BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

DOCKET NO. 060225-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S
PETITION TO DETERMINE NEED FOR
WEST COUNTY ENERGY CENTER UNITS 1 AND 2
ELECTRICAL POWER PLANT

DIRECT TESTIMONY & EXHIBIT OF:

STEVEN R. SIM

060225-EI

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DOCKET NO _______ - EI

MARCH 13, 2006

Q. Please state your name and business address.

A. My name is Steven R. Sim, and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what position do you hold?

A. I am employed by Florida Power & Light Company (FPL) as a Supervisor in the Resource Assessment & Planning Business Unit.

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

A. I supervise a group that is responsible for determining the magnitude and timing of FPL's resource needs and then developing the integrated resource plan with which FPL will meet those resource needs.

Q. Please describe your education and professional experience.

A. I graduated from the University of Miami (Florida) with a Bachelor's degree in Mathematics in 1973. I subsequently earned a Master's degree in Mathematics from the University of Miami (Florida) in 1975 and a Doctorate in Environmental Science and Engineering from the University of California at Los Angeles (UCLA) in 1979.

While completing my degree program at UCLA, I was also employed full-time as a Research Associate at the Florida Solar Energy Center during 1977 - 1979. My responsibilities at the Florida Solar Energy Center included an evaluation of Florida consumers' experiences with solar water heaters and an analysis of potential renewable resources including photovoltaics, biomass, wind power, etc., applicable in the southeastern United States.

In 1979 I joined FPL. From 1979 until 1991 I worked in various departments including Marketing, Energy Management Research, and Load Management, where my responsibilities concerned the development, monitoring, and cost-effectiveness of demand side management (DSM) programs. In 1991 I joined my current department, then named the System Planning Department, as a Supervisor whose responsibilities included the cost-effectiveness analyses of a variety of individual supply and DSM options. In 1993 I assumed my present position.

Q. **Are you sponsoring an exhibit in this case?**

A. Yes. It consists of the following documents:

SRS-1, Projection of FPL's 2009 - 2011 Capacity Needs;

SRS-2, FPL's Commission-Approved DSM Goals;

SRS-3, Overview of FPL Self-Build Options Evaluated;

SRS-4, Economic Evaluation Results for FPL Self-Build Options;

SRS-5, List of Organizations Submitting Proposals & Proposal Overview;

SRS-6, Proposal Details;

SRS-7, Economic Evaluation Results for Individual Proposals;

SRS-8, Summary of Portfolios Evaluated;

SRS-9, Economic Evaluation Results for Portfolios – Generation System Costs Only;

SRS-10, Economic Evaluation Results for Portfolios – Generation System and Transmission-Related Costs Only;

SRS-11, Calculation of Peak Hour Loss Cost for Portfolio 5 (WCEC 1 and P1);

SRS-12, Calculation of Annual Energy Loss Cost for Portfolio 5 (WCEC 1 and P1);

SRS-13, Economic Evaluation Results for Portfolios - All Costs;

SRS-14, Non-Economic Evaluation Results;

SRS-15, Eligibility Determination Evaluation Results;

SRS-16, Projection of FPL's 2006 – 2011 Capacity Needs with Updated Load Forecast (without New Resource Additions);

SRS-17, Projection of FPL's 2006 – 2011 Capacity Needs with Updated Load Forecast (with Additional DSM and New Near-Term Purchases);

SRS-18, Projection of FPL's 2006 – 2011 Capacity Needs with Updated Load Forecast (with Additional DSM, New Near-Term Purchases, and WCEC 1 and WCEC 2);

SRS-19, Change in FPL System Costs if WCEC 1 is Delayed to 2010 (A 7 Month Delay From June 2009 to January 2010); and,

SRS-20, Change in FPL System Costs if WCEC 1 is Delayed to 2010 (A One Year Delay From June 2009 to June 2010).

Q. Are you sponsoring any sections in the Need Study document?

A. Yes. I am sponsoring Sections IV and VII and co-sponsoring Sections V, VI, and VIII of the Need Study document. I also sponsor Appendices G, M, O, P, and the Confidential Appendices and co-sponsor Appendix C.

Q. What is the scope and purpose of your testimony?

A. My testimony addresses twelve main points. First, I briefly discuss FPL's resource planning process. Second, I identify FPL's additional resource needs for 2009 - 2011 and explain how these needs were determined. Third, I discuss FPL's demand side management (DSM) efforts and why DSM cannot reasonably be expected to eliminate the 2009 - 2011 resource needs. Fourth, I discuss the selection of the "next planned generating unit" presented in FPL's 2005 Request for Proposals (RFP). Fifth, I present the proposals that FPL received in response to the RFP. Sixth, I provide an overview of the processes FPL used to evaluate the RFP proposals and FPL self-build options. Seventh, I present the results of FPL's economic evaluation. Eighth, I present the results of the non-economic evaluation of proposals and portfolios. Ninth, I present the results of the eligibility determination evaluation to determine the proposals' compliance with the RFP's Minimum Requirements. Tenth, I discuss the impacts on FPL's capacity needs of a more recent load forecast than the one used in the RFP process. Eleventh, I discuss the reliability and economic impacts that would occur if the first of the two West County Energy Center units, West County Energy Center Unit 1, is delayed from 2009 to 2010. Twelfth, I summarize the results of the economic, non-economic, and compliance evaluations, plus the implications of the new load forecast. The conclusion I draw from this information is that the construction of FPL's West County Energy Center Unit 1 in 2009, followed by West County Energy Center Unit 2 in 2010, is the best choice in regard to both economic and risk profile perspectives for FPL and its customers to meet the 2009 – 2011 capacity needs.

I. FPL's Resource Planning Process

Q. What is the objective of FPL's resource planning process?

A. FPL's integrated resource planning (IRP) process was developed in the early 1990s and has been used since that time to determine three things: 1) the timing of when new resources are needed, 2) the magnitude (MW) of the needed resources, and 3) the type of resources that should be added. The type of resources that should be added is primarily based on a determination of the resources that result in the lowest average electric rates for FPL's customers. It should be noted that when only power plants or power purchases are the resources in question, the determination can be made on the basis of lowest total costs. The lowest total cost perspective in these cases is the same as the lowest average electric rate perspective, since the number of kilowatt-hours over which the costs are distributed does not change, as would be the case when demand side management resources are being examined.

Q. Please provide an overview of this resource planning process.

A. The IRP process has four main tasks. These four tasks are as follows:

- Task 1: Determine the magnitude and timing of FPL's new resource needs.
- Task 2: Identify the resource options and resource plans that are available to meet the determined magnitude and timing of FPL's resource needs (i.e., identify the available competing options and resource plans).
- Task 3: Determine the economics for the total utility system with each of the eligible competing options and resource plans.
- Task 4: Select a resource plan from which FPL management will commit, as needed, to the nearer-term options.

As previously mentioned, FPL has used this basic resource planning approach for its major resource decisions since the early 1990s.

Q. Was this resource planning approach also used to select FPL's next planned generating unit and to perform the RFP evaluation?

A. Yes. The IRP process outlined above describes the basic approach that FPL takes in its major resource planning efforts. Two examples of such efforts are analyses performed to identify FPL's best self-build option for a particular year and evaluations associated with an RFP.

In the selection of FPL's best self-build options, the four tasks are conducted to determine which self-build option should be selected as the next planned generating unit. Once the timing and magnitude of the 2009-2011 resource needs are determined, FPL's self-build options are evaluated for their ability to meet the need in a cost-effective manner. The self-build options that are cost-effective are then selected as the next planned generating unit.

In regard to the evaluation work for the current RFP, each of the four tasks outlined above was performed. After establishing a set of assumptions to be used in the analyses, FPL first determined the timing and magnitude of its 2009 - 2011 resource needs. Then it determined which resource options, both self-build and RFP proposals, were available to meet those needs and, using the available options, developed competing resource plans or "portfolios" of the available resource options with which to address the resource need. The economics of these competing portfolios were then determined (along with an assessment of associated risks), and a decision was made as to the best portfolio for FPL's customers.

II. FPL's Resource Needs for 2009 - 2011

Q. How did FPL decide it needed additional resources for the 2009 – 2011 time frame, and what was the magnitude of these resource needs?

A. FPL uses two analytical approaches in its reliability analyses to determine the timing and magnitude of its future resource needs. The first approach is to make projections of reserve margins both for Winter and Summer peak hours for future years. A minimum reserve margin criterion of 20 % is used to judge the projected reserve margins. The 20% reserve margin criterion is based on the reliability planning standard FPL committed to maintain and the Commission approved in Order No. PSC-99-2507-S-EU.

The second approach is a Loss-of-Load-Probability (LOLP) evaluation. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to the reserve margin approach, the LOLP approach looks at the daily peak demands for each year, while taking into consideration the probability of individual generators being out of service due to scheduled maintenance or forced outages. LOLP is typically expressed in units of "numbers of times per year" that the system demand could not be served.

FPL's LOLP criterion is a maximum of 0.1 days per year. This LOLP criterion is generally accepted throughout the electric utility industry.

For a number of years now, FPL's projected need for additional resources has been driven by the Summer reserve margin criterion. This again was the case in FPL's reliability analysis that was the basis for FPL's projected 2009 - 2011 resource needs. Significant levels of additional resources (MW) are needed for each of the years 2009, 2010, and 2011 to meet the Summer reserve margin criterion of 20 %.

The additional incremental MW needed by the Summer of 2009 is projected to be 950 MW if the resource is to be provided by a supply side option (i.e., power plant construction or purchase) or, due to the 20 % reserve margin criterion, 792 MW (950 MW/1.20 = 792 MW) if provided by a DSM-based reduction to the forecasted peak load. Similar incremental need values for the Summers of 2010 and 2011, respectively, are 838 MW (supply) or 698 MW (DSM) for 2010 and 583 MW (supply) or 486 MW (DSM) for 2011.

These incremental annual resource need values add to a cumulative need value for 2009 – 2011 of 2,371 MW if the resource need is to be met by supply options. The corresponding cumulative resource need for the three-year period is 1,976 MW if the resource need is to be met by DSM. The projections of resource needs to meet the Summer reserve margin criterion for

2009 - 2011 if the resource needs are to be met by supply options are shown in Document SRS-1. This document also shows that, if these levels of supply additions are added to meet the Summer needs, these additions will also easily satisfy the lower resource needs to meet the Winter reserve margin criterion.

These projections rely upon FPL's IRP 2005 load forecast that was used in designing FPL's 2005 RFP and in the economic evaluation of proposals received in response to the RFP. This load forecast was one of the set of assumptions that were established at the start of the RFP process. This forecast is addressed by Dr. Green in his testimony.

III. Demand Side Management

Q. When did FPL begin its DSM efforts, and how have they progressed over time?

A. FPL has a long history of identifying, developing and implementing DSM resources to avoid or defer the construction of new power plants. FPL first began offering DSM programs in the late 1970s with the introduction of its Watt-Wise Home Program. An increasing number of additional DSM programs were offered throughout the 1980s and 1990s. These programs have included both conservation and load management programs, targeting the residential, commercial, and industrial markets.

FPL's portfolio of DSM programs has evolved over time. FPL continually looks for new DSM opportunities in its research and development activities. When a new DSM opportunity is identified and projected to be cost-effective, FPL attempts either to implement a new DSM program or to incorporate this DSM opportunity into one or more of its existing DSM programs. In addition, FPL has modified DSM programs over time in order to maintain the cost-effectiveness of the programs. This allows FPL to continue to offer the most cost-effective programs available. On occasion, FPL also has terminated DSM programs that were no longer cost-effective and could not be modified to become cost-effective.

Q. **How effective has FPL been in implementing DSM, and what are the resulting impacts of these efforts?**

A. FPL has been very successful in cost-effectively avoiding or deferring new power plant construction using DSM. Since the inception of its programs through the end of 2005, FPL has achieved 3,519 MW (at the generator) of Summer peak demand reduction, 2,734 MW (at the generator) of Winter peak demand reduction, and 33,981 GWh (at the generator) of energy savings. FPL has also completed more than 2,192,795 energy audits of customers' homes and facilities.

This amount of peak demand reduction has eliminated the need for the equivalent of 10 power plants of 400 MW capacity each (after including the impacts for reserve margin requirements). Most importantly, FPL has achieved this level of demand reduction without penalizing customers who are non-participants in its DSM programs. FPL has been able to avoid penalizing non-participating customers by offering only DSM programs that are designed to reduce electric rates for all customers, DSM participants and non-participants alike.

