNL Financial
[8] Source: Bloomberg Professional, equals 192-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium - Settled Only

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/2/1980	15.63%	10.65%	4.98%
6/12/1980	14.25%	10.68%	3.57%
7/15/1980	15.80%	10.76%	5.04%
8/14/1980	14.00%	10.81%	3.19%
8/14/1980	16.25%	10.81%	5.44%
9/15/1980	15.80%	10.92%	4.88%
10/16/1980	16.10%	11.06%	5.04%
12/9/1980	15.35%	11.16%	4.19%
12/18/1980	15.80%	11.18%	4.62%
9/3/1981	14.50%	13.09%	1.41%
10/15/1981	16.25%	13.43%	2.82%
11/25/1981	15.35%	13.64%	1.71%
2/17/1982	15.00%	13.89%	1.11%
4/2/1982	15.50%	13.96%	1.54%
6/23/1982	16.17%	13.82%	2.35%
7/13/1982	14.00%	13.77%	0.23%
7/19/1982	16.50%	13.75%	2.75%
9/3/1982	16.20%	13.56%	2.64%
9/23/1982	17.17%	13.47%	3.70%
10/22/1982	17.15%	13.19%	3.96%
11/4/1982	16.25%	13.06%	3.19%
12/22/1982	16.25%	12.50%	3.75%
1/12/1983	14.63%	12.26%	2.37%
3/30/1983	16.71%	11.49%	5.22%
5/23/1983	14.90%	10.91%	3.99%
8/19/1983	15.00%	10.81%	4.19%
9/7/1983	15.00%	10.88%	4.12%
9/14/1983	15.78%	10.91%	4.87%
11/1/1983	16.00%	11.08%	4.92%
11/10/1983	14.35%	11.11%	3.24%
11/23/1983	16.00%	11.13%	4.87%
12/20/1983	14.69%	11.25%	3.44%
1/30/1984	16.10%	11.41%	4.69%
2/15/1984	15.70%	11.49%	4.21%
4/2/1984	15.50%	11.76%	3.74%
6/22/1984	16.25%	12.23%	4.02%
7/19/1984	14.30%	12.41%	1.89%
9/26/1984	14.50%	12.60%	1.90%
9/28/1984	15.00%	12.60%	2.40%
11/9/1984	16.00%	12.62%	3.38%
11/14/1984	15.75%	12.62%	3.13%
12/3/1984	15.80%	12.59%	3.21%
12/20/1984	16.00%	12.54%	3.46%
3/15/1985	15.62%	12.20%	3.42%
5/10/1985	16.50%	11.81%	4.69%
5/29/1985	14.61%	11.69%	2.92%
5/31/1985	16.00%	11.67%	4.33%
6/14/1985	15.50%	11.57%	3.93%
9/9/1985	14.90%	11.09%	3.81%
10/28/1985	16.00%	10.92%	5.08%
10/31/1985	15.06%	10.90%	4.16%
11/7/1985	15.50%	10.87%	4.63%
2/5/1986	15.75%	10.27%	5.48%
3/5/1986	14.90%	10.04%	4.86%

5/16/1986	14.50%	9.26%	5.24%
9/16/1986	12.75%	7.98%	4.77%
12/16/1986	13.60%	7.50%	6.10%
3/31/1987	13.00%	7.46%	5.54%
4/6/1987	13.00%	7.47%	5.53%
8/27/1987	13.25%	8.09%	5.16%
9/30/1987	12.75%	8.35%	4.40%
10/15/1987	13.00%	8.48%	4.52%
12/17/1987	11.75%	8.85%	2.90%
12/18/1987	13.50%	8.86%	4.64%
12/22/1987	13.00%	8.87%	4.13%
1/26/1988	13.90%	8.98%	4.92%
3/30/1988	12.72%	8.94%	3.78%
5/16/1988	13.00%	9.00%	4.00%
8/23/1988	11.70%	8.93%	2.77%
8/30/1988	13.50%	8.94%	4.56%
9/8/1988	12.60%	8.94%	3.66%
12/27/1988	13.00%	9.05%	3.95%
12/30/1988	13.40%	9.05%	4.35%
2/17/1989	13.00%	9.05%	3.95%
3/8/1989	13.00%	9.04%	3.96%
4/5/1989	14.20%	9.05%	5.15%
12/27/1989	13.00%	8.25%	4.75%
1/26/1990	12.00%	8.16%	3.84%
5/29/1990	12.40%	8.30%	4.10%
6/4/1990	12.90%	8.31%	4.59%
9/26/1990	11.45%	8.62%	2.83%
10/19/1990	13.00%	8.68%	4.32%
11/21/1990	12.70%	8.70%	4.00%
12/19/1990	12.00%	8.67%	3.33%
12/20/1990	12.75%	8.67%	4.08%
12/27/1990	12.79%	8.66%	4.13%
2/4/1991	12.50%	8.59%	3.91%
2/12/1991	13.00%	8.57%	4.43%
2/22/1991	12.80%	8.54%	4.26%
6/28/1991	12.50%	8.35%	4.15%
7/3/1991	12.50%	8.34%	4.16%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.25%	8.23%	4.02%
10/23/1991	12.55%	8.20%	4.35%
1/16/1992	12.75%	8.07%	4.68%
1/21/1992	12.00%	8.06%	3.94%
1/22/1992	13.00%	8.05%	4.95%
4/14/1992	11.50%	7.90%	3.60%
7/13/1992	13.50%	7.84%	5.66%
9/28/1992	11.40%	7.72%	3.68%
10/12/1992	12.20%	7.71%	4.49%
10/30/1992	11.75%	7.71%	4.04%
11/3/1992	12.00%	7.70%	4.30%
12/30/1992	12.00%	7.61%	4.39%
12/31/1992	11.90%	7.61%	4.29%
2/2/1993	11.40%	7.54%	3.86%
8/24/1993	11.50%	6.93%	4.57%
11/2/1993	10.80%	6.57%	4.23%
1/4/1994	10.07%	6.42%	3.65%
2/25/1994	11.25%	6.32%	4.93%
3/1/1994	11.00%	6.32%	4.68%
5/13/1994	10.50%	6.46%	4.04%
11/28/1994	11.06%	7.53%	3.53%

2/17/1995	11.90%	7.72%	4.18%
3/9/1995	11.50%	7.73%	3.77%
3/23/1995	12.81%	7.73%	5.08%
4/6/1995	11.10%	7.72%	3.38%
6/9/1995	11.25%	7.60%	3.65%
9/27/1995	11.75%	7.09%	4.66%
11/9/1995	12.36%	6.86%	5.50%
11/9/1995	11.38%	6.86%	4.52%
11/17/1995	11.00%	6.82%	4.18%
12/4/1995	11.35%	6.75%	4.60%
3/29/1996	10.67%	6.41%	4.26%
4/24/1996	11.25%	6.41%	4.84%
4/30/1996	11.00%	6.41%	4.59%
5/13/1996	11.00%	6.41%	4.59%
5/23/1996	11.25%	6.42%	4.83%
6/25/1996	11.25%	6.47%	4.78%
6/27/1996	11.20%	6.48%	4.72%
8/12/1996	10.40%	6.59%	3.81%
10/16/1996	12.25%	6.79%	5.46%
11/5/1996	11.00%	6.84%	4.16%
12/18/1996	11.75%	6.84%	4.91%
12/12/1997	11.00%	6.59%	4.41%
3/6/1998	10.75%	6.24%	4.51%
3/20/1998	10.50%	6.20%	4.30%
11/30/1998	12.60%	5.56%	7.04%
9/23/1999	10.75%	5.73%	5.02%
11/17/1999	11.10%	5.92%	5.18%
1/23/2001	11.25%	5.79%	5.46%
6/26/2001	11.00%	5.61%	5.39%
7/31/2001	11.00%	5.59%	5.41%
8/31/2001	10.50%	5.56%	4.94%
9/7/2001	10.75%	5.55%	5.20%
10/24/2001	10.30%	5.54%	4.76%
11/28/2001	10.60%	5.49%	5.11%
1/22/2002	10.00%	5.49%	4.51%
6/18/2002	11.16%	5.47%	5.69%
6/20/2002	11.00%	5.47%	5.53%
12/4/2002	11.55%	5.28%	6.27%
12/13/2002	11.75%	5.25%	6.50%
12/20/2002	11.40%	5.22%	6.18%
1/8/2003	11.10%	5.17%	5.93%
6/25/2003	10.75%	4.80%	5.95%
6/26/2003	10.75%	4.80%	5.95%
7/9/2003	9.75%	4.79%	4.96%
7/25/2003	9.50%	4.78%	4.72%
8/26/2003	10.50%	4.82%	5.68%
12/17/2003	10.70%	4.94%	5.76%
12/18/2003	11.50%	4.94%	6.56%
12/23/2003	10.50%	4.94%	5.56%
5/27/2004	10.25%	5.07%	5.18%
6/2/2004	11.22%	5.07%	6.15%
6/30/2004	10.50%	5.10%	5.40%
6/30/2004	10.50%	5.10%	5.40%
8/25/2004	10.25%	5.10%	5.15%
11/9/2004	10.50%	5.07%	5.43%
12/14/2004	10.97%	5.08%	5.89%
12/21/2004	11.25%	5.09%	6.16%
12/29/2004	9.85%	5.08%	4.77%
1/6/2005	10.70%	5.08%	5.62%

2/25/2005	10.50%	4.94%	5.56%
3/24/2005	10.30%	4.88%	5.42%
4/7/2005	10.25%	4.85%	5.40%
5/18/2005	10.25%	4.77%	5.48%
5/25/2005	10.75%	4.75%	6.00%
5/26/2005	9.75%	4.75%	5.00%
6/1/2005	9.75%	4.74%	5.01%
8/15/2005	10.13%	4.60%	5.53%
9/28/2005	10.00%	4.53%	5.47%
10/4/2005	10.75%	4.52%	6.23%
12/21/2005	10.29%	4.53%	5.76%
12/21/2005	10.40%	4.53%	5.87%
3/3/2006	10.39%	4.54%	5.85%
6/27/2006	10.75%	4.81%	5.94%
7/6/2006	10.20%	4.84%	5.36%
7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4.87%	5.63%
9/14/2006	10.00%	4.92%	5.08%
10/6/2006	9.67%	4.93%	4.74%
12/1/2006	10.50%	4.97%	5.53%
12/1/2006	10.25%	4.97%	5.28%
12/7/2006	10.75%	4.97%	5.78%
12/22/2006	10.25%	4.96%	5.29%
1/5/2007	10.00%	4.95%	5.05%
3/21/2007	11.35%	4.85%	6.50%
3/22/2007	9.75%	4.85%	4.90%
5/25/2007	9.67%	4.80%	4.87%
6/22/2007	10.50%	4.83%	5.67%
7/12/2007	9.67%	4.86%	4.81%
8/15/2007	10.40%	4.89%	5.51%
11/29/2007	10.90%	4.88%	6.02%
12/14/2007	10.70%	4.86%	5.84%
12/19/2007	10.20%	4.86%	5.34%
12/20/2007	10.20%	4.86%	5.34%
12/20/2007	11.00%	4.86%	6.14%
12/28/2007	10.25%	4.85%	5.40%
12/31/2007	11.25%	4.85%	6.40%
1/31/2008	10.71%	4.79%	5.92%
3/12/2008	10.25%	4.70%	5.55%
4/22/2008	10.25%	4.58%	5.67%
5/1/2008	10.70%	4.57%	6.13%
6/27/2008	10.50%	4.53%	5.97%
7/16/2008	9.40%	4.50%	4.90%
7/31/2008	10.70%	4.50%	6.20%
9/10/2008	10.30%	4.49%	5.81%
9/30/2008	10.20%	4.48%	5.72%
10/8/2008	10.15%	4.47%	5.68%
11/13/2008	10.55%	4.44%	6.11%
11/17/2008	10.20%	4.44%	5.76%
12/1/2008	10.25%	4.39%	5.86%
12/29/2008	10.20%	4.23%	5.97%
12/31/2008	10.75%	4.21%	6.54%
3/4/2009	10.50%	3.93%	6.57%
4/2/2009	11.10%	3.82%	7.28%
4/21/2009	10.61%	3.76%	6.85%
5/20/2009	10.25%	3.71%	6.54%
5/28/2009	10.50%	3.71%	6.79%
7/8/2009	10.63%	3.75%	6.88%
7/17/2009	10.50%	3.76%	6.74%

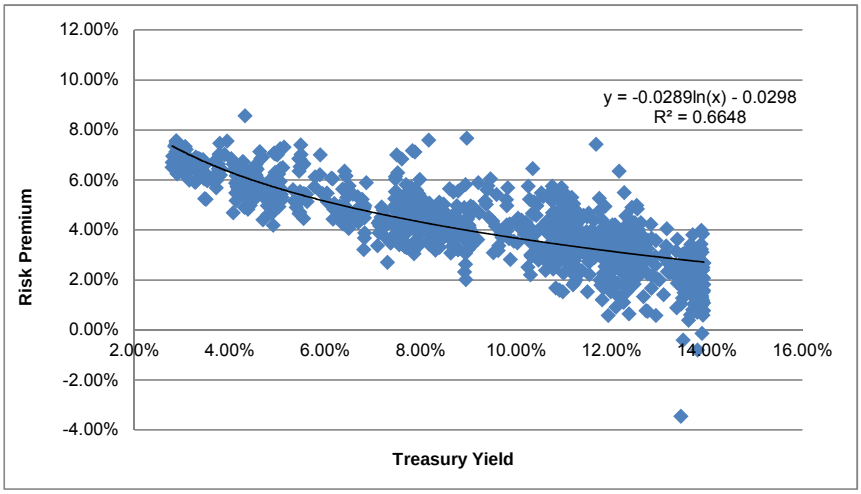
10/14/2009	10.70%	4.06%	6.64%
11/3/2009	10.70%	4.12%	6.58%
11/24/2009	10.25%	4.18%	6.07%
11/25/2009	10.75%	4.18%	6.57%
12/3/2009	10.50%	4.20%	6.30%
12/7/2009	10.70%	4.21%	6.49%
12/16/2009	11.00%	4.24%	6.76%
12/16/2009	10.90%	4.24%	6.66%
1/26/2010	10.13%	4.37%	5.76%
1/27/2010	10.40%	4.37%	6.03%
1/27/2010	10.40%	4.37%	6.03%
1/27/2010	10.70%	4.37%	6.33%
2/24/2010	10.18%	4.41%	5.77%
3/4/2010	10.50%	4.40%	6.10%
3/5/2010	10.50%	4.40%	6.10%
3/11/2010	11.90%	4.41%	7.49%
3/17/2010	10.00%	4.41%	5.59%
3/25/2010	10.15%	4.42%	5.73%
5/12/2010	10.30%	4.45%	5.85%
5/12/2010	10.30%	4.45%	5.85%
5/28/2010	10.20%	4.45%	5.75%
6/7/2010	10.30%	4.45%	5.85%
6/16/2010	10.00%	4.45%	5.55%
6/28/2010	10.50%	4.45%	6.05%
6/28/2010	9.67%	4.45%	5.22%
7/15/2010	10.70%	4.44%	6.26%
7/30/2010	10.70%	4.42%	6.28%
8/4/2010	10.50%	4.41%	6.09%
9/3/2010	10.60%	4.35%	6.25%
9/14/2010	10.70%	4.32%	6.38%
9/16/2010	10.00%	4.32%	5.68%
9/16/2010	10.00%	4.32%	5.68%
10/14/2010	10.35%	4.22%	6.13%
10/28/2010	10.70%	4.19%	6.51%
11/19/2010	10.20%	4.15%	6.05%
12/1/2010	10.13%	4.14%	5.99%
12/9/2010	10.25%	4.13%	6.12%
12/13/2010	10.70%	4.13%	6.57%
12/14/2010	10.13%	4.13%	6.00%
12/17/2010	10.00%	4.12%	5.88%
12/21/2010	10.30%	4.12%	6.18%
12/29/2010	11.15%	4.11%	7.04%
1/5/2011	10.15%	4.10%	6.05%
1/20/2011	10.13%	4.09%	6.04%
2/25/2011	10.00%	4.14%	5.86%
3/30/2011	10.00%	4.19%	5.81%
4/26/2011	9.67%	4.24%	5.43%
6/8/2011	10.75%	4.33%	6.42%
6/17/2011	9.95%	4.34%	5.61%
8/8/2011	10.00%	4.39%	5.61%
8/11/2011	10.00%	4.38%	5.62%
8/19/2011	10.25%	4.36%	5.89%
9/22/2011	10.00%	4.23%	5.77%
10/12/2011	10.30%	4.12%	6.18%
12/14/2011	10.00%	3.77%	6.23%
12/14/2011	10.30%	3.77%	6.53%
12/20/2011	10.20%	3.73%	6.47%
12/21/2011	10.20%	3.72%	6.48%
1/25/2012	10.50%	3.53%	6.97%

1/27/2012	10.50%	3.52%	6.98%
2/15/2012	10.20%	3.43%	6.77%
2/23/2012	9.90%	3.40%	6.50%
2/29/2012	10.40%	3.38%	7.02%
3/29/2012	10.37%	3.27%	7.10%
4/4/2012	10.00%	3.25%	6.75%
4/26/2012	10.00%	3.16%	6.84%
5/2/2012	10.00%	3.15%	6.85%
5/15/2012	10.00%	3.12%	6.88%
6/14/2012	9.40%	3.05%	6.35%
6/18/2012	9.60%	3.05%	6.55%
6/29/2012	10.00%	3.04%	6.96%
7/9/2012	10.20%	3.03%	7.17%
7/16/2012	9.80%	3.01%	6.79%
9/19/2012	9.80%	2.94%	6.86%
10/12/2012	9.60%	2.93%	6.67%
10/23/2012	9.75%	2.93%	6.82%
10/24/2012	10.30%	2.93%	7.37%
11/29/2012	9.88%	2.89%	6.99%
11/29/2012	9.75%	2.89%	6.86%
12/13/2012	10.50%	2.86%	7.64%
12/19/2012	10.25%	2.85%	7.40%
12/20/2012	10.25%	2.85%	7.40%
12/20/2012	10.25%	2.85%	7.40%
12/20/2012	9.80%	2.85%	6.95%
12/20/2012	9.50%	2.85%	6.65%
12/26/2012	9.80%	2.84%	6.96%
1/9/2013	9.70%	2.83%	6.87%
1/9/2013	9.70%	2.83%	6.87%
1/9/2013	9.70%	2.83%	6.87%
1/16/2013	9.60%	2.83%	6.77%
1/16/2013	9.60%	2.83%	6.77%
2/27/2013	10.00%	2.86%	7.14%
3/14/2013	9.30%	2.89%	6.41%
3/27/2013	9.80%	2.91%	6.89%
5/1/2013	9.84%	2.96%	6.88%
5/15/2013	10.30%	2.97%	7.33%
5/30/2013	10.20%	2.99%	7.21%
5/31/2013	9.00%	2.99%	6.01%
6/11/2013	10.00%	3.01%	6.99%
6/21/2013	9.75%	3.03%	6.72%
6/25/2013	9.80%	3.04%	6.76%
9/11/2013	10.25%	3.28%	6.97%
9/11/2013	10.20%	3.28%	6.92%
9/24/2013	10.20%	3.32%	6.88%
11/21/2013	10.00%	3.46%	6.54%
12/3/2013	10.25%	3.48%	6.77%
12/9/2013	9.75%	3.50%	6.25%
12/16/2013	9.95%	3.52%	6.43%
12/16/2013	9.95%	3.52%	6.43%
12/17/2013	9.50%	3.52%	5.98%
12/17/2013	10.95%	3.52%	7.43%
12/18/2013	9.80%	3.52%	6.28%
12/19/2013	10.15%	3.53%	6.62%
2/20/2014	9.20%	3.71%	5.49%
2/26/2014	9.75%	3.71%	6.04%
3/17/2014	9.55%	3.73%	5.82%
5/16/2014	9.80%	3.70%	6.10%
6/30/2014	9.55%	3.64%	5.91%

7/10/2014	9.95%	3.63%	6.32%
7/23/2014	9.75%	3.61%	6.14%
7/29/2014	9.45%	3.60%	5.85%
7/31/2014	9.90%	3.60%	6.30%
8/20/2014	9.75%	3.55%	6.20%
8/25/2014	9.60%	3.54%	6.06%
8/29/2014	9.80%	3.53%	6.27%
9/11/2014	9.60%	3.50%	6.10%
9/15/2014	10.25%	3.49%	6.76%
10/9/2014	9.80%	3.43%	6.37%
12/4/2014	9.68%	3.29%	6.39%
12/11/2014	10.07%	3.27%	6.80%
2/24/2015	9.83%	3.02%	6.81%
4/23/2015	10.20%	2.85%	7.35%
5/1/2015	9.60%	2.83%	6.77%
6/17/2015	9.00%	2.80%	6.20%
6/17/2015	9.00%	2.80%	6.20%
10/15/2015	9.00%	2.83%	6.17%
12/15/2015	9.60%	2.92%	6.68%
12/18/2015	9.50%	2.93%	6.57%
1/6/2016	9.50%	2.96%	6.54%
2/23/2016	9.75%	2.94%	6.81%
6/15/2016	9.00%	2.78%	6.22%
6/15/2016	9.00%	2.78%	6.22%
		# of Cases:	373
		Average:	5.38%

Bond Yield Plus Risk Premium - Fully Litigated Only

	[1]	[2]	[3]	[4]	[5]
	Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity
	-2.98%	-2.89%			
Current 30-Year Treasury			2.50%	7.67%	10.18%
Blue Chip Financial Forecast 2017Q3 Projection			3.40%	6.79%	10.19%
Blue Chip Financial Forecast 2020 Projection			4.40%	6.04%	10.44%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
[3] Projected = Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 2.
[3] Projected = Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 14.
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: SNL Financial
[7] Source: SNL Financial
[8] Source: Bloomberg Professional, equals 204-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium - Fully Litigated Only

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/1/1980	14.50%	9.35%	5.15%
1/7/1980	14.39%	9.38%	5.01%
1/9/1980	15.00%	9.39%	5.61%
1/14/1980	15.17%	9.41%	5.76%
1/17/1980	13.93%	9.43%	4.50%
1/23/1980	15.50%	9.46%	6.04%
1/30/1980	13.86%	9.51%	4.35%
1/31/1980	12.61%	9.52%	3.09%
2/6/1980	13.71%	9.57%	4.14%
2/13/1980	12.80%	9.62%	3.18%
2/14/1980	13.00%	9.64%	3.36%
2/19/1980	13.50%	9.67%	3.83%
2/27/1980	13.75%	9.77%	3.98%
2/29/1980	13.75%	9.80%	3.95%
2/29/1980	14.00%	9.80%	4.20%
2/29/1980	14.77%	9.80%	4.97%
3/7/1980	12.70%	9.88%	2.82%
3/14/1980	13.50%	9.95%	3.55%
3/26/1980	14.16%	10.08%	4.08%
3/27/1980	14.24%	10.10%	4.14%
3/28/1980	14.50%	10.11%	4.39%
4/11/1980	12.75%	10.25%	2.50%
4/14/1980	13.85%	10.26%	3.59%
4/16/1980	15.50%	10.28%	5.22%
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5/7/1980	15.00%	10.42%	4.58%
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5/29/1980	16.00%	10.52%	5.48%
5/30/1980	13.80%	10.53%	3.27%
6/9/1980	15.90%	10.57%	5.33%
6/10/1980	13.78%	10.57%	3.21%
6/19/1980	13.40%	10.59%	2.81%
6/30/1980	13.00%	10.62%	2.38%
6/30/1980	13.40%	10.62%	2.78%
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7/10/1980	15.00%	10.65%	4.35%
7/18/1980	13.80%	10.68%	3.12%
7/22/1980	14.10%	10.69%	3.41%
7/24/1980	15.00%	10.70%	4.30%
7/25/1980	13.48%	10.70%	2.78%
7/31/1980	14.58%	10.73%	3.85%
8/8/1980	14.00%	10.76%	3.24%
8/8/1980	13.50%	10.76%	2.74%
8/8/1980	15.45%	10.76%	4.69%
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9/24/1980	12.50%	10.91%	1.59%
9/24/1980	15.00%	10.91%	4.09%
9/26/1980	13.75%	10.93%	2.82%
9/30/1980	14.20%	10.94%	3.26%
9/30/1980	14.10%	10.94%	3.16%
10/1/1980	13.90%	10.95%	2.95%
10/3/1980	15.50%	10.96%	4.54%
10/7/1980	12.50%	10.98%	1.52%
10/9/1980	14.50%	10.99%	3.51%
10/9/1980	14.50%	10.99%	3.51%
10/9/1980	13.25%	10.99%	2.26%
10/17/1980	14.50%	11.01%	3.49%
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10/31/1980	13.75%	11.09%	2.66%
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11/5/1980	14.00%	11.11%	2.89%
11/5/1980	13.75%	11.11%	2.64%
11/8/1980	13.75%	11.13%	2.62%
11/10/1980	14.85%	11.14%	3.71%
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11/18/1980	14.00%	11.18%	2.82%
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12/8/1980	14.15%	11.24%	2.91%
12/12/1980	15.45%	11.26%	4.19%
12/17/1980	13.25%	11.26%	1.99%
12/19/1980	14.50%	11.25%	3.25%
12/19/1980	14.64%	11.25%	3.39%
12/22/1980	13.45%	11.25%	2.20%
12/22/1980	15.00%	11.25%	3.75%
12/30/1980	14.50%	11.24%	3.26%
12/30/1980	14.95%	11.24%	3.71%
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1/31/1981	13.47%	11.22%	2.25%
2/3/1981	15.25%	11.23%	4.02%
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2/11/1981	15.60%	11.28%	4.32%
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11/24/1981	15.50%	13.58%	1.92%
11/25/1981	16.10%	13.59%	2.51%
11/25/1981	16.10%	13.59%	2.51%
11/25/1981	15.25%	13.59%	1.66%
12/1/1981	16.50%	13.59%	2.91%
12/1/1981	15.70%	13.59%	2.11%
12/1/1981	16.49%	13.59%	2.90%
12/1/1981	16.00%	13.59%	2.41%
12/4/1981	16.00%	13.60%	2.40%
12/11/1981	16.25%	13.61%	2.64%
12/14/1981	14.00%	13.61%	0.39%
12/15/1981	15.81%	13.61%	2.20%
12/15/1981	16.00%	13.61%	2.39%
12/16/1981	15.25%	13.62%	1.63%
12/17/1981	16.50%	13.62%	2.88%
12/18/1981	15.45%	13.62%	1.83%
12/30/1981	16.00%	13.65%	2.35%
12/30/1981	16.25%	13.65%	2.60%
12/30/1981	14.25%	13.65%	0.60%
12/31/1981	16.15%	13.65%	2.50%
1/4/1982	15.50%	13.65%	1.85%
1/11/1982	14.50%	13.70%	0.80%
1/11/1982	17.00%	13.70%	3.30%
1/13/1982	14.75%	13.72%	1.03%
1/14/1982	15.75%	13.73%	2.02%
1/15/1982	15.00%	13.74%	1.26%
1/15/1982	16.50%	13.74%	2.76%
1/22/1982	16.25%	13.77%	2.48%
1/27/1982	16.84%	13.79%	3.05%
1/28/1982	13.00%	13.80%	-0.80%
1/29/1982	15.50%	13.80%	1.70%
2/1/1982	15.85%	13.81%	2.04%
2/3/1982	16.44%	13.82%	2.62%
2/8/1982	15.50%	13.84%	1.66%
2/11/1982	16.00%	13.86%	2.14%
2/11/1982	16.20%	13.86%	2.34%
2/19/1982	15.17%	13.88%	1.29%
2/26/1982	15.25%	13.89%	1.36%
3/1/1982	15.03%	13.89%	1.14%
3/1/1982	16.00%	13.89%	2.11%
3/3/1982	15.00%	13.88%	1.12%
3/8/1982	17.10%	13.88%	3.22%
3/12/1982	16.25%	13.87%	2.38%
3/17/1982	17.30%	13.87%	3.43%
3/22/1982	15.10%	13.87%	1.23%
3/27/1982	15.40%	13.88%	1.52%
3/30/1982	15.50%	13.89%	1.61%
3/31/1982	17.00%	13.89%	3.11%
4/1/1982	16.50%	13.89%	2.61%
4/1/1982	14.70%	13.89%	0.81%
4/5/1982	15.50%	13.90%	1.60%
4/8/1982	16.40%	13.91%	2.49%
4/13/1982	14.50%	13.92%	0.58%

4/23/1982	15.75%	13.93%	1.82%
4/27/1982	15.00%	13.93%	1.07%
4/28/1982	15.75%	13.93%	1.82%
4/30/1982	15.50%	13.93%	1.57%
4/30/1982	14.70%	13.93%	0.77%
5/3/1982	16.60%	13.93%	2.67%
5/4/1982	16.00%	13.93%	2.07%
5/14/1982	15.50%	13.92%	1.58%
5/18/1982	15.42%	13.91%	1.51%
5/19/1982	14.69%	13.91%	0.78%
5/20/1982	15.10%	13.91%	1.19%
5/20/1982	15.50%	13.91%	1.59%
5/20/1982	16.30%	13.91%	2.39%
5/20/1982	15.00%	13.91%	1.09%
5/21/1982	17.75%	13.91%	3.84%
5/27/1982	15.00%	13.90%	1.10%
5/28/1982	15.50%	13.89%	1.61%
5/28/1982	17.00%	13.89%	3.11%
6/1/1982	13.75%	13.89%	-0.14%
6/1/1982	16.60%	13.89%	2.71%
6/9/1982	17.86%	13.88%	3.98%
6/14/1982	15.75%	13.88%	1.87%
6/15/1982	14.85%	13.88%	0.97%
6/18/1982	15.50%	13.88%	1.62%
6/21/1982	14.90%	13.88%	1.02%
6/23/1982	16.00%	13.88%	2.12%
6/24/1982	14.85%	13.88%	0.97%
6/25/1982	14.70%	13.87%	0.83%
7/1/1982	16.00%	13.86%	2.14%
7/2/1982	15.62%	13.86%	1.76%
7/2/1982	17.00%	13.86%	3.14%
7/13/1982	16.80%	13.83%	2.97%
7/14/1982	15.76%	13.82%	1.94%
7/14/1982	16.02%	13.82%	2.20%
7/22/1982	17.00%	13.79%	3.21%
7/22/1982	14.50%	13.79%	0.71%
7/27/1982	16.75%	13.77%	2.98%
7/29/1982	16.50%	13.76%	2.74%
8/11/1982	17.50%	13.70%	3.80%
8/18/1982	17.07%	13.65%	3.42%
8/20/1982	15.73%	13.63%	2.10%
8/25/1982	16.00%	13.59%	2.41%
8/26/1982	15.50%	13.57%	1.93%
8/30/1982	15.00%	13.56%	1.44%
9/8/1982	15.00%	13.52%	1.48%
9/15/1982	13.08%	13.49%	-0.41%
9/15/1982	16.25%	13.49%	2.76%
9/16/1982	16.00%	13.49%	2.51%
9/17/1982	15.25%	13.48%	1.77%
9/24/1982	14.50%	13.46%	1.04%
9/27/1982	15.25%	13.45%	1.80%
10/1/1982	15.50%	13.42%	2.08%
10/15/1982	15.90%	13.33%	2.57%
10/22/1982	15.75%	13.26%	2.49%
10/29/1982	15.54%	13.19%	2.35%
11/1/1982	15.50%	13.17%	2.33%
11/3/1982	17.20%	13.15%	4.05%
11/5/1982	16.20%	13.12%	3.08%
11/9/1982	16.00%	13.08%	2.92%
11/23/1982	15.85%	12.91%	2.94%
11/23/1982	15.50%	12.91%	2.59%
11/30/1982	16.50%	12.84%	3.66%
12/1/1982	17.04%	12.82%	4.22%

12/6/1982	15.00%	12.76%	2.24%
12/6/1982	16.35%	12.76%	3.59%
12/10/1982	15.50%	12.68%	2.82%
12/13/1982	16.00%	12.67%	3.33%
12/14/1982	16.40%	12.65%	3.75%
12/14/1982	15.30%	12.65%	2.65%
12/20/1982	16.00%	12.59%	3.41%
12/21/1982	15.85%	12.57%	3.28%
12/21/1982	14.75%	12.57%	2.18%
12/22/1982	16.75%	12.56%	4.19%
12/22/1982	16.58%	12.56%	4.02%
12/29/1982	14.90%	12.50%	2.40%
12/29/1982	16.25%	12.50%	3.75%
12/30/1982	16.35%	12.49%	3.86%
12/30/1982	16.00%	12.49%	3.51%
12/30/1982	16.77%	12.49%	4.28%
1/5/1983	17.33%	12.43%	4.90%
1/11/1983	15.90%	12.37%	3.53%
1/12/1983	15.50%	12.35%	3.15%
1/20/1983	17.75%	12.26%	5.49%
1/21/1983	15.00%	12.25%	2.75%
1/24/1983	14.50%	12.24%	2.26%
1/24/1983	15.50%	12.24%	3.26%
1/25/1983	15.85%	12.22%	3.63%
1/27/1983	16.14%	12.19%	3.95%
2/1/1983	18.50%	12.15%	6.35%
2/4/1983	14.00%	12.12%	1.88%
2/10/1983	15.00%	12.08%	2.92%
2/21/1983	15.50%	12.01%	3.49%
2/22/1983	15.50%	12.00%	3.50%
2/23/1983	15.10%	11.98%	3.12%
2/23/1983	16.00%	11.98%	4.02%
3/2/1983	15.25%	11.92%	3.33%
3/9/1983	15.20%	11.85%	3.35%
3/15/1983	13.00%	11.80%	1.20%
3/18/1983	15.25%	11.76%	3.49%
3/23/1983	15.40%	11.72%	3.68%
3/24/1983	15.00%	11.71%	3.29%
3/29/1983	15.50%	11.67%	3.83%
3/31/1983	15.00%	11.64%	3.36%
4/4/1983	15.20%	11.62%	3.58%
4/8/1983	15.50%	11.56%	3.94%
4/11/1983	14.81%	11.54%	3.27%
4/19/1983	14.50%	11.43%	3.07%
4/20/1983	16.00%	11.41%	4.59%
4/29/1983	16.00%	11.29%	4.71%
5/1/1983	14.50%	11.29%	3.21%
5/9/1983	15.50%	11.19%	4.31%
5/11/1983	16.46%	11.16%	5.30%
5/12/1983	14.14%	11.15%	2.99%
5/18/1983	15.00%	11.10%	3.90%
5/23/1983	15.50%	11.05%	4.45%
5/25/1983	15.50%	11.03%	4.47%
5/27/1983	15.00%	11.00%	4.00%
5/31/1983	15.50%	10.99%	4.51%
5/31/1983	14.00%	10.99%	3.01%
6/2/1983	14.50%	10.97%	3.53%
6/17/1983	15.03%	10.87%	4.16%
7/1/1983	14.80%	10.81%	3.99%
7/1/1983	14.90%	10.81%	4.09%
7/8/1983	16.25%	10.78%	5.47%
7/13/1983	13.20%	10.77%	2.43%
7/19/1983	15.10%	10.76%	4.34%

7/19/1983	15.00%	10.76%	4.24%
7/25/1983	16.25%	10.75%	5.50%
7/28/1983	15.90%	10.75%	5.15%
8/3/1983	16.50%	10.75%	5.75%
8/3/1983	16.34%	10.75%	5.59%
8/22/1983	16.40%	10.80%	5.60%
8/22/1983	15.50%	10.80%	4.70%
8/31/1983	14.75%	10.84%	3.91%
9/16/1983	15.00%	10.90%	4.10%
9/19/1983	14.50%	10.90%	3.60%
9/20/1983	16.50%	10.91%	5.59%
9/28/1983	14.50%	10.93%	3.57%
9/29/1983	15.50%	10.94%	4.56%
9/30/1983	16.15%	10.94%	5.21%
9/30/1983	15.25%	10.94%	4.31%
10/4/1983	14.80%	10.95%	3.85%
10/7/1983	16.00%	10.96%	5.04%
10/13/1983	15.52%	10.98%	4.54%
10/17/1983	15.50%	10.99%	4.51%
10/18/1983	14.50%	10.99%	3.51%
10/19/1983	16.50%	11.00%	5.50%
10/19/1983	16.25%	11.00%	5.25%
10/26/1983	15.00%	11.03%	3.97%
10/27/1983	15.20%	11.03%	4.17%
11/9/1983	14.90%	11.08%	3.82%
11/23/1983	16.15%	11.13%	5.02%
11/30/1983	15.00%	11.14%	3.86%
12/5/1983	15.25%	11.15%	4.10%
12/6/1983	15.07%	11.15%	3.92%
12/8/1983	15.90%	11.16%	4.74%
12/9/1983	14.75%	11.16%	3.59%
12/12/1983	14.50%	11.17%	3.33%
12/15/1983	15.56%	11.18%	4.38%
12/19/1983	14.80%	11.20%	3.60%
12/20/1983	16.00%	11.20%	4.80%
12/20/1983	16.25%	11.20%	5.05%
12/22/1983	15.75%	11.22%	4.53%
12/22/1983	14.75%	11.22%	3.53%
1/3/1984	14.75%	11.26%	3.49%
1/10/1984	15.90%	11.28%	4.62%
1/12/1984	15.60%	11.29%	4.31%
1/18/1984	13.75%	11.31%	2.44%
1/19/1984	15.90%	11.32%	4.58%
1/31/1984	15.25%	11.36%	3.89%
2/1/1984	14.80%	11.36%	3.44%
2/6/1984	14.75%	11.38%	3.37%
2/6/1984	13.75%	11.38%	2.37%
2/9/1984	15.25%	11.40%	3.85%
2/20/1984	15.00%	11.44%	3.56%
2/20/1984	15.00%	11.44%	3.56%
2/22/1984	14.75%	11.45%	3.30%
2/28/1984	14.50%	11.49%	3.01%
3/2/1984	14.25%	11.51%	2.74%
3/20/1984	16.00%	11.63%	4.37%
3/23/1984	15.50%	11.65%	3.85%
3/26/1984	14.71%	11.66%	3.05%
4/6/1984	14.74%	11.73%	3.01%
4/11/1984	15.72%	11.76%	3.96%
4/17/1984	15.00%	11.79%	3.21%
4/18/1984	16.20%	11.80%	4.40%
4/25/1984	14.64%	11.84%	2.80%
4/30/1984	14.40%	11.86%	2.54%
5/16/1984	14.69%	11.97%	2.72%

5/16/1984	15.00%	11.97%	3.03%
5/22/1984	14.40%	12.01%	2.39%
5/29/1984	15.10%	12.06%	3.04%
6/13/1984	15.25%	12.14%	3.11%
6/15/1984	15.60%	12.16%	3.44%
6/29/1984	15.25%	12.24%	3.01%
7/2/1984	13.35%	12.25%	1.10%
7/10/1984	16.00%	12.30%	3.70%
7/12/1984	16.50%	12.31%	4.19%
7/13/1984	16.25%	12.32%	3.93%
7/17/1984	14.14%	12.33%	1.81%
7/18/1984	15.50%	12.34%	3.16%
7/18/1984	15.30%	12.34%	2.96%
7/24/1984	16.79%	12.37%	4.42%
7/31/1984	16.00%	12.41%	3.59%
8/3/1984	14.25%	12.43%	1.82%
8/17/1984	14.30%	12.47%	1.83%
8/20/1984	15.00%	12.48%	2.52%
8/27/1984	16.30%	12.49%	3.81%
8/31/1984	15.55%	12.51%	3.04%
9/6/1984	16.00%	12.52%	3.48%
9/10/1984	14.75%	12.52%	2.23%
9/13/1984	15.00%	12.53%	2.47%
9/17/1984	17.38%	12.54%	4.84%
9/28/1984	16.25%	12.56%	3.69%
10/9/1984	14.75%	12.57%	2.18%
10/12/1984	15.60%	12.57%	3.03%
10/22/1984	15.00%	12.57%	2.43%
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11/7/1984	15.60%	12.56%	3.04%
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11/20/1984	15.92%	12.56%	3.36%
11/23/1984	15.00%	12.56%	2.44%
11/28/1984	16.15%	12.55%	3.60%
12/4/1984	16.50%	12.55%	3.95%
12/18/1984	16.40%	12.53%	3.87%
12/19/1984	14.75%	12.52%	2.23%
12/19/1984	15.00%	12.52%	2.48%
12/28/1984	16.00%	12.50%	3.50%
1/3/1985	14.75%	12.49%	2.26%
1/10/1985	15.75%	12.47%	3.28%
1/11/1985	16.30%	12.46%	3.84%
1/23/1985	15.80%	12.43%	3.37%
1/24/1985	15.82%	12.43%	3.39%
1/25/1985	16.75%	12.42%	4.33%
1/30/1985	14.90%	12.40%	2.50%
1/31/1985	14.75%	12.39%	2.36%
2/8/1985	14.47%	12.36%	2.11%
3/1/1985	13.84%	12.31%	1.53%
3/8/1985	16.85%	12.30%	4.55%
3/14/1985	15.50%	12.27%	3.23%
3/29/1985	15.62%	12.19%	3.43%
4/3/1985	14.60%	12.17%	2.43%
4/9/1985	15.50%	12.14%	3.36%
4/16/1985	15.70%	12.08%	3.62%
4/22/1985	14.00%	12.04%	1.96%
4/26/1985	15.50%	12.00%	3.50%
4/29/1985	15.00%	12.00%	3.00%
5/2/1985	14.68%	11.97%	2.71%
5/8/1985	15.62%	11.92%	3.70%
7/9/1985	15.00%	11.47%	3.53%
7/16/1985	14.50%	11.41%	3.09%

7/26/1985	14.50%	11.34%	3.16%
8/2/1985	14.80%	11.31%	3.49%
8/7/1985	15.00%	11.29%	3.71%
8/28/1985	14.25%	11.16%	3.09%
8/28/1985	15.50%	11.16%	4.34%
8/29/1985	14.50%	11.16%	3.34%
9/9/1985	14.60%	11.12%	3.48%
9/17/1985	14.90%	11.10%	3.80%
9/23/1985	15.00%	11.07%	3.93%
9/27/1985	15.80%	11.05%	4.75%
9/27/1985	15.50%	11.05%	4.45%
10/2/1985	14.75%	11.04%	3.71%
10/2/1985	14.00%	11.04%	2.96%
10/3/1985	15.25%	11.04%	4.21%
10/24/1985	15.40%	10.97%	4.43%
10/24/1985	15.85%	10.97%	4.88%
10/24/1985	15.82%	10.97%	4.85%
10/29/1985	16.65%	10.95%	5.70%
11/4/1985	14.50%	10.93%	3.57%
11/8/1985	14.30%	10.90%	3.40%
12/12/1985	14.75%	10.74%	4.01%
12/18/1985	15.00%	10.70%	4.30%
12/20/1985	15.00%	10.69%	4.31%
12/20/1985	14.50%	10.69%	3.81%
12/20/1985	14.50%	10.69%	3.81%
1/24/1986	15.40%	10.43%	4.97%
1/31/1986	15.00%	10.37%	4.63%
2/5/1986	15.00%	10.34%	4.66%
2/10/1986	13.30%	10.31%	2.99%
2/11/1986	12.50%	10.30%	2.20%
2/14/1986	14.40%	10.27%	4.13%
2/18/1986	16.00%	10.25%	5.75%
2/24/1986	14.50%	10.20%	4.30%
2/26/1986	14.00%	10.17%	3.83%
3/11/1986	14.50%	10.04%	4.46%
3/12/1986	13.50%	10.02%	3.48%
3/27/1986	14.10%	9.86%	4.24%
3/31/1986	13.50%	9.85%	3.65%
4/1/1986	14.00%	9.84%	4.16%
4/2/1986	15.50%	9.82%	5.68%
4/4/1986	15.00%	9.79%	5.21%
4/14/1986	13.40%	9.71%	3.69%
4/23/1986	15.00%	9.59%	5.41%
5/16/1986	14.50%	9.35%	5.15%
5/29/1986	13.90%	9.22%	4.68%
5/30/1986	15.10%	9.21%	5.89%
6/2/1986	12.81%	9.20%	3.61%
6/11/1986	14.00%	9.10%	4.90%
6/24/1986	16.63%	8.97%	7.66%
6/26/1986	12.00%	8.94%	3.06%
6/26/1986	14.75%	8.94%	5.81%
6/30/1986	13.00%	8.91%	4.09%
7/10/1986	14.34%	8.79%	5.55%
7/11/1986	12.75%	8.77%	3.98%
7/14/1986	12.60%	8.75%	3.85%
7/17/1986	12.40%	8.70%	3.70%
7/25/1986	14.25%	8.61%	5.64%
8/6/1986	13.50%	8.48%	5.02%
8/14/1986	13.50%	8.39%	5.11%
9/19/1986	13.25%	8.07%	5.18%
10/1/1986	14.00%	7.98%	6.02%
10/3/1986	13.40%	7.96%	5.44%
10/31/1986	13.50%	7.81%	5.69%

11/5/1986	13.00%	7.78%	5.22%
12/3/1986	12.90%	7.61%	5.29%
12/4/1986	14.44%	7.60%	6.84%
12/22/1986	13.80%	7.52%	6.28%
12/30/1986	13.00%	7.50%	5.50%
1/2/1987	13.00%	7.49%	5.51%
1/12/1987	12.40%	7.48%	4.92%
1/27/1987	12.71%	7.46%	5.25%
3/2/1987	12.47%	7.47%	5.00%
3/3/1987	13.60%	7.47%	6.13%
3/4/1987	12.38%	7.47%	4.91%
3/10/1987	13.50%	7.47%	6.03%
3/13/1987	13.00%	7.47%	5.53%
4/14/1987	12.50%	7.49%	5.01%
4/16/1987	14.50%	7.50%	7.00%
4/27/1987	12.00%	7.53%	4.47%
5/5/1987	12.85%	7.57%	5.28%
5/12/1987	12.65%	7.61%	5.04%
5/28/1987	13.50%	7.69%	5.81%
6/15/1987	13.20%	7.77%	5.43%
6/29/1987	15.00%	7.83%	7.17%
6/30/1987	12.50%	7.83%	4.67%
7/8/1987	12.00%	7.85%	4.15%
7/10/1987	12.90%	7.86%	5.04%
7/15/1987	13.50%	7.87%	5.63%
7/16/1987	15.00%	7.88%	7.12%
7/16/1987	13.50%	7.88%	5.62%
7/27/1987	13.00%	7.91%	5.09%
7/27/1987	13.40%	7.91%	5.49%
7/27/1987	13.50%	7.91%	5.59%
7/31/1987	12.98%	7.94%	5.04%
8/26/1987	12.63%	8.05%	4.58%
8/26/1987	12.75%	8.05%	4.70%
9/9/1987	13.00%	8.12%	4.88%
9/30/1987	13.00%	8.29%	4.71%
10/2/1987	11.50%	8.31%	3.19%
11/2/1987	13.00%	8.52%	4.48%
11/19/1987	13.00%	8.61%	4.39%
11/30/1987	12.00%	8.66%	3.34%
12/3/1987	14.20%	8.68%	5.52%
12/15/1987	13.25%	8.75%	4.50%
12/16/1987	13.72%	8.76%	4.96%
12/16/1987	13.50%	8.76%	4.74%
12/21/1987	12.01%	8.78%	3.23%
12/22/1987	12.75%	8.79%	3.96%
12/22/1987	12.00%	8.79%	3.21%
12/22/1987	12.00%	8.79%	3.21%
1/20/1988	13.80%	8.91%	4.89%
1/29/1988	13.20%	8.94%	4.26%
2/4/1988	12.60%	8.95%	3.65%
3/1/1988	11.56%	8.94%	2.62%
3/23/1988	12.87%	8.92%	3.95%
3/24/1988	11.24%	8.92%	2.32%
4/1/1988	12.50%	8.92%	3.58%
4/7/1988	13.25%	8.92%	4.33%
4/25/1988	10.96%	8.95%	2.01%
5/3/1988	12.91%	8.97%	3.94%
5/11/1988	13.50%	8.98%	4.52%
6/30/1988	12.75%	9.01%	3.74%
7/1/1988	12.75%	9.00%	3.75%
7/20/1988	13.40%	8.98%	4.42%
8/5/1988	12.75%	8.94%	3.81%
8/29/1988	12.75%	8.94%	3.81%

10/13/1988	13.10%	8.94%	4.16%
12/19/1988	13.00%	9.00%	4.00%
12/20/1988	13.00%	9.01%	3.99%
12/20/1988	12.25%	9.01%	3.24%
12/21/1988	12.90%	9.01%	3.89%
12/28/1988	13.10%	9.02%	4.08%
1/27/1989	13.00%	9.05%	3.95%
1/31/1989	13.00%	9.05%	3.95%
2/20/1989	12.40%	9.05%	3.35%
3/1/1989	12.76%	9.05%	3.71%
3/30/1989	14.00%	9.05%	4.95%
4/18/1989	13.00%	9.05%	3.95%
5/5/1989	12.40%	9.05%	3.35%
6/2/1989	13.20%	9.01%	4.19%
6/8/1989	13.50%	8.99%	4.51%
6/27/1989	13.25%	8.92%	4.33%
6/30/1989	13.00%	8.90%	4.10%
8/14/1989	12.50%	8.77%	3.73%
9/28/1989	12.25%	8.64%	3.61%
10/24/1989	12.50%	8.55%	3.95%
11/9/1989	13.00%	8.49%	4.51%
12/15/1989	13.00%	8.35%	4.65%
12/20/1989	12.90%	8.33%	4.57%
12/21/1989	12.90%	8.33%	4.57%
12/27/1989	12.50%	8.31%	4.19%
1/10/1990	12.80%	8.26%	4.54%
1/11/1990	12.90%	8.25%	4.65%
1/17/1990	12.80%	8.24%	4.56%
2/9/1990	12.10%	8.19%	3.91%
2/24/1990	12.86%	8.16%	4.70%
3/30/1990	12.90%	8.16%	4.74%
4/4/1990	15.76%	8.17%	7.59%
4/12/1990	12.52%	8.18%	4.34%
4/19/1990	12.75%	8.19%	4.56%
5/21/1990	12.10%	8.28%	3.82%
5/31/1990	12.00%	8.30%	3.70%
6/6/1990	12.25%	8.30%	3.95%
6/15/1990	13.20%	8.31%	4.89%
6/20/1990	12.92%	8.32%	4.60%
6/27/1990	12.90%	8.33%	4.57%
6/29/1990	12.50%	8.33%	4.17%
7/6/1990	12.35%	8.34%	4.01%
7/6/1990	12.10%	8.34%	3.76%
8/10/1990	12.55%	8.40%	4.15%
8/16/1990	13.21%	8.42%	4.79%
8/22/1990	13.10%	8.44%	4.66%
8/24/1990	13.00%	8.45%	4.55%
10/2/1990	13.00%	8.60%	4.40%
10/5/1990	12.84%	8.61%	4.23%
10/25/1990	12.30%	8.67%	3.63%
12/13/1990	12.30%	8.67%	3.63%
12/17/1990	12.87%	8.67%	4.20%
12/18/1990	13.10%	8.66%	4.44%
12/21/1990	12.50%	8.66%	3.84%
1/2/1991	13.10%	8.65%	4.45%
1/4/1991	12.50%	8.65%	3.85%
1/15/1991	12.75%	8.64%	4.11%
1/25/1991	11.70%	8.63%	3.07%
2/7/1991	12.50%	8.60%	3.90%
2/14/1991	12.72%	8.57%	4.15%
3/6/1991	13.10%	8.53%	4.57%
3/8/1991	13.00%	8.53%	4.47%
3/8/1991	12.30%	8.53%	3.77%

4/22/1991	13.00%	8.49%	4.51%
5/7/1991	13.50%	8.47%	5.03%
5/13/1991	13.25%	8.47%	4.78%
5/30/1991	12.75%	8.45%	4.30%
6/12/1991	12.00%	8.42%	3.58%
6/25/1991	11.70%	8.40%	3.30%
7/1/1991	12.00%	8.39%	3.61%
7/19/1991	12.10%	8.35%	3.75%
8/1/1991	12.90%	8.33%	4.57%
8/16/1991	13.20%	8.30%	4.90%
10/17/1991	13.00%	8.21%	4.79%
10/23/1991	12.50%	8.20%	4.30%
10/31/1991	11.80%	8.19%	3.61%
11/1/1991	12.00%	8.19%	3.81%
11/5/1991	12.25%	8.19%	4.06%
11/12/1991	12.50%	8.18%	4.32%
11/12/1991	13.25%	8.18%	5.07%
11/25/1991	12.40%	8.17%	4.23%
11/26/1991	12.50%	8.17%	4.33%
11/26/1991	11.60%	8.17%	3.43%
11/27/1991	12.10%	8.17%	3.93%
12/18/1991	12.25%	8.15%	4.10%
12/19/1991	12.60%	8.15%	4.45%
12/19/1991	12.80%	8.15%	4.65%
12/20/1991	12.65%	8.14%	4.51%
1/9/1992	12.80%	8.09%	4.71%
1/27/1992	12.65%	8.06%	4.59%
1/31/1992	12.00%	8.05%	3.95%
2/11/1992	12.40%	8.03%	4.37%
2/25/1992	12.50%	8.02%	4.48%
3/16/1992	11.43%	7.99%	3.44%
3/18/1992	12.28%	7.99%	4.29%
4/2/1992	12.10%	7.96%	4.14%
4/9/1992	11.45%	7.95%	3.50%
4/10/1992	11.50%	7.94%	3.56%
5/5/1992	11.50%	7.90%	3.60%
5/12/1992	12.46%	7.89%	4.57%
5/12/1992	11.87%	7.89%	3.98%
6/1/1992	12.30%	7.87%	4.43%
6/12/1992	10.90%	7.86%	3.04%
6/26/1992	12.35%	7.85%	4.50%
6/29/1992	11.00%	7.85%	3.15%
6/30/1992	13.00%	7.85%	5.15%
7/13/1992	11.90%	7.84%	4.06%
7/22/1992	11.20%	7.83%	3.37%
8/3/1992	12.00%	7.81%	4.19%
8/6/1992	12.50%	7.80%	4.70%
9/22/1992	12.00%	7.72%	4.28%
9/30/1992	11.75%	7.70%	4.05%
10/2/1992	13.00%	7.70%	5.30%
10/16/1992	13.16%	7.70%	5.46%
12/3/1992	11.85%	7.68%	4.17%
12/15/1992	11.00%	7.67%	3.33%
12/16/1992	11.90%	7.67%	4.24%
12/16/1992	12.40%	7.67%	4.74%
12/17/1992	12.00%	7.66%	4.34%
12/22/1992	12.40%	7.65%	4.75%
12/22/1992	12.30%	7.65%	4.65%
12/29/1992	12.25%	7.64%	4.61%
1/12/1993	12.00%	7.61%	4.39%
1/21/1993	11.25%	7.59%	3.66%
2/15/1993	12.30%	7.53%	4.77%
2/24/1993	11.90%	7.50%	4.40%

2/26/1993	11.80%	7.49%	4.31%
2/26/1993	12.20%	7.49%	4.71%
4/23/1993	11.75%	7.30%	4.45%
5/11/1993	11.75%	7.25%	4.50%
5/14/1993	11.50%	7.24%	4.26%
5/25/1993	11.50%	7.23%	4.27%
5/28/1993	11.00%	7.22%	3.78%
6/3/1993	12.00%	7.21%	4.79%
6/16/1993	11.50%	7.19%	4.31%
6/18/1993	12.10%	7.18%	4.92%
6/25/1993	11.67%	7.17%	4.50%
7/21/1993	11.38%	7.11%	4.27%
7/23/1993	10.46%	7.10%	3.36%
9/21/1993	10.50%	6.82%	3.68%
9/29/1993	11.47%	6.78%	4.69%
9/30/1993	11.60%	6.77%	4.83%
11/12/1993	12.00%	6.58%	5.42%
11/26/1993	11.00%	6.53%	4.47%
12/14/1993	10.55%	6.49%	4.06%
12/16/1993	10.60%	6.48%	4.12%
12/21/1993	11.30%	6.48%	4.82%
1/13/1994	11.00%	6.43%	4.57%
1/21/1994	11.00%	6.41%	4.59%
1/28/1994	11.35%	6.40%	4.95%
2/3/1994	11.40%	6.39%	5.01%
2/17/1994	10.60%	6.37%	4.23%
2/25/1994	12.00%	6.36%	5.64%
3/4/1994	11.00%	6.36%	4.64%
4/25/1994	11.00%	6.41%	4.59%
5/10/1994	11.75%	6.45%	5.30%
6/3/1994	11.00%	6.53%	4.47%
6/27/1994	11.40%	6.63%	4.77%
8/5/1994	12.75%	6.86%	5.89%
10/31/1994	10.00%	7.31%	2.69%
11/9/1994	10.85%	7.37%	3.48%
11/9/1994	10.85%	7.37%	3.48%
11/18/1994	11.20%	7.43%	3.77%
11/22/1994	11.60%	7.45%	4.15%
12/8/1994	11.70%	7.53%	4.17%
12/8/1994	11.50%	7.53%	3.97%
12/14/1994	10.95%	7.55%	3.40%
12/15/1994	11.50%	7.55%	3.95%
12/19/1994	11.50%	7.56%	3.94%
12/28/1994	12.15%	7.60%	4.55%
1/9/1995	12.28%	7.63%	4.65%
1/31/1995	11.00%	7.68%	3.32%
2/10/1995	12.60%	7.70%	4.90%
3/20/1995	12.00%	7.71%	4.29%
3/29/1995	11.60%	7.71%	3.89%
4/7/1995	11.00%	7.71%	3.29%
4/19/1995	11.00%	7.70%	3.30%
5/12/1995	11.63%	7.67%	3.96%
5/25/1995	11.20%	7.64%	3.56%
6/21/1995	12.25%	7.56%	4.69%
6/30/1995	11.10%	7.52%	3.58%
9/11/1995	11.30%	7.22%	4.08%
9/27/1995	11.50%	7.14%	4.36%
9/27/1995	11.30%	7.14%	4.16%
9/29/1995	11.00%	7.13%	3.87%
12/11/1995	11.40%	6.76%	4.64%
12/20/1995	11.60%	6.71%	4.89%
12/27/1995	12.00%	6.68%	5.32%
2/5/1996	12.25%	6.50%	5.75%

4/8/1996	11.00%	6.42%	4.58%
4/11/1996	12.59%	6.43%	6.16%
4/11/1996	12.59%	6.43%	6.16%
9/27/1996	11.00%	6.70%	4.30%
11/26/1996	11.30%	6.82%	4.48%
12/31/1996	11.50%	6.83%	4.67%
1/3/1997	10.70%	6.83%	3.87%
2/13/1997	11.80%	6.83%	4.97%
2/20/1997	11.80%	6.82%	4.98%
3/31/1997	10.02%	6.81%	3.21%
4/2/1997	11.65%	6.81%	4.84%
4/28/1997	11.50%	6.81%	4.69%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
12/23/1997	11.12%	6.58%	4.54%
2/2/1998	12.75%	6.41%	6.34%
3/2/1998	11.25%	6.30%	4.95%
4/30/1998	12.20%	6.13%	6.07%
7/10/1998	11.40%	5.94%	5.46%
9/15/1998	11.90%	5.79%	6.11%
12/10/1998	12.20%	5.55%	6.65%
12/17/1998	12.10%	5.53%	6.57%
2/5/1999	10.30%	5.39%	4.91%
3/4/1999	10.50%	5.35%	5.15%
4/6/1999	10.94%	5.33%	5.61%
7/29/1999	10.75%	5.51%	5.24%
1/7/2000	11.50%	6.04%	5.46%
1/7/2000	11.50%	6.04%	5.46%
2/17/2000	10.60%	6.17%	4.43%
3/28/2000	11.25%	6.19%	5.06%
5/24/2000	11.00%	6.18%	4.82%
7/18/2000	12.20%	6.16%	6.04%
9/29/2000	11.16%	6.04%	5.12%
11/28/2000	12.90%	5.89%	7.01%
11/30/2000	12.10%	5.89%	6.21%
2/8/2001	11.50%	5.78%	5.72%
5/8/2001	10.75%	5.62%	5.13%
7/25/2001	11.02%	5.60%	5.42%
7/25/2001	11.02%	5.60%	5.42%
9/10/2001	11.00%	5.55%	5.45%
9/20/2001	10.00%	5.55%	4.45%
12/3/2001	12.88%	5.49%	7.39%
12/20/2001	12.50%	5.49%	7.01%
3/27/2002	10.10%	5.45%	4.65%
4/22/2002	11.80%	5.45%	6.35%
5/28/2002	10.17%	5.46%	4.71%
6/10/2002	12.00%	5.47%	6.53%
6/20/2002	12.30%	5.47%	6.83%
7/15/2002	11.00%	5.47%	5.53%
9/12/2002	12.30%	5.45%	6.85%
9/26/2002	10.45%	5.41%	5.04%
1/31/2003	12.45%	5.14%	7.31%
2/28/2003	12.30%	5.06%	7.24%
3/6/2003	10.75%	5.04%	5.71%
3/7/2003	9.96%	5.03%	4.93%
3/20/2003	12.00%	5.00%	7.00%
4/3/2003	12.00%	4.97%	7.03%
4/15/2003	11.15%	4.95%	6.20%
7/16/2003	9.75%	4.79%	4.96%
12/17/2003	9.85%	4.93%	4.92%
12/19/2003	12.00%	4.93%	7.07%
12/19/2003	12.00%	4.93%	7.07%
1/13/2004	12.00%	4.95%	7.05%

3/2/2004	10.75%	4.97%	5.78%
3/26/2004	10.25%	5.01%	5.24%
4/5/2004	11.25%	5.02%	6.23%
5/18/2004	10.50%	5.08%	5.42%
5/25/2004	10.25%	5.08%	5.17%
7/16/2004	11.60%	5.11%	6.49%
9/9/2004	10.40%	5.10%	5.30%
11/23/2004	11.00%	5.06%	5.94%
12/21/2004	11.50%	5.06%	6.44%
12/22/2004	10.70%	5.06%	5.64%
12/22/2004	11.50%	5.06%	6.44%
2/18/2005	10.30%	4.99%	5.31%
3/10/2005	11.00%	4.94%	6.06%
4/4/2005	10.00%	4.89%	5.11%
7/19/2005	11.50%	4.65%	6.85%
8/5/2005	11.75%	4.63%	7.12%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6.20%
12/22/2005	11.15%	4.55%	6.60%
12/22/2005	11.00%	4.55%	6.45%
12/28/2005	10.00%	4.54%	5.46%
12/28/2005	10.00%	4.54%	5.46%
1/5/2006	11.00%	4.54%	6.46%
1/27/2006	9.75%	4.52%	5.23%
4/17/2006	10.20%	4.61%	5.59%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.74%	5.26%
7/28/2006	10.05%	4.86%	5.19%
8/23/2006	9.55%	4.88%	4.67%
9/1/2006	10.54%	4.89%	5.65%
11/21/2006	10.08%	4.94%	5.14%
11/21/2006	10.08%	4.94%	5.14%
11/21/2006	10.12%	4.94%	5.18%
12/21/2006	10.90%	4.95%	5.95%
12/21/2006	11.25%	4.95%	6.30%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.90%	4.95%	5.95%
1/12/2007	10.10%	4.95%	5.15%
1/13/2007	10.40%	4.95%	5.45%
1/19/2007	10.80%	4.95%	5.85%
5/15/2007	10.00%	4.81%	5.19%
5/17/2007	10.25%	4.81%	5.44%
5/17/2007	10.25%	4.81%	5.44%
5/22/2007	10.20%	4.81%	5.39%
5/22/2007	10.50%	4.81%	5.69%
5/23/2007	10.70%	4.81%	5.89%
6/15/2007	9.90%	4.82%	5.08%
6/21/2007	10.20%	4.83%	5.37%
6/28/2007	10.75%	4.84%	5.91%
7/19/2007	10.00%	4.87%	5.13%
7/19/2007	10.00%	4.87%	5.13%
10/9/2007	10.00%	4.91%	5.09%
10/17/2007	9.10%	4.91%	4.19%
10/31/2007	9.96%	4.90%	5.06%
12/6/2007	10.75%	4.86%	5.89%
12/13/2007	9.96%	4.85%	5.11%
12/14/2007	10.80%	4.85%	5.95%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.82%	5.93%
1/28/2008	9.40%	4.80%	4.60%
1/30/2008	10.00%	4.79%	5.21%

2/29/2008	10.25%	4.75%	5.50%
3/25/2008	9.10%	4.70%	4.40%
4/24/2008	10.10%	4.61%	5.49%
5/19/2008	11.00%	4.57%	6.43%
5/27/2008	10.00%	4.56%	5.44%
6/10/2008	10.70%	4.55%	6.15%
6/27/2008	11.04%	4.55%	6.49%
7/10/2008	10.43%	4.53%	5.90%
7/30/2008	10.80%	4.51%	6.29%
8/11/2008	10.25%	4.51%	5.74%
8/26/2008	10.18%	4.50%	5.68%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
12/23/2008	11.00%	4.27%	6.73%
12/29/2008	10.00%	4.24%	5.76%
1/14/2009	10.50%	4.15%	6.35%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/27/2009	10.76%	4.10%	6.66%
1/30/2009	10.50%	4.08%	6.42%
2/4/2009	8.75%	4.07%	4.68%
3/12/2009	11.50%	3.95%	7.55%
4/24/2009	10.00%	3.80%	6.20%
4/30/2009	11.25%	3.79%	7.46%
5/4/2009	10.74%	3.79%	6.95%
6/22/2009	10.00%	3.77%	6.23%
6/24/2009	10.80%	3.77%	7.03%
8/31/2009	10.25%	3.82%	6.43%
10/23/2009	10.88%	4.03%	6.85%
11/2/2009	10.70%	4.08%	6.62%
11/30/2009	10.35%	4.15%	6.20%
12/18/2009	10.40%	4.21%	6.19%
12/18/2009	10.40%	4.21%	6.19%
12/22/2009	10.20%	4.22%	5.98%
12/22/2009	10.40%	4.22%	6.18%
12/22/2009	10.40%	4.22%	6.18%
12/30/2009	10.00%	4.25%	5.75%
1/4/2010	10.80%	4.26%	6.54%
1/11/2010	11.00%	4.29%	6.71%
2/9/2010	9.80%	4.37%	5.43%
2/18/2010	10.60%	4.39%	6.21%
3/2/2010	9.63%	4.41%	5.22%
4/2/2010	10.10%	4.43%	5.67%
4/27/2010	10.00%	4.46%	5.54%
4/29/2010	9.90%	4.46%	5.44%
4/29/2010	10.06%	4.46%	5.60%
4/29/2010	10.26%	4.46%	5.80%
5/28/2010	10.10%	4.44%	5.66%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.42%	5.83%
7/15/2010	10.53%	4.42%	6.11%
8/6/2010	9.83%	4.41%	5.42%
8/25/2010	9.90%	4.37%	5.53%
9/30/2010	9.75%	4.29%	5.46%
11/2/2010	10.38%	4.21%	6.17%
11/4/2010	10.70%	4.20%	6.50%
11/22/2010	10.00%	4.18%	5.82%
12/6/2010	9.86%	4.16%	5.70%
12/15/2010	10.44%	4.16%	6.28%
12/20/2010	10.60%	4.16%	6.44%
12/27/2010	9.90%	4.15%	5.75%

1/12/2011	10.30%	4.14%	6.16%
1/13/2011	10.30%	4.14%	6.16%
1/18/2011	10.00%	4.13%	5.87%
1/20/2011	9.30%	4.13%	5.17%
1/31/2011	9.60%	4.13%	5.47%
2/3/2011	10.00%	4.13%	5.87%
3/25/2011	9.80%	4.18%	5.62%
4/12/2011	10.00%	4.20%	5.80%
4/25/2011	10.74%	4.23%	6.51%
4/27/2011	10.40%	4.23%	6.17%
5/4/2011	10.00%	4.24%	5.76%
5/4/2011	10.00%	4.24%	5.76%
5/24/2011	10.50%	4.26%	6.24%
6/16/2011	9.20%	4.30%	4.90%
7/13/2011	10.20%	4.35%	5.85%
8/1/2011	9.20%	4.38%	4.82%
8/12/2011	10.35%	4.37%	5.98%
9/2/2011	12.88%	4.32%	8.56%
10/20/2011	10.50%	4.11%	6.39%
11/30/2011	10.90%	3.89%	7.01%
11/30/2011	10.90%	3.89%	7.01%
12/22/2011	9.90%	3.76%	6.14%
12/22/2011	10.40%	3.76%	6.64%
12/23/2011	10.19%	3.76%	6.43%
2/27/2012	10.25%	3.44%	6.81%
5/7/2012	9.80%	3.19%	6.61%
5/29/2012	10.05%	3.11%	6.94%
6/7/2012	10.30%	3.09%	7.21%
6/15/2012	10.40%	3.06%	7.34%
6/19/2012	9.25%	3.06%	6.19%
6/26/2012	10.10%	3.04%	7.06%
7/20/2012	9.81%	3.01%	6.80%
7/20/2012	9.31%	3.01%	6.30%
9/13/2012	9.80%	2.94%	6.86%
9/19/2012	10.05%	2.94%	7.11%
9/26/2012	9.50%	2.94%	6.56%
11/9/2012	10.30%	2.92%	7.38%
11/28/2012	10.40%	2.90%	7.50%
12/5/2012	9.71%	2.89%	6.82%
12/5/2012	10.40%	2.89%	7.51%
12/12/2012	9.80%	2.89%	6.91%
12/13/2012	9.50%	2.89%	6.61%
12/14/2012	10.40%	2.88%	7.52%
12/19/2012	9.71%	2.88%	6.83%
12/20/2012	10.40%	2.88%	7.52%
12/20/2012	10.30%	2.88%	7.42%
12/20/2012	10.45%	2.88%	7.57%
12/21/2012	10.20%	2.88%	7.32%
2/13/2013	10.20%	2.85%	7.35%
2/22/2013	9.75%	2.85%	6.90%
7/12/2013	9.36%	3.07%	6.29%
8/8/2013	9.83%	3.14%	6.69%
8/14/2013	9.15%	3.15%	6.00%
10/3/2013	9.65%	3.32%	6.33%
11/6/2013	10.20%	3.40%	6.80%
11/26/2013	10.00%	3.45%	6.55%
12/4/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.47%	6.73%
12/9/2013	8.72%	3.48%	5.24%
12/13/2013	9.75%	3.49%	6.26%
12/16/2013	10.12%	3.50%	6.62%
12/18/2013	8.72%	3.50%	5.22%
12/30/2013	9.50%	3.53%	5.97%

3/26/2014	9.40%	3.72%	5.68%
3/26/2014	9.96%	3.72%	6.24%
4/2/2014	9.70%	3.72%	5.98%
5/30/2014	9.70%	3.68%	6.02%
6/6/2014	10.40%	3.67%	6.73%
7/2/2014	9.62%	3.64%	5.98%
11/6/2014	9.56%	3.38%	6.18%
11/6/2014	10.20%	3.38%	6.82%
11/14/2014	10.20%	3.36%	6.84%
11/26/2014	9.70%	3.33%	6.37%
11/26/2014	10.20%	3.33%	6.87%
12/10/2014	9.25%	3.30%	5.95%
12/10/2014	9.25%	3.30%	5.95%
12/12/2014	10.20%	3.29%	6.91%
12/17/2014	9.17%	3.28%	5.89%
12/18/2014	9.83%	3.27%	6.56%
1/23/2015	9.50%	3.15%	6.35%
3/18/2015	9.75%	2.99%	6.76%
3/25/2015	9.50%	2.97%	6.53%
3/26/2015	9.72%	2.96%	6.76%
4/29/2015	9.53%	2.87%	6.66%
5/26/2015	9.75%	2.84%	6.91%
9/2/2015	9.50%	2.79%	6.71%
9/10/2015	9.30%	2.79%	6.51%
11/19/2015	10.30%	2.87%	7.43%
11/19/2015	10.00%	2.87%	7.13%
12/3/2015	10.00%	2.89%	7.11%
12/9/2015	9.14%	2.90%	6.24%
12/9/2015	9.14%	2.90%	6.24%
12/11/2015	10.30%	2.90%	7.40%
12/17/2015	9.70%	2.90%	6.80%
12/30/2015	9.50%	2.92%	6.58%
3/16/2016	9.85%	2.91%	6.94%
4/29/2016	9.80%	2.84%	6.96%
6/3/2016	9.75%	2.80%	6.95%
6/8/2016	9.48%	2.80%	6.68%
		# of Cases:	1,102
		Average:	4.22%

Implied Return on Equity with M/B Ratio at Unity

Institution Name	Ticker	ROACE (%) 2015	Price/ Book (%) 2015
ALLETE, Inc.	ALE	7.97	137.0
Alliant Energy Corporation	LNT	10.40	190.3
Ameren Corporation	AEE	9.23	151.0
American Electric Power Company, Inc.	AEP	11.74	159.9
Avista Corporation	AVA	8.17	144.2
Black Hills Corporation	BKH	N/A	162.1
CMS Energy Corporation	CMS	13.65	253.9
Consolidated Edison, Inc.	ED	9.28	144.3
Dominion Resources, Inc.	D	15.46	318.5
Duke Energy Corporation	DUK	7.01	123.7
Edison International	EIX	9.03	169.7
El Paso Electric Company	EE	8.21	153.2
Entergy Corporation	ETR	N/A	131.7
Eversource Energy	ES	8.62	156.5
FirstEnergy Corp.	FE	4.63	108.2
IDACORP, Inc.	IDA	9.72	166.3
MGE Energy, Inc.	MGEE	10.56	233.0
NextEra Energy, Inc.	NEE	12.93	212.2
NorthWestern Corporation	NWE	9.95	163.3
OGE Energy Corp.	OGE	8.24	157.9
Otter Tail Corporation	OTTR	10.05	166.6
PG&E Corporation	PCG	5.42	157.9
Pinnacle West Capital Corporation	PNW	9.76	156.1
PNM Resources, Inc.	PNM	0.91	147.1
Portland General Electric Company	POR	8.12	143.0
SCANA Corporation	SCG	14.00	158.8
Southern Company	SO	11.67	207.2
WEC Energy Group, Inc.	WEC	9.08	187.2
Xcel Energy Inc.	XEL	9.50	171.9

Source: SNL Financial

Implied Return on Equity with M/B Ratio at Unity

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.696375
R Square	0.484938
Adjusted R Square	0.464336
Standard Error	31.472311
Observations	27

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	23314.418992	23314.418992	23.537879	0.000055
Residual	25	24762.658747	990.506350		
Total	26	48077.077739			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	76.870997	20.484734	3.752599	0.000933	34.681898	119.060097
ROACE (%)	10.119661	2.085846	4.851585	0.000055	5.823780	14.415542

ROE (%)	PRICE/BOOK
2.29	100.00
3.27	110.00

Constant Growth Discounted Cash Flow Model and Credit Rating Regression
30 Day Dividend Yield

Company	Ticker	[1] Dividend Yield	[2] Expected Dividend Yield	[3] Yahoo Earnings Growth	[4] Reuters Earnings Growth	[5] Zacks Earnings Growth	[6] Average Earnings Growth	[7] Mean ROE	[8] S&P Issuer Credit Rating	Numeric Credit Score
ALLETE, Inc.	ALE	3.70%	3.77%	3.00%	NA	4.50%	3.75%	7.52%	BBB+	5
Alliant Energy Corporation	LNT	3.30%	3.41%	6.60%	6.60%	6.10%	6.43%	9.84%	A-	4
Ameren Corporation	AEE	3.50%	3.60%	5.20%	5.20%	6.10%	5.50%	9.10%	BBB+	5
American Electric Power Company, Inc.	AEP	3.50%	3.58%	4.10%	4.10%	4.90%	4.37%	7.94%	BBB	6
Avista Corporation	AVA	3.40%	3.49%	5.00%	NA	5.00%	5.00%	8.49%	BBB	6
Black Hills Corporation	BKH	2.80%	2.89%	6.50%	NA	6.50%	6.50%	9.39%	BBB	6
CMS Energy Corporation	CMS	3.00%	3.10%	7.20%	7.20%	6.40%	6.93%	10.04%	BBB+	5
Consolidated Edison, Inc.	ED	3.70%	3.74%	1.90%	1.90%	2.30%	2.03%	5.77%	A-	4
Dominion Resources, Inc.	D	4.00%	4.12%	5.90%	5.90%	6.80%	6.20%	10.32%	BBB+	5
Duke Energy Corporation	DUK	4.20%	4.30%	4.60%	4.60%	4.80%	4.67%	8.96%	A-	4
Edison International	EIX	2.70%	2.74%	2.50%	2.50%	4.90%	3.30%	6.04%	BBB+	5
El Paso Electric Company	EE	2.80%	2.90%	7.00%	NA	6.70%	6.85%	9.75%	BBB	6
Entergy Corporation	ETR	4.50%	4.45%	-2.40%	-2.40%	-2.30%	-2.37%	2.08%	BBB	6
Eversource Energy	ES	3.20%	3.30%	6.30%	6.30%	6.30%	6.30%	9.60%	A	3
FirstEnergy Corp.	FE	4.30%	4.26%	-2.50%	-2.50%	-1.00%	-2.00%	2.26%	BBB-	7
IDACORP, Inc.	IDA	2.80%	2.86%	4.00%	4.00%	4.00%	4.00%	6.86%	BBB	6
MGE Energy, Inc.	MGEE	2.30%	2.35%	4.00%	NA	NA	4.00%	6.35%	AA-	1
NextEra Energy, Inc.	NEE	2.90%	3.00%	7.40%	7.40%	6.90%	7.23%	10.24%	A-	4
NorthWestern Corporation	NWE	3.50%	3.59%	5.00%	5.00%	5.00%	5.00%	8.59%	BBB	6
OGE Energy Corp.	OGE	3.70%	3.79%	4.30%	4.30%	5.20%	4.60%	8.39%	A-	4
Otter Tail Corporation	OTTR	4.30%	4.43%	6.00%	NA	NA	6.00%	10.43%	BBB	6
PG&E Corporation	PCG	3.30%	3.40%	6.10%	6.10%	5.10%	5.77%	9.16%	BBB	6
Pinnacle West Capital Corporation	PNW	3.40%	3.47%	3.70%	3.70%	4.10%	3.83%	7.30%	A-	4
PNM Resources, Inc.	PNM	2.70%	2.81%	8.80%	8.80%	7.60%	8.40%	11.21%	BBB+	5
Portland General Electric Company	POR	3.20%	3.30%	6.60%	6.60%	6.40%	6.53%	9.84%	BBB	6
SCANA Corporation	SCG	3.30%	3.38%	4.80%	4.80%	5.30%	4.97%	8.35%	BBB+	5
Southern Company	SO	4.50%	4.58%	3.30%	3.20%	4.10%	3.53%	8.11%	A-	4
WEC Energy Group, Inc.	WEC	3.40%	3.51%	6.80%	6.80%	6.30%	6.63%	10.15%	A-	4
Xcel Energy Inc.	XEL	3.30%	3.39%	5.30%	5.30%	5.30%	5.30%	8.69%	A-	4
PROXY GROUP MEAN		3.42%	3.50%	4.72%	4.58%	4.94%	4.80%	8.30%	BBB+	4.9
PROXY GROUP MEDIAN		3.40%	3.47%	5.00%	5.00%	5.20%	5.00%	8.69%	BBB+	5.0

REGRESSION OUTPUT

Regression Statistics	
Multiple R	0.133707
R Square	0.017878
Adjusted R Square	-0.018497
Standard Error	0.022034
Observations	29

ANOVA

	df	*SS*	*MS*	*F*	*Signif. F*
Regression	1	0.000239	0.000239	0.491482	0.489266
Residual	27	0.013108	0.000485		
Total	28	0.013347			

	Coefficients	*Stand. Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.094593	0.017012	5.560305	0.000007	0.059687	0.129499
Credit Score	-0.002364	0.003372	-0.701058	0.489266	-0.009284	0.004555

Notes:
[1] Source: JRW-10
[2] Equals [1] x (1 + 0.5 x [6])
[3] Source: JRW-10
[4] Source: JRW-10
[5] Source: JRW-10
[6] Equals Average([3], [4], [5])
[7] Equals [4] + [8]
[8] Source: JRW-4

Constant Growth Discounted Cash Flow Model and Credit Rating Regression
90 Day Dividend Yield

Company	Ticker	[1] Dividend Yield	[2] Expected Dividend Yield	[3] Zacks Earnings Growth	[4] First Call Earnings Growth	[5] Value Line Earnings Growth	[6] Average Earnings Growth	[7] Mean ROE	[8] S&P Issuer Credit Rating	Numeric Credit Score
ALLETE, Inc.	ALE	3.80%	3.87%	3.00%	NA	4.50%	3.75%	7.62%	BBB+	5
Alliant Energy Corporation	LNT	3.30%	3.41%	6.60%	6.60%	6.10%	6.43%	9.84%	A-	4
Ameren Corporation	AEE	3.60%	3.70%	5.20%	5.20%	6.10%	5.50%	9.20%	BBB+	5
American Electric Power Company, Inc.	AEP	3.50%	3.58%	4.10%	4.10%	4.90%	4.37%	7.94%	BBB	6
Avista Corporation	AVA	3.50%	3.59%	5.00%	NA	5.00%	5.00%	8.59%	BBB	6
Black Hills Corporation	BKH	2.90%	2.99%	6.50%	NA	6.50%	6.50%	9.49%	BBB	6
CMS Energy Corporation	CMS	3.10%	3.21%	7.20%	7.20%	6.40%	6.93%	10.14%	BBB+	5
Consolidated Edison, Inc.	ED	3.70%	3.74%	1.90%	1.90%	2.30%	2.03%	5.77%	A-	4
Dominion Resources, Inc.	D	4.00%	4.12%	5.90%	5.90%	6.80%	6.20%	10.32%	BBB+	5
Duke Energy Corporation	DUK	4.30%	4.40%	4.60%	4.60%	4.80%	4.67%	9.07%	A-	4
Edison International	EIX	2.80%	2.85%	2.50%	2.50%	4.90%	3.30%	6.15%	BBB+	5
El Paso Electric Company	EE	2.90%	3.00%	7.00%	NA	6.70%	6.85%	9.85%	BBB	6
Entergy Corporation	ETR	4.60%	4.55%	-2.40%	-2.40%	-2.30%	-2.37%	2.18%	BBB	6
Eversource Energy	ES	3.20%	3.30%	6.30%	6.30%	6.30%	6.30%	9.60%	A	3
FirstEnergy Corp.	FE	4.30%	4.26%	-2.50%	-2.50%	-1.00%	-2.00%	2.26%	BBB-	7
IDACORP, Inc.	IDA	2.80%	2.86%	4.00%	4.00%	4.00%	4.00%	6.86%	BBB	6
MGE Energy, Inc.	MGEE	2.40%	2.45%	4.00%	NA	NA	4.00%	6.45%	AA-	1
NextEra Energy, Inc.	NEE	3.00%	3.11%	7.40%	7.40%	6.90%	7.23%	10.34%	A-	4
NorthWestern Corporation	NWE	3.40%	3.49%	5.00%	5.00%	5.00%	5.00%	8.49%	BBB	6
OGE Energy Corp.	OGE	3.90%	3.99%	4.30%	4.30%	5.20%	4.60%	8.59%	A-	4
Otter Tail Corporation	OTTR	4.40%	4.53%	6.00%	NA	NA	6.00%	10.53%	BBB	6
PG&E Corporation	PCG	3.40%	3.50%	6.10%	6.10%	5.10%	5.77%	9.26%	BBB	6
Pinnacle West Capital Corporation	PNW	3.50%	3.57%	3.70%	3.70%	4.10%	3.83%	7.40%	A-	4
PNM Resources, Inc.	PNM	2.70%	2.81%	8.80%	8.80%	7.60%	8.40%	11.21%	BBB+	5
Portland General Electric Company	POR	3.30%	3.41%	6.60%	6.60%	6.40%	6.53%	9.94%	BBB	6
SCANA Corporation	SCG	3.40%	3.48%	4.80%	4.80%	5.30%	4.97%	8.45%	BBB+	5
Southern Company	SO	4.60%	4.68%	3.30%	3.20%	4.10%	3.53%	8.21%	A-	4
WEC Energy Group, Inc.	WEC	3.40%	3.51%	6.80%	6.80%	6.30%	6.63%	10.15%	A-	4
Xcel Energy Inc.	XEL	3.40%	3.49%	5.30%	5.30%	5.30%	5.30%	8.79%	A-	4
PROXY GROUP MEAN		3.49%	3.57%	4.72%	4.58%	4.94%	4.80%	8.37%	BBB+	4.9
PROXY GROUP MEDIAN		3.40%	3.50%	5.00%	5.00%	5.20%	5.00%	8.79%	BBB+	5.0

REGRESSION OUTPUT

Regression Statistics	
Multiple R	0.137677
R Square	0.018955
Adjusted R Square	-0.017380
Standard Error	0.022042
Observations	29

ANOVA

	df	*SS*	*MS*	*F*	*Signif. F*
Regression	1	0.000253	0.000253	0.521673	0.476338
Residual	27	0.013117	0.000486		
Total	28	0.013371			

	Coefficients	*Stand. Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.095618	0.017018	5.618640	0.000006	0.060700	0.130536
X Variable 1	-0.00244	0.003373	-0.722270	0.476338	-0.009358	0.004485

Notes:
[1] Source: JRW-10
[2] Equals [1] x (1 + 0.5 x [6])
[3] Source: JRW-10
[4] Source: JRW-10
[5] Source: JRW-10
[6] Equals Average([3], [4], [5])
[7] Equals [4] + [8]
[8] Source: JRW-4

Constant Growth Discounted Cash Flow Model and Credit Rating Regression
180 Day Dividend Yield

Company	Ticker	[1] Dividend Yield	[2] Expected Dividend Yield	[3] Zacks Earnings Growth	[4] First Call Earnings Growth	[5] Value Line Earnings Growth	[6] Average Earnings Growth	[7] Mean ROE	[8] S&P Issuer Credit Rating	Numeric Credit Score
ALLETE, Inc.	ALE	4.00%	4.08%	3.00%	NA	4.50%	3.75%	7.83%	BBB+	5
Alliant Energy Corporation	LNT	3.60%	3.72%	6.60%	6.60%	6.10%	6.43%	10.15%	A-	4
Ameren Corporation	AEE	3.80%	3.90%	5.20%	5.20%	6.10%	5.50%	9.40%	BBB+	5
American Electric Power Company, Inc.	AEP	3.80%	3.88%	4.10%	4.10%	4.90%	4.37%	8.25%	BBB	6
Avista Corporation	AVA	3.80%	3.90%	5.00%	NA	5.00%	5.00%	8.90%	BBB	6
Black Hills Corporation	BKH	3.40%	3.51%	6.50%	NA	6.50%	6.50%	10.01%	BBB	6
CMS Energy Corporation	CMS	3.30%	3.41%	7.20%	7.20%	6.40%	6.93%	10.35%	BBB+	5
Consolidated Edison, Inc.	ED	3.90%	3.94%	1.90%	1.90%	2.30%	2.03%	5.97%	A-	4
Dominion Resources, Inc.	D	4.10%	4.23%	5.90%	5.90%	6.80%	6.20%	10.43%	BBB+	5
Duke Energy Corporation	DUK	4.50%	4.61%	4.60%	4.60%	4.80%	4.67%	9.27%	A-	4
Edison International	EIX	3.00%	3.05%	2.50%	2.50%	4.90%	3.30%	6.35%	BBB+	5
El Paso Electric Company	EE	3.40%	3.52%	7.00%	NA	6.70%	6.85%	10.37%	BBB	6
Entergy Corporation	ETR	4.90%	4.84%	-2.40%	-2.40%	-2.30%	-2.37%	2.48%	BBB	6
Eversource Energy	ES	3.40%	3.51%	6.30%	6.30%	6.30%	6.30%	9.81%	A	3
FirstEnergy Corp.	FE	4.50%	4.46%	-2.50%	-2.50%	-1.00%	-2.00%	2.46%	BBB-	7
IDACORP, Inc.	IDA	3.00%	3.06%	4.00%	4.00%	4.00%	4.00%	7.06%	BBB	6
MGE Energy, Inc.	MGEE	2.50%	2.55%	4.00%	NA	NA	4.00%	6.55%	AA-	1
NextEra Energy, Inc.	NEE	3.20%	3.32%	7.40%	7.40%	6.90%	7.23%	10.55%	A-	4
NorthWestern Corporation	NWE	3.60%	3.69%	5.00%	5.00%	5.00%	5.00%	8.69%	BBB	6
OGE Energy Corp.	OGE	4.10%	4.19%	4.30%	4.30%	5.20%	4.60%	8.79%	A-	4
Otter Tail Corporation	OTTR	4.60%	4.74%	6.00%	NA	NA	6.00%	10.74%	BBB	6
PG&E Corporation	PCG	3.60%	3.70%	6.10%	6.10%	5.10%	5.77%	9.47%	BBB	6
Pinnacle West Capital Corporation	PNW	3.70%	3.77%	3.70%	3.70%	4.10%	3.83%	7.60%	A-	4
PNM Resources, Inc.	PNM	2.90%	3.02%	8.80%	8.80%	7.60%	8.40%	11.42%	BBB+	5
Portland General Electric Company	POR	3.40%	3.51%	6.60%	6.60%	6.40%	6.53%	10.04%	BBB	6
SCANA Corporation	SCG	3.70%	3.79%	4.80%	4.80%	5.30%	4.97%	8.76%	BBB+	5
Southern Company	SO	4.80%	4.88%	3.30%	3.20%	4.10%	3.53%	8.42%	A-	4
WEC Energy Group, Inc.	WEC	3.70%	3.82%	6.80%	6.80%	6.30%	6.63%	10.46%	A-	4
Xcel Energy Inc.	XEL	3.60%	3.70%	5.30%	5.30%	5.30%	5.30%	9.00%	A-	4
PROXY GROUP MEAN		3.72%	3.80%	4.72%	4.58%	4.94%	4.80%	8.61%	BBB+	4.9
PROXY GROUP MEDIAN		3.70%	3.77%	5.00%	5.00%	5.20%	5.00%	9.00%	BBB+	5.0

REGRESSION OUTPUT

Regression Statistics	
Multiple R	0.122515
R Square	0.015010
Adjusted R Square	-0.021471
Standard Error	0.022188
Observations	29

ANOVA

	df	*SS*	*MS*	*F*	*Signif. F*
Regression	1	0.000203	0.000203	0.411444	0.526646
Residual	27	0.013293	0.000492		
Total	28	0.013495			

	Coefficients	*Stand. Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.09672	0.017131	5.645785	0.000005	0.061570	0.131871
X Variable 1	-0.00218	0.003396	-0.641439	0.526646	-0.009146	0.004790

Notes:
[1] Source: JRW-10
[2] Equals [1] x (1 + 0.5 x [6])
[3] Source: JRW-10
[4] Source: JRW-10
[5] Source: JRW-10
[6] Equals Average([3], [4], [5])
[7] Equals [4] + [8]
[8] Source: JRW-4

Hypothetical Example: Flotation Cost Recovery

Return on Equity	11.00%
Flotation Costs	3.28%
Market Value	$ 25.00
Dividend Yield	4.50%
Growth Rate	6.50%
Adjusted ROE	11.15%
Flotation Cost Recovery:	**No**
DCF Estimate	**10.85%**

	Common Stock	Retained Earnings	Book Value	Market Price	Market/ Book Value	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 24.18		$ 24.18	$ 25.00	1.0339	$ 2.66	$ 1.13	42.30%
2	$ 24.18	$ 1.53	$ 25.71	$ 26.59	1.0339	$ 2.83	$ 1.20	42.30%
3	$ 24.18	$ 3.17	$ 27.35	$ 28.27	1.0339	$ 3.01	$ 1.27	42.30%
4	$ 24.18	$ 4.90	$ 29.08	$ 30.07	1.0339	$ 3.20	$ 1.35	42.30%
5	$ 24.18	$ 6.75	$ 30.93	$ 31.98	1.0339	$ 3.40	$ 1.44	42.30%
6	$ 24.18	$ 8.71	$ 32.89	$ 34.01	1.0339	$ 3.62	$ 1.53	42.30%
7	$ 24.18	$ 10.80	$ 34.98	$ 36.17	1.0339	$ 3.85	$ 1.63	42.30%
8	$ 24.18	$ 13.02	$ 37.20	$ 38.46	1.0339	$ 4.09	$ 1.73	42.30%
9	$ 24.18	$ 15.38	$ 39.56	$ 40.90	1.0339	$ 4.35	$ 1.84	42.30%
10	$ 24.18	$ 17.89	$ 42.07	$ 43.50	1.0339	$ 4.63	$ 1.96	42.30%
	Growth Rate		6.35%	6.35%		6.35%	6.35%	

Return on Equity	11.00%
Flotation Costs	3.28%
Market Value	$ 25.00
Dividend Yield	4.50%
Growth Rate	6.50%
Adjusted ROE	11.15%
Flotation Cost Recovery:	**Yes**
DCF Estimate	**11.00%**

	Common Stock	Retained Earnings	Book Value	Market Price	Market/ Book Value	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 24.18		$ 24.18	$ 25.00	1.0339	$ 2.70	$ 1.13	41.72%
2	$ 24.18	$ 1.57	$ 25.75	$ 26.63	1.0339	$ 2.87	$ 1.20	41.72%
3	$ 24.18	$ 3.25	$ 27.43	$ 28.36	1.0339	$ 3.06	$ 1.28	41.72%
4	$ 24.18	$ 5.03	$ 29.21	$ 30.20	1.0339	$ 3.26	$ 1.36	41.72%
5	$ 24.18	$ 6.93	$ 31.11	$ 32.16	1.0339	$ 3.47	$ 1.45	41.72%
6	$ 24.18	$ 8.95	$ 33.13	$ 34.25	1.0339	$ 3.69	$ 1.54	41.72%
7	$ 24.18	$ 11.10	$ 35.28	$ 36.48	1.0339	$ 3.93	$ 1.64	41.72%
8	$ 24.18	$ 13.40	$ 37.58	$ 38.85	1.0339	$ 4.19	$ 1.75	41.72%
9	$ 24.18	$ 15.84	$ 40.02	$ 41.37	1.0339	$ 4.46	$ 1.86	41.72%
10	$ 24.18	$ 18.44	$ 42.62	$ 44.06	1.0339	$ 4.75	$ 1.98	41.72%
	Growth Rate		6.50%	6.50%		6.50%	6.50%	

Analysis Using Gorman's Rolling Average Equity Risk Premium Data

Year	Authorized Electric Returns	Treasury Bond Yield	Indicated Risk Premium	Rolling 5-Year Average Treasury	Rolling 5-Year Average Risk Premium	Slope	Rolling 10-Year Average Treasury	Rolling 10-Year Average Risk Premium	Slope
1986	13.93%	7.80%	6.13%						
1987	12.99%	8.58%	4.41%						
1988	12.79%	8.96%	3.83%						
1989	12.97%	8.45%	4.52%						
1990	12.70%	8.61%	4.09%	8.48%	4.60%	-46.02%			-47.73%
1991	12.55%	8.14%	4.41%	8.55%	4.25%				
1992	12.09%	7.67%	4.42%	8.36%	4.26%				
1993	11.41%	6.60%	4.81%	7.89%	4.45%				
1994	11.34%	7.37%	3.97%	7.68%	4.34%				
1995	11.55%	6.88%	4.67%	7.33%	4.46%		7.91%	4.53%	
1996	11.39%	6.70%	4.69%	7.04%	4.51%		7.80%	4.38%	
1997	11.40%	6.61%	4.79%	6.83%	4.59%		7.60%	4.42%	
1998	11.66%	5.58%	6.08%	6.63%	4.84%		7.26%	4.65%	
1999	10.77%	5.87%	4.90%	6.33%	5.03%		7.00%	4.68%	
2000	11.43%	5.94%	5.49%	6.14%	5.19%		6.73%	4.82%	
2001	11.09%	5.49%	5.60%	5.90%	5.37%		6.47%	4.94%	
2002	11.16%	5.43%	5.73%	5.66%	5.56%		6.25%	5.07%	
2003	10.97%	4.96%	6.01%	5.54%	5.55%		6.08%	5.19%	
2004	10.75%	5.05%	5.70%	5.37%	5.71%		5.85%	5.37%	
2005	10.54%	4.65%	5.89%	5.11%	5.79%		5.63%	5.49%	
2006	10.36%	4.99%	5.37%	5.01%	5.74%		5.46%	5.56%	
2007	10.36%	4.83%	5.53%	4.90%	5.70%		5.28%	5.63%	
2008	10.46%	4.28%	6.18%	4.76%	5.73%		5.15%	5.64%	
2009	10.48%	4.07%	6.41%	4.56%	5.88%		4.97%	5.79%	
2010	10.24%	4.25%	5.99%	4.49%	5.89%		4.80%	5.84%	
2011	10.07%	3.91%	6.16%	4.27%	6.05%		4.64%	5.90%	
2012	10.01%	2.92%	7.09%	3.89%	6.37%		4.39%	6.03%	
2013	9.79%	3.45%	6.34%	3.72%	6.40%		4.24%	6.07%	
2014	9.76%	3.34%	6.42%	3.57%	6.40%		4.07%	6.14%	
2015	9.58%	2.84%	6.74%	3.29%	6.55%		3.89%	6.22%	
2016	9.68%	2.72%	6.96%	3.05%	6.71%		3.66%	6.38%	
Average	11.17%	5.71%	5.46%	5.72%	5.40%		5.69%	5.40%	
Minimum				3.05%	4.25%		3.66%	4.38%	
Maximum				8.55%	6.71%		7.91%	6.38%	

Source: Exhibit MPG-13

Analysis Using Gorman's Rolling Average Equity Risk Premium Data

Year	Authorized Electric Returns	Utiltiy Bond Yield	Rolling Indicated Risk Premium	Rolling 5-Year Average Utility Bond	5-Year Average Risk Premium	Rolling Slope	Rolling 10-Year Average Utility Bond	10-Year Average Risk Premium	Slope
1986	13.93%	9.58%	4.35%						
1987	12.99%	10.10%	2.89%						
1988	12.79%	10.49%	2.30%						
1989	12.97%	9.77%	3.20%						
1990	12.70%	9.86%	2.84%	9.96%	3.12%	-45.15%			-44.87%
1991	12.55%	9.36%	3.19%	9.92%	2.88%				
1992	12.09%	8.69%	3.40%	9.63%	2.99%				
1993	11.41%	7.59%	3.82%	9.05%	3.29%				
1994	11.34%	8.31%	3.03%	8.76%	3.26%				
1995	11.55%	7.89%	3.66%	8.37%	3.42%		9.16%	3.27%	
1996	11.39%	7.75%	3.64%	8.05%	3.51%		8.98%	3.20%	
1997	11.40%	7.60%	3.80%	7.83%	3.59%		8.73%	3.29%	
1998	11.66%	7.04%	4.62%	7.72%	3.75%		8.39%	3.52%	
1999	10.77%	7.62%	3.15%	7.58%	3.77%		8.17%	3.52%	
2000	11.43%	8.24%	3.19%	7.65%	3.68%		8.01%	3.55%	
2001	11.09%	7.76%	3.33%	7.65%	3.62%		7.85%	3.56%	
2002	11.16%	7.37%	3.79%	7.61%	3.61%		7.72%	3.60%	
2003	10.97%	6.58%	4.39%	7.52%	3.57%		7.62%	3.66%	
2004	10.75%	6.16%	4.59%	7.22%	3.86%		7.40%	3.81%	
2005	10.54%	5.65%	4.89%	6.71%	4.20%		7.18%	3.94%	
2006	10.36%	6.07%	4.29%	6.37%	4.39%		7.01%	4.00%	
2007	10.36%	6.07%	4.29%	6.11%	4.49%		6.86%	4.05%	
2008	10.46%	6.53%	3.93%	6.10%	4.40%		6.81%	3.98%	
2009	10.48%	6.04%	4.44%	6.07%	4.37%		6.65%	4.11%	
2010	10.24%	5.46%	4.78%	6.03%	4.35%		6.37%	4.27%	
2011	10.07%	5.04%	5.03%	5.83%	4.49%		6.10%	4.44%	
2012	10.01%	4.13%	5.88%	5.44%	4.81%		5.77%	4.65%	
2013	9.79%	4.48%	5.31%	5.03%	5.09%		5.56%	4.74%	
2014	9.76%	4.28%	5.48%	4.68%	5.30%		5.37%	4.83%	
2015	9.58%	4.12%	5.46%	4.41%	5.43%		5.22%	4.89%	
2016	9.68%	4.18%	5.50%	4.24%	5.53%		5.03%	5.01%	
Average	11.17%	7.09%	4.08%	7.09%	4.03%		7.09%	4.00%	
Minimum				4.24%	2.88%		5.03%	3.20%	
Maximum				9.96%	5.53%		9.16%	5.01%	

Source: Exhibit MPG-14

Analysis Using Gorman's Rolling Average Equity Risk Premium Data

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.979694
R Square	0.959801
Adjusted R Square	0.958193
Standard Error	0.001584
Observations	27

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.001497	0.001497	596.900197	0.000000
Residual	25	0.000063	0.000003		
Total	26	0.001560			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.080351	0.001119	71.795082	0.000000	0.078046	0.082656	0.078046	0.082656
X Variable 1	-0.460208	0.018837	-24.431541	0.000000	-0.499003	-0.421413	-0.499003	-0.421413

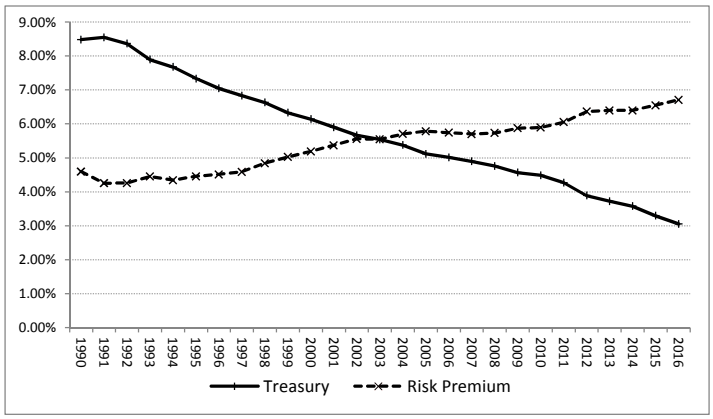
SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.980565
R Square	0.961508
Adjusted R Square	0.959968
Standard Error	0.001497
Observations	27

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.001400	0.001400	624.479845	0.000000
Residual	25	0.000056	0.000002		
Total	26	0.001456			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.072307	0.001314	55.042967	0.000000	0.069601	0.075012	0.069601	0.075012
X Variable 1	-0.451532	0.018069	-24.989595	0.000000	-0.488746	-0.414319	-0.488746	-0.414319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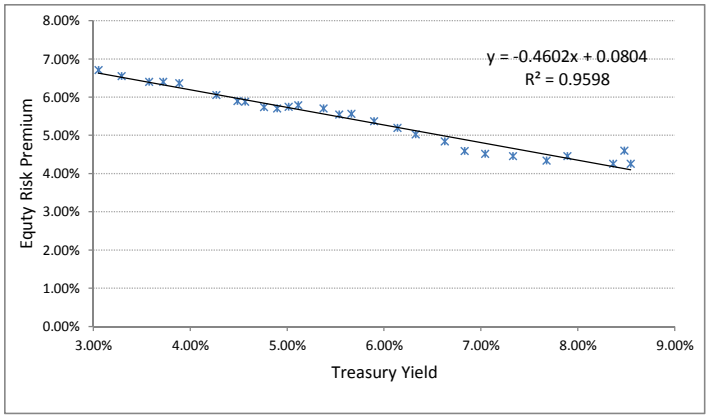
Treasury
Risk Premium


y = -0.4602x + 0.0804
R² = 0.9598
Equty Risk Premium
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9.00%
Treasury Yield

Analysis Using Mr. Gorman's Annual Equity Risk Premium Data

Year	ROE	Utility "A" Bond Yield	Treasury Bond Yield	Credit Spread	Treasury Equity Risk Premium	Utility Bond Equity Risk Premium	Treasury Yield	Credit Spread
1986	13.93%	9.58%	7.80%	1.78%	6.13%	4.35%	7.80%	1.78%
1987	12.99%	10.10%	8.58%	1.52%	4.41%	2.89%	8.58%	1.52%
1988	12.79%	10.49%	8.96%	1.53%	3.83%	2.30%	8.96%	1.53%
1989	12.97%	9.77%	8.45%	1.32%	4.52%	3.20%	8.45%	1.32%
1990	12.70%	9.86%	8.61%	1.25%	4.09%	2.84%	8.61%	1.25%
1991	12.55%	9.36%	8.14%	1.22%	4.41%	3.19%	8.14%	1.22%
1992	12.09%	8.69%	7.67%	1.02%	4.42%	3.40%	7.67%	1.02%
1993	11.41%	7.59%	6.60%	0.99%	4.81%	3.82%	6.60%	0.99%
1994	11.34%	8.31%	7.37%	0.94%	3.97%	3.03%	7.37%	0.94%
1995	11.55%	7.89%	6.88%	1.01%	4.67%	3.66%	6.88%	1.01%
1996	11.39%	7.75%	6.70%	1.05%	4.69%	3.64%	6.70%	1.05%
1997	11.40%	7.60%	6.61%	0.99%	4.79%	3.80%	6.61%	0.99%
1998	11.66%	7.04%	5.58%	1.46%	6.08%	4.62%	5.58%	1.46%
1999	10.77%	7.62%	5.87%	1.75%	4.90%	3.15%	5.87%	1.75%
2000	11.43%	8.24%	5.94%	2.30%	5.49%	3.19%	5.94%	2.30%
2001	11.09%	7.76%	5.49%	2.27%	5.60%	3.33%	5.49%	2.27%
2002	11.16%	7.37%	5.43%	1.94%	5.73%	3.79%	5.43%	1.94%
2003	10.97%	6.58%	4.96%	1.62%	6.01%	4.39%	4.96%	1.62%
2004	10.75%	6.16%	5.05%	1.11%	5.70%	4.59%	5.05%	1.11%
2005	10.54%	5.65%	4.65%	1.00%	5.89%	4.89%	4.65%	1.00%
2006	10.36%	6.07%	4.99%	1.08%	5.37%	4.29%	4.99%	1.08%
2007	10.36%	6.07%	4.83%	1.24%	5.53%	4.29%	4.83%	1.24%
2008	10.46%	6.53%	4.28%	2.25%	6.18%	3.93%	4.28%	2.25%
2009	10.48%	6.04%	4.07%	1.97%	6.41%	4.44%	4.07%	1.97%
2010	10.24%	5.46%	4.25%	1.21%	5.99%	4.78%	4.25%	1.21%
2011	10.07%	5.04%	3.91%	1.13%	6.16%	5.03%	3.91%	1.13%
2012	10.01%	4.13%	2.92%	1.21%	7.09%	5.88%	2.92%	1.21%
2013	9.79%	4.48%	3.45%	1.03%	6.34%	5.31%	3.45%	1.03%
2014	9.76%	4.28%	3.34%	0.94%	6.42%	5.48%	3.34%	0.94%
2015	9.58%	4.12%	2.84%	1.27%	6.74%	5.46%	2.84%	1.27%
2016	9.68%	4.18%	2.72%	1.46%	6.96%	5.50%	2.72%	1.46%

Sources: Exhibit MPG-13 and MPG-14

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.898826
R Square	0.807887
Adjusted R Square	0.801263
Standard Error	0.004088
Observations	31

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.002038	0.002038	121.953137	0.000000
Residual	29	0.000485	0.000017		
Total	30	0.002522			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.079782	0.002393	33.337504	0.000000	0.074887	0.084676
Treasury Yield	-0.440736	0.039910	-11.043239	0.000000	-0.522361	-0.359111

RESIDUAL OUTPUT

Observation	*Equity Risk F*	*Residuals*	$(e_t - e_{(t-1)})^2$	$(e_t)^2$
1	0.0454116	0.015905067		
2	0.04196651	0.002133486	0.00019	0.00000
3	0.04029539	-0.001987057	0.00002	0.00000
4	0.04254314	0.00266519	0.00002	0.00001
5	0.04184164	-0.000924972	0.00001	0.00000
6	0.04392412	0.000217551	0.00000	0.00000
7	0.0459919	-0.001758569	0.00000	0.00000
8	0.05070043	-0.002583764	0.00000	0.00001
9	0.04729942	-0.007599419	0.00003	0.00006
10	0.04944066	-0.002782328	0.00002	0.00001
11	0.05024868	-0.00335701	0.00000	0.00001
12	0.05066738	-0.002725709	0.00000	0.00001
13	0.05519594	0.005620729	0.00007	0.00003
14	0.05392882	-0.004887155	0.00011	0.00002
15	0.05359092	0.001284076	0.00004	0.00000
16	0.05557056	0.000396103	0.00000	0.00000
17	0.0558497	0.001450304	0.00000	0.00000
18	0.05793217	0.002192827	0.00000	0.00000
19	0.05753918	-0.00050585	0.00001	0.00000
20	0.0593058	-0.000364134	0.00000	0.00000
21	0.05777792	-0.004102916	0.00001	0.00002
22	0.05847575	-0.003217414	0.00000	0.00001
23	0.06092183	0.000886501	0.00002	0.00000
24	0.06184738	0.002260956	0.00000	0.00001
25	0.06104671	-0.001155041	0.00001	0.00000
26	0.06254521	-0.000953543	0.00000	0.00000
27	0.0669085	0.003983172	0.00002	0.00002
28	0.06458361	-0.001166946	0.00003	0.00000
29	0.06506108	-0.000861077	0.00000	0.00000
30	0.06726108	0.000130583	0.00000	0.00000
31	0.06779364	0.00180636	0.00000	0.00000
			0.00062	0.00023
		Durbin-Watson	2.69423	
		dL	1.147	4-dL 2.853
		dU	1.274	4-dU 2.726
		DW>2	TRUE	
		DW<4-dU?	TRUE	No Autocorrelation

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.916176
R Square	0.839379
Adjusted R Square	0.833841
Standard Error	0.003777
Observations	31

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.002162	0.002162	151.549633	0.000000
Residual	29	0.000414	0.000014		
Total	30	0.002575			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.072374	0.002653	27.275585	0.000000	0.066947	0.077801
Utility "A" Bond Yiel	-0.445377	0.036178	-12.310550	0.000000	-0.519370	-0.371384

RESIDUAL OUTPUT

Observation	*d Equity Risk F*	*Residuals*	$(e_t - e_{(t-1)})^2$	$(e_t)^2$
1	0.02970688	0.013793119		
2	0.02739092	0.001509079	0.00015	0.00000
3	0.02565395	-0.00265395	0.00002	0.00001
4	0.02886067	0.003139335	0.00003	0.00001
5	0.02845983	-5.98258E-05	0.00001	0.00000
6	0.03068671	0.001213289	0.00000	0.00000
7	0.03367074	0.000329263	0.00000	0.00000
8	0.03856988	-0.000369884	0.00000	0.00000
9	0.03536317	-0.00506317	0.00002	0.00003
10	0.03723375	-0.000633753	0.00002	0.00000
11	0.03785728	-0.001457281	0.00000	0.00000
12	0.03852535	-0.000525347	0.00000	0.00000
13	0.04101946	0.005180542	0.00003	0.00003
14	0.03843627	-0.006936271	0.00015	0.00005
15	0.03565638	-0.003798043	0.00001	0.00001
16	0.03780161	-0.004526609	0.00000	0.00002
17	0.03953858	-0.001663579	0.00001	0.00000
18	0.04306448	0.000827186	0.00001	0.00000
19	0.0449384	0.000960762	0.00000	0.00000
20	0.04721391	0.001694423	0.00000	0.00000
21	0.04534704	-0.002430372	0.00002	0.00001
22	0.04532477	-0.002458103	0.00000	0.00001
23	0.0432983	-0.003981637	0.00000	0.00002
24	0.04548776	-0.001055128	0.00001	0.00000
25	0.04805082	-0.00026338	0.00000	0.00000
26	0.04992204	0.000366821	0.00000	0.00000
27	0.05397643	0.004815707	0.00002	0.00002
28	0.05243845	0.000700483	0.00002	0.00000
29	0.0533234	0.001502504	0.00000	0.00000
30	0.05404497	0.000601063	0.00000	0.00000
31	0.05375724	0.001242759	0.00000	0.00000
			0.00053	0.00022

Durbin-Watson	2.37384			
dL	1.085	4-dL	4-dU	
dU	1.345	2.915	2.655	
DW>2	TRUE			
DW<4-dU?	TRUE	No Autocorrelation		

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.917057
R Square	0.840994
Adjusted R Square	0.829636
Standard Error	0.003785
Observations	31

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	0.002121	0.001061	74.046865	0.000000
Residual	28	0.000401	0.000014		
Total	30	0.002522			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.074097	0.003233	22.918543	0.000000	0.067474	0.080720
Treasury Yield	-0.438638	0.036962	-11.867392	0.000000	-0.514351	-0.362926
Credit Spread	0.402273	0.166607	2.414503	0.022540	0.060994	0.743552

RESIDUAL OUTPUT

Observation	*d Equity Risk F*	*Residuals*	$(e_t - e_{(t-1)})^2$	$(e_t)^2$
1	0.04705767	0.014258992		
2	0.04257637	0.001523628	0.00016	0.00000
3	0.04095678	-0.002648449	0.00002	0.00001
4	0.04234906	0.00285927	0.00003	0.00001
5	0.04137266	-0.000455992	0.00001	0.00000
6	0.0433346	0.000807068	0.00000	0.00000
7	0.04458464	-0.000351311	0.00000	0.00000
8	0.04914338	-0.001026709	0.00000	0.00000
9	0.04555071	-0.00585071	0.00002	0.00003
10	0.04794659	-0.001288257	0.00002	0.00000
11	0.04892508	-0.002033412	0.00000	0.00000
12	0.04912053	-0.001178868	0.00000	0.00000
13	0.05550817	0.005308499	0.00004	0.00003
14	0.05542373	-0.006382065	0.00014	0.00004
15	0.05728989	-0.002414887	0.00002	0.00001
16	0.05912936	-0.003162698	0.00000	0.00001
17	0.05809308	-0.000793077	0.00001	0.00000
18	0.05888172	0.001243279	0.00000	0.00000
19	0.05643934	0.000593988	0.00000	0.00000
20	0.05775472	0.001186949	0.00000	0.00000
21	0.05652575	-0.002850753	0.00002	0.00001
22	0.05787731	-0.002618976	0.00000	0.00001
23	0.06437471	-0.002566375	0.00000	0.00001
24	0.06416306	-5.47269E-05	0.00001	0.00000
25	0.0603204	-0.000428735	0.00000	0.00000
26	0.06148938	0.000102283	0.00000	0.00000
27	0.0661524	0.004739265	0.00002	0.00002
28	0.06310572	0.000310942	0.00002	0.00000
29	0.06321741	0.000982594	0.00000	0.00000
30	0.06676322	0.000628445	0.00000	0.00000
31	0.0680392	0.001560796	0.00000	0.00000
			0.00054	0.00020

Durbin-Watson	2.73514			
dL	1.147	4-dL	4-dU	
dU	1.274	2.853	2.726	
DW>2	TRUE			
DW<4-dU	FALSE			
4-dU<DW<4-dL	TRUE	Inconclusive		

Forecasting 30 Year Treasury Yields: Regression Results Based on Data in Exhibit MPG-21

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.744743
R Square	0.554642
Adjusted R Square	0.546545
Standard Error	0.005857
Observations	57

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.002350	0.002350	68.496210	0.000000
Residual	55	0.001887	0.000034		
Total	56	0.004236			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.006803	0.004302	1.581230	0.119560	-0.001819	0.015424
PRIOR QUARTER ACTUAL YIELD (X)	0.783457	0.094663	8.276244	0.000000	0.593747	0.973166

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.905824
R Square	0.820516
Adjusted R Square	0.817253
Standard Error	0.003718
Observations	57

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.003476	0.003476	251.434812	0.000000
Residual	55	0.000760	0.000014		
Total	56	0.004236			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.055590	0.000998	55.697993	0.000000	0.053589	0.057590
TREND	-0.000475	0.000030	-15.856696	0.000000	-0.000535	-0.000415

December 2018 Trend Variable	105
Implied Treasury Yield	0.58%

Source: Exhibit MPG-21

Mr. Gorman's Financial Integrity Analysis (Exhibit MPG-19)

Description	Retail Cost of Service Amount (1)	S&P Benchmark (Medial Volatility) Intermediate (2)	Significant (3)	Aggressive (4)	Reference (5)
Rate Base	$ 32,536,116				Schedule A-1.
Weighted Common Return	4.17%				Exhibit MPG-19, Page 3, Line 3, Col. 3.
Pre-Tax Rate of Return	8.19%				Exhibit MPG-19, Page 3, Line 7, Col. 4.
Income to Common	$ 1,358,228				Line 1 x Line 2.
EBIT	$ 2,663,715				Line 1 x Line 3.
Depreciation & Amortization	$ 1,665,925				Schedule C-1
Imputed Amortization	$ 52,057				Exhibit MPG-19, Page 1, Line 7, Col. 1.
Deferred Income Taxes & ITC	$ 598,846				Schedule C-22
Funds from Operations (FFO)	$ 3,675,056				Sum of Line 4 and Lines 6 through 8.
Imputed Interest Expense	$ 40,363				Exhibit MPG-19, Page 1, Line 10, Col. 1.
EBITDA	$ 4,422,060				Sum of Lines 5 through 7 and Line 10.
Total Debt Ratio	41%				Exhibit MPG-19, Page 4, Line4, Col. 2.
Debt to EBITDA	3.0x	2.5x - 3.5x	3.5x - 4.5x	4.5x - 5.5x	(Line 1 x Line 12) / Line 11.
FFO to Total Debt	27%	23% - 35%	13% - 23%	9% - 13%	Line 9 / (Line 1 x Line 12).

Gorman's Financial Integrity Analysis, ROE of 6.55%

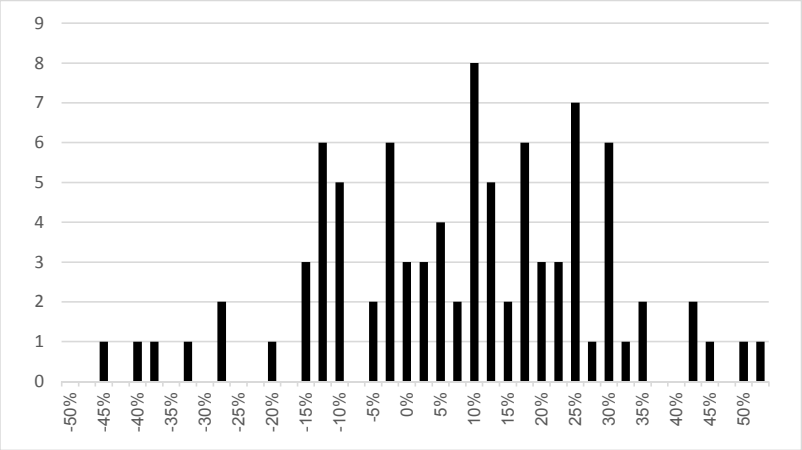
Description	Retail Cost of Service Amount (1)	S&P Benchmark (Medial Volatility) Intermediate (2)	Significant (3)	Aggressive (4)	Reference (5)
Rate Base	$ 32,536,116				Schedule A-1.
Weighted Common Return	2.96%				Exhibit MPG-19, Page 3, Line 3, Col. 3 set as 4%
Pre-Tax Rate of Return	6.20%				Exhibit MPG-19, Page 3, Line 7, Col. 4 set as 4%
Income to Common	$ 961,772				Line 1 x Line 2.
EBIT	$ 2,017,397				Line 1 x Line 3.
Depreciation & Amortization	$ 1,665,925				Schedule C-1
Imputed Amortization	$ 52,057				CreditStats, www.globalcreditportal.com, June 30, 2016.
Deferred Income Taxes & ITC	$ 598,846				Schedule C-22
Funds from Operations (FFO)	$ 3,278,600				Sum of Line 4 and Lines 6 through 8.
Imputed Interest Expense	$ 40,363				CreditStats, www.globalcreditportal.com, June 30, 2016.
EBITDA	$ 3,775,742				Sum of Lines 5 through 7 and Line 10.
Total Debt Ratio	41%				Page 4, Line4, Col. 2.
Debt to EBITDA	3.5x	2.5x - 3.5x	3.5x - 4.5x	4.5x - 5.5x	(Line 1 x Line 12) / Line 11.
FFO to Total Debt	25%	23% - 35%	13% - 23%	9% - 13%	Line 9 / (Line 1 x Line 12).

Gorman's Financial Integrity Analysis, ROE of 11.00%

Description	Retail Cost of Service Amount (1)	S&P Benchmark (Medial Volatility) Intermediate (2)	Significant (3)	Aggressive (4)	Reference (5)
Rate Base	$ 32,536,116				Schedule A-1.
Weighted Common Return	4.96%				Exhibit MPG-19, Page 3, Line 3, Col. 3 set as 10.25%
Pre-Tax Rate of Return	9.47%				Exhibit MPG-19, Page 3, Line 7, Col. 4 set as 10.25%
Income to Common	$ 1,615,190				Line 1 x Line 2.
EBIT	$ 3,082,625				Line 1 x Line 3.
Depreciation & Amortization	$ 1,665,925				Schedule C-1
Imputed Amortization	$ 52,057				CreditStats, www.globalcreditportal.com, June 30, 2016.
Deferred Income Taxes & ITC	$ 598,846				Schedule C-22
Funds from Operations (FFO)	$ 3,932,018				Sum of Line 4 and Lines 6 through 8.
Imputed Interest Expense	$ 40,363				CreditStats, www.globalcreditportal.com, June 30, 2016.
EBITDA	$ 4,840,970				Sum of Lines 5 through 7 and Line 10.
Total Debt Ratio	41%				Page 4, Line4, Col. 2.
Debt to EBITDA	2.8x	2.5x - 3.5x	3.5x - 4.5x	4.5x - 5.5x	(Line 1 x Line 12) / Line 11.
FFO to Total Debt	29%	23% - 35%	13% - 23%	9% - 13%	Line 9 / (Line 1 x Line 12).

Source:
Exhibit MPG-19 (differences due to rounding)

Frequency Distribution of Observed Market Risk Premia, 1926 - 2015



Sources: Morningstar, Inc., Ibbotson SBBI 2016 Appendix A, at 3-5, 21-23.

