BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 100437-EI

PROGRESS ENERGY FLORIDA, INC.

October 10, 2011

IN RE: EXAMINATION OF THE OUTAGE AND REPLACEMENT FUEL/POWER COSTS ASSOCIATED WITH THE CR3 STEAM GENERATOR REPLACEMENT PROJECT, BY PROGRESS ENERGY FLORIDA, INC.

REDACTED

TESTIMONY & EXHIBITS OF:

ALEXANDER J. "SASHA" WEINTRAUB

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PROGRESS ENERGY FLORIDA, INC.

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I. INTRODUCTION AND QUALIFICATONS.

Q. Please state your name and address.

A. My name is Alexander J. "Sasha" Weintraub. My business address is 410 South Wilmington Street, Raleigh, North Carolina 27601.

Q. Please describe your position in the Company.

A. I serve as Vice President of the Fuels and Power Optimization Department ("FPO") for both Progress Energy Florida, Inc. ("PEF" or the "Company") and Progress Energy Carolinas, Inc. ("PEC").

Q. Please describe your duties and job responsibilities in that position.

A. As Vice President of the FPO Department, I am responsible for the procurement of coal, natural gas, and fuel oil for the PEF and PEC generation fleet. I am also responsible for portfolio management and short term power trading for both PEC and PEF. In addition, I am responsible for the Company's coal, natural gas, and fuel oil price forecasts used for fuel filings and resource planning purposes in connection with the Company's Ten Year Site Plan filing each year, and I work closely with PEF's and PEC's System Planning groups, which are responsible for recommending long term capacity and energy purchases to meet reliability requirements for the respective systems.

Q. Please summarize your educational background and work experience.

A. I have a Bachelor of Science in Engineering from Rensselaer Polytechnic Institute. I have a Masters in Mechanical Engineering from Columbia University, and I have a Ph.D. in Industrial Engineering from North Carolina State University. From February of 2003 until June of 2005, I was the Director of Coal Marketing and Trading for Progress Fuels Corporation, a former subsidiary of Progress Energy. Before assuming my current position, I was the Director of Coal Procurement for PEF and PEC.

Q. Have you previously testified before the Florida Public Service Commission?

A. Yes. I have previously testified for PEF in a proceeding involving coal procurement for two of PEF's coal-fired units. I later testified for PEF in the Company's need determination proceeding for Levy Units 1 and 2. My most recent testimony was in connection with PEF's 2009 Petition for a base rate increase.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support the reasonableness and prudence of PEF's fuel purchases and replacement power costs associated with the Crystal

River Unit 3 ("CR3") nuclear power plant extended outage. I will explain the role of FPO and System Planning during the extended outage. In addition, I will also explain PEF's actions during the repair process with regard to PEF's fuel and power availability including contingency planning, reviewing load factors, and capacity plans to replace the CR3 unit during the extended outage including the methodology used. Finally, I will provide the actual replacement power and fuel costs through August 31, 2011 for the CR3 extended outage, net of Nuclear Electric Insurance Limited ("NEIL") insurance proceeds reimbursed to date, prior to filing my testimony in this proceeding.

Q. Do you have any exhibits to your testimony?

A. Yes, I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (SAW-1), Assessment of Potential Fuel and Purchase Power Impacts of CR3 Extension and Mitigation Activities to Minimize Costs presentation to the Senior Management Committee ("SMC") dated December 7, 2009;
- Exhibit No. ___ (SAW-2), Confidential PEF solicitation for replacement power for January – February 2010 and PEF evaluation of solicitation responses;
- Exhibit No. ___ (SAW-3), PEF 2010 Generating Unit Maintenance Outage Schedule;
- Exhibit No. ___ (SAW-4), Confidential PEF solicitation for replacement power for March – June 2010 and PEF evaluation of solicitation responses;

- Exhibit No. ___ (SAW-5), Confidential PEF solicitation for replacement power for June – September 2010 and PEF evaluation of solicitation responses;
- Exhibit No. ___ (SAW-6), Confidential PEF solicitation for replacement power for September – October 2010 and PEF evaluation of solicitation responses;
- Exhibit No. ___ (SAW-7), Confidential PEF solicitation for replacement power for November – December 2010 and PEF evaluation of solicitation responses;
- Exhibit No. ___ (SAW-8), Confidential PEF solicitation for replacement power for January – February 2011 and PEF evaluation of solicitation responses;
- Exhibit No. ___ (SAW-9), Confidential PEF solicitations for replacement power for March –April 2011 and PEF evaluation of solicitation responses;
- Exhibit No. ___ (SAW-10), Confidential PEF solicitations for replacement power for May—June 2011 and PEF evaluation of solicitation responses;
- Exhibit No. ____ (SAW-11), Confidential PEF solicitations for replacement power for June – September 2011 and PEF evaluation of solicitation responses;
- Exhibit No. ___ (SAW-12), Confidential CR3 Actual Replacement Power and Fuel Costs through August 31, 2011; and

- Exhibit No. ___ (SAW-13), Chart showing the application of the expected NEIL reimbursements to incremental recoverable costs attributable to the CR3 outage through August 31, 2011.

These exhibits were prepared by the Company under my direction and they are true and correct.

Q. Please summarize your testimony.

A. After discovery of the delamination event on October 2, 2009 at the CR3 nuclear plant resulting in an extended outage of the CR3 unit, FPO and the PEF System Planning group ("System Planning") within the Transmission Operations and Planning ("TOP") Department worked to ensure that the Company obtained cost-effective replacement fuel and power to assure that PEF reliably met system requirements during the extended outage. FPO and System Planning took reasonable and prudent measures to mitigate replacement fuel and power costs during the extended outage. These measures included acquiring additional gas flexibility and electric transmission capacity as well as firm and non-firm energy purchases when market prices were lower than PEF's forecasted marginal or avoided costs. However, except in peak months when PEF's costs can be at times higher than the market, PEF's marginal generation costs are equivalent to the market prices and, therefore, PEF generally determined that replacing the CR3 generation with generation from the PEF fleet was more economical for PEF's customers. In those limited economic opportunities where PEF's marginal cost of generation was above the market, PEF reasonably executed purchases to match the marginal cost profile of the system. In combination with these cost effective energy and gas supply purchases, PEF also adjusted planned maintenance schedules for a number of power plants during the extended outage to mitigate system cost risk during potential periods of higher system demand volatility throughout the outage. As a result of the Company's actions, PEF was able to mitigate CR3 replacement power cost risk by securing cost-effective fuel and replacement power for our customers. PEF reasonably and prudently incurred $438,976,648 in replacement fuel and power costs through August 31, 2011 during the CR3 unit extended outage before applying any NEIL insurance proceeds. The expected reimbursement to be received from NEIL based on submitted claims for the period from April 9, 2010 through August 31, 2011 is $308,571,429. After deducting the expected NEIL reimbursements, the total net balance of reasonably and prudently incurred actual replacement power and fuel costs through August 31, 2011 is $130,405,219.

Q. Please describe the role and responsibilities of you and your organization with regard to responding to an unplanned outage such as the one experienced at CR3.

A. The FPO Department's primary goal is to ensure that our customer's needs are met reliably and cost effectively. To that end, FPO is responsible for fuel procurement, fuel transportation, short term energy market engagement, and unit commitment and dispatch planning. The FPO Department also produces the Fuel & Operations Forecast ("FOF"), which projects how the Company plans to meet future energy and capacity needs and is used to assist with fuel procurement decisions over a three year horizon and purchases and sales of energy and capacity over a one year horizon.

In order to fulfill its responsibilities, FPO works closely and coordinates with other organizations within PEF, including TOP System Planning. TOP System Planning is primarily responsible for long term resource planning to provide PEF with resources necessary to serve projected customer needs. The TOP Department is also responsible for real time system dispatch. In addition, the Company's POG and Nuclear Generation Group ("NGG") are responsible for the operation of PEF's fossil-fired generation and nuclear generation fleets, respectively. As part of its normal business operations, the FPO Department coordinates with all of these organizations to ensure that its analysis and decisions properly reflect projected customer needs, system conditions, and generating unit availability.

In terms of responding to an unplanned generation outage, FPO's role is two-fold. First, FPO is responsible for assessing the situation from a near-term reliability perspective. FPO evaluates the outage to determine whether it threatens PEF's ability to serve customer needs or meet the Company's Florida Reliability Coordinating Council ("FRCC") generation capacity reserve margin obligations. This evaluation requires coordination among FPO, TOP, POG and NGG because factors such as forecasted load, planned generation outage schedules, and unit availability must be considered.

Second, regardless of whether the unplanned outage presents a reliability concern, FPO is responsible for mitigating the effects of the unplanned outage in a cost-effective manner. At a high level, FPO's cost mitigation strategy is similar for any significant outage of baseload generation, and could involve making additional power purchases, purchasing strategic incremental transmission capacity, adjusting fuel positions, and adjusting maintenance outage schedules for other units. The actions taken can vary depending on a number of factors, including the length of the unplanned outage, the load forecasted for that period, projected fuel cost and availability during the outage, availability of other PEF generation and demand-side resources, and the cost and availability of capacity and energy from third parties.

Q. Did the FPO Department take the steps you described to address an unplanned outage with the unplanned outage of CR3?

A. Yes. As explained in more detail below, FPO, in conjunction with TOP, POG, and NGG, developed and effectively executed a plan that addressed the extended CR3 outage from both a reliability and economic perspective. In order to evaluate whether CR3's unavailability created any potential reliability concerns, FPO conducted periodic assessments throughout the outage period based on a range of assumptions and scenarios to determine whether, at any point, the loss of CR3 might cause a shortfall of capacity that could threaten system reliability. As FPO concluded that additional capacity was not needed for reliability reasons to compensate for the loss of CR3, FPO then took several steps to mitigate the potential economic impact of the CR3 outage. PEF's marginal generation costs are generally at parity with FRCC market prices, with the exception of peak months when our costs can be somewhat higher. Consequently, it was predominantly more economical to replace CR3 generation from the PEF fleet than to purchase it from the power market. However, when necessary during the peak months, based on periodic market solicitations, and the continuing nature of the extended outage, FPO identified the limited economic opportunities and executed purchases in monthly, daily, and hourly tenors as best fit the marginal cost profile of the system during the course of the outage. PEF also acquired additional electric transmission from neighboring utilities to ensure the deliverability of these energy purchases. This strategy enabled PEF to identify and execute economic purchases when the cost of energy from the market was lower than our marginal system generation cost. PEF actively and continuously engaged the short and mid-term market to identify the most economic replacement power solution. For the period of December 20, 2009 through August 31, 2011, this strategy resulted in a CR3 replacement energy mix of 82% self-generation and 18% market purchases. Again, the goal of our market engagement was to efficiently use the power market as a resource to reduce the impact of the CR3 outage on our customers. In addition, FPO worked with POG to adjust planned maintenance schedules of other PEF resources to mitigate the effect of the CR3 outage.

Q. Did FPO keep the Company's senior management informed of the steps you were taking to obtain replacement power and fuel to respond to the extended unplanned CR3 outage?

A. Yes. The issues surrounding the outage at CR3 were of critical importance to PEF. Accordingly, senior management and the Board of Directors were kept well-informed regarding these issues, including our efforts to ensure that the

Company fulfilled its obligations to maintain reliable service to its customers in a cost-effective manner. Specifically, I met with Paula Sims, Senior Vice President over Power Operations, on a regular basis to keep her apprised of these matters. In addition, either I or Ms. Sims provided updates on reliability and replacement power activities related to the CR3 outage at our SMC meetings beginning in December 2009. Further, periodic updates and reports were provided at the PEF CEO's monthly business review meetings, which is attended by all of PEF's department heads, and at the monthly meetings of Progress Energy's Risk Management Committee, which is comprised of several members of senior management. In addition, TOP System Planning provided operational assessments to the PEF CEO outlining the steps the Company was taking to ensure reliable system performance during the outage period. Finally, beginning with the March 22, 2010 Board of Directors meeting, reports on the status of our activities and plans to address PEF's energy needs in light of the CR3 outage were presented to the full Board of Directors.

Q. When did you first learn of the October 2, 2009 CR3 delamination?

A. I first heard of this issue on October 9, 2009 during a Progress Energy management meeting. Jim Scarola, the Company's Chief Nuclear Officer, gave a brief update of the CR3 outage and reported that a delamination was discovered in the containment building, and that NGG was in the process of assessing the extent of the issue.

Q. What steps did you take upon learning of this delamination?

A. Because NGG's investigation into the delamination was at an early stage, it was not yet clear how the delamination might impact the outage schedule beyond the scheduled December 20, 2009 outage completion date. Even though the delamination's impact on the CR3 outage remained uncertain, FPO began contingency planning in late November 2009 in the event that the outage lasted beyond its scheduled completion date. This initial contingency planning for a potential extended unplanned outage at CR3 was prudent for two reasons. First, it would give the Company a better understanding of the potential customer impact of such an outage. Second, it would provide an indication of the incremental fuel needs resulting from a potential extended CR3 outage, which would allow FPO to begin contingency planning for the Company's 2010 fuel and power acquisition strategy.

Q. What form did FPO's contingency planning take for a potential extended unplanned outage at the CR3 unit?

A. FPO studied the following issues: i) the opportunities available to mitigate the cost impact of the outage if it lasted until the end of February 2010, ii) the impact of the unavailability of CR3 during the 2010 winter and summer peak periods from a reliability perspective, and iii) the incremental fuel and cost impact of the potential extended outage on a month-by-month basis through the end of 2010. FPO studied the opportunities available to mitigate the cost impact of an unplanned outage through February 2010 because this was PEF's winter peak period when PEF historically experienced weather-related increases in system load demand. As a result, FPO specifically studied this period because additional resources beyond PEF's generation resources were possibly needed to replace CR3 during this period of historically higher peak demands.

Similarly, PEF studied the impact of an extended unplanned outage at CR3 during both the winter and summer peak periods in 2010 to ensure that PEF's customers were reliably served. Any such reliability concerns would be most evident during the periods of highest customer demand. FPO therefore believed prudent planning required PEF to look ahead to its peak customer demand periods in the upcoming year to determine whether an extended outage at CR3 during those peak demand periods posed any reliability concerns even though it was not yet clear how long CR3 would be out of service. Waiting until PEF later learned of an extended outage into the peak periods to begin to determine if that extended outage required PEF to seek outside generation resources to reliably provide service to PEF's customers during the peak periods may have compromised our ability to meet that reliability need in the most cost-effective manner.

Finally, PEF studied the impact of extending the CR3 outage on a month-by-month basis through the end of 2010. The reason for this study is that PEF needs to look at potential longer term reliability and economic impacts as a consequence of its decisions to make replacement power or fuel decisions even during a more limited time period. In this way, FPO ensures that it is considering the preceding and subsequent consequences of a replacement fuel or power decision in its determination that the decision is the most cost-effective means of reliably meeting customer demand. Indeed, FPO takes both a short and long term view of all fuel decisions and, as a result, FPO will typically consider system needs over several months around the purchase decision and on an annual basis to ensure that it has the full picture of the system and its needs before making a decision.

