**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**DOCKET NO. 040206-EI**
**FLORIDA POWER & LIGHT COMPANY**

# IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR TURKEY POINT UNIT 5 ELECTRICAL POWER PLANT

**DIRECT TESTIMONY & EXHIBIT OF:**

**STEVEN R. SIM**

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**FLORIDA POWER & LIGHT COMPANY**

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**DOCKET NO _______ - EI**

**MARCH 8, 2004**

**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 2007 Capacity Need;

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

SRS-3, Summary of FPL Self-Build Options Considered;

SRS-4, Summary of Evaluation of FPL Construction Options to Meet 2007 Need: Top 5 Options;

SRS-5, List of Organizations Submitting Proposals;

SRS-6, Summary of Proposals;

SRS-7, Summary of Portfolios Evaluated;

SRS-8, FPL Rankings of Portfolios - EGEAS Costs Only;

SRS-9, FPL Rankings of Portfolios - EGEAS & Transmission-Related Costs Only;

SRS-10, Calculation of Peak Hour Loss Cost for the FPL 4 CT & Proposal 4 Portfolio;

SRS-11, Calculation of Annual Energy Loss Cost for the FPL 4 CT & Proposal 4 Portfolio;

SRS–12, FPL Rankings of Portfolios Prior to Short List Announcement - All Costs;

SRS-13, FPL Final Rankings of Portfolios After Best and Final Offer from Short List Proposer

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

A. Yes. I am sponsoring Sections IV and VII and co-sponsoring Sections VI and VIII of the Need Study document. I also sponsor Appendices M, P, C-1, C-2, C-3, and C-4, and co-sponsor Appendices C and C-5.

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

A. My testimony has seven main points. First, I discuss FPL's resource planning process. Second, I identify FPL's additional resource need for 2007 and explain how this need was determined. Third, I discuss FPL's demand side management (DSM) efforts and why DSM cannot reasonably be expected to meet the 2007 resource need. Fourth, I discuss the selection of the "next planned generating unit" presented in the RFP. Fifth, I present the proposals that FPL received in response to the RFP. Sixth, I explain the process FPL used in analyzing the economics of the RFP proposals and FPL construction options. Seventh, I present the results of these analyses.

## 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) 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 near-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 for 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 construction option for a particular year and evaluations associated with an RFP.

In regard to the current RFP, each of the four tasks outlined above was performed. FPL first determined the timing and magnitude of its 2007 resource need. 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 then were determined, and a decision was made as to the best portfolio for FPL's customers.

## II. FPL's Resource Need for 2007

**Q. How did FPL decide it needed additional resources for 2007, and what was the magnitude of this resource need?**

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 project reserve margins both for Winter and Summer peak hours for future years. A minimum reserve margin criterion of 15 percent is used to judge the projected reserve margins through the Winter of 2004. Then, starting with the projected reserve margin for the Summer of 2004, and for all projected Winter and Summer reserve margins for subsequent years, the minimum criterion increases to 20 percent. This increase in the reserve margin criterion is due to a Commission-approved stipulation in FPSC Docket No. 981890-EU that included FPL.

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. In other words, the Summer reserve margin criterion is projected to be violated before either the Winter reserve margin or LOLP criterion is violated. This again was the case in FPL's reliability analysis that was the basis for FPL's projected 2007 capacity need. Additional MW are needed to meet the 2007 Summer reserve margin criterion of 20 percent. The additional MW needed by the Summer of 2007 are projected to be 1,066 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 percent reserve margin criterion, 888 MW (1,066 MW/1.20 = 888 MW) if provided by a DSM-based reduction to the forecasted peak load. This projection of a 1,066 MW need for the Summer of 2007 is shown in Document SRS-1, which also shows that no capacity addition would be needed based on the Winter reserve margin criterion. This projection relies upon FPL's load forecast that is addressed by Dr. Leo 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 new power plant construction using DSM. Since the inception of its programs through the end of 2003, FPL has achieved 3,270 MW (at the generator) of Summer peak demand reduction, 2,604 MW (at the generator) of Winter peak demand reduction, and 25,429 GWh (at the generator) of energy savings. FPL has also completed more than 1,900,000 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 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 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 2001, FPL is ranked number one nationally for cumulative conservation achievement and number five in load management.

Another important indication of the success of DSM in Florida and FPL's service territory was the outcome of a benchmarking study conducted by the State of Florida Energy Office in 1992, entitled "Electricity Conservation and Energy Efficiency in Florida." That study found that since the early 1980s, FPL had been actively involved in DSM programs and had been an industry leader in DSM application. It further found that: "The Florida utilities have been extremely successful in reducing peak capacity requirements. The Florida utility peak capacity savings are generally higher than those obtained by other utilities. While the Florida utilities have been focusing their efforts on load management, they have been among the leaders in achieving energy savings."

**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-99-1942-FOF-EG. As shown in this document, FPL's DSM Goals are 765 MW (Summer MW at the meter) through 2009. This determination was made based upon a comprehensive analysis.

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

A. Yes, since implementing its latest DSM Plan in 2000, FPL has made changes to existing programs. These include revising incentive schedules for several programs as well as enhancing eligibility requirements to encourage additional participation and the addition of new measures.

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

A. Yes. Historically, FPL has performed extensive DSM research and development. FPL has continued such 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 2007 with DSM?**

A. No. FPL's 2007 resource need already reflects all of the reasonably achievable, cost-effective level of DSM for FPL between 2000 and 2007 (625 MW at the meter) as determined in FPL's Commission-approved DSM Goals. In other words, FPL's analysis already has captured the cost-effective DSM available on FPL's system and determined that FPL still needed additional capacity resources.

If the 2007 resource need were to be met solely by additional new DSM resources, FPL would need to find an additional 888 MW of cost-effective DSM to meet the 2007 resource need. (After accounting for FPL's 20 percent reserve margin criterion, the 1,066 capacity need is reduced to 1,066 MW/1.20 = 888 MW.) It is unrealistic to conclude that FPL could implement sufficient new DSM programs in the next three years (mid-2004 to mid-2007) to meet this need.

The Commission previously determined that there was only 765 MW of additional, achievable, cost-effective DSM for the entire ten-year period of 2000-2009. Therefore, it is not reasonable to conclude that FPL could achieve an additional 888 MW of cost-effective DSM in the next three years. This is particularly so given that it would take some time to secure Commission approval to proceed with new DSM programs or to modify existing programs. In fact, the time needed for FPL to prepare needed filings and secure this approval would likely reduce the available time to implement additional DSM from 3 years to 2½ years. So, even if there were cost-effective DSM potential out there not previously found by FPL or the Commission, not enough could be added in the time remaining to meet FPL's 2007 resource needs.

Consequently, cost-effective DSM could not meet the 2007 resource need. This need must be met by capacity (construction and/or purchase) options.

