CHAPTER 8
NEED FOR POWER

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ACRONYMS AND ABBREVIATIONS

ALJ	Administrative Law Judge
BEBR	Bureau of Economic and Business Research
BP	British Petroleum, Inc.
CBM	Capacity Benefit Margin
CC	combined cycle
COLA	Combined License Application
CT	combustion turbine
DCA	Department of Community Affairs
DOE	U.S. Department of Energy
DSM	demand-side management
EIA	Energy Information Administration
ER	Environmental Report
ERO	electric reliability organization
ESRP	Environmental Standard Review Plan
F.A.C.	Florida Administrative Code
F.S.	Florida Statute
FDEP	Florida Department of Environmental Protection
FEECA	Florida Energy Efficiency and Conservation Act
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company
FMPA	Florida Municipal Power Agency
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission

ACRONYMS AND ABBREVIATIONS (CONTINUED)

FR	full requirements
FRCC	Florida Reliability Coordinating Council, Inc.
GHG	greenhouse gas
GNG	Gulfstream Natural Gas System
GWh	gigawatt hour
IOU	investor-owned utility
IRP	integrated resource planning
ISO	independent system operator
km	kilometer
km^2	square kilometer
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
kWh/yr	kilowatt hour per year
LEED	Leadership in Energy and Environmental Design
LNG	liquefied natural gas
LNP	proposed Levy Nuclear Plant Units 1 and 2
LOLP	Loss of Load Probability
mi.	mile
$mi.^2$	square mile
MW	megawatt
MWh	megawatt hour
NEL	net energy for load

ACRONYMS AND ABBREVIATIONS (CONTINUED)

NERC	North American Electric Reliability Corporation
NP	steam power – nuclear
NRC	U.S. Nuclear Regulatory Commission
OUC	Orlando Utilities Commission
PAA	Proposed Agency Action
PEF	Florida Power Corporation doing business as Progress Energy Florida, Inc.
PPSA	Power Plant Siting Act
PR	partial requirements
QF	qualifying facility
RCI	residential, commercial, and industrial
RIM	Rate Impact Measure
ROI	Region of Interest
RTO	regional transmission operator
SCA	Site Certification Application
SECI	Seminole Electric Cooperative, Inc.
ST	steam turbine
TECO	Tampa Electric Company
TLSA	Transmission Line Siting Act
TRC	Total Resource Cost Test
TYSP	Ten-Year Site Plan
USEPA	U.S. Environmental Protection Agency

8.0 NEED FOR POWER

The U.S. Nuclear Regulatory Commission (NRC) has indicated that the Environmental Report (ER) should include consideration of the benefits of the proposed action and that the ER must assess the need for power to accurately characterize the benefits associated with the proposed action. This chapter describes the integrated resource planning (IRP) process of applicant Florida Power Corporation doing business as Progress Energy Florida (PEF), and PEF's need for power in its Region of Interest (ROI) requiring the addition of two large baseload electric generating plants in the 2016 – 2017 timeframe. More specifically, this chapter will detail, among other things: (1) the State of Florida's comprehensive regulation and oversight of investor-owned utilities' (IOUs') IRP process, (2) PEF's rigorous and thorough IRP process that involves the integrated review and analysis of generating and non-generating resource alternatives, (3) Florida's Determination of Need process, by which the Florida Public Service Commission (FPSC) confirms the need for new generating resources to meet the demand described in the Integrated Resource Plan, and (4) PEF's Petition for Determination of Need for the proposed Levy Nuclear Plant Units 1 and 2 (LNP) filed with the FPSC on March 11, 2008 (Reference 8.0-001).

Additionally, this chapter will address the geographic scope for PEF's need for power analysis. According to NUREG-1555, Environmental Standard Review Plan (ESRP) 8.1, "The geographic scope for the need for power may be defined in the application by a utility service area, but it also exists in a larger geographic context because power from the plant will flow outside a relevant utility service area boundary. This larger area is the relevant market area. The boundary of the relevant market area is primarily a function of the way the transmission system is planned and managed. This has both electrical and economic features."

Florida remains a traditional cost-of-service, rate-regulated state in which IOUs, such as PEF, are highly regulated by the FPSC. This includes regulation of PEF's rates, electric service and grid reliability, and the planning and implementation of generating and non-generating resources to meet native load needs. Currently, there is no electric deregulation in the State of Florida.

As part of the regulatory process for power generation, the Florida Legislature has enacted a comprehensive statutory scheme, (1) requiring IOUs to plan for new generating and non-generating resources, and (2) addressing the construction of new baseload power plants within the State. Section 186.801, Florida Statute (F.S.), requires electric generating utilities to submit a Ten-Year Site Plan (TYSP) to the FPSC. The TYSP includes historical and projected data pertaining to the utility's load and resource needs, as well as a review of those needs (Reference 8.0-002). The FPSC has promulgated rules setting forth the detailed requirements a utility must include in its TYSP. These rules include Rules 25-22.070 through 22.072, Florida Administrative Code (F.A.C.). The TYSP addresses in detail four principal areas: (1) an overview of PEF's generating resources, as well as its transmission and distribution system; (2) the history and forecast for load and peak demand, the forecast methodology used, and demand-side management (DSM) savings and fuel requirement projections;

(3) the resource planning forecast, transmission planning forecast, and status of the proposed generating facilities and bulk transmission line additions; and (4) detailed information regarding the utility's preferred and potential site locations along with applicable environmental and land use information. (Reference 8.0-002)

Following TYSP submittal by the utility, the FPSC reviews the plan, holds a public workshop to discuss the plan, makes a suitability determination on each utility's TYSP, and provides an annual report to the Florida Legislature. PEF's TYSPs have been found to be suitable by the FPSC every year since the establishment of the TYSP requirement in the early 1980s.

In addition to the TYSP requirements, in the early 1970s, the Florida Legislature enacted the Power Plant Siting Act (PPSA). Under Sections 403.501 through 403.539, F.S., the PPSA governs the siting and environmental permitting of any power plant, including associated transmission facilities, in the State of Florida that exceeds 75 megawatts (MW) of steam generating capacity. Under the PPSA, a utility that proposes to construct a new power plant exceeding 75 MW of steam generating capacity must: (1) obtain from the FPSC an order approving the utility's need for the additional capacity, and (2) obtain a Site Certification from the Governor and Cabinet serving as the State Siting Board, prior to the construction of any such new plant.

In 2006, the Florida Legislature amended the PPSA to promote the development of nuclear generation in the state. Under the 2006 amendments, the determination of need for a proposed electrical power plant using nuclear materials must be based on: (1) the need for electric system reliability and integrity including fuel diversity, (2) the need for base-load generating capacity, (3) the need for adequate electricity at a reasonable cost, and (4) whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available. Further, the Florida Legislature specifically determined that certain matters were relevant and therefore must be considered in determining the need for the nuclear power plant. These are whether the proposed nuclear power plant will: (1) provide needed base-load capacity, (2) enhance the reliability of electric power production within the state by improving the balance of power plant fuel diversity and reducing Florida's dependence on fuel oil and natural gas, and (3) provide the most cost-effective source of power, taking into account the need to improve the balance of fuel diversity, reduce Florida's dependence on fuel oil and natural gas, reduce air emission compliance costs, and contribute to the long-term stability and reliability of the electric grid.

The FPSC has adopted rules implementing the PPSA, including the 2006 amendments. The rules (Rules 25-22.080, 25-22.081, and 28-106.201, F.A.C) specify in detail the requirements a utility must meet in order to obtain FPSC approval of the need for power and of the power plant selected to meet that need. Among these rules are the following, as provided in Rule 25-22.081, F.A.C.:

(1) Petition for Fossil, Integrated Gasification Combined Cycle, or Nuclear Fuel Electric Plants. Petitions submitted to commence a proceeding to determine the need for a proposed fossil, integrated gasification combined cycle, or nuclear fuel electrical power plant or responses to the Commission's order commencing such a proceeding shall comply with the other requirements of Chapter 25-22, F.A.C., as to form and style except that a utility may, at its option, submit its petition in the same format and style as its application for site certification pursuant to Sections 403.501 through 403.517, F.S., so long as the informational requirements of this rule and Chapter 25-22, F.A.C., are satisfied. To allow the Commission to take into account the need for electric system reliability and integrity, the need for adequate reasonable cost electricity, the need for fuel diversity and supply reliability, the need to determine whether the proposed plant is the most cost effective alternative available, and the need to determine whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available, the petition shall contain the following information:

(a) A general description of the utility or utilities primarily affected, including the load and electrical characteristics, generating capability, and interconnections.

(b) A general description of the proposed electrical power plant, including the size, number of units, fuel type and supply modes, the approximate costs, and projected in-service date or dates.

(c) A statement of the specific conditions, contingencies or other factors which indicate a need for the proposed electrical power plant including the general time within which the generating units will be needed. Documentation shall include historical and forecasted summer and winter peaks, number of customers, net energy for load, and load factors with a discussion of the more critical operating conditions. Load forecasts shall identify the model or models on which they were based and shall include sufficient detail to permit analysis of the model or models. If a determination is sought on some basis in addition to or in lieu of capacity needs, such as fuel diversity, then detailed analysis and supporting documentation of the projected costs and benefits is required. Where a determination is sought for a nuclear or integrated gasification combined cycle power plant, the nonbinding estimate provided for in paragraph (2)(b) below shall be considered to be sufficient for purposes of this paragraph.

(d) A summary discussion of the major available generating alternatives which were examined and evaluated in arriving at the decision to pursue the proposed generating unit. The discussion shall include a general description of the generating unit alternatives, including purchases where appropriate; and an evaluation of each alternative in terms of economics, reliability, long-term flexibility and usefulness and any other relevant factors such as fuel diversity and fuel supply reliability. These major generating technologies generally available and potentially

appropriate for the timing of the proposed plant and other conditions specific to it shall be discussed. In addition, each investor-owned utility shall include a detailed description of the selection process used and a detailed description of the generating unit alternatives proposed by each finalist, if any, selected to participate in subsequent contract negotiations pursuant to Rule 25-22.082, F.A.C. No provision of Rule 25-22.082, F.A.C., shall be applicable to a nuclear or integrated gasification combined cycle power plant sited after June 19, 2006.

(e) A discussion of viable nongenerating alternatives including an evaluation of the nature and extent of reductions in the growth rates of peak demand, [kilowatt hour {kWh}] consumption and oil consumption resulting from the goals and programs adopted pursuant to the Florida Energy Efficiency and Conservation Act both historically and prospectively and the effects on the timing and size of the proposed plant.

(f) An evaluation of the adverse consequences which will result if the proposed electrical power plant is not added in the approximate size sought or in the approximate time sought.

(g) If the generation addition is the result of a purchased power agreement between an investor-owned utility and a nonutility generator, the petition shall include a discussion of the potential for increases or decreases in the utility's cost of capital, the effect of the seller's financing arrangements on the utility's system reliability, any competitive advantage the financing arrangements may give the seller and the seller's fuel supply adequacy.

(2) In addition to complying with paragraphs (1)(a) through (g) above, a nuclear or integrated gasification combined cycle power plant petition shall contain the following information:

(a) The description required by Section 403.519(4)(a)2., F.S., including a discussion about how the proposed nuclear or integrated gasification combined cycle power plant will enhance the electric supply reliability by reducing the exposure to fossil fuel supply disruptions;

(b) A description of and a nonbinding estimate of the cost of the proposed nuclear or integrated gasification combined cycle power plant, including associated transmission facilities;

(c) The annualized base revenue requirement for the first 12 months of operation of the proposed nuclear or integrated gasification combined cycle power plant, based on the nonbinding estimate of the cost provided pursuant to paragraph (2)(b) above; and

(d) A summary of any discussions with other electric utilities regarding ownership of a portion of the plant by such electric utilities.

Pursuant to its rules, the FPSC will hold several public hearings on the utility's petition, including service hearings within the utility's service territory, and a technical hearing on the petition.

As noted above, PEF submitted its Petition for Determination of Need for the LNP with the FPSC on March 11, 2008. In support of its petition, PEF submitted

a detailed Need Study and the testimony of ten witnesses. Several interested parties intervened in the docket, including the Office of Public Counsel, the independent ratepayer advocate appointed by the Legislature, and large industrial customers. Following voluminous discovery and a three-day public hearing, the FPSC unanimously voted to approve PEF's need for the plant, including substantial associated transmission facilities, and the FPSC agreed that the plant was the most cost-effective generating alternative. The FPSC is expected to issue its final order in July 2008.

In addition to the FPSC's role over the need for power, the PPSA vests responsibility for the overall environmental and land use permitting of power plant projects in the Florida Department of Environmental Protection (FDEP) and the ultimate approval of a power plant with the Governor and Cabinet, sitting as the State Siting Board. Under the PPSA, a utility must file a Site Certification Application (SCA) with the FDEP to obtain all necessary state environmental permits and to assure consistency with all applicable local rules and regulations. The SCA must include detailed information regarding potential environmental impacts of the proposed project, including wetlands impacts, endangered species review, and water impacts. Numerous state agencies are allowed to comment on the application, and several public hearings are held, including a local land use hearing, and a hearing before a FDEP Administrative Law Judge (ALJ). If the ALJ approves the SCA, the Secretary of the FDEP can then either approve or disapprove the application. If the Secretary approves the application, the Governor and Cabinet, serving as the State Siting Board, conducts a public hearing and has the ultimate authority to grant or deny the Site Certification. The process typically takes 12 to 18 months.

The PEF SCA was prepared in parallel with the Combined License Application (COLA) for the LNP. PEF submitted the SCA to the FDEP on June 2, 2008, approximately 2 months earlier than the anticipated submittal of the COLA to the NRC on July 28, 2008. The SCA was prepared pursuant to the requirements of the Florida PPSA (Sections 403.501 through 403.518, F.S.) and follows the general outline established in the Draft Application *Instruction Guide: Electrical Power Plant Sites and Associated Facilities, Electrical Transmission Lines,* FDEP Form 62-16.900.

The SCA incorporates the LNP ER in its entirety (with the possible exception of redactions of specific and limited information as deemed necessary) as an attachment to the document. The ER contains most of the information needed to satisfy the requirements of the SCA, and this information is referenced, rather than repeated, in the main body of the SCA. The SCA, in and of itself, serves as a cross-walk to the ER, directing the SCA reader to specific chapters, sections, tables, figures, or other information in the ER. Information specifically required in the SCA that is not provided in the ER or required by NRC is included in the SCA document, including any additional chapters, sections, tables, figures, or clarifying text that are necessary to meet the SCA guidelines.

ESRP 8.1 provides the following information about the NRC's criteria for and analysis of need-for-power evaluations:

> Affected States and/or regions may prepare a need-for-power evaluation as part of a State or regional planning exercise. Similarly, State or regional agencies may require the applicant to document a need for power or plan for future plant construction. The applicant may choose to rely on those documents rather than prepare a description of the power system of its own. If so, NRC staff should review these documents to determine if they are (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. Of particular concern are third-party plans or reports restricted to boundaries smaller than relevant service and market areas. Another concern is plans and studies that do not extend far enough into the future to provide an adequate basis for comparison. If NRC staff conclude these other documents are acceptable, no additional independent review by NRC staff may be needed and that analysis can be the basis for ESRPs 8.2 through 8.4.
>
> If NRC staff determine these documents are not acceptable, it may request additional information from the applicant, or it may supplement the information provided with information from other sources, such as the Energy Information Administration [EIA], the Federal Energy Regulatory Commission (FERC), [North American Electric Reliability Corporation] NERC, and applicable member councils, and others to ensure adequate geographic coverage.

Additionally, ESRP 8.1 provides the following information about the NRC's criteria for and analysis of regional transmission system evaluations:

> The determination of the need for new generation requires evaluation of both utility supplies compared to projected demand, and demand in the relevant service and market areas. The applicant may provide or NRC staff obtain information from sources that encompass different geographic areas. Therefore NRC staff must be specific about what area they are referencing, such as utility service area, State, [regional transmission operator/independent system operator] RTO/ISO area or regional market, NERC region, or other area if appropriate.

PEF's transmission planning assessment practices, as outlined in the FERC Form 715 filing, are developed to test the ability of the planned system to meet the reliability criteria and to assure the system meets PEF, Florida Reliability Coordinating Council, Inc. (FRCC), and NERC criteria. This involves the use of load flow and transient stability programs to model various contingency situations that may occur and determining if the system response meets the reliability criteria. In general, this involves running simulations for the loss of any single line, generator, or transformer. PEF normally runs this analysis for system peak and off-peak load levels for possible contingencies and for both summer and winter. Additional studies are performed by PEF to determine the system response to credible, but less probable, criteria. These studies include the loss of multiple generators, lines, or combinations of each, and some load loss is

permissible under these more severe disturbances. These credible, but less probable, scenarios are also evaluated at various load levels because some of the more severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs. Further discussion of the FRCC methodology used by PEF to determine transmission capacity benefits is presented in ER Subsection 8.3.2.

As set forth above, Florida's comprehensive process for analyzing and evaluating the need for power within public utility service areas and the regional process for evaluating the need for power satisfies these NRC criteria. The following sections describe the evaluation of need for power:

- ER Section 8.1 — Description of Power System
- ER Section 8.2 — Power Demand
- ER Section 8.3 — Power Supply
- ER Section 8.4 — Assessment of Need for Power

8.1 DESCRIPTION OF POWER SYSTEM

This section provides a description of the PEF power system and reviews the criteria described in NUREG-1555. The NRC's four criteria for need-for-power evaluations are discussed in ER Section 8.0. The following subsections demonstrate that the Florida TYSP process and Determination of Need process for the LNP meet these four criteria and support the need for power evaluation in this chapter.

Progress Energy is a Fortune 250 diversified energy company that operates power generating facilities at 32 sites in the states of Florida, North Carolina, and South Carolina with more than 21,000 MW of generation capacity and nearly $10 billion in annual revenues. Progress Energy operates a diverse mix of plant technologies and fuel sources, including hydroelectric, nuclear, coal, oil, and natural gas. This fuel diversity enables the company to minimize cost impacts from any one fuel source and ensures reliable power for residential, commercial, industrial, and wholesale customers. PEF is a wholly-owned subsidiary of Progress Energy.