Q. What was the FPO assessment of the 2010 winter and summer peak periods?

A. In early December 2009, FPO completed a high level assessment of the 2010 winter and summer peak periods assuming normal weather and potential generation constraints, including possible extension of the CR3 outage through these peak periods, scheduled generating unit maintenance outages, and possible derates of generation facilities during the summer peak period. Based on that review, we determined that PEF was able to meet expected 2010 winter firm peak demand without CR3. Similarly, if the CR3 outage extended into the summer of 2010, FPO's analysis showed that PEF was also able to meet its expected 2010 summer firm peak demand without CR3. In light of the results of this analysis, we concluded that the loss of CR3 was at that point an economic matter rather than a reliability issue. FPO, of course, continued to monitor the Company's reliability needs closely throughout the outage for any changes in this assessment.

Q. What was the FPO month-to-month assessment of a potential year-long CR3 outage?

A. The assessment was based on the November 2009 FOF, which was the Company's most current projection of system operations for 2010. FPO ran the November 2009 FOF without CR3, assuming normal weather and normal fuel and capacity availability. The assessment, which applied mid-October 2009 commodity prices, was completed in early December, and provided the Company with a general overview of the potential impact of an outage lasting through the end of 2010.

Based on this assessment, the Company estimated that replacement power and fuel costs were approximately $300 million, before the application of insurance proceeds, if the CR3 outage lasted through the end of 2010. The Company recognized that several factors could impact the accuracy of that estimate, including weather conditions, availability of PEF's other units, availability of capacity and energy in the market, and changes in commodity prices. The assessment also showed, however, that no significant adjustments were needed to the Company's 2010 fuel procurement plans, with the possible exception of evaluating the need for additional gas flexibility during the summer seasonal months of April through October, if the unplanned outage at CR3 extended to the end of 2010. This assessment demonstrated that the Company was well positioned with its own resources to reliably and efficiently replace CR3 in a scenario where the unplanned outage extended to the end of 2010.

At the time of this assessment PEF had not completed its investigation of the delamination event to estimate the expected length of the CR3 outage. FPO selected the end of 2010 as the outage period because this period covered both upcoming peak periods in 2010 when the need to reliably provide power is most critical and provided a broader view of PEF's capacity and energy resources and needs consistent with FPO's typical outage assessments. An annual period provided PEF with this broader view and for that reason the end of 2010 was selected for the CR3 extended outage for this assessment. This assessment was presented to SMC on December 7, 2009 and is included as Exhibit No. ___ (SAW-1) to my testimony.

Q. What steps were taken by FPO to assess the opportunity to mitigate the potential cost impact of CR3 being unavailable for the winter in January and February 2010?

A. In early December of 2009, PEF solicited market offers for available block energy products for January – February 2010 at the Florida – Georgia border and in the regional market for comparison against PEF's projected avoided cost. As part of this solicitation, FPO also evaluated the availability of potential firm and non-firm transmission positions for the January – February 2010 period.

Q. Before further discussing FPO's solicitation activities, can you briefly discuss FPO's experience in the Florida and regional power markets, and how that knowledge informs PEF's approach to potential unplanned generation outages?

A. Yes. The FPO power trading desk has extensive experience in the electric power markets, and more than 10 years of experience trading on behalf of Progress Energy in the Florida and regional power markets.

As part of its normal business activities, FPO actively monitors these power markets throughout the year to assess whether economic purchases of capacity and/or energy can be made below PEF's avoided costs. Even absent an unplanned outage, PEF routinely enters into economic energy transactions during a given period to ensure customers are being served in a reliable and cost-effective manner. When an unplanned outage does occur, PEF uses its market knowledge combined with PEF's assessment of the expected duration and generation resource-impact of the unplanned outage to evaluate whether additional purchases would be economic. FPO similarly evaluates potential transmission purchase opportunities to determine whether sufficient savings would be expected from prospective market purchases below PEF's incremental generation costs to offset the fixed transmission capacity charge.

Q. Can you also briefly discuss the Florida and regional power markets?

A. Yes. The Florida power markets are unique in that transmission capacity into the Florida peninsula is constrained, and for the most part fully subscribed. Generally, the available supply of competitive generation at the Georgia – Florida border greatly exceeds the available transmission capacity into the state. Consequently, if a purchaser has access to import capability, the imported power tends to be somewhat less expensive than power available from in-state suppliers because of the larger number of supply options available from the Southern Company ("SOCO") power markets compared to peninsular Florida. For that reason, PEF has strategically invested in a 100 megawatt ("MW") long term transmission position across the Jacksonville Electric Authority ("JEA") system into Florida, which provides the Company access to the regional SOCO market.

Beyond the short term spot market, the Florida and out-of-state regional energy markets are most liquid in standard block sizes and standard delivery periods such as 16- or 24-hour five or seven day blocks (these are referenced in the industry as "5x16," "7x16" and "5x24," "7x24," respectively). Normally these energy block products are offered for monthly or seasonal periods, with the January – February period being a common seasonal trading block. The economic benefit of such purchases is derived from displacing higher-cost Company resources, while the potential cost risk is that purchases made in these standard trading blocks and delivery periods do not economically displace higher cost generation during enough hours to offset the cost of committing to these purchases during hours when lower cost gas or coal generation could be the marginal generation resource. Similarly, purchasing firm or non-firm transmission with the intent of facilitating spot market purchase opportunities also carries cost risk if it is not used often enough.

Q. Returning to FPO's solicitation activities, describe FPO's solicitation approach and its evaluation of potential purchase opportunities for the January – February 2010 period?

A. For purposes of addressing the potential unavailability of CR3 through February of 2010, FPO's solicitation particularly focused on potential purchases at the Georgia – Florida border, which, as noted above, tend to be somewhat less expensive than similarly available in-state products. Through its solicitation, FPO sought firm 7x16 energy delivered on firm transmission to a PEF interface or at the JEA interface on the Georgia – Florida border. As set forth in Exhibit No. ___ (SAW-2), FPO received a number of responses from solicited potential counterparties. In order to evaluate whether the offers FPO received in response to its solicitation were projected to be economic, FPO compared such potential purchase opportunities to the Company's avoided cost.

Q. Please explain how FPO calculated PEF's avoided costs and evaluated whether the potential energy purchases received in response to its solicitation would be economic.

A. Avoided costs were calculated with the same production cost model used to produce the PEF FOF. This process begins with updating the most recent FOF model as needed with current information, such as fuel cost and generating unit outage schedules. This model is then run with and without the potential transaction. The change in production cost between the two cases is then compared to the total cost of the potential purchase to determine if the transaction is economical. As transactions were evaluated, determined to be economic, and then executed by PEF, FPO's avoided cost modeling incorporated these executed transactions in its evaluation of future transactions. This approach of using a production cost model to forecast avoided cost is consistent with the method supported by Florida Public Service Commission ("FPSC" or the "Commission") Staff as the most accurate method available to calculate replacement costs. *See* Order No. PSC-10-0381-FOF-EI. This approach is also consistent with the general methodology approved for the PEF As-Available Tariff. Exhibit No. ___ (SAW-2) compares PEF's projected avoided costs for January – February 2010 with the offers received in response to FPO's solicitation.

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Q. Based on this analysis, did PEF make any block energy purchases or reserve transmission for the January – February 2010 period in the event the CR3 unplanned outage was extended into this time period?

A. No. As Exhibit No. ___ (SAW-2) shows, PEF's avoided cost projection for the January – February period was approximately [redacted] per MWh for energy received at the PEF interface [redacted] per MWh at the JEA/SOCO interface) and the responses FPO received ranged from [redacted] per MWh to [redacted] per MWh. Thus, even without risk adjustments for deliverability due to transmission curtailment or load forecast variability, all of the energy offers received were above PEF's anticipated avoided dispatch costs, and, therefore, were deemed to be uneconomic. It should be noted that the offers received were almost exclusively from out-of-state counterparties. As noted above, power purchased from such out-of-state sources tends to be slightly less expensive than similar in-state purchases.

Regarding transmission purchases, at the time, there was no additional firm transmission available from any Florida – Georgia border transmission provider. FPO also considered purchasing an available 100 MW of non-firm transmission into Florida across the JEA system to facilitate potential spot market purchases, but determined that the few periods of relatively short duration when such spot purchases were projected to displace higher priced PEF generation did not justify incurring the fixed cost of reserving transmission capacity for this period. FPO also had concerns over whether this non-firm transmission would be interrupted, as it is not uncommon in Florida for non-firm transmission to be curtailed in order to maintain reliability during peak demand periods when purchases would otherwise be most beneficial. Based on these analyses, FPO chose not to purchase blocks of wholesale power or to reserve additional transmission for the January – February 2010 time period. Instead, FPO elected to continue to monitor the energy markets and make more economically certain, shorter duration transmission and spot market purchases if they proved economic.

Q. Did you make such spot purchases during the January – February 2010 period?

A. Yes. The FPO Department was particularly active in the market during early to mid–January 2010. Again, it is important to note, however, that FPO constantly evaluates the regional wholesale power markets in an effort to identify economic short-term purchase opportunities for the benefit of PEF's customers, even when all of its resources are available. When abnormal events such as an unplanned extended outage or extreme weather occur, FPO is well equipped to evaluate whether potential opportunities exist to obtain replacement resources at costs lower than PEF's available generation resources.

As the Commission will recall, January 2010 was one of the coldest on record, during which record lows were set throughout the State and temperatures remained well-below normal for an extended period during the first two weeks of the year. As a result of these unprecedented conditions, PEF had to rely upon higher cost resources than previously anticipated, which resulted in a greater number of economic purchases during these two weeks of January 2010 than anticipated. In addition, an emergency purchase of 738 MWh from a neighboring utility was made on January 11^{th}, during the two highest hours of the winter peak day. This purchase would have been necessary to meet load requirements on the PEF system even if CR3 had remained online. In total, PEF purchased 83,418 MWh in January 2010, approximately 90% of which was purchased for the period of January 4 – 12 during the height of the cold snap.

Q. What is Direct Load Control ("DLC")?

A. DLC refers to when utilities, in accordance with contractual arrangements, can interrupt consumer load at times of seasonal peak load by direct control of the utility system operator or by action of the consumer at the direct request of the system operator.

Q. Has DLC been implemented during the outage?

A. Yes. PEF's approach to the use of DLC has remained consistent throughout the outage.

Q. Was increased reliance on DLC considered as an economic alternative to market power purchases during the winter peak?

A. No. From an operational planning perspective, the primary purpose of DLC is to respond to emergent or immediate loss of supply resources or short term unusual or rapidly changing load conditions, such as extreme weather. Importantly, increased reliance on DLC is not considered as an alternative to market power purchases because DLC is preserved as the only immediate response capability for emergent contingencies. For example, the regional reliability coordinator requires that PEF recover from the loss of a generating unit within 30 minutes, and DLC is one of the primary tools used to satisfy this requirement when reliability is threatened. DLC can also play an economic role by reducing system demand until a more economic mix of resources is available to replace the emergent loss of a generating unit. However, excessive reliance on DLC, either in duration of consecutive hours or successive periods over a number of days, can result in cancellations and loss of DLC MW capability (as we have experienced in the past), and could potentially threaten system reliability.

Q. During the January – February 2010 timeframe, was FPO receiving updates on the projected length of the CR3 outage?

A. Yes. During that period, members of FPO, including myself, were having regular conversations with NGG regarding the CR3 repair effort. During this time period the scope of the repair effort was still being determined; PEF had decided that the repair required removal of the delaminated concrete; however the repair plan was still being finalized. Nevertheless, based upon the information FPO received, the probability increased that the outage would last at least until mid-year and on January 25, 2010 the Company provided a status report to the Commission indicating that PEF expected at that time CR3 to return to service by mid-year 2010.

Q. How did FPO respond to this information?

A. FPO began working on a second solicitation to assess opportunities to further mitigate the impact of the outage during the March – June 2010 period through potential economic purchase opportunities. In early February, PEF conducted this second market solicitation in a similar manner to the earlier solicitation conducted for the January – February timeframe. PEF continued to use a solicitation process rather than a formal Request for Proposal ("RFP") process in order to maintain flexibility. At this point, the CR3 repair process was still at an early stage and the potential need to adjust the Company's strategies and contingency plans in response to changes to the CR3 repair plan was paramount. Utilizing this more flexible solicitation approach allowed PEF to minimize the risk of potentially unnecessary or uneconomic purchases of transmission, energy, or capacity. Consequently, PEF elected an approach that allowed FPO to have open, iterative dialogues with a broad range of potential counterparties. FPO was satisfied these dialogues yielded competitive offers for transmission, energy, or capacity because the potential counterparties were aware of PEF's potential needs due to the extended CR3 outage and that FPO was having discussions with other, potential counterparties to meet these potential needs.

In addition, given the now apparent likelihood that the CR3 outage would last into the summer of 2010, FPO worked with PEF System Planning and POG to update its earlier reliability analysis and analyze the potential impact of the outage extending into the summer peak demand period. Utilizing historical load data and the most current forecast inputs, high, expected, and low case scenarios were developed for projected load and capacity. This sensitivity analysis showed that in almost all scenarios, PEF was projected to have sufficient capacity to meet firm peak demand during the March – June 2010 time period. The one exception was the high load/low capacity scenario, which assumed the second highest peak loads in the past 10 years and the unavailability of the single largest unit in addition to the unavailability of CR3. In that scenario, there was a 150 MW shortfall in May 2010 due, in part, to several planned maintenance outages during that month. At this point, however, ongoing assessments of potential outage adjustments were underway to address this extreme scenario and to further improve economic resource availability during the May timeframe.

Q. What did you conclude from that updated analysis?

A. The impact of the CR3 outage still appeared to be primarily an economic issue, not a reliability issue. However, the fact that one scenario suggested a possible, albeit unlikely, capacity shortfall in May 2010, PEF determined that options to mitigate that possibility should be considered.

The assessment also indicated that meeting customer demand through the summer without incremental purchases required utilization of virtually all of PEF's resources, including its least efficient units. Consequently, purchases during the May – June 2010 period likely could mitigate the economic impact of the CR3 outage. Finally, in order to ensure that natural gas supply, gas transportation, and electric transmission availability would not become limiting factors during the summer, FPO concluded that assessing options for procuring additional gas flexibility and electric transmission should be considered.