	Large Company Stocks Total Returns	Long-Term Government Bond Income Returns	
Year	**Jan-Dec***	**Jan-Dec***	**MRP**
1926	0.1162	0.0373	7.890
1927	0.3749	0.0341	34.080
1928	0.4361	0.0322	40.390
1929	-0.0842	0.0347	-11.890
1930	-0.2490	0.0332	-28.220
1931	-0.4334	0.0333	-46.670
1932	-0.0819	0.0369	-11.880
1933	0.5399	0.0312	50.870
1934	-0.0144	0.0318	-4.620
1935	0.4767	0.0281	44.860
1936	0.3392	0.0277	31.150
1937	-0.3503	0.0266	-37.690
1938	0.3112	0.0264	28.480
1939	-0.0041	0.0240	-2.810
1940	-0.0978	0.0223	-12.010
1941	-0.1159	0.0194	-13.530
1942	0.2034	0.0246	17.880
1943	0.2590	0.0244	23.460
1944	0.1975	0.0246	17.290
1945	0.3644	0.0234	34.100
1946	-0.0807	0.0204	-10.110
1947	0.0571	0.0213	3.580
1948	0.0550	0.0240	3.100
1949	0.1879	0.0225	16.540
1950	0.3171	0.0212	29.590
1951	0.2402	0.0238	21.640
1952	0.1837	0.0266	15.710
1953	-0.0099	0.0284	-3.830
1954	0.5262	0.0279	49.830
1955	0.3156	0.0275	28.810
1956	0.0656	0.0299	3.570
1957	-0.1078	0.0344	-14.220
1958	0.4336	0.0327	40.090

1959	0.1196	0.0401	7.950
1960	0.0047	0.0426	-3.790
1961	0.2689	0.0383	23.060
1962	-0.0873	0.0400	-12.730
1963	0.2280	0.0389	18.910
1964	0.1648	0.0415	12.330
1965	0.1245	0.0419	8.260
1966	-0.1006	0.0449	-14.550
1967	0.2398	0.0459	19.390
1968	0.1106	0.0550	5.560
1969	-0.0850	0.0595	-14.450
1970	0.0386	0.0674	-2.880
1971	0.1430	0.0632	7.980
1972	0.1899	0.0587	13.120
1973	-0.1469	0.0651	-21.200
1974	-0.2647	0.0727	-33.740
1975	0.3723	0.0799	29.240
1976	0.2393	0.0789	16.040
1977	-0.0716	0.0714	-14.300
1978	0.0657	0.0790	-1.330
1979	0.1861	0.0886	9.750
1980	0.3250	0.0997	22.530
1981	-0.0492	0.1155	-16.470
1982	0.2155	0.1350	8.050
1983	0.2256	0.1038	12.180
1984	0.0627	0.1174	-5.470
1985	0.3173	0.1125	20.480
1986	0.1867	0.0898	9.690
1987	0.0525	0.0792	-2.670
1988	0.1661	0.0897	7.640
1989	0.3169	0.0881	22.880
1990	-0.0310	0.0819	-11.290
1991	0.3047	0.0822	22.250
1992	0.0762	0.0726	0.360
1993	0.1008	0.0717	2.910
1994	0.0132	0.0659	-5.270
1995	0.3758	0.0760	29.980
1996	0.2296	0.0618	16.780
1997	0.3336	0.0664	26.720
1998	0.2858	0.0583	22.750
1999	0.2104	0.0557	15.470
2000	-0.0910	0.0650	-15.600
2001	-0.1189	0.0553	-17.420
2002	-0.2210	0.0559	-27.690
2003	0.2868	0.0480	23.880
2004	0.1088	0.0502	5.860
2005	0.0491	0.0469	0.220
2006	0.1579	0.0468	11.110
2007	0.0549	0.0486	0.630
2008	-0.3700	0.0445	-41.450
2009	0.2646	0.0347	22.990
2010	0.1506	0.0425	10.810
2011	0.0211	0.0390	-1.790
2012	0.1600	0.0246	13.540
2013	0.3239	0.0288	29.510
2014	0.1369	0.0341	10.280
2015	0.0138	0.0247	-1.090
Average	0.1195	0.0505	6.904
Std. Dev.	0.1999	0.0263	20.078

Bin	*Frequency*	*Cumulative %*
-50.00%	0	0.000%
-47.50%	0	0.000%
-45.00%	1	1.111%
-42.50%	0	1.111%
-40.00%	1	2.222%
-37.50%	1	3.333%
-35.00%	0	3.333%
-32.50%	1	4.444%
-30.00%	0	4.444%
-27.50%	2	6.667%
-25.00%	0	6.667%
-22.50%	0	6.667%
-20.00%	1	7.778%
-17.50%	0	7.778%
-15.00%	3	11.111%
-12.50%	6	17.778%
-10.00%	5	23.333%
-7.50%	0	23.333%
-5.00%	2	25.556%
-2.50%	6	32.222%
0.00%	3	35.556%
2.50%	3	38.889%
5.00%	4	43.333%
7.50%	2	45.556%
10.00%	8	54.444%
12.50%	5	60.000%
15.00%	2	62.222%
17.50%	6	68.889%
20.00%	3	72.222%
22.50%	3	75.556%
25.00%	7	83.333%
27.50%	1	84.444%
30.00%	6	91.111%
32.50%	1	92.222%
35.00%	2	94.444%
37.50%	0	94.444%
40.00%	0	94.444%
42.50%	2	96.667%
45.00%	1	97.778%
47.50%	0	97.778%
50.00%	1	98.889%
51.00%	1	100.000%
Count:	90	

Average MRP	Rank:
10.68	55.90%

Alternative Bond Yield Plus Risk Premium Analysis

	[1] Constant	[2] LN(30-Year Treasury)	[3] Moody's Utility Baa Credit Spread	[4] VIX
Regression Coefficients	-0.026	-0.025	0.215	0.00005
Long Term Averages [5], [6]			1.81%	22.36

	30-Yr. Treasury Yield [7]	Risk Premium [8]	Return on Equity [9]
Current 30-Year Treasury	2.50%	7.33%	9.83%
Blue Chip Financial Forecast 2017 Projection	3.40%	6.55%	9.95%
Blue Chip Financial Forecast 2020 Projection	4.40%	5.89%	10.29%

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.820612
R Square	0.673404
Adjusted R Square	0.671829
Standard Error	0.005498
Observations	626

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	0.038767	0.012922	427.497607	0.000000
Residual	622	0.018802	0.000030		
Total	625	0.057569			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-0.025758	0.002491	-10.340783	0.000000	-0.030649	-0.020866	-0.030649	-0.020866
LN(30-Year Treasury)	-0.025474	0.000843	-30.202755	0.000000	-0.027131	-0.023818	-0.027131	-0.023818
Utility Baa Credit Spread	0.214700	0.047428	4.526891	0.000007	0.121562	0.307838	0.121562	0.307838
VIX	0.000055	0.000034	1.618449	0.106073	-0.000012	0.000122	-0.000012	0.000122

Notes:
[1] Constant of regression equation (1992-2016)
[2] Equals Regression Coefficient of LN(30-year Treasury Yield variable)
[3] Equals Regression Coefficient of Credit Spread variable
[4] Equals Regression Coefficient of VIX variable
[5] Long-Term Historical Average of Baa Credit Spread
[6] Source: http://www.cboe.com/data/volatilityindexes/volatilityindexes.aspx; accessed July 27, 2016
[7] Source: Current = Bloomberg Professional,
Near-Term Projected = Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 2. Forecast for Q3 2017.
Long-Term Projected = Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 14.
[8] Equals [1] + ([2] x LN[7]) + ([3] x [5]) + ([4] x [6])
[9] Equals [7] + [8]
[10] Source: SNL Financial
[11] Source: SNL Financial
[12] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period)
[13] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period)
[14] Equals LN[12]
[15] Equals [13] - [12]
[16] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period)
[17] Equals [11] - [12]

[10] Date of Electric Rate Case	[11] Return on Equity	[12] 30-Year Treasury Yield	[13] Moody's Utility Baa Yield	[14] LN(30-Year Treasury)	[15] Moody's Utility Baa Credit Spread	[16] VIX	[17] Risk Premium
1/10/1990	12.80%	8.24%		-2.496477861		19.95	4.56%
1/11/1990	12.90%	8.23%		-2.497024601		19.96	4.67%
1/17/1990	12.80%	8.22%		-2.499113014		21.59	4.58%
1/26/1990	12.00%	8.19%		-2.501942804		22.87	3.81%
2/9/1990	12.10%	8.17%		-2.504801539		23.58	3.93%
2/24/1990	12.86%	8.15%		-2.507522892		23.35	4.71%
3/30/1990	12.90%	8.16%		-2.505906927		22.17	4.74%
4/4/1990	15.76%	8.17%		-2.505240839		22.16	7.59%
4/12/1990	12.52%	8.18%		-2.503520424		22.04	4.34%
4/19/1990	12.75%	8.20%		-2.501412987		22.01	4.55%
5/21/1990	12.10%	8.28%		-2.490818765		21.42	3.82%
5/29/1990	12.40%	8.30%		-2.489147186		21.25	4.10%
5/31/1990	12.00%	8.30%		-2.488692501		21.17	3.70%
6/4/1990	12.90%	8.30%		-2.4883905		21.11	4.60%
6/6/1990	12.25%	8.31%		-2.488115209		21.06	3.94%
6/15/1990	13.20%	8.32%		-2.486948935		20.80	4.88%

6/20/1990	12.92%	8.32%	-2.486220477	20.68	4.60%
6/27/1990	12.90%	8.33%	-2.484996704	20.52	4.57%
6/29/1990	12.50%	8.34%	-2.484701847	20.45	4.16%
7/6/1990	12.35%	8.34%	-2.48420579	20.33	4.01%
7/6/1990	12.10%	8.34%	-2.48420579	20.33	3.76%
8/10/1990	12.55%	8.41%	-2.475736762	20.52	4.14%
8/16/1990	13.21%	8.43%	-2.473575512	20.64	4.78%
8/22/1990	13.10%	8.45%	-2.471018017	20.82	4.65%
8/24/1990	13.00%	8.46%	-2.469496155	21.00	4.54%
9/26/1990	11.45%	8.59%	-2.454201215	21.96	2.86%
10/2/1990	13.00%	8.61%	-2.451809401	22.09	4.39%
10/5/1990	12.84%	8.63%	-2.450337442	22.18	4.21%
10/19/1990	13.00%	8.67%	-2.445512392	22.69	4.33%
10/25/1990	12.30%	8.68%	-2.444370992	22.80	3.62%
11/21/1990	12.70%	8.69%	-2.442615086	22.98	4.01%
12/13/1990	12.30%	8.67%	-2.44490271	22.97	3.63%
12/17/1990	12.87%	8.67%	-2.44545674	23.00	4.20%
12/18/1990	13.10%	8.67%	-2.445757644	23.02	4.43%
12/19/1990	12.00%	8.66%	-2.446009336	23.04	3.34%
12/20/1990	12.75%	8.66%	-2.446187995	23.05	4.09%
12/21/1990	12.50%	8.66%	-2.446334775	23.07	3.84%
12/27/1990	12.79%	8.66%	-2.44671836	23.13	4.13%
1/2/1991	13.10%	8.66%	-2.446942427	23.25	4.44%
1/4/1991	12.50%	8.65%	-2.4473669	23.31	3.85%
1/15/1991	12.75%	8.65%	-2.448168141	23.75	4.10%
1/25/1991	11.70%	8.63%	-2.450247154	23.94	3.07%
2/4/1991	12.50%	8.60%	-2.453128134	23.92	3.90%
2/7/1991	12.50%	8.59%	-2.454862821	23.95	3.91%
2/12/1991	13.00%	8.57%	-2.456475087	23.99	4.43%
2/14/1991	12.72%	8.56%	-2.457500722	24.02	4.16%
2/22/1991	12.80%	8.55%	-2.459800347	24.08	4.25%
3/6/1991	13.10%	8.53%	-2.461874245	24.18	4.57%
3/8/1991	13.00%	8.52%	-2.462251459	24.21	4.48%
3/8/1991	12.30%	8.52%	-2.462251459	24.21	3.78%
4/22/1991	13.00%	8.49%	-2.466242714	24.23	4.51%
5/7/1991	13.50%	8.47%	-2.468214975	24.22	5.03%
5/13/1991	13.25%	8.47%	-2.468668749	24.15	4.78%
5/30/1991	12.75%	8.43%	-2.473033695	23.59	4.32%
6/12/1991	12.00%	8.41%	-2.476341626	23.03	3.59%
6/25/1991	11.70%	8.38%	-2.478854049	22.47	3.32%
6/28/1991	12.50%	8.38%	-2.479875908	22.31	4.12%
7/1/1991	12.00%	8.37%	-2.480289386	22.25	3.63%
7/3/1991	12.50%	8.36%	-2.481170322	22.15	4.14%
7/19/1991	12.10%	8.34%	-2.484421541	21.55	3.76%
8/1/1991	12.90%	8.32%	-2.486808759	20.89	4.58%
8/16/1991	13.20%	8.29%	-2.490493686	20.12	4.91%
9/27/1991	12.50%	8.23%	-2.496936101	19.02	4.27%
9/30/1991	12.25%	8.23%	-2.49722421	18.99	4.02%
10/17/1991	13.00%	8.20%	-2.500713128	18.47	4.80%
10/23/1991	12.50%	8.20%	-2.501422183	18.20	4.30%
10/23/1991	12.55%	8.20%	-2.501422183	18.20	4.35%
10/31/1991	11.80%	8.19%	-2.502275923	17.68	3.61%
11/1/1991	12.00%	8.19%	-2.502450195	17.63	3.81%
11/5/1991	12.25%	8.19%	-2.502725164	17.55	4.06%
11/12/1991	12.50%	8.18%	-2.503292528	17.35	4.32%
11/12/1991	13.25%	8.18%	-2.503292528	17.35	5.07%
11/25/1991	12.40%	8.18%	-2.503712733	17.21	4.22%
11/26/1991	12.50%	8.18%	-2.503769265	17.20	4.32%
11/26/1991	11.60%	8.18%	-2.503769265	17.20	3.42%
11/27/1991	12.10%	8.18%	-2.503814739	17.19	3.92%
12/18/1991	12.25%	8.15%	-2.507331083	17.07	4.10%
12/19/1991	12.60%	8.15%	-2.507721524	17.06	4.45%
12/19/1991	12.80%	8.15%	-2.507721524	17.06	4.65%
12/20/1991	12.65%	8.14%	-2.508180009	17.04	4.51%
1/9/1992	12.80%	8.09%	-2.51476261	17.13	4.71%
1/16/1992	12.75%	8.07%	-2.516799408	17.14	4.68%
1/21/1992	12.00%	8.06%	-2.517809082	17.12	3.94%
1/22/1992	13.00%	8.06%	-2.518107633	17.10	4.94%
1/27/1992	12.65%	8.05%	-2.519087429	17.09	4.60%
1/31/1992	12.00%	8.04%	-2.520318057	17.12	3.96%
2/11/1992	12.40%	8.03%	-2.522191565	17.16	4.37%
2/25/1992	12.50%	8.01%	-2.524420455	17.14	4.49%
3/16/1992	11.43%	7.98%	-2.5279667	17.25	3.45%
3/18/1992	12.28%	7.98%	-2.528600856	17.26	4.30%
4/2/1992	12.10%	7.95%	-2.532341542	17.24	4.15%
4/9/1992	11.45%	7.93%	-2.534038199	17.24	3.52%
4/10/1992	11.50%	7.93%	-2.534424003	17.23	3.57%
4/14/1992	11.50%	7.92%	-2.535249959	17.21	3.58%
5/5/1992	11.50%	7.89%	-2.539367717	17.08	3.61%
5/12/1992	12.46%	7.88%	-2.540491605	17.09	4.58%
5/12/1992	11.87%	7.88%	-2.540491605	17.09	3.99%
6/1/1992	12.30%	7.86%	-2.542849882	17.02	4.44%

6/12/1992	10.90%	7.85%		-2.544044864		16.97	3.05%
6/26/1992	12.35%	7.85%		-2.544922989		16.91	4.50%
6/29/1992	11.00%	7.85%		-2.545003672		16.88	3.15%
6/30/1992	13.00%	7.85%		-2.545063228		16.86	5.15%
7/13/1992	13.50%	7.84%		-2.546223031		16.78	5.66%
7/13/1992	11.90%	7.84%		-2.546223031		16.78	4.06%
7/22/1992	11.20%	7.83%		-2.547220512		16.65	3.37%
8/3/1992	12.00%	7.81%		-2.550005891		16.52	4.19%
8/6/1992	12.50%	7.80%		-2.550979453		16.48	4.70%
9/22/1992	12.00%	7.71%		-2.562150915		15.88	4.29%
9/28/1992	11.40%	7.71%		-2.563005971		15.78	3.69%
9/30/1992	11.75%	7.71%		-2.563248543		15.75	4.04%
10/2/1992	13.00%	7.70%		-2.563503569		15.74	5.30%
10/12/1992	12.20%	7.70%		-2.563555104		15.85	4.50%
10/16/1992	13.16%	7.71%		-2.563267456		15.82	5.45%
10/30/1992	11.75%	7.71%		-2.563084214		15.75	4.04%
11/3/1992	12.00%	7.71%		-2.56315855		15.74	4.29%
12/3/1992	11.85%	7.68%		-2.566695907		15.36	4.17%
12/15/1992	11.00%	7.66%		-2.569018479		15.17	3.34%
12/16/1992	11.90%	7.66%		-2.569326814		15.14	4.24%
12/16/1992	12.40%	7.66%		-2.569326814		15.14	4.74%
12/17/1992	12.00%	7.66%		-2.569679219		15.10	4.34%
12/22/1992	12.40%	7.65%		-2.571003981		14.99	4.75%
12/22/1992	12.30%	7.65%		-2.571003981		14.99	4.65%
12/29/1992	12.25%	7.63%	8.61%	-2.573127127	0.98%	14.86	4.62%
12/30/1992	12.00%	7.63%	8.61%	-2.573498663	0.98%	14.84	4.37%
12/31/1992	11.90%	7.62%	8.61%	-2.573859792	0.99%	14.82	4.28%
1/12/1993	12.00%	7.61%	8.62%	-2.5762929	1.01%	14.72	4.39%
1/21/1993	11.25%	7.59%	8.61%	-2.578757112	1.02%	14.52	3.66%
2/2/1993	11.40%	7.56%	8.56%	-2.582792324	1.01%	14.35	3.84%
2/15/1993	12.30%	7.52%	8.52%	-2.587853331	1.00%	14.22	4.78%
2/24/1993	11.90%	7.49%	8.48%	-2.591873816	0.99%	14.18	4.41%
2/26/1993	11.80%	7.48%	8.46%	-2.593142317	0.98%	14.16	4.32%
2/26/1993	12.20%	7.48%	8.46%	-2.593142317	0.98%	14.16	4.72%
4/23/1993	11.75%	7.29%	8.29%	-2.619128589	1.00%	13.85	4.46%
5/11/1993	11.75%	7.24%	8.26%	-2.62487387	1.02%	13.86	4.51%
5/14/1993	11.50%	7.24%	8.26%	-2.625954403	1.02%	13.87	4.26%
5/25/1993	11.50%	7.22%	8.26%	-2.627704331	1.04%	13.87	4.28%
5/28/1993	11.00%	7.22%	8.26%	-2.628492033	1.04%	13.84	3.78%
6/3/1993	12.00%	7.21%	8.26%	-2.629953568	1.05%	13.83	4.79%
6/16/1993	11.50%	7.19%	8.24%	-2.633023609	1.06%	13.77	4.31%
6/18/1993	12.10%	7.18%	8.24%	-2.633671358	1.06%	13.77	4.92%
6/25/1993	11.67%	7.17%	8.23%	-2.635647271	1.06%	13.74	4.50%
7/21/1993	11.38%	7.10%	8.20%	-2.64572959	1.10%	13.42	4.28%
7/23/1993	10.46%	7.09%	8.16%	-2.646920829	1.08%	13.34	3.37%
8/24/1993	11.50%	6.95%	8.13%	-2.665744765	1.18%	12.79	4.55%
9/21/1993	10.50%	6.80%	8.05%	-2.687542088	1.25%	12.72	3.70%
9/29/1993	11.47%	6.76%	8.03%	-2.693671658	1.27%	12.73	4.71%
9/30/1993	11.60%	6.76%	8.03%	-2.694664066	1.27%	12.74	4.84%
11/2/1993	10.80%	6.60%	7.89%	-2.718055616	1.29%	12.67	4.20%
11/12/1993	12.00%	6.56%	7.86%	-2.723624369	1.30%	12.76	5.44%
11/26/1993	11.00%	6.52%	7.83%	-2.730429154	1.31%	12.85	4.48%
12/14/1993	10.55%	6.48%	7.80%	-2.736143407	1.32%	12.75	4.07%
12/16/1993	10.60%	6.48%	7.80%	-2.736836716	1.32%	12.72	4.12%
12/21/1993	11.30%	6.47%	7.80%	-2.738096605	1.33%	12.66	4.83%
1/4/1994	10.07%	6.44%	7.78%	-2.742426307	1.34%	12.49	3.63%
1/13/1994	11.00%	6.42%	7.77%	-2.746265671	1.35%	12.45	4.58%
1/21/1994	11.00%	6.40%	7.75%	-2.748645306	1.35%	12.39	4.60%
1/28/1994	11.35%	6.39%	7.74%	-2.750446141	1.35%	12.37	4.96%
2/3/1994	11.40%	6.38%	7.73%	-2.75225574	1.35%	12.34	5.02%
2/17/1994	10.60%	6.36%	7.71%	-2.755429452	1.35%	12.38	4.24%
2/25/1994	11.25%	6.35%	7.70%	-2.756899777	1.36%	12.39	4.90%
2/25/1994	12.00%	6.35%	7.70%	-2.756899777	1.36%	12.39	5.65%
3/1/1994	11.00%	6.35%	7.70%	-2.757370833	1.36%	12.40	4.65%
3/4/1994	11.00%	6.34%	7.70%	-2.757695555	1.36%	12.43	4.66%
4/25/1994	11.00%	6.40%	7.74%	-2.74819011	1.33%	13.03	4.60%
5/10/1994	11.75%	6.44%	7.77%	-2.741906094	1.32%	13.20	5.31%
5/13/1994	10.50%	6.46%	7.78%	-2.739522199	1.32%	13.25	4.04%
6/3/1994	11.00%	6.54%	7.84%	-2.727421288	1.30%	13.32	4.46%
6/27/1994	11.40%	6.65%	7.94%	-2.710605473	1.29%	13.42	4.75%
8/5/1994	12.75%	6.88%	8.15%	-2.676571985	1.27%	13.42	5.87%
10/31/1994	10.00%	7.33%	8.54%	-2.613065108	1.21%	13.77	2.67%
11/9/1994	10.85%	7.40%	8.60%	-2.604267563	1.20%	13.94	3.45%
11/9/1994	10.85%	7.40%	8.60%	-2.604267563	1.20%	13.94	3.45%
11/18/1994	11.20%	7.46%	8.65%	-2.59623401	1.20%	14.12	3.74%
11/22/1994	11.60%	7.47%	8.67%	-2.594037077	1.20%	14.14	4.13%
11/28/1994	11.06%	7.50%	8.69%	-2.590418601	1.20%	14.20	3.56%
12/8/1994	11.70%	7.55%	8.75%	-2.584071324	1.21%	14.29	4.15%
12/8/1994	11.50%	7.55%	8.75%	-2.584071324	1.21%	14.29	3.95%
12/14/1994	10.95%	7.57%	8.78%	-2.581380139	1.21%	14.28	3.38%
12/15/1994	11.50%	7.57%	8.78%	-2.580740162	1.21%	14.26	3.93%
12/19/1994	11.50%	7.58%	8.80%	-2.579505183	1.21%	14.24	3.92%

12/28/1994	12.15%	7.61%	8.83%	-2.575147209	1.21%	14.14	4.54%
1/9/1995	12.28%	7.64%	8.87%	-2.571310299	1.22%	14.14	4.64%
1/31/1995	11.00%	7.69%	8.93%	-2.565244175	1.24%	13.71	3.31%
2/10/1995	12.60%	7.70%	8.95%	-2.563744305	1.25%	13.56	4.90%
2/17/1995	11.90%	7.70%	8.96%	-2.563497046	1.26%	13.49	4.20%
3/9/1995	11.50%	7.72%	8.98%	-2.561774453	1.26%	13.37	3.78%
3/20/1995	12.00%	7.72%	8.98%	-2.561279667	1.26%	13.35	4.28%
3/23/1995	12.81%	7.72%	8.99%	-2.561193104	1.27%	13.32	5.09%
3/29/1995	11.60%	7.72%	8.99%	-2.561390321	1.27%	13.31	3.88%
4/6/1995	11.10%	7.72%	8.99%	-2.561975041	1.28%	13.30	3.38%
4/7/1995	11.00%	7.71%	8.99%	-2.562117041	1.28%	13.28	3.29%
4/19/1995	11.00%	7.70%	8.99%	-2.563551842	1.29%	13.20	3.30%
5/12/1995	11.63%	7.68%	8.97%	-2.566903376	1.29%	13.21	3.95%
5/25/1995	11.20%	7.65%	8.95%	-2.570704328	1.30%	13.22	3.55%
6/9/1995	11.25%	7.60%	8.91%	-2.576999458	1.31%	13.26	3.65%
6/21/1995	12.25%	7.56%	8.88%	-2.582523025	1.32%	13.24	4.69%
6/30/1995	11.10%	7.51%	8.85%	-2.588289223	1.33%	13.20	3.59%
9/11/1995	11.30%	7.20%	8.58%	-2.630863753	1.38%	12.48	4.10%
9/27/1995	11.50%	7.12%	8.50%	-2.642117081	1.38%	12.24	4.38%
9/27/1995	11.75%	7.12%	8.50%	-2.642117081	1.38%	12.24	4.63%
9/27/1995	11.30%	7.12%	8.50%	-2.642117081	1.38%	12.24	4.18%
9/29/1995	11.00%	7.11%	8.49%	-2.643930188	1.38%	12.24	3.89%
11/9/1995	12.36%	6.89%	8.30%	-2.674546417	1.40%	12.47	5.47%
11/9/1995	11.38%	6.89%	8.30%	-2.674546417	1.40%	12.47	4.49%
11/17/1995	11.00%	6.85%	8.26%	-2.680612738	1.41%	12.51	4.15%
12/4/1995	11.35%	6.78%	8.21%	-2.69155484	1.43%	12.52	4.57%
12/11/1995	11.40%	6.74%	8.18%	-2.697079693	1.44%	12.52	4.66%
12/20/1995	11.60%	6.69%	8.13%	-2.704042664	1.44%	12.50	4.91%
12/27/1995	12.00%	6.66%	8.11%	-2.709184261	1.45%	12.48	5.34%
2/5/1996	12.25%	6.48%	7.97%	-2.737087325	1.50%	12.63	5.77%
3/29/1996	10.67%	6.42%	7.92%	-2.746308744	1.50%	13.49	4.25%
4/8/1996	11.00%	6.42%	7.92%	-2.745813123	1.50%	13.63	4.58%
4/11/1996	12.59%	6.43%	7.93%	-2.74496808	1.51%	13.74	6.16%
4/11/1996	12.59%	6.43%	7.93%	-2.74496808	1.51%	13.74	6.16%
4/24/1996	11.25%	6.43%	7.95%	-2.744033106	1.51%	13.93	4.82%
4/30/1996	11.00%	6.43%	7.95%	-2.744203463	1.52%	13.99	4.57%
5/13/1996	11.00%	6.44%	7.97%	-2.743373053	1.53%	14.15	4.56%
5/23/1996	11.25%	6.43%	7.98%	-2.743837779	1.54%	14.24	4.82%
6/25/1996	11.25%	6.48%	8.01%	-2.736832837	1.53%	14.73	4.77%
6/27/1996	11.20%	6.48%	8.01%	-2.736140306	1.53%	14.77	4.72%
8/12/1996	10.40%	6.57%	8.09%	-2.722275526	1.51%	15.35	3.83%
9/27/1996	11.00%	6.71%	8.19%	-2.701473883	1.48%	15.98	4.29%
10/16/1996	12.25%	6.76%	8.22%	-2.693650854	1.46%	16.22	5.49%
11/5/1996	11.00%	6.81%	8.25%	-2.686455654	1.44%	16.44	4.19%
11/26/1996	11.30%	6.83%	8.27%	-2.683157094	1.43%	16.58	4.47%
12/18/1996	11.75%	6.84%	8.27%	-2.683065193	1.44%	16.80	4.91%
12/31/1996	11.50%	6.83%	8.27%	-2.683536548	1.44%	16.84	4.67%
1/3/1997	10.70%	6.83%	8.27%	-2.683469618	1.43%	16.85	3.87%
2/13/1997	11.80%	6.82%	8.24%	-2.684796545	1.42%	17.23	4.98%
2/20/1997	11.80%	6.82%	8.23%	-2.685897396	1.42%	17.29	4.98%
3/31/1997	10.02%	6.80%	8.21%	-2.688051022	1.40%	17.83	3.22%
4/2/1997	11.65%	6.80%	8.20%	-2.687962365	1.40%	17.86	4.85%
4/28/1997	11.50%	6.81%	8.20%	-2.686810534	1.39%	18.20	4.69%
4/29/1997	11.70%	6.81%	8.20%	-2.686853335	1.39%	18.20	4.89%
7/17/1997	12.00%	6.77%	8.14%	-2.692346266	1.37%	19.04	5.23%
12/12/1997	11.00%	6.60%	7.96%	-2.717610327	1.36%	22.58	4.40%
12/23/1997	11.12%	6.57%	7.88%	-2.722946277	1.31%	22.85	4.55%
2/2/1998	12.75%	6.39%	7.80%	-2.750652989	1.41%	23.45	6.36%
3/2/1998	11.25%	6.28%	7.71%	-2.76702993	1.42%	23.41	4.97%
3/6/1998	10.75%	6.27%	7.69%	-2.769940573	1.43%	23.39	4.48%
3/20/1998	10.50%	6.22%	7.64%	-2.777213672	1.42%	23.36	4.28%
4/30/1998	12.20%	6.12%	7.54%	-2.79337985	1.42%	23.68	6.08%
7/10/1998	11.40%	5.94%	7.39%	-2.824188014	1.46%	23.14	5.46%
9/15/1998	11.90%	5.78%	7.30%	-2.850769112	1.52%	23.80	6.12%
11/30/1998	12.60%	5.58%	7.26%	-2.886003023	1.68%	26.06	7.02%
12/10/1998	12.20%	5.54%	7.25%	-2.89315573	1.71%	26.34	6.66%
12/17/1998	12.10%	5.52%	7.25%	-2.897314092	1.73%	26.58	6.58%
2/5/1999	10.30%	5.38%	7.24%	-2.922553735	1.86%	27.54	4.92%
3/4/1999	10.50%	5.34%	7.25%	-2.930709887	1.91%	28.19	5.16%
4/6/1999	10.94%	5.32%	7.28%	-2.933623209	1.96%	28.47	5.62%
7/29/1999	10.75%	5.52%	7.54%	-2.897188406	2.02%	25.77	5.23%
9/23/1999	10.75%	5.70%	7.72%	-2.864128491	2.02%	24.95	5.05%
11/17/1999	11.10%	5.90%	7.90%	-2.830538984	2.00%	24.31	5.20%
1/7/2000	11.50%	6.05%	8.03%	-2.805234019	1.98%	23.49	5.45%
1/7/2000	11.50%	6.05%	8.03%	-2.805234019	1.98%	23.49	5.45%
2/17/2000	10.60%	6.17%	8.15%	-2.784697924	1.98%	23.35	4.43%
3/28/2000	11.25%	6.20%	8.23%	-2.781387114	2.03%	22.96	5.05%
5/24/2000	11.00%	6.18%	8.34%	-2.783420237	2.16%	23.84	4.82%
7/18/2000	12.20%	6.16%	8.40%	-2.787689912	2.24%	23.36	6.04%
9/29/2000	11.16%	6.03%	8.42%	-2.808572357	2.39%	22.44	5.13%
11/28/2000	12.90%	5.89%	8.40%	-2.832402316	2.51%	22.97	7.01%
11/30/2000	12.10%	5.88%	8.40%	-2.83326822	2.52%	23.03	6.22%

1/23/2001	11.25%	5.79%	8.33%	-2.848668238	2.54%	23.49	5.46%
2/8/2001	11.50%	5.77%	8.31%	-2.852595652	2.54%	23.15	5.73%
5/8/2001	10.75%	5.62%	8.12%	-2.878885019	2.50%	24.39	5.13%
6/26/2001	11.00%	5.62%	8.08%	-2.878717819	2.46%	24.93	5.38%
7/25/2001	11.02%	5.60%	8.06%	-2.882979849	2.46%	25.07	5.42%
7/25/2001	11.02%	5.60%	8.06%	-2.882979849	2.46%	25.07	5.42%
7/31/2001	11.00%	5.59%	8.05%	-2.883621127	2.46%	24.96	5.41%
8/31/2001	10.50%	5.56%	8.01%	-2.88991106	2.45%	24.49	4.94%
9/7/2001	10.75%	5.55%	8.01%	-2.890944082	2.45%	24.53	5.20%
9/10/2001	11.00%	5.55%	8.00%	-2.8911758	2.45%	24.55	5.45%
9/20/2001	10.00%	5.55%	8.00%	-2.891508082	2.45%	24.84	4.45%
10/24/2001	10.30%	5.54%	8.00%	-2.892931715	2.46%	25.69	4.76%
11/28/2001	10.60%	5.49%	8.01%	-2.902140335	2.52%	26.17	5.11%
12/3/2001	12.88%	5.49%	8.01%	-2.902751896	2.52%	26.22	7.39%
12/20/2001	12.50%	5.50%	8.03%	-2.900883598	2.53%	26.14	7.00%
1/22/2002	10.00%	5.50%	8.06%	-2.901113059	2.56%	25.49	4.50%
3/27/2002	10.10%	5.45%	8.10%	-2.910256497	2.65%	24.65	4.65%
4/22/2002	11.80%	5.45%	8.12%	-2.909549875	2.67%	24.49	6.35%
5/28/2002	10.17%	5.46%	8.15%	-2.906892594	2.69%	24.29	4.71%
6/10/2002	12.00%	5.47%	8.17%	-2.905117339	2.69%	24.33	6.53%
6/18/2002	11.16%	5.48%	8.17%	-2.904826571	2.70%	24.42	5.68%
6/20/2002	11.00%	5.48%	8.18%	-2.904761693	2.70%	24.46	5.52%
6/20/2002	12.30%	5.48%	8.18%	-2.904761693	2.70%	24.46	6.82%
7/15/2002	11.00%	5.48%	8.19%	-2.904867042	2.71%	24.08	5.52%
9/12/2002	12.30%	5.45%	8.14%	-2.909336723	2.69%	25.15	6.85%
9/26/2002	10.45%	5.41%	8.12%	-2.916605702	2.70%	25.82	5.04%
12/4/2002	11.55%	5.29%	8.04%	-2.939312994	2.75%	28.03	6.26%
12/13/2002	11.75%	5.27%	8.02%	-2.943691118	2.75%	28.29	6.48%
12/20/2002	11.40%	5.25%	8.01%	-2.947529791	2.76%	28.48	6.15%
1/8/2003	11.10%	5.19%	7.96%	-2.958831509	2.77%	28.93	5.91%
1/31/2003	12.45%	5.13%	7.89%	-2.970990735	2.76%	29.66	7.32%
2/28/2003	12.30%	5.04%	7.79%	-2.987360779	2.75%	30.74	7.26%
3/6/2003	10.75%	5.02%	7.76%	-2.991151425	2.74%	30.99	5.73%
3/7/2003	9.96%	5.02%	7.75%	-2.992064936	2.74%	31.04	4.94%
3/20/2003	12.00%	4.98%	7.70%	-2.999369836	2.71%	31.54	7.02%
4/3/2003	12.00%	4.95%	7.63%	-3.00477383	2.68%	31.74	7.05%
4/15/2003	11.15%	4.93%	7.59%	-3.008823419	2.65%	31.70	6.22%
6/25/2003	10.75%	4.79%	7.24%	-3.038054451	2.44%	28.27	5.96%
6/26/2003	10.75%	4.79%	7.23%	-3.038241201	2.44%	28.19	5.96%
7/9/2003	9.75%	4.79%	7.18%	-3.038725594	2.39%	27.44	4.96%
7/16/2003	9.75%	4.79%	7.16%	-3.038182058	2.36%	26.97	4.96%
7/25/2003	9.50%	4.79%	7.12%	-3.037864695	2.33%	26.27	4.71%
8/26/2003	10.50%	4.83%	7.02%	-3.030347336	2.19%	24.78	5.67%
12/17/2003	9.85%	4.94%	6.75%	-3.008547812	1.82%	20.47	4.91%
12/17/2003	10.70%	4.94%	6.75%	-3.008547812	1.82%	20.47	5.76%
12/18/2003	11.50%	4.94%	6.75%	-3.008306374	1.81%	20.40	6.56%
12/19/2003	12.00%	4.94%	6.75%	-3.008139377	1.81%	20.31	7.06%
12/19/2003	12.00%	4.94%	6.75%	-3.008139377	1.81%	20.31	7.06%
12/23/2003	10.50%	4.94%	6.74%	-3.007905668	1.80%	20.15	5.56%
1/13/2004	12.00%	4.95%	6.71%	-3.006044052	1.76%	19.31	7.05%
3/2/2004	10.75%	4.99%	6.63%	-2.997661168	1.63%	18.17	5.76%
3/26/2004	10.25%	5.02%	6.60%	-2.990888746	1.58%	17.96	5.23%
4/5/2004	11.25%	5.03%	6.60%	-2.98876185	1.57%	17.85	6.22%
5/18/2004	10.50%	5.07%	6.61%	-2.981503433	1.54%	17.43	5.43%
5/25/2004	10.25%	5.07%	6.60%	-2.980961895	1.53%	17.36	5.18%
5/27/2004	10.25%	5.08%	6.60%	-2.980817422	1.52%	17.33	5.17%
6/2/2004	11.22%	5.08%	6.59%	-2.980403032	1.52%	17.30	6.14%
6/30/2004	10.50%	5.10%	6.57%	-2.975822055	1.47%	16.96	5.40%
6/30/2004	10.50%	5.10%	6.57%	-2.975822055	1.47%	16.96	5.40%
7/16/2004	11.60%	5.11%	6.56%	-2.974028017	1.45%	16.69	6.49%
8/25/2004	10.25%	5.10%	6.53%	-2.975274132	1.43%	16.53	5.15%
9/9/2004	10.40%	5.10%	6.51%	-2.976412668	1.42%	16.35	5.30%
11/9/2004	10.50%	5.07%	6.43%	-2.982694322	1.37%	15.94	5.43%
11/23/2004	11.00%	5.06%	6.42%	-2.983091699	1.36%	15.75	5.94%
12/14/2004	10.97%	5.07%	6.42%	-2.982380897	1.35%	15.59	5.90%
12/21/2004	11.25%	5.07%	6.41%	-2.981810537	1.34%	15.51	6.18%
12/21/2004	11.50%	5.07%	6.41%	-2.981810537	1.34%	15.51	6.43%
12/22/2004	10.70%	5.07%	6.41%	-2.981683878	1.34%	15.47	5.63%
12/22/2004	11.50%	5.07%	6.41%	-2.981683878	1.34%	15.47	6.43%
12/29/2004	9.85%	5.08%	6.41%	-2.980600108	1.34%	15.30	4.77%
1/6/2005	10.70%	5.08%	6.41%	-2.980446978	1.33%	15.12	5.62%
2/18/2005	10.30%	4.98%	6.33%	-3.000646136	1.35%	14.59	5.32%
2/25/2005	10.50%	4.96%	6.31%	-3.004643114	1.35%	14.46	5.54%
3/10/2005	11.00%	4.93%	6.27%	-3.010737966	1.34%	14.18	6.07%
3/24/2005	10.30%	4.89%	6.23%	-3.017006419	1.34%	14.05	5.41%
4/4/2005	10.00%	4.87%	6.21%	-3.021138837	1.33%	14.02	5.13%
4/7/2005	10.25%	4.87%	6.19%	-3.022686157	1.33%	14.00	5.38%
5/18/2005	10.25%	4.78%	6.08%	-3.040911423	1.30%	13.89	5.47%
5/25/2005	10.75%	4.76%	6.06%	-3.044157534	1.30%	13.75	5.99%
5/26/2005	9.75%	4.76%	6.06%	-3.044786764	1.30%	13.71	4.99%
6/1/2005	9.75%	4.75%	6.05%	-3.047722875	1.30%	13.64	5.00%
7/19/2005	11.50%	4.64%	5.95%	-3.069666948	1.31%	13.17	6.86%

8/5/2005	11.75%	4.62%	5.93%	-3.074217217	1.31%	12.94	7.13%
8/15/2005	10.13%	4.61%	5.92%	-3.076430355	1.31%	12.84	5.52%
9/28/2005	10.00%	4.54%	5.87%	-3.091984314	1.32%	12.77	5.46%
10/4/2005	10.75%	4.53%	5.86%	-3.093410813	1.33%	12.78	6.22%
12/12/2005	11.00%	4.55%	5.93%	-3.090657422	1.38%	12.97	6.45%
12/13/2005	10.75%	4.55%	5.93%	-3.090774901	1.38%	12.96	6.20%
12/21/2005	10.29%	4.54%	5.93%	-3.091653062	1.39%	12.91	5.75%
12/21/2005	10.40%	4.54%	5.93%	-3.091653062	1.39%	12.91	5.86%
12/22/2005	11.15%	4.54%	5.94%	-3.091878642	1.39%	12.90	6.61%
12/22/2005	11.00%	4.54%	5.94%	-3.091878642	1.39%	12.90	6.46%
12/28/2005	10.00%	4.54%	5.94%	-3.092997227	1.40%	12.87	5.46%
12/28/2005	10.00%	4.54%	5.94%	-3.092997227	1.40%	12.87	5.46%
1/5/2006	11.00%	4.53%	5.93%	-3.094948	1.41%	12.82	6.47%
1/27/2006	9.75%	4.52%	5.94%	-3.096670977	1.42%	12.72	5.23%
3/3/2006	10.39%	4.53%	5.96%	-3.094156765	1.43%	12.39	5.86%
4/17/2006	10.20%	4.62%	6.05%	-3.075605406	1.44%	12.34	5.58%
4/26/2006	10.60%	4.64%	6.08%	-3.070230581	1.44%	12.34	5.96%
5/17/2006	11.60%	4.69%	6.14%	-3.058721844	1.45%	12.47	6.91%
6/6/2006	10.00%	4.75%	6.19%	-3.047813395	1.44%	12.72	5.25%
6/27/2006	10.75%	4.80%	6.25%	-3.036302206	1.45%	13.07	5.95%
7/6/2006	10.20%	4.83%	6.28%	-3.031062883	1.45%	13.12	5.37%
7/24/2006	9.60%	4.86%	6.32%	-3.02480261	1.46%	13.29	4.74%
7/26/2006	10.50%	4.86%	6.33%	-3.023940481	1.47%	13.29	5.64%
7/28/2006	10.05%	4.87%	6.33%	-3.022998842	1.47%	13.27	5.18%
8/23/2006	9.55%	4.89%	6.36%	-3.018275015	1.47%	13.20	4.66%
9/1/2006	10.54%	4.90%	6.36%	-3.016566705	1.47%	13.19	5.64%
9/14/2006	10.00%	4.91%	6.37%	-3.014511628	1.47%	13.25	5.09%
10/6/2006	9.67%	4.92%	6.37%	-3.011845109	1.45%	13.30	4.75%
11/21/2006	10.08%	4.95%	6.39%	-3.005242783	1.44%	13.12	5.13%
11/21/2006	10.08%	4.95%	6.39%	-3.005242783	1.44%	13.12	5.13%
11/21/2006	10.12%	4.95%	6.39%	-3.005242783	1.44%	13.12	5.17%
12/1/2006	10.50%	4.96%	6.38%	-3.004548713	1.43%	13.07	5.54%
12/1/2006	10.25%	4.96%	6.38%	-3.004548713	1.43%	13.07	5.29%
12/7/2006	10.75%	4.96%	6.38%	-3.004570614	1.43%	13.06	5.79%
12/21/2006	10.90%	4.95%	6.38%	-3.004971508	1.42%	12.98	5.95%
12/21/2006	11.25%	4.95%	6.38%	-3.004971508	1.42%	12.98	6.30%
12/22/2006	10.25%	4.95%	6.38%	-3.00491217	1.42%	12.98	5.30%
1/5/2007	10.00%	4.95%	6.37%	-3.00518353	1.42%	12.98	5.05%
1/11/2007	10.10%	4.95%	6.37%	-3.00597145	1.42%	12.98	5.15%
1/11/2007	10.10%	4.95%	6.37%	-3.00597145	1.42%	12.98	5.15%
1/11/2007	10.90%	4.95%	6.37%	-3.00597145	1.42%	12.98	5.95%
1/12/2007	10.10%	4.95%	6.37%	-3.006139	1.42%	12.98	5.15%
1/13/2007	10.40%	4.95%	6.36%	-3.006139	1.41%	12.98	5.45%
1/19/2007	10.80%	4.94%	6.36%	-3.00724106	1.42%	12.96	5.86%
3/21/2007	11.35%	4.86%	6.26%	-3.023136318	1.40%	12.81	6.49%
3/22/2007	9.75%	4.86%	6.26%	-3.023543588	1.40%	12.78	4.89%
5/15/2007	10.00%	4.81%	6.18%	-3.035131286	1.38%	12.22	5.19%
5/17/2007	10.25%	4.80%	6.18%	-3.035523183	1.38%	12.21	5.45%
5/17/2007	10.25%	4.80%	6.18%	-3.035523183	1.38%	12.21	5.45%
5/22/2007	10.20%	4.80%	6.18%	-3.035813023	1.37%	12.19	5.40%
5/22/2007	10.50%	4.80%	6.18%	-3.035813023	1.37%	12.19	5.70%
5/23/2007	10.70%	4.80%	6.18%	-3.035807374	1.37%	12.18	5.90%
5/25/2007	9.67%	4.80%	6.18%	-3.035748374	1.37%	12.16	4.87%
6/15/2007	9.90%	4.82%	6.18%	-3.032185058	1.36%	12.27	5.08%
6/21/2007	10.20%	4.83%	6.19%	-3.030757034	1.36%	12.30	5.37%
6/22/2007	10.50%	4.83%	6.19%	-3.030419127	1.36%	12.31	5.67%
6/28/2007	10.75%	4.84%	6.19%	-3.028770569	1.35%	12.38	5.91%
7/12/2007	9.67%	4.86%	6.21%	-3.024328119	1.35%	12.56	4.81%
7/19/2007	10.00%	4.87%	6.21%	-3.023067835	1.35%	12.65	5.13%
7/19/2007	10.00%	4.87%	6.21%	-3.023067835	1.35%	12.65	5.13%
8/15/2007	10.40%	4.88%	6.24%	-3.020041442	1.36%	13.76	5.52%
10/9/2007	10.00%	4.91%	6.32%	-3.01403012	1.41%	15.94	5.09%
10/17/2007	9.10%	4.91%	6.32%	-3.013249941	1.41%	16.15	4.19%
10/31/2007	9.96%	4.90%	6.33%	-3.015111405	1.43%	16.62	5.06%
11/29/2007	10.90%	4.87%	6.34%	-3.022447269	1.47%	18.14	6.03%
12/6/2007	10.75%	4.86%	6.35%	-3.023872047	1.49%	18.45	5.89%
12/13/2007	9.96%	4.86%	6.36%	-3.024379313	1.50%	18.60	5.10%
12/14/2007	10.70%	4.86%	6.37%	-3.024419338	1.51%	18.62	5.84%
12/14/2007	10.80%	4.86%	6.37%	-3.024419338	1.51%	18.62	5.94%
12/19/2007	10.20%	4.86%	6.37%	-3.024925123	1.52%	18.74	5.34%
12/20/2007	10.20%	4.86%	6.37%	-3.025146904	1.52%	18.77	5.34%
12/20/2007	11.00%	4.86%	6.37%	-3.025146904	1.52%	18.77	6.14%
12/28/2007	10.25%	4.85%	6.39%	-3.026113672	1.54%	18.84	5.40%
12/31/2007	11.25%	4.85%	6.39%	-3.026472202	1.54%	18.88	6.40%
1/8/2008	10.75%	4.83%	6.39%	-3.029431558	1.56%	19.16	5.92%
1/17/2008	10.75%	4.81%	6.40%	-3.033564395	1.58%	19.51	5.94%
1/28/2008	9.40%	4.80%	6.40%	-3.037591447	1.60%	19.99	4.60%
1/30/2008	10.00%	4.79%	6.40%	-3.038613023	1.61%	20.14	5.21%
1/31/2008	10.71%	4.79%	6.40%	-3.039198674	1.61%	20.21	5.92%
2/29/2008	10.25%	4.75%	6.44%	-3.047449143	1.70%	21.45	5.50%
3/12/2008	10.25%	4.73%	6.46%	-3.052209146	1.73%	21.99	5.52%
3/25/2008	9.10%	4.68%	6.47%	-3.061558162	1.79%	22.55	4.42%

4/22/2008	10.25%	4.60%	6.49%	-3.078832624	1.89%	23.32	5.65%
4/24/2008	10.10%	4.60%	6.50%	-3.080067582	1.90%	23.35	5.50%
5/1/2008	10.70%	4.58%	6.50%	-3.082615966	1.92%	23.46	6.12%
5/19/2008	11.00%	4.56%	6.52%	-3.087540151	1.96%	23.32	6.44%
5/27/2008	10.00%	4.55%	6.53%	-3.090159256	1.98%	23.18	5.45%
6/10/2008	10.70%	4.54%	6.55%	-3.091971478	2.01%	22.89	6.16%
6/27/2008	11.04%	4.54%	6.58%	-3.092903964	2.05%	22.73	6.50%
6/27/2008	10.50%	4.54%	6.58%	-3.092903964	2.05%	22.73	5.96%
7/10/2008	10.43%	4.52%	6.60%	-3.096262708	2.07%	22.88	5.91%
7/16/2008	9.40%	4.51%	6.60%	-3.09785137	2.09%	23.08	4.89%
7/30/2008	10.80%	4.51%	6.64%	-3.099343455	2.13%	23.33	6.29%
7/31/2008	10.70%	4.51%	6.64%	-3.09948303	2.13%	23.34	6.19%
8/11/2008	10.25%	4.50%	6.67%	-3.099990996	2.16%	23.37	5.75%
8/26/2008	10.18%	4.50%	6.70%	-3.101220659	2.20%	23.23	5.68%
9/10/2008	10.30%	4.50%	6.73%	-3.102089265	2.24%	23.01	5.80%
9/24/2008	10.65%	4.48%	6.77%	-3.105445296	2.29%	23.46	6.17%
9/24/2008	10.65%	4.48%	6.77%	-3.105445296	2.29%	23.46	6.17%
9/24/2008	10.65%	4.48%	6.77%	-3.105445296	2.29%	23.46	6.17%
9/30/2008	10.20%	4.47%	6.79%	-3.106880921	2.32%	23.77	5.73%
10/8/2008	10.15%	4.46%	6.83%	-3.109380865	2.37%	24.61	5.69%
11/13/2008	10.55%	4.45%	7.14%	-3.113307793	2.70%	29.58	6.10%
11/17/2008	10.20%	4.44%	7.17%	-3.113801229	2.73%	29.98	5.76%
12/1/2008	10.25%	4.39%	7.27%	-3.124869944	2.88%	31.79	5.86%
12/23/2008	11.00%	4.27%	7.40%	-3.153518936	3.13%	34.13	6.73%
12/29/2008	10.00%	4.24%	7.41%	-3.16118106	3.17%	34.34	5.76%
12/29/2008	10.20%	4.24%	7.41%	-3.16118106	3.17%	34.34	5.96%
12/31/2008	10.75%	4.22%	7.42%	-3.165299335	3.20%	34.47	6.53%
1/14/2009	10.50%	4.15%	7.48%	-3.182081347	3.33%	35.25	6.35%
1/21/2009	10.50%	4.11%	7.50%	-3.191026293	3.38%	35.81	6.39%
1/21/2009	10.50%	4.11%	7.50%	-3.191026293	3.38%	35.81	6.39%
1/21/2009	10.50%	4.11%	7.50%	-3.191026293	3.38%	35.81	6.39%
1/27/2009	10.76%	4.09%	7.52%	-3.196810512	3.43%	36.26	6.67%
1/30/2009	10.50%	4.07%	7.54%	-3.200583476	3.46%	36.58	6.43%
2/4/2009	8.75%	4.06%	7.55%	-3.203900576	3.49%	36.94	4.69%
3/4/2009	10.50%	3.96%	7.64%	-3.228968418	3.69%	39.59	6.54%
3/12/2009	11.50%	3.93%	7.68%	-3.237197803	3.75%	40.42	7.57%
4/2/2009	11.10%	3.85%	7.77%	-3.257597848	3.92%	42.04	7.25%
4/21/2009	10.61%	3.80%	7.83%	-3.270969095	4.04%	42.91	6.81%
4/24/2009	10.00%	3.78%	7.85%	-3.274149923	4.07%	43.10	6.22%
4/30/2009	11.25%	3.77%	7.87%	-3.277842627	4.10%	43.29	7.48%
5/4/2009	10.74%	3.77%	7.88%	-3.279318491	4.12%	43.40	6.97%
5/20/2009	10.25%	3.74%	7.92%	-3.286204298	4.18%	43.96	6.51%
5/28/2009	10.50%	3.74%	7.94%	-3.286261679	4.20%	44.24	6.76%
6/22/2009	10.00%	3.76%	7.98%	-3.280184058	4.22%	45.01	6.24%
6/24/2009	10.80%	3.76%	7.98%	-3.27948786	4.22%	45.06	7.04%
7/8/2009	10.63%	3.76%	7.98%	-3.279556337	4.22%	44.95	6.87%
7/17/2009	10.50%	3.77%	7.96%	-3.276804414	4.19%	44.55	6.73%
8/31/2009	10.25%	3.82%	7.63%	-3.265340673	3.81%	38.96	6.43%
10/14/2009	10.70%	4.02%	7.28%	-3.214483475	3.26%	33.90	6.68%
10/23/2009	10.88%	4.06%	7.22%	-3.203174858	3.15%	33.22	6.82%
11/2/2009	10.70%	4.10%	7.17%	-3.195312051	3.08%	32.57	6.60%
11/3/2009	10.70%	4.10%	7.16%	-3.194201474	3.06%	32.48	6.60%
11/24/2009	10.25%	4.16%	7.04%	-3.180528246	2.88%	30.89	6.09%
11/25/2009	10.75%	4.16%	7.03%	-3.179847438	2.87%	30.79	6.59%
11/30/2009	10.35%	4.17%	7.02%	-3.177361286	2.85%	30.58	6.18%
12/3/2009	10.50%	4.18%	6.99%	-3.175090026	2.82%	30.18	6.32%
12/7/2009	10.70%	4.19%	6.98%	-3.173207062	2.79%	29.90	6.51%
12/16/2009	11.00%	4.22%	6.93%	-3.165967328	2.71%	28.98	6.78%
12/16/2009	10.90%	4.22%	6.93%	-3.165967328	2.71%	28.98	6.68%
12/18/2009	10.40%	4.22%	6.91%	-3.164249054	2.69%	28.70	6.18%
12/18/2009	10.40%	4.22%	6.91%	-3.164249054	2.69%	28.70	6.18%
12/22/2009	10.20%	4.23%	6.90%	-3.162096838	2.66%	28.46	5.97%
12/22/2009	10.40%	4.23%	6.90%	-3.162096838	2.66%	28.46	6.17%
12/22/2009	10.40%	4.23%	6.90%	-3.162096838	2.66%	28.46	6.17%
12/30/2009	10.00%	4.26%	6.85%	-3.155121845	2.59%	27.91	5.74%
1/4/2010	10.80%	4.28%	6.84%	-3.151395302	2.56%	27.67	6.52%
1/11/2010	11.00%	4.31%	6.79%	-3.145305506	2.49%	27.09	6.69%
1/26/2010	10.13%	4.35%	6.69%	-3.134367263	2.34%	26.08	5.78%
1/27/2010	10.40%	4.36%	6.68%	-3.133477673	2.32%	26.01	6.04%
1/27/2010	10.40%	4.36%	6.68%	-3.133477673	2.32%	26.01	6.04%
1/27/2010	10.70%	4.36%	6.68%	-3.133477673	2.32%	26.01	6.34%
2/9/2010	9.80%	4.38%	6.60%	-3.127793047	2.21%	25.43	5.42%
2/18/2010	10.60%	4.40%	6.55%	-3.123777636	2.15%	25.05	6.20%
2/24/2010	10.18%	4.41%	6.52%	-3.121686872	2.11%	24.80	5.77%
3/2/2010	9.63%	4.41%	6.49%	-3.121269972	2.08%	24.54	5.22%
3/4/2010	10.50%	4.41%	6.47%	-3.120908261	2.06%	24.43	6.09%
3/5/2010	10.50%	4.41%	6.46%	-3.120784568	2.05%	24.37	6.09%
3/11/2010	11.90%	4.42%	6.44%	-3.120123654	2.02%	24.10	7.48%
3/17/2010	10.00%	4.41%	6.40%	-3.120488042	1.99%	23.85	5.59%
3/25/2010	10.15%	4.42%	6.36%	-3.119876023	1.94%	23.47	5.73%
4/2/2010	10.10%	4.43%	6.33%	-3.117231477	1.90%	23.15	5.67%
4/27/2010	10.00%	4.46%	6.26%	-3.110636567	1.80%	22.16	5.54%

4/29/2010	9.90%	4.46%	6.25%	-3.110494299	1.79%	22.11	5.44%
4/29/2010	10.06%	4.46%	6.25%	-3.110494299	1.79%	22.11	5.60%
4/29/2010	10.26%	4.46%	6.25%	-3.110494299	1.79%	22.11	5.80%
5/12/2010	10.30%	4.45%	6.21%	-3.111299926	1.75%	22.26	5.85%
5/12/2010	10.30%	4.45%	6.21%	-3.111299926	1.75%	22.26	5.85%
5/28/2010	10.20%	4.44%	6.17%	-3.113932092	1.73%	22.81	5.76%
5/28/2010	10.10%	4.44%	6.17%	-3.113932092	1.73%	22.81	5.66%
6/7/2010	10.30%	4.44%	6.17%	-3.114055732	1.73%	23.00	5.86%
6/16/2010	10.00%	4.44%	6.17%	-3.114597301	1.73%	23.16	5.56%
6/28/2010	10.50%	4.43%	6.17%	-3.115717468	1.73%	23.19	6.07%
6/28/2010	9.67%	4.43%	6.17%	-3.115717468	1.73%	23.19	5.24%
6/30/2010	9.40%	4.43%	6.17%	-3.116340439	1.74%	23.30	4.97%
7/1/2010	10.25%	4.43%	6.17%	-3.116562245	1.74%	23.34	5.82%
7/15/2010	10.70%	4.43%	6.17%	-3.117118905	1.74%	23.43	6.27%
7/15/2010	10.53%	4.43%	6.17%	-3.117118905	1.74%	23.43	6.10%
7/30/2010	10.70%	4.41%	6.16%	-3.120221767	1.74%	23.39	6.29%
8/4/2010	10.50%	4.41%	6.15%	-3.120995743	1.74%	23.40	6.09%
8/6/2010	9.83%	4.41%	6.15%	-3.121498459	1.74%	23.41	5.42%
8/25/2010	9.90%	4.37%	6.10%	-3.130131006	1.73%	23.38	5.53%
9/3/2010	10.60%	4.35%	6.07%	-3.135016174	1.72%	23.44	6.25%
9/14/2010	10.70%	4.33%	6.06%	-3.139529881	1.73%	23.46	6.37%
9/16/2010	10.00%	4.32%	6.05%	-3.140935713	1.73%	23.44	5.68%
9/16/2010	10.00%	4.32%	6.05%	-3.140935713	1.73%	23.44	5.68%
9/30/2010	9.75%	4.28%	6.02%	-3.150230015	1.73%	23.47	5.47%
10/14/2010	10.35%	4.24%	5.98%	-3.160773329	1.74%	23.50	6.11%
10/28/2010	10.70%	4.21%	5.95%	-3.168341788	1.75%	23.55	6.49%
11/2/2010	10.38%	4.20%	5.95%	-3.17043425	1.75%	23.60	6.18%
11/4/2010	10.70%	4.19%	5.94%	-3.171543411	1.75%	23.54	6.51%
11/19/2010	10.20%	4.17%	5.93%	-3.176070512	1.76%	23.28	6.03%
11/22/2010	10.00%	4.17%	5.93%	-3.176584599	1.76%	23.24	5.83%
12/1/2010	10.13%	4.16%	5.92%	-3.180510957	1.76%	23.21	5.97%
12/6/2010	9.86%	4.15%	5.91%	-3.181566727	1.76%	23.18	5.71%
12/9/2010	10.25%	4.15%	5.91%	-3.182246769	1.76%	23.14	6.10%
12/13/2010	10.70%	4.15%	5.91%	-3.182883161	1.76%	23.13	6.55%
12/14/2010	10.13%	4.15%	5.91%	-3.183079988	1.76%	23.12	5.98%
12/15/2010	10.44%	4.15%	5.91%	-3.183167264	1.76%	23.12	6.29%
12/17/2010	10.00%	4.14%	5.90%	-3.183507953	1.76%	23.11	5.86%
12/20/2010	10.60%	4.14%	5.90%	-3.183684527	1.76%	23.10	6.46%
12/21/2010	10.30%	4.14%	5.90%	-3.18386368	1.76%	23.09	6.16%
12/27/2010	9.90%	4.14%	5.90%	-3.184538125	1.76%	23.07	5.76%
12/29/2010	11.15%	4.14%	5.90%	-3.185177677	1.76%	23.07	7.01%
1/5/2011	10.15%	4.13%	5.89%	-3.187112059	1.77%	23.08	6.02%
1/12/2011	10.30%	4.12%	5.89%	-3.188930455	1.77%	23.07	6.18%
1/13/2011	10.30%	4.12%	5.89%	-3.189224696	1.77%	23.06	6.18%
1/18/2011	10.00%	4.12%	5.88%	-3.189817587	1.77%	23.05	5.88%
1/20/2011	9.30%	4.12%	5.88%	-3.190121488	1.77%	23.06	5.18%
1/20/2011	10.13%	4.12%	5.88%	-3.190121488	1.77%	23.06	6.01%
1/31/2011	9.60%	4.11%	5.88%	-3.190920371	1.76%	23.12	5.49%
2/3/2011	10.00%	4.11%	5.88%	-3.190715033	1.76%	23.13	5.89%
2/25/2011	10.00%	4.14%	5.88%	-3.183839904	1.74%	22.58	5.86%
3/25/2011	9.80%	4.18%	5.87%	-3.175519517	1.70%	21.29	5.62%
3/30/2011	10.00%	4.18%	5.87%	-3.173985214	1.69%	21.16	5.82%
4/12/2011	10.00%	4.21%	5.86%	-3.167347489	1.65%	20.69	5.79%
4/25/2011	10.74%	4.23%	5.86%	-3.162361798	1.63%	20.17	6.51%
4/26/2011	9.67%	4.24%	5.86%	-3.161766449	1.62%	20.13	5.43%
4/27/2011	10.40%	4.24%	5.86%	-3.161170032	1.62%	20.08	6.16%
5/4/2011	10.00%	4.25%	5.85%	-3.159264664	1.61%	19.84	5.75%
5/4/2011	10.00%	4.25%	5.85%	-3.159264664	1.61%	19.84	5.75%
5/24/2011	10.50%	4.27%	5.85%	-3.153484574	1.58%	19.44	6.23%
6/8/2011	10.75%	4.30%	5.86%	-3.145562201	1.55%	19.02	6.45%
6/16/2011	9.20%	4.32%	5.86%	-3.142525313	1.55%	18.83	4.88%
6/17/2011	9.95%	4.32%	5.86%	-3.142110224	1.55%	18.83	5.63%
7/13/2011	10.20%	4.37%	5.88%	-3.131313145	1.51%	18.48	5.83%
8/1/2011	9.20%	4.39%	5.89%	-3.126053204	1.50%	18.46	4.81%
8/8/2011	10.00%	4.38%	5.88%	-3.127241649	1.49%	18.77	5.62%
8/11/2011	10.00%	4.38%	5.87%	-3.128765757	1.49%	19.05	5.62%
8/12/2011	10.35%	4.38%	5.87%	-3.129218642	1.49%	19.13	5.97%
8/19/2011	10.25%	4.36%	5.85%	-3.133372714	1.49%	19.53	5.89%
9/2/2011	12.88%	4.32%	5.82%	-3.141667397	1.50%	20.31	8.56%
9/22/2011	10.00%	4.24%	5.76%	-3.160554415	1.52%	21.34	5.76%
10/12/2011	10.30%	4.14%	5.70%	-3.185236225	1.57%	22.82	6.16%
10/20/2011	10.50%	4.10%	5.68%	-3.194899365	1.58%	23.27	6.40%
11/30/2011	10.90%	3.87%	5.54%	-3.251672762	1.66%	25.28	7.03%
11/30/2011	10.90%	3.87%	5.54%	-3.251672762	1.66%	25.28	7.03%
12/14/2011	10.00%	3.79%	5.49%	-3.271703753	1.70%	25.67	6.21%
12/14/2011	10.30%	3.79%	5.49%	-3.271703753	1.70%	25.67	6.51%
12/20/2011	10.20%	3.76%	5.47%	-3.280231611	1.71%	25.76	6.44%
12/21/2011	10.20%	3.75%	5.46%	-3.282150288	1.71%	25.76	6.45%
12/22/2011	9.90%	3.75%	5.46%	-3.284074128	1.71%	25.77	6.15%
12/22/2011	10.40%	3.75%	5.46%	-3.284074128	1.71%	25.77	6.65%
12/23/2011	10.19%	3.74%	5.45%	-3.285945923	1.71%	25.76	6.45%
1/25/2012	10.50%	3.57%	5.36%	-3.333877869	1.80%	25.89	6.93%

1/27/2012	10.50%	3.55%	5.35%	-3.33779292	1.80%	25.91	6.95%
2/15/2012	10.20%	3.47%	5.29%	-3.361409425	1.82%	26.12	6.73%
2/23/2012	9.90%	3.43%	5.27%	-3.371270593	1.84%	26.14	6.47%
2/27/2012	10.25%	3.42%	5.27%	-3.374743262	1.84%	26.15	6.83%
2/29/2012	10.40%	3.41%	5.26%	-3.378194589	1.85%	26.16	6.99%
3/29/2012	10.37%	3.31%	5.20%	-3.407607481	1.89%	25.99	7.06%
4/4/2012	10.00%	3.29%	5.19%	-3.413550962	1.90%	25.89	6.71%
4/26/2012	10.00%	3.20%	5.14%	-3.441427686	1.94%	25.91	6.80%
5/2/2012	10.00%	3.18%	5.13%	-3.448747519	1.95%	25.85	6.82%
5/7/2012	9.80%	3.16%	5.12%	-3.453275485	1.95%	25.85	6.64%
5/15/2012	10.00%	3.14%	5.10%	-3.460060701	1.95%	25.79	6.86%
5/29/2012	10.05%	3.11%	5.08%	-3.4721097	1.98%	25.23	6.94%
6/7/2012	10.30%	3.07%	5.07%	-3.482000441	2.00%	24.77	7.23%
6/14/2012	9.40%	3.06%	5.06%	-3.486617828	2.00%	24.45	6.34%
6/15/2012	10.40%	3.06%	5.06%	-3.487549095	2.01%	24.40	7.34%
6/18/2012	9.60%	3.05%	5.06%	-3.488645419	2.01%	24.33	6.55%
6/19/2012	9.25%	3.05%	5.06%	-3.489530491	2.01%	24.25	6.20%
6/26/2012	10.10%	3.04%	5.06%	-3.493695579	2.02%	23.82	7.06%
6/29/2012	10.00%	3.04%	5.05%	-3.494637933	2.02%	23.58	6.96%
7/9/2012	10.20%	3.03%	5.05%	-3.497048482	2.02%	23.14	7.17%
7/16/2012	9.80%	3.02%	5.04%	-3.500418657	2.02%	22.59	6.78%
7/20/2012	9.81%	3.01%	5.04%	-3.504340258	2.03%	22.07	6.80%
7/20/2012	9.31%	3.01%	5.04%	-3.504340258	2.03%	22.07	6.30%
9/13/2012	9.80%	2.94%	4.99%	-3.527182873	2.05%	19.11	6.86%
9/19/2012	10.05%	2.94%	4.99%	-3.526826754	2.05%	18.84	7.11%
9/19/2012	9.80%	2.94%	4.99%	-3.526826754	2.05%	18.84	6.86%
9/26/2012	9.50%	2.94%	4.98%	-3.527062671	2.04%	18.51	6.56%
10/12/2012	9.60%	2.93%	4.95%	-3.52951591	2.02%	18.04	6.67%
10/23/2012	9.75%	2.93%	4.93%	-3.529590812	2.00%	17.84	6.82%
10/24/2012	10.30%	2.93%	4.93%	-3.529748862	2.00%	17.83	7.37%
11/9/2012	10.30%	2.92%	4.90%	-3.533860924	1.98%	17.75	7.38%
11/28/2012	10.40%	2.90%	4.86%	-3.542070693	1.97%	17.60	7.50%
11/29/2012	9.88%	2.89%	4.86%	-3.542597759	1.97%	17.58	6.99%
11/29/2012	9.75%	2.89%	4.86%	-3.542597759	1.97%	17.58	6.86%
12/5/2012	9.71%	2.89%	4.85%	-3.544668433	1.96%	17.53	6.82%
12/5/2012	10.40%	2.89%	4.85%	-3.544668433	1.96%	17.53	7.51%
12/12/2012	9.80%	2.88%	4.84%	-3.547301552	1.96%	17.48	6.92%
12/13/2012	10.50%	2.88%	4.84%	-3.547776921	1.96%	17.47	7.62%
12/13/2012	9.50%	2.88%	4.84%	-3.547776921	1.96%	17.47	6.62%
12/14/2012	10.40%	2.88%	4.83%	-3.548313291	1.96%	17.47	7.52%
12/19/2012	9.71%	2.87%	4.83%	-3.55032707	1.96%	17.44	6.84%
12/19/2012	10.25%	2.87%	4.83%	-3.55032707	1.96%	17.44	7.38%
12/20/2012	10.40%	2.87%	4.83%	-3.551071791	1.96%	17.43	7.53%
12/20/2012	10.30%	2.87%	4.83%	-3.551071791	1.96%	17.43	7.43%
12/20/2012	10.45%	2.87%	4.83%	-3.551071791	1.96%	17.43	7.58%
12/20/2012	10.25%	2.87%	4.83%	-3.551071791	1.96%	17.43	7.38%
12/20/2012	10.25%	2.87%	4.83%	-3.551071791	1.96%	17.43	7.38%
12/20/2012	9.80%	2.87%	4.83%	-3.551071791	1.96%	17.43	6.93%
12/20/2012	9.50%	2.87%	4.83%	-3.551071791	1.96%	17.43	6.63%
12/21/2012	10.20%	2.87%	4.82%	-3.552029679	1.96%	17.43	7.33%
12/26/2012	9.80%	2.86%	4.82%	-3.554468047	1.96%	17.46	6.94%
1/9/2013	9.70%	2.84%	4.79%	-3.560007089	1.95%	17.50	6.86%
1/9/2013	9.70%	2.84%	4.79%	-3.560007089	1.95%	17.50	6.86%
1/9/2013	9.70%	2.84%	4.79%	-3.560007089	1.95%	17.50	6.86%
1/16/2013	9.60%	2.84%	4.78%	-3.561332869	1.94%	17.45	6.76%
1/16/2013	9.60%	2.84%	4.78%	-3.561332869	1.94%	17.45	6.76%
2/13/2013	10.20%	2.84%	4.74%	-3.560233115	1.90%	17.01	7.36%
2/22/2013	9.75%	2.85%	4.73%	-3.556516105	1.88%	16.89	6.90%
2/27/2013	10.00%	2.86%	4.73%	-3.555309947	1.87%	16.85	7.14%
3/14/2013	9.30%	2.88%	4.72%	-3.546517094	1.83%	16.34	6.42%
3/27/2013	9.80%	2.90%	4.71%	-3.539647787	1.80%	15.88	6.90%
5/1/2013	9.84%	2.94%	4.65%	-3.526125487	1.71%	15.25	6.90%
5/15/2013	10.30%	2.96%	4.64%	-3.519540807	1.68%	15.02	7.34%
5/30/2013	10.20%	2.98%	4.64%	-3.513066975	1.66%	14.88	7.22%
5/31/2013	9.00%	2.98%	4.64%	-3.512192166	1.65%	14.89	6.02%
6/11/2013	10.00%	3.00%	4.64%	-3.505315119	1.63%	14.96	7.00%
6/21/2013	9.75%	3.02%	4.65%	-3.498759074	1.62%	14.99	6.73%
6/25/2013	9.80%	3.03%	4.65%	-3.49675999	1.62%	15.02	6.77%
7/12/2013	9.36%	3.08%	4.68%	-3.481789788	1.60%	15.07	6.28%
8/8/2013	9.83%	3.14%	4.73%	-3.45936077	1.59%	14.82	6.69%
8/14/2013	9.15%	3.16%	4.75%	-3.453855638	1.58%	14.72	5.99%
9/11/2013	10.25%	3.27%	4.83%	-3.421529571	1.57%	14.57	6.98%
9/11/2013	10.20%	3.27%	4.83%	-3.421529571	1.57%	14.57	6.93%
9/24/2013	10.20%	3.31%	4.87%	-3.409215674	1.57%	14.47	6.89%
10/3/2013	9.65%	3.33%	4.90%	-3.401082413	1.56%	14.45	6.32%
11/6/2013	10.20%	3.41%	4.96%	-3.379044872	1.55%	14.40	6.79%
11/21/2013	10.00%	3.44%	4.99%	-3.368809925	1.54%	14.36	6.56%
11/26/2013	10.00%	3.45%	4.99%	-3.366096324	1.54%	14.36	6.55%
12/3/2013	10.25%	3.47%	5.00%	-3.360895981	1.53%	14.38	6.78%
12/4/2013	9.50%	3.47%	5.01%	-3.359715842	1.53%	14.38	6.03%
12/5/2013	10.20%	3.48%	5.01%	-3.35846819	1.53%	14.38	6.72%
12/9/2013	8.72%	3.49%	5.01%	-3.356206097	1.53%	14.34	5.23%

12/9/2013	9.75%	3.49%	5.01%	-3.356206097	1.53%	14.34	6.26%
12/13/2013	9.75%	3.50%	5.03%	-3.352419421	1.53%	14.34	6.25%
12/16/2013	9.95%	3.50%	5.03%	-3.351442572	1.53%	14.35	6.45%
12/16/2013	9.95%	3.50%	5.03%	-3.351442572	1.53%	14.35	6.45%
12/16/2013	10.12%	3.50%	5.03%	-3.351442572	1.53%	14.35	6.62%
12/17/2013	9.50%	3.51%	5.03%	-3.350513821	1.52%	14.37	5.99%
12/17/2013	10.95%	3.51%	5.03%	-3.350513821	1.52%	14.37	7.44%
12/18/2013	8.72%	3.51%	5.03%	-3.349557441	1.52%	14.37	5.21%
12/18/2013	9.80%	3.51%	5.03%	-3.349557441	1.52%	14.37	6.29%
12/19/2013	10.15%	3.51%	5.04%	-3.348558925	1.52%	14.38	6.64%
12/30/2013	9.50%	3.54%	5.05%	-3.341237101	1.51%	14.41	5.96%
2/20/2014	9.20%	3.69%	5.14%	-3.300809253	1.46%	14.62	5.51%
2/26/2014	9.75%	3.70%	5.15%	-3.298142577	1.46%	14.65	6.05%
3/17/2014	9.55%	3.72%	5.17%	-3.291654434	1.45%	14.72	5.83%
3/26/2014	9.40%	3.73%	5.18%	-3.289458707	1.45%	14.66	5.67%
3/26/2014	9.96%	3.73%	5.18%	-3.289458707	1.45%	14.66	6.23%
4/2/2014	9.70%	3.73%	5.17%	-3.289430531	1.45%	14.58	5.97%
5/16/2014	9.80%	3.70%	5.11%	-3.296016163	1.40%	14.38	6.10%
5/30/2014	9.70%	3.68%	5.08%	-3.30223463	1.40%	14.35	6.02%
6/6/2014	10.40%	3.67%	5.07%	-3.304183446	1.40%	14.26	6.73%
6/30/2014	9.55%	3.64%	5.02%	-3.312939972	1.38%	13.95	5.91%
7/2/2014	9.62%	3.64%	5.01%	-3.313638177	1.38%	13.91	5.98%
7/10/2014	9.95%	3.63%	5.00%	-3.316024339	1.37%	13.86	6.32%
7/23/2014	9.75%	3.61%	4.97%	-3.321269779	1.36%	13.68	6.14%
7/29/2014	9.45%	3.60%	4.96%	-3.323360677	1.35%	13.57	5.85%
7/31/2014	9.90%	3.60%	4.95%	-3.324172133	1.35%	13.55	6.30%
8/20/2014	9.75%	3.56%	4.92%	-3.334006414	1.36%	13.61	6.19%
8/25/2014	9.60%	3.56%	4.91%	-3.336650742	1.36%	13.59	6.04%
8/29/2014	9.80%	3.54%	4.90%	-3.340939413	1.36%	13.57	6.26%
9/11/2014	9.60%	3.51%	4.88%	-3.349211325	1.37%	13.57	6.09%
9/15/2014	10.25%	3.51%	4.87%	-3.35067505	1.37%	13.57	6.74%
10/9/2014	9.80%	3.44%	4.83%	-3.368938807	1.39%	13.62	6.36%
11/6/2014	9.56%	3.37%	4.78%	-3.390572121	1.41%	14.09	6.19%
11/6/2014	10.20%	3.37%	4.78%	-3.390572121	1.41%	14.09	6.83%
11/14/2014	10.20%	3.35%	4.78%	-3.395556187	1.42%	13.94	6.85%
11/26/2014	9.70%	3.32%	4.77%	-3.403705802	1.44%	13.82	6.38%
11/26/2014	10.20%	3.32%	4.77%	-3.403705802	1.44%	13.82	6.88%
12/4/2014	9.68%	3.30%	4.76%	-3.409936411	1.45%	13.78	6.38%
12/10/2014	9.25%	3.29%	4.75%	-3.414456607	1.46%	13.80	5.96%
12/10/2014	9.25%	3.29%	4.75%	-3.414456607	1.46%	13.80	5.96%
12/11/2014	10.07%	3.28%	4.75%	-3.415853404	1.47%	13.83	6.79%
12/12/2014	10.20%	3.28%	4.75%	-3.417360316	1.47%	13.86	6.92%
12/17/2014	9.17%	3.27%	4.75%	-3.421672047	1.48%	13.96	5.90%
12/18/2014	9.83%	3.26%	4.74%	-3.422874511	1.48%	13.98	6.57%
1/23/2015	9.50%	3.14%	4.69%	-3.461973582	1.55%	14.37	6.36%
2/24/2015	9.83%	3.04%	4.65%	-3.494634623	1.62%	14.67	6.79%
3/18/2015	9.75%	2.98%	4.64%	-3.514002626	1.66%	14.90	6.77%
3/25/2015	9.50%	2.95%	4.63%	-3.521791091	1.67%	14.96	6.55%
3/26/2015	9.72%	2.95%	4.63%	-3.52324442	1.68%	14.98	6.77%
4/23/2015	10.20%	2.87%	4.61%	-3.551824778	1.74%	15.21	7.33%
4/29/2015	9.53%	2.86%	4.60%	-3.556018437	1.75%	15.22	6.67%
5/1/2015	9.60%	2.85%	4.60%	-3.55764862	1.75%	15.23	6.75%
5/26/2015	9.75%	2.83%	4.63%	-3.565489209	1.80%	15.16	6.92%
6/17/2015	9.00%	2.82%	4.66%	-3.569012071	1.84%	15.30	6.18%
6/17/2015	9.00%	2.82%	4.66%	-3.569012071	1.84%	15.30	6.18%
9/2/2015	9.50%	2.79%	4.79%	-3.579016567	2.00%	15.68	6.71%
9/10/2015	9.30%	2.79%	4.81%	-3.579283498	2.02%	15.99	6.51%
10/15/2015	9.00%	2.81%	4.90%	-3.571012447	2.09%	16.66	6.19%
11/19/2015	10.30%	2.88%	5.04%	-3.547076162	2.16%	16.28	7.42%
11/19/2015	10.00%	2.88%	5.04%	-3.547076162	2.16%	16.28	7.12%
12/3/2015	10.00%	2.90%	5.08%	-3.541396988	2.19%	16.28	7.10%
12/9/2015	9.14%	2.90%	5.11%	-3.539568146	2.20%	16.33	6.24%
12/9/2015	9.14%	2.90%	5.11%	-3.539568146	2.20%	16.33	6.24%
12/11/2015	10.30%	2.90%	5.12%	-3.53922282	2.21%	16.42	7.40%
12/15/2015	9.60%	2.91%	5.13%	-3.538307892	2.22%	16.50	6.69%
12/17/2015	9.70%	2.91%	5.14%	-3.537386373	2.23%	16.54	6.79%
12/18/2015	9.50%	2.91%	5.14%	-3.536907801	2.23%	16.57	6.59%
12/30/2015	9.50%	2.93%	5.18%	-3.530756888	2.25%	16.60	6.57%
1/6/2016	9.50%	2.94%	5.20%	-3.526766416	2.26%	16.72	6.56%
2/23/2016	9.75%	2.94%	5.34%	-3.528253531	2.40%	18.32	6.81%
3/16/2016	9.85%	2.91%	5.36%	-3.537673349	2.45%	18.69	6.94%
4/29/2016	9.80%	2.83%	5.31%	-3.563568465	2.47%	18.60	6.97%
6/3/2016	9.75%	2.80%	5.24%	-3.573972869	2.43%	18.79	6.95%
6/8/2016	9.48%	2.80%	5.23%	-3.576092552	2.43%	18.56	6.68%
6/15/2016	9.00%	2.79%	5.20%	-3.580432911	2.42%	18.29	6.21%
6/15/2016	9.00%	2.79%	5.20%	-3.580432911	2.42%	18.29	6.21%
				Average:	1.81%	20	
				Count:		748	

Value Line Projected Sustainable Growth And Return On Common Equity

Company	Value Line Return on Common Equity ("R")	Value Line Payout Ratio	Retention Ratio ("B")	B x R	Value Line Retained to Common Equity	Difference
ALE	8.50%	63.00%	37.00%	3.15%	3.00%	0.15%
LNT	12.50%	61.00%	39.00%	4.88%	5.50%	-0.63%
AVA	9.00%	63.00%	37.00%	3.33%	3.50%	-0.17%
ED	8.50%	69.00%	31.00%	2.64%	2.50%	0.14%
EIX	11.50%	54.00%	46.00%	5.29%	5.50%	-0.21%
ES	9.50%	58.00%	42.00%	3.99%	4.00%	-0.01%
IDA	9.00%	60.00%	40.00%	3.60%	3.50%	0.10%
NWE	10.00%	59.00%	41.00%	4.10%	4.00%	0.10%
OGE	12.00%	70.00%	30.00%	3.60%	3.50%	0.10%
POR	9.00%	56.00%	44.00%	3.96%	4.00%	-0.04%
WEC	11.00%	67.00%	33.00%	3.63%	3.50%	0.13%
XEL	10.50%	63.00%	37.00%	3.89%	4.00%	-0.12%
AVERAGE:	10.08%	61.92%	38.08%	3.84%	3.88%	-0.04%
MEDIAN:	9.75%	62.00%	38.00%	3.76%	3.75%	0.04%

Source: Value Line projections 2019-2021 period, as of June 30, 2016.
Note: Retention Ratio equals 1 - Payout Ratio

Mr. Baudino's Exhibit No.___(RAB-7) Adjusted

AS FILED:

COMPANY	TICKER	Value Line DPS	Value Line EPS	Value Line B x R	Zacks	IBES
ALLETE, Inc.	ALE	3.50%	4.00%	3.00%	4.50%	3.00%
Alliant Energy Corporation	LNT	4.50%	6.00%	5.50%	6.10%	6.60%
Avista Corporation	AVA	4.00%	5.00%	3.50%	5.00%	5.00%
Consolidated Edison, Inc.	ED	3.00%	1.50%	2.50%	2.30%	1.89%
Edison International	EIX	9.00%	3.50%	5.50%	4.90%	2.45%
Eversource Energy	ES	6.00%	6.00%	4.00%	6.30%	6.01%
IDACORP, Inc.	IDA	7.50%	3.00%	3.50%	4.00%	4.00%
NorthWestern Corp.	NWE	5.50%	6.50%	4.00%	5.00%	5.00%
OGE Energy	OGE	9.50%	3.00%	3.50%	5.20%	4.30%
Portland General Electric Company	POR	6.00%	5.50%	4.00%	6.40%	6.57%
WEC Energy	WEC	7.00%	6.00%	3.50%	6.30%	6.77%
Xcel Energy Inc.	XEL	6.00%	5.50%	4.00%	5.30%	5.27%
	Average:	5.96%	4.63%	3.88%	5.11%	4.74%
	Median:	6.00%	5.25%	3.75%	5.10%	5.00%

Method 1	Value Line DPS	Value Line EPS	Zacks	Thomson Financial	Average of All Growth Rates
Dividend Yield	3.44%	3.44%	3.44%	3.44%	3.44%
Growth Rate	5.96%	4.63%	5.11%	4.74%	5.11%
Expected Div Yield	3.54%	3.52%	3.53%	3.52%	3.53%
DCF ROE	9.50%	8.14%	8.64%	8.26%	8.64%
				Midpoint:	8.82%
Method 2					
Dividend Yield	3.44%	3.44%	3.44%	3.44%	3.44%
Growth Rate	6.00%	5.25%	5.10%	5.00%	5.34%
Expected Div Yield	3.54%	3.53%	3.53%	3.53%	3.53%
DCF ROE	9.54%	8.78%	8.63%	8.53%	8.87%
				Midpoint:	9.03%

SOURCE: EXHIBIT NO.___(RAB-7); differences due to rounding.

EQUITY DURATION CALCULATION USING MR. BAUDINO's DCF MODEL DATA

Company	Ticker	Using Data As-Filed: 6-Month Average Price	Annual Dividend	Mean Projected Growth Rate	Constant Growth DCF ROE	Solved ROE	Price	Div 1	Div 2	Div 3	Div 4	Div 5	Div 6	Div 7	Div 8	Div 9	Div 10	Div 199	Div 200
ALLETE	ALE	53.33	2.08	3.75%	7.72%	7.72%	($53.33)	$ 2.12	$ 2.20	$ 2.28	$ 2.37	$ 2.46	$ 2.55	$ 2.64	$ 2.74	$ 2.84	$ 2.95	$ 3,102.96	$ 3,219.32
Alliant Energy	LNT	67.75	2.35	5.80%	9.37%	9.37%	($67.75)	$ 2.42	$ 2.56	$ 2.71	$ 2.87	$ 3.03	$ 3.21	$ 3.39	$ 3.59	$ 3.80	$ 4.02	$ 170,614.09	$ 180,509.71
Avista Corp.	AVA	38.11	1.37	4.75%	8.44%	8.43%	($38.11)	$ 1.40	$ 1.47	$ 1.54	$ 1.61	$ 1.69	$ 1.77	$ 1.86	$ 1.94	$ 2.04	$ 2.13	$ 13,741.88	$ 14,394.62
Consolidated Edison	ED	70.26	2.68	2.17%	6.03%	6.03%	($70.26)	$ 2.71	$ 2.77	$ 2.83	$ 2.89	$ 2.95	$ 3.02	$ 3.08	$ 3.15	$ 3.22	$ 3.29	$ 190.97	$ 195.12
Edison International	EIX	65.84	1.92	4.96%	7.95%	7.94%	($65.84)	$ 1.97	$ 2.07	$ 2.17	$ 2.28	$ 2.39	$ 2.51	$ 2.63	$ 2.76	$ 2.90	$ 3.04	$ 28,754.81	$ 30,181.77
Eversoure Energy	ES	54.30	1.78	6.08%	9.46%	9.45%	($54.30)	$ 1.83	$ 1.95	$ 2.06	$ 2.19	$ 2.32	$ 2.46	$ 2.61	$ 2.77	$ 2.94	$ 3.12	$ 217,184.69	$ 230,384.09
IDACORP	IDA	70.54	2.04	4.63%	7.58%	7.57%	($70.54)	$ 2.09	$ 2.18	$ 2.28	$ 2.39	$ 2.50	$ 2.62	$ 2.74	$ 2.86	$ 3.00	$ 3.14	$ 16,120.63	$ 16,866.21
Northwestern Corp.	NWE	57.06	2.00	5.50%	9.10%	9.10%	($57.06)	$ 2.06	$ 2.17	$ 2.29	$ 2.41	$ 2.55	$ 2.69	$ 2.83	$ 2.99	$ 3.15	$ 3.33	$ 82,565.54	$ 87,106.65
OGE Energy	OGE	26.98	1.10	5.50%	9.69%	9.69%	($26.98)	$ 1.13	$ 1.19	$ 1.26	$ 1.33	$ 1.40	$ 1.48	$ 1.56	$ 1.64	$ 1.73	$ 1.83	$ 45,411.05	$ 47,908.66
Portland General Electric	POR	38.43	1.20	6.12%	9.34%	9.33%	($38.43)	$ 1.24	$ 1.31	$ 1.39	$ 1.48	$ 1.57	$ 1.66	$ 1.77	$ 1.87	$ 1.99	$ 2.11	$ 157,795.31	$ 167,448.44
WEC Energy	WEC	55.70	1.98	6.52%	10.19%	10.18%	($55.70)	$ 2.04	$ 2.18	$ 2.32	$ 2.47	$ 2.63	$ 2.80	$ 2.99	$ 3.18	$ 3.39	$ 3.61	$ 549,468.87	$ 585,280.51
Xcel Energy	XEL	38.62	1.36	5.52%	9.14%	9.13%	($38.62)	$ 1.40	$ 1.47	$ 1.56	$ 1.64	$ 1.73	$ 1.83	$ 1.93	$ 2.04	$ 2.15	$ 2.27	$ 58,023.96	$ 61,225.43

Duration calculation

Company	Ticker	Equity Duration	Div 1	Div 2	Div 3	Div 4	Div 5	Div 6	Div 7	Div 8	Div 9	Div 10	Div 199	Div 200
ALLETE	ALE	26.99	0.04	0.07	0.10	0.13	0.16	0.18	0.21	0.23	0.25	0.26	0.00	0.00
Alliant Energy	LNT	30.32	0.03	0.06	0.09	0.12	0.14	0.17	0.19	0.21	0.23	0.24	0.01	0.01
Avista Corp.	AVA	29.19	0.03	0.07	0.10	0.12	0.15	0.17	0.19	0.21	0.23	0.25	0.01	0.01
Consolidated Edison	ED	27.36	0.04	0.07	0.10	0.13	0.16	0.18	0.20	0.22	0.24	0.26	0.00	0.00
Edison International	EIX	35.26	0.03	0.05	0.08	0.10	0.12	0.14	0.16	0.18	0.20	0.22	0.02	0.02
Eversoure Energy	ES	31.97	0.03	0.06	0.09	0.11	0.14	0.16	0.18	0.20	0.22	0.23	0.01	0.01
IDACORP	IDA	35.47	0.03	0.05	0.08	0.10	0.12	0.14	0.16	0.18	0.20	0.21	0.02	0.02
Northwestern Corp.	NWE	30.01	0.03	0.06	0.09	0.12	0.14	0.17	0.19	0.21	0.23	0.24	0.01	0.01
OGE Energy	OGE	26.09	0.04	0.07	0.11	0.14	0.16	0.19	0.21	0.23	0.25	0.27	0.00	0.00
Portland General Electric	POR	33.38	0.03	0.06	0.08	0.11	0.13	0.15	0.17	0.19	0.21	0.22	0.02	0.02
WEC Energy	WEC	29.76	0.03	0.06	0.09	0.12	0.15	0.17	0.19	0.21	0.23	0.25	0.01	0.01
Xcel Energy	XEL	29.89	0.03	0.06	0.09	0.12	0.14	0.17	0.19	0.21	0.23	0.24	0.01	0.01
	Average:	30.47												
	Median:	29.95												

Notes:
Source: Exhibit No.___(RAB-6) and Exhibit No.___(RAB-7)
Mean projected growth rate excludes Mr. Baudino's Sustainable Growth rate since that rate was not used in his DCF calculations

$$D = \frac{\sum_{t=1}^{T} t \times \frac{CF_t}{(1+r)^t}}{P}$$

Where: t = time period (1 through 200)
CF = Cash Flow (i.e. dividend) at time t
r = ROE
P = Current Stock Price

Duration of Treasury Bonds at Current Interest Rates

Start Date	6/30/2016	6/30/2016	6/30/2016	
Maturity Date	6/30/2046	6/30/2036	6/30/2021	
Term (years)	30	20	5	
Par	100	100	100	
Interest Rate	2.50%	2.07%	1.22%	(30-day average)
Excel Duration	21.46	16.57	4.88	

Manual calculation (check):

Cash Flows

	Period	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	30year Treasury:	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	102.50
	20year Treasury:	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	102.07										
	5year Treasury:	1.22	1.22	1.22	1.22	101.22																									

Duration / Discounted Value of Cash Flow

Duration																															
21.46	30year Treasury:	2.44	2.38	2.32	2.26	2.21	2.15	2.10	2.05	2.00	1.95	1.90	1.86	1.81	1.77	1.73	1.68	1.64	1.60	1.56	1.53	1.49	1.45	1.42	1.38	1.35	1.32	1.28	1.25	1.22	48.89
16.57	20year Treasury:	2.03	1.99	1.95	1.91	1.87	1.83	1.80	1.76	1.72	1.69	1.65	1.62	1.59	1.56	1.52	1.49	1.46	1.43	1.40	67.71										
4.88	5year Treasury:	1.20	1.19	1.18	1.16	95.27																									

Notes:

Interest rates based on 30-day average; Source: Bloomberg Professional

$$D = \frac{\sum_{t=1}^{T} t \times \frac{CF_t}{(1+r)^t}}{P}$$

Where: t = time period
CF = cash flow (i.e. coupon) at time t
r = discount rate
P = current price (assumed par)

Docket No. 160021-EI
Sponsored by Robert B. Hevert
Exhibit RBH-37, Page 1 of 1

DCF Model ROE Estimate Assuming Different Holding Periods and No Terminal Value

Perpetual Holding Period (200 years)

Using Data As-Filed

Company	Ticker	6-Month Average Price	Annual Dividend	Mean Projected Growth Rate	Constant Growth DCF ROE	Solved ROE	Price	Div 1	Div 2	Div 3	Div 4	Div 5	Div 6	Div 7	Div 8	Div 9	Div 10	Div 199	Div 200
ALLETE	ALE	53.33	2.08	3.75%	7.72%	7.72%	($53.33)	$ 2.12	$ 2.20	$ 2.28	$ 2.37	$ 2.46	$ 2.55	$ 2.64	$ 2.74	$ 2.84	$ 2.95	$ 3,102.96	$ 3,219.32
Alliant Energy	LNT	67.75	2.35	5.80%	9.37%	9.37%	($67.75)	$ 2.42	$ 2.56	$ 2.71	$ 2.87	$ 3.03	$ 3.21	$ 3.39	$ 3.59	$ 3.80	$ 4.02	$ 170,614.09	$ 180,509.71
Avista Corp.	AVA	38.11	1.37	4.75%	8.44%	8.43%	($38.11)	$ 1.40	$ 1.47	$ 1.54	$ 1.61	$ 1.69	$ 1.77	$ 1.86	$ 1.94	$ 2.04	$ 2.13	$ 13,741.88	$ 14,394.62
Consolidated Edison	ED	70.26	2.68	2.17%	6.03%	6.03%	($70.26)	$ 2.71	$ 2.77	$ 2.83	$ 2.89	$ 2.95	$ 3.02	$ 3.08	$ 3.15	$ 3.22	$ 3.29	$ 190.97	$ 195.12
Edison International	EIX	65.84	1.92	4.96%	7.95%	7.94%	($65.84)	$ 1.97	$ 2.07	$ 2.17	$ 2.28	$ 2.39	$ 2.51	$ 2.63	$ 2.76	$ 2.90	$ 3.04	$ 28,754.81	$ 30,181.77
Eversource Energy	ES	54.30	1.78	6.08%	9.46%	9.45%	($54.30)	$ 1.83	$ 1.95	$ 2.06	$ 2.19	$ 2.32	$ 2.46	$ 2.61	$ 2.77	$ 2.94	$ 3.12	$ 217,184.69	$ 230,384.09
IDACORP	IDA	70.54	2.04	4.63%	7.58%	7.57%	($70.54)	$ 2.09	$ 2.18	$ 2.28	$ 2.39	$ 2.50	$ 2.62	$ 2.74	$ 2.86	$ 3.00	$ 3.14	$ 16,120.63	$ 16,866.21
Northwestern Corp.	NEW	57.06	2.00	5.50%	9.10%	9.10%	($57.06)	$ 2.06	$ 2.17	$ 2.29	$ 2.41	$ 2.55	$ 2.69	$ 2.83	$ 2.99	$ 3.15	$ 3.33	$ 82,565.54	$ 87,106.65
OGE Energy	OGE	26.98	1.10	5.50%	9.69%	9.69%	($26.98)	$ 1.13	$ 1.19	$ 1.26	$ 1.33	$ 1.40	$ 1.48	$ 1.56	$ 1.64	$ 1.73	$ 1.83	$ 45,411.05	$ 47,908.66
Portland General Electric	POR	38.43	1.20	6.12%	9.34%	9.33%	($38.43)	$ 1.24	$ 1.31	$ 1.39	$ 1.48	$ 1.57	$ 1.66	$ 1.77	$ 1.87	$ 1.99	$ 2.11	$ 157,795.31	$ 167,448.44
WEC Energy	WEC	55.70	1.98	6.52%	10.19%	10.18%	($55.70)	$ 2.04	$ 2.18	$ 2.32	$ 2.47	$ 2.63	$ 2.80	$ 2.99	$ 3.18	$ 3.39	$ 3.61	$ 549,468.87	$ 585,280.51
Xcel Energy	XEL	38.62	1.36	5.52%	9.14%	9.13%	($38.62)	$ 1.40	$ 1.47	$ 1.56	$ 1.64	$ 1.73	$ 1.83	$ 1.93	$ 2.04	$ 2.15	$ 2.27	$ 58,023.96	$ 61,225.43
						Mean:	8.66%												
						Median:	9.11%												

Twenty Year Holding Period

Company	Ticker	6-Month Average Price	Annual Dividend	Mean Projected Growth Rate	Constant Growth DCF ROE	Solved ROE	Price	Div 1	Div 2	Div 3	Div 4	Div 5	Div 6	Div 7	Div 8	Div 9	Div 10	Div 19	Div 20
ALLETE	ALE	53.33	2.08	3.75%	7.72%	1.24%	($53.33)	$ 2.12	$ 2.20	$ 2.28	$ 2.37	$ 2.46	$ 2.55	$ 2.64	$ 2.74	$ 2.84	$ 2.95	$ 4.11	$ 4.26
Alliant Energy	LNT	67.75	2.35	5.80%	9.37%	2.12%	($67.75)	$ 2.42	$ 2.56	$ 2.71	$ 2.87	$ 3.03	$ 3.21	$ 3.39	$ 3.59	$ 3.80	$ 4.02	$ 6.68	$ 7.06
Avista Corp.	AVA	38.11	1.37	4.75%	8.44%	1.47%	($38.11)	$ 1.40	$ 1.47	$ 1.54	$ 1.61	$ 1.69	$ 1.77	$ 1.86	$ 1.94	$ 2.04	$ 2.13	$ 3.24	$ 3.39
Consolidated Edison	ED	70.26	2.68	2.17%	6.03%	-0.42%	($70.26)	$ 2.71	$ 2.77	$ 2.83	$ 2.89	$ 2.95	$ 3.02	$ 3.08	$ 3.15	$ 3.22	$ 3.29	$ 3.99	$ 4.08
Edison International	EIX	65.84	1.92	4.96%	7.95%	-0.13%	($65.84)	$ 1.97	$ 2.07	$ 2.17	$ 2.28	$ 2.39	$ 2.51	$ 2.63	$ 2.76	$ 2.90	$ 3.04	$ 4.71	$ 4.94
Eversource Energy	ES	54.30	1.78	6.08%	9.46%	1.88%	($54.30)	$ 1.83	$ 1.95	$ 2.06	$ 2.19	$ 2.32	$ 2.46	$ 2.61	$ 2.77	$ 2.94	$ 3.12	$ 5.30	$ 5.63
IDACORP	IDA	70.54	2.04	4.63%	7.58%	-0.51%	($70.54)	$ 2.09	$ 2.18	$ 2.28	$ 2.39	$ 2.50	$ 2.62	$ 2.74	$ 2.86	$ 3.00	$ 3.14	$ 4.71	$ 4.93
Northwestern Corp.	NEW	57.06	2.00	5.50%	9.10%	1.92%	($57.06)	$ 2.06	$ 2.17	$ 2.29	$ 2.41	$ 2.55	$ 2.69	$ 2.83	$ 2.99	$ 3.15	$ 3.33	$ 5.39	$ 5.68
OGE Energy	OGE	26.98	1.10	5.50%	9.69%	3.28%	($26.98)	$ 1.13	$ 1.19	$ 1.26	$ 1.33	$ 1.40	$ 1.48	$ 1.56	$ 1.64	$ 1.73	$ 1.83	$ 2.96	$ 3.13
Portland General Electric	POR	38.43	1.20	6.12%	9.34%	1.50%	($38.43)	$ 1.24	$ 1.31	$ 1.39	$ 1.48	$ 1.57	$ 1.66	$ 1.77	$ 1.87	$ 1.99	$ 2.11	$ 3.60	$ 3.82
WEC Energy	WEC	55.70	1.98	6.52%	10.19%	2.99%	($55.70)	$ 2.04	$ 2.18	$ 2.32	$ 2.47	$ 2.63	$ 2.80	$ 2.99	$ 3.18	$ 3.39	$ 3.61	$ 6.37	$ 6.79
Xcel Energy	XEL	38.62	1.36	5.52%	9.14%	1.98%	($38.62)	$ 1.40	$ 1.47	$ 1.56	$ 1.64	$ 1.73	$ 1.83	$ 1.93	$ 2.04	$ 2.15	$ 2.27	$ 3.67	$ 3.88
						Mean:	1.44%												
						Median:	1.69%												

Five Year Holding Period

Company	Ticker	6-Month Average Price	Annual Dividend	Mean Projected Growth Rate	Constant Growth DCF ROE	Solved ROE	Price	Div 1	Div 2	Div 3	Div 4	Div 5
ALLETE	ALE	53.33	2.08	3.75%	7.72%	-35.69%	($53.33)	$ 2.12	$ 2.20	$ 2.28	$ 2.37	$ 2.46
Alliant Energy	LNT	67.75	2.35	5.80%	9.37%	-36.50%	($67.75)	$ 2.42	$ 2.56	$ 2.71	$ 2.87	$ 3.03
Avista Corp.	AVA	38.11	1.37	4.75%	8.44%	-36.46%	($38.11)	$ 1.40	$ 1.47	$ 1.54	$ 1.61	$ 1.69
Consolidated Edison	ED	70.26	2.68	2.17%	6.03%	-36.90%	($70.26)	$ 2.71	$ 2.77	$ 2.83	$ 2.89	$ 2.95
Edison International	EIX	65.84	1.92	4.96%	7.95%	-39.66%	($65.84)	$ 1.97	$ 2.07	$ 2.17	$ 2.28	$ 2.39
Eversource Energy	ES	54.30	1.78	6.08%	9.46%	-37.28%	($54.30)	$ 1.83	$ 1.95	$ 2.06	$ 2.19	$ 2.32
IDACORP	IDA	70.54	2.04	4.63%	7.58%	-39.96%	($70.54)	$ 2.09	$ 2.18	$ 2.28	$ 2.39	$ 2.50
Northwestern Corp.	NEW	57.06	2.00	5.50%	9.10%	-36.50%	($57.06)	$ 2.06	$ 2.17	$ 2.29	$ 2.41	$ 2.55
OGE Energy	OGE	26.98	1.10	5.50%	9.69%	-33.99%	($26.98)	$ 1.13	$ 1.19	$ 1.26	$ 1.33	$ 1.40
Portland General Electric	POR	38.43	1.20	6.12%	9.34%	-38.02%	($38.43)	$ 1.24	$ 1.31	$ 1.39	$ 1.48	$ 1.57
WEC Energy	WEC	55.70	1.98	6.52%	10.19%	-35.74%	($55.70)	$ 2.04	$ 2.18	$ 2.32	$ 2.47	$ 2.63
Xcel Energy	XEL	38.62	1.36	5.52%	9.14%	-36.42%	($38.62)	$ 1.40	$ 1.47	$ 1.56	$ 1.64	$ 1.73
						Mean:	-36.93%					
						Median:	-36.50%					

Notes:
Source: Exhibit No.___(RAB-6) and Exhibit No.___(RAB-7)
Mean projected growth rate excludes Mr. Baudino's Sustainable Growth rate since that rate was not used in his DCF calculations

R-Squared of Beta Coefficient Regressions for Mr. Baudino's Proxy Group:
Value Line Methodology

Company	Ticker	R-Squared of Beta Coefficient
ALLETE, Inc.	ALE	0.2556
Alliant Energy Corporation	LNT	0.2146
Avista Corporation	AVA	0.2359
Consolidated Edison, Inc.	ED	0.0468
Edison International	EIX	0.1443
Eversource Energy	ES	0.1868
IDACORP, Inc.	IDA	0.2941
NorthWestern Corporation	NWE	0.2257
OGE Energy Corp.	OGE	0.2426
Portland General Electric Company	POR	0.2204
WEC Energy Group, Inc.	WEC	0.1147
Xcel Energy Inc.	XEL	0.1258
Mean		0.1923

Notes:

Source: Bloomberg Professional; Beta coefficients were calculated using Value Line's methodology which derives the Beta coefficient from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Composite Index over a period of five years.

Bond Yield Plus Risk Premium Analysis Applying 95.00% Confidence Interval

	[1]	[2]	[3]	[4]	[5]	95% Confidence Interval [6]	[7]
	Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity	Lower Bound Return on Equity	Upper Bound Return on Equity
Current	-2.70%	-2.78%	2.50%	7.53%	10.04%	9.47%	10.61%
Blue Chip Financial Forecast 2017 Projection	-2.70%	-2.78%	3.40%	6.68%	10.08%	9.54%	10.63%
Blue Chip Financial Forecast 2020 Projection	-2.70%	-2.78%	4.40%	5.97%	10.37%	9.85%	10.89%

SUMMARY OUTPUT

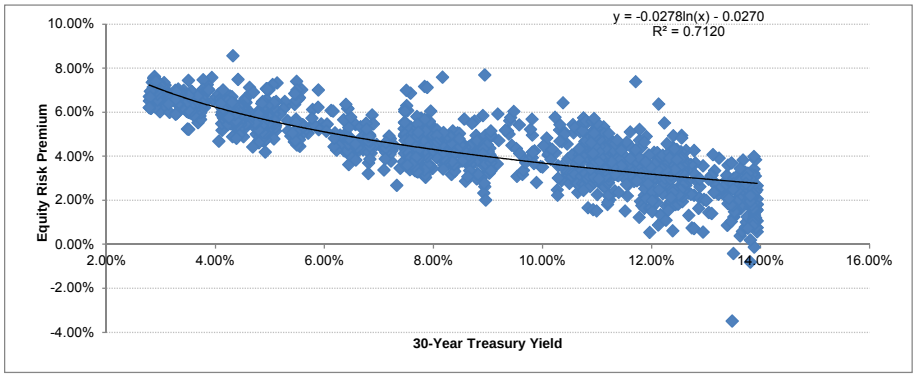
Regression Statistics	
Multiple R	0.843796
R Square	0.711991
Adjusted R Square	0.711796
Standard Error	0.008539
Observations	1475

ANOVA

	df	*SS*	*MS*	*F*	*Signif. F*
Regression	1	0.265541	0.265541	3641.432302	0.000000
Residual	1473	0.107414	0.000073		
Total	1474	0.372955			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-0.027000	0.001215	-22.220102	0.000000	-0.029384	-0.024617
X Variable 1	-0.027751	0.000460	-60.344281	0.000000	-0.028654	-0.026849

Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
Projected = Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 2. Forecast for Q3 2017.
Projected = Blue Chip Financial Forecasts, Vol. 35, No. 6, June 1, 2016, at 14.
[4] Equals [1] + [2] x ln([3])
[5] Equals [3] + [4]
[6] Using 95% confidence interval data reported in regression output: (lower bound constant + LN([3]) x upper bound slope) + [3]
[7] Using 95% confidence interval data reported in regression output: (upper bound constant + LN([3]) x lower bound slope) + [3]



Source: RBH-12

Date of Electric Rate Case	Return on Equity	Average 30-Year Treasury Yield	Risk Premium
1/1/1980	14.50%	9.36%	5.14%
1/7/1980	14.39%	9.38%	5.01%
1/9/1980	15.00%	9.40%	5.60%
1/14/1980	15.17%	9.42%	5.75%
1/17/1980	13.93%	9.44%	4.49%
1/23/1980	15.50%	9.47%	6.03%
1/30/1980	13.86%	9.52%	4.34%
1/31/1980	12.61%	9.53%	3.08%
2/6/1980	13.71%	9.58%	4.13%
2/13/1980	12.80%	9.63%	3.17%
2/14/1980	13.00%	9.65%	3.35%
2/19/1980	13.50%	9.68%	3.82%
2/27/1980	13.75%	9.78%	3.97%

2/29/1980	13.75%	9.81%	3.94%
2/29/1980	14.00%	9.81%	4.19%
2/29/1980	14.77%	9.81%	4.96%
3/7/1980	12.70%	9.89%	2.81%
3/14/1980	13.50%	9.97%	3.53%
3/26/1980	14.16%	10.10%	4.06%
3/27/1980	14.24%	10.12%	4.12%
3/28/1980	14.50%	10.13%	4.37%
4/11/1980	12.75%	10.27%	2.48%
4/14/1980	13.85%	10.29%	3.56%
4/16/1980	15.50%	10.31%	5.19%
4/22/1980	13.25%	10.35%	2.90%
4/22/1980	13.90%	10.35%	3.55%
4/24/1980	16.80%	10.38%	6.43%
4/29/1980	15.50%	10.41%	5.09%
5/6/1980	13.70%	10.45%	3.25%
5/7/1980	15.00%	10.45%	4.55%
5/8/1980	13.75%	10.46%	3.29%
5/9/1980	14.35%	10.47%	3.88%
5/13/1980	13.60%	10.48%	3.12%
5/15/1980	13.25%	10.49%	2.76%
5/19/1980	13.75%	10.51%	3.24%
5/27/1980	13.62%	10.54%	3.08%
5/27/1980	14.60%	10.54%	4.06%
5/29/1980	16.00%	10.56%	5.44%
5/30/1980	13.80%	10.56%	3.24%
6/2/1980	15.63%	10.57%	5.06%
6/9/1980	15.90%	10.60%	5.30%
6/10/1980	13.78%	10.60%	3.18%
6/12/1980	14.25%	10.61%	3.64%
6/19/1980	13.40%	10.62%	2.78%
6/30/1980	13.00%	10.65%	2.35%
6/30/1980	13.40%	10.65%	2.75%
7/9/1980	14.75%	10.67%	4.08%
7/10/1980	15.00%	10.68%	4.32%
7/15/1980	15.80%	10.70%	5.10%
7/18/1980	13.80%	10.71%	3.09%
7/22/1980	14.10%	10.72%	3.38%
7/24/1980	15.00%	10.73%	4.27%
7/25/1980	13.48%	10.73%	2.75%
7/31/1980	14.58%	10.75%	3.83%
8/8/1980	13.50%	10.78%	2.72%
8/8/1980	14.00%	10.78%	3.22%
8/8/1980	15.45%	10.78%	4.67%
8/11/1980	14.85%	10.78%	4.07%
8/14/1980	14.00%	10.79%	3.21%
8/14/1980	16.25%	10.79%	5.46%
8/25/1980	13.75%	10.82%	2.93%
8/27/1980	13.80%	10.83%	2.97%
8/29/1980	12.50%	10.84%	1.66%
9/15/1980	13.50%	10.88%	2.62%
9/15/1980	13.93%	10.88%	3.05%
9/15/1980	15.80%	10.88%	4.92%
9/24/1980	12.50%	10.93%	1.57%
9/24/1980	15.00%	10.93%	4.07%
9/26/1980	13.75%	10.94%	2.81%
9/30/1980	14.10%	10.96%	3.14%
9/30/1980	14.20%	10.96%	3.24%
10/1/1980	13.90%	10.97%	2.93%
10/3/1980	15.50%	10.98%	4.52%
10/7/1980	12.50%	10.99%	1.51%
10/9/1980	13.25%	11.00%	2.25%
10/9/1980	14.50%	11.00%	3.50%
10/9/1980	14.50%	11.00%	3.50%
10/16/1980	16.10%	11.02%	5.08%
10/17/1980	14.50%	11.03%	3.47%
10/31/1980	13.75%	11.11%	2.64%
10/31/1980	14.25%	11.11%	3.14%
11/4/1980	15.00%	11.12%	3.88%
11/5/1980	13.75%	11.12%	2.63%
11/5/1980	14.00%	11.12%	2.88%
11/8/1980	13.75%	11.14%	2.61%
11/10/1980	14.85%	11.15%	3.70%
11/17/1980	14.00%	11.18%	2.82%
11/18/1980	14.00%	11.19%	2.81%
11/19/1980	13.00%	11.19%	1.81%
11/24/1980	14.00%	11.21%	2.79%
11/26/1980	14.00%	11.21%	2.79%
12/8/1980	14.15%	11.22%	2.93%
12/8/1980	15.10%	11.22%	3.88%
12/9/1980	15.35%	11.22%	4.13%
12/12/1980	15.45%	11.23%	4.22%
12/17/1980	13.25%	11.23%	2.02%

12/18/1980	15.80%	11.23%	4.57%
12/19/1980	14.50%	11.23%	3.27%
12/19/1980	14.64%	11.23%	3.41%
12/22/1980	13.45%	11.23%	2.22%
12/22/1980	15.00%	11.23%	3.77%
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12/30/1980	14.95%	11.22%	3.73%
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1/2/1981	15.25%	11.22%	4.03%
1/7/1981	14.30%	11.21%	3.09%
1/19/1981	15.25%	11.20%	4.05%
1/23/1981	13.10%	11.20%	1.90%
1/23/1981	14.40%	11.20%	3.20%
1/26/1981	15.25%	11.20%	4.05%
1/27/1981	15.00%	11.21%	3.79%
1/31/1981	13.47%	11.22%	2.25%
2/3/1981	15.25%	11.23%	4.02%
2/5/1981	15.75%	11.25%	4.50%
2/11/1981	15.60%	11.28%	4.32%
2/20/1981	15.25%	11.33%	3.92%
3/11/1981	15.40%	11.49%	3.91%
3/12/1981	14.51%	11.50%	3.01%
3/12/1981	16.00%	11.50%	4.50%
3/13/1981	13.02%	11.52%	1.50%
3/18/1981	16.19%	11.55%	4.64%
3/19/1981	13.75%	11.56%	2.19%
3/23/1981	14.30%	11.58%	2.72%
3/25/1981	15.30%	11.60%	3.70%
4/1/1981	14.53%	11.68%	2.85%
4/3/1981	19.10%	11.71%	7.39%
4/9/1981	15.00%	11.78%	3.22%
4/9/1981	15.30%	11.78%	3.52%
4/9/1981	16.50%	11.78%	4.72%
4/9/1981	17.00%	11.78%	5.22%
4/10/1981	13.75%	11.80%	1.95%
4/13/1981	13.57%	11.82%	1.75%
4/15/1981	15.30%	11.85%	3.45%
4/16/1981	13.50%	11.87%	1.63%
4/17/1981	14.10%	11.87%	2.23%
4/21/1981	14.00%	11.90%	2.10%
4/21/1981	16.80%	11.90%	4.90%
4/24/1981	16.00%	11.95%	4.05%
4/27/1981	12.50%	11.97%	0.53%
4/27/1981	13.61%	11.97%	1.64%
4/29/1981	13.65%	12.00%	1.65%
4/30/1981	13.50%	12.02%	1.48%
5/4/1981	16.22%	12.05%	4.17%
5/5/1981	14.40%	12.07%	2.33%
5/7/1981	16.25%	12.11%	4.14%
5/7/1981	16.27%	12.11%	4.16%
5/8/1981	13.00%	12.13%	0.87%
5/8/1981	16.00%	12.13%	3.87%
5/12/1981	13.50%	12.16%	1.34%
5/15/1981	15.75%	12.22%	3.53%
5/18/1981	14.88%	12.23%	2.65%
5/20/1981	16.00%	12.26%	3.74%
5/21/1981	14.00%	12.27%	1.73%
5/26/1981	14.90%	12.30%	2.60%
5/27/1981	15.00%	12.31%	2.69%
5/29/1981	15.50%	12.34%	3.16%
6/1/1981	16.50%	12.35%	4.15%
6/3/1981	14.67%	12.37%	2.30%
6/5/1981	13.00%	12.39%	0.61%
6/10/1981	16.75%	12.42%	4.33%
6/17/1981	14.40%	12.46%	1.94%
6/18/1981	16.33%	12.47%	3.86%
6/25/1981	14.75%	12.51%	2.24%
6/26/1981	16.00%	12.52%	3.48%
6/30/1981	15.25%	12.54%	2.71%
7/1/1981	15.50%	12.56%	2.94%
7/1/1981	17.50%	12.56%	4.94%
7/10/1981	16.00%	12.62%	3.38%
7/14/1981	16.90%	12.64%	4.26%
7/15/1981	16.00%	12.65%	3.35%
7/17/1981	15.00%	12.67%	2.33%
7/20/1981	15.00%	12.68%	2.32%
7/21/1981	14.00%	12.69%	1.31%
7/28/1981	13.48%	12.74%	0.74%
7/31/1981	13.50%	12.78%	0.72%
7/31/1981	15.00%	12.78%	2.22%
7/31/1981	16.00%	12.78%	3.22%
8/5/1981	15.71%	12.83%	2.88%
8/10/1981	14.50%	12.87%	1.63%

8/11/1981	15.00%	12.88%	2.12%
8/20/1981	13.50%	12.95%	0.55%
8/20/1981	16.50%	12.95%	3.55%
8/24/1981	15.00%	12.97%	2.03%
8/28/1981	15.00%	13.01%	1.99%
9/3/1981	14.50%	13.05%	1.45%
9/10/1981	14.50%	13.11%	1.39%
9/11/1981	16.00%	13.12%	2.88%
9/16/1981	16.00%	13.15%	2.85%
9/17/1981	16.50%	13.16%	3.34%
9/23/1981	15.85%	13.20%	2.65%
9/28/1981	15.50%	13.23%	2.27%
10/9/1981	15.75%	13.33%	2.42%
10/15/1981	16.25%	13.37%	2.88%
10/16/1981	15.50%	13.38%	2.12%
10/16/1981	16.50%	13.38%	3.12%
10/19/1981	14.25%	13.39%	0.86%
10/20/1981	15.25%	13.41%	1.84%
10/20/1981	17.00%	13.41%	3.59%
10/23/1981	16.00%	13.45%	2.55%
10/27/1981	10.00%	13.48%	-3.48%
10/29/1981	14.75%	13.51%	1.24%
10/29/1981	16.50%	13.51%	2.99%
11/3/1981	15.17%	13.53%	1.64%
11/5/1981	16.60%	13.55%	3.05%
11/6/1981	15.17%	13.56%	1.61%
11/24/1981	15.50%	13.61%	1.89%
11/25/1981	15.25%	13.61%	1.64%
11/25/1981	15.35%	13.61%	1.74%
11/25/1981	16.10%	13.61%	2.49%
11/25/1981	16.10%	13.61%	2.49%
12/1/1981	15.70%	13.61%	2.09%
12/1/1981	16.00%	13.61%	2.39%
12/1/1981	16.49%	13.61%	2.88%
12/1/1981	16.50%	13.61%	2.89%
12/4/1981	16.00%	13.61%	2.39%
12/11/1981	16.25%	13.63%	2.62%
12/14/1981	14.00%	13.63%	0.37%
12/15/1981	15.81%	13.63%	2.18%
12/15/1981	16.00%	13.63%	2.37%
12/16/1981	15.25%	13.63%	1.62%
12/17/1981	16.50%	13.63%	2.87%
12/18/1981	15.45%	13.63%	1.82%
12/30/1981	14.25%	13.67%	0.58%
12/30/1981	16.00%	13.67%	2.33%
12/30/1981	16.25%	13.67%	2.58%
12/31/1981	16.15%	13.67%	2.48%
1/4/1982	15.50%	13.67%	1.83%
1/11/1982	14.50%	13.72%	0.78%
1/11/1982	17.00%	13.72%	3.28%
1/13/1982	14.75%	13.74%	1.01%
1/14/1982	15.75%	13.75%	2.00%
1/15/1982	15.00%	13.76%	1.24%
1/15/1982	16.50%	13.76%	2.74%
1/22/1982	16.25%	13.79%	2.46%
1/27/1982	16.84%	13.81%	3.03%
1/28/1982	13.00%	13.81%	-0.81%
1/29/1982	15.50%	13.82%	1.68%
2/1/1982	15.85%	13.82%	2.03%
2/3/1982	16.44%	13.84%	2.60%
2/8/1982	15.50%	13.86%	1.64%
2/11/1982	16.00%	13.88%	2.12%
2/11/1982	16.20%	13.88%	2.32%
2/17/1982	15.00%	13.89%	1.11%
2/19/1982	15.17%	13.89%	1.28%
2/26/1982	15.25%	13.89%	1.36%
3/1/1982	15.03%	13.89%	1.14%
3/1/1982	16.00%	13.89%	2.11%
3/3/1982	15.00%	13.88%	1.12%
3/8/1982	17.10%	13.88%	3.22%
3/12/1982	16.25%	13.88%	2.37%
3/17/1982	17.30%	13.88%	3.42%
3/22/1982	15.10%	13.89%	1.21%
3/27/1982	15.40%	13.89%	1.51%
3/30/1982	15.50%	13.90%	1.60%
3/31/1982	17.00%	13.91%	3.09%
4/1/1982	14.70%	13.91%	0.79%
4/1/1982	16.50%	13.91%	2.59%
4/2/1982	15.50%	13.91%	1.59%
4/5/1982	15.50%	13.92%	1.58%
4/8/1982	16.40%	13.93%	2.47%
4/13/1982	14.50%	13.94%	0.56%
4/23/1982	15.75%	13.94%	1.81%

4/27/1982	15.00%	13.94%	1.06%
4/28/1982	15.75%	13.94%	1.81%
4/30/1982	14.70%	13.94%	0.76%
4/30/1982	15.50%	13.94%	1.56%
5/3/1982	16.60%	13.94%	2.66%
5/4/1982	16.00%	13.94%	2.06%
5/14/1982	15.50%	13.92%	1.58%
5/18/1982	15.42%	13.92%	1.50%
5/19/1982	14.69%	13.92%	0.77%
5/20/1982	15.00%	13.91%	1.09%
5/20/1982	15.10%	13.91%	1.19%
5/20/1982	15.50%	13.91%	1.59%
5/20/1982	16.30%	13.91%	2.39%
5/21/1982	17.75%	13.91%	3.84%
5/27/1982	15.00%	13.89%	1.11%
5/28/1982	15.50%	13.89%	1.61%
5/28/1982	17.00%	13.89%	3.11%
6/1/1982	13.75%	13.89%	-0.14%
6/1/1982	16.60%	13.89%	2.71%
6/9/1982	17.86%	13.88%	3.98%
6/14/1982	15.75%	13.88%	1.87%
6/15/1982	14.85%	13.88%	0.97%
6/18/1982	15.50%	13.87%	1.63%
6/21/1982	14.90%	13.87%	1.03%
6/23/1982	16.00%	13.86%	2.14%
6/23/1982	16.17%	13.86%	2.31%
6/24/1982	14.85%	13.86%	0.99%
6/25/1982	14.70%	13.86%	0.84%
7/1/1982	16.00%	13.84%	2.16%
7/2/1982	15.62%	13.84%	1.78%
7/2/1982	17.00%	13.84%	3.16%
7/13/1982	14.00%	13.82%	0.18%
7/13/1982	16.80%	13.82%	2.98%
7/14/1982	15.76%	13.82%	1.94%
7/14/1982	16.02%	13.82%	2.20%
7/19/1982	16.50%	13.80%	2.70%
7/22/1982	14.50%	13.77%	0.73%
7/22/1982	17.00%	13.77%	3.23%
7/27/1982	16.75%	13.75%	3.00%
7/29/1982	16.50%	13.74%	2.76%
8/11/1982	17.50%	13.68%	3.82%
8/18/1982	17.07%	13.63%	3.44%
8/20/1982	15.73%	13.60%	2.13%
8/25/1982	16.00%	13.57%	2.43%
8/26/1982	15.50%	13.56%	1.94%
8/30/1982	15.00%	13.55%	1.45%
9/3/1982	16.20%	13.53%	2.67%
9/8/1982	15.00%	13.52%	1.48%
9/15/1982	13.08%	13.50%	-0.42%
9/15/1982	16.25%	13.50%	2.75%
9/16/1982	16.00%	13.50%	2.50%
9/17/1982	15.25%	13.50%	1.75%
9/23/1982	17.17%	13.47%	3.70%
9/24/1982	14.50%	13.46%	1.04%
9/27/1982	15.25%	13.46%	1.79%
10/1/1982	15.50%	13.42%	2.08%
10/15/1982	15.90%	13.32%	2.58%
10/22/1982	15.75%	13.24%	2.51%
10/22/1982	17.15%	13.24%	3.91%
10/29/1982	15.54%	13.16%	2.38%
11/1/1982	15.50%	13.15%	2.35%
11/3/1982	17.20%	13.13%	4.07%
11/4/1982	16.25%	13.11%	3.14%
11/5/1982	16.20%	13.09%	3.11%
11/9/1982	16.00%	13.05%	2.95%
11/23/1982	15.50%	12.89%	2.61%
11/23/1982	15.85%	12.89%	2.96%
11/30/1982	16.50%	12.81%	3.69%
12/1/1982	17.04%	12.79%	4.25%
12/6/1982	15.00%	12.73%	2.27%
12/6/1982	16.35%	12.73%	3.62%
12/10/1982	15.50%	12.66%	2.84%
12/13/1982	16.00%	12.65%	3.35%
12/14/1982	15.30%	12.63%	2.67%
12/14/1982	16.40%	12.63%	3.77%
12/20/1982	16.00%	12.57%	3.43%
12/21/1982	14.75%	12.56%	2.19%
12/21/1982	15.85%	12.56%	3.29%
12/22/1982	16.25%	12.54%	3.71%
12/22/1982	16.58%	12.54%	4.04%
12/22/1982	16.75%	12.54%	4.21%
12/29/1982	14.90%	12.48%	2.42%
12/29/1982	16.25%	12.48%	3.77%

12/30/1982	16.00%	12.47%	3.53%
12/30/1982	16.35%	12.47%	3.88%
12/30/1982	16.77%	12.47%	4.30%
1/5/1983	17.33%	12.40%	4.93%
1/11/1983	15.90%	12.34%	3.56%
1/12/1983	14.63%	12.33%	2.30%
1/12/1983	15.50%	12.33%	3.17%
1/20/1983	17.75%	12.24%	5.51%
1/21/1983	15.00%	12.22%	2.78%
1/24/1983	14.50%	12.21%	2.29%
1/24/1983	15.50%	12.21%	3.29%
1/25/1983	15.85%	12.19%	3.66%
1/27/1983	16.14%	12.17%	3.97%
2/1/1983	18.50%	12.13%	6.37%
2/4/1983	14.00%	12.10%	1.90%
2/10/1983	15.00%	12.06%	2.94%
2/21/1983	15.50%	11.98%	3.52%
2/22/1983	15.50%	11.97%	3.53%
2/23/1983	15.10%	11.96%	3.14%
2/23/1983	16.00%	11.96%	4.04%
3/2/1983	15.25%	11.89%	3.36%
3/9/1983	15.20%	11.82%	3.38%
3/15/1983	13.00%	11.77%	1.23%
3/18/1983	15.25%	11.73%	3.52%
3/23/1983	15.40%	11.69%	3.71%
3/24/1983	15.00%	11.67%	3.33%
3/29/1983	15.50%	11.63%	3.87%
3/30/1983	16.71%	11.61%	5.10%
3/31/1983	15.00%	11.59%	3.41%
4/4/1983	15.20%	11.58%	3.62%
4/8/1983	15.50%	11.51%	3.99%
4/11/1983	14.81%	11.49%	3.32%
4/19/1983	14.50%	11.38%	3.12%
4/20/1983	16.00%	11.36%	4.64%
4/29/1983	16.00%	11.24%	4.76%
5/1/1983	14.50%	11.24%	3.26%
5/9/1983	15.50%	11.15%	4.35%
5/11/1983	16.46%	11.12%	5.34%
5/12/1983	14.14%	11.11%	3.03%
5/18/1983	15.00%	11.05%	3.95%
5/23/1983	14.90%	11.01%	3.89%
5/23/1983	15.50%	11.01%	4.49%
5/25/1983	15.50%	10.98%	4.52%
5/27/1983	15.00%	10.96%	4.04%
5/31/1983	14.00%	10.95%	3.05%
5/31/1983	15.50%	10.95%	4.55%
6/2/1983	14.50%	10.93%	3.57%
6/17/1983	15.03%	10.84%	4.19%
7/1/1983	14.80%	10.78%	4.02%
7/1/1983	14.90%	10.78%	4.12%
7/8/1983	16.25%	10.76%	5.49%
7/13/1983	13.20%	10.75%	2.45%
7/19/1983	15.00%	10.74%	4.26%
7/19/1983	15.10%	10.74%	4.36%
7/25/1983	16.25%	10.73%	5.52%
7/28/1983	15.90%	10.74%	5.16%
8/3/1983	16.34%	10.75%	5.59%
8/3/1983	16.50%	10.75%	5.75%
8/19/1983	15.00%	10.80%	4.20%
8/22/1983	15.50%	10.80%	4.70%
8/22/1983	16.40%	10.80%	5.60%
8/31/1983	14.75%	10.84%	3.91%
9/7/1983	15.00%	10.86%	4.14%
9/14/1983	15.78%	10.89%	4.89%
9/16/1983	15.00%	10.90%	4.10%
9/19/1983	14.50%	10.91%	3.59%
9/20/1983	16.50%	10.91%	5.59%
9/28/1983	14.50%	10.94%	3.56%
9/29/1983	15.50%	10.95%	4.55%
9/30/1983	15.25%	10.95%	4.30%
9/30/1983	16.15%	10.95%	5.20%
10/4/1983	14.80%	10.96%	3.84%
10/7/1983	16.00%	10.97%	5.03%
10/13/1983	15.52%	10.99%	4.53%
10/17/1983	15.50%	11.00%	4.50%
10/18/1983	14.50%	11.00%	3.50%
10/19/1983	16.25%	11.01%	5.24%
10/19/1983	16.50%	11.01%	5.49%
10/26/1983	15.00%	11.04%	3.96%
10/27/1983	15.20%	11.04%	4.16%
11/1/1983	16.00%	11.06%	4.94%
11/9/1983	14.90%	11.09%	3.81%
11/10/1983	14.35%	11.10%	3.25%

11/23/1983	16.00%	11.13%	4.87%
11/23/1983	16.15%	11.13%	5.02%
11/30/1983	15.00%	11.14%	3.86%
12/5/1983	15.25%	11.15%	4.10%
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1/19/1984	15.90%	11.33%	4.57%
1/30/1984	16.10%	11.37%	4.73%
1/31/1984	15.25%	11.37%	3.88%
2/1/1984	14.80%	11.38%	3.42%
2/6/1984	13.75%	11.40%	2.35%
2/6/1984	14.75%	11.40%	3.35%
2/9/1984	15.25%	11.42%	3.83%
2/15/1984	15.70%	11.44%	4.26%
2/20/1984	15.00%	11.46%	3.54%
2/20/1984	15.00%	11.46%	3.54%
2/22/1984	14.75%	11.47%	3.28%
2/28/1984	14.50%	11.51%	2.99%
3/2/1984	14.25%	11.54%	2.71%
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7/31/1984	16.00%	12.43%	3.57%
8/3/1984	14.25%	12.44%	1.81%
8/17/1984	14.30%	12.49%	1.81%
8/20/1984	15.00%	12.49%	2.51%
8/27/1984	16.30%	12.51%	3.79%
8/31/1984	15.55%	12.52%	3.03%
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12/18/1984	16.40%	12.53%	3.87%
12/19/1984	14.75%	12.53%	2.22%
12/19/1984	15.00%	12.53%	2.47%
12/20/1984	16.00%	12.53%	3.47%
12/28/1984	16.00%	12.50%	3.50%
1/3/1985	14.75%	12.49%	2.26%
1/10/1985	15.75%	12.47%	3.28%
1/11/1985	16.30%	12.46%	3.84%
1/23/1985	15.80%	12.43%	3.37%
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1/25/1985	16.75%	12.42%	4.33%
1/30/1985	14.90%	12.40%	2.50%
1/31/1985	14.75%	12.39%	2.36%
2/8/1985	14.47%	12.35%	2.12%
3/1/1985	13.84%	12.31%	1.53%
3/8/1985	16.85%	12.28%	4.57%
3/14/1985	15.50%	12.25%	3.25%
3/15/1985	15.62%	12.25%	3.37%
3/29/1985	15.62%	12.17%	3.45%
4/3/1985	14.60%	12.14%	2.46%
4/9/1985	15.50%	12.11%	3.39%
4/16/1985	15.70%	12.06%	3.64%
4/22/1985	14.00%	12.02%	1.98%
4/26/1985	15.50%	11.98%	3.52%
4/29/1985	15.00%	11.97%	3.03%
5/2/1985	14.68%	11.94%	2.74%
5/8/1985	15.62%	11.89%	3.73%
5/10/1985	16.50%	11.87%	4.63%
5/29/1985	14.61%	11.73%	2.88%
5/31/1985	16.00%	11.71%	4.29%
6/14/1985	15.50%	11.61%	3.89%
7/9/1985	15.00%	11.45%	3.55%
7/16/1985	14.50%	11.39%	3.11%
7/26/1985	14.50%	11.33%	3.17%
8/2/1985	14.80%	11.29%	3.51%
8/7/1985	15.00%	11.27%	3.73%
8/28/1985	14.25%	11.15%	3.10%
8/28/1985	15.50%	11.15%	4.35%
8/29/1985	14.50%	11.15%	3.35%
9/9/1985	14.60%	11.11%	3.49%
9/9/1985	14.90%	11.11%	3.79%
9/17/1985	14.90%	11.08%	3.82%
9/23/1985	15.00%	11.06%	3.94%
9/27/1985	15.50%	11.05%	4.45%
9/27/1985	15.80%	11.05%	4.75%
10/2/1985	14.00%	11.03%	2.97%
10/2/1985	14.75%	11.03%	3.72%
10/3/1985	15.25%	11.03%	4.22%
10/24/1985	15.40%	10.96%	4.44%
10/24/1985	15.82%	10.96%	4.86%
10/24/1985	15.85%	10.96%	4.89%
10/28/1985	16.00%	10.95%	5.05%
10/29/1985	16.65%	10.94%	5.71%
10/31/1985	15.06%	10.93%	4.13%
11/4/1985	14.50%	10.92%	3.58%
11/7/1985	15.50%	10.90%	4.60%
11/8/1985	14.30%	10.89%	3.41%
12/12/1985	14.75%	10.73%	4.02%
12/18/1985	15.00%	10.69%	4.31%
12/20/1985	14.50%	10.67%	3.83%
12/20/1985	14.50%	10.67%	3.83%
12/20/1985	15.00%	10.67%	4.33%
1/24/1986	15.40%	10.41%	4.99%
1/31/1986	15.00%	10.35%	4.65%
2/5/1986	15.00%	10.32%	4.68%
2/5/1986	15.75%	10.32%	5.43%
2/10/1986	13.30%	10.29%	3.01%
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2/18/1986	16.00%	10.23%	5.77%
2/24/1986	14.50%	10.18%	4.32%
2/26/1986	14.00%	10.15%	3.85%
3/5/1986	14.90%	10.08%	4.82%
3/11/1986	14.50%	10.02%	4.48%
3/12/1986	13.50%	10.00%	3.50%
3/27/1986	14.10%	9.86%	4.24%
3/31/1986	13.50%	9.84%	3.66%
4/1/1986	14.00%	9.83%	4.17%
4/2/1986	15.50%	9.81%	5.69%
4/4/1986	15.00%	9.78%	5.22%

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4/23/1986	15.00%	9.57%	5.43%
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5/30/1986	15.10%	9.18%	5.92%
6/2/1986	12.81%	9.17%	3.64%
6/11/1986	14.00%	9.07%	4.93%
6/24/1986	16.63%	8.94%	7.69%
6/26/1986	12.00%	8.91%	3.09%
6/26/1986	14.75%	8.91%	5.84%
6/30/1986	13.00%	8.87%	4.13%
7/10/1986	14.34%	8.75%	5.59%
7/11/1986	12.75%	8.73%	4.02%
7/14/1986	12.60%	8.71%	3.89%
7/17/1986	12.40%	8.66%	3.74%
7/25/1986	14.25%	8.57%	5.68%
8/6/1986	13.50%	8.44%	5.06%
8/14/1986	13.50%	8.35%	5.15%
9/16/1986	12.75%	8.06%	4.69%
9/19/1986	13.25%	8.03%	5.22%
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10/3/1986	13.40%	7.93%	5.47%
10/31/1986	13.50%	7.77%	5.73%
11/5/1986	13.00%	7.75%	5.25%
12/3/1986	12.90%	7.58%	5.32%
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12/16/1986	13.60%	7.52%	6.08%
12/22/1986	13.80%	7.51%	6.29%
12/30/1986	13.00%	7.49%	5.51%
1/2/1987	13.00%	7.49%	5.51%
1/12/1987	12.40%	7.47%	4.93%
1/27/1987	12.71%	7.46%	5.25%
3/2/1987	12.47%	7.47%	5.00%
3/3/1987	13.60%	7.47%	6.13%
3/4/1987	12.38%	7.47%	4.91%
3/10/1987	13.50%	7.47%	6.03%
3/13/1987	13.00%	7.47%	5.53%
3/31/1987	13.00%	7.46%	5.54%
4/6/1987	13.00%	7.47%	5.53%
4/14/1987	12.50%	7.49%	5.01%
4/16/1987	14.50%	7.50%	7.00%
4/27/1987	12.00%	7.54%	4.46%
5/5/1987	12.85%	7.58%	5.27%
5/12/1987	12.65%	7.62%	5.03%
5/28/1987	13.50%	7.70%	5.80%
6/15/1987	13.20%	7.78%	5.42%
6/29/1987	15.00%	7.83%	7.17%
6/30/1987	12.50%	7.84%	4.66%
7/8/1987	12.00%	7.86%	4.14%
7/10/1987	12.90%	7.86%	5.04%
7/15/1987	13.50%	7.88%	5.62%
7/16/1987	13.50%	7.88%	5.62%
7/16/1987	15.00%	7.88%	7.12%
7/27/1987	13.00%	7.92%	5.08%
7/27/1987	13.40%	7.92%	5.48%
7/27/1987	13.50%	7.92%	5.58%
7/31/1987	12.98%	7.95%	5.03%
8/26/1987	12.63%	8.06%	4.57%
8/26/1987	12.75%	8.06%	4.69%
8/27/1987	13.25%	8.06%	5.19%
9/9/1987	13.00%	8.14%	4.86%
9/30/1987	12.75%	8.31%	4.44%
9/30/1987	13.00%	8.31%	4.69%
10/2/1987	11.50%	8.33%	3.17%
10/15/1987	13.00%	8.43%	4.57%
11/2/1987	13.00%	8.55%	4.45%
11/19/1987	13.00%	8.64%	4.36%
11/30/1987	12.00%	8.68%	3.32%
12/3/1987	14.20%	8.70%	5.50%
12/15/1987	13.25%	8.77%	4.48%
12/16/1987	13.50%	8.78%	4.72%
12/16/1987	13.72%	8.78%	4.94%
12/17/1987	11.75%	8.79%	2.96%
12/18/1987	13.50%	8.80%	4.70%
12/21/1987	12.01%	8.81%	3.20%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	12.75%	8.81%	3.94%
12/22/1987	13.00%	8.81%	4.19%
1/20/1988	13.80%	8.94%	4.86%
1/26/1988	13.90%	8.95%	4.95%
1/29/1988	13.20%	8.96%	4.24%

2/4/1988	12.60%	8.96%	3.64%
3/1/1988	11.56%	8.94%	2.62%
3/23/1988	12.87%	8.92%	3.95%
3/24/1988	11.24%	8.92%	2.32%
3/30/1988	12.72%	8.92%	3.80%
4/1/1988	12.50%	8.92%	3.58%
4/7/1988	13.25%	8.93%	4.32%
4/25/1988	10.96%	8.96%	2.00%
5/3/1988	12.91%	8.97%	3.94%
5/11/1988	13.50%	8.99%	4.51%
5/16/1988	13.00%	8.99%	4.01%
6/30/1988	12.75%	9.00%	3.75%
7/1/1988	12.75%	8.99%	3.76%
7/20/1988	13.40%	8.96%	4.44%
8/5/1988	12.75%	8.92%	3.83%
8/23/1988	11.70%	8.93%	2.77%
8/29/1988	12.75%	8.94%	3.81%
8/30/1988	13.50%	8.94%	4.56%
9/8/1988	12.60%	8.95%	3.65%
10/13/1988	13.10%	8.93%	4.17%
12/19/1988	13.00%	9.02%	3.98%
12/20/1988	12.25%	9.02%	3.23%
12/20/1988	13.00%	9.02%	3.98%
12/21/1988	12.90%	9.02%	3.88%
12/27/1988	13.00%	9.03%	3.97%
12/28/1988	13.10%	9.03%	4.07%
12/30/1988	13.40%	9.04%	4.36%
1/27/1989	13.00%	9.05%	3.95%
1/31/1989	13.00%	9.05%	3.95%
2/17/1989	13.00%	9.05%	3.95%
2/20/1989	12.40%	9.05%	3.35%
3/1/1989	12.76%	9.05%	3.71%
3/8/1989	13.00%	9.05%	3.95%
3/30/1989	14.00%	9.05%	4.95%
4/5/1989	14.20%	9.05%	5.15%
4/18/1989	13.00%	9.05%	3.95%
5/5/1989	12.40%	9.05%	3.35%
6/2/1989	13.20%	9.00%	4.20%
6/8/1989	13.50%	8.98%	4.52%
6/27/1989	13.25%	8.91%	4.34%
6/30/1989	13.00%	8.90%	4.10%
8/14/1989	12.50%	8.77%	3.73%
9/28/1989	12.25%	8.63%	3.62%
10/24/1989	12.50%	8.54%	3.96%
11/9/1989	13.00%	8.49%	4.51%
12/15/1989	13.00%	8.34%	4.66%
12/20/1989	12.90%	8.32%	4.58%
12/21/1989	12.90%	8.31%	4.59%
12/27/1989	12.50%	8.29%	4.21%
12/27/1989	13.00%	8.29%	4.71%
1/10/1990	12.80%	8.24%	4.56%
1/11/1990	12.90%	8.24%	4.66%
1/17/1990	12.80%	8.22%	4.58%
1/26/1990	12.00%	8.20%	3.80%
2/9/1990	12.10%	8.17%	3.93%
2/24/1990	12.86%	8.15%	4.71%
3/30/1990	12.90%	8.16%	4.74%
4/4/1990	15.76%	8.17%	7.59%
4/12/1990	12.52%	8.18%	4.34%
4/19/1990	12.75%	8.20%	4.55%
5/21/1990	12.10%	8.28%	3.82%
5/29/1990	12.40%	8.30%	4.10%
5/31/1990	12.00%	8.30%	3.70%
6/4/1990	12.90%	8.30%	4.60%
6/6/1990	12.25%	8.31%	3.94%
6/15/1990	13.20%	8.32%	4.88%
6/20/1990	12.92%	8.32%	4.60%
6/27/1990	12.90%	8.33%	4.57%
6/29/1990	12.50%	8.33%	4.17%
7/6/1990	12.10%	8.34%	3.76%
7/6/1990	12.35%	8.34%	4.01%
8/10/1990	12.55%	8.41%	4.14%
8/16/1990	13.21%	8.43%	4.78%
8/22/1990	13.10%	8.45%	4.65%
8/24/1990	13.00%	8.46%	4.54%
9/26/1990	11.45%	8.59%	2.86%
10/2/1990	13.00%	8.61%	4.39%
10/5/1990	12.84%	8.62%	4.22%
10/19/1990	13.00%	8.67%	4.33%
10/25/1990	12.30%	8.68%	3.62%
11/21/1990	12.70%	8.69%	4.01%
12/13/1990	12.30%	8.67%	3.63%
12/17/1990	12.87%	8.67%	4.20%

12/18/1990	13.10%	8.67%	4.43%
12/19/1990	12.00%	8.66%	3.34%
12/20/1990	12.75%	8.66%	4.09%
12/21/1990	12.50%	8.66%	3.84%
12/27/1990	12.79%	8.66%	4.13%
1/2/1991	13.10%	8.65%	4.45%
1/4/1991	12.50%	8.65%	3.85%
1/15/1991	12.75%	8.64%	4.11%
1/25/1991	11.70%	8.63%	3.07%
2/4/1991	12.50%	8.60%	3.90%
2/7/1991	12.50%	8.59%	3.91%
2/12/1991	13.00%	8.58%	4.43%
2/14/1991	12.72%	8.57%	4.15%
2/22/1991	12.80%	8.55%	4.25%
3/6/1991	13.10%	8.53%	4.57%
3/8/1991	12.30%	8.52%	3.78%
3/8/1991	13.00%	8.52%	4.48%
4/22/1991	13.00%	8.49%	4.51%
5/7/1991	13.50%	8.47%	5.03%
5/13/1991	13.25%	8.47%	4.78%
5/30/1991	12.75%	8.44%	4.31%
6/12/1991	12.00%	8.41%	3.59%
6/25/1991	11.70%	8.39%	3.31%
6/28/1991	12.50%	8.38%	4.12%
7/1/1991	12.00%	8.38%	3.62%
7/3/1991	12.50%	8.37%	4.13%
7/19/1991	12.10%	8.34%	3.76%
8/1/1991	12.90%	8.32%	4.58%
8/16/1991	13.20%	8.29%	4.91%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.25%	8.23%	4.02%
10/17/1991	13.00%	8.20%	4.80%
10/23/1991	12.50%	8.20%	4.30%
10/23/1991	12.55%	8.20%	4.35%
10/31/1991	11.80%	8.19%	3.61%
11/1/1991	12.00%	8.19%	3.81%
11/5/1991	12.25%	8.19%	4.06%
11/12/1991	12.50%	8.18%	4.32%
11/12/1991	13.25%	8.18%	5.07%
11/25/1991	12.40%	8.18%	4.22%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.50%	8.18%	4.32%
11/27/1991	12.10%	8.18%	3.92%
12/18/1991	12.25%	8.15%	4.10%
12/19/1991	12.60%	8.15%	4.45%
12/19/1991	12.80%	8.15%	4.65%
12/20/1991	12.65%	8.14%	4.51%
1/9/1992	12.80%	8.09%	4.71%
1/16/1992	12.75%	8.07%	4.68%
1/21/1992	12.00%	8.06%	3.94%
1/22/1992	13.00%	8.06%	4.94%
1/27/1992	12.65%	8.05%	4.60%
1/31/1992	12.00%	8.04%	3.96%
2/11/1992	12.40%	8.03%	4.37%
2/25/1992	12.50%	8.01%	4.49%
3/16/1992	11.43%	7.98%	3.45%
3/18/1992	12.28%	7.98%	4.30%
4/2/1992	12.10%	7.95%	4.15%
4/9/1992	11.45%	7.94%	3.51%
4/10/1992	11.50%	7.93%	3.57%
4/14/1992	11.50%	7.93%	3.57%
5/5/1992	11.50%	7.89%	3.61%
5/12/1992	11.87%	7.88%	3.99%
5/12/1992	12.46%	7.88%	4.58%
6/1/1992	12.30%	7.87%	4.43%
6/12/1992	10.90%	7.86%	3.04%
6/26/1992	12.35%	7.85%	4.50%
6/29/1992	11.00%	7.85%	3.15%
6/30/1992	13.00%	7.85%	5.15%
7/13/1992	11.90%	7.84%	4.06%
7/13/1992	13.50%	7.84%	5.66%
7/22/1992	11.20%	7.83%	3.37%
8/3/1992	12.00%	7.81%	4.19%
8/6/1992	12.50%	7.80%	4.70%
9/22/1992	12.00%	7.71%	4.29%
9/28/1992	11.40%	7.71%	3.69%
9/30/1992	11.75%	7.70%	4.05%
10/2/1992	13.00%	7.70%	5.30%
10/12/1992	12.20%	7.70%	4.50%
10/16/1992	13.16%	7.70%	5.46%
10/30/1992	11.75%	7.71%	4.04%
11/3/1992	12.00%	7.71%	4.29%
12/3/1992	11.85%	7.68%	4.17%

