BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for an electrical power plant in Martin County by Florida Power & Light Company.	DOCKET NO. 020262-EI
In re: Petition to determine need for an electrical power plant in Manatee County by Florida Power & Light Company.	DOCKET NO. 020263-EI ORDER NO. PSC-02-1743-FOF-EI ISSUED: December 10, 2002

The following Commissioners participated in the disposition of this matter:

LILA A. JABER, Chairman
J. TERRY DEASON
BRAULIO L. BAEZ
MICHAEL A. PALECKI
RUDOLPH "RUDY" BRADLEY

APPEARANCES:

CHARLES A. GUYTON, ESQUIRE, JOHN T. BUTLER, ESQUIRE, WILLIAM HILL, ESQUIRE, GABRIEL E. NIETO, ESQUIRE, and ELIZABETH C. DALY, ESQUIRE, Steel, Hector & Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, and R. WADE LITCHFIELD, ESQUIRE, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408, appearing on behalf of Florida Power & Light Company.

JON C. MOYLE, JR., ESQUIRE, and CATHY M. SELLERS, ESQUIRE, Moyle, Flanigan, Katz, Raymond & Sheehan, P.A., The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of CPV Gulfcoast, Ltd.

JOSEPH A. McGLOTHLIN, ESQUIRE, McWhirter, Reeves, McGlothlin, Davidson, Dekker, Kaufman, Arnold & Steen, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Partnership for Affordable Competitive Energy.

JOHN W. McWHIRTER, JR., ESQUIRE, McWhirter, Reeves, McGlothlin, Davidson, Decker, Kaufman & Arnold, P.A., 400 North Tampa Street, Suite 2450, Tampa, Florida 33601-3350 appearing on behalf of the Florida Industrial Power Users Group.

MICHAEL B. TWOMEY, ESQUIRE, P. O. Box 5256, Tallahassee, Florida 32314-5256, appearing on behalf of Florida Action Coalition Team.

MARTHA CARTER BROWN, ESQUIRE, and LAWRENCE D. HARRIS, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Commission.

BY THE COMMISSION:

ORDER GRANTING DETERMINATION OF NEED

I. CASE BACKGROUND

On August 13, 2001, Florida Power & Light Company (FPL) issued a request for proposals (RFP) for capacity resources to meet an anticipated need for 1,708 MW of capacity in the Summers of 2005 and 2006. In this initial RFP, FPL identified several self-build options: the conversion of existing units from combustion turbine to combined cycle operation at FPL's existing Martin and Ft. Myers sites and the construction of new combined cycle units at Martin and at a new site, Midway. As a result of its initial RFP analysis, however, FPL identified, and requested a determination of need for, two different self-build options to meet its capacity need: the Martin Unit 8 expansion project and a new unit, Manatee Unit 3.

The Martin Unit 8 expansion project consists of 789 MW of new capacity additions to two existing combustion turbine units, Martin Units 8A and 8B. When the expansion project is completed, Martin Unit 8 will be a 1,107 MW natural gas-fired, combined cycle power plant. Using distillate oil as backup fuel, Martin Unit 8 would be located at the existing Martin site in Martin County, Florida, and is expected to be placed into service by June, 2005. Manatee Unit 3 consists of a new 1,107 MW natural gas-fired, combined cycle power plant identical to Martin Unit 8. Manatee Unit 3 will not use an alternate fuel type as backup, since the unit will rely upon two natural gas transportation pipelines, FGT and Gulfstream, to supply primary and backup fuel. Manatee Unit 3 would be located at the existing Manatee site in Manatee County, Florida, and is also expected to be placed into service by June, 2005. On March 22, 2002, FPL filed a Petition for Determination of Need with the Commission for Martin Unit 8 and Manatee Unit 3.

A number of unsuccessful respondents in FPL's initial RFP process were granted leave to intervene in this proceeding. These intervenors included Reliant Energy Power Generation, Inc. (Reliant), Mirant Corporation (Mirant), Calpine Eastern Corporation (Calpine), South Pond Energy Park, LLC (South Pond), and CPV Cana, Ltd. (CPV Cana). In part due to concerns raised by the intervenors over FPL's RFP process, FPL filed an Emergency Motion to Hold Proceedings in Abeyance on April 22, 2002. In its motion, FPL agreed to issue a supplemental RFP to allow bidders an additional opportunity to provide cost-effective alternatives to FPL's self-build option. FPL issued the supplemental RFP on April 26, 2002. As a result of its supplemental RFP analysis, FPL again identified the Martin Unit 8 expansion and Manatee Unit 3 as the most cost-effective alternative available to meet its identified need. On July 16, 2002, FPL filed a Motion for Leave to Amend Petitions for Determination of Need, Amended Petitions for Determination of Need for Martin Unit 8 and Manatee Unit 3, and associated prefiled testimony and exhibits.

In response to FPL's supplemental RFP and subsequent amended need determination petitions, several other parties intervened in this proceeding, including CPV Gulfcoast, Ltd. (CPV Gulfcoast), Florida Industrial Power Users Group (FIPUG), the Florida Partnership for Affordable Competitive Energy (PACE), and the Florida Action Coalition Team and several individual FPL retail customers (collectively, FACT et. al.). Several of the original intervenors subsequently withdrew from the proceeding, including Reliant, Calpine, Mirant, and South Pond. CPV Cana was dismissed from the case because it did not bid in response to FPL's supplemental RFP.

At the prehearing conference held on September 23, 2002, eighteen substantive issues were identified for resolution in this proceeding. We conducted an evidentiary administrative hearing on those issues October 2, 2002, through October 4, 2002. Posthearing briefs were filed on October 14, 2002. PACE, FIPUG, CPV Gulfcoast, and FACT et. al. participated in the hearing and submitted briefs. Separate public hearings are scheduled to be held by the Department of Environmental Protection before the Division of Administrative Hearings to consider the environmental and other impacts of the proposed plants.

