BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Cost Recovery Clause

DOCKET NO. 120009-EI
Submitted for filing: April 30, 2012

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DIRECT TESTIMONY OF JOHN ELNITSKY

ON BEHALF OF
PROGRESS ENERGY FLORIDA

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IN RE: NUCLEAR COST RECOVERY CLAUSE

BY PROGRESS ENERGY FLORIDA

FPSC DOCKET NO. 120009-EI

DIRECT TESTIMONY OF JOHN ELNITSKY

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name and business address.

A. My name is John Elnitsky. My business address is 299 1st Avenue North, St. Petersburg, Florida.

Q. Who do you work for and what is your position with that company?

A. I am currently employed by Progress Energy, Inc. as the Vice President of New Generation Programs and Projects ("NGPP"). As the Vice President of NGPP, I am responsible for the licensing and construction of the Levy Nuclear power plant project ("LNP"), including the direct management of the Engineering, Procurement, and Construction ("EPC") Agreement with Westinghouse and Shaw, Stone & Webster (the "Consortium"). In this role I am also responsible for the LNP base load transmission project, and the program coordination and support teams for the LNP. Representatives from these program coordination and support teams include project controls, business and financial management services, contract management and administration, and other support functions that make up the Program Management Team ("PMT") that I lead to manage the EPC Agreement and the related projects under the LNP.

Q. In your role as Vice President of NGPP, are you involved in the senior management review of the LNP?

A. Yes, as the Vice President of NGPP, I report on the LNP directly to the Senior Management Committee ("SMC"). The SMC has corporate responsibility for the LNP and includes Progress Energy's Chief Executive Officer ("CEO"), Chief Financial Officer, the Executive Vice President ("EVP") and General Counsel for Administration and Corporate relations, the EVP-Energy Supply, the CEOs of PEF and Progress Energy Carolinas, the Senior Vice President ("SVP") for Corporate Development and Improvement, the SVPs for PEF and PEC Energy Delivery, and the Chief Nuclear Officer. I update the SMC with respect to the LNP, the EPC Agreement, the Consortium discussions and negotiations, project and enterprise risk updates, and the LNP quantitative and qualitative feasibility analysis.

As Vice President of NGPP, I also lead the Levy Program Performance Review and report directly to Jeff Lyash, the EVP-Energy Supply for Progress Energy, who has senior management oversight responsibility for the LNP. Under the Levy Program Governance Policy (MGT-NPDF-00001), Mr. Lyash is the Executive Sponsor of the Levy Program Performance Review. The Levy Program Performance Review includes the following functional areas with respect to the LNP: transmission planning; finance; regulatory; external relations; communications; and nuclear operations, safety, and quality.

II. PURPOSE AND SUMMARY OF DIRECT TESTIMONY.

Q. What is the purpose of your direct testimony?

A. My testimony supports the Company's request for cost recovery for the Company's LNP actual/estimated 2012 and projected 2013 costs pursuant to the nuclear cost recovery statute and rule. I will also explain the Company's feasibility and implementation analyses for the LNP and the LNP PMT recommendation to the SMC with respect to the Company's LNP implementation decision. I will provide and explain the Company's long-term feasibility analyses consistent with Commission Order No. PSC-09-0783-FOF-EI in Docket No. 090009-EI. I will explain that the LNP PMT determined that the LNP is feasible, both from a qualitative and quantitative perspective, but there is increased near term uncertainty and, thus, increased near term enterprise risks with respect to immediate implementation of a decision to construct the LNP.

I will explain the Company's further determination of the most beneficial implementation of the LNP for the Company and its customers. As a result of this determination, I will explain that the LNP PMT evaluated whether implementation of the LNP consistent with the 2010 and 2011 LNP program of record, or an extension of the current project suspension, was in the best interests of the Company's customers. Based on this determination, the LNP PMT recommended that the Company implement an extension of the current project suspension. The SMC accepted the recommendation and decided that a longer term project suspension is in the best interests of the Company and its customers. The SMC decision is reflected in the approval of the Integrated Project Plan

("IPP"), Revision 4, for the LNP. The SMC decision is also explained by Mr. Jeff Lyash in his pre-filed direct testimony in this nuclear cost recovery clause ("NCRC") proceeding.

Q. Do you have any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit No. ___ (JE-1), a copy of the confidential IPP Revision 4 for the LNP;
- Exhibit No. ___ (JE-2), PEF's updated cumulative life-cycle net present value revenue requirements ("CPVRR") calculation for the LNP compared to the cost-effectiveness analysis presented in the Need Determination proceedings for Levy Units 1 and 2;
- Exhibit No. ___ (JE-3), the Florida Legislative Office of Economic and Demographic Research ("EDR") March 2012 Florida Economic Overview;
- Exhibit No. ____ (JE-4), a copy of the Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-12-0104-FOF-EI;
- Exhibit No. ___ (JE-5), the Nuclear Regulatory Commission ("NRC") review schedule for the LNP Combined Operating License Application ("COLA");
- Exhibit No. ___ (JE-6), an updated, graphic illustration of the steps and timing of the PEF LNP COLA review hearing process; and
- Exhibit No. ___ (JE-7), a confidential chart of the Company's long lead equipment ("LLE") purchase order ("PO") disposition status.

These exhibits were prepared by the Company, or they are public, government reports generally used and relied on by the public and regularly used by the Company in the regular course of its business, and they are true and correct.

I am also sponsoring or co-sponsoring portions of the schedules attached to Thomas G. Foster's testimony. Specifically, I am co-sponsoring portions of Schedules AE-4, AE-4A, and AE-6 and sponsoring Schedules AE-6A through AE-7B of the Nuclear Filing Requirements ("NFRs"), included as part of Exhibit No. __ (TGF-1) to Thomas G. Foster's testimony. I will also be co-sponsoring portions of Schedules P-4 and P-6 and sponsoring Schedules P-6A through P-7B included as part of Exhibit No. ___ (TGF-2) to Mr. Foster's testimony, and co-sponsoring Schedules TOR-4, TOR-6, TOR-6A, and TOR-7, which is Exhibit No. ___ (TGF-3) to Mr. Foster's testimony. A description of these Schedules follows:

- Schedule AE-4 reflects Capacity Cost Recovery Clause ("CCRC") recoverable Operations and Maintenance ("O&M") expenditures for the period.
- Schedule AE-4A reflects CCRC recoverable O&M expenditure variance explanations for the period.
- Schedule AE-6 reflects actual/estimated monthly expenditures for site selection, preconstruction, and construction costs for the period.
- Schedule AE-6A reflects descriptions of the major tasks.
- Schedule AE-6B reflects annual variance explanations.
- Schedule AE-7 reflects contracts executed in excess of $1.0 million.

- Schedule AE-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule AE-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Schedule P-4 reflects CCRC recoverable O&M expenditures for the projected period.
- Schedule P-6 reflects projected monthly expenditures for preconstruction and construction costs for the period.
- Schedule P-6A reflects descriptions of the major tasks.
- Schedule P-7 reflects contracts executed in excess of $1.0 million.
- Schedule P-7A reflects details pertaining to the contracts executed in excess of $1.0 million.
- Schedule P-7B reflects contracts executed in excess of $250,000, yet less than $1.0 million.
- Schedule TOR-4 reflects CCRC recoverable actual to date and projected O&M expenditures.
- Schedule TOR-6 reflects actual to date and projected annual expenditures for site selection, preconstruction and construction costs for the duration of the project.
- Schedule TOR-6A reflects descriptions of the major tasks.
- Schedule TOR-7 reflects total project costs exclusive of carrying costs and fuel costs.

These schedules are true and accurate.

Q. Please summarize your direct testimony.

A. The Company can complete construction of the Levy nuclear power plants. The LNP is, therefore, feasible. The LNP Combined Operating License ("COL") and necessary permits for construction of the LNP can be obtained. The LNP is feasible from a regulatory perspective. The LNP is also feasible from a technical perspective because the AP1000 nuclear reactor design can be installed at the Levy site. The LNP is economically feasible despite lower near term natural gas prices and delayed carbon cost impacts. From a qualitative perspective, however, there is increased near term uncertainty and, therefore, increased near term enterprise risks associated with the commencement of LNP construction activities in 2013. As a result of this current uncertainty and increased near term enterprise risks, the Company had to decide if commencing construction next year was in the customers' and Company's best interests. This assessment led the Company to decide to shift the projected in-service dates for the LNP to 2024 and 2025.

The Company determined the best decision for PEF and its customers was to build the LNP at a later date, with expected commercial in-service dates for Levy Unit 1 in 2024 and Levy Unit 2 in 2025. This decision mitigates near term uncertainty and increased enterprise risks. It allows more time for the Florida economy to recover, for Florida economic conditions to improve for PEF's customers and the Company, for natural gas demand to meet market supply conditions, and for federal and state energy, environmental, and nuclear policy to develop. As a result, the decision provides PEF and its customers additional time for increased certainty to develop with respect to the project's enterprise risks.

The decision further provides the Company the flexibility to commence construction sooner than currently planned if prudent to do so. The decision to extend the commencement of construction of the LNP next year to build the LNP in 2024 and 2025 is in the customers' and Company's best interests and, therefore, the prudent management decision for the LNP.

III. LNP EVALUATION.

Q. How did the Company evaluate the LNP?

A. The LNP PMT evaluates the LNP each year with any major change in the project enterprise risks or project schedule, scope, or cost as part of its on-going project management for the Company. This evaluation is consistent with the way the Company has performed its review since the Commission approved the need for the LNP in 2008, and which the Commission has found reasonable and prudent for the past three years. This evaluation includes the analyses used to determine the feasibility of completing the Levy nuclear units. The Company also takes a broader view to determine how to implement the LNP in the best interests of the Company and its customers. In this broader view, the Company weighs the LNP costs and benefits, including the long-term benefits of additional nuclear generation for the Company and the State of Florida such as fuel diversity, reduced reliance on foreign fossil fuels, base load capacity needs, and the reduction in environmental emissions from clean nuclear energy generation. The Florida Legislature recognized these longer-term, nuclear generation benefits in the 2006 legislation that included adoption of the nuclear cost recovery statute and required the Commission to consider them in need determinations for proposed nuclear power plants. This Commission granted the Company's LNP need determination based on this legislation.

Q. What did the Company consider in this year's project evaluation?

A. As it has in each of the past three years, the Company evaluated the project status, the feasibility of completing the Levy nuclear units, including enterprise and project risks, and the short- and long-term LNP costs and benefits. This evaluation ensures that the Company aligns the LNP plan with the best interests of the Company and its customers. Based on this evaluation, as explained below, the LNP PMT considered both a short- and longer-term extension of the current partial suspension of the LNP.

Q. What is the current LNP project status?

A. The EPC Agreement for the LNP was partially suspended in 2009. The original schedule contemplated certain preconstruction site work under a Limited Work Authorization ("LWA") issued by the NRC in advance of the COL for the LNP. The NRC determined that it would review the LWA on the same schedule as the COL under the Company's COLA. This determination meant that preconstruction site work contemplated under the LWA could not be performed early, before COL issuance, but would have to be performed after COL issuance. The subsequent impact of the NRC LWA determination to the original LNP schedule was a minimum twenty (20) month schedule shift. As a result of this

NRC determination, the Company evaluated implementation of the LNP and decided to focus LNP work on obtaining the Combined Operating License ("COL") for the LNP from the NRC while minimizing near term costs until after the LNP COL was obtained. As a result of this decision, the Company amended the EPC Agreement to extend the partial suspension of the EPC Agreement for the project until the COL was obtained. This decision was explained in detail in the Company's 2010 NCRC testimony and exhibits in Docket No. 100009-EI. The Commission determined that PEF's decision to continue pursuing a COL for the LNP was reasonable in Order No. PSC-11-0095-FOF-EI. Since 2010, the Company has implemented this decision by focusing work on obtaining the LNP COL and minimizing other project costs until after the NRC issues the LNP COL.

Q. What were the results of the Company's LNP evaluation this year?

A. The LNP PMT determined that a longer term project suspension is in the best interests of the Company and its customers. IPP Revision 4 was prepared based on the recommendation that a longer term project suspension should be implemented and presented to the SMC for approval. The SMC approved the LNP PMT recommendation in IPP Revision 4 and decided to implement a longer term suspension of the project. See Exhibit No. ___ (JE-1) to my testimony.

Continuation of the LNP is still in the customers' best interests. The LNP is feasible from a regulatory, technical, and economic perspective. The LNP COL can be obtained and is still expected from the NRC in mid-2013. The LNP can be built at the Levy site. Even with lower natural gas price forecasts, the LNP is projected to be economically beneficial to PEF's customers over the sixty-year life of the Levy nuclear units. The LNP still fulfills the Florida legislative objectives of enhanced State and Company fuel diversity, reduced reliance on fossil fuels especially from foreign sources, reduced environmental emissions through clean energy generation, and enhanced base load capacity. The long-term LNP fuel savings and other, long-term benefits for PEF's customers exist and, therefore, justify completion of the LNP. Accordingly, PEF still intends to build the LNP.

At this time, however, ending the partial suspension, issuing the full notice to proceed ("FTNP"), and ramping up engineering and construction for the LNP are not in the best interests of PEF's customers. The increased near term enterprise risks resulting from continuing, near-term economic uncertainty, and legislative and regulatory uncertainty regarding federal and state energy and environmental policy require, in the exercise of the Company's reasonable management judgment, an extension of the current project suspension. Accordingly, the Company decided not to commence construction, but instead decided to obtain the LNP COL and build the LNP at a later time than previously planned.

IV. FEASIBILITY.

A. <u>The Company's 2012 Evaluation of the LNP Feasibility Analyses.</u>

Q. Did the Company prepare updated LNP feasibility analyses?

A. Yes. The Company prepared the current feasibility analyses consistent with the feasibility analyses previously performed for the LNP that were reviewed and approved by the Commission in the prior three NCRC dockets. The Company employs both a qualitative and quantitative feasibility analysis. The qualitative analysis is an analysis of the technical and regulatory capability of completing the plants, the enterprise risks, and the short- and long-term costs and benefits of completing the Levy nuclear power plants. The quantitative analysis is an updated CPVRR economic analysis that includes comparisons to the cost-effectiveness CPVRR analysis in the Company's need determination proceeding for the LNP described in Order No. PSC-08-0518-FOF-EI. The Company's updated CPVRR economic analysis for the LNP is included as Exhibit No. ___ (JE-2) to my testimony. I explain the results of the Company's feasibility analysis for the LNP in my testimony and the exhibits to my testimony.

Q. How does the Company evaluate the LNP enterprise risks?

A. The Company's qualitative analysis of the enterprise risks facing the LNP is more of a holistic analysis rather than a pure measurable or computable analysis. As I explained in previously filed testimony, the effects of most enterprise risks cannot be quantified or measured in mathematical terms, they cannot realistically be weighed against other enterprise risks, and, therefore, they cannot be compared based on a quantifiable or measureable standard. The Company must instead evaluate the enterprise risks by identifying events or circumstances that have changed and then use its reasonable, business judgment to determine if those events or circumstances represent fundamental changes in the enterprise risks that impact the project. The Company continued this process for evaluating the LNP enterprise risks as part of its qualitative feasibility analysis this year.

Q. What were the Company's conclusions when the Company evaluated the LNP enterprise risks this year?

A. The Company concluded from its qualitative analysis of the LNP enterprise risks this year that the LNP is still feasible, both qualitatively and quantitatively, over the long-term life of the Levy nuclear units, however, near term there is greater uncertainty and, thus, increased near term enterprise risks. As a result, prudent project management requires that the Company plan to mitigate the increased near term enterprise risks. The LNP PMT plan to mitigate the increased near term enterprise risks extends the current project suspension to build the LNP later instead of right now. Issuance of the FTNP next year to commence full scale LNP construction is not supported by near term, lower natural gas prices and delayed carbon cost impacts due to legislative and regulatory energy and environmental policy uncertainty. Extending the time for the commencement of the LNP construction provides more time for the Florida economy to recover, for economic conditions for Florida customers to improve, for federal and state energy and environmental policy to develop, and therefore, for more certainty to develop with respect to the project's enterprise risks. As a result, this LNP PMT plan mitigates the increased near term LNP enterprise risks. The Company will continue under this project plan to move forward with the LNP on a slower pace with work focused on obtaining the LNP COL and other, required permits for the project. As explained in more detail below, this project plan was presented by the LNP PMT to the SMC in IPP Revision 4 and the SMC approved this LNP plan to mitigate the near term increased project enterprise risks.

B. Increased Near Term Enterprise Risks.

Q. How did the Company assess the Florida economic conditions in its *evaluation of the LNP enterprise risks?*

A. Economic conditions have been flat last year and this year in Florida with growth expected at a rate that is far below the rate of growth experienced prior to the recession. The rate of economic growth in Florida is anemic and it follows the worst economic recession since the Great Depression. The effects of this recession continue in Florida. The Florida unemployment rate, while recently declining, is still more than a full percentage point higher than the national average. It remains among the nation's highest unemployment rates. And, despite a recent decline in the Florida unemployment rate, the number of employed people in the state actually decreased because people have given up and are no longer looking for employment or have moved elsewhere where economic conditions are better. The Florida Legislative Office of Economic and Demographic Research ("EDR") concluded in March 2012 that it will take a long time for the Florida job market to recover. Florida lost nearly 800,000 jobs in the recession and needs to create over one million jobs for the same percentage of the total population to be working at peak employment prior to the recession. See Exhibit No. ___ (JE-3) to my testimony.

Florida's housing and construction industries, which led past Florida economic recoveries, have not yet recovered from the recession. Florida's home vacancy rate leads the nation and Florida continues to be among the nation's leading states in foreclosures. In 2009, 2010, and 2011, Florida had the second highest number of foreclosure filings in the nation. Additionally, Florida has the third longest foreclosure resolution period in the nation at a little over two years from filing to resolution. Home inventories are declining, but they do not reflect vacant houses that are foreclosed on but not yet listed for sale or that have been pulled from the market because of continuing low prices, nor do they reflect existing, delinquent mortgages. See Exhibit No. ___ (JE-3). Even so, existing home vacancies and foreclosures have saturated the Florida housing market, holding down the need for new residential construction, depressing existing home sales, and holding flat existing home prices. Significant commercial foreclosures in Florida have also increased commercial space vacancies. Florida real estate and construction employment were devastated by the recession, and as a result of the residential and commercial foreclosures and vacancies, the real estate and residential and commercial construction industry remain weak. The Company was equally affected, as new meter sets declined dramatically during the recession and have only recently leveled off. Consequently, Florida's housing, real estate, and construction industries have not rebounded from the recession and will not soon lead the economic recovery in Florida.

It will take additional time for the Florida economy to recover from the recent recession. This recession is the nation's longest recession since the Great Depression, and the nation has not yet recovered. So far, the recovery has been half as strong as the average economic gain from prior recessions. See Exhibit No. ___ (JE-3). Florida's economic recovery is lagging behind the national recovery. The EDR concluded in March 2012 that Florida growth rates are slowly returning to more typical levels, but drags are more persistent than in past recessions, and it will take years to climb completely out of the hole left by the recession. <u>See</u> Exhibit No. ___ (JE-3).

Q. Have these economic conditions also affected the Company?

A. Yes, as we explained last year PEF was not immune to the recession, or to the subsequent effects that represent a drag on Florida's economic recovery. PEF lost customers during and immediately following the recession. Between 2009 and 2010, PEF experienced twenty-one straight months of negative year-over-year retail customer growth. PEF experienced dramatic declines in customer energy use and a dramatic increase in low use, vacant, but active accounts. PEF's retail energy sales also declined.

Residential and commercial vacancies and foreclosures, depressed real estate and construction industries, and high unemployment slow the Florida economic recovery and adversely affect the Company. PEF's customer growth has returned and is expected to continue to grow, but at a rate below the Company's pre-recession customer growth rates. Near term customer energy use and retail energy sales remain flat. Continuing difficulties in the Florida economy adversely impact growth in energy consumption, retail sales, and sales revenues in the near term.

Over the long term, customer growth, customer energy use and, thus, retail energy sales and load are expected to increase. Near term, however, customer growth, customer energy use, and energy sales remain at levels well below pre-recession growth rates.

Q. What conclusions did the Company draw from its evaluation of the Florida economic conditions?

A. We expected that it would take time for the Florida economy to recover. We explained last year that we expected the Florida economy to slowly improve in 2011 and 2012, but we did not expect a return to pre-recession growth. We now recognize it is taking even longer for the Florida economy to rebound from the recession than we expected last year. We did not see the expected improvement in 2011 until this year and the improvement is even more sluggish than anticipated. The economic recovery in Florida is simply going to take more time.

We further understand that the near-term Florida economic conditions continue to affect our customers. These conditions diminish customer support for and ability to pay for construction of the LNP. This is one of the reasons for the levelized LNP costs in the recent settlement between PEF and the customer group representatives that was approved by the Commission. <u>See</u> Exhibit No. ___ (JE-4) to my testimony. This settlement reduces the near-term impact of the LNP costs on customer bills until the Florida economy can more fully recover from the recession.

The Company has long sought to balance the customers' ability to pay for the LNP and the need to develop new nuclear generation with the LNP to achieve the long-term fuel savings, fuel diversity, and clean energy benefits for PEF's customers. The Company took steps in 2008 and again in 2009, during the height of the recession, to mitigate the impact of nuclear cost recovery on customer bills. The Company's Commission-approved proposals deferred the recovery of prudent nuclear costs from 2009 to 2010, and then amortized them over a five year period commencing in 2010, thus reducing customer bills due to the LNP costs. The Company's 2010 decision to extend the partial suspension of the LNP under the EPC Agreement and proceed with the project work on a slower pace, focusing on obtaining the LNP COL, also reduced the near term project costs resulting in lower customer bills. The recent settlement continues the Company's efforts to balance the customers' ability to pay for the LNP and the need to develop the LNP for the customers' long term benefit as the Florida economy continues to slowly recover from the recession.

Q. Can you summarize how the Company's assessment of the current Florida economic conditions influenced its LNP enterprise risk evaluation?

A. Yes. The Florida economic recovery is fragile, with significant near term problems that can easily impair the current recovery. These economic circumstances represent an increased risk for the Company with respect to the significant, near term capital investments required to commence construction of the LNP next year.

Q. Were there other increased enterprise risks in your qualitative evaluation of the LNP enterprise risks this year?

A. Yes. As I explained last year, we observed a trend in the federal and state energy and environmental policy to delay climate control and greenhouse gas ("GHG") legislation and regulation. There remains continued, near term uncertainty with respect to the impact of federal and state energy and environmental policy, affecting the immediate development of the LNP.

There is no federal or state climate control legislation or GHG legislation that implements a cap-and-trade system or carbon tax on fossil fuel generation. Congress did not take action on any climate control or GHG emission bill. A clean energy bill that includes nuclear energy generation was introduced this year. With the elections in 2012, however, action on clean energy or climate legislation that implements some form of a cap-and-trade system or carbon tax is not expected this year. All Congressional climate control and clean energy efforts have stalled.

In Florida, the Legislature passed legislation this year to repeal the Florida Climate Protection Act. This Act was created in 2008 to implement Governor Crist's Executive Order No. 07-127 establishing GHG emission reduction targets for the State of Florida. The Act granted the Florida Department of Environmental Protection ("DEP") the authority to adopt rules for a cap-and-trade regulatory program to reduce GHG emissions from electric utilities. The Florida Legislature directed DEP in the Act to delay the adoption of any carbon emissions rule until 2010 subject to further approval by the Florida Legislature. Subsequently, the DEP chose not to promulgate a cap-and-trade rule. This year, the bill repealing the Act was introduced and passed by the Florida Legislature and signed by the Governor. No state climate control or GHG legislation or regulation is imminent.

Q. Has the Environmental Protection Agency implemented its regulation of GHG emissions from existing electric utility power plants?

A. No. As we explained last year, the federal Environmental Protection Agency ("EPA") was aggressively pursuing the regulation of GHG emissions under the Clean Air Act, even though Congress and the Florida Legislature had not acted on climate control legislation or regulation. In 2010, EPA implemented the Tailoring Rule under the stationary provisions of the Clean Air Act. The Tailoring Rule requires limits on GHG emissions in air permits for new, large industrial sources and other, major new and modified sources. As of January 2011, these sources had to obtain Prevention of Significant Deterioration ("PSD") permits requiring them to comply with GHG emission limits using best available control technology ("BACT"). EPA also issued a guidance document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" to address the PSD applicability to GHG, BACT, and other requirements. EPA also imposed GHG reporting requirements on certain facilities and EPA expected to propose new source performance standards ("NSPS") that set the level of GHG emissions for new and existing power plants.

The aggressive EPA action in 2010 and early 2011 to regulate GHG emissions has now stalled. The deadline for GHG reporting requirements was extended. EPA recently proposed a carbon emission standard for new power plants, but EPA has not yet issued a NSPS for GHG emissions for existing power plants, and it is unclear when EPA will issue the NSPS for GHG emissions from existing power plants. While congressional legislation and litigation to delay EPA's efforts to regulate GHG emissions stalled, as we explained last year, EPA has not pursued the regulation of GHG emissions as aggressively since these actions commenced. With an election in 2012, further aggressive action this year by EPA to regulate GHG emissions is not expected. EPA regulation of GHG emissions from existing power plants, therefore, is not imminent.

Q. What conclusion did you draw this year from your evaluation of federal and state energy and environmental policy?

A. We continue to believe that federal and state energy and environmental policy is a fundamental enterprise risk to the LNP from both a qualitative and quantitative perspective. Quantitatively, the effect of climate control or GHG legislation or regulation is reflected in an estimated carbon cost impact in the Company's economic, CPVRR feasibility analysis. Qualitatively, climate control or GHG legislation or regulation promotes nuclear generation because nuclear energy generation produces no GHG emissions. The current lack of federal and state energy and environmental policy with respect to GHG emissions increases the near term uncertainty regarding the qualitative and quantitative benefits of nuclear energy generation. In the near term, as we explained last year, the lack of certainty regarding what this legislation will be and when it will impact the Company represents an increased enterprise risk in our qualitative analysis.

Q. Does the Company still expect there to be climate control or GHG emission legislation or regulation?

A. Yes. PEF still expects some form of climate control or GHG emission legislation or regulation. There is no general movement to abandon climate control or GHG emission legislation or regulation at the federal level despite such action recently at the state level. EPA, for example, has not abandoned the regulation of GHG emissions even though it appears EPA cannot do so without congressional action, which has not occurred and is currently unlikely to occur. Despite this fact, EPA regulation of GHG emissions is still expected. EPA, in fact, recently proposed the first Clean Air Act standard for carbon emission from new power plants. This action demonstrates that future carbon and other GHG emission regulation can be expected. Near term, however, there is increased uncertainty regarding GHG regulation. There is no clear federal or state legislative GHG emission policy and without that legislative direction, what form GHG emission regulation for all power plants will take and when that regulation will be implemented, remains unclear. The fact that a uniform climate control or GHG emission policy remains unsettled this year increases this enterprise risk for the LNP.

Q. Were there any other federal or state legislative or regulatory policies that you evaluated in your enterprise risk analysis for the LNP?

A. Yes. PEF continues to follow the potential development of a renewable portfolio standard ("RPS") at the federal level and in Florida. A RPS for Florida utilities impacts customers because RPS resource options and resource alternatives that must be available when RPS resources are unavailable generally are more costly than conventional generation resource options. Despite the actual adoption of RPS in various jurisdictions across the country, there still is no federal RPS for electric utilities. There also is no state RPS in Florida. The Florida Legislature has not considered the Commission's proposed RPS rule in four straight legislative sessions after the Commission approved the rule, which the Commission was required to develop and present to the Florida Legislature for approval as a result of 2008 legislation. At the federal level, legislation including federal RPS for utilities has stalled and more recently Congress has moved toward a "Clean Energy" standard, which would include new nuclear, clean coal, and other non-traditional renewable resources not typically included in RPS. However, there has been no Congressional action on a "Clean Energy" standard and none is expected this year because of the elections.

The Company also follows other Florida legislation that may potentially impact the LNP. This includes repeated attempts by the same state legislators to repeal the nuclear cost recovery statute, which so far, have proved unsuccessful. Since the near unanimous support for the enactment of the nuclear cost recovery statute in 2006, individual legislators have introduced legislation nearly every year to repeal this statute. In addition, in 2010 and again in 2011, purported class action lawsuits were filed in state and then federal court challenging the constitutionality of the nuclear cost recovery statute. Currently, a group opposed to new nuclear development has appealed the Commission's decision in the 2011 NCRC docket to the Florida Supreme Court, apparently challenging the decision and constitutionality of the nuclear cost recovery statute. The same state legislators who have sought to repeal the nuclear cost recovery statute are seeking to be heard in this appeal to the Florida Supreme Court. The Company does not believe that these legal challenges are well founded, and the state and federal courts have so far agreed. The existence of these efforts to undermine the nuclear cost recovery statute, however, creates additional risk and uncertainty for the LNP.

As we explained last year, these repeated legislative and now legal attempts to repeal or overturn the nuclear cost recovery statute contradict the express State energy policy to increase fuel diversity and reduce Florida's dependence on fossil fuels subject to supply interruptions and price volatility that led to the enactment of the nuclear cost recovery statute. We continue to believe that this express State energy policy cannot be met without continued legislative support for the nuclear cost recovery statute and other legislation that promotes this State energy policy. Continued legislative support is necessary to the development of new nuclear generation in Florida.

Federal support for new nuclear development is also important. However, federal support for new nuclear generation remains unclear. Despite continued opposition at the federal and state level, including opposition by the National Association of Regulatory Utility Commissioners ("NARUC"), the current Administration still appears to support the abandonment of Yucca Mountain as the federal nuclear waste storage option. The current Administration's support for the development of new nuclear generation remains uncertain and ill defined. That situation is not expected to change in an election year.

Near term, then, there is no reason to expect significant movement at the federal or state level on energy, environmental, or nuclear generation policies that can affect the LNP one way or the other. The lack of federal or state legislative or regulatory direction, however, increases the near term uncertainty and thus, the near term enterprise risks associated with the immediate construction of the LNP within the next year.

Q. Were there any other changes in the LNP enterprise risks that affected your qualitative feasibility analysis this year?

A. Yes. Natural gas fuel prices have fallen to near historic low prices over the last three years and they have remained low. As we explained last year, the recession significantly contributed to these low natural gas fuel prices. Short-term natural gas prices remain depressed, reflecting over supply conditions and current natural gas storage running at near capacity. The economy, historically mild winter weather conditions in the winter of 2011/2012, and the development of unconventional shale gas resources have contributed to recent over supply conditions. As a result of these near term conditions, natural gas prices declined in recent natural gas forecasts, reflecting a down-ward trend in the forecasts.

This trend in natural gas prices is quantified in the Company's economic CPVRR feasibility analysis. Natural gas prices are a key driver in the CPVRR analysis. Generally, lower natural gas price forecasts reduce, and higher natural gas price forecasts increase, the cost-effectiveness of new nuclear generation. With the recent, lower natural gas price forecasts we have observed a decline in the economic feasibility of the LNP, although we think the LNP remains feasible even if the Company decided to implement the project plan commencing construction of the LNP next year. Qualitatively, however, we must evaluate the decline in natural gas prices in the near term forecasts to determine if this decision is the best implementation of the LNP. This qualitative assessment of the natural gas price forecasts considers a broader time period than the annual quantitative feasibility analysis update.

While we have observed a downward trend in natural gas prices, this trend does not appear to represent a long-term trend in natural gas price forecasts. The recession is certainly still having an impact on the near term natural gas prices, but long-term, continuous recessionary conditions cannot reasonably be expected. The downward trend in natural gas prices also corresponds to the development of additional natural gas supplies from shale gas reserves in the United States. This development contributes to the oversupply conditions and near term natural gas storage capacity. Likewise, mild weather conditions have contributed to the oversupply and natural gas storage capacity conditions.

There are supply and demand factors that could put upward pressure on natural gas prices over time. On the demand side these factors include but are not limited to the potential for the continued acceleration in coal plant retirements that will be replaced with gas generation given the aging coal fleet and proposed EPA regulations such as the Clean Water Act 316b, Maximum Achievable Control Technology ("MACT"), and Cross State Air Pollution Rule ("CSAPR"); the on-going developments by domestic LNG liquefaction projects looking for capabilities to export domestic U.S. gas; and increased industrial demand. On the supply side, there is risk of new regulations around gas production associated with hydraulic fracturing and there have already been announcements to shut in or reduce dry gas production given the current low gas price environment.

Over the long-term, natural gas prices are forecasted to increase. As a result, we do not believe there has been a fundamental shift in fuel prices reflecting a longer-term trend of natural gas prices at the prices experienced over the last three years and still expected in the near term such that these historically low natural gas prices will continue over the expected sixty-year life of the Levy nuclear units.

Q. What were the results of the Company's qualitative feasibility analysis?

A. As I have explained, our qualitative analysis of the LNP enterprise risks indicates greater near term uncertainty and increased near term enterprise risks. This increase in uncertainty and increased enterprise risk coincides with the Company's plan last year to commence construction of the LNP next year to implement the LNP. The increased near term enterprise risks, however, required the Company to determine if the plan to implement the LNP by commencing construction next year was the best implementation plan for the Company's customers. Based on the factors that I have discussed above, the Company determined that commencing construction of the LNP next year is not in the best interests of the Company or its customers.

C. <u>Regulatory Feasibility.</u>

Q. Is the LNP feasible from a regulatory perspective?

A. Yes. All legal and regulatory licenses and permits for the LNP can be obtained, including the LNP COL. I have attached as Exhibit No. ___ (JE-5) the current NRC review schedule for the LNP COLA. The Company filed its COLA with the NRC in July 2008 and it was docketed with the NRC for acceptance review in October 2008. This acceptance review initiated a period of NRC Requests for

Additional Information ("RAIs") to respond to NRC questions about the LNP COLA. This period for NRC RAIs officially ended in 2010 with the successful completion of the NRC RAIs.

There are three parts to the NRC COLA review process, (i) the environmental review process, (ii) the safety review process, and (iii) the formal hearing process. All three parts of the NRC's review for the LNP COLA must be complete before the NRC will issue a COL for the LNP. All three parts of the review are on target for completion with a schedule for issuance of the LNP COL in the second quarter of 2013. See Exhibit No. ___ (JE-5) to my testimony.

Q. What is the status of the environmental review process?

A. The environmental review process involves the issuance of a draft environmental impact statement ("DEIS") followed by a public comment period before issuance of a final environmental impact statement ("FEIS"). The LNP DEIS was issued in August 2010, the public comment period on the DEIS ended in October 2010, and the NRC Staff completed its responses to the public comments on the LNP DEIS in late 2011. PEF also completed responses to all identified U.S. Army Corps of Engineers ("USACE") information needs for the FEIS. As a result, the LNP FEIS is expected in April 2012.

