ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070098-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR FPL GLADES POWER PARK UNITS 1 AND 2 ELECTRICAL POWER PLANT

CMP ______
COM 5
CTR ______
ECR ______
GCL 1
OPC 1
RCA ______
SCR ______
SGA ______
SEC ______
OTH PIF

NEED STUDY FOR ELECTRICAL POWER

Need Study for Electrical Power

FPL

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TABLE OF ABBREVIATIONS

ACOE	U.S. Army Corps of Engineers
AQCS	Air Quality Control System
AFUDC	Allowance for Funds Used During Construction
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BLS	Bureau of Labor Statistics
BTU	British Thermal Unit
BV	Black & Veatch
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAPP	Central Appalachian Coal
CC	Combined Cycle
CFB	Circulating Fluidized Bed
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
CPVRR	Cumulative Present Value of Revenue Requirements
CSXT	CSXT Railroad
CT	Combustion Turbine
D.C.	District of Columbia
DSM	Demand Side Management
EPA	U.S. Environmental Protection Agency
EPC	Engineering Procurement and Construction
ESP	Electrostatic Precipitator
F.A.C.	Florida Administrative Code
FEC	Florida East Coast Railway
FDEP	Florida Department of Environmental Protection
FGPP	FPL's Glades Power Park
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
GPPRP	Green Power Pricing Research Project
GSU	Generator Step-Up Transformer
GWh	Gigawatt Hour
Hg	Mercury
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Planning
JEA	Jacksonville Electric Authority
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LNB	Low-NO_X Burners
LNG	Liquefied Natural Gas
LOLP	Loss-of-Load-Probability

TABLE OF ABBREVIATIONS (continued)

MW	Megawatt
MMBTU	Millions of British Thermal Units
NEL	Net Energy for Load
NOAA	National Oceanographic and Atmospheric Association
NO_X	Nitrogen Oxide
NS	Norfolk Southern Railway
OFA	Overfire Air
OPEC	Organization of Petroleum Exporting Countries
PC	(Sub critical) Pulverized Coal
PCE	Pollution Control Equipment
PPSA	Florida Electrical Power Plant Siting Act
PSD	Prevention of Significant Deterioration
PSIA	Pounds per Square Inch Absolute
PV	Photovoltaic
RFP	Request for Proposals
SCFE	South Central Florida Express
SCR	Selective Catalytic Nitrogen Oxide Reduction
SIP	State Implementation Plan
SJRPP	St. Johns River Power Park
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
STG	Steam Turbine Generator
TIGER	Tie-Line Assistance and Generation Reliability Model
TREC	Tradeable Renewable Energy Credits
UIC	Underground Injection Control
USCPC	Ultra-SuperCritical Pulverized Coal
WCEC	West County Energy Center
WESP	Wet Electric Static Precipitator
WFGD	Wet Flue Gas Desulphurization

I. EXECUTIVE SUMMARY

In its 2006 integrated resource planning (IRP) process, Florida Power & Light Company (FPL) determined it needed to add a total of 2,283 MW of generation capacity starting in 2012 through 2015 to meet its reserve margin planning criterion approved by the Florida Public Service Commission. In addition to the need to meet the 20% reserve margin planning criterion, FPL's 2006 IRP process directly addressed another very important objective: how best to maintain a balanced fuel mix in FPL's generation portfolio to achieve fuel cost stability and maintain system reliability.

Maintaining fuel diversity on FPL's system is important for several reasons. Lack of fuel diversity would result in vulnerability to potential supply disruptions in one type of fuel (such as could occur in the event of a major hurricane disrupting the flow of natural gas into Florida or interruption in the pipeline delivery systems), as well as price volatility in natural gas.

With the issue of fuel diversity in mind, the Florida Legislature recently enacted Senate Bill 888 that encouraged fuel diversity by directing the Florida Public Service Commission to consider fuel diversity in reviewing Ten-Year Site Plans submitted annually by electric utilities. Senate Bill 888 further encouraged fuel diversity by authorizing the siting of nuclear power plants and providing for an alternative cost-recovery mechanism for new nuclear power plants. In addition, the Florida Public Service Commission has specifically added the issue of fuel diversity to items that will be considered in Determination of Need filings for new power plants.

FPL has considered and will continue to consider renewable resources as a contributor to fuel diversity. However, maintaining fuel diversity on FPL's system can only be accomplished through the addition of new coal and/or nuclear power plants. Since it is not possible to permit and construct a new nuclear unit until at least several years after 2013, new coal units are the only feasible option for maintaining system fuel diversity by 2013. FPL evaluated various coal-based generating alternatives to meet its capacity and fuel diversity needs in this time period. These alternatives included sub-critical pulverized coal (PC) units, circulating fluidized bed (CFB) units, integrated gasification combined cycle (IGCC) units, and ultra-supercritical pulverized coal (USCPC or advanced technology coal) units. This evaluation included both qualitative and quantitative analyses of these four options. FPL concluded that the best way to meet its capacity and fuel diversity needs in this time period consisted of adding two 980 MW advanced technology coal units, one by 2013 and one by 2014, respectively, in Glades County at FPL Glades Power Park (FGPP).

Adding these generating units require site certification under the Florida Electrical Power Plant Siting Act (PPSA). In accordance with Rule 25-22.082, Florida Administration Code (F.A.C.) (the Bid Rule), FPL sought approval from the Florida Public Service Commission (Commission) for a waiver from the Request for Proposals (RFP) process normally required by the Bid Rule. This waiver was sought by FPL in order to accelerate the introduction of new, non-gas-fired capacity to FPL's system, thus maintaining fuel diversity on FPL's system as early as possible.

Once the advanced technology coal option was selected and a site was chosen in Glades County, FPL conducted comparative economic and fuel diversity analyses of the resource plan based with the two advanced technology coal units, the Fuel Diversity Resource Plan with Coal (Plan with Coal) vs. an alternative resource plan, a Resource Plan without Coal (Plan without Coal) that does not include any coal additions and, instead, adds only gas-fired combined cycle (CC) units in the 2012 – 2015 time period.

In order to address uncertainty in regard to future costs, these analyses utilized four fuel cost forecasts and four environmental compliance cost forecasts combined into 16 scenarios of future fuel costs and environmental compliance costs for each of the two resource plans. Therefore, when comparing the Plan with Coal to the Plan without Coal, there are 16 outcomes.

The results of the economic analyses comparing the Plan with Coal versus a Plan without Coal show that, as expected, neither plan is the lower cost choice under all scenarios. Each of the two plans emerged as the lower cost choice in approximately half of the 16 scenarios; the Plan with Coal emerged as the lower cost choice in seven scenarios and the Plan without Coal emerged as the lower cost choice in nine scenarios. The Plan with Coal emerged as the lower cost choice in all scenarios featuring high gas-coal cost differentials and in most other scenarios with relatively low environmental compliance costs. Conversely, the Plan without Coal emerged as the lower cost choice in all scenarios featuring low gas-coal cost differentials and in most other scenarios relatively high environmental compliance costs. These results point out that neither alternative will be the lower cost choice under all possible circumstances.

In regard to the fuel diversity analyses of these two resource plans, only the Plan with Coal, maintains fuel diversity in FPL's system. Without FGPP, by 2016, the Plan without Coal would result in 71% of FPL's annual energy being supplied by natural gas with only 7% being supplied by coal. The Plan with Coal would result in a significantly lower 60% of FPL's annual energy for 2016 being supplied by natural gas and an 18% being supplied by coal. This is the same percent contribution provided by coal in 2005.

Based on the results of FPL's analysis, the addition of FGPP 1 and 2 is FPL's best alternative to maintain electric system reliability and integrity, provide adequate electricity at a reasonable cost, and maintain fuel diversity on FPL's system by 2013. There is not sufficient additional, cost-effective demand side management (DSM) that is reasonably available to mitigate the need for these units.

As previously noted in FPL's Report on Clean Coal Generation provided to the Commission in March 2005, there are significant areas of uncertainty related to the long-term gas-coal price differential, the need to develop a cost-competitive coal delivery system, future environmental compliance requirements and the type and cost of emission management systems necessary to meet those requirements, the actual capital cost of building FGPP, and public policy issues. All of these issues can affect the viability and cost-competitiveness of coal generation. FPL, however, will continue its effort to obtain the necessary approvals to build the proposed advanced technology coal generation units and place them in commercial operation, and will continue to purchase fuel diverse generation from other sources when doing so is in the best interests of FPL's customers.

FPL intends to bring the FGPP advanced technology coal units into service as soon as reasonably possible. FPL believes that the earliest date that it can place the first FGPP unit into service is during the second half of 2012, and the second unit during the second half of 2013, assuming that no unforeseen permitting, construction, or other delays occur. For analysis purposes in this filing, it was necessary to select a specific in-service date for each FGPP unit. FPL chose June 1, 2013 and June 1, 2014 for FGPP 1 and 2, respectively. The use of June 1 in-service dates for these analyses are consistent with FPL's normal practice in the last five years.

The remainder of this Need Study contains more detailed information, analyses, and discussion supporting FPL's requested determination of need for FGPP 1 and 2 by 2013 and 2014, respectively.

II. INTRODUCTION

A. Purpose and Overview of this Document

This document supports FPL's petition to the Commission to determine the need for the FPL Glades Power Park units 1 and 2 (FGPP 1 and 2). The new units will be two ultra-supercritical pulverized coal facilities located in Glades County. Once completed, FGPP 1 and 2 will each have Summer net capacities of approximately 980 MW for a combined capacity of approximately 1,960 MW[1].

This document contains the information required by Rule 25-22.081, F.A.C. It provides the information that will "allow the Commission to take into account the

[1] This is the combined Summer net rating for the units. The combined Winter net rating is 1,980 MW. For ease of presentation, throughout this Need Study only the Summer net ratings of the units are mentioned.

need for electric system reliability and integrity, the need for adequate reasonable cost electricity, and the need to determine whether the proposed plant is the most cost-effective alternative available…." This document also contains information regarding FPL's system fuel mix both current and in the future and discusses how the proposed advanced technology coal units would maintain system fuel diversity. The following information is provided in subsequent sections:

- a description of the existing FPL system (Section II.B);
- a description of the proposed generating units (Section III);
- an explanation of FPL's need for the proposed generating units (Section IV);
- a discussion of factors affecting the selection of the proposed generating units (Section V);
- a discussion of the analyses which determined that the proposed generating units represents the best alternative to meet FPL's needs (Section VI);
- a discussion of non-generating alternatives and an analysis of their potential for mitigating the need for FGPP 1 and 2 (Section VII); and
- a discussion of the adverse consequences that would result from denial of a Determination of Need for FGPP 1 and 2 (Section VIII).

B. Description of FPL and Its System

FPL is the largest investor-owned electric utility in Florida and is among the largest in the United States. During 2005, the last full year for which data was available at the time this document was prepared, FPL served an average of 4.3 million customer accounts in 35 counties. FPL's service area contains approximately 27,650 square miles within which the population is approximately 8.5 million. FPL is charged with providing service not only to its existing customers, but also to new customers requesting service. FPL's load forecasts predict substantial continued customer growth within its service territory.

FPL currently serves its customers from a variety of resources including: FPL-owned oil, gas, coal, and nuclear generating units, firm capacity purchases from both utility and non-utility-owned generators, and demand side management (DSM). Each type of resource is discussed in more detail later in this document.

During 2005, FPL's bulk transmission system was comprised of 6,470 circuit miles transmission lines. Integration of the generation, transmission, and distribution system was achieved through FPL's 542 substations. FPL is interconnected directly with eight other electric utilities. A list of FPL's projected major interconnections with other utilities is presented in Appendix A of this Need Study.

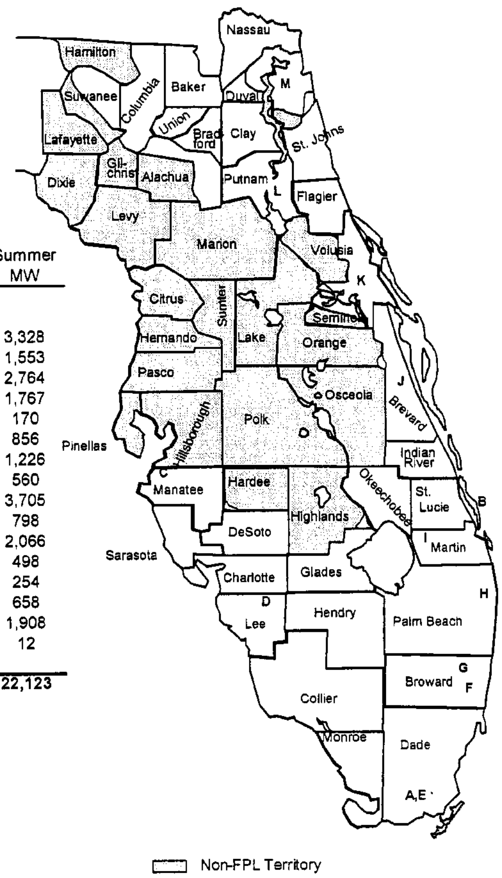
1. FPL-Owned Generating Resources

FPL's existing generating resources are located at 14 generating sites distributed geographically throughout its service territory, and they also include partial ownership of one unit located in Georgia and two units located in Jacksonville, Florida. By the Summer of 2007, FPL's generating facilities will consist of four nuclear steam units, three coal units, 12 combined cycle units, 17 fossil fuel steam units, 48 combustion turbines (CTs), and 5 diesel units. The location of these generating units, their fuel type(s), and the projected Summer capability for 2007 is shown on Figure II.B.1.1. More detailed information regarding FPL's existing generating resources is presented in Appendix B of this Need Study.

Figure II.B.1 1

FPL Generating Resources by Location
(projected for Summer 2007)

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	5	3,328
B	St. Lucie *	2	1,553
C	Manatee	3	2,764
D	Fort Myers	2	1,767
E	Cutler	2	170
F	Lauderdale	2	856
G	Port Everglades	4	1,226
H	Riviera	2	560
I	Martin	5	3,705
J	Cape Canaveral	2	798
K	Sanford	3	2,066
L	Putnam	2	498
M	SJRPP **	2	254
	Scherer ***	1	658
	Gas Turbines	48	1,908
	Internal Combustion Turbines	5	12
	FPL Generation =	**90**	**22,123**



* Represents FPL's ownership share: St Lucie nuclear: 100% unit 1, 85% unit 2: St. Johns River: 20% of two units.

** SJRPP = St. John's River Power Park

*** The Scherer unit is located in Georgia and is not shown on this map.

2. Firm Capacity Purchases

FPL has contracts to purchase firm capacity and energy from six cogeneration and small power production facilities. A cogeneration facility is one that simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) used for industrial, commercial, or cooling and heating purposes. A small power production facility is one that does not exceed 80 MW of capacity and that uses solar, wind, waste, geothermal, or other renewable resources for at least 50% of its energy.[2]

FPL also has contracts with two utilities, Southern Company (Southern) and Jacksonville Electric Authority (JEA), to purchase 931 MW and 381 MW, respectively. In addition, FPL also has a number of short-term firm purchase contracts with other parties.

A summary of all of FPL's firm capacity purchases is presented in Table II.B.2.1. This table presents the dates of the terms of these current contracts and the projected Summer MW purchase amounts through the year 2015.

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[2] Certain small power production facilities are exempt from the 80 MW size limitations by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990.

Table II.B.2. 1

FPL's Firm Capacity Purchases: 2007 – 2015

(Summer MW)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. Broward South	4/1/1991	8/1/2009	50.6	50.6	0	0	0	0	0	0	0
2. Broward South	1/1/1993	12/31/2026	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
3. Broward South	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
4. Broward South	1/1/1997	12/31/2026	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
5. Broward North	4/1/1992	12/31/2010	45.0	45.0	45.0	45.0	0	0	0	0	0
6. Broward North	1/1/1993	12/31/2026	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
7. Broward North	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
8.Broward North	1/1/1997	12/31/2026	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
9. Cedar Bay Generating Co.	1/25/1994	12/31/2024	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
10. Indiantown Cogen., LP	12/22/1995	12/1/2025	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
11. Palm Beach SWA	4/1/1992	3/31/2010	47.5	47.5	47.5	0	0	0	0	0	0
12. Florida Crushed Stone	4/1/1992	10/31/2005	0	0	0	0	0	0	0	0	0
13. Florida Crushed Stone	1/1/1994	10/31/2005	0	0	0	0	0	0	0	0	0
14. Florida Crushed Stone	1/1/1995	10/31/2005	0	0	0	0	0	0	0	0	0
	QF Purchases Sub Total:		**738**	**738**	**687**	**640**	**595**	**595**	**595**	**595**	**595**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. UPS from Southern Co.	7/20/1988	5/31/2010	931	931	931	0	0	0	0	0	0
2. UPS Replacement	6/1/2010	12/31/2015	0	0	0	930	930	930	930	930	930
3. SJRPP	4/2/1982	10/31/2015	381	381	381	381	381	381	381	381	381
	Utility Purchases Sub Total:		**1312**	**1312**	**1312**	**1311**	**1311**	**1311**	**1311**	**1311**	**1311**

Total of QF and Utility Purchases =	**2050**	**2050**	**1999**	**1951**	**1906**	**1906**	**1906**	**1906**	**1906**

III. Other Purchases:

	Contract Start Date	Contract End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. Reliant/Pasco/Shady Hills	2/28/2002	2/28/2007	0	0	0	0	0	0	0	0	0
2. Reliant/Indian River	1/1/2006	12/31/2009	354	576	250	0	0	0	0	0	0
2a. Indian River (Additional)	5/1/2006	12/31/2009	222	0	0	0	0	0	0	0	0
3. Progress Energy Ventures/Desoto (Put option)	6/1/2005	5/31/2007	0	0	0	0	0	0	0	0	0
4. Oleander/Southern Co (Put option)	6/1/2005	5/31/2007	0	0	0	0	0	0	0	0	0
4a. Oleander (Extension)	6/1/2007	5/31/2012	156	156	156	156	156	0	0	0	0
5. Williams	3/1/2006	12/31/2009	106	106	106	0	0	0	0	0	0
6. Progress Energy Ventures	4/1/2006	3/31/2009	105	105	0	0	0	0	0	0	0
	Other Purchases Sub Total		**943**	**943**	**512**	**156**	**156**	**0**	**0**	**0**	**0**

Total "Non-QF" Purchase Sub-Total =	**2255**	**2255**	**1824**	**1467**	**1467**	**1311**	**1311**	**1311**	**1311**

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Summer Firm Capacity Purchases Total MW:	**2993**	**2993**	**2511**	**2107**	**2062**	**1906**	**1906**	**1906**	**1906**

3. Demand Side Management

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include both conservation initiatives and load management. FPL's DSM efforts through 2005, the last full year for which information was available at the time this document was prepared, have resulted in a cumulative

Summer peak reduction of approximately 3,519 MW at the generator and an estimated cumulative energy saving of approximately 33,981 Gigawatt Hour (GWh) at the generator. Accounting for reserve margin requirements, FPL's DSM efforts have eliminated the need to construct the equivalent of more than 10 new 400 MW generating units.

Table II.B.3.1 presents FPL's approved DSM Goals for Summer MW reduction. These DSM Goals are over and above the significant levels of DSM implementation FPL achieved before the year 2005. FPL's current DSM Plan was approved by the Commission in 2004 and was designed to achieve the DSM Goals for the 2005–2014 time periods.

In addition, FPL recently received approval from the Commission to modify 8 existing DSM programs and to introduce two new DSM programs. These efforts will result in a projected increase of 564 Summer MW at the generator of additional DSM beyond FPL's DSM Goals by 2015 as is also presented in Table II.B.3.1. The table shows that when these additional 564 MW of DSM are added to the 802 MW of DSM Goals at the generator from 2006 – 2015, FPL is adding 1,366 MW at the generator of cost-effective DSM during this period.

FPL's projected need for additional capacity starting in 2012 includes all of this DSM. There is not sufficient additional, reasonably available, cost-effective DSM available to mitigate FPL's need for FGPP 1 and 2.

Table II.B.3.1

FPL's DSM Goals and Additional DSM: 2006 – 2015

(Summer MW)

Year	(1) DSM Goals 2005 - 2015 Summer MW at Meter (1)	(2) = (1) /(1-0.0923) DSM Goals 2005 - 2015 Summer MW at Generator (2)	(3) DSM Goals 2006 - 2015 Summer MW at Generator (3)	(4) Additional DSM 2006 - 2015 Summer MW at Generator (4)	(5) = (3) + (4) 2006 - 2015 Total Projected Summer MW at Generator (5)
2005	74.0	82	---	---	---
2006	141.7	156	75	39	114
2007	211.9	233	152	229	381
2008	287.2	316	235	289	524
2009	365.9	403	322	334	656
2010	447.9	493	412	372	784
2011	532.1	586	505	413	918
2012	618.8	682	600	456	1,056
2013	707.9	780	698	501	1,199
2014	801.7	883	802	548	1,350
2015	801.7	883	802	564	1,366

Notes: (1) The Commission-approved DSM Goals address 2005 - 2014 and represent DSM MW at the meter.

(2) The DSM Summer MW at the Generator are approximate values based on a 9.23% line loss factor.

