STATE OF FLORIDA
OFFICE OF PUBLIC COUNSEL

C/O THE FLORIDA LEGISLATURE
111 WEST MADISON ST.
ROOM 812
TALLAHASSEE, FLORIDA 32399-1400
1-800-342-0222

EMAIL: OPC_WEBSITE@LEG.STATE.FL.US
WWW.FLORIDAOPC.GOV

October 16, 2013

Ann Cole
Commission Clerk and
Administrative Services
Room 100, Easley Building
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket Nos. 130140-EI, 130151-EI, & 130092-EI

Dear Ms. Cole:

Today the Office of Public Counsel's Testimony and Exhibits of Jacob Pous are being submitted via the Florida Public Service Commission's web based electronic filing system.

Yours truly,

Joe A. McGlothlin

Joseph A. McGlothlin
Associate Public Counsel

JAM:bsr

cc: All parties of record
Suzanne Brownless
Martha Barrera
Martha Brown
Charles Murphy
Caroline Klancke

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Gulf Power Company	DOCKET NO. 130140-EI
In re: 2013 depreciation and dismantlement study by Gulf Power Company	DOCKET NO. 130151-EI
In re: Petition of Gulf Power Company to include the Plant Daniel Bromine and ACI Project, the Plant Crist Transmission Upgrades Project, and the Plant Smith Transmission Upgrades Project in the Company's program, and approve the costs associated with these compliance strategies for recovery through the ECRC.	DOCKET NO. 130092-EI FILED: October 16, 2013

DIRECT TESTIMONY

OF

JACOB POUS

ON BEHALF OF THE CITIZENS OF THE STATE OF FLORIDA

TABLE OF CONTENTS

SECTION I: INTRODUCTION	**1**
A. General	1
B. Overview	3
C. General Background	4
D. Executive Summary	11
SECTION II: DEPRECIATION	**15**
SECTION III: INTERIM RETIREMENTS	**22**
A. General	22
B. Account Specific	25
Account 312 – Steam Production Boiler Plant	25
Account 343 – Prime Movers Combined Cycle	29
SECTION IV: PRODUCTION INTERIM NET SALVAGE	**31**
SECTION V: PRODUCTION PLANT DISMANTLEMENT COSTS	**34**
A. General	34
B. Escalation of Dismantlement Costs	36
C. Contingency/Other Factors	40
D. Combined Impact	46
SECTION VI: MASS PROPERTY LIFE	**46**
A. General	46
B. Actuarial Analyses	49

C. Simulated Property Records (SPR) Analyses 54

D. Account Specific 59

Account 350.2 – Transmission Easements and Right-of-Ways 59

Account 353 – Transmission Station Equipment 61

Account 356 – Transmission Overhead Conductors 63

Account 364 – Distribution Poles and Fixtures 65

Account 365 – Distribution Overhead Conductors 67

Account 367 – Distribution Underground Conductors and Devices 69

Account 368 – Distribution Line Transformers 72

Account 369.1 – Distribution Overhead Services 73

Account 370.1 – Distribution Meters – AMR 76

Account 373 – Distribution Street Lights 78

Account 390 – General Plant Structures and Improvements 80

Account 303 – Intangible Plant – Software 82

SECTION VII: MASS PROPERTY NET SALVAGE 84

A. General 84

B. Account Specific 86

Account 356 – Transmission Overhead Conductors and Devices 86

Account 362 – Distribution Station Equipment 88

Account 368 – Distribution Line Transformers 91

Account 390 – General Plant Structures and Improvements 94

Account 392.3 – General Plant Heavy Trucks 96

EXHIBITS

Recommended Depreciation Adjustments Summary JP-1

Mass Life Adjustment Summary JP-2

Life-Curve Combination for Account 353 ....JP-3

Life-Curve Combination for Account 356 Full Band JP-4

Life-Curve Combination for Account 356 21-Year Band JP-5

Life-Curve Combination for Account 390 ....JP-6

Calculation of Adjustment for Account 303 ....JP-7

Resume JP-8

DIRECT TESTIMONY

OF

Jacob Pous

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket Nos. 130140-EI, 130151-EI, and 130092-EI

SECTION I: INTRODUCTION

A. General

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jacob Pous. My business address is 1912 W Anderson Lane, Suite 202, Austin, Texas 78757.

Q. WHAT IS YOUR OCCUPATION?

A. I am a principal in the firm of Diversified Utility Consultants, Inc. ("DUCI"). A copy of my qualifications appears as Exhibit__(JP-8).

Q. PLEASE DESCRIBE DIVERSIFIED UTILITY CONSULTANTS, INC.

A. DUCI is a consulting firm located in Austin, Texas with an international client base. The personnel of DUCI provide engineering, accounting, economic, and financial services to its clients. DUCI provides utility consulting services to municipal governments with utility systems, to end-users of utility services, and to regulatory bodies such as state public service commissions. DUCI provides complete rate case analyses, expert testimony, negotiation services, and litigation support to clients in electric, gas, telephone, water, and sewer utility matters.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN PUBLIC UTILITY PROCEEDINGS?

A. Yes. Exhibit__(JP-8) also includes a list of proceedings in which I have previously presented testimony. In addition, I have been involved in numerous utility rate proceedings that resulted in settlements before testimony was filed. In total, I have participated in well over 400 utility rate proceedings in the United States and Canada. I have testified on behalf of the staff of six different state regulatory commissions and one Canadian commission on subjects relating to appropriate depreciation rates.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I am a registered professional engineer. I am registered to practice as a Professional Engineer in the State of Texas, as well as other states.

Q. ON WHOSE BEHALF ARE YOU PROVIDING THIS TESTIMONY?

A. Florida's Office of Public Counsel ("OPC") engaged me to address the depreciation study and the depreciation aspects of the revenue requirements request of Gulf Power Company ("Gulf" or "Company") pending before the Florida Public Service Commission (the "Commission" or "FPSC").

B. Overview

Q. CAN YOU PROVIDE A QUICK OVERVIEW OF THE RELATIVE SIGNIFICANCE OF DEPRECIATION-RELATED MATTERS IN THE CONTEXT OF GULF'S REQUESTED INCREASE IN REVENUES?

A. Yes. In terms of revenue impacts, the subject of depreciation is significant in this proceeding. In my testimony, I will report the results of my account-by-account analysis of the depreciation study that Gulf is sponsoring, the results of which are reflected in Gulf's calculation of its revenue requirements. I will identify numerous examples in which Gulf's witness overstates depreciation expense, and refute Gulf's proposed treatment on the basis of the inappropriate assumptions and rationales that he employed. My approach is a "from the bottom up" type of analysis, in which I review the details of individual accounts and build up the individual adjustments into a total dollar recommendation. In the aggregate, my adjustments amount to $13.8 million of reduced depreciation expense annually based on estimated plant as of December 31, 2013. When related to Gulf's proposed increase in depreciation expense of $6.2 million, the impact of my recommendation is to reduce Gulf's overall request for depreciation expense by $19,986,106. These values relate to total depreciation expense associated with all plant, regardless of whether Gulf collects the expense through base rates or through cost recovery clauses outside of base rates. Based on Gulf's answer to Citizens' Interrogatory No. 201, in which OPC asked Gulf to identify the specific accounts associated with depreciation expense embedded in base rates, my recommendation would reduce base rate-related depreciation expense (and thus the amount of Gulf's base rate-related revenue requirement) by

$14,133,538. Due to unexplained values that appear to be unusual in the above noted interrogatory answer, the base rate component of my recommendation may need to be revised upon receipt of Gulf's responses to pending additional discovery requests.

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. I will begin with an introductory background section, in which I will define and describe the basic nature and role of depreciation in the context of a regulated electric utility. Next, I will provide an "executive summary" of my analysis. I will then develop the issues that I have identified and my analysis of the appropriate disposition of those issues in detail.

C. General Background

Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF DEPRECIATION AS IT APPLIES TO A REGULATED ELECTRIC UTILITY.

A. While the term "depreciation" is commonly used to describe a loss of value due to "wear and tear," it has a precise and specialized meaning as an accounting concept. Depreciation refers to the recoupment of a capital investment, less net salvage, over the useful life of the asset to which the investment relates.

Q. CAN YOU ILLUSTRATE THE MEANING OF THE TERM?

A. Yes. Perhaps the best way to explain the concept is to contrast an item that is depreciated with one that is not depreciated. As the example of an item that is not depreciated, let's use copier paper. Assume that the utility purchases 1,000 reams of paper for $5,000, and that it consumes all of the paper within the month in which it was purchased. The utility therefore "expenses" the full $5,000 in the period of the purchase. Assume the utility spends $250,000 on copier paper annually. The annual total cost of copier paper is recorded as a portion of operations and maintenance expense, which is deducted from operating revenues to calculate net income for the year in which the paper was purchased. Recognizing the full cost of the paper purchased in the year is appropriate from a matching standpoint because the paper was consumed completely in the period in which it was purchased. Moreover, because rates are designed to recover operating costs and provide a return on investment, the annual cost of copier paper is embedded in the rates that the utility charges its customers, and $250,000 of overall revenues serves the purpose of recovering from customers the cost of copier paper consumed during the year.

Q. PLEASE CONTINUE.

A. Now, let's compare that situation with the example of an investment in copper conductor. Assume that the conductor costs $100,000 to purchase and install, and that the utility expects to use it to provide service for 40 years. At the end of 40 years, the utility expects to sell the copper for $30,000; however, it also anticipates it will incur $10,000 of cost in removing it from the system. This means that its net depreciable investment will be $80,000 ($100,000-$30,000+$10,000). To recognize the full $80,000 in a single year would be to distort the manner in which that investment in copper conductor is employed in the operation of the business. Said differently, the utility expects to "consume" the service value of the conductor — not within a year — but over 40 years. Therefore, the investment is "capitalized" and added to rate base. Subsequently, each year 1/40th, or $2,000, of the capitalized cost is recognized as depreciation expense associated with the conductor. Because depreciation expense is a component of the utility's overall cost of providing service, it is reflected in the design of rates that the utility charges its customers. The $2,000 of annual depreciation expense associated with the conductor is accumulated with other depreciation and operating expenses and netted against operating revenues to determine net income for the period. Of the revenues collected during the year, $2,000 serves to recoup the portion of the capital investment that is applicable to the period. Accordingly, the utility will reduce its rate base by the annual amount of the $2,000 that it recouped from customers. It does so by recording $2,000 in an account called the "accumulated provision for depreciation" or "reserve." The value of the rate base is calculated by subtracting the total of the accumulated provision for depreciation from the original investment. Each year the utility incurs depreciation expense and adds the amount of expense to the reserve, thereby reducing rate base by that amount in its next rate case.

Q. IN ADDITION TO THE BASIC DEFINITION, WHAT ELSE CAN BE GLEANED FROM YOUR EXAMPLES?

A. First, the examples illustrate a major difference between depreciation expense and other operating expenses. In the case of copier paper, the utility must make a cash outlay during each annual period. In the case of the conductor, there is an initial cash outlay to purchase and install the conductor; thereafter, the recognition of the annual component of expense applicable to the period does not involve cash outlays. For this reason, depreciation is referred to as a "non-cash" expense. However, the dollars that are collected and applied to defray this non-cash expense are as real to the utility and to the customers who pay them through rates as the dollars that were expended to acquire the capital item or pay for the copier paper.

Q. DOES THE EXAMPLE OF THE CONDUCTOR ILLUSTRATE ANY OF THE ISSUES TO WHICH A DEPRECIATION STUDY MAY GIVE RISE?

A. Certainly. The example illustrates the determination of the appropriate useful life; the assumed salvage value upon retirement; and the projected cost of removing the item from service that the utility may incur to realize the salvage. While the analytical techniques, which may involve statistical measurements, actuarial and semi-actuarial analyses, and the review of historical and comparative industry data can become technical and involved, all of the debates surrounding the establishing of appropriate depreciation rates feature the interplay between and among service lives and related remaining lives, salvage values, and the cost of removal. If the utility assumes too short of a useful life, the total depreciation expense will be allocated over too few periods, and the expense recognized in a single period will be higher than it should be. If a utility understates expected salvage or overstates the cost of removing the item upon retirement, it will overstate the amount of depreciation expense that is allocated over the life of the asset. When in my testimony I observe that Gulf has been overly aggressive in proposing depreciation rates, I mean that it attempts to overstate depreciation expense currently through one or more of these means.

Q. DO YOU HAVE ANY ADDITIONAL OBSERVATIONS OF A GENERAL NATURE BEFORE YOU BEGIN THE PRESENTATION OF YOUR ANALYSIS OF GULF'S DEPRECIATION STUDY?

A. Yes. Generally speaking, it is in an electric utility's financial self-interest to collect more dollars from customers than fewer dollars, to collect those dollars sooner than later and, once having collected the dollars, to keep them rather than returning them to customers. This is true of depreciation practices. Because depreciation expense results in revenues that do not have a concurrent cash outlay associated with them, depreciation expense is a source of cash flow, and higher depreciation expense means greater cash flow. Plus, recouping more of an investment in early years than would be warranted would reduce the risk of not recouping the investment in later years. Accordingly, even though depreciation issues affect the timing of recoupment of capital investments rather than whether or not the utility should recover its claimed capital costs, a utility has an incentive to favor higher depreciation expense and higher depreciation reserves. The Commission, therefore, must scrutinize the utility's practices and studies to ensure that current customers are not called on to bear more than their appropriate share of the depreciation expense.

Q. WHY DO YOU REFER TO "CURRENT CUSTOMERS" IN YOUR ANSWER?

A. There is an important intergenerational dimension to depreciation accounting. If depreciation expense is overstated early in the life of an asset, current customers will be overcharged, and future customers will pay less than their fair share during the periods in which they receive service. Similarly, if current depreciation rates are lower than they should be, future customers will be required to pay an inordinate portion of the cost of plant, thereby subsidizing the earlier generation of customers.

Q. HOW DOES THE COMMISSION DEAL WITH THIS INTERGENERATIONAL ASPECT OF DEPRECIATION ACCOUNTING?

A. If the parameters that drive the calculation of depreciation expense remained static over time, there would be no issue of intergenerational inequity. However, service lives, salvage values, and costs of removal are all estimates that fluctuate with changes in information and assumptions over time. For that reason, the Commission requires Gulf and other regulated utilities to prepare and submit depreciation studies periodically. As such, Gulf filed its pending depreciation study pursuant to that requirement.

Q. WHAT ARE THE OBJECTIVES OF SUCH A STUDY?

A. The objectives of a depreciation study are to: (1) make any needed changes to the estimates of service lives, salvage values, and costs of removal; and (2) take any corrective action needed to ensure equity between generations of customers in light of the changes made.

Q. HOW IS A DEPRECIATION STUDY USED TO IDENTIFY ANY NEEDED CORRECTIVE ACTION?

A. The depreciation analyst knows the actual reserve (depreciation expense and related transactions recorded to date) for an asset that has accumulated over time. Once the analyst has developed the values for service life, salvage value, and cost of removal, the amount of depreciation expense that would have been collected had those modified and improved estimates been employed from the outset can be calculated. This is called the "theoretical reserve." The difference between the actual reserve and the theoretical reserve represents either a shortfall (negative imbalance) or an over collection (positive imbalance, or reserve excess).

Q. WHAT ACTION IS TAKEN TO CORRECT AN IMBALANCE?

A. If the imbalance is of so severe a magnitude as to impose a serious inequity on a generation of customers, the Commission can require the utility to amortize the imbalance over a compressed period of time, and the annual amount of ordered amortization will affect test year revenue requirements in a base rate proceeding that coincides with the amortization period (amortization of an excess will offset depreciation expense and lower revenue requirements). This is what happened in Docket No. 080677-EI, when the Commission ordered Florida Power & Light Company ("FPL") to return $894 million of excess reserve to its customers over a period of four years. More typically, the imbalance (whether an excess or shortfall) is rolled into the calculation of depreciation expense yet to be collected, and the correction is implemented gradually over the remaining lives of the related assets, rather than over a prescribed amortization period.

Q. HOW DOES THE ACTUAL RESERVE COMPARE TO THE THEORETICAL RESERVE IN THIS CASE, AND HOW SHOULD THE COMMISSION ADDRESS ANY IMBALANCES?

A. The total reserve imbalance as calculated by the Company is not significant. Therefore, there is no need to take any action to compress the period over which the true-up amortization should transpire when compared to the remaining life approach. However, this does not diminish the need to adjust Gulf's proposed depreciation rates which, unless modified, would overstate depreciation expense and exacerbate the current imbalance over time.

D. Executive Summary

Q. PLEASE PRESENT YOUR MAIN POINTS IN SUMMARY FASHION.

A. The Company retained American Appraisal Associates, Inc. to perform a new depreciation study, the results of which are sponsored by Gulf witness Mr. Peter S. Huck. The Company's depreciation analysis is based on estimated plant levels through the end of 2013. Based on the plant in service as projected through December 31, 2013, the Company proposes $162,841,527 of depreciation expense, which represents a $6,197,289 increase (2013 Study, Volume 1, Tab 5: Proforma Expense Comparison, page 3). After reviewing the Company's presentation, data, responses to discovery requests, and information in the public domain, I conclude that the Company's request is significantly overstated. In fact, rather than a proposed increase in depreciation expense as requested by the Company, a reduction of $20.0

million (rounded) to the requested level, or a $13.8 million reduction to existing depreciation expense, is warranted as set forth on Exhibit__(JP-1).

The acceleration of depreciation expense as proposed by the Company is not warranted and should be denied by the Commission. A brief discussion of the various issues I will address in detail later in my testimony follows.

- **Interim Retirements**: Interim retirements are intended to represent limited downward adjustments to the life span for generating units due to items of investment that will retire and be replaced prior to the ultimate retirement date for a generating facility. Correcting the level of estimated interim retirements for the Company's largest steam and other production functions results in a $5.2 million annual reduction in depreciation expense, based on estimated plant as of December 31, 2013.

- **Interim Production Net Salvage**: There are two types of production net salvage. The first is interim retirement net salvage associated with the interim retirements that are estimated to transpire prior to the final termination of a generating station or unit. The second type of production net salvage is terminal net salvage as reflected in the Company's request for dismantlement costs discussed elsewhere. Based on excessively negative net salvage estimates for interim retirements, and an excessive level of projected interim retirements, the Company seeks $108 million of interim net salvage to be collected over the remaining life of its generating facilities. Correcting the Company's excessively negative levels of interim retirement related production net salvage by retaining the existing -20% value results in a $940,000 reduction to annual depreciation expense, based on estimated plant as of December 31, 2013.

- **Terminal Production Net Salvage**: The Company has presented dismantlement calculations for its various generating facilities. These studies represent a worst case scenario of the ultimate disposition of the investment. In addition to assuming the worst case scenario of having to completely remove each facility and restore the site, the Company relies on many assumptions that inappropriately increase its demolition cost estimate and the level of annual recovery. Moreover, the Company incorporates an unjustified level of contingencies, as well as other costs that further inflate the overall demolition cost estimates artificially. A review of the Company's proposal supports a reduction to the Company's request. While there are many problems with the Company's request, I am recommending only two adjustments. First, I recommend the removal of future projected inflation for as much as 40 years into the future. Second, I recommend reversal of the proposed 10% contingency adder, as contingencies are already included in many of the individual assumptions in the dismantlement study. The combined impact of these two adjustments is a $6.3 million reduction in annual dismantlement expense.

- **<u>Mass Property Life Analysis</u>**: Mass property consists of transmission, distribution, general, and intangible plant. The Company has relied on its interpretation of actuarial and Simulated Property Records ("SPR") results to propose life characteristics for its various accounts. The Company's proposals are not the best statistical results obtained from its actuarial analysis and fail to recognize other Company-specific information which would result in longer average service lives ("ASL"). After reviewing the Company's proposals on an account by account basis, I recommend adjustments to 12 mass property accounts which result in a $6.6 million reduction to annual depreciation expense, based on estimated plant as of December 31, 2013.

- **<u>Mass Property Salvage Analysis:</u>** The Company performed an analysis on 32 years of historical data. The Company failed to provide adequate support for various proposals. After my review and investigation, I recommend adjustments to the proposed net salvage level for 5 mass property accounts. The standalone impact of these recommendations results in a reduction of $1.4 million in annual depreciation expense, based on estimated plant as of December 31, 2013.

- **<u>Combined Impact:</u>** Due to the interaction of life and salvage parameters, life spans, and interim retirement levels, the combined impact of my various recommendations is not simply the summation of each standalone adjustment. As shown on Exhibit__(JP-1), the combined impact of all adjustments results in a $19,986,106 million reduction to annual depreciation expense based on estimated plant as of December 31, 2013.

SECTION II: DEPRECIATION

Q. PLEASE ELABORATE ON THE BASIC DEFINITION OF DEPRECIATION THAT YOU PROVIDED IN THE GENERAL BACKGROUND SECTION.

A. There are two commonly-cited definitions of depreciation. The first, from the Federal Energy Regulatory Commission ("FERC"), appears in Title 18 of the Code of Federal Regulation ("CFR"), Part 101:

> 'Depreciation', as applied to depreciable plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

The second definition, from the American Institute of Certified Public Accountants ("AICPA"), is similar:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is a portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.

Q. WHAT ARE THE TWO GENERAL FORMULAS USED IN DETERMINING DEPRECIATION RATES?

A. The *whole life* and the *remaining life* techniques are the most commonly used formulas. The whole life technique is as follows:

$$\text{Depreciation Rate (\%)} = \left[\frac{\frac{(\text{Original Cost} - \text{Net Salvage})}{\text{Average Service Life}}}{\text{Original Cost}} \right]$$

The remaining life technique is as follows:

$$\text{Depreciation Rate (\%)} = \left[\frac{\frac{\text{Original Cost} - \text{Accumulated Provision For Depreciation} - \text{Net Salvage}}{\text{Remaining Service Life}}}{\text{Original Cost}} \right]$$

The two formulas should equal each other when the difference between the theoretical reserve and the actual Accumulated Provision for Depreciation is recovered over the remaining life of the investment under the whole life formula.

Q. ARE THERE ADDITIONAL CONSIDERATIONS IN DEPRECIATION BEYOND THE DEFINITIONS?

A. Yes. The definitions provide only a general outline of the overall utility depreciation concept. In order to arrive at a depreciation-related revenue requirement in a rate proceeding, a depreciation system must be established.

Q. WHAT IS A DEPRECIATION SYSTEM?

A. A depreciation system constitutes the method, procedure, and technique employed in the development of depreciation rates.

Q. BRIEFLY DESCRIBE WHAT IS MEANT BY "METHOD".

A. Method identifies whether a straight-line, liberalized, compound interest, or other type of calculation is being performed. The straight-line method is normally employed for utility depreciation proceedings.

Q. BRIEFLY DESCRIBE WHAT IS MEANT BY "PROCEDURE".

A. "Procedure" identifies a calculation approach or grouping. For example, procedures can reflect the grouping of only a single item, items by vintage (year of addition), items by broad group or total grouping, and equal life groupings. The average life group ("ALG") procedure is used by the vast majority of utilities.

Q. PLEASE BRIEFLY DESCRIBE WHAT IS MEANT BY "TECHNIQUES".

A. There are two main categories of "techniques" with various sub-groupings: the whole life technique, and the remaining life technique. The whole life technique simply reflects the calculation of a depreciation rate based on the whole life (e.g., a 10-year life would imply a 10% depreciation rate over the life of a plant using a straight-line depreciation method). The remaining life technique recognizes that depreciation is a forecast or estimation process that is never precisely accurate and requires true-ups in order to recover only 100% of what a utility is entitled to over the entire life of the investment. Therefore, as time passes, the remaining life technique attempts to recover the remaining unrecovered balance over the remaining life or other period of time. Most utilities rely on a remaining life technique in utility rate matters.

Q. DO THE METHODS, PROCEDURES, AND TECHNIQUES INTERACT WITH ONE ANOTHER?

A. Yes. Different depreciation rates will result depending on the combination of method, procedure, and technique that is employed. Differences can occur, even if the same average service life and net salvage values are employed at the outset.

Q. HOW ARE THE LIFE AND REMAINING LIFE DETERMINED?

A. The determination of the appropriate life to associate with production plant differs from the corresponding determination for mass property, which includes transmission, distribution and general plant. The estimation of production plant life relies on a life span method. The life span method requires an estimate of the probable future retirement date and the impact of interim additions, both of which are discussed in detail later in my testimony. The estimation of mass property plant life normally relies on an actuarial or an SPR analysis. These approaches recognize a dispersion pattern of retirements in the life estimation process. The industry relies on a series of standardized dispersion patterns identified as Iowa Survivor curves to arrive at the appropriate ASL for a mass property category.