The PEF service territory consists of an area of approximately 51,800 square kilometers (km^2) (20,000 square miles [$mi.^2$]) and includes the most densely populated areas around the cities of Orlando, St. Petersburg, and Clearwater (Reference 8.0-002). In addition to the population centers, PEF's service territory covers 35 of the state's 67 counties (Reference 8.1-001). The ROI for the need for power evaluation in this chapter is PEF's service territory in Florida, consistent with the requirements of the FPSC IRP process. Figure 8.1-1 shows the PEF service territory. In addition, the location of the LNP facility will be within

the FRCC subregion of NERC and will serve as a baseload power generation facility, thereby providing much needed additional electrical power to the subregion.

PEF's service territory is within the FRCC. The FRCC is a 27-member regional non-profit company that includes IOU, cooperative utilities, municipal utilities, federal power agency, power marketers and independent power producers. The FRCC is designed to ensure and enhance the reliability and adequacy of current and future bulk electricity supply in Florida. The entire FRCC region is within the Eastern Interconnection and is under the direction of the FRCC Reliability Coordinator (Reference 8.1-002).

Any new baseload power plant in Florida would require an expansion of the electric transmission system to deliver large amounts of power from plants to communities. The PEF transmission system includes approximately 8047 kilometers (km) (5000 miles [mi.]) of transmission lines in Florida. The distribution system includes approximately 28,968 km (18,000 mi.) of overhead distribution conductors and approximately 20,922 km (13,000 mi.) of underground cable (Reference 8.0-002). PEF evaluates transmission system capabilities and needs to continually ensure that the system provides a reliable means of moving energy to where there is a need, regardless of weather and challenging scenarios. PEF has identified the likely transmission upgrades needed to interconnect and integrate the LNP into PEF's grid. As set forth in its SCA to be filed with the FDEP, PEF also has identified the necessary transmission corridors to within a 1.6-km (1-mi.) wide band. The final specific routes will be determined by the end of 2008 or early 2009. Four major transmission lines will leave the new common dual voltage 500-kV/230-kV switchyard and connect with three high-voltage substations. Two of the four 500-kV transmission lines will connect to the proposed Citrus Substation, one will connect to the proposed Central Florida South Substation, and one will connect to the CREC 500-kV switchyard. Additional system upgrades will be constructed to accommodate demand in the central and south Florida areas primarily served by the LNP. Detailed descriptions of the transmission line system and associated environmental impacts from construction and operation are described in ER Section 3.7 and ER Chapters 4 and 5, respectively.

During 2006, PEF provided electricity service to over 1.6 million customers in Florida. PEF supplies electricity at retail to approximately 350 communities and at wholesale to about 21 Florida municipalities, utilities, and power agencies (Reference 8.1-001). Table 8.1-1 shows the annual peak demand and historical energy consumption and number of PEF customers for 1997 through 2006.

As part of the wholesale sales, PEF sells electricity to other electric power utilities (municipal or investor-owned), as well as rural or municipal power agencies. Firm retail and wholesale electricity sales are discussed further in ER Section 8.2.

On August 9, 2004, the FPSC issued a Proposed Agency Action (PAA) Order approving new conservation goals for PEF that span the 10-year period from

2005 through 2014, as well as a new DSM plan for PEF that was specifically designed to meet the new conservation goals (Reference 8.0-002).

PEF customers participating in the company's residential Energy Management program help to manage future growth and costs. At the close of 2007, approximately 390,000 customers participating in the Energy Management program contributed about 760,500 kilowatts (kW) of winter peak-shaving capacity while 273,414 participants contributed about 290,042 kW of summer peak-shaving capacity for use during high load periods. PEF's DSM plan currently consists of seven residential programs, eight commercial and industrial programs, and one research and development program. This includes the 39 additional DSM measures and two new residential programs approved by the FPSC on January 5, 2007. PEF's DSM performance is presented in the Tables 8.1-2 and 8.1-3, which compare the conservation savings actually achieved through PEF's DSM programs for the reporting years of 2005 through 2007 with the FPSC-approved conservations goals. (Reference 8.0-002)

The forecasts contained in PEF's 2008 TYSP are based on these 2007 program additions and modifications to PEF's DSM plan and, therefore, appropriately reflect the most current projection of DSM savings over the next 10 years. PEF's DSM plan consists of seven residential programs, eight commercial and industrial programs, and one research and development program. The programs are subject to periodic monitoring and evaluation for the purpose of ensuring that all DSM resources are acquired in a cost-effective manner and that the program savings are durable.

8.1.1 SYSTEMATIC FLORIDA PROCESS

As noted in ER Section 8.0, Florida imposes a two-step process for evaluating the need for power. The PPSA licensing process was enacted in October 1973 and the TYSP process in January 1974. The first step involves preparing and submitting a TYSP to the FPSC, and the second step involves submitting a petition and obtaining a Determination of Need certification from the FPSC for electricity-generating power plants and transmission lines for the PPSA licensing process. This systematic two-step process is described below.

The FPSC has specific authority under Chapter 366, F.S., to regulate the rates and service of investor-owned electric companies in the state. It also has authority to oversee the reliability of the electric grid, to determine the need for new electricity-generating facilities, to establish utility conservation goals, and to oversee the safety of electricity-generating facilities.

The FPSC oversees the submission of a TYSP by the utilities. The TYSP describes current generation capacity and anticipated need for more capacity. The TYSP also includes historical and projected data pertaining to the utility's load and resource needs, as well as a review of those needs. In addition, the TYSP provides generic information on future sites for power plants to accommodate the anticipated need. This information includes land use data, environmental factors, and similar topics, which allow other state and local

agencies to comment on the TYSP. Comments may range from suggestions on how to improve utilization of the site and on-site problems, to recommendations that the site not be considered. Based on evaluation of comments received and its own conclusions, the FPSC will determine the suitability of the plan and issue an annual review.

PEF is required to prepare a TYSP annually for its service territory in Florida. As previously noted, Section 186.801, F.S., requires electricity-generating utilities to submit an annual TYSP to the FPSC. The TYSP estimates a utilities power-generating needs and the general location of its proposed power plant sites. These plans are not docketed, and no formal orders come from them. They are used as baseline information for other formal proceedings, such as rate cases, DSM plans, power purchases, etc. By statute, they must be declared "suitable" or "unsuitable" by the FPSC. To fulfill the requirements of Section 186.801, F.S., the FPSC adopted Rules 25-22.070 through 22.072, F.A.C. Rule 25-22.071 defines an overall framework within which the TYSP filing occurs. Rule 25-22.071 requires each regulated utility in Florida with existing generating capacity of 250 MW or greater (such as PEF) to submit a TYSP to the FPSC. Utilities whose existing generating capacity is below 250 MW are exempt from this requirement unless the utility plans to build a new unit larger than 75 MW within the 10-year planning period. Electric utilities must file an annual TYSP by April 1.

PEF compiles the TYSP in accordance with the FPSC rules and submits the TYSP to the FPSC Office of Commission Clerk on the first working day of April of each year. The FPSC reviews the PEF TYSP and incorporates the review into its annual report to the FDEP and PEF. In August of each year, the FPSC commissioners hold a workshop to review the TYSP, question utilities, and hear public comments. FPSC staff analyze the TYSP and public input, and draft a review. The FPSC commissioners publish a final review in December of each year, which is forwarded to the FDEP and the Florida Department of Community Affairs (DCA), and is made available to the public.

A TYSP gives state, regional, and local agencies advance notice of proposed power plants and transmission facilities. By statute, the FPSC must declare a plan "suitable" or "unsuitable." The FPSC may address any concerns raised by a utility's TYSP at a public hearing.

Because a utility's TYSP is a planning document containing tentative data, it may not contain sufficient information to allow regional planning councils, water management districts, and other review agencies to evaluate site-specific issues within their jurisdictions. Each utility must provide detailed data, based on in-depth environmental assessments, during certification proceedings under the PPSA, Sections 403.501 through 403.518, F.S.

In addition to the TYSP process and prior to the start of construction of any new baseload generating plant, PEF will seek a Determination of Need certificate from the FPSC. Pursuant to the requirements of Chapter 25-22.080 and contained within the Florida PPSA, an applicant for a new plant that exceeds

75 MW of steam generating capacity must file a petition for a Determination of Need with the FPSC. As noted in ER Section 8.0, PEF took a significant step toward securing Florida's energy future with carbon-free nuclear power by submitting a Determination of Need filing in March 2008 (Reference 8.0-001). PEF submitted a filing with the FPSC that outlines its need for additional electricity and proposed to meet that need with two nuclear units in Levy County. PEF indicated in its filing that nuclear power is one of three critical components of the company's balanced solution to meeting its customers' energy needs over the long term; this also includes the use of renewable energy sources and one of the nation's best energy efficiency programs. PEF's filing provided an estimate of the total cost of the project, including the two units and the necessary transmission facilities. This estimate includes land price, plant components, financing costs, construction, labor, regulatory fees and reactor fuel for two units. It also includes an estimate for approximately 321.9 km (200 mi.) of transmission lines and associated facilities necessary to interconnect and integrate the plants with PEF's existing transmission system.

The PPSA provides clear timelines and regulatory requirements for utilities seeking to build new power plants and directly associated facilities (such as transmission lines) in the state. The PPSA applies to proposed steam electric or solar power plants that are 75 MW or larger. The FDEP coordinates a multi-agency review of proposed generating units under the PPSA.

As part of the PPSA process, utilities must receive a Determination of Need certification from the FPSC. Pursuant to Section 403.519(3), F.S., the FPSC has the following statutory responsibility for determining the need for proposed generating units, other than nuclear units, which are subject to PPSA requirements:

> In making its determination, the commission shall take into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, the need for fuel diversity and supply reliability, whether the proposed plant is the most cost-effective alternative available, and whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available. The commission shall also expressly consider the conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant and other matters within its jurisdiction which it deems relevant.

Nuclear generating units have different, requirements under Section 403.519(4), F.S. Under this statute, the FPSC has the following statutory responsibility:

> In making its determination to either grant or deny the petition, the commission shall consider the need for electric system reliability and integrity, including fuel diversity, the need for base-load generating capacity, the need for adequate electricity at a reasonable cost, and whether renewable energy sources

and technologies, as well as conservation measures, are utilized to the extent reasonably available.

Certification may include a power plant's associated facilities, which are necessary to connect the plant to the existing transmission grid, and in the case of a nuclear power generating facility, any system upgrades necessary to interconnect and integrate the plant into the PEF transmission grid. Other associated facilities include, but are not limited to, natural gas pipelines supplying the plant's fuel, rail lines for delivery of fuel, equipment, and materials to the site, or roads.

Key aspects of the PPSA approval process include a need determination proceeding, a local land use hearing, and a site certification hearing before final approval by the Power Plant Siting Board, comprised of the Governor and Cabinet. Figure 8.1-2 shows the general PPSA flowchart.

The intent of this process is to provide a streamlined, one-stop licensing review for the plant and associated facilities.

8.1.2 COMPREHENSIVE FLORIDA PROCESS

As discussed in detail in ER Sections 8.0 and 8.1, the State of Florida has in place a comprehensive statutory and regulatory regime for governing electric utility resource planning and determining the need for a generating facility to meet the need described in the TYSP.

The FPSC conducts a preliminary review of the TYSP. The FPSC reviews the need for the proposed generation in relation to the energy needs of the region, and to the state as a whole. The FPSC examines criteria including whether the proposed facility would be the most cost-effective means of generation, balancing the region's and state's need for fuel diversity and fuel security.

After the FPSC receives the petition filing, the process calls for the FPSC to set a hearing date for the applicant to present its case and allow testimony by all potentially affected parties. The FPSC and its staff review the testimony and the applicant's reasoning why the plant is needed, and then make a determination to approve or disapprove.

Determination of Need is a formal process required under Section 403.519, F.S., and conducted by the FPSC. The FPSC reviews the need for the generation capacity that would be produced by the proposed facility in relation to the needs of the region, and to the state as a whole.

If the proposed power generating facility will use nuclear materials as fuel, the FPSC must look at matters within its jurisdiction that it deems relevant, including whether the nuclear power generating facility will achieve the following (per Section 403.519[3], F.S.):

- Provide needed baseload capacity.

- Enhance the reliability of electric power production within the state by improving the balance of power plant fuel diversity and reducing Florida's dependence on fuel oil and natural gas.

- Provide the most cost-effective source of power, taking into account the need to improve the balance of fuel diversity, reduce Florida's dependence on fuel oil and natural gas, reduce air emission compliance costs, and contribute to the long-term stability and reliability of the electric grid.

The comprehensive Determination of Need process can occur prior to or after the filing of a certification application; however, an applicant must have an affirmative Determination of Need from the FPSC in order to obtain a certification.

8.1.3 FLORIDA CONFIRMATION PROCESS

Florida's consolidated review of power plants and transmission lines provides an important opportunity for coordination and confirmation within state government. The FPSC serves as a central point of contact. FPSC staff communicates with other agencies to ensure that all issues are identified, and the program undertakes impact evaluations with input and involvement of those agencies.

The TYSP allows for an agency comment and response period. The TYSP is submitted to the FPSC Office of Commission Clerk on the first working day of April of each year. Rule 25-22.071, F.A.C., provides the following information:

> (3) The Commission [FPSC] will solicit comments from various federal, state, and local agencies, water management districts, and regional planning councils regarding the individual utility ten-year site plans. Any written comments shall be filed with the Commission within 90 days from the date of receipt of the plans. The state agencies from which comments will be solicited will include:
>
> (a) The Department of Environmental Protection.
>
> (b) The Department of Transportation.
>
> (c) The Department of Agriculture and Consumer Services.
>
> (d) The Department of Health.
>
> (e) The Fish and Wildlife Conservation Commission.
>
> (f) The Board of Trustees of the Internal Improvement Trust Fund.
>
> (g) The Department of Community Affairs.

> (4) The Commission will complete its review of the plans within nine months following submission and will report its findings, along with any comments or recommendations, to the Florida Department of Environmental Protection and the utilities filing a plan.

As part of the PPSA process (Rules 62-17.011 through 62-17.293, F.A.C.), utilities must receive a Determination of Need certification from the FPSC. As previously noted, PEF filed a Determination of Need with the FPSC on March 11, 2008 (Reference 8.0-001). From receipt of a utility's petition for Determination of Need, the FPSC has 90 days to hold a hearing and 135 days to issue a final order granting a Determination of Need. The final order is submitted to the FDEP, which coordinates a multi-agency review of the proposed generating unit. As part of its review, the FDEP evaluates the proposed plant's impact on land use, air quality, water quality and consumption, and all other environmental impacts of the proposed plant. The PPSA certification process can take as long as 430 days to complete.

As previously discussed as part of FDEP's review, PEF must also file an SCA with the FDEP to obtain all necessary state environmental permits and to assure consistency with all applicable local rules and regulations. The SCA approval consolidates state and local government permitting requirements. Permits that the FDEP administers pursuant to federal permit programs are approved separately from the SCA, and those separate federal permits must still be issued. These permits are integral to the authorization for construction and operation of a power plant.

The review of these federal permits is concurrent with the PPSA certification process, but does not operate under the same time schedules. In the instance of disputes regarding these permits, petitions for hearings are handled independent of the PPSA certification process. However, to facilitate coordination between these key parts of the power plant review, when possible, any hearings may be conducted in conjunction with the administrative hearing on certification. The final approval body for federal permits is not the Siting Board, but the FDEP through its authority granted by the U.S. Environmental Protection Agency (USEPA).

As previously noted, the Governor of Florida and Cabinet, serving as the State Siting Board, have the ultimate authority to grant or deny the site certification for a new generating facility. The IRP process and the decision on the Determination of Need and site certification process for a new generating facility are very much subject to confirmation.

8.1.4 FLORIDA CONSIDERATION OF UNCERTAINTY PROCESS

Pursuant to Rule 25-22.071, F.A.C., PEF submitted a TYSP to FPSC in the first quarter of 2008. PEF notes that it uses a set of customer class-specific econometric models to predict customer, energy, and peak demand forecasts. Further, in determining the forecasts, the models that PEF uses are discussed in the 2008 TYSP, as follows (Reference 8.0-002):

> These models are expressly designed to capture class-specific variation over time. By modeling customer growth and average energy usage individually, subtle changes in existing customer usage are better captured as well as growth from new customers. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, load management, and interruptible service.

PEF understands that accurate forecasts of long-range electric energy consumption, customer growth, and peak demand are essential elements in electric utility planning. As part of considering uncertainty, PEF first develops assumptions upon which the forecast is based. These assumptions generally specify the major factors that will influence the level of customers, energy sales, or peak demand over the forecast horizon. In addition to general assumptions, PEF develops short- and long-term economic assumptions to assist in framing the future demand scenario. Short-term economic assumptions assessed include short-term interest rates, federal tax cuts, local and regional housing sector growth, and energy consumption growth. Long-term economic assumptions assume that changes in economic and demographic conditions will follow a trended behavior pattern; therefore, the focus with these assumptions is to identify the trend. Projections of DSM programs are also incorporated as reductions to the forecast. The assumptions and methodology used to develop the base caseload and energy forecast is described in ER Section 8.2 and is illustrated in Tables 8.1-4, 8.1-5, 8.1-6, 8.1-7, 8.1-8, and 8.1-9.

Additionally, PEF develops its resource plans based on maintaining capacity margins in the 11 percent to 17 percent range to account for the forecasting uncertainty in the long-term or potential delays in bringing capacity online.

The FPSC also recognizes and accounts for uncertainty specifically related to fuel diversity and fuel prices, as provided in its *Review of 2007 Ten-Year Site Plans for Florida's Electric Utilities* (Reference 8.1-003):

> Proposed solid fuel plants identified in the utilities' 2007 Ten-Year Site Plans have encountered resistance on many fronts. Fuel cost uncertainties, high capital costs, and uncertainties regarding potential expenses related to future carbon emission regulations have all been cited as concerns. Consequently, the generation additions identified in many of the utilities' 2007 Ten-Year Site Plans are no longer indicative of Florida's future capacity additions. As a result, more than 4,000 MW of proposed capacity additions identified in the 2007 Ten-Year Site Plans need to be replaced.

As part of that uncertainty, the FPSC expects that utilities will need to address alternatives to existing fossil fuel power generating facilities by continuing to evaluate DSM conservation and supply-side generation necessary for maintaining adequate, reliable, economical, and environmentally-sound supplies of electricity for Florida residents. The FPSC notes that nuclear generation is one generating technology that produces no greenhouse gas emissions. However,

the FPSC also acknowledges that the licensing, certification, and construction of a new nuclear power plant in Florida is expected to take at least 10 years. Any commitment to the construction of new nuclear power plants presents considerable financial risks. The Florida Legislature amended the PPSA by enacting Section 366.93, F.S, in June 2006, to promote the development of nuclear generation in the state. This amendment established new rules to provide for early cost recovery mechanisms for costs related to the siting, design, licensing, and construction of nuclear power plants in Florida.