(3) These values represent DSM Goals values from 2006 through 2015 and omit the 2005 Goals values.

(4) The values shown above for 2006 through 2008 were originally presented in FPL's 2006 Ten Year Site Plan in Table III.D.2 on page 62. Those values represented the additional DSM MW contribution through 2008 at the time the Site Plan was filed. The 2009 - on values represent a current projection of additional DSM due to FPSC approval in mid-2006 of modifications to existing FPL DSM programs and of new DSM programs.

4. Renewable Energy

FPL has been, and continues to be, involved in utilizing renewable energy sources from both a supply side and demand side perspective. In regard to supply side utilization of renewable energy, FPL has firm capacity contracts with several waste-to-energy facilities as is shown in Table II.B.2.1 and has as-available energy contracts with several other facilities that provide energy to FPL on a non-firm basis. FPL is also currently seeking a suitable Florida site for a wind energy demonstration project and is supporting Florida Atlantic University's

Department of Ocean Engineering in its efforts to evaluate the feasibility of utilizing ocean thermal energy conversion off Florida's coasts.

In regard to utilizing renewable energy for demand side purposes, FPL has offered a variety of DSM programs that have utilized renewable energy and is actively engaged in research projects to identify additional feasible, cost-effective ways in which renewable energy may be used in a DSM offering. A description of FPL's renewable energy DSM activities is presented in Section VII of this document.

5. Current and Projected Electrical Demand and Sales

In FPL's load forecasting work, coincident peak loads both for Summer and Winter, as well as annual energy amounts, are projected for future years. The peak loads and annual energy amounts are forecasted to increase beyond current levels. FPL also continues to forecast significant customer growth and associated growth in per-customer load and energy usage. Appendix C discusses the computer models FPL uses to develop its load forecasts (as well the computer models used in FPL's other resource planning work).

In 2006, FPL experienced a Summer peak load of 21,819 MW and a Winter peak load of 19,683 MW. For 2012 through 2015, FPL is forecasting increasing Summer and Winter peak loads as shown in Table II.B.5.1. The projected effects of DSM will result in the Summer and Winter firm peak loads being lower than the forecasted peak loads as is shown in Table II.B.5.1.[3] FPL's complete load forecast is provided in Appendix D.

[3] These projected "firm" peak loads are net of DSM and are the loads upon which FPL bases its capacity need projections.

Table II.B.5.1

Forecasted Peak and Firm Peak Loads: 2012 - 2015

Year	Summer Forecasted Peak (MW)	Summer Forecasted Firm Peak (MW)	Winter Forecasted Peak (MW)	Winter Forecasted Firm Peak (MW)
2012	25,115	22,727	24,498	22,544
2013	25,590	23,074	24,952	22,924
2014	26,100	23,449	25,416	23,310
2015	26,772	23,982	26,048	23,860

6. Fuel Mix

In 2005, the last full year for which data was available at the time this document was prepared, FPL's fuel mix consisted of natural gas (42%), nuclear generation (19%), coal (18%), fuel oil (17%), and other sources (about 4%). If only natural gas-fueled generation were to be added to FPL's system in the future, the contribution of natural gas would increase to approximately 71% of total electricity delivered to FPL's customers in 2016, while that of coal would decrease to approximately 7% in 2016.

However, if the two advanced technology coal units are added by 2013 and 2014, respectively, the contribution of natural gas would decrease to approximately 60% by 2016, while that of coal would increase to approximately 18% by 2016.

The primary benefits of fuel diversity are greater system reliability and reduced fuel price volatility. An electric system that relies on a single fuel and a single technology to generate all the electricity needed to meet its customers' demand, all else equal, is less reliable than a system that uses a more balanced, fuel-diverse generation portfolio. In addition, greater fuel diversity mitigates the impact of wide or sudden swings in the price of one fuel, a phenomenon that has characterized the natural gas market over the last several years. In section IV of this report the various benefits associated with balancing the fuel mix are addressed in detail.

C. FPL's Proposed Approach

1. Choices for Maintaining Fuel Diversity

FPL evaluated four coal-based technologies to determine whether they could reliably contribute to the fuel diversity and capacity needs of FPL's system in the 2012 -2015 time period, and to select the best among those technologies that could provide those benefits. The technologies were: sub-critical pulverized coal (PC) technology, circulating fluidized bed (CFB) technology, integrated gasification combined cycle (IGCC) technology, and ultra-supercritical pulverized coal (USCPC or advanced technology coal).

2. FPL's Approach: Advanced Technology Coal

The results of FPL's analyses of these four coal-based technologies clearly established that the fourth of these technologies listed above, the advanced technology coal option, is the best alternative. Specifically, FPL concluded that advanced technology coal is the most cost-effective of the four, has reliability that has been established to be as good as, or better than, the other three options, is the most fuel-efficient, and can be constructed in the large size required by FPL's rapidly increasing demand. In regard to another of the options of interest to FPL, the IGCC technology option, the performance of IGCC technology has not been proven to be as reliable as that of the other alternatives, and the effectiveness of recently proposed design changes aimed at improving IGCC performance will not be determined until after 2013. Based on these factors, FPL has concluded that advanced technology coal at FGPP is by far the best choice to maintain fuel diversity and address FPL's generation capacity needs in this time frame.

3. Consequences of Advanced Technology Coal Selection

There are two types of consequences associated with the selection of any coal-based option, including the advanced technology coal option.

1) High Capital Cost

There are factors that could cause the capital cost of FGPP to be higher than projected. One reason for this is that there is a much longer lead time required, at least five and a half years from the date of this Need filing for development, permitting and construction of the first FGPP unit, compared to just over three years for gas-fired units, and a correspondingly greater opportunity for changes in the cost of equipment, labor and materials to occur.

Because of the greater uncertainty regarding the capital costs of various aspects of the addition of FGPP that FPL proposes that the Commission apply an indexed cost mechanism as the basis for establishing in the Determination of Need the capital cost that FPL will be authorized to recover for FGPP without having to demonstrate extraordinary circumstances. FPL's current estimate of the total cost of adding FGPP is based, in part, on FPL's current forecast of economic indices that will reflect future market changes in labor and materials that will, in turn, affect the cost of equipment and construction services. Therefore, it is reasonable to assume that actual market changes in the future will likely differ from those reflected in the current forecast of future movement in economic indices. Because of the unpredictability of these changes and the long lead time over which they can affect the cost of FGPP, FPL proposes that the cost for FGPP on which a Need Determination for FGPP should be based be indexed to those economic indices that will reflect movements in relevant markets.

2) Uncertainty Factors

There are a number of key areas of uncertainty associated with FPL's decision to place FGPP in commercial operation by 2013 and 2014. Some of these factors relate to: 1) the date by which FPL will obtain a final, non-appealable Site Certification for the FGPP units; 2) the final outcome of FPL's Site Certification Application for FGPP: 3) the future fuel price differential between natural gas and coal; 4) the ability to transport and deliver coal to FGPP at reasonable costs from diverse sources of coal; 5) costs of compliance with future environmental requirements or unanticipated Site Certification conditions; and 6) the actual capital cost of completing FGPP and placing the generating units in commercial operation. The first two of these factors are discussed in greater detail in Section IV.8 and the remaining four factors are discussed in more detail in Section V.A.4.

III. DESCRIPTION OF THE PROPOSED POWER PLANT

A. Overview

The FGPP project involves the proposed construction of FGPP Units 1 and 2. Each unit will be a solid fuel-fired coal generating unit with a nominal net electrical output of 980 Summer megawatts (MW). The FGPP will be located on a 4,900-acre property located in unincorporated Glades County. The site is located approximately four miles northwest of the town of Moore Haven in an unincorporated area of Glades County. Site access will be from State Road 78 which is approximately 1 mile to the east of the site. Figure III.A.1 is a vicinity map of the area surrounding the site showing various roads and the town of Moore Haven.

Figure III.A.1

Vicinity Map of FGPP Site

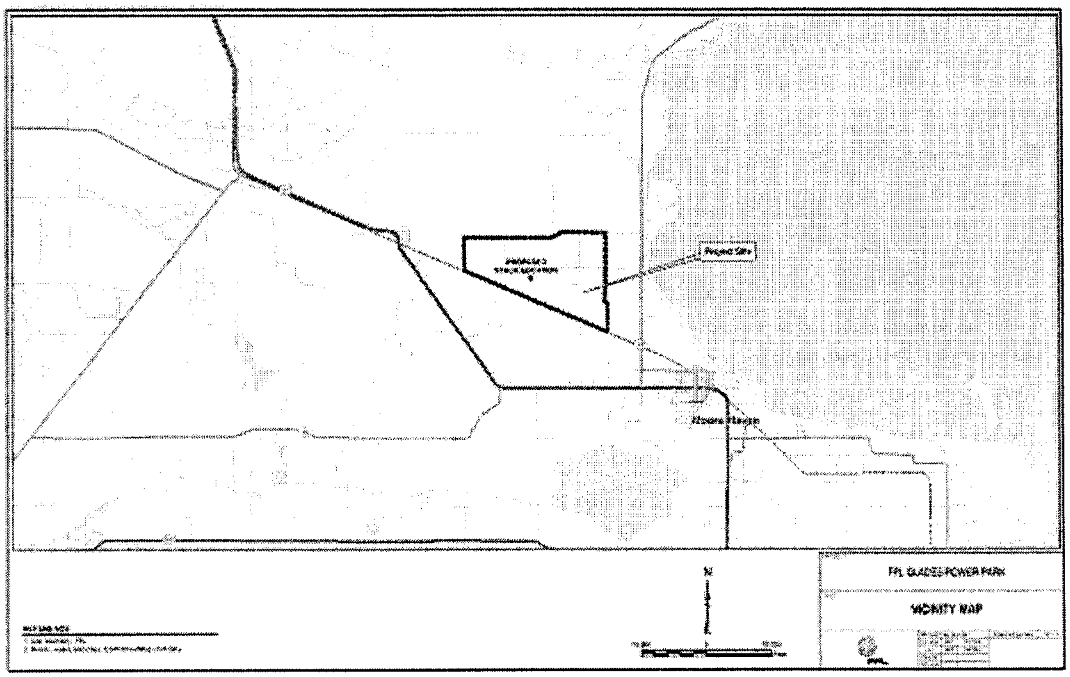
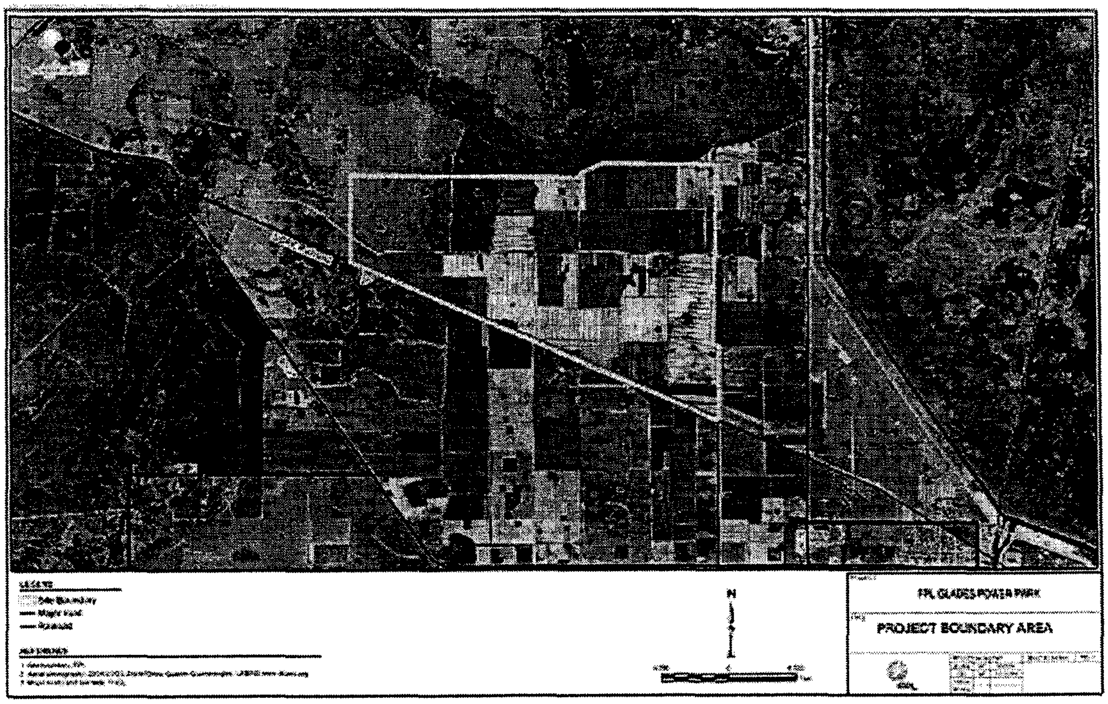


Figure III.A.2 is an aerial photo of the site showing the property boundary along with other surrounding features. The general area surrounding the site consists of undeveloped land currently owned by private landowners, generally to the north and west, and agricultural land, generally to the east and south. The town of Moore Haven is to the south east. Lake Okeechobee is directly east of the site. The site has direct rail access which abuts the entire southern boundary of the site.

Figure III.A.2

Aerial Photo of FGPP Site



The advanced technology coal design selected by FPL is an ultra-supercritical, pulverized coal, steam-electric generating station designed for base load operation. Bituminous coal, both domestic and foreign supply, will be the primary fuel with the use of up to 20% petroleum coke. The site has direct rail access to the South Central Florida Express which is connected to two major rail carriers for the delivery of bituminous coal and petroleum coke. The rail access can also be used for delivery of bulk materials such as ammonia and limestone, and for the off-site shipment of by-products such as gypsum and ash. Common associated facilities will include fuel handling and storage facilities for fuel, limestone and ammonia along with handling and storage facilities for by-products such as gypsum and ash.

As shown in Figure III.A.3, the power plant is proposed to be located essentially in the center of the proposed 4,900 acre site. This will provide the maximum separation distance from the power plant to the property boundaries, helping minimize impact on off-site land uses and plant visibility. Figure III.A.4 shows a more detailed plan view of the two power islands.

Figure III.A.3

Location of Power Plant on FGPP Site

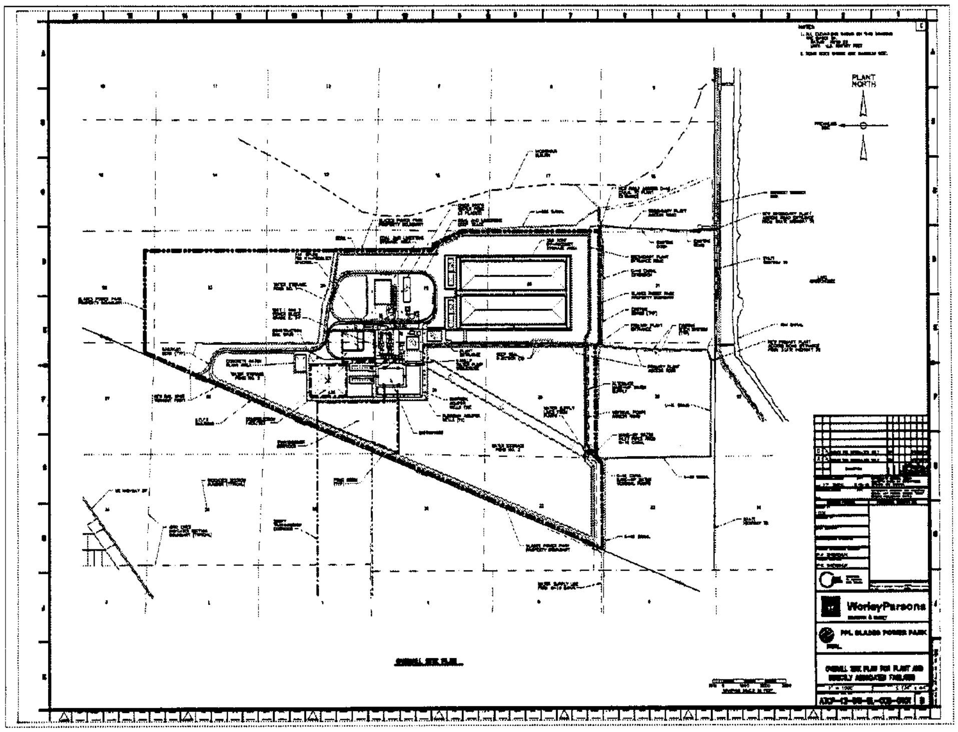
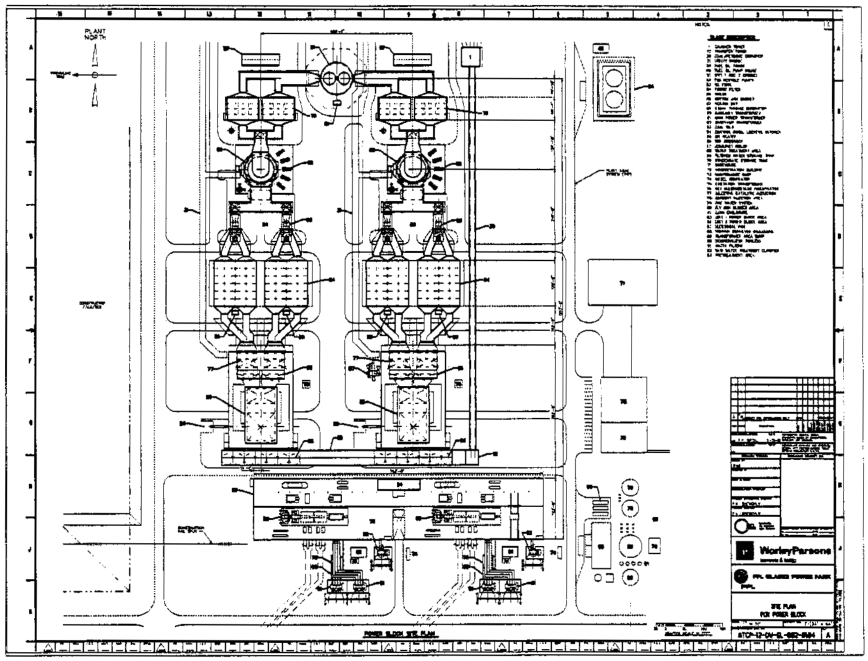


Figure III.A.4

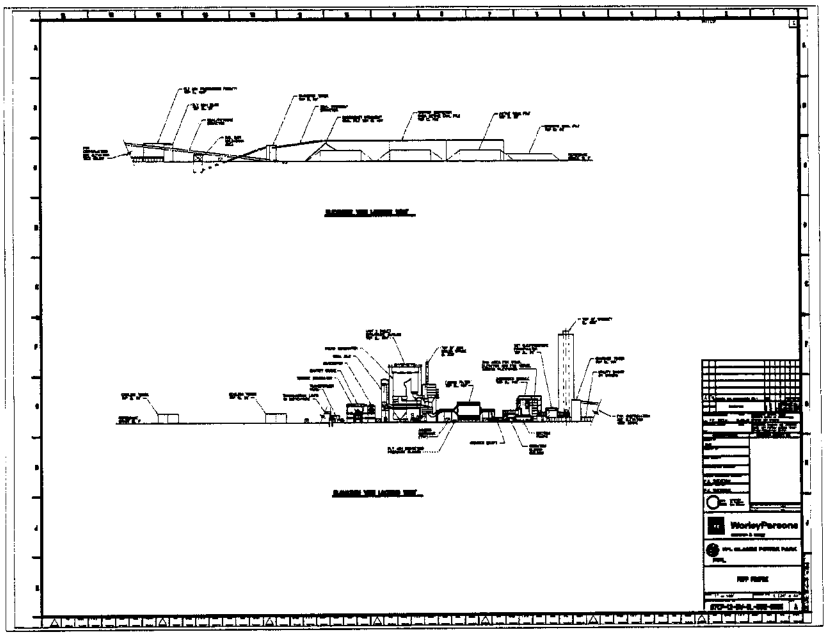
Detailed Plan View of FGPP Power Islands



Other prominent power-island related features of the site are shown on Figure III.A.3. These include the by-product and material delivery, handling and storage facilities to the north of the power islands, long-term by-product storage facilities to the northeast, water storage ponds to the east, electrical interconnection and heat dissipation systems to the south, and temporary construction areas to the west. Figure III.A.5 shows typical elevation views of the various facilities.

Figure III.A.5

Elevation Views of FGPP Facilities



B. FGPP 1 and 2 Design

Each unit will consist of a supercritical steam generator (boiler), one steam turbine generator (STG), a mechanical draft cooling tower and a suite of back-end pollution control equipment. The term "supercritical" in the context of a boiler refers to higher steam operating temperatures and pressures than conventional (sub-critical) boiler designs and results in much greater efficiency of the plant. The operating pressure and temperature will be approximately 3,700 pounds per square inch absolute (psia) and 1,130°F as compared to sub-critical designs of approximately 2,400 psia and 1,000°F.

