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LARRY CRETUL
Speaker of the House of Representatives

February 10, 2010

Ms. Ann Cole, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 090505-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 David E. Dismukes, Ph.D.

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

Sincerely,

Charlie Beck

Charlie Beck
Deputy Public Counsel

Enclosures

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OPC ____
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Review of Replacement Fuel Costs	)	Docket No. 090505-EI
Associated with the February 26, 2008 outage	)	
On Florida Power & Light's electrical system	)	
	)	

DIRECT TESTIMONY

OF

DAVID E. DISMUKES, PH.D.

On Behalf of the Citizens of the State of Florida

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Attorney for the Citizens
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In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage On Florida Power & Light's electrical system	))))	Docket No. 090505-EI

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DIRECT TESTIMONY

OF

DAVID E. DISMUKES, PH.D.

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 090505-EI

I. <u>INTRODUCTION</u>

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana with additional staff in Los Angeles, California, and Fallon, Nevada.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am also a full Professor, Associate Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University. I also hold an appointment as an Adjunct Professor in the E.J. Ourso College of Business

Administration (Department of Economics) and I am a full member of the graduate research faculty at LSU.

Q. HAVE YOU PREPARED ANY ATTACHMENTS TO YOUR TESTIMONY OUTLINING YOUR QUALIFICATIONS IN ENERGY AND REGULATED INDUSTRIES?

A. Yes. Exhibit DED-1 to my testimony provides my academic vita that includes a full listing of my publications, grant research, presentations, and pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. HAVE YOU PREPARED ANY EXHIBITS TO SUPPORT YOUR TESTIMONY?

A. Yes. OPC Exhibits DED-2 through DED-11 were prepared for that purpose.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the Florida Office of Public Counsel ("OPC") on the behalf of the Citizens of the State of Florida ("Citizens") to provide an expert opinion on the net replacement power cost ("net RPC") estimate proposed by Florida Power & Light Company ("FPL" or "the Company"). The Company has offered this net RPC estimate in order to credit ratepayers for the loss of load event in Florida on February 26, 2008, referred to as the "Florida Blackout" by the Federal Energy Regulatory Commission ("FERC").[1] My expert testimony: (1) offers an opinion on the merits of FPL's proposal; (2) provides a series of alternative net RPC credit calculations including an alternative RPC recommendation for the Commission's consideration;

[1] Federal Energy Regulatory Commission, Docket No. IN08-5-000, Order No. 129, FERC Stats. & Regs. 61,016 (October 8, 2009). *Order Approving Stipulation and Consent Agreement*, at paragraph 1.

and (3) rebuts many of the Company's policy rationales for proposing a significantly reduced net RPC credit to FPL's ratepayers.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Background on the Florida Blackout
- Section IV: Overview of the Company's Proposals
- Section V: Alternative RPC Calculation and Recommendation
- Section VI: FPL's Proposals Are Not Consistent with Sound Economic Principles and Regulatory Practices
- Section VII: Conclusions and Recommendations

II. SUMMARY OF RECOMMENDATIONS

Q. WHAT ARE YOUR GENERAL RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED RPC?

A. I recommend the Commission reject the Company's proposed net RPC credit and accept the $15,974,055 credit I have offered in my direct testimony. The Company's proposal does not reflect the true replacement cost of energy associated with the transmission-created outages of February 2008 and simply represents a transfer of wealth from ratepayers to the Company and its shareholders. The Commission should also reject the policy arguments offered by the Company as support for its proposed RPC credit. Having ratepayers subsidize FPL's replacement costs would have little to no effect on any decision to invest in new nuclear, solar, wind, and energy efficiency resources given other issues that are (1) beyond the scope of this proceeding and (2) overwhelmingly more significant than the net RPC credit due to ratepayers from the February 2008 outages. Accepting the Company's net RPC proposal places the Commission in the position of setting a policy precedent that would significantly deviate from sound economic principles and traditional regulatory practices.

III. BACKGROUND ON THE FLORIDA BLACKOUT

Q. WOULD YOU BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE FLORIDA BLACKOUT?

A. Yes. On February 26, 2008, portions of the lower two-thirds of the Bulk Electric System ("BES") in peninsular Florida experienced a loss of electrical service. The event led to the loss of 22 transmission lines, 4,300 megawatts ("MWs") of generation capacity, and 3,750 MW of customer load. According to the FERC, approximately 596,000 FPL customer accounts and 354,000 non-FPL customer accounts were out of service.[2]

Q. WAS THIS EVENT INVESTIGATED BY REGIONAL AND NATIONAL RELIABILITY ADMINISTRATORS?

A. Yes, it is my understanding that this outage was investigated by the Florida Reliability Coordinating Counsel ("FRCC"), a not-for-profit company incorporated in Florida that serves as the "Regional Entity" responsible for, among other things, proposing and enforcing "Reliability Standards" within its region (peninsular

[2] Federal Energy Regulatory Commission, Docket No. IN08-5-000, Order No. 129, FERC Stats. & Regs. 61,016 (October 8, 2009). *Order Approving Stipulation and Consent Agreement*, Stipulation and Consent Agreement at paragraph 2.

Florida).[3] The outage was also investigated by the North American Electric Reliability Corporation ("NERC"), a reliability organization responsible for the development and enforcement of national reliability standards as required by Section 215 of the Federal Power Act ("FPA").[4]

Q. WAS THIS EVENT ALSO INVESTIGATED BY THE FERC?

A. Yes, on March 19, 2008, FERC authorized the Office of Enforcement to conduct an investigation of the outage. According to the FERC Stipulation Order, both the FERC Enforcement Division and the NERC alleged that FPL violated Reliability Standards across a number of different reliability areas.[5] The FERC Stipulation, which provides a more detailed background concerning the blackout, is attached as Exhibit DED-2.

Q. DID THE FERC STIPULATION ADDRESS THE NET REPLACEMENT POWER COSTS RELATED TO THE BLACKOUT?

A. No.

Q. WHAT ARE THE ORIGINS OF THIS DOCKET BEFORE THE FLORIDA COMMISSION?

A. Issues regarding a potential ratepayer refund for the net RPC associated with the February 2008 outage were originally raised in the Company's 2009 fuel and

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[3] See https://www.frcc.com/default.aspx

[4] Federal Energy Regulatory Commission, Docket No. RR06-1-000, *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing.* Issued July 20, 2006.

[5] Federal Energy Regulatory Commission, Docket No. IN08-5-000, Order No. 129, FERC Stats. & Regs. 61,016 (October 8, 2009). *Order Approving Stipulation and Consent Agreement*, Stipulation and Consent Agreement at paragraph 22.

purchased power cost recovery proceeding (Docket No. 090001-EI). The Company and OPC agreed to defer the issue to the 2010 fuel and purchased power cost recovery proceeding. However, on October 30, 2009, the Prehearing Officer in Docket No. 090001-EI directed the RPC issue to be "spun-out and addressed in a separate proceeding as early as practicable in [the] 2010 calendar year."[6] This docket was established on November 9, 2009 to satisfy the requirements of the Prehearing Officer's Order.[7]

Q. WOULD YOU PLEASE EXPLAIN THE STIPULATION APPROVED BY THE COMMISSION IN THIS PROCEEDING?

A. On December 16, 2009, FPL filed a Proposed Resolution of Issues ("PRI" or "Resolution"). The PRI was also signed by the OPC and the Attorney General. The PRI sought Commission approval of a resolution agreeing that FPL should bear the cost of replacement power attributable to the outage. The Commission approved this Resolution on January 26, 2010.[8] A copy of the resolution has been provided as Exhibit DED-3.

Q. WHAT, IN YOUR OPINION, IS THE PURPOSE OF THE CURRENT PROCEEDING?

A. Two primary purposes of this proceeding are: (1) to determine the appropriate measure of the net RPC credit, and (2) to determine the appropriate method to credit

[6] In re: Fuel and purchased power; cost recovery clause with generating performance incentive factor; Docket No. 090001-EI; Order No. PSC-09-0723-PHO-EI; Florida Public Service Commission; October 30, 2009, Issued.

[7] Memorandum from Division of Regulatory Analysis; Division of Economic Regulation; and Office of the General Counsel to Office of Commission Clerk (Cole). Re: Docket No. 090505-EI; Agenda: 1/26/10 – Regular Agenda – Decision on Stipulation Prior to Hearing – Interested Persons May Participate. January 13, 2010. See http://www.psc.state.fl.us/library/filings/10/00313-10/00313-10.pdf

[8] Florida Public Service Commission, Docket 090505-EI, Vote Sheet, January 26, 2010. See http://www.psc.state.fl.us/library/filings/10/00592-10/00592-10.pdf

customers for the replacement power costs associated with the February 2008 outages.

IV. OVERVIEW OF THE COMPANY'S PROPOSALS

Q. WOULD YOU PLEASE DISCUSS THE COMPANY'S RPC PROPOSAL?

A. The Company has estimated and recommended a RPC credit of $2,024,035.[9] This proposed net RPC ratepayer credit represents the amount FPL believes is appropriate to credit to its ratepayers for the Florida Blackout.

Q. IS THE NET RPC CREDIT BASED UPON THE TRUE REPLACEMENT COST?

A. No, and even the Company appears to recognizes that its methodology is not based on the true cost of replacing the nuclear power generation that was tripped as a result of the outage.[10] Instead, the Company has discounted its net RPC credit by using a modified system average generation cost instead of the avoided cost of nuclear generation displaced by the February 2008 outages. This simple fact alone should stand as an immediate basis for rejecting the Company's proposal. Its net RPC credit is not based upon the true replacement cost of power and, from a policy analysis perspective, does not reflect the prudently-avoided nuclear power costs.

Q. ON WHAT BASIS DOES THE COMPANY JUSTIFY ITS RPC CREDIT PROPOSAL?

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[9] In Re: Review of replacement fuel costs associated with the February 26, 2008 outage on Florida Power & Light's electrical system. Florida Public Service Commission; Docket No. 090505-EI; Florida Power & Light Company's Petition to Approve Appropriate Amount of Credit to Customer Bills; January 13, 2010.

[10] Testimony of Gerard J. Yupp, 5:9-14.

A. The Company's justifications for its RPC credit are based upon two policy arguments: (1) that assessing the RPC credit on the true avoided cost of the outage (nuclear generation) would be "unfair;"[11] and (2) that assessing the RPC credit on the true cost of avoided power would create disincentives for future resource development.[12] Both arguments are entirely without merit from the perspective of what the Company refers to as "sound economic principles" as well as traditional "regulatory policy."[13] The later portions of my testimony will discuss the economic and policy shortcomings of the Company's proposal. Initially, I discuss the mechanics of the Company's net RPC calculation and how that calculation can be corrected in order to apply an appropriate net RPC credit to FPL's ratepayers.

Q. CAN YOU PLEASE EXPLAIN HOW AN APPROPRIATE NET RPC COST CREDIT SHOULD BE DEVELOPED BEFORE DISCUSSING THE COMPANY'S METHODOLOGY?

A. Yes and I have also outlined the various steps needed to undertake this calculation in Exhibit DED-4. Assume a hypothetical nuclear power plant, with a capacity rating of 1,000 megawatts ("MW"), a variable fuel cost of $5 per megwatthour ("MWh"), and an outage that lasts for 100 hours. The energy production lost from this outage is simply the product of the capacity and the hours, leading to a total lost generation amount of 100,000 MWhs. Assume that 100 percent of this lost energy is purchased from the wholesale power market at a cost of $100/MWh. The total cost of the outage is $10,000,000. However, the nuclear unit avoided its own fuel costs by being out for 100 hours. The variable fuel cost avoided from this outage is the lost

[11] Testimony of William E. Avera, 4:15-17.
[12] ibid.
[13] Testimony of William E. Avera, 4:11-15.

generation (100,000 MWhs) times the variable fuel costs of \$5/MWh resulting in a total avoided fuel cost of \$500,000. The net replacement cost is the total replacement cost (wholesale power purchases of \$10,000,000) less the costs avoided by the outage (\$500,000). Thus, in this example, net replacement costs are \$9,500,000.

Q. NOW, CAN YOU PLEASE EXPLAIN THE MECHANICS OF THE COMPANY'S NET RPC CREDIT?

A. Yes. The Company limits its calculations to an eight-hour period, even though the Turkey Point 3 and Turkey Point 4 nuclear units were out of service for a longer period. Turkey Point Unit 3 was offline for 158 hours, and Turkey point Unit 4 was offline for 107 hours. The Company calculates net RPC using two components. The first component estimates the "replacement fuel that was required to off-set the loss of generation that occurred as a result of the event."[14] This calculation is based on the increased cost associated with running four different peaking units for an eight-hour period during the outage and does not account for the increased cost of other generating resources. The second component of the RPC calculation sums the off-system power purchases that the Company executed in the eight-hour period immediately following the event.[15]

Q. CAN YOU EXPLAIN IN GREATER DETAIL HOW THE COMPANY ESTIMATED THE TOTAL PEAK GENERATION COSTS ASSOCIATED WITH THE OUTAGE?

[14] Testimony of Gerard J. Yupp, 2:6-7.
[15] Testimony of Gerard J. Yupp, 2:8-9.

A. The Company utilized generation, heat rate, and fuel use information from its February 2008 A4 Schedule to estimate the unit-specific costs of generating electricity from four peaking units over an eight-hour period. The estimated peak production costs are simply the sum of each peaking units' fuel cost over the period in question. The Company estimates total peaking generation costs of $1,992,270, or $174.30/MWh. A breakdown of this calculation has been provided in Exhibit DED-5.

Q. HOW WERE THE PURCHASED POWER COSTS CALCULATED?

A. FPL reports that it made 5,214 MWhs of off-system purchases during the outage. The total cost of this purchased power was $885,935.19 or $169.91/MWh.[16]

Q. DID THE COMPANY ADJUST THESE COSTS IN ANY WAY?

A. Yes. As I noted in my earlier hypothetical example, total replacement costs associated with an outage are typically adjusted to account for the costs that were avoided as a result of generation outage. Avoided costs should be the variable nuclear fuel costs that are not incurred since the nuclear plant in question did not generate electricity. The Company's approach differs from my earlier hypothetical since it reduces total replacement costs by an adjusted version of its own system average generation costs during what it defines as the relevant time period of the outage. However, as I noted in my introductory comments, this calculation is not based upon the true avoided (or non-incurred) cost of nuclear generation, but on an adjusted system average cost. The use of this adjusted system average costs reduces the overall credit due to ratepayers since the system average (which includes more

[16] Testimony of Gerard J. Yupp, Exhibit GJY-9.

expensive natural gas and oil fuel costs) is higher than the average fuel costs for nuclear power.

Q. HOW CAN AN ADJUSTED SYSTEM AVERAGE COST RESULT IN A LOWER RPC CREDIT THAN THE USE OF AVERAGE NUCLEAR FUEL COSTS?

A. Assume, for simplicity, a total replacement cost of $100/MWh. Now also assume a system average fuel cost of $50/MWh and an average nuclear fuel cost of $5/MWh. Assume we are replacing one MWh. Then the net total replacement cost under the traditional approach would be $95 ($100/MWh - $5/MWh times 1 MWh). Under the Company's approach, the net total replacement cost in this hypothetical would be $50 ($100/MWh - $50/MWh times 1 MWh). By using the adjusted system average cost, rather than the true cost of generation avoided (nuclear), the Company's approach significantly reduces the credit due to ratepayers.

Q. PLEASE EXPLAIN HOW THE NET PEAKING PRODUCTION COSTS WERE ESTIMATED.

A. The average peaking RPC rate was estimated to be $174.30/MWh. The Company subtracted its adjusted system average cost of $51.32/MWh from the average peaking RPC rate, rather than the average nuclear fuel cost of $4.4/MWh to arrive at a net RPC rate of $122.98/MWh. The net peak RPC rate was multiplied by the lost generation associated with the Company's recommended outage duration period (11,430 MWhs) to arrive at a total net peaking RPC of $1,405,682. As I noted earlier, the Company uses an adjusted system average fuel cost ($51.32/MWh) as opposed to the average nuclear fuel cost of $4.5/MWh. This step significantly reduces the RPC credit due to FPL's ratepayers.

Q. HOW WERE OFF-SYSTEM REPLACEMENT PURCHASES ADJUSTED?

A. The Company simply takes the average purchased power RPC rate of $169.91/MWh and subtracts the adjusted system average rate ($51.32) to arrive at a net average purchased power RPC rate of $118.59. This, multiplied by the total off-system purchase energy (5,214 MWh), leads to a total net purchased power RPC of $618,353. Again, the Company subtracts an unnecessarily high adjusted system average cost rate ($51.32/MWh) as opposed to the average nuclear fuel cost rate of $4.4/MWh, in order to determine the net replacement cost associated with purchased power.

Q. HAVE YOU PREPARED A SCHEMATIC THAT HELPS ILLUSTRATE HOW THESE CALCULATIONS WORK?

A. Yes, Exhibit DED-6 provides a graphical illustration of how the Company's replacement cost estimation approach works. The vertical axis on this chart represents the average costs ($/MWh), while the horizontal axis represents total generation and purchased power (or system supply). The line labeled "a" is the Company's estimated adjusted system average cost ($51.32/MWh). If the outage had not occurred, the Company estimates that it could have generated 6,701,778 MWhs of electricity at an average cost of $51.32/MWh. This, however, did not occur, and the outage put the Company in the position of having to (a) increase its own generation and (b) purchase power from the wholesale market. The Company's estimated net purchased power costs are represented by the shaded area labeled "C" and the net peaking costs are estimated by the shaded area "D." The Company's net replacement cost estimate is the sum of the area "C" and "D."

Q. CAN YOU EXPLAIN THE SHADED AREA LABELED "C" IN GREATER DETAIL?

A. Yes. This area represents the net cost associated with purchased power requirements created by the outage. Under the Company's approach, the net cost is estimated as the difference between the per-unit cost of purchased power ($169.91/MWh) and the adjusted system average unit cost of ($51.32/MWh) multiplied by the power purchased (5,214 MWh). The total amount results in the Company's net purchased power RPC estimate of $618,353.

Q. CAN YOU EXPLAIN THE SHADED AREA LABELED "D" IN GREATER DETAIL?

A. Yes. This area represents the Company's estimated net peak power replacement costs. These costs are estimated, under the Company's methodology, by taking the difference between the peak generation unit costs ($174.30/MWh) and the adjusted system average cost ($51.32/MWh) and multiplying that difference by the peak generation amount (11,430 MWh) associated with the Company's recommended outage duration of 8 hours. The total net peak power replacement costs estimated using the Company's methodology is $1,405,682.

Q. DOES THIS ILLUSTRATION HIGHLIGHT ANY SHORTCOMINGS IN THE COMPANY'S RPC METHODOLOGY?

A. Yes. The Company RPC misses an entire class of increased costs incurred by ratepayers as a result of the outage: the increased system average cost created by the outage. This shortcoming has been highlighted graphically in greater detail in Exhibit DED-6. The shaded area represented as "B" represents the net increase in non-peaking fuel costs that were created by the outage. Net non-peaking generation costs, can be estimated using an approach similar to that offered by the Company, as the difference between outage-related system average cost ($77.55/MWh) and the adjusted system average with nuclear generation of ($51.32/MWh). This difference, in turn, is multiplied by the non-nuclear replacement generation level (107,311 MWhs) to arrive at a total net non-nuclear replacement cost estimate of $2,814,768. This represents an important conceptual difference in how replacement costs are estimated since the Company incurred additional increased generation costs associated with the outage that go beyond the use of its peaking generators.