Q. How do FPL's DSM efforts compare to those of other utilities?

A. The U.S. Department of Energy (DOE) reports annually on the effectiveness of utility DSM efforts through its Energy Information Administration. DOE separately measures both conservation and load management. Based on the most current comparative data available, which is for the year 2004, FPL is ranked number one nationally for cumulative conservation achievement and number four in load management.

Q. What are FPL's current DSM goals?

A. Document SRS-2 shows FPL's current DSM goals that were approved by the Commission in Order No. PSC-04-0763-PAA-EG. As shown in this document, FPL's DSM Goals are 802 MW (Summer MW at the meter) through 2014. This determination was made based upon a comprehensive analysis.

Q. Has FPL continued to refine and improve its DSM programs?

A. Yes, FPL continually seeks ways to refine and improve its portfolio of DSM programs through its on-going program monitoring work as well as its research and development activities.

Q. Has FPL continued to look for new DSM opportunities?

A. Yes. As mentioned above, FPL performs extensive DSM research and development. FPL undertakes these activities not only through its Conservation Research and Development Program, but also through individual research projects. These efforts examine a wide variety of technologies, which build on prior FPL research, where applicable, and will expand the research to new and promising technologies as they emerge.

Q. Could FPL have met its resource need for 2009 - 2011 with DSM?

A. No. FPL's 2009 - 2011 resource needs presented in Document SRS-1 already account for all of the reasonably achievable, cost-effective level of DSM for FPL between 2005 and 2011 (532 MW at the meter) as determined in FPL's Commission-approved DSM Goals. In other words, FPL's RFP analysis already captured the cost-effective DSM known to be available on FPL's system based on the IRP 2005 load forecast. This analysis determined that FPL still needs additional capacity resources.

As previously mentioned, if the 2009 - 2011 resource needs were to be met solely by additional new DSM resources, FPL would need to find an <u>additional</u> 1,976 MW of cost-effective DSM to meet these resource needs. It is unrealistic to conclude that FPL could implement sufficient new DSM programs in the next five years (mid-2006 through mid-2011) to meet these needs. Consequently, cost-effective DSM could not meet the 2009 - 2011 resource needs. These needs must be met by capacity (construction and/or purchase) additions.

Later in my testimony I discuss an updated load forecast, including the potential impact of the updated load forecast on the amount of cost-effective DSM.

IV. The Selection of FPL's Next Planned Generating Unit

Q. What power plant self-build options and sites were considered before designating two West County Energy Center combined cycle units as FPL's "next planned generating unit" as prescribed in the Bid Rule?

A. A variety of FPL self-build options and sites were considered prior to identifying two 3x1 combined cycle units at the West County Energy Center (WCEC) site as the best self-build choice for FPL and its customers. The self-build options initially considered included combustion turbine (CT), combined cycle (CC), and solid fuel (i.e., coal) technology options. However, the self-build solid fuel options were effectively eliminated from consideration for meeting the 2009 – 2011 capacity needs since the permitting and construction lead times necessary for these options would not allow these options to come in-service prior to 2012. (However, it should be noted that the RFP was open to the receipt of proposals from existing or otherwise available solid fuel facilities for the 2009 - 2011 period.) Coal options, and the fuel diversity benefits that are derived from these options, remain an important part of FPL's resource planning strategy for the 2012 – 2014 time frame. This fact is discussed in greater detail in the testimonies of Messrs. Silva and Hicks and also mentioned later in my testimony.

In regard to specific sites for FPL's next planned generating unit, a number of sites were considered before the West County 1 and 2 in western Palm Beach County was selected. FPL's last (2004) Determination of Need filing first identified the West County Energy Center site (then called the Corbett site) as one of the top sites for new power plant development and FPL has continued to evaluate this site since that time. Mr. Hicks' testimony provides details of the various prospective sites considered and an explanation of why the West County Energy Center site emerged as the best site.

Returning to the self-build technology choices that could practically be considered for meeting FPL's 2009 – 2011 capacity needs, CT and CC units were the feasible options. Analyses have consistently shown that CC units were better economic choices for FPL's system than are CT units because of

FPL's continued growth in net energy for load. Consequently, FPL's detailed economic analyses of construction options to meet its 2009 – 2011 capacity needs quickly began to focus on different CC technologies and configurations at the West County Energy Center site. Document SRS-3 summarizes the self-build options FPL analyzed in selecting its next planned generating units. As this document shows, FPL analyzed 31 different variations of CC technologies and configurations in its analyses.

Q. Please describe the analytical approach FPL used to determine its best self-build option.

A. Once FPL had determined that CC options were the best choices for meeting its 2009 – 2011 capacity needs, portfolios primarily consisting of combinations of various types of CC options, with similar types of CC units being added in 2009, 2010, and in some cases, 2011, to meet the capacity needs for those years. All of the CC options were assumed to be placed at the West County Energy Center. The portfolios that examined each of these options assumed that advanced coal units would be added in 2012 and 2013, reflecting FPL's plans for adding solid fuel units as soon as those units can be permitted and constructed. In addition, 2x1 CC "filler" units were assumed to be added in the 2014 – on time frame to satisfy FPL's reserve margin requirements for each portfolio for the remaining years of the analysis. The addition of both the advanced coal and filler units throughout the remainder of the analysis period to meet annual reserve margin requirements ensured that the portfolios being evaluated were both comparable and meaningful.

For each portfolio, FPL evaluated the generator capital and O&M costs, transmission interconnection cost, system emission costs, gas pipeline costs, and system fuel costs (i.e., the "generator system" costs) in a multi-year resource plan approach using its Electric Generation Expansion and Analysis System (EGEAS) model. This model was designed by Stone & Webster for the Electric Power Research Institute (EPRI) some years ago, and FPL has used it since its development. The EGEAS model and its results have been used for purposes of evaluations and analyses that have served as the basis for a host of decisions in previous Commission proceedings.

Since all of the capacity options being evaluated for the 2009 – 2011 time frame were assumed to be placed at the same site, the West County Energy Center site, the portfolios were identical in regard to both transmission-related costs (integration, losses, and impacts on the dispatch of FPL existing FPL generating units located in Southeast Florida) and upstream gas system infrastructure costs. Likewise, all of the self-build options were assumed to be constructed with a capital structure of 55% equity/45% debt so there is no impact from any of the self-build options on FPL's target adjusted capital structure of 55 % equity / 45 % debt.

Therefore, there were no differences between these self-build options in regard to costs related to transmission, gas infrastructure, or capital structure. As a result, the EGEAS analyses were able to capture the total cost differences between the portfolios.

Q. Was the analytical approach used to determine FPL's best self-build option similar to the economic evaluation process FPL later utilized to examine proposals received in response to its RFP?

A. Yes. The basic analytical approach used to determine FPL's next planned generating unit is very similar to the approach used later to evaluate the proposals received in response to the RFP and self-build options. Both analytical approaches capture all of the cost differences between the competing options/resource plans. However, in the RFP analyses, the fact that there were different locations and payment structures for the various proposals necessitated analyses of transmission, gas infrastructure, and capital structure impacts, an unnecessary step for the next planned generating unit analyses as discussed above.

Q. Please briefly describe the results of the analyses to determine the best self-build option for FPL.

A. The CC units were categorized by the type of CT used in their design. The CTs are generally classified as 7FA, 7FB, G, and H units. The associated CC units were also classified using these designations. The analyses first identified that CC units based on the 7FA and H combustion turbines were not as economical on FPL's system as were CC units based on the G and 7FB combustion turbines. Consequently, the 7FA and H options were dropped from further analyses and the evaluation focus from that point forward was solely on the G and 7FB options.

These analyses subsequently resulted in identifying the 3x1 Mitsubishi 501G option as the economic choice for FPL's system for the 2009 – 2011 time frame. The final results of these comparative analyses are presented in Document SRS-4. Once the 3x1 Mitsubishi 501G option was designated as the best choice, optimization analyses of various capacity (MW) and heat rate (BTU/kwh) levels for this technology were performed. The outcome of these analyses is the version of the 3x1 Mitsubishi 501G CC unit identified as FPL's next planned generating unit in the RFP and which Mr. Hicks describes in his testimony.

Due to the fact that CC units with steam generators in excess of 75 MW were selected as FPL's self-build options, the Bid Rule is triggered and FPL subsequently issued a Request For Proposal (RFP) as detailed in Mr. Scroggs' testimony.

Q. In its RFP, FPL presented not only a pair of units, one in 2009 and one in 2010, as its next planned generating unit, but also an "alternative generating unit." Why did FPL also present an alternative generating unit of a single 2009 CC in its RFP?

A. As explained in its RFP on page 22, FPL went beyond the requirements of Rule 25-22.082, Florida Administrative Code (the Bid Rule) and presented this alternative generating unit of a single 3x1 Mitsubishi 501G CC unit at West County Energy Center for several reasons. First, the inclusion of this option offers a means of increasing the number of portfolios that could potentially be created that meet FPL's capacity needs for 2009 – 2011. Second, the potential portfolios benefit from the fact that they are paired with a significant amount of generation in Southeast Florida that would help address the load/generation imbalance concern in that region that FPL has discussed in its 2004 and 2005 Site Plans and in the RFP. Third, it provided potential Bidders with a known-in-advance portfolio "pairing partner" for entities considering proposals that could only partially meet the 2009 - 2011 capacity needs.

V. Proposals Received in Response to the RFP

Q. Please provide a general description of the proposals that FPL received in response to the RFP.

A. FPL received 5 proposals from 3 organizations. A listing of the organizations (Bidders) that submitted proposals is presented in Document SRS-5. This document also lists the types of proposals submitted and whether the proposals were based on a new or existing generating source. Four of the proposals were purchased power offerings and one was a proposed sale of existing generating capacity. Three proposals were natural gas-based (with one being CC-based and two being CT-based) and two proposals were based on sales from an existing utility system. More detailed information regarding the proposals is presented in Document SRS-6. As this document indicates, one of the proposals, P5, was eventually withdrawn by the Bidder after the evaluation process was underway. The rest of my testimony will generally refer to only the four proposals remaining after the withdrawal of proposal P5.

Q. Did all of the proposals clearly provide the information FPL requested for its evaluations and meet the RFP Minimum Requirements, so that FPL could immediately begin its evaluations?

A. No. FPL and the independent evaluator, Sedway Consulting, reviewed all proposals received on the Proposal Due Date of November 9, 2005. Questions regarding whether or not RFP Minimum Requirements had been met were immediately raised for several proposals during this initial review. In addition, certain information requested on the RFP forms was either omitted or needed clarification. Issues regarding omitted or confusing information were brought to the Bidders' attention and most were resolved relatively quickly.

However, issues regarding whether proposals complied with the RFP Minimum Requirements were not resolved as quickly. As is discussed later in my testimony, one of the four remaining proposals ultimately did not comply with the RFP Minimum Requirements after FPL's efforts to seek clarification.

VI. Overview of the RFP Evaluation

Q. How did FPL conduct the RFP evaluation work to determine the best options with which to meet its 2009 – 2011 capacity needs?

A. The evaluation methodology described in Appendix E of the RFP was utilized in FPL's RFP evaluation work. This evaluation methodology is described in the RFP as consisting of 8 steps. In practice, a number of these steps are being conducted simultaneously. Therefore, in an effort to simplify the explanation of the evaluation process and its results, my discussion will condense the first 7 steps described in the RFP into 3 general types of evaluation: economic (that encompasses RFP steps 2 through 6), non-economic (RFP step 7), and eligibility determination (RFP step 1). These three general evaluation types will be discussed separately. (Note that the 8th step in the RFP evaluation description is a compilation and comparison of the results from the previous 7 steps.)

The first type of evaluation addresses the economic evaluation of both individual options and combinations of options to determine the most economical way to meet FPL's capacity needs. The second and third evaluation types are essentially designed to evaluate different elements of risk associated with the various options that are not captured in the economic evaluation. The second evaluation type is a non-economic evaluation that is essentially designed to analyze three different elements of risk. These three elements of risk are: environmental, technical, and project execution. The third type of evaluation is an eligibility determination in which each proposal is analyzed to determine if it met all of the Minimum Requirements set forth in the RFP.

From these three evaluations, FPL sought, and believes it obtained, a comprehensive picture of the options available to it and its customers for meeting the 2009 – 2011 capacity needs.

Q. Please describe how the RFP's economic evaluations were performed.

A. FPL conducted its own evaluation of all of the proposals received in response to the RFP, FPL's next planned generating units, West County Energy Center

1 and West County Energy Center 2 (WCEC 1 and WCEC 2), and the alternative generating unit (WCEC 1). In addition, independent evaluations of these options were performed by Sedway Consulting. The testimony of Mr. Taylor addresses Sedway Consulting's analyses; in my testimony I will focus on FPL's evaluations.