Q. What is the status of the safety review process?

A. The second part of the NRC COLA review is the review and issuance of a Final Safety Evaluation Report ("FSER"). This is preceded by NRC review of the LNP COLA and the NRC's issuance of an Advanced Safety Evaluation Report

("ASER") with no open items. Completion of the ASER signifies that the NRC Staff has completed the required safety review. The LNP ASER was completed on September 16, 2011.

The next step is review of the ASER by the Advisory Committee on Reactor Safeguards ("ACRS"). The ACRS is independent of the NRC staff and reports directly to the NRC Commissioners. The ACRS is an advisory body that is structured to provide a forum for experts representing different technical perspectives. The ACRS provides independent advice to the NRC Commissioners for consideration in their licensing decisions. Progress Energy and the NRC Staff met with the ACRS committee in December 2011 and the ACRS completed review of the LNP ASER, ahead of the January 2012 milestone.

The ACRS review and report is followed by NRC review and issuance of the FSER. Following the ACRS review, the NRC Staff determined that certain recommendations from the Fukushima Near Term Task Force should be implemented for new reactors prior to licensing. This was the basis for an additional RAI that was issued for the LNP COLA on March 15, 2012 that will require update of seismic information to incorporate the Central-Eastern U.S. ("CEUS") source data and computer model. Plans are to address other information requests in the RAI by establishment of license conditions.

The requirement to perform a seismic update prior to COL may delay conduct of the mandatory hearing, however, issuance of the COL is still expected in the second quarter of 2013.

Q. Can you generally explain the NRC Fukushima Near Term Task Force recommendations that are relevant to the LNP COL?

A. Yes. The Fukushima Near Term Task Force recommendations that are relevant to the NRC's review of the LNP COLA include a seismic update to adopt CEUS model information. The NRC issued a RAI on March 15, 2012 and the response to this RAI will require the update of seismic information to incorporate the CEUS source data and computer model. These recommendations also include post COL license conditions for emergency planning, severe accident mitigating actions, and spent fuel pool instrumentation design upgrades. The emergency planning recommendations require the evaluation of staffing levels and communication to address such factors as multi-unit, prolonged events. The spent fuel pool instrumentation design updates require instrumentation that can withstand design basis natural events and provide remote indications of event impacts.

Q. Will the NRC Fukushima Near Term Task Force recommendations adversely affect issuance of the LNP COL?

A. We do not think so. As I explained last year, the events in Japan as a result of the March 2011 earthquake and tsunami were expected to result in additional review of existing and new nuclear generation units in the United States as a natural part of the NRC review process. Further delays in parts or all of the existing AP1000 nuclear reactor or design reviews, like the additional delay in issuance of the LNP FSER, were expected as a result of this process of incorporating lessons learned into the NRC licensing review processes.

As I further explained last year, the United States nuclear industry also has a long history of continuously incorporating lessons learned from the operating experience of nuclear power plants around the world. We expected the NRC and the nuclear industry to carefully analyze the Japanese accident at Fukushima and incorporate lessons learned into United States reactor designs and operating practices. The NRC formed the Fukushima Near Term Task Force for this purpose shortly after the nuclear incidents at Fukushima. The Task Force issued new rules in March 2012 requiring United States commercial nuclear reactors to enhance planning and safety equipment to address accidental and natural disaster damage similar to that experienced at Fukushima in the wake of the earthquake and tsunami last year. Progress Energy and other nuclear power plant operators were also taking steps to analyze and incorporate lessons learned from the Fukushima nuclear incidents in concert with the Task Force's review and analysis of the Japanese accident.

This is the way the United States nuclear industry operates to ensure safety at existing and planned nuclear power plants. The process of incorporating lessons learned, including the Task Force recommendations, into the nuclear industry licensing reviews and operating practices, however, does not mean that regulatory approval of the LNP COL will not ultimately be granted or significantly delayed following the completion of this process.

Q. Why are you confident that the LNP COL can be issued by the NRC when the NRC Fukushima Task Force recently issued its recommendations?

A. As I also explained last year, all existing and planned nuclear power plants, including plants employing the AP1000 nuclear reactor design, must be designed to deal with a wide range of natural disasters, whether they are earthquakes, tsunamis, tornados, hurricanes, storm surges, floods, or other extreme seismic or weather events. In this regard, the AP1000 is a passive design that does not rely on emergency diesel generators for safety related power to ensure core cooling. This passive system relies on internal condensation and natural recirculation, natural convection and air discharge, and stored water all contained within the robust structures of the containment and its shield building to cool the reactor even without electrical power. For safety related cooling the damaged Japanese nuclear units depended on electrical power from diesel generators that were inoperable as a result of the tsunami. Unlike the Japanese reactors, the AP1000 design will automatically place itself in a safe shutdown state, cooling the reactor passively without reliance on an external power source for some time until power is restored to the active coolant systems.

Additionally, the Fukushima reactors were in a high seismic risk area on the coast and located on the same power plant site. The LNP site is located in an area of low seismic risk, it is located away from the Crystal River site therefore avoiding the concentration of generation at one site, and the LNP site is located approximately eight miles inland at an elevation of fifty feet. Still, the LNP AP1000 reactors will be designed and built to withstand natural disasters, including earthquakes, tsunamis, and the more likely hurricanes and storm surges.

As I also explained last year, the AP1000 design and LNP COLA addresses extreme conditions resulting from potential man-made dangers. The AP1000 shield building design was revised to address concerns regarding possible aircraft impact and the LNP COLA incorporates strategies to address beyond design basis events in response to 9/11 security considerations. These strategies also provide additional protection against beyond design basis events regardless of the initiating event. The LNP COLA specifically contains Mitigative Strategies Description and Plans that the Levy plant will implement in the event that a large area of the facility is lost due to beyond design basis events.

As these examples illustrate, the AP1000 nuclear reactor design and its application to the Levy site under the LNP COLA will meet all requirements for operation under all potential conditions or circumstances. These include the operating conditions and circumstances addressed in the Fukushima Near Term Task Force recommendations.

Q. Does the Company still expect to receive the COL for the LNP from the NRC?

A. Yes. The NRC is still proceeding with the LNP COLA review process even with the issuance of the Fukushima Near Term Task Force recommendations. The LNP FSER is expected in September 2012, not April 2012, but the LNP FEIS is still expected in April 2012, and the LNP COL is still expected in the second quarter of 2013, after completion of the formal hearing process this year, which is the third part of the NRC COLA review process.

In addition, the NRC's issuance of the LNP COL is dependent on the issuance of both the final rule approving the AP1000 design certification amendment and the reference COL ("R-COL") for the AP1000 design. The R-COL is the Georgia Power Company Vogtle AP1000 plant site. The NRC and the Advisory Committee on Reactor SafeGuards ("ACRS") reviewed the AP1000 nuclear reactor design and declared that it is safe and meets all regulatory requirements. In December 2011, the NRC completed the AP1000 Design Control Document ("DCD") review and issued the final rule approving the AP1000 nuclear reactor design. In February 2012, the NRC voted to approve the R-COL for the Vogtle AP1000 plant site. Both conditions precedent to issuance of the LNP COL have now been met and both were satisfied when the Fukushima Near Term Task Force was completing its work and preparing its recommendations. Therefore, we see no reason to think that the issuance of the Task Force recommendations will further delay issuance of the LNP COL.

Q. **What is the status of the NRC formal hearing process for the LNP COLA?**

A. The contested hearing is conducted by the NRC Atomic Safety and Licensing Board ("ASLB") for any contentions to the LNP COLA admitted by the ASLB. In 2009, the ASLB allowed three private anti-nuclear groups, the Nuclear Information and Resource Service ("NIRS"), the Ecology Party of Florida ("EPF"), and the Green Party of Florida ("GPF"), to intervene in PEF's NRC LNP COLA docket. The ASLB ruled on their contentions and admitted parts of three contentions to the LNP COL. One of the three admitted contentions was dismissed by the ASLB in 2010. During the fourth quarter of 2011, the ASLB completed its review of the pending and revised contentions for the LNP COLA and, based on additional information provided by the Company, the ASLB dismissed another admitted contention. Only one environmental contention remains for consideration in the ASLB hearing. The ASLB has scheduled the contested hearing later this year in October, 2012.

There is also a mandatory hearing for the LNP COL. The mandatory hearing is conducted by the NRC Commissioners. The focus of the mandatory hearing is on the adequacy of the NRC Staff review of the LNP COLA. The NRC has already conducted mandatory hearings for the R-COLA for the Vogtle AP1000 nuclear power plants and the COLA for the V.C. Summer AP1000 nuclear power plants. As I explained above, the NRC has issued the R-COL for the Vogtle nuclear power plants. The NRC also recently issued the COL for the V.C. Summer AP1000 nuclear power plants.

The commencement of the LNP COLA mandatory hearing process is expected to be delayed by later issuance of the LNP FSER, but this delay in issuance of the LNP FSER is not expected to impact completion of the contested hearing before the ASLB this year. Exhibit No. ___ (JE-6) to my testimony graphically illustrates the steps and timing of the LNP COLA that I have addressed in my testimony. As indicated in that exhibit, the LNP COL is still expected from the NRC in the second quarter of 2013.

Q. Does the Fukushima nuclear incident affect in any way your assessment of the feasibility of completing the LNP?

A. No. The Fukushima event naturally led to increased interest globally in the safe design and operation of existing nuclear units and those that will be developed in the future. A reduction in the support for new nuclear development occurred as a result of the public reaction last year to the nuclear operating experience in Japan following the extreme earthquake and tsunami at Fukushima. Certain countries, in particular Germany, expressed the intent to abandon nuclear generation. Other countries, for example China and India, continue to develop new nuclear generation. In the United States, as I explained above, the Fukushima event did not upset or delay regulatory licensing reviews for the Vogtle and Summer new nuclear generation projects. The NRC approved the AP1000 DCD for the AP1000 nuclear reactor design and approved the R-COL for the AP1000 nuclear reactor.

I think that the NRC licensing review of new nuclear reactors has continued after Fukushima in large part because, as I testified earlier, the United States nuclear industry has a long history of continuously incorporating lessons learned from the operating experience of nuclear power plants around the world. The nuclear industry will continue to carefully analyze the Japanese accident and how reactors, systems, structures, components, fuel, and operators performed and incorporate lessons learned into United States reactor designs and operating practices. This is the way the nuclear industry in the United States operates to ensure safety at existing and planned nuclear power plants.

Also we are, of course, continuing to closely monitor international and national responses to the Fukushima event. PEF is also actively involved in industry groups, such as the Nuclear Energy Institutes ("NEI") New Plant Working Group, NEI New Plant Oversight Committee, and the Institute of Nuclear Power Operations ("INPO") New Plant Deployment Executive Working Group, which are working with the NRC to respond to emerging issues like the issues in Japan. These groups follow and help establish consistent direction around industry and regulatory issues associated with new nuclear projects. These groups will continue to be directly involved in addressing the implications from the Fukushima event in Japan and will continue to assist in shaping potential regulation. There is, therefore, no reason to believe now that the nuclear industry cannot successfully incorporate the lessons learned from Fukushima into its operating practices for existing nuclear generation and its licensing activities for new nuclear generation and sustain public support for nuclear energy generation.

D. Technical Feasibility.

Q. Is the LNP feasible from a technical standpoint?

A. Yes, it is. Completion of the LNP is technically feasible because the AP1000 nuclear reactor design can be successfully installed at the Levy site. The AP1000 nuclear reactor design remains a viable nuclear reactor technology. The NRC has approved the AP1000 design, the AP1000 DCD, and the AP1000 R-COL. The NRC also approved the AP1000 COLA for the SCANA V.C. Summer nuclear power units in South Carolina. SCANA is moving forward with the preconstruction work for its AP1000 nuclear reactors at Summer. Southern

Company also is moving forward with preconstruction and construction work for its Vogtle nuclear units using the AP1000 design. China is constructing AP1000 nuclear reactors at Haiyang and Sanmen and the Chinese government decided last year to focus its nuclear generation development on the AP1000 nuclear reactor design. The NRC is continuing its review of the LNP COLA with the understanding that the AP1000 nuclear reactor design will be used at the Levy site. The NRC has not indicated that the AP1000 nuclear reactor design cannot be used at the Levy site. As a result, there is no reason to believe that the AP1000 nuclear reactor design cannot be successfully installed at the Levy site.

V. LNP PMT RECOMMENDATION AND SMC DECISION.

Q. What were the results of the PMT's evaluation of the LNP this year?

A. The LNP PMT determined that the LNP is both qualitatively and quantitatively feasible. The Company can complete the Levy nuclear power plants. The LNP PMT determined that the LNP is feasible from a regulatory perspective. The LNP COL and other necessary permits to construct the LNP have been or can be obtained. The LNP is technically feasible because the AP1000 nuclear reactor design can be installed at the Levy site. The LNP PMT determined that lower near term natural gas prices and delayed carbon cost impacts diminish but do not eliminate the economic feasibility of the LNP. The LNP remains economically feasible for customers over the expected sixty-year life of the Levy nuclear units. Qualitatively, however, the LNP PMT determined that there is greater near term uncertainty and increased near term enterprise risks for the LNP. This greater near term uncertainty and increased near term enterprise risk necessarily affected the Company's implementation of the LNP. Once the LNP PMT determined that the near term LNP enterprise risks had increased, prudent project management required mitigation of the increased enterprise risks associated with the project. Accordingly, the LNP PMT developed a recommendation to mitigate the increased near term LNP enterprise risks.

Q. What was the LNP PMT recommendation to mitigate the increased near term LNP enterprise risks?

A. The LNP PMT recommended that the Company consider an extension of the current suspension of the EPC agreement to build the LNP later instead of implementing the plan to commence construction of the LNP next year. This recommendation was discussed with SMC members of senior management at the March 16, 2012 Levy Program Performance Review meeting. As a result of this meeting, the LNP PMT was directed to proceed with this recommendation and develop a plan to build the LNP later for presentation to and approval by the SMC in a revised IPP for the LNP. This plan included the development of later in-service dates for Levy Units 1 and 2, a revised LNP total project cost estimate, and an updated economic feasibility analysis. The recommended plan extended the current EPC agreement suspension and provided for the later construction of the LNP to place Levy Unit 1 in service in 2024 and Levy Unit 2 in service eighteen months later in late 2025. The updated economic analysis demonstrated that this plan was economically feasible with the revised total project cost estimate and the later in-service dates for the Levy units. This plan was presented to SMC for approval in IPP Revision 4. The SMC approved IPP Revision 4 in April of this year.

Q. Why did the LNP PMT recommend this later date for construction of the LNP?

A. As I explained above, the LNP PMT determined that the LNP is still qualitatively and quantitatively feasible even if the Company proceeded with the commencement of construction next year. The LNP still represents the best long-term, base load generation resource for PEF's customers. It will provide long-term fuel savings benefits to customers from a low-cost and clean energy fuel source. The LNP will also improve fuel diversity for the Company and the State and reduce their reliance on fossil fuels, especially fossil fuels from foreign sources, to generate electrical energy. The LNP will provide customers with a reliable, long-term source of base load generation. For all these reasons, the prudent decision for PEF's customers in 2010 and now is to build the LNP.

However, commencement of construction of the LNP next year is not supported by current Florida economic conditions for PEF's customers or for PEF. Near term natural gas prices and delayed carbon cost impacts further diminish the incentive to commence the construction of the LNP next year. The immediate construction of the LNP, therefore, is not in the best interests of PEF's customers or the Company.

Extending the commencement of construction of the LNP provides more time for the Florida economy to recover, for economic conditions for PEF's customers and for PEF to improve, for federal and state energy and environmental policy to develop and, therefore, for more certainty to develop with respect to the project's enterprise risks. Extending the commencement of construction of the LNP, therefore, mitigates the near term increased enterprise risks for the project while preserving the long term benefits of new nuclear generation for PEF's customers.

VI. TRUE UP TO ORIGINAL COST FILING FOR 2012.

Q. Has the Company filed schedules to provide information truing up the original estimates to the actual costs incurred?

A. Yes. The true up to original cost ("TOR") schedules are attached as Exhibit No. ___ (TGF-3) to Mr. Foster's testimony. I am co-sponsoring schedule TOR-6 and sponsoring schedule TOR-7 attached as Exhibit No. ___ (TGF-3) to Mr. Foster's testimony.

Q. Do these schedules reflect the revised LNP total project cost estimate based on the Company's decision approved by the SMC in IPP Revision 4?

A. Yes. The updated project baseline estimate is consistent with the Company's decision to build the LNP later, with an estimated in-service for Levy Unit 1 in 2024 and an estimated in-service for Levy unit 2 in 2025, that was approved by the SMC in IPP Revision 4. The current LNP total project cost estimate for the LNP is still premised on a conservative Class 5 estimate consistent with the best practices of the Association for the Advancement of Cost Engineering ("AACE"), fundamental terms and conditions of the existing EPC Agreement and current market conditions, and the current project schedule for the LNP with the in-service dates for Levy Units 1 and 2 in 2024 and 2025. The current total project cost estimate is dependent however, upon among other things, future Consortium negotiations to amend, modify, or alter the EPC agreement, or enter into some other contractual mechanism to implement the Company's decision. As a result of the 2010 EPC Amendment that implemented the current long term partial suspension, the Company is required to amend the EPC agreement anyway to end the current partial suspension and issue the FTNP to commence construction of the LNP next year. As a result, the Company's current decision does not place the Company in a significantly different negotiation position regarding the EPC contract with the Consortium. We think, then, that the current total project cost estimate for the LNP is reasonable and in line with our prior estimate for construction of the LNP, albeit on a later schedule for the in-service dates for the Levy nuclear units.

VII. QUANTITATIVE FEASIBILITY ANALYSIS.

Q. Did the Company prepare a quantitative feasibility analysis based on the Company's decision to build the LNP at a later date?

A. Yes. PEF prepared a CPVRR analysis consistent with the economic analysis approved by the Commission in Commission Orders No. PSC-09-0783-FOF-EI, No. PSC-11-0095-FOF-EI, and No. PSC-11-0547-FOF-EI. The CPVRR analysis includes the required updated fuel, environmental, and carbon compliance cost estimates. The CPVRR analysis also includes a project cost estimate based on the Company's decision to build the LNP later with the current, estimated 2024 (U1) and 2025 (U2) future in-service dates for the Levy nuclear power plants. Similar to our prior CPVRR analyses, the updated CPVRR economic analysis compares the LNP to an all natural gas-fired base load generation scenario using a range of fuel forecasts and a range of potential carbon compliance cost estimates. Likewise, the current CPVRR analysis includes CPVRRs for PEF ownership levels of the LNP of 100 percent, 80 percent, and 50 percent. And, the current CPVRR analysis also includes total LNP project cost sensitivities for cases ranging from 15 percent less to 25 percent greater than the current, estimated total project cost. Accordingly, this is the same approach that the Company used to prepare the CPVRR cost-effectiveness analysis in the need determination proceeding for the LNP and in the 2009, 2010, and 2011 NCRC proceedings. See Exhibit No. __ (JE-2) to my testimony.

Q. What were the results of the Company's quantitative feasibility analysis?

A. The updated CPVRR analysis shows that the LNP overall is more cost effective than the all natural gas generation resource plan. The CPVRR analysis shows that the LNP generation resource plan is more cost effective in 10 out of 15 cases at the 100 and 80 percent ownership levels, and 9 out of 15 cases at the 50 percent ownership level. See Exhibit No. __ (JE-2), p. 7. The CPVRR analysis this year demonstrates similar to prior CPVRR analyses that forecasted fuel prices are a significant driver in the analysis with lower forecasted fuel prices decreasing the benefits of the LNP resource plan and higher forecasted fuel prices favoring the LNP generation resource plan. Even with the shift in the in-service dates for Levy Units 1 and 2 to 2024 and 2025, however, the CPVRR analysis demonstrates that the LNP resource plan remains cost-effective.

Q. How does this updated CPVRR compare to the CPVRR provided in the LNP need case?

A. The results in the updated CPVRR analysis are similar to the results in the CPVRR analysis in the LNP need case. At the 100 percent ownership level, the LNP is more favorable than the all natural gas resource plan in 10 out of 15 potential fuel and carbon cost emission scenarios in the updated CPVRR analysis and in the CPVRR analysis in the LNP need determination proceeding. The difference is that the LNP is more cost effective in the current CPVRR analysis in all of the high and mid-fuel reference cases except the no carbon, mid-fuel reference case, and in only the highest carbon, low fuel reference case, while the LNP is more cost effective in the CPVRR analysis in the LNP need case in all of the high and mid-fuel reference cases, except the lowest carbon and no carbon cases, and more cost effective in the highest and second highest carbon cases in the low fuel reference case. See Exhibit No. ___ (JE-2), pp. 7-8. Both CPVRR analyses indicate that the LNP is more cost effective than the all natural gas resource plan in more potential fuel and carbon cost emission scenarios at the 100 percent, 80 percent, and 50 percent ownership levels. See Exhibit No. ___ (JE-2), pp. 7-8. The updated CPVRR analysis produces similar results to the CPVRR analysis results in the LNP need case even though the updated CPVRR analysis includes the current 2024 and 2025 in-service dates for the Levy nuclear units and a corresponding higher total project cost than the need case CPVRR analysis.

Q. What conclusions were drawn from the updated CPVRR feasibility analysis?

A. The updated CPVRR analysis continues to indicate that the LNP is cost effective and, therefore, an economically viable future generation resource. The updated CPVRR analysis confirms the Company's preference for the LNP as a future base load generation resource. The LNP continues to have the potential to provide PEF and its customers with billions of dollars of savings over the expected sixty-year life of the project. As I have explained before, the CPVRR analysis, however, is not a litmus test for the LNP. The CPVRR analysis is a snapshot of the project's estimated economic viability and the Company continues to believe that the long term projections upon which the CPVRR analysis are based on are necessarily uncertain and subject to change from year-to-year. Consequently, this type of analysis cannot be the sole basis for the Company to determine when to proceed with construction of the project. Instead, the CPVRR is one factor among many factors that must be considered in making a decision about moving forward with construction of the project.

Q. What did the Company conclude with respect to the economic feasibility of completing the LNP based on the Company's current decision to begin construction of the LNP at a later date?

A. Completion of the LNP in 2024 and 2025 based upon the Company's current decision to build the LNP later is economically feasible. Later construction of the LNP with estimated in-service dates for Levy Units 1 and 2 in 2024 and 2025 further mitigates the increased near term enterprise risks and is, therefore, feasible based upon the Company's qualitative feasibility analysis. Accordingly, based on the Company's quantitative and qualitative feasibility analyses, the LNP continues to be feasible based on the Company's decision to extend the current suspension of the EPC agreement and build the LNP at a later time.

VIII. IMPLEMENTATION OF LNP DECISION.

Q. What does the Company have to do to implement its decision?

A. Near term, there is little that needs to be done to implement this decision. The EPC agreement is already in an extended partial suspension and the Company slowed work on the project in 2010 based on its decision then to proceed with the LNP on a slower pace until the COL is obtained. PEF, therefore, expects to continue work to obtain the LNP COL, which is expected in the second quarter of 2013. Thereafter, PEF must incur additional licensing and engineering work to maintain the LNP COL.

The benefit of this decision is the flexibility it provides the Company with respect to the ultimate decision to construct the LNP. If near term project uncertainty and enterprise risks decrease, the Company has the flexibility to implement a decision to move up the construction of the LNP. Absent a change in the near term enterprise risks, the Company can defer the decision to commence construction of the LNP and the implementation of the necessary contractual mechanism to carry out that decision.

Q. What work will be performed for the LNP in 2012 and 2013?

A. As I have explained, the Company will continue work necessary to obtain the LNP COL from the NRC in 2012 and 2013. This work includes licensing and engineering work to address the NRC Fukushima Near Term Task Force recommendations. It also includes the licensing and engineering work to support the Company during the contested and mandatory hearing process. After this process is complete, and the Company obtains the LNP COL from the NRC, additional licensing and engineering work is necessary to maintain the COL. This will include licensing and engineering work associated with the review of standard design changes, and updates to the license to reflect design changes. We also expect licensing and engineering work to maintain the COL to include updates to incorporate emergency plan rule changes and other response actions as a result of the Fukushima Near Term Task Force recommendations.

Licensing and engineering work is also necessary in 2012 and 2013 to continue to support environmental permitting and implementation of conditions of certification ("CoC"). The environmental permitting work includes work on the USACE Section 404 permit for the LNP. Work supporting the completion of the Section 404 Permit includes consultations with other federal agencies regarding cultural resources, threatened and endangered species, and finalizing the Wetland Mitigation Plan to support the Section 404 Permit. We anticipate receiving the Section 404 Permit later in 2012. Work in 2012 and 2013 is also necessary to ensure compliance with the Site Certification CoC. Environmental work scope will include preconstruction environmental monitoring, wetland mitigation plan implementation, aquifer performance testing, and other site CoC.

Some work on strategic land acquisitions for transmission lines will also continue in 2012 and 2013 and the Company will incur a residual real estate acquisition payment required upon receipt of the LNP COL. The Company will further incur some incremental LLE disposition and storage costs based on the schedule extension, and continued LLE milestone payments and Quality Assessment ("QA") and vendor oversight activities associated with the continued LLE for the LNP. Additional Consortium Project Management Organization ("PMO") costs are also expected in 2012 and 2013 as a result of this continued work scope.

The Company further continues its participation in industry groups to advance the AP1000 design and operation. This includes the AP1000 owners group ("APOG") engineering committee participation. The Company will also continue its active involvement in industry groups such as the NEI New Plant Working Group, NEI Nuclear Plant Oversight Committee, and INPO New Plant Deployment Executive Working Group. The Company is also continuing its evaluation and disposition of AP1000 operating experience ("OE") in China and with the domestic Vogtle and Summer AP1000 projects. This will involve benchmarking and monitoring of licensing activities at these other plants including the assignment of Company engineering, project controls, and construction personnel at the Vogtle and/or V.C. Summer projects in 2012 and 2013. PEF will continue to provide project management for all these work tasks and activities for the LNP in 2012 and 2013.

Q. Does PEF have nuclear generation preconstruction costs in 2012 and 2013 as a result of the planned work scope and activities on the LNP?

A. Yes. PEF has 2012 actual/estimated and 2013 projected preconstruction costs for the LNP. Schedule AE-6 of Exhibit No. ___ (TGF-1) to Mr. Foster's testimony, shows actual/estimated generation preconstruction costs for 2012 in the following categories: License Application development costs of [redacted] and Engineering, Design & Procurement costs of [redacted]. Schedule P-6 of Exhibit No. __ (TGF-2) to Mr. Foster's testimony breaks down the 2013 projected generation preconstruction costs into the following categories: License Application costs of [redacted] and Engineering, Design & Procurement costs of [redacted].

Q. What are the License Application costs?

A. The License Application costs are necessary to support the on-going LNP licensing, environmental, and permitting activities that I have described above. These License Application costs are necessary for the LNP. PEF developed the preconstruction License Application cost estimates on a reasonable licensing and engineering basis, using the best available information to the Company, and consistent with utility industry and PEF practices. For the costs associated with the COLA review and other permit processes, PEF used the terms of its existing contracts, approved change orders, as well as updated forecasts, which are provided on a monthly basis by the contractors, to estimate the costs they will incur for the technical and engineering support necessary for these license and permit review processes. In addition, PEF based its projections on known project milestones necessary to obtain the requisite approvals. PEF is using actual or expected contract costs, NRC estimates, and its own experience including industry lessons learned, therefore, PEF's cost estimates for the preconstruction License Application work are reasonable.

Q. Please describe the Engineering, Design & Procurement preconstruction costs.

A. As I described above, the Engineering, Design & Procurement preconstruction costs in 2012 and 2013 are for defined PMO activities and shared AP1000 module program development work, implementation and oversight of the LLE change order terms and conditions, and site development for the LNP CoC. PEF developed the preconstruction Engineering, Design & Procurement cost estimates on a reasonable engineering basis, using the best available information. To develop the cost estimates, PEF utilized cost information from the EPC Agreement and information obtained through negotiations with the Consortium. In addition, PEF based its projections on the project schedule and staffing requirements as well as known project milestones necessary for the LNP CoC. Because PEF is using actual or expected contract costs and its own experience, PEF's cost estimates for the preconstruction Engineering, Design & Procurement work are reasonable.

Q. Does PEF have LNP generation construction costs in 2012 and 2013?

A. Yes. PEF will have 2012 actual/estimated and 2013 projected construction costs for nuclear generation for the LNP. Schedule AE-6 of Exhibit No. __ (TGF-1) to Mr. Foster's testimony breaks down the 2012 actual/estimated generation construction costs into the following categories: Real Estate Acquisitions costs of [redacted] and Power Block Engineering, Procurement, and related costs of [redacted] Schedule P-6 of Exhibit No. __ (TGF-2) to Mr. Foster's testimony breaks down the 2013 projected generation construction costs into the following categories: Real Estate Acquisitions costs of [redacted] and Power Block Engineering, Procurement, and related costs of [redacted]

Q. Please describe the Real Estate Acquisition costs.

A. For 2012, LNP real estate acquisition costs will be incurred to convey the bike trail state lands easement. Costs will also be incurred in 2013 for a deferred payment on the Levy plant site land acquisition required upon receipt of the COL, payment for a portion of the remaining barge slip easement acquisition, and to acquire land for a portion of the Blowdown pipeline easement.

The NGPP Real Estate Governance Document (REI-NGPF-00001) provides guidance for the acquisition of land needed for PEF's nuclear plant development. This document identifies participants; outlines the acquisition procedure and payment process; and outlines document tracking, approval, filing, reporting and document management and retention procedures. It was developed to define and formalize the management and execution of acquiring land and land rights and to provide for cost oversight and management concerning land acquisition. This document was updated in December 2010 to incorporate NGPP organization changes and payment process refinements. Utilizing these procedures, PEF developed these construction Real Estate Acquisition cost estimates on a reasonable basis, using the best available information, consistent with utility industry and PEF practice.

Q. Please describe the Power Block Engineering, Procurement, and related costs.

A. LNP Power Block Engineering, Procurement, and related costs in both 2012 and 2013 consist primarily of contractual milestone payments and incremental storage and shipping, insurance, and warranty costs on select LLE items. For example, in 2012, these LLE contractual milestone payments include [redacted] and incremental costs include [redacted]. In 2013, LLE contractual milestone payments include [redacted], and incremental costs include [redacted]

PEF developed these cost estimates utilizing cost information from the EPC Agreement and executed LLE change orders with the Consortium. PEF's cost estimates for the construction Power Block Engineering and Procurement work are reasonable.

Q. Did the Company's decision to build the LNP at a later date, with Levy Unit in-service dates in 2024 and 2025, change the disposition of LLE PO items?

A. No. The Company worked with the Consortium and its vendors in 2010 and 2011 to disposition the LLE POs in accordance with the Company's 2010 decision to extend the partial suspension to proceed with the work on a slower pace until the COL is obtained. This LLE PO disposition work involved a detailed disposition methodology that combined quantitative and qualitative criteria to meet the Company's objectives to minimize the near term costs and impact to customers while maintaining optimal flexibility for the future LNP construction. These objectives ensure that the LLE PO disposition decisions made by the Company and negotiated with the Consortium and its vendors are still prudent and in the customers' best interests even with the Company's current decision to build the LNP at a later date, with in-service dates for Levy Units 1 and 2 in 2024 and 2025 instead of 2021 and 2022. In other words, the LLE PO dispositions provide the Company the flexibility to build the LNP at a later date as currently planned. There is, therefore, no reason to revisit these LLE PO disposition decisions now, before the Company has obtained the COL and entered into negotiations with the Consortium to amend or modify the EPC Agreement, or to enter into some other contractual mechanism to implement the Company's current decision. Exhibit No. ___ (JE-7) to my testimony is a chart of the LLE PO disposition decisions for all fourteen LLE PO items.

Q. Does PEF have transmission-related preconstruction costs for the LNP in 2012 and 2013?

A. No.

Q. Does PEF have transmission-related construction costs for the LNP in 2012 and 2013?

A. Yes. PEF will have 2012 actual/estimated and 2013 projected transmission-related construction costs for the LNP. Schedule AE-6 of Exhibit No. ___ (TGF-1) to Mr. Foster's testimony shows transmission construction costs for 2012 actual/estimated in the following categories: Real Estate Acquisition costs of [redacted] and Other costs of [redacted]. Schedule P-6 of Exhibit No. __ (TGF-2) to Mr. Foster's testimony breaks down the 2013 projected transmission construction costs into the following categories: Real Estate Acquisition costs of [redacted] and Other. Costs of [redacted]

Q. What are the LNP transmission-related Real Estate Acquisition and Other costs?

A. In 2012 and 2013, Real Estate Acquisition activity for the LNP includes ongoing costs related to strategic Right-of-Way ("ROW") acquisition for the transmission lines during the partial suspension period. These costs are necessary to ensure that the ROW and other land upon which the transmission facilities will be located are available for the LNP. For 2012 and 2013, the Other LNP transmission costs include labor and related indirect costs, overheads, and contingency in support of strategic transmission ROW acquisition activities. They also include general project management, project scheduling, and cost estimating, legal services and external community relations outreach to local, state, and federal agencies. These construction costs are necessary for the transmission project work in support of the LNP.

PEF developed these LNP Real Estate Acquisition and Other transmission construction cost estimates on a reasonable engineering basis, in accordance with the Association for the Advancement of Cost Engineering International ("AACEI") standards, using the best available construction and utility market information at the time, consistent with utility industry and PEF practice. Real estate costs within the project estimates are based on an expected dollar per acre amount based on the type and location of the property using current route selection analysis. The management and indirect costs within the project estimates were developed based on the project schedule and staffing requirements. Costs include labor and related overheads and indirect costs, contingency, and escalation related to the inherent risk associated with a conceptual and preliminary design. These estimates reasonably reflect the necessary LNP transmission project work for 2012 and 2013.

Q. Is all of this work in 2012 and 2013 necessary for the LNP?

A. Yes. All of this work is reasonable and necessary in 2012 and 2013 to move the LNP forward on a schedule with the expected in-service dates for Levy Units 1 and 2 in 2024 and 2025, respectively. PEF currently intends to build the LNP and to build the LNP with the current 2024 and 2025 estimated in-service dates for Levy Units 1 and 2. All of this work in 2012 and 2013 is reasonable and necessary to meet that schedule.

Q. Must the Company amend or modify the EPC Agreement to implement its current decision?

A. Yes, or the Company must enter into some other contractual mechanism with the Consortium to implement its decision to build the LNP at a later date, with the commercial in-service for Levy Units 1 and 2 in 2024 and 2025. The Company's 2010 decision to proceed with the LNP on a slower pace, however, also required another amendment to the EPC Agreement to terminate the partial suspension terms, issue the FNTP, and establish a contract schedule for the work necessary to complete Levy Units 1 and 2. The Company's current decision and schedule to build the LNP, therefore, places PEF in the same position it was in prior to this decision with respect to the need for EPC contract negotiation preparations and negotiations. The Company also has the flexibility to negotiate an earlier commencement of construction, if conditions warrant that decision, or to negotiate for the commencement of construction in time to place the Levy Units in service in 2024 and 2025.

