William P. Cox
Senior Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5662
(561) 691-7135 (Facsimile)
Will.Cox@fpl.com

September 3, 2015

-VIA ELECTRONIC FILING-

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket 150_____
In re: Florida Power & Light Company's Petition for Determination of Need for Okeechobee Clean Energy Center Unit 1

Dear Ms. Stauffer:

Enclosed for filing on behalf of Florida Power & Light Company ("FPL") is FPL's Petition for Determination of Need for Okeechobee Clean Energy Center Unit 1, along with testimony and exhibits of Dr. Steven R. Sim, Jacquelyn K. Kingston, Richard Feldman, and Heather C. Stubblefield, which support the petition.

Please contact me should you or your Staff have any questions regarding this filing.

Sincerely,

s/ William P. Cox
William P. Cox
Senior Attorney

WPC/msw
Enclosures

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition for Determination of Need for Okeechobee Clean Energy Center Unit 1)	Docket No.______________ Filed: September 3, 2015

PETITION

Pursuant to Sections 366.04 and 403.519, Florida Statutes, and Rules 25-22.080, 25-22.081, 25-22.082, and 28-106.201 Florida Administrative Code ("F.A.C."), Florida Power & Light Company ("FPL" or "the Company"), hereby petitions the Florida Public Service Commission ("Commission") for an affirmative determination need for the construction of a combined cycle generating unit at a greenfield site in Okeechobee County, together with the associated facilities, including transmission line and substation facilities, needed to integrate, interconnect and transmit energy from this site to FPL's transmission network for delivery to customers. The unit and associated facilities may be referred to herein collectively as the Okeechobee Clean Energy Center Unit 1 ("OCEC Unit 1" or the "Project").

FPL proposes to build at a greenfield site in Okeechobee County a highly fuel-efficient, state-of-the-art combined cycle ("CC") natural gas unit with about 1,622 MW (summer) of generation for commercial operation beginning in June 2019. This generation will allow FPL to meet a projected need for additional generation resources that begins in 2019 (1,052 MW), continues in 2020 (1,409 MW (cumulative)), and increases each year thereafter.

OCEC Unit 1 is the best, most cost-effective option with which to meet FPL's resource needs beginning in 2019 and will result in the lowest electric rates for FPL's customers. OCEC Unit 1 will ensure reliable service for FPL's customers and is expected to save FPL's customers up to $281 million cumulative present value of revenue requirements ("CPVRR") (net present value) in electricity costs over the next best alternative, while operating with excellent environmental performance. Once this new CC unit goes into operation, it is projected to be the most fuel-efficient CC unit on FPL's generation system, thus further enhancing the efficiency of an already highly efficient FPL generating system. It is also projected to be the most fuel-efficient CC unit in the state of Florida. Beyond the fuel savings, system reliability improvements, and air emission reductions, OCEC Unit 1 is estimated to generate significant economic benefits, including millions of dollars in tax revenues for local governments and school districts and hundreds of temporary and permanent jobs.

I. Introduction and Overview

1. Florida is one of the most populous states in the nation, and FPL is expected to continue experiencing growth in its customer base. FPL's customer forecast indicates that by 2019 the number of customer accounts in FPL's service territory will surpass the five million mark, and the cumulative increase in customer accounts from 2014 to 2024 is expected to reach about 675,000. FPL is projecting an annual increase of 1.6 percent in the summer peak demand between 2015 and 2024. While the projected percentage growth is lower than the long term rate experienced historically, the absolute level of growth remains very large. An annual increase of 387 MW is projected between 2015 and 2024. By 2019, the summer peak is projected to reach 25,045 MW, a cumulative increase of 2,110 MW relative to the actual 2014 summer peak.

2. Based on FPL's 2015 Ten Year Site Plan forecast, FPL projects that by 2019, after accounting for its extensive Demand Side Management ("DSM") reductions as well as significant efficiency improvements from lighting and equipment energy efficiency standards, FPL will have to add about 1,052 MW of new generation capacity over and above the capacity that will have been added prior to 2019, as a result of the previously approved uprates at FPL's existing nuclear units and the modernization of FPL's Cape Canaveral, Riviera Beach, and Port

Everglades plants.

3. FPL's request for an affirmative determination of need for OCEC Unit 1 is the culmination of extensive investigation and analyses designed to identify the best, most cost-effective alternative available to meet FPL's forecasted resource need for new generating capacity beginning in 2019, after accounting for all identified cost-effective DSM measures and renewable resources. That work included not only FPL's assessment of its capacity need and analysis of various self-build generation options to select the most cost-effective option for meeting that need, but also the preparation and issuance of a Request for Proposals ("RFP") that solicited proposals as alternatives to FPL's self-build option. No RFP submission received satisfied the minimum requirements of the RFP. The RFP was reviewed and monitored by an independent evaluator, Sedway Consulting, Inc.

4. OCEC Unit 1 involves the construction of a CC power plant with a summer peak capacity rating of about 1,622 MW and a commercial operation date of June 1, 2019. OCEC Unit 1 will serve to satisfy 1,052 MW of customer load requirements beginning in 2019. The modernized plant's primary fuel will be natural gas, and it will have the capability to burn a light fuel oil as a back-up fuel.

5. Implementation of OCEC Unit 1 by 2019 is an integral part of FPL's plan to meet the growing resource needs of its customers and continue to deliver electricity at a reasonable cost, while complying with both existing and anticipated environmental requirements.

6. An affirmative determination of need for OCEC Unit 1 beginning in 2019 is projected to provide several important benefits to customers and Florida residents that will be reflected in lower electric rate and bill impacts for all FPL customers:

- First, FPL customers are projected to receive substantial electricity cost savings over the 30-year analysis period.

- FPL's customers would be saving up to $281 million CPVRR with the OCEC Unit 1 as compared to an alternative that would consist of simple cycle CTs only.

- The best resource plan with a CC unit at the Okeechobee County site (OCEC Unit 1) was projected to be $65 million CPVRR more economic than the best resource plan with a CC unit sited at the Putnam County site, the runner-up site.

- Second, OCEC Unit 1 is also projected to provide public welfare benefits.

  - OCEC Unit 1 is projected to create an estimated $238.8 million in new tax revenue to local governments and school districts over the life of the project.

  - OCEC Unit 1 will create an estimated 650 direct jobs at its peak during construction and approximately 30 permanent jobs, as well as additional benefits for the local economy through additional demands for goods and services.

II. The Utility Primarily Affected (Rule 25-22.081(a)(1))

In support of its Petition, FPL states:

7. The Petitioner's name and address are:

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

8. FPL's representatives who should receive communications regarding this docket:

William P. Cox
Senior Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408
Will.Cox@fpl.com
561-304-5662
561-691-7135 (fax)

Kenneth A. Hoffman
Vice President, Regulatory Affairs
Florida Power & Light Company
215 S. Monroe Street
Tallahassee, Florida 32301
Ken.Hoffman@fpl.com
850-521-3919
850-521-3939 (fax)

9. FPL is a Florida corporation with headquarters at 700 Universe Boulevard, Juno Beach, Florida, 33408. FPL is a utility as defined in Section 366.82(1), Florida Statutes, and is an applicant as defined in Section 403.503(4), for purposes of Section 403.519, Florida Statutes. FPL is the primarily affected utility within the meaning of Rule 25-22.081, F.A.C..

10. FPL currently serves over 4.7 million retail customers throughout Florida. Its service area covers about 27,650 square miles in 35 Florida counties. Approximately nine million people live within the area FPL serves, which spans from St. Johns County in the north to Miami-Dade County in the south, and westward to Manatee County. The largest concentration of electric sales is in Southeast Florida, which consists of the region south and east of, and including FPL's Corbett Substation; geographically, this includes a portion of southern Palm Beach County and all of Miami-Dade and Broward Counties. Miami-Dade and Broward Counties account for 43 percent of the Company's summer peak load.

11. FPL is part of the nation's Eastern Interconnection transmission network. It has multiple points of interconnection with other utilities that enable power to be exchanged among utilities. The FPL bulk transmission system is comprised of approximately 6,888 circuit-miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 596 substations.

12. FPL has one of the cleanest generating fleets in the country, and is an industry leader in energy efficiency, conservation, and load management through its DSM programs. FPL meets its customers' energy needs through a mix of fossil and nuclear generating units, renewable generation, purchased power, which also includes renewable generation, and DSM. FPL's existing generation resources are located at 16 sites distributed geographically throughout its service territory, and also include partial ownership of one unit located in Georgia and two units located in Jacksonville, Florida. At the time of filing this Petition, FPL's active generation fleet totals approximately 25,072 MW (summer) of firm capacity and its generating units consist of four nuclear steam units, three coal steam units in which it holds partial ownership interests, 15 CC units, five oil/gas steam units, 48 CT units, and two solar photovoltaic ("PV") units.

13. FPL presently has a long-term Unit Power Sales ("UPS") contract to purchase up to 931 MW of coal-fired generation from Southern Company. However, the UPS contract expires at the end of 2015. FPL also has contracts with Jacksonville Electric Authority for the purchase of 375 MW (summer) of coal-fired generation from St. Johns River Power Park ("SJRPP") Units One and Two. Unfortunately, due to Internal Revenue Service regulations, the total amount of energy that FPL may receive from this purchase is limited. FPL currently projects that this limit will be reached in the second quarter of 2019.

14. At the end of 2014, FPL had contracted to purchase firm capacity and energy from cogeneration and small power production facilities (qualifying facilities or "QFs") totaling 1,945 MW. FPL currently projects that about 455 MW of these third party renewable contracts will be available to FPL in 2019. FPL has also fostered the expansion of renewable energy sources through development of its own renewable generation projects. FPL operates three commercial-scale solar generation facilities in Florida. FPL's two solar PV facilities, DeSoto and Space Coast, represent a combined 35 MW (nameplate). In addition, the Martin facility

represents 75 MW of solar thermal (nameplate) that displaces fossil fuel usage.

III. The Proposed Electrical Power Plant (Rule 25-22.081(1)(b))

15. FPL plans to build a state-of-the-art, highly-efficient, low-emission CC plant located at a greenfield site (2,842 acres) in northeast Okeechobee County previously acquired by the Company. FPL has attained a great deal of experience in building and operating CC plants to achieve the best possible efficiencies. FPL has also proven its ability to implement CC plant projects on budget.

16. OCEC Unit 1 will be configured as a CC unit, which will use three of the latest generation CTs, three heat recovery steam generators ("HRSGs"), and one steam driven turbine generator ("STG"). Each CT is connected to an electric generator that produces electricity to meet the needs of FPL's customers. The exhaust gas produced by each CT then passes through an HRSG and produces steam, which, in turn, is used to drive an STG and produce additional electricity for FPL's customers. This waste heat recovery feature of the CC system improves overall plant efficiency beyond that of simple-cycle CTs or simple-cycle steam plants.

17. The OCEC Unit 1 three-on-one (3x1) CC unit is expected to have a summer peak capacity of about 1,622 MW. OCEC Unit 1 will be a 3x1 CC unit consisting of three nominally 350-MW GE 7HA.02 CTs, with dry low-NO_x combustors, peak-firing, inlet cooling, wet compression, and three HRSGs, which will use the waste heat from the CTs to produce steam to be utilized in a new steam turbine generator. The HRSG stacks will be approximately 149 feet tall.

18. Generally, new CC plants can be expected to achieve an energy conversion rate ("heat rate") of less than 7,000 British thermal units ("Btu") per kilowatt hour ("kWh"). FPL anticipates that OCEC Unit 1 will have an average base heat rate as low as approximately 6,304 Btu/kWh, based on an average ambient air temperature of 75°F. This compares very favorably

to heat rate values averaging in the 10,000 Btu/kWh range for the conventional steam-electric generating units.

19. The CTs will use natural gas delivered by pipeline to the plant as their primary fuel. The OCEC Unit 1 site is projected to have reasonable access to a gas pipeline for necessary fuel transportation, and a new pipeline lateral will be constructed to transport natural gas to the site. FPL has sufficient gas transportation capacity to serve OCEC Unit 1. To provide a backup fuel to the unit in the event of an extended disruption of natural gas supply, OCEC Unit 1 will also be designed to burn a light fuel oil, more specifically a light fuel oil with an ultra-low sulfur content (maximum of 0.0015 percent), as a back-up fuel. Light fuel oil will be delivered to the site by truck, and can be stored in sufficient quantities to allow the plant to function at full capacity for 72 hours of continuous operation using back-up fuel.

20. OCEC Unit 1 will connect to a new 500 kV transmission switchyard on the OCEC Unit 1 property. Transmission lines from the existing Martin-Poinsett 500 kV line will be looped into the new switchyard to interconnect the facilities to the FPL transmission grid. The Florida Reliability Coordinating Council ("FRCC") has determined that FPL's proposed transmission interconnection and integration plan will be reliable and adequate and will not adversely impact the FRCC transmission system reliability.

21. The cooling water source for OCEC Unit 1 will be groundwater from the Floridan Aquifer. The surficial aquifer will be used for process and potable water. The use of natural gas as a primary fuel source with light fuel oil as a backup fuel, combined with combustion control technologies, will minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. By using natural gas as the primary fuel for OCEC Unit 1 and technology that is recognized by the Florida Department of Environmental Protection as the Best Available Control Technology for minimizing air emissions, OCEC Unit 1 is projected to be

among the cleanest and most efficient fossil fuel-fired, electric-power generating units in Florida, if not the world.

22. FPL expects that OCEC Unit 1 will be a highly reliable source of energy for FPL's customers. The new CC unit is estimated to have an equivalent availability factor of up to 96.7 percent based on an estimated average forced outage factor of approximately 1.1 percent and a planned outage factor of 2.2 percent. Adding this highly reliable unit will help maintain the system reliability and integrity of FPL and peninsular Florida.

23. The total construction cost of OCEC Unit 1 will be $1,196.0 million. Principal components include the power block at $1,031.5 million, transmission interconnection and integration at $52.0 million, and allowance for funds used during construction ("AFUDC") at $112.5 million. FPL will annually report to the Commission's Director of Economic Regulation the budgeted and actual cost of OCEC Unit 1, compared to the estimated total in-service cost presented in this Petition.

IV. The Need for OCEC Unit 1 (Rule 25-22.081(1)(c))

24. ***Projected Demand and Energy Growth.*** FPL continually assesses the timing and magnitude of its future resource needs in order to continue to provide reliable electric service to its customers. To determine its future resource needs, FPL first forecasts its customer growth, summer and winter peak demand, and net energy for load ("NEL"). FPL then applies this forecast to a reliability assessment based on a minimum peak period total reserve margin ("RM") for summer and winter of 20 percent, a minimum generation-only reserve margin ("GRM") for summer and winter of 10 percent, and a maximum loss-of-load ("LOLP") of 0.1 day per year. If one (or more than one) of these criteria are projected to not be met in a given future year, then additional resources are needed in that year. The system reliability analyses using these three criteria identify both the timing (year) of FPL's next resource need and the magnitude (MW) of

that need.

a. *Customer growth.* FPL is responsible for serving its existing customers, as well as new customers locating in its service territory. FPL forecasts moderate continued customer growth. Using an econometric model, the Company projects an average annual increase of about 67,000 new customers amounting to an annualized retail customer growth rate of 1.3 percent between 2015 and 2024, and continued growth thereafter. This 2015-2024 forecasted growth rate is considerably higher than the rate experienced between 2008 and 2010 and represents a return to more historically typical growth rates.

b. *Peak Demand and Net Energy for Load.* FPL has forecasted its coincident summer and winter peak demands, as well as its NEL for 2015 through 2024. Each of these forecasts reflects FPL's estimated increase in customers and includes incremental wholesale loads, additional projected load from plug-in electric vehicles, the Economic Development Rider, and the Existing Facility Economic Rider, as well as the projected savings from energy efficiency codes and standards and the impact of distributed solar generation. FPL's forecasted summer peak drives FPL's resource need.

i. *Summer peak.* In 2014, FPL experienced a coincident summer peak demand of 22,935 MW. FPL projects its summer peak demand to increase annually by 1.6 percent between 2015 and 2024. This amounts to an average annual increase of about 387 MW per year. By 2019, the cumulative increase over the 2015 summer peak is projected to be 2,110 MW for a total of 25,045 MW.

ii. *Winter peak.* In 2014, FPL experienced a coincident winter peak demand of 17,500 MW. FPL projects that its winter peak demand will increase 0.7 percent annually between 2015 and 2024. This amounts to an average annual increase of about 141 MW per year between 2015 and 2024. By 2019, the cumulative increase over the 2015 winter peak is projected to be 2,074 MW for a total of 21,792 MW.

iii. *Net energy for load* In 2014, FPL's total NEL was 115,968 Gigawatt-hours ("GWh"). FPL projects a 1.2 percent annual growth rate in NEL between 2015 and 2024. The forecast shows an annual NEL increase of 1,507 GWh between 2015 and 2024, which is lower than that experienced historically.

25. Applying the 2015 Ten Year Site Plan load forecast to its reliability assessment, FPL projects that by 2019 it will have to add 1,052 MW of new generation capacity over and above the capacity that will have been added as a result of the previously approved uprates at FPL's existing nuclear units and the modernization of FPL's Cape Canaveral, Riviera Beach, and Port Everglades plants, as well as all anticipated cost-effective firm generating capacity that will be available from renewable resources and QFs through 2019. FPL further projects that its resource needs will increase to 1,409 MW by 2020. Without the proposed OCEC Unit 1 plant or a more costly alternative, FPL would not maintain a 20 percent RM or 10 percent GRM in 2019. Specifically, without OCEC Unit 1, FPL's GRM would fall to 5.8 percent, and its RM would fall to 15.7 percent.

26. The resource plan that includes bringing OCEC Unit 1 into service by June of 2019 will not only satisfy FPL's projected resource need, but also is projected to result in substantially greater benefits to FPL's customers than the other resource plans that FPL has evaluated. As set forth in greater detail below, OCEC Unit 1 is projected to save FPL's customers up to an estimated $281 million CPVRR compared to CT-based capacity. OCEC Unit 1 will also improve system fuel efficiency, maintain system reliability, reduce air

emissions, and provide important public benefits.

V. FPL's Analysis of Generating Alternatives (Rule 25-22.081(1)(d))

27. Having determined the magnitude and timing of resource needs, FPL next identified competing resource plans and evaluated each plan. FPL used a thirty-year period for the analyses, including thirty-year customer and load forecasts, in order to fully capture and fairly compare all of the system economic impacts of different capacity options that could be added to a utility system.

28. The economic analysis involves a calculation of the CPVRR for each resource plan. The resource plan with the lowest CPVRR also results in the lowest system average electric rates for FPL's customers over the analysis period.

29. Beginning in mid-2013, FPL conducted an extensive evaluation process in order to determine what its best self-build generation option was for meeting this need, including examination of various generation technologies and associated costs. This evaluation process examined multiple sites and various CC and simple cycle CT capacity options from three different vendors, as well as solar PV options.

30. Through this extensive evaluation process, FPL identified a CC unit sited in Okeechobee County, OCEC Unit 1, as its best self-build generation option for meeting the 2019 and 2020 capacity needs. FPL's customers were projected to save up to $281 million CPVRR with the OCEC CC unit as compared to an alternative that would consist of simple cycle CTs only. Further, the best resource plan with a CC unit at the Okeechobee County site (OCEC Unit 1) was projected to be $65 million CPVRR more economic than the best resource plan with a CC unit sited at the Putnam County site, the runner-up site.

31. Before issuing an RFP for supply side generation alternatives to the FPL self-build proposal (OCEC Unit 1), *i.e.*, the next planned generating unit, consistent with the

Commission's Bid Rule (Rule 25-22.082, F.A.C.), FPL went back to vendors and asked them to refine their proposals so FPL could further optimize its self-build option for the FPL system. This second stage of the analysis yielded further cost-savings and efficiencies that were captured in FPL's final selection of OCEC Unit 1.

32. In accordance with the Commission's Bid Rule, FPL then developed and issued a capacity RFP in March 2015 to identify non-FPL proposals that would be evaluated versus FPL's proposed OCEC Unit 1. The RFP contained a detailed breakout of the cost and performance information for OCEC Unit 1. FPL developed its RFP with a focus on establishing requirements that would achieve the lowest cost and most reliable electricity to serve its customers.

33. While there were 46 registrants for the RFP prior to the submission of bids, only one proposal was submitted in response to the RFP. The submission did not conform to a number of the Minimum Requirements of the RFP, including failure to submit to required bid evaluation fee, non-binding bid, and failure to satisfy performance requirements, including availability, reliability, and original equipment manufacturer parts for critical components, as well as failure to present a plan for firm transmission service of the power to FPL's system. Based on correspondence with the submitting entity, and after review by the independent evaluator and FPL, it was determined that no further evaluation of the submittal should be conducted.

34. Accordingly, the results of FPL's economic analysis and the RFP establish that the OCEC Unit 1 was the best, most cost-effective alternative to meet FPL customers' needs for additional resources in 2019 and 2020.

VI. FPL's Analysis of Non-Generating Alternatives (Rule 25-22.081(1)(e))

35. FPL employs comprehensive and cost-effective DSM programs to reduce peak

load requirements and reduce energy consumption. Without its DSM achievements, FPL would require more additional capacity to meet its present and projected needs. Since the inception of its DSM programs through 2014, FPL has eliminated the need for the equivalent of 14 new 400 MW generating units. FPL has achieved this level of demand reduction through DSM programs designed to reduce electric rates for all customers, DSM participants and non-participants alike.

36. The projected cumulative effect of FPL's DSM programs from their inception through 2024 is truly significant. FPL's summer MW Goals for the 2015 – 2024 time period were set at 526 MW or about 53 MW of DSM per year on average.

37. FPL's forecast of resource needs takes into account all projected DSM from cost-effective programs approved by the Commission. FPL has not identified additional cost-effective DSM beyond that already reflected in FPL's reliability assessment calculations. Additional cost-effective DSM cannot be counted on to contribute to system reliability, and there is no evidence to suggest that additional DSM could provide economic benefits to FPL's customers that could in any way diminish the unquestionable benefits projected to be provided by OCEC Unit 1 beginning in 2019. Taking these benefits into consideration, the interests of FPL's customers are best served by placing OCEC Unit 1 in commercial operation in June of 2019.

VII. Adverse Consequences (Rule 25-22.081(f))

38. If an affirmative determination of need for OCEC Unit 1 in 2019 is not granted, FPL's customers would face adverse consequences in terms of increased costs and potentially diminished service reliability. Without placing OCEC Unit 1 in service in 2019, FPL customers would lose significant cost savings and would feel the impact on their electric bills as early as 2019. The estimated incremental cost to FPL's customers ranges from $65 million up to $281 million CPVRR when comparing OCEC Unit 1 to other supply-side generation alternatives.

39. Further, if the need determination for OCEC Unit 1 is denied, and no other self-build generation option is allowed to replace it, then FPL's projected GRM in 2019 would fall to 5.8 percent, well below FPL's GRM reliability criterion value of a minimum of 10 percent. In addition, FPL's projected total RM in 2019 would fall to 15.7 percent, well below FPL's total RM reliability criterion value of a minimum of 20 percent. Therefore, if the need determination for OCEC Unit 1 is denied, and no other self-build generation option replaces it, system reliability for FPL's customers would be significantly degraded.

40. In summary, FPL's customers would be harmed if the Commission were to deny FPL's request for an affirmative determination of need for OCEC Unit 1 with a planned commercial operation date of June 2019.

VIII. Disputed Issues of Material Fact

41. FPL is presently unaware of any disputed issues of material fact affecting this proceeding. FPL will demonstrate that approving a need determination for OCEC Unit 1 in 2019 will best serve FPL's customers by providing substantial economic benefits. FPL also will demonstrate that there are no reasonably available renewable resources, DSM, or other non-generation alternative that would significantly mitigate the need for OCEC Unit 1.

CONCLUSION

As proposed, OCEC Unit 1 is a highly cost-effective choice for serving FPL's customers. OCEC Unit 1 is projected to deliver major cost savings to benefit FPL's customers, provide firm capacity needed to serve FPL's customers, and improve the efficiency for FPL's system.

Based upon the foregoing and the more detailed information in the pre-filed testimony and exhibits submitted contemporaneously with this Petition, FPL requests that the Commission grant FPL an affirmative determination of need for OCEC Unit 1 in 2019. FPL will annually report to the Commission's Director of Economic Regulation updates to the budgeted and actual cost of OCEC Unit 1, compared to the estimated total in-service cost presented in this Petition.

FPL also requests that, as part of the Commission's order granting an affirmative determination of need for OCEC Unit 1, the Commission provide that its determination is not predicated on FPL's selection of a particular design or model of combustion turbine ("CT"), heat recovery steam generator ("HRSG"), steam turbine (the "Power Train Components") or other related equipment necessary for operation of the unit, thus providing FPL the flexibility through its negotiations and analyses to select the technology that best meets FPL customers' needs in terms of reliability and cost-effectiveness.

FPL would select an enhanced design or model only if the enhanced design or model results in lower projected system CPVRR cost to FPL's customers. In the event that FPL selects an enhanced design or model other than the analyzed technology subsequent to the Commission having granted a determination of need for OCEC Unit 1, FPL proposes to make an informational filing to the Commission that documents the projected comparative CPVRR cost advantage of the alternate technology chosen.

WHEREFORE, FPL respectfully requests that the Commission grant an affirmative determination of need for OCEC Unit 1 beginning in 2019 that is not limited to a particular design or model of Power Train Components or other related equipment necessary for operation of the unit, but rather would allow FPL to select an enhanced design or model other than the analyzed technology if the Company documents through an informational filing that the projected CPVRR to FPL's customers would be lower.

Respectfully submitted this 3rd day of September, 2015.

R. Wade Litchfield
Vice President and General Counsel
William P. Cox
Senior Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408-0420

Charles A. Guyton
Gunster, Yoakley & Stewart, P.A.
215 South Monroe Street, Suite 601
Tallahassee, Florida 32301-1804

Attorneys for Florida Power & Light Company

By: *s/ William P. Cox*________
William P. Cox
Florida Bar No. 0093531

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

PETITION FOR DETERMINATION OF NEED

REGARDING THE OKEECHOBEE CLEAN ENERGY CENTER UNIT 1

DIRECT TESTIMONY OF DR. STEVEN R. SIM

DOCKET NO. ____________-EI

SEPTEMBER 3, 2015

TABLE OF CONTENTS

I. INTRODUCTION AND CREDENTIALS 3

II. PURPOSE AND SCOPE 5

III. FPL'S REQUEST FOR FPSC APPROVAL 7

IV. INTRODUCTION OF FPL WITNESSES 11

V. PROJECTION OF FPL'S RESOURCE NEEDS....................................... 12

VI. FPL'S EVALUATION OF SELF-BUILD GENERATION OPTIONS.... 17

VII. THE CAPACITY RFP PROCESS AND RESULTS 27

VIII. ADVERSE CONSEQUENCES OF NOT BUILDING OCEC UNIT 1..... 37

IX. CONCLUSION.. 39

I. INTRODUCTION AND CREDENTIALS

Q. Please state your name and business address.

A. My name is Steven R. Sim. My business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Senior Manager of Integrated Resource Planning in the Resource Assessment and Planning (RAP) department.

Q. Please describe your duties and responsibilities in that position.

A. I supervise and coordinate analyses that are designed to determine the magnitude and timing of FPL's resource needs and then develop the integrated resource plan with which FPL will meet those resource needs.

Q. Please describe your educational background and business experience.

A. I graduated from the University of Miami (Florida) with a Bachelor's degree in Mathematics in 1973. I subsequently earned a Master's Degree in Mathematics from the University of Miami (Florida) in 1975 and a Doctorate in Environmental Science and Engineering from the University of California at Los Angeles (UCLA) in 1979. While completing my degree program at UCLA, I was also employed full-time as a Research Associate at the Florida Solar Energy Center (FSEC) during 1977-1979 where I analyzed potential renewable resources in the Southeastern United States.

In 1979, I joined FPL. From 1979 until 1991, I worked in various departments including Marketing, Energy Management Research, and Load Management, where my responsibilities concerned the development, monitoring, and cost-effectiveness analyses of demand side management (DSM) programs. In 1991, I joined my current department, then named the System Planning Department, where I held different supervisory positions dealing with integrated resource planning. In late 2007, I assumed my current position.