Q. What actions did the Company take as a result of this updated assessment?

A. During the February – April 2010 timeframe, FPO undertook several tasks in parallel, including optimizing its spring generation maintenance outage schedule and evaluating and executing cost effective power purchases for the May – June

2010 period. First, FPO worked with POG to review the maintenance schedule for PEF's fossil fleet in order to optimize capacity availability. FPO and POG were particularly focused on the May time period during which capacity margins were projected to be tightest. As a result of that effort, POG made several changes to its maintenance schedule during this period. These changes, as reflected on Exhibit No. ___ (SAW-3), included:

- Anclote Unit 1's three-week spring outage scheduled to begin May 8 was moved up a week in order to bring the unit back earlier in May.
- Anclote Unit 2's one-week spring outage scheduled to begin April 17 was shifted to the fall to coincide with an already planned extended outage for the unit.
- Tiger's Bay's three-week spring outage scheduled to begin April 14 was shortened and performed during the late March timeframe to ensure summer reliability, while the main portion of Tiger Bay's planned work scope was moved to the unit's planned fall outage.
- Suwannee Units 2 and 3's two-week outages scheduled to take place in May were shifted to lower load periods in March and April when these units were not in demand.
- Crystal River Unit 5's one-week spring outage scheduled to begin May 22 for an inspection of the unit's newly installed scrubber was ultimately cancelled after it was deemed unnecessary by the vendor and POG due to satisfactory performance of the new scrubber.

As a result of these generation maintenance schedule changes, the risk of further unit unavailability during May 2010 was reduced by approximately 500-700 MWs and this capacity was made available for economic dispatch for the majority of the month. These adjustments greatly mitigated any possible capacity concerns associated with the CR3 outage during the spring outage and summer peak season.

Q. What other steps did you take to mitigate the impact of the extension of the CR3 outage into the summer period?

A. In order to further mitigate the economic impact of the CR3 outage, PEF also solicited offers for economic wholesale energy purchases through June 2010. PEF sought proposals for up to 500 MWs of energy delivered to a PEF interface in the standard and most liquid 7x16 or 7x24 blocks, as well as allowing for more customized products that often carry a premium price. PEF also sought offers for up to 100 MWs of energy delivered at the Florida/JEA interface, also in 7x16 or 7x24 blocks, in order to utilize PEF's 100 MW firm transmission path into the State into PEF's system. Further, while FPO primarily focused on potential energy-only purchases to help mitigate the economic impact of the outage, FPO also solicited and evaluated energy offers that included fixed capacity payments. These energy call options, while offering the operational benefit of not having must take energy provisions, generally include a large fixed capacity charge. Similar to the energy-only offers FPO received, FPO analyzed these transaction structures through its modeling analysis to evaluate potential displaced generation savings.

Q. What were the results of the solicitation for the spring outage and summer peak periods?

A. The results of FPO's solicitation for March – June 2010 and PEF's projected avoided costs for this period are summarized in Exhibit No. ___ (SAW-4) to my testimony. PEF received offers from 10 parties, some of which offered multiple options, all of which are set forth on Exhibit No. ___ (SAW-4). Initially, throughout the month of February 2010, FPO focused on potential economic purchases for the March – April 2010 period, and continued to evaluate its system requirements and potential opportunities for cost effective purchases into the summer. As with FPO's analysis of the earlier offers received for January – February, FPO chose not to make any block purchases for the March – April 2010 period because PEF was not projecting a capacity need and the offers FPO received in response to its solicitation were determined not to be economic.

The offers received for May – June 2010 presented a range of options in terms of quantity, length of time, delivery points and firmness. In order to assess these offers, FPO developed a matrix to organize the offers by structure (i.e., 7x16 and 7x24), delivery point, and price. Several offers appeared favorable compared to PEF's higher avoided costs for these months. PEF, therefore, targeted the following opportunities:

- Purchase 100 MWs of on-peak energy at the Florida interface and utilizing PEF's existing transmission path across JEA for May and June;
- Purchase 100 MWs of on-peak energy at a PEF interface for May only, as June market offers at the time did not provide economic benefit; and
- Amend the executed 2-year Vandolah facility (158 MW) tolling agreement to accelerate the start date from June 1, 2010 to May 1, 2010.

The most economic offers for delivery at the Florida border were provided by [redacted] and [redacted]. Consequently, FPO focused on negotiating with these parties for the potential delivery of 100 MWs of energy at the Florida/JEA interface[redacted] also appeared to provide the best offer for energy delivered to the PEF border, but FPO continued to discuss possible transactions with [redacted] in the event that a satisfactory transaction could not be negotiated with [redacted]

Q. What specific actions did FPO and TOP take to execute the foregoing strategy?

A. In March 2010, FPO negotiated three energy purchases – two 50 MW, 7x16 blocks delivered at the Southern Company/JEA interface [redacted] for May and June 2010, and a 100 MW 7x16 block from [redacted] delivered to PEF for May 2010. In early April 2010, PEF also successfully negotiated with RRI Energy Services ("Reliant") to accelerate delivery of energy from the Vandolah facility for the month of May. This negotiation expanded the scope of a then-final, multi-year purchase power agreement previously scheduled to commence on June 1, 2010.

Q. When did FPO know that the CR3 outage would extend beyond mid-year?

A. Throughout March and April, FPO was receiving regular updates from NGG regarding the status of the CR3 outage. Some of these communications were through participation in management updates and others were less formal discussions. As a result, by mid-April, it appeared possible that the CR3 outage could extend beyond mid-year. This determination was made later, and the Company announced on May 5, 2010 that PEF expected that CR3 would return to service in the third quarter of 2010, but in the meantime FPO commenced contingency planning for an additional extended outage.

Q. What actions did you take to plan for an additional extended outage at CR3?

A. FPO followed essentially the same process that it used previously to assess the impact of the CR3 outage from both a reliability and economic standpoint. FPO in conjunction with the TOP Department and POG developed an updated scenario analysis using high, expected, and low cases for load and capacity availability for the July – September period. This analysis was based on inputs used for the May FOF to ensure that the most current information and projections were used.

The results of the updated scenario analysis were generally similar to the results of previous analyses. The unavailability of CR3 during the July – September 2010 period did not appear to pose an immediate reliability concern. In most scenarios, PEF projected that PEF's generation and available DLC resources were sufficient to meet projected peak demands. Here again, however, a modest capacity shortfall resulted in the low capacity/high load scenario. Although these results did not suggest any immediate reliability concerns, FPO was cognizant of the potential that extreme weather could extend high peak loads for long periods of time beyond the normal, reasonable availability of PEF's

DLC resources. FPO concluded that specifically seeking out capacity purchase opportunities was not necessary, but was aware of these scenario analyses and took them into consideration as it analyzed potential economic purchase opportunities for the summer period. FPO's analysis also showed that PEF's avoided cost for this period was expected to be significantly higher than it was in previous periods, which suggested that there may be opportunities to make economic purchases during the July – September 2010 timeframe to mitigate the economic impact of a continued outage at CR3.

Q. What actions did you take based on this updated scenario analysis?

A. Beginning on or about April 19, 2010, FPO commenced a new solicitation seeking offers from the same broad group of in-state and regional power suppliers that FPO had solicited in February. For this late summer period, FPO also focused its solicitation on on-peak only energy schedules because these 7x16 and more narrow on-peak products better fit PEF's system load profile and their cost premium relative to 7x24 products was minimal. Again, PEF received a wide range of responses and FPO developed a matrix to organize its analysis of the responses received. Because PEF was seeking offers for summer energy, FPO received some responses for June as well as July – September. The responses to this solicitation for the summer 2010 period as well as PEF's projected avoided costs for June – September are summarized in Exhibit No. ___ (SAW-5).

After reviewing the responses, PEF chose to pursue a 100 MW 7x16 block delivered to PEF for the June – August period from [redacted] PEF also bought a

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100 MW 7x16 block from [redacted], delivered at the Southern Company/JEA border, for July and August. Both of these transactions were executed in late April. In addition, on May 11, PEF also purchased from [redacted] three smaller 7x8 blocks delivered to the PEF system – 10 MWs in June and 20 MWs in July and August, respectively.

Finally, after reviewing the responses that PEF received, PEF further determined that an additional purchase from Reliant's Indian River facility for the months of July through September 2010 was cost-effective. Although the primary rationale of this purchase was economic, the incremental capacity provided by the Indian River purchase also mitigated the risk of a potential capacity shortfall in the event of extraordinary high loads coupled with the loss of one of PEF's largest remaining generating units. Accordingly, in late June, PEF executed a tolling agreement for a 300 MW gas-fired steam boiler unit, with the output delivered to the PEF system. Under that agreement, PEF elected when to take the energy from the plant and provided the gas used at the plant if and when PEF made this election. After consideration of the [redacted]-month capacity charge for the Indian River transaction, PEF determined this transaction was cost-effective based on the total of the capacity and transmission payments compared to PEF's total cost of production.

Q. During the summer, did FPO plan for the contingency that the CR3 outage could extend into the 4th Quarter of 2010?

A. Yes. During the summer months, FPO actively monitored power flow under the executed transactions while continuing to receive regular updates from NGG regarding the status of the CR3 outage and the ongoing repair effort. Based on these updates the possibility existed, that the CR3 outage might extend beyond the planned third-quarter 2010 return to service date. In response to this possibility, FPO took a number of actions in mid-July to ensure that PEF was adequately prepared for a potential further extension of the CR3 outage. First, FPO and POG identified and recommended a number of opportunities to adjust the duration and timing of the fall generating unit outages such that additional generation reserves were available during periods where PEF was likely to experience higher loads. Second, FPO updated its assessment of the impact of the CR3 outage from both a reliability and economic perspective through the end of the year in preparation for another potential power market solicitation. These actions proved necessary when the Company announced on August 6, 2010 that the expected return to service date for CR3 was extended to the 4th quarter of 2010.

Q. Describe FPO's assessment of the fall generation maintenance outage schedule.

A. Initially, the fall generation maintenance schedule included a significant amount of capacity that was out of service for maintenance during October and November 2010. As Exhibit No. ___ (SAW-3) shows, scheduled outages were planned for Anclote Unit 2, Bartow Unit 4, Hines Units 1, 3, and 4, and Tiger Bay during this period. Also, Southern Company's Scherer Unit 3 and Franklin unit, which were under firm capacity contracts with PEF, were scheduled for maintenance outages during this period. In combination with the unavailability of CR3, these maintenance outages would likely require PEF to utilize nearly all of its remaining supply resources, including its less efficient units to reliably serve customers during the fall generation maintenance outage period. FPO also recognized that PEF's risk of high loads was greatest during the first two weeks of October compared to later periods during the fall maintenance outage. These factors presented FPO and POG with an opportunity to optimize PEF's maintenance outage schedule in order to improve system reserve margins during early October as well as potentially mitigate the economic impact of the CR3 outage throughout the fall.

Q. What actions did PEF take to optimize the planned generation maintenance outage schedule during the fall?

A. In July 2010, FPO worked with POG to revise the fall maintenance schedule for PEF's fossil fleet in order to increase the amount of capacity available early in October when the monthly peak has historically occurred. As a result of that effort, POG made several changes to its maintenance schedule in late July 2010 for the fall. These changes are reflected on Exhibit No. ___ (SAW-3) and include:

- Anclote Unit 2's 42-day fall outage scheduled to begin on October 2 was reduced in scope and duration to a 28-day outage extending from October 16 through November 12.
- Crystal River Unit 1's one-week outage scheduled to begin on October 23 was shifted to November 6 through November 14 in order to improve system economics and reserve margins.

- Crystal River Unit 5's eight-day scrubber warranty outage scheduled to begin on November 6 was shifted to November 13 through November 20, which was one of the weeks vacated by shifting the Anclote Unit 2 outage in order to improve system economics and reserve margins.
- Bartow Unit 4's 62-day outage scheduled to begin on October 18 and continue to mid-December was reduced in scope and duration to a 35-day outage extending from October 16 through November 20 in order to improve the overall system maintenance schedule and reserve margins.

As a result of these changes to the generation maintenance schedule, PEF was able to substantially improve system economics by moderating the use of less efficient generation while ensuring that PEF had sufficient reserve margins throughout the fall.

Q. Can you describe the updated scenario analysis FPO developed for September – December 2010?

A. Yes. Similar to prior periods during the outage, FPO, in conjunction with the TOP Department and POG, developed an updated scenario analysis using high, expected, and low cases for load and capacity availability for the September – December 2010 period. This updated analysis, which incorporated the fall generation maintenance schedule modifications, was based on inputs used for the July FOF to ensure that the most current information and projections were incorporated. The results of the updated scenario analysis showed that the unavailability of CR3 during the September – December 2010 period was an economic issue that did not appear to pose an immediate reliability concern.

FPO's analysis projected that PEF's resources were sufficient to meet PEF's expected firm peak demands for the September – December 2010 period.

Q. What mitigation actions did PEF take for the September through December 2010 period based on FPO's updated scenario analysis?

A. In early July, PEF secured 100 MWs of incremental non-firm transmission across JEA's system and 100 MW of incremental firm transmission across Seminole Electric Cooperative, Inc. ("Seminole") for October to connect the Georgia-Florida border and PEF control area. These incremental transmission positions were purchased to facilitate daily and hourly economy purchases and as a contingency for above normal weather or forced outages of other units, where additional purchases would be economically beneficial. On or about July 26, 2010, FPO also commenced a new solicitation process for potential economic energy purchase opportunities for the September through December 2010 period. PEF again received a wide range of responses from both in-state and out-of-state suppliers, including offers to extend a number of the purchases made during the summer months. For example, the 300 MW Indian River purchase, which currently only extended through September, was evaluated for potential extension through October. FPO once again developed a matrix to organize its analysis of the responses received. The responses to this solicitation for the September – December 2010 period as well as PEF's projected monthly avoided costs for this period are summarized in Exhibit No. ___ (SAW-6). Based on the responses received and FPO's avoided cost analysis, FPO determined that economy purchases could be beneficial during the September – October time period, but that the market offers received were less attractive during the November – December period when load was expected to be lower.

Based on its analysis, PEF made two additional economic block purchases of firm 7x16 energy for the September – October 2010 period. On August 5, 2010, PEF purchased 50 MW of firm 7x16 energy from [redacted] deliverable to PEF's system and, on August 6, 2010, PEF purchased a second 50 MW block of firm 7x16 energy from [redacted] deliverable to PEF's system for the September – October period. With these economic purchases completed, the cost of extending the 300 MW Indian River purchase into October was determined not to be economic.

In addition to the generation maintenance schedule changes that PEF made, PEF also negotiated two economic energy transactions tied to unit maintenance outages occurring during the month of October in order to further improve capacity margins during this period. Specifically, PEF purchased 74 MW of 7x16 firm energy delivered to the Southern Company – PEF border from [redacted] for September 18 through October 31 in order to ameliorate the 84 MW that was out of service during this part of the Scherer unit maintenance outage, scheduled to begin on September 18 and extend into December. Similarly, in order to partially ameliorate the impact of the Franklin unit maintenance outage in late October, PEF purchased 318 MW of 7x16 firm energy delivered to the Southern Company – PEF border from [redacted] for the period of October 24 through October 31, 2010.

Q. As the fall progressed, did FPO update its analysis of the November – December 2010 period and commence any new solicitations for these two months as a result?

