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ORIGINAL

June 19, 2008

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Ms. 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 No. 070052-EI

Dear Ms. Cole:

Enclosed for filing, on behalf of the Citizens of the State of Florida, are the original and 15 copies of the Direct Testimony of Daniel J. Lawton.

Please indicate the time and date of receipt on the enclosed duplicate of this letter and return it to our office.

Sincerely,

Joe A. McGlothlin

Joseph A. McGlothlin
Associate Public Counsel

Enclosures

JAM:bsr

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COM 5
CTR 1
ECR ____
GCL 1
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ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Progress Energy to Recover Costs of Crystal River Unit 3 uprate through the fuel Clause.	)	Docket No. 070052-EI Filed: June 19, 2007

DIRECT TESTIMONY

OF

DANIEL J. LAWTON

On Behalf of the Citizens of the State of Florida

Charles J. Beck
Interim Public Counsel

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Attorneys for the Citizens
of the State of Florida

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Attorneys for the Citizens
of the State of Florida

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070052-EI

DIRECT TESTIMONY OF DANIEL J. LAWTON

ON BEHALF OF CITIZENS OF THE STATE OF FLORIDA

SECTION 1: QUALIFICATIONS, BACKGROUND AND INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel J. Lawton and my business address is 12113 Roxie Drive, Suite 110 Austin, Texas 78728.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a principal in the firm of Diversified Utility Consultants, Inc. ("DUCI").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I have been working in the utility business as an economist for the last 25 years. Consulting engagements have included electric utility load and revenue forecasting, cost of capital and financial analyses, revenue requirement/cost of service issues, prudence inquiries, and rate design/cost allocation studies in litigated rate proceedings as well as developing rate studies for municipally owned utilities. In addition to my duties at DUCI, I also have a law practice based in Austin, Texas. My main areas of practice include Administrative Law representing municipalities in utility rate matters before regulatory agencies and contract matters and litigation. I have included a brief description of my relevant educational background and professional experience in my Exhibit __ (DJL-1).

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN RATE PROCEEDINGS?

A. Yes. A list of cases where I have previously filed testimony is included in my Exhibit ___ (DJL-1).

Q. ON WHOSE BEHALF ARE YOU FILING TESTIMONY IN THIS PROCEEDING?

A. DUCI has been retained by the Office of Public Counsel ("OPC") to review and respond to the Progress Energy Florida ("PEF" or "Company") Petition to Recover Costs of Crystal River Unit 3 ("CR3") Uprate through the Fuel Clause ("Uprate Petition").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. As noted above, the purpose of my testimony is to address the issues raised in the Company's proposal to collect base rate costs through the fuel clause. My testimony is organized in the following fashion with regard to the issues I specifically address:

<u>Section 2:</u> Company Uprate Proposal;

Section 3: Evaluation Standards and Ratemaking Alternatives;

Section 4: The General Rate Setting Process;

Section 5: Inappropriate Rate Components of PEF's Uprate Request

A. Depreciation

B. Accumulated Deferred Income Taxes

C. Cost of Capital

D. Timing Consideration

Section 6: Transmission and POD Proposals

My analysis of these issues is based on my background in utility regulation as a consultant, economist and as an advisor to regulatory authorities. OPC witness Merchant addresses some of these same issues from the perspective of an accountant.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR FINDINGS AND CONCLUSIONS.

A. The facts and circumstances of this case do not support fuel clause treatment of the Company's Uprate request. The size of this major nuclear addition is an issue that is typically analyzed in the context of a major rate proceeding where all costs (increases and decreases) are examined to determine the appropriate customer rates. Fuel cost recovery is unwarranted, in that these amounts can and should be considered timely in the context of a base rate filing. The Company is not in any danger of under earning its cost of capital or revenue erosion, because it has the ability and opportunity to recover this nuclear investment following a normal base rate proceeding. This fact distinguishes this case from the situation envisioned in the Commission order on which PEF chiefly relies. The Company's proposal would result in lopsidedly enormous benefits to shareholders at the expense of customers. PEF proposes accelerated recovery, guaranteed returns and enhancement of shareholder values by shifting risks of recovery to customers. Under PEF's proposal PEF would recover its costs from current customers on an accelerated basis, but the projected fuel savings would be delayed in reaching customers, creating intergenerational inequities among customers. Moreover, the costs and benefits of this project are most difficult to analyze, given the very preliminary nature of the cost estimates. Any material failure to adequately project the costs could result in further delays in customer benefits under the Company's plan.

Given the above, I recommend that this Commission deny the Company's request to treat the proposed $448 million of nuclear investment as a cost eligible for fuel clause treatment.

SECTION 2: <u>COMPANY UPRATE PROPOSAL</u>

Q. PLEASE DESCRIBE THE COMPANY'S CR3 POWER UPRATE PROJECTS.

A. The Company proposes to "uprate", (increase the power output of) CR3 by approximately 180 MWe. (See Direct Testimony of Javier Portuondo at 4:20-23). The uprate, if successfully completed, will increase the capability of CR3 from

900 MWe to 1,080 MWe. The increase of 180 MWe's of low cost CR3 nuclear generation will provide customers with increased low fuel cost output resulting in fuel savings, by displacing other more costly generation and/or purchased power. The Company asserts that there will be $2.6 billion (nominal) of fuel net savings (net present value fuel savings ("NPV") of $640 million) by the end of 2036, based on the numbers included in its amended filing. (Id at 7:1-3).

The expected investment including AFUDC to complete this uprate project is a total expected outlay of about $448 million. (PEF's response to OPC Interrogatory 12 Attachment 1). This cost estimate is based on the following three components; (i) a $293 million investment required for the power uprate; (ii) modifications required for transmission system reliability of $103.9 million; and (iii) point of discharge ("POD") investment to address water cooling issues from the power uprate of $51.1 million. These are not firm final cost proposals, but rather Company estimates subject to refinement. (See Direct Testimony of Javier Portuondo at 6:1-2). In fact, with the exception of the MUR phase scheduled for installation in 2007, it is clear that PEF's estimates are preliminary "placeholders," and that the studies necessary to estimate the costs have not been completed. Under the Company's uprate proposal in this case, the Company asserts customers are expected to enjoy lower fuel costs of about $706 million (NPV) resulting in a total $353 million benefit (NPV) to customers. (PEF's response to OPC Interrogatory No. 12 Attachment 1)

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE COSTS ASSOCIATED WITH THIS PROJECT FROM CUSTOMERS?

A. The Company proposes to recover the entire non-fuel base rate costs associated with this nuclear investment project, approximately $448 million of costs, (CR3 nuclear power plant investment, transmission investment, Point of Discharge investment, O&M and auxiliary power costs) through the fuel clause. In other words, the Uprate capital costs which normally are recovered through base rates would instead be recovered as part of the fuel factor. The costs proposed by the Company to be recovered through the fuel clause include; (i) the recovery of all capital costs incurred for the CR3 power Uprate; (ii) all costs associated with transmission system changes; and (iii) all costs incurred to offset the POD impact for the project. (Id at 8:20 – 25). These costs include a return on average investment and taxes, depreciation, deferred tax impacts and O&M, with the recovery of the investment shortened from the service life (2036) to 1-year or 10-year periods.

The Company proposes to begin recovery through the fuel clause as each of the three phases of the project is completed. Phase 1 resulting in a 12 MWe power uprate associated with the measurement uncertainty recovery ("MUR") project is to be completely recovered in 2008. Phase 2 and Phase 3 of this project are expected to result in the start of cost recovery in of 2009 and 2011, respectively.

SECTION 3: EVALUATION STANDARDS AND RATEMAKING ALTERNATIVES

Q. HAS THE COMMISSION PREVIOUSLY ESTABLISHED STANDARDS THAT ARE APPLICABLE TO ITEMS THAT ARE NORMALLY BASE RATE ITEMS BUT MAY BE ALLOWED FOR RECOVERY THROUGH FUEL ADJUSTMENT CLAUSES?