Q. Have you previously testified on resource planning issues before the Florida Public Service Commission?

A. Yes. I have testified before the Florida Public Service Commission (FPSC) in numerous dockets. These dockets have dealt with various resource planning issues such as system reliability and economic analyses of resource options. The specific subjects of these dockets have included: (i) need determination filings for combined cycle (CC) units, advanced coal units, and nuclear units, (ii) nuclear feasibility analyses, and (iii) demand side management (DSM) goal-setting.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit SRS-1, which is presented as a separate document, and Exhibits SRS-2 through SRS-5, which are attached to my direct testimony:

Exhibit SRS-1 FPL's 2015 Capacity Request for Proposals (RFP);

Exhibit SRS-2 Projection of FPL's Resource Needs: 2015 through 2020;

Exhibit SRS-3 Evaluation of FPL Self-Build Options: A Representative List of CC and CT Generating Options at Two Sites Evaluated in the First Stage of the Analyses;

Exhibit SRS-4 Evaluation of FPL Self-Build Options: Results of Analyses of CC and CT Generating Options at Two Sites Evaluated in the First Stage of the Analyses; and,

Exhibit SRS-5 Evaluation of FPL Self-Build Options: List of Generating Option Technologies Evaluated in the Second Stage of the Analyses and the Results of These Analyses.

II. PURPOSE AND SCOPE

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

A. The primary purpose of my testimony is to support FPL's request that the FPSC grant an affirmative determination of need for the construction of the Okeechobee Clean Energy Center (OCEC) Unit 1, a new CC unit sited in Okeechobee County.

My testimony addresses seven main points. First, I summarize what FPL is requesting from the FPSC. Second, I introduce the FPL witnesses who are providing direct testimony in this docket and briefly describe what information each FPL witness is providing in his/her direct testimony. Third, I discuss FPL's projection of its resource needs which begin in 2019 and increase thereafter and how this projection was derived. Fourth, I discuss FPL's analyses of its self-build generation options and the results of those analyses which led to the designation of a new CC unit in Okeechobee County, OCEC Unit 1, as FPL's best self-build option. As such, the Okeechobee CC unit was presented as FPL's Next Planned Generating Unit (NPGU) in the subsequent capacity Request for Proposals (RFP) issued by FPL in March 2015. This unit was also presented as a placeholder resource addition in FPL's 2015 Ten Year Site Plan pending the final result of the RFP process. Fifth, I discuss FPL's RFP schedule and the submittal FPL received in response to the RFP. Sixth, I discuss the significant adverse consequences FPL and its customers would face if the FPSC does not grant an affirmative determination of need for OCEC Unit 1. Seventh, I offer my conclusions regarding OCEC Unit 1 and its ability to cost-effectively meet FPL's 2019 capacity needs.

Q. Please summarize your testimony.

A. Based on FPL's current load forecast, and after accounting for all FPL- and FPSC-identified cost-effective DSM, FPL projects that it has a significant generation resource need that begins in June 2019. FPL conducted an extensive evaluation process in order to determine what its best self-build generation option was for meeting this need, including examination of various generation technologies from different vendors as well as different sites.

Through this extensive evaluation process, FPL first identified a type of technology (CC) and a site (a greenfield site in Okeechobee County) that were the best choices for a self-build generating unit. FPL then conducted additional analyses that further refined the CC technology choice. The result of all of these analyses, OCEC Unit 1, is the best self-build generation option for meeting the 2019 capacity need. In accordance with Florida's Bid Rule, FPL then issued a capacity RFP in March 2015 to identify non-FPL proposals that would be evaluated versus FPL's NPGU. No proposals were submitted which conformed to the Minimum Requirements of the RFP. Thus, OCEC Unit 1 has been identified as the most cost-effective/economic generation option available to meet FPL's 2019 reliability need, and it is the best choice for FPL's customers. Consequently, FPL is respectfully requesting that the FPSC grant a determination of need for OCEC Unit 1.

III. FPL'S REQUEST FOR FPSC APPROVAL

Q. Please explain the FPSC decision that FPL seeks in this proceeding.

A. FPL seeks from the FPSC an affirmative determination of need for OCEC Unit 1 with an in-service date of June 1, 2019.

Q. What is the basis for FPL's requested need determination?

A. FPL's request for an affirmative determination of need for this unit is based on an extensive evaluation designed to identify the best, most cost-effective generation alternative available to meet FPL's resource needs that begin in 2019. FPL's evaluation began with FPL's assessment of its customers' future generation capacity needs after accounting for all identified cost-effective DSM. FPL then examined feasible self-build generation options, including CC units, combustion turbine (CT) units, and solar photovoltaic (PV) facilities which potentially might have been able to meet the 2019 resource need. FPL also evaluated three specific FPL-owned sites at which new generation facilities could be built. One of these sites is in Okeechobee County, one is in Hendry County, and the third is the site in Putnam County of the recently retired FPL Putnam 1 & 2 units. The result of all of these analyses was that a new CC unit at the Okeechobee site, OCEC Unit 1, was determined to be FPL's best, most economic self-build option.

FPL then issued in March 2015 an RFP in accordance with Florida's Bid Rule to solicit non-FPL generation options that could be evaluated as an alternative to OCEC Unit 1. One submittal was received. However, this submittal did not offer enough capacity to meet the 2019 need. In addition, the submittal failed to meet numerous Minimum Requirements of the RFP and was, therefore, a non-conforming bid. Thus, no viable alternatives were presented in response to the RFP. Therefore, based on the extensive evaluation discussed above and the results of the RFP process, OCEC Unit 1 is the best, most cost-effective option with which to meet FPL's resource needs beginning in 2019. Once this new CC unit goes into operation, it is projected to be the most fuel-efficient CC unit on FPL's generation system, further enhancing the efficiency of an already highly efficient FPL generating system. It is also projected to be the most fuel-efficient CC unit in the state of Florida.

Q. In your opinion, please address how, if at all, the OCEC Unit 1 meets the need determination criteria set forth in Section 403.519, Florida Statutes.

A. Under Section 403.519(3), Florida Statutes, there are a number of criteria that the FPSC is to consider in a determination of need proceeding. Most of those criteria involve principles of resource planning. So my comments will now address each of those resource planning principles.

OCEC Unit 1 is the best resource available to meet FPL's need for system reliability and integrity to serve its customers. A new supply-side generating unit is needed in 2019 to meet FPL's system reliability criteria, and OCEC Unit 1 will meet all of FPL's reliability criteria. In addition, OCEC Unit 1 is the best resource available to FPL and its customers to meet the need for adequate electricity at a reasonable cost. The unit is projected to result in the lowest system cost of all the various alternatives considered by and available to FPL, and the unit is also projected to result in the lowest electric rates for FPL's customers. OCEC Unit 1 is a highly fuel-efficient unit which will generate fuel savings even on a system as efficient as FPL's, and its projected installed cost per kW is projected to be the lowest in the industry for a modern CC unit.

OCEC Unit 1 will not improve FPL's fuel diversity, but given other capacity additions and retirements, plus the high level of fuel efficiency of this new unit, it will not significantly increase FPL's reliance on natural gas. FPL is pursuing other approaches that would improve its fuel diversity in terms of gas supply, the volatility of the cost of gas, and the use of other energy sources. With the FPSC's approval of a third major natural gas pipeline serving FPL's service area from onshore shale gas production areas, and FPL having contracted for such pipeline capacity, FPL has improved the supply availability of natural gas to its system. Recent FPSC approval of FPL's Woodford project, and FPSC guidelines to govern approval of future similar projects, will assist in lowering the volatility of the cost of gas with which FPL serves its customers. In terms of utilizing other energy sources, FPL is actively pursuing additional solar and nuclear energy.

The OCEC Unit 1 is the most economic alternative that has been identified to meet the reliability needs of FPL's customers. It is the most economic self-build option available to FPL and its customers. A market assessment was done in accordance with the FPSC's Bid Rule, and the results of that solicitation presented no market alternative available to FPL.

In determining the need for the OCEC Unit 1, FPL took account of all identified cost-effective renewable energy and conservation measures. FPL projected that approximately half of the 223 MW nameplate rating from new PV facilities by the end of 2016 will contribute firm capacity at FPL's Summer peak, and this has been accounted for in FPL's projection of its resource needs. In addition, FPL accounted for all achievable, cost-effective DSM approved by the FPSC. Even after accounting for these contributions, FPL and its customers still have a significant need for generating capacity in 2019. The OCEC Unit 1 is the best alternative available to meet that need.

IV. INTRODUCTION OF FPL WITNESSES

Q. Who are FPL's other witnesses in this docket and what subject(s) will each witness address in his/her direct testimony?

A. There are three other FPL witnesses who are also providing testimony in this docket. A brief description of the witnesses, presented in alphabetical order, and the subject(s) each addresses in his/her direct testimony, is as follows:

- FPL witness Richard Feldman, also of FPL's Resource Assessment & Planning department, presents FPL's load forecasting process, discusses the methodologies and assumptions used in the forecasting process, and presents FPL's current load forecast which was used in determining FPL's 2019 capacity need.

- FPL witness Jacquelyn K. Kingston, of FPL's Project Development department, presents the engineering details of FPL's OCEC Unit 1 which involves the construction of a new state-of-the-art 3x1 combined cycle unit at a greenfield site in Okeechobee County. Included in witness Kingston's testimony are the capital and O&M costs, as well as the performance characteristics of the technology to be used in OCEC Unit 1 which were accounted for in FPL's economic analyses.
- FPL witness Heather C. Stubblefield, of FPL's Energy Marketing and Trading (EMT) department, describes the fuel transportation plan to deliver natural gas and light oil to OCEC Unit 1 and testifies to the ready availability of natural gas for OCEC Unit 1. Witness Stubblefield also supports FPL's current fuel price forecast.

V. PROJECTION OF FPL'S RESOURCE NEEDS

Q. How does FPL determine its next resource need?

A. FPL utilizes three reliability criteria to project the timing and magnitude of its future resource needs. The three reliability criteria are:

- A minimum total reserve margin (total RM) for Summer and Winter of 20%;
- A minimum generation-only reserve margin (GRM) for Summer and Winter of 10%; and
- A maximum loss-of-load-probability (LOLP) of 0.1 day per year.

If one (or more than one) of these criteria is projected to not be met in a given future year, then additional resources are needed in that year. The system reliability analyses using these three criteria identify both the timing (year) of FPL's next resource need and the magnitude (MW) of that need.

Q. What is the timing and magnitude of FPL's next projected resource need?

A. FPL's reliability analyses show that FPL's next projected significant resource need is in 2019. These projections show that neither the total RM criterion nor the GRM reliability criterion will be met beginning in 2019 based on projected Summer peak load. This information is presented in Exhibit SRS-2, which shows the projections for both the total RM and GRM reliability criteria. The magnitude of FPL's resource need in 2019 is 1,052 MW. This need increases by another 357 MW to a need of 1,409 MW in 2020.

Q. Is this projection of FPL's next resource need based on FPL's current load forecast?

A. Yes. This forecast was presented in FPL's 2015 Ten Year Site Plan. FPL witness Feldman discusses this load forecast in his direct testimony.

Q. Did FPL's reliability analysis account for FPL's new DSM Goals?

A. Yes. FPL's new DSM Goals for 2015 through 2024 were fully accounted for in the reliability analysis.

Q. Is FPL aware of any additional DSM that would be cost-effective that is not accounted for in FPL's DSM Goals?

A. No.

Q. However, if one were to assume that additional cost-effective DSM were available, how much cost-effective DSM in terms of Summer MW would be needed to meet FPL's 2019 resource needs and how does that value compare with FPL's DSM Goals?

A. Additional DSM would not assist in meeting the projected 2019 capacity need based on FPL's 10% GRM reliability criterion because that reliability criterion focuses solely on the need for new generation resources to ensure there is an appropriate balance between generation and DSM resources. However, if one were to ignore this FPL reliability criterion, and focus solely on FPL's 20% total RM criterion, then an additional 988 MW/1.20 = 823 MW (at the generator) of cost-effective DSM would be needed in less than 4 years to meet this particular reliability criterion.

If one were to assume that this amount of DSM was to be added evenly over a 4-year period, this would equate to approximately 206 MW per year of additional cost-effective DSM. By comparison, in the DSM Goals docket, the FPSC found that the total amount of achievable, cost-effective DSM for FPL over a 10-year period was 526 MW (Summer) or about 53 MW of DSM per year on average. Thus, for DSM to solely meet this one reliability criterion for 2019, FPL would have to find and implement approximately 53 MW + 206 MW = 259 MW of cost-effective DSM each year over the next 4 years. This is five times the amount of achievable, cost-effective DSM per year, 53 MW, identified in the DSM Goals docket.

It may also help to view such a large hypothetical amount of DSM from the perspective of an existing FPL DSM program. FPL’s Residential Air Conditioning Program has generally signed up more annual participants than any other DSM program. The historical high water mark for signups for this program was slightly higher than 100,000 participants per year. Due to the impacts of energy efficiency codes and standards, and the diminished cost-effectiveness of this program due to lower fuel costs and increasing efficiency of FPL’s system, current projections of annual signups for the program are considerably lower.

However, if one were to ignore both this fact and any cost-effectiveness concerns, and keeping in mind that the program has a 0.25 Summer kW reduction per participant value, FPL would need to sign up the equivalent of more than 800,000 participants in this program each year for four years, or a total of more than 3,200,000 customers, to achieve 800 MW more of new DSM based on the program’s current Summer kW reduction per participant value of 0.25. This equates to enrolling more than 70% of FPL’s total residential customer accounts in the program in just 4 years.

Therefore, I do not believe that cost-effective DSM can meet even this one reliability criterion regarding FPL’s needs in 2019.

Q. The projected resource need in 2019 is 1,052 MW when viewed from the perspective of the GRM reliability criterion and 988 MW when viewed from the perspective of the total RM reliability criterion. Please discuss these two results.

A. From a reliability perspective, the GRM-driven need projection of 1,052 MW ensures that a generation addition of at least 1,052 MW will enable FPL to meet both the total RM and GRM criteria. Conversely, an addition of 988 MW would result in only one of these two reliability criteria, the total RM criterion, being met. Consequently, the result of FPL's reliability analyses was that a minimum of 1,052 MW of generation capacity needed to be added in 2019 to ensure that both of these reliability criteria were met.

Q. Did the additional MW need identified by the GRM reliability criterion have a significant impact on the analyses which FPL performed?

A. No. From a numerical perspective, the differential of 64 MW (1,052 MW – 988 MW = 64 MW) in projected need between the need identified by the GRM reliability criterion and the need identified by the total RM criterion represents a very small incremental need, approximately 0.002 (or 0.2%) of FPL's system of 26,498 MW of total generation capability in 2019 before any new generation is added. Moreover, the most economical self-build option, OCEC Unit 1, provides sufficient capacity (1,622 MW Summer) to allow FPL to meet both of these reliability criteria. The OCEC Unit 1 would have been selected as FPL's best self-build generation option regardless of whether the

GRM or the total RM reliability criterion were driving FPL's resource need in 2019.

VI. FPL'S EVALUATION OF SELF-BUILD GENERATION OPTIONS

Q. Please provide an overview of the process FPL used to determine its best self-build generation option for 2019.

A. In mid-2013, FPL's reliability analyses began to project a need for additional resources beginning in the Summer of 2019. Therefore, FPL began considering what types of generation facilities and what specific sites might be viable by mid-2019 for a self-build generation option.

In regard to types of generating facilities, two types were quickly eliminated from further consideration. First, coal-fired technologies were removed from consideration due to current and prospective environmental concerns and regulations. Second, due to the 2019 need date, new nuclear capacity was removed from consideration because such capacity could not be added by that time.

The two types of self-build generation options that were initially viewed as most likely candidates for meeting the 2019 need were gas-fired CCs and simple cycle CTs. In addition, PV facilities were also considered and evaluated.

In regard to sites on which self-build gas-fired generation options could potentially be built in time to address the 2019 resource need, three sites were identified and evaluated. These sites are located in Okeechobee, Putnam, and Hendry counties. The Okeechobee and Hendry county sites are greenfield sites. The Putnam County site is a brownfield site where FPL's Putnam 1 & 2 units formerly operated.

Having identified certain types of generation options that were potentially viable by 2019, as well as potentially viable sites, analyses of combinations of generation types and sites began. In regard to CC and CT options, the analyses examined different technologies offered by three vendors: General Electric (GE), Siemens, and Mitsubishi Heavy Industries (MHI). More specifically, these analyses examined the technology for the CT component of the CC unit and the subsequent design of the CC unit.

For discussion purposes, I will describe the overall evaluation process as consisting of two analysis stages. In the first stage, the best combination of type of generation and site were identified. Also in this first stage, FPL reached a preliminary conclusion regarding the best CT component technology. The second stage consisted of analyses designed to refine the evaluation of the CT technologies available from all three vendors and to reach a final conclusion regarding the best overall self-build choice for FPL's customers.

Q. What was the basic analysis approach that FPL utilized?

A. The analyses performed in both stages were based on a comparison of resource plans. Each resource plan consisted of a specific generation option added in 2019 such as a specific CC unit of sufficient size (MW) to meet the 2019 need. Additional filler unit capacity was then added in subsequent years for each resource plan to meet the projected future resource needs in all of these years. Then economic analysis of these resource plans was performed.

Q. You mentioned that resource plans were first developed and then analyzed. Were the economic analyses of these resource plans based on the projected cumulative present value of revenue requirements (CPVRR) for each resource plan?

A. Yes. Having already accounted for all known achievable and cost-effective DSM, and ensuring that this amount of DSM was included in all of the resource plans, a CPVRR analysis approach for generation-only options identifies the best generation option from both a cost perspective and an electric rate perspective. (This is because the number of total kWh of sales over which costs are recovered are unaffected when DSM levels remain unchanged, and only generation options are evaluated.)

Q. What costs were included in these economic evaluations of FPL's self-build generation options and what computer models were used?

A. For each resource plan, a number of costs were included in the analyses depending upon the computer model that was being used. A partial listing of these costs includes: generator capital, capital replacement, operation and maintenance (O&M), transmission interconnection, transmission integration, transmission losses, system emissions, firm gas transportation, self-build generator fuel, and system fuel. Because all of the self-build options were assumed to be constructed with the same equity/debt ratio as FPL's target adjusted capital structure, none of the self-build options would have an impact on FPL's cost of capital. Therefore, there was no need to address cost of capital impacts in these analyses of self-build options (as there would need to be when evaluating power purchase options).

Analyses of the resource plans utilized several computer models including the PMArea production costing model, FPL's Fixed Cost Spreadsheet, and the EGEAS optimization model.

Q. Please briefly discuss the first stage of FPL's analysis and the results of those analyses.

A. The first stage analyses were performed during 2014 and utilized all of FPL's then current forecasts (such as load forecasts and fuel cost forecasts) and assumptions that were being used in all of FPL's resource planning work. Early in the analyses, it was determined that it was unlikely that new capacity could be brought in-service at the Hendry site in time to address the 2019 need. Consequently, the Hendry site was dropped from further consideration, and the subsequent analyses focused solely on the Okeechobee and Putnam sites. A representative listing of the types of CC and CT generation options at the remaining two sites, and the CT component technologies, examined by FPL in the first stage of the analysis is provided in Exhibit SRS-3.

Exhibit SRS-4 then presents the results of the first stage of FPL's analyses of these generating options. From these results, two conclusions were drawn. First, the best resource plan with a CC unit at the Okeechobee site was projected to be $65 million CPVRR more economic than the best resource plan with a CC unit sited at Putnam. Therefore, the Putnam site was then removed from further consideration. Second, the best resource plan containing only simple cycle CT units was projected to be $124 million CPVRR more expensive than the best CC resource plan. At that point, simple cycle CT-only generation options were removed from further consideration.

Therefore, at this point the results from the first stage of the analyses were that a CC unit at the Okeechobee site would be FPL's best fossil-fueled self-build option for 2019. In addition, the GE 7HA.02 technology CT component of a CC unit was preliminarily determined to be the most cost-effective CT component of the CC unit. The best CC unit to-date based on the GE 7HA.02 was projected to have a capacity of 1,523 MW (Summer).

Q. You mentioned that FPL also evaluated PV as a potential option with which to meet the 2019 resource need. Please discuss first the PV facilities that FPL is adding by the end of 2016.

A. As presented in the 2015 Ten Year Site Plan, new PV facilities of approximately 74.5 MW-AC will be added, one at each of the three specific sites in DeSoto, Manatee, and Charlotte counties by the end of 2016. These specific sites are especially favorable for PV facilities for a variety of reasons including: the land is either already owned by FPL (Manatee and DeSoto) or FPL is in the process of acquiring ownership of the land at a favorable cost (Charlotte), proximity to existing transmission lines, and proximity to staff at nearby existing FPL generation facilities. In addition, these three facilities could each be completed and in-service by the end of 2016 which would allow the PV facilities to take advantage of the currently available 30% federal investment tax credits that are set to decrease to 10% at the end of 2016.

The combination of these advantages for the three specific sites resulted in a projection that PV at those specific sites by the end of 2016 would be cost-effective, but only by a slight margin. Recognizing that additional PV facilities added after 2016 will likely not have all of these advantages, FPL nonetheless considered additional PV as a potential self-build option with which to address its 2019 resource need.

Q. Please discuss.

A. In its consideration of PV as a self-build option with which to potentially meet all or a portion of FPL's 2019 resource need, FPL largely focused on several specific concerns or areas of uncertainty regarding utilizing PV in this potential role.

The first of these concerns was in regard to land and its costs. A significant amount of land would be required to site the very large amount of PV that would be needed to supply all, or a substantial portion, of the needed 1,052 firm MW of Summer capacity. From a schedule perspective, if FPL were to decide to base its capacity RFP on a gas-fired self-build option, it would have to do so by the first quarter of 2015. With that in mind, the ability to purchase large tracts of land suitable for PV development in this time frame was not only highly uncertain, but would likely have ended up with higher land costs being borne by FPL's customers than if more time were available to make the purchases.

The second concern was in regard to costs of the PV equipment. There is uncertainty regarding what PV costs will be in the future. Although costs are projected to decline, what those costs will be several years in the future when an order would need to be placed for a PV facility with a mid-2019 PV in-service date cannot be known with great accuracy. Therefore, the cost-effectiveness of PV versus the 2019 self-build CC unit could not be assured.

Third, and perhaps the most important concern, is in regard to system reliability. FPL has now begun applying a methodology for determining what firm capacity values PV facilities are projected to deliver. FPL believes this methodology provides the best possible projection of firm capacity value for PV. However, FPL recognizes that, at this point in time, there is less certainty regarding the firm capacity that will be delivered by PV than there is for CC and CT generating units. With that in mind, FPL was understandably reluctant to attempt to meet such a large, near-term resource need either solely, or in large part, with PV.

FPL determined that these areas of uncertainty could not be resolved by the first quarter of 2015. Therefore, FPL's decision was to proceed with the much more certain and highly economic CC unit and to continue to pursue PV for future resource needs.

Q. The first stage analysis results can be summarized by stating that a CC unit at Okeechobee was the best choice for an FPL self-build option. With that conclusion in hand, what was the objective of the second stage of the analysis?

A. The objective of the second stage of the analysis was to further refine the CT technology component upon which a CC unit at Okeechobee would be based in order to identify potential improvements in the self-build option.

Q. Please describe how the second stage of the analysis was performed.

A. The second stage analyses were performed in the second half of 2014 and in early 2015. As FPL's assumptions and forecasts were updated, these updated inputs were incorporated into the ongoing analyses. The second stage analysis had three basic steps. In the first step, FPL went back to all three CT vendors, GE, Siemens, and MHI, and requested that they refresh their CT cost and performance values. Once this was done, FPL again constructed resource plans with a 2019 CC unit at Okeechobee based on each vendor's CT technology and analyzed each resource plan. The CC options examined, and the results of the resource plan analysis for this first step, are presented in Exhibit SRS-5, page 1 of 2. A variation of the GE 7HA.02 technology was again projected to be the clear economic choice. As shown by comparing the first and fourth rows of this page, a CC unit based on a GE 7HA.02 CT design with duct firing, in a configuration that offered 1,582 MW (Summer), was projected to be $191 million CPVRR more economic than any CC based on non-GE technology. In fact, the top three highest ranked CC options were each based on GE technology. Based on these results, FPL's continuing second stage analyses focused solely on the GE 7HA.02 technology. It is also worth noting that in this first step of the second stage of the analyses, an improved CC design from GE emerged that was $109 million CPVRR more economic than the 1,523 MW CC that had been identified as the best CC option in the first stage analyses. This is shown by comparing the first and third rows of this page.

In the second step, FPL examined additional refinements to the GE 7HA.02 that included updated assumptions for heat rate, costs, and capacity (MW). One of these updates was an examination of peak firing and wet compression added to the previously analyzed technology configurations. FPL witness Kingston discusses these characteristics of the CC unit in her testimony. The result of these analyses is presented at the top of Exhibit SRS-5, page 2 of 2. A slightly larger, 1,586 MW CC based on the GE 7HA.02 CT without duct firing, but with peak firing and wet compression, emerged as a $42 million CPVRR more economic choice compared to the former leading candidate: the 1,582 MW CC based on the GE 7HA.02 with duct firing only.

The third and final step analyzed still more refinements to the technology. These refinements examined potential changes in the capacity (MW) of the units, the heat rates, and fixed costs including capital, fixed O&M, and capital replacement costs. The analyses carried out during this third step allowed FPL to finalize its choice of the best FPL self-build generating option.

Q. What was the final outcome of FPL's evaluation of its self-build generation options?

A. The final result is presented at the bottom of Exhibit SRS-5, page 2 of 2. As shown in the exhibit, a 1,622 MW (Summer) CC based on the GE 7HA.02 without duct firing, and with peak firing and wet compression, was projected to be $6 million CPVRR more economic than the 1,586 MW CC without duct firing and with peak firing and wet compression. Thus, the refinements in the second stage of the analyses resulted in improving the economics of the FPL CC at Okeechobee by approximately $157 million CPVRR ($109 million + $42 million + $6 million = $157 million) compared to the 1,523 MW CC that had been identified in the first stage of the analyses.

Therefore, this 1,622 MW (Summer) CC unit at the Okeechobee site emerged from FPL's extensive evaluation as the most economic self-build option for FPL's customers. Consequently, it was presented in FPL's 2015 Capacity RFP (Exhibit SRS-1) as FPL's NPGU.

VII. THE CAPACITY RFP PROCESS AND RESULTS

Q. Did FPL issue a capacity Request for Proposals (RFP) for its 2019 capacity need?

A. Yes. The RFP was issued on March 16, 2015. In compliance with Florida's Bid Rule (Rule 25-22.082, F.A.C.), the RFP contained a detailed breakout of the cost and performance information for the NPGU. FPL witness Kingston's testimony further discusses the cost and performance information for the NPGU.

Q. Please list these key steps carried out, including the schedule for these steps, in the RFP process through the date that proposals to the RFP were due.

A. The RFP's key steps through the Due Date for Proposals were as follows:

- Pre-Issuance Discussion Meeting (March 9, 2015);
- Issuance of the RFP (March 16, 2015);
- Pre-Bid Workshop (March 24, 2015);
- Cutoff Date for RFP Questions (April 17, 2015); and,
- Due Date for Proposals (May 15, 2015).

Q. Was there interest in FPL's RFP?

A. Yes. A total of 46 separate parties registered for the RFP and were provided access to the RFP and all RFP-related information through FPL's RFP website. There was also participation, either in person or by telephone, in the Pre-Issuance Discussion Meeting and in the Pre-Bid Workshop.

Q. Florida's Bid Rule allows a party to object to the FPSC regarding aspects of a utility's RFP. Were there any objections filed with the FPSC regarding FPL's RFP?

A. Yes. Of these 46 registered parties, only one objected to aspects of the RFP in a filing to the FPSC. That party's filing was made on March 26, 2015. FPL filed its reply to the objections on March 31, 2015. On April 16, 2015, the FPSC heard oral arguments from both sides and reached a decision that FPL's RFP complied with the Bid Rule, and no changes to the RFP were needed.

Q. How many submittals did FPL receive in response to its RFP?

A. FPL received one submittal in response to the RFP. This submittal was a power purchase agreement based on an existing CC unit located in Alabama. However, immediately upon opening this submittal, the Independent Evaluator for the RFP, Alan Taylor of Sedway Consulting, and FPL determined that it did not conform to at least one of the RFP's Minimum Requirements: submission of a Bid Evaluation Fee.

Q. Were there any other problems with this submittal in regard to complying with the RFP's Minimum Requirements?

A. Yes. The submittal was reviewed to determine if it complied with the rest of the RFP's Minimum Requirements. The result of this review was that the submittal failed to comply not only with the Minimum Requirement for provision of a Bid Evaluation Fee, but also failed to comply with a number of additional RFP Minimum Requirements, including, but not necessarily limited to, the following:

- The submittal was not a firm, binding bid. (The party described their submittal as an "*…indicative, non-binding proposal…*"
- The submittal did not agree to meet the original equipment manufacturer (OEM) Parts for Critical Components Minimum Requirement.
- The submittal did not agree to guarantee the availability and reliability values contained in the submittal.
- The submittal did not comply with the portion of the "Proposal Transmission Requirements" Minimum Requirement that states that, for proposals with generation located outside of the FPL system, it is the responsibility of the Proposer to secure firm transmission service. The submittal stated that it did not have firm

transmission service for its full capacity on the Southern transmission system and offered no plans or schedule for securing the needed transmission capacity.