Q. Are there other issues that need to be addressed during future negotiations with the Consortium?

A. Yes. I discussed last year existing EPC Agreement design change proposals that must be addressed in any contractual negotiations with the Consortium. These design change proposals reflect changes to the AP1000 design identified during Westinghouse design finalization activities in response to the NRC AP1000 DCD review. These design changes occurred after PEF executed the EPC Agreement, therefore, they need to be incorporated into any future EPC Agreement amendment or modification, or other contractual mechanism for construction of the LNP with the NRC-approved AP1000 nuclear reactor design. The Design Change Proposal negotiations will include a determination of financial responsibility for the changes between the Consortium and the Company and, consequently, they may impact the LNP total project cost. The current LNP total project cost estimate contains a contingency for some design change cost impacts but the final cost impact cannot be determined at this time.

IX. JOINT OWNERSHIP.

Q. Has PEF's position on joint ownership changed as a result of its current implementation decision for the LNP?

A. No. PEF continues to believe that joint ownership in the LNP provides PEF and its customers the benefits of sharing the costs and risks of the LNP with other potential joint owners. Accordingly, PEF will continue to pursue joint ownership opportunities in the LNP.

Q. Has the status of joint ownership in the LNP changed?

A. No. The Company has continued and will continue joint ownership discussions and meetings with potential joint owners. There is continued interest in joint ownership participation in the LNP because potential joint owners still value the fuel diversity and clean energy production that new nuclear generation provides in a future that includes increasing fossil fuel environmental regulations and carbon and other GHG emission constraints. Florida utilities continue to view new nuclear generation as a prudent future generation resource for Florida.

X. PROJECT MANAGEMENT AND COST CONTROL OVERSIGHT.

Q. Has the Company implemented any additional project management and cost control oversight mechanisms for the LNP since the testimony you filed on March 1, 2012?

A. The Company has not implemented any additional project management or cost control oversight policies or procedures for the LNP since the discussion of these procedures in Mr. Daryl O'Cain's March 1, 2012 testimony. The Company continues to utilize the Company policies and procedures described in Mr. O'Cain's March 1, 2012 testimony to ensure that costs for the LNP are reasonably and prudently incurred.

The Company continues to review policies, procedures, and controls on an ongoing basis and makes revisions and enhancements based on changing business conditions, organizational changes, and lessons learned, as necessary. This process of continuous review of our policies, procedures, and controls is a best practice in our industry and is part of our existing LNP project management and cost control oversight.

Q. Are these the same policies and procedures that the Commission has previously reviewed for the LNP?

A. Yes. The Commission has previously determined that the LNP project management and cost oversight controls were reasonable and prudent. The Company's current LNP management and cost oversight controls policies and procedures are substantially the same as the policies and procedures reviewed and previously determined to be reasonable and prudent by the Commission.

Q. Are these LNP management and cost controls policies and procedures consistent with best practices in the industry?

A. Yes. We believe that our LNP project management and cost oversight policies and procedures are consistent with best practices for capital project management in the industry. We believe the project management, contracting, and cost control policies and procedures that we have implemented for the LNP are reasonable and prudent and consistent with industry best practices.

XI. CONCLUSION.

Q. Was the Company's 2012 LNP evaluation and LNP decision prudent?

A. Yes. PEF's decision to extend the commencement of construction of the LNP next year to complete the Levy units in 2024 and 2025 is the prudent decision at this time. This decision allows the Company and its customers additional time prior to construction of the LNP for economic conditions to improve for the Company's customers and the Company, for federal and state energy and environmental legislation and regulation to develop, and for natural gas prices to react to conditions approaching market equilibrium. This decision further provides the Company the flexibility to respond to changes in these near term enterprise risks by advancing the implementation of the LNP or continuing on the current path to build the LNP in 2024 and 2025. Given this flexibility, the Company's decision simply makes the most sense for the Company and its customers.

Q. Does this conclude your direct testimony?

A. Yes.

Levy Nuclear Project

Integrated Project Plan (IPP)

Financial Analysis Control Number: 2012-1646

Project Profile Matrix [PPM] Ranking: Black

Please Note: **This document contains confidential transmission information and is subject to Progress Energy's Standards of Conduct Procedure, #REG-SUBS-00002. Please do not distribute to Fuels & Power Optimization or Efficiency and Innovative Technology groups.**

Sponsoring Business Unit:	New Generation Programs & Projects
Funding Legal Entity:	PEF
Date Prepared:	04/23/2012

Key Project Contacts

Role, Department / Group	Name	Phone No.
VP – New Generation Programs & Projects (NGPP)	John Elnitsky	230-4481
GM - CDG Engineering	Vann Stephenson	770-6698
Mgr – Nuclear Plant Licensing	Bob Kitchen	770-6992
Director – Program Strategy and Development	Mike Rib	230-4474
Director – NGPPD Business Services	Daryl O'Cain	770-3791
Mgr – NPD Project Controls	Leigh Formanek	770-6377
Supervisor – Project Controls (Nuclear)	Lewis Spragins	770-5376

Plan Revision Control

Rev No.	Primary Author(s)	Revision Description	Rev Date
0	G. Miller/ D. Roderick/ G. Furman	Initial Consolidated Presentation	09/05/08
1	V. Stephenson/S. Hardison	Interim update for schedule shift and funding for first quarter 2010 key milestones	12/18/09
2	V. Stephenson/S. Hardison	Rev 2 to approve 2010 annual spending for Levy Partial Suspension and provide updates related to decision to continue partial suspension	04/28/10
3	V. Stephenson/D. O'Cain	Rev 3 to approve 2011-12 annual spending for Levy Partial Suspension and provide updates related to decision to continue partial suspension	03/29/11
4	V. Stephenson/D. O'Cain	Rev 4 to approve schedule shift and 2012-13 annual spending for Levy Partial Suspension	04/23/12

REDACTED

Progress Energy

Levy Nuclear Project IPP

Request for Approval

Purpose: ☐ Gate 0 - Initiate Project ☐ Gate 1 - Go Commit

☐ Gate 2 - Go Build / Baseline ☒ Revision

Authorization to make new commitments up to [redacted]

Authorization to spend additional funds up to [redacted] for May 2012 through April 2013 *

Estimated total project cost: *Expected $18.8 billion, estimate range $15.1billion to $21.6 billion* *

Next approval gate expected on: April 2013. Expected in-service date: Q2-2024 (Unit 1) and Q4-2025 (Unit 2).

Notes or Exceptions:

* *Full Financial View; excludes AFUDC; no joint owner assumption.*

Approval Required

This IPP requires approval by the: Senior Management Committee

Approvals

The parties signing below indicate by their signature that they, or the body they represent below, have reviewed the IPP and either recommend approval of or approve the above Request for Approval.

Action	Name [Type / Print]	Reviewing Position	Signature	Date
Recommend Approval	John Elnitsky	VP – New Generation Programs & Projects	(see attached)	
Recommend Approval	Vann Stephenson	GM – CDG Engineering	[signature]	4/23/12
Recommend Approval	Daryl O'Cain	Director – NGPPD Business Services	[signature]	4/23/12
Recommend Approval	Peter Toomey	Legal Entity Finance VP	(see attached)	
Senior Management Committee Approval				
Approve	Bill Johnson	Chairman, President & CEO – PGN	[signature]	4/23/12
Approve	Vinny Dolan	President & CEO – PGN Florida	(see attached)	
Approve	Jeffrey J. Lyash	Executive VP – Energy Supply	[signature]	4/23/12
Approve	Paula Sims	Senior VP – Corporate Development & Improvement	[signature]	4/23/12
Approve	Mark F. Mulhern	Chief Financial Officer	[signature]	4/23/12

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Recommend Approval	Peter Toomey	Legal Entity Finance VP	Pete E. Toomey	4/23/12
Senior Management Committee Approval				
Approve	Bill Johnson	Chairman, President & CEO – PGN		
Approve	Vinny Dolan	President & CEO – PGN Florida		4/24/12
Approve	Jeffrey J. Lyash	Executive VP – Energy Supply		
Approve	Paula Sims	Senior VP – Corporate Development & Improvement		
Approve	Mark F. Mulhern	Chief Financial Officer		

Table of Contents

1) Executive Summary

The scope of the Levy Nuclear Project (LNP) includes two (2) 1,105-MWe AP1000™ reactors and related transmission requirements. The transmission requirements include two (2) new 500/230kV substations, approximately 91 miles of 500kV and 88 miles of 230kV transmission lines, upgrades to five (5) transmission substations and two (2) new distribution substations, as well as low-voltage line upgrades to accommodate added nuclear generation.

Each year, the Levy Program Management Team evaluates the LNP with any major change in project enterprise risks or project scope, schedule, or cost. Since the evaluation that preceded the previous IPP update March 29, 2011, no significant changes in the overall project scope have occurred. With regard to transmission, an updated system planning study was deferred. With regard to the COLA, the scope was revised to include seismic evaluation updates and other information in response to NRC Near-Term Fukushima Task Force recommendations. COLA revisions related to NRC Near-Term Fukushima Task Force recommendations are expected to delay NRC issuance of the COL by 2-3 months. The COL receipt is anticipated in 2nd quarter 2013. There are no technical impediments to installing the AP1000™ reactors at the Levy site. The LNP is also cost-effective despite lower near-term natural gas prices and delayed carbon cost impacts. The current evaluation of project enterprise risks, however, reveals near-term greater uncertainty and increased enterprise risks.

Project enterprise risks include the economy, federal and state energy and environmental policies, and fuel market conditions. Near-term economic conditions in Florida remain weak and are not expected to significantly improve. Uncertainty continues with respect to federal and state energy and environmental policy. No federal or Florida climate control or further GHG emission legislation or regulation is expected this year. Fuel markets reflect economic, weather, and market conditions that depress near-term natural gas prices. Overall, the project enterprise risks have increased in the near term. Increased near-term uncertainty and enterprise risks coincide with the Company's program of record in the previous IPP update to commence construction of the LNP next year.

The LNP project team recommends a shift in the expected in-service dates for the Levy nuclear power plants to 2024 and 2025. This shift in the LNP in-service dates mitigates the current uncertainty and increased near-term enterprise risks. Increased near-term enterprise risks are mitigated by providing additional time prior to LNP construction commencement for Florida economic conditions to improve, for natural gas demand and supply to align in fuel markets, and for more certainty with respect to environmental emission costs, including GHG emission costs, from developing energy and environmental legislation and regulation. This shift in the LNP in-service dates further preserves the LNP as the preferred future base load generation resource. As a result, long term benefits of fuel portfolio diversity, reduced reliance on fossil fuels, carbon free energy generation, and electric grid reliability with a low cost fuel source that additional base load nuclear generation provides are maintained consistent with Progress Energy's Balanced Solution strategic plan.

As a result of the shift in commercial operation dates, the overall project estimate (Class 5) is an expected $18.8 billion, within a range of $15.1 to $21.6 billion.

In conjunction with this IPP and the May 1 regulatory filing, PEF completed the 2012 annual feasibility analysis and the quantitative feasibility results indicate that the Levy project remains favorable in more cases than not. The LNP remains cost-effective.

The LNP project team further recommends continued funding of approximately [redacted] for the period May 1, 2012 through April 30, 2013. Anticipated capital expenditures for the three-year period 2013-2015 are projected to be [redacted]. The project team will return in mid-2013 with an update and any needed funding requests.

2) Scope

When completed, the Levy project will add approximately 1,105 MWe of electrical generating resources to the PEF system in the summer of 2024, and 1,105 MWe of electrical generating resources to its system eighteen months later, with two state-of-the-art Westinghouse AP1000™ Advanced Passive nuclear power plants in Levy County, Florida.

The transmission requirements as include two (2) new 500/230kV substations, approximately 91 miles of 500 kV and 88 miles of 230kv transmission lines, upgrades to five (5) transmission substations and two (2) new distribution substations, as well as certain low-voltage line upgrades to accommodate the added nuclear generation. Additional system planning studies that may impact overall Levy Transmission project scope are expected to be conducted after COL issuance, which is currently projected for April 2013.

The Levy COLA scope is being revised to include seismic evaluation updates and other information in response to recent RAIs resulting from the Fukushima event. The NRC commissioners have approved SECY 12-0025, which contains lessons learned from the Fukushima accident and which was the basis for the Levy RAIs requesting additional information and evaluations in areas such as Seismic, Flooding and Emergency Planning.

Based on the revised commercial operation dates, the near-term non-COLA scope of work primarily consists of the following activities:

1. Amend the long-lead equipment (LLE) change orders;
2. Manage the LLE disposition;
3. Conduct AP1000™ design reviews;
4. Participate on the APOG Licensing, Operations, and Engineering Committees;
5. Evaluate/disposition OE from China and domestic AP1000™ projects;
6. Conduct post-receipt COL maintenance, including evaluation of DCP departures, required license change evaluations, and resulting COL updates; and
7. Assign Progress Energy engineering, project controls, and construction personnel to Vogtle and/or V.C. Summer projects.

3) Key Milestones & Project Gates

Due to the shift in the project commercial operation dates, the project schedule has been re-baselined. The following table highlights the key project milestones:

Key Milestones & Project Gates				
Milestone	**Date**			**Critical Path**
	Baseline	**Forecast**	**Actual**	**(Y/N)**
FEIS	Apr-12	Apr-12		N
FSER	Sep-12	Sep-12		N
Receive COL	Q2-13	Q2-13		N
[redacted]	[redacted]	[redacted]		N
Resume Site Specific Engineering	Q2-15	Q2-15		Y
Resume Transmission Work	Q1-16	Q1-16		Y
[redacted]	[redacted]	[redacted]		Y
[redacted]	[redacted]	[redacted]		Y
First Nuclear Concrete - Unit 1	Q1-20	Q1-20		Y
First Nuclear Concrete - Unit 2	Q2-21	Q2-21		Y
Unit 1 In-Service Date	Q2-24	Q2-24		Y
Unit 2 In-Service Date	Q4-25	Q4-25		Y

4) Estimated Project Cost

a) Estimate at Completion

The project team assumed the following:

1. Class 5 Estimate (According to AACEI Guidelines);
2. In-service date for Unit 1 is Q2-2024 and Unit 2 is Q4-2025;
3. EPC Consortium's current base contract price is used in the estimate basis;
4. [redacted]
6. No EPC Agreement termination costs are included in this estimate;
7. Maintain current disposition status of all LLE;
8. Existing transmission scope is included in base estimate. Adjustments for potential changes in transmission scope due to the change in the in-service date have been made using a probabilistic/EMV approach; and
9. Estimate excludes AFUDC.

The table below provides the key components of the estimate ($ in millions):

#	Description	Paid to Date Costs (thru Dec, 2011)	Estimate to Complete (ETC)	Total - Most Likely	% of Total Project	Range Min	Range Max
1	Transmission						
2	Subtotal- Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Generation						
5	EPC						
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Subtotal EPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	Owner Managed Scope						
13	COLA (excl. Labor & Contingency)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	Owner Managed Scope	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	Owner Labor & Staff Augmentation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	Perm Plant Equip (Spares, Maintenance Equip etc.)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	Real Estate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Other Owner Indirects (Fees, Permits, Taxes, Warranty, Ins, Temp Facilities, etc.)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	Subtotal Owner Managed Scope	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	Other						
22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	Subtotal- Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26	Total w/o Fuel	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
28	Fuel						
29	Fuel	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
30	Total with Fuel	$675	$18,172	$18,846		$15,076	$21,610

b) Capital Expenditures by Year (no joint owner assumption made)

Capital Expenditures by Year ($ Millions)							
CapEx	PTD 2011	2012	2013	2014	2015	2016+	Total
Prior IPP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	17,635.5
This IPP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	18,846.3
Difference	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(1,210.8)

Note: Amounts above exclude AFUDC.

Supplemental Information: Capital Expenditures by Subproject ($ Millions)							
CapEx	PTD 2011	2012	2013	2014	2015	2016+	Total
COLA (excl. Labor, Contingency)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Generation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**18,846.3**

Note: Amounts above exclude AFUDC.

5) Post Implementation Incremental Operational Costs

Post Implementation Incremental Operational Costs ($ Millions)					
Operational Cost	**2024**	**2025**	**2026**	**2027**	**2028**
O&M expense	[redacted]				
Fuel					
Maintenance capital					

Notes: (1) Fixed O&M, Variable O&M (Nuclear Refueling); (2) Includes $1/MWh back-end cost; (3) Assumed to begin 10 years after in-service date.

6) Industry Experience and Benchmarking

In March 2011, a benchmark was performed at South Texas Units 3 & 4 reviewing their COL Configuration Management (CM) Program. The benchmark identified one action item; to develop a pre-operational configuration management program for LNP that includes input from the generic AP1000™ configuration management program and South Texas CM procedures obtained during the benchmark. This action item is due May-2012.

In 2011, self assessments were completed to identify lessons learned for Operational Readiness/License Implementation (AR# 446582) and Environmental Permitting (AR# 440890).

The following benchmarking activities are scheduled for 2012/2013:

- Nuclear Design Control Program for COL Maintenance; Vogtle 3 & 4, Q2-2012 (AR 511039)
- Operations Readiness Schedule; V.C. Summer 2 & 3 and Vogtle 3 & 4, Q2-2012 (AR 511013)
- License Configuration Management Program, AP1000™ Design Center Working Group, Q2-2012 (AR 530868)
- Nuclear Construction Engineering Organization, Interfaces, and Operational Readiness; V.C. Summer 2 & 3, Q3-2013 (AR 511060)

Additionally, OE and CE are shared through participation in the APOG Executive, Engineering, Licensing, Operations, and Construction Experience Committees as well as the various APOG subcommittees. New Nuclear Plant OE and CE are also provided by non-APOG organizations including the NEI New Plant Working Group and INPO New Plant Deployment organization.

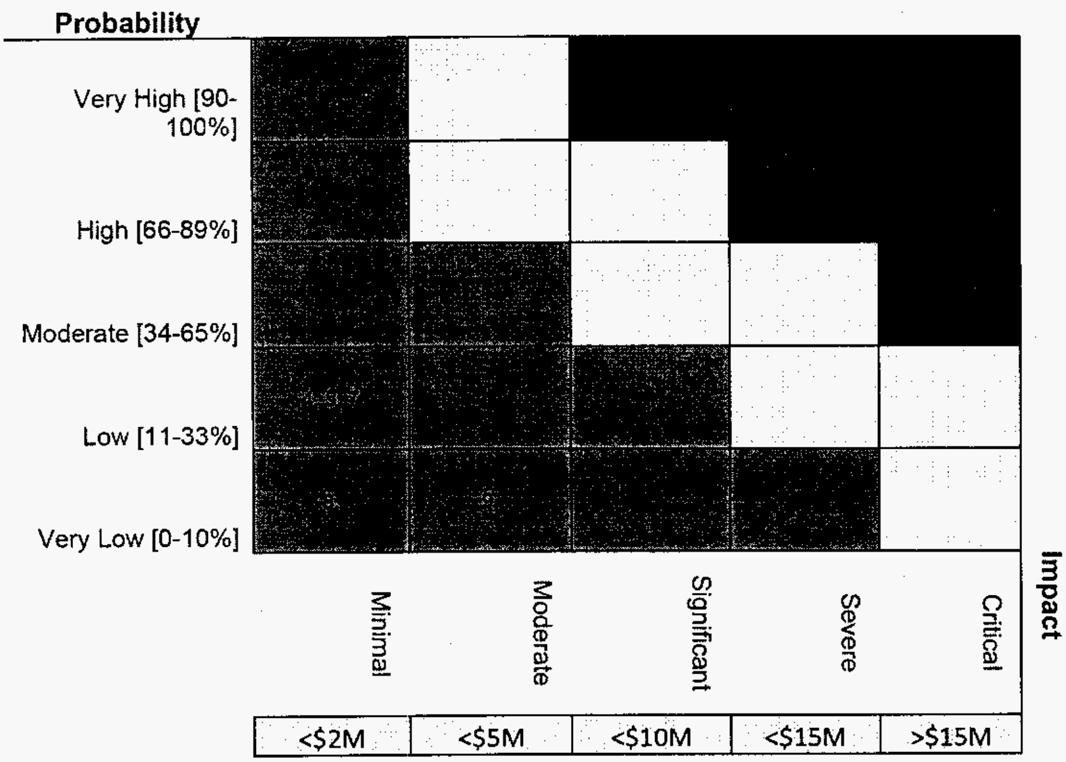
Finally, NGPP also holds weekly meetings to review OE and CE items to determine if the information is potentially applicable to the Levy Project and/or the AP1000™ new reactor design. Since 2011, 32 events have been further evaluated specific to the Levy Project and an additional 28 items have been forwarded to the APOG Construction Experience Committee for AP1000™ standard plant consideration.

7) Risk Assessment

The Enterprise Risk Management Framework (ERM-SUBS-00021) was followed to identify the standardized risk types for the project. The major risks for this project are summarized below.

a) Risk Matrix - COLA

Risks for the Levy COLA are identified, assessed and categorized by following PJM-SUBS-00008.



Quantification of Risk – COLA:

Expected Monetary Values [Total Risk Exposure]		
No.	**Risk Name**	**EMV ($ Millions)**
4	Contested hearings could impact schedule	[redacted]
5	[redacted]	[redacted]
7	Delay in environmental permit review and issuance	[redacted]
8	QA program implementation	[redacted]
9	Resolution of LEDPA analysis for USACE could delay licensing proceedings	[redacted]
	Total Risk Exposure - All Risks [$M]	[redacted]

Please note, Risks #1 through 3 (regarding changes to security rules, Probable Maximum Tsunami RAI, and Seismic/Structural RAI, respectively) have been closed. Risk #6 (Impact of Fukushima on regulatory and political environment) has been triggered.

b) Risk Descriptions and Mitigation Strategy - COLA

Risk #4: Contested Hearings Could Impact Schedule or Cost

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: IF contentions filed and admitted by ASLB are not thoroughly addressed or if new contentions are filed and admitted due to the recent events in Japan, THEN the contested hearing could result in unfavorable recommendation by ASLB and delay in COL or require additional manhours for NRC to support.

Trend: Current Ranking = Green Prior IPP Ranking = Green

Mitigation Plan:

- Conduct detailed witness preparation for each area of contention.
- Provide response to ASLB for any new or revised contentions.

[redacted]

Impact to:

Cost	☑	Schedule	n/a	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: [redacted]

Trend: Current Ranking = Green Prior IPP Ranking = Green

Mitigation Plan:

- [redacted]

Risk #7: Delay in environmental permit review and issuance

Impact to:

Cost	☑	Schedule	n/a	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: IF environmental permits are not received in a timely manner or maintained as required, THEN schedule delays could occur.

Trend: Current Ranking = Green Prior IPP Ranking = Green

Mitigation Plan:

- Develop Levy Environmental Permitting Schedule document. This document should include schedules for completion of SCA conditions of certification and other environmental commitments relative to construction and operation.
- Indoctrinate personnel on Levy Environmental Permitting Strategy.
- Monitor and Review.
- Update Environmental Permitting Schedule for 2012.
- Work closely with FDEP and USACE to develop sound permitting strategies to help streamline reviews.

Risk #8: QA Program Implementation

Impact to:

Cost	☑	Schedule	n/a	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: IF NQA-1 requirements are not implemented correctly, THEN NRC violations and corrective actions to address quality concerns could result.

Trend: Current Ranking = Green Prior IPP Ranking = Green

Mitigation Plan:

- Detailed scoping of procedures and processes that are required to support COL issuance has been developed.
- Project to develop new procedures and revise existing procedures has been initiated to complete prior to COL issuance.

Risk #9: Resolution of Least Environmentally Damaging Practicable Alternative (LEDPA) for USACE could delay COL

Impact to:

Cost	☑	Schedule	☑	n/a	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: IF resolution of Least Environmentally Damaging Practicable Alternative (LEDPA) analysis for US Army Corps of Engineers (USACE) is not completed in Q2-2012, THEN the mandatory and contested hearings and COL will be delayed.

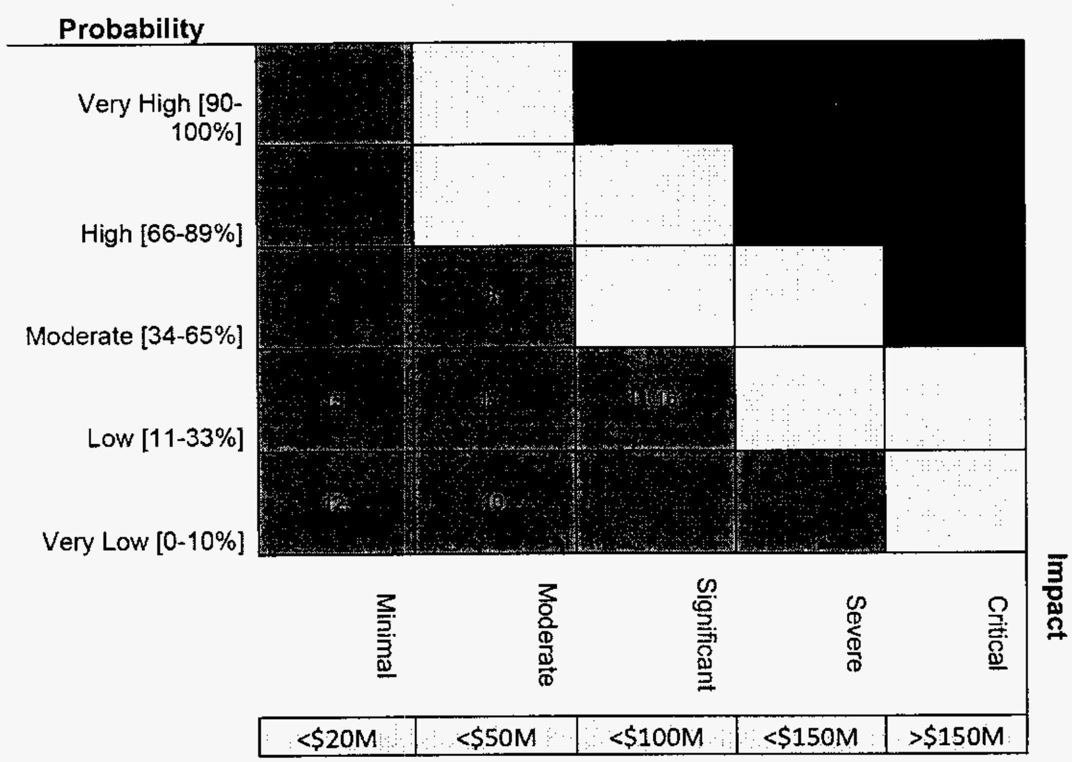
Trend: Current Ranking = Green Prior IPP Ranking = Yellow

Mitigation Plan:

- Meetings were held with USACE, EPA and NRC to ensure that information needs were defined and response plans understood.
- Progress Energy provided formal response to USACE documenting results of these meetings and committed to provide Environmental Monitoring Plan and establish contingency to implement desalination plant, if required, to prevent significant impact to groundwater.
- Review of draft Environmental Monitoring Plan and site tour with USACE, EPA and NRC was completed in April 2012.
- NRC has confirmed to Progress Energy and to the ASLB that the Final Environmental Impact Statement (FEIS) is on track to be issued April 27, 2012, as scheduled.

c) Risk Matrix – Near-term non-COLA

Due to the size and complexity of the Levy project, the Levy Non-COLA Near-Term Risk Register follows the Enterprise Risk Management Standard impact scale from ERM-SUBS-00021.



Quantification of Risk – Near-Term Non-COLA:

Expected Monetary Values [Total Risk Exposure]			
No.	Risk Name	Total Cost Impact ($ Millions)	Project Risk Exposure - EMV ($ Millions)
5	Modified Transmission Scope Uncertainty	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]
10	Change in Timing and Scope of Crystal River Switchyard work	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]
12	Recruiting Nuclear Operators	[redacted]	[redacted]
13	Land Acquisition required to support transmission, pipeline routing and wetland mitigation	[redacted]	[redacted]
16	RCC Test Pad Resolution	[redacted]	[redacted]
17	Aquifer Performance Test	[redacted]	[redacted]
	Total Risk Exposure - All Risks [$M]	[redacted]	[redacted]

Please note Risks #1, 2, 3, 4, 7, 14, 15, and 18 have been closed or triggered.

d) Risk Descriptions and Mitigation Strategy – Near-term non-COLA

Risk #5: Modified Transmission Scope Uncertainty

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: IF the revised Transmission Study or other transmission system changes impact the scope of work, THEN both cost and schedule may be impacted.

Trend: Current Ranking = Green Prior IPP Ranking = Green

Mitigation Plan: PEF has outlined a timeline to do a Transmission Study that will confirm the transmission scope of work. Following the study, PEF will assess the impacts and adjust the scope accordingly.

[redacted]

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: [redacted]

Trend: Current Ranking = Red Prior IPP Ranking = Red

Mitigation Plan: [redacted]

[redacted]

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: [redacted]

Trend: Current Ranking = Green Prior IPP Ranking = Green

Mitigation Plan: [redacted]

<u>Risk #10: Change in Timing and Scope of Crystal River Switchyard work</u>

Impact to:

Cost	☑	Schedule	n/a	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: IF the revised transmission study or other transmission system changes requires additional work to be done at the Crystal River Substation , THEN there is an increased potential that this will adversely affect the cost and schedule of this work.

Trend: Current Ranking = Green Prior IPP Ranking = Green

Mitigation Plan: PEF plans to re-conduct a transmission study that will confirm the transmission scope. Following the study, the project team will inform management of any changes and will adjust the plan accordingly.

[redacted]

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: [redacted]

Trend: Current Ranking = Green Prior IPP Ranking = Green.

Mitigation Plan: [redacted]

Risk #12: Recruiting Nuclear Operators

Impact to:

Cost	☑	Schedule	n/a	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: IF PEF is unable to attract the necessary number of nuclear operators to support startup, commissioning and operations, THEN PEF may need to have to train a higher percentage of new reactor operators than planned which potentially could affect the project cost and schedule.

Trend: Current Ranking = Green Prior IPP Ranking = Green

Mitigation Plan: PEF will develop a staffing and recruiting plan to support the project.

Risk #13: Land Acquisition required to support transmission, pipeline routing and wetland mitigation

Impact to:

Cost	☑	Schedule	n/a	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: IF the percentage of parcels in eminent domain is greater than planned, THEN PEF may need to pay additional money.

Trend: Current Ranking = Green Prior IPP Ranking = Green

Mitigation Plan: PEF will manage the land acquisition process using the Land Acquisition Plan and inform management of potential trends.

Risk #16: RCC Test Pad Resolution

Impact to:

Cost	☑	Schedule	☑	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: IF the results of the final RCC Test are not acceptable, THEN the reactor foundation will be redesigned.

Trend: Current Ranking = Green Prior IPP Ranking = N/A

Mitigation Plan:

- Determine root cause of small test pad testing failure.
- Provide oversight of test pad design, construction and testing. Provide results to NRC 180 days prior to scheduled foundation construction start date.
- Develop alternate foundation design and License Amendment Request that support project schedule.

Risk #17: Aquifer Performance Test

Impact to:

Cost	☑	Schedule	n/a	Performance	n/a	Environmental	n/a	Safety	n/a

Risk: IF the "Aquifer Performance Test" or environmental monitoring fails, THEN the Levy project team will have to prepare an alternate water supply plan which may impact the project cost and schedule.

Trend: Current Ranking = Green Prior IPP Ranking = N/A

Mitigation Plan: Levy team is working with the USACE to further define and understand the requirements.

e) Enterprise Risk

In addition to the project-specific risks previously discussed, there are a number of enterprise risks that are generally outside the control of the Company and that can affect the Company's ability to proceed with the LNP project. These enterprise risks are monitored as part of the LNP risk management and include the following risks: economic conditions in Florida; economic conditions for the Company including capital market reactions; load growth impacts; customer rates for nuclear generation; continued state legislative support for nuclear generation; state energy efficiency policy and regulation; state energy and environmental policy and regulation; federal energy and environmental policy and regulation; federal support for nuclear generation; and energy market conditions.

The Company considers the effects of these enterprise risks in its qualitative analysis of the feasibility of completing the LNP and identifies events or circumstances that present potential for fundamental changes in the project's enterprise risks. A summary of findings related to these conditions and other considerations since the last review is provided below:

Florida Economic Conditions: This recession was the nation's longest recession since the Great Depression, and the nation has not yet recovered. Economic conditions have been flat last year and this year in Florida, with growth expected at a rate that is far below the rate of growth experienced prior to the recession. The Florida unemployment rate, while recently declining, is still more than a full percentage point higher than the national average. Florida's housing and construction industries, which led past Florida economic recoveries, have not yet recovered from the recession. Florida's home vacancy rate leads the nation and Florida continues to be among the nation's leading states in foreclosures. The Florida economy will likely take additional time to recover from this recession.

Load Growth: Florida's economic recovery is lagging behind the national recovery. Continuing difficulties in the Florida economy adversely impact growth in energy consumption, retail sales, and sales revenues in the near term. Near-term customer growth, customer energy use, and energy sales remain at levels well below pre-recession growth rates. Over the long term, customer growth, customer energy use and, thus, retail energy sales and load, are expected to increase.

Customer Impacts: The Company's 2010 decision to extend the partial suspension of the LNP under the EPC Agreement and proceed with the project work on a slower pace, focusing on obtaining the LNP COL, reduced the near-term project costs and resulted in lower customer bills. The recent settlement continues the Company's efforts to balance the customers' ability to pay for the LNP and the need to develop the LNP for the customers' long-term benefit as the Florida economy continues to slowly recover from the recession.

State and Federal Policy: In Florida, there have been repeated legislative and legal attempts to repeal or overturn the nuclear cost recovery statute. The attempts to repeal the statute contradict the express State energy policy to increase fuel diversity and reduce Florida's dependence on fossil fuels. Continued legislative support is necessary to support State energy policy and development of new nuclear generation in Florida. Federal support for new nuclear development is also important but remains unclear. The current Administration's support for the development of new nuclear generation remains uncertain and ill defined. That situation is not expected to change in an election year. In the near term, there is no reason to expect significant movement at the federal or state level on energy, environmental, or nuclear generation policies that can affect the LNP one way or the other. The lack of federal or state legislative or regulatory direction increases the near-term uncertainty and thus, the near-term enterprise risks associated with near-term construction of the LNP.

Climate Policy: The Company continues to believe that federal and state energy and environmental policy is a fundamental enterprise risk to the LNP from both a qualitative and quantitative perspective. Qualitatively, climate control or GHG legislation or regulation promotes nuclear generation because nuclear energy generation produces no GHG emissions. The current lack of federal and state energy and environmental policy with respect to GHG emissions increases the near-term uncertainty regarding the qualitative and quantitative benefits of nuclear energy generation. In the near term, the lack of certainty regarding what this legislation will be and when it will impact the Company represents an increased enterprise risk in this qualitative analysis. At this point, there is no general movement to abandon climate control or GHG emission legislation or regulation at the federal level and ultimately, the Company still expects some form of climate control or GHG emission legislation or regulation.

