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October 26, 2015

-VIA ELECTRONIC FILING-

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

Re: Docket No. 150196-EI

Dear Ms. Stauffer:

Attached for filing in the above docket is the prepared rebuttal testimony and exhibits of Florida Power & Light Company witnesses Dr. Steven R. Sim and Richard Feldman. This letter, the two pieces of rebuttal testimony, and a certificate of service together are being submitted via the Florida Public Service Commission's Electronic Filing Web Form as a single PDF file.

If there are any questions regarding this filing, please contact me at 561-304-5662

Sincerely,

s/ William P. Cox

William P. Cox
Senior Attorney
Florida Bar No. 0093531

WPC/msw

Enclosures
cc: Counsel for Parties of Record (w/encl.)

CERTIFICATE OF SERVICE
Docket No. 150196-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail on this 26th day of October, 2015 to the following:

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By: *s/ William P. Cox*
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

PETITION FOR DETERMINATION OF NEED

REGARDING THE OKEECHOBEE CLEAN ENERGY CENTER UNIT 1

REBUTTAL TESTIMONY OF DR. STEVEN R. SIM

DOCKET NO. 150196 - EI

OCTOBER 26, 2015

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Q. Please state your name and business address.

A. My name is Steven R. Sim, and my business address is Florida Power & Light Company, 9250 West Flagler Street, Miami, Florida 33174.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following 7 exhibits that are attached to my rebuttal testimony:

Exhibit SRS – 6: Incorrect and/or Misleading Statements Made in the Testimonies of Witnesses Rábago, Wilson, and Mims;

Exhibit SRS – 7: Commission Proceedings Approving or Applying 20% Reserve Margin;

Exhibit SRS – 8: <u>Duke Energy Progress, North Carolina Integrated Resource Plan (Annual Report), September 1, 2015;</u>

Exhibit SRS – 9: Relevant Testimony from FPL Witness Rene Silva in the Petition to Determine Need for Riviera Plant and Cape Canaveral Plant (Docket Nos. 080245-EI and 080246-EI);

Exhibit SRS – 10: A Look at January 11, 2010 If FPL Had Planned to a 15% Total Reserve Margin Criterion;

Exhibit SRS – 11: The Need for a 3rd Reliability Criterion for FPL: A Generation-Only Reserve Margin (GRM) Criterion; and,

Exhibit SRS – 12: Comparison of the Major Drivers of Benefits in DSM Cost-Effectiveness: 2014 DSM Goals Docket Inputs and Forecasts versus 2015 Inputs and Forecasts.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony discusses and/or responds to the three intervenor witnesses in this docket: Mr. Karl Rábago (Environmental Confederation of Southwest Florida (ECOSWF)), Mr. John Wilson (Southern Alliance for Clean Energy (SACE)), and Ms. Natalie Mims (SACE).

Q. How is your rebuttal testimony structured?

A. My rebuttal testimony contains 5 main parts. Part I provides an overview in which I first summarize key points of FPL's filing in this docket that the three intervenor witnesses do not contest. I then summarize my view of the key points in each of the intervenors' testimonies. Then my testimony examines problems inherent in each of their testimonies. I begin with ECOSWF's witness, Mr. Rábago (Part II), and then review the testimonies of SACE's witnesses, Mr. Wilson (Part III) and Ms. Mims (Part IV). In Part V, I offer my conclusions that their collective testimonies: (i) seek to shift the discussion away from the facts of this docket and disregard Florida Public Service Commission (FPSC) decisions and basic principles of resource planning, (ii) offer recommendations that, when examined critically, would not be in the best interests of FPL's (and peninsular Florida's) customers, (iii) repeatedly attempt to convey the impression that the FPSC is not doing its job, and (iv) contain a number of other incorrect and/or misleading statements. I conclude that these witnesses' testimonies are unreliable and should not be given serious consideration in this docket.

Part I: Overview of Key Points

Q. Please provide a concise summary of key positions in FPL's filing.

A. FPL's filing includes the following three key positions:

- Based on two of the three reliability criteria (20% minimum total reserve margin, and 10% minimum generation-only reserve margin or GRM) that FPL utilized in 2014 (when the bulk of FPL's analyses were performed) and in 2015 (when analyses were completed and FPL's filing for a determination of need for OCEC Unit 1 was made), FPL projects a significant resource need of 1,052 MW starting in the year 2019, and this projected resource need increases in subsequent years.
- The most cost-effective self-build generation option identified by FPL with which to meet that need is the OCEC Unit 1 combined cycle (CC).
- No non-FPL generating option was submitted in response to FPL's March 2015 capacity request for proposals (RFP) solicitation that met the RFP's Minimum Requirements. Thus, no viable market alternatives to OCEC Unit 1 were offered.

Q. Do any of the intervenor testimonies contest the results of FPL's analyses based on FPL's existing reliability criteria that project this large resource need beginning in 2019?

A. No.

Q. Do any of the intervenor testimonies contest the results of FPL's analyses that led to the selection of OCEC Unit 1 as the most cost-effective self-build generation option with which to meet this need?

A. No.

Q. Do any of the intervenor testimonies contest the fact that no viable market alternatives to OCEC Unit 1 were offered in response to FPL's capacity RFP solicitation?

A. No.

Q. Please summarize your view of the intervenors' testimonies.

A. The following five points summarize their testimonies:

1) The intervenors attempt to shift the focus of the discussion away from the facts of the case by disregarding FPSC decisions and basic principles of resource planning.

2) Mr. Rábago's testimony has as a main theme that FPL has a *"campaign"* to build new power plants that is "out of control" and that this alleged campaign has been in place for several decades. In an attempt to justify this contention, he presents deeply flawed statements that attempt to compare load growth first with a pattern of power plant construction and second with a change in the size of FPL's 2019 CC unit. In addition, by

making his unsubstantiated claim of a long *"campaign"* of building power plants Mr. Rábago fails to recognize that the FPSC has conducted numerous hearings analyzing the need for, and the economics of, new power plants before approving the need for, and cost recovery for, these plants.

3) Mr. Wilson's testimony attempts to avoid the reality of FPSC precedent and prudent utility resource planning practice by stating that OCEC Unit 1 would not be needed if FPL's reliability criteria were simply ignored. He then offers a recommendation that FPL's reliability criteria be replaced with the Florida Reliability Coordinating Council's (FRCC) lower 15% total reserve margin criterion. In making this "change the rules after the game (*i.e.*, the analyses) is over" recommendation, he appears willing to accept that this would result in lower reliability not only for FPL's customers, but also for all utility customers throughout peninsular Florida, and would automatically lower the cost-effectiveness of all demand side management (DSM) options on FPL's system. Mr. Wilson fails to consider prior Commission decisions confirming that a utility's need determination proceeding is not the appropriate forum for consideration of the existing total reserve margin criterion that applies to all of peninsular Florida's investor-owned utilities (IOU). Mr. Wilson's claim that FPL has done no analyses justifying its 20% total reserve margin criterion is incorrect. Analyses addressing the merits of a 20% reserve margin versus a 15% reserve margin have been performed, and two such analyses are

attached as exhibits to this rebuttal testimony. Each of these analyses shows that FPL's system would be significantly less reliable if his recommended 15% criterion were used. Mr. Wilson also attempts to convey the impression that the stipulation that led to the establishment of a minimum 20% total reserve margin criterion for the three IOUs was something that was established by the FPSC with very little consideration. He ignores the fact that the docket was initiated by the FPSC due to significant concerns regarding electric system reliability in Florida and that an extensive investigation was conducted regarding this issue. In regard to FPL's GRM criterion, Mr. Wilson is open to such a third reliability criterion as long as it addresses only load management (LM), not energy efficiency (EE). He mischaracterizes FPL's analyses which led to the establishment of the GRM criterion as not addressing both LM and EE, when the results of the actual analyses, after using optimistic-for-EE assumptions, clearly show the need for the GRM criterion which accounts for both LM and EE.

4) Ms. Mims spends the bulk of her testimony criticizing the FPSC's recent decision in the 2014 DSM Goals docket (Docket No. 130199-EI). Thus she is denying history and the fact that the DSM Goals docket is closed following the FPSC's DSM Goals decision (Order No. PSC-14-0696-FOF-EU) last year. Ms. Mims' attempt to relitigate the concluded DSM Goals Docket is not appropriate and should be rejected by the Commission.

5) All three intervenor testimonies attempt to leave the impression that the FPSC is not doing its job. Each witness' testimony includes claims of: (i) a long-standing *"campaign"* to build new power plants that has been ignored by the FPSC, (ii) a reliability criterion stipulation that was approved by the FPSC after only minimal consideration and/or (iii) mistakes in a recent docket. These claims, either directly or indirectly, suggest that the FPSC is not providing oversight of Florida utilities including FPL. These testimonies do not acknowledge the extensive evidentiary hearings that the FPSC has conducted regarding resource option decisions, both generation and DSM, in Florida and for FPL.

My rebuttal testimony will examine each of these points. In addition, I will also discuss a number of incorrect and/or misleading statements made in the intervenor testimonies. After considering the problematic points in the intervenors' testimonies summarized above, and the incorrect and/or misleading statements, I conclude that the intervenor testimonies are unreliable and not worthy of serious consideration by the FPSC in this docket.

Part II: Mr. Rábago's Testimony

Q. What is the main theme in Mr. Rábago's testimony?

A. The main theme is that FPL is somehow manipulating its reliability criteria as part of an on-going campaign to build new generating units. This is indicated by the following statement in his testimony:

> *"The Company application is characterized by results-oriented arguments that use the reserve margin criteria as the vehicle for justifying a power plant building campaign."* (Page 11, Lines 1 & 2)

Q. On what basis does Mr. Rábago make this claim?

A. Mr. Rábago appears to base this claim on a comparison over time of percentage growth in capacity built by FPL with forecasted growth in load. He states the following in his testimony:

> "Q. *The Company forecast seems to indicate that all major drivers of demand and demand itself are likely to grow at an average rate of 2% or less during the period of 2015 - 2024. What is the rate of capacity increases the Company has implemented? A. The Company has increased capacity at a rate of about 5% average annual growth since 2000, when the Reserve Margin settlement order was issued. The NPGU in this Application would continue that trend of growth."* (Page 13, Line 24 through Page 14, Line 4.)

Q. What is your interpretation of this passage?

A. Mr. Rábago appears to be indicating that something is amiss because FPL is building capacity faster than load is growing.

Q. Is such an occurrence out of the ordinary?

A. Not at all. In fact, it is to be expected. The increase in a utility's load is almost never the only factor in determining how much generation is needed. Other factors that are completely unrelated to load, such as cost-effective retirements of existing generating units and the end of power purchase agreements, also increase the amount of new generation that is needed. Mr. Rábago ignores this fundamental fact about utility resource planning.

Q. Does Mr. Rábago make any other statements about generation capacity growth compared to load growth?

A. On page 5, starting at line 5, Mr. Rábago makes the following statement:

> *"Q. How does this proposal compare with the plant addition contemplated in the Company's 2014 Ten Year Site Plan ("TYSP")?*
>
> *A. The proposed NPGU is 353 MW larger[3] than that contemplated in the 2014 TYSP—a 28% larger plant reflecting an increase in capacity of 5.5% per year in the planned unit size over the time from 2014 to 2019… This significant increase in the already planned growth in generation stands in stark contrast to forecasted growth rates for customer population, load, and household income over the same period."*

Mr. Rábago apparently believes that the increase in the size of the projected 2019 CC in FPL's 2014 Ten-Year Site Plan (TYSP or Site Plan) to the ultimately selected 2019 CC (OCEC Unit 1) is or should be tied to load growth. Once again Mr. Rábago demonstrates a lack of understanding of utility resource planning as well as a failure to review FPL's filing documents. His mistake would have been evident if he had more carefully reviewed FPL's filing to see that FPL's projected resource need in 2019 was 1,052 MW, which might have been met by any generating unit of 1,052 MW or larger, including the 1,269 MW CC listed in FPL's 2014 Site Plan. Then a review of the petition and my direct testimony in this docket would have shown that the 1,622 MW OCEC Unit 1 was selected because it was the most cost-effective self-build generating unit identified by FPL. The smaller CC unit provided in the 2014 Site Plan was a reasonable placeholder at the time FPL was in the midst of conducting extensive analyses to determine its best self-build generating option. Those analyses selected a larger CC unit included in this filing as the most economic choice to serve FPL's customers.

Q. Is there evidence that rebuts Mr. Rábago's contention that FPL has a campaign to build new power plants?

A. Yes. One has to look no further than FPL's DSM actions to-date. As of the end of 2014, FPL had implemented approximately 4,793 MW of DSM. After accounting for FPL's 20% total reserve margin criterion, this amount of DSM is equivalent to approximately 5,752 MW of equivalent power plant capacity that has been avoided by DSM. Stated another way, FPL's DSM activities through 2014 have avoided the construction of the equivalent of 14 new power plants of 400 MW each. These actions are hardly consistent with those of a utility which is conducting a *"campaign"* to build new generation.

Q. Please discuss the subject of loss of load probability (LOLP) in regard to Mr. Rábago's testimony.

A. Mr. Rábago's testimony makes a couple of LOLP-related statements in regard to FPL and its LOLP reliability criterion that include the following:

- *"Q. How does the Company forecast LOLP? A. It does not."* (Page 6, Lines 5 & 6)
- *"The* (FPL's) *LOLP numbers are enormously lower than the LOLP standard of 0.1 days per year that the Company asserts is required to maintain system reliability…The LOLP rises to 0.007782 by 2018—still a massive difference from the 0.1 day LOLP standard the Company claims to use. The Company provided data that showed that under its projections in place at the time of that Docket, it anticipated an LOLP value of …0.007782 in 2018*[7]*, on the eve of the intended operation of its NPGU."* (Page 7, Line 3-11)

These two statements in Mr. Rábago's testimony are again problematic. First, the two statements are clearly contradictory. On the one hand, he states that FPL does not forecast LOLP. Then, he immediately quotes FPL projections of LOLP values. Clearly one of his statements cannot be correct. The reality is FPL annually projects LOLP as part of its ongoing resource planning work, and these LOLP values are supplied to the FPSC each year in response to the FPSC Staff's Supplemental Data Requests as part of the Ten-Year Site Plan filing process.

There are also at least two problems with his second statement. First, he appears to believe that as long as the LOLP reliability criterion is met, then a utility system is automatically reliable. He ignores the fact that both LOLP and reserve margin criteria are commonly used as complementary perspectives in evaluating utility system reliability. Both perspectives are valuable.

Second, and related to his first problem, he believes that a relatively low LOLP value is an indication of an unnecessarily overbuilt generation system. He refers to FPL's projected LOLP values as *"outrageously low"* (Page 3, Line 9). He fails to understand that LOLP projections are not infallible, which is why multiple reliability criteria are regularly used in utility resource planning.

An example may help. Later in my rebuttal testimony, I discuss a recent and very difficult day for FPL's system operators. The day was January 11, 2010. Load was higher than expected, and a higher-than-normal amount of FPL generation was either out-of-service or operating at less than full capacity. Other utility systems in Florida were also experiencing difficulties, and FPL provided support by implementing a significant portion of its load management capability to assist at least one other utility.

The good news is that FPL's system operators were able to serve all firm load customers that day, although it was a struggle. However, there is bad news for someone who believes, as Mr. Rábago appears to do, that a projected LOLP value even modestly below the LOLP criterion of 0.100000 essentially ensures system reliability. In FPL's 2009 LOLP analyses, the projected LOLP for the next year of 2010 was 0.002255, an even lower LOLP value than Mr. Rábago refers to in his statement.

Therefore, even with this "*outrageously low*" LOLP projection for 2010, there was a struggle at FPL (and at other Florida utilities) to keep the lights on. This is a prime real-life reminder that no single reliability criterion is infallible. It is for this reason that there is value in using multiple reliability criteria.

Q. Are there any other problematic statements in Mr. Rábago's testimony?

A. Yes. Mr. Rábago made a number of other incorrect and/or misleading statements in his testimony. These are presented in Exhibit SRS-6. I will discuss several of the more problematic statements.

Q. What is the first statement of Mr. Rábago that you will discuss?

A. On page 9, stating on line 10, Mr. Rábago states the following as a rationale for why he believes FPL should re-analyze its reliability criteria:

"The potential for increased reliance on other generation in the Eastern Interconnection."

With this statement, it appears that Mr. Rábago does not recognize that:

- Florida is different from most states in that it is a peninsula into which assistance from out-of-state entities to meet Florida's power needs can essentially only come from one direction: from the north through Georgia;
- There is only limited transmission capacity access into Florida from Georgia and much of this is already committed;
- The bulk of FPL's load is located at the southern tip of the long peninsula. Consequently, any assistance that might be possible from outside Florida would be economically challenged by wheeling rates and higher transmission losses that would occur not only to get capacity and energy to Florida, but also down the Florida peninsula to FPL's main load center;
- In addition, there would have to be a generation supplier with excess capacity that they would be willing to sell on a firm basis at a price competitive with OCEC Unit 1. No such viable proposals were received in response to FPL's capacity RFP; and,
- FPL's reliability analyses already account for the projected amount of firm capacity available through the transmission ties with Georgia.

Based on these facts, it is evident that there is no viable significant untapped firm capacity from the Eastern Interconnection that can realistically be projected to meet FPL's projected capacity needs that begin in 2019.

Q. What is the next problematic statement from Mr. Rábago's testimony that you will address?

A. Mr. Rábago makes the following statement on page 15, beginning on line 12:

> *"The Company evaluates the DSM resource option solely for its ability to meet all of the increase in forecasted need. This approach is unrealistic, does not consider matching an increase in demand side resources coupled with a smaller NPGU… Options not considered include sufficient demand side resources to defer the NPGU for a single year, for example. Instead, the Company constructs a hyperbolic hypothetical in which 800 MW of new DSM must be obtained solely through increases in the residential air conditioning control program."*

There are several problems with this passage. First, FPL does not view DSM cost-effectiveness in the context of this need determination docket *"…solely for its ability to meet all of the increase in forecasted need"* as he claims. FPL evaluates DSM options versus the planned generating unit on a per kW basis. For example, if a DSM measure is projected to reduce load by 1 kW, it is compared to 1.2 kW of the planned generating unit and assumes (optimistically-for-DSM) that the cost per kW of that generating unit is unchanged by “shrinking” the unit to a 1.2 kW size power plant. This provides the best opportunity for DSM measures to pass economic screening analyses versus generation.

Second, the hypothetical Mr. Rábago refers to from my direct testimony was included merely to provide an example of the huge amount of additional, cost-effective DSM that would be required to fully meet the need at a time when it is likely that some of the DSM approved in the 2014 DSM Goals docket, that is fully accounted for in FPL’s analyses, is no longer cost-effective (as is discussed later in Part IV of my rebuttal testimony). This example is designed solely to show how unrealistic it is to claim that additional DSM would be able to cost-effectively defer or avoid the need for OCEC Unit 1.

In addition, Mr. Rábago’s contention that DSM, combined with a smaller power plant, might cost-effectively defer or avoid OCEC Unit 1 is illogical. Later in this rebuttal testimony, I point out that even the DSM that was previously projected to be cost-effective in last year’s DSM Goals docket would now be projected to be less cost-effective. Therefore, additional DSM that was previously projected not to be cost-effective will not suddenly become cost-effective. The opposite will be true; the previously non-cost-effective DSM will now be even less cost-effective. And, as explained in my direct testimony, different sizes of power plants – including smaller CC and combustion turbine units – were found not to be cost-effective compared to

OCEC Unit 1.

Mr. Rábago's contention that two resource options, each of which is not cost-effective versus OCEC Unit 1 (on either a per kW basis or as a large MW block), would somehow combine to be cost-effective versus OCEC Unit 1 is clearly neither accurate nor reasonable.

Q. Please address the following statement by Mr. Rábago: *"The Company reliance on the 10% generation-only reserve margin is also a significant factor in the Company's justifications for building new capacity."* (Page 17, Lines 15 & 16)

A. I have two reactions to this statement. First, it appears that Mr. Rábago may be making this statement to attempt to support his inaccurate and unsubstantiated claim of some long-term FPL strategy to unnecessarily build new power plants. Second, in this docket, the GRM is not a significant factor in regard to determining FPL's reliability need in 2019. As stated in my direct testimony, FPL's projected resource needs beginning in 2019 are large regardless of whether the projection is based on the 20% minimum total reserve margin criterion (988 MW) or on the 10% minimum GRM criterion (1,052 MW). On a system the size of FPL's (over 26,000 MW of total capacity), this 64 MW differential is quite small. In addition, and as also stated in my direct testimony, the 1,622 MW OCEC Unit 1 that was selected as FPL's most cost-effective self-build generating unit satisfies both of these projected resource needs and would have been selected as the most economic self-build generation option even absent the GRM criterion. Therefore, the GRM criterion is <u>not</u> a significant factor in this docket.

Q. Please address Mr. Rábago's statement at page 16, starting on line 12: ***"The Company does not evaluate the solar option from the perspective of the time frame required to develop that option."***

A. This statement is misleading because it omits key information that was explained in my direct testimony. FPL recognized that although it might be able to wait until approximately two years prior to the in-service date to place an order for the solar equipment to meet a given need, it also recognized that to do so would forego the opportunity to select a new CC unit. The latest date by which FPL could select a new CC unit as its self-build generating option, and still meet its 2019 resource need date, was approximately March 2015.

In my direct testimony, I outlined several uncertainties related to solar meeting all or a substantial portion of FPL's 2019 need. These significant uncertainties included: (i) the need to quickly acquire large tracts of land for solar and the cost of that land, (ii) problems in being able to accurately project the cost of the PV equipment this far ahead of the 2019 in-service date, and (iii) whether FPL's projections of the firm capacity value of solar were accurate enough at this time to attempt to address all or a substantial portion of FPL's 2019 need with solar.

FPL believed that these uncertainties regarding solar were too great to forego the opportunity to meet the 2019 resource need with other highly efficient generation options whose firm capacity contributions and costs were much better understood. Thus, in this instance, solar was appropriately evaluated based on the longer timetable for other generating technologies.

Q. Please address Mr. Rábago's statement at page 19, starting on line 14: "*… the Commission should direct the Company to explore "extreme" or "fast response" demand response resources specifically designed to provide reliability support.*"

A. This statement struck me as interesting for two reasons. First, Mr. Rábago appears to be unaware that FPL already has approximately 2,000 MW of fast response resources in its residential and commercial/industrial load management programs. Second, Mr. Rábago's recommendation to pursue load management programs appears directly opposed to Mr. Wilson's concerns regarding such programs. (I will address Mr. Wilson's concerns in Part III of this testimony.)

Q. On page 13, on lines 15 and 16, Mr. Rábago states: "*Q. Does the risk-adjusted analysis suggest the potential for over-building of capacity? A. Yes.*" Do you agree?

A. No. There are two problems in his statement. First, FPL did not utilize the risk-adjusted load forecast discussed in FPL witness Feldman's testimony in determining its 2019 need. FPL used its base load forecast which has a 50% probability that the actual load will be higher than the forecasted load. Second, the notion that the addition of OCEC Unit 1 is an example of "*overbuilding*" does not reconcile with reality. OCEC Unit 1 is being added because: (i) FPL's reliability analyses show a significant need beginning in 2019, (ii) all reasonably achievable, cost-effective DSM have been accounted for in the resource need projection, (iii) OCEC Unit 1 was found to be the most cost-effective self-build generating option, and (iv) a capacity RFP found no viable market alternatives to OCEC Unit 1. Thus, instead of this unit being an example of "*overbuilding,*" bringing OCEC Unit 1 into service in 2019 is exactly the appropriate resource addition for FPL's customers.

Q. Please summarize your conclusions regarding Mr. Rábago's testimony.

A. Mr. Rábago's testimony is based on a mistaken belief that FPL has a "*campaign*" to build new power plants based on his incomplete observation that power plant capacity is growing faster than load growth. However, such differentials between growth rates in generation additions and growth rates in load are to be expected due to plant retirements and the end of power purchase agreements. Mr. Rábago's testimony is also paradoxical because he first claims that FPL develops no LOLP projections, but then he uses FPL's LOLP projected values in his testimony.

In addition, Mr. Rábago's testimony also contains a number of incorrect and/or misleading statements, as discussed in this testimony and presented in Exhibit SRS-6. With these statements, and the other previously discussed problems regarding his testimony, Mr. Rábago has demonstrated that his testimony is unreliable at best.

Part III: Mr. Wilson's Testimony

Q. What are the main themes in Mr. Wilson's testimony?

A. There appear to be four main themes in Mr. Wilson's testimony, which I will paraphrase as follows:

- If FPL's current 20% minimum total reserve margin and 10% minimum GRM reliability criteria suddenly vanished, then FPL would not have a need in 2019.
- FPL should change its reliability criterion to the same 15% total reserve margin criterion used by the FRCC for peninsular Florida.
- FPL has not performed analyses that demonstrate that a 20% total reserve margin criterion is needed.
- FPL should not be using its 10% minimum GRM reliability criterion, but should use instead a different third reliability criterion that focuses only on load management.

Q. What is your reaction to Mr. Wilson's first theme that if FPL did not have its current reliability criteria, then it would not have a resource need in 2019?

A. This is an effort by Mr. Wilson to ignore the facts. FPL does utilize both the 20% total reserve margin and 10% GRM criteria, as well as the LOLP criterion. These criteria were used in 2014 when FPL began its analyses of the best self-build generation with which to meet resource needs beginning in 2019, and in 2015 when FPL completed its analyses and issued its capacity RFP. To pretend that these reliability criteria are not in place in the context of this need determination is illogical.

In the context of this need determination, an attempt to change the minimum 20% total reserve margin criterion applicable to all peninsular Florida IOUs is analogous to changing the rules of the game after the game (*i.e.*, the analyses) is over just to invalidate the final score. Allowing the "rules of the game" to be changed for the 20% minimum total reserve margin criterion retroactively after all of the analyses have been completed would result in great uncertainty in utility planning and decision-making, which is not a desirable outcome for a utility or its customers.

Q. Has the FPSC previously addressed the continued use of the 20% total reserve margin criterion and whether a change to this criterion should be an issue in a need determination filing?

A. Yes. Since this criterion's adoption, the FPSC has consistently and repeatedly upheld the use of the 20% total reserve margin criterion. It has also stated that a need determination docket is not the appropriate forum in which to attempt to change that criterion. Exhibit SRS-7 summarizes the FPSC's rulings and statements regarding this criterion.

Q. Mr. Wilson recommends that FPL should be instructed to use the same 15% total reserve margin criterion as the FRCC uses for peninsular Florida. Does this recommendation make sense to you?

A. No. A fundamental principle of utility resource planning is that all utility systems are different; therefore, what may make sense for one utility system will not necessarily make sense for another system. The peninsular Florida utility system is much larger than the FPL system. FPL is a subset of the FRCC system, making up roughly 50% of the FRCC system.

Therefore, there are many more generators in the FRCC system than in FPL's system. A general rule of thumb in utility reliability analyses is that, all else equal including the total MW amount of generating capacity, a utility system with more generating units is more reliable from an LOLP perspective than is a system with fewer generating units. As a result, larger utility systems, such as the FRCC's system, may be able to operate reliably with a lower reserve margin than smaller systems, such as FPL's system, will require.

Q. Are you familiar with the FRCC's reliability analyses and, if so, are there aspects of its reliability analyses that are relevant to consideration of Mr. Wilson's recommendation?

A. Yes. I am familiar with the FRCC's reliability analyses. I have served as a member of the FRCC's Reliability Working Group (RWG) for many years and am currently serving as the chairman of the RWG. As such, I am familiar with the reliability analyses performed by the RWG on behalf of the FRCC.

One aspect of the FRCC's reliability analyses that is commonly overlooked is that although the FRCC's reliability criterion is 15% total reserve margin, the FRCC actually expects a minimum total reserve margin level of approximately 19%.

Q. Please explain.

A. The FRCC's 15% total reserve margin criterion is based on analyses that assume that peninsular Florida's three IOUs – Tampa Electric (TECO), Duke Energy Florida (DEF), and FPL – will meet their 20% total reserve margin criteria that was agreed to in a joint stipulation with the FPSC approximately 16 years ago. Together, these three IOUs comprise roughly 75% of the load and generating resources in the FRCC system. The respective percentages attributable to each IOU are roughly 50% for FPL, 20% for DEF, and 5% for TECO.

As a result of the IOUs' 20% total reserve margin criterion, these three companies alone will provide the peninsular Florida system with a total reserve margin of approximately 15% even if all other utilities in the FRCC that comprise the remaining 25% of the total load and generation contribute nothing. This is shown by the following calculation:

<u>IOUs</u> <u>Non-IOUs</u>

(75% x 20%) + (25% x 0%) = 15% + 0% = **15%**

However, to better ensure reliability for the FRCC system, and to ensure that all utilities in the FRCC are contributing to peninsular Florida's reliability, each member utility is expected to maintain a minimum of 15% total reserve margin. As a result, what the FRCC expects the minimum total reserve margin for peninsular Florida to actually be is shown below in a revised version of the previous calculation:

(75% x 20%) + (25% x *15%*) = 15% + *3.75%* = **18.75%**

Therefore, the FRCC system is actually expecting that the effective total reserve margin for peninsular Florida will be at least 18.75%.

Q. If the FPSC were to adopt Mr. Wilson's recommendation to have FPL utilize a 15% total reserve margin criterion, would there be adverse consequences regarding the reliability of peninsular Florida?

A. Yes. The impact is shown in the new calculation below in which FPL's 50% role in the FRCC system now shifts from using a 20% criterion to a 15% criterion. The resulting change in the total reserve margin for the FRCC is as follows:

(*25%* x 20%) + (*75%* x 15%) = *5%* + *11.25%* = **16.25%**

As a consequence of Mr. Wilson's recommendation, the effective minimum total reserve margin for peninsular Florida would drop from 18.75% to

16.25%. This represents a significant lowering in projected reliability for all utility customers in peninsular Florida.

Q. Would there be other unintended consequences from following Mr. Wilson's recommendation to instruct FPL to lower its total reserve margin criterion from 20% to 15%?

A. Yes. All DSM options would automatically become less cost-effective on FPL's system. This is because, when analyzing the economics of 1 kW of demand reduction from DSM, DSM is now credited with avoiding at least 1.20 kW of generation. Mr. Wilson's recommendation would result in DSM now being credited with only avoiding 1.15 kW of generation.

As a result, the projected avoided costs for a number of types of generator-related costs (such as generator capital, fixed O&M, variable O&M, and capital replacement) that represent DSM benefits would automatically be lowered. Consequently, the current trend of decreasing cost-effectiveness of DSM on FPL's system would be exacerbated by Mr. Wilson's recommendation and even less DSM would be cost-effective for FPL's customers. This result would be the same regardless of whether the rate impact measure (RIM) or total resource cost (TRC) test was used to gauge DSM cost-effectiveness, because both tests calculate DSM benefits in an identical way.

Q. Please summarize your view of Mr. Wilson's recommendation that FPL should be instructed retroactively to use a 15% total reserve margin criterion.

A. In an attempt to stop the construction of a highly efficient, low emissions power plant, Mr. Wilson's recommendation would:

- change the rules of the game after the game (*i.e.*, the analyses) is over;
- result in lower reliability for FPL's customers;
- result in lower reliability for all utility customers in peninsular Florida; and,
- result in even less DSM being cost-effective for FPL's customers.

Therefore, my view is that Mr. Wilson's recommendation should be rejected.

Q. The third main theme of Mr. Wilson's testimony deals with analyses of FPL's reserve margin criteria. He mentions that a 2010 analysis for Duke Energy Carolinas resulted in a lowering of Duke's reserve margin criterion. Please comment on this.

A. Starting on page 7, line 20, and continuing through page 8, line 10, Mr. Wilson's testimony states the following:

> *"…in 2010, the North Carolina Utilities Commission required Duke Energy Carolinas to conduct a reserve margin study… The result of Duke Energy Carolinas' reserve margin study (provided as Exhibit (JDW-2) was to reduce Duke's reserve margin from 17% to 15.5%, which had a material impact on Duke's resource plan."*

Presumably, the intent of including this passage in his testimony was to imply that an analysis of reliability criteria for a utility will likely lower those criteria, thus lowering the amount of resources (generation and DSM) that a utility would need to add.

However, what the Commission should be aware of is that Duke Energy Carolinas (DEC) has recently (2015) completed another analysis of its reliability criteria, using the same consultant, which has resulted in DEC not only increasing its Summer reserve margin criterion back to 17%, but also in DEC considering adding a new dual Summer/Winter reserve margin criterion for the first time. Exhibit SRS-8 presents this document: Duke Energy Progress, North Carolina Integrated Resource Plan (Annual Report), September 1, 2015 which discusses this change in DEC's reserve margin criterion on pages 11 and 12.

Thus, contrary to what Mr. Wilson's testimony implies, analyses of reliability criteria can also result in increases to reserve margin criteria and corresponding increases in resource needs.

Q. In regard to analysis and setting of reliability criteria, Mr. Wilson appears to attempt to dismiss the 20% total reserve margin requirement for the IOUs as something developed by the FPSC with minimal consideration. Is that your impression as well?

A. No. Although I was not a witness in that proceeding (due in part to DSM Goals responsibilities that year), my recollection of the activity surrounding that proceeding is that it was an issue the parties took very seriously. Mr. Wilson's testimony attempts to almost dismiss the FPSC's concerns and interest regarding the reliability of the Florida electric system by quoting only four brief statements made by the FPSC from what was an extensive investigation.

However, as noted in Order No. PSC-99-2507-S-EU, the Commission expressed concerns about the adequacy of the reserve margins planned for Peninsular Florida as a result of its reviews of both the Ten-Year Site Plans that were filed in 1997 and 1998. As a result, an investigation was opened to consider the appropriate reserve margin for Peninsular Florida IOUs. That investigation included at least one workshop, comments, and ultimately testimony filed by an array of stakeholders.

Mr. Wilson also fails to mention problems experienced by several Florida utilities who were planning to a 15% total reserve margin criterion and whose resource plans had a heavy dependency on DSM. Furthermore, the mere fact that the FPSC initiated such a docket indicates the seriousness the FPSC attached to this issue.

For these reasons, I disagree with Mr. Wilson's view that a less-than-serious look at Florida electric system reliability led to the FPSC's adoption of the 20% total reserve margin criterion for the peninsular Florida IOUs. I also view Mr. Wilson's comments regarding the continued use of the 20% total reserve margin criterion by FPL to be a criticism not only of FPL, but also of the FPSC as well.

Q. Regarding that 20% criterion, Mr. Wilson states (paraphrasing) that FPL has not recently conducted an analysis of whether a 20% total reserve margin criterion is still appropriate. Is that true?

A. No. This part of his testimony is perhaps best summarized by the following two passages from his testimony:

- *"Q. Has FPL provided any evidence in support of the need for a 20% reserve margin? A. No. According to the testimony of Dr. Steven Sim, FPL utilized a minimum total reserve margin of 20% for both seasons; however, his testimony contains no reference to any FPL or third-party study or substantive analysis to validate this 20% RM criteria."*(Page 7, Lines 10-15); and,
- *"Q. Are you aware of any recent studies or substantive analysis conducted by FPL which would support the continued use of a 20% reserve margin?*

A. No. In fact, FPL witness Dr. Steven Sim testified during his telephonic deposition taken in this matter on October 8, 2015, that no such study or substantive analysis existed.” (Page 7, Lines 3-7)

The first statement is in regard to whether FPL has included a justification for its 20% total reserve margin criterion as part of this filing. FPL has not included such a justification because FPL believes such a justification is not required as part of a need determination filing. As indicated by the FPSC’s statements in past need determination proceedings presented in Exhibit SRS-7, the time to question an already established reliability criterion, such as the 20% minimum total reserve margin, is outside a need determination docket, not during the docket.

The second statement is in regard to whether FPL has performed analyses regarding whether a 20% total reserve margin criterion is still appropriate. Contrary to Mr. Wilson’s statement, FPL has performed such analyses. The results of those analyses have led FPL to conclude that a 20% criterion is still appropriate for its system.

In my deposition, I was asked at several points whether FPL had conducted analyses regarding the 20% total reserve margin reliability criterion. My understanding of the intent of these questions was whether FPL had recently conducted an analysis that attempts to determine what single total reserve margin value is – at that point in time – projected to be the best total reserve margin value to use (*i.e.*, an analysis similar to the DEC analysis Mr. Wilson presents in his testimony). As I stated, FPL has not done such an analysis for many years. That is because FPL is operating under a Commission-approved stipulation, and, until FPL gets to a point where it begins to question whether that 20% reserve margin might not be appropriate, or is directed to utilize another total reserve margin criterion value by the Commission as a result of a generic proceeding, FPL will continue to plan its system based, in part, on that 20% total reserve margin criterion.

I also explained in the deposition that FPL has conducted other types of analyses designed to look at whether a 20% total reserve margin analysis is still appropriate. Such an analysis was presented in Docket Nos. 080245-EI and 080246-EI, Petition to Determine Need for Riviera Plant and Cape Canaveral Plant, by Florida Power & Light Company in the testimony of FPL witness Rene Silva. Mr. Wilson selectively chose to ignore that information from my deposition. The relevant portions of Mr. Silva's testimony, including both his testimony text and exhibits, are presented in Exhibit SRS-9.

To further address any concerns about the continued appropriateness of FPL's 20% total reserve margin criterion, FPL has also performed a new analysis regarding this question, which is presented in Exhibit SRS-10.

Q. Please explain the analysis approach taken in Exhibit SRS-10.

A. The analysis approach starts with an earlier examination that FPL did in regard to whether a new GRM reliability criterion was needed. (Note that this earlier examination is presented later as Exhibit SRS-11 and will be discussed later in regard to FPL's GRM reliability criterion.)

The earlier examination is of the previously mentioned January 11, 2010 peak day, which was a very difficult day for FPL's system operators and other systems around Florida. Fortunately, FPL's system operators were able to continue to serve firm load that day. However, they used all of their available generating capacity, and their reserves consisted solely of a remaining portion of their load management capacity. Any combination of additional failures by FPL or third party generation, and/or higher load, that totaled slightly over 1,100 MW would have resulted in the start of feeder rotations (*i.e.*, temporarily ceasing electrical service to a designated number of customers, often on the same feeder, then resuming electrical service to those customers while sequentially temporarily ceasing electrical service to another group of customers). In fact, a 750 MW unit failed only hours after the peak load occurred that day. Had it failed on the peak hour, FPL's remaining reserves would have been reduced to less than 400 MW. This is shown on page 1 of 2 of Exhibit SRS-10.

The key point in regard to this discussion regarding the continued appropriateness of FPL's 20% total reserve margin criterion is that FPL had planned the system to meet a 20% total reserve margin criterion in 2010, and it was able to maintain service to all firm load customers on that very difficult day. The question is whether FPL's firm load customers could all have been served on that day if FPL had been planning instead to a 15% total reserve margin criterion and the exact set of circumstances occurred.

Q. What were the results of this analysis and what conclusions do you draw from it?

A. Service to firm load customers would not have been maintained if FPL had been planning to a 15% total reserve margin criterion. As shown on page 2 of 2 of Exhibit SRS-10, FPL would have exhausted all reserves, both generation and load management, and would have been 68 MW short of firm load requirements. This would have necessitated feeder rotation at a level of approximately 40,000 customers. However, that situation could be worse. If the 750 MW unit failure had occurred at the peak hour instead of missing the peak by only several hours, then FPL would have been about 818 MW short of firm load requirements, thus necessitating feeder rotation at a level of approximately 470,000 customers.

The conclusion that FPL draws from this analysis of a recent, real-life event is that planning to a 20% total reserve margin criterion allowed FPL to maintain service to all firm load customers through a very difficult day, but if FPL had been planning to a 15% total reserve margin criterion, it could not have maintained service to all of its customers.

Q. In regard to FPL's GRM reliability criterion, would you please discuss FPL's analysis approach and the results of those analyses that led FPL to implement the GRM reliability criterion?

A. Yes. The analysis approach, and the results of the analyses, are summarized in Exhibit SRS-11. This is a PowerPoint presentation that was provided to FPL executives in late February 2014. At the conclusion of that meeting, a decision was made to implement a new 10% GRM reliability criterion to complement FPL's existing 20% total reserve margin and 0.1 day/year LOLP reliability criteria.

As Exhibit SRS-11 shows, one of the key findings of FPL's analyses was that resource plans with identical total reserve margins are not equal in regard to system reliability if they differ in the amounts of DSM and generation that combine to get to that identical total reserve margin value. FPL's analyses showed that resource plans with higher DSM levels are projected to have higher LOLP, and thus are projected to have lower system reliability from an LOLP perspective, than are resource plans with lower DSM levels and with an identical total reserve margin level.