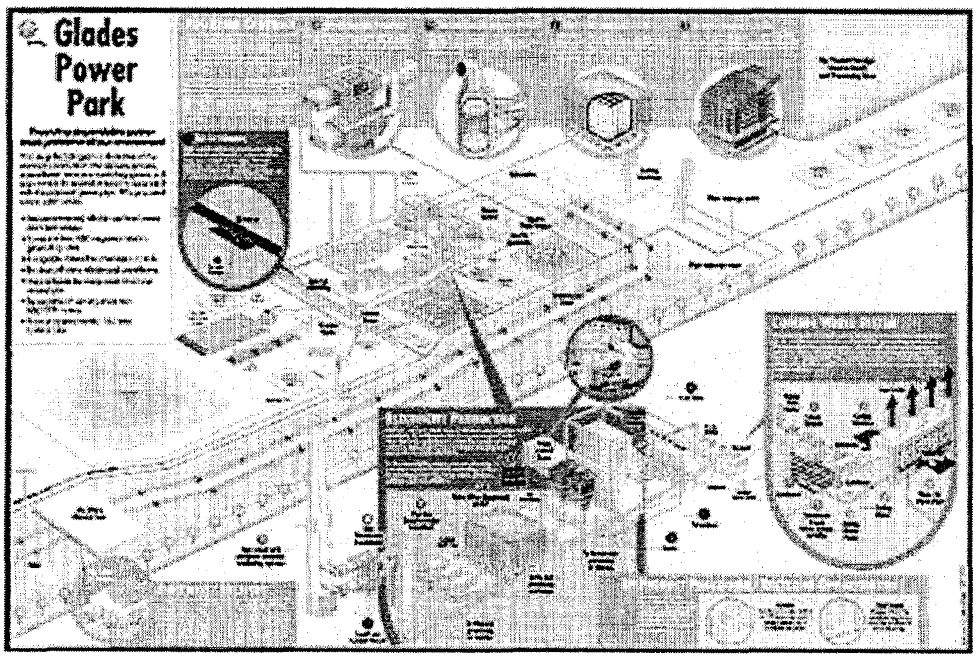
The units are being designed with state-of-the-art performance features including an extremely efficient power generation cycle design. The projected output of 980 MW (Summer) per unit with an average predicted heat rate of 8,800 Btu/kWh will make it among the most efficient coal-fired electric generating facilities in the United States.

The ultra-supercritical technology that FPL has selected is proven, having been applied at facilities in Japan and Europe.

Figure III.B.1 shows an overall process diagram of the FGPP. Each unit's power island will consist of a supercritical pulverized coal steam generator, a steam turbine generator, a mechanical draft cooling tower and a suite of back-end pollution control equipment. Coal and petroleum coke will be delivered to the site via rail cars which will be unloaded and transferred to either an active or inactive storage pile. The active storage area will be designed to hold approximately three days of fuel supply while the inactive storage area will have the ability to store up to 60 days of fuel.

Figure III.B.1

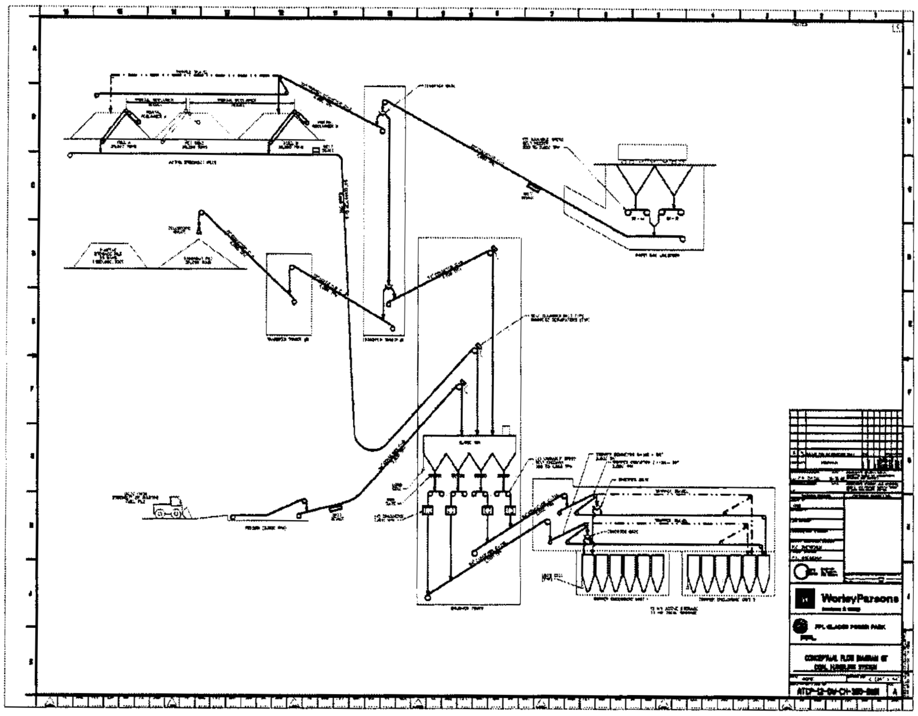
FGPP Overall Process Diagram



Fuel will be mechanically reclaimed from the active storage area and conveyed to a crusher tower where the fuel is processed by crushing to a specified grain size. The crushed fuel is then transferred to fuel storage silos which will feed the coal into the boiler for combustion. Figure III.B.2 shows a more detailed process flow diagram of the coal handling system.

Figure III.B.2

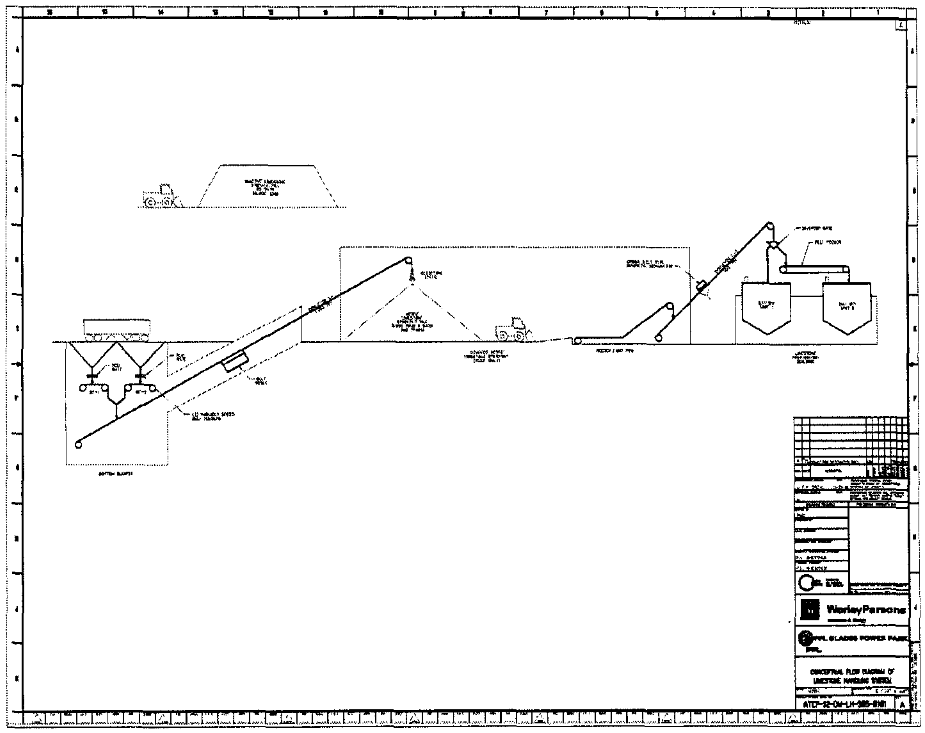
FGPP Process Flow Diagram of the Coal Handling System



Another significant material delivery and storage feature of the facility will be for limestone that will be used as part of pollution control equipment, more specifically the Wet Flue Gas Desulphurization (WFGD) system. The limestone will also be delivered by rail to the site, and will be unloaded and transferred to a covered storage area. The limestone will be mechanically reclaimed and transferred to a preparation building prior to use in the WFGD system. Figure III.B.3 shows a more detailed process flow diagram of the limestone handling system.

Figure III.B.3

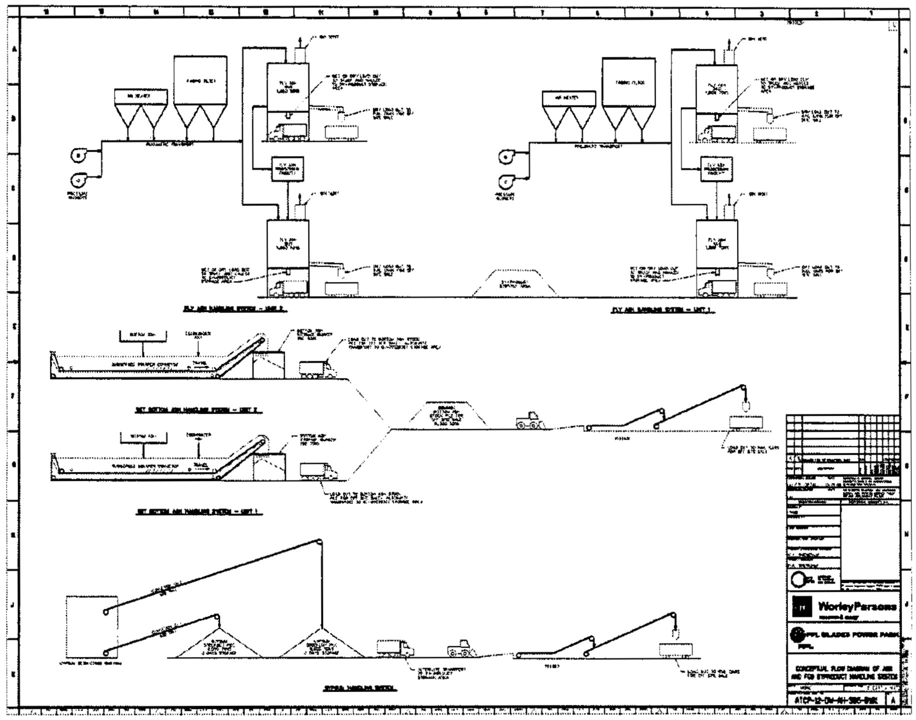
FGPP Process Flow Diagram of the Limestone Handling System



By-product handling and storage for the FGPP project would include facilities for fly ash, bottom ash, and gypsum. These are by-products from either the combustion process (ash) or from the removal of sulfur dioxide from the flue gas. In all three cases, the by-products are collected and processed for off-site recycling. In addition, a permanent long-term by-product storage area will be provided for off-specification material and for use in the event that recycling opportunities are interrupted or otherwise unavailable. Figure III.B.4 shows a more detailed process flow diagram for the ash and the gypsum by-product facilities.

Figure III.B.4

FGPP Process Flow Diagram for Ash and Gypsum By-Product Facilities



The primary water requirements for the FGPP include make-up water to the heat dissipation system which would consist of mechanical draft cooling towers, water for the WFGD system, process water for cycle make-up into the steam cycle, service water for general maintenance, fire protection water, waste treatment systems, by-product handling, and fugitive emissions control for material handling operations.

C. Environmental Controls

Environmental compliance is important to FPL's business, both as an environmental steward and because FPL is required to comply with the applicable environmental laws and regulations. Other federal and state agencies will fully review the environmental compliance of FGPP. However, in this filing, FPL has included information with respect to environmental compliance in order to provide assurance to the Commission that these, as well as other legal and regulatory requirements, will be satisfied through FPL's construction of FGPP, and so that the Commission is informed concerning the expected costs of environmental compliance. To this end, FPL will install and operate those environmental controls necessary to comply with all applicable environmental laws and regulations.

For example, from an air emissions compliance perspective, environmental controls will be installed to control emissions of nitrogen oxides (NO_X), sulfur oxides (SO_2 and SO_3), mercury, and particulate matter. Sources of air emissions consist of the plant's two supercritical boilers, two mechanical draft cooling towers, two emergency generators, the auxiliary boiler, and the material handling facilities.

NO_X is a chemical by-product formed by the combustion of fossil fuels such as oil, natural gas, and coal. NO_X formation in the two ultra-supercritical boilers will be minimized through application of good combustion controls, particularly by controlling combustion temperatures and by properly staging combustion. The boilers will minimize NO_X production by using low-NO_X burners (LNB) and over-fire air (OFA). Additional environmental controls for NO_X will include a post-combustion environmental control process further reducing NO_X emissions. The post-combustion technology being proposed for FGPP is Selective Catalytic Reduction (SCR). SCR technology is a proven and widely used post-combustion NO_X-control technology that utilizes the selective reaction of ammonia with NO_X in the presence of a catalyst. In the process, ammonia is injected into the flue gas upstream of a catalyst. The selective reduction reactions occur on the surface of the catalyst to transform NO_X into water and nitrogen. Overall, the removal efficiency of the NO_X environmental controls will be greater than 90% and will fully comply with applicable environmental laws and regulations.

The primary source of sulfur compounds from the combustion of fossil fuels comes from the fuel itself with very minimal contribution from the air being introduced into the boiler. For pulverized coal-fired utility boilers, sulfur dioxide (SO_2) emission reduction is accomplished by treating the post-combustion flue gas. The technology being proposed for FGPP will involve the use of a WFGD process. The wet scrubbing process involves a reaction in which the SO_2 is transferred to a scrubbing liquid, which, in this case, is a calcium-based wet limestone. The resulting by-product of the process after further oxidation is gypsum, a marketable by-product used in building materials such as wallboard. Overall, the removal efficiency of the SO_2 environmental controls will be greater than 98.5% and will fully comply with applicable environmental laws and regulations.

Sulfur trioxide (SO_3) produced through the combustion process is condensed into an aerosol in the flue gas desulphurization system. The technology being proposed for FGPP will involve the use of a Wet Electric Static Precipitator (WESP). This technology utilizes an electric field which imparts an electric charge to the aerosol particles in the flue gas. These particles are attracted to collector plates. Water is used to wash the particles from the collector plates and out of the flue gas stream. Overall, the removal efficiency of SO_3 achieved through environmental controls will be greater than 90% and will fully comply with applicable environmental laws and regulations.

The primary sources of particulate matter emissions from the facility will be from the combustion of the fossil fuel in the boiler (which will be discussed in more detail later), emissions from the mechanical draft cooling towers, and fugitive emissions from the handling facilities associated with bulk materials such as fuel, limestone, and by-products.

With respect to the cooling towers, water droplets exhausted into the atmosphere as part of the cooling process contain dissolved solids and chemical impurities which come from the original make-up water supply. In order to minimize the release of these water droplets into the atmosphere, thus minimizing particle matter carry over, drift eliminators will be installed to remove the water droplets from the air stream exhausting from the cooling towers.

Fugitive particulate emissions from bulk material handling and storage facilities will be minimized by equipment design and operating procedures. Materials such as fuel and limestone will be unloaded into bottom dump underground hoppers, which will be protected from wind and which will minimize the generation of fugitive dust. Dust that does get generated from unloading operations will be further controlled using dust collection and suppression systems. Conveyors used for transfer of the bulk materials will be enclosed for minimizing wind-borne fugitive dust. Conveyance points will be designed with either telescoping chutes for stock piling into storage piles, or will be provided with dust collection and suppression systems at the points of on-loading into enclosed hoppers, silos, or staging areas for storage. All conveyor transfer points will have a dust collection system.

The major source of particulate matter from the FGPP project will be from combusting coal in the boiler. Combusting coal and petroleum coke in a pulverized coal-fired boiler produces ash which is the non-combustible portion of the fuel. Ash is solid and is therefore classified as particulate matter. About 20% of the ash falls to the bottom of the boiler as bottom ash and is removed by the bottom ash system. The remaining 80% of the ash, which does not fall to the bottom of the boiler, is called "fly ash" and is entrained by the flue gases leaving the boiler. The two most commonly used particulate matter environmental controls technologies being used in the industry today are electrostatic precipitators (ESP) and fabric filters. ESP technology uses an electric field to impart an electric charge to particles in the flue gas. Particles are magnetically attracted to collector plates. Rapping mechanisms, that are operated intermittently, dislodge the collected particles, which subsequently fall into a hopper for collection and disposal. Fabric filter technology, in contrast, removes particulate matter from the flue gas as it passes through a fabric filter media, such as woven cloths or felts. The filters are arranged as a number of cylinders or tubes (commonly referred to as "bags") through which the flue gas is directed. Cleaning of the bags in the fabric filter usually involves shaking, pulse-jet, or reverse-air methods. Dislodged particulates subsequently fall into a hopper for collection and disposal. The technology selected for FGPP is the fabric filter. This technology is highly efficient, providing up to 99.9% removal efficiency, and will fully comply with applicable environmental laws and regulations.

Trace amounts of metals are released in the combustion process and are collected using a combination of pollution controls of the types already described in order to achieve compliance with applicable environmental regulations. As an example, the combination of controls greatly enhances the control of emissions of mercury, one of the trace elements in coal. Mercury removal is facilitated by the SCR which oxidizes elemental mercury into a form that can be readily collected by the particulate and sulfur control systems. Additionally, the project will include a sorbent injection system specifically for the control of mercury emissions. The sorbent injection system will oxidize the mercury, further enhancing its collection in the particulate and sulfur removal control systems.

D. Transmission Facilities

As mentioned in the Executive Summary, and as will be discussed in detail in Section VI, two resource plans were developed for the purposes of analyzing the addition of FGPP 1 and 2 to FPL's system. As part of the analyses of these two resource plans, the Plan with Coal and the Plan without Coal, the transmission facilities required to interconnect and integrate the sited generation facilities included in each plan were determined. The overall transmission requirements for the two resource plans are very similar with only significant differences in the timing of the transmission facilities. This section discusses the transmission facilities associated with the two advanced technology coal units in the Plan with Coal. A discussion of the transmission interconnection and integration facilities associated with all non-coal units in both resource plans, including the cost and schedule for these transmission facilities, is provided in Appendix O.

With respect to the FGPP site, substantial new transmission facilities will be required in order to reliably interconnect and integrate the amounts of generation being projected at this site for both of the resource plans. The requirement to add transmission facilities is the result of the necessity to deliver approximately 2,000 MW of new generation from the FGPP site in Glades County, an area where no existing major transmission infrastructure exists, to FPL's load centers. FPL's existing 500 and 230 kV east-to-west coast transmission right-of-ways will be utilized, and new corridors, primarily north-to-south, from the plant site to meet the existing right-of-ways, will also be required. The required new corridors are proposed by FPL for certification under the Florida Power Plant Siting Act (PPSA).

1. Interconnection and Integration

When the first 980 MW advanced technology coal unit, FGPP 1, is placed in-service, the unit will be connected to the FGPP 500 kV switchyard located at the FGPP site in Glades County. This switchyard will be connected by two new 500 kV transmission lines to the 500 kV facilities at the new Hendry substation, which will be located in Hendry County approximately 25 miles south of the FGPP switchyard. This Hendry transmission substation will have both 500 kV facilities and 230 kV facilities. FPL's existing Orange River to Andytown 500 kV line will be looped into the Hendry 500 kV section by constructing two new parallel 500 kV lines from Hendry substation to FPL's existing 500 kV right-of-way, approximately 24 miles to the south. At the point where the new lines meet the existing Andytown to Orange River 500 kV line, the existing line will be cut and rerouted, effectively eliminating the Andytown to Orange River 500 kV line and creating two new 500 kV lines, the Hendry to Orange River line, and the Hendry to Andytown line. The 500 kV facilities at Hendry substation will be stepped down, via a 500/230 kV auto-transformer, and connected to 230 kV facilities at the Hendry substation. The existing Alva to Corbett 230 kV line, which is in close proximity to the proposed Hendry substation, will be looped into the Hendry 230 kV section. This will result in effectively eliminating the Alva to Corbett 230 kV line and creating two new 230 kV lines, the Hendry to Alva line, and the Hendry to Corbett line.

When the second 980 MW advanced technology coal unit, FGPP 2, is placed in-service, the unit will also be connected to the FGPP 500 kV switchyard. In order to integrate this additional generation, a new 500 kV transmission line from the Hendry substation to the Andytown substation will be necessary. At this point, the existing Andytown-Levee 500 kV line will be disconnected from Andytown substation and reconnected to the new line from Hendry, thereby creating the Hendry to Levee 500 kV line.

2. Cost, Construction, and Schedule

Construction of the transmission facilities required for the interconnection and integration of FGPP 1 will be done in two phases. Phase 1 will include the transmission facilities required to provide the necessary power to the plant to energize electrical equipment for testing and commissioning and Phase 2 will include the transmission facilities required to put FGPP 1 into commercial service.

The facilities required for Phase 1 include the generator step up (GSU) transformers and attendant bus equipment, the string buses from the GSU transformers to the FGPP switchyard, the FGPP switchyard, the Hendry substation including a 500/230 kV autotransformer, one 500 kV transmission line between the FGPP switchyard and the Hendry substation, and the looping of the existing Alva to Corbett 230 kV transmission line into Hendry substation.

The facilities required for Phase 2 include the second 500 kV line between the FGPP switchyard and Hendry substation, the looping of the existing Andytown to Orange River 500 kV transmission line to Hendry substation, and the associated substation work required to energize these lines.