As previously discussed, FPL's economic evaluation approach for the RFP analysis is essentially the same as the IRP analysis process and the analysis approach used to determine FPL's best self-build option. The economic evaluation approach creates multi-year resource plans that not only meet FPL's capacity needs for the "decision years" in question (2009 – 2011) for the RFP work, but also meet FPL's capacity needs for the remainder of the study period; through 2037. As was the case in the analyses performed to identify FPL's best self-build option, the RFP analyses assumed that each portfolio evaluated had one advanced coal unit in 2012 and another in 2013, followed by 2x1 "filler" CC units to meet annual reserve margin requirements, thus ensuring that the portfolios being evaluated are both comparable and meaningful.

The economic evaluation began without regard to whether the proposal met all of the RFP's Minimum Requirements. As previously mentioned, there were questions regarding whether certain proposals met all of the Minimum Requirements when the proposals were opened. For these proposals, inquiries were made to their submitters in an attempt to achieve clarification. In order to avoid delays in the economic evaluation, and to give the Bidders ample opportunity to adjust their proposals as needed to meet the Minimum Requirements, the economic evaluations were initiated for all proposals.

The RFP economic evaluation can be described as having four basic parts that can be summarized as follows:

Part 1: Individual Proposal Evaluation:

Economic evaluations of individual proposals are carried out using the EGEAS model. In the evaluation, an individual proposal, proposal P1 for example, is assumed to come in-service on its proposed in-service date; (in either 2009 or 2010 for all of the proposals received). In addition, the two previously mentioned advanced coal units are assumed to come in-service in 2012 and 2013. Then FPL's annual capacity needs for 2009 – 2037 that have not been met by the proposal and the two advanced coal units are met by adding 2x1 CC "filler" units. The total cost in cumulative present value of revenue requirements (CPVRR) of this resource plan is calculated and noted. Then proposal P1 is removed from the resource plan and P2 is substituted. The needed number and timing of the filler units is again determined and the CPVRR cost for this resource plan is calculated and noted. This process is continued until each proposal has been evaluated in the same manner.

The objective of the individual proposal evaluation is to determine the relative economics of each proposal on the FPL system. The results may, and in this case were, used to eliminate more expensive proposals that do not have other redeeming attributes that might otherwise justify retaining them in the on-going analyses.

Part 2: Developing Portfolios of Options

The individual proposals that remain after the individual proposal evaluations, plus the next planned generating units and the alternative generating unit, were then combined by the EGEAS model into portfolios that meet FPL's 2009 – 2011 capacity needs. Each portfolio includes the 2012 and 2013 advanced coal units plus the appropriate number of filler units from 2014 through 2037 to satisfy the annual reserve margin requirements.

Part 3: Separate Evaluations of the Portfolios:

Six separate evaluations of each portfolio were performed (with a number of the evaluations being carried out in parallel):

a) The following fixed costs were calculated for each portfolio:

- capital and capacity payment costs;
- fixed O&M and capital replacement costs;
- transmission interconnection costs; and,
- firm gas transportation and gas pipeline lateral costs.

These costs were calculated by FPL using an FPL spreadsheet model, the Fixed Cost Spreadsheet Model, which consists of a series of linked spreadsheets designed for this purpose.

b) The following variable costs were calculated for each portfolio:

- individual option and FPL system fuel/energy costs;
- variable O&M costs;
- FPL system emission costs; and,
- impacts on the dispatch of existing FPL generating units in Southeast Florida.

These costs were calculated by FPL using the P-MArea production costing model. This model is a detailed, hourly production costing model that FPL utilizes and the Commission has accepted for use in Fuel Cost Recovery filings and other production cost-related analyses.

c) The following transmission-related costs and impacts were calculated for each portfolio:

- transmission integration costs;
- peak hour losses (MW) and average load losses (MW); and,
- transmission transfer limits between Southeast Florida and the rest of the FPL system.

These costs and impacts were calculated under the direction and supervision of Roger Clayton, an independent transmission planning consultant. Mr. Clayton's testimony details this portion of the economic evaluation.

d) Costs for the projection of the peak hour losses (MW) provided by Mr. Clayton, and for a projection of average energy losses (MWH) that FPL computed from the peak hour losses (MW) and average load losses (MW) provided by Mr. Clayton, were calculated for each portfolio. These costs were calculated by FPL using spreadsheets presented both in the RFP and later in my testimony.

e) Upstream gas system costs were evaluated for each portfolio. These costs were evaluated by FPL.

f) Net equity adjustment costs were calculated for each portfolio based upon the equity adjustment calculation and a calculation of offsetting mitigating factor values. Both aspects of the net equity adjustment calculation were performed by FPL using spreadsheets and calculation methodologies described in the RFP (and presented in this filing in Confidential Appendix C-5).

Part 4: Combining the results of the separate evaluations carried out in Step 3. The six different types of costs developed in Part 3 were then combined. The resulting sum of these costs provides a total economic picture for each portfolio.

This basic four part approach was used throughout the economic evaluation work. This work included evaluations of two "types" of assumptions: an "As Bid" set of assumptions and a "Realistic" set of assumptions.

Q. Please explain the difference in these two types of assumptions and why two types of assumptions were needed.

A. The first "type" of assumption, which FPL has dubbed the "As Bid" assumptions, almost exclusively used the assumptions that had been supplied by the Bidders for each proposal as inputs to the evaluation. On occasion, FPL substituted its own assumption if it was to the economic advantage of the proposal/portfolio. An example of this is that the evaluators substituted the lower commodity and firm gas transportation costs for Gulfstream gas for portfolios containing WCEC 1 and proposal P1 instead of using proposal P1's assumption of FGT gas.

In using the As Bid assumptions, FPL and Sedway Consulting chose to disregard, at this time, proposal input that was not of the type or quality that the RFP requested. An example of this is that although the RFP requested that each proposal provide a Guaranteed Heat Rate that represented an average heat rate over the life of the proposal, proposal P1 provided a heat rate that was not guaranteed and, instead of being an average heat rate, was a "new and clean" heat rate for the entire term of the proposed contract (i.e., a heat rate that was better than an average heat rate). In the evaluations using the "As Bid" assumptions, FPL and Sedway Consulting used the "new and clean" heat rate that was supplied for the duration of the analysis period.

During much of the As Bid evaluation work, discussions took place between FPL and the Bidders to obtain the desired information (as in the P1 heat rate example) or sought clarification regarding the Bidder's desired interpretation of the supplied data. Many of these questions were answered during the As Bid assumption evaluation work.

After FPL had received clarification from the Bidders, another review of the assumptions was made and it was determined that changes in some of the assumptions were needed in order to create a more realistic set of assumptions for the final economic evaluation. These "Realistic" assumption changes included the following:

- changing proposal P1's "new and clean" heat rate to a representative average heat rate value for analysis purposes;
- changing the higher gas price forecast assumed in proposal P4's calculation of energy prices to lower gas prices consistent with

FPL's fuel cost forecast being used for the economic evaluation; and,

- adding a capital cost component ($16 million nominal in 2010) to Portfolios 4 and 5 to provide a more realistic total cost picture for FPL's earlier assumption that these portfolios could make use of the forecasted lower priced Gulfstream natural gas, commodity and firm gas transportation costs, for portfolios containing both WCEC 1 and proposal P1 instead of assuming that P1 would be supplied by FGT gas as stated in the proposal. This cost was captured in the generation system costs.

The results of the economic evaluation performed with these more realistic assumptions are the more meaningful evaluation results and, therefore, constitute FPL's final evaluation results that are presented in this testimony.

Q. How significant were the differences in the results of the economic evaluations performed with the Realistic assumptions from those with the As Bid assumptions?

A. In regard to determining what options were the economic choices with which to meet FPL's 2009 – 2011 capacity needs, the differences in the evaluation results were not significant. Neither the rankings of the individual bids nor the rankings of the portfolios changed when FPL and Sedway Consulting switched from the As Bid assumptions to the Realistic assumptions. In regard to the most important results, the economic differences between the portfolios, the use of realistic assumptions lowered the cost difference between the best portfolio and the next best portfolio by approximately $1 million CPVRR while the cost differences between the best portfolio and the remaining portfolios increased by $61 million CPVRR.

Q. You mentioned above that "resource plans" containing the portfolios were evaluated. Why is it appropriate to perform the economic evaluations based on multi-year resource plan costs?

A. It is not only appropriate to do this, but also necessary if one is to capture and fairly compare all of the impacts the various options or portfolios designed to address FPL's capacity needs for a specific time period (in this case, for 2009 - 2011) will have on FPL's system, and the resulting costs to be incurred by FPL's customers, over a longer time period. A multi-year resource plan is designed to address FPL's capacity needs in years after the 2009 - 2011 option or portfolio is placed in-service to capture the option's or portfolio's cost and impacts on FPL's system in later years.

For example, assume we are comparing Option A and Option B that both offer the same amount of capacity. Option A has a heat rate of 7,000 Btu/kWh and is offered to FPL for 15 years while Option B has an 8,000 Btu/kWh heat rate and is offered for 20 years. Evaluating these options from an expansion plan perspective allows one to capture the economic impacts of both the heat rate and term-of-service differences. The lower heat rate of Option A will allow it to be dispatched more than Option B, thus reducing the run time of FPL's existing units more than will Option B. This results in greater production cost savings for Option A. However, Option B's longer term-of-service means that it defers the need for future generation for a longer period. Therefore, Option B will get capacity avoidance benefits for more years.

Only by taking a multi-year resource plan approach to the evaluation can factors such as these be captured and effectively compared. In the RFP economic evaluation, the resource plans created addressed the FPL system through the year 2037.

Q. Why are "filler" units needed in a resource plan evaluation?

A. The "filler" units are needed in a multi-year resource plan analysis as a proxy resource added to meet FPL's capacity needs for 2014 – on (i.e., after the advanced coal units in 2012 and 2013 have been added). In this way the resource plans being compared all meet FPL's reliability criteria for each year in the analysis period, ensuring both that the portfolios are comparable and that the results of the evaluation are meaningful.

Q. Please explain the second type of RFP evaluation that was performed, the non-economic evaluation?

A. As previously mentioned, the non-economic evaluation is a form of risk assessment. This evaluation focused on three aspects of risk: environmental, technical, and project execution. These three aspects of risk were evaluated both for individual options and for the portfolios. Representatives from FPL's Environmental, Power Generation, and Resource Assessment & Planning departments/business units (who had not participated in either the development or the selection of FPL's next planned generating units) performed these evaluations. These assessments evaluated the individual proposals in comparison with each other, and in comparison with the next planned generating units/alternative generating unit, to judge the relative risks of the individual proposals. Once the individual proposal risk assessment evaluations were completed, FPL examined the portfolios comprised of these individual options and assessed the overall risk associated with each portfolio.

Q. Please describe the third type of RFP evaluation that was conducted.

A. FPL also determined the eligibility of the individual proposals to ensure that they were properly submitted and complied with all of the Minimum Requirements listed in the RFP. This "eligibility" or compliance evaluation was on-going while the economic evaluation work took place. In an effort to clarify the positions that were being taken by various Bidders, correspondence was exchanged and other discussions took place between FPL and the Bidders for some time after the proposals were received. After these communications had taken place, each proposal was evaluated to determine if all of the RFP Minimum Requirements had been met.

VII. The Results of the RFP Economic Evaluation

Q. What were the results of Part 1 of the economic evaluation in which the individual proposals were examined for their economic competitiveness on the FPL system?

A. The results of the economic evaluation of the individual proposals are presented in Document SRS-7. As shown on this document, the basic impact of each proposal on FPL's "generation system" costs (including capital, capacity payments, fixed O&M, variable O&M, capital replacement, option & system fuel/energy, transmission interconnection, system emissions, and gas pipeline lateral costs) was determined. In addition, the net equity adjustment costs were also included in this analysis. Other costs such as transmission integration and losses costs, plus upstream gas pipeline costs, are heavily dependent upon how capacity options are combined to form portfolios. Consequently, attempting to calculate these cost categories for individual proposals would not yield meaningful results at this stage of the evaluation so these calculations were not made in Part 1.

Two basic results emerged from this evaluation. First, P1 was clearly the most economically competitive proposal since it was at least $195 million CPVRR less expensive than the next best proposal, P4. Second, the next best proposal P4 was more economical by at least $41 million CPVRR than either of the remaining proposals P2 or P3.

