ORIGINAL

060225-EI

Need Study for Electrical Power Plant 2009

FPL

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

(This page is intentionally left blank)

TABLE OF CONTENTS

APPENDICES

CONFIDENTIAL APPENDICES

Appendix C-1	Summary of Proposal Information
Appendix C-2:	EGEAS Run for Individual Bids
Appendix C-3:	Fixed Cost Spreadsheets for Portfolios
Appendix C-4:	P-MArea Cases for All Portfolios
Appendix C-5:	Net Equity Adjustment Calculations for Proposals and Portfolios

TABLE OF FIGURES AND TABLES

TABLE OF ABBREVIATIONS

AFUDC	Allowance for Funds Used During Construction
BACT	Best Available Control Technology
BAFO	Best and Final Offer
Btu	British Thermal Unit
CC	Combined Cycle
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CPVRR	Cumulative Present Value Revenue Requirement
CT	Combustion Turbine
DLN	Dry Low Nitrogen Oxide Combustion Technology
DSM	Demand Side Management
EAF	Equivalent Availability Factor
EFOR	Equivalent Forced Outage Rate
EGEAS	Electric Generation Expansion and System Analysis Model
F.A.C.	Florida Administrative Code
FGT	Florida Gas Transmission
FMPA	Florida Municipal Power Association
FPL	Florida Power & Light Company
FRCC	Florida Reliability Coordinating Council
GDP	Gross Domestic Product
GE	General Electric Corporation
GWh	Gigawatt Hour
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
IRP	Integrated Resource Planning
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LNG	Liquefied Natural Gas
LOLP	Loss-of-Load Probability
LNTP	Limited Notice to Proceed
MGD	Million Gallons per Day
MW	Megawatt
MWh	Megawatt Hour
NEL	Net Energy for Load
NOx	Nitrogen Oxide
NPGU	Next Planned Generating Unit
OASIS	Open Access Same-Time Information System
O & M	Operation and Maintenance
PC	Pulverized Coal

TABLE OF ABBREVIATIONS (continued)

PM10	Particulate Matter (larger than 10 microns)
POF	Planned Outage Factor
PPA	Purchase Power Agreement
PPSA	Florida Electrical Power Plant Siting Act
ppmvd	Parts per Million Volume Dry
RAP	Resource Assessment and Planning
RFP	Request for Proposals
RSM	Sedway Consulting, Inc.'s Response Surface Model
scf/hr	Standard Cubic Feet per Hour
SCA	Site Certification Application
SCR	Selective Catalytic Nitrogen Oxide Reduction
Sedway	Sedway Consulting, Inc., the Independent Evaluator
SJRPP	St. Johns River Power Park
SO2	Sulfur Dioxide
STG	Steam Turbine Generator
SFWMD	South Florida Water Management District
TIGER	Tie-Line Assistance and Generation Reliability Model
UPS	Unit Power Sales
WCEC	West County Energy Center

I. EXECUTIVE SUMMARY

In its 2005 integrated resource planning process, Florida Power & Light Company (FPL) determined it needed to add a total of 3,454 MW between 2009 and 2013 to meet the 20 percent system generation reserve margin planning criterion approved by the Commission. In addition to the need to meet the 20 percent reserve margin planning criterion, FPL's 2005 integrated resource planning process continued to address another very important objective; how to economically maintain a balanced fuel mix in FPL's generation portfolio to achieve fuel cost stability and enhance system reliability.

FPL investigated various self-build generating alternatives to meet its capacity needs in 2009 through 2013. These alternatives included advanced combustion turbines, advanced combined cycle units and advanced supercritical coal generating units. In August 2005 FPL concluded that the most cost-effective plan to meet its customers' needs in 2009 through 2013 consisted of adding two 1,219 MW advanced combined cycle units in 2009 and 2010, respectively, and two 850 MW advanced supercritical coal units in 2012 and 2013, respectively. This plan also provided an effective way to maintain a balanced fuel mix in FPL's portfolio. The advanced combined cycle units proposed for 2009 and 2010 are West County Energy Center Units 1 and 2 (West County 1 and 2). FPL is evaluating two potential sites for the two advanced supercritical coal units proposed for 2012 and 2013.

Adding these generating units require site certification under the Florida Electrical Power Plant Siting Act (PPSA). In accord with Rule 25-22.082, Florida Administration Code (F.A.C) (the Bid Rule), FPL developed and issued a two-part Request for Proposals (RFP) on September 9, 2005. Part 1 of the RFP solicited proposals for generating capacity to determine whether any combination that included viable proposals would be more cost-effective than FPL's West County 1 and 2 in meeting the resource needs in 2009 through 2011. Part 2 of the RFP notified interested parties of FPL's plan to build two advanced supercritical coal units in 2012 and 2013, and invited them to proceed with any early development work that would enable them to submit proposals to FPL's RFP Supplement, to be issued in 2006, soliciting proposals consisting of fuel diverse alternatives to be evaluated with FPL's proposed coal units.

In its RFP, FPL expressed its keen interest in enhancing fuel diversity and in Part 1 invited interested parties to submit proposals that used any technology and any fuel. In Part 2 of its RFP FPL will restrict proposals to those that enhance fuel diversity.

FPL held two workshops and posted answers to questions posed by all interested entities on a dedicated website, or distributed them directly to all participants by e-mail. On November 9, 2005, FPL received five proposals from three different entities.

FPL conducted the evaluation described in the RFP to determine the best, most cost-effective alternative to meet the need in 2009 through 2011. The evaluation consisted of three major steps.

The first step was an initial assessment to determine proposal completeness and compliance with minimum requirements. The minimum requirements were designed primarily to provide meaningful assurance that proposers would perform the obligations undertaken, as well as to protect FPL's customers from the consequences of non-performance. These minimum requirements were specified by FPL in the RFP.

The second step was a full economic evaluation to determine the costs of operating the FPL system with the addition of the various portfolios of proposed generation resources. These costs included all costs involved in the development and operation of the various portfolios as part of the FPL system (e.g., capital costs, fuel, O&M, transmission), as well as costs related to the operational and financial impact on FPL's system created by each of the candidate portfolios. An external consultant conducted an independent evaluation of the generation costs of the proposals.

The third step was a review of non-economic attributes. This review was conducted for FPL's West County 1 and 2 and the alternative proposals.

FPL conducted the economic evaluation of all proposals by constructing portfolios to meet the required capacity need using combinations of the received proposals and FPL's proposed West County 1. Some portfolios included a proposal combined with both West County units. The economic evaluation clearly indicated that the combination of West County 1 and 2 offered very significant savings over all portfolios that did not include both West County units. The next closest portfolio that did not include both West County units was more costly than the addition of West County 1 and 2 by more than $750 million cumulative present value revenue requirement (CPVRR).

The RFP process clearly demonstrated that the addition of FPL's West County 1 and 2 is the best, most cost-effective alternative to meet the capacity need in 2009 through 2011. The West County units also will increase the efficiency of FPL's system and reduce fuel costs by improving the average heat rate of the system by 4%. In addition, these units will enhance FPL's operating flexibility and reliability for Southeast Florida by mitigating the growing imbalance between generation and load in this region.

Based on the advantages of West County 1 and 2 demonstrated by its selection among FPL's self-build alternatives and the results of Part 1 of FPL's RFP process, FPL is continuing with the licensing process of the West County units. This choice is FPL's most cost-effective alternative for 2009 through 2011 to maintain electric system reliability and integrity and provide adequate electricity at a reasonable cost. There is not sufficient additional, cost-effective demand side management (DSM) that is reasonably available to mitigate the need for these units.

FPL has considered generation alternatives that use coal and petroleum coke as part of its annual integrated resource planning process and has compared these solid fuel generation alternatives to other generation technologies, such as advanced combined cycle units that use natural gas. Prior to 2004, the technology generally used for coal generation was much less efficient than that of advanced combined cycle units, the capital cost of building coal generation was significantly greater than that of advanced combined cycle units and although the price of coal was lower than that of natural gas, the gas-coal price differential was not sufficiently large to offset the other economic disadvantages of coal generation. Nevertheless, because of FPL's interest in maintaining a balanced fuel mix, FPL initiated in late 2003 a re-evaluation of solid fuel generation alternatives, including a review of technological, economic and environmental characteristics and recent developments related to this type of generation. This effort was completed in early 2005. The findings and conclusions of FPL's re-evaluation of solid fuel generation, which were reported to the Commission in FPL's Report on Clean Coal Generation

(Coal Report), dated March 10, 2005, led FPL to include in its generation capacity plan the addition of the two proposed 850 MW advanced supercritical coal generation units with projected commercial operation dates of June 2012 and June 2013, respectively, referred to above.

Two developments that coincided with the timing of FPL's evaluation in 2004 and 2005 combined to change the analytical picture for coal generation. First, in late 2004 FPL's and the general market's fuel price forecasts resulted in much greater projected gas-coal price differentials in the future. Second, FPL was able to confirm that new information regarding improvements in the efficiency and availability of coal generation technology could be relied on. The combination of these two developments led to analysis results in 2005 that enabled FPL to determine that coal generation was competitive with advanced combined cycle generation. However, because of the longer lead times required for engineering, permitting and construction of coal generation, the earliest that FPL could place in service coal generation is June 2012.

As noted in FPL's Coal Report, there are significant areas of uncertainty related to the long-term gas-coal price differential, the challenge of developing an economically competitive coal delivery infrastructure, future environmental requirements and the type and cost of emission management systems necessary to meet those requirements, the actual capital cost of building coal generation, and public perception regarding coal generation. All of these issues can affect the viability and economic competitiveness of coal generation. However, FPL will continue its effort to obtain the necessary approvals to build the proposed coal generation units, as well as purchase fuel diverse generation from others for implementation in 2012 and 2013, while it monitors development related to these areas of uncertainty.

As part of that continuing effort, FPL plans to issue by September 2006 its RFP Supplement to solicit fuel diverse proposals to meet FPL's need in 2012 and 2013.

The remainder of this Need Study contains more detailed information, analyses and discussion supporting FPL's requested determination of need for West County 1 and 2 in 2009 and 2010, 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 West County Energy Center Units 1 and 2 (West County 1 and 2). The new units will be two natural gas-fired combined cycle facilities located in Western Palm Beach County. Once completed, West County 1 and 2 will each have summer net capacities of approximately 1,219 MW for a combined capacity of 2,438 MW[1]. The net increase in FPL's total generating capacity will be approximately 2,438 MW.

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 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...." The following information is provided in subsequent sections:

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

[1] This is the combined summer net rating for the units. The combined winter net rating is 2,670 MW. For ease of presentation, throughout this Need Study only the summer net rating of the unit is mentioned unless the winter rating is specifically being discussed.

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. FPL served an average of 4.3 million customer accounts in 35 counties during 2005. 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 fossil fuel and nuclear generating units, non-utility-owned generation, DSM, and interchange/purchased power. Each type of resource is discussed in more detail later in this document.

FPL's bulk transmission system is comprised of 6,381 circuit miles transmission lines. Integration of the generation, transmission and distribution system is achieved through FPL's 543 substations. FPL is interconnected directly with eight other electric utilities. A list of FPL's major interconnections with other utilities is presented in Appendix A of this Need Study.