After the Site Certification Order is issued, the land rights have been secured, post certification reviews have been completed, and all of the otherwise applicable local, state, and federal permits have been obtained, the first step in the construction of the FGPP switchyard and Hendry substation sites will be site preparation. The sites will be prepared by clearing and removing any undesirable material from the site. Fill material will then be hauled in, placed, and compacted to the required elevation. The relay vaults will then be constructed. The next step will be to install the foundations required to set the equipment. After the foundations have been installed, the installation of structural and electrical equipment begins. This will include the installation of structures, switches, circuit breakers, buses, transformers, and other electrical equipment. During this phase, the GSU transformers and attendant buses will also be installed at the FGPP site and the 500/230 kV auto-transformer will be installed at Hendry substation. This will be followed by the installation of the protective relay equipment and commissioning activities associated with placing equipment in-service.

The first step to construct the transmission lines will be right-of-way preparation. This preparation involves the clearing of vegetation that might interfere with the construction, and the safe and reliable operation, of the transmission lines. Where roads are not available for access, new roads will need to be constructed. New access roads will be constructed from fill material and will not be paved. These roads will provide a suitable driving surface that will be used for access during construction, future patrol, and maintenance of the transmission lines. At structure locations, a structure pad will be constructed using the same process as the new access roads. After the access roads and pads have been built, foundations will be constructed at each structure location of the 500 kV line. Once foundations are completed, tubular steel structures will be hauled to the structure location, assembled, framed, and erected on the foundations. The structures for the 230 kV loop will consist of single concrete poles. Similarly to the steel structures, the concrete poles will be hauled to the structure location, framed, and set in the ground. Once the structures have been erected, the insulators, conductors, and overhead ground wires will be installed.

At this time, it is anticipated that construction for Phases 1 and 2 will begin on or about March 2009. It is anticipated that Phase 1 will be completed by November 2010 and Phase 2 will be completed by November 2011. Phase 2 of the project needs to be completed prior to FGPP 1 going in-service. These dates are consistent with FPL's plans to bring FGPP 1 and 2 into service as soon as reasonably possible. FPL believes that the earliest possible date that it can place the first FGPP unit in-service is during the second half of 2012, and the second unit during the latter half of 2013. In order to ensure that these transmission facilities will be available to deliver electricity from FGPP as soon as the units are available, FPL developed a transmission facilities construction schedule sufficient to support an early in-service date.

The facilities required for the interconnection and integration of FGPP 2 include the transmission line between the Andytown and Hendry substations, tying this line to an existing Andytown to Levee transmission line to form the new Hendry to Levee 500kV line, and the associated substation work required to energize these lines.

Construction of these transmission facilities for FGPP 2 will be done in the same manner as previously described for FGPP 1. At this time, we anticipate that construction for FGPP 2 will begin on or about March 2009 and be completed by November 2012. This portion of the project is required to be complete prior to FGPP 2 going in-service.

The costs and schedule of the transmission facilities required to interconnect and integrate the two advanced coal units are provided in Table III.D.1 below:

Table III.D.1

Costs and Schedule for Transmission Facilities for FGPP 1 and 2

Facility	Description		Total Cost	Construction Start	Construction Finish
TF-1	The connection of FGPP 1 and 2 Generator Step Up ("GSU") transformers to the FGPP switchyard, and attendant bus equipment; (TF-1)	$	2,295,000	September-2009	November-2010
TF-2	The FGPP switchyard; (TF-2)	$	19,090,000	September-2009	November-2010
TF-3	The Hendry 500/230 kV Substation; (TF-3)	$	56,035,000	January-2009	November-2010
TF-4	The two 500 kV transmission lines from the FGPP switchyard to the Hendry Substation; (TF-4)	$	123,461,000	March-2009 March-2009	November-2010 November-2011
TF-5	The looping in of the Alva to Corbett 230 kV and the Andytown to Orange River 500 kV transmission lines into the Hendry substation; (TF-5)	$	172,566,000	May-2010 March-2009	November-2010 November-2011
TF-6	A new 500 kV transmission circuit from the Hendry to Levee substations. This transmission line will be constructed between Hendry and Andytown substations and connected to an existing Andytown to Levee 500 kV line resulting in a Hendry to Levee 500 kV transmission line; (TF-6)	$	96,020,000	March-2009	November-2012
	Total FGPP	$	469,467,000		

Notes:
1. Costs were estimated in 2007 dollars and then escalated to the year that the expense would be incurred.
2. TF- Transmission Facilities for Fuel Diversisty Expansion Plan with Coal

E. Overall Project Construction Schedule

FPL will begin Project construction upon receipt of the necessary federal and state certifications and permits. The expected construction duration for the FGPP as a whole is approximately 64 months, with Unit 1 taking approximately 52 months to complete and Unit 2 following approximately 12 months later. Due to market conditions relating to demand for power generation equipment and engineering, procurement and construction (EPC) services, as well as other uncertainties associated with the permitting and construction schedules, it is more likely that the in-service date of FGPP 1 will occur later in 2012 or early in 2013 instead of the previously projected in-service date of June 2012 and, likewise, that the in-service date of FGPP 2 will occur later in 2013 or early in 2014, instead of June 2013. For purposes of the analysis, however, FPL is assuming in-service dates of June 1, 2013 for Unit 1 and June 1, 2014 for Unit 2.

F. Estimated Capital Costs with Indexing Approach

1. Estimated Capital Costs

The estimated installed cost for the FGPP is $3,456 million (2013 dollars) and $2,244 million (2014 dollars) for Unit 2, resulting in a total installed cost of $5,700 million.

For Unit 1, this cost includes $2,396 million for the power block, $125 million for land acquisition for the power block, $73 million for land acquisition for the off-site transmission system, $201 million for the transmission interconnection and integration, and $661 million in allowances for funds used during construction (AFUDC) assuming an in-service date of June 1, 2013.

For Unit 2, this cost includes $1,668 million for the power block, $195 million for the transmission interconnection and integration, and $381 million in allowances for funds used during construction (AFUDC) assuming an in-service date of June 1, 2014. All land acquisition costs are included in the first unit's costs.

The components of the total plant costs are shown in Table III.F.1. These expected costs are based on indexed costs for certain risk elements.

Table III.F.1

FGPP Plant Cost Components

(Millions, in-service year $)

	Unit 1 (2012$)	Unit 2 (2013$)
Power Plant	$2,396	$1,668
Transmission Interconnect and Integration	$201	$195
Land- Power Plant	$125	
Land- Transmission	$73	
AFUDC	$661	$381
Total Plant Cost	$3,456	$2,244
Total Project Costs	$5,700	

2. Indexing Approach

Over the last two years the industry has experienced sharp increases in labor and material costs that have adversely impacted the suppliers and contractors. In general the costs of bulk material such as metals have also increased substantially. Changes in the backlog of shop orders have also risen significantly as a result of the number of announced orders for coal projects in the United States and abroad. This competition for suppliers has placed a premium on the acquisition of major equipment for FGPP.

In some cases, like the pollution control equipment (e.g., Fabric Filter, Wet Flue Gas Desulphurization, and Wet Electric Static Precipitator), the market is so saturated with buyers and orders that firm pricing is not even attainable. This market saturation is due not only to the current backlog of proposed new coal projects, but also to the numerous coal plant retrofit projects underway. Such retrofit projects are in response to new environmental compliance programs such as the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Best Available Retrofit Technology (BART). There are two components of the total estimated capital costs for the power plant that are based on indices: escalation for labor costs in the Engineering, Procurement, and Construction (EPC) agreement and the escalation for high alloy steels and metal costs in the pollution control equipment.

These two cost components are subject to particular market price risks that suppliers simply are not willing to assume. Essentially, these indices address market risks over which neither the supplier nor FPL will have control. Thus, in each case, it is necessary to apply indices for these particular cost components. For the EPC pricing, the labor component will be indexed to a rate derived from the United States Department of Labor Bureau of Labor Statistics (BLS) County Employment and Wages Bulletin. For the pollution control equipment contracts, high alloy steels and metal costs will be indexed to published market indices for high alloy steels and metals used in producing the equipment.

G. Reasonableness of FPL's Capital Cost Estimates

The FGPP capital cost estimate was developed using competitive pricing for those major cost components of the power plant. FPL secured firm pricing for three major pieces of equipment and the EPC. Specifically, FPL sought and obtained competitive equipment pricing for the boiler, steam turbine, and the pollution control equipment. The selection process included at least three bids for each of the major equipment procurements. For the boiler and steam turbine, the process resulted in firm pricing. For the pollution control equipment this resulted in pricing with the majority of the costs firm and the remaining portion subject to an adjustment based on a predetermined index.

The immense scope of this project, in the first instance, necessarily limits the number of potential EPC contractors. Thus, the EPC pricing was based on an initial inquiry to three major contractors with coal engineering, procurement, and construction experience. The result of this inquiry produced only one contractor with resources available in sufficient quantity to handle a project of this magnitude in the timeframe required. FPL promptly undertook to negotiate a market competitive agreement for the EPC services. In negotiating a competitive agreement, FPL employed two fundamental approaches. First, the terms and conditions from the competitively bid West County Energy Center EPC contract were used. Second, the cost was benchmarked against a similar competitively bid project. These costs included quantities for materials and equipment along with fees and labor man-hours adjusted for scope differences between the projects. Scope differences included the unit size and number of units (one versus two) along with site and regional differences.

In order to help ensure the reasonableness of the project's estimated cost, FPL also hired the services of a consultant, Cummins & Barnard, who has performed an independent detailed review of the installed cost estimate for FGPP. The results of the review concludes that the estimated installed cost for FGPP are reasonable and competitive.

H. FGPP Fact Sheet

The details of the FGPP units are presented in Figure III.H.1.

Figure III.H.1

FGPP 1 and 2 Fact Sheet

Generation Technology: Ultra-Supercritical Pulverized Coal Steam Electric Generator:

- Two (2) 3700 # Coal Fired Steam Electric Generators (Boiler)
- Two (2) Single-Reheat Steam Turbine Generator
- Two (2) Mechanical Draft Cooling Towers
- Particulate Matter Environmental Controls- Two (2) Fabric Filter Baghouses
- Nitrogen Oxide Environmental Controls- Two (2) Selective Catalytic Reduction Systems
- Sulfur Dioxide Environmental Controls- Two (2) Wet Flue Gas Desulfurization Systems
- SAM and Fine Particulate Environmental Controls- Two (2) Wet Electric Static Precipitators

Expected Plant Peak Capacity:

Summer (95°F / 50% RH)	980 MW
Winter (35°F / 60% RH)	990 MW

Projected Unit Performance Data:

Average Forced Outage Rate (EFOR)	3.0%
Average Scheduled Maintenance Outages	2.6 wks/yr (5.0% POF)
Average Equivalent Availability Factor (EAF)	92%
Base Average Net Operating Heat Rate @ 75°F / 60% RH	8,800 Btu/kWh (HHV)
Annual Fixed O&M – average 2 Units (2013 dollars)	$28.02/kW-yr
Variable O&M –average 2 Units (2013 dollars) (excluding fuel)	$1.75/MWh

Fuel Type and Base Load Typical Usage @ 75°F:

Primary Fuel	Coal
Alternate Fuel	Petroleum Coke (up to 20%)
Maximum Heat Input	8,700 mmbtu/hr/Unit

Expected Base Load Air Emissions Per Train @ 75°F:

NO_x	0.05 lb/mmBtu
CO_2	205 lb/mmBtu
Hg	1.2×10^{-6} lb/mmBtu
SO_2	0.04 lb/mmbtu

Water Balance:

- Annual average consumptive use for FPL Glades Power Park Units 1 and 2 is approximately 30 MGD.
- Wastewater deep well injected

Linear Facilities:

- One (1) Off-Site Transmission Sub-Station
- Approximately 170 Circuit Miles of 500 kV Transmission

IV. FPL'S NEED FOR THE PROPOSED POWER PLANT

FPL determined in its 2006 integrated resource planning (IRP) work that it would need significant additional resources starting in 2012 to meet its reserve margin criterion. The reliability assessment portion of the IRP process is designed to determine both the magnitude and timing of FPL's resource needs. It is a determination of how much load reduction, new capacity, or a combination of both load reduction and new capacity is needed, and when these resources need to be added to meet FPL's reliability criteria. Based on this analysis, FPL determined it would need a minimum of either 2,283 MW of new supply (power plant construction or power purchase), or approximately 1,903 MW of new DSM, to meet its 2012-2015 reserve margin requirements.

A. Reliability Assessment

In the reliability assessment portion of its 2006 IRP analysis, FPL started with updated power plant capability and reliability data, plus an updated load forecast. The updated load forecast is presented in Appendix D. In addition, the reliability assessment took into account committed construction capacity additions, firm capacity purchases, and DSM.

1. Committed Construction Capacity Additions

FPL included its previously committed generation construction projects in its 2006 reliability assessment. These committed construction projects are the new 1,144 MW combined cycle (CC) unit at FPL's existing Turkey Point plant site (Turkey Point Unit 5) that will be placed into service in mid-2007, the new 1,219 MW CC unit at the West County Energy Center (WCEC) that is scheduled to be placed into service in mid-2009 (WCEC Unit 1), and the new 1,219 MW CC unit (WCEC Unit 2) that is scheduled to be placed into service in mid-2010.

2. Firm Capacity Purchases

FPL took into account all of its current short-term and long-term firm capacity purchases from a combination of utility and non-utility generators in its 2006 reliability assessment. These firm capacity purchases are discussed in Section II.B.2 and are presented in Table II.B.2.1.

3. DSM

Since 1994, FPL's IRP process has used the amount of DSM capacity in FPL's approved DSM Goals as a basis for the system reliability analysis. The currently approved DSM Goals for FPL are discussed in Section II.B.3 and presented in Table II.B.3.1. This table also presents the projection of additional DSM beyond the DSM Goals that are a result of recent Commission approval of FPL's request to modify 8 existing DSM programs and to introduce two new DSM programs. In its 2006 reliability assessment work, FPL used both the approved DSM Goals through the year 2014, and the projected additional DSM MW resulting from the recent approvals for program modifications and for new programs, as a key assumption in the assessment. In this way, FPL includes in its reliability analysis the projected incremental impact of all of FPL's DSM programs from 2006-on, plus the cumulative demand reduction capability from its load management programs prior to 2006. The cumulative impact from all of FPL's conservation program efforts prior to 2006 is captured in the 2006 load forecast that is discussed in Section V.A.1.

These DSM projections typically address the next ten-year period; i.e. from 2006 through 2015. In the analyses conducted that led to the selection of FGPP 1 and 2, it was apparent that one of the two resource plans used in the analyses, the Plan without Coal, added generation in 2016. In order to attempt to provide as realistic a projection as possible for the analyses of the Plan without Coal compared to the Plan with Coal, FPL assumed an extension of DSM implementation for another 5 years after 2015. The assumption used was that an incremental 120 MW of DSM per year for each year in the 2016 through 2020 time period would be implemented. The 120 MW represents a continuation of the projected annual trend in DSM signups in the 2006 through 2015 time period.

B. FPL's Reliability Criteria

System reliability analyses were based on the dual planning criteria of: (1) a minimum Summer and Winter reserve margin of 20%, and (2) a maximum of 0.1 days per year Loss-of-Load-Probability (LOLP). The reserve margin criterion of 20% applies for reserve margin analyses addressing both Summer and Winter peak hours. The Commission approved this reserve margin criterion in Order No. PSC-99-2507-S-EU. The LOLP criterion of 0.1 days per year is an electric industry standard that the Commission has accepted in numerous resource planning-related dockets.

Reserve margin analysis is a deterministic approach, while LOLP analysis is a probabilistic approach. The reserve margin analysis is essentially a calculation of excess firm capacity at the time of the Summer system peak hour and at the time of the Winter system peak hour. This calculation provides a measure of the capability a generating system possesses to meet its native load during peak hours. However, a deterministic approach such as a reserve margin calculation does not take into account probabilistic elements such as the reliability of individual generating units and the total number and sizes of generating units on the system. A deterministic approach also does not fully account for the value of an interconnected system.

Therefore, FPL also utilizes a probabilistic approach, LOLP, to provide additional information on the reliability of its generating system. LOLP is an indicator of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages. LOLP is expressed in units of "number of times per year" that the system demand could not be served and requires a more complicated calculation than does reserve margin analysis. FPL calculates LOLP using the Tie-Line Assistance and Generation Reliability (TIGER) model. A listing and summary of the computer models utilized by FPL in its resource planning work, including the TIGER model, is provided in Appendix C.

In a reliability assessment, either the reserve margin criterion or the LOLP criterion will "drive" the need for additional resources. This means that, for a given future year, FPL's system will not have a reserve margin high enough to meet its 20% criterion or it will have a projected LOLP value greater than 0.1 days per year. Whichever criterion is not met first is said to drive FPL's future resource needs. For the last few years, the Summer reserve margin criterion has driven FPL's future needs. This again was the case in FPL's most current reliability assessment performed as part of its 2006 IRP work.

C. FPL's 2006 Reliability Assessment Results

FPL's reliability analyses showed that with no additional resources beyond its existing generating units, existing purchases, and the committed construction capacity additions mentioned above, FPL would not meet its Summer reserve margin criterion of 20% starting in the Summer of 2012 and for each Summer thereafter. (A relatively small 167 MW capacity need exists in 2011. FPL currently plans to address the 2011 need with a short-term purchase(s), enhancements to its existing generating units, and/or additional cost-effective DSM.) Assuming that the small 2011 need is met with a one-year capacity purchase, 2,283 MW of additional supply resources would be needed during the 2012 - 2015 timeframe for FPL to continue to meet its Summer reserve margin criterion of 20% for those years. This need is demonstrated in Table IV.C.1. This table also shows that meeting the Summer capacity needs will also easily meet the much smaller Winter need that appears only in 2015.

If the 2012-2015 resource needs were to be met solely by additional new DSM resources, FPL would need to find an additional 1,903 MW of cost-effective DSM. Accounting for FPL's 20% reserve margin criterion, the 2,283 MW of generating capacity need would become 1,903 MW of DSM (2,283 MW/1.20 = 1,903 MW). There is not 1,903 MW of additional, cost-effective DSM available to meet this need. This will be further discussed in Section VII.D.

Table IV.C.1

Projection of FPL's 2007 - 2015 Capacity Needs (without New Resource Additions)

Summer

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Reserve Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2007	22,123	2,993	25,116	22,259	1,768	20,491	4,625	22.6%	(527)
2008	22,150	2,993	25,143	22,770	1,908	20,862	4,281	20.5%	(109)
2009	23,370	2,511	25,881	23,435	2,034	21,401	4,480	20.9%	(200)
2010	24,589	2,107	26,696	24,003	2,146	21,857	4,839	22.1%	(468)
2011	24,589	2,062	26,651	24,612	2,264	22,348	4,303	19.3%	**167**
2012	24,589	1,906	26,495	25,115	2,388	22,727	3,768	16.6%	**777**
2013	24,589	1,906	26,495	25,590	2,516	23,074	3,421	14.8%	**1,194**
2014	24,589	1,906	26,495	26,100	2,651	23,449	3,046	13.0%	**1,644**
2015	24,589	1,906	26,495	26,772	2,790	23,982	2,513	10.5%	**2,283**

Winter

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
January of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Winter DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Winter Reserves (MW)	Forecast of Winter Reserve Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2007	22,294	3,862	26,156	22,247	1,555	20,692	5,464	26.4%	(1,326)
2008	23,503	3,026	26,529	22,627	1,649	20,978	5,551	26.5%	(1,355)
2009	23,531	2,700	26,231	23,115	1,750	21,365	4,866	22.8%	(593)
2010	24,866	2,188	27,054	23,587	1,814	21,773	5,281	24.3%	(926)
2011	26,201	2,095	28,296	24,047	1,883	22,164	6,132	27.7%	(1,699)
2012	26,201	2,095	28,296	24,498	1,954	22,544	5,752	25.5%	(1,243)
2013	26,201	1,915	28,116	24,952	2,028	22,924	5,192	22.6%	(607)
2014	26,201	1,915	28,116	25,416	2,106	23,310	4,806	20.6%	(144)
2015	26,201	1,915	28,116	26,048	2,188	23,860	4,256	17.8%	**516**

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

D. Consistency with Peninsular Florida Need

FPL's need for an additional 2,283 MW of supply resources (or 1,903 MW of demand side resources) is consistent with the Peninsular Florida need that will be identified by the Florida Reliability Coordinating Council (FRCC) in its 2007 reliability work that will be reported in its FRCC 2007 Regional Load and Resource Plan. The FRCC's 2007 reliability work will use FPL-specific data that will be contained in FPL's 2007 Ten-Year Site Plan in conjunction with similar information from other Florida electric utilities. FPL's 2007 Ten-Year Site Plan will be consistent with the results of the reliability assessment discussed above.

E. System Fuel Diversity

1. Current

In 2005, the last full year for which data was available at the time this document was prepared, FPL's fuel mix consisted of natural gas (42%), nuclear generation (19%), coal (18%), fuel oil (17%), and other sources (about 4%).

2. Future

If only natural gas-fueled generation were to be added to FPL's system in the future, the contribution of natural gas would increase to approximately 71% of total electricity delivered to FPL's customers in 2016, while that of coal would decrease to approximately 7% in 2016.