Q. ARE THERE ANY DEFICIENCIES WITH THE COMPANY'S RPC METHODOLOGY?

A. Yes. As noted earlier, the Company's approach suffers from two significant conceptual flaws. First, the Company has based its RPC on an outage duration that does not fully represent the total cost imposed on ratepayers by the Florida Blackout. Second, the Company is using an adjusted system average cost that effectively deflates the full refund amount due to ratepayers. The Company justifies both flaws on policy positions that are entirely inconsistent with what it refers to as "sound economic principles" and "regulatory practices." I will discuss these policy inconsistencies in later sections of my testimony. The subsequent section of my testimony, however, provides a number of alternative net RPC calculations, and a recommended net RPC credit of $15,977,050 that more appropriately reflects (1) the true outage duration of the Turkey Point nuclear units and (2) the fuel costs avoided by those units' outage.

V. ALTERNATIVE RPC CALCULATION AND RECOMMENDATION

Q. HAVE YOU PREPARED ANY ALTERNATIVE RPC CALCULATIONS?

A. Yes, I have prepared two different net RPC calculations that correct (1) the Company's inappropriate outage duration and associated replacement generation levels and (2) the actual costs that were avoided as a result of the outage. I am providing these calculations in a cumulative fashion so that the Commission can see the results from the incremental changes in the Company's assumptions. My primary recommendation, however, is that the Commission adopt my second set of calculations as the basis for the net RPC credit.

Q. LET'S DISCUSS THE FIRST SET OF CALCULATIONS. CAN YOU PLEASE EXPLAIN WHY THE COMPANY'S PROPOSED OUTAGE DURATION AND CORRESPONDING REPLACEMENT GENERATION IS INAPPROPRIATE?

A. The Company offers a number of reasons to justify its recommendation that only an eight hour outage duration period should be used to calculate a net RPC credit. These arguments have very little merit, and all fail to address the simple empirical fact that the Turkey Point units were out of service by the transmission outage for a period spanning 158 hours and 107 hours, respectively, not eight.[17] Any replacement cost

[17] Turkey Point Unit 3 was offline for a total of 158 hours and Turkey Point Unit 4 was offline for a total of 107 hours (Testimony of J.A. Stall, 7:6-7).

estimate needs to be based upon the actual hours upon which these nuclear units were off-line. If not for the transmission outage, Turkey Point Units 3 and 4 are likely to not have been abruptly taken off-line during February and early March 2008.[18]

Q. CAN YOU EXPLAIN HOW YOUR FIRST ALTERNATIVE RPC CALCULATION CORRECTS FOR THE DEFICIENCY IN THE COMPANY'S OUTAGE AND REPLACEMENT GENERATION ESTIMATES?

A. Yes. The first step in my alternative net RPC calculation was to separate the total outage duration period into peak replacement generation and non-peak replacement generation components. The total peak replacement generation component was constrained to the eight hours identified by the Company. The total non-peak replacement generation component comprised the balance of the replacement generation which spanned a period across two months including February and March of 2008. Total February non-peak replacement generation is estimated to be 107,311 MWhs and total March non-peak replacement generation is estimated to be 71,270 MWhs. These calculations, and their corresponding amounts, are provided in Exhibit DED-7.

Q. PLEASE EXPLAIN HOW PEAK REPLACEMENT GENERATION COSTS WERE ESTIMATED UNDER YOUR FIRST ALTERNATIVE RPC CALCULATION.

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[18] Turkey Point Unit 4 was scheduled to be out of service for refueling from March 30, 2008 until May 4, 2008. No planned outages were scheduled for Turkey Point Unit 3. See In Re: Levelized Fuel Cost Recovery and Capacity Cost Recovery, Projections January 2008 through December 2008, Florida Public Service Commission, Docket No. 070001-EI, Testimony of Gerard J. Yupp, September 4, 2007.

A. Since peak replacement generation was constrained to an eight-hour period, my alternative total replacement cost estimate is the same as that proposed by the Company and is provided on the first page of Exhibit DED-7.

Q. WHAT SYSTEM AVERAGE COSTS DID YOU UTILIZE IN YOUR FIRST ALTERNATIVE RPC CALCULATIONS?

A. The methodology for estimating these costs is similar to those recommended by the Company; however, it is based upon two months of data (February and March, 2008) rather than one.

Q. HOW DID YOU ESTIMATE NET PEAK REPLACEMENT COSTS?

A. Net peak generation replacement costs were first calculated as the difference between total peak average generation costs ($174.30/MWh) and adjusted system average costs ($51.32/MWh). This difference was then multiplied by a peak generation amount of 11,430 MWhs to arrive at a total net peak replacement cost of $1,389,446 which is provided on the first page of Exhibit DED-7.

Q. HOW DID YOU ESTIMATE TOTAL NON-PEAK REPLACEMENT GENERATION COSTS?

A. These costs were estimated by multiplying the Company's monthly adjusted system average costs ($/MWh) by its corresponding replacement generation amounts. Total non-peak replacement costs for February 2008 are estimated to be $8,322,465 and total non-peak replacement costs for March 2008 are estimated at $5,695,529. These estimates are provided on the second page of Exhibit DED-7.

Q. HOW DID YOU ESTIMATE NET NON-PEAK REPLACEMENT COSTS?

A. Net non-peak generation replacement costs were estimated for both February and March, 2008. The February non-peak replacement generation costs were estimated as the difference between the average cost without solid fuel generation ($77.55/MWh) and the Company's adjusted system average cost ($51.32/MWh). This amount was then multiplied by the February non-peak replacement generation amount (107,311 MWh) to arrive at a total net February non-peak generation replacement cost. A similar calculation was conducted for the outages associated with March 2008. The estimated total net non-peak replacement generation costs of $4,383,296 is provided at the bottom of page 2 of Exhibit DED-7.

Q. DID YOU ESTIMATE NET PURCHASED POWER COSTS?

A Yes, but under my first approach, these costs do not differ from those recommended by the Company.

Q. WHAT ARE THE TOTAL NET REPLACEMENT COSTS ONCE THE COMPANY'S TOTAL OUTAGE DURATION AND GENERATION LEVELS ARE CORRECTED?

A. The last page of Exhibit DED-7 provides an estimate of the total net replacement costs for the actual outage period under the Company's adjusted system average cost approach. The total net replacement costs are $6,384,707 and are based upon the sum of (a) net peak replacement costs of $1,389,446; (b) net non-peak replacement generation costs of $4,383,296; and (c) net purchased power costs of $611,965.

Q. DO YOU BELIEVE THIS IS AN APPROPRIATE REPLACEMENT COST CREDIT FOR RATEPAYERS?

A. No, because the calculations included in Exhibit DED-7 are still based upon the Company's inappropriate use of an adjusted average system. The more appropriate estimate should be based upon the true cost avoided by the outage, which are the Turkey Point-specific fuel costs. The use of an adjusted system average cost, combined with a much shorter outage period, simply reduces the overall net RPC credit due to ratepayers.

Q. HAVE YOU PREPARED A SECOND SET OF CALCULATIONS THAT CORRECTS FOR THE COMPANY'S INAPPROPRIATE USE OF AN ADJUSTED SYSTEM AVERAGE COST?

A. Yes, Exhibit DED-8 provides those estimates and is the approach I recommend the Commission adopt in estimating the net RPC credit for FPL's ratepayers. The approach utilized in these estimates is similar to my prior discussion since it includes a corrected outage duration period and replacement generation levels. The only significant difference between my recommended approach, and those discussed earlier, is that Turkey Point-specific fuel cost (roughly $4.5/MWh) have been used to estimate net replacement cost impacts, not the adjusted system average. Turkey Point-specific costs are the appropriate avoided costs to utilize in developing a replacement cost estimate since the Company was avoiding nuclear fuel costs, not adjusted system average costs, during the course of the Blackout. Making this correction yields a total net replacement cost estimate of $15,974,055 and is the sum of (a) net peak replacement generation costs of $1,938,577; (b) net non-peak replacement generation costs of $13,173,954; and (c) net purchased power replacement costs of $861,525.

Q. ARE YOUR ESTIMATES SIMILAR TO ANY CALCULATIONS PREPARED BY THE COMPANY IN DEVELOPING ITS OWN REPLACEMENT COST ESTIMATES?

A. Yes and I have provided a copy of these estimates in Exhibit DED-9. An important difference in the calculations included in these estimates, and those provided in the Company's Application and Direct Testimony, is that the "fuel costs not incurred" as a result of the outage are based upon the Turkey Point 3 and 4 fuel costs and not a modified system average cost that includes nuclear power generation. This is a more appropriate method to calculate the replacement costs associated with the February 2008 outage and consistent with the recommended calculations I discussed above.

Q. WHAT IS YOUR RECOMMENDED REPLACEMENT COST CREDIT?

A. I recommend that the Commission direct the Company to credit its ratepayers an amount of $15,974,055, as well as interest on this amount as allowed under Rule 25-6.109(4), Florida Administrative Code.

VI. FPL'S PROPOSALS ARE NOT CONSISTENT WITH SOUND ECONOMIC PRINCIPLES AND REGULATORY PRACTICES

Q. CAN YOU PLEASE EXPLAIN THE COMPANY'S POSITION THAT IT'S RECOMMENDATIONS ARE BASED UPON SOUND ECONOMIC PRINCIPLES?

A. No, because while the Company has made this assertion in a number of places in its filing,[19] it has failed to identify the specific economic principles that support its recommendations, how the various aspects of its proposals are consistent with those principles, nor any economic literature that is remotely supportive of its proposed net RPC credit. There are no sound economic principles nor good regulatory policies that would support the Company's proposal to transfer close to $14 million in consumer wealth to itself and its shareholders.

Q. ARE THERE ANY SOUND ECONOMIC PRINCIPLES OR THEORIES THAT WOULD REFUTE THE COMPANY'S PROPOSALS?

A. Yes. In particular, the Company's proposals are entirely inconsistent with the efficiency principles of setting prices at levels that reflect the true opportunity cost of making a decision. The Company's proposals are also entirely inconsistent with the efficiency principles of general equilibrium theory and the role of moral hazard in reducing societal welfare.

Q. LET'S TALK ABOUT THE FIRST ECONOMIC PRINCIPLE YOU DISCUSS. CAN YOU EXPLAIN HOW THE COMPANY'S PROPOSALS WILL RESULT IN AN ECONOMIC INEFFICIENCY?

A. Markets are said to be efficient when the price of a particular good or service is equal to the marginal cost of producing that good or service. Opportunity costs underlie this basic definition of marginal costs since they define what is given up in order to produce the next increment of a good or service. Market inefficiencies are said to arise when prices depart from the marginal (opportunity) costs. The Company's

[19] See Testimony of William E. Avera, 4:11-15 and 4:22-23.

proposal would effectively set prices (or a refund) at levels that do not match the true opportunity costs of power generation forgone by the February 2008 outages. The source of this inefficiency is twofold since the Company's proposal departs from an efficient outcome in both the "rate" used to estimate the refund amount, and the "level" of the forgone output used to estimate the refund.

Q. WHAT DO YOU MEAN BY THE "RATE" AT WHICH THE COMPANY IS PROPOSING TO ESTABLISH A REPLACEMENT COST REFUND?

A. The "rate," in this discussion, can be generalized as the replacement cost rate used to establish a refund amount. Rather than examining the actual replacement cost against the actual generation costs that were avoided (nuclear generation), the Company is proposing to evaluate those costs against an adjusted system average cost. In other words, the Company uses an average cost, to establish a refund that should be based upon marginal costs. This is inefficient since marginal and average costs differ, and differ significantly from one another: roughly \$51/MWh on an average cost basis versus \$5/MWh on a marginal cost basis. As a result, the Company's proposal fails a primary efficiency standard posited in basic economics that ties the marginal rate of technical substitution to marginal costs.[20]

Q. WHAT DO YOU MEAN BY THE "LEVEL" ON WHICH THE COMPANY HAS SET ITS REFUND?

A. The Company's proposals are also based upon an incorrect level of output that was avoided as a consequence of the outage. The Company proposes to reduce its overall

[20] While ratepayers tend to be billed an average monthly fuel rate (and cost), this rate will be biased upwards under an inappropriately set RPC credit.

refund amount to the energy avoided with only an eight-hour period, not the full outage period of 158 hours for Turkey Point Unit 3 and 107 hours for Turkey Point Unit 4.[21]

Q. HOW DOES THIS NOTION OF OPPORTUNITY COSTS RELATE TO POWER GENERATION AND THE LEVEL AT WHICH AN APPROPRIATE RPC CREDIT SHOULD BE SET?

A. Opportunity costs are defined as the next best option that is forgone by undertaking a particular activity. In the case of power generation, utilities can generate electricity through either nuclear or fossil fuel based resources. When utilities generate electricity with nuclear power they are forgoing the opportunity to generate that same electricity with another technological option like fossil fuel. Likewise, when a nuclear unit is unexpectedly taken off-line, fossil fuel generation has to increase in order to replace the forgone nuclear power. The regulatory process attempts to set rates that reflect those trade-offs. Inefficiencies are said to arise to the extent that prices are not set in a fashion that reflect the relative costs of producing from the two generation technologies (i.e., nuclear, fossil). If the regulatory goal associated with an outage is to make ratepayers whole for the outage, relative prices will need to be balanced, through a refund (transfer), in order to maintain non-outage consumption levels. If the refund is too low, relative prices will increase, and consumption will have to fall relative to non-outage levels, and ratepayers will be worse off. Alternatively, if the refund is too high, consumption will increase relative to non-outage levels, and ratepayers will be made more than whole.

[21] Testimony of J.A. Stall, 7:6-7

Q. WHAT ARE THE ECONOMIC IMPLICATIONS OF THE COMPANY'S PROPOSAL?

A. The Company's proposal would set the refund level at a level too low to make ratepayers whole for the outage related costs since, as I noted earlier, the proposed refund does not reflect the true marginal cost of the outage. The effective prices paid by ratepayers (actual rates less the refund) are likely to be higher resulting in a reduced level of consumption and lower consumer welfare. The Company's proposal would effectively transfer wealth away from customers and to shareholders. Such an outcome is not only inequitable, it is simply inefficient, and entirely inconsistent with "sound economic principles."

Q. LET'S TALK ABOUT THE SECOND ECONOMIC PRINCIPLE YOU MENTIONED EARLIER. WHAT IS MORAL HAZARD?

A. Moral hazard is said to occur in instances where an economic agent facing a certain degree of risk behaves differently when it is insulated from that risk than it would if the risk were not insured.[22] Moral hazard is, in effect, the behavioral difference that results from the presence or introduction of insurance. Moral hazard results in a "market failure" or inefficiency because the agent receiving the insurance does not have to bear the full responsibility for its actions. As Bonbright, et.al. notes:

> A moral hazard is involved when someone other than the purchaser pays for the purchase and hence the purchaser acts, unconstrained by ethics or other institutions, as if there is no resource cost on society from his or her purchases. In other words, moral hazard increases the risk of an event turning out favorably because there may be positive rewards or at least insufficient penalties for opportunistic behavior.[23]

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[22] W. Nicholson. *Intermediate Microeconomics and Its Applications*. 5th Edition. (1990) Chicago: Dryden Press, 695.

[23] J. Bonbright, A. Danielsen, and D. Kamerschen. (1988) *Principles of Public Utility Rates*. Arlington, VA: Public Utility Reports, 138.

Q. ARE THERE ANY RECENT EXAMPLES OF MORAL HAZARD PROBLEMS ARISING IN PUBLIC POLICY?

A. Yes. One good example is the recent banking and financial crisis that led to policies bailing out banks and other financial institutions that were considered "too big to fail." Many financial institutions were given billions of dollars in bail-outs and other forms of financial support to buttress their financial positions devastated by past risky lending actions. Some analysts have argued that these policy actions have done nothing to correct the underlying problem leading to the 2009 financial crisis and in fact, in the long run, may have exacerbated these problems since in the future, banks may use this policy precedent as support for future rescue actions from continued risky practices.[24]

Q. HOW DOES MORAL HAZARD RELATE TO THE COMPANY'S PROPOSAL?

A. The Company's proposals, if adopted, could lead to an opportunity for moral hazard, because it would establish a regulatory precedent that clearly reduces the opportunity cost of outcomes the regulatory process seeks to avoid. If regulated utilities know that the economic consequences of these negative outcomes are not valued at their true costs, it will reduce incentives to avoid actions leading to those negative outcomes. The Company proposes that the Commission reduce the overall refund due to ratepayers in order to avoid creating a potential disincentive to future nuclear, solar, wind, and energy efficiency resource development. Even if the Commission

[24] Wilson, L. and Wu, Y. Common (stock) Sense About Risk-Shifting and Bank Bailouts. *Financial Markets and Portfolio Management*, Forthcoming; Hakenes, H. and Schnabel, I. Banks Without Parachutes: Competitive Effects of Government Bail-Out Policies. *Journal of Financial Stability.* May 21, 2009; and Helwege, J. Financial Firm Bankruptcy and Systemic Risk. *Journal of International Financial Markets, Institutions & Money.* November 14, 2009.

accepted the Company's arguments, it runs the very clear risk of avoiding one type of disincentive by creating another. The efficient policy choice, *in this instance*, would be to adopt policies that eliminate disincentives for operating known and existing assets over a policy that may reduce the disincentive of an unknown, speculative, and yet to be identified resource investment in the future. Therefore, the Commission should reject the Company's proposals and set an RPC refund at the true value of February 2008 outages.

VII. RPC CREDIT AND GENERATION INCENTIVES

Q. WOULD YOU PLEASE EXPLAIN THE COMPANY'S ASSERTIONS REGARDING POWER COST RECOVERY AND GENERATION INCENTIVES?

A. Yes. The Company's RPC refund proposal is justified, in part, on the faulty and one-sided premise that "FPL recovers power costs without profit"[25] and "100 percent of the benefits of the low nuclear fuel costs (units) are passed along to FPL's customers."[26] According to the Company, it would be "unfair" to credit ratepayers for the full cost of the outage since ratepayers have received all of the benefits of nuclear power.[27] This assertion biases and mischaracterizes how nuclear power costs, as well as other generation-related costs, are recovered from ratepayers.

Q. CAN YOU PLEASE EXPLAIN HOW THE COMPANY'S ASSERTION MISCHARACTERIZES GENERATION COST RECOVERY?

[25] Testimony of William E. Avera, 4:13.
[26] Testimony of William E. Avera, 5:6-7.
[27] Testimony of William E. Avera, 4:15-23 and 5:1-2.

A. Yes. Power generation facilities are developed, and eventually run, with a variety of inputs that includes capital, labor, materials, and fuel. Prior to the energy crisis of the 1970s, many states required utilities to recover all of their costs of generation (capital, labor, materials, and fuel) through base rates. The energy crises of the 1970s, and its corresponding increase in fossil fuel prices, led many regulatory commissions to change their cost recovery practices by adopting Fuel Adjustment Clauses ("FACs"). This process bifurcated the generation cost recovery process into two parts with variable fuel-related expenses being recovered through the FAC, and the remaining costs (capital, labor and other operating costs) to be recovered in base rates. Thus, low fuel cost/high capital cost assets, like nuclear power, tend to have their low fuel costs recovered through FACs while their relatively higher capital costs are paid through base rates. So whatever gains are made from lower FACs tend to be offset by higher base rates, and vice versa.

Q. DO FPL'S RATEPAYERS MAKE CONTRIBUTIONS IN THEIR BASE RATES TO THESE LOW FUEL COST RESOURCES?

A. Yes, and as shown in Exhibit DED-10, FPL's customers pay (on average, total customers) a considerable amount in base rates relative to other peer utilities. So it is difficult to suggest that FPL's customers do not also make sizable contributions for these low fuel cost (and higher capital cost) assets. While it is true that fuel expenses generally do not earn an allowed rate of return: they typically never did prior to the advent of FACs. The capital investments included in base rates, however, have, and still do have, the opportunity to earn an allowed rate of return. This allowed rate of return is the benefit a utility and its shareholders attain for having invested in generation to serve ratepayers. Thus, to assert, or to suggest, that ratepayers have received all of the benefits from nuclear power, without clearly recognizing the obvious benefits received by the utility and its shareholders through ratepayer contributions in base rates, is biased and one-sided at best.