- The Proposal Submission Minimum Requirement states that: “All forms specified in the RFP must be submitted by the Proposer, and the information requested therein must be complete and accurate.” However, the submittal did not provide information required on the forms in a number of places. One example is that required actual and projected Forced Outage Hours and Planned Outage Hours values were not provided as required on the RFP forms.

Q. Was this bidder afforded an opportunity to submit the required Bid Evaluation Fee?

A. Yes, but the bidder refused to do so.

Q. Did FPL or the Independent Evaluator perform economic analyses of this non-complying submittal?

A. No. There were several reasons for this. First, the submittal was clearly an ineligible proposal that failed to meet many of the RFP’s Minimum Requirements. Second, because the bid contained missing or incomplete information (as mentioned above), the results of any such analysis would have been highly questionable. Third, had FPL analyzed this ineligible proposal, it would have been unfair to other potential participants who chose not to bid rather than submit a non-conforming proposal.

Fourth, if FPL or the Independent Evaluator had performed economic analyses of such a blatantly ineligible proposal, the precedent this would set would likely result in some parties to future FPL (and perhaps other utilities') RFPs submitting proposals that attempted to ignore as many of that RFP's Minimum Requirements as they thought they could get away with. In other words, such parties would conduct a "race to the bottom" that would make any analyses of such ineligible proposals not only problematic in regard to how meaningful the analyses would be, but also would be unfair to proposals that did comply with the RFP's Minimum Requirements. FPL did not want to set such a precedent and encourage this behavior.

Q. Why do you believe FPL received only one submittal in response to its RFP?

A. I believe that there are two reasons for this: (i) the requirement in Florida's Bid Rule that a utility must provide detailed cost and performance data regarding its best self-build option, and (ii) the strength of FPL's NPGU.

Q. Please discuss.

A. Florida's Bid Rule requires utilities to publish in detail the cost and performance characteristics of their best self-build generation option (the NPGU) at the start of the RFP process. By doing so, potential bidders can readily judge whether their contemplated proposal would likely be competitive against the NPGU. If they do not believe it will be competitive, they will likely not go through the time and expense of preparing and submitting a bid.

I believe that it is likely that some potential bidders examined the NPGU's cost and performance data, concluded that the NPGU was a very strong generating option that their contemplated proposal was unlikely to beat, and decided not to submit a bid to this RFP.

Q. How would have a prospective bidder have judged the strength of FPL's NPGU?

A. There are two ways a prospective bidder could have quickly made this judgment. One way would have been to look at certain characteristics of the NPGU versus those same characteristics for the unit(s) upon which their contemplated proposal would be based to see how the two generation options compared. Those characteristics would likely have included installed cost (or capacity payments) and the efficiency (heat rate) of the two generation options.

Q. What is the second way a prospective bidder could have judged the strength of FPL's NPGU?

A. Another approach would have been to examine the outcome of FPL's last capacity RFP, in which FPL's NPGU at that time was judged to be the best, most economic choice for FPL's customers, then to compare cost and performance characteristics of FPL's previous NPGU with those for FPL's current NPGU.

In FPL's last RFP, FPL's NPGU was also a large (1,219 MW Summer) CC unit. In that RFP, three eligible bids were received. Each of the three bids individually met FPL's resource needs, and the three bids were evaluated both in resource plans based solely on the individual bid and in resource plans that combined the individual bids. These resource plans were then evaluated by both the Independent Evaluator and FPL. The outcome in the Independent Evaluator's economic analyses was that the most economic resource plan that did not include the NPGU as part of the resource plan was determined to be $538 million CPVRR more expensive than a resource plan based solely on FPL's NPGU. The outcome of FPL's economic analyses was similar: the most economic resource plan that did not include the NPGU was $607 million CVPRR more expensive than the resource plan based solely on FPL's NPGU. (Note that neither of these projected economic advantages of FPL's NPGU account for the projected impacts of the Net Equity Adjustment on the proposals received.)

In short, in FPL's last RFP, the resource plan based solely on the large CC unit designated as FPL's NPGU had a very significant economic advantage over all resource plans that included one or more eligible bids and which did not include the NPGU.

Q. How does FPL's current NPGU (OCEC Unit 1), compare to the FPL NPGU in its previous RFP?

A. In FPL's last RFP, the NPGU was the West County Energy Center Unit 3 (WCEC 3) with an in-service date of June 2011. Using publicly available information from FPL's Site Plans for these two units, a comparison of three important projections of cost and performance shows the following results:

1) Capacity (Summer MW): OCEC Unit 1's Summer capacity is 1,622 MW. WCEC 3's Summer capacity is 1,219 MW.
2) Efficiency (Heat Rate): OCEC Unit 1's heat rate is 6,304 BTU/kWh. WCEC 3's heat rate is 6,582 BTU/kWh.
3) Installed Cost ($/kW in 2019$): OCEC Unit 1's installed cost in 2019 is $737/kW. WCEC 3's installed cost in 2019$ is $831/kW. (Note that for this comparison, WCEC 3's projected installed cost value of $709/kW in 2011 has been escalated to 2019 at 2% per year to place the installed cost values for both NPGUs in 2019$.)

For all three characteristics, the values for the current OCEC Unit 1 NPGU are better than they were for the WCEC 3 NPGU from the previous RFP. Thus, potential bidders who reviewed the results of the prior RFP's economic analyses would have seen that the NPGU in that RFP was determined to have an economic advantage of more than a half billion dollars CPVRR over the most competitive bids. Then a comparison of the previous NPGU versus the NPGU for this RFP would have shown that the current NPGU is bigger, more fuel-efficient, and has a lower $/kW installed cost. Parties who conducted such a comparison would also likely recognize that OCEC Unit 1 is projected to be the most fuel-efficient fossil-fueled generating unit that FPL has built and might well have decided not to expend the time and money necessary to prepare and submit a bid for the current RFP.

Q. Does the result of this second approach for judging the strength of FPL's NPGU provide additional confidence that FPL's NPGU is the best resource option for meeting the 2019 need?

A. Yes.

Q. At the conclusion of the RFP process, what was FPL's decision regarding the best option with which to meet its 2019 capacity needs?

A. Having emerged from an extensive evaluation of FPL self-build options as the best self-build choice, and with no eligible outside proposals to compete with OCEC Unit 1, FPL concluded that the OCEC Unit 1 is the best, most economic choice for FPL's customers with which to meet capacity needs beginning in 2019.

Q. Will FPL continue to evaluate OCEC Unit 1?

A. Yes. As explained in the testimony of FPL witness Kingston, FPL will continue to evaluate different designs and models for the OCEC Unit 1 CTs, the heat recovery steam generator (HRSG), the steam turbine (collectively, the "Power Train Components"), and other related equipment necessary for operation of the unit, as a part of FPL's continuing efforts to determine which technology will provide the greatest benefits to FPL's customers.

Q. If FPL were to select an enhanced design or model for the OCEC Unit 1 Power Train Components or other related equipment, how does FPL propose to address such selection as it pertains to the determination of need requested by FPL in this proceeding?

A. FPL requests that, as a part of the FPSC's order granting an affirmative determination of need for OCEC Unit 1, the FPSC provide that its determination is not predicated on FPL's selection of a particular design or model for the Power Train Components or other related equipment necessary for operation of the unit, thus providing FPL the flexibility through its negotiations and analyses to select the Power Train Components and other related equipment that best meet FPL customers' needs in terms of reliability and cost-effectiveness. Of course, FPL would select an enhanced design or model only if the enhanced design or model results in lower projected system CPVRR cost to FPL's customers. In the event that FPL selects an enhanced design or model other than the analyzed technology subsequent to the FPSC having granted a determination of need for OCEC Unit 1, FPL proposes to make an informational filing to the FPSC that documents the projected comparative CPVRR cost advantage of the alternate technology chosen.

VIII. ADVERSE CONSEQUENCES OF NOT BUILDING OCEC UNIT 1

Q. Would there be any adverse consequences to FPL and its customers if the FPSC were not to grant an affirmative determination of need for OCEC Unit 1 in this proceeding?

A. Yes. If a determination of need for OCEC Unit 1 were not granted in this proceeding, FPL's customers will face significant adverse consequences related to either system reliability or the cost of electricity.

Q. Please describe the adverse consequences of denying the need determination of OCEC Unit 1.

A. FPL's reliability analyses show that the FPL system needs a significant amount of capacity (1,052 MW) in 2019. If the need determination for OCEC Unit 1 is denied, and no other self-build generation option is allowed to replace it, then, as shown previously in Exhibit SRS-2, FPL's projected GRM in 2019 would fall to 5.8%, well below FPL's GRM reliability criterion value of a minimum of 10%. In addition, FPL's projected total RM in 2019 would fall to 15.7%, well below FPL's total RM reliability criterion value of a minimum of 20%. Therefore, if the need determination for OCEC Unit 1 is denied, and no other self-build generation option replaces it, system reliability for FPL's customers would be significantly degraded.

On the other hand, if the need determination for OCEC Unit 1 is denied, and FPL's 2019 capacity need is met by another FPL self-build unit, FPL's customers will face higher costs. Denying a need determination for OCEC Unit 1 at the conclusion of this docket would leave roughly 3.5 years until June 1, 2019 when the additional capacity is needed. This would likely result in the only self-build option that could be constructed in time being simple cycle CT capacity. In the first stage of FPL's self-build analyses, a CT-only addition in 2019 was judged to be approximately $124 million CPVRR more expensive than what was identified at that point as the best CC option. As discussed above, further refinement of the CC option in the second stage of the analysis resulted in a $157 million CPVRR improvement in the economics of the CC unit. Therefore, FPL's customers would be paying up to $281 million CPVRR more if a need for OCEC Unit 1 was denied, and simple cycle CTs had to be built.

In addition to this cost penalty, simple cycle CTs are much less fuel-efficient units than OCEC Unit 1. Consequently, FPL's system air emissions would also increase over what they would have been if the more fuel-efficient OCEC Unit 1 was placed in-service.

Granting a need determination for OCEC Unit 1 will result in FPL's customers benefiting from both a reliability perspective and an economic perspective. Bringing OCEC Unit 1 onto the FPL system by June 1, 2019 will maintain system reliability and allow FPL's customers to be served by the most economic and fuel-efficient generation option available to meet this need.

IX. CONCLUSION

Q. What is your conclusion about the OCEC Unit 1 project?

A. Building OCEC Unit 1 with an in-service date of June 1, 2019 is the best, most cost-effective choice for FPL's customers for maintaining reliable electric service beginning in that year. This unit was determined to be the most cost-effective FPL self-build option through extensive analyses. Furthermore, FPL's capacity RFP that was issued to identify non-FPL capacity options that would be evaluated as alternatives to OCEC Unit 1 resulted in no viable alternatives being offered. Thus, the OCEC Unit 1 is the best, most economic choice among the available alternatives to meet FPL's customers' resource needs in 2019 and is projected to be the most fuel-efficient CC unit on FPL's system, further enhancing the fuel efficiency of an already highly efficient generation system. It is also projected to be the most fuel-efficient CC unit in the state of Florida.

Therefore, I believe the FPSC should grant an affirmative determination of need for OCEC Unit 1 with a target in-service date of June 1, 2019, based on a finding that this project is the best, most cost-effective choice to meet the needs of FPL's customers in 2019.

Q. Does this conclude your direct testimony?

A. Yes.

FPL

Florida Power & Light Company's

2015 Request for Proposals

To Meet Generation Capacity Needs Beginning in 2019

March 16, 2015

2015 Request for Proposals - Generation Capacity

Section I - 2015 RFP Overview
A. Introduction …………………………………………………………. 3
B. General Notices...…………………………………………………..3
C. Description of Appendices……………………………………... 6
D. Projected RFP Schedule…..…………………………………............ 6
E. Pre-Bid Workshop, RFP Notices, and Addenda…..…………..……..7

Section II - General Information
A. Issues Influencing System Costs, Environmental Impacts, and Reliability.. 8
B. Proposer Responsibilities.. 9
C. Contact Person and Confidentiality...11

Section III – Minimum Requirements for Proposals…………………….….. 12

Section IV – Minimum Requirements Pursuant to Purchase Agreement..………22

Section V – Overview of the Evaluation Process…………………………..….34

Section VI – Detailed FPL Information Regarding FPL's Capacity Needs and NPGU………………………………………………………….38

Appendices
A. FPL's 2014 Ten Year Power Plant Site Plan (TYSP)
B. Power Purchase Agreement Key Conditions
C. Forms for Proposers
D. Evaluation Information
1. Evaluation Methodology
2. Transmission Integration & Losses
3. Net Equity Adjustment
E. Changes in Key Forecasts and FPL's Resource Plan from FPL's 2014 Ten-Year Site Plan

Section I - 2015 RFP Overview

A. Introduction

Florida Power & Light Company (FPL) set forth a comprehensive resource plan in its 2014 Ten Year Power Plant Site Plan (Site Plan). This plan included a mix of cost-effective demand side management (DSM) and generation resources to meet FPL's projected resource needs. The 2014 Site Plan document projected that, after all cost-effective DSM had been accounted for, FPL would have a need for additional generation beginning in the year 2019. Although a number of key forecasts have changed since those used in the resource planning work reflected in the 2014 Site Plan, FPL continues to project a significant need for new generation beginning in the year 2019. FPL currently projects a need for new generation of approximately 1,052 MW beginning in the Summer of 2019.

Therefore, FPL is initiating a Request for Proposals (RFP) process in 2015 to identify viable firm capacity and energy generation resources that will be compared to FPL's best self-build generation option; i.e., FPL's Next Planned Generating Unit (NPGU), to meet FPL's projected capacity needs beginning in 2019.

The aim of this RFP process is to obtain a variety of eligible supply-side resource proposals that can provide firm capacity, then evaluate those proposals, and/or combinations of proposals, in comparison to FPL's NPGU. This will enable FPL to select the best, most cost-effective generation resource or combination of generation resources that meets FPL's system reliability and performance standards in an environmentally responsible manner, all for the benefit of FPL's customers.

B. General Notices

1. Definition of RFP

It is important that all participants in this RFP process clearly understand that, in order to protect the interests of FPL's customers, FPL retains the right during the RFP process to: select only FPL's NPGU, or selecting FPL's NPGU in conjunction with one or more proposals, or select a proposal or combination of proposals that is, or is not, the lowest-priced generating unit, proposal, or combination, waive a non-compliance aspect in any proposal, reject any and all proposals, modify or cancel the RFP process, modify the cost and/or performance assumptions of FPL's NPGU, and modify FPL's projected need for new generation resources. In the event that FPL modifies the cost and/or performance assumptions of FPL's NPGU, those Proposers that have eligible and competitive proposals under evaluation at that time will be given an opportunity to amend their proposals with respect to only those aspects that are affected by FPL's modifications to the NPGU.

This RFP is not an offer to enter into a contract. It is a solicitation of exclusive firm offers of fixed duration from Proposers. Nothing in this RFP or any communication associated with this RFP shall be taken as constituting an offer or representation between FPL and any other party. Neither issuance of this RFP, nor the entry of FPL into negotiations with any Proposer, will be deemed to create any commitment or obligation on the part of FPL to enter into a binding agreement with any Proposer. Those entities that elect to submit proposals do so without recourse against FPL or any of its affiliates for either FPL's rejection of their proposal(s) or for failure, for any reason, of the Proposer and FPL to execute a definitive purchase agreement or tolling agreement (jointly "Purchase Agreement") related to FPL's RFP.

2. Regulatory Background

The Florida Administrative Code Rule 25-22.082 requires public utilities to issue an RFP prior to filing a petition for Determination of Need in accordance with Section 403.519, Florida Statutes. FPL's projections indicate that FPL will have a need for additional generation capacity from a reliability perspective starting in 2019, and this projected capacity need increases every year thereafter. FPL has determined that adding the most cost-effective FPL self-build option that can provide additional capacity starting in 2019 would require a Determination of Need. FPL recognizes that proposals that may be submitted as alternatives to FPL's NPGU may or may not require a Determination of Need.

3. Overall RFP Description

This RFP addresses FPL's projected capacity needs starting in the Summer of 2019. The RFP presents a NPGU with a June 1, 2019 in-service date. The RFP seeks alternatives with an in-service date of June 1, 2019 that can be compared to FPL's self-build option. (Proposals with earlier and later in-service dates are unacceptable.) This process will enable FPL to select the most cost-effective generation capacity resource(s) that will meet FPL's reliability and performance requirements and that can be placed in service to meet FPL's 2019 capacity need.

4. Proposal Price

All proposals must ensure their price reflects all capital costs to construct, and all O&M costs to operate and maintain, any pipeline laterals(s), railway equipment, fuel handling equipment, facility infrastructure, land costs, and any other facilities necessary to deliver the full fuel or energy requirements (including backup fuel requirements) to the proposed generating unit.

5. Types of Proposals

The solicitation is designed to accommodate a wide range of proposals for supply-side generation alternatives from various fuels, technologies, locations, and under differing commercial frameworks. For example, FPL may receive proposals for power sales under a Purchase Power Agreement from existing facilities (currently in operation) and newly constructed facilities (greenfield or brownfield offerings). These proposals may have fuel supply and firm transportation arrangements or request a natural gas tolling arrangement where FPL would provide the natural gas supply and firm transportation. A reasonable attempt will be made to accommodate creative variations that may be proposed. Nonetheless, it is conceivable that a Proposer may offer a unique attribute that has not been explicitly considered in this RFP and the associated forms. In that instance, FPL will contact the Proposer to understand, and if possible, evaluate the unique features of a particular offering.

FPL will not consider or evaluate proposals to sell an existing, or new (turnkey project) generating unit to FPL. FPL will not consider or evaluate proposals from specific units that use coal or petroleum coke as fuel. However, FPL will consider and evaluate proposals of system sales that include units that use coal or petroleum coke as a fuel, subject to the conditions specified below in section III, 7 below.

6. Firm Capacity and Dispatchability

FPL seeks proposals that would allow FPL to meet its firm capacity requirement in future years. Therefore, all proposals will be required to offer the commitment of firm capacity and energy to FPL. FPL defines Firm Capacity and Energy as follows:

> *"All electric energy and capacity owned or acquired by the Proposer to be made available exclusively to FPL pursuant to the RFP as if FPL owned the generating capacity on its own system. Firm Capacity and Energy shall not include any electric generating capacity that another Party, including the Proposer, can utilize or purchase."*

The firm capacity and energy proposed in any proposal must be fully dispatchable under the operational control of FPL and must include all of the facility's output, inclusive of ancillary service products and environmental attributes. Requiring that all proposals satisfy the firm and dispatchability conditions ensures that proposals can be evaluated on an equal basis regarding their total costs and reliability benefits to FPL's customers.

C. Description of Appendices

There are five appendices to this 2014 RFP that are summarized below.

Appendix A provides a copy of FPL's 2014 Ten Year Power Plant Site Plan.

Appendix B lists key conditions that will be incorporated into any Power Purchase Agreement (PPA) that may be entered into as a result this RFP.

Appendix C provides the specific forms that Proposers will need to submit as part of their proposals, and a description of the information that must be provided in those forms.

Appendix D provides detailed information regarding FPL's evaluation methodology, including examples of how specific evaluation calculations will be applied.

Appendix E discusses changes in key forecasts from those utilized in the development of FPL's 2014 Ten Year Site Plan (provided in Appendix A). The current forecasts will be used in the evaluation of the NPGU and proposals submitted in response to this RFP and have been used in the evaluation of FPL's NPGU. This appendix also discusses key changes to FPL's resource plan, compared to the resource plan discussed in FPL's 2014 Ten Year Site Plan, up to the year 2019.

D. Projected RFP Schedule

FPL envisions that the milestone schedule for the RFP process will be as described below in Table I.D below. FPL reserves the right to change the schedule at its sole discretion.

Table I.D Schedule of Milestones

Milestone	Date
• RFP Pre-Issuance Discussion Meeting	March 9, 2015
• Release RFP Document	March 16, 2015
• Pre-Bid Workshop	March 24, 2015
• Cutoff Date for RFP Questions	April 17, 2015
• Proposals Due	May 15, 2015
• Short List Announcement – if relevant	TBD
• Permitting Activity Commences	TBD
• Best and Final Offers Due – if relevant	TBD
• Initial Negotiations – if relevant	June 15 to July 30, 2015
• Selection Announced (on or before)	July 31, 2015

Note: The above dates are projections. All dates are subject to change at FPL's sole discretion to accommodate unforeseen delays or required procedural actions. Certain dates are listed as TBD because these dates are heavily dependent upon the number, type, and/or complexity of eligible proposals that will be received and evaluated.

E. Pre-Bid Meeting, RFP Notices, and Addenda

1. Pre-Bid Meeting

FPL will hold a Pre-Bid Meeting in the Miami, Florida area. The meeting will be on Tuesday, March 24, 2015 beginning at 9:30 a.m. at the InterContinental At Doral, 2505 NW 87th Avenue, Doral, Florida 33172-1610. The hotel's phone number is 305-468-1400. Interested parties may attend in person or remotely via a conference call connection. Regardless of whether an interested party plans to attend in person or remotely, the party must first register for the meeting on FPL's RFP website at FPL.com/2015rfp. This meeting is scheduled to conclude by 12 p.m. The purpose of the Pre-Bid Workshop is to assist Proposers in understanding the submittal requirements, provide background on FPL's most recent resource planning results, and begin to respond to questions from potential proposers.

2. RFP Notices and Addenda

RFP-related notices and addenda will, as needed, be posted on the RFP website. In addition, all RFP-related questions posed to FPL, along with FPL's responses to those questions, will also be posted on the RFP website.

Section II - General Information

A. Issues Influencing Evaluation Regarding System Costs, Environmental Impacts, and Reliability

1. Geographic Location

System cost-effectiveness and reliability measures are improved when new generation units are located near the system load center. The ability of a generator to deliver power in or near the area of greatest need lowers the cost of delivering that power to customers and provides greater operational flexibility for the system. FPL's RFP evaluation methodology recognizes the value of geographic location and this is discussed in more detail in Appendix D.

2. Greenhouse Gas (GHG) Emissions

FPL's evaluation process will examine the projected impacts of proposals (and FPL's NPGU) on FPL's system emissions including GHG emissions (as represented by carbon dioxide, CO2). GHG emission-related costs to the FPL system will be addressed as discussed in Appendix D.

3. Fuel Diversity

FPL's has always sought to maintain a generation system that utilizes a diverse range of fuel sources in order to ensure reliable service to its customers. For example, FPL's NPGU would receive natural gas through the new Sabal Trail and Florida Southeast Connection pipelines, which would enable FPL to obtain natural gas from diverse geographic locations.

In addition to FPL's economic analyses of proposals and FPL's NPGU, FPL's RFP evaluation process will also generally recognize the value offered by fuel diverse generation options in the context of the non-economic evaluation of environmental and technical or operational factors. The non-economic aspects of a proposal, including fuel diversity, will be appropriately balanced with the economic aspects of the proposal, during the overall evaluation process.

B. Proposer Responsibilities

1. Regulatory Compliance

The Proposer is solely responsible for acquiring and maintaining compliance with all licenses, permits, and other regulatory approvals (including environmental) that will be required by current or future federal, state, or other local government laws, regulations, or ordinances to successfully implement the proposal. For a selected proposal that requires new power plant construction falling under the Florida Electrical Power Plant Siting Act, Section 403.501 – 403.518, Florida Statutes (Siting Act), FPL would be a co-applicant in a Determination of Need filing with the Florida Public Service Commission under Section 403.519, Florida Statutes. FPL will cooperate with any selected Proposer(s) to provide information or such other assistance as may reasonably be necessary for the Proposer(s) to satisfy licensing and regulatory requirements. Likewise, the selected Proposer(s) shall fully support all of FPL's regulatory requirements associated with this potential capacity and energy arrangement.

For any proposal that requires new power plant construction falling under the Siting Act, the Proposer must demonstrate as part of the proposal a permitting and construction schedule that allows the new plant to be in commercial operation on or before the Capacity Delivery Date. Appendix C includes a discussion of Form # 7 that requires, in part, key milestone dates regarding permitting and construction schedules.

2. Development Activities

The Proposer is solely and completely responsible for the location, acquisition, and development of the plant site and other land or infrastructure that is needed for any proposed new generating units.

The Proposer is also completely responsible for securing, locating, or guaranteeing any emissions allowances, credits, or offsets which may be required by the Title IV Clean Air Act Amendments, Clean Air Interstate Rule, Clean Air Mercury Rule or other federal, state, or local requirements, or otherwise complying with environmental regulations to allow the construction and/or operation of the proposed facility. Proposers whose proposals offer the sale of capacity and energy from an existing power plant(s) must secure the emission allowances, credits, or approvals necessary, or in otherwise complying with environmental regulations to operate the facility during the term of the contract.[1]

3. Project Funding and Costs

All Proposers are completely responsible for all financing activities related to the project and for engineering, design, procurement, and construction of all aspects of the facility. These include, but are not limited to: the cost of the land, the power block, environmental control systems, fuel delivery systems (from the fuel delivery point, if a tolling arrangement is proposed), and transmission system interconnections. The Proposer is also completely responsible for sourcing and contracting for a reliable fuel supply and firm fuel transportation (unless the proposal is a gas tolling proposal) and any other activity required for the reliable delivery of firm capacity and energy to FPL at the identified delivery or interconnection point. All costs associated with the design, construction, operation, and maintenance of the transmission interconnection facilities (including but not limited to generator step-up transformers and high-voltage breakers) and natural gas pipeline laterals associated with the delivery of firm capacity and energy to FPL will be the responsibility of the Proposer.

4. Interconnection and Transmission Service

The Proposer must secure with the appropriate transmission provider(s) all needed transmission facilities and arrangements required to deliver the firm capacity and energy to the FPL transmission system on a firm long-term basis for the entire term of the proposal. Per FPL's OATT, the Proposer will also be responsible for funding (on a reimbursable basis) any network upgrades to FPL's transmission system that are necessitated by the purchase of capacity and energy form the Proposer's resource.

5. Cooperation

Any selected Proposer(s) agrees by the act of submitting a proposal in response to this RFP to file, as needed, an application under the Siting Act and to fully

[1] Due to uncertainty regarding GHG regulations and costs, a projection of GHG $/ton costs (represented by projected CO2 costs) will be used in the evaluation of proposals and the NPGU regarding their projected impacts on system GHG emissions and costs. The treatment of GHG regulation-based operational costs in a potential power purchase agreement will be addressed in negotiations for such an agreement. However, FPL and its customers will not agree to pay the Proposer for any GHG emission costs due to GHG emission rates higher than the guaranteed rates submitted by the Proposer and must take into consideration any free GHG emission allowances or credits that are ultimately allocated to the Seller/resource under environmental law. In the event of a future change in law or regulation that would have the effect of shifting to or imposing upon FPL GHG emission costs greater than those agreed to in the PPA, FPL would have the right to terminate the PPA if such additional costs were not found to be prudent and approved for FPL cost recovery by the Florida PSC.

support, as requested by FPL, any FPL regulatory proceeding(s) related to firm capacity purchases emanating from this solicitation. Proposers shall be responsible for all of Proposer's costs to participate in the necessary regulatory proceedings.

C. Contact Person and Confidentiality

1. FPL Contact Person

Name: Steven Sim
Florida Power & Light Company
Department: Resource Assessment & Planning/RAP
Street Address: 9250 W. Flagler Street
City/State/Zip Code: Miami, Florida 33174
Email: steve.r.sim@fpl.com
Office Phone: 305-552-2246
Fax: 305-552-2716

FPL's evaluation of all proposals and FPL's NPGU will be reviewed, and a parallel evaluation will be conducted, by Sedway Consulting, Inc. Therefore, please copy Alan.Taylor@sedwayconsulting.com on all RFP-related questions and emails to FPL. All answers to questions will be provided solely on FPL's RFP website.

2. Proposal Confidentiality

FPL will take reasonable precautions and use reasonable efforts to protect proprietary and confidential information contained in a proposal, provided that such information is clearly identified by the Proposer as Proprietary and Confidential on each page(s) on which the information appears.

To clearly identify confidential information, the Proposer must (1) stamp each such page with the label "**Confidential Information**" and (2) highlight/shade the specific confidential information contained on the pages stamped "**Confidential Information**". (A blanket statement that an entire page or proposal is proprietary and confidential will not be considered clear identification.)

Notwithstanding the foregoing, FPL shall disclose Confidential Information in the event that it determines, in its sole discretion, that disclosure is necessary in order to comply with any applicable law, order, regulation, ruling, subpoena, or order of the Florida Public Service Commission or other governmental authority or tribunal with competent jurisdiction. Such disclosure may include, but is not limited to, production of Confidential Information to the Florida Public Service Commission and to parties in legal and regulatory proceedings conducted to consider and to approve the project(s) which is the subject of this Request for Proposals.