A. Yes, the Commission has previously addressed this issue in Order 14546, which states at item 10:

> Fossil fuel-related costs normally recovered through base rates but which were not recognized <u>or anticipated in the cost levels used to determine current base rates</u> and which, if expended, will result in fuel savings to customers. Recovery of <u>such costs should be made on a case by case basis</u> after Commission approval. (Emphasis added).

The Commission further stated in Order No. 14546 the types of costs more appropriately considered in the computation of base rates. Those items are as follows.

1. Operations and maintenance expense at generating plants or system storage facilities. This includes unloading and fuel handling cost at the generating plant or storage facility.
2. Transportation charges between dedicated storage facilities and generating plants.
3. Fuel procurement administrative functions.
4. Fuel additives neither blended with fuel prior to burning nor injected into the boiler fire chamber along with the fuel.

Q. DID THE COMMISSION PROVIDE GUIDANCE AS TO WHY IT HAS ALLOWED WHAT MIGHT NORMALLY BE CONSIDERED NON-FUEL ITEMS TO BE RECOVERED THROUGH BASE RATES?

A. Yes. The Commission said it wanted to provide the utility an incentive and opportunity to take advantage of certain projects which will result in the savings of fossil fuel-related costs to customers when such costs savings arise after rates have been established and before they could be recognized in future base rates.

Q. IN YOUR OPINION, DOES THE COMPANY'S REQUEST IN THIS PROCEEDING MEET THE STANDARDS OR GUIDELINES PREVIOUSLY ESTABLISHED BY THE COMMISSION?

A. No. In short, the Company's argument is that these uprate costs are not in current base rates and if the costs are expended the result will be fuel savings for customers. (Direct Testimony Mr. Portuondo at 4:9-12). The Company's approach is rather simplistic and fails to establish a reasonable basis for including these costs in the fuel clause – especially given the substantial detrimental impacts on customers.

In my opinion, the Company's proposal should be denied for the following reasons;

- First, the vast majority of such costs can and should be recognized in the Company's future rate proceedings that could occur in 2009. At that time, such costs can be better estimated along with all other base rate costs to determine the appropriate level of earnings, and will not deprive the Company of a reasonable and necessary level of return on such investment.

- Second, the costs associated with the Uprate of CR3 are not volatile in nature. This is one of the key criteria underlying the establishment of the fuel cost recovery clause in the first place. The projected investments associated with the CR3 Uprate and POD investment are one-time expenditures that have an identifiable, useful life equal to the expected life of the CR3 generating facility. Once placed into service, such expenditures are known and measurable and are not volatile over the period they will be used and useful in the providing service to customers.

- Third, the Company's request, as it pertains to the transmission related expenditures, are not associated with fuel savings. Rather, the expenditures for transmission are tied to reliability concerns necessary to meet the outage of the largest single unit on the system.

- Fourth, while the expenditures associated with the MUR investment project are anticipated to be in service prior to the next rate proceeding, these costs are not only relatively small in nature, but further have not been distinguished from other capital expenditures normally made by the Company in between rate proceedings for which it has not sought similar rate treatment.

- Fifth, the Company's cost recovery request incorporates a useful life that is a form of accelerated depreciation that conflicts with principles of normal ratemaking as well as the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Allowance of such artificially short depreciation periods would significantly reduce NPV savings to customers during the early years of the project.

- Sixth, the Company's requested overall cost of capital of 13.19% (including income taxes) is excessive given that in the event the Commission were to allow clause treatment, there is no risk of non-recovery under the Company's proposal. The application of debt costs would be the appropriate proxy for return in this situation. PEF's approach therefore overstates the costs that should be borne by the customers under PEF's proposal.

The Commission's Order No. 14546 clearly states that requests such as the Company's will be reviewed on a case by case basis.

Thus, as to guidance for the consideration of the Company's proposal the Commission should consider the following:

1) The Company's proposal guarantees 100% recovery of costs and returns and enhances shareholder values while minimizing shareholder risks;

2) Customers must wait behind shareholders for years before enjoying any savings;

3) Cost estimates have not been refined, which would place estimates of fuel savings to customers at more risk;

4) Most of the fuel savings are in outer years where forecast estimates are most likely to be incorrect; and

5) The Company does not face any substantial risks if these costs are included in base rates.

The bottom line is that this Uprate project can be included in base rates and customer savings can be improved without jeopardizing the Company's financial integrity. There is no compelling reason or necessity for including the Uprate costs in the fuel clause. On the other hand, to grant PEF's request would be detrimental to customers.

Q. IF THE COMMISSION DENIES PEF'S PETITION, WILL THE COMPANY BE ABLE TO RECOVER THE FULL REVENUE REQUIREMENT OF THE MUR UPRATE PROJECT THAT IS SCHEDULED FOR COMPLETION BY THE END OF 2007?

A. Yes. Under any scenario, the Company's financial integrity will not be harmed by requiring PEF to place the MUR-related capital costs in rate base. OPC witness Merchant has calculated that, if the Company places the MUR in rate base and depreciates the plant over the useful life of the asset, the full 2008 revenue requirement associated with MUR will be about $1.05 million. Absorbing this amount in base rate revenues would reduce the Company's equity return from 10.90% to about 10.86%. Even under the Company's inappropriate cost recovery request (where $6.45 million of MUR investment is recovered in the single year 2008), the 2008 and 2009 total MUR-related revenue requirement would be $8.67 million. If the Company is required to recover these costs in base rates, I estimate that the Company's equity return would drop from about 10.90% to about 10.50% based on PEF's recent return report.

SECTION 4: <u>BASIC RATEMAKING</u>

Q. WHAT IS THE PRINCIPAL UNDERLYING BASIS ASSOCIATED WITH THE RATE SETTING PROCESS FOR ELECTRIC UTILITIES?

A. OPC witness Patricia Merchant will address this topic in some detail. I provide the following brief summary of the differences between fuel cost recovery and base rate recovery for regulated electric monopolies, from my perspective as an economist. My purpose is to explain more fully why requiring PEF to place the Uprate investment in rate base in the normal fashion is the appropriate regulatory outcome in this case. The basic economic proposition underlying utility regulation is that a utility incurs costs in order to provide electricity and customers reimburse the utility for all reasonable and necessary costs. A utility recovers its costs by billing its customers based on their usage.

Q. WHAT ARE THE COMPONENTS OF THE BILL THAT CUSTOMERS NORMALLY RECEIVE?

A. A customer's bill typically has a base rate component and separate rate elements that apply to special cost recovery mechanisms. I am informed that in Florida there are several such special mechanisms. As PEF's proposal involves a decision between base rates and the fuel clause, I will confine this discussion to those components.

Q. WHY DOES A CUSTOMER'S BILL SHOW FUEL COSTS SEPARATELY FROM BASE RATES?

A. Many decades ago, there was no fuel adjustment clause. Fuel costs were generally stable enough and could be reasonably predicted and included along with all other costs such as salaries, material costs, etc. in establishing the rates charged to customers. As the cost of fuel became volatile and unpredictable, utilities sought relief outside the confines of traditional rate cases. While the timing of the initial implementation of a fuel clause varied between utilities, many began employing fuel clauses after the 1973 Oil Embargo. Regulators allowed the creation and implementation of fuel adjustment clauses that were intended to recover the actual fuel costs incurred to provide electric service to customers, given that fuel costs were normally outside the control of a utility. In fact, regulators normally created fuel adjustment clauses with a true-up provision so that a utility would not over or under recover its fuel costs and would not be subject to the corresponding financial risk.

Q. TRADITIONALLY, IS THERE A STRICT SEPARATION BETWEEN BASE RATE COST AND FUEL COST?

A. Yes. Given the underlying basis for the fuel adjustment clause and its associated reduced level of risk due to the true-up mechanism, the traditional process has been to limit costs to be recovered through the fuel clause to be those associated with the actual cost of fuel. Base rate costs continue to be reviewed in a base rate proceeding, so as to permit the establishment of a normalized level of annual costs along with a reasonable rate of return on net investment.