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

**Q. Did FPL consider other power plant construction options before designating the Turkey Point combined cycle unit as its "next planned generating unit"?**

A. Yes. More than two dozen combustion turbine (CT) and combined cycle (CC) options were considered in FPL's efforts to determine its best construction option for meeting the 2007 need. Included in these options were various configurations of both CT and CC units at a number of sites. Document SRS-3 summarizes the self-build options FPL initially considered.

**Q. Please describe the analytical approach FPL used to determine its best construction option.**

A. In its efforts to evaluate the construction options, FPL first identified the construction options that could be permitted and built in time to begin service by mid-2007. For those options that met this criterion, portfolios of one or more construction options were developed that met the 2007 capacity need. For each portfolio, FPL evaluated the capital and O&M costs, plus the system fuel costs and costs associated with meeting subsequent years' resource needs, in a multi-year expansion plan approach using its Electric Generation Expansion and Analysis System (EGEAS) model. FPL then combined those results with the results of an analysis of the transmission-related costs and impacts of siting generation both within and outside of Southeast Florida. In this way, FPL sought to identify the portfolio whose combination of construction option type(s) <u>and</u> site(s) was the best FPL choice, based on total economics (i.e., generation costs, system fuel costs, and transmission-related costs).

For its analysis of transmission-related costs for each portfolio, the portfolio's component capacity option(s), including the site(s) on which the option(s) was located, was examined. FPL first evaluated the transmission interconnection and integration requirements and costs for the portfolio. These costs then were combined with the cost of transmission losses associated with the portfolio. The transmission loss approach first developed MW loss values both for peak hour and average load periods, converted the peak and average load (MW) losses to annual energy (MWH) loss values, then assigned a dollar cost to both the MW and MWH losses.

**Q. Was the analytical approach used to determine FPL's best construction option similar to the economic evaluation process FPL later utilized to examine responses to its RFP?**

A. Yes. Most of the analyses used to determine FPL's "next planned generating unit" (i.e., the EGEAS analyses and the transmission interconnection and integration cost calculations) were essentially identical to the analyses later used to evaluate RFP responses. The remaining part of the analysis, the evaluation of the cost of transmission losses, was similar in basic concept to that used in the evaluation of transmission loss costs during the RFP analyses. The calculation process ultimately used in this analysis to determine the cost of losses was subsequently further refined prior to issuance of the RFP.

**Q. Were there any other differences in the evaluation approach used in determining FPL's best construction option compared to the evaluation approach used in the RFP economic evaluations?**

A. Yes. There was one cost calculation that was used in the RFP evaluation work that was not used in the work carried out to determine FPL's best construction option. This calculation of increased operating costs from operating FPL's Southeast Florida gas turbines out of economic dispatch is due to generation/load imbalance in the region. At the time the analyses to determine the best construction option were being conducted, FPL was working on an approach to capture these increased operating costs but did not complete this work in time to utilize the approach in these analyses.

**Q. If this "additional" cost calculation used in the RFP evaluations had been included in the work to determine FPL's best construction option, would a different FPL construction option have emerged as the best choice?**

A. No. As will be discussed below, the top two construction options were 4x1 CC units, one located within the Southeast Florida region and one located just north of that region. In regard to increased operating costs, the inclusion of these costs would have favored the CC option located in Southeast Florida in comparison to the CC option located just outside of that region. However, because the CC option located in Southeast Florida already had been selected as the best FPL construction option without consideration of the increased operating costs, including these costs would only have reinforced its selection as the best construction option.

**Q. Was the impact of the construction options on FPL's capital structure considered in this analysis of construction options?**

A. Yes. FPL considers the impact of all resource additions on FPL's capital structure, whether they are FPL self-build options or non-FPL options. In considering FPL self-build options, such as in the evaluation of construction options to meet the 2007 capacity need, FPL uses a 55 percent equity / 45 percent debt incremental capital structure; therefore, self-build capacity additions will have no impact on FPL's target adjusted capital structure of 55 percent equity / 45 percent debt.

**Q. Please briefly describe the results of the analyses to determine the best construction option for FPL.**

A. The analyses yielded several results. First, the 4x1 CC options were more economical than the 2x1 CC's. This result was consistent with results from resource planning analyses in prior years. Second, when considering only generation-related costs captured in the EGEAS model work, a 4x1 CC sited at FPL's Martin site emerged as the leading candidate. Third, after all of the transmission-related costs for interconnection, integration, and losses were added to the generation-related costs, a 4x1 CC unit located at FPL's Turkey Point site emerged as the most economical alternative.

The results of this evaluation of FPL construction options to meet the 2007 need are summarized on Document SRS-4, which presents the evaluation results for the top 5 options considered. Based upon its evaluation, FPL selected the Turkey Point CC unit (Turkey Point Unit 5) as its best, most economical construction option and designated Turkey Point Unit 5 as the next planned generating unit in the RFP.

**Q. In its RFP, FPL presented not only Turkey Point Unit 5 as its next planned generating unit, but also an "alternative generating unit." Why did FPL also present an alternative generating unit of a 4x0 CT in its RFP?**

A. As explained in its RFP, pages 7 and 8, FPL went beyond the requirements of Rule 25-22.082, Florida Administrative Code (the Bid Rule) and presented this alternative generating unit of 4 CTs at Turkey Point for several reasons. First and foremost, this option increased the number of possible portfolios of capacity options that could be created and still include a significant amount of generation in Southeast Florida that would help address the load/generation imbalance concern in that region. Second, it provided potential proposers with a known-in-advance portfolio "pairing partner" for entities considering proposals that could only partially meet the 2007 need requirement. Third, it allowed FPL flexibility to address unexpected developments that might have occurred (such as significant changes in the load forecast) during the RFP evaluation process.

As will be discussed later, the Turkey Point 4 CT option was useful in creating additional portfolios for consideration, and those portfolios contained a substantial number of MW in Southeast Florida. The inclusion of this alternative generating unit, which was not required, actually worked to the benefit of several proposals by allowing them to be included in portfolios that could meet the required 1,066 MW need.

## IV. The RFP Proposals

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

A. FPL received 5 proposals from 4 organizations (proposers). A listing of the organizations 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. All proposals were power purchase offerings, with four proposals being natural gas-based and one proposal being coal-based. Three proposals were based on combined cycle technology, one proposal was based on combustion turbine technology, and one proposal was based on circulating fluidized bed (CFB) technology. More detailed information regarding the proposals is presented in Document SRS-6.

**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 an independent evaluator, Alan Taylor of Sedway Consulting, reviewed all proposals received on the Proposal Due Date of October 24, 2003. Questions regarding whether or not RFP Minimum Requirements had been met were immediately raised after the initial review of the proposals. 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 proposers' attention and were resolved relatively quickly.

However, issues regarding whether proposals complied with the RFP Minimum Requirements were not resolved as quickly. Mr. Silva discusses in his testimony that four of the five proposals ultimately did not comply with the RFP Minimum Requirements after FPL's efforts to encourage the proposers of these proposals to meet the RFP Minimum Requirements were unsuccessful.