Q. HOW LARGE ARE THESE POTENTIAL BENEFITS?

A. For the past 37 years, the Company has had the opportunity to earn a significant return on, and a significant return of, its Turkey Point nuclear investments. Assuming a 10 percent allowed return, the Company has earned as an estimated return on, and estimated return of, the Turkey Point units of $4.7 billion. This pales in comparison to an appropriately constructed RPC credit of approximately $15.9 million, and still fails to consider the ongoing future returns the Company and its shareholders will receive as long as the units remain operational.

Q. ARE FUEL ADJUSTMENT CLAUSES DEVELOPED TO PROVIDE GUARANTEED COST RECOVERY?

A. No, and establishing an appropriately-determined RPC does not deprive FPL recovery of its prudently-incurred fuel costs and would not constitute a change in the policy balance underlying most FACs. This policy balance insulates utilities from fuel cost volatility by creating a frequent fuel cost collection and true-up process. This is a significant benefit to utilities in today's markets that can see natural gas prices swing from as high as $13/MMBtu to as low as $3/MMBtu in a matter of less than one year. In return, utilities are allowed to recover prudently-incurred fuel costs. FACs are not a one-sided process with all benefits going to ratepayers and none for utilities and its shareholders. If there are any asymmetries in the process, then they are likely levied against ratepayers since the applied and academic literature on FACs have recognized many of their deficiencies.[28] A recent report on cost trackers by the National Regulatory Research Institute ("NRRI"), for instance, notes:

> Cost trackers, in various ways, can result in higher utility costs. First, they mitigate the positive effects of regulatory lag on a utility's costs. Regulatory lag refers to the time gap between when a utility undergoes a change in cost or sales levels, and when the utility can reflect these changes in new rates. Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs. The reason is that when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility, consequently, would have an incentive to minimize additional costs. Commissions rely on regulatory lag as an important tool for motivating utilities to act efficiently. As economist and regulator Alfred Kahn once remarked:
>
> > Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites; companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.
>
> Rational utility management, as a general rule, would exert minimal effort in controlling costs if it has no effect on the utility's profits. This condition occurs when a utility is able to pass through (with little or no regulatory scrutiny) higher costs to customers with minimal consequences on sales. Cost containment constitutes a real cost to management. Without any expected benefits, management would exert minimum effort on cost containment. The difficult problem for the regulator is to detect when management is lax. Regulators should concern themselves with this problem: lax management translates into higher cost of service and, if undetected, higher rates to the utility's customers. Regulators should closely monitor and scrutinize costs like those subject to cost trackers that utilities have little incentive to control.[29]

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[28] The recent NRRI report cited in the subsequent sentence outlines the theoretical and empirical studies that provide evidence of the incentive problems associated with FACs. *See*, for example, David P. Baron and Raymond R. DeBondt, "Fuel Adjustment Mechanisms and Economic Efficiency," *Journal of Industrial Economics*, Vol. 27 (1979): 243-69; David P. Baron and Raymond R. DeBondt, "On the Design of Regulatory Price Adjustment Mechanisms," *Journal of Economic Theory*, Vol. 24 (1981): 70-94; David L. Kaserman and Richard C. Tepel, "The Impact of the Automatic Adjustment Clause on Fuel Purchase and Utilization Practices in the U.S. Electric Utility Industry," *Southern Economics Journal*, Vol. 48 (1982): 687-700; and Frank A. Scott, Jr., "The Effect of a Fuel Adjustment Clause on a Regulated Firm's Selection of Inputs," *The Energy Journal*, Vol. 6 (1985): 117-126. The first two studies applied a general model to show that FACs tend to cause a utility to overuse fuel relative to other inputs, pay more for fuel prices, and choose non-optimal, fuel-intensive generation technologies. The third study provided empirical support for this prediction. The fourth study showed that some types of FACs cause biasness in fuel use and that FACs in general weaken the incentive of a utility to search for lower-priced fuel. It provided empirical evidence that electric utilities with an FAC pay higher fuel prices than utilities without an FAC. See footnote 29 for additional detail and source.

[29] K. Costello. "How Should Regulators View Cost Trackers?" Washington, DC: National Regulatory Research Institute: 4, footnotes excluded.

Q. WOULD YOUR PROPOSAL CONSTITUTE ANYTHING ASYMETRICAL ABOUT NUCLEAR POWER COST RECOVERY?

A. No, and again, such assertions are biased and fail to recognize the big picture on nuclear power plant cost recovery and its long and storied history. Throughout the 1980s and 1990s, for instance, many utilities that developed, or cancelled nuclear power plants, received significant investment disallowances because of numerous and varied prudence-related issues driving cost and schedule overruns. A summary of these investment disallowances, as well as each unit's cost and schedule overruns, is provided in Exhibit DED-11. FPL however, is not reported to have received an investment disallowance for its Turkey Point units. This point has not been highlighted to raise questions about the prudence of FPL's historic nuclear investments, but it has been provided to show that FPL and its shareholders have already received considerable cost recovery benefits that other utilities did not receive during a comparable time period. Thus, to suggest, or at least imply, that assessing an appropriately calculated net RPC credit to ratepayers would somehow be unfair fails to recognize the significant policy support that nuclear power has already been afforded, and continues to be afforded, in Florida.

Q. IS YOUR RECOMMENDATION COMPARABLE TO A NUCLEAR POWER PLANT INVESTMENT DISALLOWANCE?

A. No, and any assertions offered by the Company that adopting an appropriately-determined RPC credit somehow represents a nuclear disallowance, or is a vote "against" nuclear power, is simply a distraction from the true issues. An appropriately-determined RPC credit, based upon the true opportunity cost of replacement power, will not disallow one dollar of nuclear capital or fuel costs. The calculation is simply based upon the total generation costs of replacement power (which in this case is a series of natural gas/oil generation assets and purchased power resources) less the generation that was off-line (or avoided) as a consequence of the outage: which was nuclear power. This calculation does not require the disallowance of one dollar of nuclear power cost (capital nor fuel) and as such, cannot in any way be interpreted as a vote against nuclear energy.

Q. REGARDLESS, DO YOU AGREE WITH THE COMPANY'S ASSERTION THAT PROPER REGULATORY ACTIONS CAN CREATE DISINCENTIVES TO NUCLEAR GENERATION DEVELOPMENT?

A. No, and the Company's position is not supported by any evidence or studies that would suggest otherwise. In fact, the recent academic literature on this subject would prove otherwise. Several years ago, research was published in the *Rand Journal of Economics*, that tested the hypothesis that capital disallowances discouraged regulated firms from making future capital investments. The article, using a variety of different empirical specifications, rejected the hypothesis that investment disallowances were "opportunistic," and discouraged efficient capital investment. The article specifically found that:

> The empirical results do not support the proposition that there was a violation of the "regulatory compact" as a result of the cost disallowances of the 1980s. Regulators may have become more stringent in their treatment of nuclear power operations, but they may simply have been responding to lax cost control by operators of nuclear plants with highly dispersed ownership structures. There is no evidence of a shift in treatment of customer plant owners (who did not operate the plant) or of utilities building conventional generating facilities. Most utilities apparently viewed the disallowances as

> indicative of bad management by the affected firms and saw no reason to change their own investment practices.[30]

Q. DID THIS ARTICLE TEST ANY OTHER INTERESTING QUESTIONS ABOUT REGULATED FIRM INVESTMENT DECISIONS?

A. Yes, the aforementioned research also examined the impact of the Duff and Phelps investment analysts' regulatory climate rating to test whether utilities regulated by commissions considered "less favorable" by Wall Street tend to have lower overall investment rates than those regulated by Commissions considered "more favorable." Since the ratings range from the best at a level of 1, and the worst at a level of 6, the empirical hypothesis assumed a negative relationship between investment and rating. The empirical results, however, found the exact opposite relationship: that investment actually increased the "less favorable" a Commission is rated from an investor perspective. The empirical result, however, was statistically insignificant, indicating that, at best, it was impossible to discern any relationship between investor ratings of regulatory commissions and the investment practices of their utilities.

Q. DOES FLORIDA HAVE ANY ATTRACTIVE POLICIES SUPPORTING NUCLEAR POWER PLANT DEVELOPMENT?

A. Yes. Florida has one of the most attractive set of cost recovery rules and regulations for nuclear power plant development in the U.S. These rules (PSC Rule 25-6.0423 Nuclear or Integrated Gasification Combined Cycle Power Plant Cost Recovery) are based upon authorizing legislation included in F.S. 366.93. While many states have legislation and/or rules that are comparable, few provide the full panoply of cost and

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[30] T. Lyons and J. Mayo (2005). "Regulatory Opportunism an Investment Behavior: Evidence from the U.S. Electric Utility Industry." *Rand Journal of Economics*. 36, 3: 642.

development assurances that are included in the Florida process. A comparison of these rules and legislation has been provided in Exhibit DED-12. The combination of Florida's legislation and administrative cost recovery rules provides a high degree of cost assurance on capital cost recovery even in the event a project cancellation. This form of capital securitization, as well as the allowance for cash earnings on construction work in progress ("CWIP"), is far more important in nuclear project development than unknown issues about future replacement costs on new reactors that generally have no operating history. The cash earnings on CWIP for instance can be as large as $1 billion for a typical nuclear power plant, which is far larger than the $15.9 million net RPC.

Q. **IS THERE ANY RELATIONSHIP BETWEEN THE PROPOSED RPC CREDIT IN THIS PROCEEDING AND NUCLEAR PLANT DEVELOPMENT COST RECOVERY?**

A. No, since the promotion of nuclear power and the determination of an appropriately-determined RPC are unrelated, and any attempt to try to tie them together is simply an attempt to confuse and obfuscate the issue. The issue before the Commission is one of determining the appropriate value for replacement cost of power for generation resources that were knocked off-line by the February 2008 outage. The Commission, and the Florida Legislature, have clearly defined a strong and supportive policy for nuclear power plant development and that policy, and the rules and regulations underlying that policy, have not changed, and are not being proposed to be changed as a consequence of the February 2008 outage. In fact, pursuing consistent regulatory policy by setting a net RPC credit on the true opportunity cost of the outage is actually more consistent with Florida's big picture nuclear public policy goals than what the Company is proposing.

Q. CAN YOU PLEASE EXPLAIN WHY CONSISTENCY IS MORE IMPORTANT TO NUCLEAR AND RENEWABLE POWER COST RECOVERY THAN SETTING POLICY IN A ONE-TIME OPPORTUNISTIC FASHION?

A. The real challenge in the development of high capital cost power generation assets such as nuclear, solar, and offshore wind, tends to rest more with policy consistency, than in creating set-asides, tax credits, or in this case, the shareholder subsidies. In fact, in some instances, these policies can create as much harm as they do good. Consider that many states have aggressive renewable portfolio standards ("RPS"), have strong positive statements and policies supporting renewable energy, and in many cases, generous rebate programs. Yet many of these states are falling short of their RPS goals over investors concerns about the longevity of these renewable support mechanisms. If high capital cost assets are not "securitized," through some form of contract or other binding long term agreement, markets will have only two means of reacting: (1) the risk premium included in the projects will have to rise to higher levels, meaning higher costs for ratepayers or (2) under-investment in the resource.

Q. HOW DOES THIS RELATE TO FLORIDA'S NUCLEAR POWER POLICY, INCENTIVES FOR NEW GENERATION, AND THE ISSUES IN THIS PROCEEDING?

A. Florida's legislation, rules, and regulations provide the effective "securitization" that provide long term assurances on capital cost recovery for nuclear power, and to some extent renewables. The true issue for incentivizing high capital cost asset development is the recovery of their capital costs. So, to argue that a decision associated with a $14 million net RPC credit somehow creates a disincentive for the development of a $6 billion or more nuclear asset, is challenged. An appropriately determined net RPC credit will not deny the Company one dollar in capital cost recovery of its nuclear assets, so it should not, by definition, create a disincentive in developing new nuclear assets.

Q. HOW WOULD THE REPLACEMENT COSTS OF NUCLEAR POWER BE HANDLED IN COMPETITIVE MARKETS?

A. The full value of that replacement cost would typically be borne by the nuclear power plant operator and its shareholders.[31] In fact, FPL Group recently reported lower earnings of $0.17 to $0.21 per share as a consequence of nuclear outages and replacement cost purchases, associated with the Seabrook nuclear unit it owns and operates in New Hampshire.[32]

Q. WOULD YOU PLEASE EXPLAIN THE COMPANY'S ASSERTIONS REGARDING AN APPROPRIATELY-DETERMINED RPC CREDIT AND DISINCENTIVES FOR RENEWABLES?

[31] This assumes replacement costs are not defined in any contracts or regulations approving the transfer of the nuclear plant.

[32] The reduction in earnings is also attributed to lower than expected wind resources. See Reuters, Update 1-FPL cuts adjusted 2009 earnings forecast, December 22, 2009.

A. Yes, the Company also argues that an appropriately-developed RPC will create a disincentive for solar and wind energy development.[33] The Company specifically argues that if the Commission sets an appropriately-determined RPC credit it will reduce FPL's incentive to invest in solar or wind. The Company's argument, however, is incorrect and fails to recognize a number of other factors associated with renewable energy development that far exceed the very limited range of issues open for debate in this proceeding that include:

- The basic economics of renewable power generation.
- Policy mechanisms and alternatives open to the Commission in supporting renewable power.
- The perverse incentives that would be created by accepting the company's proposals in this proceeding that could lead to (a) inefficient renewable energy development and (b) underinvestment in distributed resources like renewable energy.

Q. HOW DO BASIC ECONOMICS INFLUENCE RENEWABLE ENERGY INVESTMENT DECISIONS?

A. Many renewable power generation investments require subsidies and support mechanisms that include investment tax credits, production tax credits, grants/subsidies/rebates, renewable energy credit ("REC") revenue streams, and/or some type of contracted long-term fixed revenue stream that (generally) supports the difference between the levelized cost of the renewable asset in question and its next best alternative, which tends to be natural gas-fired combined cycle generation. The levelized cost of solar energy (photovoltaic) is approximately \$370/MWh while the

[33] Testimony of William E. Avera, 4:11-15.

levelized cost of natural gas combined cycle power generation is roughly $60/MWh, assuming $5.00 per million Btu ("MMBtu") priced natural gas. Put another way, the capital cost premium of replacing the Turkey Point nuclear units with comparably-sized solar power is potentially a $6.2 billion issue: a number that dwarfs the $14 million at issue in this proceeding. Thus, the single biggest hurdle in developing solar energy (and other renewables) is overcoming this capital cost premium, not the Commission's decision in a relatively limited RPC credit proceeding.

Q. WOULDN'T AN UNFAVORABLE DECISION IN THIS PROCEEDING CREATE A DISINCENTIVE FOR FPL TO PRESENT A SOLAR ENERGY PROPOSAL BEFORE THE COMMISSION GIVEN THESE ALREADY SIGNIFICANT ECONOMIC HURDLES?

A. Not necessarily since, as I noted earlier, the overwhelming policy question associated with promoting solar energy (and other non-economic renewable resources) is the state's willingness to support renewable assets which is simply (a) not at issue in this proceeding and (b) will not be resolved by the outcome of this proceeding. Regardless, renewable energy development in the U.S. is supported through mandate, not discretion. These mandates vary from a variety of publicly-supported tax credits, rebates from societal benefit funds, dedicated ear marks and grant set-asides, and most importantly, renewable portfolio standards ("RPS"). If federal RPS legislation passes, like the provisions included in the pending Waxman-Markey bill, a national RPS will become the law of the land, and from a policy perspective, FPL will be required to either abide by the standards set in that bill, or make alternative compliance payments ("ACPs").

Q. SUPPOSE THE COMMISSION DID DECIDE IT WANTED TO SIGNIFICANTLY EXPAND ITS PROMOTION OF RENEWABLE ENERGY. COULD THE OUTCOME OF THIS PROCEEDING SET ANY NEGATIVE PRECEDENTS FOR FUTURE RENEWABLE DEVELOPMENT?

A. Yes, there may be some implications based upon the precedent set by the Commission in this proceeding. Consider, as a hypothetical, a situation where a solar energy developer contracts with FPL to provide firm power. Now assume that, for whatever reason, the solar developer was only able to deliver half of its contracted generation. If the Commission were to establish the precedent the Company recommends in this proceeding, the solar developer in this example, who did not deliver the required amounts energy, could easily make the argument that FPL should continue to pay for the full contracted amount, in the spirit of "promoting a low-fuel cost resource." This request could be based on the Commission's precedent established in this proceeding which uses the FAC process to support nuclear and renewable development. While, solar energy developers generally do not make firm power sales commitments to utilities, some other renewable generation resources with interruptible fuel sources can, and accepting the policy rationales offered by the Company in this proceeding invites future similar requests. In summary, using the FAC process to subsidize resource preferences is simply a bad idea.

Q. CAN YOU EXPLAIN THE OTHER PERVERSE OUTCOMES THAT COULD ARISE SHOULD THE COMMISSION ACCEPT THE COMPANY'S PROPOSAL?

A. One perverse outcome that could arise from accepting the Company's proposal in this proceeding is the creation of a disincentive to invest in distributed resources like solar, wind, and other technologies. These disincentives could arise if the full economic consequences of supporting reliability are diminished. One commonly recognized benefit of distributed energy resources ("DER") are the localized reliability benefits these resources can provide at the distribution level. If those values are not appropriately valued, but discounted from the true cost of reliability-related events, it can lead to: (1) a sub-optimal level of DER investment; (2) a sub-optimal level of other complementary reliability investment compliments; and/or (3) a sub-optimal level of reliability. Thus, assessing an appropriate RPC-credit can actually lead to greater policy support for DER and enhanced reliability, not less.

VIII. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR GENERAL RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED RPC?

A. I recommend the Commission reject the Company's proposed RPC credit and accept the $15,974,055 credit I have offered in my direct testimony. The Company's proposal does not reflect the actual replacement cost of energy associated with the transmission-created outages of February 2008, and simply represents a transfer of wealth from ratepayers to the Company and its shareholders. The Commission should also reject the policy arguments offered by the Company as support for its proposed RPC credit. Having ratepayers subsidize FPL's replacement costs would have little to no effect on any decision to invest in new nuclear, solar, wind, and energy efficiency resources given other issues that are (1) beyond the scope of this proceeding and (2) overwhelmingly more significant than the RPC credit due to ratepayers from the February 2008 outages. Accepting the Company's RPC proposal places the Commission in the position of setting a policy precedent that would significantly deviate from sound economic principles and traditional regulatory practices.

Q. DOES THIS CONCLUDE YOUR TESTIMONY FILED ON FEBRUARY 10, 2010?

A. Yes.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the Direct Testimony of David E. Dismukes, Ph.D. has been furnished by U.S. Mail on this 10th day of February, 2010, to the following persons:

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola Junior College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-Current	Associate Executive Director
2001-2006	Associate Professor
2000-2001	Research Fellow and Adjunct Assistant Professor
1999-2000	Managing Director, Distributed Energy Resources Initiative
1995-2000	Assistant Professor

E.J. Ourso College of Business Administration, Department of Economics

2006-Current	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Florida State University, Tallahassee, Florida
College of Social Sciences, Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-2000	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

2000-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida
Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida &
Florida Solar Energy Industries Association, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT APPOINTMENTS

2007-Current	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.
2007-Current	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

PUBLICATIONS: BOOKS AND MONOGRAPHS

1. *Power System Operations and Planning in a Competitive Market.* (2002). With Fred I. Denny. New York: CRC Press.

2. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy.

PUBLICATIONS: PEER REVIEWED ACADEMIC JOURNALS

1. "The Value of Lost Production from the 2004-2005 Hurricane Seasons in the Gulf of Mexico." (2009). With Mark J. Kaiser and Yunke Yu. *Journal of Business Valuation and Economic Loss Analysis*. Status: Accepted, Forthcoming.