Q. Is this the sole reason that FPL introduced its 10% GRM reliability criterion?

A. No. It was only one of two primary reasons. The other reason was a look at how resource plans with identical total reserve margins, but different levels of DSM and generation, would fare when it came time to actually operate FPL's system.

One of the key considerations for resource planners is that a utility's resource plan "sets the table" for the utility's system operators who must then operate that system. Consequently, FPL's resource planning and system operations groups have frequent communications. Early in 2010, FPL had experienced the previously mentioned difficult system operations day of January 11, 2010, and had recently received the FPSC's order in the 2009 DSM Goals docket (Docket No. 080407-EG), which had set much higher DSM Goals than had been set for FPL before.

The FPSC order meant that FPL's resource plans would be more dependent on DSM resources, and less reliant on generation resources, than had been the case in the past. FPL began to look at what implications for system reliability might ensue from the current (or from a future) change in the generation/DSM makeup of FPL's resource plans. Both the resource planning and system operations groups were involved in this analysis and in an analysis of what occurred on January 11, 2010.

Q. Do FPL's system operators view DSM and generation from a different perspective than do FPL's resource planners?

A. Yes. They do so out of necessity. Whereas FPL's resource planners view DSM (both EE and LM) and generation as resource options that can be implemented in future years, FPL's system operators have to take an immediate "real time" view of resources at their disposal to manage and meet the electrical load.

Consequently, FPL's system operators are dealing with actual load from moment to moment. Any impact from EE has already occurred in the actual load they must react to. There is no "button" to activate additional EE as there is for both LM and generation resources. FPL's analyses of system reliability recognized this reality for system operators.

Q. Please describe how FPL conducted these system reliability analyses.

A. In order to perform these analyses, FPL developed a "generation-only reserve margin" (GRM) metric, which is similar in some respects to TECO's Supply-Side Reserve Margin metric that they have used for over a decade in their resource planning. FPL then constructed alternate resource plans with identical total reserve margins, but different levels of DSM and generation (*i.e.*, different GRM levels). Analyses were conducted that examined both historical and future perspectives. The historical perspective consisted of a look at January 11, 2010. The future perspective consisted of a look at FPL's then current resource plan for both the Summer and Winter of 2021, then modified the DSM/generation mix while maintaining the total reserve margin value.

For both the historical and forecasted perspectives, FPL examined how well the system could be operated based on these resource plans given different assumptions of higher-than-forecasted load and/or generating unit unavailability. For both perspectives, the analysis results were that FPL's system operators were projected to have more reserves at their disposal with resource plans that had a higher GRM than with a lower GRM.

Thus, based on both resource planning type analyses involving LOLP projections, and on system operations type analyses involving projected levels of reserves, FPL decided to implement a third reliability criterion – the 10% minimum GRM criterion – in 2014 with a starting date of 2019. A 10% GRM value was selected as the criterion minimum value based on recommendations from FPL's system operators because it closely matched various reserve requirements projected to be needed by the operators.

Q. The fourth main theme in Mr. Wilson's testimony concerns FPL's GRM reliability criterion, and he states (paraphrasing) that FPL should not be using its 10% minimum GRM reliability criterion, but a different third reliability criterion that focuses only on LM. Please discuss.

A. Let me start by examining Mr. Wilson's statements supporting a third reliability criterion that focuses on LM, but not EE. Starting on page 15, line 18 of his testimony, he states:

> "*I do agree with one of the reasons FPL gives for DSM programs adversely affecting LOLP relative to generation resources. Exhibit 20 JDW-3(p.7) illustrates FPL's discussion of load management 'fatigue.'*[22] *I agree with FPL's conclusion that evidence on this topic is 'inconclusive,' but nonetheless, it is reasonable for FPL to plan around this issue. While customer response to load management requests is usually quite good for the first several times, FPL reasonably concludes that there should be 'No greater than 10 events/year,' among other limitations. To the extent that a peak event repeatedly draws on load management resources, it could result in lower customer response and hence a higher LOLP associated with use of load management resources.*"

In this statement, Mr. Wilson is partly correct, but mostly wrong regarding FPL's findings in its analyses of the reliability of resource plans with identical total reserve margins, but differing levels of DSM. Although FPL did examine the concept of load management “fatigue” early in its analyses, it was not accounted for in FPL’s analyses of LOLP for different resource plans or in FPL’s system operations-based analyses.

As discussed in my deposition, the reason DSM options typically result in higher LOLP compared to generation options is because many DSM options can only provide a lower level of demand reduction in non-peak months compared to their contribution in peak months. Air conditioning-based DSM programs are a relevant example in Florida and for FPL. Air conditioning-based kW demand reductions are lower in Spring and Fall months than in the Summer because air conditioners run less in those months. Thus, they provide less support if the utility system has unexpected outages of generation equipment. Furthermore, such cooling system-based DSM options typically offer little or no support in the Winter months on cold days. Conversely, generating units typically provide a constant level of output during most months and an even higher level of output in Winter months due to cooler ambient air temperatures.

It is primarily for this reason that a resource plan heavily reliant on DSM options is typically projected to have higher LOLP on FPL’s system than another resource plan with less DSM but an identical total reserve margin value.

However, while load management "fatigue" was not a factor in these LOLP analyses that FPL performed, FPL does agree generally with Mr. Wilson on the need for a third reliability criterion (GRM) that takes into account levels of DSM.

Q. Mr. Wilson's testimony indicates that he is willing to consider the reliability implications of LM levels. Does his testimony indicate that he is also willing to consider the reliability implications of EE levels?

A. No. This is shown by the following statement that appears beginning on page 15, line 9 of his testimony:

"FPL cites uncertainty about the performance of future EE programs, presenting a reliability risk in the form of load forecast uncertainty. This analysis is unreliable because it (1) is out of date (based on 2002 technology) and (2) is based on a simple average of program uncertainty without any evidence that averaging is the proper statistical technique, given the likelihood that there are relationships between the program outcomes.[21] *This type of analysis should be supported by a current evaluation, measurement and verification (EM&V) study conducted by an independent consultant and its novel application in this circumstance certainly requires greater scrutiny."*

Mr. Wilson has misunderstood the use of the information on the page to which he is referring. That page was simply a look at what the uncertainty range might be for FPL's then current annual DSM implementation if FPL's 2002

DSM uncertainty values still applied. The 2002 values were used by me in constructing the page simply because I had that information readily available, and it was suitable for my objective to obtain a ballpark view regarding what DSM uncertainty levels might be. And, based on the portion of Mr. Wilson's statement above referring to DSM evaluation, measurement, and verification, he clearly agrees that there is uncertainty surrounding the actual performance of DSM measures after they are installed. If there were no uncertainty, why incur all of the expense of evaluating, measuring, and verifying?

However, no attempt was made to utilize uncertainty levels surrounding the performance of DSM installations in any of FPL's previously described LOLP analyses of differing levels of DSM in resource plans that have identical total reserve margin values.

Q. Why did FPL choose to ignore uncertainty regarding the actual performance of installed DSM measures and are there other uncertainty aspects of DSM that were also not used in FPL's reliability analyses of DSM levels in resource plans?

A. FPL chose to ignore uncertainty regarding actual performance of installed DSM measures at the time these analyses were performed in order to take an optimistic-for-DSM perspective regarding DSM's impact on system reliability. In regard to the second part of the question, there is at least one other aspect of uncertainty regarding DSM that was also not included in FPL's analyses of DSM impacts on system reliability in order to maintain an optimistic-for-DSM approach.

That aspect is the uncertainty regarding the <u>number of DSM installations</u> that will actually occur over the long-term. As evidenced in last year's DSM Goals docket, DSM has become increasingly less cost-effective on FPL's system. As a result, various DSM programs and their installations that may have been planned several years ago have either been cancelled or significantly scaled back due to a change in the programs' cost-effectiveness. This adds uncertainty in resource planning that looks out more than a year or two into the future.

Q. Therefore, in order to utilize optimistic-to-DSM assumptions in its analyses of the impacts on system reliability of different levels of DSM in resource plans with identical total reserve margins, is it correct that FPL chose to ignore uncertainty about both the actual performance of DSM installations and the actual versus projected levels of DSM installations?

A. Yes. FPL's analyses optimistically assumed that DSM performance was exactly as currently assumed in regard to kW reductions for any DSM installation, and FPL also assumed that all currently planned DSM installations in the future would occur exactly as projected. Even with those favorable assumptions for DSM, resource plans with higher levels of DSM – whether EE or LM – are projected to have higher LOLP values than other resource plans with lower levels of DSM but with the same total reserve margin levels.

To put it succinctly, resource plans with identical total reserve margins are not created equal in regard to system reliability if they differ in the amount of DSM and generation that is planned to achieve that identical total reserve margin value. Resource plans with higher DSM levels are projected to have higher LOLP and thus result in lower system reliability for FPL's customers.

Q. Are there any other problematic statements in Mr. Wilson's testimony?

A. Yes. The first one I will address appears on page 21, starting on line 20:

> *"If FPL had made greater investments in energy efficiency and pursued opportunities to procure renewable energy in South Carolina, it might be possible for FPL to avoid adding any additional natural gas power plants – including the proposed OCEC Unit 1."*

It appears that Mr. Wilson has taken efficiency seriously by recycling testimony he previously filed on behalf of SACE in South Carolina. That aside, Mr. Wilson's suggestion to do more energy efficiency simply ignores the reality that there is no additional cost-effective DSM for FPL's system (as discussed in Part IV of this rebuttal testimony) and that, all else equal, greater dependence on DSM in a resource plan results in higher LOLP and less reliability for FPL's system. He appears to be advocating for higher electric rates and lower system reliability for FPL's customers. This is another recommendation lacking any reasonable measure of support.

As for his suggestion to seek more renewable energy, FPL has already announced 233 MW more of solar will be added by the end of 2016. In addition, FPL will continue to look for additional cost-effective solar resources in its on-going resource planning work.

Q. Do you agree with Mr. Wilson's statements regarding FPL's evaluation of solar options?

A. No. Mr. Wilson made two related comments about FPL's resource planning process and FPL's evaluation of solar options. These two comments are as follows:

- *"FPL did not appear to consider solar resources as a generation alternative in its most recent ten-year site plan."* (Page 22, Lines 4 & 5); and,
- *"FPL's newest solar facilities are not the result of FPL's resource planning process as described in the ten-year site plan, but are the result of some other business development process that is not clearly described."* (Page 22, Lines 10-12)

Mr. Wilson is mistaken. Solar resources, particularly photovoltaic (PV) resources, are actively evaluated as a generation alternative in FPL's resource planning process. Mr. Wilson appears to be misinterpreting the intent of the description of FPL's resource planning process in FPL's 2015 Ten-Year Site Plan. The intent of this portion of the Site Plan is simply to provide a description of FPL's resource planning process, not to provide a listing of all resource options that FPL is considering in that process. Furthermore, my direct testimony describes the evaluation of PV as a resource option that was considered for its potential to meet all or a substantial portion of FPL's resource needs that begin in 2019. That alone should have made it clear that FPL is actively evaluating PV as a generation option.

Q. Please summarize your conclusions regarding Mr. Wilson's testimony.

A. As with the testimonies of the other intervenor witnesses, Mr. Wilson's testimony wants to shift the discussion away from reality. He wants to ignore the results of FPL's reliability analyses which use FPL's 20% total reserve margin and 10% GRM reliability criteria so that he can claim that there would be no projected need for new resources starting in 2019. However, FPL does plan its system using these two reliability criteria (and its LOLP criterion), and it does have a significant resource need beginning in 2019 that must be addressed.

Mr. Wilson then recommends that FPL be instructed to use the same 15% total reserve margin criterion that the FRCC uses. However, Mr. Wilson does not acknowledge that FPL's system and the FRCC's peninsular Florida system are quite different, which means what may be an appropriate reliability criterion for one system may not be appropriate for another system. Furthermore, Mr. Wilson does not understand that the FRCC's continued use of a 15% criterion is based on the expectation that the 20% total reserve margin criterion used by the three IOUs ensures that peninsular Florida will actually be served by a minimum total reserve margin of almost 19%. Mr. Wilson's poorly conceived recommendation, intended to not allow FPL to build what is projected to be the most fuel-efficient natural gas-fired generating unit in Florida, would result in a series of unintended negative consequences including: (i) lower reliability for FPL's customers, (ii) lower reliability for all utility customers in peninsular Florida, and (iii) automatically decreasing the cost-effectiveness of all DSM options on FPL's system.

Mr. Wilson incorrectly claims that FPL has not performed any analyses that demonstrate that its continued use of the 20% minimum total reserve margin criterion is appropriate. Exhibit SRS-9 presents testimony and analyses regarding this subject that FPL previously provided in a prior need filing. In addition, Exhibit SRS-10 provides a new analysis based on a recent actual event in which the FPL system, if it had been based on a 15% instead of a 20% total reserve margin criterion, would not have able to serve all of its firm load customers.

In regard to FPL's GRM reliability criterion, Mr. Wilson is open to a third reliability criterion in regard to LM, but not to EE. Not surprisingly, his testimony seeks to avoid the analysis-based support for the GRM criterion, which shows that when analyzing two resource plans on FPL's system with identical total reserve margins, but differing levels of DSM, the results are that the resource plan with lower DSM levels/a higher GRM value will have:

- lower projected LOLP values, thus higher system reliability from an LOLP perspective; and,
- more reserves from a system operator's perspective, thus better allowing the system operators to deal with real time problems that may occur.

As an advocate for ever-higher levels of utility DSM, it is understandable why Mr. Wilson might seek to ignore the results of FPL's analyses regarding DSM levels and the reliability impact on the FPL system. However, in so doing he is providing still further evidence that he is seeking to shift the discussion in this docket away from the reality that FPL's system operators and resource planners must operate in. In so doing, Mr. Wilson makes recommendations that are clearly not in the best interest of FPL's customers.

Finally, like Mr. Rábago and Ms. Mims, Mr. Wilson's testimony also contains a number of incorrect and/or misleading statements. A few of these have been discussed on the preceding pages, and the rest are presented in Exhibit SRS-6.

With these statements and the other problems discussed above regarding his testimony, Mr. Wilson has clearly demonstrated that his testimony should not be given serious consideration by the FPSC in this docket.

Part IV: Ms. Mims' Testimony

Q. What are the main themes of Ms. Mims' testimony?

A. Her testimony appears to have two main themes. First, she briefly discusses her contention that OCEC Unit 1 does nothing to improve fuel diversity for the FPL system. Second, she spends the vast majority of her testimony arguing that the FPSC made an incorrect decision in the 2014 DSM Goals docket that concluded last year when the FPSC decided to reject her recommendations in that docket.

Q. What does Ms. Mims state in regard to fuel diversity?

A. Ms. Mims' view regarding fuel diversity is best conveyed by the following portion of her testimony:

> *"In fact, in FPL's 2015 Ten Year Site Plan, natural gas contributed to 68% of the Company's energy generation in 2014, and the Company forecasted that it is the only fuel type that will increase in 2016, and continue to grow from 2019 (when OCEC unit 1 is scheduled to come online) to 2024.[2] Ultimately, FPL anticipates that natural gas will be used to generate 73% of its energy in 2024.[3] However, FPL anticipates solar energy contributing*

> *about 0.5% annually from 2019 to 2024, and the amount of energy coming from nuclear declining as a percentage of total generation in the same time frame. It would seem that if FPL is truly trying to diversify its fuel sources, at least one of these resources would be increasing as a percent of total generation over time, not just natural gas.* (Page 4, Lines 1-10)

Ms. Mims then presents her Table 1 which shows FPL's projection of fuel mix by percentage by fuel/energy type by year for the years 2015 through 2024.

Q. Are there problems with this statement and her table?

A. Yes. There are at least two problems. First, she states that gas is the "*only fuel type that will increase in 2016, and continue to grow from 2019 (when OCEC unit 1 is scheduled to come online) to 2024.*" She mistakenly ignores the projection in her own table for solar that shows solar starting at 0.2% in 2015, then tripling its contribution in 2016 and continuing to contribute at least more than twice its 2015 value for the remaining years. Second, by selecting her starting year to be 2015 and her ending year to be 2024, she selectively ignores: (i) the increase in solar's contribution in 2010, (ii) nuclear energy's increased contribution that began in 2012 and 2013 when FPL's nuclear uprate project was completed, and (iii) the projected impact of FPL's new nuclear units Turkey Point 6 & 7 beginning in 2027, which will significantly reduce natural gas' percentage of FPL's fuel mix.

Q. In regard to nuclear, has SACE been supportive of FPL's efforts to enhance fuel diversity through additional nuclear capacity?

A. No. SACE has actively opposed both the nuclear uprates project and the Turkey Point 6 & 7 project. Apparently, SACE is not as interested in fuel diversity for FPL's system as they now claim to be in this docket.

Q. Does Ms. Mims' testimony discuss the fact that the OCEC Unit 1 will utilize the new gas pipeline into Florida, thus increasing diversity of fuel supply sources for FPL and its customers?

A. No. She has chosen to ignore this diversity of fuel supply benefit of OCEC Unit 1.

Q. Did Ms. Mims' testimony at least acknowledge that OCEC Unit 1, in addition to being the most cost-effective resource option with which to meet FPL's 2019 resource need, will also be the most fuel-efficient fossil fuel generating unit on FPL's system and thus minimize the amount of natural gas that will be used?

A. No. She appears to have not considered the fact that other generating options that are feasible for meeting FPL's 2019 resource need would result in higher amounts of natural gas being used.

Q. What is your impression of Ms. Mims' testimony in regard to the FPSC's decision in the recent DSM Goals docket?

A. Because Ms. Mims spends the vast majority of her testimony discussing what she believes are flaws and errors that were made in the DSM Goals docket, including at least one that she refers to as *"statutorily incorrect"* (Page 6, Line

9), it is apparent that Ms. Mims disagrees with the FPSC's 2014 DSM Goals decision. She provided testimony in the DSM Goals docket, and her testimony was both reviewed by the FPSC and rebutted by FPL. The FPSC ultimately rejected the recommendations she made in her testimony and set goals based on the utilities' analyses. It appears she is asking the FPSC, well after the fact, to reconsider a decision it has already made.

Q. In regard to this docket, Ms. Mims claims that there is additional DSM that is available. Is this either relevant or important?

A. No. There are always 'other' alternatives to what FPL's analyses identify as the most cost-effective resource option, and these alternatives may be either DSM or other generation options. The fact that other alternatives exist is to be expected, but it is neither relevant nor important. From a resource planning perspective, what is relevant and important for this docket is whether there are resource options <u>that are more cost-effective than OCEC Unit 1</u>.

FPL's direct testimony in this docket discusses the analyses that show the OCEC Unit 1 is the most cost-effective generation option available with which to meet FPL's resource needs that begin in 2019. In addition, my direct testimony states that I do not believe there is any additional DSM that is cost-effective on FPL's system that is not already accounted for in FPL's resource plan.

Q. Why do you believe there is no additional DSM that is cost-effective which could defer or avoid the need of OCEC Unit 1?

A. When setting DSM goals, the FPSC is responsible for identifying the reasonably achievable, cost-effective DSM for the utilities regulated by the Florida Energy Efficiency and Conservation Act (FEECA). The FPSC did so in its 2014 DSM Goals decision. Thus, the FPSC has very recently (late 2014) determined what the amount of reasonably achievable, cost-effective DSM is in Florida for each utility. The only relevant question is whether updated cost-based information would cause that amount of cost-effective DSM to increase or decrease.

That question is addressed in Exhibit SRS-12. This exhibit compares the major drivers of the benefits projected for DSM in economic analyses of DSM during the DSM Goals docket versus those same drivers as they were projected in 2015 at the conclusion of the analyses that led to FPL designating OCEC Unit 1 as the most cost-effective generating option with which to meet FPL's resource needs that begin in 2019.

In the DSM Goals analyses, FPL utilized a 2019 CC unit as the basis for all of the economic analyses that concluded with the DSM Achievable Potential values for both the RIM and TRC screening paths. Column (2) of Exhibit SRS-12 shows the key cost drivers for the 2019 CC unit in the DSM Goals analyses. Column (3) of the exhibit shows the comparative values for OCEC

Unit 1. As shown in Column (4), the OCEC Unit 1 is significantly less expensive in regard to capital, fixed O&M, and variable O&M costs than the CC unit utilized in the DSM Goals docket. In addition, OCEC Unit 1 has a lower heat rate. Furthermore, the exhibit also shows that the more current forecast for natural gas, used in the latter stages of the next planned generating unit analyses and presented in FPL's 2015 Ten-Year Site Plan, is significantly lower than the natural gas forecast used in the DSM Goals work.

What this means is that if the DSM Goals analyses were to be rerun today, the benefits of DSM would be significantly lower than what was projected during the DSM Goals docket. The lower capital and O&M costs mean there would be lower avoided costs for each DSM kW reduction. The lower heat rate and lower natural gas forecast mean there would be lower avoided costs from each DSM kWh reduction.

From this I conclude that not only is there no additional cost-effective DSM over and above the DSM Goals amount of DSM assumed in the analyses of OCEC Unit 1, but also a significant amount of that DSM which is included in the OCEC Unit 1 analyses is likely no longer cost-effective. This outcome is consistent with the trend of decreasing cost-effectiveness of DSM that FPL discussed at length in the 2014 DSM Goals docket.

Q. Ms. Mims attempts to discuss the fact that the RIM cost-effectiveness test addresses unrecovered revenue requirements on page 17, starting on line 10, when she states: *"… 'unrecovered revenue requirements' result from policy decisions, not from resource decisions."* Is she correct?

A. No. An outcome of net unrecovered revenue requirements, which puts upwards pressure on electric rates, is directly attributable to a poor resource decision. That resource decision, simply stated, is one in which sales are reduced by a greater percentage than revenue requirements are reduced. A utility, or its regulator, might choose to address this undesirable outcome of being unable to meet revenue requirements with current electric rates through various policy means. However, FPL believes that it is far better practice to simply make resource decisions that avoid this undesirable outcome. FPL does this by utilizing the RIM cost-effectiveness test and by adding DSM to meet FPL's specific resource needs.

Q. Ms. Mims appears to believe that additional DSM would now be found to be cost-effective if only the TRC cost-effectiveness test were used. Is this correct?

A. No. I have two reactions. First, in the DSM Goals docket, FPL presented results of analyses utilizing both the RIM and TRC tests. The Achievable Potential MW values for these two analyses through the year 2019 are presented in Ms. Mims' Tables 5 and 6. Those values are: 252.4 MW for RIM and 266.5 MW for TRC. Thus, the relevant values in terms of discussing a 2019 need, Summer MW through the year 2019, for RIM and TRC differ by merely 14 MW. Even if the FPSC had not rejected the TRC-based values in their 2014 DSM Goals decision, 14 MW would not have made a noticeable difference in either FPL's projection of 2019 resource needs or in FPL's analyses to identify its best self-build generating unit to meet its needs in 2019.

Second, as just discussed, I would expect that both of these 2019 DSM Achievable Potential values would decrease significantly if the DSM analyses were rerun using the more current assumptions shown in Exhibit SRS-12. The result of such an updated analysis would likely be that both the 2019 RIM or TRC MW values would now be lower than the 252.4 MW currently assumed in the OCEC Unit 1 analyses.

Q. Are there any other incorrect and/or misleading statements in Ms. Mims' testimony?

A. Yes. Exhibit SRS-6 presents at least a partial listing of incorrect and/or misleading statements made by Ms. Mims and the other intervenor witnesses in their respective testimonies. I will discuss three such statements by Ms. Mims here and leave the remaining statements for the reader to examine in Exhibit SRS-6.

Q. What is the first of these incorrect and/or misleading statements by Ms. Mims?

A. On page 8, starting at line 21, Ms. Mims quotes FPL witness Koch in his DSM Goals docket testimony:

> *"FPL Witness Koch stated: 'After the TP [technical potential] was updated, FPL's resource needs during the DSM Goals timeframe were determined and other facets of FPLs resource planning process were then used to conduct an Economic Potential (EP) or cost effectiveness screening of the DSM measures.[12]'"*

Then Ms. Mims provides her opinion:

> *"It is inappropriate to evaluate the Company's resource needs prior to determining if measures are economic. The only factor that should be considered when calculating economic potential is whether or not the energy efficiency is less expensive than avoided cost."*

Ms. Mims is again wrong. It is entirely appropriate to examine a utility's resource needs when determining if resource options are economic. In fact, one cannot accurately make that determination without knowing when resources are needed, the magnitude of the needed resources, and what resource(s) a utility would likely otherwise add to meet the need absent DSM. Therefore, the approach FPL used in the DSM Goals analyses is both logical and appropriate. FPL determined that it would have a resource need in 2019 and that a CC unit at Okeechobee would likely be the most economic generation option. Then FPL analyzed DSM options against that 2019 CC. FPL consistently utilizes this approach in a number of resource option analyses as well as in developing cost information for Standard Offer Contracts.

Q. What are the other incorrect and/or misleading statements Ms. Mims made that you will discuss?

A. The other two such statements also relate to Ms. Mims' attempt to relitigate the already concluded DSM Goals docket:

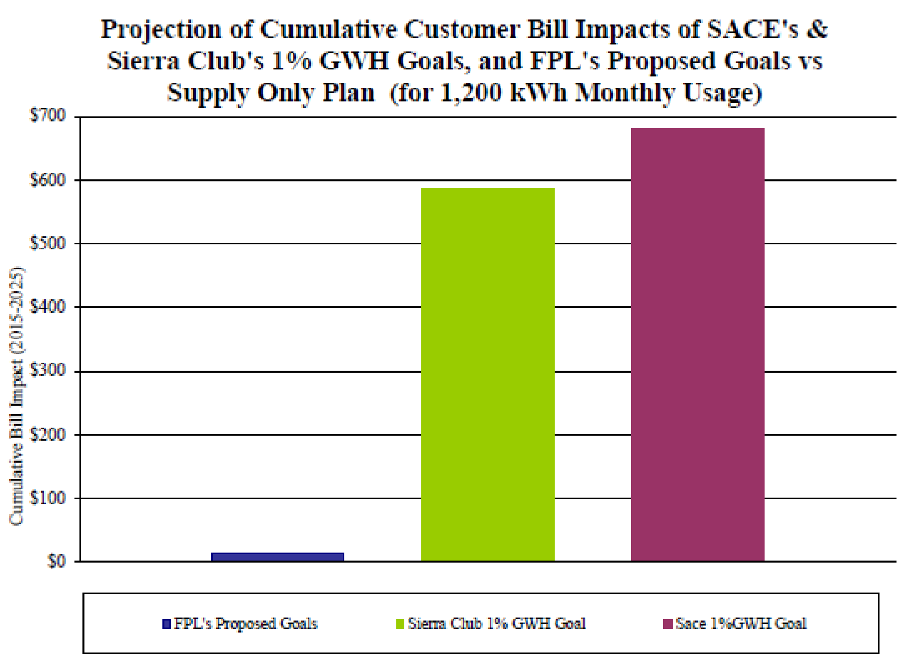
- *"In 2014, FPL insisted that, between the RIM and TRC tests, 'only the RIM test really addresses the issue of whether it makes sense for a utility to offer a [demand-side management] measure when considering all customers on a utility system.*[22] *By focusing on the impacts on customers that do not participate in demand-side programs, FPL's narrow perspective ignores opportunities for benefits and savings for all customers.'"* (Page 30, Lines 6-12)

- *"FPL witness Sim stated, I would agree the SACE plan is lower in total cost or revenue requirements."* (Page 16, Lines 18 & 19)

There are a couple of problems with her first statement above. First, Ms. Mims begins by attempting to endorse the TRC test despite the fact that, in the 2014 DSM Goals docket, SACE did not even base its proposed goals on the TRC test. Instead, they chose to completely ignore cost-effectiveness tests and propose goals based on an arbitrary 'percentage of retail sales' basis. Second, the rest of Ms. Mims' statement, "*By focusing on the impacts on customers that do not participate in demand-side programs, FPL's narrow perspective <u>ignores opportunities for benefits and savings for all customers</u>*", (emphasis added) is clearly not consistent with the evidence presented in the DSM Goals docket.

Based on SACE's 'percentage of retail sales' recommendation, and a similar recommendation by the Sierra Club, FPL performed an analysis in that docket of what the impacts of these recommendations would be on non-participating customers. The result was that electric rates would increase for all FPL customers and that bills for non-participating customers would significantly increase over the 10-year goals period. Figure SRS-1 below presents the electric bill results graphically.

Figure SRS-1



As seen in Figure SRS-1, non-participants were projected to have a cumulative bill increase of almost $700 during that time based on SACE's specific recommendations compared to a resource plan that contained no incremental DSM and compared to FPL's proposed DSM goals which had only a negligible bill increase for non-participants.

It is difficult to reconcile almost $700 in higher bills for non-participants with Ms. Mims' contention that, by ignoring non-participants, somehow there will be *"benefits and savings for all customers."*

Ms. Mims' second statement above is also misleading. She selectively provided half of the discussion that took place in the 2014 DSM Goals docket in which I stated that high levels of DSM would lower total costs or revenue requirements. However, she selectively chose to not include the second part of that discussion which appears in my testimonies in the DSM Goals docket. In those discussions, I explained that high levels of DSM that do not pass the RIM test, and which are not tied to FPL's resource needs, would: (i) increase electric rates for all FPL customers, (ii) significantly increase monthly electric bills for non-participating customers, and (iii) introduce unnecessary cross-subsidization between customer groups.

Q. Please summarize your conclusions regarding Ms. Mims' testimony.

A. In her testimony, Ms. Mims attempts to ignore history and the fact that the DSM Goals docket has been concluded. She offers no explanation for why she thinks additional cost-effective DSM is now suddenly available in such a short time removed from the concluded DSM Goals docket, which exhaustively examined the issue of DSM's cost-effectiveness. Indeed, Exhibit SRS-12 demonstrates the opposite to be true: the trend of decreasing cost-effectiveness of DSM on FPL's system continues, and DSM is less cost-effective today for FPL's system than it was at the conclusion of the 2014 DSM Goals docket. Finally, as discussed briefly here, and presented in Exhibit SRS-6, Ms. Mims makes a number of incorrect and/or misleading statements which further undermines her testimony.

Part V: Summary and Conclusions

Q. Please provide a summary of the testimonies of the three intervenor witnesses.

A. The intervenors do not contest that:

1) when utilizing FPL's existing reliability criteria, FPL projects a significant resource need (1,052 MW) beginning in 2019 and increasing in subsequent years;

2) the results of FPL's analyses concluded that the OCEC Unit 1 is the most cost-effective self-build generating option with which to meet that resource need; and,

3) no non-FPL generating option was submitted in response to FPL's capacity RFP solicitation that met the RFP's Minimum Requirements, thus no market alternatives to OCEC Unit 1 were offered.

In addition, there are inherent problems and flaws in the intervenor testimonies, most notably as follows:

1) The intervenors attempt to shift the focus of the discussion away from the facts of the case by disregarding FPSC decisions and basic principles of resource planning.
2) Mr. Rábago's testimony has as its main point a false and unsubstantiated claim that FPL has a *"campaign"* to build new power plants now running for several decades, during which he apparently believes the FPSC has failed to review and regulate the utility appropriately.
3) Mr. Wilson's testimony attempts to avoid reality by stating that OCEC Unit 1 would not be needed if FPL's reliability criteria were simply ignored, including the 20% minimum total reserved margin criterion approved and applied by the FPSC since 1999 for all peninsular Florida IOUs.
4) Ms. Mims spends the bulk of her testimony criticizing the FPSC's 2014 decision in the DSM Goals docket, repeating her recommendations from that concluded docket that have already been rejected by the FPSC.

These problems, coupled with numerous other incorrect and/or misleading statements detailed in my rebuttal testimony and exhibits, demonstrate that the intervenor testimonies are unreliable and not worthy of serious consideration by the FPSC in this docket.

Q. What would be the best decision in this docket for FPL's customers?

A. Based on multiple, appropriate reliability criteria, FPL has a large resource need beginning in the year 2019 which can only be met cost-effectively by additional generation. OCEC Unit 1 has been shown to be the most cost-effective generation option for FPL's customers. Therefore, it would be in the best interests of FPL's customers for the FPSC to grant a determination of need for OCEC Unit 1.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
1	Rábago	5/9	*"This significant increase in the already planned growth in generation stands in stark contrast to forecasted growth rates for customer population, load, and household income over the same period."* **(Misleading)**	Capacity needs are driven by a variety of factors including load growth, reserve margin requirements, unit retirements, and termination of power purchase agreements. Decisions on a unit's actual capacity are based on an economic decision-making process, once the capacity needs are known.
2	Rábago	6/5	*"How does the Company forecast LOLP? …It does not. As a result, the LOLP test really has no practical meaning in this application."* **(Incorrect)**	FPL provides a forecast of LOLP every year with its Ten Year Site Plan as part of FPL's response to Supplemental Data Requests. Also, the witness' testimony actually uses some of those forecasted LOLP values in his testimony.
3	Rábago	7/13	*"This number[LOLP] indicates that the proposed NPGU is not required in order to maintain system reliability or integrity."* **(Incorrect)**	The need for the NPGU is not based on LOLP, nor has FPL ever stated that it was. LOLP is merely one of three reliability criteria that FPL utilizes to determine the timing and magnitude of its resource needs. The other two reliability criteria are projected not to be met in 2019, thus indicating a need to add resources in that year.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
4	Rábago	9/6	*"In all, the factors suggesting a need to reexamine both the RM and GRM test include…the potential for increased reliance on other generation in the Eastern Interconnection."* **(Incorrect)**	FPL's reliance on the Eastern Interconnection is limited by transmission capacity access into Florida from Georgia as well as the high transmission losses that would be incurred bringing this energy to FPL's load centers.
5	Rábago	10/9	*"In short, the Company should conduct an objective and quantitative assessment of the ratepayer impact measure of its generation construction program over the past fifteen years in order to honestly claim customer benefits."* **(Incorrect and Misleading)**	It is incorrect to suggest that the FPSC has not been doing its job during these past 15 years as he alludes to here. The FPSC regularly holds evidentiary hearings in which power plant decisions are scrutinized before the FPSC grants a need determination and cost recovery for the new units. In other words, just this sort of analysis is regularly carried out by the FPSC.
6	Rábago	11/4	*"…the Company appears to have recently decided that they would like to have another generating unit operating by 2019, and they built a case to support that conclusion."* **(Incorrect and aisleading)**	The need for new capacity in 2019 is clearly demonstrated by FPL's filing in this docket that shows: (i) a projected need in 2019, (ii) OCEC Unit 1 is the most cost-effective self-build generating option, (iii) no viable market generation alternatives to OCEC Unit 1, and (iv) the continued trend of declining DSM cost-effectiveness.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
7	Rábago	15/12	*"The Company evaluates the DSM resource option solely for its ability to meet all of the increase in forecasted need. This approach is unrealistic, does not consider matching an increase in demand side resources coupled with a smaller NPGU."* **(Incorrect)**	FPL evaluates DSM options versus the planned generating unit on a per kW basis. This provides the best opportunity for DSM measures to pass economic screening analyses versus generation. Consequently, FPL does not evaluate DSM *"solely for its ability to meet all of the increase in forecasted need."* In addition, DSM is continuing its trend of declining cost-effectiveness.
8	Rábago	15/17	*"Options not considered include sufficient demand side resources to defer the NPGU for a single year, for example."* **(Incorrect)**	FPL has already accounted for all DSM found to be readily available and cost-effective in the 2013-2014 DSM Goals docket. Since that time, the trend of declining cost-effectiveness for DSM has continued. Therefore, there is no additional cost-effective DSM with which to partially address FPL's 2019 need. In fact, FPL's 2019 need would likely be larger if DSM's cost-effectiveness had been re-analyzed in 2015.
9	Rábago	15/18	*"Instead, the Company constructs a hyperbolic hypothetical in which 800MW of new DSM must be obtained solely through increases in the residential air-conditioning control program."* **(Incorrect l·yŘ Misleading)**	This hypothetical was included merely to provide an example of the huge amount of additional, cost-effective DSM that would be required to fully meet the need. It was clearly hypothetical because there is no additional, readily available DSM that is cost-effective on FPL's system.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
10	Rábago	16/12	*"The Company does not evaluate the solar option from the perspective of the time frame required to develop that option."* **(Misleading)**	This statement ignores the uncertainties involved with meeting the 2019 need with solar and the fact that other, much more certain generation options would have to be bypassed if FPL were to wait several more years just to minimize the uncertainties surrounding solar. These issues were addressed in direct testimony.
11	Rábago	16/16	*"As detailed by Company witness Sim, the fact that the Company uses such a large, self-build NPGU size has a significant impact on dampening participation by non-utility bidders."* **(Misleading)**	The testimony referenced after this statement refers to the results of FPL's previous Bid process. These results were included to demonstrate that FPL's self-build option in that RFP prevailed over other bids because of economics, not simply because of its large size. Bidders were free to bid to provide all or a portion of FPL's 1,052 MW need. FPL believes that potential bidders were discouraged by the economic strength of OCEC Unit 1, primarily its cost and heat rate, not by its MW size.
12	Rábago	17/15	*"The Company reliance on the 10% generation-only reserve margin is also a significant factor in the Company's justifications for building new capacity."* **(Incorrect)**	The additional MW need required based on the 10% GRM over the 20% standard RM is only 64 MW, a very small amount compared to FPL's total system and, therefore, not a significant factor in this docket.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
13	Rábago	19/14	*"…the Commission should direct the Company to explore 'extreme' or 'fast response' demand response resources specifically designed to provide reliability support."* **(Incorrect l·yŘ Misleading)**	FPL already has approximately 2,000 MW of fast response resources in its residential and commercial/industrial load management programs.
14	Wilson	7/5	*"…FPL witness Dr. Steven Sim testified during his telephonic deposition … that no such study or substantive analysis existed."* **(Incorrect and/or Misleading)**	In the deposition, FPL witness Sim interpreted the question to mean analyses which, starting from scratch, were designed to identify a specific RM value to use as a criterion. In has been many years since FPL did such a study, in large part due to the 20% stipulation reached in 1999. However, FPL has performed analyses that compared a 20% criterion versus a 15% criterion as discussed in the rebuttal testimony.
15	Wilson	7/20	*"…in 2010, the North Carolina Utilities Commission required Duke Energy Carolinas to conduct a reserve margin study… The result of Duke Energy Carolinas' reserve margin study (provided as Exhibit (JDW-2) was to reduce Duke's reserve margin from 17% to 15.5%, which had a material impact on Duke's resource plan."* **(Misleading)**	Mr. Wilson selectively chose to mention this 2010 study, but selectively decided not to mention the 2015 study in which Duke energy Carolinas decided not only to restore the 17% reserve margin criterion, but to consider for the first time a dual Summer/Winter reserve margin criterion.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
16	Wilson	11/2	*"I am not aware of any other utility that uses a GRM criterion."* **(Incorrect and/or aisleading)**	Although FPL has no way of knowing what Mr. Wilson may be aware of, he should be aware that TECO has utilized a similar supply-side reserve margin criterion for many years and continues to use it.
17	Wilson	12/17	*"…but those goals have been superseded by significantly lower goals adopted by the Commission in 2014 and are no longer in effect for FPL."* **(Misleading)**	This statement ignores the obvious possibility that FPL's DSM goals could be set again at very high levels. In fact, Mr. Wilson and SACE have been advocating - and continue to advocate - for just such very high DSM goals.
18	Wilson	15/4	*"But to the extent that peak events in June are driven by the same type of hot conditions that are more likely to occur in August, these programs should perform identically. I am unaware of evidence that energy efficiency or load control program technologies perform less effectively on a hot June or October day than on an equally hot August day."* **(Incorrect and aisleading)**	The probabilistic study referenced examines the effect of a DSM measure on reliability across all months, not just months reasonably close to Summer. Also, the statement ignores the possibility of a utility having generation problems on a mild weather day and the possibility of previously set DSM implementation levels being lowered due to lowered DSM cost-effectiveness cancelling the program or significantly reducing incentive payments.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
19	Wilson	15/9	*“FPL cites uncertainty about the performance of future EE programs, presenting a reliability risk in the form of load forecast uncertainty. This analysis is unreliable because it (1) is out of date (based on 2002 technology) and (2) is based on a simple average of program uncertainty without any evidence that averaging is the proper statistical technique, given the likelihood that there are relationships between the program outcomes.21 This type of analysis should be supported by a current evaluation, measurement and verification (EM&V) study conducted by an independent consultant and its novel application in this circumstance certainly requires greater scrutiny.”* **(Misleading)**	Mr. Wilson misinterpreted the use of this data. It was never used in either the LOLP-based analyses or the system operations-based analyses. It was merely developed to get a ballpark idea of what the uncertainty range around DSM kW reductions per installation (and by program type) might be. Mr. Wilson's reference to EM&V confirms that there is uncertainty regarding the performance of DSM once it is installed. In addition, there is also uncertainty regarding the number of DSM installations that may occur in the future due to changes in DSM cost-effectiveness. However, FPL did not utilize either of these DSM uncertainty factors in its LOLP-based or system operations-based analyses.
20	Wilson	16/8	*"The GRM designed by FPL includes energy conservation programs, which are not subject to 'fatigue'. In fact, just the opposite as many of these programs involve the use of passive measures (e.g., insulation) or installation of lower power equipment."* **(Misleading l·yŘ Irrelevant)**	Load management fatigue was not a factor in the LOLP-based and system operations-based analyses that led FPL to adopt the GRM criterion.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
21	Wilson	21/4	*"By adopting an unnecessary and wrongly designed criterion, FPL's customers will carry the cost of unnecessary power plant construction."* **(Incorrect l·yŘ Misleading)**	The criterion is needed to ensure reliability on FPL's system and is correctly designed for the specific conditions of FPL's system. In addition, FPL's resource planning considers the electric rate impact of all resource options when considering resource additions to FPL's system.
22	Wilson	21/20	*"If FPL had made greater investments in energy efficiency and pursued opportunities to procure renewable energy in South Carolina, it might be possible for FPL to avoid adding any additional natural gas power plants - including the proposed OCEC Unit 1 - and the costs that they represent for customers."* **(Incorrect l·yŘ Confusing)**	FPL neither operates in South Carolina nor adds renewable resource options in South Carolina. And there is no additional readily available, cost-effective DSM on FPL's system with which to meet FPL's 2019 resource needs. In addition, FPL is already tripling its solar generating resources in 2016 and is actively evaluating more solar resources.
23	Wilson	22/9	*"In other words, FPL's newest solar facilities are not the result of FPL's resource planning process as described in the ten-year site plan, but are the result of some other business development process that is not clearly described."* **(Incorrect)**	This statement appears to be a misinterpretation of FPL's Site Plan document. The process behind the selection of FPL's 3 new solar units is clearly described on Page 80 of FPL's 2015 Ten Year Site Plan which describes the activities carried out in FPL's 2014/early 2015 resource planning work. In addition, FPL's direct testimony describes how solar was evaluated as part of its resource planning process for the feasibility of addressing FPL's 2019 need.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
24	Wilson	23/11	*"...I cannot speculate as to the extent that solar technologies could substitute for any need that may exist (now or in the future) for a combined cycle natural gas plant. I would expect FPL to increase its plans to invest in solar resources if solar was included in the capacity optimization process."* **(Misleading)**	Solar is actively being evaluated in FPL's on-going resource planning work. As viable cost-effective solar applications are identified in this evaluation of resource options, FPL will likely incorporate them into its resource plan.
25	Mims	4/8	*"It would seem that if FPL is truly trying to diversify its fuel sources, at least one of these resources [solar or nuclear] would be increasing as a percent of total generation over time, not just natural gas."* **(Incorrect l·yŘ Misleading)**	The statement ignores the fact that FPL's solar contribution will triple in 2016. Also, the discussion and associated table is very selective in regard to the years addressed. The years appear to have been carefully chosen to leave out recent fuel diversity additions such as: 110 MW of solar around 2010, more than 500 MW of additional nuclear capacity around 2012, and 2,200 MW of new nuclear capacity in 2027/2028. Furthermore, SACE actively opposed these nuclear additions which have enormous fuel diversity benefits as well as fuel hedge and environmental cost hedge benefits.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
26	Mims	6/13	*"Clearly, eliminating measures associated with codes and standards results in the evaluation of less than all demand side and supply side conservation measures."* **(Incorrect l·yŘ Misleading)**	If energy efficiency (EE) codes and standards remove a measure from the potential for utility EE programs, but the impact of that measure is accounted for in FPL's load forecast, then the impact of that measure is still captured. All that has changed is the mechanism by which the measure is accounted for (through codes and standards or through utility programs).
27	Mims	7/21	*"This means that FPL's entire 2014 Potential Study is flawed, and furthermore, the basis for FPL's statement that it evaluated all cost-effective energy efficiency prior to determining its need for the proposed OCEC Unit 1 is inaccurate."* **(Incorrect and Misleading)**	The FPSC decided otherwise. It decided that the utilities' analyses that determined DSM Achievable Potential were accurate and reliable enough to set DSM Goals at these Achievable Potential values. Ms. Mims argued her same points in the concluded 2013-2014 DSM Goals docket and the FPSC was unconvinced by her testimony.
28	Mims	8/13	*"Again, FPL did not use the best practices outlined by the EPA when it calculated economic potential in its 2014 Potential Study."* ***(Misleading l·yŘ Irrelevant)***	"Best practices" is in the eye of the beholder. FPL utilizes best practices for its system, its customers, and Florida rules and statutes.
29	Mims	8/21	*"It is inappropriate to evaluate the Company's resource needs prior to determining if measures are economic. The only factor that should be considered is whether or not energy efficiency is less expensive than avoided cost."* **(Incorrect)**	Evaluating resource needs to determine the magnitude and timing of a utility's resource needs, and what generating resource would likely be utilized to meet those resource needs absent DSM, is the only way to accurately determine the economics of DSM. Therefore, FPL's approach is both appropriate and logical.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
30	Mims	9/10	*"As shown in Table 3 and 4, this screen eliminated 1,550 - 6,392 GWh from FPL's energy efficiency potential under the Company's RIM and TRC portfolio."* **(Misleading and Irrelevant)**	GWh reduction is irrelevant in regard to whether DSM can meet a utility's projected resource needs (which is the only relevant DSM-related issue in this docket). In addition, the FPSC decided that the utilities' analyses from Technical Potential through to Achievable Potential were accurate and reliable enough to set DSM Goals at these Achievable Potential values. Because DSM is even less cost-effective in 2015 than it was in 2014, there is no additional cost-effective DSM that is not already accounted for in FPL's load forecast and resource planning. Ms. Mims argued her same points in the concluded 2014 DSM Goals docket which the FPSC rejected.
31	Mims	10/15	*"...FPL completely omitted calculating the achievable potential and instead moved directly to calculating the program potential."* **(Incorrect)**	FPL calculated its achievable potential for DSM based on FEECA statutes and FPSC rules. The "NAPEE" definitions for achievable potential and program potential are not applicable or relevant in the Florida DSM Goals process. The FPSC accepted the Achievable Potential values developed by the utilities in the 2014 DSM Goals Docket.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
32	Mims	13/3	*"only one other state (Virginia) relies on the RIM test to make investment decisions* **(Incorrect l·yŘ Irrelevant)**	Once again the intervenor witness draws an inappropriate inference to conclude that Florida should rely exclusively on the TRC test. Further, many other states continue to use the RIM test in conjunction with the TRC test. And other states impose rate impact limitations on the amount of conservation they approve for their regulated utilities. This, to an extent, is relying on the RIM test to set conservation goals. And most importantly, Florida's historical reliance on the RIM test has proven both appropriate and beneficial for Florida customers.
33	Mims	13/6	*"In 2014, FPL insisted that, between the RIM and TRC tests, 'only the RIM test really addresses the issue of whether it makes sense for a utility to offer a [demand-side management] measure when considering all customers on a utility system. By focusing on the impacts on customers that do not participate in demand-side programs, FPL's narrow perspective ignores opportunities for benefits and savings for all customers."* **(Incorrect)**	By utilizing SACE's proposed goals instead of RIM-based goals, non-participants were projected to have a cumulative bill increase of almost $700 over a 10-year period, which makes it illogical to say that there will be "benefits and savings for all customers."