As of December 31, 2007, PEF had total summer capacity resources of approximately 11,215 MW consisting of installed capacity of 9293 MW (excluding Crystal River 3 joint ownership) and 1922 MW of firm purchased power. This capacity resource includes nuclear (769 MW), fossil steam (3889 MW), combined-cycle plants (2134 MW), combustion turbine (2501 MW, 143 MW of which is owned by Georgia Power for the months June through September), utility purchased power (484 MW), independent power purchases (636 MW), and non-utility purchased power (802 MW). (Reference 8.0-002)

In 2008, nuclear and coal generation are projected to provide approximately 44 percent of PEF's total capacity resources. Gas and oil generation are projected to account for approximately 38 percent of total supply capacity in 2008.

PEF's gas and oil resources are projected to increase to about 35 percent of total supply capacity in 2017. Nuclear and coal are projected to account for approximately 58 percent of total capacity resources in 2017 (Reference 8.0-002). This indicates that nuclear and coal resources will continue to account for the greater share of the PEF system capacity. PEF's fuel requirements and energy sources reflect a diverse fuel supply system that is not dependent on any one fuel source. Near-term natural gas consumption is projected to increase as plants and purchases with tolling agreements are added to meet future load growth. However, a decrease in future fossil fuel consumption is projected with the addition of planned nuclear units in the years 2016 and 2017 (Reference 8.0-002). Tables 8.1-4 and 8.1-5 depict the 2-year actual and 10-year projected energy sources by fuel type in gigawatt hours (GWh) and percent, respectively. These tables show that PEF's fuel requirements and energy sources are a diverse fuel supply system that is not dependent on any single fuel source. Additionally, the near-term natural gas consumption is projected to increase as plants and purchases with tolling agreements are added to meet future load growth. However, a decrease in future fossil fuel consumption is projected with the addition of planned nuclear units in the years 2016 and 2017.

PEF's planned supply resource additions and changes for summer and winter are shown in Tables 8.1-6 and 8.1-7, respectively, and are commonly referred to as PEF's Base Expansion Plan. This plan includes a net gain in summer capacity of 3903 MW through the summer of 2017. Lastly, PEF's forecasts of capacity and demand for the projected summer and winter peaks are shown in Tables 8.1-8 and 8.1-9, respectively.

Additionally, based on 2003 data, residential users accounted for approximately 51 percent of the major users of energy produced, the commercial sector accounted for approximately 32 percent, the industrial sector users accounted for approximately 12 percent, and other purposes accounted for approximately 5 percent (Reference 8.1-004).

The FPSC recognizes that uncertainties in market trends and income, rapid increase in population and demand, and fuel supply diversity will remain significant uncertainties in forecast methodology. These uncertainties have resulted in reasonably conservative measures for identifying future fuel and supply needs.

Table 8.1-1
Annual Peak Demand, History of Energy Consumption, and Total Number of Customers

Year	Total Sales to Ultimate Consumers (GWh)	Net Energy for Load (GWh)	Annual Peak Demand Winter Base (MW)	Annual Peak Demand Summer Base (MW)	Total Number of Customers
1998	33,386	37,763	7752	8367	1,340,851
1999	33,442	39,160	10,473	9039	1,376,597
2000	34,832	41,242	10,047	8916	1,400,299
2001	35,262	40,933	11,458	8847	1,444,958
2002	36,859	42,567	10,685	9426	1,475,783
2003	37,958	43,911	11,555	8886	1,510,516
2004	38,194	45,268	9325	9589	1,548,627
2005	39,176	46,878	10,833	10,356	1,583,417
2006	39,432	46,041	10,700	10,153	1,620,396
2007	39,282	47,633	9899	10,938	1,632,368

Notes:

GWh = gigawatt hour
MW = megawatt

Source: Reference 8.0-002

Table 8.1-2
Residential Conservation Savings Goals and Achievements

	Summer MW		Winter MW		Annual GWh Energy	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
2005	13	18	43	48	21	29
2006	21	37	75	99	35	58
2007	30	58	108	153	50	85

Notes:

GWh = gigawatt hour
MW = megawatt

Source: Reference 8.0-002

Table 8.1-3
Commercial Conservation Savings Goals and Achievements

	Summer MW		Winter MW		Annual GWh Energy	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
2005	4	8	3	6	3	3
2006	7	16	7	12	6	9
2007	11	44	10	38	9	30

Notes:

GWh = gigawatt hour
MW = megawatt

Source: Reference 8.0-002

Table 8.1-4
Energy Sources (GWh)

Energy Source	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Annual Firm Interchange [a]	2091	2956	1347	1028	1098	1063	981	627	638	909	454	43
Nuclear	6382	6124	6751	5156	6954	6107	7974	7533	8042	7490	13,268	21,505
Coal	14,968	15,293	14,457	14,506	14,906	16,034	15,894	15,724	15,956	16,247	15,630	13,511
Residual – Steam	4656	4575	4766	3508	2749	2799	2682	2128	2195	2186	2084	1853
Distillate – Steam	0	50	0	0	0	0	0	0	0	0	0	0
Distillate – CC	1	13	0	0	0	0	0	0	0	0	0	0
Distillate – CT	257	244	242	299	301	391	396	309	313	474	326	258
Natural Gas – Steam	161	475	0	0	0	0	0	0	0	0	0	0
Natural Gas – CC	8517	9093	12,063	16,853	18,197	19,064	18,616	22,085	23,266	24,160	21,914	18,366
Natural Gas – CT	979	1011	1201	1184	1147	1262	1269	1342	1133	1319	1131	994
QF Purchases [b]	2990	3002	3237	2542	2457	2456	2463	2278	1428	1428	1431	1403
Renewables [b]	1404	1210	1220	1216	1221	1849	2613	2580	2255	2217	2214	2108
Import from Out of State [b]	3683	3658	3450	3476	2585	1888	1807	1639	1679	1736	996	795
Export to Out of State [b]	-48	-71	0	0	0	0	0	0	0	0	0	0
Net Energy for Load	46,041	47,633	48,734	49,768	51,615	52,913	54,695	56,045	56,905	58,166	59,448	60,836

Notes:

a) Net Energy Purchased (+) or Sold (-) within the FRCC Region.

b) Net Energy Purchased (+) or Sold (-).

CC = combined cycle
CT = combustion turbine
FRCC = Florida Reliability Coordinating Council, Inc.
GWh = gigawatt hour
QF = qualifying facility

Source: Reference 8.0-002

Table 8.1-5
Energy Sources (Percent)

Energy Source	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Annual Firm Interchange [a]	4.5	6.2	2.8	2.1	2.1	2.0	1.8	1.1	1.1	1.6	0.8	0.1
Nuclear	13.9	12.9	13.9	10.4	13.5	11.5	14.6	13.4	14.1	12.9	22.3	35.3
Coal	32.5	32.1	29.7	29.1	28.9	30.3	29.1	28.1	28.0	27.9	26.3	22.2
Residual – Steam	10.1	9.6	9.8	7.0	5.3	5.3	4.9	3.8	3.9	3.8	3.5	3.0
Distillate – Steam	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distillate – CT	0.6	0.5	0.5	0.6	0.6	0.7	0.7	0.6	0.6	0.8	0.5	0.4
Natural Gas – Steam	0.3	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas – CC	18.5	19.1	24.8	33.9	35.3	36.0	34.0	39.4	40.9	41.5	36.9	30.2
Natural Gas – CT	2.1	2.1	2.5	2.4	2.2	2.4	2.3	2.0	2.0	2.3	1.9	1.6
QF Purchases [b]	6.5	6.3	6.6	5.1	4.8	4.6	4.5	4.1	2.5	2.5	2.4	2.3
Renewables	3.0	2.5	2.5	2.4	2.4	3.5	4.8	4.6	4.0	3.8	3.7	3.5
Import from Out of State [b]	8.0	7.7	7.1	7.0	5.0	3.6	3.3	2.9	3.0	3.0	1.7	1.3
Export to Out of State [b]	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Net Energy for Load	100	100	100	100	100	100	100	100	100	100	100	100

Notes:

a) Net Energy Purchased (+) or Sold (-) within the FRCC Region.

b) Net Energy Purchased (+) or Sold (-).

CC = combined cycle
CT = combustion turbine
FRCC = Florida Reliability Coordinating Council, Inc.
GWh = gigawatt hour
QF = qualifying facility

Source: Reference 8.0-002

Table 8.1-6 (Sheet 1 of 2)
Planned and Prospective Generating Facility Additions and Changes (MW)
(Net Capability — Summer)

Plant Location and Type	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Polk County CC [e]	10	--	--	--	--	--	--	--	--	--
Citrus County ST [b]	--	(30) [g]	--	--	--	--	--	--	--	--
Citrus County ST [f]	--	14	--	--	--	--	--	--	--	--
Pinellas County ST [d]	--	(444) [g]	--	--	--	--	--	--	--	--
Pinellas County CC [d]	--	1159	--	--	--	--	--	--	--	--
Citrus County NP [c]	--	37	--	--	--	--	--	--	--	--
Citrus County ST [b]	--	--	(30) [g]	--	--	--	--	--	--	--
Pasco County ST [f]	--	--	10	--	--	--	--	--	--	--
Citrus County ST [f]	--	--	14	--	--	--	--	--	--	--
Pasco County ST [f]	--	--	--	10	--	--	--	--	--	--
Citrus County NP [c]	--	--	--	129	--	--	--	--	--	--
Citrus County ST [f]	--	--	--	--	7	--	--	--	--	--
Suwannee County ST [a]	--	--	--	--	(129) [g]	--	--	--	--	--
Suwannee County CC [a]	--	--	--	--	--	1159	--	--	--	--
Orange County CT [a]	--	--	--	--	--	(12) [g]	--	--	--	--
Volusia County CT [a]	--	--	--	--	--	(22) [g]	--	--	--	--
Highlands County CT [a]	--	--	--	--	--	(49) [g]	--	--	--	--
Pinellas County CT [a]	--	--	--	--	--	(113) [g]	--	--	--	--
Levy County [a]	--	--	--	--	--	--	--	--	1092	--
Levy County NP [a]	--	--	--	--	--	--	--	--	--	1092

Table 8.1-6 (Sheet 2 of 2)
Planned and Prospective Generating Facility Additions and Changes (MW)
(Net Capability — Summer)

Notes:

a) Planned, prospective, or committed project.

b) Planned durations due to flue gas desulphurization scrubber installation.

c) Planned uprates.

d) Repowering.

e) Scheduled major inspection and rotor exchange.

f) Turbine project.

g) Expected retirement. Parentheses indicate expected deficits in net capability (MW) for any given year.

-- = No data reported
CC = combined cycle
CT = combustion turbine
MW = megawatt
NP = steam power – nuclear
ST = steam turbine

Source: Reference 8.0-002

Table 8.1-7 (Sheet 1 of 2)
Planned and Prospective Generating Facility Additions and Changes (MW)
(Net Capability — Winter)

Plant Location and Type	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Polk County CC [e]	10	--	--	--	--	--	--	--	--	--
Citrus County ST [b]	--	(30) [g]	--	--	--	--	--	--	--	--
Citrus County ST [f]	--	14	--	--	--	--	--	--	--	--
Pinellas County ST [d]	--	(464) [g]	--	--	--	--	--	--	--	--
Pinellas County CC [d]	--	1279	--	--	--	--	--	--	--	--
Citrus County NP [c]	--	37	--	--	--	--	--	--	--	--
Citrus County ST [b]	--	--	(30) [g]	--	--	--	--	--	--	--
Pasco County ST [f]	--	--	10	--	--	--	--	--	--	--
Citrus County ST [f]	--	--	14	--	--	--	--	--	--	--
Pasco County ST [f]	--	--	--	10	--	--	--	--	--	--
Citrus County NP [c]	--	--	--	129	--	--	--	--	--	--
Citrus County ST [f]	--	--	--	--	7	--	--	--	--	--
Suwannee County ST [a]	--	--	--	--	(146) [g]	--	--	--	--	--
Suwannee County CC [a]	--	--	--	--	--	1279	--	--	--	--
Orange County CT [a]	--	--	--	--	--	(16) [g]	--	--	--	--
Volusia County CT [a]	--	--	--	--	--	(32) [g]	--	--	--	--
Highlands County CT [a]	--	--	--	--	--	(70) [g]	--	--	--	--
Pinellas County CT [a]	--	--	--	--	--	(133) [g]	--	--	--	--
Levy County [a]	--	--	--	--	--	--	--	--	1120	--
Levy County NP [a]	--	--	--	--	--	--	--	--	--	1120

Table 8.1-7 (Sheet 2 of 2)
Planned and Prospective Generating Facility Additions and Changes (MW)
(Net Capability — Winter)

Notes:

a) Planned, prospective, or committed project.

b) Planned durations due to flue gas desulphurization scrubber installation.

c) Planned uprates.

d) Repowering.

e) Scheduled major inspection and rotor exchange.

f) Turbine project.

g) Expected retirement. Parentheses indicate expected deficits in net capability (MW) for any given year.

-- = No data reported
CC = combined cycle
CT = combustion turbine
MW = megawatt
NP = steam power – nuclear
ST = steam turbine

Source: Reference 8.0-002

Table 8.1-8
Forecast of Capacity and Demand at Time of Summer Peak (MW)

	Year [a]									
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Total Installed Capacity [b]	9160	9859	9890	9900	10,035	11,065	11,065	11,065	11,961	13,053
FIRM Capacity Import [c]	2087	1467	1592	1680	1989	1879	1748	1748	1336	1336
FIRM Capacity Export	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	173	173	173	323	439	439	439	439	439	439
Total Capacity Available	11,420	11,499	11,655	11,903	12,463	13,383	13,252	13,252	13,736	14,828
System Firm Summer Peak Demand	9424	9451	9689	9873	10,195	10,393	10,568	10,776	10,961	11,150
RESERVES (Summer)	1996	2048	1966	2030	2268	2990	2684	2476	2775	3678
Reserve Margin	21%	22%	20%	21%	22%	29%	25%	23%	25%	33%

Notes:

a) PEF is pursuing summer seasonal purchases of approximately 250 MW in 2008. The deals are not yet consummated as of the time of the TYSP filing. Because the purchase is expected to be from peaking capacity, no energy impact has been included in the plan at this time.

b) Total installed capacity does not include the 143 MW to Southern Company from Intercession City.

c) FIRM capacity import includes cogeneration, utility and independent power producers, and short-term purchase contracts.

MW = megawatt

Source: Reference 8.0-002

Table 8.1-9
Forecast of Capacity and Demand at Time of Winter Peak (MW)

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Total Installed Capacity	10,285	10,295	11,131	11,125	11,263	11,270	12,403	12,403	12,403	13,272	14,392
FIRM Capacity Import	1934	1667	1478	1636	1725	2077	1836	1836	1424	1424	1424
FIRM Capacity Export	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	173	173	173	173	439	439	439	439	439	439	439
Total Capacity Available	12,392	12,135	12,782	12,934	13,427	13,786	14,678	14,678	14,266	15,135	16,255
System Firm Winter Peak Demand	10,075	9881	10,311	10,524	10,974	11,250	11,318	11,549	11,786	12,011	12,242
RESERVES (Winter)	2317	2254	2471	2410	2453	2536	3360	3129	2480	3124	4013
Reserve Margin	23%	23%	24%	23%	22%	23%	30%	27%	21%	26%	33%

Notes:

a) Total installed capacity does not include the 143 MW to Southern Company from Intercession City.

b) FIRM capacity import includes cogeneration, utility and independent power producers, and short-term purchase contracts.

MW = megawatt

Source: Reference 8.0-002

8.2 POWER DEMAND

The guidance in NUREG-1555, ESRP 8.2, indicates that a state program describing current power demand and forecasts may be used to support the need for power, as discussed in this chapter. The NRC's criteria for and analysis of power demand evaluations is provided in NUREG-1555, ESRP 8.2.1. This ESRP "directs the staff's analysis and evaluation of the historic and projected electricity consumption and peakload demands in the relevant service area or market. The scope of the review directed by this plan should include a detailed analysis and evaluation of the applicant's treatment of these projections and, where needed, an independent assessment of forecasts of growth in electricity consumption and peakload demand in the relevant utility service and market areas."

This section describes PEF's power planning.

8.2.1 POWER AND ENERGY REQUIREMENTS

The NRC's criteria for and analysis of need-for-power evaluations are described in ER Section 8.0.

PEF submitted its demand forecast tables (reproduced in this ER as Tables 8.1-6, 8.1-7, 8.1-8, and 8.1-9) with the 2008 TYSP report. PEF employs an IRP process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy the customers' future demand and energy needs. Table 8.2-1 shows the history and forecast of energy consumption by customer class for 1998 through 2017. PEF's history and projected (1998 – 2017) base, high load, and low load forecasts for summer and winter peak demand from 1998 through 2017 are presented in Tables 8.2-2 and 8.2-3, respectively. Lastly, PEF's history and forecasts of annual net energy for base, high load, and low load capacity are shown in Table 8.2-4. PEF's IRP process incorporates state-of-the-art computer models that are used to evaluate a wide range of future generation alternatives and cost-effective conservation and dispatchable DSM programs on a consistent and integrated basis.

PEF's 2008 TYSP provides the following information about the IRP methodology (Reference 8.0-002):

> **INTRODUCTION**
> Accurate forecasts of long-range electric energy consumption, customer growth, and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric energy usage over the planning horizon. PEF's forecasting framework utilizes a set of econometric models to achieve this end. This section will describe the underlying methodology of the customer, energy, and peak demand forecasts including the principal assumptions incorporated within each. Also included is a description of how Demand-Side Management (DSM) impacts the forecast, the

development of high and low forecast scenarios and a review of DSM programs.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. The Financial Services Department develops these assumptions based on discussions with a number of departments within PEF, as well as through the research efforts of a number of external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions forms the basis for the forecast presented in this document.

GENERAL ASSUMPTIONS

1. Normal weather conditions for energy sales are assumed over the forecast horizon using a sales-weighted thirty-year average of conditions at seven (7) weather stations across Florida (Saint Petersburg, Tampa, Orlando, Winter Haven, Gainesville, Daytona Beach, and Tallahassee). For kilowatt-hour sales projections, normal weather is based on a historical thirty-year average of the service area weighted billing month degree-days. Seasonal peak demand projections are based on a thirty-year historical average of system-weighted temperatures at time of seasonal peak at the Tampa, Orlando, and Tallahassee weather stations; the other weather stations are not used in developing the historic average because they lack the historic hourly data needed for peak-weather normalization.

2. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies Bulletin No. 147 (February 2007) provide the basis for development of the customer forecast. State and national economic assumptions produced by Economy.Com in their national and Florida forecasts (April 2007) are also incorporated.

3. Within the PEF service area, the phosphate mining industry is the dominant sector in the industrial sales class. Four (4) major customers accounted for 28% of the industrial class [megawatt hour] MWh sales in 2007. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. Both supply and demand for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. Load and energy consumption at the PEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by these global as well as the local conditions. After years of excess mining capacity and weak product pricing power, the industry has consolidated down to just a few players in time to take advantage of

better market conditions. In addition, a weaker U.S currency value on the foreign exchange is expected to help the industry in two (2) ways. First, American farm commodities will be more competitive overseas and lead to higher crop production at home. The demand for corn-based ethanol has also increased farm acreage significantly. Therefore, both likely will result in greater demand for fertilizer products. Second, a weak U.S. dollar results in U.S. fertilizer producers becoming more price competitive relative to foreign producers. Going forward, energy consumption is expected to increase in the near term, as a new mine operation is expected to open. A significant risk to this projection lies in the volatile price of energy (natural gas), which is a major cost of both mining and producing phosphoric fertilizers. The energy projection for this industry assumes no major reductions or shutdowns of operations in the service territory. This includes any change in output from self-owned generation facilities, which remove load from PEF generation facilities.

4. PEF supplies load and energy service to wholesale customers on a "full", "partial", and "supplemental" requirement basis. Full requirements (FR) customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Contracts for this service include the cities of Bartow, Chattahoochee, Mt. Dora, Quincy, Williston, and Winter Park. Partial requirements (PR) customer load is assumed to reflect the current contractual obligations reflected by the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for PR service included in this forecast are with the Florida Municipal Power Agency (FMPA), Reedy Creek Utilities, [Tampa Electric Company] TECO Energy, Seminole Electric Cooperative, Inc. (SECI) and the cities of New Smyrna Beach, Tallahassee, and Homestead. PEF's contractual arrangement with SECI includes a "supplemental" service contract (1983 contract) for service over and above stated levels they commit to supply themselves. This contract has been renegotiated and will become a seasonal purchase for “stratified peaking” capacity in 2014 when the term of this contract expires in December 2013. A firm contract with SECI for stratified intermediate service, which includes both 450 MW (October 1995 contract) and 150 MW in 2012, is contained in this projection. Two additional contracts, a 50 MW sale which began in December 2007 (Market Mitigation Sale) and a FR contract which will commence in 2010, and last through the forecast horizon, are also contained in this forecast. Finally, an agreement to provide interruptible service at a SECI metering site has also been included in this projection.

5. This forecast assumes that PEF will successfully renew all future franchise agreements.

6. This forecast incorporates demand and energy reductions from PEF's dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the FPSC.

7. Expected energy and demand reductions from customer-owned self-service cogeneration facilities are also included in this forecast. PEF will supply the supplemental load of self-service cogeneration customers. While PEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for power at time of peak.

8. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the company does not plan for generation resources unless a long-term contract is in place. Current FR customers are assumed to renew their contracts with PEF except those who have given notice to terminate. Current PR contracts are projected to terminate as terms reach their expiration date. Deviation from these assumptions can occur based on information provided by the Regulated Commercial Operations Department.

The IRP process is described in PEF's 2008 TYSP as follows (Reference 8.0-002):

Forecasts and Assumptions
The evaluation of possible supply- and demand-side alternatives, and development of the optimal plan, is an integral part of the IRP process. These steps together comprise the integration process that begins with the development of forecasts and collection of input data. Base forecasts that reflect PEF's view of the most likely future scenarios are developed, along with high and low forecasts that reflect alternative future scenarios. Computer models used in the process are brought up-to-date to reflect this data, along with the latest operating parameters and maintenance schedules for PEF's existing generating units. This establishes a consistent starting point for all further analysis.

Reliability Criteria
Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment and to refuel nuclear plants. At any given time during the year, some capacity may be out of service due to unanticipated equipment failures resulting in may be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserve capacity must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity

must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis.

PEF plans its resources in a manner consistent with utility industry planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. A Reserve Margin criterion is used as a deterministic measure of PEF's ability to meet its forecasted seasonal peak load with firm capacity. PEF plans its resources to satisfy a twenty (20) percent Reserve Margin criterion.

Loss of Load Probability (LOLP) is a probabilistic criterion that measures the probability that a company will be unable to meet its load throughout the year. While Reserve Margin considers the peak load and amount of installed resources, LOLP takes into account generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by PEF, is a maximum of one (1) day in ten (10) years loss of load probability.

PEF has based its resource planning on the use of dual reliability criteria since the early 1990s, a practice that has been accepted by the FPSC. PEF's resource portfolio is designed to satisfy the twenty (20) percent Reserve Margin requirement and probabilistic analyses are periodically conducted to ensure that the one (1) day in ten (10) years LOLP criterion is also satisfied. By using both the Reserve Margin and LOLP planning criteria, PEF's resource portfolio is designed to have sufficient capacity available to meet customer peak demand, and to provide reliable generation service under expected load conditions. PEF has found that resource additions are typically triggered to meet the twenty (20) percent Reserve Margin thresholds before LOLP becomes a factor.

Supply-Side Screening

Potential supply-side resources are screened to determine those that are the most cost-effective. Data used for the screening analysis is compiled from various industry sources and PEF's experiences. The wide range of resource options is pre-screened to set aside those that do not warrant a detailed cost-effectiveness analysis. Typical screening criteria are costs, fuel source, technology maturity, environmental parameters, and overall resource feasibility.

Economic evaluation of generation alternatives is performed using the STRATEGIST optimization program. This optimization tool evaluates revenue requirements for specific resource plans generated from multiple combinations of future resource additions that meet system reliability criteria and other system constraints. All resource plans are then ranked by system revenue requirements.

Demand-Side Screening
Like supply-side resources, data for large numbers of potential demand-side resources are also collected. These resources are pre-screened to eliminate those alternatives that are still in research and development, addressed by other regulations (e.g. building code), or not applicable to PEF's customers. STRATEGIST is updated with cost data and load impact parameters for each potential DSM measure to be evaluated.

The Base Optimal Supply-Side Plan is used to establish avoidable units for screening future demand-side resources. Each future demand-side alternative is individually tested in this plan over the ten-year planning horizon to determine the benefit or detriment that the addition of this demandside resource provides to the overall system. STRATEGIST calculates the benefits and costs for each demand-side measure evaluated and reports the appropriate ratios for the Rate Impact Measure (RIM), the Total Resource Cost Test (TRC), and the Participant Test. Demand-side programs that pass the RIM test are then bundled together to create demand-side portfolios. These portfolios contain the appropriate DSM options and make the optimization solvable with the STRATEGIST model.

Resource Integration and the Integrated Optimal Plan
The cost-effective generation alternatives and the demand-side portfolios developed in the screening process can then be optimized together to formulate integrated optimal plans. The optimization program considers all possible future combinations of supply- and demand-side alternatives that meet the company's reliability criteria in each year of the ten-year study period and reports those that provide both flexibility and low revenue requirements (rates) for PEF's ratepayers.

Developing the Base Expansion Plan
The integrated optimized plans that provide the lowest revenue requirements are then further tested using sensitivity analysis. The economics of the plan may be evaluated under high and low forecast scenarios for fuel, load and financial assumptions, or any other sensitivities which the planner deems relevant. From the sensitivity assessment, the ten-year plan that is identified as achieving the best balance of flexibility and cost is then reviewed within the corporate framework to determine how the plan potentially impacts or is impacted by many other factors. If the plan is judged robust under this review, it evolves as the Base Expansion Plan.

ER Section 9.1 and ER Subsection 9.2.1 provide further discussion of the power and energy requirements of the PEF service territory.

8.2.2 FACTORS AFFECTING POWER GROWTH AND DEMAND

This subsection reviews the factors that affect growth in power demand in the service territory. The FPSC has historically conducted a program that establishes rates and monitors independent electricity load forecasts as part of its efforts to both monitor the adequacy of future power supplies and to independently evaluate the potential for excess generating capacity. The stability of retail rates enjoyed by ratepayers over the past 20 years was primarily due to stable fuel prices and to utilities maintaining a diverse and balanced fuel supply. As gas price volatility has shown, over-dependence on a single fuel can lead to unacceptable risk of rate increases if a balance is not maintained.

PEF's forecasts of capacity and demand are based on serving expected growth in retail requirements in its regulated service area and meeting commitments to wholesale power customers who have entered into supply contracts with PEF. In its IRP process, PEF balances its supply plan for the needs of retail and wholesale customers and endeavors to ensure that cost-effective resources are available to meet the needs across the customer base. Over the years, as wholesale markets have grown more competitive, PEF has remained active in the competitive solicitations while planning in a manner that maintains an appropriate balance of commitments and resources within the overall regulated supply framework.

As previously noted, the Integrated Resource Plan provides PEF with substantial guidance in assessing and optimizing PEF's overall resource mix on both the supply side and the demand side. When a decision supporting a significant resource commitment is developed (such as plant construction, DSM program implementation, or power purchase), PEF uses the directional guidance from the Integrated Resource Plan to move forward and explore in greater detail the specific levels of examination that are required. This more detailed evaluation typically provides PEF with an assessment of very specific technical requirements and cost estimates, detailed corporate financial considerations, and the most current dynamics of the business and regulatory environments.

8.2.2.1 Economic and Demographic Trends

As discussed in ER Section 2.5, the LNP is located in a region of historically rapid economic and population growth. Over the past several years, Florida added about a third of a million new residents each year and about a third of a million jobs per year — the most in the nation in sheer numbers, and at one of the fastest growth rates (Reference 8.2-001).

PEF's 2008 TYSP provides the following information about PEF's electric power demand and energy consumption (Reference 8.0-002):

> PEF's customer growth is expected to average 1.8 percent between 2008 and 2017, which is less than the ten-year historical average of 2.2 percent. Slower population growth, based on the latest projection from the University of Florida's Bureau of Economic and Business Research, and economic conditions less favorable for the housing/construction industry

(including, for example, tighter mortgage credit availability as well as higher property insurance rates and property taxes) result in a lower base case customer projection when compared to the higher historical growth rate. This translates into lower projected energy and demand growth rates from historic rate levels.

Net energy for load (NEL), which had grown at an average of 2.6 percent between 1998 and 2007, is expected to increase by 2.5 percent per year from 2008 to 2017 in the base case, 2.7 percent in the high case and 2.2 percent in the low case. A lower contribution from the wholesale jurisdiction, which grew an average of 10.2 percent between 1998 and 2007, results in lower expected system growth going forward than the historic rate. Retail NEL, which grew at a 1.8 percent average rate historically, is expected to grow 2.2 percent over the next ten-year period. The higher projected growth rate is solely due to the hottest summer weather in over thirty-two (32) years in 1998 as well as extremely mild winter weather conditions in 2007. Both conditions work to hold down the historical average growth rate. The projected growth rate for NEL assumes normal weather. Wholesale NEL is expected to average 2.4 percent between 2008 and 2017.

Summer net firm demand is expected to grow at an average of 1.9 percent per year during the next ten (10) years. This is lower than the 3.5 percent growth rate experienced throughout the last ten (10) years. Again, lower contribution from the wholesale jurisdiction is expected going forward and a higher load management capability for the projected period. High and low summer growth rates for net firm demand are 2.2 percent and 1.6 percent per year, respectively. Winter net firm demand is projected to grow at 2.4 percent per year after having increased by 2.7 percent per year from 1998 to 2007. High and low winter net firm demand growth rates are 2.7 percent and 1.7 percent, respectively.

Summer net firm retail demand is expected to grow at an average of 2.0 percent per year during the next ten (10) years; this is lower than the 3.2 percent average annual growth rate experienced throughout the last ten-year period. The historical growth percentage is driven by a period of declining load management capability while the projection period has a return to higher capability. High and low summer growth rates for net firm retail demand are 2.3 percent and 1.6 percent per year, respectively. Winter net firm retail demand is projected to grow at approximately 1.6 percent per year after having grown by 2.1 percent from 1998 to 2007. Again, higher load control capability is incorporated in the projection period. High and low winter net firm retail demand growth rates are 2.0 percent and 1.3 percent, respectively.

In 2001, the Florida Growth Management Study Commission projected that the population of Florida is expected to increase by 50 percent from 16 million to 23 million over the next three decades (Reference 8.2-002). In addition, the 2007

Florida DCA's Long-Range Program Plan projects that Florida's population will increase to 23 million by the year 2031 (Reference 8.2-003). Recent economic trends (such as high energy costs, high gasoline prices, and a decrease in new housing units) have led to a slowdown in economic activity, thereby reducing consumer confidence levels. In Florida, specifically, increases in property taxes and property insurance have led to a feeling of anxiety and a tarnishing of Florida's reputation as a low-cost-of-living state. Despite these recent economic slowdowns, Florida's job and population growth has fared better than most states. This job and population growth also leads to increased energy consumption in Florida.

There are, however, some indicators in 2008 that the Florida population growth is slowing down: (1) the enormous growth in population and corresponding development of the 1980s, 1990s, and early 2000s made portions of Florida less desirable and less affordable for retirement living, and (2) the fear and expense associated with storm events, such as hurricanes, appear to deter new in-migrants (Reference 8.0-002). Although population growth projections for Florida are affected by other outside influences and may result in lower than previously projected growth rates, the demand for electricity in Florida is expected to continue to increase due to consumer purchasing trends, as well as probable revitalization of housing trends in the near future. In addition, it is expected that, although a smaller percentage of the population of baby boomers will continue to consider Florida as a potential location to retire, Florida will still remain a likely destination for relocation and for retirement — simply not at the same rate as previously projected in the early 2000s.

8.2.2.2 Energy Efficiency and Substitution

In August 2004, by Order No. PSC-04-0769-PAA-EG, the FPSC set new numeric goals for PEF for the period 2005 through 2014. The FPSC approved slight reductions in each of PEF's numeric goals as compared to its previous goals, with the exception of the commercial/industrial energy goal. The primary reasons for the reduced goals are: (1) the forecasted impact of more stringent energy codes, particularly on residential air conditioning systems, and (2) decreased participation in certain existing DSM programs due to saturation. (Reference 8.2-004)

In an effort to encourage renewable energy resources, the 2005 Florida Legislature enacted Section 366.91, F.S. The statute requires that the Florida Energy Efficiency and Conservation Act (FEECA) utilities continuously provide a contract for purchasing capacity and energy from renewable energy resources. PEF has taken steps to meet these requirements.

The FPSC's *Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act* provides the following information (Reference 8.2-004):

> Progress Energy has a total peak interconnected photovoltaic capacity of 331.3 kW. Including the small photovoltaic systems program, Progress

> Energy has implemented several other programs under which photovoltaic capacity has been interconnected. For example, PEF has joined with Palm Harbor Homes, a manufactured housing company, to study the operation of photovoltaic systems in manufactured homes. One of the objectives of the project is to research customer acceptance and the technical feasibility of offering a green pricing program to interested customers. The total installed capacity in this program is 6.5 kW. Progress also continues to conduct research on the potential of photovoltaics at the Econlockhatchee solar array in Orlando. This system has been recommissioned and has a capacity of 3 kW. Progress has formed a partnership with Disney, installing 6.5 kW of photovoltaics at the Nature Conservancy. Progress has also worked with [British Petroleum, Inc.] BP to interconnect photovoltaic systems with a total capacity of 260 kW at 16 BP gas stations.

Electrical demand and energy usage in Florida are unique because residential customers make up largest part of the customer base. Residential customers make up over 88 percent of Florida's electricity customers, purchasing 53 percent of the state's total electrical energy. At approximately 11 percent, Florida's industrial electrical energy usage is much smaller than the national average of 31 percent. Florida's utilities have been successful in meeting the overall objectives of the FEECA. Utility-sponsored DSM programs have reduced statewide summer peak demand by an estimated 4951 MW, winter peak demand by 5563 MW, and energy consumption by an estimated 5488 GWh since 1980. (Reference 8.2-004) This has deferred the need for 11 typical 500-MW power generating facilities, or enough capacity to serve approximately 1.6 million households. By 2015, DSM programs are forecasted to further reduce aggregate peak demand and energy consumption. Summer and winter aggregate peak reduction forecasts are 6062 MW and 6447 MW, respectively, with a forecasted reduction in annual energy consumption of 7342 GWh (Reference 8.2-005).

PEF is committed to a long-term balanced solution to meet the energy needs of the region. PEF described an active DSM program in its 2008 TYSP. Approximately 389,000 customers participated in the Energy Management program at the end of 2007, contributing about 760,500 kW of winter peak-shaving capacity, while 273,414 participants contributed about 290,042 kW of summer peak-shaving capacity for use during high load periods (Reference 8.0-002). Other energy efficiency programs have reduced PEF's summer and winter peak load demand, and these programs are implicitly captured in the company's 2008 report. These residential, business, commercial, and industrial programs include aggressive customer education programs, "home energy checks," financial incentives, rate incentives, and commercial reduction strategies. PEF also has an active program to review future DSM programs to encourage energy efficiency and reduce peak demand. In September 2006, PEF filed a Determination of Need petition for the 180-MW uprate of PEF's Crystal River 3 nuclear unit. In 2006, the FPSC approved several new and revised DSM programs offered by PEF, which are expected to save approximately 700 MW over the planning horizon. PEF received FPSC approval to purchase 116 MW of

biomass-fired capacity and energy from a renewable energy provider, Florida Biomass, in central Florida. (Reference 8.2-006)

PEF provides numerous options for customers to decrease their energy usage and save money on their power bills. Through participation in energy-efficiency programs, PEF customers have saved more than $750 million in energy costs over the last 25 years. That equates to more than 10 billion kWh of electricity that did not have to be generated (roughly equivalent to the city of Orlando's power use over 2 years), and it represents a significant reduction in energy-related emissions (Reference 8.2-007). In addition, in late 2006, the FPSC approved a number of additional efficiency programs for PEF residential, commercial, and industrial customers.