Natural Gas Markets: Natural gas fuel prices have fallen to near historic low prices over the last three years and they have remained low, driven in part by the extended recession. Short-term natural gas prices remain depressed, reflecting over supply conditions and current natural gas storage running at near capacity. However, the qualitative assessment of natural gas price forecasts considers a broader time period than the annual review cycle in the short term. Over the long term, natural gas prices are forecasted to increase over the expected life of the Levy nuclear units.

Nuclear Plant Licensing: The Company recognizes that there are risks associated with all LNP regulatory approvals and schedule milestones in the Company's risk management process, including approvals for the FSER, the review and issuance of a FEIS, and a formal hearing for any admissible contentions to the COL issuance by the NRC ASLB. All three parts must be completed before a COL can be issued to PEF for the LNP. The Company works closely with the NRC and other state and federal regulatory agencies whose decisions affect the LNP schedule to monitor and analyze schedule determinations and events affecting the LNP COLA review schedule. In recent months, COLs have been issued by the NRC for both the Vogtle and V. C. Summer AP1000™ projects, which helps provide greater certainty for the Company in its assessment of risks in the licensing and review process.

Fukushima: In 2011, the risks associated with the events at the Fukushima plants in Japan were reflected in the Company's enterprise risk assessment. The NRC has assessed the long term risks associated with these events and developed a framework for assessment in the plant licensing process. Portions of this review process were developed in the COL reviews for the Vogtle and V. C. Summer projects. The NRC has provided the Company with more detailed requirements for the LNP COLA review, so this risk is more defined and is being tracked as a COL risk item, now considered to be triggered as noted in Section 7 above.

The PMT concludes from its qualitative analysis of the LNP enterprise risks this year that the LNP is still feasible over the long-term life of the Levy nuclear units; however, in the near term there is greater uncertainty and, thus, increased near-term enterprise risks. Applying prudent project management principles PMT recommends a plan to mitigate the increased near-term enterprise risks. The LNP PMT plan to mitigate the increased near-term enterprise risks extends the current project suspension and shifts the in-service dates for the Levy units to build the LNP later than previously planned. Issuance of the FNTP next year to commence full-scale LNP construction is not supported by near-term lower natural gas prices and delayed carbon cost impacts due to legislative and regulatory energy and environmental policy uncertainty. Extending the time for the commencement of the LNP construction, as outlined in this IPP, provides more time for the Florida economy to recover, for economic conditions for Florida customers to improve, for natural gas markets to balance supply and demand, for federal and state energy and environmental policy to develop, and therefore, for more certainty to develop with respect to the project's enterprise risks. The recommended decision in this IPP implements the mitigation plan by extending the commencement of construction of the LNP to complete the units in 2024 and 2025.

8) Economic Evaluation

The Florida Public Service Commission (FPSC) Nuclear Cost Recovery Clause (NCRC) Rule and Order No. PSC-09-0783-FOF-EI require annual feasibility studies. These feasibility assessments were last completed in April 2011 and filed with the FPSC on April 29, 2011. Updates are being prepared for inclusion in the NCRC filings scheduled for April 30, 2012. As the results described below reflect, the updated CPVRR assessment continues to indicate that the plan including the LNP is favorable in more cases than not.

One aspect of the feasibility assessment is a life-cycle net present worth assessment (also known as cumulative present value of revenue requirements, or CPVRR) of the project. These CPVRR assessments are typically prepared by PEF's System Planning group in support of need petitions. In the 2009 NCRC Proceeding, FPSC Staff required that PEF provide an updated CPVRR analysis for the LNP in a manner consistent with the assessment filed in the Need Proceeding (FPSC Docket 080148-EI). The CPVRR assessment was updated for the 2011 filing based on the Company's then current forecasts, construction schedule and cost estimates for the LNP and other generation technologies. Based on the forecast assumptions used in the 2011 filing, the results of the CPVRR assessment indicated that the plan including the LNP would be favorable in more cases than not. Based on the information presented in the 2011 filing, including the CPVRR study updates and other qualitative factors set forth, the LNP was deemed feasible based on PEF's assessment of the revised estimate and forecasts.

In anticipation of this requirement in the 2012 NCRC Proceeding, PEF has updated the CPVRR assessment based on the Company's current forecasts for submission in the 2012 filing.

In review of the updated results, several key considerations provide guidance on the changes to the project analysis.

- Capital expenditures for the LNP and alternative projects are one of the key inputs to the feasibility assessment. The estimates have been updated based on consideration of proposed revised in-service dates of June 2024 and December 2025. The revised results reflect changes to the estimate discussed in Section 3, impacts of discounting related to delayed expenditures, and the impacts of the delayed benefits related to fuel savings and emissions costs.

- The long-range forecasts for fuels have changed since the 2011 study was performed. The forecast price of natural gas continues to fall, particularly in the near term with impacts reflected in the longer term price forecasts as well.

The long-range expectations for cost of capital and operating costs, long-range forecasts of customer growth, and expectations surrounding future environmental legislation are also among the key inputs. The analyses incorporate recent updates to all of these inputs. In general, these inputs have not changed significantly from the forecasts used in the 2011 study. The carbon emission cost forecasts used are the same as those used in the 2011 study.

In addition to completing the feasibility analysis, the importance of the long-term benefits of the LNP cannot be ignored or dismissed. These long-term benefits are consistent with the legislative policy of the state of Florida and the purpose of the nuclear cost recovery statute, and are the reasons to encourage utility investment in nuclear power plants. The Commission must determine whether the nuclear power plant will provide the most cost effective source of power, taking into account the need to improve the balance of fuel diversity, reduce Florida's dependence on fuel oil and natural gas, reduce air emission compliance costs, and contribute to the long-term stability and reliability of the Florida electric grid.

The CPVRR assessments performed address the relative impacts of key forecast sensitivities on the life-cycle cost effectiveness projections for the optimized PEF resource plans including LNP (LNP Plan) and competing resource plans excluding the LNP (an All Gas Reference Plan). The results summary tables report the differences in CPVRR between these competing plans. A positive value in the results table depicts a scenario where the LNP Plan is economically favorable to the All Gas Reference Plan over the life cycle period being evaluated.

The first CPVRR summary table below refers to the sensitivities surrounding fuel forecasts and carbon policy scenarios. The fuel forecast sensitivities assessed address the relative impacts of the selected fuel forecast scenarios on life cycle cost effectiveness projections for both plans. The CPVRR results for carbon policy scenarios assess the relative cost impacts of compliance with carbon emission restrictions which may be influenced by factors including, but not limited to, the compliance levels required, the timing of policy implementation and the technologies and advancements believed to be available to help reduce emissions in the future.

Fuel Sensitivities			
041012 - 100% Ownership, 2024 COD - 6.47% Levy Case Versus All Gas CPVRR $Million			
Base Capital Reference Case	Low Fuel Reference	**Mid Fuel Reference**	High Fuel Reference
No CO2	($12,022)	($3,907)	$7,859
EPA WM	($7,785)	$402	$12,372
CRA WM	($5,113)	$3,023	$15,027
EPRI Full	($2,794)	$5,347	$17,448
EPRI Ltd	$3,037	$11,184	$23,224

Fuel Sensitivities			
041012 - 80% Ownership, 2024 COD - 6.47% Levy Case Versus All Gas CPVRR $Million			
Base Capital Reference Case	Low Fuel Reference	**Mid Fuel Reference**	High Fuel Reference
No CO2	($9,613)	($3,121)	$6,335
EPA WM	($6,284)	$194	$9,859
CRA WM	($4,182)	$2,224	$11,894
EPRI Full	($2,356)	$4,045	$13,757
EPRI Ltd	$2,228	$8,639	$18,176

Fuel Sensitivities			
041012 - 50% Ownership, 2024 COD - 6.47% Levy Case Versus All Gas CPVRR $Million			
Base Capital Reference Case	Low Fuel Reference	Mid Fuel Reference	High Fuel Reference
No CO2	($7,007)	($2,852)	$3,232
EPA WM	($4,803)	($655)	$5,454
CRA WM	($3,423)	$768	$6,782
EPRI Full	($2,194)	$2,039	$8,027
EPRI Ltd	$812	$5,084	$11,101

The second CPVRR results summary table below provides the sensitivities surrounding capital cost forecasts and carbon policy scenarios. In these sensitivities, the initial capital costs of the LNP and the competing alternatives are adjusted in a range of (-15%) to (+25%) to assess the relative impacts on life-cycle cost effectiveness comparisons between the plans. The carbon policy sensitivities are the same.

CapEx Sensitivities						
041012 - 100% Ownership, 2024 COD - 6.47% Levy Case Versus All Gas CPVRR $Million						
Mid Fuel Reference Case	LNP CapEx (15%)	LNP CapEx (5%)	Mid Fuel Reference	LNP CapEx +5%	LNP CapEx +15%	LNP CapEx +25%
No CO2	($2,400)	($3,405)	($3,907)	($4,410)	($5,415)	($6,421)
EPA WM	$1,910	$905	$402	($100)	($1,105)	($2,111)
CRA WM	$4,531	$3,526	$3,023	$2,520	$1,515	$510
EPRI Full	$6,855	$5,850	$5,347	$4,844	$3,839	$2,834
EPRI Ltd	$12,692	$11,687	$11,184	$10,682	$9,676	$8,671

CapEx Sensitivities						
041012 - 80% Ownership, 2024 COD - 6.47% Levy Case Versus All Gas CPVRR $Million						
Mid Fuel Reference Case	LNP CapEx (15%)	LNP CapEx (5%)	Mid Fuel Reference	LNP CapEx +5%	LNP CapEx +15%	LNP CapEx +25%
No CO2	($1,959)	($2,734)	($3,121)	($3,509)	($4,284)	($5,059)
EPA WM	$1,357	$582	$194	($194)	($969)	($1,744)
CRA WM	$3,387	$2,611	$2,224	$1,836	$1,061	$286
EPRI Full	$5,208	$4,432	$4,045	$3,657	$2,882	$2,107
EPRI Ltd	$9,802	$9,026	$8,639	$8,251	$7,476	$6,701

CapEx Sensitivities						
041012 - 50% Ownership, 2024 COD - 6.47% Levy Case Versus All Gas CPVRR $Million						
Mid Fuel Reference Case	LNP CapEx (15%)	LNP CapEx (5%)	**Mid Fuel Reference**	LNP CapEx +5%	LNP CapEx +15%	LNP CapEx +25%
No CO2	($2,073)	($2,592)	($2,852)	($3,111)	($3,631)	($4,150)
EPA WM	$124	($395)	($655)	($914)	($1,433)	($1,953)
CRA WM	$1,546	$1,027	$768	$508	($11)	($530)
EPRI Full	$2,817	$2,298	$2,039	$1,779	$1,260	$741
EPRI Ltd	$5,863	$5,344	$5,084	$4,825	$4,305	$3,786

As in previous analyses, the Levy Nuclear Project is preferred to the all-gas case in the majority of the scenarios studied.

9) Organization

No staffing changes are expected in the near term to support the scope identified in this updated IPP. Engineering and Licensing will remain at current staffing levels to support obtaining and maintaining the Levy COL. Additional project support is provided by NGPP's Project Coordination and Performance Improvement Section in the areas of project controls and performance improvement. Other Progress Energy internal organizations such as Service Company Finance, Environmental Services, and Legal provide additional project support. In 2013, it is anticipated that Progress Energy engineering, project controls, and construction personnel will be assigned to the Vogtle and/or V.C. Summer projects in order to collect OE and CE to be applied to the Levy project.

10) Contract & Procurement Strategy

The table below identifies the major contracts that have been issued by PEF for the Levy Project. PEF has contracted with the Joint Venture Team (JVT) of Sargent & Lundy, CH2M Hill, and Worley Parsons for preparation and support of the COLA, SCA, and SCA Conditions of Certification. PEF has contracted with a Consortium comprised of Westinghouse Electric Company and Stone & Webster for the engineering and procurement of plant equipment (including the nuclear island and balance-of-plant equipment) as well as for the construction of the plant. Finally, PEF has contracted with Environmental Services Inc. to complete detail design to the wetland mitigation plan for the LNP and associated transmission lines. The contract with WEC for the fabrication of the initial core load of nuclear fuel was cancelled in December 2011. [redacted]

PEF continues to focus work on obtaining the COL for the LNP from the NRC and obtaining or fulfilling other regulatory permit requirements for the project, while minimizing near-term costs until after the COL is obtained.

The EPC Agreement with the Consortium is currently under a partial suspension until the LNP COL is obtained from the NRC, which as noted above is currently expected in the second quarter of 2013. The Company will continue with all of the work necessary to obtain the COL during 2012 and 2013 and does not need to take any action at this time with regard to the EPC Agreement. Any changes to the current EPC Agreement will be reviewed after receipt of the COL, [redacted].

Summary of Contract Status -$1M & above
($ Millions)

Vendor Name	Cost item	Original est'd value	Executed or current est'd value	Change Order / Amend.	Cumulative amended Value (Notes 2, 3)	Status	Contract type
EPC Consortium (Westinghouse Electric Company, Stone & Webster Inc.)	EPC	[redacted]	[redacted]	[redacted]	[redacted]	Active	[redacted]
Joint Venture Team (Sargent & Lundy, CH2M Hill, WorleyParsons)	Lic	[redacted]	[redacted]	[redacted]	[redacted]	Active	[redacted]
Environmental Services Inc.	Env	[redacted]	[redacted]	[redacted]	[redacted]	Closed	[redacted]

Note 1 – [redacted]

Note 2 – [redacted]

Note 3 – [redacted]

10A) LLE Update

LLE change orders to adjust the storage, warranty and remanufacturing terms will need to be negotiated with the Consortium to support the shift in schedule. The following table outlines the current disposition status of the LLE components and the estimated near-term spend.

Equipment Name	Equipment Manufacturer	Current Disposition Status	2012 Estimated Costs ($M)	2013 Estimated Costs ($M)	Total 2012-2013 ($M)
[redacted]					

11) Change in Inventory Detail

As noted above, PEF has contracted with a Consortium comprised of Westinghouse Electric Company and Stone & Webster for the engineering and procurement of plant equipment (including the nuclear island and balance-of-plant equipment) as well as for the construction of the plant. This Contract also includes the initial inventory needed, and the associated costs are included in the total project costs presented in Section 4 above. [redacted]

12) Regulatory Requirements

Updates to the COL schedule and status are discussed in detail in Sections 2 and 3 of this IPP. The COL is expected to be issued by the NRC in April 2013.

The Fukushima Daiichi nuclear event that occurred on March 11, 2011 has resulted in significant review of regulatory requirements by the NRC and industry initiatives to identify appropriate response actions to improve nuclear plant safety. Specifically, the NRC commissioners have approved SECY 12-0025, which contains lessons learned from the Fukushima accident and which was the basis for RAIs requesting additional information and evaluations in areas such as Seismic, Flooding and Emergency Planning. The impact to the COLA phase of the LNP project is one such RAI, which was issued on March 15, 2012. Response to this RAI will require update of seismic information to incorporate the Central-Eastern U.S. (CEUS) source data and computer model. Plans are to address other information requests in the RAI by establishment of license conditions. These items include the following:

- Develop mitigation strategies for beyond design-bases external events;
- Develop design change to improve reliability of spent fuel pool instrumentation; and
- Evaluate and implement staffing and communications to respond to multi-unit events with prolonged Station Blackout (SBO) conditions.

The requirement to perform a seismic update prior to COL may delay conduct of the mandatory hearing and, as a result, issuance of the COL is expected in April 2013. The AP1000™ design has significant improvements over previous generation reactor designs and, with relatively small change, can cope with seismic, flooding and extended SBO conditions that are being required by NRC orders. Therefore major design change to the AP1000™ to address requirements resulting from the Fukushima event is not anticipated.

In addition to the COL, PEF must obtain required environmental permits to support LNP plant construction and operation. Environmental permitting for the LNP involves certain basic steps: first, an application to the NRC for a COL; second, an application to the State of Florida for site certification; and third, applications for certain additional federal environmental permits, including the following:

- National Pollutant Discharge Elimination Permit for water discharge;
- Prevention of Significant Deterioration air permit;
- 316(b) demonstration for the proposed cooling water intake;
- USACE Section 404 and Section 10 permits to construct structures in wetlands and regulated waterways;
- Hazardous waste management and disposal; and
- Determination of consistency under the requirements of the Coastal Zone Management Act to ensure the LNP is consistent with existing federal and state coastal zone management plans.

The Florida Power Plant Siting Act mandates a site certification process for obtaining a single site-related license that will include state, regional, and local requirements for construction and operation of an energy facility of the type and magnitude of the LNP and associated transmission system additions. The Site Certification for LNP was approved by the State on August 26, 2009. Initial coordination has begun and will continue through meetings and informal consultations as the Environmental Impact Statement (EIS) is developed. During the EIS development process, the regulatory agencies will be a part of the stakeholder group, and therefore are likely to provide formal comments on the draft and final EIS. Several of the permit processes can be started prior to finalization of the EIS; however, it is likely that coordination with the regulatory agencies will influence the exact timing and submission of the permits associated with this project.

The Final EIS is being prepared by the NRC with the USACE as a cooperating agency. The Draft EIS was issued for comment in August 2010. The USACE will use the Final EIS as a basis for their Record of Decision to grant the Clean Water Act Section 404 Dredge and Fill Permit, which will be needed to allow construction activities in waters of the State.

Current milestones for the safety and environmental reviews are shown below:

Safety Review Phase	**Target Date**
Phase A – RAIs and Supplemental RAIs	3/24/2010 (A)
Phase B – Advanced Safety Evaluation Report	9/16/2011 (A)
Phase C – Advisory Committee on Reactor Safeguards (ACRS) Review	12/7/2011 (A)
Phase D – Final Safety Evaluation Report (FSER) Issued	April 2012
Environmental Review Phase	**Target Date**
Phase 1 – Environmental Scoping Report	5/28/2009 (A)
Phase 2 – Draft Environmental Impact Statement (DEIS)	8/5/2010 (A)
Phase 3 – Responses to Public Comment on DEIS	November 2011
Phase 4 – Final Environmental Impact Statement (FEIS)	April 2012

Currently there are no safety contentions. One environmental contention has been admitted and will require conduct of a contested hearing. The Atomic Safety and Licensing Board (ASLB) has scheduled the contested hearing to be conducted on October 31 and November 1, 2012. Issuance of the Final Environmental Impact Statement (FEIS), which is scheduled for April 27, 2012, will initiate activities required to support conduct of the contested hearing. Progress Energy has initiated development of witness testimony and other preparations for the contested hearing.

A mandatory hearing is also required to complete COL approval and must be conducted separately from the contested hearing. The mandatory hearing will be conducted by the NRC Commissioners and is currently planned for July 2012. The mandatory hearing may be delayed if the NRC requires Progress Energy to respond to a request for additional information (RAI) issued by the NRC on March 15, 2012 prior to COL issuance. This RAI requires Progress Energy to address seismic and other concerns that have resulted from the Fukushima nuclear event. Although the V.C. Summer COL was issued on March 30, 2012 with license conditions to address Fukushima, the NRC has requested Progress Energy to reevaluate seismic to incorporate the CEUS update prior to COL. Unless directed otherwise by the NRC Commission the mandatory hearing will be delayed until late 2012 resulting in COL issuance expected in April 2013.

In addition, PEF and/or its contractors will be required to follow and adhere to all applicable state and federal Occupational Safety and Health Administration (OSHA) regulations and requirements regarding worker safety. All necessary permits will be obtained prior to and during the pre-construction and construction phases of the project.

Finally, the project team has worked with Regulatory Planning and PEF legal counsel during late 2011 through the current date to ensure all key nuclear cost recovery clause milestones are met. The following items are complete through April 2012:

- Data Requests #1 and #2 (Nuclear Project Management & Controls Audit)
- 2011 Cost true-up filings and associated testimony to support 2011 costs
- Support of FPSC financial audit requests received
- April 4th & 5th FPSC Project Management & Controls Audit interviews
- Annual NCRC schedules and testimony to be finalized for submittal April 30, 2012

13) Market Analysis

As of March 2012, applications for COLs have been filed for fourteen AP1000™ reactors at seven plant locations in the US, including the COLs approved for Vogtle and V. C. Summer. Of those projects, there are currently three projects for which EPC agreements have been executed (Vogtle, V.C. Summer and Levy). No new AP1000™ EPC agreements have been executed since PEF's agreement for the Levy project in December 2008.

14) External Relations Plan

The following list highlights the key near-term external communications regarding the shift in commercial operation dates for Units 1 and 2:

- 4/30/2012: Submittal of annual NCRC schedules and testimony
- 4/30/2012: External-facing stakeholder call
- 5/1/2012: Issuance of press release on external PGN website
- 5/1/2012: Issuance of 8-K SEC filing

With regard to outreach activities, the following items are planned to support the schedule shift filing and announcement:

- 4/30/2012: Outreach in the late afternoon to announce as appropriate to governor and Cabinet, key agencies (e.g. FDEP, NRC, NEI, APOG, FPSC, DCA, OPC), Senate and Congressional delegation for Levy and surrounding counties, and Levy County Commission chairman
- 4/30/2012 (late) and 05/01/2012: Outreach as appropriate to officials and key leaders in Levy and surrounding counties including UF; includes targeted follow up in-person visits within two weeks following announcement
- 5/01/2012: Targeted communication relating to property owners in the 10-county route study area
- 5/01/2012: Outreach to officials and key leaders in other counties along transmission routes as appropriate
- 5/01/2012: Communications to County Emergency Management directors and staff in Levy and surrounding counties in EPZ as appropriate
- As Needed: Reactive communications statewide to address inquiries and concerns

15) Internal Stakeholders

The below table identifies the Progress Energy organizations and primary contacts with a vested interest in the outcome of the Levy Project and have an impact on its success.

Internal Stakeholders		
Stakeholder	**Primary Contact**	**Role**
Executive Project Sponsor	Jeff Lyash	Provide senior management oversight and input (as necessary) after initial project approval and during construction, including executive sponsorship of the Levy Program Performance Review.
PEF Project Sponsor	Vinny Dolan	Provide utility-level oversight and input (as necessary) after initial project approval and during construction, including sponsorship of the Levy Program Performance Review.

Internal Stakeholders		
Stakeholder	**Primary Contact**	**Role**
Asset Owner	Jim Scarola	Provide insight to NGG-specific requirements. Receive final commissioned asset from the construction organization and integrates asset into the NGG fleet.
Sr VP – Corp Dev and Improvement	Paula Sims	Provide senior management input (as necessary) after initial project approval and during construction.
VP – New Generation Programs and Projects	John Elnitsky	Primary responsibility for leadership of the project organization and oversight of the project implementation.
Project Manager-COL	Bob Kitchen	Primary responsibility for planning, organizing, and managing resources to obtain COLA approval from the NRC.
Project Manager-EPC	Vann Stephenson	Primary responsibility for planning, organizing, and managing resources to bring about the successful implementation and completion of the Levy EPC contract.
Director – Program Coordination and Performance Improvement	Jon Kerin	Provide oversight of Project Controls and Project Management Center of Excellence support of the project as well as oversight of the lessons learned program.

16) Next Steps

The following milestone meetings will provide Senior Management with updates on the project and the opportunity to defer, stop, or otherwise change the project direction as needed:

Next Steps	
Date	**Milestone – Request**
April 2013	Annual funding request
Further updates to be determined as the project develops.	

Appendix A – Definitions & Acronyms

Definitions & Acronyms	
Term	**Definition**
AACEI	Association for the Advancement of Cost Estimating International
ACRS	Advisory Committee on Reactor Safeguards
AFUDC	Allowance for Funds Used During Construction
APOG	AP1000™ Owners Group
ASER	Advanced Safety Evaluation Report
ASLB	Atomic Safety and Licensing Board
CE	Construction Experience
CM	Configuration Management
CO	Change Order
COL(A)	Combined Operating License (Application)
CPVRR	Cumulative Present Value of Revenue Requirements
DCA	Department of Community Affairs
DCD	Design Control Document
DCP	Design Change Proposal
DEIS	Draft Environmental Impact Statement
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPZ	Emergency Planning Zone
FDEP	Florida Department of Environmental Protection
FEIS	Final Environmental Impact Statement
FNTP	Full Notice to Proceed
FPSC	Florida Public Service Commission
FSER	Final Safety Evaluation Report
GHG	Greenhouse Gas
INPO	Institute of Nuclear Power Operations
JVT	Joint Venture Team
LEDPA	Least Environmentally Damaging Practicable Alternative
LLE	Long-Lead Equipment
NCRC	Nuclear Cost Recovery Clause

NEI	Nuclear Energy Institute
NGPPD	New Generation Programs & Projects Department
NRC	Nuclear Regulatory Commission
OE	Operating Experience
OPC	Office of Public Counsel
PO	Purchase Order
RAI	Request for Additional Information
RCC	Roller Compacted Concrete
SCA	Site Certification Application
SER	Safety Evaluation Report
SSI	Soil-Structure Interaction
USACE	US Army Core of Engineers

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Summary Brief

Progress Energy Florida

Levy Nuclear Project NCRC 2012 Feasibility Assessment

Updated Life-Cycle Net Present Worth (CPVRR) Assessment

Prepared by:

PEF System Planning & Regulatory Performance

April 30, 2012

Objective:

The Florida Public Service Commission (FPSC) Nuclear Cost Recovery Clause (NCRC) Rule and Order No. PSC-09-0783-FOF-EI require annual feasibility updates for projects under clause recovery. In the 2009 NCRC Proceeding, FPSC Staff required that Progress Energy Florida (PEF) provide an updated life-cycle net present worth (also referred to as cumulative present value of revenue requirements, or CPVRR) assessment of the Levy Nuclear Project as a part of the 2009 feasibility assessment. In anticipation of that requirement in the 2012 NCRC Proceeding, PEF prepared an updated CPVRR assessment of the Levy Nuclear Project based on PEF's current forecasts for submission in the April 30th NCRC filing. PEF's System Planning group, which prepares these evaluations for Need Determination proceedings, updated the life cycle assessment to support this filing.

The results of this updated assessment are presented herein based on the best information available at this time and consistent with the updated projections filed in this proceeding. This assessment has been performed in a manner consistent with the approach presented in the Levy Need Determination Study (FPSC Docket 080148-EI).

Overview of the Updated Assessment:

In the Levy Need Determination Study, PEF initially established the available potential in-service dates for the new nuclear plants and then developed optimized resource portfolios to accompany the new units during the duration of the projected life of the facility (the "Levy Plan"). The remaining resources were selected from natural gas fired simple cycle and combined cycle units to complete each scenario portfolio over the study period. An alternate scenario was also developed based exclusively on natural gas fired generation resources without the nuclear units to develop the "All Gas Reference Plan" resource portfolio. The same approach was followed in developing the results for this updated assessment.

The optimizations were performed using the Strategist™ model in the same manner the scenarios were developed in the Levy Need Study based on PEF's forecasts for Load and Energy requirements, fuel prices, emission allowance costs and the development costs for new unit additions. The study period costs were then compared for these two portfolios (plans) to project the life cycle savings (or costs) between the Levy Plan and the All Gas Reference Plan on a cumulative present value of revenue requirements (CPVRR) basis.

A Summary of Key Assumptions and Key Drivers:

In the Levy Need Determination Study, the key drivers identified in the economic assessment were determined to be the forecasted costs of fuel, the potential impacts of carbon policy and the projected capital costs for new nuclear units and natural gas generation alternatives. PEF's Levy Need filing addressed the relative impacts of each of these drivers in the study results by comparing the cumulative present value of system revenue requirements (CPVRR) for each sensitivity applied to the Levy Nuclear

Plan versus the All Gas Reference Plan. This approach provides a comparable comparison of life cycle cost between alternatives being considered. Forecasts and adjustments included in this updated assessment are summarized below and provided in an appendix for review:

Fuel Forecasts: This assessment was performed with the long term planning fuel forecasts which were updated in 2011 supporting this year's normal planning cycle. PEF included low and high (statistical) forecast sensitivities around the mid reference case in a manner consistent with the approach used in the Levy Need Study.

Emission Forecasts: This assessment was performed with the long term planning emissions forecasts which were updated in late 2011 in support of this year's normal planning cycle. The carbon policy scenarios used in the 2011 study have been retained for this year's study. This reflects the lack of ongoing action on carbon policy at federal and state levels, but recognizes the consensus understanding, supported by PEF, that some carbon policy will be enacted in the timeframe prior to the planned in-service dates for the Levy units. In this year's studies, as in last year's, the analysis was run with no CO_2 cost and with four CO_2 emissions cost projections provided in nominal $/ton of equivalent CO_2. The four scenarios were based on studies of the Waxman-Markey draft bill performed by the Environmental Protection Agency (EPA), Charles River Associates (CRA) and the Electric Power Research Institute (EPRI). Two EPRI scenarios were utilized representing the "Full Portfolio" and "Limited Portfolio" perspectives, based on their assessment of the cost and availability of low carbon generating resources in the future. While there are evolving policy developments at the state and national levels, these forecasts are deemed to be a reasonable characterization of potential outcomes and, as such, have been used for this updated assessment.

Commercial In-Service and Cost Projection Update for the Levy Project: To perform this assessment, PEF's Nuclear Project Development (NPD) team was asked to provide an updated project cash flow estimate for construction cost based on the latest projected project schedule. This assessment was performed with the estimates updated in early 2012 which project the first unit entering commercial service in mid-2024 with the second unit entering service approximately 18 months later.

Cost Projections for Gas-Fired New Unit Additions: This assessment was performed with long term planning project cost estimates for new peaking and combined cycle generation resource options which were updated this year to support the regular planning cycle.

Capital Cost Sensitivities: The sensitivities included in this study reflect a range of projected capital costs for all new resources ranging from -15%, -5% to 5%, 15% and 25%.

Load and Energy Forecast: This assessment was performed using the long term planning Load and Energy forecast that was used in preparing PEF's 2012 Ten Year Site Plan (TYSP'12).

Nuclear Joint Ownership: In this updated assessment, PEF is presenting results for ownership sensitivities of 100%, 80% and 50% in a manner consistent with the Levy Need filing.

Discount Rate: This assessment was performed using a discount rate adjusted to reflect the planning basis for weighted average cost of capital based on PEF's current allowed rate of return. The current discount rate being used for long term planning is 6.47%.

Summary Results Overview:

In the Levy Need Determination Study, PEF provided tabular summaries of the economic assessment results (ref Table 1). The results tables represent the benefit (cost) of the life cycle cost comparisons of the Levy Nuclear Plan versus the All Gas Reference Plan based on Cumulative Present Value of Revenue Requirements (CPVRR) for each of the sensitivities addressed. The updated assessment results have been summarized and tabulated in a similar manner in Table 2.

Table 1 provides an overview of the results originally presented in the Levy Need.

Table 2 provides an overview of the updated planning results based on PEF's updated estimates and forecasts based on a 2024 commercial in-service date with an 18 month spread between units.

Observations:

In comparing results for this updated assessment with the Levy Need, these observations are noted:

Mid Reference Fuel Forecasts: The fossil fuel price forecasts (e.g. natural gas, coal and oil) used in the updated assessment are generally lower than the forecasts used in the 2011 analysis. When compared to the Levy Need analysis, forecast prices are now lower over the full length of the analysis. The updated nuclear fuel forecast received a slight downward adjustment from 2011, but is similar to the forecasts presented in previous NCRC filings. The updated projections reflect changes in fuel market conditions over time and are based on the most current long term fuel forecasts available to PEF. Lower forecasted fuel prices tend to decrease the life cycle costs projected for the All Gas resource portfolio more than those projected for the Levy Need portfolio which results in a less favorable projection for the Levy Nuclear plan. The fuel forecast updates appear to be a significant driver in the changes in results between these assessments.

Fuel Forecast Sensitivities: The low and high fuel sensitivities presented in the Levy Need and the updated assessment are based on PEF's standard methodology for confidence intervals. The fuel prices in the updated *low* sensitivity forecast are generally lower than the comparable values in the Levy Need. As a result, the projected CPVRR differentials are lower for the *low* fuel forecast sensitivity in the updated assessment. The fuel prices in the updated *high* sensitivity forecast are generally lower in the near term than the comparable values in the Levy Need, but are generally similar over the full length of the analysis. As a result, the projected CPVRR differentials are similar for the *high* fuel sensitivity in the updated assessment.

Emission Forecasts: The emission forecasts for SO_2, NO_X and Hg were updated in this assessment, but the differentials resulting from the changes appear to be negligible. The projections for the impacts of carbon policy were retained from the 2011 study. Thus, the range of potential carbon cost impacts being studied is still similar to the Levy Need, but narrower to a limited extent. As a result, the impacts in CPVRR differentials due to carbon policy, while still significant, have narrowed to a limited extent.

Commercial In-Service and Cost Projection Updates for the Levy Project: As discussed previously, the updated assessment was performed with information for projected project cost changes based on the updated in-service date. The 2012 estimate differs from the 2011 estimate, in allowing for the schedule shift to 2024 and 2025, resulting in a lower nuclear capital cost impact on the differential CPVRR values. These costs are greater than those in the Levy Need.

Cost Projections for New Natural Gas Fired Unit Additions: As discussed, the updated assessment was performed with adjusted long term planning project cost estimates for new peaking and combined cycle generation resource options. The cost projections for natural gas fired generation are generally lower than the projections in the Levy Need which provides downward pressure on the life cycle costs for both the Levy Nuclear and All Gas resource portfolios being compared (since most of the new generation resources in both portfolios are natural gas additions). The cost decreases projected for the natural gas fired units appears to result in a small offset in the life cycle cost results when the CPVRR differentials between resource portfolios are compared.

Load and Energy Forecast: The updated assessment was performed using the long term planning Load and Energy forecast that was developed for PEF's 2012 Ten Year Site Plan (TYSP'12). The updated forecast incorporates lower projected load and energy requirements reflecting reduced growth being experienced. The resource plans were adjusted accordingly to reflect appropriately fewer resource additions.

Nuclear Joint Ownership: The results provided for Ownership sensitivities of 100%, 80% and 50% are directionally similar to the results submitted in the Levy Need. The impacts of many of the key drivers previously discussed affect the results in a manner proportional to ownership percentage.

Discount Rate: The results provided in Table 2 reflect the use of a 6.47% discount rate which reflects the Company's average weighted cost of capital (WACC) for planning purposes. This is a slightly lower discount rate than that utilized in the 2011 analysis. New nuclear project economics are heavily influenced by the initial capital investment in the early years of the assessment weighed against the substantial long term fuel savings and emission cost offsets projected over the life of the project.