In the event that FPL is requested or required to disclose any Confidential Information, FPL will provide prior notice to the entity whose Confidential Information has been requested so that such entity may, if it chooses, seek an appropriate protective order subject to protections available under the Florida Statutes, Florida Administrative Code, and Florida Rules of Civil Procedure.

With respect to any disclosure made by FPL pursuant to the foregoing paragraphs, FPL will furnish only that portion of the Confidential Information that FPL determines in its sole discretion to be consistent with the scope of the subpoena, demand, or request and will seek reasonable assurances that confidential treatment will be accorded such Confidential Information.

Section III. Minimum Requirements for Proposals

Proposers must agree, both in their proposals and as part of any Power Purchase Agreement arising from this RFP, to comply with (as applicable) each of the provisions of the Minimum Requirements for Proposals listed in this Section III, and of the Minimum Requirements Pursuant to Purchase Agreement listed in Section IV. Failure of a Proposer to agree to and/or comply with (as applicable), or failure of a proposal to agree with or comply with one or more Minimum Requirements for Proposals or Minimum Requirements Pursuant to Purchase Agreement, will be grounds for determining a proposal ineligible. FPL reserves the right to waive inconsequential non-compliance with these Minimum Requirements. Proposals determined to be ineligible will be returned to the Proposer along with a refund of 50% of the RFP Evaluation Fee.

1. Financial Viability Requirements of Proposers

For each proposal submitted pursuant to FPL's RFP, the Proposer or Qualified Guarantor of the Proposer must have a senior unsecured debt rating of no less than "BBB-" from Standard & Poor's, or"Baa3" from Moody's Investors Service with a "stable" outlook, and be able to satisfy the Completion and Performance Security requirements set forth in section 8 below.

Each proposer must certify (as part of its proposal) that there are no pending legal or civil or regulatory actions that could affect the ability of the Proposer to maintain an acceptable debt rating consistent with the above criteria.

2. Experience of Proposer

Proposers whose proposal reflects (i) the construction of a new generating unit, or (ii) an upgrade to an existing generating unit (each a "New Unit") must demonstrate that it has successfully executed the development, permitting, design, procurement, construction and commissioning of a project similar to that reflected in the proposal.

The entity that will operate and maintain the proposed generating unit(s) submitted pursuant to FPL's RFP must demonstrate that it has a minimum of 5 years of experience in the successful, reliable operation and maintenance of generating units utilizing similar technology. The success and reliability of operations may be demonstrated through operational records and/or NERC GADS reporting data as requested in Appendix C, Form # 4.

3. Proposal Submission Requirements

All proposals and variations to proposals must be received by the FPL RFP Contact Person by 4:00 p.m., Eastern Daylight Savings Time, on May 15, 2015 (Proposal Due Date and Time). Proposers must submit five (5) bound hard copies, plus an electronic copy of the completed forms on a CD, by the Proposal Due Date and Time. The RFP Evaluation Fee and/or Variation Fee, must accompany each proposal and, separately, each proposal variation.

All forms specified in the RFP must be submitted by the Proposer, and the information requested therein must be complete and accurate. FPL may choose to contact a Proposer to request that omitted or incomplete information be provided, but is under no obligation to do so. Any attempt by a Proposer to disclaim generally the terms and conditions of this RFP without stating specific exceptions and alternative language will be grounds for determining a proposal to be incomplete, and therefore, ineligible.

Proposer must comply with the Publication Notice requirement of Rule 25-22.082(7), Florida Administrative Code, which requires a notice to be published in a newspaper of general circulation in each county in which the Proposer intends to build a new electric generating unit or upgrade an existing electrical generating unit. The Publication Notice shall be at least one-quarter of a page and shall be published not later than 10 days after the Proposal Due Date. The Publication Notice shall state that the Proposer has submitted a proposal to build a new electric generating unit or upgrade an existing electrical generating unit, and shall include the name and address of the Proposer submitting the proposal, the name and address of the public utility that solicited the proposals, and a general description of the proposed new or upgraded generating and its location. A copy of the notice, including an affidavit confirming publication, must be submitted to the FPL Contact Person within 10 days of publication of such notice, or within 20 days of the Proposal Due Date.

4. RFP Evaluation Fee

Each proposal must be accompanied by a non-refundable check of $25,000 ("RFP Evaluation Fee") made out to "Florida Power & Light Company" and delivered to the FPL RFP Contact Person on or before the Proposal Due Date (no later than 4:00 p.m. EDST). If more than one proposal is submitted by a specific Proposer, then a separate, non-refundable $25,000 fee must accompany each proposal. Proposals deemed ineligible or otherwise non-responsive after an initial review will not be evaluated further and 50% of the Evaluation Fee will be refunded.

One proposal consists of a specific combination of a site, technology, fuel source, total capacity level, term (*e.g.*, 10 years), and pricing submittal. If a Proposer submits variations of term and/or price related to a specific proposal (a single variation is defined as a change in one or both term and/or price), the Proposer must accompany such variations with an additional check for $5,000 per variation (the Variation Fee). There are no limitations to the number of price/term variations submitted, as long as each variation is accompanied by a separate $5,000 Variation Fee.

Changes in site, technology, fuel source, or capacity level, or in any parameter other than term or price will constitute a separate proposal and will require a separate full $25,000 RFP Evaluation Fee. Any proposals and the related variations that are deemed by FPL to be ineligible or non-responsive (as determined by FPL at its sole discretion) will not be evaluated further and 50% of the applicable fee(s) received will be refunded.

5. Term of the Proposal

Proposals must offer to deliver firm capacity and energy beginning on June 1, 2019, and throughout the term specified in the proposal (the "Proposal Term"). The acceptable proposal terms for proposals are as follows:

i. The minimum proposal term for proposals offering system sales or sales from new or existing units that do not require a need determination is five (5) years.
ii. The minimum proposal term for proposals offering PPA or Tolling sales from a new unit that requires a need determination is ten (10) years.
iii. The minimum term length for proposals requiring a Natural Gas Tolling Agreement is fifteen (15) years.

iv. The maximum proposal term of any proposal is thirty (30) years.

6. Range of Acceptable Proposals

FPL will consider a power purchase agreement pursuant to which FPL would purchase firm capacity and energy from:

i. An existing generating unit that is currently in operation and that satisfies (in whole or in part) FPL's projected 2019 generation needs ("Existing Unit"); and
ii. A New Unit that satisfies (in whole or in part) FPL's projected 2019 generation needs.

FPL will also consider a gas Tolling Agreement pursuant to which FPL would deliver natural gas and purchase firm capacity and energy from:

a. An Existing Unit that satisfies (in whole or in part) FPL's projected 2019 generation needs, and
b. A New Unit that satisfies (in whole or in part) FPL's projected 2019 generation needs.

FPL will also consider a purchase from a system sale subject to the conditions specified below in section 7 below.

FPL will not consider or evaluate proposals to sell an existing, or new (turnkey project) generating unit to FPL. FPL will not consider or evaluate proposals from specific units that use coal or petroleum coke as fuel. However, FPL will consider and evaluate proposals of system sales that include units that use coal or petroleum coke as a fuel, subject to the conditions specified below in section 7 below.

7. System Sales

Proposals that consist of system sales will be considered only if such system sales are: (i) from electric systems that are subject to the jurisdiction of the Florida Public Service Commission ("FPSC") (or similar public regulatory authority), (ii) have direct control of generation and transmission facilities, and (iii) are members in good standing of a NERC reliability coordinating council.

Proposers that offer firm capacity and energy sales from system sales must provide a clear explanation of how the firm capacity and energy will be produced, scheduled, and delivered to FPL.

Proposers that offer firm capacity and energy system sales must also describe how the Proposer's commitment of such firm capacity to FPL would affect the

Proposer's own reserve margin, and explain how the Proposer's reserve margin will remain above the minimum reserve margin criteria approved for the Proposer by the FPSC or similar public regulatory authority.

8. Firm Capacity Nature of Proposal

i. Proposals must offer firm capacity solely to FPL year-round.
ii. Proposed firm capacity and energy must be fully dispatchable under the operational control of FPL for all proposals except those that are system sales.
    a. With respect to proposals for sales from a generating unit with capacity greater than 100 MW, such unit must be equipped with automatic generation control ("AGC") that can be directed remotely by FPL.
iii. Proposals offering firm capacity and energy from an identifiable unit (*i.e.*, not a system sale) must dedicate to FPL all of the unit's output, including any ancillary service products and environmental attributes.
    a. No portion of the output of the proposed generating unit shall be available to any third party, nor to the Proposer.
iv. The firm capacity and energy delivery must commence within the required time frame of the solicitation and remain as firm capacity and energy throughout the term of the proposal.
v. Capacity and energy from a system sale must be delivered to FPL when called upon by FPL based on FPL's own economic dispatch.

9. Permit and Authorization Feasibility

The Proposer must demonstrate that there are no significant barriers to obtaining the necessary regulatory and governmental permits and authorizations to execute or implement the proposed project on a schedule that meets the Capacity Delivery Date. All proposed projects will be subject to the approval of the appropriate Regulatory Authorities.

The Proposer is responsible for acquiring and maintaining compliance with all licenses, permits, and other regulatory approvals (including environmental) that will be required by current or future federal, state, or other local government laws, regulations, or ordinances to successfully implement the proposal during the Proposal Term.

10. Binding Nature of Proposal

Each proposal must be firm and binding, and must be certified (as part of the proposal) as a "binding, definitive proposal" by an Officer of the proposing entity. "Indicative" proposals are not eligible for consideration and will be rejected.

The terms of each proposal must remain valid and binding for 180 days from the Proposal Due Date, unless the proposal is withdrawn in full. Proposals cannot be modified, except where modified specifically in response to a modification of FPL's description of its NPGU, or in response to FPL's explicit invitation for a Proposer to submit a Best and Final Offer ("BAFO"). Clarifications requested by FPL are not considered modifications.

If FPL selects a proposal for a "Short List" and invites the selected Proposer to submit a BAFO, such BAFO (or the original proposal if the Proposer elects to remain with the original proposal) must then remain valid and binding for 180 days from the date the Proposer submits a BAFO.

11. Identifiable Capacity Source

The proposal's firm capacity and energy must be from one or more specific generating unit(s) that is/are clearly identified and described in detail in the proposal.

Exceptions to this requirement will be made for system sales from electric systems that are subject to the jurisdiction of the FPSC or similar public authority, have direct control of generation and transmission assets, and are members in good standing of a NERC reliability coordinating council. Firm capacity and energy sales from systems must include a clear explanation of how the capacity is to be obtained and delivered. The proposal must also explain how commitment of such system capacity to FPL will affect the Proposer's ability to meet the FPSC reserve margin requirements (or the requirements of other state agencies as appropriate).

12. Site Description

With respect to a proposed new generating unit, the Proposer shall provide a detailed description of the site on which the unit is proposed to be built including, but not limited to, the exact location of the site, the required transmission interconnection, fuel delivery system(s), and water resources to be used by the Proposer in operating the resources, and any other site or project characteristics that affect the capacity and energy values associated with the proposal.

FPL will not consider any proposals that would use property owned or controlled by FPL.

13. OATT Requirement

All generating units reflected in proposals must be located within FPL's transmission system and be interconnected to FPL's transmission system or, if located outside FPL's system, must have accounted for all interconnection and system upgrades necessary to allow the generating unit to qualify as a designated network resource (pursuant to FPL's OATT).

In order to be considered, each Proposer submitting a proposed, new generating unit to be located within FPL's system must also submit, as applicable, at least 15 days prior to the Proposal Due Date, a completed "Large Generator Interconnect Request" application and a security deposit (as applicable) in accordance with the provisions of FPL's OATT. To evidence that the application and security deposit have been submitted, the Proposer must include a copy of the OASIS request confirmation statement with the proposal.

14. OEM Parts for Critical Components

Proposers whose proposals are based on natural gas-fired combustion turbines and/or combined cycle units will be required to represent that, if selected, the proposed generating unit will install and continue to use original equipment manufacturer (OEM) parts for gas turbine hot path components listed below:

- Rotor Discs, Spacers, and Stud Assembly Hardware (e.g., Turbine Thru Bolts, Nuts, and Washers)
- Turbine Stationary Airfoils (e.g., Vanes/Nozzles/Diaphragm)
- Turbine Rotating Airfoils (e.g., Blades/Buckets)
- Turbine Vane Support Rings or Vane Carriers

Any power purchase arrangement entered into pursuant to the RFP will reflect this OEM commitment, and the OEM parts will be installed prior to the start of the purchase arrangement. On an annual basis, the Proposer will be required to obtain a certification from the equipment manufacturer(s) to the effect that OEM parts have been installed and maintained in accordance with the requirements of the purchase arrangement entered into pursuant to this RFP.

Failure to install and properly maintain such OEM parts, or to obtain and deliver to FPL OEM's annual certification, will place the selected Proposer in default, with 120 days to cure. If not cured, FPL may terminate the Purchase Agreement and or collect damages as specified in the Purchase Agreement.

15. Resource Block Size (MW) Range

The minimum power block size associated with a generating unit ("Power Block") that FPL will consider in a proposal is 50 MW. The maximum Power Block size that will be considered for a proposal is 1,650 MW (Summer).

16. Security Requirements

i. By submitting a proposal, a Proposer agrees to provide Completion Security and Performance Security as specifically defined in section IV, 8 of this document.
ii. For proposals supported by existing facilities, Proposer must agree to provide the Performance Security as specifically defined in section IV, 8.
iii. Proposer must certify that there are no pending legal or civil actions that would affect the ability of the Proposer and/or its guarantor to maintain the criteria identified in section IV, 8.

17. Proposal Pricing and Fuel Supply, Transportation, and Delivery Choices

Except as set forth in subsection i. below in regard to GHG costs, a proposal's price must reflect an "all in" contract price (including any related fees and expenses) that FPL would pay to the selected Proposer for all aspects related to, and products (including ancillary services and environmental attributes) associated with the generation and delivery to FPL of firm capacity and energy, including without limitation:

i. Payments related to all costs, fees, and expenses incurred by Proposer to maintain compliance with all laws and regulations applicable to Proposer's generating unit(s) during the Proposal Term. This includes, but is not limited to, the costs of all equipment, development, design, construction, commissioning, and all costs of meeting and maintaining compliance with environmental regulations that are in effect as of the Capacity Delivery Date or are known as of the Capacity Delivery Date to be in effect during the pendency of a PPA that would result from selection of the proposal. Due to the uncertainty currently existing in regard to GHG costs, the treatment of GHG regulation-based operational costs in any power purchase agreement would be addressed in negotiations for such an agreement.

ii. Payments related to all capital and O&M costs incurred by Proposer. This includes, but is not limited to, costs to transport natural gas from the Proposer-designated interstate pipeline to the proposed generating unit. This requirement applies to all PPAs, including natural gas tolling or non-tolling agreements.

iii. Payments related to all costs, fees, and expenses the Proposer would incur related to the purchase of fuel, delivery of fuel to Proposer's generating unit, and inventory of fuel to support operation of Proposer's generating unit.

iv. Payments related to all costs for transmission facilities (and any necessary transmission upgrades) the Proposer would incur to enable its proposed generating unit to interconnect to the FPL system and deliver firm capacity and energy to a receipt point on FPL's system acceptable to FPL.

v. FPL will not make any payments not reflected in the proposal pricing other than those for GHG emission costs agreed to in negotiations.

vi. Proposers of Natural Gas Tolling arrangements must acknowledge and agree that Proposer will post additional security to cover costs that may arise from any firm gas transportation agreement entered into by FPL to support the project in the event of a Proposer, then Seller's, default.

If a Proposer offers to provide its own fuel supply, the proposal price must also include all costs for the required amount of firm fuel transportation and delivery. The Proposer must also provide evidence of feasibility documenting arrangements that support the above fuel transportation and delivery costs. The proposal must also guarantee these fuel transportation and delivery costs and demonstrate credit support for the guarantee that is satisfactory to FPL.

If a Proposer wishes FPL to use Proposer's fuel commodity costs – instead of FPL's projected fuel commodity costs – in the evaluation of its proposal, the Proposer must also provide evidence of feasibility documenting the basis for Proposer's fuel commodity costs, and must also guarantee these fuel commodity costs for the proposed contract term and demonstrate credit support satisfactory to FPL for such guarantee.

vii. The proposed prices must be presented in the format specified in Appendix C, Form # 5.

18. Proposal Transmission Requirements

i. For proposals with generation located outside of the FPL system, FPL will not accept any proposal that requires FPL to secure firm transmission service and any associated rights, as this shall be a responsibility of the Proposer. Proposed prices must include all costs of delivering capacity and energy to the Proposer-designated FPL System Receipt Point. Form # 5 in Appendix C requires the Proposer's projection of transmission losses (MW) associated with the third party transmission service that was used by the Proposer in developing the proposed prices.

ii. Transmission interconnection costs to connect the proposed units to the FPL system, or to a third party system, must be included in the proposal price and separately identified in Appendix C, Form # 5.

iii. Transmission integration costs on the FPL system and the costs of energy and capacity losses within the FPL system will be developed by FPL during the economic analysis of eligible proposals and resource plans and should not be included in the proposal price.

iv. To the extent a RTO or ISO or similar arrangement is implemented in Florida, proposers should note that the FPL System Receipt Point shall be defined as the location where the facility (or a third party transmission system if the facility is not in FPL territory) connects with the FPL system.

19. Dual Fuel Capability for Natural Gas-Fired Proposals

Based on the impact of hurricanes and other unforeseeable events on the production and transport of natural gas, FPL considers that, for newly built natural gas-fired generation proposals, the fuel continuity and operability characteristics of on-site distillate fuel oil capability as a backup fuel source is the most effective approach to meet system reliability and service continuity needs. Just as FPL's NPGU has on-site distillate fuel oil capability, all proposals based on New Unit additions designed to operate on natural gas as primary fuel must include the capability to operate on distillate fuel oil as a backup fuel, while complying with all applicable regulations, to satisfy system reliability and service continuity needs.

Proposals supported by such new unit gas-fired generation, and the specified prices for such proposals, shall reflect the necessary equipment to meet the following backup fuel continuity and operability characteristics. The distillate fuel oil inventory must be: immediately accessible to the new unit, sized to provide seventy-two (72) hours of continuous operation at full capacity (as rated on distillate oil) at a minimum, and must be independent of the primary fuel supply. The new unit must be able to start up on distillate fuel oil and operate at full capacity for a minimum of 72 continuous hours while complying with all applicable regulations. Additionally, the new unit must be able to make the transition from natural gas fuel supply to distillate fuel oil supply without disconnecting electrically from the transmission grid. Test demonstrations of these capabilities will be required as a condition in any PPA that might be signed between FPL and the Proposer. These are the same continuity and operability requirements that FPL requires of its own NPGU.

Due to the sequence of the permitting process, FPL recognizes that Proposers will be unable to ascertain, by the Proposal Due Date, the success of permitting the facility for full use of distillate fuel oil capability. However, a selected Proposer will be required to obtain permits and authorizations necessary to support a minimum of 500 hours of operation per year on distillate fuel oil as a contract obligation.

20. Project Milestone Schedule
All Proposers must agree to meet all applicable Critical Milestone dates presented below. FPL retains the right to terminate negotiations if a Finalist with whom FPL is negotiating a contract fails to meet the filing dates scheduled for the Site Certification filing, Air Permit filing, or Interconnection Application filing. The remaining milestones would be a part of any contract entered into by FPL as a result of this RFP and are referenced below as months prior to (-) the Capacity Delivery Date (CDD):

Site Certification Application Filed	CDD - 39 months
Air Permit Application Filed	CDD - 39 months
Interconnection Application Filed	CDD - 39 months
Irrevocable Orders Placed for Major Equipment	CDD - 28 months
Fuel Transportation Agreement(s) Executed	CDD - 24 months
Contractor Mobilized, Financing Closed	CDD - 20 months

Section IV. Minimum Requirements of Selected Proposer Pursuant to Purchase Agreement

1. General Minimum Purchase Agreement Requirements

Site Acquisition and Development
A selected Proposer shall be responsible for the location, acquisition, development, and permitting of the Proposer's own site where the proposed generating unit is to be constructed (if applicable). The selected Proposer shall also establish "site control" and demonstrate to FPL's satisfaction that Proposer has "site control" for the Proposal Term by the Proposal Due Date. The selected

Proposer shall procure adequate water resources to operate the generating unit during the Proposal Term and demonstrate to FPL's satisfaction that Proposer has adequate water resources to operate the generating unit for the Proposal Term.

Licenses and Permits

A selected Proposer will be solely responsible for obtaining and maintaining all licenses, permits, and approvals required now, or in the future, by current or future federal, state or local government laws, regulations or ordinances, to construct, upgrade, operate and maintain the Proposer's proposed generating units (including a Site Certification under the Florida Power Plant Siting Act (the "Siting Act"), if applicable), as well as maintaining compliance with all laws and regulations applicable to Proposer's generating units during the Proposal Term.

Emission Allowances, Credits and Offsets

A selected Proposer will be solely responsible for securing, locating, or guaranteeing any emission allowances, credits, or offsets which may be required by any law, regulation, or government agency. Proposer shall be solely responsible for paying any costs related to emissions from Proposer's unit(s) other than those GHG emission costs agreed to in the PPA.

Project Funding and Costs

A selected Proposer will be solely responsible for any necessary financing with respect to all aspects of the proposed generating unit(s). All costs associated with the design, construction, upgrade, operation, and maintenance of the generating units including, but not limited to, (i) the power block, (ii) environmental control systems, (iii) fuel delivery systems (including natural gas pipeline laterals), (iv) transmission facilities and upgrades (including, step-up transformers and high voltage breakers) necessary to interconnect to FPL's system will be the sole responsibility of a selected Proposer. A selected Proposer will be permitted to assign the Purchase Agreement as collateral for any financing or refinancing of the generating units with the prior written consent of FPL and pursuant to a form of consent acceptable to FPL in its sole discretion.

Fuel Supply

Except with respect to a proposed gas Tolling Agreement, a selected Proposer will be solely responsible for maintaining reliable fuel supply (primary and backup fuel) that is delivered to the Proposer's proposed generating unit(s) to ensure reliable delivery of firm capacity and energy to FPL at the specified delivery point on FPL's system.

Interconnection and Transmission

A selected Proposer is solely responsible for securing all necessary transmission facilities and rights necessary for delivering firm capacity and energy to FPL at the specified delivery point on FPL's system. The Proposer would acknowledge that the Purchase Agreement will be between (i) Proposer and (ii) FPL, acting solely in its power procurement function, and that Proposer would have no rights against FPL under the Purchase Agreement with respect to any relationship between the parties in which FPL is acting in its capacity as transmission owner, including orders or instructions relating to Electric System Upgrades and/or curtailments.

Dispatch, Control, Operation and Maintenance of the Generating Unit

i. Proposer shall at all times operate the generating unit consistent with FPL's dispatch and control instructions. Control shall be either by Proposer's manual control pursuant to FPL's oral or written directions, or by Automated Generation Control by FPL's system control center for units with capacity greater than 100 MW, unless otherwise explicitly agreed to by FPL.

ii. During the term, Proposer shall employ qualified and trained personnel for managing, operating, and maintaining the generating unit and shall ensure that such personnel are on-duty 24 hours per day, each day, throughout the term of the agreement.

iii. Proposer shall be responsible for compliance with all applicable NERC regulations and requirements.

iv. Proposer shall operate and maintain the generating unit in accordance with good engineering and operating practices, including all applicable environmental requirements. Proposer shall operate the generating unit with all automatic controls (except Automatic Generation Control) and have appropriate protection equipment in service whenever the generating unit is connected to, or operating in parallel with, the FPL system. Automatic Generation Control shall be operated pursuant to FPL's direction.

v. On an annual basis, Proposer shall submit to FPL preliminary, desired outage schedules for the following five years, and a detailed plan for the next year. FPL shall notify Proposer if the outage schedule is accepted, or will cooperate reasonably with Proposer to agree upon a revised schedule. Under no circumstances will outages be scheduled during peak months.

Exclusivity
During the Proposal Term, Proposer shall have no right to sell energy, capacity, ancillary services or environmental attributes generated by the generating unit to any third party.

Testing and Capacity Rating

i. A capacity test will be required to demonstrate commercial operation and such test results must be satisfactory to FPL in all respects.
ii. FPL, in its sole discretion, may require Proposer to perform an annual summer period capacity test and an annual winter period capacity test. In addition, a capacity test will be required in the event Proposer is (A) unable to comply with any material obligation under the Purchase Agreement for a period of 30 days or more as a consequence of an event of Force Majeure, or (B) at any time should Proposer fail, on two consecutive times, to satisfy the operating levels set by FPL dispatch instructions. Upon completion of a capacity test, the available capacity will be the lower of the demonstrated capacity or committed capacity, but in no case shall it be less than the minimum contract capacity.

Role in Regulatory Proceedings
A selected Proposer that proposes a new unit that is subject to the Siting Act shall apply to obtain a Determination of Need from the FPSC and, at Proposer's sole cost and expense, shall satisfy all requirements imposed by the FPSC, as well as fully support FPL in its role as co-applicant in the Determination of Need proceeding.

2. Generating Unit Operating Characteristics

i. **Operating Characteristics** Generating units must achieve and maintain operation at the proposed level of availability, reliability, heat rate and capacity, as well as satisfy the proposed cold start time and ramp rate, all of which shall be guaranteed by the Proposer or, if applicable, the Qualified Guarantor. If the unit in a selected proposal fails to achieve the availability, reliability, capacity, and/or heat rate levels reflected in the proposal and guaranteed in the PPA, the Proposer would be subject to liquidated damages. The selected Proposer will have 120 days to cure the problem. If not cured, FPL may terminate the PPA
    a. A proposal will be rejected if:
        1. The demonstrated average, actual availability of an Existing Unit over the past five years is less than 85%;

2. With respect to a new unit, the demonstrated average, actual availability of Proposer's similar existing units over the past five years is less than 85%; or
3. With respect to an existing unit or a new unit, the guaranteed availability submitted with the proposal is less than 85%.

b. A proposal with a CC unit will be rejected if any of the EFOR levels below is above 4.2%:
   1. The demonstrated average, actual EFOR of an existing unit over the past five years is above 4.2%;
   2. With respect to a new unit, the demonstrated average, actual EFOR of Proposer's similar existing units over the past five years is above 4.2%; or
   3. With respect to an existing unit or a new unit, the guaranteed EFOR submitted as part of the proposal is above 4.2%.
c. A proposal with a CT unit will be rejected if any of the FOF levels below is above 2.6%:
   1. The demonstrated average, actual FOF of an existing unit over the past five years is above 2.6%;
   2. With respect to a new unit, the demonstrated average, actual FOF of Proposer's similar existing units over the past five years is above 2.6%; or
   3. With respect to an existing unit or a new unit, the guaranteed FOF submitted as part of the proposal is above 2.6%.
d. The Availability, EFOR, and FOF to be reflected in the economic analysis of a proposal that has not been rejected for the reasons set forth above shall be the "worse of" the actual average Availability, EFOR, and FOF levels, or the levels guaranteed in the proposal.

ii. Heat Rate Levels

Proposer must guarantee that the generating unit will consistently achieve the heat rate levels reflected in the proposal and must provide to FPL the results of annual heat rate tests. FPL shall have the right to require a heat rate test at any time, at its sole discretion. If the generating unit fails to achieve the heat rate levels reflected in the proposal, liquidated damages in the form of a heat rate adjustment payment will be due from the Proposer. In addition, in the event of a chronic heat rate failure, the Proposer will be in default, subject to a 120 day cure period. If not cured, FPL may terminate the Purchase Agreement and collect damages, all as prescribed in the Purchase Agreement.

iii. Capacity Payment

Proposer must guarantee that the peak capacity levels reflected in the proposal will be achieved and, on an annual basis, will provide to FPL the results of peak capacity tests. Failure to achieve such peak capacity levels will result in economic penalties as described below. In addition, if the Capacity Billing Factor is below 64%, the Proposer will be in default and will have 120 days to cure. If not cured, FPL may terminate the Purchase Agreement and collect damages.

a. Capacity payments shall be made on a sliding scale, based upon Capacity Billing Factor ("CBF") over a rolling 12-month period:
   1. if the CBF is less than 64%, there is no capacity payment;
   2. if the CBF is greater than 94%, then the full capacity payment will be received;
b. between 64% and 94%, the Proposer will forfeit 2% of capacity payment for each 1% that CBF is below 94%;
c. Proposer will be entitled to a capacity bonus of 0.5% of capacity payment for each 1% that CBF is above 96% in any month;
d. Failure to maintain a CBF of 64% or greater is an event of default, and FPL can terminate the purchase agreement and collect damages.

iv. Pipeline Quality Gas

Proposed generating units that utilize natural gas must (i) be designed to handle the expected range of fuels from its source(s). However, all specified unit performance values provided by the Proposer shall be based on the "Average Fuel Analysis" specifications as presented in RFP Form # 4 in Appendix C, (ii) satisfy the operating characteristics specified in the proposal, and (iii) maintain compliance with the conditions of all permits and authorizations.

v. Compliance with Changes in Laws

Notwithstanding any change in law, during the Proposal Term the Proposer will be solely responsible for taking all actions necessary to continue to deliver reliably to FPL the firm capacity and energy offered in the proposal, in a manner that is in compliance with all applicable laws, regulations, ordinances, licenses, permits, and other regulatory approvals (including compliance with all applicable environmental law).