As noted in ER Section 8.1, PEF's DSM plan currently consists of seven residential programs, eight commercial and industrial programs, and one research and development program. This DSM plan includes the 39 additional DSM measures and two new residential programs approved by the FPSC on January 5, 2007. Tables 8.1-2 and 8.1-3 present a comparison of the conservation savings achieved through PEF's DSM programs for the reporting years of 2005 through 2007 with the FPSC-approved conservation goals for the years 2005 through 2007.

PEF plans to implement aggressive residential, commercial, and industrial energy-efficiency programs and evaluate their effectiveness and participation rates to determine their viability in further reducing electricity demand. The additional reductions in future electricity demand growth through energy efficiency could push the need for new power plants further into the future. As part of the energy-needs balanced solution, PEF plans to invest in renewable energy sources and other emerging technologies, as well as upgrade existing power plants and consider investing in new plants when needed. PEF plans to initiate energy-efficiency programs that demonstrate to its electricity customers that they can contribute to meeting the state's and the utilities' goals through buying smaller homes, owning energy-efficient appliances, including air conditioning systems, making energy-efficiency improvements to their homes to reduce energy losses, and taking advantage of natural gas for heating, water heating, and cooking where available and cost-effective. PEF recognizes that customer choices to reduce energy consumption may help defer the need for future generating units and transmission lines.

PEF provides the following information in a July 2006 issue of *The Lakeland Ledger* (Reference 8.2-007):

> We continually seek newer, cleaner ways to produce energy for our customers. We have partnered with the state and federal government and other companies and agencies in investing in hydrogen fuel-cell projects, including Florida's first hydrogen vehicle fueling station.
>
> We've signed a contract to purchase the energy generated by a planned power plant in central Florida that will use a bamboo-like grass as its fuel

> source. [That project was approved by the FPSC in August 2006.] Renewable biomass generation projects such as this one can help reduce the need to burn other fuels, and they provide significant environmental benefits.

PEF is committed to a long-term, balanced, strategic solution to meeting growing energy needs — a solution that includes four main components: (1) increased energy efficiency/demand side management programs and incentives, (2) investments in renewable energy sources and other emerging energy technologies, (3) upgrading of existing power plants with modern state-of-the-art equipment, and (4) an investment in new, cleaner and more efficient electric power generation. Because it takes many years to site and build new power plants, PEF is working to keep future power plant options open.

This strategy provides long-term stability for PEF's growing customer base and delivers a reliable supply of electricity, more stable cost structure, less dependence on imported energy, and a cleaner environment.

8.2.2.3 Price and Rate Structure

The FPSC's *Review of 2007 Ten-Year Site Plans for Florida's Electric Utilities* provides the following information (Reference 8.1-003):

> Over the last 20 years, Florida's utilities have turned to natural gas to satisfy the state's growing energy demand. The recent volatility of natural gas prices, however, has shown that the overdependence on a single fuel can lead to an unacceptable risk of supply disruptions and rate increases.
>
> Florida's increased dependence on natural gas has caused the state to be more vulnerable to supply disruptions due to severe storms and hurricanes. Such supply disruptions have caused severe price increases and power disruptions. Having a diverse fuel mix can mitigate the impacts of such events. Fuel diversity also serves as a risk mitigation strategy by providing a dampening effect on fuel price volatility caused by daily market conditions, thus allowing utilities to shield ratepayers from volatile price fluctuations.
>
> Prices for solid fuels such as nuclear and coal are forecasted to remain stable compared to oil and natural gas prices. Such a relationship highlights the importance of maintaining a balanced fuel supply.

8.2.2.3.1 Price Response in Forecast

A real price term is included in the forecast regression equations. PEF's forecast methodology uses the following factors to develop the price models: the number of customers, weather, energy prices, employment, personal income, population, and housing stock. Table 8.2-5 presents PEF's historical and projected electric prices in cents per kWh.

PEF's 2008 TYSP provides the following information (Reference 8.0-002):

> The PEF forecast of customers, energy sales, and peak demand is developed using customer class-specific econometric models. These models are expressly designed to capture class-specific variation over time. By modeling customer growth and average energy usage individually, subtle changes in existing customer usage are better captured as well as growth from new customers. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, load management, and interruptible service.
>
> In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and annual data for customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting concerns. The external sources of data include Moody's Economy.Com and the University of Florida's Bureau of Economic and Business Research. Internal company forecasts are used for projections of electricity price, weather conditions, and the length of the billing month. Normal weather, which is assumed throughout the forecast horizon, is based on the 30-year average of heating and cooling degree-days by month as measured at several weather stations throughout Florida for energy projections and temperatures around the hour of peak for the firm retail demand forecast . . .
>
> The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, PEF's coincident system peak is separated into five (5) major components. These components consist of potential firm retail load, conservation and load management program capability, wholesale demand, company use demand and interruptible demand.
>
> Potential firm retail load refers to projections of PEF retail hourly seasonal net peak demand (excluding the non-firm interruptible/curtailable/standby services) before the cumulative effects of any conservation activity or the activation of PEF's Load Management program. The historical values of this series are constructed to show the size of PEF's firm retail net peak demand assuming no utility-induced conservation or load control had taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to total system customer levels and coincident weather conditions at the time of the peak without the impacts of year-to-year variation in conservation activity or load control reductions. Seasonal peaks are projected using historical seasonal peak data regardless of which month the peak occurred. The projections become the potential

> retail demand projection for the month of January (winter) and August (summer) since this is typically when the seasonal peaks occur. The non-seasonal peak months are projected the same as the seasonal peaks, but the analysis is limited to the specific month being projected . . .
>
> PEF's current TYSP includes new natural gas fueled resources in 2009 and 2013. The plan also includes uprates to the Crystal River nuclear unit No. 3 in 2009 and 2011, and new nuclear units in 2016 and 2017. PEF focused its fuel forecast sensitivity on price projections for natural gas. Higher gas prices would improve the economics for non gas-fueled resources and lower gas prices would benefit gas-fueled resources. Uncertainty over future environmental regulation, particularly as it relates carbon, as well as fuel security and reliability considerations, favors pursuit of the nuclear option.

PEF compares the forecast retail residential, commercial, and industrial (RCI) real prices with the rates provided in the most recent U.S. Department of Energy (DOE) EIA Annual Energy Outlook for the southeastern United States.

8.2.2.3.2 Effect of Growth on Load-Shape

The PEF load and energy process starts at the retail class and individual wholesale customer level. The demand forecast for an individual class or customer is a direct product of the energy forecast and the individual coincidence peak load factor of the entity. This process allows for a dynamic system load factor for modeling future system load-shape.

8.2.2.3.3 Competition

The largest portion of PEF's wholesale sales is under contracts for only a portion of the customers load. For those smaller customers on full-requirements contracts, other factors are more critical than price in forecasting future load. The prospect of adding or losing a major manufacturing facility, or opportunity to grow commercial load along new highways, are larger drivers than price. PEF collects this information and the account representatives for the wholesale accounts reflect this in the forecast. The forecast assumes that FR customers continue after contract expiration. However, a forecast version is prepared that recognizes the contract termination dates of these customers.

8.2.2.3.4 Appliance Efficiency

The historic forecast data in PEF's 2008 TYSP contains the effects of past appliance efficiency gains and company conservation programs. As such, the forecast reflects these historic trends continuing into the future. Additional DSM and conservation programs are directly reduced from the forecast. Table 8.2-6 provides a listing of historical average appliance usage in a single family home within in the PEF relevant area. Table 8.2-7 presents results of a survey conducted by PEF and FPSC comparing residential energy usage practices and trends in 2002 and 2006.

ER Section 9.1 and ER Subsections 9.2.1 and 9.2.2 provide further information about the factors affecting growth of electricity demand that could affect the need for or choice of alternative energy sources and systems.

Table 8.2-1
History and Forecast of Energy Consumption by Customer Class

	Rural and Residential		Commercial		Industrial	
Year	Average Number of Customers	Average Consumption by Customer (kWh)	Average Number of Customers	Average Consumption by Customer (kWh)	Average Number of Customers	Average Consumption by Customer (kWh)
1998	1,182,786	13,972	136,345	73,336	2707	1,616,180
1999	1,213,470	13,387	140,897	73,295	2629	1,648,536
2000	1,234,286	13,867	143,475	75,368	2535	1,676,134
2001	1,274,672	13,810	146,983	75,251	2551	1,517,836
2002	1,301,515	14,409	150,577	75,842	2535	1,512,821
2003	1,331,914	14,587	154,294	74,876	2643	1,513,810
2004	1,364,677	14,177	158,780	73,898	2733	1,488,840
2005	1,397,012	14,240	161,001	74,190	2703	1,531,632
2006	1,431,743	13,983	162,774	73,568	2697	1,542,455
2007	1,442,853	13,800	162,837	74,821	2668	1,431,409
2008	1,469,283	14,354	165,924	75,672	2655	1,531,450
2009	1,497,230	14,538	169,772	75,866	2650	1,563,396
2010	1,525,168	14,662	173,623	75,824	2645	1,572,401
2011	1,553,139	14,826	177,480	75,784	2645	1,605,671
2012	1,581,044	15,002	181,327	75,828	2645	1,617,391
2013	1,609,030	15,162	185,185	75,824	2645	1,648,015
2014	1,636,914	15,307	189,028	75,900	2645	1,655,577
2015	1,664,515	15,454	192,832	76,022	2645	1,656,333
2016	1,690,042	15,603	196,351	76,344	2645	1,663,894
2017	1,715,109	15,777	199,807	76,832	2645	1,677,127

Notes:

kWh = kilowatt hour

Source: Reference 8.0-002

Table 8.2-2 (Sheet 1 of 4)
History and Forecast of Summer Peak Demand (MW)

Base Case

Year	Total (2)	Wholesale (3)	Retail (4)	Interruptible (5)	Residential Load Management (6)	Residential Conservation (7)	Commercial/ Industrial Load Management (8)	Commercial/ Industrial Conservation (9)	Other Demand Reductions (OTH)	Net Firm Demand (10)
1998	8367	943	7424	291	438	100	42	151	182	7163
1999	9039	1326	7713	292	505	115	45	156	183	7743
2000	8916	1319	7597	277	455	129	48	158	75	7774
2001	8847	1117	7730	283	414	142	48	159	75	7726
2002	9426	1203	8223	305	390	156	43	161	75	8296
2003	8886	887	7999	300	354	172	44	164	75	7778
2004	9589	1071	8518	531	320	188	39	166	110	8235
2005	10,356	1118	9238	448	309	206	38	169	110	9076
2006	10,153	1257	8896	329	292	226	37	172	66	9031
2007	10,938	1544	9394	290	294	243	43	179	110	9778
2008	10,647	1343	9304	305	308	259	52	189	110	9424
2009	10,742	1191	9551	306	326	275	61	198	125	9451
2010	11,026	1265	9762	297	347	292	70	207	125	9689
2011	11,272	1282	9990	302	368	308	79	217	125	9873
2012	11,659	1439	10,220	310	389	325	89	226	125	10,195
2013	11,912	1464	10,449	316	403	342	98	235	125	10,393
2014	12,132	1463	10,670	316	413	360	107	244	125	10,568
2015	12,361	1475	10,886	316	417	367	112	248	125	10,776
2016	12,578	1491	11,087	317	424	380	115	256	125	10,961
2017	12,797	1510	11,287	318	429	393	119	263	125	11,150

Table 8.2-2 (Sheet 2 of 4)
History and Forecast of Summer Peak Demand (MW)

High Load Forecast

Year	Total (2)	Wholesale (3)	Retail (4)	Interruptible (5)	Residential Load Management (6)	Residential Conservation (7)	Commercial/ Industrial Load Management (8)	Commercial/ Industrial Conservation (9)	Other Demand Reductions (OTH)	Net Firm Demand (10)
1998	8367	943	7424	291	438	100	42	151	182	7163
1999	9039	1326	7713	292	505	115	45	156	183	7743
2000	8916	1319	7597	277	455	129	48	158	75	7774
2001	8847	1117	7730	283	414	142	48	159	75	7726
2002	9426	1203	8223	305	390	156	43	161	75	8296
2003	8886	887	7999	300	354	172	44	164	75	7778
2004	9589	1071	8518	531	320	188	39	166	110	8235
2005	10,356	1118	9238	448	309	206	38	169	110	9076
2006	10,153	1257	8896	329	292	226	37	172	66	9031
2007	10,938	1544	9394	290	294	243	43	179	110	9778
2008	10,780	1343	9437	305	308	259	52	189	110	9557
2009	10,894	1191	9703	306	326	275	61	198	125	9603
2010	11,206	1265	9941	297	347	292	70	207	125	9868
2011	11,468	1282	10,186	302	368	308	79	217	125	10,069
2012	11,890	1439	10,451	310	389	325	89	226	125	10,426
2013	12,163	1464	11,699	316	403	342	98	235	125	10,644
2014	12,416	1463	10,953	316	413	360	107	244	125	10, 851
2015	12, 696	1475	11,221	316	417	367	112	248	125	11,111
2016	12,951	1491	11,460	317	424	380	115	256	125	11,334
2017	13,220	1510	11,710	318	429	393	119	263	125	11,573

Table 8.2-2 (Sheet 3 of 4)
History and Forecast of Summer Peak Demand (MW)

Low Load Forecast

Year	Total (2)	Wholesale (3)	Retail (4)	Interruptible (5)	Residential Load Management (6)	Residential Conservation (7)	Commercial/ Industrial Load Management (8)	Commercial/ Industrial Conservation (9)	Other Demand Reductions (OTH)	Net Firm Demand (10)
1998	8367	943	7424	291	438	100	42	151	182	7163
1999	9039	1326	7713	292	505	115	45	156	183	7743
2000	8916	1319	7597	277	455	129	48	158	75	7774
2001	8847	1117	7730	283	414	142	48	159	75	7726
2002	9426	1203	8223	305	390	156	43	161	75	8296
2003	8886	887	7999	300	354	172	44	164	75	7778
2004	9589	1071	8518	531	320	188	39	166	110	8235
2005	10,356	1118	9238	448	309	206	38	169	110	9076
2006	10,153	1257	8896	329	292	226	37	172	66	9031
2007	10,938	1544	9394	290	294	243	43	179	110	9778
2008	10,512	1343	9169	305	308	259	52	189	110	9289
2009	10,598	1191	9407	306	326	275	61	198	125	9307
2010	10, 867	1265	9602	297	347	292	70	207	125	9529
2011	11,082	1282	9800	302	368	308	79	217	125	9683
2012	11,440	1439	10,001	310	389	325	89	226	125	9976
2013	11,657	1464	10,193	316	403	342	98	235	125	10,138
2014	11,841	1463	10,378	316	413	360	107	244	125	10,276
2015	12,027	1475	10,552	316	417	367	112	248	125	10,442
2016	12,208	1491	10,717	317	424	380	115	256	125	10,591
2017	12,366	1510	10,856	318	429	393	119	263	125	10,719

Table 8.2-2 (Sheet 4 of 4)
History and Forecast of Summer Peak Demand (MW)

Notes:

Historical Values (1998 – 2007):
Col (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.
Col (5) – (9) represent total cumulative capabilities at peak. Col (8) includes commercial load management and standby generation.
Col (OTH) = Customer-owned self-service generation.
Col (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2008 – 2017):
Col (2) – (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.
Col (5) – (9) = cumulative conservation and load capabilities at peak. Col (8) includes commercial load management and standby generation.
Col (OTH) = customer-owned self-service cogeneration.
Col (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

MW = megawatt

Source: Reference 8.0-002

Table 8.2-3 (Sheet 1 of 4)
History and Forecast of Winter Peak Demand (MW)

Base Case

Year	Total (2)	Wholesale (3)	Retail (4)	Interruptible (5)	Residential Load Management (6)	Residential Conservation (7)	Commercial/ Industrial Load Management (8)	Commercial/ Industrial Conservation (9)	Other Demand Reductions (OTH)	Net Firm Demand (10)
1997/98	7752	941	6811	318	663	166	17	114	168	6306
1998/99	10,473	1741	8732	305	874	200	18	119	187	8770
1999/00	10,047	1728	8319	225	849	234	20	121	182	8416
2000/01	11,458	1984	9474	255	826	259	23	123	187	9785
2001/02	10,685	1624	9061	285	819	285	24	123	188	8961
2002/03	11,555	1538	10,017	271	793	313	27	124	198	9829
2003/04	9325	1167	8158	498	786	343	26	125	262	7286
2004/05	10,833	1600	9233	575	777	371	26	125	282	8676
2005/06	10,700	1467	9233	298	768	413	26	126	239	8830
2006/07	9899	1576	8323	248	758	454	27	128	262	8022
2007/08	12,125	2035	10,090	312	774	495	37	135	297	10,075
2008/09	12,002	1715	10,288	305	791	538	47	142	299	9881
2009/10	12,515	1999	10,516	292	809	580	57	149	318	10,311
2010/11	12,819	2073	10,747	302	827	623	67	155	321	10,524
2011/12	13,351	2382	10,969	304	844	666	76	162	325	10,974
2012/13	13,721	2518	11,203	316	862	710	86	169	328	11,250
2013/14	13,873	2448	11,425	317	880	754	96	176	332	11,318
2014/15	14,182	2538	11,644	315	897	798	105	183	335	11,549
2015/16	14,484	2628	11,855	316	906	837	110	189	339	11,786
2016/17	14,771	2716	12,054	317	914	876	115	195	342	12,011
2017/18	15,059	2807	12,253	318	921	913	118	201	345	12,242

Table 8.2-3 (Sheet 2 of 4)
History and Forecast of Winter Peak Demand (MW)

High Load Forecast

Year	Total (2)	Wholesale (3)	Retail (4)	Interruptible (5)	Residential Load Management (6)	Residential Conservation (7)	Commercial/ Industrial Load Management (8)	Commercial/ Industrial Conservation (9)	Other Demand Reductions (OTH)	Net Firm Demand (10)
1997/98	7752	941	6811	318	663	166	17	114	168	6306
1998/99	10,473	1741	8732	305	874	200	18	119	187	8770
1999/00	10,047	1728	8319	225	849	234	20	121	182	8416
2000/01	11,458	1984	9474	255	826	259	23	123	187	9785
2001/02	10,685	1624	9061	285	819	285	24	123	188	8961
2002/03	11,555	1538	10,017	271	793	313	27	124	198	9829
2003/04	9325	1167	8158	498	786	343	26	125	262	7286
2004/05	10,833	1600	9233	575	777	371	26	125	282	8676
2005/06	10,700	1467	9233	298	768	413	26	126	239	8830
2006/07	9899	1576	8323	248	758	454	27	128	262	8022
2007/08	12,267	2035	10,232	312	774	495	37	135	297	10,217
2008/09	12,165	1715	10,451	305	791	538	47	142	299	10,044
2009/10	12,704	1999	10,704	292	809	580	57	149	318	10,499
2010/11	13,026	2073	10,954	302	827	623	67	155	321	10,731
2011/12	13,593	2382	11,210	304	844	666	76	162	325	11,215
2012/13	13,982	2518	11,464	316	862	710	86	169	328	11,511
2013/14	14,168	2448	11,720	317	880	754	96	176	332	11,613
2014/15	14,530	2538	11,992	315	897	798	105	183	335	11,897
2015/16	14,870	2628	12,242	316	906	837	110	189	339	12,173
2016/17	15,208	2716	12,492	317	914	876	115	195	342	12,449
2017/18	15,568	2807	12,761	318	921	913	118	201	345	12,751