Q. WHAT TYPE OF COSTS ARE INCLUDED IN THE BASE RATE PORTION OF A BILL?

A. The short answer is that the base rate component includes all costs excluding fuel or other clause recovered costs. This component normally includes salaries, other operating and maintenance expenses, administrative costs, depreciation of capital investment, taxes and a return on the capital investment of the utility.

Q. DO BASE RATES CHANGE ON A FREQUENT BASIS?

A. No. If annual costs and sale levels are reasonably estimated when rates are established, then as a utility continues to operate and incur different levels of costs over time, it is also anticipated that it will experience corresponding changes in the level of sales. As part of the rate setting process, per unit customer, energy, and demand charges are established so as to recover the utility's revenue requirements from individual customers through their monthly bills. While not normally in lock step, costs and revenues tend to move in the same direction. Normally, residential and small commercial customers have a customer charge and a per unit energy charge. Larger commercial and industrial customers normally have a customer charge, an energy charge, and a demand charge. Each of these charges is established on a per-unit basis. In other words, a customer charge applies to each customer delivery point. An energy charge applies to each Kilowatt hour sold, and a demand charge applies to each Kw of metered capacity. Thus, as a customer uses more energy or demand, that customer also pays the unit charge for each unit of use. As long as the relationship between costs and revenues does not vary significantly on a per unit basis over time then the base rate can continue to be used without change.

Q. IF A UTILITY EXPERIENCES GROWTH IN SALES, DOES IT ALSO EXPERIENCES A GROWTH IN REVENUES.

A. Yes. The more units of electricity sold, the more revenues charged and collected by the utility. However, just like any other business, as sales increase, so do expenses. While the interrelationship between revenues and expenses is a dynamic process, it normally stays within a reasonable level of equilibrium for a period of time. Only when expenses change in a disproportionate manner to sales is it necessary to reestablish an equilibrium through a new base rate proceeding.

Q. DOES A UTILITY NORMALLY EARN A LEVEL OF RETURN DIFFERENT THAN WHAT WAS ALLOWED IN ITS LAST RATE CASE?

A. Yes. The allowed rate of return set in a rate proceeding is a point estimate established to be representative of a reasonable range of earnings. Since, for example, weather may be colder or warmer than normal, the actual level of sales may be greater or less than anticipated during the rate setting process resulting in a variation from the allowed rate of return. As long as the return level stays within a reasonable range of the point estimate, it is assumed that base rates are functioning properly.

Q. IF A UTILITY CONTINUES TO ADD INVESTMENT TO MEET THE NEEDS OF EXISTING AND NEW CUSTOMERS AFTER A RATE CASE, WILL THE ADDITIONAL INVESTMENT RESULT IN A NEED FOR A NEW BASE RATE PROCEEDING?

A. No, not necessarily. For example, if sales and expenses increase by one percent and the net investment level increases by one percent, then the net return remains relatively constant. In other words, it is fully anticipated that a utility will make expenditures for capital requirements, incur different levels of expenses, as well as different types of expenses over time yet can properly function on a consistent financial basis without the need for a base rate adjustment. However, if sales decline or stay flat, but expenses and net investment rise appreciably then a rate adjustment most likely would be required.

Q. WHAT TYPES OF COSTS ARE INCLUDED IN THE FUEL PORTION OF A BILL?

A. Normally the fuel adjustment clause recovers only the costs of various types of fuel necessary to generate electricity (i.e. natural gas, coal, oil and nuclear) paid by the utility to fuel suppliers.

Q. HOW DOES THE COMPANY'S CASE IN THIS PROCEEDING CONFLICT WITH THE TRADITIONAL RATE SETTING PROCESS?

A. The Company seeks to recover base rate costs through the fuel cost recovery clause. This request is inconsistent with the traditional rate setting process.

Q. PLEASE EXPLAIN HOW THE COMPANY'S REQUEST IS INCONSISTENT WITH RATEMAKING STANDARDS.

A. All the costs in the proposed Uprate are non fuel costs. In other words, <u>all</u> the Uprate costs are properly included as part of non fuel base rates. As is explained elsewhere in this testimony, the timing of the completion of the project is such that the Company is not harmed by including these Uprate base rate costs in future base rate cases. However, if the Company's requested fuel treatment of those non-fuel Uprate costs is approved, customers will be harmed while shareholders enjoy a substantial windfall.

Q. IN YOUR OPINION, WOULD A UTILITY PREFER TO COLLECT ITS ENTIRE REVENUE REQUIREMENT THROUGH A FUEL ADJUSTMENT CLAUSE?

A. Yes. Under a fuel adjustment mechanism, with true-up and reconciliation, a utility is guaranteed 100% cost recovery. Thus, a utility would recover all costs and a guarantee of its authorized return. On the other hand, when base rate recovery is authorized, a utility is allowed to charge a rate that recovers costs plus an <u>opportunity</u> to earn its cost of capital. Given the two alternative models a rational company will vote for the <u>guaranteed</u> return – especially if that return is not adjusted to reflect the much lower risk associated with a true-up mechanism.. In this case, the Company's proposal would in fact be a guaranteed return to equity shareholders of 11.75% after tax.

This argument is supported by the Company's own analysis contained in the MUR Project Plan where the following is stated:

> Progress Energy plans to increase the electrical power output of Crystal River 3 in order to minimize cost to our customers and enhance shareholder value. (Project Plan at Bates PEF – CR3-0482).

The Company goes on to state:

> The business case for a series of power up-rates was developed to seek funding from either corporate sources or through the Fuel Adjustment Clause... The Florida Public Service Commission is currently reviewing a request for approval to utilize the Fuel Adjustment Clause as a source of funding for this project. The strategy to minimize risk and cost exposure is to increase power level in three distinct phases... (Id. at Bates PEF – CR3-0486).

The Company obviously evaluated seeking internal funding (a base rate case alternative) and the Fuel Adjustment Clause approach and selected the Fuel Adjustment Clause. The inclusion of the costs in fuel minimizes risk and cost exposure to the Company and enhances shareholder value – both goals of the Company are satisfied.

Q. IS THE COMPANY PROPOSING TO MAKE THE UPRATE EXPENDITURES IN ORDER TO SAVE CUSTOMERS FUEL COSTS?

A. Yes.

Q. ISN'T IT FAIR TO ALLOW THE RECOVERY OF SUCH COSTS THROUGH THE FUEL RECOVERY CLAUSE IF IT SAVES CUSTOMERS FUEL EXPENSE?

A. No, it would be unfair to customers. Many base rate expenditures can, and do, save customers fuel expense, yet they are not included in the fuel cost recovery process. However, without analyzing all of the new expenditures in total along with existing costs, no one can tell if a utility is over or under earning its allowed return. Thus, allowing a base rate cost to be recovered through the fuel cost recovery clause may result in excess earnings; once through the fuel costs and a second time through the existing base rate charges. In other words, without testing the entire regulatory base rate level of normalized costs in comparison to normalized revenues, it is impossible to precisely determine if a utility's earnings are falling outside the allowed reasonable range of earnings due to any particular transaction. There may very well be costs that are decreasing that more than offset costs that are increasing.

Q. ISN'T IT A RATHER STRAIGHTFORWARD PROCESS TO DETERMINE WHETHER THE EQUILIBRIUM LEVEL OF BASE RATES FALLS OUTSIDE OF A REASONABLE RANGE?