## V. Overview of the RFP Economic Evaluation Process

**Q. What was the general approach used in the RFP economic evaluation work?**

A. FPL conducted its own evaluation of all of the proposals, the FPL alternative generating unit, and the next planned generating unit, Turkey Point Unit 5. In addition, separate analyses of these options were performed by an independent evaluator, Mr. Alan Taylor of Sedway Consulting, Inc (Sedway). Mr. Taylor's testimony addresses Sedway's analysis; I will focus on FPL's evaluation.

FPL first ensured that its economic analyses of the proposals were "blind" by providing code numbers to the proposals. FPL adopted the convention of coding the proposals as Bid 1, Bid 2, etc. for FPL's and Sedway's economic evaluation work as is shown in the Confidential Appendices. However, the proposals are referred to as Proposal 1, Proposal 2, etc. throughout FPL's Need filing.

Using the coding, the analyses of the proposals were conducted without organizational names attached to the proposals. FPL's alternative generating unit and Turkey Point Unit 5 could not be evaluated "blind," because these two options were listed in the RFP document and, therefore, were easily recognizable.

FPL then used what I will describe as a four-step evaluation approach to determine the economics of the proposals, consistent with the evaluation framework described in the RFP. The approach is based on creating capacity multi-year expansion plans that utilize the proposals only, Turkey Point Unit 5 only, or a combination of RFP proposals and FPL's alternative generating unit to meet FPL's 2007 capacity need. For 2008 and beyond, greenfield "filler" units are added to the expansion plan as needed to maintain FPL's reserve margin.

As previously mentioned, FPL used the EGEAS model in these analyses. 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.

The four-step evaluation approach that FPL used can be summarized as follows:

<u>Step 1: Determining Portfolios to Evaluate:</u>

Two determinations were made in this step. The first determination was to identify the <u>proposals</u> that would be carried forward in the economic evaluation. The second determination was to identify the <u>portfolios</u> that would be created from these proposals, or from combinations of these proposals and FPL's alternative generating unit, for purposes of comparison to Turkey Point Unit 5.

Regarding the first determination, it was decided that FPL and Sedway would proceed with the economic evaluation including all proposals received pending resolution of questions regarding the proposers' compliance with the RFP Minimum Requirements.

The second determination was made by FPL with input from Mr. Taylor. Once these determinations had been made, the portfolios to be evaluated were transmitted to Mr. Taylor, who proceeded to conduct separate evaluations in parallel with FPL, as well as to Mr. Reppen and FPL transmission engineers working under his direction.

Step 2: The Separate Evaluations:

In Step 2, five separate evaluations were carried out largely in parallel.

a) FPL conducted an EGEAS-based evaluation that addressed the following system generation-related costs associated with each portfolio:

- capital or capacity costs;
- fixed O&M, variable O&M, and capital replacement costs;
- option and FPL system fuel/energy costs;
- transmission interconnection costs; and,
- gas pipeline lateral costs.

b) Mr. Taylor used Sedway's RSM model to also evaluate these same costs associated with each portfolio.

c) Mr. Reppen directed and led the evaluation of the following transmission-related costs and impacts of each portfolio:

- transmission integration costs;
- peak hour losses (MW) and average load losses (MW); and,
- increased operational costs.

d) FPL took the peak hour and average load losses (MW) results from Mr. Reppen, used these to develop annual energy losses (MWH), and assigned costs to both the MW and MWH loss values to develop portfolio-based costs of losses.

e) FPL developed net equity adjustment costs 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 consistently with the calculations described in the RFP.

Step 3: Combining the results of the separate evaluations carried out in Step 2.

The combination of the different types of costs developed in Step 2 provides a total cost picture of each portfolio. In essence, two total cost pictures for each portfolio were developed, one EGEAS-based picture (containing the EGEAS results, the transmission integration and increased operating costs, the cost of losses, and the net equity adjustment costs) and one RSM-based picture (in which the above-mentioned EGEAS results are replaced by the RSM results). FPL then used these two total cost pictures, along with the results of the non-economic evaluation discussed by Mr. Silva, to identify which, if any, proposals should be identified as finalists. Such proposals would then be asked to provide a Best and Final Offer which would be evaluated.

Step 4: Final cost determination after Best and Final Offer was received.

In this final step, the total cost for each portfolio that contained the finalist proposal was re-evaluated to incorporate that proposal's Best and Final Offer. This resulted in two final total cost pictures, one EGEAS-based and one RSM-based, for all portfolios.

**Q. You mentioned above that "expansion plans" containing the portfolios were evaluated. Why is it appropriate to perform the economic evaluations based on multi-year expansion 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 need for a specific year (in this case, for 2007) 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 expansion plan is designed to address FPL's capacity needs in years <u>after</u> the 2007 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. 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 for a longer period the need for future generation. Therefore, Option B will get capacity avoidance benefits for more years.

Only by taking a multi-year expansion plan approach to the evaluation can factors such as these be captured and effectively compared. In the RFP economic evaluation, the expansion plans created addressed the FPL system through the year 2031.

**Q. Are "filler" units needed in an expansion plan evaluation?**

A. Yes. The "filler" units are needed in a multi-year expansion plan analysis to meet FPL's capacity needs for 2008 and beyond. In this way one can ensure that the expansion plans being compared all meet FPL's reliability criteria for each year in the analysis period, ensuring that the results of the comparison are meaningful.

**Q. What type of "filler" units were assumed in the evaluation?**

A. Two "types" of filler units were used: a complete or "full," 1,144 MW 4x1 CC unit and a scaled down 250 MW version of the larger CC unit that maintained the same $/kW cost structure and performance characteristics. Based on results of analyses carried out in preparation for the RFP evaluation, only one unit (either the full CC unit or the scaled down version) was the available filler unit option in EGEAS for each year in the 2008 - 2031 time frame. The full CC option was used to meet FPL's capacity needs for the 2008 – 2023 time frame, while the scaled down 250 MW version was used from 2024 – 2031.

FPL chose to use a scaled down version of the large CC unit for the later years for two reasons. First, the use of a smaller filler unit in the time frame from 2024 – 2031 would allow better consistency in the amount of total long-term system MW associated with each of the portfolios. Second, the use of a smaller filler unit avoids unduly penalizing portfolios for which one or more component capacity options' proposed term-of-service would end in the 2024 – 2031 time frame. FPL believed that adding the capital cost of the full-sized CC unit in those late years of the analysis period could unduly penalize such portfolios because there are not enough remaining years in the analysis period over which the fuel savings of the CC unit can overcome its capital costs. For these reasons, the scaled down version of the CC unit was used as the filler unit addition in the 2024 – 2031 time frame to meet FPL's reserve margin.

## VI. The Results of the Analyses

**Q. How did the eligibility of the proposals affect the economic evaluation?**

A. Four of the five proposals ultimately were determined not to have met the RFP Minimum Requirements, and the corresponding proposers were notified that these proposals would not be considered further. Mr. Silva addresses that eligibility determination in his testimony.