Q. Please describe how the portfolios were created in Part 2 of the economic evaluation.

A. FPL and Sedway Consulting compared the results of their separate analyses of the individual proposals and found that their rankings of the individual proposal were identical. After considering that P2 and P3 not only were the most expensive proposals, but that these two CT-based proposals did not offer any mitigating attributes (such as fuel diversity benefits), it was mutually decided to not carry P2 and P3 forward into the rest of FPL's economic evaluation. (However, Sedway Consulting did evaluate these two proposals further as part of its sensitivity analyses.)

The remaining proposals, P1, P4, and P5 were carried forward in order to develop portfolios. (Note that at the time that Part 2 of the economic evaluation was completed, proposal P5 had not yet been withdrawn by the Bidder.) Portfolios were created that consisted of combinations of these options and the alternative generating unit to meet the 2009 – 2011 capacity needs, plus advanced coal units in 2012 and 2013 followed by 2x1 CC filler units from 2014 through 2037 to meet FPL's capacity needs for all years addressed in the analyses.

Document SRS-8 presents the 6 portfolios that were created and designated as Portfolios 1 through 6. After the portfolio economic evaluation was underway, proposal P5 was withdrawn which eliminated the two portfolios, Portfolios 3 and 6, that had included P5. The remaining four portfolios continued to be evaluated (without changing the numbering of the portfolios).

An examination of the remaining 4 portfolios shows that there are two basic types of portfolios: one type consisting on WCEC 1 and WCEC 2, with or without the 50 MW system sale offered in proposal P4 (i.e., Portfolios 1 and 2); and the other type consisting of WCEC 1 and proposal P1, with or without proposal P4 (i.e., Portfolios 4 and 5). Thus all portfolios contain WCEC 1 in 2009 which essentially answered the question of what option should be selected for 2009.

Two basic questions remained to be answered by the portfolio evaluation that would follow: (1) "Is WCEC 2 or P1 a more economic choice in 2010 to follow WCEC 1 in 2009"? , and (2) "Does the inclusion of P4 in 2009 offer economic advantages to a portfolio"?

Q. Did the portfolio evaluation in Part 3 of the RFP economic evaluation definitely answer these two questions?

A. Yes. The answers to these two questions emerged as the six separate evaluations that make up this part of the economic evaluation began to produce results. The first and second evaluations produced the generation system fixed and variable costs and Document SRS-9 presents those results. This document shows that Portfolio 2 (WCEC 1 and WCEC 2) had a truly significant cost advantage of at least $567 million CPVRR over Portfolios 4 and 5 consisting of WCEC 1 and P1, with and without P4. In addition, Portfolio 2 also had a $15 million CPVRR cost advantage over Portfolio 1 (WCEC 1, P4, and WCEC 2).

Q. How did the results change after the inclusion of the transmission-related costs?

A. These results are presented in Document SRS-10. The inclusion of the transmission-related costs basically increased the cost advantage of Portfolio 2 (WCEC 1 and WCEC 2). This portfolio's cost advantage over Portfolios 4 and 5 increased to at least $641 million CPVRR. The cost advantage of Portfolio 2 over Portfolio 1 also increased to $22 million CPVRR.

Q. You mentioned earlier that FPL assigned costs to peak hour losses (MW) and annual energy (MWH) losses for each portfolio. How did FPL develop the costs that were assigned?

A. As discussed on page E-30 of Appendix E of FPL's RFP, FPL assigned an initial proxy purchase cost of $5/kw-month, with an annually escalation rate of 2%, to the peak hour losses. In assigning costs to annual energy losses, FPL first had to convert the peak hour losses (MW) and the average load losses (MW) provided by Mr. Clayton into annual energy losses (MWH) for all years in the analysis period.

The peak hour loss (MW) value for each portfolio was multiplied by 876 hours (FPL assumed 10 % of the annual hours were on-peak) to obtain a peak hour energy loss (MWH). This value was multiplied by an on-peak marginal energy cost to obtain an on-peak energy loss cost. The average load loss (MW) value was multiplied by the 6,570 annual hours (to reflect the fact that the portfolios predominately consisted of baseload options) to derive an off-peak energy loss (MWH). This value was multiplied by an off-peak marginal energy cost to obtain an off-peak energy loss cost. FPL used the fuel cost forecast supplied to prospective Bidders to develop marginal fuel costs for both peak hours and off-peak hours.

The on-peak and off-peak annual energy loss costs were then summed to derive a total annual energy loss cost. Document SRS-11 and Document SRS-

12, respectively, present the calculations of costs for the peak hour capacity losses and annual energy losses for one of the portfolios (Portfolio 5 consisting of WCEC 1 and proposal P1) to demonstrate how the calculation methodology was applied to all portfolios relative to Portfolio 2. The proxy purchase and marginal energy cost values shown for this portfolio were used in evaluating the cost of losses for all portfolios.

Q. Documents SRS-9 and SRS-10 show that two cost components remain to be factored in: upstream gas pipeline costs and the net equity adjustment. How did the picture change when these two remaining cost components were added?

A. In regard to upstream gas pipeline costs, FPL concluded that none of the four portfolios would incur additional gas pipeline costs that were "upstream" of the proposed capacity sites. Consequently, a zero cost was assigned to all portfolios for this cost component.

In regard to the net equity adjustment, three of the four portfolios resulted in the need for an equity adjustment because these portfolios contained one or more power purchase options with a proposed term-of-service of more than 3 years. (The impact on FPL's capital structure for the fourth portfolio, Portfolio 2 consisting of WCEC 1 and WCEC 2, was already captured by assuming an incremental 55 % equity / 45 % debt investment for the new units.) Consequently, a net equity adjustment value, derived by calculating an equity adjustment less mitigating factor values, was computed for each of these three other portfolios. The calculations of the net equity adjustment value for each of these three portfolios are presented in Confidential Appendix C-5 of the Need Study.

The results of including these upstream gas pipeline and net equity adjustment costs are presented on Document SRS-13. The inclusion of these additional costs increased the cost advantage of Portfolio 2 (WCEC 1 and WCEC 2) to at least $758 million CPVRR over Portfolios 4 and 5. The cost advantage of Portfolio 2 over Portfolio 1 (WCEC 1, P4, and WCEC 2) also increased to $24 million CPVRR.

Q. How were the net equity adjustment costs calculated?

A. The two components of the net equity adjustment, the equity adjustment and mitigating factor values, were calculated following the process and using the formulae presented in Section E.3 of FPL's RFP.

In regard to the equity adjustment calculation, the methodology was presented on pages E-39 and E-40 of the RFP document. On those pages, the equity adjustment value for a hypothetical purchase of 500 MW with a constant $7/kw-month capacity payment was calculated. In evaluating the proposals received in response to the RFP, FPL input the proposed capacity amount and annual capacity payments into the spreadsheet to develop the equity adjustment value for each proposal.

The mitigating factor methodology was explained in detail on pages E-35 through E-38 of the RFP document. In addition, a calculation of the mitigating factor values was also presented on pages E-40 and E-41 of the RFP document using the same hypothetical purchase of 500 MW used in the equity adjustment example calculation.

In evaluating the proposals received in response to the RFP, FPL entered the proposed capacity amount into the calculation methodology outlined in the RFP to develop the total mitigation factor value for each proposal. This total mitigation factor value was then subtracted from the equity adjustment value to derive a net equity adjustment value for each proposal. As previously mentioned, the results of the equity adjustment and mitigating factor calculations for each proposal and each portfolio are presented in Confidential Appendix C-5.

Q. The Bid Rule allows FPL to change its cost estimate during the RFP as long as the remaining Bidders are given the opportunity to revise their proposals. Did FPL change the cost estimate for its next planned generating units or alternative generating unit at any time during the RFP?

A. No.

Q. How did the results shown in Document SRS-13 answer the two questions previously discussed?

A. In regard to the first question ("Is WCEC 2 or P1 a better choice in 2010 to follow WCEC 1 in 2009"?), the results shown in Document SRS-13 clearly indicate that the addition of WCEC 2 in 2010 is overwhelmingly superior economically to the addition of proposal P1 in 2010. The cost advantage is at least $758 million CPVRR.

In regard to the second question ("Does the inclusion of P4 in 2009 offer economic advantages to a portfolio"?), the results presented in Document SRS-13 show that the addition of proposal P4 to Portfolio 2 would increase costs by $24 million CPVRR. (A similar cost increase is seen when comparing Portfolio 4 (WCEC 1, P4, and P1) versus Portfolio 5 (WCEC 1 and P1).

Q. What conclusions did FPL draw from the economic analyses?

A. Two basic conclusions were drawn. First, the addition of Portfolio 2 (WCEC 1 in 2009 and WCEC 2 in 2010) is economically superior to its main competitor Portfolio 5 (WCEC 1 in 2009 and P1 in 2010) by the overwhelming margin of at least $758 million CPVRR. Second, the inclusion of proposal P4 to a portfolio consisting solely of WCEC 1 & WCEC 2 increases costs by $24 million CPVRR.

Therefore, the selection of WCEC 1 in 2009 and WCEC 2 in 2010 is clearly the economic choice.

VIII. Results of the RFP Non-Economic Evaluation

Q. What were the results of the non-economic evaluation of risk elements?

A. The results of the non-economic evaluation are presented on Document SRS-14. These results for the individual proposal evaluation can be summarized in two statements. First, Proposals P2 and P4 were judged to be satisfactory in regard to all 3 evaluation categories. Second (and conversely), Proposals P1 and P3 were judged to present unsatisfactory levels of risk in regard to the Project Execution category due to significant exceptions both proposals took to the RFP's Draft Power Purchase Agreement. (However, an unsatisfactory rating in this non-economic evaluation did not affect the eligibility of a proposal. The eligibility determination evaluation solely addressed proposal eligibility.)

Proposal P3 had been dropped from FPL's economic evaluation after the economic evaluation of the individual proposals had been completed. Consequently, none of four portfolios that were carried through the rest of the economic evaluation included P3. Therefore, the result that P3 carried an unsatisfactory level of risk did not affect any portfolios.

However, proposal P1 is included in two of the four portfolios, Portfolio 4 and Portfolio 5. Since P1's capacity (1,050 MW for 25 years) comprises such an integral part of these portfolios, the fact that the proposal itself has an unsatisfactory level of risk also results in these two portfolios having an unacceptable level of risk.

IX. Results of the RFP Eligibility Determination Evaluation

Q. What were the results of the eligibility determination evaluation?

A. These results, similar to those described above for the non-economic evaluation, are presented in Document SRS-15. Proposals P2 and P4 met all of the RFP Minimum Requirements. Conversely, Proposal P1 did not meet all of the Minimum Requirements and it is questionable if proposal P3 met them.

As a result, proposal P1 again is found to have an unacceptable level of risk and proposal P3's risk profile was not enhanced by this review of compliance with the RFP Minimum Requirements.

IX. Updated Load Forecast

Q. Has FPL's load forecast changed since the assumptions were established at the start of the RFP process?

A. Yes. As discussed in greater detail in Dr. Green's testimony, FPL updated its load forecast in mid-November 2005 as part of its normal, ongoing resource planning process. This new forecast projected significantly higher peak loads, but showed little change in projected annual energy consumption levels compared to the "original" load forecast used in the RFP economic evaluation.

Q. What is the resource planning impact of the more recent load forecast?

A. The impact on FPL's projected capacity needs is presented in Document SRS-16. Document SRS-16 is essentially identical to Document SRS-1 except that the values presented in Column (4) have been changed to show the more recent load forecast. (There are also a few modifications to existing purchase values presented in Column 2(a) for 2006 and 2007 due to the inclusion of updated information regarding the purchases.)

In comparing the two documents, one can see that FPL's total capacity needs through 2011 have increased from 2,371 MW to 3,512 MW, an increase of 1,141 MW of additional need. One can also see that FPL's first year of capacity need has accelerated from 2009 to 2006.

In order to help meet FPL's capacity needs starting in 2006, FPL has identified several new near-term purchases that are promising as well as a sizeable amount of additional DSM that appears cost-effective to implement. Although not yet finalized, FPL's best current projection of the impact of the new near-term purchases and the additional DSM are presented in Document SRS-17. This document is identical to Document SRS-16 except that two new columns, Column (2b) and Column (5b), have been added to show the respective magnitude and timing of the new purchases and additional DSM. (In addition, there are a few modifications to existing purchase amounts presented in Column 2(a) for 2006 and 2007 due to a combination of updated unit testing results and temporary deratings of firm purchases until the process of securing transmission capacity is completed.)