With the proposed addition of the two advanced technology coal units at FGPP, the share of electricity produced by natural gas would be approximately 60% in 2016, while that of coal would be approximately 18% in 2016. These fuel mix projections, both with and without the addition of FGPP, are presented later in Section VI in Table VI.D.2.1. This table shows that the addition of FGPP is needed to prevent a significant reduction in the contribution of coal-fueled generation to FPL's system and a corresponding significant increase in dependency on natural gas.

3. Reasons to Balance the Fuel Mix

The primary benefits of fuel diversity are greater system reliability and reduced fuel price volatility. An electric system that relies on a single fuel and a single technology to generate all the electricity needed to meet its customers' demand, all else equal, is less reliable than a system that uses a more balanced, fuel-diverse generation portfolio. In addition, greater fuel diversity mitigates the impact of large and/or sudden swings in the price of one fuel, a phenomenon that has characterized the natural gas market over the last several years.

In regard to improved system reliability, there are at least three ways in which a more fuel diverse system is more reliable than a less fuel diverse system, all other aspects being equal.

a) Fuel Diversity Enhances System Reliability

An electric system that relies exclusively on one fuel is more susceptible to events that cause delays or interruptions in the production of that fuel. For example, in 2005 a significant number of natural gas production facilities in the Gulf of Mexico were shut down as a result of hurricanes. The shutdown of these facilities, which occurred with very little advance warning, significantly reduced the quantities of natural gas available to FPL to meet electricity demand. Had FPL's system relied exclusively on natural gas to produce electricity it would have been difficult, if not impossible, to continue to meet its customers' demand for electricity until some gas production capability was restored. It is unlikely that FPL would have been able to obtain sufficient natural gas from other regions to make up for the reduced gas supply from the Gulf of Mexico, particularly at a time when other natural gas users would also be seeking natural gas supplies to replace what could not be produced in the Gulf of Mexico. However, because FPL's system is fuel-diverse, there was sufficient energy produced by generating units that use other fuels such as nuclear fuel, coal, and oil to enable FPL to offset the reduction in natural gas supply and meet customers' needs. An inventory of these other fuels is maintained on-site at FPL's generation locations to further enhance system reliability.

b) Diversity in Fuel Transportation and Delivery Methods and Routes Also Improves System Reliability

The ability of a generating system that relies on only one fuel transportation and delivery method and route to serve its customers can be severely impaired by delays or interruptions in the transportation and delivery of that single fuel to the generating plants. Diversity in transportation methods and routes enables a utility to mitigate the effects of such interruptions and delays by fully utilizing other transportation channels that remain unaffected until transportation problems are resolved.

Because different fuels usually originate from different geographical areas and are transported and delivered via different methods and routes, having a fuel diverse generation system helps mitigate the effect of problems related to transportation and delivery as well as production.

c) Diversity, Not Just in Fuel Type, but in Generation Technology, also Improves Reliability

Occasionally, equipment design or manufacturing problems manifest themselves in the form of systematic failure of the same part in a number of generating plants that utilize the same part design, or those plants that use parts produced in the same production batch. Having diversity in generation technology also is important because any generic equipment problem will affect a smaller portion of a utility's generation portfolio, and will make it easier for the utility to mitigate the effect of that problem without adversely affecting service to its customers. Because generating units that use different fuels usually also use different technologies, a fuel diverse system also helps mitigate the effect of equipment problems that affect one specific type of generation technology, such as gas turbines.

4. Alternatives to Balance the Fuel Mix

FPL evaluated four coal-based technologies to determine whether they could reliably contribute to the fuel diversity and capacity needs of FPL's system in the 2012 – 2015 time period, and to select the best among those technologies that could provide those benefits. The technologies were: sub-critical pulverized coal (PC), circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), and ultra-supercritical pulverized coal (advanced technology coal).

5. The Alternative Selected by FPL

The results of FPL's analyses of these four coal-based technologies clearly established that the fourth of these technologies listed above, the advanced technology coal option, is the best alternative. Specifically, FPL concluded that advanced technology coal is the most cost-effective of the four, has reliability that has been established to be as good as, or better than, the other three options, is the most fuel-efficient, and can be constructed in the large size required by FPL's rapidly increasing demand. In regard to another of the options of interest to FPL, the IGCC technology option, the performance of IGCC technology has not been proven to be as reliable as that of the other alternatives, and the effectiveness of recently proposed design changes aimed at improving IGCC performance will not be determined until after 2013. Based on these factors, FPL has concluded that advanced technology coal at FGPP is by far the best choice to maintain fuel diversity and meet FPL's generation capacity need in the 2012 – 2015 time period.

6. Benefits of the Selected Alternative

By 2016, the quantity of firm power FPL will purchase from coal-fueled plants under existing contracts will decrease by 1,312 MW as a result of the terms of those contracts. Thus, the effect of adding 1,960 MW of coal-fired generation at FGPP, less the anticipated 1,312 MW reduction in power delivered under existing power purchase contracts served by coal generation, will be a net increase of only 648 (= 1,960 – 1,312) MW of coal-fueled generation in FPL's system by 2016 compared to the current level.

Moreover, aside from FPL's planned addition of FGPP, between 2007 and 2016 FPL will need about 4,482 MW of net additional generation capacity to continue to meet its reliability criteria. About half of this net 4,482 MW requirement will be met by new gas-fired generation that has already been granted Determinations of Need by the Commission and will be in operation by 2010. The technology for the additional net generation that will be needed in 2015 and 2016 (after the addition of FGPP) has not been selected, but if gas-fueled generation were selected to meet those needs, then the 648 MW net increase in system coal generation achieved by the addition of FGPP would represent only 13.0% of the total net increase in generation capacity needed between 2007 and 2016. Thus, it is clear that the addition of FGPP is critically needed to help maintain fuel diversity in FPL's system.

All of the benefits described above associated with having fuel diversity in the system are applicable to the addition of FGPP. Adding 1,960 MW of advanced technology coal generation to FPL's system will reduce dependence on natural gas and will enable FPL to more effectively offset decreases in natural gas supply because factors that affect gas production will not affect coal production. The fuels used in FGPP will be produced in Central Appalachia, South America, and other locations instead of the Gulf of Mexico, and they will be transported via ship and rail instead of pipeline so any event that affects gas transportation is unlikely to affect coal transportation. The technology to be used in FGPP will be different from that used in most of FPL's gas-fueled units, so technical problems that affect the gas units are less likely to affect FGPP.

There are additional benefits in regard to the ability to store coal on-site. Unlike natural gas, coal can be economically stored in significant quantities at the plant site. The addition of FGPP will enable FPL to maintain a 60-day inventory of coal on-site to mitigate the effect of coal transportation delays or interruptions. If FPL were to maintain a similar (60-day supply for 1,960 MW of generation) inventory of natural gas in Florida, the cost would be approximately $1.4 billion cumulative present value of revenue requirements (CPVRR), and if the storage were to be accomplished through additional oil storage at FPL's existing CC unit sites, the cost would be approximately $1.5 billion CPVRR. In addition, because the reserves of coal in the U.S. are so large, fuel supply that meets the specifications required by FGPP from secure domestic sources is assured for the entire operating life of the plant.

7. Cost of the Selected Alternative: Cost of Hedge Provided by Fuel Diversity

Fuel diversity helps mitigate the effects of price volatility in one or two fuels. For example, if a utility relies solely on natural gas to produce all the electricity needed by its customers, any increase or decrease in the market price of natural gas would translate into a direct and comparable increase or decrease in the cost of electricity. Because natural gas prices are projected to be volatile in the future, the customers would be subject to significant volatility in the future cost of electricity. Recent history has demonstrated how volatile natural gas prices can be. Because the prices of coal and nuclear fuel are relatively stable, and because changes in these fuels are not directly linked to changes in the prices of natural gas and fuel oil, having a fuel diverse portfolio that includes significant contributions from coal and nuclear fuels helps dampen the effect of volatility in natural gas prices. For this reason the addition of FGPP will help dampen the volatility in system fuel costs and make the cost of electricity more stable and predictable.

8. Uncertainty Factors Related to the Selected Alternative

There are several major areas of uncertainty in regard to bringing any coal-based option, such as the FGPP units, in-service. First, there is uncertainty regarding the date by which FPL will obtain a final, non-appealable Site Certification for FGPP. According to the requirements of the Florida Power Plant Siting Act, after the Commission grants a determination of need for FGPP, a Site Certification from the Siting Board made up of the Governor and members of the Cabinet, plus an Air Emissions Permit issued by the Florida Department of Environmental Protection (FDEP), will be required before construction can commence. The process to obtain these approvals for FGPP likely will be contentious and, as a result, both the timing for completing the process and the outcome are uncertain. If a final Site Certification, with acceptable terms, for FGPP is delayed beyond the first quarter of 2008, or if any governmental agency were to impose restrictions that hinder the construction process, completion of one or both of the FGPP units could be delayed. There is also substantial uncertainty regarding the construction schedule that could delay the in-service date of FGPP.

Second, in addition to uncertainty regarding potential delays in obtaining a Site Certification, there is also uncertainty regarding the final outcome of FPL's Site Certification Application for FGPP, as well as actions that may be taken by other government agencies that could prevent FPL from completing FGPP. If a final Site Certification is not granted, or if the conditions imposed on the Site Certification are not acceptable, or if any government agency imposes restrictions that block the construction process, FPL would not be able to proceed with construction of FGPP. Furthermore, if any government agency were to prevent FPL from performing any aspect of the plant's operation, FGPP could not be placed in commercial operation, even after having incurred significant costs.

The above-mentioned factors have actually delayed or prevented the construction of other generating facilities in the past. For example, subsequent to FPL receiving Commission approval to proceed with a plan to modify the boilers at its existing Manatee Units 1 and 2 and add emission control equipment to enable it to utilize a much less costly fuel – Orimulsion – in order to reduce FPL's use of fuel oil and decrease fuel costs, the Siting Board twice rejected FPL's application for Site Certification in spite of a very positive recommendation in favor of granting the Site Certification from the Administrative Law Judge who conducted the hearing.

Other key areas of uncertainty that affect the relative cost to the customer of adding FGPP, compared to adding a different type of generation technology, such as gas-fueled combined cycle units, relate to : (1) the future fuel price differential between natural gas and coal; (2) the ability to transport and deliver coal to FGPP at reasonable costs from diverse sources of coal; (3) costs of compliance with future environmental requirements or unanticipated Site Certification conditions; and (4) the actual capital cost of completing FGPP and placing the advanced technology coal units in commercial operation.

V. FACTORS AFFECTING SELECTION

A. Forecasts and Assumptions

The forecasts of electric load and fuel prices are developed by FPL analysts who aggregate data and perform various analyses to develop these forecasts that are used in FPL's IRP process.

1. The Load Forecast

Long-term (20-year) forecasts of sales, net energy for load (NEL), and peak loads are developed on an annual basis for resource planning work at FPL. These forecasts are a key input to the models used during the IRP process. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

a) Forecast Assumptions

The primary drivers to develop these forecasts are demographic trends, weather, economic conditions, and the price of electricity. In addition to these drivers, the resulting forecasts are an integration of economic evaluations, inputs of local economic development boards, weather assessments from the National Oceanographic and Atmospheric Association (NOAA), and inputs from FPL's own customer service planning areas. Population trends by county, plus characteristics such as housing starts, housing size, and vintage of homes, are assessed in the area of demographics.

Econometric models are developed for each revenue class using the statistical tool called Metrix ND. The methodologies used to develop sales forecasts for each jurisdictional revenue class are outlined below.

b) Forecast Methodology

(i) Sales

(A) Residential electric usage per customer is estimated by using a linear multiple regression model that contains the real residential price of electricity, income, Cooling and Heating Degree Days as explanatory variables, and dummy variables for hurricanes and historical periods.

(B) Commercial sales are forecast using a linear multiple regression model which contains the following explanatory variables: Gross Domestic Product, commercial real price of electricity, Cooling Degree Days, and dummy variables for hurricanes and historical periods.

(C) Industrial sales are forecast through a linear multiple regression model using Gross Domestic Product, Cooling Degree Days, and several dummy variables for outliers, hurricanes, and months.

(D) Resale (Wholesale) customers are composed of municipalities and/or electric cooperatives. Currently, there are four customers in this class: the Florida Keys Electric Cooperative; the City Electric System of the Utility Board of the City of Key West, Florida; Metro-Dade County Solid Waste Management; and the Florida Municipal Power Authority.

Sales forecasts for these and other classes are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, an expansion factor is applied to generate a forecast of annual NEL.

(ii) Net Energy for Load

A monthly model econometric model is also developed to produce a NEL forecast.[4] The key inputs to the model are: the real price of electricity, Heating and Cooling Degree Days, and Real Florida Personal Income. Once the NEL forecast is obtained using this methodology, the results are compared for reasonability to the separate NEL forecast generated using the revenue class sales forecasts. The revenue class sales forecasts are then adjusted to match the NEL from the monthly econometric NEL model.

(iii) System Peak Forecasts

In recent years, the absolute growth in FPL system load has been associated with a larger customer base, weather conditions, continued economic growth, changing patterns of customer behavior (including an increase in electricity-consuming appliances), and more efficient heating and cooling appliances. The Peak Forecast models were developed to capture these behavioral relationships.

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[4] This calculation is independent from that used to determine NEL by applying an expansion factor to the revenue class sales forecasts described above.

(A) Summer peak demand is developed using an econometric regression model developed on a per-customer basis. The key variables included in the Summer peak model are total average customers, the real price of electricity, Florida Real Personal Income, average temperature on peak day, and a heat buildup factor consisting of the sum of the Cooling Degree hours during the peak day and three prior days.

(B) Winter peak demand is forecast using the same methodology and taking into account weather-related variables. The Winter peak model is a per customer model that contains the following explanatory variables: the square of the minimum temperature on the peak day and Heating Degree hours from the prior day until 9:00 a.m. of the peak day. The model also includes an economic variable: Florida Real Personal Income.

c) Load Forecast Results

The historical and projected compound average annual growth rates in customers, energy, and demand are summarized in Table V.A.1.c.1 below.

Table V.A.1.c.1
FPL's 2006 Load Forecast Results
Compound Average Annual Growth

Years	Total Customers	Net Energy For Load	Summer Peak	Winter Peak
1997-2006	2.2%	3.1%	3.1%	2.0%
2007-2016	1.8%	3.1%	2.3%	2.0%
2017-2040	1.1%	2.2%	2.1%	2.1%

The actual forecasts of peak demands and NEL used in the IRP analyses are presented in Appendix D. These forecasts address the 2006 through 2040 time period. For purposes of the analyses, FPL assumed that the load was constant from 2041 through 2054.

2. The Fuel Price Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future generating capacity needs. FPL's forecasts are generally consistent with other published contemporary forecasts.

a) Fuel Price Forecast Methodology

Future oil and natural gas prices, and to a lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, coal, and petroleum coke. These drivers include: (1) current and projected worldwide demand for crude oil and petroleum products; (2) current and projected worldwide refinery capacity/production; (3) expected worldwide economic growth, in particular in China and the other Pacific Rim countries; (4) Organization of Petroleum Exporting Countries (OPEC) production and the availability of spare OPEC production capacity and the assumed growth in spare OPEC production capacity; (5) non-OPEC production and expected growth in non-OPEC production; (6) the geopolitics of the Middle East, West Africa, the Former Soviet Union, Venezuela, etc., as well as, the uncertainty and impact upon worldwide energy consumption related to U. S. and worldwide environmental legislation, politics, etc.; (7) current and projected North American natural gas demand; (8) current and projected U. S., Canadian, and Mexican natural gas production; (9) the worldwide supply and demand for Liquefied Natural Gas (LNG); and (10) the growth in solid fuel generation on a U. S. and worldwide basis.

The inherent uncertainty and unpredictability in these factors today, tomorrow, and during the life of FGPP 1 and 2, clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal and petroleum coke) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed Low, Medium, and High price forecasts for oil, natural gas, and solid fuel, and a Shocked Medium (Shocked) price forecast for oil and natural gas which were used in the analyses of the two resource plans.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology: (1) for 2006 through 2008, the methodology used the October 3, 2006 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil, and Henry Hub natural gas commodity prices; (2) for the next two years (2009 and 2010), FPL used a 50/50 blend of the October 3, 2006 forward curve and monthly projections from The PIRA Energy Group; (3) for the 2011 through 2020 period, FPL used the annual projections from The PIRA Energy Group, and (4) for the period beyond 2020, recognizing that prices cannot increase indefinitely and that significantly high prices have created, and will continue to create, technological and economic opportunities for commodity substitution in the energy markets, FPL applied the annual rate of increase in the delivered price of solid fuel to the commodity cost of oil and natural gas. In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts. These delivered price forecasts were used in the analyses of the resource plans.

FPL's Medium price forecast methodology is also consistent for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach: (1) the price forecasts for Central Appalachian coal (CAPP), South American coal, and petroleum coke were provided by JD Energy; (2) the marine transportation rates from the loading port for coal and petroleum coke to an import terminal were also provided by JD Energy; (3) the Terminal Throughput Fee was based on a range of offers from comparable facilities throughout the Southeast U.S.; (4) the rail transportation rates from CAPP and from the import terminal facility to FGPP were based on the proposed rail transportation rates as of October 3, 2006. In order to achieve the maximum fuel supply diversity and delivery flexibility for FPL's customers, FPL assumed that the delivered price of solid fuel to FGPP would be a mix of 40% Central Appalachian coal, 40% South American coal, and 20% petroleum coke.

The development of FPL's Low and High price forecasts for oil, natural gas, coal, and petroleum coke prices were based upon the historical relationship of prices realized by FPL's customers compared to the average for the 2000 through 2005 time frame. For example, the 2000 through 2005 average natural gas price delivered to FPL's system was $6.45/MMBtu. The high price range was $9.34/MMBtu or 145% of the average and the low price range was $4.20/MMBtu or 65% of the average. These factors were multiplied by the monthly Medium price forecast to determine the Low and High price for each commodity for the duration of the forecast period. This same process was applied to oil, coal, and petroleum coke. FPL developed these forecasts to account for the uncertainty which exists within each commodity as well as across commodities. These forecasts align with FPL's actual price variability realized by FPL's customers during the 2000 to 2005 period, thus ensuring that the analyses of the two resource plans will reflect all reasonable forecast outcomes.

The development of the Shocked Medium (Shocked) price forecast was based on the same methodology as the Low and High price forecasts described above. The equivalent oil and natural gas price was $45.12 per barrel and $11.86/MMBtu for the 2000 to 2005 period. The shock was applied only to the oil and natural gas prices through 2016. In 2017, FPL averaged the Medium price forecast with the Shocked price forecast. From 2018 forward, all commodity prices are the same as in the Medium price forecast. FPL developed the Shocked price forecast as a sensitivity to show the impact of what a significant price increase in oil and natural gas could have on the value of the adding FGPP to FPL's portfolio of assets.

FPL's long-term oil, natural gas, coal, and petroleum coke price forecasts are reasonable and necessary for the analyses of the two resource plans. FPL's set of fuel price forecasts bound the projected range of future forecast outcomes based on the actual range of prices realized by FPL's customers during the 2000 through 2005 period. During this period of time, all commodities showed significant variability, including periods of low and high prices, and periods of low and high price differentials between commodities, on both a domestic and worldwide basis.

b) Fuel Price Forecast Results

Details of the four fuel price forecasts (High, Shocked Medium, Medium, and Low) for all fuels, as well as, the differential between natural gas and solid fuel, are presented in Appendix E.

c) Fuel Supply, Availability, and Delivery

(i) Natural gas

It was assumed that, for all gas-fired combined cycle (CC) units contained in the two resource plans used in the analyses, natural gas was the primary fuel source and light oil was the backup fuel. (Please refer to section VI.C for details regarding these two resource plans.) Natural gas was assumed to be supplied by an expansion of the Gulfstream Natural Gas Pipeline System to the vicinity of West County Energy Center for a 1,219 MW combined cycle (200,000 MMBTU/day) and to the FGPP site for a new 1,119 MW combined cycle plant (175,000 MMBTU/day), and that Florida Gas Transmission pipeline system was also expanded and extended to the FGPP site for a second 1,119 MW combined cycle plant (175,000 MMBTU/day).

Currently, there are significant quantities of proven natural gas reserves in the United States to ensure a continuing long-term supply of natural gas from U.S. production. In addition to the supply of proven reserves, FPL's, and energy industry consultants', long-term natural gas supply and demand balances show additional quantities of Canadian and Liquefied Natural Gas (LNG) imports that will add to the projected domestic natural gas production to meet the projected growth in natural gas demand of the United States. According to recent data from the Department of Energy's Energy Information Administration, there is adequate supply and projected natural gas reserves available in the United States to meet the natural gas demand for at least the next 25 years.

(ii) Oil

The two resource plans assumed that all CC additions will be capable of burning light oil as a backup fuel in the event of a natural gas supply disruption. Light oil would be trucked from local markets to the plant sites where it would be stored.