However, before compliance with Minimum Requirements was finally determined, FPL decided that Sedway Consulting and FPL would conduct economic analyses of <u>all</u> proposals received. This decision was made primarily because FPL wanted to allow proposers every opportunity to revise their proposals and achieve compliance, but at the same time, FPL did not want to delay the evaluation process. It would take time to communicate with proposers to discuss - and, hopefully, correct - the aspects of the proposals that failed to meet Minimum Requirements. Waiting for this communication to be completed would have significantly delayed completion of the evaluation. Consequently, <u>all</u> proposals were included in the economic evaluation.

**Q. How did FPL decide what portfolios would be evaluated alongside FPL's next planned generating unit in the economic evaluation?**

A. The objective was to evaluate portfolios against FPL's next planned generating unit, Turkey Point Unit 5. Therefore, Turkey Point Unit 5 was one portfolio evaluated. FPL utilized its EGEAS model to create potential portfolios for consideration as alternatives to Turkey Point Unit 5 and decided on 7 alternative portfolios. Two other "single option" portfolios; Proposal 2 (1,220 MW) and Proposal 3 (1,220 MW), were identified. All other portfolios consisted of two or more capacity options (i.e., a combination of two or more proposals or a combination of FPL's alternative generating unit and one or more proposals). Five portfolios consisting of two or more capacity options, along with the two "single option" portfolios mentioned above were selected to be included in the evaluation alongside the portfolio consisting of Turkey Point Unit 5. Therefore, a total of eight portfolios were evaluated.

Document SRS-7 presents these 8 portfolios. These 8 portfolios then were utilized by FPL's Resource Assessment & Planning Business Unit for its EGEAS, costs of losses, and net equity adjustment evaluations; by Mr. Taylor for his RSM evaluation; and by Mr. Reppen for the transmission-related evaluation work. As previously mentioned, all of these work efforts proceeded in parallel.

**Q. What were the EGEAS-based results of the evaluation of these 8 portfolios?**

A. The results of the EGEAS analyses are presented in Document SRS-8. This document shows that Turkey Point Unit 5 emerged from the EGEAS analyses with a substantial cost advantage, $104 million cumulative present value of revenue requirements CPVRR, over the next most economic portfolio. This next most economic portfolio consisted of a combination of FPL's alternative generating unit, the Turkey Point 4 CT option, and Proposal 4. All of the remaining portfolios ranged from $121 to $197 million CPVRR more expensive than Turkey Point Unit 5.

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

A. These results are presented in Document SRS-9. As previously discussed, the transmission-related costs include several different costs: 1) transmission integration costs, 2) the costs of peak hour losses, 3) the costs of annual energy losses (that are derived from the peak hour losses and the average load losses), and 4) increased operating costs. Mr. Reppen provided the transmission integration and increased operating costs, plus the peak hour losses (MW) and average load losses (MW).

The inclusion of these transmission-related costs resulted in two basic changes to the EGEAS-only results presented in Document SRS-8. First, the cost advantage of Turkey Point Unit 5 increased from $104 to $204 million, CPVRR. Second, the ranking order of the remaining portfolios changed, with the portfolio consisting of Proposal 3 and Proposal 1 now moving into the runner-up slot.

**Q. You mentioned 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-12 of Appendix E of FPL's RFP, FPL assigned an initial proxy purchase cost of $5/kw-month to the peak hour losses. This cost was assumed to begin in 2009 and to escalate at 1.7 percent per year. 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. Reppen 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 percent 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 remaining 7,884 annual hours 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 proposers 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-10 and Document SRS-11, respectively, present the calculations of costs for the peak hour capacity losses and annual energy losses for the portfolio containing the FPL 4 CT option and Proposal 4. The proxy purchase and marginal energy cost values shown for this portfolio were used in evaluating all portfolios.

**Q. Document SRS-9 shows 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, page 10 of FPL's RFP states that each natural gas-based proposal has to include all costs to build and maintain any pipeline lateral to the generating unit, and include "all capital costs associated with any interstate mainline improvements required to deliver the full fuel requirements, at the required pressure, to the Proposer-designated Fuel Delivery Point." In its economic evaluation, FPL assumed that every proposal complied with this requirement and included all proposal-specific gas pipeline costs.

The "upstream gas pipeline costs" component of the RFP economic evaluation was designed to address gas pipeline costs, different from those reflected in each individual proposal, that might occur if two or more gas-based capacity options were combined in a portfolio. Of the eight portfolios considered, five did <u>not</u> consist of multiple gas-fired units: Turkey Point Unit 5; Proposal 2; Proposal 3; Proposal 2 & Proposal 1; and Proposal 3 & Proposal 1. Consequently, for these five portfolios, the issue of upstream gas pipeline costs was not relevant; i.e., there were zero upstream gas pipeline costs for these five portfolios.

The determination of upstream gas pipeline costs for the three remaining portfolios that consisted of more than one gas-fired capacity option (FPL 4 CT & Proposal 4; FPL 4 CT & Proposal 4 & Proposal 1; and FPL 4 CT & Proposal 4 & Proposal 5) was to be addressed as one of the last steps in the economic evaluation. However, by the time FPL turned to address the upstream gas pipeline question for these three portfolios, the results of the other economic evaluation steps that had been completed clearly showed that these three remaining portfolios were <u>significantly</u> more expensive than Turkey Point Unit 5. Since the inclusion of upstream gas pipeline costs, if any, for these three portfolios would likely have <u>increased</u> this economic differential, and the review that would be needed to determine those costs would require additional time, FPL decided <u>not</u> to carry out the analysis to determine potential upstream gas pipeline costs for these three remaining portfolios. Instead, FPL chose to assign an upstream gas pipeline cost of zero for these remaining portfolios for purposes of the economic evaluation.

In regard to the net equity adjustment, seven of the eight portfolios resulted in the need for an equity adjustment because these portfolios contained one or more power purchase option. (The impact on FPL's capital structure for the eighth portfolio consisting of Turkey Point Unit 5 was already captured by assuming an incremental 55 percent equity / 45 percent debt investment in the new unit.) Consequently, a net equity adjustment value, derived by calculating an equity adjustment less mitigating factor values, was computed for each of these seven other portfolios that included at least one purchased power option. The calculations of the net equity adjustment value for each of these seven portfolios are presented in 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-12. Once again, two basic changes to the previously presented results occurred. First, the economic advantage of Turkey Point Unit 5 increased further to $266 million CPVRR. Second, the ranking order of the remaining portfolios again changed with the portfolio consisting of the FPL 4 CT option and Proposal 4 returning to the runner-up slot.