Table 8.2-3 (Sheet 3 of 4)
History and Forecast of Winter Peak Demand (MW)

Low Load Forecast

Year	Total (2)	Wholesale (3)	Retail (4)	Interruptible (5)	Residential Load Management (6)	Residential Conservation (7)	Commercial/ Industrial Load Management (8)	Commercial/ Industrial Conservation (9)	Other Demand Reductions (OTH)	Net Firm Demand (10)
1997/98	7752	941	6811	318	663	166	17	114	168	6306
1998/99	10,473	1741	8732	305	874	200	18	119	187	8770
1999/00	10,047	1728	8319	225	849	234	20	121	182	8416
2000/01	11,458	1984	9474	255	826	259	23	123	187	9785
2001/02	10,685	1624	9061	285	819	285	24	123	188	8961
2002/03	11,555	1538	10,017	271	793	313	27	124	198	9828
2003/04	9325	1167	8158	498	786	343	26	125	262	7286
2004/05	10,833	1600	9233	575	777	371	26	125	282	8676
2005/06	10,700	1467	9233	298	768	413	26	126	239	8830
2006/07	9899	1576	8323	248	758	454	27	128	262	8022
2007/08	11,981	2035	9946	312	774	495	37	135	297	9931
2008/09	11,851	1715	10,137	305	791	538	47	142	299	9730
2009/10	12,346	1999	10,346	292	809	580	57	149	318	10,141
2010/11	12,620	2073	10,548	302	827	623	67	155	321	10,325
2011/12	13,121	2382	10,738	304	844	666	76	162	325	10,743
2012/13	13,454	2518	10,936	316	862	710	86	169	328	10,983
2013/14	13,568	2448	11,120	317	880	754	96	176	332	11,013
2014/15	13,835	2538	11,297	315	897	798	105	183	335	11,202
2015/16	14,099	2628	11,471	316	906	837	110	189	339	11,402
2016/17	14,326	2716	11,610	317	914	876	115	195	342	11,567

Table 8.2-3 (Sheet 4 of 4)
History and Forecast of Winter Peak Demand (MW)

Notes:

Historical Values (1998 – 2007):
Col (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.
Col (5) – (9) represent total cumulative capabilities at peak. Col (8) includes commercial load management and standby generation.
Col (OTH) = voltage reduction and customer-owned self-service cogeneration.
Col (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2008 – 2018):
Col (2) – (4) = forecasted peak without load control and conservation.
Col (5) – (9) represent cumulative conservation and load capabilities at peak. Col (8) includes commercial load management and standby generation.
Col (OTH) = voltage reduction and customer-owned self-service cogeneration
Col (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

MW = megawatt

Source: Reference 8.0-002

Table 8.2-4 (Sheet 1 of 4)
History and Forecast of Annual Net Energy for Load (GWh)

Base Case

Year (1)	Total (2)	Residential Conservation (3)	Commercial/ Industrial Conservation (4)	Other Energy Reduction (OTH)	Retail (5)	Wholesale (6)	Utility Use and Losses (7)	Net Energy for Load (8)	Load Factor (%) (9)
1998	38,949	289	333	564	33,387	2340	2036	37,763	53.9
1999	40,375	312	339	564	33,441	3267	2452	39,160	50.0
2000	42,486	334	345	565	34,832	3732	2678	41,242	50.5
2001	42,200	354	349	564	35,263	3839	1831	40,933	47.5
2002	43,860	377	352	564	36,859	3173	2535	42,567	50.0
2003	45,233	402	357	564	37,957	3359	2595	43,911	47.7
2004	46,833	426	360	780	38,193	4301	2774	45,268	56.5
2005	48,474	455	363	779	39,177	5195	2506	46,878	52.3
2006	47,399	484	365	509	39,432	4220	2389	46,041	52.1
2007	49,306	511	383	779	39,282	5598	2753	47,633	52.3
2008	50,467	552	401	780	41,208	4798	2728	48,734	55.1
2009	51,548	582	419	779	42,395	4527	2846	49,768	57.5
2010	53,535	612	437	871	43,407	5238	2970	51,615	57.1
2011	54,881	642	455	871	44,563	5363	2987	52,913	57.4
2012	56,711	672	473	871	45,708	5892	3095	54,695	56.7
2013	58,109	702	491	871	46,884	6032	3129	56,045	56.9
2014	59,017	732	509	871	47,999	5708	3198	56,905	57.4
2015	60,321	760	525	871	49,113	5795	3258	58,166	57.5
2016	61,646	786	540	871	50,245	5874	3329	59,448	57.4
2017	63,075	812	556	871	51,469	5953	3414	60,836	57.8

Table 8.2-4 (Sheet 2 of 4)
History and Forecast of Annual Net Energy for Load (GWh)

High Load Forecast

Year (1)	Total (2)	Residential Conservation (3)	Commercial/ Industrial Conservation (4)	Other Energy Reduction (OTH)	Retail (5)	Wholesale (6)	Utility Use and Losses (7)	Net Energy for Load (8)	Load Factor (%) (9)
1998	38,949	289	333	564	33,387	2340	2036	37,763	53.9
1999	40,375	312	339	564	33,441	3267	2452	39,160	50.0
2000	42,486	334	345	565	34,832	3732	2678	41,242	50.5
2001	42,200	354	349	564	35,263	3839	1831	40,933	47.5
2002	43,860	377	352	564	36,859	3173	2535	42,567	50.0
2003	45,233	402	357	564	37,957	3359	2595	43,911	47.7
2004	46,833	426	360	780	38,193	4301	2774	45,268	56.5
2005	48,474	455	363	779	39,177	5195	2506	46,878	52.3
2006	47,399	484	365	509	39,432	4220	2389	46,041	52.1
2007	49,306	511	383	779	39,282	5598	2753	47,633	52.3
2008	51,137	552	401	780	41,835	4798	2771	49,404	55.0
2009	52,320	582	419	779	43,116	4527	2897	50,540	57.4
2010	54,442	612	437	871	44,257	5238	3027	52,522	57.1
2011	55,882	642	455	871	45,498	5363	3053	53,914	57.4
2012	57,890	672	473	871	46,814	5892	3168	55,874	56.7
2013	59,392	702	491	871	48,085	6032	3211	57,328	56.9
2014	60,481	732	509	871	49,366	5708	3295	58,369	57.4
2015	62,052	760	525	871	50,735	5795	3367	59,897	57.5
2016	63,588	786	540	871	52,062	5874	3454	61,390	57.6
2017	65,292	812	556	871	53,541	5953	3559	63,053	57.8

Table 8.2-4 (Sheet 3 of 4)
History and Forecast of Annual Net Energy for Load (GWh)

Low Load Forecast

Year (1)	Total (2)	Residential Conservation (3)	Commercial/ Industrial Conservation (4)	Other Energy Reduction (OTH)	Retail (5)	Wholesale (6)	Utility Use and Losses (7)	Net Energy for Load (8)	Load Factor (%) (9)
1998	38,949	289	333	564	33,387	2340	2036	37,763	53.9
1999	40,375	312	339	564	33,441	3267	2452	39,160	50.0
2000	42,486	334	345	565	34,832	3732	2678	41,242	50.5
2001	42,200	354	349	564	35,263	3839	1831	40,933	47.5
2002	43,860	377	352	564	36,859	3173	2535	42,567	50.0
2003	45,233	402	357	564	37,957	3359	2595	43,911	47.7
2004	46,833	426	360	780	38,193	4301	2774	45,268	56.5
2005	48,474	455	363	779	39,177	5195	2506	46,878	52.3
2006	47,399	484	365	509	39,432	4220	2389	46,041	52.1
2007	49,306	511	383	779	39,282	5598	2753	47,633	52.3
2008	49,791	552	401	780	40,574	4798	2686	48,058	55.1
2009	50,822	582	419	779	41,715	4527	2800	49,042	57.5
2010	52,722	612	437	871	42,648	5238	2916	50,802	57.2
2011	53,913	642	455	871	43,657	5363	2925	51,945	57.4
2012	55,590	672	473	871	44,660	5892	3022	53,574	56.8
2013	56,795	702	491	871	45,655	6032	3044	54,731	56.9
2014	57,509	732	509	871	46,588	5708	3101	55,397	57.4
2015	58,596	760	525	871	47,496	5795	3150	56,441	57.5
2016	59,719	786	540	871	48,444	5874	3203	57,521	57.6
2017	60,829	812	556	871	49,358	5953	3279	58,590	57.8

Table 8.2-4 (Sheet 4 of 4)
History and Forecast of Annual Net Energy for Load (GWh)

Notes:

Column (OTH) includes conservation energy for lighting and public authority customers, customer-owned self-service cogeneration.

Column (9) = Load factors for historical years are calculated using the actual winter peak demand, except the 1998, 2004, and 2007 historical load factors, which are based on the actual summer peak demand.
Load factors for future years are calculated using the net firm winter peak demand.

GWh = gigawatt hour

Source: Reference 8.0-002

Table 8.2-5 (Sheet 1 of 4)
Historical and Projected Electric Prices (Cents per kWh)

Year	Residential	Commercial	Industrial	Retail	Consumer Price Index 1982-84	(Real Prices based on 1982-84 dollar values)			
						Residential	Commercial	Industrial	Retail
1960	3.02	3.32	1.20	2.59	0.296	10.203	11.216	4.054	8.748
1961	3.04	3.32	1.29	2.70	0.299	10.167	11.104	4.314	9.041
1962	2.89	3.08	1.16	2.55	0.302	9.570	10.199	3.841	8.435
1963	2.79	2.97	1.09	2.46	0.306	9.118	9.706	3.562	8.050
1964	2.75	2.91	1.09	2.46	0.310	8.871	9.387	3.516	7.926
1965	2.68	2.76	1.06	2.37	0.315	8.508	8.762	3.365	7.510
1966	2.63	2.75	1.05	2.34	0.324	8.117	8.488	3.241	7.209
1967	2.59	2.66	1.04	2.26	0.334	7.754	7.964	3.114	6.777
1968	2.41	2.52	1.02	2.17	0.348	6.925	7.241	2.931	6.222
1969	2.22	2.38	1.02	2.06	0.367	6.049	6.485	2.779	5.619
1970	2.13	2.23	1.03	2.03	0.388	5.490	5.747	2.655	5.241
1971	2.11	2.17	1.03	2.04	0.405	5.210	5.358	2.543	5.039
1972	2.09	2.16	1.09	2.08	0.418	5.000	5.167	2.608	4.982
1973	2.17	2.24	1.20	2.24	0.444	4.887	5.045	2.703	5.047
1974	3.42	3.51	2.25	3.68	0.493	6.937	7.120	4.564	7.456
1975	4.09	4.16	2.82	4.40	0.538	7.602	7.732	5.242	8.186

Table 8.2-5 (Sheet 2 of 4)
Historical and Projected Electric Prices (Cents per kWh)

Year	Residential	Commercial	Industrial	Retail	Consumer Price Index 1982-84	(Real Prices based on 1982-84 dollar value)			
						Residential	Commercial	Industrial	Retail
1976	4.19	4.31	2.81	4.53	0.569	7.364	7.575	4.938	7.964
1977	4.51	4.66	3.13	4.98	0.606	7.442	7.690	5.165	8.214
1978	4.78	4.98	3.45	5.35	0.652	7.331	7.638	5.291	8.201
1979	5.15	5.32	3.77	4.85	0.726	7.094	7.328	5.193	6.685
1980	5.56	5.81	4.18	5.27	0.824	6.748	7.051	5.073	6.391
1981	7.09	6.85	5.32	6.62	0.909	7.800	7.536	5.853	7.279
1982	7.23	6.74	5.42	6.71	0.965	7.492	6.984	5.617	6.955
1983	7.54	6.42	5.08	6.74	0.996	7.570	6.446	5.100	6.763
1984	7.69	6.45	5.02	6.80	1.039	7.401	6.208	4.832	6.541
1985	8.07	6.33	4.70	6.88	1.076	7.500	5.883	4.368	6.390
1986	8.12	6.29	4.69	6.92	1.096	7.409	5.739	4.279	6.313
1987	7.28	5.56	4.02	6.14	1.136	6.408	4.894	3.539	5.401
1988	6.93	5.38	3.95	5.88	1.183	5.858	4.548	3.339	4.975
1989	7.01	5.47	4.00	5.92	1.240	5.653	4.411	3.226	4.772
1990	7.27	5.68	4.41	6.15	1.307	5.562	4.346	3.374	4.703
1991	7.03	5.69	4.38	6.33	1.362	5.162	4.178	3.216	4.650

Table 8.2-5 (Sheet 3 of 4)
Historical and Projected Electric Prices (Cents per kWh)

Year	Residential	Commercial	Industrial	Retail	Consumer Price Index 1982-84	(Real Prices based on 1982-84 dollar values)			
						Residential	Commercial	Industrial	Retail
1992	6.90	5.51	4.19	6.02	1.403	4.918	3.927	2.986	4.289
1993	7.54	5.80	4.36	6.46	1.445	5.218	4.014	3.017	4.471
1994	7.84	5.85	4.39	6.63	1.482	5.290	3.947	2.962	4.474
1995	8.12	5.97	4.44	6.83	1.524	5.328	3.917	2.913	4.482
1996	8.18	6.06	4.41	6.86	1.569	5.214	3.862	2.811	4.375
1997	8.37	6.12	4.50	6.97	1.605	5.215	3.813	2.804	4.343
1998	8.42	6.07	4.45	6.99	1.630	5.166	3.724	2.730	4.291
1999	8.41	5.96	4.35	6.91	1.666	5.048	3.577	2.611	4.150
2000	8.46	6.10	4.56	7.04	1.722	4.913	3.542	2.648	4.089
2001	9.18	6.80	5.38	7.80	1.770	5.186	3.842	3.040	4.404
2002	8.54	6.29	4.96	7.00	1.799	4.747	3.496	2.757	3.891
2003	8.59	6.39	5.06	7.35	1.840	4.668	3.473	2.750	3.993
2004	9.24	7.26	5.79	8.07	1.889	4.891	3.843	3.065	4.274
2005	9.97	7.93	6.42	8.96	1.953	5.105	4.060	3.287	4.586
2006	11.71	9.60	7.91	10.45	2.016	5.809	4.762	3.924	5.186
2007	11.79	9.45	7.88	10.67	2.073	5.687	4.559	3.801	5.146

Table 8.2-5 (Sheet 4 of 4)
Historical and Projected Electric Prices (Cents per kWh)

Year	Residential	Commercial	Industrial	Retail	Consumer Price Index 1982-84	(Real Prices based on 1982-84 dollar value)			
						Residential	Commercial	Industrial	Retail
2008	11.60	9.59	8.06	10.42	2.125	5.462	4.514	3.796	4.905
2009	12.19	10.18	8.63	11.01	2.164	5.634	4.703	3.990	5.088
2010	12.54	10.46	8.89	11.33	2.206	5.687	4.743	4.029	5.136
2011	12.71	10.66	9.09	11.51	2.255	5.638	4.727	4.033	5.107
2012	12.83	10.79	9.23	11.65	2.307	5.563	4.677	4.002	5.048
2013	13.27	11.24	9.70	12.10	2.359	5.625	4.766	4.111	5.128
2014	13.70	11.69	10.15	12.54	2.412	5.678	4.846	4.210	5.198
2015	14.22	12.23	10.70	13.07	2.466	5.766	4.959	4.338	5.302
2016	14.70	12.72	11.20	13.57	2.520	5.834	5.049	4.445	5.385
2017	14.79	12.82	11.31	13.67	2.574	5.747	4.979	4.395	5.309
2018	14.89	12.93	11.44	13.78	2.630	5.663	4.915	4.348	5.238
2019	14.76	12.80	11.32	13.65	2.687	5.495	4.762	4.212	5.080
2020	14.66	12.69	11.22	13.54	2.745	5.339	4.621	4.086	4.934

Notes:

January 2008 price forecast from Financial Planning.

kWh = kilowatt hour

Table 8.2-6
Single Family Home – Average Appliance Usage

Appliance	% of Total	kWh/yr
Air	33%	5650
Heat	6%	1070
Domestic Hot Water	13%	2240
Lighting	7%	1220
Pool [(a)]	7%	1199
Refrigerator	7%	1196
Ceil Fans	6%	1102
Dryer	5%	857
Television	3%	507
Range	2%	343
Dishwasher	2%	315
Computer	1%	224
Washer	1%	200
Freezer	1%	195
Waterbed	1%	140
Window Air Conditioner	1%	134
Exhaust Fan	0%	83
Average Single Family Home	--	17,130

Notes:

Data represent 1999 end use.

a) 24 percent of homes have pools.

kWh/yr = kilowatt hour per year

Table 8.2-7
Comparison of PEF and FPSC Residential Survey Results

PEF FPSC Residential Survey	Electric	Gas	Propane	Oil	Solar	Other
2006 Primary Heating Fuel	87.4%	10.0%	1.5%	0.0%	0.0%	1.1%
2002 Primary Heating Fuel	92.3%	4.2%	3.2%	0.3%	0.0%	0.0%
2006 Primary Water Heating Fuel	83.0%	13.7%	2.2%	0.4%	0.7%	0.0%
2002 Primary Water Heating Fuel	89.4%	8.1%	1.8%	0.0%	0.4%	0.0%

	2006		2002	
Major Appliances	Electric	Gas	Electric	Gas
Wall Oven	13.7%	7.0%	15.1%	1.8%
Cooktop	32.6%	5.6%	34.7%	4.2%
Ranges	82.6%	10.4%	81.4%	7.4%
Clothes Dryer	87.8%	4.8%	82.8%	5.3%

8.3 POWER SUPPLY

In Florida, the FPSC is tasked with determining the adequacy of power supply. Greater reliability depends on several electric grid infrastructure additions and upgrades, in which timing may be problematic.