(iii) Coal (Domestic and International)

The fuel supply plan for the FGPP advanced technology coal units assumes that low-sulfur bituminous coal from domestic and international sources will be the principal fuel. These coal sources are expected to be the least-cost on a delivered basis because of the proximity of these coals to Florida, resulting in lower freight costs. The principal domestic coal source is expected to be from the Central Appalachia coal supply region in East Kentucky, Virginia, Tennessee, and Southern West Virginia. This is the largest coal-producing region in the East, with 2005 production exceeding 230 million tons. A diverse group of producing companies report 38 years of coal reserves at current production rates. Demand for this coal is expected to decline, as utilities in the Midwest switch to local high sulfur coals, which will extend the supply availability of low sulfur coal for plants in Florida and the Southeast. Central Appalachia coal will be delivered to FGPP by two railroads that serve the coal fields. The CSX railroad will interchange at Sebring, Florida with the South Central Florida Express (SCFE) for the final delivery to the plant. The Norfolk Southern railroad will interchange at Jacksonville, Florida with the Florida East Coast (FEC) railway, which will interchange at Fort Pierce or Lake Harbor, Florida with the SCFE for final delivery to the plant.

International coal supplies will be delivered by ocean vessel to a port facility in the Southeastern U.S. The coal will be loaded into railcars at the terminal and released for final delivery to the plant. The most likely sources of imported coal will from Colombia and/or Venezuela which have large and growing coal supplies. These are the most likely sources because their proximity to Florida minimizes the cost of ocean freight. Coal from a number of other countries will also be potential sources of supply including Russia, South Africa, Indonesia, and Australia.

(iv) Petroleum Coke

Petroleum coke is expected to be a low-cost source of fuel which can be blended in quantities up to 20% of FGPP's fuel supply. This fuel is a by-product of the refining of crude oil. The largest source of world supply is from oil refineries located on the Gulf Coast (Texas, Louisiana, and Mississippi) and in the Caribbean. With increasing demand for transportation fuels, petroleum coke production is expected to continue to grow, as refineries add coking capacity to upgrade heavy oil into light products. Petroleum coke will be delivered by vessel to a port in the Southeastern U.S. and loaded into railcars at the terminal for final delivery to the plant.

(v) Solid Fuel Receiving Terminal

FPL's solid fuel price forecasts have assumed access to a solid fuel receiving terminal with direct access to rail. The terminal Throughput Fee that was included in the delivered cost of solid fuel to FGPP site in all four fuel cost forecasts assumed that the terminal could receive up to Panamax-sized vessels and maintain adequate throughput capacity to handle 100% of FGPP's proposed mix of fuels. In addition, the site would be able to store up to 30 days supply of coal and petroleum coke in order to allow for uninterrupted service to be provided at the terminal for loading of unit trains.

(vi) Fuel Reliability via On-site Storage

FGPP will be able to store up to 60 days of solid fuel at the plant site and the capital cost, operation and maintenance expenses, and working capital were assumed in the economic evaluation of FGPP. This equates to approximately 1,000,000 tons of coal and petroleum coke available for consumption if FPL were to experience a curtailment in the solid fuel supply chain. In comparison, a natural gas-fired combined cycle plant is assumed to not have access to on-site natural gas storage, mainly due to the lack of economically viable sites for natural gas storage in Florida. The cost to build, operate and maintain, including working capital, for an on-site LNG storage facility in order to achieve the same reliability benefits of a Solid Fuel Plant would be approximately $1.4 billion dollars cumulative present value of revenue requirements (CPVRR) to FPL's customers. Another on-site reliability alternative could be to build light oil storage at the plant site. In this alternative, the cost to build, operate and maintain, including working capital, a 3.7 million barrel tank farm in order to achieve the same reliability benefits of a solid fuel plant would be approximately $0.4 billion dollars CPVRR of costs for FPL's customers. Additionally, when the light oil is consumed, there would be an incremental commodity cost of approximately $6.00 per MMBtu for light oil compared with natural gas. Assuming one turn per year on the inventory, the incremental light oil commodity cost versus natural gas plus the total capital, operating and maintenance, and working capital for the light oil storage would result in a total cost of approximately $1.5 billion CPVRR for FPL's customers. The major challenge for this alternative would be to gain air permitting approval from the DOE to burn light oil on an as needed basis and not have the 500 hours per year restriction which applies to our light oil back up facilities today.

3. Environmental Regulations

FGPP is required to obtain federal, state, and regional environmental approvals and permits. The principal environmental approval is Site Certification under Florida's Power Plant Siting Act (PPSA) codified in 403.500 Florida Statutes. This is a comprehensive review of all environmental aspects of the FGPP coordinated through the Florida Department of Environmental Protection (FDEP) and involving all state and regional agencies with environmental responsibility and those potentially affected by the FGPP. This includes, but is not limited to, the FDEP, Florida Department of Community Affairs, Florida Department of Transportation, Florida Fish and Wildlife Conservation Commission, and the South Florida Water Management District. This comprehensive environmental review evaluates the FGPP's environmental controls and determines compliance with applicable environmental standards. This ultimately leads to a comprehensive analysis by agencies and Conditions of Certification that set forth environmental requirements. The FGPP will also require federal and federally delegated permits. This includes an approval by the U.S. Army Corp of Engineers (ACOE) for impacts to wetlands, a Prevention of Significant Deterioration (PSD)/Air Construction Permit by the FDEP, and an Underground Injection Control (UIC) Permit from FDEP.

The ACOE permit is required under Section 404 of the Clean Water Act and includes a demonstration that impacts to wetlands have been minimized and compensatory wetland mitigation has been provided as needed. FGPP has been designed to minimize impacts to wetlands and a portion of the FGPP site was dedicated to wetland mitigation.

Under the federally authorized FDEP PSD program, FGPP will be required to install Best Available Control Technology (BACT) and demonstrate that project will comply with all air quality standards including those applicable to the PSD Class I Areas, which includes the Everglades National Park. FDEP PSD rules are codified in Rule 62-212 F.A.C. An important aspect of PSD review is the determination of BACT. BACT is a technology standard under FDEP's PSD program that establishes an emission rate for all regulated pollutants requiring review. BACT cannot be any less stringent than any established emission standard for new facilities and is generally the lowest emission rate that is technically feasible for the specific type of facility. The FDEP ultimately establishes BACT based on the information in the PSD/Air Construction Permit Application and an evaluation of all recent similar projects in the U.S. For a coal-fired power generation facility, the air emissions controls are typically the most significant from a cost and environmental perspective.

FGPP will be required to obtain approval under FDEP's federally delegated UIC Program codified in Rule 62-528 F.A.C. This process will consist of obtaining approval to perform an exploratory UIC well at the FGPP site and converting this to a test injection well after site-specific information is developed.

Other approvals and notifications include a Notice of Proposed Construction or Alteration for FGPP stack and structures over 200 feet to the Federal Aviation Authority and Notice of Intent to Use Generic Permit for Stormwater Discharge from Large and Small Construction Activities as required by Rule 62-621.300(4) F.A.C.

4. Projected Costs of Coal Units

a) Uncertainty Regarding Costs Directly Related to the Advanced Technology Coal Addition

(i) Capital Costs and Cost Indexing Approach

There are two components of the total estimated capital costs for the power plant that should be based on indices: escalation for labor costs in the EPC agreement and the escalation for high alloy steels and metal costs in the pollution control equipment (e.g., Fabric Filter, Wet Flue Gas Desulphurization, and the Wet Electric Static Precipitator). The portion of the total estimated cost representing the projected escalation for labor costs, including AFUDC, in the EPC scope is nominally $594 million, or about 10% of the total capital cost of FGPP. The portion of the total cost estimate representing the alloy material component of the pollution control equipment is nominally $151 million, including AFUDC, or about 3% of the total capital cost of FGPP.

These two cost components are subject to particular market price risks that suppliers simply are not willing to assume. Essentially, these indices address market risks over which neither the supplier nor FPL will have control. Thus, in each case, it is necessary to apply indices for these particular cost components. For the EPC pricing, the labor component will be indexed to a rate derived from the United States Department of Labor Bureau of Labor Statistics (BLS) County Employment and Wages Bulletin. For the pollution control equipment contracts, high alloy steels and metal costs will be indexed to published market indices for high alloy steels and metals used in producing the equipment.

Over the last two years the industry has experienced sharp increases in labor and material costs that have adversely impacted the suppliers and contractors. In general, the costs of bulk material such as metals have also increased substantially. Changes in the backlog of shop orders have also risen significantly as a result of the number of announced orders for coal projects in the United States and abroad. This competition for suppliers has placed a premium on the acquisition of major equipment for FGPP.

In some cases, like the pollution control equipment, the market is so saturated with buyers and orders that firm pricing is not even attainable. This market saturation is due not only to the current backlog of proposed new coal projects, but also to the numerous coal plant retrofit projects underway. Such retrofit projects are in response to new environmental compliance programs such as the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Best Available Retrofit Technology (BART).

The current project cost for the power plant includes the projected escalations based on the current projections for the future value of each index. In the event that the actual value of the index is higher than projected, the contract cost would increase. Any increases in the contract cost due to such a higher than projected value for the index would result in an increase in the total project cost. FPL proposes that the total approved cost of the project approved by the Commission be based on the indexing mechanism provided below for the labor component in the EPC costs and a similar approach utilizing a yet to be-determined material-based index for pollution control equipment.

FPL GLADES POWER PARK UNITS 1 AND 2
EPC INDEXING

Overview:

The EPC contractor has agreed to utilize wage data published by the United States government to true up labor costs on an annual basis. The source of the wage data to be used in determining the annual labor adjustment is the United States Department of Labor Bureau of Labor Statistics County Employment and Wages Bulletin (BLS Data) which is published on a quarterly basis and available on the department's web site with the following address: (http://www.bls.gov/news.release/pdf/cewqtr.pdf).

The process for determining the annual labor adjustment is to:

1.Determine the year-to-year difference between the annual wage growth rate as determined from the BLS Data and the annual wage growth rate that the EPC contractor used as a basis for the bid price (4%). The BLS Data derived annual growth rate will be a weighted annual average of the regions of the United States that the workforce will be drawn from (examples: Florida, Georgia, Texas, Mississippi, Louisiana).

2.Multiply the expected labor cost from the EPC contractor bid in a given year by the difference in wage growth rates for that year.

3.Add or deduct the resulting amount from future payments to the EPC contractor.

4.Repeat the above steps for each year of the project.

Example:

The values in Table V.A.4.a.(i).1 are indicative and intended only to demonstrate the process for calculating the annual labor cost adjustment as described above.

Table V.A.4.a.(i).1 Example of Capital Cost Indexing Approach

Year	Expected Annual Labor Cost from EPC Proposal (includes AFUDC)	BLS Weighted Annual Average	Growth Rate Difference	Annual Adjustment
2009	$13,000,000	4.075%	0.075%	$9,750
2010	$46,000,000	3.922%	-0.078%	($35,880)
2011	$168,000,000	5.882%	1.882%	$3,161,760
2012	$208,000,000	4.113%	0.113%	$235,040
2013	$140,000,000	3.878%	-0.122%	($170,800)
2014	$19,000,000	4.034%	0.034%	$6,403
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Totals =	$594,000,000			$3,206,273

(ii) Delivered Price Spread between Natural Gas and Solid Fuel

The projected price spread between natural gas delivered to the FPL system and solid fuel delivered to the FGPP site is a major driver in the economic analyses of the two resource plans. Consistent with FPL's fuel price forecast methodology, a range of projected price spreads were developed using the four fuel cost forecasts to provide a reasonable range of future fuel cost differentials by which FPL could compare the two resource plans.

(iii) Environmental Compliance Costs

Additional costs associated with future environmental regulations applicable to FGPP will likely occur. The U.S. Environmental Protection Agency (EPA) recently promulgated two major environmental regulations that will be applicable to FGPP. These regulations are EPA's Clean Air Interstate Rule (CAIR) promulgated as 40 Code of Federal Regulations (CFR) Part 96 and the Clean Air Mercury Rule (CAMR) promulgated as 40 CFR Part 60, Subpart HHHH. CAIR establishes state limits on annual and seasonal emissions on NO_X and annual emissions of SO_2. The limits apply to 25 states, primarily in the eastern U.S., and the District of Columbia (D.C.). The limits were established in two timeframes: for NO_X - 2009 through 2014 and 2015 and beyond, and for SO_2 – 2010 through 2014 and 2015 and beyond. EPA's rule includes a cap-and-trade system that allows affected facilities to meet the requirements through either the addition of control technologies or by obtaining allowances through a market-based system. The cap-and-trade system in EPA's CAIR regulations is similar to the successful Acid Rain Program referred to as Title IV that was initially developed through the 1990 amendments of the Clean Air Act. In implementing CAIR, EPA allowed states to utilize model rules or develop specific regulations to meet the requirements of CAIR. The FDEP has adopted the EPA model rule as Rule 62-296.470 F.A.C. that would allow the use of the national cap-and-trade system.

EPA's CAMR regulations have two components. First, EPA issued New Source Performance Standards for the mercury emissions from new sources like FGPP. The FGPP advanced technology coal units will have a mercury emission rate that is about one-half of the new EPA standards. Second, EPA's CAMR established mercury emission limits on states, and similar to CAIR, allows for a cap-and-trade program to meet requirements. The state mercury emission limits start in 2010 and are reduced in 2018. FDEP has established a hybrid rule that is more stringent than the EPA rule in the 2010 through 2017 time frame, and than the EPA model rule in 2018. FDEP's rule was promulgated as Rule 62-296.480 F.A.C. Florida allows the use of the cap-and-trade program.

FDEP is submitting these rules as part of Florida's State Implementation Plan (SIP) for EPA approval. With some minor exceptions, the FDEP's rules for CAIR and CAMR were adopted by reference. EPA has not yet approved the FDEP rules as part of the SIP.

FPL will be required to hold allowances for the actual emissions from FGPP of NO_X, SO_2, and mercury (Hg). These allowances would have a potential economic impact because allowances must be obtained through a state pool or the cap-and-trade system.

Potential costs for allowances were based on projections developed through a comprehensive analysis of multiple factors involving air pollution control costs, fuel utilization, and market factors. These projections, while necessarily having a range of uncertainty, are based on air pollution control costs and experience from the Acid Rain Program (Title IV). The control technologies for NO_X and SO_2 are well established and their cost can be estimated with reasonable accuracy. The Acid Rain Program has been operating for a decade and, while there have been fluctuations in allowance costs, past projections have been within the expected range. The cost estimates for mercury were developed in a similar manner and also considered the fact that some states will implement CAMR outside the model cap-and-trade system.

Although there are no current laws regulating emissions of carbon dioxide (CO_2), the potential future regulation of CO_2 was considered using projections developed from federal legislative initiatives and the basic framework of the cap-and-trade system. Over the last several years there have been several federal legislative initiatives that have proposed different forms of CO_2 regulation based on the cap-and-trade system. These initiatives have included both multi-sector and electric sector regulation with variable reductions of CO_2 emissions. These federal legislative initiatives formed the bounds for the potential costs that may occur in the future.

Appendix F presents the environmental compliance (i.e., allowance) costs in nominal dollars used in the analyses for FGPP. The allowance costs were based on information from ICF International in a report titled U.S. Emission and Fuel Markets Outlook, 2006 edition. The ICF report provides allowance cost forecasts that are based on integrated modeling of the electric, fuel, and environmental markets in the U.S. Four allowance cost forecasts were used in the economic analysis of FGPP. These cost forecasts are labeled as A through D and can be summarized as follows: Forecast A consists of allowance costs for SO_2, NO_X, and Hg and is referred to in the ICF report as 3P (P in this case means "Pollutant"); Forecast B consists of allowance costs for SO_2, NO_X, and Hg, plus low CO_2 allowance costs, and is referred to in the ICF report as 4P-mild; Forecast C consists of allowance costs for SO_2, NO_X, and Hg, plus moderate CO_2 allowance costs, and is referred to in the ICF report as 4P-medium; and Forecast D consists of allowance costs for SO_2, NO_X, and Hg, plus high CO_2 allowance costs, and is referred to in the ICF report as 4P-Stringent. The range of low, medium, and high costs of CO_2 allowances that were used are consistent with current legislative proposals being considered by Congress and reflect the appropriate range of potential future allowance costs for CO_2. The allocations of SO_2, NO_X, and Hg allowances were based on the CAIR and CAMR rules developed by FDEP. For CO_2 it was assumed that 100% of the required allowances would be purchased under a cap-and-trade system similar to an auction.

b) Uncertainty in Relative Costs of the Advanced Technology Coal Addition

There are at least four areas of uncertainty that can affect the relative cost of an advanced technology coal addition compared to a non-coal alternative such as combined cycle technology.

The first area of uncertainty is the future price differential between natural gas and coal. The capital and operation and maintenance (O&M) costs of FGPP will be greater than those of a similarly sized gas-fueled generating plant. A sufficiently large price differential between natural gas and coal would help offset the capital and O&M cost differential. However, it is not possible to know today, or even tomorrow, what the fuel price differential will be during the 40-year life of FGPP. If the future actual fuel price differential is not sufficiently large, then, in retrospect, it could be determined that having added FGPP resulted in higher costs than would have been incurred by adding gas-fueled generation. This possible outcome is shown in the economic analysis results presented in Section VI of this document.

The second area of uncertainty is the ability to transport and deliver coal at reasonable costs from diverse coal sources. The cost of adding FGPP will depend, in part, on FPL's future access to diverse and competing sources of coal and petroleum coke, as well as competitively priced transportation and delivery of the fuels from those sources to the plant. This will require that FPL have access to fuel port facilities for receipt of fuel transported by water from foreign and domestic sources, as well as competitively priced rail transportation and delivery from the ports, as well as from domestic fuel sources, to the plant. FPL is evaluating a number of potential commercial arrangements to ensure that FPL will have the necessary access to port facilities. FPL is also involved in negotiations to obtain the necessary rail transportation services. However, until FPL finalizes contractual agreements to ensure access to port facilities and rail transportation services, there will be some uncertainty regarding the cost of delivering coal and petroleum coke to FGPP, which in turn could affect the comparative economics between adding FGPP and, in the alternate, adding gas-fueled generation.

The third area of uncertainty is in regard to the costs of compliance with future environmental requirements or with conditions imposed as part of the Site Certification. The results of FPL's economic analysis of FGPP indicate that the cost of complying with all currently known environmental requirements that would be applicable by 2013 and in later years would not, in itself, make the addition of FGPP more costly than adding gas-fueled generation. However, there is significant uncertainty regarding what additional requirements may be imposed by future legislation or regulation, especially regarding emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon dioxide (CO_2), and mercury (Hg). Complying with future additional requirements regarding these emissions could involve installing and operating additional control equipment, or purchasing emission allowances, or paying a tax, or paying more for fuel, or a combination of some or all of these measures. Neither the requirements nor the resulting compliance costs, all of which would be borne by FPL's customers, may be known until after construction of FGPP has begun, or even until after FGPP has been placed in commercial operation. Furthermore, the cost of compliance with such unknown future requirements could be very large. Consequently, the absolute economic outcome of adding FGPP will simply not be knowable until well after the units have been in operation. The results of FPL's economic analyses presented in Section VI illustrate this point, showing that in some environmental compliance cost forecast scenarios the cost of adding FGPP could be significantly greater than that of adding gas-fueled generation.

Similarly, the adoption by the Siting Board of unanticipated conditions as part of the Site Certification could impose additional capital or O&M costs on FGPP. Such conditions and associated costs were not specifically modeled because it is not possible to know at this point what conditions may be adopted.

The fourth area of uncertainty is that of the actual capital cost of FGPP. There is a much longer lead time required – at least five and a half years from the date of this Need filing - for development, permitting, and construction of the first FGPP unit, compared to just over three years for gas-fueled units, and a correspondingly greater opportunity for changes in the cost of equipment, labor, and materials to occur. It is because of the greater uncertainty regarding the capital costs of various aspects of the addition of FGPP that FPL proposes that the Commission apply an indexed cost mechanism as the basis for establishing in the Determination of Need the capital cost that FPL will be authorized to recover for FGPP without having to demonstrate "extraordinary circumstances." In addition, if there is any delay in the process of obtaining a final Site Certification for FGPP, the capital cost could rise due to escalation.

These factors, which would be outside the control of FPL, could cause the capital cost of FGPP to be higher than projected and cause the addition of FGPP to be more costly than adding gas-fueled generation.

c) Cost of Hedge

Fuel diversity helps mitigate the effects of price volatility in one or two fuels. For example, if a utility relies solely on natural gas to produce all the electricity needed by its customers, any increase or decrease in the market price of natural gas would translate into a direct and comparable increase or decrease in the cost of electricity. Because natural gas prices are projected to be volatile in the future, the customers would be subject to significant volatility in the future cost of electricity. Recent history has demonstrated how volatile natural gas prices can be. Because the prices of coal and nuclear fuel are relatively stable, and because changes in these fuels are not directly linked to changes in the prices of natural gas and fuel oil, having a fuel diverse portfolio that includes significant contributions from coal and nuclear helps dampen the effect of volatility in natural gas prices. For this reason, the addition of FGPP will help dampen the volatility in system fuel costs and make the cost of electricity more stable and predictable.