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
34	Mims	14/21	*"FPL's refusal to allow energy efficiency to reduce the size of a natural gas power plant is just one of the factors that FPL used to undervalue energy efficiency in its 2014 ten year site plan, and subsequently in this docket."* **(Incorrect)**	DSM cannot physically "reduce" the size of a generating unit; it can reduce a utility's projected resource needs provided the DSM is cost-effective compared to the generating unit that would otherwise be built. Although combined cycle plants of different sizes can be built, utilities select the combined cycle size and other unit characteristics that are best economically for their specific utility system. That is precisely why different utilities select different size combined cycle units.
35	Mims	16/3	*"...SACE proposed that FPL achieve 1% of prior year retail sales with energy efficiency."* **(Misleading)**	SACE's goals were incomplete, arbitrary, and not based on any sort of analytical process. Furthermore, SACE did not present MW goals as part of its Goals which violated Florida rules for DSM Goals. For this, and other reasons, SACE's recommendations were deficient and ultimately rejected by the FPSC.
36	Mims	16/14	*"FPL found that the cumulative present value revenue requirement for SACE's energy efficiency goal would cost less than FPL's goal ... FPL witness Sim stated, 'I would agree that the SACE plan is lower in total cost or revenue requirements.' "* **(Misleading)**	This statement selectively leaves out the rest of FPL's testimonies in the DSM Goals docket which stated that SACE's proposed goals would (i) increase electric rates for all FPL customers, (ii) significantly increase monthly electric bills for non-participating customers, and (iii) introduce unnecessary cross-subsidization between customer groups.

Incorrect and/or Misleading Statements Made in the Testimonies of Rábago, Wilson, and Mims

	Witness	Starting Page/Line	Incorrect and/or Misleading Testimony Statement	Correct Information
37	Mims	17/3	*"FPL uses the cumulative present value of revenue requirement to determine the best generation option from a cost and electric rate perspective. FPL does not allow DSM to be a part of this calculation by holding it constant across each option."* **(Misleading)**	First, FPL's economic criteria for determining the best resource option is only based on rates, not cost. Cost can be used as a proxy for electric rates when plans have similar total load (i.e. when plans have similar amounts of DSM). Second, there was no additional, reasonably achievable, cost-effective DSM to consider. Therefore, FPL held DSM constant. This was actually an optimistic-for-DSM assumption because FPL believes that less DSM is now cost-effective than when the DSM Goals were set in 2014.
38	Mims	17/9	*"However, the critical piece of knowledge that FPL refuses to discuss is that 'unrecovered revenue requirements' results from policy decisions, not from resource decisions."* **(Incorrect)**	Poor resource decisions, such as those advocated by SACE, will result in net unrecovered revenue requirements, higher electric rates for all customers, and significantly higher electric bills for non-participants. Policy decisions do not cause this problem.

Commission Proceedings
Approving or Applying 20% Reserve Margin

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
981890 PSC-99-2507-S-EU	FPL, FPC, TECO	Generic Investigation	Commission approved 20% reserve margin stipulation for FPL, FPC and TECO. "During our reviews of the Ten Year Site Plans filed in 1997 and 1998, we expressed concerns about the adequacy of the reserve margins planned for Peninsular Florida. At the December 15, 1998, Internal Affairs meeting, we directed staff to open this docket to consider the reserve margins planned for Peninsular Florida electric utilities. … We approve the Stipulation agreed to by Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company. It addresses the basic concern about the adequacy of planned reserve margins for Peninsular Florida. Collectively, these three utilities plan for approximately 80 percent of the Peninsular Florida load. Thus, a twenty percent planning criterion adopted by these three utilities is a significant increase over the fifteen percent criterion currently employed."
991973 PSC-00-0504-PAA-EQ	FPC	Standard Offer	Commission granted rule waiver, in part because of 20% reserve margin standard. "If the waiver were not granted, FPC's efforts to meet the new 20% reserve margin would be frustrated."
001064 PSC-01-0029-FOF-EI	FPC	Need Determination	Commission granted a determination of need for Hines Unit 2. "We find that Florida Power Corporation has a need for additional capacity to maintain the reliability and integrity of its system, as contemplated by Section 403.519, Florida Statutes. The record shows that FPC has demonstrated **a** need for additional capacity to meet its 20 percent minimum reserve margin criteria. … In Order No. PSC-99-2507-S-EU, Docket No. 981890-EU, the Commission approved the stipulation reached by the peninsular Florida investor-owned utilities (IOUs). These IOUs agreed to implement a 20 percent minimum reserve margin criteria to be fully effective by the summer of 2004. P r i o r to t h i s stipulation, FPC utilized a 15 percent minimum reserve margin criteria. As shown in Exhibit 10, answers to staff's interrogatories, FPC's projected reserve margin in the winter of 2003/04 is 18.4 percent, if Hines 2 is not brought into service. FPC needs only

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			approximately 130 MW to precisely reach a 20 percent reserve margin in the winter of 2003/04. FPC will violate its 20 percent minimum reserve margin criterion, in the winter of 2004/05, if Hines 2 is delayed. FPC, therefore, is only accelerating the proposed capacity addition six months in order to meet the stipulation."
001437 PSC-00-2434-PAA-EI	FPL	Depreciation	Commission approved new depreciation rates for units added to meet the 20% reserve margin criterion. "Subsequently, by Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU, FPL agreed to a minimum reserve margin planning criterion of twenty percent reserve beginning with the Summer of 2004. To achieve this goal, FPL now plans to install six CTs at Ft. Myers, which will initially operate in a stand-alone mode until the overall completion of the repowering, currently projected for June 1, 2002."
010107 PSC-01-1337-PAA-EI	FPL	Depreciation	Commission approved new depreciation rates for units added to meet the 20% reserve margin criterion. "By Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU, FPL agreed to a minimum reserve margin planning criterion of twenty percent reserve beginning with the Summer of 2004. However, in an effort to achieve this goal by the Summer of 2001, FPL plans to install two combustion turbines (CTs) at the Martin Site in June, 2001. These units will initially operate in a stand-alone peaking mode with planned conversion to natural gas-fired, combined-cycle generators in the 2005-2006 time period to meet FPL's expected increased customer growth and usage."
	FPL, FPC, TECO	2001 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed *Ten-Year Site Plans* filed by twelve (12) reporting utilities and two (2) merchant plant companies. The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are ***suitable*** for planning purposes. Forecasted reserve margins for Peninsular Florida range from 20% to 23% during summer peak seasons, and from 23% to 26% during winter peak seasons. The Commission makes no determination on the suitability of the merchant plant filings."
020262 020263 PSC-02-1743-FOF-EI	FPL	Need Determination	Commission granted a determination of need for Martin Unit 8 and Manatee Unit 3. "We find that Florida Power & Light company has a need for additional capacity to maintain the reliability and integrity of its system, which will be provided by-

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			Manatee Unit 3 and Martin Unit 8. FPL has an estimated need for 1,122 MW of additional capacity for Summer, 2005, and an additional need for 600 MW of capacity for Summer, 2006. The 1,107 MW of summer capacity from Manatee Unit 3 will contribute to FPL's electric system reliability and integrity. With the addition of that capacity, FPL's projected reserve margin for Summer, 2005 is 19.92%. In order to precisely meet a planning reserve margin criterion of 20.0%' FPL needs only 15 MW of capacity with the addition of Manatee Unit *3* in Summer, 2005. Therefore, FPL does not have a pressing reliability need for the entire 789 MW of capacity from Martin Unit 8 until Summer, 2006. As discussed below, however, the record shows that it is more cost-effective for FPL to place Martin Unit 8 into commercial service in 2005 rather than 2006.”
020295 PSC-02-0909-PAA-EQ	FPC	Standard Offer	Commission granted waiver of a Commission rule because of the need to meet the 20% reserve margin criterion. “We agree that if the waiver is not granted, FPC‘s efforts to meet the new 20% reserve margin would be frustrated. On November 30, 1999, we approved an agreement between FPC, FPL, and TECO adopting a 20% reserve margin planning criterion starting in the summer of 2004. A delay in the RFP process could seriously jeopardize FPC’s ability to bring Hines 3 on line by the December, 2005, in-service date.”
020332 PSC-02-1103-PAA-EI	FPL	Depreciation	Commission approved depreciation rates for units added by FPL to meet the 20% reserve margin criterion. “By Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU, FPL agreed to a minimum reserve margin planning criterion of twenty percent beginning with the Summer of 2004. To achieve this goal in a more timely fashion, FPL installed six CTs at Ft. Myers in *2000* and 2001, initially operating in a stand-alone mode. This provided immediate increases to the FPL system. With the recent addition of the six HRSGs, Ft. Myers became a combined cycle operating facility on May 31, 2022.”
020953 PSC-03-0175-FOF-EI	FPC	Need Determination	Commission granted a determination of need for Hines Unit 3. “Reserve Margin PACE questioned whether there is a present need for the Hines Unit 3. PACE argues that FPC has done well over the past with a 15 percent reserve margin and if this margin is maintained, Hines Unit 3 is not needed. Regardless of past experience, however, Order No. PSC-99-2507-S-EU,issued December 22, 1999, in Docket No.

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			981890-EUf requires Florida's investor owned utilities (IOUs) to increase minimum planning reserve margins to a 20% reserve margin by the summer of 2004. By approving the stipulation proposed by the IOUs and issuing the above Order, we have already determined that 20% is the appropriate reserve margin criteria, and the IOUs are required to utilize this criteria, unless modified in a subsequent proceeding. To provide reliable service, utilities are required to maintain a margin of generating capacity above the firm demand of their customers (planned reserves). At any given time during the year, some generating plants will be out of service and unavailable due to forced outages, periodic maintenance, refueling of nuclear plants, etc. Therefore, adequate reserves must be available to provide for this unavailable capacity and for higher than projected peak demand due to forecast uncertainty and abnormal weather. The proper forum to address what minimum reserves are necessary should be in a generic docket, as was previously done, and not in a particular utility's power plant need determination docket. FPC has relied heavily in the past on demand side management (DSM) to meet its reserve requirements. FPC cannot use DSM as often or with the same duration as physical generation without eventually affecting customer participation levels, as was demonstrated by FPC's customer attrition from its DSM programs in 1998 and 1999. The record indicates FPC's DSM programs are becoming less cost-effective compared to the cost of generation. For these reasons, FPC is attempting to build up its physical reserve percentage." … "In summary, we find that FPC's load forecast is reasonable. FPC's projected reserve margin in the winter of 2005/2006 is 17 percent if Hines Unit 3 is not brought into service, and therefore FPC will violate its 20 percent minimum reserve margin in the winter of 2005/06 . FPC projects that the growth in winter peak demand will average approximately 159 MW a year from 2002/03 to 2006/07, with a projected peak in 2006/07 of 9,195 MW. FPC has projected a growth in winter peak demand of 416 MW for the period 2004/05 to 2006/07. Therefore, we find that Hines Unit 3 will be needed by December 2005 , to maintain FPC' s electric system reliability and integrity."
	FPL, PEF, TECO	2002 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes.

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			"The Commission has reviewed *Ten-Year Site Plans* filed by twelve (12) reporting utilities and two (2) merchant plant companies. The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are ***suitable*** for planning purposes. Forecasted statewide reserve margins range from 24% to 27% during summer peak seasons, and from 27% to 31% during winter peak seasons. The Commission makes no determination on the suitability of the merchant plant filings."
030866 PSC-03-1329-PAA-EQ	PEF	Standard Offer/ Bid Rule Waiver	Commission granted a waiver of the Bid Rule due to a likely inability to meet the 20% reserve margin criterion. "We believe that if the waiver is not granted, Progress's efforts to meet the 20% reserve margin would be frustrated. In 1999, an agreement was approved between Progress Energy Florida, Florida Power & Light Company, and Tampa Electric Company adopting a 20% reserve margin planning criterion, effective with the summer of 2004. See Order No. PSC-99-2507-S-EU, issued December 22, 1999, Docket No. 981890-EU, In Re: Generic Investigation into the Adequate Electric Utility Reserve Margins Planned f o r Peninsular Florida. A delay in the RFP process could seriously jeopardize Progress's ability to bring Hines 4 on line by the December 2007 in-service date, an action which is necessary to ensure that the Company maintains a 20% reserve margin. As a result, we agree with the Company that this potential impairment to the reliability of Progress's generation resources constitutes "substantial hardship" within the meaning of Section- 120.542, Florida Statutes."
	FPL, PEF, TECO	2003 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed *Ten-Year Site Plans* filed by eleven reporting utilities and one independent power producer (IPP). The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are ***suitable*** for planning purposes. Forecasted statewide reserve margins range from 23% to 26% during summer peak seasons, and from 26% to 30% during winter peak seasons. The Commission makes no determination on the suitability of the IPP filing."
040029 040031 040033 PSC-04-0763-PAA-EG	FPL PEF TECO	DSM Goals DSM Goals DSM Goals	Established DSM goals for FPL, PEF, and TECO using avoided costs calculated assuming a 20% reserve margin.

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PSC-04-0769-PAA-EG PSC-04-0765-PAA-EG			
040206 PSC-04-0609-FOF-EI	FPL	Need Determination	Commission granted a determination of need for Turkey Point Unit 5. "There is a need for the proposed Turkey Point Unit 5, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, Florida Statutes. Absent the timely addition of Turkey Point Unit 5, FPL's summer reserve margins will fall to 14.7 percent in the summer of 2007, well below the Commission-approved 20 percent reserve margin planning criterion. Further, the addition of Turkey Point Unit 5 will enhance FPL's operating flexibility and system reliability in Southeast Florida by reducing the growing imbalance between generation and load in this region."
	FPL, PEF, TECO	2004 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed *Ten-Year Site Plans* filed by eleven reporting utilities and one independent power producer (IPP). The Commission has determined that the *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. Forecasted statewide reserve margins range from 23% to 26% during summer peak seasons, and from 26% to 30% during winter peak seasons. The Commission makes no determination on the suitability of the IPP filing."
	FPL, PEF, TECO	2005 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. " Based on our review, the Commission finds the Ten-Year Site Plans filed by the eleven reporting utilities to be suitable."
060225 PSC-06-0555-FOF-EI	FPL	Need Determination	Commission granted a determination of need for West County 1 & 2. "We find that there is a need for FPL's proposed West County Units 1 and 2, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, Florida Statutes. Without completing West County Unit 1 by June 2009, FPL's and Peninsular Florida's electric system reliability and integrity would be significantly reduced. FPL would also fail to meet its 20 percent reserve margin planning criterion. Without the unit, FPL's summer reserve margin for 2009 would decrease to 15.5% and decrease further in each following year."
060387 PSC-06-0743-PAA-EQ	PEF	PPA Approval	Commission approved a PPA with a renewable resource, Florida Biomass. "By the terms of the negotiated contract, the Florida Biomass combined cycle

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			generator is to be operational no later than December 1, 2009, with net output projected to be 116 MW. PEF's 2006 Ten Year Site Plan shows projected growth of approximately 200 MW of demand each year. PEF asserts that it will need additional capacity by 2009 to maintain its 20% reserve margin. The next planned unit is the Bartow Repowering Project, currently scheduled to come on line in June 2009. There are six additional units planned through 2015 to meet PEF's demonstrated need for capacity in that period. While PEF has not included the Florida Biomass contract as a firm resource in its 2006 Ten Year Site Plan, if the contract is approved, PEF will include the projected committed capacity as a firm resource."
	FPL, PEF, TECO	2006 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "Pursuant to Section 186.801, Florida Statutes, the Florida Public Service Commission (Commission) has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities and finds them to be suitable."
070100 PSC-07-0456-PAA-EQ	FPL	Depreciation	Approved of Depreciation rates for Turkey Point Unit 5. "By Order No. PSC-99-2507-S-EU,2 FPL agreed to a minimum reserve margin planning criterion of 20 percent beginning in the summer of 2004. However, in 2003, FPL's integrated resource planning work determined that an additional 1,066 megawatts (MW) of capacity was needed by the summer of 2007. If the additional megawatts were not obtained, FPL and the Peninsular Florida's electric system reliability and integrity would be reduced and the required 20 percent reserve margin would not be met for 2007. Also, the balance between the amount of generating capacity located in southeast Florida and the electrical load would not be maintained. Pursuant to Order No. PSC-04-0609-FOF-EI,3 the Commission approved the construction of Turkey Point Unit 5 to meet FPL's needed capacity."
070602 PSC-08-0021-FOF-EI	FPL	Need Determination for Expansion	Commission granted a determination of need for expansion of Turkey Point and St. Lucie nuclear units. "There is a need for the Turkey Point nuclear power plant ("PTN") and St. Lucie nuclear power plant ("PSL") uprates, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519(4), Florida Statutes. Without the uprates, FPL's electric system reliability and integrity will be significantly reduced, and FPL will fail to meet its 20% reserve margin beginning in 2012 ….

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			FPL has future resource needs of 490 MW of incremental capacity in 2012. All demand side management (“DSM”) that is known to be cost-effective through 2013 is already reflected in FPL’s 2006/2007 resource planning work, which identified this capacity need. Consequently, to meet FPL’s summer reserve margin criterion of 20% through 2013, FPL needs new capacity in the form of power plant construction and or purchases.”
070650 PSC-08-0237-FOF-EI	FPL	Need Determination	Commission granted a determination of need for for Turkey Point units 6 and 7. “There is a need for Turkey Point 6 and 7, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519(4), F.S. FPL argues that there is a need for Turkey Point 6 and 7 because overall system demand is expected to grow by 40%. FPL further contends that without Turkey Point 6 and 7, the reserve margin would fall below 20% and FPL would have to rely more heavily on DSM, which would render FPL’s system less reliable. … Based on the foregoing, we find that FPL’s capacity need projections are reasonable. We note that no party took issue with the load forecast. FPL’s need was determined after taking into account 1,899 MW of additional DSM, all other currently committed supply projects, 414 MW of recently approved nuclear capacity includes previously certified nuclear uprates in 2012 and 2013 as well as new uncertified gas CC units in 2011, 2015, 2016, and 2017, includes previously certified nuclear uprates in 2012 and 2013, but no new gas units and 287 MW of renewable generation, although none are yet contracted, from 2 biomass projects and 3 municipal waste-to-energy projects. FPL’s need for additional capacity to meet rising electricity demands cannot be satisfied with additional purchased power from renewable generation. Additional DSM programs and renewables are not capable of deferring the need for additional capacity. In conclusion, the evidence shows that FPL has a need for 8,350 MW of additional capacity beginning in the 2011 through 2020 period. Turkey Point 6 and 7 will provide only a portion of FPL’s need for capacity.”
		2007 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. “Pursuant to Section 186.801, Florida Statutes, the Commission has reviewed the

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			utilities' 2007 Ten-Year Site Plans and finds them to be suitable because the plans were responsive to the energy policies in place at the time of filing."
080407 080408 080409 PSC-09-0855-FOF-EG		DSM Goals	The Commission approved DSM Goals based on avoided cost calculation for FPL, FPC and TECO that employed a 20% reserve margin criterion.
080203 080245 080246 PSC-08-0591-FOF-EI	FPL	Need Determination	Commission granted a determination of need for West County Energy Center Unit 3, Conversion of Riviera Plant, and Conversion of Cape Canaveral Plant. "FPL has demonstrated a reliability need for additional resource capacity in 2013. Usually, when a company seeks to satisfy a need for additional resource capacity using natural gas facilities, a petition for need determination would be submitted approximately 3 years before the facility's in-service date. The company decided, however, that unique economic opportunities and site-specific circumstances made it more cost effective to build WCEC 3 for operation in 201 1 and perform the conversions at Cape Canaveral and Riviera by 2013 and 2014. FPL contends that it will not be able to perform the conversions of Cape Canaveral and Riviera without approval of the proposed WCEC 3. FPL chose gas-fired combined cycle units as its resource option to meet its capacity needs. This decision was made primarily because coal and nuclear generation have longer construction times and would not be able to provide the additional capacity in the time needed. This approach will maintain FPL's reserve margin above 20 percent throughout the period."
080512 PSC-08-0707-PAA-EQ	PEF	PPA Approval	Commission approved a PPA with Vision/FL, LLC. "The Facility is projected to have a maximum nominal generating capacity of 50 MW. After serving internal loads, the Facility will provide firm capacity of approximately 40 MW to PEF. The expected annual energy amounts to 3 11,853 MWh. As a renewable energy resource, Vision's projected committed capacity of 40 MW will be independent **of** the current fossil fuel infrastructure as it uses a separate, distinct supply mechanism for its biomass fuel. It is noted that the addition of 40 MW of firm capacity and energy from Vision in 2010 to PEF pursuant to the contract will not completely defer or avoid the need for additional capacity in order to meet a 20% reserve margin. However, the Facility will displace energy generated by fossil fuels, reducing the state's dependence on these resources and promoting fuel diversity."

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		2008 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. “The Commission has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities and finds that the projections of load growth appear reasonable and that the reporting utilities have identified additional generation facilities required in order to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2008 Ten-Year Site Plans filed by the eleven reporting utilities to be suitable for planning purposes.”
		2009 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. “The Commission has reviewed the Ten-Year Site Plans filed by the 11 reporting utilities and finds that the projections of load growth appear reasonable and that the reporting utilities have identified additional generation facilities required in order to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2009 Ten-Year Site Plans filed by the 11 reporting utilities to be suitable for planning purposes.”
		2010 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. “The Commission finds the 2010 Ten-Year Site Plans filed by the eleven reporting utilities to be suitable for planning purposes. While the plans are suitable for planning purposes, they are subject to modification due to factors such as changes to fuel cost, energy use projections, evolving technology, and shifting energy policy. Therefore, the Commission will continue to closely monitor the future rate of load growth in Florida and its effect on the need for additional generation and transmission facilities in the state.”
110018 PSC-11-0293-FOF-EI	FPL	Need Determination	Commission granted a determination of need for expansion of Solid Waste Authority of Palm Beach County unit. “FPL determines the magnitude and timing of its resource needs based on a minimum reserve margin. The reserve margin represents available generating capacity during peak demand periods. FPL has established a minimum reserve margin of 20 percent above peak demand for reliability purposes. FPL has identified a reliability need beginning in 2016. This projection is consistent with FPL's 2011 Ten Year Site Plan ("TYSP"). Commencing in 2015, SW A will provide the output

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			if the Expanded Facility as firm capacity and energy to FPL. … Upon review, we find that the Joint Petitioners are persuasive in their argument that the Expanded Facility will improve electric system reliability and integrity on FPL's system. FPL is currently projecting a need for additional capacity. The Expanded Facility, projected to provide between 70 and 80 MW of firm capacity by 2015, will satisfy a portion of FPL's projected need. Therefore, the SWA Expanded Facility will contribute to the reliability and integrity of FPL's electric system. In addition to providing additional capacity, the Expanded Facility, which will be located in Southeast Florida, has attributes that will address two system concerns for FPL: a) enhancing fuel diversity; and b) maintaining a regional balance between load and generating capacity, particularly in Southeastern Florida. We find that there is a need for the SWA Expanded Facility taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519, F.S.
110309 PSC-12-0187-FOF-EI	FPL	Need Determination	Commission granted a determination of need for Port Everglades plant. "There is a need for Port Everglades Next Generation Energy Center, taking into account the need for electric system reliability and integrity. Based on the 20 percent reserve margin criterion adopted by FPL pursuant to a stipulation with this Commission, FPL projected in its filing that additional capacity to meet firm peak demand will be needed by the summer of 2016. If FPL did not construct PEEC until 2019, the Company's projected reserve margin would drop to 18.2 percent in 2017 and 2018 and would be primarily made up of Demand Side Management resources. After accounting for all projected DSM from cost-effective programs approved by this Commission, FPL' s projections at the time of the filing indicate that by 2016, the Company will have a capacity need of 284 MW in order to adhere to FPL's minimum reserve margin criterion of 20 percent. The timing of FPL's projected need was largely driven by the expiration of existing purchased power agreements totaling 1,306 MW of summer capacity and the decision to place certain units into inactive reserve mode. PEEC will provide 1,277 MW of capacity to help satisfy the Company's capacity needs through 2020."

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	FPL, DEF, TECO	2011 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities, as well as supplemental data provided through data requests, and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2011 Ten-Year Site Plans filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes."
120234 PSC-13-0014-FOF-EI	TECO	Need Determination	Commission granted a determination of need for Polk unit 205 conversion. "We find that there is a need for Polk 2-5 as proposed by TECO to maintain electric system reliability and integrity as this criterion is used in Section 403.519(3), F.S. For planning purposes, TECO utilizes a 20 percent firm reserve margin reliability criteria above the system firm peak demand. After taking into account load growth, existing power plant unit capacity, firm purchased power agreements, and demand-side management (DSM), TECO's summer reserve margin is projected to fall below 20 percent in 2017. By providing up to approximately 459 MW of additional capacity, Polk 2-5 will help TECO meet its needs for additional capacity beginning in 2017."
120314 PSC-13-0164-PAA-EQ	FPL	PPA Approval	Commission approved PPA agreements with U.S. EcoGen. "FPL maintains a planning reserve margin of 20 percent pursuant to a stipulation approved by this Commission.[1] FPL's next major generating additions are the Cape Canaveral Modernization (1,210 MW) in 2013, the Riviera Modernization (1,212 MW) in 2014, and the Port Everglades Modernization (1,277 MW) in 2016, followed by Turkey Point Units 6 and 7 (1,100 MW each) in 2022 and 2023. … The firm capacity to be delivered under the terms of the Contracts, and the resulting potential to defer or delay a portion of FPL's next generating unit, meets

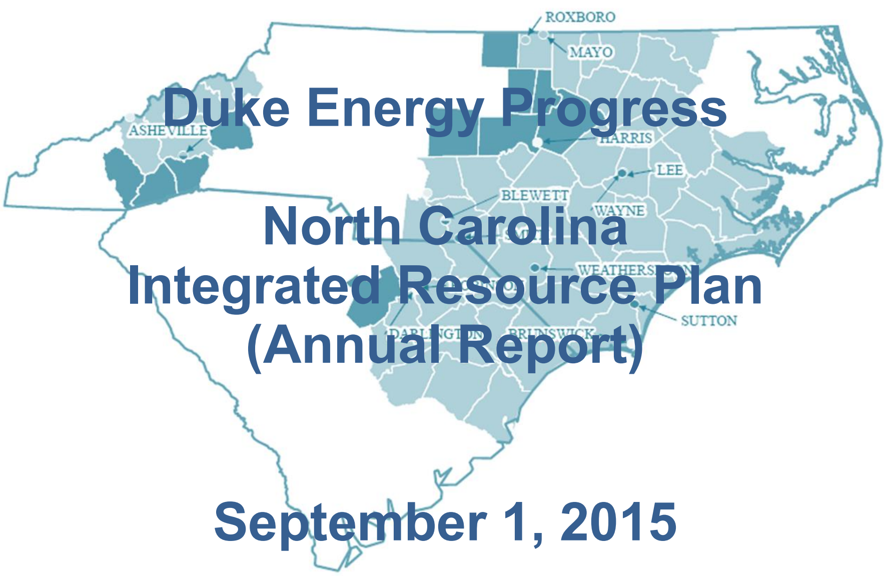
[1] *See* Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 981890-EU - In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			the requirement of Rule 25-17.0832(3)(a), F.A.C. (which addresses the need for capacity by the purchasing utility and the state as a whole). Therefore, upon review, we find that approval of the proposed Contracts will enhance FPL's system reliability, encourage the use of renewable fuels in Florida, and promote fuel diversity for FPL's ratepayers."
	FPL, DEF, TECO	2012 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities, as well as supplemental data provided through data requests, and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2012 Ten-Year Site Plans filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes."
130199 130200 130201 PSC-14-0696-FOF-EU	FPL, DEF, TECO	DSM Goals	The Commission approved DSM Goals based on avoided cost calculation for FPL, FPC and TECO that employed a 20% reserve margin criterion.
	FPL, DEF, TECO	2013 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "Based on its review, the Commission finds the 2013 TYSPs filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes. Since the TYSP is not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's TYSP at a public hearing."
140110 PSC-14-0557-FOF-EI	DEF	Need Determination	Commission granted a determination of need for Citrus County plant. "As described by Witness Borsch, DEF employs two reliability criteria in its resource planning process: (1) a loss of load probability criterion, and (2) a reserve margin criterion. Witness Borsch stated that DEF's resource plans have been reviewed by this Commission each year since the early 1990s in the annual Ten-Year Site Plan review process. Witness Borsch asserted that the Company's need for the

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			proposed Citrus County Plant in the summer of 2018 is driven by the aforementioned reserve margin criterion. DEF's minimum reserve margin threshold is 20 percent and the Company calculates its reserve margin based on the relationship between peak load and total capacity available to serve that load. In addition to DEF's claimed need to satisfy its reserve margin criterion, Witness Borsch testified that the Citrus County Plant would provide reliability and stability to the Florida electric grid as determined by the Florida Reliability Coordinating Council, Inc. … There is no record evidence to indicate the recession has fundamentally altered DEF's expected forecast result for 2018 demand in a manner that casts doubt on the forecast. We find DEF's load forecast presented in this docket to be reasonable for the purposes of determining the need for DEF's proposed Citrus County Plant in 2018. Based on the evidence in the record, if DEF did not construct the proposed Citrus County Plant in 2018, the projected reserve margin could drop as low as 12.3 percent in 2018."
140111 PSC-14-0590-FOF-EI	DEF	Need Determination	Commission granted a determination of need for Hines unit Chiller project. "Based on the evidence in the record, we recalculated DEF's originally filed reserve margin to ensure that the Company still has a reliability need in 2017. Table 2, below, shows that DEF's reserve margin in 2017 would fall to 19 percent absent any new generation. This represents a 94 MW need. Although, the need is relatively small, Witness Borsch testified that the addition of the Hines Project is cost-effective even when the capacity of the project was not needed to meet the Company's reserve margin criteria. We also note that no party in this docket disputed the need for the Hines Project. … Given a 20 percent reserve margin criterion, we find that the evidence in the record demonstrates a need for the Hines Project beginning in 2017. Based on our calculations, if DEF did not construct the proposed Hines Project in 2017, the projected reserve margin could fall below the Company's 20 percent criterion."
	FPL, DEF, TECO	2014 TYSP Review	Commission determined *Ten-Year Site Plans* filed by the utility companies are suitable for planning purposes. "The Commission has reviewed the 2014 Ten-Year Site Plans and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of

Docket No(s). / Order No(s).	Company	Proceeding Type	Commission Statement /Action
			electricity at a reasonable cost. The Commission will continue to monitor the impact of current and proposed EPA Rules and the state's dependence on natural gas for electricity production. Based on its review, the Commission finds the 2014 Ten-Year Site Plans to be suitable for planning purposes. Since the Plans are not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing."

DUKE ENERGY PROGRESS



Duke Energy Progress

North Carolina Integrated Resource Plan (Annual Report)

September 1, 2015

PUBLIC

DEP NC 2015 IRP
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SECTION **PAGE:**

1. INTRODUCTION

For more than a century, Duke Energy Progress (DEP) has provided affordable and reliable electricity to customers in North Carolina (NC) and South Carolina (SC) now totaling more than 1.5 million in number. Each year, as required by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC), DEP submits a long-range planning document called the Integrated Resource Plan (IRP) detailing potential infrastructure needed to match the forecasted electricity requirements for our customers over the next 15 years.

The 2015 IRP is the best projection of how the Company's energy portfolio will look over the next 15 years, based on current data assumptions. This projection will change as variables such as projected load forecasts, fuel prices, new environmental regulations and other outside factors change.

On July 20, 2015, the NCUC ordered that the IRP process between biennial IRPs be significantly streamlined. As such, the remainder of this document provides the information ordered by the NCUC for this update (odd year) IRP.