Given that Proposal 4 was the only proposal that complied with all Minimum Requirements, that the runner-up portfolio consisted of the FPL 4 CT option and Proposal 4, and that the results of the non-economic evaluation did not adversely affect the viability of Proposal 4, FPL informed the proposer that offered Proposal 4 that it had made FPL's RFP Short List and requested a Best and Final Offer.

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 Appendix C of FPL's RFP.

In regard to the equity adjustment calculation, the methodology was presented on page C-7 of the RFP document. On that page, 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 C-3 through C-6 of the RFP document. In addition, a calculation of the mitigating factor values was also presented on page C-8 of the RFP document using the same hypothetical purchase of 500 MW used in the equity adjustment example calculation. In this example, the hypothetical capacity amount was multiplied by the sum of the dollar amounts for the Completion Security mitigating factor ($526/MW) and for the Performance Security mitigating factor ($2,014/MW).

In evaluating the proposals received in response to the RFP, FPL input the proposed capacity amount into this formula 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. 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 proposers are given the opportunity to revise their proposals. Did FPL change the cost estimate for its next planned generating unit at any time during the RFP?**

A. No.

**Q. How did the values shown in Document SRS –12 change after the Best and Final Offer for Proposal 4 was received?**

A. The Best and Final Offer increased the overall cost (i.e., capacity payment and equity adjustment) for Proposal 4 by approximately $5 million CPVRR, with no changes to other aspects of the proposal. Therefore, the cost of the three portfolios that contained Proposal 4 all increased by approximately $5 million CPVRR as is shown in Document SRS-13.

**Q. Please summarize your testimony.**

A. FPL's 2003 resource planning work determined that FPL had a need for additional resources in 2007. In order to meet FPL's Summer reserve margin criterion of 20 percent for that year, FPL needed 1,066 MW if the resource need was to be filled by new supply (power plant construction and/or purchase) or 888 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 new DSM, so the need would have to be met by one or more new supply options. Because the type of new power plant (a combined cycle unit) that FPL selected as its next planned generating unit to meet this need would require a determination of need, FPL issued an RFP for new capacity to meet this 2007 need.

Five proposals from four organizations were received in response to the RFP. Although four of the five proposals ultimately did not comply with the RFP Minimum Requirements, FPL decided in Step 1 of its economic evaluation process to consider all five proposals in its initial economic evaluation. FPL then utilized those five proposals and its alternative generating unit to develop seven portfolios of capacity options that were analyzed alongside an eighth portfolio consisting of Turkey Point Unit 5 during the remainder of the evaluation.

After three of the four steps in FPL's economic evaluation had been completed, Turkey Point Unit 5 emerged as the clear economic choice by being \$266 million CPVRR less expensive than the runner-up portfolio that consisted of FPL's 4 CT option and Proposal 4. Based on the results of the economic and non-economic evaluations, Proposal 4 was named to the RFP Short List, and a Best and Final Offer was requested for Proposal 4.

Once Proposal 4's Best and Final Offer was received, FPL incorporated it in the last step of its economic evaluation process. The final EGEAS-based total cost picture showed that Turkey Point Unit 5 was the most economical choice by $271 million CPVRR over the runner-up plan. The results of Sedway's analysis also clearly showed Turkey Point Unit 5 to be the most economical choice. All other plans were even more expensive than the runner-up plan.

Therefore, the results of FPL's and Sedway's analyses show that FPL's Turkey Point Unit 5 is the most cost-effective alternative and the best choice for meeting FPL's 2007 capacity need.

**Q. Does this conclude your testimony?**

A. Yes.

## Projection of FPL's 2007 Capacity Need
## (without Capacity Addition)

**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) |
| 2007 | 21,018 | 2,044 | 23,062 | 21,851 | 1,744 | 20,107 | 2,955 | 14.7% | **1,066** |

**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) |
| 2007 | 22,389 | 2,522 | 24,911 | 21,605 | 1,723 | 19,882 | 5,029 | 25.3% | **(1,053)** |

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

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

| Year | MW |
|---|---|
| 2000 | 122 |
| 2001 | 200 |
| 2002 | 269 |
| 2003 | 339 |
| 2004 | 410 |
| 2005 | 484 |
| 2006 | 554 |
| 2007 | 625 |
| 2008 | 697 |
| 2009 | 765 |

## Summary of FPL Self-Build Options Considered

| Technology | Option's Summer Capacity (MW) | Number of Locations Considered | Locations Considered |
|---|---|---|---|
| Combustion Turbine (2x0) | 314 | 6 | Turkey Point, Corbett, Midway, Martin, Andytown, Levee |
| Combustion Turbine (3x0) | 471 | 6 | Turkey Point, Corbett, Midway, Martin, Andytown, Levee |
| Combustion Turbine (4x0) | 628 | 6 | Turkey Point, Corbett, Midway, Martin, Andytown, Levee |
| Combined Cycle (2x1) | 538 | 1 | Turkey Point |
| Combined Cycle (4x1) | 1,107 | 6 | Turkey Point, Corbett, Midway, Martin, Andytown, Levee |

## Summary of Evaluation of FPL Construction Options to Meet 2007 Need: Top 5 Options

**(millions, 2003 $, CPVRR)**

| | | (1) | (2) | (3) | (4) | (5) = (3) + (4) | (6) |
|---|---|---|---|---|---|---|---|
| Final Option Rank | 2007 FPL Construction Option | Subtotal EGEAS Costs Only | Subtotal Difference from Lowest Cost Option | Transmission Integration & Interconnection Costs | Relative Capacity & Energy Losses | Total Costs | Total Difference from Lowest Cost Option |
| 1 | TP 4x1 CC | 52,498 | 70 | 42 | 45 | 52,585 | 0 |
| 2 | Andytown 4x1 CC | 52,563 | 135 | 29 | 8 | 52,600 | 15 |
| 3 | Martin 4x1 CC | 52,428 | 0 | 81 | 105 | 52,614 | 29 |
| 4 | Levee 4x1 CC | 52,575 | 147 | 55 | 0 | 52,630 | 45 |
| 5 | Corbett 4x1 CC | 52,538 | 110 | 57 | 64 | 52,659 | 74 |

# List of Organizations Submitting Proposals
(in alphabetical order)

| Organization | Number of Proposals Submitted | Type of Proposal | New or Existing Source |
|---|---|---|---|
| Calpine (Blue Heron Energy Center) | 1 | Purchased Power | New |
| Progress Energy Ventures | 1 | Purchased Power | Existing/New * |
| Southern Power Company | 2 | Purchased Power | New |
| Summit Energy Partners | 1 | Purchased Power | New |
| | 5 | | |

* Proposal was based on two existing CT's and one new CT.