2. "Estimating the Impact of Royalty Relief on Oil and Gas Production on Marginal State Leases in the US." (2006). With Jeffrey M. Burke and Dmitry V. Mesyanzhinov. *Energy Policy* 34(12): 1389-1398.

3. "Using Competitive Bidding As A Means of Securing the Best of Competitive and Regulated Worlds." (2004). With Tom Ballinger and Elizabeth A. Downer. *NRRI Journal of Applied Regulation.* 2 (November): 69-85. (*Received 2005 Best Paper Award by NRRI*)

4. "Deregulation of Generating Assets and the Disposition of Excess Deferred Federal Income Taxes." (2004). With K.E. Hughes II. *International Energy Law and Taxation Review.* 10 (October): 206-212.

5. "Reflections on the U.S. Electric Power Production Industry: Precedent Decisions Vs. Market Pressures." (2003). With Robert F. Cope III and John W. Yeargain. *Journal of Legal, Ethical, and Regulatory Issues*. Volume 6, Number 1.

6. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001) *Public Resources Law Digest.* 38: 2.

7. "A Comment on the Integration of Price Cap and Yardstick Competition Schemes in Electrical Distribution Regulation." (2001). With Steven A. Ostrover. *IEEE Transactions on Power Systems.* 16 (4): 940 -942.

8. "Modeling Regional Power Markets and Market Power." (2001). With Robert F. Cope. *Managerial and Decision Economics.* 22:411-429.

9. "A Data Envelopment Analysis of Levels and Sources of Coal Fired Electric Power Generation Inefficiency" (2000). With Williams O. Olatubi. *Utilities Policy.* 9 (2): 47-59.

10. "Cogeneration and Electric Power Industry Restructuring" (1999). With Andrew N. Kleit. *Resource and Energy Economics.* 21:153-166.

11. "Capacity and Economies of Scale in Electric Power Transmission" (1999). With Robert F. Cope and Dmitry Mesyanzhinov. *Utilities Policy* 7: 155-162.

12. "Oil Spills, Workplace Safety, and Firm Size: Evidence from the U.S. Gulf of Mexico OCS." (1997). With O. O. Iledare, A. G. Pulsipher, and Dmitry Mesyanzhinov. *Energy Journal* 4: 73-90.

13. "A Comment on Cost Savings from Nuclear Regulatory Reform" (1997). *Southern Economic Journal*. 63:1108-1112.

14. "The Demand for Long Distance Telephone Communication: A Route-Specific Analysis of Short-Haul Service." (1996). *Studies in Economics and Finance* 17:33-45.

PUBLICATIONS: PEER REVIEWED PROCEEDINGS

1. "Technology Based Ethical Issues Surrounding the California Energy Crisis." (2002). With Robert F. Cope III and John Yeargain. *Proceedings of the Academy of Legal, Ethical, and Regulatory Issues.* September: 17-21.

2. "Electric Utility Restructuring and Strategies for the Future." (2001). With Scott W. Geiger. *Proceedings of the Southwest Academy of Management*. March.

3. "Applications for Distributed Energy Resources in Oil and Gas Production: Methods for Reducing Flare Gas Emissions and Increasing Generation Availability" *(2000)*. With Ritchie D. Priddy. *Proceedings of the International Energy Foundation – ENERGEX 2000*. July.

4. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry" (1998). With Fred I. Denny. *IEEE Proceedings: Large Engineering Systems Conference on Power Engineering*. June: 294-298.

5. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. *Proceedings of the International Association of Science and Technology for Development*. October: 499-504.

6. "Safety Regulations, Firm Size, and the Risk of Accidents in E&P Operations on the Gulf of Mexico Outer Continental Shelf" (1996). With Allan Pulsipher, Omowumi Iledare, and Bob Baumann. *Proceedings of the American Society of Petroleum Engineers: Third International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production*, June.

7. "Comparing the Safety and Environmental Records of Firms Operating Offshore Platforms in the Gulf of Mexico." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the American Society of Mechanical Engineers: Offshore and Arctic Operations 1996*, January.

PUBLICATIONS: OTHER SCHOLARLY PROCEEDINGS

1. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements" (2005). *Proceedings of the 23rd Annual Information Technology Meetings*. U.S. Department of the Interior, Minerals Management Service, Gulf Coast Region, New Orleans, LA. January 12, 2005.

2. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) *Proceedings of the 51st Mineral Law Institute*, Louisiana State University, Baton Rouge, LA. April 2, 2004.

3. "Competitive Bidding in the Electric Power Industry." (2003). *Proceedings of the Association of Energy Engineers*. December 2003.

4. "The Role of ANS Gas on Southcentral Alaskan Development." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: Energy Markets in Turmoil: Making Sense of It All.* October.

5. "A New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities." (2002). With Vicki Zatarain. *Proceedings of the 2002 National IMPLAN Users Conference*: 241-258.

6. "Analysis of the Economic Impact Associated with Oil and Gas Activities on State Leases." (2002). With Dmitry Mesyanzhinov, Robert H. Baumann, and Allan G. Pulsipher. *Proceedings of the 2002 National IMPLAN Users Conference*: 149-155.

7. "Do Deepwater Activities Create Different Impacts to Communities Surrounding the Gulf OCS?" (2001). *Proceedings of the International Association for Energy Economics: 2001: An Energy Odyssey?* April.

8. "Modeling the Economic Impact of Offshore Activities on Onshore Communities." (2000). With Williams O. Olatubi. *Proceedings of the 20th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana.

9. "Empirical Challenges in Estimating the Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico" (2000). With Williams O. Olatubi. *Proceedings of the International Association for Energy Economics: Transforming Energy Markets*. August.

10. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: The Only Constant is Change* August: 444-452.

11. "Modeling Electric Power Markets in a Restructured Environment" (1998). With Robert F. Cope and Dan Rinks. *Proceedings of the International Association for Energy Economics: Technology's Critical Role in Energy and Environmental Markets.* October: 48-56.

12. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Bob Baumann, and Dmitry Mesyanzhinov. *Proceedings of the 16th Annual Information Transfer Meeting.* U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana: 162-166.

13. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the 15th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana.

PUBLICATIONS: BOOK CHAPTERS

1. "The Role of Distributed Energy Resources in a Restructured Power Industry." (2006). In *Electric Choices: Deregulation and the Future of Electric Power.* Edited by Andrew N. Kleit. Oakland, CA: The Independent Institute (Rowman & Littlefield Publishers, Inc.), 181-208.

2. "The Road Ahead: The Outlook for Louisiana Energy." (2006). In *Commemorating Louisiana Energy: 100 Years of Louisiana Natural Gas Development.* Houston, TX: Harts Energy Publications, 68-72.

3. "Competitive Power Procurement An Appropriate Strategy in a Quasi-Regulated World." (2004). In *Electric and Natural Gas Business: Using New Strategies, Understanding the Issues.* With Elizabeth A. Downer. Edited by Robert Willett. Houston, TX: Financial Communications Company, 91-104.

4. "Alaskan North Slope Natural Gas Development." (2003). In *Natural Gas and Electric Industries Analysis 2003.* With William E. Nebesky, Dmitry Mesyanzhinov, and Jeffrey M. Burke. Edited by Robert Willett. Houston, TX: Financial Communications Company, 185-205.

5. "Challenges and Opportunities for Distributed Energy Resources in the Natural Gas Industry." (2002). In *Natural Gas and Electric Industries Analysis 2001-2002.* Edited by Robert Willett. With Martin J. Collette, Ritchie D. Priddy, and Jeffrey M. Burke. Houston, TX: Financial Communications Company, 114-131.

6. "The Hydropower Industry of the United States." (2000). With Dmitry Mesyanzhinov. In *Renewable Energy: Trends and Prospects.* Edited by E.W. Miller and A.I. Panah. Lafayette, PN: The Pennsylvania Academy of Science, 133-146.

7. "Electric Power Generation." (2000). In the *Macmillan Encyclopedia of Energy.* Edited by John Zumerchik. New York: Macmillan Reference.

PUBLICATIONS: BOOK REVIEWS

1. Review of ***Renewable Resources for Electric Power: Prospects and Challenges***. Raphael Edinger and Sanjay Kaul. (Westport, Connecticut: Quorum Books, 2000), pp 154. ISBN 1-56720-233-0. *Natural Resources Forum. (2000).*

2. Review of ***Electricity Transmission Pricing and Technology***, edited by Michael Einhorn and Riaz Siddiqi. (Boston: Kluwer Academic Publishers, 1996) pp. 282. ISBN 0-7923-9643-X. *Energy Journal* 18 (1997): 146-148.

3. Review of ***Electric Cooperatives on the Threshold of a New Era*** by Public Utilities Reports. (Vienna, Virginia: Public Utilities Reports, 1996) pp. 232. ISBN 0-910325-63-4. *Energy Journal* 17 (1996): 161-62.

PUBLICATIONS: TRADE AND PROFESSIONAL JOURNALS

1. "Value of Production Losses Tallied for 2004-2005 Storms." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.27: 32-26 (July 21) (part 3 of 3).

2. "Model Framework Can Aid Decision on Redevelopment." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.26: 49-53 (July 14) (part 2 of 3).

3. "Field Redevelopment Economics and Storm Impact Assessment." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.25: 42-50 (July 7) (part 1 of 3).

4. "The IRS' Latest Proposal on Tax Normalization: A Pyrrhic Victory for Ratepayers," (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 55(1): 217-236

5. "Executive Compensation in the Electric Power Industry: Is It Excessive?" (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(4): 913-940.

6. "Renewable Portfolio Standards in the Electric Power Industry." With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(3): 693-706.

7. "Regulating Mercury Emissions from Electric Utilities: Good Environmental Stewardship or Bad Public Policy? (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54 (2): 401-424

8. "Using Industrial-Only Retail Choice as a Means of Moving Competition Forward in the Electric Power Industry." (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(1): 211-223

9. "The Nuclear Power Plant Endgame: Decommissioning and Permanent Waste Storage. (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (4): 981-997

10. "Can LNG Preserve the Gas-Power Convergence?" (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (3):783-796.

11. "Competitive Bidding as a Means of Securing Opportunities for Efficiency." (2004). With Elizabeth A. Downer. *Electricity and Natural Gas* 21 (4): 15-21.

12. "The Evolving Markets for Polluting Emissions: From Sulfur Dioxide to Carbon Dioxide." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53(2): 479-494.

13. "The Challenges Associated with a Nuclear Power Revival: Its Past." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (1): 193-211.

14. "Deregulation of Generating Assets and The Disposition of Excess Deferred Federal Income Taxes: A 'Catch-22' for Ratepayers." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 873-891.

15. "Will Competitive Bidding Make a Comeback?" (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 659-674

16. "An Electric Utility's Exposure to Future Environmental Costs: Does It Matter? You Bet!" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 52: 457-469.

17. "White Paper or White Flag: Do FERC's Concessions Represent A Withdrawal from Wholesale Power Market Reform?" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 52: 197-207.

18. "Clear Skies" or Storm Clouds Ahead? The Continuing Debate over Air Pollution and Climate Change" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 51: 823-848.

19. "Economic Displacement Opportunities in Southeastern Power Markets." (2003). With Dmitry V. Mesyanzhinov. *USAEE Dialogue.* 11: 20-24.

20. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 51: 635-652.

21. "Is There a Role for the TVA in Post-Restructured Electric Markets?" (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 51: 433-454.

22. "The Role of Alaska North Slope Gas in the Southcentral Alaska Regional Energy Balance." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Natural Gas Journal.* 19: 10-15.

23. "Standardizing Wholesale Markets For Energy." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 51: 207-225.

24. "Do Economic Activities Create Different Economic Impacts to Communities Surrounding the Gulf OCS?" (2002). With Williams O. Olatubi. *IAEE Newsletter.* Second Quarter: 16-20.

25. "Will Electric Restructuring Ever Get Back on Track? Texas is not California." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 50: 943-960.

26. "An Assessment of the Role and Importance of Power Marketers." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly. 50: 713-731.*

27. "The EPA v. The TVA, et. al. Over New Source Review." (2001) With K.E. Hughes, II. *Oil, Gas and Energy Quarterly.* 50:531-543.

28. "Energy Policy by Crisis: Proposed Federal Changes for the Electric Power Industry." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 50:235-249.

29. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 49:947-973.

30. "California Dreaming: Are Competitive Markets Achievable?" (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 49: 743-759.

31. "Distributed Energy Must Be Watched As Opportunity for Gas Companies." (2001). With Martin Collette, and Ritchie D. Priddy. *Natural Gas Journal.* January: 9-16.

32. "Clean Air, Kyoto, and the Boy Who Cried Wolf." (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. December: 529-540.

33. "Energy Conservation Programs and Electric Restructuring: Is There a Conflict?" (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. September: 211-224.

34. "The Post-Restructuring Consolidation of Nuclear-Power Generation in the Electric Power Industry." (2000) With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 751-765.

35. "Issues and Opportunities for Small Scale Electricity Production in the Oil Patch." (2000). With Ritchie D. Priddy. *American Oil and Gas Reporter*. 49: 78-82.

36. "Distributed Energy Resources: The Next Paradigm Shift in the Electric Power Industry." (2000). With K.E. Hughes II *Oil, Gas and Energy Quarterly*. 48:593-602.

37. "Coming to a Neighborhood Near You: The Merchant Electric Power Plant." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly*. 48:433-441.

38. "Slow as Molasses: The Political Economy of Electric Restructuring in the South." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly*. 48: 163-183.

39. "Stranded Investment and Non-Utility Generation." (1999). With Michael T. Maloney. *Electricity Journal* 12: 50-61.

40. "Reliability or Profit? Why Entergy Quit the Southwest Power Pool." (1998). With Fred I. Denny. *Public Utilities Fortnightly*. February 1: 30-33.

41. "Electric Utility Mergers and Acquisitions: A Regulator's Guide." (1996). With Kimberly H. Dismukes. *Public Utilities Fortnightly*. January 1.

<u>PUBLICATIONS: REPORTS AND OTHER PUBLICATIONS</u>

1. *The Benefits of Continued and Expanded Investments in the Port of Venice*. (2009). With Christopher Peters and Kathryn Perry. Baton Rouge, LA: LSU Center for Energy Studies. 83 pp.

2. *Examination of the Development of Liquefied Natural Gas on the Gulf of Mexico*. (2008). U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA OCS Study MMS 2008-017. 106 pp.

3. *Gulf of Mexico OCS Oil and Gas Scenario Examination: Onshore Waste Disposal*. (2007). With Michelle Barnett, Derek Vitrano, and Kristen Strellec. OCS Report, MMS 2007-051. New Orleans, LA: U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico Region.

4. *Economic Impact Analysis of the Proposed Lake Charles Gasification Project*. (2007). Report Prepared on Behalf of Leucadia Corporation.

5. *The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard*. (2005)

Report Prepared on Behalf of the New Jersey Division of Ratepayer Advocate.

6. *The Importance of Energy Production and Infrastructure in Plaquemines Parish*. (2006). Report Prepared on Behalf of Project Rebuild Plaquemines.

7. *Louisiana's Oil and Gas Industry: A Study of the Recent Deterioration in State Drilling Activity*. (2005). With Kristi A.R. Darby, Jeffrey M. Burke, and Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources.

8. *Comparison of Methods for Estimating the NO_x Emission Impacts of Energy Efficiency and Renewable Energy Projects Shreveport, Louisiana Case Study*. (2005). With Adam Chambers, David Kline, Laura Vimmerstedt, Art Diem, and Dmitry Mesyanzhinov. Golden, Colorado: National Renewable Energy Laboratory.

9. *Economic Opportunities for a Limited Industrial Retail Choice Plan in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana State University Center for Energy Studies.

10. *Economic Opportunities for LNG Development in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana Department of Economic Development and Greater New Orleans, Inc.

11. *Marginal Oil and Gas Production in Louisiana: An Empirical Examination of State Activities and Policy Mechanisms for Stimulating Additional Production*. (2004). With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

12. *Deepwater Program: OCS-Related Infrastructure in the Gulf of Mexico Fact Book*. (2004). With Louis Berger Associates, University of New Orleans National Ports and Waterways Institute, and Research and Planning Associates. MMS Study No. 1435-01-99-CT-30955. U.S. Department of the Interior, Minerals Management Service.

13. *The Power of Generation: The Ongoing Benefits of Independent Power Development in Louisiana*. With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, and Elizabeth A. Downer. Baton Rouge, LA: LSU Center for Energy Studies, 2003.

14. *Modeling the Economic Impact of Offshore Oil and Gas Activities in the Gulf of Mexico: Methods and Application*. (2003). With Williams O. Olatubi, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Prepared by the Center for Energy Studies, Louisiana State University, Baton Rouge, LA. OCS Study MMS2000-0XX. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA.

15. *An Analysis of the Economic Impacts Associated with Oil and Gas Activities on State Leases*. (2002) With Robert H. Baumann, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

16. *Alaska In-State Natural Gas Demand Study*. (2002). With Dmitry Mesyanzhinov, et.al. Anchorage, Alaska: Alaska Department of Natural Resources, Division of Oil and Gas.

17. *Moving to the Front of the Lines: The Economic Impacts of Independent Power Plant Development in Louisiana.* (2001). With Dmitry Mesyanzhinov and Williams O. Olatubi. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

18. *The Economic Impacts of Merchant Power Plant Development in Mississippi.* (2001). Report Prepared on Behalf of the US Oil and Gas Association, Alabama and Mississippi Division. Houston, TX: Econ One Research, Inc.

19. *Energy Conservation and Electric Restructuring In Louisiana.* (2000). With Dmitry Mesyanzhinov, Ritchie D. Priddy, Robert F. Cope III, and Vera Tabakova. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

20. *Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS.* (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

21. *Restructuring the Electric Utility Industry: Implications for Louisiana.* (1996). With Allan Pulsipher and Kimberly H. Dismukes. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

GRANT RESEARCH

1. *Principal Investigator.* "Economic Contributions and Benefits Support by the Port of Venice." Port of Venice Coalition. Total Project: $20,000. Status: Completed.

2. *Principal Investigator.* "Energy Policy Development in Louisiana." Louisiana Department of Natural Resources. Total Project: $49,500. Status: Completed.

3. *Principal Investigator.* "Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: In Progress.

4. *Principal Investigator.* "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: $377,917 (3 years). Status: Awarded, In Progress.

5. *Principal Investigator.* "State and Local Level Fiscal Effects of the Offshore Petroleum Industry." (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: $241,216 (2.5 years). Status: Awarded, In Progress.

6. *Principal Investigator.* "Understanding Current and Projected Gulf OCS Labor and Ports Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Awarded, In Progress.

7. *Principal Investigator.* "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, In Progress.

8. *Principal Investigator.* "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

9. *Principal Investigator.* "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, In Progress.

10. *Principal Investigator.* "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: $244,837. Status: In Progress.

11. *Principal Investigator.* "Ultra Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

12. *Principal Investigator.* "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: $75,000. Status: Completed.

13. *Principal Investigator.* " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

14. *Principal Investigator.* "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

15. *Principal Investigator.* "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

16. *Principal Investigator.* "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $72,000. Status: Completed.

17. *Principal Investigator.* "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding:

$557,744. Status: Awarded, In Progress.

18. *Co-Principal Investigator.* "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

19. *Principal Investigator.* "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

20. *Principal Investigator.* "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

21. *Principal Investigator.* "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

22. *Principal Investigator.* "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

23. *Co-Principal Investigator.* "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "Analysis of Risk and Post-Hurricane Reaction." (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7, 2009.

2. "Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials." (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

3. "Gulf Coast Energy Infrastructure Renaissance: Overview." (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

4. "Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure." (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7, 2008.

5. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19, 2007.

6. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16, 2007.