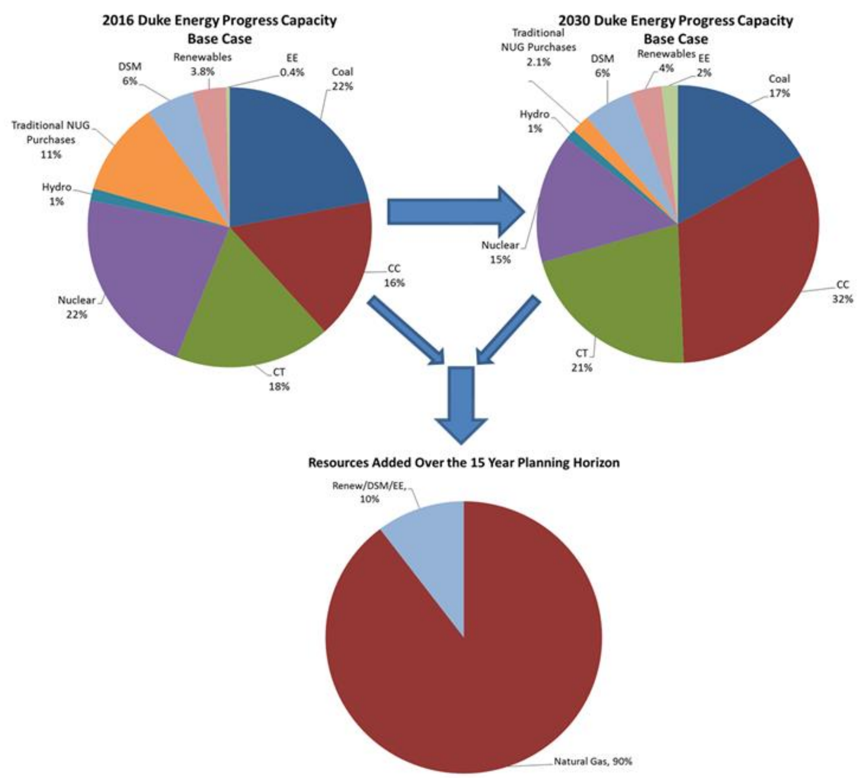
The Company files separate 2015 IRPs for North Carolina and South Carolina. However, the IRP analyzes the system as one DEP utility across both states including customer demand, energy efficiency (EE), demand side management (DSM), renewable resources and traditional supply-side resources. As such, the quantitative analysis contained in both the North Carolina and South Carolina filings is identical, while certain sections dealing with state-specific issues such as state renewable standards or environmental standards may be specific to that state's IRP.

2. 2015 IRP SUMMARY

As 2015 is an update year for the IRP, DEP developed two cases based on the results of the 2014 IRP. The first case, or the "Base Case" is an update to the presented Base Case in the 2014 IRP which includes the expectation of carbon legislation beginning in 2020. Additionally, a "No Carbon Sensitivity" was developed in which no carbon legislation is considered. All results presented in this IRP represent the Base Case, except where otherwise noted.

As shown in the 2015 IRP Base Case, projected incremental needs are driven by load growth and the retirement of aging combustion turbine (CT) and coal-fired resources. The 2015 IRP seeks to achieve a reliable, economic long term power supply through a balance of incremental renewable resources, EE, DSM, nuclear, and traditional supply-side resources planned over the coming years. In order to reliably and affordably meet our customers' needs into the future, the Company projects the need for incremental investments in these resources as depicted in the charts below.

Chart 2-A 2016 and 2030 Base Case Summer Capacity Mix and Sources of Incremental Capacity



The additional assets included over the 15 year planning horizon were selected as the most reliable and affordable resource mix to meet customer demand into the future. Furthermore, the selected mix of renewable resources, EE programs, DSM programs, nuclear generation, and state-of-the-art natural gas facilities also help the Company maintain a diversified resource mix while reducing the environmental footprint associated with each unit of energy production.

3. IRP PROCESS OVERVIEW

To meet the future needs of DEP's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, the Company develops a load forecast of cumulative energy sales and hourly peak demand. To determine total resources needed, the Company considers the peak demand load obligation plus a 17% minimum planning reserve margin. The projected capability of existing resources, including generating units, EE and DSM, renewable resources and purchased power contracts, is measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meet the load obligation and planning reserve margin while complying with all environmental and regulatory requirements. It should be noted that DEP considers the non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with Duke Energy Carolinas (DEC) in the development of its independent Base Case. To accomplish this, DEP and DEC plans are determined simultaneously to minimize revenue requirements of the combined jointly-dispatched system while maintaining independent reserve margins for each company.

The use of a 17% reserve margin represents an increase over last year's IRP that is discussed in more detail in Chapter 4. As discussed in Chapter 4, this increase does not materially impact the near-term resource needs of the Company as projected in the Short-Term Action Plan but rather influences the subsequent years of the plan.

For the 2015 Update IRP, the Company presents a Base Case with a CO_2 tax beginning in 2020. The current assumption of a CO_2 tax is intended to serve as a placeholder for future carbon regulation. Consistent with this assumption, the final Environmental Protection Agency (EPA) Clean Power Plan (CPP) was released in mid-August and each state is in the process of developing individual state plans to comply with the rule as discussed in Chapter 4. Furthermore, a primary focus of this update IRP is the Short-Term Action Plan (STAP) which runs from 2016 to 2020. It was determined that the inclusion of the CO_2 tax did not have a significant impact on the STAP, and therefore the majority of the data presented in this report is taken from the CO_2 case (Base Case).

Figure 3-A represents a simplified overview of the resource planning process in the update years (odd years) of the IRP cycle.

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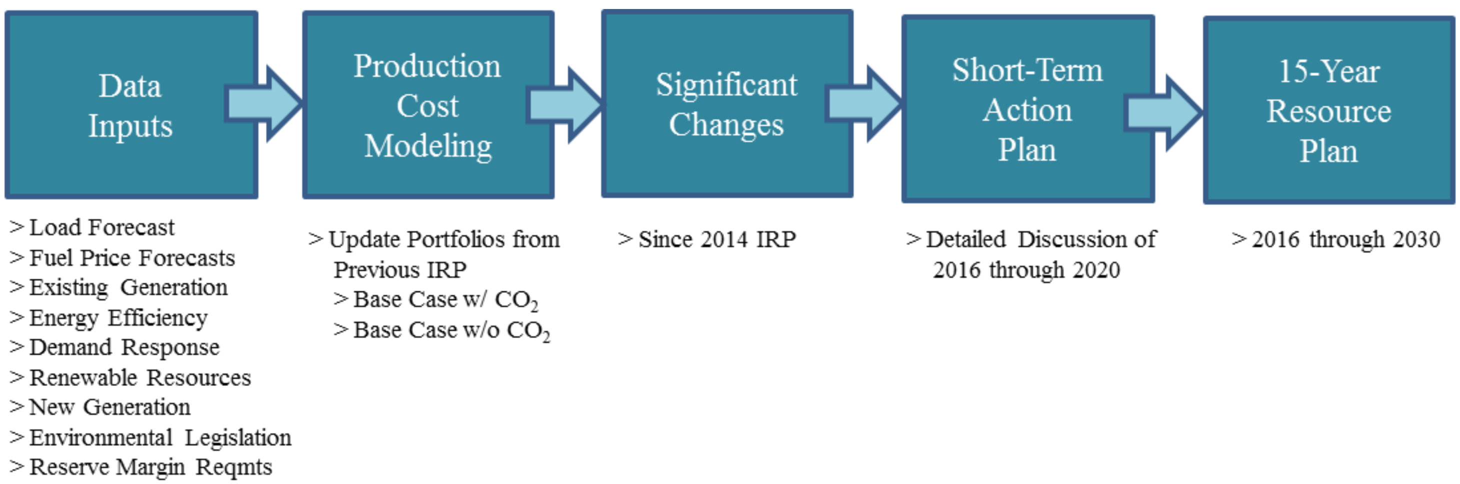
Figure 3-A Simplified IRP Process



4. SIGNIFICANT CHANGES FROM THE 2014 IRP

As an initial step in the IRP process, all production cost modeling data is updated to include the most current and relative data. Throughout the year, best practices are implemented to ensure the IRP best represents the Company's generation system, conservation programs, renewable energy and fuel costs. The data and methodologies are regularly updated and reviewed to determine if adjustments can be made to further improve the IRP process and results.

As part of the review process, certain data elements, with varying impacts on the IRP, inevitably change. A discussion of newly included or updated data elements that had the most substantial impact on the 2015 IRP is provided below.

a) Load Forecast

The 2015 DEP Spring Load Forecast is updated to include the most current data available at this time. The process and models for the load forecast remain the same, however the method by which utility energy efficiency (UEE) [1] impacts are incorporated into the load forecast has changed since the 2014 IRP. UEE programs are energy efficiency programs that were developed and offered to customers by the Company The impacts of UEE on the load forecast do not include load reductions from free-riders. Free-riders are those customers who would have adopted the energy efficiency program regardless of incentives provided by the Company.

Program lives of UEE programs were previously considered indefinite in the IRP process, but in this year's IRP, are more clearly incorporated in the load forecast. Many UEE programs have a finite program life, much like the useful life of any generating resource. By including the useful life of the programs, the Company is better able to account for the UEE programs available to the DEP system, and as such represent a more realistic and accurate representation of these programs. A numerical representation of the impacts of these changes and impacts to the load forecast are included in Chapter 5.

In the development of the load forecast, many variables may cause the load forecast projection to change. A brief comparison of the growth of the DEP load forecast is presented in Table 4-A and a more detailed discussion can be found in Chapter 5.

[1] The term UEE is utilized in the load forecasting sections which represents utility-sponsored EE impacts net of free riders. The term "Gross EE" represents UEE plus naturally occurring energy efficiency in the marketplace.

Table 4-A 2015 DEP Load Forecast Growth Rates vs. 2014 Load Forecast Growth Rates (Retail and Wholesale Customers)

	2015 Forecast (2016 – 2030)			**2014 Forecast (2015 – 2029)**		
	Summer Peak Demand	**Winter Peak Demand**	**Energy**	**Summer Peak Demand**	**Winter Peak Demand**	**Energy**
Excludes impact of new EE programs	1.5%	1.3%	1.2%	1.6%	1.5%	1.3%
Includes impact of new EE programs	1.3%	1.2%	1.2%	1.4%	1.3%	1.0%

b) Renewable Energy

The Company is committed to full compliance with the North Carolina Renewable Energy Portfolio Standard (NC REPS). Currently signed projects and additional resources needed to fully comply with NC REPS are included in the 2015 IRP. There is currently a large influx of solar resources in the interconnection queue in the DEP system. With this influx, more solar projects are utilized to meet the NC REPS general compliance requirement, replacing biomass and wind resources that were represented in the 2014 IRP.

Additionally, the newly approved South Carolina Distributed Energy Resource Program (SC DERP) has been included. The SC DERP was approved by the PSCSC on July 15, 2015. The Company's commitment to meet the increasing goals of this program through 2020 is included in the 2015 IRP.

Finally, growing customer demand for renewable generation is driving the need for additional solar resources. These resources are included as Utility-owned projects and are projected in the IRP. Such projects are incremental to NC REPS or SC DERP compliance renewables. Utility-owned projects include the expected projects procured by the Company that will increase the capacity of renewable generation on the DEP system.

As mentioned above, DEP has seen a large influx of solar resources in the interconnection queue. A summary of the projects currently in the interconnection queue is represented in Table 4-B. The table shows not only the amount of resources, but also the type of resources.

Table 4-B DEP QF Interconnection Queue

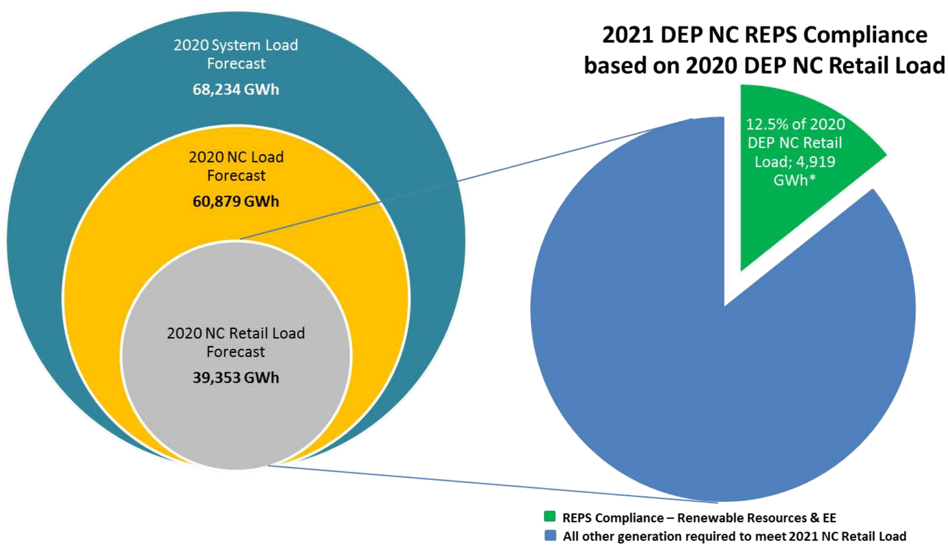
Utility	Facility State	Energy Source Type	Number of Pending Projects	Pending Capacity MW AC
DEP	**NC**	Biogas	2	7
		Biomass	3	53
		Landfill Gas	2	16
		Other	2	1
		Solar	436	3244
		Wood Waste	1	5
DEP	**NC Total**		**446**	**3326**
	SC	Solar	37	605
	SC Total		**37**	**605**
DEP Total			**483**	**3931**

Renewables Compliance

A large portion of the renewable resources added over the planning horizon are a result of complying with NC REPS. The pie charts presented in Chapter 2 above represent the capacity of each asset by fuel type. However, the NC REPS compliance plan sets compliance targets based upon retail energy sales. As such, the renewable *capacity* percentage detailed above is not adequate for determining the Company's compliance with the NC REPS *energy* target.

In an effort to explain NC REPS compliance needs, Chart 4-A shows the energy forecasts and the ultimate NC REPS compliance need for DEP.

Chart 4-A DEP - Meeting NC REPS Compliance



* 4,919 GWh represents the projected amount of Renewables and EE required to meet REPS compliance in 2021 based on the NC Retail load forecast for the year 2020. The cumulative EE and renewables energy on the DEP system is expected to be greater than what is represented here. Additionally, NC REPS allows 65% of the 2021 target to be met by EE and Out of State Renewable Energy Certificates (RECs).

c) Addition of Combined Heat & Power (CHP) to the IRP

Combined Heat and Power (CHP) systems, also known as cogeneration, generate electricity and useful thermal energy in a single, integrated system. CHP is not a new technology, but an approach to applying existing technologies. Heat that is normally wasted in conventional power generation is recovered as useful energy, which avoids the losses that would otherwise be incurred from separate generation of heat and power. CHP incorporating a CT and heat recovery steam generator (HRSG) is more efficient than the conventional method of producing usable heat and power separately via a gas package boiler.

Duke Energy is exploring and working with potential customers with good base thermal loads on a regulated Combined Heat and Power offer. The CHP asset will be included as part of Duke Energy's IRP as a placeholder for future projects as described below. The steam sales are credited back to the revenue requirement of the projects to reduce the total cost of this generation grid resource. Along with the potential to be a competitive cost generation resource, CHP can result in CO_2 emission reductions, and present economic development opportunities for the state.

Projections for CHP have been included in the following quantities in the 2015 IRP:

2019: 20 MW
2021: 20 MW

As CHP continues to be pursued, future IRP processes will incorporate additional CHP as appropriate.

Additional technologies evaluated as part of the 2015 IRP are discussed in Chapter 6.

d) Reserve Margin

In 2012, DEP and DEC hired Astrape Consulting to conduct a reserve margin study for each utility. Astrape conducted a detailed resource adequacy assessment that incorporated the uncertainty of weather, economic load growth, unit availability and transmission availability for emergency tie assistance. Astrape analyzed the optimal planning reserve margin based on providing an acceptable level of physical reliability and minimizing economic costs to customers. The most common physical metric used in the industry is to target a system reserve margin that satisfies the one day in 10 years Loss of Load Expectation (LOLE) standard. This standard is interpreted as one firm load shed event every 10 years due to a shortage of generating capacity. From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. Similarly, as planning reserve margin decreases, the cost of reserves decreases while the costs related to reliability events increase, including the costs to customers of loss of power. Thus, there is an economic optimum point where the cost of additional reserves plus the cost of reliability events to customers is minimized. Based on past reliability assessments, results of the Astrape analysis, and to enhance consistency and communication regarding reserve targets, both DEP and DEC had adopted a 14.5% minimum summer planning reserve margin for scheduling new resource additions.

In 2015, DEP and DEC contracted again with Astrape Consulting to perform an updated resource adequacy study. The Companies believe that the study was warranted at this time due to several factors. First, the severe, extreme weather experienced in the service territory the last two winter periods was so impactful to the systems that additional review with the inclusion of recent years' weather history was warranted. Second, since the last reliability study the system has added, and projects to add, a large amount of resources that provide meaningful capacity benefits in the summer only. From a peak reduction perspective such summer oriented resources include solar generation, HVAC load control and chiller uprates to existing natural gas combined cycle units. The interconnection queue for solar facilities shows potential to add significantly to the solar resources already incorporated in the system.

Initial results of this updated study indicate that a 17% summer planning reserve margin is required to maintain the one day in 10 year LOLE standard. As such, DEP has utilized a 17% planning reserve margin in the 2015 IRP as opposed to the 14.5% reserve margin used in the 2014 IRP. However, preliminary findings also indicate that a summer-only reserve margin target may not be adequate for providing long term reliability given the increasing levels of summer-only resources. Additional study is needed to determine whether dual summer/winter planning reserve margin targets are required in the future. Once the final results are determined, any changes will be included in the 2016 IRP.

Adequacy of Projected Reserves

DEP's resource plan reflects reserve margins ranging from 17.0% to 21.9%. Reserves projected in DEP's IRP meet the minimum planning reserve margin target and thus satisfy the one day in 10 years LOLE criterion. The projected reserve margin exceeds the minimum 17% target by 3% or more in 2016-2018 primarily due to a decrease in the load forecast compared to earlier projections. The projected reserve margin exceeds the target by 3% or more in 2022 as a result of the economic addition of a large combined-cycle facility.

A significant increase in projected solar capacity causes reserves to exceed 3% of the target in 2023. The projected reserve margin also exceeds the target by 3% or more in 2027 as a result of the economic addition of a large block of combustion turbine capacity.

The IRP provides general guidance in the type and timing of resource additions. Since capacity is generally added in large blocks to take advantage of economies of scale, it should be noted that projected planning reserve margins in years immediately following new generation additions will often be somewhat higher than the minimum target. Large resource additions are deemed economic only if they have a lower Present Value Revenue Requirement (PVRR) over the life of the asset as compared to smaller resources that better fit the short-term reserve margin need. Development of detailed self-build projects and utilization of the Request for Proposals (RFP) process to consider purchased power alternatives will ensure the Company selects the most cost-effective resource additions. Reserves projected in DEP's IRP are appropriate for providing an economic and reliable power supply.

e) <u>Fuel Costs</u>

In the 2014 IRP, the first 5 years of natural gas prices were based on market data and the remaining years were based off of fundamental pricing. Market prices represent liquid, tradable gas prices offered at the present time, also called "future or forward prices." These prices represent an actual contractually agreed upon price that willing buyers and sellers agree to transact upon at a specified future date. As such, assuming market liquidity, they represent the markets view of spot prices for a given point in the future. Fundamental prices developed through external econometric models, on the other hand, represent a projection of fuel prices into the future taking into account changing supply and demand assumptions of the changing dynamics of the external marketplace. The natural gas market has become more liquid, and there are now multiple buyers and sellers of natural gas in the marketplace that are willing to transact at longer transaction terms. Due to the evolving natural gas market, DEP and DEC are using market based prices for the first 10 years of the planning period (2016 – 2025). Following the 10 years of market prices, the Companies transition to fundamental pricing over a 5 year period with 100% fundamental pricing in 2030 and beyond.

As in the 2014 IRP, coal prices continue to be based on 5 years of market data in the 2015 IRP. In order to account for the impact on coal prices by using a longer market based natural gas price, the companies are transitioning to fundamental coal pricing over a 10 year period (2021 to 2030), using the same growth rate as natural gas through that time period. Previously the Companies moved to fundamental coal prices once market prices were unavailable, but the

Companies believe this creates an unrealistic disconnect between coal and natural gas prices in the medium term.

f) New Resource Retirements/Additions

Asheville Plant

As part of the Western Carolinas Modernization Project (WCMP) announced in the spring of 2015, the combined 376 MW Asheville 1 & 2 coal units are planned to be retired no later than January 31, 2020. The retired units are expected to be replaced with a 663 MW natural gas combined cycle unit on site in November 2019, along with necessary and associated natural gas delivery and electric transmission infrastructure projects. Additionally, an undetermined amount of solar generation is planned for installation at the same site shortly after the retirement of the coal plants. The Certificate of Public Convenience and Necessity (CPCN) for the new combined cycle unit is expected to be filed with the NCUC in the fourth quarter of 2015. As part of the WCMP, the three fuel oil combustion turbine units totaling 126 MW that were planned for Asheville in 2019, as included in the 2014 DEP IRP Short-Term Action Plan, are no longer necessary and have been removed from the 2015 IRP.

This retirement date for the Asheville coal units represents an acceleration of approximately 10 years from previous planning assumptions. The retirements of the units, and the corresponding investments in the required infrastructure to replace those units, are being accelerated due to a culmination of several factors. These factors include continued declines in natural gas prices, the unique opportunity to take advantage of an economic gas delivery project by the local gas distribution company, and the opportunity to avoid significant investment in additional environmental controls at the coal units that would be required by 2020.

In summary, benefits from the WCMP include, but are not limited to:

- Significant fuel cost reductions through the construction of new transmission infrastructure and combined cycle plant coupled with eliminating the uneconomic utilization of the coal units.
- Avoidance of significant capital expenditures for further environmental controls on the coal units.
- Avoidance of costs associated with three fuel oil combustion turbine units that would be required in the absence of the WCMP.
- Engagement in a unique opportunity to partner with the local gas distribution company to bring cost-effective natural gas supply to the western Carolinas.
- Enhanced reliability following multiple polar vortex events.

Sutton and Lee Inlet Air Chillers

The 2014 IRP called for installation of 137 MW of inlet air chiller technology at Sutton and Lee combined cycle plants prior to the summer of 2018. The most recent analysis of summer reserves shows that these chillers can be delayed until at least the summer of 2019. The 2015 IRP shows installation in May 2019, and a slight downward adjustment of capacity to 135 MW (77 MW at Lee CC and 58 MW at Sutton CC). The benefits to winter capacity from these chillers is not included in the plan as the chiller technology only provides summer peaking capability.

Purchase of NCEMPA Portion of Assets

The North Carolina Eastern Municipal Power Agency (NCEMPA) previously owned partial interest in several Duke Energy Progress plants, including Brunswick Nuclear Plant Units 1 and 2, Mayo Plant, Roxboro Plant Unit 4 and the Harris Nuclear Plant. The Power Agency's ownership interest in these plants represented approximately 700 megawatts of generating capacity. DEP's prior IRPs included NCEMPA's ownership share of the jointly owned assets along with the associated load obligation.

Boards of directors of Duke Energy and the NCEMPA approved an agreement for Duke Energy Progress to purchase the Power Agency's ownership in these generating assets. All required regulatory approvals have been completed and the agreement closed on July 31, 2015. DEP is now 100% owner of these previously jointly owned assets. Under the agreement, Duke Energy Progress will continue meeting the needs of NCEMPA customers previously served by the Power Agency's interest in Duke Energy Progress' plants.

g) EPA Clean Power Plan (CPP)

On August 3, 2015, the EPA signed the final CO_2 emission limits rule for existing fossil-fuel power plants, known as the "Clean Power Plan". The regulation is promulgated under Section 111(d) of the Clean Air Act and is sometimes referred to as "111(d)". The rule is both lengthy (over 1550 pages) and complex. There have been considerable legal questions raised since the initial proposal and the rule remains controversial both at the state and federal levels.

EPA has made substantial changes from the proposed rule it released in June 2014 and a complete analysis will take time. The rule maintains a building block approach and preserves the first three building blocks of heat rate improvement, re-dispatch to natural gas and construction of renewables. Building block 4, which in the proposal established energy efficiency targets, has been eliminated from the final rule. There are new elements in the final rule including additional compliance options, a model trading program and a "clean energy incentive program" to encourage early investments in renewable generation and demand-side energy efficiency.

Regulation under Section 111(d) of the Clean Air Act requires EPA to set the program requirements in a guideline document it issues to the states. The document must include:

"An emission guideline that reflects the application of the best system of emission reduction … that has been adequately demonstrated for designated facilities," taking into account both the "cost of achieving such emission reductions" as well as the "remaining useful life of sources."

States use the EPA guidance document to develop their own regulations – often referred to as a state implementation plan (SIP). States have primary implementation and enforcement authority and responsibility for the regulation.

State emission reduction goals were calculated based on EPA's determination of the "Best System of Emission Reduction" (BSER) for existing plants. Since no technology is commercially available to reduce CO_2 emissions at fossil fueled power plants, EPA proposed that the application of building blocks across the entire electric generation system was appropriate for determining the degree of emission reduction that would be achievable.

States have until September 6, 2016 to submit a complete plan or a partial plan with an extension request. States receiving an extension must submit a final state implementation plan (SIP) by September 6, 2018. EPA plans to take one year to review state plans (this could be a significant challenge for the Agency to accomplish). Duke Energy's compliance obligations will be finalized once a state compliance plan has been approved. If a state chooses not to submit a plan or a plan is deemed to be inadequate, EPA will impose a federal plan on the state.

North Carolina

The North Carolina 2030 rate target increased from 992 lbs. CO_2/MWh (proposed rule) to 1,136 lbs./MWh (final rule). In addition, the final rule includes a 2030 mass cap for North Carolina of 51,266,234 tons of CO_2. It remains unclear if the increased rate will make it easier or more difficult to comply given the uncertainty surrounding the treatment of new natural gas combined cycle (NGCC) units. Early indications are that the NC Department of Environment and Natural Resources (NC DENR) will pursue submittal of a final plan based on what utilities can achieve at the individual affected unit, referred to as 'Building Block 1', to the EPA by the September 2016 deadline. With seven operational coal-fired stations and a growing fleet of NGCC units, the final rule and implementation plan will certainly impact generation in North Carolina, but the extent of these impacts remains unclear.

South Carolina

The South Carolina 2030 rate target increased from 772 lbs. CO_2/MWh (proposed rule) to 1,156 lbs./MWh (final rule). In addition, the final rule includes a 2030 mass cap for South Carolina of 25,998,968 tons of CO_2. The SC Department of Health and Environmental Control has a robust stakeholder group evaluating options and intends to apply for the two year extension, pushing back the date for submittal of a final rule to September 2018. Duke Energy operates no coal-fired generation in South Carolina, so the impact of the rule is anticipated to be minimal.

h) Transmission Planned or Under Construction

This section contains the planned transmission line and substation additions since the 2014 IRP. Only those projects added since the 2014 IRP are included. A discussion of the adequacy of DEP's transmission system is also included. Table 4-C lists the transmission projects that are planned to meet reliability needs. This section also provides information pursuant to the North Carolina Utilities Commission Rule R8-62.

Table 4-C: DEP Transmission Line and Substation Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2016	Falls	-	336	230/115	New
2016	Selma	-	336	230/115	Upgrade
2018[2]	Vanderbilt	West Asheville	307	115	Upgrade
2018[3]	Richmond	Raeford	1195	230	Relocate, new
2018[4]	Ft. Bragg Woodruff St.	Raeford	1195	230	Relocate, new
2019	Craggy	Enka	799	230	New
2019	Asheville Plant	-	448	230/115	New
2020	Jacksonville	Grants Creek	1195	230	New
2020	Newport	Harlowe	681	230	New

[2] The date for this project in the 2014 IRP was 2016. The project has been re-scheduled for 2018.
[3] This project was included in the 2014 IRP, however some parameters have been made and are represented on the following pages.
[4] This project was included in the 2014 IRP, however some parameters have been made and are represented on the following pages.

Rule R8-62: Certificates of environmental compatibility and public convenience and necessity for the construction of electric transmission lines in North Carolina.

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(1) For existing lines, the information required on FERC Form 1, pages 422, 423, 424, and 425, except that the information reported on pages 422 and 423 may be reported every five years.

Please refer to the Company's FERC Form No. 1 filed with NCUC in April, 2015.

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(2) For lines under construction, the following:

a. Commission docket number;
b. Location of end point(s);
c. Length;
d. Range of right-of-way width;
e. Range of tower heights;
f. Number of circuits;
g. Operating voltage;
h. Design capacity;
i. Date construction started;
j. Projected in-service date;

The following pages represent those projects in response to Rule R8-62 parts (1) and (2).

DEP has no transmission line projects currently under construction.

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(3) For all other proposed lines, as the information becomes available, the following:

a. County location of end point(s);
b. Approximate length;
c. Typical right-of-way width for proposed type of line;
d. Typical tower height for proposed type of line;
e. Number of circuits;
f. Operating voltage;
g. Design capacity;
h. Estimated date for starting construction (if more than 6 month delay from last report, explain); and
i. Estimated in-service date (if more than 6-month delay from last report, explain). (NCUC docket no. E-100, sub 62, 12/4/92; NCUC docket no. E-100, sub 78a, 4/29/98.)

The following pages represent those projects in response to Rule R8-62 part (3).

Richmond – Raeford 230 kV Line Loop-In

Project Description: Loop-In the existing 230 kV transmission line from the Richmond 230 kV Substation in Richmond County to the Ft. Bragg Woodruff St 230 kV Substation in Cumberland County at Raeford 230 kV Substation in Hoke County.

a. County location of end point(s); Hoke County
b. Approximate length; 5 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 -120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 1195 MVA
h. Estimated date for starting construction; September 2015
i. Estimated in-service date; June 2018

Ft. Bragg Woodruff St – Raeford 230 kV Line loop-in

Project Description: Loop-In the existing 230 kV transmission line from the Richmond 230 kV Substation in Richmond County to the Ft. Bragg Woodruff St 230 kV Substation in Cumberland County at Raeford 230 kV Substation in Hoke County.

a. County location of end point(s); Hoke County
b. Approximate length; 5 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 1195 MVA
h. Estimated date for starting construction; September 2015
i. Estimated in-service date; June 2018

<u>Craggy – Enka 230 kV Line</u>

Project Description: Construct new 230 kV transmission line from the Craggy 230 kV Substation in Buncombe County to the Enka 230 kV Substation also in Buncombe County.

a. County location of end point(s); Buncombe County
b. Approximate length; 10 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 799 MVA
h. Estimated date for starting construction; September 2016
i. Estimated in-service date; December 2019

<u>Jacksonville – Grants Creek 230 kV Line</u>

Project Description: Construct new 230 kV transmission line from the Jacksonville 230 kV Substation in Onslow County to the Grants Creek 230 kV Substation in Onslow County.

a. County location of end point(s); Onslow County
b. Approximate length; 15 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 1195 MVA
h. Estimated date for starting construction; September 2016
i. Estimated in-service date; June 2020

Newport – Harlowe 230 kV Line

Project Description: Construct new 230 kV transmission line from the Newport 230 kV Substation in Carteret County to the Harlowe 230 kV Substation in Carteret County.

a. County location of end point(s); Carteret County
b. Approximate length; 8 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 681 MVA
h. Estimated date for starting construction; September 2016
i. Estimated in-service date; June 2020

DEP Transmission System Adequacy

DEP monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The DEP transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEP works with DEC, NCEMC and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEP and DEC systems in both North and South Carolina. In addition, transmission planning is coordinated with neighboring systems including South Carolina Electric & Gas (SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between SCE&G, Santee Cooper, DEP, and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEP's Transmission Planning Summary guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC policy and NERC Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades. The transmission system is planned to ensure that no equipment overloads and adequate voltage is maintained to provide reliable service. The most stressful scenario is typically at peak load with certain equipment out of service. A thorough screening process is used to analyze the impact of potential equipment failures or other disturbances. As problems are identified, solutions are developed and evaluated.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEP currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Summary guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the Large and Small Generator Interconnection Procedures in the OATT and the North Carolina Interconnection Procedures.

Southeastern Reliability Corporation (SERC) audits DEP every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEP to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the

Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEP in the fall of 2014. DEP received "No Findings" from the audit team.

DEP participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-balancing authority area transfer capability and interconnection reliability. Each reliability group's purpose is to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;
- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and
- Ensure interconnected system compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

Application of the practices and procedures described above have ensured DEP's transmission system is expected to continue to provide reliable service to its native load and firm transmission customers.

5. LOAD FORECAST

The Duke Energy Progress Spring 2015 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2016 – 2030 and represents the needs of the following customer classes:

- Residential
- Commercial
- Industrial
- Other Retail
- Wholesale

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather and appliance efficiency trends. Population is also used in the Residential customer model. While regression analysis has consistently yielded reasonable results over the years, processes are continually reviewed and compared between jurisdictions in an effort to improve upon the forecasting process. Large unforeseen events however, such as the "great recession" or the loss of large wholesale customers, will cause forecasts to differ from actual results.

The economic projections used in the Spring 2015 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North Carolina and South Carolina.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial.

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electric price and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The projected growth rate of Residential in the Spring 2015 Forecast after all adjustments for Utility EE programs, Solar and Electric Vehicles from 2016-2030 is 1.3%.

The Commercial forecast also uses a SAE model in an effort to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the Commercial class are Offices, Education and Retail. Commercial is expected to be the fastest growing class, with a projected growth rate of 1.5%, after adjustments.

The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output, textile output, and the price of electricity. Overall, Industrial sales are expected to grow 0.9% over the forecast horizon, after all adjustments.

County population projections are obtained from the North Carolina Office of State Budget and Management as well as the South Carolina Budget and Control Board. These are then used to derive the total population forecast for the counties that comprise the DEP service area.

Weather impacts are incorporated into the models by using Heating Degree Days and Cooling Degree Days with a base temperature of 65. The forecast of degree days is based on a 10 year average.

The appliance saturation and efficiency trends are developed by Itron using data from the EIA. Itron is a recognized firm providing forecasting services to the electric utility industry. These appliance trends are used in the residential and commercial sales models.

Peak demands were projected using the SAE approach in the Spring 2015 Forecast. The peak forecast was developed using a monthly SAE model, similar to the sales SAE models, which includes monthly appliance saturations and efficiencies, interacted with weather and the fraction of each appliance type that is in use at the time of monthly peak.

<u>Assumptions</u>

Below are the projected average annual growth rates of several key drivers from DEP's Spring 2015 Forecast.

	2016 - 2030
Real Income	2.7%
Mfg. IPI	2.1%
Population	1.0%

In addition to economic, demographic, and efficiency trends, the forecast also incorporates the expected impacts of utility-sponsored energy efficient programs, as well as projected effects of electric vehicles and behind the meter solar technology.

Wholesale

The wholesale contracts that are included in the load forecast are listed in Table 10-A in Chapter 10.

Historical Values

It should be noted that the long-term structural decline of the Textile industry and the recession of 2008-2009 have had an adverse impact on DEP sales. The worst of the Textile decline appears to be over, and Moody's Analytics expects the Carolina's economy to show solid growth going forward.

In tables 5-A & 5-B below the history of DEP customers and sales are given. As a note, the values in Table 5-B are not weather adjusted.

Table 5-A Retail Customers (Thousands, Annual Average)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Residential	1,123	1,149	1,174	1,195	1,207	1,216	1,221	1,231	1,242	1,257
Commercial	205	210	214	216	215	216	217	219	222	222
Industrial	4	4	4	4	5	5	4	4	4	4
Total	1,332	1,363	1,392	1,415	1,426	1,437	1,443	1,455	1,468	1,484

Table 5-B Electricity Sales (GWh Sold - Years Ended December 31)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Residential	16,003	16,664	16,259	17,200	17,000	17,117	19,108	17,764	16,663	18,201
Commercial	13,019	13,314	13,358	14,033	13,940	13,639	14,184	13,709	13,581	13,887
Industrial	13,036	12,741	12,416	11,883	11,216	10,375	10,677	10,573	10,508	10,321
Military &Other	1,431	1,410	1,419	1,438	1,467	1,497	1,574	1,591	1,602	1,614
Total Retail	43,490	44,129	43,451	44,553	43,622	42,628	45,544	43,637	42,355	44,023
Wholesale	12,439	12,210	12,231	12,656	12,868	12,772	12,772	12,267	12,676	13,578
Total System	55,928	56,340	55,682	57,209	56,489	55,400	58,316	55,903	55,031	57,601

Utility Energy Efficiency

A new process for reflecting the impacts of UEE on the forecast was introduced in Spring 2015. In the latest forecast, the concept of 'Program Life' for a program was included in the calculations. For example, if the accelerated benefit of a residential UEE program is expected to have occurred 7 years before the energy reduction program would have been otherwise adopted, then the UEE effects after year 7 are subtracted ("rolled off") from the total cumulative UEE. With the SAE models framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption.

The table below illustrates this process.

- Column A: Total energy demand for DEP before any reduction for UEE
- Column B: Total incremental cumulative UEE
- Column C: Roll-off amount of the historical UEE programs
- Column D: Roll-off amount of the incremental future UEE programs
- Column E: Total net UEE benefits (column B less columns C & D)
- Column F: Total DEP energy demand after incorporating UEE (column A less column E)

Table 5-C UEE Program Life Process (MWh)

	A	B	C	D	E	F
	Forecast Before EE	Total Cumulative EE	Roll-Off Historical UEE	Roll-Off Forecasted UEE	UEE to Subtract From Forecast	Forecast After UEE
2016	66,805,005	1,611,837	37,998	0	1,573,839	65,231,166
2017	67,539,168	1,789,279	104,966	0	1,684,313	65,854,855
2018	68,364,378	1,968,176	206,527	0	1,761,649	66,602,728
2019	69,176,185	2,144,881	351,978	0	1,792,903	67,383,282
2020	70,004,351	2,321,586	533,731	17,605	1,770,249	68,234,102
2021	70,639,854	2,498,291	733,010	65,593	1,699,688	68,940,166
2022	71,379,803	2,674,996	882,119	172,724	1,620,152	69,759,651
2023	72,151,810	2,851,701	999,141	298,876	1,553,685	70,598,125
2024	73,065,309	3,028,406	1,068,137	438,547	1,521,722	71,543,587
2025	73,863,360	3,205,111	1,098,140	595,656	1,511,315	72,352,045
2026	74,748,903	3,381,816	1,106,441	765,119	1,510,256	73,238,647
2027	75,636,152	3,558,521	1,106,441	948,224	1,503,856	74,132,296
2028	76,674,488	3,735,226	1,106,441	1,139,861	1,488,924	75,185,564
2029	77,495,104	3,911,931	1,106,441	1,338,884	1,466,606	76,028,497
2030	78,426,888	4,088,636	1,106,441	1,540,020	1,442,175	76,984,713

Note: UEE Data is net of free riders

Results

Tabulations of class forecasts and sales are given in Table 5-D and Table 5-E. The sales forecasts are after all adjustments for UEE, Solar and Electric Vehicles.

Table 5-D Retail Customers (Thousands, Annual Average)

	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2016	1,292	225	4	1	1,523
2017	1,309	227	4	2	1,542
2018	1,325	229	4	2	1,560
2019	1,342	231	4	2	1,578
2020	1,358	233	4	2	1,596
2021	1,373	235	4	2	1,614
2022	1,389	237	4	2	1,632
2023	1,404	239	5	2	1,649
2024	1,419	241	5	2	1,667
2025	1,434	244	5	2	1,683
2026	1,448	246	5	2	1,700
2027	1,463	248	5	2	1,717
2028	1,478	250	5	2	1,734
2029	1,492	252	5	2	1,751
2030	1,507	255	5	2	1,767

Table 5-E Electricity Sales (GWh Sold - Years Ended December 31)

	Residential Gwh	Commercial Gwh	Industrial Gwh	Other Gwh	Retail Gwh
2016	17,967	14,043	10,412	1,620	44,042
2017	18,166	14,207	10,497	1,618	44,487
2018	18,383	14,418	10,574	1,615	44,990
2019	18,620	14,635	10,658	1,612	45,525
2020	18,878	14,863	10,758	1,610	46,107
2021	19,095	15,048	10,836	1,607	46,587
2022	19,354	15,252	10,920	1,605	47,130
2023	19,615	15,476	11,020	1,602	47,713
2024	19,897	15,734	11,120	1,600	48,351
2025	20,125	15,952	11,219	1,597	48,894
2026	20,402	16,201	11,316	1,595	49,514
2027	20,681	16,460	11,416	1,593	50,150
2028	21,042	16,756	11,514	1,591	50,904
2029	21,304	17,008	11,611	1,589	51,511
2030	21,616	17,311	11,723	1,587	52,236

Tabulations of the utility's forecasts, including peak loads for summer and winter seasons of each year and annual energy forecasts, both with and without the impact of UEE programs, are shown below in Tables 5-G and 5-H.

Load duration curves, with and without UEE programs, follow Tables 5-G and 5-H, and are shown as Charts 5-A and 5-B.

The values in these tables reflect the loads that Duke Energy Progress is contractually obligated to provide and cover the period from 2016 to 2030.