A. Yes. In late September, FPO updated its avoided cost analysis for the November – December period. Then, on October 4, 2010, FPO solicited the market to evaluate whether potential economic purchases were available for the November – December period below PEF's avoided costs. FPO's solicitation again focused on 7x16 products in both the in-state and regional markets as this most closely aligned with PEF's anticipated economic energy opportunity. As set forth in Exhibit No. ___ (SAW-7), responses were received from both in-state and regional suppliers. However, all responses were substantially above PEF's anticipated avoided dispatch costs, even before factoring in transmission costs and transmission losses or making risk adjustments for deliverability due to potential transmission curtailment or load forecast variability. Based on this analysis, PEF did not make any term purchases for the months of November and December 2010, but, instead, relied on the daily and hourly markets where economy purchases became available.

Q. In late 2010 was there further contingency planning activities in the event the CR3 outage extended into 2011?

A. Yes. In late 2010, with a number of outstanding major repair activities that had to be completed prior to CR3 returning to service, FPO extended its contingency planning activities past the estimated December 2010 return to service date in order to be prepared for any further potential extension of the CR3 outage. FPO, in coordination with PEF System Planning and POG, analyzed PEF's planned generation maintenance outage schedule for January and February 2011. Then, FPO modeled PEF's anticipated avoided dispatch costs for this period based on the updated November 2010 FOF. After completing its solicitation for November and December 2010, FPO then proceeded to solicit the market for potential economic power purchase opportunities for January and February 2011. The responses to this solicitation for the January – February 2011 period as well as PEF's projected monthly avoided costs for this period are summarized in Exhibit No. ___ (SAW-8). As shown on Exhibit No. ___ (SAW-8), the offers received in response to this solicitation continued to be substantially above PEF's anticipated avoided dispatch costs. Consequently, no transactions were executed.

In mid-November, NGG informed FPO that it was now likely that the CR3 outage could extend into the first quarter of 2011. This was followed by the Company's announcement on November 30, 2010 that the return to service for CR3 was now expected in the 1st quarter of 2011. In response, FPO again solicited the market in early December for the January and February 2011 period. Again, however, the offers received in response to FPO's solicitation were substantially above PEF's anticipated avoided dispatch costs. FPO's analysis showed that none of the energy offers were economic compared to PEF's anticipated avoided dispatch costs, even without factoring in transmission costs and transmission losses or making risk adjustments for deliverability due to potential transmission curtailment or load forecast variability. Therefore, FPO determined that it would focus on the daily and hourly markets for economy purchases during January and February of 2011 if they became available.

Q. Did the changes in the estimated return to service dates for CR3 over the course of 2010 adversely affect your contingency plans to mitigate the cost impacts of the extended CR3 outage on PEF's customers?

A. No, they did not. FPO would have made the same decisions with respect to replacement power and fuel costs that it made over the course of 2010 if the initial return to service date for CR3 was estimated to be the first quarter of 2011 or beyond. As I explained initially, PEF approached the extended outage from the start with contingency planning that assessed opportunities to mitigate the cost impact of the outage during seasonal and maintenance time periods and month-to-month over the course of the year 2010. This approach ensured that we reasonably and prudently accounted for both short-, mid-, and longer-term opportunities to mitigate the cost impact to customers as a result of the extended CR3 outage. As a result, FPO would have made the same exact decisions that it made during the course of 2010 to mitigate the cost impact to customers as a result of the extended CR3 outage, regardless of the changes in the estimated return to service dates, because FPO considered the monthly, seasonal, and annual impacts of its decisions before making them.

In fact, you may recall that PEF estimated replacement fuel and power costs for 2010 from maximizing PEF's generation resources to replace CR3 in late 2009 at approximately $280 million. *See* Exhibit No. ___ (SAW-1). PEF actually experienced replacement fuel and power costs through the end of 2010 that were reasonably close to this estimate, despite changes in actual load, fuel costs, and weather, among other factors, from PEF's forecasts in late 2009. The fact that our contingency plans and decisions over the course of 2010 yielded replacement power and fuel costs that were not materially different from PEF's initial estimate of the annual cost impact if PEF's resources were maximized to replace CR3 demonstrates that PEF's decisions appropriately accounted for the cost impact of a longer-term outage than what PEF estimated at different times during 2010.

Q. When did you first become aware of the March 14, 2011 delamination event at CR3?

A. On or about March 16, 2011, I became aware that there were indications of delamination as a result of the retensioning effort.

Q. What steps did you take upon learning of this delamination event?

A. FPO followed the same general process outlined above for outages, i.e., assess the reliability impact of the outage in coordination with the TOP Department, and mitigate the cost impacts of the outage through purchases of capacity, energy, and transmission as appropriate based on market opportunities and forecasted replacement costs.

Q. Did the change in the estimated return to service date for CR3 as of March 2011 adversely affect your market replacement power purchase strategy to mitigate the cost impacts of the extended CR3 outage on PEF's customers for 2011?

A. No. The timing of the March announcement did not conflict with PEF's established market replacement power purchase strategy. The normal solicitation process for energy across the summer months would take place during March and April, and the Fall solicitation during August and September.

Q. Did you consider long-term fuel or purchased power options to minimize customer costs for replacement power and fuel costs following the March 14, 2011 delamination event?

A. While the duration of the repair effort resulting from the second delamination event was not well defined for some time after March 14, 2011, FPO did begin looking at power market purchases for May – September 2011, with the earlier months being the primary focus. As part of the normal process, FPO incorporated the updated CR3 outage schedule into the subsequent FOF updates. This provided the information necessary to make adjustments to transmission and fuel positions.

Q. Did you review and adjust maintenance and outage schedules in 2011 based on the March 14, 2011 delamination event?

A. Yes. The late spring CR1 outage was moved to the fall to provide lower CR3 replacement costs and higher reserve margins during the spring. In conjunction with the move of CR1 outage to the fall, the Anclote 1 & 2 and Hines 3 fall outages were also shifted to later in the fall to provide lower replacement costs and higher reserve margins in the weeks they were originally scheduled to occur.

Q. Were the FPO analyses following the March 14, 2011 delamination event communicated to Company senior management?

A. Yes, I provided a brief update to the SMC on April 11, 2011 regarding potential CR3 replacement costs should the outage extend through 2013.

Q. What purchases did you make in the March-April 2011 timeframe?

A. FPO solicited the market for March and April 2011 from the middle of January through the middle of March. *See* Exhibit No. ____(SAW – 9). Although some market offers on 7x16 energy products cleared PEF's avoided costs, the decision was made to not execute any transactions. There were several reasons that drove this decision. First, there were several planned PEF unit outages during March and April that had the flexibility to be shifted in the event of a period of high loads. Second, with the estimated system costs being driven significantly by short peaker runs during March and April, short schedule purchases, either day ahead or intra-day, could be tailored to offset peakers more economically than 7x16 energy schedules. Finally, transmission across Seminole and into FPC had already been secured to enable reliable access to the SOCO market, further increasing the opportunities to tailor short schedules to meet the varying daily / hourly purchase needs.

Q. What purchases have you made in the May-June 2011 timeframe?

A. FPO solicited the market for May and June 2011 from mid March to late April 2011. *See* Exhibit No. ____ (SAW-10). After an analysis of offers received, FPO made several economic purchases for the month of May 2011 on March 30th. These purchases included:

- 50 MWs of 7x16 firm energy at the GTC/JEA interface from [redacted]
- an additional 50 MWs of 7x16 firm energy at the GTC/JEA interface from [redacted], and
- 98 MWs of 7x16 firm energy at the FPL/FPC interface from [redacted]

On April 12th, the same three firm energy purchases were made for the month of June 2011 , at different transaction prices. Also, on April 20th, PEF also successfully negotiated with Reliant to accelerate delivery of energy from a second unit at the Vandolah facility for the month of May. This second unit was originally contracted to commence delivery on June 1. In anticipation that CR3 would remain out through the summer, FPO also began securing the necessary transmission to facilitate power purchases from out-of-state sources, specifically focusing on the path to utilize the firm yearly Jacksonville transmission position. Due to the fact that Seminole was posting zero available transmission for the months of August and September, FPO purchased firm FPL monthly transmission from Jacksonville to FPC. This would enable out of state purchases by re-directing the JEA yearly position for those months toward FPL.

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Q. What solicitations and purchases have you made in the June-September 2011 timeframe?

A. Beginning in early May 2011, FPO solicited the market for additional energy for June, as well as firm energy for July through September. *See* Exhibit No. ___ (SAW-11). After an analysis of the offers received, several transactions were executed on May 12th. These purchases included:

- 50 MWs of 7x16 firm energy at the GTC/JEA interface from [redacted]
- an additional 50 MWs of 7x16 firm energy at the GTC/JEA interface from [redacted], and
- 98 MWs of 7x16 firm energy at the FPL/FPC interface from [redacted], for the period July through September.

PEF also purchased an additional 27 MWs of delivered 7x16 firm energy from [redacted] for June on May 12th, and 21 MWs of delivered 7x16 firm energy from them for August on May 25th. On June 14th, FPO purchased 25 MWs of firm energy delivered to the GVL/FPC interface for the months of July and August from [redacted]. Throughout this solicitation period there were multiple offers from [redacted]. Although these offers may have been economic for June through August 2011, transmission was not available to enable the transaction to take place. Transmission did become available for September, but the [redacted] was not economical for September 2011. Offers were also evaluated from [redacted] With these units being readily available in the daily and hourly markets, and the lower than expected summer loads experienced up to that point , the decision was made to evaluate purchase opportunities hourly, daily, or weekly rather than pay the capacity payment offered by [redacted]. In addition to the purchase power analysis, transmission position evaluation was ongoing. On May 5th, PEF purchased 100 MWs of non-firm JEA transmission (firm transmission was unavailable) and matching FPL non-firm monthly transmission for the month of July. Also, with Seminole transmission having become available for use as the path for the out-of-state markets, 100 MWs of non-firm JEA transmission for the month of August was purchased to be used in conjunction with the firm monthly FPL transmission previously secured. This additional 100 MW transmission resource was intended for hourly and daily energy only economic purchases from the out-of-state markets.

Q. What decisions has FPO made at this time with respect to Fall 2011?

A. Despite the fact that the outage was now known to extend beyond the summer of 2011, FPO continued to use a short term informal solicitation strategy through the fall of 2011. While longer term purchase options will continue to be evaluated as they become known, energy only purchases generally prove more economical, especially during shoulder months.

Q. Have you conducted analyses on the longer-term impacts to system needs of the CR3 extended outage potentially extending beyond 2011?

A. FPO has incorporated the updated CR3 outage schedule into the FOF through the end of the FOF horizon, currently 2013. In addition, FPO has coordinated with the TOP Department to evaluate the impact of the outage on reserve margins. The results of this analysis indicated that PEF has sufficient capacity to meet anticipated load demands through 2013.

Q. Were the actions taken by PEF to mitigate the economic impact of the extended CR3 outage to date reasonable and prudent?

A. Yes, the Company timely and appropriately assessed its capacity and energy needs in light of the CR3 outage in a deliberate and systematic fashion. FPO optimized the use of PEF's resources by adjusting maintenance schedules and thoroughly explored opportunities in both the Florida and regional markets to reduce the potential impact of the unavailability of CR3. Throughout the outage, FPO repeatedly evaluated its system requirements and available power purchase opportunities, and then successfully executed a variety of transaction structures with multiple counterparties when necessary to mitigate potential cost impact to our customers.

Further, FPO's strategic approach to replacement power procurement combined with prevailing market circumstances allowed FPO to ensure that purchases made were competitive with available regional market pricing and helped to hedge potential volatility of replacement power costs. First, staggering PEF's purchases enabled PEF to match transactions closely to actual energy needs throughout the outage. Second, FPO's solicitations employed a disciplined strategy to achieve efficient price discovery, which allowed PEF to obtain the most competitive result for the benefit of customers. An important aspect of FPO's price discovery strategy was the ability to obtain offers from the more liquid regional markets outside of peninsular Florida as well as from in-state facilities and counterparties. Access to these more liquid regional markets helped to ensure that the pricing received from both the regional market and the in-state market were representative of true market value.

Q. What is the incremental cost of the CR3 outage that PEF is seeking to recover through its capacity, fuel, and environmental cost recovery clauses?

A. The Company is seeking recovery of all of its prudently incurred costs appropriate for recovery through the capacity, fuel, and environmental cost recovery clauses. Despite the Company's efforts to mitigate the impact of the CR3 outage, a portion of those costs are attributable to the effects of the extended CR3 outage. The amount through August 31, 2011 is $438,976,648. This amount includes actual gross costs through August 31, 2011. As presented in Exhibit No. ___ (SAW-12), the vast majority of these costs are recoverable through the fuel clause, while [redacted] are the capacity costs associated with the Vandolah and Indian River unit purchases, described above, and [redacted] is the estimated production cost simulation model incremental cost of emissions allowances, reagents for environmental controls, and other items normally recoverable thorough the environmental cost recovery clause.

Q. How did you calculate the total figure inclusive of both fuel and environmental costs that the Company is seeking to recover?

A. FPO calculated that figure by first calculating the incremental difference between the recoverable costs incurred during the outage and the costs that the Company would have incurred had the extended outage of CR3 not occurred. Essentially, as I explain further below, FPO analyzed the incremental difference between its fuel, environmental, and purchase power costs "with CR3" versus "without CR3." That figure, which is inclusive of both fuel and environmental-related costs, is then reduced for the insurance recovery obtained for replacement power cost under PEF's policy with NEIL.

Q. How did you calculate the recoverable costs that would have been incurred if CR3 had been available?

A. To calculate the recoverable energy cost for the entire system assuming that CR3 had not experienced the extended outage, FPO ran a production cost simulation model for each day for the period beginning December 20, 2009, the day on which CR3 was scheduled to return to service for each day of the extended outage. In order to approximate expected system operations assuming the availability of CR3 during this period, FPO made several assumptions.

First, FPO assumed that CR3 was available for the entire period and applied a 100 percent capacity factor to reflect the maximum potential operation of the plant. Then, PEF adjusted this 100 percent capacity factor down by a 3 percent unavailability percentage. This adjustment is consistent with PEF's historical operating experience at CR3 as well as industry experience at other nuclear power plants because a nuclear plant is unlikely to operate to a 100 percent capacity factor for the entire year. In addition, FPO removed block monthly purchases that were made to mitigate the loss of CR3 because these purchases likely would not have been made had CR3 been available. Regarding daily and hourly power market transactions, it was assumed that all executed spot market sales would have occurred if CR3 had been available. Conversely, since economy market purchase activity based on marginal system cost was so heavily influenced by the absence of CR3, we have taken the conservative approach of assuming none of those purchases would have been made if CR3 had been available (rather than taking credit for these economic purchases in calculating replacement power). This approach eliminates the need to engage in the speculative and subjective analysis of what combination of purchases would have theoretically been made had CR3 been online. This incremental cost analysis also includes only the portion of CR3 owned by PEF's retail and wholesale customers.