A. No, and that is why base rate cases are complex and time consuming. Many items of cost must be properly analyzed in order to determine if they represent a normalized or average expected level of cost for ratemaking purposes. For example, in this proceeding the Company proposes to assign a 1-year amortization "life" for the CR3 MUR uprate investment. That 1-year life assumes that 100% of the investment will be recovered in the first year of service. As noted elsewhere in this testimony, this is an inappropriate assumption, given the life expectancy for the investment is 29 years. It is precisely for this reason that expenses and other costs must be properly analyzed so that what is simply reported on the Company's books or proposed by the Company is not assumed and accepted as an appropriate or accurate presentation for ratemaking purposes.

Q. IN YOUR OPINION, WHAT IS THE DANGER OF ALLOWING PEF TO PASS BASE RATE-RELATED COSTS THROUGH THE FUEL COST RECOVERY CLAUSE?

A. The danger is that which OPC witness Merchant points out in her discussion of fundamental ratemaking principles. If PEF passes the entire project costs through the fuel clause when base rate revenues are adequate to cover some or all of the costs and provide a fair return, then customers' total bills will be too high. PEF will have circumvented the primary means of ensuring its rates are fair and reasonable, and will have realized a windfall.

Q. IN THE PAST, HAS THE COMMISSION ALLOWED CERTAIN BASE RATE COSTS TO BE RECOVERED THROUGH A FUEL CLAUSE?

A. Yes. However, the Commission requires that consideration of requests for clause treatment "of such costs should be made on a case by case basis." (Order 14546 at page 5, item 10.) The Commission did not set forth a blanket acceptance associated with the fuel saving exception to the fuel rule, but instead stated the Commission would consider requests on a case by case basis. Given it is a case by case standard – precedent has little value. For example, the only other case that involved a nuclear plant uprate was FPL's Turkey Point facilities. (Order No. PSC-96-1172-FOF-EI, Docket No. 960601-EI, September 19, 1996). The Turkey Point uprate involved an investment of $10 million, where this case entails over $448 million of investment including plant modifications. Also, FPL customers received savings in the first year. These are not comparable uprate projects.

Q. FROM A RATE SETTING PERSPECTIVE, IS THERE A REQUIREMENT TO LOOK AT THE TIMING OF EXPENDITURES?

A. Yes. For example, only the $6 million MUR related expenditures are estimated to be incurred during the current time frame. The vast majority of the Company's requested expenditures are associated with projected costs to be placed into service during 2009 to 2011. This is important, since the Company has the opportunity and capability of returning to the Commission for base rate relief, if and when, it determines that such base rate relief is necessary. Thus, the concerns set forth in Commission Order 14546 relating to expenditures not reflected in the last base rate proceeding also have to take into consideration that the vast majority of the CR3 uprate expenditures can be captured appropriately through a base rate proceeding that could occur in the 2009 time frame without the Company incurring the potential loss of return in the interim.

The traditional rate setting process is well equipped to handle the Company's proposed expenditures without undue concern for whether customers are receiving benefits or the Company will be receiving benefits in the interim. The bulk of the investment proposed can be properly tested along with all other expenditures to make sure that the dynamic rate setting process stays in equilibrium after such expenditures are incurred or, if necessary, the base rates can be modified either upward or downward to once again establish an equilibrium operation from a financial standpoint.

SECTION 5: <u>INAPPROPRIATE COMPONENTS OF PEF'S REQUEST</u>

A. <u>Depreciation</u>

Q. OVER WHAT PERIOD OF TIME DOES A UTILITY NORMALLY DEPRECIATE PLANT ASSETS?

A. Capital investment is recovered through depreciation over the useful life of the asset. In this way, costs and benefits are matched over the life of the asset. This treatment is fair to both customers and investors.

Q. HOW DOES PEF PROPOSE TO RECOVER ITS INVESTMENT FOR THE CR3 UPRATES?

A. PEF proposes a depreciation or amortization process. (PEF's response to OPC's 1-4 e).

Q. WHAT INVESTMENT RECOVERY PERIOD IS PEF PROPOSING?

A. PEF proposes to recover its investment over either a 1-year or 10-year assumed life or amortization period. (PEF's response to Interrogatory 12, Attachment 1). I will note that PEF's petition and PEF's testimony did not disclose PEF's intent in this regard.

Q. IS THE COMPANY'S PROPOSED DEPRECIATION OF CAPITAL INVESTMENT REASONABLE OR APPROPRIATE?

A. No. The depreciation proposal does not match costs and benefits over the useful life of the asset and therefore gives rise to intergenerational inequities. The term intergenerational inequity refers to the fact that today's ratepayers would be required to pay for the total cost of the Uprate plant in 1 or 10 years that will provide benefits to current and future ratepayers over the next 29 years. The inequity is that some of today's customers that pay too much will not be around in

15 years and new customers will connect in 15 years that receive the service at no incremental cost. The Company's proposal is unreasonable, goes beyond normal regulatory parameters of matching benefits and costs, and is not consistent with the FERC USOA requirements.

Q. WHAT SPECIFIC ASPECTS OF THE COMPANY'S REQUEST EXCEED REGULATORY PARAMETERS?

A. The most striking overreaching aspect of the Company's request is its proposed 1-year or 10-year depreciation life or amortization period. Normal ratemaking requires the recovery of investment over the useful life of the facility so as to eliminate intergenerational inequity and to comply with the traditional matching principle.

The Company admits that it expects a 20 year license extension for CR3 so that its license will expire in 2036. (Mr. Roderick's Amended Testimony at page 13). Moreover, PEF states that MUR equipment "is designed for the extended life of the plant." (PEF's response to OPC 1-5 a). Therefore, the life expectancy for the MUR will be in 29 years (2036-2008), while later portions of the uprate projects are now expected to have 25-27 year lives (2036-2011 or 2036-2009). Thus, there is no credible basis for the Company's position as it relates to depreciation/amortization of this investment.

Q. HOW IS THIS REQUEST INCONSISTENT WITH THE FERC USOA?

A. The USOA states that depreciation:

> As applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or perspective retirement of electric plant in the course of service and 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, actions of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities. (18 Code of Federal Regulation Part 101 definition 12). (Emphasis added).

If depreciation must capture the loss of service in value in the course of service, than it must do so over the service life of the facility. OPC witness Merchant addresses additional aspects of the FERC USOA requirements.

Q. DOES THE USOA DEFINE AMORTIZATION?

A. Yes. Definition 4 of the USOA states:

> Amortization means the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefits will be realized. (Emphasis added).

Based on these definitions under which PEF must operate, there can be no doubt that its request is inappropriate.

Q. DOES THE COMPANY'S DEPRECIATION PROPOSAL GO BEYOND USOA REQUIEMENTS PREVIOUSLY NOTED?

A. Yes. The USOA General Instructions also demonstrate that the Company's proposal is inconsistent with its requirements. Specifically, General Instruction 22-Depreciation Accounting Subpart A Method states;

> Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property. (Emphasis added).

Further, Subpart B Service Lives states;

> Estimated useful service life of depreciable property must be supported by engineering, economic, or other depreciation studies. (Emphasis added).

Obviously relying on a 1-year or 10-year life when a 25 – 29 year life is expected is neither systematic nor rational. Moreover, there are no engineering, economic, or other depreciation studies provided by the Company that support its over reaching request.

Q. HOW DOES PEF ATTEMPT TO JUSTIFY ITS PROPOSED DEPRECIATION TREATMENT IN LIGHT OF THE USOA REQUIREMENTS?

A. PEF claims that it is only recovering costs annually at a level no greater than its expected fuel savings. (PEF's response to OPC 1.5 b). Thus, PEF appears to propose accumulating all costs in aggregate and then comparing such costs to calculated savings. By employing this "lump sum" comparison approach, it appears that PEF is attempting to mask its inconsistent treatment of the USOA depreciation/amortization requirements rather than comply with acceptable standards.

Q. DOES PEF'S "LUMP SUM" APPROACH CURE THE MATCHING PROBLEM CREATED BY ITS REQUEST?

A. No. Artificially increasing an annual cost (i.e., depreciation/amortization) by employing an admittedly short life span for the investment only creates intergenerational inequities and violates the standard matching principle. The "lump sum" approach only attempts to hide such problem rather than curing the problem. Therefore, even if the Commission were to approve PEF's overall approach it would still need to adjust the annual cost level to comply with acceptable ratemaking and accounting standards.