For the period 2016-2030, the Spring 2015 Forecast resulted in the following growth rates:

Table 5-F Growth Rates of Retail and Wholesale Customers (2016-2030)

	2015 Forecast (2016 – 2030)		
	Summer Peak Demand	**Winter Peak Demand**	**Energy**
Excludes impact of new EE programs	1.5%	1.3%	1.2%
Includes impact of new EE programs	1.3%	1.2%	1.2%

The peaks and sales in the tables and charts below are at the generator, except for the Class sales forecast, which is at meter.

Table 5-G Load Forecast without Energy Efficiency Programs & Before Demand Reduction Program

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2016	13,048	12,767	66,805
2017	13,224	12,938	67,539
2018	13,402	13,133	68,364
2019	13,595	13,342	69,176
2020	13,949	13,531	70,004
2021	14,208	13,703	70,640
2022	14,444	13,882	71,380
2023	14,709	14,062	72,152
2024	14,901	14,278	73,065
2025	15,082	14,437	73,863
2026	15,264	14,621	74,749
2027	15,440	14,797	75,636
2028	15,636	15,022	76,674
2029	15,814	15,183	77,495
2030	15,981	15,352	78,427

Chart 5-A Load Duration Curve without Energy Efficiency Programs & Before Demand Reduction Programs

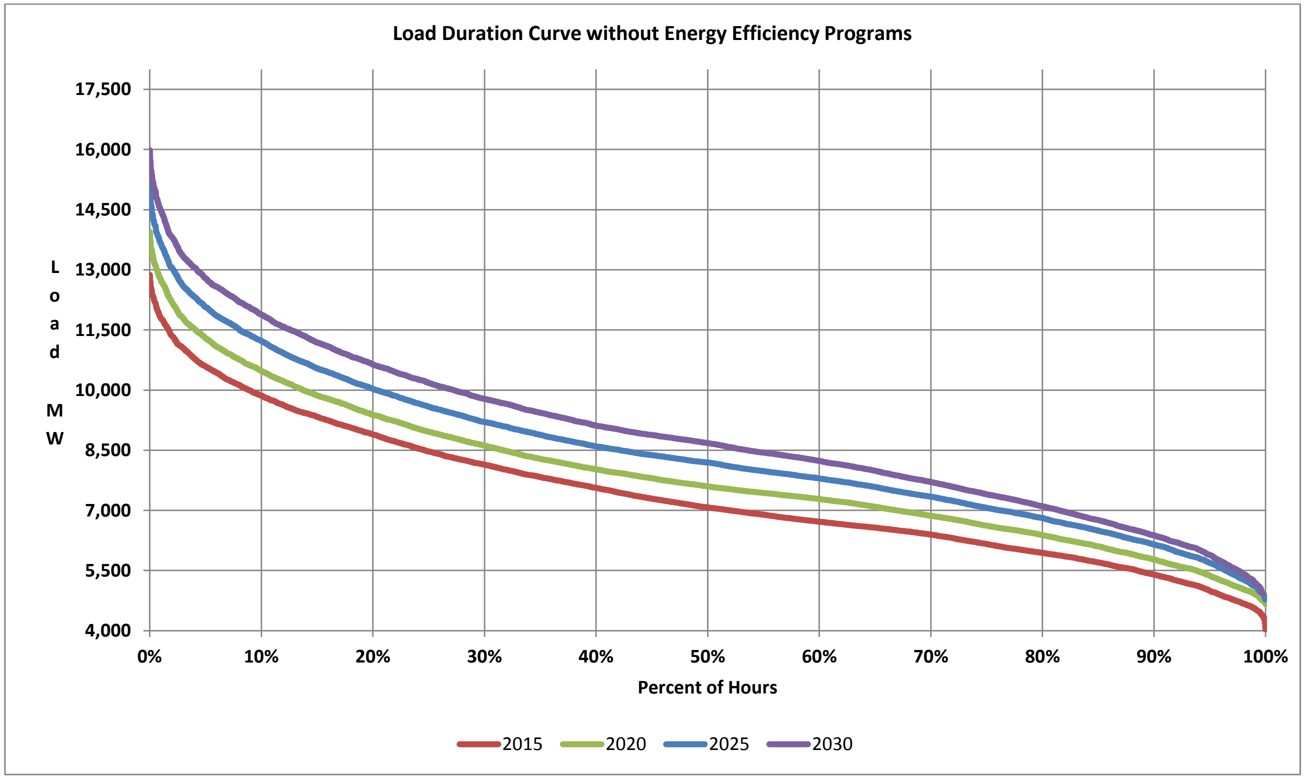
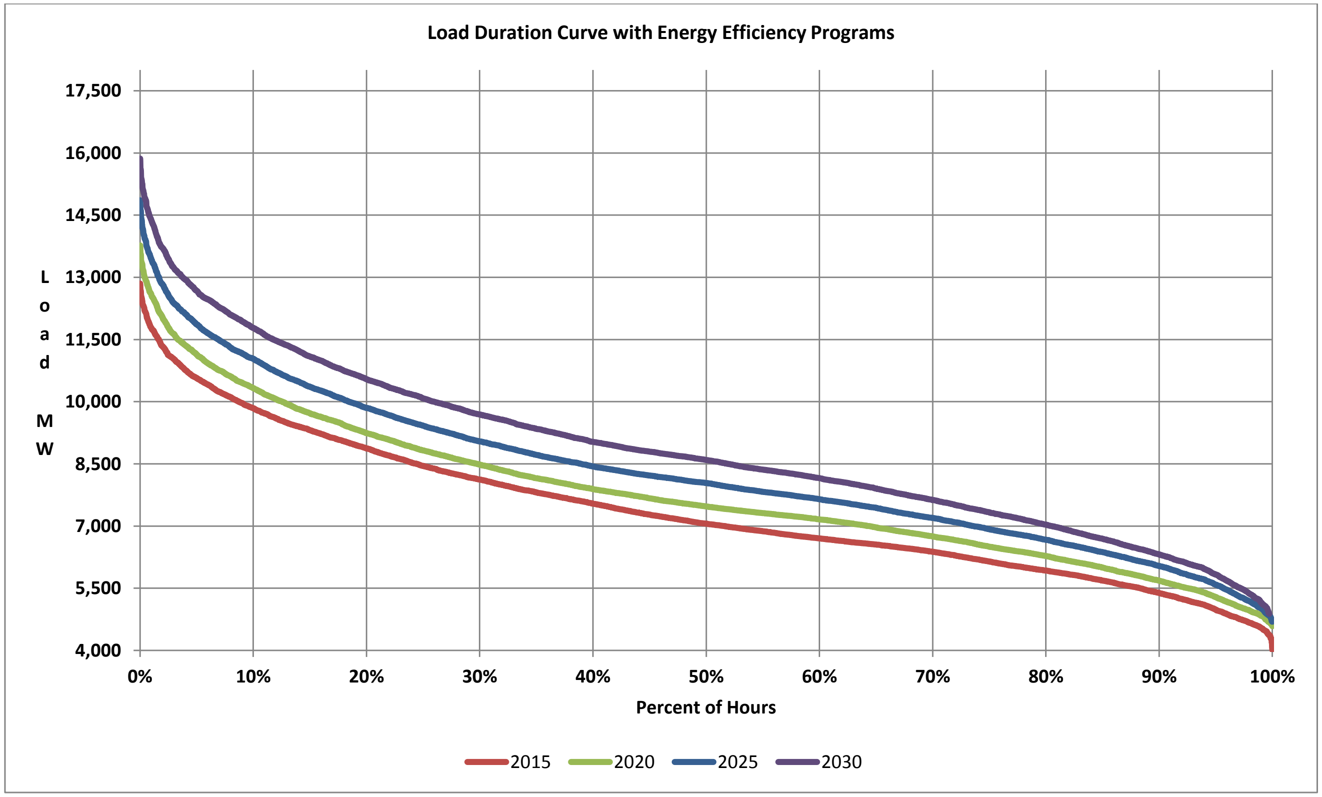


Table 5-H Load Forecast with Energy Efficiency Programs & Before Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2016	12,981	12,727	65,231
2017	13,127	12,877	65,855
2018	13,277	13,050	66,603
2019	13,440	13,236	67,383
2020	13,766	13,403	68,234
2021	13,996	13,552	68,940
2022	14,205	13,711	69,760
2023	14,445	13,872	70,598
2024	14,611	14,070	71,544
2025	14,770	14,211	72,352
2026	14,934	14,381	73,239
2027	15,098	14,548	74,132
2028	15,292	14,772	75,186
2029	15,465	14,930	76,028
2030	15,629	15,096	76,985

Chart 5-B Load Duration Curve with Energy Efficiency Programs & Before Demand Reduction Programs



6. DEVELOPMENT OF RESOURCE PLAN

The following section details the Company's expansion plan and resource mix that is required to meet the needs of DEP's customers over the next 15 years. The section also includes a discussion of the various technologies considered during the development of the IRP, as well as, a summary of the resources required in the "No Carbon" sensitivity case.

Table 6-A Load, Capacity and Reserves Table – Summer

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2015 Annual Plan

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Forecast															
1 Duke System Peak	13,048	13,224	13,402	13,595	13,949	14,208	14,444	14,709	14,901	15,082	15,264	15,440	15,636	15,814	15,981
2 Firm Sale	150	150	150	150	150	150	150	150	150	0	0	0	0	0	0
3 Cumulative New EE Programs	(67)	(96)	(125)	(155)	(183)	(212)	(239)	(265)	(290)	(313)	(330)	(342)	(344)	(349)	(352)
4 Adjusted Duke System Peak	**13,131**	**13,277**	**13,427**	**13,590**	**13,916**	**14,146**	**14,355**	**14,595**	**14,761**	**14,770**	**14,934**	**15,098**	**15,292**	**15,465**	**15,629**
Existing and Designated Resources															
5 Generating Capacity	12,776	12,776	12,813	12,828	12,963	13,194	12,844	12,844	12,844	12,844	12,844	12,844	12,664	12,664	12,664
6 Designated Additions / Uprates	0	98	15	135	1,013	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	(61)	0	0	(782)	(350)	0	0	0	0	0	(180)	0	0	(741)
8 Cumulative Generating Capacity	**12,776**	**12,813**	**12,828**	**12,963**	**13,194**	**12,844**	**12,844**	**12,844**	**12,844**	**12,844**	**12,844**	**12,664**	**12,664**	**12,664**	**11,923**
Purchase Contracts															
9 Cumulative Purchase Contracts	**1,919**	**1,930**	**1,930**	**1,761**	**1,616**	**861**	**528**	**528**	**528**	**528**	**478**	**477**	**452**	**419**	**407**
Non-Compliance Renewable Purchases	177	188	188	188	188	132	131	130	130	130	80	80	58	25	12
Non-Renewables Purchases	1,742	1,742	1,742	1,574	1,429	729	397	397	397	397	397	397	394	394	394
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Combined Cycle	0	0	0	0	0	895	895	0	0	0	0	0	0	0	895
12 Combustion Turbine	0	0	0	0	0	828	0	0	0	0	0	828	0	0	0
13 CHP	0	0	0	20	0	20	0	0	0	0	0	0	0	0	0
Renewables															
14 Cumulative Renewables Capacity	437	473	433	434	437	348	347	619	637	645	639	653	667	677	666
15 Cumulative Production Capacity	**15,132**	**15,217**	**15,191**	**15,179**	**15,268**	**15,816**	**16,378**	**16,648**	**16,666**	**16,674**	**16,618**	**17,280**	**17,269**	**17,246**	**17,377**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**871**	**923**	**967**	**1,004**	**1,021**	**1,029**	**1,032**	**1,034**	**1,037**	**1,040**	**1,043**	**1,046**	**1,049**	**1,052**	**1,055**
17 Cumulative Capacity w/ DSM	**16,003**	**16,140**	**16,159**	**16,183**	**16,288**	**16,845**	**17,409**	**17,683**	**17,703**	**17,715**	**17,662**	**18,326**	**18,319**	**18,298**	**18,432**
Reserves w/ DSM															
18 Generating Reserves	2,872	2,862	2,732	2,593	2,372	2,698	3,054	3,088	2,942	2,945	2,728	3,228	3,027	2,832	2,803
19 % Reserve Margin	**21.9%**	**21.6%**	**20.3%**	**19.1%**	**17.0%**	**19.1%**	**21.3%**	**21.2%**	**19.9%**	**19.9%**	**18.3%**	**21.4%**	**19.8%**	**18.3%**	**17.9%**

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Table 6-B Load, Capacity and Reserves Table – Winter

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2015 Annual Plan

	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Load Forecast														
1 Duke System Peak	12,767	12,938	13,133	13,342	13,531	13,703	13,882	14,062	14,278	14,437	14,621	14,797	15,022	15,183
2 Firm Sale	150	150	150	150	150	150	150	150	150	0	0	0	0	0
3 Cumulative New EE Programs	(40)	(62)	(84)	(105)	(129)	(151)	(171)	(190)	(209)	(226)	(240)	(249)	(250)	(253)
4 Adjusted Duke System Peak	**12,877**	**13,027**	**13,200**	**13,386**	**13,553**	**13,702**	**13,861**	**14,022**	**14,220**	**14,211**	**14,381**	**14,548**	**14,772**	**14,930**
Existing and Designated Resources														
5 Generating Capacity	13,895	13,899	13,917	13,935	14,289	13,772	13,772	13,772	13,772	13,772	13,772	13,772	13,540	13,540
6 Designated Additions / Uprates	4	94	18	733	350	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	(76)	0	(379)	(867)	0	0	0	0	0	0	(232)	0	0
8 Cumulative Generating Capacity	**13,899**	**13,917**	**13,935**	**14,289**	**13,772**	**13,772**	**13,772**	**13,772**	**13,772**	**13,772**	**13,772**	**13,540**	**13,540**	**13,540**
Purchase Contracts														
9 Cumulative Purchase Contracts	**2,006**	**2,017**	**2,017**	**2,017**	**1,704**	**1,148**	**502**	**502**	**502**	**502**	**452**	**452**	**441**	**434**
Non-Compliance Renewable Purchas	126	137	137	137	137	81	80	80	80	80	30	30	22	15
Non-Renewables Purchases	1,880	1,880	1,880	1,880	1,567	1,066	422	422	422	422	422	422	419	419
Undesignated Future Resources														
10 Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Combined Cycle	0	0	0	0	0	935	935	0	0	0	0	0	0	0
12 Combustion Turbine	0	0	0	0	0	878	0	0	0	0	0	878	0	0
13 CHP	0	0	0	20	0	20	0	0	0	0	0	0	0	0
Renewables														
13 **Cumulative Renewables Capacity**	222	257	216	216	218	129	129	178	174	177	176	179	178	183
14 Cumulative Production Capacity	**16,127**	**16,191**	**16,168**	**16,542**	**15,714**	**16,901**	**17,191**	**17,240**	**17,236**	**17,239**	**17,188**	**17,837**	**17,826**	**17,823**
Demand Side Management (DSM)														
15 Cumulative DSM Capacity	**531**	**552**	**569**	**583**	**595**	**606**	**610**	**613**	**617**	**621**	**624**	**628**	**631**	**634**
16 Cumulative Capacity w/ DSM	**16,658**	**16,743**	**16,737**	**17,125**	**16,310**	**17,508**	**17,800**	**17,853**	**17,853**	**17,860**	**17,813**	**18,464**	**18,456**	**18,457**
Reserves w/ DSM														
17 Generating Reserves	3,781	3,716	3,537	3,739	2,757	3,806	3,940	3,831	3,633	3,648	3,432	3,916	3,684	3,527
18 % Reserve Margin	**29.4%**	**28.5%**	**26.8%**	**27.9%**	**20.3%**	**27.8%**	**28.4%**	**27.3%**	**25.6%**	**25.7%**	**23.9%**	**26.9%**	**24.9%**	**23.6%**

DEP - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer Projections of Load, Capacity, and Reserves table. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke Energy Progress System.

2. Firm sale of 150 MW through 2024.

3. Cumulative energy efficiency and conservation programs (does not include demand response programs).

4. Peak load adjusted for firm sales and cumulative energy efficiency.

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of January 1, 2015.

   Includes total unit capacity of jointly owned units.

6. Capacity Additions include:

   Planned nuclear uprates totaling 29 MW in the 2017-2018 timeframe.

   Planned combined cycle uprates totaling 135 MW in 2019.

   84 MW Sutton Blackstart combustion turbine addition in 2017.

   A short-term 350 MW PPA is included in 2017, and removed in the fall of 2017.

   This PPA is a placeholder to ensure compliance with the minimum planning reserve margin and will be re-evaluated in the coming months.

7. Planned Retirements include:

   Sutton CT Units 1, 2A and 2B in 2017 (61 MW).

   Darlington CT Units 1-11 by 2020 (553 MW).

   Blewett CT Units 1-4 and Weatherspoon CT units 1-4 in 2027 (180 MW).

   Robinson 2 in 2030 (741 MW).

8. Sum of lines 5 through 7.

DEP - Assumptions of Load, Capacity, and Reserves Table (cont.)

9. Cumulative Purchase Contracts have several components:

   Purchased capacity from PURPA Qualifying Facilities, Anson and Hamlet CT tolling, Butler Warner purchase, Southern CC purchase, and Broad River CT purchase.

   Additional line items are shown under the total line item to show the amounts of renewable and traditional resource purchases. Renewables in these line items are not used for NC REPS compliance.

10. New nuclear resources economically selected to meet load and minimum planning reserve margin Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

    No new nuclear resources were selected in the Base Case in the 15 year study period.

11. New combined cycle resources economically selected to meet load and minimum planning reserve margin.

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

    Addition of 895 MW of combined cycle capacity in 2021, 2022 and 2030.

12. New combustion turbine resources economically selected to meet load and minimum planning reserve margin.

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

    Addition of 828 MW of combustion turbine capacity in 2021 and 2027.

13. New CHP resources. 20 MW in 2019 and 20 MW in 2021.

14. Cumulative solar, biomass, hydro and wind resources to meet NC REPS and SC DERP compliance.

    Also includes utility-owned solar.

DEP - Assumptions of Load, Capacity, and Reserves Table (cont.)

15. Sum of lines 8 through 14.

16. Cumulative Demand Side Management programs including load control and DSDR.

17. Sum of lines 15 and 16.

18. The difference between lines 17 and 4.

19. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

    Line 18 divided by Line 4.

    Minimum target planning reserve margin is 17%.

Technologies Considered

Similar to the 2014 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels in order to meet future generation needs in the 2015 IRP.

As in the 2014 IRP, the Company conducted an economic screening analysis of various technologies. Through the screening process the following technologies were considered as part of the more detailed quantitative analysis phase of the planning process in the 2015 IRP, with changes from the 2014 IRP highlighted and explained in further detail below.

- Base load – 723 MW Supercritical Pulverized Coal with CCS
- Base load – 525 MW IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear units (AP1000)
- Base load – **895 MW** – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Duct Fired)
- **Base load – 20 MW – CHP** (CT with HRSG)
- Peaking/Intermediate – **828 MW** 4-7FA CTs
- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Landfill Gas
- Renewable – 25 MW Solar Photovoltaic (PV)

Combined Cycle base capacities and technologies: Based on proprietary third party engineering studies, the 2x2x1 Advanced CC saw an increase in base load of 29 MWs. The older version base 2x1 CC and the 3x1 Advanced CC were not considered in the updated IRP. However, as the Company begins the process of evaluating particular technologies for future undesignated generation needs, these technologies, along with other new technologies, may be considered based on factors such as generation requirements, plot size, new environmental regulations, etc.

Combustion Turbine base capacities and technologies: Based on proprietary third party engineering studies, the F-Frame CT technology saw an increase in base load of 36 MWs. The LM6000 CTs were not considered in the updated IRP. However, as the Company begins the process of evaluating particular technologies for future undesignated generation needs, these technologies, along with other new technologies, may be considered based on factors such as generation requirements, plot size, new environmental regulations, etc.

CHP: As mentioned previously, two 20-MW Combined Heat & Power units are considered in the 2015 IRP and are included as resources for meeting future generation needs. Duke Energy is exploring and working with potential customers with good base thermal loads on a regulated CHP offer and, as CHP continues to be implemented, future IRP processes will incorporate additional CHP as appropriate.

In addition to the technologies listed above, Li-ion batteries with off-peak charging were considered in the screening process as an energy storage option. Energy Storage in the form or battery storage is becoming more feasible with the advances in battery technology and the reduction in battery cost; however, their uses have been concentrated on frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e. solar and wind applications).

Centralized generation will likely remain the backbone of the grid for Duke Energy in the long term; however, in addition to centralized generation it is possible that distributed generation will begin to share more and more grid responsibilities over time as technologies such as energy storage increase our grid's flexibility. At this point however, the screening analysis shows that costs are still prohibitive for large scale battery technologies to be considered in the IRP.

Expansion Plan and Resource Mix

A tabular presentation of the 2015 Base Case resource plan represented in the above LCR table is shown below:

Table 6-C DEP Base Case Resources– Summer (with CO_2)

Duke Energy Progress Resource Plan (1) Base Case - Summer		
Year	**Resource**	**MW**
2016	-	-
2017	Sutton Blackstart CTs / Nuclear Uprates	84 / 14
2018	Nuclear Uprates	15
2019	CC Uprates / CHP	135 / 20
2020	Asheville CC	663
2021	New CC / New CT / CHP	895 / 828 / 20
2022	New CC	895
2023	-	-
2024	-	-
2025	-	-
2026	-	-
2027	New CT	828
2028	-	-
2029	-	-
2030	New CC	895

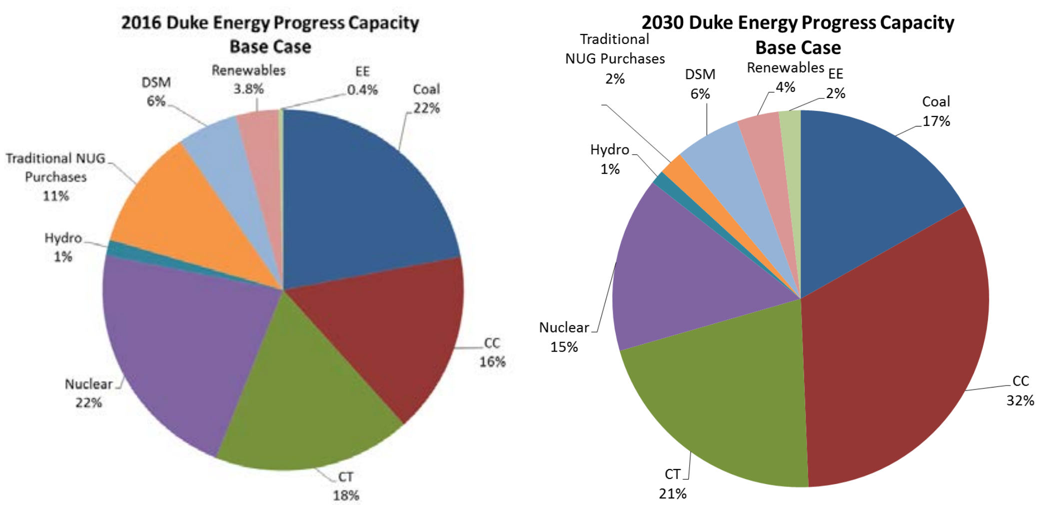
Notes: (1) Table includes both designated and undesignated capacity additions

Table 6-D DEP Base Case Resources (with CO_2) Cumulative Summer Totals

DEP Base Case Resources Cumulative Summer Totals - 2016 - 2030	
Nuclear	29
CC	3483
CT	1740
CHP	40
Total	5292

The following charts illustrate both the current and forecasted capacity by fuel type for the DEP system, as projected in the Base Case. As demonstrated in Chart 6-A, the capacity mix for the DEP system changes with the passage of time. In 2030, the Base Case projects that DEP will have a smaller reliance on coal and a higher reliance on gas-fired resources, nuclear, renewable resources and EE as compared to the current state.

Chart 6-A 2016 & 2030 Base Case Summer Capacity Mix



As a sensitivity, the Company developed a No Carbon Price scenario (No Carbon Sensitivity). The expansion plan for this case is shown below in Table 6-E. Table 6-F summarizes the capacity additions for the No Carbon Sensitivity case by technology type.

Table 6-E No Carbon Sensitivity – Summer

Duke Energy Progress Resource Plan (1)
No Carbon Sensitivity - Summer

Year	Resource			MW		
2016	-			-		
2017	Sutton Blackstart CTs	Nuclear Uprates		84	14	
2018	Nuclear Uprates			15		
2019	CC Uprates	CHP		135	20	
2020	Asheville CC			663		
2021	New CT	New CC	CHP	828	895	20
2022	New CT			414		
2023	-			-		
2024	New CT			414		
2025	-			-		
2026	-			-		
2027	New CT			414		
2028	New CT			414		
2029	-			-		
2030	New CT			1242		

Notes: (1) Table includes both designated and undesignated capacity additions

Table 6-F No Carbon Sensitivity Cumulative Summer Totals

DEP No Carbon Sensitivity Resources
Cumulative Summer Totals - 2016 - 2030

Nuclear	29
CC	1693
CT	3810
CHP	40
Total	5572

7. SHORT-TERM ACTION PLAN

The Company's Short-Term Action Plan, which identifies accomplishments in the past year and actions to be taken over the next five years, is summarized below:

Continued Reliance on EE and DSM Resources

The Company is committed to continuing to grow the amount of EE and DSM resources utilized to meet customer growth. The following are the ways in which DEP will increase these resources:

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of EE and DSM programs spanning the residential, commercial, and industrial classes.

- Continue on-going work to develop and implement additional cost-effective EE and DSM products and services. Since the last biennial IRP, DEP has implemented the following new program offerings: Residential New Construction Program, Energy Efficient Lighting Program and Small Business Energy Saver Program.

- Continue to seek enhancements to the Company's EE/DSM portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results and (3) other EE research & development pilots.

- Over the 5 year period represented in the Short-Term Action Plan, DEP projects to add an incremental 115 MW of EE and 149 MW of DSM.

Continued Focus on Renewable Energy Resources

- DEP is committed to full compliance with NC REPS in North Carolina and SC DERP in South Carolina. Due to pending expiries of Federal and State tax subsidies for solar development, the Company has experienced a substantial increase in solar QFs in the interconnection queue. With this significant level of interest in solar development, DEP continues to procure renewable purchase power resources, when economically viable, as part of its Compliance Plans. DEP is also pursuing the addition of new utility-owned solar on the DEP system.

- DEP continues to evaluate market options for renewable generation and procure capacity, as appropriate. PPAs have been signed with developers of solar PV and landfill gas resources. Additionally, REC purchase agreements have been executed for purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities.

- DEP continues to pursue CHP opportunities, as appropriate.

Addition of Clean Natural Gas Resources

- Begin construction on the Sutton Blackstart CTs in 2016 to be available for the summer peak of 2017. The Company's petition for a Certificate of Public Convenience and Necessity (CPCN) was approved by the NCUC with an order issued on August 3, 2015.

- Pursue the addition of a new combined cycle at the Asheville facility in the 2019 timeframe as part of the WCMP.

- Continue to evaluate older CTs on the DEP system. The Company is evaluating the condition and economic viability of the older CTs on the system. In doing so, DEP is preparing for the potential retirement of these units. This includes determining the type of resources needed to reliably replace these units to maintain a minimum planning reserve margin.

- Take actions to ensure capacity needs beginning in 2021 are met. In addition to seeking to meet the Company's EE and DSM goals and meeting the Company's NC REPS and SC DERP requirements, actions to secure additional capacity may include purchased power, short-term PPAs or Company-owned generation. The 2015 IRP projects that the best resources to meet this 2021 demand are combined cycle units.

- Placeholder for a short-term PPA of 350 MW is included in 2017 to meet 17% reserve margin. This will continue to be reviewed in future IRPs.

Expiration of Wholesale Purchase Contracts (CONFIDENTIAL)

In the 2016-2020 timeframe, DEP has [redacted] of wholesale purchase contracts that are scheduled to expire. At this time, DEP is not relying on contract extensions on these contracts. As such, these contract expirations are included in the IRP and Short-Term Action Plan. A summary of those expirations is shown in Table 7-A below. In addition to the expirations shown in this five year period, additional contracts expire during the 15 year IRP study period.

Table 7-A Wholesale Purchase Contract Expirations (CONFIDENTIAL)

[redacted]

Continued Focus on System Reliability and Resource Adequacy for DEP System

As previously stated, DEP has retained Astrape Consulting to conduct a reserve margin study to examine the resource adequacy of the DEP system. Based upon the recent extreme winter weather, the potential for continued extreme weather, and the large amount of expected solar resource additions, the Company felt that new examination of the reliability of the system and the adequacy of the resources was warranted.

Initial results of this updated study indicate that a 17% summer planning reserve margin is required to maintain the one day in 10 year loss of load expectation (LOLE). As such, DEP has utilized a 17% planning reserve margin in the 2015 IRP as opposed to the 14.5% reserve margin used in the 2014 IRP. However, preliminary findings also indicate that a summer-only reserve margin target may not be adequate for providing long term reliability given the increasing levels of summer-only resources. Additional study is needed to determine whether dual summer/winter planning reserve margin targets are required in the future. Once the final results are determined, any changes will be included in the 2016 IRP.

The 2015 IRP includes a placeholder for a short-term 350 MW purchased power agreement (PPA) in 2020 to satisfy the increase in the planning reserve margin to 17%. The need for this short-term PPA will be reevaluated after the reserve margin study is completed and there is greater certainty regarding reserve margin target(s), load and resource needs.

Continued Focus on Regulatory, Environmental Compliance & Wholesale Activities

- Retired older coal generation. As of December 2013, all of DEP's older, un-scrubbed coal units have been retired. DEP has retired 1,600 MW of older coal units in total since 2011.

- Retire Asheville coal units. The Company expects to retire the existing Asheville coal units no later than January 31, 2020 and replace with new combined cycle generation as part of the WCMP. The Asheville units have a combined capacity of 376 MW.

- Continue to prepare for the final rule of EPA's Clean Power Plan.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with existing and potential environmental regulations such as MATS, the Coal Combustion Residuals rule, the Cross State Air Pollution Rule (CSAPR), and the new Ozone National Ambient Air Quality Standard (NAAQS).

- Aggressively pursue compliance in North Carolina and South Carolina in addressing coal ash management and ash pond remediation. Ensure timely compliance plans and their associated costs are contemplated within the planning process and future integrated resource plans, as appropriate.

- Continue to pursue existing and potential opportunities for wholesale power sales agreements within the Duke Energy balancing authority area.

- Continue to monitor energy-related statutory and regulatory activities.

- Continue to examine the benefits of joint capacity planning and pursue appropriate regulatory actions.

A summarization of the capacity resources for the reference plan in the 2015 IRP is shown in Table 7-B below. Capacity retirements and additions are presented as incremental values in the year in which the change is projected to occur. The values shown for renewable resources, EE and DSM represent cumulative totals.

Table 7-B DEP Short-Term Action Plan

Duke Energy Progress Short-Term Action Plan								
			Compliance Renewable Resources (Cumulative Nameplate MW)			Other Non-Compliance Renewables (Cumulative Nameplate MW) (4)		
Year	Retirements	Additions	Wind (1)	Solar (1)	Biomass/Hydro (3)	Solar/Biomass/Hydro	EE	DSM (2)
2016			0	459	171	397	67	871
2017	61 MW Sutton CTs (Units 1, 2A, 2B)	84 MW Sutton Blackstart CTs 14 MW Nuc Uprate	0	462	206	409	96	923
2018		15 MW Nuc Uprate	0	465	164	408	125	967
2019		20 MW CHP 135 MW CC Uprate	0	467	164	407	155	1004
2020	406 MW Darlington CT (Units 1-3, 5, 7-10) 376 MW Asheville Coal	663 MW Asheville CC 350 MW CT PPA (5)	0	468	167	407	183	1021

Notes:

(1) Capacity is shown in nameplate ratings. For planning purposes, wind presents a 13% contribution to peak and solar has a 44% contribution to peak.

(2) Includes impacts of grid modernization.

(3) Biomass includes swine and poultry contracts.

(4) Other renewables includes NUGs and utility-owned projects.

(4) This is a placeholder PPA for 2020, and removed in 2021.

8. OWNED GENERATION

DUKE ENERGY PROGRESS OWNED GENERATION

Duke Energy Progress' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Progress-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2014, Duke Energy Progress' nuclear and coal-fired generating units met the vast majority of customer needs by providing 46% and 26%, respectively, of Duke Energy Progress' energy from generation. Hydroelectric generation, Combustion Turbine generation, Combined Cycle generation, solar generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

The tables below list the Duke Energy Progress' plants in service in North Carolina (NC) and South Carolina (SC) with plant statistics, and the system's total generating capability.

Existing Generating Units and Ratings [1, 3]
All Generating Unit Ratings are as of December 31, 2014 unless otherwise noted.

Coal						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Asheville	1	192	191	Arden, NC	Coal	Base
Asheville	2	187	185	Arden, NC	Coal	Base
Mayo [2]	1	746	727	Roxboro, NC	Coal	Base
Roxboro	1	380	379	Semora, NC	Coal	Base
Roxboro	2	673	671	Semora, NC	Coal	Base
Roxboro	3	698	691	Semora, NC	Coal	Base
Roxboro [2]	4	711	698	Semora, NC	Coal	Base
Total Coal		3,587	3,542			

Combustion Turbines						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Asheville	3	185	164	Arden, NC	Natural Gas/Oil	Peaking
Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking
Blewett	1	17	13	Lilesville, NC	Oil	Peaking
Blewett	2	17	13	Lilesville, NC	Oil	Peaking
Blewett	3	17	13	Lilesville, NC	Oil	Peaking
Blewett	4	17	13	Lilesville, NC	Oil	Peaking
Darlington	1	63	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	2	64	48	Hartsville, SC	Oil	Peaking
Darlington	3	63	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	4	66	50	Hartsville, SC	Oil	Peaking
Darlington	5	66	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	6	62	45	Hartsville, SC	Oil	Peaking
Darlington	7	65	51	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	8	66	48	Hartsville, SC	Oil	Peaking
Darlington	9	65	52	Hartsville, SC	Oil	Peaking
Darlington	10	65	51	Hartsville, SC	Oil	Peaking
Darlington	11	67	52	Hartsville, SC	Oil	Peaking
Darlington	12	133	118	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking
Smith [4]	1	183	157	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	2	183	156	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	3	185	155	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	4	186	159	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	6	187	153	Hamlet, NC	Natural Gas/Oil	Peaking
Sutton	1	12	11	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2A	31	24	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2B	33	26	Wilmington, NC	Oil/Natural Gas	Peaking
Wayne	1/10	192	177	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	2/11	192	174	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	3/12	193	173	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	4/13	185	170	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	5/14	197	169	Goldsboro, NC	Oil/Natural Gas	Peaking
Weatherspoon	1	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	2	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	3	41	33	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	4	41	31	Lumberton, NC	Natural Gas/Oil	Peaking
Total NC		2,561	2,208			
Total SC		978	787			
Total CT		3,539	2,995			

Combined Cycle

	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	CT1A	223	177	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1B	222	176	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1C	223	179	Goldsboro, NC	Natural Gas/Oil	Base
Lee	ST1	379	378	Goldsboro, NC	Natural Gas/Oil	Base
Smith [4]	CT7	189	160	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT8	189	157	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST4	175	165	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT9	214	178	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT10	214	178	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST5	246	250	Hamlet, NC	Natural Gas/Oil	Base
Sutton	CT1A	225	179	Wilmington, NC	Natural Gas/Oil	Base
Sutton	CT1B	225	179	Wilmington, NC	Natural Gas/Oil	Base
Sutton	ST1	267	264	Wilmington, NC	Natural Gas/Oil	Base
Total CC		2,991	2,620			

Hydro

	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Blewett	1	4	4	Lilesville, NC	Water	Intermediate
Blewett	2	4	4	Lilesville, NC	Water	Intermediate
Blewett	3	4	4	Lilesville, NC	Water	Intermediate
Blewett	4	5	5	Lilesville, NC	Water	Intermediate
Blewett	5	5	5	Lilesville, NC	Water	Intermediate
Blewett	6	5	5	Lilesville, NC	Water	Intermediate
Marshall	1	2	2	Marshall, NC	Water	Intermediate
Marshall	2	2	2	Marshall, NC	Water	Intermediate
Tillery	1	21	21	Mt. Gilead, NC	Water	Intermediate
Tillery	2	18	18	Mt. Gilead, NC	Water	Intermediate
Tillery	3	21	21	Mt. Gilead, NC	Water	Intermediate
Tillery	4	24	24	Mt. Gilead, NC	Water	Intermediate
Walters	1	36	36	Waterville, NC	Water	Intermediate
Walters	2	40	40	Waterville, NC	Water	Intermediate
Walters	3	36	36	Waterville, NC	Water	Intermediate
Total Hydro		227	227			

Nuclear						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Brunswick [2]	1	975	938	Southport, NC	Uranium	Base
Brunswick[2]	2	953	932	Southport, NC	Uranium	Base
Harris [2]	1	973	928	New Hill, NC	Uranium	Base
Robinson	2	797	741	Hartsville, SC	Uranium	Base
Total NC		2,901	2,798			
Total SC		797	741			
Total Nuclear		3,698	3,539			

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
TOTAL DEP SYSTEM - N.C.	12,267	11,395
TOTAL DEP SYSTEM - S.C.	1,775	1,528
TOTAL DEP SYSTEM	14,042	12,923

Note 1: Ratings reflect compliance with NERC reliability standards and are gross of co-ownership interest as of 12/31/14.
Note 2: DEP's purchase of NCEMPA's interest in these power plants was closed on July 31, 2015. DEP is now 100% owner of these previously jointly owned assets.
Note 3: Resource type based on NERC capacity factor classifications which may alternate over the forecast period.
Note 4: Richmond County Plant renamed to Sherwood H. Smith Jr. Energy Complex.

Planned Uprates			
Unit	**Date**	**Winter MW**	**Summer MW**
Brunswick 2 [1]	June 2017	10	10
Harris 1 [1]	June 2017	4	4
Harris 1[1]	June 2019	15	15
Lee CC CT1A [1]	May 2019	25.7	25.7
Lee CC CT1B [1]	May 2019	25.7	25.7
Lee CC CT1C [1]	May 2019	25.7	25.7
Sutton CC CT1A [1]	May 2019	29.0	29.0
Sutton CC CT1B [1]	May 2019	29.0	29.0

Note 1: Capacity not reflected in Existing Generating Units and Ratings section.