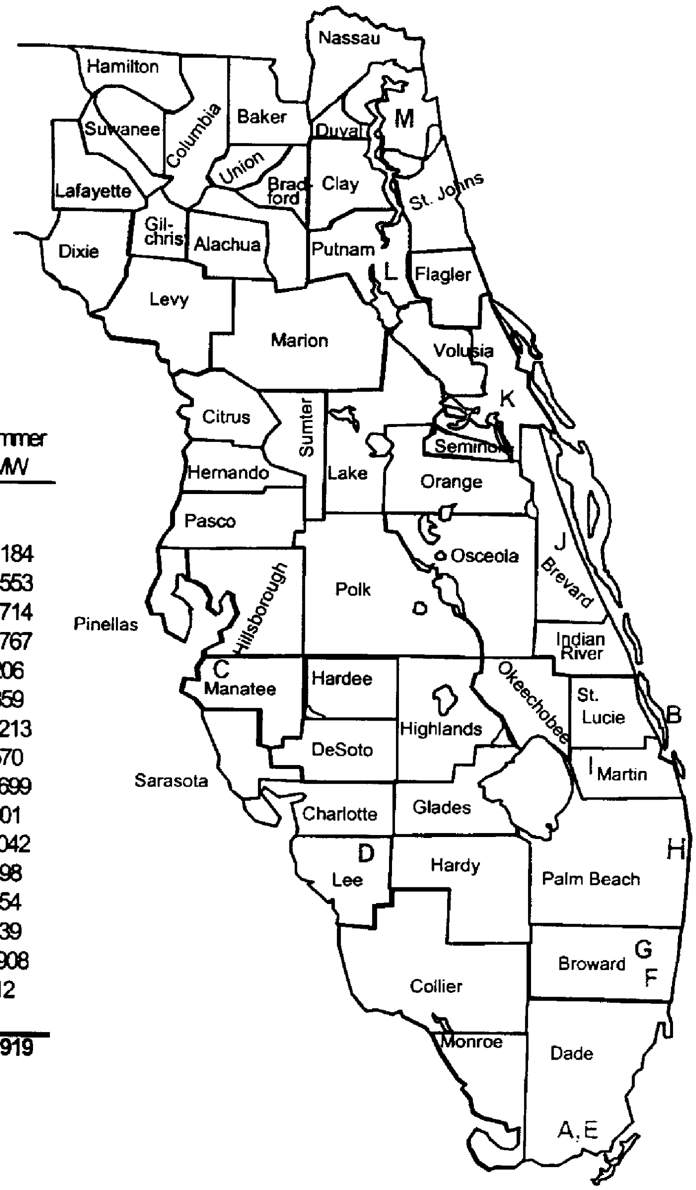
1. FPL-Owned Generating Resources

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. The current generating facilities consist of 4 nuclear steam units, 3 coal units, 11 CC 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 2006 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's Generating Resources

(Projected Summer 2006 Capabilities)



Non-FPL Territory

Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	4	2,184
B	St. Lucie *	2	1,553
C	Manatee	3	2,714
D	Fort Myers	2	1,767
E	Cutler	2	206
F	Lauderdale	2	859
G	Port Everglades	4	1,213
H	Riviera	2	570
I	Martin	5	3,699
J	Cape Canaveral	2	801
K	Sanford	3	2,042
L	Putnam	2	498
M	SJRPP **	2	254
	Scherer ***	1	639
	Gas Turbines	48	1,908
	Internal Combustion Turbines	5	12
	FPL Generation =	89	20,919

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

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

2. Purchases from Cogeneration and Small Power Production Facilities

FPL has contracts to purchase firm capacity and energy from seven 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 percent of its energy.[2]

A summary of these firm capacity agreements with cogeneration and small power production facilities is presented in Table II.B.2.1.

Table II.B.2.1

FPL's Firm Capacity & Energy Contracts with Cogeneration & Small Power Production Facilities

Project	County	Fuel	MW Capacity	In-Service Date	End Date
Broward South	Broward	Solid Waste	50.6	4/1/91	8/1/09
			1.4	1/1/93	12/31/26
			1.5	1/1/95	12/31/26
			0.6	1/1/97	12/31/26
Broward North	Broward	Solid Waste	45.0	4/1/92	12/31/10
			7.0	1/1/93	12/31/26
			1.5	1/1/95	12//31/26
			2.5	1/1/97	12/31/26
Cedar Bay Generating Co.	Duval	Coal (CFB)	250.0	1/25/94	12/31/24
Indiantown Cogen., LP	Martin	Coal (PC)	330.0	12/22/95	12/01/25
Palm Beach SWA	Palm Beach	Solid Waste	43.5	4/1/92	3/31/10

[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.

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 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.

FPL's approved DSM Goals for summer MW reduction are presented in Table II.B.3.1. These DSM Goals are over and above the significant levels of DSM implementation FPL achieved before the year 2000. FPL's current DSM Plan was approved by the Commission in 2004 and was designed to achieve these goals for the 2005–2014 period. FPL's projected need for additional capacity in 2009 - 2011 includes these DSM levels. There is not sufficient additional, reasonably available, cost-effective DSM available to mitigate FPL's need for West County1 and 2.

Table II.B.3.1

FPL's Summer MW Reduction Goals for DSM *
(At the Meter)

Year	DSM Goal Cumulative MW (Summer)
2005	74.0
2006	141.7
2007	211.9
2008	287.2
2009	365.9
2010	447.9
2011	532.1
2012	618.8
2013	707.9
2014	801.7

* Table II.B.3.1 reflects FPL's new DSM Goals for 2005 – 2014 as approved by the Florida Public Service Commission in June, 2004. These annual cumulative values assume a 1/1/05 starting point

4. Purchased Power

FPL has a long-term Unit Power Sales (UPS) contract to purchase up to 931 MW of coal-fired generation from Southern Company. FPL also has long-term contracts with JEA for the purchase of 381 MW (summer) and 390 MW (winter) of coal-fired generation from St. John's River Power Park (SJRPP) Units One and Two.[3]

In addition, FPL has a number of short-term, firm capacity purchased power contracts. These firm capacity purchases come from a variety of suppliers, and the capacity supplied will vary from 2004 through 2009.

FPL incorporated the applicable purchase amounts in the analyses that led to FPL's projection of additional capacity needs in 2009 - 2011. The annual amounts of these long-term and short-term firm purchases are presented in Table II.B.4.1.

Table II.B.4.1

FPL's Purchased Power MW

	UPS		*SJRPP*		*Other Firm Capacity Purchases*		*Total*	
Year	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*	*Summer*
2006	931	931	390	381	1,543	1,353	2,864	2,665
2007	931	931	390	381	1,567	1,049	2,888	2,361
2008	931	931	390	381	1,071	1,049	2,392	2,361
2009	931	931	390	381	745	1,049	2,066	2,361
2010	931		390	381	338	1,246	1,659	1,627
2011	0	0	390	381	1,268	1,246	1,658	1,627
2012	0	0	390	381	1,088	930	1,478	1,311
2013	0	0	390	381	930	930	1,320	1,311
2014	0	0	390	381	930	930	1,320	1,311
2015	0	0	390	381	930	930	1,320	1,311
2016	0	0	390	381	930	930	1,320	1,311

[3] FPL also has a separate 20 percent ownership interest in these units.

5. Current and Projected Electrical Demand and Sales

In FPL's 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.

In 2005, FPL experienced a winter coincident total peak load of 18,108 MW and a summer coincident total peak load of 22,361 MW. FPL's 2005 NEL was 111,301 GWh. For 2009, 2010 and 2011, FPL is forecasting increasing winter and summer coincident peak loads as shown in Table II.B.5.1. The projected effects of DSM will result in lower winter and summer coincident peak loads and are also provided in Table II.B.5.1.[4] The NEL for 2009 through 2011 is also provided below. FPL's complete load forecast is provided in Appendix E.

Table II.B.5.1

Forecasted Peak Load before and after DSM

Year	Summer Coincident Peak (MW)	Summer Coincident Peak w/ DSM (MW)	Winter Coincident Peak (MW)	Winter Coincident Peak w/ DSM (MW)	Net Energy for Load (GWH)
2009	22,884	21,125	22,916	21,237	127,521
2010	23,424	21,575	23,466	21,730	130,980
2011	23,964	22,023	24,035	22,239	133,674

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

III. DESCRIPTION OF THE PROPOSED POWER PLANT

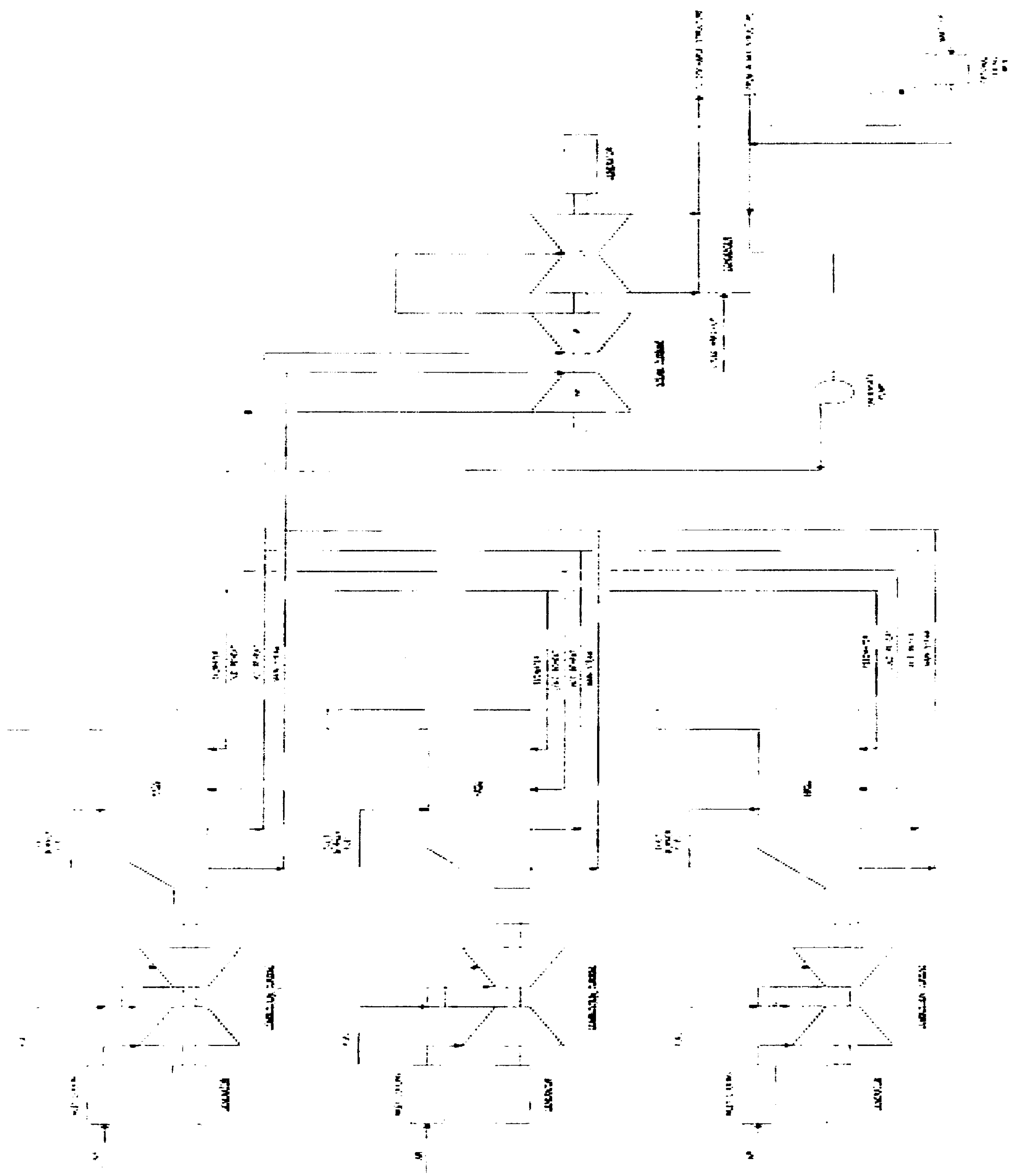
A. Overview

As depicted in Figure III.A.1, and described in Appendix J, West County 1 and 2 are each designed to utilize three CTs, three heat recovery steam generators (HRSGs), and one steam turbine generator (STG). The CTs compress outside air into a combustion area where fuel, typically natural gas or light oil, is burned. The hot gases from the burning fuel-air mixture expand to drive a turbine, which directly rotates a generator to produce electricity. The exhaust gas produced by each turbine, with temperatures on the order of 1,100°F, then passes through a HRSG to convert the exhaust gas energy to steam. The cooled exhaust gases exit the stack at approximately 200°F. The steam produced in the HRSGs is collected to drive the common STG. West County 1 and 2 will each employ three CT/HRSG trains in combination with one STG, hence the terminology "three-on-one" (3x1) Combined Cycle (CC) plant.

The utilization of waste heat from the CTs in a combined cycle provides an overall plant efficiency that is much better than that of the CTs alone (in simple cycle) or of a conventional boiler steam-electric generating facility. In general, CC plants of this design can be expected to achieve energy conversion rates (heat rates) of less than 7,000 Btu/kWh, which compares favorably to values on the order of 10,000 Btu/kWh for conventional boiler steam-electric generating units, and results in a fuel savings of about 30 percent. FPL anticipates that the new West County 1 and 2 will each achieve a highly efficient average base heat rate of 6,582 Btu/kWh (HHV at 75°F).

FIGURE III.A.1

TYPICAL 3x1 CC UNIT PROCESS DIAGRAM



The proposed CC units will use Mitsubishi Power Systems (MPS) 501G series advanced CTs.[5] In simple cycle mode, each of these turbines is peak-rated at 245 MW at summer rating conditions. The 3x1 configurations at West County are similar to the project being constructed at the Turkey Point site. Accordingly, the project planning, detailed design, procurement, construction, commissioning, and O & M will involve similar requirements. The resulting engineering and construction savings to FPL customers are reflected in the cost estimate for West County 1 and 2.