II. DETERMINATION OF NEED PURSUANT TO SECTION 403.519, FLORIDA STATUTES

We have considered the hearing testimony and exhibits, as well as the briefs filed by the parties, and on the basis of that record, we grant FPL's need determination petitions. Our jurisdiction to conduct this proceeding, and the substantive considerations of the case, are governed by Section 403.519, Florida Statutes, which contains the following five areas for review by the Commission in determining the need for an electrical power plant:

(1) the need for electric system reliability and integrity;

(2) the need for adequate electricity at reasonable cost;

(3) conservation measures taken by or reasonably available to the applicant which might mitigate the need for the proposed power plant;

(4) whether the proposed plant is the most cost-effective alternative available; and

(5) other matters within the Commission's jurisdiction which it deems relevant.

Our reasons for our decision are set forth in detail below.

A. Need for Electric System Reliability and Integrity

We find that Florida Power & Light company has a need for additional capacity to maintain the reliability and integrity of its system, which will be provided by Manatee Unit 3 and Martin Unit 8. FPL has an estimated need for 1,122 MW of additional capacity for Summer, 2005, and an additional need for 600 MW of capacity for Summer, 2006. The 1,107 MW of summer capacity from Manatee Unit 3 will contribute to FPL's electric system reliability and integrity. With the addition of that capacity, FPL's projected reserve margin for Summer, 2005 is 19.92%. In order to precisely meet a planning reserve margin criterion of 20.0%, FPL needs only 15 MW of capacity with the addition of Manatee Unit 3 in Summer, 2005. Therefore, FPL does not have a pressing reliability need for the entire 789 MW of capacity from Martin Unit 8 until Summer, 2006. As discussed below, however, the record shows that it is more cost-effective for FPL to place Martin Unit 8 into commercial service in 2005 rather than 2006.

The first step in any utility's generation expansion planning study is the load forecast. A load forecast indicates the timing and magnitude of a utility's capacity need. We find that FPL's load forecast is reasonable. FPL witness Green offered direct testimony, prefiled exhibits summarizing FPL's forecasts, and the historical data, forecast assumptions, and regression models used to create FPL's projected system peaks. The forecast assumptions were drawn from independent sources which the Commission has relied upon in prior cases. The regression models used to calculate FPL's projected peak demands conform to accepted economic and statistical practices. The projected peak demands produced by these models appear to be a reasonable extension of historical trends. No other party offered an alternative load forecast to that presented by witness Green. We find that FPL's forecast assumptions and regression models are appropriate.

PACE questioned whether FPL's forecasts were "front loaded" because the forecasted average compound growth rate for the ten-year forecast period is 2.1%, while witness Green assumes that FPL's 2003 summer peak would grow by 3.3% from the prior year. Witness Green testified that this annual growth rate is largely due to FPL's recent rate reduction causing the price of electricity to fall. We find that the 2003 summer peak demand growth rate of 3.3% is reasonable and is based upon a known and quantifiable event.

As stated above, based on its load forecast, FPL has identified a need for 1,122 MW of capacity for Summer, 2005, and an additional 600 MW of capacity for Summer, 2006, to maintain a 20% summer reserve margin criterion. FPL's capacity needs for 2005 and 2006 are consistent with what has been reflected in FPL's past two Ten-Year Site Plans. If FPL added only the 1,107 MW Manatee Unit 3 in Summer, 2005, FPL would have a projected capacity deficit of only 15 MW. Under this scenario, the resulting summer reserve margin for Summer, 2005 would be 19.92%. CPV Gulfcoast, PACE, FIPUG, and FACT et. al. take issue with FPL's position that it needs Martin Unit 8 for reliability reasons in 2005. The parties assert that FPL should have gone outside the RFP process to find a one-year seasonal purchase of 15 MW. FPL witness Silva testified that such a purchase would be possible, and that FPL frequently purchases short-term capacity. However, FPL witness Sim testified that it was not appropriate to go outside the RFP to find 15 MW, and FPL was concerned that going outside the RFP would have been unfair to the respondents. Given the parties' objections to FPL's supplemental RFP process that are discussed below, we believe that FPL's decision not to go outside the confines of the RFP process to find capacity is reasonable.

CPV Gulfcoast also argues that FPL could have simply rounded up the 19.92% reserve margin to 20.0%. That is true. If FPL had done so in this case, its forecasted Summer, 2005, reserve margin would be 20% with the one-year deferral of Martin Unit 8. Thus, while the addition of Martin Unit 8's 789 MW of capacity in Summer, 2005, certainly enhances FPL's electric system reliability and integrity, it is not, strictly speaking, needed. The addition of the unit along with Manatee Unit 3 in Summer, 2005, is expected to result in a reserve margin of 24.1%, and the true reliability need for Martin Unit 8 is for Summer, 2006. Combining the 15 MW shortfall in 2005 with FPL's identified need for 600 MW in 2006, FPL would have a need for 615 MW of additional capacity in Summer, 2006. By this analysis, electric system reliability would not be harmed by deferring the in-service date of Martin Unit 8 by one year to more closely meet FPL's projected load growth. It is, however, more cost-effective for FPL's ratepayers if FPL places Martin Unit 8 into commercial service in 2005, instead of deferring the unit by one year, and it is for that reason that we approve the need for both units in 2005.

B. Need for Adequate Electricity at a Reasonable Cost

The record shows that Florida Power & Light has a need for Martin Unit 8 and Manatee Unit 3, taking into account the need for adequate electricity at a reasonable cost. FPL has chosen a proven technology and has experience with the construction and operation of combined cycle units. The estimated costs for both units are reasonable.