Retirements				
Unit & Plant Name	**Location**	**Capacity (MW) Winter / Summer**	**Fuel Type**	**Retirement Date**
Cape Fear 5	Moncure, NC	148 / 144	Coal	10/1/12
Cape Fear 6	Moncure, NC	175 / 172	Coal	10/1/12
Cape Fear 1A	Moncure, NC	14 / 11	Combustion Turbine	3/31/13
Cape Fear 1B	Moncure, NC	14 / 12	Combustion Turbine	3/31/13
Cape Fear 2A	Moncure, NC	15 / 12	Combustion Turbine	3/31/13
Cape Fear 2B	Moncure, NC	14 / 11	Combustion Turbine	10/1/12
Cape Fear 1	Moncure, NC	12 / 11	Steam Turbine	3/31/11
Cape Fear 2	Moncure, NC	12 / 7	Steam Turbine	3/31/11
Lee 1	Goldsboro, NC	80 / 74	Coal	9/15/12
Lee 2	Goldsboro, NC	80 / 68	Coal	9/15/12
Lee 3	Goldsboro, NC	252 / 240	Coal	9/15/12
Lee 1	Goldsboro, NC	15 / 12	Combustion Turbine	10/1/12
Lee 2	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Lee 3	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Lee 4	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Morehead 1	Morehead City, NC	15 / 12	Combustion Turbine	10/1/12
Robinson 1	Hartsville, NC	179 / 177	Coal	10/1/12
Robinson 1	Hartsville, NC	15 / 11	Combustion Turbine	3/31/13
Weatherspoon 1	Lumberton, NC	49 / 48	Coal	9/30/11
Weatherspoon 2	Lumberton, NC	49 / 48	Coal	9/30/11
Weatherspoon 3	Lumberton, NC	79 / 74	Coal	9/30/11
Sutton 1	Wilmington, NC	98 / 97	Coal	11/27/13
Sutton 2	Wilmington, NC	95 / 90	Coal	11/27/13
Sutton 3	Wilmington, NC	389 / 366	Coal	11/4/13
Total		1,880 MW / 1,760 MW		

Planning Assumptions – Unit Retirements[a]

Unit & Plant Name	Location	Capacity (MW)	Fuel Type	Expected Retirement
Asheville 1	Arden, N.C.	191	Coal	1/2020
Asheville 2	Arden, N.C.	185	Coal	1/2020
Mayo 1	Roxboro, N.C.	727	Coal	6/2035
Roxboro 1	Semora, N.C.	379	Coal	6/2032
Roxboro 2	Semora, N.C.	665	Coal	6/2032
Roxboro 3	Semora, N.C.	691	Coal	6/2035
Roxboro 4	Semora, N.C.	698	Coal	6/2035
Robinson 2 [b]	Hartsville, S.C.	741	Nuclear	6/2030
Darlington 1	Hartsville, S.C.	52	Natural Gas/Oil	6/2020
Darlington 2	Hartsville, S.C.	48	Oil	6/2020
Darlington 3	Hartsville, S.C.	52	Natural Gas/Oil	6/2020
Darlington 4	Hartsville, S.C.	50	Oil	1/2014
Darlington 5	Hartsville, S.C.	52	Natural Gas/Oil	6/2020
Darlington 6	Hartsville, S.C.	45	Oil	1/2014
Darlington 7	Hartsville, S.C.	51	Natural Gas/Oil	6/2020
Darlington 8	Hartsville, S.C.	48	Oil	6/2020
Darlington 9	Hartsville, S.C.	52	Oil	6/2020
Darlington 10	Hartsville, S.C.	51	Oil	6/2020
Darlington 11	Hartsville, S.C.	52	Oil	1/2014
Sutton 1	Wilmington, N.C.	11	Natural Gas/Oil	6/2017
Sutton 2A	Wilmington, N.C.	24	Natural Gas/Oil	6/2017
Sutton 2B	Wilmington, N.C.	26	Natural Gas/Oil	6/2017
Blewett 1	Lilesville, N.C.	13	Oil	6/2027
Blewett 2	Lilesville, N.C.	13	Oil	6/2027
Blewett 3	Lilesville, N.C.	13	Oil	6/2027
Blewett 4	Lilesville, N.C.	13	Oil	6/2027
Weatherspoon 1	Lumberton, N.C.	32	Natural Gas/Oil	6/2027
Weatherspoon 2	Lumberton, N.C.	32	Natural Gas/Oil	6/2027
Weatherspoon 3	Lumberton, N.C.	33	Natural Gas/Oil	6/2027
Weatherspoon 4	Lumberton, N.C.	31	Natural Gas/Oil	6/2027
Total		5071		

Note a: Retirement assumptions are for planning purposes only; dates are based on useful life expectations of the unit
Note b: Nuclear retirements for planning purposes are based on the end of current operating license

Planned Operating License Renewal				
Unit & Plant Name	Location	Original Operating License Expiration	Date of Approval	Extended Operating License Expiration
Blewett #1-6 [1]	Lilesville, NC	04/30/08	*Pending*	2058 [2]
Tillery #1-4 [1]	Mr. Gilead, NC	04/30/08	*Pending*	2058 [2]
Robinson #2	Hartsville, SC	07/31/10	04/19/2004	07/31/2030
Brunswick #2	Southport , NC	12/27/14	06/26/2006	12/27/2034
Brunswick #1	Southport, NC	09/08/16	06/26/2006	09/08/2036
Harris #1	New Hill, NC	10/24/26	12/12/2008	10/24/2046

Note 1: The license renewal application for the Blewett and Tillery Plants was filed with the FERC on 04/26/06; the Company is awaiting issuance of the new license from FERC. Pending receipt of a new license, these plants are currently operating under a renewable one-year license extension which has been in effect since May 2008. Although Progress Energy has requested a 50-year license, FERC may not grant this term.

Note 2: Estimated - New license expiration date will be determined by FERC license issuance date and term of granted license.

9. CONCLUSIONS

DEP continues to focus on the needs of customers by meeting the growing demand in the most economical and reliable manner possible. The Company continues to improve the IRP process by determining best practices and making changes to more accurately and realistically represent the DEP System in its planning practices. The 2015 IRP represents a 15 year projection of the Company's plan to balance future customer demand and supply resources to meet this demand plus a 17% minimum planning reserve margin. Over the 15-year planning horizon, DEP expects to require 5,292 MW of additional generating resources in addition to the incremental renewable resources, EE and DSM already in the resource plan.

The Company focuses on the needs of the short-term, while keeping a close watch on market trends and technology advancements to meet the demands of customers in the long-term. The Company's short-term and long-term plans are summarized below:

Short-Term

Over the next 5 years, DEP's 2015 IRP focuses on the following:

- Begin construction on the Sutton Blackstart CTs in 2016 to be available for the summer peak of 2017.
- Pursue the addition of a new combined cycle at the Asheville facility in the 2019 timeframe as part of the WCMP.
- Take actions to ensure capacity needs beginning in 2021 are met.
- Complete the resource adequacy study currently underway with Astrape Consulting.
- Procure CHP resources as cost-effective and diverse generation sources, as appropriate.
- Continue to meet NC REPS and SC DERP compliance plans and invest in additional cost-effective renewable resources.
- Continue to invest in EE and DSM in the Carolinas region.

Long-Term

Beyond the next 5 years, DEP's 2015 IRP focuses on the following:

- Continue to seek the most cost-effective, reliable resources to meet the growing customer demand in the service territory. Currently, those are new combined cycle units and combustion turbine units in the 15 year planning horizon.
- Procure CHP resources as cost-effective and diverse generation sources, as appropriate.

- Continue to meet NC REPS and SC DERP compliance plans by investing in additional renewable resources and EE on the DEP system.
- Continue to invest in DSM in the Carolinas region.

DEP's goal is to continue to diversify the DEP system by adding a variety of cost-effective, reliable, clean resources to meet customer demand. Over the next 15 years, the Company projects filling the increasing demand with investments in natural gas, renewables, and EE and DSM.

10. NON-UTILITY GENERATION AND WHOLESALE

The following information describes the tables included in this chapter.

Wholesale Sales Contracts
This table includes wholesale sales contracts that are included in the 2015 Load Forecast. This information is **CONFIDENTIAL**.

Wholesale Purchase Contracts
This table includes all wholesale purchase contracts that are included as resources in the 2015 IRP. This information is **CONFIDENTIAL**.

Non-Utility Generation Contracts
This table includes all Non-Utility Generation contracts that have been signed since the 2014 IRP. This list includes contracts signed since June 1, 2014, as this was the date utilized in the tables in Appendix H in the 2014 IRP. This list is up to date as of June 30, 2015. This information is **CONFIDENTIAL**, so the customer names have been redacted.

Table 10-A Wholesale Sales Contracts **CONFIDENTIAL**

[redacted]

Table 10-B Firm Wholesale Purchased Power Contracts CONFIDENTIAL

[redacted]

[redacted]

Table 10-C Non-Utility Generation

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
			North Carolina Generators:			
Facility 1	Wilmington	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 2	Raleigh	NC	Solar	4.9	Intermediate/Peaking	Yes
Facility 3	Leland	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 4	Raleigh	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 5	Jacksonville	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 6	Cary	NC	Solar	9.9	Intermediate/Peaking	Yes
Facility 7	Raleigh	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 8	New Hill	NC	Solar	6.2	Intermediate/Peaking	Yes
Facility 9	Selma	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 10	Apex	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 11	Raleigh	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 12	Knightdale	NC	Solar	6.4	Intermediate/Peaking	Yes
Facility 13	Cary	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 14	Pittsboro	NC	Solar	7.0	Intermediate/Peaking	Yes
Facility 15	Raleigh	NC	Solar	5.3	Intermediate/Peaking	Yes
Facility 16	Cary	NC	Solar	2.8	Intermediate/Peaking	Yes
Facility 17	Biltmore Lakes	NC	Solar	5.5	Intermediate/Peaking	Yes
Facility 18	Asheville	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 19	Raleigh	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 20	Wilmington	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 21	Cary	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 22	Cary	NC	Solar	5.6	Intermediate/Peaking	Yes
Facility 23	Clayton	NC	Solar	5.3	Intermediate/Peaking	Yes
Facility 24	Pittsboro	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 25	Raleigh	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 26	Wilmington	NC	Solar	4.5	Intermediate/Peaking	Yes
Facility 27	Pinehurst	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 28	Weaverville	NC	Solar	3.5	Intermediate/Peaking	Yes
Facility 29	Chapel Hill	NC	Solar	5.1	Intermediate/Peaking	Yes
Facility 30	Asheville	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 31	Leicester	NC	Solar	4.9	Intermediate/Peaking	Yes
Facility 32	Asheville	NC	Solar	5.1	Intermediate/Peaking	Yes
Facility 33	Pittsboro	NC	Solar	2.4	Intermediate/Peaking	Yes
Facility 34	Apex	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 35	New Hill	NC	Solar	8.0	Intermediate/Peaking	Yes
Facility 36	Cary	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 37	Raleigh	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 38	Cary	NC	Solar	4.1	Intermediate/Peaking	Yes
Facility 39	Fuquay Varina	NC	Solar	4.6	Intermediate/Peaking	Yes
Facility 40	Apex	NC	Solar	2.6	Intermediate/Peaking	Yes
Facility 41	Pittsboro	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 42	Raleigh	NC	Solar	2.3	Intermediate/Peaking	Yes
Facility 43	Wilmington	NC	Solar	2.6	Intermediate/Peaking	Yes
Facility 44	New Bern	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 45	Raleigh	NC	Solar	6.1	Intermediate/Peaking	Yes
Facility 46	Pittsboro	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 47	Holly Springs	NC	Solar	9.2	Intermediate/Peaking	Yes
Facility 48	Chapel Hill	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 49	Raleigh	NC	Solar	3.2	Intermediate/Peaking	Yes
Facility 50	Raleigh	NC	Solar	5.5	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 51	Cary	NC	Solar	5.6	Intermediate/Peaking	Yes
Facility 52	Pittsboro	NC	Solar	2.2	Intermediate/Peaking	Yes
Facility 53	Pittsboro	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 54	Pittsboro	NC	Solar	3.6	Intermediate/Peaking	Yes
Facility 55	Pittsboro	NC	Solar	4.1	Intermediate/Peaking	Yes
Facility 56	Siler City	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 57	Clayton	NC	Solar	7.3	Intermediate/Peaking	Yes
Facility 58	Raleigh	NC	Solar	3.2	Intermediate/Peaking	Yes
Facility 59	Fayetteville	NC	Solar	3.5	Intermediate/Peaking	Yes
Facility 60	Pittsboro	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 61	Pittsboro	NC	Solar	3.9	Intermediate/Peaking	Yes
Facility 62	Pittsboro	NC	Solar	4.5	Intermediate/Peaking	Yes
Facility 63	Holly Springs	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 64	Raleigh	NC	Solar	6.3	Intermediate/Peaking	Yes
Facility 65	Pittsboro	NC	Solar	5.7	Intermediate/Peaking	Yes
Facility 66	Chapel Hill	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 67	Pittsboro	NC	Solar	4.9	Intermediate/Peaking	Yes
Facility 68	Pittsboro	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 69	Pittsboro	NC	Solar	3.2	Intermediate/Peaking	Yes
Facility 70	Pittsboro	NC	Solar	7.6	Intermediate/Peaking	Yes
Facility 71	Pittsboro	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 72	Asheville	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 73	Wilmington	NC	Solar	2.3	Intermediate/Peaking	Yes
Facility 74	Cary	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 75	Raleigh	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 76	Pittsboro	NC	Solar	2.7	Intermediate/Peaking	Yes
Facility 77	Raeford	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 78	Pittsboro	NC	Solar	6.9	Intermediate/Peaking	Yes
Facility 79	Pittsboro	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 80	Pittsboro	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 81	Siler City	NC	Solar	3.9	Intermediate/Peaking	Yes
Facility 82	Raleigh	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 83	Chapel Hill	NC	Solar	2.4	Intermediate/Peaking	Yes
Facility 84	Cary	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 85	Pittsboro	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 86	Pittsboro	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 87	Chapel Hill	NC	Solar	8.5	Intermediate/Peaking	Yes
Facility 88	Apex	NC	Solar	6.9	Intermediate/Peaking	Yes
Facility 89	Raleigh	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 90	Apex	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 91	Asheville	NC	Solar	3.6	Intermediate/Peaking	Yes
Facility 92	Swannanoa	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 93	Raleigh	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 94	Zebulon	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 95	Black Mountain	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 96	Pittsboro	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 97	Fuquay Varina	NC	Solar	4.1	Intermediate/Peaking	Yes
Facility 98	Siler City	NC	Solar	9.8	Intermediate/Peaking	Yes
Facility 99	Pittsboro	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 100	Fuquay Varina	NC	Solar	5.6	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 101	Cary	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 102	Raleigh	NC	Solar	2.7	Intermediate/Peaking	Yes
Facility 103	Raleigh	NC	Solar	2.4	Intermediate/Peaking	Yes
Facility 104	Raleigh	NC	Solar	4.1	Intermediate/Peaking	Yes
Facility 105	Fuquay Varina	NC	Solar	5.4	Intermediate/Peaking	Yes
Facility 106	Pittsboro	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 107	Cary	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 108	Willow Spring	NC	Solar	5.5	Intermediate/Peaking	Yes
Facility 109	Pittsboro	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 110	Wilmington	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 111	Chapel Hill	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 112	Cary	NC	Solar	5.7	Intermediate/Peaking	Yes
Facility 113	Raleigh	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 114	Chapel Hill	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 115	Alexander	NC	Solar	6.6	Intermediate/Peaking	Yes
Facility 116	Raleigh	NC	Solar	5.7	Intermediate/Peaking	Yes
Facility 117	Chapel Hill	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 118	Chapel Hill	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 119	Holly Springs	NC	Solar	5.9	Intermediate/Peaking	Yes
Facility 120	Carolina Beach	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 121	Chapel Hill	NC	Solar	9.5	Intermediate/Peaking	Yes
Facility 122	Raleigh	NC	Solar	4.5	Intermediate/Peaking	Yes
Facility 123	Pittsboro	NC	Solar	2.2	Intermediate/Peaking	Yes
Facility 124	Chapel Hill	NC	Solar	5.8	Intermediate/Peaking	Yes
Facility 125	Raleigh	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 126	Raleigh	NC	Solar	2.0	Intermediate/Peaking	Yes
Facility 127	Knightdale	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 128	Clayton	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 129	Raleigh	NC	Solar	3.5	Intermediate/Peaking	Yes
Facility 130	Robbins	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 131	Raleigh	NC	Solar	3.9	Intermediate/Peaking	Yes
Facility 132	Apex	NC	Solar	3.9	Intermediate/Peaking	Yes
Facility 133	Wilmington	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 134	Pittsboro	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 135	Zebulon	NC	Solar	8.1	Intermediate/Peaking	Yes
Facility 136	Leland	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 137	Chapel Hill	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 138	Chapel Hill	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 139	Angier	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 140	Pittsboro	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 141	Raleigh	NC	Solar	6.6	Intermediate/Peaking	Yes
Facility 142	Pittsboro	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 143	Benson	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 144	Pittsboro	NC	Solar	2.7	Intermediate/Peaking	Yes
Facility 145	Raleigh	NC	Solar	2.4	Intermediate/Peaking	Yes
Facility 146	Pittsboro	NC	Solar	2.3	Intermediate/Peaking	Yes
Facility 147	Cary	NC	Solar	6.7	Intermediate/Peaking	Yes
Facility 148	Chapel Hill	NC	Solar	5.1	Intermediate/Peaking	Yes
Facility 149	Raleigh	NC	Solar	6.4	Intermediate/Peaking	Yes
Facility 150	Pittsboro	NC	Solar	2.1	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 151	Raleigh	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 152	Pittsboro	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 153	Wilmington	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 154	Southern Pines	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 155	Siler City	NC	Solar	8.8	Intermediate/Peaking	Yes
Facility 156	Raleigh	NC	Solar	4.5	Intermediate/Peaking	Yes
Facility 157	Wilmington	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 158	Cary	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 159	Wilmington	NC	Solar	4.6	Intermediate/Peaking	Yes
Facility 160	Raleigh	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 161	Pittsboro	NC	Solar	6.6	Intermediate/Peaking	Yes
Facility 162	Morrisville	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 163	Raleigh	NC	Solar	3.6	Intermediate/Peaking	Yes
Facility 164	Raleigh	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 165	Raleigh	NC	Solar	6.3	Intermediate/Peaking	Yes
Facility 166	Goldsboro	NC	Solar	4.6	Intermediate/Peaking	Yes
Facility 167	Biltmore Lake	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 168	Lillington	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 169	Raleigh	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 170	Raleigh	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 171	Apex	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 172	Cary	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 173	Cary	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 174	Apex	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 175	Raleigh	NC	Solar	4.6	Intermediate/Peaking	Yes
Facility 176	Raleigh	NC	Solar	9.3	Intermediate/Peaking	Yes
Facility 177	Raleigh	NC	Solar	3.5	Intermediate/Peaking	Yes
Facility 178	Black Mountain	NC	Solar	8.0	Intermediate/Peaking	Yes
Facility 179	Apex	NC	Solar	6.6	Intermediate/Peaking	Yes
Facility 180	Raleigh	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 181	Pittsboro	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 182	Raleigh	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 183	Spring Hope	NC	Solar	7.8	Intermediate/Peaking	Yes
Facility 184	Raleigh	NC	Solar	5.9	Intermediate/Peaking	Yes
Facility 185	Raleigh	NC	Solar	5.4	Intermediate/Peaking	Yes
Facility 186	Zebulon	NC	Solar	2.0	Intermediate/Peaking	Yes
Facility 187	Henderson	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 188	New Bern	NC	Solar	3.5	Intermediate/Peaking	Yes
Facility 189	Willow Spring	NC	Solar	4.6	Intermediate/Peaking	Yes
Facility 190	Pittsboro	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 191	Raleigh	NC	Solar	2.0	Intermediate/Peaking	Yes
Facility 192	Weaverville	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 193	Cary	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 194	Fuquay Varina	NC	Solar	2.1	Intermediate/Peaking	Yes
Facility 195	Raleigh	NC	Solar	4.6	Intermediate/Peaking	Yes
Facility 196	Raleigh	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 197	Asheville	NC	Solar	7.7	Intermediate/Peaking	Yes
Facility 198	Durham	NC	Solar	34.2	Intermediate/Peaking	Yes
Facility 199	Asheville	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 200	Wilmington	NC	Solar	1.0	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 201	Asheville	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 202	Leasburg	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 203	Fairview	NC	Solar	8.0	Intermediate/Peaking	Yes
Facility 204	Asheville	NC	Solar	14.6	Intermediate/Peaking	Yes
Facility 205	Willow Spring	NC	Solar	2,000.0	Intermediate/Peaking	Yes
Facility 206	Raleigh	NC	Solar	1.8	Intermediate/Peaking	Yes
Facility 207	Asheville	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 208	Wake Forest	NC	Solar	5.9	Intermediate/Peaking	Yes
Facility 209	Asheboro	NC	Solar	2.0	Intermediate/Peaking	Yes
Facility 210	Apex	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 211	Pittsboro	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 212	Candler	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 213	Pinehurst	NC	Solar	8.0	Intermediate/Peaking	Yes
Facility 214	Asheville	NC	Solar	7.6	Intermediate/Peaking	Yes
Facility 215	Raleigh	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 216	Asheville	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 217	Asheville	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 218	Louisburg	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 219	Asheville	NC	Solar	2.1	Intermediate/Peaking	Yes
Facility 220	Raleigh	NC	Solar	9.6	Intermediate/Peaking	Yes
Facility 221	Vass	NC	Solar	6.2	Intermediate/Peaking	Yes
Facility 222	Pittsboro	NC	Solar	6.1	Intermediate/Peaking	Yes
Facility 223	Fairview	NC	Solar	7.7	Intermediate/Peaking	Yes
Facility 224	Cary	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 225	Henderson	NC	Solar	4,998.0	Intermediate/Peaking	Yes
Facility 226	Nashville	NC	Solar	2,000.0	Intermediate/Peaking	Yes
Facility 227	Cary	NC	Solar	15.0	Intermediate/Peaking	Yes
Facility 228	Clayton	NC	Solar	407.0	Intermediate/Peaking	Yes
Facility 229	Hurdle Mills	NC	Solar	20.0	Intermediate/Peaking	Yes
Facility 230	Angier	NC	Solar	2.6	Intermediate/Peaking	Yes
Facility 231	Fletcher	NC	Solar	3.2	Intermediate/Peaking	Yes
Facility 232	Waynesville	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 233	Raleigh	NC	Solar	2.6	Intermediate/Peaking	Yes
Facility 234	Asheboro	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 235	Black Mountain	NC	Solar	5.1	Intermediate/Peaking	Yes
Facility 236	Louisburg	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 237	Asheville	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 238	Cary	NC	Solar	4.5	Intermediate/Peaking	Yes
Facility 239	Candler	NC	Solar	7.6	Intermediate/Peaking	Yes
Facility 240	Weaverville	NC	Solar	10.1	Intermediate/Peaking	Yes
Facility 241	Candler	NC	Solar	0.9	Intermediate/Peaking	Yes
Facility 242	Fairview	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 243	Asheville	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 244	Southern Pines	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 245	Leicester	NC	Solar	5.9	Intermediate/Peaking	Yes
Facility 246	Fairview	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 247	Asheville	NC	Solar	7.7	Intermediate/Peaking	Yes
Facility 248	Ashville	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 249	Cary	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 250	Pittsboro	NC	Solar	6.0	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 251	Weaverville	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 252	Black Mountain	NC	Solar	5.3	Intermediate/Peaking	Yes
Facility 253	Raeford	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 254	Asheville	NC	Solar	8.6	Intermediate/Peaking	Yes
Facility 255	Wilmington	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 256	Durham	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 257	Wilmington	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 258	Angier	NC	Solar	5.8	Intermediate/Peaking	Yes
Facility 259	Asheville	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 260	Coats	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 261	Montreat	NC	Solar	2.5	Intermediate/Peaking	Yes
Facility 262	Pittsboro	NC	Solar	1.6	Intermediate/Peaking	Yes
Facility 263	Rocky Point	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 264	Pittsboro	NC	Solar	2.0	Intermediate/Peaking	Yes
Facility 265	Chapel Hill	NC	Solar	16.0	Intermediate/Peaking	Yes
Facility 266	Pittsboro	NC	Solar	8.0	Intermediate/Peaking	Yes
Facility 267	Hampstead	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 268	Raleigh	NC	Solar	8.0	Intermediate/Peaking	Yes
Facility 269	Asheville	NC	Solar	5.5	Intermediate/Peaking	Yes
Facility 270	Raleigh	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 271	Asheville	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 272	Clayton	NC	Solar	2.6	Intermediate/Peaking	Yes
Facility 273	Apex	NC	Solar	6.2	Intermediate/Peaking	Yes
Facility 274	Apex	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 275	Apex	NC	Solar	6.3	Intermediate/Peaking	Yes
Facility 276	Pittsboro	NC	Solar	2.2	Intermediate/Peaking	Yes
Facility 277	Leland	NC	Solar	3.4	Intermediate/Peaking	Yes
Facility 278	Weaverville	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 279	Raleigh	NC	Solar	7.8	Intermediate/Peaking	Yes
Facility 280	Asheville	NC	Solar	6.0	Intermediate/Peaking	Yes
Facility 281	Apex	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 282	Southern Pines	NC	Solar	1.6	Intermediate/Peaking	Yes
Facility 283	Raleigh	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 284	Asheville	NC	Solar	1.9	Intermediate/Peaking	Yes
Facility 285	Candler	NC	Solar	10.1	Intermediate/Peaking	Yes
Facility 286	Pittsboro	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 287	Fairview	NC	Solar	7.1	Intermediate/Peaking	Yes
Facility 288	Chapel Hill	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 289	Fairview	NC	Solar	2.8	Intermediate/Peaking	Yes
Facility 290	Raleigh	NC	Solar	7.7	Intermediate/Peaking	Yes
Facility 291	Asheville	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 292	Raleigh	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 293	Wilmington	NC	Solar	7.2	Intermediate/Peaking	Yes
Facility 294	Pittsboro	NC	Solar	5.2	Intermediate/Peaking	Yes
Facility 295	Raleigh	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 296	Swannanoa	NC	Solar	1.5	Intermediate/Peaking	Yes
Facility 297	Barnardsville	NC	Solar	4.4	Intermediate/Peaking	Yes
Facility 298	Wilmington	NC	Solar	8.8	Intermediate/Peaking	Yes
Facility 299	Asheville	NC	Solar	4.7	Intermediate/Peaking	Yes
Facility 300	Pittsboro	NC	Solar	2.6	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 301	Apex	NC	Solar	96.0	Intermediate/Peaking	Yes
Facility 302	Apex	NC	Solar	15.0	Intermediate/Peaking	Yes
Facility 303	Asheville	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 304	Wilmington	NC	Solar	5.0	Intermediate/Peaking	Yes
Facility 305	Candler	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 306	Asheville	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 307	Garner	NC	Solar	7.3	Intermediate/Peaking	Yes
Facility 308	Chapel Hill	NC	Solar	7.0	Intermediate/Peaking	Yes
Facility 309	Raleigh	NC	Solar	1.6	Intermediate/Peaking	Yes
Facility 310	Wilmington	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 311	Asheville	NC	Solar	4.1	Intermediate/Peaking	Yes
Facility 312	Asheville	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 313	Fletcher	NC	Solar	6.1	Intermediate/Peaking	Yes
Facility 314	Angier	NC	Solar	2.6	Intermediate/Peaking	Yes
Facility 315	Lillington	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 316	Asheville	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 317	Asheville	NC	Solar	6.5	Intermediate/Peaking	Yes
Facility 318	Asheville	NC	Solar	2.3	Intermediate/Peaking	Yes
Facility 319	Asheville	NC	Solar	3.7	Intermediate/Peaking	Yes
Facility 320	Morrisville	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 321	Sanford	NC	Solar	5.8	Intermediate/Peaking	Yes
Facility 322	Raleigh	NC	Solar	4.0	Intermediate/Peaking	Yes
Facility 323	Wilmington	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 324	Morrisville	NC	Solar	1.3	Intermediate/Peaking	Yes
Facility 325	Fuquay-Varina	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 326	Raleigh	NC	Solar	2.9	Intermediate/Peaking	Yes
Facility 327	Kinston	NC	Solar	3.0	Intermediate/Peaking	Yes
Facility 328	Asheville	NC	Solar		Intermediate/Peaking	Yes
Facility 329	Fairview	NC	Solar	5.39	Intermediate/Peaking	Yes
Facility 330	Cary	NC	Solar	7	Intermediate/Peaking	Yes
Facility 331	Fuquay Varnia	NC	Solar	2.49	Intermediate/Peaking	Yes
Facility 332	Newport	NC	Solar	7.6	Intermediate/Peaking	Yes
Facility 333	Fuquay Varina	NC	Solar	0.82	Intermediate/Peaking	Yes
Facility 334	Fletcher	NC	Solar	2.75	Intermediate/Peaking	Yes
Facility 335	Siler City	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 336	Asheville	NC	Solar	5	Intermediate/Peaking	Yes
Facility 337	Cary	NC	Solar	1.84	Intermediate/Peaking	Yes
Facility 338	Candler	NC	Solar	7.975	Intermediate/Peaking	Yes
Facility 339	Star	NC	Solar	2.3	Intermediate/Peaking	Yes
Facility 340	Fayetville	NC	Solar	5.71	Intermediate/Peaking	Yes
Facility 341	Fayetteville	NC	Solar	5	Intermediate/Peaking	Yes
Facility 342	Asheville	NC	Solar	3.9	Intermediate/Peaking	Yes
Facility 343	Asheville	NC	Solar	3.3	Intermediate/Peaking	Yes
Facility 344	Asheville	NC	Solar	3.2	Intermediate/Peaking	Yes
Facility 345	Asheboro	NC	Solar	6.88	Intermediate/Peaking	Yes
Facility 346	Wilmington	NC	Solar	1.63	Intermediate/Peaking	Yes
Facility 347	Asheville	NC	Solar	7.1	Intermediate/Peaking	Yes
Facility 348	Vass	NC	Solar	4.8	Intermediate/Peaking	Yes
Facility 349	Waynesville	NC	Solar	3.62	Intermediate/Peaking	Yes
Facility 350	Asheville	NC	Solar	7	Intermediate/Peaking	Yes

Table 10-C (cont'd)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 351	Raleigh	NC	Solar	3	Intermediate/Peaking	Yes
Facility 352	Alexander	NC	Solar	2.91	Intermediate/Peaking	Yes
Facility 353	Pittsboro	NC	Solar	6	Intermediate/Peaking	Yes
Facility 354	Raleigh	NC	Solar	2.49	Intermediate/Peaking	Yes
Facility 355	Pittsboro	NC	Solar	5	Intermediate/Peaking	Yes
Facility 356	Chapel Hill	NC	Solar	4.158	Intermediate/Peaking	Yes
Facility 357	Asheville	NC	Solar	3	Intermediate/Peaking	Yes
Facility 358	Asheville	NC	Solar	3.12	Intermediate/Peaking	Yes
Facility 359	Angier	NC	Solar	5	Intermediate/Peaking	Yes
Facility 360	Asheville	NC	Solar	3	Intermediate/Peaking	Yes
Facility 361	Clayton	NC	Solar	2000	Intermediate/Peaking	Yes
Facility 362	Raleigh	NC	Solar	4	Intermediate/Peaking	Yes
Facility 363	Holly Springs	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 364	Canton	NC	Solar	2	Intermediate/Peaking	Yes
Facility 365	Godwin	NC	Solar	5	Intermediate/Peaking	Yes
Facility 366	Raleigh	NC	Solar	3.1	Intermediate/Peaking	Yes
Facility 367	Asheville	NC	Solar	3.8	Intermediate/Peaking	Yes
Facility 368	Coats	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 369	Pittsboro	NC	Solar	8	Intermediate/Peaking	Yes
Facility 370	Raleigh	NC	Solar	7.54	Intermediate/Peaking	Yes
Facility 371	Raleigh	NC	Solar	8.64	Intermediate/Peaking	Yes
Facility 372	Climax	NC	Solar	7.68	Intermediate/Peaking	Yes
Facility 373	Aberdeen	NC	Solar	4.14	Intermediate/Peaking	Yes
Facility 374	Smyrna	NC	Wind	10	Intermediate/Peaking	Yes
Facility 375	Castalia	NC	Solar	3	Intermediate/Peaking	Yes
Facility 376	Weaverville	NC	Solar	7.5	Intermediate/Peaking	Yes
Facility 377	Benson	NC	Solar	3	Intermediate/Peaking	Yes
Facility 378	Broadway	NC	Solar	8.55	Intermediate/Peaking	Yes
Facility 379	Raleigh	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 380	Goldsboro	NC	Solar	4.2	Intermediate/Peaking	Yes
Facility 381	Weaverville	NC	Solar	6	Intermediate/Peaking	Yes
Facility 382	Pittsboro	NC	Solar	1.632	Intermediate/Peaking	Yes
Facility 383	CAMERON	NC	Solar	4.3	Intermediate/Peaking	Yes
Facility 384	Waynesville	NC	Solar	5	Intermediate/Peaking	Yes
Facility 385	Asheville	NC	Solar	4.92	Intermediate/Peaking	Yes
Facility 386	Hollister	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 387	Weaverville	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 388	Fletcher	NC	Solar	424	Intermediate/Peaking	Yes
Facility Name	**City/County**	**State**	**Primary Fuel Type**	**Capacity (AC KW)**	**Designation**	**Inclusion in Utility's Resources**
			South Carolina Generators:			
Facility 1	Sumter	SC	Biogas		Intermediate/Peaking	Yes

11. CROSS-REFERENCE TABLE

	Requirement	Location
1	Summary of significant amendments or revisions to most recently filed biennial report (including amendments to type and size of resources identified	Chapter 4
2	Short-term action plan	Chapter 7
3	REPS Compliance Plan	Attachment: NC REPS Compliance Plan
4	Most recent 10-year history and forecast of: - customers by each customer class, - energy sales (MWh) by each customer class, - utilities summer and winter peak load	Chapter 5
5	15 year table (w/ and w/o projected supply or demand side resources) of: -Peak loads for summer and winter seasons of each year - annual energy forecasts - Reserve margins - Load duration curves - Effects of DR and EE programs on forecasted annual energy and peak loads	Chapter 5
6	Description of future supply-side resources including type of capacity / resource (MW rating, fuel source, base, intermediate, or peaking)	Chapter 6
7	List of existing units in service with: - type of fuel(s) used - Type of unit (base, int, peak) - Location of existing unit - List of units to be retired with location and date - List of units for which there are specific plans for life extension, refurbishment, or upgrading - Other changes to existing generating units that are expected to impact gen capability by 10% or 10 MW	Chapter 8
8	Planned Generation Additions with: - Type of fuel used - Type of unit (MW rating, base, int, peak) - Location if determined - Summaries of analyses supporting any new gen additions included in its 15-year forecast	Chapter 6
9	List of all NUG facilities - facility name - location - primary fuel type - capacity (base, int, peak) - which are included in its total supply of resources	Chapter 10
10	Cumulative resource additions necessary to meet load obligation & reserve margins	Chapter 6

The Duke Energy Progress

NC Renewable Energy & Energy Efficiency Portfolio Standard (NC REPS) Compliance Plan

September 1, 2015

NC REPS Compliance Plan
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INTRODUCTION:

Duke Energy Progress, LLC (DEP or the Company) submits its annual Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS or REPS) Compliance Plan (Compliance Plan) in accordance with NC Gen. Stat. § 62-133.8 and North Carolina Utilities Commission (the Commission) Rule R8-67(b). This Compliance Plan, set forth in detail in Section II and Section III, provides the required information and outlines the Company's projected plans to comply with NC REPS for the period 2015 to 2017 (the Planning Period). Section IV addresses the cost implications of the Company's REPS Compliance Plan.

In 2007, the North Carolina General Assembly enacted Session Law 2007-397 (Senate Bill 3), codified in relevant part as NC Gen. Stat. § 62-133.8, in order to:

- Diversify the resources used to reliably meet the energy needs of consumers in the State;
- Provide greater energy security through the use of indigenous energy resources available within the State;
- Encourage private investment in renewable energy and energy efficiency; and
- Provide improved air quality and other benefits to energy consumers and citizens of the State.

As part of the broad policy initiatives listed above, Senate Bill 3 established the NC REPS, which requires the investor-owned utilities, electric membership corporations or co-operatives, and municipalities to procure or produce renewable energy, or achieve energy efficiency savings, in amounts equivalent to specified percentages of their respective retail megawatt-hour (MWh) sales from the prior calendar year.

Duke Energy Progress seeks to advance these State policies and comply with its REPS obligations through a diverse portfolio of cost-effective renewable energy and energy efficiency resources. Specifically, the key components of Duke Energy Progress' 2015 Compliance Plan include: (1) energy efficiency programs that will generate savings that can be counted towards the Company's REPS obligation; (2) purchases of renewable energy certificates (RECs); (3) operations of company-owned renewable facilities; and (4) research studies to enhance the Company's ability to comply with its REPS obligations in the future. The Company believes that these actions yield a diverse portfolio of qualifying resources and allow a flexible mechanism for compliance with the requirements of NC Gen. Stat. § 62-133.8.

In addition, the Company has undertaken, and will continue to undertake, specific regulatory and operational initiatives to support REPS compliance, including: (1) submission of regulatory applications to pursue reasonable and appropriate renewable energy and energy efficiency initiatives in support of the Company's REPS compliance needs; (2) solicitation, review, and analysis of proposals from renewable energy suppliers offering RECs and diligent pursuit of the most attractive opportunities, as appropriate;

and (3) development and implementation of administrative processes to manage the Company's REPS compliance operations, such as procuring and managing renewable resource contracts, accounting for RECs, safely interconnecting renewable energy suppliers, reporting renewable generation to the North Carolina Renewable Energy Tracking System (NC-RETS), and forecasting renewable resource availability and cost in the future.

The Company believes these actions collectively constitute a thorough and prudent plan for compliance with NC REPS and demonstrate the Company's commitment to pursue its renewable energy and energy efficiency strategies for the benefit of its customers.

I. REPS COMPLIANCE OBLIGATION:

Duke Energy Progress calculates its NC REPS Compliance Obligations[5] for 2015, 2016, and 2017 based on interpretation of the statute (NC Gen. Stat. § 62-133.8), the Commission's rules implementing Senate Bill 3 (Rule R8-67), and subsequent Commission orders, as applied to the Company's actual or forecasted retail sales in the Planning Period, as well as the actual and forecasted retail sales of those wholesale customers for whom the Company is supplying REPS compliance services. The Company's wholesale customers for whom it supplies REPS compliance services are the Town of Sharpsburg, the Town of Stantonsburg, the Town of Lucama, the Town of Black Creek, Town of Winterville and the City of Waynesville (Waynesville compliance provided for 2015 only, as DEP's contract with Waynesville expires 12/31/2015) (collectively referred to as Wholesale or Wholesale Customers)[6]. Table 1 below shows the Company's retail and Wholesale customers' REPS Compliance Obligation.

[5] For the purposes of this Compliance Plan, Compliance Obligation is more specifically defined as the sum of Duke Energy Progress' native load obligations for both the Company's retail sales and for wholesale native load priority customers' retail sales for whom the Company is supplying REPS compliance. All references to the respective Set-Aside requirements, the General Requirements, and REPS Compliance Obligation of the Company include the aggregate obligations of both Duke Energy Progress and the Wholesale Customers. Also, for purposes of this Compliance Plan, all references to the compliance activities and plans of the Company shall encompass such activities and plans being undertaken by Duke Energy Progress on behalf of the Wholesale Customers.

[6] For purposes of this Compliance Plan, Retail Sales is defined as the sum of Duke Energy Progress' retail sales and the retail sales of the wholesale customers for whom the company is supplying REPS compliance.

Table 1: Duke Energy Progress' NC REPS Compliance Obligation

Compliance Year	Previous Year DEP Retail Sales (MWhs)	Previous Year Wholesale Retail Sales (MWhs)	Total Retail sales for REPS Compliance (MWhs)	Solar Set-Aside (RECs)	Swine Set-Aside (RECs)	Poultry Set-Aside (RECs)	REPS Requirement (%)	Total REPS Compliance Obligation (RECs)
2015	37,490,737	212,347	37,703,084	52,784	26,392	202,536	6%	2,262,185
2016	37,084,787	120,748	37,205,535	52,088	26,044	255,925	6%	2,232,332
2017	37,500,664	121,215	37,621,879	52,671	52,671	257,740	6%	2,257,313

Note: Obligation is determined by prior-year MWh sales. Thus, retail sales figures for compliance years 2015 and 2016 are estimates.

As shown in Table 1, the Company's requirements in the Planning Period include the solar energy resource requirement (Solar Set-Aside), swine waste resource requirement (Swine Set-Aside), and poultry waste resource requirement (Poultry Set-Aside). In addition, the Company must also ensure that, in total, the RECs that it produces or procures, combined with energy efficiency savings, is an amount equivalent to 6% of its prior-year retail sales in compliance years 2015, 2016 and 2017. The Company refers to this as its Total Obligation. For clarification, the Company refers to its Total Obligation, net of the Solar, Swine, and Poultry Set-Aside requirements, as its General Requirement.

II. REPS COMPLIANCE PLAN:

In accordance with Commission Rule R8-67b(1)(i), the Company describes its planned actions to comply with the Solar, Swine, and Poultry Set-Asides, as well as the General Requirement below. The discussion first addresses the Company's efforts to meet the Set-Aside requirements and then outlines the Company's efforts to meet its General Requirement in the Planning Period.

A. SOLAR ENERGY RESOURCES:

Pursuant to NC Gen. Stat. § 62-133.8(d), the Company must produce or procure solar RECs equal to a minimum of 0.14% of the prior year's total electric energy in megawatt-hours (MWh) sold to retail customers in North Carolina in 2015, 2016 and 2017.

Based on the Company's actual retail sales in 2014, the Solar Set-Aside is 52,784 RECs in 2015. Based on forecasted retail sales, the Solar Set-Aside is projected to be approximately 52,088 RECs and 52,671 RECs in 2016 and 2017, respectively.

The Company's plan for meeting the Solar Set-Aside in the Planning Period is described in further detail below.

1. Company-Owned Solar Facilities

As the result of a solar RFP issued in February 2014, DEP announced plans to acquire and construct three solar facilities in North Carolina, totaling 128 MW of capacity: a 65MW facility in Duplin County; a 40MW facility in Wilson County and a 23MW facility in Bladen County. In addition, the Camp Lejeune Solar Facility will add approximately 13 MW of solar PV capacity to DEP's system and is the Company's first solar facility at a military base. All of these Company-owned projects are anticipated to be online by the end of 2015.