# Summary of Proposals

| Proposal Code Number * | Capacity Offered (Summer MW) | Technology | Proposed Term-of-Service (Years) |
|---|---|---|---|
| Proposal 1 | 50 | Circulating Fluidized Bed (CFB) | 25 |
| Proposal 2 | 1,220 | Combined Cycle (CC) | 15 |
| Proposal 3 | 1,220 | Combined Cycle (CC) | 25 |
| Proposal 4 | 447 | Combustion Turbine (CT) | 15 |
| Proposal 5 | 252 * * | Combined Cycle (CC) | 15 * |
| | 1,969 * * * | | |

* The proposals were actually coded as Bid 1, Bid 2, etc. for FPL's and Sedway's economic evaluation work as shown in the Confidential Appendices. However, they are referred to as "Proposal 1", "Proposal 2", etc. throughout FPL's Need filing.

** Proposal 5 originally proposed 200 MW of a larger size generating facility for a 10-year period. In response to FPL correspondence pointing out, in part, that an RFP Minimum Requirement was that 100% of the capacity of a new generating facility must be offered to FPL, and must be offered for a minimum of 15 years, the proposer increased the capacity offered for Proposal 5 from 200 MW to 252 MW (although 252 MW still did not represent 100% of the capacity of the new generating unit in question) and increased the proposed term-of-service to 15 years.

*** The capacity amounts offered for Proposal 2 and Proposal 3 were mutually exclusive.

## Summary of Portfolios Evaluated

| Capacity Options In Portfolio | Portfolio Capacity (Summer MW) |
|---|---|
| FPL Turkey Point Unit 5 | 1,144 |
| FPL Turkey Point 4 CT, Proposal 4 | 1,095 |
| Proposal 2 | 1,220 |
| Proposal 3 | 1,220 |
| FPL Turkey Point 4 CT, Proposal 4, Proposal 1 | 1,145 |
| Proposal 2, Proposal 1 | 1,270 |
| Proposal 3, Proposal 1 | 1,270 |
| FPL Turkey Point 4 CT, Proposal 4, Proposal 5 | 1,347 |

## FPL Rankings of Portfolios - EGEAS Costs Only

**(millions. CPVRR. 2003$. 2003 - 2031)**

**(note: includes proposals eventually dropped as non-compliant)**

| | | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) = sum of (1) thru (7) | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Transmission-Related Costs | | | | | | | |
| **Ranking of Portfolio** | **Description of Portfolio** | **Portfolio MW** | **EGEAS Results *** | **Integration * *** | **Peak Hour Capacity Losses * * *** | **Annual Energy Losses * * *** | **Increased Operating Costs * * *** | **Upstream Gas Pipeline Costs** | **Net Equity Adjustment** | **Total** | **Difference from lowes cost portfoli** |
| 1 | FPL Turkey Point Unit 5 | 1,144 | 62,591 | 0 | 0 | 0 | 0 | 0 | 0 | 62,591 | 0 |
| 2 | FPL 4 CT, Proposal 4 | 1,095 | 62,695 | 0 | 0 | 0 | 0 | 0 | 0 | 62,695 | 104 |
| 3 | FPL 4 CT, Proposal 4, Proposal 1 | 1,145 | 62,712 | 0 | 0 | 0 | 0 | 0 | 0 | 62,712 | 121 |
| 4 | FPL 4 CT, Proposal 4, Proposal 5 | 1,347 | 62,741 | 0 | 0 | 0 | 0 | 0 | 0 | 62,741 | 150 |
| 5 | Proposal 3, Proposal 1 | 1,270 | 62,741 | 0 | 0 | 0 | 0 | 0 | 0 | 62,741 | 150 |
| 6 | Proposal 3 | 1,220 | 62,760 | 0 | 0 | 0 | 0 | 0 | 0 | 62,760 | 169 |
| 7 | Proposal 2 | 1,220 | 62,763 | 0 | 0 | 0 | 0 | 0 | 0 | 62,763 | 172 |
| 8 | Proposal 2, Proposal 1 | 1,270 | 62,788 | 0 | 0 | 0 | 0 | 0 | 0 | 62,788 | 197 |

* EGEAS results include: capital, fixed O&M, variable O&M,capital replacement costs, project fuel/energy cost, FPL system fuel, transmission interconnection, and gas pipeline lateral costs. Values for Proposal 1 assume 80%/20% coal/pet coke mix.

** The FPL Turkey Point Unit 5's EGEAS cost already includes transmission integration costs of approx. $4 million CPVRR.

*** These transmission-related costs are relative to the FPL Turkey Point Unit 5's costs.

## FPL Rankings of Portfolios - EGEAS & Transmission-Related Costs Only

**(millions, CPVRR, 2003$, 2003 - 2031)**

**(note: includes proposals eventually dropped as non-compliant)**

| | | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) = sum of (1) thru (7) | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Transmission-Related Costs | | | | | | | |
| **Ranking of Portfolio** | **Description of Portfolio** | **Portfolio MW** | **EGEAS Results *** | **Integration ** ** | **Peak Hour Capacity Losses * * *** | **Annual Energy Losses * * *** | **Increased Operating Costs * * *** | **Upstream Gas Pipeline Costs** | **Net Equity Adjustment** | **Total** | **Difference from lowest cost portfolio** |
| 1 | FPL Turkey Point Unit 5 | 1,144 | 62,591 | 0 | 0 | 0 | 0 | 0 | 0 | 62,591 | 0 |
| 2 | Proposal 3, Proposal 1 | 1,270 | 62,741 | 6 | 14 | 19 | 15 | 0 | 0 | 62,795 | 204 |
| 3 | Proposal 2 | 1,220 | 62,763 | 7 | 14 | 29 | 15 | 0 | 0 | 62,827 | 236 |
| 4 | FPL 4 CT, Proposal 4, Proposal 1 | 1,145 | 62,712 | 56 | 6 | 47 | 11 | 0 | 0 | 62,831 | 240 |
| 5 | Proposal 3 | 1,220 | 62,760 | 7 | 16 | 34 | 15 | 0 | 0 | 62,832 | 241 |
| 6 | Proposal 2, Proposal 1 | 1,270 | 62,788 | 6 | 12 | 14 | 15 | 0 | 0 | 62,835 | 244 |
| 7 | FPL 4 CT, Proposal 4 | 1,095 | 62,695 | 56 | 11 | 64 | 16 | 0 | 0 | 62,841 | 250 |
| 8 | FPL 4 CT, Proposal 4, Proposal 5 | 1,347 | 62,741 | 56 | 7 | 41 | 15 | 0 | 0 | 62,861 | 270 |

* EGEAS results include: capital, fixed O&M, variable O&M, capital replacement costs, project fuel/energy cost, FPL system fuel, transmission interconnection, and gas pipeline lateral costs. Values for Proposal 1 assume 80%/20% coal/pet coke mix.