Summary:

PEF completed the updated CPVRR assessment and comparison of life cycle costs for the Levy Nuclear Project as part of the required feasibility assessment for the 2012 Nuclear Cost Recovery Clause (NCRC) filing. The results of the updated assessment have been presented in this Summary Report. The benefits projected for development of the Levy Nuclear Project in this updated assessment are similar to those presented in the Need filing.

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TABLE 1

Summary of CPVRR Results from the Levy Need Determination (Docket 080148-EI)

Levy Need Study CPVRR Economic Results Summary Table [$2007]

Fuel Sensitivities

Base Capital Reference Case	Low Fuel Reference	Mid Fuel Reference	High Fuel Reference
Levy Need - 100% Ownership, 2016 COD Levy Case Versus All Gas CPVRR $Million ($2007)			
No CO2	($6,416)	($2,888)	$2,635
Bingaman Specter CO2	($3,834)	($343)	$5,212
EPA No CCS	($2,684)	$793	$6,318
MIT Mid CO2	$85	$3,614	$9,077
Lieberman Warner CO2	$2,930	$6,380	$11,892
Levy Need - 80% Ownership, 2016 COD Levy Case Versus All Gas CPVRR $Million ($2007)			
No CO2	($5,566)	($2,725)	$1,732
Bingaman Specter CO2	($3,530)	($733)	$3,756
EPA No CCS	($2,619)	$171	$4,631
MIT Mid CO2	($448)	$2,403	$6,790
Lieberman Warner CO2	$1,799	$4,594	$9,018
Levy Need - 50% Ownership, 2016 COD Levy Case Versus All Gas CPVRR $Million ($2007)			
No CO2	($4,017)	($2,246)	$523
Bingaman Specter CO2	($2,766)	($963)	$1,783
EPA No CCS	($2,250)	($409)	$2,317
MIT Mid CO2	($1,018)	$908	$3,685
Lieberman Warner CO2	$339	$2,220	$5,139

CapEx Sensitivities

Mid Fuel Reference Case	LNP CapEx (5%)	Mid Fuel Reference	LNP CapEx +5%	LNP CapEx +15%	LNP CapEx +25%
Levy Need - 100% Ownership, 2016 COD Levy Case Versus All Gas CPVRR $Million ($2007)					
No CO2	($2,365)	($2,888)	($3,400)	($4,434)	($5,469)
Bingaman Specter CO2	$109	($343)	($926)	($1,960)	($2,995)
EPA No CCS	$1,207	$793	$172	($862)	($1,897)
MIT Mid CO2	$3,975	$3,614	$2,940	$1,906	$871
Lieberman Warner CO2	$6,674	$6,380	$5,640	$4,605	$3,571
Levy Need - 80% Ownership, 2016 COD Levy Case Versus All Gas CPVRR $Million ($2007)					
No CO2	($2,284)	($2,725)	($3,154)	($4,023)	($4,892)
Bingaman Specter CO2	($364)	($733)	($1,234)	($2,103)	($2,972)
EPA No CCS	$502	$171	($367)	($1,236)	($2,106)
MIT Mid CO2	$2,681	$2,403	$1,812	$942	$73
Lieberman Warner CO2	$4,805	$4,594	$3,936	$3,067	$2,197

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TABLE 2

Summary of April 2012 Updated CPVRR Results for the Levy Project

Economic Results Summary Table (NCRC '12 Study)

Fuel Sensitivities

Base Capital Reference Case	Low Fuel Reference	**Mid Fuel Reference**	High Fuel Reference
NCRC APR '12: 100% Ownership, 2024 COD Levy Case Versus All Gas CPVRR $Million, 6.47% Discount Rate			
No CO_2	**($12,022)**	**($3,907)**	$7,859
EPA WM CO_2	**($7,785)**	$402	$12,372
CRA WM CO_2	**($5,113)**	$3,023	$15,027
EPRI Full CO_2	**($2,794)**	$5,347	$17,448
EPRI Ltd CO_2	$3,037	$11,184	$23,224
NCRC APR '12: 80% Ownership, 2024 COD Levy Case Versus All Gas CPVRR $Million, 6.47% Discount Rate			
No CO_2	**($9,613)**	**($3,121)**	$6,335
EPA WM CO_2	**($6,284)**	$194	$9,859
CRA WM CO_2	**($4,182)**	$2,224	$11,894
EPRI Full CO_2	**($2,356)**	$4,045	$13,757
EPRI Ltd CO_2	$2,228	$8,639	$18,176
NCRC APR '12: 50% Ownership, 2024 COD Levy Case Versus All Gas CPVRR $Million, 6.47% Discount Rate			
No CO_2	**($7,007)**	**($2,852)**	$3,232
EPA WM CO_2	**($4,803)**	**($655)**	$5,454
CRA WM CO_2	**($3,423)**	$768	$6,782
EPRI Full CO_2	**($2,194)**	$2,039	$8,027
EPRI Ltd CO_2	$812	$5,084	$11,101

CapEx Sensitivities

Mid Fuel Reference Case	LNP CapEx (15%)	LNP CapEx (5%)	**Mid Fuel Reference**	LNP CapEx +5%	LNP CapEx +15%	LNP CapEx +25%
NCRC APR '12: 100% Ownership, 2024 COD Levy Case Versus All Gas CPVRR $Million, 6.47% Discount Rate						
No CO_2	**($2,400)**	**($3,405)**	**($3,907)**	**($4,410)**	**($5,415)**	**($6,421)**
EPA WM CO_2	$1,910	$905	$402	**($100)**	**($1,105)**	**($2,111)**
CRA WM CO_2	$4,531	$3,526	$3,023	$2,520	$1,515	$510
EPRI Full CO_2	$6,855	$5,850	$5,347	$4,844	$3,839	$2,834
EPRI Ltd CO_2	$12,692	$11,687	$11,184	$10,682	$9,676	$8,671
NCRC APR '12: 80% Ownership, 2024 COD Levy Case Versus All Gas CPVRR $Million, 6.47% Discount Rate						
No CO_2	**($1,959)**	**($2,734)**	**($3,121)**	**($3,509)**	**($4,284)**	**($5,059)**
EPA WM CO_2	$1,357	$582	$194	**($194)**	**($969)**	**($1,744)**
CRA WM CO_2	$3,387	$2,611	$2,224	$1,836	$1,061	$286
EPRI Full CO_2	$5,208	$4,432	$4,045	$3,657	$2,882	$2,107
EPRI Ltd CO_2	$9,802	$9,026	$8,639	$8,251	$7,476	$6,701
NCRC APR '12: 50% Ownership, 2024 COD Levy Case Versus All Gas CPVRR $Million, 6.47% Discount Rate						
No CO_2	**($2,073)**	**($2,592)**	**($2,852)**	**($3,111)**	**($3,631)**	**($4,150)**
EPA WM CO_2	$124	**($395)**	**($655)**	**($914)**	**($1,433)**	**($1,953)**
CRA WM CO_2	$1,546	$1,027	$768	$508	**($11)**	**($530)**
EPRI Full CO_2	$2,817	$2,298	$2,039	$1,779	$1,260	$741
EPRI Ltd CO_2	$5,863	$5,344	$5,084	$4,825	$4,305	$3,786

APPENDIX

Levy Nuclear April'12 Review
Planning and Modeling Assumptions Summary

Prepared 4/10/12 by PEF System Planning

Levy Nuclear April 2012 Review

Financial and Economic Assumptions

1 PEF Capitalization Ratios and Projected Cost of Capital

Component	**Ratio**	**Cost**
Debt	47%	3.05%
Preferred	0%	na
Equity	53%	10.50%

2 Projected Discount Rate: 6.466%

3 Projected AFUDC Rate: 6.466%

4 Tax Assumptions

a) Composite Effective Income Tax Rate	37.120%
b) Combined Cycle Book Life	25 Years
Combined Cycle Tax Depreciation Life	20 Years
c) Simple Cycle CT Book Life	25 Years
Simple Cycle CT Tax Depreciation Life	15 Years
d) Nuclear Generation Book Life	40 Years
Nuclear Generation Tax Depreciation Life	15 Years
e) Transmission Book Life	40 Years
Transmission Tax Depreciation Life	15 Years

5 General Inflation Rate 2.25%

6 General Escalation Rate 2.25%

Levy Nuclear April 2012 Review

Strategist Input Assumptions - Emission Cost Estimates

	SO2 $/ton	NOX $/ton	Hg $/oz	EPA WM CO2 $/ton	CRA WM CO2 $/ton	EPRI FP CO2 $/ton	EPRI LP CO2 $/ton
2012	1.50	50					
2013	1.50	1,613					
2014	1.50	1,196					
2015	1.50	956		14	23		
2016	1.50	822	-	15	25		
2017	1.50	781	-	16	27		
2018	1.50	639	-	18	28		
2019	1.50	427	-	19	30		
2020	1.50	173	-	20	32	70	82
2021	1.50	-	-	22	35	73	89
2022	1.50	-	-	24	38	76	96
2023	1.50	-	-	26	40	78	103
2024	1.50	-	-	28	43	81	111
2025	1.50	-	-	30	46	83	118
2026	1.50	-	-	32	50	86	125
2027	1.50	-	-	34	54	88	132
2028	1.50	-	-	36	57	91	139
2029	1.50	-	-	38	61	93	146
2030	1.50	-	-	40	65	96	153
2031	1.50	-	-	44	70	104	166
2032	1.50	-	-	48	75	112	180
2033	1.50	-	-	52	80	119	193
2034	1.50	-	-	55	85	127	206
2035	1.50	-	-	59	90	135	220
2036	1.50	-	-	63	97	143	233
2037	1.50	-	-	67	104	151	246
2038	1.50	-	-	70	112	159	259
2039	1.50	-	-	74	119	167	273
2040	1.50	-	-	78	126	174	286
2041	1.50	-	-	86	137	189	311

Levy Nuclear April 2012 Review

New Plant Modeling Information Summary

Capital Cost Estimates for Strategist Modeling

Nuclear Plant Summary Information	Levy County 2024/25	
	Levy Nuclear Project	Levy Nuclear Project
	1st Unit	2nd Unit
Reference In-Service Year	2024	2025
Projected Nominal Plant Cost ($000 Before AFUDC)	10,148,243	5,629,288
Projected Nominal Trans Cost ($000 Before AFUDC)	1,846,892	130,817
Winter Capacity Rating (MW)	1,120	1,120
Summer Capacity Rating (MW)	1,092	1,092
Fixed O&M ($000/yr)- $2012, Esc Annually at 2.25%	71,346	49,943
Variable O&M ($/MWh) - $2012, Esc Annually at 2.25%	2.21	2.21
Decom and Dism Funding ($000/yr) - $2012 Constant	10,567	10,567
Annualized Capital Replacement ($000/yr)	10,000	10,000
Back End (mill/kWh) for Fed Spent Fuel Disposal	1.00	1.00
Planned Outage Rate	3.0%	3.0%
Average Heat Rate at Maximum (Btu/kWh)	9,715	9,715

Gas Fired Generation Summary Information	Generic 2x1G Combined Cycle	Generic 2x1G Combined Cycle
	1st Unit	2nd Unit
Reference In-Service Year	2015	2015
Projected Nominal Plant Cost ($000 Before AFUDC)	742,568	635,469
Projected Nominal Trans Cost ($000 Before AFUDC)	310,242	103,414
Winter Capacity Rating (MW)	875	875
Summer Capacity Rating (MW)	767	767
Fixed O&M ($000/yr)- $2012, Esc Annually at 2.25%	5,329	2,217
Variable O&M ($/MWh) - $2012, Esc Annually at 2.25%	3.40	3.40
Pipeline Reservation Charges ($000/yr) - $2012, Constant	51,742	51,742
Planned Outage Rate	7.7%	7.7%
Average Heat Rate at Maximum (Btu/kWh)	6,710	6,710

Gas Fired Generation Summary Information	Generic F Frame Simple Cycle
	2nd Unit
Reference In-Service Year	2014
Projected Nominal Plant Cost ($000 Before AFUDC)	108,037
Projected Nominal Trans Cost ($000 Before AFUDC)	25,600
Winter Capacity Rating (MW)	205
Summer Capacity Rating (MW)	178
Fixed O&M ($000/yr)- $2012, Esc Annually at 2.25%	713
Variable O&M ($/MWh) - $2012, Esc Annually at 2.25%	11.05
Pipeline Reservation Charges ($000/yr) - $2012, Constant	12,352
Planned Outage Rate	3.84%
Average Heat Rate at Maximum (Btu/kWh)	10,359

Levy Nuclear April 2012 Review

Strategist Fuel Forecasts - Low Fuel Table

	FUEL 1 COAL 1.8	FUEL 5 COAL 5	FUEL 4 CR3	FUEL 35 LNP U1	FUEL 36 LNP U2	FUEL 7 OIL 1.1	FUEL 8 OIL 1.7	FUEL 10 GAS FGTF	FUEL 18 GulfFirm	FUEL 27 Dist 0.3	FUEL 28 Dist 0.5	FUEL 29 Dist ULS
2012	3.74	2.58				8.93	8.81	3.02	3.02	14.80	14.75	14.78
2013	3.64	2.50				7.82	7.66	3.06	3.06	12.23	11.87	12.09
2014	3.54	2.43				7.41	7.22	2.97	2.97	10.86	10.28	10.63
2015	4.04	2.34				6.90	6.73	2.92	2.92	9.62	9.78	9.38
2016	4.18	2.34				6.49	6.33	2.83	2.83	8.86	8.97	8.70
2017	4.23	2.21				6.13	5.98	2.76	2.76	8.34	8.35	8.33
2018	4.28	2.09				5.80	5.67	2.64	2.64	7.93	7.87	8.03
2019	4.35	2.14				5.50	5.41	2.57	2.57	7.71	7.65	7.81
2020	4.40	2.16				5.22	5.18	2.50	2.50	7.54	7.48	7.63
2021	4.44	2.21				4.96	4.96	2.48	2.48	7.38	7.32	7.47
2022	4.46	2.21				4.72	4.75	2.45	2.45	7.23	7.17	7.32
2023	4.49	2.24				4.62	4.65	2.42	2.42	7.12	7.06	7.20
2024	4.49	2.27				4.52	4.56	2.41	2.41	7.02	6.96	7.10
2025	4.52	2.30				4.43	4.47	2.41	2.41	6.94	6.88	7.02
2026	4.55	2.34				4.35	4.38	2.39	2.39	6.88	6.82	6.96
2027	4.57	2.38				4.27	4.31	2.36	2.36	6.82	6.77	6.90
2028	-	2.44				4.20	4.23	2.32	2.32	6.78	6.73	6.86
2029	-	2.46				4.13	4.16	2.28	2.28	6.75	6.70	6.82
2030	-	2.45				4.06	4.09	2.23	2.23	6.72	6.67	6.79
2031	-	2.47				4.00	4.03	2.22	2.22	6.70	6.65	6.78
2032	-	2.47				4.00	4.03	2.22	2.22	6.70	6.65	6.78
2033	-	2.47				4.00	4.03	2.22	2.22	6.70	6.65	6.78
2034	-	2.47				4.00	4.03	2.22	2.22	6.70	6.65	6.78
2035	-	2.47				4.00	4.03	2.22	2.22	6.70	6.65	6.78
2036	-	2.47				4.00	4.03	2.22	2.22	6.70	6.65	6.78
2037	-	2.47				4.00	4.03	2.22	2.22	6.70	6.65	6.78
2038	-	2.47				4.00	4.03	2.22	2.22	6.70	6.65	6.78
2039	-	2.47				4.00	4.03	2.22	2.22	6.70	6.65	6.78
2040	-	2.47				4.00	4.03	2.22	2.22	6.70	6.65	6.78
2041	-	2.47				4.00	4.03	2.22	2.22	6.70	6.65	6.78

Levy Nuclear April 2012 Review

Strategist Fuel Forecasts - Mid Reference Fuel Table

	FUEL 1 COAL 1.8	FUEL 5 COAL 5	FUEL 4 CR3	FUEL 35 LNP U1	FUEL 36 LNP U2	FUEL 7 OIL 1.1	FUEL 8 OIL 1.7	FUEL 10 GAS FGTF	FUEL 18 GulfFirm	FUEL 27 Dist 0.3	FUEL 28 Dist 0.5	FUEL 29 Dist ULS
2012	4.33	3.01				14.75	14.56	4.21	4.21	21.56	21.48	21.53
2013	4.39	3.12				14.91	14.61	4.77	4.77	22.26	21.58	21.99
2014	4.46	3.22				15.45	15.04	5.07	5.07	23.03	21.73	22.51
2015	5.23	3.25	0.54			15.49	15.10	5.39	5.39	22.93	23.34	22.30
2016	5.56	3.29	0.54			15.52	15.14	5.61	5.61	23.26	23.58	22.79
2017	5.81	3.19	0.70			15.55	15.18	5.83	5.83	23.78	23.81	23.72
2018	6.06	3.08	0.70			15.58	15.22	5.93	5.93	24.28	24.05	24.62
2019	6.31	3.27	0.76			15.60	15.37	6.14	6.14	25.18	24.94	25.54
2020	6.52	3.39	0.76			15.63	15.53	6.32	6.32	26.10	25.85	26.47
2021	6.70	3.60	0.85			15.66	15.67	6.63	6.63	26.92	26.66	27.30
2022	6.84	3.68	0.85			15.69	15.80	6.93	6.93	27.70	27.44	28.09
2023	6.98	3.84	0.93			16.14	16.26	7.19	7.19	28.50	28.23	28.91
2024	7.05	3.99	0.93	1.07		16.61	16.73	7.56	7.56	29.33	29.05	29.75
2025	7.20	4.12	0.98	1.07	1.08	17.09	17.21	7.93	7.93	30.18	29.90	30.61
2026	7.34	4.27	0.98	1.00	1.08	17.59	17.71	8.28	8.28	31.06	30.77	31.50
2027	7.49	4.42	1.04	1.00	1.08	18.10	18.23	8.56	8.56	31.96	31.66	32.42
2028	-	4.65	1.04	0.96	1.02	18.62	18.76	8.81	8.81	32.89	32.58	33.36
2029	-	4.74	1.10	0.96	0.98	19.16	19.30	9.10	9.10	33.85	33.53	34.33
2030	-	4.78	1.10	0.99	0.99	19.72	19.86	9.31	9.31	34.83	34.50	35.32
2031	-	4.86	1.13	1.04	1.01	20.29	20.44	9.69	9.69	35.84	35.50	36.35
2032	-	4.98	1.13	1.04	1.01	20.83	20.98	9.97	9.97	36.80	36.45	37.32
2033	-	5.10	1.17	1.08	1.05	21.37	21.52	10.25	10.25	37.75	37.40	38.29
2034	-	5.22	1.17	1.10	1.07	21.91	22.07	10.53	10.53	38.71	38.34	39.26
2035	-	5.34	1.22	1.10	1.07	22.45	22.61	10.81	10.81	39.67	39.29	40.23
2036	-	5.46	1.22	1.15	1.11	22.99	23.16	11.09	11.09	40.62	40.24	41.20
2037	-	5.58	1.27	1.17	1.13	23.53	23.70	11.37	11.37	41.58	41.19	42.17
2038	-	5.70	1.27	1.17	1.13	24.07	24.25	11.65	11.65	42.53	42.13	43.14
2039	-	5.82	1.32	1.22	1.18	24.61	24.79	11.93	11.93	43.49	43.08	44.11
2040	-	5.93	1.32	1.24	1.20	25.15	25.33	12.21	12.21	44.45	44.03	45.08
2041	-	6.05	1.37	1.24	1.20	25.69	25.88	12.49	12.49	45.40	44.97	46.05

Levy Nuclear April 2012 Review

Strategist Fuel Forecasts - High Fuel Table

	FUEL 1 COAL 1.8	FUEL 5 COAL 5	FUEL 4 CR3	FUEL 35 LNP U1	FUEL 36 LNP U2	FUEL 7 OIL 1.1	FUEL 8 OIL 1.7	FUEL 10 GAS FGTF	FUEL 18 GulfFirm	FUEL 27 Dist 0.3	FUEL 28 Dist 0.5	FUEL 29 Dist ULS
2012	4.97	3.47				21.66	21.37	5.55	5.55	29.36	29.25	29.32
2013	5.31	3.80				23.61	23.14	6.76	6.76	34.55	33.48	34.12
2014	5.69	4.11				25.52	24.85	7.56	7.56	38.52	36.31	37.64
2015	6.76	4.30				26.44	25.77	8.41	8.41	40.32	41.06	39.20
2016	7.31	4.42				27.16	26.50	9.07	9.07	42.45	43.03	41.56
2017	7.77	4.37				27.83	27.17	9.71	9.71	44.64	44.71	44.53
2018	8.23	4.29				28.46	27.80	10.15	10.15	46.62	46.17	47.30
2019	8.73	4.67				29.05	28.61	10.76	10.76	49.28	48.80	50.00
2020	9.17	4.94				29.60	29.40	11.32	11.32	51.89	51.38	52.64
2021	9.56	5.35				30.13	30.14	12.11	12.11	54.23	53.70	55.02
2022	9.87	5.56				30.62	30.84	12.90	12.90	56.44	55.90	57.27
2023	10.17	5.90				31.93	32.16	13.61	13.61	58.66	58.09	59.52
2024	10.36	6.22				33.27	33.51	14.55	14.55	60.90	60.31	61.79
2025	10.69	6.49				34.63	34.88	15.46	15.46	63.15	62.54	64.07
2026	11.01	6.79				36.01	36.27	16.37	16.37	65.44	64.80	66.39
2027	11.34	7.11				37.42	37.69	17.13	17.13	67.75	67.09	68.74
2028	-	7.57				38.86	39.14	17.84	17.84	70.11	69.43	71.13
2029	-	7.77				40.33	40.62	18.60	18.60	72.50	71.80	73.56
2030	-	7.89				41.82	42.13	19.22	19.22	74.94	74.21	76.04
2031	-	8.08				43.35	43.66	20.18	20.18	77.43	76.68	78.56
2032	-	8.33				44.82	45.14	20.94	20.94	79.83	79.05	80.99
2033	-	8.59				46.28	46.62	21.70	21.70	82.23	81.43	83.43
2034	-	8.85				47.75	48.10	22.46	22.46	84.63	83.80	85.86
2035	-	9.11				49.22	49.58	23.22	23.22	87.02	86.18	88.30
2036	-	9.36				50.69	51.05	23.98	23.98	89.42	88.55	90.73
2037	-	9.62				52.15	52.53	24.74	24.74	91.82	90.93	93.16
2038	-	9.88				53.62	54.01	25.51	25.51	94.22	93.30	95.60
2039	-	10.13				55.09	55.49	26.27	26.27	96.62	95.68	98.03
2040	-	10.39				56.56	56.97	27.03	27.03	99.02	98.06	100.47
2041	-	10.65				58.02	58.44	27.79	27.79	101.42	100.43	102.90

Levy Nuclear April 2012 Review
Energy Requirements Forecasts
Net Energy for Load (GWh)

YEAR	Forecast Base
2012	41,534
2013	40,973
2014	42,552
2015	43,633
2016	43,596
2017	43,823
2018	44,533
2019	45,854
2020	46,576
2021	47,180
2022	47,817
2023	48,429
2024	49,064
2025	47,949
2026	48,485
2027	49,096
2028	49,709
2029	50,339
2030	50,968
2031	51,528
2032	52,137
2033	52,745
2034	53,354
2035	53,963
2036	54,571
2037	55,180
2038	55,788
2039	56,397
2040	57,006
2041	57,614

Levy Nuclear April 2012 Review
Energy Demand Forecasts

	Summer Peak Net Firm Demand (MW)	Winter Peak Net Firm Demand (MW)
YEAR	Forecast	Forecast
2012	8,922	9,442
2013	8,717	9,256
2014	8,773	8,954
2015	8,964	9,604
2016	8,978	9,762
2017	9,210	9,682
2018	9,370	9,829
2019	9,781	10,220
2020	9,939	10,356
2021	10,000	10,498
2022	10,162	10,642
2023	10,326	10,787
2024	10,488	10,934
2025	10,148	10,580
2026	10,308	10,724
2027	10,465	10,867
2028	10,621	11,009
2029	10,775	11,149
2030	10,926	11,288
2031	11,081	11,429
2032	11,236	11,570
2033	11,390	11,711
2034	11,545	11,852
2035	11,699	11,993
2036	11,854	12,134
2037	12,009	12,275
2038	12,163	12,416
2039	12,318	12,557
2040	12,472	12,698
2041	12,627	12,839

Levy Nuclear Filing

Strategist Optimization Scenarios - 4/10/12 Data Runs

	2012 NCRC Nuclear Plan Full Ownership Case	2012 NCRC Nuclear Plan 80% Joint Ownership Case	2012 NCRC Nuclear Plan 50% Joint Ownership Case	2012 NCRC All Gas Reference Case	
2012	PEF Baseline Assumptions	PEF Baseline Assumptions	PEF Baseline Assumptions	PEF Baseline Assumptions	2009 to 2012
2013	10 MW Anclote 1 Gas Conversion (April '13) 10 MW Anclote 2 Gas Conversion (Dec '13)	10 MW Anclote 1 Gas Conversion (April '13) 10 MW Anclote 2 Gas Conversion (Dec '13)	10 MW Anclote 1 Gas Conversion (April '13) 10 MW Anclote 2 Gas Conversion (Dec '13)	10 MW Anclote 1 Gas Conversion (April '13) 10 MW Anclote 2 Gas Conversion (Dec '13)	2013
2014	790 MW Crystal River 3 back in Service (Nov '14)	790 MW Crystal River 3 back in Service (Nov '14)	790 MW Crystal River 3 back in Service (Nov '14)	790 MW Crystal River 3 back in Service (Nov '14)	2014
2015	154 MW Crystal River Uprate (Jan '15)	154 MW Crystal River Uprate (Jan '15)	154 MW Crystal River Uprate (Jan '15)	154 MW Crystal River Uprate (Jan '15)	2015
2016	129 MW Suwannee Steam Retirement (June '16) 185 MW Peaker Retirements (June '16)	129 MW Suwannee Steam Retirement (June '16) 185 MW Peaker Retirements (June '16)	129 MW Suwannee Steam Retirement (June '16) 185 MW Peaker Retirements (June '16)	129 MW Suwannee Steam Retirement (June '16) 185 MW Peaker Retirements (June '16)	2016
2017					2017
2018					2018
2019	Generic 2x1 G CC	Generic 2x1 G CC	Generic 2x1 G CC	Generic 2x1 G CC	2019
2020					2020
2021					2021
2022	Generic Simple Cycle CT	Generic Simple Cycle CT		Generic Simple Cycle CT	2022
2023	Generic Simple Cycle CT	Generic Simple Cycle CT		Generic Simple Cycle CT	2023
2024	**100% Levy Unit 1 - 1,092 MW (June '24)**	**80% Levy Unit 1 - 874 MW (June '24)**	**50% Levy Unit 1 - 546 MW (June '24)**	Generic 2x1 G CC	2024
2025	**100% Levy Unit 2 - 1,092 MW (December '25)**	**80% Levy Unit 2 - 874 MW (December '25)**	**50% Levy Unit 2 - 546 MW (December '25)**		2025
2026					2026
2027	375 MW Crystal River 1 Retirement (Jun '27) 494 MW Crystal River 2 Retirement (Jun '27) Generic 2x1 G CC	375 MW Crystal River 1 Retirement (Jun '27) 494 MW Crystal River 2 Retirement (Jun '27) Generic 2x1 G CC	375 MW Crystal River 1 Retirement (Jun '27) 494 MW Crystal River 2 Retirement (Jun '27) Generic 2x1 G CC (2)	375 MW Crystal River 1 Retirement (Jun '27) 494 MW Crystal River 2 Retirement (Jun '27) Generic 2x1 G CC (3)	2027
2028		Generic Simple Cycle CT			2028
2029		Generic 2x1 G CC			2029
2030	Generic 2x1 G CC				2030
2031			Generic 2x1 G CC	Generic 2x1 G CC	2031
2032					2032
2033		Generic 2x1 G CC			2033
2034	Generic Simple Cycle CT				2034
2035	Generic 2x1 G CC		Generic 2x1 G CC	Generic 2x1 G CC	2035
2036					2036
2037	Generic 2x1 G CC	Generic 2x1 G CC (2)	Generic 2x1 G CC	Generic 2x1 G CC	2037
2038	Generic 2x1 G CC		Generic 2x1 G CC	Generic 2x1 G CC	2038
2039					2039
2040		Generic Simple Cycle CT			2040
2041		Generic Simple Cycle CT			2041
2042					2042
2043					2043
2044	Generic 2x1 G CC	Generic 2x1 G CC	Generic 2x1 G CC	Generic 2x1 G CC	2044
2045					2045
2046					2046
2047	Generic Simple Cycle CT	Generic Simple Cycle CT	Generic 2x1 G CC	Generic Simple Cycle CT	2047
2048	Generic Simple Cycle CT	Generic Simple Cycle CT		Generic Simple Cycle CT	2048
2049				Generic 2x1 G CC	2049
2050					2050
2051					2051
2052	Generic 2x1 G CC	Generic 2x1 G CC	Generic 2x1 G CC (2)	Generic 2x1 G CC (3)	2052
2053		Generic Simple Cycle CT			2053
2054		Generic 2x1 G CC			2054
2055	Generic 2x1 G CC				2055
2056			Generic 2x1 G CC	Generic 2x1 G CC	2056
2057					2057
2058		Generic 2x1 G CC			2058
2059	Generic Simple Cycle CT				2059
2060	Generic 2x1 G CC		Generic 2x1 G CC	Generic 2x1 G CC	2060
2061					2061
2062	Generic 2x1 G CC	Generic 2x1 G CC (2)	Generic 2x1 G CC	Generic 2x1 G CC	2062
2063	Generic 2x1 G CC		Generic 2x1 G CC	Generic 2x1 G CC	2063
2064	**Levy Unit 1 - 20 year Life Extension**	**Levy Unit 1 - 20 year Life Extension**	**Levy Unit 1 - 20 year Life Extension**		2064
2065	**Levy Unit 2 - 20 year Life Extension**	**Levy Unit 2 - 20 year Life Extension** Generic Simple Cycle CT	**Levy Unit 2 - 20 year Life Extension**		2065
2066		Generic Simple Cycle CT			2066
2067					2067
2068					2068
2069	Generic 2x1 G CC	Generic 2x1 G CC	Generic 2x1 G CC	Generic 2x1 G CC	2069
2070					2070
2071					2071

Florida:
An Economic Overview

March 15, 2012

Presented by:

The Florida Legislature
Office of Economic and
Demographic Research
850.487 1402
http://edr.state.fl.us

Docket No. 120009
Progress Energy Florida
Exhibit No. ____ (JE-3)
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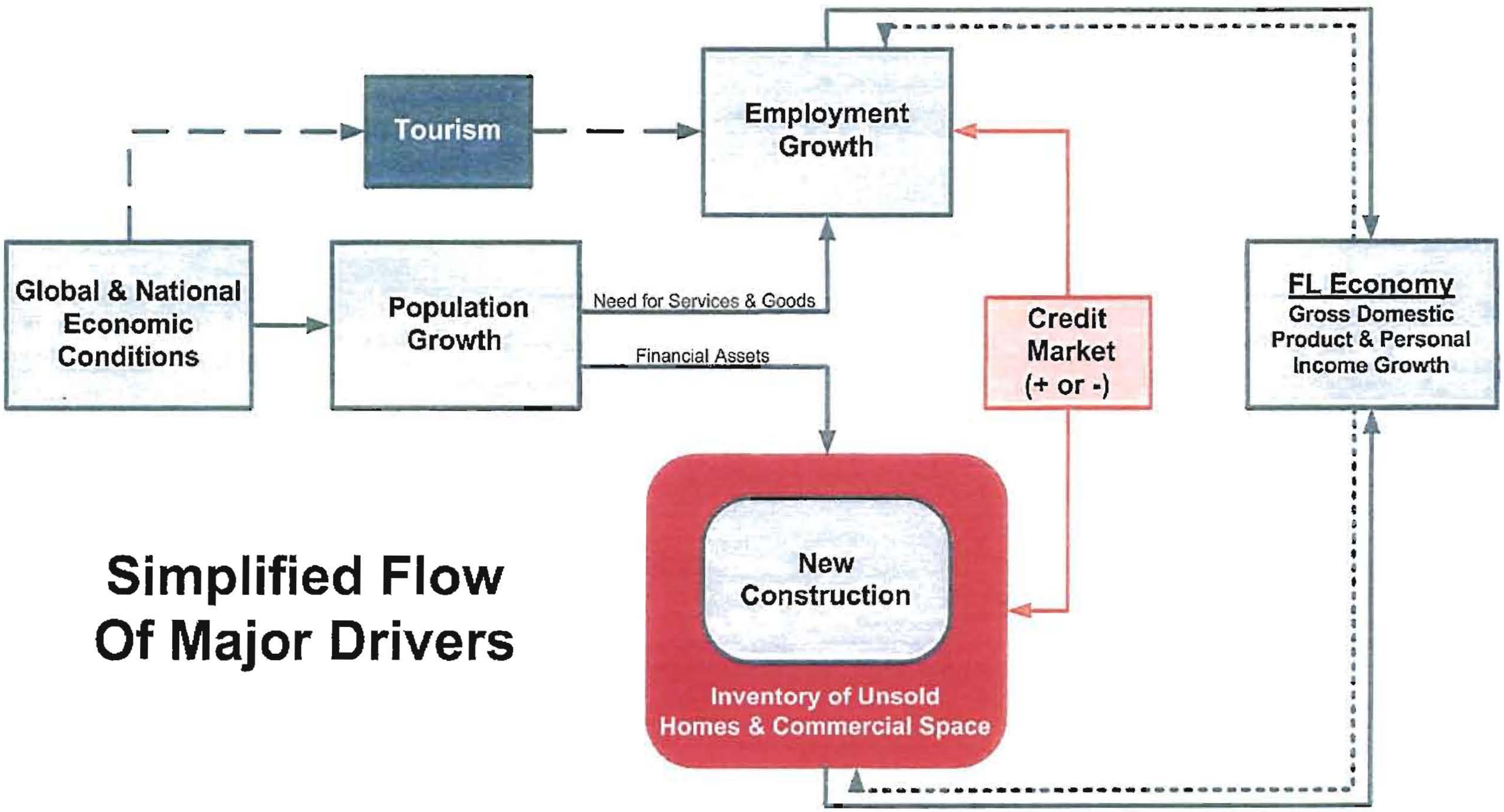
Key Economic Variables – Mixed