Q. PLEASE DISTINGUISH BETWEEN AN "ACTUARIAL" APPROACH AND A "SIMULATED PROPERTY RECORDS" TYPE OF ANALYSIS. WHAT DICTATES WHICH APPROACH IS USED?

A. Actuarial analysis is the preferred approach, as it produces more accurate results. However, actuarial analysis requires aged data (where the date of installation is known at the time of retirement). When aged data is not maintained, the default approach is the SPR method. The SPR method simulates annual plant balances to actual recorded plant balances using standardized Iowa Survivor curves based on assumed ASLs.

Q. PLEASE ELABORATE ON THE MEANING OF "IOWA SURVIVOR CURVES" AND THEIR ROLE IN A DEPRECIATION STUDY. WHAT INFORMATION IS PROVIDED BY A "STANDARDIZED DISPERSION PATTERN"?

A. The National Association of Regulatory Utility Commissioners ("NARUC") states in its publication "Public Utility Depreciation Practices" at page 68 that "physical property retirements generally follow definable patterns that can be standardized. The Iowa curves are standard curves that were empirically developed to describe the life characteristics of most industrial and utility property. They are used throughout the utility industry ... in extending stub survivor curves and forecasting life characteristics." The NARUC publication further states that the "curves were placed into L, R, or S families depending upon whether the highest point (mode) of the retirement frequency cure was left of, right of, or symmetrical to the curve's average life. The curves in each family were then ordered according to the magnitude of the mode from low (e.g., L0) to high (e.g., L5)." It should further be noted that the area under a survivor curve represents that plant's ASL.

Q. PLEASE CONTINUE.

A. Once an overall life for production plant and an ASL for mass property have been determined, a remaining life can then be calculated. The remaining life for mass property is dependent not only on the ASL, but also on the Iowa Survivor curve selected. The remaining life will be different for the same vintage database with the same ASL, but with a different Iowa Survivor curve. The differing remaining lives occur since the retirement pattern beginning from the current age through the end of the survivor curve changes, which then modifies the remaining area under the balance of the survivor curve.

Q. WHAT IS NET SALVAGE?

A. Net salvage is the value obtained from retired property (the gross salvage) less the cost of removal. Net salvage can be either positive in cases where gross salvage exceeds the cost of removal, or negative in cases where the cost of removal is greater than gross salvage.

Q. HOW DOES NET SALVAGE IMPACT THE CALCULATION OF DEPRECIATION?

A. The intent of the depreciation process is to allow the Company to recover 100% of investment less net salvage. Therefore, if net salvage is a positive 10%, then the utility should only recover 90% of its investment through annual depreciation charges, under the theory that it will recover the remaining 10% through net salvage at the time the asset retires (e.g., 90% + 10% = 100%). Alternatively, if net salvage is a negative 10%, then the utility should be allowed to recover 110% of its investment through annual depreciation charges so that the negative 10% net salvage that is expected to occur at the end of the property's life will still leave the utility whole (i.e., 110% - 10% = 100%).

Q. PLEASE IDENTIFY SOME OF THE MAJOR FACTORS THAT AFFECT A DEPRECIATION "SYSTEM."

A. The concept of depreciation utilized for utility ratemaking has evolved over time. Currently, there are still many different combinations of methods, procedures, and techniques employed in the development of utility depreciation rates. A depreciation system must, among other things, be systematic and rational. The regulator must further take into the account the quality, quantity, and timeliness of data relied upon, as well as the quality of the judgment employed by the depreciation analysts. Given the subjectivity involved in the various estimation processes, judgment plays an important role in establishing depreciation rates. While judgment is critical, that does not mean that an analyst can simply refer to "judgment" as the basis for a proposal without providing meaningful factual support for that "judgment," nor can "judgment" serve as the basis for ignoring relevant facts.

Q. WHAT ARE THE KEY ELEMENTS OF THE DEPRECIATION FORMULA AT ISSUE IN THIS PROCEEDING?

A. The life parameters, which include interim retirements for production plant, and net salvage, which includes dismantlement cost estimates for production plant in the above formula are at issue.

SECTION III: INTERIM RETIREMENTS

A. General

Q. WHAT ISSUE DO YOU ADDRESS IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony addresses the Company's estimation of interim retirements proposed for production plant accounts.

Q. WHAT ARE INTERIM RETIREMENTS?

A. Interim retirements have been characterized as a fine-tuning adjustment to the life span analysis. The life span method is used in estimating the retirement date for any large unit of property such as an entire generating unit. The theory behind interim retirement rates is that, even though a large unit or property such as a generating unit might retire after 60 years of operation, many components have to be replaced in the interim period to maintain the overall generation facility in operating condition. An analogy to this would be an office building which might be anticipated to have a service life of 70 years. During the 70-year life of the building, the owner might have to replace the roof twice, the A/C system three times, and other components in order to maintain the building in a safe and usable condition. Therefore, even though the building may have an overall 70-year life span, its dollar-weighted overall life must reflect the average of the initial investment with the average of the individual replaced components, and will be less than 70 years. In other words, the interim retirement rate would be a fine-tuning factor used to reduce the service life from 70 years to (for example) a dollar-weighted 68 years.

Q. HAS THE COMPANY INCORPORATED THE IMPACT OF INTERIM RETIREMENTS IN ITS DEPRECIATION RATES?

A. Yes. The Company proposes to implement a calculation procedure for interim retirements based on estimated annual retirement ratios.

Q. DO YOU AGREE WITH THE COMPANY'S POSITION?

A. While I agree with the Company that interim retirements should be included in the calculation of production plant depreciation rates, as well as with its calculation approach, I do not agree with the Company's proposed results for its largest steam production and other production accounts.

Q. HOW DID THE COMPANY DEVELOP ITS PROPOSED INTERIM RETIREMENT RATIOS?

A. The Company analyzed historical retirement activity compared to the dollar level of investment exposure to retirement forces in its various plant accounts. The Company excluded the impact of terminal retirements, in which an entire plant is retired rather than the components within an ongoing operating plant. The Company reviewed its 32-year database of historical activity, and also performed 5-, 10-, and 20-year band analyses. Finally, the Company recognized that its resulting values were often higher than industry indications, and elected to somewhat limit the increase in certain instances (Response to Citizens' Interrogatory No. 47, in Docket No. 130151-EI).

Q. IS IT APPROPRIATE TO LIMIT THE LEVEL OF INTERIM RETIREMENTS BASED ON INDUSTRY COMPARISONS?

A. Yes, to some extent, depending on the circumstances. However, in this particular instance, it does not appear that the limitation applied by the Company was adequate. While review of historical data provides an indication of what has occurred, it must be tested for reasonableness as it applies to future expectations. Given the sizeable modifications to the Company's plant due to one-time environmental upgrades, the Company's historical interim retirement data must be viewed as excessive and not indicative of what will transpire during the remaining portion of the plant's life. For example, the Company added approximately $350 million of investment to the Crist plant since its last depreciation study (2013 Study, Volume 1, Tab 6: Analysis Results, page 2). The increase is primarily associated with environmental upgrades.

Given that the Company proposes to retire Crist Units 4 and 5 in approximately 10 to 12 years and Crist Units 6 and 7 in approximately 20 to 23 years, it is unrealistic to expect that it would be economically viable to continue such massive levels of capital additions with constantly shorter remaining life periods. Therefore, the historical retirement activity must be normalized to recognize that many recent retirements are related to events that will not reasonably be expected to recur during the remaining life of the existing investment.

Q. BASED ON YOUR REVIEW, ARE YOU RECOMMENDING ADJUSTMENTS?

A. Yes. Based on my review, I am recommending an adjustment to the interim retirement rate proposed for Account 312 – Steam Boiler Plant Equipment and Account 343 – Other Production Prime Movers. These two accounts represent the largest individual accounts within the steam and other production functions.

B. Account Specific

Account 312 – Steam Production Boiler Plant

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 312 - STEAM PRODUCTION BOILER PLANT?

A. The Company proposes to use a 1% annual interim retirement rate (Response to Citizens' Interrogatory No. 47, page 3 of 24).

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company analyzed historical data and concluded that while its historical analysis indicated a 1.25% interim retirement rate, it recognized that the industry normally relies on values less than 1% and also recognized the "affects in the short time of larger" balances. Therefore, it elected to use a 1% value. (*Id.*)

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal is excessive. I recommend a 0.65% interim retirement rate.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. First, it is necessary to place the proposed interim retirement recommendations into proper perspective. Based on the estimated plant-in-service for Account 312 as of December 31, 2013, a 1% interim retirement rate would imply $15.5 million of annual interim retirements per year. Such a level of estimated future interim retirements for the investment in this account has been experienced in only five of the past 32 years. Moreover, in two of those years, the Company installed significant levels of pollution control-related additions which resulted in unusual levels of retirement activity. Therefore, the Company's projection of future interim retirements is appreciably overestimated.

In performing a review of historical data to obtain an indication of future ongoing activity, it is necessary to investigate whether significant historical values can reasonably be expected to recur. In this particular instance, the historical values include a $28.6 million retirement in 2004 and an $18.1 million retirement in 2009. These years correspond to periods where the Company made unusual environmental-driven capital additions associated with a selective catalytic reduction ("SCR") system at Crist Unit No. 7 and a flue-gas desulphurization ("FGD") investment at Crist Units No. 4 through 7 in 2009. (2013 Dismantlement Study at Section 4.3). Investments of this nature and this magnitude are not reasonably expected to recur through the limited balance of the life for the Company's major coal facilities. Therefore, they represent outlier events that should not be included in the historical analysis relied upon for establishing future interim retirement levels. This situation would be analogous to replacing the engine in a car when it was five years old. It may have made economic sense at that time. However, now the same car is eight years old with an expected remaining life of only four years. If problems with the engine were to recur at age 10, it would not be economically reasonable to replace the engine a second time. Therefore, reliance on this type of historical activity for deriving future expectations without a reasonable understanding as to whether it represents a logical and sound basis for predicting the future can, and in this case would, yield erroneous results. Indeed, the Company attempted to recognize the impact that such events had on its historical analysis; however, it unrealistically limited the discounting of such events in its final proposal.

In addition, given the sizeable increase in plant balances since the last depreciation study, the application of a percentage interim retirement factor to the new higher balances has a disproportionate impact. In fact, the current estimated balance for Account 312 is more than double the actual balance as of the end of 2008 and approximately three times the balance for this account as of 2002 (Response to Citizens' Interrogatory No. 47 page 3). The sizeable growth in plant balance for this account in recent years should have a significant downward impact on interim retirement ratios based on historical analyses. Indeed, the Company partially recognized that this problem exists due to the higher balances in establishing its value, but only to a minimal extent. In fact, the five-year historical interim retirement analysis yielded a 0.86% value, yet the Company proposes a 1% value, or more than 16% higher than its own recent historical calculated value.

Given the dynamics of (1) the much higher plant balance for the investment in this account, (2) the recognition that several of the retirements recorded during the past decade are associated with major one-time environmental upgrades, and (3) the fact that industry values are typically lower, a significantly lower annual interim retirement rate is appropriate and necessary. Based on a review of recent historical data (2004-2012) which reflects the new higher balance for the investment in this account, along with normalizing the impact of the retirements associated with the 2009 implementation of the FGD system (using the average of the years before and after 2009), would yield an approximate 0.65% interim retirement rate. A 0.65% interim retirement rate still provides the Company with approximately $10 million of expected annual interim retirements, a value exceeded only seven times during the past 32 years.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $4,087,401 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 343 – Prime Movers Combined Cycle

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 343 – OTHER PRODUCTION PIME MOVERS COMBINED CYCLE GENERATION?

A. The Company proposes a 2% annual interim retirement rate (Response to Citizens' Interrogatory No. 47, page 15).

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company recognized several unusual breakdowns at the Smith combined cycle station, which are reflected in its limited historical analysis. The Company also recognized the likely relatively high cost of the long-term service agreement ("LTSA") CT overhauls, the cost associated with outside contracts to maintain the units and perform major overhauls. Based on these items of information, the Company claims that "2% or so has been used by others in similar situations." (*Id.*)

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposed 2% interim retirement rate is unreasonably high. I recommend nothing greater than a 1% value.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. First, it must be noted that there is limited experience associated with new combined cycle units. By their very nature, these units are not similar to the equipment located at a coal-fired generating facility, and should not exhibit the same levels of interim retirement expected at coal-fired units. While the Company notes that 2% or so has been used by others in similar situations, I believe that more realistic values are less than 1% and, in certain instances, zero (0) level of interim retirements have been proposed or adopted for the investment associated with combined cycle units.

This Commission, in FPL's most recent proceeding, adopted a 0.57% interim retirement rate for Other Production Account 343 – Prime Movers (Order No. PSC-10-0153-FOF-EI, page 32). Also, in a current Sierra Pacific Power case, the staff of the Nevada Public Service Commission is recommending a zero (0) level of interim retirements for combined cycle units, recognizing that the interim retirements that have recently occurred are most likely associated with one-time design deficiencies (Docket No. 13-06004 before the Nevada Public Service Commission, Testimony of Staff Witness Maguire, at page 23).

My recommendation of a 1% interim retirement level provides the Company with approximately $1.2 million of future expected annual interim retirements at the Smith combined cycle station. This value provides the Company with more than adequate protection as it gains more and representative empirical data for its new combined cycle generation facility.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $1,111,513 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

SECTION IV: PRODUCTION INTERIM NET SALVAGE

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony addresses the Company's request for a -25% net salvage for proposed interim retirements, not terminal net salvage.

Q. WHAT IS INTERIM NET SALVAGE?

A. While the Company has proposed terminal net salvage values based on dismantlement studies for its fossil generating facilities, the Company has also proposed a -25% net salvage associated with plant retired prior to the retirement of the entire generating unit.

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSED INTERIM NET SALVAGE?

A. The Company reviewed historical data and performed various averages of historical bands. Based on this analysis, the Company states that the "data again indicates a continuing increasing trend" and proposes a movement "towards the amount indicated by the data." Moreover, the analysis of historical data was performed on the combined database for all steam plant accounts (2013 Study, Volume 1, Tab 8: Net Removal Costs, page 3).

Q. WHAT LEVELS OF NEGATIVE NET SALVAGE DOES THE HISTORICAL DATA INDICATE?

A. The Company's analysis yields results from approximately -40% to a -29%, depending on whether a five-year band or all 32 years of its historical database are analyzed. (*Id.*).

Q. IF THE HISTORICAL DATA INDICATES A -30% TO -40% RANGE, WHY DID THE COMPANY ONLY PROPOSE -25%?

A. While the Company does not provide any basis for its determination other than moving in the direction of the levels indicated by the historical data, the important takeaway is that even the Company recognizes the excessive level of negative net salvage reflected in its historical values.

Q. WHY DO YOU BELIEVE THAT THE HISTORICAL VALUES REFLECT AN EXCESSIVE LEVEL OF NEGATIVE NET SALVAGE?

A. The Company relied on -20% net salvage for its 2005 and 2009 studies. The level of negative net salvage reflected since those studies is more negative than for prior periods. However, it is precisely during these periods where it is more likely that the type of investment being retired would result in more negative net salvage values than would normally be expected. For example, the cost of replacing a standalone pump at a generating station would be expected to be relatively low in comparison to making modifications necessary to add a SCR or FGD system. However, that is exactly what transpired during the early to late 2000s when the Company had to modify its generating facilities to install both a SCR system and a FGD system. As noted in the interim retirement portion of my testimony, such major retirements and replacements are more indicative of one-time events and not of ongoing transactions. In other words, the most recent data reflected on the system, which apparently caused the Company to change from a -20% to a -25%, is based on activity not indicative of what can reasonably be expected to occur in the future with the remaining plant in service. Therefore, just as the Company has recognized to some degree the need to lessen the impact of its historical data, I believe that a further modification is appropriate. I recommend the retention of the existing -20% net salvage, since the likelihood of major system additions due to environmental considerations are no longer expected to be of the same magnitude that occurred from approximately 2004 to 2009. Moreover, many other utilities rely on interim production net salvage levels less negative than the Company's -25% and even values less than -20%. Indeed, in FPL's last depreciation proceeding, the Commission adopted interim net salvage values ranging from zero (0) to a -7% (Order No. PSC-10-0153-FOF-EI, pages 39-46).

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $938,853 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

SECTION V: PRODUCTION PLANT DISMANTLEMENT COSTS

A. General

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony addresses two limited areas of the Company's production plant dismantlement cost request. I address the Company's inappropriate escalation of costs into the future without appropriately discounting values back to their net present value. I increased the Company's proposed -10% contingency value to 0%.

Q. WHAT DOES THE COMPANY SPECIFICALLY PROPOSE FOR ITS PRODUCTION PLANT DISMANTLEMENT COST?

A. The Company proposes $7,023,336 of expense for dismantlement of its production plant facilities (2013 Study, Volume 1, Fossil Dismantlement, page 2). This represents a $2.6 million reduction from the current expense. (*Id.*). The Company's proposed amounts are based on an in-house dismantlement study performed by Southern Company Generation that yielded a total dismantlement cost for all plant of $239 million based on costs as of the end of 2013. (*Id.*, page 4). However, within the study the Company escalates its internally generated decommissioning cost estimate for as much as 40 years into the future (i.e., through 2053) to reflect anticipated increases in the cost of dismantlement activities over time. The Company's escalation process increases the current $239 million estimate to a $391.3 million estimate. (*Id.*). While the Company claims that it has appropriately discounted such values to net present values, the net result of its proposal reflects a recovery amount significantly greater than the current estimate of $239 million (Response to Citizens' Interrogatory No. 36). The inordinately higher value results from an inadequate and methodologically unsound discounting calculation. I discuss this in greater detail in the next section of my testimony.

Q. WHAT IS YOUR RECOMMENDATION?

A. While there are potentially many problems with the Company's dismantlement analyses, I am recommending only two adjustments. The first adjustment is to base the level of expense and the derivation of the dismantlement factor on current cost estimates without the obvious future escalation and the less-than-obvious and understated discounting. The second adjustment is the elimination of a separate additional contingency as a conservative estimate to be utilized for ratemaking purposes in this proceeding.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS?

A. My recommendations result in an annual $6,288,508 reduction in requested dismantlement expense.

B. Escalation of Dismantlement Costs

Q. DOES THE COMPANY ESCALATE ITS ESTIMATED PRODUCTION PLANT DISMANTLEMENT COSTS INTO THE FUTURE?

A. Yes. As previously noted, the Company's escalation results in a $152 million increase in dismantlement costs, which represents a 63% increase above its current estimate.

Q. IS IT APPROPRIATE TO RELY ON THE ESCALATION OF CURRENT DISMANTLEMENT ESTIMATES FOR FUTURE INFLATION WHEN DEVELOPING REVENUE REQUIREMENTS?

A. No. Requesting current customers to pay with their current dollars for future inflated costs is inappropriate and creates intergenerational inequity. By analogy, if the owners of an office building were to attempt to attract renters based on a rental arrangement that renters from Day 1 through the first 20 years would pay the same rent, but that the rent would be calculated to reflect inflation during the 20-year period, no informed potential renter would rent from such a landlord in the early years. However, an informed renter would be more than pleased to rent the office space for the last five years, since that renter would be paying with future dollars for effectively historic cost levels. In other words, it is important to charge current customers the current costs so that the amounts can be paid with current dollars, and so that no subsidy is created or imposed upon any generation of customers.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE COMPANY'S INFLATION OR ESCALATION CALCULATION?

A. Yes. Using Plant Scherer as an example, the Company calculates a total dismantlement cost of $10,463,998 as of December 31, 2013 (2013 Study, Volume 1, Tab 9: Fossil Dismantlement, page 15, Column E). The Company then compounds such value for as many as 40 years into the future, which results in a future cost estimate of $21,487,242. (*Id.* at Column G). This represents a 105% increase over the current estimate. The Company then takes the reserve for Plant Scherer as of December 31, 2013 in the amount of $5,143,641 and subtracts that amount from its future cost estimate to derive a current unrecovered amount of $16,343,601 ($21,487,242 - $5,143,641) rather than an actual unrecovered cost level of $5,320,357 ($10,463,998 - $5,143,641). In other words, the Company's approach results in a hybrid unrecovered cost three times the level of the estimated actual unrecovered costs as of the end of 2013.

Q. ARE THE COMPANY'S INFLATED COSTS THE FINAL VALUES UTILIZED TO CALCULATE THE EXPECTED 2014 ACCRUAL?

A. No. The Company performs a calculation which it claims discounts the future unrecovered cost level to a present value as of 2014 (2013 Study, Volume 1, Tab 9: Fossil Dismantlement, pages 14 and 15, Columns J and K, in conjunction with Response to Citizens' Interrogatory No. 36). Using a 40-year remaining life for the entire unrecovered amount, which corresponds to a 2053 retirement rate for the Scherer unit, would result in a $408,590 annual expense for 2014 ($16,343,601 / 40).

However, the Company identifies only a $289,454 annual expense for 2014 due to its claimed discounting calculation (2013 Study, Volume 1, Tab 9: Fossil Dismantlement, page 15, Column K). While this might appear to be an appropriate discount process, it is not. When the value is compared to the 2014 annual expense, absent any escalation and claimed discounting, the difference is dramatic. Relying on the Company's proposed 2013 dismantlement cost estimates, the 2014 expense based on a 40-year remaining life would only be $133,009 ($5,320,357 / 40). The 2014 annual expense based on the most current dismantlement study is less than one-half of the annual expense for the Scherer Plant proposed by the Company for 2014. In other words, the Company has more than doubled the necessary annual expense for dismantlement of the Scherer Plant by its manipulation of the data based on an obvious future escalation and less than obvious claims for some form of discounting.

The end result of the Company's manipulation of estimated future inflation and discounting is an artificial 95% increase in cost compared to the current estimated dismantlement cost. The Company then further escalated the 2014 annual expense to a four-year average expense into the future (i.e., 2014-2017). For the Scherer plant, the further escalation results in a $297,594 annual expense level compared to the previously noted $133,009 annual recovery amount, based on current expected dismantlement costs.

Q. IF THE COMPANY IS DISCOUNTING ITS UNRECOVERED COSTS, WHY IS IT SO MUCH HIGHER THAN IT WOULD BE BY SIMPLY RELYING ON CURRENT COSTS WITHOUT ESCALATION AND DISCOUNTING?

A. The problem lies with the fact that the Company escalates total estimated dismantlement costs, but discounts only estimated unrecovered costs, with the difference being the recognized level of the 2013 reserve level in the calculation. In other words, the discounting process is applied to a much smaller dollar value than the initial inflation calculation.

Q. WHAT DO YOU RECOMMEND?

A. I recommend relying on the most current cost estimate adjusted for the contingency factor discussed later. This should not be taken as my agreement with the Company's dismantlement cost estimate, even on a current cost basis. However, for purposes of this case, it corresponds to the minimal corrections that are required to the Company's request.

Q. WHY IS IT INAPPROPRIATE FOR THE COMPANY TO ASSUME THAT INFLATION WILL BE THE DRIVING FORCE OF FUTURE COSTS?

A. The annual recovery of future dismantlement costs, as projected by the Company, has declined since the last dismantlement study (2013 Study, Volume 1, Tab 9: Fossil Dismantlement, page 3). That fact by itself dispels the concept that inflation is, or should be considered, the driving factor in future cost estimates. Changes in the manner in which dismantlement is performed and advancements in equipment which result in productivity gains can have a greater impact than inflation. In other words, the Company's presumption that inflation is the sole or only important factor to be considered for future dismantlement estimates is a false premise. Again, even the recent history as reflected between the Company's prior dismantlement study and the current dismantlement study clearly demonstrates the fallacy of the Company's premise.

Q. WHAT IS THE STAND-ALONE IMPACT OF RELYING ON THE COMPANY'S 2013 DISMANTLEMENT ESTIMATE AND THE REMAINING LIFE OF THE VARIOUS PLANTS?

A. Adoption of my recommendation for this component of the dismantlement study will result in an annual $4,832,835 decrease in dismantlement costs. This amount does reflect the Commission required increase to reflect expected cost levels during the next four years.

C. Contingency/Other Factors

Q. WHAT CONTINGENCY LEVEL DOES THE COMPANY REQUEST IN ITS DISMANTLEMENT PROPOSAL?

A. The Company requests a 10% contingency component (2013 Dismantlement Study Section 7.7). The proposed contingency is comprised of a 5% pricing contingency and a 5% scope of mission contingency.