West County 1 and 2 will each have an approximate summer rating of 1,219 MW, based on ambient conditions of 95°F. The approximate winter rating (at 35°F) is 1,335 MW. Actual summer and winter ratings may vary based upon final design and on the results of performance testing.

West County 1 and 2 will be constructed on a 220-acre site located in unincorporated western Palm Beach County, approximately 5 miles west of the village of Wellington.

A map of the Plant site and the surrounding area is shown on Figure III.A.2. Currently there are no on-site activities or facilities. The two units will be located on the northern 100 acres of the project site. The entire 220-acre site has been zoned for power plants.

The site is comprised of lands which were partially reclaimed and restored after mining of lime rock on the northern 50-acres of the site. Generally, the Site predominately has been in agricultural use for the past 30 years, with some limited mining of lime rock on the northern 50-acres. Adjacent lands to the east and north have been extensively mined for lime rock for the last 15 years.

Figure III.A.3 is a drawing or footprint of the proposed West County 1 and 2.

[5] The term "advanced CTs" refers to the fact that the MPS G series CTs are designed to operate at a higher firing temperature than conventional CTs, which results in higher efficiency.

FIGURE III.A.2

MAP OF WEST COUNTY 1 & 2 PLANT SITE AND SURROUNDING AREA

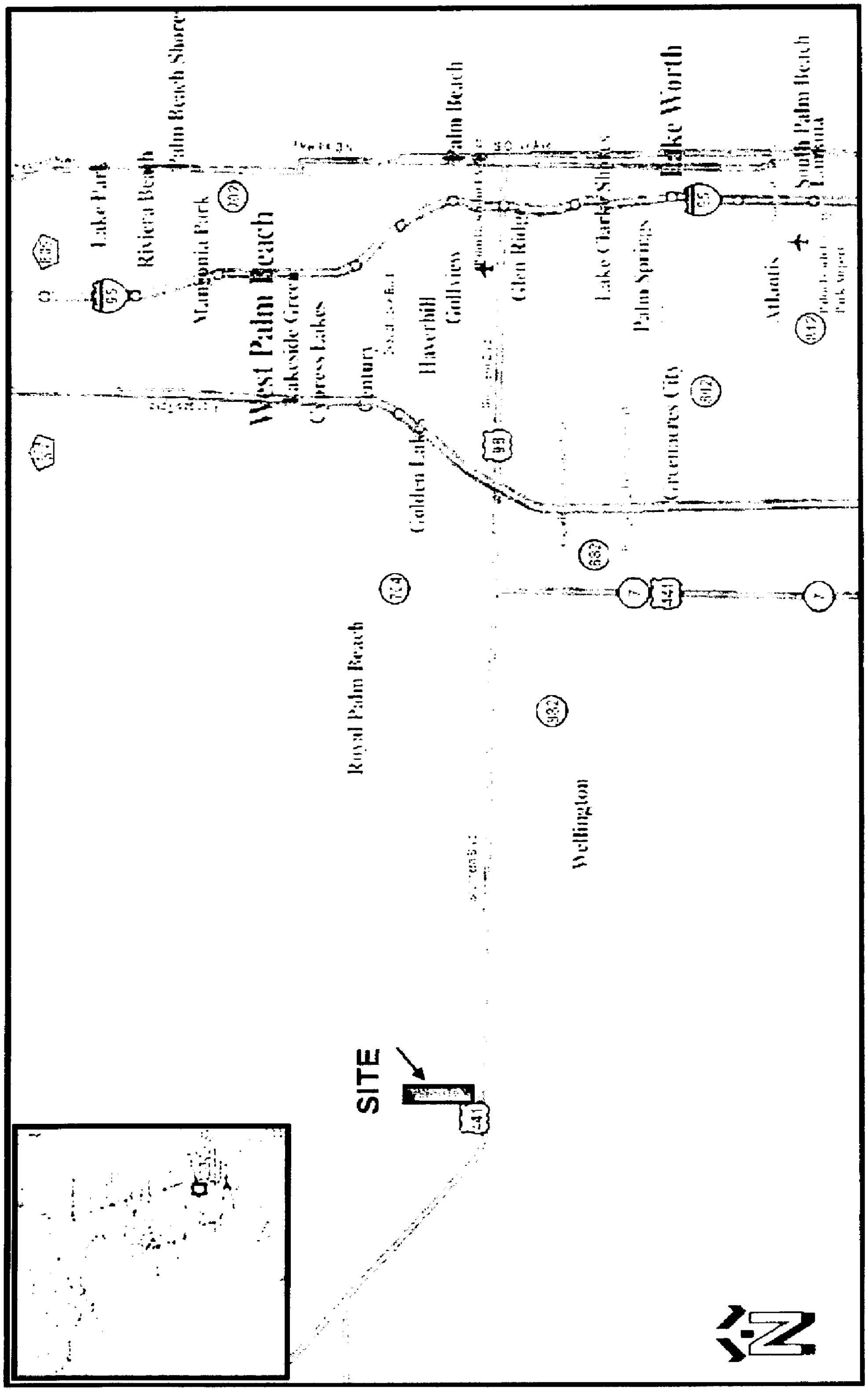
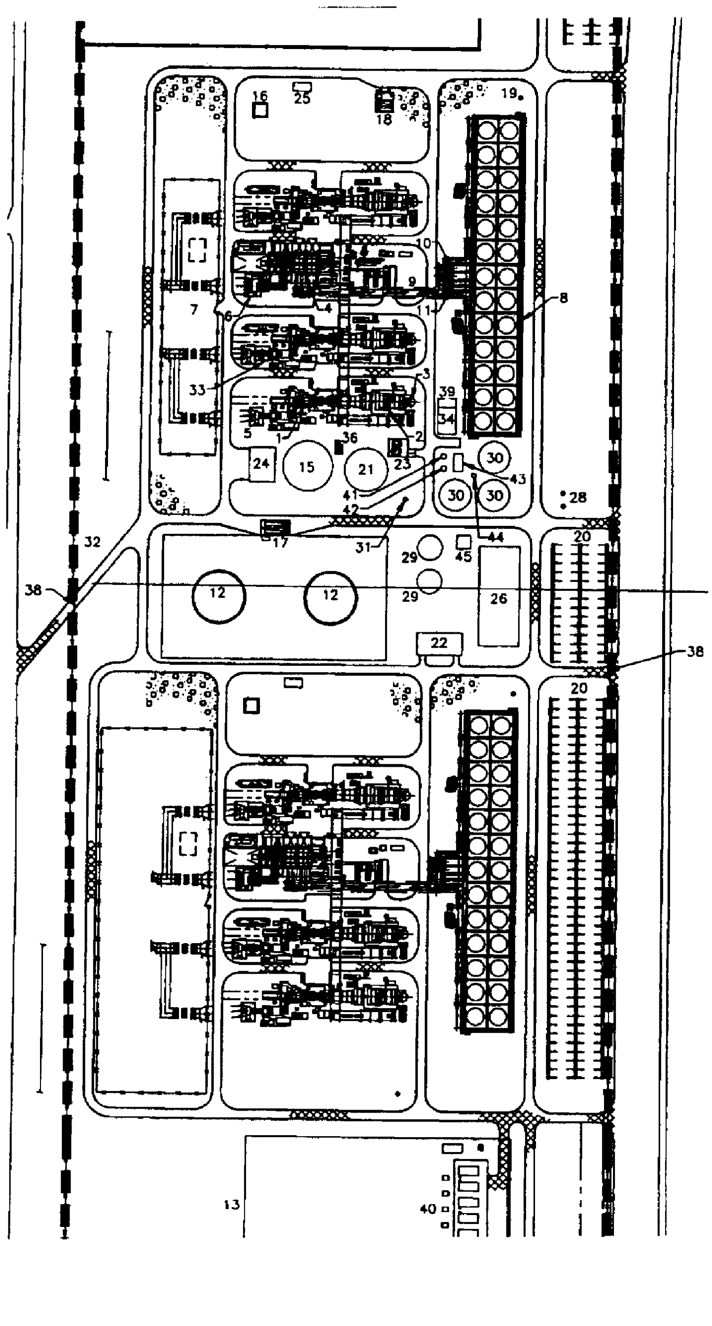


FIGURE III.A.3

FOOTPRINT OR DRAWING OF

PROPOSED WEST COUNTY 1 AND 2



B. West County 1 and 2 Design

The West County 1 and 2 3x1 CC units each will consist of three nominal 230-MW MPS Frame 501 "G" Class advanced CTs, with dry low nitrogen oxide (NOx) combustors. Each of the CTs will exhaust to a HRSG that will convert the waste heat from the CTs to steam. This steam will supply a new STG.

Each CT unit will utilize a type of inlet air conditioning commonly referred to as "evaporative cooling." Evaporative coolers cool and humidify the inlet air stream, which allows power to be produced more efficiently and with lower emissions for each MWh generated. For the MPS 501G CT, an 8°F average decrease in temperature typically results in an expected 3.0 percent increase in power and an expected 0.5 percent increase in efficiency (heat rate). The evaporative coolers would be utilized when the ambient air temperature is greater than 60°F. Based on an average annual temperature of approximately 75°F, the output and heat rate benefits associated with fogging are included in the base heat rate of 6,582 Btu/kWh (100 percent load at 75°F) and the "base operation" summer capacity rating of 1,115 MW.

Each HRSG will include duct burners. The duct burners allow for direct burn of natural gas and are used during peak demand periods to add an additional 104 MW of summer capacity to the unit at an incremental heat rate of 8,770 Btu/kWh (75oF).

The 1,115 MW of base operation and 104 MW of duct firing operation sum to a total unit summer capability of 1,219 MW.

The CTs will use natural gas as the primary fuel. The HRSG duct burners will fire natural gas only. Gas will be transported to West County 1 and 2 through a new lateral pipeline, which would be owned and operated by Gulfstream Pipeline. Gulfstream will independently undertake the permitting and construction activities for the necessary upgrades to the existing infrastructure.

Should there be a loss of natural gas to the site, West County 1 and 2 will be designed to use light oil as a backup fuel for an equivalent of up to 500 hours/year per CT at baseload conditions. Light oil will be trucked to the site and stored in two 6.2 million-gallon tanks that will be constructed as a part of the West County 1 and 2 project.

C. Environmental Controls

The use of natural gas and advanced combustion controls will minimize air emissions from West County 1 and 2 and ensure compliance with applicable emission-limiting standards. Using natural gas minimizes emissions of sulfur dioxide (SO2), particulate matter and other fuel-bound contaminants. Advanced combustion controls similarly minimize the formation of NOx, and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NOx emissions will be controlled using dry-low NOx combustion technology (DLN) and selective catalytic NOx reduction (SCR). Water injection and SCR will be used to reduce NOx emissions during CC operation when firing light oil. These design options constitute the Best Available Control Technology (BACT) for air emissions and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of West County 1 and 2 will incorporate features that will make it one of the most efficient and cleanest power plants in the state of Florida.

Primary water uses at West County 1 and 2 will be for condenser cooling, CT inlet evaporative coolers, steam cycle makeup and service water. Water also will be used on a limited basis for NOx control when firing light oil. Condenser cooling for the steam cycle portion of Units 1 and 2 will be accomplished using a mechanical draft cooling tower with make-up water from either surface water or deep Floridan Aquifer wells. Service and process water for the unit will come from the adjacent canal.

The facility has been designed to minimize direct discharge of process wastewater to offsite surface waters. Non-contact storm water runoff will be collected and routed to a storm water detention pond that has been designed to meet South Florida Water Management District (SFWMD) requirements. All process wastewaters, including process water pre-treatment backwash, plant and equipment drains, and neutralization unit effluent, will be treated as appropriate and deep well injected.

D. Transmission Interconnection

The project will connect to the adjacent existing Corbett substation via string busses. The Corbett substation will be expanded to accommodate the new interconnection to FPL's electric transmission system.

E. Transmission Integration

A study was conducted to determine the impact of integrating the West County 1 and 2 into the existing FPL transmission system. The results indicated that no upgrades to the existing transmission system or facilities are necessary to accommodate the proposed plants. The total transmission interconnection and integration costs are shown in Table III.G.1.

F. Construction Schedule

FPL will begin construction upon receipt of the necessary federal, state, and local approvals, certifications, and permits. The expected construction duration for the West County 1 and 2 is 48 months. This is based on FPL's recent experience with CC-based construction activity. To meet the planned in-service date of June 2009 for Unit 1 and June, 2010 for Unit 2, FPL needs to commence construction on or before June 1, 2007. A summary of proposed construction milestone dates is shown on Table III.F.1.