Simplified Flow
Of Major Drivers

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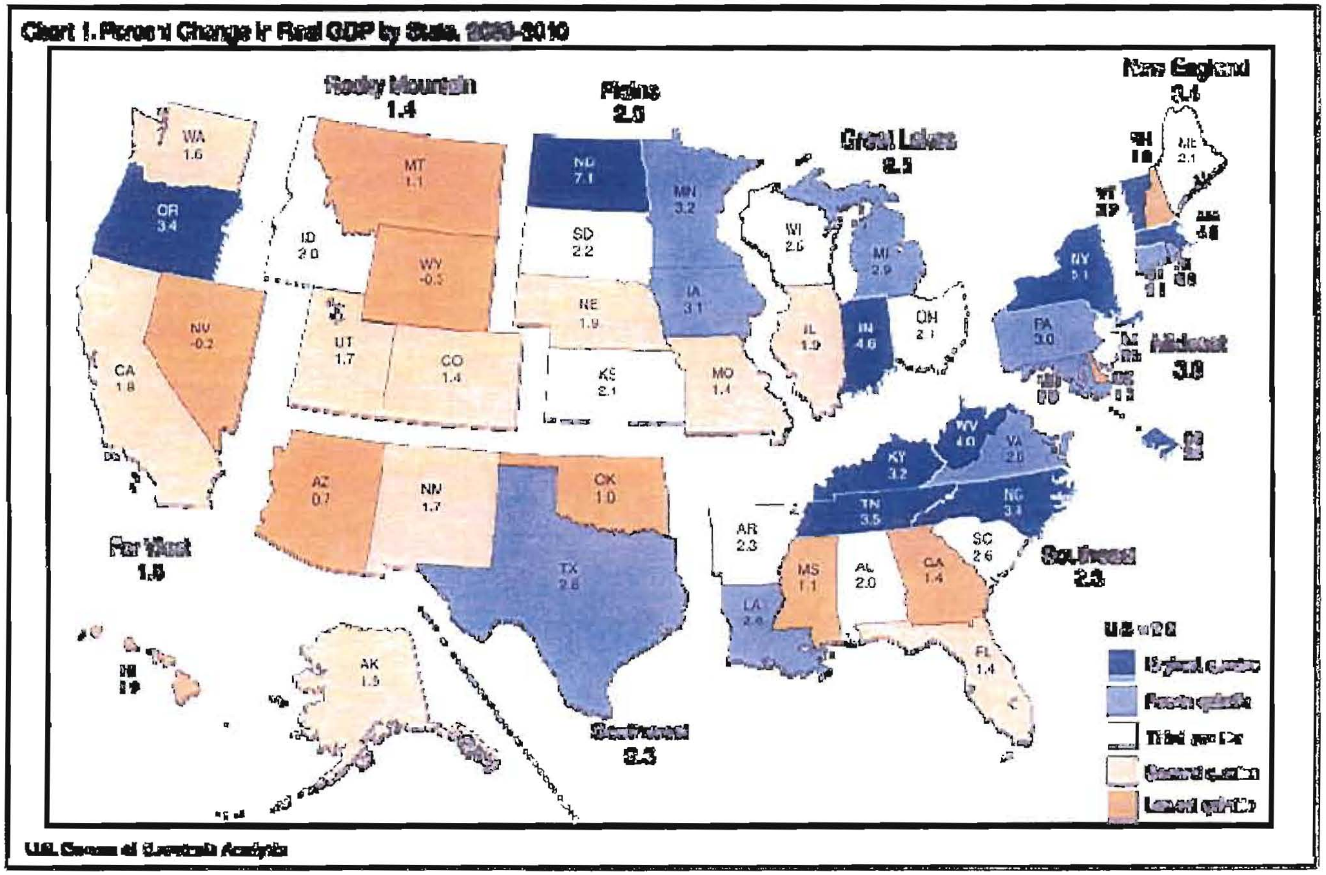
Economy Turned Positive in 2010



Florida's economic growth has returned to positive territory after declining two years in a row. State Gross Domestic Product (GDP) ranked us 40th in the nation in real growth with a gain of 1.4%

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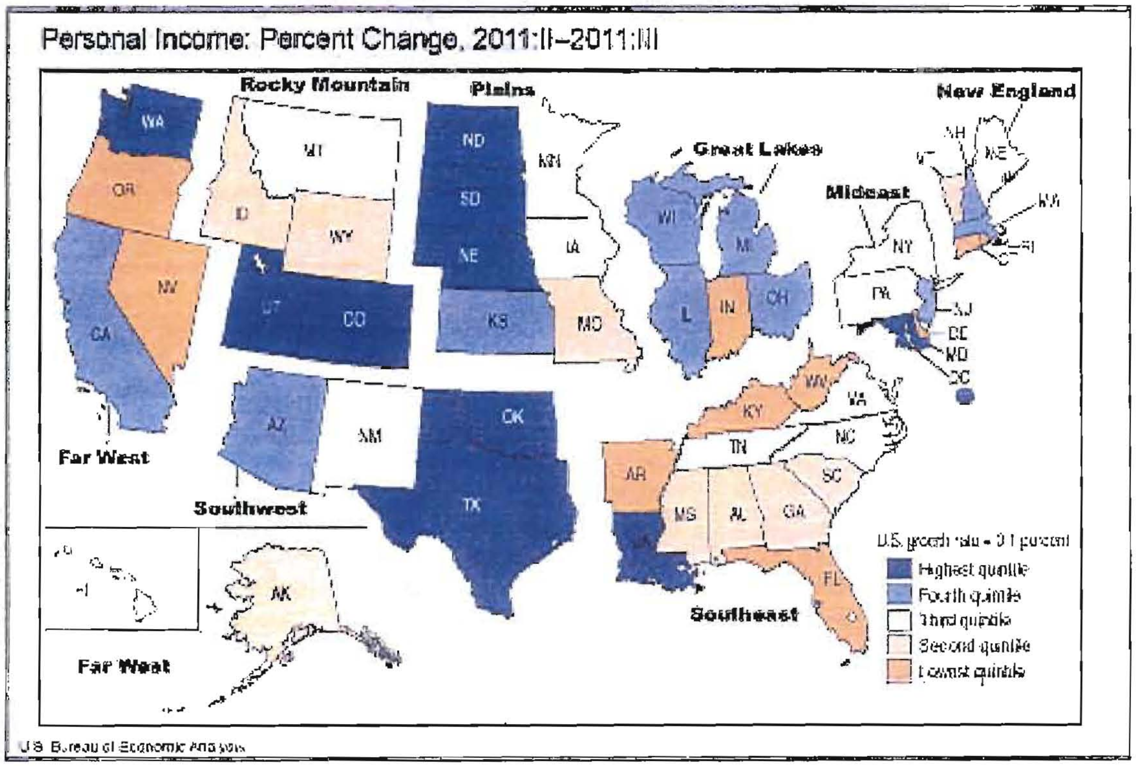
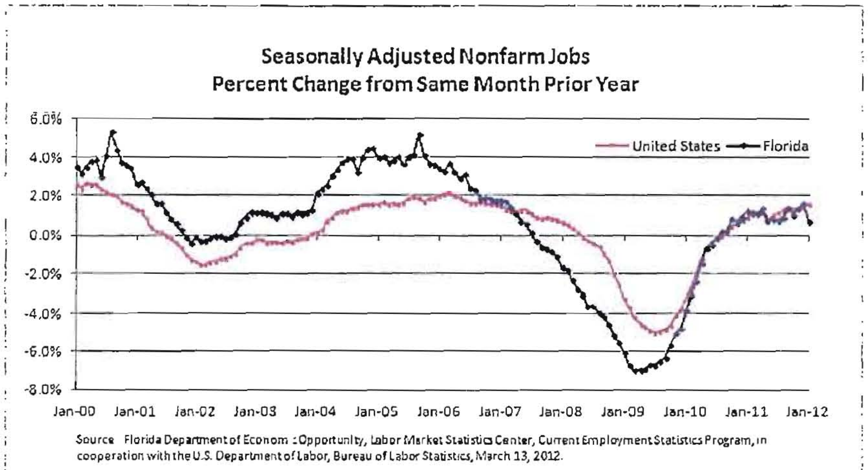
FL Personal Income Falls in Q3: 2011



Florida's quarterly personal income growth (third quarter of 2011 over the preceding quarter) fell for the first time since the third quarter of 2009. At -0.1 percent growth, we were ranked 46th in the country with respect to state growth. The national average was +0.1 percent.

Current Employment Conditions



<u>January Nonfarm Jobs (YOY)</u>

US	1.5%
FL	0.7%
YR·	54,200 jobs
Peak:	-780,200 jobs

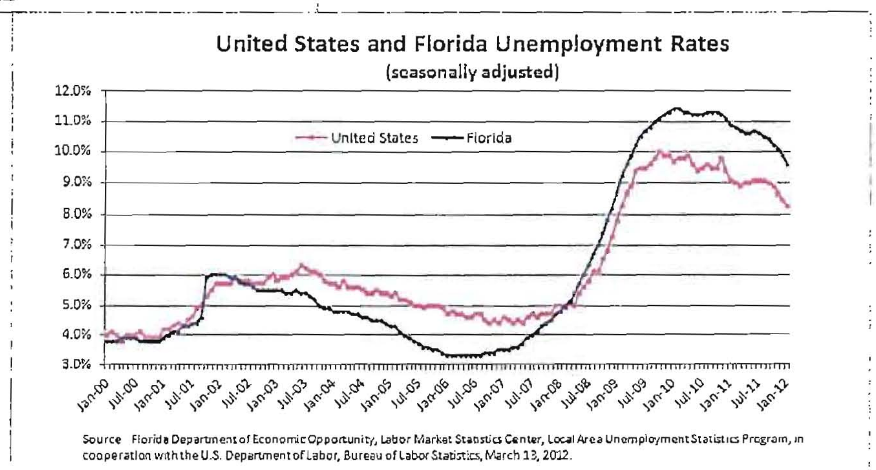
<u>January Unemployment Rate</u>

US 8.3%
FL 9.6%
(894,000 people)

Five states had a higher unemployment rate than Florida

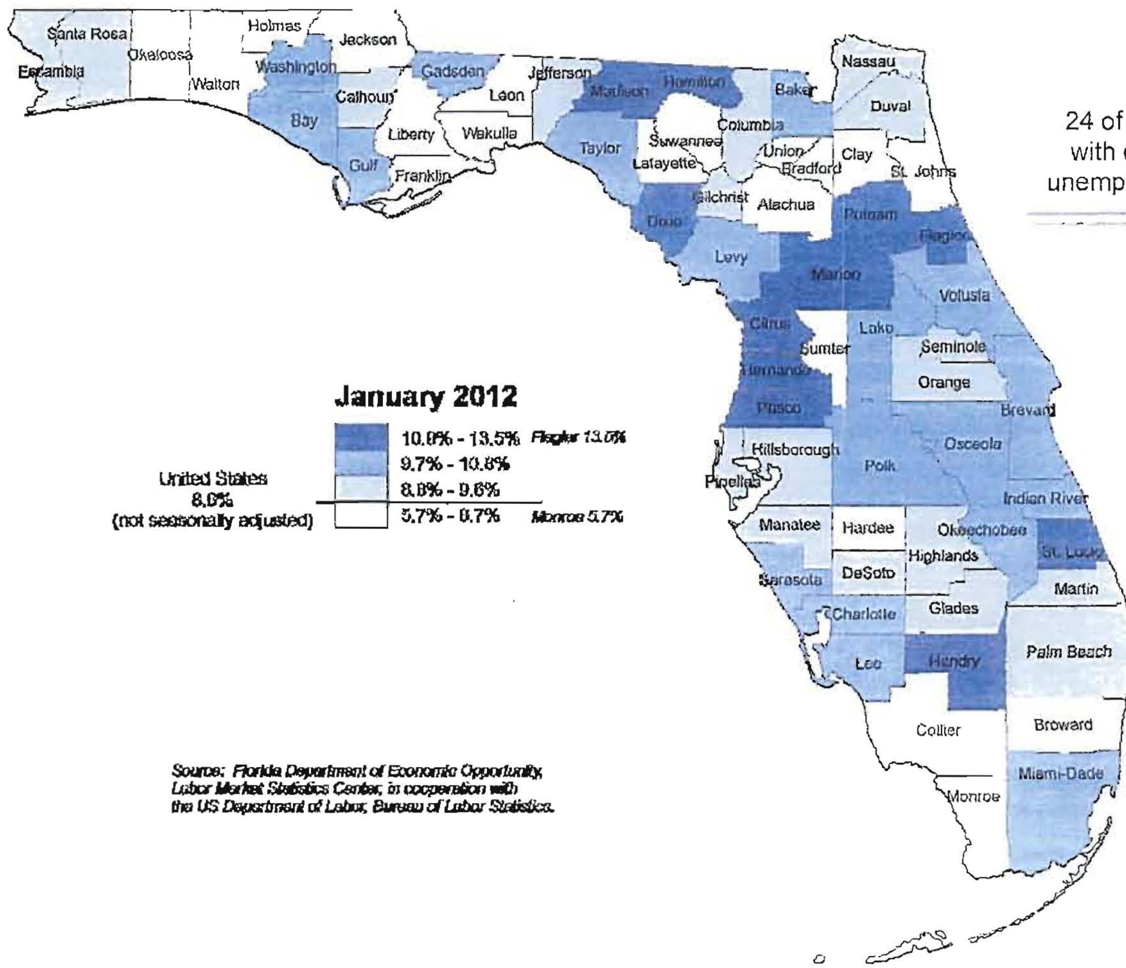
<u>Highest Monthly Rate</u>

January & February 2010
11.4%



Unemployment Rates

24 of 67 counties
with double-digit
unemployment rates



Source: Florida Department of Economic Opportunity, Labor Market Statistics Center, in cooperation with the US Department of Labor, Bureau of Labor Statistics.

EDR

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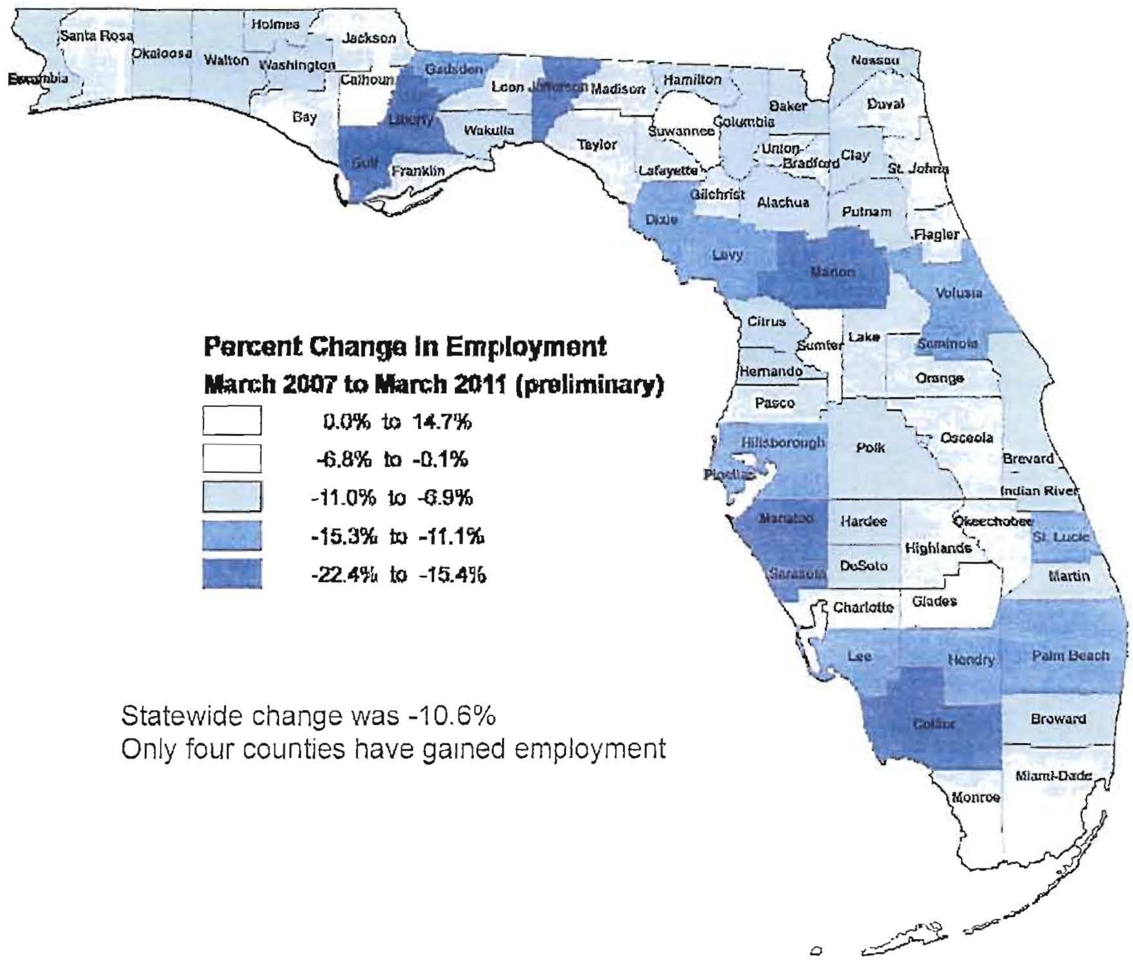
Florida's Job Market

- The job market will take a long time to recover – about 780,200 jobs have been lost since the most recent peak. Rehiring, while necessary, will not be enough.
- Florida's prime working-age population (aged 25-54) is forecast to add over 2,600 people per month, so the hole is deeper than it looks.
- It would take the creation of about 1 million jobs for the same percentage of the total population to be working as was the case at the peak.

Employment Down from Peak Levels



Statewide change was -10.6%
Only four counties have gained employment

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Population Growth Recovering

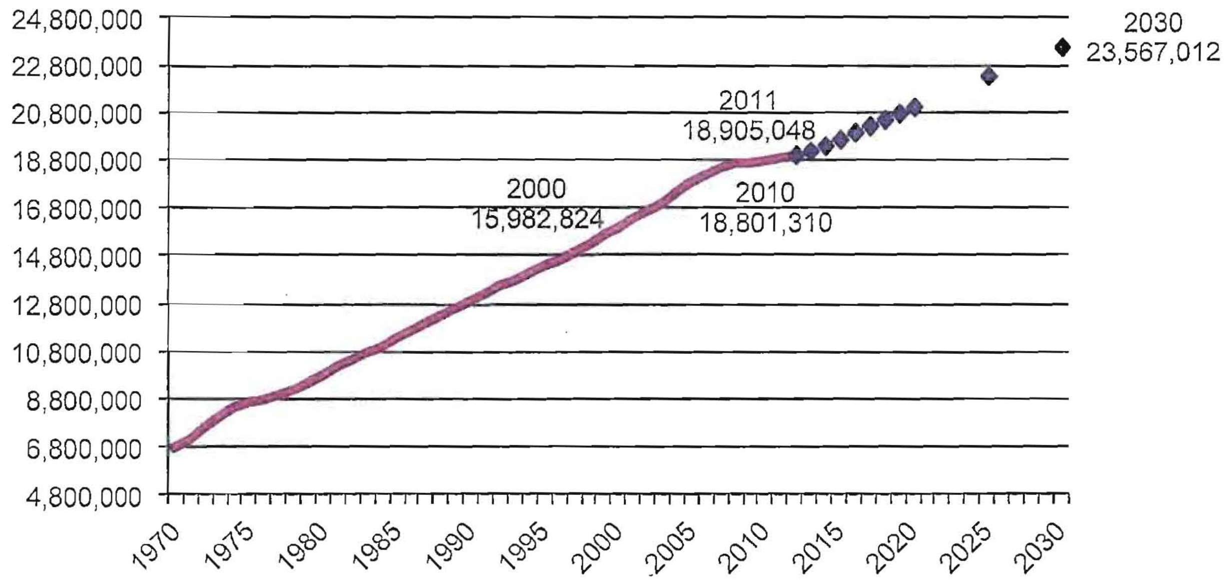
- Population growth is the state's primary engine of economic growth, fueling both employment and income growth.

- Population growth is forecast to remain relatively flat – averaging 0.85% between 2011 and 2014. However, growth is expected to recover in the future – averaging 1.1% between 2025 and 2030 with 86% of the growth coming from net migration. Nationally, average annual growth will be about 0.9%.

- The future will be different than the past; Florida's long-term growth rate between 1970 and 1995 was over 3%.

- Florida is on track to break the 20 million mark during 2016, becoming the third most populous state sometime before then – surpassing New York.

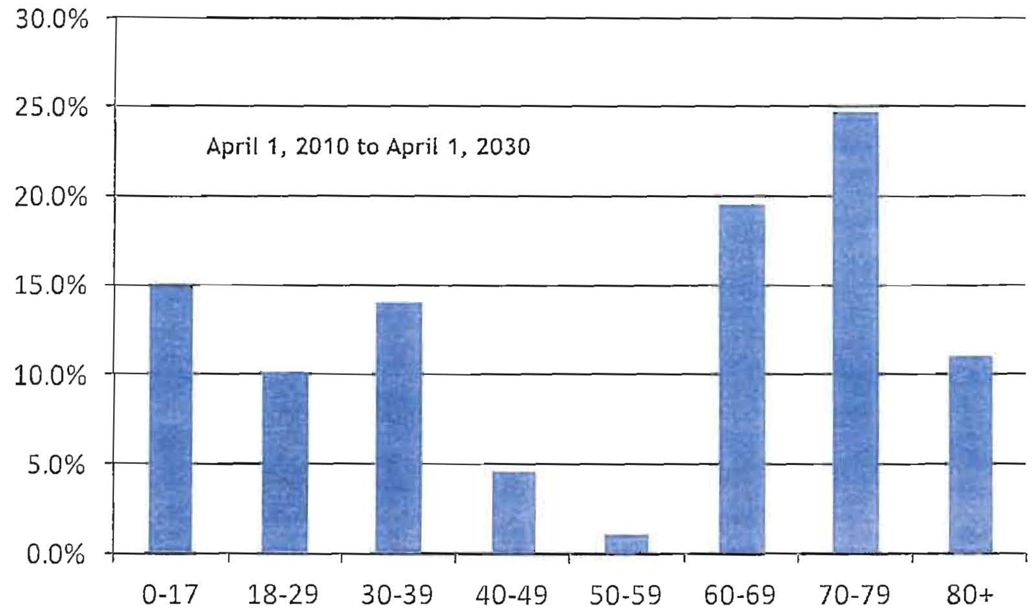
Florida's April 1 Population



Florida's population:

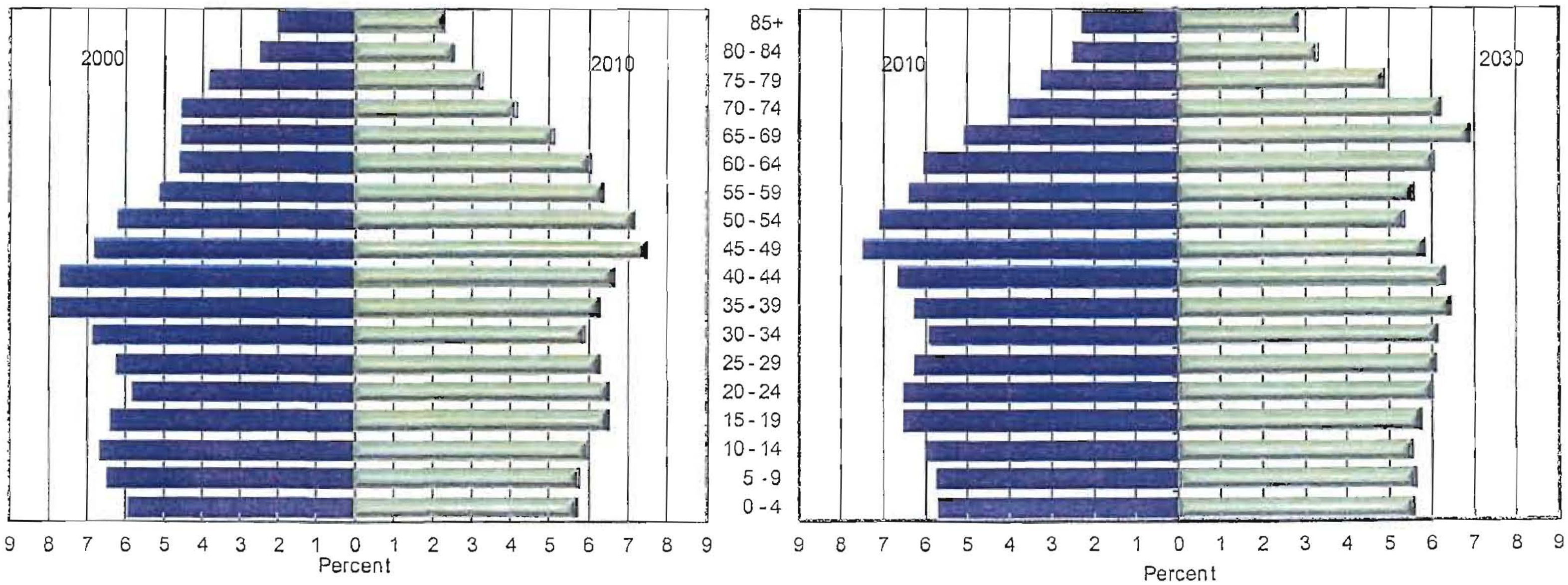
- was 15,982,824 in 2000
- was 18,801,310 in 2010
- is forecast to grow to 23,567,012 by 2030

Population Growth by Age Group



- Between 2010 and 2030, Florida's population is forecast to grow by almost 5.1 million.
- Florida's older population (age 60 and older) will account for most of Florida's population growth, representing 55.2 percent of the gains.
- Florida's younger population (age 0-17) will account for 15.0 percent of the gains.

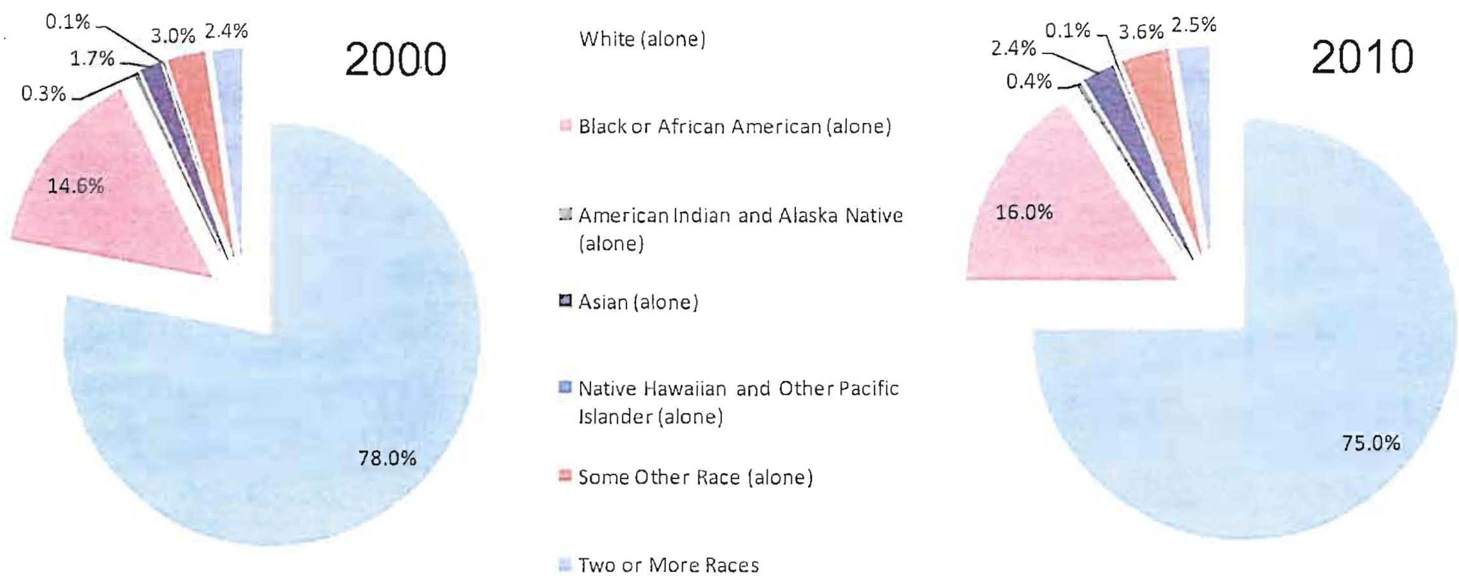
Total Population by Age Group



- In 2000, Florida's working age population (ages 25-54) represented 41.5 percent of the total population. With the aging Baby Boom generation, this population now represents 39.7 percent of Florida's total population and is expected to represent 36.0 percent by 2030.

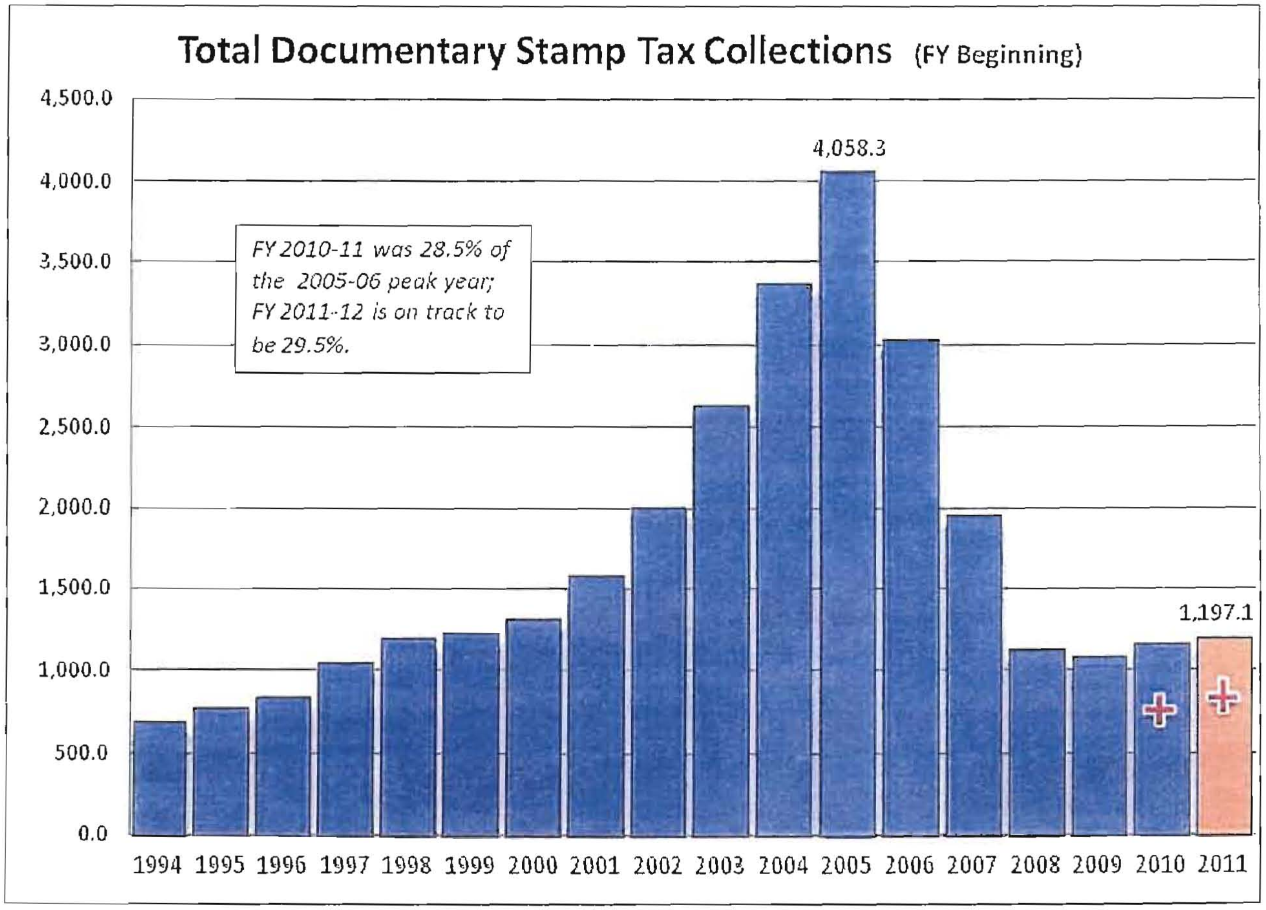
- Population aged 65 and over is forecast to represent 24 1 percent in 2030.

Diversity is Increasing



- Based on the 2010 Census, Hispanics represent about 22.5 percent of Florida's population. And, Florida will become increasingly more Hispanic; Hispanics are forecast to represent over 27 percent of Florida's population in 2030.
- Florida's minority percentage of the population is 42.1% --- New York is now at 41.7%, and the nation as a whole is at 36.3%.

Florida Housing is Generally Improving



Sales volume of existing homes and building permits are both back in positive territory, both showing year-over-year growth.