12/15/1992	11.00%	7.66%	3.34%
12/16/1992	11.90%	7.66%	4.24%
12/16/1992	12.40%	7.66%	4.74%
12/17/1992	12.00%	7.66%	4.34%
12/22/1992	12.30%	7.65%	4.65%
12/22/1992	12.40%	7.65%	4.75%
12/29/1992	12.25%	7.63%	4.62%
12/30/1992	12.00%	7.63%	4.37%
12/31/1992	11.90%	7.63%	4.27%
1/12/1993	12.00%	7.61%	4.39%
1/21/1993	11.25%	7.59%	3.66%
2/2/1993	11.40%	7.56%	3.84%
2/15/1993	12.30%	7.52%	4.78%
2/24/1993	11.90%	7.49%	4.41%
2/26/1993	11.80%	7.48%	4.32%
2/26/1993	12.20%	7.48%	4.72%
4/23/1993	11.75%	7.29%	4.46%
5/11/1993	11.75%	7.25%	4.50%
5/14/1993	11.50%	7.24%	4.26%
5/25/1993	11.50%	7.23%	4.27%
5/28/1993	11.00%	7.22%	3.78%
6/3/1993	12.00%	7.21%	4.79%
6/16/1993	11.50%	7.19%	4.31%
6/18/1993	12.10%	7.18%	4.92%
6/25/1993	11.67%	7.17%	4.50%
7/21/1993	11.38%	7.10%	4.28%
7/23/1993	10.46%	7.09%	3.37%
8/24/1993	11.50%	6.96%	4.54%
9/21/1993	10.50%	6.81%	3.69%
9/29/1993	11.47%	6.77%	4.70%
9/30/1993	11.60%	6.76%	4.84%
11/2/1993	10.80%	6.60%	4.20%
11/12/1993	12.00%	6.57%	5.43%
11/26/1993	11.00%	6.52%	4.48%
12/14/1993	10.55%	6.48%	4.07%
12/16/1993	10.60%	6.48%	4.12%
12/21/1993	11.30%	6.47%	4.83%
1/4/1994	10.07%	6.44%	3.63%
1/13/1994	11.00%	6.42%	4.58%
1/21/1994	11.00%	6.40%	4.60%
1/28/1994	11.35%	6.39%	4.96%
2/3/1994	11.40%	6.38%	5.02%
2/17/1994	10.60%	6.36%	4.24%
2/25/1994	11.25%	6.35%	4.90%
2/25/1994	12.00%	6.35%	5.65%
3/1/1994	11.00%	6.35%	4.65%
3/4/1994	11.00%	6.35%	4.65%
4/25/1994	11.00%	6.41%	4.59%
5/10/1994	11.75%	6.45%	5.30%
5/13/1994	10.50%	6.46%	4.04%
6/3/1994	11.00%	6.54%	4.46%
6/27/1994	11.40%	6.65%	4.75%
8/5/1994	12.75%	6.88%	5.87%
10/31/1994	10.00%	7.33%	2.67%
11/9/1994	10.85%	7.39%	3.46%
11/9/1994	10.85%	7.39%	3.46%
11/18/1994	11.20%	7.45%	3.75%
11/22/1994	11.60%	7.47%	4.13%
11/28/1994	11.06%	7.49%	3.57%
12/8/1994	11.50%	7.54%	3.96%
12/8/1994	11.70%	7.54%	4.16%
12/14/1994	10.95%	7.56%	3.39%
12/15/1994	11.50%	7.57%	3.93%
12/19/1994	11.50%	7.58%	3.92%
12/28/1994	12.15%	7.61%	4.54%
1/9/1995	12.28%	7.64%	4.64%
1/31/1995	11.00%	7.69%	3.31%
2/10/1995	12.60%	7.70%	4.90%
2/17/1995	11.90%	7.70%	4.20%
3/9/1995	11.50%	7.71%	3.79%
3/20/1995	12.00%	7.72%	4.28%
3/23/1995	12.81%	7.72%	5.09%
3/29/1995	11.60%	7.72%	3.88%
4/6/1995	11.10%	7.71%	3.39%
4/7/1995	11.00%	7.71%	3.29%
4/19/1995	11.00%	7.70%	3.30%
5/12/1995	11.63%	7.68%	3.95%
5/25/1995	11.20%	7.65%	3.55%
6/9/1995	11.25%	7.60%	3.65%
6/21/1995	12.25%	7.56%	4.69%
6/30/1995	11.10%	7.52%	3.58%
9/11/1995	11.30%	7.20%	4.10%
9/27/1995	11.30%	7.12%	4.18%

9/27/1995	11.50%	7.12%	4.38%
9/27/1995	11.75%	7.12%	4.63%
9/29/1995	11.00%	7.11%	3.89%
11/9/1995	11.38%	6.90%	4.48%
11/9/1995	12.36%	6.90%	5.46%
11/17/1995	11.00%	6.86%	4.14%
12/4/1995	11.35%	6.78%	4.57%
12/11/1995	11.40%	6.74%	4.66%
12/20/1995	11.60%	6.70%	4.90%
12/27/1995	12.00%	6.66%	5.34%
2/5/1996	12.25%	6.48%	5.77%
3/29/1996	10.67%	6.42%	4.25%
4/8/1996	11.00%	6.42%	4.58%
4/11/1996	12.59%	6.43%	6.16%
4/11/1996	12.59%	6.43%	6.16%
4/24/1996	11.25%	6.43%	4.82%
4/30/1996	11.00%	6.43%	4.57%
5/13/1996	11.00%	6.44%	4.56%
5/23/1996	11.25%	6.43%	4.82%
6/25/1996	11.25%	6.48%	4.77%
6/27/1996	11.20%	6.48%	4.72%
8/12/1996	10.40%	6.57%	3.83%
9/27/1996	11.00%	6.71%	4.29%
10/16/1996	12.25%	6.76%	5.49%
11/5/1996	11.00%	6.81%	4.19%
11/26/1996	11.30%	6.83%	4.47%
12/18/1996	11.75%	6.83%	4.92%
12/31/1996	11.50%	6.83%	4.67%
1/3/1997	10.70%	6.83%	3.87%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.82%	4.98%
3/31/1997	10.02%	6.80%	3.22%
4/2/1997	11.65%	6.80%	4.85%
4/28/1997	11.50%	6.81%	4.69%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
12/12/1997	11.00%	6.60%	4.40%
12/23/1997	11.12%	6.57%	4.55%
2/2/1998	12.75%	6.39%	6.36%
3/2/1998	11.25%	6.29%	4.96%
3/6/1998	10.75%	6.27%	4.48%
3/20/1998	10.50%	6.22%	4.28%
4/30/1998	12.20%	6.12%	6.08%
7/10/1998	11.40%	5.94%	5.46%
9/15/1998	11.90%	5.78%	6.12%
11/30/1998	12.60%	5.58%	7.02%
12/10/1998	12.20%	5.54%	6.66%
12/17/1998	12.10%	5.52%	6.58%
2/5/1999	10.30%	5.38%	4.92%
3/4/1999	10.50%	5.34%	5.16%
4/6/1999	10.94%	5.32%	5.62%
7/29/1999	10.75%	5.52%	5.23%
9/23/1999	10.75%	5.70%	5.05%
11/17/1999	11.10%	5.90%	5.20%
1/7/2000	11.50%	6.05%	5.45%
1/7/2000	11.50%	6.05%	5.45%
2/17/2000	10.60%	6.17%	4.43%
3/28/2000	11.25%	6.20%	5.05%
5/24/2000	11.00%	6.18%	4.82%
7/18/2000	12.20%	6.16%	6.04%
9/29/2000	11.16%	6.03%	5.13%
11/28/2000	12.90%	5.89%	7.01%
11/30/2000	12.10%	5.88%	6.22%
1/23/2001	11.25%	5.79%	5.46%
2/8/2001	11.50%	5.77%	5.73%
5/8/2001	10.75%	5.62%	5.13%
6/26/2001	11.00%	5.62%	5.38%
7/25/2001	11.02%	5.60%	5.42%
7/25/2001	11.02%	5.60%	5.42%
7/31/2001	11.00%	5.59%	5.41%
8/31/2001	10.50%	5.56%	4.94%
9/7/2001	10.75%	5.55%	5.20%
9/10/2001	11.00%	5.55%	5.45%
9/20/2001	10.00%	5.55%	4.45%
10/24/2001	10.30%	5.54%	4.76%
11/28/2001	10.60%	5.49%	5.11%
12/3/2001	12.88%	5.49%	7.39%
12/20/2001	12.50%	5.50%	7.00%
1/22/2002	10.00%	5.50%	4.50%
3/27/2002	10.10%	5.45%	4.65%
4/22/2002	11.80%	5.45%	6.35%
5/28/2002	10.17%	5.46%	4.71%
6/10/2002	12.00%	5.47%	6.53%

6/18/2002	11.16%	5.48%	5.68%
6/20/2002	11.00%	5.48%	5.52%
6/20/2002	12.30%	5.48%	6.82%
7/15/2002	11.00%	5.48%	5.52%
9/12/2002	12.30%	5.45%	6.85%
9/26/2002	10.45%	5.41%	5.04%
12/4/2002	11.55%	5.29%	6.26%
12/13/2002	11.75%	5.27%	6.48%
12/20/2002	11.40%	5.25%	6.15%
1/8/2003	11.10%	5.19%	5.91%
1/31/2003	12.45%	5.13%	7.32%
2/28/2003	12.30%	5.05%	7.25%
3/6/2003	10.75%	5.03%	5.72%
3/7/2003	9.96%	5.02%	4.94%
3/20/2003	12.00%	4.98%	7.02%
4/3/2003	12.00%	4.96%	7.04%
4/15/2003	11.15%	4.94%	6.21%
6/25/2003	10.75%	4.79%	5.96%
6/26/2003	10.75%	4.79%	5.96%
7/9/2003	9.75%	4.79%	4.96%
7/16/2003	9.75%	4.79%	4.96%
7/25/2003	9.50%	4.80%	4.70%
8/26/2003	10.50%	4.83%	5.67%
12/17/2003	9.85%	4.94%	4.91%
12/17/2003	10.70%	4.94%	5.76%
12/18/2003	11.50%	4.94%	6.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
12/23/2003	10.50%	4.94%	5.56%
1/13/2004	12.00%	4.95%	7.05%
3/2/2004	10.75%	4.99%	5.76%
3/26/2004	10.25%	5.02%	5.23%
4/5/2004	11.25%	5.03%	6.22%
5/18/2004	10.50%	5.07%	5.43%
5/25/2004	10.25%	5.08%	5.17%
5/27/2004	10.25%	5.08%	5.17%
6/2/2004	11.22%	5.08%	6.14%
6/30/2004	10.50%	5.10%	5.40%
6/30/2004	10.50%	5.10%	5.40%
7/16/2004	11.60%	5.11%	6.49%
8/25/2004	10.25%	5.10%	5.15%
9/9/2004	10.40%	5.10%	5.30%
11/9/2004	10.50%	5.07%	5.43%
11/23/2004	11.00%	5.06%	5.94%
12/14/2004	10.97%	5.07%	5.90%
12/21/2004	11.25%	5.07%	6.18%
12/21/2004	11.50%	5.07%	6.43%
12/22/2004	10.70%	5.07%	5.63%
12/22/2004	11.50%	5.07%	6.43%
12/29/2004	9.85%	5.07%	4.78%
1/6/2005	10.70%	5.08%	5.62%
2/18/2005	10.30%	4.98%	5.32%
2/25/2005	10.50%	4.96%	5.54%
3/10/2005	11.00%	4.93%	6.07%
3/24/2005	10.30%	4.90%	5.40%
4/4/2005	10.00%	4.88%	5.12%
4/7/2005	10.25%	4.87%	5.38%
5/18/2005	10.25%	4.78%	5.47%
5/25/2005	10.75%	4.76%	5.99%
5/26/2005	9.75%	4.76%	4.99%
6/1/2005	9.75%	4.75%	5.00%
7/19/2005	11.50%	4.64%	6.86%
8/5/2005	11.75%	4.62%	7.13%
8/15/2005	10.13%	4.61%	5.52%
9/28/2005	10.00%	4.54%	5.46%
10/4/2005	10.75%	4.54%	6.21%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6.20%
12/21/2005	10.29%	4.54%	5.75%
12/21/2005	10.40%	4.54%	5.86%
12/22/2005	11.00%	4.54%	6.46%
12/22/2005	11.15%	4.54%	6.61%
12/28/2005	10.00%	4.54%	5.46%
12/28/2005	10.00%	4.54%	5.46%
1/5/2006	11.00%	4.53%	6.47%
1/27/2006	9.75%	4.52%	5.23%
3/3/2006	10.39%	4.53%	5.86%
4/17/2006	10.20%	4.61%	5.59%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.74%	5.26%
6/27/2006	10.75%	4.80%	5.95%
7/6/2006	10.20%	4.83%	5.37%

7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4.86%	5.64%
7/28/2006	10.05%	4.86%	5.19%
8/23/2006	9.55%	4.89%	4.66%
9/1/2006	10.54%	4.90%	5.64%
9/14/2006	10.00%	4.91%	5.09%
10/6/2006	9.67%	4.92%	4.75%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.12%	4.95%	5.17%
12/1/2006	10.25%	4.95%	5.30%
12/1/2006	10.50%	4.95%	5.55%
12/7/2006	10.75%	4.95%	5.80%
12/21/2006	10.90%	4.95%	5.95%
12/21/2006	11.25%	4.95%	6.30%
12/22/2006	10.25%	4.95%	5.30%
1/5/2007	10.00%	4.95%	5.05%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.90%	4.95%	5.95%
1/12/2007	10.10%	4.95%	5.15%
1/13/2007	10.40%	4.95%	5.45%
1/19/2007	10.80%	4.94%	5.86%
3/21/2007	11.35%	4.87%	6.48%
3/22/2007	9.75%	4.86%	4.89%
5/15/2007	10.00%	4.81%	5.19%
5/17/2007	10.25%	4.81%	5.44%
5/17/2007	10.25%	4.81%	5.44%
5/22/2007	10.20%	4.80%	5.40%
5/22/2007	10.50%	4.80%	5.70%
5/23/2007	10.70%	4.80%	5.90%
5/25/2007	9.67%	4.80%	4.87%
6/15/2007	9.90%	4.82%	5.08%
6/21/2007	10.20%	4.83%	5.37%
6/22/2007	10.50%	4.83%	5.67%
6/28/2007	10.75%	4.84%	5.91%
7/12/2007	9.67%	4.86%	4.81%
7/19/2007	10.00%	4.87%	5.13%
7/19/2007	10.00%	4.87%	5.13%
8/15/2007	10.40%	4.88%	5.52%
10/9/2007	10.00%	4.91%	5.09%
10/17/2007	9.10%	4.91%	4.19%
10/31/2007	9.96%	4.90%	5.06%
11/29/2007	10.90%	4.87%	6.03%
12/6/2007	10.75%	4.86%	5.89%
12/13/2007	9.96%	4.86%	5.10%
12/14/2007	10.70%	4.86%	5.84%
12/14/2007	10.80%	4.86%	5.94%
12/19/2007	10.20%	4.86%	5.34%
12/20/2007	10.20%	4.85%	5.35%
12/20/2007	11.00%	4.85%	6.15%
12/28/2007	10.25%	4.85%	5.40%
12/31/2007	11.25%	4.85%	6.40%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/28/2008	9.40%	4.80%	4.60%
1/30/2008	10.00%	4.79%	5.21%
1/31/2008	10.71%	4.79%	5.92%
2/29/2008	10.25%	4.75%	5.50%
3/12/2008	10.25%	4.73%	5.52%
3/25/2008	9.10%	4.68%	4.42%
4/22/2008	10.25%	4.60%	5.65%
4/24/2008	10.10%	4.60%	5.50%
5/1/2008	10.70%	4.59%	6.11%
5/19/2008	11.00%	4.56%	6.44%
5/27/2008	10.00%	4.55%	5.45%
6/10/2008	10.70%	4.54%	6.16%
6/27/2008	10.50%	4.54%	5.96%
6/27/2008	11.04%	4.54%	6.50%
7/10/2008	10.43%	4.52%	5.91%
7/16/2008	9.40%	4.52%	4.88%
7/30/2008	10.80%	4.51%	6.29%
7/31/2008	10.70%	4.51%	6.19%
8/11/2008	10.25%	4.51%	5.74%
8/26/2008	10.18%	4.50%	5.68%
9/10/2008	10.30%	4.50%	5.80%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/30/2008	10.20%	4.48%	5.72%
10/8/2008	10.15%	4.46%	5.69%
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12/29/2008	10.20%	4.24%	5.96%
12/31/2008	10.75%	4.22%	6.53%
1/14/2009	10.50%	4.15%	6.35%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/27/2009	10.76%	4.09%	6.67%
1/30/2009	10.50%	4.08%	6.42%
2/4/2009	8.75%	4.06%	4.69%
3/4/2009	10.50%	3.96%	6.54%
3/12/2009	11.50%	3.93%	7.57%
4/2/2009	11.10%	3.85%	7.25%
4/21/2009	10.61%	3.80%	6.81%
4/24/2009	10.00%	3.79%	6.21%
4/30/2009	11.25%	3.78%	7.47%
5/4/2009	10.74%	3.77%	6.97%
5/20/2009	10.25%	3.74%	6.51%
5/28/2009	10.50%	3.74%	6.76%
6/22/2009	10.00%	3.76%	6.24%
6/24/2009	10.80%	3.77%	7.03%
7/8/2009	10.63%	3.77%	6.86%
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8/31/2009	10.25%	3.82%	6.43%
10/14/2009	10.70%	4.01%	6.69%
10/23/2009	10.88%	4.06%	6.82%
11/2/2009	10.70%	4.09%	6.61%
11/3/2009	10.70%	4.10%	6.60%
11/24/2009	10.25%	4.15%	6.10%
11/25/2009	10.75%	4.16%	6.59%
11/30/2009	10.35%	4.17%	6.18%
12/3/2009	10.50%	4.18%	6.32%
12/7/2009	10.70%	4.18%	6.52%
12/16/2009	10.90%	4.21%	6.69%
12/16/2009	11.00%	4.21%	6.79%
12/18/2009	10.40%	4.22%	6.18%
12/18/2009	10.40%	4.22%	6.18%
12/22/2009	10.20%	4.23%	5.97%
12/22/2009	10.40%	4.23%	6.17%
12/22/2009	10.40%	4.23%	6.17%
12/30/2009	10.00%	4.26%	5.74%
1/4/2010	10.80%	4.28%	6.52%
1/11/2010	11.00%	4.30%	6.70%
1/26/2010	10.13%	4.35%	5.78%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.70%	4.35%	6.35%
2/9/2010	9.80%	4.38%	5.42%
2/18/2010	10.60%	4.40%	6.20%
2/24/2010	10.18%	4.41%	5.77%
3/2/2010	9.63%	4.41%	5.22%
3/4/2010	10.50%	4.41%	6.09%
3/5/2010	10.50%	4.41%	6.09%
3/11/2010	11.90%	4.42%	7.48%
3/17/2010	10.00%	4.41%	5.59%
3/25/2010	10.15%	4.42%	5.73%
4/2/2010	10.10%	4.43%	5.67%
4/27/2010	10.00%	4.46%	5.54%
4/29/2010	9.90%	4.46%	5.44%
4/29/2010	10.06%	4.46%	5.60%
4/29/2010	10.26%	4.46%	5.80%
5/12/2010	10.30%	4.45%	5.85%
5/12/2010	10.30%	4.45%	5.85%
5/28/2010	10.10%	4.44%	5.66%
5/28/2010	10.20%	4.44%	5.76%
6/7/2010	10.30%	4.44%	5.86%
6/16/2010	10.00%	4.44%	5.56%
6/28/2010	9.67%	4.43%	5.24%
6/28/2010	10.50%	4.43%	6.07%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.43%	5.82%
7/15/2010	10.53%	4.43%	6.10%
7/15/2010	10.70%	4.43%	6.27%
7/30/2010	10.70%	4.41%	6.29%
8/4/2010	10.50%	4.41%	6.09%
8/6/2010	9.83%	4.41%	5.42%
8/25/2010	9.90%	4.37%	5.53%
9/3/2010	10.60%	4.35%	6.25%
9/14/2010	10.70%	4.33%	6.37%
9/16/2010	10.00%	4.33%	5.67%
9/16/2010	10.00%	4.33%	5.67%

9/30/2010	9.75%	4.29%	5.46%
10/14/2010	10.35%	4.24%	6.11%
10/28/2010	10.70%	4.21%	6.49%
11/2/2010	10.38%	4.20%	6.18%
11/4/2010	10.70%	4.20%	6.50%
11/19/2010	10.20%	4.18%	6.02%
11/22/2010	10.00%	4.18%	5.82%
12/1/2010	10.13%	4.16%	5.97%
12/6/2010	9.86%	4.15%	5.71%
12/9/2010	10.25%	4.15%	6.10%
12/13/2010	10.70%	4.15%	6.55%
12/14/2010	10.13%	4.15%	5.98%
12/15/2010	10.44%	4.15%	6.29%
12/17/2010	10.00%	4.15%	5.85%
12/20/2010	10.60%	4.15%	6.45%
12/21/2010	10.30%	4.14%	6.16%
12/27/2010	9.90%	4.14%	5.76%
12/29/2010	11.15%	4.14%	7.01%
1/5/2011	10.15%	4.13%	6.02%
1/12/2011	10.30%	4.12%	6.18%
1/13/2011	10.30%	4.12%	6.18%
1/18/2011	10.00%	4.12%	5.88%
1/20/2011	9.30%	4.12%	5.18%
1/20/2011	10.13%	4.12%	6.01%
1/31/2011	9.60%	4.12%	5.48%
2/3/2011	10.00%	4.12%	5.88%
2/25/2011	10.00%	4.14%	5.86%
3/25/2011	9.80%	4.18%	5.62%
3/30/2011	10.00%	4.18%	5.82%
4/12/2011	10.00%	4.21%	5.79%
4/25/2011	10.74%	4.23%	6.51%
4/26/2011	9.67%	4.23%	5.44%
4/27/2011	10.40%	4.24%	6.16%
5/4/2011	10.00%	4.24%	5.76%
5/4/2011	10.00%	4.24%	5.76%
5/24/2011	10.50%	4.27%	6.23%
6/8/2011	10.75%	4.30%	6.45%
6/16/2011	9.20%	4.32%	4.88%
6/17/2011	9.95%	4.32%	5.63%
7/13/2011	10.20%	4.36%	5.84%
8/1/2011	9.20%	4.39%	4.81%
8/8/2011	10.00%	4.38%	5.62%
8/11/2011	10.00%	4.38%	5.62%
8/12/2011	10.35%	4.37%	5.98%
8/19/2011	10.25%	4.36%	5.89%
9/2/2011	12.88%	4.32%	8.56%
9/22/2011	10.00%	4.24%	5.76%
10/12/2011	10.30%	4.14%	6.16%
10/20/2011	10.50%	4.10%	6.40%
11/30/2011	10.90%	3.87%	7.03%
11/30/2011	10.90%	3.87%	7.03%
12/14/2011	10.00%	3.80%	6.20%
12/14/2011	10.30%	3.80%	6.50%
12/20/2011	10.20%	3.76%	6.44%
12/21/2011	10.20%	3.76%	6.44%
12/22/2011	9.90%	3.75%	6.15%
12/22/2011	10.40%	3.75%	6.65%
12/23/2011	10.19%	3.74%	6.45%
1/25/2012	10.50%	3.57%	6.93%
1/27/2012	10.50%	3.56%	6.94%
2/15/2012	10.20%	3.47%	6.73%
2/23/2012	9.90%	3.44%	6.46%
2/27/2012	10.25%	3.43%	6.82%
2/29/2012	10.40%	3.41%	6.99%
3/29/2012	10.37%	3.32%	7.05%
4/4/2012	10.00%	3.30%	6.70%
4/26/2012	10.00%	3.21%	6.79%
5/2/2012	10.00%	3.18%	6.82%
5/7/2012	9.80%	3.17%	6.63%
5/15/2012	10.00%	3.14%	6.86%
5/29/2012	10.05%	3.11%	6.94%
6/7/2012	10.30%	3.08%	7.22%
6/14/2012	9.40%	3.06%	6.34%
6/15/2012	10.40%	3.06%	7.34%
6/18/2012	9.60%	3.06%	6.54%
6/19/2012	9.25%	3.05%	6.20%
6/26/2012	10.10%	3.04%	7.06%
6/29/2012	10.00%	3.04%	6.96%
7/9/2012	10.20%	3.03%	7.17%
7/16/2012	9.80%	3.02%	6.78%
7/20/2012	9.31%	3.01%	6.30%
7/20/2012	9.81%	3.01%	6.80%
9/13/2012	9.80%	2.94%	6.86%

9/19/2012	9.80%	2.94%	6.86%
9/19/2012	10.05%	2.94%	7.11%
9/26/2012	9.50%	2.94%	6.56%
10/12/2012	9.60%	2.93%	6.67%
10/23/2012	9.75%	2.93%	6.82%
10/24/2012	10.30%	2.93%	7.37%
11/9/2012	10.30%	2.92%	7.38%
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11/29/2012	9.88%	2.89%	6.99%
12/5/2012	9.71%	2.89%	6.82%
12/5/2012	10.40%	2.89%	7.51%
12/12/2012	9.80%	2.88%	6.92%
12/13/2012	9.50%	2.88%	6.62%
12/13/2012	10.50%	2.88%	7.62%
12/14/2012	10.40%	2.88%	7.52%
12/19/2012	9.71%	2.87%	6.84%
12/19/2012	10.25%	2.87%	7.38%
12/20/2012	9.50%	2.87%	6.63%
12/20/2012	9.80%	2.87%	6.93%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.30%	2.87%	7.43%
12/20/2012	10.40%	2.87%	7.53%
12/20/2012	10.45%	2.87%	7.58%
12/21/2012	10.20%	2.87%	7.33%
12/26/2012	9.80%	2.86%	6.94%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/16/2013	9.60%	2.84%	6.76%
1/16/2013	9.60%	2.84%	6.76%
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2/27/2013	10.00%	2.86%	7.14%
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3/27/2013	9.80%	2.90%	6.90%
5/1/2013	9.84%	2.94%	6.90%
5/15/2013	10.30%	2.96%	7.34%
5/30/2013	10.20%	2.98%	7.22%
5/31/2013	9.00%	2.98%	6.02%
6/11/2013	10.00%	3.00%	7.00%
6/21/2013	9.75%	3.02%	6.73%
6/25/2013	9.80%	3.03%	6.77%
7/12/2013	9.36%	3.07%	6.29%
8/8/2013	9.83%	3.14%	6.69%
8/14/2013	9.15%	3.16%	5.99%
9/11/2013	10.20%	3.26%	6.94%
9/11/2013	10.25%	3.26%	6.99%
9/24/2013	10.20%	3.31%	6.89%
10/3/2013	9.65%	3.33%	6.32%
11/6/2013	10.20%	3.41%	6.79%
11/21/2013	10.00%	3.44%	6.56%
11/26/2013	10.00%	3.45%	6.55%
12/3/2013	10.25%	3.47%	6.78%
12/4/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.48%	6.72%
12/9/2013	8.72%	3.48%	5.24%
12/9/2013	9.75%	3.48%	6.27%
12/13/2013	9.75%	3.50%	6.25%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	10.12%	3.50%	6.62%
12/17/2013	9.50%	3.51%	5.99%
12/17/2013	10.95%	3.51%	7.44%
12/18/2013	8.72%	3.51%	5.21%
12/18/2013	9.80%	3.51%	6.29%
12/19/2013	10.15%	3.51%	6.64%
12/30/2013	9.50%	3.54%	5.96%
2/20/2014	9.20%	3.68%	5.52%
2/26/2014	9.75%	3.69%	6.06%
3/17/2014	9.55%	3.72%	5.83%
3/26/2014	9.40%	3.73%	5.67%
3/26/2014	9.96%	3.73%	6.23%
4/2/2014	9.70%	3.73%	5.97%
5/16/2014	9.80%	3.70%	6.10%
5/30/2014	9.70%	3.68%	6.02%
6/6/2014	10.40%	3.67%	6.73%
6/30/2014	9.55%	3.64%	5.91%
7/2/2014	9.62%	3.64%	5.98%
7/10/2014	9.95%	3.63%	6.32%
7/23/2014	9.75%	3.61%	6.14%
7/29/2014	9.45%	3.60%	5.85%

7/31/2014	9.90%	3.60%	6.30%
8/20/2014	9.75%	3.57%	6.18%
8/25/2014	9.60%	3.56%	6.04%
8/29/2014	9.80%	3.54%	6.26%
9/11/2014	9.60%	3.51%	6.09%
9/15/2014	10.25%	3.51%	6.74%
10/9/2014	9.80%	3.45%	6.35%
11/6/2014	9.56%	3.37%	6.19%
11/6/2014	10.20%	3.37%	6.83%
11/14/2014	10.20%	3.35%	6.85%
11/26/2014	9.70%	3.33%	6.37%
11/26/2014	10.20%	3.33%	6.87%
12/4/2014	9.68%	3.31%	6.37%
12/10/2014	9.25%	3.29%	5.96%
12/10/2014	9.25%	3.29%	5.96%
12/11/2014	10.07%	3.29%	6.78%
12/12/2014	10.20%	3.28%	6.92%
12/17/2014	9.17%	3.27%	5.90%
12/18/2014	9.83%	3.26%	6.57%
1/23/2015	9.50%	3.14%	6.36%
2/24/2015	9.83%	3.04%	6.79%
3/18/2015	9.75%	2.98%	6.77%
3/25/2015	9.50%	2.96%	6.54%
3/26/2015	9.72%	2.95%	6.77%
4/23/2015	10.20%	2.87%	7.33%
4/29/2015	9.53%	2.86%	6.67%
5/1/2015	9.60%	2.85%	6.75%
5/26/2015	9.75%	2.83%	6.92%
6/17/2015	9.00%	2.82%	6.18%
6/17/2015	9.00%	2.82%	6.18%
9/2/2015	9.50%	2.79%	6.71%
9/10/2015	9.30%	2.79%	6.51%
10/15/2015	9.00%	2.81%	6.19%
11/19/2015	10.00%	2.88%	7.12%
11/19/2015	10.30%	2.88%	7.42%
12/3/2015	10.00%	2.90%	7.10%
12/9/2015	9.14%	2.90%	6.24%
12/9/2015	9.14%	2.90%	6.24%
12/11/2015	10.30%	2.90%	7.40%
12/15/2015	9.60%	2.91%	6.69%
12/17/2015	9.70%	2.91%	6.79%
12/18/2015	9.50%	2.91%	6.59%
12/30/2015	9.50%	2.93%	6.57%
1/6/2016	9.50%	2.94%	6.56%
2/23/2016	9.75%	2.94%	6.81%
3/16/2016	9.85%	2.91%	6.94%
4/29/2016	9.80%	2.83%	6.97%
6/3/2016	9.75%	2.80%	6.95%
6/8/2016	9.48%	2.80%	6.68%
6/15/2016	9.00%	2.79%	6.21%
6/15/2016	9.00%	2.79%	6.21%
		Average:	4.51%
		Count:	1,475

S&P Business Risk Profiles and Credit Rankings

Business Risk Profile (scale from 1 to 6)

"Excellent" Business Risk (score = 1)	79
Total	107
% Total	73.83%

U.S. Regulated Electric Utilities Company	Designation	Business Risk Profile	Corp. Credit Rating
AEP Texas Central Co.	Electric	1	BBB
AEP Texas North Co.	Electric	2	BBB
Alabama Power Co.	Electric	1	A
Ameren Illinois Co.	Electric	2	BBB+
Appalachian Power Co.	Electric	1	BBB
Arizona Public Service Co.	Electric	1	A-
Atlantic City Electric Co.	Electric	1	BBB+
Baltimore Gas & Electric Co.	Electric	1	A-
Black Hills Power Inc.	Electric	1	BBB
CenterPoint Energy Houston Electric LLC	Electric	1	A-
Central Hudson Gas & Electric Corp.	Electric	1	A
Central Maine Power Co.	Electric	1	BBB+
Cleco Power LLC	Electric	2	BBB+
Cleveland Electric Illuminating Co.	Electric	1	BBB-
Commonwealth Edison Co.	Electric	2	BBB
Connecticut Light & Power Co.	Electric	1	A-
Consolidated Edison Co. of New York Inc.	Electric	1	A-
Consumers Energy Co.	Electric	1	BBB+
Dayton Power & Light Co.	Electric	2	BB
Delmarva Power & Light Co.	Electric	1	BBB+
DTE Electric Co.	Electric	1	BBB+
Duke Energy Carolinas LLC	Electric	1	BBB+
Duke Energy Florida Inc.	Electric	1	BBB+
Duke Energy Indiana Inc.	Electric	1	BBB+
Duke Energy Kentucky Inc.	Electric	2	BBB+
Duke Energy Ohio Inc.	Electric	2	BBB+
Duke Energy Progress Inc.	Electric	1	BBB+
Duquesne Light Co.	Electric	1	BBB
El Paso Electric Co.	Electric	2	BBB
Empire District Electric Co.	Electric	2	BBB
Entergy Arkansas Inc.	Electric	1	BBB
Entergy Gulf States Louisiana LLC	Electric	1	BBB
Entergy Louisiana LLC	Electric	1	BBB
Entergy Mississippi Inc.	Electric	1	BBB
Entergy New Orleans Inc.	Electric	2	BBB
Entergy Texas Inc.	Electric	2	BBB
Florida Power & Light Co.	Electric	1	A-
Georgia Power Co.	Electric	1	A
Green Mountain Power Corp.	Electric	1	BBB+
Gulf Power Co.	Electric	1	A
Hawaiian Electric Co. Inc.	Electric	2	BBB-
Idaho Power Co.	Electric	2	BBB
Indiana Michigan Power Co.	Electric	1	BBB
Indianapolis Power & Light Co.	Electric	1	BB+
Interstate Power & Light Co.	Electric	1	A-
Jersey Central Power & Light Co.	Electric	2	BBB-
Kansas City Power & Light Co.	Electric	1	BBB+
Kansas Gas & Electric Co.	Electric	1	BBB+
KCP&L Greater Missouri Operations Co.	Electric	2	BBB+

Kentucky Power Co.	Electric	2	BBB
Kentucky Utilities Co.	Electric	1	BBB
LG&E and KU Energy LLC	Electric	1	BBB
Louisville Gas & Electric Co.	Electric	1	BBB
Madison Gas & Electric Co.	Electric	1	AA-
Metropolitan Edison Co.	Electric	1	BBB-
MidAmerican Energy Co.	Electric	1	A-
Mississippi Power Co.	Electric	2	A
Monongahela Power Co.	Electric	2	BBB-
Nevada Power Co.	Electric	2	BBB+
New York State Electric & Gas Corp.	Electric	1	BBB+
Niagara Mohawk Power Corp.	Electric	1	A-
Northern Indiana Public Service Co.	Electric	2	BBB-
Northern States Power Co.	Electric	1	A-
Northern States Power Wisconsin	Electric	1	A-
NSTAR Electric Co.	Electric	1	A-
Ohio Edison Co.	Electric	1	BBB-
Ohio Power Co.	Electric	1	BBB
Oklahoma Gas & Electric Co.	Electric	1	A-
Oncor Electric Delivery Co. LLC	Electric	1	BBB+
Orange and Rockland Utilities Inc.	Electric	1	A-
Otter Tail Power Co.	Electric	2	BBB
Pacific Gas & Electric Co.	Electric	1	BBB
PacifiCorp	Electric	1	A-
PECO Energy Co.	Electric	1	BBB
Pennsylvania Electric Co.	Electric	1	BBB-
Pennsylvania Power Co.	Electric	1	BBB-
Portland General Electric Co.	Electric	2	BBB
Potomac Edison Co.	Electric	2	BBB-
Potomac Electric Power Co.	Electric	1	BBB+
PPL Electric Utilities Corp.	Electric	1	BBB
Public Service Co. of Colorado	Electric	1	A-
Public Service Co. of New Hampshire	Electric	1	A-
Public Service Co. of New Mexico	Electric	2	BBB
Public Service Co. of Oklahoma	Electric	2	BBB
Public Service Electric & Gas Co.	Electric	1	BBB+
Puget Sound Energy Inc.	Electric	2	BBB
Rochester Gas & Electric Corp.	Electric	1	BBB+
San Diego Gas & Electric Co.	Electric	1	A
Sierra Pacific Power Co.	Electric	2	BBB+
South Carolina Electric & Gas Co.	Electric	1	BBB+
Southern California Edison Co.	Electric	1	BBB+
Southern Indiana Gas & Electric Co.	Electric	1	A-
Southwestern Electric Power Co.	Electric	1	BBB
Southwestern Public Service Co.	Electric	1	A-
Tampa Electric Co.	Electric	1	BBB+
Texas-New Mexico Power Co.	Electric	1	BBB
Toledo Edison Co.	Electric	1	BBB-
Tucson Electric Power Co.	Electric	2	BBB+
UIL Holdings Corp.	Electric	1	BBB
Union Electric Co. d/b/a Ameren Missouri	Electric	1	BBB+
United Illuminating Co. (The)	Electric	1	BBB
Virginia Electric & Power Co.	Electric	1	A-
West Penn Power Co.	Electric	1	BBB-
Western Massachusetts Electric Co.	Electric	1	A-
Wisconsin Electric Power Co.	Electric	1	A-
Wisconsin Power & Light Co.	Electric	1	A
Wisconsin Public Service Corp.	Electric	1	A-

Source: Standard & Poors Ratings Direct, as of March 5, 2015. (Company provided data).
Business Risk: 1 = "Excellent", 2 = "Stong", 3 = "Satisfactory", 4 = "Fair", 5 = "Weak", 6 = "Vulnerable"

Recently Authorized ROEs

State	Company	Case Identification	Service	Case Type	Date	Return on Equity (%)	Vertically Integrated	Distribution	RRA Rank	All Cases			Vertically Integrated		
										Above Average	Average	Below Average	Above Average	Average	Below Average
Missouri	Kansas City Power & Light	C-ER-2012-0174	Electric	Vertically Integrated	1/9/2013	9.70	9.70		Average / 2		9.70			9.70	
Missouri	KCP&L Greater Missouri Op Co	C-ER-2012-0175 (MPS)	Electric	Vertically Integrated	1/9/2013	9.70	9.70		Average / 2		9.70			9.70	
Missouri	KCP&L Greater Missouri Op Co	C-ER-2012-0175 (L&P)	Electric	Vertically Integrated	1/9/2013	9.70	9.70		Average / 2		9.70			9.70	
Indiana	Indiana Michigan Power Co.	Ca-44075	Electric	Vertically Integrated	2/13/2013	10.20	10.20		Above Average / 3	10.20			10.20		
Maryland	Baltimore Gas and Electric Co.	C-9299 (elec)	Electric	Distribution	2/22/2013	9.75		9.75	Below Average / 2			9.75			
Louisiana	Southwestern Electric Power Co	D-U-32220	Electric	Vertically Integrated	2/27/2013	10.00	10.00		Average / 1		10.00			10.00	
New York	Niagara Mohawk Power Corp.	D-12-E-0201	Electric	Distribution	3/14/2013	9.30		9.30	Average / 2		9.30				
Idaho	Avista Corp.	C-AVU-E-12-08	Electric	Vertically Integrated	3/27/2013	9.80	9.80		Average / 2		9.80			9.80	
Ohio	Duke Energy Ohio Inc.	C-12-1682-EL-AIR	Electric	Distribution	5/1/2013	9.84		9.84	Average / 2		9.84				
Michigan	Consumers Energy Co.	C-U-17087	Electric	Vertically Integrated	5/15/2013	10.30	10.30		Average / 1		10.30			10.30	
North Carolina	Duke Energy Progress LLC	D-E-2, Sub 1023	Electric	Vertically Integrated	5/30/2013	10.20	10.20		Average / 1		10.20			10.20	
Hawaii	Maui Electric Company Ltd	D-2011-0092	Electric	Vertically Integrated	5/31/2013	9.00	9.00		Average / 1		9.00			9.00	
Arizona	Tucson Electric Power Co.	D-E-01933A-12-0291	Electric	Vertically Integrated	6/11/2013	10.00	10.00		Average / 3		10.00			10.00	
New Jersey	Atlantic City Electric Co.	D-ER-12121071	Electric	Distribution	6/21/2013	9.75		9.75	Average / 3		9.75				
Washington	Puget Sound Energy Inc.	D-UE-130137	Electric	Vertically Integrated	6/25/2013	9.80	9.80		Average / 3		9.80			9.80	
Maryland	Potomac Electric Power Co.	C-9311	Electric	Distribution	7/12/2013	9.36		9.36	Below Average / 2			9.36			
Minnesota	Northern States Power Co. - MN	D-E-002/GR-12-961	Electric	Vertically Integrated	8/8/2013	9.83	9.83		Average / 2		9.83			9.83	
Connecticut	United Illuminating Co.	D-13-01-19	Electric	Distribution	8/14/2013	9.15		9.15	Below Average / 2			9.15			
South Carolina	Duke Energy Carolinas LLC	D-2013-59-E	Electric	Vertically Integrated	9/11/2013	10.20	10.20		Average / 1		10.20			10.20	
Florida	Tampa Electric Co.	D-130040-EI	Electric	Vertically Integrated	9/11/2013	10.25	10.25		Above Average / 3	10.25			10.25		
North Carolina	Duke Energy Carolinas LLC	D-E-7, Sub 1026	Electric	Vertically Integrated	9/24/2013	10.20	10.20		Average / 1		10.20			10.20	
Texas	Southwestern Electric Power Co	D-40443	Electric	Vertically Integrated	10/3/2013	9.65	9.65		Below Average / 1			9.65			9.65
Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-122 (Elec)	Electric	Vertically Integrated	11/6/2013	10.20	10.20		Above Average / 2	10.20			10.20		
Kansas	Westar Energy Inc.	D-13-WSEE-629-RTS	Electric	Vertically Integrated	11/21/2013	10.00	10.00		Average / 2		10.00			10.00	
Virginia	Virginia Electric & Power Co.	C-PUE-2013-00020	Electric	Vertically Integrated	11/26/2013	10.00	10.00		Above Average / 2	10.00			10.00		
Florida	Gulf Power Co.	D-130140-EI	Electric	Vertically Integrated	12/3/2013	10.25	10.25		Above Average / 3	10.25			10.25		
Washington	PacifiCorp	D-UE-130043	Electric	Vertically Integrated	12/4/2013	9.50	9.50		Average / 3		9.50			9.50	
Wisconsin	Northern States Power Co - WI	D-4220-UR-119 (Elec)	Electric	Vertically Integrated	12/5/2013	10.20	10.20		Above Average / 2	10.20			10.20		
Illinois	Ameren Illinois	D-13-0301	Electric	Distribution	12/9/2013	8.72		8.72	Below Average / 1			8.72			
Oregon	Portland General Electric Co.	D-UE-262	Electric	Vertically Integrated	12/9/2013	9.75	9.75		Average / 3		9.75			9.75	
Maryland	Baltimore Gas and Electric Co.	C-9326 (elec)	Electric	Distribution	12/13/2013	9.75		9.75	Below Average / 2			9.75			
Louisiana	Entergy Gulf States LA LLC	D-U-32707	Electric	Vertically Integrated	12/16/2013	9.95	9.95		Average / 1		9.95			9.95	
Louisiana	Entergy Louisiana LLC	D-U-32708	Electric	Vertically Integrated	12/16/2013	9.95	9.95		Average / 1		9.95			9.95	
Nevada	Sierra Pacific Power Co.	D-13-06002	Electric	Vertically Integrated	12/16/2013	10.12	10.12		Average / 2		10.12			10.12	
Arizona	UNS Electric Inc.	D-E-04204A-12-0504	Electric	Vertically Integrated	12/17/2013	9.50	9.50		Average / 3		9.50			9.50	
Georgia	Georgia Power Co.	D-36989	Electric	Vertically Integrated	12/17/2013	10.95	10.95		Above Average / 3	10.95			10.95		
Illinois	Commonwealth Edison Co.	D-13-0318	Electric	Distribution	12/18/2013	8.72		8.72	Below Average / 1			8.72			
Oregon	PacifiCorp	D-UE-263	Electric	Vertically Integrated	12/18/2013	9.80	9.80		Average / 3		9.80			9.80	
Michigan	Upper Peninsula Power Co.	C-U-17274	Electric	Vertically Integrated	12/19/2013	10.15	10.15		Average / 1		10.15			10.15	
Arkansas	Entergy Arkansas Inc.	D-13-028-U	Electric	Vertically Integrated	12/30/2013	9.50	9.50		Average / 2		9.50			9.50	
New York	Consolidated Edison Co. of NY	C-13-E-0030	Electric	Distribution	2/20/2014	9.20		9.20	Average / 2		9.20				
North Dakota	Northern States Power Co. - MN	C-PU-12-813	Electric	Vertically Integrated	2/26/2014	9.75	9.75		Average / 1		9.75			9.75	
New Hampshire	Liberty Utilities Granite St	D-DE-13-063	Electric	Distribution	3/17/2014	9.55		9.55	Average / 3		9.55				
District of Columbia	Potomac Electric Power Co.	FC-1103-2013-E	Electric	Distribution	3/26/2014	9.40		9.40	Below Average / 1			9.40			
New Mexico	Southwestern Public Service Co	C-12-00350-UT	Electric	Vertically Integrated	3/26/2014	9.96	9.96		Below Average / 1			9.96			9.96
Delaware	Delmarva Power & Light Co.	D-13-115	Electric	Distribution	4/2/2014	9.70		9.70	Average / 3		9.70				
Texas	Entergy Texas Inc.	D-41791	Electric	Vertically Integrated	5/16/2014	9.80	9.80		Below Average / 1			9.80			9.80
Massachusetts	Fitchburg Gas & Electric Light	DPU 13-90	Electric	Distribution	5/30/2014	9.70		9.70	Average / 3		9.70				
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-119 (Elec)	Electric	Vertically Integrated	6/6/2014	10.40	10.40		Above Average / 2	10.40			10.40		
Maine	Emera Maine	D-2013-00443	Electric	Distribution	6/30/2014	9.55		9.55	Average / 2		9.55				
Maryland	Potomac Electric Power Co.	C-9336	Electric	Distribution	7/2/2014	9.62		9.62	Below Average / 2			9.62			
Louisiana	Entergy Louisiana LLC	D-UD-13-01	Electric	Vertically Integrated	7/10/2014	9.95	9.95		Average / 1		9.95			9.95	
New Jersey	Rockland Electric Company	D-ER-13111135	Electric	Distribution	7/23/2014	9.75		9.75	Average / 3		9.75				
Maine	Central Maine Power Co.	D-2013-00168	Electric	Distribution	7/29/2014	9.45		9.45	Average / 2		9.45				
Wyoming	Cheyenne Light Fuel Power Co.	D-20003-132-ER-13	Electric	Vertically Integrated	7/31/2014	9.90	9.90		Average / 2		9.90			9.90	
New Jersey	Atlantic City Electric Co.	D-ER-14030245	Electric	Distribution	8/20/2014	9.75		9.75	Average / 3		9.75				
Vermont	Green Mountain Power Corp	D-8190, 8191	Electric	Vertically Integrated	8/25/2014	9.60	9.60		Average / 3		9.60			9.60	
Utah	PacifiCorp	D-13-035-184	Electric	Vertically Integrated	8/29/2014	9.80	9.80		Average / 2		9.80			9.80	
Florida	Florida Public Utilities Co.	D-140025-EI	Electric	Vertically Integrated	9/15/2014	10.25	10.25		Above Average / 3	10.25			10.25		
Nevada	Nevada Power Co.	D-14-05004	Electric	Vertically Integrated	10/9/2014	9.80	9.80		Average / 2		9.80			9.80	
Illinois	MidAmerican Energy Co.	D-14-0066	Electric	Vertically Integrated	11/6/2014	9.56	9.56		Below Average / 1			9.56			9.56
Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-123 (Elec)	Electric	Vertically Integrated	11/6/2014	10.20	10.20		Above Average / 2	10.20			10.20		
Wisconsin	Wisconsin Electric Power Co.	D-05-UR-107 (WEP-Elec)	Electric	Vertically Integrated	11/14/2014	10.20	10.20		Above Average / 2	10.20			10.20		
Virginia	Appalachian Power Co.	C-PUE-2014-00026	Electric	Vertically Integrated	11/26/2014	9.70	9.70		Above Average / 2	9.70			9.70		
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-120 (Elec)	Electric	Vertically Integrated	11/26/2014	10.20	10.20		Above Average / 2	10.20			10.20		
Oregon	Portland General Electric Co.	D-UE-283	Electric	Vertically Integrated	12/4/2014	9.68	9.68		Average / 3		9.68			9.68	

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Illinois	Ameren Illinois	D-14-0317	Electric	Distribution	12/10/2014	9.25		9.25	Below Average / 1			9.25			
Illinois	Commonwealth Edison Co.	D-14-0312	Electric	Distribution	12/10/2014	9.25		9.25	Below Average / 1			9.25			
Mississippi	Entergy Mississippi Inc.	D-2014-UN-0132	Electric	Vertically Integrated	12/11/2014	10.07	10.07		Above Average / 3	10.07			10.07		
Wisconsin	Northern States Power Co - WI	D-4220-UR-120 (Elec)	Electric	Vertically Integrated	12/12/2014	10.20	10.20		Above Average / 2	10.20			10.20		
Connecticut	Connecticut Light & Power Co.	D-14-05-06	Electric	Distribution	12/17/2014	9.17		9.17	Below Average / 2			9.17			
Colorado	Black Hills Colorado Electric	D-14AL-0393E	Electric	Vertically Integrated	12/18/2014	9.83	9.83		Average / 1		9.83			9.83	
Wyoming	PacifiCorp	D-20000-446-ER-14	Electric	Vertically Integrated	1/23/2015	9.50	9.50		Average / 2		9.50			9.50	
Colorado	Public Service Co. of CO	D-14AL-0660E	Electric	Vertically Integrated	2/24/2015	9.83	9.83		Average / 1		9.83			9.83	
New Jersey	Jersey Cntrl Power & Light Co.	D-ER-12111052	Electric	Distribution	3/18/2015	9.75		9.75	Average / 3		9.75				
Washington	PacifiCorp	D-UE-140762	Electric	Vertically Integrated	3/25/2015	9.50	9.50		Average / 3		9.50			9.50	
Minnesota	Northern States Power Co. - MN	D-E-002/GR-13-868	Electric	Vertically Integrated	3/26/2015	9.72	9.72		Average / 2		9.72			9.72	
Michigan	Wisconsin Public Service Corp.	C-U-17669	Electric	Vertically Integrated	4/23/2015	10.20	10.20		Average / 1		10.20			10.20	
Missouri	Union Electric Co.	C-ER-2014-0258	Electric	Vertically Integrated	4/29/2015	9.53	9.53		Average / 2		9.53			9.53	
West Virginia	Appalachian Power Co.	C-14-1152-E-42T	Electric	Vertically Integrated	5/26/2015	9.75	9.75		Below Average / 1			9.75			9.75
New York	Central Hudson Gas & Electric	C-14-E-0318	Electric	Distribution	6/17/2015	9.00		9.00	Average / 2		9.00				
New York	Consolidated Edison Co. of NY	C-15-E-0050/C-13-E-0030 (Ext)	Electric	Distribution	6/17/2015	9.00		9.00	Average / 2		9.00				
Missouri	Kansas City Power & Light	C-ER-2014-0370	Electric	Vertically Integrated	9/2/2015	9.50	9.50		Average / 2		9.50			9.50	
Kansas	Kansas City Power & Light	D-15-KCPE-116-RTS	Electric	Vertically Integrated	9/10/2015	9.30	9.30		Average / 2		9.30			9.30	
New York	Orange & Rockland Utlts Inc.	C-14-E-0493	Electric	Distribution	10/15/2015	9.00		9.00	Average / 2		9.00				
Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-124 (Elec)	Electric	Vertically Integrated	11/19/2015	10.00	10.00		Above Average / 2	10.00			10.00		
Michigan	Consumers Energy Co.	C-U-17735	Electric	Vertically Integrated	11/19/2015	10.30	10.30		Average / 1		10.30			10.30	
Wisconsin	Northern States Power Co - WI	D-4220-UR-121 (Elec)	Electric	Vertically Integrated	12/3/2015	10.00	10.00		Above Average / 2	10.00			10.00		
Illinois	Ameren Illinois	D-15-0305	Electric	Distribution	12/9/2015	9.14		9.14	Below Average / 1			9.14			
Illinois	Commonwealth Edison Co.	D-15-0287	Electric	Distribution	12/9/2015	9.14		9.14	Below Average / 1			9.14			
Michigan	DTE Electric Co.	C-U-17767	Electric	Vertically Integrated	12/11/2015	10.30	10.30		Average / 1		10.30			10.30	
Oregon	Portland General Electric Co.	D-UE-294	Electric	Vertically Integrated	12/15/2015	9.60	9.60		Average / 3		9.60			9.60	
Texas	Southwestern Public Service Co	D-43695	Electric	Vertically Integrated	12/17/2015	9.70	9.70		Below Average / 1			9.70			9.70
Idaho	Avista Corp.	C-AVU-E-15-05	Electric	Vertically Integrated	12/18/2015	9.50	9.50		Average / 2		9.50			9.50	
Wyoming	PacifiCorp	D-20000-469-ER-15	Electric	Vertically Integrated	12/30/2015	9.50	9.50		Average / 2		9.50			9.50	
Washington	Avista Corp.	D-UE-150204	Electric	Vertically Integrated	1/6/2016	9.50	9.50		Average / 3		9.50			9.50	
Arkansas	Entergy Arkansas Inc.	D-15-015-U	Electric	Vertically Integrated	2/23/2016	9.75	9.75		Average / 2		9.75			9.75	
Indiana	Indianapolis Power & Light Co.	Ca-44576	Electric	Vertically Integrated	3/16/2016	9.85	9.85		Above Average / 3	9.85			9.85		
Massachusetts	Fitchburg Gas & Electric Light	DPU 15-80	Electric	Distribution	4/29/2016	9.80		9.80	Average / 3		9.80				
Maryland	Baltimore Gas and Electric Co.	C-9406 (elec)	Electric	Distribution	6/3/2016	9.75		9.75	Below Average / 2			9.75			
New Mexico	El Paso Electric Co.	C-15-00127-UT	Electric	Vertically Integrated	6/8/2016	9.48	9.48		Below Average / 1			9.48			9.48
New York	NY State Electric & Gas Corp.	C-15-E-0283	Electric	Distribution	6/15/2016	9.00		9.00	Average / 2		9.00				
New York	Rochester Gas & Electric Corp.	C-15-E-0285	Electric	Distribution	6/15/2016	9.00		9.00	Average / 2		9.00				
					Total Cases	103	71	32		18	64	21	18	46	7
					Mean	9.73	9.88	9.38		10.17	9.70	9.43	10.17	9.79	9.70
					Median	9.75	9.83	9.38		10.20	9.75	9.48	10.20	9.80	9.70
					Maximum	10.95	10.95	9.84		10.95	10.30	9.96	10.95	10.30	9.96
Source: SNL Financial					Minimum	8.72	9.00	8.72		9.70	9.00	8.72	9.70	9.00	9.48

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Sponsored by Robert B. Hevert
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Summary of Adjustment Clauses & Alternative Regulation/Incentive Plans

			Adjustment Clauses						
Company	Parent	State	Fuel/ Purchased Power	Decoupling (F/P) [1]	New Capital Investment [2]	Energy Efficiency [3]	Renewables & RPS [4]	Environmental [5]	Other [6]
Ameren Illinois Company	AEE	Illinois				✓	✓	✓	✓
Union Electric Company	AEE	Missouri	✓	P		✓		✓	✓
Southwestern Electric Power Company	AEP	Arkansas	✓	P	✓	✓			✓
Indiana Michigan Power Company	AEP	Indiana	✓	P		✓		✓	✓
Kentucky Power Company	AEP	Kentucky	✓	P	✓	✓		✓	✓
Southwestern Electric Power Company	AEP	Louisiana	✓	P		✓		✓	✓
Indiana Michigan Power Company	AEP	Michigan	✓			✓	✓		
Ohio Power Company	AEP	Ohio		P	✓	✓	✓		✓
Public Service Company of Oklahoma	AEP	Oklahoma	✓	P	✓	✓			✓
Kingsport Power Company	AEP	Tennessee	✓						
AEP Texas Central Company	AEP	Texas			✓	✓			
AEP Texas North Company	AEP	Texas			✓	✓			
Southwestern Electric Power Company	AEP	Texas	✓		✓	✓			
Appalachian Power Company	AEP	Virginia	✓		✓	✓	✓	✓	✓
Appalachian Power Company	AEP	West Virginia	✓						✓
Wheeling Power Company	AEP	West Virginia	✓						✓
ALLETE (Minnesota Power)	ALE	Minnesota	✓			✓	✓	✓	✓
Alaska Electric Light and Power Company	AVA	Alaska	✓						
Avista Corporation - Electric	AVA	Idaho	✓			✓			
Avista Corporation - Electric	AVA	Washington	✓	F					
Consumers Energy Company	CMS	Michigan	✓			✓	✓		
DTE Electric Company	DTE	Michigan	✓			✓	✓		✓
El Paso Electric	EE	New Mexico	✓			✓			✓
El Paso Electric	EE	Texas	✓		✓	✓			✓
Connecticut Light & Power	ES	Connecticut	✓	F		✓			✓
NSTAR Electric	ES	Massachusetts				✓			✓
Western Massachusetts Electric	ES	Massachusetts		F	✓	✓	✓		✓
Public Service Co. of New Hampshire	ES	New Hampshire	✓		✓				✓
Entergy Arkansas	ETR	Arkansas	✓	P	✓	✓			✓
Entergy New Orleans - Electric	ETR	Louisiana	✓	P	✓	✓		✓	✓
Entergy Louisiana - Electric	ETR	Louisiana	✓	P	✓	✓		✓	✓
Entergy Mississippi	ETR	Mississippi	✓	P	✓	✓		✓	✓
Entergy Texas	ETR	Texas	✓		✓	✓			✓
Potomac Edison Company	FE	Maryland				✓			✓
Jersey Central Power & Light Company	FE	New Jersey				✓	✓		✓
Cleveland Electric Illuminating Company	FE	Ohio		P	✓	✓	✓		✓
Ohio Edison Company	FE	Ohio		P	✓	✓	✓		✓
Toledo Edison Company	FE	Ohio		P	✓	✓	✓		✓
Metropolitan Edison Company	FE	Pennsylvania				✓			✓
Pennsylvania Electric Company	FE	Pennsylvania				✓			✓
Pennsylvania Power Company	FE	Pennsylvania				✓			✓
West Penn Power Company	FE	Pennsylvania				✓			✓
Monongahela Power Company	FE	West Virginia	✓						✓
Potomac Edison Company	FE	West Virginia	✓						✓
Idaho Power Co.	IDA	Idaho	✓	P		✓			
Idaho Power Co.	IDA	Oregon	✓				✓		
Interstate Power and Light Company	LNT	Iowa	✓			✓	✓	✓	✓
Wisconsin Power and Light Company	LNT	Wisconsin	✓						✓
Madison Gas & Electric - Electric	MGEE	Wisconsin	✓						✓
Madison Gas & Electric - Gas	MGEE	Wisconsin	✓						✓
NorthWestern Corp	NWE	Montana	✓	P		✓			✓
NorthWestern Corp.	NWE	South Dakota	✓			✓			
Oklahoma Gas and Electric Company	OGE	Arkansas	✓	P	✓	✓	✓		✓
Oklahoma Gas and Electric Company	OGE	Oklahoma	✓	P	✓	✓		✓	✓
Otter Tail Power Company	OTTR	Minnesota	✓			✓	✓	✓	
Otter Tail Power Company	OTTR	North Dakota	✓		✓		✓	✓	✓
Public Service Co. of New Mexico	PNM	New Mexico	✓			✓	✓	✓	✓
Texas-New Mexico Power	PNM	Texas			✓	✓			✓
Arizona Public Service Company	PNW	Arizona	✓	P	✓	✓	✓	✓	✓
Portland General Electric Company	POR	Oregon	✓	P			✓		
South Carolina Electric & Gas Co.	SCG	South Carolina	✓		✓			✓	
Wisconsin Electric Power	WEC	Michigan	✓			✓	✓		
Wisconsin Electric Power	WEC	Wisconsin	✓						✓
Wisconsin Public Service	WEC	Wisconsin	✓						✓
Public Service Company of Colorado	XEL	Colorado	✓		✓	✓	✓		✓
Northern States Power Company - MN	XEL	Minnesota	✓			✓	✓	✓	
Southwestern Public Service Company	XEL	New Mexico	✓			✓	✓		✓
Northern States Power Company - MN	XEL	North Dakota	✓		✓		✓	✓	✓
Northern States Power Company - MN	XEL	South Dakota	✓	P	✓	✓		✓	✓
Southwestern Public Service Company	XEL	Texas	✓		✓	✓			✓
Northern States Power Company - WI	XEL	Wisconsin	✓						✓

Summary of Adjustment Clauses & Alternative Regulation/Incentive Plans

			Alternative Regulation / Incentive Plans					
Company	Parent	State	Formula-Based Rates	Price Freeze/ Cap	Earnings Sharing	Formula-Based ROE	Service Quality/ Performance	Merger Savings
Ameren Illinois Company	AEE	Illinois	✓		✓	✓	✓	
Union Electric Company	AEE	Missouri						
Southwestern Electric Power Company	AEP	Arkansas						
Indiana Michigan Power Company	AEP	Indiana						
Kentucky Power Company	AEP	Kentucky						
Southwestern Electric Power Company	AEP	Louisiana	✓	✓	✓			
Indiana Michigan Power Company	AEP	Michigan						
Ohio Power Company	AEP	Ohio		✓	✓			
Public Service Company of Oklahoma	AEP	Oklahoma						
Kingsport Power Company	AEP	Tennessee						
AEP Texas Central Company	AEP	Texas						
AEP Texas North Company	AEP	Texas						
Southwestern Electric Power Company	AEP	Texas						
Appalachian Power Company	AEP	Virginia			✓	✓	✓	
Appalachian Power Company	AEP	West Virginia						
Wheeling Power Company	AEP	West Virginia						
ALLETE (Minnesota Power)	ALE	Minnesota						
Alaska Electric Light and Power Company	AVA	Alaska						
Avista Corporation - Electric	AVA	Idaho		✓				
Avista Corporation - Electric	AVA	Washington		✓				
Consumers Energy Company	CMS	Michigan						
DTE Electric Company	DTE	Michigan						
El Paso Electric	EE	New Mexico						
El Paso Electric	EE	Texas						
Connecticut Light & Power	ES	Connecticut		✓	✓			
NSTAR Electric	ES	Massachusetts		✓			✓	
Western Massachusetts Electric	ES	Massachusetts		✓				
Public Service Co. of New Hampshire	ES	New Hampshire		✓	✓		✓	
Entergy Arkansas	ETR	Arkansas						
Entergy New Orleans - Electric	ETR	Louisiana						
Entergy Louisiana - Electric	ETR	Louisiana						
Entergy Mississippi	ETR	Mississippi	✓			✓	✓	
Entergy Texas	ETR	Texas						
Potomac Edison Company	FE	Maryland						
Jersey Central Power & Light Company	FE	New Jersey						
Cleveland Electric Illuminating Company	FE	Ohio		✓	✓			
Ohio Edison Company	FE	Ohio		✓	✓			
Toledo Edison Company	FE	Ohio		✓	✓			
Metropolitan Edison Company	FE	Pennsylvania						
Pennsylvania Electric Company	FE	Pennsylvania						
Pennsylvania Power Company	FE	Pennsylvania						
West Penn Power Company	FE	Pennsylvania						
Monongahela Power Company	FE	West Virginia						
Potomac Edison Company	FE	West Virginia						
Idaho Power Co.	IDA	Idaho			✓			
Idaho Power Co.	IDA	Oregon						
Interstate Power and Light Company	LNT	Iowa		✓				
Wisconsin Power and Light Company	LNT	Wisconsin		✓	✓			
Madison Gas & Electric - Electric	MGEE	Wisconsin		✓				
Madison Gas & Electric - Gas	MGEE	Wisconsin		✓				
NorthWestern Corp	NWE	Montana						
NorthWestern Corp.	NWE	South Dakota						
Oklahoma Gas and Electric Company	OGE	Arkansas						
Oklahoma Gas and Electric Company	OGE	Oklahoma						
Otter Tail Power Company	OTTR	Minnesota						
Otter Tail Power Company	OTTR	North Dakota						
Public Service Co. of New Mexico	PNM	New Mexico						
Texas-New Mexico Power	PNM	Texas						
Arizona Public Service Company	PNW	Arizona		✓				
Portland General Electric Company	POR	Oregon						
South Carolina Electric & Gas Co.	SCG	South Carolina		✓				
Wisconsin Electric Power	WEC	Michigan						
Wisconsin Electric Power	WEC	Wisconsin		✓				
Wisconsin Public Service	WEC	Wisconsin						
Public Service Company of Colorado	XEL	Colorado		✓	✓			
Northern States Power Company - MN	XEL	Minnesota						
Southwestern Public Service Company	XEL	New Mexico		✓				
Northern States Power Company - MN	XEL	North Dakota						
Northern States Power Company - MN	XEL	South Dakota		✓				
Southwestern Public Service Company	XEL	Texas		✓				
Northern States Power Company - WI	XEL	Wisconsin						

Notes:

A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category.

[1] Full or partial decoupling (such as Straight-Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs).

[2] Includes recovery of costs related to targeted new generation projects, infrastructure replacement, system integrity/hardening, Smart Grid, AMI metering, and other capital expenditures.

[3] Utility-sponsored conservation, energy efficiency, load control, or other demand side management programs.

[4] Recovers costs associated with renewable energy projects, Distributed Energy Resources, REC purchases, net metering, RPS expense, and renewable PPAs.

[5] EPA upgrade costs, emissions control & allowance purchase costs, nuclear decommissioning, and other costs to comply with state and federal environmental mandates.

[6] Pension expenses, bad debt costs, storm costs, vegetation management, RTO/Transmission Expense, capacity costs, transmission costs, government & franchise fees and taxes, economic development, and low

Sources: Regulatory Research Associates, *Alternative Regulation/Incentive Plans: A State-by-State Overview* , November 19, 2013; Regulatory Research Associates, *Adjustment Clauses: A State-by-State Overview, October 2, 2015* .

Mr. Lawton's Financial Integrity Analysis Replicated, as Filed (Exhibit _ (DJL-5))

	A	B	C	D	E
REQUESTED CAPITAL STRUCTURE, COST RATES, AND RETURN					
DESCRIPTION	**CAPITAL**	**RATIO**	**COST RATE**	**WEIGHTED COST**	**RETURN**
LONG TERM DEBT	$9,358,417	28.76%	4.620%	1.33%	$432,359
CUSTOMER DEPOSITS	$407,328	1.25%	2.050%	0.03%	$8,350
COMMON EQUITY	$14,682,574	45.13%	11.500%	5.19%	$1,688,496
SHORT TERM DEBT	$612,939	1.88%	1.850%	0.03%	$11,339
DEFERRED INCOME TAX	$7,368,582	22.65%	0.000%	0.00%	$0
INVESTMENT TAX CREDITS	$106,275	0.33%	8.820%	0.03%	$9,373
TOTAL CAPITAL	$32,536,115	100.00%		6.61%	$2,149,918
RATE BASE			$32,536,115		
PER COMPANY SCHEDULES B-1					

ALTERNATIVE CAPITAL STRUCTURE, COST RATES, AND RETURN ON EQUITY @ 8.75%					
DESCRIPTION	**CAPITAL**	**RATIO**	**COST RATE**	**WEIGHTED COST**	**RETURN**
LONG TERM DEBT	$11,636,598	35.56%	4.620%	1.643%	$537,611
CUSTOMER DEPOSITS	$409,700	1.25%	2.050%	0.026%	$8,399
COMMON EQUITY	$12,398,749	37.89%	8.750%	3.315%	$1,084,891
SHORT TERM DEBT	$762,151	2.33%	1.850%	0.043%	$14,100
DEFERRED INCOME TAX	$7,411,492	22.65%	0.000%	0.000%	$0
INVESTMENT TAX CREDITS	$106,894	0.33%	6.750%	0.022%	$7,215
TOTAL CAPITAL	$32,725,584	100.00%		5.049%	$1,652,215
RATE BASE			$32,725,584		($497,703)

PER COMPANY SCHEDULES B-1, ADJUSTED PER OPC TESTIMONY OF RALPH SMITH EXHIBIT RCS-2 P. 15

LINE NO.	**DESCRIPTION**	**A** **Company Requested Capital Structure & 11.5% ROE**	**B** **ALT. OPC Capital Structure ROE Adjusted to 8.75%**	**C** **Difference**	**SOURCES COL. A**	**SOURCES COL. B**
1	RATE BASE	$32,536,115	$32,725,584		COMPANY FILING SCHEDULE A-1	COMPANY FILING SCHEDULE A-1 ADJUSTED PER OPC TESTIMONY OF RALPH SMITH AT EXHIBIT RCS-2 P. 2.
2	RATE OF RETURN	6.608%	5.049%		FPL SCHEDULE D1-A	COMPANY FILING SCHEDULE A-1 ADJUSTED PER OPC TESTIMONY OF RALPH SMITH AT EXHIBIT RCS-2 P. 2.
3	RETURN	$2,149,918	$1,652,215	($497,703)	LINE 1 TIMES LINE 2	LINE 1 TIMES LINE 2
4	DEPRECIATION & AMORTIZATION	$1,665,925	$1,140,564	($525,361)	FPL SCHEDULE C-1	OPC R. SMITH EX. RCS-2
5	CASH FLOW	$3,815,843	$2,792,779	($1,023,064)	SUM LINES 3 AND 4	SUM LINES 3 AND 4
6	TOTAL DEBT	$9,971,356	$12,398,749	$2,427,393	DEBT ALL SOURCES	DEBT ALL SOURCES
7	TOTAL INTEREST ESTIMATED	$443,698	$551,711		WTD DEBT COST TIMES RATE BASE	WTD DEBT COST TIMES RATE BASE

		D	**E**	**F** **Moody's Guidelines for A Bonds**	**G** **Moody's Guidelines for Baa Bonds**
	PROJECTED METRICS				
8	CASH FLOW/INTEREST DSC (X)	8.6	5.1	4.5x-6.0x	2.7x-4.5x
9	CASH FLOW/DEBT (%)	38.27%	22.52%	22%-30%	13%-22%
10	DEBT PERCENTAGE (%)	40.40%	50.00%	35% to 45%	45%-55%

SOURCES:
COLUMNS D & E ROW 8: LINE 5/LINE 7
COLUMNS D & E ROW 9: LINE 5/LINE 6
COLUMNS D & E ROW 10: Debt Ratio Investor Sources PER CAPITAL STURCTURE RECOMMENDATION OF FPL & OPC WITNESSES
COLUMN F & G: Moody's Investor Service, "Electric & Gas Utilities, Assessing Their Credit Quality and Outlook" (January 18, 2013 at 33)
DEBT PERCENTAGE BASED ON INVESTOR SOURCES SEE MR. DEWHURST DIRECT AT 23:2 also see OPC witness O'Donnell
ALL DOLLAR AMOUNTS ARE IN ($000).

Mr. Lawton's Financial Integrity Analysis, adjusted (Exhibit _ (DJL-5))

	A	B	C	D	E
REQUESTED CAPITAL STRUCTURE, COST RATES, AND RETURN ON EQUITY ADJUSTED TO 0.00%					
DESCRIPTION	**CAPITAL**	**RATIO**	**COST RATE**	**WEIGHTED COST**	**RETURN**
LONG TERM DEBT	$9,358,417	28.76%	4.620%	1.33%	$432,359
CUSTOMER DEPOSITS	$407,328	1.25%	2.050%	0.03%	$8,350
COMMON EQUITY	$14,682,574	45.13%	**0.000%**	0.00%	$0
SHORT TERM DEBT	$612,939	1.88%	1.850%	0.03%	$11,339
DEFERRED INCOME TAX	$7,368,582	22.65%	0.000%	0.00%	$0
INVESTMENT TAX CREDITS	$106,275	0.33%	8.820%	0.03%	$9,373
TOTAL CAPITAL	$32,536,115	100.00%		1.42%	$461,422
RATE BASE			$32,536,115		
PER COMPANY SCHEDULES B-1					

OPC ALTERNATIVE CAPITAL STRUCTURE, COST RATES, AND EQUITY RATIO ADJUSTED TO 34.99%					
DESCRIPTION	**CAPITAL**	**RATIO**	**COST RATE**	**WEIGHTED COST**	**RETURN**
LONG TERM DEBT	$11,636,598	35.56%	4.620%	1.643%	$537,611
CUSTOMER DEPOSITS	$409,700	1.25%	2.050%	0.026%	$8,399
COMMON EQUITY	$12,398,749	37.89%	**6.249%**	2.368%	$774,809
SHORT TERM DEBT	$762,151	2.33%	1.850%	0.043%	$14,100
DEFERRED INCOME TAX	$7,411,492	22.65%	0.000%	0.000%	$0
INVESTMENT TAX CREDITS	$106,894	0.33%	6.750%	0.022%	$7,215
TOTAL CAPITAL	$32,725,584	100.00%		4.101%	$1,342,134
RATE BASE			$32,725,584		$880,712

PER COMPANY SCHEDULES B-1, ADJUSTED PER OPC TESTIMONY OF RALPH SMITH EXHIBIT RCS-2 P. 15

LINE NO.	DESCRIPTION	A Company Requested Capital Structure & 0.00% ROE	B ALT. OPC Capital Structure ROE Adjusted to 8.75%	C Difference	SOURCES COL. A	SOURCES COL. B
1	RATE BASE	$32,536,115	$32,725,584		COMPANY FILING SCHEDULE A-1	COMPANY FILING SCHEDULE A-1 ADJUSTED PER OPC TESTIMONY OF RALPH SMITH AT EXHIBIT RCS-2 P. 2.
2	RATE OF RETURN	1.418%	4.101%		FPL SCHEDULE D1-A	COMPANY FILING SCHEDULE A-1 ADJUSTED PER OPC TESTIMONY OF RALPH SMITH AT EXHIBIT RCS-2 P. 2.
3	RETURN	$461,422	$1,342,134	$880,712	LINE 1 TIMES LINE 2	LINE 1 TIMES LINE 2
4	DEPRECIATION & AMORTIZATION	$1,665,925	$1,140,564	($525,361)	FPL SCHEDULE C-1	OPC R. SMITH EX. RCS-2
5	CASH FLOW	$2,127,347	$2,482,698	$355,351	SUM LINES 3 AND 4	SUM LINES 3 AND 4
6	TOTAL DEBT	$9,971,356	$12,398,749	$2,427,393	DEBT ALL SOURCES	DEBT ALL SOURCES
7	TOTAL INTEREST ESTIMATED	$443,698	$551,711		WTD DEBT COST TIMES RATE BASE	WTD DEBT COST TIMES RATE BASE

		D	E	F Moody's Guidelines for A Bonds	G Moody's Guidelines for Baa Bonds
	PROJECTED METRICS				
8	CASH FLOW/INTEREST DSC (X)	**4.8**	**4.5**	4.5x-6.0x	2.7x-4.5x
9	CASH FLOW/DEBT (%)	21.33%	20.02%	22%-30%	13%-22%
10	DEBT PERCENTAGE (%)	40.40%	50.00%	35% to 45%	45%-55%

SOURCES
COLUMNS D & E ROW 8: LINE 5/LINE 7
COLUMNS D & E ROW 9: LINE 5/LINE 6
COLUMNS D & E ROW 10: Debt Ratio Investor Sources PER CAPITAL STURCTURE RECOMMENDATION OF FPL & OPC WITNESSES
COLUMN F & G: Moody's Investor Service, "Electric & Gas Utilities, Assessing Their Credit Quality and Outlook" (January 18, 2013 at 33)
DEBT PERCENTAGE BASED ON INVESTOR SOURCES SEE MR. DEWHURST DIRECT AT 23:2 also see OPC witness O'Donnell
ALL DOLLAR AMOUNTS ARE IN ($000).

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF ROXANE R. KENNEDY

DOCKET NO. 160021-EI

AUGUST 1, 2016

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II. FOSSIL PLANT OVERHAUL EXPENSES 3

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Roxane R. Kennedy, and my business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to refute Office of Public Counsel ("OPC") witness Smith's contentions that FPL's cost projections regarding its fossil fleet general overhaul expenses should be based on a normalized cost level.

II. FOSSIL PLANT OVERHAUL EXPENSES

Q. Do you agree with OPC witness Smith's proposed four year average process for projecting overhaul cost for FPL's fossil fleet?

A. No, I do not. OPC witness Smith's proposal lacks appropriate justification, is not properly based on projected operational and overhaul plans, and does not show results which are indicative of FPL's operating and maintenance ("O&M") costs going forward.

Q. Why is it inappropriate to base generation overhaul expenses going forward on normalized historical values?

A. It is inappropriate because the size and nature of FPL's generation fleet has changed significantly even over the last four years. As indicated on Exhibit RRK-2, reflecting the longer trend since 1990, FPL's fossil fleet has evolved from mainly conventional steam technology to combustion turbine ("CT") based technology. Within the past few years, FPL has recently added combined cycle generation units such as Cape Canaveral Clean Energy Center, Riviera Beach Energy Center, and Port Everglades Energy Center. Additionally, by the end of this year, FPL will be adding three large scale solar projects. This transformation to FPL's generation fleet means that historical levels and types of overhauls, and their related expenditures are not representative of current and projected overhaul work, because there is an increased level of deployed equipment that must be maintained now, and in the future.

Furthermore, because the doubling of the fossil fleet did not occur in the same year, but rather was staggered based on generation need over a number of years, the timing of the different overhaul cycles of fossil units is likewise staggered over a number of years. Therefore, the timing of historical maintenance cycles has no bearing on or relationship to current or future maintenance cycles. Consequently, normalization of previous overhaul maintenance costs is completely inappropriate as a basis to forecast

maintenance costs on a going forward basis. FPL would never use such an approach to budget for its expenditures and to do so would not properly reflect what or how FPL projects to spend to meet the fleet's needs.

Q. Please explain the effect that a change in the quantity of equipment needed to be maintained has on generation overhaul expenses?

A. With the substantial growth of the fossil generating fleet, the quantity of plant equipment that needs to be maintained has increased significantly. For example, with the addition of 13,000 MW of combined cycle capability from 2001 to 2017, FPL added 46 CTs (up from 12 CTs in 2000[1]), along with their associated major components such as generators, heat recovery steam generators ("HRSGs"), steam turbine generators, and other plant equipment (motors, fans, valves, etc.). Consequently, this growth of plant equipment and associated work scope increases the overhaul maintenance expense requirements of the fossil generating fleet.

Q. What is the appropriate method for projecting maintenance costs?

A. The appropriate way to budget for and project FPL's fossil generating fleet's overhaul costs is to base the expenditures on the level and type of work that is due for the specific projection period. Whether certain types of overhaul work need to be performed during a specified period is based on a combination of factors, potentially including FPL's condition assessment of the units; manufacturer recommendations to help maximize the life of the equipment; FPL's operational and maintenance experience; the need to maintain the

[1] Includes four smaller CTs since retired at Putnam plant.

reliability of the units: and, minimizing operational impacts to FPL customers. A simple historic average, as witness Smith suggests, fails to take any of these factors into account and certainly gives FPL no credit for its highly successful approach to the maintenance of its fleet, which as shown in Exhibit RRK-7, has allowed FPL's total fossil, non-fuel O&M costs to be about two-thirds (i.e. $22/kW) less than the industry average. This results in a cost avoidance of more than $500 million in non-fuel O&M in 2015, for an FPL fossil fleet of more than 22,000 MW.

Q. Does witness Smith's approach account for any of this?

A. No, it does not. Witness Smith's position takes none of the aforementioned factors or cost avoidance into consideration. He reaches his conclusion based solely on a mathematical averaging of historic numbers that simply does not represent the future. He also ignores FPL's best in class operations that have produced substantial customer savings.

Q. Are there specific equipment maintenance schedules that FPL follows?

A. Yes. There are equipment-specific maintenance plans for conventional steam and combined cycle units.

Q. Please describe the typical maintenance schedule for each type of equipment.

A. For example, FPL steam units like Martin 1 & 2 have a full maintenance outage cycle that is defined by the longest equipment maintenance frequency/duration and is typically associated with steam turbine maintenance that occurs every 8 to 12 years. An interim maintenance outage is driven by

major boiler maintenance and occurs mid-cycle or every 4 to 6 years. This cycle is further divided to include traditional minor boiler maintenance that occurs every 2 to 3 years. In addition, shorter annual inspection outages are required to allow for equipment condition assessments and maintenance, ensuring that reliability issues are identified and addressed.

FPL's combined cycle units have maintenance outage cycles typically driven by service hours that vary among manufacturers and outage types: CT Inspections, Hot Gas Path Inspections, and Major Inspections. The equipment component, manufacturer, work scope type, operational hours and additional units drive the overall combined cycle maintenance overhaul intervals ranging from 3 to 12 years.

The range of maintenance activity on steam turbines and generators spans 3 to 12 years. The HRSG and balance of plant equipment maintenance is executed on a 1 to 3 year interval. This work is performed in conjunction with the outage types listed above. Each unit also undergoes an annual inspection outage to perform equipment condition assessments and maintenance to ensure reliability issues are identified and addressed.

Q. So, does the type of work change from year-to-year?

A. Yes, it does. For example, Scherer Unit 4 has overhauls in even years. The 2018 overhaul is planned at a cost to FPL of $9.8 million. Consequently,

averaging 2014 through 2017 for this site alone would result in a greater than $5.0 million deficit in costs against 2018 maintenance requirements.

It is noteworthy, however, that even with these increases in steam and other production overhauls that I have described, non-fuel O&M expenses for 2017 and 2018 are significantly below the Florida Public Service Commission ("Commission") O&M benchmarks for those years.

Q. Is FPL's non-fuel O&M overhaul expense projection appropriate for 2017 and 2018?

A. Yes, it is. FPL's 2017 and 2018 non-fuel O&M overhaul projection is based on a combination of factors designed to preserve unit reliability and availability for customers. FPL's experience in overhauls and other non-fuel O&M efforts have led FPL to achieve a non-fuel expense/kW that is roughly two-thirds better than the industry average. This approach has allowed FPL to provide industry leading reliability at a cost well below the Commission's O&M benchmarks, contained in MFR C-41, which are used by the Commission to assess cost reasonableness. Witness Smith's selective adjustment is not justified.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF THOMAS R. KOCH

DOCKET NO. 160021-EI

AUGUST 1, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Thomas R. Koch. My business address is 9250 W Flagler Street, Miami, Florida 33174.

Q. Did you previously submit testimony in the proceeding?

A. No.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL") as Senior Manager, Demand-Side Management Strategy, Cost & Performance.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for regulatory filings, reporting and cost management for FPL's Demand-Side Management ("DSM") related activities.

Q. Please describe your educational background and professional experience.

A. I have a Master of Business Administration and a Master of Science in Computer Information Systems, both from University of Miami, and a Bachelor of Music from West Chester University.

I joined FPL's Finance Department in 1985 working on forecasting and regulatory projects. In 1989, I became Treasury Manager responsible for FPL's short-term cash management, investing and borrowing. In 1991, I joined Customer Service where I was responsible for program management of

various tariffed offerings, product development and commercial/industrial retail market strategy. Beginning in 1998, I served in a number of positions in Distribution: Manager, Development & Planning; Manager, Environmental Department; Manager, Underground Department; and Manager, Financial Forecasting. In these positions I was responsible for day-to-day field operations, regulatory proceedings, growth activities, policy and procedure development, and regulation compliance. In 2009, I rejoined Customer Service, initially working on securing FPL's $200 million award from the Department of Energy's Smart Grid Investment Grant program and then on DSM. I assumed my current position in 2011.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to assertions made by Florida Power Industrial Users Group ("FIPUG") witness Jeffry Pollock, Federal Executive Agencies ("FEA") witness Amanda M. Alderson, and South Florida Hospital and Healthcare Association ("SFHHA") witness Stephen J. Baron (collectively the "Intervenor Witnesses"). The Intervenor Witnesses assert that their clients should retain the level of participant financial incentives in the Commercial-Industrial Demand Reduction ("CDR") and the Commercial-Industrial Load Control ("CILC") DSM programs that were negotiated as part of the Company's 2012 base rate settlement, because paying those incentives would pass the DSM cost-effectiveness screening test.

Q. Please summarize your rebuttal testimony.

A. By focusing on cost-effectiveness screening, or an alternative analysis that would purport to demonstrate the "real value" of the program to FPL (as suggested by FEA witness Alderson), these Intervenor Witnesses are missing or ignoring the point of the process by which financial incentives are set in DSM proceedings in Florida. Anyone who has ever participated in one of those proceedings knows that cost-effectiveness screening tests serve a preliminary, but not conclusive purpose in establishing DSM program incentives. Cost-effectiveness screening tests are used as a first step to determine which measures may be *considered* for implementation and also to identify the upper limit of a financial incentive that could be paid.

However, a second, and equally important, step that the Commission's DSM proceedings employ is to determine the *appropriate* level of the incentives. Thus, actual incentives typically are set at some lower amount sufficient to obtain the participation needed from a given program to provide its projected contribution towards the DSM Goals. This second step is important to ensure that the general body of customers is not required to pay more than necessary for FPL's DSM programs to be effective, and it is a standard step in the Commission's DSM proceeding.

FPL was obtaining sufficient levels of incremental participation in its CDR program prior to the 2012 base rate settlement at the level of financial

incentives being paid pre-settlement. The CILC program, which is closed to new participants, does not contribute to DSM Goals. By definition, therefore, to pay more than what was in effect pre-2012 settlement (adjusted as described in FPL witness Cohen's testimony) would be more than what is needed to ensure the desired level of participation and additional costs would be passed directly on to other customers. In other words, no additional incentives are needed for the benefits of the program to be realized by the general body of customers.

While such an outcome obviously has been approved and upheld as a component of an overall settlement, the Intervenor Witnesses are requesting that the Commission maintain the higher financial incentive levels through this proceeding in a manner that directly conflicts with the Commission's long-standing policy and practice in designing DSM programs and establishing appropriate DSM incentive levels. The pre-2012 settlement incentive levels, with the adjustments described in FPL witness Cohen's testimony, are appropriate and consistent with the DSM incentive-setting process.

II. CDR / CILC FINANCIAL INCENTIVES RESET

Q. Please summarize the Intervenor Witnesses' arguments regarding the cost-effectiveness of the CDR/CILC financial incentives.

A. FEA witness Alderson alleges that FPL should "…prepare a study to estimate the value of these interruptible credits to the FPL system…" (page 4). FIPUG witness Pollock asserts that "The Commission has previously determined in FPL's 2015 Demand Side Management case that CILC/CDR were cost-effective at the current level of incentive payments. Accordingly, by FPL's own admission, no further change can be made in this case." (page 8) SFHHA witness Baron claims, based on FPL's response to Staff's First Data Request No. 22 in Docket No. 150085-EG (Exhibit SJB-14), that "Given the cost effectiveness of the current level of credits, there is no basis for FPL's proposed $23 million reduction in this base rate case." (page 51) He fails to point out that the same data request response also states that the credit amounts "were approved by the Commission as part of the settlement of FPL's last base rate case (Order No. PSC-13-0023-S-EI), that extend through the end of 2016."

As explained below, all these Intervenor Witnesses disregard the Commission's approach to DSM, miss the point and paint an inaccurate and incomplete picture.

Q. How are the DSM programs' financial incentives for participants typically determined?

A. The Commission sets annual residential and business DSM Goals for Summer Megawatts, Winter Megawatts and annual Gigawatt-hours which FPL must achieve. Next, FPL develops a DSM Plan which is comprised of several programs with individual customer participation targets designed to achieve the DSM Goals in the aggregate.

In order to achieve the participation targets for each program, FPL uses a two-step process to determine DSM participant financial incentives. First, FPL uses the Commission-approved Rate Impact Measure ("RIM") and Participant cost-effectiveness screening tests to determine the maximum level of financial incentive that passes these two tests with a benefit-to-cost ratio of 1.01. A ratio above 1.0 means that the benefits of a program exceed its costs and therefore the program is cost-effective.

Second, and this is the point that the intervenor witnesses ignore, FPL then determines the minimum level of financial incentive expected to be needed for each program to achieve its targeted customer participation amount. In many cases, this amount is less than the maximum cost-effective level determined in the first step. This is to avoid burdening the general body of customers with higher costs than needed to meet the DSM Goals, because all customers pay

for the cost of DSM programs through the Energy Conservation Cost Recovery ("ECCR") clause.

Q. Was the second step of this methodology used for the currently-effective financial incentives for CDR and CILC?

A. No, and it was not necessary in this situation. First, as explained above, the financial incentive levels in the CDR program clearly were sufficient at pre-settlement levels to obtain the needed program participation. Second, as explained in FPL witness Cohen's direct and rebuttal testimony, the current CDR and CILC financial incentives were implemented as one part of FPL's multi-faceted Settlement Agreement approved by the Commission in FPL's 2012 rate case, Docket No. 120015-EI, which extends through 2016. Thus, in submitting its DSM Plan in 2015, FPL simply reflected the level of credits consistent with the Settlement Agreement. Likewise, in approving FPL's current DSM Plan in 2015, the Commission accepted the level of financial incentives negotiated as a part of the 2012 Settlement Agreement.

Q. FIPUG witness Pollock suggested that a different methodology was used to set the currently-effective financial incentives. Does he accurately summarize how FPL arrived at the current incentive levels?

A. No. Mr. Pollock claims that inflationary factors and load growth combined to demonstrate a "greater value of interruptible service" that led to an increase in the incentives in 2012. Because FIPUG was actively involved in FPL's 2012 base rate case and its settlement, Mr. Pollock should be aware that the currently-effective incentive levels were simply part of that broader settlement

package that was negotiated, agreed upon, and approved by the Commission. No such factual evaluation of the "value of interruptible service" was undertaken at that time.

Q. Is it necessary to maintain the current level of financial incentives in order to attain the CDR program's participation contribution to achieving the future DSM Goals?

A. No. Prior to the financial incentive increases from the 2012 Settlement Agreement, FPL was able to achieve its participation targets for CDR. Incremental participation targets have not substantially increased since that time. Therefore, returning to that financial incentive level is adequate. Moreover, no additional payments to current customers are necessary to secure achievement of the incremental DSM goals.

III. CONCLUSION

Q. Please summarize you testimony.

A. The CDR and CILC financial incentives that were in place prior to the 2012 rate base settlement, as adjusted for new generation additions, are appropriate and sufficient to achieve the needed customer participation. The allegations made by the Intervenor Witnesses regarding the appropriate level of participant financial incentives in these programs are incorrect and without merit. While paying higher than necessary incentive levels has been approved and upheld as a component of an overall settlement, the Intervenor Witnesses

advocating to have these higher levels maintained are asking the Commission to reach a decision directly in conflict with its long-standing policy and practice in designing DSM programs and establishing appropriate DSM incentive levels. The Commission should reject this request.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF JEFFREY T. KOPP

DOCKET NOS. 160021-EI; 160062-EI

AUGUST 1, 2016

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II. DISMANTLEMENT COST ESTIMATES 5

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jeffrey (Jeff) T. Kopp. My business address is 9400 Ward Parkway Kansas City, Missouri, 64114.

Q. By whom are you employed and what is your position?

A. I am employed by Burns & McDonnell Engineering Company, Inc. ("BMcD"), as a manager in the Business Consulting Department of the Business & Technology Services Division.

Q. Please describe your duties and responsibilities in that position.

A. As a manager in the Business Consulting Department, I oversee a team of 10 project managers who provide consulting services to clients primarily in the electric power generation and electric power transmission industries, but also to other industrial and commercial clients. The services provided by this group of project managers include dismantlement studies, independent engineering assessments of existing power generation assets, economic evaluations of capital expenditures, new power generation development and evaluation, electric and water rate analysis, electric transmission planning, generation resource planning, renewable power development, and other various related engineering and economic assessments.

In my role as a group manager, project manager, and project engineer, I have worked on and overseen consulting activities on coal, natural gas, wind, solar, hydroelectric, and biomass power generation facilities.

Q. Please describe your educational background and professional experience.

A. I have a Bachelor's Degree in Civil Engineering from the University of Missouri – Rolla and a Masters of Business Administration from the University of Kansas.

Q. Are you sponsoring or co-sponsoring any exhibits as part of your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

- JTK-1 – FPL's Response to Staff's Seventh Set of Interrogatories No. 165

I am also co-sponsoring Section 8 (pages 16-84) of Exhibit KF-4 (Corrected) - FPL 2016 Dismantlement Study filed with the rebuttal testimony of witness Keith Ferguson.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is demonstrate that the recommendations in the testimony of the South Florida Hospitals and Healthcare Association ("SFHHA") witness Kollen with respect to dismantlement estimates are incorrect and should be rejected.

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony will address witness Kollen's mischaracterization of how dismantlement cost estimates are prepared and the importance of

contingency in developing these estimates. I will also demonstrate that witness Kollen's recommendation to apply either a zero or at best a 10% contingency is unreasonable and unsupported based on my professional experience and the Commission's own rule and these recommendations should be rejected by the Commission.

II. DISMANTLEMENT COST ESTIMATES

Q. Please briefly explain how the dismantlement cost estimates are developed and the role of contingency in those estimates.

A. The estimate of direct dismantlement costs is prepared with the intent of most accurately represent what BMcD would anticipate contractors bidding to dismantle the equipment, address environmental issues, and restore the site through a competitive bidding process, based on performing known dismantlement tasks under ideal conditions. In addition to these known tasks under ideal conditions, contingency is added to account for unknown, but reasonably expected to be incurred costs.

As outlined in FPL's 2016 Dismantlement Study, we prepared these cost estimates by estimating quantities for equipment based on a visual inspection and interaction with the facilities' engineers, review of engineering drawings, BMcD's in house database of plant equipment quantities, and BMcD's professional judgment. This resulted in an estimate of quantities for the tasks

required to be performed for each decommissioning effort. Current market pricing for labor rates, equipment, scrap materials, and unit pricing were then developed for each task. These pricing inputs were developed for each site based on costs specific to the area in which the work is to be performed. These rates were applied to the quantities for the plants to determine the total cost of decommissioning for each site.

Because the estimates of direct dismantlement costs are based on ideal conditions, and known dismantlement tasks, additional costs are included via contingency to cover unknown, but reasonably expected to be incurred costs. These costs include weather delays, unknown environmental contamination, discovering equipment or materials not shown on drawings, additional dewatering requirements and changes in the manner the work is performed. Contingency is a cost that is typically included by owners throughout all stages of planning through execution of the project, even once firm pricing is obtained from a contractor. These costs cover potential change orders based on these unknowns.

Q. Witness Kollen states on page 33, line 8 that BMcD has simply underestimated various dismantling projects in the past and asserts that this is not a valid basis for adding contingency. Does witness Kollen correctly understand the relationship between project cost estimation and contingency?

A. No. Witness Kollen is referring to FPL's response to Staff's Seventh Set of Interrogatories No. 165; refer to my exhibit JTK-1. In the response to that discovery request, BMcD provided two examples of projects where contingency was expended during the execution of the projects, resulting in actual costs exceeding the original estimated direct costs. In both cases, change orders were necessary, which resulted in increased costs incurred by the generating facility owners. These change orders were not the result of cost estimating inaccuracies for the direct costs for the base scope of work, but were instead the result of changes to the demolition scope of work that resulted from unknowns during the preparation of the base scope, and were later discovered during project execution. These work scope changes were outlined in the response to Staff's Seventh Set of Interrogatories No. 165. These unknown, but reasonably anticipated costs are exactly the types of costs intended to be covered by contingency. These examples demonstrate the need for project owners to carry contingency, since work scope can change, even after firm fixed pricing is provided by a demolition contractor. The direct costs cover the knowns, the contingency covers the unknowns.

Q. What qualifies BMcD to prepare accurate estimates of dismantlement costs and why should the Commission put weight into these estimates of the direct costs and application of contingency?

A. BMcD has been in business since 1898, serving multiple industries, including the electric power industry. In 2016, BMcD was rated No. 14 overall of the Top 500 Design Firms by the Engineering News Record ("ENR"). BMcD was rated as the No. 1 engineering design firm in the United States serving the electric power industry by ENR in 2016.

BMcD has vast experience in both preparation of dismantlement studies and executing actual construction projects, including hundreds of construction projects totaling more than $1 billion dollars of construction last year alone. In order to execute over $1 billion dollars of construction projects on an annual basis, BMcD has to win this work through competitive bidding processes, which requires us to be able to accurately prepare cost estimates. If we routinely estimated costs too high, we would not be successful in winning projects. If we routinely estimated costs too low, we would not be able to execute projects profitably and would no longer be active in this market. Our long history, large market presence, and top industry rankings demonstrate our ability to effectively and accurately estimate costs. In addition, we have worked with demolition contractors over the years to refine our estimating process for dismantlement studies to align our costs with theirs. However,

even with an accurate estimate of the known direct costs under ideal conditions, the application of contingency is prudent.

Q. Is witness Kollen's general characterization of contingency correct?

A. No. Witness Kollen infers that contingency represents the amount of inaccuracy in an estimate. This is not the case. The application of contingency is a common and demonstrably prudent practice in the construction industry and it is included in order to recognize the probability of increases in cost due to unknowns as described above. Experience with these unknowns impacting dismantlement costs was demonstrated in the examples provided by BMcD in FPL's response to Staff's Seventh Set of Interrogatories No. 165 (see JTK-1). The base estimated cost to dismantle assumes ideal weather and working conditions, which is an appropriate starting point for cost estimating but frequently cannot be achieved when the work is actually performed. The base cost estimate also does not include any costs for other unknowns such as additional environmental contamination or other unknowns outlined in my previous responses, but reasonably expected to be incurred, based on experience with other projects. Some of these costs cannot be determined until the dismantlement process has begun. Therefore, contingency is applied on top of the base estimated cost in order to formulate the most probable estimate to dismantle the generating facilities.

Q. Does the Florida Public Service Commission's rule on dismantlement studies provide for the application of contingency?

A. Yes. Refer to subsection (2)(a) of Rule 25-6.04364, Electric Utilities Dismantlement Studies, F.A.C., which defines and permits contingency costs to be included in cost estimates to account for "unforeseeable elements of cost within the defined scope of the project."

Q. Witness Kollen recommends on page 34, lines 16 through 20, that the Commission completely remove all contingencies from the Company's dismantlement estimates or reduce the percentage to 10%. Does witness Kollen provide any evidence to support this recommendation?

A. No. Witness Kollen does not provide any evidence to support this recommendation other than a generalized statement that dismantlement estimates should become more accurate across the industry based on experience.

Q. Please explain why you are recommending the application of 20% contingency to the dismantlement cost estimates.

A. The percentage of contingency applied to any cost estimate is directly related to the level of unknowns associated with the project. When preparing construction cost estimates for a new fossil-fuel generation facility on a greenfield site, we would typically determine the level of contingency based on the stage of planning or execution that we are in, which impacts the level of unknowns. We would apply higher contingency, typically between 10% and 15%, at early stages of planning when there are more potential unknowns.

These would include potential scope changes as well as weather delays and other factors. As engineering design progresses and some of these unknowns can be reduced through subsurface investigations, engineering design drawings, and engineering specifications, the amount of contingency may be reduced. However, contingency would never be completely eliminated, even after full detailed design is completed, since some unknowns, as common as weather delays, cannot be completely eliminated.

The dismantlement cost estimates prepared as part of this filing are most similar to the cost estimates developed in the early stages of planning for a new fossil-fuel generation facility on a greenfield site. However, when preparing a dismantlement cost estimate, there is a greater level of unknowns than new construction which cannot be eliminated at this stage of the planning process. For example, dismantlement activities occur at sites where power generation has been ongoing for many years and environmental contamination is more likely than a greenfield site. In addition, no on-site testing for hazardous materials and potential environmental contamination has been performed during these planning stages to fully identify the presence and extent of these items. No subsurface investigations or groundwater sampling has been performed to identify and define remediation requirements. And some unknowns, such as below grade storage tanks or piping, which may contain hazardous materials, may not be uncovered until the dismantlement process is underway. This is analogous to the difference between building a

new house with architectural drawings and specified quantities on an undisturbed plot of ground compared to gutting and renovating an existing house. With the latter, additional contingency would be warranted, due to the fact that a higher likelihood exists to encounter unknown materials that could be considered hazardous, unknown material types and quantities, and unknown foundation and subsurface conditions.

For all of these reasons, as well as our experience with actual dismantlement costs relative to dismantlement cost estimates, as outlined in FPL's response Staff's Seventh Set of Interrogatories No. 165 provided as Exhibit JTK-1 and our professional judgment, we recommend and apply a 20% contingency to dismantlement cost studies. We recommend the application of 20% contingency to the FPL dismantlement cost estimates, consistent with the studies we have prepared for various utility clients throughout the United States. This includes Duke Energy Florida's most recently filed dismantlement study, also prepared by BMcD, which also included a 20% contingency, and was approved in Order No. PSC-10-0131-FOF-EI, Docket No. 090079-EI.

Q. Does witness Kollen state anything further regarding the appropriateness of applying contingency to dismantlement costs?

A. Yes. On page 33, lines 19 through 21, witness Kollen contradicts his own position that a zero contingency percentage should be applied by stating, "when contractors are retained to actually dismantle and restore sites at some

date in the future, it may be appropriate to add contingencies to contract costs…." As witness Kollen confirms with this statement, it is prudent to include contingency, even after firm pricing is provided by a demolition contractor. However, witness Kollen has it backwards. Contingency is even more important during the planning stages prior to retaining a contractor to dismantle and restore the sites, due to a greater level of uncertainty at the earlier stages of project planning.

Q. Please explain why the above statement is important.

A. Witness Kollen acknowledges that contingencies are an important component of cost estimates; however, his approach in effect would saddle future customers with the risk of increased costs. This is a clear violation of the principle of intergenerational equity, which is achieved only by treating dismantlement costs, including contingencies, as part of the cost of the facility generating power. The most equitable treatment for all generations of customers is to pay for the cost of dismantlement ratably over the life of the generating facilities rather than pay increased costs at plant's end of life.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Florida Power & Light Company
Docket No. 160021-EI
Staff's Seventh Set of Interrogatories
Interrogatory No. 165
Page 1 of 2

QUESTION:
Please refer to the Direct Testimony of FPL Witness Keith Ferguson, Exhibit KF-4, Page 6 of 127.

a. Please provide an actual example of Burns & McDonnell "experience with actual costs relative to estimated costs" that supports FPL's 20 percent dismantlement contingency allowance proposal.

b. Please also discuss the general inclusion of the additional 5 percent project indirect cost provision being proposed in this case and how this project indirect provision differs from a contingency allowance.

RESPONSE:

a. Burns & McDonnell is a large multi-discipline engineering firm. They performed more than $1 billion worth of construction on hundreds of construction projects last year alone and have experience in both preparing cost estimates and in executing the projects associated with the cost estimates. This gives them valuable insight into the appropriate level of contingency to apply to cost estimates for given projects to ensure the greatest level of accuracy of the cost estimates. They have experience preparing cost estimates at various planning stages all the way through providing firm competitive bids for construction projects, and routinely apply contingency to the estimated direct costs to account for unknowns at a level commensurate with the stage at which the cost estimate is performed.

   In Burns & McDonnell's experience, the greater the level of uncertainty in the precision of the quantities in the estimate, how work will be performed, and what work conditions will be like when the project is executed, the greater the level of contingency that should be applied to the cost estimate to cover unforeseen costs that are likely to occur during project execution. For dismantlement projects, there is uncertainty associated with work conditions (including weather delays, equipment and subsurface conditions, and allowable demolition methodologies) and how the work will be performed. There is also uncertainty associated with quantities for dismantlement of facilities, due to the age and limits on drawings available, and the absence of testing results for environmental contamination prior to preparation of these types of studies.

   Therefore, a 20% contingency is appropriate for cost estimates associated with this type of study. A 20% contingency on site dismantlement estimates has been accepted by many public service commissions, including the Florida Public Service Commission in Progress Energy Florida's most recent dismantlement study prepared by Burns & McDonnell (Order No. PSC-10-0131-FOF-EI).

   Two examples of Burns & McDonnell's "experience with actual costs relative to estimated costs" are as follows. On a decommissioning and demolition project Burns &

McDonnell was supporting for a power plant in the Southwest, the original cost was estimated to be $5.125 million. During demolition, change orders were incurred for a total of approximately $440,000, or 8.6% of the direct costs, to cover additional asbestos, transite siding, and PCB containing materials not previously identified, as well as additional below ground piping not shown on drawings, and additional electrical isolation services not identified during the planning stages. On another decommissioning and demolition project Burns & McDonnell was supporting for a power plant in the Midwest, the original cost was estimated to be $4.612 million. During demolition, change orders were incurred for a total of approximately $4.182 million, or 90.7% of the direct costs, to cover additional underground transite conduits not shown on drawings provided, city requiring all subgrade foundations to be removed, additional asbestos insulation not previously identified, and dewatering requirements being significantly larger than anticipated.

b. Indirect costs refer to costs expected to be incurred by FPL during the decommissioning process, which would be in addition to the direct costs paid to demolition or other contractors, but accounts for items separate from contingency costs. This includes the costs for staff from FPL or a third party contractor to perform decommissioning activities prior to demolition, such as removing coal from feeders, conveyors, bunkers, and mills; water washing equipment to remove remaining fines; vacuum cleaning ash hoppers, duct work, boiler, Air Quality Control System, air heaters, etc. Also included in this category are costs associated with staff from FPL or a third party contractor providing oversight during demolition activities, inspections, and testing to confirm that remediation has been completed, as well as FPL overheads, general and administrative costs. In the 2009 dismantlement study, FPL captured similar costs in "Site Management Expenses." The 5% indirect cost approach was also accepted by the Florida Public Service Commission in Progress Energy Florida's most recent dismantlement study prepared by Burns & McDonnell (Order No. PSC-10-0131-FOF-EI).

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF MANUEL B. MIRANDA

DOCKET NOS. 160021-EI & 160062-EI

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Manuel B. Miranda. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring rebuttal exhibits in this case?

A. Yes. I am sponsoring the following rebuttal exhibit:

- MBM-7: FPL's Response to OPC Interrogatory No. 13

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to refute the direct testimonies of Office of Public Counsel ("OPC") witnesses Helmuth W. Schultz and Ralph Smith to reduce FPL's 2017 and 2018: distribution vegetation management and pole inspection expenses; transmission and distribution ("T&D") storm hardening capital expenditures; and T&D Property Held for Future Use ("PHFFU") costs. Additionally, I address OPC witness Jacob Pous' comments concerning FPL's increasing removal costs and provide several examples of initiatives that have been implemented to mitigate upward cost pressures affecting FPL's removal costs.

Q. Please summarize your rebuttal testimony.

A. My testimony demonstrates that Mr. Schultz's proposed recommendations to reduce FPL's forecasted 2017 and 2018 distribution vegetation management

and pole inspection expenses and T&D hardening capital expenditures are arbitrary, methodologically inconsistent, incorrectly calculated, opportunistic and unwarranted. Therefore, they should be rejected.

Additionally, my testimony shows that Mr. Smith's recommendations to remove certain T&D properties and their associated costs from FPL's 2017 and 2018 forecasted PHFFU balances should be rejected as these properties are essential components for: meeting future customer and load growth; improving reliability; complying with North American Electric Reliability Corporation ("NERC") standards; and/or integrating future generation into the grid. Exclusion of these properties would compromise FPL's ability to implement its dynamic planning process for locating and acquiring alternative properties to build necessary transmission and distribution facilities.

Finally, in response to comments contained in Mr. Pous' testimony concerning FPL's increasing removal costs, my testimony shows that FPL has taken steps to mitigate the upward cost pressures affecting FPL's removal costs.

REBUTTAL TO TESTIMONY OF HELMUTH SCHULTZ III

II. VEGETATION MANAGEMENT PROGRAM / EXPENSES

Q. Does witness Schultz's direct testimony include any inaccurate claims/representations concerning FPL's distribution vegetation management program?

A. Yes. There are several inaccurate claims/representations included in Mr. Schultz's testimony, which I will identify and briefly address.

Q. What inaccurate claims/representations have you identified in witness Schultz's direct testimony?

A. First, on page 29, lines 5 and 6, of his testimony, Mr. Schultz states that "This vegetation management plan includes cycle trimming but not the removal of danger and/or hazard trees." This statement is inaccurate. FPL's vegetation management program does, in fact, address danger/hazard trees.

Second, on page 30, lines 5 and 6, Mr. Schultz reaches the conclusion that FPL's system trim cycle "equates to a trim cycle of 2.4 years." This statement also is incorrect, as his 2.4 years trim cycle calculation inappropriately includes over 7,000 miles of mid-cycle feeder trimming (i.e., trimming fast growing vegetation before the next scheduled cycle trim date). FPL's combined feeder and lateral system (currently 36,256 miles) is effectively on a 4.4-year cycle, as FPL cycle trims approximately one-third of its feeder miles

(approximately 4,500 miles) and one-sixth of its lateral miles (approximately 3,800) annually. These trim cycles have been approved by the Commission.

Third, on page 31, lines 11-17, Mr. Schultz again refers to his inaccurately calculated 2.4–year system trim cycle, suggesting that FPL's actual system trim cycle is "accelerated" when compared to FPL's approved three-year (feeders) and six-year (laterals) cycles. FPL's three-year feeder and six-year lateral cycle trimming is not "accelerated," as it is completed per its Commission-approved plan.

Q. Witness Schultz utilizes a comparison of FPL's 2013-2015 actual vs. budgeted distribution vegetation management expenses as the basis to adjust FPL's forecasted 2017 and 2018 distribution vegetation management expenses. Do you agree with witness Schultz's methodology and his resulting proposed adjustments?

A. No. FPL's forecasted vegetation management expenses were developed by knowledgeable experts who understand both the program and FPL's system. Based on Mr. Schultz's inaccurate statements, which I previously discussed, Mr. Schultz does not appear to understand FPL's vegetation management program or FPL's system. As a result, he utilizes a simplistic approach that is based on a three-year (2013-2015) comparison of actual to budget vegetation management expenses. This simplistic approach is arbitrary and unwarranted.

Q. Please explain.

A. Mr. Schultz's Exhibit HWS-6 contains FPL's distribution vegetation management actual vs. budget variances for the five-year period 2011-2015. As shown on his Exhibit HWS-6, the three-year (2013-2015) actual to budget variance average factor is 96.6%, the five-year (2011-2015) actual to budget variance average factor is 98.8% (with variance factors ranging from 94.1% - 103.9%) and the 2015 actual to budget variance factor, the most recent year comparison, is 99.7%. To effect his proposed vegetation management expense reduction, Mr. Schultz opted to use the 2013-2015 (three-year) actual vs. budget variance. This results in an actual vs. budget variance (3.4%) that is nearly three times larger than that produced by the 2011-2015 (five-year) actual vs. budget variance (1.2%) and more than 10 times larger than that produced by the 2015 actual vs. budget variance (0.3%). He provides no support for his selection of the three-year average, which simply appears to be opportunistic for the purpose of creating the largest possible adjustment.

Q. Is witness Schultz's selection and use of the three-year historical average consistent with his testimony in other proceedings where he has proposed similar adjustments to budgeted vegetation management costs?

A. No. In previously filed testimony in another proceeding[1], Mr. Schultz's testimony includes discussions where he is challenging another investor-

[1] Case 07-E-0523, New York State Public Service Commission; Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company New York, Inc for Electric Service

owned electric utility's level of forecasted O&M expenses. In these discussions, Mr. Schultz mentions on multiple occasions how the company provided "limited" historical cost information, i.e., the company provided three years of data instead of the requested five years of data. Additionally, Mr. Schultz goes on to explain that: "Five years of information provides an opportunity to evaluate spending over a period of time in which fluctuations in any one year or two can be identified. It also allows for a comparison of requested costs to historical data to assess whether the request is reasonable. In fact, a number of jurisdictions use five or more years of data to develop an average for expenses such as uncollectibles, storms and tree trimming, which are then used in determining the utility's revenue requirements." For tree trimming expenses, Mr. Schultz specifically states that: "Although there is a preference to utilize a five-year average, if an average were to be used, we can only recommend a three-year average because the Company did not provide the five years of expenditures requested."

In FPL's current proceeding, Mr. Schultz's Exhibit HWS-6, includes FPL's actual vs. budget results for the most recent five-year period (2011-2015). However, Mr. Schultz does not utilize the five-year period results, even though he previously stated this was his preference. Instead, Mr. Shultz ignores the five-year variance average and opts to use the 2013-2015 (three-year) actual vs. budget variance average. Because he has provided no explanation or basis for using the three-year variance average instead of his

previously preferred five-year variance average, it appears it was selected only because it produces the largest proposed reduction to FPL's 2017 and 2018 vegetation management expenses.

Q. **After considering the information you have provided, are witness Schultz's proposed reductions to the 2017 and 2018 distribution vegetation management expenses warranted and appropriate?**

A. No. Witness Schultz has not provided any basis or rationale for utilizing the three-year (2013-2015) actual vs. budget variance average to reduce FPL's 2017 and 2018 vegetation management expenses. Since he has previously testified that a five-year historical average is preferred, it appears the three-year has been utilized only because it produces a larger proposed reduction in FPL's expenses.

As can be seen in in his Exhibit HWS-6, over the last five years, FPL's actual vegetation management expenses have exceeded the budget twice and differed from budget, on average, by only 1.2%. Additionally, in 2015, actual vegetation management expenses differed from budget by only 0.3%. As a result, Mr. Schultz's proposed reductions to FPL's 2017 and 2018 are unwarranted and inappropriate and should be rejected. FPL's 2017 and 2018 vegetation management expenses are reasonable and appropriate as filed and should be approved by the Commission.

Q. Are there any other reasons the Commission should not accept witness Schultz's proposed reductions to FPL's 2017 and 2018 vegetation management expenses?

A. Yes. In addition to the reasons I have previously discussed, Mr. Schultz's calculation for his proposed reduction is mathematically incorrect.

Q. Please explain.

A. In Mr. Schultz's Exhibit HWS-6, on line 12, Mr. Schultz calculates his recommended 2017 vegetation management expense amount of $60.953 million, by multiplying FPL's 2015 budget amount ($63.1 million) by his three-year (2013-2015) actual to budget variance average factor (0.965969). Even if one accepted his flawed methodology, Mr. Schultz should have applied his three-year actual to budget variance average (0.965969) to FPL's 2017 forecast expense ($65.6 million), as he did when he similarly adjusted FPL's pole inspection expenses in his Exhibit HWS-7. Correcting for this error would have resulted in an adjustment that was immaterial (i.e. increasing even Mr. Schultz's recommended vegetation management expense amounts to $63.368 million (from $60.953 million) for 2017 and $64.635 million (from $62.172 million) for 2018). Again, Mr. Schultz's choice of budget year against which to apply his adjustment appears to be result-driven.

Q. How does this correction impact witness Schultz's proposed reductions to FPL's 2017 and 2018 vegetation management expenses?

A. Correcting for Mr. Schultz's calculation error lowers his proposed reductions for 2017 and 2018 by 52% and 33%, respectively.

Q. Does this mean that you are proposing that FPL reduce its 2017 and 2018 vegetation management expenses by these corrected adjusted amounts?

A. No. I am simply pointing out additional arbitrary aspects of Mr. Schultz's inappropriate and results-oriented approach. As discussed earlier, these adjustments are unwarranted and should be rejected. When the budgeted and actual expenses are compared on an appropriate basis for 2011-2015, it is clear that the variances are immaterial and, in fact, FPL's 2017 and 2018 forecasted vegetation management expenses are reasonable and appropriate as filed and should be approved by the Commission.

III. POLE INSPECTION PROGRAM/COSTS

Q. Witness Schultz utilizes a comparison of FPL's 2013-2015 actual vs. budgeted distribution pole inspection expenses as the basis to adjust FPL's forecasted 2017 and 2018 distribution pole inspection expenses. Do you agree with witness Schultz's methodology and his resulting proposed adjustments?

A. No. Similar to his proposed recommendation to reduce FPL's vegetation management expenses, his methodology to reduce FPL's 2017 and 2018 pole inspection expenses is arbitrary, unwarranted and opportunistic.

Q. **Please explain**.

A. Mr. Schultz provides no basis or rationale for using a three-year (2013-2015) actual vs. budget variance average to calculate his proposed reduction in

distribution pole inspection expenses. Once again, it appears it has been utilized only because it produces higher proposed reductions in expenses. For example, Mr. Schultz's three-year (2013-2015) actual to budget variance average produces reductions in distribution pole inspection expenses of $1.664 million for 2017 and $1.693 million for 2018. Utilizing the five-year (2011-2015) average (which previously he has supported), Mr. Schultz's proposed reductions would be 58% lower for 2017 and 2018. Utilizing the 2015 (one-year) actual to budget variance, the proposed reductions would be 83% lower for 2017 and 2018.

Q. Are there other considerations that should be taken into account when reviewing FPL's distribution pole inspection program costs?

A. Yes. It is important also to recognize that total pole inspection program costs include both O&M expenses and capital expenditures. In fact, the vast majority of pole inspection costs are classified as capital expenditures. These capital components primarily are associated with the remediation and replacement of poles that have failed inspections. As shown in Exhibit MBM-7, which contains FPL's response to OPC Interrogatory No. 13, total actual distribution pole inspection program costs have exceeded the budget during 2011-2015, using a one year comparison (2015), three-year (2013-2015) average comparison or five-year (2011-2015) average comparison.

Q. After considering the information you have provided, are witness Schultz's proposed reductions to the 2017 and 2018 distribution pole inspection expenses warranted and appropriate?

A. No. Mr. Schultz has not provided any basis or rationale for his simplistic approach which utilizes the three-year (2013-2015) actual vs. budget variance average to reduce FPL's 2017 and 2018 distribution pole inspection expenses. In fact, utilizing the five-year (2011-2015) actual to budget variance average or the 2015 actual to budget variance significantly reduces (by 58% and 83%, respectively) his recommended expense adjustments. Additionally, from a total distribution pole inspection program cost (capital expenditures and O&M costs) perspective, FPL's actual costs have exceeded the budget during 2011-2015. Therefore, Mr. Schultz's adjustments are unwarranted and should be rejected. FPL's 2017 and 2018 pole inspection costs are reasonable and appropriate as filed and should be approved by the Commission.

Q. If the Commission were to accept witness Schultz's proposed methodology and proposed reductions in FPL's 2017 and 2018 pole inspection expenses, would other adjustments be necessary?

A. Yes. To avoid Mr. Schultz's inconsistently applied "one-sided" expense adjustment and recognize that FPL's pole inspection program costs include capital expenditures as well as O&M expenses, a comparable adjustment to increase FPL's budgeted distribution pole inspection capital expenditures for 2017 and 2018 would be appropriate.

Q. Are you proposing these adjustments?

A. No. Again, I'm simply highlighting additional arbitrary aspects of Mr. Schultz's analysis. As discussed earlier, these adjustments are unwarranted and should be rejected. FPL's 2017 and 2018 pole inspection expenses are reasonable, appropriate as filed and should be approved by the Commission.

IV. FPL's FPSC HARDENING CAPITAL EXPENDITURES

Q. In his testimony, witness Schultz claims that FPL's proposed 2016-2018 increase in storm hardening capital expenditures is "overly optimistic" because the combined proposed spending in 2016 and 2017 ($1.075 billion) is significantly higher than the spending from 2012-2015 ($1.001 billion) and the total spending for 2016-2018 ($1.943 billion) is nearly double the amount spent for the previous four years. Does FPL believe its 2016-2018 FPSC hardening plans and associated capital expenditures are achievable?

A. Yes. As shown in Mr. Schultz's Exhibit HWS-9 and acknowledged on page 36, line 10, of his testimony, during 2012-2015, FPL has met its annual storm hardening capital expenditure budget 100% of the time during this period.

Additionally, as can be seen on line 13 of Mr. Schulz's Exhibit HWS-9, the projected annual percentage increases in storm hardening capital expenditures for 2016-2018 (ranging from 128% - 144% annually, with an annual average

increase of 136%) have been previously achieved by FPL during 2013-2015, as FPL achieved annual percentage increases ranging from 116% to 152% annually, with an annual average increase of 136%.

Results demonstrate that FPL has the technical expertise and a decade of experience to successfully execute its storm hardening plans. This includes executing similar percentage increases in annual projects/capital expenditures. As a result, I am extremely confident that FPL can continue to execute these proposed levels of annual projects and capital expenditures.

Q. Witness Schultz recommends reducing FPL's 2017 and 2018 storm hardening expenditures based on a ratio (94.78%), calculated by comparing his projection of FPL's storm hardening capital expenditures (determined by annualizing FPL's May 2016 year-to-date actual storm hardening capital expenditures) to FPL's 2016 storm hardening capital expenditures budget ($446.4 million/$471 million). Do you agree that witness Schultz's proposed reductions are appropriate?

A. No. This is another example of Mr. Schultz using simplistic and inappropriate methodologies to reduce FPL's projected costs. FPL's storm hardening capital expenditures, year-to-date through June 2016, actual to budget, are $229 million vs. $233 million. This means that as of June 2016, FPL's storm hardening capital expenditures are currently under budget by less than 2%. Mr. Schultz's annualizing methodology also fails to recognize that FPL's storm hardening budget is slightly higher during the second half of 2016

($238 million vs. $233 million). Considering this immaterial year-to-date actual vs. budget variance and FPL's recent historical track record of meeting its storm hardening capital expenditure budget 100% of the time, there is no justifiable reason or explanation to assume that FPL will not meet its 2016 storm hardening capital expenditures budget.

Q. Witness Schultz's skepticism appears to also be supported by his concern that making up any current "underspent" amounts would be difficult to achieve in the second half of the year because of the approaching storm season. Do you agree?

A. It is possible that, as a result of a major storm or several major storms, FPL's ability to achieve its proposed storm hardening capital expenditure levels could be impacted. As we all know, the impacts associated with responding to major storms can have significant and widespread ramifications on all aspects of FPL's operations and costs; that is part of the reason why storm hardening is necessary and desirable. However, I disagree that this potential impact should be used as a basis to support an adjustment to reduce FPL's projected storm hardening capital expenditures.

Q. Please summarize your thoughts concerning witness Schultz's recommendations to reduce FPL's 2017 and 2018 FPSC hardening capital expenditures.

A. Although Mr. Schultz recognizes FPL for making "significant strides in hardening the system" and achieving planned expenditure levels during the years 2012 through 2015, his skepticism leads him to find a means to reduce

FPL's "overly optimistic" 2016-2018 storm hardening capital expenditures. His simplistic and unwarranted methodology to reduce FPL's 2017 and 2018 storm hardening capital expenditures by annualizing FPL's year-to-date May 2016 storm hardening capital expenditures, combined with his potential storm season impacts, are not sound or justified. Instead, the Commission should rely on FPL's demonstrated technical expertise, experience and results.

Over the period 2012-2015, FPL has met its storm hardening capital expenditure budget 100% of the time. Also, as of June 2016, FPL's storm hardening capital expenditures are less than 2% under budget. Additionally, FPL has already achieved comparable percentage increases in annual FPSC hardening capital expenditures spending levels. As a result, witness Schultz's proposed reductions are unwarranted and should be rejected. FPL's 2017 and 2018 storm hardening capital expenditures are reasonable, appropriate and should be approved by the Commission.

Q. You previously stated that Mr. Schultz's proposed adjustments were methodologically inconsistent. Please explain.

A. With his recommendations to reduce FPL's 2017 and 2018 vegetation management and pole inspection expenses, Mr. Schultz argues that an historic failure to spend an entire budget warrants an adjustment to a forecast. However, with his proposed adjustment to reduce FPL's 2017 and 2018 storm hardening capital expenditures, Mr. Schultz disregards the fact that FPL has had no such historical variance between actual and budgeted expenditures.

Rather than consistently utilizing his previously adopted adjustment methodology, Mr. Schultz abandons it, apparently because its application would result in no reduction to FPL's 2017 and 2018 storm hardening capital expenditures. This inconsistency is arbitrary, inappropriate, unwarranted and should be rejected.

REBUTTAL TO TESTIMONY OF OPC WITNESS RALPH SMITH

V. T&D PROPERTY HELD FOR FUTURE USE

Q. What is OPC witness Smith's rationale for excluding the transmission and distribution PHFFU properties that he identified?

A. Mr. Smith proposes that the specific properties he identified be removed from rate base because they have expected in-service dates of 2027 and 2028, which are beyond the 10-year planning process and, therefore, are not used and useful. Mr. Smith additionally notes that many of the sites have been classified as PHFFU for many years.

Q. What is your general response to the rationale offered by OPC witness Smith for his recommendation to exclude these specific properties from PHFFU?

A. Mr. Smith's rationale fails to take into account the realities of electric system planning and the importance of obtaining and holding property for future T&D needs to meet future growth and/or improve reliability. These properties

have been identified as being geographically and strategically located and necessary to meet future customer load growth, improve customer reliability, comply with NERC standards regulating the reliability of the grid and/or integrate future generation into the grid.

The annual planning study's ten-year horizon is not an appropriate cut-off for purposes of determining what property to acquire or when to acquire. The ten year horizon simply provides FPL with a view on what may be required in terms of design, new builds, or other considerations during that time frame. If FPL were to wait to acquire property for future transmission needs when we had a definitive in-service date for new transmission or for a specific need to manifest itself in the ten-year planning cycle, often we would be left with limited or perhaps no suitable choices, and/or face potentially higher costs (e.g., less preferred and more contested corridors, and/or paying higher prices to sellers who are aware of the time pressure we face to acquire the necessary properties).

As presented in witness Deason's rebuttal testimony, the Commission has not applied an arbitrary ten-year standard for purposes of PHFFU. Such a cut-off simply does not work in the real world of electric system planning in order to ensure we are able to meet the needs of the system and ensure we are able to move an adequate and reliable supply of power across the system to meet an ever evolving set of electrical grid conditions and needs.

Q. Please describe some of the considerations that FPL must take into account in acquiring and holding transmission PHFFU.

A. First, new T&D substations and transmission lines can take years to plan, design and construct. This includes securing necessary sites and properties. The process to initiate construction can be lengthy and typically involves rezoning from local entities and permitting from local, state and federal agencies. Additionally, the annual planning process is very dynamic and, by virtue of its close linkage to the load growth forecast, can and often does result in modifications each year to system expansion plans. This includes revising in-service dates for PHFFU sites. While certain projects with a 2027 or 2028 in-service date fall just outside ten years of the 2017 test year or 2018 subsequent year in this case, this is not the appropriate test for determining whether it is appropriately included in PHFFU. The test should be whether the facility is needed or likely to be needed. Sometimes it could also be as simple as applying common sense given certain key factors like location, population density, anticipated growth, relative availability of alternate corridors, and proximity or contiguity to other substations and transmission lines.

While each of the PHFFU properties Mr. Smith has identified is currently outside the 10-year planning cycle, FPL believes these properties are still necessary to meet future needs. Therefore, these properties should remain in PHFFU.

Q. Please explain why each of the properties identified by OPC witness Smith for removal from PHFFU should remain in the 2017 and 2018 PHFFU balances.

A. The following summarizes why each of the properties, identified in FPL's planning, study should remain in PHFFU:

Transmission

Galloway-South Miami Loop to Southwest Sub ($1.8 Million): Land rights for this right-of-way are required to provide service to the proposed Southwest distribution substation and relieve two existing substations serving the area, which are projected to have summer loads exceeding their capacity.

Harbor-Punta Gorda #2 – Easements ($0.7 million): These transmission line property easements are for construction of an additional transmission line in Charlotte County to allow for dual, continuous feeds to several existing distribution substations. FPL acquired the property rights to accommodate the remaining three mile section of 138kV overhead transmission between Harbor and Punta Gorda substations, of which approximately one mile has been constructed. In addition to the completed one mile section between Harbor and Punta Gorda, a significant portion of the overall Charlotte-Harbor 138kV #2 project south of Punta Gorda has already been completed. The project will be completed to improve reliability by providing continuous looped service to three existing distribution substations serving customer load.

Rima Sub and Rima-Volusia 230kV R/W Line ($0.6 million): The Rima Substation property and associated transmission right-of-way was acquired for

construction of a 500/230kV transmission substation west of Daytona Beach. The property is strategically located adjacent to and underneath a current 500kV transmission corridor. The Rima-Volusia right-of-way is planned to accommodate up to six 230kV lines to tie the new substation into our 230kV grid in eastern Volusia County. This project's strategic location positions FPL well for load growth response, and it will be completed when load growth materializes in the area.

Turkey Point-Levee (Levee-South Dade) ($1.4 million): This right-of-way is required for new transmission lines to integrate additional generation at the Turkey Point site into our 500kV transmission backbone, along the southeast coast of peninsular Florida. FPL currently plans to build two 500kV lines and one 230kV line in the right-of-way.

Distribution

Ariel Substation ($0.8 million) – This property is geographically and strategically located along US 1, south of New Smyrna Beach, to support initiatives to improve reliability for high exposure distribution feeders at the closest substation which is near capacity. The projected in-service date for this substation is December 2028.

Chester Substation ($0.4 million) – This property is geographically and strategically located north of Jacksonville, near the north end of FPL's service territory, to support initiatives to improve reliability for high exposure distribution feeders. The projected in-service date for this substation is December 2028.

Deerwood Substation – ($0.8 million) – This property is geographically and strategically located near St. Augustine and is expected to be utilized for reliability purposes and/or future load growth. The projected in-service date for this substation is December 2028.

Ely Substation Expansion ($0.6 million) – This parcel is adjacent to existing FPL property and will be needed to support the proposed 269 acre downtown Pompano redevelopment, new railroad transit hub and beach redevelopment. The projected in-service date for this property is December 2028.

Hargrove Substation ($0.9 million) - This property is geographically and strategically located just west of Palm Coast and is expected to be utilized for reliability purposes and/or future load growth. The projected in-service date for this substation is December 2028.

Minton Substation (formerly Henry) ($1.0 million) – This property is geographically and strategically located adjacent to transmission in Melbourne to support initiatives to improve reliability for high exposure distribution feeders. The projected in-service date for this substation is December 2028.

Pacetti ($0.2 million) - This property is geographically and strategically located north of St. Augustine and is expected to be utilized for reliability purposes and/or future load growth for stations nearing capacity. The projected in-service date for this substation is December 2028.

Sartori ($0.1 million) – This property is geographically and strategically located west of Palm Bay to support initiatives to improve reliability for high

exposure distribution feeders. The projected in-service date for this substation is December 2028.

Speedway Substation (formerly Pelican) ($0.5 million) - This property is geographically and strategically located just south of the Daytona Speedway racetrack and is expected to be utilized for reliability purposes and/or future load growth. The projected in-service date for this substation is December 2028.

Timucan Substation ($1.7 million) - This property is geographically and strategically located in Bradenton to support load growth and initiatives to improve reliability for high exposure distribution feeders at stations which are reaching capacity. The projected in-service date for this substation is December 2028.

Township – ($0.01 million) - This property is geographically and strategically located adjacent to transmission southeast of Palm Bay near US1 to support initiatives to improve reliability for high exposure distribution feeders. The projected in-service date for this substation is December 2028.

Pennsucco Expansion ($1.6 million) – This parcel is needed for expansion to accommodate a new 230kV line associated with the Turkey Point 6 and 7 project. The expected in-service date for this property is June 2027.

Vermont Substation ($0.7 million) – This property is geographically and strategically located west of St. Augustine and is expected to be utilized for reliability purposes and/or future load growth. The projected in-service date for this substation is December 2028.

Challenger (formerly Harrison St.) ($0.3 million) - This property is geographically and strategically located in Titusville to support initiatives to improve reliability for high exposure distribution feeders at a nearby station reaching capacity. The projected in-service date for this substation is December 2028.

Southwest Substation ($0.6 million) – Property currently is supporting a storage unit pilot that is already in service. Property is also being considered as part of a land swap with local railroad company. The projected in-service date for this substation is December 2028.

Q. Please summarize your thoughts concerning witness Smith's recommendations to reduce FPL's 2017 and 2018 T&D PHFFU costs.

A. The combined effects of increasing population growth and residential and commercial development, ensuring and maintaining reliability and more restrictive environmental regulations are some examples of factors that will make it more difficult for FPL to find and acquire alternative properties to build necessary future substations and transmission lines. If sold, these properties could be very difficult to replace and would likely result in increased total project costs. The purchase of the above listed rights-of-way, easements, and land plots are prudent acquisitions due to their strategic locations for development and/or reliability. FPL's T&D planners evaluate the usefulness of the T&D PHFFU properties as they are reviewing plans for upcoming projects. Adjustments to expected in-service dates for T&D PHFFU properties are made, as needed, according to the outcome of these evaluations.

Establishing a 10-year threshold for eliminating PHFFU properties and associated costs is not appropriate and should be rejected. For the reasons previously stated, FPL's T&D PHFFU properties with 2027 and 2028 in-service dates are appropriate and should be approved by the Commission.

V. MITIGATING INCREASES IN REMOVAL COSTS

Q. In his testimony, OPC witness Pous includes a reference to the Commission's 2010 order regarding FPL's 2009 depreciation study, where the Commission suggested that FPL investigate possibilities for internal changes to mitigate increasing removal costs. Has FPL taken steps to mitigate those costs since that 2010 order?

A. Yes. FPL continuously seeks opportunities to increase efficiencies and reduce costs. Initiatives that FPL has implemented that help to mitigate the trend of increasing removal costs include:

(1) Controlling contractor labor costs by utilizing the competitive bidding process to focus on achieving the lowest overall project cost;

(2) Controlling labor and equipment costs by better coordinating multiple work activities that include removal of facilities (e.g., hardening and pole inspections) and "batching" related removal work located in close proximity in order to achieve more efficient use of labor and equipment;

(3) Improving coordination and scheduling with attaching entities to better identify poles that are ready to be removed once all attached facilities are

removed; once identified, they can then be included in the process explained in (2) above; and

(4) Training/qualifying personnel with sufficient skills required to remove facilities (e.g., bare poles), who then can be used in place of more qualified and higher priced skilled labor.

In summary, while there are certain factors that have placed upward cost pressure on removal costs (e.g., increasing contractor labor costs, traffic control costs and other work requirements), FPL has aggressively acted to mitigate these cost increases.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Florida Power & Light Company
Docket No. 160021-EI
OPC's First Set of Interrogatories
Interrogatory No. 13
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QUESTION:

Pole Inspections. Provide for each year 2011 through 2015 and 2016 to date the amounts budgeted and expended for pole inspections and the amounts included in the projected test year December 31, 2017, and the subsequent base rate adjustments for years 2018 and 2019. If the cost for inspections is charged to anything other than O&M, provide a breakdown of the annual cost in O&M, capitalized, charged to storms and other.

RESPONSE:

Distribution Pole Inspections ($Millions)

	Budget			Actual		
	O&M	Capital	Total	O&M	Capital	Total
2011	$15.3	$51.5	$66.8	$17.7	$53.2	$70.9
2012	$15.0	$54.0	$69.0	$14.8	$52.7	$67.5
2013	$14.9	$53.9	$68.8	$14.2	$55.5	$69.7
2014	$12.6	$56.9	$69.5	$ 3.9	$66.2	$70.1
2015	$ 6.3	$49.5	$55.8	$ 6.0	$67.1	$73.1
YTD Mar 2016	$ 1.6	$10.4	$12.0	$ 1.4	$15.7	$17.1
2017	$ 5.8	$41.7	$47.5	N/A	N/A	N/A
2018	$ 5.9	$43.9	$49.8	N/A	N/A	N/A

N/A – Not available

Note: Information for 2019 has not been finalized. Additionally, the increase associated with FPL's 2019 limited scope base rate adjustment is limited to the additional costs associated with FPL's Okeechobee Clean Energy Center's first 12 months of operation.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF ROSEMARY MORLEY

DOCKET NO. 160021-EI

AUGUST 1, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Rosemary Morley, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Have you previously submitted direct testimony in this case?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- Exhibit RM-5 Weather-normalized Retail Delivered Sales per Customer
- Exhibit RM-6 Summary of FPL's Historical and Forecasted Sales
- Exhibit RM-7 Annual Percent Change in Weather-normalized Use-Per-Customer
- Exhibit RM-8 Weather-normalized Load Factors
- Exhibit RM-9 Comparison of FPL's Proposed Load Forecast and Those Utilized in the Okeechobee Need Determination Case
- Exhibit RM-10 Summary of Incorrect, Incomplete or Misleading Statements in OPC Witness Dismukes' Testimony

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to OPC witness Dismukes' proposed load forecast in this case. In the process, I also correct inaccurate as well as incomplete or misleading statements about FPL's load forecast made

by OPC witness Dismukes. I also address AARP witness Brosch's suggestion that FPL has an incentive to understate future sales growth. Finally, I also rebut OPC witness Dismukes' proposed inflation forecast.