Further, to the extent there were system events or circumstances that would have occurred regardless of whether CR3 was available, these events were included in both cases. For example, forced outages at other units that actually occurred are included in the model for the "with CR3" case. Similarly, the emergency purchase during the January 11, 2010 winter peak was left in the "with CR3" case since it would have been necessary to meet load requirements even if CR3 had been online. In contrast, unit derates that would have been necessary at Crystal River Units 1 & 2 during the summer months (June – September of 2010) in order to comply with point-of-discharge temperature limitations were only factored into the "with CR3" case. These derates have been a common occurrence in past years, and would be exacerbated by abnormally high summer ambient temperatures and cooling water intake temperatures. Finally, if a unit operated for system reliability or stability reasons, that operation is also reflected in the modeled results.

With the foregoing adjustments, FPO ran the model for each day applying actual load conditions and fuel costs, which produces the total system cost for the day assuming the availability of CR3. Using that information, FPO calculated the recoverable costs allocable to retail and wholesale customers for each day, consistent with the model and methodology that PEF would use in a fuel case.

Q. What was the next step in the calculation after FPO determined the daily recoverable costs "with CR3" that would have been allocable to retail customers?

A. For each day of the period in question, the actually incurred recoverable costs allocable to the retail jurisdiction were determined. Again, FPO applied the same model as would be used in a fuel case. The results of that calculation are set forth in Exhibit No. ___ (SAW-12).

Q. Please describe how these two sets of calculations are used to determine the impact of the CR3 outage on recoverable costs.

A. For each day, FPO calculated the impact of the extended CR3 outage as the difference between the actual recoverable costs incurred and the recoverable costs that would have been incurred if CR3 had been available. In other words, FPO subtracted PEF's costs of the "with CR3" case from the costs produced by the "without CR3" case to derive the incremental cost attributable to the absence of CR3. Exhibit No. ___ (SAW-12) shows the results of those daily calculations on both a month-by-month and cumulative basis.

Q. How are the proceeds received from NEIL factored into the calculation?

A. Exhibit No. ___ (SAW-12) shows the gross economic effect of the extended CR3 outage, but the impact on our customers is substantially mitigated by PEF's insurance recovery from NEIL. The Company has two NEIL policies, one that covers physical damage to the plant and one that provides coverage for replacement power in the event of an outage. Under the replacement power policy, NEIL provides a fixed amount of $4.5 million per week during a full outage commencing 12 weeks after the day the outage would have otherwise ended. NEIL and PEF agreed that the coverage period would begin on January 15, thus, the payments from NEIL began 12 weeks after January 15, 2010.

Exhibit No. ___ (SAW-13) is a chart that shows the application of the NEIL payments to incremental recoverable costs attributable to the CR3 outage on a month-by-month and cumulative basis. As noted above, the NEIL payments under the applicable policy are fixed at $4.5 million per week. Consequently, during certain periods, the incremental costs attributable to the outage are significantly higher than the expected NEIL payments. For example, costs incurred in January 2010 due to the extreme and unforeseeable cold weather that occurred were substantially higher than the expected NEIL payments received for that period. In other periods, however, the NEIL expected payments defray almost all of the incremental costs due to the CR3 outage. This is particularly true for periods later in the outage. In sum, the expected NEIL recovery mitigates the impact of the extended outage of CR3 on our customers by reducing recoverable cost associated with the outage from actual costs of $438,976,648 through August 31, 2011 to $130,405,219 as set forth in the chart attached as Exhibit No. ___ (SAW-13) to my testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT NO. ___ (SAW-1)

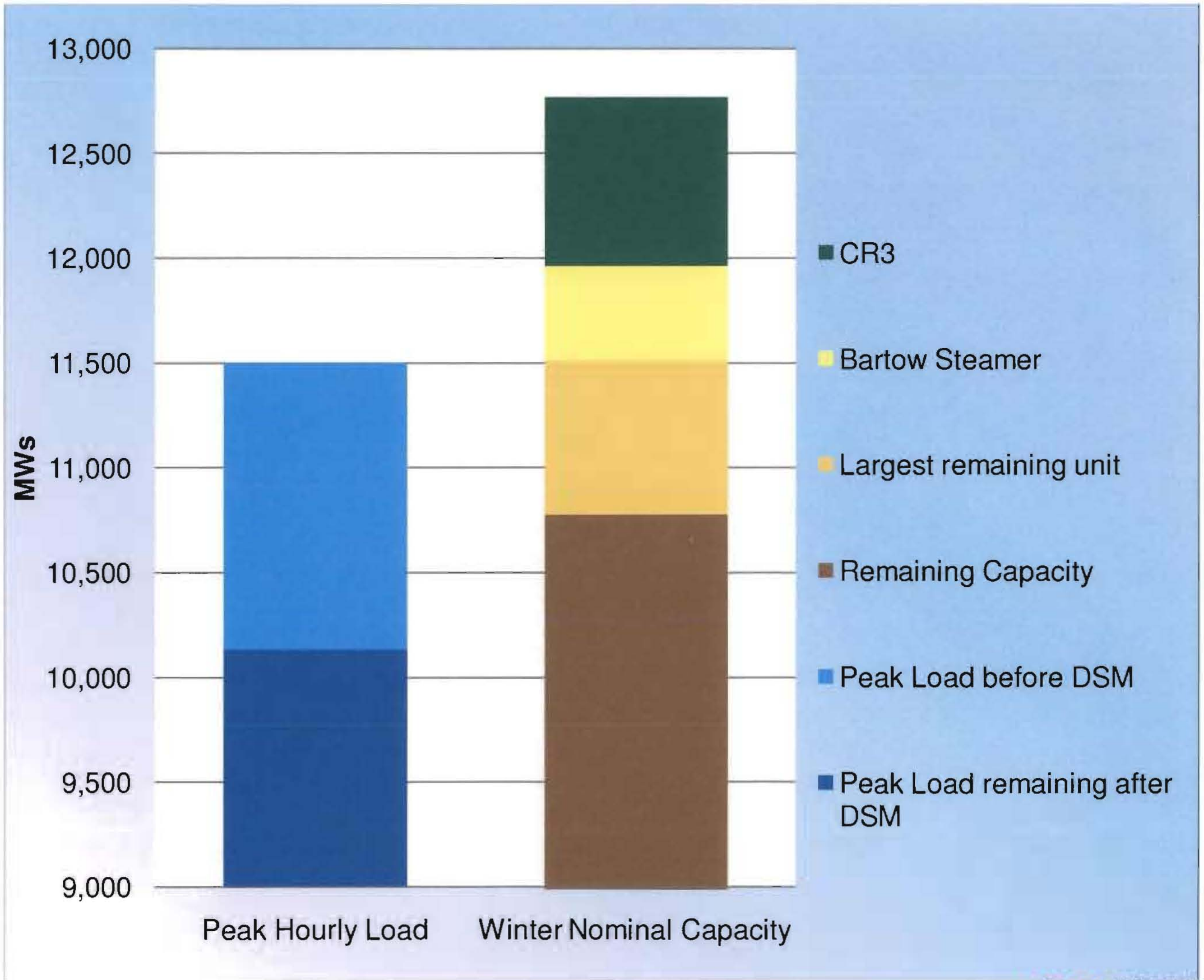
Potential Fuel and Purchase Power Impacts of CR3 Extension and Mitigation Activities to Minimize Costs

Senior Management Committee Meeting

December 7, 2009

Progress Energy

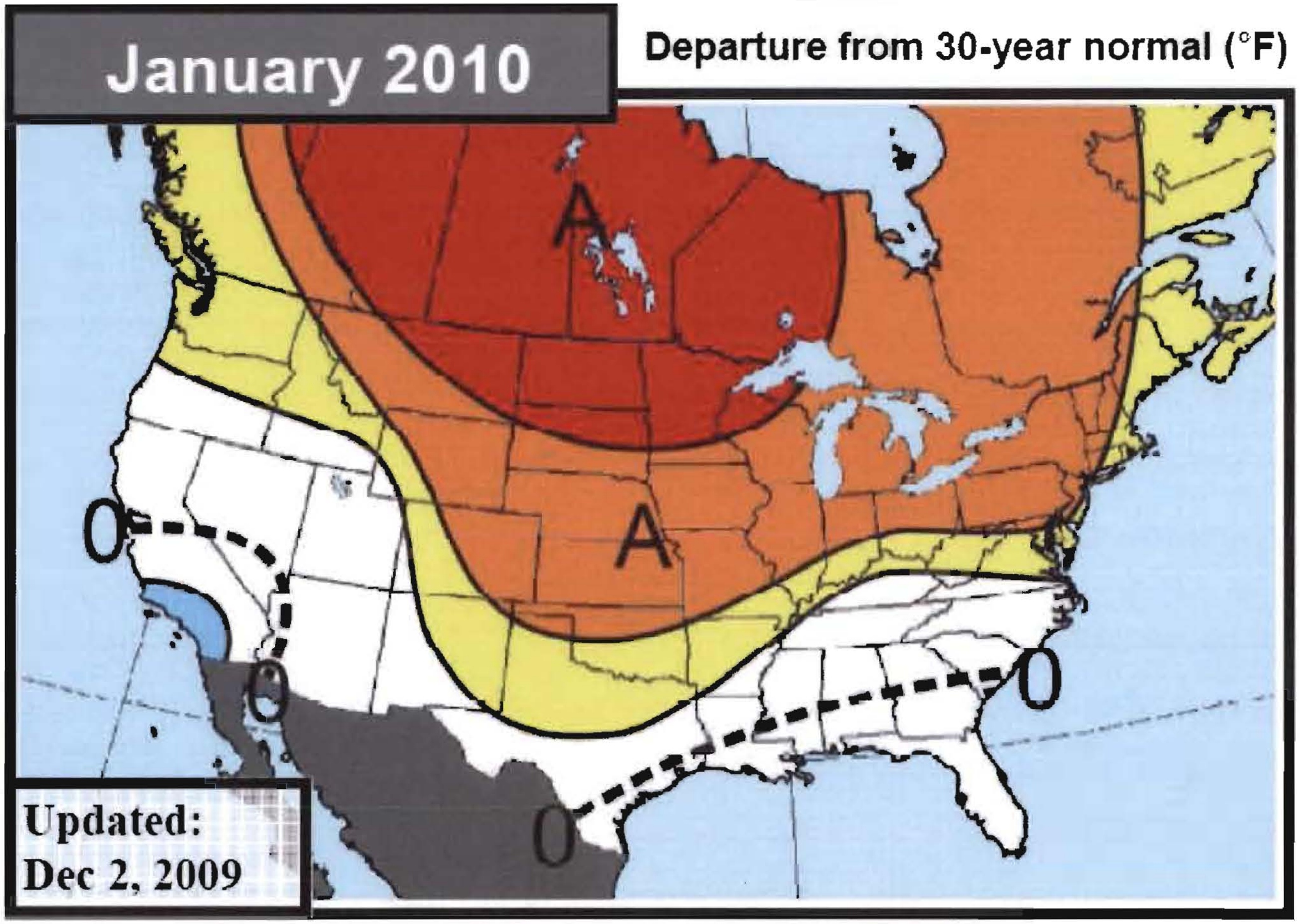
PEF Capacity Outlook for January 2009



Progress Energy

Weather Outlook for January

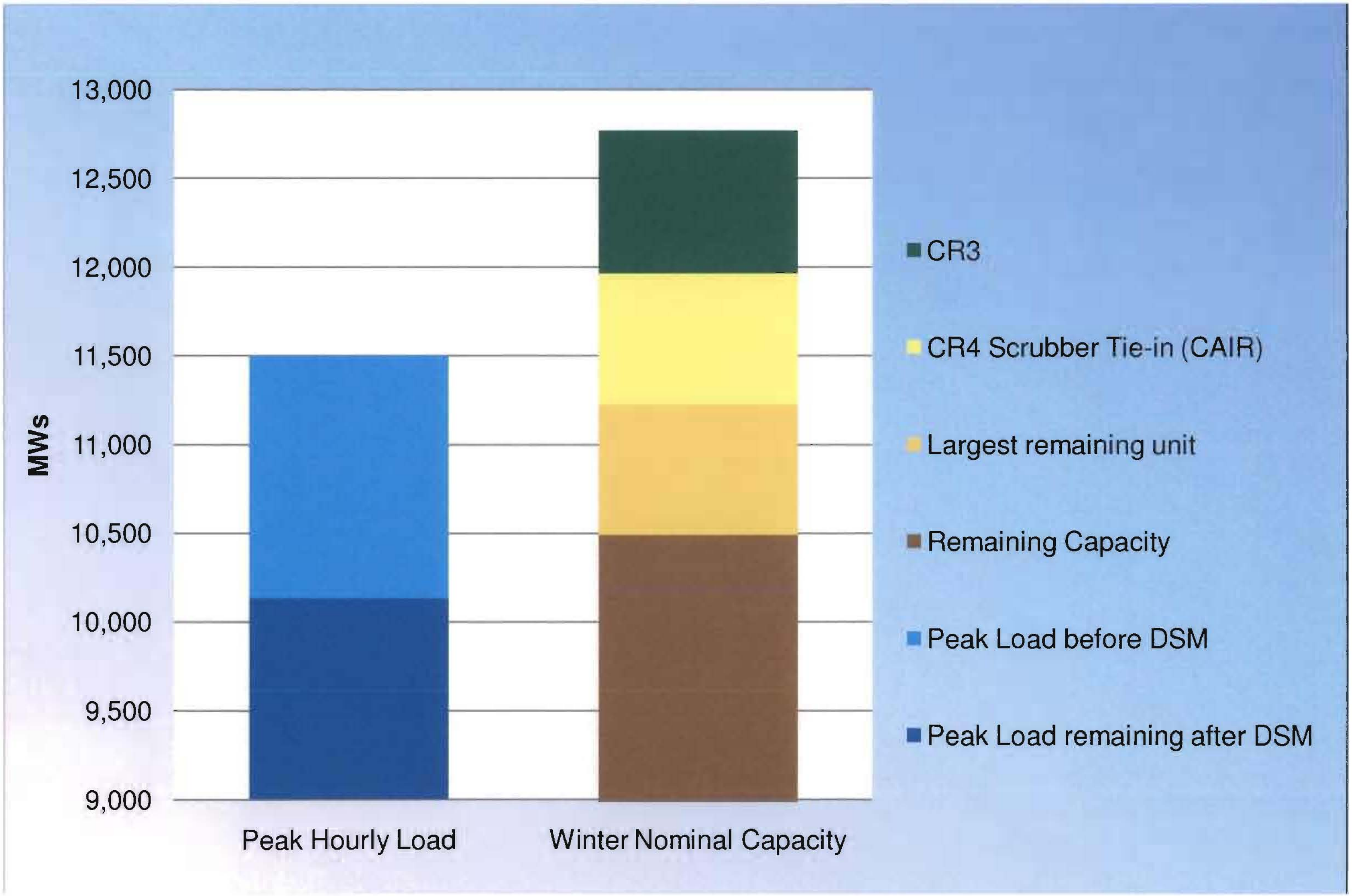
Departure from 30-year normal (°F)