5. Financial and Economic Data

The financial and economic assumptions used in FPL's IRP process and in all analyses conducted that led to the selection of FGPP 1 and 2 are presented in Appendix G.

B. Geographic or Location Preference

FPL performed an independent analysis of the local permitting requirements in the most likely candidate counties for development, conducted meetings with local leadership committees, and performed other information-gathering activities designed to ascertain the level of receptivity of those counties to the economic benefits associated with the construction and operation of an advanced technology coal-fired electric power plant.

The effort also included a comprehensive study of potential sites, based on the following six criteria:

(1) Rail access that would foster coal transportation competition at origin and destination for the delivery of domestic and foreign coal and petroleum coke;

(2) Adequate property to site a large coal-fired power plant, and required support facilities;

(3) Adequate water supplies;

(4) Location of property considering transmission proximity to FPL's major load centers;

(5) Location of property allowing feasible transmission interconnections and integration; and,

(6) Site selection considering the goal of minimizing the environmental impediments to permitting (e.g., wetlands, threatened and endangered species, contamination, etc.).

Applying the six criteria discussed above, FPL chose its proposed site in Glades County. To date, FPL has obtained resolutions of support from five different groups including government agencies and economic development. Groups that have passed resolutions include: the Moore Haven City Council, the Glades County Commission, the Glades County Economic Development Council, the School Board of Glades County and Florida's Heartland Rural Economic Development Initiative.

VI. MAJOR AVAILABLE GENERATING ALTERNATIVES EVALUATED

A. Coal/Solid Fuel Technologies Considered: FPL's Initial and Confirming Analyses

FPL's 2006 resource planning work continued earlier analyses of various generation options that could maintain fuel diversity on FPL's system. Since it is not possible to license and construct new nuclear units in time to address FPL's capacity needs that start in 2012, this ongoing analysis of generation options primarily focused on technologies that would primarily be fueled by coal and would have the capability of also utilizing petroleum coke.

In the Summer of 2003, FPL initiated a feasibility study of new coal-based generation as an addition to FPL's electric generation portfolio as discussed in the previous section.

Then, during early 2004, FPL began analyses that resulted in FPL's Report on Clean Coal Generation, which was provided to the Florida Public Service Commission (FPSC) in March 2005. As part of the report, FPL conducted an extensive evaluation of the available technologies for the clean generation of electricity from coal and petroleum coke that could be brought into service on FPL's system in the relative near-term. The four technologies considered were: sub-critical pulverized coal (PC), circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), and ultra-supercritical pulverized coal (advanced technology coal).

The result of this technology assessment was a conclusion that pursuing a state-of-the-art advanced technology coal plant, with a complete suite of emission control equipment, and plant design to allow the recycling of the major byproducts of the combustion and emissions control processes to be recycled into useful commercial products, would provide FPL's customers with the best mix of capital and operating costs, high efficiency, high demonstrated reliability and environmentally responsible conversion of coal to electricity from among the available coal generation alternatives.

FPL has continued to closely monitor continuing developments across the country and around the world with respect to solid fuel technology. For example, as part of its efforts to test and verify that its initial analysis of alternative solid fuel technologies was correct and reasonable prior to filing for a Determination of Need for FGPP 1 and 2, FPL undertook two separate analyses to check or confirm that its selection of the advanced technology coal units was the best choice. In one of these "confirming" analyses, FPL and Black & Veatch (BV) jointly prepared a detailed Clean Coal Technology Selection Study during 2006. The purpose of the study was to incorporate the most up-to-date information available in the industry concerning each technology into FPL's technology assessment in light of FPL's desired solid fuel capacity additions. Accordingly, the analysis of each technology involves consideration of the advantages and disadvantages with respect to each technology for the addition of a nominal 2,000 MW of coal-based capacity. Using cost and performance data developed by BV, this study compared the same four coal-based technologies that were originally evaluated: PC, CFB, IGCC, and advanced technology coal from both a quantitative and a qualitative perspective. A copy of this study report is found in Appendix M.

The conclusions of this study reaffirm FPL's prior conclusion that ultra-supercritical pulverized coal is the best available generating technology choice to meet FPL's solid fuel generation objectives – namely, to satisfy the needs of customers for reliable power at a reasonable price while maintaining fuel diversity on FPL's system, thus decreasing FPL's reliance upon natural gas as a fuel.

A second confirming analysis was conducted solely by FPL. This economic analysis utilized cost and performance data developed by FPL for the same four coal-based technologies. This analysis used a screening curve (or busbar analysis) approach to evaluate these technologies from a quantitative perspective.

The results of the screening curve analyses are presented in Appendix N. These results show that the economics of the advanced technology coal option are superior to the other three coal-based technologies over the entire range of capacity factors, clearly indicating that the advanced technology coal option is the superior economic choice.

B. Non-Coal Technologies Analyzed

1. General Process

The qualitative and quantitative analyses discussed above explain the approaches used by FPL to determine what the best coal-based generation option was that could be brought in-service as soon as possible in the 2012 - 2015 time period. However, in order to fully evaluate the decision to add coal-based generation to FPL's system, it was necessary to also analyze non-coal options that FPL would likely choose to build if FGPP 1 and 2 were not built.

The process FPL used to perform this analysis involved the selection of gas-fired combined cycle (CC) units that are representative of what FPL might build if FGPP 1 and 2 were not built, the selection of sites that are representative of where FPL might build such units, and then combining these units and sites into a representative alternate resource plan that could be compared to a coal-based resource plan featuring FGPP 1 and 2. The coal-based resource plan was designated as the Fuel Diversity Resource Plan with Coal (Plan with Coal) and the alternate non-coal-based resource plan was designated as the Resource Plan without Coal (Plan without Coal).

2. Gas-Fired Technologies Selected

In the process of selecting gas-fired CC units for this analysis, FPL decided that the most representative type of CC unit for the near-term would be a unit similar to those recently approved for construction at the West County Energy Center (WCEC) site. These CC units are 3x1 G machines with a Summer capacity rating of 1,219 MW or 1,119 MW if duct firing is not selected. These 3x1 G machines were used as the basis for the near-term CC capacity options that were used in the two resource plans for the years 2012 through 2016, either immediately after the FGPP units in the Plan with Coal or in place of the FGPP units in the Plan without Coal. For 2017, and for 2020 – on, smaller 2x1 F CC machines with a Summer capacity rating of 553 MW were used as unsited filler units in the two resource plans. Both resource plans also included two nuclear unit additions, one in 2018 and one in 2019.

C. Analysis Approach

1. Economic Analysis

a) Development of Resource Plans to be Analyzed

In developing the two resource plans for use in the analyses, FPL had several criteria. First, each resource plan chosen must meet FPL's system reliability criteria for all years, especially the reliability criterion that currently drives FPL's resource needs, the 20% Summer reserve margin criterion. This ensures that the resource plans will be both meaningful and comparable in regard to system reliability. Second, the cost and performance assumptions (heat rate, availability, etc.) for the generating units that are included in each resource plan should be current assumptions of comparable vintage and confidence levels. Third, the resource plans should focus as much as possible on the decision years in question, 2012 and 2013 and the immediately surrounding years, and should seek to minimize as much as possible influencing the cost and other system impact differences between resource plans that could be caused by the addition of units and/or purchases in other years.

These criteria are met by the two resource plans FPL developed. One resource plan, the Plan with Coal, includes the advanced technology coal units, FGPP 1 and 2, in 2013 and 2014, respectively. The other resource plan, the Plan without Coal, include no coal units. These two resource plans are presented in Table VI.C.1.a.1.

Table VI.C.1.a.1

The Two Resource Plans Utilized in the Analyses

Plan with Coal	2012	2013	2014	2015	2016	2017	2018	2019	2020 - 2040
- unit(s)/purchase(s) added	Short-term purchase	FGPP 1 & Short-term purchase	FGPP 2	South Florida CC	(none)	2 - 2x1 CC	Nuclear # 1	Nuclear # 2	35 - 2x1 CC
- site	Unknown	Glades & Unknown	Glades	West County vicinity	---	unsited	SE Florida	SE Florida	unsited
- annual MW added	800	980 & 200	980	1,219	0	1,106	1,090	1,090	19,355
- cumulative MW added	800	1,180	2,160	3,379	3,379	4,485	5,575	6,665	26,020
- cumulative sited MW	800	980	1,960	3,179	3,179	---	---	---	---
- Reserve Margin	20.1%	19.9%	21.3%	23.7%	19.6%	21.4%	23.1%	24.7%	(all meet criteria)

Plan without Coal	2012	2013	2014	2015	2016	2017	2018	2019	2020 - 2040
- unit(s)/purchase(s) added	South Florida CC	(none)	1 - 3x1 CC	(none)	1 - 3x1 CC	1 - 2x1 CC	Nuclear # 1	Nuclear # 2	35 - 2x1 CC
- site	West County vicinity	---	Glades	---	Glades	unsited	SE Florida	SE Florida	unsited
- annual MW added	1,219	0	1,119	0	1,119	553	1,090	1,090	19,355
- cumulative MW added	1,219	1,219	2,338	2,338	3,457	4,010	5,100	6,190	25,545
- cumulative sited MW	1,219	1,219	2,338	2,338	3,457	---	---	---	---
- Reserve Margin	21.9%	20.1%	23.0%	20.2%	20.7%	20.3%	22.0%	23.7%	(all meet criteria)

Notes: - assumes comparable replacement of UPS 930 MW purchase from Georgia for 5 years (2016 - 2020)
- assumes extension of DSM implementation beyond current forecast at 120 MW/year for 2016 - 2020
- assumes no peak load or annual energy growth after 2040

In developing the two resource plans presented in Table VI.C.a.1, several assumptions were made regarding the capacity additions for 2012 – 2016 time period. First, it was assumed for analysis purposes that all new unit additions in both resource plans would have a June 1 in-service date for the respective year in which the capacity addition is needed to meet the reserve margin requirement. For example, the first advanced technology coal unit would be added to FPL's system on June 1, 2013 with the second advanced technology coal unit added in June 1, 2014. Second, the FGPP site and a site at/near the West County Energy Center (referred to in the analyses as the South Florida site) would be the most likely sites for the next several FPL generating unit additions. Third, it was assumed that the FGPP site would be able to accommodate two large generating units, either coal-based or gas-fired, and that the South Florida site would be able to accommodate one large gas-fired generating unit. Fourth, it was assumed that the first gas-fired unit addition would be located at the South Florida site because it would be more economical. Fifth, in regard to the size of the likely gas-fired units (i.e., combined cycle (CC) units) included in the plans, FPL's recent analyses indicate that the most cost-effective size for CC units is in the 1,100 to 1,200 MW range. Therefore, it was assumed that the next several CC units added would be in the 1,100 to 1,200 MW range.

In regard to the 2012 – 2016 time period, the Plan with Coal thus includes the previously mentioned short-term purchases of 800 MW (in 2012) and 200 MW (in 2013), plus two advanced technology coal units of 980 MW each, FGPP 1 and 2, that come in-service in 2013 and 2014, respectively. A 1,219 MW CC unit is assumed to be added at the South Florida site in 2015 to meet the 2015 need. This CC unit addition also satisfies the 2016 capacity need.

The Plan without Coal first addresses the 2012 capacity need by adding a 1,219 MW CC unit at the South Florida site in 2012. Because the cumulative capacity need for 2012 and 2013 is 1,194 MW, as shown in Document No. SRS-1, this 1,219 MW unit also meets FPL's 2013 capacity need. FPL's remaining capacity needs from 2014 through 2016 are addressed in the Plan without Coal by a pair of 1,119 MW CC units sited at FGPP, one in 2014 and one in 2016.

b) **Development of Fuel Cost and Environmental Compliance Cost Forecasts to be Used in the Analyses**

When comparing generating technologies that burn different fuels, i.e., coal units versus natural gas units, it is appropriate that different fuel cost forecasts be utilized in order to determine the relative economics between the two technologies. In this way the analyses can address the uncertainty that exists regarding future fuel costs, particularly in regard to the future cost differential between natural gas and coal.

Although there are virtually an inexhaustible number of possible future fuel cost outcomes, a small number of forecasts that effectively reflect a reasonable range of future fuel costs are sufficient to conduct a meaningful economic analysis. Consequently, four different fuel cost forecasts that reflect a reasonable range of future fuel costs were developed and used in these analyses. These four fuel cost forecasts, referred to as Fuel Cost Forecast 1 through Fuel Cost Forecast 4, are provided in Appendix E and are discussed in Section V.2 of this document.

Just as there is uncertainty in regard to the future cost of fuels, there is uncertainty in regard to the future environmental regulations and the costs of complying with those regulations. When comparing generating technologies that burn different fuels and have different emission profiles, such as is the case with coal and natural gas units, the future environmental regulations will determine how the differences in the emission profiles of the generating technologies will affect the relative cost of the technologies. Therefore, FPL found it appropriate to conduct its analyses using different environmental compliance cost forecasts to address the uncertainty that exists regarding future environmental regulations and the costs of complying with those regulations.

As is the case with fuel cost forecasts, there are also a large number of environmental cost outcomes. However, a small number of forecasts that effectively reflect a reasonable range of future environmental compliance costs are sufficient to conduct a meaningful economic analysis. Therefore, four different environmental compliance cost forecasts that reflect a reasonable range of future environmental compliance costs were developed and used in these analyses. These four environmental compliance cost forecasts, referred to as Environmental Compliance Cost Forecast A through Environmental Compliance Cost Forecast D, are provided in Appendix F and are discussed in Section V.4.a.(iii) of this document.

FPL combined each of the four fuel cost forecasts with each of the four environmental compliance cost forecasts to develop 16 scenarios of forecasted fuel costs and environmental compliance costs. Each of these 16 scenarios was then utilized separately in both the economic and fuel diversity analyses of the two resource plans.

Because the fuel cost forecasts are designated as 1 through 4 and the environmental compliance cost forecasts are designated as A through D, the 16 scenarios of forecasted fuel costs and environmental compliance costs are designated as Scenario 1A, Scenario 1B, etc., through Scenario 4D.

2. Fuel Diversity Analysis

In addition to economic analyses of the two resource plans, fuel diversity analyses were also performed. These analyses focused on the projected FPL system annual fuel mix percentages regarding the percentage of total energy output that is provided by coal/petroleum coke, natural gas, oil, nuclear, and "other" (i.e., primarily purchases from waste-to-energy facilities) for each of the two resource plans for the 2012 – 2016 time period.

D. Results of the Analysis

1. Economic Analysis Results

The approach used in the economic analysis work was virtually identical to the approach used in FPL's most recent Need filings (i.e., the filings for the Turkey Point 5 and the West County 1 and 2 generating units) with one exception, the current utilization of multiple fuel cost and environmental compliance cost forecasts. Table VI.D.1.1 presents the economic evaluation results for the two resource plans for one fuel cost and environmental compliance cost scenario, Scenario 1A, using the same presentation format that FPL used in its most recent Determination of Need filings. The values presented are cumulative present value of revenue requirements (CPVRR) for the time period 2006 through 2054 in 2006.

In this document, the costs for the Generation System are broken out into two categories; Fixed Costs and Variable Costs, and a list of what costs are included in these two categories is shown. The Transmission System costs are broken out into three categories: Capital Costs, Capacity Losses, and Energy Losses. The Capital Costs shown are the actual costs for each resource plans and the Capacity Losses and Energy Losses costs are differential costs; i.e., the Plan with Coal's costs compared to the Plan without Coal's costs. As shown in the table, the Transmission System cost differentials between the two resource plans are relatively small compared to the differences in the Generation System costs. Therefore, transmission-related costs are not a deciding factor in the analyses.

Table VI.D.1.1

Economic Analysis Results for One Fuel and Environmental Compliance Cost Scenario: Generation System and Transmission System Costs
(millions, CPVRR, 2006$, 2006 - 2054)

Fuel Cost Forecast = 1
Environmental Compliance Cost Forecast = A

	(1)	(2)	(3) = (1) + (2)	(4)	(5)	(6)	(7)	(8) = (3) +(7)	(9)
	Generation System Costs			Transmission System Costs					Difference from Lowest Cost Plan
Resource Plan	Fixed Costs *	Variable Costs **	Total Costs	Capital Costs	Capacity Losses ***	Energy Losses ***	Total Costs	Total Costs	
Plan with Coal	19,185	140,185	159,370	586	(1)	(10)	575	159,945	0
Plan without Coal	16,061	146,117	162,178	559	0	0	559	162,737	2,792

* Generation system fixed costs include: capital, capacity payments, fixed O&M, capital replacement, gas pipeline lateral, and fuel inventory costs.

** Generation system variable costs include: variable O&M, plant fuel, FPL system fuel, and environmental compliance costs.

*** The Transmission System cost of losses, both for capacity and energy, for the Plan with Coal are relative to the Plan without Coal.

In regard to the costs presented in Table VI.D.1.1 for one fuel cost and environmental compliance cost forecast scenario, it is important to realize that only the Generation System Variable Costs column will change as other fuel cost and environmental compliance cost scenarios are analyzed. The capital and other fixed costs of the generating units included in each plan, and all of the Transmission System costs, will not change as other fuel cost forecasts and/or environmental compliance cost forecasts are used.

Therefore, a different format for presenting the economic analysis results for all of the fuel cost and environmental compliance cost scenarios can be used since it understood that only the Generation System Variable Costs will change from one fuel cost and environmental compliance cost scenario to another. Table VI.D.1.2 presents the complete set of analysis results for the Plan with Coal and the Plan without Coal in terms of total cost differentials between the two resource plans. The results are presented in terms of the difference between the CPVRR costs for the Plan with Coal minus the Plan without Coal. Negative values indicate that the Plan with Coal is more economical while positive values indicate that the Plan without Coal is more economical.

Table VI.D.1.2

Economic Analysis Results: the Plan with Coal vs the Plan without Coal Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

Total Cost Differentials *
(millions, CPVRR, 2006$, 2006 - 2054)

Fuel Cost Forecasts

Environmental Compliance Cost Forecasts		1 High Differential	2 Shocked Differential	3 Medium Differential	4 Low Differential
	A	(2,792)	(873)	(219)	1,912
	B	(2,045)	(113)	537	2,670
	C	(1,127)	804	1,466	3,604
	D	(666)	1,278	1,930	4,037

* A negative value indicates that the Plan with Coal is less expensive than the Plan without Coal. Conversely, a positive value indicates that Plan with Coal is more expensive than the Plan without Coal.

As expected, neither plan emerged as the economic choice under all fuel cost and environmental compliance cost forecast scenarios. Each plan emerged as the economic choice in approximately half of the 16 scenarios; i.e., in 7 scenarios for the Plan with Coal and in 9 scenarios for the Plan without Coal.

More specifically, the Plan with Coal emerges as the economic choice under all four scenarios that include the High coal-gas differential Fuel Cost Forecast 1 regardless of the environmental compliance cost forecast. Conversely, the Plan without Coal emerges as the economic choice under all four scenarios that include the Low coal-gas differential Fuel Cost Forecast 4. As for the remaining 8 scenarios that include either the Shocked or Medium coal-gas differential Fuel Cost Forecasts 2 and 3, respectively, each plan emerges as the economic choice in two of the four scenarios that include the Shocked fuel cost forecast while the

Plan without Coal generally emerges as the economic choice with the Medium coal-gas differential fuel cost forecast.

However, by examining the total costs for each resource plan for all 16 scenarios instead of just the cost differentials, another important result emerges. Table VI.D.1.3 presents the total costs for each resource plan for all 16 scenarios that leads to the cost differentials previously presented in Table VI.D.1.2.

Table VI.D.1.3

Economic Analysis Results: Total Costs and Total Cost Differentials for All Fuel and Environmental Compliance Cost Scenarios

(millions, CPVRR, 2006$, 2006 - 2054)

	(1)	(2)	(3)	(4)	(5) = (3) - (4)
			Total Costs for Plans		Total Cost Difference
Scenario	Fuel Cost Forecast	Environmental Compliance Cost Forecast	Plan with Coal	Plan without Coal	Plan with Coal - Plan without Coal
1A	1	A	159,945	162,737	(2,792)
1B	1	B	167,777	169,822	(2,045)
1C	1	C	176,514	177,640	(1,127)
1D	1	D	182,252	182,917	(666)
2A	2	A	141,840	142,713	(873)
2B	2	B	149,592	149,705	(113)
2C	2	C	158,332	157,528	804
2D	2	D	164,046	162,768	1,278
3A	3	A	118,469	118,689	(219)
3B	3	B	126,258	125,721	537
3C	3	C	134,990	133,524	1,466
3D	3	D	140,745	138,815	1,930
4A	4	A	87,989	86,077	1,912
4B	4	B	95,909	93,239	2,670
4C	4	C	104,508	100,904	3,604
4D	4	D	110,191	106,154	4,037

Note: A negative value in Column (5) indicates that the Plan with Coal is more expensive than than the Plan without Coal. Conversely, a positive value in Column (5) indicates that the Plan with Coal is more expensive than the Plan without Coal.

In those scenarios that include the Low coal-gas differential fuel cost forecasts in which the Plan with Coal was not the economic choice, the total costs for either plan are significantly lower than the total costs for scenarios that include either the High or Shocked coal-gas differential fuel cost forecasts. The same is true to a lesser extent for the total costs in those scenarios that include the Medium coal-gas differential fuel cost forecasts compared to the total costs for scenarios that include either the High or Shocked coal-gas differential fuel cost forecasts.