1. Technology and Construction Costs

The Martin site currently has two General Electric F-class advanced combustion turbines, Martin Units 8A and 8B. The 789 MW Martin Unit 8 expansion project proposed by FPL consists of two additional combustion turbines, four heat recovery steam generators, and a steam generating turbine. The total summer capacity of the unit will be 1,107 MW. FPL has extensive experience in building combined cycle plants dating back to 1976, and FPL currently has over 4,700 MW of combined cycle capacity on its system. FPL expects that air emissions from Martin Unit 8 will be minimized through the use of clean fuels and best available control technology. The location of Martin Unit 8 at an existing site is expected to minimize land-use impacts associated with the unit.

FPL's cost estimates for Martin Unit 8 are reasonable. No other party took issue with FPL's construction costs or schedule. FPL estimates that Martin Unit 8 will cost approximately $439 million to build. FPL witness Yeager testified that FPL's experience in building combined cycle plants, such as the Ft. Lauderdale, Sanford, and Ft. Myers repowering projects and the Martin Units 3 and 4, gives FPL assurances that it can complete the unit on time and on budget. We believe the record supports this assessment. Our approval of Martin Unit 8 does not, however, relieve FPL from its responsibility to prudently manage costs associated with the unit. We will review actual costs in subsequent recovery clause or rate case proceedings.

FPL's estimated average net operating heat rate for Martin Unit 8 is 6,850 Btu/kWh. This estimate is aggressive, but not out of line with what was contained in many of the RFP responses. In fact, CPV Gulfcoast's bid in response to FPL's supplemental RFP reflected a slightly lower, or better, heat rate of 6,838 BTU/kWh. FPL has estimated that the equivalent availability factor will be 97%. Witness Yeager testified that FPL's combined cycle units have historically exceeded past targets for availability and have consistently exceeded the industry average. FPL's availability estimate for Martin Unit 8 is also aggressive, but is indicative of FPL's recent operating experience at Martin Units 3 and 4. We will have the opportunity to evaluate FPL's unit performance on an ongoing basis through the Generating Performance Incentive Factor (GPIF), in which we can reward or penalize FPL based on its achievement of prescribed heat rate and unit availability targets.

Manatee Unit 3 will consist of four General Electric F-class advanced combustion turbines, four heat recovery steam generators, and a steam generating turbine. The total summer capacity of the unit will be 1,107 MW. FPL expects that air emissions from Manatee Unit 3 will be minimized through the use of clean fuels and best available control technology. The location of Manatee Unit 3 at an existing site is expected to minimize land-use impacts associated with the unit.

FPL's cost estimates for Manatee Unit 3 are reasonable. No other party took issue with FPL's construction cost or schedule. FPL estimates that Manatee Unit 3 will cost approximately $551 million to build. FPL witness Yeager testified to his belief that FPL's experience in building combined cycle plants, such as the Ft. Lauderdale, Sanford, and Ft. Myers repowering projects and the Martin Units 3 and 4, gives FPL assurances that it can complete the unit on time and on budget. We believe the record supports this assessment. Our approval of Manatee Unit 3 does not, however, relieve FPL from its responsibility to prudently manage costs associated with the unit. We will review actual costs in subsequent recovery clause or rate case proceedings.

FPL's estimated average net operating heat rate for Manatee Unit 3 is 6,850 Btu/kWh. This estimate is aggressive, but not out of line with what was contained in many of the RFP bids. FPL has estimated that the equivalent availability factor will be 97%. This estimate is also aggressive, but is indicative of FPL's recent operating experience at Martin Units 3 and 4. We will have the opportunity to evaluate FPL's unit performance on an ongoing basis through the Generating Performance Incentive Factor (GPIF), in which we can reward or penalize FPL based on its achievement of prescribed heat rate and unit availability targets.

2. Fuel Commodity and Transportation

FPL has adequately ensured the availability of fuel commodity and transportation to serve Martin Unit 8 and Manatee Unit 3. At the present time there are no signed firm natural gas supply or transportation contracts in place for FPL's proposed units. FPL witness Yupp testified however, that FPL will enter into firm contracts for both supply and transportation when the time is appropriate. Witness Yupp testified that two natural gas pipeline laterals, both tied to the Florida Gas Transmission System (FGT) interstate pipeline, currently serve the Martin site. The northern lateral supplies both residual oil and natural gas to Martin Units 1 and 2. The southern lateral supplies natural gas to the existing Martin Units 3 and 4. While adequate for Martin Units 3 and 4, the northern lateral cannot adequately supply the additional natural gas demand of Martin Unit 8 during peak periods. Another lateral or additional compression will be required to ensure sufficient supply of natural gas to the Martin site. FGT will independently undertake the necessary permitting and construction activities for any new lateral or added compression on the existing (north) lateral to the Martin site.

Witness Yupp also testified that Manatee Unit 3 will burn only natural gas. FPL has executed an interruptible transportation agreement with Gulfstream to deliver natural gas for the existing Manatee Units 1 and 2 through a recently installed lateral. This new lateral from the Gulfstream main line is sufficient in size to deliver natural gas to Manatee Units 1, 2, and 3 during peak periods.

CPV Gulfcoast was the only intervenor to question the availability of fuel commodity and transportation to the proposed units. CPV Gulfcoast contends that FPL has not adequately ensured the supply and transport of fuel to serve Martin Unit 8 and the supply of fuel to Manatee Unit 3, because contracts have not yet been signed. FPL witness Yupp stated that FPL would provide the Commission a copy of the signed contracts once they are executed. The preponderance of the evidence clearly indicates that FPL will not have difficulty acquiring fuel commodity or transportation for the proposed units. Under these circumstances, it is appropriate for FPL to gain regulatory approval for a generating unit prior to signing a firm gas supply or transportation contract.

The record shows that FPL has chosen a proven technology for the plants to fill its capacity needs, and has experience with the construction and operation of combined cycle units. The estimated costs of both units are reasonable, and FPL has adequately ensured the availability of fuel commodity and transportation to serve them. Therefore, we approve the units as appropriate contributions to the provision of adequate electricity at reasonable cost.