Q. WHY DOES THE COMPANY CLAIM THE NEED FOR A 5% PRICING CONTINGENCY?

A. The Company claims that it requires a 5% pricing contingency in order "to provide a satisfactory level of confidence that the estimate will not overrun due to pricing error." (*Id.*). However, it must be noted that the Company fails to recognize that pricing errors can be both positive and negative.

Q. WHY IS THE COMPANY SEEKING A 5% SCOPE OF MISSION CONTINGENCY?

A. The Company claims that because it had difficulty in obtaining quantities and weight records for various components of its units and unknowns regarding future hazardous waste environmental assessments, it was necessary to add another 5% contingency factor. (*Id.*).

Q. WHAT IS THE DOLLAR LEVEL OF CONTINGENCY THAT THE COMPANY IS SEEKING?

A. The Company is seeking approximately $21.7 million of contingency above and beyond its cost estimates for dismantling its various generating units.

Q. ARE CONTINGENCIES APPROPRIATE?

A. That depends on the type of estimate being performed and whether negative contingencies are considered.

Q. WHY DOES A CONTINGENCY DEPEND ON THE TYPE OF ESTIMATE?

A. If an estimate includes high-side cost components in the base estimate, then no contingency or a negative contingency is appropriate. Alternatively, if an estimate reflects conservative cost components, then a positive contingency may be warranted. Thus, before any positive contingency is allowed for cost estimates associated with a revenue requirement issue in a rate proceeding, a substantial level of justification demonstrating the quality of the estimate must be presented by the Company.

Q. DOES THE COMPANY PRESENT A DISMANTLEMENT STUDY?

A. Yes. While the Company's study comprises hundreds of pages, the quantity of information should not be confused with its quality. Critical components necessary to test the validity of the underlying cost estimates are not provided. For example, there is no justification or verification of the reasonableness of the productivity factors assumed in the process, other than that a third-party estimate was assembled by a contractor that works for Southern Company (2013 Dismantlement Study, Section 7.1). Also, the Company has not demonstrated that the various methods or processes that it employed are the most cost-effective. For example, a demolition cost estimate for fossil generating facilities was performed by one of the major international construction management companies for Nevada Power Company. Within a few years of the completion of its dismantlement cost estimate, Nevada Power Company contracted for and had three of its generating units dismantled. The cost estimate by the construction management company was overstated by 76%. In other words, the actual cost incurred by Nevada Power Company was 24 cents on the dollar compared to the estimate that had been made only a short time earlier. It is also important to note that the estimate was supported by a significant quantity of numerical calculations but, as is the case here, Gulf also failed to provide meaningful support for many of the critical assumptions.

Q. CAN YOU PROVIDE EXAMPLES OF WHY COST ESTIMATES PRESENTED BY THE COMPANY WOULD INDICATE THAT THE ESTIMATE IS A HIGH-SIDE COST ESTIMATE?

A. Yes. Section 3 of the Company's 2013 Dismantlement Study identifies various high level assumptions reflected in its calculation. Certain assumptions effectively already build in a considerable level of contingency. For example, Assumption 14 notes that equipment is assumed to have no salvage value beyond the scrap value of the material. It is hard to imagine that such a situation would be the case. While the Company does note that the market for used equipment can be volatile, that should not default to a situation where the worst-case scenario for such equipment is assumed (i.e., that it will have no salvage value other than scrap value). This is especially true given that the Company incorporates interim retirements in its depreciation rates. The inclusion of interim retirements means that there will be relatively new items of equipment at each power plant at the time it retires.

Other assumptions also reflect a high-side cost estimate. For example, Assumption 5 under Section 3.3, Environment Assumptions, states that the ash pond will be graded and that coal fields will be covered with six inches of clay, six inches of topsoil, and grass so that there is no source discharge of runoff. The coal storage area will then be graded and grassed. Such an assumption is inconsistent with Assumption 5 under Section 3.1, General Assumptions, where the Company notes that its estimate does not reflect land value or its sale. In other words, the Company includes costs to improve the site well beyond what is necessary for the removal of depreciable plant. Those additional costs result in increased value for the remaining site; however, no offsetting credit for the potential sale or reuse of the site is recognized. It should be noted that there is no legal requirement to grade and seed the site after the removal of aboveground facilities.

Q. IS THERE ANOTHER CONSIDERATION WHY A SPECIFIC ADDITIONAL CONTINGENCY ADDER SHOULD APPLY WHEN ONLY SPECIFICALLY DEMONSTRATED TO BE VALID?

A. Yes. The time between the current period and the ultimate dismantlement of a generating facility, if it occurs, is a form of contingency in and of itself. It provides time for the Company to gain better information, which can increase or decrease the cost of dismantling the plant. As previously noted, the Company's own expense estimate for dismantling its plant has decreased since its last dismantlement study. Moreover, as has happened in the past, when high-cost activities are being performed, the marketplace develops newer technology which improves productivity and reduces costs. For example, rather than dismantling generating facilities in a reverse engineering mode as was often previously proposed by utilities, Gulf and other companies are relying on explosive techniques to topple structures to the ground where they can be more easily dismantled and removed. Even in those instances in which explosive techniques are not employed, there are now ultra high reaching booms that can be fitted with beam-cutting shears that did not exist 20 years ago.

Q. IS THERE YET ANOTHER POTENTIAL MAJOR CONTINGENCY LEVEL ALREADY REFLECTED IN THE COMPANY'S ESTIMATE?

A. Yes. As previously noted, the Company is proposing to landscape, contour, seed, and mulch the site. In other words, the Company is assuming it will return the site to a green field condition. There is no requirement to return the site to such a condition. In fact, other demolition studies such as those being relied upon by Duke Energy are reflecting what is called an industrial site restoration condition. Even that level of restoration exceeds what is necessary in order to reimburse Gulf for required activity applicable to its depreciable plant when no offsetting sales value is associated with the demolition cost estimate.

Q. WHAT DO YOU CONCLUDE BASED ON YOUR REVIEW OF THE COMPANY'S ESTIMATE?

A. The Company's estimate already reflects the worst-case scenario of total dismantlement. It also includes high-side cost estimates corresponding to activities that are not required. Therefore, the Company has already incorporated positive levels of contingency in its estimate and, to the extent any contingency is to be considered, a negative contingency is appropriate.

Q. WHAT IS YOUR RECOMMENDATION?

A. Based on the information presented by the Company, a conservative estimate would be a zero (0) level of contingency, in addition to the implicit contingencies already reflected in the Company's other components of its cost estimate.

Q. WHAT IS THE STAND-ALONE IMPACT OF REMOVING THE COMPANY'S INCREMENTAL 10% SPECIFIC CONTINGENCY FACTOR?

A. While the removal of the 10% contingency factor would reduce the current cost estimate by $21.7 million due to the Company's inflation escalation calculation, the resulting impact would be a $1,483,320 reduction in requested annual dismantlement expense.

D. Combined Impact

Q. IS THE COMBINED IMPACT OF YOUR TWO STAND-ALONE ADJUSTMENTS THE SUMMATION OF EACH COMPONENT?

A. No. The two adjustments interact upon each other and result in a lower combined impact than the simple summation of the two components on a stand-alone basis. The combined interactive impact of my two recommendations associated with the Company's requested dismantlement expense is an annual reduction of $6,288,508.

SECTION VI: MASS PROPERTY LIFE

A. General

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony addresses the Company's mass property life analyses and resulting life proposals. The life analysis produces an ASL combined with a dispersion curve, a standardized Iowa Survivor curve. This information is used to calculate the remaining life of the investment, which is an integral component of the depreciation rate calculation.

Q. BASED ON YOUR REVIEW, ARE YOU RECOMMENDING SPECIFIC ADJUSTMENTS?

A. Yes. I am recommending longer ASLs for 12 mass property accounts compared to the Company's proposals as set forth on Exhibit__(JP-2). The combined impact of these 12 adjustments is a $6.6 million reduction to depreciation expense based on estimated plant as of December 31, 2013.

Q. WHAT IS THE BASIS FOR YOUR VARIOUS RECOMMENDED ADJUSTMENTS?

A. I performed an independent review of the actuarially and SPR-derived life indications. I then reviewed and analyzed all significant or meaningful items of information provided by Company. I further relied on additional information obtained either in discovery or from performing hundreds of depreciation analyses relating to United States and Canadian-based utilities to develop sound, realistic, and representative ASLs and dispersion patterns that best reflect future expectations for the investment in numerous accounts.

Q. WHY DID YOU REVIEW INFORMATION OTHER THAN THE HISTORICAL INDICATIONS OBTAINED FROM ACTUARIAL OR SPR ANALYSES?

A. Analysis of historical data provides insight to what can be expected in the future; however, it must be tested to help determine its applicability to the current plant investment. For example, historical indications based on review of SPR results for Account 367 – Distribution Underground Conductors would not be as accurate as it could be for indicating what can be expected for the current investment. Over the past several decades, the industry has relied on newer and technologically more advanced underground conductors. The newer technology-based conductors are better able to protect against faults that result in early retirements. A recognition of these changes in investment mix, which are not adequately reflected in the SPR results, warrants a longer ASL than is indicated from only a review of historical transactions. It is this type of analysis that I have performed in the evaluation phase of my depreciation study. This more meaningful analysis ensures that the most appropriate life parameters are selected for the plant at issue.

Q. HOW DID THE COMPANY DEVELOP ITS PROPOSED LIFE PARAMETERS FOR MASS PROPERTY ACCOUNTS?

A. The Company proposes a life-curve combination to define the life characteristics of the investment for each mass property account. The life portion of the combination establishes the ASL of the investment. The curve portion of the combination establishes a representative Iowa Survivor curve that identifies a pattern of retirements over a complete life cycle of an account. Like the Company, I also rely on Iowa Survivor curves in my analyses.

Q. WHAT STATISTICAL LIFE ANALYSIS APPROACH DID THE COMPANY EMPLOY?

A. The Company utilized an actuarial approach for its transmission and general plant accounts, as well as distribution Account 362 for life analysis since it maintains aged data for those accounts. Aged data simply means that when plant is retired, the year in which it was placed into service is also known. The Company utilized the SPR method, a semi-actuarial approach, for all remaining distribution accounts.

B. Actuarial Analyses

Q. HOW DID THE COMPANY DEVELOP ITS LIFE-CURVE COMBINATIONS BASED ON AN ACTUARIAL PROCESS?

A. The Company normally performed two to three different actuarial analyses. The different actuarial analyses rely on different placement and experience band combinations. (Placement bands establish the years of data reflected in the database being analyzed, while experience bands identify the time frame over which transactions reflected in the database are reviewed.)

Q. WHAT PLACEMENT-EXPERIENCE BAND COMBINATIONS DID THE COMPANY PERFORM?

A. The Company performed a full or overall placement band, generally with different 20- to 50-year experience bands, all of which end in 2013.

Q. WHAT RESULT IS OBTAINED FROM ACTUARIAL ANALYSES?

A. The results produced by actuarial analyses are identified as observed life tables ("OLT"). An OLT simply represents the pattern of actual retirement activity over history, and thus survivors, by individual age groups. In other words, at the beginning of the zero (0) age interval, 100% of the investment survives, and as additional ages are examined and retirements occur, the OLT declines from 100% surviving towards 0% surviving. If the OLT fully declines to 0% surviving, it is called a complete survivor curve. An OLT that does not decline to 0% surviving is identified as a stub curve. If a stub curve is very short (*i.e.*, it does not decline very far from 100% surviving), then limited useful information can be garnered from such analyses. The limited information in such circumstances is normally that a long ASL is indicated if a significant level of years has transpired without a significant decline in the OLT.

Q. ONCE AN OLT IS OBTAINED, HOW IS IT UTILIZED TO DEVELOP A REPRESENTATIVE LIFE-CURVE COMBINATION?

A. The normal practice in the industry is to employ visual curve-fitting of the OLTs with standardized Iowa Survivor curves. Use of standardized Iowa Survivor curves provides smooth, complete survivor curves so that various calculations necessary to establish a remaining life and depreciation rate can be obtained. In particular, the area under a survivor curve yields the ASL of the assets being analyzed. Mathematical (as opposed to visual) curve-fitting is seldom relied on due to the different levels of significance associated with different points of the OLT.

Q. IN THE PROCESS OF MATCHING AN OLT WITH IOWA SURVIVOR CURVES, ARE THERE DIFFERENT AREAS OF THE PROCESS THAT ARE SIGNIFICANT?

A. Yes. It is more important to match a standard Iowa Survivor curve with the middle and upper portions of an OLT than the tail portion, depending on the dollar level of exposures at issue. If the lower portions of an OLT, where there are limited levels of exposures, are matched while sacrificing a close fit to the middle or the upper portions of the survivor curve, then an inappropriate result will be obtained. Therefore, part of the judgmental process employed by a depreciation analyst is to determine which ASL and corresponding survivor curve constitutes the "best" fit to the OLT. The Company also recognizes this concept when it states in the notes for Account 362 – Distribution Station Equipment that "[f]ew exposures from age 60 or so, so little or no weight to the curve tail" (2013 Study, Volume 2, Tab 362, page 1).

Q. WHY IS IT IMPORTANT TO SPECIFICALLY REVIEW THE DOLLAR LEVELS OF EXPOSURES AT DIFFERENT AGE INTERVALS IN THE CURVE-FITTING PROCESS?

A. The movement in the OLT from one age to the next is affected both by the dollar level of exposures in that age interval and the corresponding dollar level of retirement activity that has transpired during the same age interval. As time passes and as both existing investment and new investment age, the pattern of the OLT will change. In other words, if plant is continuously added and there are no retirements during a five-year period, then the OLT will elevate from the position it previously exhibited in a prior study. A higher or elevated OLT normally translates into a longer ASL.

In addition, even if no new additions were to occur during the next five years, but the existing plant ages for five additional years with no additional retirements, then the mid portion and tail portion of the OLT would also be expected to elevate, thus resulting in a longer ASL. Indeed, these portions of the OLT may elevate significantly between studies. Finally, if retirement activity occurs, but not to the same degree that is reflected historically in the various age brackets, then the OLT again is expected to elevate and result in a longer ASL. The key issue is the degree of potential movement between depreciation studies due to the limited dollar level of exposures or potential for significant levels of retirement activity in different age brackets. Simply put, the tail and the lower portions of the mid section of the survivor curve that are based on limited levels of exposures can move dramatically between one depreciation study and the next. Normally, the head or top portion of the OLT remains relatively stable, as do the upper portions of the mid range of the OLT if they are based on significant dollar levels of plant exposures.

Q. HAS THE COMPANY SPECIFICALLY IDENTIFIED HOW IT OBTAINED ITS VARIOUS PROPOSED LIFE-CURVE COMBINATIONS?

A. No. At best, the Company has presented generalized statements claiming that it selected "a good fit" or a "representative" curve (2013 Study, Volume 2, Accounts 353 and 356). In other words, the Company normally performs a few actuarial analyses, then selects a life-curve combination without any specific basis supporting the selection other than claims that its selection is "good," "representative," "similar to the prior study," or "consistent with the data." The Company provides very limited specific evidence that can be reviewed, analyzed, or tested in support of its specific proposals other than the results of the actuarial analyses.

In this particular case, the Company often ignores the "best" fitting results either because it did not investigate those life-curve combinations or because it results in <u>higher</u> ASLs than it is willing to propose. This practice of ignoring better fitting results is unwarranted absent meaningful information supporting an alternative. In this case, the Company fails to provide alternative information that would support choosing its proposals over better fitting alternatives.

Q. PLEASE SUMMARIZE THE ACTUARIAL CURVE-FITTING PROCESS EMPLOYED BY THE COMPANY.

A. The Company chose various placement-experience band combinations of historical data and performed actuarial analyses on the various databases. The Company then made a life-curve combination selection. The Company provides limited meaningful narrative associated with its selection and no real support for having ignored or significantly discounted better fitting combinations that yield higher ASLs.

C. Simulated Property Records (SPR) Analyses

Q. HOW DID THE COMPANY DEVELOP ITS LIFE-CURVE COMBINATIONS BASED ON SPR ANALYSES?

A. Since the Company apparently does not have aged data for the majority of its distribution accounts, it relied on a semi-actuarial approach, the SPR balance method. This method simulates the closeness of fit over time between actual annual balances for an account compared to the simulated balance based on the best-fitting ASL for each of 27 different Iowa Survivor curves tested. The closeness of fit for the different curves is identified by a sum of square difference calculation (Response to Citizens' Interrogatory No. 28(a)).

Q. IS THE COMPANY'S SPR ANALYSIS A STANDARD PRESENTATION?

A. No. The Company's SPR analysis is anything but standard. First, it must be noted that the output to the SPR analysis lists 11 columns of data per page. The only identifiable aspect of the output is the first column heading identified as "Curve." The remaining 10 columns do not have column headings other than calendar years (2013 Study, Volume 2, Account tab for 364-373). Thus, one is left to guess as to what the numerical information presented actually represents.

Q. THROUGH DISCOVERY, WERE YOU ABLE TO IDENTIFY WHAT THE VARIOUS ITEMS OF INFORMATION ACTUALLY REPRESENT?

A. Yes, for the most part. The Company states that the first five columns represent the ASL for each of the Iowa Survivor curves for the years 2009 through 2013. It is assumed that these represent annual incremental rolling bands of data ending in the calendar year noted. The last five columns on the page represent a "goodness of fit" calculation without identifying what the actual index is. This is significant given that the normal SPR output provides a sum of squared differences value, a Conformance Index ("CI"), and sometimes an Index of Variation.

Q. IS THERE SOMETHING ELSE ABOUT THE COMPANY'S SPR PRESENTATION THAT IS UNUSUAL?

A. Yes. Basically, all other SPR presentations include what is identified as a Retirement Experience Index ("REI"). An REI represents the maturity of the account in order to provide the analyst with additional information for selecting a particular life-curve combination in conjunction with one of the sum of squared differences calculations. The Company's failure to present this additional index calls into question the reliability of its various selections.

Q. ARE THERE GENERALLY ACCEPTED RANKING CRITERIA ASSOCIATED WITH THE SPR OUTPUTS?

A. Yes. However, the CI ranking normally relied upon throughout the industry could not be used since the Company did not identify what its sum of squared difference calculation actually was. The Company simply noted that smaller numbers indicate better fits (Response to Citizens' Interrogatory No. 28(a)).

Q. HOW DID THE COMPANY ARRIVE AT ITS PROPOSALS WHEN RELYING ON THE SPR METHODOLOGY?

A. OPC requested the Company to provide a detailed narrative identifying the specific selection process for ranking each account and other factors including input from Company personnel when making its life-curve combination selection based on the SPR method. However, the Company responded by simply referring to Volume 2 of its 2013 Study (Response to Citizens' Interrogatory No. 29). In other words, the Company's entire basis and support for its life-curve combinations for the majority of its investment in Distribution Plant is based on a limited number of cryptic sentences provided by account in Volume 2 of its 2013 Study.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE COMPANY'S PRESENTATION IN VOLUME 2 OF ITS 2013 STUDY?

A. Yes. The following is the Company's entire narrative basis for its life-curve selection for Account 364 – Distribution Poles:

> $131 M Balance. Large (11.7M) write off in 2012 that, for this analysis, was spread to all years and had a noticeable effect on

> indicated lives. FIFO age of ret is 28 years. In the longer bands, fits of the curves are similar, preference to lower modes. L0, for instance, ever so slightly better fit than R0.5. Life indications increasing over time: L0 over 4-year periods, for instance, was 29 to 30 to 32 years; at L1 was 26 to 27 to 28.5; and so on. Pattern at shorter bands were similar. L curve is frequently typical for account 364. Based on the data, use L0-32.

Q. DO THE LIMITED CRYPTIC STATEMENTS PROVIDE REASONABLE AND REALISTIC SUPPORT FOR THE COMPANY'S PROPOSAL?

A. No. The first sentence simply states the balance and has no bearing on the proposal. The second sentence identifies a dollar level of write off that was spread to all years and had a noticeable effect on life without identifying what the specific impact was and explaining or justifying such impact. The third sentence refers to an average age of retirements based on a first-in, first-out accounting approach, which again provides no meaningful basis for selecting a life-curve combination. The fourth sentence identifies that there is a preference to lower modes in the longer bands without identifying what are considered the longer bands. (It should be noted that the Company ran four bands: a five-year, a 10-year, a 20-year, and a 30-year band analysis.) The fifth sentence identifies an L0 as an example that is ever so slightly better than an R0.5. However, it must be assumed that the reference to better fit is to the goodness of fit calculations presented. The next sentence indicates that life is increasing over time and provides apparent references to changes in ASLs over four-year periods. However, for example, the reference to the L0 curve values ranging from 29 to 32 years cannot be identified in the various SPR runs that follow (2013 Study, Volume 2, Account 364, pages 2-5). The next sentence states that patterns at shorter bands were similar. However, based on review of the output, this statement is not accurate. For example, the results for an L0 curve ending in 2013 for the 30-year band identifies a 32-year ASL while the same information for a five-year band identifies a 37-year ASL. A 32-year ASL and a 37-year ASL are not "similar." The final sentence of information provided simply states, without support or justification, that an L curve is frequently typical for the investment in Account 364. From these various short statements, which for the most part provide no definitive basis for the selection process, a conclusory statement is made that a 32L0 life-curve combination was chosen based on the data.

Q. IS THE COMPANY'S PRESENTATION CLEAR ENOUGH OR CONCISE ENOUGH TO SUPPORT, NOT ONLY ITS PROPOSAL, BUT HOW IT EVEN ARRIVED AT ITS PROPOSAL?

A. No. Given the unusual nature of the Company's presentation and its lack of specifics, even a relatively seasoned depreciation analyst might have difficulty analyzing what has been presented.

Q. HOW DID YOU ANALYZE THE SPR RESULTS?

A. I relied on the Company's statements that the goodness of fit criterion was that lower values represented better fits. I then reviewed the top four to five best-fitting curves for each of the band analyses, recognizing that five-year bands in particular should be given less weight in the process than other analyses given their very short duration. I also reviewed the underlying base data in order to gain further insight into the maturity of the investment in relation to the various Iowa Survivor curves being simulated. I then relied on my extensive experience and judgment gained from having performed hundreds of depreciation studies throughout the United States and Canada. In my opinion, it is necessary to bring this level of depreciation knowledge to bear in this instance, given the deficiencies of the Company's presentation. As previously noted, knowledge of the change in industry practices, such as those associated with Account 367 – Distribution Underground Conductor, provide valuable insight into the review of historical analyses as a reasonable predictor of future expectations.

D. Account Specific

Account 350.2 – Transmission Easements and Right-of-Ways

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 350.2 – TRANSMISSION EASEMENTS AND RIGHT-OF-WAYS?

A. The Company proposes a 65R5 life-curve combination (2013 Study, Volume 2, Account 350).

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company notes that there is no meaningful retirement data, so no actuarial analysis was performed. The Company notes that its proposal is an increase of five years from the existing value and that the current life is consistent with the typical nature of the property. The Company then concludes that there is no compelling reason to change the approved rate even though it has proposed a five-year increase. (*Id.*).

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal significantly understates the realistic life expectations for the investment in this account. I recommend a 90R5 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. While no meaningful retirement data has transpired, that does not necessarily imply that a statistical analysis of the historical data would not indicate a long ASL. Indeed, property of this nature is fully expected to last for well beyond one complete life cycle of the investment that resides upon it. In other words, if the transmission poles and wires have a maximum life cycle expectancy of approximately 90 years, then the easement upon which those assets reside cannot be in service for less than 90 years.

While the Company states that the typical nature of the property is consistent with a 65-year life, such is not the case. Indeed, the Company admits that less than three percent of its investment in this account is subject to a specific expiration date (Response to Citizens' Interrogatory No. 54). In other words, almost all the investment in this account is associated with perpetual easements. Therefore, an average life expectancy of well over 100 years, or as long as the Company is providing electric service, is more indicative of the typical nature of the property than is the Company's proposed 65-year level.

While an ASL of 100 years or longer would be appropriate, I recommend a gradual movement in that direction. A 90-year period reflects approximately the current maximum life for the investment in Transmission Account 356 – Overhead Conductors, prior to my recommendation for a longer ASL.