Q. IS PEF'S PROPOSAL A FORM OF ACCELERATED DEPRECIATION?

A. Yes.

Q. HAS PEF JUSTIFIED THE USE OF ACCELERATED DEPRECIATION OF UPRATE ASSETS FOR RATEMAKING PURPOSES?

A. No, PEF has not justified a departure from the principle that benefits and costs should be matched over the useful life of the assets.

Q. IS THERE ANY REASON TO ACCEPT PEF'S PROPOSAL AS IT RELATES TO THE RECOVERY OF ITS INVESTMENT?

A. No. PEF's ill conceived investment recovery proposal must be rejected.

B. <u>Accumulated Deferred Income Taxes</u>

Q. DOES THE COMPANY'S PROPOSAL TO COLLECT THE UPRATE COSTS THROUGH THE FUEL CLAUSE OVER A ONE OR TEN-YEAR

TIME HORIZON HAVE A DETRIMENTAL IMPACT ON CUSTOMERS IN THE FORM OF INCOME TAX CONSIDERATIONS?

A. Yes, by denying to customers the benefits of deferred income taxes. In the early years of an asset investment life, accelerated tax depreciation is higher than straight line book depreciation. This accelerated depreciation creates more deductible expense, resulting in lower taxable income and lower current income taxes payable. But, in later years of an asset life, after accelerated depreciation reaches zero (the asset is fully depreciated for tax purposes) the book depreciation exceeds tax depreciation, causing more income (less expense) and more taxes payable to the government.

The difference between taxes actually paid and customer rate reimbursements is what is referred to as a deferred tax. It is only a deferred tax because, at some point, the timing difference reverses and tax payments to the government will exceed customer payments for tax expense. While it is a deferred tax, such amount is a cost-free loan from the government to the utility. Deferred taxes are accumulated and recorded on the balance sheet, hence the name "accumulated deferred income taxes". When deferred taxes are recorded, the rate treatment is to reduce invested capital by the amount of the cost-free loan..

Q. PLEASE EXPLAIN HOW THE COMPANY'S PROPOSAL TO EMPLOY A ONE OR TEN-YEAR DEPRECIABLE LIFE FOR BOOK

RATEMAKING PURPOSES DENIES TO CUSTOMERS THE BENEFITS OF DEFERRED TAXES.

A. The tax depreciation life for the uprate Phase 1 & 2 plant is 15 years, while the tax depreciation life for the transmission and POD plant is 20 years. (PEF's response to Interrogatory 12). Under the Company's proposal to shorten the book depreciation life there are no upfront tax benefits, deferred tax balances, to affect investment levels. Rather, the Company's proposal creates an upfront cost to customers and increases revenue requirements.

Q. HAVE YOU QUANTIFIED THE IMPACT ON CUSTOMERS IN TERMS OF INCREASED REVENUE REQUIREMENTS RESULTING FROM THE LOSS OF DEFERRED TAX BENEFITS?

A. Yes. Included in my Exhibit (DJL-2) is an estimate of the deferred tax impact on revenue requirements comparing the Company's proposal to a result that amortizes book depreciation over the expected life of the facilities. Under PEF's proposal, customers would pay about $3.9 million NPV in additional revenue requirements because of the impact of accelerated depreciation on deferred taxes.

C. <u>Cost of Capital Impact</u>

Q. EARLIER YOU STATED THAT THE COMPANY'S PROPOSAL WOULD LEAD TO EXCESSIVE RATES RESULTING FROM THE REQUESTED RETURN ON INVESTMENT. PLEASE

EXPLAIN.

A. The Company has requested an equity return of 11.75% to be earned on investment for the Uprate assets. An equity return includes a risk premium over and above debt costs for the compensation of the risk of not earning the full return. But, in this case, there is no additional risk, as the full amount ultimately authorized will be reconciled and collected through the fuel clause. There is no basis for including an equity return of 11.75% when all the risk has been removed by the fuel clause recovery.

Q. WHAT IS THE IMPACT ON CUSTOMERS RESULTING FROM THE EXCESSIVE EQUITY RETURN?

A. I have included in Exhibit __ (DJL –3) an estimate of the impact of the excessive return included in rates by substituting a debt rate for the 11.75% equity return request. This analysis shows the Company's proposal would result in $54.93 million of excessive revenue requirements on a NPV basis.

Q. FROM A CUSTOMER PERSPECTIVE, IS THE COMPANY'S PROPOSAL TO ACCELERATE RECOVERY OF THE UPRATE COSTS THROUGH THE FUEL CLAUSE FAIR AND REASONABLE?

A. The simple and short answer is no. The Company's proposal allows the Company to collect a majority of costs before customers see one dollar of fuel savings. Customers must wait until 2016 to see fuel benefits of about $19.3 million, but shareholders will have enjoyed about $105 million in increased equity return by that time. The Company collects its investment and shareholder returns quickly while customers must wait until at least 2016 to see any cash flow fuel benefits. I have included a summary of this analysis in my Exhibit ____ (DJL- 4).

As can be seen from Exhibit 4, cumulative fuel savings become a positive $19.28 million in 2016 and equity shareholders have earned over $119 million off this project by 2016. The cumulative fuel savings do not exceed total return until the Company has completely recovered its investment, i.e., after 2021. Given that the project costs are only preliminary estimates, the delay of fuel savings may be even longer.

The above analysis shows the Company receiving a guaranteed return and receiving that return on an accelerated basis. Customers foot the bill and must wait in line behind shareholders to enjoy the benefits of the project. This is not a fair and reasonable proposal to share the risks and benefit of the project.

D. <u>Timing Considerations</u>

Q. HAS PEF RELIED ON INAPPROPRIATE ASSUMPTIONS IN ITS QUANTIFICATION OF COSTS AND NET SAVINGS TO CUSTOMERS?

A. Yes. Not only has the Company front end loaded the cost to customers but it also relied on a requested return level inconsistent with its risk exposure.

Q. WHAT TYPES OF INAPPROPRIATE ASSUMPTIONS HAS THE COMPANY INCORPORATED IN ITS ANALYSIS THAT RESULTS IN FRONT END LOADING OF COSTS?

A. As discussed elsewhere in my testimony, the Company's proposal in the area of depreciation is inequitable and inconsistent with the USOA. However, the Company's revised net savings calculation goes a step further. It now proposes that the MUR related investment be recovered in its first year of operation. In other words, the Company is seeking a 100% depreciation rate for that particular investment. This 100% depreciation rate is requested even though the Company admits that the instrumentation and other costs are designed to last for the remaining 29 year lifespan of CR3. (Mr. Roderick's May 23, 2007 deposition at page 22).

In addition to the one year depreciation assumption for the MUR investment, the Company also assumes a 10-year book depreciation for the remaining CR3 uprate investment. This artificially short capital recovery period is inequitable and is inconsistent with the USOA. Finally, given the timing of the Company's proposed depreciation, there is also a corresponding impact associated with deferred taxes.

The Company's proposed timing of fuel savings, revenue requirements and the resulting net savings are set forth in my Exhibit ___ (DJL-5).

As can be seen from Exhibit 5, the Company has front loaded the revenue requirements over the life of the facility to such an extent that customers during the last 15 years of expected operation (2021-2036) incur basically no revenue requirements. This is inconsistent with the traditional matching principle. In other words, costs and benefits should be aligned.

Q. **GIVEN THE PATTERN OF FUEL SAVINGS AND REVENUE REQUIREMENTS PROPOSED BY PEF, IS THERE ANY CERTAINTY TO ITS OVERALL PROPOSED SAVINGS CALCULATION?**

A. No. As with any estimate or projection, values estimated further out into the future are less reliable. A review of PEF's proposed net savings clearly demonstrates that over the near term planning horizon (2007-2015) when the projected values are probably more accurate, customers receive no net savings, rather they are assigned a net loss associated with the proposed Uprate. In fact, it is not until 2016 that the Company's proposal provides net savings in nominal dollars for customers.