TABLE III.F.1

WEST COUNTY 1 AND 2

EXPECTED CONSTRUCTION SCHEDULE

	Unit 1		Unit 2	
Milestone	**Begin**	**End**	**Begin**	**End**
Initiate sequence of HRSG orders (LNTP x 4)	Feb 06	Dec 06	Feb 06	Dec 07
Initiate sequence of CT orders (LNTP x 4)	Apr 06	Jun 06	Apr 06	Jun 07
Issue LNTP for steam turbine	-	Nov 06	-	May 07
Receive approvals necessary to begin construction	-	Mar 07	-	Mar 07
Site preparation & foundations	Jun 07	Feb 08	Jun 08	Feb 09
Balance of Plant	Jun 07	Dec 08	Jun 08	Dec 09
Erect HRSGs	Nov 07		Nov 08	
Erect CTs	Feb 08		Feb 09	
Erect steam turbine	Apr 08		Apr 09	
Startup	Jan 09	May 09	Jan 10	May 10
Commercial operation	-	Jun 09	-	Jun 10

G. Estimated Capital Cost

The estimated total installed cost for West County Unit 1 is $688.6 million (2009 dollars). This cost estimate was used in FPL's economic analysis, and it includes $585.3 million for the power block, $13.2 million for land, $22.7 million for the transmission interconnection and integration costs (including GSU transformers) and $67.4 million in AFUDC.

The estimated total installed cost for West County Unit 2 is $632.4 million (2010 dollars). This cost estimate was used in FPL's economic analysis, and it includes $515.9 million for the power block, $13.2 million for land, $33.6 million for the transmission interconnection and integration costs (including GSU transformers) and $69.7 million in AFUDC.

The components of the total plant costs are shown in Table III.G.1.

TABLE III.G.1

WEST COUNTY 1 AND 2

PLANT COST COMPONENTS

	Unit 1 (2009$)	Unit 2 (2010$)
Power Block	$585.3	$515.9
Land	$13.2	$13.2
Transmission Interconnect & Integration	$22.7	$33.6
Gulfstream Infrastructure Upgrades	$0	$0
AFUDC	$67.4	$69.7
Total Plant Cost	$688.6	$632.4
Total Project Costs	$1,321.0	

H. Fact Sheet

The details of the West County 1 and 2 facilities are provided in Figures III.H.1 and III.H.2.

FIGURE III.H.1

WEST COUNTY UNIT 1

FACT SHEET

Generation Technology - "Three on One" (3x1) Combined Cycle Configuration:

- Three (3) MPS 501G Combustion Turbines w/ Evaporative Coolers
- Three (3) Heat Recovery Steam Generators with Duct Burners and Selective Catalytic Reduction System for NOx Control
- One (1) Single-Reheat Steam Turbine

Expected Plant Peak Capacity:		
o Summer (95°F / 50% RH)	1,219 MW	
o Winter (35°F / 60% RH)	1,335 MW	
Projected Unit Performance Data:		
o Average Forced Outage Rate (EFOR)	1.1%	
o Average Scheduled Maintenance Outages	1 wk/yr (2.1% POF)	
o Average Equivalent Availability Factor (EAF)	96.8%	
o Base Average Net Operating Heat Rate @ 75°F / 60% RH	6,582 Btu/kWh (HHV)	
o Annual Fixed O&M – incremental (2009 dollars)	$4.61/kW-yr	
o Variable O&M – excluding fuel (2009 dollars)	$0.138/MWh	
Fuel Type and Base Load Typical Usage @ 75°F:		
o Primary Fuel	Natural Gas	
o Natural Gas Consumption	7,642,000 scf/hr	
o Backup Fuel	Light Oil	
o Light Oil Consumption	48,000 gal/hr	
Expected Base Load Air Emissions Per Train @ 75°F:	Natural Gas	Light Oil
o NOx (@ 15% O2)	2.5 ppmvd	10 ppmvd
o CO	4.1 ppmvd	8 ppmvd
o PM10	6.1 lb/hr	35.0 lb/hr
o SO2	13.7 lb/hr	3.3 lb/hr

Water Balance:

- Annual average consumptive use for West County Unit 1 is approximately 9.8 MGD.
- Process wastewater deep well injected.

Linear Facilities:

- One (1) Gulfstream gas lateral is proposed to serve the West County site.
- No light oil pipeline – light oil delivered to site by truck

FIGURE III.H.2

WEST COUNTY UNIT 2

FACT SHEET

Generation Technology - "Three on One" (3x1) Combined Cycle Configuration:

- Three (3) MPS 501G Combustion Turbines w/ Evaporative Coolers
- Three (3) Heat Recovery Steam Generators with Duct Burners and Selective Catalytic Reduction System for NOx Control
- One (1) Single-Reheat Steam Turbine

Expected Plant Peak Capacity:		
○ Summer (95°F / 50% RH)	1,219 MW	
○ Winter (35°F / 60% RH)	1,335 MW	
Projected Unit Performance Data:		
○ Average Forced Outage Rate (EFOR)	1.1%	
○ Average Scheduled Maintenance Outages	1 wk/yr (2.1% POF)	
○ Average Equivalent Availability Factor (EAF)	96.8%	
○ Base Average Net Operating Heat Rate @ 75°F / 60% RH	6,582 Btu/kWh (HHV)	
○ Annual Fixed O&M – incremental (2010 dollars)	$3.07/kW-yr	
○ Variable O&M – excluding fuel (2010 dollars)	$0.138/MWh	
Fuel Type and Base Load Typical Usage @ 75°F:		
○ Primary Fuel	Natural Gas	
○ Natural Gas Consumption	7,642,000 scf/hr	
○ Backup Fuel	Light Oil	
○ Light Oil Consumption	48,000 gal/hr	
Expected Base Load Air Emissions Per Train @ 75°F:	Natural Gas	Light Oil
○ NOx (@ 15% O_2)	2.5 ppmvd	10 ppmvd
○ CO	4.1 ppmvd	8 ppmvd
○ PM10	6.1 lb/hr	35.0 lb/hr
○ SO_2	13.7 lb/hr	3.3 lb/hr

Water Balance:

- Annual average consumptive use for West County Unit 2 is approximately 9.8 MGD.
- Process wastewater deep well injected.

Linear Facilities:

- One (1) Gulfstream gas lateral is proposed to serve the West County site.
- No light oil pipeline – light oil delivered to site by truck

IV. FPL'S NEED FOR THE PROPOSED POWER PLANTS

FPL determined in its 2005 integrated resource planning (IRP) work that it would need significant additional resources in 2009-2011 to meet its reserve margin criterion for those years. The reliability assessment (conducted as a part of the IRP) 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 available to maintain the specified reliability standard. Based on this analysis, FPL determined it would need a minimum of either 2,371 MW of new supply (power plant construction or power purchase) or 1,976 MW of new DSM to meet its 2009-2011 reserve margin requirements.

A. Reliability Assessment

In the reliability assessment portion of its 2005 IRP analysis, FPL started with updated power plant capability and reliability data, and an updated load forecast. The updated load forecast is presented in Appendix E. In addition, the reliability assessment took into account committed construction capacity additions, firm capacity power purchases and long-term DSM implementation.

1. Near-Term Capacity Additions

FPL included its previously committed construction project in its 2005 reliability assessment. This project is the addition of a new approximately 1,140 MW CC unit at FPL's existing Turkey Point plant site (Turkey Point Unit 5) that will be placed into service mid-2007.

2. Firm Capacity Purchases

FPL took into account all of its short-term and long-term firm capacity purchases from a combination of utility and non-utility generators in its 2005 reliability assessment. These firm capacity purchases are discussed in Section II.B.4 and presented in Table II.B.4.1.

3. Long-Term DSM

Since 1994, FPL's IRP process has used the amount of DSM capacity in FPL's approved DSM Goals as the basis for its analysis. The currently approved DSM Goals for FPL are discussed in Section II.B.3 and presented in Table II.B.3.1. In its 2005 resource planning, FPL used the approved DSM goals through the year 2014 as a key assumption in the analysis. In this way, FPL includes in its reliability analysis the projected incremental impact of all of FPL's DSM programs from 2005-on, plus the cumulative demand reduction capability from its load management programs prior to 2005. The cumulative impact from all of FPL's conservation program efforts before 2005 is captured in the 2005 load forecast discussed in Section V.A.1.

B. FPL's Reliability Criteria

System reliability analyses were based on the dual planning criteria of: (1) a minimum summer and winter peak period reserve margin of 20 percent, and (2) a maximum of 0.1 days per year Loss-of-Load-Probability (LOLP). The reserve margin criterion of 20 percent applies for reserve margin analyses addressing both summer and winter peak periods. 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 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 periods. 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 given 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 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 2005 IRP work.

C. FPL's 2005 Reliability Assessment Results

FPL's reliability analyses showed that with no additional resources beyond its existing generating units, existing purchases, and the planned addition mentioned above, FPL would not meet its summer reserve margin criterion of 20 percent starting in the summer of 2009 and for each summer thereafter. A minimum of 2,371 MW of additional supply resources would be needed during the 2009–2011 time frame for FPL to continue to meet its summer reserve margin criterion of 20 percent for those years. This need is demonstrated in Table IV.C.1.

If the 2009-2011 resource needs were to be met solely by additional new DSM resources, FPL would need to find an additional 1,976 MW of cost-effective DSM. Accounting for FPL's 20 percent reserve margin criterion, the 2,371 MW of generating capacity need would become 1,976 MW of DSM (2,371 MW/1.20 = 1,976 MW). There is not 1,976 MW of additional, cost-effective DSM available to meet this need. This will be further discussed in Section VII.C.

Table IV. C. 1

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

Summer

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2009	22,151	2,249	24,400	22,884	1,759	21,125	3,275	15.5%	**950**
2010	22,151	1,951	24,102	23,424	1,849	21,575	2,527	11.7%	**1,788**
2011	22,151	1,906	24,057	23,964	1,941	22,023	2,034	9.2%	**2,371**

Winter

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
January of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Winter DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Winter Reserves (MW)	Forecast of Winter Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2009	23,558	2,309	25,867	22,916	1,679	21,237	4,630	21.8%	**(383)**
2010	23,558	2,008	25,566	23,466	1,736	21,730	3,836	17.7%	**510**
2011	23,558	1,915	25,473	24,035	1,796	22,239	3,234	14.5%	**1,214**

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

D. Consistency with Peninsular Florida Need

FPL's need for an additional 2,371 MW of supply resources (or 1,976 MW of demand side resources) is consistent with Peninsular Florida's need as identified by the Florida Reliability Coordinating Council (FRCC) in its 2005 reliability work reported in its FRCC 2005 Regional Load & Resource Plan. The FRCC's 2005 reliability work used FPL-specific data contained in FPL's 2005 Ten-Year Site Plan (TYSP) in conjunction with similar information from other Florida electric utilities.

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 employ various analyses to develop the framework of future conditions used in the 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 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, 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, Florida real total personal income, and Cooling and Heating Degree Days as explanatory variables as well as a dummy variable for shoulder months.

(B) **Commercial** sales are forecast using a linear multiple regression model which contains the following explanatory variables: Florida's non-agricultural employment, commercial real price of electricity, Cooling Degree Days and an autoregressive term.

(C) **Industrial** sales are forecast through a linear multiple regression model using industrial customers, industrial real rice of electricity, Cooling Degree Days, a dummy variable for outliers, and an autoregressive term.

(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, 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 separate annual econometric model is also developed to produce a NEL forecast.[6] The key inputs to the model are: the real price of electricity, Heating and Cooling Degree Days, Florida Non-Agricultural Employment and an auto-regressive term. Once the annual 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 sales by class are then adjusted to match the NEL from the annual econometric NEL model.

In addition, a similar monthly model for NEL is developed using Florida's Real Personal Income as the economic variable and a dummy variable for the month of February. The forecasts from the annual and monthly models are combined to develop the 20-year monthly NEL forecast.

(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.

(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 total personal income and maximum peak day temperature.

(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

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

variables: the minimum temperature on the peak day and heating degree hours for the prior day as well as for the morning of the winter peak day. The model also includes an economic variable: Florida real total personal income.

b. Forecast Results

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

Table V.A.1.c.1

FPL's 2005 Load Forecast Results

Compound Average Annual Growth

Years	Total Customers	Net Energy For Load	Summer Peak	Winter Peak
1996 - 2005	2.2 percent	3.0 percent	3.7 percent	-0.1 percent
2006 - 2015	1.7 percent	2.6 percent	2.4 percent	2.4 percent
2016 - 2025	1.4 percent	2.0 percent	2.2 percent	2.3 percent

The forecasts of peak demands and NEL used in the RFP analyses are presented in Appendix E. Also presented in Appendix E are the output from the models used to develop FPL's peak load forecast and the work papers supporting the peak load forecast used in FPL's reliability assessment.