+0.1 to +0.4 | +0.5 to 0.9 | +1.0 to +1.9 | 0
+2.0 to +2.9 | ≥3.0

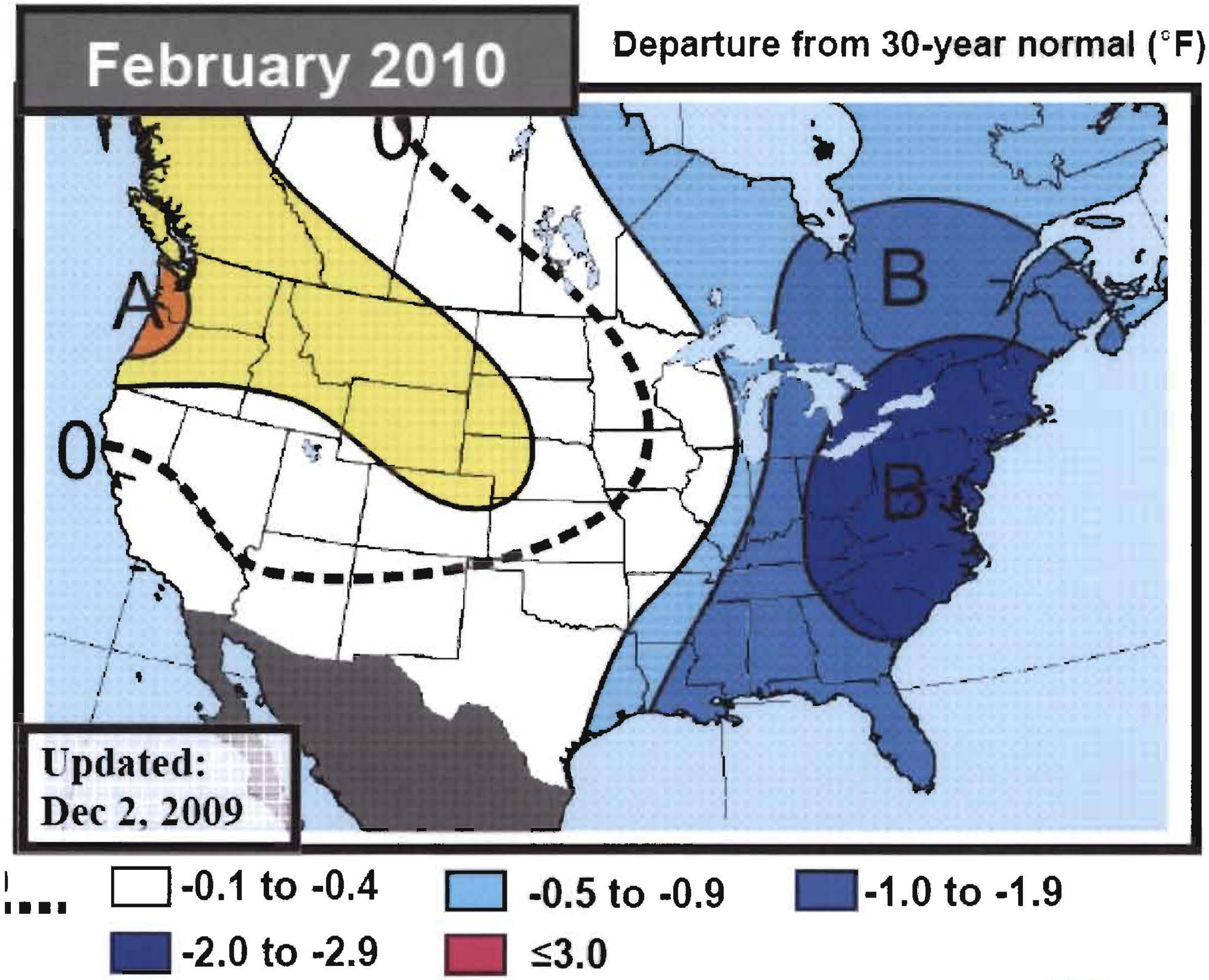
Progress Energy

PEF Capacity Outlook for February/March



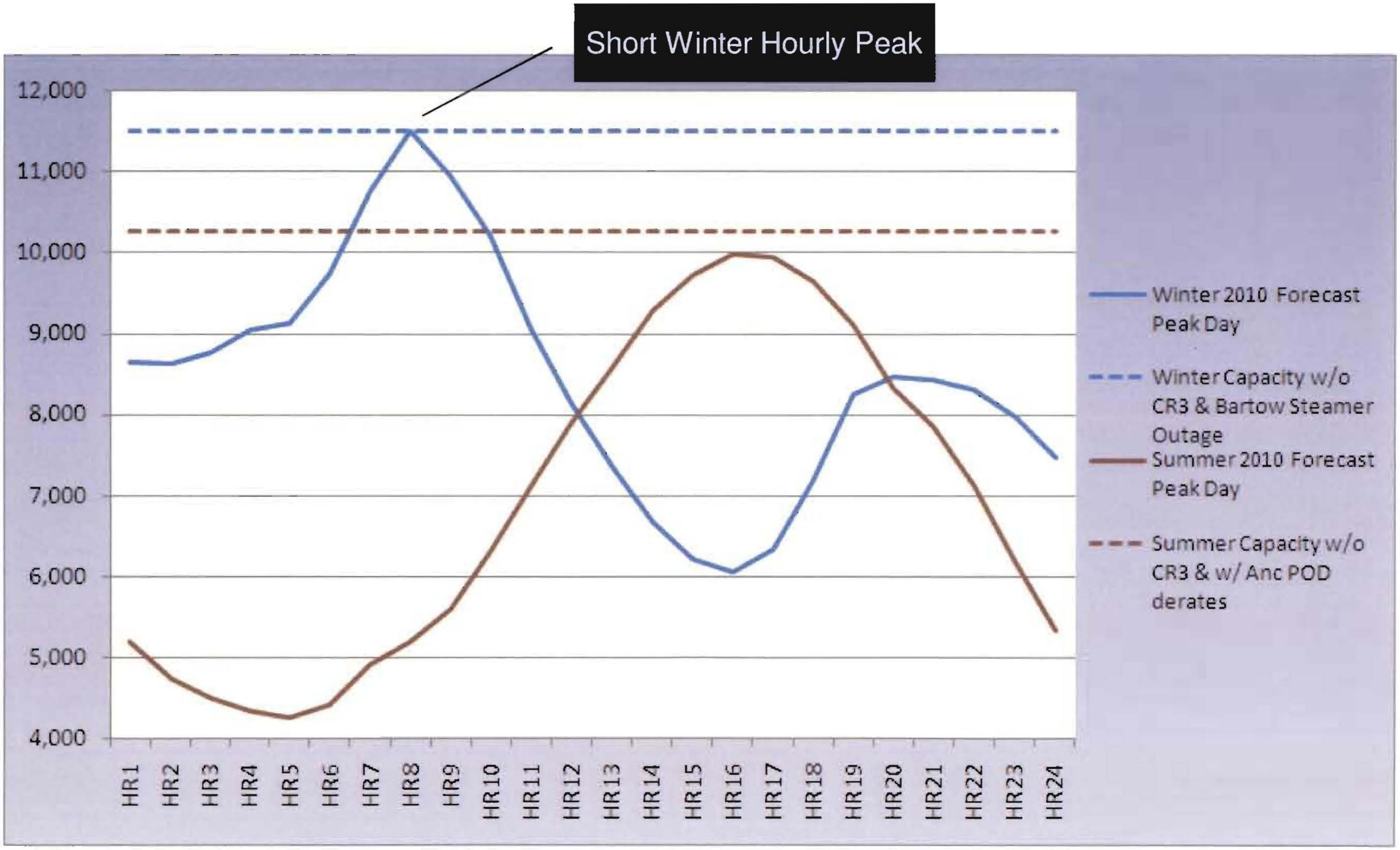
Progress Energy

Weather Outlook for February



Progress Energy

PEF DSM Impact: Winter vs. Summer



PEF Reserve Margin Changes for 2010

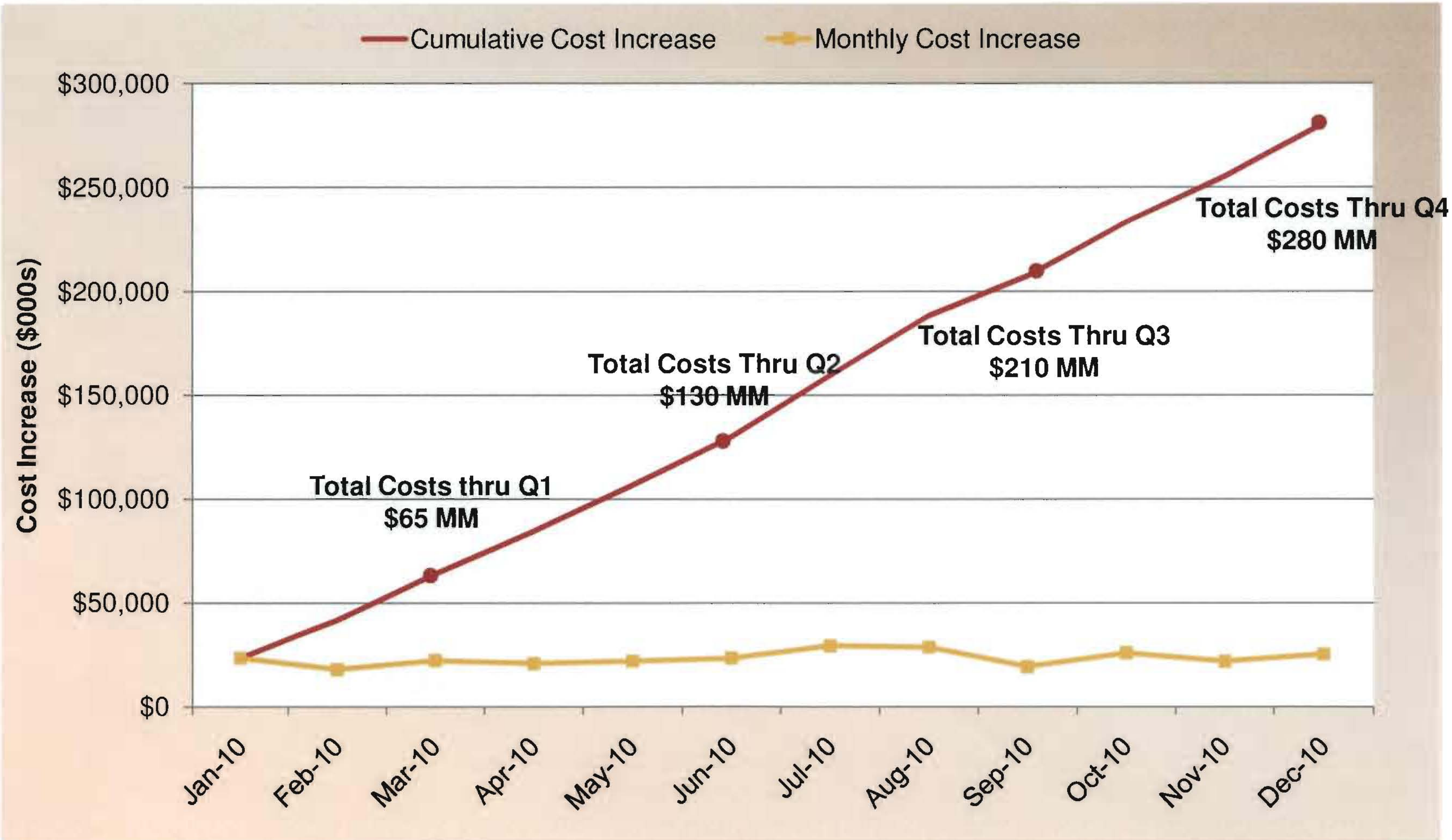
- Additional PEF generation options available in 2010
  - ~400 MW reduction in wholesale load in 2010
  - ~800 MW from Bartow repower
  - ~160 MW Vandola CT toll starts in June 2010

PEF Cost Mitigation Evaluations

- Defer planned outages where economically and operationally feasible
  - Proceed with Bartow Steamer warranty outage in January
  - Evaluation of CR4 and Hines outages continues
- Review fuel requirements vs. supply capacity
  - CT dual-fueled generation is $120/MWh higher on oil than gas
  - Maximize gas utilization for dual-fired units
- Identify potential economic power market opportunities
  - Firm capacity purchases currently not required due to ability to satisfy forecasted load with PEF assets and hourly purchase opportunities
  - Additional PEF cost mitigation activities will be evaluated if required for Summer 2010