The addition of the new purchases and additional DSM results in a projected 2009 need of 1,067 MW and a cumulative need of 2,400 MW in 2010. The 2009 unmet need of 1,067 MW is higher by a relatively small amount (117 MW) than the originally projected 950 MW need for 2009 based on the original load forecast as is shown in Document SRS-1. Furthermore, the unmet 2,400 MW cumulative need through 2010 is very similar to the cumulative 2009 – 2011 need of 2,371 MW shown in Document SRS-1, and to the 2,438 MW of capacity offered by WCEC 1 and WCEC 2.

Q. If the new load forecast, new purchases, and additional DSM had been included in your analysis, would there still have been a need for both WCEC 1 and WCEC 2?

A. Yes. As the new capacity needs projection presented in Document SRS-17 indicates, there is a need of 1,067 MW in 2009 and a combined cumulative need of 2,400 MW for 2009 and 2010. The total capacity offered by WCEC 1 and WCEC 2 is 2,438 MW; a good match of generation capacity and capacity need. Document SRS-18 presents the resulting capacity need projection if WCEC 1 and WCEC 2 are placed in-service in mid-2009 and mid-2010, respectively, with the new load forecast, new purchases, and additional DSM. This document is identical to Document SRS-17 except for the addition of a new Column 1(b) that shows the addition of the two WCEC units.

Q. Would the results of the RFP evaluations have changed if the new load forecast had been utilized in the analyses?

A. No. The results of the non-economic and eligibility determination evaluations would not have changed since they are independent of the load forecast used. The use of the new load forecast, with the corresponding additions of new near-term purchases and additional DSM, would not have changed the makeup of the portfolios that would have been created and would likely have had only a negligible impact on the economic evaluation results. Portfolio 2 consisting of WCEC 1 and WCEC 2 would again have emerged as the clearly superior economic choice for meeting the capacity needs of FPL and its customers.

XI. Impacts of Delaying WCEC 1

Q. Would there be adverse consequences if the WCEC 1 unit's in-service date were delayed from 2009 to 2010?

A. Yes. First, FPL's system reliability during 2009 would be significantly reduced if FPL were unable to obtain replacement capacity and FPL would be unable to satisfy the Commission-approved 20% reserve margin requirement. Document SRS-18 shows the projected 2009 Summer reserve margin with the addition of WCEC 1 to be 20.70%, while Document SRS-17 shows the projected 2009 Summer reserve margin without the addition of WCEC 1 to be a substantially lower 15.09%. A decrease in Summer reserve margin from 20.70% to 15.09% would represent a truly significant drop in the level of FPL's system reliability (in addition to representing a failure to maintain the Commission-approved reserve margin criterion). Second, a delay of WCEC 1 would result in a significant increase in costs to FPL's customers both during 2009 and in the long-term.

Q. What would be the cost impact to FPL's customers if WCEC 1 were delayed until 2010 and FPL maintained an equivalent level of reliability?

A. Document SRS-19 shows two perspectives on the cost impacts to FPL's customers if WCEC 1 is delayed 7 months until January 2010. The first perspective is the impact on costs for 2009 only (provided in Nominal dollars). The second perspective is the long term impact on costs from 2009 through 2034 (provided in NPV dollars).

The 2009 Nominal cost impact is summarized in the box on the lower left of the document. It shows that with replacement of the 1,067 MW of capacity to achieve a comparable level of system reliability to what would be achieved if WCEC 1 comes in-service in June 2009, costs to FPL's customers in 2009 would increase by $14.3 million (Nominal). Of course, this assumes that replacement capacity is actually available. The cost for replacement capacity assumed in this analysis, $5/kw-month, is representative of peaking type capacity options identified in the 2005 and recent RFPs, but may not be necessarily representative of what actual market conditions would be in the event that capacity were scarce.

The box on the lower right of the document provides the long term, 2009-2034 NPV cost impact of the 7-month delay. It shows that FPL's customers would incur higher costs of $51.9 million (NPV) if WCEC 1 is delayed 7 months.

Document SRS-20 is similar to Document SRS-19 but examines the cost impacts if WCEC 1 is delayed a full 12 months until June 2010. This longer delay would still result in an increase the costs to FPL's customers in the short term (in 2009 and 2010) of $10.3 million (Nominal). The full year delay would actually increase the long term, 2009-2034 NPV cost impact to FPL's customers. The cost increase would now be $63.1 million (NPV).

Q. Please summarize the conclusions to be drawn from this analysis of the impacts of delaying WCEC 1 to 2010.

A. First, delaying the unit to 2010 creates a significant reduction in FPL system reliability in 2009, resulting in FPL's reserve margin in 2009 being significantly lower than the Commission-approved 20% level. This would require FPL to seek replacement capacity that may not be available or, if available, may be at premium prices higher than what FPL has assumed in this analysis. Second, there are cost increases to FPL's customers both in the short term, $14.3 million (Nominal) with a 7 month delay and $10.3 million (Nominal) with a full year delay, and in the long term, $51.9 million (NPV) with a 7 month delay and $63.1 million (NPV) with a full year delay.

Q. What is the level of costs associated with WCEC 1 that would be recovered through the Generation Base Rate Adjustment (GBRA) provision of FPL's recent rate stipulation?

A. The total non-fuel costs for the first 12 months of operation of WCEC 1 can be extracted from Document SRS-20 and then summed to form a total cost value estimate.

The capital costs are presented in Column (1a), Nominal. The 2009 capital costs for the unit assuming a June 2009 start date are $73.9 million and these costs cover the last 7 months of 2009. The capital costs for all 12 months of 2010 are $122.8 million. Multiplying that number by 5/12 results in a 5-month capital cost of $51.2 million. Therefore, the capital cost for the first 12 months would be $73.9 + $51.2 = $125.1 million.

The rest of the non-fuel costs can be directly extracted from Document SRS-20. The fixed O&M total for the first 12 months of operation is found in Column (3), Nominal to be $3.3 + $2.4 = $5.7 million. Similarly, the capital replacement total of $8.6 million is found in Column (4), Nominal and variable O&M total of $1.3 million is found in Column (5), Nominal.

The sum of these individual 12-month costs for WCEC 1 would be $125.1 (capital) + $5.7 (fixed O&M) + $8.6 (capital replacement) + $1.3 (variable O&M) = $140.7 million.

Q. Would GBRA costs for West County 2 be calculated in the same way?

A. Yes. GBRA costs for West County 2 would be calculated using the same approach. However, the construction cost of West County 2, \$632.4 million, is lower than for West County 1, \$688.6 million, as shown in Mr. Hicks' testimony in his Document No. DNH-10. Second, the fixed O&M cost is also lower for West County 2, \$3.07/kw-year, compared to West County 1, \$4.61/kw-year, as shown in Mr. Hicks' testimony in his Documents DNH-7 and DNH-6, respectively. These lower starting costs for West County 2 compared to West County 1 in two cost categories will be partially offset by an additional year of escalation in all of the non-capital cost categories for West County 2.

Applying a simple ratio of the differences in the capital and fixed O&M starting costs mentioned above between the two units, plus an estimate of one more year of escalation for the non-capital costs would result in a GBRA cost for West County 2 of approximately \$130 million compared to the \$140.7 million value shown above for West County 1.

XII. Summary of Evaluation Results

Q. Would you please summarize the results of the three evaluations; economic, non-economic, and eligibility determination?

A. Yes. The economic evaluation results showed clearly that Portfolio 2 (WCEC 1 in 2009 and WCEC 2 in 2010) is the overwhelming economic choice since it is at least $758 million CPVRR less expensive than a portfolio that did not include both of those units. In addition, the only available option that could be added to WCEC 1 and WCEC 2, proposal P4 in 2009, would have increased costs for Portfolio 2 by $24 million CPVRR.

The non-economic evaluation resulted in proposals P1 and P3 both being found to have unacceptable levels of risk. As a consequence of P1 having such an integral role in Portfolios 4 and 5, these two portfolios are also found to have an unacceptable level of risk.

Similarly, proposal P1 was found in the eligibility determination evaluation not to be in compliance with all of the Minimum Requirements listed in the RFP, thus providing further evidence of unacceptable levels of risk for this proposal.

In summary, the addition of WCEC 1 and WCEC 2 are clearly the best options available with which to meet the capacity needs of 2009 – 2011 for FPL and its customers from both economic and risk profile perspectives.

Q. Please summarize your testimony.

A. FPL's 2005 resource planning work, using a set of assumptions established prior to the start of the RFP evaluations, determined that FPL had a cumulative need for additional resources in 2009 – 2011 of 2,371 MW. In order to meet FPL's Summer reserve margin criterion of 20 % for those years, FPL needs 2,371 MW if the resource need was to be filled by new supply (power plant construction and/or purchase) or 1,976 MW if the resource need was to be filled by new DSM. The magnitude of this additional resource need was much too great to be met by additional cost-effective DSM, so the 2009 - 2011 capacity needs would have to be met by one or more new supply options (construction and/or purchase).

FPL selected as its next planned generating units to meet these capacity needs a pair of combined cycle units sited at the West County Energy Center. Due to the selection of the combined cycle units, the Bid Rule is triggered and FPL issued an RFP for new capacity to meet these 2009 - 2011 capacity needs.

Five proposals from three organizations were received in response to the RFP. Although two of the proposals ultimately did not comply with the RFP

Minimum Requirements, FPL decided to consider all five proposals in its initial economic evaluation work. FPL then utilized the five proposals, its next planned generating units, and its alternative generating unit to develop six portfolios of capacity options that were evaluated. During the course of the evaluation, one of the proposals, P5, was withdrawn by its Bidder. This eliminated two portfolios that had included proposal P5 from further consideration. The remaining four portfolios were carried throughout the remainder of the evaluation.

After FPL's economic evaluation had been completed, FPL's next planned generating units, WCEC 1 in 2009 and WCEC 2 in 2010, emerged as the clear economic choice by being at least $758 million CPVRR less expensive than a portfolio that did not include both of those units. In addition, the only feasible option that could be added to WCEC 1 and WCEC 2, proposal P4 in 2009, would have increased costs by $24 million CPVRR. The results of Sedway Consulting's analyses also clearly showed the WCEC 1 and WCEC 2 additions alone to be the most economical choice.

Therefore, the results of both FPL's and Sedway Consulting's analyses show that the addition of FPL's WCEC 1 unit in 2009 and its WCEC 2 unit in 2010 are the most economical choices for meeting FPL's 2009 – 2011 capacity needs.

Evaluations of the risk components of the various options were carried out. The risk components evaluated included three risk areas (i.e., environmental, technical, and project execution) not addressed in the economic evaluation, plus an eligibility determination of whether proposals met all of the RFP Minimum Requirements. FPL's risk analyses concluded that the most significant proposal received in response to the RFP, in terms of the amount of capacity offered and its corresponding presence in the portfolios (proposal P1), failed to meet RFP Minimum Requirements and also carried an unacceptable level of risk. Consequently, proposal P1 and the two portfolios that include P1 (Portfolio 4 and Portfolio 5), are unacceptable from a risk perspective alone.

An analysis of the impacts of delaying the in-service date of WCEC 1 from June 2009 to January 2010 shows that both from a system reliability perspective and a cost perspective, there would be substantial adverse consequences from delaying WCEC 1.

Therefore, the addition of WCEC 1 and WCEC 2 are clearly the best options available with which to meet the 2009 – 2011 capacity needs of FPL and its customers from both an economic and risk profile perspective.

Q. Does this conclude your testimony?

A. Yes.

Projection of FPL's 2009 - 2011 Capacity Need
(without New Resource Additions)

Summer

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2006	20,919	3,130	24,049	21,178	1,516	19,662	4,387	22.3%	(455)
2007	22,139	2,404	24,543	21,769	1,592	20,177	4,366	21.6%	(331)
2008	22,151	2,626	24,777	22,306	1,674	20,632	4,145	20.1%	(19)
2009	22,151	2,249	24,400	22,884	1,759	21,125	3,275	15.5%	**950**
2010	22,151	1,951	24,102	23,424	1,849	21,575	2,527	11.7%	**1,788**
2011	22,151	1,906	24,057	23,964	1,941	22,023	2,034	9.2%	**2,371**

Winter

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
January of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Winter DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Winter Reserves (MW)	Forecast of Winter Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2006	22,304	3,215	25,519	21,336	1,532	19,804	5,715	28.9%	(1,754)
2007	22,373	3,439	25,812	21,898	1,577	20,321	5,491	27.0%	(1,427)
2008	23,558	2,635	26,193	22,369	1,626	20,743	5,450	26.3%	(1,301)
2009	23,558	2,309	25,867	22,916	1,679	21,237	4,630	21.8%	(383)
2010	23,558	2,008	25,566	23,466	1,736	21,730	3,836	17.7%	**510**
2011	23,558	1,915	25,473	24,035	1,796	22,239	3,234	14.5%	**1,214**

* DSM values shown represent cumulative load management and incremental conservation capability.