These scenarios with lower total costs for both plans are primarily driven by lower natural gas price projections. In these cases, because FPL will have very significant amounts of natural gas generation even after FGPP is added, FPL's customers will enjoy the benefits of lower natural gas costs after FGPP is added to FPL's system.

This point is illustrated by the fact that the cost differential between the two resource plans for Scenario 4D, $4,037 million CPVRR, is much smaller than the projected cost differential for the Plan without Coal under two scenarios that differ only by the projected fuel cost. This can be seen by examining the total costs for the Plan without Coal for Scenario 1D ($182,917 million CPVRR) and for Scenario 4D ($106,154 million CPVRR). In this example, this projected decrease in total costs of approximately $77,000 million, or $77 billion CPVRR, is driven solely by the projected lower fuel costs in Scenario 4D, particularly lower natural gas costs. Of this potential total cost savings to FPL's customers of $77 billion CPVRR that would occur if the Plan without Coal had been adopted, approximately $73 billion CPVRR will still be realized with the implementation of the Plan with Coal.

In other words, the Plan with Coal acts as a hedge or insurance against higher natural gas costs.

2. Fuel Diversity Analysis Results

As previously discussed, the fuel diversity analyses focused on the projected annual fuel mixes for the two resource plans for the 2012 – 2016 time period. This time period represents the years addressed in the resource plans before filler units begin to be added. Table VI.D.2.1 provides the results of these analyses for two scenarios, Scenarios 1A and 4D, selected to represent the entire range of the 16 scenarios.

Table VI.D.2.1

Fuel Diversity Analysis Results: FPL System Fuel Mix Projections by Plan

Scenario: 1A

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11) = (1) - (6)	(12) = (2) - (7)	(13) = (3) - (8)	(14) = (4) - (9)	(15) = (5) - (10)
	Plan with Coal					Plan without Coal					*Differential Plan with Coal vs Plan without Coal*				
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
2012	11.5%	62.0%	8.0%	17.4%	1.1%	11.5%	65.1%	5.0%	17.4%	1.1%	0.0%	-3.0%	3.0%	0.0%	0.0%
2013	14.5%	60.7%	6.7%	16.9%	1.1%	11.2%	65.5%	5.2%	16.9%	1.1%	3.3%	-4.8%	1.5%	0.0%	0.0%
2014	19.6%	57.2%	5.3%	16.7%	1.2%	10.9%	67.0%	4.1%	16.7%	1.2%	8.6%	-9.7%	1.1%	0.0%	0.0%
2015	20.9%	58.2%	3.5%	16.0%	1.3%	10.4%	67.3%	4.9%	16.0%	1.3%	10.5%	-9.1%	-1.4%	0.0%	0.0%
2016	17.6%	60.4%	5.1%	15.6%	1.3%	7.3%	71.1%	4.6%	15.6%	1.3%	10.3%	-10.7%	0.4%	0.0%	0.0%

Scenario: 4D

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11) = (1) - (6)	(12) = (2) - (7)	(13) = (3) - (8)	(14) = (4) - (9)	(15) = (5) - (10)
	Plan with Coal					Plan without Coal					Differential Plan with Coal vs Plan without Coal				
Year	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)	Coal/ Petroleum Coke (%)	Natural Gas (%)	Oil (%)	Nuclear (%)	Other (%)
2012	10.3%	62.8%	8.5%	17.4%	1.1%	9.8%	65.6%	6.1%	17.4%	1.1%	0.4%	-2.9%	2.4%	0.0%	0.0%
2013	13.2%	61.0%	7.7%	16.9%	1.1%	9.7%	66.2%	6.0%	16.9%	1.1%	3.5%	-5.2%	1.7%	0.0%	0.0%
2014	17.7%	58.2%	6.2%	16.7%	1.2%	9.2%	68.0%	4.9%	16.7%	1.2%	8.5%	-9.8%	1.3%	0.0%	0.0%
2015	18.8%	59.5%	4.3%	16.0%	1.3%	8.7%	68.4%	5.5%	16.0%	1.3%	10.1%	-9.0%	-1.2%	0.0%	0.0%
2016	15.9%	61.3%	5.8%	15.6%	1.3%	5.9%	71.7%	5.5%	15.6%	1.3%	10.0%	-10.3%	0.3%	0.0%	0.0%

The Plan with Coal holds a significant advantage in regard to fuel diversity compared to the Plan without Coal. There is little difference between the two plans in regard to the percent of FPL's fuel mix that is supplied by oil, nuclear, or other, but significant differences exist for coal/petroleum coke (coal) and natural gas. When looking at the results for the year 2016 for Scenario 1A, it is projected that the Plan with Coal will result in FPL's system supplying approximately 18% of its energy with coal and 60% with natural gas. By comparison, it is projected that the Plan without Coal will result in FPL's system supplying only 7% of its energy with coal and 71% with natural gas. Thus the Plan with Coal is projected to result in a 10-to-11% increase in the contribution from coal, and a corresponding 10-to-11% decrease in the contribution from natural gas, in 2016. A similar change in the percentage contribution from these two fuels is also shown for 2015, another year in which both advanced technology coal units are in-service for a full year.

For Scenario 4D, the contribution from coal is also projected to increase by approximately 10%, while the contribution from natural gas is projected to decrease by approximately 10%, for the Plan with Coal.

Therefore, the Plan with Coal is projected to have a significant fuel diversity advantage over the Plan without Coal, resulting in the FPL system being 10-to-11% more reliant on coal, and 10-to-11% less dependent on natural gas.

3. Summary of Analysis Results

The economic analyses showed that from a total CPVRR cost perspective neither resource plan had a distinct advantage throughout the range of scenarios. Each resource plan was the economic choice in approximately half of the scenarios, seven for the Plan with Coal and nine for the Plan without Coal. However, when comparing the CPVRR total cost differential between the two resource plans for those scenarios in which the Plan without Coal was the economic choice, the total cost disadvantage of the Plan with Coal versus the Plan without Coal, a maximum of approximately $4 billion CPVRR, is significantly less than the total cost differential for the Plan without Coal when comparing total costs for the High and Low fuel cost forecasts for the same environmental compliance cost forecast, a difference of approximately $77 billion CPVRR. Therefore, FPL's customers will experience significant total cost savings if actual fuel costs more closely match Fuel Cost Forecast 4 (Low coal-gas differential) than Fuel Cost Forecast 1 (High coal-gas differential). These savings of approximately $77 billion CPVRR would only be reduced by a comparatively small amount, $4 billion or less CPVRR, if the Plan with Coal had been selected. Therefore, the Plan with Coal can be viewed as a reasonable cost hedge or insurance against high fuel costs, primarily high natural gas costs.

The fuel diversity analyses showed that the Plan with Coal has a significant advantage in regard to system fuel diversity. This plan results in a projected system fuel mix that is approximately 10-to-11% more reliant on coal, and 10-to-11% less dependent on natural gas, compared to the Plan without Coal.

VII. NON-GENERATING ALTERNATIVES

A. FPL's Demand Side Management Efforts

FPL has a long history of identifying, developing, and implementing DSM resources to cost-effectively avoid or defer the construction of new power plants. FPL first began offering DSM programs in the late 1970s with the introduction of its Watt-Wise Home Program. FPL has continued to develop and offer additional DSM programs to its customers. These programs have included both conservation and load management programs, targeting the residential and business markets.

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

Since the inception of FPL's DSM programs through the end of 2005, the last full year for which data was available at the time this document was prepared, FPL has achieved 3,519 MW (at the generator) of Summer peak demand reduction, 2,734 MW (at the generator) of Winter peak demand reduction, 33,981 GWh (at the generator) of energy savings, and has completed over 2,192,000 energy audits of its customers' homes and facilities. This amount of peak demand reduction has eliminated the need for the equivalent of 10 power plants of 400 MW Summer capacity each (after accounting for the impact of reserve margin requirements). Most importantly, FPL has achieved this level of demand reduction without penalizing customers who are non-participants in its DSM programs. FPL has been able to avoid penalizing non-participating customers by offering only DSM programs that reduce electric rates for all customers, DSM participants and non-participants alike.

The U.S. Department of Energy reports on the effectiveness of utility DSM efforts through its Energy Information Administration. Based on the most current data available, which is for the year 2005, FPL is ranked number one nationally for cumulative conservation achievement and number four in load management.

B. FPL's Current DSM Goals and Commitments

DSM Goals were first set for Florida utilities in 1994 in Order No. PSC-94-1313 FOF. In 2004, new DSM Goals were set for FPL and other Florida utilities in Order No. PSC-04-0763-PPA-EG. In that order, the Commission established for FPL goals of achieving 883 MW of incremental Summer MW at the generator through DSM during the period from 2005 through 2014. This goal reflected what FPL and the Commission believed to be the reasonably achievable, cost-effective levels of incremental DSM on FPL's system.

FPL continually investigates additional cost-effective DSM opportunities and requests Commission approval of revisions to its DSM plan as appropriate. In 2005, FPL's peak load forecast increased significantly. There were also modifications to minimum equipment efficiency standards and other changing market conditions. As a result of these changes, FPL performed a comprehensive review of all its DSM programs as well as other potential measures.

In addition, in Order No. PSC-06-0555-FOF-EI, issued on June 28, 2006, in Docket No. 060225-EI, Petition for Determination of Need for West County Units 1 and 2 in Palm Beach County, FPL agreed, as a condition of approval of these two power plants, to file new and revised DSM programs to increase demand and energy savings on our system. FPL satisfied its commitment by filing modifications to 8 of its existing DSM programs. These modifications included changing the minimum qualifying Seasonal Energy Efficiency Ratio for air conditioners to reflect minimum mandated levels by the U.S. Department of Energy, modifying incentive levels for numerous program measures, enhancing program operating parameters, and adding new measures to existing DSM programs. In addition, FPL requested Commission approval of two new DSM programs -- Business Water Heating and Business Refrigeration. After review and consideration, the Commission issued Order No. PSC-06-0535-PAA-EG in Docket No. 060286-EG (Consummating Order No. PSC-06-0624-CO-EG issued July 20, 2006), approving changes to FPL's residential and business HVAC programs. On September 1, 2006, the Commission issued Order No. PSC-06-0740-TRF-EI in Docket No. 060408-EI (Consummating Order No. PSC-06-0801-CO-EI, issued September 26, 2006) approving the remaining modifications to FPL's DSM Plan for achieving these DSM reductions.

As reflected in the above-described filings instituting new and revised DSM programs, for the time period from 2006 through 2015, FPL identified an additional 564 MW (at the generator) of Summer demand reduction impact – or greater than the equivalent of a medium-sized power plant. Adding this 564 MW to FPL's current Commission-approved DSM Goals of 802 MW (at the generator) for 2006 - 2014, results in a total Summer peak demand reduction of 1,366 MW for the 2006 – 2015 time period. The projected demand reduction impacts from FPL's revised DSM Plan, which includes FPL's DSM Goals and the additional commitment resulting from this program review, were presented earlier in Table II.B.3.1.

As mentioned in Section IV, FPL assumed the successful accomplishment of this revised DSM Plan in determining its future capacity needs. Without this additional DSM, FPL's future capacity needs in 2014 would have increased by approximately 658 MW as is shown in Table II.B.3.1 after accounting for reserve margin requirements (548 MW at the generator of additional DSM by 2014 x 1.20 reserve margin requirements = 658 MW of capacity need).

FPL forecasts that it will achieve its DSM Plan through a number of Commission-approved DSM programs. FPL's current DSM Plan includes seven residential DSM programs and ten business DSM programs. A brief summary of each of these programs appears in Appendix L.

C. FPL's Demand Side Renewable Efforts

FPL has been a leader in examining ways to utilize renewable energy technologies to meet its customers' current and future needs. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was not cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program. FPL's Passive Home Program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate.

In early 1991, FPL evaluated the feasibility of using small photovoltaic (PV) systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test may be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, and various customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

More recently, FPL has analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach does not require all of its customers to bear PV's high cost, but allows customers who were interested in facilitating the use of renewable energy the means to do so. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund that FPL used to make PV purchases in bulk quantities. FPL began the effort in 1998 and received approximately $89,000 in contributions (that significantly exceeded the goal of $70,000). FPL purchased the PV modules and installed them at FPL's Martin Plant site.

In 2000, FPL launched the Photovoltaic Research, Development and Education Project. This demonstration project's objectives were to: increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks (as well as the total annual energy capabilities of roof tile PV systems), and assess the homeowner's financial benefits and costs of PV roof tile systems. This project was completed in 2003.

In November 2004, FPL launched its Green Power Pricing Research Project (GPPRP), which was marketed as the *Sunshine Energy®* program. The object of the Project was to allow residential customers to sign up voluntarily and pay for energy produced by renewable resources, which fosters the development of supplies of renewable energy that would not otherwise be developed. Project participants paid a monthly premium of $9.75 per month for a 1,000 kWh block of renewable energy attributes. To supply the renewable energy for the Project, FPL entered into a contract with a supplier for the purchase of tradable renewable energy credits (TRECs). In addition, for every 10,000 participants, FPL agreed to have built 150 kw of PV capacity in Florida. In its short history, the Project has become one of the top five renewable programs in the country with more than 25,000 customers enrolled. In less than two years, the GPPRP purchased almost 225 gigawatt hours (GWh) of TRECs (as of year-end 2005), making it the fourth largest renewable energy program in the country. It also received the 2005 Green Power Leadership Award from the U.S. Department of Environmental Protection and the Department of Energy. Other PV projects are also being built through the GPPRP. Construction of a 250 kW PV site in Sarasota is currently in process with construction expected to be completed in the first quarter of 2007. There are also several other smaller projects underway that will add additional PV capacity.

On September 17, 2006, FPL filed a petition with the Commission to convert the GPPRP to a permanent program and to extend the program to business customers. On December 1, 2006, the Commission issued Order No. PSC-06-0924-TRF-EI in Docket No. 060577-EI that approved this request.

D. The Potential for Additional Cost-Effective DSM

FPL is confident there is not sufficient additional, cost-effective DSM that could eliminate or significantly mitigate FPL's capacity needs in the 2012 – 2015 time period. There are several bases for this conclusion.

First, in 2006 FPL completed a comprehensive review of all demand side management opportunities that resulted in a total DSM commitment of 1,366 MW for the 2006 - 2015 time period. This analysis identified all the cost-effective DSM potential for this time frame. In addition, while there has been a small increase in the penetration of demand side renewable energy options over the last several years, the economics of the various technologies has not yet reached the level to make any significant impact on FPL's Summer peak.

Second, FPL has already counted this level of reasonably achievable DSM in its reliability assessment, which resulted in the projected need to add 2,238 MW of new capacity resources by 2015. Otherwise stated, FPL's analysis had already captured the cost-effective DSM available on FPL's system and determined that FPL still needed additional capacity resources.

Third, if the resource needs for just 2012 through 2014 were to be met solely by additional new DSM resources, FPL would need to identify and implement an additional 648 MW at the generator of cost-effective DSM to meet the 2012 resource needs, another 348 MW at the generator to meet the 2013 resource needs, and another 375 MW at the generator to meet the 2014 resource needs, for a total of 1,371 MW at the generator. FPL's DSM plans already take into account both maintaining FPL's large existing DSM resources and substantially increasing DSM through implementation of all of the additional cost-effective DSM that FPL has identified. Accordingly, there is no reasonable basis for concluding that FPL could implement sufficient new cost-effective DSM programs – over and above those already being performed and planned to be implemented – in the next 7 1/2 years (2007 through mid-2014) to meet these needs. While FPL hopes to identify and implement additional sources of cost-effective DSM in future years, FPL has no basis for believing that 1,371 MW at the generator of additional cost-effective DSM resources could be identified and implemented prior to mid-2014, especially when considering that 1,366 MW of cost-effective DSM represents all of the currently known cost-effective DSM and this amount of DSM is already incorporated into FPL's resource planning.

VIII. ADVERSE CONSEQUENCES IF THE PROPOSED CAPACITY ADDITIONS ARE DENIED

As evidenced by the fuel diversity results presented in Table VI.D.2.1 and discussed in Section VI, the FPL system is projected to be 10-to-11% more dependent on natural gas, and 10-to-11% less reliant on coal, if the FGPP 1 and 2 units included in the Plan with Coal are not approved.

Therefore, if FGPP 1 and 2 advanced technology coal units are not added by 2013 and 2014 as projected in the Plan with Coal, FPL's system will be significantly more dependent upon natural gas. Such an occurrence would represent a significant reduction in system fuel diversity, thus increasing the exposure of FPL's customers to greater fuel price volatility and resulting in a less reliable system.

Inherent in this discussion and in the analysis results is the assumption that, if a Need Determination for FGPP 1 and 2 is not approved, it would take an extended period of time before other coal-based capacity could be added to FPL's system. It would take a significant amount of time for FPL to be able to propose new coal-based capacity.

A consequence of FGPP 1 and 2 not receiving Need Determination approval in this docket is that the window of opportunity for bringing new coal-based capacity into FPL's system by 2013 will likely have passed. FPL would then have to seek other, non-coal-based new capacity options for meeting the 2013 capacity needs. Such capacity would likely come from new gas-fired options. At best, the earliest new coal-based capacity could be considered for additions to the FPL system would be 2014.

However, the time required for FPL to be able to add other coal-based capacity may be significantly longer than one year. Depending upon the reasons why these advanced technology coal FGPP units were not granted a Need Determination, it may take an extended time to effectively address those reasons. It is also unknown whether FPL would be granted a waiver of the Commission's Bid Rule RFP requirement in an effort to expedite a future coal-based addition. An RFP requirement would add at least a half-year to the timetable. These uncertainties point out that the additional time required to bring coal-based generation into FPL's system, if a Need Determination for FGPP 1 and 2 is not approved, might be significantly longer than one year.

IX. CONCLUSIONS

FPL, through its 2006 integrated resource planning (IRP) process, determined that 2,283 MW of new capacity would be needed between 2012 and 2015 to meet the reliability criterion of 20% Summer reserve margin approved by the Commission. Based on FPL's 2006 analysis, without the proposed additions of FGPP Units 1 and 2, FPL's summer reserve margin would drop 14.8% in 2013, 13.0% in 2014, and 10.5% in 2015. FPL determined that if all new capacity added to FPL's system through 2015 were to be natural gas-fired generation, fuel diversity in FPL's system would be significantly reduced.

FPL conducted an evaluation of various generation option alternatives to identify the best alternative to address the two objectives of meeting projected capacity needs and maintaining system fuel diversity in this time period. FPL's analysis indicated that adding the proposed FPL Glades Power Park (FGPP) units 1 and 2 by 2013 and 2014, respectively, would be the best plan to meet both objectives. Because of the nature of these proposed additions, FPL would be required to obtain a Determination of Need to support a site certification for each of these units. In this proceeding FPL seeks a Need Determination for FGPP 1 and 2. FPL sought, and was granted, Commission approval for a waiver from the Bid Rule requirement for an RFP to solicit proposals from other parties for addressing these capacity need and fuel diversity objectives primarily in order to bring coal-based capacity in-service at the earliest possible date.

FPL evaluated four coal-based technologies; sub-critical pulverized coal (PC), circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), and ultra-supercritical pulverized coal (USCPC or advanced technology coal), and determined that by early 2005 the advanced technology coal option was the best selection for this time period. In late 2006, prior to filing for Need Determination, two additional analyses were performed using updated information regarding these technologies. The results of these analyses confirmed that the advanced technology coal option was the best selection for FPL and its customers. This is the technology to be used in FGPP.

In order to determine how adding coal generation to FPL's portfolio compared to continuing to add natural gas-fired generation, FPL conducted both economic and fuel diversity analyses to compare a resource plan based on adding FGPP 1 and 2 by 2013 and 2014, respectively, the Plan with Coal, to an alternate resource plan that assumed gas-fired combined cycles would be added instead, the Plan without Coal. FPL utilized 16 scenarios of forecasted fuel costs and environmental compliance costs in these analyses in order to reflect the range of uncertainty regarding future fuel process and environmental requirements. The results of those analyses showed that neither plant was the lower-cost alternative under all circumstances. However, the plan with the addition of FGPP 1 and 2 was the lower cost alternative in approximately half of the scenarios (7 of 16), and when the benefit of maintaining a 60-day furl inventory capability at FGPP was valued, the Plan with Coal was the lower-cost alternative in 10 of the 16 scenarios. Moreover, FPL believes that a number of the scenarios with unfavorable results are not likely to occur.

In addition, the Plan with Coal provides the only effective alternative to maintain fuel diversity in FPL's system by 2013, which is essential in maintaining system reliability and mitigating the effect of volatility in the price of natural gas.

In short, FPL needs FGPP 1 and 2 to maintain system reliability and integrity, to maintain system fuel diversity, and to provide adequate electricity at a reasonable cost to its customers. There is no additional cost-effective DSM available to mitigate the need for these units.

Therefore, the Commission should grant FPL's petition for a determination of need for FGPP 1 and 2 by 2013 and 2014, respectively.