Progress Energy

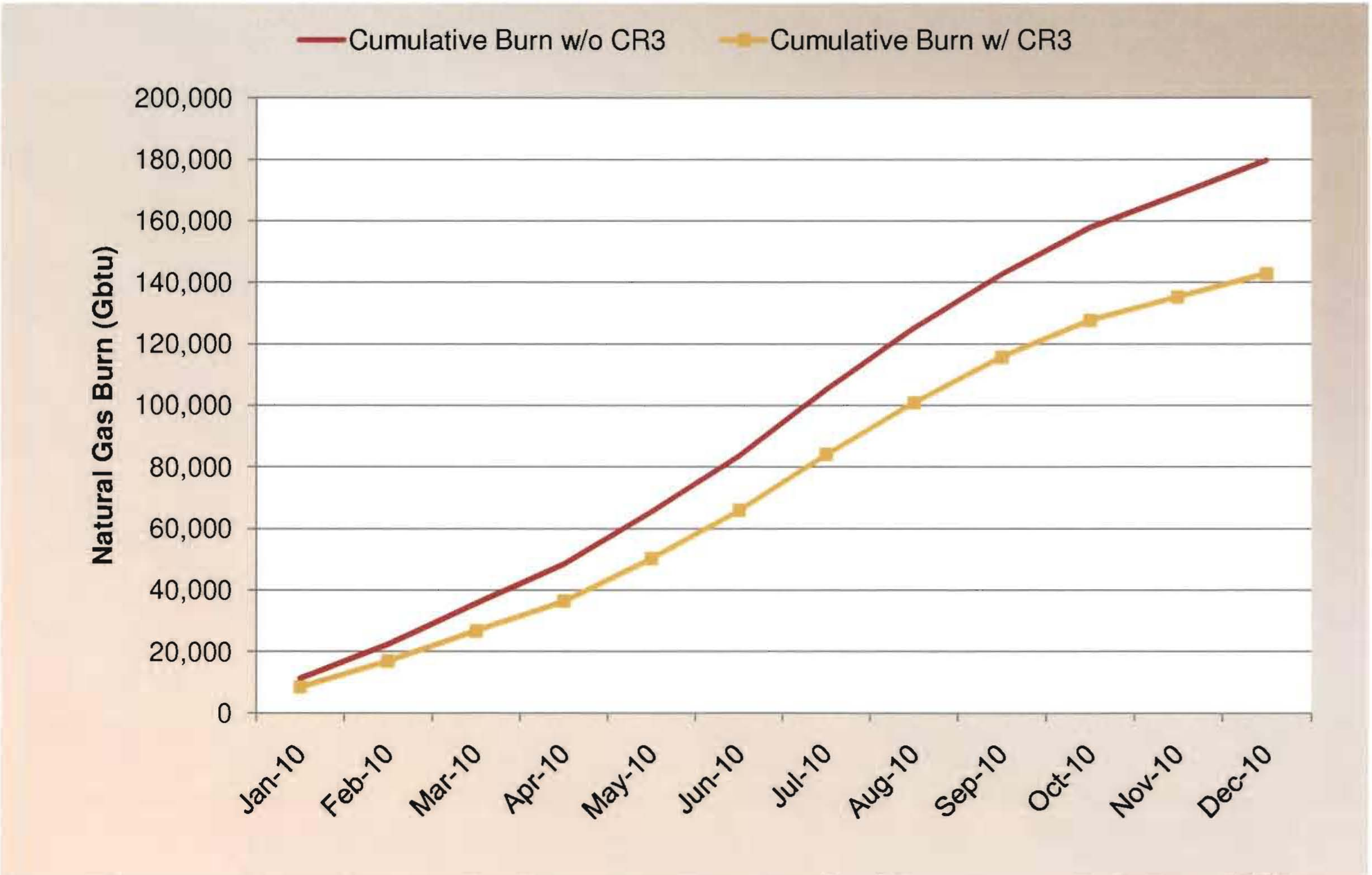
Potential PEF Fuel Cost Impact



Note: Forecast is not intended to represent probable return date for CR3

Progress Energy

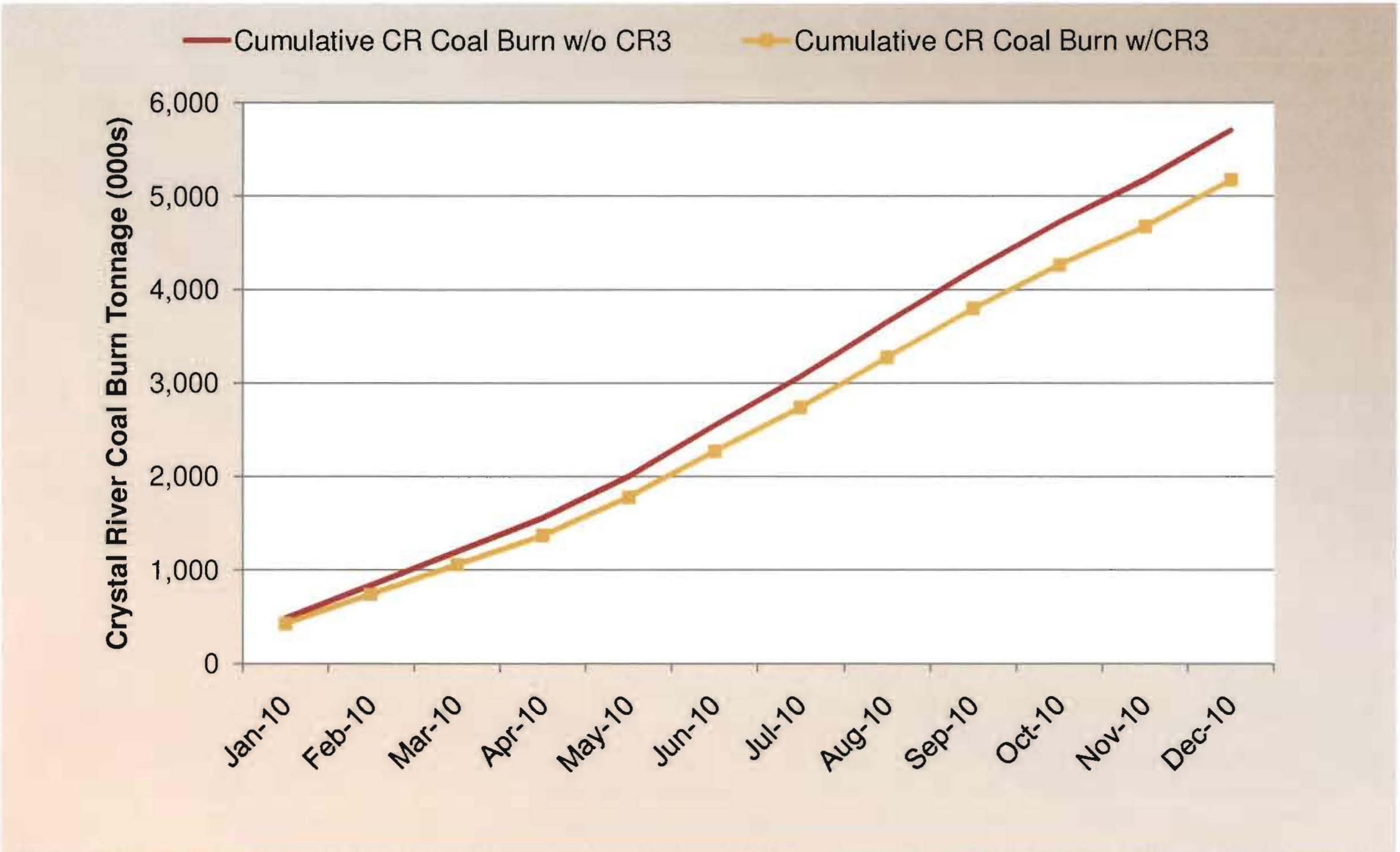
Operational Impact – PEF Gas Burn up ~26%



Note: Forecast is not intended to represent probable return date for CR3

Progress Energy

Operational Impact – PEF Coal Burn up ~12%



Note: Forecast is not intended to represent probable return date for CR3

Progress Energy

EXHIBIT NO. ___ (SAW-2)

REDACTED

[redacted]

Product Requested:
* Up to 500 MWs of 7x16 firm energy delivered on firm transmission to a Progress Energy interface
* Up to 100 MWs of 7x16 firm energy on firm transmission, delivered at the GTC/JEA interface (Georgia Florida border)
* Any additional delivered products, including energy call options

Solicitation for
January - February 2010

SOCO/FL Border

7x16 SOCO/JEA

PEF Avoided Cost ($/MWH) (net transmission and losses)		JAN	FEB
[redacted]		[redacted]	
Counterparty	Offer Date	Market Offers($/MWH)	
[redacted]		[redacted]	

Note: Due to the informal nature of the market solicitation, offers were received in general ranges indicated above.

Transactions Executed:
None Executed - no offerings were below Progress Energy's avoided cost

Delivered to FPC

7x24

PEF Avoided Cost ($/MWH)		JAN	FEB
		[redacted]	
Counterparty	Offer Date	Market Offers($/MWH)	
[redacted]		[redacted]	

7x16

PEF Avoided Cost ($/MWH)		JAN	FEB
		[redacted]	
Counterparty	Offer Date	Market Offers($/MWH)	
[redacted]		[redacted]	

EXHIBIT NO. ___ (SAW-3)

Progress Energy Florida
2010 Generating Unit Maintenance Outage Schedule

Revision Date: December 3, 2009

Week	ANCL_UN01	ANCL_UN02	CRPL_UN01	CRPL_UN02	CRPL_UN04	CRPL_UN05	SWPL_UN01	SWPL_UN02	SWPL_UN03	BART_CC01	HINE_CC01	HINE_CC02	HINE_CC03	HINE_CC04	TIGC_CT01	UFLA_CT01	Total Steam Maint. (MW)
							01/01										
01/02							32			01/08							32
01/09							32			400							432
01/16							32			400							432
01/23							32			400							432
01/30							32			01/29							32
02/06							32										32
02/13							32				02/20						32
02/20					02/27		32				534					03/01	566
02/27					767		32				534	03/06				48	1,381
03/06					767		32				534	569				48	1,950
03/13					767		32				03/14	569	03/20			48	1,416
03/20					767		32					03/21	575			48	1,422
03/27					767		32						575	04/03		48	1,422
04/03					767		32						04/04	552		48	1,399
04/10		04/17			767		32							552	04/14	48	1,399
04/17		535			767		32							552	227	48	2,161
04/24		04/26			767		32		05/01					04/23	227	48	1,074
05/01	05/08				757		04/30		75						200	04/30	1,032
05/08	515				757			05/17	75						05/09		1,347
05/15	515				757	05/22		31	05/16								1,303
05/22	515				05/21	755		31									1,301
05/29	05/28					05/29		31									31
								06/01									

Revision Date: August 13, 2010

Week	ANCL_UN01	ANCL_UN02	CRPL_UN01	CRPL_UN02	CRPL_UN04	CRPL_UN05	SWPL_UN01	BART_CC04	HINE_CC01	HINE_CC02	HINE_CC03	HINE_CC04	TIGC_CT01	UFLA_CT01	Total Steam Maint. (MW)	Change in Total Steam Maint. (MW)
							01/01									
01/02							32								32	0
01/09							32	01/14							32	400
01/16							32	1159							1,191	(759)
01/23							32	1159							1,191	(759)
01/30							32	01/28							32	0
02/06							32								32	0
02/13							32		02/20						32	0
02/20					02/27		32		534						566	0
02/27					767		32		534	03/09					1,333	48
03/06					767		32		534	569					1,902	48
03/13					767		32		03/14	569	03/20		03/22		1,368	48
03/20					767		32			569	575		227	03/27	2,170	(748)
03/27					767		32			03/25	575	04/03	227	48	1,649	(227)
04/03					767		32				04/04	552	04/02	48	1,399	0
04/10					767		32					552		48	1,399	0
04/17					767		32					552		04/18	1,351	810
04/24	05/01				767		32					04/23			799	275
05/01	515				757		04/30								1,272	(240)
05/08	515				757										1,272	75
05/15	515				757						05/20				1,272	31
05/22	05/21				05/21						508				508	793
05/29											05/28				0	31

Revision Date: June 23, 2010

Week	ANCL_UN01	ANCL_UN02	CRPL_UN01	CRPL_UN02	CRPL_UN04	CRPL_UN05	SWPL_UN01	SWPL_UN02	SWPL_UN03	BART_CC01	HINE_CC01	HINE_CC02	HINE_CC03	HINE_CC04	TIGC_CT01	UFLA_CT01	Total Steam Maint. (MW)
09/04																	0
09/11																	0
09/18																	0
09/25		10/02														10/02	0
10/02		520														47	567
10/09		520								10/18						47	567
10/16		520	10/23							320	10/23					47	887
10/23		520	400							320	476		10/30		10/28	47	1,763
10/30		520	10/31			11/06				320	476		240		200	10/31	1,756
11/06		535				766				320	11/07		575		227		2,423
11/13		11/12		11/20		11/13				320			575	11/20	227		1,122
11/20				521						320			240	552	227		1,860
11/27				521						320		12/06	240	552	11/24		1,633
12/04				521						670		569	240	12/05			2,000
12/11				521						670		569	12/10				1,760
12/18				12/17						12/17		12/17					0
12/25																	0

Revision Date: August 13, 2010

Week	ANCL_UN01	ANCL_UN02	CRPL_UN01	CRPL_UN02	CRPL_UN04	CRPL_UN05	SWPL_UN01	BART_CC04	HINE_CC01	HINE_CC02	HINE_CC03	HINE_CC04	TIGC_CT01	UFLA_CT01	Total Steam Maint. (MW)	Change in Total Steam Maint. (MW)
09/04															0	0
09/11															0	0
09/18															0	0
09/25														10/02	0	0
10/02														47	47	520
10/09		10/16						10/16						47	47	520
10/16		520						320	10/23					47	887	0
10/23		520						640	476		10/30		10/28	47	1,683	80
10/30		520	11/06					640	476		240		200	10/31	2,076	(320)
11/06		535	402			11/13		320	11/07		575		227		2,059	364
11/13		11/12	11/14	11/20		766		320			575	11/20	227		1,888	(766)
11/20				521		11/20		11/20			240	552	227		1,540	320
11/27				521						12/06	240	552	11/24		1,313	320
12/04				521						569	240	12/05			1,330	670
12/11				521						569	12/10				1,090	670
12/18				12/17						12/17					0	0
12/25															0	0

EXHIBIT NO. ___ (SAW-4)

REDACTED

Product Requested:
* Up to 500 MWs of 7x16 or 7x24 firm energy delivered on firm transmission to a Progress Energy interface
* Up to 100 MWs of 7x16 or 7x24 firm energy on firm transmission, delivered at the GTC/JEA interface (Georgia Florida border)
* Any additional delivered products, including energy call options

Solicitation for
March - June 2010

[redacted]

SOCO/FL Border

7x24

PEF Avoided Cost ($/MWH) (net transmission and losses		March	April	May	June
[redacted]		[redacted]			
Counterparty	**Offer Date**	**Market Offers ($/MWH)**			
[redacted]	2/9/2010	[redacted]			
	2/17/2010				
	2/17/2010		[redacted]		
	2/11/2010				
	2/17/2010				

7x16

PEF Avoided Cost ($/MWH) (net transmission and losses		March	April	May	June
[redacted]		[redacted]			
Counterparty	**Offer Date**	**Market Offers ($/MWH)**			
[redacted]	2/9/2010	[redacted]			
	3/4/2010			[redacted]	
	2/17/20[redacted]	[redacted]			
	2/24/2010			[redacted]	
	2/25/2010				
	3/16/2010				
	3/23/2010				
	2/17/2010	[redacted]			
	2/24/2010			[redacted]	
	3/24/2010				
	3/8/2010				

Delivered to FPC

7x24

PEF Avoided Cost ($/MWH)		March	April	May	June
		[redacted]			
Counterparty	**Offer Date**	**Market Offers ($/MWH)**			
[redacted]	2/17/2010	[redacted]			
	2/17/2010				
	2/22/2010				
	2/11/2010				
	2/11/2010		[redacted]		[redacted]
	2/18/2010	[redacted]			
	2/18/2010				
				[redacted]	

7x16

PEF Avoided Cost ($/MWH)		March	April	May	June
		[redacted]			
Counterparty	**Offer Date**	**Market Offers ($/MWH)**			
[redacted]	2/17/2010	[redacted]			
	2/24/2010			[redacted]	
	3/24/2010				
	2/11/2010		[redacted]		[redacted]
	3/12/2010			[redacted]	
	2/19/2010				

*Started Tolling Agreement 1 month early with [redacted]

Note: Prices in GREEN represented executed prices.

Transactions Executed	Term	Product	Amount	Dellevery interface	Price
[redacted]	/1/10-6/30/10	7x16 Firm	50 MWs	GTC/JEA	[redacted]
	/1/10-6/30/10	7x16 Firm	50 MWs	GTC/JEA	
	/1/10-5/31/10	7x16 Firm	98 MWs	FPL/FPC	
	/1/10-5/31/10	Tolling	158 MWs	VANDOLAH/FPC	

[redacted]

EXHIBIT NO. ___ (SAW-5)

REDACTED

Product Requested:
* Up to 500 MWs of 7x16 firm energy delivered on firm transmission to a Progress Energy interface
* Up to 100 MWs of 7x16 firm energy on firm transmission, delivered at the GTC/JEA interface (Georgia Florida border)
* Any additional delivered products, including energy call options

Solicitation for
June - September 2010

[redacted]

SOCO/FL Border

7x16

PEF Avoided Cost ($/MWH) (net transmission and losses		June	July	August	September
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]
Counterparty	**Offer Date**	**Market Offers ($/MWH)**			
[redacted]	4/20/2010		[redacted]	[redacted]	[redacted]
	4/27/2010				
	4/27/2010				
	4/19/2010				
	4/27/2010				
	4/20/2010				
	4/27/2010				

Note: Prices in GREEN represented executed prices.