** The FPL Turkey Point Unit 5's EGEAS cost already includes transmission integration costs of approx. $4 million CPVRR.

*** These transmission-related costs are relative to the FPL Turkey Point Unit 5's costs.

**Calculation of Peak Hour Loss Cost**
**for the FPL 4 CT & Proposal 4 Portfolio**

| | |
|---|---|
| Discount Rate = | 0.07819 |
| Purchase Proxy Starting Cost ($/kw) = | $5.00 |
| Annual Escalation Rate for Proxy Purchase = | 1.7% |

| | (1) | (2) | (3) | (4) = (1)*(3)*12 | (5) = (2)*(4) |
|---|---|---|---|---|---|
| Year | Proxy Purchase Cost ($/kw-mo) | Discount Factor | Peak Load Loss (MW) | Peak Hour Capacity Loss Cost Nominal ($ 000) | Peak Hour Capacity Loss Cost NPV ($ 000) |
| 2003 | $0 | 1.000 | 0 | $0 | $0 |
| 2004 | $0 | 0.927 | 0 | $0 | $0 |
| 2005 | $0 | 0.860 | 0 | $0 | $0 |
| 2006 | $0 | 0.798 | 0 | $0 | $0 |
| 2007 | $0 | 0.740 | 27 | $0 | $0 |
| 2008 | $0 | 0.686 | 27 | $0 | $0 |
| 2009 | $5.00 | 0.637 | 27 | $1,620 | $1,031 |
| 2010 | $5.09 | 0.590 | 27 | $1,648 | $973 |
| 2011 | $5.17 | 0.548 | 27 | $1,676 | $917 |
| 2012 | $5.26 | 0.508 | 27 | $1,704 | $865 |
| 2013 | $5.35 | 0.471 | 27 | $1,733 | $816 |
| 2014 | $5.44 | 0.437 | 27 | $1,762 | $770 |
| 2015 | $5.53 | 0.405 | 27 | $1,792 | $726 |
| 2016 | $5.63 | 0.376 | 27 | $1,823 | $685 |
| 2017 | $5.72 | 0.349 | 27 | $1,854 | $646 |
| 2018 | $5.82 | 0.323 | 27 | $1,885 | $610 |
| 2019 | $5.92 | 0.300 | 27 | $1,917 | $575 |
| 2020 | $6.02 | 0.278 | 27 | $1,950 | $542 |
| 2021 | $6.12 | 0.258 | 27 | $1,983 | $512 |
| 2022 | $6.23 | 0.239 | 7 | $523 | $125 |
| 2023 | $6.33 | 0.222 | 7 | $532 | $118 |
| 2024 | $6.44 | 0.206 | 7 | $541 | $111 |
| 2025 | $6.55 | 0.191 | 7 | $550 | $105 |
| 2026 | $6.66 | 0.177 | 7 | $559 | $99 |
| 2027 | $6.77 | 0.164 | 7 | $569 | $93 |
| 2028 | $6.89 | 0.152 | 7 | $579 | $88 |
| 2029 | $7.00 | 0.141 | 7 | $588 | $83 |
| 2030 | $7.12 | 0.131 | 7 | $598 | $78 |
| 2031 | $7.24 | 0.121 | 7 | $609 | $74 |
| | | | | NPV Total ($000) = | $10,644 |

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Document No. SRS -10
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## Calculation of Annual Energy Loss Cost for the FPL 4 CT & Proposal 4 Portfolio

| | |
|---|---|
| On-Peak Hours = | 876 |
| Off-Peak Hours = | 7,884 |
| Discount Rate = | 0.07819 |

| Year | (1)<br>On-Peak Marginal Energy Cost ($/mwh) | (2)<br>Off-Peak Marginal Energy Cost ($/mwh) | (3)<br>Discount Factor | (4)<br>Peak Load Loss (MW) | (5) = (4)*On-Peak Hours<br>On - Peak Hours Annual Energy Loss (MWH) | (6) = (1)*(5)/1000<br>On - Peak Hours Annual Energy Loss Cost Nominal ($ 000) | (7)<br>Average Load Loss (MW) | (8) = (7)*Off-Peak Hours<br>Off - Peak Hours Annual Energy Loss (MWH) | (9) = (2)*(8)/1000<br>Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000) | (10) = (6) + (9)<br>Total Annual Energy Loss Cost Nominal ($ 000) | (11) = (3)*(10)<br>Total Annual Energy Loss Cost NPV ($ 000) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2003 | 0 | 0 | 1.000 | 0 | 0 | $0 | 0 | 0 | $0 | $0 | $0 |
| 2004 | 0 | 0 | 0.927 | 0 | 0 | $0 | 0 | 0 | $0 | $0 | $0 |
| 2005 | 0 | 0 | 0.860 | 0 | 0 | $0 | 0 | 0 | $0 | $0 | $0 |
| 2006 | 0 | 0 | 0.798 | 0 | 0 | $0 | 0 | 0 | $0 | $0 | $0 |
| 2007 | $46.92 | $39.15 | 0.740 | 27 | 23,652 | $1,110 | 19 | 149,796 | $5,865 | $6,974 | $5,161 |
| 2008 | $45.77 | $38.49 | 0.686 | 27 | 23,652 | $1,083 | 19 | 149,796 | $5,766 | $6,848 | $4,700 |
| 2009 | $47.31 | $39.94 | 0.637 | 27 | 23,652 | $1,119 | 19 | 149,796 | $5,983 | $7,102 | $4,521 |
| 2010 | $47.82 | $40.13 | 0.590 | 27 | 23,652 | $1,131 | 19 | 149,796 | $6,011 | $7,142 | $4,217 |
| 2011 | $50.00 | $41.91 | 0.548 | 27 | 23,652 | $1,183 | 19 | 149,796 | $6,278 | $7,461 | $4,085 |
| 2012 | $50.26 | $42.68 | 0.508 | 27 | 23,652 | $1,189 | 19 | 149,796 | $6,393 | $7,582 | $3,851 |
| 2013 | $53.33 | $44.79 | 0.471 | 27 | 23,652 | $1,261 | 19 | 149,796 | $6,709 | $7,971 | $3,754 |
| 2014 | $55.90 | $44.73 | 0.437 | 27 | 23,652 | $1,322 | 19 | 149,796 | $6,700 | $8,023 | $3,505 |
| 2015 | $56.67 | $46.05 | 0.405 | 27 | 23,652 | $1,340 | 19 | 149,796 | $6,898 | $8,238 | $3,338 |
| 2016 | $58.97 | $48.44 | 0.376 | 27 | 23,652 | $1,395 | 19 | 149,796 | $7,256 | $8,651 | $3,251 |
| 2017 | $60.77 | $49.38 | 0.349 | 27 | 23,652 | $1,437 | 19 | 149,796 | $7,397 | $8,834 | $3,079 |
| 2018 | $62.69 | $51.47 | 0.323 | 27 | 23,652 | $1,483 | 19 | 149,796 | $7,710 | $9,193 | $2,972 |
| 2019 | $63.08 | $52.28 | 0.300 | 27 | 23,652 | $1,492 | 19 | 149,796 | $7,831 | $9,323 | $2,795 |
| 2020 | $63.59 | $53.21 | 0.278 | 27 | 23,652 | $1,504 | 19 | 149,796 | $7,971 | $9,475 | $2,635 |
| 2021 | $66.15 | $55.35 | 0.258 | 27 | 23,652 | $1,565 | 19 | 149,796 | $8,291 | $9,856 | $2,542 |
| 2022 | $68.21 | $57.24 | 0.239 | 7 | 6,132 | $418 | 10 | 78,840 | $4,513 | $4,931 | $1,180 |
| 2023 | $68.85 | $58.71 | 0.222 | 7 | 6,132 | $422 | 10 | 78,840 | $4,629 | $5,051 | $1,121 |
| 2024 | $72.56 | $61.38 | 0.206 | 7 | 6,132 | $445 | 10 | 78,840 | $4,839 | $5,284 | $1,087 |
| 2025 | $73.97 | $63.40 | 0.191 | 7 | 6,132 | $454 | 10 | 78,840 | $4,998 | $5,452 | $1,041 |
| 2026 | $76.54 | $65.68 | 0.177 | 7 | 6,132 | $469 | 10 | 78,840 | $5,178 | $5,648 | $1,000 |
| 2027 | $79.49 | $67.82 | 0.164 | 7 | 6,132 | $487 | 10 | 78,840 | $5,347 | $5,834 | $958 |
| 2028 | $81.41 | $70.21 | 0.152 | 7 | 6,132 | $499 | 10 | 78,840 | $5,535 | $6,035 | $919 |
| 2029 | $84.10 | $72.75 | 0.141 | 7 | 6,132 | $516 | 10 | 78,840 | $5,736 | $6,251 | $883 |
| 2030 | $86.92 | $75.34 | 0.131 | 7 | 6,132 | $533 | 10 | 78,840 | $5,940 | $6,473 | $848 |
| 2031 | $90.90 | $77.88 | 0.121 | 7 | 6,132 | $557 | 10 | 78,840 | $6,140 | $6,697 | $814 |
| | | | | | | | | | | NPV Total ($000) = | $64,254 |