Q. **WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

A. My recommendation results in an $88,959 decrease in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 353 – Transmission Station Equipment

Q. **WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 353 – TRANSMISSION STATION EQUIPMENT?**

A. The Company proposes to retain the existing 45S0 life-curve combination (2013 Study, Volume 2, Account 353, page 1).

Q. **WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?**

A. The Company notes that its actuarial analysis yielded a situation where the "data is well fitted by generally lower mode curves with indicated lives from low 40's to a high of 50 years." The Company further notes that low mode curves are unusual for this type of property, but indicates that the longer retirement band is lower than in the prior study, indicating a lower ASL. The Company then notes that the existing 45S0 life-curve combination "is, among others, a good fit to the data and a better fit than in the prior study." The Company concludes by noting that a lower life is indicated from its analyses, but the existing 45-year ASL is well within industry experience and that a change in curve and life is not indicated. (*Id.*)

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal is not indicative of the results of its actuarial analyses. I recommend a 48L0 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation reflects an appreciably better fit to the OLT than the Company's proposal. As shown on Exhibit__(JP-3), my recommendation is superior to the Company's proposal through the first 40 years of life. The Company's proposal then becomes a better fit for approximately eight years (42.5 years through 48.5 years). From approximately 50 years of age and onward through the meaningful part of the OLT, my recommendation is again a superior fit. When viewed overall, a 48L0 is a significantly superior fit as shown on Exhibit__(JP-3). Exhibit__(JP-3) and other curve presentations reflect the OLT and Iowa Survivor curves through the meaningful portion of curves to allow a better visual inspection of the data. The meaningful cut off criterion used is the point where the dollars of exposure subject to retirement forces are approximately 1% of the exposures at age zero (0).

Given that both the Company's ASL and my recommended ASL were well within industry expectations and the fact that my recommendation is an appreciably superior fit to the OLT, both on a 30- and 50-year band analysis, an increase of three years in the ASL is appropriate.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $443,434 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 356 – Transmission Overhead Conductors

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 356 – TRANSMISSION OVERHEAD CONDUCTORS?

A. The Company proposes a 50R1.5 life-curve combination, which reflects retention of the existing 50-year ASL but a change from an R2 Iowa curve dispersion pattern (2013 Study, Volume 2, Account 356, page 1).

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company performed an actuarial analysis with experience bands ranging from as short as 21 years to as long as 50 years. The Company states that the shorter retirement bands have lower indicated ASLs and further noted that the 2013 Study yielded a lower OLT than in the prior study, thus indicating a shorter life. The Company's interpretation of its actuarial analysis led it to believe that mid-to-lower mode curves such as the R1.5 or R2 with lives in the 50- to 55-year range were representative. The Company then claims that the existing life is relatively high. From these items of information, the Company concludes that it is reasonable to maintain the 50-year ASL and reduce the mode of the curve to an R1.5 Iowa Survivor curve. (*Id.*)

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal reflects too short of a life. I recommend a 53R0.5 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on a more appropriate interpretation of the actuarial results.

Based on the longer bands, a 54- to 55-year ASL with a corresponding R1 dispersion curve is a superior fit than the Company's proposal, as shown on Exhibit__(JP-4). Given the level of the ASL in question, more significance should be given to the longer experience band analyses (i.e., a 21-year experience band is appreciably less than half of the realistic range of ASLs for the investment in this account).

Turning to the shorter 21-year experience band analysis presented by the Company, a trend towards a shorter life is indicated. However, the Company's proposed value is still artificially short in comparison to the best-fitting results, even for the 21-year experience band analyses. As shown on Exhibit__(JP-5), a superior fit to the OLT for the 21-year experience band analyses would be a 52R0.5 life-curve combination.

Thus, the Company's proposal is artificially short, whether viewed from a more appropriate longer band analysis or a shorter band analysis that may indicate a trend.

Given the changing life characteristics exhibited between the shorter and longer bands, a life-curve combination in between the two is appropriate. While greater significance should be given to the longer band considering the level of data in relationship to the ASL, I have also given consideration of a trend towards a shorter ASL based on the shorter experience band analyses. Given that a 54- to 55-year life is indicated with a longer band and a 52-year life is indicated for the shorter band, my recommendation for a 53R0.5 is the most appropriate value to be utilized in this proceeding.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $279,212 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 364 – Distribution Poles and Fixtures

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 364 – DISTRIBUTION POLES AND FIXTURES?

A. The Company proposes a 32L0 life-curve combination (2013 Study, Volume 2, Account 364, page 1). This represents a two-year decrease from the previous 34R1 life-curve combination. (*Id.*)

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company relied on its interpretation of the SPR analyses. It noted that there was a large write-off in 2012 that had a noticeable effect on indicated lives. It also stated that there was a preference towards lower modes in the longer SPR bands. Lastly, it further noted that the L curve is frequently typical for Account 364.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal unreasonably shortens the ASL. I recommend a 34L0 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation relies on the Company's SPR results. A review of the SPR results indicates a trend towards longer ASLs whether viewed from more recent experience bands or from the standpoint of incremental rolling band analyses. The most recent five-year band analysis yields a 37-year ASL for L0 dispersion patterns, and the 10-year band analysis yields a 35-year ASL. Both of these values are appreciably longer than the 32-year ASL exhibited in the 20- and 30-year band analyses. In other words, from an SPR analyses standpoint, movement to a 35- or even 36-year ASL might be warranted. However, in order to remain conservative, and to recognize the closeness of fit of an R0.5 dispersion pattern, I recommend retention of the existing 34-year ASL but with an L0 Iowa curve dispersion. The L0 is the statistically best-fitting result presented by the Company.

In addition, the retention of a 34-year ASL, rather than reducing the ASL to 32 years as proposed by the Company, is more in line with the findings by the Commission in the recent FPL and Progress Energy ("PEF") depreciation analyses. In the FPL depreciation analyses, the Commission adopted an increase of five years for investment in distribution poles to 39 years (Order No. PSC-10-0153-FOF-EI, page 67), and the Commission adopted a four-year increase in ASL for PEF to 32 years (Order No. PSC-10-0131-FOF-EI, page 37). In other words, the trend in the industry as well as in Florida has been to adopt longer ASLs than previously utilized. Values in the upper-30 to even mid- or upper-40-year range or longer are being recognized by the industry as better treatment and inspection programs are implemented. Therefore, retention of the existing 34-year ASL is warranted.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $435,231 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 365 – Distribution Overhead Conductors

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 365 – DISTRIBUTION OVERHEAD CONDUCTORS?

A. The Company proposes a 40R1 life-curve combination (2013 Study, Volume 2, Account 365, page 1). This represents a two-year increase from the 2009 Study.

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company performed SPR analyses for this account. Based on its analyses, it claims that the longer bands showed a preference to lower modes and to the R family of curves. It further notes that life indications are increasing slowly over time. It concludes that, based on trends, a 40R1 life-curve combination is appropriate. (*Id.*).

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal results in an artificially short ASL. I recommend a 42R1 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on a more appropriate interpretation of the SPR results. First, it must be noted that the R0.5 Iowa Survivor curve dispersion represents a better statistical fitting curve than the R1 curve. However, the R0.5 curve yields ASLs in the 46- to 48-year range which would represent a more significant increase in ASL than I recommend. (*Id.* at pages 2-5).

The SPR results for the R1 Iowa curve dispersion pattern range from 41 years to 43 years, moving from the 30-year band analysis to a five-year band analysis. In other words, the trend as more current experience is relied upon, reflects an increase in ASL. In addition, there was a slight increase in ASL indications based on rolling band SPR analyses. Therefore, while a 43- to 48-year ASL can be justified based on the SPR results, a conservative estimate would be to only increase the ASL by two years more than what Gulf proposed.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $275,610 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 367 – Distribution Underground Conductors and Devices

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 367 – DISTRIBUTION UNDERGROUND CONDUCTORS AND DEVICES?

A. The Company proposes a 34S2 life-curve combination (2013 Study, Volume 2, Account 367, page 1). This represents a two-year increase in ASL from the 2009 Study.

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company states that in the longer bands, the preferred fits are trending to middle modes with lower modes in the shorter bands. The Company then states that the "S's [are] generally slightly more preferred than R's." While the Company then admits that the medium life indications are approximately 34 to 40 years, it has chosen to "move to or towards the overall life indications by increasing the life by two years." (*Id.*).

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. While the Company's acknowledges longer life expectations, it has artificially limited the increase to only two years. I recommend a 39R2 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on a more realistic review of the SPR results in conjunction with a more realistic, but still gradual, movement towards life indications.

First, the SPR results indicate life expectations as high as the upper-40-year range as realistic values. Indeed, an R1.5 curve for the five-year band has a 48-year ASL with a goodness of fit statistic more than twice as good as the goodness of fit for the S2 Iowa Survivor curve (a 1.6 value versus a 3.7 value where a lower value is a better indicator of goodness of fit). As longer SPR bands are analyzed, realistic ASLs in the low-to-mid-40 range are also associated with better fitting curves than the Company's proposed S2 Iowa Survivor curve. Therefore, whether viewed from a shorter or longer band analyses, the SPR analysis indicates more realistic ASL values in the 40- to 49-year range. Moreover, the R family of Iowa Survivor curves is more indicative of industry expectations. Indeed, in both FPL's and PEF's most recent depreciation proceedings, both utilities proposed R2 Iowa dispersion patterns for the investment in this account.

Another indication for a longer ASL is the fact that the industry has advanced from a technological standpoint regarding underground conductors. Underground conductors placed in service in the 1970s and early 1980s were more subject to faults, which resulted in overall shorter ASLs than can be expected with current investment. Therefore, future expectations for the current investment in the account would be longer than those reflected in the historical SPR results.

In order to more realistically recognize the lengthening in ASL, but in a gradual manner, and to be cognizant of the mid-30-year values relied upon by both FPL and PEF, I have limited the increase in ASL to 39 years, with a corresponding R2 Iowa Survivor curve dispersion pattern. The Commission can further lengthen the ASL in the next proceeding if statistical results continue to indicate life expectations in the 40- and greater year range.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in an $854,147 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 368 – Distribution Line Transformers

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 368 – DISTRIBUTION LINE TRANSFORMERS?

A. The Company proposes a 32S0 life-curve combination (2013 Study, Volume 2, Account 368, page 1). This represents a two-year increase from the existing 30-year ASL.

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company states that longer bands show a preference to lower modes. It further states that life indications are largely flat but slightly increase over time. It also states that patterns exhibited by shorter bands were similar with slightly increasing indicated lives. It then concludes that based on the data and trends, it proposes a two-year increase to a 32-year ASL. (*Id.*)

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal, while representing a step in the right direction, is inadequate. I recommend a 34R0.5 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I relied on the results of SPR analyses and the concept of gradualism. In this particular instance, the Company's proposal is not even in the top five best-fitting curves for all of the various bands analyzed. For all bands analyzed, an L0 dispersion pattern reflects the best-fitting curve, with ASL indications between 35 and 37 years, and a trend to longer lives with more recent data. The R0.5 dispersion pattern is the second best-fitting pattern, with ASL indications between 32 and 34 years, and a trend to longer lives with more recent data. Therefore, from a statistical analysis standpoint, an ASL between 33 and 37 years would be more appropriate.

In addition, the trend in the data, whether viewed from the results of shorter bands analyzed or from rolling bands, is that life indications are increasing. Thus, the higher end of the statistical indications would be a more appropriate selection. However, relying on gradualism and recognizing that life indications for this account can vary significantly, a gradual increase of two years with a change in the dispersion pattern to an R0.5 Iowa curve is recommended.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $1,149,526 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 369.1 – Distribution Overhead Services

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 369.1 – DISTRIBUTION OVERHEAD SERVICES?

A. The Company proposes a 40R1 life-curve combination (2013 Study, Volume 2, Account 369.1, page 1). This represents a five-year increase over the existing 35-year ASL.

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company states that longer bands tended to prefer lower modes, and further indicated that ASLs are increasing over time. The Company also states that shorter bands indicated lives of several years longer than longer bands, implying trends. From its observations, the Company proposed a five-year increase which it claims may be excessive if retirements resume closer to their earlier rate, and further concludes that its proposal is within the range of industry experience. (*Id.*)

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. While the Company's proposal is a step in the right direction, it still significantly understates the ASL expectations based on SPR analyses. Therefore, I recommend a further increase to a 44R1 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation combines a conservative review of the Company's SPR results and reflects a more realistic level of gradualism.

The statistical results of the SPR analyses indicate a longer ASL than either the Company or I recommend. The best-fitting dispersion pattern is an R0.5 Iowa Survivor curve. The resulting ASLs for the four bands beginning with the oldest and moving to the most current are 45.1 years, 46.5 years, 50.3 years, and 54 years. These results indicate an ASL range between 45 and 54 years, with a corresponding trend toward longer ASL expectations. Similar results are exhibited by the second and third best-fitting Iowa dispersion patterns. It is only when the R1 curve, which is the fourth best-fitting dispersion pattern, is reviewed that a value as low as 40 years is first observed, and that corresponds only to the 30-year band analysis. Shorter band analyses for the R1 curve yield 45- to 58-year ASLs. (*Id.*, pages 2-5). In other words, from the standpoint of the best-fitting SPR results, realistic ASLs range from approximately the mid-40s to the low-50 years, with a trend towards longer service lives as more recent experience is analyzed.

Even when the SPR results were reviewed from a rolling band analysis, a longer life than the 40 years proposed by the Company is indicated. In addition, the life indications for rolling bands further reinforce the concept that a trend towards longer lives is being exhibited by the Company's plant-in-service. Therefore, it would be inappropriate to rely on the shortest ASL values indicated by the SPR results for better-fitting curves.

In implementing the concept of gradualism, one can look to FPL who, in its most recent depreciation study, recognized the longer life expectations for the investment in this account, and increased its proposal to 48 years from the existing 36-year ASL (Order No. PSC-10-0153-FOF-EI, page 70). In other words, when the existing values are found to be so significantly out of line with statistical indications, significant increases in ASL are warranted, even taking into consideration the concept of gradualism. As noted, FPL proposed a 12-year increase for this account, which corresponds to a 33% increase in ASL.

Given that the lower end of the range of realistic values begins in the mid-40-year period, further increasing the ASL to 44 years with a corresponding R1 dispersion pattern reflects a conservative estimate that most likely will need to be increased in the next depreciation analysis.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $227,445 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 370.1 – Distribution Meters – AMR

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 370.1 – DISTRIBUTION METERS-AMR?

A. The Company proposes a 15R1 life-curve combination (2013 Study, Volume 1, Section 7 Parameter Schedule, page 7).

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. While the Company states that the support for its selection is found in the supporting work papers behind each account tab in Volume 2 of its 2013 Study, there is in fact no account tab for this particular account. The only identifiable basis for the Company's proposal is that it corresponds to the existing approved depreciation parameters (2013 Study, Volume 1, Section 6: Analysis Results, page 34).

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal is artificially short. Consequently, I recommend an increase to a 20R1 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The investment in new Automatic Meter Reading ("AMR") meters has not led to a meaningful opportunity to provide empirical data associated with their life expectancy. However, manufacturers have indicated a 20-year life or greater, and other utilities proposed 20-year or greater periods. Indeed, FPL in its most recent depreciation study proposed a 20-year ASL and supported such position by stating that its proposed ASL was based on a manufacturer-suggested 20-year life (Order No. PSC-10-0153-FOF-EI, page 72). The Commission may find it necessary to increase the life of the investment in this account in future depreciation studies as empirical data is obtained.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $1,137,609 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 373 – Distribution Street Lights

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 373 – DISTRIBUTION STREET LIGHTS?

A. The Company proposes a 22L1 life-curve combination (2013 Study, Volume 2, Account 373, page 1). This represents a two-year increase over the existing 20-year ASL from the Company's 2009 Study.

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company states that the longer 20-year bands yield lower mode curves, but that life indications are increasing over time. The Company also states that shorter bands have somewhat longer lives with the medium and lower mode curves yielding ASLs of 20 years or so. The Company concludes that while the data supports the existing 20-year life, the trend is for somewhat increasing life, and therefore proposes a two-year increase in the ASL. (*Id.*)

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. Based on its own results, a longer ASL is warranted. Therefore, I recommend a minimal increase to a 24-year ASL with a corresponding L0.5 Iowa curve dispersion pattern.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation again is based on a more appropriate interpretation of the SPR results, along with the concept of gradualism.

From an SPR statistical standpoint, the Company-selected Iowa dispersion pattern is not in the top five best-fitting curves. Moreover, even if an L1 dispersion pattern were selected, the most recent band would indicate a 24-year ASL. However, a review of the best-fitting curves indicates not only a trend towards longer ASLs, but more realistic ASL values in the 20- to 26-year range with a trend to the higher end of the range. A more realistic interpretation of the SPR results would yield a 24- to 25-year ASL with a corresponding low modal L curve. (*Id.*, pages 2-5).

Taking into consideration the historical change out of streetlights due to technological advancements reflected in the Company's data and that it is unlikely that future technological changes will occur as frequently would further indicate that a longer ASL is warranted. However, a minimal increase in ASL to 24 years along with a change in the dispersion pattern to an L0.5 is warranted at this time. Again, the Commission will likely need to significantly increase the ASL in future depreciation studies. In addition, it should be noted that FPL in its most recent depreciation filing proposed an increase from 20 years to 30 years for the investment in its street lighting account (Order No. PSC-10-0153-FOF-EI, page 73).

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $433,994 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 390 – General Plant Structures and Improvements

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 390 – GENERAL PLANT STRUCTURES AND IMPROVEMENTS?

A. The Company proposes a 45S1.5 life-curve combination (2013 Study, Volume 2, Account 390, page 1).

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company states that effectively one-half of the OLT has occurred and there are very few exposures after age 50; therefore, it gave lesser weight to the tail of the OLT. The Company further claims that "representative" curve fits include mid- to low-mode curves with lives of approximately 45 years. The Company then concludes by retaining the existing life-curve combination based on the data it reviewed, and that its proposal is still within the typical range of the industry. (*Id.*)

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal is artificially short. I recommend nothing less than a 50S0.5 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on a combination of a correct interpretation of actuarial results and a better understanding of the investment in the account. From an actuarial standpoint, the Company is right that lesser consideration should be given to the tail-end of the curve due to the significant decline in exposures where the tail of the curve drops off appreciably. As shown on Exhibit__(JP-6), my recommendation is a superior fit compared to the Company's proposal throughout almost the entire meaningful portion of the OLT. Only for a few age brackets in the mid-30-year range is the Company's proposal a closer fit to the OLT. Thus, from a pure actuarial standpoint, a five-year increase in ASL is warranted, along with a change in the dispersion pattern.

In addition to the actuarial results, other information applicable to this account has an impact on life expectations. More than two-thirds of the investment in the account is associated with 10 structures owned by the Company. Indeed, one-third of the entire amount of the account relates to the Company's single largest facility, its corporate office (Response to Citizens' Interrogatory No. 65, page 2). Given that the majority of the investment in this account relates to brick and glass, metal, concrete block and precast concrete buildings, a longer life than that proposed by the Company is warranted. Brick, concrete, and metal buildings can and do last for 60, 70, or even longer years. Indeed, one of the Company's general warehouse buildings, which is the sixth largest investment in the account, was placed in service in 1949. That building has already provided more than 60 years of service and the Company has no plans for retirement of any of these facilities. (*Id.*). Even after recognizing that portions of the investment in the account are associated with leasehold improvements or other short-lived property, a weighted average life greater than 45 years is warranted and most likely greater than the 50-year ASL that I recommend. Therefore, a minimum increase of five years in the ASL should be adopted.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $325,041 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 303 – Intangible Plant – Software

Q. WHAT DOES THE COMPANY REQUEST FOR ITS RECOVERY OF INVESTMENT IN SOFTWARE RECORDED IN ACCOUNT 303 – INTANGIBLE PLANT?

A. The Company seeks a seven-year amortization for its investment in intangible software (Response to Citizens' Interrogatory No. 51, page 1).

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company does not address or present justification for use of a seven-year amortization for its investment in intangible software.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposed seven-year life is too short. Because of this, I recommend an initial step to a 10-year amortization for such investment.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. First, it is necessary to note that the Company did not provide identification of its separate software systems, or the corresponding dollar level of investment in each software system. It also could not identify when the software was first installed. In other words, in spite of being requested to provide various items of information associated with its intangible software, the Company failed to provide any basis or identification associated with its software other than total dollar amounts added to the account, by year, since 2010 (Response to Citizens' Interrogatory Nos. 51 through 53; and 2013 Study, Volume 1, Tabs 10 and 11).

New software installed subsequent to when utilities addressed the concerns associated with the Y2K situation has normally been developed on an architectural basis that allows for scalability and modularization. In other words, rather than having to retire an entire software system once necessary modifications are identified or growth in items being addressed in the software have grown significantly, newer software permits continued use of the base software system with updates, modifications, or enhancements. Given that the Company initiated Account 303 – Intangible Software in 2010 with an approximate $13 million investment, it must be presumed that such investment is a major software system and not appropriately reflective of lasting only seven years. Other utility systems now utilize amortization periods often ranging from 12 to 20 years for their major software investments. Indeed, in its recent rate proceeding, FPL disclosed that it was extending the amortization period for its new general ledger accounting software from five years to 20 years. (Docket No. 120015-EI, Direct Testimony of Marlene Santos, page 14).

While a longer amortization period is most likely warranted, a minimum 10-year amortization period must be considered a first step in the right direction. In conjunction with my recommendation, I request that the Commission order the Company to fully identify its various software systems, their function, the vendor, and all basis and support for life expectation, including specific discussions as to the total replacement of systems versus the changing out of components, and to present such information in its next depreciation study.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. As set forth on Exhibit__(JP-7), I have duplicated the Company's depreciation expense from 2010 through 2013 based on a seven-year amortization period and then performed a remaining life calculation on a 10-year amortization basis. The net impact of my recommendation is a reduction of $940,535 based on plant reflected in the Company's depreciation study.

SECTION VII: MASS PROPERTY NET SALVAGE

A. General

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony will address the Company's request for approximately $377 million of negative net salvage requirements over the life of mass property accounts (2013 Study, Volume 1, Tab 7: Parameter Schedule, pages 6-8). Several of the Company's requested levels of net salvage are excessively negative. While other adjustments may be warranted, I am recommending adjustments to only five accounts. The combined impact, on a stand-alone basis, of the various adjustments that I am recommending results in an annual reduction of $1,398,483 in depreciation expense based on estimated plant as of December 31, 2013.

Q. WHAT HISTORICAL PERIOD DID THE COMPANY ANALYZE FOR ITS NET SALVAGE ANALYSIS?

A. The Company analyzed the 32-year period from 1981-2012 (2013 Study, Volume 1, Tab 8: Net Removal Cost Study, page 1).

Q. HAVE YOU REVIEWED ALL INFORMATION PRESENTED BY THE COMPANY IN SUPPORT OF ITS NET SALVAGE REQUEST?

A. Yes. The information is inadequate to support or demonstrate the reasonableness of its request for an overall -21% net salvage for mass property. Based on my review and analysis, I am recommending adjustments to the following five accounts: Transmission Account 356 – Overhead Conductors and Devices; Account 362 – Distribution Station Equipment; Account 368 – Distribution Line Transformers; Account 390 – General Plant Structures and Improvements; and Account 392.3 – General Plant Heavy Trucks.

B. Account Specific

Account 356 – Transmission Overhead Conductors and Devices

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 356 – TRANSMISSION OVERHEAD CONDUCTORS AND DEVICES?

A. The Company proposes to retain the existing -30% net salvage (2013 Study, Volume 1, Tab 8: Net Removal Cost Study, page 9).

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company states that there are rather sporadic net removal results by year as well as when the data is averaged. The Company admits that there is a trend in the data from the prior study generally towards decreasing removal cost levels, but considers that its proposed -30% is between the longer and shorter band averages it developed. Therefore, it recommends no change. (*Id.*)

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal is excessively negative. Therefore, I recommend a -20% net salvage.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I agree with the Company's statement that the trend in the data from the prior study is towards decreasing negative net salvage (less negative). I also agree with the Company's statement that salvage values both on an annual basis and as reflected through the averaging process are rather sporadic as presented. Therefore, I further analyzed the underlying data and recognized other concepts.

Retirement of transmission facilities is not a constant and consistent process. When individual poles or wires require replacement, high per-unit cost of removal might be anticipated. Alternatively, when larger quantities of retirement activity occur at a single location or project, lower per unit cost of removal values can be expected. This concept of economies of scale is not only logical, but is also recognized by authoritative sources such as NARUC in their depreciation publication. Further, it is anticipated that much larger quantities of transmission facilities will retire on an annual basis in the future, thus potentially further reducing the per-unit cost of removal experienced by the Company historically.