Q. **WHAT CAUSES THIS LEVEL OF NEGATIVE NET SAVINGS?**

A. The front end loading of expenses along with the back end loading of savings dramatically reduces the net present value savings for customers over the entire life but clearly highlights the "softness" in the Company's entire presentation for net savings. In fact, if non-nuclear fuel costs were to decrease during the next decade from the levels projected by PEF, then the level of savings proposed by the Company would shrink, and possibly shrink dramatically. PEF's proposed net savings over the projected life of CR3 do not begin to materialize for at least another 10 years. Moreover, what appears to be significant fuel savings in the future are minimized on a NPV basis. What is certain from the Company's presentation is that it will recover its costs on an accelerated basis compared to traditional ratemaking while customers will be forced to wait for savings that may not come at the proposed level.

Q. DO ADDITIONAL CONSIDERATIONS SUPPORT AVOIDING INTERGENERATIONAL INEQUITIES AND MAINTAINING THE MATCHING PRINCIPLE AS IT RELATES TO THE COMPANY'S PROPOSED DEPRECIATION PRACTICE?

A. Yes. As noted elsewhere in my testimony, the Company admits that it expects the useful life of the investment to be through CR3's license expiration in 2036. Changing the depreciation pattern to be in compliance with traditional rate setting principles and to bring it into compliance with the USOA, not only changes the level of net savings, but more importantly, changes the timing and pattern of the net savings.

The synchronization of the depreciable life with the expected useful life would reduce both the nominal and NPV savings from that proposed by PEF over the entire period. However, the nominal dollar and NPV savings through 2015 would increase. Again, it is worth emphasizing that the accuracy of future projections diminishes as time progresses into the future. Thus, a higher degree of certainty or probability of accuracy should be assigned to the near term calculations and a lower level of accuracy or certainty should be afforded the out or later years in the analysis. Moreover, NPV savings for customers are greater under the standard depreciation approach than under PEF's proposal until the year 2026. Clearly it is unreasonable to select a process that may only become beneficial to customers if values forecasted more than 20 years into the future are accurate.

Q. PLEASE SUMMARIZE THIS PORTION OF YOUR TESTIMONY.

A. There can be no doubt that the Company's proposal in this proceeding is one sided in favor of shareholders in comparison to standard regulatory treatment. The Company's proposal is presented in a format that glosses over the pattern of requested revenue requirements and resulting net savings. Even if one could always rely on the accuracy of forecasts 20 to 30 years into the future, the Company's request is still inequitable and one sided. However, it is simply not realistic or appropriate to rely on savings for customers 20 to 30 years into the future while cost recovery for shareholders are front end loaded during the near term future as proposed by the Company.

SECTION 6: <u>TRANSMISSION AND POD PROPOSALS</u>

Q. IN YOUR OPINION, SHOULD THE POINT OF DISCHARGE (POD) $51 MILLION ESTIMATE BE INCLUDED AS PART OF THE UPGRADE PROJECT AND RECOVERED THROUGH THE FUEL CLAUSE?

A. No. As I understand the Company's analysis, the additional 140 MWe's associated with the extended power uprate will increase the point of discharge temperature and the proposed POD facilities are necessary to reduce the incremental temperature increases to the temperature level prior to the uprate. (Roderick Deposition Testimony at 32: 13-25). The Company has yet to determine the most cost effective option to accomplish the goal of reducing temperature. (Id. At 34: 20-21). Thus, cost estimates and even the preferred option to solve the problem have yet to be determined. Cost estimates are extremely preliminary and may change significantly.

The key basis or reason why the POD facilities should not be included in the fuel clause is that such inclusion is not necessary or reasonable. First, these costs can easily be included in the base rates, as the project will be completed in the 2009-2011 period. Second, the Company has failed to identify a reasonable cost estimate or even the option it will employ to address the POD issues. (Roderick Deposition Testimony 35:5-14). Given the above, by waiting to include these facilities in base rates – the Company will have sufficient time to identify the option and quantify the costs and benefits of such base rate option.

Third, and most important, the POD facilities-- like transmission facilities-- are not facilities that should be recovered through the fuel clause. The proposed POD facilities ("cooling towers") are not fossil-fuel related facilities and the related costs are not volatile.

Q. IN YOUR OPINION SHOULD THE TRANSMISSION UPGRADE INVESTMENT BE INCLUDED AS PART OF THIS UPGRADE PROJECT AND RECOVERED THROUGH THE FUEL CLAUSE?

A. No. The transmission upgrade, which amounts to about $101 million (as updated from $89 million since PEF filed its testimony) of the proposed project cost, is not related to fuel savings. Instead, the transmission investment is necessitated for reliability reasons. Company witness Roderick deposition testimony makes clear that transmission investment is for reliability when he states:

> Q. Bear with me for a moment while I find a reference. You have identified an estimate of $89 million associates with transmission upgrades made necessary by the higher output of the unit, is that correct?
> A. Yes. The transmission upgrades—I'm going to change part of your questions there. It wasn't necessarily due to the output of the unit. It had to do with the unit would not be the largest single load or generator in Florida. And from a transmission standpoint, that change purely due to the power uprate means that we have to have the capability to respond to the loss of that single largest load or single largest generation unit, you know, within the stability of the grid. So those are really more the driving factors of transmission, not just output. (Roderick Deposition 24:14 - 25:5).

The transmission investment is necessary for reliability of the system. The need for transmission reliability investment is collateral to the uprate issue. These transmission investment costs should not qualify for inclusion in the fuel clause.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. There is no good reason to include the Company's proposed Uprate costs in the fuel clause. These estimated costs can be recovered through base rates and the Company will suffer no detrimental impacts. But, as discussed earlier, if the Company's fuel cost proposal is adopted – customers will be unnecessarily, detrimentally impacted in the early years of the Uprate project. Further, shareholders would receive unwarranted benefits under the Company's proposal. All these problems can be cured by including the Uprate costs in base rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

DOCKET NO. 070052-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Direct Testimony of Daniel J. Lawton has been furnished by U.S. Mail on this 19th day of June, 2007, to the following:

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Prior to beginning his own consulting practice, Diversified Utility Consultants, Inc., in 1986, Mr. Lawton had been in the utility consulting business with a national engineering and consulting firm. In addition, Mr. Lawton has been employed as a senior analyst and statistical analyst with the Department of Public Service of Minnesota. Prior to Mr. Lawton's involvement in utility regulation and consulting he taught economics, econometrics, statistics and computer science at Doane College.

Mr. Lawton has conducted numerous financial and cost of capital studies on electric, gas and telephone utilities for various interveners before local, state and federal regulatory bodies. In addition, Mr. Lawton has provided studies, analyses, and expert testimony on statistics, econometrics, accounting, forecasting, and cost of service issues. Other projects in which Mr. Lawton has been involved include rate design and analyses for electric, gas and telephone utilities. Mr. Lawton has developed software systems, databases and management systems for cost of service analyses.

In addition, Mr. Lawton has developed and reviewed numerous forecasts of energy and demand used for utility generation expansion studies as well as municipal financing. Mr. Lawton has represented numerous municipalities as a negotiator in utility related matters. Such negotiations ranged from the settlement of electric rate cases to the negotiation of provisions in purchase power contracts.

A list of cases in which Mr. Lawton has provided testimony is attached.