4. Project Execution

The Proposer will be solely and completely responsible for ensuring that the implementation of any and all parts of the proposal is carried out in full compliance with any changes, modifications, or additions to laws, regulations, ordinances, licenses, permits, and other regulatory approvals (including environmental) that affect the proposal. FPL shall not bear any price or cost risk associated with any such changes, modifications, or additions, required by regulation or legislation in existence or enacted prior to the date of the proposal.

5. Effect of FPSC Denial of Authorization for FPL Cost Recovery

i. FPL would only agree to enter into a Purchase Agreement on the basis of Rule 25.22-082(15), Florida Administrative Code, which States:

"*If the Commission approves a purchase power agreement as a result of the RFP, the public utility shall be authorized to recover the prudently incurred costs of the agreement through the public utility's capacity, fuel and purchased power cost recovery clauses absent evidence of fraud, mistake, or similar grounds sufficient to disturb the finality of the approval under governing law.*"

ii. The selected Proposer must agree that if, at any time during the Proposal Term, FPL fails to obtain, or is denied, the authorization of the FPSC (or that of any other applicable legislative, administrative, judicial or regulatory body which now has, or in the future may have, jurisdiction over FPL's rates and charges) to recover from its customers all of the payments required to be made to the selected Proposer by FPL under such Purchase Agreement (or any subsequent amendment thereto), FPL may, in FPL's sole discretion, adjust the payments made under such Purchase Agreement to the amount(s) which FPL is authorized to recover from its customers.

iii. In the event that FPL so adjusts the payments to which the selected Proposer is otherwise entitled to under the Purchase Agreement, then the selected Proposer may, at its sole option, terminate such Purchase Agreement upon 180 days' notice to FPL. If such a determination of disallowance is ultimately reversed and such payments previously disallowed are found to be recoverable, FPL shall pay all withheld payments.

iv. The selected Proposer also acknowledges that any amounts initially received by FPL from its customers, but for which recovery is subsequently disallowed and which amounts are charged back to FPL, may be offset or credited against subsequent payments to be made by FPL to the selected Proposer under the Purchase Agreement.

v. If at any time FPL receives notice that the FPSC or any other legislative, administrative, judicial, or regulatory entity seeks or will seek to prevent full recovery by FPL from its customers of all payments required to be paid by FPL under the terms of the Purchase Agreement, then FPL shall, within 30 days of its receipt of such notice, give notice thereof to the selected Proposer. FPL shall use reasonable efforts to defend and uphold the validity of the Purchase Agreement and its right to recover from its customers all payments required to be made by FPL under the terms of such Purchase Agreement, and will cooperate in any effort by the selected Proposer to intervene in any proceeding that challenges the validity of the Purchase Agreement or the right of FPL to recover from its customers all payments required under the Purchase Agreement, and to defend such validity and such right to recover costs.

6. Conditions Precedent

The selected Proposer must agree that, pursuant to an executed Purchase Agreement, the obligations of the Proposer to generate, deliver, and sell to FPL firm capacity and energy, and the obligations of FPL to accept delivery of, purchase and pay for such firm capacity and energy, shall be subject to the satisfaction of the following conditions precedent:

i. The FPSC shall have issued a final Determination of Need (if applicable) with respect to the Purchase Agreement and a final order approving such agreement, which order includes a finding that FPL is authorized to recover from its customers all payments for firm capacity and energy purchased under the agreement, and which order is no longer subject to appeal.

ii. The Federal Energy Regulatory Commission ("FERC") and any other governmental authority having jurisdiction over such Purchase Agreement, or over either FPL or the selected Proposer, shall have issued final orders approving such agreement authorizing the selected Proposer to make the sale and authorizing FPL, with conditions acceptable to FPL at its sole discretion, to make the purchase of such firm capacity and energy, and which orders are no longer subject to appeal.

iii. Execution by the Proposer of an (i) engineering, procurement, and construction agreement, and (ii) operation and maintenance agreement by specified dates (as applicable to the nature of the proposal).
iv. Receipt by Proposer of all necessary permits.
v. Successful execution by Proposer of long-term financing (for a New Unit only).
vi. Execution by Proposer of transmission interconnection agreements.
vii. Implementation by Proposer of adequate insurance coverage.
viii. Execution by Proposer of adequate fuel supply and delivery contracts.

7. FIN 46R Compliance

Certain accounting rules now in effect, or as they might be amended or interpreted in the future, may require that the selected Proposer under the PPA or tolling contract be consolidated into the financial statements of FPL. Within ten business days after being selected to supply firm capacity and energy to FPL, the selected Proposer must deliver to FPL an analysis, with supporting information, evaluating whether or not FPL would be required to consolidate the selected Proposer under the provisions of Financial Accounting Standards Board Interpretation No. 46 (Revised December 2003) (FIN 46R).

The selected Proposer who enters into a contract with FPL under this RFP must also agree to comply with terms to be included in the Purchase Agreement that specify requirements for FPL's ongoing compliance with FIN 46R. Failure of Proposer to provide the required certification, or if at any time Proposer becomes a VIE and FPL becomes the Primary Beneficiary, shall constitute an event of default under the Purchase Agreement.

8. Completion and Performance Security; Step in Rights; Security Interest

i. For all proposals with respect to a new unit or existing unit, a Proposer selected to enter into a Purchase Agreement shall provide Completion Security and Performance Security (in the amounts set forth in Table 1 – New Unit; and Table 2 – Existing Unit, below).

Table 1
Security Milestone Schedule - New Unit

Event	Security Amount	Security Type
Execution of Purchase Agreement	$20,000/MW	Completion Security
FPSC and FERC Authorization Received	$185,000/MW	Completion Security
Commercial Operation	$200,000/MW	Performance Security

Table 2
Security Milestone Schedule - Existing Unit

Event	Security Amount	Security Type
Execution of Purchase Agreement	$20,000/MW	Completion Security
FPSC and FERC Authorization Received	$200,000/MW	Performance Security

ii. Completion Security secures (i) the Proposer's obligation to negotiate a Purchase Agreement in good faith (ii) with respect to a new unit, a Proposer's obligations to satisfy certain project milestones and deliver firm capacity and energy by a June 1, 2019 in-service date, and (ii) for damages incurred by FPL related to an early termination event.

iii. Performance Security secures (i) the Proposer's performance obligations from June 1, 2019 (the "In-Service Date") through the Proposal Term, and (ii) damages incurred by FPL related to an early termination event.

iv. With respect to a new unit during the construction phase, the Proposer must provide evidence, satisfactory to FPL in all respects, that the project milestones reflected in the Purchase Agreement are being achieved (*i.e.*, execution of definitive EPC and O&M Agreements, Start of Construction and Commercial Operations). If the Proposer fails to satisfy such project milestones, FPL may, in its sole discretion, be paid delay liquidated damages and/or terminate the Purchase Agreement.

v. Form of Security:

a. Completion Security may be provided via a combination of cash or letter of credit issued in a form and by an Eligible LC Bank ("LOC"), in each case acceptable to FPL in its sole discretion. "Eligible LC Bank" means either a U.S. commercial bank, or a foreign bank issuing a LOC through its U.S. branch, and such bank must have a Credit Rating of at least: (a) "A-, with a stable designation" from S&P and "A3, with a stable designation" from Moody's, if such bank is rated by both S&P and Moody's; or (b) "A-, with a stable designation" from S&P or "A3, with a stable designation" from Moody's, if such bank is rated by either S&P or Moody's, but not both, even if such bank was rated by both S&P and Moody's as of the date of issuance of the LOC but ceases to be rated by either, but not both of those ratings agencies.

b. FPL may consider on a case-by-case basis accepting a guaranty in a form to be provided by FPL from a "Qualified Guarantor" acceptable to FPL and based on such Qualified Guarantor's credit quality and tangible net worth in accordance with Table 3 below.

Table 3

Qualified Guarantor

A credit limit may be calculated for each Proposer or Qualified Guarantor based on the entity's unsecured debt rating and tangible net worth (the "Credit Limit") as follows:

Unsecured Debt Rating	% of Tangible Net Worth
AAA+/Aaal to AA-/Aa3	20%
A+/A1 to A-/A3	15%
BBB+/Baal to BBB-/Baa3	10%
BB+/Bal and below or unrated	0%

Performance Security in excess of the Credit Limit shall be in the form of cash in U.S. Dollars or an LOC. The Credit Limit shall be recalculated and the form of Performance Security may be adjusted quarterly, in FPL's sole discretion, based on the Proposer's or Qualified Guarantor's most recent financial statements.

Definitions
"Credit Limit" means the maximum credit exposure FPL will accept from a Qualified Guarantor in the form of a guarantee.

"Qualified Guarantor" means an entity which at the time it is to provide a guaranty has (i) (A) a credit rating equal to or greater than the Ratings Limit, and (B) a consolidated net worth of at least $1,000,000,000; or (ii) is acceptable to FPL in its sole discretion as having a verifiable creditworthiness and net worth sufficient to secure a Qualified Guarantor's obligations pursuant to a guaranty.

"Ratings Limit" means with respect to Proposer or any Qualified Guarantor, a long-term credit rating (corporate or long-term senior unsecured debt) (a) "Baa3" or higher by Moody's, or (b) "BBB-" or higher by S&P, or (iii) if rated by Moody's and S&P, both (i) and (ii).

"Tangible Net Worth" means the net worth per most recent quarterly financial statements of a Qualified Guarantor providing credit support less goodwill and intangible assets.

vi. Upon the failure of a Proposer to satisfy any project milestone, or upon an event of default by Proposer and failure by Proposer to cure such default within the cure period provided, FPL (or its designee) shall have the right, but not the obligation, to enter upon and complete the licensing, permitting, construction, start-up, testing and commissioning, or operate and maintain the generating unit, as applicable, as agent for the Proposer. FPL's step-in right shall continue until the earlier of: (i) Proposer demonstrates to FPL's satisfaction that cause of the failure or default has been remedied, (ii) FPL elects, in its sole discretions, to discontinue exercising its step-in rights, or (iii) expiration or termination of the Purchase Agreement.

vii. As additional security for Proposer's performance obligations, Proposer shall execute, deliver to FPL, and record a Mortgage and Security Agreement to granting to FPL a fully perfected, subordinated security interest and mortgage lien in any and all real and personal property, contractual rights or other rights the Proposer holds with respect to the development, procurement, construction, operation, and maintenance of the generating unit.

9. Assignment; Right of First Refusal

i. The Proposer must agree that the Purchase Agreement may not be assigned in whole or in part without the express written consent of FPL at FPL's sole discretion. Any direct or indirect change of control of Proposer (whether voluntary or by operation of Law) shall be deemed an assignment and shall require the prior express written consent of FPL at FPL's sole discretion.

ii. During the Proposal Term, FPL shall have a right of first refusal with respect to any sale of the generating unit or facility that produces the capacity and energy that is the subject of the PPA.

Section V. Overview of the Evaluation Process

1. General Evaluation Concepts

i. Proposer Exceptions.

FPL will consider proposals that contain exceptions to the general terms and conditions of the RFP. However, **FPL will not accept any exceptions to the Minimum Requirements for Proposals or the Minimum Requirements Pursuant to Purchase Agreement.**

If a Proposer identifies exceptions, the exceptions must be explained in writing as part of the proposal using Form # 9 presented in Appendix C. For each exception, the Proposer must fully explain in writing the condition, requirement, or facet of the RFP to which the Proposer takes exception and provide the replacement language proposed.

Inclusion of exception information with a proposal will be used to compare proposals to one another and will facilitate potential negotiations by allowing FPL to evaluate the specific core issues of the exceptions, rather than addressing generic or conceptual comments. A more detailed discussion of the non-price evaluation is provided in Appendix D. FPL reserves the right to request from a Proposer whether, or to what extent, FPL's contemplated rejection of a particular exception would affect the pricing of the proposal.

If a Proposer fails to state exceptions and pose alternative language to the material terms set forth in the RFP, FPL shall assume that a Proposer has no objection to such terms and conditions.

ii. **Proposer Questions and Communications**

Proposers are to follow all instructions contained in this RFP and provide all information requested in the RFP and on the forms presented and discussed in Appendix C of this document. Proposers also are expected to provide supporting documentation, and answer any follow-up questions from FPL, as requested.

Proposers are encouraged, up to the Cutoff Date for RFP Questions, to contact the FPL Contact Person with questions to ensure complete and accurate proposals. Following the RFP issuance date, all questions will be recorded. FPL will post questions and answers on FPL's RFP website. All questions and answers from the Pre-Bid Workshop, and any subsequent questions posed to FPL and answers to these questions, will be posted on this website for the benefit of all Proposers.

iii. **Fuel Plan for Evaluation**

FPL will evaluate the generator-specific fuel costs of each natural gas-based proposal based on the designated FPL Fossil Fuel Price Forecast (unless a Proposer directs FPL to use Proposer's own firm, guaranteed fuel price forecast, which shall be included in the proposal). FPL system fuel cost impacts for all proposals will also be based on the above-mentioned FPL forecast. FPL's forecast will be posted on the RFP website once the RFP document has been issued.

A specific fuel plan, including Proposer's fuel transportation cost (for Non-Tolling proposals) or FPL's projection of the gas transportation cost (for natural gas Tolling proposals), will be developed by FPL for each candidate portfolio based on the size, location, and fuel requirements of the individual units included in the candidate portfolio. This will allow FPL to capture the unique fuel cost attributes offered by certain asset combinations. The portfolio-specific fuel plan will be used to conduct the detailed economic evaluation.

1. Non-Tolling Proposals

   Non-tolling proposals must be accompanied by a complete Fuel Plan. The Fuel Plan must designate the fuel type, the intended fuel source, and transportation method to be used. For proposals relying on natural gas, the Fuel Plan must provide the level of firm gas transportation that is appropriate for the technology proposed. The Fuel Plan must be accompanied by evidence of feasibility (letter of intent or other indicative planning documents) that identify the required volume, pressure, and pipeline infrastructure upgrades that will be accomplished to operate the proposed unit(s) at capacity. The proposed pricing for non-Tolling proposals must reflect firm fuel transportation costs for the entire Proposal Term. FPL will evaluate non-Tolling proposals using FPL's fuel price forecast unless the Proposer specifies and guarantees a different set of future fuel prices to be applied to such proposal.

2. Natural Gas Tolling Proposals (For specific units only - not for system sales)

   Natural Gas Tolling proposals will be evaluated using the data outlined in the designated FPL Fossil Fuel Price Forecast, as modified for the specific fuel plan of the candidate portfolio(s). FPL will not consider tolling agreements for fuels other than natural gas.

   As a part of a natural gas tolling arrangement, FPL will be required to negotiate and commit to a Firm Transportation Agreement to support the needs of the project. Selected Proposers entering into a Natural Gas Tolling agreement will be required to provide an appropriate level of additional security to cover the costs that may arise from a Proposer-default to protect FPL's customers. This will be a part of the definitive agreements that comprise the Tolling Agreement.

FPL will evaluate all natural gas tolling proposals and the NPGU utilizing FPL's forecast(s) of future fuel commodity prices.

2. The Evaluation Process

The objective of the RFP is to solicit proposals that allow FPL to assess the best eligible generating alternatives that meet the RFP's capacity requirement in the most economic, cost-effective, and reliable manner for FPL's customers. It is anticipated that FPL will receive a variety of proposals that may vary in length of term, siting, capacity, price, fuel, and other pertinent characteristics. In addition to the variations that may be presented within individual proposals, there may be a need to combine multiple proposals to develop portfolios that meet the RFP capacity need requirements.

FPL will employ an evaluation methodology that will anticipate responses that offer a wide range of individual characteristics and can evaluate the costs and benefits offered by combining various proposals into unique portfolios of generating alternatives that address FPL's resource needs beginning in the year 2019. Therefore, eligible proposals that pass initial screening and individual economic ranking (if applicable), but do not individually meet the full resource need requirement for 2019, will be evaluated in portfolios that combine them with other proposals to meet these capacity needs. FPL will then develop multi-year resource plans that incorporate proposals that individually meet the 2019 resource need, portfolios of smaller proposals, and/or the NPGU.

FPL's evaluation will examine these portfolios and resource plans from both economic and non-economic perspectives. In regard to the economic analyses, FPL typically conducts economic analyses of resource plans using a levelized system average electric rate minimization (*i.e.*, a Rate Impact Measure) approach. However, because FPL is soliciting only generation resources in this capacity RFP, the amount of projected DSM will be the same for each of these resource plans. Therefore, FPL will be comparing portfolios and resource plans based on a Cumulative Present Value of Revenue Requirements (CPVRR) approach. This is because in analyses in which DSM values will not change: (i) a levelized system average electric rate approach and a CPVRR approach will yield identical rankings for the resource plans being evaluated, and (ii) the CPVRR approach is simpler to calculate. In regard to non-economic analyses, several different perspectives will be taken.

Ultimately, FPL's objective is, after considering both economic and non-economic perspectives, to identify the best option(s) for FPL's customers with which to meet FPL's capacity needs beginning in 2019. FPL's evaluation methodology, including a description of the criteria to be used to evaluate price and non-price attributes, is discussed in detail in Appendix D.

Section VI - Detailed Information Regarding FPL's Capacity Needs and NPGU

A. FPL's Capacity Need

The projected generation capacity resource need values described below represent an update from the information presented in FPL's 2014 Ten-Year Power Plant Site Plan (Site Plan), a copy of which is attached to this RFP as Appendix A. This new capacity need projection is based on a number of factors including updated forecasts from those used in FPL's previous resource planning work that led to FPL's 2014 Site Plan. Key changes to these forecasts are discussed in Appendix E. FPL's projected capacity needs are potentially subject to further change as FPL's 2015 resource planning work continues.

FPL's projected capacity need in 2019, based on exactly meeting both the 10% generation-only reserve margin (GRM) planning criterion and the 20% total reserve margin planning criterion is 1,052 MW by June 1, 2019.

B. FPL's NPGU

Rule 25-22.082, Florida Administrative Code, requires that specific information about FPL's "next planned generating unit" (NPGU) be included in an RFP seeking firm capacity.

FPL's NPGU is a CC unit based on 3 combustion turbines in combined cycle form with 3 heat recovery system generators and a single steam turbine generator (a 3x1 G configuration). The NPGU CC would add approximately 1,622 MW (Summer).

FPL has now identified a CC unit at FPL's Okeechobee Clean Energy Center site ("OCEC Unit 1") to be installed by June 1, 2019 as the NPGU in accordance with the requirements of Rule 25-22.082(5)(a), Florida Administrative Code. The eligible proposals submitted in response to this RFP will be evaluated against this NPGU and against all other proposals received in response to this RFP.

1. **Required Information**

   FPL is providing a technical description of its NPGU with the information that follows. This technical description for the unit complies with the requirements of Rule 25-22.082 (5)(a).

2. **Tables**

   The technical information required by Rule 25-22.082 (5) (a) is presented in Tables VI.B - 1, VI.B - 2, and VI.B - 3 for FPL's NPGU.

Table VI.B – 1

Next Planned Generating Unit Data – Okeechobee Clean Energy Center (Combined Cycle)

The following data represent FPL's current estimates for this 2019 capacity addition. These planning estimates are subject to further refinement in regard to site-specific costs, detailed engineering, or vendor quotes. FPL reserves the right to modify the construction costs and/or performance parameters for this unit. If FPL exercises this option, it will do so concurrent with publication of a Short List. In that case, FPL would then inform the Short List Proposers (if any) of its intent and permit such Short List Proposers to revise their proposals.

1. A three-on-one combined cycle generating unit to be located at the Okeechobee Clean Energy Center (OCEC) in Okeechobee County, Florida.
2. Planned size is 1,622 MW (Summer rating).
3. Commercial operation for the facility is June 1, 2019.
4. The primary fuel is natural gas. Ultra low sulfur light (distillate) oil will be the backup fuel type.
5. The estimated total direct cost (without AFUDC) is $ 1,083.4 million (in 2019$). This value includes the cost of generation, transmission interconnection, and transmission integration.
6. The estimated annual levelized capital (generation, plus transmission interconnection, and transmission integration) revenue requirement with AFUDC is $136.9 million over 30 years.
7. The estimated annual value of deferral with AFUDC of this unit is $5.75/kW-year in 2019$ (excludes variable O&M, fixed O&M, and capital replacement).
8. The estimated fixed O&M, capital replacement, and variable O&M annual costs are presented in Table III.B - 2.
9. The estimated fuel cost in 2019 for the NPGU is currently forecast to be $4.69/MMBTU. Firm gas transportation for the unit will be provided from the Sabal Trail/Florida Southeast Connection (FSC) pipeline. These costs are considered sunk and will not be included in the economic analysis. A gas pipeline lateral is needed between FSC and the Okeechobee site and will be built by FSC. The costs for this lateral will be recovered through an adjustment to the rate over 25 years. This adjustment to the annual transportation rate, in $/MMBTU, is shown in Table III.B-3 and will be included in the economic evaluation of the Okeechobee Clean Energy Center. See Note 1.
10. The following are the estimates for:

Planned Outage Factor	See Table III.B - 4 and Note 2
Forced Outage Rate	See Table III.B - 4 and Note 2
Heat Rate at maximum capacity at 100% (Base Operational Mode)	6,293 Btu/kWh @75F (HHV)
Minimum load	400 MW
Ramp Rate	120 MW/min

11. The estimated transmission interconnection and integration costs associated with this unit are $52.0 million (without AFUDC in 2019 $) and are included in the cost estimate in item 5 above.
12. Air, water discharge, and other permits will be required for this unit. It is FPL's plan to comply with all air and water quality standards of the Local, State, and Federal governments.
13. The major financial assumptions in the development of these numbers were:

Capital replacement escalation for the OCEC unit, based on contract (approx.)	2.0%
General capital escalation for other than OCEC	3.0%
Escalation for O&M	2.5%
Fuel escalation	Varies by year. See Note 1
Capital Structure	40.38 % debt @ 5.05 % 59.62 % equity @ 10.5 %

Table VI.B-2

Next Planned Generating Unit Data - OCEC

Year	Estimated Fixed O&M Costs ($Millions)	Estimated Variable O&M Costs * ($Millions)	Estimated Capital Replacement Costs ($Millions)
2019	3.3	3.2	0.0
2020	4.7	3.2	19.5
2021	3.6	3.3	0.1
2022	6.9	3.3	40.0
2023	4.0	3.4	23.9
2024	5.5	3.4	0.1
2025	7.7	3.5	15.9
2026	4.8	3.6	25.0
2027	4.7	3.6	2.4
2028	9.1	3.7	79.7
2029	5.2	3.7	39.2
2030	6.3	3.8	0.2
2031	5.6	3.8	0.1
2032	25.7	3.9	0.1
2033	6.1	4.0	66.0
2034	6.4	4.0	35.9
2035	10.4	4.1	0.1
2036	6.9	4.1	0.1
2037	12.4	4.2	0.3
2038	7.9	4.3	20.1
2039	13.7	4.3	44.1
2040	8.1	4.4	0.2
2041	8.8	4.5	0.3
2042	15.2	4.5	0.4
2043	18.3	4.6	55.4
2044	10.8	4.7	33.5
2045	12.9	4.7	0.2
2046	10.3	4.8	0.2
2047	10.9	4.8	0.0
2048	11.2	4.9	0.0
2049	11.5	4.9	0.0

* Based on an average capacity factor for the life of the unit of approxi

Table VI.B-3

Lateral Cost Adder to FSC Firm Transporation Rate

Period	Dates	Okeechobee Lateral Transport Rate $/Dth
1	Sep 1, 2018 - April 30, 2019	0.0279
2	May 1, 2019 - April 30, 2020	0.0273
3	May 1, 2020 - April 30, 2021	0.0175
4	May 1, 2021 - April 30, 2022	0.0167
5	May 1, 2022 - April 30, 2023	0.0161
6	May 1, 2023 - April 30, 2024	0.0154
7	May 1, 2024 - April 30, 2025	0.0148
8	May 1, 2025 - April 30, 2026	0.0142
9	May 1, 2026 - April 30, 2027	0.0136
10	May 1, 2027 - April 30, 2028	0.0130
11	May 1, 2028 - April 30, 2029	0.0124
12	May 1, 2029 - April 30, 2030	0.0118
13	May 1, 2030 - April 30, 2031	0.0112
14	May 1, 2031 - April 30, 2032	0.0106
15	May 1, 2032 - April 30, 2033	0.0100
16	May 1, 2033 - April 30, 2034	0.0094
17	May 1, 2034 - April 30, 2035	0.0090
18	May 1, 2035 - April 30, 2036	0.0087
19	May 1, 2036 - April 30, 2037	0.0083
20	May 1, 2037 - April 30, 2038	0.0080
21	May 1, 2038 - April 30, 2039	0.0077
22	May 1, 2039 - April 30, 2040	0.0074
23	May 1, 2040 - April 30, 2041	0.0071
24	May 1, 2041 - April 30, 2042	0.0068
25	May 1, 2042 - April 30, 2043	0.0065

Table VI.B-4

Next Planned Generating Unit Data - OCEC
Base & Peak Firing Operational Modes

Year	Projected Annual Planned Outage Hours	Projected Annual Forced Outage Hours
2019	193	96
2020	193	96
2021	193	96
2022	193	96
2023	193	96
2024	193	96
2025	193	96
2026	193	96
2027	193	96
2028	193	96
2029	193	96
2030	193	96
2031	193	96
2032	193	96
2033	193	96
2034	193	96
2035	193	96
2036	193	96
2037	193	96
2038	193	96
2039	193	96
2040	193	96
2041	193	96
2042	193	96
2043	193	96
2044	193	96
2045	193	96
2046	193	96
2047	193	96
2048	193	96
2049	193	96

Notes for:
Next Planned Generating Unit Data – Okeechobee Clean Energy Center

1. For the economic evaluation of capacity options in this RFP, both for proposals received in response to this RFP and FPL's NPGU, FPL will use the designated FPL fuel cost forecast which will be provided on the RFP website.
2. The projected outage hour estimates for FPL's self-build options represent arithmetic averages of expected outage hours over the 30-year life of the unit period and do not represent "new & clean" unit values. An average capacity factor of 80% for the unit as a whole was used in making these projections. Maintenance outage hours were not included in these projections.