## FPL Rankings of Portfolios Prior to Finalist Announcement – All Costs

**(millions, CPVRR, 2003$, 2003 - 2031)**

**(note: includes proposals eventually dropped as non-compliant)**

| | | | | Transmission-Related Costs | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) = sum of (1) thru (7) | |
| **Ranking of Portfolio** | **Description of Portfolio** | **Portfolio MW** | **EGEAS Results *** | **Integration * *** | **Peak Hour Capacity Losses * * *** | **Annual Energy Losses * * *** | **Increased Operating Costs * * *** | **Upstream Gas Pipeline Costs** | **Net Equity Adjustment** | **Total** | **Difference from lowes cost portfoli** |
| 1 | FPL Turkey Point Unit 5 | 1,144 | 62,591 | 0 | 0 | 0 | 0 | 0 | 0 | 62,591 | 0 |
| 2 | FPL 4 CT, Proposal 4 | 1,095 | 62,695 | 56 | 11 | 64 | 16 | 0 | 16 | 62,857 | 266 |
| 3 | FPL 4 CT, Proposal 4, Proposal 1 | 1,145 | 62,712 | 56 | 6 | 47 | 11 | 0 | 35 | 62,867 | 276 |
| 4 | FPL 4 CT, Proposal 4, Proposal 5 | 1,347 | 62,741 | 56 | 7 | 41 | 15 | 0 | 28 | 62,888 | 297 |
| 5 | Proposal 2 | 1,220 | 62,763 | 7 | 14 | 29 | 15 | 0 | 63 | 62,891 | 300 |
| 6 | Proposal 2, Proposal 1 | 1,270 | 62,788 | 6 | 12 | 14 | 15 | 0 | 82 | 62,918 | 327 |
| 7 | Proposal 3, Proposal 1 | 1,270 | 62,741 | 6 | 14 | 19 | 15 | 0 | 132 | 62,927 | 336 |
| 8 | Proposal 3 | 1,220 | 62,760 | 7 | 16 | 34 | 15 | 0 | 113 | 62,945 | 354 |

* EGEAS results include: capital, fixed O&M, variable O&M, capital replacement costs, project fuel/energy cost, FPL system fuel, transmission interconnection, and gas pipeline lateral costs. Values for Proposal 1 assume 80%/20% coal/pet coke mix.

** The FPL Turkey Point Unit 5's EGEAS cost already includes transmission integration costs of approx. $4 million CPVRR.

*** These transmission-related costs are <u>relative to</u> the FPL Turkey Point Unit 5's costs.

# FPL Rankings of Portfolios After Best and Final Offer from Finalist

**(millions, CPVRR, 2003$, 2003 - 2031)**

**(note: includes proposals eventually dropped as non-compliant)**

| | | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) = sum of (1) thru (7) | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Transmission-Related Costs | | | | | | | |
| **Ranking of Portfolio** | **Description of Portfolio** | **Portfolio MW** | **EGEAS Results *** | **Integration ** ** | **Peak Hour Capacity Losses * * *** | **Annual Energy Losses * * *** | **Increased Operating Costs * * *** | **Upstream Gas Pipeline Costs** | **Net Equity Adjustment** | **Total** | **Difference from lowest cost portfolio** |
| 1 | FPL Turkey Point Unit 5 | 1,144 | 62,591 | 0 | 0 | 0 | 0 | 0 | 0 | 62,591 | 0 |
| 2 | FPL 4 CT, Proposal 4 | 1,095 | 62,700 | 56 | 11 | 64 | 16 | 0 | 16 | 62,862 | 271 |
| 3 | FPL 4 CT, Proposal 4, Proposal 1 | 1,145 | 62,717 | 56 | 6 | 47 | 11 | 0 | 35 | 62,872 | 281 |
| 4 | Proposal 2 | 1,220 | 62,763 | 7 | 14 | 29 | 15 | 0 | 63 | 62,891 | 300 |
| 5 | FPL 4 CT, Proposal 4, Proposal 5 | 1,347 | 62,746 | 56 | 7 | 41 | 15 | 0 | 28 | 62,893 | 302 |
| 6 | Proposal 2, Proposal 1 | 1,270 | 62,788 | 6 | 12 | 14 | 15 | 0 | 82 | 62,918 | 327 |
| 7 | Proposal 3, Proposal 1 | 1,270 | 62,741 | 6 | 14 | 19 | 15 | 0 | 132 | 62,927 | 336 |
| 8 | Proposal 3 | 1,220 | 62,760 | 7 | 16 | 34 | 15 | 0 | 113 | 62,945 | 354 |

* EGEAS results include: capital, fixed O&M, variable O&M, capital replacement costs, project fuel/energy cost, FPL system fuel, transmission interconnection, and gas pipeline lateral costs. Values for Proposal 1 assume 80%/20% coal/pet coke mix.

** The FPL Turkey Point Unit 5's EGEAS cost already includes transmission integration costs of approx. $4 million CPVRR.

*** These transmission-related costs are <u>relative to</u> the FPL Turkey Point Unit 5's costs.