2. Solar PPAs and Solar REC Purchase Agreements

DEP has executed multiple solar REC purchase agreements with third parties. These agreements include contracts with multiple counterparties to procure solar RECs from both solar photovoltaic (PV) and solar water heating installations. Also as part of the 2014 solar RFP, DEP signed power purchase agreements with five new solar projects, totaling 150 MW of capacity. Additional details with respect to the REC purchase agreements are set forth in Exhibit A.

3. Residential Solar PV Program

The Company also maintains a residential solar PV program, which offers incentives to customers who install solar. In exchange, the Company receives RECs created by the systems for 5 years. By year-end 2015, the Company expects total program participation of approximately 4MW of solar PV from around 900 program participants.

4. Review of Company's Solar Set-Aside Plan

The Company has made and continues to make reasonable efforts to meet the Solar Set-Aside requirement in the Planning Period, and remains confident that it will be able to comply with this requirement. Therefore, the Company sees minimal risk in meeting the Solar Set-Aside and will continue to monitor the development and progress of solar initiatives and take appropriate actions as necessary.

B. SWINE WASTE-TO-ENERGY RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8(e), as amended by the NCUC *Final Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief,* Docket No. E-100, Sub 113 (November 2014), for calendar years 2015 and 2016, at least 0.07%, and in 2017, at least 0.14% of prior-year total retail electric energy sold in aggregate by utilities in North Carolina must be supplied by energy derived from swine waste. The Company's Swine Set-Aside is estimated to be 26,392 RECs in 2015, 26,044 RECs in 2016, and 52,671 RECs in 2017.

Swine waste-to-energy compliance challenges have been numerous and varied. Three paths to the creation of swine waste-to-energy RECs have been identified, although each faces unique challenges.

1. **On-farm generation**

Projects consisting of digestion and generation on a single farm or tight cluster of farms often face gas production and feedstock agreement challenges, as well as interconnection difficulties. The Company understands that many farms in NC are contract growers and have only limited term agreements with the integrators. Accordingly, many contract growers are not in a position to provide a firm supply of waste sufficient to support project financing. The Company is exploring ways to overcome such risks.

2. **Centralized digestion**

This type of system would benefit farmers that cannot individually construct and operate an anaerobic digester manure handling system on their own due to the capital expense or just don't have the number of animals required to operate a digester successfully or cost effectively. Farms located close to each other could share the cost of the centrally located digester system. The centralized digester operated by an individual or private company would carry out the operation and maintenance of the digester and its mechanical systems. It would have the same advantages as on-farm digesters of odor reduction, pathogen and weed seed destruction, biogas production and a stable effluent ready to fertilize fields and crops.

The Company recognizes that NIMBY ("Not In My Back Yard") issues may scuttle some developers' plans for overcoming fuel supply and interconnection problems faced by more rural, on-farm projects.

3. **Injected/Directed biogas**

In theory, injected biogas reduces costs by using large, efficient centralized generation in the place of smaller, less-efficient reciprocating engines typical of other projects. However, practically, the Company has found such solutions in North Carolina to be economically challenged, in part due to additional gas clean-up requirements prior to injection and the general lack of physical proximity between clusters of farms and pipeline infrastructure.

The Company continues to explore directed biogas opportunities, including promising opportunities outside of North Carolina where the gas would be transported on interstate pipelines used for fuel in one of the Company's combined cycles.

In spite of Duke Energy Progress' active and diligent efforts to secure resources to comply with its Swine Waste Set-Aside requirements, the Company will not be able to procure sufficient volumes of RECs to meet its pro-rata share of the swine waste set-aside requirements in 2015. The Company remains actively engaged in seeking additional resources and continues to make every reasonable effort to comply with the swine waste set-aside requirements.

The Company's ability to comply in 2016 and 2017 remains highly uncertain and subject to multiple variables, particularly relating to counterparty achievement of projected delivery requirements and commercial operation milestones. Additional details with respect to the Company's compliance efforts and REC purchase agreements are set forth in Exhibit A and the Company's tri-annual progress reports, filed confidentially in Docket E-100 Sub113A.

Due to its expected non-compliance in 2015, the Company has submitted a motion to the Commission for approval of a request to relieve the Company from compliance with the swine-waste requirements until calendar year 2016 by delaying the compliance obligation for a one year period.

C. POULTRY WASTE-TO-ENERGY RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8(f), as amended by NCUC *Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief*, Docket No. E-100, Sub 113 (March 2014), for calendar year 2015, at least 700,000 MWhs, and for 2016 and 2017, at least 900,000 MWhs, of the prior year's total electric energy sold to retail electric customers in the State or an equivalent amount of energy shall be produced or procured each year from poultry waste, as defined per the Statute and additional clarifying Orders. As the Company's retail sales share of the State's total retail megawatt-hour sales is approximately 29%, the Company's Poultry Set-Aside is estimated to be 202,536 RECs in 2015, 255,925 RECs in 2016, and 257,740 in 2017.

In spite of Duke Energy Progress' active and diligent efforts to secure resources to comply with its Poultry Waste Set-Aside requirements, the Company will not be able to procure sufficient volumes of RECs to meet its pro-rata share of the poultry set-aside requirements in 2015. The Company remains actively engaged in seeking additional resources and continues to make every reasonable effort to comply with the poultry waste set-aside requirements.

Several near-term challenges remain to the Company's meeting the poultry set-aside targets in the future. To date, only a handful of poultry projects are operating and online in North Carolina. Ramping up to meet the increased compliance targets for 2015 - 2017 has been problematic because other suppliers have either delayed projects or lowered the volume of RECs to be produced. The Company is, nevertheless, encouraged by the growing use of thermal poultry RECs and the proposals that it has recently received from developers.

The Company's ability to comply in 2016 and 2017 remains uncertain and largely subject to counterparty performance. Additional details with respect to the Company's compliance efforts and REC purchase agreements are set forth in Exhibit A and the Company's tri-annual progress reports, filed confidentially in Docket E-100 Sub113A.

Due to its expected non-compliance in 2015, the Company has submitted a motion to the Commission for approval of a request to relieve the Company from compliance with the poultry-waste requirements until calendar year 2016 by delaying the compliance obligation for a one year period.

D. GENERAL REQUIREMENT RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8, Duke Energy Progress is required to comply with its Total Obligation in 2015, 2016, and 2017 by submitting for retirement a total volume of RECs equivalent to 6% of retail sales in North Carolina in the prior year: approximately 2,262,185 RECs in 2015, 2,232,332 RECs in 2016, and 2,257,313 RECs in 2017. This requirement, net of the Solar, Swine, and Poultry Set-Aside requirements, is estimated to be 1,980,473 RECs in 2015, 1,898,275 RECs in 2016, and 1,894,231 in 2017. The various resource options available to the Company to meet the General Requirement are discussed below, as well as the Company's plan to meet the General Requirement with these resources.

1. Energy Efficiency

During the Planning Period, the Company plans to meet 25% of the Total Obligation with Energy Efficiency (EE) savings, which is the maximum allowable amount under NC Gen. Stat. § 62-133.7(b)(2)c. The Company continues to develop and offer its customers new and innovative EE programs that will deliver savings and count towards its future NC REPS requirements. The Company has attached a list of those EE measures that it plans to use toward REPS compliance, including projected impacts, as Exhibit B.

2. Hydroelectric Power

Duke Energy Progress plans to use hydroelectric power from two sources to meet the General Requirement in the Planning Period: (1) Wholesale Customers' Southeastern Power Administration (SEPA) allocations; and (2) hydroelectric generation suppliers whose facilities have received Qualifying Facility (QF or QF Hydro) status. Wholesale Customers may also bank and utilize hydroelectric resources arising from their full allocations of SEPA. When supplying compliance for the Wholesale Customers, the Company will ensure that hydroelectric resources do not comprise more than 30% of each Wholesale Customers' respective compliance portfolio, pursuant to NC Gen. Stat. § 62-133.8(c)(2)c. In addition, RECs from QF Hydro facilities will be used towards the General Requirements of Duke Energy Progress' retail customers. Please see Exhibit A for more information.

3. Biomass Resources

Duke Energy Progress plans to meet a portion of the General Requirement through a variety of biomass resources, including landfill gas to energy, combined heat and power, and direct combustion of biomass fuels. The Company is purchasing RECs from multiple biomass facilities in the Carolinas, including landfill gas to energy facilities and biomass-fueled combined heat and power facilities, all of which qualify as renewable energy facilities. Please see Exhibit A for more information on each of these contracts.

Duke Energy Progress notes, however, that reliance on direct-combustion biomass remains limited in long-term planning horizons, in part due to continued uncertainties around the developable potential of such resources in the Carolinas and the projected availability of other forms of renewable resources to offset the need for biomass.

4. Wind

Duke Energy Progress plans to meet a portion of the General Requirement with RECs from wind facilities. While the Company expects to rely upon wind resources for REPS compliance, the extent and timing of that reliance will likely vary commensurately with changes to supporting policies and prevailing market prices. The Company recognizes that some land-based wind developers are presently pursuing projects of significant size in North Carolina. While successful projects have to navigate a litany of obstacles, these obstacles are not insurmountable. The Company also has observed that opportunities may exist to transmit land-based wind energy resources into the Carolinas from other regions, which could supplement the amount of wind that could be developed within the Carolinas.

5. Use of Solar Resources for General Requirement

Duke Energy Progress plans to meet a portion of the General Requirement with RECs from solar facilities. The Company views the downward trend in solar equipment and installation costs over the past several years as a positive development. Additionally, new solar facilities also benefit from generous supportive Federal and State policies that are expected to be in place beyond 2015. While uncertainty remains around possible alterations or extensions of policy support, as well as the pace of future cost declines, the Company fully expects solar resources to contribute to our compliance efforts beyond the solar set-aside minimum threshold for NC REPS during the Planning Period.

6. Review of Company's General Requirement Plan

The Company has contracted for or otherwise procured sufficient resources to meet its General Requirement in the Planning Period. Based on the known information available at the time of this filing, the Company is confident that it will meet this General Requirement during the Planning Period and submits that the actions and plans described herein represent a reasonable and prudent plan for meeting the General Requirement.

E. SUMMARY OF RENEWABLE RESOURCES

The Company has evaluated, procured, and/or developed a variety of types of renewable and energy efficiency resources to meet its NC REPS requirements within the compliance Planning Period. As noted above, several risks and uncertainties exist across the various types of resources and the associated parameters of the NC REPS requirements. The Company continues to carefully monitor opportunities and unexpected developments across all facets of its compliance requirements. Duke Energy Progress submits that it has crafted a prudent, reasonable plan with a diversified balance of renewable resources that will allow the Company to comply with its NC REPS obligation over the Planning Period.

III. COST IMPLICATIONS OF REPS COMPLIANCE PLAN

A. CURRENT AND PROJECTED AVOIDED COST RATES

The current variable rate represents the avoided cost rate in Schedule CSP-29 (NC), Distribution Interconnection, approved in the Commission's *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, issued in Docket No. E-100, Sub 127 (July 27, 2011). The current long-term rates represent the annualized avoided cost rates approved in the Commission's *Order on Motion to Suspend Avoided Cost Rates*, issued in Docket No. E-100, Sub 136 (December 21, 2012). The projected avoided cost rates represent the annualized avoided cost rates proposed by the Company in Docket No. E-100, Sub 140.

The projected avoided costs rates contained herein are subject to change, particularly as the underlying assumptions change and as the methodology for determining the avoided cost is addressed by the North Carolina Utilities Commission in pending Docket No. E-100, Sub 140. Primary assumptions that impact avoided cost rates are turbine costs, fuel price projections, and the expansion plans. Changes to these assumptions are addressed in greater detail in the current Integrated Resource Plan.

Table 2: Current and Projected Avoided Cost Rates Table

[BEGIN CONFIDENTIAL]

CURRENT AVOIDED ENERGY AND CAPACITY COST (from E-100 Sub 136)			
	On-Peak Energy(1) ($/MWh)	**Off-Peak Energy(1) ($/MWh)**	[redacted]
2016	47.44	38.53	
2017	47.05	40.20	
2018	54.14	42.60	

PROJECTED AVOIDED ENERGY AND CAPACITY COST			
	On-Peak Energy(5) ($/MWh)	**Off-Peak Energy(5) ($/MWh)**	[redacted]
2016	36.99	32.89	
2017	38.60	34.46	
2018	37.04	34.13	

Notes: (1) On-peak and off-peak energy rates based on Option B hours and information and assumptions available concurrent with the 2014 IRP and derived using methodology approved in Docket No. E-100, Sub 136
(2) Capacity Cost column provides the installed CT cost with AFUDC
(3) Turbine cost agreed upon in E-100 Sub 136 settlement
(4) Turbine cost proposed in E-100, Sub 140 divided by summer capacity rating
(5) On-peak and off-peak energy rates based on Option B hours and information and assumptions available concurrent with the methodology proposed in Docket No. E-100, Sub 140
(6) Does not incorporate additional considerations used in rate calculation and is subject to change

[END CONFIDENTIAL]

B. PROJECTED TOTAL NORTH CAROLINA RETAIL AND WHOLESALE SALES AND YEAR-END NUMBER OF CUSTOMER ACCOUNTS BY CLASS

The tables below reflect the inclusion of the Wholesale Customers in the Compliance Plan.

Table 3: Retail Sales for Retail and Wholesale Customers

		2014 Actual	2015 Forecast	2016 Forcast	2017 Forecast
Retail MWh Sales		37,490,737	37,084,787	37,500,664	37,909,134
Whoesale MWh Sales		212,347	120,748	121,215	121,684
Total MWh Sales		37,703,084	37,205,535	37,621,879	38,030,818

Note: The MWh sales reported above are those applicable to REPS compliance years 2015 – 2017, and represent actual MWh sales for 2014, and projected MWh sales for 2015 and 2017.

Table 4: Retail and Wholesale Year-end Number of Customer Accounts

		2014 (Actual)	2015 (Projected)	2016 (Projected)	2017 (Projected)
Residential Accts		1,215,618	1,232,841	1,247,894	1,265,529
General Accts		198,063	199,849	200,952	202,759
Industrial Accts		2,123	2,109	2,099	2,090

Note: The number of accounts reported above are those applicable to the cost caps for compliance years 2015 – 2017, and represent the actual number of accounts for year-end 2014, and the projected number of accounts for year-end 2015 through 2017.

C. PROJECTED ANNUAL COST CAP COMPARISON OF TOTAL AND INCREMENTAL COSTS, REPS RIDER AND FUEL COST IMPACT

Projected compliance costs for the Planning Period are presented in the cost tables below by calendar year. The cost cap data is based on the number of accounts as reported above.

Table 5: Projected Annual Cost Caps and Fuel Related Cost Impact

	2015	2016	2017
Total projected REPS compliance costs	$175,742,700	$238,968,551	$ 251,665,511
Recovered through the Fuel Rider	$150,405,592	$206,151,650	$ 214,179,630
Total incremental costs (REPS Rider)	$ 25,337,108	$ 32,816,901	$ 37,485,881
Total including Regulatory Fee	$ 25,370,140	$ 32,859,684	$ 37,534,751
Projected Annual Cost Caps (REPS Rider)	$ 46,419,866	$ 74,002,944	$ 74,670,196

EXHIBIT A

Duke Energy Progress, LLC's 2014 REPS Compliance Plan
Duke Energy Progress' Renewable Resource Procurement from 3rd Parties
(signed contracts as of July 1, 2015)

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

EXHIBIT B

Duke Energy Progress, LLC's 2014 REPS Compliance Plan
Duke Energy Progress, LLC's EE Programs and Projected REPS Impacts

Forecast Annual Energy Efficiency Impacts for the REPS Compliance Planning Period 2015-2017 (MWhs)			
Residential Programs	2015	2016	2017
Appliance Recycling	6,435	6,425	6,425
K-12	1,704	1,701	1,701
MultiFamily	14,229	9,976	10,931
MyHER	100,290	-	-
Neighborhood Energy Saver	1,546	1,543	1,543
Residential Home Energy Improvement	3,322	2,138	2,138
Residential Lighting	50,546	56,166	55,896
Residential New Construction	8,076	9,963	11,355
New Products*			
Sub Total	**186,149**	**87,912**	**89,989**
Non Residential Programs	2015	2016	2017
EEB	70,188	75,098	79,255
SBES	50,138	38,504	30,803
New Products*			
Sub Total	**120,326**	**113,602**	**110,059**
Total	**306,475**	**201,514**	**200,048**

been explained in FPL's testimony presented in support of its request for a determination of need for WCEC 3, because, whether with or without the proposed plant conversions, adding WCEC 3 in 2011 is the most economic resource available to FPL in 2011 through 2013, it would not be beneficial to FPL's customers to implement any other alternative. Therefore, adding WCEC 3 in 2011 is necessary and appropriate if FPL is to proceed with the cleaner, high efficiency conversion of Canaveral and Riviera and continue to ensure system reliability.

Q. Is the 20% reserve margin planning criterions appropriate for use in FPL's IRP process?

A. Yes. The 20% reserve margin reliability criterion utilized by FPL in its integrated resource planning process has been reviewed and approved by the Commission and it is appropriate and necessary to ensure reliable service for FPL's customers.

Q. Could FPL lower the planning reserve margin reliability criterion to 15% and still provide reliable service to its customers?

A. No. A 15% reserve margin is not adequate to ensure reliable service in FPL's system.

Q. How was FPL's current reserve margin criterion of 20% established?

A. Prior to 1999 FPL used a reserve margin criterion of 15%. It should be noted that FPL's reserves at that time consisted more heavily of generation reserves, with load management contributing less than half of what it will provide in 2014. However, the Commission initiated in the late 1990s a proceeding to determine what the appropriate reserve margin criterion should be to ensure reliability of electric service in the future, recognizing rapid increases in electric loads, the introduction and expansion of new technologies, and recognition that fuel supply interruptions could occur. After audits were performed by the Commission Staff, and after several stakeholders, including Florida's investor-owned utilities, presented their analyses and conclusions, all parties agreed that a 20% reserve margin for the investor-owned utilities was the appropriate level that would ensure reliability of service in the utilities' systems, as well as in peninsular Florida. These investor-owned utilities stipulated that they would agree to use a 20% reserve margin as one of the reliability criteria for resource planning, in addition to a probabilistic criterion such as LOLP, beginning in the summer of 2004. This stipulation was approved by the Commission.

Q. Why is a 15% reserve margin not adequate to ensure reliability in FPL's system?

A. Because a 15% reserve margin, as used in the resource planning process, would provide a level of generation reserves that would be too low to offset the consequences of commonly occurring differences between the assumptions used in FPL's long term plan and actual operating conditions, especially if those differences occur at times when FPL has scheduled planned maintenance outages for one or more generating units.

Q. What differences are you referring to?

A. There are a number of such differences, as one would expect when recognizing that six or more years can separate forecasts that are used to make resource decisions from actual conditions at the time the resource plan is implemented. To illustrate my point I will provide a numerical example that addresses two differences: one is the point in time during the year in which the peak load actually occurs, and the other is the difference between the actual magnitude of the peak load in a future year (2014) and the projected magnitude of the peak for that year that would have been forecasted six years earlier (2008).

Q. How will you present this illustration?

A. I will first use a calculation very similar to that presented in Exhibit SRS-2 attached to the testimony of FPL witness Sim to show, pursuant to the resource planning process FPL follows to determine future needs, how a projected reserve margin of 15% would be achieved for the summer of 2014. This calculation is presented in my Exhibit RS-3. The only difference between this calculation and that presented in SRS-2 is that the former includes sufficient firm generating capacity in FPL's portfolio to reach a reserve margin of 15%. The forecasted load for 2014 was developed in 2008 as part of FPL's IRP process. Column 3 shows the total projected capacity available in FPL's system in the summer of 2014 (27,502 MW). Column 4 shows the projected peak load in the summer of 2014 (26,576 MW). Column 5 shows the quantity of projected DSM available in the summer of 2014 (2,651 MW).

Column 6 shows the projected "firm" peak load; that is, that portion of the projected peak load that cannot be mitigated through the exercise of DSM. This projected "firm" peak load is equal to the projected peak load less the projected DSM, or 23,925 MW. It should be noted that this demonstrates that in its resource planning process FPL first considers all the cost-effective DSM as a resource before determining what additional supply-side resources are required.

Column 7 shows the projected generation reserves compared to the projected "firm" load. This projected generation reserve compared to projected "firm" peak load is equal to projected capacity available less projected "firm" peak load, or 3,577 MW. Column 8 shows the projected reserve margin that this projected generation reserve provides compared to the "firm" peak load; it is equal to the projected generation reserve against "firm" peak load divided by "firm" peak load, expressed as a percent. This is the reserve margin that is used in FPL's resource planning process to develop and compare plans that will provide a 20% reserve margin relative to "firm" peak load. In this case, however, the projected reserve margin against the projected "firm" peak load, after all the DSM is utilized is 15% in the summer of 2014. As column 9 shows, FPL would need to add 1,208 MW of additional firm capacity in order to meet the 20% reserve margin criterion.

Q. You indicated that the calculation above is consistent with FPL's resource planning process. How does FPL allocate resources to meet actual electric load?

A. In actual daily operations FPL dispatches its generation resources in economic order, with lowest cost generation first, to produce all the electricity its customers need. It is only if generation resources are insufficient to meet actual load that the load management portion of DSM is utilized. I am providing an example of the effect of having only 15% reserve margin in my Exhibit RS-4, page 1 of 2. For simplicity, my example assumes that all the DSM consists of load management. First, it is assumed that actual conditions in 2014 are the same as shown on Exhibit RS-3. In other words, the peak load is 26,576 MW and total capacity available is 27,502 MW. Therefore, FPL would be able to meet the load and have 926 MW of unused generation. It would also have 2,651 MW of unused DSM for total reserves of 3,577 MW. This is the same total of reserves as shown on column 7 of Exhibit RS-3, but note that only 926 MW are generation reserves. In other words, in actual operations, generation reserves are only about one fourth of total reserves, with DSM providing three fourths of the reserve. Another way to look at these results is that, in effect, accepting a 15% reserve margin criterion would result in generation reserves that actually provide less than 4% operational reserve margin. Applying the rest of the reserve margin, which is provided by DSM, requires partial curtailment of service to customers who subscribe to load control. This is the situation that would exist in 2014 if all happens as was forecasted six years earlier, in 2008.

Q. **How would a difference between the projected and actual date of a year's peak load affect FPL's ability to meet its customer's needs?**

A. FPL's forecast typically projects that the summer peak load will occur in August and, at present, no plant outages for inspection and maintenance are planned during that month. However, the peak load can occur in June and July when such plant outages are planned. In fact, in the last 16 years the actual peak load day has occurred in August only 9 times. Therefore, it has been a fairly common occurrence that the peak day has occurred in June or July, instead of August.

Q. **How would the actual peak day occurring in June of 2014 instead of August affect the results presented above, assuming FPL were to plan for a 15% reserve margin in 2014?**

A. Typically, about 800 MW of generation capacity will be out of service for planned maintenance in the month of June. Therefore, if the projected peak for 2014 were to occur in June, instead of having 926 MW of generation reserves on the peak load day FPL would have only 126 MW of generation reserves. In other words, the operational reserve margin provided by generation resources in this situation would be not 4%, but only 0.5%.

Q. How would a difference between the actual and projected magnitude in the peak load affect FPL's ability to meet its customer's needs?

A. If the actual peak load in a particular year is significantly greater than had been projected at the time the resource plan was developed for that year as much as six years earlier, unless the reserves are adequate FPL would not be able to meet its customers' needs.

Q. What has been the average percent difference between the actual peak load and the peak load forecast developed six years earlier?

A. On average in the last four years the actual peak load has been 7.3% higher than had been projected six years before. As stated previously, FPL's resource plan that includes the proposed addition of WCEC in 2011 and the conversions of Canaveral and Riviera by 2013 and 2014, respectively utilizes FPL's most recent peak load forecast developed in 2008.

Q. How would your results above change if instead of the actual peak in 2014 occurring in August it occurred in June, and if the actual magnitude of the peak load were 7.3% higher than the forecast, consistent with the three-year average percent variance, and assuming that FPL plans for a 15% reserve margin in 2014?

A. The actual peak load in June of 2014 would be 28,516 MW, which would exceed by 1,814 MW the amount of generation capability of 26,702 MW. In other words, if "average" differences were to occur in only these two areas that affect FPL's ability to meet its customers' needs, based on a 15% reserve margin criterion FPL would be short of generation resources to serve its customers and would be forced to exercise 1,814 MW of the DSM capability, or almost 70% of all DSM. In fact, FPL would then have zero generation reserves and would have only 821 MW of DSM left to address all other possible unexpected occurrences.

Q. Under these circumstances wouldn't FPL return to service all generation facilities that are scheduled for planned maintenance to meet the higher than projected peak load?

A. FPL would indeed try to bring as many of the resources as possible back in service. However, depending on the type of technology scheduled for planned maintenance, the type of maintenance activity to be performed or the stage at which the maintenance work is when there are indications that a significant peak load is likely, FPL may not be able to return generation to service quickly enough to meet the peak load requirement. It should be noted that as FPL continues to add advanced gas turbines to its system, there will be less and less flexibility regarding scheduling planned outages. For advanced gas turbine technology, inspections and maintenance must be performed on a strict schedule to avoid the risk of catastrophic technical failure.

Q. In your calculations above have you assumed that any unplanned generation or transmission outages would occur on the peak day?

A. No. The results provided above assume that all generation that is scheduled to operate on the peak day is operating at maximum capacity and that there are no transmission interruptions. Similarly, this calculation assumes that there are no fuel interruptions and that FPL is not providing emergency assistance to other utilities. In other words, the calculations represented in these examples reflect perfect performance of all systems, with only commonly recurring differences between actual operating conditions and the forecast on which the resource plan is based. The results above indicate that even if everything in 2014 were to occur exactly as projected, generation reserves would only be adequate to mitigate the effect of a combination of unplanned outages and interruptions totaling up to 926 MW. To put this in perspective, FPL has more than 20 generating units with generating capacity greater than 400 MW, of which 9 have a generating capacity greater than 630 MW. Therefore, unplanned outages that could exceed 926 MW are not rare.

If the only deviation from the forecast is that the peak occurs in June when 800 MW of capacity is out of service for a planned maintenance outage, the resulting generation reserves of 126 MW would not be adequate to mitigate the effect of any unplanned outage except for one occurring in FPL's smallest peaking units. As can be seen, the 15% reserve margin criterion is not adequate to ensure reliable service.

Q. **How would the results with the higher adjusted peak load occurring in June of 2014 change when FPL maintains a 20% reserve margin?**

A. As shown in Exhibit RS-3, maintaining a 20% reserve margin would require total generation capacity to be 28,711 MW in 2014. As shown in Exhibit RS-4, page 2 of 2, this plan would result in available generating capacity of 27,911 MW (after accounting for the 800 MW out for planned maintenance in

June 2014) plus 2,635 MW of DSM for a total of 30,546 MW of resources against the higher adjusted total peak of 28,516 MW. In this situation FPL would be able to meet load demand, provided that it exercises 605 MW of DSM, leaving a DSM reserve of 2,030 MW to meet any other unexpected circumstance. It is important to note that even with a 20% reserve margin in 2014, the occurrence of ordinary differences between planned and actual peak load conditions such as those presented in this example could use up all generation reserves and about 23% of available DSM would have to be utilized. That leaves only 77% of the DSM reserves, and no generation reserves to offset all other unplanned occurrences, against which the reserve margin is intended to protect FPL's customers. For this reason FPL believes that maintaining a 20% reserve margin criterion for resource planning purposes is in the best interest of its customers.

Q. Is this example intended to demonstrate that FPL's 20% reserve margin criterion will always be the correct level of reserve margin to apply to resource planning?

A. No. This example shows that the Commission should dismiss any suggestion that a 15% reserve margin planning criterion would be adequate. The results above show that a 15% reserve margin reliability criterion is totally inadequate to ensure that FPL could provide reliable service to its customers. Furthermore, these analysis results demonstrate that the additional reliability provided by a 20% reserve margin planning criterion compared to what it would be with a 15% reserve margin is very valuable to FPL's customers.

The question regarding the proper level of reserve margin for future resource planning processes would need to be addressed in an independent proceeding and the implementation date of any change should be far enough into the future to allow utilities to incorporate it into their strategic and operational planning processes, especially because it could well be determined that a reserve margin greater than 20% would be appropriate in the future. It is important to note that the reserve margin criterion is a critical starting point in a utility's multi-year process of identifying need for new resources, obtaining data on the various alternatives, evaluating those alternatives, selecting the best alternative to meet that need, negotiating contract for equipment and construction services or purchased power, and presenting a petition to the Commission to obtain a determination of need. If this basic foundation of the process were to be changed as part of the need determination proceeding, there would be no basis on which a utility could begin the planning process. This view is consistent with the Commission's own views, expressed in Commission Order No. PSC-03-0175-FOF-EI regarding a need determination petition for Progress Energy Florida's Hines Unit 3 in which the Commission stated that it is inappropriate to consider a change to the reserve margin planning criterion in a particular utility's need determination proceeding.

Calculation of FPL's Reserve Margin in Summer of 2014

Maintaining a 15% Reserve Margin

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast ** (MW)	Summer DSM Forecast *** (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2014	25,002	2,500	27,502	26,576	2,651	23,925	3,577	**15.0%**	**1,208**

Maintaining a 20% Reserve Margin

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast ** (MW)	Summer DSM Forecast *** (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2014	26,536	2,175	28,711	26,576	2,651	23,925	4,785	**20.0%**	**(0)**

* The Peak Load Forecast is FPL's Feb 2008 load forecast that includes Lee County load.

* * DSM values shown represent cumulative load management and incremental conservation capability.

EXAMPLE WHY 15% RESERVE MARGIN IS INADEQUATE
OPERATIONS WITH NO WCEC 3 NOR PLANT CONVERSIONS

ADDED 325 MW PPA TO MEET 15% RESERVE MARGIN IN 2014

Year	Month	Week	Total Generating Capacity (MW)	Planned Maintenance (MW)	Available Generating Capacity (MW)	Peak Load (MW)	Generating Capacity Reserves (MW)	DSM Available for Use (MW)	DSM Reserves (MW)	Total Reserves (MW)
2014	August	4	27,502	0	27,502	26,576	926	2,651	2,651	3,577

The above outcome assumes everything occurs in 2014 exactly as forecasted six years earlier, in 2008.

Year	Month	Week	Total Generating Capacity (MW)	Planned Maintenance (MW)	Available Generating Capacity (MW)	Peak Load (MW)	Generating Capacity Reserves (MW)	DSM Available for Use (MW)	DSM Reserves (MW)	Total Reserves (MW)
2014	June	1	27,502	(800)	26,702	26,576	126	2,635	2,635	2,761

The above outcome assumes that the forecasted peak occurs in June; otherwise, there is no change.

Year	Month	Week	Total Generating Capacity (MW)	Planned Maintenance (MW)	Available Generating Capacity (MW)	Peak Load (MW)	Generating Capacity Reserves (MW)	DSM Available for Use (MW)	DSM Reserves (MW)	Total Reserves (MW)
2014	June	1	27,502	(800)	26,702	28,516	**(1,814)**	2,635	**821**	**821**

The above outcome assumes that the peak occurs in June, and that the actual peak is higher than forecasted, and the variance is equal to the average percent variance observed in 2004 - 2007.

Note:

The results above assume that all generating capacity except that explicitly scheduled for maintenance is operating at maximum capacity (i.e., no forced outages), that there are no fuel supply interruptions or transmission interruptions, and that FPL is not providing assistance to any other utility.

EXAMPLE WHY 15% RESERVE MARGIN IS INADEQUATE

OPERATIONS WITH WCEC 3 AND CONVERSIONS OF CANAVERAL AND RIVIERA

Year	Month	Week	Total Generating Capacity (MW)	Planned Maintenance (MW)	Available Generating Capacity (MW)	Peak Load (MW)	Generating Capacity Reserves (MW)	DSM Available for Use (MW)	DSM Reserves (MW)	Total Reserves (MW)
2014	August	4	28,711	0	28,711	26,576	2,135	2,651	2,651	4,786

The above outcome assumes everything occurs in 2014 exactly as forecasted seven years earlier.

Year	Month	Week	Total Generating Capacity (MW)	Planned Maintenance (MW)	Available Generating Capacity (MW)	Peak Load (MW)	Generating Capacity Reserves (MW)	DSM Available for Use (MW)	DSM Reserves (MW)	Total Reserves (MW)
2014	June	1	28,711	(800)	27,911	26,576	1,335	2,635	2,635	3,970

The above outcome assumes that the forecasted peak occurs in June; otherwise, there is no change.

Year	Month	Week	Total Generating Capacity (MW)	Planned Maintenance (MW)	Available Generating Capacity (MW)	Peak Load (MW)	Generating Capacity Reserves (MW)	DSM Available for Use (MW)	DSM Reserves (MW)	Total Reserves (MW)
2014	June	1	28,711	(800)	27,911	28,516	**(605)**	2,635	2,030	2,030

The above outcome assumes that the peak occurs in June, and that the actual peak is higher than forecasted, and the variance is equal to the average percent variance observed in 2004 - 2007.

Note:

The results above assume that all generating capacity except that explicitly scheduled for maintenance is operating at maximum capacity (i.e., no forced outages), that there are no fuel supply interruptions or transmission interruptions, and that FPL is not providing assistance to any other utility.

A Look at January 11, 2010 If FPL Had Planned to a 15% Total Reserve Margin Criterion

I. What Actually Occurred with FPL Planning to a 20% Total Reserve Margin Criterion

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					= (2) - (3)		= (4) - (5)	= (1) - (6)	= (7) / (6)	= (7) - (5) - (3)
		Total Projected Capacity	**Forecasted Peak Load**	**Forecasted Utility EE**	**Peak Load After EE**	**Forecasted or Remaining LM**	**Forecasted Firm Load After EE and LM**	**Total Reserves**	**Total Reserve Margin as % of Firm Load**	**Generation Reserves**
		(MW)	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(%)**	**(MW)**
(1)	**2009 TYSP resource plan projection for Summer 2010**	22,916	21,147	220	20,927	1,899	19,028	3,888	20.4%	1,769
(2)	**2009 TYSP resource plan projection for Winter 2010**	26,852	18,790	114	18,676	1,705	16,971	9,881	58.2%	8,062
	Note that all subsequent rows present adjustments to show how Jan 2010 peak day actual conditions differed from planned conditions shown on row (2)									
	Load Adjustments on Jan 2010 peak day									
(3)	**Adjustment**				6,196					
(4)	**Resulting operating conditions on 2010 Winter peak hour**	26,852			24,872	1,705	23,167	3,685	15.9%	1,980
	Generation / Load Management Adjustments on Jan 2010 peak day									
(5)	**Adjustments**	(1,980)			(561)	(561)				
(6)	**Operating conditions on 2010 Winter peak hour**	24,872			24,311	1,144	23,167	1,705	7.4%	561
	Emergency Sales adjustments on Jan 2010 peak day resulted in 24,346MW of FPL load and 561MW of emergency sales. Total load (FPL and 3rd parties) served is 24,872MW									
(7)	**Adjustment**				561					
(8)	**Operating conditions on 2010 Winter peak hour**	24,872			24,872	1,144	23,728	1,144	4.8%	0
	TP Unit 4 Adjustment (if occurred at peak hour)									
(9)	**Adjustment**	(750)			(750)	(750)				
(10)	**Operating conditions on 2010 Winter peak hour**	24,122			24,122	394	23,728	394	1.7%	0

A Look at January 11, 2010 If FPL Had Planned to a 15% Total Reserve Margin Criterion

II. What Is Projected to Have Occurred If FPL Had Planned to a 15% Total Reserve Margin Criterion

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					= (2) - (3)		= (4) - (5)	= (1) - (6)	= (7) / (6)	= (7) - (5) - (3)
		Total Projected Capacity	**Forecasted Peak Load**	**Forecasted Utility EE**	**Peak Load After EE**	**Forecasted or Remaining LM**	**Forecasted Firm Load After EE and LM**	**Total Reserves**	**Total Reserve Margin as % of Firm Load**	**Generation Reserves**
		(MW)	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(%)**	**(MW)**
(1)	**2009 TYSP resource plan projection for Summer 2010**	22,916	21,147	220	20,927	1,899	19,028	3,888	20.4%	1,769
(2)	**2009 TYSP resource plan projection for Winter 2010**	26,852	18,790	114	18,676	1,705	16,971	9,881	58.2%	8,062
(1a)	**Adjusted resource plan for Summer 2010 assuming 15% RM criterion**	21,882	21,147	220	20,927	1,899	19,028	2,854	15.0%	735
(1b)	**Adjusted resource plan for Winter 2010 assuming the same Summer/Winter ratio for total projected capacity**	25,640	18,790	114	18,676	1,705	16,971	8,669	51.1%	6,850
	Note that all subsequent rows present adjustments to show how Jan 2010 peak day actual conditions would have differed from planned conditions shown on row (2b) if FPL had planned to a 15% total reserve margin									
	Load Adjustments on Jan 2010 peak day									
(3)	**Adjustment**				6,196					
(4)	**Resulting operating conditions on 2010 Winter peak hour**	25,640			24,872	1,705	23,167	2,473	10.7%	768
	Generation / Load Management Adjustments on Jan 2010 peak day									
(5)	**Adjustments**	(1,980)			(561)	(561)				
(6)	**Operating conditions on 2010 Winter peak hour**	23,660			24,311	1,144	23,167	493	2.1%	(651)
	Emergency Sales adjustments on Jan 2010 peak day resulted in 24,346MW of FPL load and 561MW of emergency sales. Total load (FPL and 3rd parties) served is 24,872MW									
(7)	**Adjustment**				561					
(8)	**Operating conditions on 2010 Winter peak hour**	23,660			24,872	1,144	23,728	(68)	-0.3%	(1,212)
	TP Unit 4 Adjustment (if occurred at peak hour)									
(9)	**Adjustment**	(750)			(750)	(750)				
(10)	**Operating conditions on 2010 Winter peak hour**	22,910			24,122	394	23,728	(818)	-3.4%	(1,212)

Note: An inability to serve 68 MW would impact ~39,000 customers. An inability to serve 818 MW would impact ~471,000 customers.

The Need for a 3rd Reliability Criterion for FPL: a Generation-Only Reserve Margin (GRM) Criterion

Bob Barrett
VP Finance
February 28, 2014

A Note Regarding this New Presentation

- **This presentation first addresses 4 "carry over" topics from the Dec. 6th meeting:**
  1. What does a projected LOLP value really mean?
  2. LM customer "fatigue" benchmarking results.
  3. Benefits of generation reserves during pre-hurricane periods.
  4. Emergency declarations and regulatory scrutiny.

- **The presentation then discusses FPL's need for a new reliability criterion from 3 perspectives:**

1. A "looking back" analysis of the Winter peak day of 2010 and what might have occurred if FPL had entered that January having a Summer GRM of 10% or 5%*
2. A "looking forward" analysis using the year 2021
3. Why 10% is a reasonable value for the new GRM criterion

- **The presentation concludes with a summary of "next steps"**

* Unless otherwise noted, all GRM values are Summer GRM values (because the Summer GRM values will have the most impact on resource planning)

Executive Summary

- **A generation-only reserve margin (GRM) reliability criterion is desirable from an operational perspective for several reasons:**

  - **If two resource plans have an identical total reserve margin value, but one plan has a 10% GRM and the other a 5% GRM, the 10% GRM plan can provide operators with hundreds of additional MW of reserves (generating and/or load management) during severe peaks**

  - **A higher GRM plan can also provide operators with significant additional reserves when hurricanes force early shut downs of nuclear units**

- **A GRM reliability criterion is also desirable from a resource planning perspective because it can lower LOLP projections**

- **A GRM criterion of a minimum of 10% matches well with Operation's projected need for 2,650 MW of "operational generation reserves" (i.e., generation above forecasted load)**

FPL

The 1st topic, "what does an LOLP value mean?", is addressed both by looking at the calculation and providing an interpretation

How is an LOLP Value Calculated?