2. The Fuel Price Forecast

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major factors 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

FPL's fuel price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's methodology is the following: (1) for the current and next two years (2005, 2006 and 2007 for the October 21, 2005 fuel price forecast used in the RFP evaluation), FPL's forecast methodology used the October 21, 2005 forward curve for oil and natural gas prices; (2) for the next two years (2008 and 2009), FPL used a 50/50 blend of the October 21, 2005 forward curve and the latest forecast from The PIRA Energy Group; (3) for the following period through 2020, FPL used the annual projections from The PIRA Energy Group in constant dollar terms; and (4) for the period beyond 2020, FPL used a fixed dollar per MMBtu difference in constant dollar terms from the delivered price of oil and natural gas, and solid fuel to the FPL system.

For coal and petroleum coke, FPL develops its constant dollar forecasts using the following approach: (1) the development of a plausible, integrated set of economic, fundamental supply and demand and environmental assumptions or drivers; (2) a qualitative and quantitative translation of these assumptions into price forecasts on a constant dollar basis; (3) a comparison to historical values and a current set of published forecasts, on a constant dollar basis, for reasonableness; and (4) a conversion from constant dollar to nominal dollar prices.

FPL's forecast methodology and resulting fuel price forecasts reflect fuel price trends that are sufficient for use in the resource planning process. The forecast describes market conditions that are considered the most likely to occur.

In addition to the development of commodity prices, real price forecasts are also prepared for fuel transportation costs. Delivered real fuel prices are derived by adding the transportation cost component to the price of the commodity. The resulting forecasts are multiplied by Global Insights' forecast of the GDP implicit price deflator to produce nominal delivered fuel price forecasts. These final forecasts for each commodity are reviewed to ensure reasonableness and consistency.

b. Fuel Price Forecast Results

The detailed fuel price forecast for these fuels is presented in Appendix F.

c. **Fuel Supply and Availability**

(i) Natural gas

Natural gas is the primary fuel source for the proposed West County 1 and 2. Natural gas would be supplied through a 34 mile extension of the Gulfstream pipeline from Station 712 near the Martin site to the West County 1 and 2 site.

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 imports and LNG imports that will add to sufficiently meet the projected growth in natural gas demand of the United States. According to recent data from the Department of Energy – 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 proposed West County 1 and 2 also will be capable of burning light oil. Light oil will be used as a backup fuel in the event of a natural gas supply disruption. Light oil would be trucked from local markets to the plant site where it would be stored in two 6.2 million gallon tanks. The 12.4 million gallons of storage represents approximately one hundred eight (108) continuous hours of full load operation for the WEST COUNTY site.

3. Financial and Economic Data

The financial and economic assumptions used in the resource planning process, the selection of the NPGU and the analysis of proposals received in response to the RFP are presented in Appendix G.

B. Geographic or Location Preference.

The Southeast area of FPL's system includes the southern half of Palm Beach County and Broward and Miami-Dade Counties. The Southeast area is a major load center in the State of Florida with a summer peak demand of approximately 12,000 MW that is growing at a rate of 250-300 MW per year. In 2005, the demand in this area was served by about 6,500 MW of generation located in the area and generation that is delivered from the north and west by transmission facilities providing import capability. The import capability into the Southeast area is finite, approximately 6000-7000 MW comprised of about 5000-6000 MW from the north and the remaining 1000 MW from the west. This import capability can be lower when generation and/or transmission facilities in and around the Southeast area are unavailable (e.g., due to maintenance or unplanned outages). No other sources of power or imports are available to the Southeast area. The discrepancy between Southeast area demand and generation resources located in Southeast Florida is what FPL refers to as the generation / load imbalance in Southeast Florida.

Reliability is maintained in the event of an unplanned outage of a generator. This is accomplished through a combination of available import capability into the area (that which is available and not currently in use) and available generation located in the area (unit capacity available but not dispatched). In order to maintain reliability in the Southeast area as load grows, either generation capacity, transmission import capacity or a combination of both must be added. Upgrades to transmission import capacity can be an option but, they not only require a lengthy permitting and construction process that must be incorporated into the planning process, transmission solutions have several cost implications. The first implication is that transmission integration costs are generally higher for new generation additions located outside the Southeast area because they require equipment across a broader area of the transmission grid. The second issue is created by the additional distance that power must be moved when locating new generation outside the Southeast area. Transmission losses are proportional to the distance traveled and therefore the cost of replacing lost capacity and energy increase for generation located outside the Southeast area. The third issue is that without new efficient generation located in Southeast Florida, the need to dispatch older, less efficient generation located in Southeast Florida out of economic merit order would occur more frequently. This dispatch requirement would necessarily result in higher fuel and operating costs for systems with new generation located outside of the Southeast area as compared to systems with new generation located within the Southeast area. These are cost factors that must be considered when comparing the relative costs of new generation.

FPL's prior planning work concluded that additional installed capacity or transmission capacity was needed to address the imbalance. In 2004 FPL received approval to construct Turkey Point Unit 5, a 1,117 MW generation facility located in southern Dade County that will be operational in the summer of 2007. This additional generation will address the imbalance that has developed prior to 2007 and provide some margin for future growth or the event that load growth to 2007 is higher than forecast. Continued load growth of 250 - 300 MW per year is forecasted for the Southeast area. This load growth will make the imbalance between generation and load more pronounced and once again will require additional generation or transmission import capacity into the Southeast area. This factor has contributed to the identification of West County 1 and 2 as FPL's next planned generating units for the period 2009 - 2011. The location of these proposed capacity additions would continue to mitigate the Southeast generation / load imbalance.

FPL includes methods to reflect all of the costs associated with transmission issues in its Integrated Resource Planning processes and in the evaluation of RFP proposals. Transmission integration costs are captured by developing specific cost estimates to integrate each candidate portfolio into the existing FPL transmission system. A specific analysis is also developed to estimate the impact of unit additions on transmission system losses during average and peak conditions and assign monetary values to these losses. These analyses and methods have been developed and applied in past RFP's. The third transmission related cost impact treated in the evaluation was the cost incurred by the system in dispatching Southeast area units out of economic merit to maintain reliability. Previous RFP's had estimated this cost using a stand alone analysis. This was necessary in past RFP evaluations because the models used were insensitive to the hourly dispatch detail and transmission constraint characterization that is necessary to assess these costs. In this RFP, the economic impact of dispatching Southeast area units out of economic merit to maintain reliability was modeled intrinsic to the production cost model used as the basis for variable costs in the integrated model. A more detailed discussion of the evaluation models is provided in Section VI.B of this Need Study.

This improvement to the economic modeling process results in the costs associated with non-economic dispatch (created by maintaining the Southeast area reliability) being developed as an intrinsic part of the generation cost estimates that are created for each portfolio. FPL has consistently communicated the existence of the Southeast generation / load imbalance and the subsequent economic impact of the geographic location of new generation capacity. The evaluation methodology is designed to objectively evaluate and account for the cost impacts created by geographic location.

C. Impact on Capital Structure

The financial obligations created by new generation resources (purchased power or self-build) can significantly impact FPL's capital structure. The selection and approval of generation resources built by FPL requires FPL to finance the development and construction of the facility. For its self-build options, FPL assumes standard financial vehicles, maintaining a 55/45 percent equity to debt ratio. When taking on new generation through a purchased power obligation, FPL is generally assigned a debt equivalency based on the magnitude of the purchase obligation by credit rating agencies. Unaddressed, this debt equivalency would shift FPL's capital structure to a more costly debt heavy ratio. Therefore, in order to conduct a fair comparison the cost necessary to neutralize the impact on the utility's capital structure of the assigned debt equivalency must be estimated and assigned to the proposal that creates the issue.

The equity adjustment is used to capture the cost to FPL of restoring its capital structure to its target 55 percent equity / 45 percent debt ratio. The cost of this adjustment is a real cost, and must therefore be included to properly capture the impact of a purchased power obligation on the Company's capital structure. In order to facilitate a fair comparison, the cost of this adjustment must be considered in the comparison of a self-build option to a purchased power proposal. This allows FPL to establish a quantitative basis under which FPL's capital structure is held neutral. Appendix E.3 of the RFP contains a description of the net equity adjustment, including the methodology to compute the adjustment of mitigating effects, that a purchased power obligation creates on FPL's balance sheet.

D. Customer Protection

FPL has a statutory obligation to serve and is extensively regulated as to its costs and performance. The Commission has jurisdiction over FPL to ensure that FPL is meeting its obligations to its customers. However, the Commission does not have jurisdiction over entities that supply electricity, or for that matter, fuel, equipment, or other services to FPL. Therefore, the Commission cannot directly protect FPL's customers from these entities in the event of delays, poor performance, misconduct or negligence. FPL's customers and the Commission rely on FPL to provide that protection. The only means FPL has to provide that protection by: (1) only entering into contracts with selected entities that can reasonably be relied upon to perform as specified in the contract; and (2) requiring that the contracts FPL enters into with those entities include terms that protect the customers' interests.

Having contract protection is essential, and for that reason FPL goes to great lengths to insist on terms that protect its customers. This applies to the purchase of fuel, the acquisition of major equipment, and the procurement of services, as well as power purchases. However, having the right contract terms is sometimes not sufficient. If a supplier becomes financially distressed, it may not be able to perform and could use bankruptcy protection to evade some contract provisions designed to protect customers. This presents two challenges to FPL regarding the RFP. The first challenge is to enter into PPAs with entities that, at least at the time the contract is entered into, can demonstrate in a number of ways that they can perform their obligations under the PPA. The second is to insist on contract terms that are designed to protect FPL's customers even in the event of a supplier's unforeseen financial distress. FPL's RFP process reflects its recognition that it must strive to meet these challenges to protect its customers.

These general concerns have become increasingly important in light of further recent deterioration in the financial condition of many suppliers in the IPP industry. As a point of fact, one of the Proposers in FPL's 2003 RFP, Calpine Corporation, has recently declared bankruptcy. In FPL's 2003 RFP the security requirements prevented that Proposer, based on their financial viability at the time of the Proposal, from being qualified as a viable entity. These criteria have worked to protect FPL's customers. In light of these circumstances, FPL has established and maintains specific financial requirements as measures to protect its customers. These measures must be met in order for FPL to consider purchased power options to be reasonably comparable to FPL self-build alternatives in terms of the risks they present to customers.

A secondary perspective regarding customer protection recognizes that the RFP, as a portion of the overall resource procurement process, is a necessary step towards maintaining system reliability. Delays in accomplishing the timely procurement of generation resources needed to maintain system reliability criteria places the customers at risk. Therefore it is important that the RFP process be constructed so that it can be successfully executed, without concern regarding its ability to withstand Commission and public review, in order to support the timely acquisition of needed generation.

E. Transmission System Restructuring

FPL endeavors to make generation alternative selections that will offer reliable and cost-effective service to its customers even in the event that governmental actions change the regulatory structure in which FPL operates. There continues to be attention at the state and federal level dealing with potential changes to the regulatory framework regarding transmission assets. Generating alternatives selected to meet FPL customer needs must be capable of delivering resource needs in a number of potential future transmission scenarios. FPL included as a minimum requirement that every proposer agree that, if its proposal were selected to provide capacity and energy under contract, the proposer would obtain and maintain the transmission rights necessary to effectively deliver the output of its generating unit to meet the needs of FPL's customers. This requirement ensures that under almost any scenario, FPL's customers will be able to retain the same level of access and relative cost in place at the time the resource selection was made.

VI. MAJOR AVAILABLE GENERATING ALTERNATIVES EVALUATED

The next step in FPL's 2005 planning work was the evaluation of economic and other key attributes of various self-build generation options available for meeting FPL's forecasted 2009 - 2011 capacity needs. This analysis led to the selection of FPL's next planned generating unit (NPGU), two new combined cycle power plants that would require certification under the Power Plant Siting Act (PPSA). In accordance with the Bid Rule, FPL developed and issued an RFP and conducted an RFP evaluation in which FPL's NPGU were compared to alternative portfolio proposals for meeting its 2009-2011 capacity needs to identify the most cost-effective alternatives available.

A. Self-Build Alternatives Considered

1. General Process

FPL assigns engineers and a project developer to conduct the preparatory analysis necessary to develop and build generation facilities. They work well in advance to identify multiple opportunities. The candidate alternatives then are provided to FPL's Resource Assessment and Planning Department, which conducts an economic analysis and coordinates the overall evaluation necessary to determine the most cost-effective self-build generation alternative(s). This analysis relies upon the skills and experience of environmental specialists, transmission system engineers and fuels specialists in addition to the economic evaluation team. The objective of this process is to develop a recommendation of a resource plan that is both cost-effective and capable of meeting the quality, environmental and reliability standards suitable for inclusion in FPL's system.