FPL's Commission-Approved DSM Goals
(Cumulative Summer MW at meter)

Year	MW
2005	74.0
2006	141.7
2007	211.9
2008	287.2
2009	365.9
2010	447.9
2011	532.1
2012	618.8
2013	707.9
2014	801.7

Overview of FPL Self-Build Options Evaluated

	Technology/Configuration	Range of Summer Capacity (MW)	Number of Variations Evaluated *	Location
(1)	4x1 General Electric 7FA Combined Cycle	1107 to 1123	6	West County Energy Center (Palm Beach County)
(2)	3x1 General Electric 7FA Combined Cycle	830	1	West County Energy Center (Palm Beach County)
(3)	2x1 General Electric 7FA Combined Cycle	528	1	West County Energy Center (Palm Beach County)
(4)	3x1 Siemens Westinghouse 501G Combined Cycle	1066 to 1217	7	West County Energy Center (Palm Beach County)
(5)	3x1 Mitsubishi 501G Combined Cycle	1170 to 1240	10	West County Energy Center (Palm Beach County)
(6)	3x1 General Electric 7H Combined Cycle	369 to 387	4	West County Energy Center (Palm Beach County)
(7)	4x1 General Electric 7FB Combined Cycle	1150 to 1194	2	West County Energy Center (Palm Beach County)
			31	

* Variations refer to different levels of capacity (MW), heat rate (BTU/kwh), different costs, etc. that were evaluated for a technology/configuration.

Economic Evaluation Results for FPL Self-Build Options
(millions, 2005 $, CPVRR)

	Portfolios of Self-Build Options Evaluated			(1)	(2)	(3)	(4)	(5)	(6)	(7) = sum of (1) thru (6)	
					Transmission-Related Costs * *						
Ranking	2009	2010	2011	Generation System Costs *	Integration	Peak Hour Capacity Losses	Annual Energy Losses	Upstream Gas Pipeline Costs * * *	Net Equity Adjustment * * * *	Total	Difference from lowest cost portfolio
1	3x1 Mitsubishi 501G CC	3x1 Mitsubishi 501G CC	---	86,715	0	0	0	0	0	86,715	0
2	3x1 Siemens Westinghouse 501G CC	3x1 Siemens Westinghouse 501G CC	---	86,752	0	0	0	0	0	86,752	37
3	4x1 General Electric 7FB CC	4x1 General Electric 7FB CC	---	86,917	0	0	0	0	0	86,917	202

* Generation system results include: capital, fixed O&M, variable O&M, project fuel/energy cost, FPL system fuel, transmission interconnection, system emissions, and gas pipeline lateral costs.

** There were no differences in any Transmission-related costs (interconnection, integration, losses, or impact of Southeast Florida unit dispatch) or in Gas infrastructure costs since all units are similar in size and are assumed to all be located at the same site, the West County Energy Center.

*** All gas system costs were captured in the Generation System Costs category.

**** The capital costs for all of the self-build options were based on a 55% equity/45% debt capital structure. Therefore there are no capital structure-related cost impacts.

List of Organizations Submitting Proposals & Proposal Overview

(in alphabetical order)

Organization	Number of Proposals Submitted	Type of Proposal(s)	New or Existing Capacity Source
Progress Energy Florida	2	Purchased Power	Existing
Progress Energy Ventures	2	Purchased Power and Sale of Unit	Existing
Southern Power Company	1	Purchased Power	New
	5		

Proposal Details

Proposal Code Number	Capacity Offered (Summer MW)	Technology	Proposed Term-of-Service (Years)
Proposal 1 (P1)	1,050	Combined Cycle (CC)	25
Proposal 2 (P2)	298	Combustion Turbine (CT)	Sale of Unit
Proposal 3 (P3)	298	Combustion Turbine (CT)	15
Proposal 4 (P4)	50	Utility System Sale	5
Proposal 5 (P5) *	50	Utility System Sale	3

	1,398 **		

* Proposal 5 (P5) was eventually withdrawn by the Bidder.

** The capacity amounts offered for P2 and P3 were mutually exclusive as were the capacity amounts offered for P4 and P5.

Exhibit No. ______
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Economic Evaluation Results for Individual Proposals

(millions, CPVRR, 2005$, 2005 - 2037)

(note: assumes all Proposals are eventually declared as "eligible")

Individual Proposal Number	Type of Proposal	Proposal Summer MW	(1) Generation System Costs *	(2) Transmission-Related Costs * * Integration	(3) Transmission-Related Costs * * Peak Hour Capacity Losses	(4) Transmission-Related Costs * * Annual Energy Losses	(5) Upstream Gas Pipeline Costs * * *	(6) Net Equity Adjustment	(7) = sum of (1) thru (6) Total	Difference from Lowest Cost Proposal
P1	25-yr PPA	1,050	106,442	0	0	0	0	117	106,559	0
P2	Sale of Unit	298	106,795	0	0	0	0	0	106,795	236
P3	15-yr PPA	298	106,882	0	0	0	0	12	106,894	335
P4	5-yr PPA	50	106,752	0	0	0	0	2	106,754	195
P5 * * * *	3-yr PPA	50	---	---	---	---	---	---	---	---

* Generation system results include: capital, fixed O&M, variable O&M, project fuel/energy cost, FPL system fuel, transmission interconnection, system emissions, and gas pipeline lateral costs.

* * These transmission-related costs (integration, losses, and impact on dispatch of Southeast Florida units) are not considered in the analysis of individual Proposals.

* * * Upstream gas pipeline costs are also not considered in the analysis of individual Proposals.

* * * * Proposal P5 was eventually withdrawn by the Bidder.

Summary of Portfolios Evaluated

Portfolio Number	Description of Portfolios 2009	2010	2011	Portfolio Capacity (Summer MW) * *
1	WCEC 1 & P4	WCEC 2	---	2,488
2	WCEC 1	WCEC 2	---	2,438
3 *	WCEC 1	WCEC 2	P5	2,488
4	WCEC 1 & P4	P1	---	2,319
5	WCEC 1	P1	---	2,269
6 *	WCEC 1	P1	P5	2,319

* Proposal 5 (P5) was withdrawn by the Bidder after the evaluation process had begun. Consequently, Portfolios 3 and 6 were dropped from the evaluation at that point.

* * All portfolios provide sufficient capacity to enable FPL to exceed a 20.0% reserve margin in 2009 and 2010 and to meet at least a 19.5% reserve margin in 2011.

Economic Evaluation Results for Portfolios - Generation System Costs Only

(millions, CPVRR, 2005$, 2005 - 2037)

(note: assumes all Proposals are eventually declared as "eligible")

					(1)	(2)	(3)	(4)	(5)	(6)	(7) = sum of (1) thru (6)	
						Transmission-Related Costs						
Ranking of Portfolio	Portfolio Number	Description of Portfolios 2009	2010	2011	Generation System Costs *	Integration	Peak Hour Capacity Losses	Annual Energy Losses	Upstream Gas Pipeline Costs	Net Equity Adjustment	Total	Difference from lowest cost portfolio
1	2	WCEC 1	WCEC 2	---	99,640	0	0	0	0	0	99,640	0
2	1	WCEC 1 & P4	WCEC 2	---	99,655	0	0	0	0	0	99,655	15
3	5	WCEC 1	P1	---	100,207	0	0	0	0	0	100,207	567
4	4	WCEC 1 & P4	P1	---	100,218	0	0	0	0	0	100,218	578

* Generation system results include: capital, fixed O&M, variable O&M,capital replacement costs, project fuel/energy cost, FPL system fuel, transmission interconnection, system emissions, and gas pipeline lateral costs.

Economic Evaluation Results for Portfolios - Generation System & Transmission-Related Costs Only

(millions, CPVRR, 2005$, 2005 - 2037)

(note: assumes all Proposals are eventually declared as "eligible")

Description of Portfolios			(1)	(2)	(3)	(4)	(5)	(6)	(7) = sum of (1) thru (6)	
				Transmission-Related Costs						
2009	2010	2011	Generation System Costs *	Integration * *	Peak Hour Capacity Losses * * *	Annual Energy Losses * * *	Upstream Gas Pipeline Costs	Net Equity Adjustment	Total	Difference from lowest cost portfolio
WCEC 1	WCEC 2	---	99,640	0	0	0	0	0	99,640	0
WCEC 1 & P4	WCEC 2	---	99,655	0	1	6	0	0	99,662	22
WCEC 1	P1	---	100,207	0	12	62	0	0	100,281	641
WCEC 1 & P4	P1	---	100,218	0	13	67	0	0	100,298	658

* Generation system results include: capital, fixed O&M, variable O&M,capital replacement costs, project fuel/energy cost, FPL system fuel, transmission interconnection, system emissions, and gas pipeline lateral costs.

** Transmission integration costs for all portfolios were projected to be $0.

*** These transmission-related costs are <u>relative to</u> the costs for Portfolio 2.

Calculation of Peak Hour Loss Cost
for Portfolio 5 (WCEC 1 and P1)

Discount Rate =	0.0837
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	2%

	(1)	(2)	(3)	(4)	(5)
				=(1)*(3)*12	=(2)*(4)
Year	Proxy Purchase Cost ($/kw-mo)	Discount Factor	Peak Load Loss (from Tables E - 1) (MW)	Peak Hour Capacity Loss Cost Nominal ($ 000)	Peak Hour Capacity Loss Cost NPV ($ 000)
2005	$0.00	1.000	0.00	$0	$0
2006	$0.00	0.923	0.00	$0	$0
2007	$0.00	0.851	0.00	$0	$0
2008	$0.00	0.786	0.00	$0	$0
2009	$5.00	0.725	0.00	$0	$0
2010	$5.10	0.669	0.00	$0	$0
2011	$5.20	0.617	0.00	$0	$0
2012	$5.31	0.570	24.00	$1,528	$871
2013	$5.41	0.526	25.00	$1,624	$854
2014	$5.52	0.485	25.00	$1,656	$803
2015	$5.63	0.448	25.00	$1,689	$756
2016	$5.74	0.413	25.00	$1,723	$712
2017	$5.86	0.381	25.00	$1,757	$670
2018	$5.98	0.352	25.00	$1,793	$630
2019	$6.09	0.325	25.00	$1,828	$593
2020	$6.22	0.299	25.00	$1,865	$559
2021	$6.34	0.276	25.00	$1,902	$526
2022	$6.47	0.255	25.00	$1,940	$495
2023	$6.60	0.235	25.00	$1,979	$466
2024	$6.73	0.217	25.00	$2,019	$438
2025	$6.86	0.200	25.00	$2,059	$413
2026	$7.00	0.185	25.00	$2,100	$388
2027	$7.14	0.171	25.00	$2,142	$366
2028	$7.28	0.157	25.00	$2,185	$344
2029	$7.43	0.145	25.00	$2,229	$324
2030	$7.58	0.134	25.00	$2,273	$305
2031	$7.73	0.124	25.00	$2,319	$287
2032	$7.88	0.114	25.00	$2,365	$270
2033	$8.04	0.105	25.00	$2,413	$254
2034	$8.20	0.097	25.00	$2,461	$239
2035	$8.37	0.090	25.00	$2,510	$225
2036	$8.53	0.083	25.00	$2,560	$212
2037	$8.71	0.076	12.75	$1,332	$102
				NPV Total ($000) =	$12,100

[redacted]

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Calculation of Annual Energy Loss Cost for Portfolio 5 (WCEC 1 and P1)

On-Peak Hours =	876	(or 10% of all hours)
Off-Peak Hours =	6,570	
Discount Factor =	0.0837	