7. "An Examination of LNG Development on the Gulf of Mexico." (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

8. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

9. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.

10. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

11. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

12. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

13. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

14. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

15. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

16. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.

17. "The Economic Impact of State Oil and Gas Leases on Louisiana." (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

18. "Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

19. "New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico." (2002). With Vicki Zatarain. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

20. "Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring." (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

21. "Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach." (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

22. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

23. "Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation." (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

24. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

25. "Modeling Regional Power Markets and Market Power." (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

26. "Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana" (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

27. "Empirical Issues in Electric Power Transmission and Distribution Cost Modeling." (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

28. "Modeling Electric Power Markets in a Restructured Environment." (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

29. "Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

30. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry." (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

31. "Benchmarking Electric Utility Transmission Performance." (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

32. "A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

33. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

34. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

35. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

36. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

37. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

38. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

39. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

40. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

41. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

42. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

43. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.

2. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.

3. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.

4. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.

5. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.

6. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.

7. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.

8. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

9. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

2. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

3. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. November 10, 2009.

4. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

5. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

6. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

7. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

8. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

9. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption," Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

10. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

11. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

12. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

13. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economists (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

14. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

15. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

16. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

17. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

18. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

19. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

20. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

21. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

22. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

23. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

24. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility *Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.*

25. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

26. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

27. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

28. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

29. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

30. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

31. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

32. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

33. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

34. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

35. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

36. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

37. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

38. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

39. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

40. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

41. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

42. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

43. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

44. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

45. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

46. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

47. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

48. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

49. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

50. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

51. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

52. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

53. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

54. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

55. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

56. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

57. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

58. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

59. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

60. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

61. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

62. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

63. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

64. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

65. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

66. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

67. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

68. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

69. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

70. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

71. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

72. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

73. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

74. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

75. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

76. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

77. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

78. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.

79. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

80. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

81. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

82. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

83. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

84. "Power Plant Siting Issues in Louisiana." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 12, 2002.

85. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

86. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

87. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

88. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

89. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

90. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

91. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

92. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

93. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

94. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

95. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

96. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

97. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

98. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

99. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

100. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

101. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

102. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

103. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

104. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

105. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

106. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

107. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

108. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

109. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

110. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

111. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

112. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

113. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

114. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

115. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

116. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

117. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

118. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

119. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

120. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

121. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

122. "Electric Utility Restructuring – Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

123. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

124. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

125. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Before the Tennessee Regulatory Authority. Docket 09-00104. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review.

2. Expert Testimony. Before the Nebraska Public Service Commission. Docket Number NG-0060. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

3. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

4. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

5. Expert Testimony. Docket EO09030249. Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

6. Expert Testimony. Docket EO0920097. Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the

Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

7. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

8. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

9. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

10. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

11. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

12. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

13. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

14. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

15. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

16. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

17. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.
18. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

19. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

20. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

21. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

22. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

23. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

24. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service

Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

25. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

26. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

27. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491,453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

28. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

29. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

30. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

31. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

32. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

33. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida

Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

34. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

35. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

36. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

37. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

38. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al.* (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

39. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

40. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

41. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

42. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

43. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities

Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

44. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

45. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

46. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

47. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

48. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

49. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

50. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

51. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

52. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

53. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with

Tax Incentives on Merchant Power Generation and Transmission.

54. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

55. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

56. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

57. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

58. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

59. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

60. Expert Testimony: Docket 940448-EG – 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

61. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

62. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Referee, 1995-Current, *Energy Journal*
Contributing Editor, 2000-Current, *Oil, Gas and Energy Quarterly*
Referee, 2005, *Energy Policy*
Referee, 2004, *Southern Economic Journal*
Referee, 2002, *Resource & Energy Economics*
Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Econometric Society, Southern Economic Association, Western Economic Association, and the International Association of Energy Economists.

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current)

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Principles of Microeconomic Theory
Principles of Macroeconomic Theory
Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.
Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept of Environmental Studies).
Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric

Engineering).

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

THESIS/DISSERTATIONS COMMITTEES

5 Thesis Committee Memberships (Environmental Studies, Geography)
3 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics).
1 Doctoral Examination Committee Membership (Information Systems & Decision Sciences)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Steering Committee Member, LSU Coastal Marine Institute (2009-Current).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-Current)

LSU Faculty Senate (2003-2006)

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Advisor (2008). National Association of Regulatory Utility Commissioners ("NARUC"). Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics ("IAEE") Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

129 FERC ¶ 61,016
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, and Philip D. Moeller.

Florida Blackout Docket No. IN08-5-000

ORDER APPROVING STIPULATION AND CONSENT AGREEMENT

(Issued October 8, 2009)

1. The Commission approves the attached Stipulation and Consent Agreement (Agreement) between the Office of Enforcement (Enforcement), the North American Electric Reliability Corporation (NERC) and Florida Power and Light Company (FPL). This order is in the public interest because it resolves on fair and reasonable terms the investigation as to FPL conducted by Enforcement, the Commission's Office of Electric Reliability and NERC into possible violations of Reliability Standards associated with the Bulk Electric System (BES) load loss event in the State of Florida on February 26, 2008, more commonly referred to as the "Florida Blackout."[1]

2. FPL has agreed to pay a civil penalty of $25,000,000. $10,000,000 shall be paid each to the United States Treasury and NERC and $5,000,000 may be spent, subject to Commission staff and NERC staff approval, by FPL on BES reliability enhancement measures that go above and beyond the Agreement's reliability compliance commitments or what the Reliability Standards require. Moreover, as stated in the Agreement, FPL is adding significant additional protection redundancy at several transmission stations. Also, in the Agreement, FPL has committed to undertake numerous specific reliability enhancement measures (apart from the $5,000,000 in expenditures noted above) including: enhancing its compliance program; enhancing training and certification requirements for operating employees; improving its frequency response; updating emergency operating procedures; providing additional staffing for BES analysis; and ensuring that specified equipment is properly inspected and maintained. FPL has also agreed to make quarterly progress reports to Enforcement and NERC and conduct an independent audit after one year following the Agreement to ensure compliance with the Agreement. These compliance and mitigation measures are in addition to numerous

[1] In *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (2007), P 75, the Commission stated that it would rely, at least for an initial period, on the NERC definition of "bulk electric system" to define the scope of facilities subject to the Reliability Standards.

actions taken by FPL on its own initiative after the event and during the course of staff's investigation.

Background

3. FPL is a public utility with transmission, distribution, and generation operations serving approximately 4.5 million customer accounts in Florida. Among other things, FPL is registered as Balancing Authority, Planning Authority, Transmission Owner, Transmission Operator, and Transmission Service Provider by NERC and is responsible for compliance with the Reliability Standards associated with those functions.

4. Florida Reliability Coordinating Council (FRCC) is a not-for-profit company incorporated in Florida. Along with serving as a "Regional Entity" responsible for proposing and enforcing Reliability Standards within its region, FRCC also performs various member services including functioning as the Reliability Coordinator (RC) under the Reliability Standards. As an RC, FRCC has the responsibility and authority for the reliable operation of the BES within FRCC and compliance with associated Reliability Standards. FRCC performs this function through a contract with FPL, by which FPL executes the RC function through FPL control room personnel. FPL also holds a substantial share of the membership of FRCC with respect to the member services functions.

5. On February 26, 2008, portions of the lower two-thirds of the State of Florida experienced a loss of load event more commonly referred to as the Florida Blackout. The event led to the loss of 22 transmission lines, 4,300 MW of generation, and 3,650 MW of customer service or load. In response to the event, the Commission publicly announced a formal non-public investigation into the cause and events surrounding the blackout.[2]

6. The event originated at the Flagami Substation on the FPL system when a field engineer was diagnosing a piece of BES transmission equipment that had previously malfunctioned. Specifically, on February 23, 2008 and February 24, 2008, when the FPL Load Dispatcher on duty in the FPL control center in Miami attempted to initiate separating one of the shunt reactors (a voltage control device) at Flagami from the 138kV bus by opening the associated circuit switcher, a lock-out relay for the reactor tripped the associated breaker. The relays were reset and the circuit switcher was tagged "emergency use only."

7. On February 26, 2008, a FPL Protection and Control (P&C) Engineer was sent to test the circuit switcher at Flagami. Once there, he disabled the primary protection and the breaker failure protection (considered the secondary level of protection). The P&C Engineer did not notify the Load Dispatcher on duty in the FPL control center that he had

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[2] *Order of Non-Public, Formal Investigation*, 122 FERC ¶ 61,244 (2008).

disabled the second level of protection and neither the System Operator on duty in the FPL Control Center nor the RC were aware that any protection had been disabled.

8. At the request of the P&C Engineer, the Load Dispatcher then opened the circuit switcher, and due to the failure of the circuit switcher's bottle interrupter, a fault on the system occurred. The fault caused a 17-19 second arc which spread to the adjacent shunt reactor's circuit switcher, which in turn caused a three phase fault on the 138 kV system. Because the primary and secondary levels of protection were disabled, the fault was cleared remotely in approximately 1.7 seconds. This resulted in significant frequency swings, voltage excursions and tripping of transmission and generation around portions of the lower two-thirds of Florida.

Applicable Reliability Standards

9. On March 16, 2007, the Commission approved the first Reliability Standards,[3] submitted by NERC, pursuant to section 215 of the Federal Power Act.[4] Those categories of Reliability Standards applicable to the Agreement are described below:

10. The Balancing (BAL) group of Reliability Standards address balancing resources and demand to maintain interconnection frequency within prescribed limits.[5]

11. The Communications (COM) group of Reliability Standards require adequate internal and external telecommunications facilities and that these communication facilities be staffed and available to address real-time emergencies and that operating personnel carry out effective communications.[6]

12. The Emergency Preparedness and Operations (EOP) group of Reliability Standards address preparation for emergencies, necessary actions during emergencies and system restoration and reporting following disturbances.[7]

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[3] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (2007).

[4] 16 U.S.C. § 824o (2006).

[5] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, P 305 (2007).

[6] *Id.* P 472.

[7] *Id.* P 541.

13. The Personnel Performance, Training and Qualifications (PER) group of Reliability Standards are intended to ensure the retention of suitably trained and qualified personnel in positions that can impact the reliable operation of the BES.[8]

14. Protection and Control (PRC) group of Reliability Standards cover a wide range of topics related to the protection and control of power systems.[9]

15. The Transmission Operations (TOP) group of Reliability Standards ensure that the transmission system is operated within operating limits and specifically cover the responsibilities and decision-making authority for reliable operations, requirements for operations planning, planned outage coordination, real-time operations, provision of operating data, monitoring of system conditions, reporting of operating limit violations and actions to mitigate such violations.[10]

16. The Transmission Planning (TPL) group of Reliability Standards ensure that the transmission system is planned and designed to meet an appropriate and specific set of reliability criteria.[11]

Stipulation and Consent Agreement

17. Enforcement and NERC allege that FPL violated Reliability Standards in the BAL, COM, EOP, PER, PRC, TOP, and TPL areas. FPL does not admit that its actions constituted violations of the Reliability Standards.

18. The Agreement provides for a substantial civil penalty in the amount of $25,000,000 that reflects the seriousness and nature of the event and yet takes account of efforts to remedy the violations. This amount is to be paid in a manner that reflects the dual nature of this investigation which both the Commission and NERC conducted and in recognition that some amount of expenditure above the requirements of the Reliability Standards on additional reliability measures is in the public interest. Accordingly, FPL shall pay $10,000,000 each to the United States Treasury and NERC and $5,000,000 may be spent, subject to Commission staff and NERC staff approval, by FPL on Bulk Electric System (BES) reliability enhancement measures that go above and beyond the reliability compliance commitments that are also a significant feature of the Agreement or what the Reliability Standards require. If FPL has not spent or committed to spend for approved projects all of the $5,000,000 amount within three years of the Effective Date of the

[8] *Id.* P 1324.

[9] *Id.* P 1418.

[10] *Id.* P 1567.

[11] *Id.* P 1683.

Agreement, the amount or any remainder of the amount shall be paid and divided equally between the U.S. Treasury and NERC. Also, except as required by law, this amount may not be deducted or otherwise treated favorably to FPL for tax purposes nor recovered in rates by FPL.

19. The Agreement also provides for substantial, wide ranging, and specific reliability enhancement measures (apart from the $5,000,000 in expenditures noted above) that are a significant element to the resolution of this matter. These include FPL committing to: enhance its overall electric reliability compliance program; enhance training and certification requirements for operating employees; improve its system's frequency response performance; update its emergency operating procedures; provide additional staffing for BES analysis; and ensure that specified equipment is properly inspected and maintained. FPL has also agreed to make quarterly progress reports to Enforcement and NERC and conduct an independent audit after one year following the Agreement to ensure compliance with the Agreement. These compliance and mitigation measures are in addition to numerous actions taken by FPL on its own initiative after the event and during the course of staff's investigation.

20. In assessing the appropriate remedy, staff considered the serious nature of the event and its impact on the BES. As the Agreement stipulates, this was a serious outage. On the other hand, staff also considered that FPL's actions were neither intentional nor fraudulent and that FPL demonstrated exemplary cooperation throughout the investigation. Also, FPL implemented voluntarily many reliability enhancement measures immediately following the event and throughout the investigation.

<u>Determination of the Appropriate Sanctions and Remedies</u>

21. We conclude that the penalty set forth in the Agreement is a fair and equitable resolution of this matter and is in the public interest, as it reflects the nature and seriousness of FPL's alleged conduct and the event as well as the efforts taken by FPL to remedy the alleged violations, recognizing the company specific considerations as stated above and in the attached Agreement. We also conclude that, under the specific circumstances of this case, the payment provisions relating to the civil penalty reflect a balanced and sensible approach, including a portion to be paid to NERC and the allowance of a limited portion of the civil penalty to be spent by FPL to provide additional reliability protections on the FPL portion of the BES. We also conclude that the reliability enhancement measures set forth in the Agreement are substantial, relate directly to the alleged violations, and will enhance BES reliability and are therefore also fair and in the public interest.

<u>The Commission orders</u>:

The attached Stipulation and Consent Agreement is hereby approved without modification.

By the Commission. Commissioners Spitzer and Moeller concurring with separate statements attached.
Commissioner Kelly is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

2008 Florida Blackout Docket No. IN08-5-000

STIPULATION AND CONSENT AGREEMENT

I. INTRODUCTION

1. Staff of the Office of Enforcement ("Enforcement") of the Federal Energy Regulatory Commission ("Commission"), staff of the North American Electric Reliability Corporation ("NERC") (collectively "staff"), and Florida Power and Light Company ("FPL") enter into this Stipulation and Consent Agreement ("Agreement") to resolve a non-public investigation conducted by Enforcement, staff of the Office of Electric Reliability of the Commission and NERC, pursuant to Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2008), and NERC's Compliance Monitoring and Enforcement Program into alleged violations of the Reliability Standards by FPL surrounding a loss of load event in Florida on February 26, 2008.

II. STIPULATED FACTS

Enforcement, NERC and FPL hereby stipulate to the following:

2. On February 26, 2008, portions of the lower two-thirds of the Bulk Electric System ("BES") in peninsular Florida experienced a loss of service to electric customers. The event led to the loss of 22 transmission lines, 4,300 MW of generation, and 3,650 MW of customer service or load. Approximately 596,000 FPL customer accounts and 354,000 non-FPL customer accounts were out of service, representing approximately 8% of Florida electric customer accounts. In response to the event, the Commission publicly opened a formal investigation into the cause and events surrounding the blackout. *Order of Non-Public, Formal Investigation*, 122 FERC ¶ 61,244 (2008). NERC also opened a parallel Compliance Violation Investigation (NERC0002CVI).

3. FPL is a public utility with transmission, distribution, and generation operations serving approximately 4.5 million customer accounts in Florida.

4. Based on industry benchmarking studies for the time period January 1, 2006 through December 31, 2008, FPL's distribution reliability, as measured by "SAIDI," ranked in the top decile of performance.

5. The FPL Control Center is located in western Miami. It has two levels, one which includes consoles for five "Load Dispatchers," and another level which includes consoles

for the "System Operator" and "Reliability Coordinator." At the time of the event, Load Dispatchers were responsible for monitoring a specific region and ensuring that proper switching orders and clearances are issued and executed. They are the main contact with Protection and Control ("P&C") Field Engineers. A Readiness Review conducted by the Florida Reliability Coordinating Council ("FRCC") and NERC in March 2004 included a recommendation relating to the Load Dispatchers and System Operator oversight. FPL took actions to address these recommendations in June 2004. A Readiness Review conducted by FRCC and NERC during April 2007 determined that "FPL has taken appropriate actions to implement and satisfactorily resolve all of the recommendations from the 2004 report" and did not identify Load Dispatcher certification as an area of concern. FPL did not require its Load Dispatchers to be NERC certified. The System Operator is responsible for supervising the Load Dispatchers and is charged with directing and implementing actions to ensure the stable and reliable operation of the FPL System. While the System Operator cannot effectively read the Load Dispatchers' monitoring screens from the System Operator desk and at the time of the event did not receive the same alarms on his monitoring screens as the Load Dispatchers, the System Operator can access the same information that is available to the Load Dispatchers from his station. FPL requires its System Operators to be NERC certified. At times, including February 26, 2008, System Operators also fulfill the function of "Reliability Coordinator," which is responsible for overseeing reliability in the entire FRCC region.

6. FPL P&C Field Engineers are responsible for conducting maintenance and troubleshooting on substation equipment. FPL P&C Field Engineers are highly skilled, experienced and trained and hold four year engineering degrees.

7. The Flagami Substation is located in western Miami and is centrally located in the southern portion of the FPL transmission system. The 230 kV/138 kV station contains two 138 kV shunt reactors, which are used to control voltage. Each shunt reactor is connected to the 138kV bus by a circuit switcher, which consists of a Sulfur Hexafluoride (SF_6) gas filled high speed bottle interrupter in series with a low speed air break disconnect switch. The circuit switchers were installed by FPL in 1987 and 1998.

8. In 2001, FPL studied the effects of a fault at Flagami. Based on the results, it added redundant primary bus differential relay protection at Flagami, but determined that it was not necessary to add redundancy around the autotransformer at Flagami.

9. On February 23, 2008 and February 24, 2008, when the Load Dispatcher on duty attempted to initiate separating one of the shunt reactors at Flagami from the 138kV bus by opening the associated circuit switcher, a lock-out relay for the reactor tripped the associated breaker. The relays were reset and the circuit switcher was tagged "emergency use only."

10. On February 26, 2008, a P&C Field Engineer was sent to test the circuit switcher at Flagami. Once there, he disabled the primary protection and the breaker failure protection (considered the secondary level of protection). At this point, the shunt reactor and its associated circuit switcher were operating live on the system with two levels of protection disabled for approximately 37 minutes.

11. The P&C Engineer communicated the disabling of the breaker trip for the primary protection for the shunt reactors to the Load Dispatcher; the Load Dispatcher, when interviewed by staff, indicated that he did not understand that any protection had been disabled. The Field Engineer did not inform the Load Dispatcher that he had disabled the secondary level of protection. The Load Dispatcher did not request authorization for the removal of any levels of protection from the System Operator and did not communicate that one level of protection had been disabled to the System Operator. The System Operator's monitoring equipment did not independently alert him to the disabling of protection by the P&C Field Engineer. The System Operator, unaware of the disabling of protection, did not conduct an assessment of the changed system configurations or take action within 30 minutes in response to the changed condition.

12. The P&C Field Engineer performed a visual inspection of the bottle interrupter per FPL policy, which showed the presence of gas (which normally indicates proper functioning), prior to working on the circuit switcher. At the request of the P&C Field Engineer, the Load Dispatcher then opened the circuit switcher, and due to the failure of the circuit switcher's bottle interrupter, a fault on the system occurred. Subsequent forensic evaluation showed that the metal contacts within the bottle interrupter were fused into in a closed condition due to a connecting rod failure. Also the semaphore indicating low gas in the bottle interrupter had failed, giving a false indication of the presence of gas (and thereby giving a false indication that it was functioning properly) during the P&C Engineer's visual inspection.