C. Conservation Measures

We find that there are no further conservation measures available to Florida Power & Light Company that might mitigate the need for Martin Unit 8 or Manatee Unit 3. FPL has already implemented a considerable amount of cost-effective conservation and demand-side management (DSM). This level of DSM savings was quantified in FPL's DSM goals, which the Commission set in August, 1999. To meet these goals, FPL has a DSM Plan consisting of six residential and eight commercial/industrial DSM programs, which the Commission approved in May, 2000. FPL fell short of several of its DSM goals in 2000, but met all DSM goals in 2001, and, therefore, we believe there are no additional cost-effective conservation or DSM measures available to defer the need for either unit.

PACE, CPV Gulfcoast, and FACT et. al. argue that FPL failed to address whether an additional 15 MW of conservation was available to defer the need for Martin Unit 8 by a year. In fact, FPL witness Brandt testified that there may be 15 MW of additional conservation available to FPL to defer Martin Unit 8 if cost-effectiveness was not a concern. As we will explain in section II(D)(7), however, cost-effectiveness is a concern, and deferral of Martin Unit 8 by one year carries an approximately $18 million cost above FPL's plan to build both units in 2005. Thus there are no cost savings associated with the deferral of Martin Unit 8 that would justify additional expenditures for the additional 15 MW of conservation savings. The preponderance of the evidence in this proceeding supports FPL's position that there are no additional cost-effective conservation or DSM measures available that might mitigate FPL's need for Martin Unit 8 or Manatee Unit 3.

D. The Most Cost Effective Alternative

In this section, we will discuss several issues raised by the parties regarding FPL's RFP process, it's evaluation of the responses it received to its supplemental RFP, and the overall cost-effectiveness of FPL's decision to build its own additional generating capacity for operation in 2005.

1. FPL's Supplemental Request for Proposals and Rule 25-22.082, Florida Administrative Code.

Commission Rule 25-22.082, Florida Administrative Code, requires investor-owned electric utilities to issue a request for proposals to provide the additional capacity the utility anticipates building that would be subject to Florida's Power Plant Siting Act. The record in this case shows that FPL's Supplemental RFP, issued April 26, 2002, satisfied all existing requirements of our rule.

FPL met the notice requirements of the RFP rule by disseminating the supplemental RFP to the public and the electric industry at large. The supplemental RFP properly identified FPL's next planned generating units, Martin Unit 8 and Manatee Unit 3, that would be evaluated against responses to the Supplemental RFP. The supplemental RFP also provided a detailed description of the next planned generating units that included all the data and information required by the RFP rule. The supplemental RFP included the schedule of critical dates for solicitation, evaluation, screening of proposals, and any subsequent contract negotiations pursuant to the RFP rule. A description of price and non-price attributes to be addressed by each bidder, as well as a description of FPL's planned evaluation methodology, including the use of the EGEAS model for economic screening, was included in the supplemental RFP.

As CPV Gulfcoast points out, FPL did not explicitly provide an evaluation criteria for the review of a responding utility's projected reserve margin in its Supplemental RFP. FPL was concerned with TECO's RFP proposal, because FPL believed that if the proposal were accepted, TECO's reserve margin would fall below 20%. TECO's proposal did not make the short list for further negotiations, as it was not part of a cost-effective grouping of proposals. Witness Sim stated that this would have been an issue for subsequent contract negotiations.

CPV Gulfcoast witness Finnerty testified that FPL did not appropriately disclose how exceptions to the supplemental RFP would be evaluated. FPL responded that it properly provided for exceptions, but without prior knowledge of what exceptions would be claimed, it could not state in the Supplemental RFP how exceptions would be treated. FPL witness Sim testified that all proposals were treated identically in the economic evaluation without regard to whether exceptions were posed.

We have carefully reviewed FPL's Supplemental RFP, the requirements of Rule 25-22.082, Florida Administrative Code, and the record in this proceeding. Our review leads us to the conclusion that FPL's Supplemental RFP satisfied the requirements of our Rule.

2. FPL's Evaluation Process

The record in this case shows that the process FPL used to evaluate Martin Unit 8, Manatee Unit 3, and projects submitted in response to its Supplemental Request for Proposals, issued April 26, 2002, was fair, reasonable, and appropriate. FPL's analysis of its self-build options, individual responses to the Supplemental RFP, and grouping of proposals for purposes of the economic evaluation was appropriate. FPL's evaluation process reasonably resulted in the choice of the most cost-effective alternative required by statute.

FPL received 53 proposals from 16 bidders in response to the Supplemental RFP. Prior to performing an economic evaluation of the proposals and the self-build options, 22 proposals were either withdrawn or determined by FPL to be ineligible. Several bidders did not agree to the Completion Security requirement; one bidder under an existing contract with FPL could not meet its in-service date and its bids were declared ineligible; and, twelve proposals were determined to be too risky due to the corporate conditions of the respective bidders. Following its receipt of clarifying information and data from the remaining proposals, FPL ranked the proposals based on relative economics, resulting in two groupings, or tiers, of proposals. FPL performed its economic analyses of its self-build options and the RFP proposals using the Electric Generation and Analysis System (EGEAS) model.

The intervenors have challenged the grouping of proposals by FPL in its economic analyses, arguing that proposals should have been evaluated on a stand-alone basis. The record evidence in this case supports a contrary conclusion. FPL's decision to group proposals for evaluation was fair, reasonable, and appropriate, given the large megawatt need, the number of proposals submitted, the variation of the proposals with regard to term and megawatts offered, and the limitations of EGEAS in evaluating a number of options in one run. FPL's evaluation process reasonably resulted in the most cost-effective alternative required by statute.