FPL's examination of construction options with which it could meet its 2009-2011 capacity needs focused on conventional technologies which could be developed, permitted and constructed within four years. These technologies were examined within FPL's IRP process that employs a multi-year, expansion plan analysis to evaluate the economics of competing generating options.

2. Nature of Alternatives Reviewed

FPL periodically examines a variety of generation construction options in the course of determining the most economical self-build options for its system. Several factors influence the decision regarding the different types of alternatives that could reasonably be included in the resource planning process.

Solid fuel-based (coal) and nuclear power plants require more than six years to permit and to construct. While FPL's resource plan includes new solid fuel-based capacity additions in 2012 and 2013, and FPL is examining the feasibility of new nuclear units after 2013, these additions could not be brought on-line in the 2009-2011 time period. Therefore, in terms of selecting its best self-build option(s), these technologies could not address FPL's capacity need for 2009-2011.

Consequently, FPL's 2005 resource planning work focused on combustion turbine (CT) and combined cycle (CC) self-build alternatives to meet its 2009-2011 capacity needs. Analyses have consistently shown that CC units were generally better economic choices for FPL's system than are CT units. Due to continued growth in net energy for load, FPL's detailed economic analyses of construction options to meet its 2009–2011 capacity needs focused on different CC technologies and configurations. Different sites were also considered. Ultimately, FPL analyzed 31 different variations of CC technologies and configurations at the West County Energy Center site in western Palm Beach County.

3. Evaluation and Selection

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

For each portfolio, FPL evaluated the generator capital and O&M costs, transmission interconnection cost, system emission costs, gas pipeline costs, and system fuel costs (i.e., the "generation system" costs) in a multi-year resource plan approach using its Electric Generation Expansion and Analysis System (EGEAS) model.

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

Therefore, there were no differences between these self-build options in regard to costs related to transmission, gas infrastructure, or capital structure. As a result, the EGEAS analyses were able to capture the total cost differences between the portfolios. These analyses resulted in identifying the 3x1 Mitsubishi 501G option as the economic choice for FPL's system for the 2009–2011 time frame. One CC unit with a summer capacity of 1,219 MW to be placed in-service at the West County Energy Center site in June 2009, and a second such unit to be placed in-service in June 2010 at the same site, are FPL's best self-build options for meeting the 2009-2011 capacity needs. These units (West County 1 and 2) were designated as FPL's NPGU in its 2005 RFP. In addition, the 2009 CC unit, by itself, was designated an alternate generating unit in the RFP. Its inclusion increased flexibility in the evaluation and gave potential respondents to the RFP a known "pairing partner" if their anticipated capacity offering could not meet all of FPL's capacity needs.

B. Request for Proposal Process

FPL developed and employed a Request for Proposals (RFP) process in 2005 to solicit viable firm capacity and energy resources that could be compared to FPL's Next Planned Generating Units (NPGUs). Beyond addressing the timing and magnitude of capacity additions required by Florida's continued growth, FPL's Integrated Resource Planning process further identified additional needs. Key among these has been recognition that generation selection is the most effective means of addressing the reliability and economic impacts of geographic location and fuel diversity. Significant analytical activities were undertaken in 2003-2004 resulting in FPL's Clean Coal Technology Study (March 2005). That study demonstrated that advanced technology coal generation had approached an economic equivalency with efficient gas fired generation. As a result of those efforts, FPL's 2005 Ten Year Site Plan identified a generation plan that met the reliability, efficiency and fuel diversity needs of the system by proposing two efficient combined cycle generation units in 2009 and 2010 to address the system needs for the 2009-2011 period and proposing two advanced technology pulverized coal units in 2012 and 2013 to address system needs for the 2012-2014 period.

Specific to this Need Study, the 2005 Integrated Resource Planning process identified West County 1 and 2, installed as a combined project with delivery in 2009 and 2010, respectively, as the "Next Planned Generating Unit" (NPGU) for the 2009-2011 period. This selection set in motion the Power Plant Siting Act (PPSA) process. In connection with that process, FPL is required to obtain a Determination of Need from the Commission. The Determination of Need requires that a utility provide a demonstration of cost-effectiveness through a Request for Proposal (the Bid Rule) that solicits generation alternatives to the FPL NPGU. In accord with the Bid Rule, FPL issued a two part RFP in 2005.

Part One, which is the focus of this Need Study, addressed capacity resources needed to maintain or improve FPL's reliability and efficiency between 2009 and 2011. The timeline to complete the West County 1 and 2 in time for the 2009-2010 need required that the RFP for this segment be issued in 2005. Part Two, which is only partially discussed in this document, will solicit alternatives to maintain or improve FPL's reliability and fuel diversity needs between 2012 and 2014. Due to the longer timeline required to develop fuel diverse technologies, FPL chose to take the public step of identifying its intent to solicit proposals in 2006 in the 2005 RFP document. This action, along with the well published FPL position supporting fuel diversity in its Site Plans, served as a clear signal to potential participants to prepare their projects for submission in 2006.

When this two-part RFP process is completed, it is envisioned that it will result in the addition of approximately 4,000 MW of reliable, efficient and fuel diverse generation resources obtained under power purchases and/or FPL self-build units for the benefit of FPL's customers.

1. Development and Publication of the RFP

FPL considered four important areas in the development of the Request for Proposal process, including but not limited to: 1) compliance with the Bid Rule (Section 403.519, Florida Statutes), 2) an evaluation process that provided a fair comparison of proposals with FPL's next planned generating unit, 3) a process that protected the interests of FPL's customers, and 4) a process that will encourage participation of those who can offer opportunities to maintain a balanced fuel supply.

a. Compliance with the Bid Rule.

The Bid Rule was used as the primary reference for the development and execution of the FPL RFP process. Where specific actions were required of the utility or participants, FPL ensured those actions were taken and the completion of the steps documented. Where the Bid Rule directed specific content be included in the RFP, such as the description of FPL's Next Planned Generating

Unit, FPL ensured that the specified content was included in clear and concise terms. The content was reviewed by multiple departments within FPL to ensure compliance with the Bid Rule and accuracy of information. Equally important, the Bid Rule provides general guidance as to how the RFP process is to be organized and conducted. Throughout the entire process FPL ensured that the RFP met the spirit and letter of the Bid Rule requirements.

As encouraged by the Bid Rule, FPL drafted its RFP to enable proposers to present a wide range of resource alternatives in a number of transactional formats. The 2005 RFP allows for purchased power sales from interconnected utility systems, purchased power sales from existing or new construction assets, outright facility sales (transfer of ownership) and Engineer, Procure, Construct (EPC) Turnkey offerings. This format resulted in the solicitation of four proposals from three bidders representing four distinct types of transactions in the 2005 RFP. FPL was offered a purchased power sale from an interconnected utility system, a purchased power sale from an existing asset and a purchased power sale from a new construction asset, as well as the transfer of ownership of an existing asset.

FPL also included an alternative generating unit located in Southeast Florida with which potential proposals could be combined in portfolios that satisfied the need for the 2009-2011 period. The FPL alternative generation unit was a single 3x1 CC unit at West County with a COD of June 1, 2009. The inclusion of such an alternative generation option was intended to aid proposers by (a) creating an option with which proposals smaller than FPL's entire need could be combined, and (b) provide a generating alternative that was located in Southeast Florida, thereby reducing the likely impact of transmission-related costs for portfolios that included proposals located outside Southeast Florida combined with the alternative generating unit.

As FPL has done in past solicitations, an external evaluator was contracted to independently conduct an economic evaluation and review FPL's overall RFP evaluation process. Mr. Alan Taylor provides direct testimony to describe the results of his activities.

b. Fair Comparison.

FPL's 2005 Generation Capacity RFP contained several specific features to ensure that the subsequent evaluation of proposals solicited by the RFP could be conducted in a fair comparison with FPL's Next Planned Generating Unit. These include, but are not limited to (1) requiring specific data requirements for all proposals, (2) a clear description of the evaluation process, and (3) minimum requirements that established the framework for proposals to ensure that proposals were economically and functionally similar in key respects to enable a fair comparison to each other and to the Next Planned Generating Unit.

Appendix D to the 2005 RFP document provided a discussion of the specific data required and forms for the submission of data to ensure all Proposers included the necessary detail to support the evaluation. These forms were provided to Proposers on the website download page in an Excel® format file.

Section II.E of the RFP provided a step-by-step description of the evaluation process from proposal receipt to Final Selection. Further detail on the evaluation process, including example calculations, were provided in Appendix E.1-E.4 of the 2005 RFP document. This process was reviewed at the Pre-Issuance meeting and Participants were able to ask clarifying questions throughout the process.

FPL communicated explicit threshold proposal data and content necessary for a proposal to be considered as compliant through its minimum requirements. Due to the two part nature of the RFP, these were divided into General Minimum Requirements (Section II.C) that applied to Part One and Part Two, and Specific Minimum Requirements (Section III.E) that applied only to Part One.

The first eight general minimum requirements (Section II.C.1-8) define proposal submission requirements to ensure that necessary information is provided, and that the resulting proposals all meet the same criteria for contract term, firm capacity and other important defining features.

Three specific minimum requirements (Section III.E.3, 4 and 6) delineate the cost components that a Proposer is required to include within their quoted price and describe the Proposer's obligations with respect to transmission and maintaining fuel supply continuity. Explicitly describing the expected content of each proposal helps to ensure that the proposals can be fairly compared to each other and the Next Planned Generating Unit.

c. Protection of Customers.

Minimum requirements also enable FPL to convey concepts to Participants that FPL has identified as necessary to protect customers.

Four specific minimum requirements (Section III.E.1, 2, 5 and 7) limit the scope of the RFP to a prescribed capacity and define the necessary financial, schedule and experience qualifications required of bidders. These minimum requirements ensure that FPL is negotiating with entities that have the capability, financial fortitude and experience to perform and obtains financial and schedule commitments to ensure that performance.

Three general minimum requirements (Section II.C.9, 10 and 11) describe items that would be a part of any purchased power agreement resulting from the RFP process. These requirements are necessary inclusions that ensure that FPL can manage the contracts within the regulatory environment and that FPL would have access to information that is required to be reported under the current accounting standards.

An additional perspective related to ensuring customer protection recognizes that the RFP process is one part in the overall resource procurement process. By ensuring that the RFP is conducted in compliance with the Bid Rule, FPL protects its customers by limiting the opportunity for delay in procuring the capacity resources needed to maintain system reliability criteria.

d. Maintaining a Balanced Fuel Supply.

FPL's Integrated Resource Planning processes continue to indicate a need for generation capacity to meet load growth. Recent studies have also demonstrated the benefits of maintaining a balanced fuel supply and the need to pursue cost-effective options that provide fuel diversity. This work motivated development work that began in 2003 to firm up the costs and viability of different technologies that could provide fuel diversity. In 2004 an economic analysis was conducted that compared the lifecycle costs of coal fired generation and natural gas fired generation under a range of fuel market and emission compliance scenarios. The results of the study were presented to the Commission in March of 2005 noting that the economics were supportive of coal fired generation in many of the scenarios studied. The 2005 Ten Year Site Plan reflected this finding and identified that the generation plan that best met the timing and magnitude of additional capacity and helped to maintain a balanced fuel supply combined two efficient combined cycle generation units in 2009 and 2010 with two advanced technology pulverized coal units in 2012 and 2013.

FPL chose to send a clear signal to potential Participants in the market to indicate our desire to maintain a balanced fuel supply and explain the steps we were taking to foster fuel diverse generation alternatives. The need for generation in 2009 coupled with the most expeditious timeline to install cost-effective, efficient baseload generation required that an RFP be initiated in 2005. The longer timeline required by coal-based generating technologies required that FPL initiate the process to select those resources no later than 2006. It was determined that a two part RFP issued in 2005 would help satisfy both objectives.

FPL recognized it was important to demonstrate our commitment by initiating the RFP process for fuel diverse options early so that prospective developers of alternative fuel generation facilities would be motivated to undertake the activities necessary to develop projects that could be proposed in Part Two of the RFP, scheduled for 2006. This was in keeping with the information FPL published in our Clean Coal Study of March 2005 and the identified need for fuel diversity discussed in the 2003, 2004 and 2005 Ten Year Power Plant Site Plans.

2. Post–Issuance/Proposal Workshop, Objection Process, and RFP Addenda

On August 18, 2005, in accordance with the Bid Rule, FPL issued a press release for trade publications and newspapers and published a Notice in the New York Times, the Wall Street Journal and the Miami Herald newspapers announcing its intent to issue an RFP. FPL's press release and notices also announced pre-issuance and proposal workshop meetings to be held in Miami that interested entities could attend in-person or by telephone. The press release and the notices published by FPL announcing these meetings and FPL's RFP are provided in Appendix H to the Need Study.