Next, a review of the years with the largest levels of retirement activity further supports a lower negative net salvage. For example, the Company retired almost $2 million of investment both in 2008 and 2012. Both of these years reflect retirement levels more than double the level experienced in the next highest year of retirement activity. During these two years, the Company experienced a 1.8% negative net salvage and an 8.4% negative net salvage, respectively (2013 Study, Volume 1, Tab 8: Net Removal Cost Study, page 9). Indeed, the Company retired its greatest quantity of overhead conductors in 2012 when it experienced only an 8.4% negative net salvage (Response to Citizens' Interrogatory No. 59(b)). These less negative net salvage levels during years with the highest levels of retirement activity reinforce the concept of economies of scale.

In addition, review of individual work orders associated with retirements of one mile or longer of transmission lines identifies instances where the Company retired large quantities of overhead conductors and experienced approximately a -20% negative net salvage. (*Id.* at (e)).

In summary, while trends to less negative net salvage values and indications of economies of scale as exhibited in the historical data that indicate a net salvage value in the -5% to -10% range, a conservative estimate at this point in time would result in a reduction in negative net salvage to a -20%.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $261,960 decrease in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 362 – Distribution Station Equipment

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 362 – DISTRIBUTION STATION EQUIPMENT?

A. The Company proposes a -8% net salvage compared to the existing -5% value (2013 Study, Volume 1, Tab 8: Net Removal Cost Study, page 12).

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company states that the results of the current study are similar to those of the prior study, though higher by approximately 2 percentage points. The Company also states that indications are generally in the -10% range. The Company further states that consistent with the indications for Account 353 and the industry, an increase in removal costs is indicated. Therefore, it proposes a more negative value than the existing -5% net salvage. (*Id.*)

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. There is insufficient basis to change from the existing -5% net salvage.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is also based on review of the historical data, but further takes into account unusual practices incorporated in the Company's analysis, and recognition of recent significant changes in the scrap metal market.

Review of the historical data indicates that there is insufficient data to change from the existing -5% net salvage. First, it must be recognized that large transformers normally comprise a significant amount of the investment in Account 362. The salvage characteristics for large transformers can be noticeably different from those of switches and breakers or other items that may fail. Large transformers normally do not retire annually, and thus a review of short historical periods can understate the potential positive net salvage associated with the retirement of transformers.

Review of longer periods of the Company's historical database identifies that it failed to record any gross salvage for the first 25 years out of its 32-year database. (*Id.*). Either this is an error or the Company changed its accounting practices in 2006. Either way, the failure to record gross salvage for the vast majority of the historical database limits the degree to which even the longer historical review of data can be relied upon. However, under any analysis, the historical database will show an inappropriate skewing of the data to a more negative net salvage value than is realistic or that undoubtedly occurred on the Company's system.

Yet another basis for retaining the existing -5% net salvage is the fact that large transformers contain large quantities of copper. The price of copper has escalated by hundreds of percent over the last decade, from approximately $0.50 to over $3.00 per pound. Recognition of current higher prices for scrap copper can result in positive net salvage in those instances where transformers are retired. Moreover, the expectation in the scrap metal market is that scrap copper prices will remain high if not go higher due to the expanding economies of China and India.

The retention of a -5% net salvage, and possibly even a less negative value, are all supported by the Company's failure to quantify gross salvage prior to 2006, the intermittent activity associated with transformer retirements and the much higher scrap price of copper.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $198,610 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 368 – Distribution Line Transformers

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 368 – DISTRIBUTION LINE TRANSFORMERS?

A. The Company proposes a -24% net salvage (2013 Study, Volume 1, Tab 8: Net Removal Cost Study, page 17).

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company relied on its review of historical data. While the Company's interpretation of the historical data resulted in a belief that their experience has been relatively constant, it also noted that there was a reversal from the prior study which identified a trend toward a less negative net salvage value. The Company next stated that net removal costs have increased since the last study by 2% to 4%. Finally, the Company recognizes that its proposal "would seem to be at the high end of the industry range given the nature of the property." Based on these items of information, it concludes that movement towards the data indications should be made. (*Id.*)

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal for a more negative net salvage value is not warranted. Consequently, I recommend retaining the existing -20% net salvage.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is also based on a review of historical data, but in greater detail than that performed by the Company. This account reflects a changing mix of investment over time between pole-mounted and pad-mounted transformers. However, the Company's analysis combines the two categories and analyzes the total combined values.

In response to discovery, the Company provided a breakout between its investment in pole-mounted and pad-mounted transformers, identifying that they are approximately equal in value, but that there are approximately four times as many pole-mounted line transformers as there are pad-mounted transformers (Response to Citizen's Interrogatory No. 63(a)). Further investigation into the quantity and types of transformers retired during the past 10 years supports retention of the existing -20% rather than a more negative value.

First, 2012 reflects the year with the greatest level of pad-mounted transformer investment being retired, with an approximate equal split between pole-mounted and pad-mounted transformer investment retirements. This level is consistent with the investment mix in the account as identified by the Company. During 2012, the Company experienced a -21% net salvage. Given the trend in the industry towards installation of pad-mounted transformers and undergrounding of distribution facilities, future expectations should give weight to the fact that lower retirement costs should be incurred when retiring pad-mounted transformers.

In addition, the number of transformers retired in any given year can have further impact on the per-unit cost of removal. 2012 and 2005 are the two years with the greatest level of total line transformers retired, as well as the greatest number of pad-mounted transformers retired during the past 10 years. (*Id.*). As previously noted, during 2012 and 2005, the Company experienced a -21% and a -11% net salvage, respectively. Therefore, when the concept of economies of scale is considered, represented in this case by greater quantities of transformers being retired in a given year, a lesser or lower level of negative net salvage than even the existing -20% may be warranted. On average, greater levels of annual retirements should occur in the future compared to historical activity. The expectation of higher levels of annual retirements only reinforces the potential for an even less negative net salvage level. Also, it should further be emphasized that lower levels of negative net salvage are consistent with the Company's recognition that its proposal for a higher or more negative level of negative net salvage "would seem to be at the high end of the industry range given the nature of the property" (2013 Study, Volume 1, Tab 8: Removal Cost Study, page 17).

One final consideration is the fact that line transformers contain copper. As previously noted, the price of scrap copper has escalated by hundreds of percents during the past decade. There are no current indications for any appreciable reduction in scrap copper prices, and there are expectations of higher scrap copper prices. Therefore, while not a major consideration, taking into account potential gross salvage associated with copper contained in line transformers should further limit any consideration of an increase of the level of negative net salvage proposed by the Company.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $429,037 decrease in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 390 – General Plant Structures and Improvements

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 390 – GENERAL PLANT STRUCTURES AND IMPROVEMENTS?

A. The Company proposes a -5% net salvage (2013 Study, Volume 1, Tab 8: Net Removal Cost Study, page 22).

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company relies on historical activity. While the Company admits that its historical analysis is not conclusive, it does believe that the results are similar to that of the prior study and more in line with industry data. (*Id.*).

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. I recommend a positive 10% net salvage as a first step to a more realistic value.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. The investment in this account can vary significantly by utility. If a utility rents office space and warehouses, then the investment for those utilities corresponds to leasehold improvement. Leasehold improvements can result in negative net salvage. Alternatively, those utilities that own their structures and improvements for the most part can expect significant levels of positive net salvage when such facilities are retired and sold. However, even those utilities will often experience annual levels of negative net salvage as they change out roofs, air conditioning systems, carpeting, and other short-lived investment; however, the overall level should be positive.

For this Company, the vast majority of its investment in this account is associated with offices and warehouses owned by the Company (Response to Citizens' Interrogatory No. 65, page 2). When brick and steel buildings are sold 40, 50, 70, or even longer years after they are placed into service, these can be expected to yield quite significant levels of positive net salvage. The likelihood of demolishing such buildings rather than selling such buildings does exist, but it is limited in nature. In other words, the Company's analysis is flawed as it does not take into account the significant positive level of net salvage that has a high probability of occurring when such buildings are retired and sold. Indeed, over one-third of the investment in this account is associated with the Company's corporate office, which is a brick and glass building placed into service in 1987 and consists of over 300,000 square feet. It is unrealistic and inappropriate to charge customers approximately $1.25 million for future demolition of such building when in reality there is a much greater certainty that the building will be sold for some appreciable level of positive net salvage. While it is realistic to expect positive values of 100% or more for a building appropriately maintained, even after it is 50 years old or older, I recommend only a 10% positive net salvage based on the concept of gradualism. I further recommend that the Commission order the Company to properly analyze the investment in this account for its next depreciation study, fully taking into account its ownership of offices and warehouses and the likelihood of potential sale of such facilities when no longer required for utility service.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $392,480 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Account 392.3 – General Plant Heavy Trucks

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 392.3 – GENERAL PLANT HEAVY TRUCKS?

A. The Company proposes a positive 13% net salvage (2013 Study, Volume 1, Tab 8: Net Removal Cost Study, page 24).

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company relied on its historical database and indicated that there is a trend towards decreasing salvage. Based on this trend, it proposes a decrease from the current positive 15% to a positive 13%. (*Id.*).

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. Retention of the existing positive 15% net salvage is warranted.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is also based on a review of the historical data. The Company has experienced a value less than the Company's proposed positive 13% net salvage in only five out of the last 20 years. The decline in the level of positive net salvage referenced by the Company is driven heavily by one year, that being 2010 in which the Company retired $1.3 million of heavy trucks and experienced only a positive 9% net salvage. Given the propensity of higher levels of net salvage experienced by the Company during the past 20 years, and recognizing that individual large trucks can be in poorer condition in certain years compared to other years, there is no reasonable basis to change the existing positive 15% net salvage because it is indicative of both the 15- and 20-year band analyses performed by the Company.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $116,397 reduction in annual depreciation expense based on estimated plant as of December 31, 2013.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, to the extent that I have not addressed an issue, method, procedures, or other matter relevant to the Company's case, it should not be construed that I am in agreement with the Company's proposed issue, method, or procedures.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing Direct Testimony of Jacob Pous has been furnished by U.S. Mail and/or hand delivery to the following parties on this 16th day of October, 2013, to the following:

Martha Barrera/Martha Brown
Suzanne Brownless
2540 Shumard Oaks Boulevard
Florida Public Service Commission
Tallahassee, FL 32399-0850

Jeffrey A. Stone, Esquire
Russell A. Badders, Esquire
Steven R. Griffin, Esquire
Beggs & Lane
P. O. Box 12950
Pensacola, FL 32576-2950

Robert L. McGee
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780

Gregory J. Fike, Lt Col, USAF
AFLOA/ULFSC
139 Barnes Drive, Suite 1
Tyndall Air Force Base, Florida 32403

Jon C. Moyle, Jr.
Karen A. Putnal
Moyle Law Firm, P.A.
118 North Gadsden Street
Tallahassee, FL 32301

Richard D. Melson
705 Piedmont Drive
Tallahassee, FL 32312
Phone: 850-894-1351

Thomas A. Jernigan
AFLOA/JACE - ULFSC
139 Barnes Drive Suite 1
Tyndall Air Force Base, Florida 32403-5319

Christopher Thompson
AFLOA/JACE – ULFSC
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403-5319

Charles A. Guyton
Governmental Affairs
215 S. Monroe Street, Suite 601
Tallahassee, FL 32301

Robert Scheffel Wright
John T. LaVia, III
Gardner Bist Law Firm
1300 Thomaswood Drive
Tallahassee, FL 32308

Charles Murphy
Caroline Klancke
2540 Shumard Oaks Boulevard
Florida Public Service Commission
Tallahassee, FL 32399-0850

Joseph A. McGlothlin

Joseph A. McGlothlin
Associate Public Counsel

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance	Average Service Life	IRR Net Removal Excl. Dismantling Amount	IRR Net Removal Excl. Dismantling Percent	Reserve Requirement w/ Net Removal	12/31/2013 Accumulated Depreciation Reserve	Amount to be Recovered	Average Remaining Life	Recommended Annual Depreciation	Depreciation Rate
		$	Yrs	$	%	$	$	$	Years	$	%
STEAM PRODUCTION PLANT											
Plant Crist Common 4-7											
311	Structures and Improvements	$ 122,456,878	36.4	$ 1,500,097	1.2%	$ 43,248,725	$ 40,140,631	$ 83,816,344	23.7	$ 3,536,555	2.89%
312	Boiler Plant Equipment	$ 473,369,675	26.9	$ 15,076,824	3.2%	$ 79,001,455	$ 73,323,971	$ 415,122,528	22.5	$ 18,409,645	3.89%
314	Turbogenerator Units	$ 26,920,570	34.6	$ 1,121,242	4.2%	$ 10,292,804	$ 9,553,106	$ 18,488,706	21.9	$ 844,233	3.14%
315	Accessory Electric Equipment	$ 95,875,088	28.9	$ 2,348,940	2.5%	$ 20,052,656	$ 18,611,561	$ 79,612,467	23.0	$ 3,461,412	3.61%
316	Misc. Power Plant Equipment	$ 12,203,409	25.7	$ 747,459	6.1%	$ 2,519,624	$ 2,338,550	$ 10,612,318	20.7	$ 512,672	4.20%
	Subtotal	$ 730,825,620	28.6	$ 20,794,561	2.8%	$ 155,115,263	$ 143,967,819	$ 607,652,362	22.70	$ 26,764,516	3.66%
Plant Crist Unit #4											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 32,345,400	23.2	$ 441,515	1.4%	$ 18,454,387	$ 17,128,152	$ 15,658,762	10.1	$ 1,544,000	4.77%
314	Turbogenerator Units	$ 10,116,143	21.4	$ 180,573	1.8%	$ 5,485,167	$ 5,090,972	$ 5,205,744	10.0	$ 520,574	5.15%
315	Accessory Electric Equipment	$ 3,454,218	21.7	$ 36,269	1.1%	$ 1,849,797	$ 1,716,861	$ 1,773,627	10.2	$ 173,885	5.03%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 45,915,761	22.7	$ 658,357	1.4%	$ 25,789,351	$ 23,935,985	$ 22,638,133	10.11	$ 2,238,459	4.88%
Plant Crist Unit #5											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 34,665,998	24.0	$ 563,322	1.6%	$ 17,626,128	$ 16,359,417	$ 18,869,904	12.0	$ 1,573,516	4.54%
314	Turbogenerator Units	$ 12,976,335	17.9	$ 275,747	2.1%	$ 4,516,073	$ 4,191,523	$ 9,060,560	11.8	$ 767,844	5.92%
315	Accessory Electric Equipment	$ 3,139,986	22.1	$ 39,250	1.3%	$ 1,438,568	$ 1,335,185	$ 1,844,051	12.1	$ 152,401	4.85%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 50,782,319	22.0	$ 878,319	1.7%	$ 23,580,769	$ 21,886,124	$ 29,774,514	11.94	$ 2,493,761	4.91%
Plant Crist Unit #6											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 259,851,934	22.8	$ 7,262,862	2.8%	$ 32,830,664	$ 30,471,270	$ 236,643,526	20.0	$ 11,833,545	4.55%
314	Turbogenerator Units	$ 47,404,661	24.7	$ 1,732,640	3.7%	$ 10,344,695	$ 9,601,268	$ 39,536,034	19.5	$ 2,027,489	4.28%
315	Accessory Electric Equipment	$ 31,688,605	23.8	$ 681,305	2.2%	$ 4,760,281	$ 4,418,181	$ 27,951,729	20.3	$ 1,376,932	4.35%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 338,945,200	23.1	$ 9,676,807	2.9%	$ 47,935,640	$ 44,490,718	$ 304,131,289	19.96	$ 15,237,966	4.50%
Plant Crist Unit #7											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 206,674,810	31.4	$ 6,582,593	3.2%	$ 60,111,506	$ 55,791,559	$ 157,465,843	22.5	$ 6,983,216	3.38%
314	Turbogenerator Units	$ 78,417,397	29.1	$ 3,266,085	4.2%	$ 20,210,346	$ 18,757,918	$ 62,925,563	21.9	$ 2,873,313	3.66%
315	Accessory Electric Equipment	$ 28,881,007	33.8	$ 707,585	2.5%	$ 9,454,343	$ 8,774,901	$ 20,813,690	23.0	$ 904,943	3.13%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 313,973,214	31.0	$ 10,556,262	3.4%	$ 89,776,195	$ 83,324,379	$ 241,205,097	22.41	$ 10,761,472	3.43%
Total Plant Crist Depreciable		$ 1,480,442,114	27.09	$ 42,564,307	2.9%	$ 342,197,218	$ 317,605,025	$ 1,205,401,396	20.96	$ 57,496,175	3.88%
310	Easements	$ -					$ 420				

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance	Average Service Life	IRR Net Removal Excl. Dismantling Amount	IRR Net Removal Excl. Dismantling Percent	Reserve Requirement w/ Net Removal	12/31/2013 Accumulated Depreciation Reserve	Amount to be Recovered	Average Remaining Life	Recommended Annual Depreciation	Depreciation Rate
		$	Yrs	$	%	$	$	$	Years	$	%
Plant Crist Other Recovery/Non-Depreciable											
310	Land	$ 6,023,266					$ -				
312	Base Coal	$ 141,840					$ 141,840				
316	Amortization Property (5 yr.)	$ 137,572					$ 86,586				
316	Amortization Property (7 yr.)	$ 2,678,299					$ 1,425,704				
317	ARO	$ 1,132,431					$ 721,122				
	Dismantlement						$ 73,645,939				
TOTAL PLANT CRIST		$ 1,490,555,522					$ 393,626,636				
Plant Scholz Common											
311	Structures and Improvements	$ 6,225,461	31.1	$ 4,669	0.1%	$ 5,929,642	$ 6,230,130	$ -	1.5	$ -	0.00%
312	Boiler Plant Equipment	$ 6,035,087	21.4	$ 11,768	0.2%	$ 5,625,077	$ 6,032,994	$ 13,862	1.5	$ 9,286	0.15%
314	Turbogenerator Units	$ 1,115,804	13.1	$ 2,845	0.3%	$ 990,560	$ 1,062,393	$ 56,257	1.5	$ 37,504	3.36%
315	Accessory Electric Equipment	$ 3,202,528	31.8	$ 4,804	0.2%	$ 3,056,043	$ 3,207,332	$ -	1.5	$ -	0.00%
316	Misc. Power Plant Equipment	$ 453,566	8.8	$ 1,701	0.4%	$ 377,665	$ 405,052	$ 50,215	1.5	$ 33,477	7.38%
	Subtotal	$ 17,032,446	23.7	$ 25,787	0.2%	$ 15,978,985	$ 16,937,900	$ 120,333	1.50	$ 80,267	0.47%
Plant Scholz Unit #1											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 4,689,139	34.2	$ 9,144	0.2%	$ 4,493,222	$ 4,698,283	$ -	1.5	$ -	0.00%
314	Turbogenerator Units	$ 2,498,880	39.6	$ 6,372	0.3%	$ 2,410,356	$ 2,505,252	$ -	1.5	$ -	0.00%
315	Accessory Electric Equipment	$ 105,404	10.1	$ 158	0.2%	$ 89,885	$ 96,403	$ 9,159	1.5	$ 6,106	5.79%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 7,293,423	34.6	$ 15,674	0.2%	$ 6,993,463	$ 7,299,938	$ 9,159	1.50	$ 6,106	0.08%
Plant Scholz Unit #2											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 4,337,721	25.5	$ 8,459	0.2%	$ 4,091,768	$ 4,346,180	$ -	1.5	$ -	0.00%
314	Turbogenerator Units	$ 1,986,288	43.3	$ 5,065	0.3%	$ 1,922,369	$ 1,991,353	$ -	1.5	$ -	0.00%
315	Accessory Electric Equipment	$ 168,285	14.0	$ 252	0.2%	$ 150,480	$ 161,392	$ 7,145	1.5	$ 4,763	2.83%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 6,492,294	28.5	$ 13,776	0.2%	$ 6,164,617	$ 6,498,925	$ 7,145	1.50	$ 4,763	0.07%
Total Plant Scholz Depreciable		$ 30,818,163	26.6	$ 55,238	0.2%	$ 29,137,065	$ 30,736,763	$ 136,638	1.50	$ 91,137	0.30%
Plant Scholz Other Recovery/Non-Depreciable											
310	Land	$ 44,579					$ -				
312	Base Coal	$ 71,300					$ 71,300				
316	Amortization Property (5 yr.)	$ 8,730					$ 4,635				
316	Amortization Property (7 yr.)	$ 102,910					$ 61,526				
317	ARO	$ 242,640					$ 13,751,261				
	Dismantlement						$ 286,986				
TOTAL PLANT SCHOLZ		$ 31,288,322					$ 44,912,471				

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance	Average Service Life	IRR Net Removal Excl. Dismantling Amount	IRR Net Removal Excl. Dismantling Percent	Reserve Requirement w/ Net Removal	12/31/2013 Accumulated Depreciation Reserve	Amount to be Recovered	Average Remaining Life	Recommended Annual Depreciation	Depreciation Rate
		$	Yrs	$	%	$	$	$	Years	$	%
Plant Smith Common											
311	Structures and Improvements	$ 36,837,541	35.6	$ 340,747	0.9%	$ 18,275,844	$ 19,353,854	$ 17,824,434	18.1	$ 984,775	2.67%
312	Boiler Plant Equipment	$ 24,185,788	30.2	$ 581,668	2.4%	$ 10,507,563	$ 11,127,357	$ 13,640,100	17.4	$ 784,469	3.24%
314	Turbogenerator Units	$ 2,964,511	34.0	$ 93,234	3.1%	$ 1,528,872	$ 1,619,054	$ 1,438,691	17.0	$ 84,629	2.85%
315	Accessory Electric Equipment	$ 4,154,684	40.5	$ 76,862	1.9%	$ 2,392,652	$ 2,533,784	$ 1,697,762	17.6	$ 96,464	2.32%
316	Misc. Power Plant Equipment	$ 1,870,741	25.0	$ 86,522	4.6%	$ 673,298	$ 713,013	$ 1,244,250	16.4	$ 75,869	4.06%
	Subtotal	$ 70,013,265	33.3	$ 1,179,033	1.7%	$ 33,378,229	$ 35,347,061	$ 35,845,236	17.69	$ 2,026,206	2.89%
Plant Smith Unit #1											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 32,652,589	27.1	$ 700,398	2.1%	$ 14,134,790	$ 14,968,538	$ 18,384,449	15.6	$ 1,177,344	3.61%
314	Turbogenerator Units	$ 13,496,717	38.4	$ 378,583	2.8%	$ 8,346,860	$ 8,839,204	$ 5,036,096	15.3	$ 329,157	2.44%
315	Accessory Electric Equipment	$ 4,217,804	33.7	$ 69,594	1.7%	$ 2,277,282	$ 2,411,609	$ 1,875,789	15.8	$ 118,721	2.81%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 50,367,110	30.0	$ 1,148,575	2.3%	$ 24,758,932	$ 26,219,351	$ 25,296,334	15.56	$ 1,625,222	3.23%
Plant Smith Unit #2											
311	Structures and Improvements	$ -									
312	Boiler Plant Equipment	$ 42,290,474	30.3	$ 1,017,086	2.4%	$ 18,455,470	$ 19,544,076	$ 23,763,484	17.4	$ 1,366,685	3.23%
314	Turbogenerator Units	$ 12,536,935	37.9	$ 394,287	3.1%	$ 7,130,938	$ 7,551,560	$ 5,379,662	17.0	$ 316,451	2.52%
315	Accessory Electric Equipment	$ 1,596,035	45.9	$ 29,527	1.9%	$ 1,002,253	$ 1,061,371	$ 564,191	17.6	$ 32,056	2.01%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 56,423,444	32.0	$ 1,440,899	2.6%	$ 26,588,660	$ 28,157,006	$ 29,707,337	17.32	$ 1,715,192	3.04%
Total Plant Smith Depreciable		$ 176,803,819	31.9	$ 3,768,507	2.1%	$ 84,725,822	$ 89,723,419	$ 90,848,907	16.93	$ 5,366,619	3.04%
Plant Smith Other Recovery/Non-Depreciable											
310	Land	$ 1,363,924					$ -				
312	Base Coal	$ 108,300					$ 108,300				
316	Amortization Property (5 yr.)	$ 29,526					$ 15,715				
316	Amortization Property (7 yr.)	$ 1,174,466					$ 667,192				
317	ARO	$ 471,938					$ 21,657,782				
	Dismantlement						$ 350,848				
TOTAL PLANT SMITH		$ 179,951,973					$ 112,523,256				