The intervenors argue that the process used by FPL was biased in favor of FPL. They claim that FPL was predisposed to select its self-build options instead of fairly considering alternatives. PACE and FACT et. al. also argue that FPL's use of the equity adjustment biased the results of the evaluation process. We find no credible evidence in this case to support these allegations, and, as we will discuss later in detail, the objective economic comparisons between FPL's self-build projects and projects proposed by respondents to the Supplemental RFP favored FPL's proposed projects with or without an equity adjustment. FPL witness Silva also pointed to FPL's decisions to issue capacity solicitations in the past and to purchase power from other entities as evidence that FPL is not pre-disposed to select its self-build options. Further, the intervenor's argument that FPL's failure to provide assurance in the RFP that exceptions to the terms would not result in elimination is without merit. The record testimony indicates that no proposal was evaluated differently if exceptions were included, and there is no record testimony that FPL's failure to provide this assurance in any way affected the RFP process.

The RFP required by Rule 25-22.082, Florida Administrative Code, is a tool to measure the cost-effectiveness of an investor-owned utility's proposed capacity selection. Having the statutory obligation to serve retail consumers, the utility is responsible for deciding which generation resources it should build or buy in order to ensure reliable and cost-effective power for its consumers. As explained in subsection 1. above, FPL's supplemental RFP complied with the requirements of our rule. We find here that the process FPL used to evaluate its self-build options and proposals received in response to the Supplemental RFP was fair, reasonable, and appropriate.

3. <u>FPL's Assumptions and Methodologies</u>

We find that FPL employed fair and reasonable assumptions and methodologies to evaluate Martin Unit 8, Manatee Unit 3, and projects filed in response to its Supplemental RFP. Given the variation in the proposals with regard to term and megawatts proposed, the methodologies employed to evaluate supply-side options were appropriate.

PACE contends that the EGEAS model FPL used to evaluate the responses to its RFP and its self-build options is not adequate or appropriate to model a dynamic system. While the EGEAS model's production cost capability is less sophisticated than other computer programs that model hourly production costs, FPL modeled the self-build units and all RFP projects equally with EGEAS. The present worth costs of all proposals and groups of proposals were within 1.3% of each other, and there is no record evidence to show that use of a different production cost model would render any of the RFP proposals cost-effective. Therefore, the facts of this case support the determination that FPL's use of EGEAS to evaluate supply-side options was fair and reasonable.

We find that FPL's heat rate and availability assumptions for Martin Unit 8 and Manatee Unit 3 are reasonable. FPL's estimated average net operating heat rate for both Martin Unit 8 and Manatee Unit 3 is 6,850 Btu/kWh. This estimate is aggressive, but not out of line with what was contained in many of the RFP bids. CPV Gulfcoast's bid in response to FPL's supplemental RFP reflected a slightly lower, or better, heat rate of 6,838 BTU/kWh. FPL has estimated that the equivalent availability factor for both Martin Unit 8 and Manatee Unit 3 will be 97%. Witness Yeager testified that FPL's combined cycle units have historically exceeded past targets for availability and have consistently exceeded the industry average. While this estimate is also aggressive, it is supported by FPL's recent operating experience at Martin Units 3 and 4. PACE asserts that comparison of FPL's proposals with peak firing mode to the bidder's proposals without peak firing mode is misleading. That assertion is without record support. PACE further asserts that the Commission "must consider the risk of nonperformance by FPL relative to the contractual commitments of the outside alternatives." We have done so. We have continuing oversight of the performance of FPL's new units through the GPIF. For these reasons, we believe that FPL's heat rate and availability assumptions for Martin Unit 8 and Manatee Unit 3 are reasonable and appropriate.

We find that FPL appropriately modeled variable O&M costs in its analysis. Variable O&M expenses are the non-fuel expenses of electricity production that vary according to the amount of energy generated. FPL used the variable O&M costs contained in its supplemental RFP for the self-build projects, and modeled variable O&M costs for the bidders as they were bid. FPL witness Taylor described the variety of ways bidders divided total O&M expenses between fixed and variable, and FPL witness Sim testified that there is no single correct method of dividing O&M costs between fixed and variable, as the wide range of variable O&M costs supplied by the bidders shows. Witness Taylor did testify that units with higher than average variable costs might be dispatched less frequently, and PACE contends that FPL inappropriately modeled variable O&M expenses to the detriment of the bidders because of its relatively low variable costs. Witness Taylor responded that each bidder had the choice to structure its fixed and variable charges as it saw fit. In evaluating the RFP projects, FPL modeled variable O&M costs exactly as they were bid, and in evaluating Martin Unit 8 and Manatee Unit 3, FPL used the same variable O&M costs that were contained in the supplemental RFP. Thus, FPL modeled variable O&M on the same basis. FPL properly used the data that was provided in the bid responses for RFP projects, and in the supplemental RFP for Martin Unit 8 and Manatee Unit 3. It would have been inappropriate for FPL to make any changes to variable O&M costs bid by RFP respondents, or to its self-build units, after-the-fact.

We find that FPL fairly and appropriately compared the costs of projects having different durations, and its use of greenfield filler units in its expansion plan studies was appropriate. When FPL performs its generation expansion planning studies, additional capacity in the form of filler units is added in future years to maintain FPL's reserve margin criterion. Once FPL identifies the size and type of filler unit to be used, the EGEAS model automatically adds these filler units as needed. If a short-term capacity purchase is considered, EGEAS will add a filler unit earlier than with a long-term purchase or new generating unit. The filler unit, however, will be the same without regard to whether the expansion plan consists of FPL's self-build plan, the all-outside RFP plan, or a combination of both. FPL chose a "greenfield" filler unit, a generating unit built on a new, previously undisturbed site, because, witness Sim testified, FPL would likely run out of brownfield sites before the end of the 30-year expansion plan period. He believed that the majority of filler units built during the expansion plan period would be at greenfield sites. Since a greenfield unit is typically more costly than a unit built at an existing site (brownfield unit), PACE argues that FPL's choice of a greenfield filler unit was inappropriate. FPL's EGEAS analysis, however, chose the same greenfield filler unit for all expansion plans, including the all-FPL self-build plan. Further, FPL witness Taylor testified that the costs associated with FPL's greenfield filler unit were actually less expensive than nine of the thirteen combined cycle proposals submitted in response to FPL's supplemental RFP. PACE also asserts that some expansion plans having short-term RFP proposals would see more filler units, introduced at earlier points in time, than would FPL's self-build expansion plan. It appears, however, that all expansion plans evaluated by FPL contained approximately the same number of filler units. For these reasons, we believe that FPL used the appropriate filler unit in its expansion planning studies, and thus appropriately modeled and quantified the costs of projects having different durations.