UTILITY RATE PROCEEDINGS IN WHICH TESTIMONY HAS BEEN PRESENTED BY DANIEL J. LAWTON

JURISDICTION/COMPANY	DOCKET NO.	TESTIMONY TOPIC
ALASKA REGULATORY COMMISSION		
Beluga Pipe Line Company	P-04-81	Cost of Capital
FEDERAL ENERGY REGULATORY COMMISSION		
Alabama Power Company	ER83-369-000	Cost of Capital
Arizona Public Service Company	ER84-450-000	Cost of Capital
Florida Power & Light	EL83-24-000	Cost Allocation, Rate Design
Florida Power & Light	ER84-379-000	Cost of Capital, Rate Design, Cost of Service
Southern California Edison	ER82-427-000	Forecasting
LOUISIANA PUBLIC SERVICE COMMISSION		
Louisiana Power & Light	U-15684	Cost of Capital, Depreciation
Louisiana Power & Light	U-16518	Interim Rate Relief
Louisiana Power & Light	U-16945	Nuclear Prudence, Cost of Service
MINNESOTA PUBLIC UTILITIES COMMISSION		
Continental Telephone	P407/GR-81-700	Cost of Capital
Interstate Power Co.	E001/GR-81-345	Financial
Montana Dakota Utilities	G009/GR-81-448	Financial, Cost of Capital
New ULM Telephone Company	P419/GR81767	Financial
Norman County Telephone	P420/GR-81-230	Rate Design, Cost of Capital
Northern States Power	G002/GR80556	Statistical Forecasting, Cost of Capital
Northwestern Bell	P421/GR80911	Rate Design, Forecasting

NORTH CAROLINA UTILITIES COMMISSION		
North Carolina Natural Gas	G-21, Sub 235	Forecasting, Cost of Capital, Cost of Service
OKLAHOMA PUBLIC SERVICE COMMISSION		
Arkansas Oklahoma Gas Corporation	200300088	Cost of Capital
Public Service Company of Oklahoma	200600285	Cost of Capital
PUBLIC SERVICE COMMISSION OF INDIANA		
Kokomo Gas & Fuel Company	38096	Cost of Capital
PUBLIC UTILITY COMMISSION OF NEVADA		
Nevada Bell	99-9017	Cost of Capital
Nevada Power Company	99-4005	Cost of Capital
Sierra Pacific Power Company	99-4002	Cost of Capital
PUBLIC SERVICE COMMISSION OF UTAH		
PacifiCorp	04-035-42	Cost of Capital
SOUTH CAROLINA PUBLIC SERVICE COMMISSION		
Piedmont Municipal Power	82-352-E	Forecasting
PUBLIC UTILITY COMMISSION OF TEXAS		
Central Power & Light Company	6375	Cost of Capital, Financial Integrity
Central Power & Light Company	9561	Cost of Capital, Revenue Requirements
Central Power & Light Company	7560	Deferred Accounting
Central Power & Light Company	8646	Rate Design, Excess Capacity
Central Power & Light Company	12820	STP Adj. Cost of Capital, Post Test-year adjustments, Rate Case Expenses
Central Power & Light Company	14965	Salary & Wage Exp., Self-Ins. Reserve, Plant Held for Future use, Post Test Year Adjustments, Demand Side Management, Rate Case Exp.
Central Power & Light Company	21528	Securitization of Regulatory Assets
El Paso Electric Company	9945	Cost of Capital, Revenue Requirements, Decommissioning Funding
El Paso Electric Company	12700	Cost of Capital, Rate Moderation Plan, CWIP, Rate Case Expenses

Entergy Gulf States Incorporated	16705	Cost of Service, Rate Base, Revenues, Cost of Capital, Quality of Service
Entergy Gulf States Incorporated	21111	Cost Allocation
Entergy Gulf States Incorporated	21984	Unbundling
Entergy Gulf States Incorporated	22344	Capital Structure
Entergy Gulf States Incorporated	22356	Unbundling
Entergy Gulf States Incorporated	24336	Price to Beat
Gulf States Utilities Company	5560	Cost of Service
Gulf States Utilities Company	6525	Cost of Capital, Financial Integrity
Gulf States Utilities Company	6755/7195	Cost of Service, Cost of Capital, Excess Capacity
Gulf States Utilities Company	8702	Deferred Accounting, Cost of Capital, Cost of Service
Gulf States Utilities Company	10894	Affiliate Transaction
Gulf States Utilities Company	11793	Section 63, Affiliate Transaction
Gulf States Utilities Company	12852	Deferred acctng., self-Ins. reserve, contra AFUDC adj., River Bend Plant specifically assignable to Louisiana, River Bend Decomm., Cost of Capital, Financial Integrity, Cost of Service, Rate Case Expenses
GTE Southwest, Inc.	15332	Rate Case Expenses
Houston Lighting & Power	6765	Forecasting
Houston Lighting & Power	18465	Stranded costs
Lower Colorado River Authority	8400	Debt Service Coverage, Rate Design
Southwestern Electric Power Company	5301	Cost of Service
Southwestern Electric Power Company	4628	Rate Design, Financial Forecasting
Southwestern Electric Power Company	24449	Price to Beat Fuel Factor
Southwestern Bell Telephone Company	8585	Yellow Pages
Southwestern Bell Telephone	18509	Rate Group Re-Classification

Company		
Southwestern Public Service Company	13456	Interruptible Rates
Southwestern Public Service Company	11520	Cost of Capital
Southwestern Public Service Company	14174	Fuel Reconciliation
Southwestern Public Service Company	14499	TUCO Acquisition
Southwestern Public Service Company	19512	Fuel Reconciliation
Texas-New Mexico Power Company	9491	Cost of Capital, Revenue Requirements, Prudence
Texas-New Mexico Power Company	10200	Prudence
Texas-New Mexico Power Company	17751	Rate Case Expenses
Texas-New Mexico Power Company	21112	Acquisition risks/merger benefits
Texas Utilities Electric Company	9300	Cost of Service, Cost of Capital
Texas Utilities Electric Company	11735	Revenue Requirements
TXU Electric Company	21527	Securitization of Regulatory Assets
West Texas Utilities Company	7510	Cost of Capital, Cost of Service
West Texas Utilities Company	13369	Rate Design
RAILROAD COMMISSION OF TEXAS		
Energas Company	5793	Cost of Capital
Energas Company	8205	Cost of Capital
Energas Company	9002-9135	Cost of Capital, Revenues, Allocation
Lone Star Gas Company	8664	Rate Design, Cost of Capital, Accumulated Depr. & DFIT, Rate Case Exp.
Lone Star Gas Company-Transmission	8935	Implementation of Billing Cycle Adjustment
Southern Union Gas Company	6968	Rate Relief
Southern Union Gas Company	8878	Test Year Revenues, Joint and Common Costs
Texas Gas Service Company	9465	Cost of Capital, Cost of Service, Allocation
TXU Lone Star Pipeline	8976	Cost of Capital, Capital Structure
TXU-Gas Distribution	9145-9151	Cost of Capital, Transport Fee, Cost Allocation, Adjustment Clause
TXU-Gas Distribution	9400	Cost of Service, Allocation, Rate Base, Cost of Capital, Rate Design

Westar Transmission Company	4892/5168	Cost of Capital, Cost of Service
Westar Transmission Company	5787	Cost of Capital, Revenue Requirement
TEXAS WATER COMMISSION		
Southern Utilities Company	7371-R	Cost of Capital, Cost of Service
SCOTSBLUFF, NEBRASKA CITY COUNCIL		
K. N. Energy, Inc.		Cost of Capital
HOUSTON CITY COUNCIL		
Houston Lighting & Power Company		Forecasting
PUBLIC UTILITY REGULATION BOARD OF EL PASO, TEXAS		
Southern Union Gas Company		Cost of Capital
DISTRICT COURT CAMERON COUNTY, TEXAS		
City of San Benito, et. al. vs. PGE Gas Transmission et. al.	96-12-7404	Fairness Hearing
DISTRICT COURT HARRIS COUNTY, TEXAS		
City of Wharton, et al vs. Houston Lighting & Power	96-016613	Franchise fees
DISTRICT COURT TRAVIS COUNTY, TEXAS		
City of Round Rock, et al vs. Railroad Commission of Texas et al	GV 304,700	Mandamus