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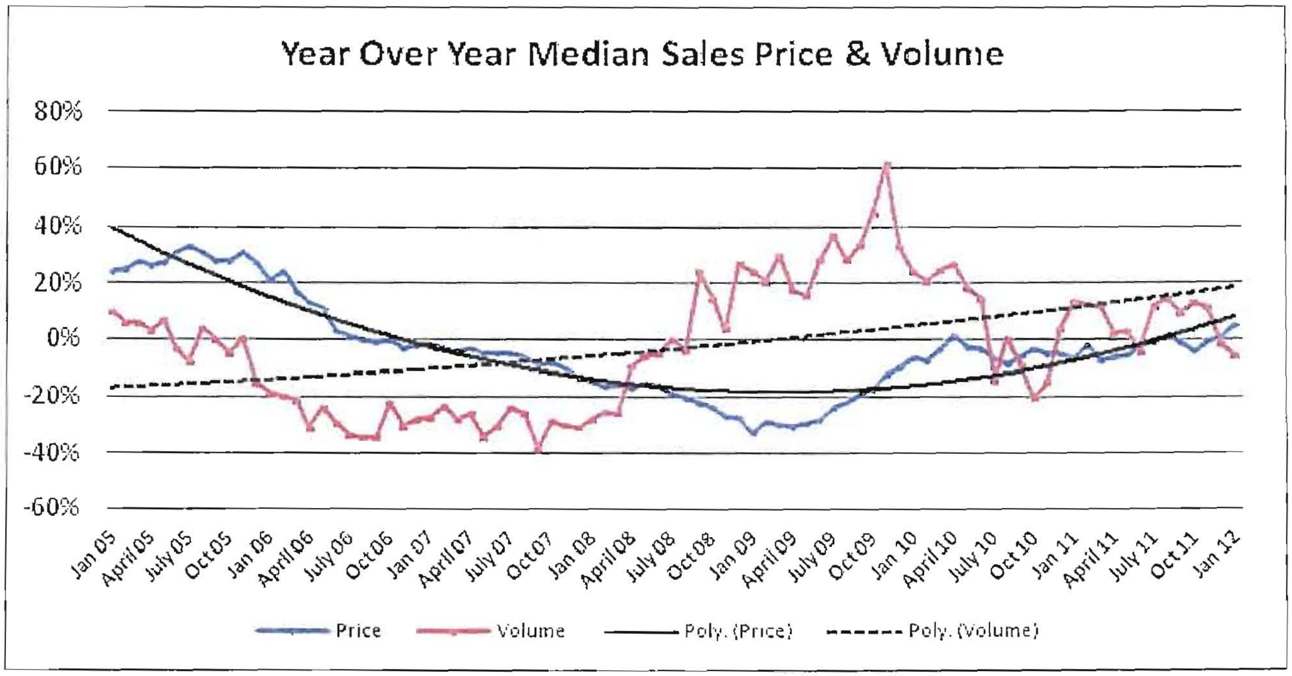
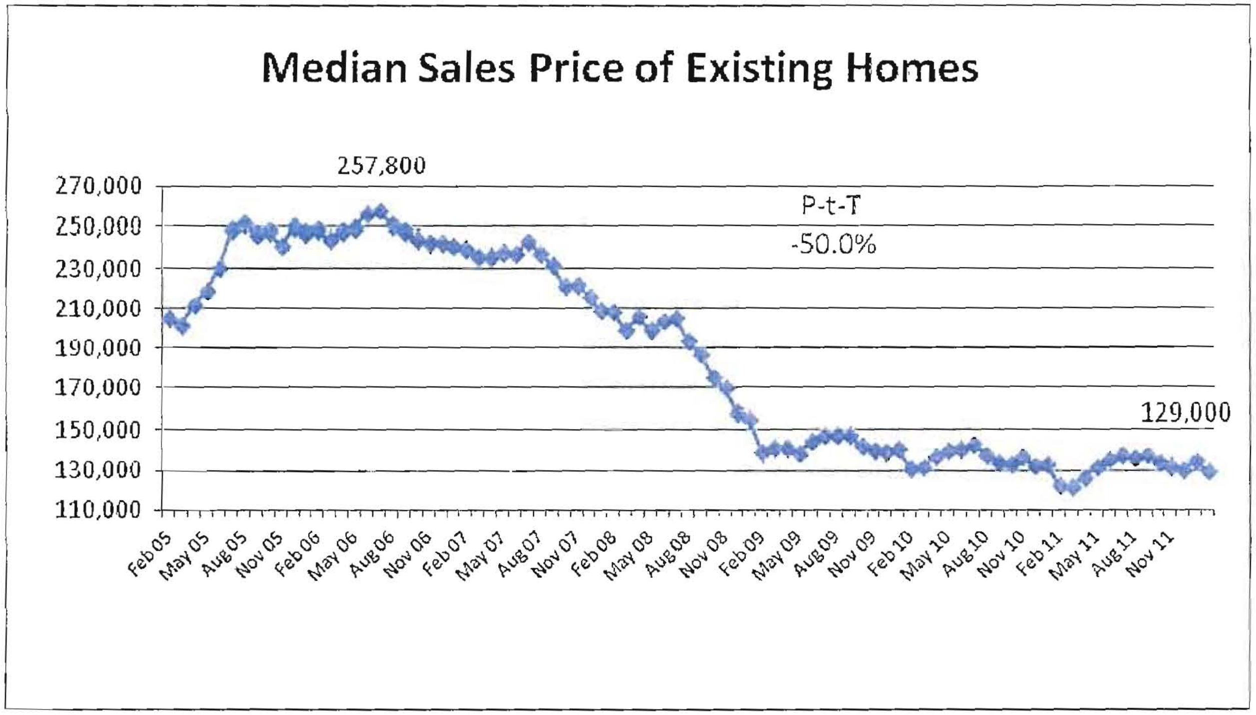
But, Existing Homes Sales Are Sputtering



Data through January 2012

Sales Level in CY 2010 was 70.1% of 2005 boom level; for this year, 76.4%.

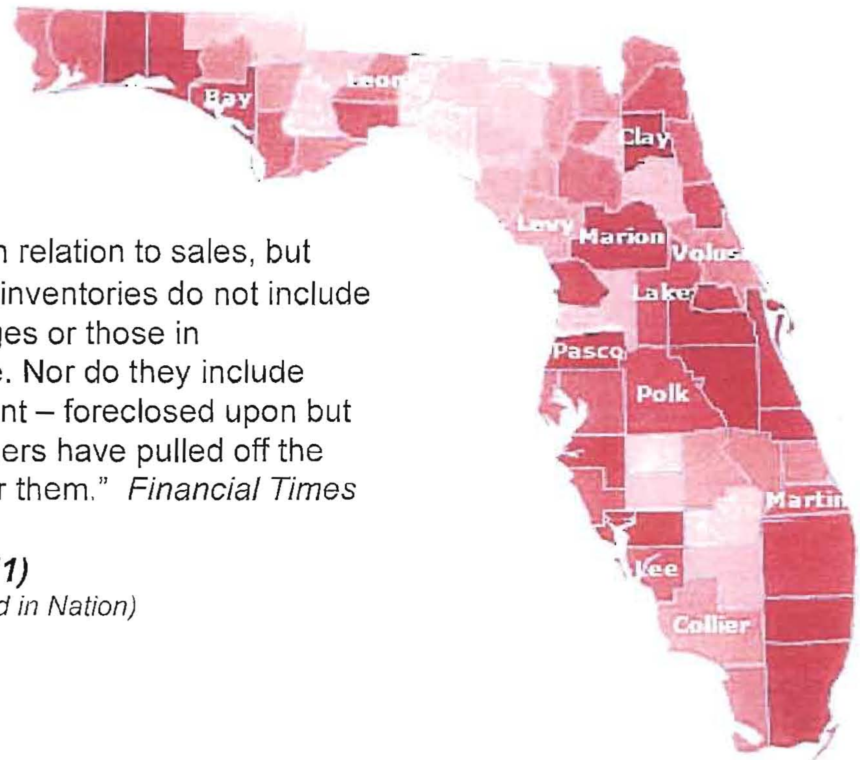
And, Existing Home Prices Are Flat



Data through January 2012

Median Sales Prices for Existing Homes have been essentially flat since January 2009 --- 36 months --- with a slight downward drift.

Foreclosure Filings Remain Daunting



"Optimists point to declining home inventories in relation to sales, but they are looking at an illusion. Those supposed inventories do not include about 5m housing units with delinquent mortgages or those in foreclosure, which will soon be added to the pile. Nor do they include approximately 3m housing units that stand vacant – foreclosed upon but not yet listed for sale, or vacant homes that owners have pulled off the market because they can't get a decent price for them." *Financial Times*

Foreclosure Process (once begun; Q4: 2011)

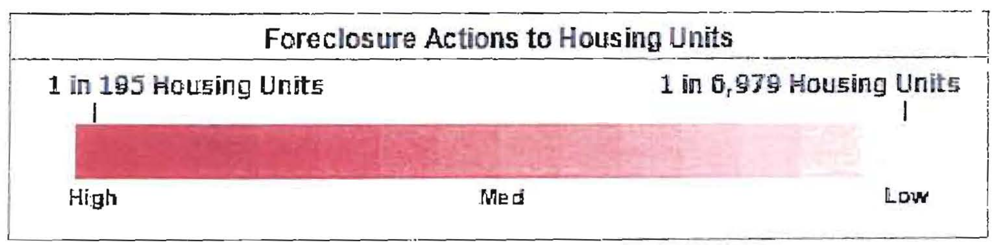
806 Days - 2.2 yrs - in Florida (3rd Longest Period in Nation)
At the beginning of 2007, 169 days.

2010

2nd Highest # of Filings
3rd Highest Foreclosure Rate

2011

2nd Highest # of Filings
6th Highest Foreclosure Rate



Data from RealtyTrac

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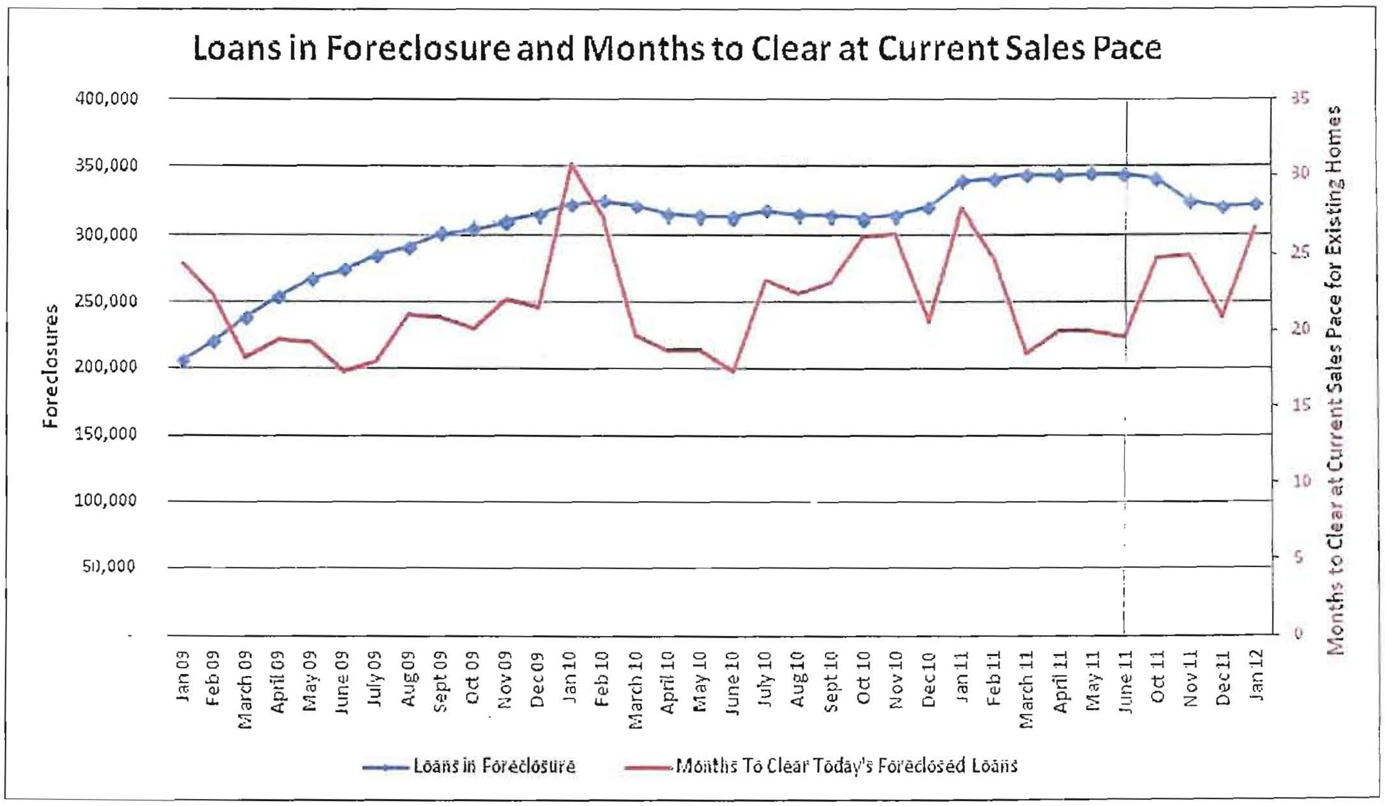
Residential Loans in Foreclosure



Loan Data from LPS. December

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Foreclosures & Shadow Inventory

State		Del %	FC %	Non-Curr %	Yr/Yr Change in NC%
National		8.2%	4.1%	12.3%	-5.5%
FL	*	8.7%	13.9%	22.7%	-2.5%
MS		14.7%	3.9%	18.7%	-0.8%
NV		10.6%	6.1%	16.6%	-18.9%
NJ	*	8.3%	7.5%	15.8%	6.9%
IL	*	7.9%	[illegible]	14.9%	4.0%
IN	*	9.9%	4.8%	14.7%	0.3%
OH	*	9.7%	5.0%	[illegible]	0.3%
GA		11.5%	2.8%	14.3%	-6.4%
LA	*	10.5%	3.3%	13.8%	-4.0%
NY	*	7.8%	5.6%	13.4%	2.9%
MD	*	9.9%	3.5%	13.4%	1.4%
SC	*	8.7%	4.6%	13.2%	0.1%
RI		9.9%	3.3%	13.2%	-6.7%
TN		10.7%	2.4%	13.1%	-3.7%
ME	*	7.4%	5.4%	12.8%	4.3%
CT	*	7.4%	5.2%	12.7%	3.9%
WV		10.2%	2.5%	12.6%	-5.8%

State		Del %	FC %	Non-Curr %	Yr/Yr Change in NC%
National		8.2%	4.1%	12.3%	-5.5%
AL		10.9%	1.7%	12.6%	-4.7%
KY	*	8.4%	3.8%	12.2%	4.1%
PA	*	8.7%	3.4%	12.1%	2.3%
NC		8.9%	3.2%	12.1%	0.8%
DE	*	8.1%			
AR		10.1%			
MI		9.2%			
HI	*	5.8%			
OK	*	7.8%			
WI	*	6.8%			
NM		6.5%			
AZ		7.3%			
TX		8.8%			
MO		8.4%			
MA		7.7%			
CA		7.1%	3.0%	10.1%	-21.0%
DC		6.7%	3.1%	9.9%	-0.1%

State		Del %	FC %	Non-Curr %	Yr/Yr Change in NC%
National		8.2%	4.1%	12.3%	-5.5%
WA		7.9%	1.6%	9.5%	0.2%
KS	*	7.2%	2.2%	9.4%	-0.9%
NH		6.9%	2.1%	9.0%	-6.0%
VT	*	5.4%	3.5%	9.0%	7.8%
				[illegible]	-9.7%
				[illegible]	-2.5%
				[illegible]	-7.5%
				[illegible]	-13.6%
				[illegible]	-3.1%
				[illegible]	-4.5%
				[illegible]	-9.4%
				[illegible]	-9.6%
				[illegible]	-9.8%
				[illegible]	-17.3%
				[illegible]	1.0%
AK		4.3%	1.0%	5.3%	-7.8%
ND	*	3.2%	1.1%	4.3%	-2.3%

* - *Indicates Judicial State*

State		Del %	FC %	Non-Curr %
National		8.2%	4.1%	12.3%
FL	*	8.7%	13.9%	22.7%

About half of all residential loans in Florida are for homes that are underwater.

(LPS Data for August and November)

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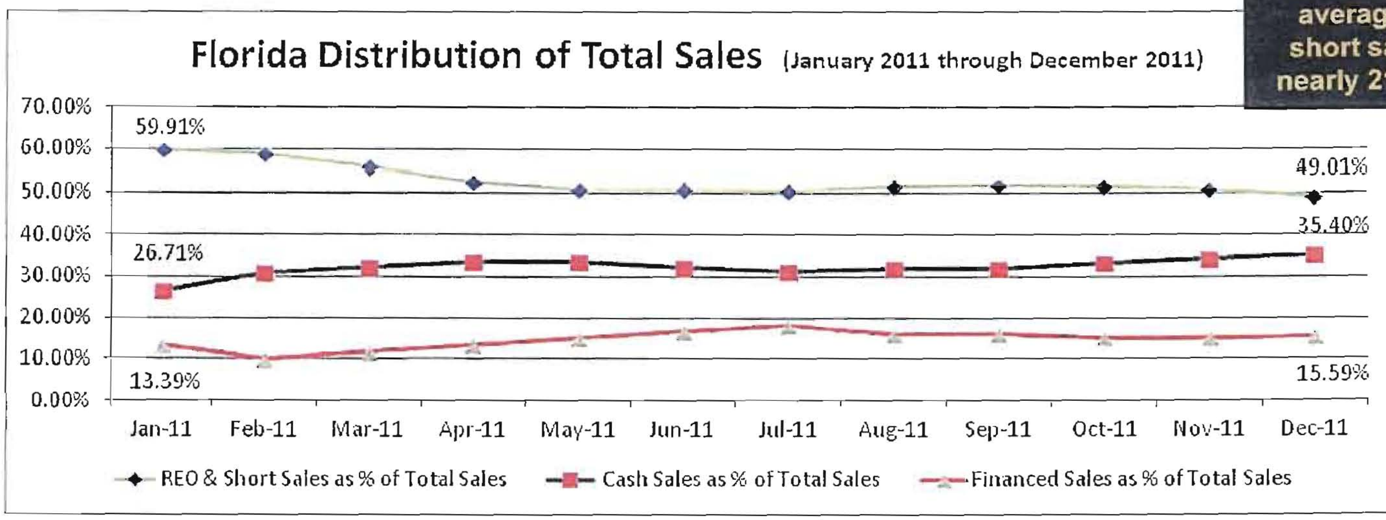
Sales Mix Points to Lower Prices

REO price nearly 40% lower than average price; short sale price nearly 21% below



LPS: Lender Processing Services

Cash Sales have been growing as a percentage of all sales, and financed sales have been declining. While short sales have been increasing in some states, that is not yet the case in Florida, where they have essentially been flat.

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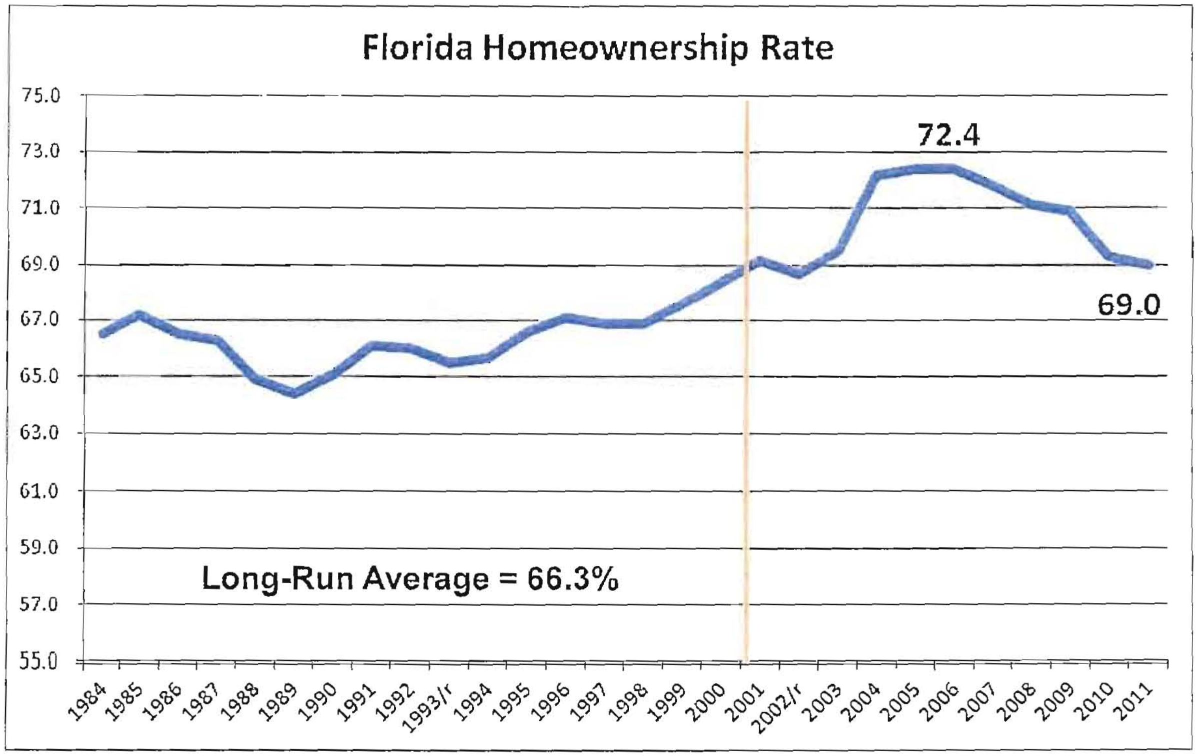
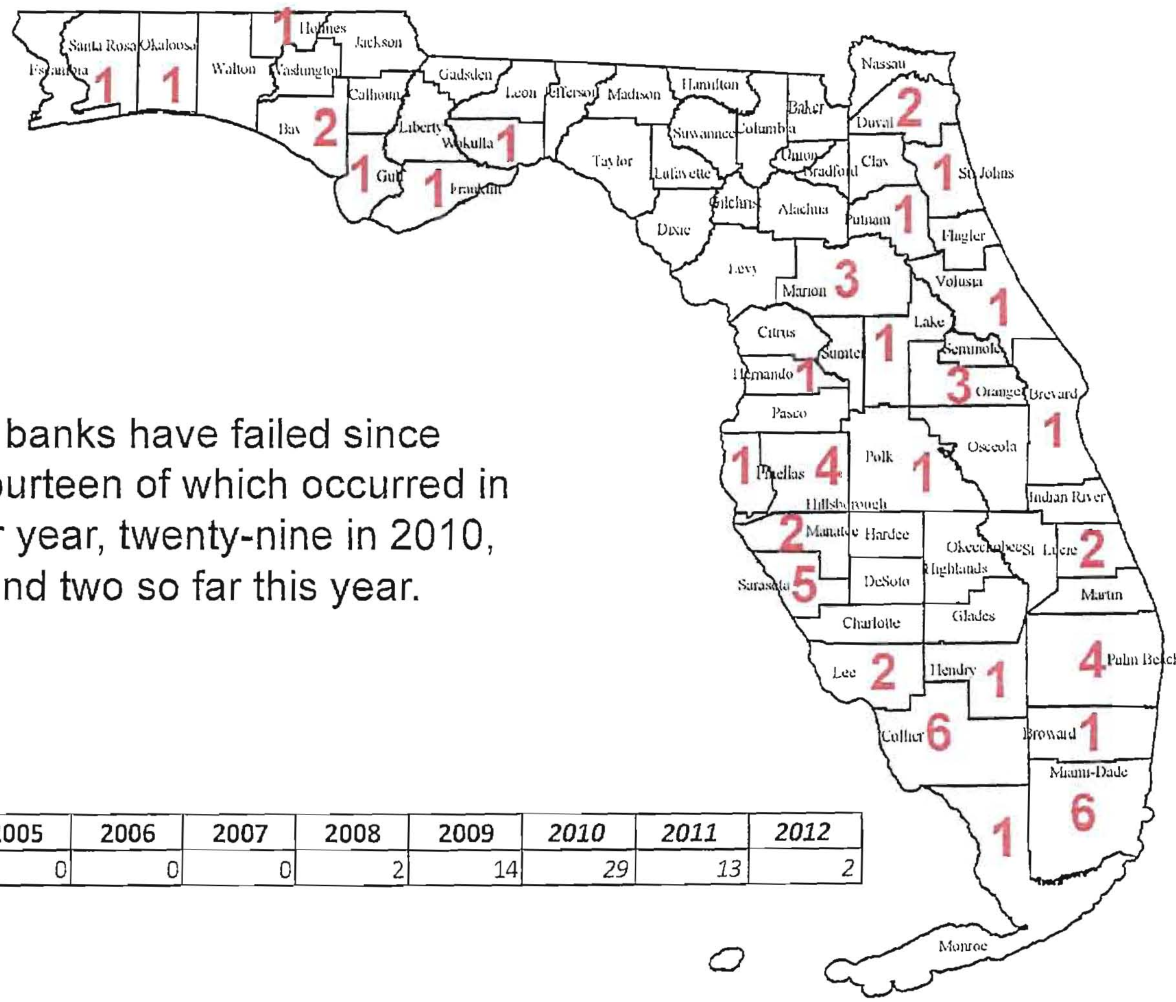
Vulnerability



The 2010 percentage is the lowest since 2002. If the 2010 rate dropped immediately back to the long-run average, about 222,600 homeowners would be affected and $30.8 billion of value.

Bank Failures Since January 2009



Fifty-eight Florida banks have failed since January 2009 – fourteen of which occurred in the 2009 calendar year, twenty-nine in 2010, thirteen in 2011, and two so far this year.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
2	0	1	0	0	0	2	14	29	13	2

Credit Conditions Remain Tight

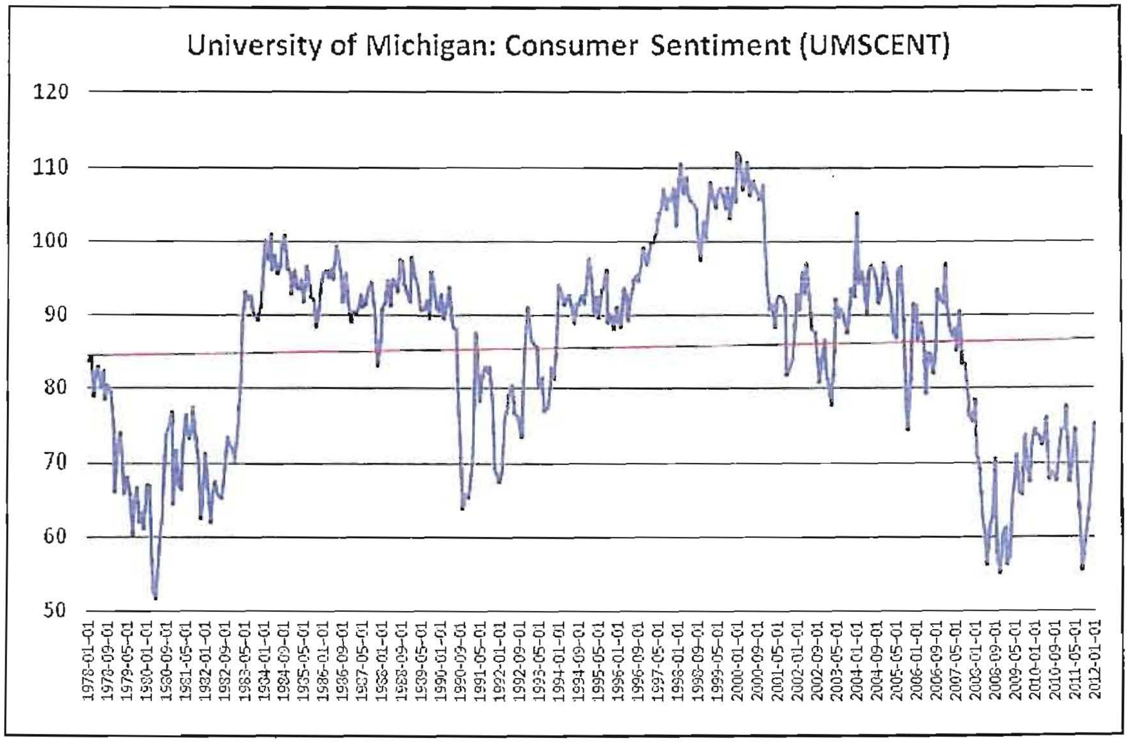
Question to Senior Loan Officers:

Over the past three months, how have your bank's credit standards for approving applications from individuals for **prime residential mortgage loans** to purchase homes changed?

	All Respondents						
	Jan '12 %	Oct '11 %	July '11 %	Apr '11 %	Jan '11 %	Oct '10 %	July '10 %
Tightened considerably	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tightened somewhat	0.0	4.2	5.7	3.8	3.7	13.0	3.6
Remained basically unchanged	**94.3**	**91.7**	**86.8**	**92.5**	**94.4**	**83.3**	**87.3**
Eased somewhat	5.7	4.2	7.5	2.0	1.9	3.7	9.1
Eased considerably	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0

January 2012 Senior Loan Officer Opinion Survey on Bank Lending Practices (Federal Reserve Board)

Perceptions Recover After August Dive



- Consumer sentiment can be a leading indicator of recession, but not always: nationally, it had been improving, but fell in August to near the lowest level of the Great Recession and not far from the lowest level ever posted. The subsequent months have all shown improvement. (77.5 in February versus the lowest point of 51 7 in May 1980) and February matches where we were one year ago.
- Florida's consumer confidence (January: 77) is roughly mirroring the national trend.

Economy Slowly Recovering

Florida growth rates are slowly returning to more typical levels. But, drags are more persistent than past events, and it will take several years to climb completely out of the hole left by the recession. Overall...

- The national economy is still in recovery and, more importantly, the credit markets are still recovering stability – however, they still remain sluggish and difficult to access. So far, the recovery has been roughly half as strong as the average gain of 9.8% over the same period during the past seven recoveries.
- The subsequent turnaround in Florida housing will be led by:
  - Low home prices that begin to attract buyers and clear the inventory.
  - Long-run sustainable demand caused by continued population growth and household formation.
  - Florida's unique demographics and the aging of the baby-boom generation (2011 marks the first wave of boomers hitting retirement).

Eurozone Problems Still Persist

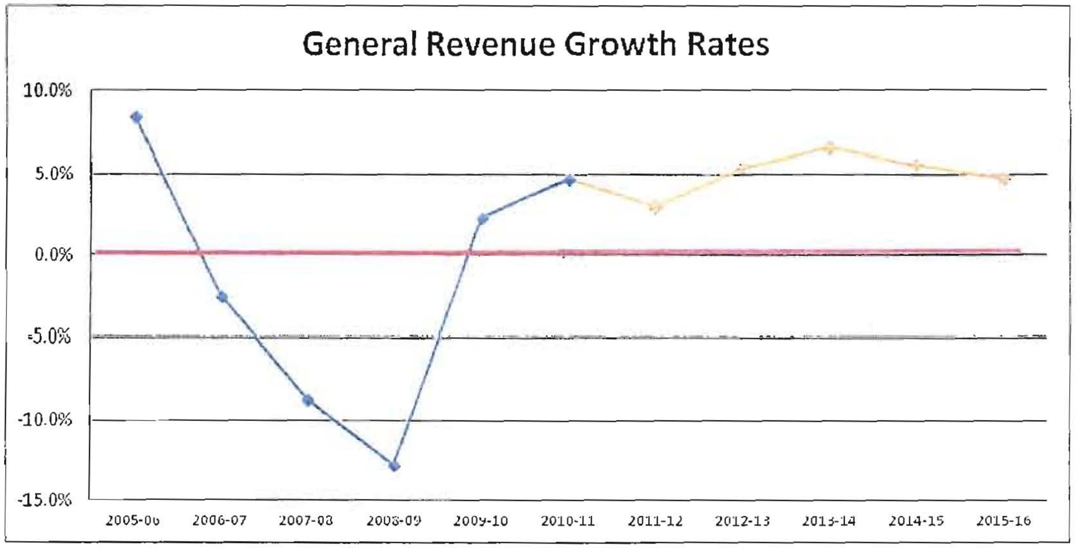
- The sovereign debt crisis in the Eurozone has led to banking instability with spillover effects on the global credit market: threats are reduced, but still present.
  - The debt reduction agreement put in place last week for Greece is the biggest sovereign restructuring so far Even so, the second bailout and debt restructuring does not preclude a messier default or even a euro exit further down the line.
  - Fitch has indicated that once the latest private sector debt swap is completed, it will place Greece temporarily in default. Standard & Poor's has already done so.
  - Standard & Poor's has downgraded 9 of the Eurozone's 17 members, including France, Austria, Italy, Spain and Portugal.
  - Fitch has taken action on six eurozone sovereigns, cutting the long-term ratings of Italy, Spain and Belgium.
  - Moody's has put the UK, France and Austria on negative outlook, signaling a potential future downgrade, and downgraded Italy, Spain and Portugal as well as three other Euro areas.
  - Standard & Poor's has also downgraded the rescue fund – the temporary European Financial Stability Facility If this downgrade is replicated by the other rating agencies, the permanent rescue plan (the European Stability Mechanism) is likely unworkable as designed and the dollars available for bailout will be reduced.
  - International Monetary Fund (IMF) and the United States have warned that the Eurozone needs a larger bail-out fund (a "larger firewall") to prevent the crisis from spreading. Germany has resisted this move
  - The region's banks still need to be recapitalized, w th significant improvement required by summer
- It appears that the Eurozone slipped into recession during the fourth quarter of the last calendar year.
- These conditions will negatively affect the United States if no significant improvement is made.
  - Tighter credit conditions already exist.
  - Reduced exports and corporate earnings already exist.

Other Risks to the Forecast

- Florida's quarterly personal income growth (third quarter of 2011 over the preceding quarter) fell for the first time since the third quarter of 2009. At -0.1 percent growth, the state was ranked 46th in the country. If below expected personal income growth continues, the outlook will be negatively affected. New data will be available March 28, 2012.

- As a result of the Supercommittee's failure, automatic spending cuts are scheduled to kick in at the beginning of 2013. Referred to as the Automatic Sequester, this is the enforcement mechanism used to ensure an additional $1.2 trillion in spending reductions —falling equally on defense and non-defense spending. Further details likely unknown through the 2012 Election.
  - In Federal Fiscal Year 2008, 13,294 Florida businesses received nearly $16 billion in federal contracts. The vast majority of this money was defense-related. In 2009, contracts awarded by the Department of Defense accounted for 77 percent of total procurement contracts awarded to Florida.

General Revenue Forecast



Fiscal Year	Oct Forecast	January Forecast	Difference (Jan - Oct)	Incremental Growth	Growth
2005-06	27074.8	[redacted]			8.4%
2006-07	26404.1	[redacted]			-2.5%
2007-08	24112.1	[redacted]			-8.7%
2008-09	21025.6	[redacted]			-12.8%
2009-10	21523.1	[redacted]			2.4%
2010-11	22551.6	[redacted]			4.8%
2011-12	23195.5	23241.5	46.0	689.9	3.1%
2012-13	24526.8	24506.9	(19.9)	1265.4	5.4%
2013-14	26071.8	26117.6	45.8	1610.7	6.6%
2014-15	27417.9	27580.8	162 9	1463.2	5.6%
2015-16	28838.6	28901.3	62.7	1320.5	4.8%

EXHIBIT A

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause	Docket No. 120009-EI
In re: Examination of the outage and replacement fuel/power costs associated with the CR3 steam generator replacement project, by Progress Energy Florida, Inc.	Docket No. 100437-EI
In re: Petition of Progress Energy Florida, Inc. for limited proceeding to approve Stipulation and Settlement Agreement, including Certain Rate Adjustments.	Docket No. ___________

STIPULATION AND SETTLEMENT AGREEMENT

WHEREAS, Progress Energy Florida ("PEF" or the "Company"), the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), White Springs Agricultural Chemicals, Inc. ("White Springs"), and the Federal Executive Agencies ("FEA") (collectively referenced as the "Parties") have reached a resolution of certain outstanding issues in the above-referenced dockets and other matters which are set forth in this Stipulation and Settlement Agreement (the "Agreement") dated January 20, 2012; and

WHEREAS, unless the context clearly requires otherwise, the term Party or Parties means a signatory to this Agreement, and Intervenor Parties means collectively OPC, FIPUG, FRF, White Springs, and FEA; and

WHEREAS, the Parties recognize that there are disputed issues in the above-referenced Public Service Commission ("PSC" or "Commission") dockets that may have

EXHIBIT A

substantial consequences for PEF, consumers and investors alike, and that settlement of the various positions of the Parties on these issues is in the best interests of the Parties, the interests they represent, and the public; and

WHEREAS, settlement of these issues promotes administrative efficiency and avoids the time, expense, and uncertainty associated with resolving these issues in the above-referenced Commission dockets and potentially other Commission proceedings; and

WHEREAS, the Parties further recognize that the issues addressed by this Agreement resolve in a comprehensive manner an unprecedented combination of circumstances at a difficult time in the Florida economy, and that all Floridians have been affected by the current economic climate; and

WHEREAS, the Parties further recognize that continued uncertainty related to the issues addressed in the Agreement adversely affects the Company and its customers, and this Agreement will mitigate those uncertainties; and

WHEREAS, this Agreement will also help to mitigate the impact of energy prices by, among other things, refunding $288 million through the Fuel Cost Recovery Clause ("Fuel Clause") to customers between 2013 and 2016, and potentially up to an additional $100 million through the Fuel Clause between 2015 and 2016; removing the Crystal River Unit 3 ("CR3") nuclear plant from rate base while CR3 is out of service; and limiting the costs consumers can be charged for the Levy Nuclear Project ("LNP") through 2017; and

WHEREAS, the Intervenor Parties support PEF's efforts to repair and restore CR3 to a safe and fully operable condition in a timely fashion; and

EXHIBIT A

WHEREAS, the Intervenor Parties further support and encourage PEF's efforts to pursue complete coverage of the costs of repairing CR3 under its insurance policies with Nuclear Electric Insurance Limited ("NEIL") to the full extent of the coverage limits in any policies,

NOW, THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby agree and stipulate as follows:

1. This Agreement will become effective upon approval by final Commission vote (the "Implementation Date"), and continue through the last billing cycle in December 2016 (the "Term"), unless otherwise specified in this Agreement.