A website was established for the 2005 RFP where participants could register their interest in the RFP process and be retained on a listing to receive process communications and access to RFP documents. Through the course of the pre-publication period 31 individuals representing 20 companies or organizations registered in the process. Seventeen of those registrants indicated they had an interest in participating as a bidder in Part One or Part Two of the RFP, the remainder having peripheral interest in the process. The registered participants are provided in Appendix I, Table 1.

Consistent with its press release and published notices, FPL conducted a pre-issuance meeting in Miami on September 7, 2005. Fifteen individuals representing 10 organizations participated in the forum in person or by teleconference. Following RFP Publication, FPL conducted a Pre-Bid Workshop on September 14, 2005. Ten individuals, representing 7 organizations participated in the workshop in person or by teleconference. The individuals attending FPL's RFP related meetings are identified in Appendix I, Table 1. Consistent with the Bid Rule, FPL invited not only the Commission Staff, but also the Office of Public Counsel to both the pre-issuance meeting and Pre-Bid Workshop.

When FPL published its RFP on September 9, 2005, a number of provisions were included that were intended to assist Participants in providing proposals that would benefit FPL customers. For example, FPL included two draft Purchased Power Agreements (Tolling and Non-tolling) in its RFP setting forth FPL's preferred terms to which potential proposers could state exceptions and propose alternative language. The publication of this information better informed proposers of FPL's preferences and allowed proposers to offer alternatives.

Enabled by the Bid Rule, Participants were provided an opportunity to raise objections if they felt that FPL's RFP did not comply with the Bid Rule. No objections were raised in the 2005 RFP process.

FPL continued to engage interested participants and observers throughout the period leading up to proposal submission. FPL published one Addendum on September 12, 2005, correcting a typographical error in a table located on page 41, Section III.C.6.a of the RFP. FPL also published two Notices. Notice #1 of October 13, 2005 discussed issues related to developing the Fuel Forecast, and Notice #2 of November 4, 2005 provided the Fuel Forecast that was used for the RFP evaluation. The RFP is included as Appendix D and Addendum One and Notices #1 and #2 are included in Appendix H to this Need Study.

Additionally, FPL maintained an open line of communication with Participants fielding and answering questions as Proposers developed their bids. Fifty-Nine Questions and Answers were published in three sections, as they were received, on September 30, October 13, and November 4, 2005. The Questions and Answers are provided as Appendix I to this Need Study.

3. Proposals Received

Three Bidders provided five proposals in response to FPL's 2005 RFP. This level of response is consistent with the levels of response in FPL's most recent (2003) capacity solicitation. The five proposals received by FPL in response to the 2005 RFP are summarized in Table VI.B.3.1. below.

Table VI.B.3.1.

Summary of Proposals Received

Proposal	Location	Capacity & Term	Technology	Fuel
P1	St. Lucie	1,050 MW, 25 years	New 3x1 G CC unit	Natural Gas
P2	DeSoto County	298 MW, Sale of units	Existing Combustion Turbine	Natural Gas
P3	DeSoto County	298 MW, 15 years	Existing Combustion Turbine	Natural Gas
P4	Inter-connected system	50 MW, 5 years	Sale from utility system	Various
P5	Inter-connected system	50 MW, 3 years	Sale from utility system	Various

4. Initial Assessment

As previously discussed, FPL set forth criteria as minimum requirements that had to be met by all proposals. Proposals from all three Bidders included information that was incomplete, confusing, and/or which contained proposed exceptions to some of the minimum requirements. FPL notified these Bidders of the nature and extent of the problems with the data submitted with the proposals and encouraged them to provide the missing data, clarify the data, and/or to make changes to bring the proposals into compliance. In parallel with this effort, FPL initiated its economic evaluation of all proposals in order to avoid delays in the evaluation process.

5. Economic Evaluation

FPL first evaluated the five individual proposals to determine their relative economic strength on the FPL system. These results showed that proposal P1 was the most economic, followed next by P4 and P5. P2 and P3, the CT-based proposals, were the least economic proposals. After considering these results, the fact that CT-based capacity did not enhance FPL's fuel diversity, and the largely superfluous role these proposals would play in a portfolio designed to address FPL's 2009–2011 capacity needs, P2 and P3 were dropped from further consideration in the economic evaluation.

FPL next constructed 6 portfolios. One portfolio consisted solely of FPL's NPGU. The other 5 portfolios consisted of various combinations of FPL's alternate generating unit and proposals P1, P4, and P5. The 6 portfolios created, including FPL's NPGU, are identified in Table VI.B.5.1 below.

Table VI.B.5.1

Summary of Portfolios Evaluated

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

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

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

Following the creation of these 6 portfolios, proposal P5 was withdrawn by its Bidder, effectively eliminating Portfolios 3 and 6 from further consideration. FPL continued on with its evaluation of the remaining 4 portfolios (with no change in the portfolio numbering).

The economic evaluation of the remaining four portfolios quantified four major cost categories: generation system costs, transmission-related costs, upstream gas pipeline costs and the impact of each option on FPL's capital structure. All costs presented are cumulative present value of revenue requirement (CPVRR) costs in 2005$ addressing the years 2005 through 2037.

a. Generation System Costs

FPL's calculation of the generation system costs was performed with the combination of its P-MArea production costing model and the Fixed Cost Spreadsheet model designed to capture all fixed costs associated with the competing portfolios. The generation system costs include all capital costs to develop, construct, commission, and operate the facility for the term of the analysis in the case of a self-build option, and all capacity and energy payments in the case of a PPA. O&M costs as well as fuel commodity, fuel transportation, fuel infrastructure, system emission (SO2) costs, and transmission interconnection costs are included in this analysis. In addition, the use of the P-MArea model allows the inclusion of geographic transfer limits in the production costing analyses, thus capturing the impact that each portfolio will have on the dispatch of existing generating units in the Southeast Florida region.

The evaluation of these costs in terms of long-term resource plans allows an economic analysis of how the capacity options included in the portfolios will be dispatched in the FPL generation system. Therefore, this portion of the analysis reflects system benefits created by how the specific attributes of the portfolio interact with the current FPL generation system.

Portfolio 2 (consisting of West County 1 and 2) offered the lowest generation system cost of all portfolios with a \$15 million CPVRR advantage over the next most competitive portfolio, Portfolio 1 (consisting of West County 1 and 2 and the 50 MW system sale offered by proposal P4). The other two portfolios, Portfolios 5 and 4 (respectively consisting of West County 1 and proposal P1 alone, or West County 1, P1, and P4), were at least \$567 more expensive than Portfolio 2. The independent evaluator conducted a parallel system cost analysis using the RSM. That analysis confirmed FPL's results, with the independent evaluator concluding that Portfolio 2 was the lowest cost portfolio by \$5 million CPVRR over Portfolio 1 and by at least \$564 million CPVRR over the other two portfolios. FPL's results of the comparison of the portfolios are shown on Table VI.B.5.a.1.

Table VI.B.5.a.1

Economic Evaluation Results for Portfolios: Generation System Costs Only

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

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

Portfolio Number	Description of Portfolios 2009	2010	2011	Generation System Costs	Difference from lowest cost portfolio
2	WCEC 1	WCEC 2	---	99,640	0
1	WCEC 1 & P4	WCEC 2	---	99,655	15
5	WCEC 1	P1	---	100,207	567
4	WCEC 1 & P4	P1	---	100,218	578

All four portfolios contained West County 1. This demonstrated that FPL's offer to include the alternate generating unit in the analysis worked to the advantage of the Bidders. If the alternate generating unit had not been included in the RFP, only two portfolios would have been available to be evaluated. This is due to the fact that the maximum possible capacity that could be created by external proposals with 2009 in service dates totaled only 348 MW, far short of the 950 MW needed for 2009. Consequently, without the alternative generating unit, only the two portfolios, Portfolios 1 and 2, both containing West County 1 and 2, would have emerged as viable portfolios that met FPL's 2009 capacity needs. The inclusion of the alternative generating unit allowed two more portfolios, to be created and evaluated.

b. **Transmission-Related Costs.**

To ensure the evaluation considered the complete system operating cost created by the selection of a particular portfolio, it is necessary to model how that portfolio would be integrated into and operate within FPL's transmission system. There are three aspects to this determination: (1) calculation of system integration costs; (2) calculation of losses; and (3) the calculation of increased operating costs for existing Southeast Florida generating units. As previously mentioned, the third cost listed above was already captured by the use of the P-MArea production costing model and these costs are reflected in the Generation System costs.

When the portfolios are developed, the portfolio information is provided to transmission engineers who conduct an integration study to determine the capital improvements to the FPL system necessary to integrate the resource(s) in accord with reliability criteria. The costs of these capital improvements comprise the transmission integration cost for the portfolio. After evaluating the four portfolios, the conclusion was that there were no transmission integration costs for any of the portfolios.

The transmission engineers also conduct analyses to determine the peak load (MW) and average load (MW) losses associated with the portfolio. The economic evaluation team converted these MW losses into annual energy (MWH) losses. The capacity and energy loss estimates for each portfolio are provided in Appendix L. The physical loss estimates then are converted to monetary costs by the Resource Assessment and Planning Department based on the procedure identified in Appendix E of the RFP. These costs comprise the transmission loss costs for the portfolios. The costs are referenced to the lowest cost portfolio in terms of loss as differential costs and are listed for each portfolio in Appendix M.

The results of the transmission analysis increased the separation between Portfolio 2 and all other portfolios, with Portfolio 2 now at a $22 million CPVRR advantage over the next most competitive portfolio, Portfolio 1, and at least a

$641 million CPVRR advantage over the other two portfolios. The results of this intermediate step are shown in Table VI.B.5.b.1.

Table VI.B.5.b.1

Economic Evaluation Results for Portfolios:
Generation System & Transmission-Related Costs Only
(millions, CPVRR, 2005$, 2005 - 2037)
(note: assumes all Proposals are eventually declared as "eligible")

Portfolio Number	Description of Portfolios 2009	2010	2011	Generation System Costs	Transmission-Related Costs	Total Costs	Difference from lowest cost portfolio
2	WCEC 1	WCEC 2	---	99,640	0	99,640	0
1	WCEC 1 & P4	WCEC 2	---	99,655	7	99,662	22
5	WCEC 1	P1	---	100,207	74	100,281	641
4	WCEC 1 & P4	P1	---	100,218	80	100,298	658

a. Upstream Gas Pipeline Costs.

The goal of this aspect of the analysis was to capture the effect of each portfolio on both upstream gas pipeline costs not accounted for by the cost of the individual proposals and self-build options. In regard to upstream gas pipeline costs, it was determined that there were no additional gas pipeline costs for any of the portfolios. Consequently, this cost was zero for all portfolios.

b. Impacts on Capital Structure.

This portion of the analysies was designed to capture the impact of the portfolios on FPL's capital structure. The impact on FPL's capital structure of FPL's NPGU and FPL's alternate generating unit had already been addressed by employing an incremental capital structure of 55 % equity and 45 % debt in the analysis of these additions. The impact on FPL's capital structure of PPA obligations with proposed terms of service greater than three years was taken into account through a net equity adjustment applied to the proposals.

The equity adjustment formula was adapted from Standard & Poor's rating methodology. It considers the magnitude and term of the PPA capacity payments, and it employs a 10 % discount factor and a 30 % risk factor to calculate an amount of imputed debt. Next, the amount of additional equity necessary to offset the imputed debt and restore a 55 % equity and 45 % debt capital structure is calculated. Then the cost of this additional equity is calculated. Additionally, FPL incorporated mitigating factors that contributed to offset the equity adjustment. The combination of the equity adjustment calculation and the mitigating amount is the net equity adjustment for a portfolio. The methodology employed to calculate the net equity adjustment in this RFP was provided in detail in Appendix E to the RFP, which is Appendix D of the Need Study.

The impact on capital structure analysis completed FPL's economic evaluation of the competing portfolios and the results are presented in Table VI.B.5.c.1. The primary conclusion to be drawn from the economic evaluation now that all costs had been accounted for is that Portfolio 2, consisting of West County 1 and 2, is FPL's most economic approach to meet its 2009–2011 capacity needs by at least $24 million CPVRR over the next best portfolio, Portfolio 1, that consists of West County 1 and 2, and P4 and by at least $758 million CPVRR over the other two portfolios.