II. LOAD FORECAST OVERVIEW

Q. Please summarize OPC witness Dismukes' proposal regarding the load forecast that should be used in this case.

A. OPC witness Dismukes states that for the purpose of ratemaking the Commission should revert back to the energy sales forecast filed by FPL in its 2015 Ten Year Site Plan in April 2015. Throughout the remainder of my testimony I refer to FPL's 2015 Ten Year Site Plan sales forecast as "OPC's proposed 2016 rate case sales forecast" because it is OPC's stated position that this earlier forecast be used in this case.

Q. Please summarize your concerns with OPC's proposed 2016 rate case sales forecast.

A. Rather than challenge the specific methodology, input data, assumptions or out-of-model adjustments incorporated into FPL's proposed sales forecast, OPC rejects the superior forecast in this case, FPL's proposed sales forecast, for the thinly-veiled purpose of raising the forecasted level of sales. The data demonstrates unambiguously that FPL's proposed sales forecast is clearly the superior choice for setting rates in this case.

Q. Is OPC's proposed 2016 rate case sales forecast providing a more accurate projection of net energy for load?

A. Not at all. Based on actuals through June 2016, OPC's proposed 2016 rate case sales forecast is over-forecasting weather-normalized net energy for load (NEL) by 2.5%. By contrast, FPL's proposed sales forecast, including the adjustment to the sales forecast acknowledged in FPL's May 3, 2016 Notice of Identified Adjustments, is over-forecasting weather-normalized NEL on a year-to-date basis through June 2016 by only 0.5%. In other words, FPL's proposed sales forecast is much closer to weather-normalized 2016 *actual* sales; indeed, the forecast error in OPC's proposed 2016 rate case sales forecast is five times larger.

Q. Is OPC's proposed 2016 rate case sales forecast providing a more accurate projection of retail delivered sales relative to FPL's proposed sales forecast?

A. Again the answer is no. Based on actuals through June 2016, OPC's proposed 2016 rate case sales forecast is over-forecasting weather-normalized retail delivered sales by 2.1%. By contrast, FPL's proposed sales forecast, including the adjustment noted in FPL's May 3, 2016 Notice of Identified Adjustments, has a minimal over-forecasting weather-normalized forecasting variance of 0.01%.

Q. Please describe the adjustments to the sales forecast noted in FPL's May 3, 2016 Notice of Identified Adjustment.

A. A correction to the price of electricity forecast used as input into the sales forecast was listed as item number 4 in the May 3, 2016 Notice of Identified Adjustments. This correction eliminates the overstatement of fuel expenses assumed in the prior price of electricity forecast. The adjustment to FPL's proposed sales forecast incorporating this correction results in an increase in retail delivered sales in 2017 of less than 0.1% and an increase in 2018 of less than 0.2%. Exhibits RM-5 and RM-6 to my rebuttal testimony are updated versions of Exhibits RM-2 and RM-3 included in my direct testimony, which were affected by this adjustment. The May 3, 2016 Notice of Identified Adjustments also noted that FPL's proposed peak demand forecast should be adjusted for the impact of incremental demand-side management. No other adjustments to FPL's proposed sales or peak forecast have been identified.

Q. Has FPL developed a chart comparing the weather-normalized variances for OPC's proposed 2016 rate case sales forecast versus FPL's proposed sales forecast?

A. Yes. Figures 1 and 2 below show the stark differences between the forecasting accuracy of FPL's proposed sales forecast versus OPC's proposed 2016 rate case sales forecast. Following FPL's standard reporting practice, an over-forecasting variance is shown on these charts as a negative value while an under-forecasting variance would be shown as a positive value.

Figure 1

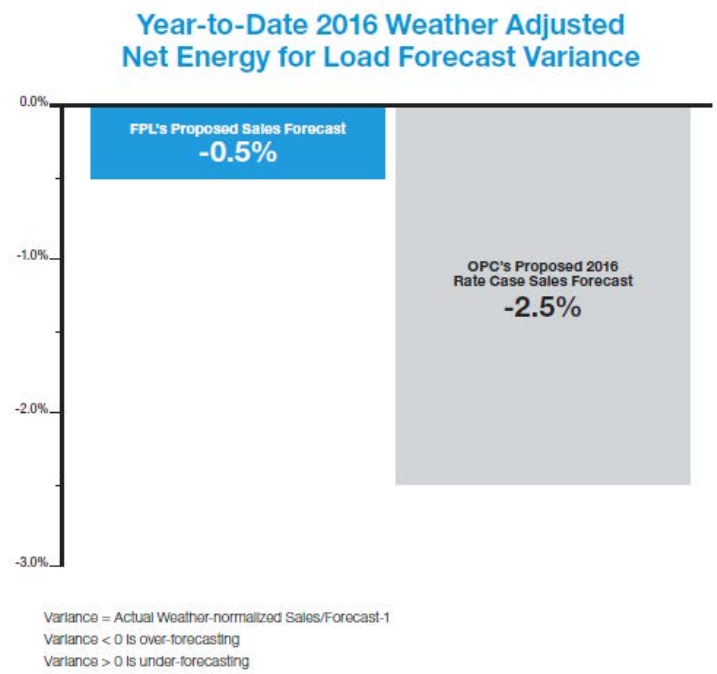
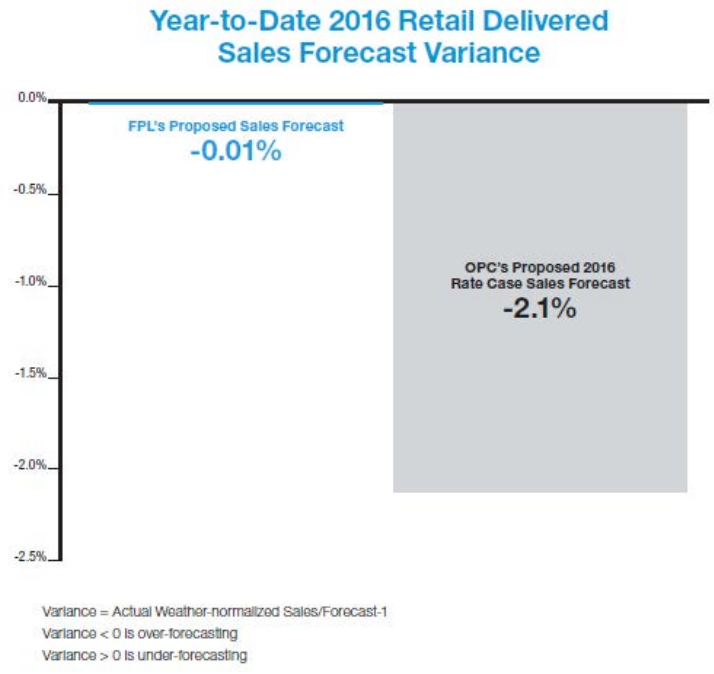


Figure 2



Q. What does the size of its weather-normalized variance to date suggest about OPC's proposed 2016 rate case sales forecast?

A. It suggests that OPC's proposed 2016 rate case sales forecast is both inferior to FPL's proposed sales forecast and unrealistically high. OPC's proposed 2016 rate case sales forecast is already over-forecasting weather-normalized 2016 NEL by over 1,424 GWh and retail delivered sales by approximately 1,084 GWh based on year-to-date data through June. Given such large variances, the level of 2016 sales in OPC's proposed sales forecast is unachievable barring a record-setting increase in sales during the July through December 2016 time frame.

Q. Please explain.

A. OPC's proposed 2016 rate case sales forecast shows that retail delivered sales should reach 109,487 GWh in 2016. Given actual weather-normalized retail delivered sales through June, this level of sales could be achieved only if weather-normalized retail delivered sales from July through December 2016 grew at a year-over-year rate of 4.5%. To put this figure into perspective, a 4.5% annual growth rate would be the highest increase in weather-normalized retail sales in more than twenty years. Given that FPL's weather-normalized retail delivered sales grew by only 0.8% in 2015 and hasn't reached close to a 4% annual growth rate in decades, such an extreme jump in sales in the second half of 2016 is exceedingly far-fetched. That is neither a sound assumption nor a reasonable basis upon which to adopt a forecast in this case.

Q. Why is OPC's proposed 2016 rate case sales forecast over-forecasting sales by such a substantial margin?

A. As explained in various discovery responses, including FPL's answer to Staff's Interrogatory No. 70, the 2015 Ten Year Site Plan sales forecast which is OPC's proposed 2016 rate case sales forecast, began over-forecasting sales in 2015. The net energy for load per customer forecasting model used in the 2015 Ten Year Site Plan forecast included a term for the CPI for energy, and it assumed that net energy for load per customer would increase as the CPI for energy decreased. However, the linkage between the CPI for energy and monthly electricity consumption weakened in 2015 and as a result, the increases in usage assumed in the 2015 Ten Year Site Plan forecast did not materialize. Instead, the 2015 Ten Year Site Plan over-forecasted weather-normalized 2015 NEL by 1.4%, FPL's largest year-ahead forecasting variance in seven years.

Q. Did this cause FPL to reevaluate its sales forecasting model?

Yes. FPL continuously reassesses its forecasting models for potential improvements, and it was particularly appropriate to do so in view of the comparatively large variances that resulted from the 2015 Ten Year Site Plan forecast.

Q. Did you implement any changes to FPL's forecasting model?

Yes. The role of energy prices in the net energy for load per customer model was reexamined. In place of the CPI for energy, two variables for the price of electricity are now used in the net energy for load per customer model relied

on in FPL's proposed sales forecast in this proceeding. These changes resulted in an improved sales forecasting model as evidenced by the lower weather-normalized forecasting variances. Yet OPC proposes in this proceeding to disregard these improvements and instead revert back to the earlier 2015 Ten Year Site Plan forecast.

Q. You noted over-forecasting variances in OPC's proposed 2016 rate case sales forecast for both 2015 and on a year-to-date basis in 2016. Is this pattern significant?

A. Yes. As noted above, OPC's proposed 2016 rate case sales forecast over-forecasted the actual level of 2015 weather-normalized NEL by 1.4%. As of June 2016, this over-forecasting weather-normalized variance has grown to 2.5%. This indicates a compounding effect in which past variances build on one another suggesting even larger variances in the future.

Q. Does OPC witness Dismukes have a history of proposing inflated sales forecasts during FPL's rate proceedings?

A. Yes. In Docket Nos. 050045-EI and 050188-EI, OPC witness Dismukes proposed a NEL forecast of 116,600 GWh for the 2006 test year, a 1% increase from FPL's proposed forecast of 115,463 GWh for that test year. OPC witness Dismukes' proposal over-forecasted weather-normalized 2006 NEL by 1.9% while FPL's proposed forecast had a much lower variance. FPL's proposed forecast in that case over-forecasted 2006 weather-normalized NEL by 0.9%. In other words, OPC witness Dismukes' forecasting variance was more than twice that of FPL's.

Q. Does FPL plan on continuing to track the accuracy of both FPL's proposed sales forecast in this case and OPC's proposed 2016 rate case sales forecast?

A. Yes. FPL will continue to monitor the accuracy of both FPL's proposed sales forecast and OPC's proposed 2016 rate case sales forecast. FPL plans on reporting back to the Commission on the accuracy of both forecasts in its next rate proceeding.

Q. Do the weather-normalized variances cited above support AARP witness Brosch's claim that FPL has an incentive to under-forecast sales?

A. No. As shown in Figure 1 FPL's proposed forecast is over-forecasting the actual level of 2016 weather-normalized NEL by 0.5%. Likewise, as shown in Figure 2 FPL's proposed forecast of retail delivered sales has a minimal over-forecasting variance. In addition, as discussed on page 11 of my direct testimony, FPL sales forecast for the 2013 test year in the last rate case, was highly accurate, over-forecasting weather-normalized sales for that year by only 0.35%. A pattern of highly accurate forecasted sales factually belies witness Brosch's contention that FPL has an incentive to under-forecast sales.

Q. Can you put FPL's weather-normalized forecasting variance from its 2012 rate case into perspective?

A. Yes. FPL's most recent 0.35% rate case variance would be equivalent to forecasting a residential customer's average monthly usage of 1,110 kWh to within less than 4 kWh. To put this variance into perspective, 4 kWh is

roughly equivalent to using a couple of efficient compact fluorescent bulbs a few hours nightly or daily use of a toaster.

III. SPECIFIC ARGUMENTS BY OPC WITNESS DISMUKES

Q. Given that OPC's proposed 2016 rate case sales forecast clearly is not performing as well as FPL's proposed sales forecast in this proceeding, does OPC witness Dismukes offer any reasons why the Commission should approve OPC's proposed 2016 rate case sales forecast in this proceeding?

A. Witness Dismukes' purported arguments in support of OPC's proposed 2016 rate case sales forecast generally fall into three categories. First, OPC witness Dismukes argues that FPL's proposed sales forecast projects a decline in sales and, therefore, it must be wrong. Second, he argues that because FPL's proposed sales forecast and proposed summer peak forecast are not consistently moving in unison, the former (again) must be wrong. Third, OPC witness Dismukes argues that because FPL's proposed sales forecast includes an adjustment to reconcile the sum of the individual revenue class forecasts with the sales derived from the NEL forecast, the forecast must be wrong. None of these arguments have merit. In each argument, OPC witness Dismukes dismisses FPL's proposed sales forecast because it differs from a clearly inferior alternative, as I will demonstrate below.

Q. At what points in his testimony does OPC witness Dismukes argue that FPL's proposed sales forecast in this case must be wrong because it projects a contraction in sales?

A. On page 9, OPC witness Dismukes states the following in describing his comparison of ***historical weather-normalized sales*** [emphasis added] with FPL's proposed sales forecast:

> The Company, for instance, projects that its retail delivered sales for its 2017 test year will be 0.16 percent less than what was reported in 2016, and 0.55 percent less than sales reported for 2015. Furthermore, the Company projects that its 2018 retail delivered sales will only be 0.58 percent greater than its 2017 projection (which itself is anticipated to fall relative to 2016). The projected decline in energy sales is even more prevalent when the forecast for wholesale sales are included (page 2 of Exhibit DED-1), wherein the Company projects that it will not reach its 2015 level of delivered sales until 2019, well after the end of its projected test year, and subsequent adjustment, in this proceeding. In other words, the Company is anticipating a contraction (decrease) of overall sales relative to reported 2015 numbers, and that its overall sales numbers will not recover until 2019.

Q. Does OPC witness Dismukes accurately compare FPL's proposed sales forecast with historic weather-normalized sales?

A. No. OPC witness Dismukes states that FPL's proposed retail delivered sales forecast in 2017 is "0.55 percent less than reported in 2015." However, as shown in Exhibit RM-6, the forecasted level of retail delivered sales in 2017 is ***higher*** than the 2015 weather-normalized actual. In fact, the level of 2017 sales is 1.6% higher than the weather-normalized 2015 actuals. Contrary to OPC witness Dismukes' testimony, the level of retail delivered sales in every year from 2016 through 2020 is consistently ***higher*** than 2015 weather-normalized actual retail delivered sales.

Q. If it is not a comparison of FPL's proposed sales forecast with historic weather-normalized sales, what is OPC witness Dismukes comparing in this section of his testimony?

A. OPC witness Dismukes compares non-weather-normalized actuals with FPL's proposed forecast, and he fails to incorporate Item No. 4 in FPL's May 3 Notice of Identified Adjustments. As I noted on page 11 of my direct testimony, actual weather-normalized sales are a better reflection of usage trends than are the unadjusted level of actual sales, which may be influenced by erratic and unpredicted weather fluctuations. The potentially erratic nature of non-weather normalized actuals is evident in OPC witness Dismukes' own exhibits. As shown in Exhibit DED-1, non-weather normalized retail delivered sales declined in two of five of the historical years where a directional change is shown, i.e., non-weather normalized retail delivered

sales declined in 2011 and 2012 and increased in 2013, 2014 and 2015. Exhibit DED-2 likewise shows declines in non-weather-normalized NEL in two out of five of the historical years shown.

Q. Are declines in the actual non-weather-normalized values for NEL and retail delivered sales an unusual event?

A. Not at all. A decline in the non-weather-normalized values of NEL and retail delivered sales has occurred on multiple occasions over the last several years. FPL's non-weather-normalized NEL declined in 2004, 2008 and 2011. FPL's non-weather-normalized retail delivered sales likewise declined in 2004, 2008, 2011, and again in 2012. Such declines in non-weather-normalized sales have typically occurred following years with an unusually large positive weather impact as occurred in 2003 and 2010.

Q. Were the weather impacts experienced in 2015 also unusually large?

A. Yes. Even OPC witness Dismukes acknowledges this on page 13 lines 8-10 of his testimony. Given that sales in 2015 were also subject to an unusually large weather impact, a decline from the non-weather-normalized level of 2015 sales is to be expected and is entirely consistent with historical trends. In fact, it can take years before the level of sales surpasses a single year with an unusually large weather impact. For example, five years elapsed before the level of non-weather-normalized retail delivered sales surpassed the level reached in 2010 and eight years elapsed before the level of non-weather-normalized retail delivered sales surpassed the level reached in 2007.

Q. In summary, are past levels of non-weather-normalized sales appropriate for assessing the reasonableness of a sales forecast?

A. No. The past levels of unadjusted non-weather-normalized sales simply are not good yardsticks for future sales.

Q. Has another intervenor in this case previously argued that FPL's sales forecast must be wrong because it projected a decline in sales relative to non-weather normalized historical sales?

A. Yes. In FPL's previous rate case, Docket No. 120015-EI, the attorney for the Florida Retail Federation asserted in customer service hearings that FPL's proposed sales forecast was "unrealistic" because FPL was "actually projecting that they're going to sell less electricity in 2013 than they did in 2011." (Sarasota Service Hearing transcript page 26, lines 10-11.) Just as OPC witness Dismukes has done in this case, the Florida Retail Federation in the prior case made the erroneous assumption that the past levels of non-weather normalized sales establish the lower limit on the level of future sales. More specifically, the Florida Retail Federation in the prior case took issue with FPL's "unrealistic" assumption that retail sales in 2013 could fall below the non-weather normalized level reached in 2011. Such claims to the contrary, the actual level of retail delivered sales in 2013 was 0.5% lower than the actual level in 2011 when non-weather normalized values are used for both years. In fact, the data OPC witness Dismukes provides in his Exhibit DED-1 shows the lower level of non-weather normalized retail delivered sales in 2013 versus 2011.

Q. OPC witness Dismukes also takes issue with the minimal decline in forecasted retail delivered sales between 2016 and 2017. Do you agree that this minimal decline indicates an inherent problem in FPL's proposed forecast?

A. No. A minimal decline of less than 0.09% in FPL's retail delivered sales is projected between 2016 and 2017 based on FPL's proposed sales forecast as shown in Exhibit RM-6. The absence in 2017 of the additional day of electricity consumption present in 2016 as a result of leap year, in itself results in a 0.2% decline in forecasted retail sales. In other words, if 2016 and 2017 had an equal number of calendar days, there would be no decline in retail delivered sales forecasted for 2017. As explained in discovery responses including FPL's responses to Staff Interrogatory No. 162 and AARP Interrogatory No. 61, the minimal decline in sales is further explained by a number of factors including moderating economic growth, electric prices that reflect the conclusion of the 2016 fuel true-up, and the continued impact from energy efficiency codes and standards and incremental demand-side management.

Q. At what points in his testimony does OPC witness Dismukes argue that FPL's proposed sales forecast in this case must be wrong because FPL's proposed sales forecast and proposed summer peak forecast are not consistently moving in unison?

A. On page 10, line 21 OPC witness Dismukes states that "there appears to be a serious disconnect between the Company's peak demand, customer, and sales

forecasts." OPC witness Dismukes then devotes a number of pages to a discussion on load factor. Load factor represents the relationship between sales and peak demands. OPC witness Dismukes' testimony argues that a decreasing load factor suggests something inherently wrong in the forecast and that the forecasted load factor should be stable if not increasing. Ultimately, OPC witness Dismukes concludes that either FPL's sales forecast or its summer peak demand forecast must be wrong and that the "weight of the evidence" suggests that FPL's sales forecast is in error.

Q. Is there any reason to believe that load factors should remain fixed over time as OPC witness Dismukes suggests?

A. No. Load factor is driven by two different variables: summer peak demands and NEL. Summer peak demands represent the highest demand in any hour of the summer season and typically the highest demand in any hour of the year. Not surprisingly, the summer peak demand usually occurs on or near the hottest day of the year. By contrast, NEL represents aggregate usage across all hours and all seasons of the year. If NEL increases faster than summer peak demand, then load factor tends to increase. Conversely, if summer peak demands increase faster than NEL then load factor tends to decline. Because summer peak demands and NEL differ fundamentally in the type of usage they are measuring there is no reason that load factors should remain constant.

Q. Are OPC witness Dismukes' projections of NEL based on the assumption of a constant load factor over time reasonable?

A. No. OPC witness Dismukes' projections based on the assumption of a constant load factor over time would imply a truly unbelievable increase in sales. In Exhibit DED-7 OPC witness Dismukes projects that NEL in 2016 should reach 124,993 GWh based on a constant five year average load factor. Given the actual level of weather-normalized NEL through June 2016, OPC witness Dismukes' projection for 2016 is only achievable if weather-normalized NEL increases at a year-over-year rate of 9.6% in the second half of the year, almost five times the rate experienced in the first half of the year and twice as fast as the highest annual growth since the early 1990s.

Q. Does the evidence in this case support an "either or" conclusion as argued by OPC witness Dismukes, namely that either FPL's proposed sales forecast or its proposed summer peak demand forecast must be wrong?

A. No. As previously demonstrated, the weather-normalized variances clearly show that FPL's proposed sales forecast is superior to OPC's proposed 2016 rate case sales forecast. In addition, the evidence presented in this case also supports FPL's proposed summer peak demand forecast.

Q. Please explain how the evidence in this case supports FPL's proposed summer peak demand forecast.

A. As FPL described in its response to Staff's interrogatory No. 73, FPL has had an excellent record forecasting weather-normalized summer peak demands in recent years. More specifically, the 2015 Ten Year Site Plan forecast

projected the actual level of the 2015 weather-normalized summer peak within 0.5%. This suggests that the basic methodology used to forecast summer peak demands in the 2015 Ten Year Site Plan remains solid. This basic methodology includes using variables for real household disposable income, energy efficiency codes & standards and a proxy for energy prices as the primary drivers of summer peak demands, along with appropriate out-of-model adjustments. These same drivers and adjustments are incorporated into the summer peak demand forecast in the case herein.

Q. Historically have FPL's summer peak demands and NEL consistently moved in unison as OPC witness Dismukes suggests?

A. No. To examine this issue, Exhibit RM-7 compares the trends in the summer peak versus NEL on a weather-normalized per customer basis. As shown in Exhibit RM-7, the magnitude and even direction of changes in FPL's weather-normalized net energy for load per customer has differed from that of weather-normalized summer peak per customer on multiple occasions. FPL's weather-normalized summer peak per customer has at times increased while FPL's weather-normalized net energy for load per customer has decreased as was the case in 2009 and 2005. At other times, FPL's weather-normalized summer peak per customer has increased by more than double the increase in weather-normalized NEL as was true in 2014. Thus, based on history there should be no expectation that FPL's weather-normalized NEL and summer peak per customer always move in the same direction or with a similar magnitude.

Q. Has FPL's summer peak historically grown at a faster rate than its NEL?

A. Yes. On a weather-normalized per customer basis, the summer peak has increased at an annual rate of 0.3% based on the 2008 to 2015 time period cited by OPC witness Dismukes. Over the same period, weather-normalized net energy for load per customer declined by 0.1%.

Q. What has been the long-term trend in FPL's load factor?

A. Exhibit RM-8 shows FPL's weather-normalized load factors over time. The data show that while there have been year-to-year fluctuations, the general trend has been one of a decline in load factors.

Q. Is the forecasted growth in summer peak demands expected to continue to exceed that of NEL in FPL's proposed forecast?

A. Yes. In the short-term, the forecasted growth in summer peak demands is expected to surpass that of NEL before they converge to a similar percentage growth in 2020.

Q. Why is the forecasted growth in summer peak demands expected to continue to exceed that of NEL in FPL's proposed forecast?

A. Certain customer-initiated conservation measures, such as those associated with lighting end-uses, will likely have a larger impact on NEL than they do on summer peak demands. This is a particularly important factor for the next few years when the growth of highly efficient LEDs is expected to accelerate. In addition, FPL's forecasting models show that economic growth and low energy prices over the next few years are likely to drive larger increases in summer peak demands relative to NEL. For example, FPL's econometric

modeling indicates that summer peak demands are more income-sensitive than is NEL. Consequently, rising income levels are projected to result in proportionately larger increases in summer peak demands relative to NEL.

Q. Does OPC witness Dismukes' testimony offer any credible support for his claim that FPL's projected decline in load factor inherently indicates some problem in FPL's proposed sales forecast?

A. No. OPC witness Dismukes provides multiple tables on load factors, none of which appropriately incorporate weather-normalized historical values for both NEL and summer peak demands. OPC witness Dismukes also offers a table which purports to show that FPL's projected decline in its load factor is inconsistent with the projected load factors of other Florida Investor Owned Utilities ("IOUs"). His Exhibit DED-4 shows the historical and projected load factors reported by FPL, Duke Energy Florida (DEF), Tampa Electric Company (TECO) and Gulf Power in their respective 2016 Ten Year Site Plan filings. Of course, to offer a valid source for drawing any conclusions, the load factors reported in Exhibit DED-4 would need to provide an "apples to apples" comparison between utilities.

Q. Do the load factors for Florida IOUs presented in OPC witness Dismukes' Exhibit DED-4 provide an "apples to apples" comparison between utilities?

A. No. Weather conditions vary across the Florida IOUs making it difficult to draw conclusions from the non-weather-normalized historical load factors shown in Exhibit DED-4. In addition, on a forecasted basis, FPL and Gulf are

the only utilities forecasted to be consistently summer-peaking. Other issues that influence load factor, including the impact of customer mix on sales and peak demands, also vary by utility. Ultimately, each Florida IOU has their own unique set of external circumstances beyond their control making it all but impossible to draw conclusions based on the information provided in Exhibit DED-4.

Q. Is there another reason to doubt the significance of OPC witness Dismukes' Exhibit DED-4?

A. Yes. OPC witness Dismukes fails to take into account that each utility is reporting load factor on a different basis.

- DEF calculates its load factor in historical years based on the actual non-weather-normalized annual peak and NEL experienced. However, DEF calculates its load factor in future years based on forecasted NEL reduced for incremental company-sponsored conservation and on net firm winter peak demand. DEF defines net firm winter peak demand as total peak demand minus any interruptible load, load management, company-sponsored conservative and other demand reductions.
- FPL calculates its historical load factors based on actual non-weather-normalized summer peak experienced and actual NEL experienced. FPL then calculates its forecasted load factors based on forecasted NEL before any reductions for incremental company-sponsored conservation and on forecasted summer peak demands without

reductions for incremental company-sponsored conservation or cumulative load management.

- TECO and Gulf calculate their respective historical load factors based on actual non-weather normalized annual peaks and actual NEL experienced. Both utilities then calculate their respective forecasted load factors based on forecasted NEL reduced for any incremental company-sponsored conservation and on the forecasted annual peak reduced for any company-sponsored conservation.

In summary, not only does each Florida IOU face its own unique set of circumstances that determine its individual load factors, but even the method of calculating load factor varies by Florida IOU.

Q. You noted previously that OPC witness Dismukes argues that FPL's proposed sales forecast in this case must be wrong because the forecast includes an adjustment whereby the sales summed across individual revenue classes are reconciled with the sales derived from the NEL forecast. Can you provide more detail regarding the adjustment at issue?

A. Yes. As discussed in my direct testimony, pages 38-40, preliminary forecasts of billed sales for each revenue class are initially developed using econometric models and customer-specific information. The preliminary residential and commercial sales forecasts are then proportionately adjusted for the difference between the sum of the revenue classes and the overall billed sales derived from the total NEL forecast. The individual revenue classes are reconciled to the total sales forecast derived from the NEL forecast because the net energy

for load per customer econometric model is superior in a number of respects. The net energy for load per customer model encompasses a richer array of variables relative to the individual revenue class models. The net energy for load per customer model includes a variable for the impact of energy efficiency codes and standards, not included in the individual revenue class models. In addition, the NEL forecast includes adjustments for the impact of plug-in electric vehicles and distributed solar generation. The net energy for load per customer model also has the advantage of reflecting monthly weather conditions without the potential distortions created by the billing cycle. Accordingly, the net energy for load per customer model has better statistical diagnostics relative to the revenue class models.

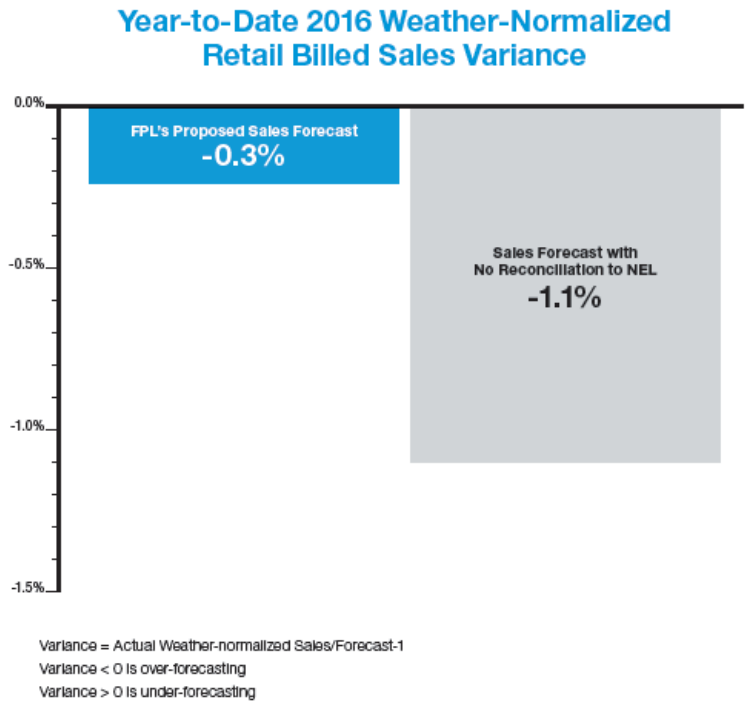
Q. At what point in OPC witness Dismukes' testimony does he argue that FPL's proposed sales forecast in this case must be wrong because the forecast includes an adjustment whereby the sales summed across individual revenue classes are reconciled with the sales derived from the NEL forecast?

A. On page 21 OPC witness Dismukes states that he compared FPL's proposed sales forecast to one based on the sum of the individual revenue classes without the adjustment needed to reconcile sales with the NEL forecast. He then concludes on page 21, line 20, "The comparison shows that the NEL model is significantly underestimating total retail sales by as much a two percent in 2016, three percent in 2017 and more than four percent in 2018."

Q. Do you agree with OPC witness Dismukes' conclusion?

A. Not at all. OPC witness Dismukes is once again rejecting FPL's proposed sales forecast in favor of a clearly inferior alternative. As shown in Figure 3 below, FPL's proposed billed sales forecast has a year-to-date weather-normalized over-forecasting variance of only 0.3%. By contrast, the billed sales forecast without the adjustment to reconcile the sum of the individual revenue classes with the NEL forecast has a year-to-date weather-normalized over forecasting variance of 1.1%, nearly four times the variance of FPL's proposed sales forecast.

Figure 3



III. LOAD FORECAST IN THE OKEECHOBEE NEED DETERMINATION

Q. Are there any additional corrections to OPC witness Dismukes' testimony that need to be made beyond what you've already covered?

A. Yes. In the interest of brevity Exhibit RM-10 enumerates the inaccuracies as well as misleading or incomplete statements in OPC witness Dismukes' testimony. There is one particular inaccuracy in his testimony, however, that merits closer attention.

Q. Please explain.

A. On page 16, lines 5 through 13, OPC witness Dismukes' testimony contains the following question and answer:

> Q. Did the Company Claim the load forecast filed in this rate case was the same as what was filed in the Okeechobee Need Determination?
>
> A. Yes. The Company states that, with the exception of one minor change, its current model is identical to that filed by the Company in its 2015 Okeechobee need determination, and makes allusions to it being essentially the same as the 2015 TYSP.

Q. Did witness OPC Dismukes accurately cite your direct testimony?

A. No. My direct testimony clearly stated that "[i]n filing for the Okeechobee Need Determination the Company relied on the 2015 Ten Year Site Plan load

forecast, which was the Company's official load forecast at the time the filing was made." My direct testimony goes on to say that an updated forecast, the October 2015 load forecast, was used to update an analysis in the Okeechobee Need Determination case, and that "[w]ith the exception of a new price of electricity projection . . . the models and assumptions incorporated into the October 2015 load forecast are identical to those utilized in the load forecast supported in the current proceeding."

Q. Why was the price of electricity projection used in this proceeding revised from what was used in the October 2015 load forecast?

A. Due to the 2016 mid-course fuel clause correction, the decision was made to revisit the price of electricity projections used in the proposed sales forecast in this case.

Q. Please explain in more detail how the October 2015 load forecast, which is identical to FPL's proposed sales forecast in this case with the exception of assumptions on the price of electricity, was used to update the analysis in the Okeechobee Need Determination case.

A. On October 22, 2015, FPL received Staff Interrogatory No. 62 in the Okeechobee Need Determination case requesting that FPL perform a certain analysis regarding the cost-effectiveness of the Okeechobee unit relative to other options using an updated fuel cost forecast. Because FPL also had developed the October 2015 load forecast at that time, the Company included it in the analysis for Staff, as well as other updated cost and resource plan assumptions. FPL's response to Staff Interrogatory No. 62 clearly indicated

that a new load forecast, the October 2015 load forecast, was used in the analysis. Subsequently, FPL provided an updated version of an exhibit to FPL witness Sim's direct testimony reflecting the October 2015 load forecast and other updated assumptions upon a request from Commission Staff.

Q. Did the new October 2015 load forecast include updated forecasts for customers, peak demands and NEL?

A. Yes.

Q. Did the new October 2015 load forecast, particularly, the new NEL forecast, have any impact on the refreshed cost-effectiveness analysis provided in the Okeechobee Need Determination case?

A. Yes. The NEL forecast, along with other factors, is important in determining the fuel savings likely to result from a new generation resource, such as the Okeechobee unit.

Q. How did the NEL forecast in the October 2015 load forecast compare with that in the 2015 Ten Year Site Plan forecast and with FPL's proposed forecast in this case?

A. As shown in Exhibit RM-9, the NEL forecast in the October 2015 load forecast was consistently lower than the 2015 Ten Year Site Plan forecast. The differences between the October 2015 and the proposed sales forecast in this case are, comparatively speaking, quite small.

Q. Was this updated cost-effectiveness analysis using the October 2015 load forecast and other updated assumptions discussed in the final order approving the Okeechobee Need Determination?

A. Yes. Page 23 of the order states: "In response to a discovery request, provided on November 10, 2015, FPL provided updated analyses of OCEC Unit 1 and other self-build options. FPL's updated analyses incorporated updated load and fuel cost forecasts and its most current planning assumptions, such as a delayed in-service date for Turkey Point Units 6 and 7." The order goes on to say that this updated analysis confirmed that the Okeechobee unit remained the most cost-effective resource option.

Q. Please summarize the evolution of FPL's load forecasting methodology from the 2015 Ten Year Site Plan to its proposed sales forecast in this proceeding.

A. Fundamentally, FPL has always relied on the same method to forecast sales, namely using econometric models incorporating the drivers of electricity demand. However, from time to time, the drivers incorporated into these models need to be revisited. Such was the case with the 2015 Ten Year Site Plan sales forecast. In response to over-forecasting variances in the 2015 Ten Year Site Plan forecast, FPL reassessed the drivers incorporated into the net energy for load per customer model. As a result, in late 2015, FPL developed a new model which incorporated two variables for the price of electricity. The October 2015 sales forecast incorporated this new model. The proposed sales forecast in this case is also based on this new model. The evidence shown in

Figures 1 and 2 of my rebuttal testimony clearly demonstrates that the new model used in this case is an improvement over the 2015 Ten Year Site Plan forecast.

V. INFLATION FORECAST

Q. According to OPC witness Dismukes how is FPL's forecast of inflation utilized in this case?

A. OPC witness Dismukes recognizes that FPL's inflation forecast is utilized along with customer growth in the development of the operations and maintenance benchmark which is reported in a number of MFRs. He further states on page 25 of his testimony the following:

> "Second, the Company utilizes its inflation estimate to adjust the costs associated with several other goods and services identified in its internal budget process."

OPC witness Dismukes then cites my direct testimony as the source for this statement.

Q. Is that an accurate representation of your testimony?

A. No. Page 48 of my direct testimony simply states that "FPL utilizes a forecast of the CPI for all goods and services (or overall CPI) as part of the budgeting process."

Q. Is the forecast of the CPI for all goods and services (or overall CPI) discussed in your direct testimony the same forecast that OPC witness Dismukes refers to as the CPI-U forecast?

A. Yes.

Q. How does FPL utilize its forecast of CPI-U in the budgeting process?

A. My understanding from FPL witness Barrett is that there is not a one-to-one relationship between the CPI-U forecast and the total projected amount of O&M spending. Rather, the CPI-U forecast is used as a benchmark to assist individual business units in developing their proposed budgets.

Q. Would it be appropriate to base the inflation forecast used as a benchmark in the budgeting process on a measure other than the CPI-U, such as the producer price index or some other measure?

A. No. Using the CPI-U as the measure of inflation ensures a consistent view of inflation. Multiple schedules included in the Commission's minimum filing requirements dictate that the utility must use the CPI-U in developing its O&M benchmark. For example, MFR C-40, O&M Compound Multiplier states "For each year since the benchmark year, provide the amounts and percent increases associated with customers and average CPI." Moreover, the requirement to base the O&M benchmark on the CPI-U is specified in Commission Form PSC/AFD/011-E (2/04). Thus, the Commission rules specifically require that the O&M benchmark be based on the CPI-U. It is precisely for this reason that FPL uses a forecast of the CPI-U as a guideline for its budgeting process.

Q. Did FPL also use the CPI-U as a benchmark in the budgeting process in its last rate proceeding?

A. Yes.

Q. What does OPC witness Dismukes propose in terms of an inflation forecast in this case?

A. OPC witness Dismukes states that while *maintaining the Company's practice of utilizing the CPI-U* [emphasis added], he would propose using a composite forecast which places a 60% weight on the Federal Reserve's inflation rate forecast and a 40% weight based on the Wall Street Journal June 2016 survey of inflation expectations. More specifically, OPC witness Dismukes is proposing an inflation rate of 1.44% in 2016, followed by 2.06% in 2017 and again in 2018. By comparison, FPL is forecasting an inflation rate of 2.0% in 2016, followed 2.5% in 2017 and 2.6% in 2018.

Q. Is FPL's proposed forecast for CPI-U for the 2017 test year still reasonable in light of the Wall Street Journal June 2016 survey of professional forecasters?

A. Yes. The Wall Street Journal's June 2016 survey shows an escalation in inflation in 2017 with an average forecast among participants of 2.2% for that year. Likewise, FPL's proposed inflation forecast shows inflation increasing to a 2.5% rate of increase in 2017. In addition, more than a quarter of professional forecasters responding to the Wall Street Journal June 2016 survey predict an increase in CPI-U equal to or higher than FPL's proposed CPI-U forecast for 2017.

Q. Was the Wall Street Journal June 2016 survey of professional forecasters available at the time FPL approved its CPI-U forecast for use as a benchmark in the budgeting process?

A. No.

Q. Is FPL's proposed forecast of CPI-U reasonable in light of the Wall Street Journal survey of professional forecasters that was available at the time the forecast was approved?

A. Yes. The Wall Street Journal June 2015 survey of professional forecasters projected a 2.3% increase in the CPI-U by the end of 2016 and a 2.4% increase in the CPI-U by the end of 2017. By comparison, FPL's proposed forecast indicates a 2.0% increase in the CPI-U in 2016 and a 2.5% increase in the CPI-U in 2017.

Q. Is FPL's proposed forecast for CPI-U for the 2017 Test Year and 2018 Subsequent Year reasonable in light of the Federal Reserve's 2.0% annual inflation target?

A. Yes. As OPC witness Dismukes' own testimony recognizes, the Federal Reserve's inflation targets and forecasts are based not on the CPI-U, but on the Personal Consumption Expenditures (PCE) index. Moreover, the PCE index typically increases by less than the CPI-U. Historically, annual increases in the PCE index have been about 0.4% below those of the CPI-U although in certain years the gap between the two series has been wider. Thus, the 2.5% increase and 2.6% increase in the CPI-U that FPL is projecting for 2017 and 2018 respectively are not inconsistent with the Federal Reserve's

2.0% annual inflation target. Nor are FPL's proposed forecasts for the CPI-U for 2017 and 2018 inconsistent with the Federal Reserve's PCE forecast as of their June 2016 Federal Open Market Committee meeting.

Q. In addition to the reasons outlined in your direct testimony is there another factor supporting the reasonableness of FPL's proposed inflation forecast?

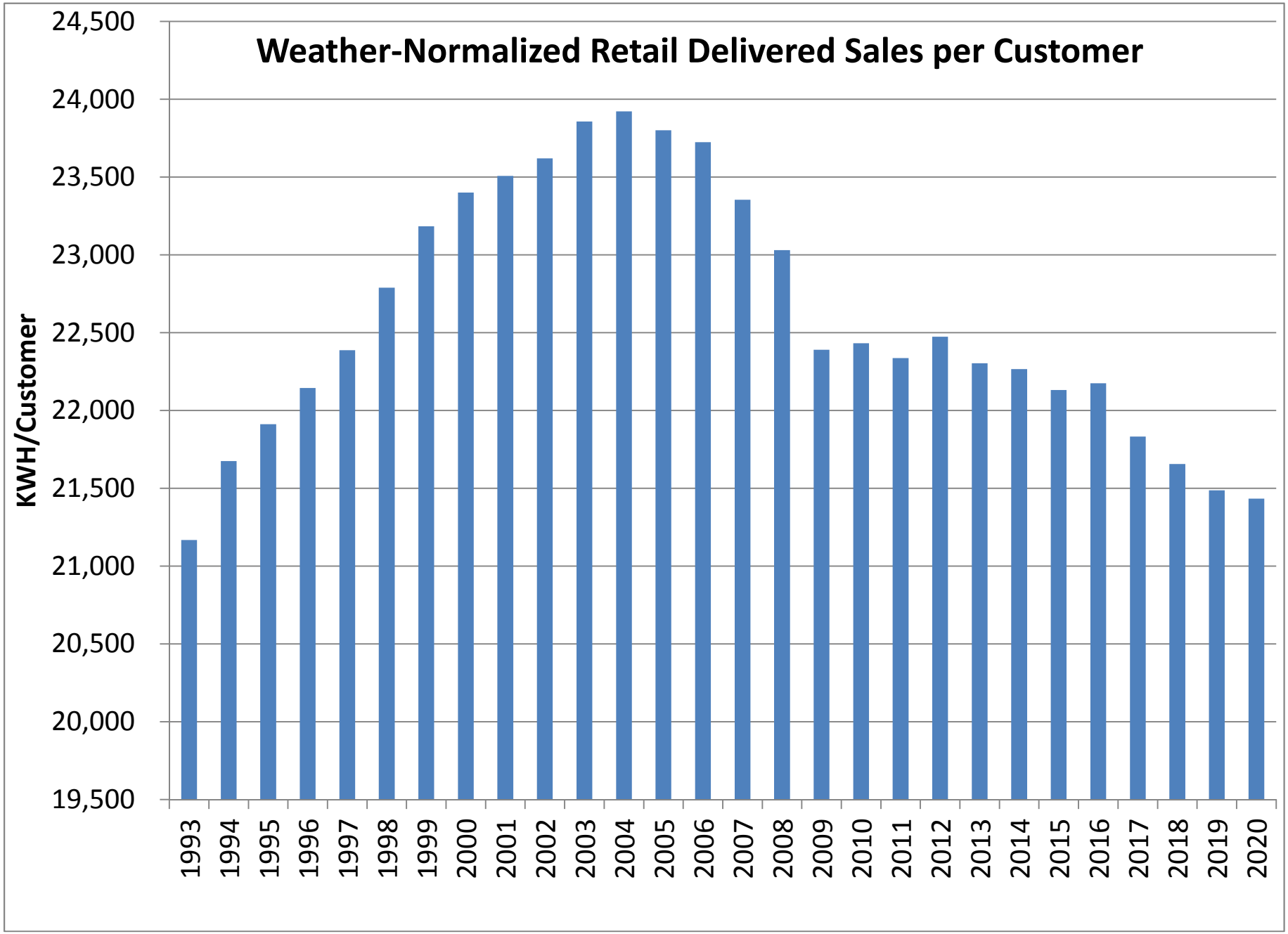
A. Yes. Based on data through June 2016, the core CPI is increasing at an annual rate of 2.2%, up from an increase of 1.8% during 2015. Thus, the core CPI, which excludes the volatile energy and food sectors, suggests a moderately positive rate of inflation going forward.

Q. Please summarize your conclusions regarding the inflation forecast that should be used in this case.

A. FPL's proposed forecasts for CPI-U are reasonable and appropriate projections for use in this case. FPL's CPI-U projections are consistent with the underlying rate of inflation indicated by recent actuals in the core CPI. FPL's proposed forecast for CPI-U was consistent with projections available from other third-party experts at the time the forecast was approved and remains reasonable in light of more recent projections

Q. Does this conclude your rebuttal testimony?

A. Yes.



Docket No. 160021
Weather-normalized Retail Delivered Sales per Customer
Exhibit RM-5, Page 1 of 1

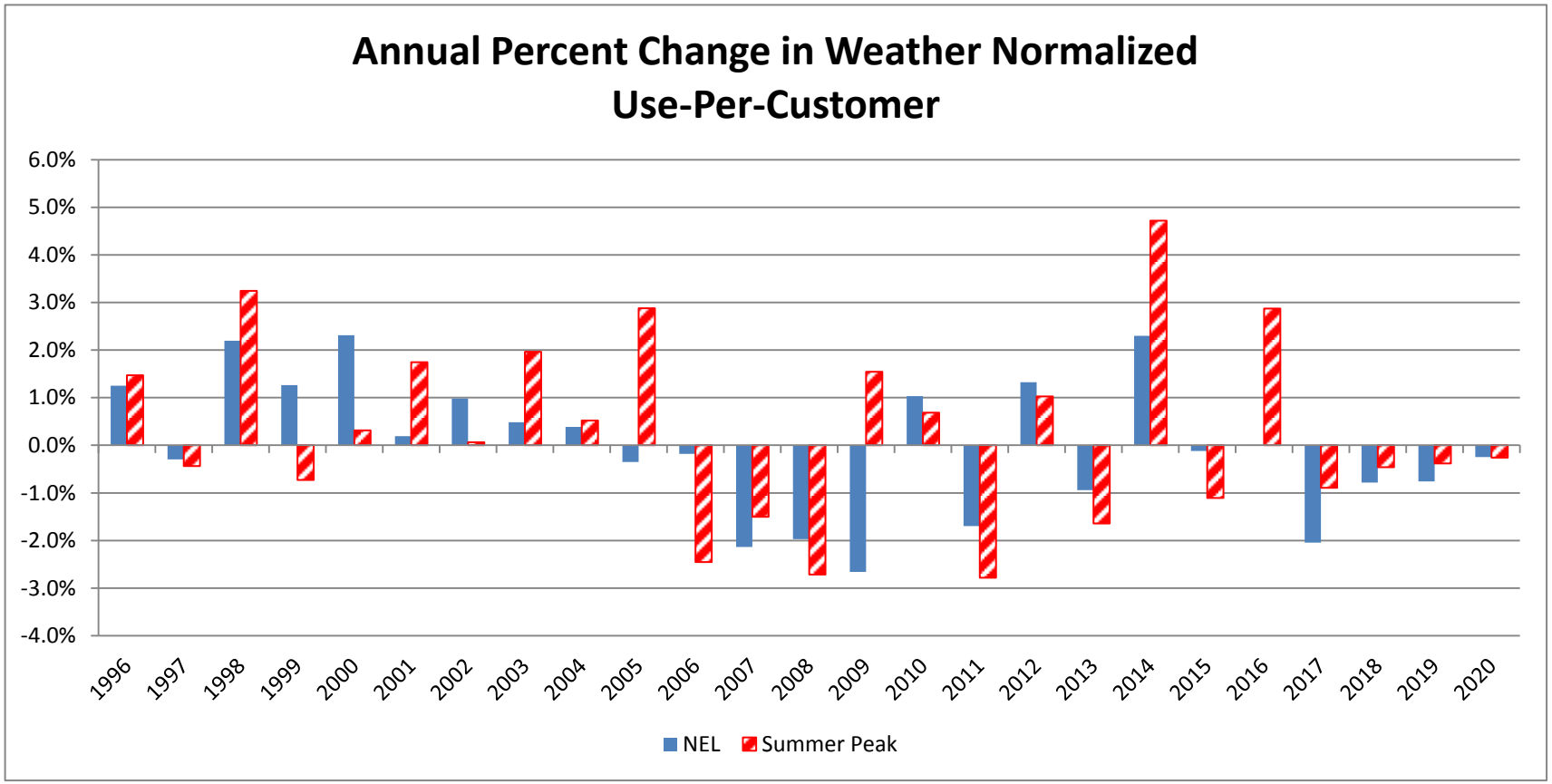
MWh

		Customers	Net Energy for Load	Retail Delivered Sales	Retail Billed Sales Residential	Commercial	Industrial	Street & Highway Lighting	Railroads & Railways	Other	Total
WN ACTUALS	2006	4,409,563	114,462,762	104,614,536	55,305,822	44,712,366	4,037,248	421,744	93,763	49,319	104,620,262
WN ACTUALS	2007	4,496,589	114,225,713	105,013,791	55,531,823	45,785,417	3,774,578	436,892	91,442	52,813	105,672,964
WN ACTUALS	2008	4,509,730	112,298,237	103,860,476	54,294,505	45,563,409	3,587,960	422,854	81,095	37,394	103,987,217
WN ACTUALS	2009	4,499,067	109,055,355	100,734,123	52,780,660	44,592,023	3,243,139	421,698	79,928	33,846	101,151,293
WN ACTUALS	2010	4,520,328	110,704,589	101,400,074	52,479,109	44,202,186	3,127,756	430,802	81,325	27,620	100,348,799
WN ACTUALS	2011	4,547,051	109,467,257	101,569,361	52,959,866	44,547,490	3,084,417	437,470	81,936	27,129	101,138,307
WN ACTUALS	2012	4,576,449	111,635,607	102,853,385	54,492,331	45,280,555	3,024,260	441,330	80,598	25,362	103,344,437
WN ACTUALS	2013	4,626,934	111,806,187	103,198,402	54,472,918	45,318,352	2,956,005	441,529	87,847	27,630	103,304,281
WN ACTUALS	2014	4,708,829	116,402,559	104,849,040	55,792,253	45,658,798	2,941,269	445,947	91,405	24,052	104,953,724
WN ACTUALS	2015	4,775,382	117,907,706	105,704,055	56,955,541	46,449,670	3,039,120	448,137	91,781	23,380	107,007,630
FORECAST	2016	4,845,390	119,644,060	107,447,158	57,251,548	46,374,078	3,173,057	477,951	91,274	23,297	107,391,206
FORECAST	2017	4,917,036	118,929,391	107,354,177	57,095,025	46,383,095	3,255,349	488,393	91,208	22,924	107,335,994
FORECAST	2018	4,989,889	119,748,223	108,064,394	57,515,219	46,584,182	3,319,445	498,758	91,241	23,056	108,031,901
FORECAST	2019	5,062,605	120,572,980	108,778,520	57,950,754	46,807,002	3,368,402	509,044	91,225	22,936	108,749,362
FORECAST	2020	5,134,692	121,987,485	110,053,494	58,725,598	47,243,631	3,406,861	519,254	91,233	22,942	110,009,518
CAGR 2006-2015		0.9%	0.3%	0.1%	0.3%	0.4%	-3.1%	0.7%	-0.2%	-8.0%	0.3%
CAGR 2015-2020		1.5%	0.7%	0.8%	0.6%	0.3%	2.3%	3.0%	-0.1%	-0.4%	0.6%

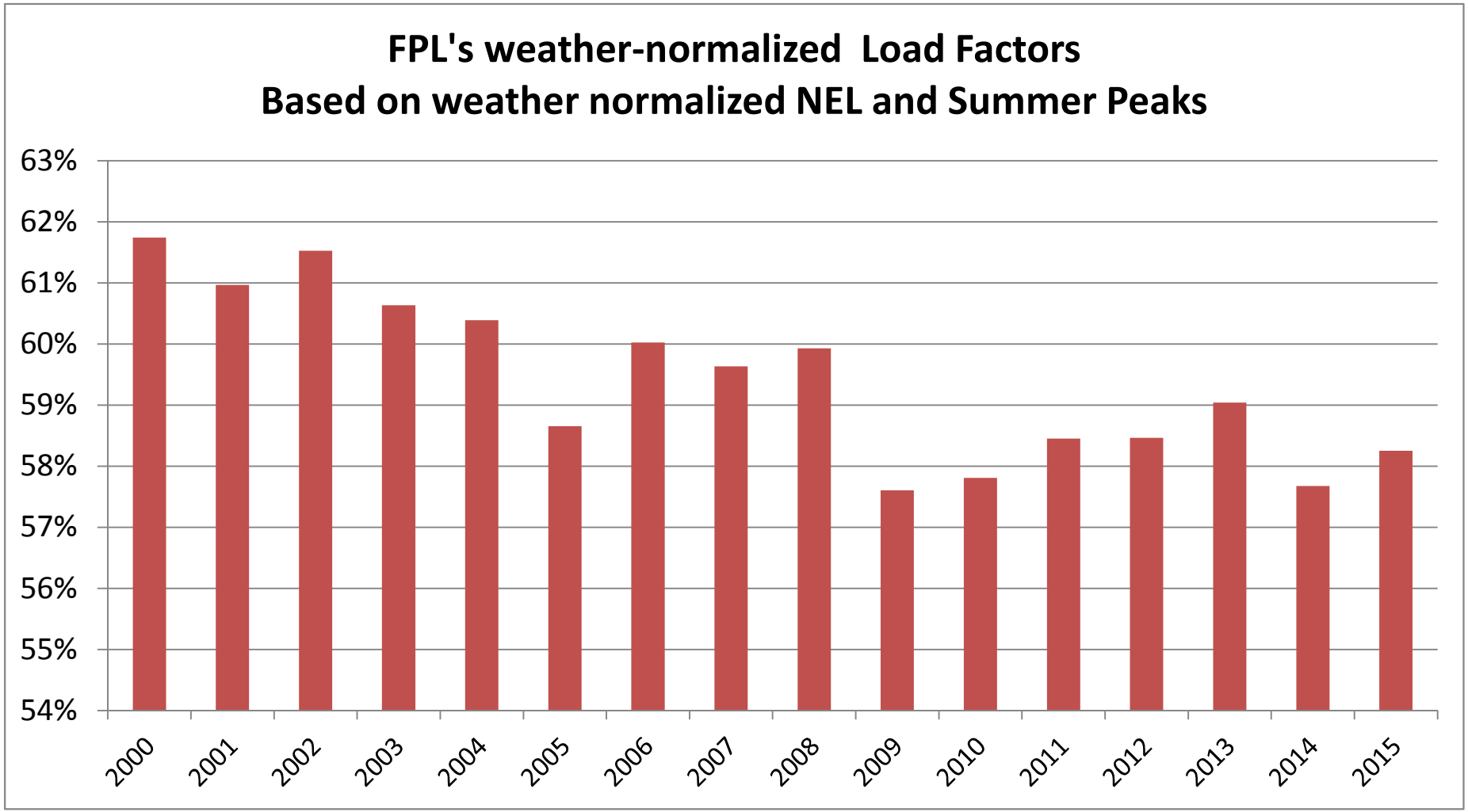
Weather-normalized (WN)

Incorporates Adjustment No. 4 from FPL's May 3, 2016 Notice of Adjustments

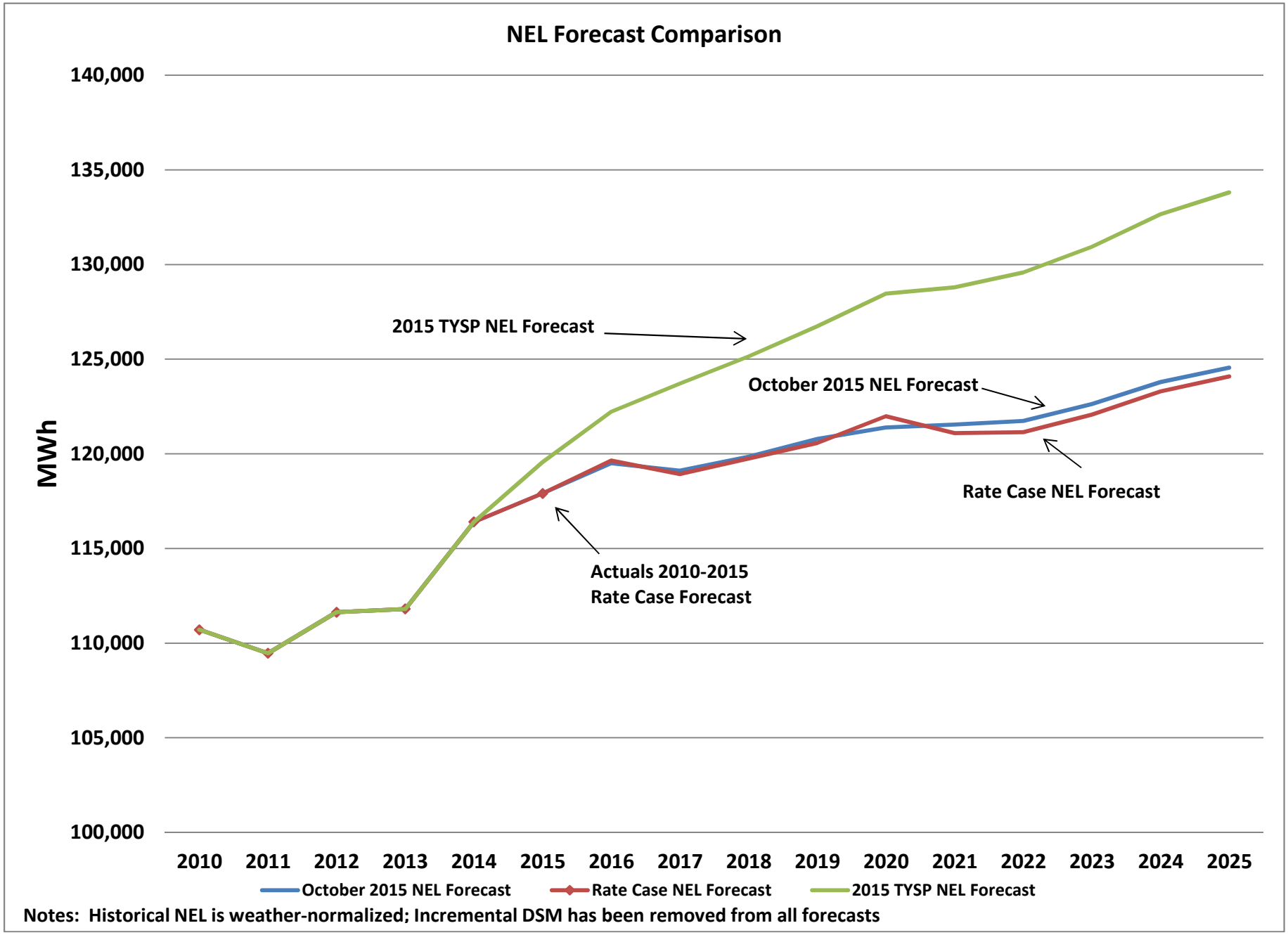
Docket No. 160021
Summary of FPL's Historical and Forecasted Sales
Exhibit RM-6, Page 1 of 1



Docket No. 160021
Annual Percent Change in Weather-normalized Use-Per-Customer
Exhibit RM-7, Page 1 of 1



Docket No. 160021
Weather-normalized Load Factors
Exhibit RM-8, Page 1 of 1



Docket No. 160021
Comparison of FPL's Proposed Load Forecast and Those Utilized in the Okeechobee Need Determination Case
Exhibit RM-9, Page 1 of 1

	Page/ Line	Incorrect, Incomplete or Misleading Statements Made by OPC Witness Dismukes	Correct Information
1.	4:5-7	Inaccurate Statement "In fact, the differences are quiet [sic] considerable, go far beyond updating the forecast models with more contemporaneous data, and have not been explained by the Company."	Explanations provided in FPL's responses to OPC Int. 397, Staff Ints. 70, 255, and 257, SFHHA Ints. 30 and 199; and OPC Reqs. for Prod. 76 and 149.
2.	6:3-6	Inaccurate Statement "First, there are 13 separate customer and sales models estimating individual monthly customer and energy sales by major customer class (e.g. residential, small commercial, large commercial, small industrial, and large industrial)."	There are 11 separate regression models to estimate customer and sales by major customer class and 6 exponential smoothing models. Regression models include sales models for residential, commercial (lighting, small, medium, and large), and industrial (small and medium). Customer models include residential, small commercial, small industrial, and street and highway. Separate exponential smoothing models are used for large industrial sales, commercial customers (lighting, medium, and large), and industrial customers (medium and large).
3.	6:19-21	Incomplete Statement "The remaining seven variables are included to: measure the impact of energy efficiency codes and standards; the impact of changes in real electricity prices and per capita income"	Per capita income is not a variable in the model. The variable is real per capita income weighted by the percentage of the population employed.
4.	Page 7, fn. #4	Misleading Statement "The Company failed to provide adequate documentation through testimony, discovery, or its Minimum Filing Requirements regarding its reason for the 1990 and 2005 dummy variables."	Documentation was never requested regarding the 1990 and 2005 dummy variables in our summer peak model. The dummy variables for 2005 and 1990 are used to account for abnormal weather conditions.
5.	8:17-18	Inaccurate Statement "The Company's forecasting discussion includes no annual comparisons across this broad 2015-2020 time period."	Annual values, both historical for 2006-2015 and forecasts for 2016-2020, are provided in Exhibit RM-3. Year-to-year changes are discussed in FPL witness direct Morley's testimony on pages 30-31, 35-36.
6.	8:19-21	Inaccurate Statement "Most importantly, the Company fails to highlight the specific forecasting results for its 2017 test year and its proposed 2018 adjustment and how those forecasting results compare to annual historic trends."	FPL witness Morley's direct testimony provides specific MWh and growth rates for 2017 and 2018. (see no. 5, above)
7	9:1-4	Inaccurate Statement "Q. Have you prepared a comparison of historic weather-normalized sales to projected sales A. Yes."	Witness Dismukes' discussion on trends in sales, as well as Exhibits DED-1 and DED-2 are not based on historical weather-normalized actual sales. They are based on non-weather normalized actual sales.

	Page/ Line	Incorrect, Incomplete or Misleading Statements Made by OPC Witness Dismukes	Correct Information
8.	9:12-14	Misleading and Incomplete "The Company, for instance, projects that its retail delivered sales for its 2017 test year will be 0.16 percent less than what was reported in 2016, and 0.55 percent less than sales reported for 2015."	Witness Dismukes is comparing 2017 retail delivered sales with non-weather normalized 2015 sales. FPL's forecast for 2017 retail delivered sales (including Adjustment No. 4) are 1.6% higher than the level of weather-normalized 2015 sales and less than 0.1% lower than 2016 retail delivered sales.
9.	9:15-17	Incomplete "Furthermore, the Company projects that its 2018 retail delivered sales will only be 0.58 percent greater than its 2017 projection (which itself is anticipated to fall relative to 2016)."	Taking into account Adjustment No. 4, 2018 retail delivered sales is projected to be 0.7% higher than 2017 retail delivered sales. Retail delivered sales in 2018 are also projected to be 2.2% higher than weather-normalized 2015 retail delivered sales .
10.	9:20-22	Misleading and Incomplete "In other words, the Company is anticipating a contraction (decrease) of overall sales relative to reported 2015 numbers, and that its overall sales numbers will not recover until 2019."	Witness Dismukes uses non-weather normalized overall 2015 sales in his comparisons. Retail delivered sales in 2016, 2017 and 2018 (including Adjustment No. 4) are projected to exceed the level of weather-normalized 2015 retail delivered sales, as shown in Exhibit RM-6.
11.	10:7-9	Incomplete "Likewise, the Company projects its summer peak to increase by 5.27 percent in 2016, 0.69 percent in 2017, and 1.11 percent in 2018."	The summer peak demand growth percentages quoted by OPC witness Dismukes are not based on weather-normalized actual 2015 values and do not take into account Adjustment No. 6 in the May 3, 2016 Notice of Identified Adjustments. The summer peak is expected to grow 4.4% in 2016, compared with the weather normalized 2015 peak, and by 0.6% in 2017 and 1.0% in 2018. This is after adjusting for Item No. 6 in the May 3, 2016 Notice of Identified Adjustments.
12.	10:12-14	Misleading and Incomplete "The Company forecasts a decrease, not an increase, in its energy sales of 0.28 percent and 0.66 percent in 2016 and 2017 respectively."	Witness Dismukes is comparing the forecasted levels of NEL with non-weather normalized 2015 NEL. Taking into account Adjustment No. 4, FPL forecasts a 1.5% increase in NEL in 2016 relative to weather-normalized 2015 actuals, not a decrease. The 0.6% decline in NEL projected for 2017 is addressed on pages 31-32 of FPL witness Morley's direct testimony.
13.	10:14-15	Misleading and Incomplete "Energy sales are forecast to increase, at a very tepid rate of 0.62 percent in 2018."	NEL incorporating Adjustment No. 4 is forecasted to increase by 0.7% in 2018. This is more than twice the rate experienced over the last ten years (2006-2015).

	Page/ Line	Incorrect, Incomplete or Misleading Statements Made by OPC Witness Dismukes	Correct Information
14.	10:15-17	Misleading and Incomplete "Thus, the Company's customer and peak demand forecasts are moving in one direction (upward) while its energy sales forecasts are estimated to move in an entirely opposite direction (downwards)"	Relative to weather-normalized historical actuals the forecasts for retail delivered sales, peak demands and customers are forecasted to consistently increase with the exception of a minimal (i.e., less than 0.1%) decline in retail delivered sales in 2017. As explained on page 36 of FPL witness Morley's direct testimony, a one year decline in retail delivered sales is projected in 2017. However, in all other years retail delivered sales from 2016 through 2020 NEL is projected to increase.
15.	11:9-11	Misleading and Incomplete "A system that is estimated to have a high load factor is often thought to be utilizing electricity more efficiently since electric usage is relatively consistent and does not swing between average and peak periods by a considerable level."	The statement is based on a system "utilizing" electricity. In fact, the source (footnote 7) listed by OPC witness Dismukes for this statement is an article designed to help farmers manage their electric bills. FPL is not a system that is "utilizing" electricity. FPL is a utility that is providing electricity. The efficiency of an electric utility should not be based on achieving a particularly load factor. Appropriate criteria for the productive efficiency of electric utilities are discussed in the direct testimony of FPL witness Reed.
16.	11:19-12:2	Misleading "Indeed, during the eight years 2008 through 2015, the Company's annual system load factor averaged 58.77 percent, ranging from a 2009 low of 56.81 percent to a 2008 high of 60.22 percent: a relatively tight spread of around 3.4 percent from the high to low observations."	Load factors discussed by OPC witness Dismukes are not weather-normalized and do not show long-term trends. The correct information is presented in Exhibit RM-8.
17.	13:5	Inaccurate "The data used in the Company's forecast is not weather-normalized."	FPL's proposed sales forecast is based on the assumption of normal weather using 20-year averages for weather variables (FPL witness Morley direct testimony at pages 12-13).
18.	13:10-12	Misleading and Incomplete "Exhibit DED-5, however, examines the Company's historic averages and projections on a weather-normalized basis and shows results similar to the ones discussed earlier (i.e., declining load factor)."	In Exhibit DED-5, only NEL is weather normalized. Witness Dismukes fails to weather normalize the summer peak. In addition, forecasted NEL does not incorporate Adjustment No. 4 and forecasted summer peak does not incorporate Adjustment No. 6.
19.	13:21-22	Incomplete "Exhibit DED-6 estimates the forward-looking load factors removing the potential impacts associated with energy efficiency."	Witness Dismukes removes the impact of incremental demand-side management from the NEL forecast but not the summer peak forecast. This is inconsistent with Adjustment No. 6 in the May 3, 2016 Notice of Identified Adjustments. Also the only adjustment for energy efficiency in Exhibit DED-6 appears to be incremental utility-sponsored demand-side management.

	Page/ Line	Incorrect, Incomplete or Misleading Statements Made by OPC Witness Dismukes	Correct Information
20.	16:8-10	Incorrect Statement "The Company states that, with the exception of one minor change, its current model is identical to that filed by the Company in its 2015 Okeechobee need determination, and makes allusions to it being essentially the same as the 2015 TYSP."	See rebuttal testimony of FPL witness Morley Section IV.
21.	16:10-13	Misleading "The Company, however, provides no narrative nor quantitative comparison of its current load forecasts to its 2015 TYSP. However, in response to discovery, the Company provided a workpaper that included such a comparative analysis."	Explanations of differences between the current forecast, the 2015 TYSP, and the updated October 2015 forecast used in the Okeechobee need determination are provided in FPL's responses to OPC Int. 397, Staff Ints. 70, 255, and 257,and SFHHA Ints. 30 and 199, and OPC Reqs. For Prod. 76 and 149.
22.	20:14-22	Inaccurate Statement "This leads to one of the following conclusions that either (1) the Company's NEL forecast is in error in this proceeding or (2) the Company's peak demand forecast is in error in this proceeding. However, the weight of the evidence suggests that it is the Company's NEL forecast that is in error since (1) the peak demand forecast included in this proceeding is relatively consistent with the peak demand forecasts in the Okeechobee need determination and the 2015 TYSP, and (2) the Commission explicitly found that the peak demand forecasts in the TYSP and the Okeechobee need determination were appropriate. Thus, the Company's NEL forecast needs to be adjusted for ratemaking purposes in this proceeding."	The evidence in this case clearly indicates that the FPL's proposed NEL forecast is accurate with a year-to-date weather-normalized over-forecasting variance through June 2016 of 0.5% versus a weather-normalized over-forecasting variance of 2.5% for OPC's proposed 2016 rate case forecast.
23.	21:20-22	Inaccurate Statement "The comparison shows that the NEL model is significantly under estimating total retail sales by as much as two percent in 2016, three percent in 2017 and more than four percent in 2018."	Figures 1 and 2 in FPL witness Morley's rebuttal testimony confirm that FPL's proposed sales forecast in this case is not "significantly under estimating total retail sales", but is in fact very accurate.
24.	22:11-13	Incomplete and Misleading "That percent difference is more than twice as large in the instant rate case, clearly indicating that something is amiss with the Company's current rate case NEL forecast."	The impact of energy efficiency codes & standards has increased since the last rate case. The adjustment to the individual revenue class forecasts is needed, in part, to account for the impact from energy efficiency codes & standards.
25.	31:14-16	Inaccurate Statement "The Company's proposed inflation measure is based solely upon the opinions of Global Insight, without any input from other economic forecasters who routinely assess and forecast inflationary pressures within the economy."	FPL compared IHS Global Insight's forecast against projections developed by other professional forecasters (FPL witness Morley's direct testimony page 52).

	Page/ Line	Incorrect, Incomplete or Misleading Statements Made by OPC Witness Dismukes	Correct Information
26.	32:3-8	Inaccurate Statement "The Company claims that it review[ed] the forecasts developed by other sources and considered historical trends in order to assess the reasonableness of IHS Global Insight's forecast.' However, in response to discovery requests, the Company was unable to provide proof of any such analysis besides those produced by Global Insight, in additional to claiming work product privilege regarding an internal analysis of customer growth statistics."	Inflation forecasts used to evaluate the reasonableness of IHS Global Insight's forecast were provided in response to discovery (Staff's Req. for Prod. No. 12). Historical comparisons were discussed in FPL witness Morley's direct testimony at pages 51-52.
27.	Exhibit DED-6	Incomplete and Misleading OPC witness Dismukes' exhibit purports to show load factors which are weather-normalized and with DSM reductions.	Only values for NEL have been weather-normalized in Exhibit DED-8. OPC witness Dismukes did not weather normalize values for the summer peak demands. In addition, witness Dismukes removed DSM only from the NEL values and not the summer peak demands. The correct information is shown in Exhibit RM-8.
28.	Exhibit DED-8	Incomplete and Misleading OPC witness Dismukes' exhibit purports to show a comparison of the forecast from the 2015 TYSP and the current filing.	OPC witness Dismukes compares NEL values from FPL's current filing net of incremental DSM against NEL values from FPL's 2015 TYSP that do not include reductions for incremental demand-side management. FPL's filed 2015 TYSP shows the NEL forecast net of incremental demand-side management but witness Dismukes chose not to use this column. In addition, the forecast listed under "Current Forecast" does not include the impact of Adjustment No. 4 from FPL's May 3, 2016 Notice of Identified Adjustments.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF KIM OUSDAHL

DOCKET NO. 160021-EI

AUGUST 1, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kim Ousdahl, and my business address is Florida Power & Light Company ("FPL or "the Company"), 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- KO-15 – Calculation of the Deferred Income Tax on Okeechobee Limited Scope Adjustment ("Okeechobee LSA")
- KO-16 – Historical and Forecasted Injuries and Damages Reserve
- KO-17 – Comparison of 2009 Actual and 2016 Estimated Rate Case Expenses
- KO-18 – Docket No. 080677-EI Actual Rate Case Expense Letter
- KO-20 – Recalculated Revenue Requirements including Impact of Identified Adjustments

I am also co-sponsoring KO-19 – 1st, 2nd and 3rd Notices of Identified Adjustments.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to demonstrate that the following recommendations in the testimonies of the Office of Public Counsel's

("OPC") witness Smith and South Florida Hospitals and Healthcare Association's ("SFHHA") witness Kollen are incorrect, not based on evidence, and should be rejected:

- Okeechobee LSA Calculation
- Deferred Federal Income Tax Proration Calculation
- Injuries and Damages Expense
- Unbilled Revenues in Rate Base
- Capital Structure and Deferred Tax Liabilities
- Recovery of Rate Case Expenses

I will also address two proposals of witness Kollen which are not in accordance with current Commission practice.

- Revision to Revenue Expansion Factor
- Merger Savings Credit Rider

Lastly, I present the previously filed adjustments to FPL's revenue requirements calculations that FPL has identified as being appropriate.

Q. Please summarize your rebuttal testimony.

A. I will demonstrate that, contrary to intervenor assertions, the Company's calculations of the 2019 Okeechobee LSA are properly presented in FPL's filing. I will explain that rates are set based on accrual accounting and that therefore, both incurred liabilities and accrued revenue are appropriately included in rate base. My testimony corrects misunderstandings regarding deferred income tax proration and inclusion in capital structure, and supports the Company's request to recover rate case expenses. I will discuss the

recommendations for changes in Commission practice as it relates to the calculation of the revenue expansion factor and a new merger savings rider. Finally, I will present the revenue requirement impact of FPL's previously identified adjustments.

II. OKEECHOBEE LIMITED SCOPE ADJUSTMENT

Q. Witnesses Kollen and Smith challenge the Company's Okeechobee LSA calculation. Do you agree with their proposed revisions?

A. No. Witness Kollen challenges everything about the Okeechobee LSA, despite it being presented in this case exactly as the Generation Base Rate Adjustment ("GBRA") has been calculated and implemented as a result of prior FPL rate settlements. Contrary to his statements on page 67, we have properly included $359.6 million of federal income tax bonus depreciation in the first year of the Okeechobee Unit's commercial operation, resulting in an increase in the deferred tax liability and a corresponding reduction in the Okeechobee LSA rate base.

Witness Kollen is confused about two important inputs to this calculation. First, the proper amount of deferred tax liability to reduce rate base is reflected on MFR B-6 and represents a 13-month average of accumulated deferred income taxes related to all timing differences, including bonus depreciation. Second, the depreciation-related deferred tax liability for the

Okeechobee LSA was prorated in accordance with Internal Revenue Code ("IRC") rules set forth in Treasury Regulation §1.167(l)-1(h)(6)(ii). Witness Kollen's calculation of the Okeechobee LSA deferred taxes is incorrect, as he applies a combined tax rate[1] to the federal tax depreciation timing difference only and ignores the fact that there are other timing differences related to the Okeechobee Unit. See Exhibit KO-15, which shows a summary calculation of deferred income taxes for the Okeechobee LSA. The detail for this summary was provided on April 18, 2016 to all parties, including the SFHHA, in FPL's response to OPC's First Request for Production of Documents, No. 1.

Witness Smith expresses concern that the Company's calculation of capital structure and deferred taxes for the Okeechobee Unit will violate the IRC normalization requirements. He states on page 48 that the proper test for compliance with normalization rules is a demonstration that "…using an incremental cost of capital, with an incremental reduction to rate base for deferred income taxes results in a revenue neutral method of calculating the revenue requirement compared to setting rates using the Commission practice of including all deferred income taxes in the overall costs of capital." Contrary to his opinion, revenue neutrality is not a requirement identified in the normalization rules contained in IRC §168(i)(9) nor the Treasury

[1] Under Florida Statute §220.13, Florida does not conform to the federal treatment of bonus depreciation provisions under IRC §168 and therefore, the use of a combined tax rate applied to the federal tax depreciation timing difference is inappropriate.

Regulations §1.167(l)-1. Rather, these rules call for consistency in the computation of depreciation expense, tax expense, reserve for deferred taxes and rate base. Additionally, the amount of reserve for deferred taxes permitted as a reduction to rate base is to be prorated when based on projected data. All components were calculated based on incremental costs and over the same time period. FPL has properly synchronized its 13-month average rate base, including a 13-month average deferred income tax liability -- properly prorated -- and its 13-month average capital structure with its first year's income tax expense just as it does when setting base rates overall. Presenting the deferred tax liability as a reduction to rate base is equivalent to presenting it in capital structure at zero cost. No violation of IRS requirements exists.

Q. Does witness Smith have other concerns with the calculation of the Okeechobee LSA?

A. Yes. As he states on page 45, witness Smith believes it inappropriate to use an incremental capital structure to recover the incremental revenue requirements of the Okeechobee LSA. But his objection ignores reality. It is evident that to finance a large incremental capital project like the Okeechobee Unit, the Company cannot rely on increases in customer deposits or Investment Tax Credits ("ITC"), neither of which can be unilaterally increased to finance the Okeechobee Unit. Nor will FPL use short term debt to finance this long term asset. Instead, FPL will issue debt and balance its equity in capital structure as it constructs and places this asset into service.

The incremental capital structure presented in FPL's filing reflects the incremental cost to finance this investment.

In addition, witness Smith is apparently unfamiliar with the long-standing approach FPL has used in its GBRA implementations from prior base rate proceedings to ensure that only the actual capital costs, no higher than those estimated, are recovered from customers. As such, customers are protected from paying any more than the actual cost capped by the approved project estimate. The incremental recovery calculation presented by FPL in its base rate filing is consistent with that used to develop the revenue requirements in FPL's need determination and is also consistent with that used to develop the incremental base rate increases associated with cost recovery for FPL's Turkey Point Unit 5, West County Unit 1, West County Unit 2 and West County Unit 3 generation plants, as well as the Cape Canaveral, Riviera Beach, and Port Everglades modernizations under Order No. PSC-05-0902-S-EI, Docket Nos. 050045-EI and 050188-EI, Order No. PSC-11-0089-S-EI, Docket No. 080677-EI, and Order No. PSC-13-0023-S-EI, Docket No. 120015-EI.

III. DEFERRED INCOME TAX PRORATION CALCULATION

Q. Is witness Kollen's testimony beginning on page 55 correct regarding the Company's deferred income tax proration calculation?

A. No. Witness Kollen believes the Company has overstated the amount of deferred income tax proration required by Treasury Regulation § 1.167(1). He argues on page 57 that the IRC examples do not require a 13-month average to be applied to the prorated monthly accumulated deferred income tax ("ADIT") balances. However, the examples merely specify the formula for computing the prorated ADIT activity to be used in arriving at the appropriate ADIT monthly balances. Witness Kollen ignores the additional normalization requirement contained in IRC 168(i)(9)(B)(ii), often referred to as the consistency requirement. The consistency requirement mandates that whatever convention is used for calculating rate base must also be applied in computing the associated ADIT balance treated as zero-cost capital. The proration and consistency requirements are distinct and independent. The IRS has addressed this issue specifically in several Private Letter Rulings ("PLRs"). Specifically, PLR 9202029 (10/15/1991) concluded:

> "Failure to average the deferred tax reserve, as prorated, before excluding the reserve from the average rate base WILL violate the consistency requirement of §168(i)(9)(B)."

The IRS ruled similarly in PLR 9224040 (3/16/1992), PLR 9313008 (12/17/1992) and most recently in PLR 201541010 (10/9/2015). Accordingly,

the Company has appropriately applied the 13-month average to the prorated ADIT balance as required under the normalization rules.

IV. WORKING CAPITAL

Injuries and Damages Expense

Q. What is witness Kollen's position with regard to accounting for injuries and damages expense?

A. Witness Kollen states on page 14 of his testimony that FERC Account 228.2, Accumulated Provision for Injuries and Damages, is a "…cost tracking mechanism…," the goal of which is to "…ensure that the Company's costs are recovered from customers dollar for dollar over time so that neither the Company nor customers are benefitted or harmed."

Q. Is he correct?

A. No. FERC Account 228.2 reflects the balance of liabilities *incurred* by the Company for personal injury or property damage that have not yet been paid. Generally Accepted Accounting Principles ("GAAP") require FPL to apply the accrual basis of accounting and that method is likewise the basis for setting rates by the FPSC and FERC. These liability accounts do not exist in order to track recovery of costs, and of course, the Company is not truing up the recovery of its base rate costs dollar for dollar as witness Kollen mistakenly asserts. Instead, as liabilities are incurred, they are recorded with a debit to injuries and damages expense and a credit to the reserve. When paid,

the reserve is debited and reduced. This forms the basis for accrual accounting, which differs from the cash method that witness Kollen mistakenly suggests is the basis for FPL's ratemaking.

Q. In what way does witness Kollen suggest use of a cash method?

A. Witness Kollen would like FPL to zero out its injuries and damages reserve and flow back the accrued reserve to customers over four years.

Q. Could FPL comply with that recommendation and remain compliant with GAAP?

A. No. FPL's current incurred liabilities for injuries and damages at June 30, 2016 are $16.6 million. If FPL were to return those dollars to customers by amortizing its injuries and damages reserve, it would violate GAAP, FPSC, and FERC accounting requirements. Ratemaking principles provide for symmetry with GAAP accounting by including the current period expense in rates while reducing return on rate base by the amount of the incurred liabilities recorded in the reserve thereby recognizing the cost free capital associated with the balance in the liability account. Witness Kollen's recommendation would destroy this symmetry and should be ignored.

Q. Witness Kollen is also concerned that FPL overstated its injuries and damages accrual for 2017 and 2018? Is he correct?

A. No. Exhibit KO-16 reflects the historical and forecasted injuries and damages reserve activity for the period 2011 through 2018. As noted on the exhibit, the accruals for 2017 and 2018 are lower than the actual payments made as recently as 2015 and lower than the five year historical average. It is very

difficult to predict these contingent losses, but the analysis demonstrates that FPL has not overstated its estimate.

Unbilled Revenues

Q. Should the Commission adopt SFHHA witness Kollen's recommendation to remove unbilled revenues from working capital?

A. No. Unbilled revenues, as witness Kollen describes on page 46, lines 19 through 21 of his testimony, are "…estimated revenues that will be billed for service that was provided during the month, but that were not yet billed at the end of the month." I agree with witness Kollen that the Company has provided the electric service to which those unbilled revenues relate. Therefore, FPL has incurred costs all of which have been accrued or paid, to deliver the energy that gave rise to both customer accounts receivables and the receivable for unbilled revenues. As such, the Company must finance the costs of providing that service and should earn a return on the promise of payment whether invoiced or not. For this reason, the Commission has a long standing practice of including unbilled revenues in working capital. The Commission included unbilled revenues in the working capital calculation for FPL in the following rate cases: Docket No. 820097-EU, Order No. 11437; Docket No. 830465-EI, Order No. 13537; and Docket No. 080677-EI, Order No. PSC-10-0153-FOF-EI.

Q. On page 47, lines 10 through 14, witness Kollen states that "[i]f the Company does not accrue unbilled revenues for fuel clause recovery revenues, then it also does not accrue accounts payable for the related fuel expense and there is no incremental amount in the accounts payable account to offset the nonfuel unbilled revenues." Do you agree?

A. No, I do not. FPL records payables in full at the end of each calendar period as required under GAAP. FPL's accounting practice reflects a calendar month of revenue and expense, and likewise records the balance of receivables and payables.

I should note that, in contrast to unbilled base revenues, it is not necessary to record unbilled revenues associated with clause recoveries for GAAP or ratemaking purposes. The form of accounting used for clause recovery activity renders the recording of clause unbilled revenues unnecessary. Accounting Standards Codification ("ASC") 980 (former FAS 71) allows FPL to defer to the balance sheet the over/under recoveries resulting from differences between recorded clause revenues and recorded clause expenses. Therefore, accrual of additional revenues (unbilled revenues) would also require a posting of an additional entry equal to the clause revenue. The entry would be as follows:

1) Debit-- Receivable for clause unbilled revenue

Credit-- Unbilled clause revenue

To record the unbilled clause revenue; and

2) Debit-- Unbilled clause revenue

Credit-- Regulatory Liability-Overrecovery or

Credit-- Regulatory Asset-Underrecovery

To record the deferral of additional clause revenue to the balance sheet.

Thus, for GAAP and ratemaking purposes, the effect of the unbilled clause revenues is offset and therefore, unnecessary.

V. CAPITAL STRUCTURE

Q. On page 55, lines 1 through 16, witness Kollen proposes an increase of $49 million to deferred tax liabilities for the 2017 Test Year despite a proposed decrease in rate base of $511 million. Similarly, he proposes a deferred tax liability increase of $152 million in the 2018 Subsequent Year despite a proposed decrease in rate base of $248 million. Does he provide any support for this adjustment to *increase* zero cost capitalization despite his sizable proposed *decrease* in rate base?

A. No, he does not. To be clear, FPL disagrees with witness Kollen's proposed decrease to rate base. However, if the Commission were to reduce FPL's forecasted rate base in either the 2017 Test Year or 2018 Subsequent Year, the amount of deferred income taxes reflected in capital structure would likewise need to decrease, not increase. Witness Kollen's proposal to increase deferred income taxes over and above the amount presented in FPL's original filing despite a sizable proposed decrease in rate base is inexplicable. His proposal

would be the opposite of the rate base/capital structure synchronization method the FPSC requires and would distort the capital structure, which should be consistent with rate base. Not surprisingly, he provides no evidence to support the method or the amount of his proposed adjustment.

Q. In your opinion, could witness Kollen's proposed increase in deferred income taxes result in a potential tax normalization violation?

A. Yes. As discussed above, IRS tax normalization rules require that any ratemaking adjustments with respect to the utility's tax expense, depreciation expense, or reserve for deferred income taxes be consistently applied with respect to the other two items and with respect to rate base. Consistent with past FPSC orders and tax normalization rules, FPL has properly allocated pro rata adjustments to all sources of capital.

VI. RATE CASE EXPENSES

Q. Do intervenor witnesses object to FPL's recovery of its estimated rate case expenses with a return on the unamortized balance?

A. Yes. Both witness Smith and witness Kollen dispute FPL's recovery request for rate case expenses.

Q. What is witness Kollen's position on whether rate case expenses should be recovered?

A. Witness Kollen insists that no rate case expenses should be recovered because he asserts that no rate increase is justified. I disagree with this wholly

unsupported assertion. The recovery of rate case expenses should not be based on whether or not FPL is granted a base rate increase as it has requested, and the Company should not be penalized in seeking such request in accordance with Commission policy.

Q. What is witness Smith's concern with recovery of necessary rate case expenses by FPL?

A. Witness Smith proposes to deny FPL recovery of incremental labor expenses, outside services and certain travel and lodging costs.

Q. Are the estimated costs presented by FPL for incremental labor, outside services, and travel and lodging being incurred directly as a result of the rate proceeding?

A. Yes. Witness Smith's reference to the Commission's 2009 disallowance of overtime paid to salaried or exempt employees is not applicable. FPL no longer pays overtime to salaried or exempt employees for rate case support. Therefore, the labor costs reflected in FPL's estimated rate case expenses relate solely to overtime paid to non-exempt employees. FPL is obligated to pay overtime for non-exempt employees, and the cost of overtime worked in support of the rate case is entirely appropriate for recovery as incremental labor. In addition, witness Smith suggests by his back of the envelope calculations that FPL's estimate for hotel expenses for this proceeding is unreasonably high. Exhibit KO-17 demonstrates that FPL's actual hotel expenses for the 2009 rate proceeding exceed those of our filed estimate in this case. FPL's modest hotel accommodations include individual rooms for

employee and consulting witness overnight stays along with common space for group meetings and meals – witness Smith's overly simplistic analysis failed to account for the cost of this necessary common space.

Q. Does witness Smith adjust these amounts based on better evidence of the actual costs to be incurred?

A. No. Instead, after four pages of written testimony regarding his concerns, he simply calculates an overall recovery amount based on the amount allowed to be recovered in FPL's 2009 rate case adjusted for inflation.

Q. Is this calculation reasonable?

A. No. First of all, witness Smith's use of the 2009 rate case expenses as a proxy is not supported in any way. The Company must seek rate relief in 2017 to avoid its return on equity dropping to an inadequate 7.88%, as shown in my direct testimony Exhibit KO-3 – an amount even lower than the return on equity proposed by OPC witness Woolridge. Each base rate filing is developed based on the evidence needed in that case to support the Company's request.

Secondly, FPL's actual 2009 base rate case expenses were $4.7 million, not the $3.2 million used by witness Smith in his calculation. FPL reported its total 2009 rate case expenses to the Commission by letter dated March 4, 2011, in response to a request from the Commission Staff. A copy of that letter is Exhibit KO-18. Exhibit KO-17 shows that FPL's estimated 2016 rate case expenses are only $222,070 higher than the 2009 actual expenses, an

increase that is well below the rate of inflation. While there clearly are differences in the scope of work between the two cases (both higher and lower) as the Company must determine how to present evidence to support its request, this comparison illustrates that the 2016 estimated rate case expenses are not inconsistent with FPL's actual experience in the prior rate case that witness Smith has chosen as his point of comparison.

Q. Should FPL be allowed to earn a return on the unamortized balance of rate case expenses?

A. Yes. I am well aware of the FPSC policy and practice regarding the prohibition against inclusion of the unamortized balance of rate case expenses in rate base; however, it is important for the Commission to recognize that its treatment results in an implicit disallowance of otherwise prudently incurred costs required by the Company to litigate its case and present evidence effectively. The Commission practice imposes an unwarranted penalty on the Company for seeking rates that will allow it an opportunity to earn a reasonable return on its investment.

VII. INTERVENOR PROPOSED ADJUSTMENTS

Revision of the Revenue Expansion Factor

Q. What does witness Kollen propose be done to the revenue expansion factor to accommodate inclusion of permanent income tax differences, such as the Section 199 Manufacturer's Deduction, in FPL's proposed base rates?

A. Witness Kollen suggests the Commission reflect the impact of forecasted reductions in federal income taxes associated with inclusion of the Section 199 Manufacturer's Deduction (Section 199) in the revenue expansion factor.

Q. Did FPL's filing inappropriately withhold income tax benefits due to customers from the application of Section 199?

A. On the contrary, FPL passed along the current rates income tax benefit due to Section 199 consistent with the MFRs, prior practice and previous orders by the Commission approving this same treatment for FPL and other IOUs. In addition, in FPL's Third Notice of Identified Adjustments we provided customers the benefit of the full exclusion of the gas reserves Section 199 detriment, despite the fact that the Woodford project is a part of FPL's consolidated financial results and will be a part of the consolidated Section 199 calculation that FPL must include in its proforma federal income tax filing now and in the future.

Q. Has the adjustment to the revenue expansion factor proposed by witness Kollen been approved by the Commission before?

A. No. The Commission's current process and historical practice, as codified in MFR C-44, provides only for an income tax gross up of the return on equity in proposed base rates at the statutory income tax rate. The current filing approach passes on the benefit of FPL's forecasted Section 199 Manufacturer's Deduction to customers on the net operating income at current rates reflected on MFR C-1 for both the 2017 Test Year and 2018 Subsequent Year. FPL can find no instance of the application of the adjustment proposed by witness Kollen in any prior FPSC base rate filing or final order.

Merger Savings Credit Rider

Q. Do you agree with witness Kollen's proposal that the Commission adopt a merger savings surcredit rider intended to flow back to customers any savings achieved from future mergers?

A. No. There are at least four reasons the Commission should not approve this recommendation. First, merger savings will typically not be material to FPL's cost of service; second, savings are slow to be realized and are offset in early years by costs to achieve; third, any consideration of this proposal should be through a workshop or rulemaking process; and lastly, the Commission has the tools it needs to ensure FPL does not over earn its allowed ROE.

FPL has presented a solid forecast of 2017, 2018 and the Okeechobee LSA related costs to be relied on in setting base rates. The probability of a successfully consummated merger materially impacting these forecasts -- even with a four year stay out proposal -- is small and no greater than any other future variability (up or down) in revenue and/or operations.

Even if successful, after lengthy proceedings for regulatory approval, full integration of multiple operating businesses will typically evolve over a long period of time. In most cases, the acquirer must agree to conditions that prohibit termination of existing employees of the acquired entity for some time; resulting in a delay in the realization of savings and synergies. Therefore, even if NextEra Energy, Inc. ("NEE") consummates a successful merger during the four year stay out, any incremental savings to FPL customers would likely be realized slowly.

The Commission should not approve a rider for this single issue in the context of an ongoing rate proceeding. Any consideration that the Commission may wish to give to this proposal would be more properly vetted in a workshop or rulemaking proceeding. Merger impacts on future rates would be applicable to the other IOU's — not just to FPL. Every merger will be different, with unique merger commitments, differing organizational structures and inherently different outcomes with regard to synergies and costs to achieve.

In any event, the FPSC does not need to adopt a special rider at this juncture; it has continued oversight to review earnings affected by merger synergies, even during the four year term of the stay out.

VIII. ADJUSTMENTS IDENTIFIED BY FPL

Q. Has FPL identified adjustments that it believes should be made to the revenue requirements for the 2017 Base Rate Increase, 2018 Subsequent Year Adjustment, and 2019 Okeechobee LSA?

A. Yes. The three notices of identified adjustments previously filed by FPL during the course of this proceeding are included as a composite Exhibit KO-19. In addition, we have identified two other necessary corrections. Deferred rate case expenses are double counted in FPL's rate base for both the 2017 Test Year and 2018 Subsequent Year. FPL forecasted total deferred rate case expenses of $4.9 million in rate base for both periods and also included a Company adjustment for the unamortized balance, which reflects amortization over a four year period, of $4.3 million for the 2017 Test Year and $3.1 million for the 2018 Subsequent Year. Therefore, rate base is overstated by $4.9 million for each period. Secondly, injuries and damage expense is overstated by $2.1 million in the 2017 Test Year and $1.0 million in the 2018 Subsequent Year.

All of these adjustments mentioned above are included on Exhibit KO-20,

which reflects a recalculation of FPL's proposed rate increase requests for each period, taking into account the impact of each of the previously filed adjustments on rate base, net operating income and capital structure.

Q. How does FPL propose that the Commission use the adjustments in this proceeding?

A. The Commission should include the effect of the adjustments in determining FPL's revenue requirements for the 2017 Base Rate Increase, 2018 Subsequent Year Adjustment and 2019 Okeechobee LSA. Some of those adjustments will result in increases to revenue requirements while others will result in decreases, but the net impact of the adjustments is a reduction in FPL's revenue requirements for each of those rate requests.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Florida Power and Light Company
Calculation of Deferred Income Taxes for the Okeechobee LSA
Exhibit KO-15

Line No.	Date (1)	Pre-Tax Timing Differences - Okeechobee: AFUDC (2)	CPI (3)	Book Depreciation (4)	Federal Tax Depreciation[A] (5)	State Tax Depreciation (6)	Deferred Income Taxes - Okeechobee: AFUDC (Fed & State) (7)	CPI (Fed & State) (8)	Federal Tax Depreciation (Federal) (9)	State Tax Depreciation (State) (10)	State Tax Depreciation (FBOS) (11)	Book Depreciation (Fed & State) (12)	Deferred Taxes (Activity) (13)	Deferred Taxes (GL Balance) (14)	Prorated Activity/Balances: Deferred Taxes (Activity) (15)	Deferred Taxes (Balance) (16)
1																
2	Tax Rate						0.38575	0.38575	0.35	0.055	0.35	0.38575				
3																
4	May 2019	$ (28,359,142)	$ 90,533,134	$ -	$ -	$ -	$ (10,939,539)	$ 34,923,157	$ -	$ -	$ -	$ -	$ 23,983,617	$ 23,983,617	$ -	$ 23,983,617
5	Jun 2019	-	-	3,332,135	(364,217,042)	(11,927,681)	-	-	(127,475,965)	(656,022)	229,608	1,285,371	(126,617,008)	(102,633,391)	(116,557,027)	(92,573,409)
6	Jul 2019	-	-	3,332,214	(4,588,320)	(11,927,681)	-	-	(1,605,912)	(656,022)	229,608	1,285,402	(746,925)	(103,380,316)	(624,143)	(93,197,552)
7	Aug 2019	-	-	3,332,214	(4,588,320)	(11,927,681)	-	-	(1,605,912)	(656,022)	229,608	1,285,402	(746,925)	(104,127,240)	(560,705)	(93,758,257)
8	Sep 2019	-	-	3,332,214	(4,588,320)	(11,927,681)	-	-	(1,605,912)	(656,022)	229,608	1,285,402	(746,925)	(104,874,165)	(499,314)	(94,257,571)
9	Oct 2019	-	-	3,332,214	(4,588,320)	(11,927,681)	-	-	(1,605,912)	(656,022)	229,608	1,285,402	(746,925)	(105,621,090)	(435,877)	(94,693,448)
10	Nov 2019	-	-	3,332,214	(4,588,320)	(11,927,681)	-	-	(1,605,912)	(656,022)	229,608	1,285,402	(746,925)	(106,368,015)	(374,486)	(95,067,934)
11	Dec 2019	-	-	3,332,214	(4,588,320)	(11,927,681)	-	-	(1,605,912)	(656,022)	229,608	1,285,402	(746,925)	(107,114,940)	(311,048)	(95,378,982)
12	Jan 2020	-	-	3,332,214	(5,147,042)	(9,428,336)	-	-	(1,801,465)	(518,558)	181,495	1,285,402	(853,126)	(107,968,066)	(282,817)	(95,661,799)
13	Feb 2020	-	-	3,332,214	(5,147,042)	(9,428,336)	-	-	(1,801,465)	(518,558)	181,495	1,285,402	(853,126)	(108,821,192)	(217,372)	(95,879,171)
14	Mar 2020	-	-	3,332,214	(5,147,042)	(9,428,336)	-	-	(1,801,465)	(518,558)	181,495	1,285,402	(853,126)	(109,674,318)	(144,915)	(96,024,085)
15	Apr 2020	-	-	3,332,214	(5,147,042)	(9,428,336)	-	-	(1,801,465)	(518,558)	181,495	1,285,402	(853,126)	(110,527,444)	(74,795)	(96,098,880)
16	May 2020	-	-	3,332,214	(5,147,042)	(9,428,336)	-	-	(1,801,465)	(518,558)	181,495	1,285,402	(853,126)	(111,380,570)	(2,337)	(96,101,217)
17		$ (28,359,142)	$ 90,533,134	$ 39,986,493	$ (417,482,171)	$ (130,635,452)	$ (10,939,539)	$ 34,923,157	$ (146,118,760)	$ (7,184,950)	$ 2,514,732	$ 15,424,790	$ (111,380,570)		$ (120,084,835)	
18																
19				Tax Rate Used by Kollen	0.3858									*13 Month Avg*		*13 Month Avg*
20				Taxes on Federal Tax Depreciation	$ (161,064,622)									**$ (96,808,241)**	MFR B-6 - Per Books	**$ (85,746,822)**
21				MFR B-6 - Juris Factor	94.88%										MFR B-6 - Juris Factor	94.88%
22				Jurisdictional Deferred Taxes Per Kollen	$ (152,821,931)										MFR B-6 - Retail	**$ (81,358,617)**
23																
24																
25																
26																
27																
28	Notes:															
29	(A) Amount reflected for June 2019 incudes bonus depreciation of $359.6 million.															
30																

Docket No. 160021-EI
Calculation of the Deferred
Income Tax on Okeechobee LSA
Exhibit KO-15, Page 1 of 1

Florida Power and Light Company
Injuries & Damages Reserve
FERC Account 228.2
($000's)

Line No.		Actual 2011	Actual 2012	Actual 2013	Actual 2014	Actual 2015 [A]	Forecasted 2016	Forecasted 2017 [B]	Forecasted 2018	5 year Historical Avg (2011-2015)
1	Beginning Balance	$ (27,283)	$ (24,829)	$ (29,412)	$ (23,244)	$ (24,370)	$ (17,258)	$ (20,796)	$ (19,500)	$ (25,828)
2	Total Accruals	(12,998)	(16,792)	(11,696)	(12,455)	(5,590)	(11,338)	(10,404)	(11,700)	(11,906)
3	Total Payments	15,452	12,209	17,864	11,329	12,708	7,800	11,700	11,700	13,912
4	Ending Balance	$ (24,829)	$ (29,412)	$ (23,244)	$ (24,370)	$ (17,252)	$ (20,796)	$ (19,500)	$ (19,500)	$ (23,821)
5										
6										
7	Notes									
8	(A) 2015 actual expenses were unusually low due to a large accrual reversal related to a favorable claim settlement as well as lower than average claim activity.									
9	(B) 2017 Forecast I&D expense of ~$12M was based on historical averages.									
10										

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
RETAIL RATE CASE EXPENSES

Line No.	Description	Dkt. 080677-EI 2009 Rate Case Actuals	Dkt. 160021-EI MFR C-10 Forecast
1	Employee Related and Office Administration:		
2	Incremental FPL Payroll	$ 987,124	$ 102,092
3	Hotel and Lodging	261,262	244,300
4	Business Meals and Travel	254,790	190,200
5	Office Administration and Other	307,326	324,108
6	Employee Related and Office Administration Total	$ 1,810,502	$ 860,700
7			
8	Outside Services - Professional:		
9	Expert Witnesses	$ 1,371,396	2,323,400
10	Technical Support	313,041	40,000
11	Outside Services - Professional Total	$ 1,684,437	$ 2,363,400
12			
13	Outside Services - Legal	$ 524,084	$ 750,000
14			
15	Outside Services - Other:		
16	Project Support	$ 388,037	$ 606,400
17	Utilities International	-	225,000
18	Accurate Stenotype Reporters, Inc.	128,691	45,000
19	Deloitte & Touche LLP	53,000	8,500
20	Security	38,099	24,000
21	Other	76,080	42,000
22	Outside Services - Other Total	$ 683,907	$ 950,900
23			
24	**Total**	**$ 4,702,930**	**$ 4,925,000**
25			
26			

Kenneth Hoffman
Vice President, Regulatory Relations
Florida Power & Light Company
215 S. Monroe Street, Suite 810
Tallahassee, FL 32301
(850)521-3919
Kenneth.Hoffman@fpl.com

March 4, 2011

- VIA HAND DELIVERY -

Mr. John Slemkewicz, Supervisor
Division of Economic Regulation
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Fl 32399-0850

RE: Docket No. 080677-EI

Dear Mr. Slemkewicz:

As requested in your letter dated February 10, 2011, I am enclosing Florida Power & Light Company's ("FPL's") response to your request for actual rate case expenses incurred in Docket 080677-EI.

Should you have any questions or need further assistance, please do not hesitate to contact me.

Sincerely,

Kenneth A. Hoffman
Vice President, Regulatory Relations

DETAIL OF RATE CASE EXPENSES

Florida Public Service Commission
Florida Power & Light Company
Docket No. 080677-EI
Test Year: 2010
Page 1 of 2

Line No. (1)	Vendor Name (2)	Counsel, Consultant or Witness (3)	Fee (4)	Basis of Charge (5)	* Travel Expenses (6)	Other (7)	Total (8)	** Type of Services (9)	Specific Services Rendered (10)
1	Concentric Energy Advisors, Inc.	Witness	352,060	Hourly plus Expenses	10,561	305	$ 362,926	O	Benchmarking Testimony
2	Radey, Thomas, Yon and Clark	Witness	163,424	Hourly plus Expenses	4,456	-	167,880	A & O	Regulatory Treatment Testimony
3	ABSG Consulting, Inc.	Witness	236,015	Fixed Fee	3,663	30	239,708	O	Storm Reserve Testimony
4	Minsky Consulting	Consultant	237,500	Monthly Fixed Fee	Included in Fee	Included in Fee	237,500	O	Human Resources Consulting
5	Gannett Fleming, Inc.	Witness	200,488	Hourly plus Expenses	10,983	106	211,577	A & O	Depreciation Study and Testimony
6	Financial Concepts and Applications, Inc.	Witness	194,648	Hourly plus Expenses	6,151	-	200,799	C	Return on Equity Testimony
7	The Brattle Group	Witness	183,388	Hourly plus Expenses	3,126	1,992	188,506	O	Forecasting Testimony
8	Towers Perin	Witness	75,541	Hourly plus Expenses	Not Itemized	Not Itemized	75,541	O	Compensation Testimony
11	Total Outside Consultants						$ 1,684,437		
12									
13	Radey, Thomas, Yon and Clark	Counsel	473,231	Hourly plus Expenses	6,776	397	480,404	L	Outside Legal Services
14	Rutledge, Ecenia and Purnell	Counsel	42,027	Hourly plus Expenses		1,792	43,819	L	Outside Legal Services
15	Total Outside Legal Services						$ 524,084		
16									
17	All other Expenses						2,494,409		
18	Total (All)						$ 4,702,930 (a)		

* Travel Expenses should include the amount of time billed while traveling.
** A = Accounting C = Cost of Capital E = Engineering L = Legal O = Other

Notes:
(a) According to the rate case order issued on March 17, 2010, FPL is only permitted to recover $3,207,000, amortized over four years.

TOTAL RATE CASE EXPENSES AND COMPARISONS

Florida Public Service Commission
Florida Power & Light Company
Docket No. 080677-EI
Test Year: 2010
Page 2 of 2

COMPARISON OF CURRENT RATE CASE EXPENSES WITH PRIOR CASE

Line No.	Item	Current Case	Prior Case	% Variance	Reason for Changes (if 10% or greater)
1.	Outside Consultants	$ 1,684,437	$ 1,131,902	49%	The prior case settled prior to the first day of the technical hearing, whereas the technical hearing in the current case extended over 15 days. This was substantially more days of technical hearing than have been required for Florida electric rate cases historically, and substantially more technical hearing days than were required for the contemporaneous Progress Energy Florida rate case (Docket No. 090079-EI). Because outside consultants must be paid for their time in attending and participating in the technical hearing, the lengthy hearing had a major impact on FPL's expense for outside consultants in the current case.
2.	Outside Legal Services	524,084	939,766	-44%	Fewer outside lawyers were used
3.	Reimbursement of PSC Out-of-State Audit Travel Costs	-	-	N/A	N/A
4.	Paid Overtime	826,975	603,044	37%	The prior case settled prior to the first day of the technical hearing, whereas the technical hearing in the current case extended over 15 days. This was substantially more days of technical hearing than have been required for Florida electric rate cases historically, and substantially more technical hearing days than were required for the contemporaneous Progress Energy Florida rate case (Docket No. 090079-EI). Most of the increase in paid overtime for the current case related to FPL personnel who had to attend and participate in the lengthy technical hearing.
5.	Other Expenses	1,667,434	1,731,742	-4%	N/A
6.	Total Rate Case Expense	$ 4,702,930 (a)	$ 4,406,454 (b)		

SCHEDULE OF RATE CASE EXPENSE AMORTIZATION

Line No.	Rate Case	Total Expense	Rate Oder Date	Amortization Period	Test Year Amortization
7.	Current Docket No. 080677-EI	3,207,000	March 17, 2010	4 years	801,750
8.	Prior Case Docket No. 050045-EI	N/A	N/A	N/A	N/A
9.	Prior Case Docket No. 001148-EI	N/A	N/A	N/A	N/A
10.	Total	3,207,000 (a)			801,750

Line No.	Statistics	Current Case	Prior Case
11.	Rate Case Expenses Incurred as a Percent of Jurisdictional Rate Base (c)	0.03%	0.03%
12.	Rate Case Expenses Incurred as a Percent of Jurisdictional Revenues (d)	0.11%	0.12%
13.	Rate Case Expenses Incurred (per Access Line)	N/A - Does not apply to electric utility	
14	Rate Case Expenses Incurred (per Average Customer) (e)	$0.01 per 1,000 kWh (e)	N/A
15	Rate Case Expenses Incurred per (ERC) etc.	N/A - Does not apply to electric utility	

Notes:

(a) According to the rate case order issued on March 17, 2010, FPL is only permitted to recover $3,207,000, amortized over four years.

(b) The prior rate case was settled with no separate recovery of rate case expenses.

(c) Jurisdictional Rate Base Source:
Current Case - Rate Case Order (Docket No. 080677-EI, Dated March 17, 2010)
Prior Case - Actual December 2006 Earnings Surveillance Report

(d) Jurisdictional Revenues Source:
Current Case - Rate Case Order (Docket No. 080677-EI, Dated March 17, 2010)
Prior Case - Actual December 2006 Earnings Surveillance Report

(e) Approximate impact of allowed amortization of rate case expenses ($801,750 per year) on a 1,000 kWh Typical Residential Bill.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for base rate increase by Florida Power & Light Company	Docket No. 160021-EI Filed: May 3, 2016

FLORIDA POWER & LIGHT COMPANY'S
NOTICE OF IDENTIFIED ADJUSTMENTS

Florida Power & Light Company ("FPL") hereby files this Notice of Identified Adjustments, to advise the Florida Public Service Commission, its Staff and intervenors of minor adjustments to certain information contained in its rate case filing that have been identified early in this proceeding. The adjustments are described in Attachment 1 to this Notice.

As reflected in Attachment 1, the adjustments fall into two categories: (i) Adjustments Affecting Revenue Requirements[1] for 2017 and 2018; and (ii) Adjustments Affecting Cost Allocations. The Adjustments Affecting Cost Allocations have no impact on revenue requirements. The Adjustments Affecting Revenue Requirements, if made, would net to an approximate net $9 million decrease in FPL's overall 2017 test year revenue requirements and a decrease of approximately $7 million for FPL's overall 2018 Subsequent Year revenue requirements.

FPL will include all adjustments identified on Attachment 1 in an exhibit of adjustments that it will file with rebuttal testimony, along with any other adjustments that may be identified between now and then. Final rates determined by the Commission would include such adjustments as may be determined appropriate through this proceeding. FPL included similar

[1] As described in Attachment 1, the Adjustments Affecting Revenue Requirements include minor corrections to FPL's dismantlement study. To ease the burden to parties, FPL will produce a dismantlement study with these identified corrections which will be filed in Docket 160062, *2016 Depreciation and Dismantlement Study by Florida Power & Light Company*.

exhibits with the rebuttal testimony of FPL witnesses in its 2009 and 2012 rate cases.

Respectfully submitted,

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By: *s/ John T. Butler*
John T. Butler
Florida Bar No. 283479

CERTIFICATE OF SERVICE
Docket No. 160021-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Notice has been furnished by electronic mail this 3rd day of May 2016 to the following parties:

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By: *s/ John T. Butler*
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Florida Bar No. 283479

ATTACHMENT 1

DOCKET NO. 160021-EI
FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
SUMMARY OF IDENTIFIED ADJUSTMENTS

Item No.	Category Affected	Item	Per Book Adjustments/Corrections with Revenue Requirement Impact	Impact on 2017 Retail Revenue Requirements Incr/(Decr) ($000)	Impact on 2018 Retail Revenue Requirements Incr/(Decr) ($000)	Impact on 2019 OK LSA Revenue Requirements Incr/(Decr) ($000)
1	RB	Deferred Pension Debit	Deferred pension debit in FERC Account 186 was forecasted inconsistently with forecasted pension expense amounts reflected on MFR C-17. As such, rate base is overstated by approximately $3.6M and $8.9M for 2017 and 2018, respectively.	($329)	($808)	N/A
2	NOI	West County Water Reclamation	O&M expense for the servicing of the water reclamation bonds was double counted, resulting in an overstatement to O&M of $4.2M for both 2017 and 2018.	($4,037)	($4,038)	N/A
3	NOI	Outdoor Lighting Revenues	An incorrect present rate was used for the "OL-1 Underground conductors excluding trenching (rate per foot)" in the 2018 revenue forecast. As shown on MFR E-13d page 13 of 21, line 19, column 5, the rate entered was "1.078" and the correct rate is "0.078." Adjusting this rate to reflect the correct value decreases 2018 revenues under present rates by approximately $3.8M.	N/A	$3,838	N/A
4	NOI	Retail Base Revenues	The long-term price of electricity for both 2017 and 2018 was calculated incorrectly as it included higher fuel expense than should have been forecasted. This underestimated the amount of usage by customers and results in less than 0.1% increase in the amount of megawatt hours sold for 2017 and less than 0.2% for 2018. This results in $4.9M of additional retail base revenues for 2017 and $9.3M for 2018.	($4,911)	($9,338)	N/A
5	Changes Related to Forecasted Revenues		The following components of revenue requirement were not forecast consistent with the final forecasted retail revenue from the sales of electricity:			
	NOI	Late Payment Charges	Incorrect Late payment charges for 2017 and 2018 result in an understatement of revenues in 2017 and overstatement of revenues in 2018.	($245)	$491	N/A
	NOI	Returned Checks	Incorrect returned check charges for 2017 and 2018 result in an understatement of revenues in 2017 and overstatement of revenues in 2018.	($6)	$12	N/A
	NOI & RB	Uncollectible Accounts Expense	Incorrect uncollectible accounts expense for 2017 and 2018 result in an understatement of O&M expense in 2017 and overstatement of O&M expense in 2018.	$402	($21)	N/A
	NOI Multiplier	NOI Multiplier - Bad Debt Rate	Incorrect bad debt rate reflected on MFR C-44 for all periods should be 0.066% and the resulting NOI multiplier should be 1.63025.	$4	$1	$2
6	NOI & RB	Demand Side Management (DSM) Peaking Adjustment	FPL includes adjustments to Net Energy for Load (NEL) in its forecast for incremental DSM to account for DSM impacts not reflected in historical data; however, did not include comparable adjustments in its peak forecasts. Including the incremental DSM impact to its peak forecasts lowers the retail share of the system monthly coincident peak demand resulting in a reduction in production demand-based separation factors of 0.014% in 2017 and 0.018% in 2018. There is no impact on the allocation between the rate classes as a result of this adjustment.	($723)	($944)	N/A
7	NOI	Amortization of Gains - Aviation	Gain amortization related to the sale of aviation assets ceased in 2016 and should not have been included in 2017 or 2018. This results in an overstatement of the credit to FERC Account 407 by approximately $1.2M for both 2017 and 2018. FPL did not forecast any activity in the related regulatory liability (FERC Account 254); therefore, no adjustment to rate base is required.	$1,231	$1,231	N/A
8	NOI & RB	Amortization of Gains - Mitigation Bank - Phase II	FPL included a $25.1M as the estimated phase II mitigation bank gain on MFR C-29 and related amortization in 2018 in error. This benefit cannot be recognized until beyond 2020. This results in an overstatement of the credit to FERC Account 407 by approximately $5.0M for 2018.	N/A	$4,807	N/A
9	RB	Company Adjustment - Fukushima	Accumulated depreciation reserve for the Fukushima Company adjustment for 2018 contained a formula error for January 2018. The accumulated depreciation reserve adjustment was understated by $0.1M for 2018, with a resulting $7K impact on revenue requirements.	N/A	($7)	N/A
10	NOI & RB	Company Adjustment - Depreciation	Company adjustment for base depreciation expense was not reflected in the correct distribution plant accounts. The majority of distribution plant accounts have a separation factor of 1; however, plant account 370 has a factor lower than 1. The retail jurisdictional amount for the credit to depreciation expense for the distribution function for both 2017 and 2018 was understated.	($3)	($3)	N/A
11	NOI & RB	Company Adjustment - Dismantlement	Company adjustment dismantlement calculations for both 2017 and 2018 are as follows: 1. Useful life of the Okeechobee plant (currently 52 years, should be 40 years); 2. Alignment of forecasted dismantlement costs for Turkey Point and gas turbines with the study assumptions; and 3. Certain formula errors in the 2016 Dismantlement Study prepared by Burns & McDonnell. The impact of these adjustments result in an overstatement of FPL's dismantlement expense Company adjustment for 2017 and 2018 of $1.4M. Corrections to the 2016 Dismantlement Study will be filed in Docket No. 160062-EI.	($1,315)	($1,186)	N/A

Notes:
The amounts reflected above are approximate amounts and were independently calculated of each other. None of the calculations take into account the impact of other items listed, nor do the calculations for 2018 reflect the impacts for 2017.

DOCKET NO. 160021-EI
FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
SUMMARY OF IDENTIFIED ADJUSTMENTS

Item No.	Category Affected	Item	Per Book Adjustments/Corrections with Revenue Requirement Impact	Impact on 2017 Retail Revenue Requirements Incr/(Decr) ($000)	Impact on 2018 Retail Revenue Requirements Incr/(Decr) ($000)	Impact on 2019 OK LSA Revenue Requirements Incr/(Decr) ($000)
12	Cost of Capital	Company Adjustment - ADIT Proration	ADIT proration company adjustment for 2017 and 2018 did not include the impact of bonus depreciation associated with FPL's Gas Reserves investment. In addition, 2018 was calculated incorrectly due to a formula error. The beginning balance for the 2018 13-month average company adjustment should have been zero, not the ending balance of the ADIT company adjustment for 2017. As such, the weighted average cost of capital for 2017 and 2018 should be 6.6080% and 6.7032%, respectively.	$537	($876)	N/A
13	Cost of Capital	Customer Deposits	Amount of customer deposits for 2017 and 2018 was not updated for the final forecasted retail revenues from the sales of electricity. In addition, the amount of forecasted refunds for excess deposits on master accounts was input incorrectly. As such, the amount of total company per book customer deposits should increase $1.2M and $1.8M for 2017 and 2018, respectively, and all other classes of capital should be adjusted in order for rate base to reconcile to capital structure. The weighted average cost of capital for 2017 and 2018 should be 6.6071% and 6.7048%, respectively. Because the amounts of long term debt and common equity have changed based on these adjustments, the amount of long term debt and common equity used in the calculation of the incremental cost of capital for the 2019 Okeechobee LSA requires an adjustment. Adjusting for these changes decreases the incremental cost of capital for the OK LSA by 0.000098%.	$176	($168)	($2)
14	Cost of Capital	Incremental Cost of Capital	The calculation of the incremental cost of capital for the 2019 Okeechobee LSA was based on the jurisdictional adjusted capital structure amounts from 2018, which included an ADIT proration adjustment specific to 2018 forecasted activity. The ADIT proration adjustment for the 2019 Okeechobee LSA was already reflected in the calculation of deferred income taxes, which is a reduction to rate base. As such, incremental cost of capital should be based on the jurisdictional adjusted 2018 capital structure, less the 2018 ADIT proration adjustment. Adjusting for these changes decreases incremental cost of capital by 0.000002%	N/A	N/A	($0)
NET INCREASE/(DECREASE) IN FPL'S REVENUE REQUIREMENTS				**($9,219)**	**($7,006)**	**($0)**

Item No.	Category Affected	Item	Adjustments/Corrections Without Revenue Requirement Impact	Impact on 2017 Allocations and Unit Costs	Impact on 2018 Allocations and Unit Costs
15	Cost Allocation and Unit Cost	Transmission Pull-off Cost Basis	The cost basis for FPL301, Transmission Customer Pull-offs shown in MFR E- 10, Attachment 2, page 13, for the Test Year and the Subsequent Year is stated as $273,879 per pull-off. The correct cost basis is $167,663.	Shifts $2.952M from demand to customer classification. Increases customer unit costs for transmission level customers ~$1000	Shifts $2.957M from demand to customer classification. Increases customer unit costs for transmission level customers ~$1000
16	Unit Cost	Wholesale interchange revenue	Revenues from Sales of Electricity shown on MFR E1, Test Year and Subsequent Year - Attachment 1, line 15, includes $3.1M of interchange sales revenue that should have been reclassified to other operating revenues. The reclassification from sales revenues to other revenues is needed in order to not impact retail revenue reflected in MFR E-6. This has no impact on revenue recovered through base rates and only a minor impact on unit cost.	The impact on demand unit cost is $0.01/kW or less. The impact to customer and energy unit costs is less than $0.001 per month and 0.0001¢/kWh, respectively	The impact on demand unit cost is $0.01/kW or less. The impact to customer and energy unit costs is less than $0.001 per month and 0.0001¢/kWh, respectively
17	Unit Cost	Transformer depreciation expense	The portion of the 2017 company adjustment to depreciation expense for distribution transformers was $21.8M and the correct adjustment should be $18.2M. For 2018, the difference in the depreciation expense is approximately $0.4M.	Decreases the transformation rider credit unit costs $0.01/kW	<$0.01/kW

Notes:
The amounts reflected above are approximate amounts and were independently calculated of each other. None of the calculations take into account the impact of other items listed, nor do the calculations for 2018 reflect the impacts for 2017.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	Docket No. 160021-EI
In re: Petition for approval of 2016-2018 storm hardening plan, by Florida Power & Light Company	Docket No. 160061-EI
In re: 2016 depreciation and dismantlement study by Florida Power & Light Company	Docket No. 160062-EI
In re: Petition for limited proceeding to modify and continue incentive mechanism by Florida Power & Light Company	Docket No. 160088-EI Filed: June 16, 2016

FLORIDA POWER & LIGHT COMPANY'S
SECOND NOTICE OF IDENTIFIED ADJUSTMENTS

Florida Power & Light Company ("FPL") hereby files this Second Notice of Identified Adjustments, to advise the Florida Public Service Commission, its Staff and intervenors of three adjustments to information contained in its rate case filing that have been identified subsequent to the Notice of Identified Adjustments that was filed on May 3, 2016 in this proceeding. Those adjustments are briefly described below and in Attachment 1 to this Notice:

Supplement to 2016 Depreciation Study. As filed, FPL's 2016 depreciation study developed service lives and net salvage characteristics based on historical data through year-end 2014. Those parameters were then applied to estimated plant and reserve balances brought forward to year-end 2017. Because the primary test year in FPL's base rate case is 2017, FPL considered year-end 2017 estimated plant and reserve balances as best representing FPL's depreciable plant during the test year. Discovery to date from Staff and others has raised questions about whether using year-end 2016 balances would be more appropriate and consistent with past Commission practice. FPL continues to believe that the use of year-end 2017 balances would provide a good match with FPL's 2017 Test Year and 2018 Subsequent Year, but has no

objection to using results for year-end 2016 balances for the purpose of setting depreciation rates and determining FPL's base rates in this proceeding and accordingly is proposing the adjustment described below.

FPL has prepared a supplemental version of Tables 1 through 8 that appear in Part VI of the 2016 Depreciation Study, using year-end 2016 balances. Those tables present summaries by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives, and thus set forth in considerable detail the depreciation parameters resulting from the use of the year-end 2016 balances. The supplemental tables are Attachment 2 to this Notice. As shown on Attachment 1, using year-end 2016 balances results in reductions in revenue requirements of $20.9 million in FPL's requested 2017 Test Year and $20.5 million in the 2018 Subsequent Year, and an increase in revenue requirements of approximately $200,000 for the 2019 Okeechobee Limited Scope Adjustment. The supplemental tables in Attachment 2 to this notice also include non-substantive corrections to existing net salvage and survivor curve parameters for certain accounts that have been identified in the course of discovery. All workpapers and supporting schedules for the supplemental tables and for the impact on FPL's revenue requirements will be made available electronically to Staff and the intervenors as a supplemental discovery response contemporaneously with the filing of this Notice.

Economic Development Rider. In responding to discovery, FPL determined that its projection of test period revenues for customers taking service under the Economic Development Rider and the Existing Facility Economic Development Rider did not take into account the base rate discounts provided under those riders and thus test period revenues were overstated by the amount of the discounts. At the same time, FPL determined that it needed to correct the five percent of economic development expenses (*i.e.*, rate reductions and O&M expenses) from test period revenue requirements that is contemplated by Rule 25-6.0426, Florida Administrative

Code. These two corrections partially offset and result in increases in revenue requirements of approximately $700,000 in 2017 and $800,000 in 2018, as shown on Attachment 1.

SJRPP Dismantlement Costs. In responding to discovery, FPL determined that it had not correctly forecast the dismantlement costs that are to be accrued for the 30% of SJRPP output that FPL purchases from JEA under a PPA. As shown on Attachment 1, this correction results in decreases in revenue requirements of approximately $70,000 in 2017 and $85,000 in 2018.

FPL will include the adjustments identified on Attachment 1 in an exhibit of adjustments that it will file with rebuttal testimony, along with any other adjustments that may be identified between now and then. Final rates determined by the Commission would include such adjustments as may be determined appropriate through this proceeding. FPL included similar exhibits with the rebuttal testimony of FPL witnesses in its 2009 and 2012 rate cases.

Respectfully submitted,

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By: *s/ John T. Butler*
John T. Butler
Florida Bar No. 283479

CERTIFICATE OF SERVICE
Docket No. 160021-EI
(Consolidated)

I HEREBY CERTIFY that a true and correct copy of the foregoing Notice has been furnished by electronic mail this 16th day of June 2016 to the following parties:

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ATTACHMENT 1

DOCKET NO. 160021-EI
FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
SUMMARY OF IDENTIFIED ADJUSTMENTS

Item No.	Category Affected	Item	Per Book Adjustments/Corrections with Revenue Requirement Impact	Impact on 2017 Retail Revenue Requirements Incr/(Decr) ($000)	Impact on 2018 Retail Revenue Requirements Incr/(Decr) ($000)	Impact on 2019 OK LSA Revenue Requirements Incr/(Decr) ($000)
1	NOI & RB	Company Adjustment - Depreciation	FPL has calculated the impact to its proposed 2017 and 2018 depreciation company adjustments based on December 31, 2016 balances. This results in a reduction of depreciation expense of $23M in 2017 and $25M in 2018, and decrease in the 13-month average accumulated depreciation reserve of $11M and $35M in 2017 and 2018, respectively. It also results in small increases in depreciation expense and the 13-month average accumulated depreciation for the Okeechobee LSA due to a small increase in the depreciation rate for the Port Everglades unit that is used as a proxy for Okeechobee.	($20,858)	($20,518)	$197
2	NOI	Retail Revenues - EDR and EFEDR	As described in FPL's response to Staffs 15th Set of Interrogatories No.288, FPL incorrectly forecasted EDR and EFEDR revenues for both the 2017 Test Year and 2018 Subsequent Year. Retail revenues should have been lower by $715K in 2017 and $850K in 2018. In addition, the FPSC adjustment to remove 5% of economic development expenses was incorrectly calculated. The FPSC adjustment was too low by $20K in 2017 and $26K in 2018.	$697	$825	N/A
3	RB	SJRPP - Deferred Credit - Dismantlement	As described in FPL's response to SFHHA's 8th Set of Interrogatories No.172, FPL incorrectly forecasted the accrual for dismantlement at SJRPP related to FPL's 30% power purchase agreement for both the 2017 Test Year and 2018 Subsequent Year. The deferred credit should be lower by $816K in 2017 and $961K in 2018.	$72	$86	N/A
NET INCREASE/(DECREASE) IN FPL'S REVENUE REQUIREMENTS				**($20,089)**	**($19,607)**	**$197**

Notes:
The amounts reflected above are approximate amounts and do not take into account the impact of the items listed in FPL's Notice of Identified Adjustments filed in this docket on May 3, 2016. In addition, none of the calculations for 2018 reflect the impacts for 2017.