   Using these outage hour values, FPL projects the following values for both the Base and Peak Firing operational modes:

POF	2.2%
FOR	1.1%
Availability	96.7%

APPENDIX A

2014 Ten Year Site Plan

Ten Year Power Plant Site Plan
2014 – 2023

FPL

Ten Year Power Plant Site Plan

2014-2023

Submitted To:

***Florida Public
Service Commission***

***Miami, Florida
April 2014***

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Table of Contents

List of Figures and Tables iii

List of Schedules iv

Overview of the Document 1

List of Abbreviations 3

Executive Summary 5

I. Description of Existing Resources 11

- **A. FPL-Owned Resources** 13
- **B. Capacity and Energy Power Purchases** 17
- **C. Demand Side Management (DSM)** 22

II. Forecast of Electric Power Demand 25

- **A. Overview of the Load Forecasting Process** 27
- **B. Comparison of FPL's Current and Previous Load Forecasts** 28
- **C. Long-Term Sales Forecasts** 29
- **D. Net Energy for Load** 32
- **E. System Peak Forecasts** 33
- **F. Hourly Load Forecast** 35
- **G. Uncertainty** 35
- **H. DSM** 36

III. Projection of Incremental Resource Additions 45

- **A. FPL's Resource Planning** 47
- **B. Projected Incremental Resource Additions/Changes in the Resource Plan** 57
- **C. Discussion of the Projected Resource Plan and Issues Impacting FPL's Resource Planning Work** 58
- **D. Demand Side Management (DSM)** 65
- **E. Transmission Plan** 66
- **F. Renewable Resources** 71
- **G. FPL's Fuel Mix and Price Forecasts** 77

IV. Environmental and Land Use Information 107

- **A. Protection of the Environment** 109
- **B. FPL's Environmental Statement** 110
- **C. Environmental Management** 111
- **D. Environmental Assurance Program** 112
- **E. Environmental Communication and Facilitation** 112
- **F. Preferred and Potential Sites** 113
  1. **Preferred Site # 1 - Port Everglades Plant** 114
  2. **Preferred Site # 2 - Lauderdale Plant** 119
  3. **Preferred Site # 3 - Hendry County** 124
  4. **Preferred Site # 4 - NE Okeechobee County** 127
  5. **Preferred Site # 5 - Putnam County** 130

6. Preferred Site # 6 – Turkey Point Plant 133
7. Potential Site # 1 - Babcock Ranch 143
8. Potential Site # 2 - DeSoto Solar Expansion 143
9. Potential Site # 3 - Manatee Plant Site 144
10. Potential Site # 4 - Martin County 145

V. Other Planning Assumptions and Information 193

Introduction 195

Discussion Item #1 195

Discussion Item #2 196

Discussion Item #3 197

Discussion Item #4 197

Discussion Item #5 197

Discussion Item #6 198

Discussion Item #7 198

Discussion Item #8 199

Discussion Item #9 200

Discussion Item #10 200

Discussion Item #11 201

Discussion Item #12 202

List of Figures and Tables

Table ES-1 Projected Capacity & Firm Purchase Power Changes 10

Figure I.A.1 Capacity Resources by Location (Map) 14

Table I.A.1 Capacity Resource by Unit Type 15

Figure I.A.2 FPL Substation & Transmission System Configuration (Map) 16

Table I.A.3 Purchase Power Resources by Contract 19

Table I.B.1 FPL's Firm Purchased Power Summer MW 20

Table I.B.2 FPL's Firm Purchased Power Winter MW 21

Table I.C.1 As-Available Energy Purchases From Non-Utility Generators in 2012 26

Figure III.A.1 Overview of FPL's IRP Process 48

Table III.E.1 List of Proposed Power Lines 66

Table IV.E.1 2012 FPL Environmental Outreach Activities 113

Preferred Site # 1 - Port Everglades Plant Maps 147
Preferred Site # 2 - Lauderdale Plant Maps 153
Preferred Site # 3 - Hendry County Maps 185
Preferred Site # 4 - Northeast Okeechobee County Maps 161
Preferred Site # 5 – Putnam Site Maps 167
Preferred Site # 6 – Turkey Point Maps 171
Potential Site # 1 – Babcock Ranch Maps 177
Potential Site # 2 – Desoto Solar Expansion Maps 181
Potential Site # 3 - Manatee Plant Maps 185
Potential Site # 4 – Martin County Maps 189

List of Schedules

Schedule 1 Existing Generating Facilities 23

Schedule 2.1 History and Forecast of Energy Consumption & Number of Customers by Customer Class (Rural & Residential) 37

Schedule 2.2 History and Forecast of Energy Consumption & Number of Customers by Customer Class (Industrial) 38

Schedule 2.3 History and Forecast of Energy Consumption & Number of Customers by Customer Class (Sales for Resale) 39

Schedule 3.1 History and Forecast of Summer Peak Demand (Base Case) 40

Schedule 3.2 History and Forecast of Winter Peak Demand (Base Case) 41

Schedule 3.3 History and Forecast of Annual Net Energy for Load GWh (Base Case) 42

Schedule 4 Previous Year Actual and Two-Year Forecast of Retail Peak Demand and Net Energy for Load by Month 43

Schedule 5 Fuel Requirements 85

Schedule 6.1 Energy Sources 86

Schedule 6.2 Energy Sources % by Fuel Type 87

Schedule 7.1 Forecast of Capacity, Demand and Scheduled Maintenance at Time of Summer Peak 88

Schedule 7.2 Forecast of Capacity, Demand and Scheduled Maintenance at Time of Winter Peak 89

Schedule 8 Planned and Prospective Generating Facility Additions and Changes 90

Schedule 9 Status Report and Specifications of Proposed Generating Facilities 92

Schedule 10 Status Report and Specifications of Proposed Transmission Lines 98

Schedule 11.1 Existing Firm and Non-Firm Capacity & Energy by Primary Fuel Type 106

Schedule 11.2 Existing Non- Firm Self-Service Renewable Generation Facilities 106

Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten Year Power Plant Site Plan (Site Plan). This Site Plan should include an estimate of the utility's future electric power generating needs, a projection of how these estimated generating needs could be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The information contained in this Site Plan is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains uncertain forecasts and tentative planning information. Forecasts evolve, and all planning information is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This Site Plan document is based on Florida Power & Light Company's (FPL) integrated resource planning (IRP) analyses that were carried out in 2013 and that were on-going in the first Quarter of 2014. The forecasted information presented in this plan addresses the years 2014 through 2023.
This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand side management, and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, based on FPL's IRP work in 2013 and early 2014. This chapter also discusses a number of issues that may change the resource plan presented in this Site Plan. Furthermore, this chapter briefly discusses the status of FPL's DSM planning efforts, as well as FPL's, renewable energy efforts, transmission planning additions, and fuel cost forecasts.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as Preferred and Potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve "discussion items" which pertain to additional information that is included in a Site Plan filing.

FPL
List of Abbreviations
Used in FPL Forms

Reference	***Abbreviation***	***Definition***
Unit Type	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	ST	Stean Unit (Fossil or Nuclear)
	PV	Photovoltaic
Fuel Type	NUC	Uranium
	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	NG	Natural Gas
	No	None
	Solar	Solar Energy
	SUB	Sub Bituminous Coal
	Pet	Petroleum Coke
Fuel Transportation	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	OT	Other
	L	Regulatory approval pending. Not under construction
	P	Planned Unit
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	ESP	Electrostatic Precipitators

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Executive Summary

Florida Power & Light Company's (FPL) 2014 Ten Year Power Plant Site Plan (Site Plan) presents FPL's current plans to augment and enhance its electric generation capability (owned or purchased) as part of its efforts to meet its projected incremental resource needs for the 2014 - 2023 time period. By design, the primary focus of this document is on supply side additions; i.e., electric generation capability and the sites for these additions. The supply side additions discussed in this document are resources projected to be needed, based on FPL's load forecast, after accounting for FPL's demand side management (DSM) resource additions. In 2014, new DSM Goals for FPL for the time period 2015 through 2024 will be set by the Florida Public Service Commission (FPSC). At almost the same time FPL is filing this 2014 Site Plan, FPL will also be filing its proposed DSM Goals with the FPSC. Consequently, the level of DSM additions reflected in the 2014 Site Plan is consistent with FPL's proposed DSM Goals. The proposed level of DSM is discussed further below and in Chapter III.

FPL's load forecast accounts for a significant amount of efficiency that results from federal and state energy efficiency codes and standards. The projected impacts of these codes and standards are directly accounted for in FPL's load forecast as discussed below and in Chapter II.

The resource plan that is presented in FPL's 2014 Site Plan contains four key similarities to the resource plan presented in FPL's 2013 Site Plan. However, there are several factors that have contributed to differences between the resource plan presented in the 2014 Site Plan and the resource plan that was previously presented in FPL's 2013 Site Plan. Additional factors will continue to influence FPL's on-going resource planning work and could result in changes in the resource plan presented in this document. A brief discussion of these similarities and factors is provided below. Additional information regarding these topics is presented in Chapter III.

I. Similarities Between the Current Resource Plan and the Resource Plan Previously Presented in FPL's 2013 Site Plan:

There are four key similarities between the current resource plan presented in this document and the resource plan presented in the 2013 Site Plan.

<u>Similarity # 1: Modernizations of Existing Power Plant Sites.</u>

The modernization of FPL's Cape Canaveral plant site was completed on time in 2013 and the modernization of FPL's existing Riviera Beach plant site is scheduled to be completed on/near the April 1, 2014 date this 2014 Site Plan is to be filed. In addition, the modernization of FPL's existing Port Everglades plant site is underway and is projected to be completed in 2016.

Similarity # 2: FPL continues to pursue additional nuclear energy generation to significantly (i) reduce its use of fossil fuels, (ii) lower system fuel costs, (iii) lower system air emissions, and (iv) provide a valuable hedge against future increases in fuel costs and environmental compliance costs.

In 2013 FPL successfully completed its capacity uprate projects at its four existing nuclear units ; Turkey Point Units 3 & 4 and St. Lucie Units 1 & 2. The nuclear uprate project added about 520 MW of additional nuclear capacity to FPL's system which was about 30% more additional nuclear capacity than was originally projected when the project began. FPL's customers are already benefiting from lower fuel costs and reduced system air emissions provided by this additional nuclear capacity.

FPL is also continuing its work to obtain all of the licenses, permits, and approvals that will be necessary to construct and operate two new nuclear units at its Turkey Point site in the future. The earliest deployment dates for these two new units remain 2022 and 2023, respectively, and this Site Plan projects the two new nuclear units going in-service in those years.

Similarity #3: FPL is projected to serve Vero Beach's electrical load.

An agreement to this effect was reached between Vero Beach and FPL on February 19, 2013, and a referendum was held on March 12, 2013 that resulted in a majority of Vero Beach voters approving the agreement. FPL's current load forecast projects that FPL will begin serving Vero Beach's load in January 2015.

Similarity #4: Specific generating units are projected to be retired and/or converted to synchronous condenser operation.

In the last two years, FPL has retired a number of older, less efficient generating units including: Sanford Unit 3, Cutler Units 5 & 6, Cape Canaveral Units 1 & 2, Riviera Beach Units 3 & 4, and Port Everglades Units 1 – 4. In addition, Turkey Point Unit 2 has been converted to operate in synchronous condenser mode to provide voltage support for the transmission system in Southeastern Florida.

This trend is projected to continue. Putnam Units 1 & 2 are now projected to be retired by the end of 2014. And, similar to the earlier conversion of Turkey Point Unit 2, FPL projects that Turkey Point Unit 1 will be converted to run in synchronous condenser mode starting in 2016. In addition, for planning purposes, FPL is projecting that all of its existing gas turbines (GTs) at its two Broward County sites will be retired by the end of 2018 and that 5 new combustion turbines (CTs) will be installed at FPL's Lauderdale plant site also by the end of 2018. This projection is further discussed later in this executive summary and in Chapter III.

II. Factors Influencing FPL's Resource Planning Work Which Have Impacted, or Which Could Impact, FPL's Resource Plan:

There are a number of factors that influence FPL's resource planning work. Eight (8) of these are briefly discussed below and are discussed again in Chapters II and/or III.

Two of these factors are on-going system concerns that FPL has considered in its resource planning work for a number of years. These two on-going system concerns are: (1) maintaining/enhancing fuel diversity in the FPL system, and (2) maintaining a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward Counties.

The third and fourth factors that will be discussed are factors that directly impacted the resource plan presented in this document because they affect FPL's forecast of its future load and its future firm load. The third factor is the impact of federal and state energy efficiency codes and standards on FPL's future loads. The impact of these codes and standards has been incorporated into FPL's current load forecast. The magnitude of efficiency that is being delivered to FPL's customers through these codes and standards is significant. For example, by the year 2023 (the last year addressed in this Site Plan), FPL's Summer peak is projected to be lower by approximately 3,477 MW compared to what the projected load would have been without the codes and standards based on cumulative savings beginning in 2005. This represents a decrease of approximately 12% in what the forecasted Summer peak load for 2023 would have been without the codes and standards. Likewise, FPL's forecasted net energy for load (NEL) in the year 2023 is projected to be approximately 9,991 GWh lower compared to what the projected NEL would have been without the efficiency codes and standards based on cumulative savings beginning in 2005. This represents a decrease of approximately 7% from what the forecasted NEL for 2023 would have been without the codes and standards.

There are two significant impacts from these codes and standards. The first impact is to substantially lower FPL's forecasted peak load and NEL. The second impact is that the codes and standards lower the potential for future MW and GWh reductions from FPL's DSM programs that address the specific appliances and equipment impacted by the codes and standards. Thus, significant energy efficiency regarding this equipment will be delivered to FPL's customers through codes and standards, thus precluding the potential for FPL to pursue these same efficiency gains through utility DSM programs.

The fourth factor is a projected decline in the cost-effectiveness of a number of utility DSM measures due to reasons that are beneficial overall for FPL's customers. Compared to 2009 (when DSM Goals were last set): (i) forecasted fuel costs have dropped by 50%, thus lowering the potential benefits from DSM kwh reductions; (ii) projected compliance costs for carbon dioxide (CO_2), have not only been significantly lowered, but their forecasted start date has been delayed by almost a decade, thus again lowering the potential benefits from DSM kwh reductions; and, (iii) FPL’s generating system, due to the retirement of older, less efficient generators and replacement with highly efficient generators, plus additional nuclear capacity, has gotten more fuel-efficient, thus lowering fuel-related costs that would otherwise represent potential benefits for DSM kwh reductions. These factors are benefitting FPL’s customers through lower electric rates, but they also lower the potential economic benefits that otherwise could be offered by DSM. When combined with the previously discussed fact that codes and standards have reduced the potential for efficiency gains in regard to appliance and equipment addressed by these codes and standards, the result is that FPL is logically projecting a lower contribution from utility DSM in the near-term. That lower contribution is accounted for in the 2014 Site Plan. These factors are discussed in detail in the filing FPL is making in its DSM Goals proceeding.

The fifth factor is the need to take measures to limit FPL’s projected increasing dependence upon DSM resources to maintain system reliability. This factor has been previously discussed in FPL’s 2011, 2012, and 2013 Site Plans. In these previous Site Plans, FPL has discussed this projection of increasing dependence upon DSM resources using a new type of reserve margin projection as an indicator: a “generation-only reserve margin” or “GRM”.

The GRM projections from the 2011, 2012, and 2013 Site Plans consistently showed that these values were projected to significantly decrease over the 10-year reporting period of the Site Plans, declining to single-digit values in the latter years of the reporting periods. These projections indicated a steadily growing dependence on DSM resources to maintain system reliability. FPL’s analyses show that system reliability risk increases, particularly from a system operations perspective, as dependence on DSM resources increases to a point where DSM resources account for more than half of FPL’s 20% total reserve margin criterion value. Therefore, FPL is implementing a new reliability criterion of a 10% GRM in its resource planning work to complement its other two reliability criteria: a 20% total reserve margin criterion for Summer and Winter, and an annual 0.1 day/year loss-of-load-probability (LOLP) criterion. FPL is implementing the GRM criterion so that FPL’s resource plans will begin to meet this criterion in the year 2019. A further discussion of the GRM criterion is presented in Chapter III.

There are additional factors that did not impact FPL’s resource plan presented in this document, but which could result in future changes to this resource plan. For example, a sixth factor is the project schedule for the Turkey Point Units 6 & 7 nuclear units. At the time the 2014 Site Plan is being finalized, the Nuclear Regulatory Commission (NRC) has not provided a schedule for its review of FPL’s Combined Operating License Application (COLA). Once the NRC’s COLA review schedule is available, FPL will review the overall schedule for the Turkey Point Units 6 & 7 project. FPL’s review will also consider the impacts of the recently amended nuclear cost recovery clause (NCRC) statute and the ongoing feasibility analyses that are part of Florida Nuclear Cost Recovery process.

The seventh factor is environmental regulation. As developments occur in regard to either new environmental regulations, and/or in how environmental regulations are interpreted and applied, the potential exists for such developments to affect FPL's resource plan that is presented in this document. For example, FPL is aware of potential impacts to generating units of recent EPA changes to the National Ambient Air Quality Standards that include shorter duration 1-hour standards for nitrogen dioxide (NO_2) and sulfur dioxide (SO_2). As a consequence, FPL filed in mid-2013 for FPSC approval to recover costs through the environmental cost recovery clause for removing all of its existing gas turbines (GTs) and partially replacing that peaking unit capacity with new combustion turbines (CTs). Although FPL withdrew its filing in December 2013 pending further analyses including on-site monitoring, FPL believes that the results of the monitoring and analyses will require that the Broward GTs be replaced. Therefore, FPL is currently projecting the retirement of all GTs in Broward County; i.e., at its existing Lauderdale and Port Everglades plant sites (a decrease in generating capacity of 1,260 MW Summer), and the installation of 5 new 201 MW CTs at its existing Lauderdale plant site (an increase of 1,005 MW Summer).

The eighth factor that will be discussed is the possibility of the establishment of a Florida standard for renewable energy or clean energy. Although no such legislation has been enacted to-date, Renewable Portfolio Standards, or Clean Energy Portfolio Standards legislation, or other legislative initiatives regarding renewable or clean energy contributions, may occur in the future at either the state or national level. If such legislation is enacted, FPL would then determine what steps need to be taken to address the legislation.

Each of these factors will continue to be examined in FPL's on-going resource planning work during the rest of 2014 and in future years.

Table ES-1 presents a current projection of major changes to specific generating units and firm capacity purchases for 2014 – 2023. (Although this table does not specifically identify the impacts of projected DSM additions on FPL's resource needs and resource plan, FPL's projected DSM additions have been fully accounted for in the resource plan presented in this Site Plan.)

Table ES-1: Projected Capacity & Firm Purchase Power Changes

Year *	Projected Capacity & Firm Purchase Power Changes	Summer MW	Date	Summer Reserve Margin **
2014	Martin Unit 1 ESP - Return from ESP outage	823	March-14	
	Martin Unit 2 ESP - Temporary Outage to install ESPs	(826)	March-14	
	Turkey Point Unit 5 CT Upgrade	30	March-14	
	Sanford 5 CT Upgrade	9	September-13	
	Riviera Beach Next Generation Clean Energy Center	1,212	April-14	
	Total of MW changes to Summer firm capacity:	**1,247**		**28.0%**
2015	Manatee Unit 3 CT Upgrade	32	October-14	
	Martin Unit 2 ESP - Returned from ESP Outage	823	December-14	
	Putnam 1&2 Retirement	(498)	December-14	
	OUC - Stanton PPAs	37	January-15	
	Vero Beach Combined Cycle 1/	46	January-15	
	Palm Beach SWA - additional capacity	70	January-15	
	Fort Myers Unit 2 CT Upgrades	18	June-15	
	Fort Myers Unit 2 CT Upgrades	18	March-15	
	Fort Myers Unit 2 CT Upgrades	18	May-15	
	Total of MW changes to Summer firm capacity:	**563**		**27.5%**
2016	UPS Replacement	(928)	December-15	
	Port Everglades Next Generation Clean Energy Center	1,237	June-16	
	Total of MW changes to Summer firm capacity:	**309**		**26.6%**
2017	Turkey Point Unit 1 synchronous condenser	(396)	October-16	
	Total of MW changes to Summer firm capacity:	**(396)**		**22.6%**
2018	OUC - Stanton PPAs	(37)	December-17	
	Vero Beach Combined Cycle 1/	(46)	January-18	
	Total of MW changes to Summer firm capacity:	**(83)**		**20.5%**
2019	Port Everglades GT retirement	(420)	December-18	
	Lauderdale GT retirement	(840)	December-18	
	Lauderdale CT	1,005	January-19	
	SJRPP suspension of energy	(381)	April-19	
	Unsited CC	1,269	June-19	
	Total of MW changes to Summer firm capacity:	**633**		**21.6%**
2020	Unspecified Purchase	129	June-20	
	Total of MW changes to Summer firm capacity:	**129**		**20.5%**
2021	Eco-Gen PPA	180	January-21	
	Unspecified Purchase	168	June-21	
	Total of MW changes to Summer firm capacity:	**348**		**20.6%**
2022	Cape Next Generation Clean Energy Center	87	June-22	
	Turkey Point Nuclear Unit 6	1,100	June-22	
	Total of MW changes to Summer firm capacity:	**1,187**		**22.6%**
2023	Riviera Beach Next Generation Clean Energy Center	55	June-23	
	Turkey Point Nuclear Unit 7	1,100	June-23	
	Total of MW changes to Summer firm capacity:	**1,155**		**24.4%**

* Year shown reflects when the MW change begins to be accounted for in Summer reserve margin calculations. (Note that addition of MW values for each year will not yield a current cumulative value.)

** Winter Reserve Margins are typically high than Summer Reserve Margin. Winter Reserve Margin are shown on Schedule 7.2 in Chapter III.

1/ This unit will be added as part of the agreement that FPL will serve Vero Beach's electric load starting January, 2015. This unit is expected to be retired within 3 years.

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 9.0 million people. FPL served an average of 4,626,934 customer accounts in thirty-five counties during 2013. These customers were served by a variety of resources including: FPL-owned fossil-fueled, renewable, and nuclear generating units, non-utility owned generation, demand side management (DSM), and interchange/purchased power.

I.A. FPL-Owned Resources

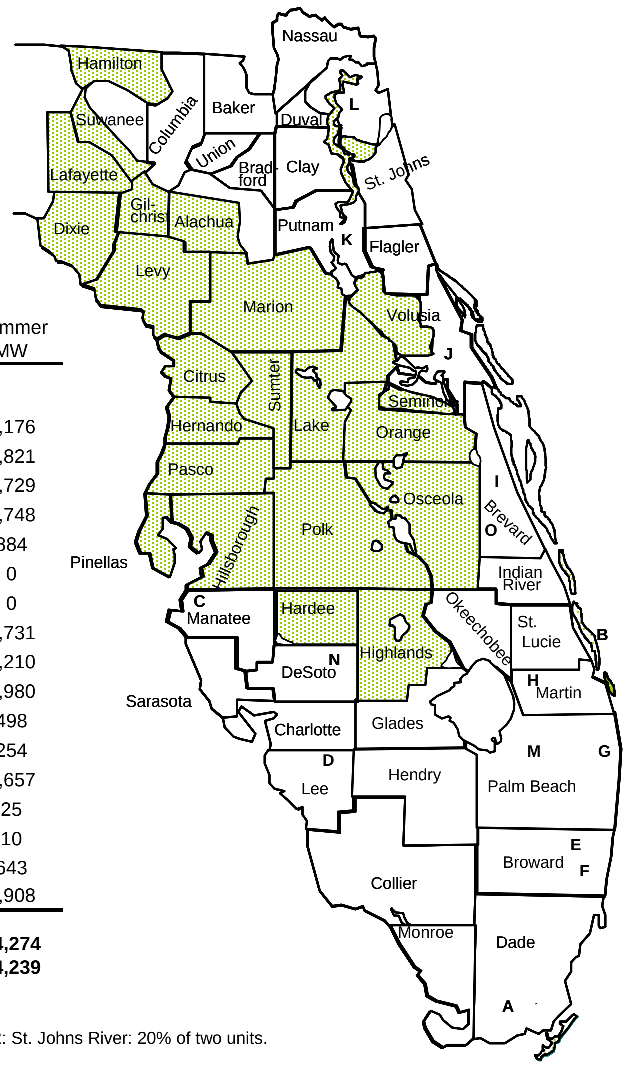
The existing FPL generating resources are located at fourteen generating sites distributed geographically around its service territory, plus one site in Georgia (partial FPL ownership of one unit) and one site in Jacksonville, Florida (partial FPL ownership of two units). The current electrical generating facilities consist of four nuclear units, three coal units, sixteen combined cycle (CC) units, five fossil steam units, forty-eight combustion gas turbines, two simple cycle combustion turbines, and two photovoltaic facilities[1]. The locations of these eighty generating units are shown on Figure I.A.1 and in Table I.A.1.

FPL's bulk transmission system is comprised of 6,734 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 589 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2.

1 FPL also has one 75 MW solar thermal facility at its Martin plant site. This facility does not generate electricity as the other units mentioned above do. Instead, it produces steam that reduces the use of fossil fuel to produce steam for electricity generation.

FPL Generating Resources by Location



Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	4	3,176
B	St. Lucie [1/]	2	1,821
C	Manatee	3	2,729
D	Fort Myers	3	1,748
E	Lauderdale	2	884
F	Everglades [2/]	0	0
G	Riviera [2/]	0	0
H	Martin	5	3,731
I	Cape Canaveral	1	1,210
J	Sanford	2	1,980
K	Putnam	2	498
L	St. John's River Power Park [1/]	2	254
M	West County	3	3,657
N	DeSoto [3/]	1	25
O	Space Coast [3/]	1	10
	Scherer [4/]	1	643
	Gas Turbines	48	1,908
	Total System Generation =	**80**	**24,274**
	System Firm Generation =	**78**	**24,239**

1/ Represents FPL's ownership share: St Lucie nuclear: 100% Unit 1, 85% Unit 2: St. Johns River: 20% of two units.
2/ Will be site of new Modernization Plants.
3/ The 25 MW of PV at DeSoto and the 10 MW of PV at Space Coast are considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generation" row at the end of the table.
4/ The Scherer unit is located in Georgia and is not shown on this map.

Non-FPL Territory

Figure I.A.1: Capacity Resources by Location (as of December 31, 2013)

Table I.A.1: Capacity Resource by Unit Type (as of December 31, 2013)

Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW
Nuclear				
St. Lucie [1/]	Hutchinson Island, FL	2	Nuclear	1,821
Turkey Point	Florida City, FL	2	Nuclear	1,632
Total Nuclear:		**4**		**3,453**
Coal Steam				
Scherer	Monroe County, Ga	1	Coal	643
St. John's River Power Park [2/]	Jacksonville, FL	2	Coal	254
Total Coal Steam:		**3**		**897**
Combined-Cycle				
Fort Myers	Fort Myers, FL	1	Gas	1,432
Manatee	Parrish, FL	1	Gas	1,111
Martin	Indiantown, FL	3	Gas	2,079
Sanford	Lake Monroe, FL	2	Gas	1,980
Cape Canaveral	Cocoa, FL	1	Gas/Oil	1,210
Lauderdale	Dania, FL	2	Gas/Oil	884
Putnam	Palatka, FL	2	Gas/Oil	498
Turkey Point	Florida City, FL	1	Gas/Oil	1,148
West County	Palm Beach County, FL	3	Gas/Oil	3,657
Total Combined Cycle:		**16**		**13,999**
Oil/Gas Steam				
Manatee	Parrish, FL	2	Oil/Gas	1,618
Martin	Indiantown,FL	2	Oil/Gas	1,652
Turkey Point	Florida City, FL	1	Oil/Gas	396
Total Oil/Gas Steam:		**5**		**3,666**
Gas Turbines(GT)				
Fort Myers (GT)	Fort Myers, FL	12	Oil	648
Lauderdale (GT)	Dania, FL	24	Gas/Oil	840
Port Everglades (GT)	Port Everglades, FL	12	Gas/Oil	420
Total Gas Turbines/Diesels:		**48**		**1,908**
Combustion Turbines				
Fort Myers	Fort Myers, FL	2	Gas/Oil	316
Total Combustion Turbines:		**2**		**316**
PV				
DeSoto [3/]	DeSoto, FL	1	Solar Energy	25
Space Coast [3/]	Brevard County, FL	1	Solar Energy	10
Total PV:		**2**		**35**
Total System Generation as of December 31, 2013 =		**80**		**24,274**
System Firm Generation as of December 31, 2013 =		**78**		**24,239**

1/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/860. FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively.
2/ Capabilities shown represent FPL's output share from each of the units (approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit. Represents FPL's ownership share: SJRPP coal: 20% of two units).
3/ The 25 MW of PV at DeSoto and the 10 MW of PV at Space Coast are considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generation" row at the end of the table.

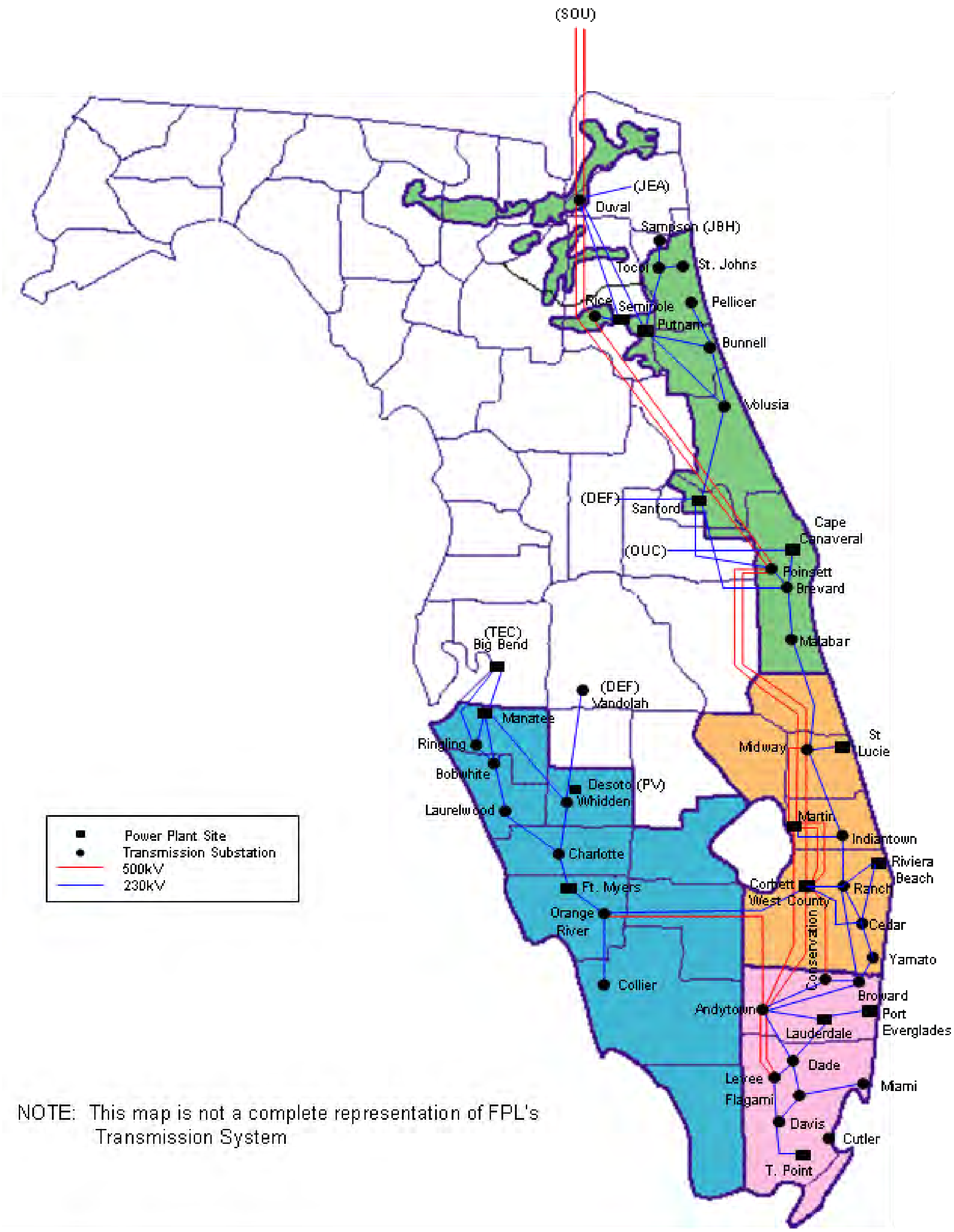


Figure I.A.2: FPL Substation and Transmission System Configuration

Description of Existing Resources

I.B Capacity and Energy Power Purchases

Firm Capacity Purchases from Qualifying Facilities (QF)

Firm capacity power purchases are an important part of FPL's resource mix. FPL currently has contracts with eight qualifying facilities; i.e., cogeneration/small power production facilities, to purchase firm capacity and energy during the 10-year reporting period of this Site Plan as shown in Table I.A.3, Table I.B.1, and Table I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source solar, wind, waste, geothermal, or other renewable resources.