We find that FPL employed fair, reasonable and appropriate assumptions regarding the gas transportation costs applicable to filler units. FPL used identical gas transportation cost assumptions for filler units for generation expansion plans containing both FPL's self-build units and the RFP projects. PACE asserts that FPL's use of FGT's gas transportation cost assumptions, rather than Gulfstream's, for the filler units was unfairly biased against the RFP projects, but this assertion is not supported by the preponderance of the evidence. FPL applied FGT's cost assumptions uniformly to all filler units for generation expansion plans containing FPL's self-build units and the RFP projects. FGT's cost assumptions were applied because FGT's existing system covers a substantially larger part of the state than the Gulfstream system. Also, most RFP bidders stated that they would be served by FGT. There is no record evidence indicating that FPL inappropriately relied on FGT cost estimates for modeling filler units. For these reasons, we believe that FPL's assumptions were fair, reasonable, and appropriate.

We find that FPL appropriately and adequately took cycling and start-up costs into account when modeling the costs of all options, and modeled the costs identically for its self-build units and the RFP projects. In its analysis for the initial RFP, FPL did not use EGEAS to calculate start-up costs. Start-up costs were calculated separately and added to the EGEAS results. FPL witness Sim testified that EGEAS was used to model these costs during the supplemental RFP analysis. He testified that annual start-up costs were calculated based on cost per start-up information submitted by the RFP respondents, added to each bid's O&M costs and, therefore, modeled by EGEAS. FPL uniformly assumed six starts per year for all combined cycle units, both its own units and bidders' units. FPL witness Taylor testified that units with higher variable costs might be dispatched less, causing more frequent - and costly - starts and stops than normal for a combined cycle unit, and therefore FPL's method of modeling start-up and cycling costs may have provided an advantage for certain RFP projects with higher variable costs. But in any event, the potential cost impact associated with modeling start-up costs appears to be minuscule. Witness Sim discussed a sensitivity where FPL's units were modeled with six start-ups per year but all RFP projects were modeled with <u>no</u> start-up costs. He testified that this extreme case had a cost impact of less than $800,000 Net Present Value (NPV). Thus it appears that variations in modeling start-up costs would not change the results of FPL's analysis. FPL appropriately and adequately accounted for cycling and start-up costs when modeling and quantifying the costs of its self-build units and the RFP projects.

We find that FPL appropriately and adequately accounted for the impact of seasonal variations on heat rate and unit output. Greater precision in modeling seasonal variations on heat rate and unit output was unnecessary and would have affected both the FPL self-build units and the RFP projects to virtually the same degree. FPL's self-build units, as well as the vast majority of the RFP projects, are natural gas-fired combined cycle units. FPL witness Sim testified that all combined cycle units, whether owned by FPL or a bidder, would have similar seasonal variations, and that any relative differences would be negligible. FPL witness Taylor testified that the further precision required to model seasonal variations in a unit's output would not materially affect the outcome of FPL's analysis, and greater precision would have increased the run time of FPL's computer models substantially. PACE argues that FPL's analysis was imprecise, and thus introduced some level of error into the results. There is no record evidence, however, to show that seasonal variations in unit output would materially differ between combined cycle units. PACE witness Slater testified only that there were variations in unit output between summer and winter. The preponderance of the evidence clearly indicates that FPL used an acceptable level of precision in modeling its self-build options and the RFP projects. Further refinement would have added unnecessary work with minimal, if any, measurable benefit. All expansion plans evaluated by FPL, including the self-build units and the RFP projects, fell within 1.3% of each other on a cumulative present worth revenue requirements basis. For these reasons, we believe that FPL appropriately and adequately accounted for the impact of seasonal variations on heat rate and unit output in its analysis.

4. <u>TECO's Reserve Margin</u>

In the Prehearing Order, Issue 11(g) was identified for consideration in this proceeding. Issue 11(g) asked the following question: "Did FPL act in a fair, reasonable and appropriate manner in not considering for the short list portfolios that included TECO and other bidders, in part, because TECO's reserve margin requirement might be impaired?" The issue was originally raised by CPV/Gulfcoast. TECO did not intervene in this case, did not raise the issue itself, and has provided no evidence that it was harmed by FPL's evaluation of its RFP response. In light of these facts, we decline to address this issue.

5. <u>FPL's Equity Penalty Adjustment</u>

While we find that consideration of the impact of a purchased power agreement (PPA) on a company's cost of capital is proper, we decline to apply it in these dockets. We further find that any application of an equity adjustment should be evaluated on a case by case basis, with full consideration of the appropriate risk factor to be applied and mitigating factors considered by rating agencies. We also note that while we have decided not to apply an equity adjustment, FPL's Martin Unit 8 and Manatee Unit 3 are still the most cost effective options by at least $2 Million.

The equity adjustment (or "equity penalty") is a cost that is applied to PPAs to recognize the perceived negative impact those PPAs have on the company's overall capital structure due to their debt-like characteristics. The equity adjustment concept was used in FPL's evaluation of outside supply options in response to its Supplemental RFP.