13. The fault caused a 17-19 second arc which spread to the adjacent shunt reactor's circuit switcher causing a three phase fault on the 138 kV system. Because the primary and secondary levels of protection were disabled, the fault was cleared remotely in approximately 1.7 seconds. This resulted in significant frequency swings, voltage excursions and tripping of transmission and generation around portions of the lower two-thirds of Florida.

14. Immediately after the fault, the System Operator/Reliability Coordinator assigned the Reliability Coordinator responsibilities to a NERC-certified System Operator present in the Control Center, but not involved in operations that day. The System Operator then focused on restoring the FPL system. At the time of the event, there were four operators NERC-certified at the Reliability Coordinator level in the Control Center.

15. The System Operator then questioned the Load Dispatcher about the problem at Flagami. The Load Dispatcher reported that there had been a reactor fire at Flagami. After noting that Flagami was de-energized, the System Operator ordered all breakers at Flagami open.

16. Of affected firm customers, 56% were restored to service within one hour, 84% were restored within two hours, and all non-interruptible customers were restored within three hours.

17. While not the most significant event the BES has experienced, this was a serious outage.

18. FPL's action were neither intentional nor fraudulent.

19. FPL demonstrated exemplary cooperation throughout the investigation.

20. FPL implemented reliability enhancement measures immediately after the event and throughout the investigation.

21. As part of FPL's ongoing reliability improvements to the system, FPL: (a) is implementing protection redundancy for new transmission substations above 100 kV with in-service dates of 2010 and beyond that is intended to ensure single-points-of-failure on protection systems would not result in N-1 transmission system contingencies from evolving into more severe or extreme events; (b) is adding high speed redundant protection on the autotransformers at Flagami Substation; (c) is implementing protection redundancy for the autotransformers at eight substations that have similar bus arrangements as Flagami (Davis, Ft. Myers, Lauderdale Inner, Lauderdale Outer, Midway, Sanford Plant, Brevard and Ringling)(with two substations completed in each year commencing in 2009); and (d) in the interim period prior to completed in-service dates, is implementing automatic remote monitoring of the protection circuit fuses and developing a procedure for immediate action in the case of an alarm.

III. RESOLUTION

22. Enforcement and NERC alleged that FPL violated Reliability Standards in the BAL, COM, EOP, PER, PRC, TOP, and TPL areas. FPL does not admit that its actions constitute violations of the Reliability Standards or that it committed any violations of the Reliability Standards. Nonetheless, in view of the costs and risks of litigation, and in the interest of resolving all matters in dispute between Enforcement, NERC, and itself regarding the acts in question, FPL agrees to undertake the obligations set forth in this Agreement.

23. This agreement does not constitute an admission of liability or wrongdoing by FPL to any third party and FPL does not consent to the use of this Agreement by any other party in any other proceeding.

24. For purposes of settling any and all civil and administrative disputes arising from Enforcement's and NERC's investigation of FPL, and in lieu of any other remedy that the Commission or NERC might assess, determine, initiate, or pursue, concerning any of the matters referred to above, FPL agrees that after the Commission issues an order approving this Agreement without modification or condition, it shall take the following actions:

A. Civil Penalty

25. FPL shall pay a civil penalty in the amount of $25,000,000. $10,000,000 shall be paid each to the United States Treasury and NERC, within 10 days of the Effective Date. $5,000,000 shall be remitted and FPL may spend it to further enhance the reliability of the BES upon staff approval (which will not be unreasonably withheld) on additional BES reliability enhancement measures not otherwise required under this Agreement or by the reliability standards as in effect on the date of this Agreement. If FPL has not spent or committed to spend for approved projects all of such amount within three years of the Effective Date, the amount or any remainder of the amount shall be paid and split equally between the U.S. Treasury and NERC. Except as required by law, this amount shall not be deducted or otherwise treated favorably to FPL for tax purposes nor recovered in rates by FPL.

B. Reliability Enhancement Measures

26. FPL will adopt the following reliability enhancement measures:

1. *Enhancements to FPL Compliance Program*: Within 6 months of the Effective Date, FPL will undertake incremental enhancements to its existing Reliability Standards compliance program with respect to all FPL owned or operated Bulk Electric System operations. This shall include specified roles for senior management involvement, independent reporting of compliance management to senior executives outside of the business units that plan, operate and maintain BES equipment, internal auditing, accountability for reliability in compensation packages, a compliance hotline, a written reliability compliance manual, and improvements to document databases, processes, and training. In addition, FPL will perform practice audits of all FPL Business Units, including a review of procedures, process flowcharts, and compliance documentation. FPL will also assess NERC compliance education and training for all employees responsible for compliance with the Reliability Standards and implement improvements in

these programs. To execute these enhancements, perform additional training, document control and spot audits to enhance a sustainable culture of compliance, FPL will provide additional employee support for its compliance program. In its quarterly progress reports to the Commission as described below, FPL shall document compliance improvement actions taken to date. Some of the incremental enhancements set forth herein have been undertaken prior to the effectiveness of the Agreement.

2. *Training and Certification:* FPL will enhance training to operating employees staffing the control room on the functionalities and limitations of the protection schemes, emergency operations procedures and the requirement to utilize three part communication protocols of Direct-Repeat-Acknowledge. This training shall address the reliability risks to the BES when a part or all of a protection scheme is removed for maintenance or other purposes. FPL will also provide detailed technical training for field relay testing engineers regarding Protection and Control compliance activities, which will include a phased-in certification program. This training shall address seeking express permission from System Operators before switching or before work can be performed on energized BES facilities and the protection systems. Some of the incremental enhancements set forth herein have been undertaken prior to the effectiveness of the Agreement. In addition, FPL's initiative to NERC-certify all load dispatchers is currently in progress and will be completed per the schedule agreed upon in a separate Remedial Action Directive Settlement with NERC.

3. *Frequency Response*: FPL will implement measures to maintain its average frequency response for any calendar year (measured as being equal to its average frequency response in response to all events, as defined by the Resource Subcommittee of the NERC Operating Committee, that occur during such calendar year) to be as close as reasonably practicable to its frequency bias setting for such calendar year (it being understood that the Company's frequency bias setting is equal to 1% of its maximum peak load). For the purpose of maintaining such frequency response, both generation and load demand response measures will be acceptable. Frequency response measures to meet the above-referenced performance criteria shall include some combination of the following:

    - Modify generating units' droop characteristics.

    - Apply controllable demand response technology (it being understood that such technology that responds in a manner that is substantially similar to the response shown on example Attachments A-1 and A-2 would be among technology that is considered acceptable for these purposes).

FPL's obligation to maintain such frequency response shall commence in no event later than one year from the Effective Date (as this obligation likely will commence in the midst of a calendar year, the parties agree that only events that occur after the commencement of such obligation through the remainder of such calendar year shall be considered in determining whether FPL has complied with such obligations for such initial calendar year).

4. *Update Emergency Operating Procedures*: FPL will review and modify, as is reasonably necessary, plans to mitigate operating physical emergencies including fires within stations or on BES transmission facilities. These revised procedures will be reviewed by NERC and FERC Staff. Such procedures shall specify a situational assessment to identify and, if possible, isolate the specific portion of the switchyard that is on fire. In the quarterly progress reports to the Commission, FPL shall document actions to be taken to conduct reasonably adequate emergency training of these revised procedures to operators of the BES.

5. *Additional Operations Engineers for BES Analysis*: FPL will staff two additional operations engineers to perform additional BES analysis including increased modeling scenarios for both planning and real-time scenarios as well as day-to-day contingency analysis.

6. *Equipment Maintenance*: To the extent not heretofore done: FPL will review its maintenance practices for Bulk Electric System circuit switchers to assure all such equipment is maintained based on condition assessment and performance monitoring practices that are consistent with standard utility practice. Such condition assessment and maintenance may include a combination of thermography, visual inspection, operational testing, lubrication and adjustment and other means. FPL will, with respect to all 1986 through 1995 S&C Series 2000 circuit switchers, (a) inspect them for potentially defective low gas indicators, (b) to the extent practicable, conduct non-destructive testing of control rods and (c) develop procedures to avoid operation of any switchers that are identified as defective.

7. *Quarterly Progress Reports*: FPL will make quarterly progress reports to FERC and NERC staff before a final independent audit is conducted one year after the Effective Date. The audit will evaluate FPL's compliance with the terms of this Agreement. FERC Staff and FPL shall reasonably

agree on the audit firm, with due regard for the independence of such firm, and any audit recommendations to be implemented.

IV. TERMS OF CONSENT AGREEMENT

27. The Effective Date of this Agreement shall be the date upon which the Commission issues an order approving this Agreement without modification or condition. Given unique circumstances of this case concerning FPL's role with respect to FRCC, staff covenants and agrees that it does not intend to pursue an agreement between staff and FRCC, or other resolution, resolving all or any matters in this same docket pertaining to FRCC (the "FRCC Matters") that includes (a) payments by FRCC that exceed the payments contemplated by the draft agreement that staff has provided (with the knowledge and concurrence of FRCC) to FPL most recently prior to the time of execution this Agreement (the "Current Draft FRCC Agreement") or (b) terms and conditions that are substantively different from, or in addition to, those set forth in the Current Draft FRCC Agreement. Staff covenants and agrees to use best efforts to cause this Agreement to be presented to the Commission for consideration as promptly as practicable following the execution of this Agreement.

28. Unless the Commission issues an order approving the Agreement in its entirety and without modification or condition, the Agreement shall be null and void and of no effect whatsoever, and neither Commission staff, NERC, nor FPL shall be bound by any provision or term of the Agreement, unless otherwise agreed in writing by Commission staff, NERC and FPL.

29. The Agreement shall remain confidential until approved by *each* party and the Commission issues an order approving the Agreement without modification or condition. The Agreement shall be made public only after the Commission's approval without modification or condition.

30. The Agreement binds FPL and its agents, successors and assigns. The Agreement does not create or impose any additional or independent obligations on FPL, or any affiliated entity, its agents, officers, directors or employees, other than the obligations identified in Section III of this Agreement.

31. All information and documents provided by FPL to the Commission and/or NERC as part of the investigation and/or the settlement of the investigation were submitted on a confidential basis and are not information and documents that would normally be disclosed to the public. Aside from the public release of the Agreement after the Commission issues an order approving the Agreement in its entirety and without modification or condition, no information or documents pertaining to the investigation shall be disclosed by the Commission or NERC, except as required by law.

32. In connection with the payment of the civil penalty provided for herein, FPL agrees that the Commission's order approving the Agreement without modification or condition shall be a final order assessing a civil penalty under section 316A(b) of the FPA, 16 U.S.C. § 825o-1(b), as amended. FPL further waives rehearing of any Commission order approving the Agreement without modification or condition, and judicial review by any court of any Commission order approving the Agreement without modification or condition. FPL also waives any rights of appeals provided by the NERC Rules of Procedure.

33. Commission approval of this Agreement without modification or condition shall fully, irrevocably, and unconditionally release FPL, its agents, officers, directors, employees, shareholders, representatives and affiliates, both past and present, and their respective successors and assigns, and forever bar the Commission and NERC from holding or seeking in any forum to hold FPL, its agents, officers, directors, employees, shareholders, representatives and affiliates, both past and present, and their respective successors and assigns liable for any and all direct and/or indirect administrative, civil, criminal or other claims or liability (whether or not now known) arising out of, related to, or connected with the event or the investigation. In further consideration for this release, FPL represents that it is not aware of any cause of the event that was not disclosed to staff during the investigation and which might reasonably be considered to be a violation of any Reliability Standard.

34. Upon the Effective Date of this Agreement, Enforcement's and NERC's investigation of FPL shall terminate in Docket No. IN08-5-000 and NERC0002CVI.

35. Failure to make a timely payment or to comply with any other provision of this Agreement once effective shall be deemed a violation of a final order of the Commission issued pursuant to the FPA, 16 U.S.C. § 792, *et seq.*, and may subject FPL to additional action under the enforcement and penalty provisions of the FPA.

36. If FPL does not make the payment above at or before the time agreed by the parties, interest payable to the United States Treasury and NERC will begin to accrue, pursuant to the Commission's regulations at 18 C.F.R. § 35.19(a)(2)(iii), from the date that payment is due.

37. The signatories to the Agreement agree that they enter into the Agreement voluntarily and that, other than the recitations set forth herein, no tender, offer or promise of any kind by any member, employee, officer, director, agent or representative of Enforcement, NERC, or FPL has been made to induce the signatories or any other party to enter into the Agreement.

38. Each of the undersigned warrants that he or she is an authorized representative of the entity designated, is authorized to bind such entity and accepts the Agreement on the entity's behalf.

39. The undersigned representative of FPL affirms that he or she has read the Agreement, that all of the matters set forth in the Agreement are true and correct to the best of his or her knowledge, information and belief, and that he or she understands that the Agreement is entered into by Enforcement and NERC in express reliance on those representations.

40. The Agreement may be signed in counterparts.

41. This Agreement is executed in duplicate, each of which so executed shall be deemed to be an original.

Agreed to and accepted:

Norman C. Bay 9/25/09

Norman C. Bay
Director, Office of Enforcement
Federal Energy Regulatory Commission

Date

David W. Hilt

09/25/09

David Hilt
Vice President and Director of Compliance
North American Electric Reliability Corporation

Date

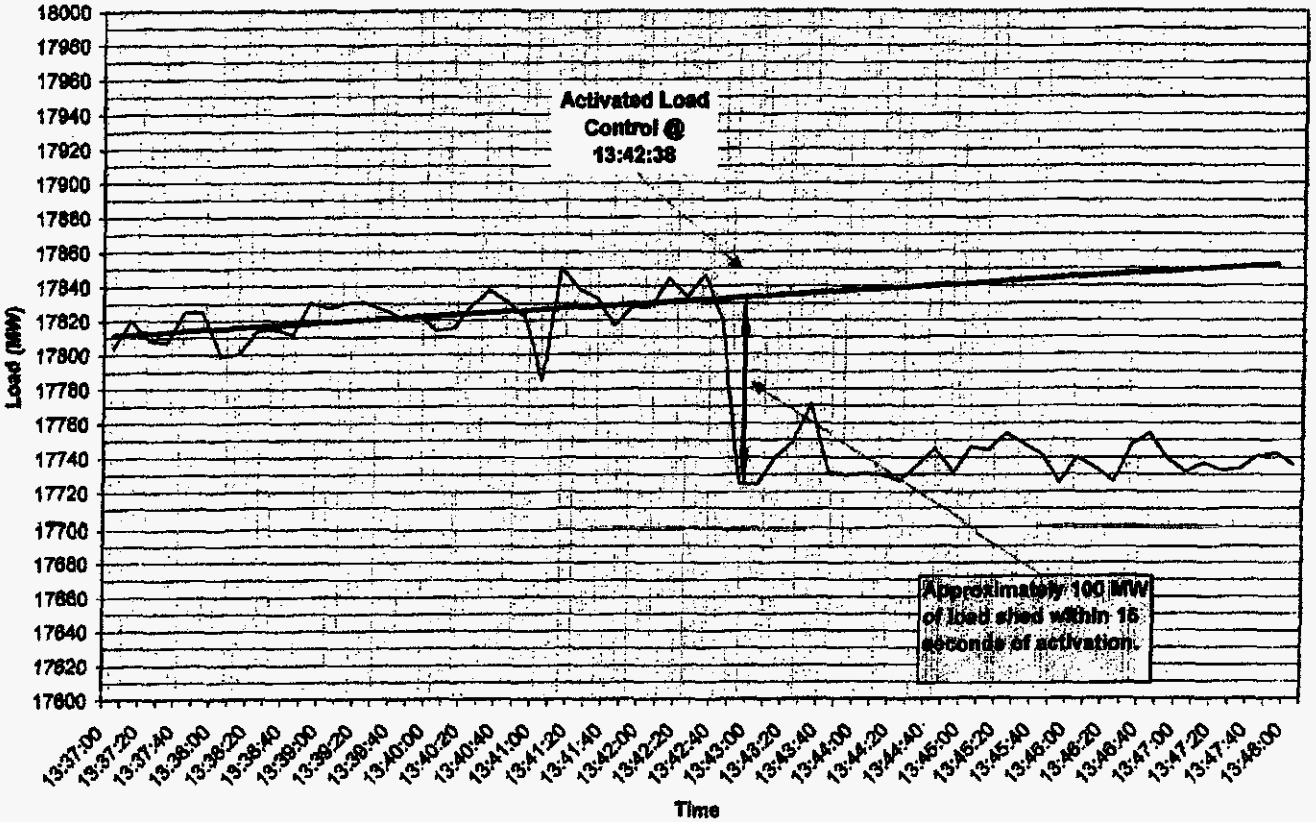
AJ Olivera

9/24/09

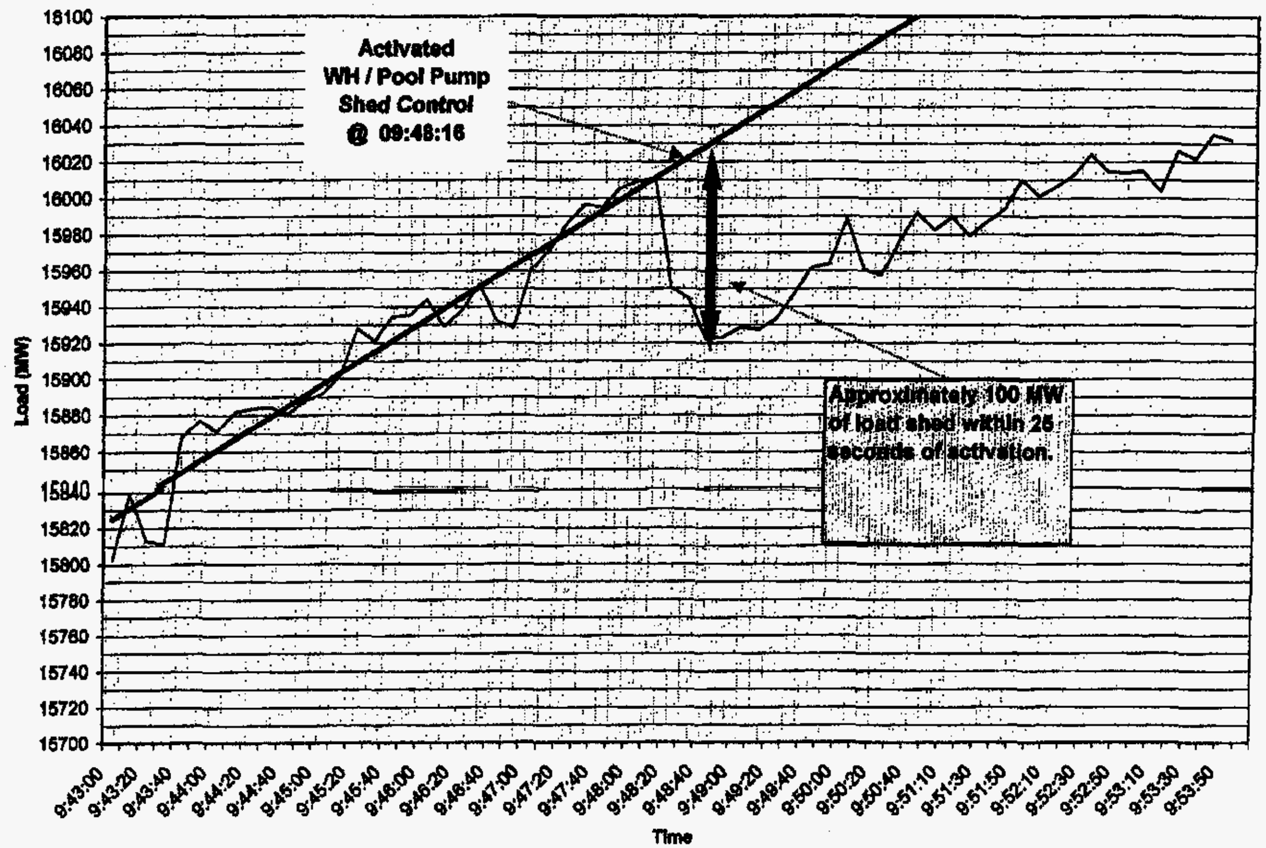
Armando J. Olivera
President and CEO
Florida Power and Light Company

Date

Attachment A - 1
Load Graph - 07-20-2006



Attachment A - 2
Load Graph - 06-22-2007



UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Florida Blackout Docket No. IN08-5-000

(Issued October 8, 2009)

SPITZER, Commissioner, concurring:

I support the Order as a reasonable outcome. However, I write separately to express my concern with a lack of transparency and an absence of clarity in the Order. In light of the importance of our reliability program and compliance with the Reliability Standards, I would have required that the Order identify with specificity the Reliability Standards alleged to have been violated in this matter and how the facts of this case apply to those Reliability Standards. In the future, I expect that all orders on settlements addressing alleged violations of the Reliability Standards will provide this important information.