Table VI.B.5.c.1

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

Portfolio Number	Description of Portfolios 2009	2010	2011	Generation System Costs	Transmission-Related Costs	Upstream Gas Pipeline Costs	Net Equity Adjustment	Total	Difference from lowest cost portfolio
2	WCEC 1	WCEC 2	---	99,640	0	0	0	99,640	0
1	WCEC 1 & P4	WCEC 2	---	99,655	7	0	2	99,664	24
5	WCEC 1	P1	---	100,207	74	0	117	100,398	758
4	WCEC 1 & P4	P1	---	100,218	80	0	119	100,417	777

6. Non-Economic Evaluation

There were a number of non-economic attributes associated with each proposal. These attributes taken together presented a risk profile associated with the selection of each proposal. To evaluate these additional risk attributes, FPL identified three major areas to be reviewed by subject matter experts. The areas covered environmental, technical, and project execution factors. Appendix E of the RFP provides the details of the three areas that are summarized below.

a. **Environmental Area.** This review evaluated the likelihood that each of these portfolios would successfully attain the necessary permits, licenses and regulatory approvals in the time frame needed to meet the needs stated in the RFP. The experience of the Bidder was considered along with the technical specifics of the proposal.

b. **Technical Area.** This review evaluated the technical and operational merits of the two portfolios. Factors such as the technology employed as well as the design limitations and ratings of the equipment were reviewed.

c. **Project Execution Area.** This review primarily focused on the exceptions taken by Bidders to the RFP terms or the draft PPA (in areas that were not minimum requirements). This allowed FPL to consider the likelihood of reaching a mutually agreeable PPA within the required timeframe should a portfolio containing their respective proposals be selected.

d. **Overall Assessment.** In summary, both proposal P1 and proposal P3 were determined to be unsatisfactory in regard to the exceptions taken in their proposals. Since none of the four remaining portfolios included P3, there was no impact on the portfolios resulting from this risk assessment of P3. However, since P1 plays such an integral role (based on its capacity amount and term of service) in two of the remaining four portfolios, those portfolios (Portfolios 4 and 5) were determined to be unsatisfactory in terms of risk. See Appendix O for the details of these non-economic reviews.

7. .Eligibility Determination Evaluation

As previously mentioned, an eligibility determination evaluation was conducted for each proposal to determine if the proposal complied with the Minimum Requirements of the RFP. After discussions with the individual proposers had taken place regarding proposal areas that did not appear to meet these Minimum Requirements, proposal P1 was determined not to meet all of the Minimum Requirements and it is questionable if proposal P3 met them. As a result, proposal P1 again was found to have an unacceptable level of risk and proposal P3's risk profile was not enhanced by this review of compliance with the RFP Minimum Requirements.

8. Conclusions and Recommendations to FPL Management

The results of both FPL's and Sedway Consulting's economic evaluations showed significant cost difference of at least $758 million CPVRR between Portfolio 2 consisting of West County 1 and 2 and the two competing portfolios that did not contain both West County 1 and 2. The other competing portfolio, Portfolio 1 that consisted of West County 1 and 2, and P4, was $24 million CPVRR more expensive than Portfolio 2 due to the inclusion of proposal P4.

In addition, both the non-economic evaluation and the eligibility determination evaluation found that proposal P1 and, therefore, the two portfolios including P1, were unsatisfactory from a risk perspective.

Based upon these evaluations, FPL's Resource Assessment and Planning Department recommended to FPL's management that West County 1 and 2 be recognized as the best and most cost-effective alternatives available to meet FPL's 2009-2011 capacity needs. FPL's management concurred with this recommendation.

VII. NON-GENERATING ALTERNATIVES

A. FPL's Demand Side Management Efforts

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

The mix of DSM programs FPL has offered has evolved over time. Indeed, FPL continually looks for new DSM opportunities in its research and development activities. When a new DSM opportunity is projected to be cost-effective, FPL will introduce a new DSM program or incorporate the new DSM opportunity into one or more of its existing DSM programs. In addition, FPL has modified DSM programs over the years whenever possible to maintain the cost-effectiveness of the program and its continued viability. On occasion, FPL also has terminated DSM programs whose viability could not be maintained.

FPL's DSM efforts have made it a recognized leader in DSM in the United States. These efforts have resulted in summer peak demand reduction through 2005 of 3,519 MW at the generator. After accounting for reserve margin requirements, this amount of peak reduction that otherwise would have been needed is approximately equivalent to 10 power plants of 400 MW capacity. FPL has achieved this level of demand reduction and avoidance of new generating units without penalizing customers who are non-participants in its DSM programs. This is accomplished by offering only those DSM programs that reduce electric rates for all customers, DSM participants and non-participants alike.

B. FPL's Current DSM Goals

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 an aggressive goal of achieving 802 MW of incremental summer MW at the meter 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's current DSM Goals were presented in Table II.B.3.1.

FPL's DSM Goals call for FPL to implement 532 incremental MW of summer peak reduction at the meter during the 2005 through 2011 time frame. As mentioned in Section III, FPL assumed the successful accomplishment of these DSM Goals in determining its future capacity needs. Without this additional DSM, FPL's future capacity needs for 2009-2011 would have increased by over 600 MW (after accounting for line losses and reserve margin requirements) and capacity needs would have emerged a year earlier in 2008 as well.

FPL forecasts that it will achieve its DSM goals of 532 MW at the meter of DSM through 2011 (and, subsequently, the 2014 Goal of 802 MW at the meter) through a number of DSM programs. These programs are part of FPL's DSM Plan that was approved by the Commission in Consummating Order No. PSC-05-0323-CO-EG. FPL's current DSM Plan consists of six residential DSM programs, eight commercial/industrial DSM programs, one research program, and four research projects. A brief summary of each of these programs and research projects appears in Appendix P.

C. 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 for 2009-2011. There are several bases for this conclusion.

First, the Commission has previously determined that the reasonably achievable, cost-effective summer MW level of DSM on FPL's system between 2005 and 2011 is 532 MW at the meter as previously mentioned. Second, FPL has already counted this level of reasonably achievable DSM in its reliability assessment that resulted in the projected need to add 2,371 MW of new supply side resources. 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 2009-2011 resource needs were to be met solely by additional new DSM resources, FPL would need to find an additional 1,976 MW at the generator of cost-effective DSM to meet the 2009-2011 resource needs. It is unrealistic to conclude that FPL could implement sufficient new DSM programs in the next five years (mid-2006 through mid-2011) to meet these needs. The Commission previously determined there was only 802 MW at the meter of additional, achievable, cost-effective DSM for the entire ten-year period, 2005-2014. It would be unreasonable to conclude that FPL could achieve an additional 1,976 MW at the generator of cost-effective DSM in the next five years. This is particularly so given that it would take some time to secure Commission approval to proceed with new DSM programs or to modify existing programs. In fact, the time needed to secure this approval would likely reduce the available time to implement additional DSM from 5 years to 4 ½ years. Even if there exists cost-effective DSM not previously found by FPL or the Commission, not enough could be added in the time remaining to meet FPL's 2009-2011 resource needs.

VIII. ADVERSE CONSEQUENCES IF THE PROPOSED CAPACITY ADDITIONS ARE DELAYED OR DENIED

If West County 1 and 2 are not added, there are at least two adverse consequences that FPL's customers will likely face. One of these is lower system reliability and the other is higher system costs.[7]

A. Adverse Effects Upon FPL System Reliability

If West County 1 and 2 are not added in 2009 and 2010, and FPL makes no alternative arrangements to maintain its reliability criterion of a 20% reserve margin for those years, then FPL's customers would be served by a less reliable system than either the Commission or FPL have identified as appropriate. Using the updated November 2005 load forecast, plus the new power purchases and additional DSM that are projected to be added to address the earlier resource needs that result from the updated load forecast, FPL's summer reserve margins for those three years would decrease to 15.1% in 2009, 9.2% in 2010, and 6.5% in 2011. System reliability would be significantly degraded with these reserve margins. Consequently, FPL would need to seek replacement capacity to substitute for the MW that would have been supplied by West County 1 and 2.

As previously discussed, all of the portfolios examined included West County 1 in 2009; no credible alternative to the construction of this unit emerged from the RFP process. The responses to FPL's RFP identified only two proposals, one for 298 MW and another for 50 MW, totaling 348 MW for 2009. For 2010, a PPA option (proposal P1) of substantial size was identified through the RFP process for 2010. However, system reliability would still be significantly degraded in 2010 if West County 1 is not added in 2009 and proposal P1 is added in 2010. This is due to two factors. First, the unmet capacity need for 2009 simply carries over into 2010. Second, proposal P1 offers approximately 169 MW less than does either of the West County units. Therefore, a resulting 2010 unmet capacity need of over 700 MW would still exist if West County 1 and 2 were not added and proposal P1 is added in 2010.

[7] If West County 1 and 2 are not added, there would be a higher level of system emissions associated with the energy that these two units would have supplied now being generated by other FPL units.

In summary, FPL would need to seek replacement capacity for West County 1 and 2 if these units were delayed or denied. Insufficient capacity emerged from the RFP process to meet this need for replacement capacity.

B. Adverse Impact on Adequate Electricity at Reasonable Cost

West County 1 and 2 will be a highly efficient, reasonable cost units. If the project is delayed or denied, FPL's customers would forgo the lower costs associated with this generation addition. It would have to be replaced with higher-cost generation resources, either through increased operation of less-efficient existing FPL units, through higher cost power purchases (although not enough were identified through the RFP process to meet FPL's capacity needs), or through a combination of a higher cost FPL option(s) in conjunction with a higher cost purchase(s), assuming sufficient purchase MW could be found.

As discussed previously, all portfolios evaluated contained West County 1. The least cost portfolio not containing West County 2 was $758 million (CPVRR) more expensive than a portfolio consisting of West County 1 and 2. This cost would be expected to increase dramatically if West County 1 were not built.

In addition, even a delay in the in-service date of West County 1 will result in higher costs to FPL's customers. A seven month delay from the currently planned West County 1 start date of June 2009 to January 2010 would result in an increase of more than $14 million (Nominal) and a greater long term cost increase of approximately $52 million (NPV).

IX. CONCLUSION

FPL conducted a resource planning process to identify future capacity needs. FPL identified that 3,454 MW of new capacity would be needed between 2009 and 2013 to meet the reliability criterion of 20 percent summer reserve margin approved by the Commission. Based on FPL's 2005 analysis, without the proposed additions, FPL's summer reserve margin would drop to 15.5 percent in 2009, 11.7 percent in 2010, 9.2 percent in 2011, 7.0 percent in 2012 and 4.9 percent in 2013. In addition, FPL's 2005 integrated resource planning continued to address how to economically maintain a balanced fuel mix in its generation portfolio.

FPL conducted an evaluation of self-build alternatives to identify the best and most cost-effective alternatives to meet the projected needs during this period, as well as maintain a balanced fuel mix. FPL's analysis indicated that adding the proposed West County units 1 and 2 in 2009 and 2010, respectively, followed by the two proposed advanced supercritical coal units in 2012 and 2013 would be the best plan to meet both objectives for the benefit of FPL's customers. 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 West County 1 and 2.

In accord with the Commission's Bid Rule, FPL issued a Request for Proposals (RFP) on September 9, 2005 to solicit bids to supply capacity and energy for 2009 through 2011 that could be more beneficial than FPL's West County 1 and 2. In addition, in order to initiate the process of soliciting fuel diverse alternatives for 2012 and 2013 to compete with FPL's proposed coal units, the RFP issued by FPL was a two-part RFP, with Part 1 addressing the need in 2009 through 2011, and Part 2 inviting interested parties to prepare to respond to FPL's upcoming 2006 solicitation for fuel diverse proposals to meet FPL's needs in 2012 and 2013.

FPL evaluated four proposals with West County 1 and 2 as part of Part 1 of its RFP and determined that the addition of West County 1 and 2 is the most cost-effective option to meet customers' needs in 2009 through 2011 and that the next best alternative that does not include both West County units would be over $750 million (CPVRR) more costly to FPL's customers.

FPL's evaluation and conclusions were confirmed by an independent evaluator, who also found that the savings to FPL customers would be at least $750 million.

FPL needs West County 1 and 2 to maintain system reliability and integrity in 2009 and beyond, and to provide adequate electricity at a reasonable cost to its customers. The addition of West County 1 and 2 will also reduce fuel costs to FPL's customers because it will reduce the system average heat rate by 4 percent.

FPL is continuing the development process to add the two proposed advanced supercritical coal units in 2012 and 2013 and will issue an RFP Supplement by September 2006 to solicit fuel diverse bids to compete with these coal units in meeting its reliability needs and fuel diversity objectives in 2012 and 2013.

The addition of West County 1 and 2 in 2009 and 2010, respectively, which is the first part of a four-unit plan to meet FPL's reliability needs and fuel diversity objectives, is the best, most cost-effective alternative to meet the needs of FPL and its customers in 2009 through 2011, and there is no additional cost-effective DSM available to mitigate the need for these units. The Commission should grant FPL's petition for a determination of need for West County Units 1 and 2 in 2009 and 2010, respectively.