ATTACHMENT 2

FLORIDA POWER AND LIGHT COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED REMAINING LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

	PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	FUTURE ACCRUALS (6)=(100%-(3))x(4)-(5)	COMPOSITE REMAINING LIFE (7)	ANNUAL DEPRECIATION ACCRUALS (8)=(6)/(7)	ANNUAL DEPRECIATION RATE (9)=(8)/(4)
STEAM PRODUCTION PLANT									
MANATEE STEAM PLANT									
MANATEE COMMON									
311 STRUCTURES AND IMPROVEMENTS	06-2028	80 - R2 *	(1)	112,114,271	73,128,598	40,106,815	11.28	3,555,569	3.17
312 BOILER PLANT EQUIPMENT	06-2028	50 - S0 *	(2)	7,715,628	1,329,813	6,540,127	11.13	587,612	7.62
314 TURBOGENERATOR UNITS	06-2028	55 - R0.5 *	(1)	9,652,310	7,657,288	2,091,545	10.74	194,743	2.02
315 ACCESSORY ELECTRIC EQUIPMENT	06-2028	65 - S0 *	(2)	9,646,848	7,389,490	2,450,295	10.86	225,626	2.34
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2028	65 - R0.5 *	(1)	2,450,703	1,919,506	555,705	10.92	50,889	2.08
TOTAL MANATEE COMMON				*141,579,760*	*91,424,696*	*51,744,487*	*11.21*	*4,614,439*	*3.26*
MANATEE UNIT 1									
311 STRUCTURES AND IMPROVEMENTS	06-2028	80 - R2 *	(1)	6,836,328	5,584,432	1,320,260	11.12	118,728	1.74
312 BOILER PLANT EQUIPMENT	06-2028	50 - S0 *	(2)	181,481,969	93,495,502	91,616,107	10.89	8,412,866	4.64
314 TURBOGENERATOR UNITS	06-2028	55 - R0.5 *	(1)	72,660,531	41,616,767	31,770,370	10.86	2,925,448	4.03
315 ACCESSORY ELECTRIC EQUIPMENT	06-2028	65 - S0 *	(2)	14,261,784	8,023,680	6,523,339	11.12	586,631	4.11
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2028	65 - R0.5 *	(1)	3,924,407	2,278,883	1,684,768	10.97	153,580	3.91
TOTAL MANATEE UNIT 1				*279,165,019*	*150,999,264*	*132,914,844*	*10.90*	*12,197,253*	*4.37*
MANATEE UNIT 2									
311 STRUCTURES AND IMPROVEMENTS	06-2028	80 - R2 *	(1)	4,986,744	4,017,696	1,018,916	11.15	91,383	1.83
312 BOILER PLANT EQUIPMENT	06-2028	50 - S0 *	(2)	183,957,418	87,494,700	100,141,866	10.92	9,170,501	4.99
314 TURBOGENERATOR UNITS	06-2028	55 - R0.5 *	(1)	70,765,381	42,942,308	28,530,727	10.85	2,629,560	3.72
315 ACCESSORY ELECTRIC EQUIPMENT	06-2028	65 - S0 *	(2)	12,273,816	6,398,866	6,120,427	11.14	549,410	4.48
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2028	65 - R0.5 *	(1)	3,453,782	1,668,499	1,819,820	10.99	165,589	4.79
TOTAL MANATEE UNIT 2				*275,437,142*	*142,522,068*	*137,631,756*	*10.92*	*12,606,443*	*4.58*
TOTAL MANATEE STEAM PLANT				***696,181,920***	***384,946,028***	***322,291,087***	*10.96*	***29,418,135***	*4.23*
MARTIN STEAM PLANT									
MARTIN COMMON									
311 STRUCTURES AND IMPROVEMENTS	06-2031	80 - R2 *	(1)	241,950,141	158,600,994	85,768,649	14.04	6,108,878	2.52
312 BOILER PLANT EQUIPMENT	06-2031	50 - S0 *	(2)	7,068,506	2,944,759	4,265,118	13.57	314,305	4.45
314 TURBOGENERATOR UNITS	06-2031	55 - R0.5 *	(1)	27,474,257	14,912,384	12,836,615	13.43	955,816	3.48
315 ACCESSORY ELECTRIC EQUIPMENT	06-2031	65 - S0 *	(2)	10,295,313	5,435,309	5,065,911	13.78	367,628	3.57
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2031	65 - R0.5 *	(1)	3,888,459	1,913,639	2,013,704	13.67	147,308	3.79
TOTAL MARTIN COMMON				*290,676,676*	*183,807,084*	*109,949,997*	*13.93*	*7,893,935*	*2.72*
MARTIN PIPELINE									
312 BOILER PLANT EQUIPMENT	06-2031	50 - S0 *	0	370,942	370,942	-	13.04	-	0.00
TOTAL MARTIN PIPELINE				*370,942*	*370,942*	-		-	*0.00*
MARTIN UNIT 1									
311 STRUCTURES AND IMPROVEMENTS	06-2031	80 - R2 *	(1)	16,404,681	10,400,297	6,168,431	14.03	439,660	2.68
312 BOILER PLANT EQUIPMENT	06-2031	50 - S0 *	(2)	212,830,965	87,624,020	129,463,564	13.44	9,632,706	4.53
314 TURBOGENERATOR UNITS	06-2031	55 - R0.5 *	(1)	90,120,383	50,448,065	40,573,522	13.44	3,018,863	3.35
315 ACCESSORY ELECTRIC EQUIPMENT	06-2031	65 - S0 *	(2)	24,391,137	14,440,333	10,438,627	13.72	760,833	3.12
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2031	65 - R0.5 *	(1)	3,594,165	1,758,500	1,871,607	13.67	136,913	3.81
TOTAL MARTIN UNIT 1				*347,341,330*	*164,671,214*	*188,515,751*	*13.48*	*13,988,975*	*4.03*
MARTIN UNIT 2									
311 STRUCTURES AND IMPROVEMENTS	06-2031	80 - R2 *	(1)	11,266,842	7,618,893	3,760,618	13.98	269,000	2.39
312 BOILER PLANT EQUIPMENT	06-2031	50 - S0 *	(2)	215,154,508	84,744,456	134,713,142	13.48	9,993,557	4.64
314 TURBOGENERATOR UNITS	06-2031	55 - R0.5 *	(1)	82,856,949	30,043,134	53,642,385	13.52	3,967,632	4.79
315 ACCESSORY ELECTRIC EQUIPMENT	06-2031	65 - S0 *	(2)	23,045,156	12,167,493	11,338,566	13.83	819,853	3.56
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2031	65 - R0.5 *	(1)	3,280,816	1,374,670	1,938,954	13.71	141,426	4.31
TOTAL MARTIN UNIT 2				*335,604,270*	*135,948,644*	*205,393,665*	*13.52*	*15,191,468*	*4.53*
TOTAL MARTIN STEAM PLANT				***973,993,219***	***484,797,884***	***503,859,413***	***13.59***	***37,074,378***	***3.81***

FLORIDA POWER AND LIGHT COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED REMAINING LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

	PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	FUTURE ACCRUALS (6)=(100%-(3))x(4)-(5)	COMPOSITE REMAINING LIFE (7)	ANNUAL DEPRECIATION ACCRUALS (8)=(6)/(7)	ANNUAL DEPRECIATION RATE (9)=(8)/(4)
SCHERER STEAM PLANT									
SCHERER COAL CARS									
312 BOILER PLANT EQUIPMENT	06-2039	50 - S0 *	0	33,149,442	33,149,442	-	19.25	-	0.00
TOTAL SCHERER COAL CARS				*33,149,442*	*33,149,442*	-	*19.25*	-	*0.00*
SCHERER COMMON									
311 STRUCTURES AND IMPROVEMENTS	06-2039	80 - R2 *	(1)	39,391,667	20,717,188	19,068,395	21.60	882,796	2.24
312 BOILER PLANT EQUIPMENT	06-2039	50 - S0 *	(4)	25,844,055	12,070,575	14,807,242	19.34	765,628	2.96
314 TURBOGENERATOR UNITS	06-2039	55 - R0.5 *	(1)	4,336,718	1,830,764	2,549,321	19.91	128,042	2.95
315 ACCESSORY ELECTRIC EQUIPMENT	06-2039	65 - S0 *	(4)	1,226,257	679,212	596,095	20.22	29,480	2.40
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2039	65 - R0.5 *	(1)	3,659,825	1,735,162	1,961,262	20.49	95,718	2.62
TOTAL SCHERER COMMON				*74,458,521*	*37,032,900*	*38,982,315*	*20.50*	*1,901,664*	*2.55*
SCHERER COMMON UNIT 3 AND 4									
311 STRUCTURES AND IMPROVEMENTS	06-2039	80 - R2 *	(1)	2,999,449	1,646,858	1,382,585	21.56	64,127	2.14
312 BOILER PLANT EQUIPMENT	06-2039	50 - S0 *	(4)	22,335,968	9,614,113	13,615,294	19.59	695,012	3.11
314 TURBOGENERATOR UNITS	06-2039	55 - R0.5 *	(1)	2,831,158	224,639	2,634,831	20.55	128,216	4.53
315 ACCESSORY ELECTRIC EQUIPMENT	06-2039	65 - S0 *	(4)	2,818,575	245,786	2,685,532	21.48	125,025	4.44
TOTAL SCHERER COMMON UNIT 3 AND 4				*30,985,149*	*11,731,396*	*20,318,242*	*20.07*	*1,012,380*	*3.27*
SCHERER UNIT 4									
311 STRUCTURES AND IMPROVEMENTS	06-2039	80 - R2 *	(1)	159,104,427	39,437,115	121,258,357	21.89	5,539,441	3.48
312 BOILER PLANT EQUIPMENT	06-2039	50 - S0 *	(4)	671,515,648	178,043,157	520,333,117	20.16	25,810,174	3.84
314 TURBOGENERATOR UNITS	06-2039	55 - R0.5 *	(1)	122,853,491	58,668,053	65,413,972	19.88	3,290,441	2.68
315 ACCESSORY ELECTRIC EQUIPMENT	06-2039	65 - S0 *	(4)	49,374,419	14,135,035	37,214,361	20.96	1,775,494	3.60
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2039	65 - R0.5 *	(1)	5,117,266	2,275,999	2,892,440	20.62	140,274	2.74
TOTAL SCHERER UNIT 4				*1,007,965,252*	*292,559,359*	*747,112,247*	*20.44*	*36,555,824*	*3.63*
TOTAL SCHERER STEAM PLANT				***1,146,558,365***	***374,473,097***	***806,412,804***	***20.43***	***39,469,868***	***3.44***

FLORIDA POWER AND LIGHT COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED REMAINING LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	COMPOSITE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(100%-(3))x(4)-(5)	(7)	(8)=(6)/(7)	(9)=(8)/(4)
SJRPP STEAM PLANT									
SJRPP COAL AND LIMESTONE									
311 STRUCTURES AND IMPROVEMENTS	06-2038	80 - R2 *	(1)	3,562,391	1,817,206	1,780,809	20.48	86,954	2.44
312 BOILER PLANT EQUIPMENT	06-2038	50 - S0 *	(4)	30,883,389	15,259,114	16,859,611	18.00	936,645	3.03
315 ACCESSORY ELECTRIC EQUIPMENT	06-2038	65 - S0 *	(4)	3,773,252	2,142,570	1,781,612	19.17	92,938	2.46
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	65 - R0.5 *	(1)	300,302	161,831	141,474	19.33	7,319	2.44
TOTAL SJRPP COAL AND LIMESTONE				*38,519,334*	*19,380,721*	*20,563,506*	*18.30*	*1,123,856*	*2.92*
SJRPP COAL CARS									
312 BOILER PLANT EQUIPMENT	06-2038	50 - S0 *	0	52,105	52,105	-	17.84	-	0.00
TOTAL SJRPP COAL CARS				*52,105*	*52,105*	-	*17.84*	-	*0.00*
SJRPP COMMON									
311 STRUCTURES AND IMPROVEMENTS	06-2038	80 - R2 *	(1)	33,146,529	22,171,912	11,306,083	20.54	550,442	1.66
312 BOILER PLANT EQUIPMENT	06-2038	50 - S0 *	(4)	3,694,843	2,563,468	1,279,168	18.22	70,207	1.90
314 TURBOGENERATOR UNITS	06-2038	55 - R0.5 *	(1)	2,497,878	1,684,864	837,993	18.75	44,693	1.79
315 ACCESSORY ELECTRIC EQUIPMENT	06-2038	65 - S0 *	(4)	5,833,698	3,990,701	2,076,346	19.27	107,750	1.85
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	65 - R0.5 *	(1)	1,598,862	1,006,658	608,193	19.52	31,157	1.95
TOTAL SJRPP COMMON				*46,771,810*	*31,417,602*	*16,107,783*	*20.03*	*804,249*	*1.72*
SJRPP GYPSUM AND ASH									
311 STRUCTURES AND IMPROVEMENTS	06-2038	80 - R2 *	(1)	2,172,989	1,122,277	1,072,442	20.54	52,212	2.40
312 BOILER PLANT EQUIPMENT	06-2038	50 - S0 *	(4)	17,085,257	9,494,175	8,274,492	17.87	463,038	2.71
315 ACCESSORY ELECTRIC EQUIPMENT	06-2038	65 - S0 *	(4)	52,571	31,682	22,992	19.35	1,188	2.26
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	65 - R0.5 *	(1)	154,892	64,476	91,965	19.65	4,680	3.02
TOTAL SJRPP GYPSUM AND ASH				*19,465,709*	*10,712,610*	*9,461,891*	*18.16*	*521,118*	*2.68*
SJRPP UNIT 1									
311 STRUCTURES AND IMPROVEMENTS	06-2038	80 - R2 *	(1)	9,049,629	6,497,954	2,642,171	20.45	129,202	1.43
312 BOILER PLANT EQUIPMENT	06-2038	50 - S0 *	(4)	99,626,681	50,079,303	53,532,445	18.54	2,887,403	2.90
314 TURBOGENERATOR UNITS	06-2038	55 - R0.5 *	(1)	31,463,410	15,259,034	16,519,010	19.20	860,365	2.73
315 ACCESSORY ELECTRIC EQUIPMENT	06-2038	65 - S0 *	(4)	12,475,837	7,908,663	5,066,208	19.36	261,684	2.10
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	65 - R0.5 *	(1)	2,038,425	1,391,601	667,209	19.40	34,392	1.69
TOTAL SJRPP UNIT 1				*154,653,983*	*81,136,555*	*78,427,043*	*18.79*	*4,173,046*	*2.70*
SJRPP UNIT 2									
311 STRUCTURES AND IMPROVEMENTS	06-2038	80 - R2 *	(1)	7,177,145	4,116,166	3,132,751	20.43	153,341	2.14
312 BOILER PLANT EQUIPMENT	06-2038	50 - S0 *	(4)	90,153,231	39,507,420	54,251,940	18.56	2,923,057	3.24
314 TURBOGENERATOR UNITS	06-2038	55 - R0.5 *	(1)	28,479,810	10,690,425	18,074,183	19.21	940,874	3.30
315 ACCESSORY ELECTRIC EQUIPMENT	06-2038	65 - S0 *	(4)	10,105,912	5,314,628	5,195,520	19.27	269,617	2.67
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	65 - R0.5 *	(1)	1,571,822	869,236	718,304	19.45	36,931	2.35
TOTAL SJRPP UNIT 2				*137,487,920*	*60,497,875*	*81,372,698*	*18.82*	*4,323,820*	*3.14*
TOTAL SJRPP STEAM PLANT				***396,950,861***	***203,197,468***	***205,932,921***	***18.81***	***10,946,089***	***2.76***
TOTAL STEAM PRODUCTION				**3,213,684,365**	**1,447,414,477**	**1,838,496,225**	***15.73***	**116,908,470**	***3.64***

FLORIDA POWER AND LIGHT COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED REMAINING LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

	PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	FUTURE ACCRUALS (6)=(100%-(3))x(4)-(5)	COMPOSITE REMAINING LIFE (7)	ANNUAL DEPRECIATION ACCRUALS (8)=(6)/(7)	ANNUAL DEPRECIATION RATE (9)=(8)/(4)
NUCLEAR PRODUCTION PLANT									
ST. LUCIE NUCLEAR PLANT									
ST. LUCIE COMMON									
321 STRUCTURES AND IMPROVEMENTS	04-2043	100 - R1.5 *	(1)	396,984,357	176,282,726	224,671,475	25.17	8,926,161	2.25
322 REACTOR PLANT EQUIPMENT	04-2043	60 - R1 *	(2)	55,565,218	31,403,213	25,273,310	23.69	1,066,835	1.92
323 TURBOGENERATOR UNITS	04-2043	45 - R0.5 *	0	12,402,700	(7,534,768)	19,937,468	22.26	895,663	7.22
324 ACCESSORY ELECTRIC EQUIPMENT	04-2043	75 - R2.5 *	(1)	34,367,943	16,891,518	17,820,104	24.78	719,133	2.09
325 MISCELLANEOUS POWER PLANT EQUIPMENT	04-2043	50 - R1.5 *	(3)	20,722,317	2,245,775	19,098,211	22.70	841,331	4.06
TOTAL ST. LUCIE COMMON				*520,042,535*	*219,288,464*	*306,800,568*	*24.64*	*12,449,123*	*2.39*
ST. LUCIE UNIT 1									
321 STRUCTURES AND IMPROVEMENTS	03-2036	100 - R1.5 *	(1)	194,729,786	100,039,207	96,637,876	18.67	5,176,105	2.66
322 REACTOR PLANT EQUIPMENT	03-2036	60 - R1 *	(2)	838,073,831	293,588,602	561,246,706	18.00	31,180,373	3.72
323 TURBOGENERATOR UNITS	03-2036	45 - R0.5 *	0	412,318,467	47,813,095	364,505,372	17.31	21,057,503	5.11
324 ACCESSORY ELECTRIC EQUIPMENT	03-2036	75 - R2.5 *	(1)	119,762,438	49,415,234	71,544,828	18.68	3,830,023	3.20
325 MISCELLANEOUS POWER PLANT EQUIPMENT	03-2036	50 - R1.5 *	(3)	11,320,232	6,997,958	4,661,881	15.87	293,754	2.59
TOTAL ST. LUCIE UNIT 1				*1,576,204,754*	*497,854,096*	*1,098,596,663*	*17.85*	*61,537,758*	*3.90*
ST. LUCIE UNIT 2									
321 STRUCTURES AND IMPROVEMENTS	04-2043	100 - R1.5 *	(1)	297,759,844	130,332,823	170,404,619	25.16	6,772,839	2.27
322 REACTOR PLANT EQUIPMENT	04-2043	60 - R1 *	(2)	1,053,686,661	387,788,728	686,971,666	23.70	28,986,146	2.75
323 TURBOGENERATOR UNITS	04-2043	45 - R0.5 *	0	350,014,044	46,854,392	303,159,652	22.42	13,521,840	3.86
324 ACCESSORY ELECTRIC EQUIPMENT	04-2043	75 - R2.5 *	(1)	188,938,115	84,917,442	105,910,054	24.68	4,291,331	2.27
325 MISCELLANEOUS POWER PLANT EQUIPMENT	04-2043	50 - R1.5 *	(3)	24,130,684	11,189,066	13,665,539	20.78	657,629	2.73
TOTAL ST. LUCIE UNIT 2				*1,914,529,349*	*661,082,451*	*1,280,111,530*	*23.61*	*54,229,785*	*2.83*
TOTAL ST. LUCIE NUCLEAR PLANT				***4,010,776,637***	***1,378,225,011***	***2,685,508,761***	***20.95***	***128,216,666***	***3.20***
TURKEY POINT NUCLEAR PLANT									
TURKEY POINT COMMON									
321 STRUCTURES AND IMPROVEMENTS	04-2033	100 - R1.5 *	(1)	360,056,132	183,734,299	179,922,394	15.98	11,259,224	3.13
322 REACTOR PLANT EQUIPMENT	04-2033	60 - R1 *	(2)	137,627,469	24,011,347	116,368,671	15.58	7,469,106	5.43
323 TURBOGENERATOR UNITS	04-2033	45 - R0.5 *	0	21,825,767	5,398,454	16,427,313	14.91	1,101,765	5.05
324 ACCESSORY ELECTRIC EQUIPMENT	04-2033	75 - R2.5 *	(1)	53,673,512	34,021,888	20,188,359	15.97	1,264,143	2.36
325 MISCELLANEOUS POWER PLANT EQUIPMENT	04-2033	50 - R1.5 *	(3)	37,213,998	17,421,764	20,908,654	15.30	1,366,579	3.67
TOTAL TURKEY POINT COMMON				*610,396,877*	*264,587,751*	*353,815,391*	*15.75*	*22,460,817*	*3.68*
TURKEY POINT UNIT 3									
321 STRUCTURES AND IMPROVEMENTS	07-2032	100 - R1.5 *	(1)	183,462,252	38,437,467	146,859,407	15.31	9,592,385	5.23
322 REACTOR PLANT EQUIPMENT	07-2032	60 - R1 *	(2)	586,039,767	168,441,241	429,319,321	14.82	28,968,915	4.94
323 TURBOGENERATOR UNITS	07-2032	45 - R0.5 *	0	756,080,929	81,959,597	674,121,333	14.39	46,846,514	6.20
324 ACCESSORY ELECTRIC EQUIPMENT	07-2032	75 - R2.5 *	(1)	150,385,799	72,326,463	79,563,194	15.28	5,207,015	3.46
325 MISCELLANEOUS POWER PLANT EQUIPMENT	07-2032	50 - R1.5 *	(3)	15,687,982	752,238	15,406,383	14.84	1,038,166	6.62
TOTAL TURKEY POINT UNIT 3				*1,691,656,730*	*361,917,007*	*1,345,269,638*	*14.68*	*91,652,995*	*5.42*
TURKEY POINT UNIT 4									
321 STRUCTURES AND IMPROVEMENTS	04-2033	100 - R1.5 *	(1)	128,297,844	49,379,171	80,201,652	16.01	5,009,472	3.90
322 REACTOR PLANT EQUIPMENT	04-2033	60 - R1 *	(2)	514,072,790	183,833,792	340,520,454	15.49	21,983,244	4.28
323 TURBOGENERATOR UNITS	04-2033	45 - R0.5 *	0	599,706,206	78,908,563	520,797,643	15.02	34,673,611	5.78
324 ACCESSORY ELECTRIC EQUIPMENT	04-2033	75 - R2.5 *	(1)	175,176,467	103,877,312	73,050,920	15.93	4,585,745	2.62
325 MISCELLANEOUS POWER PLANT EQUIPMENT	04-2033	50 - R1.5 *	(3)	11,936,247	187,688	12,106,646	15.48	782,083	6.55
TOTAL TURKEY POINT UNIT 4				*1,429,189,554*	*416,186,526*	*1,026,677,315*	*15.32*	*67,034,155*	*4.69*
TOTAL TURKEY POINT NUCLEAR PLANT				***3,731,243,161***	***1,042,691,284***	***2,725,762,344***	***15.05***	***181,147,967***	***4.85***
TOTAL NUCLEAR PRODUCTION PLANT				**7,742,019,799**	**2,420,916,295**	**5,411,271,105**	***17.49***	**309,364,633**	***4.00***

FLORIDA POWER AND LIGHT COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED REMAINING LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	COMPOSITE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
		(1)	(2)	(3)	(4)	(5)	(6)=(100%-(3))x(4)-(5)	(7)	(8)=(6)/(7)	(9)=(8)/(4)
COMBINED CYCLE PRODUCTION PLANT										
LAUDERDALE COMBINED CYCLE PLANT										
	LAUDERDALE COMMON									
341	STRUCTURES AND IMPROVEMENTS	06-2033	80 - R2 *	(2)	84,760,736	56,466,915	29,989,036	16.08	1,864,990	2.20
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2033	50 - R1.5 *	(3)	11,513,771	6,416,278	5,442,906	15.29	355,978	3.09
343	PRIME MOVERS - GENERAL	06-2033	50 - R1 *	(3)	27,106,051	5,912,889	22,006,343	15.62	1,408,857	5.20
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2033	9 - L0 *	35	37,564,239	7,262,311	17,154,444	7.11	2,412,721	6.42
344	GENERATORS	06-2033	60 - R2 *	(3)	680,446	405,162	295,698	15.89	18,609	2.73
345	ACCESSORY ELECTRIC EQUIPMENT	06-2033	50 - R2.5 *	(2)	12,121,303	9,401,592	2,962,137	15.25	194,238	1.60
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	50 - S0.5 *	(2)	1,234,438	609,250	649,876	15.38	42,255	3.42
	TOTAL LAUDERDALE COMMON				*174,980,983*	*86,474,396*	*78,500,440*	*12.47*	*6,297,648*	*3.60*
	LAUDERDALE UNIT 4									
341	STRUCTURES AND IMPROVEMENTS	06-2033	80 - R2 *	(2)	5,090,645	3,478,638	1,713,819	16.07	106,647	2.09
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2033	50 - R1.5 *	(3)	673,633	511,484	182,358	15.20	11,997	1.78
343	PRIME MOVERS - GENERAL	06-2033	50 - R1 *	(3)	121,376,511	49,359,731	75,658,076	15.16	4,990,638	4.11
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2033	9 - L0 *	35	64,237,235	8,573,139	33,181,064	6.74	4,923,007	7.66
344	GENERATORS	06-2033	60 - R2 *	(3)	28,799,680	20,523,754	9,139,917	15.69	582,531	2.02
345	ACCESSORY ELECTRIC EQUIPMENT	06-2033	50 - R2.5 *	(2)	29,810,853	19,234,929	11,172,142	15.43	724,053	2.43
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	50 - S0.5 *	(2)	2,599,158	1,902,628	748,513	14.87	50,337	1.94
	TOTAL LAUDERDALE UNIT 4				*252,587,715*	*103,584,302*	*131,795,889*	*11.57*	*11,389,210*	*4.51*
	LAUDERDALE UNIT 5									
341	STRUCTURES AND IMPROVEMENTS	06-2033	80 - R2 *	(2)	3,203,159	1,949,981	1,317,241	16.11	81,765	2.55
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2033	50 - R1.5 *	(3)	742,434	503,872	260,835	15.38	16,959	2.28
343	PRIME MOVERS - GENERAL	06-2033	50 - R1 *	(3)	121,964,623	33,068,495	92,555,067	15.19	6,093,158	5.00
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2033	9 - L0 *	35	24,160,830	1,666,194	14,038,345	7.21	1,947,066	8.06
344	GENERATORS	06-2033	60 - R2 *	(3)	31,767,828	22,571,172	10,149,691	15.76	644,016	2.03
345	ACCESSORY ELECTRIC EQUIPMENT	06-2033	50 - R2.5 *	(2)	24,918,023	15,461,507	9,954,876	15.51	641,836	2.58
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	50 - S0.5 *	(2)	1,810,688	1,287,343	559,558	14.89	37,579	2.08
	TOTAL LAUDERDALE UNIT 5				*208,567,584*	*76,508,564*	*128,835,613*	*13.62*	*9,462,379*	*4.54*
TOTAL LAUDERDALE COMBINED CYCLE PLANT					***636,136,282***	***266,567,261***	***339,131,942***	***12.49***	***27,149,237***	***4.27***

FLORIDA POWER AND LIGHT COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED REMAINING LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	COMPOSITE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(100%-(3))x(4)-(5)	(7)	(8)=(6)/(7)	(9)=(8)/(4)
FT. MYERS COMBINED CYCLE PLANT									
FT. MYERS COMMON									
341 STRUCTURES AND IMPROVEMENTS	06-2043	80 - R2 *	(2)	8,824,312	2,131,886	6,868,912	25.06	274,099	3.11
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2043	50 - R1.5 *	(3)	794,049	284,358	533,513	15.56	34,287	4.32
343 PRIME MOVERS - GENERAL	06-2043	50 - R1 *	(3)	3,709,607	1,045,250	2,775,645	23.96	115,845	3.12
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2043	9 - L0 *	35	441,577	231,377	55,648	5.82	9,562	2.17
344 GENERATORS	06-2043	60 - R2 *	(3)	230,729	16,354	221,297	25.42	8,706	3.77
345 ACCESSORY ELECTRIC EQUIPMENT	06-2043	50 - R2.5 *	(2)	1,163,312	139,908	1,046,670	24.91	42,018	3.61
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	50 - S0.5 *	(2)	768,815	197,971	586,220	22.83	25,678	3.34
TOTAL FT. MYERS COMMON				*15,932,401*	*4,047,105*	*12,087,905*	*23.69*	*510,195*	*3.20*
FT. MYERS UNIT 2									
341 STRUCTURES AND IMPROVEMENTS	06-2043	80 - R2 *	(2)	28,751,597	12,204,747	17,121,883	25.41	673,825	2.34
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2043	50 - R1.5 *	(3)	6,194,175	1,967,815	4,412,184	23.43	188,313	3.04
343 PRIME MOVERS - GENERAL	06-2043	50 - R1 *	(3)	367,522,551	79,088,073	299,460,154	23.53	12,726,738	3.46
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2043	9 - L0 *	35	302,123,631	39,131,213	157,249,147	7.01	22,432,118	7.42
344 GENERATORS	06-2043	60 R2 *	(3)	57,280,635	19,398,986	39,600,067	24.73	1,601,297	2.80
345 ACCESSORY ELECTRIC EQUIPMENT	06-2043	50 R2.5 *	(2)	55,628,985	25,417,944	31,323,620	24.10	1,299,735	2.34
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	50 S0.5 *	(2)	3,539,476	1,628,771	1,981,494	22.90	86,528	2.44
TOTAL FT. MYERS UNIT 2				*821,041,049*	*178,837,550*	*551,148,549*	*14.13*	*39,008,554*	*4.75*
FT. MYERS UNIT 3									
341 STRUCTURES AND IMPROVEMENTS	06-2043	80 - R2 *	(2)	10,445,289	1,539,033	9,115,162	25.82	353,027	3.38
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2043	50 - R1.5 *	(3)	13,425,923	2,081,549	11,747,152	24.47	480,063	3.58
343 PRIME MOVERS - GENERAL	06-2043	50 - R1 *	(3)	164,165,759	(10,456,672)	179,547,404	24.09	7,453,192	4.54
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2043	25 - R1 *	29	20,183,733	(1,479,151)	15,809,602	19.90	794,452	3.94
344 GENERATORS	06-2043	60 - R2 *	(3)	46,926,130	7,152,354	41,181,560	25.38	1,622,599	3.46
345 ACCESSORY ELECTRIC EQUIPMENT	06-2043	50 - R2.5 *	(2)	32,964,437	5,278,646	28,345,079	25.32	1,119,474	3.40
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	50 - S0.5 *	(2)	1,734,913	212,247	1,557,364	24.53	63,488	3.66
TOTAL FT. MYERS UNIT 3				*289,846,185*	*4,328,006*	*287,303,323*	*24.17*	*11,886,295*	*4.10*
TOTAL FT. MYERS COMBINED CYCLE PLANT				***1,126,819,634***	***187,212,661***	***850,539,777***	***16.55***	***51,405,044***	***4.56***
MANATEE COMBINED CYCLE PLANT									
MANATEE UNIT 3									
341 STRUCTURES AND IMPROVEMENTS	06-2045	80 - R2 *	(2)	28,927,929	10,726,313	18,780,174	27.38	685,908	2.37
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2045	50 - R1.5 *	(3)	4,008,361	1,497,584	2,631,028	25.26	104,158	2.60
343 PRIME MOVERS - GENERAL	06-2045	50 - R1 *	(3)	236,795,038	46,167,493	197,731,395	24.95	7,925,106	3.35
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2045	9 - L0 *	35	146,248,668	19,013,518	76,048,115	6.60	11,522,442	7.88
344 GENERATORS	06-2045	60 - R2 *	(3)	41,417,902	16,420,596	26,239,842	26.60	986,460	2.38
345 ACCESSORY ELECTRIC EQUIPMENT	06-2045	50 - R2.5 *	(2)	45,110,148	16,629,259	29,383,092	26.16	1,123,207	2.49
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2045	50 - S0.5 *	(2)	10,976,397	3,676,138	7,519,787	24.71	304,322	2.77
TOTAL MANATEE UNIT 3				*513,484,442*	*114,130,902*	*358,333,433*	*15.82*	*22,651,603*	*4.41*
TOTAL MANATEE COMBINED CYCLE PLANT				***513,484,442***	***114,130,902***	***358,333,433***	***15.82***	***22,651,603***	***4.41***

FLORIDA POWER AND LIGHT COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED REMAINING LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	COMPOSITE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
		(1)	(2)	(3)	(4)	(5)	(6)=(100%-(3))x(4)-(5)	(7)	(8)=(6)/(7)	(9)=(8)/(4)
MARTIN COMBINED CYCLE PLANT										
	MARTIN COMMON									
341	STRUCTURES AND IMPROVEMENTS	06-2034	80 - R2 *	(2)	49,379,840	31,469,365	18,898,072	17.05	1,108,391	2.24
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2034	50 - R1.5 *	(3)	4,766,331	3,048,070	1,861,250	16.15	115,248	2.42
343	PRIME MOVERS - GENERAL	06-2034	50 - R1 *	(3)	22,788,940	14,037,911	9,434,696	16.17	583,469	2.56
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2034	9 - L0 *	35	2,230,422	770,616	679,158	6.01	113,005	5.07
345	ACCESSORY ELECTRIC EQUIPMENT	06-2034	50 - R2.5 *	(2)	5,321,992	3,662,480	1,765,952	16.28	108,474	2.04
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2034	50 - S0.5 *	(2)	4,194,043	2,750,673	1,527,251	15.74	97,030	2.31
	TOTAL MARTIN COMMON				*88,681,567*	*55,739,115*	*34,166,379*	*16.07*	*2,125,617*	*2.40*
	MARTIN UNIT 3									
341	STRUCTURES AND IMPROVEMENTS	06-2034	80 - R2 *	(2)	1,660,028	1,129,406	563,823	17.02	33,127	2.00
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2034	50 - R1.5 *	(3)	178,721	126,140	57,943	15.96	3,631	2.03
343	PRIME MOVERS - GENERAL	06-2034	50 - R1 *	(3)	152,279,614	46,856,499	109,991,504	16.10	6,831,770	4.49
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2034	9 - L0 *	35	67,628,799	4,931,417	39,027,303	7.50	5,203,640	7.69
344	GENERATORS	06-2034	60 - R2 *	(3)	26,577,658	12,491,844	14,883,144	16.83	884,322	3.33
345	ACCESSORY ELECTRIC EQUIPMENT	06-2034	50 - R2.5 *	(2)	28,440,138	16,413,361	12,595,580	16.44	766,155	2.69
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2034	50 - S0.5 *	(2)	569,569	403,368	177,593	15.63	11,362	1.99
	TOTAL MARTIN UNIT 3				*277,334,527*	*82,352,034*	*177,296,890*	*12.91*	*13,734,007*	*4.95*
	MARTIN UNIT 4									
341	STRUCTURES AND IMPROVEMENTS	06-2034	80 - R2 *	(2)	1,498,690	779,399	749,264	17.08	43,868	2.93
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2034	50 - R1.5 *	(3)	178,315	125,767	57,897	15.96	3,628	2.03
343	PRIME MOVERS - GENERAL	06-2034	50 - R1 *	(3)	157,866,532	62,665,792	99,936,736	16.16	6,184,204	3.92
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2034	9 - L0 *	35	100,540,570	14,593,390	50,757,980	6.94	7,313,830	7.27
344	GENERATORS	06-2034	60 - R2 *	(3)	32,812,957	17,243,431	16,553,914	16.82	984,180	3.00
345	ACCESSORY ELECTRIC EQUIPMENT	06-2034	50 - R2.5 *	(2)	25,564,311	14,499,926	11,575,671	16.46	703,261	2.75
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2034	50 - S0.5 *	(2)	826,194	416,190	426,528	16.21	26,313	3.18
	TOTAL MARTIN UNIT 4				*319,287,568*	*110,323,895*	*180,057,990*	*11.80*	*15,259,284*	*4.78*
	MARTIN UNIT 8									
341	STRUCTURES AND IMPROVEMENTS	06-2045	80 - R2 *	(2)	23,755,210	8,515,386	15,714,928	27.38	573,956	2.42
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2045	50 - R1.5 *	(3)	11,392,824	3,970,615	7,763,994	25.22	307,851	2.70
343	PRIME MOVERS - GENERAL	06-2045	50 - R1 *	(3)	256,002,412	48,218,164	215,464,320	25.00	8,618,573	3.37
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2045	9 - L0 *	35	213,276,994	24,119,658	114,510,387	6.92	16,547,744	7.76
344	GENERATORS	06-2045	60 - R2 *	(3)	41,069,900	13,445,958	28,856,038	26.58	1,085,630	2.64
345	ACCESSORY ELECTRIC EQUIPMENT	06-2045	50 - R2.5 *	(2)	51,655,998	17,489,445	35,199,672	26.06	1,350,717	2.61
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2045	50 - S0.5 *	(2)	4,899,017	1,751,981	3,245,016	24.88	130,427	2.66
	TOTAL MARTIN UNIT 8				*602,052,355*	*117,511,209*	*420,754,355*	*14.70*	*28,614,898*	*4.75*
TOTAL MARTIN COMBINED CYCLE PLANT					***1,287,356,017***	***365,926,253***	***812,275,614***	***13.60***	***59,733,806***	***4.64***

FLORIDA POWER AND LIGHT COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED REMAINING LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	COMPOSITE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
		(1)	(2)	(3)	(4)	(5)	(6)=(100%-(3))x(4)-(5)	(7)	(8)=(6)/(7)	(9)=(8)/(4)
SANFORD COMBINED CYCLE PLANT										
	SANFORD COMMON									
341	STRUCTURES AND IMPROVEMENTS	06-2043	80 - R2 *	(2)	71,585,766	29,616,249	43,401,232	25.28	1,716,821	2.40
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2043	50 - R1.5 *	(3)	88,875	42,745	48,796	23.56	2,071	2.33
343	PRIME MOVERS - GENERAL	06-2043	50 - R1 *	(3)	5,932,378	(4,737,256)	10,847,605	22.96	472,457	7.96
344	GENERATORS	06-2043	60 - R2 *	(3)	200,500	36,233	170,282	25.29	6,733	3.36
345	ACCESSORY ELECTRIC EQUIPMENT	06-2043	50 - R2.5 *	(2)	2,142,789	643,155	1,542,490	23.55	65,499	3.06
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	50 - S0.5 *	(2)	2,233,762	820,161	1,458,276	23.23	62,776	2.81
	TOTAL SANFORD COMMON				*82,184,069*	*26,421,287*	*57,468,681*	*24.70*	*2,326,357*	*2.83*
	SANFORD UNIT 4									
341	STRUCTURES AND IMPROVEMENTS	06-2043	80 - R2 *	(2)	7,424,610	3,124,501	4,448,602	25.09	177,306	2.39
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2043	50 - R1.5 *	(3)	1,803,717	789,469	1,068,359	23.63	45,212	2.51
343	PRIME MOVERS - GENERAL	06-2043	50 - R1 *	(3)	196,875,732	18,672,684	184,109,321	23.36	7,881,392	4.00
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2043	9 - L0 *	35	140,077,308	7,071,393	83,978,857	6.94	12,100,700	8.64
344	GENERATORS	06-2043	60 - R2 *	(3)	32,820,452	10,272,329	23,532,737	24.81	948,518	2.89
345	ACCESSORY ELECTRIC EQUIPMENT	06-2043	50 - R2.5 *	(2)	35,200,492	14,915,272	20,989,230	23.91	877,843	2.49
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	50 - S0.5 *	(2)	3,326,653	1,415,407	1,977,779	23.03	85,878	2.58
	TOTAL SANFORD UNIT 4				*417,528,965*	*56,261,055*	*320,104,885*	*14.47*	*22,116,849*	*5.30*
	SANFORD UNIT 5									
341	STRUCTURES AND IMPROVEMENTS	06-2042	80 - R2 *	(2)	7,275,953	3,148,967	4,272,505	24.28	175,968	2.42
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2042	50 - R1.5 *	(3)	1,814,776	859,918	1,009,301	22.77	44,326	2.44
343	PRIME MOVERS - GENERAL	06-2042	50 - R1 *	(3)	214,894,008	20,990,061	200,350,767	22.61	8,861,157	4.12
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2042	9 - L0 *	35	126,367,538	6,255,267	75,883,633	7.00	10,840,519	8.58
344	GENERATORS	06-2042	60 - R2 *	(3)	32,632,812	11,677,845	21,933,951	23.92	916,971	2.81
345	ACCESSORY ELECTRIC EQUIPMENT	06-2042	50 - R2.5 *	(2)	34,685,483	14,818,331	20,560,862	23.15	888,158	2.56
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2042	50 - S0.5 *	(2)	2,899,894	1,243,698	1,714,194	22.31	76,835	2.65
	TOTAL SANFORD UNIT 5				*420,570,464*	*58,994,088*	*325,725,213*	*14.94*	*21,803,934*	*5.18*
TOTAL SANFORD COMBINED CYCLE PLANT					***920,283,497***	***141,676,429***	***703,298,779***	***15.21***	***46,247,140***	***5.03***
TURKEY POINT COMBINED CYCLE PLANT										
	TURKEY POINT UNIT 5									
341	STRUCTURES AND IMPROVEMENTS	06-2047	80 - R2 *	(2)	32,284,855	10,891,633	22,038,919	29.27	752,952	2.33
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2047	50 - R1.5 *	(3)	12,410,131	4,106,992	8,675,443	26.99	321,432	2.59
343	PRIME MOVERS - GENERAL	06-2047	50 - R1 *	(3)	250,685,264	39,618,917	218,586,904	26.56	8,229,929	3.28
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2047	9 - L0 *	35	128,220,285	12,943,274	70,399,912	7.07	9,957,555	7.77
344	GENERATORS	06-2047	60 - R2 *	(3)	41,669,542	11,132,485	31,787,143	28.45	1,117,299	2.68
345	ACCESSORY ELECTRIC EQUIPMENT	06-2047	50 - R2.5 *	(2)	51,980,475	16,506,639	36,513,445	27.96	1,305,917	2.51
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2047	50 - S0.5 *	(2)	12,433,804	3,613,736	9,068,744	26.47	342,605	2.76
	TOTAL TURKEY POINT UNIT 5				*529,684,355*	*98,813,676*	*397,070,510*	*18.03*	*22,027,689*	*4.16*
TOTAL TURKEY POINT COMBINED CYCLE PLANT					***529,684,355***	***98,813,676***	***397,070,510***	***18.03***	***22,027,689***	***4.16***

FLORIDA POWER AND LIGHT COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED REMAINING LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	COMPOSITE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
		(1)	(2)	(3)	(4)	(5)	(6)=(100%-(3))x(4)-(5)	(7)	(8)=(6)/(7)	(9)=(8)/(4)
WEST COUNTY COMBINED CYCLE PLANT										
	WEST COUNTY COMMON									
341	STRUCTURES AND IMPROVEMENTS	06-2051	80 - R2 *	(2)	3,120,798	482,630	2,700,584	33.12	81,539	2.61
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2051	50 - R1.5 *	(3)	450,604	68,020	396,103	30.44	13,013	2.89
343	PRIME MOVERS - GENERAL	06-2051	50 - R1 *	(3)	31,206,902	1,389,969	30,753,140	30.22	1,017,642	3.26
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2051	9 - L0 *	35	126,771,982	12,726,022	69,675,767	7.32	9,518,547	7.51
345	ACCESSORY ELECTRIC EQUIPMENT	06-2051	50 - R2.5 *	(2)	1,291,342	107,199	1,209,969	32.12	37,670	2.92
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2051	50 - S0.5 *	(2)	836,533	111,543	741,721	30.31	24,471	2.93
	TOTAL WEST COUNTY COMMON				*163,678,161*	*14,885,382*	*105,477,284*	*9.86*	*10,692,882*	*6.53*
	WEST COUNTY UNIT 1									
341	STRUCTURES AND IMPROVEMENTS	06-2049	80 - R2 *	(2)	109,835,744	20,012,782	92,019,677	31.19	2,950,294	2.69
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2049	50 - R1.5 *	(3)	21,806,447	2,710,694	19,749,946	28.76	686,716	3.15
343	PRIME MOVERS - GENERAL	06-2049	50 - R1 *	(3)	300,710,821	(22,756,245)	332,488,391	28.21	11,786,189	3.92
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2049	9 - L0 *	35	81,954,083	(7,349,277)	60,619,430	6.27	9,668,171	11.80
344	GENERATORS	06-2049	60 - R2 *	(3)	49,469,105	7,847,276	43,105,902	30.31	1,422,168	2.87
345	ACCESSORY ELECTRIC EQUIPMENT	06-2049	50 - R2.5 *	(2)	72,300,016	12,231,627	61,514,390	29.82	2,062,857	2.85
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2049	50 - S0.5 *	(2)	8,042,081	1,335,110	6,867,813	28.22	243,367	3.03
	TOTAL WEST COUNTY UNIT 1				*644,118,297*	*14,031,966*	*616,365,549*	*21.39*	*28,819,762*	*4.47*
	WEST COUNTY UNIT 2									
341	STRUCTURES AND IMPROVEMENTS	06-2049	80 - R2 *	(2)	39,659,646	6,204,493	34,248,346	31.19	1,098,055	2.77
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2049	50 - R1.5 *	(3)	7,471,457	284,961	7,410,639	28.84	256,957	3.44
343	PRIME MOVERS - GENERAL	06-2049	50 - R1 *	(3)	255,637,285	17,744,809	245,561,594	28.19	8,710,947	3.41
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2049	9 - L0 *	35	149,878,251	12,481,512	84,939,351	6.19	13,722,028	9.16
344	GENERATORS	06-2049	60 - R2 *	(3)	43,599,023	6,676,878	38,230,116	30.32	1,260,888	2.89
345	ACCESSORY ELECTRIC EQUIPMENT	06-2049	50 - R2.5 *	(2)	33,177,136	5,335,502	28,505,176	29.82	955,908	2.88
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2049	50 - S0.5 *	(2)	11,893,351	1,719,196	10,412,022	28.41	366,491	3.08
	TOTAL WEST COUNTY UNIT 2				*541,316,149*	*50,447,351*	*449,307,244*	*17.04*	*26,371,274*	*4.87*
	WEST COUNTY UNIT 3									
341	STRUCTURES AND IMPROVEMENTS	06-2051	80 - R2 *	(2)	57,671,242	8,518,122	50,306,545	33.08	1,520,754	2.64
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2051	50 - R1.5 *	(3)	10,754,858	742,790	10,334,714	30.48	339,065	3.15
343	PRIME MOVERS - GENERAL	06-2051	50 - R1 *	(3)	480,389,197	32,738,513	462,062,360	29.77	15,521,074	3.23
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2051	9 - L0 *	35	98,598,036	8,887,181	55,201,543	6.60	8,363,870	8.48
344	GENERATORS	06-2051	60 - R2 *	(3)	64,525,280	9,184,372	57,276,667	32.17	1,780,437	2.76
345	ACCESSORY ELECTRIC EQUIPMENT	06-2051	50 - R2.5 *	(2)	48,252,610	7,322,267	41,895,395	31.68	1,322,456	2.74
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2051	50 - S0.5 *	(2)	12,454,466	7,732,043	4,971,512	29.98	165,828	1.33
	TOTAL WEST COUNTY UNIT 3				*772,645,690*	*75,125,287*	*682,048,736*	*23.51*	*29,013,484*	*3.76*
TOTAL WEST COUNTY COMBINED CYCLE PLANT					***2,121,758,297***	***154,489,986***	***1,853,198,813***	***19.53***	***94,897,402***	***4.47***
CAPE CANAVERAL COMBINED CYCLE PLANT										
	CAPE CANAVERAL COMBINED CYCLE									
341	STRUCTURES AND IMPROVEMENTS	06-2053	80 - R2 *	(2)	82,092,869	6,368,724	77,366,003	34.98	2,211,721	2.69
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2053	50 - R1.5 *	(3)	47,723,728	3,579,557	45,575,882	32.18	1,416,280	2.97
343	PRIME MOVERS - GENERAL	06-2053	50 - R1 *	(3)	385,108,676	38,729,543	357,932,393	31.38	11,406,386	2.96
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2053	9 - L0 *	35	206,255,249	28,539,906	105,526,006	7.38	14,298,917	6.93
344	GENERATORS	06-2053	60 - R2 *	(3)	70,269,257	5,194,564	67,182,771	34.03	1,974,222	2.81
345	ACCESSORY ELECTRIC EQUIPMENT	06-2053	50 - R2.5 *	(2)	111,693,785	8,403,920	105,523,740	33.59	3,141,522	2.81
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2053	50 - S0.5 *	(2)	10,309,493	738,999	9,776,684	31.85	306,960	2.98
	TOTAL CAPE CANAVERAL COMBINED CYCLE				*913,453,057*	*91,555,214*	*768,883,479*	*22.12*	*34,756,008*	*3.80*
TOTAL CAPE CANAVERAL COMBINED CYCLE PLANT					***913,453,057***	***91,555,214***	***768,883,479***	***22.12***	***34,756,008***	***3.80***

FLORIDA POWER AND LIGHT COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED REMAINING LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

	PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	FUTURE ACCRUALS (6)=(100%-(3))x(4)-(5)	COMPOSITE REMAINING LIFE (7)	ANNUAL DEPRECIATION ACCRUALS (8)=(6)/(7)	ANNUAL DEPRECIATION RATE (9)=(8)/(4)
RIVIERA COMBINED CYCLE PLANT									
RIVIERA COMBINED CYCLE									
341 STRUCTURES AND IMPROVEMENTS	06-2054	80 - R2 *	(2)	80,630,958	7,456,698	74,786,879	35.90	2,083,200	2.58
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2054	50 - R1.5 *	(3)	217,306,004	18,577,338	205,247,846	33.03	6,213,983	2.86
343 PRIME MOVERS - GENERAL	06-2054	50 - R1 *	(3)	525,780,412	35,938,896	505,614,928	32.21	15,697,452	2.99
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2054	9 - L0 *	35	139,494,633	16,409,879	74,261,633	7.56	9,822,967	7.04
344 GENERATORS	06-2054	60 - R2 *	(3)	79,977,232	5,875,063	76,501,486	34.97	2,187,632	2.74
345 ACCESSORY ELECTRIC EQUIPMENT	06-2054	50 - R2.5 *	(2)	82,800,568	6,849,745	77,606,835	34.50	2,249,473	2.72
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2054	50 - S0.5 *	(2)	11,446,561	1,663,361	10,012,131	32.80	305,248	2.67
TOTAL RIVIERA COMBINED CYCLE				*1,137,436,368*	*92,770,979*	*1,024,031,738*	*26.56*	*38,559,955*	*3.39*
TOTAL RIVIERA COMBINED CYCLE PLANT				***1,137,436,368***	***92,770,979***	***1,024,031,738***	***26.56***	***38,559,955***	***3.39***
PT EVERGLADES COMBINED CYCLE PLANT									
PT EVERGLADES COMBINED CYCLE									
341 STRUCTURES AND IMPROVEMENTS	06-2056	80 - R2 *	(2)	101,607,532	2,299,667	101,340,016	37.84	2,678,119	2.64
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2056	50 - R1.5 *	(3)	59,665,117	1,350,391	60,104,680	34.77	1,728,636	2.90
343 PRIME MOVERS - GENERAL	06-2056	50 - R1 *	(3)	499,500,579	8,382,316	506,103,280	33.84	14,955,771	2.99
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2056	9 - L0 *	35	191,363,196	7,253,893	117,132,184	8.61	13,604,203	7.11
344 GENERATORS	06-2056	60 - R2 *	(3)	87,208,139	1,973,768	87,850,615	36.84	2,384,653	2.73
345 ACCESSORY ELECTRIC EQUIPMENT	06-2056	50 - R2.5 *	(2)	138,483,956	3,134,285	138,119,349	36.42	3,792,404	2.74
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2056	50 - S0.5 *	(2)	12,795,087	289,589	12,761,400	34.72	367,552	2.87
TOTAL PT EVERGLADES COMBINED CYCLE				*1,090,623,606*	*24,683,910*	*1,023,411,524*	*25.90*	*39,511,338*	*3.62*
TOTAL PT EVERGLADES COMBINED CYCLE PLANT				***1,090,623,606***	***24,683,910***	***1,023,411,524***	***25.90***	***39,511,338***	***3.62***
TOTAL COMBINED CYCLE PRODUCTION PLANT				**10,277,035,554**	**1,537,827,272**	**8,130,175,609**	***18.61***	**436,939,222**	***4.25***
PEAKER PLANTS									
LAUDERDALE GTS									
341 STRUCTURES AND IMPROVEMENTS	06-2028	80 - R2 *	(2)	601,222	330,322	282,924	11.26	25,126	4.18
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2028	50 - R1.5 *	(3)	194,417	102,093	98,157	10.68	9,191	4.73
343 PRIME MOVERS - GENERAL	06-2028	50 - R1 *	(3)	14,841,925	1,714,581	13,572,602	11.08	1,224,964	8.25
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2028	25 - R1 *	29	1,858,779	673,466	646,267	8.31	77,770	4.18
344 GENERATORS	06-2028	60 - R2 *	(3)	1,748,135	750,005	1,050,575	10.61	99,017	5.66
345 ACCESSORY ELECTRIC EQUIPMENT	06-2028	50 - R2.5 *	(2)	420,107	174,657	253,852	10.04	25,284	6.02
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2028	50 - S0.5 *	(2)	20,935	8,570	12,784	9.84	1,299	6.21
TOTAL LAUDERDALE GTS				*19,685,520*	*3,753,692*	*15,917,161*	***10.88***	*1,462,651*	***7.43***
FT. MYERS GTS									
341 STRUCTURES AND IMPROVEMENTS	06-2028	80 - R2 *	(2)	941,093	168,137	791,778	11.37	69,637	7.40
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2028	50 - R1.5 *	(3)	724,318	117,795	628,252	11.07	56,753	7.84
343 PRIME MOVERS - GENERAL	06-2028	50 - R1 *	(3)	10,218,903	1,207,170	9,318,300	11.09	840,243	8.22
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2028	25 - R1 *	29	2,807,095	1,254,825	738,213	6.28	117,550	4.19
344 GENERATORS	06-2028	60 - R2 *	(3)	4,602,022	551,085	4,188,998	11.27	371,695	8.08
345 ACCESSORY ELECTRIC EQUIPMENT	06-2028	50 - R2.5 *	(2)	3,450,438	485,852	3,033,595	11.32	267,985	7.77
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2028	50 - S0.5 *	(2)	20,936	2,632	18,723	11.13	1,682	8.03
TOTAL FT. MYERS GTS				*22,764,804*	*3,787,495*	*18,717,859*	***10.85***	*1,725,545*	***7.58***
LAUDERDALE AND FT. MYERS PEAKERS									
341 STRUCTURES AND IMPROVEMENTS	06-2056	80 - R2 *	(2)	43,805,886	76,824	44,605,179	37.84	1,178,784	2.69
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2056	50 - R1.5 *	(3)	26,150,085	45,861	26,888,727	34.77	773,331	2.96
343 PRIME MOVERS - GENERAL	06-2056	50 - R1 *	(3)	213,843,171	389,972	219,868,494	33.84	6,497,296	3.04
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2056	25 - R1 *	29	83,870,827	132,142	59,416,145	24.32	2,443,098	2.91
344 GENERATORS	06-2056	60 - R2 *	(3)	38,221,667	67,031	39,301,286	36.84	1,066,810	2.79
345 ACCESSORY ELECTRIC EQUIPMENT	06-2056	50 - R2.5 *	(2)	60,694,881	106,443	61,802,335	36.42	1,696,934	2.80
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2056	50 - S0.5 *	(2)	5,607,843	9,835	5,710,165	34.72	164,463	2.93
TOTAL LAUDERDALE AND FT. MYERS PEAKERS				*472,194,358*	*828,108*	*457,592,331*	***33.11***	*13,820,716*	***2.93***
TOTAL PEAKER PLANTS				**514,644,682**	**8,369,296**	**492,227,351**	***28.94***	**17,008,912**	***3.30***

FLORIDA POWER AND LIGHT COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED REMAINING LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

	PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	FUTURE ACCRUALS (6)=(100%-(3))x(4)-(5)	COMPOSITE REMAINING LIFE (7)	ANNUAL DEPRECIATION ACCRUALS (8)=(6)/(7)	ANNUAL DEPRECIATION RATE (9)=(8)/(4)
SOLAR PRODUCTION PLANT									
DESOTO SOLAR									
341 STRUCTURES AND IMPROVEMENTS	06-2039	SQUARE *	0	4,635,209	990,040	3,645,168	22.52	161,864	3.49
343 PRIME MOVERS - GENERAL	06-2039	SQUARE *	0	118,689,127	28,800,157	89,888,970	22.52	3,991,517	3.36
345 ACCESSORY ELECTRIC EQUIPMENT	06-2039	SQUARE *	0	27,532,945	4,878,293	22,654,652	22.52	1,005,979	3.65
TOTAL DESOTOSOLAR				*150,857,280*	*34,668,490*	*116,188,790*	*22.52*	*5,159,360*	*3.42*
SPACE COAST SOLAR									
341 STRUCTURES AND IMPROVEMENTS	06-2040	SQUARE *	0	3,986,978	748,519	3,238,459	23.52	137,690	3.45
343 PRIME MOVERS - GENERAL	06-2040	SQUARE *	0	52,858,699	11,827,508	41,031,191	23.52	1,744,523	3.30
345 ACCESSORY ELECTRIC EQUIPMENT	06-2040	SQUARE *	0	6,281,496	1,091,797	5,189,698	23.52	220,650	3.51
TOTAL SPACE COAST SOLAR				*63,127,172*	*13,667,824*	*49,459,348*	*23.52*	*2,102,863*	*3.33*
MARTIN SOLAR									
341 STRUCTURES AND IMPROVEMENTS	06-2045	SQUARE *	0	21,320,036	3,172,447	18,147,589	28.48	637,205	2.99
343 PRIME MOVERS - GENERAL	06-2045	SQUARE *	0	405,752,300	73,095,004	332,657,296	28.47	11,684,485	2.88
345 ACCESSORY ELECTRIC EQUIPMENT	06-2045	SQUARE *		4,239,215	633,733	3,605,482	28.47	126,641	2.99
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2045	SQUARE *	0	1,335	257	1,079	28.47	38	2.85
TOTAL MARTIN SOLAR				*431,312,886*	*76,901,441*	*354,411,446*	*28.47*	*12,448,369*	*2.89*
BABCOCK RANCH SOLAR									
341 STRUCTURES AND IMPROVEMENTS	06-2046	SQUARE *	0	4,078,184	18,086	4,060,098	29.53	137,491	3.37
343 PRIME MOVERS - GENERAL	06-2046	SQUARE *	0	104,118,206	461,738	103,656,468	29.53	3,510,209	3.37
345 ACCESSORY ELECTRIC EQUIPMENT	06-2046	SQUARE *	0	24,224,241	107,428	24,116,813	29.53	816,689	3.37
TOTAL BABCOCK RANCH SOLAR				*132,420,631*	*587,252*	*131,833,379*	*29.53*	*4,464,389*	*3.37*
MANATEE SOLAR									
341 STRUCTURES AND IMPROVEMENTS	06-2046	SQUARE *	0	4,118,679	7,223	4,111,456	29.53	139,230	3.38
343 PRIME MOVERS - GENERAL	06-2046	SQUARE *	0	105,224,179	184,536	105,039,643	29.53	3,557,049	3.38
345 ACCESSORY ELECTRIC EQUIPMENT	06-2046	SQUARE *	0	24,464,781	42,905	24,421,876	29.53	827,019	3.38
TOTAL MANATEE SOLAR				*133,807,639*	*234,664*	*133,572,975*	*29.53*	*4,523,298*	*3.38*
CITRUS SOLAR									
341 STRUCTURES AND IMPROVEMENTS	06-2046	SQUARE *	0	4,207,181	18,559	4,188,622	29.53	141,843	3.37
343 PRIME MOVERS - GENERAL	06-2046	SQUARE *	0	107,250,213	473,102	106,777,111	29.53	3,615,886	3.37
345 ACCESSORY ELECTRIC EQUIPMENT	06-2046	SQUARE *	0	24,990,480	110,238	24,880,242	29.53	842,541	3.37
TOTAL CITRUS SOLAR				*136,447,874*	*601,899*	*135,845,975*	*29.53*	*4,600,270*	*3.37*
TOTAL SOLAR PRODUCTION PLANT				**1,047,973,483**	**126,661,571**	**921,311,913**	***27.67***	**33,298,549**	***3.18***
TOTAL PRODUCTION PLANT				**22,795,357,882**	**5,541,188,910**	**16,793,482,203**	***18.38***	**913,519,786**	***4.01***

FLORIDA POWER AND LIGHT COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED REMAINING LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	FUTURE ACCRUALS (6)=(100%-(3))x(4)-(5)	COMPOSITE REMAINING LIFE (7)	ANNUAL DEPRECIATION ACCRUALS (8)=(6)/(7)	ANNUAL DEPRECIATION RATE (9)=(8)/(4)
TRANSMISSION, DISTRIBUTION, AND GENERAL PLANT										
	TRANSMISSION PLANT									
350.2	EASEMENTS		75 - S4	0	240,510,767	80,181,515	160,329,252	53.20	3,013,708	1.25
352	STRUCTURES AND IMPROVEMENTS		65 - R3	(15)	154,719,740	40,213,775	137,713,926	52.43	2,626,625	1.70
353	STATION EQUIPMENT		40 - R1	(2)	1,741,377,472	504,497,585	1,271,707,436	30.90	41,155,580	2.36
353.1	STATION EQUIPMENT - STEP-UP TRANSFORMERS		30 - R1	0	400,209,880	67,360,985	332,848,894	23.69	14,050,185	3.51
354	TOWERS AND FIXTURES		60 - R4	(25)	349,056,185	225,421,515	210,898,716	35.88	5,877,891	1.68
355	POLES AND FIXTURES		50 - R2	(50)	1,242,636,001	420,741,337	1,443,212,664	39.88	36,188,883	2.91
356	OVERHEAD CONDUCTORS AND DEVICES		51 - R1	(55)	854,174,816	364,102,828	959,868,136	39.61	24,232,975	2.84
357	UNDERGROUND CONDUIT		65 - R4	0	75,512,192	26,533,422	48,978,770	45.29	1,081,448	1.43
358	UNDERGROUND CONDUCTORS AND DEVICES		65 - R3	(20)	104,576,520	29,275,918	96,215,905	49.27	1,952,829	1.87
359	ROADS AND TRAILS		75 - R4	(10)	113,485,941	42,504,639	82,329,896	54.53	1,509,809	1.33
	TOTAL TRANSMISSION PLANT				**5,276,259,513**	**1,800,833,520**	**4,744,103,595**	***36.02***	**131,689,933**	***2.50***
	DISTRIBUTION PLANT									
361	STRUCTURES AND IMPROVEMENTS		65 - R3	(15)	198,554,703	55,416,150	172,921,759	49.85	3,468,842	1.75
362	STATION EQUIPMENT		45 - R1.5	(10)	1,740,028,154	531,280,566	1,382,750,404	33.67	41,067,728	2.36
364.1	POLES, TOWERS AND FIXTURES - WOOD		40 - R2	(100)	1,083,692,909	481,024,953	1,686,360,865	28.90	58,351,587	5.38
364.2	POLES, TOWERS AND FIXTURES - CONCRETE		50 - R1.5	(100)	706,877,719	98,411,503	1,315,343,935	45.65	28,813,668	4.08
365	OVERHEAD CONDUCTORS AND DEVICES		48 - R1	(80)	1,991,793,394	740,342,106	2,844,886,003	38.90	73,133,316	3.67
366.6	UNDERGROUND CONDUIT - DUCT SYSTEM		70 - R3	0	1,528,850,821	345,598,141	1,183,252,679	54.59	21,675,264	1.42
366.7	UNDERGROUND CONDUIT - DIRECT BURIED		50 - R4	0	193,885,661	26,860,958	167,024,703	43.04	3,880,685	2.00
367.6	UNDERGROUND CONDUCTORS AND DEVICES - DUCT SYSTEM		42 - S0	(5)	1,723,803,662	475,313,897	1,334,679,948	31.87	41,878,881	2.43
367.7	UNDERGROUND CONDUCTORS AND DEVICES - DIRECT BURIED		35 - R2	0	731,720,379	288,138,701	443,581,678	23.06	19,235,979	2.63
368	LINE TRANSFORMERS		34 - S0	(15)	2,172,571,477	977,456,673	1,521,000,525	23.48	64,778,557	2.98
369.1	SERVICES - OVERHEAD		53 - R1	(125)	429,359,956	121,671,610	844,388,292	45.82	18,428,378	4.29
369.6	SERVICES - UNDERGROUND		45 - R2	(15)	818,122,343	316,173,519	624,667,176	31.75	19,674,557	2.40
370	METERS		38 - R2	(30)	90,547,258	64,524,789	53,186,646	17.18	3,095,847	3.42
370.1	METERS - AMI		20 - R2.5	(30)	752,056,781	195,134,861	782,538,954	15.60	50,162,753	6.67
371	INSTALLATIONS ON CUSTOMER'S PREMISES		30 - L0	(15)	77,912,064	32,661,220	56,937,653	21.97	2,591,609	3.33
373	STREET LIGHTING AND SIGNAL SYSTEMS		35 - O1	(15)	463,393,095	175,429,642	357,472,417	27.34	13,075,070	2.82
	TOTAL DISTRIBUTION PLANT				**14,703,170,376**	**4,925,439,290**	**14,770,993,637**	***31.88***	**463,312,721**	***3.15***
	GENERAL PLANT									
390	STRUCTURES AND IMPROVEMENTS		55 - R1.5	(10)	435,222,597	123,109,607	355,635,249	41.11	8,650,821	1.99
392.1	AUTOMOBILES		6 - L2.5	15	9,038,959	1,913,929	5,769,186	4.06	1,420,982	15.72
392.2	LIGHT TRUCKS		9 - L3	15	47,500,083	12,551,216	27,823,854	5.86	4,748,098	10.00
392.3	HEAVY TRUCKS		12 - S3	15	241,647,650	99,939,976	105,460,527	7.09	14,874,545	6.16
392.4	TRACTOR TRAILERS		9 - L2.5	5	767,855	638,910	90,553	4.48	20,213	2.63
392.9	TRAILERS		20 - L1	15	21,065,643	2,761,578	15,144,219	14.42	1,050,223	4.99
396.1	POWER OPERATED EQUIPMENT		11 - L1.5	15	4,766,126	2,061,673	1,989,534	5.92	336,070	7.05
397.8	COMMUNICATION EQUIPMENT - FIBER OPTICS		20 - S2	0	11,992,500	9,422,442	2,570,057	11.01	233,429	1.95
	TOTAL GENERAL PLANT				**772,001,412**	**252,399,331**	**514,483,179**	***16.42***	**31,334,381**	***4.06***
TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT					**20,751,431,301**	**6,978,672,141**	**20,029,580,411**	***31.98***	**626,337,035**	***3.02***
GRAND TOTAL					**43,546,789,183**	**12,519,861,051**	**36,823,062,614**	***23.91***	**1,539,856,821**	***3.54***

* CURVE SHOWN IS INTERIM SURVIVOR CURVE. LIFE SPAN METHOD IS USED.

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

	PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
STEAM PRODUCTION PLANT						
MANATEE STEAM PLANT						
MANATEE COMMON						
311 STRUCTURES AND IMPROVEMENTS	06-2028	80 - R2 *	(1)	112,114,271	4,167,137	3.72
312 BOILER PLANT EQUIPMENT	06-2028	50 - S0 *	(2)	7,715,628	523,052	6.78
314 TURBOGENERATOR UNITS	06-2028	55 - R0.5 *	(1)	9,652,310	341,657	3.54
315 ACCESSORY ELECTRIC EQUIPMENT	06-2028	65 - S0 *	(2)	9,646,848	291,034	3.02
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2028	65 - R0.5 *	(1)	2,450,703	80,055	3.27
TOTAL MANATEE COMMON				*141,579,760*	*5,402,935*	*3.82*
MANATEE UNIT 1						
311 STRUCTURES AND IMPROVEMENTS	06-2028	80 - R2 *	(1)	6,836,328	159,392	2.33
312 BOILER PLANT EQUIPMENT	06-2028	50 - S0 *	(2)	181,481,969	8,666,680	4.78
314 TURBOGENERATOR UNITS	06-2028	55 - R0.5 *	(1)	72,660,531	3,139,705	4.32
315 ACCESSORY ELECTRIC EQUIPMENT	06-2028	65 - S0 *	(2)	14,261,784	655,292	4.59
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2028	65 - R0.5 *	(1)	3,924,407	154,817	3.94
TOTAL MANATEE UNIT 1				*279,165,019*	*12,775,886*	*4.58*
MANATEE UNIT 2						
311 STRUCTURES AND IMPROVEMENTS	06-2028	80 - R2 *	(1)	4,986,744	118,649	2.38
312 BOILER PLANT EQUIPMENT	06-2028	50 - S0 *	(2)	183,957,418	9,090,018	4.94
314 TURBOGENERATOR UNITS	06-2028	55 - R0.5 *	(1)	70,765,381	2,874,737	4.06
315 ACCESSORY ELECTRIC EQUIPMENT	06-2028	65 - S0 *	(2)	12,273,816	596,285	4.86
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2028	65 - R0.5 *	(1)	3,453,782	152,781	4.42
TOTAL MANATEE UNIT 2				*275,437,142*	*12,832,470*	*4.66*
TOTAL MANATEE STEAM PLANT				***696,181,920***	***31,011,291***	*4.45*

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
MARTIN STEAM PLANT							
	MARTIN COMMON						
311	STRUCTURES AND IMPROVEMENTS	06-2031	80 - R2 *	(1)	241,950,141	6,222,741	2.57
312	BOILER PLANT EQUIPMENT	06-2031	50 - S0 *	(2)	7,068,506	313,017	4.43
314	TURBOGENERATOR UNITS	06-2031	55 - R0.5 *	(1)	27,474,257	965,141	3.51
315	ACCESSORY ELECTRIC EQUIPMENT	06-2031	65 - S0 *	(2)	10,295,313	380,826	3.70
316	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2031	65 - R0.5 *	(1)	3,888,459	143,228	3.68
	TOTAL MARTIN COMMON				*290,676,676*	*8,024,953*	*2.76*
	MARTIN PIPELINE						
312	BOILER PLANT EQUIPMENT	06-2031	50 - S0 *	0	370,942	11,202	3.02
	TOTAL MARTIN PIPELINE				*370,942*	*11,202*	
	MARTIN UNIT 1						
311	STRUCTURES AND IMPROVEMENTS	06-2031	80 - R2 *	(1)	16,404,681	415,594	2.53
312	BOILER PLANT EQUIPMENT	06-2031	50 - S0 *	(2)	212,830,965	8,803,028	4.14
314	TURBOGENERATOR UNITS	06-2031	55 - R0.5 *	(1)	90,120,383	3,280,656	3.64
315	ACCESSORY ELECTRIC EQUIPMENT	06-2031	65 - S0 *	(2)	24,391,137	842,616	3.45
316	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2031	65 - R0.5 *	(1)	3,594,165	136,791	3.81
	TOTAL MARTIN UNIT 1				*347,341,330*	*13,478,685*	*3.88*
	MARTIN UNIT 2						
311	STRUCTURES AND IMPROVEMENTS	06-2031	80 - R2 *	(1)	11,266,842	270,118	2.40
312	BOILER PLANT EQUIPMENT	06-2031	50 - S0 *	(2)	215,154,508	9,093,979	4.23
314	TURBOGENERATOR UNITS	06-2031	55 - R0.5 *	(1)	82,856,949	3,493,740	4.22
315	ACCESSORY ELECTRIC EQUIPMENT	06-2031	65 - S0 *	(2)	23,045,156	903,472	3.92
316	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2031	65 - R0.5 *	(1)	3,280,816	130,785	3.99
	TOTAL MARTIN UNIT 2				*335,604,270*	*13,892,094*	*4.14*
TOTAL MARTIN STEAM PLANT					***973,993,219***	***35,406,934***	***3.64***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
SCHERER STEAM PLANT							
	SCHERER COAL CARS						
312	BOILER PLANT EQUIPMENT	06-2039	50 - S0 *	0	33,149,442	942,509	2.84
	TOTAL SCHERER COAL CARS				*33,149,442*	*942,509*	*2.84*
	SCHERER COMMON						
311	STRUCTURES AND IMPROVEMENTS	06-2039	80 - R2 *	(1)	39,391,667	976,488	2.48
312	BOILER PLANT EQUIPMENT	06-2039	50 - S0 *	(4)	25,844,055	781,528	3.02
314	TURBOGENERATOR UNITS	06-2039	55 - R0.5 *	(1)	4,336,718	125,125	2.89
315	ACCESSORY ELECTRIC EQUIPMENT	06-2039	65 - S0 *	(4)	1,226,257	32,201	2.63
316	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2039	65 - R0.5 *	(1)	3,659,825	103,027	2.82
	TOTAL SCHERER COMMON				*74,458,521*	*2,018,369*	*2.71*
	SCHERER COMMON UNIT 3 AND 4						
311	STRUCTURES AND IMPROVEMENTS	06-2039	80 - R2 *	(1)	2,999,449	71,885	2.40
312	BOILER PLANT EQUIPMENT	06-2039	50 - S0 *	(4)	22,335,968	712,151	3.19
314	TURBOGENERATOR UNITS	06-2039	55 - R0.5 *	(1)	2,831,158	125,146	4.42
315	ACCESSORY ELECTRIC EQUIPMENT	06-2039	65 - S0 *	(4)	2,818,575	121,987	4.33
	TOTAL SCHERER COMMON UNIT 3 AND 4				*30,985,149*	*1,031,169*	*3.33*
	SCHERER UNIT 4						
311	STRUCTURES AND IMPROVEMENTS	06-2039	80 - R2 *	(1)	159,104,427	5,219,160	3.28
312	BOILER PLANT EQUIPMENT	06-2039	50 - S0 *	(4)	671,515,648	24,296,899	3.62
314	TURBOGENERATOR UNITS	06-2039	55 - R0.5 *	(1)	122,853,491	3,502,383	2.85
315	ACCESSORY ELECTRIC EQUIPMENT	06-2039	65 - S0 *	(4)	49,374,419	1,688,068	3.42
316	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2039	65 - R0.5 *	(1)	5,117,266	163,872	3.20
	TOTAL SCHERER UNIT 4				*1,007,965,252*	*34,870,382*	*3.46*
TOTAL SCHERER STEAM PLANT					***1,146,558,365***	***38,862,429***	***3.39***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
SJRPP STEAM PLANT							
	SJRPP COAL AND LIMESTONE						
311	STRUCTURES AND IMPROVEMENTS	06-2038	80 - R2 *	(1)	3,562,391	80,115	2.25
312	BOILER PLANT EQUIPMENT	06-2038	50 - S0 *	(4)	30,883,389	852,428	2.76
315	ACCESSORY ELECTRIC EQUIPMENT	06-2038	65 - S0 *	(4)	3,773,252	92,799	2.46
316	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	65 - R0.5 *	(1)	300,302	7,195	2.40
	TOTAL SJRPP COAL AND LIMESTONE				*38,519,334*	*1,032,537*	*2.68*
	SJRPP COAL CARS						
312	BOILER PLANT EQUIPMENT	06-2038	50 - S0 *	0	52,105	1,339	2.57
	TOTAL SJRPP COAL CARS				*52,105*	*1,339*	*2.57*
	SJRPP COMMON						
311	STRUCTURES AND IMPROVEMENTS	06-2038	80 - R2 *	(1)	33,146,529	772,382	2.33
312	BOILER PLANT EQUIPMENT	06-2038	50 - S0 *	(4)	3,694,843	106,655	2.89
314	TURBOGENERATOR UNITS	06-2038	55 - R0.5 *	(1)	2,497,878	64,109	2.57
315	ACCESSORY ELECTRIC EQUIPMENT	06-2038	65 - S0 *	(4)	5,833,698	148,376	2.54
316	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	65 - R0.5 *	(1)	1,598,862	42,650	2.67
	TOTAL SJRPP COMMON				*46,771,810*	*1,134,172*	*2.42*
	SJRPP GYPSUM AND ASH						
311	STRUCTURES AND IMPROVEMENTS	06-2038	80 - R2 *	(1)	2,172,989	50,567	2.33
312	BOILER PLANT EQUIPMENT	06-2038	50 - S0 *	(4)	17,085,257	461,076	2.70
315	ACCESSORY ELECTRIC EQUIPMENT	06-2038	65 - S0 *	(4)	52,571	1,376	2.62
316	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	65 - R0.5 *	(1)	154,892	4,674	3.02
	TOTAL SJRPP GYPSUM AND ASH				*19,465,709*	*517,693*	*2.66*
	SJRPP UNIT 1						
311	STRUCTURES AND IMPROVEMENTS	06-2038	80 - R2 *	(1)	9,049,629	196,903	2.18
312	BOILER PLANT EQUIPMENT	06-2038	50 - S0 *	(4)	99,626,681	3,076,074	3.09
314	TURBOGENERATOR UNITS	06-2038	55 - R0.5 *	(1)	31,463,410	1,002,785	3.19
315	ACCESSORY ELECTRIC EQUIPMENT	06-2038	65 - S0 *	(4)	12,475,837	327,432	2.62
316	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	65 - R0.5 *	(1)	2,038,425	51,143	2.51
	TOTAL SJRPP UNIT 1				*154,653,983*	*4,654,337*	*3.01*
	SJRPP UNIT 2						
311	STRUCTURES AND IMPROVEMENTS	06-2038	80 - R2 *	(1)	7,177,145	155,409	2.17
312	BOILER PLANT EQUIPMENT	06-2038	50 - S0 *	(4)	90,153,231	2,784,542	3.09
314	TURBOGENERATOR UNITS	06-2038	55 - R0.5 *	(1)	28,479,810	913,323	3.21
315	ACCESSORY ELECTRIC EQUIPMENT	06-2038	65 - S0 *	(4)	10,105,912	260,459	2.58
316	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	65 - R0.5 *	(1)	1,571,822	39,132	2.49
	TOTAL SJRPP UNIT 2				*137,487,920*	*4,152,865*	*3.02*
TOTAL SJRPP STEAM PLANT					***396,950,861***	***11,492,943***	***2.90***
TOTAL STEAM PRODUCTION					**3,213,684,365**	**116,773,597**	***3.63***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
NUCLEAR PRODUCTION PLANT							
ST. LUCIE NUCLEAR PLANT							
	ST. LUCIE COMMON						
321	STRUCTURES AND IMPROVEMENTS	04-2043	100 - R1.5 *	(1)	396,984,357	8,957,721	2.26
322	REACTOR PLANT EQUIPMENT	04-2043	60 - R1 *	(2)	55,565,218	1,649,174	2.97
323	TURBOGENERATOR UNITS	04-2043	45 - R0.5 *	0	12,402,700	429,315	3.46
324	ACCESSORY ELECTRIC EQUIPMENT	04-2043	75 - R2.5 *	(1)	34,367,943	744,591	2.17
325	MISCELLANEOUS POWER PLANT EQUIPMENT	04-2043	50 - R1.5 *	(3)	20,722,317	605,441	2.92
	TOTAL ST. LUCIE COMMON				*520,042,535*	*12,386,242*	*2.38*
	ST. LUCIE UNIT 1						
321	STRUCTURES AND IMPROVEMENTS	03-2036	100 - R1.5 *	(1)	194,729,786	5,277,085	2.71
322	REACTOR PLANT EQUIPMENT	03-2036	60 - R1 *	(2)	838,073,831	31,002,374	3.70
323	TURBOGENERATOR UNITS	03-2036	45 - R0.5 *	0	412,318,467	18,482,534	4.48
324	ACCESSORY ELECTRIC EQUIPMENT	03-2036	75 - R2.5 *	(1)	119,762,438	3,645,089	3.04
325	MISCELLANEOUS POWER PLANT EQUIPMENT	03-2036	50 - R1.5 *	(3)	11,320,232	291,602	2.58
	TOTAL ST. LUCIE UNIT 1				*1,576,204,754*	*58,698,684*	*3.72*
	ST. LUCIE UNIT 2						
321	STRUCTURES AND IMPROVEMENTS	04-2043	100 - R1.5 *	(1)	297,759,844	6,479,145	2.18
322	REACTOR PLANT EQUIPMENT	04-2043	60 - R1 *	(2)	1,053,686,661	30,686,947	2.91
323	TURBOGENERATOR UNITS	04-2043	45 - R0.5 *	0	350,014,044	12,277,090	3.51
324	ACCESSORY ELECTRIC EQUIPMENT	04-2043	75 - R2.5 *	(1)	188,938,115	4,007,253	2.12
325	MISCELLANEOUS POWER PLANT EQUIPMENT	04-2043	50 - R1.5 *	(3)	24,130,684	588,229	2.44
	TOTAL ST. LUCIE UNIT 2				*1,914,529,349*	*54,038,664*	*2.82*
TOTAL ST. LUCIE NUCLEAR PLANT					***4,010,776,637***	***125,123,590***	***3.12***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
TURKEY POINT NUCLEAR PLANT							
	TURKEY POINT COMMON						
321	STRUCTURES AND IMPROVEMENTS	04-2033	100 - R1.5 *	(1)	360,056,132	12,946,820	3.60
322	REACTOR PLANT EQUIPMENT	04-2033	60 - R1 *	(2)	137,627,469	6,679,713	4.85
323	TURBOGENERATOR UNITS	04-2033	45 - R0.5 *	0	21,825,767	1,057,706	4.85
324	ACCESSORY ELECTRIC EQUIPMENT	04-2033	75 - R2.5 *	(1)	53,673,512	1,738,045	3.24
325	MISCELLANEOUS POWER PLANT EQUIPMENT	04-2033	50 - R1.5 *	(3)	37,213,998	1,540,161	4.14
	TOTAL TURKEY POINT COMMON				*610,396,877*	*23,962,445*	*3.93*
	TURKEY POINT UNIT 3						
321	STRUCTURES AND IMPROVEMENTS	07-2032	100 - R1.5 *	(1)	183,462,252	8,355,653	4.55
322	REACTOR PLANT EQUIPMENT	07-2032	60 - R1 *	(2)	586,039,767	26,200,563	4.47
323	TURBOGENERATOR UNITS	07-2032	45 - R0.5 *	0	756,080,929	40,579,305	5.37
324	ACCESSORY ELECTRIC EQUIPMENT	07-2032	75 - R2.5 *	(1)	150,385,799	5,188,389	3.45
325	MISCELLANEOUS POWER PLANT EQUIPMENT	07-2032	50 - R1.5 *	(3)	15,687,982	802,594	5.12
	TOTAL TURKEY POINT UNIT 3				*1,691,656,730*	*81,126,504*	*4.80*
	TURKEY POINT UNIT 4						
321	STRUCTURES AND IMPROVEMENTS	04-2033	100 - R1.5 *	(1)	128,297,844	4,903,600	3.82
322	REACTOR PLANT EQUIPMENT	04-2033	60 - R1 *	(2)	514,072,790	22,022,789	4.28
323	TURBOGENERATOR UNITS	04-2033	45 - R0.5 *	0	599,706,206	31,642,709	5.28
324	ACCESSORY ELECTRIC EQUIPMENT	04-2033	75 - R2.5 *	(1)	175,176,467	5,244,473	2.99
325	MISCELLANEOUS POWER PLANT EQUIPMENT	04-2033	50 - R1.5 *	(3)	11,936,247	555,252	4.65
	TOTAL TURKEY POINT UNIT 4				*1,429,189,554*	*64,368,823*	*4.50*
TOTAL TURKEY POINT NUCLEAR PLANT					***3,731,243,161***	***169,457,772***	***4.54***
TOTAL NUCLEAR PRODUCTION PLANT					**7,742,019,799**	**294,581,362**	***3.80***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
COMBINED CYCLE PRODUCTION PLANT							
LAUDERDALE COMBINED CYCLE PLANT							
	LAUDERDALE COMMON						
341	STRUCTURES AND IMPROVEMENTS	06-2033	80 - R2 *	(2)	84,760,736	2,684,137	3.17
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2033	50 - R1.5 *	(3)	11,513,771	431,151	3.74
343	PRIME MOVERS - GENERAL	06-2033	50 - R1 *	(3)	27,106,051	1,537,585	5.67
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2033	9 - L0 *	35	37,564,239	2,760,417	7.35
344	GENERATORS	06-2033	60 - R2 *	(3)	680,446	25,250	3.71
345	ACCESSORY ELECTRIC EQUIPMENT	06-2033	50 - R2.5 *	(2)	12,121,303	354,489	2.92
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	50 - S0.5 *	(2)	1,234,438	49,400	4.00
	TOTAL LAUDERDALE COMMON				*174,980,983*	*7,842,429*	*4.48*
	LAUDERDALE UNIT 4						
341	STRUCTURES AND IMPROVEMENTS	06-2033	80 - R2 *	(2)	5,090,645	156,191	3.07
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2033	50 - R1.5 *	(3)	673,633	22,192	3.29
343	PRIME MOVERS - GENERAL	06-2033	50 - R1 *	(3)	121,376,511	4,443,321	3.66
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2033	9 - L0 *	35	64,237,235	4,706,190	7.33
344	GENERATORS	06-2033	60 - R2 *	(3)	28,799,680	889,607	3.09
345	ACCESSORY ELECTRIC EQUIPMENT	06-2033	50 - R2.5 *	(2)	29,810,853	956,997	3.21
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	50 - S0.5 *	(2)	2,599,158	83,452	3.21
	TOTAL LAUDERDALE UNIT 4				*252,587,715*	*11,257,950*	*4.46*
	LAUDERDALE UNIT 5						
341	STRUCTURES AND IMPROVEMENTS	06-2033	80 - R2 *	(2)	3,203,159	106,359	3.32
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2033	50 - R1.5 *	(3)	742,434	26,748	3.60
343	PRIME MOVERS - GENERAL	06-2033	50 - R1 *	(3)	121,964,623	4,533,303	3.72
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2033	9 - L0 *	35	24,160,830	1,781,463	7.37
344	GENERATORS	06-2033	60 - R2 *	(3)	31,767,828	1,036,294	3.26
345	ACCESSORY ELECTRIC EQUIPMENT	06-2033	50 - R2.5 *	(2)	24,918,023	828,235	3.32
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	50 - S0.5 *	(2)	1,810,688	58,645	3.24
	TOTAL LAUDERDALE UNIT 5				*208,567,584*	*8,371,047*	*4.01*
TOTAL LAUDERDALE COMBINED CYCLE PLANT					***636,136,282***	***27,471,426***	***4.32***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
FT. MYERS COMBINED CYCLE PLANT							
	FT. MYERS COMMON						
341	STRUCTURES AND IMPROVEMENTS	06-2043	80 - R2 *	(2)	8,824,312	219,464	2.49
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2043	50 - R1.5 *	(3)	794,049	17,811	2.24
343	PRIME MOVERS - GENERAL	06-2043	50 - R1 *	(3)	3,709,607	140,380	3.78
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2043	9 - L0 *	35	441,577	31,888	7.22
344	GENERATORS	06-2043	60 - R2 *	(3)	230,729	8,447	3.66
345	ACCESSORY ELECTRIC EQUIPMENT	06-2043	50 - R2.5 *	(2)	1,163,312	41,075	3.53
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	50 - S0.5 *	(2)	768,815	22,945	2.98
	TOTAL FT. MYERS COMMON				*15,932,401*	*482,010*	*3.03*
	FT. MYERS UNIT 2						
341	STRUCTURES AND IMPROVEMENTS	06-2043	80 - R2 *	(2)	28,751,597	761,861	2.65
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2043	50 - R1.5 *	(3)	6,194,175	178,852	2.89
343	PRIME MOVERS - GENERAL	06-2043	50 - R1 *	(3)	367,522,551	12,362,824	3.36
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2043	9 - L0 *	35	302,123,631	21,817,858	7.22
344	GENERATORS	06-2043	60 - R2 *	(3)	57,280,635	1,663,763	2.90
345	ACCESSORY ELECTRIC EQUIPMENT	06-2043	50 - R2.5 *	(2)	55,628,985	1,539,029	2.77
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	50 - S0.5 *	(2)	3,539,476	102,810	2.90
	TOTAL FT. MYERS UNIT 2				*821,041,049*	*38,426,997*	*4.68*
	FT. MYERS UNIT 3						
341	STRUCTURES AND IMPROVEMENTS	06-2043	80 - R2 *	(2)	10,445,289	368,771	3.53
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2043	50 - R1.5 *	(3)	13,425,923	504,571	3.76
343	PRIME MOVERS - GENERAL	06-2043	50 - R1 *	(3)	164,165,759	6,595,542	4.02
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2043	25 - R1 *	29	20,183,733	647,655	3.21
344	GENERATORS	06-2043	60 - R2 *	(3)	46,926,130	1,696,151	3.61
345	ACCESSORY ELECTRIC EQUIPMENT	06-2043	50 - R2.5 *	(2)	32,964,437	1,180,213	3.58
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	50 - S0.5 *	(2)	1,734,913	64,343	3.71
	TOTAL FT. MYERS UNIT 3				*289,846,185*	*11,057,246*	*3.81*
TOTAL FT. MYERS COMBINED CYCLE PLANT					***1,126,819,634***	***49,966,253***	***4.43***
MANATEE COMBINED CYCLE PLANT							
	MANATEE UNIT 3						
341	STRUCTURES AND IMPROVEMENTS	06-2045	80 - R2 *	(2)	28,927,929	774,539	2.68
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2045	50 - R1.5 *	(3)	4,008,361	117,518	2.93
343	PRIME MOVERS - GENERAL	06-2045	50 - R1 *	(3)	236,795,038	7,309,129	3.09
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2045	9 - L0 *	35	146,248,668	10,561,348	7.22
344	GENERATORS	06-2045	60 - R2 *	(3)	41,417,902	1,147,783	2.77
345	ACCESSORY ELECTRIC EQUIPMENT	06-2045	50 - R2.5 *	(2)	45,110,148	1,266,131	2.81
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2045	50 - S0.5 *	(2)	10,976,397	321,067	2.93
	TOTAL MANATEE UNIT 3				*513,484,442*	*21,497,515*	*4.19*
TOTAL MANATEE COMBINED CYCLE PLANT					***513,484,442***	***21,497,515***	***4.19***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
MARTIN COMBINED CYCLE PLANT							
	MARTIN COMMON						
341	STRUCTURES AND IMPROVEMENTS	06-2034	80 - R2 *	(2)	49,379,840	1,560,067	3.16
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2034	50 - R1.5 *	(3)	4,766,331	164,475	3.45
343	PRIME MOVERS - GENERAL	06-2034	50 - R1 *	(3)	22,788,940	911,905	4.00
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2034	9 - L0 *	35	2,230,422	161,548	7.24
345	ACCESSORY ELECTRIC EQUIPMENT	06-2034	50 - R2.5 *	(2)	5,321,992	163,525	3.07
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2034	50 - S0.5 *	(2)	4,194,043	135,080	3.22
	TOTAL MARTIN COMMON				*88,681,567*	*3,096,600*	*3.49*
	MARTIN UNIT 3						
341	STRUCTURES AND IMPROVEMENTS	06-2034	80 - R2 *	(2)	1,660,028	49,496	2.98
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2034	50 - R1.5 *	(3)	178,721	5,624	3.15
343	PRIME MOVERS - GENERAL	06-2034	50 - R1 *	(3)	152,279,614	5,785,901	3.80
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2034	9 - L0 *	35	67,628,799	4,963,800	7.34
344	GENERATORS	06-2034	60 - R2 *	(3)	26,577,658	989,920	3.72
345	ACCESSORY ELECTRIC EQUIPMENT	06-2034	50 - R2.5 *	(2)	28,440,138	947,997	3.33
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2034	50 - S0.5 *	(2)	569,569	17,712	3.11
	TOTAL MARTIN UNIT 3				*277,334,527*	*12,760,450*	*4.60*
	MARTIN UNIT 4						
341	STRUCTURES AND IMPROVEMENTS	06-2034	80 - R2 *	(2)	1,498,690	50,367	3.36
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2034	50 - R1.5 *	(3)	178,315	5,611	3.15
343	PRIME MOVERS - GENERAL	06-2034	50 - R1 *	(3)	157,866,532	6,274,125	3.97
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2034	9 - L0 *	35	100,540,570	7,360,245	7.32
344	GENERATORS	06-2034	60 - R2 *	(3)	32,812,957	1,190,575	3.63
345	ACCESSORY ELECTRIC EQUIPMENT	06-2034	50 - R2.5 *	(2)	25,564,311	857,838	3.36
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2034	50 - S0.5 *	(2)	826,194	31,438	3.81
	TOTAL MARTIN UNIT 4				*319,287,568*	*15,770,199*	*4.94*
	MARTIN UNIT 8						
341	STRUCTURES AND IMPROVEMENTS	06-2045	80 - R2 *	(2)	23,755,210	637,408	2.68
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2045	50 - R1.5 *	(3)	11,392,824	333,613	2.93
343	PRIME MOVERS - GENERAL	06-2045	50 - R1 *	(3)	256,002,412	7,989,561	3.12
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2045	9 - L0 *	35	213,276,994	15,401,798	7.22
344	GENERATORS	06-2045	60 - R2 *	(3)	41,069,900	1,140,799	2.78
345	ACCESSORY ELECTRIC EQUIPMENT	06-2045	50 - R2.5 *	(2)	51,655,998	1,437,166	2.78
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2045	50 - S0.5 *	(2)	4,899,017	146,203	2.98
	TOTAL MARTIN UNIT 8				*602,052,355*	*27,086,548*	*4.50*
TOTAL MARTIN COMBINED CYCLE PLANT					***1,287,356,017***	***58,713,797***	***4.56***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
SANFORD COMBINED CYCLE PLANT							
	SANFORD COMMON						
341	STRUCTURES AND IMPROVEMENTS	06-2043	80 - R2 *	(2)	71,585,766	1,828,012	2.55
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2043	50 - R1.5 *	(3)	88,875	2,603	2.93
343	PRIME MOVERS - GENERAL	06-2043	50 - R1 *	(3)	5,932,378	200,553	3.38
344	GENERATORS	06-2043	60 - R2 *	(3)	200,500	6,834	3.41
345	ACCESSORY ELECTRIC EQUIPMENT	06-2043	50 - R2.5 *	(2)	2,142,789	65,322	3.05
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	50 - S0.5 *	(2)	2,233,762	68,478	3.07
	TOTAL SANFORD COMMON				*82,184,069*	*2,171,802*	*2.64*
	SANFORD UNIT 4						
341	STRUCTURES AND IMPROVEMENTS	06-2043	80 - R2 *	(2)	7,424,610	178,864	2.41
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2043	50 - R1.5 *	(3)	1,803,717	53,886	2.99
343	PRIME MOVERS - GENERAL	06-2043	50 - R1 *	(3)	196,875,732	6,321,430	3.21
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2043	9 - L0 *	35	140,077,308	10,115,683	7.22
344	GENERATORS	06-2043	60 - R2 *	(3)	32,820,452	970,633	2.96
345	ACCESSORY ELECTRIC EQUIPMENT	06-2043	50 - R2.5 *	(2)	35,200,492	989,186	2.81
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	50 - S0.5 *	(2)	3,326,653	98,209	2.95
	TOTAL SANFORD UNIT 4				*417,528,965*	*18,727,891*	*4.49*
	SANFORD UNIT 5						
341	STRUCTURES AND IMPROVEMENTS	06-2042	80 - R2 *	(2)	7,275,953	181,639	2.50
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2042	50 - R1.5 *	(3)	1,814,776	54,358	3.00
343	PRIME MOVERS - GENERAL	06-2042	50 - R1 *	(3)	214,894,008	7,079,624	3.29
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2042	9 - L0 *	35	126,367,538	9,127,854	7.22
344	GENERATORS	06-2042	60 - R2 *	(3)	32,632,812	968,004	2.97
345	ACCESSORY ELECTRIC EQUIPMENT	06-2042	50 - R2.5 *	(2)	34,685,483	989,693	2.85
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2042	50 - S0.5 *	(2)	2,899,894	87,043	3.00
	TOTAL SANFORD UNIT 5				*420,570,464*	*18,488,215*	*4.40*
TOTAL SANFORD COMBINED CYCLE PLANT					***920,283,497***	***39,387,908***	***4.28***
TURKEY POINT COMBINED CYCLE PLANT							
	TURKEY POINT UNIT 5						
341	STRUCTURES AND IMPROVEMENTS	06-2047	80 - R2 *	(2)	32,284,855	862,567	2.67
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2047	50 - R1.5 *	(3)	12,410,131	364,566	2.94
343	PRIME MOVERS - GENERAL	06-2047	50 - R1 *	(3)	250,685,264	7,665,459	3.06
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2047	9 - L0 *	35	128,220,285	9,259,428	7.22
344	GENERATORS	06-2047	60 - R2 *	(3)	41,669,542	1,155,573	2.77
345	ACCESSORY ELECTRIC EQUIPMENT	06-2047	50 - R2.5 *	(2)	51,980,475	1,444,649	2.78
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2047	50 - S0.5 *	(2)	12,433,804	363,521	2.92
	TOTAL TURKEY POINT UNIT 5				*529,684,355*	*21,115,763*	*3.99*
TOTAL TURKEY POINT COMBINED CYCLE PLANT					***529,684,355***	***21,115,763***	***3.99***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
WEST COUNTY COMBINED CYCLE PLANT							
	WEST COUNTY COMMON						
341	STRUCTURES AND IMPROVEMENTS	06-2051	80 - R2 *	(2)	3,120,798	83,834	2.69
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2051	50 - R1.5 *	(3)	450,604	13,227	2.94
343	PRIME MOVERS - GENERAL	06-2051	50 - R1 *	(3)	31,206,902	1,008,224	3.23
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2051	9 - L0 *	35	126,771,982	9,154,839	7.22
345	ACCESSORY ELECTRIC EQUIPMENT	06-2051	50 - R2.5 *	(2)	1,291,342	37,624	2.91
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2051	50 - S0.5 *	(2)	836,533	24,804	2.97
	TOTAL WEST COUNTY COMMON				*163,678,161*	*10,322,552*	*6.31*
	WEST COUNTY UNIT 1						
341	STRUCTURES AND IMPROVEMENTS	06-2049	80 - R2 *	(2)	109,835,744	2,944,128	2.68
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2049	50 - R1.5 *	(3)	21,806,447	644,693	2.96
343	PRIME MOVERS - GENERAL	06-2049	50 - R1 *	(3)	300,710,821	9,206,911	3.06
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2049	9 - L0 *	35	81,954,083	5,918,314	7.22
344	GENERATORS	06-2049	60 - R2 *	(3)	49,469,105	1,374,568	2.78
345	ACCESSORY ELECTRIC EQUIPMENT	06-2049	50 - R2.5 *	(2)	72,300,016	2,010,145	2.78
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2049	50 - S0.5 *	(2)	8,042,081	234,270	2.91
	TOTAL WEST COUNTY UNIT 1				*644,118,297*	*22,333,029*	*3.47*
	WEST COUNTY UNIT 2						
341	STRUCTURES AND IMPROVEMENTS	06-2049	80 - R2 *	(2)	39,659,646	1,063,085	2.68
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2049	50 - R1.5 *	(3)	7,471,457	223,319	2.99
343	PRIME MOVERS - GENERAL	06-2049	50 - R1 *	(3)	255,637,285	7,804,907	3.05
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2049	9 - L0 *	35	149,878,251	10,823,458	7.22
344	GENERATORS	06-2049	60 - R2 *	(3)	43,599,023	1,213,035	2.78
345	ACCESSORY ELECTRIC EQUIPMENT	06-2049	50 - R2.5 *	(2)	33,177,136	922,368	2.78
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2049	50 - S0.5 *	(2)	11,893,351	352,260	2.96
	TOTAL WEST COUNTY UNIT 2				*541,316,149*	*22,402,432*	*4.14*
	WEST COUNTY UNIT 3						
341	STRUCTURES AND IMPROVEMENTS	06-2051	80 - R2 *	(2)	57,671,242	1,537,469	2.67
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2051	50 - R1.5 *	(3)	10,754,858	317,030	2.95
343	PRIME MOVERS - GENERAL	06-2051	50 - R1 *	(3)	480,389,197	14,507,390	3.02
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2051	9 - L0 *	35	98,598,036	7,120,257	7.22
344	GENERATORS	06-2051	60 - R2 *	(3)	64,525,280	1,788,090	2.77
345	ACCESSORY ELECTRIC EQUIPMENT	06-2051	50 - R2.5 *	(2)	48,252,610	1,335,296	2.77
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2051	50 - S0.5 *	(2)	12,454,466	361,154	2.90
	TOTAL WEST COUNTY UNIT 3				*772,645,690*	*26,966,686*	*3.49*
TOTAL WEST COUNTY COMBINED CYCLE PLANT					***2,121,758,297***	***82,024,699***	***3.87***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
CAPE CANAVERAL COMBINED CYCLE PLANT							
	CAPE CANAVERAL COMBINED CYCLE						
341	STRUCTURES AND IMPROVEMENTS	06-2053	80 - R2 *	(2)	82,092,869	2,193,088	2.67
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2053	50 - R1.5 *	(3)	47,723,728	1,400,412	2.93
343	PRIME MOVERS - GENERAL	06-2053	50 - R1 *	(3)	385,108,676	11,593,863	3.01
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2053	9 - L0 *	35	206,255,249	14,894,723	7.22
344	GENERATORS	06-2053	60 - R2 *	(3)	70,269,257	1,941,819	2.76
345	ACCESSORY ELECTRIC EQUIPMENT	06-2053	50 - R2.5 *	(2)	111,693,785	3,093,215	2.77
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2053	50 - S0.5 *	(2)	10,309,493	298,911	2.90
	TOTAL CAPE CANAVERAL COMBINED CYCLE				*913,453,057*	*35,416,031*	*3.88*
TOTAL CAPE CANAVERAL COMBINED CYCLE PLANT					***913,453,057***	***35,416,031***	***3.88***
RIVIERA COMBINED CYCLE PLANT							
	RIVIERA COMBINED CYCLE						
341	STRUCTURES AND IMPROVEMENTS	06-2054	80 - R2 *	(2)	80,630,958	2,138,363	2.65
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2054	50 - R1.5 *	(3)	217,306,004	6,367,219	2.93
343	PRIME MOVERS - GENERAL	06-2054	50 - R1 *	(3)	525,780,412	15,830,359	3.01
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2054	9 - L0 *	35	139,494,633	10,073,605	7.22
344	GENERATORS	06-2054	60 - R2 *	(3)	79,977,232	2,209,764	2.76
345	ACCESSORY ELECTRIC EQUIPMENT	06-2054	50 - R2.5 *	(2)	82,800,568	2,287,187	2.76
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2054	50 - S0.5 *	(2)	11,446,561	331,830	2.90
	TOTAL RIVIERA COMBINED CYCLE				*1,137,436,368*	*39,238,327*	*3.45*
TOTAL RIVIERA COMBINED CYCLE PLANT					***1,137,436,368***	***39,238,327***	***3.45***
PT EVERGLADES COMBINED CYCLE PLANT							
	PT EVERGLADES COMBINED CYCLE						
341	STRUCTURES AND IMPROVEMENTS	06-2056	80 - R2 *	(2)	101,607,532	2,704,023	2.66
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2056	50 - R1.5 *	(3)	59,665,117	1,745,324	2.93
343	PRIME MOVERS - GENERAL	06-2056	50 - R1 *	(3)	499,500,579	15,021,164	3.01
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2056	9 - L0 *	35	191,363,196	13,819,293	7.22
344	GENERATORS	06-2056	60 - R2 *	(3)	87,208,139	2,407,293	2.76
345	ACCESSORY ELECTRIC EQUIPMENT	06-2056	50 - R2.5 *	(2)	138,483,956	3,827,974	2.76
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2056	50 - S0.5 *	(2)	12,795,087	370,648	2.90
	TOTAL PT EVERGLADES COMBINED CYCLE				*1,090,623,606*	*39,895,719*	*3.66*
TOTAL PT EVERGLADES COMBINED CYCLE PLANT					***1,090,623,606***	***39,895,719***	***3.66***
TOTAL COMBINED CYCLE PRODUCTION PLANT					**10,277,035,554**	**414,727,438**	***4.04***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
PEAKER PLANTS							
	LAUDERDALE GTS						
341	STRUCTURES AND IMPROVEMENTS	06-2028	80 - R2 *	(2)	601,222	20,500	3.41
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2028	50 - R1.5 *	(3)	194,417	7,193	3.70
343	PRIME MOVERS - GENERAL	06-2028	50 - R1 *	(3)	14,841,925	1,208,680	8.14
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2028	25 - R1 *	29	1,858,779	69,480	3.74
344	GENERATORS	06-2028	60 - R2 *	(3)	1,748,135	43,263	2.47
345	ACCESSORY ELECTRIC EQUIPMENT	06-2028	50 - R2.5 *	(2)	420,107	11,778	2.80
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2028	50 - S0.5 *	(2)	20,935	508	2.43
	TOTAL LAUDERDALE GTS				*19,685,520*	*1,361,402*	***6.92***
	FT. MYERS GTS						
341	STRUCTURES AND IMPROVEMENTS	06-2028	80 - R2 *	(2)	941,093	58,404	6.21
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2028	50 - R1.5 *	(3)	724,318	47,016	6.49
343	PRIME MOVERS - GENERAL	06-2028	50 - R1 *	(3)	10,218,903	826,898	8.09
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2028	25 - R1 *	29	2,807,095	92,610	3.30
344	GENERATORS	06-2028	60 - R2 *	(3)	4,602,022	289,704	6.30
345	ACCESSORY ELECTRIC EQUIPMENT	06-2028	50 - R2.5 *	(2)	3,450,438	235,636	6.83
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2028	50 - S0.5 *	(2)	20,936	1,276	6.09
	TOTAL FT. MYERS GTS				*22,764,804*	*1,551,544*	***6.82***
	LAUDERDALE AND FT. MYERS PEAKERS						
341	STRUCTURES AND IMPROVEMENTS	06-2056	80 - R2 *	(2)	43,805,886	1,166,200	2.66
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2056	50 - R1.5 *	(3)	26,150,085	764,942	2.93
343	PRIME MOVERS - GENERAL	06-2056	50 - R1 *	(3)	213,843,171	6,431,547	3.01
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	06-2056	25 - R1 *	29	83,870,827	2,411,706	2.88
344	GENERATORS	06-2056	60 - R2 *	(3)	38,221,667	1,055,071	2.76
345	ACCESSORY ELECTRIC EQUIPMENT	06-2056	50 - R2.5 *	(2)	60,694,881	1,677,728	2.76
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2056	50 - S0.5 *	(2)	5,607,843	162,448	2.90
	TOTAL LAUDERDALE AND FT. MYERS PEAKERS				*472,194,358*	*13,669,642*	***2.89***
TOTAL PEAKER PLANTS					**514,644,682**	**16,582,588**	***3.22***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
SOLAR PRODUCTION PLANT							
	DESOTO SOLAR						
341	STRUCTURES AND IMPROVEMENTS	06-2039	SQUARE *	0	4,635,209	157,728	3.40
343	PRIME MOVERS - GENERAL	06-2039	SQUARE *	0	118,689,127	3,983,267	3.36
345	ACCESSORY ELECTRIC EQUIPMENT	06-2039	SQUARE *	0	27,532,945	926,273	3.36
	TOTAL DESOTOSOLAR				*150,857,280*	*5,067,268*	*3.36*
	SPACE COAST SOLAR						
341	STRUCTURES AND IMPROVEMENTS	06-2040	SQUARE *	0	3,986,978	133,487	3.35
343	PRIME MOVERS - GENERAL	06-2040	SQUARE *	0	52,858,699	1,769,750	3.35
345	ACCESSORY ELECTRIC EQUIPMENT	06-2040	SQUARE *	0	6,281,496	210,309	3.35
	TOTAL SPACE COAST SOLAR				*63,127,172*	*2,113,546*	*3.35*
	MARTIN SOLAR						
341	STRUCTURES AND IMPROVEMENTS	06-2045	SQUARE *	0	21,320,036	616,569	2.89
343	PRIME MOVERS - GENERAL	06-2045	SQUARE *	0	405,752,300	11,731,524	2.89
345	ACCESSORY ELECTRIC EQUIPMENT	06-2045	SQUARE *	0	4,239,215	121,994	2.88
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2045	SQUARE *	0	1,335	38	2.88
	TOTAL MARTIN SOLAR				*431,312,886*	*12,470,125*	*2.89*
	BABCOCK RANCH SOLAR						
341	STRUCTURES AND IMPROVEMENTS	06-2046	SQUARE *	0	4,078,184	135,804	3.33
343	PRIME MOVERS - GENERAL	06-2046	SQUARE *	0	104,118,206	3,467,136	3.33
345	ACCESSORY ELECTRIC EQUIPMENT	06-2046	SQUARE *	0	24,224,241	806,667	3.33
	TOTAL BABCOCK RANCH SOLAR				*132,420,631*	*4,409,607*	*3.33*
	MANATEE SOLAR						
341	STRUCTURES AND IMPROVEMENTS	06-2046	SQUARE *	0	4,118,679	137,152	3.33
343	PRIME MOVERS - GENERAL	06-2046	SQUARE *	0	105,224,179	3,503,965	3.33
345	ACCESSORY ELECTRIC EQUIPMENT	06-2046	SQUARE *	0	24,464,781	814,677	3.33
	TOTAL MANATEE SOLAR				*133,807,639*	*4,455,794*	*3.33*
	CITRUS SOLAR						
341	STRUCTURES AND IMPROVEMENTS	06-2046	SQUARE *	0	4,207,181	140,099	3.33
343	PRIME MOVERS - GENERAL	06-2046	SQUARE *	0	107,250,213	3,571,432	3.33
345	ACCESSORY ELECTRIC EQUIPMENT	06-2046	SQUARE *	0	24,990,480	832,183	3.33
	TOTAL CITRUS SOLAR				*136,447,874*	*4,543,714*	*3.33*
TOTAL SOLAR PRODUCTION PLANT					**1,047,973,483**	**33,060,054**	***3.15***
TOTAL PRODUCTION PLANT					**22,795,357,882**	**875,725,039**	***3.84***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
TRANSMISSION, DISTRIBUTION, AND GENERAL PLANT							
	TRANSMISSION PLANT						
350.2	EASEMENTS		75 - S4	0	240,510,767	3,198,793	1.33
352	STRUCTURES AND IMPROVEMENTS		65 - R3	(15)	154,719,740	2,740,087	1.77
353	STATION EQUIPMENT		40 - R1	(2)	1,741,377,472	44,405,126	2.55
353.1	STATION EQUIPMENT - STEP-UP TRANSFORMERS		30 - R1	0	400,209,880	13,326,989	3.33
354	TOWERS AND FIXTURES		60 - R4	(25)	349,056,185	7,286,548	2.09
355	POLES AND FIXTURES		50 - R2	(50)	1,242,636,001	37,279,080	3.00
356	OVERHEAD CONDUCTORS AND DEVICES		51 - R1	(55)	854,174,816	25,949,831	3.04
357	UNDERGROUND CONDUIT		65 - R4	0	75,512,192	1,162,888	1.54
358	UNDERGROUND CONDUCTORS AND DEVICES		65 - R3	(20)	104,576,520	1,932,574	1.85
359	ROADS AND TRAILS		75 - R4	(10)	113,485,941	1,660,299	1.46
	TOTAL TRANSMISSION PLANT				**5,276,259,513**	**138,942,215**	***2.63***
	DISTRIBUTION PLANT						
361	STRUCTURES AND IMPROVEMENTS		65 - R3	(15)	198,554,703	3,516,404	1.77
362	STATION EQUIPMENT		45 - R1.5	(10)	1,740,028,154	42,491,488	2.44
364.1	POLES, TOWERS AND FIXTURES - WOOD		40 - R2	(100)	1,083,692,909	54,184,645	5.00
364.2	POLES, TOWERS AND FIXTURES - CONCRETE		50 - R1.5	(100)	706,877,719	28,275,109	4.00
365	OVERHEAD CONDUCTORS AND DEVICES		48 - R1	(80)	1,991,793,394	74,572,745	3.74
366.6	UNDERGROUND CONDUIT - DUCT SYSTEM		70 - R3	0	1,528,850,821	21,862,567	1.43
366.7	UNDERGROUND CONDUIT - DIRECT BURIED		50 - R4	0	193,885,661	3,877,713	2.00
367.6	UNDERGROUND CONDUCTORS AND DEVICES - DUCT SYSTEM		42 - S0	(5)	1,723,803,662	43,077,854	2.50
367.7	UNDERGROUND CONDUCTORS AND DEVICES - DIRECT BURIED		35 - R2	0	731,720,379	20,927,196	2.86
368	LINE TRANSFORMERS		34 - S0	(15)	2,172,571,477	73,450,948	3.38
369.1	SERVICES - OVERHEAD		53 - R1	(125)	429,359,956	18,258,532	4.25
369.6	SERVICES - UNDERGROUND		45 - R2	(15)	818,122,343	20,886,663	2.55
370	METERS		38 - R2	(30)	90,547,258	3,095,811	3.42
370.1	METERS - AMI		20 - R2.5	(30)	752,056,781	48,883,691	6.50
371	INSTALLATIONS ON CUSTOMER'S PREMISES		30 - L0	(15)	77,912,064	2,983,643	3.83
373	STREET LIGHTING AND SIGNAL SYSTEMS		35 - O1	(15)	463,393,095	15,240,285	3.29
	TOTAL DISTRIBUTION PLANT				**14,703,170,376**	**475,585,294**	***3.23***

FLORIDA POWER AND LIGHT COMPANY

TABLE 2. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST AND CALCULATED WHOLE LIFE ANNUAL DEPRECIATION ACCRUALS AND RATES RELATED TO ELECTRIC PLANT IN SERVICE AS OF DECEMBER 31, 2016

		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)
	GENERAL PLANT						
390	STRUCTURES AND IMPROVEMENTS		55 - R1.5	(10)	435,222,597	8,713,156	2.00
392.1	AUTOMOBILES		6 - L2.5	15	9,038,959	1,280,775	14.17
392.2	LIGHT TRUCKS		9 - L3	15	47,500,083	4,485,670	9.44
392.3	HEAVY TRUCKS		12 - S3	15	241,647,650	17,085,712	7.07
392.4	TRACTOR TRAILERS		9 - L2.5	5	767,855	76,002	9.90
392.9	TRAILERS		20 - L1	15	21,065,643	895,290	4.25
396.1	POWER OPERATED EQUIPMENT		11 - L1.5	15	4,766,126	368,255	7.73
397.8	COMMUNICATION EQUIPMENT - FIBER OPTICS		20 - S2	0	11,992,500	599,625	5.00
	TOTAL GENERAL PLANT				**772,001,412**	**33,504,485**	***4.34***
TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT					**20,751,431,301**	**648,031,994**	***3.12***
GRAND TOTAL					**43,546,789,183**	**1,523,757,033**	***3.50***

* CURVE SHOWN IS INTERIM SURVIVOR CURVE. LIFE SPAN METHOD IS USED.

FLORIDA POWER AND LIGHT COMPANY

TABLE 3. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST (1)	BOOK RESERVE (2)	PROBABLE RETIREMENT DATE (3)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (4)	NET SALVAGE (5)	ANNUAL DEPRECIATION RATE (6)	ANNUAL DEPRECIATION ACCRUALS (7)=(6)x(1)	PROBABLE RETIREMENT DATE (8)	SURVIVOR CURVE (9)	NET SALVAGE (10)	ANNUAL DEPRECIATION ACCRUALS (11)	ANNUAL DEPRECIATION RATE (12)	INCREASE/ DECREASE (13)=(12)-(7)
STEAM PRODUCTION PLANT													
MANATEE STEAM PLANT													
MANATEE COMMON													
311 STRUCTURES AND IMPROVEMENTS	112,114,271	73,128,598	06-2027	0.0032	(1)	2.1	2,354,400	06-2028	80 - R2 *	(1)	3,555,569	3.17	1,201,169
312 BOILER PLANT EQUIPMENT	7,715,628	1,329,813	06-2027	0.0094	(2)	2.6	200,606	06-2028	50 - S0 *	(2)	587,612	7.62	387,006
314 TURBOGENERATOR UNITS	9,652,310	7,657,288	06-2027	0.0120	0	2.6	250,960	06-2028	55 - R0.5 *	(1)	194,743	2.02	(56,217)
315 ACCESSORY ELECTRIC EQUIPMENT	9,646,848	7,389,490	06-2027	0.0052	(5)	2.4	231,524	06-2028	65 - S0 *	(2)	225,626	2.34	(5,898)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	2,450,703	1,919,506	06-2027	0.0071	(1)	2.4	58,817	06-2028	65 - R0.5 *	(1)	50,889	2.08	(7,928)
TOTAL MANATEE COMMON	*141,579,760*	*91,424,696*				*2.2*	*3,096,307*				*4,614,439*	*3.26*	*1,518,132*
MANATEE UNIT 1													
311 STRUCTURES AND IMPROVEMENTS	6,836,328	5,584,432	06-2027	0.0032	(1)	2.1	143,563	06-2028	80 - R2 *	(1)	118,728	1.74	(24,835)
312 BOILER PLANT EQUIPMENT	181,481,969	93,495,502	06-2027	0.0094	(2)	2.6	4,718,531	06-2028	50 - S0 *	(2)	8,412,866	4.64	3,694,335
314 TURBOGENERATOR UNITS	72,660,531	41,616,767	06-2027	0.0120	0	2.6	1,889,174	06-2028	55 - R0.5 *	(1)	2,925,448	4.03	1,036,274
315 ACCESSORY ELECTRIC EQUIPMENT	14,261,784	8,023,680	06-2027	0.0052	(5)	2.4	342,283	06-2028	65 - S0 *	(2)	586,631	4.11	244,348
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,924,407	2,278,883	06-2027	0.0071	(1)	2.4	94,186	06-2028	65 - R0.5 *	(1)	153,580	3.91	59,394
TOTAL MANATEE UNIT 1	*279,165,019*	*150,999,264*				*2.6*	*7,187,737*				*12,197,253*	*4.37*	*5,009,516*
MANATEE UNIT 2													
311 STRUCTURES AND IMPROVEMENTS	4,986,744	4,017,696	06-2027	0.0032	(1)	2.1	104,722	06-2028	80 - R2 *	(1)	91,383	1.83	(13,339)
312 BOILER PLANT EQUIPMENT	183,957,418	87,494,700	06-2027	0.0094	(2)	2.6	4,782,893	06-2028	50 - S0 *	(2)	9,170,501	4.99	4,387,608
314 TURBOGENERATOR UNITS	70,765,381	42,942,308	06-2027	0.0120	0	2.6	1,839,900	06-2028	55 - R0.5 *	(1)	2,629,560	3.72	789,660
315 ACCESSORY ELECTRIC EQUIPMENT	12,273,816	6,398,866	06-2027	0.0052	(5)	2.4	294,572	06-2028	65 - S0 *	(2)	549,410	4.48	254,838
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,453,782	1,668,499	06-2027	0.0071	(1)	2.4	82,891	06-2028	65 - R0.5 *	(1)	165,589	4.79	82,698
TOTAL MANATEE UNIT 2	*275,437,142*	*142,522,068*				*2.6*	*7,104,978*				*12,606,443*	*4.58*	*5,501,465*
TOTAL MANATEE STEAM PLANT	***696,181,920***	***384,946,028***				***2.5***	***17,389,022***				***29,418,135***	***4.23***	***12,029,113***
MARTIN STEAM PLANT													
MARTIN COMMON													
311 STRUCTURES AND IMPROVEMENTS	241,950,141	158,600,994	06-2031	0.0032	(1)	2.1	5,080,953	06-2031	80 - R2 *	(1)	6,108,878	2.52	1,027,925
312 BOILER PLANT EQUIPMENT	7,068,506	2,944,759	06-2031	0.0094	(5)	2.6	183,781	06-2031	50 - S0 *	(2)	314,305	4.45	130,524
314 TURBOGENERATOR UNITS	27,474,257	14,912,384	06-2031	0.0120	0	2.6	714,331	06-2031	55 - R0.5 *	(1)	955,816	3.48	241,485
315 ACCESSORY ELECTRIC EQUIPMENT	10,295,313	5,435,309	06-2031	0.0052	(5)	2.4	247,088	06-2031	65 - S0 *	(2)	367,628	3.57	120,540
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,888,459	1,913,639	06-2031	0.0071	0	2.4	93,323	06-2031	65 - R0.5 *	(1)	147,308	3.79	53,985
TOTAL MARTIN COMMON	*290,676,676*	*183,807,084*				*2.2*	*6,319,476*				*7,893,935*	*2.72*	*1,574,459*
MARTIN PIPELINE													
312 BOILER PLANT EQUIPMENT	370,942	370,942	06-2031	0.0094	(5)	2.6	9,644	06-2031	50 - S0 *	0	-	0.00	(9,644)
TOTAL MARTIN PIPELINE	*370,942*	*370,942*				*2.6*	*9,644*				-		*(9,644)*
MARTIN UNIT 1													
311 STRUCTURES AND IMPROVEMENTS	16,404,681	10,400,297	06-2031	0.0032	(1)	2.1	344,498	06-2031	80 - R2 *	(1)	439,660	2.68	95,162
312 BOILER PLANT EQUIPMENT	212,830,965	87,624,020	06-2031	0.0094	(5)	2.6	5,533,605	06-2031	50 - S0 *	(2)	9,632,706	4.53	4,099,101
314 TURBOGENERATOR UNITS	90,120,383	50,448,065	06-2031	0.0120	0	2.6	2,343,130	06-2031	55 - R0.5 *	(1)	3,018,863	3.35	675,733
315 ACCESSORY ELECTRIC EQUIPMENT	24,391,137	14,440,333	06-2031	0.0052	(5)	2.4	585,387	06-2031	65 - S0 *	(2)	760,833	3.12	175,446
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,594,165	1,758,500	06-2031	0.0071	0	2.4	86,260	06-2031	65 - R0.5 *	(1)	136,913	3.81	50,653
TOTAL MARTIN UNIT 1	*347,341,330*	*164,671,214*				*2.6*	*8,892,880*				*13,988,975*	*4.03*	*5,096,095*
MARTIN UNIT 2													
311 STRUCTURES AND IMPROVEMENTS	11,266,842	7,618,893	06-2031	0.0032	(1)	2.1	236,604	06-2031	80 - R2 *	(1)	269,000	2.39	32,396
312 BOILER PLANT EQUIPMENT	215,154,508	84,744,456	06-2031	0.0094	(5)	2.6	5,594,017	06-2031	50 - S0 *	(2)	9,993,557	4.64	4,399,540
314 TURBOGENERATOR UNITS	82,856,949	30,043,134	06-2031	0.0120	0	2.6	2,154,281	06-2031	55 - R0.5 *	(1)	3,967,632	4.79	1,813,351
315 ACCESSORY ELECTRIC EQUIPMENT	23,045,156	12,167,493	06-2031	0.0052	(5)	2.4	553,084	06-2031	65 - S0 *	(2)	819,853	3.56	266,769
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,280,816	1,374,670	06-2031	0.0071	0	2.4	78,740	06-2031	65 - R0.5 *	(1)	141,426	4.31	62,686
TOTAL MARTIN UNIT 2	*335,604,270*	*135,948,644*				*2.6*	*8,616,726*				*15,191,468*	*4.53*	*6,574,742*
TOTAL MARTIN STEAM PLANT	***973,993,219***	***484,797,884***				***2.4***	***23,838,726***				***37,074,378***	***3.81***	***13,235,652***

FLORIDA POWER AND LIGHT COMPANY

TABLE 3. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST (1)	BOOK RESERVE (2)	PROBABLE RETIREMENT DATE (3)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (4)	NET SALVAGE (5)	ANNUAL DEPRECIATION RATE (6)	ANNUAL DEPRECIATION ACCRUALS (7)=(6)x(1)	PROBABLE RETIREMENT DATE (8)	SURVIVOR CURVE (9)	NET SALVAGE (10)	ANNUAL DEPRECIATION ACCRUALS (11)	ANNUAL DEPRECIATION RATE (12)	INCREASE/ DECREASE (13)=(12)-(7)
SCHERER STEAM PLANT													
SCHERER COAL CARS													
312 BOILER PLANT EQUIPMENT	33,149,442	33,149,442	06-2039	0.0094	(5)	2.6	861,885	06-2039	50 - S0 *	0	-	0.00	(861,885)
TOTAL SCHERER COAL CARS	*33,149,442*	*33,149,442*				*2.6*	*861,885*				*-*	*0.00*	*(861,885)*
SCHERER COMMON													
311 STRUCTURES AND IMPROVEMENTS	39,391,667	20,717,188	06-2039	0.0032	(1)	2.1	827,225	06-2039	80 - R2 *	(1)	882,796	2.24	55,571
312 BOILER PLANT EQUIPMENT	25,844,055	12,070,575	06-2039	0.0094	(5)	2.6	671,945	06-2039	50 - S0 *	(4)	765,628	2.96	93,683
314 TURBOGENERATOR UNITS	4,336,718	1,830,764	06-2039	0.0120	0	2.6	112,755	06-2039	55 - R0.5 *	(1)	128,042	2.95	15,287
315 ACCESSORY ELECTRIC EQUIPMENT	1,226,257	679,212	06-2039	0.0052	(4)	2.4	29,430	06-2039	65 - S0 *	(4)	29,480	2.40	50
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,659,825	1,735,162	06-2039	0.0071	(1)	2.4	87,836	06-2039	65 - R0.5 *	(1)	95,718	2.62	7,882
TOTAL SCHERER COMMON	*74,458,521*	*37,032,900*				*2.3*	*1,729,191*				*1,901,664*	*2.55*	*172,473*
SCHERER COMMON UNIT 3 AND 4													
311 STRUCTURES AND IMPROVEMENTS	2,999,449	1,646,858	06-2039	0.0032	(1)	2.2	65,988	06-2039	80 - R2 *	(1)	64,127	2.14	(1,861)
312 BOILER PLANT EQUIPMENT	22,335,968	9,614,113	06-2039	0.0094	(5)	2.7	603,071	06-2039	50 - S0 *	(4)	695,012	3.11	91,941
314 TURBOGENERATOR UNITS	2,831,158	224,639	06-2039	0.0120	0	2.6	73,610	06-2039	55 - R0.5 *	(1)	128,216	4.53	54,606
315 ACCESSORY ELECTRIC EQUIPMENT	2,818,575	245,786	06-2039	0.0052	(4)	2.4	67,646	06-2039	65 - S0 *	(4)	125,025	4.44	57,379
TOTAL SCHERER COMMON UNIT 3 AND 4	*30,985,149*	*11,731,396*				*2.6*	*810,315*				*1,012,380*	*3.27*	*202,065*
SCHERER UNIT 4													
311 STRUCTURES AND IMPROVEMENTS	159,104,427	39,437,115	06-2039	0.0032	(1)	2.1	3,341,193	06-2039	80 - R2 *	(1)	5,539,441	3.48	2,198,248
312 BOILER PLANT EQUIPMENT	671,515,648	178,043,157	06-2039	0.0094	(5)	2.6	17,459,407	06-2039	50 - S0 *	(4)	25,810,174	3.84	8,350,767
314 TURBOGENERATOR UNITS	122,853,491	58,668,053	06-2039	0.0120	0	2.6	3,194,191	06-2039	55 - R0.5 *	(1)	3,290,441	2.68	96,250
315 ACCESSORY ELECTRIC EQUIPMENT	49,374,419	14,135,035	06-2039	0.0052	(4)	2.4	1,184,986	06-2039	65 - S0 *	(4)	1,775,494	3.60	590,508
316 MISCELLANEOUS POWER PLANT EQUIPMENT	5,117,266	2,275,999	06-2039	0.0071	(1)	2.4	122,814	06-2039	65 - R0.5 *	(1)	140,274	2.74	17,460
TOTAL SCHERER UNIT 4	*1,007,965,252*	*292,559,359*				*2.5*	*25,302,591*				*36,555,824*	*3.63*	*11,253,233*
TOTAL SCHERER STEAM PLANT	***1,146,558,365***	***374,473,097***				***2.5***	***28,703,982***				***39,469,868***	***3.44***	***10,765,886***
SJRPP STEAM PLANT													
SJRPP COAL AND LIMESTONE													
311 STRUCTURES AND IMPROVEMENTS	3,562,391	1,817,206	06-2038	0.0032	(1)	2.1	74,810	06-2038	80 - R2 *	(1)	86,954	2.44	12,144
312 BOILER PLANT EQUIPMENT	30,883,389	15,259,114	06-2038	0.0094	(5)	2.6	802,968	06-2038	50 - S0 *	(4)	936,645	3.03	133,677
315 ACCESSORY ELECTRIC EQUIPMENT	3,773,252	2,142,570	06-2038	0.0052	(4)	2.4	90,558	06-2038	65 - S0 *	(4)	92,938	2.46	2,380
316 MISCELLANEOUS POWER PLANT EQUIPMENT	300,302	161,831	06-2038	0.0071	(1)	2.4	7,207	06-2038	65 - R0.5 *	(1)	7,319	2.44	112
TOTAL SJRPP COAL AND LIMESTONE	*38,519,334*	*19,380,721*				*2.5*	*975,543*				*1,123,856*	*2.92*	*148,313*
SJRPP COAL CARS													
312 BOILER PLANT EQUIPMENT	52,105	52,105	06-2038	0.0094	(5)	2.6	1,355	06-2038	50 - S0 *	0	-	0.00	(1,355)
TOTAL SJRPP COAL CARS	*52,105*	*52,105*				*2.6*	*1,355*				*-*	*0.00*	*(1,355)*
SJRPP COMMON													
311 STRUCTURES AND IMPROVEMENTS	33,146,529	22,171,912	06-2038	0.0032	(1)	2.1	696,077	06-2038	80 - R2 *	(1)	550,442	1.66	(145,635)
312 BOILER PLANT EQUIPMENT	3,694,843	2,563,468	06-2038	0.0094	(5)	2.6	96,066	06-2038	50 - S0 *	(4)	70,207	1.90	(25,859)
314 TURBOGENERATOR UNITS	2,497,878	1,684,864	06-2038	0.0120	0	2.6	64,945	06-2038	55 - R0.5 *	(1)	44,693	1.79	(20,252)
315 ACCESSORY ELECTRIC EQUIPMENT	5,833,698	3,990,701	06-2038	0.0052	(4)	2.4	140,009	06-2038	65 - S0 *	(4)	107,750	1.85	(32,259)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	1,598,862	1,006,658	06-2038	0.0071	(1)	2.4	38,373	06-2038	65 - R0.5 *	(1)	31,157	1.95	(7,216)
TOTAL SJRPP COMMON	*46,771,810*	*31,417,602*				*2.2*	*1,035,470*				*804,249*	*1.72*	*(231,221)*
SJRPP GYPSUM AND ASH													
311 STRUCTURES AND IMPROVEMENTS	2,172,989	1,122,277	06-2038	0.0032	(1)	2.1	45,633	06-2038	80 - R2 *	(1)	52,212	2.40	6,579
312 BOILER PLANT EQUIPMENT	17,085,257	9,494,175	06-2038	0.0094	(5)	2.6	444,217	06-2038	50 - S0 *	(4)	463,038	2.71	18,821
315 ACCESSORY ELECTRIC EQUIPMENT	52,571	31,882	06-2038	0.0052	(4)	2.4	1,262	06-2038	65 - S0 *	(4)	1,188	2.26	(74)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	154,892	64,476	06-2038	0.0071	(1)	2.4	3,717	06-2038	65 - R0.5 *	(1)	4,680	3.02	963
TOTAL SJRPP GYPSUM AND ASH	*19,465,709*	*10,712,610*				*2.5*	*494,829*				*521,118*	*2.68*	*26,289*
SJRPP UNIT 1													
311 STRUCTURES AND IMPROVEMENTS	9,049,629	6,497,954	06-2038	0.0032	(1)	2.1	190,042	06-2038	80 - R2 *	(1)	129,202	1.43	(60,840)
312 BOILER PLANT EQUIPMENT	99,626,681	50,079,303	06-2038	0.0094	(5)	2.6	2,590,294	06-2038	50 - S0 *	(4)	2,887,403	2.90	297,109
314 TURBOGENERATOR UNITS	31,463,410	15,259,034	06-2038	0.0120	0	2.6	818,049	06-2038	55 - R0.5 *	(1)	860,365	2.73	42,316
315 ACCESSORY ELECTRIC EQUIPMENT	12,475,837	7,908,663	06-2038	0.0052	(4)	2.4	299,420	06-2038	65 - S0 *	(4)	261,684	2.10	(37,736)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	2,038,425	1,391,601	06-2038	0.0071	(1)	2.4	48,922	06-2038	65 - R0.5 *	(1)	34,392	1.69	(14,530)
TOTAL SJRPP UNIT 1	*154,653,983*	*81,136,555*				*2.6*	*3,946,727*				*4,173,046*	*2.70*	*226,319*
SJRPP UNIT 2													
311 STRUCTURES AND IMPROVEMENTS	7,177,145	4,116,166	06-2038	0.0032	(1)	2.1	150,720	06-2038	80 - R2 *	(1)	153,341	2.14	2,621
312 BOILER PLANT EQUIPMENT	90,153,231	39,507,420	06-2038	0.0094	(5)	2.6	2,343,984	06-2038	50 - S0 *	(4)	2,923,057	3.24	579,073
314 TURBOGENERATOR UNITS	28,479,810	10,690,425	06-2038	0.0120	0	2.6	740,475	06-2038	55 - R0.5 *	(1)	940,874	3.30	200,399
315 ACCESSORY ELECTRIC EQUIPMENT	10,105,912	5,314,628	06-2038	0.0052	(4)	2.4	242,542	06-2038	65 - S0 *	(4)	269,617	2.67	27,075
316 MISCELLANEOUS POWER PLANT EQUIPMENT	1,571,822	869,236	06-2038	0.0071	(1)	2.4	37,724	06-2038	65 - R0.5 *	(1)	36,931	2.35	(793)
TOTAL SJRPP UNIT 2	*137,487,920*	*60,497,875*				*2.6*	*3,515,445*				*4,323,820*	*3.14*	*808,375*
TOTAL SJRPP STEAM PLANT	***396,950,861***	***203,197,468***				***2.5***	***9,969,369***				***10,946,089***	***2.76***	***976,720***
TOTAL STEAM PRODUCTION	**3,213,684,365**	**1,447,414,477**				**2.5**	**79,901,099**				**116,908,470**	**3.64**	**37,007,371**

FLORIDA POWER AND LIGHT COMPANY

TABLE 3. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST (1)	BOOK RESERVE (2)	PROBABLE RETIREMENT DATE (3)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (4)	NET SALVAGE (5)	ANNUAL DEPRECIATION RATE (6)	ANNUAL DEPRECIATION ACCRUALS (7)=(6)x(1)	PROBABLE RETIREMENT DATE (8)	SURVIVOR CURVE (9)	NET SALVAGE (10)	ANNUAL DEPRECIATION ACCRUALS (11)	ANNUAL DEPRECIATION RATE (12)	INCREASE/ DECREASE (13)=(12)-(7)
NUCLEAR PRODUCTION PLANT													
ST. LUCIE NUCLEAR PLANT													
ST. LUCIE COMMON													
321 STRUCTURES AND IMPROVEMENTS	396,984,357	176,282,726	06-2043	0.0028	0	1.8	7,145,718	04-2043	100 - R1.5 *	(1)	8,926,161	2.25	1,780,443
322 REACTOR PLANT EQUIPMENT	55,565,218	31,403,213	06-2043	0.0056	(2)	2.0	1,111,304	04-2043	60 - R1 *	(2)	1,066,835	1.92	(44,469)
323 TURBOGENERATOR UNITS	12,402,700	(7,534,768)	06-2043	0.0138	0	2.4	297,665	04-2043	45 - R0.5 *	0	895,663	7.22	597,998
324 ACCESSORY ELECTRIC EQUIPMENT	34,367,943	16,891,518	06-2043	0.0012	(2)	1.8	618,623	04-2043	75 - R2.5 *	(1)	719,133	2.09	100,510
325 MISCELLANEOUS POWER PLANT EQUIPMENT	20,722,317	2,245,775	06-2043	0.0032	0	1.8	373,002	04-2043	50 - R1.5 *	(3)	841,331	4.06	468,329
TOTAL ST. LUCIE COMMON	*520,042,535*	*219,288,464*				*1.8*	*9,546,312*				*12,449,123*	*2.39*	*2,902,811*
ST. LUCIE UNIT 1													
321 STRUCTURES AND IMPROVEMENTS	194,729,786	100,039,207	06-2036	0.0028	0	1.8	3,505,136	03-2036	100 - R1.5 *	(1)	5,176,105	2.66	1,670,969
322 REACTOR PLANT EQUIPMENT	838,073,831	293,588,602	06-2036	0.0056	(2)	2.0	16,761,477	03-2036	60 - R1 *	(2)	31,180,373	3.72	14,418,896
323 TURBOGENERATOR UNITS	412,318,467	47,813,095	06-2036	0.0138	0	2.4	9,895,643	03-2036	45 - R0.5 *	0	21,057,503	5.11	11,161,860
324 ACCESSORY ELECTRIC EQUIPMENT	119,762,438	49,415,234	06-2036	0.0012	(2)	1.8	2,155,724	03-2036	75 - R2.5 *	(1)	3,830,023	3.20	1,674,299
325 MISCELLANEOUS POWER PLANT EQUIPMENT	11,320,232	6,997,958	06-2036	0.0032	0	1.8	203,764	03-2036	50 - R1.5 *	(3)	293,754	2.59	89,990
TOTAL ST. LUCIE UNIT 1	*1,576,204,754*	*497,854,096*				*2.1*	*32,521,744*				*61,537,758*	*3.90*	*29,016,014*
ST. LUCIE UNIT 2													
321 STRUCTURES AND IMPROVEMENTS	297,759,844	130,332,823	06-2043	0.0028	0	1.8	5,359,677	04-2043	100 - R1.5 *	(1)	6,772,839	2.27	1,413,162
322 REACTOR PLANT EQUIPMENT	1,053,686,661	387,788,728	06-2043	0.0056	(2)	2.0	21,073,733	04-2043	60 - R1 *	(2)	28,986,146	2.75	7,912,413
323 TURBOGENERATOR UNITS	350,014,044	46,854,392	06-2043	0.0138	0	2.4	8,400,337	04-2043	45 - R0.5 *	0	13,521,840	3.86	5,121,503
324 ACCESSORY ELECTRIC EQUIPMENT	188,938,115	84,917,442	06-2043	0.0012	(2)	1.8	3,400,886	04-2043	75 - R2.5 *	(1)	4,291,331	2.27	890,445
325 MISCELLANEOUS POWER PLANT EQUIPMENT	24,130,684	11,189,066	06-2043	0.0032	0	1.8	434,352	04-2043	50 - R1.5 *	(3)	657,629	2.73	223,277
TOTAL ST. LUCIE UNIT 2	*1,914,529,349*	*661,082,451*				*2.0*	*38,668,985*				*54,229,785*	*2.83*	*15,560,800*
TOTAL ST. LUCIE NUCLEAR PLANT	***4,010,776,637***	***1,378,225,011***				***2.0***	***80,737,041***				***128,216,666***	***3.20***	***47,479,625***
TURKEY POINT NUCLEAR PLANT													
TURKEY POINT COMMON													
321 STRUCTURES AND IMPROVEMENTS	360,056,132	183,734,299	06-2033	0.0028	0	1.8	6,481,010	04-2033	100 - R1.5 *	(1)	11,259,224	3.13	4,778,214
322 REACTOR PLANT EQUIPMENT	137,627,469	24,011,347	06-2033	0.0056	(2)	2.0	2,752,549	04-2033	60 - R1 *	(2)	7,469,106	5.43	4,716,557
323 TURBOGENERATOR UNITS	21,825,767	5,398,454	06-2033	0.0138	0	2.4	523,818	04-2033	45 - R0.5 *	0	1,101,765	5.05	577,947
324 ACCESSORY ELECTRIC EQUIPMENT	53,673,512	34,021,888	06-2033	0.0012	(2)	1.8	966,123	04-2033	75 - R2.5 *	(1)	1,264,143	2.36	298,020
325 MISCELLANEOUS POWER PLANT EQUIPMENT	37,213,998	17,421,764	06-2033	0.0032	0	1.8	669,852	04-2033	50 - R1.5 *	(3)	1,366,579	3.67	696,727
TOTAL TURKEY POINT COMMON	*610,396,877*	*264,587,751*				*1.9*	*11,393,352*				*22,460,817*	*3.68*	*11,067,465*
TURKEY POINT UNIT 3													
321 STRUCTURES AND IMPROVEMENTS	183,462,252	38,437,467	06-2032	0.0028	0	1.8	3,302,321	07-2032	100 - R1.5 *	(1)	9,592,385	5.23	6,290,064
322 REACTOR PLANT EQUIPMENT	586,039,767	168,441,241	06-2032	0.0056	(2)	2.0	11,720,795	07-2032	60 - R1 *	(2)	28,968,915	4.94	17,248,120
323 TURBOGENERATOR UNITS	756,080,929	81,959,597	06-2032	0.0138	0	2.4	18,145,942	07-2032	45 - R0.5 *	0	46,846,514	6.20	28,700,572
324 ACCESSORY ELECTRIC EQUIPMENT	150,385,799	72,326,463	06-2032	0.0012	(2)	1.8	2,706,944	07-2032	75 - R2.5 *	(1)	5,207,015	3.46	2,500,071
325 MISCELLANEOUS POWER PLANT EQUIPMENT	15,687,982	752,238	06-2032	0.0032	0	1.8	282,384	07-2032	50 - R1.5 *	(3)	1,038,166	6.62	755,782
TOTAL TURKEY POINT UNIT 3	*1,691,656,730*	*361,917,007*				*2.1*	*36,158,386*				*91,652,995*	*5.42*	*55,494,609*
TURKEY POINT UNIT 4													
321 STRUCTURES AND IMPROVEMENTS	128,297,844	49,379,171	06-2033	0.0028	0	1.8	2,309,361	04-2033	100 - R1.5 *	(1)	5,009,472	3.90	2,700,111
322 REACTOR PLANT EQUIPMENT	514,072,790	183,833,792	06-2033	0.0056	(2)	2.0	10,281,456	04-2033	60 - R1 *	(2)	21,983,244	4.28	11,701,788
323 TURBOGENERATOR UNITS	599,706,206	78,908,563	06-2033	0.0138	0	2.4	14,392,949	04-2033	45 - R0.5 *	0	34,673,611	5.78	20,280,662
324 ACCESSORY ELECTRIC EQUIPMENT	175,176,467	103,877,312	06-2033	0.0012	(2)	1.8	3,153,176	04-2033	75 - R2.5 *	(1)	4,585,745	2.62	1,432,569
325 MISCELLANEOUS POWER PLANT EQUIPMENT	11,936,247	187,688	06-2033	0.0032	0	1.8	214,852	04-2033	50 - R1.5 *	(3)	782,083	6.55	567,231
TOTAL TURKEY POINT UNIT 4	*1,429,189,554*	*416,186,526*				*2.1*	*30,351,794*				*67,034,155*	*4.69*	*36,682,361*
TOTAL TURKEY POINT NUCLEAR PLANT	***3,731,243,161***	***1,042,691,284***				***2.1***	***77,903,532***				***181,147,967***	***4.85***	***103,244,435***
TOTAL NUCLEAR PRODUCTION PLANT	**7,742,019,799**	**2,420,916,295**				***2.0***	**158,640,573**				**309,364,633**	***4.00***	**150,724,060**