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance	Average Service Life	IRR Net Removal Excl. Dismantling Amount	IRR Net Removal Excl. Dismantling Percent	Reserve Requirement w/ Net Removal	12/31/2013 Accumulated Depreciation Reserve	Amount to be Recovered	Average Remaining Life	Recommended Annual Depreciation	Depreciation Rate
		$	Yrs	$	%	$	$	$	Years	$	%
Plant Daniel #1-2 Common											
311	Structures and Improvements	$ 13,441,253	51.0	$ 218,420	1.6%	$ 5,303,167	$ 6,789,975	$ 6,869,698	31.2	$ 220,183	1.64%
312	Boiler Plant Equipment	$ 31,539,058	51.7	$ 1,332,525	4.2%	$ 14,390,259	$ 18,424,743	$ 14,446,840	29.1	$ 497,015	1.58%
314	Turbogenerator Units	$ 3,484,941	53.0	$ 192,543	5.5%	$ 1,734,662	$ 2,220,996	$ 1,456,488	28.0	$ 52,017	1.49%
315	Accessory Electric Equipment	$ 1,215,206	44.7	$ 39,494	3.3%	$ 415,426	$ 531,896	$ 722,804	29.9	$ 24,174	1.99%
316	Misc. Power Plant Equipment	$ 2,127,402	47.2	$ 172,851	8.1%	$ 1,038,038	$ 1,329,065	$ 971,189	25.9	$ 37,498	1.76%
	Subtotal	$ 51,807,860	51.2	$ 1,955,834	3.8%	$ 22,881,553	$ 29,296,675	$ 24,467,019	29.45	$ 830,887	1.60%
Plant Daniel #1-4 Common											
311	Structures and Improvements	$ 4,587,856	59.5	$ 74,553	1.6%	$ 2,217,583	$ 2,839,309	$ 1,823,100	31.2	$ 58,433	1.27%
312	Boiler Plant Equipment	$ 3,051,458	42.0	$ 128,924	4.2%	$ 979,316	$ 1,253,880	$ 1,926,503	29.1	$ 66,278	2.17%
314	Turbogenerator Units	$ -									
315	Accessory Electric Equipment	$ 138,010	36.8	$ 4,485	3.3%	$ 26,718	$ 34,209	$ 108,287	29.9	$ 3,622	2.62%
316	Misc. Power Plant Equipment	$ 1,107,637	36.1	$ 89,996	8.1%	$ 338,389	$ 433,261	$ 764,372	25.9	$ 29,512	2.66%
	Subtotal	$ 8,884,961	48.2	$ 297,958	3.4%	$ 3,562,006	$ 4,560,658	$ 4,622,261	29.28	$ 157,844	1.78%
Plant Daniel Unit #1											
311	Structures and Improvements	$ 8,591,584	63.1	$ 122,430	1.4%	$ 4,916,306	$ 6,294,652	$ 2,419,362	27.5	$ 87,977	1.02%
312	Boiler Plant Equipment	$ 52,849,104	42.2	$ 1,958,059	3.7%	$ 21,221,298	$ 27,170,948	$ 27,636,216	25.9	$ 1,068,678	2.02%
314	Turbogenerator Units	$ 19,983,679	41.0	$ 968,209	4.8%	$ 8,176,347	$ 10,468,685	$ 10,483,203	25.0	$ 419,328	2.10%
315	Accessory Electric Equipment	$ 10,401,463	52.0	$ 296,442	2.9%	$ 5,246,088	$ 6,716,893	$ 3,981,012	26.5	$ 150,227	1.44%
316	Misc. Power Plant Equipment	$ 12,158	39.0	$ 866	7.1%	$ 5,210	$ 6,670	$ 6,354	23.4	$ 272	2.23%
	Subtotal	$ 91,837,988	44.2	$ 3,346,007	3.6%	$ 39,565,248	$ 50,657,848	$ 44,526,147	25.79	$ 1,726,481	1.88%
Plant Daniel Unit #2											
311	Structures and Improvements	$ 9,478,035	60.6	$ 154,018	1.6%	$ 4,672,976	$ 5,983,102	$ 3,648,951	31.2	$ 116,954	1.23%
312	Boiler Plant Equipment	$ 62,892,747	45.0	$ 2,657,219	4.2%	$ 23,208,785	$ 29,715,651	$ 35,834,315	29.1	$ 1,232,810	1.96%
314	Turbogenerator Units	$ 24,457,004	44.0	$ 1,351,249	5.5%	$ 9,384,819	$ 12,015,968	$ 13,792,285	28.0	$ 492,582	2.01%
315	Accessory Electric Equipment	$ 10,953,732	53.4	$ 355,996	3.3%	$ 4,977,128	$ 6,372,526	$ 4,937,202	29.9	$ 165,124	1.51%
316	Misc. Power Plant Equipment	$ 559,888	28.1	$ 45,491	8.1%	$ 47,396	$ 60,684	$ 544,695	25.9	$ 21,031	3.76%
	Subtotal	$ 108,341,406	46.4	$ 4,563,973	4.2%	$ 42,291,104	$ 54,147,931	$ 58,757,448	28.97	$ 2,028,500	1.87%
		$ 260,872,215	46.5	$ 10,163,772	3.9%	$ 108,299,911	$ 138,663,112	$ 132,372,875	27.90	$ 4,743,712	1.82%
310	Daniel Common 1-2, Easements	$ 77,160	69.0	$ -	0.0%	$ 40,817	$ 41,511	$ 35,649	32.5	$ 1,097	1.42%
311	Daniel, Rail Track System	$ 2,782,273	66.4	$ -	0.0%	$ 1,420,468	$ 1,373,795	$ 1,408,478	32.5	$ 43,338	1.56%
Total Plant Daniel Depreciable		$ 263,731,648	46.7	$ 10,163,772	3.9%	$ 109,761,195	$ 140,078,418	$ 133,817,002	27.95	$ 4,788,147	1.82%
Plant Daniel Other Recovery/Non-Depreciable											
310	Land	$ 1,028,761					$ -				
310	Cooling Lake	$ 2,621,892					$ 2,621,892				
311	Cooling Lake	$ 6,331,377					$ 6,331,377				
316	Cooling Lake	$ 923					$ 923				
317	ARO	$ 391,150					$ 19,870,960				
	Dismantlement						$ 110,114				
TOTAL PLANT DANIEL		$ 274,105,751					$ 169,013,684				

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance	Average Service Life	IRR Net Removal Excl. Dismantling Amount	IRR Net Removal Excl. Dismantling Percent	Reserve Requirement w/ Net Removal	12/31/2013 Accumulated Depreciation Reserve	Amount to be Recovered	Average Remaining Life	Recommended Annual Depreciation	Depreciation Rate
		$	Yrs	$	%	$	$	$	Years	$	%
Plant Scherer Common A											
311	Structures and Improvements	$ 1,235,793	48.1	$ 6,542	0.5%	$ 297,024	$ 425,236	$ 817,098	36.6	$ 22,325	1.81%
312	Boiler Plant Equipment	$ 16,715,253	38.0	$ 230,065	1.4%	$ 1,925,217	$ 2,756,250	$ 14,189,067	33.7	$ 421,257	2.52%
314	Turbogenerator Units	$ 222,745	40.6	$ 4,009	1.8%	$ 46,915	$ 67,166	$ 159,588	32.2	$ 4,956	2.23%
315	Accessory Electric Equipment	$ 456,660	40.4	$ 4,835	1.1%	$ 63,970	$ 91,583	$ 369,912	34.8	$ 10,630	2.33%
316	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 18,630,451	38.6	$ 245,451	1.3%	$ 2,333,125	$ 3,340,235	$ 15,535,667	33.83	$ 459,168	2.46%
Plant Scherer Common B											
311	Structures and Improvements	$ 11,293,552	62.3	$ 59,785	0.5%	$ 4,683,479	$ 6,705,137	$ 4,648,200	36.6	$ 127,000	1.12%
312	Boiler Plant Equipment	$ 21,225,807	40.1	$ 292,147	1.4%	$ 3,443,577	$ 4,930,022	$ 16,587,932	33.7	$ 492,476	2.32%
314	Turbogenerator Units	$ 1,255,314	62.6	$ 22,594	1.8%	$ 620,582	$ 888,460	$ 389,448	32.2	$ 12,095	0.96%
315	Accessory Electric Equipment	$ 423,964	60.8	$ 4,489	1.1%	$ 183,220	$ 262,308	$ 166,145	34.8	$ 4,774	1.13%
316	Misc. Power Plant Equipment	$ 5,249,100	47.5	$ 138,937	2.6%	$ 2,075,812	$ 2,971,851	$ 2,416,186	29.2	$ 82,746	1.58%
	Subtotal	$ 39,447,737	46.5	$ 517,952	1.3%	$ 11,006,670	$ 15,757,778	$ 24,207,910	33.66	$ 719,092	1.82%
Plant Scherer Unit #3											
311	Structures and Improvements	$ 20,590,821	61.6	$ 109,003	0.5%	$ 8,400,902	$ 12,027,213	$ 8,672,611	36.6	$ 236,957	1.15%
312	Boiler Plant Equipment	$ 240,286,487	40.3	$ 3,307,243	1.4%	$ 39,998,408	$ 57,264,009	$ 186,329,721	33.7	$ 5,531,914	2.30%
314	Turbogenerator Units	$ 39,516,176	53.2	$ 711,242	1.8%	$ 15,879,244	$ 22,733,634	$ 17,493,784	32.2	$ 543,285	1.37%
315	Accessory Electric Equipment	$ 9,763,934	54.9	$ 103,376	1.1%	$ 3,612,622	$ 5,172,036	$ 4,695,274	34.8	$ 134,922	1.38%
316	Misc. Power Plant Equipment	$ 1,385,524	45.1	$ 36,673	2.6%	$ 501,395	$ 717,826	$ 704,371	29.2	$ 24,122	1.74%
	Subtotal	$ 311,542,942	43.0	$ 4,267,536	1.4%	$ 68,392,571	$ 97,914,718	$ 217,895,761	33.67	$ 6,471,199	2.08%
Total Plant Scherer Depreciable		$ 369,621,130	43.1	$ 5,030,939	1.4%	$ 81,732,366	$ 117,012,731	$ 257,639,338	33.68	$ 7,649,459	2.07%
Plant Scherer Other Recovery/Non-Depreciable											
310	Land	986,244					$ -				
316	Amortization Property (7 yr.)	161,971					$ 91,483				
317	ARO	230,322					$ 67,907				
	Dismantlement						$ 5,143,641				
TOTAL PLANT SCHERER		$ 370,999,667					$ 122,315,762				
Total Depreciable Steam Excl. A/C 317		$ 2,321,416,874	30.7	$ 61,582,761	2.7%	$ 647,553,665	$ 695,156,356	$ 1,687,843,279	22.39	$ 75,391,537	3.25%

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance	Average Service Life	IRR Net Removal Excl. Dismantling Amount	IRR Net Removal Excl. Dismantling Percent	Reserve Requirement w/ Net Removal	12/31/2013 Accumulated Depreciation Reserve	Amount to be Recovered	Average Remaining Life	Recommended Annual Depreciation	Depreciation Rate
		$	Yrs	$	%	$	$	$	Years	$	%
OTHER PRODUCTION PLANT											
Plant Smith CT											
341	Structures and Improvements	$ 1,310,239	16.7	$ 1,327	0.1%	$ 259,172	$ 149,582	$ 1,161,984	13.4	$ 86,715	6.62%
342	Fuel Holders	$ 697,862	21.2	$ 1,413	0.2%	$ 263,877	$ 209,481	$ 489,794	13.2	$ 37,106	5.32%
343	Prime Movers	$ 2,405,737	16.1	$ 4,872	0.2%	$ 434,209	$ 304,536	$ 2,106,073	13.2	$ 159,551	6.63%
344	Generators	$ 3,438,922	43.1	$ 5,803	0.2%	$ 2,381,736	$ 3,074,249	$ 370,476	13.3	$ 27,855	0.81%
345	Accessory Electric Equipment	$ 48,475	34.3	$ 82	0.2%	$ 29,729	$ 29,087	$ 19,470	13.3	$ 1,464	3.02%
346	Misc. Power Plant Equipment	$ 43,147	16.6	$ 87	0.2%	$ 8,855	$ (7,302)	$ 50,536	13.2	$ 3,829	8.87%
	Subtotal	$ 7,944,382	23.1	$ 13,584	0.2%	$ 3,377,578	$ 3,759,633	$ 4,198,333	13.26	$ 316,520	3.98%
Plant Smith CC											
341	Structures and Improvements	$ 13,847,570	33.6	$ 98,664	0.7%	$ 2,946,972	$ 878,718	$ 13,067,516	26.5	$ 493,114	3.56%
342	Fuel Holders	$ 3,585,547	34.4	$ 17,883	0.5%	$ 764,681	$ (532,194)	$ 4,135,624	27.1	$ 152,606	4.26%
343	Prime Movers	$ 116,898,041	27.1	$ 1,665,797	1.4%	$ 11,643,100	$ (8,563,463)	$ 127,127,301	24.4	$ 5,201,874	4.45%
344	Generators	$ 70,111,812	37.3	$ 349,683	0.5%	$ 19,268,291	$ 13,342,220	$ 57,119,275	27.1	$ 2,107,722	3.01%
345	Accessory Electric Equipment	$ 12,700,514	36.0	$ 72,393	0.6%	$ 3,228,707	$ 1,307,781	$ 11,465,126	26.9	$ 426,213	3.36%
346	Misc. Power Plant Equipment	$ 1,421,987	30.1	$ 15,197	1.1%	$ 219,636	$ (852,368)	$ 2,289,552	25.5	$ 89,786	6.31%
	Subtotal	$ 218,565,471	30.7	$ 2,219,617	1.0%	$ 38,071,388	$ 5,580,694	$ 215,204,394	25.40	$ 8,471,316	3.88%
Plant Pace CT											
341	Structures and Improvements	$ -					$ -				
342	Fuel Holders	$ -					$ -				
343	Prime Movers	$ 6,790,595	20.0	$ 4,584	0.1%	$ 5,266,263	$ 5,343,698	$ 1,451,481	4.5	$ 322,551	4.75%
344	Generators	$ 3,107,233	20.0	$ 1,748	0.1%	$ 2,409,460	$ 2,455,849	$ 653,132	4.5	$ 145,140	4.67%
345	Accessory Electric Equipment	$ 584,090	20.0	$ 329	0.1%	$ 452,924	$ 461,444	$ 122,975	4.5	$ 27,328	4.68%
346	Misc. Power Plant Equipment	$ -									
	Subtotal	$ 10,481,918	20.0	$ 6,660	0.1%	$ 8,128,648	$ 8,260,991	$ 2,227,587	4.50	$ 495,019	4.72%
Perdido Landfill Plant											
341	Structures and Improvements	$ 2,803,840	17.7	$ 3,470	0.1%	$ 222,047	$ 118,928	$ 2,688,382	16.3	$ 164,931	5.88%
342	Fuel Holders	$ 896,565	18.4	$ 2,219	0.2%	$ 112,348	$ 72,536	$ 826,248	16.1	$ 51,320	5.72%
343	Prime Movers	$ 4,561,649	18.3	$ 11,290	0.2%	$ 549,752	$ 344,295	$ 4,228,644	16.1	$ 262,649	5.76%
344	Generators	$ -					$ -				
345	Accessory Electric Equipment	$ 1,151,915	18.6	$ 2,376	0.2%	$ 148,941	$ 98,807	$ 1,055,484	16.2	$ 65,153	5.66%
346	Misc. Power Plant Equipment	$ 227,150	17.1	$ 562	0.2%	$ 13,317	$ 175,707	$ 52,005	16.1	$ 3,230	1.42%
	Subtotal	$ 9,641,119	18.1	$ 19,917	0.2%	$ 1,046,405	$ 810,273	$ 8,850,763	16.17	$ 547,283	5.68%
Total Depreciable Other Production		$ 246,632,890	29.0	$ 2,259,778	0.9%	$ 50,624,018	$ 18,411,591	$ 230,481,077	23.45	$ 9,830,138	3.99%
Total Depreciable Production		$ 2,568,049,764	30.5	$ 63,842,539	2.5%	$ 698,177,683	$ 713,567,947	$ 1,918,324,356	22.61	$ 85,221,674	3.32%
Company Proposed Depr. Production		$ 2,568,049,764		$ 107,508,936		$ 790,091,702	$ 713,567,947	$ 1,961,990,753		$ 91,086,749	
Difference		$ -		$ (43,666,397)		$ (91,914,019)	$ -	$ (43,666,397)		$ (5,865,075)	

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance	Average Service Life	IRR Net Removal Excl. Dismantling Amount	IRR Net Removal Excl. Dismantling Percent	Reserve Requirement w/ Net Removal	12/31/2013 Accumulated Depreciation Reserve	Amount to be Recovered	Average Remaining Life	Recommended Annual Depreciation	Depreciation Rate
		$	Yrs	$	%	$	$	$	Years	$	%
TRANSMISSION PLANT											
350.0	Easements	$ 13,166,131	90.0	$ -	0	$ 6,710,802		$ 6,455,329	56.1	$ 115,130	0.87%
								$ -			
352.0	Structures and Improvements	$ 10,584,304	55.0	$ 529,215	5%	$ 3,554,243		$ 7,559,276	40.2	$ 188,135	1.78%
353.0	Station Equipment	$ 148,680,261	48.0	$ 10,407,618	7%	$ 30,353,808		$ 128,734,071	41.4	$ 3,111,774	2.09%
354.0	Towers and Fixtures	$ 40,666,668	55.0	$ 8,133,333	20%	$ 25,694,763		$ 23,105,238	31.2	$ 740,078	1.82%
355.0	Poles and Fixtures	$ 126,998,316	40.0	$ 63,499,159	50%	$ 26,103,300		$ 164,394,175	33.2	$ 4,947,161	3.90%
356.0	Overhead Conductors and Devices	$ 110,339,741	55.0	$ 22,067,948	20%	$ 26,243,685		$ 106,164,004	46.5	$ 2,285,063	2.07%
358.0	Underground Conductors and Devices	$ 14,094,502	50.0	$ -	0%	$ 7,530,398		$ 6,564,104	26.3	$ 249,491	1.77%
359.0	Roads and Trails	$ 235,919	55.0	$ -	0%	$ 37,796		$ 198,123	45.0	$ 4,406	1.87%
Sub-Total Excluding Easements		$ 451,599,711	47.6	$ 104,637,273	23%	$ 119,517,993		$ 436,718,991		$ 11,526,107	
Sub-Total Including Easements		$ 464,765,842	48.2	$ 104,637,273	23%	$ 126,228,795		$ 443,174,320		$ 11,641,237	
350	Land	$ 4,782,914									
TOTAL TRANSMISSION PLANT		$ 469,548,756		$ 104,637,273		$ 126,228,795		$ 443,174,320		$ 11,641,237	
Company Proposed Transmission Plant										$ 12,690,336	
Difference										$ (1,049,099)	

GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

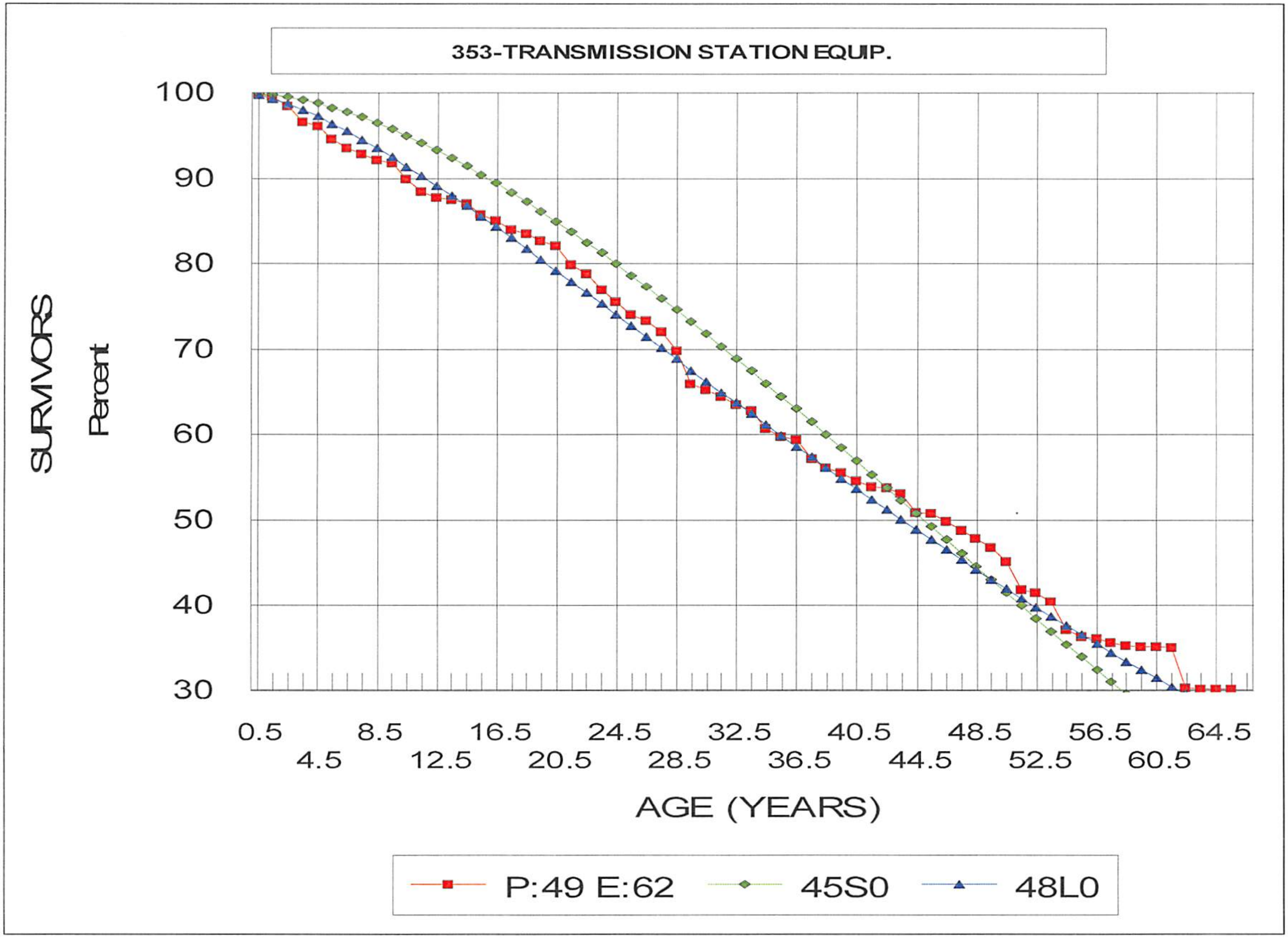
Account	Account Name	12/31/2013 Plant Balance	Average Service Life	IRR Net Removal Excl. Dismantling Amount	IRR Net Removal Excl. Dismantling Percent	Reserve Requirement w/ Net Removal	12/31/2013 Accumulated Depreciation Reserve	Amount to be Recovered	Average Remaining Life	Recommended Annual Depreciation	Depreciation Rate
		$	Yrs	$	%	$	$	$	Years	$	%
DISTRIBUTION PLANT											
360.2	Easements	$ 555,176	55.0	$ -	0%	$ 29,160		$ 526,016	52.2	$ 10,083	1.82%
361.0	Structures and Improvements	$ 20,429,669	52.0	$ 1,021,483	5%	$ 7,593,011		$ 13,858,141	36.5	$ 379,779	1.86%
362.0	Station Equipment	$ 239,656,818	46.0	$ 11,982,841	5%	$ 60,317,168		$ 191,322,491	36.2	$ 5,285,152	2.21%
364.0	Poles and Fixtures	$ 131,001,902	34.0	$ 91,701,330	70%	$ 68,016,181		$ 154,687,051	26.9	$ 5,754,727	4.39%
365.0	Overhead Conductors and Devices	$ 135,820,193	42.0	$ 33,955,048	25%	$ 49,189,082		$ 120,586,159	30.0	$ 4,014,186	2.96%
366.0	Underground Conduit	$ 1,160,719	60.0	$ -	0%	$ 793,560		$ 367,159	26.3	$ 13,960	1.20%
367.0	Underground Conductors and Devices	$ 141,302,574	39.0	$ 14,130,257	10%	$ 50,241,099		$ 105,191,732	29.8	$ 3,525,192	2.49%
368.0	Line Transformers	$ 247,768,588	34.0	$ 49,553,718	20%	$ 90,887,756		$ 206,434,550	26.3	$ 7,855,196	3.17%
369.1	Overhead Services	$ 53,372,992	44.0	$ 29,355,145	55%	$ 33,119,104		$ 49,609,033	31.0	$ 1,599,775	3.00%
369.2	Underground Services	$ 45,243,221	44.0	$ 4,524,322	10%	$ 16,563,038		$ 33,204,505	33.0	$ 1,006,807	2.23%
370.0	Meters	$ 20,142,321	33.0	$ (2,014,232)	-10%	$ 5,944,152		$ 12,183,937	23.0	$ 529,736	2.63%
370.1	Meters - AMI	$ 51,097,347	20.0	$ -	0%	$ 3,019,144		$ 48,078,203	17.3	$ 2,787,142	5.45%
	Meters - FPSC Segregated	$ 1,860,712	30.0	$ -	0%	$ 1,860,712		$ -	0.0	$ -	0.00%
	Meters - Non FPSC Segregated	$ 3,430,772	30.0	$ -	0%	$ 3,776,973		$ (346,201)	0.0	$ -	0.00%
373.0	Street Lighting and Signal Systems	$ 64,373,931	24.0	$ 9,656,090	15%	$ 32,627,557		$ 41,402,464	17.3	$ 2,395,976	3.72%
Sub-Total		$ 1,157,216,935	36.3	$ 243,866,002	21%	$ 423,977,697		$ 977,105,240		$ 35,157,712	
360	Land	$ 3,928,365									
TOTAL DISTRIBUTION PLANT		$ 1,161,145,300		$ 243,866,002		$ 423,977,697		$ 977,105,240		$ 35,157,712	
Company Proposed Distribution Plant										$ 40,247,006	
Difference										$ (5,089,294)	
GENERAL PLANT											
390.0	Structures and Improvements	$ 77,711,059	50.0	$ (7,771,106)	-10	$ 27,003,165		$ 42,936,788	36.1	$ 1,190,044	1.53%
396.0	Power Operated Equipment	$ 864,641	17.0	$ (172,928)	-20	$ 513,177		$ 178,536	6.8	$ 26,217	3.03%
397.0	Communications Equipment	$ 23,194,669	17.0	$ -	0	$ 11,822,212		$ 11,372,457	10.4	$ 1,094,558	4.72%
	Transportation Equipment										
392.2	Light Trucks	$ 7,120,679	11.0	$ (356,034)	-5	$ 3,363,803		$ 3,400,842	3.5	$ 985,751	13.84%
392.3	Heavy Trucks	$ 22,519,409	12.0	$ (3,377,911)	-15	$ 12,458,065		$ 6,683,433	4.3	$ 1,565,207	6.95%
392.4	Tailers	$ 1,269,865	20.0	$ (114,288)	-9	$ 634,261		$ 521,316	8.9	$ 58,575	4.61%
Total Transportation Equipment		$ 30,909,953	11.9	$ (3,848,233)	-12	$ 16,456,129		$ 10,605,591	4.1	$ 2,609,533	
TOTAL DEPRECIABLE GENERAL PLANT		$ 132,680,322		$ (11,792,267)		$ 55,794,683		$ 65,093,372		$ 4,920,352	
Company Proposed General Plant										$ 5,673,948	
Difference										$ (753,596)	