OPC'S QUANTIFICATION OF DEFERRED INCOME TAXES AND REVENUE REQUIREMENTS OF DEFERRED INCOME TAXES DUE TO CORRECTION OF DEPRECIATION TIMING THROUGH 2036

(Millions of Dollars)

Year	PEF Proposed Deferred Tax	Corrected Deferred Tax	PEF Proposed Revenue Req.	Corrected Revenue Req.
	(a)	(b)	(c)	(d)
2006	$0.00	$0.00	$0.00	$0.00
2007	$0.00	$0.00	$0.00	$0.00
2008	$2.39	-$0.04	$0.32	-$0.01
2009	-$1.66	-$1.76	-$0.22	-$0.23
2010	-$0.04	-$2.11	-$0.01	-$0.28
2011	-$3.54	-$6.99	-$0.47	-$0.92
2012	$2.68	-$7.70	$0.35	-$1.02
2013	$4.03	-$6.35	$0.53	-$0.84
2014	$5.24	-$5.14	$0.69	-$0.68
2015	$6.22	-$4.16	$0.82	-$0.55
2016	$7.02	-$3.36	$0.93	-$0.44
2017	$7.51	-$2.87	$0.99	-$0.38
2018	$7.73	-$2.65	$1.02	-$0.35
2019	$7.49	-$2.61	$0.99	-$0.34
2020	$4.35	-$2.61	$0.57	-$0.34
2021	$2.05	-$2.61	$0.27	-$0.34
2022	-$9.44	-$2.61	-$1.24	-$0.34
2023	-$9.36	-$2.54	-$1.24	-$0.33
2024	-$8.28	-$1.45	-$1.09	-$0.19
2025	-$7.27	-$0.44	-$0.96	-$0.06
2026	-$4.98	$1.85	-$0.66	$0.24
2027	-$2.70	$4.13	-$0.36	$0.55
2028	-$2.70	$4.13	-$0.36	$0.55
2029	-$2.70	$4.13	-$0.36	$0.55
2030	-$2.70	$4.13	-$0.36	$0.55
2031	-$1.35	$5.48	-$0.18	$0.72
2032	$0.00	$6.83	$0.00	$0.90
2033	$0.00	$6.83	$0.00	$0.90
2034	$0.00	$6.83	$0.00	$0.90
2035	$0.00	$6.83	$0.00	$0.90
2036	$0.00	$6.83	$0.00	$0.90
Total	$0.00	$0.00	$0.00	$0.00
NPV	$9.68	-$19.83	$1.28	-$2.62
Difference		-$29.50		-$3.89

SOURCES AND REFERENCES

Column (a) : PEF's response to OPC Interrogatory 12 spreadsheet line 95.
Columns (b, d) : OPC's corrected depreciation through 2036.
Column (c) : PEF's response to OPC Interrogatory 12 spreadsheet line 96.
NPV : NPV based on 8.1% as proposed by PEF.

OPC'S QUANTIFICATION OF IMPACT ON NET SAVINGS DUE TO A REDUCED 7.5% OVERALL COST OF CAPITAL

(Millions of Dollars)

		PEF's Proposed		Based On 7.5% ROR	
Year	Fuel Savings	Revenue Requirements	Net Savings	Revenue Requirements	Net Savings
	(a)	(b)	(c)	(d)	(e)
2006	$0.00	$0.00	$0.00	$0.00	$0.00
2007	$0.00	$0.00	$0.00	$0.00	$0.00
2008	$7.91	$7.20	$0.71	$6.87	$1.03
2009	$6.31	$1.47	$4.84	$1.15	$5.16
2010	$20.24	$19.68	$0.56	$19.68	$0.55
2011	$25.87	$31.60	-$5.73	$31.81	-$5.94
2012	$96.63	$97.85	-$1.22	$75.21	$21.42
2013	$85.47	$92.11	-$6.64	$71.90	$13.57
2014	$88.54	$86.44	$2.10	$68.68	$19.86
2015	$84.26	$80.82	$3.44	$65.51	$18.75
2016	$96.31	$75.10	$21.21	$62.26	$34.05
2017	$93.78	$69.43	$24.35	$59.07	$34.70
2018	$96.86	$63.65	$33.22	$55.79	$41.07
2019	$98.99	$57.21	$41.78	$51.86	$47.13
2020	$114.15	$43.69	$70.46	$40.76	$73.39
2021	$104.87	$33.29	$71.58	$32.34	$72.53
2022	$108.42	$0.29	$108.13	$0.83	$107.59
2023	$102.26	$0.30	$101.96	$0.84	$101.43
2024	$113.07	$0.52	$112.55	$0.99	$112.08
2025	$114.07	$0.79	$113.28	$1.20	$112.86
2026	$108.31	$1.04	$107.27	$1.33	$106.98
2027	$108.92	$1.39	$107.53	$1.55	$107.37
2028	$109.49	$1.76	$107.73	$1.59	$107.89
2029	$110.02	$1.48	$108.54	$1.64	$108.38
2030	$110.53	$1.53	$109.00	$1.69	$108.84
2031	$111.01	$1.76	$109.25	$1.83	$109.18
2032	$111.47	$1.98	$109.48	$1.98	$109.48
2033	$111.90	$2.03	$109.87	$2.03	$109.87
2034	$112.32	$2.08	$110.24	$2.08	$110.24
2035	$112.72	$2.13	$110.59	$2.13	$110.59
2036	$113.10	$2.18	$110.92	$2.18	$110.92
Total	$2,677.80	$780.79	$1,897.00	$666.78	$2,011.02
Difference - Nominal					-$114.01
NPV Total	$706.23	$353.61	$352.62	$298.68	$407.55
Difference - NPV					-$54.93

SOURCE AND REFERENCES

Columns (a-c) : PEF's response to OPC Interrogatory 12 spreadsheet.
Column (d & e) : PEF's response to OPC Interrogatory 12 spreadsheet modified to reflect a 7.5% rate of return.
NPV : NPV based on 8.1% as proposed by PEF.

CUSTOMER/SHAREHOLDER CASH FLOW BENEFITS OF UPRATE PROPOSAL FOR THE PERIOD THROUGH 2016

Year	Revenue Requirement	Fuel Savings	Customer Net Savings	Cumulative Net Savings	Equity Return	Cumulative Equity Return
	(a)	(b)	(c)	(d)	(e)	(f)
2008	$7.20	$7.91	$0.71	$0.71	$0.22	$0.22
2009	$1.47	$6.31	$4.84	$5.55	$0.49	$0.72
2010	$19.68	$20.24	$0.56	$6.11	$5.62	$6.34
2011	$31.60	$25.87	-$5.73	$0.38	$8.97	$15.31
2012	$97.85	$96.63	-$1.22	-$0.84	$26.88	$42.19
2013	$92.11	$85.47	-$6.64	-$7.48	$23.87	$66.07
2014	$86.44	$88.54	$2.10	-$5.38	$20.87	$86.94
2015	$80.82	$84.26	$3.44	-$1.94	$17.87	$104.81
2016	$75.10	$96.31	$21.21	$19.27	$14.87	$119.68

SOURCE AND REFERENCES

Columns (a-c)	: PEF's response to OPC Interrogatory 12 spreadsheet.
Column (d)	: Accumulation of Column (c).
Column (e)	: PEF's response to Interrogatory 8 in Docket No. 060642-EI. speadsheet "Debt-Equity Returns" cost of equity divided by grossed up return of 13.19% times average investment in PEF's response to OPC Interrogatory 12 spreadsheet in this case. OPC Interrogatory 12 spreadsheet in this case.
Column (f)	: Accumulation of Column (e).

DOCKET NO. 070052-EI
PEF'S Proposed Timing
Exhibit _________ (DJL-5)
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