FLORIDA POWER AND LIGHT COMPANY

TABLE 3. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST (1)	BOOK RESERVE (2)	PROBABLE RETIREMENT DATE (3)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (4)	NET SALVAGE (5)	ANNUAL DEPRECIATION RATE (6)	ANNUAL DEPRECIATION ACCRUALS (7)=(6)x(1)	PROBABLE RETIREMENT DATE (8)	SURVIVOR CURVE (9)	NET SALVAGE (10)	ANNUAL DEPRECIATION ACCRUALS (11)	ANNUAL DEPRECIATION RATE (12)	INCREASE/ DECREASE (13)=(12)-(7)
COMBINED CYCLE PRODUCTION PLANT													
LAUDERDALE COMBINED CYCLE PLANT													
LAUDERDALE COMMON													
341 STRUCTURES AND IMPROVEMENTS	84,760,736	56,466,915	06-2023	0.0023	(2)	3.5	2,966,626	06-2033	80 - R2 *	(2)	1,864,990	2.20	(1,101,636)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	11,513,771	6,416,278	06-2023	0.0095	0	3.8	437,523	06-2033	50 - R1.5 *	(3)	355,978	3.09	(81,545)
343 PRIME MOVERS - GENERAL	27,106,051	5,912,889	06-2023	0.0057	0	6.0	1,626,363	06-2033	50 - R1 *	(3)	1,408,857	5.20	(217,506)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	37,564,239	7,262,311	06-2023	0.1565	0	6.0	2,253,854	06-2033	9 - L0 *	35	2,412,721	6.42	158,867
344 GENERATORS	680,446	405,162	06-2023	0.0016	(1)	3.4	23,135	06-2033	60 - R2 *	(3)	18,609	2.73	(4,526)
345 ACCESSORY ELECTRIC EQUIPMENT	12,121,303	9,401,592	06-2023	0.0013	(1)	3.4	412,124	06-2033	50 - R2.5 *	(2)	194,238	1.60	(217,886)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,234,438	609,250	06-2023	0.0026	0	3.4	41,971	06-2033	50 - S0.5 *	(2)	42,255	3.42	284
TOTAL LAUDERDALE COMMON	*174,980,983*	*86,474,396*				*4.4*	*7,761,596*				*6,297,648*	*3.60*	*(1,463,948)*
LAUDERDALE UNIT 4													
341 STRUCTURES AND IMPROVEMENTS	5,090,645	3,478,638	06-2023	0.0023	(2)	3.5	178,173	06-2033	80 - R2 *	(2)	106,647	2.09	(71,526)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	673,633	511,484	06-2023	0.0095	0	3.8	25,598	06-2033	50 - R1.5 *	(3)	11,997	1.78	(13,601)
343 PRIME MOVERS - GENERAL	121,376,511	49,359,731	06-2023	0.0057	0	4.3	5,219,190	06-2033	50 - R1 *	(3)	4,990,638	4.11	(228,552)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	64,237,235	8,573,139	06-2023	0.1565	0	4.3	2,762,201	06-2033	9 - L0 *	35	4,923,007	7.66	2,160,806
344 GENERATORS	28,799,680	20,523,754	06-2023	0.0016	(1)	3.4	979,189	06-2033	60 - R2 *	(3)	582,531	2.02	(396,658)
345 ACCESSORY ELECTRIC EQUIPMENT	29,810,853	19,234,929	06-2023	0.0013	(1)	3.4	1,013,569	06-2033	50 - R2.5 *	(2)	724,053	2.43	(289,516)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	2,599,158	1,902,628	06-2023	0.0026	0	3.4	88,371	06-2033	50 - S0.5 *	(2)	50,337	1.94	(38,034)
TOTAL LAUDERDALE UNIT 4	*252,587,715*	*103,584,302*				*4.1*	*10,266,291*				*11,389,210*	*4.51*	*1,122,919*
LAUDERDALE UNIT 5													
341 STRUCTURES AND IMPROVEMENTS	3,203,159	1,949,981	06-2023	0.0023	(2)	3.5	112,111	06-2033	80 - R2 *	(2)	81,765	2.55	(30,346)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	742,434	503,872	06-2023	0.0095	0	3.8	28,212	06-2033	50 - R1.5 *	(3)	16,959	2.28	(11,253)
343 PRIME MOVERS - GENERAL	121,964,623	33,068,495	06-2023	0.0057	0	4.2	5,122,514	06-2033	50 - R1 *	(3)	6,093,158	5.00	970,644
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	24,160,830	1,666,194	06-2023	0.1565	0	4.2	1,014,755	06-2033	9 - L0 *	35	1,947,066	8.06	932,311
344 GENERATORS	31,767,828	22,571,172	06-2023	0.0016	(1)	3.4	1,080,106	06-2033	60 - R2 *	(3)	644,016	2.03	(436,090)
345 ACCESSORY ELECTRIC EQUIPMENT	24,918,023	15,461,507	06-2023	0.0013	(1)	3.4	847,213	06-2033	50 - R2.5 *	(2)	641,836	2.58	(205,377)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,810,688	1,287,343	06-2023	0.0026	0	3.4	61,563	06-2033	50 - S0.5 *	(2)	37,579	2.08	(23,984)
TOTAL LAUDERDALE UNIT 5	*208,567,584*	*76,508,564*				*4.0*	*8,266,474*				*9,462,379*	*4.54*	*1,195,905*
TOTAL LAUDERDALE COMBINED CYCLE PLANT	***636,136,282***	***266,567,261***				***4.1***	***26,294,361***				***27,149,237***	***4.27***	***854,876***
FT. MYERS COMBINED CYCLE PLANT													
FT. MYERS COMMON													
341 STRUCTURES AND IMPROVEMENTS	8,824,312	2,131,886	06-2033	0.0023	(2)	3.5	308,851	06-2043	80 - R2 *	(2)	274,099	3.11	(34,752)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	794,049	284,358	06-2033	0.0095	0	3.8	30,174	06-2043	50 - R1.5 *	(3)	34,287	4.32	4,113
343 PRIME MOVERS - GENERAL	3,709,607	1,045,250	06-2033	0.0057	0	5.8	215,157	06-2043	50 - R1 *	(3)	115,845	3.12	(99,312)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	441,577	231,377	06-2033	0.1565	0	5.8	25,611	06-2043	9 - L0 *	35	9,562	2.17	(16,049)
344 GENERATORS	230,729	16,354	06-2033	0.0016	(1)	3.4	7,845	06-2043	60 - R2 *	(3)	8,706	3.77	861
345 ACCESSORY ELECTRIC EQUIPMENT	1,163,312	139,908	06-2033	0.0013	(1)	3.4	39,553	06-2043	50 - R2.5 *	(2)	42,018	3.61	2,465
346 MISCELLANEOUS POWER PLANT EQUIPMENT	768,815	197,971	06-2033	0.0026	0	3.4	26,140	06-2043	50 - S0.5 *	(2)	25,678	3.34	(462)
TOTAL FT. MYERS COMMON	*15,932,401*	*4,047,105*				*4.1*	*653,331*				*510,195*	*3.20*	*(143,136)*
FT. MYERS UNIT 2													
341 STRUCTURES AND IMPROVEMENTS	28,751,597	12,204,747	06-2033	0.0023	(2)	3.5	1,006,306	06-2043	80 - R2 *	(2)	673,825	2.34	(332,481)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	6,194,175	1,967,815	06-2033	0.0095	0	3.8	235,379	06-2043	50 - R1.5 *	(3)	188,313	3.04	(47,066)
343 PRIME MOVERS - GENERAL	367,522,551	79,088,073	06-2033	0.0057	0	4.2	15,435,947	06-2043	50 - R1 *	(3)	12,726,738	3.46	(2,709,209)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	302,123,631	39,131,213	06-2033	0.1565	0	4.2	12,689,192	06-2043	9 - L0 *	35	22,432,118	7.42	9,742,926
344 GENERATORS	57,280,635	19,398,986	06-2033	0.0016	(1)	3.4	1,947,542	06-2043	60 R2 *	(3)	1,601,297	2.80	(346,245)
345 ACCESSORY ELECTRIC EQUIPMENT	55,628,985	25,417,944	06-2033	0.0013	(1)	3.4	1,891,385	06-2043	50 R2.5 *	(2)	1,299,735	2.34	(591,650)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	3,539,476	1,628,771	06-2033	0.0026	0	3.4	120,342	06-2043	50 S0.5 *	(2)	86,528	2.44	(33,814)
TOTAL FT. MYERS UNIT 2	*821,041,049*	*178,837,550*				*4.1*	*33,326,093*				*39,008,554*	*4.75*	*5,682,461*
FT. MYERS UNIT 3													
341 STRUCTURES AND IMPROVEMENTS	10,445,289	1,539,033	06-2033	0.0023	(2)	3.5	365,585	06-2043	80 - R2 *	(2)	353,027	3.38	(12,558)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	13,425,923	2,081,549	06-2033	0.0095	0	3.8	510,185	06-2043	50 - R1.5 *	(3)	480,063	3.58	(30,122)
343 PRIME MOVERS - GENERAL	164,165,759	(10,456,672)	06-2033	0.0057	0	5.2	8,536,619	06-2043	50 - R1 *	(3)	7,453,192	4.54	(1,083,427)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	20,183,733	(1,479,151)	06-2033	0.1565	0	5.2	1,049,554	06-2043	25 - R1 *	29	794,452	3.94	(255,102)
344 GENERATORS	46,926,130	7,152,354	06-2033	0.0016	(1)	3.4	1,595,488	06-2043	60 - R2 *	(3)	1,622,599	3.46	27,111
345 ACCESSORY ELECTRIC EQUIPMENT	32,964,437	5,278,646	06-2033	0.0013	(1)	3.4	1,120,791	06-2043	50 - R2.5 *	(2)	1,119,474	3.40	(1,317)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,734,913	212,247	06-2033	0.0026	0	3.4	58,987	06-2043	50 - S0.5 *	(2)	63,488	3.66	4,501
TOTAL FT. MYERS UNIT 3	*289,846,185*	*4,328,006*				*4.6*	*13,237,209*				*11,886,295*	*4.10*	*(1,350,914)*
TOTAL FT. MYERS COMBINED CYCLE PLANT	***1,126,819,634***	***187,212,661***				***4.2***	***47,216,633***				***51,405,044***	***4.56***	***4,188,411***

FLORIDA POWER AND LIGHT COMPANY

TABLE 3. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST (1)	BOOK RESERVE (2)	PROBABLE RETIREMENT DATE (3)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (4)	NET SALVAGE (5)	ANNUAL DEPRECIATION RATE (6)	ANNUAL DEPRECIATION ACCRUALS (7)=(6)x(1)	PROBABLE RETIREMENT DATE (8)	SURVIVOR CURVE (9)	NET SALVAGE (10)	ANNUAL DEPRECIATION ACCRUALS (11)	ANNUAL DEPRECIATION RATE (12)	INCREASE/ DECREASE (13)=(12)-(7)
MANATEE COMBINED CYCLE PLANT													
MANATEE UNIT 3													
341 STRUCTURES AND IMPROVEMENTS	28,927,929	10,726,313	06-2035	0.0023	(2)	3.5	1,012,478	06-2045	80 - R2 *	(2)	685,908	2.37	(326,570)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	4,008,361	1,497,584	06-2035	0.0095	0	3.8	152,318	06-2045	50 - R1.5 *	(3)	104,158	2.60	(48,160)
343 PRIME MOVERS - GENERAL	236,795,038	46,167,493	06-2035	0.0057	0	4.3	10,182,187	06-2045	50 - R1 *	(3)	7,925,106	3.35	(2,257,081)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	146,248,668	19,013,518	06-2035	0.1565	0	4.3	6,288,693	06-2045	9 - L0 *	35	11,522,442	7.88	5,233,749
344 GENERATORS	41,417,902	16,420,596	06-2035	0.0016	(1)	3.4	1,408,209	06-2045	60 - R2 *	(3)	986,460	2.38	(421,749)
345 ACCESSORY ELECTRIC EQUIPMENT	45,110,148	16,629,259	06-2035	0.0013	(1)	3.4	1,533,745	06-2045	50 - R2.5 *	(2)	1,123,207	2.49	(410,538)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	10,976,397	3,676,138	06-2035	0.0026	0	3.4	373,197	06-2045	50 - S0.5 *	(2)	304,322	2.77	(68,875)
TOTAL MANATEE UNIT 3	*513,484,442*	*114,130,902*				*4.1*	*20,950,827*				*22,651,603*	*4.41*	*1,700,776*
TOTAL MANATEE COMBINED CYCLE PLANT	***513,484,442***	***114,130,902***				***4.1***	***20,950,827***				***22,651,603***	***4.41***	***1,700,776***
MARTIN COMBINED CYCLE PLANT													
MARTIN COMMON													
341 STRUCTURES AND IMPROVEMENTS	49,379,840	31,469,365	06-2024	0.0023	(2)	3.5	1,728,294	06-2034	80 - R2 *	(2)	1,108,391	2.24	(619,903)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	4,766,331	3,048,070	06-2024	0.0095	0	3.8	181,121	06-2034	50 - R1.5 *	(3)	115,248	2.42	(65,873)
343 PRIME MOVERS - GENERAL	22,788,940	14,037,911	06-2024	0.0057	0	4.3	979,924	06-2034	50 - R1 *	(3)	583,469	2.56	(396,455)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	2,230,422	770,616	06-2024	0.1565	0	4.3	95,908	06-2034	9 - L0 *	35	113,005	5.07	17,097
345 ACCESSORY ELECTRIC EQUIPMENT	5,321,992	3,662,480	06-2024	0.0013	(1)	3.4	180,948	06-2034	50 - R2.5 *	(2)	108,474	2.04	(72,474)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	4,194,043	2,750,673	06-2024	0.0026	0	3.4	142,597	06-2034	50 - S0.5 *	(2)	97,030	2.31	(45,567)
TOTAL MARTIN COMMON	*88,681,567*	*55,739,115*				*3.7*	*3,308,792*				*2,125,617*	*2.40*	*(1,183,175)*
MARTIN UNIT 3													
341 STRUCTURES AND IMPROVEMENTS	1,660,028	1,129,406	06-2024	0.0023	(2)	3.5	58,101	06-2034	80 - R2 *	(2)	33,127	2.00	(24,974)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	178,721	126,140	06-2024	0.0095	0	3.8	6,791	06-2034	50 - R1.5 *	(3)	3,631	2.03	(3,160)
343 PRIME MOVERS - GENERAL	152,279,614	46,856,499	06-2024	0.0057	0	4.2	6,395,744	06-2034	50 - R1 *	(3)	6,831,770	4.49	436,026
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	67,628,799	4,931,417	06-2024	0.1565	0	4.2	2,840,410	06-2034	9 - L0 *	35	5,203,640	7.69	2,363,230
344 GENERATORS	26,577,658	12,491,844	06-2024	0.0016	(1)	3.4	903,640	06-2034	60 - R2 *	(3)	884,322	3.33	(19,318)
345 ACCESSORY ELECTRIC EQUIPMENT	28,440,138	16,413,361	06-2024	0.0013	(1)	3.4	966,965	06-2034	50 - R2.5 *	(2)	766,155	2.69	(200,810)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	569,569	403,368	06-2024	0.0026	0	3.4	19,365	06-2034	50 - S0.5 *	(2)	11,362	1.99	(8,003)
TOTAL MARTIN UNIT 3	*277,334,527*	*82,352,034*				*4.0*	*11,191,016*				*13,734,007*	*4.95*	*2,542,991*
MARTIN UNIT 4													
341 STRUCTURES AND IMPROVEMENTS	1,498,690	779,399	06-2024	0.0023	(2)	3.5	52,454	06-2034	80 - R2 *	(2)	43,868	2.93	(8,586)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	178,315	125,767	06-2024	0.0095	0	3.8	6,776	06-2034	50 - R1.5 *	(3)	3,628	2.03	(3,148)
343 PRIME MOVERS - GENERAL	157,866,532	62,665,792	06-2024	0.0057	0	4.2	6,630,394	06-2034	50 - R1 *	(3)	6,184,204	3.92	(446,190)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	100,540,570	14,593,390	06-2024	0.1565	0	4.2	4,222,704	06-2034	9 - L0 *	35	7,313,830	7.27	3,091,126
344 GENERATORS	32,812,957	17,243,431	06-2024	0.0016	(1)	3.4	1,115,641	06-2034	60 - R2 *	(3)	984,180	3.00	(131,461)
345 ACCESSORY ELECTRIC EQUIPMENT	25,564,311	14,499,926	06-2024	0.0013	(1)	3.4	869,187	06-2034	50 - R2.5 *	(2)	703,261	2.75	(165,926)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	826,194	416,190	06-2024	0.0026	0	3.4	28,091	06-2034	50 - S0.5 *	(2)	26,313	3.18	(1,778)
TOTAL MARTIN UNIT 4	*319,287,568*	*110,323,895*				*4.0*	*12,925,247*				*15,259,284*	*4.78*	*2,334,037*
MARTIN UNIT 8													
341 STRUCTURES AND IMPROVEMENTS	23,755,210	8,515,386	06-2035	0.0023	(2)	3.5	831,432	06-2045	80 - R2 *	(2)	573,956	2.42	(257,476)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	11,392,824	3,970,615	06-2035	0.0095	0	3.8	432,927	06-2045	50 - R1.5 *	(3)	307,851	2.70	(125,076)
343 PRIME MOVERS - GENERAL	256,002,412	48,218,164	06-2035	0.0057	0	4.3	11,008,104	06-2045	50 - R1 *	(3)	8,618,573	3.37	(2,389,531)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	213,276,994	24,119,658	06-2035	0.1565	0	4.3	9,170,911	06-2045	9 - L0 *	35	16,547,744	7.76	7,376,833
344 GENERATORS	41,069,900	13,445,958	06-2035	0.0016	(1)	3.4	1,396,377	06-2045	60 - R2 *	(3)	1,085,630	2.64	(310,747)
345 ACCESSORY ELECTRIC EQUIPMENT	51,655,998	17,489,445	06-2035	0.0013	(1)	3.4	1,756,304	06-2045	50 - R2.5 *	(2)	1,350,717	2.61	(405,587)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	4,899,017	1,751,981	06-2035	0.0026	0	3.4	166,567	06-2045	50 - S0.5 *	(2)	130,427	2.66	(36,140)
TOTAL MARTIN UNIT 8	*602,052,355*	*117,511,209*				*4.1*	*24,762,622*				*28,614,898*	*4.75*	*3,852,276*
TOTAL MARTIN COMBINED CYCLE PLANT	***1,287,356,017***	***365,926,253***				***4.1***	***52,187,677***				***59,733,806***	***4.64***	***7,546,129***
SANFORD COMBINED CYCLE PLANT													
SANFORD COMMON													
341 STRUCTURES AND IMPROVEMENTS	71,585,766	29,616,249	06-2033	0.0023	(2)	3.5	2,505,502	06-2043	80 - R2 *	(2)	1,716,821	2.40	(788,681)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	88,875	42,745	06-2033	0.0095	0	3.8	3,377	06-2043	50 - R1.5 *	(3)	2,071	2.33	(1,306)
343 PRIME MOVERS - GENERAL	5,932,378	(4,737,256)	06-2033	0.0057	0	4.5	266,957	06-2043	50 - R1 *	(3)	472,457	7.96	205,500
344 GENERATORS	200,500	36,233	06-2033	0.0016	(1)	3.4	6,817	06-2043	60 - R2 *	(3)	6,733	3.36	(84)
345 ACCESSORY ELECTRIC EQUIPMENT	2,142,789	643,155	06-2033	0.0013	(1)	3.4	72,855	06-2043	50 - R2.5 *	(2)	65,499	3.06	(7,356)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	2,233,762	820,161	06-2033	0.0026	0	3.4	75,948	06-2043	50 - S0.5 *	(2)	62,776	2.81	(13,172)
TOTAL SANFORD COMMON	*82,184,069*	*26,421,287*				*3.6*	*2,931,456*				*2,326,357*	*2.83*	*(605,099)*
SANFORD UNIT 4													
341 STRUCTURES AND IMPROVEMENTS	7,424,610	3,124,501	06-2033	0.0023	(2)	3.5	259,861	06-2043	80 - R2 *	(2)	177,306	2.39	(82,555)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,803,717	789,469	06-2033	0.0095	0	3.8	68,541	06-2043	50 - R1.5 *	(3)	45,212	2.51	(23,329)
343 PRIME MOVERS - GENERAL	196,875,732	18,672,684	06-2033	0.0057	0	4.8	9,450,035	06-2043	50 - R1 *	(3)	7,881,392	4.00	(1,568,643)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	140,077,308	7,071,393	06-2033	0.1565	0	4.8	6,723,711	06-2043	9 - L0 *	35	12,100,700	8.64	5,376,989
344 GENERATORS	32,820,452	10,272,329	06-2033	0.0016	(1)	3.4	1,115,895	06-2043	60 - R2 *	(3)	948,518	2.89	(167,377)
345 ACCESSORY ELECTRIC EQUIPMENT	35,200,492	14,915,272	06-2033	0.0013	(1)	3.4	1,196,817	06-2043	50 - R2.5 *	(2)	877,843	2.49	(318,974)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	3,326,653	1,415,407	06-2033	0.0026	0	3.4	113,106	06-2043	50 - S0.5 *	(2)	85,878	2.58	(27,228)
TOTAL SANFORD UNIT 4	*417,528,965*	*56,261,055*				*4.5*	*18,927,966*				*22,116,849*	*5.30*	*3,188,883*
SANFORD UNIT 5													
341 STRUCTURES AND IMPROVEMENTS	7,275,953	3,148,967	06-2032	0.0023	(2)	3.5	254,658	06-2042	80 - R2 *	(2)	175,968	2.42	(78,690)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,814,776	859,918	06-2032	0.0095	0	3.8	68,961	06-2042	50 - R1.5 *	(3)	44,326	2.44	(24,635)
343 PRIME MOVERS - GENERAL	214,894,008	20,990,061	06-2032	0.0057	0	4.2	9,025,548	06-2042	50 - R1 *	(3)	8,861,157	4.12	(164,391)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	126,367,538	6,255,267	06-2032	0.1565	0	4.2	5,307,437	06-2042	9 - L0 *	35	10,840,519	8.58	5,533,082
344 GENERATORS	32,632,812	11,677,845	06-2032	0.0016	(1)	3.4	1,109,516	06-2042	60 - R2 *	(3)	916,971	2.81	(192,545)
345 ACCESSORY ELECTRIC EQUIPMENT	34,685,483	14,818,331	06-2032	0.0013	(1)	3.4	1,179,306	06-2042	50 - R2.5 *	(2)	888,158	2.56	(291,148)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	2,899,894	1,243,698	06-2032	0.0026	0	3.4	98,596	06-2042	50 - S0.5 *	(2)	76,835	2.65	(21,761)
TOTAL SANFORD UNIT 5	*420,570,464*	*58,994,088*				*4.1*	*17,044,022*				*21,803,934*	*5.18*	*4,759,912*
TOTAL SANFORD COMBINED CYCLE PLANT	***920,283,497***	***141,676,429***				***4.2***	***38,903,444***				***46,247,140***	***5.03***	***7,343,696***

FLORIDA POWER AND LIGHT COMPANY

TABLE 3. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST (1)	BOOK RESERVE (2)	PROBABLE RETIREMENT DATE (3)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (4)	NET SALVAGE (5)	ANNUAL DEPRECIATION RATE (6)	ANNUAL DEPRECIATION ACCRUALS (7)=(6)x(1)	PROBABLE RETIREMENT DATE (8)	SURVIVOR CURVE (9)	NET SALVAGE (10)	ANNUAL DEPRECIATION ACCRUALS (11)	ANNUAL DEPRECIATION RATE (12)	INCREASE/ DECREASE (13)=(12)-(7)
TURKEY POINT COMBINED CYCLE PLANT													
TURKEY POINT UNIT 5													
341 STRUCTURES AND IMPROVEMENTS	32,284,855	10,891,633	06-2037	0.0023	(2)	3.5	1,129,970	06-2047	80 - R2 *	(2)	752,952	2.33	(377,018)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	12,410,131	4,106,992	06-2037	0.0095	0	3.8	471,585	06-2047	50 - R1.5 *	(3)	321,432	2.59	(150,153)
343 PRIME MOVERS - GENERAL	250,685,264	39,618,917	06-2037	0.0057	0	5.7	14,289,060	06-2047	50 - R1 *	(3)	8,229,929	3.28	(6,059,131)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	128,220,285	12,943,274	06-2037	0.1565	0	5.7	7,308,556	06-2047	9 - L0 *	35	9,957,555	7.77	2,648,999
344 GENERATORS	41,669,542	11,132,485	06-2037	0.0016	(1)	3.4	1,416,754	06-2047	60 - R2 *	(3)	1,117,299	2.68	(299,465)
345 ACCESSORY ELECTRIC EQUIPMENT	51,980,475	16,506,639	06-2037	0.0013	(1)	3.4	1,767,336	06-2047	50 - R2.5 *	(2)	1,305,917	2.51	(461,419)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	12,433,804	3,613,736	06-2037	0.0026	0	3.4	422,749	06-2047	50 - S0.5 *	(2)	342,605	2.76	(80,144)
TOTAL TURKEY POINT UNIT 5	*529,684,355*	*98,813,676*				*5.1*	*26,806,020*				*22,027,689*	*4.16*	*(4,778,331)*
TOTAL TURKEY POINT COMBINED CYCLE PLANT	***529,684,355***	***98,813,676***				***5.1***	***26,806,020***				***22,027,689***	***4.16***	***(4,778,331)***
WEST COUNTY COMBINED CYCLE PLANT													
WEST COUNTY COMMON													
341 STRUCTURES AND IMPROVEMENTS	3,120,798	482,630	06-2041	SQUARE *	0	3.3	102,986	06-2051	80 - R2 *	(2)	81,539	2.61	(21,447)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	450,604	68,020	06-2041	SQUARE *	0	3.3	14,870	06-2051	50 - R1.5 *	(3)	13,013	2.89	(1,857)
343 PRIME MOVERS - GENERAL	31,206,902	1,389,969	06-2041	SQUARE *	0	3.3	1,029,828	06-2051	50 - R1 *	(3)	1,017,642	3.26	(12,186)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	126,771,982	12,726,022	06-2041	SQUARE *	0	3.3	4,183,475	06-2051	9 - L0 *	35	9,518,547	7.51	5,335,072
345 ACCESSORY ELECTRIC EQUIPMENT	1,291,342	107,199	06-2041	SQUARE *	0	3.3	42,614	06-2051	50 - R2.5 *	(2)	37,670	2.92	(4,944)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	836,533	111,543	06-2041	SQUARE *	0	3.3	27,606	06-2051	50 - S0.5 *	(2)	24,471	2.93	(3,135)
TOTAL WEST COUNTY COMMON	*163,678,161*	*14,885,382*				*3.3*	*5,401,379*				*10,692,882*	*6.53*	*5,291,503*
WEST COUNTY UNIT 1													
341 STRUCTURES AND IMPROVEMENTS	109,835,744	20,012,782	06-2039	SQUARE *	0	3.3	3,624,580	06-2049	80 - R2 *	(2)	2,950,294	2.69	(674,286)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	21,806,447	2,710,694	06-2039	SQUARE *	0	3.3	719,613	06-2049	50 - R1.5 *	(3)	686,716	3.15	(32,897)
343 PRIME MOVERS - GENERAL	300,710,821	(22,756,245)	06-2039	SQUARE *	0	3.3	9,923,457	06-2049	50 - R1 *	(3)	11,786,189	3.92	1,862,732
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	81,954,083	(7,349,277)	06-2039	SQUARE *	0	3.3	2,704,485	06-2049	9 - L0 *	35	9,668,171	11.80	6,963,686
344 GENERATORS	49,469,105	7,847,276	06-2039	SQUARE *	0	3.3	1,632,480	06-2049	60 - R2 *	(3)	1,422,168	2.87	(210,312)
345 ACCESSORY ELECTRIC EQUIPMENT	72,300,016	12,231,627	06-2039	SQUARE *	0	3.3	2,385,901	06-2049	50 - R2.5 *	(2)	2,062,857	2.85	(323,044)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	8,042,081	1,335,110	06-2039	SQUARE *	0	3.3	265,389	06-2049	50 - S0.5 *	(2)	243,367	3.03	(22,022)
TOTAL WEST COUNTY UNIT 1	*644,118,297*	*14,031,966*				*3.3*	*21,255,905*				*28,819,762*	*4.47*	*7,563,857*
WEST COUNTY UNIT 2													
341 STRUCTURES AND IMPROVEMENTS	39,659,646	6,204,493	06-2039	SQUARE *	0	3.3	1,308,768	06-2049	80 - R2 *	(2)	1,098,055	2.77	(210,713)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	7,471,457	284,961	06-2039	SQUARE *	0	3.3	246,558	06-2049	50 - R1.5 *	(3)	256,957	3.44	10,399
343 PRIME MOVERS - GENERAL	255,637,285	17,744,809	06-2039	SQUARE *	0	3.3	8,436,030	06-2049	50 - R1 *	(3)	8,710,947	3.41	274,917
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	149,878,251	12,481,512	06-2039	SQUARE *	0	3.3	4,945,982	06-2049	9 - L0 *	35	13,722,028	9.16	8,776,046
344 GENERATORS	43,599,023	6,676,878	06-2039	SQUARE *	0	3.3	1,438,768	06-2049	60 - R2 *	(3)	1,260,888	2.89	(177,880)
345 ACCESSORY ELECTRIC EQUIPMENT	33,177,136	5,335,502	06-2039	SQUARE *	0	3.3	1,094,845	06-2049	50 - R2.5 *	(2)	955,908	2.88	(138,937)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	11,893,351	1,719,196	06-2039	SQUARE *	0	3.3	392,481	06-2049	50 - S0.5 *	(2)	366,491	3.08	(25,990)
TOTAL WEST COUNTY UNIT 2	*541,316,149*	*50,447,351*				*3.3*	*17,863,432*				*26,371,274*	*4.87*	*8,507,842*
WEST COUNTY UNIT 3													
341 STRUCTURES AND IMPROVEMENTS	57,671,242	8,518,122	06-2041	SQUARE *	0	3.3	1,903,151	06-2051	80 - R2 *	(2)	1,520,754	2.64	(382,397)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	10,754,858	742,790	06-2041	SQUARE *	0	3.3	354,910	06-2051	50 - R1.5 *	(3)	339,065	3.15	(15,845)
343 PRIME MOVERS - GENERAL	480,389,197	32,738,513	06-2041	SQUARE *	0	3.3	15,852,844	06-2051	50 - R1 *	(3)	15,521,074	3.23	(331,770)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	98,598,036	8,887,181	06-2041	SQUARE *	0	3.3	3,253,735	06-2051	9 - L0 *	35	8,363,870	8.48	5,110,135
344 GENERATORS	64,525,280	9,184,372	06-2041	SQUARE *	0	3.3	2,129,334	06-2051	60 - R2 *	(3)	1,780,437	2.76	(348,897)
345 ACCESSORY ELECTRIC EQUIPMENT	48,252,610	7,322,267	06-2041	SQUARE *	0	3.3	1,592,336	06-2051	50 - R2.5 *	(2)	1,322,456	2.74	(269,880)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	12,454,466	7,732,043	06-2041	SQUARE *	0	3.3	410,997	06-2051	50 - S0.5 *	(2)	165,828	1.33	(245,169)
TOTAL WEST COUNTY UNIT 3	*772,645,690*	*75,125,287*				*3.3*	*25,497,307*				*29,013,484*	*3.76*	*3,516,177*
TOTAL WEST COUNTY COMBINED CYCLE PLANT	***2,121,758,297***	***154,489,986***				***3.3***	***70,018,023***				***94,897,402***	***4.47***	***24,879,379***
CAPE CANAVERAL COMBINED CYCLE PLANT													
CAPE CANAVERAL COMBINED CYCLE													
341 STRUCTURES AND IMPROVEMENTS	82,092,869	6,368,724	06-2043	SQUARE *	0	3.3	2,709,065	06-2053	80 - R2 *	(2)	2,211,721	2.69	(497,344)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	47,723,728	3,579,557	06-2043	SQUARE *	0	3.3	1,574,883	06-2053	50 - R1.5 *	(3)	1,416,280	2.97	(158,603)
343 PRIME MOVERS - GENERAL	385,108,676	38,729,543	06-2043	SQUARE *	0	3.3	12,708,586	06-2053	50 - R1 *	(3)	11,406,386	2.96	(1,302,200)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	206,255,249	28,539,906	06-2043	SQUARE *	0	3.3	6,806,423	06-2053	9 - L0 *	35	14,298,917	6.93	7,492,494
344 GENERATORS	70,269,257	5,194,564	06-2043	SQUARE *	0	3.3	2,318,885	06-2053	60 - R2 *	(3)	1,974,222	2.81	(344,663)
345 ACCESSORY ELECTRIC EQUIPMENT	111,693,785	8,403,920	06-2043	SQUARE *	0	3.3	3,685,895	06-2053	50 - R2.5 *	(2)	3,141,522	2.81	(544,373)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	10,309,493	738,999	06-2043	SQUARE *	0	3.3	340,213	06-2053	50 - S0.5 *	(2)	306,960	2.98	(33,253)
TOTAL CAPE CANAVERAL COMBINED CYCLE	*913,453,057*	*91,555,214*				*3.3*	*30,143,950*				*34,756,008*	*3.80*	*4,612,058*
TOTAL CAPE CANAVERAL COMBINED CYCLE PLANT	***913,453,057***	***91,555,214***				***3.3***	***30,143,950***				***34,756,008***	***3.80***	***4,612,058***

FLORIDA POWER AND LIGHT COMPANY

TABLE 3. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST (1)	BOOK RESERVE (2)	PROBABLE RETIREMENT DATE (3)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (4)	NET SALVAGE (5)	ANNUAL DEPRECIATION RATE (6)	ANNUAL DEPRECIATION ACCRUALS (7)=(6)x(1)	PROBABLE RETIREMENT DATE (8)	SURVIVOR CURVE (9)	NET SALVAGE (10)	ANNUAL DEPRECIATION ACCRUALS (11)	ANNUAL DEPRECIATION RATE (12)	INCREASE/ DECREASE (13)=(12)-(7)
RIVIERA COMBINED CYCLE PLANT													
RIVIERA COMBINED CYCLE													
341 STRUCTURES AND IMPROVEMENTS	80,630,958	7,456,698	06-2044	SQUARE *	0	3.3	2,660,822	06-2054	80 - R2 *	(2)	2,083,200	2.58	(577,622)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	217,306,004	18,577,338	06-2044	SQUARE *	0	3.3	7,171,098	06-2054	50 - R1.5 *	(3)	6,213,983	2.86	(957,115)
343 PRIME MOVERS - GENERAL	525,780,412	35,938,896	06-2044	SQUARE *	0	3.3	17,350,754	06-2054	50 - R1 *	(3)	15,697,452	2.99	(1,653,302)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	139,494,633	16,409,879	06-2044	SQUARE *	0	3.3	4,603,323	06-2054	9 - L0 *	35	9,822,967	7.04	5,219,644
344 GENERATORS	79,977,232	5,875,063	06-2044	SQUARE *	0	3.3	2,639,249	06-2054	60 - R2 *	(3)	2,187,632	2.74	(451,617)
345 ACCESSORY ELECTRIC EQUIPMENT	82,800,568	6,849,745	06-2044	SQUARE *	0	3.3	2,732,419	06-2054	50 - R2.5 *	(2)	2,249,473	2.72	(482,946)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	11,446,561	1,663,361	06-2044	SQUARE *	0	3.3	377,737	06-2054	50 - S0.5 *	(2)	305,248	2.67	(72,489)
TOTAL RIVIERA COMBINED CYCLE	*1,137,436,368*	*92,770,979*				*3.3*	*37,535,402*				*38,559,955*	*3.39*	*1,024,553*
TOTAL RIVIERA COMBINED CYCLE PLANT	***1,137,436,368***	***92,770,979***				***3.3***	***37,535,402***				***38,559,955***	***3.39***	***1,024,553***
PT EVERGLADES COMBINED CYCLE PLANT													
PT EVERGLADES COMBINED CYCLE													
341 STRUCTURES AND IMPROVEMENTS	101,607,532	2,299,667	06-2046	SQUARE *	0	3.3	3,353,049	06-2056	80 - R2 *	(2)	2,678,119	2.64	(674,930)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	59,665,117	1,350,391	06-2046	SQUARE *	0	3.3	1,968,949	06-2056	50 - R1.5 *	(3)	1,728,636	2.90	(240,313)
343 PRIME MOVERS - GENERAL	499,500,579	8,382,316	06-2046	SQUARE *	0	3.3	16,483,519	06-2056	50 - R1 *	(3)	14,955,771	2.99	(1,527,748)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	191,363,196	7,253,893	06-2046	SQUARE *	0	3.3	6,314,985	06-2056	9 - L0 *	35	13,604,203	7.11	7,289,218
344 GENERATORS	87,208,139	1,973,768	06-2046	SQUARE *	0	3.3	2,877,869	06-2056	60 - R2 *	(3)	2,384,653	2.73	(493,216)
345 ACCESSORY ELECTRIC EQUIPMENT	138,483,956	3,134,285	06-2046	SQUARE *	0	3.3	4,569,971	06-2056	50 - R2.5 *	(2)	3,792,404	2.74	(777,567)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	12,795,087	289,589	06-2046	SQUARE *	0	3.3	422,238	06-2056	50 - S0.5 *	(2)	367,552	2.87	(54,686)
TOTAL PT EVERGLADES COMBINED CYCLE	*1,090,623,606*	*24,683,910*				*3.3*	*35,990,580*				*39,511,338*	*3.62*	*3,520,758*
TOTAL PT EVERGLADES COMBINED CYCLE PLANT	***1,090,623,606***	***24,683,910***				***3.3***	***35,990,580***				***39,511,338***	***3.62***	***3,520,758***
TOTAL COMBINED CYCLE PRODUCTION PLANT	**10,277,035,554**	**1,537,827,272**				***3.8***	**386,046,917**				**436,939,222**	***4.25***	**50,892,305**

FLORIDA POWER AND LIGHT COMPANY

TABLE 3. COMPARISON OF REMAINING LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST (1)	BOOK RESERVE (2)	PROBABLE RETIREMENT DATE (3)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (4)	NET SALVAGE (5)	ANNUAL DEPRECIATION RATE (6)	ANNUAL DEPRECIATION ACCRUALS (7)=(6)x(1)	PROBABLE RETIREMENT DATE (8)	SURVIVOR CURVE (9)	NET SALVAGE (10)	ANNUAL DEPRECIATION ACCRUALS (11)	ANNUAL DEPRECIATION RATE (12)	INCREASE/ DECREASE (13)=(12)-(7)
PEAKER PLANTS													
LAUDERDALE GTS													
341 STRUCTURES AND IMPROVEMENTS	601,222	330,322	06-2020	0.0023	(2)	2.2	13,227	06-2028	80 - R2 *	(2)	25,126	4.18	11,899
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	194,417	102,093	06-2020	0.0095	0	2.6	5,055	06-2028	50 - R1.5 *	(3)	9,191	4.73	4,136
343 PRIME MOVERS - GENERAL	14,841,925	1,714,581	06-2020	0.0057	0	2.9	430,416	06-2028	50 - R1 *	(3)	1,224,964	8.25	794,548
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	1,858,779	673,466	06-2020	0.1565	0	2.9	53,905	06-2028	25 - R1 *	29	77,770	4.18	23,865
344 GENERATORS	1,748,135	750,005	06-2020	0.0016	(1)	2.1	36,711	06-2028	60 - R2 *	(3)	99,017	5.66	62,306
345 ACCESSORY ELECTRIC EQUIPMENT	420,107	174,657	06-2020	0.0013	(1)	2.1	8,822	06-2028	50 - R2.5 *	(2)	25,284	6.02	16,462
346 MISCELLANEOUS POWER PLANT EQUIPMENT	20,935	8,570	06-2020	0.0026	0	2.2	461	06-2028	50 - S0.5 *	(2)	1,299	6.21	838
TOTAL LAUDERDALE GTS	*19,685,520*	*3,753,692*				*2.8*	*548,597*				*1,462,651*	***7.43***	*914,054*
FT. MYERS GTS													
341 STRUCTURES AND IMPROVEMENTS	941,093	168,137	06-2020	0.0023	(2)	2.3	21,645	06-2028	80 - R2 *	(2)	69,637	7.40	47,992
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	724,318	117,795	06-2020	0.0095	0	2.7	19,557	06-2028	50 - R1.5 *	(3)	56,753	7.84	37,196
343 PRIME MOVERS - GENERAL	10,218,903	1,207,170	06-2020	0.0057	0	3.1	316,786	06-2028	50 - R1 *	(3)	840,243	8.22	523,457
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	2,807,095	1,254,825	06-2020	0.1565	0	3.1	87,020	06-2028	25 - R1 *	29	117,550	4.19	30,530
344 GENERATORS	4,602,022	551,085	06-2020	0.0016	(1)	2.2	101,244	06-2028	60 - R2 *	(3)	371,695	8.08	270,451
345 ACCESSORY ELECTRIC EQUIPMENT	3,450,438	485,852	06-2020	0.0013	(1)	2.2	75,910	06-2028	50 - R2.5 *	(2)	267,985	7.77	192,075
346 MISCELLANEOUS POWER PLANT EQUIPMENT	20,936	2,632	06-2020	0.0026	0	2.3	482	06-2028	50 - S0.5 *	(2)	1,682	8.03	1,200
TOTAL FT. MYERS GTS	*22,764,804*	*3,787,495*				*2.7*	*622,644*				*1,725,545*	***7.58***	*1,102,901*
LAUDERDALE AND FT. MYERS PEAKERS													
341 STRUCTURES AND IMPROVEMENTS	43,805,886	76,824	06-2046	SQUARE *	0	3.3	1,445,594	06-2056	80 - R2 *	(2)	1,178,784	2.69	(266,810)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	26,150,085	45,861	06-2046	SQUARE *	0	3.3	862,953	06-2056	50 - R1.5 *	(3)	773,331	2.96	(89,622)
343 PRIME MOVERS - GENERAL	213,843,171	389,972	06-2046	SQUARE *	0	3.3	7,056,825	06-2056	50 - R1 *	(3)	6,497,296	3.04	(559,529)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	83,870,827	132,142	06-2046	SQUARE *	0	3.3	2,767,737	06-2056	25 - R1 *	29	2,443,098	2.91	(324,639)
344 GENERATORS	38,221,667	67,031	06-2046	SQUARE *	0	3.3	1,261,315	06-2056	60 - R2 *	(3)	1,066,810	2.79	(194,505)
345 ACCESSORY ELECTRIC EQUIPMENT	60,694,881	106,443	06-2046	SQUARE *	0	3.3	2,002,931	06-2056	50 - R2.5 *	(2)	1,696,934	2.80	(305,997)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	5,607,843	9,835	06-2046	SQUARE *	0	3.3	185,059	06-2056	50 - S0.5 *	(2)	164,463	2.93	(20,596)
TOTAL LAUDERDALE AND FT. MYERS PEAKERS	*472,194,358*	*828,108*				*3.3*	*15,582,414*				*13,820,716*	*2.93*	*(1,761,698)*
TOTAL PEAKER PLANTS	**514,644,682**	**8,369,296**				***3.3***	**16,753,655**				**17,008,912**	***3.30***	**255,257**
SOLAR PRODUCTION PLANT													
DESOTO SOLAR													
341 STRUCTURES AND IMPROVEMENTS	4,635,209	990,040	06-2039	SQUARE *	0	3.3	152,962	06-2039	SQUARE *	0	161,864	3.49	8,902
343 PRIME MOVERS - GENERAL	118,689,127	28,800,157	06-2039	SQUARE *	0	3.3	3,916,741	06-2039	SQUARE *	0	3,991,517	3.36	74,776
345 ACCESSORY ELECTRIC EQUIPMENT	27,532,945	4,878,293	06-2039	SQUARE *	0	3.3	908,587	06-2039	SQUARE *	0	1,005,979	3.65	97,392
TOTAL DESOTOSOLAR	*150,857,280*	*34,668,490*				*3.3*	*4,978,290*				*5,159,360*	*3.42*	*181,070*
SPACE COAST SOLAR													
341 STRUCTURES AND IMPROVEMENTS	3,986,978	748,519	06-2040	SQUARE *	0	3.3	131,570	06-2040	SQUARE *	0	137,690	3.45	6,120
343 PRIME MOVERS - GENERAL	52,858,699	11,827,508	06-2040	SQUARE *	0	3.3	1,744,337	06-2040	SQUARE *	0	1,744,523	3.30	186
345 ACCESSORY ELECTRIC EQUIPMENT	6,281,496	1,091,797	06-2040	SQUARE *	0	3.3	207,289	06-2040	SQUARE *	0	220,650	3.51	13,361
TOTAL SPACE COAST SOLAR	*63,127,172*	*13,667,824*				*3.3*	*2,083,196*				*2,102,863*	*3.33*	*19,667*
MARTIN SOLAR													
341 STRUCTURES AND IMPROVEMENTS	21,320,036	3,172,447	06-2040	SQUARE *	0	3.3	703,561	06-2045	SQUARE *	0	637,205	2.99	(66,356)
343 PRIME MOVERS - GENERAL	405,752,300	73,095,004	06-2040	SQUARE *	0	3.3	13,389,826	06-2045	SQUARE *	0	11,684,485	2.88	(1,705,341)
345 ACCESSORY ELECTRIC EQUIPMENT	4,239,215	633,733	06-2040	SQUARE *	0	3.3	139,894	06-2045	SQUARE *		126,641	2.99	(13,253)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,335	257	06-2040	SQUARE *	0	3.3	44	06-2045	SQUARE *	0	38	2.85	(6)
TOTAL MARTIN SOLAR	*431,312,886*	*76,901,441*				*3.3*	*14,233,325*				*12,448,369*	*2.89*	*(1,784,956)*
BABCOCK RANCH SOLAR													
341 STRUCTURES AND IMPROVEMENTS	4,078,184	18,086	06-2039	SQUARE *	0	3.3	134,580	06-2046	SQUARE *	0	137,491	3.37	2,911
343 PRIME MOVERS - GENERAL	104,118,206	461,738	06-2039	SQUARE *	0	3.3	3,435,901	06-2046	SQUARE *	0	3,510,209	3.37	74,308
345 ACCESSORY ELECTRIC EQUIPMENT	24,224,241	107,428	06-2039	SQUARE *	0	3.3	799,400	06-2046	SQUARE *	0	816,689	3.37	17,289
TOTAL BABCOCK RANCH SOLAR	*132,420,631*	*587,252*				*3.3*	*4,369,881*				*4,464,389*	*3.37*	*94,508*
MANATEE SOLAR													
341 STRUCTURES AND IMPROVEMENTS	4,118,679	7,223	06-2040	SQUARE *	0	3.3	135,916	06-2046	SQUARE *	0	139,230	3.38	3,314
343 PRIME MOVERS - GENERAL	105,224,179	184,536	06-2040	SQUARE *	0	3.3	3,472,398	06-2046	SQUARE *	0	3,557,049	3.38	84,651
345 ACCESSORY ELECTRIC EQUIPMENT	24,464,781	42,905	06-2040	SQUARE *	0	3.3	807,338	06-2046	SQUARE *	0	827,019	3.38	19,681
TOTAL MANATEE SOLAR	*133,807,639*	*234,664*				*3.3*	*4,415,652*				*4,523,298*	*3.38*	*107,646*
CITRUS SOLAR													
341 STRUCTURES AND IMPROVEMENTS	4,207,181	18,559	06-2040	SQUARE *	0	3.3	138,837	06-2046	SQUARE *	0	141,843	3.37	3,006
343 PRIME MOVERS - GENERAL	107,250,213	473,102	06-2040	SQUARE *	0	3.3	3,539,257	06-2046	SQUARE *	0	3,615,886	3.37	76,629
345 ACCESSORY ELECTRIC EQUIPMENT	24,990,480	110,238	06-2040	SQUARE *	0	3.3	824,686	06-2046	SQUARE *		842,541	3.37	17,855
TOTAL CITRUS SOLAR	*136,447,874*	*601,899*				*3.3*	*4,502,780*				*4,600,270*	*3.37*	*97,490*
TOTAL SOLAR PRODUCTION PLANT	**1,047,973,483**	**126,661,571**				***3.3***	**34,583,124**				**33,298,549**	***3.18***	**(1,284,575)**
TOTAL PRODUCTION PLANT	**22,795,357,882**	**5,541,188,910**				***3.0***	**675,925,368**				**913,519,786**	***4.01***	**237,594,418**

FLORIDA POWER AND LIGHT COMPANY

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BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST (1)	BOOK RESERVE (2)	PROBABLE RETIREMENT DATE (3)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (4)	NET SALVAGE (5)	ANNUAL DEPRECIATION RATE (6)	ANNUAL DEPRECIATION ACCRUALS (7)=(6)x(1)	PROBABLE RETIREMENT DATE (8)	SURVIVOR CURVE (9)	NET SALVAGE (10)	ANNUAL DEPRECIATION ACCRUALS (11)	ANNUAL DEPRECIATION RATE (12)	INCREASE/ DECREASE (13)=(12)-(7)
TRANSMISSION, DISTRIBUTION, AND GENERAL PLANT													
TRANSMISSION PLANT													
350.2 EASEMENTS	240,510,767	80,181,515		75 - S4	0	1.3	3,126,640		75 - S4	0	3,013,708	1.25	(112,932)
352 STRUCTURES AND IMPROVEMENTS	154,719,740	40,213,775		60 - R3	(15)	1.9	2,939,675		65 - R3	(15)	2,626,625	1.70	(313,050)
353 STATION EQUIPMENT	1,741,377,472	504,497,585		40 - R1.5	(2)	2.6	45,275,814		40 - R1	(2)	41,155,580	2.36	(4,120,234)
353.1 STATION EQUIPMENT - STEP-UP TRANSFORMERS	400,209,880	67,360,985		35 - R2	0	2.9	11,606,087		30 - R1	0	14,050,185	3.51	2,444,098
354 TOWERS AND FIXTURES	349,056,185	225,421,515		52 - R5	(15)	2.2	7,679,236		60 - R4	(25)	5,877,891	1.68	(1,801,345)
355 POLES AND FIXTURES	1,242,636,001	420,741,337		44 - R2	(50)	3.4	42,249,624		50 - R2	(50)	36,188,883	2.91	(6,060,741)
356 OVERHEAD CONDUCTORS AND DEVICES	854,174,816	364,102,828		47 - R1.5	(50)	3.2	27,333,594		51 - R1	(55)	24,232,975	2.84	(3,100,619)
357 UNDERGROUND CONDUIT	75,512,192	26,533,422		60 - R4	0	1.7	1,283,707		65 - R4	0	1,081,448	1.43	(202,259)
358 UNDERGROUND CONDUCTORS AND DEVICES	104,576,520	29,275,918		60 - L3	(10)	1.8	1,882,377		65 - R3	(20)	1,952,829	1.87	70,452
359 ROADS AND TRAILS	113,485,941	42,504,639		65 - SQ	(10)	1.7	1,929,261		75 - R4	(10)	1,509,809	1.33	(419,452)
TOTAL TRANSMISSION PLANT	**5,276,259,513**	**1,800,833,520**				***2.8***	**145,306,015**				**131,689,933**	***2.50***	**(13,616,082)**
DISTRIBUTION PLANT													
361 STRUCTURES AND IMPROVEMENTS	198,554,703	55,416,150		60 - R3	(15)	1.9	3,772,539		65 - R3	(15)	3,468,842	1.75	(303,697)
362 STATION EQUIPMENT	1,740,028,154	531,280,566		43 - R1.5	(10)	2.6	45,240,732		45 - R1.5	(10)	41,067,728	2.36	(4,173,004)
364.1 POLES, TOWERS AND FIXTURES - WOOD	1,083,692,909	481,024,953		39 - R2	(60)	4.1	44,431,409		40 - R2	(100)	58,351,587	5.38	13,920,178
364.2 POLES, TOWERS AND FIXTURES - CONCRETE	706,877,719	98,411,503		39 - R2	(60)	4.1	28,981,986		50 - R1.5	(100)	28,813,668	4.08	(168,318)
365 OVERHEAD CONDUCTORS AND DEVICES	1,991,793,394	740,342,106		41 - S0	(60)	3.9	77,679,942		48 - R1	(80)	73,133,316	3.67	(4,546,626)
366.6 UNDERGROUND CONDUIT - DUCT SYSTEM	1,528,850,821	345,598,141		70 - S1.5	(2)	1.5	22,932,762		70 - R3	0	21,675,264	1.42	(1,257,498)
366.7 UNDERGROUND CONDUIT - DIRECT BURIED	193,885,661	26,860,958		50 - R4	0	2.0	3,877,713		50 - R4	0	3,880,685	2.00	2,972
367.6 UNDERGROUND CONDUCTORS AND DEVICES - DUCT SYSTEM	1,723,803,662	475,313,897		38 - S0	0	2.6	44,818,895		42 - S0	(5)	41,878,881	2.43	(2,940,014)
367.7 UNDERGROUND CONDUCTORS AND DEVICES - DIRECT BURIED	731,720,379	288,138,701		35 - R2	0	2.9	21,219,891		35 - R2	0	19,235,979	2.63	(1,983,912)
368 LINE TRANSFORMERS	2,172,571,477	977,456,673		33 - L1.5	(25)	3.8	82,557,716		34 - S0	(15)	64,778,557	2.98	(17,779,159)
369.1 SERVICES - OVERHEAD	429,359,956	121,671,610		48 - R1	(85)	3.9	16,745,038		53 - R1	(125)	18,428,378	4.29	1,683,340
369.6 SERVICES - UNDERGROUND	818,122,343	316,173,519		38 - R2	(5)	2.8	22,907,426		45 - R2	(15)	19,674,557	2.40	(3,232,869)
370 METERS	90,547,258	64,524,789		36 - R2.5	(30)	3.6	3,259,701		38 - R2	(30)	3,095,847	3.42	(163,854)
370.1 METERS - AMI	752,056,781	195,134,861		20 - R2.5	(30)	6.5	48,883,691		20 - R2.5	(30)	50,162,753	6.67	1,279,062
371 INSTALLATIONS ON CUSTOMER'S PREMISES	77,912,064	32,661,220		30 - L0	(20)	4.0	3,116,483		30 - L0	(15)	2,591,609	3.33	(524,874)
373 STREET LIGHTING AND SIGNAL SYSTEMS	463,393,095	175,429,642		30 - R0.5	(20)	4.0	18,535,724		35 - O1	(15)	13,075,070	2.82	(5,460,654)
TOTAL DISTRIBUTION PLANT	**14,703,170,376**	**4,925,439,290**				***3.3***	**488,961,648**				**463,312,721**	***3.15***	**(25,648,927)**
GENERAL PLANT													
390 STRUCTURES AND IMPROVEMENTS	435,222,597	123,109,607		50 - R1.5	(5)	2.1	9,139,675		55 - R1.5	(10)	8,650,821	1.99	(488,854)
392.1 AUTOMOBILES	9,038,959	1,913,929		6 - L2	15	14.2	1,283,532		6 - L2.5	15	1,420,982	15.72	137,450
392.2 LIGHT TRUCKS	47,500,083	12,551,216		9 - L3	15	9.4	4,465,008		9 - L3	15	4,748,098	10.00	283,090
392.3 HEAVY TRUCKS	241,647,650	99,939,976		12 - S3	15	7.1	17,156,983		12 - S3	15	14,874,545	6.16	(2,282,438)
392.4 TRACTOR TRAILERS	767,855	638,910		9 - L2.5	0	11.1	85,232		9 - L2.5	5	20,213	2.63	(65,019)
392.9 TRAILERS	21,065,643	2,761,578		20 - L1	30	3.5	737,298		20 - L1	15	1,050,223	4.99	312,925
396.1 POWER OPERATED EQUIPMENT	4,766,126	2,061,673		10 - L0.5	20	8.0	381,290		11 - L1.5	15	336,070	7.05	(45,220)
397.8 COMMUNICATION EQUIPMENT - FIBER OPTICS	11,992,500	9,422,442		10 - L0	0	10.0	1,199,250		20 - S2	0	233,429	1.95	(965,821)
TOTAL GENERAL PLANT	**772,001,412**	**252,399,331**				***4.5***	**34,448,268**				**31,334,381**	***4.06***	**(3,113,887)**
TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT	**20,751,431,301**	**6,978,672,141**				***3.2***	**668,715,931**				**626,337,035**	***3.02***	**(42,378,896)**
GRAND TOTAL	**43,546,789,183**	**12,519,861,051**				***3.1***	**1,344,641,299**				**1,539,856,821**	***3.54***	**195,215,522**

* CURVE SHOWN IS INTERIM SURVIVOR CURVE. LIFE SPAN METHOD IS USED.

FLORIDA POWER AND LIGHT COMPANY

TABLE 4. COMPARISON OF WHOLE LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

		ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST	PROBABLE RETIREMENT DATE	SURVIVOR CURVE/ INTERIM RETIREMENT RATE	NET SALVAGE	ANNUAL DEPRECIATION RATE	ANNUAL DEPRECIATION ACCRUALS	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)-(6)
STEAM PRODUCTION PLANT												
MANATEE STEAM PLANT												
MANATEE COMMON												
311 STRUCTURES AND IMPROVEMENTS	112,114,271	06-2027	0.0032	(1)	2.1	2,354,400	06-2028	80 - R2 *	(1)	4,167,137	3.72	1,812,737
312 BOILER PLANT EQUIPMENT	7,715,628	06-2027	0.0094	(2)	2.6	200,606	06-2028	50 - S0 *	(2)	523,052	6.78	322,446
314 TURBOGENERATOR UNITS	9,652,310	06-2027	0.0120	0	2.6	250,960	06-2028	55 - R0.5 *	(1)	341,657	3.54	90,697
315 ACCESSORY ELECTRIC EQUIPMENT	9,646,848	06-2027	0.0052	(5)	2.4	231,524	06-2028	65 - S0 *	(2)	291,034	3.02	59,510
316 MISCELLANEOUS POWER PLANT EQUIPMENT	2,450,703	06-2027	0.0071	(1)	2.4	58,817	06-2028	65 - R0.5 *	(1)	80,055	3.27	21,238
TOTAL MANATEE COMMON	*141,579,760*				*2.2*	*3,096,307*				*5,402,935*	*3.82*	*2,306,628*
MANATEE UNIT 1												
311 STRUCTURES AND IMPROVEMENTS	6,836,328	06-2027	0.0032	(1)	2.1	143,563	06-2028	80 - R2 *	(1)	159,392	2.33	15,829
312 BOILER PLANT EQUIPMENT	181,481,969	06-2027	0.0094	(2)	2.6	4,718,531	06-2028	50 - S0 *	(2)	8,666,680	4.78	3,948,149
314 TURBOGENERATOR UNITS	72,660,531	06-2027	0.0120	0	2.6	1,889,174	06-2028	55 - R0.5 *	(1)	3,139,705	4.32	1,250,531
315 ACCESSORY ELECTRIC EQUIPMENT	14,261,784	06-2027	0.0052	(5)	2.4	342,283	06-2028	65 - S0 *	(2)	655,292	4.59	313,009
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,924,407	06-2027	0.0071	(1)	2.4	94,186	06-2028	65 - R0.5 *	(1)	154,817	3.94	60,631
TOTAL MANATEE UNIT 1	*279,165,019*				*2.6*	*7,187,737*				*12,775,886*	*4.58*	*5,588,149*
MANATEE UNIT 2												
311 STRUCTURES AND IMPROVEMENTS	4,986,744	06-2027	0.0032	(1)	2.1	104,722	06-2028	80 - R2 *	(1)	118,649	2.38	13,927
312 BOILER PLANT EQUIPMENT	183,957,418	06-2027	0.0094	(2)	2.6	4,782,893	06-2028	50 - S0 *	(2)	9,090,018	4.94	4,307,125
314 TURBOGENERATOR UNITS	70,765,381	06-2027	0.0120	0	2.6	1,839,900	06-2028	55 - R0.5 *	(1)	2,874,737	4.06	1,034,837
315 ACCESSORY ELECTRIC EQUIPMENT	12,273,816	06-2027	0.0052	(5)	2.4	294,572	06-2028	65 - S0 *	(2)	596,285	4.86	301,713
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,453,782	06-2027	0.0071	(1)	2.4	82,891	06-2028	65 - R0.5 *	(1)	152,781	4.42	69,890
TOTAL MANATEE UNIT 2	*275,437,142*				*2.6*	*7,104,978*				*12,832,470*	*4.66*	*5,727,492*
TOTAL MANATEE STEAM PLANT	***696,181,920***				***2.5***	***17,389,022***				***31,011,291***	*4.45*	***13,622,269***
MARTIN STEAM PLANT												
MARTIN COMMON												
311 STRUCTURES AND IMPROVEMENTS	241,950,141	06-2031	0.0032	(1)	2.1	5,080,953	06-2031	80 - R2 *	(1)	6,222,741	2.57	1,141,788
312 BOILER PLANT EQUIPMENT	7,068,506	06-2031	0.0094	(5)	2.6	183,781	06-2031	50 - S0 *	(2)	313,017	4.43	129,236
314 TURBOGENERATOR UNITS	27,474,257	06-2031	0.0120	0	2.6	714,331	06-2031	55 - R0.5 *	(1)	965,141	3.51	250,810
315 ACCESSORY ELECTRIC EQUIPMENT	10,295,313	06-2031	0.0052	(5)	2.4	247,088	06-2031	65 - S0 *	(2)	380,826	3.70	133,738
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,888,459	06-2031	0.0071	0	2.4	93,323	06-2031	65 - R0.5 *	(1)	143,228	3.68	49,905
TOTAL MARTIN COMMON	*290,676,676*				*2.2*	*6,319,476*				*8,024,953*	*2.76*	*1,705,477*
MARTIN PIPELINE												
312 BOILER PLANT EQUIPMENT	370,942	06-2031	0.0094	(5)	2.6	9,644		50 - S0 *	0	11,202	3.02	1,558
TOTAL MARTIN PIPELINE	*370,942*				*2.6*	*9,644*				*11,202*		*1,558*
MARTIN UNIT 1												
311 STRUCTURES AND IMPROVEMENTS	16,404,681	06-2031	0.0032	(1)	2.1	344,498	06-2031	80 - R2 *	(1)	415,594	2.53	71,096
312 BOILER PLANT EQUIPMENT	212,830,965	06-2031	0.0094	(5)	2.6	5,533,605	06-2031	50 - S0 *	(2)	8,803,028	4.14	3,269,423
314 TURBOGENERATOR UNITS	90,120,383	06-2031	0.0120	0	2.6	2,343,130	06-2031	55 - R0.5 *	(1)	3,280,656	3.64	937,526
315 ACCESSORY ELECTRIC EQUIPMENT	24,391,137	06-2031	0.0052	(5)	2.4	585,387	06-2031	65 - S0 *	(2)	842,616	3.45	257,229
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,594,165	06-2031	0.0071	0	2.4	86,260	06-2031	65 - R0.5 *	(1)	136,791	3.81	50,531
TOTAL MARTIN UNIT 1	*347,341,330*				*2.6*	*8,892,880*				*13,478,685*	*3.88*	*4,585,805*
MARTIN UNIT 2												
311 STRUCTURES AND IMPROVEMENTS	11,266,842	06-2031	0.0032	(1)	2.1	236,604	06-2031	80 - R2 *	(1)	270,118	2.40	33,514
312 BOILER PLANT EQUIPMENT	215,154,508	06-2031	0.0094	(5)	2.6	5,594,017	06-2031	50 - S0 *	(2)	9,093,979	4.23	3,499,962
314 TURBOGENERATOR UNITS	82,856,949	06-2031	0.0120	0	2.6	2,154,281	06-2031	55 - R0.5 *	(1)	3,493,740	4.22	1,339,459
315 ACCESSORY ELECTRIC EQUIPMENT	23,045,156	06-2031	0.0052	(5)	2.4	553,084	06-2031	65 - S0 *	(2)	903,472	3.92	350,388
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,280,816	06-2031	0.0071	0	2.4	78,740	06-2031	65 - R0.5 *	(1)	130,785	3.99	52,045
TOTAL MARTIN UNIT 2	*335,604,270*				*2.6*	*8,616,726*				*13,892,094*	*4.14*	*5,275,368*
TOTAL MARTIN STEAM PLANT	***973,993,219***				***2.4***	***23,838,726***				***35,406,934***	***3.64***	***11,568,208***

FLORIDA POWER AND LIGHT COMPANY

TABLE 4. COMPARISON OF WHOLE LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

		ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST	PROBABLE RETIREMENT DATE	SURVIVOR CURVE/ INTERIM RETIREMENT RATE	NET SALVAGE	ANNUAL DEPRECIATION RATE	ANNUAL DEPRECIATION ACCRUALS	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)-(6)
SCHERER STEAM PLANT												
SCHERER COAL CARS												
312 BOILER PLANT EQUIPMENT	33,149,442	06-2039	0.0094	(5)	2.6	861,885	06-2039	50 - S0 *	0	942,509	2.84	80,624
TOTAL SCHERER COAL CARS	*33,149,442*				*2.6*	*861,885*				*942,509*	*2.84*	*80,624*
SCHERER COMMON												
311 STRUCTURES AND IMPROVEMENTS	39,391,667	06-2039	0.0032	(1)	2.1	827,225	06-2039	80 - R2 *	(1)	976,488	2.48	149,263
312 BOILER PLANT EQUIPMENT	25,844,055	06-2039	0.0094	(5)	2.6	671,945	06-2039	50 - S0 *	(4)	781,528	3.02	109,583
314 TURBOGENERATOR UNITS	4,336,718	06-2039	0.0120	0	2.6	112,755	06-2039	55 - R0.5 *	(1)	125,125	2.89	12,370
315 ACCESSORY ELECTRIC EQUIPMENT	1,226,257	06-2039	0.0052	(4)	2.4	29,430	06-2039	65 - S0 *	(4)	32,201	2.63	2,771
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,659,825	06-2039	0.0071	(1)	2.4	87,836	06-2039	65 - R0.5 *	(1)	103,027	2.82	15,191
TOTAL SCHERER COMMON	*74,458,521*				*2.3*	*1,729,191*				*2,018,369*	*2.71*	*289,178*
SCHERER COMMON UNIT 3 AND 4												
311 STRUCTURES AND IMPROVEMENTS	2,999,449	06-2039	0.0032	(1)	2.2	65,988	06-2039	80 - R2 *	(1)	71,885	2.40	5,897
312 BOILER PLANT EQUIPMENT	22,335,968	06-2039	0.0094	(5)	2.7	603,071	06-2039	50 - S0 *	(4)	712,151	3.19	109,080
314 TURBOGENERATOR UNITS	2,831,158	06-2039	0.0120	0	2.6	73,610	06-2039	55 - R0.5 *	(1)	125,146	4.42	51,536
315 ACCESSORY ELECTRIC EQUIPMENT	2,818,575	06-2039	0.0052	(4)	2.4	67,646	06-2039	65 - S0 *	(4)	121,987	4.33	54,341
TOTAL SCHERER COMMON UNIT 3 AND 4	*30,985,149*				*2.6*	*810,315*				*1,031,169*	*3.33*	*220,854*
SCHERER UNIT 4												
311 STRUCTURES AND IMPROVEMENTS	159,104,427	06-2039	0.0032	(1)	2.1	3,341,193	06-2039	80 - R2 *	(1)	5,219,160	3.28	1,877,967
312 BOILER PLANT EQUIPMENT	671,515,648	06-2039	0.0094	(5)	2.6	17,459,407	06-2039	50 - S0 *	(4)	24,296,899	3.62	6,837,492
314 TURBOGENERATOR UNITS	122,853,491	06-2039	0.0120	0	2.6	3,194,191	06-2039	55 - R0.5 *	(1)	3,502,383	2.85	308,192
315 ACCESSORY ELECTRIC EQUIPMENT	49,374,419	06-2039	0.0052	(4)	2.4	1,184,986	06-2039	65 - S0 *	(4)	1,688,068	3.42	503,082
316 MISCELLANEOUS POWER PLANT EQUIPMENT	5,117,266	06-2039	0.0071	(1)	2.4	122,814	06-2039	65 - R0.5 *	(1)	163,872	3.20	41,058
TOTAL SCHERER UNIT 4	*1,007,965,252*				*2.5*	*25,302,591*				*34,870,382*	*3.46*	*9,567,791*
TOTAL SCHERER STEAM PLANT	***1,146,558,365***				***2.5***	***28,703,982***				***38,862,429***	***3.39***	***10,158,447***
SJRPP STEAM PLANT												
SJRPP COAL AND LIMESTONE												
311 STRUCTURES AND IMPROVEMENTS	3,562,391	06-2038	0.0032	(1)	2.1	74,810	06-2038	80 - R2 *	(1)	80,115	2.25	5,305
312 BOILER PLANT EQUIPMENT	30,883,389	06-2038	0.0094	(5)	2.6	802,968	06-2038	50 - S0 *	(4)	852,428	2.76	49,460
315 ACCESSORY ELECTRIC EQUIPMENT	3,773,252	06-2038	0.0052	(4)	2.4	90,558	06-2038	65 - S0 *	(4)	92,799	2.46	2,241
316 MISCELLANEOUS POWER PLANT EQUIPMENT	300,302	06-2038	0.0071	(1)	2.4	7,207	06-2038	65 - R0.5 *	(1)	7,195	2.40	(12)
TOTAL SJRPP COAL AND LIMESTONE	*38,519,334*				*2.5*	*975,543*				*1,032,537*	*2.68*	*56,994*
SJRPP COAL CARS												
312 BOILER PLANT EQUIPMENT	52,105	06-2038	0.0094	(5)	2.6	1,355	06-2038	50 - S0 *	0	1,339	2.57	(16)
TOTAL SJRPP COAL CARS	*52,105*				*2.6*	*1,355*				*1,339*	*2.57*	*(16)*
SJRPP COMMON												
311 STRUCTURES AND IMPROVEMENTS	33,146,529	06-2038	0.0032	(1)	2.1	696,077	06-2038	80 - R2 *	(1)	772,382	2.33	76,305
312 BOILER PLANT EQUIPMENT	3,694,843	06-2038	0.0094	(5)	2.6	96,066	06-2038	50 - S0 *	(4)	106,655	2.89	10,589
314 TURBOGENERATOR UNITS	2,497,878	06-2038	0.0120	0	2.6	64,945	06-2038	55 - R0.5 *	(1)	64,109	2.57	(836)
315 ACCESSORY ELECTRIC EQUIPMENT	5,833,698	06-2038	0.0052	(4)	2.4	140,009	06-2038	65 - S0 *	(4)	148,376	2.54	8,367
316 MISCELLANEOUS POWER PLANT EQUIPMENT	1,598,862	06-2038	0.0071	(1)	2.4	38,373	06-2038	65 - R0.5 *	(1)	42,650	2.67	4,277
TOTAL SJRPP COMMON	*46,771,810*				*2.2*	*1,035,470*				*1,134,172*	*2.42*	*98,702*
SJRPP GYPSUM AND ASH												
311 STRUCTURES AND IMPROVEMENTS	2,172,989	06-2038	0.0032	(1)	2.1	45,633	06-2038	80 - R2 *	(1)	50,567	2.33	4,934
312 BOILER PLANT EQUIPMENT	17,085,257	06-2038	0.0094	(5)	2.6	444,217	06-2038	50 - S0 *	(4)	461,076	2.70	16,859
315 ACCESSORY ELECTRIC EQUIPMENT	52,571	06-2038	0.0052	(4)	2.4	1,262	06-2038	65 - S0 *	(4)	1,376	2.62	114
316 MISCELLANEOUS POWER PLANT EQUIPMENT	154,892	06-2038	0.0071	(1)	2.4	3,717	06-2038	65 - R0.5 *	(1)	4,674	3.02	957
TOTAL SJRPP GYPSUM AND ASH	*19,465,709*				*2.5*	*494,829*				*517,693*	*2.66*	*22,864*
SJRPP UNIT 1												
311 STRUCTURES AND IMPROVEMENTS	9,049,629	06-2038	0.0032	(1)	2.1	190,042	06-2038	80 - R2 *	(1)	196,903	2.18	6,861
312 BOILER PLANT EQUIPMENT	99,626,681	06-2038	0.0094	(5)	2.6	2,590,294	06-2038	50 - S0 *	(4)	3,076,074	3.09	485,780
314 TURBOGENERATOR UNITS	31,463,410	06-2038	0.0120	0	2.6	818,049	06-2038	55 - R0.5 *	(1)	1,002,785	3.19	184,736
315 ACCESSORY ELECTRIC EQUIPMENT	12,475,837	06-2038	0.0052	(4)	2.4	299,420	06-2038	65 - S0 *	(4)	327,432	2.62	28,012
316 MISCELLANEOUS POWER PLANT EQUIPMENT	2,038,425	06-2038	0.0071	(1)	2.4	48,922	06-2038	65 - R0.5 *	(1)	51,143	2.51	2,221
TOTAL SJRPP UNIT 1	*154,653,983*				*2.6*	*3,946,727*				*4,654,337*	*3.01*	*707,610*
SJRPP UNIT 2												
311 STRUCTURES AND IMPROVEMENTS	7,177,145	06-2038	0.0032	(1)	2.1	150,720	06-2038	80 - R2 *	(1)	155,409	2.17	4,689
312 BOILER PLANT EQUIPMENT	90,153,231	06-2038	0.0094	(5)	2.6	2,343,984	06-2038	50 - S0 *	(4)	2,784,542	3.09	440,558
314 TURBOGENERATOR UNITS	28,479,810	06-2038	0.0120	0	2.6	740,475	06-2038	55 - R0.5 *	(1)	913,323	3.21	172,848
315 ACCESSORY ELECTRIC EQUIPMENT	10,105,912	06-2038	0.0052	(4)	2.4	242,542	06-2038	65 - S0 *	(4)	260,459	2.58	17,917
316 MISCELLANEOUS POWER PLANT EQUIPMENT	1,571,822	06-2038	0.0071	(1)	2.4	37,724	06-2038	65 - R0.5 *	(1)	39,132	2.49	1,408
TOTAL SJRPP UNIT 2	*137,487,920*				*2.6*	*3,515,445*				*4,152,865*	*3.02*	*637,420*
TOTAL SJRPP STEAM PLANT	***396,950,861***				***2.5***	***9,969,369***				***11,492,943***	***2.90***	***1,523,574***
TOTAL STEAM PRODUCTION	**3,213,684,365**				***2.5***	**79,901,099**				**116,773,597**	***3.63***	**36,872,498**

FLORIDA POWER AND LIGHT COMPANY

TABLE 4. COMPARISON OF WHOLE LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

		ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST	PROBABLE RETIREMENT DATE	SURVIVOR CURVE/ INTERIM RETIREMENT RATE	NET SALVAGE	ANNUAL DEPRECIATION RATE	ANNUAL DEPRECIATION ACCRUALS	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)-(6)
NUCLEAR PRODUCTION PLANT												
ST. LUCIE NUCLEAR PLANT												
ST. LUCIE COMMON												
321 STRUCTURES AND IMPROVEMENTS	396,984,357	06-2043	0.0028	0	1.8	7,145,718	04-2043	100 - R1.5 *	(1)	8,957,721	2.26	1,812,003
322 REACTOR PLANT EQUIPMENT	55,565,218	06-2043	0.0056	(2)	2.0	1,111,304	04-2043	60 - R1 *	(2)	1,649,174	2.97	537,870
323 TURBOGENERATOR UNITS	12,402,700	06-2043	0.0138	0	2.4	297,665	04-2043	45 - R0.5 *	0	429,315	3.46	131,650
324 ACCESSORY ELECTRIC EQUIPMENT	34,367,943	06-2043	0.0012	(2)	1.8	618,623	04-2043	75 - R2.5 *	(1)	744,591	2.17	125,968
325 MISCELLANEOUS POWER PLANT EQUIPMENT	20,722,317	06-2043	0.0032	0	1.8	373,002	04-2043	50 - R1.5 *	(3)	605,441	2.92	232,439
TOTAL ST. LUCIE COMMON	*520,042,535*				*1.8*	*9,546,312*				*12,386,242*	*2.38*	*2,839,930*
ST. LUCIE UNIT 1												
321 STRUCTURES AND IMPROVEMENTS	194,729,786	06-2036	0.0028	0	1.8	3,505,136	03-2036	100 - R1.5 *	(1)	5,277,085	2.71	1,771,949
322 REACTOR PLANT EQUIPMENT	838,073,831	06-2036	0.0056	(2)	2.0	16,761,477	03-2036	60 - R1 *	(2)	31,002,374	3.70	14,240,897
323 TURBOGENERATOR UNITS	412,318,467	06-2036	0.0138	0	2.4	9,895,643	03-2036	45 - R0.5 *	0	18,482,534	4.48	8,586,891
324 ACCESSORY ELECTRIC EQUIPMENT	119,762,438	06-2036	0.0012	(2)	1.8	2,155,724	03-2036	75 - R2.5 *	(1)	3,645,089	3.04	1,489,365
325 MISCELLANEOUS POWER PLANT EQUIPMENT	11,320,232	06-2036	0.0032	0	1.8	203,764	03-2036	50 - R1.5 *	(3)	291,602	2.58	87,838
TOTAL ST. LUCIE UNIT 1	*1,576,204,754*				*2.1*	*32,521,744*				*58,698,684*	*3.72*	*26,176,940*
ST. LUCIE UNIT 2												
321 STRUCTURES AND IMPROVEMENTS	297,759,844	06-2043	0.0028	0	1.8	5,359,677	04-2043	100 - R1.5 *	(1)	6,479,145	2.18	1,119,468
322 REACTOR PLANT EQUIPMENT	1,053,686,661	06-2043	0.0056	(2)	2.0	21,073,733	04-2043	60 - R1 *	(2)	30,686,947	2.91	9,613,214
323 TURBOGENERATOR UNITS	350,014,044	06-2043	0.0138	0	2.4	8,400,337	04-2043	45 - R0.5 *	0	12,277,090	3.51	3,876,753
324 ACCESSORY ELECTRIC EQUIPMENT	188,938,115	06-2043	0.0012	(2)	1.8	3,400,886	04-2043	75 - R2.5 *	(1)	4,007,253	2.12	606,367
325 MISCELLANEOUS POWER PLANT EQUIPMENT	24,130,684	06-2043	0.0032	0	1.8	434,352	04-2043	50 - R1.5 *	(3)	588,229	2.44	153,877
TOTAL ST. LUCIE UNIT 2	*1,914,529,349*				*2.0*	*38,668,985*				*54,038,664*	*2.82*	*15,369,679*
TOTAL ST. LUCIE NUCLEAR PLANT	***4,010,776,637***				***2.0***	***80,737,041***				***125,123,590***	***3.12***	***44,386,549***
TURKEY POINT NUCLEAR PLANT												
TURKEY POINT COMMON												
321 STRUCTURES AND IMPROVEMENTS	360,056,132	06-2033	0.0028	0	1.8	6,481,010	04-2033	100 - R1.5 *	(1)	12,946,820	3.60	6,465,810
322 REACTOR PLANT EQUIPMENT	137,627,469	06-2033	0.0056	(2)	2.0	2,752,549	04-2033	60 - R1 *	(2)	6,679,713	4.85	3,927,164
323 TURBOGENERATOR UNITS	21,825,767	06-2033	0.0138	0	2.4	523,818	04-2033	45 - R0.5 *	0	1,057,706	4.85	533,888
324 ACCESSORY ELECTRIC EQUIPMENT	53,673,512	06-2033	0.0012	(2)	1.8	966,123	04-2033	75 - R2.5 *	(1)	1,738,045	3.24	771,922
325 MISCELLANEOUS POWER PLANT EQUIPMENT	37,213,998	06-2033	0.0032	0	1.8	669,852	04-2033	50 - R1.5 *	(3)	1,540,161	4.14	870,309
TOTAL TURKEY POINT COMMON	*610,396,877*				*1.9*	*11,393,352*				*23,962,445*	*3.93*	*12,569,093*
TURKEY POINT UNIT 3												
321 STRUCTURES AND IMPROVEMENTS	183,462,252	06-2032	0.0028	0	1.8	3,302,321	07-2032	100 - R1.5 *	(1)	8,355,653	4.55	5,053,332
322 REACTOR PLANT EQUIPMENT	586,039,767	06-2032	0.0056	(2)	2.0	11,720,795	07-2032	60 - R1 *	(2)	26,200,563	4.47	14,479,768
323 TURBOGENERATOR UNITS	756,080,929	06-2032	0.0138	0	2.4	18,145,942	07-2032	45 - R0.5 *	0	40,579,305	5.37	22,433,363
324 ACCESSORY ELECTRIC EQUIPMENT	150,385,799	06-2032	0.0012	(2)	1.8	2,706,944	07-2032	75 - R2.5 *	(1)	5,188,389	3.45	2,481,445
325 MISCELLANEOUS POWER PLANT EQUIPMENT	15,687,982	06-2032	0.0032	0	1.8	282,384	07-2032	50 - R1.5 *	(3)	802,594	5.12	520,210
TOTAL TURKEY POINT UNIT 3	*1,691,656,730*				*2.1*	*36,158,386*				*81,126,504*	*4.80*	*44,968,118*
TURKEY POINT UNIT 4												
321 STRUCTURES AND IMPROVEMENTS	128,297,844	06-2033	0.0028	0	1.8	2,309,361	04-2033	100 - R1.5 *	(1)	4,903,600	3.82	2,594,239
322 REACTOR PLANT EQUIPMENT	514,072,790	06-2033	0.0056	(2)	2.0	10,281,456	04-2033	60 - R1 *	(2)	22,022,789	4.28	11,741,333
323 TURBOGENERATOR UNITS	599,706,206	06-2033	0.0138	0	2.4	14,392,949	04-2033	45 - R0.5 *	0	31,642,709	5.28	17,249,760
324 ACCESSORY ELECTRIC EQUIPMENT	175,176,467	06-2033	0.0012	(2)	1.8	3,153,176	04-2033	75 - R2.5 *	(1)	5,244,473	2.99	2,091,297
325 MISCELLANEOUS POWER PLANT EQUIPMENT	11,936,247	06-2033	0.0032	0	1.8	214,852	04-2033	50 - R1.5 *	(3)	555,252	4.65	340,400
TOTAL TURKEY POINT UNIT 4	*1,429,189,554*				*2.1*	*30,351,794*				*64,368,823*	*4.50*	*34,017,029*
TOTAL TURKEY POINT NUCLEAR PLANT	***3,731,243,161***				***2.1***	***77,903,532***				***169,457,772***	***4.54***	***91,554,240***
TOTAL NUCLEAR PRODUCTION PLANT	**7,742,019,799**				***2.0***	**158,640,573**				**294,581,362**	***3.80***	**135,940,789**

FLORIDA POWER AND LIGHT COMPANY

TABLE 4. COMPARISON OF WHOLE LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

		ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST	PROBABLE RETIREMENT DATE	SURVIVOR CURVE/ INTERIM RETIREMENT RATE	NET SALVAGE	ANNUAL DEPRECIATION RATE	ANNUAL DEPRECIATION ACCRUALS	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)-(6)
COMBINED CYCLE PRODUCTION PLANT												
LAUDERDALE COMBINED CYCLE PLANT												
LAUDERDALE COMMON												
341 STRUCTURES AND IMPROVEMENTS	84,760,736	06-2023	0.0023	(2)	3.5	2,966,626	06-2033	80 - R2 *	(2)	2,684,137	3.17	(282,489)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	11,513,771	06-2023	0.0095	0	3.8	437,523	06-2033	50 - R1.5 *	(3)	431,151	3.74	(6,372)
343 PRIME MOVERS - GENERAL	27,106,051	06-2023	0.0057	0	6.0	1,626,363	06-2033	50 - R1 *	(3)	1,537,585	5.67	(88,778)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	37,564,239	06-2023	0.1565	0	6.0	2,253,854	06-2033	9 - L0 *	35	2,760,417	7.35	506,563
344 GENERATORS	680,446	06-2023	0.0016	(1)	3.4	23,135	06-2033	60 - R2 *	(3)	25,250	3.71	2,115
345 ACCESSORY ELECTRIC EQUIPMENT	12,121,303	06-2023	0.0013	(1)	3.4	412,124	06-2033	50 - R2.5 *	(2)	354,489	2.92	(57,635)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,234,438	06-2023	0.0026	0	3.4	41,971	06-2033	50 - S0.5 *	(2)	49,400	4.00	7,429
TOTAL LAUDERDALE COMMON	*174,980,983*				*4.4*	*7,761,596*				*7,842,429*	*4.48*	*80,833*
LAUDERDALE UNIT 4												
341 STRUCTURES AND IMPROVEMENTS	5,090,645	06-2023	0.0023	(2)	3.5	178,173	06-2033	80 - R2 *	(2)	156,191	3.07	(21,982)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	673,633	06-2023	0.0095	0	3.8	25,598	06-2033	50 - R1.5 *	(3)	22,192	3.29	(3,406)
343 PRIME MOVERS - GENERAL	121,376,511	06-2023	0.0057	0	4.3	5,219,190	06-2033	50 - R1 *	(3)	4,443,321	3.66	(775,869)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	64,237,235	06-2023	0.1565	0	4.3	2,762,201	06-2033	9 - L0 *	35	4,706,190	7.33	1,943,989
344 GENERATORS	28,799,680	06-2023	0.0016	(1)	3.4	979,189	06-2033	60 - R2 *	(3)	889,607	3.09	(89,582)
345 ACCESSORY ELECTRIC EQUIPMENT	29,810,853	06-2023	0.0013	(1)	3.4	1,013,569	06-2033	50 - R2.5 *	(2)	956,997	3.21	(56,572)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	2,599,158	06-2023	0.0026	0	3.4	88,371	06-2033	50 - S0.5 *	(2)	83,452	3.21	(4,919)
TOTAL LAUDERDALE UNIT 4	*252,587,715*				*4.1*	*10,266,291*				*11,257,950*	*4.46*	*991,659*
LAUDERDALE UNIT 5												
341 STRUCTURES AND IMPROVEMENTS	3,203,159	06-2023	0.0023	(2)	3.5	112,111	06-2033	80 - R2 *	(2)	106,359	3.32	(5,752)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	742,434	06-2023	0.0095	0	3.8	28,212	06-2033	50 - R1.5 *	(3)	26,748	3.60	(1,464)
343 PRIME MOVERS - GENERAL	121,964,623	06-2023	0.0057	0	4.2	5,122,514	06-2033	50 - R1 *	(3)	4,533,303	3.72	(589,211)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	24,160,830	06-2023	0.1565	0	4.2	1,014,755	06-2033	9 - L0 *	35	1,781,463	7.37	766,708
344 GENERATORS	31,767,828	06-2023	0.0016	(1)	3.4	1,080,106	06-2033	60 - R2 *	(3)	1,036,294	3.26	(43,812)
345 ACCESSORY ELECTRIC EQUIPMENT	24,918,023	06-2023	0.0013	(1)	3.4	847,213	06-2033	50 - R2.5 *	(2)	828,235	3.32	(18,978)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,810,688	06-2023	0.0026	0	3.4	61,563	06-2033	50 - S0.5 *	(2)	58,645	3.24	(2,918)
TOTAL LAUDERDALE UNIT 5	*208,567,584*				*4.0*	*8,266,474*				*8,371,047*	*4.01*	*104,573*
TOTAL LAUDERDALE COMBINED CYCLE PLANT	***636,136,282***				***4.1***	***26,294,361***				***27,471,426***	***4.32***	***1,177,065***
FT. MYERS COMBINED CYCLE PLANT												
FT. MYERS COMMON												
341 STRUCTURES AND IMPROVEMENTS	8,824,312	06-2033	0.0023	(2)	3.5	308,851	06-2043	80 - R2 *	(2)	219,464	2.49	(89,387)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	794,049	06-2033	0.0095	0	3.8	30,174	06-2043	50 - R1.5 *	(3)	17,811	2.24	(12,363)
343 PRIME MOVERS - GENERAL	3,709,607	06-2033	0.0057	0	5.8	215,157	06-2043	50 - R1 *	(3)	140,380	3.78	(74,777)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	441,577	06-2033	0.1565	0	5.8	25,611	06-2043	9 - L0 *	35	31,888	7.22	6,277
344 GENERATORS	230,729	06-2033	0.0016	(1)	3.4	7,845	06-2043	60 - R2 *	(3)	8,447	3.66	602
345 ACCESSORY ELECTRIC EQUIPMENT	1,163,312	06-2033	0.0013	(1)	3.4	39,553	06-2043	50 - R2.5 *	(2)	41,075	3.53	1,522
346 MISCELLANEOUS POWER PLANT EQUIPMENT	768,815	06-2033	0.0026	0	3.4	26,140	06-2043	50 - S0.5 *	(2)	22,945	2.98	(3,195)
TOTAL FT. MYERS COMMON	*15,932,401*				*4.1*	*653,331*				*482,010*	*3.03*	*(171,321)*
FT. MYERS UNIT 2												
341 STRUCTURES AND IMPROVEMENTS	28,751,597	06-2033	0.0023	(2)	3.5	1,006,306	06-2043	80 - R2 *	(2)	761,861	2.65	(244,445)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	6,194,175	06-2033	0.0095	0	3.8	235,379	06-2043	50 - R1.5 *	(3)	178,852	2.89	(56,527)
343 PRIME MOVERS - GENERAL	367,522,551	06-2033	0.0057	0	4.2	15,435,947	06-2043	50 - R1 *	(3)	12,362,824	3.36	(3,073,123)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	302,123,631	06-2033	0.1565	0	4.2	12,689,192	06-2043	9 - L0 *	35	21,817,858	7.22	9,128,666
344 GENERATORS	57,280,635	06-2033	0.0016	(1)	3.4	1,947,542	06-2043	60 - R2 *	(3)	1,663,763	2.90	(283,779)
345 ACCESSORY ELECTRIC EQUIPMENT	55,628,985	06-2033	0.0013	(1)	3.4	1,891,385	06-2043	50 - R2.5 *	(2)	1,539,029	2.77	(352,356)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	3,539,476	06-2033	0.0026	0	3.4	120,342	06-2043	50 - S0.5 *	(2)	102,810	2.90	(17,532)
TOTAL FT. MYERS UNIT 2	*821,041,049*				*4.1*	*33,326,093*				*38,426,997*	*4.68*	*5,100,904*
FT. MYERS UNIT 3												
341 STRUCTURES AND IMPROVEMENTS	10,445,289	06-2033	0.0023	(2)	3.5	365,585	06-2043	80 - R2 *	(2)	368,771	3.53	3,186
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	13,425,923	06-2033	0.0095	0	3.8	510,185	06-2043	50 - R1.5 *	(3)	504,571	3.76	(5,614)
343 PRIME MOVERS - GENERAL	164,165,759	06-2033	0.0057	0	5.2	8,536,619	06-2043	50 - R1 *	(3)	6,595,542	4.02	(1,941,077)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	20,183,733	06-2033	0.1565	0	5.2	1,049,554	06-2043	25 - R1 *	29	647,655	3.21	(401,899)
344 GENERATORS	46,926,130	06-2033	0.0016	(1)	3.4	1,595,488	06-2043	60 - R2 *	(3)	1,696,151	3.61	100,663
345 ACCESSORY ELECTRIC EQUIPMENT	32,964,437	06-2033	0.0013	(1)	3.4	1,120,791	06-2043	50 - R2.5 *	(2)	1,180,213	3.58	59,422
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,734,913	06-2033	0.0026	0	3.4	58,987	06-2043	50 - S0.5 *	(2)	64,343	3.71	5,356
TOTAL FT. MYERS UNIT 3	*289,846,185*				*4.6*	*13,237,209*				*11,057,246*	*3.81*	*(2,179,963)*
TOTAL FT. MYERS COMBINED CYCLE PLANT	***1,126,819,634***				***4.2***	***47,216,633***				***49,966,253***	***4.43***	***2,749,620***

FLORIDA POWER AND LIGHT COMPANY

TABLE 4. COMPARISON OF WHOLE LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

		ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST	PROBABLE RETIREMENT DATE	SURVIVOR CURVE/ INTERIM RETIREMENT RATE	NET SALVAGE	ANNUAL DEPRECIATION RATE	ANNUAL DEPRECIATION ACCRUALS	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)-(6)
MANATEE COMBINED CYCLE PLANT												
MANATEE UNIT 3												
341 STRUCTURES AND IMPROVEMENTS	28,927,929	06-2035	0.0023	(2)	3.5	1,012,478	06-2045	80 - R2 *	(2)	774,539	2.68	(237,939)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	4,008,361	06-2035	0.0095	0	3.8	152,318	06-2045	50 - R1.5 *	(3)	117,518	2.93	(34,800)
343 PRIME MOVERS - GENERAL	236,795,038	06-2035	0.0057	0	4.3	10,182,187	06-2045	50 - R1 *	(3)	7,309,129	3.09	(2,873,058)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	146,248,668	06-2035	0.1565	0	4.3	6,288,693	06-2045	9 - L0 *	35	10,561,348	7.22	4,272,655
344 GENERATORS	41,417,902	06-2035	0.0016	(1)	3.4	1,408,209	06-2045	60 - R2 *	(3)	1,147,783	2.77	(260,426)
345 ACCESSORY ELECTRIC EQUIPMENT	45,110,148	06-2035	0.0013	(1)	3.4	1,533,745	06-2045	50 - R2.5 *	(2)	1,266,131	2.81	(267,614)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	10,976,397	06-2035	0.0026	0	3.4	373,197	06-2045	50 - S0.5 *	(2)	321,067	2.93	(52,130)
TOTAL MANATEE UNIT 3	*513,484,442*				*4.1*	*20,950,827*				*21,497,515*	*4.19*	*546,688*
TOTAL MANATEE COMBINED CYCLE PLANT	***513,484,442***				***4.1***	***20,950,827***				***21,497,515***	***4.19***	***546,688***
MARTIN COMBINED CYCLE PLANT												
MARTIN COMMON												
341 STRUCTURES AND IMPROVEMENTS	49,379,840	06-2024	0.0023	(2)	3.5	1,728,294	06-2034	80 - R2 *	(2)	1,560,067	3.16	(168,227)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	4,766,331	06-2024	0.0095	0	3.8	181,121	06-2034	50 - R1.5 *	(3)	164,475	3.45	(16,646)
343 PRIME MOVERS - GENERAL	22,788,940	06-2024	0.0057	0	4.3	979,924	06-2034	50 - R1 *	(3)	911,905	4.00	(68,019)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	2,230,422	06-2024	0.1565	0	4.3	95,908	06-2034	9 - L0 *	35	161,548	7.24	65,640
345 ACCESSORY ELECTRIC EQUIPMENT	5,321,992	06-2024	0.0013	(1)	3.4	180,948	06-2034	50 - R2.5 *	(2)	163,525	3.07	(17,423)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	4,194,043	06-2024	0.0026	0	3.4	142,597	06-2034	50 - S0.5 *	(2)	135,080	3.22	(7,517)
TOTAL MARTIN COMMON	*88,681,567*				*3.7*	*3,308,792*				*3,096,600*	*3.49*	*(212,192)*
MARTIN UNIT 3												
341 STRUCTURES AND IMPROVEMENTS	1,660,028	06-2024	0.0023	(2)	3.5	58,101	06-2034	80 - R2 *	(2)	49,496	2.98	(8,605)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	178,721	06-2024	0.0095	0	3.8	6,791	06-2034	50 - R1.5 *	(3)	5,624	3.15	(1,167)
343 PRIME MOVERS - GENERAL	152,279,614	06-2024	0.0057	0	4.2	6,395,744	06-2034	50 - R1 *	(3)	5,785,901	3.80	(609,843)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	67,628,799	06-2024	0.1565	0	4.2	2,840,410	06-2034	9 - L0 *	35	4,963,800	7.34	2,123,390
344 GENERATORS	26,577,658	06-2024	0.0016	(1)	3.4	903,640	06-2034	60 - R2 *	(3)	989,920	3.72	86,280
345 ACCESSORY ELECTRIC EQUIPMENT	28,440,138	06-2024	0.0013	(1)	3.4	966,965	06-2034	50 - R2.5 *	(2)	947,997	3.33	(18,968)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	569,569	06-2024	0.0026	0	3.4	19,365	06-2034	50 - S0.5 *	(2)	17,712	3.11	(1,653)
TOTAL MARTIN UNIT 3	*277,334,527*				*4.0*	*11,191,016*				*12,760,450*	*4.60*	*1,569,434*
MARTIN UNIT 4												
341 STRUCTURES AND IMPROVEMENTS	1,498,690	06-2024	0.0023	(2)	3.5	52,454	06-2034	80 - R2 *	(2)	50,367	3.36	(2,087)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	178,315	06-2024	0.0095	0	3.8	6,776	06-2034	50 - R1.5 *	(3)	5,611	3.15	(1,165)
343 PRIME MOVERS - GENERAL	157,866,532	06-2024	0.0057	0	4.2	6,630,394	06-2034	50 - R1 *	(3)	6,274,125	3.97	(356,269)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	100,540,570	06-2024	0.1565	0	4.2	4,222,704	06-2034	9 - L0 *	35	7,360,245	7.32	3,137,541
344 GENERATORS	32,812,957	06-2024	0.0016	(1)	3.4	1,115,641	06-2034	60 - R2 *	(3)	1,190,575	3.63	74,934
345 ACCESSORY ELECTRIC EQUIPMENT	25,564,311	06-2024	0.0013	(1)	3.4	869,187	06-2034	50 - R2.5 *	(2)	857,838	3.36	(11,349)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	826,194	06-2024	0.0026	0	3.4	28,091	06-2034	50 - S0.5 *	(2)	31,438	3.81	3,347
TOTAL MARTIN UNIT 4	*319,287,568*				*4.0*	*12,925,247*				*15,770,199*	*4.94*	*2,844,952*
MARTIN UNIT 8												
341 STRUCTURES AND IMPROVEMENTS	23,755,210	06-2035	0.0023	(2)	3.5	831,432	06-2045	80 - R2 *	(2)	637,408	2.68	(194,024)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	11,392,824	06-2035	0.0095	0	3.8	432,927	06-2045	50 - R1.5 *	(3)	333,613	2.93	(99,314)
343 PRIME MOVERS - GENERAL	256,002,412	06-2035	0.0057	0	4.3	11,008,104	06-2045	50 - R1 *	(3)	7,989,561	3.12	(3,018,543)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	213,276,994	06-2035	0.1565	0	4.3	9,170,911	06-2045	9 - L0 *	35	15,401,798	7.22	6,230,887
344 GENERATORS	41,069,900	06-2035	0.0016	(1)	3.4	1,396,377	06-2045	60 - R2 *	(3)	1,140,799	2.78	(255,578)
345 ACCESSORY ELECTRIC EQUIPMENT	51,655,998	06-2035	0.0013	(1)	3.4	1,756,304	06-2045	50 - R2.5 *	(2)	1,437,166	2.78	(319,138)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	4,899,017	06-2035	0.0026	0	3.4	166,567	06-2045	50 - S0.5 *	(2)	146,203	2.98	(20,364)
TOTAL MARTIN UNIT 8	*602,052,355*				*4.1*	*24,762,622*				*27,086,548*	*4.50*	*2,323,926*
TOTAL MARTIN COMBINED CYCLE PLANT	***1,287,356,017***				***4.1***	***52,187,677***				***58,713,797***	***4.56***	***6,526,120***

FLORIDA POWER AND LIGHT COMPANY

TABLE 4. COMPARISON OF WHOLE LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

		ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST	PROBABLE RETIREMENT DATE	SURVIVOR CURVE/ INTERIM RETIREMENT RATE	NET SALVAGE	ANNUAL DEPRECIATION RATE	ANNUAL DEPRECIATION ACCRUALS	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)-(6)
SANFORD COMBINED CYCLE PLANT												
SANFORD COMMON												
341 STRUCTURES AND IMPROVEMENTS	71,585,766	06-2033	0.0023	(2)	3.5	2,505,502	06-2043	80 - R2 *	(2)	1,828,012	2.55	(677,490)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	88,875	06-2033	0.0095	0	3.8	3,377	06-2043	50 - R1.5 *	(3)	2,603	2.93	(774)
343 PRIME MOVERS - GENERAL	5,932,378	06-2033	0.0057	0	4.5	266,957	06-2043	50 - R1 *	(3)	200,553	3.38	(66,404)
344 GENERATORS	200,500	06-2033	0.0016	(1)	3.4	6,817	06-2043	60 - R2 *	(3)	6,834	3.41	17
345 ACCESSORY ELECTRIC EQUIPMENT	2,142,789	06-2033	0.0013	(1)	3.4	72,855	06-2043	50 - R2.5 *	(2)	65,322	3.05	(7,533)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	2,233,762	06-2033	0.0026	0	3.4	75,948	06-2043	50 - S0.5 *	(2)	68,478	3.07	(7,470)
TOTAL SANFORD COMMON	*82,184,069*				*3.6*	*2,931,456*				*2,171,802*	*2.64*	*(759,654)*
SANFORD UNIT 4												
341 STRUCTURES AND IMPROVEMENTS	7,424,610	06-2033	0.0023	(2)	3.5	259,861	06-2043	80 - R2 *	(2)	178,864	2.41	(80,997)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,803,717	06-2033	0.0095	0	3.8	68,541	06-2043	50 - R1.5 *	(3)	53,886	2.99	(14,655)
343 PRIME MOVERS - GENERAL	196,875,732	06-2033	0.0057	0	4.8	9,450,035	06-2043	50 - R1 *	(3)	6,321,430	3.21	(3,128,605)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	140,077,308	06-2033	0.1565	0	4.8	6,723,711	06-2043	9 - L0 *	35	10,115,683	7.22	3,391,972
344 GENERATORS	32,820,452	06-2033	0.0016	(1)	3.4	1,115,895	06-2043	60 - R2 *	(3)	970,633	2.96	(145,262)
345 ACCESSORY ELECTRIC EQUIPMENT	35,200,492	06-2033	0.0013	(1)	3.4	1,196,817	06-2043	50 - R2.5 *	(2)	989,186	2.81	(207,631)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	3,326,653	06-2033	0.0026	0	3.4	113,106	06-2043	50 - S0.5 *	(2)	98,209	2.95	(14,897)
TOTAL SANFORD UNIT 4	*417,528,965*				*4.5*	*18,927,966*				*18,727,891*	*4.49*	*(200,075)*
SANFORD UNIT 5												
341 STRUCTURES AND IMPROVEMENTS	7,275,953	06-2032	0.0023	(2)	3.5	254,658	06-2042	80 - R2 *	(2)	181,639	2.50	(73,019)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,814,776	06-2032	0.0095	0	3.8	68,961	06-2042	50 - R1.5 *	(3)	54,358	3.00	(14,603)
343 PRIME MOVERS - GENERAL	214,894,008	06-2032	0.0057	0	4.2	9,025,548	06-2042	50 - R1 *	(3)	7,079,624	3.29	(1,945,924)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	126,367,538	06-2032	0.1565	0	4.2	5,307,437	06-2042	9 - L0 *	35	9,127,854	7.22	3,820,417
344 GENERATORS	32,632,812	06-2032	0.0016	(1)	3.4	1,109,516	06-2042	60 - R2 *	(3)	968,004	2.97	(141,512)
345 ACCESSORY ELECTRIC EQUIPMENT	34,685,483	06-2032	0.0013	(1)	3.4	1,179,306	06-2042	50 - R2.5 *	(2)	989,693	2.85	(189,613)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	2,899,894	06-2032	0.0026	0	3.4	98,596	06-2042	50 - S0.5 *	(2)	87,043	3.00	(11,553)
TOTAL SANFORD UNIT 5	*420,570,464*				*4.1*	*17,044,022*				*18,488,215*	*4.40*	*1,444,193*
TOTAL SANFORD COMBINED CYCLE PLANT	***920,283,497***				***4.2***	***38,903,444***				***39,387,908***	***4.28***	***484,464***
TURKEY POINT COMBINED CYCLE PLANT												
TURKEY POINT UNIT 5												
341 STRUCTURES AND IMPROVEMENTS	32,284,855	06-2037	0.0023	(2)	3.5	1,129,970	06-2047	80 - R2 *	(2)	862,567	2.67	(267,403)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	12,410,131	06-2037	0.0095	0	3.8	471,585	06-2047	50 - R1.5 *	(3)	364,566	2.94	(107,019)
343 PRIME MOVERS - GENERAL	250,685,264	06-2037	0.0057	0	5.7	14,289,060	06-2047	50 - R1 *	(3)	7,665,459	3.06	(6,623,601)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	128,220,285	06-2037	0.1565	0	5.7	7,308,556	06-2047	9 - L0 *	35	9,259,428	7.22	1,950,872
344 GENERATORS	41,669,542	06-2037	0.0016	(1)	3.4	1,416,764	06-2047	60 - R2 *	(3)	1,155,573	2.77	(261,191)
345 ACCESSORY ELECTRIC EQUIPMENT	51,980,475	06-2037	0.0013	(1)	3.4	1,767,336	06-2047	50 - R2.5 *	(2)	1,444,649	2.78	(322,687)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	12,433,804	06-2037	0.0026	0	3.4	422,749	06-2047	50 - S0.5 *	(2)	363,521	2.92	(59,228)
TOTAL TURKEY POINT UNIT 5	*529,684,355*				*5.1*	*26,806,020*				*21,115,763*	*3.99*	*(5,690,257)*
TOTAL TURKEY POINT COMBINED CYCLE PLANT	***529,684,355***				***5.1***	***26,806,020***				***21,115,763***	***3.99***	***(5,690,257)***

FLORIDA POWER AND LIGHT COMPANY

TABLE 4. COMPARISON OF WHOLE LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

		ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST	PROBABLE RETIREMENT DATE	SURVIVOR CURVE/ INTERIM RETIREMENT RATE	NET SALVAGE	ANNUAL DEPRECIATION RATE	ANNUAL DEPRECIATION ACCRUALS	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)-(6)
WEST COUNTY COMBINED CYCLE PLANT												
WEST COUNTY COMMON												
341 STRUCTURES AND IMPROVEMENTS	3,120,798	06-2041	SQUARE *	0	3.3	102,986	06-2051	80 - R2 *	(2)	83,834	2.69	(19,152)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	450,604	06-2041	SQUARE *	0	3.3	14,870	06-2051	50 - R1.5 *	(3)	13,227	2.94	(1,643)
343 PRIME MOVERS - GENERAL	31,206,902	06-2041	SQUARE *	0	3.3	1,029,828	06-2051	50 - R1 *	(3)	1,008,224	3.23	(21,604)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	126,771,982	06-2041	SQUARE *	0	3.3	4,183,475	06-2051	9 - L0 *	35	9,154,839	7.22	4,971,364
345 ACCESSORY ELECTRIC EQUIPMENT	1,291,342	06-2041	SQUARE *	0	3.3	42,614	06-2051	50 - R2.5 *	(2)	37,624	2.91	(4,990)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	836,533	06-2041	SQUARE *	0	3.3	27,606	06-2051	50 - S0.5 *	(2)	24,804	2.97	(2,802)
TOTAL WEST COUNTY COMMON	*163,678,161*				*3.3*	*5,401,379*				*10,322,552*	*6.31*	*4,921,173*
WEST COUNTY UNIT 1												
341 STRUCTURES AND IMPROVEMENTS	109,835,744	06-2039	SQUARE *	0	3.3	3,624,580	06-2049	80 - R2 *	(2)	2,944,128	2.68	(680,452)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	21,806,447	06-2039	SQUARE *	0	3.3	719,613	06-2049	50 - R1.5 *	(3)	644,693	2.96	(74,920)
343 PRIME MOVERS - GENERAL	300,710,821	06-2039	SQUARE *	0	3.3	9,923,457	06-2049	50 - R1 *	(3)	9,206,911	3.06	(716,546)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	81,954,083	06-2039	SQUARE *	0	3.3	2,704,485	06-2049	9 - L0 *	35	5,918,314	7.22	3,213,829
344 GENERATORS	49,469,105	06-2039	SQUARE *	0	3.3	1,632,480	06-2049	60 - R2 *	(3)	1,374,568	2.78	(257,912)
345 ACCESSORY ELECTRIC EQUIPMENT	72,300,016	06-2039	SQUARE *	0	3.3	2,385,901	06-2049	50 - R2.5 *	(2)	2,010,145	2.78	(375,756)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	8,042,081	06-2039	SQUARE *	0	3.3	265,389	06-2049	50 - S0.5 *	(2)	234,270	2.91	(31,119)
TOTAL WEST COUNTY UNIT 1	*644,118,297*				*3.3*	*21,255,905*				*22,333,029*	*3.47*	*1,077,124*
WEST COUNTY UNIT 2												
341 STRUCTURES AND IMPROVEMENTS	39,659,646	06-2039	SQUARE *	0	3.3	1,308,768	06-2049	80 - R2 *	(2)	1,063,085	2.68	(245,683)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	7,471,457	06-2039	SQUARE *	0	3.3	246,558	06-2049	50 - R1.5 *	(3)	223,319	2.99	(23,239)
343 PRIME MOVERS - GENERAL	255,637,285	06-2039	SQUARE *	0	3.3	8,436,030	06-2049	50 - R1 *	(3)	7,804,907	3.05	(631,123)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	149,878,251	06-2039	SQUARE *	0	3.3	4,945,982	06-2049	9 - L0 *	35	10,823,458	7.22	5,877,476
344 GENERATORS	43,599,023	06-2039	SQUARE *	0	3.3	1,438,768	06-2049	60 - R2 *	(3)	1,213,035	2.78	(225,733)
345 ACCESSORY ELECTRIC EQUIPMENT	33,177,136	06-2039	SQUARE *	0	3.3	1,094,845	06-2049	50 - R2.5 *	(2)	922,368	2.78	(172,477)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	11,893,351	06-2039	SQUARE *	0	3.3	392,481	06-2049	50 - S0.5 *	(2)	352,260	2.96	(40,221)
TOTAL WEST COUNTY UNIT 2	*541,316,149*				*3.3*	*17,863,432*				*22,402,432*	*4.14*	*4,539,000*
WEST COUNTY UNIT 3												
341 STRUCTURES AND IMPROVEMENTS	57,671,242	06-2041	SQUARE *	0	3.3	1,903,151	06-2051	80 - R2 *	(2)	1,537,469	2.67	(365,682)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	10,754,858	06-2041	SQUARE *	0	3.3	354,910	06-2051	50 - R1.5 *	(3)	317,030	2.95	(37,880)
343 PRIME MOVERS - GENERAL	480,389,197	06-2041	SQUARE *	0	3.3	15,852,844	06-2051	50 - R1 *	(3)	14,507,390	3.02	(1,345,454)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	98,598,036	06-2041	SQUARE *	0	3.3	3,253,735	06-2051	9 - L0 *	35	7,120,257	7.22	3,866,522
344 GENERATORS	64,525,280	06-2041	SQUARE *	0	3.3	2,129,334	06-2051	60 - R2 *	(3)	1,788,090	2.77	(341,244)
345 ACCESSORY ELECTRIC EQUIPMENT	48,252,610	06-2041	SQUARE *	0	3.3	1,592,336	06-2051	50 - R2.5 *	(2)	1,335,296	2.77	(257,040)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	12,454,466	06-2041	SQUARE *	0	3.3	410,997	06-2051	50 - S0.5 *	(2)	361,154	2.90	(49,843)
TOTAL WEST COUNTY UNIT 3	*772,645,690*				*3.3*	*25,497,307*				*26,966,686*	*3.49*	*1,469,379*
TOTAL WEST COUNTY COMBINED CYCLE PLANT	***2,121,758,297***				***3.3***	***70,018,023***				***82,024,699***	***3.87***	***12,006,676***

FLORIDA POWER AND LIGHT COMPANY

TABLE 4. COMPARISON OF WHOLE LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

		ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST	PROBABLE RETIREMENT DATE	SURVIVOR CURVE/ INTERIM RETIREMENT RATE	NET SALVAGE	ANNUAL DEPRECIATION RATE	ANNUAL DEPRECIATION ACCRUALS	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)-(6)
CAPE CANAVERAL COMBINED CYCLE PLANT												
CAPE CANAVERAL COMBINED CYCLE												
341 STRUCTURES AND IMPROVEMENTS	82,092,869	06-2043	SQUARE *	0	3.3	2,709,065	06-2053	80 - R2 *	(2)	2,193,088	2.67	(515,977)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	47,723,728	06-2043	SQUARE *	0	3.3	1,574,883	06-2053	50 - R1.5 *	(3)	1,400,412	2.93	(174,471)
343 PRIME MOVERS - GENERAL	385,108,676	06-2043	SQUARE *	0	3.3	12,708,586	06-2053	50 - R1 *	(3)	11,593,863	3.01	(1,114,723)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	206,255,249	06-2043	SQUARE *	0	3.3	6,806,423	06-2053	9 - L0 *	35	14,894,723	7.22	8,088,300
344 GENERATORS	70,269,257	06-2043	SQUARE *	0	3.3	2,318,885	06-2053	60 - R2 *	(3)	1,941,819	2.76	(377,066)
345 ACCESSORY ELECTRIC EQUIPMENT	111,693,785	06-2043	SQUARE *	0	3.3	3,685,895	06-2053	50 - R2.5 *	(2)	3,093,215	2.77	(592,680)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	10,309,493	06-2043	SQUARE *	0	3.3	340,213	06-2053	50 - S0.5 *	(2)	298,911	2.90	(41,302)
TOTAL CAPE CANAVERAL COMBINED CYCLE	*913,453,057*				*3.3*	*30,143,950*				*35,416,031*	*3.88*	*5,272,081*
TOTAL CAPE CANAVERAL COMBINED CYCLE PLANT	***913,453,057***				***3.3***	***30,143,950***				***35,416,031***	***3.88***	***5,272,081***
RIVIERA COMBINED CYCLE PLANT												
RIVIERA COMBINED CYCLE												
341 STRUCTURES AND IMPROVEMENTS	80,630,958	06-2044	SQUARE *	0	3.3	2,660,822	06-2054	80 - R2 *	(2)	2,138,363	2.65	(522,459)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	217,306,004	06-2044	SQUARE *	0	3.3	7,171,098	06-2054	50 - R1.5 *	(3)	6,367,219	2.93	(803,879)
343 PRIME MOVERS - GENERAL	525,780,412	06-2044	SQUARE *	0	3.3	17,350,754	06-2054	50 - R1 *	(3)	15,830,359	3.01	(1,520,395)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	139,494,633	06-2044	SQUARE *	0	3.3	4,603,323	06-2054	9 - L0 *	35	10,073,605	7.22	5,470,282
344 GENERATORS	79,977,232	06-2044	SQUARE *	0	3.3	2,639,249	06-2054	60 - R2 *	(3)	2,209,764	2.76	(429,485)
345 ACCESSORY ELECTRIC EQUIPMENT	82,800,568	06-2044	SQUARE *	0	3.3	2,732,419	06-2054	50 - R2.5 *	(2)	2,287,187	2.76	(445,232)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	11,446,561	06-2044	SQUARE *	0	3.3	377,737	06-2054	50 - S0.5 *	(2)	331,830	2.90	(45,907)
TOTAL RIVIERA COMBINED CYCLE	*1,137,436,368*				*3.3*	*37,535,402*				*39,238,327*	*3.45*	*1,702,925*
TOTAL RIVIERA COMBINED CYCLE PLANT	***1,137,436,368***				***3.3***	***37,535,402***				***39,238,327***	***3.45***	***1,702,925***
PT EVERGLADES COMBINED CYCLE PLANT												
PT EVERGLADES COMBINED CYCLE												
341 STRUCTURES AND IMPROVEMENTS	101,607,532	06-2046	SQUARE *	0	3.3	3,353,049	06-2056	80 - R2 *	(2)	2,704,023	2.66	(649,026)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	59,665,117	06-2046	SQUARE *	0	3.3	1,968,949	06-2056	50 - R1.5 *	(3)	1,745,324	2.93	(223,625)
343 PRIME MOVERS - GENERAL	499,500,579	06-2046	SQUARE *	0	3.3	16,483,519	06-2056	50 - R1 *	(3)	15,021,164	3.01	(1,462,355)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	191,363,196	06-2046	SQUARE *	0	3.3	6,314,985	06-2056	9 - L0 *	35	13,819,293	7.22	7,504,308
344 GENERATORS	87,208,139	06-2046	SQUARE *	0	3.3	2,877,869	06-2056	60 - R2 *	(3)	2,407,293	2.76	(470,576)
345 ACCESSORY ELECTRIC EQUIPMENT	138,483,956	06-2046	SQUARE *	0	3.3	4,569,971	06-2056	50 - R2.5 *	(2)	3,827,974	2.76	(741,997)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	12,795,087	06-2046	SQUARE *	0	3.3	422,238	06-2056	50 - S0.5 *	(2)	370,648	2.90	(51,590)
TOTAL PT EVERGLADES COMBINED CYCLE	*1,090,623,606*				*3.3*	*35,990,580*				*39,895,719*	*3.66*	*3,905,139*
TOTAL PT EVERGLADES COMBINED CYCLE PLANT	***1,090,623,606***				***3.3***	***35,990,580***				***39,895,719***	***3.66***	***3,905,139***
TOTAL COMBINED CYCLE PRODUCTION PLANT	**10,277,035,554**				***3.8***	**386,046,917**				**414,727,438**	***4.04***	**28,680,521**

FLORIDA POWER AND LIGHT COMPANY

TABLE 4. COMPARISON OF WHOLE LIFE ANNUAL DEPRECIATION RATES AND ACCRUALS FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016
BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

		ORDERED IN DOCKET NO. 090130-EI					PROPOSED ESTIMATES					
	ORIGINAL COST	PROBABLE RETIREMENT DATE	SURVIVOR CURVE/ INTERIM RETIREMENT RATE	NET SALVAGE	ANNUAL DEPRECIATION RATE	ANNUAL DEPRECIATION ACCRUALS	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)-(6)
PEAKER PLANT												
LAUDERDALE GTS												
341 STRUCTURES AND IMPROVEMENTS	601,222	06-2020	0.0023	(2)	2.2	13,227	06-2028	80 - R2 *	(2)	20,500	3.41	7,273
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	194,417	06-2020	0.0095	0	2.6	5,055	06-2028	50 - R1.5 *	(3)	7,193	3.70	2,138
343 PRIME MOVERS - GENERAL	14,841,925	06-2020	0.0057	0	2.9	430,416	06-2028	50 - R1 *	(3)	1,208,680	8.14	778,264
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	1,858,779	06-2020	0.1565	0	2.9	53,905	06-2028	25 - R1 *	29	69,480	3.74	15,575
344 GENERATORS	1,748,135	06-2020	0.0016	(1)	2.1	36,711	06-2028	60 - R2 *	(3)	43,263	2.47	6,552
345 ACCESSORY ELECTRIC EQUIPMENT	420,107	06-2020	0.0013	(1)	2.1	8,822	06-2028	50 - R2.5 *	(2)	11,778	2.80	2,956
346 MISCELLANEOUS POWER PLANT EQUIPMENT	20,935	06-2020	0.0026	0	2.2	461	06-2028	50 - S0.5 *	(2)	508	2.43	47
TOTAL LAUDERDALE GTS	*19,685,520*				*2.8*	*548,597*				*1,361,402*	***6.92***	*812,805*
FT. MYERS GTS												
341 STRUCTURES AND IMPROVEMENTS	941,093	06-2020	0.0023	(2)	2.3	21,645	06-2028	80 - R2 *	(2)	58,404	6.21	36,759
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	724,318	06-2020	0.0095	0	2.7	19,557	06-2028	50 - R1.5 *	(3)	47,016	6.49	27,459
343 PRIME MOVERS - GENERAL	10,218,903	06-2020	0.0057	0	3.1	316,786	06-2028	50 - R1 *	(3)	826,898	8.09	510,112
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	2,807,095	06-2020	0.1565	0	3.1	87,020	06-2028	25 - R1 *	29	92,610	3.30	5,590
344 GENERATORS	4,602,022	06-2020	0.0016	(1)	2.2	101,244	06-2028	60 - R2 *	(3)	289,704	6.30	188,460
345 ACCESSORY ELECTRIC EQUIPMENT	3,450,438	06-2020	0.0013	(1)	2.2	75,910	06-2028	50 - R2.5 *	(2)	235,636	6.83	159,726
346 MISCELLANEOUS POWER PLANT EQUIPMENT	20,936	06-2020	0.0026	0	2.3	482	06-2028	50 - S0.5 *	(2)	1,276	6.09	794
TOTAL FT. MYERS GTS	*22,764,804*				*2.7*	*622,644*				*1,551,544*	***6.82***	*928,900*
LAUDERDALE AND FT. MYERS PEAKERS												
341 STRUCTURES AND IMPROVEMENTS	43,805,886	06-2046	SQUARE *	0	3.3	1,445,594	06-2056	80 - R2 *	(2)	1,166,200	2.66	(279,394)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	26,150,085	06-2046	SQUARE *	0	3.3	862,953	06-2056	50 - R1.5 *	(3)	764,942	2.93	(98,011)
343 PRIME MOVERS - GENERAL	213,843,171	06-2046	SQUARE *	0	3.3	7,056,825	06-2056	50 - R1 *	(3)	6,431,547	3.01	(625,278)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	83,870,827	06-2046	SQUARE *	0	3.3	2,767,737	06-2056	25 - R1 *	29	2,411,706	2.88	(356,031)
344 GENERATORS	38,221,667	06-2046	SQUARE *	0	3.3	1,261,315	06-2056	60 - R2 *	(3)	1,055,071	2.76	(206,244)
345 ACCESSORY ELECTRIC EQUIPMENT	60,694,881	06-2046	SQUARE *	0	3.3	2,002,931	06-2056	50 - R2.5 *	(2)	1,677,728	2.76	(325,203)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	*5,607,843*	06-2046	SQUARE *	0	3.3	185,059	06-2056	50 - S0.5 *	(2)	162,448	2.90	(22,611)
TOTAL LAUDERDALE AND FT. MYERS PEAKERS	*472,194,358*				*3.3*	*15,582,414*				*13,669,642*	*2.89*	*(1,912,772)*
TOTAL PEAKER PLANT	**514,644,682**				***3.3***	**16,753,655**				**16,582,588**	***3.22***	**(171,067)**
SOLAR PRODUCTION PLANT												
DESOTO SOLAR												
341 STRUCTURES AND IMPROVEMENTS	4,635,209	06-2039	SQUARE *	0	3.3	152,962	06-2039	SQUARE *	0	157,728	3.40	4,766
343 PRIME MOVERS - GENERAL	118,689,127	06-2039	SQUARE *	0	3.3	3,916,741	06-2039	SQUARE *	0	3,983,267	3.36	66,526
345 ACCESSORY ELECTRIC EQUIPMENT	27,532,945	06-2039	SQUARE *	0	3.3	908,587	06-2039	SQUARE *	0	926,273	3.36	17,686
TOTAL DESOTOSOLAR	*150,857,280*				*3.3*	*4,978,290*				*5,067,268*	*3.36*	*88,978*
SPACE COAST SOLAR												
341 STRUCTURES AND IMPROVEMENTS	3,986,978	06-2040	SQUARE *	0	3.3	131,570	06-2040	SQUARE *	0	133,487	3.35	1,917
343 PRIME MOVERS - GENERAL	52,858,699	06-2040	SQUARE *	0	3.3	1,744,337	06-2040	SQUARE *	0	1,769,750	3.35	25,413
345 ACCESSORY ELECTRIC EQUIPMENT	6,281,496	06-2040	SQUARE *	0	3.3	207,289	06-2040	SQUARE *	0	210,309	3.35	3,020
TOTAL SPACE COAST SOLAR	*63,127,172*				*3.3*	*2,083,196*				*2,113,546*	*3.35*	*30,350*
MARTIN SOLAR												
341 STRUCTURES AND IMPROVEMENTS	21,320,036	06-2040	SQUARE *	0	3.3	703,561	06-2045	SQUARE *	0	616,569	2.89	(86,992)
343 PRIME MOVERS - GENERAL	405,752,300	06-2040	SQUARE *	0	3.3	13,389,826	06-2045	SQUARE *	0	11,731,524	2.89	(1,658,302)
345 ACCESSORY ELECTRIC EQUIPMENT	4,239,215	06-2040	SQUARE *	0	3.3	139,894	06-2045	SQUARE *		121,994	2.88	(17,900)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,335	06-2040	SQUARE *	0	3.3	44	06-2045	SQUARE *	0	38	2.88	(6)
TOTAL MARTIN SOLAR	*431,312,886*				*3.3*	*14,233,325*				*12,470,125*	*2.89*	*(1,763,200)*
BABCOCK RANCH SOLAR												
341 STRUCTURES AND IMPROVEMENTS	4,078,184	06-2039	SQUARE *	0	3.3	134,580	06-2046	SQUARE *	0	135,804	3.33	1,224
343 PRIME MOVERS - GENERAL	104,118,206	06-2039	SQUARE *	0	3.3	3,435,901	06-2046	SQUARE *	0	3,467,136	3.33	31,235
345 ACCESSORY ELECTRIC EQUIPMENT	24,224,241	06-2039	SQUARE *	0	3.3	799,400	06-2046	SQUARE *	0	806,667	3.33	7,267
TOTAL BABCOCK RANCH SOLAR	*132,420,631*				*3.3*	*4,369,881*				*4,409,607*	*3.33*	*39,726*
MANATEE SOLAR												
341 STRUCTURES AND IMPROVEMENTS	4,118,679	06-2040	SQUARE *	0	3.3	135,916	06-2046	SQUARE *	0	137,152	3.33	1,236
343 PRIME MOVERS - GENERAL	105,224,179	06-2040	SQUARE *	0	3.3	3,472,398	06-2046	SQUARE *	0	3,503,965	3.33	31,567
345 ACCESSORY ELECTRIC EQUIPMENT	24,464,781	06-2040	SQUARE *	0	3.3	807,338	06-2046	SQUARE *	0	814,677	3.33	7,339
TOTAL MANATEE SOLAR	*133,807,639*				*3.3*	*4,415,652*				*4,455,794*	*3.33*	*40,142*
CITRUS SOLAR												
341 STRUCTURES AND IMPROVEMENTS	4,207,181	06-2040	SQUARE *	0	3.3	138,837	06-2046	SQUARE *	0	140,099	3.33	1,262
343 PRIME MOVERS - GENERAL	107,250,213	06-2040	SQUARE *	0	3.3	3,539,257	06-2046	SQUARE *	0	3,571,432	3.33	32,175
345 ACCESSORY ELECTRIC EQUIPMENT	24,990,480	06-2040	SQUARE *	0	3.3	824,686	06-2046	SQUARE *		832,183	3.33	7,497
TOTAL CITRUS SOLAR	*136,447,874*				*3.3*	*4,502,780*				*4,543,714*	*3.33*	*40,934*
TOTAL SOLAR PRODUCTION PLANT	**1,047,973,483**				***3.3***	**34,583,124**				**33,060,054**	***3.15***	**(1,523,070)**
TOTAL PRODUCTION PLANT	**22,795,357,882**				***3.0***	**675,925,368**				**875,725,039**	***3.84***	**199,799,671**

FLORIDA POWER AND LIGHT COMPANY

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BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

		ORIGINAL COST	ORDERED IN DOCKET NO. 090130-EI: PROBABLE RETIREMENT DATE	SURVIVOR CURVE/ INTERIM RETIREMENT RATE	NET SALVAGE	ANNUAL DEPRECIATION RATE	ANNUAL DEPRECIATION ACCRUALS	PROPOSED ESTIMATES: PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ DECREASE
		(1)	(2)	(3)	(4)	(5)	(6)=(5)x(1)	(7)	(8)	(9)	(10)	(11)	(12)=(11)-(6)
TRANSMISSION, DISTRIBUTION, AND GENERAL PLANT													
	TRANSMISSION PLANT												
350.2	EASEMENTS	240,510,767		75 - S4	0	1.3	3,126,640		75 - S4	0	3,198,793	1.33	72,153
352	STRUCTURES AND IMPROVEMENTS	154,719,740		60 - R3	(15)	1.9	2,939,675		65 - R3	(15)	2,740,087	1.77	(199,588)
353	STATION EQUIPMENT	1,741,377,472		40 - R1.5	(2)	2.6	45,275,814		40 - R1	(2)	44,405,126	2.55	(870,688)
353.1	STATION EQUIPMENT - STEP-UP TRANSFORMERS	400,209,880		35 - R2	0	2.9	11,606,087		30 - R1	0	13,326,989	3.33	1,720,902
354	TOWERS AND FIXTURES	349,056,185		52 - R5	(15)	2.2	7,679,236		60 - R4	(25)	7,286,548	2.09	(392,688)
355	POLES AND FIXTURES	1,242,636,001		44 - R2	(50)	3.4	42,249,624		50 - R2	(50)	37,279,080	3.00	(4,970,544)
356	OVERHEAD CONDUCTORS AND DEVICES	854,174,816		47 - R1.5	(50)	3.2	27,333,594		51 - R1	(55)	25,949,831	3.04	(1,383,763)
357	UNDERGROUND CONDUIT	75,512,192		60 - R4	0	1.7	1,283,707		65 - R4	0	1,162,888	1.54	(120,819)
358	UNDERGROUND CONDUCTORS AND DEVICES	104,576,520		60 - L3	(10)	1.8	1,882,377		65 - R3	(20)	1,932,574	1.85	50,197
359	ROADS AND TRAILS	113,485,941		65 - SQ	(10)	1.7	1,929,261		75 - R4	(10)	1,660,299	1.46	(268,962)
	TOTAL TRANSMISSION PLANT	**5,276,259,513**				***2.8***	**145,306,015**				**138,942,215**	***2.63***	**(6,363,800)**
	DISTRIBUTION PLANT												
361	STRUCTURES AND IMPROVEMENTS	198,554,703		60 - R3	(15)	1.9	3,772,539		65 - R3	(15)	3,516,404	1.77	(256,135)
362	STATION EQUIPMENT	1,740,028,154		43 - R1.5	(10)	2.6	45,240,732		45 - R1.5	(10)	42,491,488	2.44	(2,749,244)
364.1	POLES, TOWERS AND FIXTURES - WOOD	1,083,692,909		39 - R2	(60)	4.1	44,431,409		40 - R2	(100)	54,184,645	5.00	9,753,236
364.2	POLES, TOWERS AND FIXTURES - CONCRETE	706,877,719		39 - R2	(60)	4.1	28,981,986		50 - R1.5	(100)	28,275,109	4.00	(706,877)
365	OVERHEAD CONDUCTORS AND DEVICES	1,991,793,394		41 - S0	(60)	3.9	77,679,942		48 - R1	(80)	74,572,745	3.74	(3,107,197)
366.6	UNDERGROUND CONDUIT - DUCT SYSTEM	1,528,850,821		70 - S1.5	(2)	1.5	22,932,762		70 - R3	0	21,862,567	1.43	(1,070,195)
366.7	UNDERGROUND CONDUIT - DIRECT BURIED	193,885,661		50 - R4	0	2.0	3,877,713		50 - R4	0	3,877,713	2.00	-
367.6	UNDERGROUND CONDUCTORS AND DEVICES - DUCT SYSTEM	1,723,803,662		38 - S0	0	2.6	44,818,895		42 - S0	(5)	43,077,854	2.50	(1,741,041)
367.7	UNDERGROUND CONDUCTORS AND DEVICES - DIRECT BURIED	731,720,379		35 - R2	0	2.9	21,219,891		35 - R2	0	20,927,196	2.86	(292,695)
368	LINE TRANSFORMERS	2,172,571,477		33 - L1.5	(25)	3.8	82,557,716		34 - S0	(15)	73,450,948	3.38	(9,106,768)
369.1	SERVICES - OVERHEAD	429,359,956		48 - R1	(85)	3.9	16,745,038		53 - R1	(125)	18,258,532	4.25	1,513,494
369.6	SERVICES - UNDERGROUND	818,122,343		38 - R2	(5)	2.8	22,907,426		45 - R2	(15)	20,886,663	2.55	(2,020,763)
370	METERS	90,547,258		36 - R2.5	(30)	3.6	3,259,701		38 - R2	(30)	3,095,811	3.42	(163,890)
370.1	METERS - AMI	752,056,781		20 - R2.5	(30)	6.5	48,883,691		20 - R2.5	(30)	48,883,691	6.50	-
371	INSTALLATIONS ON CUSTOMER'S PREMISES	77,912,064		30 - L0	(20)	4.0	3,116,483		30 - L0	(15)	2,983,643	3.83	(132,840)
373	STREET LIGHTING AND SIGNAL SYSTEMS	463,393,095		30 - R0.5	(20)	4.0	18,535,724		35 - O1	(15)	15,240,285	3.29	(3,295,439)
	TOTAL DISTRIBUTION PLANT	**14,703,170,376**				***3.3***	**488,961,648**				**475,585,294**	***3.23***	**(13,376,354)**
	GENERAL PLANT												
390	STRUCTURES AND IMPROVEMENTS	435,222,597		50 - R1.5	(5)	2.1	9,139,675		55 - R1.5	(10)	8,713,156	2.00	(426,519)
392.1	AUTOMOBILES	9,038,959		6 - L2	15	14.2	1,283,532		6 - L2.5	15	1,280,775	14.17	(2,757)
392.2	LIGHT TRUCKS	47,500,083		9 - L3	15	9.4	4,465,008		9 - L3	15	4,485,670	9.44	20,662
392.3	HEAVY TRUCKS	241,647,650		12 - S3	15	7.1	17,156,983		12 - S3	15	17,085,712	7.07	(71,271)
392.4	TRACTOR TRAILERS	767,855		9 - L2.5	0	11.1	85,232		9 - L2.5	5	76,002	9.90	(9,230)
392.9	TRAILERS	21,065,643		20 - L1	30	3.5	737,298		20 - L1	15	895,290	4.25	157,992
396.1	POWER OPERATED EQUIPMENT	4,766,126		10 - L0.5	20	8.0	381,290		11 - L1.5	15	368,255	7.73	(13,035)
397.8	COMMUNICATION EQUIPMENT - FIBER OPTICS	11,992,500		10 - L0	0	10.0	1,199,250		20 - S2	0	599,625	5.00	(599,625)
										0			
	TOTAL GENERAL PLANT	**772,001,412**				***4.5***	**34,448,268**				**33,504,485**	***4.34***	**(943,783)**
TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT		**20,751,431,301**				***3.2***	**668,715,931**				**648,031,994**	***3.12***	**(20,683,937)**
GRAND TOTAL		**43,546,789,183**				***3.1***	**1,344,641,299**				**1,523,757,033**	***3.50***	**179,115,734**

* CURVE SHOWN IS INTERIM SURVIVOR CURVE. LIFE SPAN METHOD IS USED.