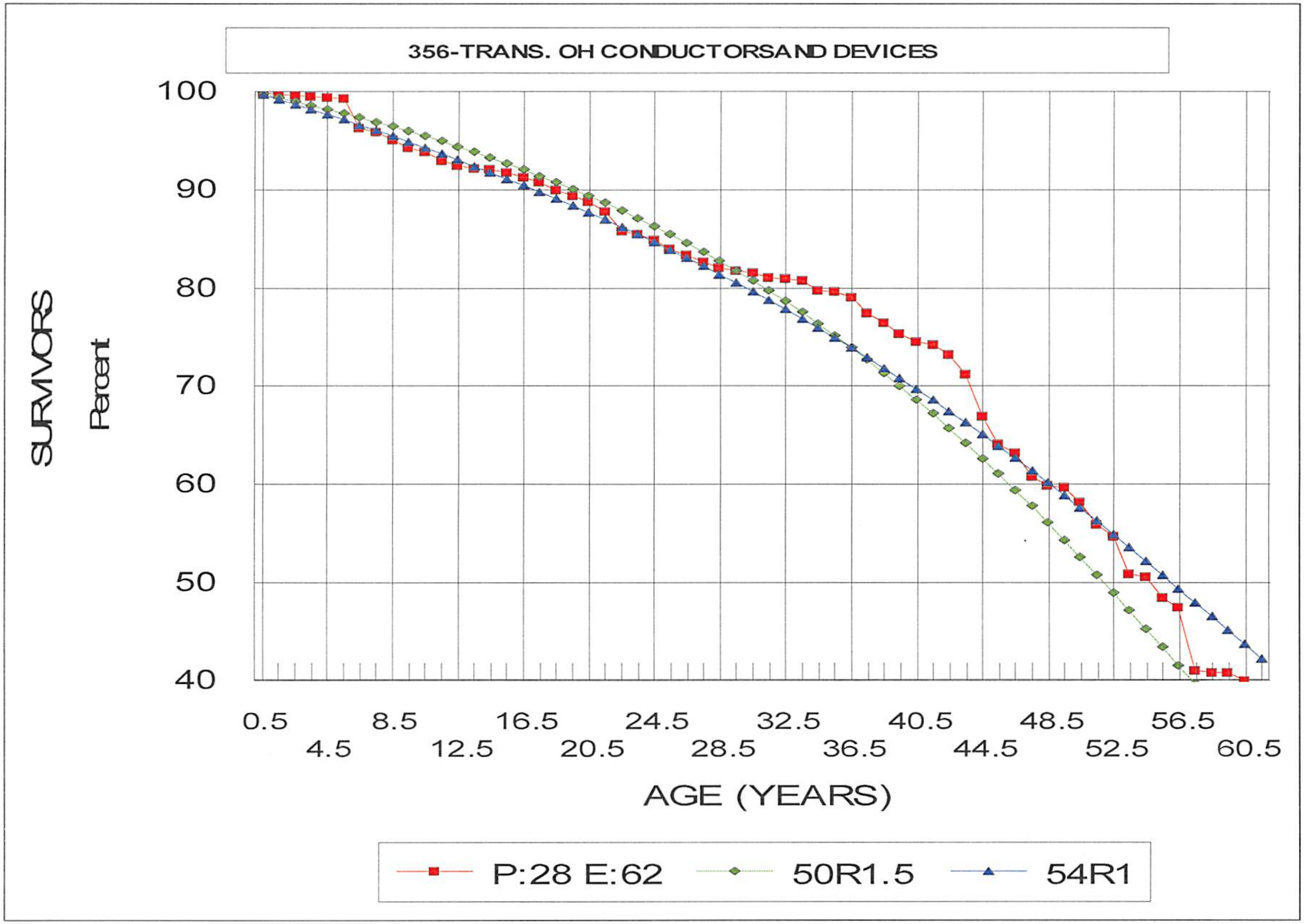
GULF POWER COMPANY
PROPOSED DEPRECIATION FACTORS AND RATES
AT DECEMBER 31, 2013

Account	Account Name	12/31/2013 Plant Balance $	Average Service Life Yrs	IRR Net Removal Excl. Dismantling Amount $	IRR Net Removal Excl. Dismantling Percent %	Reserve Requirement w/ Net Removal $	12/31/2013 Accumulated Depreciation Reserve $	Amount to be Recovered $	Average Remaining Life Years	Recommended Annual Depreciation $	Depreciation Rate %
GENERAL PLANT AMORTIZATION											
	Office Furniture & Equipment										
391.1	Furniture/Non-Computer	$ 2,463,098	7.0	$ -	0.0	$ 1,332,801		$ 1,130,297		$ 172,699	7.01%
391.2	Computer Equipment	$ 2,395,968	5.0	$ -	0.0	$ 2,054,272		$ 341,696		$ 1,034,767	43.19%
Total Office Furniture & Equipment		$ 4,859,066		$ -	0.0	$ 3,387,073		$ 1,471,993		$ 1,207,466	
	Auxiliary General Equipment										
392.5	Marine Equipment	$ 213,594	5.0	$ -	0.0	$ (21,324)		$ 234,918		$ 32,880	15.39%
393.0	Stores Equipment	$ 1,231,907	7.0	$ -	0.0	$ 152,426		$ 1,079,481		$ 73,314	5.95%
394.0	Tools, Shop & Garage Equipment	$ 4,075,785	7.0	$ -	0.0	$ 1,433,369		$ 2,642,416		$ 354,558	8.70%
395.0	Laboratory Equipment	$ 3,361,355	7.0	$ -	0.0	$ 1,672,165		$ 1,689,190		$ 324,632	9.66%
397.0	Communication Equip	$ 3,620,424	7.0	$ -	0.0	$ 1,173,223		$ 2,447,201		$ 459,701	12.70%
398.0	Miscellaneous Equipment	$ 3,572,092	7.0	$ -	0.0	$ (219,160)		$ 3,791,252		$ 1,185,033	33.17%
Total Auxiliary General Equipment		$ 16,075,157		$ -	0.0	$ 4,190,699		$ 11,649,540		$ 2,397,238	
Total Amortizable General Plant		$ 20,934,223				$ 7,577,772					
Total Depreciable & Amortizable General Plant		$ 153,614,545				$ 63,372,455					
NON-DEPRECIABLE GENERAL PROPERTY											
389.0	Land	$ 7,112,487									
		$ 7,112,487									
TOTAL GENERAL PLANT		$ 160,727,032				$ 63,372,455					
INTANGIBLE ASSET											
303.0	Intangible Software	$ 15,892,775	10.0	$ -	0.0	$ 6,143,733		$ 9,749,042		$ 1,329,862	8.37%
Company Proposed Intangible Asset										$ 2,270,396	
Difference										$ (940,534)	
	Dismantling									$ (6,288,508)	
Total Adjustments										$ (19,986,106)	

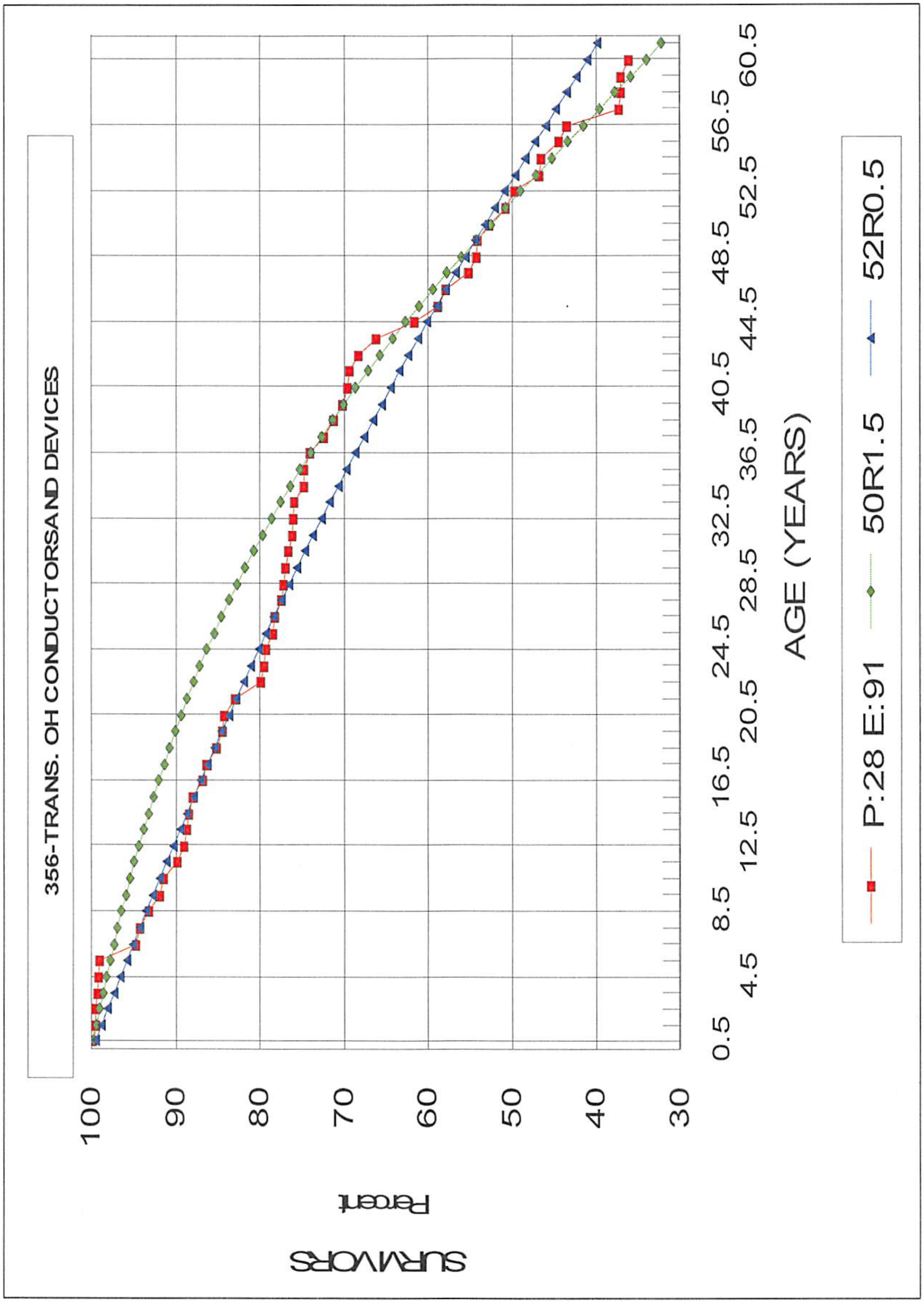
OFFICE OF PUBLIC COUNSEL'S RECOMMENDED
MASS PROPERTY LIFE ADJUSTMENTS
FOR GULF POWER COMPANY
BASED ON ESTIMATED PLANT AS OF 12/31/2013

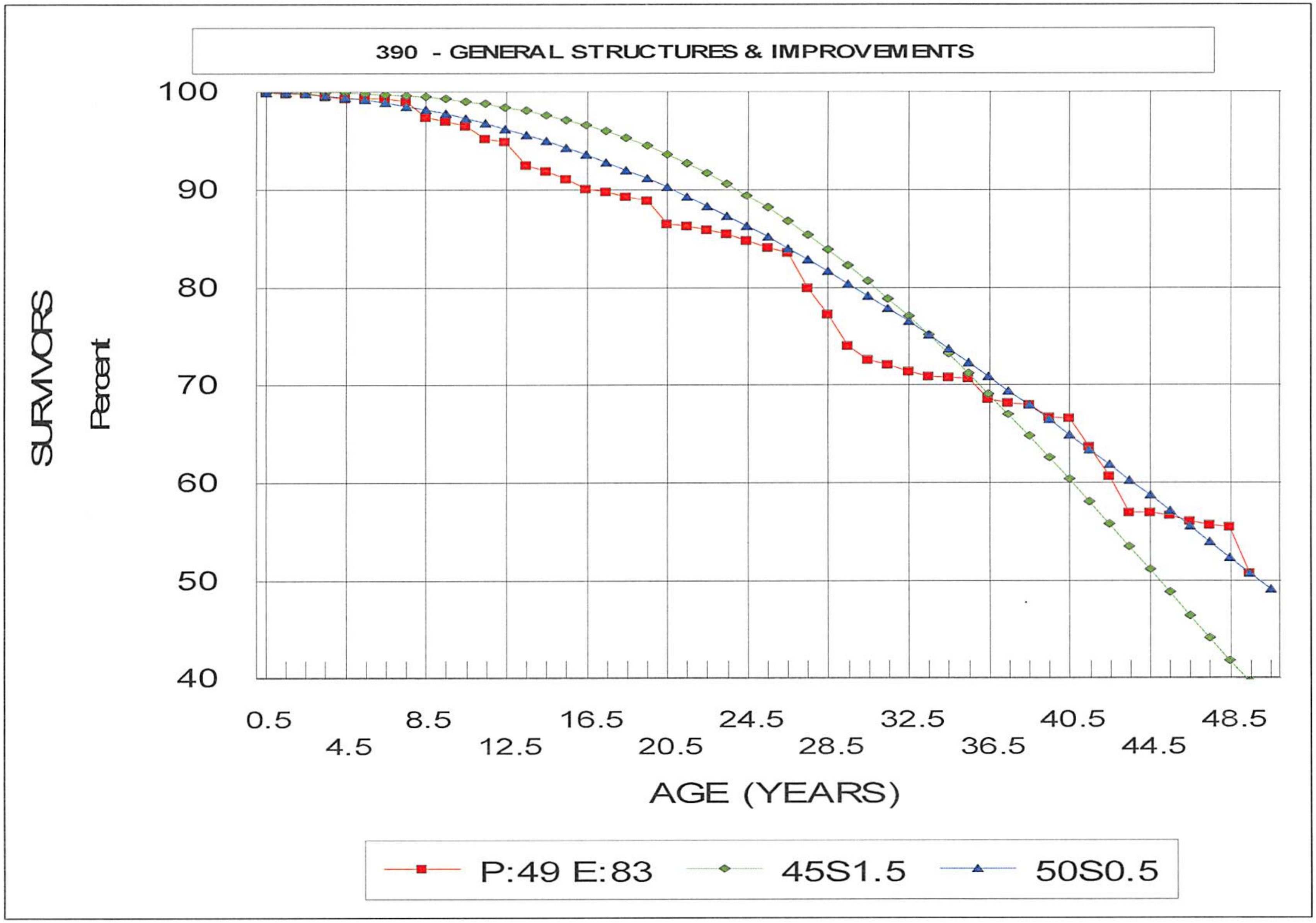
Account	Gulf Existing	Gulf Proposed	OPC Proposed	OPC Adjustment	Impact
350.2 – Transmission Easements and Right-of-Ways	60SQ	65R5	90R5	25	$88,959
353 – Transmission Station Equipment	45S0	45S0	48L0	3	$443,434
356 – Transmission Overhead Conductors	50R2	50R1.5	53R0.5	3	$279,212
364 – Distribution Poles and Fixtures	34R1	32L0	34L0	2	$435,231
365 – Distribution Overhead Conductors	38R1	40L1	42R1	2	$275,610
367 – Distribution Underground Conductors and Devices	32S2	34S2	39R2	5	$854,147
368 – Distribution Line Transformers	30S0	32S0	34R0.5	2	$1,149,526
369.1 – Distribution Overhead Services	35R1	40R1	44R1	4	$227,445
370.1 – Distribution Meters – AMR	15R1	15R1	20R1	5	$1,137,609
373 – Distribution Street Lights	20L1	22L1	24L0.5	2	$433,994
390 – General Plant Structures and Improvements	45S1.5	45S1.5	50S0.5	5	$325,041
303 – Intangible Plant – Software	N/A	7SQ	10SQ	3	$940,539
Total					$6,587,747


353-TRANSMISSION STATION EQUIP.
SURVIVORS
Percent
100
90
80
70
60
50
40
30
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
36.5
40.5
44.5
48.5
52.5
56.5
60.5
64.5
AGE (YEARS)
P:49 E:62
45S0
48L0



Docket Nos. 130140-EI, 130151-EI, 130092-EI
Exhibit__(JP-4)
Life-Curve Combination for Account 356 Full Band
Page 1 of 1


356-TRANS. OH CONDUCTORSAND DEVICES
SURVIVORS
Percent
100
90
80
70
60
50
40
30
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
36.5
40.5
44.5
48.5
52.5
56.5
60.5
AGE (YEARS)
P:28 E:91
50R1.5
52R0.5



Docket Nos. 130140-EI, 130151-EI, 130092-EI
Exhibit__(JP-6)
Life-Curve Combination for Account 390
Page 1 of 1

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED
AMORTIZATION OF ACCOUNT 303 INTANGIBLE SOFTWARE
FOR GULF POWER COMPANY
BASED ON ESTIMATED PLANT AS OF 12/31/2013

		Gulf Power Annual Amortization				Remaining	Remaining	Gulf Power	OPC
Year	Addition	2011	2012	2013	Total	Balance	Life 10SQ	Life 7SQ	Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
2010	$12,848,863	$1,835,552	$1,835,552	$1,835,552	$5,506,656	$7,342,207	$1,048,887	$1,835,552	$ (786,665)
2011	$1,831,497	$0	$261,642	$261,642	$523,285	$1,308,212	$163,527	$261,642	$ (98,116)
2012	$796,550	$0	$0	$113,793	$113,793	$682,757	$75,862	$113,793	$ (37,931)
2013	$415,865	$0	$0	$0	$0	$415,865	$41,587	$59,409	$ (17,823)
Total	$15,892,775	$1,835,552	$2,097,194	$2,210,987	$6,143,733	$9,749,042	$1,329,862	$2,270,396	$ (940,535)

SOURCES AND REFERENCES

Column (a):	: 2013 Study Volumn 1 Tab 10 Plant Investment Activity 2009-2013 page 1 for each year.
Columns (b-d)	: 2013 Study Volumn 1 Tab 11 Depreciation Reserve Activity 2009-2013 page 1 for each year.
Column (e)	: Summation of Columns b-d.
Column (f)	: Column (a) less Column (e).
Column (g)	: Column (g) divided by 10.
Column (h)	: Column (a) divided by 7.
Column (i)	: Column (g) less Column (h).

JACOB POUS, P.E.

PRESIDENT, DIVERSIFIED UTILITY CONSULTANTS, INC.

B.S. INDUSTRIAL ENGINEERING, M.S. MANAGEMENT

I graduated from the University of Missouri in 1972, receiving a Bachelor of Science Degree in Engineering, and I graduated with a Master of Science in Management from Rollins College in 1980. I have also completed a series of depreciation programs sponsored by Western Michigan University, and have attended numerous other utility related seminars.

Since my graduation from college, I have been continuously employed in various aspects of the utility business. I started with Kansas City Power & Light Company, working in the Rate Department, Corporate Planning and Economic Controls Department, and for a short time in a power plant. My responsibilities included preparation of testimony and exhibits for retail and wholesale rate cases. I participated in cost of service studies, a loss of load probability study, fixed charge analysis, and economic comparison studies. I was also a principal member of project teams that wrote, installed, maintained, and operated both a computerized series of depreciation programs and a computerized financial corporate model.

I joined the firm of R. W. Beck and Associates, an international consulting engineering firm with over 500 employees performing predominantly utility related work, in 1976 as an Engineer in the Rate Department of its Southeastern Regional Office. While employed with that firm, I prepared and presented rate studies for various electric, gas, water, and sewer systems, prepared and assisted in the preparation of cost of service studies, prepared depreciation and decommissioning analyses for wholesale and retail rate proceedings, and assisted in the development of power supply studies for electric systems. I resigned from that firm in November 1986 in order to co-found Diversified Utility Consultants, Inc. At the time of my resignation, I held the titles of Executive Engineer, Associate and Supervisor of Rates in the Austin office of R. W. Beck and Associates.

As a principal of the firm of Diversified Utility Consultants, Inc., I have presented and prepared numerous electric, gas, and water analyses in both retail and wholesale proceedings. These analyses have been performed on behalf of clients, including public utility commissions, throughout the United States and Canada.

I have been involved in over 400 different utility rate proceedings, many of which have resulted in settlements prior to the presentation of testimony before regulatory bodies. I am registered to practice as a Professional Engineer in many states.