The FPSC analyzes the need for power and power supply issues by dividing existing capacity into the following three categories:

- Baseload — Operates nearly full cycle.
- Intermediate — Cycles with load increases and decreases.
- Peaking — Operates infrequently to meet system peak demand.

The NRC's NUREG-1555 guidance also allows an applicant to rely on a state's regulatory power planning structure. The NRC's criteria for and analysis of need-for-power evaluations are described in ER Section 8.0.

The FPSC has expressed concern about Florida's increasing reliance on natural-gas-fired generation, and consequent fuel costs that continue to rise and experience volatile swings. The state's landmark energy plan, adopted in 2006, recognizes the need for new plants, as well as the critical role that nuclear power already plays in promoting reliable electricity and rate stability for Florida customers (Reference 8.3-001). In addition, recent legislation (in April 2007) contained in Section 403.519(4), F.S., encourages nuclear generation by allowing utilities to begin recovering costs for a new unit while still under construction. The legislation requires the FPSC to consider fuel diversity in the Determination of Need process and exempts utilities from the requirement to issue a request for proposals for nuclear units. While currently pursuing rule revisions to implement the legislation, the FPSC has always considered fuel diversity when evaluating utility resource plans.

The FPSC's *Review of 2007 Ten-Year Site Plans for Florida's Electric Utilities* provides the following information (Reference 8.1-003):

> Both [Florida Power & Light Company] FPL and PEF have announced plans to expand the capacity of their existing nuclear power plants and to construct new nuclear units. The Commission approved the need for an uprate to PEF's Crystal River 3 nuclear unit on February 8, 2007.
>
> Combined, the uprates of the PEF and FPL units will add approximately 600 MW of additional nuclear capacity for the years 2009 through 2013. In addition to these uprates to existing units, PEF's Ten-Year Site Plan currently includes plans to construct a new 1,125 MW nuclear plant by 2016. PEF is expected to file a petition for need determination in early 2008 . . .

> As filed in its 2007 Ten-Year Site Plan, PEF plans an addition of over 1,300 MW from nuclear generation. The Crystal River Unit 3 will be uprated by 40 MW in 2009 and by 140 MW in 2011; the Crystal River Unit 3 uprate was granted a need determination in February 2007. PEF also expects to bring on line in 2016 an advanced light water reactor to provide 1,125 MW of generation. A determination of need for this unit should be filed in early 2008 . . .
>
> Gulfstream: Gulfstream's Phase III expansion will provide service to FPL's West County Energy Center and is expected to begin service in the summer of 2008. The Phase IV expansion will provide pipeline capacity for PEF's Bartow site in Pinellas County.
>
> Cypress Pipeline: Phase I of this project is a 24" pipeline that connects the Elba Island [liquefied natural gas] LNG facility near Savannah, Georgia, to [Florida Gas Transmission Company's] FGT's system near Jacksonville. This pipeline began service in May 2007 and provides gas to PEF's Hines units. This pipeline plans additional phases involving looping and additional compression.

Tables 8.1-8 and 8.1-9 show the power analysis performed by PEF to satisfy the FPSC requirement. The need for power analysis in this section is supported by the FPSC's TYSP review and Determination of Need process, described in ER Section 8.1.

Oil and natural gas are readily available to ultimate customers in the PEF service territory area (for example, gas curtailments and status of gas hookups to new customers). Most of the oil (fuel oil diesel, gasoline, and jet fuel) supply for end users in the PEF service territory comes through the port in Tampa, Florida. Refineries in the U.S. Gulf Coast region produce the oil products and transport them to Tampa by tanker. The oil is distributed out of Tampa terminals by truck or through the Central Florida Pipeline to the Orlando area. In the northern portion of the service area, oil is supplied from terminals in Jacksonville, Florida or Bainbridge, Georgia. Jacksonville receives oil products by tanker from the U.S. Gulf Coast or Caribbean refineries. Bainbridge, Georgia, receives oil supply through the Colonial Pipeline Company from U.S. Gulf Coast refineries. Oil is distributed from Jacksonville and Bainbridge primarily by truck.

Because the majority of the oil supply to the area comes by ship or barge from the U.S. Gulf Coast, weather can be a significant factor. Coastal refineries are subject to storm damage, and ships and barges can be delayed due to weather issues. Also, shortages of gasoline and diesel can occur when hurricanes approaching the State cause surges in demand due to coastal area evacuations.

No significant changes in the supply structure are expected in the next several years. Volumes required are expected to grow over time with population growth and through the introduction of ethanol and other "bio-fuels" into the market. During the period from 2008 to 2020, supplies of all the major oil products should

be readily available from the sources discussed above. However, occasional shortages caused by weather-related interruptions to supply may occur.

Natural gas in the State of Florida is transported into the state to serve PEF's service territory by two major interstate pipelines: FGT and Gulfstream Natural Gas System (GNG).

The FGT serves most of Florida from the Panhandle east and south covering most of the population centers in peninsular Florida. It traverses the western portion of Levy County with natural gas flow from north to south. Currently, this pipeline's firm capacity is fully subscribed and has the ability to access various sources most of which are located in the Gulf of Mexico (offshore Texas, Louisiana, Mississippi, and Alabama). The FGT's capacity can be expanded by adding compression and looping of the mainline with the majority of the supply sources located in the Eastern Gulf of Mexico area. Currently, FGT serves all of PEF's gas-fired power generation sites.

The GNG serves Central Florida from the Tampa/St. Petersburg area east to Palm Beach County and as far north as the Southern Orlando (Northern Polk and Western Osceola counties). GNG does not serve Levy County. Currently, this pipeline's firm capacity is fully subscribed and has the ability to be expanded from sources located in the Pascagoula, Mississippi and Mobile Bay area, Alabama, accessing supplies from upstream interconnecting pipelines accessing supply from the offshore area of the eastern Gulf of Mexico. The capacity of GNG is expandable by adding compression and looping of the mainline. GNG serves only three of PEF's gas-fired power generation sites in Florida with one to be added in the 2008 – 2009 timeframe.

As noted in other sections of this chapter, PEF relies primarily on the TYSP process for their service territory in Florida to outline the existing power supply and need for power.

8.3.1 EXISTING AND PLANNED CAPACITY IN THE REGION OF INTEREST

Historically, the regulated utilities in Florida have met demand by power purchase and by installing their own generating capacity. The FPSC manages power supply information through a TYSP, captured annually in a report provided to the FDEP. The FPSC's annual review of the 2007 TYSP outlines the state's traditional mix of power generation and supply. In addition, the state relies on reliability reports from NERC and the FRCC, as described in the following subsections.

The PEF TYSP outlines total supply resources for the service territory. An increase of 2199 MW in summer and 2361 MW in winter are identified as "uncommitted" in Tables 8.1-6 and 8.1-7, respectively. PEF is investing in the repowering of its Bartow Plant on Tampa Bay in Pinellas County by June 2009 to burn natural gas instead of oil. This project is followed by the installation of natural gas fired combined cycle technology in 2013 at the Suwannee River Plant

and new nuclear generation at the Company's Levy County site in 2016 and 2017. Combined, the repowering of the Bartow Plant, the new Suwannee River Plant, and the two new nuclear reactors at LNP site will produce approximately 4500 additional MW of new natural gas and nuclear generation. Within PEF's service territory, 3903 MW is identified as the net gain in summer capacity through the summer of 2017. (Reference 8.0-002) In order to meet the requirements for planned additions, new baseload generation will be necessary. Baseload units are the most cost-effective new resources to address a very predictable and stable load. Nuclear and natural gas-fired plants provide most of the baseload capacity in the service territory. Intermediate capacity is provided by older plants and small oil facilities. Peaking needs are primarily supplied by gas turbines and other sources.

PEF's 2008 TYSP provides the following information (Reference 8.0-002):

> PEF's current TYSP includes a combined cycle addition in 2013 with nuclear unit additions in 2016 and 2017. Lower cost of capital and escalation rates would favor options with longer construction lead times and higher capital costs such as the nuclear addition. However, PEF does not expect these assumptions to go much lower than the current base case forecast and nuclear generation is not projected to be feasible before 2016. Conversely, higher financial assumptions would disfavor the nuclear addition. PEF will continue to assess the economics of future generation alternatives including consideration of the uncertainties in planning assumptions.

PEF acknowledged in its 2008 TYSP that a public announcement had been issued in December 2006 that identified and named a site in southern Levy County as the preferred location for construction of a new nuclear power plant to increase baseload capacity in the service territory. DSM, as previously described, will result in the reduction in peak demand, but will not eliminate the need for additional baseload capacity. PEF's TYSP process clearly establishes the need for additional baseload capacity in the service territory by 2017.

8.3.2 RELIABILITY IN THE REGION OF INTEREST

The measures of reliability generally are divided between probabilistic measures (loss of load probability, frequency, and duration of outages) and non-probabilistic measures (reserve margin and capacity margin). The commonly used "capacity margin" is the ratio of reserve capacity to actual capacity. PEF bases its reserve criterion on both deterministic and probabilistic assessments of generation reliability, industry practice, historical operating experience, and judgment, and employs both deterministic and probabilistic reliability criteria in the resource planning process. A reserve margin criterion is used as a deterministic measure of PEF's ability to meet its forecasted seasonal peak load with firm capacity. PEF plans its resources to satisfy a 20 percent reserve margin criterion. (Reference 8.0-002) As part of its IRP process, PEF considers LOLP, which is a probabilistic criterion that measures the probability that a company will

be unable to meet its load throughout the year. This criterion is discussed in ER Subsection 8.2.1.

Reserves projected in PEF's 2008 TYSP (Tables 8.1-8 and 8.1-9) are appropriate for providing an adequate and reliable power supply with reserve margins ranging from approximately 21 to 33 percent through the winter and summer peaks study period (2007 – 2008 through 2017 – 2018) (Reference 8.0-002). The higher reserves occur later in the planning period with the possible addition of large baseload generating plants.

The NERC's *2007 Long-Term Reliability Assessment* indicates that all Florida utilities are required to meet the FPSC reserve margin, and the FRCC reports adequate resources through 2016. Much of the resources in the 6- to 10-year timeframe are not sited, but are considered committed and deemed to be deliverable, representing FRCC's member obligation to meet this reserve margin. The FRCC expects to have an adequate reserve margin with transmission system deliverability throughout the 2007-2016 reliability assessment to meet the forecasted growth in peak demand and energy throughout the same timeframe. In addition, the FRCC region expects to reliably serve the forecasted firm peak demand and energy requirements through 2016 by adding 17,991 MW of resources.

The 10-year demand forecast of 2007 for the FRCC region exhibits a compounded average annual growth rate of 2.2 percent over the next 10 years, compared to the compounded average annual growth rate of 2.4 percent in 2006. The decrease in peak demand forecast growth rate is attributed to an increase in DSM participation, as well as higher electricity costs and a decrease in economic development in Florida. The 10-year energy forecast of 2007 for the FRCC region displayed growth similar to the 2006 forecast. Yearly energy consumption is expected to rise by 2.8 percent over the next decade, exactly matching the projected 10-year growth of 2.8 percent in 2006. The actual energy consumption for 2006 was 230,115 GWh, which is lower than the forecasted value of 232,561 GWh. Lower energy consumption was mainly attributed to lower than forecasted summer temperatures. (Reference 8.3-002)

As a member of the FRCC, PEF complies with the FRCC Operating Reserve Policy, which requires that operating reserves be maintained by all FRCC control areas at a value equal to or greater than the loss of generation that would result from the most severe single generation contingency, which is currently 910 MW. The Operating Reserve Policy further requires that FRCC control areas shall provide spinning reserves equal to or greater than 25 percent of the amount of the FRCC Operating Reserves. FRCC Operating Reserves must be fully available within 15 minutes, and each control area's operating reserve allocation shall be available to the other FRCC control areas not restricted by any transmission limitations.

The FRCC Operating Reserve requirement is allocated among the FRCC control areas in proportion to each control area's peak hour net energy load for the year 2000 and the summer gross FRCC capability of its largest unit or ownership

share of a joint unit operational in 2000, whichever is greater. Fifty percent is allocated on the basis of peak hour NEL and 50 percent on the basis of the summer gross FRCC capability of the largest unit.

The allocations stated in the February 2008 FRCC Handbook require PEF to maintain 181.7 MW of operating reserves and a minimum of 45.4 MW of spinning reserves. (Reference 8.3-003)

The FPSC's *Review of 2007 Ten-Year Site Plans for Florida's Electric Utilities* provides the following information (Reference 8.1-003):

> Nationwide, electric utilities plan their bulk power systems (100 kV and above) to comply with North American Electric Reliability Corporation (NERC) and regional reliability standards. NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate, and secure. Since its formation in 1968, NERC operated successfully as a self-regulatory organization, and the electric industry voluntarily complied with NERC reliability standards. However, changes in the electric industry have rendered the voluntary compliance system inadequate. In response to these industry changes, Congress required the Federal Energy Regulatory Commission (FERC) to develop a new mandatory system of reliability standards and compliance. The Energy Policy Act of 2005 authorized the creation of an electric reliability organization (ERO) with the statutory authority to enforce compliance with reliability standards among all market participants. NERC received certification as the ERO from the FERC in July 2006 . . .
>
> In response to congressional actions to require mandatory reliability standards, which were supported by the Commission, the FRCC has implemented a compliance program that will monitor and enforce compliance with NERC and FRCC reliability standards. The program relies on self-assessment, periodic reporting, and on-site audits to ensure compliance. In administering the compliance program, the FRCC works closely with all owners, operators, and users of the state's bulk electric system. The Commission staff attends FRCC meetings and maintains an open dialog with the FRCC on reliability matters affecting the state. The Commission will continue to work closely with the FRCC, NERC, and FERC to ensure the adequacy and reliability of Florida's electric grid.

PEF uses the FRCC Capacity Benefit Margin (CBM) methodology to assess its CBM needs. PEF currently has zero CBM reserved on each of its interfaces (posted paths). PEF's CBM on each path is currently established through the transmission provider functions within PEF using deterministic and probabilistic generation reliability analysis. Currently, PEF proposes several bulk transmission additions that must be certified under either the Florida Transmission Line Siting Act (TLSA) or PPSA. PEF proposed bulk transmission line additions are summarized in Table 8.3-1. PEF has listed only the larger projects in the 2016 timeframe that may be required for the LNP. These projects may change depending

upon the outcome of PEF's final corridor and specific route selection process. (Reference 8.0-002)

While the FPSC notes that reserve margins are adequate to provide reliable power supplies, the 2006 TYSPs raise some concern over the reliability of resources. For example, the FPSC notes that most of the new generating facilities throughout the area use natural gas as the primary fuel. The FPSC is particularly concerned about natural gas deliverability (Reference 8.3-004). Additionally, price concerns, availability concerns, and supply constraints have led to a growing preference for fuel diversity. As a result, the FPSC noted that there is an increasing interest in the use of coal and nuclear facilities to meet future baseload generation needs.

8.3.3 EFFECT OF PURCHASES AND SALES IN THE REGION OF INTEREST

The FPSC annual report on activities pursuant to the FEECA notes that significant portions of Florida's power supply are generated within the state by the IOUs, municipally-owned electric utilities, and rural electric cooperatives. Purchased power, where the regulated utilities purchase power from non-utilities or merchant plants outside the state, was about 3.0 percent of the total energy resources in 2004 and is projected to be 1.5 percent in 2014 (Reference 8.2-004). Table 8.1-5 indicates that by 2017, PEF projects that approximately 0.1 percent of its net energy will be purchased or sold within the FRCC region. While at the same time, about 1.3 percent of its net energy purchased or sold will be imported from outside the state, and another 2.3 percent of its net energy purchased or sold will be derived from qualifying facility (QF) purchased power.

ER Subsection 9.2.2 further reviews restrictions on the use of energy sources available to the ROI and the FRCC region.

Table 8.3-1 (Sheet 1 of 2)
Proposed Bulk Transmission Line Additions: 2008 – 2017

MVA Rating Winter	Line Ownership	Terminals		Line Length (Circuit Miles)	Commercial In-Service Date (Month/Year)	Nominal Voltage (kV)
1141	PEF	Lake Bryan	Windermere #1	10 [a]	5/2008	230
1141	PEF	Lake Bryan	Windermere #2	10	5/2008	230
1141	PEF	Avalon	Gifford	7	5/2009	230
612	PEF	Bartow	Northeast - Circuit 1	4	6/2009	230
612	PEF	Bartow	Northeast -Circuit 2	4	6/2009	230
612	PEF	Bartow	Northeast -Circuit 3	4	6/2009	230
525	PEF	Northeast	32nd Street	2.4	9/2008	115
810	PEF	Northeast	40th Street	8.3 [a]	9/2008	230
810	PEF	Pasadena	51st Street	0.4	9/2008	230
810	PEF	51st Street	40th Street	0.2	9/2008	230
837	PEF	Avon Park	Fort Meade	26 [b]	6/2009	230
1141	PEF	Hines Energy Complex	West Lake Wales #2	21	5/2010	230
1141	PEF	Intercession City	West Lake Wales #2	30	6/2010	230
1141	PEF/TECO	Lake Agnes (TECO)	Gifford	32	6/2011	230
1141	PEF	Intercession City	West Lake Wales #1	30 [a]	6/2011	230
1141	PEF	Bithlo	Stanton (OUC)	6 [c]	5/2010	230
1141	PEF	Ft. White	Suwannee	40	6/2013	230
2870	PEF	Levy	Central Florida South	50 [d]	6/2016	500
2870	PEF	Levy	Crystal River	10 [d]	6/2016	500
2870	PEF	Levy	Citrus #1	10 [d]	6/2016	500
2870	PEF	Levy	Citrus #2	10 [d]	6/2016	500
2870	PEF	Citrus	Brookridge	35 [d]	6/2016	500
2870	PEF	Brookridge	Lake Tarpon	40 [d]	6/2016	500
1141	PEF	Crystal River	Brookridge	35 [d]	6/2016	230
1141	PEF	Brookridge	Brooksville West	4 [d]	6/2016	230
1141	PEF	Citrus	Crystal River East #1	6 [d]	6/2016	230
1141	PEF	Citrus	Crystal River East #2	6 [d]	6/2016	230

Table 8.3-1 (Sheet 2 of 2)
Proposed Bulk Transmission Line Additions: 2008 – 2017

MVA Rating Winter	Line Ownership	Terminals		Line Length (Circuit Miles)	Commercial In-Service Date (Month/Year)	Nominal Voltage (kV)
1141	PEF	Kathleen	Lake Tarpon	45 [(d)]	6/2016	230

Notes:

a) Rebuild existing circuit.

b) Convert existing 115-kV line to 230-kV line.

d) 6 miles is the present estimated distance for PEF's portion of this 12-mile PEF-OUC tie line.

d) Each of these projects is part of one or more transmission options for the LNP project. Out of several options under consideration, the final option has yet to be chosen, and thus, the above list of projects is subject to change.

kV = kilovolt
OUC = Orlando Utilities Commission
TECO = Tampa Electric Company

Source: Reference 8.0-002

8.4 ASSESSMENT OF NEED FOR POWER

In assessing the costs and benefits of the project, NUREG-1555, ESRP 8.4 provides the following review criterion:

> Affected States and/or regions, NERC reliability councils, and regional transmission organizations may prepare need-for-power evaluations for proposed generation and transmission facilities. The NRC will review the evaluation of the proposed facility and determine if it is (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. If the need-for-power evaluation is found acceptable, no additional independent review by NRC is needed and the analysis can be the basis for ESRPs 8.2 through 8.4.
>
> As part of their analyses, States and/or regional authorities would normally collect data for the need for power. These data may be supplemented by information sources such as the Energy Information Administration, FERC, NERC and member reliability councils, and others.
>
> If a need-for-power analysis conducted by or for one or more relevant regions affected by the proposed plant concludes there is a need for new generating capacity, that finding should be given great weight provided that the analysis was systematic, comprehensive, subject to confirmation, and responsive to forecast uncertainty.
>
> Although this criterion does not show a need for baseload capacity, it does demonstrate a need for new capacity that is independent of type. This criterion, coupled with an affirmative indication that there is a need for baseload capacity, justifies a baseload addition within the time span determined by the reviewer's forecast analysis.