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

	ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
STEAM PRODUCTION PLANT				
MANATEE STEAM PLANT				
MANATEE COMMON				
311 STRUCTURES AND IMPROVEMENTS	112,114,271	73,128,598	66,216,171	6,912,427
312 BOILER PLANT EQUIPMENT	7,715,628	1,329,813	2,046,045	(716,232)
314 TURBOGENERATOR UNITS	9,652,310	7,657,288	6,080,941	1,576,347
315 ACCESSORY ELECTRIC EQUIPMENT	9,646,848	7,389,490	6,678,052	711,438
316 MISCELLANEOUS POWER PLANT EQUIPMENT	2,450,703	1,919,506	1,600,947	318,559
TOTAL MANATEE COMMON	*141,579,760*	*91,424,696*	*82,622,156*	*8,802,540*
MANATEE UNIT 1				
311 STRUCTURES AND IMPROVEMENTS	6,836,328	5,584,432	5,132,719	451,713
312 BOILER PLANT EQUIPMENT	181,481,969	93,495,502	90,737,380	2,758,122
314 TURBOGENERATOR UNITS	72,660,531	41,616,767	39,290,074	2,326,693
315 ACCESSORY ELECTRIC EQUIPMENT	14,261,784	8,023,680	7,261,523	762,157
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,924,407	2,278,883	2,265,993	12,890
TOTAL MANATEE UNIT 1	*279,165,019*	*150,999,264*	*144,687,689*	*6,311,575*
MANATEE UNIT 2				
311 STRUCTURES AND IMPROVEMENTS	4,986,744	4,017,696	3,713,478	304,218
312 BOILER PLANT EQUIPMENT	183,957,418	87,494,700	88,348,078	(853,378)
314 TURBOGENERATOR UNITS	70,765,381	42,942,308	40,284,566	2,657,742
315 ACCESSORY ELECTRIC EQUIPMENT	12,273,816	6,398,866	5,873,713	525,153
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,453,782	1,668,499	1,809,688	(141,189)
TOTAL MANATEE UNIT 2	*275,437,142*	*142,522,068*	*140,029,523*	*2,492,545*
TOTAL MANATEE STEAM PLANT	***696,181,920***	***384,946,028***	***367,339,368***	***17,606,660***

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

	ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
MARTIN STEAM PLANT				
MARTIN COMMON				
311 STRUCTURES AND IMPROVEMENTS	241,950,141	158,600,994	157,024,180	1,576,814
312 BOILER PLANT EQUIPMENT	7,068,506	2,944,759	2,961,071	(16,312)
314 TURBOGENERATOR UNITS	27,474,257	14,912,384	14,791,800	120,584
315 ACCESSORY ELECTRIC EQUIPMENT	10,295,313	5,435,309	5,252,636	182,673
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,888,459	1,913,639	1,969,348	(55,709)
TOTAL MARTIN COMMON	*290,676,676*	*183,807,084*	*181,999,035*	*1,808,049*
MARTIN PIPELINE				
312 BOILER PLANT EQUIPMENT	370,942	370,942	224,898	146,044
TOTAL MARTIN PIPELINE	*370,942*	*370,942*	*224,898*	*146,044*
MARTIN UNIT 1				
311 STRUCTURES AND IMPROVEMENTS	16,404,681	10,400,297	10,739,007	(338,710)
312 BOILER PLANT EQUIPMENT	212,830,965	87,624,020	98,738,722	(11,114,702)
314 TURBOGENERATOR UNITS	90,120,383	50,448,065	46,914,427	3,533,638
315 ACCESSORY ELECTRIC EQUIPMENT	24,391,137	14,440,333	13,322,397	1,117,936
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,594,165	1,758,500	1,759,583	(1,083)
TOTAL MARTIN UNIT 1	*347,341,330*	*164,671,214*	*171,474,136*	*(6,802,922)*
MARTIN UNIT 2				
311 STRUCTURES AND IMPROVEMENTS	11,266,842	7,618,893	7,602,514	16,379
312 BOILER PLANT EQUIPMENT	215,154,508	84,744,456	96,857,949	(12,113,493)
314 TURBOGENERATOR UNITS	82,856,949	30,043,134	36,456,356	(6,413,222)
315 ACCESSORY ELECTRIC EQUIPMENT	23,045,156	12,167,493	11,012,140	1,155,353
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,280,816	1,374,670	1,520,592	(145,922)
TOTAL MARTIN UNIT 2	*335,604,270*	*135,948,644*	*153,449,551*	*(17,500,907)*
TOTAL MARTIN STEAM PLANT	***973,993,219***	***484,797,884***	***507,147,620***	***(22,349,736)***

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
SCHERER STEAM PLANT					
	SCHERER COAL CARS				
312	BOILER PLANT EQUIPMENT	33,149,442	33,149,442	15,009,847	18,139,595
	TOTAL SCHERER COAL CARS	*33,149,442*	*33,149,442*	*15,009,847*	*18,139,595*
	SCHERER COMMON				
311	STRUCTURES AND IMPROVEMENTS	39,391,667	20,717,188	18,689,897	2,027,291
312	BOILER PLANT EQUIPMENT	25,844,055	12,070,575	11,763,795	306,780
314	TURBOGENERATOR UNITS	4,336,718	1,830,764	1,888,600	(57,836)
315	ACCESSORY ELECTRIC EQUIPMENT	1,226,257	679,212	624,070	55,142
316	MISCELLANEOUS POWER PLANT EQUIPMENT	3,659,825	1,735,162	1,585,006	150,156
	TOTAL SCHERER COMMON	*74,458,521*	*37,032,900*	*34,551,368*	*2,481,532*
	SCHERER COMMON UNIT 3 AND 4				
311	STRUCTURES AND IMPROVEMENTS	2,999,449	1,646,858	1,479,572	167,286
312	BOILER PLANT EQUIPMENT	22,335,968	9,614,113	9,275,525	338,588
314	TURBOGENERATOR UNITS	2,831,158	224,639	287,713	(63,074)
315	ACCESSORY ELECTRIC EQUIPMENT	2,818,575	245,786	310,655	(64,869)
	TOTAL SCHERER COMMON UNIT 3 AND 4	*30,985,149*	*11,731,396*	*11,353,465*	*377,931*
	SCHERER UNIT 4				
311	STRUCTURES AND IMPROVEMENTS	159,104,427	39,437,115	46,444,574	(7,007,459)
312	BOILER PLANT EQUIPMENT	671,515,648	178,043,157	208,633,408	(30,590,251)
314	TURBOGENERATOR UNITS	122,853,491	58,668,053	54,470,074	4,197,979
315	ACCESSORY ELECTRIC EQUIPMENT	49,374,419	14,135,035	15,966,566	(1,831,531)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	5,117,266	2,275,999	1,788,757	487,242
	TOTAL SCHERER UNIT 4	*1,007,965,252*	*292,559,359*	*327,303,379*	*(34,744,020)*
TOTAL SCHERER STEAM PLANT		***1,146,558,365***	***374,473,097***	***388,218,059***	***(13,744,962)***

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

	ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
SJRPP STEAM PLANT				
SJRPP COAL AND LIMESTONE				
311 STRUCTURES AND IMPROVEMENTS	3,562,391	1,817,206	1,957,124	(139,918)
312 BOILER PLANT EQUIPMENT	30,883,389	15,259,114	16,779,272	(1,520,158)
315 ACCESSORY ELECTRIC EQUIPMENT	3,773,252	2,142,570	2,145,214	(2,644)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	300,302	161,831	164,197	(2,366)
TOTAL SJRPP COAL AND LIMESTONE	*38,519,334*	*19,380,721*	*21,045,807*	*(1,665,086)*
SJRPP COAL CARS				
312 BOILER PLANT EQUIPMENT	52,105	52,105	28,219	23,886
TOTAL SJRPP COAL CARS	*52,105*	*52,105*	*28,219*	*23,886*
SJRPP COMMON				
311 STRUCTURES AND IMPROVEMENTS	33,146,529	22,171,912	17,609,732	4,562,180
312 BOILER PLANT EQUIPMENT	3,694,843	2,563,468	1,899,199	664,269
314 TURBOGENERATOR UNITS	2,497,878	1,684,864	1,321,065	363,799
315 ACCESSORY ELECTRIC EQUIPMENT	5,833,698	3,990,701	3,208,339	782,362
316 MISCELLANEOUS POWER PLANT EQUIPMENT	1,598,862	1,006,658	782,381	224,277
TOTAL SJRPP COMMON	*46,771,810*	*31,417,602*	*24,820,716*	*6,596,886*
SJRPP GYPSUM AND ASH				
311 STRUCTURES AND IMPROVEMENTS	2,172,989	1,122,277	1,155,876	(33,599)
312 BOILER PLANT EQUIPMENT	17,085,257	9,494,175	9,529,384	(35,209)
315 ACCESSORY ELECTRIC EQUIPMENT	52,571	31,682	28,055	3,627
316 MISCELLANEOUS POWER PLANT EQUIPMENT	154,892	64,476	64,604	(128)
TOTAL SJRPP GYPSUM AND ASH	*19,465,709*	*10,712,610*	*10,777,919*	*(65,309)*
SJRPP UNIT 1				
311 STRUCTURES AND IMPROVEMENTS	9,049,629	6,497,954	5,112,579	1,385,375
312 BOILER PLANT EQUIPMENT	99,626,681	50,079,303	46,567,786	3,511,517
314 TURBOGENERATOR UNITS	31,463,410	15,259,034	12,528,019	2,731,015
315 ACCESSORY ELECTRIC EQUIPMENT	12,475,837	7,908,663	6,635,390	1,273,273
316 MISCELLANEOUS POWER PLANT EQUIPMENT	2,038,425	1,391,601	1,066,758	324,843
TOTAL SJRPP UNIT 1	*154,653,983*	*81,136,555*	*71,910,532*	*9,226,023*
SJRPP UNIT 2				
311 STRUCTURES AND IMPROVEMENTS	7,177,145	4,116,166	4,074,211	41,955
312 BOILER PLANT EQUIPMENT	90,153,231	39,507,420	42,081,111	(2,573,691)
314 TURBOGENERATOR UNITS	28,479,810	10,690,425	11,221,140	(530,715)
315 ACCESSORY ELECTRIC EQUIPMENT	10,105,912	5,314,628	5,490,126	(175,498)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	1,571,822	869,236	826,613	42,623
TOTAL SJRPP UNIT 2	*137,487,920*	*60,497,875*	*63,693,201*	*(3,195,326)*
TOTAL SJRPP STEAM PLANT	***396,950,861***	***203,197,468***	***192,276,394***	***10,921,074***
TOTAL STEAM PRODUCTION	**3,213,684,365**	**1,447,414,477**	**1,454,981,441**	**(7,566,964)**

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

	ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
NUCLEAR PRODUCTION PLANT				
ST. LUCIE NUCLEAR PLANT				
ST. LUCIE COMMON				
321 STRUCTURES AND IMPROVEMENTS	396,984,357	176,282,726	175,475,861	806,865
322 REACTOR PLANT EQUIPMENT	55,565,218	31,403,213	17,605,964	13,797,249
323 TURBOGENERATOR UNITS	12,402,700	(7,534,768)	2,844,691	(10,379,459)
324 ACCESSORY ELECTRIC EQUIPMENT	34,367,943	16,891,518	16,263,499	628,019
325 MISCELLANEOUS POWER PLANT EQUIPMENT	20,722,317	2,245,775	7,598,070	(5,352,295)
TOTAL ST. LUCIE COMMON	*520,042,535*	*219,288,464*	*219,788,085*	*(499,621)*
ST. LUCIE UNIT 1				
321 STRUCTURES AND IMPROVEMENTS	194,729,786	100,039,207	98,130,550	1,908,657
322 REACTOR PLANT EQUIPMENT	838,073,831	293,588,602	296,841,653	(3,253,051)
323 TURBOGENERATOR UNITS	412,318,467	47,813,095	92,420,728	(44,607,633)
324 ACCESSORY ELECTRIC EQUIPMENT	119,762,438	49,415,234	52,866,594	(3,451,360)
325 MISCELLANEOUS POWER PLANT EQUIPMENT	11,320,232	6,997,958	7,030,949	(32,991)
TOTAL ST. LUCIE UNIT 1	*1,576,204,754*	*497,854,096*	*547,290,474*	*(49,436,378)*
ST. LUCIE UNIT 2				
321 STRUCTURES AND IMPROVEMENTS	297,759,844	130,332,823	137,734,028	(7,401,205)
322 REACTOR PLANT EQUIPMENT	1,053,686,661	387,788,728	347,558,538	40,230,190
323 TURBOGENERATOR UNITS	350,014,044	46,854,392	74,803,815	(27,949,423)
324 ACCESSORY ELECTRIC EQUIPMENT	188,938,115	84,917,442	91,937,709	(7,020,267)
325 MISCELLANEOUS POWER PLANT EQUIPMENT	24,130,684	11,189,066	12,628,535	(1,439,469)
TOTAL ST. LUCIE UNIT 2	*1,914,529,349*	*661,082,451*	*664,662,625*	*(3,580,174)*
TOTAL ST. LUCIE NUCLEAR PLANT	***4,010,776,637***	***1,378,225,011***	***1,431,741,184***	***(53,516,173)***

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

	ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
TURKEY POINT NUCLEAR PLANT				
TURKEY POINT COMMON				
321 STRUCTURES AND IMPROVEMENTS	360,056,132	183,734,299	156,727,193	27,007,106
322 REACTOR PLANT EQUIPMENT	137,627,469	24,011,347	36,308,226	(12,296,879)
323 TURBOGENERATOR UNITS	21,825,767	5,398,454	6,058,260	(659,806)
324 ACCESSORY ELECTRIC EQUIPMENT	53,673,512	34,021,888	26,448,817	7,573,071
325 MISCELLANEOUS POWER PLANT EQUIPMENT	37,213,998	17,421,764	14,764,756	2,657,008
TOTAL TURKEY POINT COMMON	*610,396,877*	*264,587,751*	*240,307,252*	*24,280,499*
TURKEY POINT UNIT 3				
321 STRUCTURES AND IMPROVEMENTS	183,462,252	38,437,467	57,330,885	(18,893,418)
322 REACTOR PLANT EQUIPMENT	586,039,767	168,441,241	209,439,178	(40,997,937)
323 TURBOGENERATOR UNITS	756,080,929	81,959,597	171,964,897	(90,005,300)
324 ACCESSORY ELECTRIC EQUIPMENT	150,385,799	72,326,463	72,629,850	(303,387)
325 MISCELLANEOUS POWER PLANT EQUIPMENT	15,687,982	752,238	4,245,584	(3,493,346)
TOTAL TURKEY POINT UNIT 3	*1,691,656,730*	*361,917,007*	*515,610,394*	*(153,693,387)*
TURKEY POINT UNIT 4				
321 STRUCTURES AND IMPROVEMENTS	128,297,844	49,379,171	51,084,933	(1,705,762)
322 REACTOR PLANT EQUIPMENT	514,072,790	183,833,792	183,239,225	594,567
323 TURBOGENERATOR UNITS	599,706,206	78,908,563	124,386,621	(45,478,058)
324 ACCESSORY ELECTRIC EQUIPMENT	175,176,467	103,877,312	93,387,753	10,489,559
325 MISCELLANEOUS POWER PLANT EQUIPMENT	11,936,247	187,688	3,701,637	(3,513,949)
TOTAL TURKEY POINT UNIT 4	*1,429,189,554*	*416,186,526*	*455,800,169*	*(39,613,643)*
TOTAL TURKEY POINT NUCLEAR PLANT	***3,731,243,161***	***1,042,691,284***	***1,211,717,815***	***(169,026,531)***
TOTAL NUCLEAR PRODUCTION PLANT	**7,742,019,799**	**2,420,916,295**	**2,643,458,999**	**(222,542,704)**

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
COMBINED CYCLE PRODUCTION PLANT					
LAUDERDALE COMBINED CYCLE PLANT					
	LAUDERDALE COMMON				
341	STRUCTURES AND IMPROVEMENTS	84,760,736	56,466,915	43,286,101	13,180,814
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	11,513,771	6,416,278	5,265,108	1,151,170
343	PRIME MOVERS - GENERAL	27,106,051	5,912,889	3,904,041	2,008,848
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	37,564,239	7,262,311	4,795,010	2,467,301
344	GENERATORS	680,446	405,162	299,621	105,541
345	ACCESSORY ELECTRIC EQUIPMENT	12,121,303	9,401,592	6,957,890	2,443,702
346	MISCELLANEOUS POWER PLANT EQUIPMENT	1,234,438	609,250	499,171	110,079
	TOTAL LAUDERDALE COMMON	*174,980,983*	*86,474,396*	*65,006,942*	*21,467,454*
	LAUDERDALE UNIT 4				
341	STRUCTURES AND IMPROVEMENTS	5,090,645	3,478,638	2,682,311	796,327
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	673,633	511,484	356,472	155,012
343	PRIME MOVERS - GENERAL	121,376,511	49,359,731	57,655,119	(8,295,388)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	64,237,235	8,573,139	10,013,939	(1,440,800)
344	GENERATORS	28,799,680	20,523,754	15,705,873	4,817,881
345	ACCESSORY ELECTRIC EQUIPMENT	29,810,853	19,234,929	15,636,950	3,597,979
346	MISCELLANEOUS POWER PLANT EQUIPMENT	2,599,158	1,902,628	1,409,966	492,662
	TOTAL LAUDERDALE UNIT 4	*252,587,715*	*103,584,302*	*103,460,630*	*123,672*
	LAUDERDALE UNIT 5				
341	STRUCTURES AND IMPROVEMENTS	3,203,159	1,949,981	1,553,966	396,015
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	742,434	503,872	353,235	150,637
343	PRIME MOVERS - GENERAL	121,964,623	33,068,495	56,773,176	(23,704,681)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	24,160,830	1,666,194	2,860,581	(1,194,387)
344	GENERATORS	31,767,828	22,571,172	16,389,998	6,181,174
345	ACCESSORY ELECTRIC EQUIPMENT	24,918,023	15,461,507	12,572,388	2,889,119
346	MISCELLANEOUS POWER PLANT EQUIPMENT	1,810,688	1,287,343	973,472	313,871
	TOTAL LAUDERDALE UNIT 5	*208,567,584*	*76,508,564*	*91,476,816*	*(14,968,252)*
TOTAL LAUDERDALE COMBINED CYCLE PLANT		***636,136,282***	***266,567,261***	***259,944,388***	***6,622,873***

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
FT. MYERS COMBINED CYCLE PLANT					
	FT. MYERS COMMON				
341	STRUCTURES AND IMPROVEMENTS	8,824,312	2,131,886	3,500,191	(1,368,305)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	794,049	284,358	540,796	(256,438)
343	PRIME MOVERS - GENERAL	3,709,607	1,045,250	457,525	587,725
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	441,577	231,377	101,278	130,099
344	GENERATORS	230,729	16,354	22,908	(6,554)
345	ACCESSORY ELECTRIC EQUIPMENT	1,163,312	139,908	163,248	(23,340)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	768,815	197,971	260,388	(62,417)
	TOTAL FT. MYERS COMMON	*15,932,401*	*4,047,105*	*5,046,334*	*(999,229)*
	FT. MYERS UNIT 2				
341	STRUCTURES AND IMPROVEMENTS	28,751,597	12,204,747	9,968,648	2,236,099
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	6,194,175	1,967,815	2,189,065	(221,250)
343	PRIME MOVERS - GENERAL	367,522,551	79,088,073	87,596,757	(8,508,684)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	302,123,631	39,131,213	43,341,142	(4,209,929)
344	GENERATORS	57,280,635	19,398,986	17,855,754	1,543,232
345	ACCESSORY ELECTRIC EQUIPMENT	55,628,985	25,417,944	19,654,721	5,763,223
346	MISCELLANEOUS POWER PLANT EQUIPMENT	3,539,476	1,628,771	1,256,430	372,341
	TOTAL FT. MYERS UNIT 2	*821,041,049*	*178,837,550*	*181,862,517*	*(3,024,967)*
	FT. MYERS UNIT 3				
341	STRUCTURES AND IMPROVEMENTS	10,445,289	1,539,033	1,133,599	405,434
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	13,425,923	2,081,549	1,483,561	597,988
343	PRIME MOVERS - GENERAL	164,165,759	(10,456,672)	10,180,429	(20,637,101)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	20,183,733	(1,479,151)	1,440,075	(2,919,226)
344	GENERATORS	46,926,130	7,152,354	5,279,936	1,872,418
345	ACCESSORY ELECTRIC EQUIPMENT	32,964,437	5,278,646	3,744,594	1,534,052
346	MISCELLANEOUS POWER PLANT EQUIPMENT	1,734,913	212,247	191,486	20,761
	TOTAL FT. MYERS UNIT 3	*289,846,185*	*4,328,006*	*23,453,680*	*(19,125,674)*
TOTAL FT. MYERS COMBINED CYCLE PLANT		***1,126,819,634***	***187,212,661***	***210,362,531***	***(23,149,870)***
MANATEE COMBINED CYCLE PLANT					
	MANATEE UNIT 3				
341	STRUCTURES AND IMPROVEMENTS	28,927,929	10,726,313	8,296,002	2,430,311
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	4,008,361	1,497,584	1,159,898	337,686
343	PRIME MOVERS - GENERAL	236,795,038	46,167,493	61,506,546	(15,339,053)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	146,248,668	19,013,518	25,330,720	(6,317,202)
344	GENERATORS	41,417,902	16,420,596	12,133,154	4,287,442
345	ACCESSORY ELECTRIC EQUIPMENT	45,110,148	16,629,259	12,885,118	3,744,141
346	MISCELLANEOUS POWER PLANT EQUIPMENT	10,976,397	3,676,138	3,262,339	413,799
	TOTAL MANATEE UNIT 3	*513,484,442*	*114,130,902*	*124,573,777*	*(10,442,875)*
TOTAL MANATEE COMBINED CYCLE PLANT		***513,484,442***	***114,130,902***	***124,573,777***	***(10,442,875)***

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
MARTIN COMBINED CYCLE PLANT					
	MARTIN COMMON				
341	STRUCTURES AND IMPROVEMENTS	49,379,840	31,469,365	23,773,916	7,695,449
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	4,766,331	3,048,070	2,253,102	794,968
343	PRIME MOVERS - GENERAL	22,788,940	14,037,911	8,729,373	5,308,538
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	2,230,422	770,616	479,202	291,414
345	ACCESSORY ELECTRIC EQUIPMENT	5,321,992	3,662,480	2,766,537	895,943
346	MISCELLANEOUS POWER PLANT EQUIPMENT	4,194,043	2,750,673	2,151,278	599,395
	TOTAL MARTIN COMMON	*88,681,567*	*55,739,115*	*40,153,408*	*15,585,707*
	MARTIN UNIT 3				
341	STRUCTURES AND IMPROVEMENTS	1,660,028	1,129,406	850,807	278,599
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	178,721	126,140	94,320	31,820
343	PRIME MOVERS - GENERAL	152,279,614	46,856,499	63,714,248	(16,857,749)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	67,628,799	4,931,417	6,705,612	(1,774,195)
344	GENERATORS	26,577,658	12,491,844	10,709,993	1,781,851
345	ACCESSORY ELECTRIC EQUIPMENT	28,440,138	16,413,361	13,422,597	2,990,764
346	MISCELLANEOUS POWER PLANT EQUIPMENT	569,569	403,368	304,135	99,233
	TOTAL MARTIN UNIT 3	*277,334,527*	*82,352,034*	*95,801,712*	*(13,449,678)*
	MARTIN UNIT 4				
341	STRUCTURES AND IMPROVEMENTS	1,498,690	779,399	668,566	110,833
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	178,315	125,767	94,105	31,662
343	PRIME MOVERS - GENERAL	157,866,532	62,665,792	61,237,920	1,427,872
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	100,540,570	14,593,390	14,260,872	332,518
344	GENERATORS	32,812,957	17,243,431	13,769,800	3,473,631
345	ACCESSORY ELECTRIC EQUIPMENT	25,564,311	14,499,926	11,957,393	2,542,533
346	MISCELLANEOUS POWER PLANT EQUIPMENT	826,194	416,190	333,167	83,023
	TOTAL MARTIN UNIT 4	*319,287,568*	*110,323,895*	*102,321,823*	*8,002,072*
	MARTIN UNIT 8				
341	STRUCTURES AND IMPROVEMENTS	23,755,210	8,515,386	6,775,384	1,740,002
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	11,392,824	3,970,615	3,321,100	649,515
343	PRIME MOVERS - GENERAL	256,002,412	48,218,164	63,970,845	(15,752,681)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	213,276,994	24,119,658	31,999,454	(7,879,796)
344	GENERATORS	41,069,900	13,445,958	11,982,297	1,463,661
345	ACCESSORY ELECTRIC EQUIPMENT	51,655,998	17,489,445	15,243,347	2,246,098
346	MISCELLANEOUS POWER PLANT EQUIPMENT	4,899,017	1,751,981	1,359,801	392,180
	TOTAL MARTIN UNIT 8	*602,052,355*	*117,511,209*	*134,652,228*	*(17,141,019)*
TOTAL MARTIN COMBINED CYCLE PLANT		***1,287,356,017***	***365,926,253***	***372,929,171***	***(7,002,918)***

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
SANFORD COMBINED CYCLE PLANT					
	SANFORD COMMON				
341	STRUCTURES AND IMPROVEMENTS	71,585,766	29,616,249	26,805,292	2,810,957
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	88,875	42,745	30,212	12,533
343	PRIME MOVERS - GENERAL	5,932,378	(4,737,256)	1,505,411	(6,242,667)
344	GENERATORS	200,500	36,233	33,682	2,551
345	ACCESSORY ELECTRIC EQUIPMENT	2,142,789	643,155	647,388	(4,233)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	2,233,762	820,161	687,839	132,322
	TOTAL SANFORD COMMON	*82,184,069*	*26,421,287*	*29,709,824*	*(3,288,537)*
	SANFORD UNIT 4				
341	STRUCTURES AND IMPROVEMENTS	7,424,610	3,124,501	3,085,189	39,312
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,803,717	789,469	584,574	204,895
343	PRIME MOVERS - GENERAL	196,875,732	18,672,684	55,094,575	(36,421,891)
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	140,077,308	7,071,393	20,864,456	(13,793,063)
344	GENERATORS	32,820,452	10,272,329	9,720,338	551,991
345	ACCESSORY ELECTRIC EQUIPMENT	35,200,492	14,915,272	12,253,817	2,661,455
346	MISCELLANEOUS POWER PLANT EQUIPMENT	3,326,653	1,415,407	1,131,257	284,150
	TOTAL SANFORD UNIT 4	*417,528,965*	*56,261,055*	*102,734,206*	*(46,473,151)*
	SANFORD UNIT 5				
341	STRUCTURES AND IMPROVEMENTS	7,275,953	3,148,967	3,010,875	138,092
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,814,776	859,918	631,373	228,545
343	PRIME MOVERS - GENERAL	214,894,008	20,990,061	61,244,253	(40,254,192)
343.2	PRIME MOVERS - CAPITALIZED SPARE PARTS	126,367,538	6,255,267	18,251,455	(11,996,188)
344	GENERATORS	32,632,812	11,677,845	10,454,876	1,222,969
345	ACCESSORY ELECTRIC EQUIPMENT	34,685,483	14,818,331	12,467,391	2,350,940
346	MISCELLANEOUS POWER PLANT EQUIPMENT	2,899,894	1,243,698	1,016,194	227,504
	TOTAL SANFORD UNIT 5	*420,570,464*	*58,994,088*	*107,076,417*	*(48,082,329)*
TOTAL SANFORD COMBINED CYCLE PLANT		***920,283,497***	***141,676,429***	***239,520,447***	***(97,844,018)***
TURKEY POINT COMBINED CYCLE PLANT					
	TURKEY POINT UNIT 5				
341	STRUCTURES AND IMPROVEMENTS	32,284,855	10,891,633	7,680,779	3,210,854
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	12,410,131	4,106,992	2,942,223	1,164,769
343	PRIME MOVERS - GENERAL	250,685,264	39,618,917	54,613,714	(14,994,797)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	128,220,285	12,943,274	17,841,988	(4,898,714)
344	GENERATORS	41,669,542	11,132,485	10,041,485	1,091,000
345	ACCESSORY ELECTRIC EQUIPMENT	51,980,475	16,506,639	12,621,247	3,885,392
346	MISCELLANEOUS POWER PLANT EQUIPMENT	12,433,804	3,613,736	3,059,400	554,336
	TOTAL TURKEY POINT UNIT 5	*529,684,355*	*98,813,676*	*108,800,836*	*(9,987,160)*
TOTAL TURKEY POINT COMBINED CYCLE PLANT		***529,684,355***	***98,813,676***	***108,800,836***	***(9,987,160)***

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
WEST COUNTY COMBINED CYCLE PLANT					
	WEST COUNTY COMMON				
341	STRUCTURES AND IMPROVEMENTS	3,120,798	482,630	406,752	75,878
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	450,604	68,020	61,455	6,565
343	PRIME MOVERS - GENERAL	31,206,902	1,389,969	1,678,318	(288,349)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	126,771,982	12,726,022	15,366,036	(2,640,014)
345	ACCESSORY ELECTRIC EQUIPMENT	1,291,342	107,199	108,498	(1,299)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	836,533	111,543	101,460	10,083
	TOTAL WEST COUNTY COMMON	*163,678,161*	*14,885,382*	*17,722,519*	*(2,837,137)*
	WEST COUNTY UNIT 1				
341	STRUCTURES AND IMPROVEMENTS	109,835,744	20,012,782	20,210,641	(197,859)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	21,806,447	2,710,694	3,919,620	(1,208,926)
343	PRIME MOVERS - GENERAL	300,710,821	(22,756,245)	50,044,321	(72,800,566)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	81,954,083	(7,349,277)	16,162,137	(23,511,414)
344	GENERATORS	49,469,105	7,847,276	9,286,257	(1,438,981)
345	ACCESSORY ELECTRIC EQUIPMENT	72,300,016	12,231,627	13,794,840	(1,563,213)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	8,042,081	1,335,110	1,591,865	(256,755)
	TOTAL WEST COUNTY UNIT 1	*644,118,297*	*14,031,966*	*115,009,681*	*(100,977,715)*
	WEST COUNTY UNIT 2				
341	STRUCTURES AND IMPROVEMENTS	39,659,646	6,204,493	7,297,431	(1,092,938)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	7,471,457	284,961	1,255,472	(970,511)
343	PRIME MOVERS - GENERAL	255,637,285	17,744,809	43,270,480	(25,525,671)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	149,878,251	12,481,512	30,436,000	(17,954,488)
344	GENERATORS	43,599,023	6,676,878	8,128,379	(1,451,501)
345	ACCESSORY ELECTRIC EQUIPMENT	33,177,136	5,335,502	6,332,294	(996,792)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	11,893,351	1,719,196	2,122,037	(402,841)
	TOTAL WEST COUNTY UNIT 2	*541,316,149*	*50,447,351*	*98,842,093*	*(48,394,742)*
	WEST COUNTY UNIT 3				
341	STRUCTURES AND IMPROVEMENTS	57,671,242	8,518,122	7,968,373	549,749
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	10,754,858	742,790	1,415,063	(672,273)
343	PRIME MOVERS - GENERAL	480,389,197	32,738,513	62,928,595	(30,190,082)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	98,598,036	8,887,181	17,082,566	(8,195,385)
344	GENERATORS	64,525,280	9,184,372	8,941,870	242,502
345	ACCESSORY ELECTRIC EQUIPMENT	48,252,610	7,322,267	6,918,185	404,082
346	MISCELLANEOUS POWER PLANT EQUIPMENT	12,454,466	7,732,043	1,877,503	5,854,540
	TOTAL WEST COUNTY UNIT 3	*772,645,690*	*75,125,287*	*107,132,155*	*(32,006,868)*
TOTAL WEST COUNTY COMBINED CYCLE PLANT		***2,121,758,297***	***154,489,986***	***338,706,448***	***(184,216,462)***

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
CAPE CANAVERAL COMBINED CYCLE PLANT					
	CAPE CANAVERAL COMBINED CYCLE				
341	STRUCTURES AND IMPROVEMENTS	82,092,869	6,368,724	7,013,007	(644,283)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	47,723,728	3,579,557	4,096,291	(516,734)
343	PRIME MOVERS - GENERAL	385,108,676	38,729,543	32,829,732	5,899,811
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	206,255,249	28,539,906	24,192,319	4,347,587
344	GENERATORS	70,269,257	5,194,564	6,306,711	(1,112,147)
345	ACCESSORY ELECTRIC EQUIPMENT	111,693,785	8,403,920	10,028,749	(1,624,829)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	10,309,493	738,999	996,517	(257,518)
	TOTAL CAPE CANAVERAL COMBINED CYCLE	*913,453,057*	*91,555,214*	*85,463,326*	*6,091,888*
TOTAL CAPE CANAVERAL COMBINED CYCLE PLANT		***913,453,057***	***91,555,214***	***85,463,326***	***6,091,888***
RIVIERA COMBINED CYCLE PLANT					
	RIVIERA COMBINED CYCLE				
341	STRUCTURES AND IMPROVEMENTS	80,630,958	7,456,698	5,474,267	1,982,431
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	217,306,004	18,577,338	13,486,347	5,090,991
343	PRIME MOVERS - GENERAL	525,780,412	35,938,896	31,729,157	4,209,739
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	139,494,633	16,409,879	14,487,691	1,922,188
344	GENERATORS	79,977,232	5,875,063	5,110,934	764,129
345	ACCESSORY ELECTRIC EQUIPMENT	82,800,568	6,849,745	5,547,650	1,302,095
346	MISCELLANEOUS POWER PLANT EQUIPMENT	11,446,561	1,663,361	792,903	870,458
	TOTAL RIVIERA COMBINED CYCLE	*1,137,436,368*	*92,770,979*	*76,628,949*	*16,142,030*
TOTAL RIVIERA COMBINED CYCLE PLANT		***1,137,436,368***	***92,770,979***	***76,628,949***	***16,142,030***
PT EVERGLADES COMBINED CYCLE PLANT					
	PT EVERGLADES COMBINED CYCLE				
341	STRUCTURES AND IMPROVEMENTS	101,607,532	2,299,667	1,310,895	988,772
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	59,665,117	1,350,391	767,574	582,817
343	PRIME MOVERS - GENERAL	499,500,579	8,382,316	6,228,069	2,154,247
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	191,363,196	7,253,893	5,389,650	1,864,243
344	GENERATORS	87,208,139	1,973,768	1,132,685	841,083
345	ACCESSORY ELECTRIC EQUIPMENT	138,483,956	3,134,285	1,834,885	1,299,400
346	MISCELLANEOUS POWER PLANT EQUIPMENT	12,795,087	289,589	181,539	108,050
	TOTAL PT EVERGLADES COMBINED CYCLE	*1,090,623,606*	*24,683,910*	*16,845,297*	*7,838,613*
TOTAL PT EVERGLADES COMBINED CYCLE PLANT		***1,090,623,606***	***24,683,910***	***16,845,297***	***7,838,613***
TOTAL COMBINED CYCLE PRODUCTION PLANT		**10,277,035,554**	**1,537,827,272**	**1,833,775,170**	**(295,947,898)**

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
PEAKER PLANTS					
	LAUDERDALE GTS				
341	STRUCTURES AND IMPROVEMENTS	601,222	330,322	382,344	(52,022)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	194,417	102,093	123,397	(21,304)
343	PRIME MOVERS - GENERAL	14,841,925	1,714,581	1,889,396	(174,815)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	1,858,779	673,466	742,131	(68,665)
344	GENERATORS	1,748,135	750,005	1,341,541	(591,536)
345	ACCESSORY ELECTRIC EQUIPMENT	420,107	174,657	310,276	(135,619)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	20,935	8,570	16,355	(7,785)
	TOTAL LAUDERDALE GTS	*19,685,520*	*3,753,692*	*4,805,440*	*(1,051,748)*
	FT. MYERS GTS				
341	STRUCTURES AND IMPROVEMENTS	941,093	168,137	295,660	(127,523)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	724,318	117,795	225,606	(107,811)
343	PRIME MOVERS - GENERAL	10,218,903	1,207,170	1,358,142	(150,972)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	2,807,095	1,254,825	1,411,757	(156,932)
344	GENERATORS	4,602,022	551,085	1,475,161	(924,076)
345	ACCESSORY ELECTRIC EQUIPMENT	3,450,438	485,852	852,300	(366,448)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	20,936	2,632	7,158	(4,526)
	TOTAL FT. MYERS GTS	*22,764,804*	*3,787,495*	*5,625,784*	*(1,838,289)*
	LAUDERDALE AND FT. MYERS PEAKERS				
341	STRUCTURES AND IMPROVEMENTS	43,805,886	76,824	548,248	(471,424)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	26,150,085	45,861	336,413	(290,552)
343	PRIME MOVERS - GENERAL	213,843,171	389,972	2,634,291	(2,244,319)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	83,870,827	132,142	892,629	(760,487)
344	GENERATORS	38,221,667	67,031	496,434	(429,403)
345	ACCESSORY ELECTRIC EQUIPMENT	60,694,881	106,443	804,195	(697,752)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	5,607,843	9,835	79,565	(69,730)
	TOTAL LAUDERDALE AND FT. MYERS PEAKERS	*472,194,358*	*828,108*	*5,791,775*	*(4,963,667)*
TOTAL PEAKER PLANTS		**514,644,682**	**8,369,296**	**16,222,999**	**(7,853,703)**

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

	ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
SOLAR PRODUCTION PLANT				
DESOTO SOLAR				
341 STRUCTURES AND IMPROVEMENTS	4,635,209	990,040	1,083,432	(93,392)
343 PRIME MOVERS - GENERAL	118,689,127	28,800,157	28,981,407	(181,250)
345 ACCESSORY ELECTRIC EQUIPMENT	27,532,945	4,878,293	6,672,208	(1,793,915)
TOTAL DESOTOSOLAR	*150,857,280*	*34,668,490*	*36,737,047*	*(2,068,557)*
SPACE COAST SOLAR				
341 STRUCTURES AND IMPROVEMENTS	3,986,978	748,519	847,026	(98,507)
343 PRIME MOVERS - GENERAL	52,858,699	11,827,508	11,229,727	597,781
345 ACCESSORY ELECTRIC EQUIPMENT	6,281,496	1,091,797	1,334,492	(242,695)
TOTAL SPACE COAST SOLAR	*63,127,172*	*13,667,824*	*13,411,245*	*256,579*
MARTIN SOLAR				
341 STRUCTURES AND IMPROVEMENTS	21,320,036	3,172,447	3,762,432	(589,985)
343 PRIME MOVERS - GENERAL	405,752,300	73,095,004	71,714,409	1,380,595
345 ACCESSORY ELECTRIC EQUIPMENT	4,239,215	633,733	765,617	(131,884)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,335	257	242	15
TOTAL MARTIN SOLAR	*431,312,886*	*76,901,441*	*76,242,700*	*658,741*
BABCOCK RANCH SOLAR				
341 STRUCTURES AND IMPROVEMENTS	4,078,184	18,086	67,983	(49,897)
343 PRIME MOVERS - GENERAL	104,118,206	461,738	1,735,650	(1,273,912)
345 ACCESSORY ELECTRIC EQUIPMENT	24,224,241	107,428	403,818	(296,390)
TOTAL BABCOCK RANCH SOLAR	*132,420,631*	*587,252*	*2,207,451*	*(1,620,199)*
MANATEE SOLAR				
341 STRUCTURES AND IMPROVEMENTS	4,118,679	7,223	68,658	(61,435)
343 PRIME MOVERS - GENERAL	105,224,179	184,536	1,754,087	(1,569,551)
345 ACCESSORY ELECTRIC EQUIPMENT	24,464,781	42,905	407,828	(364,923)
TOTAL MANATEE SOLAR	*133,807,639*	*234,664*	*2,230,573*	*(1,995,909)*
CITRUS SOLAR				
341 STRUCTURES AND IMPROVEMENTS	4,207,181	18,559	70,134	(51,575)
343 PRIME MOVERS - GENERAL	107,250,213	473,102	1,787,861	(1,314,759)
345 ACCESSORY ELECTRIC EQUIPMENT	24,990,480	110,238	416,591	(306,353)
TOTAL CITRUS SOLAR	*136,447,874*	*601,899*	*2,274,586*	*(1,672,687)*
TOTAL SOLAR PRODUCTION PLANT	**1,047,973,483**	**126,661,571**	**133,103,602**	**(6,442,031)**
TOTAL PRODUCTION PLANT	**22,795,357,882**	**5,541,188,910**	**6,081,542,211**	**(540,353,301)**

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
TRANSMISSION, DISTRIBUTION, AND GENERAL PLANT					
	TRANSMISSION PLANT				
350.2	EASEMENTS	240,510,767	80,181,515	70,338,849	9,842,666
352	STRUCTURES AND IMPROVEMENTS	154,719,740	40,213,775	34,271,162	5,942,613
353	STATION EQUIPMENT	1,741,377,472	504,497,585	403,916,862	100,580,723
353.1	STATION EQUIPMENT - STEP-UP TRANSFORMERS	400,209,880	67,360,985	84,475,813	(17,114,828)
354	TOWERS AND FIXTURES	349,056,185	225,421,515	174,893,168	50,528,347
355	POLES AND FIXTURES	1,242,636,001	420,741,337	377,201,142	43,540,195
356	OVERHEAD CONDUCTORS AND DEVICES	854,174,816	364,102,828	296,136,869	67,965,959
357	UNDERGROUND CONDUIT	75,512,192	26,533,422	22,845,111	3,688,311
358	UNDERGROUND CONDUCTORS AND DEVICES	104,576,520	29,275,918	30,276,369	(1,000,451)
359	ROADS AND TRAILS	113,485,941	42,504,639	34,294,521	8,210,118
	TOTAL TRANSMISSION PLANT	**5,276,259,513**	**1,800,833,520**	**1,528,649,866**	**272,183,654**
	DISTRIBUTION PLANT				
361	STRUCTURES AND IMPROVEMENTS	198,554,703	55,416,150	53,060,060	2,356,090
362	STATION EQUIPMENT	1,740,028,154	531,280,566	483,537,213	47,743,353
364.1	POLES, TOWERS AND FIXTURES - WOOD	1,083,692,909	481,024,953	601,487,567	(120,462,614)
364.2	POLES, TOWERS AND FIXTURES - CONCRETE	706,877,719	98,411,503	123,056,600	(24,645,097)
365	OVERHEAD CONDUCTORS AND DEVICES	1,991,793,394	740,342,106	684,391,577	55,950,529
366.6	UNDERGROUND CONDUIT - DUCT SYSTEM	1,528,850,821	345,598,141	335,367,143	10,230,998
366.7	UNDERGROUND CONDUIT - DIRECT BURIED	193,885,661	26,860,958	26,987,876	(126,918)
367.6	UNDERGROUND CONDUCTORS AND DEVICES - DUCT SYSTEM	1,723,803,662	475,313,897	437,155,963	38,157,934
367.7	UNDERGROUND CONDUCTORS AND DEVICES - DIRECT BURIED	731,720,379	288,138,701	249,066,376	39,072,325
368	LINE TRANSFORMERS	2,172,571,477	977,456,673	774,017,804	203,438,869
369.1	SERVICES - OVERHEAD	429,359,956	121,671,610	129,524,820	(7,853,210)
369.6	SERVICES - UNDERGROUND	818,122,343	316,173,519	277,745,936	38,427,583
370	METERS	90,547,258	64,524,789	64,524,789	-
370.1	METERS - AMI	752,056,781	195,134,861	215,044,621	(19,909,760)
371	INSTALLATIONS ON CUSTOMER'S PREMISES	77,912,064	32,661,220	24,048,937	8,612,283
373	STREET LIGHTING AND SIGNAL SYSTEMS	463,393,095	175,429,642	116,183,611	59,246,031
	TOTAL DISTRIBUTION PLANT	**14,703,170,376**	**4,925,439,290**	**4,595,200,893**	**330,238,397**

FLORIDA POWER AND LIGHT COMPANY

TABLE 5. COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE FOR ELECTRIC PLANT AS OF DECEMBER 31, 2016

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	THEORETICAL RESERVE IMBALANCE (4) = (2) - (3)
	GENERAL PLANT				
390	STRUCTURES AND IMPROVEMENTS	435,222,597	123,109,607	120,539,875	2,569,732
392.1	AUTOMOBILES	9,038,959	1,913,929	2,480,372	(566,443)
392.2	LIGHT TRUCKS	47,500,083	12,551,216	14,073,348	(1,522,132)
392.3	HEAVY TRUCKS	241,647,650	99,939,976	84,279,588	15,660,388
392.4	TRACTOR TRAILERS	767,855	638,910	389,251	249,659
392.9	TRAILERS	21,065,643	2,761,578	4,998,653	(2,237,075)
396.1	POWER OPERATED EQUIPMENT	4,766,126	2,061,673	1,869,508	192,165
397.8	COMMUNICATION EQUIPMENT - FIBER OPTICS	11,992,500	9,422,442	5,389,473	4,032,969
	TOTAL GENERAL PLANT	**772,001,412**	**252,399,331**	**234,020,068**	**18,379,263**
TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT		**20,751,431,301**	**6,978,672,141**	**6,357,870,827**	**620,801,314**
GRAND TOTAL		**43,546,789,183**	**12,519,861,051**	**12,439,413,038**	**80,448,013**

FLORIDA POWER AND LIGHT COMPANY

TABLE 6. COMPARISON OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, AVERAGE AGES, AVERAGE REMAINING LIVES AND ANNUAL DEPRECIATION RATES BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

	ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009						PROPOSED COMPONENTS AS OF DECEMBER 31, 2016					
	PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (2)	NET SALVAGE (3)	AVERAGE AGE (4)	AVERAGE REMAINING LIFE (5)	ANNUAL DEPRECIATION RATE (6)	PROBABLE RETIREMENT DATE (7)	SURVIVOR CURVE (8)	NET SALVAGE (9)	AVERAGE AGE (10)	AVERAGE REMAINING LIFE (11)	ANNUAL DEPRECIATION RATE (12)
STEAM PRODUCTION PLANT												
MANATEE STEAM PLANT												
MANATEE COMMON												
311 STRUCTURES AND IMPROVEMENTS	06-2027	0.0032	(1)	23.9	17.0	2.1	06-2028	80 - R2 *	(1)	26.3	11.28	3.17
312 BOILER PLANT EQUIPMENT	06-2027	0.0094	(2)	21.5	16.1	2.6	06-2028	50 - S0 *	(2)	8.2	11.13	7.62
314 TURBOGENERATOR UNITS	06-2027	0.0120	0	21.5	15.7	2.6	06-2028	55 - R0.5 *	(1)	30.8	10.74	2.02
315 ACCESSORY ELECTRIC EQUIPMENT	06-2027	0.0052	(5)	29.0	16.7	2.4	06-2028	65 - S0 *	(2)	34.3	10.86	2.34
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2027	0.0071	(1)	22.5	16.4	2.4	06-2028	65 - R0.5 *	(1)	29.6	10.92	2.08
MANATEE UNIT 1												
311 STRUCTURES AND IMPROVEMENTS	06-2027	0.0032	(1)	29.5	17.0	2.1	06-2028	80 - R2 *	(1)	38.6	11.12	1.74
312 BOILER PLANT EQUIPMENT	06-2027	0.0094	(2)	19.7	16.1	2.6	06-2028	50 - S0 *	(2)	18.6	10.89	4.64
314 TURBOGENERATOR UNITS	06-2027	0.0120	0	18.6	15.7	2.6	06-2028	55 - R0.5 *	(1)	20.9	10.86	4.03
315 ACCESSORY ELECTRIC EQUIPMENT	06-2027	0.0052	(5)	19.7	16.7	2.4	06-2028	65 - S0 *	(2)	19.2	11.12	4.11
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2027	0.0071	(1)	28.2	16.4	2.4	06-2028	65 - R0.5 *	(1)	27.7	10.97	3.91
MANATEE UNIT 2												
311 STRUCTURES AND IMPROVEMENTS	06-2027	0.0032	(1)	28.8	17.0	2.1	06-2028	80 - R2 *	(1)	37.4	11.15	1.83
312 BOILER PLANT EQUIPMENT	06-2027	0.0094	(2)	17.5	16.1	2.6	06-2028	50 - S0 *	(2)	16.3	10.92	4.99
314 TURBOGENERATOR UNITS	06-2027	0.0120	0	19.7	15.7	2.6	06-2028	55 - R0.5 *	(1)	22.4	10.85	3.72
315 ACCESSORY ELECTRIC EQUIPMENT	06-2027	0.0052	(5)	15.4	16.7	2.4	06-2028	65 - S0 *	(2)	15.5	11.14	4.48
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2027	0.0071	(1)	27.1	16.4	2.4	06-2028	65 - R0.5 *	(1)	22.8	10.99	4.79
MARTIN STEAM PLANT												
MARTIN COMMON												
311 STRUCTURES AND IMPROVEMENTS	06-2031	0.0032	(1)	26.5	21	2.1	06-2031	80 - R2 *	(1)	31.9	14.04	2.52
312 BOILER PLANT EQUIPMENT	06-2031	0.0094	(5)	20.5	19.4	2.6	06-2031	50 - S0 *	(2)	16.6	13.57	4.45
314 TURBOGENERATOR UNITS	06-2031	0.0120	0	17.6	18.8	2.6	06-2031	55 - R0.5 *	(1)	22.6	13.43	3.48
315 ACCESSORY ELECTRIC EQUIPMENT	06-2031	0.0052	(5)	24.0	20	2.4	06-2031	65 - S0 *	(2)	23.1	13.78	3.57
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2031	0.0071	0	23.2	19.9	2.4	06-2031	65 - R0.5 *	(1)	22.5	13.67	3.79
MARTIN PIPELINE												
312 BOILER PLANT EQUIPMENT	06-2031	0.0094	(5)	16.5	19.4	2.6	06-2031	50 - S0 *	0	23.5	13.04	0.00
MARTIN UNIT 1												
311 STRUCTURES AND IMPROVEMENTS	06-2031	0.0032	(1)	28.0	21	2.1	06-2031	80 - R2 *	(1)	32.4	14.03	2.68
312 BOILER PLANT EQUIPMENT	06-2031	0.0094	(5)	25.1	19.4	2.6	06-2031	50 - S0 *	(2)	20.1	13.44	4.53
314 TURBOGENERATOR UNITS	06-2031	0.0120	0	20.1	18.8	2.6	06-2031	55 - R0.5 *	(1)	22.0	13.44	3.35
315 ACCESSORY ELECTRIC EQUIPMENT	06-2031	0.0052	(5)	23.7	20	2.4	06-2031	65 - S0 *	(2)	24.9	13.72	3.12
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2031	0.0071	0	25.2	19.9	2.4	06-2031	65 - R0.5 *	(1)	23.3	13.67	3.81
MARTIN UNIT 2												
311 STRUCTURES AND IMPROVEMENTS	06-2031	0.0032	(1)	27.2	21	2.1	06-2031	80 - R2 *	(1)	33.5	13.98	2.39
312 BOILER PLANT EQUIPMENT	06-2031	0.0094	(5)	23.1	19.4	2.6	06-2031	50 - S0 *	(2)	19.0	13.48	4.64
314 TURBOGENERATOR UNITS	06-2031	0.0120	0	20.5	18.8	2.6	06-2031	55 - R0.5 *	(1)	18.7	13.52	4.79
315 ACCESSORY ELECTRIC EQUIPMENT	06-2031	0.0052	(5)	19.2	20	2.4	06-2031	65 - S0 *	(2)	19.8	13.83	3.56
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2031	0.0071	0	25.1	19.9	2.4	06-2031	65 - R0.5 *	(1)	21.5	13.71	4.31

FLORIDA POWER AND LIGHT COMPANY

TABLE 6. COMPARISON OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, AVERAGE AGES, AVERAGE REMAINING LIVES AND ANNUAL DEPRECIATION RATES BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

	ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009						PROPOSED COMPONENTS AS OF DECEMBER 31, 2016					
	PROBABLE RETIREMENT DATE	SURVIVOR CURVE/ INTERIM RETIREMENT RATE	NET SALVAGE	AVERAGE AGE	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION RATE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	AVERAGE AGE	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
SCHERER STEAM PLANT												
SCHERER COAL CARS												
312 BOILER PLANT EQUIPMENT	06-2039	0.0094	(5)	12.0	26	2.6	06-2039	50 - S0 *	0	19.2	19.25	0.00
SCHERER COMMON												
311 STRUCTURES AND IMPROVEMENTS	06-2039	0.0032	(1)	14.9	28	2.1	06-2039	80 - R2 *	(1)	21.2	21.60	2.24
312 BOILER PLANT EQUIPMENT	06-2039	0.0094	(5)	14.4	26	2.6	06-2039	50 - S0 *	(4)	19.2	19.34	2.96
314 TURBOGENERATOR UNITS	06-2039	0.0120	0	16.0	25	2.6	06-2039	55 - R0.5 *	(1)	20.6	19.91	2.95
315 ACCESSORY ELECTRIC EQUIPMENT	06-2039	0.0052	(4)	15.9	27	2.4	06-2039	65 - S0 *	(4)	22.7	20.22	2.40
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2039	0.0071	(1)	15.0	27	2.4	06-2039	65 - R0.5 *	(1)	20.1	20.49	2.62
SCHERER COMMON UNIT 3 AND 4												
311 STRUCTURES AND IMPROVEMENTS	06-2039	0.0032	(1)	16.0	28	2.2	06-2039	80 - R2 *	(1)	22.6	21.56	2.14
312 BOILER PLANT EQUIPMENT	06-2039	0.0094	(5)	14.6	26	2.7	06-2039	50 - S0 *	(4)	17.5	19.59	3.11
314 TURBOGENERATOR UNITS	06-2039	0.0120	0	16.0	25	2.6	06-2039	55 - R0.5 *	(1)	3.7	20.55	4.53
315 ACCESSORY ELECTRIC EQUIPMENT	06-2039	0.0052	(4)	14.7	27	2.4	06-2039	65 - S0 *	(4)	3.6	21.48	4.44
SCHERER UNIT 4												
311 STRUCTURES AND IMPROVEMENTS	06-2039	0.0032	(1)	15.8	28	2.1	06-2039	80 - R2 *	(1)	11.6	21.89	3.48
312 BOILER PLANT EQUIPMENT	06-2039	0.0094	(5)	15.0	26	2.6	06-2039	50 - S0 *	(4)	11.7	20.16	3.84
314 TURBOGENERATOR UNITS	06-2039	0.0120	0	15.7	25	2.6	06-2039	55 - R0.5 *	(1)	21.4	19.88	2.68
315 ACCESSORY ELECTRIC EQUIPMENT	06-2039	0.0052	(4)	15.6	27	2.4	06-2039	65 - S0 *	(4)	12.7	20.96	3.60
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2039	0.0071	(1)	12.7	27	2.4	06-2039	65 - R0.5 *	(1)	16.1	20.62	2.74
SJRPP STEAM PLANT												
SJRPP COAL AND LIMESTONE												
311 STRUCTURES AND IMPROVEMENTS	06-2038	0.0032	(1)	20.2	28	2.1	06-2038	80 - R2 *	(1)	27.0	20.48	2.44
312 BOILER PLANT EQUIPMENT	06-2038	0.0094	(5)	19.8	26	2.6	06-2038	50 - S0 *	(4)	26.2	18.00	3.03
315 ACCESSORY ELECTRIC EQUIPMENT	06-2038	0.0052	(4)	20.6	27	2.4	06-2038	65 - S0 *	(4)	27.6	19.17	2.46
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	0.0071	(1)	21.6	27	2.4	06-2038	65 - R0.5 *	(1)	29.1	19.33	2.44
SJRPP COAL CARS												
312 BOILER PLANT EQUIPMENT	06-2038	0.0094	(5)	15.0	26	2.6	06-2038	50 - S0 *	0	26.6	17.84	0.00
SJRPP COMMON												
311 STRUCTURES AND IMPROVEMENTS	06-2038	0.0032	(1)	15.4	27	2.1	06-2038	80 - R2 *	(1)	26.3	20.54	1.66
312 BOILER PLANT EQUIPMENT	06-2038	0.0094	(5)	13.5	25	2.6	06-2038	50 - S0 *	(4)	24.2	18.22	1.90
314 TURBOGENERATOR UNITS	06-2038	0.0120	0	15.7	24	2.6	06-2038	55 - R0.5 *	(1)	28.3	18.75	1.79
315 ACCESSORY ELECTRIC EQUIPMENT	06-2038	0.0052	(4)	15.9	26	2.4	06-2038	65 - S0 *	(4)	27.0	19.27	1.85
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	0.0071	(1)	13.9	26	2.4	06-2038	65 - R0.5 *	(1)	24.6	19.52	1.95
SJRPP GYPSUM AND ASH												
311 STRUCTURES AND IMPROVEMENTS	06-2038	0.0032	(1)	21.0	27	2.1	06-2038	80 - R2 *	(1)	26.2	20.54	2.40
312 BOILER PLANT EQUIPMENT	06-2038	0.0094	(5)	20.0	25	2.6	06-2038	50 - S0 *	(4)	27.0	17.87	2.71
315 ACCESSORY ELECTRIC EQUIPMENT	06-2038	0.0052	(4)	16.0	26	2.4	06-2038	65 - S0 *	(4)	23.3	19.35	2.26
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	0.0071	(1)	21.5	26	2.4	06-2038	65 - R0.5 *	(1)	21.3	19.65	3.02
SJRPP UNIT 1												
311 STRUCTURES AND IMPROVEMENTS	06-2038	0.0032	(1)	16.0	27	2.1	06-2038	80 - R2 *	(1)	28.6	20.45	1.43
312 BOILER PLANT EQUIPMENT	06-2038	0.0094	(5)	15.0	25	2.6	06-2038	50 - S0 *	(4)	21.2	18.54	2.90
314 TURBOGENERATOR UNITS	06-2038	0.0120	0	14.4	24	2.6	06-2038	55 - R0.5 *	(1)	20.1	19.20	2.73
315 ACCESSORY ELECTRIC EQUIPMENT	06-2038	0.0052	(4)	15.7	26	2.4	06-2038	65 - S0 *	(4)	25.7	19.36	2.10
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	0.0071	(1)	15.2	26	2.4	06-2038	65 - R0.5 *	(1)	27.5	19.40	1.69
SJRPP UNIT 2												
311 STRUCTURES AND IMPROVEMENTS	06-2038	0.0032	(1)	20.7	27	2.1	06-2038	80 - R2 *	(1)	28.2	20.43	2.14
312 BOILER PLANT EQUIPMENT	06-2038	0.0094	(5)	19.2	25	2.6	06-2038	50 - S0 *	(4)	20.6	18.56	3.24
314 TURBOGENERATOR UNITS	06-2038	0.0120	0	18.0	24	2.6	06-2038	55 - R0.5 *	(1)	19.4	19.21	3.30
315 ACCESSORY ELECTRIC EQUIPMENT	06-2038	0.0052	(4)	20.4	26	2.4	06-2038	65 - S0 *	(4)	25.8	19.27	2.67
316 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2038	0.0071	(1)	19.6	26	2.4	06-2038	65 - R0.5 *	(1)	27.2	19.45	2.35

FLORIDA POWER AND LIGHT COMPANY

TABLE 6. COMPARISON OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, AVERAGE AGES, AVERAGE REMAINING LIVES AND ANNUAL DEPRECIATION RATES BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

	ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009						PROPOSED COMPONENTS AS OF DECEMBER 31, 2016					
	PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (2)	NET SALVAGE (3)	AVERAGE AGE (4)	AVERAGE REMAINING LIFE (5)	ANNUAL DEPRECIATION RATE (6)	PROBABLE RETIREMENT DATE (7)	SURVIVOR CURVE (8)	NET SALVAGE (9)	AVERAGE AGE (10)	AVERAGE REMAINING LIFE (11)	ANNUAL DEPRECIATION RATE (12)
NUCLEAR PRODUCTION PLANT												
ST. LUCIE NUCLEAR PLANT												
ST. LUCIE COMMON												
321 STRUCTURES AND IMPROVEMENTS	06-2043	0.0028	0	20.8	32	1.8	04-2043	100 - R1.5 *	(1)	25.9	25.17	2.25
322 REACTOR PLANT EQUIPMENT	06-2043	0.0056	(2)	11.0	30	2.0	04-2043	60 - R1 *	(2)	17.5	23.69	1.92
323 TURBOGENERATOR UNITS	06-2043	0.0138	0	20.4	27	2.4	04-2043	45 - R0.5 *	0	12.1	22.26	7.22
324 ACCESSORY ELECTRIC EQUIPMENT	06-2043	0.0012	(2)	20.3	33	1.8	04-2043	75 - R2.5 *	(1)	26.4	24.78	2.09
325 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	0.0032	0	19.5	32	1.8	04-2043	50 - R1.5 *	(3)	18.4	22.70	4.06
ST. LUCIE UNIT 1												
321 STRUCTURES AND IMPROVEMENTS	06-2036	0.0028	0	25.4	26	1.8	03-2036	100 - R1.5 *	(1)	27.1	18.67	2.66
322 REACTOR PLANT EQUIPMENT	06-2036	0.0056	(2)	16.6	25	2.0	03-2036	60 - R1 *	(2)	14.9	18.00	3.72
323 TURBOGENERATOR UNITS	06-2036	0.0138	0	25.0	22	2.4	03-2036	45 - R0.5 *	0	8.0	17.31	5.11
324 ACCESSORY ELECTRIC EQUIPMENT	06-2036	0.0012	(2)	24.3	26	1.8	03-2036	75 - R2.5 *	(1)	21.6	18.68	3.20
325 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2036	0.0032	0	29.0	25	1.8	03-2036	50 - R1.5 *	(3)	33.9	15.87	2.59
ST. LUCIE UNIT 2												
321 STRUCTURES AND IMPROVEMENTS	06-2043	0.0028	0	24.9	32	1.8	04-2043	100 - R1.5 *	(1)	27.0	25.16	2.27
322 REACTOR PLANT EQUIPMENT	06-2043	0.0056	(2)	17.7	30	2.0	04-2043	60 - R1 *	(2)	17.2	23.70	2.75
323 TURBOGENERATOR UNITS	06-2043	0.0138	0	24.4	27	2.4	04-2043	45 - R0.5 *	0	10.1	22.42	3.86
324 ACCESSORY ELECTRIC EQUIPMENT	06-2043	0.0012	(2)	24.7	33	1.8	04-2043	75 - R2.5 *	(1)	27.7	24.68	2.27
325 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	0.0032	0	25.9	32	1.8	04-2043	50 - R1.5 *	(3)	29.2	20.78	2.73
TURKEY POINT NUCLEAR PLANT												
TURKEY POINT COMMON												
321 STRUCTURES AND IMPROVEMENTS	06-2033	0.0028	0	17.4	23	1.8	04-2033	100 - R1.5 *	(1)	19.1	15.98	3.13
322 REACTOR PLANT EQUIPMENT	06-2033	0.0056	(2)	16.3	22	2.0	04-2033	60 - R1 *	(2)	8.4	15.58	5.43
323 TURBOGENERATOR UNITS	06-2033	0.0138	0	6.2	19.9	2.4	04-2033	45 - R0.5 *	0	9.8	14.91	5.05
324 ACCESSORY ELECTRIC EQUIPMENT	06-2033	0.0012	(2)	16.7	23	1.8	04-2033	75 - R2.5 *	(1)	21.0	15.97	2.36
325 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	0.0032	0	15.4	23	1.8	04-2033	50 - R1.5 *	(3)	15.5	15.30	3.67
TURKEY POINT UNIT 3												
321 STRUCTURES AND IMPROVEMENTS	06-2032	0.0028	0	19.2	23	1.8	07-2032	100 - R1.5 *	(1)	10.2	15.31	5.23
322 REACTOR PLANT EQUIPMENT	06-2032	0.0056	(2)	16.7	22	2.0	07-2032	60 - R1 *	(2)	12.6	14.82	4.94
323 TURBOGENERATOR UNITS	06-2032	0.0138	0	23.5	19.9	2.4	07-2032	45 - R0.5 *	0	5.7	14.39	6.20
324 ACCESSORY ELECTRIC EQUIPMENT	06-2032	0.0012	(2)	22.3	23	1.8	07-2032	75 - R2.5 *	(1)	19.9	15.28	3.46
325 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2032	0.0032	0	26.7	23	1.8	07-2032	50 - R1.5 *	(3)	8.4	14.84	6.62
TURKEY POINT UNIT 4												
321 STRUCTURES AND IMPROVEMENTS	06-2033	0.0028	0	15.9	23	1.8	04-2033	100 - R1.5 *	(1)	15.3	16.01	3.90
322 REACTOR PLANT EQUIPMENT	06-2033	0.0056	(2)	16.3	22	2.0	04-2033	60 - R1 *	(2)	13.3	15.49	4.28
323 TURBOGENERATOR UNITS	06-2033	0.0138	0	20.5	19.9	2.4	04-2033	45 - R0.5 *	0	6.1	15.02	5.78
324 ACCESSORY ELECTRIC EQUIPMENT	06-2033	0.0012	(2)	19.9	23	1.8	04-2033	75 - R2.5 *	(1)	22.3	15.93	2.62
325 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	0.0032	0	22.6	23	1.8	04-2033	50 - R1.5 *	(3)	10.2	15.48	6.55

FLORIDA POWER AND LIGHT COMPANY

TABLE 6. COMPARISON OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, AVERAGE AGES, AVERAGE REMAINING LIVES AND ANNUAL DEPRECIATION RATES BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

	ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009						PROPOSED COMPONENTS AS OF DECEMBER 31, 2016					
	PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (2)	NET SALVAGE (3)	AVERAGE AGE (4)	AVERAGE REMAINING LIFE (5)	ANNUAL DEPRECIATION RATE (6)	PROBABLE RETIREMENT DATE (7)	SURVIVOR CURVE (8)	NET SALVAGE (9)	AVERAGE AGE (10)	AVERAGE REMAINING LIFE (11)	ANNUAL DEPRECIATION RATE (12)
COMBINED CYCLE PRODUCTION PLANT												
LAUDERDALE COMBINED CYCLE PLANT												
LAUDERDALE COMMON												
341 STRUCTURES AND IMPROVEMENTS	06-2023	0.0023	(2)	15.8	13.3	3.5	06-2033	80 - R2 *	(2)	19.8	16.08	2.20
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2023	0.0095	0	15.6	12.6	3.8	06-2033	50 - R1.5 *	(3)	18.0	15.29	3.09
343 PRIME MOVERS - GENERAL	06-2023	0.0057	0	3.3	8.9 **	6.0	06-2033	50 - R1 *	(3)	3.7	15.62	5.20
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2023	0.1565	0	2.5	8.9 **	6.0	06-2033	9 - L0 *	35	3.1	7.11	6.42
344 GENERATORS	06-2023	0.0016	(1)	16.7	13.3	3.4	06-2033	60 - R2 *	(3)	15.5	15.89	2.73
345 ACCESSORY ELECTRIC EQUIPMENT	06-2023	0.0013	(1)	16.1	13.4	3.4	06-2033	50 - R2.5 *	(2)	22.5	15.25	1.60
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2023	0.0026	0	13.0	13.2	3.4	06-2033	50 - S0.5 *	(2)	14.7	15.38	3.42
LAUDERDALE UNIT 4												
341 STRUCTURES AND IMPROVEMENTS	06-2023	0.0023	(2)	16.0	13.3	3.5	06-2033	80 - R2 *	(2)	20.4	16.07	2.09
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2023	0.0095	0	13.2	12.6	3.8	06-2033	50 - R1.5 *	(3)	19.7	15.20	1.78
343 PRIME MOVERS - GENERAL	06-2023	0.0057	0	12.9	11.2 **	4.3	06-2033	50 - R1 *	(3)	18.5	15.16	4.11
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2023	0.1565	0	4.9	11.2 **	4.3	06-2033	9 - L0 *	35	4.3	6.74	7.66
344 GENERATORS	06-2023	0.0016	(1)	15.4	13.3	3.4	06-2033	60 - R2 *	(3)	21.0	15.69	2.02
345 ACCESSORY ELECTRIC EQUIPMENT	06-2023	0.0013	(1)	15.9	13.4	3.4	06-2033	50 - R2.5 *	(2)	20.0	15.43	2.43
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2023	0.0026	0	14.8	13.2	3.4	06-2033	50 - S0.5 *	(2)	20.8	14.87	1.94
LAUDERDALE UNIT 5												
341 STRUCTURES AND IMPROVEMENTS	06-2023	0.0023	(2)	16.0	13.3	3.5	06-2033	80 - R2 *	(2)	18.4	16.11	2.55
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2023	0.0095	0	12.2	12.6	3.8	06-2033	50 - R1.5 *	(3)	16.9	15.38	2.28
343 PRIME MOVERS - GENERAL	06-2023	0.0057	0	13.3	11.5 **	4.2	06-2033	50 - R1 *	(3)	17.9	15.19	5.00
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2023	0.1565	0	4.8	11.5 **	4.2	06-2033	9 - L0 *	35	3.2	7.21	8.06
344 GENERATORS	06-2023	0.0016	(1)	14.6	13.3	3.4	06-2033	60 - R2 *	(3)	19.4	15.76	2.03
345 ACCESSORY ELECTRIC EQUIPMENT	06-2023	0.0013	(1)	16.0	13.4	3.4	06-2033	50 - R2.5 *	(2)	19.1	15.51	2.58
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2023	0.0026	0	15.2	13.2	3.4	06-2033	50 - S0.5 *	(2)	20.6	14.89	2.08
FT. MYERS COMBINED CYCLE PLANT												
FT. MYERS COMMON												
341 STRUCTURES AND IMPROVEMENTS	06-2033	0.0023	(2)	26.8	23	3.5	06-2043	80 - R2 *	(2)	23.8	25.06	3.11
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2033	0.0095	0	41.8	21	3.8	06-2043	50 - R1.5 *	(3)	48.4	15.56	4.32
343 PRIME MOVERS - GENERAL	06-2033	0.0057	0	1.5	13.9 **	5.8	06-2043	50 - R1 *	(3)	4.4	23.96	3.12
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2033	0.1565	0	1.5	13.9 **	5.8	06-2043	9 - L0 *	35	6.9	5.82	2.17
344 GENERATORS	06-2033	0.0016	(1)	20.7	23	3.4	06-2043	60 - R2 *	(3)	3.2	25.42	3.77
345 ACCESSORY ELECTRIC EQUIPMENT	06-2033	0.0013	(1)	29.6	23	3.4	06-2043	50 - R2.5 *	(2)	5.9	24.91	3.61
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	0.0026	0	15.2	23	3.4	06-2043	50 - S0.5 *	(2)	15.9	22.83	3.34
FT. MYERS UNIT 2												
341 STRUCTURES AND IMPROVEMENTS	06-2033	0.0023	(2)	10.3	22	3.5	06-2043	80 - R2 *	(2)	15.8	25.41	2.34
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2033	0.0095	0	9.1	20	3.8	06-2043	50 - R1.5 *	(3)	14.8	23.43	3.04
343 PRIME MOVERS - GENERAL	06-2033	0.0057	0	6.6	18 **	4.2	06-2043	50 - R1 *	(3)	10.0	23.53	3.46
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2033	0.1565	0	3.4	18 **	4.2	06-2043	9 - L0 *	35	4.3	7.01	7.42
344 GENERATORS	06-2033	0.0016	(1)	10.0	22	3.4	06-2043	60 - R2 *	(3)	13.2	24.73	2.80
345 ACCESSORY ELECTRIC EQUIPMENT	06-2033	0.0013	(1)	8.4	22	3.4	06-2043	50 - R2.5 *	(2)	14.3	24.10	2.34
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	0.0026	0	8.5	22	3.4	06-2043	50 - S0.5 *	(2)	14.1	22.90	2.44
FT. MYERS UNIT 3												
341 STRUCTURES AND IMPROVEMENTS	06-2033	0.0023	(2)	6.1	23	3.5	06-2043	80 - R2 *				
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2033	0.0095	0	6.1	21	3.8	06-2043	50 - R1.5 *	(2)	4.1	25.82	3.38
343 PRIME MOVERS - GENERAL	06-2033	0.0057	0	4.8	15.5 **	5.2	06-2043	50 - R1 *	(3)	4.2	24.47	3.58
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2033	0.1565	0	3.6	15.5 **	5.2	06-2043	25 - R1 *	(3)	2.2	24.09	4.54
344 GENERATORS	06-2033	0.0016	(1)	6.1	23	3.4	06-2043	60 - R2 *	29	3.1	19.90	3.94
345 ACCESSORY ELECTRIC EQUIPMENT	06-2033	0.0013	(1)	6.1	23	3.4	06-2043	50 - R2.5 *	(3)	4.2	25.38	3.46
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	0.0026	0	6.1	23	3.4	06-2043	50 - S0.5 *	(2)	4.2	25.32	3.40
									(2)	4.0	24.53	3.66
MANATEE COMBINED CYCLE PLANT												
MANATEE UNIT 3												
341 STRUCTURES AND IMPROVEMENTS	06-2035	0.0023	(2)	4.4	25	3.5	06-2045	80 - R2 *	(2)	11.3	27.38	2.37
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2035	0.0095	0	4.4	23	3.8	06-2045	50 - R1.5 *	(3)	11.4	25.26	2.60
343 PRIME MOVERS - GENERAL	06-2035	0.0057	0	4.2	20 **	4.3	06-2045	50 - R1 *	(3)	10.4	24.95	3.35
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2035	0.1565	0	3.4	20 **	4.3	06-2045	9 - L0 *	35	5.1	6.60	7.88
344 GENERATORS	06-2035	0.0016	(1)	4.4	25	3.4	06-2045	60 - R2 *	(3)	11.4	26.60	2.38
345 ACCESSORY ELECTRIC EQUIPMENT	06-2035	0.0013	(1)	4.2	25	3.4	06-2045	50 - R2.5 *	(2)	10.9	26.16	2.49
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2035	0.0026	0	4.5	25	3.4	06-2045	50 - S0.5 *	(2)	11.1	24.71	2.77

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TABLE 6. COMPARISON OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, AVERAGE AGES, AVERAGE REMAINING LIVES AND ANNUAL DEPRECIATION RATES BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

	ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009						PROPOSED COMPONENTS AS OF DECEMBER 31, 2016					
	PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (2)	NET SALVAGE (3)	AVERAGE AGE (4)	AVERAGE REMAINING LIFE (5)	ANNUAL DEPRECIATION RATE (6)	PROBABLE RETIREMENT DATE (7)	SURVIVOR CURVE (8)	NET SALVAGE (9)	AVERAGE AGE (10)	AVERAGE REMAINING LIFE (11)	ANNUAL DEPRECIATION RATE (12)
MARTIN COMBINED CYCLE PLANT												
MARTIN COMMON												
341 STRUCTURES AND IMPROVEMENTS	06-2024	0.0023	(2)	14.7	14.2	3.5	06-2034	80 - R2 *	(2)	18.6	17.05	2.24
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2024	0.0095	0	14.1	13.5	3.8	06-2034	50 - R1.5 *	(3)	18.0	16.15	2.42
343 PRIME MOVERS - GENERAL	06-2024	0.0057	0	11.6	12.0 **	4.3	06-2034	50 - R1 *	(3)	14.4	16.17	2.56
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2024	0.1565	0	1.7	12.0 **	4.3	06-2034	9 - L0 *	35	6.3	6.01	5.07
345 ACCESSORY ELECTRIC EQUIPMENT	06-2024	0.0013	(1)	15.0	14.4	3.4	06-2034	50 - R2.5 *	(2)	20.0	16.28	2.04
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2024	0.0026	0	14.4	14.2	3.4	06-2034	50 - S0.5 *	(2)	19.7	15.74	2.31
MARTIN UNIT 3												
341 STRUCTURES AND IMPROVEMENTS	06-2024	0.0023	(2)	14.5	14.2	3.5	06-2034	80 - R2 *	(2)	19.8	17.02	2.00
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2024	0.0095	0	15.1	13.5	3.8	06-2034	50 - R1.5 *	(3)	20.9	15.96	2.03
343 PRIME MOVERS - GENERAL	06-2024	0.0057	0	12.1	12.5 **	4.2	06-2034	50 - R1 *	(3)	16.2	16.10	4.49
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2024	0.1565	0	3.9	12.5 **	4.2	06-2034	9 - L0 *	35	2.5	7.50	7.69
344 GENERATORS	06-2024	0.0016	(1)	13.6	14.3	3.4	06-2034	60 - R2 *	(3)	14.7	16.83	3.33
345 ACCESSORY ELECTRIC EQUIPMENT	06-2024	0.0013	(1)	15.0	14.4	3.4	06-2034	50 - R2.5 *	(2)	17.9	16.44	2.69
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2024	0.0026	0	15.1	14.2	3.4	06-2034	50 - S0.5 *	(2)	20.9	15.63	1.99
MARTIN UNIT 4												
341 STRUCTURES AND IMPROVEMENTS	06-2024	0.0023	(2)	15.1	14.2	3.5	06-2034	80 - R2 *	(2)	17.0	17.08	2.93
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2024	0.0095	0	15.1	13.5	3.8	06-2034	50 - R1.5 *	(3)	20.9	15.96	2.03
343 PRIME MOVERS - GENERAL	06-2024	0.0057	0	11.5	12.4 **	4.2	06-2034	50 - R1 *	(3)	14.9	16.16	3.92
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2024	0.1565	0	3.7	12.4 **	4.2	06-2034	9 - L0 *	35	4.4	6.94	7.27
344 GENERATORS	06-2024	0.0016	(1)	11.6	14.3	3.4	06-2034	60 - R2 *	(3)	15.0	16.82	3.00
345 ACCESSORY ELECTRIC EQUIPMENT	06-2024	0.0013	(1)	14.7	14.4	3.4	06-2034	50 - R2.5 *	(2)	17.7	16.46	2.75
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2024	0.0026	0	15.1	14.2	3.4	06-2034	50 - S0.5 *	(2)	14.5	16.21	3.18
MARTIN UNIT 8												
341 STRUCTURES AND IMPROVEMENTS	06-2035	0.0023	(2)	4.9	25	3.5	06-2045	80 - R2 *	(2)	11.4	27.38	2.42
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2035	0.0095	0	5.5	23	3.8	06-2045	50 - R1.5 *	(3)	11.8	25.22	2.70
343 PRIME MOVERS - GENERAL	06-2035	0.0057	0	4.5	20 **	4.3	06-2045	50 - R1 *	(3)	10.1	25.00	3.37
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2035	0.1565	0	3.9	20 **	4.3	06-2045	9 - L0 *	35	4.2	6.92	7.76
344 GENERATORS	06-2035	0.0016	(1)	5.4	25	3.4	06-2045	60 - R2 *	(3)	11.6	26.58	2.64
345 ACCESSORY ELECTRIC EQUIPMENT	06-2035	0.0013	(1)	5.3	25	3.4	06-2045	50 - R2.5 *	(2)	11.6	26.06	2.61
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2035	0.0026	0	4.7	24	3.4	06-2045	50 - S0.5 *	(2)	10.4	24.88	2.66
SANFORD COMBINED CYCLE PLANT												
SANFORD COMMON												
341 STRUCTURES AND IMPROVEMENTS	06-2033	0.0023	(2)	14.7	22	3.5	06-2043	80 - R2 *	(2)	18.8	25.28	2.40
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2033	0.0095	0	7.3	20	3.8	06-2043	50 - R1.5 *	(3)	13.7	23.56	2.33
343 PRIME MOVERS - GENERAL	06-2033	0.0057	0	10.8	17.8 **	4.5	06-2043	50 - R1 *	(3)	14.7	22.96	7.96
344 GENERATORS	06-2033	0.0016	(1)	0.0	22	3.4	06-2043	60 - R2 *	(3)	5.2	25.29	3.36
345 ACCESSORY ELECTRIC EQUIPMENT	06-2033	0.0013	(1)	18.2	22	3.4	06-2043	50 - R2.5 *	(2)	14.5	23.55	3.06
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	0.0026	0	9.3	22	3.4	06-2043	50 - S0.5 *	(2)	12.6	23.23	2.81
SANFORD UNIT 4												
341 STRUCTURES AND IMPROVEMENTS	06-2033	0.0023	(2)	16.8	23	3.5	06-2043	80 - R2 *	(2)	22.5	25.09	2.39
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2033	0.0095	0	6.4	21	3.8	06-2043	50 - R1.5 *	(3)	12.8	23.63	2.51
343 PRIME MOVERS - GENERAL	06-2033	0.0057	0	6.6	16.8 **	4.8	06-2043	50 - R1 *	(3)	11.7	23.36	4.00
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2033	0.1565	0	5.0	16.8 **	4.8	06-2043	9 - L0 *	35	4.2	6.94	8.64
344 GENERATORS	06-2033	0.0016	(1)	8.7	23	3.4	06-2043	60 - R2 *	(3)	12.3	24.81	2.89
345 ACCESSORY ELECTRIC EQUIPMENT	06-2033	0.0013	(1)	8.6	23	3.4	06-2043	50 - R2.5 *	(2)	14.4	23.91	2.49
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2033	0.0026	0	6.6	23	3.4	06-2043	50 - S0.5 *	(2)	13.0	23.03	2.58
SANFORD UNIT 5												
341 STRUCTURES AND IMPROVEMENTS	06-2032	0.0023	(2)	16.6	22	3.5	06-2042	80 - R2 *	(2)	21.5	24.28	2.42
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2032	0.0095	0	7.3	20	3.8	06-2042	50 - R1.5 *	(3)	13.7	22.77	2.44
343 PRIME MOVERS - GENERAL	06-2032	0.0057	0	6.9	18.1 **	4.2	06-2042	50 - R1 *	(3)	11.9	22.61	4.12
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2032	0.1565	0	3.6	18.1 **	4.2	06-2042	9 - L0 *	35	4.0	7.00	8.58
344 GENERATORS	06-2032	0.0016	(1)	9.8	22	3.4	06-2042	60 - R2 *	(3)	13.0	23.92	2.81
345 ACCESSORY ELECTRIC EQUIPMENT	06-2032	0.0013	(1)	8.8	22	3.4	06-2042	50 - R2.5 *	(2)	14.6	23.15	2.56
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2032	0.0026	0	7.7	22	3.4	06-2042	50 - S0.5 *	(2)	13.3	22.31	2.65

FLORIDA POWER AND LIGHT COMPANY

TABLE 6. COMPARISON OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, AVERAGE AGES, AVERAGE REMAINING LIVES AND ANNUAL DEPRECIATION RATES BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

		ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009							PROPOSED COMPONENTS AS OF DECEMBER 31, 2016					
		PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (2)	NET SALVAGE (3)	AVERAGE AGE (4)		AVERAGE REMAINING LIFE (5)		ANNUAL DEPRECIATION RATE (6)	PROBABLE RETIREMENT DATE (7)	SURVIVOR CURVE (8)	NET SALVAGE (9)	AVERAGE AGE (10)	AVERAGE REMAINING LIFE (11)	ANNUAL DEPRECIATION RATE (12)
TURKEY POINT COMBINED CYCLE PLANT															
	TURKEY POINT UNIT 5														
341	STRUCTURES AND IMPROVEMENTS	06-2037	0.0023	(2)	2.5		27		3.5	06-2047	80 - R2 *	(2)	9.6	29.27	2.33
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2037	0.0095	0	2.5		24		3.8	06-2047	50 - R1.5 *	(3)	9.3	26.99	2.59
343	PRIME MOVERS - GENERAL	06-2037	0.0057	0	2.5		15.9	**	5.7	06-2047	50 - R1 *	(3)	8.8	26.56	3.28
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2037	0.1565	0	2.5		15.9	**	5.7	06-2047	9 - L0 *	35	3.6	7.07	7.77
344	GENERATORS	06-2037	0.0016	(1)	2.5		27		3.4	06-2047	60 - R2 *	(3)	9.3	28.45	2.68
345	ACCESSORY ELECTRIC EQUIPMENT	06-2037	0.0013	(1)	2.3		27		3.4	06-2047	50 - R2.5 *	(2)	9.3	27.96	2.51
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2037	0.0026	0	2.5		27		3.4	06-2047	50 - S0.5 *	(2)	9.1	26.47	2.76
WEST COUNTY COMBINED CYCLE PLANT															
	WEST COUNTY COMMON														
341	STRUCTURES AND IMPROVEMENTS	06-2041	0.0023	(2)	0.0	***	30	***	3.3	06-2051	80 - R2 *	(2)	5.1	33.12	2.61
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2041	0.0095	0	0.0	***	30	***	3.3	06-2051	50 - R1.5 *	(3)	5.3	30.44	2.89
343	PRIME MOVERS - GENERAL	06-2041	0.0057	0	0.0	***	30	***	3.3	06-2051	50 - R1 *	(3)	2.0	30.22	3.26
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2041	0.1565	0	0.0	***	30	***	3.3	06-2051	9 - L0 *	35	3.0	7.32	7.51
345	ACCESSORY ELECTRIC EQUIPMENT	06-2041	0.0013	(1)	0.0	***	30	***	3.3	06-2051	50 - R2.5 *	(2)	3.1	32.12	2.92
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2041	0.0026	0	0.0	***	30	***	3.3	06-2051	50 - S0.5 *	(2)	4.3	30.31	2.93
	WEST COUNTY UNIT 1														
341	STRUCTURES AND IMPROVEMENTS	06-2039	0.0023	(2)	0.0	***	30	***	3.3	06-2049	80 - R2 *	(2)	7.3	31.19	2.69
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2039	0.0095	0	0.0	***	30	***	3.3	06-2049	50 - R1.5 *	(3)	7.0	28.76	3.15
343	PRIME MOVERS - GENERAL	06-2039	0.0057	0	0.0	***	30	***	3.3	06-2049	50 - R1 *	(3)	6.7	28.21	3.92
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2039	0.1565	0	0.0	***	30	***	3.3	06-2049	9 - L0 *	35	5.9	6.27	11.80
344	GENERATORS	06-2039	0.0016	(1)	0.0	***	30	***	3.3	06-2049	60 - R2 *	(3)	7.2	30.31	2.87
345	ACCESSORY ELECTRIC EQUIPMENT	06-2039	0.0013	(1)	0.0	***	30	***	3.3	06-2049	50 - R2.5 *	(2)	7.3	29.82	2.85
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2039	0.0026	0	0.0	***	30	***	3.3	06-2049	50 - S0.5 *	(2)	7.3	28.22	3.03
	WEST COUNTY UNIT 2														
341	STRUCTURES AND IMPROVEMENTS	06-2039	0.0023	(2)	0.0	***	30	***	3.3	06-2049	80 - R2 *	(2)	7.3	31.19	2.77
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2039	0.0095	0	0.0	***	30	***	3.3	06-2049	50 - R1.5 *	(3)	6.5	28.84	3.44
343	PRIME MOVERS - GENERAL	06-2039	0.0057	0	0.0	***	30	***	3.3	06-2049	50 - R1 *	(3)	6.8	28.19	3.41
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2039	0.1565	0	0.0	***	30	***	3.3	06-2049	9 - L0 *	35	6.0	6.19	9.16
344	GENERATORS	06-2039	0.0016	(1)	0.0	***	30	***	3.3	06-2049	60 - R2 *	(3)	7.2	30.32	2.89
345	ACCESSORY ELECTRIC EQUIPMENT	06-2039	0.0013	(1)	0.0	***	30	***	3.3	06-2049	50 - R2.5 *	(2)	7.3	29.82	2.88
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2039	0.0026	0	0.0	***	30	***	3.3	06-2049	50 - S0.5 *	(2)	6.5	28.41	3.08
	WEST COUNTY UNIT 3														
341	STRUCTURES AND IMPROVEMENTS	06-2041	0.0023	(2)	0.0	***	30	***	3.3	06-2051	80 - R2 *	(2)	5.4	33.08	2.64
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2041	0.0095	0	0.0	***	30	***	3.3	06-2051	50 - R1.5 *	(3)	5.1	30.48	3.15
343	PRIME MOVERS - GENERAL	06-2041	0.0057	0	0.0	***	30	***	3.3	06-2051	50 - R1 *	(3)	5.3	29.77	3.23
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	06-2041	0.1565	0	0.0	***	30	***	3.3	06-2051	9 - L0 *	35	4.8	6.60	8.48
344	GENERATORS	06-2041	0.0016	(1)	0.0	***	30	***	3.3	06-2051	60 - R2 *	(3)	5.3	32.17	2.76
345	ACCESSORY ELECTRIC EQUIPMENT	06-2041	0.0013	(1)	0.0	***	30	***	3.3	06-2051	50 - R2.5 *	(2)	5.5	31.68	2.74
346	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2041	0.0026	0	0.0	***	30	***	3.3	06-2051	50 - S0.5 *	(2)	5.5	29.98	1.33

FLORIDA POWER AND LIGHT COMPANY

TABLE 6. COMPARISON OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, AVERAGE AGES, AVERAGE REMAINING LIVES AND ANNUAL DEPRECIATION RATES BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

	ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009							PROPOSED COMPONENTS AS OF DECEMBER 31, 2016					
	PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (2)	NET SALVAGE (3)	AVERAGE AGE (4)		AVERAGE REMAINING LIFE (5)		ANNUAL DEPRECIATION RATE (6)	PROBABLE RETIREMENT DATE (7)	SURVIVOR CURVE (8)	NET SALVAGE (9)	AVERAGE AGE (10)	AVERAGE REMAINING LIFE (11)	ANNUAL DEPRECIATION RATE (12)
CAPE CANAVERAL COMBINED CYCLE PLANT														
CAPE CANAVERAL COMBINED CYCLE														
341 STRUCTURES AND IMPROVEMENTS	06-2043	0.0023	(2)	0.0	***	30	***	3.3	06-2053	80 - R2 *	(2)	3.4	34.98	2.69
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2043	0.0095	0	0.0	***	30	***	3.3	06-2053	50 - R1.5 *	(3)	3.4	32.18	2.97
343 PRIME MOVERS - GENERAL	06-2043	0.0057	0	0.0	***	30	***	3.3	06-2053	50 - R1 *	(3)	3.5	31.38	2.96
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2043	0.1565	0	0.0	***	30	***	3.3	06-2053	9 - L0 *	35	2.8	7.38	6.93
344 GENERATORS	06-2043	0.0016	(1)	0.0	***	30	***	3.3	06-2053	60 - R2 *	(3)	3.5	34.03	2.81
345 ACCESSORY ELECTRIC EQUIPMENT	06-2043	0.0013	(1)	0.0	***	30	***	3.3	06-2053	50 - R2.5 *	(2)	3.4	33.59	2.81
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2043	0.0026	0	0.0	***	30	***	3.3	06-2053	50 - S0.5 *	(2)	3.5	31.85	2.98
RIVIERA COMBINED CYCLE PLANT														
RIVIERA COMBINED CYCLE														
341 STRUCTURES AND IMPROVEMENTS	06-2044	0.0023	(2)	0.0	***	30	***	3.3	06-2054	80 - R2 *	(2)	3.0	35.90	2.58
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2044	0.0095	0	0.0	***	30	***	3.3	06-2054	50 - R1.5 *	(3)	2.4	33.03	2.86
343 PRIME MOVERS - GENERAL	06-2044	0.0057	0	0.0	***	30	***	3.3	06-2054	50 - R1 *	(3)	2.5	32.21	2.99
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2044	0.1565	0	0.0	***	30	***	3.3	06-2054	9 - L0 *	35	2.4	7.56	7.04
344 GENERATORS	06-2044	0.0016	(1)	0.0	***	30	***	3.3	06-2054	60 - R2 *	(3)	2.5	34.97	2.74
345 ACCESSORY ELECTRIC EQUIPMENT	06-2044	0.0013	(1)	0.0	***	30	***	3.3	06-2054	50 - R2.5 *	(2)	2.6	34.50	2.72
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2044	0.0026	0	0.0	***	30	***	3.3	06-2054	50 - S0.5 *	(2)	2.5	32.80	2.67
PT EVERGLADES COMBINED CYCLE PLANT														
PT EVERGLADES COMBINED CYCLE														
341 STRUCTURES AND IMPROVEMENTS	06-2046	0.0023	(2)	0.0	***	30	***	3.3	06-2056	80 - R2 *	(2)	0.5	37.84	2.64
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2046	0.0095	0	0.0	***	30	***	3.3	06-2056	50 - R1.5 *	(3)	0.5	34.77	2.90
343 PRIME MOVERS - GENERAL	06-2046	0.0057	0	0.0	***	30	***	3.3	06-2056	50 - R1 *	(3)	0.5	33.84	2.99
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2046	0.1565	0	0.0	***	30	***	3.3	06-2056	9 - L0 *	35	0.5	8.61	7.11
344 GENERATORS	06-2046	0.0016	(1)	0.0	***	30	***	3.3	06-2056	60 - R2 *	(3)	0.5	36.84	2.73
345 ACCESSORY ELECTRIC EQUIPMENT	06-2046	0.0013	(1)	0.0	***	30	***	3.3	06-2056	50 - R2.5 *	(2)	0.5	36.42	2.74
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2046	0.0026	0	0.0	***	30	***	3.3	06-2056	50 - S0.5 *	(2)	0.5	34.72	2.87

FLORIDA POWER AND LIGHT COMPANY

TABLE 6. COMPARISON OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, AVERAGE AGES, AVERAGE REMAINING LIVES AND ANNUAL DEPRECIATION RATES BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

	ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009							PROPOSED COMPONENTS AS OF DECEMBER 31, 2016					
	PROBABLE RETIREMENT DATE (1)	SURVIVOR CURVE/ INTERIM RETIREMENT RATE (2)	NET SALVAGE (3)	AVERAGE AGE (4)		AVERAGE REMAINING LIFE (5)		ANNUAL DEPRECIATION RATE (6)	PROBABLE RETIREMENT DATE (7)	SURVIVOR CURVE (8)	NET SALVAGE (9)	AVERAGE AGE (10)	AVERAGE REMAINING LIFE (11)	ANNUAL DEPRECIATION RATE (12)
PEAKER PLANTS														
LAUDERDALE GTS														
341 STRUCTURES AND IMPROVEMENTS	06-2020	0.0023	(2)	24.8	***	10.4	***	2.2	06-2028	80 - R2 *	(2)	27.3	11.26	4.18
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2020	0.0095	0	21.7	***	9.9	***	2.6	06-2028	50 - R1.5 *	(3)	26.8	10.68	4.73
343 PRIME MOVERS - GENERAL	06-2020	0.0057	0	23.9	***	8.9	***	2.9	06-2028	50 - R1 *	(3)	4.7	11.08	8.25
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2020	0.1565	0	4.9	***	8.9	***	2.9	06-2028	25 - R1 *	29	19.4	8.31	4.18
344 GENERATORS	06-2020	0.0016	(1)	36.2	***	10.4	***	2.1	06-2028	60 - R2 *	(3)	40.2	10.61	5.66
345 ACCESSORY ELECTRIC EQUIPMENT	06-2020	0.0013	(1)	30.2	***	10.4	***	2.1	06-2028	50 - R2.5 *	(2)	36.5	10.04	6.02
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2020	0.0026	0	34.7	***	10.3	***	2.2	06-2028	50 - S0.5 *	(2)	41.9	9.84	6.21
FT. MYERS GTS														
341 STRUCTURES AND IMPROVEMENTS	06-2020	0.0023	(2)	30.8	***	10.4	***	2.3	06-2028	80 - R2 *	(2)	14.7	11.37	7.40
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2020	0.0095	0	25.0	***	9.9	***	2.7	06-2028	50 - R1.5 *	(3)	13.7	11.07	7.84
343 PRIME MOVERS - GENERAL	06-2020	0.0057	0	23.4	***	8.7	***	3.1	06-2028	50 - R1 *	(3)	4.5	11.09	8.22
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2020	0.1565	0	3.7	***	8.7	***	3.1	06-2028	25 - R1 *	29	29.0	6.28	4.19
344 GENERATORS	06-2020	0.0016	(1)	25.2	***	10.4	***	2.2	06-2028	60 - R2 *	(3)	14.2	11.27	8.08
345 ACCESSORY ELECTRIC EQUIPMENT	06-2020	0.0013	(1)	10.9	***	10.4	***	2.2	06-2028	50 - R2.5 *	(2)	7.3	11.32	7.77
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2020	0.0026	0	30.9	***	10.3	***	2.3	06-2028	50 - S0.5 *	(2)	16.8	11.13	8.03
LAUDERDALE AND FT. MYERS PEAKERS														
341 STRUCTURES AND IMPROVEMENTS	06-2046	0.0023	(2)	0.0	***	30	***	3.3	06-2056	80 - R2 *	(2)	0.5	37.84	2.69
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	06-2046	0.0095	0	0.0	***	30	***	3.3	06-2056	50 - R1.5 *	(3)	0.5	34.77	2.96
343 PRIME MOVERS - GENERAL	06-2046	0.0057	0	0.0	***	30	***	3.3	06-2056	50 - R1 *	(3)	0.5	33.84	3.04
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	06-2046	0.1565	0	0.0	***	30	***	3.3	06-2056	25 - R1 *	29	0.5	24.32	2.91
344 GENERATORS	06-2046	0.0016	(1)	0.0	***	30	***	3.3	06-2056	60 - R2 *	(3)	0.5	36.84	2.79
345 ACCESSORY ELECTRIC EQUIPMENT	06-2046	0.0013	(1)	0.0	***	30	***	3.3	06-2056	50 - R2.5 *	(2)	0.5	36.42	2.80
346 MISCELLANEOUS POWER PLANT EQUIPMENT	06-2046	0.0026	0	0.0	***	30	***	3.3	06-2056	50 - S0.5 *	(2)	0.5	34.72	2.93
SOLAR PRODUCTION PLANT														
DESOTO SOLAR														
341 STRUCTURES AND IMPROVEMENTS	06-2039	SQUARE *	0	0.0	***	30	***	3.3	06-2039	SQUARE *	0	6.9	22.52	3.49
343 PRIME MOVERS - GENERAL	06-2039	SQUARE *	0	0.0	***	30	***	3.3	06-2039	SQUARE *	0	7.3	22.52	3.36
345 ACCESSORY ELECTRIC EQUIPMENT	06-2039	SQUARE *	0	0.0	***	30	***	3.3	06-2039	SQUARE *	0	7.3	22.52	3.65
SPACE COAST SOLAR														
341 STRUCTURES AND IMPROVEMENTS	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2040	SQUARE *	0	6.4	23.52	3.45
343 PRIME MOVERS - GENERAL	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2040	SQUARE *	0	6.4	23.52	3.30
345 ACCESSORY ELECTRIC EQUIPMENT	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2040	SQUARE *	0	6.4	23.52	3.51
MARTIN SOLAR														
341 STRUCTURES AND IMPROVEMENTS	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2045	SQUARE *	0	6.1	28.48	2.99
343 PRIME MOVERS - GENERAL	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2045	SQUARE *	0	6.2	28.47	2.88
345 ACCESSORY ELECTRIC EQUIPMENT	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2045	SQUARE *	0	6.3	28.47	2.99
346 MISC. POWER PLANT EQUIPMENT	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2045	SQUARE *	0	6.3	28.47	2.85
BABCOCK RANCH SOLAR														
341 STRUCTURES AND IMPROVEMENTS	06-2039	SQUARE *	0	0.0	***	30	***	3.3	06-2046	SQUARE *	0	0.5	29.53	3.37
343 PRIME MOVERS - GENERAL	06-2039	SQUARE *	0	0.0	***	30	***	3.3	06-2046	SQUARE *	0	0.5	29.53	3.37
345 ACCESSORY ELECTRIC EQUIPMENT	06-2039	SQUARE *	0	0.0	***	30	***	3.3	06-2046	SQUARE *	0	0.5	29.53	3.37
MANATEE SOLAR														
341 STRUCTURES AND IMPROVEMENTS	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2046	SQUARE *	0	0.5	29.53	3.38
343 PRIME MOVERS - GENERAL	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2046	SQUARE *	0	0.5	29.53	3.38
345 ACCESSORY ELECTRIC EQUIPMENT	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2046	SQUARE *	0	0.5	29.53	3.38
CITRUS SOLAR														
341 STRUCTURES AND IMPROVEMENTS	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2046	SQUARE *	0	0.5	29.53	3.37
343 PRIME MOVERS - GENERAL	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2046	SQUARE *	0	0.5	29.53	3.37
345 ACCESSORY ELECTRIC EQUIPMENT	06-2040	SQUARE *	0	0.0	***	30	***	3.3	06-2046	SQUARE *	0	0.5	29.53	3.37

FLORIDA POWER AND LIGHT COMPANY

TABLE 6. COMPARISON OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, AVERAGE AGES, AVERAGE REMAINING LIVES AND ANNUAL DEPRECIATION RATES BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

		ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009						PROPOSED COMPONENTS AS OF DECEMBER 31, 2016					
		PROBABLE RETIREMENT DATE	SURVIVOR CURVE/ INTERIM RETIREMENT RATE	NET SALVAGE	AVERAGE AGE	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION RATE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	AVERAGE AGE	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION RATE
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
TRANSMISSION, DISTRIBUTION, AND GENERAL PLANT													
	TRANSMISSION PLANT												
350.2	EASEMENTS		75 - S4	0	0.0	58	1.3		75 - S4	0	22.1	53.20	1.25
352	STRUCTURES AND IMPROVEMENTS		60 - R3	(15)	0.0	47	1.9		65 - R3	(15)	13.4	52.43	1.70
353	STATION EQUIPMENT		40 - R1.5	(2)	0.0	29	2.6		40 - R1	(2)	13.5	30.90	2.36
353.1	STATION EQUIPMENT - STEP-UP TRANSFORMERS		35 - R2	0	0.0	25	2.9		30 - R1	0	9.3	23.69	3.51
354	TOWERS AND FIXTURES		52 - R5	(15)	0.0	34	2.2		60 - R4	(25)	24.9	35.88	1.68
355	POLES AND FIXTURES		44 - R2	(50)	0.0	33	3.4		50 - R2	(50)	12.2	39.88	2.91
356	OVERHEAD CONDUCTORS AND DEVICES		47 - R1.5	(50)	0.0	35	3.2		51 - R1	(55)	16.6	39.61	2.84
357	UNDERGROUND CONDUIT		60 - R4	0	0.0	40	1.7		65 - R4	0	20.5	45.29	1.43
358	UNDERGROUND CONDUCTORS AND DEVICES		60 - L3	(10)	0.0	40	1.8		65 - R3	(20)	17.1	49.27	1.87
359	ROADS AND TRAILS		65 - SQ	(10)	0.0	47	1.7		75 - R4	(10)	21.0	54.53	1.33
	DISTRIBUTION PLANT												
361	STRUCTURES AND IMPROVEMENTS		60 - R3	(15)	0.0	50	1.9		65 - R3	(15)	16.0	49.85	1.75
362	STATION EQUIPMENT		43 - R1.5	(10)	0.0	33	2.6		45 - R1.5	(10)	15.1	33.67	2.36
364.1	POLES, TOWERS AND FIXTURES - WOOD		43 - R1.5	(10)	0.0	27	4.1		40 - R2	(100)	13.8	28.90	5.38
364.2	POLES, TOWERS AND FIXTURES - CONCRETE		43 - R1.5	(10)	0.0	27	4.1		50 - R1.5	(100)	5.6	45.65	4.08
365	OVERHEAD CONDUCTORS AND DEVICES		41 - S0	(60)	0.0	30	3.9		48 - R1	(80)	13.3	38.90	3.67
366.6	UNDERGROUND CONDUIT - DUCT SYSTEM		70 - S1.5	(2)	0.0	59	1.5		70 - R3	0	16.2	54.59	1.42
366.7	UNDERGROUND CONDUIT - DIRECT BURIED		50 - R4	0	0.0	40	2.0		50 - R4	0	7.2	43.04	2.00
367.6	UNDERGROUND CONDUCTORS AND DEVICES - DUCT SYSTEM		38 - S0	0	0.0	29	2.6		42 - S0	(5)	13.9	31.87	2.43
367.7	UNDERGROUND CONDUCTORS AND DEVICES - DIRECT BURIED		35 - R2	0	0.0	18.4	2.9		35 - R2	0	16.0	23.06	2.63
368	LINE TRANSFORMERS		33 - L1.5	(25)	0.0	22	3.8		34 - S0	(15)	15.5	23.48	2.98
369.1	SERVICES - OVERHEAD		48 - R1	(85)	0.0	36	3.9		53 - R1	(125)	10.3	45.82	4.29
369.6	SERVICES - UNDERGROUND		38 - R2	(5)	0.0	26	2.8		45 - R2	(15)	16.1	31.75	2.40
370	METERS		36 - R2.5	(30)	0.0	24	3.6		38 - R2	(30)	27.8	17.18	3.42
370.1	METERS - AMI		20 - R2.5	(30)	0.0	19.2	6.5		20 - R2.5	(30)	4.8	15.60	6.67
371	INSTALLATIONS ON CUSTOMER'S PREMISES		30 - L0	(20)	0.0	22	4.0		30 - L0	(15)	17.2	21.97	3.33
373	STREET LIGHTING AND SIGNAL SYSTEMS		30 - R0.5	(20)	0.0	22	4.0		35 - O1	(15)	15.3	27.34	2.82
	GENERAL PLANT												
390	STRUCTURES AND IMPROVEMENTS		50 - R1.5	(5)	0.0	36	2.1		55 - R1.5	(10)	18.1	41.11	1.99
392.1	AUTOMOBILES		6 - L2	15	0.0	3.0	14.2		6 - L2.5	15	2.2	4.06	15.72
392.2	LIGHT TRUCKS		9 - L3	15	0.0	4.6	9.4		9 - L3	15	3.7	5.86	10.00
392.3	HEAVY TRUCKS		12 - S3	15	0.0	5.0	7.1		12 - S3	15	5.8	7.09	6.16
392.4	TRACTOR TRAILERS		9 - L2.5	0	0.0	2.6	11.1		9 - L2.5	5	8.0	4.48	2.63
392.9	TRAILERS		20 - L1	30	0.0	11.9	3.5		20 - L1	15	9.6	14.42	4.99
396.1	POWER OPERATED EQUIPMENT		10 - L0.5	20	0.0	6.3	8.0		11 - L1.5	15	8.8	5.92	7.05
397.8	COMMUNICATION EQUIPMENT - FIBER OPTICS		10 - L0	0	0.0	7.7	10.0		20 - S2	0	11.1	11.01	1.95

* CURVE SHOWN IS INTERIM SURVIVOR CURVE. LIFE SPAN METHOD IS USED.

** IN DOCKET NO. 090130-EI THE COMMISSION ORDERED A COMPOSITE REMAINING LIFE FOR ACCOUNT 343 PRIME MOVERS, AS OPPOSED TO SEPARATE REMAINING LIVES FOR ACCOUNT 343 PRIME MOVERS - GENERAL AND ACCOUNT 343.2 PRIME MOVERS - CAPITAL SPARE PARTS. THE AVERAGE REMAINING LIFE SHOWN HERE FOR BOTH ACCOUNTS IS THE COMPOSITE REMAINING LIFE ORDERED BY THE COMMISSION FOR THE COMBINED ACCOUNT.

*** FOR NEW UNITS IN DOCKET NO. 090130-EI AND UNITS ADDED SUBSEQUENT TO THAT DOCKET THE AVERAGE AGE SHOWN IS 0 AND THE AVERAGE REMAINING LIFE IS EQUAL TO THE LIFE SPAN OF THE UNIT.

FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009				PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
STEAM PRODUCTION PLANT										
MANATEE STEAM PLANT										
MANATEE COMMON										
311 STRUCTURES AND IMPROVEMENTS	112,114,271	73,128,598	64.47	17.0	2,354,400	2.1	65.23	11.28	3,555,569	3.52
312 BOILER PLANT EQUIPMENT	7,715,628	1,329,813	60.95	16.1	200,606	2.6	17.24	11.13	587,612	7.62
314 TURBOGENERATOR UNITS	9,652,310	7,657,288	58.68	15.7	250,960	2.6	79.33	10.74	194,743	2.02
315 ACCESSORY ELECTRIC EQUIPMENT	9,646,848	7,389,490	65.15	16.7	231,524	2.4	76.60	10.86	225,626	2.34
316 MISCELLANEOUS POWER PLANT EQUIPMENT	2,450,703	1,919,506	61.56	16.4	58,817	2.4	78.32	10.92	50,889	2.08
TOTAL MANATEE COMMON	*141,579,760*	*91,424,696*			*3,096,307*	*2.2*			*4,614,439*	*3.26*
MANATEE UNIT 1										
311 STRUCTURES AND IMPROVEMENTS	6,836,328	5,584,432	64.47	17.0	143,563	2.1	81.69	11.12	118,728	1.74
312 BOILER PLANT EQUIPMENT	181,481,969	93,495,502	60.95	16.1	4,718,531	2.6	51.52	10.89	8,412,866	4.64
314 TURBOGENERATOR UNITS	72,660,531	41,616,767	58.68	15.7	1,889,174	2.6	57.28	10.86	2,925,448	4.03
315 ACCESSORY ELECTRIC EQUIPMENT	14,261,784	8,023,680	65.15	16.7	342,283	2.4	56.26	11.12	586,631	4.11
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,924,407	2,278,883	61.56	16.4	94,186	2.4	58.07	10.97	153,580	3.91
TOTAL MANATEE UNIT 1	*279,165,019*	*150,999,264*			*7,187,737*	*2.6*			*12,197,253*	*4.37*
MANATEE UNIT 2										
311 STRUCTURES AND IMPROVEMENTS	4,986,744	4,017,696	64.47	17.0	104,722	2.1	80.57	11.15	91,383	1.83
312 BOILER PLANT EQUIPMENT	183,957,418	87,494,700	60.95	16.1	4,782,893	2.6	47.56	10.92	9,170,501	4.99
314 TURBOGENERATOR UNITS	70,765,381	42,942,308	58.68	15.7	1,839,900	2.6	60.68	10.85	2,629,560	3.72
315 ACCESSORY ELECTRIC EQUIPMENT	12,273,816	6,398,866	65.15	16.7	294,572	2.4	52.13	11.14	549,410	4.48
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,453,782	1,668,499	61.56	16.4	82,891	2.4	48.31	10.99	165,589	4.79
TOTAL MANATEE UNIT 2	*275,437,142*	*142,522,068*			*7,104,978*	*2.6*			*12,606,443*	*4.58*
TOTAL MANATEE STEAM PLANT	***696,181,920***	***384,946,028***			***17,389,022***	***2.5***			***29,418,135***	***4.23***
MARTIN STEAM PLANT										
MARTIN COMMON										
311 STRUCTURES AND IMPROVEMENTS	241,950,141	158,600,994	55.87	21	5,080,953	2.1	65.55	14.04	6,108,878	2.52
312 BOILER PLANT EQUIPMENT	7,068,506	2,944,759	54.08	19.4	183,781	2.6	41.66	13.57	314,305	4.45
314 TURBOGENERATOR UNITS	27,474,257	14,912,384	50.53	18.8	714,331	2.6	54.28	13.43	955,816	3.48
315 ACCESSORY ELECTRIC EQUIPMENT	10,295,313	5,435,309	57.27	20	247,088	2.4	52.79	13.78	367,628	3.57
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,888,459	1,913,639	52.62	19.9	93,323	2.4	49.21	13.67	147,308	3.79
TOTAL MARTIN COMMON	*290,676,676*	*183,807,084*			*6,319,476*	*2.2*			*7,893,935*	*2.72*
MARTIN PIPELINE										
312 BOILER PLANT EQUIPMENT	370,942	370,942	54.08	19.4	9,644	2.6	100.00	13.04	-	0.00
TOTAL MARTIN PIPELINE	*370,942*	*370,942*			*9,644*	*2.6*			-	
MARTIN UNIT 1										
311 STRUCTURES AND IMPROVEMENTS	16,404,681	10,400,297	55.87	21	344,498	2.1	63.40	14.03	439,660	2.68
312 BOILER PLANT EQUIPMENT	212,830,965	87,624,020	54.08	19.4	5,533,605	2.6	41.17	13.44	9,632,706	4.53
314 TURBOGENERATOR UNITS	90,120,383	50,448,065	50.53	18.8	2,343,130	2.6	55.98	13.44	3,018,863	3.35
315 ACCESSORY ELECTRIC EQUIPMENT	24,391,137	14,440,333	57.27	20	585,387	2.4	59.20	13.72	760,833	3.12
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,594,165	1,758,500	52.62	19.9	86,260	2.4	48.93	13.67	136,913	3.81
TOTAL MARTIN UNIT 1	*347,341,330*	*164,671,214*			*8,892,880*	*2.6*			*13,988,975*	*4.03*
MARTIN UNIT 2										
311 STRUCTURES AND IMPROVEMENTS	11,266,842	7,618,893	55.87	21	236,604	2.1	67.62	13.98	269,000	2.39
312 BOILER PLANT EQUIPMENT	215,154,508	84,744,456	54.08	19.4	5,594,017	2.6	39.39	13.48	9,993,557	4.64
314 TURBOGENERATOR UNITS	82,856,949	30,043,134	50.53	18.8	2,154,281	2.6	36.26	13.52	3,967,632	4.79
315 ACCESSORY ELECTRIC EQUIPMENT	23,045,156	12,167,493	57.27	20	553,084	2.4	52.80	13.83	819,853	3.56
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,280,816	1,374,670	52.62	19.9	78,740	2.4	41.90	13.71	141,426	4.31
TOTAL MARTIN UNIT 2	*335,604,270*	*135,948,644*			*8,616,726*	*2.6*			*15,191,468*	*4.53*
TOTAL MARTIN STEAM PLANT	***973,993,219***	***484,797,884***			***23,838,726***	***2.4***			***37,074,378***	***3.81***

FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009				PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
SCHERER STEAM PLANT										
SCHERER COAL CARS										
312 BOILER PLANT EQUIPMENT	33,149,442	33,149,442	36.75	26	861,885	2.6	100.00	19.25	-	0.00
TOTAL SCHERER COAL CARS	*33,149,442*	*33,149,442*			*861,885*	*2.6*			-	*0.00*
SCHERER COMMON										
311 STRUCTURES AND IMPROVEMENTS	39,391,667	20,717,188	40.83	28	827,225	2.1	52.59	21.60	882,796	2.24
312 BOILER PLANT EQUIPMENT	25,844,055	12,070,575	36.75	26	671,945	2.6	46.71	19.34	765,628	2.96
314 TURBOGENERATOR UNITS	4,336,718	1,830,764	34.21	25	112,755	2.6	42.22	19.91	128,042	2.95
315 ACCESSORY ELECTRIC EQUIPMENT	1,226,257	679,212	40.18	27	29,430	2.4	55.39	20.22	29,480	2.40
316 MISCELLANEOUS POWER PLANT EQUIPMENT	3,659,825	1,735,162	36.07	27	87,836	2.4	47.41	20.49	95,718	2.62
TOTAL SCHERER COMMON	*74,458,521*	*37,032,900*			*1,729,191*	*2.3*			*1,901,664*	*2.55*
SCHERER COMMON UNIT 3 AND 4										
311 STRUCTURES AND IMPROVEMENTS	2,999,449	1,646,858	41.23	28	65,988	2.2	54.91	21.56	64,127	2.14
312 BOILER PLANT EQUIPMENT	22,335,968	9,614,113	37.10	26	603,071	2.7	43.04	19.59	695,012	3.11
314 TURBOGENERATOR UNITS	2,831,158	224,639	34.21	25	73,610	2.6	7.93	20.55	128,216	4.53
315 ACCESSORY ELECTRIC EQUIPMENT	2,818,575	245,786	40.57	27	67,646	2.4	8.72	21.48	125,025	4.44
TOTAL SCHERER COMMON UNIT 3 AND 4	*30,985,149*	*11,731,396*			*810,315*	*2.6*			*1,012,380*	*3.27*
SCHERER UNIT 4										
311 STRUCTURES AND IMPROVEMENTS	159,104,427	39,437,115	40.83	28	3,341,193	2.1	24.79	21.89	5,539,441	3.48
312 BOILER PLANT EQUIPMENT	671,515,648	178,043,157	36.75	26	17,459,407	2.6	26.51	20.16	25,810,174	3.84
314 TURBOGENERATOR UNITS	122,853,491	58,668,053	34.21	25	3,194,191	2.6	47.75	19.88	3,290,441	2.68
315 ACCESSORY ELECTRIC EQUIPMENT	49,374,419	14,135,035	40.18	27	1,184,986	2.4	28.63	20.96	1,775,494	3.60
316 MISCELLANEOUS POWER PLANT EQUIPMENT	5,117,266	2,275,999	36.07	27	122,814	2.4	44.48	20.62	140,274	2.74
TOTAL SCHERER UNIT 4	*1,007,965,252*	*292,559,359*			*25,302,591*	*2.5*			*36,555,824*	*3.63*
TOTAL SCHERER STEAM PLANT	***1,146,558,365***	***374,473,097***			***28,703,982***	***2.5***			***39,469,868***	***3.44***

FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009				PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
SJRPP STEAM PLANT										
SJRPP COAL AND LIMESTONE										
311 STRUCTURES AND IMPROVEMENTS	3,562,391	1,817,206	40.83	28	74,810	2.1	51.01	20.48	86,954	2.44
312 BOILER PLANT EQUIPMENT	30,883,389	15,259,114	36.75	26	802,968	2.6	49.41	18.00	936,645	3.03
315 ACCESSORY ELECTRIC EQUIPMENT	3,773,252	2,142,570	40.18	27	90,558	2.4	56.78	19.17	92,938	2.46
316 MISCELLANEOUS POWER PLANT EQUIPMENT	300,302	161,831	36.07	27	7,207	2.4	53.89	19.33	7,319	2.44
TOTAL SJRPP COAL AND LIMESTONE	*38,519,334*	*19,380,721*			*975,543*	*2.5*			*1,123,856*	*2.92*
SJRPP COAL CARS										
312 BOILER PLANT EQUIPMENT	52,105	52,105	36.75	26	1,355	2.6	100.00	17.84	-	0.00
TOTAL SJRPP COAL CARS	*52,105*	*52,105*			*1,355*	*2.6*			-	*0.00*
SJRPP COMMON										
311 STRUCTURES AND IMPROVEMENTS	33,146,529	22,171,912	42.98	27	696,077	2.1	66.89	20.54	550,442	1.66
312 BOILER PLANT EQUIPMENT	3,694,843	2,563,468	39.38	25	96,066	2.6	69.38	18.22	70,207	1.90
314 TURBOGENERATOR UNITS	2,497,878	1,684,864	36.84	24	64,945	2.6	67.45	18.75	44,693	1.79
315 ACCESSORY ELECTRIC EQUIPMENT	5,833,698	3,990,701	42.55	26	140,009	2.4	68.41	19.27	107,750	1.85
316 MISCELLANEOUS POWER PLANT EQUIPMENT	1,598,862	1,006,658	38.48	26	38,373	2.4	62.96	19.52	31,157	1.95
TOTAL SJRPP COMMON	*46,771,810*	*31,417,602*			*1,035,470*	*2.2*			*804,249*	*1.72*
SJRPP GYPSUM AND ASH										
311 STRUCTURES AND IMPROVEMENTS	2,172,989	1,122,277	42.98	27	45,633	2.1	51.65	20.54	52,212	2.40
312 BOILER PLANT EQUIPMENT	17,085,257	9,494,175	39.38	25	444,217	2.6	55.57	17.87	463,038	2.71
315 ACCESSORY ELECTRIC EQUIPMENT	52,571	31,682	42.55	26	1,262	2.4	60.26	19.35	1,188	2.26
316 MISCELLANEOUS POWER PLANT EQUIPMENT	154,892	64,476	38.48	26	3,717	2.4	41.63	19.65	4,680	3.02
TOTAL SJRPP GYPSUM AND ASH	*19,465,709*	*10,712,610*			*494,829*	*2.5*			*521,118*	*2.68*
SJRPP UNIT 1										
311 STRUCTURES AND IMPROVEMENTS	9,049,629	6,497,954	42.98	27	190,042	2.1	71.80	20.45	129,202	1.43
312 BOILER PLANT EQUIPMENT	99,626,681	50,079,303	39.38	25	2,590,294	2.6	50.27	18.54	2,887,403	2.90
314 TURBOGENERATOR UNITS	31,463,410	15,259,034	36.84	24	818,049	2.6	48.50	19.20	860,365	2.73
315 ACCESSORY ELECTRIC EQUIPMENT	12,475,837	7,908,663	42.55	26	299,420	2.4	63.39	19.36	261,684	2.10
316 MISCELLANEOUS POWER PLANT EQUIPMENT	2,038,425	1,391,601	38.48	26	48,922	2.4	68.27	19.40	34,392	1.69
TOTAL SJRPP UNIT 1	*154,653,983*	*81,136,555*			*3,946,727*	*2.6*			*4,173,046*	*2.70*
SJRPP UNIT 2										
311 STRUCTURES AND IMPROVEMENTS	7,177,145	4,116,166	42.98	27	150,720	2.1	57.35	20.43	153,341	2.14
312 BOILER PLANT EQUIPMENT	90,153,231	39,507,420	39.38	25	2,343,984	2.6	43.82	18.56	2,923,057	3.24
314 TURBOGENERATOR UNITS	28,479,810	10,690,425	36.84	24	740,475	2.6	37.54	19.21	940,874	3.30
315 ACCESSORY ELECTRIC EQUIPMENT	10,105,912	5,314,628	42.55	26	242,542	2.4	52.59	19.27	269,617	2.67
316 MISCELLANEOUS POWER PLANT EQUIPMENT	1,571,822	869,236	38.48	26	37,724	2.4	55.30	19.45	36,931	2.35
TOTAL SJRPP UNIT 2	*137,487,920*	*60,497,875*			*3,515,445*	*2.6*			*4,323,820*	*3.14*
TOTAL SJRPP STEAM PLANT	***396,950,861***	***203,197,468***			***9,969,369***	***2.5***			***10,946,089***	***2.76***
TOTAL STEAM PRODUCTION	**3,213,684,365**	**1,447,414,477**			**79,901,099**	***2.5***			**116,908,470**	***3.64***

FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009				PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
NUCLEAR PRODUCTION PLANT										
ST. LUCIE NUCLEAR PLANT										
ST. LUCIE COMMON										
321 STRUCTURES AND IMPROVEMENTS	396,984,357	176,282,726	42.86	32	7,145,718	1.8	44.41	25.17	8,926,161	2.25
322 REACTOR PLANT EQUIPMENT	55,565,218	31,403,213	42.00	30	1,111,304	2.0	56.52	23.69	1,066,835	1.92
323 TURBOGENERATOR UNITS	12,402,700	(7,534,768)	34.15	27	297,665	2.4	-60.75	22.26	895,663	7.22
324 ACCESSORY ELECTRIC EQUIPMENT	34,367,943	16,891,518	43.97	33	618,623	1.8	49.15	24.78	719,133	2.09
325 MISCELLANEOUS POWER PLANT EQUIPMENT	20,722,317	2,245,775	41.82	32	373,002	1.8	10.84	22.70	841,331	4.06
TOTAL ST. LUCIE COMMON	*520,042,535*	*219,288,464*			*9,546,312*	*1.8*			*12,449,123*	*2.39*
ST. LUCIE UNIT 1										
321 STRUCTURES AND IMPROVEMENTS	194,729,786	100,039,207	53.57	26	3,505,136	1.8	51.37	18.67	5,176,105	2.66
322 REACTOR PLANT EQUIPMENT	838,073,831	293,588,602	52.00	25	16,761,477	2.0	35.03	18.00	31,180,373	3.72
323 TURBOGENERATOR UNITS	412,318,467	47,813,095	46.34	22	9,895,643	2.4	11.60	17.31	21,057,503	5.11
324 ACCESSORY ELECTRIC EQUIPMENT	119,762,438	49,415,234	56.28	26	2,155,724	1.8	41.26	18.68	3,830,023	3.20
325 MISCELLANEOUS POWER PLANT EQUIPMENT	11,320,232	6,997,958	54.55	25	203,764	1.8	61.82	15.87	293,754	2.59
TOTAL ST. LUCIE UNIT 1	*1,576,204,754*	*497,854,096*			*32,521,744*	*2.1*			*61,537,758*	*3.90*
ST. LUCIE UNIT 2										
321 STRUCTURES AND IMPROVEMENTS	297,759,844	130,332,823	42.86	32	5,359,677	1.8	43.77	25.16	6,772,839	2.27
322 REACTOR PLANT EQUIPMENT	1,053,686,661	387,788,728	42.00	30	21,073,733	2.0	36.80	23.70	28,986,146	2.75
323 TURBOGENERATOR UNITS	350,014,044	46,854,392	34.15	27	8,400,337	2.4	13.39	22.42	13,521,840	3.86
324 ACCESSORY ELECTRIC EQUIPMENT	188,938,115	84,917,442	43.97	33	3,400,886	1.8	44.94	24.68	4,291,331	2.27
325 MISCELLANEOUS POWER PLANT EQUIPMENT	24,130,684	11,189,066	41.82	32	434,352	1.8	46.37	20.78	657,629	2.73
TOTAL ST. LUCIE UNIT 2	*1,914,529,349*	*661,082,451*			*38,668,985*	*2.0*			*54,229,785*	*2.83*
TOTAL ST. LUCIE NUCLEAR PLANT	***4,010,776,637***	***1,378,225,011***			***80,737,041***	***2.0***			***128,216,666***	***3.20***
TURKEY POINT NUCLEAR PLANT										
TURKEY POINT COMMON										
321 STRUCTURES AND IMPROVEMENTS	360,056,132	183,734,299	58.93	23	6,481,010	1.8	51.03	15.98	11,259,224	3.13
322 REACTOR PLANT EQUIPMENT	137,627,469	24,011,347	58.00	22	2,752,549	2.0	17.45	15.58	7,469,106	5.43
323 TURBOGENERATOR UNITS	21,825,767	5,398,454	51.46	19.9	523,818	2.4	24.73	14.91	1,101,765	5.05
324 ACCESSORY ELECTRIC EQUIPMENT	53,673,512	34,021,888	61.55	23	966,123	1.8	63.39	15.97	1,264,143	2.36
325 MISCELLANEOUS POWER PLANT EQUIPMENT	37,213,998	17,421,764	58.18	23	669,852	1.8	46.82	15.30	1,366,579	3.67
TOTAL TURKEY POINT COMMON	*610,396,877*	*264,587,751*			*11,393,352*	*1.9*			*22,460,817*	*3.68*
TURKEY POINT UNIT 3										
321 STRUCTURES AND IMPROVEMENTS	183,462,252	38,437,467	58.93	23	3,302,321	1.8	20.95	15.31	9,592,385	5.23
322 REACTOR PLANT EQUIPMENT	586,039,767	168,441,241	58.00	22	11,720,795	2.0	28.74	14.82	28,968,915	4.94
323 TURBOGENERATOR UNITS	756,080,929	81,959,597	51.46	19.9	18,145,942	2.4	10.84	14.39	46,846,514	6.20
324 ACCESSORY ELECTRIC EQUIPMENT	150,385,799	72,326,463	61.55	23	2,706,944	1.8	48.09	15.28	5,207,015	3.46
325 MISCELLANEOUS POWER PLANT EQUIPMENT	15,687,982	752,238	58.18	23	282,384	1.8	4.79	14.84	1,038,166	6.62
TOTAL TURKEY POINT UNIT 3	*1,691,656,730*	*361,917,007*			*36,158,386*	*2.1*			*91,652,995*	*5.42*
TURKEY POINT UNIT 4										
321 STRUCTURES AND IMPROVEMENTS	128,297,844	49,379,171	58.93	23	2,309,361	1.8	38.49	16.01	5,009,472	3.90
322 REACTOR PLANT EQUIPMENT	514,072,790	183,833,792	58.00	22	10,281,456	2.0	35.76	15.49	21,983,244	4.28
323 TURBOGENERATOR UNITS	599,706,206	78,908,563	51.46	19.9	14,392,949	2.4	13.16	15.02	34,673,611	5.78
324 ACCESSORY ELECTRIC EQUIPMENT	175,176,467	103,877,312	61.55	23	3,153,176	1.8	59.30	15.93	4,585,745	2.62
325 MISCELLANEOUS POWER PLANT EQUIPMENT	11,936,247	187,688	58.18	23	214,852	1.8	1.57	15.48	782,083	6.55
TOTAL TURKEY POINT UNIT 4	*1,429,189,554*	*416,186,526*			*30,351,794*	*2.1*			*67,034,155*	*4.69*
TOTAL TURKEY POINT NUCLEAR PLANT	***3,731,243,161***	***1,042,691,284***			***77,903,532***	***2.1***			***181,147,967***	***4.85***
TOTAL NUCLEAR PRODUCTION PLANT	**7,742,019,799**	**2,420,916,295**			**158,640,573**	***2.0***			**309,364,633**	***4.00***

FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009				PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
COMBINED CYCLE PRODUCTION PLANT										
LAUDERDALE COMBINED CYCLE PLANT										
LAUDERDALE COMMON										
341 STRUCTURES AND IMPROVEMENTS	84,760,736	56,466,915	55.22	13.3	2,966,626	3.5	66.62	16.08	1,864,990	2.20
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	11,513,771	6,416,278	51.54	12.6	437,523	3.8	55.73	15.29	355,978	3.09
343 PRIME MOVERS - GENERAL	27,106,051	5,912,889	47.02 *	8.9 **	1,626,363	6.0	21.81	15.62	1,408,857	5.20
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	37,564,239	7,262,311	47.02 *	8.9 **	2,253,854	6.0	19.33	7.11	2,412,721	6.42
344 GENERATORS	680,446	405,162	56.22	13.3	23,135	3.4	59.54	15.89	18,609	2.73
345 ACCESSORY ELECTRIC EQUIPMENT	12,121,303	9,401,592	55.89	13.4	412,124	3.4	77.56	15.25	194,238	1.60
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,234,438	609,250	54.48	*13.2*	41,971	3.4	49.35	15.38	42,255	3.42
TOTAL LAUDERDALE COMMON	*174,980,983*	*86,474,396*			*7,761,596*	*4.4*			*6,297,648*	*3.60*
LAUDERDALE UNIT 4										
341 STRUCTURES AND IMPROVEMENTS	5,090,645	3,478,638	55.22	13.3	178,173	3.5	68.33	16.07	106,647	2.09
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	673,633	511,484	51.54	12.6	25,598	3.8	75.93	15.20	11,997	1.78
343 PRIME MOVERS - GENERAL	121,376,511	49,359,731	51.30 *	11.2 **	5,219,190	4.3	40.67	15.16	4,990,638	4.11
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	64,237,235	8,573,139	51.30 *	11.2 **	2,762,201	4.3	13.35	6.74	4,923,007	7.66
344 GENERATORS	28,799,680	20,523,754	56.22	13.3	979,189	3.4	71.26	15.69	582,531	2.02
345 ACCESSORY ELECTRIC EQUIPMENT	29,810,853	19,234,929	55.89	*13.4*	1,013,569	3.4	64.52	15.43	724,053	2.43
346 MISCELLANEOUS POWER PLANT EQUIPMENT	2,599,158	1,902,628	54.48	13.2	88,371	3.4	73.20	14.87	50,337	1.94
TOTAL LAUDERDALE UNIT 4	*252,587,715*	*103,584,302*			*10,266,291*	*4.1*			*11,389,210*	*4.51*
LAUDERDALE UNIT 5										
341 STRUCTURES AND IMPROVEMENTS	3,203,159	1,949,981	55.22	13.3	112,111	3.5	60.88	16.11	81,765	2.55
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	742,434	503,872	51.54	12.6	28,212	3.8	67.87	15.38	16,959	2.28
343 PRIME MOVERS - GENERAL	121,964,623	33,068,495	52.08 *	11.5 **	5,122,514	4.2	27.11	15.19	6,093,158	5.00
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	24,160,830	1,666,194	52.08 *	11.5 **	1,014,755	4.2	6.90	7.21	1,947,066	8.06
344 GENERATORS	31,767,828	22,571,172	56.22	*13.3*	1,080,106	3.4	71.05	15.76	644,016	2.03
345 ACCESSORY ELECTRIC EQUIPMENT	24,918,023	15,461,507	55.89	13.4	847,213	3.4	62.05	15.51	641,836	2.58
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,810,688	1,287,343	54.48	*13.2*	61,563	3.4	71.10	14.89	37,579	2.08
TOTAL LAUDERDALE UNIT 5	*208,567,584*	*76,508,564*			*8,266,474*	*4.0*			*9,462,379*	*4.54*
TOTAL LAUDERDALE COMBINED CYCLE PLANT	***636,136,282***	***266,567,261***			***26,294,361***	***4.1***			***27,149,237***	***4.27***

Docket No. 160021-EI
1st, 2nd and 3rd Notices of Identified Adjustments
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FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009						PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
FT. MYERS COMBINED CYCLE PLANT										
FT. MYERS COMMON										
341 STRUCTURES AND IMPROVEMENTS	8,824,312	2,131,886	21.10	23	308,851	3.5	24.16	25.06	274,099	3.11
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	794,049	284,358	19.23	21	30,174	3.8	35.81	15.56	34,287	4.32
343 PRIME MOVERS - GENERAL	3,709,607	1,045,250	18.71 *	13.9 **	215,157	5.8	28.18	23.96	115,845	3.12
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	441,577	231,377	18.71 *	13.9 **	25,611	5.8	52.40	5.82	9,562	2.17
344 GENERATORS	230,729	16,354	23.57	23	7,845	3.4	7.09	25.42	8,706	3.77
345 ACCESSORY ELECTRIC EQUIPMENT	1,163,312	139,908	23.57	*23*	39,553	3.4	12.03	24.91	42,018	3.61
346 MISCELLANEOUS POWER PLANT EQUIPMENT	768,815	197,971	20.69	23	26,140	3.4	25.75	22.83	25,678	3.34
TOTAL FT. MYERS COMMON	*15,932,401*	*4,047,105*			*653,331*	*4.1*			*510,195*	*3.20*
FT. MYERS UNIT 2										
341 STRUCTURES AND IMPROVEMENTS	28,751,597	12,204,747	24.62	22	1,006,306	3.5	42.45	25.41	673,825	2.34
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	6,194,175	1,967,815	23.08	20	235,379	3.8	31.77	23.43	188,313	3.04
343 PRIME MOVERS - GENERAL	367,522,551	79,088,073	25.00 *	18 **	15,435,947	4.2	21.52	23.53	12,726,738	3.46
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	302,123,631	39,131,213	25.00 *	18 **	12,689,192	4.2	12.95	7.01	22,432,118	7.42
344 GENERATORS	57,280,635	19,398,986	26.93	*22*	1,947,542	3.4	33.87	24.73	1,601,297	2.80
345 ACCESSORY ELECTRIC EQUIPMENT	55,628,985	25,417,944	26.93	22	1,891,385	3.4	45.69	24.10	1,299,735	2.34
346 MISCELLANEOUS POWER PLANT EQUIPMENT	3,539,476	1,628,771	24.14	22	120,342	3.4	46.02	22.90	86,528	2.44
TOTAL FT. MYERS UNIT 2	*821,041,049*	*178,837,550*			*33,326,093*	*4.1*			*39,008,554*	*4.75*
FT. MYERS UNIT 3										
341 STRUCTURES AND IMPROVEMENTS	10,445,289	1,539,033	21.10	23	365,585	3.5	14.73	25.82	353,027	3.38
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	13,425,923	2,081,549	19.23	*21*	510,185	3.8	15.50	24.47	480,063	3.58
343 PRIME MOVERS - GENERAL	164,165,759	(10,456,672)	18.85 *	15.5 **	8,536,619	5.2	-6.37	24.09	7,453,192	4.54
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	20,183,733	(1,479,151)	18.85 *	15.5 **	1,049,554	5.2	-7.33	19.90	794,452	3.94
344 GENERATORS	46,926,130	7,152,354	23.57	*23*	1,595,488	3.4	15.24	25.38	1,622,599	3.46
345 ACCESSORY ELECTRIC EQUIPMENT	32,964,437	5,278,646	23.57	*23*	1,120,791	3.4	16.01	25.32	1,119,474	3.40
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,734,913	212,247	20.69	*23*	58,987	3.4	12.23	24.53	63,488	3.66
TOTAL FT. MYERS UNIT 3	*289,846,185*	*4,328,006*			*13,237,209*	*4.6*			*11,886,295*	*4.10*
TOTAL FT. MYERS COMBINED CYCLE PLANT	***1,126,819,634***	***187,212,661***			***47,216,633***	***4.2***			***51,405,044***	***4.56***
MANATEE COMBINED CYCLE PLANT										
MANATEE UNIT 3										
341 STRUCTURES AND IMPROVEMENTS	28,927,929	10,726,313	14.07	25	1,012,478	3.5	37.08	27.38	685,908	2.37
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	4,008,361	1,497,584	11.54	*23*	152,318	3.8	37.36	25.26	104,158	2.60
343 PRIME MOVERS - GENERAL	236,795,038	46,167,493	13.04 *	20 **	10,182,187	4.3	19.50	24.95	7,925,106	3.35
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	146,248,668	19,013,518	13.04 *	20 **	6,288,693	4.3	13.00	6.60	11,522,442	7.88
344 GENERATORS	41,417,902	16,420,596	16.83	25	1,408,209	3.4	39.65	26.60	986,460	2.38
345 ACCESSORY ELECTRIC EQUIPMENT	45,110,148	16,629,259	16.83	25	1,533,745	3.4	36.86	26.16	1,123,207	2.49
346 MISCELLANEOUS POWER PLANT EQUIPMENT	10,976,397	3,676,138	13.79	25	373,197	3.4	33.49	24.71	304,322	2.77
TOTAL MANATEE UNIT 3	*513,484,442*	*114,130,902*			*20,950,827*	*4.1*			*22,651,603*	*4.41*
TOTAL MANATEE COMBINED CYCLE PLANT	***513,484,442***	***114,130,902***			***20,950,827***	***4.1***			***22,651,603***	***4.41***

FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009				PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
MARTIN COMBINED CYCLE PLANT										
MARTIN COMMON										
341 STRUCTURES AND IMPROVEMENTS	49,379,840	31,469,365	52.06	*14.2*	1,728,294	3.5	63.73	17.05	1,108,391	2.24
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	4,766,331	3,048,070	48.08	13.5	181,121	3.8	63.95	16.15	115,248	2.42
343 PRIME MOVERS - GENERAL	22,788,940	14,037,911	47.83 *	12 **	979,924	4.3	61.60	16.17	583,469	2.56
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	2,230,422	770,616	47.83 *	12 **	95,908	4.3	34.55	6.01	113,005	5.07
345 ACCESSORY ELECTRIC EQUIPMENT	5,321,992	3,662,480	52.52	14.4	180,948	3.4	68.82	16.28	108,474	2.04
346 MISCELLANEOUS POWER PLANT EQUIPMENT	4,194,043	2,750,673	51.03	14.2	142,597	3.4	65.59	15.74	97,030	2.31
TOTAL MARTIN COMMON	*88,681,567*	*55,739,115*			*3,308,792*	*3.7*			*2,125,617*	*2.40*
MARTIN UNIT 3										
341 STRUCTURES AND IMPROVEMENTS	1,660,028	1,129,406	52.06	14.2	58,101	3.5	68.04	17.02	33,127	2.00
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	178,721	126,140	48.08	13.5	6,791	3.8	70.58	15.96	3,631	2.03
343 PRIME MOVERS - GENERAL	152,279,614	46,856,499	47.92 *	12.5 **	6,395,744	4.2	30.77	16.10	6,831,770	4.49
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	67,628,799	4,931,417	47.92 *	12.5 **	2,840,410	4.2	7.29	7.50	5,203,640	7.69
344 GENERATORS	26,577,658	12,491,844	52.86	14.3	903,640	3.4	47.00	16.83	884,322	3.33
345 ACCESSORY ELECTRIC EQUIPMENT	28,440,138	16,413,361	52.52	*14.4*	966,965	3.4	57.71	16.44	766,155	2.69
346 MISCELLANEOUS POWER PLANT EQUIPMENT	569,569	403,368	51.03	14.2	19,365	3.4	70.82	15.63	11,362	1.99
TOTAL MARTIN UNIT 3	*277,334,527*	*82,352,034*			*11,191,016*	*4.0*			*13,734,007*	*4.95*
MARTIN UNIT 4										
341 STRUCTURES AND IMPROVEMENTS	1,498,690	779,399	52.06	14.2	52,454	3.5	52.01	17.08	43,868	2.93
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	178,315	125,767	48.08	13.5	6,776	3.8	70.53	15.96	3,628	2.03
343 PRIME MOVERS - GENERAL	157,866,532	62,665,792	48.33 *	12.4 **	6,630,394	4.2	39.70	16.16	6,184,204	3.92
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	100,540,570	14,593,390	48.33 *	12.4 **	4,222,704	4.2	14.51	6.94	7,313,830	7.27
344 GENERATORS	32,812,957	17,243,431	52.86	*14.3*	1,115,641	3.4	52.55	16.82	984,180	3.00
345 ACCESSORY ELECTRIC EQUIPMENT	25,564,311	14,499,926	52.52	14.4	869,187	3.4	56.72	16.46	703,261	2.75
346 MISCELLANEOUS POWER PLANT EQUIPMENT	826,194	416,190	51.03	*14.2*	28,091	3.4	50.37	16.21	26,313	3.18
TOTAL MARTIN UNIT 4	*319,287,568*	*110,323,895*			*12,925,247*	*4.0*			*15,259,284*	*4.78*
MARTIN UNIT 8										
341 STRUCTURES AND IMPROVEMENTS	23,755,210	8,515,386	14.07	25	831,432	3.5	35.85	27.38	573,956	2.42
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	11,392,824	3,970,615	11.54	23	432,927	3.8	34.85	25.22	307,851	2.70
343 PRIME MOVERS - GENERAL	256,002,412	48,218,164	13.04 *	20 **	11,008,104	4.3	18.84	25.00	8,618,573	3.37
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	213,276,994	24,119,658	13.04 *	20 **	9,170,911	4.3	11.31	6.92	16,547,744	7.76
344 GENERATORS	41,069,900	13,445,958	16.83	25	1,396,377	3.4	32.74	26.58	1,085,630	2.64
345 ACCESSORY ELECTRIC EQUIPMENT	51,655,998	17,489,445	16.83	*25*	1,756,304	3.4	33.86	26.06	1,350,717	2.61
346 MISCELLANEOUS POWER PLANT EQUIPMENT	4,899,017	1,751,981	17.24	24	166,567	3.4	35.76	24.88	130,427	2.66
TOTAL MARTIN UNIT 8	*602,052,355*	*117,511,209*			*24,762,622*	*4.1*			*28,614,898*	*4.75*
TOTAL MARTIN COMBINED CYCLE PLANT	***1,287,356,017***	***365,926,253***			***52,187,677***	***4.1***			***59,733,806***	***4.64***

Docket No. 160021-EI
1st, 2nd and 3rd Notices of Identified Adjustments
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FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009					PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
SANFORD COMBINED CYCLE PLANT										
SANFORD COMMON										
341 STRUCTURES AND IMPROVEMENTS	71,585,766	29,616,249	24.62	22	2,505,502	3.5	41.37	25.28	1,716,821	2.40
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	88,875	42,745	23.08	20	3,377	3.8	48.10	23.56	2,071	2.33
343 PRIME MOVERS - GENERAL	5,932,378	(4,737,256)	19.09 *	17.8 **	266,957	4.5	-79.85	22.96	472,457	7.96
344 GENERATORS	200,500	36,233	26.93	22	6,817	3.4	18.07	25.29	6,733	3.36
345 ACCESSORY ELECTRIC EQUIPMENT	2,142,789	643,155	26.93	22	72,855	3.4	30.01	23.55	65,499	3.06
346 MISCELLANEOUS POWER PLANT EQUIPMENT	2,233,762	820,161	24.14	22	75,948	3.4	36.72	23.23	62,776	2.81
TOTAL SANFORD COMMON	*82,184,069*	*26,421,287*			*2,931,456*	*3.6*			*2,326,357*	*2.83*
SANFORD UNIT 4										
341 STRUCTURES AND IMPROVEMENTS	7,424,610	3,124,501	21.10	*23*	259,861	3.5	42.08	25.09	177,306	2.39
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,803,717	789,469	19.23	21	68,541	3.8	43.77	23.63	45,212	2.51
343 PRIME MOVERS - GENERAL	196,875,732	18,672,684	20.00 *	16.8 **	9,450,035	4.8	9.48	23.36	7,881,392	4.00
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	140,077,308	7,071,393	20.00 *	16.8 **	6,723,711	4.8	5.05	6.94	12,100,700	8.64
344 GENERATORS	32,820,452	10,272,329	23.57	23	1,115,895	3.4	31.30	24.81	948,518	2.89
345 ACCESSORY ELECTRIC EQUIPMENT	35,200,492	14,915,272	23.57	23	1,196,817	3.4	42.37	23.91	877,843	2.49
346 MISCELLANEOUS POWER PLANT EQUIPMENT	3,326,653	1,415,407	20.69	23	113,106	3.4	42.55	23.03	85,878	2.58
TOTAL SANFORD UNIT 4	*417,528,965*	*56,261,055*			*18,927,966*	*4.5*			*22,116,849*	*5.30*
SANFORD UNIT 5										
341 STRUCTURES AND IMPROVEMENTS	7,275,953	3,148,967	24.62	*22*	254,658	3.5	43.28	24.28	175,968	2.42
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,814,776	859,918	23.08	20	68,961	3.8	47.38	22.77	44,326	2.44
343 PRIME MOVERS - GENERAL	214,894,008	20,990,061	24.58 *	18.1 **	9,025,548	4.2	9.77	22.61	8,861,157	4.12
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	126,367,538	6,255,267	24.58 *	18.1 **	5,307,437	4.2	4.95	7.00	10,840,519	8.58
344 GENERATORS	32,632,812	11,677,845	26.93	22	1,109,516	3.4	35.79	23.92	916,971	2.81
345 ACCESSORY ELECTRIC EQUIPMENT	34,685,483	14,818,331	26.93	22	1,179,306	3.4	42.72	23.15	888,158	2.56
346 MISCELLANEOUS POWER PLANT EQUIPMENT	2,899,894	1,243,698	24.14	22	98,596	3.4	42.89	22.31	76,835	2.65
TOTAL SANFORD UNIT 5	*420,570,464*	*58,994,088*			*17,044,022*	*4.1*			*21,803,934*	*5.18*
TOTAL SANFORD COMBINED CYCLE PLANT	***920,283,497***	***141,676,429***			***38,903,444***	***4.2***			***46,247,140***	***5.03***
TURKEY POINT COMBINED CYCLE PLANT										
TURKEY POINT UNIT 5										
341 STRUCTURES AND IMPROVEMENTS	32,284,855	10,891,633	7.03	27	1,129,970	3.5	33.74	29.27	752,952	2.33
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	12,410,131	4,106,992	7.69	24	471,585	3.8	33.09	26.99	321,432	2.59
343 PRIME MOVERS - GENERAL	250,685,264	39,618,917	9.66 *	15.9 **	14,289,060	5.7	15.80	26.56	8,229,929	3.28
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	128,220,285	12,943,274	9.66 *	15.9 **	7,308,556	5.7	10.09	7.07	9,957,555	7.77
344 GENERATORS	41,669,542	11,132,485	10.10	27	1,416,764	3.4	26.72	28.45	1,117,299	2.68
345 ACCESSORY ELECTRIC EQUIPMENT	51,980,475	16,506,639	10.10	27	1,767,336	3.4	31.76	27.96	1,305,917	2.51
346 MISCELLANEOUS POWER PLANT EQUIPMENT	12,433,804	3,613,736	6.90	27	422,749	3.4	29.06	26.47	342,605	2.76
TOTAL TURKEY POINT UNIT 5	*529,684,355*	*98,813,676*			*26,806,020*	*5.1*			*22,027,689*	*4.16*
TOTAL TURKEY POINT COMBINED CYCLE PLANT	***529,684,355***	***98,813,676***			***26,806,020***	***5.1***			***22,027,689***	***4.16***

FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

				ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009					PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
WEST COUNTY COMBINED CYCLE PLANT										
WEST COUNTY COMMON										
341 STRUCTURES AND IMPROVEMENTS	3,120,798	482,630	0.00 ***	30 ***	102,986	3.3	15.46	33.12	81,539	2.61
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	450,604	68,020	0.00 ***	30 ***	14,870	3.3	15.10	30.44	13,013	2.89
343 PRIME MOVERS - GENERAL	31,206,902	1,389,969	0.00 ***	30 ***	1,029,828	3.3	4.45	30.22	1,017,642	3.26
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	126,771,982	12,726,022	0.00 ***	30 ***	4,183,475	3.3	10.04	7.32	9,518,547	7.51
345 ACCESSORY ELECTRIC EQUIPMENT	1,291,342	107,199	0.00 ***	30 ***	42,614	3.3	8.30	32.12	37,670	2.92
346 MISCELLANEOUS POWER PLANT EQUIPMENT	836,533	111,543	0.00 ***	30 ***	27,606	3.3	13.33	30.31	24,471	2.93
TOTAL WEST COUNTY COMMON	*163,678,161*	*14,885,382*			*5,401,379*	*3.3*			*10,692,882*	*6.53*
WEST COUNTY UNIT 1										
341 STRUCTURES AND IMPROVEMENTS	109,835,744	20,012,782	0.00 ***	30 ***	3,624,580	3.3	18.22	31.19	2,950,294	2.69
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	21,806,447	2,710,694	0.00 ***	30 ***	719,613	3.3	12.43	28.76	686,716	3.15
343 PRIME MOVERS - GENERAL	300,710,821	(22,756,245)	0.00 ***	30 ***	9,923,457	3.3	-7.57	28.21	11,786,189	3.92
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	81,954,083	(7,349,277)	0.00 ***	30 ***	2,704,485	3.3	-8.97	6.27	9,668,171	11.80
344 GENERATORS	49,469,105	7,847,276	0.00 ***	30 ***	1,632,480	3.3	15.86	30.31	1,422,168	2.87
345 ACCESSORY ELECTRIC EQUIPMENT	72,300,016	12,231,627	0.00 ***	30 ***	2,385,901	3.3	16.92	29.82	2,062,857	2.85
346 MISCELLANEOUS POWER PLANT EQUIPMENT	8,042,081	1,335,110	0.00 ***	30 ***	265,389	3.3	16.60	28.22	243,367	3.03
TOTAL WEST COUNTY UNIT 1	*644,118,297*	*14,031,966*			*21,255,905*	*3.3*			*28,819,762*	*4.47*
WEST COUNTY UNIT 2										
341 STRUCTURES AND IMPROVEMENTS	39,659,646	6,204,493	0.00 ***	30 ***	1,308,768	3.3	15.64	31.19	1,098,055	2.77
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	7,471,457	284,961	0.00 ***	30 ***	246,558	3.3	3.81	28.84	256,957	3.44
343 PRIME MOVERS - GENERAL	255,637,285	17,744,809	0.00 ***	30 ***	8,436,030	3.3	6.94	28.19	8,710,947	3.41
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	149,878,251	12,481,512	0.00 ***	30 ***	4,945,982	3.3	8.33	6.19	13,722,028	9.16
344 GENERATORS	43,599,023	6,676,878	0.00 ***	30 ***	1,438,768	3.3	15.31	30.32	1,260,888	2.89
345 ACCESSORY ELECTRIC EQUIPMENT	33,177,136	5,335,502	0.00 ***	30 ***	1,094,845	3.3	16.08	29.82	955,908	2.88
346 MISCELLANEOUS POWER PLANT EQUIPMENT	11,893,351	1,719,196	0.00 ***	30 ***	392,481	3.3	14.46	28.41	366,491	3.08
TOTAL WEST COUNTY UNIT 2	*541,316,149*	*50,447,351*			*17,863,432*	*3.3*			*26,371,274*	*4.87*
WEST COUNTY UNIT 3										
341 STRUCTURES AND IMPROVEMENTS	57,671,242	8,518,122	0.00 ***	30 ***	1,903,151	3.3	14.77	33.08	1,520,754	2.64
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	10,754,858	742,790	0.00 ***	30 ***	354,910	3.3	6.91	30.48	339,065	3.15
343 PRIME MOVERS - GENERAL	480,389,197	32,738,513	0.00 ***	30 ***	15,852,844	3.3	6.81	29.77	15,521,074	3.23
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	98,598,036	8,887,181	0.00 ***	30 ***	3,253,735	3.3	9.01	6.60	8,363,870	8.48
344 GENERATORS	64,525,280	9,184,372	0.00 ***	30 ***	2,129,334	3.3	14.23	32.17	1,780,437	2.76
345 ACCESSORY ELECTRIC EQUIPMENT	48,252,610	7,322,267	0.00 ***	30 ***	1,592,336	3.3	15.17	31.68	1,322,456	2.74
346 MISCELLANEOUS POWER PLANT EQUIPMENT	12,454,466	7,732,043	0.00 ***	30 ***	410,997	3.3	62.08	29.98	165,828	1.33
TOTAL WEST COUNTY UNIT 3	*772,645,690*	*75,125,287*			*25,497,307*	*3.3*			*29,013,484*	*3.76*
TOTAL WEST COUNTY COMBINED CYCLE PLANT	***2,121,758,297***	***154,489,986***			***70,018,023***	***3.3***			***94,897,402***	***4.47***

FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009						PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
CAPE CANAVERAL COMBINED CYCLE PLANT										
CAPE CANAVERAL COMBINED CYCLE										
341 STRUCTURES AND IMPROVEMENTS	82,092,869	6,368,724	0.00 ***	30 ***	2,709,065	3.3	7.76	34.98	2,211,721	2.69
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	47,723,728	3,579,557	0.00 ***	30 ***	1,574,883	3.3	7.50	32.18	1,416,280	2.97
343 PRIME MOVERS - GENERAL	385,108,676	38,729,543	0.00 ***	30 ***	12,708,586	3.3	10.06	31.38	11,406,386	2.96
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	206,255,249	28,539,906	0.00 ***	30 ***	6,806,423	3.3	13.84	7.38	14,298,917	6.93
344 GENERATORS	70,269,257	5,194,564	0.00 ***	30 ***	2,318,885	3.3	7.39	34.03	1,974,222	2.81
345 ACCESSORY ELECTRIC EQUIPMENT	111,693,785	8,403,920	0.00 ***	30 ***	3,685,895	3.3	7.52	33.59	3,141,522	2.81
346 MISCELLANEOUS POWER PLANT EQUIPMENT	10,309,493	738,999	0.00 ***	30 ***	340,213	3.3	7.17	31.85	306,960	2.98
TOTAL CAPE CANAVERAL COMBINED CYCLE	*913,453,057*	*91,555,214*			*30,143,950*	*3.3*			*34,756,008*	*3.80*
TOTAL CAPE CANAVERAL COMBINED CYCLE PLANT	***913,453,057***	***91,555,214***			***30,143,950***	***3.3***			***34,756,008***	***3.80***
RIVIERA COMBINED CYCLE PLANT										
RIVIERA COMBINED CYCLE										
341 STRUCTURES AND IMPROVEMENTS	80,630,958	7,456,698	0.00 ***	30 ***	2,660,822	3.3	9.25	35.90	2,083,200	2.58
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	217,306,004	18,577,338	0.00 ***	30 ***	7,171,098	3.3	8.55	33.03	6,213,983	2.86
343 PRIME MOVERS - GENERAL	525,780,412	35,938,896	0.00 ***	30 ***	17,350,754	3.3	6.84	32.21	15,697,452	2.99
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	139,494,633	16,409,879	0.00 ***	30 ***	4,603,323	3.3	11.76	7.56	9,822,967	7.04
344 GENERATORS	79,977,232	5,875,063	0.00 ***	30 ***	2,639,249	3.3	7.35	34.97	2,187,632	2.74
345 ACCESSORY ELECTRIC EQUIPMENT	82,800,568	6,849,745	0.00 ***	30 ***	2,732,419	3.3	8.27	34.50	2,249,473	2.72
346 MISCELLANEOUS POWER PLANT EQUIPMENT	11,446,561	1,663,361	0.00 ***	30 ***	377,737	3.3	14.53	32.80	305,248	2.67
TOTAL RIVIERA COMBINED CYCLE	*1,137,436,368*	*92,770,979*			*37,535,402*	*3.3*			*38,559,955*	*3.39*
TOTAL RIVIERA COMBINED CYCLE PLANT	***1,137,436,368***	***92,770,979***			***37,535,402***	***3.3***			***38,559,955***	***3.39***
PT EVERGLADES COMBINED CYCLE PLANT										
PT EVERGLADES COMBINED CYCLE										
341 STRUCTURES AND IMPROVEMENTS	101,607,532	2,299,667	0.00 ***	30 ***	3,353,049	3.3	2.26	37.84	2,678,119	2.64
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	59,665,117	1,350,391	0.00 ***	30 ***	1,968,949	3.3	2.26	34.77	1,728,636	2.90
343 PRIME MOVERS - GENERAL	499,500,579	8,382,316	0.00 ***	30 ***	16,483,519	3.3	1.68	33.84	14,955,771	2.99
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	191,363,196	7,253,893	0.00 ***	30 ***	6,314,985	3.3	3.79	8.61	13,604,203	7.11
344 GENERATORS	87,208,139	1,973,768	0.00 ***	30 ***	2,877,869	3.3	2.26	36.84	2,384,653	2.73
345 ACCESSORY ELECTRIC EQUIPMENT	138,483,956	3,134,285	0.00 ***	30 ***	4,569,971	3.3	2.26	36.42	3,792,404	2.74
346 MISCELLANEOUS POWER PLANT EQUIPMENT	12,795,087	289,589	0.00 ***	30 ***	422,238	3.3	2.26	34.72	367,552	2.87
TOTAL PT EVERGLADES COMBINED CYCLE	*1,090,623,606*	*24,683,910*			*35,990,580*	*3.3*			*39,511,338*	*3.62*
TOTAL PT EVERGLADES COMBINED CYCLE PLANT	***1,090,623,606***	***24,683,910***			***35,990,580***	***3.3***			***39,511,338***	***3.62***
TOTAL COMBINED CYCLE PRODUCTION PLANT	**10,277,035,554**	**1,537,827,272**			**386,046,917**	***3.8***			**436,939,222**	***4.25***

FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009						PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
PEAKER PLANTS										
LAUDERDALE GTS										
341 STRUCTURES AND IMPROVEMENTS	601,222	330,322	79.43 ***	10.4 ***	13,227	2.2	54.94	11.26	25,126	4.18
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	194,417	102,093	74.62 ***	9.9 ***	5,055	2.6	52.51	10.68	9,191	4.73
343 PRIME MOVERS - GENERAL	14,841,925	1,714,581	73.82 ***	8.9 ***	430,416	2.9	11.55	11.08	1,224,964	8.25
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	1,858,779	673,466	73.82 ***	8.9 ***	53,905	2.9	36.23	8.31	77,770	4.18
344 GENERATORS	1,748,135	750,005	79.12 ***	10.4 ***	36,711	2.1	42.90	10.61	99,017	5.66
345 ACCESSORY ELECTRIC EQUIPMENT	420,107	174,657	79.12 ***	10.4 ***	8,822	2.1	41.57	10.04	25,284	6.02
346 MISCELLANEOUS POWER PLANT EQUIPMENT	20,935	8,570	77.61 ***	10.3 ***	461	2.2	40.94	9.84	1,299	6.21
TOTAL LAUDERDALE GTS	*19,685,520*	*3,753,692*			*548,597*	*2.8*			*1,462,651*	***7.43***
FT. MYERS GTS										
341 STRUCTURES AND IMPROVEMENTS	941,093	168,137	77.89 ***	10.4 ***	21,645	2.3	17.87	11.37	69,637	7.40
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	724,318	117,795	73.24 ***	9.9 ***	19,557	2.7	16.26	11.07	56,753	7.84
343 PRIME MOVERS - GENERAL	10,218,903	1,207,170	72.81 ***	8.7 ***	316,786	3.1	11.81	11.09	840,243	8.22
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	2,807,095	1,254,825	72.81 ***	8.7 ***	87,020	3.1	44.70	6.28	117,550	4.19
344 GENERATORS	4,602,022	551,085	77.66 ***	10.4 ***	101,244	2.2	11.97	11.27	371,695	8.08
345 ACCESSORY ELECTRIC EQUIPMENT	3,450,438	485,852	77.66 ***	10.4 ***	75,910	2.2	14.08	11.32	267,985	7.77
346 MISCELLANEOUS POWER PLANT EQUIPMENT	20,936	2,632	76.59 ***	10.3 ***	482	2.3	12.57	11.13	1,682	8.03
TOTAL FT. MYERS GTS	*22,764,804*	*3,787,495*			*622,644*	*2.7*			*1,725,545*	***7.58***
LAUDERDALE AND FT. MYERS PEAKERS										
341 STRUCTURES AND IMPROVEMENTS	43,805,886	76,824	0.00 ***	30 ***	1,445,594	3.3	0.18	37.84	1,178,784	2.69
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	26,150,085	45,861	0.00 ***	30 ***	862,953	3.3	0.18	34.77	773,331	2.96
343 PRIME MOVERS - GENERAL	213,843,171	389,972	0.00 ***	30 ***	7,056,825	3.3	0.18	33.84	6,497,296	3.04
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	83,870,827	132,142	0.00 ***	30 ***	2,767,737	3.3	0.16	24.32	2,443,098	2.91
344 GENERATORS	38,221,667	67,031	0.00 ***	30 ***	1,261,315	3.3	0.18	36.84	1,066,810	2.79
345 ACCESSORY ELECTRIC EQUIPMENT	60,694,881	106,443	0.00 ***	30 ***	2,002,931	3.3	0.18	36.42	1,696,934	2.80
346 MISCELLANEOUS POWER PLANT EQUIPMENT	5,607,843	9,835	0.00 ***	30 ***	185,059	3.3	0.18	34.72	164,463	2.93
TOTAL LAUDERDALE AND FT. MYERS PEAKERS	*472,194,358*	*828,108*			*15,582,414*	*3.3*			*13,820,716*	*2.93*
TOTAL PEAKER PLANTS	**514,644,682**	**8,369,296**			**16,753,655**	***3.3***	1.63		**17,008,912**	***3.30***

FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009				PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
SOLAR PRODUCTION PLANT										
DESOTO SOLAR										
341 STRUCTURES AND IMPROVEMENTS	4,635,209	990,040	0.00	30	152,962	3.3	21.36	22.52	161,864	3.49
343 PRIME MOVERS - GENERAL	118,689,127	28,800,157	0.00	30	3,916,741	3.3	24.27	22.52	3,991,517	3.36
345 ACCESSORY ELECTRIC EQUIPMENT	27,532,945	4,878,293	0.00	30	908,587	3.3	17.72	22.52	1,005,979	3.65
TOTAL DESOTOSOLAR	*150,857,280*	*34,668,490*			*4,978,290*	*3.3*			*5,159,360*	*3.42*
SPACE COAST SOLAR										
341 STRUCTURES AND IMPROVEMENTS	3,986,978	748,519	0.00	30	131,570	3.3	18.77	23.52	137,690	3.45
343 PRIME MOVERS - GENERAL	52,858,699	11,827,508	0.00	30	1,744,337	3.3	22.38	23.52	1,744,523	3.30
345 ACCESSORY ELECTRIC EQUIPMENT	6,281,496	1,091,797	0.00	30	207,289	3.3	17.38	23.52	220,650	3.51
TOTAL SPACE COAST SOLAR	*63,127,172*	*13,667,824*			*2,083,196*	*3.3*			*2,102,863*	*3.33*
MARTIN SOLAR										
341 STRUCTURES AND IMPROVEMENTS	21,320,036	3,172,447	0.00	30	703,561	3.3	14.88	28.48	637,205	2.99
343 PRIME MOVERS - GENERAL	405,752,300	73,095,004	0.00	30	13,389,826	3.3	18.01	28.47	11,684,485	2.88
345 ACCESSORY ELECTRIC EQUIPMENT	4,239,215	633,733	0.00	30	139,894	3.3	14.95	28.47	126,641	2.99
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,335	257	0.00	30	44	3.3	19.23	28.47	38	2.85
TOTAL MARTIN SOLAR	*431,312,886*	*76,901,441*			*14,233,325*	*3.3*			*12,448,369*	*2.89*
BABCOCK RANCH SOLAR										
341 STRUCTURES AND IMPROVEMENTS	4,078,184	18,086	0.00	30	134,580	3.3	0.44	29.53	137,491	3.37
343 PRIME MOVERS - GENERAL	104,118,206	461,738	0.00	30	3,435,901	3.3	0.44	29.53	3,510,209	3.37
345 ACCESSORY ELECTRIC EQUIPMENT	24,224,241	107,428	0.00	30	799,400	3.3	0.44	29.53	816,689	3.37
TOTAL BABCOCK RANCH SOLAR	*132,420,631*	*587,252*			*4,369,881*	*3.3*			*4,464,389*	*3.37*
MANATEE SOLAR										
341 STRUCTURES AND IMPROVEMENTS	4,118,679	7,223	0.00	30	135,916	3.3	0.18	29.53	139,230	3.38
343 PRIME MOVERS - GENERAL	105,224,179	184,536	0.00	30	3,472,398	3.3	0.18	29.53	3,557,049	3.38
345 ACCESSORY ELECTRIC EQUIPMENT	24,464,781	42,905	0.00	30	807,338	3.3	0.18	29.53	827,019	3.38
TOTAL MANATEE SOLAR	*133,807,639*	*234,664*			*4,415,652*	*3.3*			*4,523,298*	*3.38*
CITRUS SOLAR										
341 STRUCTURES AND IMPROVEMENTS	4,207,181	18,559	0.00	30	138,837	3.3	0.44	29.53	141,843	3.37
343 PRIME MOVERS - GENERAL	107,250,213	473,102	0.00	30	3,539,257	3.3	0.44	29.53	3,615,886	3.37
345 ACCESSORY ELECTRIC EQUIPMENT	24,990,480	110,238	0.00	30	824,686	3.3	0.44	29.53	842,541	3.37
TOTAL CITRUS SOLAR	*136,447,874*	*601,899*			*4,502,780*	*3.3*			*4,600,270*	*3.37*
TOTAL SOLAR PRODUCTION PLANT	**1,047,973,483**	**126,661,571**			**34,583,124**	***3.3***			**33,298,549**	***3.18***
TOTAL PRODUCTION PLANT	**22,795,357,882**	**5,541,188,910**			**675,925,368**	***3.0***			**913,519,786**	***4.01***

FLORIDA POWER AND LIGHT COMPANY

TABLE 7. COMPARISON OF BOOK RESERVE PERCENTS, AVERAGE REMAINING LIVES, ANNUAL DEPRECIATION RATES AND ANNUAL DEPRECIATION ACCRUALS BASED ON DEPRECIATION RATES ORDERED IN DOCKET NO. 090130-EI AND PROPOSED DEPRECIATION RATES

			ORDERED COMPONENTS IN DOCKET NO. 090130-EI AS OF DECEMBER 31, 2009				PROPOSED COMPONENTS AS OF DECEMBER 31, 2016			
	ORIGINAL COST	BOOK RESERVE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	BOOK RESERVE PERCENT	AVERAGE REMAINING LIFE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
TRANSMISSION, DISTRIBUTION, AND GENERAL PLANT										
TRANSMISSION PLANT										
350.2 EASEMENTS	240,510,767	80,181,515	22.67	58	3,126,640	1.3	33.34	53.20	3,013,708	1.25
352 STRUCTURES AND IMPROVEMENTS	154,719,740	40,213,775	24.92	47	2,939,675	1.9	25.99	52.43	2,626,625	1.70
353 STATION EQUIPMENT	1,741,377,472	504,497,585	28.05	29	45,275,814	2.6	28.97	30.90	41,155,580	2.36
353.1 STATION EQUIPMENT - STEP-UP TRANSFORMERS	400,209,880	67,360,985	28.57	25	11,606,087	2.9	16.83	23.69	14,050,185	3.51
354 TOWERS AND FIXTURES	349,056,185	225,421,515	39.81	34	7,679,236	2.2	64.58	35.88	5,877,891	1.68
355 POLES AND FIXTURES	1,242,636,001	420,741,337	37.50	33	42,249,624	3.4	33.86	39.88	36,188,883	2.91
356 OVERHEAD CONDUCTORS AND DEVICES	854,174,816	364,102,828	38.30	35	27,333,594	3.2	42.63	39.61	24,232,975	2.84
357 UNDERGROUND CONDUIT	75,512,192	26,533,422	33.33	40	1,283,707	1.7	35.14	45.29	1,081,448	1.43
358 UNDERGROUND CONDUCTORS AND DEVICES	104,576,520	29,275,918	36.67	40	1,882,377	1.8	27.99	49.27	1,952,829	1.87
359 ROADS AND TRAILS	113,485,941	42,504,639	30.46	47	1,929,261	1.7	37.45	54.53	1,509,809	1.33
TOTAL TRANSMISSION PLANT	**5,276,259,513**	**1,800,833,520**			**145,306,015**	***2.8***			**131,689,933**	***2.50***
DISTRIBUTION PLANT										
361 STRUCTURES AND IMPROVEMENTS	198,554,703	55,416,150	19.17	50	3,772,539	1.9	27.91	49.85	3,468,842	1.75
362 STATION EQUIPMENT	1,740,028,154	531,280,566	25.58	33	45,240,732	2.6	30.53	33.67	41,067,728	2.36
364.1 POLES, TOWERS AND FIXTURES - WOOD	1,083,692,909	481,024,953	49.23	27	44,431,409	4.1	44.39	28.90	58,351,587	5.38
364.2 POLES, TOWERS AND FIXTURES - CONCRETE	706,877,719	98,411,503	49.23	27	28,981,986	4.1	13.92	45.65	28,813,668	4.08
365 OVERHEAD CONDUCTORS AND DEVICES	1,991,793,394	740,342,106	42.93	30	77,679,942	3.9	37.17	38.90	73,133,316	3.67
366.6 UNDERGROUND CONDUIT - DUCT SYSTEM	1,528,850,821	345,598,141	16.03	59	22,932,762	1.5	22.61	54.59	21,675,264	1.42
366.7 UNDERGROUND CONDUIT - DIRECT BURIED	193,885,661	26,860,958	20.00	40	3,877,713	2.0	13.85	43.04	3,880,685	2.00
367.6 UNDERGROUND CONDUCTORS AND DEVICES - DUCT SYSTEM	1,723,803,662	475,313,897	23.68	29	44,818,895	2.6	27.57	31.87	41,878,881	2.43
367.7 UNDERGROUND CONDUCTORS AND DEVICES - DIRECT BURIED	731,720,379	288,138,701	47.43	18.4	21,219,891	2.9	39.38	23.06	19,235,979	2.63
368 LINE TRANSFORMERS	2,172,571,477	977,456,673	41.67	22	82,557,716	3.8	44.99	23.48	64,778,557	2.98
369.1 SERVICES - OVERHEAD	429,359,956	121,671,610	46.25	36	16,745,038	3.9	28.34	45.82	18,428,378	4.29
369.6 SERVICES - UNDERGROUND	818,122,343	316,173,519	33.16	26	22,907,426	2.8	38.65	31.75	19,674,557	2.40
370 METERS	90,547,258	64,524,789	43.33	24	3,259,701	3.6	71.26	17.18	3,095,847	3.42
370.1 METERS - AMI	752,056,781	195,134,861	5.20	19.2	48,883,691	6.5	25.95	15.60	50,162,753	6.67
371 INSTALLATIONS ON CUSTOMER'S PREMISES	77,912,064	32,661,220	32.00	22	3,116,483	4.0	41.92	21.97	2,591,609	3.33
373 STREET LIGHTING AND SIGNAL SYSTEMS	463,393,095	175,429,642	32.00	22	18,535,724	4.0	37.86	27.34	13,075,070	2.82
TOTAL DISTRIBUTION PLANT	**14,703,170,376**	**4,925,439,290**			**488,961,648**	***3.3***			**463,312,721**	***3.15***
GENERAL PLANT										
390 STRUCTURES AND IMPROVEMENTS	435,222,597	123,109,607	29.40	36	9,139,675	2.1	28.29	41.11	8,650,821	1.99
392.1 AUTOMOBILES	9,038,959	1,913,929	42.50	3.0	1,283,532	14.2	21.17	4.06	1,420,982	15.72
392.2 LIGHT TRUCKS	47,500,083	12,551,216	41.56	4.6	4,465,008	9.4	26.42	5.86	4,748,098	10.00
392.3 HEAVY TRUCKS	241,647,650	99,939,976	49.58	5.0	17,156,983	7.1	41.36	7.09	14,874,545	6.16
392.4 TRACTOR TRAILERS	767,855	638,910	71.11	2.6	85,232	11.1	83.21	4.48	20,213	2.63
392.9 TRAILERS	21,065,643	2,761,578	28.35	11.9	737,298	3.5	13.11	14.42	1,050,223	4.99
396.1 POWER OPERATED EQUIPMENT	4,766,126	2,061,673	29.60	6.3	381,290	8.0	43.26	5.92	336,070	7.05
397.8 COMMUNICATION EQUIPMENT - FIBER OPTICS	11,992,500	9,422,442	23.00	7.7	1,199,250	10.0	78.57	11.01	233,429	1.95
TOTAL GENERAL PLANT	**772,001,412**	**252,399,331**			**34,448,268**	***4.5***			**31,334,381**	***4.06***
TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT	**20,751,431,301**	**6,978,672,141**			**668,715,931**	***3.2***			**626,337,035**	***3.02***
GRAND TOTAL	**43,546,789,183**	**12,519,861,051**			**1,344,641,299**	***3.1***			**1,539,856,821**	***3.54***

* FPL HAS HISTORICALLY MAINTAINED THE BOOK RESERVE FOR ACCOUNTS 343 AND ACCOUNT 364 AT THE ACCOUNT LEVEL, AS OPPOSED TO AT THE LEVEL OF THE SUBACCOUNTS RECOMMENDED IN THE DEPRECIATION STUDY. THE BOOK RESERVE PERCENTS SHOWN FOR DOCKET NO. 090130-EI ARE THE BOOK RESERVE PERCENTS FOR THE ACCOUNT INCLUDED IN THAT DOCKET.

** IN DOCKET NO. 090130-EI THE COMMISSION ORDERED A COMPOSITE REMAINING LIFE FOR ACCOUNT 343, PRIME MOVERS - GENERAL AND ACCOUNT 343.2 PRIME MOVERS - CAPITAL SPARE PARTS. THE AVERAGE REMAINING LIFE SHOWN HERE FOR BOTH ACCOUNTS IS THE COMPOSITE REMAINING LIFE ORDERED BY THE COMMISSION FOR ALL OF ACCOUNT 343.

*** FOR NEW UNITS IN DOCKET NO. 090130-EI AND UNITS ADDED SUBSEQUENT TO THAT DOCKET THE RESERVE PERCENT SHOWN IS 0% AND THE AVERAGE REMAINING LIFE IS EQUAL TO THE LIFE SPAN OF THE UNIT.

FLORIDA POWER AND LIGHT COMPANY

TABLE 8. ALLOCATION OF BOOK RESERVE TO NEW SUBACCOUNTS FOR ACCOUNTS 343 AND 364

	ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	ALLOCATED BOOK RESERVE (4)
COMBINED CYCLE PRODUCTION PLANT				
LAUDERDALE COMBINED CYCLE PLANT				
LAUDERDALE COMMON				
343 PRIME MOVERS - GENERAL	27,106,051		3,904,041	5,912,889
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	37,564,239		4,795,010	7,262,311
TOTAL LAUDERDALE COMMON ACCOUNT 343	*64,670,290*	*13,175,200*	*8,699,051*	*13,175,200*
LAUDERDALE UNIT 4				
343 PRIME MOVERS - GENERAL	121,376,511		57,655,119	49,359,731
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	64,237,235		10,013,939	8,573,139
TOTAL LAUDERDALE UNIT 4 ACCOUNT 343	*185,613,746*	*57,932,869*	*67,669,058*	*57,932,869*
LAUDERDALE UNIT 5				
343 PRIME MOVERS - GENERAL	121,964,623		56,773,176	33,068,495
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	24,160,830		2,860,581	1,666,194
TOTAL LAUDERDALE UNIT 5 ACCOUNT 343	*146,125,452*	*34,734,688*	*59,633,757*	*34,734,688*
TOTAL LAUDERDALE COMBINED CYCLE PLANT	***396,409,488***	***105,842,758***	***136,001,866***	***105,842,758***
FT. MYERS COMBINED CYCLE PLANT				
FT. MYERS COMMON				
343 PRIME MOVERS - GENERAL	3,709,607		457,525	1,045,250
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	441,577		101,278	231,377
TOTAL FT. MYERS COMMON ACCOUNT 343	*4,151,184*	*1,276,628*	*558,803*	*1,276,628*
FT. MYERS UNIT 2				
343 PRIME MOVERS - GENERAL	367,522,551		87,596,757	79,088,073
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	302,123,631		43,341,142	39,131,213
TOTAL FT. MYERS UNIT 2 ACCOUNT 343	*669,646,182*	*118,219,286*	*130,937,899*	*118,219,286*
FT. MYERS UNIT 3				
343 PRIME MOVERS - GENERAL	164,165,759		10,180,429	(10,456,672)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	20,183,733		1,440,075	(1,479,151)
TOTAL FT. MYERS UNIT 3 ACCOUNT 343	*184,349,492*	*(11,935,823)*	*11,620,504*	*(11,935,823)*
TOTAL FT. MYERS COMBINED CYCLE PLANT	***858,146,857***	***107,560,091***	***143,117,206***	***107,560,091***

FLORIDA POWER AND LIGHT COMPANY

TABLE 8. ALLOCATION OF BOOK RESERVE TO NEW SUBACCOUNTS FOR ACCOUNTS 343 AND 364

	ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	ALLOCATED BOOK RESERVE (4)
MANATEE COMBINED CYCLE PLANT				
MANATEE UNIT 3				
343 PRIME MOVERS - GENERAL	236,795,038		61,506,546	46,167,493
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	146,248,668		25,330,720	19,013,518
TOTAL MANATEE UNIT 3 ACCOUNT 343	*383,043,705*	*65,181,012*	*86,837,266*	*65,181,012*
TOTAL MANATEE COMBINED CYCLE PLANT	***383,043,705***	***65,181,012***	***86,837,266***	***65,181,012***
MARTIN COMBINED CYCLE PLANT				
MARTIN COMMON				
343 PRIME MOVERS - GENERAL	22,788,940		8,729,373	14,037,911
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	2,230,422		479,202	770,616
TOTAL MARTIN COMMON ACCOUNT 343	*25,019,361*	*14,808,527*	*9,208,575*	*14,808,527*
MARTIN UNIT 3				
343 PRIME MOVERS - GENERAL	152,279,614		63,714,248	46,856,499
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	67,628,799		6,705,612	4,931,417
TOTAL MARTIN UNIT 3 ACCOUNT 343	*219,908,413*	*51,787,915*	*70,419,860*	*51,787,915*
MARTIN UNIT 4				
343 PRIME MOVERS - GENERAL	157,866,532		61,237,920	62,665,792
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	100,540,570		14,260,872	14,593,390
TOTAL MARTIN UNIT 4 ACCOUNT 343	*258,407,102*	*77,259,182*	*75,498,792*	*77,259,182*
MARTIN UNIT 8				
343 PRIME MOVERS - GENERAL	256,002,412		63,970,845	48,218,164
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	213,276,994		31,999,454	24,119,658
TOTAL MARTIN UNIT 8 ACCOUNT 343	*469,279,406*	*72,337,823*	*95,970,299*	*72,337,823*
TOTAL MARTIN COMBINED CYCLE PLANT	***972,614,282***	***216,193,447***	***251,097,526***	***216,193,447***

FLORIDA POWER AND LIGHT COMPANY

TABLE 8. ALLOCATION OF BOOK RESERVE TO NEW SUBACCOUNTS FOR ACCOUNTS 343 AND 364

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	ALLOCATED BOOK RESERVE (4)
SANFORD COMBINED CYCLE PLANT					
	SANFORD COMMON				
343	PRIME MOVERS - GENERAL	5,932,378		1,505,411	(4,737,256)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	-		-	-
	TOTAL SANFORD COMMON ACCOUNT 343	*5,932,378*	*(4,737,256)*	*1,505,411*	*(4,737,256)*
	SANFORD UNIT 4				
343	PRIME MOVERS - GENERAL	196,875,732		55,094,575	18,672,684
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	140,077,308		20,864,456	7,071,393
	TOTAL SANFORD UNIT 4 ACCOUNT 343	*336,953,040*	*25,744,077*	*75,959,031*	*25,744,077*
	SANFORD UNIT 5				
343	PRIME MOVERS - GENERAL	214,894,008		61,244,253	20,990,061
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	126,367,538		18,251,455	6,255,267
	TOTAL SANFORD UNIT 5 ACCOUNT 343	*341,261,545*	*27,245,328*	*79,495,708*	*27,245,328*
TOTAL SANFORD COMBINED CYCLE PLANT		***684,146,964***	***48,252,149***	***156,960,150***	***48,252,149***
TURKEY POINT COMBINED CYCLE PLANT					
	TURKEY POINT UNIT 5				
343	PRIME MOVERS - GENERAL	250,685,264		54,613,714	39,618,917
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	128,220,285		17,841,988	12,943,274
	TOTAL TURKEY POINT UNIT 5 ACCOUNT 343	*378,905,549*	*52,562,191*	*72,455,702*	*52,562,191*
TOTAL TURKEY POINT COMBINED CYCLE PLANT		***378,905,549***	***52,562,191***	***72,455,702***	***52,562,191***

FLORIDA POWER AND LIGHT COMPANY

TABLE 8. ALLOCATION OF BOOK RESERVE TO NEW SUBACCOUNTS FOR ACCOUNTS 343 AND 364

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	ALLOCATED BOOK RESERVE (4)
WEST COUNTY COMBINED CYCLE PLANT					
	WEST COUNTY COMMON				
343	PRIME MOVERS - GENERAL	31,206,902		1,678,318	1,389,969
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	126,771,982		15,366,036	12,726,022
	TOTAL WEST COUNTY COMMON ACCOUNT 343	*157,978,884*	*14,115,990*	*17,044,354*	*14,115,990*
	WEST COUNTY UNIT 1				
343	PRIME MOVERS - GENERAL	300,710,821		50,044,321	(22,756,245)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	81,954,083		16,162,137	(7,349,277)
	TOTAL WEST COUNTY UNIT 1 ACCOUNT 343	*382,664,904*	*(30,105,522)*	*66,206,458*	*(30,105,522)*
	WEST COUNTY UNIT 2				
343	PRIME MOVERS - GENERAL	255,637,285		43,270,480	17,744,809
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	149,878,251		30,436,000	12,481,512
	TOTAL WEST COUNTY UNIT 2 ACCOUNT 343	*405,515,536*	*30,226,321*	*73,706,480*	*30,226,321*
	WEST COUNTY UNIT 3				
343	PRIME MOVERS - GENERAL	480,389,197		62,928,595	32,738,513
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	98,598,036		17,082,566	8,887,181
	TOTAL WEST COUNTY UNIT 3 ACCOUNT 343	*578,987,233*	*41,625,693*	*80,011,161*	*41,625,693*
TOTAL WEST COUNTY COMBINED CYCLE PLANT		***1,525,146,558***	***55,862,483***	***236,968,453***	***55,862,483***
CAPE CANAVERAL COMBINED CYCLE PLANT					
	CAPE CANAVERAL COMBINED CYCLE				
343	PRIME MOVERS - GENERAL	385,108,676		32,829,732	38,729,543
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	206,255,249		24,192,319	28,539,906
	TOTAL CAPE CANAVERAL COMBINED CYCLE ACCOUNT 343	*591,363,925*	*67,269,449*	*57,022,051*	*67,269,449*
TOTAL CAPE CANAVERAL COMBINED CYCLE PLANT		***591,363,925***	***67,269,449***	***57,022,051***	***67,269,449***

FLORIDA POWER AND LIGHT COMPANY

TABLE 8. ALLOCATION OF BOOK RESERVE TO NEW SUBACCOUNTS FOR ACCOUNTS 343 AND 364

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	ALLOCATED BOOK RESERVE (4)
RIVIERA COMBINED CYCLE PLANT					
	RIVIERA COMBINED CYCLE				
343	PRIME MOVERS - GENERAL	525,780,412		31,729,157	35,938,896
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	139,494,633		14,487,691	16,409,879
	TOTAL RIVIERA COMBINED CYCLE ACCOUNT 343	*665,275,044*	*52,348,774*	*46,216,848*	*52,348,774*
TOTAL RIVIERA COMBINED CYCLE PLANT		***665,275,044***	***52,348,774***	***46,216,848***	***52,348,774***
PT EVERGLADES COMBINED CYCLE PLANT					
	PT EVERGLADES COMBINED CYCLE				
343	PRIME MOVERS - GENERAL	499,500,579		6,228,069	8,382,316
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	191,363,196		5,389,650	7,253,893
	TOTAL PT EVERGLADES COMBINED CYCLE	690,863,775	15,636,209	11,617,719	15,636,209
TOTAL PT EVERGLADES COMBINED CYCLE PLANT		***690,863,775***	***15,636,209***	***11,617,719***	***15,636,209***
TOTAL COMBINED CYCLE PRODUCTION PLANT		**7,145,916,147**	**786,708,564**	**1,198,294,787**	**786,708,564**
GAS TURBINES					
	LAUDERDALE GTS				
343	PRIME MOVERS - GENERAL	14,841,925		1,889,396	1,714,581
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	1,858,779		742,131	673,466
343	*TOTAL LAUDERDALE GTS*	*16,700,704*	*2,388,047*	*2,631,527*	*2,388,047*
	FT. MYERS GTS				
343	PRIME MOVERS - GENERAL	10,218,903		1,358,142	1,207,170
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	2,807,095		1,411,757	1,254,825
343	*TOTAL FT. MYERS GTS*	*13,025,998*	*2,461,994*	*2,769,899*	*2,461,994*
	LAUDERDALE AND FT. MYERS PEAKERS				
343	PRIME MOVERS - GENERAL	213,843,171		2,634,291	389,972
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	83,870,827		892,629	132,142
	TOTAL LAUDERDALE AND FT. MYERS PEAKERS	*297,713,998*	*522,114*	*3,526,920*	*522,114*
TOTAL GAS TURBINES		**327,440,700**	**5,372,156**	**5,401,426**	**5,372,156**
TOTAL PRODUCTION PLANT		**7,473,356,846**	**792,080,719**	**1,207,223,133**	**792,080,719**

FLORIDA POWER AND LIGHT COMPANY

TABLE 8. ALLOCATION OF BOOK RESERVE TO NEW SUBACCOUNTS FOR ACCOUNTS 343 AND 364

		ORIGINAL COST (1)	BOOK RESERVE (2)	THEORETICAL RESERVE (3)	ALLOCATED BOOK RESERVE (4)
	DISTRIBUTION PLANT				
364.1	POLES, TOWERS AND FIXTURES - WOOD	1,083,692,909		601,487,567	481,024,953
364.2	POLES, TOWERS AND FIXTURES - CONCRETE	706,877,719		123,056,600	98,411,503
	TOTAL POLES, TOWERS AND FIXTURES	*1,790,570,627*	*579,436,455*	*724,544,167*	*579,436,455*
	TOTAL DISTRIBUTION PLANT	**1,790,570,627**	**579,436,455**	**724,544,167**	**579,436,455**
GRAND TOTAL		**9,263,927,474**	**1,371,517,175**	**1,931,767,300**	**1,371,517,175**

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	Docket No. 160021-EI
In re: Petition for approval of 2016-2018 storm hardening plan, by Florida Power & Light Company	Docket No. 160061-EI
In re: 2016 depreciation and dismantlement study by Florida Power & Light Company	Docket No. 160062-EI
In re: Petition for limited proceeding to modify and continue incentive mechanism by Florida Power & Light Company	Docket No. 160088-EI Filed: June 30, 2016

FLORIDA POWER & LIGHT COMPANY'S
THIRD NOTICE OF IDENTIFIED ADJUSTMENTS

Florida Power & Light Company ("FPL") hereby files this Third Notice of Identified Adjustments, to advise the Florida Public Service Commission, its Staff and intervenors of adjustments to information contained in its rate case filing that implement the Florida Supreme Court's May 19, 2016 *Citizens v. Graham* decision reversing the Commission's orders approving cost recovery for the Woodford gas reserves project.

In January 2015, the Commission issued Order No. PSC-15-0038-FOF-EI approving Fuel Clause recovery for the costs associated with FPL's owning and operating the Woodford gas reserves project. In July 2015, the Commission issued Order No. PSC-15-0284-FOF-EI approving guidelines for FPL investments in future gas reserves projects. Based on those orders, FPL included both the Woodford project and estimates of additional gas reserves projects in developing its Total Company financial forecast underlying the rate case filing in this docket. Because the costs for gas reserves projects were to be recovered through the Fuel Clause, FPL then made Commission adjustments to remove the costs of those projects from the test period

base rate revenue requirements calculations, consistent with the Commission's Earnings Surveillance Report ("ESR") and MFR practice for clause-recoverable activities.

On May 19, 2016, the Florida Supreme Court reversed Order No. PSC-15-0038-FOF-EI and two companion orders, finding that the Commission does not have authority to allow FPL to recover costs associated with the Woodford gas reserves project from customers. While the Court's May 19 order directly addressed only the Woodford project, its rationale would apply to future gas reserves projects as well. On June 15, 2016, the Commission and all parties to the appeal of Order No. PSC-15-0284-FOF-EI filed a joint motion for the Court to relinquish jurisdiction over that order so that the Commission may vacate it. The Court granted the joint motion on June 28, 2016.

In light of the May 19 order, Staff held an informal meeting with FPL and parties to discuss removing the impact of gas reserves projects from the Fuel Clause and rate case filings. Following that meeting, FPL has rerun its financial forecasts for the 2017 Test Year, 2018 Subsequent Year and the 2019 Okeechobee LSA as if (1) there had been no Woodford investments historically and thus no sale of Woodford gas production to FPL and (2) no additional gas reserves investments would be made in the rate effective years.[1] As noted above, FPL had already made a Commission adjustment to remove gas reserves costs from base rate revenue requirements consistent with the Commission's ESR and MFR practice for clause-recoverable activities. However, for the reasons discussed in Attachment 1 to this Notice, there are some minor differences in the revenue requirements calculation when the financial forecasts assume no gas reserves projects rather than assuming that there will be gas reserves projects with

[1] In its actual/estimated true-up filing in Docket No. 160001-EI on August 4, 2016, FPL will include a refund calculation for the difference between the amounts it is collecting for the Woodford project in the Fuel Clause, versus the market price of the gas produced from that project.

a Commission adjustment to treat them as clause-recoverable. The net effect of those differences is a modest reduction in revenue requirements for the 2017 Test Year and 2018 Subsequent Year, with a negligible impact on the 2019 Okeechobee LSA.

FPL will include the adjustments identified on Attachment 1 in an exhibit of adjustments that it will file with rebuttal testimony, along with any other adjustments that may be identified between now and then. Final rates determined by the Commission would include such adjustments as may be determined appropriate through this proceeding. FPL included similar exhibits with the rebuttal testimony of FPL witnesses in its 2009 and 2012 rate cases.

Respectfully submitted,

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By: *s/ John T. Butler*
John T. Butler
Florida Bar No. 283479

CERTIFICATE OF SERVICE
Docket No. 160021-EI
(Consolidated)

I HEREBY CERTIFY that a true and correct copy of the foregoing Notice has been furnished by electronic mail this 30th day of June 2016 to the following parties:

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ATTACHMENT 1

DOCKET NO. 160021-EI
FLORIDA POWER & LIGHT COMPANY'S
SUMMARY OF IDENTIFIED ADJUSTMENTS
REMOVAL OF THE WOODFORD PROJECT AND FORECASTED FUTURE GAS RESERVES INVESTMENTS

The Company has rerun its financial forecast for the 2017 Test Year, 2018 Subsequent Year and the 2019 Okeechobee LSA as if there had been no Woodford investments historically and thus no sale of Woodford gas production to FPL but that the MCF of gas that would have been provided by Woodford was provided instead through market purchases. FPL's rerun financial forecasts also assume no additional gas reserves investments (i.e., beyond Woodford) in any of the test periods. Attached are the detailed schedules for each period supporting the change in revenue requirements.

As filed in March 2016, FPL's MFRs already reflected clause recovery rather than base rate recovery for Woodford and projected future gas reserves investments. The process of developing base rate revenue requirements for the MFRs began with a consolidated FPL forecast including Woodford and future gas reserves investments, and then removed those investments and calculated the resulting NOI using the Commission's ESR and MFR practice for clause-recoverable activities. The process of creating new financial forecasts and recalculating the Company's proposed revenue requirements for those periods has resulted in a further reduction in base rate revenue requirements. This further reduction is due to the fundamental reasons described below.

First, and foremost, the FPSC base ratemaking approach reflects all permanent tax differences in the base ratemaking process. In clause ratemaking, current taxes are reflected at the statutory rate, whereas all permanent tax differences due to clause investments are flowed through the base ratemaking process. In the new forecasts with all gas reserves investments removed, there are no longer permanent tax differences related to gas reserves to reflect in base rates. This item has created the primary reduction in revenue requirements.

Secondly, when FPL recreated the financial forecasts without gas reserves, the resulting capital structure had less deferred taxes than the original forecasts with gas reserves. This is because the gas reserves investments had a higher proportion of deferred taxes than the company's overall ratio of deferred taxes to total capitalization. The pro forma capital structure resulting from the new forecasts increases base rate revenue requirements.

Third, some accounts on the Company's consolidated books and records do not distinguish between clause and base recovery and therefore, the entire balance of the account remains for base ratemaking. This is true for accrued taxes payable, which can only be accounted for on a consolidated basis. When FPL recreated its forecasts without future gas reserves investments, the taxable loss associated with gas reserves was eliminated. In 2017, this increased the taxes payable account, decreased rate base, and ultimately decreased revenue requirements under the new forecasts. In 2018, the forecasted taxable income for FPL consolidated resulted in higher estimated tax payments throughout the year, which on a 13-month average basis, resulted in a decrease in taxes payable and an increase in rate base.

Finally, FPL has removed from its test period forecasts the small amount of payroll costs that FPL projects to provide general support of its gas reserves investments. Removing these costs has minimally reduced revenue requirements in the 2017 and 2018 test periods.

The net effect of these items is a reduction in 2017 Test Year revenue requirements of approximately $7.3 million, a decrease in 2018 Subsequent Year revenue requirements of $5.7 million, and a negligible increase of about $65 thousand in the 2019 Okeechobee LSA.

DOCKET NO. 160021-EI
FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
SUMMARY OF IDENTIFIED ADJUSTMENTS
REMOVAL OF THE WOODFORD PROJECT AND FORECASTED FUTURE GAS RESERVES INVESTMENTS
2017 TEST YEAR
($000's)

Line No.	DESCRIPTION	MFR REFERENCE	2017 FILED REVENUE REQUIREMENTS	2017 REVISED REVENUE REQUIREMENTS	INCREASE/ (DECREASE)	Notes
1						
2	JURISDICTIONAL ADJUSTED RATE BASE	B-1	$ 32,536,116	$ 32,457,144	$ (78,973)	(1)
3						
4	RATE OF RETURN ON RATE BASE REQUESTED	D-1A	6.607%	6.632%	0.025%	(2)
5						
6	JURISDICTIONAL NET OPERATING INCOME REQUESTED	LINE 2 X LINE 4	$ 2,149,618	$ 2,152,437	$ 2,819	
7						
8	JURISDICTIONAL ADJUSTED NET OPERATING INCOME	C-1	$ 1,618,192	$ 1,625,491	$ 7,299	(3)
9						
10	NET OPERATING INCOME DEFICIENCY (EXCESS)	LINE 6 - LINE 8	$ 531,427	$ 526,946	$ (4,480)	
11						
12	EARNED RATE OF RETURN	LINE 8 / LINE 2	4.974%	5.008%	0.034%	
13						
14	NET OPERATING INCOME MULTIPLIER	C-44	1.63024	1.63024	-	
15						
16	REVENUE REQUIREMENT	LINE 10 X LINE 14	$ 866,354	$ 859,050	$ (7,304)	(4)
17						
18						
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22						
23						
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25 Notes:

26 (1) Decrease in jurisdictional adjusted rate base is mainly due to an increase of $76.9M in accrued income tax payable. The total amount of accrued income taxes at year-end represents the total consolidated company accrued income taxes, including the income tax obligation related to gas reserves activity. FPL's taxable income has increased due to the elimination of the forecasted taxable losses associated with the gas reserves investments.

27 (2) In FPL's original base rate filing, all gas reserves rate base amounts were removed from capital structure on a pro rata basis. As part of this notice of identified adjustments, FPL has removed the actual historical capitalization resulting from investment in the Woodford Project subsidiary and the projected Woodford Project subsidiary capitalization supporting the projected Woodford investment. For future forecasted gas reserves investments, FPL created a new financial forecast which does not contemplate gas reserves investments and in doing so, balanced its capital structure by adjusting long term debt, short term debt, and common equity. The impact of these changes results in a higher weighted average cost of capital due to higher common equity and long term debt ratios due to the exclusion of proportionally higher deferred income taxes enabled by gas reserves investments.

28 (3) Increase in jurisdictional net operating income is mainly due to a $6.9M reduction in total income tax expense, resulting from the removal of permanent differences (Section 199 manufacturer's deduction) associated with gas reserves investments. Section 199 is calculated on a consolidated basis and reflected in FPL's current jurisdictional adjusted net operating income. In FPL's base rate filing, the total company Section 199 manufacturer's deduction was lower due to inclusion of gas reserves investments' taxable loss. By removing all gas reserves investments, FPL's Section 199 deduction increases which results in lower taxable income at FPL. In addition, FPL has also removed approximately $419,000 of forecasted O&M expense for general support of gas reserves investments, which was originally included in the 2017 Test Year filing.

29 (4) Does not include any impacts associated with the first or second notice of identified adjustments filed on May 3, 2016 and June 16, 2016, respectively.

DOCKET NO. 160021-EI
FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
SUMMARY OF IDENTIFIED ADJUSTMENTS
REMOVAL OF THE WOODFORD PROJECT AND FORECASTED FUTURE GAS RESERVES INVESTMENTS
2018 SUBSEQUENT YEAR
($000's)

Line No.	DESCRIPTION	MFR REFERENCE	2018 FILED REVENUE REQUIREMENTS	2018 REVISED REVENUE REQUIREMENTS	INCREASE/ (DECREASE)	Notes
1						
2	JURISDICTIONAL ADJUSTED RATE BASE	B-1	$ 33,870,897	$ 33,876,633	$ 5,736	(1)
3						
4	RATE OF RETURN ON RATE BASE REQUESTED	D-1A	6.705%	6.701%	(0.004%)	(2)
5						
6	JURISDICTIONAL NET OPERATING INCOME REQUESTED	LINE 2 X LINE 4	$ 2,271,063	$ 2,269,987	$ (1,076)	
7						
8	JURISDICTIONAL ADJUSTED NET OPERATING INCOME	C-1	$ 1,575,711	$ 1,578,145	$ 2,434	(3)
9						
10	NET OPERATING INCOME DEFICIENCY (EXCESS)	LINE 6 - LINE 8	$ 695,352	$ 691,842	$ (3,510)	
11						
12	EARNED RATE OF RETURN	LINE 8 / LINE 2	4.652%	4.659%	0.007%	
13						
14	NET OPERATING INCOME MULTIPLIER	C-44	1.63024	1.63024	-	
15						
16	REVENUE REQUIREMENT	LINE 10 X LINE 14	$ 1,133,593	$ 1,127,871	$ (5,722)	(4)
17						
18	2017 REVENUE INCREASE REQUESTED		$ 871,301	$ 863,955	$ (7,346)	
19						
20	RATE INCREASE REQUESTED (AFTER FULL 2017 RATE INCREASE)	LINE 16 - LINE 18	$ 262,292	$ 263,915	$ 1,624	
21						
22						
23						
24						

25 Notes:
26 (1) Increase in jurisdictional adjusted rate base is due to the following:

27	Rate Base Category	13-mo Avg Rate Base Impact (MM)	Reason for Change
28	Decrease in Accrued Taxes	$10.4	Due to higher tax payments forecasted in 2018 associated with the removal of gas reserves tax losses from future investments. The higher tax payments reduce the tax payable.
29	Decrease in Accounts Receivable	(21.3)	Due to lower forecasted fuel revenues associated with the removal of future gas reserves investments
30	Decrease in Accounts Payable	5.5	Due to the removal of gas reserves CWIP construction payments
31	Decrease in Accrued Revenue Taxes	2.0	Due to lower fuel revenues associated with the removal of future gas reserves investments
32	Decrease in Accrued Interest	6.8	Due to a reduction in long term debt issuances in the rebalancing of total company capital structure associated with the reforecast
33	Decrease in Fuel Clause Net Over Recovery	2.3	FPL's forecast assumes perfect ratemaking for clause recovery in the forecasted years. On a 13-month average basis, the clauses might be in either an over or under recovered position; however by year end, it is zero. The decrease in fuel clause net over recovery is driven by lower fuel revenues associated with the removal of future gas reserves investments.
34	Total increase in jurisdictional adjusted rate base:	$5.7	

35
36 (2) In FPL's original base rate filing, all gas reserves rate base amounts were removed from capital structure on a pro rata basis. As part of this notice of identified adjustments, FPL has removed the actual historical capitalization resulting from investment in the Woodford Project subsidiary and the projected Woodford Project subsidiary capitalization supporting the projected Woodford investment. For future forecasted gas reserves investments, FPL created a new financial forecast which does not contemplate gas reserves investments and in doing so, balanced its capital structure by adjusting long term debt, short term debt, and common equity. The impact of these changes results in a lower weighted average cost of capital mainly due to the reduction of long term debt issuances.

37 (3) Increase in jurisdictional net operating income is mainly due to a $2M reduction in total income tax expense, resulting from the removal of permanent differences (Section 199 manufacturer's deduction) associated with gas reserves investments. Section 199 is calculated on a consolidated basis and reflected in FPL's current jurisdictional adjusted net operating income. In FPL's base rate filing, the total company Section 199 manufacturer's deduction was lower due to inclusion of gas reserves investments' taxable loss. By removing all gas reserves investments, FPL's Section 199 deduction increases which results in lower taxable income at FPL. In addition, FPL has also removed approximately $432,000 of forecasted O&M expense for general support of gas reserves investments, which was originally included in the 2018 Subsequent Year Adjustment.

38 (4) Does not include any impacts associated with the first or second notice of identified adjustments filed on May 3, 2016 and June 16, 2016, respectively.

DOCKET NO. 160021-EI
FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
SUMMARY OF IDENTIFIED ADJUSTMENTS
REMOVAL OF THE WOODFORD PROJECT AND FORECASTED FUTURE GAS RESERVES INVESTMENTS
2019 OKEECHOBEE LIMITED SCOPE ADJUSTMENT
($000's)

Line No.	DESCRIPTION	SCHEDULE REFERENCE	2019 OCEC LSA FILED REVENUE REQUIREMENTS	2019 OCEC LSA REVISED REVENUE REQUIREMENTS	INCREASE/ (DECREASE)	Notes
1						
2	JURISDICTIONAL ADJUSTED RATE BASE	B-1	$ 1,063,315	$ 1,063,315	$ -	
3						
4	RATE OF RETURN ON RATE BASE REQUESTED	D-1A	8.873%	8.877%	0.004%	(1)
5						
6	JURISDICTIONAL NET OPERATING INCOME REQUESTED	LINE 2 X LINE 4	$ 94,348	$ 94,388	$ 40	
7						
8	JURISDICTIONAL ADJUSTED NET OPERATING INCOME	C-1	$ (33,868)	$ (33,868)	$ -	
9						
10	NET OPERATING INCOME DEFICIENCY (EXCESS)	LINE 6 - LINE 8	$ 128,217	$ 128,256	$ 40	
11						
12	EARNED RATE OF RETURN	LINE 8 / LINE 2	(3.19%)	(3.19%)	-	
13						
14	NET OPERATING INCOME MULTIPLIER	C-44	1.63024	1.63024	-	
15						
16	REVENUE REQUIREMENT	LINE 10 X LINE 14	$ 209,024	$ 209,089	$ 65	(2)
17						
18						
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25 Notes:

26 (1) Change is due to an increase in common equity ratio of 0.44% and decrease in long term debt ratio of 0.44%, which is based on the revised capital
27 structure for the 2018 Subsequent Year. In addition, the long term debt cost rate decreased by 0.07% due to decrease in forecasted balances of long
28 term debt.
29
30 (2) Does not include any impacts associated with the first or second notice of identified adjustments filed on May 3, 2016 and June 16, 2016, respectively.

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
2017 RECALCULATED REVENUE REQUIREMENTS[A]
($000's)

LINE NO.	DESCRIPTION	REFERENCE		2017 REVISED REVENUE REQUIREMENTS PER FPL'S 3rd NOIA[B] (1)	FPL'S 2017 JURISDICTIONAL ADJUSTMENTS[C] (2)	2017 RECALCULATED REVENUE REQUIREMENTS (3)
1						
2	JURISDICTIONAL ADJUSTED RATE BASE	PAGE 2		$32,457,144	$800	$32,457,944
3						
4	RATE OF RETURN ON RATE BASE REQUESTED	PAGE 4	x	6.63%	0.00%	6.63%
5						
6	JURISDICTIONAL NET OPERATING INCOME REQUESTED	LINE 2 X LINE 4		2,152,437	48	2,152,485
7						
8	JURISDICTIONAL ADJUSTED NET OPERATING INCOME	PAGE 3		1,625,491	20,194	1,645,685
9						
10	NET OPERATING INCOME DEFICIENCY (EXCESS)	LINE 6 - LINE 8		526,946	(20,146)	506,800
11						
12	EARNED RATE OF RETURN	LINE 8 / LINE 2		5.01%	0.06%	5.07%
13						
14	NET OPERATING INCOME MULTIPLIER[D]	PAGE 13	x	1.63024	0.00001	1.63025
15						
16	REVENUE REQUIREMENT	LINE 10 X LINE 14		$859,050	($32,838)	$826,212
17						
18						
19						

20 NOTES:
21 (A) TOTALS MAY NOT ADD DUE TO ROUNDING
22 (B) REPRESENTS RECALCULATED 2017 REVENUE REQUIREMENTS PER FPL'S THIRD NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 30,
23 2016, WHICH EXCLUDES ALL GAS RESERVE INVESTMENTS.
24 (C) INCLUDES IMPACT OF FPL'S FIRST AND SECOND NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON MAY 3, 2016 AND JUNE 16, 2016,
25 RESPECTIVELY. ALSO INCLUDES THE CORRECTION OF RATE CASE EXPENSES DISCUSSED IN FPL WITNESS OUSDAHL'S REBUTTAL
26 TESTIMONY.
27 (D) RECALCULATED NOI MULTIPLIER AS REFLECTED ON PAGE 13 OF EXHIBIT KO-20.

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
2017 JURISDICTIONAL RATE BASE ADJUSTMENTS
($000's)

LINE NO.		3rd NOIA [A]	1st NOIA[B]					2nd NOIA[C]				
		Rate Base (1)	Deferred Pension Debit (2)	Uncollectible Accounts Expense (3)	DSM Adjustment (4)	Depreciation Company Adj (5)	Dismantlement Company Adj (6)	Depreciation Company Adj (7)	SJRPP Deferred Credit Dismantlement (8)	Rate Case Expenses (9)	Total Rate Base Adjustments (10)	Revised Rate Base[D][E] (11)
1	PLANT IN SERVICE	$ 43,122,297	$ -	$ -	$ (3,960)	$ -	$ -	$ -	$ -	$ -	$ (3,960)	$ 43,118,337
2												
3	DEPRECIATION & AMORT RESERVE	13,074,538	-	-	(1,146)	(1)	(689)	(10,669)	-	-	(12,506)	13,062,032
4												
5	NET PLANT IN SERVICE	30,047,759	-	-	(2,814)	1	689	10,669	-	-	8,545	30,056,305
6												
7	FUTURE USE PLANT	233,315	-	-	(26)	-	-	-	-	-	(26)	233,289
8												
9	CWIP	747,987	-	-	(85)	-	-	-	-	-	(85)	747,902
10												
11	NUCLEAR FUEL	630,075	-	-	-	-	-	-	-	-	-	630,075
12												
13	NET UTILITY PLANT	31,659,136	-	-	(2,925)	1	689	10,669	-	-	8,435	31,667,571
14												
15	WORKING CAPITAL	798,008	(3,528)	30	12	-	-	-	776	(4,925)	(7,635)	790,373
16												
17	RATE BASE	$ 32,457,144	$ (3,528)	$ 30	$ (2,913)	$ 1	$ 689	$ 10,669	$ 776	$ (4,925)	$ 800	$ 32,457,944
18												
19												
20												
21												
22												

23 NOTES:

24 (A) REPRESENTS RATE BASE ADJUSTMENTS REFLECTED IN FPL'S THIRD NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 30, 2016.

25 (B) REPRESENTS RATE BASE ADJUSTMENTS REFLECTED IN FPL'S FIRST NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON MAY 3, 2016.

26 (C) REPRESENTS RATE BASE ADJUSTMENTS REFLECTED IN FPL'S SECOND NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 16, 2016.

27 (D) TOTALS MAY NOT ADD DUE TO ROUNDING.

28 (E) REPRESENTS RATE BASE AS REFLECTED ON PAGE 1 OF EXHIBIT KO-20.

Docket No. 160021-EI
Recalculated Revenue Requirements
including Impact of Identified Adjustments
Exhibit KO-20, Page 2 of 13

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
2017 JURISDICTIONAL NET OPERATING INCOME ADJUSTMENTS
($000's)

LINE NO.		3rd NOIA[A]	1st NOIA[B]									2nd NOIA[C]					
		NOI	Aviation Gains	WCEC Water Reclamation	Late Payment Charges	Returned Check	Uncollectible Accounts Expense	Retail Base Revenues	DSM Adjust	Depreciation Company Adj	Dismantlement Company Adj	Depreciation Company Adj	EDR & EFEDR	Injuries & Damages Exp	Interest Synch Adj	Total NOI Adjustments	Revised NOI[D][E]
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
1	REVENUE FROM SALES	$ 5,728,329	$ -	$ -	$ -	$ -	$ -	$ 4,904	$ (0)	$ -		$ -	$ (715)	$ -	$ -	$ 4,188	$ 5,732,517
2																	
3	OTHER OPERATING REVENUES	193,876	-	-	245	6	-	-	(4)	-	-	-	-	-	-	247	194,123
4																	
5	TOTAL OPERATING REVENUES	5,922,205	-	-	245	6	-	4,904	(5)	-	-	-	(715)	-	-	4,435	5,926,640
6																	
7	OPERATION AND MAINTENANCE EXPENSE																
8	OTHER	1,329,721	-	(4,031)	-	-	399	-	(101)	-	-	-	19	(2,080)	-	(5,795)	1,323,926
9	FUEL & INTERCHANGE	24,466	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24,466
10	PURCHASED POWER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	DEFERRED COSTS		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	SUBTOTAL O&M EXPENSE	1,354,187	-	(4,031)	-	-	399	-	(101)	-	-	-	19	(2,080)	-	(5,795)	1,348,392
13																	
14	DEPRECIATION & AMORTIZATION	1,665,925	1,190	-	-	-	-	-	(171)	(3)	(1,378)	(21,824)	-	-	-	(22,185)	1,643,740
15																	-
16	TAXES OTHER THAN INCOME TAXES	578,186	-	-	-	-	-	-	(80)	-	-	-	-	-	-	(80)	578,106
17																	-
18	INCOME TAXES																-
19	INCOME TAX EXPENSE	704,175	(459)	1,555	95	2	(154)	1,892	(99)	1	531	8,419	(283)	802	-	12,302	716,478
20	INTEREST SYNCHRONIZATION (PAGE 4)[F]		-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)
21	SUBTOTAL INCOME TAX EXPENSE	704,175	(459)	1,555	95	2	(154)	1,892	(99)	1	531	8,419	(283)	802	(1)	12,302	716,477
22																	
23	(GAIN)/LOSS ON DISPOSAL OF PLANT	(5,759)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,759)
24																	
25	TOTAL OPERATING EXPENSES	4,296,714	731	(2,476)	95	2	245	1,892	(451)	(2)	(846)	(13,405)	(264)	(1,278)	(1)	(15,758)	4,280,956
26																	
27	NET OPERATING INCOME	$ 1,625,491	$ (731)	$ 2,476	$ 150	$ 4	$ (245)	$ 3,012	$ 446	$ 2	$ 846	$ 13,405	$ (451)	$ 1,278	$ 1	$ 20,194	$ 1,645,685
28																	
29																	

30 NOTES:

31 (A) REPRESENTS NOI ADJUSTMENTS REFLECTED IN FPL'S THIRD NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 30, 2016.

32 (B) REPRESENTS NOI ADJUSTMENTS REFLECTED IN FPL'S FIRST NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON MAY 3, 2016.

33 (C) REPRESENTS NOI ADJUSTMENTS REFLECTED IN FPL'S SECOND NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 16, 2016.

34 (D) TOTALS MAY NOT ADD DUE TO ROUNDING.

35 (E) REPRESENTS NOI AS REFLECTED ON PAGE 1 OF EXHIBIT KO-20.

36 (F) REPRESENTS INTEREST SYNCHRONIZATION ADJUSTMENTS RELATED TO THE RATE BASE ADJUSTMENTS REFLECTED ON PAGE 2 OF EXHIBIT KO-20.

Docket 160021-EI
Recalculated Revenue Requirements
including Impact of Identified
Adjustments
Exhibit KO-20, Page 3 of 13

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
2017 RECALCULATED COST OF CAPITAL
($000's)

RECALCULATED 2017 TEST YEAR COST OF CAPITAL PER 3RD NOIA[(A)]

LINE NO.		(1) JURISDICTIONAL ADJUSTED	RATIO	COST RATE	WTD COC	(5) CAPITAL COSTS
	JURIS ADJ UTILITY					
1	LONG TERM DEBT	$ 9,420,701	29.03%	4.60%	1.33%	$ 433,279
2	PREFERRED STOCK	-	0.00%	0.00%	0.00%	-
3	CUSTOMER DEPOSITS	415,924	1.28%	2.05%	0.03%	8,507
4	COMMON EQUITY	14,703,870	45.30%	11.50%	5.21%	1,690,945
5	SHORT TERM DEBT	510,770	1.57%	1.99%	0.03%	10,150
6	DEFERRED INCOME TAX	7,297,350	22.48%	0.00%	0.00%	-
7	INVESTMENT TAX CREDITS	108,528	0.33%	8.81%	0.03%	9,556
8	**WEIGHTED COST OF CAPITAL**	$ 32,457,144	100.00%		6.63%	$ 2,152,437
9						
10						
11	**ITC WEIGHTED COC**	JURISDICTIONAL ADJUSTED	RATIO	COST RATE	WTD COC	CAPITAL COSTS
12	LONG TERM DEBT	$ 9,420,701	39.05%	4.60%	1.80%	$ 433,279
13	PREFERRED STOCK	-	0.00%	0.00%	0.00%	-
14	COMMON EQUITY	14,703,870	60.95%	11.50%	7.01%	1,690,945
15	**TOTAL**	$ 24,124,571	100.00%		8.81%	$ 0
16						
17						
18						
19						
20						

RECALCULATED 2017 TEST YEAR COST OF CAPITAL

		(1)	(2) KO-20	(3) CUSTOMER DEPOSIT	(4) ADJUSTED CAPITAL				(8)
	JURIS ADJ UTILITY	JURISDICTIONAL ADJUSTED	RATE BASE CHANGES	ADJUSTMENT[(B)]	STRUCTURE	(5) RATIO	(6) COST RATE	(7) WTD COC	CAPITAL COSTS
26	LONG TERM DEBT	$ 9,420,701	$ 232	$ 21	$ 9,420,954	29.03%	4.60%	1.33%	$ 433,291
27	PREFERRED STOCK	0	0	-	0	0.00%	0.00%	0.00%	0
28	CUSTOMER DEPOSITS	415,924	10	(1,832)	414,102	1.28%	2.04%	0.03%	8,462
29	COMMON EQUITY	14,703,870	362	33	14,704,265	45.30%	11.50%	5.21%	1,690,990
30	SHORT TERM DEBT	510,770	13	1,762	512,545	1.58%	1.99%	0.03%	10,185
31	DEFERRED INCOME TAX	7,297,350	180	16	7,297,546	22.48%	0.00%	0.00%	0
32	INVESTMENT TAX CREDITS	108,528	3	0	108,530	0.33%	8.81%	0.03%	9,556
33	**WEIGHTED COST OF CAPITAL**	$ 32,457,144	$ 800	$ 0	$ 32,457,944	100.00%		6.63%	$ 2,152,485
34									
35									
36	**ITC WEIGHTED COC**	JURISDICTIONAL ADJUSTED	RATIO	COST RATE	WTD COC	CAPITAL COSTS			
37	LONG TERM DEBT	$ 9,420,954	39.05%	4.60%	1.80%	$ 433,291			
38	PREFERRED STOCK	-	0.00%	0.00%	0.00%	-			
39	COMMON EQUITY	14,704,265	60.95%	11.50%	7.01%	1,690,990			
40	**TOTAL**	$ 24,125,219	100.00%		8.81%	$ 0			
41									
42									
43	**TAX INTEREST SYNCH ADJUSTMENT**		**$ (1)**						
44									
45									
46									

47 NOTES:
48 (A) REPRESENTS RECALCULATED 2017 WEIGHTED AVERAGE COST OF CAPITAL PER FPL'S THIRD NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 30,
49 2016, WHICH EXCLUDES ALL GAS RESERVE INVESTMENTS.
50 (B) REPRESENTS CUSTOMER DEPOSIT ADJUSTMENT REFLECTED IN FPL'S FIRST NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON MAY 3, 2016.

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
2018 RECALCULATED REVENUE REQUIREMENTS[A]
($000's)

LINE NO.	DESCRIPTION	REFERENCE		2018 REVISED REVENUE REQUIREMENTS PER FPL'S 3rd NOIA[B] (1)	FPL'S 2018 JURISDICTIONAL ADJUSTMENTS[C] (2)	2018 RECALCULATED REVENUE REQUIREMENTS (3)
1						
2	JURISDICTIONAL ADJUSTED RATE BASE	PAGE 6		$33,876,633	$16,862	$33,893,496
3						
4	RATE OF RETURN ON RATE BASE REQUESTED	PAGE 8	x	6.70%	0.00%	6.70%
5						
6	JURISDICTIONAL NET OPERATING INCOME REQUESTED	LINE 2 X LINE 4		2,269,987	1,123	2,271,110
7						
8	JURISDICTIONAL ADJUSTED NET OPERATING INCOME	PAGE 7		1,578,145	17,876	1,596,021
9						
10	NET OPERATING INCOME DEFICIENCY (EXCESS)	LINE 6 - LINE 8		691,842	(16,753)	675,089
11						
12	EARNED RATE OF RETURN	LINE 8 / LINE 2		4.66%	0.05%	4.71%
13						
14	NET OPERATING INCOME MULTIPLIER[D]	PAGE 13	x	1.63024	0.00001	1.63025
15						
16	REVENUE REQUIREMENT	LINE 10 X LINE 14		$1,127,871	($27,307)	$1,100,564
17						
18	2017 REVENUE INCREASE REQUESTED			$863,955	($33,025)	$830,930
19						
20	RATE INCREASE REQUESTED (AFTER FULL 2017 RATE INCREASE)			$263,915	$5,719	$269,634
21						
22						

NOTES:
(A) TOTALS MAY NOT ADD DUE TO ROUNDING
(B) REPRESENTS RECALCULATED 2018 REVENUE REQUIREMENTS PER FPL'S THIRD NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 30, 2016, WHICH EXCLUDES ALL GAS RESERVE INVESTMENTS.
(C) INCLUDES IMPACT OF FPL'S FIRST AND SECOND NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON MAY 3, 2016 AND JUNE 16, 2016, RESPECTIVELY. ALSO INCLUDES THE CORRECTION OF RATE CASE EXPENSES DISCUSSED IN FPL WITNESS OUSDAHL'S REBUTTAL TESTIMONY.
(D) RECALCULATED NOI MULTIPLIER AS REFLECTED ON PAGE 13 OF EXHIBIT KO-20.

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
2018 JURISDICTIONAL RATE BASE ADJUSTMENTS
($000's)

LINE NO.		3rd NOIA[A]	1st NOIA[B]							2nd NOIA[C]				
		Rate Base (1)	Deferred Pension Debit (2)	Uncollectible Accounts Expense (3)	DSM Adjustment (4)	Mitigation Bank Gain (5)	Fukushima (6)	Depreciation Company Adj (7)	Dismantlement Company Adj (8)	Depreciation Company Adj (9)	SJRPP Deferred Credit Dismantlement (10)	Rate Case Expenses (11)	Total Rate Base Adjustments (12)	Revised Rate Base[D][E] (13)
1	PLANT IN SERVICE	$ 45,511,408	$ -	$ -	$ (5,315)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,315)	$ 45,506,093
2														
3	DEPRECIATION & AMORT RESERVE	14,227,659	-	-	(1,638)	-	78	(4)	(2,068)	(33,803)	-	-	(37,435)	$ 14,190,224
4														
5	NET PLANT IN SERVICE	31,283,750	-	-	(3,677)	-	(78)	4	2,068	33,803	-	-	32,120	31,315,869
6														
7	FUTURE USE PLANT	242,917	-	-	(36)	-	-	-	-	-	-	-	(36)	$ 242,882
8		-												
9	CWIP	807,675	-	-	(119)	-	-	-	-	-	-	-	(119)	$ 807,556
10		-												
11	NUCLEAR FUEL	606,781	-	-	-	-	-	-	-	-	-	-	-	$ 606,781
12														
13	NET UTILITY PLANT	32,941,123	-	-	(3,832)	-	(78)	4	2,068	33,803	-	-	31,965	32,973,088
14														
15	WORKING CAPITAL	935,510	(8,600)	(81)	19	(2,431)	-	-	-	-	914	(4,925)	(15,103)	$ 920,407
16														
17	RATE BASE	$ 33,876,633	$ (8,600)	$ (81)	$ (3,812)	$ (2,431)	$ (78)	$ 4	$ 2,068	$ 33,803	$ 914	$ (4,925)	$ 16,862	$ 33,893,496
18														
19														
20														
21														
22														

23 NOTES:
24 (A) REPRESENTS RATE BASE ADJUSTMENTS REFLECTED IN FPL'S THIRD NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 30, 2016.
25 (B) REPRESENTS RATE BASE ADJUSTMENTS REFLECTED IN FPL'S FIRST NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON MAY 3, 2016.
26 (C) REPRESENTS RATE BASE ADJUSTMENTS REFLECTED IN FPL'S SECOND NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 16, 2016.
27 (D) TOTALS MAY NOT ADD DUE TO ROUNDING.
28 (E) REPRESENTS RATE BASE AS REFLECTED ON PAGE 5 OF EXHIBIT KO-20.

Docket No. 160021-EI
Recalculated Revenue Requirements
including Impact of Identified Adjustments
Exhibit KO-20, Page 6 of 13

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
2018 JURISDICTIONAL NET OPERATING INCOME ADJUSTMENTS
($000's)

LINE NO.		3rd NOIA[A]	1st NOIA[B]											2nd NOIA[C]					
		NOI	Aviation Gains	WCEC Water Reclamation	Late Payment Charges	Returned Check	Uncollectible Accounts Expense	Retail Base Revenues	DSM Adjust	Mitigation Bank Gain	Outdoor Lighting	Depreciation Company Adj	Dismantlement Company Adj	Depreciation Company Adj	EDR & EFEDR	Injuries & Damages Exp	Interest Synch Adj	Total NOI Adjustments	Revised NOI[(D)(E)]
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
1	REVENUE FROM SALES	$ 5,766,631	$ -	$ -	$ -	$ -	$ -	$ 9,325	$ (1)	$ -	$ (3,833)	$ -		$ -	$ (850)	$ -	$ -	$ 4,641	$ 5,771,272
2																			
3	OTHER OPERATING REVENUES	200,898	-	-	(490)	(12)	-	-	(5)	-	-	-	-	-	-	-	-	(507)	200,391
4																			
5	TOTAL OPERATING REVENUES	5,967,529	-	-	(490)	(12)	-	9,325	(6)	-	(3,833)	-	-	-	(850)	-	-	4,134	5,971,663
6																			
7	OPERATION AND MAINTENANCE EXPENSE																		
8	OTHER	1,378,961	-	(4,033)	-	-	(13)	-	(134)	-	-	-	-	-	26	(1,024)	-	(5,179)	1,373,783
9	FUEL & INTERCHANGE	24,262	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24,262
10	PURCHASED POWER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	DEFERRED COSTS		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	SUBTOTAL O&M EXPENSE	1,403,223	-	(4,033)	-	-	(13)	-	(134)	-	-	-	-	-	26	(1,024)	-	(5,179)	1,398,044
13																			
14	DEPRECIATION & AMORTIZATION	1,738,419	1,190	-	-	-	-	-	(226)	-	-	(3)	(1,379)	(23,660)	-	-	-	(24,078)	1,714,341
15																			-
16	TAXES OTHER THAN INCOME TAXES	615,467	-	-	-	-	-	-	(110)	-	-	-	-	-	-	-	-	(110)	615,358
17																			-
18	INCOME TAXES																		-
19	INCOME TAX EXPENSE	643,033	(459)	1,556	(189)	(5)	5	3,597	(116)	(1,940)	(1,479)	1	532	9,127	(338)	395	-	10,689	653,722
20	INTEREST SYNCHRONIZATION (PAGE 8)[(F)]	-	-	-	-	-	-	-	-							-	(93)	(93)	(93)
21	SUBTOTAL INCOME TAX EXPENSE	643,033	(459)	1,556	(189)	(5)	5	3,597	(116)	(1,940)	(1,479)	1	532	9,127	(338)	395	(93)	10,595	653,629
22																			
23	(GAIN)/LOSS ON DISPOSAL OF PLANT	(10,759)	-	-	-	-	-	-	-	5,029	-	-	-	-	-	-	-	5,029	(5,730)
24																			
25	TOTAL OPERATING EXPENSES	4,389,384	731	(2,477)	(189)	(5)	(8)	3,597	(585)	3,089	(1,479)	(2)	(847)	(14,533)	(312)	(629)	(93)	(13,742)	4,375,642
26																			
27	NET OPERATING INCOME	$ 1,578,145	$ (731)	$ 2,477	$ (301)	$ (7)	$ 8	$ 5,728	$ 579	$ (3,089)	$ (2,354)	$ 2	$ 847	$ 14,533	$ (538)	$ 629	$ 93	$ 17,876	$ 1,596,021

28
29
30 NOTES:
31 (A) REPRESENTS NOI ADJUSTMENTS REFLECTED IN FPL'S THIRD NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 30, 2016.
32 (B) REPRESENTS NOI ADJUSTMENTS REFLECTED IN FPL'S FIRST NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON MAY 3, 2016.
33 (C) REPRESENTS NOI ADJUSTMENTS REFLECTED IN FPL'S SECOND NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 16, 2016.
34 (D) TOTALS MAY NOT ADD DUE TO ROUNDING.
35 (E) REPRESENTS NOI AS REFLECTED ON PAGE 5 OF EXHIBIT KO-20.
36 (F) REPRESENTS INTEREST SYNCHRONIZATION ADJUSTMENTS RELATED TO THE RATE BASE ADJUSTMENTS REFLECTED ON PAGE 6 OF EXHIBIT KO-20.

Docket 160021-EI
Recalculated Revenue Requirements
including Impact of Identified
Adjustments
Exhibit KO-20, Page 7 of 13

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
2018 RECALCULATED COST OF CAPITAL
($000's)

RECALCULATED 2018 SUBSEQUENT YEAR COST OF CAPITAL PER 3RD NOIA[(A)]

LINE NO.		(1) JURISDICTIONAL ADJUSTED	(2) RATIO	(3) COST RATE	(4) WTD COC	(5) CAPITAL COSTS
	JURIS ADJ UTILITY					
1	LONG TERM DEBT	$ 9,890,403	29.20%	4.80%	1.40%	$ 474,930
2	PREFERRED STOCK	-	0.00%	0.00%	0.00%	-
3	CUSTOMER DEPOSITS	397,599	1.17%	2.04%	0.02%	8,111
4	COMMON EQUITY	15,363,162	45.35%	11.50%	5.22%	1,766,764
5	SHORT TERM DEBT	459,870	1.36%	2.39%	0.03%	10,998
6	DEFERRED INCOME TAX	7,662,145	22.62%	0.00%	0.00%	-
7	INVESTMENT TAX CREDITS	103,454	0.31%	8.88%	0.03%	9,183
8	**WEIGHTED COST OF CAPITAL**	$ 33,876,633	100.00%		6.70%	$ 2,269,987
9						
10						
11	**ITC WEIGHTED COC**	JURISDICTIONAL ADJUSTED	RATIO	COST RATE	WTD COC	CAPITAL COSTS
12	LONG TERM DEBT	$ 9,890,403	39.16%	4.80%	1.88%	$ 474,930
13	PREFERRED STOCK	-	0.00%	0.00%	0.00%	-
14	COMMON EQUITY	15,363,162	60.84%	11.50%	7.00%	1,766,764
15	**TOTAL**	$ 25,253,565	100.00%		8.88%	$ 0
16						
17						
18						
19						

RECALCULATED 2018 SUBSEQUENT YEAR COST OF CAPITAL

		(1)	(2) KO-20	(3) CUSTOMER	(4) ADJUSTED				(8)
		JURISDICTIONAL	RATE BASE	DEPOSIT	CAPITAL	(5)	(6)	(7)	CAPITAL
25	**JURIS ADJ UTILITY**	ADJUSTED	CHANGES	ADJUSTMENT[(B)]	STRUCTURE	RATIO	COST RATE	WTD COC	COSTS
26	LONG TERM DEBT	$ 9,890,403	$ 4,923	$ (19)	$ 9,895,307	29.20%	4.80%	1.40%	$ 475,166
27	PREFERRED STOCK	0	0	-	0	0.00%	0.00%	0.00%	0
28	CUSTOMER DEPOSITS	397,599	198	1,699	399,496	1.18%	2.04%	0.02%	8,152
29	COMMON EQUITY	15,363,162	7,647	(29)	15,370,780	45.35%	11.50%	5.22%	1,767,640
30	SHORT TERM DEBT	459,870	229	(1,636)	458,463	1.35%	2.39%	0.03%	10,964
31	DEFERRED INCOME TAX	7,662,145	3,814	(15)	7,665,944	22.62%	0.00%	0.00%	0
32	INVESTMENT TAX CREDITS	103,454	51	(0)	103,505	0.31%	8.88%	0.03%	9,188
33	**WEIGHTED COST OF CAPITAL**	$ 33,876,633	$ 16,862	$ 0	$33,893,496	100.00%		6.70%	$ 2,271,110
34									
35									
36	**ITC WEIGHTED COC**	JURISDICTIONAL ADJUSTED	RATIO	COST RATE	WTD COC	CAPITAL COSTS			
37	LONG TERM DEBT	$ 9,895,307	39.16%	4.80%	1.88%	$ 475,166			
38	PREFERRED STOCK	-	0.00%	0.00%	0.00%	-			
39	COMMON EQUITY	15,370,780	60.84%	11.50%	7.00%	1,767,640			
40	**TOTAL**	$ 25,266,087	100.00%		8.88%	$ 0			
41									
42									
43									
44	**TAX INTEREST SYNCH ADJUSTMENT**		**$ (93)**						
45									
46									
47									

48 NOTES:
49 (A) REPRESENTS RECALCULATED 2017 WEIGHTED AVERAGE COST OF CAPITAL PER FPL'S THIRD NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE
50 30, 2016, WHICH EXCLUDES ALL GAS RESERVE INVESTMENTS.
51 (B) REPRESENTS CUSTOMER DEPOSIT ADJUSTMENT REFLECTED IN FPL'S FIRST NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON MAY 3, 2016.
52
53
54

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
OKEECHOBEE LSA RECALCULATED REVENUE REQUIREMENTS[A]
($000's)

LINE NO.	DESCRIPTION	REFERENCE		OKEECHOBEE LSA REVISED REVENUE REQUIREMENTS PER FPL'S 3rd NOIA[B] (1)	OKEECHOBEE LSA JURISDICTIONAL ADJUSTMENTS[C] (2)	OKEECHOBEE LSA RECALCULATED REVENUE REQUIREMENTS (3)
1						
2	JURISDICTIONAL ADJUSTED RATE BASE	PAGE 10		$1,063,315	($105)	$1,063,210
3						
4	RATE OF RETURN ON RATE BASE REQUESTED	PAGE 12	x	8.87%	-0.03%	8.85%
5						
6	JURISDICTIONAL NET OPERATING INCOME REQUESTED	LINE 2 X LINE 4		94,388	(325)	94,063
7						
8	JURISDICTIONAL ADJUSTED NET OPERATING INCOME	PAGE 11		(33,868)	(130)	(33,998)
9						
10	NET OPERATING INCOME DEFICIENCY (EXCESS)	LINE 6 - LINE 8		128,256	(195)	128,061
11						
12	EARNED RATE OF RETURN	LINE 8 / LINE 2		-3.19%	-0.01%	-3.20%
13						
14	NET OPERATING INCOME MULTIPLIER[D]	PAGE 13	x	1.63024	0.00001	1.63025
15						
16	REVENUE REQUIREMENT	LINE 10 X LINE 14		$209,089	($318)	$208,771
17						
18						
19						

20 NOTES:
21 (A) TOTALS MAY NOT ADD DUE TO ROUNDING
22 (B) REPRESENTS RECALCULATED OKEECHOBEE LSA REVENUE REQUIREMENTS PER FPL'S THIRD NOTICE OF IDENTIFIED ADJUSTMENTS
23 FILED ON JUNE 30, 2016, WHICH EXCLUDES ALL GAS RESERVE INVESTMENTS.
24 (C) INCLUDES IMPACT OF FPL'S FIRST AND SECOND NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON MAY 3, 2016 AND JUNE 16, 2016,
25 RESPECTIVELY.
26 (D) RECALCULATED NOI MULTIPLIER AS REFLECTED ON PAGE 13 OF EXHIBIT KO-20.

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
OKEECHOBEE LSA JURISDICTIONAL RATE BASE ADJUSTMENTS
($000's)

LINE NO.		Originally Filed Rate Base (1)	2nd NOIA[A] Depreciation Company Adjustment (2)	Revised Rate Base[B][C] (3)
1	PLANT IN SERVICE	$ 1,165,226	$ -	$ 1,165,226
2				
3	DEPRECIATION & AMORT RESERVE	20,553	105	20,658
4				
5	NET PLANT IN SERVICE	1,144,673	(105)	1,144,568
6				
7	FUTURE USE PLANT	-	-	-
8		-		
9	CWIP	-	-	-
10		-		
11	NUCLEAR FUEL	-	-	-
12				
13	NET UTILITY PLANT	1,144,673	(105)	1,144,568
14				
15	OTHER RATE BASE ITEMS	(81,359)	-	(81,359)
16				
17	RATE BASE	$ 1,063,315	$ (105)	$ 1,063,210

NOTES:
(A) REPRESENTS RATE BASE ADJUSTMENTS REFLECTED IN FPL'S SECOND NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 16, 2016.
(B) TOTALS MAY NOT ADD DUE TO ROUNDING.
(C) REPRESENTS RATE BASE AS REFLECTED ON PAGE 9 OF EXHIBIT KO-20.

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
OKEECHOBEE LSA JURISDICTIONAL NET OPERATING INCOME ADJUSTMENTS
($000's)

LINE NO.		Originally Filed NOI (1)	2nd NOIA[A] Depreciation Company Adjustment (2)	Interest Synch Adj (3)	Total NOI Adjustments (4)	Revised NOI[B][C] (5)
1	REVENUE FROM SALES	$ -	$ -	$ -	$ -	$ -
2						
3	OTHER OPERATING REVENUES	-	-	-	-	-
4						
5	TOTAL OPERATING REVENUES	-	-	-	-	-
6						
7	OPERATION AND MAINTENANCE EXPENSE					
8	OTHER	7,905	-	-	-	7,905
9	FUEL & INTERCHANGE	-	-	-	-	-
10	PURCHASED POWER	-	-	-	-	-
11	DEFERRED COSTS	-	-	-	-	-
12	SUBTOTAL O&M EXPENSE	7,905	-	-	-	7,905
13						
14	DEPRECIATION & AMORTIZATION	41,105	210	-	210	41,315
15						-
16	TAXES OTHER THAN INCOME TAXES	17,110	-	-	-	17,110
17						-
18	INCOME TAXES					-
19	INCOME TAX EXPENSE	(32,252)	(81)	-	(81)	(32,333)
20	INTEREST SYNCHRONIZATION (PAGE 12)[D]	-	-	1	1	1
21	SUBTOTAL INCOME TAX EXPENSE	(32,252)	(81)	1	(80)	(32,332)
22						
23	(GAIN)/LOSS ON DISPOSAL OF PLANT	-	-	-	-	-
24						
25	TOTAL OPERATING EXPENSES	33,868	129	1	130	33,998
26						
27	NET OPERATING INCOME	$ (33,868)	$ (129)	$ (1)	$ (130)	$ (33,998)
28						
29						
30	NOTES:					
31	(A) REPRESENTS NET OPERATING INCOME ADJUSTMENTS REFLECTED IN FPL'S SECOND NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 16, 2016.					
32	(B) TOTALS MAY NOT ADD DUE TO ROUNDING.					
33	(C) REPRESENTS NOI AS REFLECTED ON PAGE 9 OF EXHIBIT KO-20.					
34	(D) REPRESENTS INTEREST SYNCHRONIZATION ADJUSTMENTS RELATED TO THE RATE BASE ADJUSTMENTS REFLECTED ON PAGE 10 OF EXHIBIT KO-20.					
35						

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
OKEECHOBEE LSA RECALCULATED COST OF CAPITAL
($000's)

RECALCULATED OKEECHOBEE COST OF CAPITAL PER 3RD NOIA[(A)]

LINE NO.	JURIS ADJ UTILITY	(1) JURISDICTIONAL ADJUSTED	(2) RATIO	(3) COST RATE	(4) WTD COC	(5) CAPITAL COSTS
1	LONG TERM DEBT	$ 421,152	39.16%	4.80%	1.881%	$ 20,223
2	PREFERRED STOCK	-	0.00%	0.00%	0.000%	-
3	CUSTOMER DEPOSITS	-	0.00%	0.00%	0.000%	-
4	COMMON EQUITY	642,163	60.84%	11.50%	6.996%	73,849
5	SHORT TERM DEBT	-	0.00%	0.00%	0.000%	-
6	DEFERRED INCOME TAX	-	0.00%	0.00%	0.000%	-
7	INVESTMENT TAX CREDITS	-	0.00%	0.00%	0.000%	-
8	WEIGHTED COST OF CAPITAL	$ 1,063,315	100.00%		8.8767%	$ 94,072

RECALCULATED OCEC COST OF CAPITAL

16	JURIS ADJ UTILITY	(1) JURISDICTIONAL ADJUSTED	(2) KO-20 RATE BASE CHANGES	(3) ADJUSTED CAPITAL STRUCTURE	(4) RATIO	(5) COST RATE	(6) WTD COC	(7) CAPITAL COSTS
17	LONG TERM DEBT	$ 421,152	$ (42)	$ 421,110	39.61%	4.80%	1.902%	$ 20,221
18	PREFERRED STOCK	-	-	-	0.00%	0.00%	0.000%	-
19	CUSTOMER DEPOSITS	-	-	-	0.00%	0.00%	0.000%	-
20	COMMON EQUITY	642,163	(63)	642,100	60.39%	11.50%	6.945%	73,841
21	SHORT TERM DEBT	-	-	-	0.00%	0.00%	0.000%	-
22	DEFERRED INCOME TAX	-	-	-	0.00%	0.00%	0.000%	-
23	INVESTMENT TAX CREDITS	-	-	-	0.00%	0.00%	0.000%	-
24	WEIGHTED COST OF CAPITAL	$ 1,063,315	$ (105)	$ 1,063,210	100.00%		8.8471%	$ 94,063

28 **TAX INTEREST SYNCH ADJUSTMENT** $ 1

NOTES:
(A) REPRESENTS RECALCULATED OKEECHOBEE WEIGHTED AVERAGE COST OF CAPITAL PER FPL'S THIRD NOTICE OF IDENTIFIED ADJUSTMENTS FILED ON JUNE 30, 2016, WHICH EXCLUDES ALL GAS RESERVE INVESTMENTS.

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
Multiplier Correction for Bad Debt Rate

LINE NO.			2017	2018	Okeechobee LSA
1	REVENUE REQUIREMENT		1.00000	1.00000	1.00000
2					
3	REGULATORY ASSESSMENT RATE		0.00072	0.00072	0.00072
4					
5	BAD DEBT RATE[(A)]		0.00066	0.00066	0.00066
6					
7	NET BEFORE INCOME TAXES	LINE 1 - 3 - 5	0.99862	0.99862	0.99862
8					
9	STATE INCOME TAX RATE		0.05500	0.05500	0.05500
10					
11	STATE INCOME TAX	LINE 7 X 9	0.05492	0.05492	0.05492
12					
13	NET BEFORE FEDERAL INCOME TAX		0.94370	0.94370	0.94370
14					
15	FEDERAL INCOME TAX RATE		0.35000	0.35000	0.35000
16					
17	FEDERAL INCOME TAX	LINE 13 X 15	0.33029	0.33029	0.33029
18					
19	REVENUE EXPANSION FACTOR	LINE 13 - 17	0.61340	0.61340	0.61340
20					
21	NET OPERATING INCOME MULTIPLIER	100% / LINE 15	1.63025	1.63025	1.63025
22					
23	NOTES:				
24	(A) REPRESENTS REVISED BAD DEBT RATE PROVIDED IN FPL'S FIRST NOTICE OF IDENTIFIED ADJUSTMENTS				

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF KATHLEEN SLATTERY

DOCKET NO. 160021-EI

AUGUST 1, 2016

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Q. Please state your name and business address.

A. My name is Kathleen Slattery. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes, I am sponsoring the following exhibit:

- KS-9, FPL Planned vs. Actual Gross Payroll 2011 - 2015

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this testimony is to rebut the direct testimony of Office of Public Counsel ("OPC") witness Helmuth Schultz III regarding the payroll expense, incentive compensation, employee benefits, and payroll tax expense of Florida Power & Light Company ("FPL" or "the Company").

I. SUMMARY

Q. Please summarize your rebuttal testimony.

A. As demonstrated in my direct testimony, FPL's projected compensation and benefits expense is reasonable and prudent. The only witness to take issue with any aspect of FPL's compensation and benefits expense is OPC witness Schultz, who recommends several adjustments. Those recommended adjustments should be rejected.

Witness Schultz recommends limiting FPL's recovery of one component of its total compensation and benefits program – non-executive performance-based cash incentive compensation – but offers no evidence that the Company's total compensation and benefits levels (which include such performance-based cash incentive compensation) are not reasonable or necessary to attract and retain the required workforce to deliver on FPL's commitments to its customers. Instead, witness Schultz focuses on a flawed philosophy that advocates the sharing of cash incentive compensation costs between customers and shareholders. My rebuttal testimony addresses: (1) the market-based evidence that supports the reasonableness of the plan, (2) the current competitive position of the plan and potential negative impact of witness Schultz's recommended disallowance, and (3) the customer-focused design of the plan.

OPC witness Schultz has also made recommendations to disallow portions of payroll, benefits and payroll tax expense based on FPL's planned staffing levels, but in doing so erroneously concludes that headcount is the only factor in the payroll, benefits and payroll tax expense equations. He fails to consider the cost of turnover or acknowledge that when less-than-optimal staffing levels are employed, FPL spends additional money on expenses such as overtime. My rebuttal testimony demonstrates the flaws in witness Schultz's analysis of staffing and payroll and the associated benefits and payroll tax expense and provides further evidence of the reasonableness of these costs.

II. TOTAL COMPENSATON AND BENEFITS EXPENSE

Q. Is FPL's projected total compensation and benefits expense for 2017 reasonable?

A. Yes. As previously demonstrated in my direct testimony and exhibits, FPL's projected total compensation and benefits expense is reasonable and prudent, and does not include any type of expense that the Commission has not previously approved for recovery. *FPL's total gross compensation and benefits costs in 2017 and 2018 are projected to be less than FPL's total gross compensation and benefits cost in 2013.* The total rewards package, emphasizing pay for performance, has successfully provided value to FPL's employees *and* its customers by driving a culture that rewards improved efficiency and performance.

As described in my direct testimony, FPL employs a total rewards approach. One of the stated objectives of this approach is to control fixed costs by placing emphasis on performance-based variable pay rather than fixed pay and traditional benefits. The strategic emphasis on performance-based variable pay rather than salary and benefits lowers the Company's exposure to steadily increasing salary and fringe benefit costs and adds flexibility in recognizing performance.

III. VALIDITY AND COMPARISONS OF DATA

Q. In his testimony, OPC witness Schultz takes issue with certain perceived variances in the Company's payroll-related discovery responses or other alleged discrepancies in information supplied by the Company. Are OPC witness Schultz's concerns valid?

A. No. Most of witness Schultz's concerns arise from his attempt to compare apples to oranges, such as discovery responses based on gross dollars versus discovery responses based on net Operations & Maintenance ("O&M") dollars. The following examples from witness Schultz's testimony demonstrate that the confusion is on his part:

- Page 11, lines 1 through 15, regarding the executive incentive compensation adjustments: The supposed "significant" differences between the 2016 filing adjustment and the 2012 filing adjustment for executive incentive compensation are a result of witness Schultz trying to compare amounts that are dissimilar. FPL's response to OPC Interrogatory No. 139 presents cumulative Rate Base adjustments from January 2013 and annual Net Operating Income ("NOI") adjustments for 2017 and 2018 net of affiliate charges. He then combines these adjustments and compares them to amounts on MFR C-35 worksheets from Docket No. 120015-EI, which reflect total *gross* amounts before subtraction of capital, below-the-line amounts, affiliate allocations and other amounts. FPL's 2017 and 2018 adjustments are correct.

- Page 11, line 19 through page 12, line 4, regarding MFR C-35 payroll detail for executive incentive amounts: First, witness Schultz states that MFR C-35 "indicates that for the projected test year 2017 the executive incentives amount is $13.220 million and stock based compensation is $34.407 for a total of $47.627 million." Witness Schultz has mistakenly added stock based compensation for 2018 ($34.407) instead of stock based compensation for 2017 ($33.336); thus, the correct 2017 total is $46.556 million. Then, he tries to compare his incorrect calculation of a *gross* amount to the sum of the cumulative Rate Base adjustment and the *NOI* adjustment for executive incentive compensation. Again, FPL's 2017 Rate Base and NOI executive incentive adjustments are correct
- Page 12, lines 4 through 6, "Performance Incentive": Witness Schultz noted that in the 2012 filing, FPL's executive incentive compensation also included what was identified as "Performance Incentive," and he further states that he has not seen a reference to that in this filing. The simple reason for witness Schultz's confusion on this point is that a different account was used for budgeting purposes. In 2012 and 2013, Account 5992259 Executive Performance Incentive was used to budget the gross Executive Annual Cash Incentive, whereas in 2017 and 2018 Account 5230000 Executive Incentives was used. FPL's executive incentive compensation adjustments are correct.
- Page 12, lines 8 through 12, regarding C-35 payroll detail for Employee Incentives: The supposed discrepancy is a result of witness Schultz

trying to compare amounts that are not comparable; specifically, he incorrectly compares the amount on MFR C-35 workpapers for Employee Incentives for 2017, which is a *gross* number for non-executive, non-bargaining, short-term and long-term incentives and which does not break out capital, below-the-line amounts, affiliate allocations, clause and other non-base O&M, to *net* amounts in FPL's response to Staff Interrogatory No. 21 for the base O&M and capital expenditure portion of non-executive, non-bargaining short-term only incentive amounts.

In summary, FPL's filings and discovery responses are accurate and reliable.

Q. In his testimony, OPC witness Schultz takes issue with certain confidential documents being treated as "highly sensitive." Are OPC witness Schultz's concerns valid?

A. No. FPL has provided reasonable access to any confidential and highly sensitive documents requested, while appropriately protecting them. It is in customers' best interests for FPL to properly protect highly sensitive compensation and benefits information, since safeguarding this competitive information ultimately aids in controlling escalation of compensation and benefits expense over the long term.

Q. Do you have concerns with the validity of data provided by witness Schultz?

A. Yes. In his testimony and exhibits, OPC witness Schultz calculates recommended disallowances to payroll and benefits expense based on assumed O&M allocation factors. However, witness Schultz has used incorrect O&M allocation factors in

his calculated disallowances for both 2017 and 2018. The correct O&M allocation factors are as shown below.

O&M Factor for Employee Compensation Expense

	Schultz (Incorrect)	Correct
2017	66.29%	59.40%
2018	66.29%	59.70%

O&M Factor for Employee Benefit Expense

	Schultz (Incorrect)	Correct
2017	70.48%	61.10%
2018	70.56%	61.27%

Q. Were you able to discern the basis of his incorrect O&M allocation factors?

A. Yes. With regards to employee compensation expense, witness Shultz used FPL's response to Staff's Interrogatory No. 21 as the basis for calculating his O&M Factor, which mistakenly assumes the figures summed to a gross amount; the response included only the base O&M and capital expenditure components of the gross amount. With regards to employee benefits expense, witness Shultz used MFR C-4 and Federal Energy Regulatory Commission ("FERC") account 926000, employee pensions and benefits, as the basis for calculating his O&M Factor. MFR C-4 account 926000 is inappropriate as it includes items such as clause O&M and affiliate charges.

IV. NON-EXECUTIVE PERFORMANCE-BASED CASH INCENTIVE COMPENSATION

Q. What is OPC witness Schultz's recommendation regarding non-executive performance-based cash incentive compensation?

A. Witness Schultz refers to non-executive performance-based cash incentive compensation as non-executive incentive compensation and is recommending a disallowance of 70% of such expense; his 70% disallowance is comprised of 100% disallowance of the 40% of the plan that he erroneously characterizes as based on "financial-related goals" (page 24, lines 22 and 23), and a 50% disallowance of the remaining 60% of the plan that he describes as based on "customer-related goals" (page 25, lines 1 through 3).

Q. Is witness Schultz's assertion that 40% of the non-executive performance-based variable compensation plan is based on financial-related goals accurate?

A. No. 100% of the plan is based on customer-related goals. Witness Schultz's characterization of O&M costs and capital expenditures as "financial" goals is misleading; they are only "financial" in the sense that they are measured in dollars. Examples of true measures of "financial" performance – which are *not* used in FPL's plan – would be earnings, revenue growth, return on equity, total shareholder return, earnings per share, and so forth. Instead, both O&M costs and capital expenditures are tied directly to the customer value proposition.

Capital expenditures include investments such as those that FPL makes to maintain and upgrade the T&D system, for storm hardening, and for improving the efficiency of our power plants, all of which lead to improved reliability and long-term savings to customers. These capital investments have contributed to our industry-leading service reliability performance and average customer bills that are the lowest in Florida and 30 percent below the national average. Clearly they benefit customers.

Similarly, FPL's focus on containing non-fuel O&M expenses directly benefits customers. FPL's performance on O&M expenses relative to other investor-owned-utilities shows that FPL has outperformed its peers. As discussed by FPL witness Reed in his direct testimony, FPL is a top performer in non-fuel O&M, and as discussed by FPL witness Barrett, all of these projected savings are fully reflected in the forecasts in this filing. In fact, FPL projects that the non-fuel O&M expense in 2017 will be lower than the amount incurred in 2013 (Barrett direct testimony page 23, lines 9 through 11). That performance directly reduces FPL revenue requirements presented in this case, and therefore directly benefits customers.

Q. Does witness Schultz base his recommendation for partial disallowance on empirical data or any other analysis which suggests that the Company's non-executive performance-based cash incentive compensation is not reasonable or effective?

A. No, he does not. Significantly, witness Schultz has not criticized FPL employee pay levels or FPL's inclusion of performance-based cash incentive compensation in its total rewards design. Neither witness Schultz nor any other witness has made any allegations or presented any evidence that the total compensation paid to FPL employees, including performance-based cash incentive compensation, is not reasonable, not necessary or ineffective. Nor have they presented any analysis of FPL's compensation levels compared to market pay levels to refute the evidence presented in my direct testimony that FPL employees' base salaries and performance-based variable compensation are at or near the market median (Exhibits KS-3 and KS-4). Witness Schultz's recommendation therefore is not based on empirical evidence.

Q. Is non-executive performance-based cash incentive compensation a typical and necessary component of a utility's total rewards program?

A. Yes. Even witness Schultz, in his testimony, admits that he is not aware of any utility that does not have some form of incentive compensation (page 23, lines 21 and 22). Market data from Aon Hewitt shows that over 90 percent of U.S.-based companies include incentive compensation as part of their total rewards mix.

Q. On what basis then does witness Schultz recommend a partial disallowance of the Company's non-executive performance-based cash incentive compensation?

A. At its core, Witness Schultz's recommendation is based on the flawed premise that a properly designed performance-based incentive compensation plan benefits shareholders and customers equally and therefore the costs should be shared equally. FPL witness Deason explains why allowing cost recovery on the basis of assigning proportions of costs based on perceived benefits is contrary to basic cost-of-service regulation.

Q. If FPL's non-executive performance-based cash incentive compensation expense is disallowed, in whole or in part, what impact would a corresponding elimination or reduction of the program have on FPL salaried employee's compensation compared to market median?

A. In the aggregate, FPL salaried employees would be compensated more than 13% below market median if performance-based cash incentive compensation were eliminated. As shown in Exhibit KS-4 to my direct testimony, median levels of performance-based variable pay have recently been at 13% of base salaries. Also, as shown in Exhibit KS-3 to my direct testimony, exempt employees' base salaries are, in the aggregate, 1.2% below the market median. Without its current levels of performance-based variable compensation, FPL would not be able to attract and retain the caliber of employees that sustain a high-performing organization.

Q. OPC witness Schultz makes several references to the Progress Energy Florida 2009 rate case (Docket Nos. 090079-EI, 090144-EI, 090145-EI), wherein the Commission disallowed, in its March 2010 order (Order No. PSC-10-0131-FOF-EI), all incentive compensation costs due to the plans' design. Are there other cases not cited by witness Schultz?

A. Yes, in fact he fails to cite a more recent case in which the Commission rejected this same position taken by OPC. In its April 2012 order in Gulf Power's rate case (Order No. PSC-12-0179-FOF-EI), this Commission rejected OPC's recommended adjustment to exclude all incentive compensation, calling it "unreasonable" and citing the negative impact such a disallowance would have on Gulf employee's compensation compared to market median (page 97). The Commission allowed 100 percent of Gulf's non-executive annual cash incentive program to be included in O&M expense (page 94). FPL witness Deason discusses the Commission's precedent on this topic in more detail.

Q. Witness Schultz claims there is a discrepancy between FPL's implementation of its non-executive adjustment and the "true intent" of the Commission's 2010 Order issued in Docket No. 080677-EI. Please respond.

A. Witness Schultz claims that the Commission's 2010 order "appears to have inadvertently omitted the cash-based portion of the non-executive incentive compensation" (page 16, lines 1 through 3). However, it was OPC's own witness in that docket who calculated the disallowance later adopted by the Commission. In addressing "Non-Executive Incentive Compensation" in her testimony in Docket No. 080677-EI, OPC witness Sheree L. Brown recommended an

adjustment of $5.7 million for 2010 to "the stock-based compensation for non-executives" (page 57, lines 11 through 16). Her calculated disallowance contained no adjustment to cash-based non-executive incentive compensation. Commission Staff then recommended that the Commission accept this adjustment at page 344 of their recommendation (citing Ms. Brown's recommendation on *stock-based compensation*), and the Commission did in its final order (Order No. PSC-10-0153-FOF-EI, pages 149 and 150). The disallowed amount, and what it represented, is clear.

Q. As further support for his recommendation for partial disallowance, witness Schultz criticizes FPL's goal setting. How does FPL establish its annual goals under the non-executive performance-based cash incentive compensation plan?

A. FPL's robust annual goal-setting process is based on industry benchmarks and historic company performance on each customer-focused metric: O&M costs, capital expenditures, fossil generation availability, nuclear industry composite performance index score, three measures of service reliability, employee safety, environmental compliance, customer satisfaction as measured by residential and business value surveys, and performance under FERC and the North American Electric Reliability Corporation ("NERC") reliability standards. FPL's typical performance goals are equal to or better than the top quartile performers in the utility industry.

Q. Witness Schultz cites a concern that FPL's customer satisfaction goals lack measurable values and performance is subjectively determined. Is that an accurate assessment?

A. No, it is not. In arriving at this inference, witness Schultz focuses on select excerpts from FPL's parent company's proxy filings. Under the Securities and Exchange Commission's disclosure rules governing such proxy filings, companies are permitted to curtail select details from broad public disclosure that may need to be kept confidential for competitive purposes. Thus when witness Schultz opines on page 19 of his testimony that FPL's customer satisfaction goal "does not provide any way to measure performance" and that "identified achievement provides no measurement value" (lines 9 through 11), this is contrary to the facts. FPL's residential and business customer satisfaction goals do in fact have specified and challenging quantitative, measurable objectives. FPL's performance relative to these quantitative, measurable objectives are based on the results of customer satisfaction surveys conducted each year, which witness Schultz himself recommends should be the basis for measuring customer satisfaction (page 19, line 13).

Moreover, customer satisfaction survey scores are metrics under FPL's plan due to its customer-centric culture and FPL's desire to incent its workforce to focus on producing the best results possible for customers. Results demonstrate that this strategy is working; FPL has been recognized by various third parties for its continued high performance with regard to customer satisfaction. In July 2016,

J.D Power released its rankings of utility performance with respect to customer satisfaction. FPL ranked #1 amongst large utilities in customer satisfaction in the South and #2 across the entire nation. Additional information on FPL's high levels of customer satisfaction can be found in the direct testimony of FPL witnesses Dewhurst and Santos.

Q. Witness Schultz suggests that FPL "is willing to relax the requirements [under its non-executive performance-based cash incentive compensation plan] to allow a better opportunity for achieving an incentive payout" (page 20, lines 4-5). He cites service reliability as an example of this. Can you respond to this assertion?

A. In explaining why he is incorrect, I would like to start by briefly discussing FPL's overall process for determining performance objectives under the plan. FPL employs a robust, iterative process to establish challenging but achievable annual performance goals, which are designed to drive employee behavior to achieve results that benefit customers. Where applicable, FPL's goals are directly benchmarked against industry data from third-party sources such as the Electric Edison Institute, NERC, FERC filings, and the Institute of Nuclear Power Operations. FPL typically sets goals at a level equal to or more challenging than the top quartile of the utility industry. In several cases, the goals are in fact set at the top-decile level or higher.

Witness Schultz's testimony on the evolution of FPL performance goals is focused on 2011 through 2015. With respect to service reliability, he specifically

focuses on the average number of momentary interruptions per customer metric ("MAIFI"). Witness Schultz's analysis of FPL's service reliability goals is lacking from several perspectives. For each of the years 2011 through 2015, FPL's annual MAIFI goal was established at a level that was at least equal to or more challenging than the prior year's goal, with the exception of one year, 2012 - the only year that witness Schultz relies upon as the basis for his positon. When viewing our MAIFI goal over the entirety of the period that witness Schultz analyzed, the goal decreased from 13.4 in 2011 to 11.7 in 2015, representing an aggregate decrease (i.e., more challenging) of 13%. Accordingly, for witness Schultz to look solely at the 2012 MAIFI goal relative to 2011 and incorrectly imply that this is indicative of a trend is simply inaccurate.

If one were also to look at the other two service reliability metrics under the plan, service unavailability ("SAIDI") and average frequency of customer interruptions ("SAIFI"), a trend of continuously raising the bar is evident. In each year during the 2011 through 2015 period, FPL's SAIDI and SAIFI goals have been set at a level either equal to the prior year, or, in the majority of instances, at an increasingly challenging level.

Q. Witness Schultz levied a similar charge with respect to employee safety, claiming that there is inadequate goal-setting in the area of safety. Is his claim with respect to Occupational Safety and Health Administration ("OSHA") supportable?

A. No, once again witness Schultz fails to analyze the entirety of the period 2011 through 2015 that he references. Let me first note that OSHA recordable events are another metric where a lower score is better. Over the period that witness Schultz reviewed (i.e., from 2011 through 2015) FPL's employee safety goal (measured by number of OSHA recordable events per 200,000 work hours) moved from 1.47 in 2011 to 0.61 in 2015.

Because of the tremendous results that FPL has achieved in improving safety, FPL's safety goals year over year have become increasingly challenging. FPL's management places a very high degree of importance on safety. For that reason, we continue to set aggressive goals. This is reflected in the benchmarking that we do. For 2015, the year witness Schultz' criticizes, FPL's OSHA goal of 0.61 was *lower* than the most-recently reported top-decile OSHA score for our industry. It is not reasonable for one to suggest that setting a safety goal that is more challenging than top decile performance is indicative of inadequate goal setting. Rather, it simply underscores the high degree of importance FPL management places on safety.

Q. Witness Schultz indicates at page 23 that incentive pay, in general, is not a shift from one form of remuneration to another but is instead just an add-on. Is this true of FPL?

A. No. I disagree with his general contention and it is specifically not true with regard to FPL. As explained in my direct testimony, FPL's approach to the design and administration of compensation and benefits is to consider them parts of one total rewards package, and I specifically addressed the redesign of the employment package in 1997. Prior to the redesign, the Company did not have a broad-based non-executive incentive plan; any awards were granted on a very limited basis to top management. The redesign of the employment package implemented the current non-executive performance-based cash incentive plan, but not as an "extra" program element. The variable pay component was funded by reducing benefit plan costs, specifically the conversion of the traditional pension plan to a much leaner cash balance plan and the elimination of retirement medical and life insurance benefits for all employees hired after 1997. To be clear, FPL did not reduce base salaries at the time that it implemented the non-executive performance-based cash incentive plan, but it did reduce the value of the pension plan and cut other post-retirement benefits. Witness Schultz appears to be looking only for evidence of a shifting of dollars from base salaries to variable pay programs, and is ignoring the impact of fixed-cost benefit plans in the total rewards equation. Moreover, those changes were made nearly 20 years ago and the design elements of our total compensation plan have been the subject of our benchmarking for years. As I have explained, and a point that is not

refuted by witness Schultz or any other witness in this case, our total compensation packages are consistent with market.

Q. Would FPL need to consider restructuring its total compensation package if any non-executive performance-based cash incentive compensation was excluded?

A. Yes. Contrary to witness Schultz's contention, if denied recovery of its reasonable, prudently-incurred variable compensation expense, FPL would need to consider reallocating non-executive total compensation and benefits to assure cost recovery for a reasonable, competitive level of total rewards. This could potentially lead us to a reduction in performance-based cash incentive compensation programs and an increase in base salaries and/or other traditional fixed-cost programs.

FPL believes that its current total rewards program, with its emphasis on performance-based pay, is optimal and directly benefits customers. However, if future regulatory decisions were to perpetuate disallowance of performance-based incentive compensation, then FPL naturally would be inclined to re-evaluate the program design. Legitimate, reasonable expenses incurred in delivering service to our customers need to be recovered; if regulatory policy were to precludes recovery of a portion of total compensation otherwise consistent with market rates, simply because it is labeled incentive compensation, then FPL (and perhaps other penalized utilities) will be induced to re-design the compensation and

benefits programs to conform to regulatory policy that disfavors performance-based compensation. We do not believe this is the right result for customers.

Q Please summarize why it would be inappropriate to disallow 70% of the cost of the non-executive performance-based variable cash compensation plan as recommended by OPC witness Schultz.

A. There are five primary reasons: (1) the plan is part of a market-based, competitive total rewards program that has been demonstrated to be prudent and reasonable, and effective in producing the desired results; (2) the focus of the discussion should be on how much is paid, not how it is paid, and no witness has presented evidence that FPL's employee compensation is excessive or unreasonable; (3) the incentive plan relies solely on customer-based operating performance goals (not any measures of "financial" performance) to determine employee payouts; (4) eliminating or reducing the plan would negatively impact the competitive position of the Company's total rewards package and the Company's ability to attract and retain talent; and (5) disallowance of part or all of the cost would be inconsistent with the most recent Commission precedent.

V. PAYROLL AND STAFFING LEVELS

Q. OPC witness Schultz has made recommendations regarding FPL's projected staffing and payroll for 2017. Has he evaluated the required staffing level in view of FPL's specific workload or requirements?

A. No. He has incorrectly relied only on historical staffing levels; as has been the case in past FPL rate proceedings in which he has participated, he evidently has made no attempt to analyze FPL's specific workload trends and requirements which are much better predictors of actual needs and, in fact, are the basis for budgeting.

Q. Please explain the difference between forecast and actual staffing that OPC witness Schultz claims to have identified.

A. The staffing-level forecasts are management's reasonable estimates of what is needed to do the required work based on optimal staffing levels. Like all companies our size, FPL experiences some turnover of personnel each year and is constantly recruiting, hiring, training and developing new talent. Every effort is made to fill the forecast positions, but a number of factors have made it difficult for the Company to fill all open positions. Among these are fluctuations in the housing market, limited availability of a technical and engineering related labor force, increased desirability of in-demand technology skills, and the fiscal constraints the Company has placed on the competitiveness of its pay and benefits package. All of these factors and more have resulted historically in the hiring process lagging slightly behind expectations. But this does not mean that the

Company does not incur the costs corresponding to the budgeted headcount in ensuring that the required work is completed.

Q. Citing the observed historical difference between budgeted and actual staffing, OPC witness Schultz recommends staffing level, and corresponding payroll reductions, for the 2017 Test Year and 2018 Subsequent Year. Should the Commission accept that analysis?

A. No. His conclusion is premised on the incorrect assumption that the payroll budget is solely a function of headcount. FPL budgets employee projections at the staffing level necessary to most efficiently get the work done to ensure the Company delivers on its customer service and reliability commitments. However, the Company has to sometimes rely on less efficient staffing models (such as overtime, temporary labor, etc.), which drives costs up. In order to insulate customers from these potentially higher costs, the Company focuses on total compensation and benefits at optimal staffing levels when formulating its forecast. Therefore, the methodology employed by OPC witness Schultz, which only considers one input in a dynamic equation, is an incomplete analysis, underestimates FPL's actual costs, and should be rejected. As I will discuss later, the past five years of actual versus planned gross payroll bears this out. Payroll, of course, includes the costs I referenced above (overtime, temporary labor, etc.) that are incurred in order to accomplish the work, even when we are temporarily delayed in finding the right person to fill an open position.

Q. Do you have other concerns with OPC witness Schultz's methodology?

A. Yes. Although he presents more than 10 years of data on his exhibit (HWS–2), he elects to base his recommended adjustment selectively on the 2015 average headcount (8,835). It shows a lack of understanding of the variability and complexity of the work. He also overstates the O&M "Expense Factor" in his calculation for Exhibit HWS-2, "Payroll Adjustments," which should be reflected as 59.4% for 2017 and 59.7% for 2018, rather than the 66.29% used on the exhibit. This correction would reduce his recommended adjustment by $1.78 million for 2017 (to $15.38 million) and by $1.58 million for 2018 (to $14.35 million).

Q. Is there a more appropriate methodology to analyze the reasonableness of payroll costs?

A. Yes. It would be more appropriate to actually analyze the dollars spent on payroll.

Q. Have you analyzed the Company's historical payroll expense?

A. Yes. Exhibit KS-9 presents a variance analysis of FPL's planned to actual gross payroll expense from 2011 to 2015. It is essential to get a representative view of reasonable and necessary payroll, and omitting an analysis on gross payroll is a flaw in OPC witness Schultz's analysis.

Q. Please summarize the results of the analysis of historical payroll expense.

A. As demonstrated in the table on Exhibit KS-9, the variance between actual and planned gross payroll, as reflected in filings with the FPSC for available years, is 1.21% over that five year period. In other words, the aggregate actual gross

payroll expense has been 1.21% *higher* than planned, and overall quite close to planned. This directly contradicts witness Shultz's assertion that FPL's headcount projections, which are higher than actuals, "corresponds to tens of millions of dollars in over-collected payroll costs" (page 4, line 19). In fact, FPL would have slightly under-collected payroll costs if these forecasts had served as the basis for cost recovery (rather than settlements over this time frame). Exhibit KS-9 supports the conclusion that no payroll adjustment of any size is warranted.

Q. What other conclusions should the Commission draw from the planned versus actual gross payroll analysis in Exhibit KS-9?

A. In addition to the above conclusions, the analysis (1) demonstrates that the one-year average headcount sample upon which witness Schultz bases his recommendation is skewed and cannot be considered representative; (2) illustrates the fulfillment of gross payroll expectations on a continued basis, raising questions about a methodology that entirely ignores that part of the data; and (3) provides evidence that the assumed predictability inherent in witness Schultz's analysis and recommendation does not exist.

My analysis demonstrates what I have stated previously: this is a dynamic equation and the payroll budget is not solely a function of the staffing levels. Based on ever-changing operational demands, environmental challenges, and economic conditions, payroll expense will fluctuate, sometimes slightly under and sometimes slightly over budget. But overall the aggregate variance (actual gross

payroll 1.21% above planned gross payroll over that five year period) does not correlate to OPC witness Schultz's recommended adjustment.

Q. Based on his analysis, OPC witness Schultz makes reference to "excessive" (page 3, line21) headcount and recommends a disallowance of the payroll associated with nearly 232 positions. Should the Commission accept that recommendation?

A. No. First of all, FPL has demonstrated that no adjustment is necessary to its projected payroll expense, which reflects far more than staffing headcount.

Second, it is inaccurate to describe FPL planned staffing levels as "excessive" when FPL's labor efficiency (a combined metric that includes employees per customer and pay and benefits on a per customer and per employee basis) has been demonstrated to be the best among large Florida electric utilities and top quartile in a broader 27-company electric utility comparator group (Reed direct testimony, pages 26 and 27, and Exhibit JJR-6, pages 27 through 29).

Third, even if one accepted witness Schultz's methodology, his recommendation can only be characterized as excessive. Witness Schultz has referenced dozens of headcount figures from various disparate sources in his testimony, but I would highlight four relevant numbers with respect to the Company's staffing complement:

2015 Average Actual Staffing	8,836
July 2016 Actual Staffing	9,092

2016 Average Staffing	9,087
2017 Test Year Average Budgeted Staffing	9,091

The July 2016 actual staffing number is 5 positions above the MFR C-35 2016 average staffing figure of 9,087, and is 1 position above the 2017 test year average staffing figure of 9,091. Despite the fact that the Company's 2017 Test Year projected average staffing level is 1 position *less* than the July 2016 actual staffing level, OPC witness Schultz considers it reasonable to recommend a disallowance of 232 positions from the 2017 Test Year staffing, and claims he is making a "conservative adjustment." His analysis is flawed and anything but conservative, and should be rejected.

VI. BENEFITS AND PAYROLL TAXES

Q. OPC witness Schultz has recommended an adjustment of $2.6 million in employee benefits costs for 2017 and $2.4 million in employee benefits costs for 2018, based on his analysis of headcount. Do you have concerns with his recommendation?

A. Yes. His recommendation is inappropriate based on my testimony regarding his headcount adjustment. But beyond that, his assumptions and analysis are invalid in that benefits participation is not identical to the Company headcount numbers that witness Schultz used in his analysis. FPL employees are not required to elect benefits coverage, and some opt out of the various benefits plans. FPL's benefits

department calculates the benefits costs included in MFR C-35, for most benefits, based on *enrolled* headcount. As a result, his adjustment is overstated.

Q. Do you have other concerns with witness Schultz's analysis of benefits?

A. Yes. Witness Schultz excludes pension and post-retirement benefits ("OPEB") costs arbitrarily from his disallowance calculation without providing an explanation for this adjustment. Perhaps it is because they net to a credit as opposed to an expense. This demonstrates the bias in his analysis. Additionally, as previously stated, the O&M benefits expense used in his disallowance calculation improperly includes clause-related adjustments and charges to affiliates.

Q. You have explained that witness Shultz uses an incorrect O&M factor for employee benefits expense. If the correct MFR C-35 O&M factor for employee benefit expense was applied to witness Shultz's Benefit Expense Adjustment Exhibit (HWS-4), and pension and post retirement costs were included in total benefits costs, what would be the impact on his recommended disallowance?

A. First, I must repeat that no disallowance is warranted. However, if one were to accept his headcount-related arguments, these corrections would reduce his recommended adjustment by $1.1 million for 2017 (to $1.47 million) and by $1.1 million for 2018 (to $1.37 million). Even then it would remain overstated because it relies upon total headcount, as opposed to enrolled headcount.

Q. OPC witness Schultz also has recommended an adjustment of $1.1 million in payroll tax expense for 2017 and for 2018 based on his analysis of headcount. Do you have concerns with his recommendation?

A. Yes. His recommendation is inappropriate based on my testimony regarding his payroll headcount analysis. It should be rejected.

Q. OPC witness Schultz has recommended a separate adjustment of $1.7 million in payroll tax expense for 2017 and 2018 to correspond with his adjustment to incentive compensation. Do you have concerns with his recommendation?

A. Yes. Any adjustment would be inappropriate because the non-executive performance-based cash incentive compensation should be allowed for recovery, as discussed above.

VII. CONCLUSION

Q. Does OPC witness Schultz provide any valid evidence to challenge the overall reasonableness of the total compensation and benefits package?

A. No, his conclusions are based on the selective application of individual data points, unsound or incomplete analyses, or no analysis at all. He has proposed reducing recovery of non-executive cash incentive expense based on a cost sharing philosophy that would result in the disallowance of reasonable and prudently-incurred expenses, and he has recommended reducing payroll without analyzing payroll expense. But importantly, he has not provided any evidence to challenge the overall reasonableness of the total compensation and benefits

package. And that is the real test of any total compensation and benefits program. FPL's program has been demonstrated to be reasonable, and has supported the Company's achievement of the superior performance documented by other FPL witnesses.

Q. Does this conclude your rebuttal testimony?

A. Yes.

FPL Planned vs. Actual Gross Payroll 2011-2015

	Planned		Actual		Var
2011	1,076,330	(1)	1,029,367	(2)	-4.36%
2012	1,075,925	(2)	1,093,152	(3)	1.60%
2013	1,048,734	(2)	1,064,850	(6)	1.54%
2014	1,003,751	(4)	1,019,556	(6)	1.57%
2015	1,025,638	(5)	1,086,566	(6)	5.94%
Total	**5,230,378**		**5,293,491**		**1.21%**

(1) Schedule C-35 2011 Subsequent Test Year Adjustment, Docket 080677-EI
(2) Schedule C-35, Docket 120015-EI
(3) FERC Form 1 (2012) Page 355 line 96
(4) 2014 Payroll Data - FPL Cost Ctr Rollup.xls
(5) 2015 Payroll Data - FPL Cost Ctr Rollup.xls
(6) Schedule C-35, Docket 160021-EI