- **LOLP calculations project the probability that a utility will not be able to serve 100% of its firm load (i.e., at least 1 MW of firm load cannot be served) during the time period analyzed after all available generation and LM have been used**
- **LOLP calculations do not provide information regarding: (1) the MW amount that cannot be served; and (2) the duration of the event**
- **The probability of not being able to serve all firm load is calculated for the peak hour for each day in the year**
- **These daily probabilities are then summed to derive a monthly probability of not being able to meet firm load on a peak hour during the month**
- **Then the monthly probabilities are summed to derive an annual probability of not being able to meet firm load on a peak hour during the year**
- **Thus an LOLP value is a sum of daily probabilities (which can exceed 1.00) and the LOLP value is commonly expressed in terms of "days per year"**

FPL

A monthly breakdown of previously provided annual LOLP projections is provided below

Monthly Breakdown of Previous LOLP Values

- In the 12/06/2013 presentation, two LOLP values were presented for the year 2021: 0.0358 days/year for a 5% GRM plan and 0.0257 days/year for a 10% GRM plan
- The following table shows a monthly breakdown of these values:

	w/ 5% GRM		w/ 10% GRM	
	----------------		-------------------	
Month	Projected Days per Individual Month	Projected Cumulative Days per Year	Projected Days per Individual Month	Projected Cumulative Days per Year
January	0.000018	0.0000	0.000003	0.0000
February	0.000000	0.0000	0.000000	0.0000
March	0.000030	0.0000	0.000004	0.0000
April	0.000002	0.0001	0.000001	0.0000
May	0.000065	0.0001	0.000022	0.0000
June	0.001522	0.0016	0.000819	0.0008
July	0.000436	0.0021	0.000351	0.0012
August	0.001456	0.0035	0.001203	0.0024
September	0.031795	0.0353	0.023089	0.0255
October	0.000506	0.0358	0.000210	0.0257
November	0.000000	0.0358	0.000000	0.0257
December	0.000000	0.0358	0.000000	0.0257
Annual Days per Year =		**0.0358**		**0.0257**

FPL

LOLP discussion may be “flipped” from “days per year” to “years per day” terms to provide an easier-to-use interpretation

A Useful Interpretation of LOLP Values

- **If one assumes that a projected LOLP value for a given year remains constant for each year in an LOLP analysis, one can project how many years will pass before the utility will not be able to meet firm load (i.e., before the sum of the annual LOLP values = 1.0) by dividing the annual LOLP into 1.0**

- **Some utilities, such as Hawaiian Electric Company, use this “years per day” format when reporting results of LOLP analyses**

- **The 5% GRM plan had an annual LOLP value of 0.0358 which converts to 27.9 years, and the 10% GRM plan had an annual LOLP value of 0.0257 or 38.9 years, before LOLP sums to 1.0**

In this analysis, the 10% GRM plan is projected to allow FPL to meet firm load for 11 more years without an interruption than with the 5% GRM plan

FPL

Regarding the 2nd topic of LM "fatigue", benchmarking data was sought from multiple sources

Benchmarking Results

- **The DSM group contracted with Esource to canvas various industry leaders (utilities / consultants)**
- **No empirical data exists on customer fatigue due to over use of LM, but opinions received are in-line with FPL's view regarding avoiding LM fatigue:**
  - No greater than 10 events/year
  - Events should be spread out throughout the year (e.g., not all in summer or extreme winter events)
  - Events should not be prolonged (e.g., greater than 2-3 hours)
- **Ahmad Faruqui, Ph.D., an industry expert, stated this is a question "for which I have not been able to find any good data"**
  - He implied a range for which fatigue may occur: "Survey results indicate that the maximum realistic call duration for ERCOT is 4 hrs. and frequency should be no greater than 10 events/year."

LM benchmarking on customer fatigue is inconclusive

FPL

The 3rd topic is the relevance of generation reserves to address generation needed prior to hurricane landfall

Generation Margins Needed Pre-Hurricane

- **Prior to land fall, loads are high due to customers cooling their homes and lowering refrigerator temperatures**
- **High loads prior to land fall occur while FPL is shutting down specific units**
  - For example, a hurricane impacting the St. Lucie units (almost 2,000 MW of generation/gross output), must go to 60% output as early as 24 hours prior to land fall, and complete shut down at 18 hours prior to hurricane winds at the site.
- **Activation of LM due to a capacity shortfall prior to landfall would have an impact on our customers' preparations including efforts to pre-cool their homes**
- **A generation reserve of approximately 2,650 MW (as discussed on slide 20 – Operational generation reserves) provides additional reliability, allowing service for our customers prior to hurricane impact**

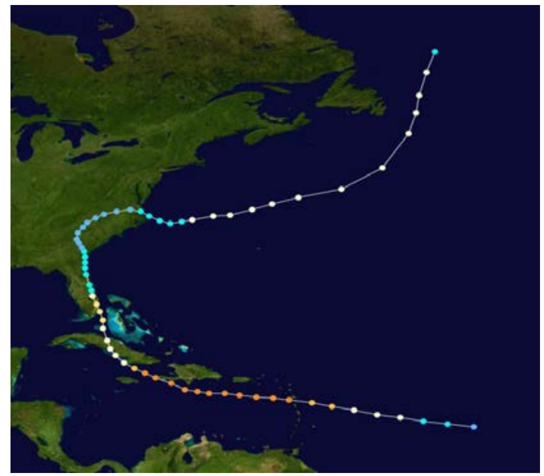
Operations prior to hurricane landfall must consider the unavailability of specific generation and impact to customers

FPL

If a hurricane impacts both PTN and PSL, there is high potential to shut down both units

PTN and PSL Impact and Generation Reserves

- **Over the past 100 years, multiple hurricanes have impacted the PTN and PSL areas**
- **In 1960, Hurricane Cleo (Category 2) may have resulted in sustained hurricane force winds at both PTN and PSL (no anemometers in area)**
- **Both plants, with output of approx. 3,600 MW, would need to shut down if affected**



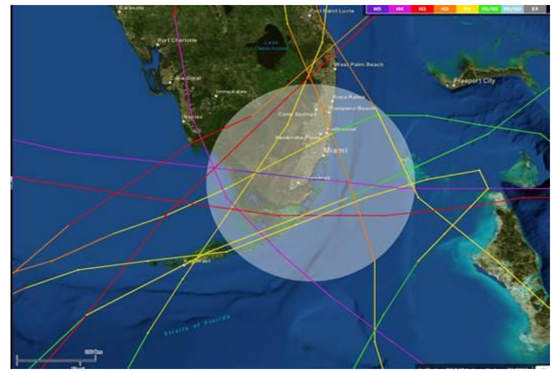
- **The operational generation reserves provide additional reliability to mitigate the unavailability of generation prior to hurricane impact**

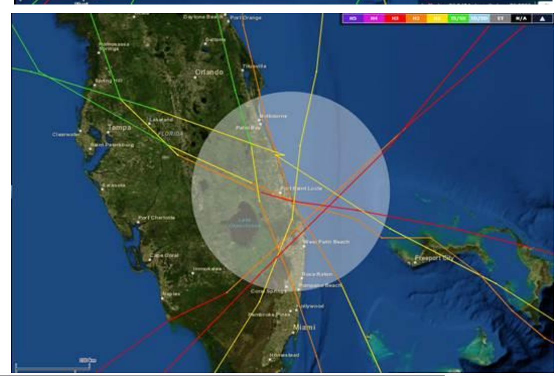
The impact of a hurricane affecting PTN and PSL would require the use of large amounts of LM. Shedding of firm customers is not expected.

Generation reserves are needed to account for generation during periods prior to hurricane landfall

Generation Reserves Needed Pre-Hurricane

- **From the period of 1960-2013 eleven hurricanes tracked within 65 nautical miles of Turkey Point and another 8 hurricanes tracked within 65 nautical miles of St. Lucie**
  - Turkey Point hurricanes would reduce the total reserve margin from 21.0% (year 2021) to 13.9%
  - St. Lucie hurricanes would reduce the total reserve margin from 21.0% (year 2021) to 12.2%





The impact from a hurricane to one of the nuclear sites is significant, resulting in the loss of most of the generation

FPL

The 4th topic is that the potential for regulatory implications due to emergency operations declarations

North American Electric Reliability Corporation (NERC) Standards

- **EOP-002 NERC Reliability Standard: Declaration of Energy Emergency Alert (EEA)**
  - FPL's plan based on its interpretation of EOP-002 which is to declare an EEA-2 when LC capability is less (or close to less) than the required reserves necessary to cover the loss of largest FPL unit (FM2 at 1,515 MW by 2021)
    -- Note: EEA-3 is when load shedding is eminent or underway
  - FPL plan will not result in a declaration for limited (e.g., less than 400 MW) use of LC
    -- FPL has not declared an EEA under EOP-002
  - From discussions with peers in the Southeast and limited information on NERC website, FPL's practice appears to be consistent with historical declarations in other regions

The 4th topic is that the potential for regulatory implications also influences FPL's operating philosophy (Cont'd)

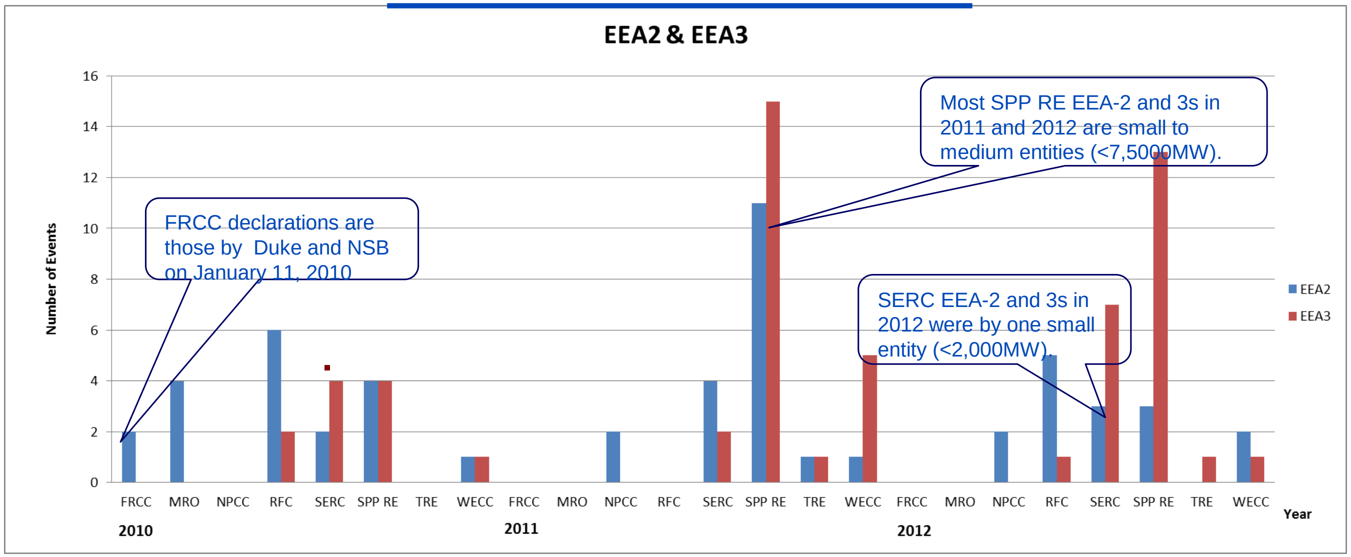
North American Electric Reliability Corporation (NERC) Standards

- **EOP-002 triggers for EEA-2s is not clear, and recognized as such industry-wide**
  - Standard implies that a declaration of an EEA-2 is linked to LC deployment
  - FRCC procedure linking the FRCC Emergency Capacity Plan with EOP-002 does clarify triggers for EEA-2
- **NERC tracks EEA-2s and EEA-3s under EOP-002 to measure the number of events declared during peak load periods, this may serve as leading indicator of capacity shortfall**

FPL

NERC historical tracking of alert declarations varies by region

EEA-2 and EEA-3 Events



- **Legitimate emergencies will be tracked by NERC**
  - NERC states that EEA-2 events calling solely for activation of DSM or interruption of non-firm load will be excluded from the metric in the future as demand response is a legitimate resource and are not of direct concern regarding reliability.

The potential, form, and results of regulatory scrutiny based on what NERC considers too many legitimate emergencies is unclear

FPL

The need for a new GRM reliability criterion can be supported by 3 points

FPL's Need for a New Reliability Criterion

- **These 3 points (presented in decreasing order of importance) are:**
  1. "All resource plans with identical total reserve margins are not created equal" from an operational perspective (a higher GRM plan will result in significantly more total resources - generation and load management - available for system operators than a lower GRM plan in severe peak conditions)
  2. A resource plan with a higher GRM value is projected to be more reliable from an LOLP perspective (slides 3 through 5)
  3. A resource plan with a higher GRM value is projected to have to use its LM resources less frequently (from 12/06/13 presentation)
- **In regard to point 1 above:**
  – This point can be demonstrated by a "look backwards" analysis of Winter 2010 (slides 15 – 17 and Appendix slides 24 - 27)
  – This point can also be demonstrated by a "looking forward" analysis for Summer and Winter for the year 2021 (slides 18 & 19 and Appendix slides 28 -33)

FPL

In the "look backwards" analysis, several perspectives were taken of the Winter peak day in 2010

Regarding the January 2010 Peak Day

- **The first perspective was of what actually happened on that day (the 2009 Site Plan's projections for the year 2010 were used as the starting point for this analysis)**

- **The second perspective was to see how FPL's system would have fared if the resource plan had been different with a GRM of 10% in 2010 (but an identical Summer total RM of 20.4%)**

- **The third perspective was to see how FPL's system would have fared if the resource plan had been different with a GRM of 5% in 2010 (but an identical Summer total RM of 20.4%)**

Sufficient generation reserves are needed for peak load periods

January 11, 2010 (7- 8 AM) – All Time FPL Peak Load

- **Relative to the 2009 Ten Year Site Plan (TYSP), the total reserves for the Winter were 58.2% with a Generation Reserve Margin (GRM) of 42.9%. The Summer reserve margin was 20.4% with an 8.4% GRM**
  - FPL's load was 24,872 MW, 6,196 MW higher than forecasted
  - FPL entered day with 7.4% reserves, all in load management (LM)
  - 24,872 MW of generation was available
  - FPL implemented C/I LM and voltage reduction (561 MW)
  - FPL sold 526 MW of emergency power
  - 1,144 MW of LM remained available during the peak hour
  - No firm load was curtailed by FPL or any other Florida utility
  - Several hours after the peak hour Turkey Point 4 (PTN4) tripped with 750 MW of generation

In Winter 2010, the generation reserves were just sufficient to provide reliable operations with no curtailment of firm load in Florida

FPL

Analyses of Winter 2010, using different GRM values, provide a couple of key "takeaways"*

Takeaways from the January 2010 Peak Day Analyses

	Firm Load is Shed?		
Scenario	**W/ TP4**	**W/O TP4**	**Comments**
Actual: 8.4% GRM	No	No	If PTN4 would have tripped prior to the peak, FPL would have implemented additional LM
w/ 10% GRM	No	No	A 10% GRM (as compared to a 5%) would have resulted in a 659 MW increase in LM reserves, and no utilities would have had to shed firm load Similar to the 8.4% GRM scenario, if PTN4 would have tripped prior to the peak, FPL would have implemented additional LM
w/ 5% GRM	No	Yes	W/O TP4 either FPL or another utility in Florida would have had to shed 52 MW of firm load impacting over 30,000 customers

* The actual analyses are presented in Appendix slides 24 - 27

On 1/11/10, a 5% GRM would have resulted in 30,000 firm load customers being shed, but a 10% GRM would have provided 659 MW of additional reserves

FPL

A "looking forward" analysis of 2021 addressed both Summer and Winter with 5% and 10% GRM-based resource plans

How the Analyses of 2021 Were Conducted

- The 2013 Site Plan's resource plan for the year 2021 was the starting point: 6.9% GRM, 21.0% Summer total RM, and 34.5% Winter total RM
- Then two alternate resource plans with the same 21.0% Summer total RM, but either 5% or 10% Summer GRM were "constructed" for Summer (comparable alternate resource plans for Winter 2021 were also constructed)
- To simplify the analysis, the alternate plans differed in regard to EE and generation only (similar results would occur if LM instead of EE had been varied in the plans)
- Identical changes of 9% were made to forecasted load, EE, and available generation (the percentage change chosen is arbitrary, but reasonable and consistent)
- The resulting available generation and total resources remaining after these changes were made are compared (note that EE's impact has already "happened" at the peak)

FPL

The "looking forward" analyses of resource plans for 2021 provides additional support for a 10% GRM-based resource plan compared to a 5% GRM-based plan

Key Points from the "Looking Forward" Analyses

- **Only the 10% GRM-based resource plan is projected to allow FPL to meet firm load in both Summer and Winter of 2021**
- **Furthermore, when comparing the two GRM-based resource plans, the 10% GRM-based plan provides significantly more MW of resources for both Summer and Winter**

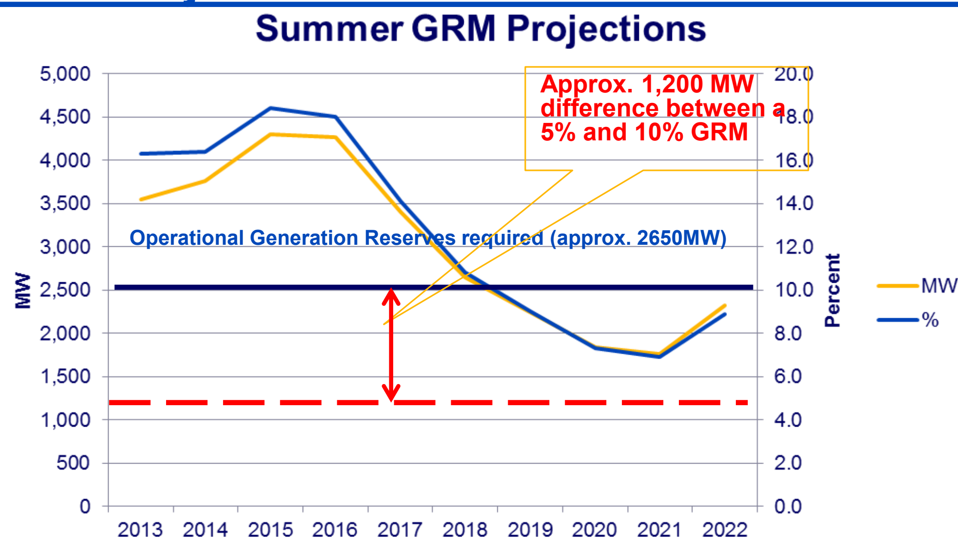
	Summer of 2021			Winter of 2021		
	w/ 10% GRM	w/ 5% GRM	Increased Total Reserves w/ 10% GRM	w/ 10% GRM	w/ 5% GRM	Increased Total Reserves w/ 10% GRM
Total Reserves Remaining after Load, EE, and Generation Adjustments	34	(169)	202	2,921	2,193	728

This "looking forward" analysis again shows system operators will have more resources for their use with a 10% GRM, rather than a 5% GRM, resource plan

FPL

A 10% GRM criterion is a reasonable, easy-to-articulate proxy for FPL's operational generation reserves need

GRM Projections from FPL's 2013 Site Plan



- **FPL's goal is to maintain ~ 2,650 MW of Operational Generation Reserves to cover the following operational situations:**
  - Expected unavailable generation (687 MW)
  - The generation loss of the largest the largest unit (1,515 MW)
  - Real time operating reserves deployable within 15 minutes as part of the Florida Reserve Sharing Group (450 MW by 2021)

A 10% GRM is consistent with FPL's required operational reserves

FPL has begun using the new GRM criterion in its resource planning process and in 2014 analyses to be filed w/ the FPSC

Next Steps regarding the GRM Criterion

- Text explaining why FPL is using the new criterion will be included in the 2014 TYSP filing and as part of the DSM Goals testimony
- The explanation focuses on analyses comparing resource plans with 10% GRM vs. 5% GRM and include these key points :
  - A 10% GRM results in hundreds of MW of additional operational reserves on severe peak days
  - A 10% GRM results in lower LOLP projections
  - A 10% GRM criterion matches well with the approximately 2,650 MW of generation reserves necessary for operations
- Analyses supporting the 2014 TYSP and DSM Goals filings in April, and the 2014 NCRC filing in early May, all are using the 10% GRM criterion
- These analyses all assume that the 10% GRM criterion must be met beginning in the Summer of 2019

FPL is not making a separate filing seeking official FPSC approval for FPL's GRM criterion

Next Steps regarding the GRM Criterion (Continued)

- No separate filing/request seeking official FPSC approval for the new GRM criterion will be made
- The only time the FPSC has officially approved a reliability criterion is in the late 1990s when it approved the voluntary stipulation by FPL, TECO, and DEF to move from a 15% to a 20% total reserve margin criterion to close an FPSC docket examining Florida reserves
- TECO did not request approval for its similar supply side reserve margin which it has been using for approximately 10 years
- It is anticipated that discovery requests focused on the new GRM criterion will be received in regard to both the TYSP and DSM Goals filings

FPL

Appendix

FPL and others utilities in Florida were marginally able to serve their entire firm load and FPL met its operational reserve requirements with an 8.4% GRM

January 11, 2010 (7-8 AM) – All Time FPL Peak Load

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
				= (2) - (3)		= (4) - (5)	= (1) - (6)	= (7) / (6)	= (7) - (5) - (3)	= (9) / (2)	
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
2009 TYSP resource plan projection for Summer 2010	22,916	21,147	220	20,927	1,899	19,028	3,888	20.4%	1,769	8.4%	---
2009 TYSP resource plan projection for Winter 2010	26,852	18,790	114	18,676	1,705	16,971	9,881	58.2%	8,062	42.9%	---
Note that all subsequent rows present adjustments to show how Jan 2010 peak day actual conditions differed from planned conditions shown on row (2)											
Load Adjustments on Jan 2010 peak day											
Increase in FPL load served after EE (w/o DSM)				6,196							---
Resulting operating conditions on 2010 Winter peak hour	26,852			24,872	1,705	23,167	3,685	15.9%	1,980	8.0%	**Yes**

FPL and other utilities in Florida were marginally able to serve entire firm load and meet operational reserve requirements with 8.4% GRM (additional adjustments)

January 11, 2010 (7-8AM) – All Time FPL Peak Load

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
				= (2) - (3)		= (4) - (5)	= (1) - (6)	= (7) / (6)	= (7) - (5) - (3)	= (9) / (2)	
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
Generation / Load Management (CILC and Voltage reduction) Adjustments of on Jan 2010 peak day											
	(1,980)			(561)	(561)						---
Operating conditions on 2010 Winter peak hour	24,872			24,311	1,144	23,167	1,705	7.4%	561	2.3%	**Yes**
Emergency Sales adjustments on Jan 2010 peak day resulted in 24,346MW of FPL load and 526MW of emergency sales. Total load (FPL and 3rd parties) served is 24,872MW											
Emergency sales (recallable)				526							---
Operating conditions on 2010 Winter peak hour	24,872			24,872	1,144	23,728	1,144	4.8%	0	0.0%	**Yes**
TP Unit 4 Nuclear Trip on Jan 2010 prior to peak day											
TP Nuclear Adjustment	(750)			(750)	(750)						---
Operating conditions on 2010 Winter peak hour	24,122			24,122	394	23,728	394	1.7%	**0**	0.0%	**Yes**

Two "what if" analyses examined how FPL would have fared if it had entered Winter 2010 with a higher (10%) or lower (5%) GRM

"What If"for January 2010 Peak Day w/ 10% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
Creation of Revised 10% GRM Summer Plan and Corresponding Winter Plan											---
Modify the 2009 TYSP resource plan for Summer 2010 to achieve a 10% GRM	23,262	21,147	(72)	21,219	1,899	19,320	3,941	20.4%	2,115	10.0%	---
Using Winter vs Summer differentials, and the modified Summer resource plan, create a comparable resource plan for Winter 2010	27,216	18,790	(37)	18,827	1,705	17,122	10,094	59.0%	8,426	44.8%	Yes
Load Adjustments on Jan 2010 peak day											
Increase in FPL load served after EE but prior to LM utilization				6,231							
Resulting operating conditions on 2010 Winter peak hour due to load	27,216		(37)	25,058	1,705	23,353	3,863	16.5%	2,158	8.6%	Yes
Generation / Load Management / Further FPL Load Adjustments of on Jan 2010 peak day											
	(1,980)			(561)	(561)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments	25,236			24,497	1,144	23,353	1,883	8.1%	739	3.0%	Yes
Emergency Sales Adjustments on Jan 2010 peak day											
Emergency sales				526							
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments+Em. Sales	25,236			25,023	1,144	23,879	1,357	5.7%	213	0.9%	Yes
TP Unit 4 Nuclear Trip on Jan 2010 prior to peak day											
TP Nuclear Adjustment	(750)			(750)	(750)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, generation & TP adjustments	24,486			24,273	394	23,879	607	2.5%	213	0.9%	Yes

* The 2010 Tony letter showed FPL unit capability as 23,333 MW for Winter 2010 & 22,142 MW for Summer. The Winter/Summer ratio is 1.054.

FPL's generation and LM resources would have been greater with a 10% GRM than with 8.4% GRM

The second "what if" analysis examined how FPL would have fared if it had entered Winter 2010 with a lower (5%) GRM

"What If"for January 2010 Peak Day w/ 5% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
Creation of Revised 5% GRM Summer Plan and Corresponding Winter Plan											---
Modify the 2009 TYSP resource plan for Summer 2010 to achieve a 5% GRM	22,204	21,147	806	20,341	1,899	18,442	3,762	20.4%	1,057	5.0%	---
Using Winter vs Summer differentials, and the modified Summer resource plan, create a comparable resource plan for Winter 2010	26,102	18,790	418	18,372	1,705	16,667	9,435	56.6%	7,312	38.9%	Yes
Load Adjustments on Jan 2010 peak day											
Increase in FPL load served after EE but prior to LM utilization				6,231							
Resulting operating conditions on 2010 Winter peak hour due to load	26,102		418	24,603	1,705	22,898	3,204	14.0%	1,499	6.1%	Yes
Generation / Load Management / Further FPL Load Adjustments of on Jan 2010 peak day											
	(1,980)			(561)	(561)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments	24,122			24,042	1,144	22,898	1,224	5.3%	80	0.3%	Yes
Emergency Sales Adjustments on Jan 2010 peak day											
Emergency sales				526							
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments+Em. Sales	24,122			24,568	1,144	23,424	698	3.0%	(446)	-1.8%	No
TP Unit 4 Nuclear Trip on Jan 2010 prior to peak day											
TP Nuclear Adjustment	(750)			(750)	(750)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, generation & TP adjustments	23,372			23,818	394	23,424	(52)	-0.2%	(446)	-1.9%	No

* The 2010 Tony letter showed FPL unit capability as 23,333 MW for Winter 2010 & 22,142 MW for Summer. The Winter/Summer ratio is 1.054.

Even after exhausting FPL's generation and LM resources, FPL would not have been able to meet its firm load with a 5% GRM

FPL

Regarding a "look forward" to 2021, the 5% Summer GRM-based resource plan was examined first in regard to Summer peak

"What If" Summer 2021 Peak Day w/ 5% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
Summer	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
5% GRM resource plan	26,838	25,560	1,230	24,330	2,150	22,180	4,658	21.0%	1,278	5.0%
Higher-than-Projected Peak Load *		2,300								
Lower-than-projected EE Reduction *			(111)							
Resulting actual operating conditions on 2021 peak hour	26,838	27,860	1,119	26,741	2,150	24,591	2,247	9.1%	97	0.3%
Unavailable Generation *	(2,415)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	24,423	27,860	1,119	26,741	2,150	24,591	(169)	-0.7%	(2,319)	-8.3%

* A 9% adjustment was made to the starting point value in the first row.

With the 5% GRM plan, FPL would not be able to meet Summer firm load (as seen by the negative 169 MW) of Total Reserves in Col. 7)

FPL

Docket No. 150196-EI
The Need for a 3rd Reliability Criterion for FPL:
A Generation-Only Reserve Margin (GRM) Criterion
Exhibit SRS-11, Page 29 of 33

The 10% Summer GRM-based resource plan was examined next in regard to Summer peak

“What If” Summer 2021 Peak Day w/ 10% GRM

Summer	(1) Total Projected Capacity (MW)	(2) Forecasted Peak Load (MW)	(3) Forecasted Utility EE (MW)	(4) = (2) - (3) Peak Load After EE (MW)	(5) Forecasted LC (MW)	(6) = (4) - (5) Forecasted Firm Load After EE and LC (MW)	(7) = (1) - (6) Total Reserves (MW)	(8) = (7) / (6) Total Reserve Margin as % of Firm Load (%)	(9) = (1) - (2) or = (1) - (4) Generation Reserves (MW)	(10) = (9) / (2) GRM (%)
10% GRM resource plan	28,116	25,560	174	25,386	2,150	23,236	4,880	21.0%	2,556	10.0%
Higher-than-Projected Peak Load *		2,300								
Lower-than-projected EE Reduction *			(16)							
Resulting actual operating conditions on 2021 peak hour	28,116	27,860	158	27,702	2,150	25,552	2,564	10.0%	414	1.5%
Unavailable Generation *	(2,530)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	25,586	27,860	158	27,702	2,150	25,552	34	0.1%	(2,117)	-7.6%

* A 9% adjustment was made to the starting point value in the first row.

With the 10% GRM plan, FPL would be able to meet Summer firm load (as seen by the positive 34 MW of Total Reserves)

The 5% Summer GRM-based resource plan was examined next in regard to Winter peak

"What If" Winter 2021 Peak Day w/ 5% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
Winter	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
Winter resource plan corresponding to the Summer plan w/ 5% GRM	28,287	23,601	637	22,964	1,597	21,367	6,920	32.4%	4,686	19.9%
Higher-than-Projected Peak Load *		2,124								
Lower-than-projected EE Reduction *			(57)							
Resulting actual operating conditions on 2021 peak hour	28,287	25,725	580	25,145	1,597	23,548	4,739	20.1%	3,142	12.2%
Unavailable Generation *	(2,546)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	25,741	25,725	580	25,145	1,597	23,548	2,193	9.3%	596	2.3%

* A 9% adjustment was made to the starting point value in the first row.

With the 5% GRM resource plan, FPL would be able to meet Winter firm load with 2,193 MW of Total Reserves to spare

FPL

The 10% Summer GRM-based resource plan was then examined in regard to Winter peak

"What If" Winter 2021 Peak Day w/ 10% GRM

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				= (2) - (3)		= (4) - (5)	= (1) - (6)	= (7) / (6)	= (1) - (2) or	= (9) / (2)
Winter	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
Winter resource plan corresponding to the Summer plan w/ 10% GRM	29,634	23,601	90	23,511	1,597	21,914	7,720	35.2%	6,033	25.6%
Higher-than-Projected Peak Load *		2,124								
Lower-than-projected EE Reduction *			(8)							
Resulting actual operating conditions on 2021 peak hour	29,634	25,725	82	25,643	1,597	24,046	5,588	23.2%	3,991	15.5%
Unavailable Generation *	(2,667)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	26,967	25,725	82	25,643	1,597	24,046	2,921	12.1%	1,324	5.1%

* A 9% adjustment was made to the starting point value in the first row.

With the 10% GRM resource plan, FPL would be able to meet Winter firm load with 2,921 MW of Total Reserves to spare

FPL

Another "look forward to 2021" case was analyzed in which LM, not EE, was allowed to vary

"What If" Summer 2021 Peak Day w/ 5% GRM & LM Varying

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
Summer	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
5% GRM resource plan	26,838	25,560	830	24,730	2,550	22,180	4,658	21.0%	1,278	5.0%
Higher-than-Projected Peak Load *		2,300								
Lower-than-projected EE and LM Reduction *					(230)					
Resulting actual operating conditions on 2021 peak hour	26,838	27,860	830	27,030	2,321	24,710	2,128	8.6%	-192	-0.7%
Unavailable Generation *	(2,415)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	24,423	27,860	830	27,030	2,321	24,710	(287)	-1.2%	(2,608)	-9.4%

* A 9% adjustment was made to the starting point value in the first row.

With the 5% GRM plan, FPL would not be able to meet Summer firm load (as seen by the negative 287 MW of Total Reserves in Col. 7)

FPL

Another "look forward to 2021" case was analyzed in which LM, not EE, was allowed to vary - continued

"What If" Summer 2021 Peak Day w/ 10% GRM & LM Varying

Summer	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
10% GRM resource plan	28,116	25,560	830	24,730	1,494	23,236	4,880	21.0%	2,556	10.0%
Lower-than-projected EE and LM Reduction *		2,300								
Lower-than-projected EE Reduction *					(134)					
Resulting actual operating conditions on 2021 peak hour	28,116	27,860	830	27,030	1,360	25,671	2,445	9.5%	1,086	3.9%
Unavailable Generation *	(2,530)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	25,586	27,860	830	27,030	1,360	25,671	(85)	-0.3%	(1,445)	-5.2%

* A 9% adjustment was made to the starting point value in the first row.

With the 10% GRM plan, FPL comes closer to meeting Summer firm load (as seen by the negative 85 MW of Total Reserves in Col. 7)

FPL

Comparison of the Major Drivers of Benefits in DSM Cost-Effectiveness: 2014 DSM Goals Docket Inputs and Forecasts versus 2015 Inputs and Forecasts

(Source: 2015 FPL RFP and 2014 DSM Goals Filing/2014 TYSP)

(1)	(2)	(3)	(4) = (3) - (2)	(5) = (4) / (2)	(6)
	DSM Goals Avoided Unit (All costs in 2019$)	**OCEC Unit 1 (All Costs in 2019$)**	**Difference (OCEC Unit 1 - DSM Goals Avoided Unit)**	**% Decrease re $/kW or $/MWh**	**Comments**
Summer MW	1,269	1,622	353		OCEC Unit 1 is larger
In-Service Year	2019	2019	0		No difference
Total Installed Cost (In-service year $/kW)	$968	$737	(231)	-24%	OCEC Unit 1 has lower $/kW total installed cost
Total Installed Cost (In-service year $M)	$1,228.4	$1,195.4	(33.0)		See Note (1) below
Gas Expansion (Addl.) OCEC Unit 1 only (In-service year $M)	$0	$20.9	20.9		OCEC Unit 1 gas pipeline lateral costs will be recovered through an adjustment to the annual transportation rate over 25 years
Fixed O&M ($/kW-yr)	$22.25	$16.89	(5.36)	-24%	OCEC Unit 1 has lower FOM costs. (Note: values are levelized (30 years with no 7/12 for first year and 5/12 for last year convention) and includes FOM and capital replacement)
Variable O&M ($/MWh)	$0.72	$0.28	(0.44)	-61%	OCEC Unit 1 has lower VOM costs.
Average Net Operating Heat Rate (BTU/kWh)	6,334	6,304	(30)	-0.5%	OCEC Unit 1 has a lower heat rate (and, therefore, is more fuel efficient).
Planned Outage Factor (POF - %)	3.5	2.2	(1.3)		Advantage to OCEC Unit 1
Forced Outage Factor (FOF - %)	1.1	1.1	0		Advantage to OCEC Unit 1
Equivalent Availability Factor (EAF - %)	95.4	96.7	1.3		Advantage to OCEC Unit 1
Book Life (Years)	30	30	0		No difference
Natural Gas Costs ($/mmBTU)					
for 2019:	6.15	4.70	(1.45)	-24%	Current gas prices are significantly lower
for 2020:	6.31	5.16	(1.15)	-18%	Current gas prices are significantly lower
for 2025:	7.65	6.49	(1.16)	-15%	Current gas prices are significantly lower
for 2030:	9.19	7.53	(1.66)	-18%	Current gas prices are significantly lower
for 2035:	11.06	8.55	(2.51)	-23%	Current gas prices are significantly lower
for 2040:	13.32	9.63	(3.69)	-28%	Current gas prices are significantly lower

Notes:

1) DSM Goals 2019 Avoided Unit Total Installed Cost includes: AFUDC, gas expansion, transmission interconnection, and integration.
OCEC Unit 1 Total Installed Cost includes AFUDC, transmission interconnection, and integration (does not include gas expansion).
Gas expansion costs for both units are roughly equal ($20M for the DSM Goals unit; $20.9M for Okeechobee)
2) Both FPL units $/kW values are based on Summer MW rating.
3) The DSM Goals 2019 Avoided Unit was based on a Greenfield CC located at the Okeechobee site.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

PETITION FOR DETERMINATION OF NEED

REGARDING OKEECHOBEE CLEAN ENERGY CENTER UNIT 1

REBUTTAL TESTIMONY OF RICHARD FELDMAN

DOCKET NO. 150196-EI

OCTOBER 26, 2015

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Richard Feldman, 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 rebuttal exhibit:

- Exhibit RF-9: Winter Peak Weather Impact

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address misstatements about the load forecast made by the Environmental Confederation of Southwest Florida's witness Rábago. I will also address the Southern Alliance for Clean Energy witness Wilson's comments that the 1999 stipulation was in part the result of an outdated evaluation of historical weather anomalies.

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony addresses incorrect statements made in witness Rábago's testimony regarding the probability of occurrence of FPL's base case and risk-adjusted forecasts. Additionally, I'll examine data that shows extreme weather conditions, such as the "1989 Christmas experience," are not one-time anomalies that no longer present a risk. Indeed, these extreme weather events have occurred periodically since the 1980s and continue to pose a risk to the forecasted load values and, therefore, to FPL system reliability.

II. RISK-ADJUSTED FORECAST

Q. Does witness Rábago's testimony demonstrate an accurate understanding of FPL's base case and risk-adjusted load forecasts and how each forecast is used?

A. No. Witness Rábago makes a number of misstatements regarding FPL's base case and risk-adjusted load forecasts. I address each of these below.

Q. On page 13, lines 9-10, witness Rábago states that there is a 25% chance that the summer peak demand could grow at a rate of 2.1% per year. Is this statement accurate?

A. No. The correct interpretation of the risk-adjusted forecast is that there is a 25% chance that the summer peak demand could grow at a rate of 2.1% per year *or higher (emphasis added).* Accordingly, as discussed on pages 19 and 20 of my direct testimony, there is a 25% chance that the 2019 summer peak will be 26,188 MW or higher.

Q. On page 13, lines 13-14, witness Rábago states that, "There is a 75% chance that the growth in demand will be less than the base forecast..." Is this statement correct?

A. No, it is not. There is not a 75% chance that growth in demand will be less than the base case forecast. As I've stated in my direct testimony on page 19, lines 8-10, the base case forecast is designed such that there is a 50% chance that growth in demand will be less than the base case forecast and a 50% chance that growth in demand will be more than the base case forecast. Moreover, and as I've stated in my direct testimony, the capacity need addressed in this case is based on the base case forecast and not on the risk-adjusted forecast.

Q. Are there any other inaccuracies in witness Rábago's testimony, as it relates to references to your testimony?

A. Yes. On page 12, lines 18-20, witness Rábago summarizes my testimony as follows: "in order to forecast customer growth, net energy for load, and peak demand, the Company looks at forecasts of pollution, economic conditions, the weather, and codes and standards." This is incorrect. In my direct testimony I identified population growth, not pollution as a factor in FPL's forecasts.

III. EXTREME WEATHER

Q. Referring to witness Wilson's testimony at pages 4 and 5, he outlines four statements of the Staff's position in selecting a 20% reserve margin. One statement refers to "unpredicted severe weather," specifically the "1989 Christmas experience." Has FPL experienced any other "unpredicted severe weather" events since 1989?

A. Yes. There have been a number of extreme weather events since the "1989 Christmas experience." Exhibit RF-9 presents the top 10 winter peak weather impacts since and including the "1989 Christmas experience" along with an important weather variable that drives the winter peak, specifically the cold buildup from the prior day up until the morning of the peak expressed in heating degree hours. The 2009 – 2011 winters had colder weather during the days leading up to the peak day than did the "1989 Christmas experience." In fact, the winter peak of 2009 – 2010 had a weather impact in excess of 4,400 MW, which is almost 1,000 MW more than the weather impact associated with the "1989 Christmas experience."

Q. Does this conclude your testimony?

A. Yes.

	Winter Peak	
Year	**Weather Impact (MW)**	**Cold Buildup (Heating Degree Hours)****
2009-2010	**4,410**	**919**
2010-2011	**2,479**	**815**
1989-1990*	**3,497**	**789**
1996-1997	**1,727**	**743**
1988-1989	**1,428**	**738**
2002-2003	**2,164**	**669**
1995-1996	**1,764**	**669**
2007-2008	**1,223**	**654**
2000-2001	**1,125**	**653**
2008-2009	**1,190**	**575**

*1989 Christmas experience

** Heating Degree Hours are the number of degrees that the hourly temperature is below 66 °F