	(1)	(2)	(3)	(4)	(5) = (4)*On-Peak Hours	(6) = (1)*(5)/1000	(7)	(8) = (7)*Off-Peak Hours	(9) = (2)*(8)/1000	(10) = (6) + (9)	(11) = (3)*(10)
Year	On-Peak Marginal Energy Cost ($/mwh)	Off-Peak Marginal Energy Cost ($/mwh)	Discount Factor	Peak Load Loss (from Tables E - 1) (MW)	On - Peak Hours Annual Energy Loss (MWH)	On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Average Load Loss (from Tables E - 2) (MW)	Off - Peak Hours Annual Energy Loss (MWH)	Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost NPV ($ 000)
2005	0	0	1.000	0	0	$0	0	0	$0	$0	$0
2006	0	0	0.923	0	0	$0	0	0	$0	$0	$0
2007	0	0	0.851	0	0	$0	0	0	$0	$0	$0
2008	0	0	0.786	0	0	$0	0	0	$0	$0	$0
2009	$81.82	$64.82	0.725	0.00	0	$0	0.00	0	$0	$0	$0
2010	$76.32	$57.39	0.669	24.00	21,024	$1,605	3.00	19,710	$1,131	$2,736	$1,830
2011	$80.45	$59.39	0.617	25.00	21,900	$1,762	11.00	72,270	$4,292	$6,054	$3,738
2012	$83.69	$61.47	0.570	25.00	21,900	$1,833	11.00	72,270	$4,443	$6,275	$3,575
2013	$87.97	$64.02	0.526	25.00	21,900	$1,927	11.00	72,270	$4,627	$6,553	$3,445
2014	$91.25	$65.51	0.485	25.00	21,900	$1,998	11.00	72,270	$4,735	$6,733	$3,266
2015	$95.63	$68.13	0.448	25.00	21,900	$2,094	11.00	72,270	$4,924	$7,018	$3,141
2016	$105.76	$73.13	0.413	25.00	21,900	$2,316	11.00	72,270	$5,285	$7,601	$3,140
2017	$112.21	$76.99	0.381	25.00	21,900	$2,457	11.00	72,270	$5,564	$8,021	$3,057
2018	$122.39	$80.51	0.352	25.00	21,900	$2,680	11.00	72,270	$5,818	$8,499	$2,989
2019	$130.47	$83.78	0.325	25.00	21,900	$2,857	11.00	72,270	$6,055	$8,912	$2,892
2020	$141.86	$88.84	0.299	25.00	21,900	$3,107	11.00	72,270	$6,420	$9,527	$2,853
2021	$143.31	$91.06	0.276	25.00	21,900	$3,139	11.00	72,270	$6,581	$9,720	$2,686
2022	$146.96	$91.81	0.255	25.00	21,900	$3,218	11.00	72,270	$6,635	$9,854	$2,513
2023	$151.43	$93.44	0.235	25.00	21,900	$3,316	11.00	72,270	$6,753	$10,069	$2,369
2024	$156.42	$94.02	0.217	25.00	21,900	$3,426	11.00	72,270	$6,795	$10,221	$2,219
2025	$160.53	$98.27	0.200	25.00	21,900	$3,516	11.00	72,270	$7,102	$10,618	$2,127
2026	$165.15	$99.36	0.185	25.00	21,900	$3,617	11.00	72,270	$7,181	$10,798	$1,996
2027	$166.08	$99.48	0.171	25.00	21,900	$3,637	11.00	72,270	$7,189	$10,827	$1,847
2028	$172.67	$102.08	0.157	25.00	21,900	$3,781	11.00	72,270	$7,377	$11,159	$1,757
2029	$175.45	$103.20	0.145	25.00	21,900	$3,842	11.00	72,270	$7,459	$11,301	$1,642
2030	$180.04	$106.31	0.134	25.00	21,900	$3,943	11.00	72,270	$7,683	$11,626	$1,558
2031	$187.85	$110.13	0.124	25.00	21,900	$4,114	11.00	72,270	$7,959	$12,073	$1,493
2032	$186.96	$109.23	0.114	25.00	21,900	$4,094	11.00	72,270	$7,894	$11,988	$1,368
2033	$198.76	$114.68	0.105	25.00	21,900	$4,353	11.00	72,270	$8,288	$12,641	$1,331
2034	$195.56	$111.16	0.097	25.00	21,900	$4,283	11.00	72,270	$8,034	$12,316	$1,197
2035	$205.89	$116.49	0.090	12.75	11,169	$2,300	8.08	53,086	$6,184	$8,484	$761
2036	$207.39	$119.21	0.083	4.00	3,504	$727	6.00	39,387	$4,696	$5,422	$449
2037	$192.29	$120.79	0.076	4.00	3,504	$674	6.00	39,387	$4,758	$5,431	$415
										NPV Total ($000) =	$61,657

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Economic Evaluation Results for Portfolios - All Costs
(millions, CPVRR, 2005$, 2005 - 2037)
(note: assumes all Proposals are eventually declared as "eligible")

					(1)	(2)	(3)	(4)	(5)	(6)	(7) = sum of (1) thru (6)	
						Transmission-Related Costs						
Ranking of Portfolio	Portfolio Number	Description of Portfolios 2009	2010	2011	Generation System Costs *	Integration * *	Peak Hour Capacity Losses * * *	Annual Energy Losses * * *	Upstream Gas Pipeline Costs * * * *	Net Equity Adjustment	Total	Difference from lowest cost portfolio
1	2	WCEC 1	WCEC 2	---	99,640	0	0	0	0	0	99,640	0
2	1	WCEC 1 & P4	WCEC 2	---	99,655	0	1	6	0	2	99,664	24
3	5	WCEC 1	P1	---	100,207	0	12	62	0	117	100,398	758
4	4	WCEC 1 & P4	P1	---	100,218	0	13	67	0	119	100,417	777

* Generation system results include: capital, fixed O&M, variable O&M,capital replacement costs, project fuel/energy cost, FPL system fuel, transmission interconnection, system emissions, and gas pipeline lateral costs.

* * Transmission integration costs for all portfolios were projected to be $0.

* * * These transmission-related costs are relative to the costs for Portfolio 2.

* * * * Upstream gas pipeline costs for all portfolios were projected to be $0.

Non-Economic Evaluation Results

I. Evaluation of Individual Proposals:

Proposal	Non-Economic Evaluation Categories: Environmental	Technical	Project Execution	Overall Risk
P1	Satisfactory	Satisfactory	Unsatisfactory	Unsatisfactory
P2	Satisfactory	Satisfactory	Satisfactory	Satisfactory
P3	Satisfactory	Satisfactory	Unsatisfactory	Unsatisfactory
P4	Satisfactory	Satisfactory	Satisfactory	Satisfactory

II. Evaluation of Portfolios:

Portfolio Number	Description of Portfolios: 2009	2010	2011	Portfolio Risk
1	WCEC 1 & P4	WCEC 2	---	Acceptable
2	WCEC 1	WCEC 2	---	Acceptable
4	WCEC 1 & P4	P1	---	Unacceptable due to P1 component
5	WCEC 1	P1	---	Unacceptable due to P1 component

Eligibility Determination Evaluation Results

Proposal	Did Proposal Meet All RFP Minimum Requirements ?	Comments
P1	No	Bidder did not provide Guaranteed Heat Rate as required. (Also, exceptions to Min. Requirements taken in Bidder's rewrite of PPA.)
P2	Yes	---
P3	Questionable	Bidder disagreed with Security amount and proposes that existing PPA be used that does not contain several RFP Minimum Requirements.
P4	Yes	---

Projection of FPL's 2009 - 2011 Capacity Need: With Updated Load Forecast (without New Resource Additions)

Summer

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases * (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast * * (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2006	20,919	2,950	23,869	21,916	1,516	20,400	3,469	17.0%	**611**
2007	22,139	2,404	24,543	22,543	1,592	20,951	3,592	17.1%	**598**
2008	22,151	2,626	24,777	23,179	1,674	21,505	3,272	15.2%	**1,029**
2009	22,151	2,249	24,400	23,782	1,759	22,023	2,377	10.8%	**2,028**
2010	22,151	1,951	24,102	24,375	1,849	22,526	1,576	7.0%	**2,929**
2011	22,151	1,906	24,057	24,915	1,941	22,974	1,083	4.7%	**3,512**

Winter

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
January of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases * (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Winter DSM Forecast * * (MW)	Forecast of Firm Peak (MW)	Forecast of Winter Reserves (MW)	Forecast of Winter Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2006	22,304	3,205	25,509	21,792	1,532	20,260	5,249	25.9%	(1,197)
2007	22,373	3,067	25,440	22,294	1,577	20,717	4,723	22.8%	(580)
2008	23,558	2,635	26,193	22,753	1,626	21,127	5,066	24.0%	(841)
2009	23,558	2,309	25,867	23,245	1,679	21,566	4,301	19.9%	**12**
2010	23,558	2,008	25,566	23,714	1,736	21,978	3,588	16.3%	**808**
2011	23,558	1,915	25,473	24,155	1,796	22,359	3,114	13.9%	**1,358**

* Changes from Firm Purchase values shown on Document SRS-1 are due to updated unit testing results and temporary "derating" of total purchase amount until the process of securing transmission capacity is completed.

* * DSM values shown represent cumulative load management and incremental conservation capability.

Projection of FPL's 2009 - 2011 Capacity Need: With Updated Load Forecast (with Additional DSM and New Near-Term Purchases)

Summer

	(1)	(2a)	(2b)	(3) = (1)+(2)	(4)	(5a)	(5b)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projections of New Near-Term Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast * (MW)	Projections of Additional Summer DSM (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res. Margins w/ Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2006	20,919	2,950	457	24,326	21,916	1,516	39	20,361	3,965	19.47%	**107**
2007	22,139	2,404	591	25,134	22,543	1,592	229	20,722	4,412	21.29%	(268)
2008	22,151	2,626	369	25,146	23,179	1,674	289	21,216	3,930	18.52%	**313**
2009	22,151	2,249	590	24,990	23,782	1,759	309	21,714	3,276	15.09%	**1,067**
2010	22,151	1,951	158	24,260	24,375	1,849	309	22,217	2,043	9.20%	**2,400**
2011	22,151	1,906	158	24,215	24,915	1,941	309	22,665	1,550	6.84%	**2,983**

Winter

	(1)	(2a)	(2b)	(3) = (1)+(2)	(4)	(5a)	(5b)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
January of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projections of New Near-Term Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Winter DSM Forecast * (MW)	Projections of Additional Winter DSM (MW)	Forecast of Firm Peak (MW)	Forecast of Winter Reserves (MW)	Forecast of Winter Res. Margins w/ Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2006	22,304	3,205	0	25,509	21,792	1,532	3	20,257	5,252	25.9%	(1,201)
2007	22,373	3,067	211	25,651	22,294	1,577	70	20,647	5,004	24.2%	(875)
2008	23,558	2,635	391	26,584	22,753	1,626	120	21,007	5,577	26.5%	(1,376)
2009	23,558	2,309	391	26,258	23,245	1,679	171	21,395	4,863	22.7%	(584)
2010	23,558	2,008	180	25,746	23,714	1,736	171	21,807	3,939	18.1%	**422**
2011	23,558	1,915	180	25,653	24,155	1,796	171	22,188	3,465	15.6%	**973**

* DSM values shown represent cumulative load management and incremental conservation capability.

Projection of FPL's 2009 - 2011 Capacity Need: With Updated Load Forecast (with Additional DSM, New Near-Term Purchases, and WCEC 1 and 2)

Summer

	(1a)	(1b)	(2a)	(2b)	(3) = (1)+(2)	(4)	(5a)	(5b)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Addition of WCEC 1 & WCEC 2 (MW)	Projections of Firm Purchases (MW)	Projections of New Near-Term Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast * (MW)	Projections of Additional Summer DSM (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res. Margins w/ Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2006	20,919	0	2,950	457	24,326	21,916	1,516	39	20,361	3,965	19.47%	107
2007	22,139	0	2,404	591	25,134	22,543	1,592	229	20,722	4,412	21.29%	(268)
2008	22,151	0	2,626	369	25,146	23,179	1,674	289	21,216	3,930	18.52%	**313**
2009	22,151	1,219	2,249	590	26,209	23,782	1,759	309	21,714	4,495	20.70%	(152)
2010	22,151	2,438	1,951	158	26,698	24,375	1,849	309	22,217	4,481	20.17%	(38)
2011	22,151	2,438	1,906	158	26,653	24,915	1,941	309	22,665	3,988	17.60%	**545**

Winter

	(1a)	(1b)	(2a)	(2b)	(3) = (1)+(2)	(4)	(5a)	(5b)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
January of the Year	Projections of FPL Unit Capability (MW)	Addition of WCEC 1 & WCEC 2 (MW)	Projections of Firm Purchases (MW)	Projections of New Near-Term Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Winter DSM Forecast * (MW)	Projections of Additional Winter DSM (MW)	Forecast of Firm Peak (MW)	Forecast of Winter Reserves (MW)	Forecast of Winter Res. Margins w/ Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2006	22,304	0	3,205	0	25,509	21,792	1,532	3	20,257	5,252	25.9%	(1,201)
2007	22,373	0	3,067	211	25,651	22,294	1,577	70	20,647	5,004	24.2%	(875)
2008	23,558	0	2,635	391	26,584	22,753	1,626	120	21,007	5,577	26.5%	(1,376)
2009	23,558	0	2,309	391	26,258	23,245	1,679	171	21,395	4,863	22.7%	(584)
2010	23,558	1,335	2,008	180	27,081	23,714	1,736	171	21,807	5,274	24.2%	(913)
2011	23,558	2,670	1,915	180	28,323	24,155	1,796	171	22,188	6,135	27.7%	(1,697)

* DSM values shown represent cumulative load management and incremental conservation capability.