Delivered to FPC

7x16

PEF Avoided Cost ($/MWH)		June	July	August	September
		[redacted]	[redacted]	[redacted]	[redacted]
Counterparty	**Offer Date**	**Market Offers ($/MWH)**			
[redacted]	4/19/2010		[redacted]		
	4/23/2010	[redacted]			[redacted]
	4/26/2010				
	4/27/2010				
	4/28/2010			[redacted]	
	5/4/2010				
	4/19/2010			[redacted]	[redacted]
	6/23/2010				
	5/11/2010	[redacted]			

[redacted]

Transactions Executed	Term	Product	Amount	Delievery interface	Price
[redacted]	/1/10-8/31/10	7x16 Firm	100 MWs	GTC/JEA	[redacted]
	/1/10-8/31/10	7x16 Firm	98 MWs	FPL/FPC	
	/1/10-8/31/10	*8 HR Firm	10/20/20	RC/FPC	
	/1/10-9/30/10	Tolling	300 MWs	Indian River Bus	

[redacted]

EXHIBIT NO. ___ (SAW-6)

REDACTED

Product Requested:
* Up to 500 MWs of 7x16 firm energy delivered on firm transmission to a Progress Energy interface
* Up to 100 MWs of 7x16 firm energy on firm transmission, delivered at the GTC/JEA interface (Georgia Florida border)
* 7x16 firm energy, 74 MWs to either SOCO/FPC or an "into SOCO" interface, for 9/18/10 - 10/31/10, to replace existing Scherer purchase during unit outage
* 7x16 firm energy, 318 MWs to either SOCO/FPC or an "into SOCO" interface, for 10/24/10 - 10/31/10, to replace existing Franklin purchase during unit outage
* Any additional delivered products, including energy call options

Solicitation for
September - October 2010

[redacted]

SOCO/FL Border

7x16

PEF Avoided Cost ($/MWH) (net transmission and losses		September	October	9/18-10/31	10/24-10/31
[redacted]		[redacted]			
		[redacted]			
Counterparty	Offer Date	Market Offers ($/MWH)			
[redacted]	8/2/2010	[redacted]			
	8/3/2010				
	7/27/2010				
	8/4/2010				[redacted]
	8/5/2010				
	7/28/2010				
	8/3/2010				
	8/6/2010				
	7/28/2010				
	8/10/2010				
	8/19/2010				
	9/2/2010				
	8/30/2010				

[redacted]

Note: Prices in GREEN represented executed prices.

Transactions Executed	Term	Product	Amount	Delievery Interface	Price
[redacted]	/1/10-10/31/10	7x16 Firm	50 MWs	GTC/JEA	[redacted]
	/1/10-10/31/10	7x16 Firm	50 MWs	GTC/JEA	
	/18/10-10/31/10	7x16 Firm	74 MWs	SOCO/FPC	
	0/24/10-10/31/10	7x16 Firm	318 MWs	EES/SOCO	

Delivered to FPC

7x16

PEF Avoided Cost ($/MWH)		September	October
		[redacted]	
		[redacted]	
Counterparty	Offer Date	Market Offers ($/MWH)	
[redacted]	7/28/2010	[redacted]	
	8/17/2010		

[redacted]

EXHIBIT NO. ___ (SAW-7)

REDACTED

Product Requested:
* Up to 500 MWs of 7x16 firm energy delivered on firm transmission to a Progress Energy interface
* Up to 100 MWs of 7x16 firm energy on firm transmission, delivered at the GTC/JEA interface (Georgia Florida border)
* Any additional delivered products, including energy call options

Solicitation for
November - December 2010

[redacted]

SOCO/FL Border

7x16 SOCO/JEA

PEF Avoided Cost ($/MWH) (net transmission and losses [redacted]		November	December
		[redacted]	
Counterparty	Offer Date	Market Offers($/MWH)	
[redacted]	10/5/2010	[redacted]	
	10/5/2010		
	10/6/2010		
	10/5/2010		[redacted]

Delivered to FPC

7x16

PEF Avoided Cost ($/MWH)		November	December
		[redacted]	
Counterparty	Offer Date	Market Offers($/MWH)	
[redacted]	10/5/2010	[redacted]	
	10/7/2010		
	10/14/2010		
	10/8/2010		

[redacted]

Transactions Executed:
None Executed - no offerings were below Progress Energy's avoided cost.

EXHIBIT NO. ___ (SAW-8)

REDACTED

Product Requested:
- Up to 500 MWs of 7x16 firm energy delivered on firm transmission to a Progress Energy interface
- Up to 100 MWs of 7x16 firm energy on firm transmission, delivered at the GTC/JEA interface (Georgia Florida border)
- Any additional delivered products, including energy call options

Solicitation for
January - February 2011

[redacted]

SOCO/FL Border

7x16 SOCO/JEA

PEF Avoided Cost ($/MWH) (net transmission and losses [redacted]		January	February
		[redacted]	
Counterparty	Offer Date	Market Offers($/MWH)	
[redacted]	11/4/2010	[redacted]	
	12/6/2010		
	11/3/2010		
	12/6/2010		
	12/6/2010		
	12/6/2010		

Delivered to FPC

7x16

PEF Avoided Cost ($/MWH)		January	February
		[redacted]	
Counterparty	Offer Date	Market Offers($/MWH)	
[redacted]	11/9/2010	[redacted]	
	12/23/2010		
	12/6/2010		

Transactions Executed:
None Executed - no offerings were below Progress Energy's avoided cost.

EXHIBIT NO. ___ (SAW-9)

REDACTED

Product Requested:
* Up to 500 MWs of 7x16 firm energy delivered on firm transmission to a Progress Energy interface
* Up to 100 MWs of 7x16 firm energy on firm transmission, delivered at the GTC/JEA interface (Georgia Florida border)
* Any additional delivered products, including energy call options

Solicitation for
March - April 2011

Counterparties Contacted:

[redacted]

SOCO/FL Border

7x16 SOCO/JEA

PEF Avoided Cost ($/MWH) (net transmission and losses		March	April
[redacted]		[redacted]	
Counterparty	Offer Date	Market Offers($/MWH)	
[redacted]	1/24/2011	[redacted]	
[redacted]	2/15/2011	[redacted]	
[redacted]	1/19/2011	[redacted]	
[redacted]	2/15/2011	[redacted]	
[redacted]	1/18/2011	[redacted]	

Delivered to FPC

7x16

PEF Avoided Cost ($/MWH)		March	April
		[redacted]	
Counterparty	Offer Date	Market Offers($/MWH)	
[redacted]	1/28/2011	[redacted]	
[redacted]	2/15/2011	[redacted]	
[redacted]	1/27/2011	[redacted]	
[redacted]	2/4/2011	[redacted]	
[redacted]	2/15/2011	[redacted]	

Transactions Executed:

None Executed for the following reasons:

1) there are several planned unit outages during March and April that have the flexibility to be shifted in the event of high loads.
2) estimated system costs contain forced outages and normalized weather; good unit performance or moderate weather would result in avoided lower costs.
3) estimated system cost numbers are impacted by short peaker runs during March and April; short daily purchase schedules can be tailored to offset peakers more economically than 7x16 energy schedules.
4) transmission across SEC and into FPC has already been secured to enable a continuous path available for utilizing PEF's yearly firm JEA transmission for hourly/daily purchases as needed.

EXHIBIT NO. ___ (SAW-10)

REDACTED

Product Requested:
* Up to 500 MWs of 7x16 firm energy delivered on firm transmission to a Progress Energy interface
* Up to 100 MWs of 7x16 firm energy on firm transmission, delivered at the GTC/JEA interface (Georgia Florida border)
* Any additional delivered products, including energy call options

Solicitation for May - June 2011

Counterparties Contacted:

[redacted]

SOCO/FL Border

7x16 SOCO/JEA

PEF Avoided Cost ($/MWH) (net transmission and losses		May	June
[redacted]		[redacted]	
Counterparty	Offer Date	Market Offers($/MWH)	
[redacted]	3/16/2011	[redacted]	
	3/16/2011		
	3/29/2011		
	4/11/2011		
	3/18/2011		
	3/30/2011		
	4/11/2011		
	3/23/2011		

Delivered to FPC

7x16

PEF Avoided Cost ($/MWH)		May	June
		[redacted]	
Counterparty	Offer Date	Market Offers($/MWH)	
[redacted]	3/29/2011	[redacted]	
	3/23/2011		

[redacted]

Transactions Executed	Term	Product	Amount	Dellevery interface	Price
[redacted]	5/1/11-5/31/11	7x16 Firm	50 MWs	GTC/JEA	[redacted]
	5/1/11-5/31/11	7x16 Firm	50 MWs	GTC/JEA	
	5/1/11-5/31/11	7x16 Firm	98 MWs	FPL/FPC	
	6/1/11-6/30/11	7x16 Firm	50 MWs	GTC/JEA	
	6/1/11-6/30/11	7x16 Firm	50 MWs	GTC/JEA	
	6/1/11-6/30/11	7x16 Firm	98 MWs	FPL/FPC	
	5/1/11-5/31/11	Tolling	158 MWs	VANDOLAH/FPC	

[redacted]

EXHIBIT NO. ___ (SAW-11)

REDACTED

Product Requested:
* Up to 500 MWs of 7x16 firm energy delivered on firm transmission to a Progress Energy interface
* Up to 100 MWs of 7x16 firm energy on firm transmission, delivered at the GTC/JEA interface (Georgia Florida border)
* Any additional delivered products, including energy call options

Solicitation for
June - September 2011

[redacted]

SOCO/FL Border

7x16

PEF Avoided Cost ($/MWH) (net transmission and losses [redacted]		June	July	August	September
		[redacted]			
Counterparty	Offer Date	Market Offers ($/MWH)			
[redacted]	5/9/2011		[redacted]		
	5/9/2011				
	5/4/2011				
	5/10/2011				
	5/12/2011				

Note: Prices in GREEN **represented executed prices.**

Delivered to FPC

7x16

PEF Avoided Cost ($/MWH)		June	July	August	September
		[redacted]			
Counterparty	Offer Date	Market Offers ($/MWH)			
[redacted]	5/6/2011	[redacted]			
	5/11/2011				
	5/24/2011				
	5/9/2011				
	5/31/2011				
	4/26/2011				
	6/14/2011				
	6/27/2011				

[redacted]

Transactions Executed	Term	Product	Amount	Delievery Interface	Price
[redacted]	7/1/11-9/30/11	7x16 Firm	50 MWs	GTC/JEA	[redacted]
	7/1/11-9/30/11	7x16 Firm	50 MWs	GTC/JEA	
	6/1/11-6/30/11	7x16 Firm	27 MWs	FPL/FPC	
	7/1/11-9/30/11	7x16 Firm	98 MWs	FPL/FPC	
	8/1/11-8/31/11	7x16 Firm	21 MWs	FPL/FPC	
	7/1/11-8/31/11	7x16 Firm	25 MWs	GVL/FPC	

EXHIBIT NO. ___ (SAW-12)

Impact of CR3 Containment Repair Outage Based on 97% Capacity Factor

Note: Impact is based on net of Joint Ownership share

REDACTED

	Fuel Δ	Env Δ	**Fuel + Env Δ**	**Capacity Cost**	**Gross Cost Δ**	**NEIL Reimbursement (Actual/*Projected*)**	**Cumulative Costs Net of NEIL**
Dec-09	$8,371,985	[redacted]	$8,512,914	[redacted]	$8,512,914		$8,512,914
Jan-10	$41,436,426	[redacted]	$41,799,394	[redacted]	$41,799,394		$50,312,309
Feb-10	$18,342,905	[redacted]	$18,600,228	[redacted]	$18,600,228		$68,912,536
Mar-10	$17,985,227	[redacted]	$18,230,627	[redacted]	$18,230,627		$87,143,164
Apr-10	$14,325,374	[redacted]	$14,433,654	[redacted]	$14,433,654	$13,500,000	$88,076,818
May-10	$20,997,519	[redacted]	$21,092,164	[redacted]	$21,408,164	$19,928,571	$89,556,410
Jun-10	$27,119,446	[redacted]	$27,318,372	[redacted]	$27,318,372	$19,285,714	$97,589,068
Jul-10	$23,428,943	[redacted]	$23,535,091	[redacted]	$24,728,661	$19,928,571	$102,389,157
Aug-10	$23,494,011	[redacted]	$23,589,272	[redacted]	$24,706,906	$19,928,571	$107,167,492
Sep-10	$19,389,377	[redacted]	$19,491,437	[redacted]	$20,576,690	$19,285,714	$108,458,468
Oct-10	$16,637,114	[redacted]	$16,707,008	[redacted]	$16,707,008	$19,928,571	$105,236,904
Nov-10	$14,658,005	[redacted]	$14,742,640	[redacted]	$14,742,640	$19,285,714	$100,693,830
Dec-10	$32,006,976	[redacted]	$32,083,970	[redacted]	$32,083,970	*$19,928,571*	*$112,849,228*
Jan-11	$18,947,411	[redacted]	$19,023,861	[redacted]	$19,023,861	*$19,928,571*	*$111,944,518*
Feb-11	$13,167,607	[redacted]	$13,208,348	[redacted]	$13,208,348	*$18,000,000*	*$107,152,866*
Mar-11	$13,920,148	[redacted]	$13,973,847	[redacted]	$13,973,847	*$19,928,571*	*$101,198,142*
Apr-11	$24,138,816	[redacted]	$24,231,806	[redacted]	$24,231,806	*$16,457,143*	*$108,972,805*
May-11	$20,782,609	[redacted]	$20,814,171	[redacted]	$21,130,171	*$15,942,857*	*$114,160,119*
Jun-11	$20,920,213	[redacted]	$20,958,569	[redacted]	$20,958,569	*$15,428,571*	*$119,690,116*
Jul-11	$21,622,942	[redacted]	$21,662,616	[redacted]	$21,662,616	*$15,942,857*	*$125,409,875*
Aug-11	$20,914,435	[redacted]	$20,938,201	[redacted]	$20,938,201	*$15,942,857*	***$130,405,219***
Totals	$432,607,488	[redacted]	**$434,948,190**	[redacted]	**$438,976,648**	***$308,571,429***	

Notes:

- NEIL Reimbursements have been received through Dec 17, 2010; remaining amounts are shown in italics.

EXHIBIT NO. ___ (SAW-13)

CR3 Replacement Power Costs

August 2011