Firm Capacity Purchases from Utilities

FPL has a Unit Power Sales (UPS) contract to purchase 928 MW from the Southern Company (Southern) through the end of December 2015. This capacity is being supplied by Southern from a mix of gas-fired and coal-fired units.

In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 375 MW (Summer) and 383 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Units No. 1 and No. 2. However, due to Internal Revenue Service (IRS) regulations, the total amount of energy that FPL may receive from this purchase is limited. FPL currently assumes, for planning purposes, that this limit will be reached in April 2019. Once this limit is reached, FPL will be unable to receive firm capacity and energy from these purchases. (However, FPL will continue to receive firm capacity and energy from its ownership portion of the SJRPP units.)

As part of the agreement that FPL will begin serving Vero Beach's electrical needs beginning in January 2015, FPL has acquired two existing power purchase agreements totaling approximately 37 MW of coal-fired capacity. These agreements will run through the end of 2017.

These purchases are shown in Table I.A.3, Table I.B.1, and Table I.B.2. FPL also has ownership interest in the SJRPP units. The ownership amount is reflected in FPL's installed capacity shown on Figure I.A.1, in Table I.A.1, and on Schedule 1.

Firm Capacity Other Purchases

FPL has two other firm capacity purchase contracts with non-QF, non-utility suppliers. These contracts with the Palm Beach Solid Waste Authority were previously listed as QFs. However, the addition of a second unit will cause both units to no longer meet the statutory definition of a QF. These contracts are therefore listed as "Other Purchases" after the current estimated in-service date of the new unit. Table I.B.1 and I.B.2 present the Summer and Winter MW, respectively, resulting from these contracts under the category heading of Other Purchases.

Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from several cogeneration and small power production facilities. Table I.A.3 shows the amount of energy purchased in 2013 from these facilities.

Table 1.A.3: Purchase Power Resources by Contract (as of December 31, 2013)

Firm Capacity Purchases (MW)	Location (City or County)	Fuel	Summer MW
I. Purchases from QF's: Cogeneration/Small Power Production Facilities			
Cedar Bay Generating Co.	Duval	Coal (Cogen)	250
Indiantown Cogen., LP	Martin	Coal (Cogen)	330
Broward South	Broward	Solid Waste	4
Broward North	Broward	Solid Waste	11
Palm Beach SWA - extension			40
		Total:	**635**
II. Purchases from Utilities:			
UPS from Southern Company	Various in Georgia	Coal	928
SJRPP	Jacksonville, FL	Coal	381
		Total:	**1,309**
	Total Net Firm Generating Capability:		**1,944**

Non-Firm Energy Purchases (MWH)

Project	County	Fuel	In-Service Date	Energy (MWH) Delivered to FPL in 2013
Okeelanta (known as Florida Crystals and New Hope Power Partners) *	Palm Beach	Bagasse/Wood	11/95	87,723
Broward South *	Broward	Solid Waste	9/09	90,116
Broward North *	Broward	Solid Waste	1/12	81,316
Waste Management - Renewable Energy *	Broward	Landfill Gas	1/10	47,249
Waste Management - Collier County Landfill *	Broward	Landfill Gas	5/11	25,578
Tropicana	Manatee	Natural Gas	2/90	8,900
Georgia Pacific	Putnam	Paper by-product	2/94	5,294
Rothenbach Park (known as MMA Bee Ridge)	Sarasota	PV	10/07	289
First Solar	Miami	PV	4/11	210
Customer - Owned PV & Wind	Various	PV/Wind	9/12	1,018
INEOS Bio *	Indian River	Wood	Various	922
Miami Dade Resource Recovery*	Dade	Solid Waste	12/13	28,759

* These Non-Firm Energy Purchases are Renewable and are reflected on Schedule 11.1 row 9 column 6.

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA -extension 1/	01/01/12	04/01/32	40	0	0	0	0	0	0	0	0	0
U.S. EcoGen - Clay 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
U.S. EcoGen -Okeechobee 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
U.S. EcoGen - Martin 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
		QF Purchases Sub Total:	**635**	**595**	**595**	**595**	**595**	**595**	**595**	**775**	**775**	**775**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
UPS Replacement	06/01/10	12/31/15	928	928	0	0	0	0	0	0	0	0
SJRPP 3/	04/02/82	04/01/19	375	375	375	375	375	0	0	0	0	0
OUC - Stanton 1 4/	01/01/15	12/31/17	0	21	21	21	0	0	0	0	0	0
OUC - Stanton 2 4/	01/01/15	12/31/17	0	16	16	16	0	0	0	0	0	0
		Utility Purchases Sub Total:	**1,303**	**1,340**	**412**	**412**	**375**	**0**	**0**	**0**	**0**	**0**

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total of QF and Utility Purchases =	**1,938**	**1,934**	**1,006**	**1,006**	**970**	**595**	**595**	**775**	**775**	**775**

III. Other Purchases:

	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Palm Beach SWA -extension 1/	01/01/12	04/01/32	0	40	40	40	40	40	40	40	40	40
Palm Beach SWA - additional	01/01/15	04/01/32	0	70	70	70	70	70	70	70	70	70
Unspecified Purchases 5/	01/01/20	12/31/20	0	0	0	0	0	0	129	0	0	0
Unspecified Purchases 5/	01/01/21	12/31/21	0	0	0	0	0	0	0	168	0	0
		Other Purchases Sub Total:	**0**	**110**	**110**	**110**	**110**	**110**	**239**	**278**	**110**	**110**

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total "Non-QF" Purchase =	**1,303**	**1,450**	**522**	**522**	**485**	**110**	**239**	**278**	**110**	**110**

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Summer Firm Capacity Purchases Total MW:	**1,938**	**2,044**	**1,116**	**1,116**	**1,080**	**705**	**834**	**1,053**	**885**	**885**

1/ When the second unit comes into service at the Palm Beach SWA, neither unit will meet the standards to be a small power producers, and both units then will be accounted for under "Other Purchases".

2/ The EcoGen units will enter service in 2019, and initially provide non-firm energy. Firm capacity delivery will commence in 2021.

3/ Contract End Date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.

4/ These units are part of the purchase of the Vero Beach Electric System.

5/ These unspecified purchases are short-term purchases that are included for resource planning purposes. No decision regarding such purchases is needed at this time.

Table I.B.2: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA -extension 1/	01/01/12	04/01/32	40	0	0	0	0	0	0	0	0	0
U.S. EcoGen - Clay 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
U.S. EcoGen -Okeechobee 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
U.S. EcoGen - Martin 2/	01/01/21	12/31/49	0	0	0	0	0	0	0	60	60	60
		QF Purchases Sub Total:	**635**	**595**	**595**	**595**	**595**	**595**	**595**	**775**	**775**	**775**

II. Purchases from Utilities:	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
UPS Replacement	06/01/10	12/31/15	928	928	0	0	0	0	0	0	0	0
SJRPP 3/	04/02/82	04/01/19	383	383	383	383	383	383	0	0	0	0
OUC - Stanton 1 4/	01/01/15	12/31/17	0	21	21	21	0	0	0	0	0	0
OUC - Stanton 2 4/	01/01/15	12/31/17	0	16	16	16	0	0	0	0	0	0
		Utility Purchases Sub Total:	**1,311**	**1,348**	**420**	**420**	**383**	**383**	**0**	**0**	**0**	**0**
		Total of QF and Utility Purchases =	**1,946**	**1,942**	**1,014**	**1,014**	**978**	**978**	**595**	**775**	**775**	**775**

III. Other Purchases:	Contract Start Date	Contract End Date	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Palm Beach SWA -extension 1/	01/01/12	04/01/32	0	40	40	40	40	40	40	40	40	40
Palm Beach SWA - additional	01/01/15	04/01/32	0	70	70	70	70	70	70	70	70	70
Unspecified Purchases 5/	01/01/20	12/31/20	0	0	0	0	0	0	129	0	0	0
Unspecified Purchases 5/	01/01/21	12/31/21	0	0	0	0	0	0	0	168	0	0
		Other Purchases Sub Total:	**0**	**110**	**110**	**110**	**110**	**110**	**239**	**278**	**110**	**110**
		"Non-QF" Purchase =	**1,311**	**1,458**	**530**	**530**	**493**	**493**	**239**	**278**	**110**	**110**

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Winter Firm Capacity Purchases Total MW:	**1,946**	**2,052**	**1,124**	**1,124**	**1,088**	**1,088**	**834**	**1,053**	**885**	**885**

1/ When the second unit comes into service at the Palm Beach SWA, neither unit will meet the standards to be a small power producers, and both units then will be accounted for under "Other Purchases".
2/ The EcoGen units will enter service in 2019, and initially provide non-firm energy. Firm capacity delivery will commence in 2021.
3/ Contract End Date shown for the SJRPP purchase does not represent the actual contract end date. Instead, this date represents a projection of the earliest date at which FPL's ability to receive further capacity and energy from this purchase could be suspended due to IRS regulations.
4/ These units are part of the purchase of the Vero Beach Electric System.
5/ These unspecified purchases are short-term purchases that are included for resource planning purposes. No decision regarding such purchases is needed at this time.

I.C Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include a number of conservation/energy efficiency and load management initiatives. FPL's DSM efforts through 2013 have resulted in a cumulative Summer peak reduction of approximately 4,753 MW at the generator and an estimated cumulative energy saving of approximately 66,782 Gigawatt-hour (GWh) at the generator. After accounting for reserve margin requirements, FPL's DSM efforts through 2013 have eliminated the need to construct the equivalent of approximately 14 new 400 MW generating units. New DSM Goals for FPL for the 2015 through 2024 time period will be set by the FPSC in the second half of 2014. DSM is discussed further in Chapter III.

Schedule 1

Existing Generating Facilities
As of December 31, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Plant Name	Unit No.	Location	Unit Type	Fuel Pri.	Fuel Alt.	Fuel Transport. Pri.	Fuel Transport. Alt.	Alt. Fuel Days Use	Commercial In-Service Month/Year	Actual/ Expected Retirement Month/Year	Gen.Max. Nameplate KW	Net Capability [1/] Winter MW	Net Capability [1/] Summer MW
Cape Modernization		Brevard County											
		19/24S/36F									1,295,400	1,355	1,210
	1		CC	NG	FO2	PL	TK	Unknown	Apr-13	Unknown	1,295,400	1,355	1,210
DeSoto [2/]		DeSoto County											
		27/36S/25E									27,000	25	25
	1		PV	Solar	Solar	N/A	N/A	Unknown	Oct-09	Unknown	27,000	25	25
Fort Myers		Lee County											
		35/43S/25E									2,841,990	2,552	2,396
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,721,490	1,490	1,432
	3A		CT	NG	FO2	PL	TK	Unknown	Jun-03	Unknown	188,190	176	158
	3B		CT	NG	FO2	PL	TK	Unknown	Jun-03	Unknown	188,190	176	158
	1-12		GT	FO2	No	TK	No	Unknown	May-74	Unknown	744,120	710	648
Lauderdale		Broward County											
		30/50S/42E									1,873,968	1,884	1,724
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	483	442
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	483	442
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
	13-24		GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	459	420
Manatee		Manatee County											
		18/33S/20E									2,951,110	2,806	2,729
	1		ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	819	809
	2		ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	819	809
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,168	1,111
Martin		Martin County											
		29/29S/38E									4,317,510	3,870	3,731
	1		ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	832	826
	2		ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	832	826
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	489	469
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	489	469
	8 [3/]		CC	NG	FO2	PL	TK	Unknown	Jun-05	Unknown	1,224,510	1,228	1,141
Port Everglades		City of Hollywood											
		23/50S/42E									410,734	459	420
	1-12		GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	459	420
Putnam		Putnam County											
		16/10S/27E									580,008	530	498
	1		CC	NG	FO2	PL	TK	Unknown	Apr-78	Unknown	290,004	265	249
	2		CC	NG	FO2	PL	TK	Unknown	Aug-77	Unknown	290,004	265	249

1/ These ratings are peak capability.

2/ The capacity shown for the PV facility at DeSoto is considered as non-firm generating capacity and the capacity from these units has been removed from the "System Firm Generating Capacity as of December 31, 2013" row at the end of the table.

3/ Martin Unit 8 is also partially fueled by a 75 MW solar thermal facility that supplies steam when adequate sunlight is available, thus reducing fossil fuel use.

Schedule 1

Existing Generating Facilities
As of December 31, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt.		Actual/			
						Fuel		Fuel	Commercial	Expected	Gen.Max.	Net Capability [1/]	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Winter	Summer
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Sanford		Volusia County											
		16/19S/30E									2,377,720	2,158	1,980
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,860	1,078	989
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	1,080	991
Scherer [2/]		Monroe, GA									680,368	651	643
	4		ST	SUB	No	RR	No	Unknown	Jul-89	Unknown	680,368	651	643
Space Coast [3/]		Brevard County											
		13/23S/36E									10,000	10	10
	1		PV	Solar	Solar	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10
St. Johns River		Duval County											
Power Park [4/]		12/15/28E											
		(RPC4)									271,836	260	254
	1		ST	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	130	127
	2		ST	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	130	127
St. Lucie [5/]		St. Lucie County											
		16/36S/41E									1,743,775	1,863	1,821
	1		ST	Nuc	No	TK	No	Unknown	May-76	Unknown	1,020,000	1,003	981
	2		ST	Nuc	No	TK	No	Unknown	Jun-83	Unknown	723,775	860	840
Turkey Point		Miami Dade County											
		27/57S/40E									3,380,960	3,263	3,176
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	398	396
	3		ST	Nuc	No	TK	No	Unknown	Nov-72	Unknown	877,200	839	811
	4		ST	Nuc	No	TK	No	Unknown	Jun-73	Unknown	877,200	848	821
	5		CC	NG	FO2	PL	TK	Unknown	May-07	Unknown	1,224,510	1,178	1,148
West County		Palm Beach County											
		29&32/43S/40E									2,733,600	4,005	3,657
	1		CC	NG	FO2	PL	TK	Unknown	Aug-09	Unknown	1,366,800	1,335	1,219
	2		CC	NG	FO2	PL	TK	Unknown	Nov-09	Unknown	1,366,800	1,335	1,219
	3		CC	NG	FO2	PL	TK	Unknown	May-11	Unknown	1,366,800	1,335	1,219
Total System Generating Capacity as of December 31, 2013 [6/] =												**25,691**	**24,274**
System Firm Generating Capacity as of December 31, 2013 [7/] =												**25,656**	**24,239**

1/ These ratings are peak capability.
2/ These ratings represent Florida Power & Light Company's share of Scherer Unit 4, adjusted for transmission losses.
3/ The capacity shown for the PV facility at Space Coast is considered as non-firm generating capacity due to the intermittent nature of the solar resource.
4/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Units 1 and 2, excluding the Jacksonville Electric Authority (JEA) share of 80%.
5/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/860.FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively, as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.44776% per unit.
6/ The Total System Generating Capacity value shown includes FPL-owned firm and non-firm generating capacity.
7/ The System Firm Generating Capacity value shown includes only firm generating capacity.

CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

II. A. Overview of the Load Forecasting Process

Long-term forecasts of sales, net energy for load (NEL), and peak loads are typically developed on an annual basis for resource planning work at FPL. New long-term forecasts were developed by FPL in late 2013 that replaced the previous long-term load forecasts that were used by FPL during 2013 in much of its resource planning work and which were presented in FPL's 2013 Site Plan. These new load forecasts are utilized throughout FPL's 2014 Site Plan. These forecasts are a key input to the models used to develop FPL's integrated resource plan.

The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads. Consistent with past forecasts, the primary drivers to develop these forecasts include economic conditions and weather.

The projections for the national and Florida economies are obtained from the consulting firm IHS Global Insight. Population projections are obtained from the Florida Legislature's Office of Economic and Demographic Research (EDR). These projections are developed in conjunction with the Bureau of Economic and Business Research (BEBR) of the University of Florida. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is always a key factor that affects FPL's energy sales and peak demand. Three sets of weather variables are developed and used in FPL's forecasting models:

1. Cooling degree-hours based on 72^{o} F, winter heating degree-days based on 66^{o} F, and heating degree-days based on 45^{o} F are used to forecast energy sales.
2. The maximum temperature on the peak day, along with the build-up of cooling degree-hours prior to the peak, is used to forecast Summer peaks.
3. The minimum and average temperatures on the peak day, along with the build-up of heating degree-hours based on 66^{o} F, one and two days prior to the peak, are used to forecast Winter peaks.

The cooling degree-hours and winter heating degree-days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric space heaters. Heating degree-days based on 45^{o} F are used to capture heating load resulting from sustained periods of unusually cold weather not fully captured by heating degree-days based on 66^{o} F. A composite hourly temperature profile is derived using hourly temperatures across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained. In developing the composite hourly profile, these regional temperatures are weighted by regional energy sales. The resulting composite temperature is used to derive projected cooling and heating degree-hours and heating degree-days. Similarly, composite temperature and hourly profiles of temperatures are used to calculate the weather variables used in the Summer and Winter peak models.

II. B. Comparison of FPL's Current and Previous Load Forecasts

While reflecting some fluctuations by year, FPL's current load forecast is generally in line with the load forecast presented in its 2013 Site Plan. There are four primary factors that are driving the current load forecast: projected population growth, the continued recovery of the Florida economy, energy efficiency codes and standards, and the additional load expected as a result of the acquisition of the City of Vero Beach electric utility.

In early 2013, FPL came to an agreement with the City of Vero Beach to purchase the City's electric system. This agreement was approved by the City voters on March 12, 2013. Beginning in January 2015, NEL, customers, and peaks for Vero Beach are included in FPL's forecasts and are reflected in FPL's 2014 Site Plan.

The customer forecast is based on recent population projections as well as the actual levels of customer growth experienced historically and the additional customers expected as a result of the acquisition of Vero Beach. Population projections are derived from the EDR's July 2013 Demographic Estimating Conference. This forecast is generally consistent with previous forecasts indicating a gradual rebound in Florida's population growth. Net migration into Florida fell to a record low in 2009 during the height of the recession. Florida has since experienced an improvement in net migration which now accounts for a majority of the population growth. However, population growth rates have remained modest by historical standards. Moderately higher rates of population growth are projected from 2014 until 2018 when the projected rate of population growth gradually begins to decelerate. Consistent with past population projections, the rates of population growth in the later years of the forecast are below the rates historically experienced in Florida.

Effective January 2015, FPL is expected to begin providing electric service to more than 34,000 customers formerly served by the City of Vero Beach. Reflecting this increase, the current forecast shows an increase in customer growth in 2015. Thereafter, customer growth is expected to mirror the overall level of population growth in the state. By 2019, the total number of customers served by FPL is expected to exceed five million. Between 2013 and 2023 the total number of customers is projected to increase at an annual rate of 1.4%, the same increase projected in the 2013 Site Plan.

The economic projections incorporated into FPL's load forecast are provided by IHS Global Insight, a leading economic forecasting firm. IHS Global Insight projects a continued recovery in the Florida economy with relatively healthy increases in employment and income levels between 2014 and 2020. Particularly robust growth is projected for the tourism and healthcare industries. Consistent with past projections, economic growth in the later years of the forecast is expected to moderate slightly.

Estimates of savings from energy efficiency codes and standards are developed by ITRON, a leading expert in this area. Included in these estimates are savings from federal and state energy efficiency codes and standards, including the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the savings occurring from the use of compact fluorescent bulbs[2]. The impact of these savings began in 2005 and their cumulative impact on the Summer peak is expected to reach 3,477 MW by 2023, the equivalent of approximately a 12% reduction in what the forecasted Summer peak load for 2023 would have been without these codes and standards. The cumulative impact from these savings on NEL is expected to reach 9,991 GWH over the same period while the cumulative impact on the Winter peak is expected to be 1,689 MW by 2023. This represents a decrease of approximately 7% in the forecasted NEL for 2023 and a 4% reduction in forecasted Winter peak load for 2023.

Consistent with the forecast presented in FPL's 2013 Site Plan, the total growth projected for the ten-year reporting period of this document is significant. The Summer peak is projected to increase to 26,528 MW by 2023, an increase of 4,952 MW over the 2013 actual Summer peak. Likewise, NEL is projected to reach 132,357 GWH in 2023, an increase of 20,702 GWH from the actual 2013 value.

II.C. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for the major revenue classes and are adjusted to match the NEL forecast. The results of these sales forecasts for the years 2014 - 2023 are presented in Schedules 2.1 - 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical software package MetrixND. The methodologies used to develop energy sales forecasts for each jurisdictional revenue class and NEL forecast are outlined below.

[2] Note that in addition to the fact that these energy efficiency codes and standards lower the forecasted load (as described later in this chapter), these standards also lower the potential for efficiency gains that would otherwise be available through utility DSM programs.

1. Residential Sales

Residential electric usage per customer is estimated by using an econometric model. Residential sales are a function of the following variables: cooling degree-hours, winter heating degree-days, lagged cooling degree-hours, lagged winter heating degree-days, retail gasoline prices, and Florida real per capita income weighted by the percent of the population employed. The impact of weather is captured by the cooling degree-hours, heating degree-days, and the one month lag of these variables. The impact energy prices have on electricity consumption is captured through retail gasoline prices. As energy prices rise, less disposable income is available for all goods and services, electricity included. To capture economic conditions, the model includes a composite variable based on Florida real per capita income and the percent of the state's population that is employed. Residential energy sales are forecasted by multiplying the forecasted residential use per customer by the number of residential customers forecasted.

2. Commercial Sales

The commercial sales forecast is also developed using an econometric model. Commercial sales are a function of the following variables: Florida real per capita income weighted by the percent of the population employed, cooling degree-hours, heating degree-hours, lagged cooling degree-hours, a variable designed to reflect the impact of empty homes, dummy variables for the month of December and for the specific months of January 2007, November 2005, and March 2013, and an autoregressive term. Cooling degree-hours, heating degree-hours, and the one month lag of cooling degree-hours are used to capture weather-sensitive load in the commercial sector.

3. Industrial Sales

The industrial class is comprised of three distinct groups: very small accounts (those with less than 20 kW of demand), medium accounts (those with 21 kW to 499 kW of demand), and large accounts (those with demands of 500 kW or higher). As such, the forecast is developed using a separate econometric model for each group of industrial customers. The small industrial sales model utilizes the following variables: cooling degree-hours, heating degree-hours, dummy variables for the specific months of November 2005 and August 2004, and two autoregressive terms. The medium industrial sales model utilizes the following variables: cooling degree-hours, Florida real per capita income weighted by the percent of the population employed, dummy variables for the specific months of February 2005 and 2006 and November 2005, and three autoregressive terms,. The large industrial sales model utilizes the following variables: cooling degree-hours, Florida real per capita income weighted by the percent of the population employed, the Consumer Price Index, and dummy variables for the specific months of October 2004 and 2005, November 2004, and September 2005.

4. Railroad and Railways Sales and Street and Highway Sales

This class consists solely of Miami-Dade County's Metrorail system. The projections for railroad and railways sales are based on a historical moving average.

The forecast for street and highway sales is developed by first developing a trended use per customer value, then multiplying this value by the number of forecasted customers.

5. Other Public Authority Sales

This class consists of a sports field rate schedule, which is closed to new customers, and one government account. The forecast for this class is based on its historical usage characteristics.

6. Total Sales to Ultimate Customer

Sales forecasts by revenue class are summed to produce a total sales forecast.

7. Sales for Resale

Sales for resale (wholesale) customers are composed of municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers. Currently there are five customers in this class: the Florida Keys Electric Cooperative; Lee County Electric Cooperative; Wauchula; Winter Park; and Blountstown. In addition, FPL will begin making sales to Seminole Electric Cooperative in June 2014 under a long term agreement[3].

Beginning in May 2011, FPL began providing service to the Florida Keys Electric Cooperative under a long-term full requirements contract. Previously FPL was serving the Florida Keys under a partial requirements contract. The sales to Florida Keys Electric Cooperative are based on customer-supplied information and historical coincidence factors.

Lee County has contracted with FPL for FPL to supply a portion of their load through 2013, then to begin serving their entire load beginning in 2014. This contract began in January 2010. Lee County provides a forecast of their sales by delivery point which is used to derive their sales forecast.

FPL's sales to Wauchula began in October 2011 and will continue through December 2016.

[3] FPL continues to evaluate the possibility of serving the electrical loads of other entities at the time the 2014 Site Plan is being prepared. Because these possibilities are still being evaluated, the load forecast presented in this Site Plan does not include these potential loads.

Sales to Winter Park began in January 2014 and will continue through December 2016.

Blountstown became an FPL wholesale customer in May 2012. FPL's contract with Blountstown expires in April 2017.

A new contract with Seminole Electric Cooperative is included in the forecast which includes delivery of 200 MW beginning in June 2014 and continuing through May 2021.

II.D. Net Energy for Load (NEL)

An econometric model is developed to produce a NEL per customer forecast. The inputs to the model include Florida real per capita income weighted by the percent of the population employed, and a proxy for energy prices. The model also includes several weather variables including cooling degree-hours and heating degree-days by calendar month, and heating degree-days based on 45^{o} F. In addition, the model also includes variables for energy efficiency codes and standards and a variable designed to capture the impact of empty homes. Dummy variables are included for the specific months of May 2004, and November 2005. There is also an autoregressive term in the model.

The energy efficiency variable is included to capture the impacts from major codes and standards, including those associated with the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the savings occurring from the use of compact fluorescent bulbs. The estimated impact from these codes and standards is inclusive of engineering estimates and any resulting behavioral changes. The impact of these savings began in 2005 and their cumulative impact on NEL is expected to reach 9,991 GWH by 2023. This represents a 7.0% reduction in what the forecasted NEL for 2023 would have been absence these codes and standards. On an incremental basis, net of the reduction already experienced through 2013, the reduction in 2023 is expected to reach 6,075 GWH.

The decline in the number of empty homes resulting from the current housing recovery has affected use per customer and is captured in a separate variable. The forecast was also adjusted for additional load estimated from hybrid vehicles, beginning in 2013, which resulted in an increase of approximately 1,587 GWH by the end of the ten-year reporting period. The forecast was also adjusted for the incremental load resulting from FPL's economic development riders which began in 2013, and this incremental load is projected to grow to 537 GWH before leveling off in 2018. An additional adjustment to the NEL forecast was made to reflect the acquisition of the Vero Beach electric system. The Vero Beach acquisition is projected to add 793 GWH by 2023.

The NEL forecast is developed by first multiplying the NEL per customer forecast by the total number of customers forecasted (excluding the customers formerly served by Vero Beach) and then adjusting the forecasted results for the expected incremental load resulting from hybrid vehicles, new wholesale contracts, the Vero Beach acquisition, and FPL's economic development riders. Once the NEL forecast is obtained, total billed sales are computed using a historical ratio of sales to NEL. The sales by class forecasts previously discussed are then adjusted to match the total billed sales. The forecasted NEL values for 2014 - 2023 are presented in Schedule 3.3 that appears at the end of this chapter.