FPL developed the equity adjustment concept to be used in the evaluation of power supply alternatives. FPL has based its calculation of the equity penalty on Standard and Poor's (S&P) methodology of imputing debt. In order to rebalance its capital structure and to account for the incremental impact purchased power will have on its capital structure, FPL has calculated an equity adjustment to be assessed on top of each proposal submitted. First, for a particular electric utility, S&P calculates the net present value of capacity payments arising from a purchased power agreement. S&P then assigns a risk factor, from 0% to 100%, based on its determination of how debt-like the obligation is. The risk factor determines how much of the net present value is added to reported obligations for purposes of financial analysis. An adjusted debt-equity ratio is then calculated.

There is a significant distinction to be made between FPL's equity adjustment concept and S&P's methodology for evaluating PPAs. S&P's overall credit assessment of a company is performed on a consolidated basis. S&P considers the impact PPAs may have on a company's capital structure. S&P also considers the terms associated with a PPA and will assign a risk factor. This risk factor is used to calculate the amount of off-balance sheet debt associated with these contracts. The amount of off-balance sheet debt is used in the calculation of the company's adjusted equity ratio, but this consideration is not done in isolation. It is only one of many factors S&P considers when performing a credit analysis. There are other risks and benefits that are taken into account both inside and outside of the scope of PPAs.

FPL's witnesses Avera, Taylor, and Dewhurst testified extensively about the validity of the equity adjustment concept, its applicability to this proceeding, and the methods of calculating the adjustment. FPL also addresses this issue extensively in its brief. The intervenors take the position to the contrary. They argue that the equity adjustment is an unfair and unsupported means of disadvantaging outside proposals in favor of a utility's self build option. The intervenors take the view that an equity adjustment is simply one factor out of many to be considered by financial rating agencies, and should not be applied in isolation of those other factors.

Although consideration of an equity adjustment is appropriate, from the record in these dockets it is not clear whether the adjustment was appropriately determined, what the correct equity adjustment, if any, is, or whether it should have been applied to the analysis of these PPA proposals. We are particularly concerned that the record does not contain sufficient evidence of the presence or amount of other factors which financial rating agencies may take into account in mitigation of the equity adjustment. We are also concerned with FPL's use of a 40% risk factor in its calculation. We find that in future dockets, a case-by-case examination of the entire circumstances surrounding the evaluation of PPAs, including the appropriateness of any risk factors used, the appropriate risk factor, and the presence or absence of mitigating factors shall be considered. Even without the application of an equity adjustment, FPL's Martin 8 and Manatee 3 proposals are still the most cost effective method of adding capacity. For the reasons stated, we decline to recognize the application of an equity adjustment in these dockets, but we note that this decision does not affect the ultimate determination of need.

6. <u>Transmission Interconnection and Integration Costs</u>

Based upon the record before us, we find that FPL properly and accurately evaluated transmission interconnection and integration costs in its analysis.

The capital costs for the RFP projects and FPL's self-build options included a cost for interconnecting the units to FPL's transmission system. Interconnection costs are the transmission capital costs needed to interconnect the unit with the electrical grid. Integration costs are the transmission capital costs needed to deliver that unit's power output throughout the grid.

FPL performed load flow studies to assess what new transmission facilities or system upgrades were needed to integrate each capacity portfolio. FPL then developed cost estimates for each of these transmission facilities. Finally, FPL compiled total transmission integration costs for each portfolio, as well as an estimated monthly cash flow of the costs for these projects.

FPL witness Stillwagon testified that, due to the limited existing capability to transfer power between Florida's east coast and west coast, the simultaneous addition of capacity resources on both coasts may balance power flows within the state. As a result, fewer transmission additions or upgrades may be required in these instances, resulting in lower transmission integration costs. Witness Stillwagon testified that the capacity portfolios requiring the least amount of transmission integration costs consisted of a relative balance of east coast versus west coast capacity additions, or were predominately on the east coast.

PACE, FIPUG, and FACT et. al. did not take a position on this issue. CPV Gulfcoast appears to have no issue with how FPL evaluated transmission interconnection costs. However, CPV Gulfcoast asserts that FPL did not properly evaluate transmission integration costs because these costs were not broken out for each proposed facility. FPL witness Stillwagon testified that it was not possible to designate transmission integration costs for each separate facility. The simultaneous addition of more than one capacity resource may stabilize power flows on the transmission system, resulting in the need for fewer new transmission facilities or upgrades. When a utility plans to add more than one capacity resource in a single year, the only proper way to evaluate the impact of these resources on the transmission system is to study them as a group.

There is no evidence in the record to indicate that FPL did not correctly evaluate transmission-related costs for the RFP projects and FPL's self-build options. Therefore, we find that FPL properly and accurately evaluated transmission interconnection and integration costs in its analysis.

7. Overall Cost Effectiveness of Martin Unit 8 and Manatee Unit 3

We find that both Martin Unit 8 and Manatee Unit 3 are the most cost effective alternatives available to meet FPL's capacity need beginning in 2005. We further find that it is $18 million more cost effective for FPL to build both plants in 2005, rather than building Manatee Unit 8 in 2005 and Martin Unit 8 in 2006.

FPL modeled a total of 36 expansion plans containing portfolios of capacity alternatives. These plans contained combinations of Martin Unit 8, Manatee Unit 3, and the RFP projects. There was an approximately $535 million cost differential between the least-cost FPL self-build plan and the highest-cost all-outside plan. However, all of the expansion plans evaluated by FPL fell within 1.3% of each other on a cumulative present worth revenue requirements basis.

The record evidence shows FPL's base-case self-build plan to be approximately $2 million more cost-effective than the most competitive expansion plan containing at least one bidder's project. The most competitive expansion plan contains FPL's Manatee Unit 3; a three-year, 50 MW capacity purchase from FPC; and a 25-year, 708 MW capacity purchase from El Paso. FPL's base-case self-build plan is approximately $320 million less costly than the best expansion plan containing all outside bids.