Change in FPL System Costs if WCEC 1 is Delayed to 2010

(A 7 Month Delay From June 2009 to January 2010)

WCEC 1 Cost & Heat Rate Assumptions:

Installed cost of generating unit =	$688.6	million
Firm Gas Transportation =	$36.4	million per year
Fixed O&M =	$4.61	$/kw - year
Capital Replacement =	$7.04	$/kw - year
Variable O&M =	$0.138	$/MWH
Heat Rate =	6,582	BTU/kwh
Installed cost of generating unit =	$705.6	million for 1/2010 start date

Other Assumptions:

2009 Projected Energy Output =	5,256	GWH		
2009 Gas cost =	$7.30	per mmBTU		
2010 Gas cost =	$6.38	per mmBTU		
2009 System Marginal Energy cost ($/MWH) =	$81.82	on peak	$64.82	off peak
2010 System Marginal Energy cost ($/MWH) =	$76.32	on peak	$57.39	off peak
Replacement Capacity Needed in 2009 =	1067	MW		
Replacement Capacity Costs (assuming capacity is available) =	$5.00	per kw-month		
Number of months for Replacement Capacity =	4	months		

		Cost Savings from 7 Month Delay														Costs Incurred from 7 Month Delay			
		(1a) Capital Costs if Unit is Added in 6/2009		(1b) Capital Costs if Unit is Delayed to 1/2010		(1c) = (1a) - (1b) Change in Capital Costs with 7 Month Delay		(2) Firm Gas Trans. Costs with 7 Month Delay		(3) Fixed O&M Costs with 7 Month Delay		(4) Capital Replace. Costs with 7 Month Delay		(5) Variable O&M Costs with 7 Month Delay		(6) Cost of Fuel Not Burned with 7 Month Delay		(7) Replacement Energy Costs with 7 Month Delay		(8) Replacement Capacity Costs with 7 Month Delay	
Year	Annual Discount Factor 0.0837	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)
2005	1.000																				
2006	0.923																				
2007	0.851																				
2008	0.786																				
2009	0.725	73.9	53.6	0.0	0.0	73.9	53.6	21.2	15.4	3.3	2.4	5.0	3.6	0.7	0.5	252.5	183.1	349.6	253.5	21.3	15.5
2010	0.669	122.8	82.1	129.1	86.4	(6.4)	(4.3)														
2011	0.617	117.9	72.8	124.7	77.0	(6.8)	(4.2)														
2012	0.570	113.2	64.5	119.7	68.2	(6.5)	(3.7)														
2013	0.526	108.7	57.1	114.9	60.4	(6.2)	(3.3)														
2014	0.485	104.3	50.6	110.3	53.5	(6.0)	(2.9)														
2015	0.448	100.1	44.8	105.8	47.3	(5.7)	(2.5)														
2016	0.413	96.0	39.7	101.5	41.9	(5.4)	(2.2)														
2017	0.381	92.0	35.1	97.3	37.1	(5.3)	(2.0)														
2018	0.352	88.1	31.0	93.2	32.8	(5.1)	(1.8)														
2019	0.325	84.1	27.3	89.2	28.9	(5.1)	(1.7)														
2020	0.299	80.1	24.0	85.1	25.5	(5.0)	(1.5)														
2021	0.276	76.1	21.0	81.0	22.4	(4.9)	(1.3)														
2022	0.255	72.2	18.4	76.9	19.6	(4.8)	(1.2)														
2023	0.235	68.2	16.0	72.9	17.2	(4.7)	(1.1)														
2024	0.217	64.2	13.9	68.8	14.9	(4.6)	(1.0)														
2025	0.200	60.2	12.1	64.7	13.0	(4.5)	(0.9)														
2026	0.185	56.3	10.4	60.7	11.2	(4.4)	(0.8)														
2027	0.171	52.3	8.9	56.6	9.7	(4.3)	(0.7)														
2028	0.157	48.3	7.6	52.5	8.3	(4.2)	(0.7)														
2029	0.145	44.7	6.5	48.5	7.0	(3.7)	(0.5)														
2030	0.134	42.0	5.6	44.8	6.0	(2.8)	(0.4)														
2031	0.124	39.6	4.9	42.0	5.2	(2.4)	(0.3)														
2032	0.114	37.3	4.3	39.6	4.5	(2.3)	(0.3)														
2033	0.105	34.9	3.7	37.1	3.9	(2.2)	(0.2)														
2034	0.097	13.9	1.3	34.7	3.4	(20.9)	(2.0)														
		1,891.2	717.2	1,951.4	705.2	(60.2)	12.0	21.2	15.4	3.3	2.4	5.0	3.6	0.7	0.5	252.5	183.1	349.6	253.5	21.3	15.5

System Cost Changes from a 7-Month Delay (Millions, Nominal)

2009 Savings (Nominal):	73.9	Capital
	21.2	Firm Gas Transportation
	3.3	Fixed O&M
	5.0	Capital Replacement
	0.7	Variable O&M
	252.5	Fuel Not Burned
Total Savings =	**356.7**	
2009 Costs (Nominal):	349.6	Replacement Energy
	21.3	Replacement Capacity
Total Costs =	**371.0**	
2009 Net Costs (Costs minus Savings, Nominal) =	**14.3**	**Total Cost Impact**

System Cost Changes from a 7-Month Delay (Millions, NPV)

2009 - 2034 Savings (NPV):	12.0	Capital
	15.4	Firm Gas Transportation
	2.4	Fixed O&M
	3.6	Capital Replacement
	0.5	Variable O&M
	183.1	Fuel Not Burned
Total Savings =	**217.0**	
2009 - 2034 Costs (NPV):	253.5	Replacement Energy
	15.5	Replacement Capacity
Total Costs =	**269.0**	
2009 - 2034 Net Costs (Costs minus Savings, NPV) =	**51.9**	**Total Cost Impact**

Exhibit No. ______
Document SRS-20
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Change in FPL System Costs if WCEC 1 is Delayed to 2010

(A One Year Delay From June 2009 to June 2010)

WCEC 1 Cost & Heat Rate Assumptions:

Installed cost of generating unit =	$688.6	million for 6/2009 start date
Firm Gas Transportation =	$36.4	million per year
Fixed O&M =	$4.61	$/kw - year
Capital Replacement =	$7.04	$/kw - year
Variable O&M =	$0.138	$/MWH
Heat Rate =	6,582	BTU/kwh
Installed cost of generating unit =	$717.7	million for 6/2010 start date

Other Assumptions:

2009 Projected Energy Output =	5,256	GWH		
2010 Projected Energy Output (1st 5 months) =	3,671	GWH		
2009 Gas cost =	$7.30	per mmBTU		
2010 Gas cost =	$6.38	per mmBTU		
2009 System Marginal Energy cost ($/MWH) =	$81.82	on peak	$64.82	off peak
2010 System Marginal Energy cost ($/MWH) =	$76.32	on peak	$57.39	off peak
Replacement Capacity Needed in 2009 =	1067	MW		
Replacement Capacity Costs (assuming capacity is available) =	$5.00	per kw-month		
Number of months for Replacement Capacity =	4	months		

			Cost Savings from One Year Delay																Costs Incurred from One Year Delay			
			(1a) Capital Costs if Unit is Added in 6/2009		(1b) Capital Costs if Unit is Delayed to 6/2010		(1c) = (1a) - (1b) Change in Capital Costs with One Year Delay		(2) Firm Gas Trans. Costs with One Year Delay		(3) Fixed O&M Costs with One Year Delay		(4) Capital Replace.Costs with One Year Delay		(5) Variable O&M Costs with One Year Delay		(6) Cost of Fuel Not Burned with One Year Delay		(7) Replacement Energy Costs with One Year Delay		(8) Replacement Capacity Costs with One Year Delay	
Number of Years	Year	Annual Discount Factor 0.0837	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)	Nominal (millions)	NPV (millions)
	2005	1.000																				
	2006	0.923																				
	2007	0.851																				
	2008	0.786																				
1	2009	0.725	73.9	53.6	0.0	0.0	73.9	53.6	21.2	15.4	3.3	2.4	5.0	3.6	0.7	0.5	252.5	183.1	349.6	253.5	21.3	15.5
2	2010	0.669	122.8	82.1	77.0	51.5	45.8	30.6	15.2	10.1	2.4	1.6	3.6	2.4	0.5	0.3	154.2	103.1	217.6	145.6		
3	2011	0.617	117.9	72.8	127.9	79.0	(10.1)	(6.2)														
4	2012	0.570	113.2	64.5	122.9	70.0	(9.7)	(5.5)														
5	2013	0.526	108.7	57.1	118.0	62.0	(9.3)	(4.9)														
6	2014	0.485	104.3	50.6	113.3	54.9	(8.9)	(4.3)														
7	2015	0.448	100.1	44.8	108.7	48.7	(8.6)	(3.9)														
8	2016	0.413	96.0	39.7	104.3	43.1	(8.3)	(3.4)														
9	2017	0.381	92.0	35.1	100.1	38.1	(8.0)	(3.1)														
10	2018	0.352	88.1	31.0	95.9	33.7	(7.9)	(2.8)														
11	2019	0.325	84.1	27.3	91.8	29.8	(7.7)	(2.5)														
12	2020	0.299	80.1	24.0	87.6	26.2	(7.5)	(2.3)														
13	2021	0.276	76.1	21.0	83.5	23.1	(7.4)	(2.0)														
14	2022	0.255	72.2	18.4	79.3	20.2	(7.2)	(1.8)														
15	2023	0.235	68.2	16.0	75.2	17.7	(7.0)	(1.7)														
16	2024	0.217	64.2	13.9	71.1	15.4	(6.9)	(1.5)														
17	2025	0.200	60.2	12.1	66.9	13.4	(6.7)	(1.3)														
18	2026	0.185	56.3	10.4	62.8	11.6	(6.5)	(1.2)														
19	2027	0.171	52.3	8.9	58.6	10.0	(6.3)	(1.1)														
20	2028	0.157	48.3	7.6	54.5	8.6	(6.2)	(1.0)														
21	2029	0.145	44.7	6.5	50.3	7.3	(5.6)	(0.8)														
22	2030	0.134	42.0	5.6	46.6	6.2	(4.6)	(0.6)														
23	2031	0.124	39.6	4.9	43.7	5.4	(4.1)	(0.5)														
24	2032	0.114	37.3	4.3	41.3	4.7	(4.0)	(0.5)														
25	2033	0.105	34.9	3.7	38.8	4.1	(3.9)	(0.4)														
	2034	0.097	13.9	1.3	36.4	3.5	(22.5)	(2.2)														
			1,891.2	717.2	1,956.6	688.4	(65.4)	28.8	36.4	25.5	5.7	4.0	8.6	6.0	1.2	0.9	406.7	286.2	567.3	399.1	21.3	15.5

System Cost Changes
A One Year Delay
(Millions, Nominal)

2009-2010 Savings (Nominal):	196.6	Capital
	36.4	Firm Gas Transportation
	5.7	Fixed O&M
	8.6	Capital Replacement
	1.2	Variable O&M
	406.7	Fuel Not Burned
Total Savings =	655.3	
2009-2010 Costs (Nominal):	77.0	Capital
	567.3	Replacement Energy
	21.3	Replacement Capacity
Total Costs =	665.6	
2009-2010 Net Costs (Costs minus Savings, Nominal) =	10.3	Total Cost Impact

System Cost Changes from:
A One Year Delay
(Millions, NPV)

2009 - 2034 Savings (NPV):	28.8	Capital
	25.5	Firm Gas Transportation
	4.0	Fixed O&M
	6.0	Capital Replacement
	0.9	Variable O&M
	286.2	Fuel Not Burned
Total Savings =	351.5	
2009 - 2034 Costs (NPV):		
	399.1	Replacement Energy
	15.5	Replacement Capacity
Total Costs =	414.6	
2009 - 2034 Net Costs (Costs minus Savings, NPV) =	63.1	Total Cost Impact