Historically, Florida's electric utilities have pursued fuel diversity by maintaining a balanced fuel supply in terms of the types of fuel used to generate electricity. Florida's utilities had a relative balance of energy generation from coal, nuclear, natural gas, oil, and other sources. However, due to continued growth in the state's electricity demand and relatively low natural gas prices, Florida's utilities turned to gas-fired generating units to satisfy economic and reliability needs. Between 1990 and 2004, over 90 percent of the new generating capacity constructed in Florida was natural gas-fired. This trend is projected to continue. Natural gas is projected to increase from 30 percent of total energy generated in 2004 to 44 percent by 2014. (Reference 8.2-004)

As discussed in ER Sections 8.0 and 8.1, the statutory and regulatory framework of Florida's TYSP and PPSA processes, which are well established, provide clear requirements for determining increased demand, reserve margins, energy efficiency, and need for new baseload capacity.

8.4.1 ASSESSMENT OF THE NEED FOR NEW CAPACITY

PEF provides the following information in a March 2008 press release (Reference 8.4-001):

> PEF serves one of the fastest-growing regions in the country. As the fourth-largest state, Florida ranks third nationally in per-capita energy consumption. Over the past three decades, the size of the average home has grown by 50 percent and uses 30 percent more electricity.
>
> Even after customers take advantage of the company's numerous energy-efficiency programs -- considered one of the best of any utility in the nation -- energy demand is expected to grow 25 percent in PEF's 35-county service area over the next decade.

PEF expects the demand for electricity in its service territory to grow by more than 25 percent in the next decade (Reference 8.4-002). Over the last 20 years, more than 600,000 new customers have moved to PEF's service area. In addition to having more people in our service area, each of us individually is using more electricity today than in years past. Our society's increasing reliance on technology and electronics and our larger homes mean the demand for electricity is likely to grow significantly in the near future and beyond. Energy efficiency and alternative technologies can help meet that growing demand, and they will continue to be critical parts of the solution. But to match Florida's considerable growth, the company also will need to add significant new power generation. (Reference 8.3-001)

PEF's 2008 TYSP provides the following information about how PEF will address Florida's growth demands (Reference 8.0-002):

> PEF's Base Expansion Plan projects the need for additional units with proposed in-service dates during the ten-year period from 2008 through 2017. These units, together with purchases from Qualifying Facilities (QF), Investor Owned Utilities, and Independent Power Producers including but not limited to Reliant/Osceola (January 2007 - March 2009), Mirant Shady Hills (April 2007 - April 2024), and Southern Company (June 2010 - December 2015), help the PEF system meet the growing energy requirements of its customer base. The capacity needs identified in this plan may be impacted by PEF's ability to extend or replace existing purchase power as well as cogenerator and QF contracts and to secure the new renewable purchased power resources in their respective projected timeframes . . .
>
> Through its ongoing planning process, PEF will continue to evaluate the timetables for all projected resource additions and assess alternatives for the future considering, among other things, projected load growth, fuel prices, current lead times in the construction marketplace, project development timelines for new fuels, and technologies, and environmental compliance considerations. The Company will continue to

examine the merits of new generation alternatives and adjust its resource plans accordingly to ensure optimal selection of resource additions based on the best information available.

The FPSC, pursuant to Section 186.801, F.S., has reviewed the 2007 TYSP filed by the 10 reporting utilities, which includes PEF. The FPSC finds the plans to be suitable, yet the FPSC does expect that 2008 TYSPs will need to address alternatives to coal-fired power plants, including a thorough review of additional demand-side conservation and supply-side generation needed to maintain an adequate, reliable, economical, and environmentally-sound supply of electricity for the citizens of Florida (Reference 8.1-003). A summary of the FPSC's findings include the following, as provided in its *Review of 2007 Ten-Year Site Plans for Florida's Electric Utilities* (Reference 8.1-003):

- A first step toward attaining fuel diversity is the pursuit of non-generating alternatives to new construction, such as energy conservation and demand-side management (DSM). During 2007, the Commission approved 12 new DSM programs for electric utilities, as well as modifications to 9 existing electric utility DSM programs. These actions should increase customer participation and reduce peak demand by approximately 66 MW over the planning horizon.

- Florida's utilities must continue to explore alternatives to natural gas energy generation. Greater emphasis must be placed on increasing public knowledge and awareness of energy conservation. Utilities must continue to develop and employ all cost-effective DSM measures. Ongoing efforts to further develop and employ renewable energy generation by both utilities and customers should provide Florida's utilities with added non-traditional energy generation. The construction of new nuclear generation will not only increase fuel diversity but provide energy without the emission of greenhouse gases. Advancements toward "clean coal" technology and the resolution of greenhouse gas emission standards are needed to address the uncertainties currently associated with the addition of coal generated energy.

- Customer choices to reduce energy consumption will help electric utilities defer the need for future generating units and transmission lines. Using existing resources as long as possible and taking full advantage of DSM and energy conservation measures is important as fossil fuels, plant sites, and transmission corridors become increasingly scarce in the state.

- Maintaining a balanced fuel supply adds value in terms of supply reliability and price stability. Fuel diversity is not always a cost-saving measure, but rather a risk mitigation strategy. Maintaining a balanced mix of fuel sources enhances reliability of supply and allows utilities to mitigate the effects of volatile price fluctuations.

- Because of the long lead times associated with new nuclear generation and the removal of several coal-fired generating plants from the current planning process utilities are likely to add natural gas-fired power plants in the near future. Therefore, utilities should continue to evaluate diversity within a fuel type, such as liquefied natural gas (LNG) and gas storage, as options to traditional sources and delivery methods for natural gas.

- Both FPL and PEF have announced plans to expand the capacity at each of their existing nuclear plants. The Commission approved the need for the uprate for the PEF unit on February 8, 2007.

- PEF's Ten-Year Site Plan includes plans to construct a new 1,125 MW nuclear plant by 2016 . . . PEF is expected to file a petition for need determination in early 2008.

PEF's 2008 TYSP provides the following information (Reference 8.0-002):

> PEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. PEF's IRP process incorporates state-of-the-art computer models to evaluate a wide range of future generation alternatives and cost-effective conservation and dispatchable demand-side management programs on a consistent and integrated basis . . .
>
> The Integrated Resource Plan provides PEF with substantial guidance in assessing and optimizing the Company's overall resource mix on both the supply side and demand side. When a decision supporting a significant resource commitment is being developed (e.g. plant construction, power purchase, DSM program implementation), the Company will move forward with directional guidance from the IRP and delve much further into the specific levels of examination required. This more detailed assessment will typically address very specific levels of examination required, specific technical requirements and cost estimates, detailed corporate financial considerations, and the most current dynamic of the business and regulatory environments.

A summary of PEF's expandable renewable energy solutions that will allow it to adhere to the FPSC's requirements include the following:

- PEF is issuing a request for renewables to expand the company's renewable portfolio, to provide cost-effective renewable energy to its customers, and to offset the need for new power plants. PEF seeks to identify and participate in cost-competitive renewable energy to reduce Florida's dependence on fossil fuels. PEF is seeking information, contacts, questions, and potential contracts from all sources. Renewable energy is a key component in the company's long-term balanced

approach to meet growing energy demand, which also includes energy efficiency and state-of-the-art power plants. The company is continually looking for newer, cleaner ways to produce energy. The continued development of renewable energy has been part of the company's balanced approach to meeting growing customer demand for years, and it will play a vital role in Florida's energy future. This strategy is consistent with the Governor's executive order suggesting a 20 percent renewable portfolio standard for utilities. To be considered renewable energy, projects must use renewable fuels, such as solar, geothermal, or ocean energy, hydrogen, biomass, wind, hydroelectric power, or waste heat from a commercial or industrial manufacturing process.

- PEF is looking to expand its solar energy programs by implementing a photovoltaics for schools program. PEF launched an innovative solar-energy initiative that offers customers rebates and incentives to install a solar-thermal water heater. Customers can save up to 85 percent on the hot-water portion of their electric bill, which equates to a savings of $200 to $300 annually for an average family.

- PEF has two types of renewable energy contracts that have been pre-approved by the FPSC.

- PEF signed a contract with the Biomass Investment Group to purchase the energy output (130 MW) from the nation's largest biomass plant to be built in central Florida. The project will reduce carbon emissions by more than 20 million tons over the 25-year life of the contract when compared to coal.

- PEF offers some of the nation's most innovative and successful energy-efficiency programs. The company launched its "Save the Watts" campaign to raise customer awareness of programs to save money and reduce energy use. Since 1981, PEF customers have saved nearly $825 million in energy costs and eliminated nearly 7 million tons of carbon dioxide through participation in energy-efficiency programs.

- Florida's first hydrogen fueling station — a partnership between PEF, Ford Motor Company, Chevron, and the state — is located near the Orlando International Airport and will fuel eight Ford V-10, E-450 hydrogen-powered shuttle buses. PEF recognizes the importance of the continued development of renewable technologies and innovative energy-efficiency programs. Alternative energy and energy efficiency currently account for 5 percent of PEF's energy portfolio (Reference 8.4-002).

- As noted in PEF's 2008 TYSP, "Through its ongoing planning process, PEF will continue to evaluate the timetables for all projected resource additions and assess alternatives for the future considering, among other things, projected load growth, fuel prices, current lead times in the

construction marketplace, project development timelines for new fuels, and technologies, and environmental compliance considerations. The Company will continue to examine the merits of new generation alternatives and adjust its resource plans accordingly to ensure optimal selection of resource additions based on the best information available." (Reference 8.0-002)

- As noted in PEF's 2008 TYSP, "The nuclear units were identified as the most cost-effective option to meet the need, taking into account the need to improve fuel diversity, reduce Florida's dependence on fuel oil and natural gas, reduce current and potential future air emission compliance costs, and contribute to the long-term stability of the electric grid. Since nuclear units involve very long licensing and construction lead times, PEF plans to continue with the design and development of the infrastructure and transmission requirements, negotiations for procurement and construction contracts and permitting and licensing to support the current planned in-service dates." (Reference 8.0-002)

- PEF continues to make purchases of energy from renewable energy facilities, such as municipal solid waste facilities; waste heat from exothermic processes; waste wood, tires, and landfill gas; and photovoltaics. In addition, PEF has entered into contracts with facilities that use a biomass crop and a gas from wood products to generate energy. (Reference 8.0-002)

Besides assessing the need for additional capacity based on the state's comprehensive plans, NUREG-1555 allows power companies, such as PEF, to assess the need for proposed capacity on other grounds. The following criteria suggest the continuing benefits of, and the need for, new baseload generation capacity in the state:

- The relevant region's need to diversify sources of energy (such as using a mix of nuclear fuel and coal for baseload generation): As noted above, the FPSC identified the need for Florida's energy utilities to increase fuel diversity within the state. One method that may be used to help diversify sources of energy within the state is the State of Florida's Renewable Energy Technologies and Energy Efficiency Act, which was signed into law in June 2006. This comprehensive plan aims to ensure that the State of Florida takes a balanced approach to meeting the energy need of its residents over the next generation (Reference 8.2-006). PEF is committed to abiding by the FPSC's recommendation by seeking newer, cleaner ways to produce energy for its customers. PEF has partnered with the state and federal government and other companies and agencies to invest in hydrogen fuel-cell projects, as well as solar projects at schools and around the state. PEF is involved in a renewable biomass generation project in central Florida. PEF will purchase the energy generated by a planned power plant that will use a bamboo-like grass as its fuel source. PEF operates a diverse mix of power plants in Florida to meet the needs of its customers. The diversity ensures a reliable, affordably priced supply

of electricity even when fuel prices and supplies are volatile (Reference 8.2-006).

- The potential to reduce the average cost of electricity to consumers: In its 2007 review of the TYSP, the FPSC approved two new DSM programs that should result in greater customer participation, with corresponding demand and energy savings (Reference 8.1-003). PEF participates in energy management and energy efficiency programs to help reduce the average cost of electricity to its customers (Reference 8.2-006). Approximately 393,000 PEF customers participate in the company's residential Energy Management program, contributing approximately 760,500 kW of winter peak-shaving capacity for use during high load periods. In addition, PEF's DSM plan currently consists of seven residential programs, eight commercial and industrial programs, and one research and development program. This includes the 39 additional DSM measures and 2 new residential programs approved by the FPSC on January 5, 2007. Megawatt contributions to the TYSP have increased because of these changes to conservation, standby, and residential load management programs (Reference 8.0-002).

- The nationwide need to reduce reliance on fossil fuels generally, and imported petroleum in particular: The current national policy develops ways to reduce dependence on fossil fuels and, in particular, petroleum. The FPSC notes that utilities should continue to increase the supply of solid-fuel generation including nuclear energy in Florida (Reference 8.1-003).

Although NUREG-1555 does not specifically identify reduction of greenhouse gases (GHGs) as one of the benefits of adding new baseload generation capacity in the state, more recent state and national policy statements assert the benefits of baseload capacity that reduces GHG.

Florida Governor Charlie Crist signed three GHG-related executive orders on July 13, 2007, including one that sets targets of reducing the state's overall emissions to 2000 levels by 2017, to 1990 levels by 2025, and to 20 percent of 1990 levels by 2050. Executive Order 07-127 directs the FDEP to develop rules that set those same milestones for the state's electric utilities, to adopt California's GHG standards for motor vehicles, and to establish an idle reduction standard for diesel engines.

It also directs the Florida DCA to convene the Florida Building Commission in order to set new building standards that increase the energy performance of new buildings by 15 percent by 2009. The DCA is also directed to set new standards that mandate a 15-percent increase in the efficiency of certain consumer products by 2009. Finally, the Executive Order asks the FPSC to initiate rulemaking that would require utilities to draw on renewable energy for 20 percent of their electricity, to adopt international standards for connecting renewable energy systems to the grid, and to allow net metering for renewable

energy systems up to 1 MW in capacity. However, the FPSC is not bound by the governor's executive orders.

Executive Order 07-126 sets tougher near-term GHG emissions goals for state agencies, namely a 10-percent reduction from today's levels by 2012, a 25-percent reduction by 2017, and a 40-percent reduction by 2025. To meet those goals, the Executive Order calls for all state agencies to inventory their energy-related GHG emissions and directs the Department of Management Services to set Leadership in Energy and Environmental Design (LEED) green building standards for the state's new and existing state-owned buildings. LEED is the standard set by the U.S. Green Building Council. State agencies are also precluded from renting office space that does not meet Energy Star standards. The order also applies GHG standards to the state's procurement processes and the state's vehicle fleets.

Executive Order 07-128 creates a new Action Team on Energy and Climate Change, which will develop a comprehensive Energy and Climate Change Action Plan. The governor also signed partnership agreements with the United Kingdom and Germany. (Reference 8.4-003)

In addition to these new State policies, the concern over GHG and the resulting climate change has triggered a number of national policy trends, as follows:

- During the 109th Congress, both houses of the U.S. Congress introduced resolutions calling for a national program of carbon reduction (Reference 8.4-004). The Senate Committee on Energy and Natural Resources is reviewing “cap and trade” legislation to reduce GHG emissions during the early days of the 110th Congress (Reference 8.4-005).

- Several states have joined regional GHG initiatives (References 8.4-006 and 8.4-007).

- PEF has also responded to its shareholder concerns by developing steps to reduce carbon emissions. Additionally, its resource studies show that carbon emissions (produced by coal and natural gas capacity) will continue to rise through 2017. PEF notes, however, that one new nuclear plant will decrease these emissions significantly (Reference 8.4-008).

8.4.2 COST-BENEFIT SUMMARY

In summary, the costs and benefits of the LNP include the following:

- Florida has a well-defined, systematic, and comprehensive resource planning program, which is subject to confirmation and takes into account uncertainty in forecasting. The IRP process has demonstrated a growing demand for electricity and need for additional baseload capacity in PEF’s service territory in the 2016 – 2017 timeframe.

- Within PEF's service territory, 2199 MW are identified as "uncommitted" (Tables 8.1-6 and 8.1-7). This planned addition starting in 2016 will need to be baseload capacity.

- The FPSC has concluded that there is a need for new baseload capacity in PEF's service territory. The NRC accords such determinations great weight and deference.

- The IRP process gives NRC assurance that the need for power is real and that the benefits of satisfying that need would be realized.

- The growing demand for new capacity shows benefits to be derived from the proposed LNP.

- Given concerns in Florida and the rest of the south about climate change and carbon emissions, the LNP will serve another important need by reducing carbon emissions in the state. When operational, the LNP will not produce the significant amount of carbon associated with a comparable coal-fired generating plant.

ER Section 9.2 discusses the viability of various baseload energy alternatives. ER Section 10.4 further reviews the costs and benefits of the LNP.

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