FPL evaluated a sensitivity plan in which Manatee Unit 3 enters service in Summer, 2005, and Martin Unit 8 is deferred by one year. No equity adjustment was applied to this sensitivity, since it contains only FPL-constructed generation. FPL's analysis showed that deferral of Martin Unit 8 by one year was $18 million more costly than FPL's base-case plan. We are also mindful of our Order No. PSC-02-0501-AS-EI, issued April 11, 2002 in Docket No. 020001-EI, where we approved a revenue sharing agreement between FPL and its ratepayers. Although that Order could permit FPL to seek a rate increase in certain circumstances, given FPL's current financial position, we do not believe this is likely to occur. Accordingly, FPL will not be able to recover the fixed costs of these plants in base rates until 2006, seven months after the proposed in-service dates.

FPL's financial assumptions include a capital structure consisting of 55% equity and 45% debt, a 7.4% cost rate for debt, and an 11.7% cost rate for equity. The assumptions also include a discount rate of 8.5%. FPL witness Avera stated that he found FPL's financial assumptions to be reasonable. In addition, staff witness Maurey reviewed FPL's financial assumptions and agreed that the financial assumptions appeared to be reasonable. Based on the testimony before us, we find that the financial assumptions used for FPL's self-build option are reasonable.

To perform its generation expansion planning analysis, FPL used the Electric Generation Expansion and Analysis System (EGEAS) resource optimization model, written by Stone & Webster for the Electric Power Research Institute. EGEAS combines multiple capacity options to come up with a series of expansion plans that satisfy a utility's capacity need, with the associated cumulative present worth revenue requirements (CPWRR) for each expansion plan. FPL used EGEAS to evaluate 31 proposals from 13 bidders, plus the two FPL self-build units. Witness Sim testified that EGEAS can run a maximum of 50 supply options in one "run." However, due to substantial time requirements for EGEAS to perform such large runs for a thirty-year forecast period, a practical limitation of 20 options was set for each EGEAS run. As a result, FPL performed hundreds of EGEAS runs which resulted in thousands of capacity combinations. After the EGEAS analysis was completed, FPL added equity penalty calculations and transmission integration costs for each expansion plan.

PACE asserts that an hourly production cost model such as POWERSYM would have given FPL more accurate results than an annual model such as EGEAS. However, witness Sim testified that POWERSYM would take substantially more time to produce 30 years' worth of hourly calculations, and that POWERSYM is more appropriate for short-term studies such as the fuel adjustment filing. Witness Sim testified that use of a different production cost model will change only the fuel cost, and that the different model would not have mattered in the Supplemental RFP analysis because the fuel cost and heat rates for both FPL's and the bidders' units were close. Witness Sim further testified that any inaccuracies in the input data would be multiplied by use of an hourly production cost model over a 25-30 year period. The record contains no credible evidence to contradict FPL's use of EGEAS to perform its generation expansion planning studies.

The majority of testimony from the only two intervenor witnesses, CPV Gulfcoast witness Finnerty and PACE witness Slater, is that FPL's RFP violated the RFP Rule, that the process used by FPL was not conducted fairly and favored FPL's own units, and that FPL did not properly evaluate the bids. According to CPV Gulfcoast, PACE, FIPUG, and FACT et. al., because of these perceived flaws, we should not conclude that Martin Unit 8 and Manatee Unit 3 are the most cost-effective alternatives available. No party offered any evidence, however, that an RFP bid was more cost-effective than FPL's units. In fact, FPL's base-case self-build plan appears to be approximately $2 million more cost-effective than the next-best plan containing at least one outside bid, and there is no evidence in the record that an outside bidder's proposal could be made more cost-effective using a different evaluation process or set of assumptions. Therefore, we find that FPL's plan to place Martin Unit 8 and Manatee Unit 3 into service in Summer, 2005, appears to the most cost-effective alternative. For these reasons, we believe that FPL's proposed Martin Unit 8 and Manatee Unit 3 projects are the most cost effective alternatives to fill FPL's capacity needs in 2005 and 2006. We also believe that it is most cost-effective for FPL's ratepayers to bring both projects into service in the summer of 2005.

C. <u>CONCLUSION</u>

As discussed above, the record demonstrates that FPL has met the statutory requirements for a determination of need. Therefore, we grant Florida Power & Light Company's petitions to determine the need for the proposed Manatee Unit 3 and Martin Unit 8.

Based upon the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power and Light Company's Petition to determine need for the Manatee Unit 3 power plant in Manatee County is hereby granted. It is further

ORDERED that Florida Power and Light Company's petition to determine need for the Martin Unit 8 power plant in Martin County is hereby granted. It is further

ORDERED that these Dockets shall be closed.

By ORDER of the Florida Public Service Commission this 10th Day of December, 2002.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

(S E A L)

LDH

CONCURRING OPINION BY COMMISSIONER PALECKI

While I concur with the Commission's vote, I have concerns about maintaining Florida's fuel diversity that were not adequately addressed in this proceeding.

Over the past several years, in Florida and across the nation, the electric industry has been building natural gas-fired combined cycle plants almost exclusively. While natural gas plants now appear to be the preferred alternative due to their lower capital cost, we seem to be placing excessive dependence on a fuel that is in increasingly high demand and for which storage is limited. This Commission needs to take a closer look at other generating technologies and fuel alternatives. Specifically, in need determination cases, the applicant, our staff, and ultimately, this

Commission, should determine whether combined cycle proposals remain cost-effective considering varying gas price increase scenarios.

The Merriam-Webster definition of "lemming" makes reference to mass migration into the sea where vast numbers are drowned. I sincerely hope that our country's single-minded reliance on natural gas generation does not come to resemble the unfortunate path of this furry-footed rodent.

DISSENT BY COMMISSIONERS DEASON AND BRADLEY

Commissioners Deason and Bradley dissent from the Commission's decision on the Equity Adjustment, discussed in section II(D)(5), above.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.