On February 26, 2008, the lower two-thirds of Florida lost electricity for several hours. That event, which the Order refers to as the Florida Blackout, knocked out 22 transmission lines and 4,300 MW of generation. The Florida Blackout resulted in the loss of 3,560 MW of customer service or load. Clearly, the Florida Blackout was a major event for the system and for consumers. Order P 5, 20.

Today's Order is the outcome of our investigation into Florida Power and Light Company's (FPL) role in the Florida Blackout. We find that the event originated on the FPL system. Order P 6. We outline certain actions of FPL preceding the Florida Blackout. Order P 6-8. However, when it comes to identifying the Reliability Standards that FPL is alleged to have violated with regard to the Florida Blackout – the basis for the Commission's and North American Electric Reliability Corporation's (NERC) investigation into FPL in the first place – the Order merely identifies the *categories* of the relevant Reliability Standards. Order P 17. Although we impose a substantial penalty on FPL and require FPL to enhance its reliability measures through specific mitigation, nowhere does the Order identify with any specificity the Reliability Standards that the Commission and NERC alleged FPL violated in connection with the Florida Blackout. Nowhere does the Order provide an explanation of how the facts support the application of those Reliability Standards in this case.

In the Energy Policy Act of 2005, Congress vested the Commission with the authority to approve and enforce Reliability Standards. Critical to that responsibility are clear rules, regulations and policies. Indeed, as I have explained before, such clarity and transparency is an important means to ensure a meaningful enforcement program. *See, e.g., Tenaska Marketing Ventures, et al.*, 126 FERC ¶ 61,040 at 61,247 (2009) (Spitzer, dissenting).

The problem with today's Order is that, by failing to identify with any specificity the Reliability Standards that FPL is alleged to have violated or how the facts support the application of the Reliability Standards, the Commission fails to provide clarity or transparency to the industry as to what is expected under the relevant Reliability Standards. I appreciate that settlements are case-specific matters rather than industry-wide promulgations. This proceeding, however, is the first reliability enforcement matter in which we impose a substantial penalty and specific mitigation measures in response to a serious outage. Yet we provide no meaningful information as to why the actions taken by FPL leading up to and after the Florida Blackout are, in the Commission's view, violative of the Reliability Standards. We provide no information as to which Reliability Standards caused the Commission and NERC to investigate the matter in the first instance or to impose the penalty and mitigation program herein.

The Commission's enforcement authority, including the imposition of sanctions, is a component of the Commission's mission. However, the Commission's ultimate objective is to promote compliance with our rules, regulations and orders. We best achieve that objective by providing all users, owners and operators of the grid clarity as to how the Commission will apply the Reliability Standards. Today's Order fails to provide that important information.

For these reasons, I respectfully concur in the Order.

Marc Spitzer
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Florida Blackout Docket No. IN08-5-000

(Issued October 8, 2009)

MOELLER, Commissioner, *concurring*:

I respectfully concur in the Order as a reasonable outcome. As I have stated several times, "[t]hose who are subject to Commission penalties need to know, in advance, what they must do to avoid a penalty."[1] For that reason, I agree with Commissioner Spitzer's concurring statement in this case that, "[i]n the future, … all orders on settlements addressing alleged violations of the Reliability Standards" should, "… identify with specificity the Reliability Standards alleged to have been violated … and how the facts of [the] case apply to those reliability standards."

Philip D. Moeller
Commissioner

[1] Concurring Opinions of Commissioner Moeller in *Enforcement of Statutes, Regulations, and Orders*, 123 FERC ¶ 61,156 (2008) and *Compliance with Statutes, Regulations, and Orders*, 125 FERC ¶ 61,058 (2008). This statement was repeated in the dissenting opinions of Commissioner Moeller in *Seminole Energy Services, LLC, et al.*, 126 FERC ¶ 61,041 (2009) and *National Fuel Marketing Co., LLC, et al.*, 126 FERC ¶ 61,042 (2009).

PROPOSED RESOLUTION OF ISSUES ("PRI")
DOCKET NO. 090505-EI
DECEMBER 4, 2009

Background

On February 26, 2008, a fault occurred at FPL's Flagami substation in connection with troubleshooting a switch used to connect a shunt inductor to FPL's transmission system. The fault created conditions that, among other things, caused three fossil-fueled generating units and Turkey Point Nuclear Units 3 and 4 to trip offline, which is how they are designed to operate in such a situation. This event is referred to herein as the "Flagami Transmission Event."

The Federal Energy Regulatory Commission ("FERC") and the North American Electric Reliability Council ("NERC") conducted investigations of the Flagami Transmission Event. On October 8, 2009, FPL agreed with FERC and NERC to settle claims that FPL allegedly violated certain FERC and NERC transmission-reliability standards. As part of the settlement agreement, FERC does not conclude that FPL violated any reliability standards or laws, and FPL does not admit any violations or liability in connection with the outage.

Docket 090001-EI contained the following issue: "With respect to the February 26, 2008 outages, should FPL or its customers be responsible for replacement power costs associated with the outages?" This docket was opened in November 2009 to address that issue by itself. In light of FPL's agreement herein to bear the cost of replacement power attributable to the Flagami Transmission Event, FPL proposes and the other parties to this PRI agree that the scope of this docket should now be limited to determining the appropriate measure of replacement power costs.

Components of the PRI

FPL will ask the Commission to approve the following, and the other parties to this PRI agree to support FPL's request:

1. FPL agrees to bear the cost of replacement power attributable to the Flagami Transmission Event; provided, however, that:

    a. FPL does not admit imprudence or any other improper action or failure with regard to the Flagami Transmission Event and reserves all of its rights and defenses with respect to the propriety of its actions in connection with the Flagami Transmission Event; and

    b. the appropriate measure of replacement power costs that are attributable to the Flagami Transmission Event remains an issue to be determined by the Commission in this docket.

2. All parties to this PRI and Staff may each take any position that it wishes concerning the proper measure of replacement power costs, if any, that FPL should refund to customers as a result of the Flagami Transmission Event. Testimony and discovery will be limited to the issue of the appropriate measure of replacement power costs.

3. This PRI is a one-time response to an extraordinary situation. All of the parties to this PRI acknowledge, and the Commission finds, that approval of this PRI will establish no precedent with respect to any matter resolved herein.

4. This PRI may be executed in counterparts, and all such counterparts will constitute one instrument binding on the signatories, notwithstanding that all parties may not be signatories to the original or the same counterpart. Facsimile transmission of an executed copy of this PRI will be accepted as evidence of a party's execution of the PRI.

Agreed and accepted on behalf of:

Office of Public Counsel
c/o The Florida Legislature
111 W. Madison Street, Room 812
Tallahassee, FL 32399-1400

By: Charlie Beck
Charlie Beck, Esq.

Florida Power & Light Company
700 Universe Boulevard
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By:
John T. Butler, Esq.

Office of the Attorney General
The Capitol - PL01
Tallahassee, FL 32399-1050

By: Cecilia Bradley
Cecilia Bradley, Esq.

Replacement Cost Credit
Hypothetical Example

Plant Capacity (MW)	(a)		1,000
Outage (hours)	(b)		100
Total Lost Generation (MWh)	**(c) = (a)*(b)**		**100,000**
Cost of Purchased Power ($/MWh)	(d)	$	100.00
Total Cost of Outage ($)	**(e) = (c)*(d)**	**$**	**10,000,000**
Variable Fuel Cost ($/MWh)	(f)	$	5.00
Total Avoided Fuel Cost ($)	**(g) = (c)*(f)**	**$**	**500,000**
Net Replacement Cost	**(h) = (e)-(g)**	**$**	**9,500,000**

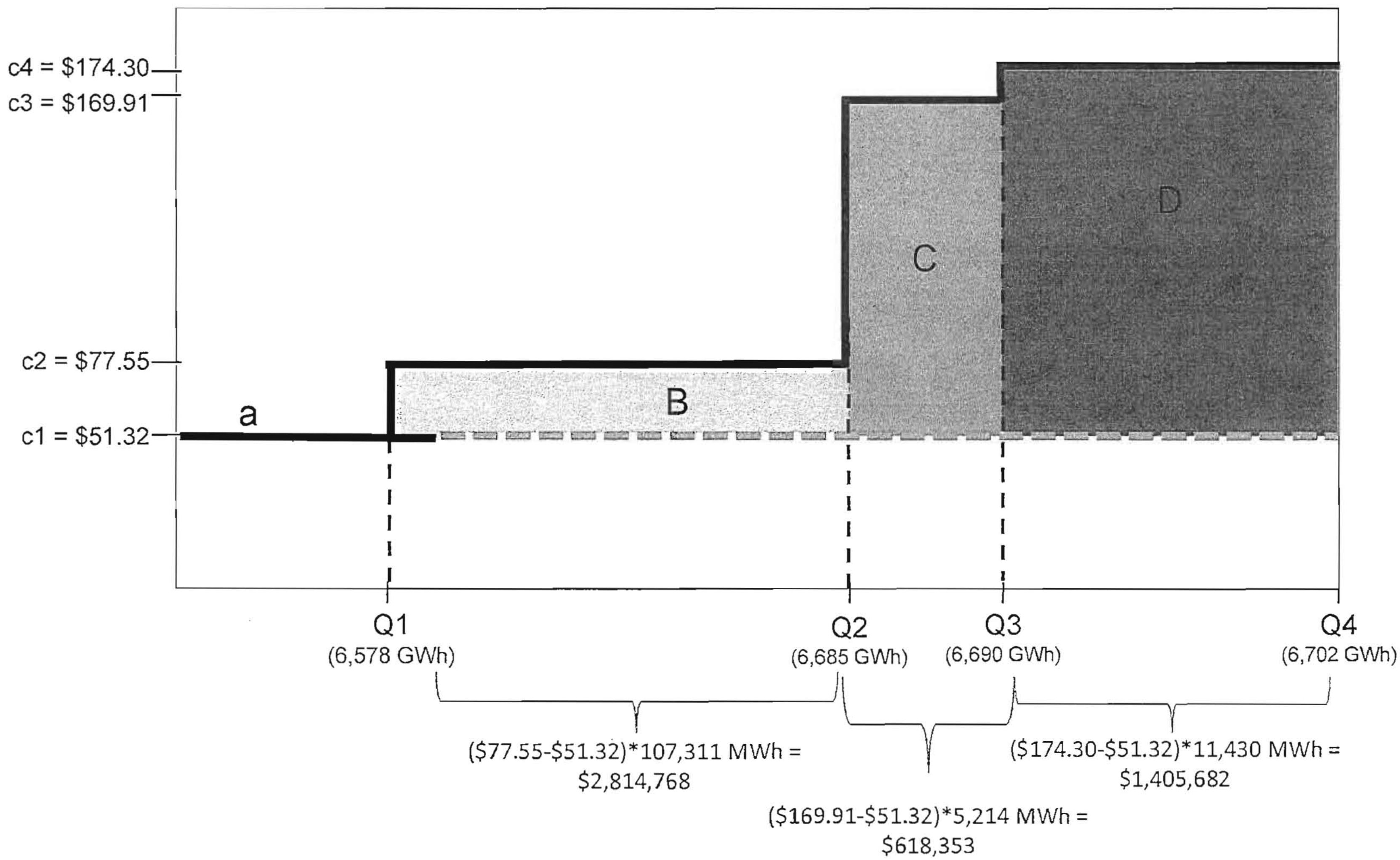
Florida Power & Light Company
Peaking Unit Production Cost Calculation

Unit	Heat Rate (MMBtu/MWh)	Fuel Cost Natural Gas ($/MMBtu)	Fuel Cost #2 Oil ($/MMBtu)	Fuel Consumption Natural Gas (MMBtu)	Fuel Consumption #2 Oil (MMBtu)	Fuel Consumption Total (MMBtu)	Percent of Total Natural Gas (%)	Percent of Total #2 Oil (%)	Blended Fuel Cost ($/MMBtu)	Production Cost ($/MWh)
LG1	17.716	$ 9.94	$ 14.33	86,334	714	87,048	99.2%	0.8%	$ 9.98	$ 176.81
LG2	16.450	$ 9.94	$ 14.33	52,402	3,444	55,846	93.8%	6.2%	$ 10.21	$ 167.95
PGT	17.727	$ 9.94	$ 12.10	42,141	111	42,252	99.7%	0.3%	$ 9.95	$ 176.38
FGT	13.265	n.a.	$ 13.25						$ 13.25	$ 175.76

Hourly MWh Production & Peaking Unit Production Cost

Hour Ending	LG1 (MWh)	LG2 (MWh)	PGT (MWh)	FGT (MWh)	Total (MWh)
1400	173	178	180	532	1,063
1500	262	321	302	559	1,444
1600	267	335	307	550	1,459
1700	270	338	309	559	1,476
1800	276	347	305	559	1,487
1900	289	356	305	550	1,500
2000	292	357	308	550	1,507
2100	287	297	169	485	1,238
2200	59	72	13	112	256
Total	**2,175**	**2,601**	**2,198**	**4,456**	**11,430**
Total Peaking Unit Production Cost	$ 384,562	$ 436,838	$ 387,683	$ 783,187	$ 1,992,270

Florida Power & Light Company
Replacement Cost Estimate



Note: For illustration purposes only.

Docket No. 090505-EI
Exhibit DED-6
FPL Replacement Cost Estimate
Page 1 of 1

1. NET PEAK REPLACEMENT GENERATION COST

1A. Replacement Fuel Cost

Hour Ending	Hourly Production LG1	LG2	PGT	FGT	Total	Replacement Fuel Cost LG1	LG2	PGT	FGT	Total
	(MWh)					($)				
1400	173	178	180	532	1,063	$ 30,587	$ 29,896	$ 31,749	$ 93,505	$ 185,737
1500	262	321	302	559	1,444	$ 46,323	$ 53,913	$ 53,268	$ 98,251	$ 251,755
1600	267	335	307	550	1,459	$ 47,207	$ 56,265	$ 54,150	$ 96,669	$ 254,290
1700	270	338	309	559	1,476	$ 47,738	$ 56,769	$ 54,503	$ 98,251	$ 257,259
1800	276	347	305	559	1,487	$ 48,798	$ 58,280	$ 53,797	$ 98,251	$ 259,126
1900	289	356	305	550	1,500	$ 51,097	$ 59,792	$ 53,797	$ 96,669	$ 261,354
2000	292	357	308	550	1,507	$ 51,627	$ 59,960	$ 54,326	$ 96,669	$ 262,582
2100	287	297	169	485	1,238	$ 50,743	$ 49,882	$ 29,809	$ 85,244	$ 215,679
2200	59	72	13	112	256	$ 10,432	$ 12,093	$ 2,293	$ 19,685	$ 44,503
Total	**2,175**	**2,601**	**2,198**	**4,456**	**11,430**	**$ 384,552**	**$ 436,850**	**$ 387,691**	**$ 783,192**	**$ 1,992,285**

1B. Total Fuel Not Incurred

	Generation (MWh)	Fuel Mix (%)	Fuel Cost ($/MWh)	System Average Cost ($/MWh)
Natural Gas	4,052,626	94.7%	76.05	$ 72.01
Light Oil	4,669	0.1%	178.943	$ 0.20
Heavy Oil	222,625	5.2%	102.873	$ 5.35
Total	**4,279,920**	**100.0%**		**$ 77.55**

	Fuel Cost ($/MWh)	Capacity (MW)	Non-Peak Outage Hours	Energy to Replace (MWh)	Fuel Cost ($)
Turkey Point Unit 3	$ 4.440	717	74.8	53,656	$ 238,230
Turkey Point Unit 4	$ 4.440	717	74.8	53,656	$ 238,230
Total		**1,434**	**149.7**	**107,311**	**$ 476,461**

Total Fuel Cost (A3)	$ 352,372,341
Adjusted Total Fuel Cost	$ 351,895,880
Total System MWh	6,696,564
Adjusted System Average Cost	**$ 52.55**

	Capacity (MW)	Peak Outage Hours	Not Incurred Generation	Fuel Cost ($/MWh)	Fuel Cost Not Incurred ($)
Turkey Point Unit 3	717	8	5,736	$ 52.55	$ 301,419
Turkey Point Unit 4	717	8	5,736	$ 52.55	$ 301,419
Total	**1,434**		**11,472**		**$ 602,839**

1A. REPLACEMENT FUEL COST	**$ 1,992,285**
1B. TOTAL FUEL NOT INCURRED	**$ 602,839**
NET PEAK REPLACEMENT GENERATION COST	**$ 1,389,446**

2. NET NON-PEAK REPLACEMENT GENERATION COST

2A. Replacement Fuel Cost

	Generation		Fuel Mix		Fuel Cost		System Average Cost	
	February	March	February	March	February	March	February	March
	— (MWh) —		— (%) —		— ($/MWh) —		($/MWh)	
Natural Gas	4,052,626	4,401,718	94.7%	93.3%	76.05	78.367	$ 72.01	$ 73.15
Light Oil	4,669	628	0.1%	0.0%	178.943	222.013	$ 0.20	$ 0.03
Heavy Oil	222,625	313,262	5.2%	6.6%	102.873	101.382	$ 5.35	$ 6.73
Total	4,279,920	4,715,608	100.0%	100.0%			$ 77.55	$ 79.92

	Capacity		Non-Peak Outage Hours		Non-Peak Energy to Replace		Replacement Generation Cost		
	February	March	February	March	February	March	February	March	Total
	— (MW) —		— (hours) —		— (MWh) —			— ($) —	
Turkey Point Unit 3	717	717	74.8	75.2	53,656	53,918	$ 4,161,233	$ 4,308,891	$ 8,470,124
Turkey Point Unit 4	717	717	74.8	24.2	53,656	17,351	$ 4,161,233	$ 1,386,638	$ 5,547,871
Total	1,434	1,434	149.7	99.4	107,311	71,270	$ 8,322,465	$ 5,695,529	$\boxed{\$\ 14,017,994}$
							$ 77.55	$ 79.92	

2B. Fuel Cost Not Incurred

	Turkey Point Fuel Cost		Non-Peak Energy to Replace		Turkey Point Fuel Cost		
	February	March	February	March	February	March	Total
	— ($/MWh) —		— (MWh) —			($)	
Turkey Point Unit 3	$ 4.983	$ 4.945	53,656	53,918	$ 267,365	$ 266,626	$ 533,992
Turkey Point Unit 4	$ 4.350	$ 4.332	53,656	17,351	$ 233,401	$ 75,166	$ 308,568
Total			107,311	71,270	$ 500,767	$ 341,793	$ 842,560