UTILITY RATE PROCEEDINGS IN WHICH TESTIMONY HAS BEEN PRESENTED BY JACOB POUS

ALASKA		
ALASKA REGULATORY COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Beluga Pipe Line Company	P-04-81	Refundable Rates
Beluga Pipe Line Company	U-07-141	Depreciation
Kenai Nikiski Pipeline	U-04-81	Rate Base
ARIZONA		
ARIZONA CORPORATION COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Citizens Utilities Company	E-1032-93-111	Depreciation
ARKANSAS		
ARKANSAS PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Reliant Energy ARKLA	01-0243-U	Depreciation
CALIFORNIA		
CALIFORNIA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Pacific Gas & Electric Company	App. No. 97-12-020	Depreciation, Net Salvage, and Amortization of True-Up
Pacific Gas & Electric Company	App. No. 02-11-017	Mass Property Salvage, Net Salvage, Mass Property Life, Life Analysis, Remaining Life, Depreciation
Pacific Gas & Electric Company	App. No. 12-11-009	Depreciation, Mass Property Net Salvage, Mass Property Life, Hydroelectric
San Diego Gas & Electric Company		Value of Power Plants
Southern California Edison Company	App 02-05-004	Depreciation, Net Salvage
Southern California Edison Company	App 10-11-015	Mass Property Life and Net Salvage
Southern California Gas & San Diego Gas & Electric Company	Apps 10-12-005 & 10-12-006	Mass Property Life, Mass Property Net Salvage
CANADA		
ALBERTA ENERGY AND UTILITIES BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
AltaLink Management/ Transalta Utilities Corporation	App. Nos. 1279345 and 1279347	Depreciation
Epcor Distribution, Inc.	App. No. 1306821	Depreciation
Enmax Corporation	App. No. 1306818	Depreciation
Transalta Utilities Corporation	TFO Tariff App. 1287507	Depreciation
UtiliCorp Networks Canada (Alberta) Ltd.	App. No. 1250392	Depreciation
Atco Electric	App. No. 1275494	Depreciation

ALBERTA PUBLIC UTILITIES BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Alberta Power Limited	E 91095	Depreciation
Alberta Power Limited	E 97065	Depreciation
Canadian Western Natural Gas Company, Ltd.		Depreciation
Centra Gas Alberta, Inc.		Depreciation
Edmonton Power Company	E 97065	Depreciation
Edmonton Power Generation, Inc.	1999/2000	GUR Compliance, Depreciation
Northwestern Utilities, Ltd	E 91044	Depreciation
NOVA Gas Transmission, Ltd.	RE95006	Depreciation
TransAlta Utilities Corporation	E 91093	Depreciation
TransAlta Utilities Corporation	E 97065	Depreciation
TransAlta Utilities Corporation	App. No. 200051	Gain on Sale
ALBERTA UTILITIES COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
AltaGas Utilities	1606694	Life Analysis, Net Salvage
AltaLink Management, Ltd.	1606895	Life Analysis, Net Salvage
AltaLink Management, Ltd.	1608711	Life Analysis, Net Salvage
ATCO Gas	1606822	Life Analysis, Net Salvage
FortisAlberta	1607159	Life Analysis, Net Salvage
NEWFOUNDLAND AND LABRADOR BOARD OF COMMISSIONERS OF PUBLIC UTILITIES		
Newfoundland & Labrador Hydro		Depreciation, Life Analysis
Newfoundland Power, Inc.	2013/2014 GRA	Depreciation, Life Analysis, Net Salvage, ELG vs. ALG
NORTHWEST TERRITORIES PUBLIC UTILITIES BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Northwest Territories Power Corporation	1995/96 and 1996-97	Depreciation
Northwest Territories Power Corporation	2001	Depreciation
NOVA SCOTIA UTILITY AND REVIEW BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Nova Scotia Power, Inc.	M03665	Production Plant Life and Net Salvage (Inflation), Interim Retirements, Mass Property Life and Net Salvage, ELG vs. ALG, Remaining Life, Fully Accrued
CONNECTICUT		
CONNECTICUT PUBLIC UTILITIES REGULATORY AUTHORITY		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Connecticut Natural Gas Co.	13-06-08	Depreciation, Life, Net Salvage
COURTS		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
7th Judicial Circuit Court of Florida	2008-30441-CICI	Depreciation Valuation
112th Judicial District Court of Texas	5093	Ratemaking Principles, Calculation of damages
253rd Judicial District Court of Texas	45,615	Ratemaking Principles, Level of Bond
126th Judicial District Court of Texas	91-1519	Ratemaking Principles, Level of Bond

172 Judicial District Court of Texas		Franchise Fees
United States Bankruptcy Court Eastern District of Texas	93-10408S	Level of Harm, Ratemaking, Equity for Creditors
3rd Judicial District Court of Texas		Adequacy of Notice
DISTRICT OF COLUMBIA		
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Washington Gas Light Company	768	Depreciation
FLORIDA		
FLORIDA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Progress Energy Florida, Inc.	090079-EI	Depreciation, Excess Reserve
Progress Energy Florida, Inc.	050078-EL	Depreciation, Excess Reserve
Florida Power & Light Company	790380-EU	Territorial Dispute
Florida Power & Light Company	080677-EI 090130-EI	Depreciation, Excess Reserve
Florida Power & Light Company	120015-EI	Excess Reserve
Florida Power & Light Company	120015-EI	Settlement Analysis
Tampa Electric Co.	13-0040-EI	Depreciation, Amortization
FEDERAL ENERGY REGULATORY COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Alabama Power Company	ER83-369	Depreciation
Connecticut Municipal Electric Energy Cooperative v. Connecticut Light & Power Company	EL83-14	Decommissioning
Florida Power & Light Company	ER84-379	Depreciation, Decommissioning
Florida Power & Light Company	ER93-327-000	Transmission Access
Georgia Power Company	ER76-587	Rate Base
Georgia Power Company	ER79-88	Depreciation
Georgia Power Company	ER81-730	Coal Fuel Stock Inventory, Depreciation
ISO New England, Inc.	ER07-166-000	Depreciation
Maine Yankee Atomic Power Company	ER84-344-001	Depreciation, Decommissioning
Maine Yankee Atomic Power Company	ER88-202	Decommissioning
Pacific Gas & Electric	ER80-214	Depreciation
Public Service of Indiana	ER95-625-000, ER95-626-000 & ER95-039-000	Depreciation, Dismantlement
Southern California Edison Company	ER81-177	Depreciation
Southern California Edison Company	ER82-427	Depreciation, Decommissioning
Southern California Edison Company	ER84-75	Depreciation, Decommissioning
Southwestern Public Service Company	EL 89-50	Depreciation, Decommissioning
System Energy Resource, Inc.	ER95-1042-000	Depreciation, Decommissioning
Vermont Electric Power Company	ER83 342000 & 343000	Decommissioning
Virginia Electric and Power Company	ER78-522	Depreciation, Rate Base

Jurisdiction / Company	Docket No.	Testimony Topic
INDIANA		
INDIANA UTILITY REGULATORY COMMISSION		
Jurisdiction / Company	Docket No.	Testimony Topic
Indianapolis Water Company	39128	Depreciation
Indiana Michigan Power Company	39314	Depreciation, Decommissioning
KANSAS		
KANSAS CORPORATION COMMISSION		
Jurisdiction / Company	Docket No.	Testimony Topic
Arkansas Louisiana Gas Company	181,200-U	Depreciation
United Cities Gas Company	181,940-U	Depreciation
LOUISIANA		
LOUISIANA PUBLIC SERVICE COMMISSION		
Jurisdiction / Company	Docket No.	Testimony Topic
Louisiana Power & Light Company	U-16945	Nuclear Prudence, Depreciation
CITY OF NEW ORLEANS		
Jurisdiction / Company	Docket No.	Testimony Topic
Entergy New Orleans, Inc.	UD-00-2	Rate Base, Depreciation
MASSACHUSETTS		
MASSACHUSETTS TELECOMMUNICATION AND ENERGY		
Jurisdiction / Company	Docket No.	Testimony Topic
Bay State Gas	D.T.E.-0527	Depreciation
National Grid/KeySpan	07-30	Quality of Service
MISSISSIPPI		
MISSISSIPPI PUBLIC SERVICE COMMISSION		
Jurisdiction / Company	Docket No.	Testimony Topic
Mississippi Power Company	U-3739	Cost of Service, Rate Base, Depreciation
MONTANA		
MONTANA PUBLIC SERVICE COMMISSION		
Jurisdiction / Company	Docket No.	Testimony Topic
Montana Power Company (Gas)	90.6.39	Depreciation
Montana Power Company (Electric)	90.3.17	Depreciation, Decommissioning
Montana Power Company (Electric and Gas)	95.9.128	Depreciation
Montana-Dakota Utilities	D2007.7.79	Depreciation
Montana-Dakota Utilities	D2010.8.82	Depreciation, Interim Retirements, Production Plant Life and Net Salvage
Montana-Dakota Utilities	D2012.9.100	Depreciation
NEVADA		
PUBLIC UTILITIES COMMISSION OF NEVADA		
Jurisdiction / Company	Docket No.	Testimony Topic
Nevada Power Company	81-602, 81-685 Cons.	Depreciation
Nevada Power Company	83-667, Consolidated	Depreciation
Nevada Power Company	91-5032	Depreciation, Decommissioning
Nevada Power Company	03-10002	Depreciation
Nevada Power Company	08-12002	Depreciation, CWC

Nevada Power Company	06-06051	Depreciation, Life Spans, Decommissioning Costs, Deferred Accounting
Nevada Power Company	06-11022	General Rate Case
Nevada Power Company	10-02009	Production Life Spans
Nevada Power Company	11-06007	Early Retirement, Production Plant Net Salvage, Mass Property Life, Mass Property Net Salvage, Excess APFD
Sierra Pacific Gas Company	06-07010	Depreciation, Generating Plant Life Spans, Decommissioning Costs, Carrying Costs
Sierra Pacific Power Company	83-955	Depreciation (Electric, Gas, Water, Common)
Sierra Pacific Power Company	86-557	Depreciation, Decommissioning
Sierra Pacific Power Company	89-516, 517, 518	Depreciation, Decommissioning (Electric, Gas, Water, Common)
Sierra Pacific Power Company	91-7079, 80, 81	Depreciation, Decommissioning (Electric, Gas, Water, Common)
Sierra Pacific Power Company	03-12002	Allowable Level of Plant in Service
Sierra Pacific Power Company	05-10004	Depreciation
Sierra Pacific Power Company	05-10006	Depreciation
Sierra Pacific Power Company	07-12001	Depreciation, CWC
Sierra Pacific Power Company	10-06003	Depreciation, Excess Reserve, Life Spans, Net Salvage
Sierra Pacific Power Company	10-06004	Depreciation, Net Salvage
Sierra Pacific Power Company	12-08009	IRP-Coal Plant Service Life
Sierra Pacific Power Company	13-06004	Depreciation, Life, Net Salvage
Southwest Gas Corporation	93-3025 & 93-3005	Depreciation
Southwest Gas Corporation	04-3011	Depreciation
Southwest Gas Corporation	07-09030	Depreciation
Southwest Gas Corporation	12-04005	Depreciation
NORTH CAROLINA		
NORTH CAROLINA UTILITIES COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
North Carolina Natural Gas	G-21, Sub 177	Cost of Service, Rate Design, Depreciation
OKLAHOMA		
OKLAHOMA CORPORATION COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Arkansas Oklahoma Gas Corporation	PUD 200300088	CWC, Legal Expenses, Factoring, Cost Allocation, Depreciation
Oklahoma Natural Gas Company	PUD 980000683	Depreciation, Calculation Procedure, Depreciation on CWIP
Reliant Energy ARKLA	PUD 200200166	Depreciation, Net Salvage, Software Amortization
Public Service Company of Oklahoma	PUD 960000214	Depreciation, Interim Activity, Net Salvage, Mass Property, Rate Calculation Technique

Public Service Company of Oklahoma	PUD 200600285	Depreciation
Public Service Company of Oklahoma	PUD 200800144	Depreciation
Public Service Company of Oklahoma	PUD 201000050	Depreciation, Evaluation vs. Measurement, Interim and Terminal Net Salvage, Economies of Scale
Oklahoma Gas & Electric	PUD 201100087	Depreciation
SOUTH DAKOTA		
PUBLIC UTILITY COMMISSION OF THE STATE OF SOUTH DAKOTA		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Montana-Dakota Utilities	NG12-008	Depreciation, Life, Net Salvage
TEXAS		
PUBLIC UTILITY COMMISSION OF TEXAS		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
CenterPoint Energy Houston Electric, LLC	29526	Stranded Costs
CenterPoint Energy Houston Electric, LLC	36918	Hurricane Cost Recovery
CenterPoint Energy Houston Electric, LLC	38339	Depreciation, Net Salvage, Excess Reserve, Gain on Sale
Central Power & Light Company	6375	Depreciation, Rate Base, Cost of Service
Central Power & Light Company	8439	Fuel Factor
Central Power & Light Company	8646	Rate Base, Excess Capacity, Depreciation, Rate Design, Rate Case Expense
Central Power & Light Company	9561	Depreciation, Excess Capacity, Cost of Service, Rate Base, Taxes
Central Power & Light Company	11371	Economic Development Rate
Central Power & Light Company	12820	Nuclear Fuel and Process, OPEB, Pension, Factoring, Depreciation
Central Power & Light Company	14965	Depreciation, Cash Working Capital, Pension, OPEB, Factoring, Demonstration and Selling Expense, Non-Nuclear Decommissioning
Central Power & Light Company	22352	Depreciation
Central Telephone & United Telephone Company of Texas d/b/a Sprint	17809	Rate Case Expenses
City of Fredericksburg	7661	Territorial Dispute
El Paso Electric Company	9165	Depreciation
Entergy Gulf States, Inc.	16705	Depreciation, Prepayments, Payroll Expense, Pension Expense, OPEB, CWC, Transfer of T&D Depreciation
Entergy Gulf States, Inc.	21111	Reconcilable Fuel Costs
Entergy Gulf States, Inc.	21384	Fuel Surcharge
Entergy Gulf States, Inc.	23000	Fuel Surcharge
Entergy Gulf States, Inc.	22356	Unbundling, Competition, Cost of Service
Entergy Gulf States, Inc.	23550	Reconcilable Fuel Costs
Entergy Gulf States, Inc.	24336	Price to Beat

Entergy Gulf States, Inc.	24460	Implement PUC Subst.R.25.41(f)(3)(D)
Entergy Gulf States, Inc.	24469	Delay of Deregulation
Entergy Gulf States, Inc.	24953	Interim Fuel Surcharge
Entergy Gulf States, Inc.	26612	Fuel Surcharge
Entergy Gulf States, Inc.	28504	Interim Fuel Surcharge
Entergy Gulf States, Inc.	28818	Cert. for Independent Organization
Entergy Gulf States, Inc.	29408	Fuel Reconciliation
Entergy Gulf States, Inc.	30163	Interim Fuel Surcharge
Entergy Gulf States, Inc.	31315	Incremental Purchase Capacity Rider
Entergy Gulf States, Inc.	31544	Transition to Competition Cost
Entergy Gulf States, Inc.	·32465	Interim Fuel Surcharge
Entergy Gulf States, Inc.	32710	River Bend 30%, Explicit Capacity, Imputed Capacity, IPCR, SGSF Operating Costs and Depreciation Recovery, Option Costs
Entergy Gulf States, Inc.	33687	Transition to Competition
Entergy Gulf States, Inc.	33966	Interim Fuel Surcharge
Entergy Gulf States, Inc.	32907	Hurricane Reconstruction
Entergy Gulf States, Inc.	34724	IPCR
Entergy Gulf States, Inc.	34800	JSP, Depreciation, Decommissioning, Amortization, CWC, Franchise Fees, Rate Case Exp.
Entergy Texas Inc.	37744	Depreciation, Property Insurance Reserve, Cash Working Capital, Decommissioning Funding, Gas Storage
Entergy Texas Inc.	39896	Depreciation, Amortization, Property Insurance Reserve, Cash Working Capital
Gulf States Utilities Company	5560	Depreciation, Fuel Cost Factor
Gulf States Utilities Company	5820	Fuel Cost, Capacity Factors, Heat Rates
Gulf States Utilities Company	6525	Depreciation, Rate Case Expenses
Gulf States Utilities Company	7195 & 6755	Depreciation, Interim Cash Study, Excess Capacity, Rate Case Expense
Gulf States Utilities Company	8702	Rate Case Expenses, Depreciation
Gulf States Utilities Company	10,894	Fuel Reconciliation, Rate Case Expenses
Gulf States Utilities Company & Entergy Corporation	11292	Acquisition Adjustment Regulatory Plan, Base Rate, Rate Case Expenses
Gulf States Utilities Company & Entergy Corporation	12423	North Star Steel Agreement
Gulf States Utilities Company & Entergy Corporation	12852	Depreciation, OPEB, Pensions, Cash Working Capital, Other Cost of Service, and Rate Base Items
Houston Light & Power Company	6765	Depreciation, Production Plant, Early Retirement
Lower Colorado River Authority	8400	Rate Design
Magic Valley Electric Cooperative, Inc.	10820	Cost of Service, Financial Integrity, Rate Case Expenses

Oncor Electric Delivery, LLC	35717	Depreciation, Self-Insurance, Payroll, Automated Meters, Regulatory Assets, PHFU
Southwestern Bell Telephone Company	18513	Rate Case Expenses
Southwestern Electric Power Company	3716	Depreciation
Southwestern Electric Power Company	4628	Depreciation
Southwestern Electric Power Company	5301	Depreciation, Fuel Charges, Franchise Fees
Southwestern Electric Power Company	24449	Fuel Factor Component of Price to Beat Rates
Southwestern Electric Power Company	24468	Delay of Deregulation
Southwestern Public Service Company	11520	Depreciation, Cash Working Capital, Rate Case Expenses
Southwestern Public Service Company	32766	Depreciation Expense Revenue Requirements
Southwestern Public Service Company	35763	Depreciation
Texas-New Mexico Power Company	9491	Avoided Cost, Rate Case Expenses
Texas-New Mexico Power Company	10200	Jurisdictional Separation, Cost Allocation, Rate Case Expenses
Texas-New Mexico Power Company	17751	Rate Case Expenses
Texas-New Mexico Power Company	36025	Depreciation
Texas-New Mexico Power Company	38480	Depreciation, Mass Property Life, Net Salvage
Texas Utilities Electric Company	5640	Franchise Fees
Texas Utilities Electric Company	9300	Depreciation, Rate Base, Cost of Service, Fuel Charges, Rate Case Expenses
Texas Utilities Electric Company	11735	Cost Allocation, Rate Design, Rate Case Expenses
Texas Utilities Electric Company	18490	Depreciation Reclassification
West Texas Utilities Company	7510	Depreciation, Decommissioning, Rate Base, Cost of Service, Rate Design, Rate Case Expenses
West Texas Utilities Company	10035	Fuel Reconciliation, Rate Case Expenses
West Texas Utilities Company	13369	Depreciation, Payroll, Pension, OPEB, Cash Working Capital, Fuel Inventory, Cost Allocation
West Texas Utilities Company	22354	Depreciation
RAILROAD COMMISSION OF TEXAS		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Atmos Energy Corporation	9530	Gas Cost, Gas Purchases, Price Mitigation, Rate Case Expense
Atmos Energy Corporation	9670	CWC, Depreciation, Expenses, Shared Services, Taxes Other Than FIT, Excess Return
Atmos Energy Corporation	9695	Rate Case Expense
Atmos Energy Corporation	9762	Depreciation, O&M Expense
Atmos Energy Corporation	9732	Rate Case Expense
Atmos Energy Corporation	9869	Revenue Requirements

Atmos Energy Corporation	10041	Mass Property Life, Net Salvage
Atmos Energy Corporation	10170	Depreciation, Mass Property Life, Net Salvage
Atmos Pipeline-Texas	10000	Rate Base, Depreciation Life and Net Salvage, Incentive Compensation, Merit Increase, Outside Director Retirement Costs, SEBP
CenterPoint Energy Entex – City of Tyler	9364	Capital Investment, Affiliates
CenterPoint Energy Entex – Gulf Coast Division	9791	Rate Base, Cost Allocation, Affiliate Expenses, Depreciation Net Salvage, Call Center, Litigation, Uncollectibles, Post Test Year Adjustments
CenterPoint Energy Entex – City of Houston	9902	CWC, Plant Adjustments, Depreciation, Payroll, Pensions, Cost Allocation
CenterPoint Energy Entex – South Texas Division	10038	CWC, Incentive Compensation, Payroll, Depreciation
CenterPoint Energy – Beaumont/East Texas	10182	Rate Base, Expense, Incentive Compensation, Pension, Payroll, Injuries & Damages
CenterPoint Energy – Texas Coast Division	10007	Cost of Service Adjustment, CWC, ADIT, Incentive Compensation, Pension, Meter Reading, Customer Records and Collection, Investor Relations/Investor Services
CenterPoint Energy – Texas Coast Division	10097	Pension, Severance Expense
Energas Company	5793	Depreciation
Energas Company v. Westar Transmissions Company	5168 & 4892 Cons.	Cost of Service, Refunds, Contracts, Depreciation
Energas Company	8205	Cost of Service, Rate Base, Depreciation, Affiliate Transactions, Sale/Leaseback, Losses, Income Taxes
Energas Company	9002-9135	Depreciation, Pension, Cash Working Capital, OPEB, Rate Design
Lone Star Gas Company	8664	Cash Working Capital, Depreciation Expense, Gain on Sale of Plant, OPEB, Rate Case Expenses
Rio Grande Valley Gas Company	7604	Depreciation
Southern Union Gas Company	2738, 2958, 3002, 3018, 3019 Cons.	Cost of Service, Rate Design, Depreciation
Southern Union Gas Company	6968 Interim & Cons.	Affiliate Transactions, Rate Base, Income Taxes, Revenues, Cost of Service, Conservation, Depreciation
Southern Union Gas Company	8033 Consolidated	Acquisition Adjustment, Depreciation, Excess Reserve, Distribution Plant, Cost of Gas Clause, Rate Case Expenses

Southern Union Gas Company	8878	Depreciation, Cash Working Capital, Gain on Sale of Building, Rate Case Expenses, Rate Design
Texas Gas Service Company	9988 & 9992 Cons.	Cash Working Capital, Post Test Year Plant, ADFIT, Excess Reserve, Depreciation Expense, Amortization of General Plant, Corporate and Division Expenses, Incentive Compensation, Hotel and Meals Expense, Pipeline Integrity Costs
TXU Gas Distribution	9145-9147	Depreciation, Cash Working Capital, Revenues, Gain on Sale of Assets, Clearing Accounts, Over-Recovery of Clearing Accounts, SFAS 106, Wages and Salaries, Merger Costs, Intra System Allocation, Zero Intercept, Customer Weighting Factor, Rate Design
TXU Gas Distribution	9400	Depreciation, Net Salvage, Cash Working Capital, Affiliate Transactions, Software Amortization, Securitization, O&M Expenses, Safety Compliance
TXU Lone Star Pipeline	8976	Depreciation, Net Salvage, Cash Working Capital, ALG vs. ELG
Westar Transmissions Company	5787	Depreciation, Rate Base, Cost of Service, Rate Design, Contract Issues, Revenues, Losses, Income Taxes
TEXAS WATER COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
City of Harlingen-Certificate for Convenience & Necessity	8480C/8485C/8512C	Rate Impact for CCN
City of Round Rock	8599/8600M	Rate Discrimination, Cost of Service
Devers Canal System	8388-M	Affiliate Transactions, O&M Expense, Return, Allocation, Acquisition Adjustment, Retroactive Ratemaking, Rate Case Expenses, Depreciation
Devers Canal System	30102-M	Cost of Service, Rate Base, Ratemaking Principles, Affiliate Transactions
Southern Utilities Company	7371-R	Affiliate Transactions, Cost of Service
Scenic Oaks Water Supply Corporation	8097-G	Affiliate Transactions, Cost of Service, Rate base, Cost of Capital, Rate Design, Depreciation
Sharyland Water Supply vs. United Irrigation District	8293-M	Rate Discrimination, Cost of Service, Rate Case Expenses
Southern Water Corporation	2008-1811-UCR	Cost of Service
Travis County Water Control & Improv. District No. 20		Cost of Service
EL PASO PUBLIC UTILITY REGULATION BOARD		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Southern Union Gas Company	1991	Depreciation, Calculation Procedure
Southern Union Gas Company	1997	Depreciation, Calculation Procedure

Southern Union Gas Company	GUD 8878 – 1998	Depreciation, Cash Working Capital, Rate Design, Rate Case Expenses
Texas Gas Services Company	2007	Revenue Requirements
Texas Gas Services Company	2011	Revenue Requirements
UTAH		
UTAH PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
PacifiCorp	98-2035-03	Production Plant Net Salvage, Production Life Span, Interim Additions, Mass Property, Depreciation
Questar	05-057-T01	Conservation Enabling Tariff Adjustment Option and Accounting Orders
Rocky Mountain Power	07-035-13	Depreciation
Rocky Mountain Power	13-035-02	Depreciation, Interim Additions, Production Plant Life Spans, Interim Retirements, Net Salvage, Mass Property Life
WYOMING		
WYOMING PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
PacifiCorp	20000-ER-00-162	Rate Parity