2. This Agreement resolves numerous disputed or potentially disputed matters before the Commission. The Parties reserve all rights, unless such rights are expressly waived under the terms of this Agreement.

<u>LNP</u>

3. The Parties do not oppose PEF obtaining the LNP Combined Operating License ("COL") from the U.S. Nuclear Regulatory Commission ("NRC"), terminating the LNP engineering, procurement, and construction contract, and recovering the costs associated with those activities through the Nuclear Cost Recovery Clause ("NCRC") as set forth in the Agreement. Any future PEF actions concerning the LNP shall not be attributed to this Agreement or to the Intervenor Parties' agreement to the terms and conditions herein. To the extent that final LNP costs are above or below the estimated $350 million LNP remaining balance, PEF shall submit a final true-up filing (subject to

EXHIBIT A

verification) to the PSC setting forth the final actual LNP costs, and the amount of any true-up cost or credit to customer bills.

4. The LNP component of the Company's NCRC charges shall, effective the first billing cycle in January 2013, be set at $3.45/1,000 kWh, for a residential customer, and a corresponding adjustment from the current LNP factors shall be made for commercial and industrial rates as shown on Exhibit 5. This factor shall be fixed at the levels shown on Exhibit 5 until the estimated remaining LNP balance of approximately $350 million (retail), and carrying costs, is recovered (estimated to be 5 years), with true up occurring in the final year of recovery, in accordance with paragraph 3. Concurrent with the adjustment of the LNP NCRC factor, PEF shall, effective with the first billing cycle in January 2013, transfer its collection of the annual retail revenue requirements associated with the carrying costs on the deferred tax asset in the amount reflected in Exhibit 6 from the NCRC to base rates. Such base rate adjustment shall be established by the application of a uniform percentage increase to the demand and energy charges of the Company's base rates, including delivery voltage credits, power factor adjustment and premium distribution service. This uniform percent adjustment will be calculated using the billing determinants set forth in Exhibit 1, Attachment A to this Agreement and presented in the format of MFRs E-12 and E-13c for the projected year of 2013.

5. PEF shall not recover any LNP costs from customers, apart from those identified in this Agreement, throughout the Term. PEF shall not, before March 1, 2017, file for any additional LNP nuclear cost recovery, unless otherwise agreed to by the Parties, it being the Parties' intent that PEF will not recover any additional LNP costs from customers before the first billing cycle of January 2018.

EXHIBIT A

6. PEF will treat the allocated wholesale cost of LNP as a Retail Regulatory Asset, and include this asset as a component of rate base and amortization expense in reported net operating income for earnings surveillance. PEF will have the ability to amortize that Retail Regulatory Asset through 2016, with PEF's discretion to suspend such amortization in full or in part and/or to accelerate such amortization in full or in part as deemed appropriate by the Company; provided, however, PEF shall amortize 100% of the regulatory asset on or before December 31, 2016. This adjustment shall not be taken into account for purposes of determining whether PEF can seek a base rate adjustment pursuant to paragraph 20.

CR3

7. It is the intent of the Parties and the Parties stipulate that this Agreement resolves issues regarding the CR3 steam generator replacement ("SGR") project in all phases of PSC Docket No. 100437-EI subject to the terms of this Agreement. It is the intent of the Parties that, within five days of the Implementation Date, PEF will file a motion to dismiss Phase 1 and to stay Phases 2 and 3 of Docket No. 100437-EI consistent with the terms of this Agreement. The Parties agree that this Agreement makes no allocation or determination of fault, prudence or reasonableness in or related to PEF's actions taken in connection with the SGR project or the repair activities associated with the delaminations, including but not limited to the actions which resulted in the delaminations of the CR3 containment building in 2009 and 2011. The Parties, however, have not contended and do not now contend that the delaminations prior to the Implementation Date were foreseeable or expected by the Company. The Intervenor Parties waive their rights to challenge the prudence of PEF's actions taken during the

period from the SGR project inception through the Implementation Date in connection with the SGR project or the repair activities associated with the delaminations, including but not limited to the actions which resulted in the delaminations of the CR3 containment building in 2009 and 2011. Absent evidence of fraud, intentional misrepresentation, or intentional misconduct by PEF during the period referenced in this paragraph 7, the Intervenor Parties cannot and will not challenge the prudence of PEF's actions on the SGR project or PEF's repair activities from the inception date of the SGR project through the Implementation Date in any PSC or judicial proceeding.

8. a. PEF shall place CR3 in extended cold shutdown effective January 1, 2011, at which time depreciation and other accruals will be suspended and/or reversed until the unit is returned to commercial operation or retired and amortized. PEF shall remove CR3 from rate base, the revenue requirement of which is excluded from the rates established in paragraph 13, effective the first billing cycle of January 2013 and until the plant returns to commercial operation. Effective with its removal from customer rates, an accrual of a carrying charge equivalent to that authorized in PSC Order No. PSC-10-0604-PAA-EI (which rate is 7.44 percent, as shown on Exhibit 2 to this Agreement) on CR3 investments removed from customer rates shall be allowed until these investments, along with accrued carrying costs, are placed back into customer rates. The ratemaking treatment of placing CR3 in extended cold shutdown is based on the unprecedented and complex nature of the totality of the circumstances addressed in this Agreement and shall have no precedential effect in any future Commission proceeding.

b. Upon the return of CR3 to commercial operation, PEF shall be authorized to increase its base rates for the annual revenue requirements of all CR3 investments (excluding O&M which was not removed from customer rates), and including (1) all capitalized delamination repair costs (in excess of such repair costs that are reimbursed through Nuclear Electric Insurance Limited ("NEIL") proceeds and subject to the provisions in paragraph 10.c), and (2) carrying costs accrued during the extended cold shutdown. Such base rate increase shall be established by the application of a uniform percentage increase to the demand and energy charges of the Company's base rates including delivery voltage credits, power factor adjustment and premium distribution service. This uniform percentage increase will be calculated using the billing determinants included as Exhibit 1 to this Agreement for the projected year of 2013, adjusted for the increases provided herein, and at the return on equity set forth in paragraph 15; with the capital structure as set forth in Exhibit 4. The Intervenor Parties reserve their rights to participate in any such proceeding, to challenge the appropriateness of PEF's CR3 revenue requirements, and to challenge the actual capitalized delamination repair costs as set forth in paragraph 10.

9. Refunds through the Fuel Clause. Pursuant to the terms of this Agreement, PEF agrees to the following:

a. Refund to customers $288 million (retail) as of December 31, 2011. PEF shall refund through the Fuel Clause 50% of $258 million in 2013, and the remaining 50% through the Fuel Clause in 2014. The remaining balance of $30 million will be refunded through the Fuel Clause solely to customers on Rate Schedules RS-1, RSL-1, RSL-2, GS-1, and GS-2 (and their time-of-use counterpart schedules, to the

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extent applicable) based on an allocation of 94% of such refund amounts to the Residential Service rate schedules and 6% to the General Service, Non-Demand rate schedules, at an annual rate of $10 million per year in years 2014, 2015, and 2016.

b. In the event PEF, in good faith, commits, through formal Board and/or senior management action to commence, and then commences, containment building repairs by December 31, 2012 in accordance with a publicly announced plan and schedule issued after the Implementation Date and designed to return CR3 to service within the final approved schedule (estimated at this time to be 30 months), PEF shall have no obligation to refund or forego any CR3 replacement fuel and purchased power costs in 2015 or 2016. If PEF does not in good faith commence CR3 containment building repairs by December 31, 2012, PEF shall be obligated to: (1) refund a pro-rated amount not to exceed $40 million towards replacement fuel and purchased power costs if CR3 remains out of service in 2015 (for example, if CR3 commences commercial operation on February 1, 2015, PEF shall refund $3.33 million); and (2) refund a pro-rated amount not to exceed $60 million towards replacement fuel and purchased power costs if CR3 remains out of service in 2016 (for example, if CR3 commences commercial operation on February 1, 2016, PEF shall refund $5 million).

c. Except for the aforementioned refunds, PEF shall be entitled to recover its prudently incurred fuel and purchased power costs through the Fuel Clause without regard to the absence of CR3 for the period beginning October 1, 2009 and ending on the earlier of December 31, 2016 or the date on which CR3 commences commercial operation following the completion of the delamination repairs. PEF's right to recover its prudently incurred fuel and purchased power costs does not affect the rights of customers to receive reimbursement from NEIL proceeds for such costs as otherwise provided in this Agreement. Thus, for that period, the unavailability of CR3 shall not be the basis for any disallowance of fuel or purchased power costs, and the Intervenor Parties waive their rights to challenge PEF's recovery of such costs, except as provided below in this paragraph 9.c. Intervenor Parties reserve the right to raise issues regarding the prudence and reasonableness of PEF's fuel acquisition and power purchases, and other fuel prudence issues unrelated to the CR3 extended outage. In the event that repair activities continue beyond December 31, 2016, the Parties are not prohibited from contesting PEF's right to recover replacement fuel costs beyond that period due to the continued CR3 repair outage.

10. CR3 Repair. To the extent that PEF pursues repair of CR3, the following shall apply:

a. (1) PEF will establish an estimated cost and schedule to repair the unit, and shall meet with the Intervenor Parties in advance of senior management and Board approval of any such repair plan. The Intervenor Parties shall provide to PEF in writing within twenty (20) business days following such meeting any concerns regarding PEF's repair plan, and PEF shall provide such concerns to its senior management and Board of Directors as part of the advice and consultation process. The Parties agree to implement a process whereby the Intervenor Parties' concerns and PEF's response to the Intervenor Parties' concerns are shown to be formally acted upon by the Company's Board and/or senior management with any reasons for rejection explained in writing. Approval of or by any or all of the Intervenor Parties is not required with respect to PEF's decision to repair CR3, the repair cost estimate, or the repair schedule.

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(2) In the event PEF, in good faith, commits, through formal Board and/or senior management action to commence, and then commences, containment building repairs by December 31, 2012, and continues to implement such repairs (except as otherwise provided in paragraph 11) in accordance with a publicly announced plan and schedule designed to return CR3 to service within any schedule approved by the Board as part of the Board's decision to commence repairs (such schedule estimated at this time to be 30 months with recognition that such estimated schedule could change due to events beyond the Company's reasonable control), the Intervenor Parties waive their rights to challenge PEF's decision to repair and the selected repair plan. However, Intervenor Parties retain and do not waive any rights to challenge PEF's execution of the repair plan and the prudence of PEF's repair costs; except as provided in paragraphs 10.a.(3) and 10.a.(4) below, the Intervenor Parties waive their rights to challenge PEF's execution of the repairs, as long as PEF's repair efforts and activities commence prior to December 31, 2012, and are materially consistent with the estimated repair costs and schedule associated with PEF's publicly announced repair plan. The Intervenor Parties reserve their rights to challenge any potential double recovery of CR3 O&M costs that are shown to have also been capitalized as part of the CR3 repairs; it being PEF's intent not to treat such costs in a manner that would result in double recovery (e.g., payment of O&M costs through base rates during the repair period and then seeking a return on such costs as capitalized components of the CR3 rate base when CR3 is returned to service).

(3) The waiver of rights set forth in paragraph 10.a.(2) above shall remain in effect up through and including the earlier of (i) the time at which PEF

obtains final resolution of PEF's insurance coverage claims for CR3 with NEIL (through arbitration, litigation, settlement, or otherwise) for CR3 repairs, or (ii) December 31, 2013. Once PEF receives such a resolution of its NEIL insurance claims for CR3, the waiver of rights in paragraph 10.a.(2) will no longer apply prospectively for any new actions after that time should PEF decide to continue with repairs after such final coverage resolution and discussion with the Parties in accord with Section 10.a.(1) above.

(4) If PEF does not commence CR3 containment building repairs in accordance with the publicly announced plan referred to above by December 31, 2012, the Intervenor Parties reserve all rights to challenge any PEF decision to repair CR3 and the prudence of implementing any such subsequent repairs.

b. PEF will meet with and advise the Intervenor Parties of any potential or final resolution of insurance coverage amounts either resulting from arbitration, litigation, or settlement of the Company's NEIL claims. The Intervenor Parties shall provide to PEF in writing within twenty (20) business days following such meeting any concerns regarding any such proposed litigation, arbitration, or settlement, and PEF shall provide such concerns to its senior management and Board of Directors as a part of the advice and consultation process. The Parties agree to implement a process whereby the Intervenor Parties' concerns and PEF's response to the Intervenor Parties' concerns are shown to be formally acted upon by the Board and/or senior management with any reasons for rejection explained in writing. No approval of any such litigation, arbitration, or settlement from the Intervenor Parties is required, and the

Intervenor Parties are not precluded from challenging the reasonableness or prudence of such course of action.

c. To the extent that PEF receives a final resolution of NEIL insurance coverage for project repairs (by arbitration, litigation, settlement of its claims, or otherwise) that does not cover the total cost of the repairs to return CR3 to commercial operation, the Parties agree to meet and discuss how best to address that deficiency. If resolution cannot be reached, the Parties agree to present the issue to the Commission for resolution, subject to the limitations set forth in paragraph 10.

d. PEF will conduct meetings at least quarterly until CR3 commences commercial operation (or is retired) to brief the Intervenor Parties on all matters relating to: the status of the unit; repair of the unit; construction status; design status; estimated schedule; estimated cost; NEIL insurance claims and coverage determinations and disputes, if any; licensing status and issues; and risk identification and mitigation measures. PEF will also provide updated metrics for the project, monthly management PowerPoint presentation documents, if any, and periodic project status reports that PEF keeps in the ordinary course of its business as agreed between PEF and the Parties. Information disclosed will be subject to appropriate confidentiality agreements in support of PEF's obligation and commitment to provide the Intervenor Parties with non-privileged information that is similar to that provided to senior management. If there is a dispute about whether such information is privileged, the Parties agree to meet and discuss how best to address any such dispute. If resolution cannot be reached, the Parties agree to present the issue to the Commission for resolution.

e. In the event the repair costs exceed the initial repair estimate initially approved by the Progress Energy's (or its successor's) Board subsequent to the Implementation Date, the Parties agree that every dollar of such costs shall be shared on a 50% Progress shareholders/50% Progress customers basis up to $400 million (retail) over the Board's initially approved cost estimate. In the event that costs exceed $400 million above the Board's initially approved cost estimate, the Parties agree to meet and discuss how best to address that amount of cost increase (e.g., if the initial cost estimate initially approved by the Board is $1.3 billion and actual repair cost to return CR3 to commercial operation is $1.8 billion, each dollar of the first $400 million shared above $1.3 billion will be shared equally by Progress shareholders and Progress customers, and the Parties will meet to discuss how best to address the additional $100 million cost increase). If resolution cannot be reached, the Parties agree to present the issue to the Commission for resolution.

f. The Parties agree that any documents provided by any Party pursuant to the advice and consultation process in this paragraph 10 may be used by any Party in any future Commission or judicial proceeding. Any discussions during any such meetings (or records of such discussions) shall be confidential, for ongoing settlement purposes only, and not subject to discovery by any means or method or admissible in any such Commission or judicial proceeding.

11. CR3 Retirement.

a. Notwithstanding any other provisions of this Agreement, the Parties recognize that the decision making related to repairing or decommissioning CR3 is complex and subject to a number of unknown factors, including but not limited to the

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cost of the repair and the likelihood of obtaining NRC approval to restart CR3 after the repair. PEF, therefore, reserves the right to decommission CR3 if it determines that it is prudent to do so. If PEF determines to decommission rather than repair CR3 and return the unit to commercial operation, all NEIL insurance proceeds will, unless otherwise agreed among the Parties, be applied first to offset the consumers' share of replacement fuel costs incurred after December 31, 2012, with any remaining proceeds to be applied to any unrecovered CR3-related investments, i.e., the remaining unamortized rate base balance for CR3. For purposes of this provision, the replacement fuel costs from January 2013 through year end 2016 shall be calculated as the difference between PEF's total fuel and purchased power costs as incurred without CR3 available for service, and the estimated PEF total fuel and purchased power costs that PEF would have incurred if CR3 had been available.

b. Upon PEF's decision to retire CR3, and until inclusion in customer rates, which inclusion shall not occur prior to the first billing cycle in January 2017, PEF will be authorized to implement deferral accounting through the creation of regulatory assets to address the revenue requirement associated with all CR3 related costs (including, but not limited to actual depreciation/amortization expense, operation and maintenance expense, property taxes, and cost of capital return) and regulatory liabilities to address O&M costs, which may be funded from the Nuclear Decommissioning Trust or obviated by ceasing operations, and property taxes which may no longer be assessed (for example, a type of regulatory liability would entail Retail Nuclear O&M 2010 MFR C-4 $90 million (per year) (See Exhibit 7) less actual incurred O&M deferred as a regulatory asset). The cost of capital return or carrying charge will

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be based on the approved AFUDC rate with the cost of equity set to 70% of the then Commission authorized rate (See Exhibit 3); it being the intent of the Parties that whenever the Commission authorizes a change (whether an increase or a decrease) to PEF's return on equity in the future, the 70% formula in this paragraph will apply to any remaining CR3 investments. PEF shall not seek an increase in customer rates for the aforementioned revenue requirements on the net costs deferred and accumulated in the regulatory assets or liabilities such that the effective date of said increase would occur prior to the first billing cycle of January, 2017. Nothing in this Agreement shall preclude PEF from filing for such an increase during the Term so long as the increase would not occur prior to the first billing cycle of January 2017. Any subsequent request for increase in customer rates to include recovery of the costs of the retired CR3 asset shall also be based on the overall cost of capital utilizing the same formula of 70% of the cost of equity being requested, with the cost of equity remaining subject to the Commission's final order. The Intervenor Parties waive their rights to challenge the prudence of any decision by the Company to retire CR3, and to contest PEF's right to recover a return of and return on the deferred and accumulated CR3 investments, regulatory assets/liabilities, and carrying costs, in the above referenced rate increase proceeding using the reduced rate of return specified above, or any other proceeding. The Intervenor Parties retain the right to contest the calculation of the deferred regulatory asset, and the execution of the repairs, if any, subject to the terms of paragraph 10. The Parties agree that the balance of regulatory assets pursuant to this Agreement shall not be used as the basis for interim rate relief or included for purposes of determining whether PEF's rate of return on equity has fallen below 9.5% so as to trigger PEF's right to seek a base rate increase pursuant to paragraph 20 of this Agreement. The Parties agree that any remaining CR3 investments shall be amortized through 2036.

c. PEF acknowledges that a PEF decision, if any, to retire rather than repair CR3 shall be solely its own decision and not be attributed to the Intervenor Parties as a result of their entering into this Agreement.

12. CR3 Uprate. PEF will recover carrying costs and other NCRC recoverable costs through the NCRC consistent with section 366.93, Florida Statutes, but will not petition for in-service cost recovery related to any uprate of CR3 prior to nine months following the commencement of commercial operation of CR3. PEF shall use deferral accounting (for depreciation, property taxes and O&M costs) until cost recovery becomes effective, and all carrying costs will continue to be recovered through NCRC until such time as base rates have been increased consistent with the no-sooner-than nine-month provision above. At such time as base rates are increased for these assets, recovery through NCRC will cease except for true-ups of prior costs. In-service investments from the Uprate project will be part of the CR3 investments removed from rate base as set forth in paragraph 8 above.

13. Base Rate Matters Effective with the first billing cycle in January 2013, PEF shall adjust its base rates to effect a $150 million (retail) increase in annual revenue requirements, which includes the impact of paragraph 8.a above. Such base rate adjustment shall be established by the application of a uniform percentage increase to the demand and energy charges reflected in the Company's existing base rate schedules, including delivery voltage credits, power factor adjustment and premium distribution service. This uniform percentage increase will be calculated using the billing

determinants included as Exhibit 1, attached to this Agreement and presented in the format of MFRs E-12 and E-13c for the projected year of 2013. All existing rate schedules shall remain in effect except as modified above. Except as otherwise provided for in this paragraph and this Agreement, the Company shall freeze its base rates through the last billing cycle of December 2016.

14. Effective with the first billing cycle of January 2014, the Company will be authorized to remove the capital assets installed and in service on the Crystal River Units 4 & 5 ("CR4 & 5") power plants to comply with the Federal Clean Air Interstate Rule ("CAIR") from the Environmental Cost Recovery Clause ("ECRC") and transfer those capital assets to base rates in an amount which will equal the annual retail revenue requirements of the assets projected to be in-service as of December 31, 2013 (excluding O&M related costs) which will be reflected in the Company's filing (Form 42-4P; Project 7.4) in Docket 120007-EI. Such base rate adjustment shall be established by the application of a uniform percentage increase to the demand and energy charges of the Company's base rates including delivery voltage credits, power factor adjustment and premium distribution service. This uniform percent increase will be calculated using the billing determinants for the projected year of 2014, consistent with the format shown in Exhibit 1, Attachment A, adjusted for the increases provided herein. These adjustments are in addition to the base rate adjustments provided for in paragraphs 4, 8.b, and 13 of the Agreement.

15. Effective on the Implementation Date, PEF will have an authorized return on equity of 10.5% with a range of reasonableness of +/-100 basis points for the purpose of addressing earnings levels, earnings surveillance and cost recovery clauses.

In the month following CR3's commencement of commercial operation, PEF's ROE shall increase to 10.7% +/-100 basis points, including a return calculated using the 10.7% ROE as specified above, on CR3 in-service revenue requirements as set forth in paragraph 8.b. Commencing with the Implementation Date, the applicable annual AFUDC rate will be 7.44%. (See Exhibit 2). In the month following CR3's commencement of commercial operation, PEF's applicable AFUDC rate will be 7.53%. (See Exhibit 4).

Other Matters

16. Effective on the Implementation Date, PEF will be authorized, at its discretion, to accelerate in full or in part the amortization of the regulatory assets for FAS 109 Deferred Tax Benefits Previously Flowed Through, Unamortized Loss on Reacquired Debt, 2009 Pension Regulatory Asset, and Interest on Income Tax Deficiency over the Term of this Agreement. PEF will be authorized to make a new specific adjustment to its common equity balance and rate base working capital balance for the purposes of calculation of rate base and the capitalization ratios used for surveillance reporting pursuant to Rule 25-6.1352, F.A.C., and pass-through clauses. The calculation of this adjustment will be based on the methodology employed by Standard and Poor's Ratings Service ("S&P") in its determination of imputed off balance sheet obligations related to future capacity payments to qualifying facilities and other entities under long-term purchase power agreements. The amount of the adjustment to common equity and rate base will fluctuate over time with changes in the amount of future purchase power obligations. The Parties agree that the common equity and rate base adjustment set forth in this paragraph is unique to the specific circumstances of

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PEF, as it relates to this Agreement, and the treatment of PEF's common equity and rate base in this paragraph shall not constitute binding Commission precedent or create a presumption of correctness as to the adjustment for future ratemaking in any future proceeding involving PEF or any other utility. Moreover, this adjustment and the Parties' agreement to such adjustment in this unique proceeding shall be without prejudice to any Party's ability to advocate a different position in future proceedings not involving this Agreement. This adjustment shall not be taken into account for purposes of calculating interim rates or determining whether PEF can seek a base rate adjustment pursuant to paragraph 20 of this Agreement.

17. All other cost of service and rate design issues will be determined in accordance with Exhibit 1 to this Agreement.

18. PEF will have the discretion to record a retail jurisdictional annual credit to depreciation expense, with any reduction in depreciation expense recorded as a cost of removal regulatory asset pursuant to a FERC accounting order received by the Company in 2011. This reduction in depreciation expense will be limited by any remaining balance of the cost of removal reserve throughout the Term. PEF shall not be permitted to use cost of removal if the use would cause the Company to exceed the high point of the ROE range established in this Agreement, i.e., 11.5% or 11.7%, as applicable. These credit amounts to depreciation expense are in lieu of the annual amortization of any theoretical depreciation reserve surplus approved in PEF's previous base rate order PSC-10-0131-FOF-EI. The cost of removal regulatory asset will be recovered commencing on the earlier of the Company's next filed base rate proceeding or upon completion and approval by this Commission of the Company's next

depreciation study. Any recovery period of this regulatory asset will be no longer than the average remaining service life of the assets, approved in Company's most recent depreciation study. PEF agrees to file a Depreciation Study, Fossil Dismantlement Study or Nuclear Decommissioning Study on or before July 31, 2017.

19. No Party to this Agreement will request, support, or seek to impose a change to any provision in this Agreement. This Agreement, and the attached exhibits and schedules, represent the entire and complete agreement between the parties. The Parties consider each provision to be integral to their respective support for the Agreement in its entirety, and no provision may be changed or altered without the consent of each signatory Party in a written document duly executed by all parties to this Agreement. To the extent a dispute arises among the Parties about the provisions, interpretation, or application of this Agreement, the Parties agree to meet and confer in an effort to resolve the dispute. To the extent that the Parties cannot resolve any dispute, the matter may be submitted to the Commission for resolution. Except as provided in paragraph 20, the Intervenor Parties will neither seek nor support any reduction in PEF's base rates and charges, including limited, interim, or any other rate decreases, that would take effect prior to the first billing cycle for January 2017, except for any such reduction requested by PEF or as otherwise provided for in this Agreement. PEF may not petition for an increase in base rates and charges that would take effect prior to the first billing cycle for January 2017, except as otherwise provided for in this Agreement. Notwithstanding the rate relief mechanism described in paragraph 20, PEF is prohibited from seeking or implementing an interim rate increase

pursuant to Section 366.071, Florida Statutes, until the expiration of the Term of this Agreement.

20. If PEF's retail base rate earnings fall below a 9.5% return on equity (ROE) (9.7% ROE if such earnings reduction occurs after CR3 is returned to commercial operation) as reported on a Commission adjusted or pro-forma basis on a PEF monthly earnings surveillance report during the Term of the Agreement, PEF may petition the Commission to amend its base rates during the Term of this Agreement. Such request by the Company shall be limited to an increase that would achieve a 10.5% ROE (10.7% ROE if CR3 is returned to commercial operation). No Party waives its right to participate in such a proceeding, and such participation will only be limited by the terms of this Agreement. If PEF's retail base rate earnings exceed an 11.5% ROE (11.7% ROE if CR3 is returned to commercial operation) as reported on a Commission adjusted or pro-forma basis on a PEF monthly earnings surveillance report during the Term of the Agreement, any Intervenor Party to this Agreement shall be entitled to petition the Commission for a review of PEF's base rates and charges. Prior to requesting any such relief under this paragraph, PEF must have reflected on its referenced surveillance report any remaining credited depreciation expense (cost of removal) identified in paragraph 18. The Parties to this Agreement are not precluded from participating in any such proceedings. This paragraph shall not be construed to bar or limit PEF from any recovery of costs otherwise contemplated by this Agreement.

21. Nothing shall preclude the Company from requesting the Commission to approve the recovery of the following types of costs:

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a. Costs that are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or

b. Costs which the Legislature or Commission determines are clause recoverable prior to or subsequent to the approval of this Agreement.

c. With respect to storm damage costs caused by a tropical system named by the National Hurricane Center or its successor, nothing in this Agreement shall preclude PEF from petitioning the Commission to seek recovery of costs associated with any storms without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings or level of cost of removal reserve. The Parties agree that recovery from customers for storm damage costs will begin, subject to Commission approval, on an interim basis, sixty days following the filing of a cost recovery petition with the Commission, and subject to true-up pursuant to further proceedings before the Commission, and will be based on a 12-month recovery period. All storm related costs shall be calculated and disposed of pursuant to Rule 25-6.0143, F.A.C., and will be limited to costs resulting from a tropical system named by the National Hurricane Center or its successor, an estimate of incremental costs above the level of storm reserve prior to the storm event, and replenishment of the storm reserve to the level as of the Implementation Date of this Agreement. The Intervenor Parties to this Agreement are not precluded from participating in any such proceedings. The Parties expressly agree that any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the

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Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings or level of cost of removal reserve.

22. The provisions of this Agreement are contingent on approval of this Agreement in its entirety by the Commission. The Parties further agree that they will support this Agreement and will not request or support any order, relief, outcome, or result in express conflict with the terms of this Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this Agreement or the subject matter hereof. No Party will assert in any proceeding before the Commission that this Agreement or any of the terms in the Agreement shall have any precedential value.

23. This Agreement dated as of January 20, 2012 may be executed in counterpart originals, and a facsimile of an original signature shall be deemed an original.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Agreement by their signatures below.

[Remainder of page left intentionally blank]

EXHIBIT A

Florida Power Corporation dba
Progress Energy Florida, Inc.

By_______________

Alex Glenn, Esquire
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Office of Public Counsel

By_______________________

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Charles Rehwinkel, Esquire
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EXHIBIT A

Florida Industrial Power Users Group

By Vicki Gordon Kaufman

Jon C. Moyle, Jr., Esquire
Vicki Gordon Kaufman, Esquire
Keefe Anchors Gordon & Moyle, PA
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White Springs Agricultural Chemicals, Inc.

By ______________________

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EXHIBIT A

Florida Retail Federation

By Robert Scheffel Wright

Robert Scheffel Wright, Esquire
Gardner Law Firm
1300 Thomaswood Drive
Tallahassee, FL 32308

EXHIBIT A

Federal Executive Agencies

By_______________

Capt. Samuel Miller
c/o AFCESA-ULFSC
139 Barnes Drive, Suite 1
Tyndall Afb, FL 32403-5319

NRC Meeting Update and Timeline

Response to NRC Requirements to Address Fukushima

- Seismic update to adopt Central Eastern US (CEUS) model
- License conditions for:
  - Emergency planning – staffing & communications evaluation
  - Severe accident mitigating actions
  - Spent Fuel Pool Instrumentation design upgrade

Mandatory hearing delayed 5-6 months

Contested hearing will not be delayed

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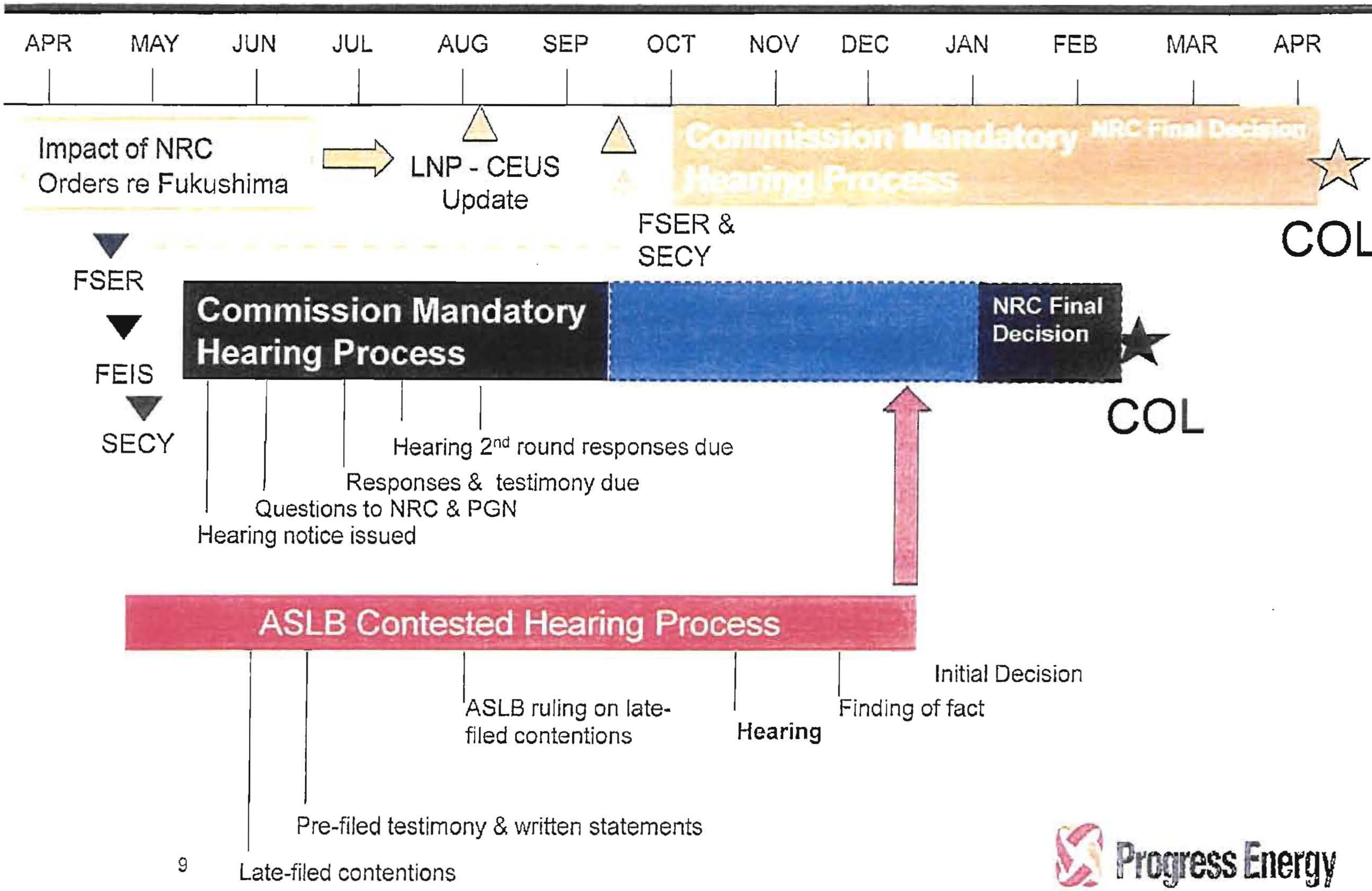
NRC Meeting Update and Timeline

LNP COLA Schedule



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Long Lead Equipment Status/Spend

[redacted]

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