Total Fuel Cost (A3)	$ 352,372,341	$ 389,720,951	742,093,292
Adjusted Total Fuel Cost	$ 351,871,574	$ 389,379,158	741,250,732
Total System MWh	6,696,564	6,944,633	13,641,197
Adjusted System Average Cost	$ 52.55	$ 56.07	$ 54.34

	MWh		Fuel Cost		Fuel Cost Not Incurred		
	February	March	February	March	February	March	Total
	— (MWh) —		($/MWh)			($)	
Turkey Point Unit 3	53,656	53,918	$ 52.55	$ 56.07	$ 2,819,333	$ 3,023,155	$ 5,842,488
Turkey Point Unit 4	53,656	17,351	$ 52.55	$ 56.07	$ 2,819,333	$ 972,877	$ 3,792,210
Total	107,311	71,270			$ 5,638,666	$ 3,996,032	$\boxed{\$\ 9,634,698}$

Replacement Fuel Cost	$ 14,017,994
Fuel Cost Not Incurred	$ 9,634,698
Net Non-Peak Replacement Generation Cost	$\boxed{\$\ 4,383,296}$

3. NET PURCHASED POWER REPLACEMENT COST

Purchased Power (MWh)		5,214
Cost of Purchased Power ($)	$	885,935
Average Nuclear Production Cost Avoided ($/MWh)	$	52.55
Adjusted Cost of Purchased Power ($)	$	273,970
Net Purchased Power Replacement Cost	$	**611,965**

4. TOTAL REPLACEMENT COST CREDIT

NET PEAK REPLACEMENT GENERATION COST	$	1,389,446
NET NON-PEAK REPLACEMENT GENERATION COST	$	4,383,296
NET PURCHASED POWER REPLACEMENT COST	$	611,965
TOTAL REPLACEMENT COST CREDIT	**$**	**6,384,707**

1. NET PEAK REPLACEMENT GENERATION COST

1A. Replacement Fuel Cost

Hour Ending	Hourly Production LG1 (MWh)	LG2 (MWh)	PGT (MWh)	FGT (MWh)	Total (MWh)	Replacement Fuel Cost LG1 ($)	LG2 ($)	PGT ($)	FGT ($)	Total ($)
1400	173	178	180	532	1,063	$ 30,587	$ 29,896	$ 31,749	$ 93,505	$ 185,737
1500	262	321	302	559	1,444	$ 46,323	$ 53,913	$ 53,268	$ 98,251	$ 251,755
1600	267	335	307	550	1,459	$ 47,207	$ 56,265	$ 54,150	$ 96,669	$ 254,290
1700	270	338	309	559	1,476	$ 47,738	$ 56,769	$ 54,503	$ 98,251	$ 257,259
1800	276	347	305	559	1,487	$ 48,798	$ 58,280	$ 53,797	$ 98,251	$ 259,126
1900	289	356	305	550	1,500	$ 51,097	$ 59,792	$ 53,797	$ 96,669	$ 261,354
2000	292	357	308	550	1,507	$ 51,627	$ 59,960	$ 54,326	$ 96,669	$ 262,582
2100	287	297	169	485	1,238	$ 50,743	$ 49,882	$ 29,809	$ 85,244	$ 215,679
2200	59	72	13	112	256	$ 10,432	$ 12,093	$ 2,293	$ 19,685	$ 44,503
Total	2,175	2,601	2,198	4,456	11,430	$ 384,552	$ 436,850	$ 387,691	$ 783,192	$ 1,992,285

1B. Total Fuel Not Incurred

	Capacity (MW)	Peak Outage Hours	Not Incurred Generation	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost Not Incurred ($)
Turkey Point Unit 3	717	8	5,736	10.864	0.460	$ 28,665
Turkey Point Unit 4	717	8	5,736	10.915	0.400	$ 25,043
Total	1,434		11,472			$ 53,709

footnote don't match.

1A. REPLACEMENT FUEL COST	$ 1,992,285
1B. TOTAL FUEL NOT INCURRED	$ 53,709
NET PEAK REPLACEMENT GENERATION COST	$ 1,938,577

2. NET NON-PEAK REPLACEMENT GENERATION COST

2A. Replacement Fuel Cost

	Generation		Fuel Mix		Fuel Cost		System Average Cost	
	February	March	February	March	February	March	February	March
	— (MWh) —		— (%) —		— ($/MWh) —		($/MWh)	
Natural Gas	4,052,626	4,401,718	94.7%	93.3%	76.047	78.367	$ 72.01	$ 73.15
Light Oil	4,669	628	0.1%	0.0%	178.943	222.013	$ 0.20	$ 0.03
Heavy Oil	222,625	313,262	5.2%	6.6%	102.873	101.382	$ 5.35	$ 6.73
Total	4,279,920	4,715,608	100.0%	100.0%			$ 77.55	$ 79.92

	Capacity		Non-Peak Outage Hours		Non-Peak Energy to Replace		Replacement Generation Cost		
	February	March	February	March	February	March	February	March	Total
	— (MW) —		— (hours) —		— (MWh) —			— ($) —	
Turkey Point Unit 3	717	717	74.8	75.2	53,656	53,918	$ 4,161,233	$ 4,308,891	$ 8,470,124
Turkey Point Unit 4	717	717	74.8	24.2	53,656	17,351	$ 4,161,233	$ 1,386,638	$ 5,547,871
Total	1,434	1,434	149.7	99.4	107,311	71,270	$ 8,322,465	$ 5,695,529	$ 14,017,994
							$ 77.55		

2B. Fuel Cost Not Incurred

	Non-Peak Total Outage Hours		Not Incurred Generation		Heat Rate		Fuel Cost		Fuel Cost Not Incurred		
	February	March	February	March	February	March	February	March	February	March	Total
	— (hours) —		— (MWh) —		— (MMBtu/MWh) —		($/MMBtu)			— ($) —	
Turkey Point Unit 3	74.8	75.2	53,656	53,918	10.864	10.950	0.460	0.450	$ 268,140	$ 265,683	$ 533,823
Turkey Point Unit 4	74.8	24.2	53,656	17,351	10.915	10.944	0.400	0.400	$ 234,260	$ 75,957	$ 310,217
Total			107,311	71,270					$ 502,400	$ 341,640	$ 844,040
									$ 4.68		

2A. REPLACEMENT FUEL COST	$ 14,017,994
2B. TOTAL FUEL NOT INCURRED	$ 844,040
NET NON-PEAK REPLACEMENT GENERATION COST	$ 13,173,954

3. NET PURCHASED POWER REPLACEMENT COST

Purchased Power (MWh)		5,214
Cost of Purchased Power ($)	$	885,935
Average Nuclear Production Cost Avoided ($/MWh)	$	4.68
Adjusted Cost of Purchased Power ($)	$	24,410
NET PURCHASED POWER REPLACEMENT COST	**$**	**861,525**

4. TOTAL REPLACEMENT COST CREDIT

NET PEAK REPLACEMENT GENERATION COST	**$**	**1,938,577**
NET NON-PEAK REPLACEMENT GENERATION COST	**$**	**13,173,954**
NET PURCHASED POWER REPLACEMENT COST	**$**	**861,525**
TOTAL REPLACEMENT COST CREDIT	**$**	**15,974,055**

Fuel Assumptions:

February Gas/Heavy Oil/Light Oil Mix		
Fuel	MWh	%
Gas	4,052,626	94.69%
Light Oil	4,669	0.11%
Heavy Oil	222,625	5.20%
Total	4,279,920	100.00%

March Gas/Heavy Oil/Light Oil Mix		
Fuel	MWh	%
Gas	4,401,718	93.34%
Light Oil	628	0.01%
Heavy Oil	313,262	6.64%
Total	4,715,608	100.00%

Outage Assumptions: Part A

Turkey Point 3 and 4	
Capacity	1,434
Outage Hours	8.17

Outage Assumptions: Part B

Turkey Point 3	
February Capacity	717
February Outage hours	75
March Capacity	717
March Outage hours	75

Turkey Point 4	
February Capacity	717
February Outage hours	75
March Capacity	717
March Outage hours	24

REPLACEMENT FUEL COST (Part A) - Immediately Following Incident

Replacement fuel cost ($) = (Gas fuel cost ($/MMBtu) * Lauderdale/Port Aircraft Gas Turbine Heat Rate (MMBtu/MWh) * Lauderdale/Port Aircraft Gas Turbine MWh) + (Light Oil fuel cost ($/MMBtu) * Fort Myers Gas Turbine Heat Rate (MMBtu/MWh) * Fort Myers Gas Turbine MWh)

H.E.	LG1	LG2	PGT	FMGT	
14	173	178	180	532	MWh
15	252	321	302	559	MWh
16	267	335	307	550	MWh
17	270	338	309	558	MWh
18	276	347	306	559	MWh
19	289	356	305	550	MWh
20	292	357	308	550	MWh
21	287	297	169	485	MWh
22	59	72	13	112	MWh
	2,175	2,601	2,198	4,456	MWh
Heat Rate*	17.716	16.450	17.727	13.265	MMBtu/MWh
Fuel Price*	9.94	9.94	9.94	13.25	$/MMBtu

H.E.	LG1	LG2	PGT	FMGT	
14	30,463	29,105	31,717	63,505	($)
15	46,137	52,486	53,214	98,251	($)
16	47,016	54,777	54,095	96,663	($)
17	47,548	55,267	54,448	98,251	($)
18	48,603	56,739	53,743	98,251	($)
19	50,892	58,211	53,743	96,663	($)
20	51,420	58,374	54,272	96,669	($)
21	50,540	48,563	29,779	85,244	($)
22	10,390	11,773	2,291	19,685	($)
Total	383,011	425,297	387,302	783,192	($)

*Values based on Schedule A4
*Values based on Schedule A4

Replacement Fuel Cost (Part A) Total 1,978,802

REPLACEMENT FUEL COST (Part B) - Time Period Following Part A

Replacement fuel cost ($/MWh) = ((Gas fuel cost (¢/KWh) * Gas percentage) + (Light Oil fuel cost (¢/KWh) * Light Oil percentage) + (Heavy Oil fuel cost (¢/KWh) * Heavy Oil percentage))*10

Based on A3 Schedule for February 2008:

Gas fuel cost =	7.6047	
Light Oil fuel cost =	17.8943	
Heavy Oil fuel cost =	10.2873	
Replacement fuel cost =	77.55	per MWh

Based on A3 Schedule for March 2008:

Gas fuel cost =	7.8357	
Light Oil fuel cost =	22.2013	
Heavy Oil fuel cost =	10.1382	
Replacement fuel cost =	79.92	per MWh

Replacement fuel cost ($) = Replacement fuel cost ($/MWh) * Energy to replace (MWh)
where Energy to replace (MWh) = (Turkey Point 3 Capacity (MW) * Outage hours (TP3)) + (Turkey Point 4 Capacity (MW) * Outage hours (TP4))

Energy to replace = 178,533 MWh
Replacement fuel cost = 14,013,610

TOTAL FUEL NOT INCURRED BY OUTAGE (Part A and Part B)

Fuel not incurred per each unit = Energy to replace (MWh) * heat rate (MMBtu/MWh) * fuel cost ($/MMBtu) (Note: Total fuel not incurred = sum of fuel not incurred for each unit)

	MWh (Part A)	MWh (Part B)	Heat Rate* (MMBtu/MWh)	Fuel Cost* ($/MMBtu)	Fuel Not Incurred ($) (Part A)	Fuel Not Incurred ($) (Part B)
TP3 February	5,858	53,775	10.864	0.46	29,274	268,737
TP3 March	0	53,775	10.950	0.45	0	264,976
TP4 February	5,858	53,775	10.915	0.40	25,578	234,782
TP4 March	0	17,208	10.944	0.40	0	75,330
Total	11,716	178,533			54,850	843,825

*Values based on Schedule A4

ADDITIONAL FUEL COST INCURRED DUE TO OUTAGE

Additional fuel cost incurred ($) = Replacement fuel cost (Part A) ($) + Replacement fuel cost (Part B) ($) - Total fuel not incurred (Part A) ($) - Total fuel not incurred (Part B) ($)
= 15,093,737

Comparison of Non-Fuel Base Rates

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
	($/MWh)									
Florida Power and Light*	**$ 52.51**	**$ 48.91**	**$ 55.66**	**$ 50.20**	**$ 46.64**	**$ 51.83**	**$ 50.71**	**$ 68.83**	**$ 62.17**	**$ 52.19**
Alabama Power*	$ 39.13	$ 38.22	$ 35.53	$ 38.22	$ 37.95	$ 40.07	$ 41.40	$ 43.27	$ 49.30	$ 51.25
Carolina Power and Light*	$ 47.33	$ 47.20	$ 48.79	$ 47.92	$ 48.07	$ 47.75	$ 44.33	$ 48.09	$ 49.27	$ 49.50
CLECO	$ 39.43	$ 44.84	$ 48.96	$ 47.46	$ 52.03	$ 54.83	$ 65.10	$ 70.89	$ 70.87	$ 77.11
Duke Power*	$ 45.10	$ 45.53	$ 45.74	$ 46.10	$ 46.64	$ 45.97	$ 45.20	$ 44.37	$ 46.37	$ 44.68
Florida Power Corp*	$ 52.72	$ 44.22	$ 55.90	$ 51.47	$ 49.07	$ 52.10	$ 44.90	$ 63.37	$ 52.93	$ 54.60
Georgia Power*	$ 45.21	$ 43.86	$ 46.39	$ 43.55	$ 42.73	$ 45.49	$ 48.29	$ 47.00	$ 45.46	$ 55.08
Gulf Power	$ 31.77	$ 34.94	$ 35.34	$ 35.72	$ 36.04	$ 34.77	$ 37.99	$ 33.37	$ 40.40	$ 39.14
Mississippi Power	$ 31.10	$ 32.07	$ 22.66	$ 27.06	$ 30.80	$ 27.59	$ 30.66	$ 24.38	$ 25.79	$ 22.34
Savannah Electric	$ 51.64	$ 56.69	$ 55.02	$ 54.91	$ 57.91	$ 64.68	$ 71.44	$ 64.56	n.a.	n.a.
South Carolina Electric & Gas*	$ 48.19	$ 49.05	$ 50.74	$ 49.70	$ 53.88	$ 50.79	$ 53.07	$ 54.42	$ 54.55	$ 60.29
Tampa Electric	$ 47.96	$ 50.18	$ 54.16	$ 62.62	$ 56.57	$ 55.43	$ 46.33	$ 56.59	$ 60.60	$ 55.77

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
	(Rank)									
Florida Power and Light*	**2**	**4**	**2**	**4**	**7**	**5**	**4**	**2**	**2**	**6**
Alabama Power*	10	10	10	10	10	10	10	10	6	7
Carolina Power and Light*	6	5	7	6	6	7	9	7	7	8
CLECO	9	7	6	7	4	3	2	1	1	1
Duke Power*	8	6	9	8	8	8	7	9	8	9
Florida Power Corp*	1	8	1	3	5	4	8	4	5	5
Georgia Power*	7	9	8	9	9	9	5	8	9	4
Gulf Power	11	11	11	11	11	11	11	11	10	10
Mississippi Power	12	12	12	12	12	12	12	12	11	11
Savannah Electric	3	1	3	2	1	1	1	3	n.a.	n.a.
South Carolina Electric & Gas*	4	3	5	5	3	6	3	6	4	2
Tampa Electric	5	2	4	1	2	2	6	5	3	3

Source: Federal Energy Regulatory Commission

Nuclear Investment Disallowances and Overruns

Unit	Utility	Original Cost	Final Cost (million $)	Cost Overrun	Percent Increase (%)	Disallowed (million $)	Disallowance as a Percent of Final Cost (%)
Braidwood 1	Commonwealth Edison Co.	$ 501.4	$ 3,265.6	$ 2,764.2	551%	$ 278.3	8.5%
Byron 2	Commonwealth Edison Co.	$ 350.0	$ 1,981.2	$ 1,631.2	466%	$ 180.6	9.1%
Byron 1	Commonwealth Edison Co.	$ 400.0	$ 2,558.4	$ 2,158.4	540%	$ 101.5	4.0%
Fermi 2	Detroit Edison	$ 220.7	$ 4,542.8	$ 4,322.1	1958%	$ 1,310.0	28.8%
Vogtle 1&2	Georgia Power Co	$ 847.8	$ 5,269.0	$ 4,421.2	521%	$ 541.0	10.3%
River Bend 1	Gulf States Utilities Co.	$ 390.0	$ 3,802.6	$ 3,412.6	875%	$ 1,297.0	34.1%
South Texas 1&2	Houston Light & Power	$ 959.8	$ 3,797.9	$ 2,838.1	296%	$ 375.5	9.9%
Clinton 1	Illinois Power Co.	$ 403.9	$ 4,264.3	$ 3,860.4	956%	$ 665.0	15.6%
Shoreham 1	Long Island Lighting	$ 223.0	$ 2,252.0	$ 2,029.0	910%	$ 1,395.0	61.9%
Waterford 3	Louisiana Power & Light	$ 230.0	$ 2,840.2	$ 2,610.2	1135%	$ 284.0	10.0%
Nine Mile Point 2	Multiple	$ 370.0	$ 6,030.4	$ 5,660.4	1530%	$ 2,141.0	35.5%
Wolf Creek 1	Multiple	$ 605.7	$ 2,641.3	$ 2,035.6	336%	$ 1,617.6	61.2%
Perry 1	Multiple	$ 1,234.0	$ 5,398.5	$ 4,164.5	337%	$ 665.0	12.3%
Seabrook 1	Multiple	n.a.	n.a.	n.a.	n.a.	$ 646.4	n.a.
Hope Creek 1	Multiple	$ 573.9	$ 4,494.9	$ 3,921.0	683%	$ 511.6	11.4%
Millstone 3	Multiple	$ 641.7	$ 3,825.0	$ 3,183.3	496%	$ 353.0	9.2%
San Onofre 1&2	Multiple	$ 378.5	$ 2,694.3	$ 2,315.8	612%	$ 252.0	9.4%
Grand Gulf 1	Multiple	$ 600.0	$ 3,281.2	$ 2,681.2	447%	$ 246.2	7.5%
Palo Verde 1-3	Multiple	$ 1,797.4	$ 5,859.7	$ 4,062.3	226%	$ 188.0	3.2%
Beaver Valley 2	Multiple	$ 295.9	$ 4,544.3	$ 4,248.4	1436%	$ 125.3	2.8%
Diablo Canyon 1&2	Pacific Gas & Electric	$ 304.1	$ 6,043.2	$ 5,739.1	1887%	$ 2,000.0	33.1%
Susquehanna 1&2	Pennsylvania Light & Power	$ 300.0	$ 2,171.1	$ 1,871.1	624%	$ 847.0	39.0%
Limerick 1	Philadelphia Electric Co.	$ 251.8	$ 3,822.0	$ 3,570.2	1418%	$ 368.9	9.7%
Summer 1	South Carolina Electric & Gas	n.a.	n.a.	n.a.	n.a.	$ 123.0	n.a.
Comanche Peak 1&2	Texas Utilities	n.a.	n.a.	n.a.	n.a.	$ 1,381.0	n.a.
Callaway 1	Union Electric Co	$ 839.0	$ 3,070.0	$ 2,231.0	266%	$ 413.7	13.5%

Nuclear Legislation and Regulation

Issue	Florida	Georgia	North Carolina	South Carolina	Louisiana	Kansas	Mississippi
Allows prudence finding on decision to move forward with nuclear	✓	✓	✓	✓	✓	✓	✓
Recognizes various nuclear power plant development phases	✓	✓	✓	✓	✓	✓	✓
Allows recovery of pre-construction investments prior to commercial operation	✓	✓	✓		✓	✓	✓
Allows recovery of cancelled plants	✓	✓	✓	✓			✓
Cash earnings on CWIP	✓			✓		✓	
Cost subject to prudence review	✓	✓	✓	✓	✓	✓	✓