II.E. System Peak Forecasts

The rate of absolute growth in FPL system peak load has been a function of the size of the customer base, varying weather conditions, projected economic conditions, changing patterns of customer behavior, and more efficient appliances and lighting. FPL developed the peak forecast models to capture these behavioral relationships. In addition, FPL's peak forecast also reflects changes in load expected as a result of the acquisition of Vero Beach, changes in wholesale contracts, and the expected number of hybrid vehicles.

The savings from energy efficiency codes and standards incorporated into the peak forecast include the impacts from the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the use of compact fluorescent light bulbs. The impact from these energy efficiency standards began in 2005 and their cumulative impact on the Summer peak is expected to reach 3,477 MW by 2023. This reduction is inclusive of engineering estimates and any resulting behavioral changes. The cumulative 2023 impact from these energy efficiency codes and standards effectively reduces FPL's Summer peak for that year by 11.6%. On an incremental basis, net of the reduction already experienced through 2013, the impact on the Summer peak from these energy efficiency codes and standards is expected to reach 1,997 MW in 2023. By 2023, the Winter peak is expected to be reduced by 1,689 MW as result of the cumulative impact from these energy efficiency standards since 2005. On an incremental basis, net of the reduction already experienced through 2013, the impact on the Winter peak from these energy efficiency standards is expected to reach 1,065 MW in 2023.

The forecast was also adjusted for additional load estimated from hybrid vehicles which results in an expected increase of approximately 443 MW in the Summer and 221 MW in the Winter by the end of the ten-year reporting period and for the acquisition of the Vero Beach electric system. The Vero Beach acquisition will add 169 MW to the Summer peak, and 179 MW to the Winter peak, forecast by the end of the ten-year reporting period.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2014 – 2023 are presented at the end of this chapter in Schedules 3.1 and 3.2, and in Chapter III in Schedules 7.1 and 7.2.

1. System Summer Peak

The Summer peak forecast is developed using an econometric model. The variables included in the model are the price of gasoline, lagged one month, Florida real household disposable income, cooling degree-hours two days prior to the peak day, the maximum temperature on the day of the peak, a variable for energy efficiency standards, and a moving average term. The model is based on the Summer peak contribution per customer which is multiplied by total customers (excluding the customers that have been served by Vero Beach), and adjusted to account for incremental loads resulting from hybrid vehicles, new wholesale contracts, the Vero Beach acquisition, and FPL's economic development riders to derive FPL's system Summer peak.

2. System Winter Peak

Like the system Summer peak model, this model is also an econometric model. The model consists of three weather-related variables: the average temperature on the peak day, heating degree-hours for the prior day squared, and heating degree-hours two days prior to the peak day. The model also includes two dummy variables; one for Winter peaks occurring on weekends and one for winter peaks with minimum temperature below 40.5 degrees. Also included in the model are a variable for housing starts per capita, and an autoregressive term. The forecasted results are adjusted for the impact of energy efficiency standards. The model is based on the Winter peak contribution per customer which is multiplied by total customers (excluding the customers that have been served by Vero Beach), and then adjusted for the expected incremental loads resulting from hybrid vehicles, new wholesale contracts, the Vero Beach acquisition, and FPL's economic development riders.

3. Monthly Peak Forecasts

The forecasting process for monthly peaks consists of the following steps:

a. The forecasted annual summer peak is assumed to occur in the month of August. The month of August has historically accounted for more annual summer peaks than any other month.

b. The forecasted annual winter peak is assumed to occur in the month of January. The month of January has historically accounted for more annual winter peaks than any other month.

c. The remaining monthly peaks are forecasted based on the historical relationship between the monthly peaks and the annual summer peak.

II.F. The Hourly Load Forecast

Forecasted values for system hourly load for the period 2014 - 2023 are produced using a System Load Forecasting "shaper" program. This model uses years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model generates a projection of hourly load values based on these load shapes and the forecast of monthly peaks and energy.

II.G. Uncertainty

In order to address uncertainty in the forecasts of aggregate peak demand and NEL, FPL first evaluates the assumptions underlying the forecasts. FPL takes a series of steps in evaluating the input variables, including comparing projections from different sources, identifying outliers in the series, and assessing the series' consistency with past forecasts. As needed, FPL reviews additional factors which may affect the input variables.

Uncertainty is also addressed in the modeling process. Generally, econometric models are used to forecast the aggregate peak demand and NEL. During the modeling process, the relevant statistics (goodness of fit, F-statistic, P-values, mean absolute deviation (MAD), mean absolute percentage error (MAPE), etc.) are scrutinized to ensure that the models adequately explain historical variation. Once a forecast is developed, it is compared with past forecasts. Deviations from past forecasts are examined in light of changes in input assumptions to ensure that the drivers underlying the forecast are well understood. Finally, forecasts of aggregate peak demand and NEL are compared with the actual values as these become available. An ongoing process of variance analyses is performed. To the extent that the variance analysis identifies large unexplained deviations between the forecast and actual values, revisions to the econometric model may be considered.

The inherent uncertainty in load forecasting is addressed in different ways in regard to FPL's overall resource planning and operational planning work. In regard to FPL's resource planning work, FPL's utilization of a 20% total reserve margin criterion, and a 10% generation-only reserve margin criterion, are designed to maintain reliable electric service to FPL's customers in light of forecasting (and other) uncertainty. In addition, banded forecasts of the projected Summer peak and net energy for load are produced based on an analysis of past forecasting variances. In regard to operational planning, a banded forecast for the projected Summer and Winter peak days is developed based on the historical weather variations. These bands are then used to develop similar bands for the monthly peaks.

II.H. DSM

The effects of FPL's DSM energy efficiency programs implementation through August 2013 are assumed to be imbedded in the actual usage data for forecasting purposes. The impacts of incremental energy efficiency that FPL plans to implement in the future, plus the cumulative and projected incremental impacts of FPL's load management programs, are accounted for as "line item reductions" to the forecasts as part of the IRP process as shown in Chapter III in Schedules 7.1 and 7.2. After making these adjustments to the load forecasts, the resulting "firm" load forecast is then used in FPL's IRP work.

Schedule 2.1
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,620,855	2.21	54,570	3,906,267	13,970	44,487	478,867	92,901
2007	8,729,806	2.19	55,138	3,981,451	13,849	45,921	493,130	93,121
2008	8,771,694	2.20	53,229	3,992,257	13,333	45,561	500,748	90,987
2009	8,732,591	2.19	53,950	3,984,490	13,540	45,025	501,055	89,860
2010	8,762,399	2.19	56,343	4,004,366	14,070	44,544	503,529	88,464
2011	8,860,158	2.20	54,642	4,026,760	13,570	45,052	508,005	88,685
2012	8,948,850	2.21	53,434	4,052,174	13,187	45,220	511,887	88,340
2013	9,025,275	2.20	53,930	4,097,172	13,163	45,341	516,500	87,786

Historical Values (2004 - 2013):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent actual energy sales including the impacts of existing conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.1
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2014	9,111,384	2.20	55,739	4,141,538	13,458	47,155	524,494	89,905
2015	9,302,665	2.20	57,047	4,228,484	13,491	48,634	538,771	90,267
2016	9,437,042	2.20	58,097	4,289,564	13,544	49,793	547,360	90,969
2017	9,571,922	2.20	58,693	4,350,874	13,490	50,418	555,714	90,726
2018	9,705,104	2.20	59,404	4,411,411	13,466	51,110	563,753	90,661
2019	9,835,541	2.20	60,036	4,470,700	13,429	51,667	571,672	90,379
2020	9,961,263	2.20	60,791	4,527,847	13,426	52,337	579,453	90,322
2021	10,079,425	2.20	61,219	4,581,557	13,362	52,675	587,147	89,713
2022	10,198,087	2.20	61,929	4,635,494	13,360	53,264	594,908	89,534
2023	10,318,293	2.20	62,870	4,690,133	13,405	54,043	602,612	89,681

Projected Values (2014 - 2023):

Col. (2) represents population only in the area served by FPL.

Col. (4) and Col. (7) represent forecasted energy sales that do not include the impact of incremental conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.2
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads	Street &	Sales to	Sales to
		Average No. of	Average kWh Consumption	& Railways	Highway Lighting	Public Authorities	Ultimate Consumers
Year	GWh	Customers	Per Customer	GWh	GWh	GWh	GWh
2004	3,964	18,512	214,139	93	413	58	99,095
2005	3,913	20,392	191,873	95	424	49	102,296
2006	4,036	21,211	190,277	94	422	49	103,659
2007	3,774	18,732	201,499	91	437	53	105,415
2008	3,587	13,377	268,168	81	423	37	102,919
2009	3,245	10,084	321,796	80	422	34	102,755
2010	3,130	8,910	351,318	81	431	28	104,557
2011	3,086	8,691	355,104	82	437	27	103,327
2012	3,024	8,743	345,871	81	441	25	102,226
2013	2,956	9,541	309,772	88	442	28	102,784

Historical Values (2004 - 2013):

Col. (10) and Col.(15) represent actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.2
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
		Industrial		Railroads	Street &	Sales to	Sales to
		Average No. of	Average kWh Consumption	& Railways	Highway Lighting	Public Authorities	Ultimate Consumers
Year	GWh	Customers	Per Customer	GWh	GWh	GWh	GWh
2014	2,990	10,242	291,973	82	442	24	106,432
2015	3,009	10,890	276,263	83	453	23	109,248
2016	3,008	11,520	261,101	82	460	23	111,463
2017	3,001	11,893	252,369	83	466	23	112,684
2018	2,970	12,003	247,426	83	473	23	114,063
2019	2,931	12,030	243,618	83	478	23	115,218
2020	2,875	12,017	239,256	83	484	23	116,593
2021	2,814	11,991	234,676	83	489	23	117,303
2022	2,754	11,971	230,057	83	494	23	118,548
2023	2,692	11,907	226,087	83	499	23	120,210

Projected Values (2014 - 2023):

Col. (10) and Col.(15) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Col. (4) + Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2004	1,531	7,467	108,093	3,029	4,224,509
2005	1,506	7,498	111,301	3,156	4,321,895
2006	1,569	7,909	113,137	3,218	4,409,563
2007	1,499	7,401	114,315	3,276	4,496,589
2008	993	7,092	111,004	3,348	4,509,730
2009	1,155	7,394	111,303	3,439	4,499,067
2010	2,049	7,870	114,475	3,523	4,520,328
2011	2,176	6,950	112,454	3,596	4,547,051
2012	2,237	6,403	110,866	3,645	4,576,449
2013	2,158	6,713	111,655	3,722	4,626,934

Historical Values (2004 - 2013):

Col. (19) represents actual energy sales including the impacts of existing conservation.

Col. (19) = Col. (16) + Col. (17) + Col. (18). Historical NEL includes the impacts of existing conservation and agrees to Col. (5) on schedule 3.3. Historical GWH, prior to 2011, are based on a fiscal year beginning 12/29 and ending 12/28. The 2011 value is based on 12/29/10 to 12/31/11. The 2012-2013 values are based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 2.3
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2014	4,907	6,662	118,001	3,780	4,680,054
2015	5,654	6,703	121,606	4,323	4,782,469
2016	5,706	6,775	123,943	4,383	4,852,827
2017	5,419	6,811	124,914	4,437	4,922,918
2018	5,440	6,896	126,399	4,491	4,991,659
2019	5,496	6,959	127,673	4,543	5,058,945
2020	5,559	7,035	129,187	4,592	5,123,909
2021	5,133	7,018	129,454	4,638	5,185,333
2022	4,846	7,124	130,517	4,681	5,247,054
2023	4,908	7,239	132,357	4,724	5,309,376

Projected Values (2014 - 2023):

Col. (19) represents forecasted energy sales that do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

Col. (19) = Col. (16) + Col. (17) + Col. (18). These values are based on calendar year.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Col. (5) + Col. (8) + Col. (11) + Col. (20).

Schedule 3.1
History of Summer Peak Demand (MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2004	20,545	258	20,287	0	894	846	588	577	19,063
2005	22,361	264	22,097	0	902	895	600	611	20,858
2006	21,819	256	21,563	0	928	948	635	640	20,256
2007	21,962	261	21,701	0	952	982	716	683	20,295
2008	21,060	181	20,879	0	966	1,042	760	706	19,334
2009	22,351	249	22,102	0	981	1,097	811	732	20,558
2010	22,256	419	21,837	0	990	1,181	815	758	20,451
2011	21,619	427	21,192	0	1,000	1,281	821	781	19,798
2012	21,440	431	21,009	0	1,013	1,351	833	810	19,594
2013	21,576	396	21,180	0	1,025	1,394	833	827	19,718

Historical Values (2004 - 2013):

Col. (2) - Col. (4) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) represent actual DSM capabilities starting from January 1988 and are annual (12-month) values except for 2013 values which are through August.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.1
Forecast of Summer Peak Demand (MW)

(1) August of Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management*	(7) Residential Conservation	(8) C/I Load Management*	(9) C/I Conservation	(10) Net Firm Demand
2014	22,768	1,173	21,595	0	1,077	65	816	33	20,777
2015	23,356	1,206	22,149	0	1,093	88	830	46	21,298
2016	23,778	1,212	22,565	0	1,103	89	841	49	21,695
2017	24,190	1,159	23,031	0	1,113	91	853	52	22,081
2018	24,544	1,166	23,378	0	1,124	92	865	56	22,407
2019	24,896	1,172	23,723	0	1,134	94	877	62	22,729
2020	25,239	1,179	24,061	0	1,144	97	889	67	23,042
2021	25,439	985	24,454	0	1,154	100	901	73	23,211
2022	25,908	992	24,916	0	1,165	104	912	79	23,648
2023	26,528	998	25,530	0	1,175	109	924	85	24,235

Projected Values (2014 - 2023):

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected August values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC.

Schedule 3.2
History of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2004	14,752	211	14,541	0	813	567	534	227	13,405
2005	18,108	225	17,883	0	816	583	542	233	16,751
2006	19,683	225	19,458	0	823	600	550	240	18,311
2007	16,815	223	16,592	0	846	620	577	249	15,392
2008	18,055	163	17,892	0	868	644	636	279	16,551
2009	20,081	207	19,874	0	881	666	676	285	18,524
2010	24,346	500	23,846	0	895	687	721	291	22,730
2011	21,126	383	20,743	0	903	717	723	303	19,501
2012	17,934	382	17,552	0	856	755	722	314	16,356
2013	15,931	348	15,583	0	843	781	567	326	14,521

Historical Values (2004 - 2013):

Col. (2) - Col. (4) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand. For year 2011, the actual peaked occurred in December of 2010.

Col. (5) - Col. (9) for 2003 through 2012 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.2
Forecast of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
January of Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2014	19,875	992	18,883	0	883	13	601	5	18,373
2015	20,971	1,235	19,736	0	905	52	557	16	19,442
2016	21,490	1,238	20,252	0	913	52	562	17	19,947
2017	21,731	1,164	20,567	0	921	53	568	17	20,173
2018	21,968	1,159	20,809	0	929	53	573	18	20,396
2019	22,180	1,162	21,018	0	937	53	579	19	20,592
2020	22,383	1,165	21,218	0	945	54	584	20	20,780
2021	22,584	1,168	21,416	0	953	54	590	22	20,965
2022	22,601	971	21,630	0	961	55	595	23	20,966
2023	22,891	974	21,918	0	970	56	601	24	21,240

Projected Values (2014 - 2023):

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected January values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC.

Schedule 3.3
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1) Year	(2) Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) **Actual** Net Energy For Load GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Total Billed Retail Energy Sales (GWh)	(9) Load Factor(%)
2004	111,659	1,872	1,693	108,093	1,531	7,467	99,095	59.9%
2005	115,065	1,970	1,793	111,301	1,506	7,498	102,296	56.8%
2006	117,116	2,078	1,901	113,137	1,569	7,909	103,659	59.2%
2007	118,518	2,138	2,066	114,315	1,499	7,401	105,415	59.4%
2008	115,379	2,249	2,126	111,004	993	7,092	102,919	60.0%
2009	115,844	2,345	2,196	111,303	1,155	7,394	102,755	56.8%
2010	119,220	2,487	2,259	114,475	2,049	7,870	104,557	58.7%
2011	117,460	2,683	2,324	112,454	2,176	6,950	103,327	59.4%
2012	116,083	2,823	2,394	110,866	2,237	6,403	102,226	58.9%
2013	117,087	2,962	2,469	111,655	2,158	6,713	102,784	59.1%

Historical Values (2004 - 2013):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5).

Col. (3) & Col. (4) are DSM values starting in January 1988 and are annual (12-month) values. Col. (3) and Col. (4) for 2013 are "estimated actuals" and are also annual (12-month) values. The values represent the total GWh reductions experienced each year .

Col. (5) is the actual Net Energy for Load (NEL) for years 2003 - 2013.

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (2), "Total", from Schedule 3.1 using the formula: Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 3.3
Forecast of Annual Net Energy for Load (GWh)
(All values are "at the generator"values except for Col (8))

(1) Year	(2) Forecasted Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Net Energy For Load Adjusted for DSM GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Forecasted Total Billed Retail Energy Sales w/o DSM GWh	(9) Load Factor(%)
2014	118,001	91	53	117,858	4,907	6,662	106,432	59.2%
2015	121,606	142	80	121,383	5,654	6,703	109,248	59.4%
2016	123,943	144	81	123,718	5,706	6,775	111,463	59.3%
2017	124,914	147	81	124,686	5,419	6,811	112,684	58.9%
2018	126,399	150	81	126,168	5,440	6,896	114,063	58.8%
2019	127,673	155	80	127,438	5,496	6,959	115,218	58.5%
2020	129,187	159	81	128,948	5,559	7,035	116,593	58.3%
2021	129,454	164	82	129,208	5,133	7,018	117,303	58.1%
2022	130,517	170	82	130,264	4,846	7,124	118,548	57.5%
2023	132,357	179	83	132,095	4,908	7,239	120,210	57.0%

Projected Values (2014 - 2023):

Col. (2) represents Forecasted Net Energy for Load and does not include incremental DSM from 2013 - on. The Col. (2) values are extracted from Schedule 2.3, Col(19). The effects of conservation implemented prior to September 2012 are incorporated into the load forecast values in Col. (2).

Col. (3) & Col. (4) are forecasted values of the reduction on sales from incremental conservation from Jan 2014 - on and are mid-year (6-month) values reflecting DSM signups occurring evenly thoughout each year.

Col. (5) is the forecasted Net Energy for Load (NEL) after adjusting for impacts of incremental DSM for years 2014 - 2023 using the formula:
Col. (5) = Col. (2) - Col. (3) - Col. (4)

Col. (8) is the Total Retail Billed Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7).
These values are at the meter.

Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. Col. (9) = ((Col. (2)*1000) / ((Col. (2) * 8760)
Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of
Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2013 Actual		2014 FORECAST		2015 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	15,135	8,089	19,875	8,719	20,971	9,093
FEB	15,627	7,468	17,441	7,781	18,050	8,126
MAR	15,931	7,936	17,273	8,753	17,875	9,103
APR	18,419	8,967	18,149	9,047	18,782	9,386
MAY	19,579	9,494	20,331	10,369	21,040	10,701
JUN	21,147	10,460	21,852	10,865	22,416	11,127
JUL	20,261	10,649	22,413	11,625	22,991	11,884
AUG	21,576	11,392	22,768	11,840	23,356	12,096
SEP	20,297	10,229	21,959	10,997	22,525	11,256
OCT	19,313	9,969	20,458	10,354	20,986	10,617
NOV	18,028	8,506	17,994	8,686	18,458	8,960
DEC	16,161	8,497	17,563	8,965	18,016	9,257
Annual Values:		**111,655**		**118,001**		**121,606**

Col. (3) annual value shown is consistent with value shown in Col.(5) of Schedule 3.3.

Cols. (4) - (7) do not include the impacts of cumulative load management, incremental conservation, and incremental load management.

Cols. (5) and Col. (7) annual values shown are consistent with values shown in Col.(2) of Schedule 3.3.

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CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL utilizes its well established integrated resource planning (IRP) process in whole or in part as analysis needs are warranted, to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of new power plants, the primary subjects of this document, are determined as part of the IRP process work.

This section describes FPL's basic IRP process. Some of the key assumptions, in addition to a new load forecast, that were used in developing the resource plan presented in this Site Plan are also discussed.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental steps to FPL's resource planning. These steps can be generally described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans);

Step 3: Evaluate the competing options and resource plans in regard to system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process

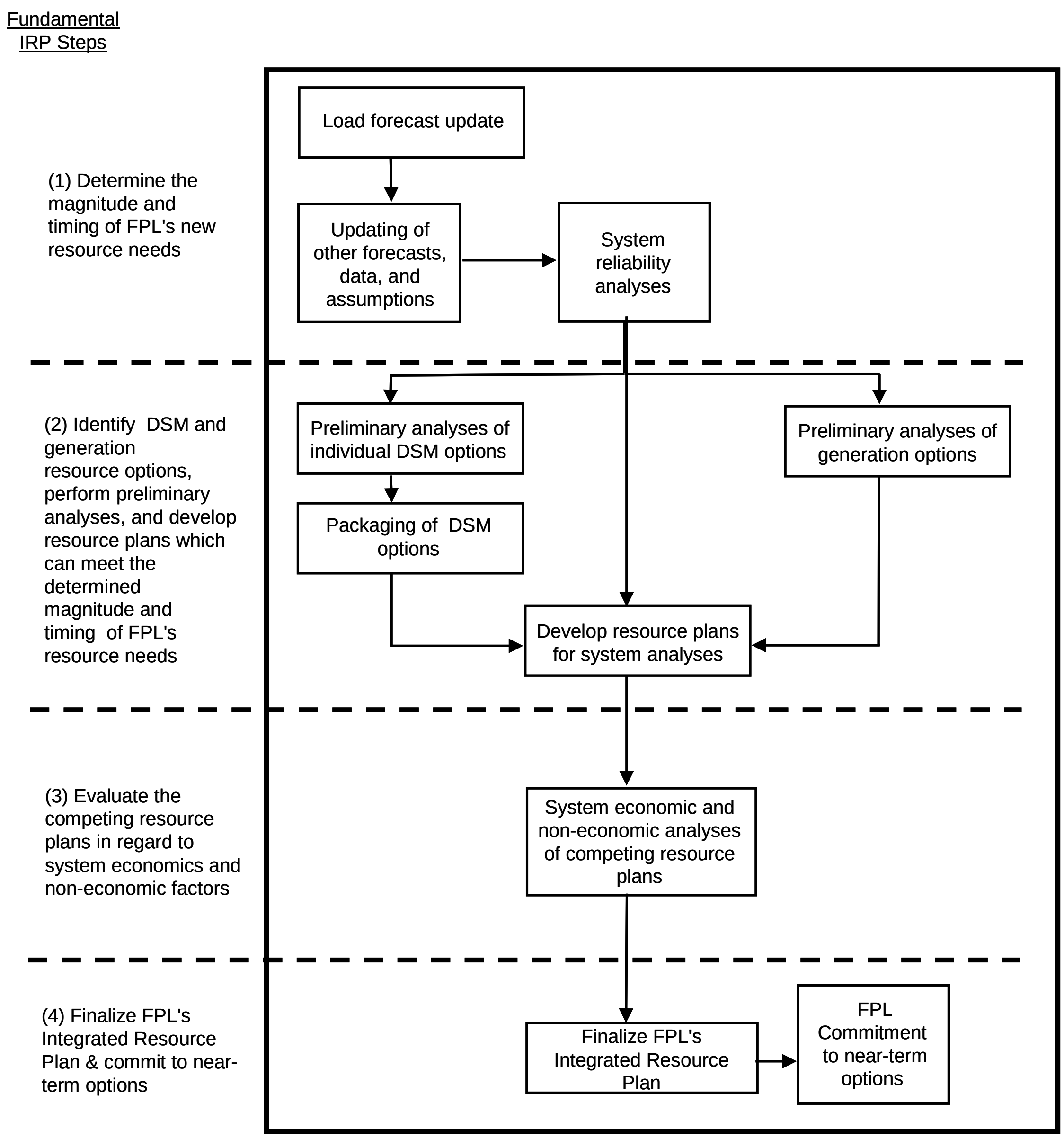

Figure III.A.1: Overview of FPL's IRP Process

Step 1: Determine the Magnitude and Timing of FPL's New Resource Needs:

The first of the four resource planning steps, determining the magnitude and timing of FPL's resource needs, is essentially a determination of the amount of capacity or megawatts (MW) of load reduction, new capacity additions, or a combination of both load reduction and new capacity additions that are needed to maintain system reliability. Also determined in this step is when the MW additions are needed to meet FPL's reliability criteria. This step is often referred to as a reliability assessment, or resource adequacy, analysis for the utility system.

Step 1 typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used in many of the fundamental steps in resource planning. Examples of this new information include, but are not limited to: delivered fuel price projections, current financial and economic assumptions, and power plant capability and operating assumptions. FPL also includes key sets of assumptions regarding three specific types of resources: (1) FPL unit capacity changes, (2) firm capacity power purchases, and (3) demand side management (DSM) implementation.

Key Assumptions Regarding the Three Types of Resources:

The first set of assumptions, FPL unit capacity changes, is based on the current projection of new generating capacity additions and planned retirements of existing generating units. In FPL's 2014 Site Plan, there are five such projected capacity changes. These are listed below in chronological order:

1) Planned retirement of existing Putnam Units 1 & 2:
   Analyses conducted during 2013 and early 2014 showed that it would be cost-effective to retire the two existing units, Putnam Units 1 & 2, and replace the capacity with new combined cycle (CC) capacity at a later date and at a site to be determined. The new CC capacity would have a significantly better heat rate, thus reducing FPL's system fuel usage and system emissions. Consequently, FPL currently projects that the two existing units will be retired by the end of 2014.

2) CT upgrades at existing CC plant sites:
   In the fourth quarter of 2011, FPL started upgrading the 7FA combustion turbines (CT) that are components at a number of its existing CC units. These upgrades will economically benefit FPL's customers by increasing the MW output of these CC units by approximately 209 MW (Summer peak value) in total. As reflected in Schedule 1 in Chapter I, 133 MW of the increased capacity from these CT upgrades is already in

service. The work for the remaining upgrades is continuing and the project is projected to be completed in 2015.

3) Modernization of the Port Everglades plant site:

The work to modernize the existing Port Everglades site by adding new combined cycle (CC) capacity continues. The new generating unit, called the Port Everglades Next Generation Clean Energy Center (PEEC), is projected to be in-service in mid-2016 and is projected to have a peak Summer output of 1,237 MW. The FPSC issued the final need order for this modernization project in April 2012 in Order No. PSC-12-0187-FOF-EI. The site certification order for the project, DOAH Case No. 12-0422EPP, was received for the Port Everglades project in October 2012. (Note that a similar modernization of the FPL's existing Riviera Beach plant site is scheduled to be completed on/near the April 1, 2014 filing date of this 2014 Site Plan.)

4) Retirement of existing gas turbines (GTs) in Broward County and partial capacity replacement with new combustion turbines (CTs) at FPL's Lauderdale plant site:

Due to new nitrogen dioxide (NO_2) environmental regulations, FPL filed in June 2013 for FPSC approval to recover costs for removing all of its existing GTs and replacing a portion of the GT capacity with new CTs. In December 2013, FPL withdrew this request pending additional environmental monitoring and analyses. Computer modeling of the emissions from the GTs projected that the GTs would exceed the new NO_2 limit. FPL believes this monitoring and analyses will confirm that the operation of its existing GTs in Broward County will not comply with the new NO_2 regulations. Therefore, for planning purposes, FPL has assumed that all of its existing Broward County GTs will be removed (a loss of 1,260 MW Summer) and that this capacity will be partially replaced by 5 new CTs that would be sited in Broward County (an increase of 1,005 MW Summer). This GT removal and CT partial replacement is assumed to occur by the end of 2018.

5) Turkey Point Nuclear Units 6 & 7:

FPL is continuing its work to obtain all of the licenses, permits, and approvals that will be necessary to construct and operate two new nuclear units at its Turkey Point site. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. FPL received need determination approval from the FPSC for the two nuclear units in April 2008 in Order No. PSC-08-0237-FOF-EI. The earliest deployment dates for these two new units, Turkey Point Units 6 & 7, remain 2022 and 2023, respectively. Each new nuclear unit is projected to have a peak Summer output of 1,100 MW.

Also in regard to FPL unit capacity changes, as part of FPL's planned acquisition of Vero Beach's electric utility system, FPL is projected to take ownership of Vero Beach's five existing generating units starting January 2015. The current plan, based on the units' poor economics, is to immediately retire three of these older generating units and operate the remaining two, which supply approximately 46 MW (Summer) of combined cycle capacity, for a maximum of three years.

The second set of assumptions involves firm capacity power purchases. FPL's current projection of firm capacity purchases has changed from the projection in the 2013 Site Plan in regard to only two purchases. As part of the projected agreement that FPL will begin serving Vero Beach's electrical needs beginning in January 2015, FPL has acquired two existing power purchase agreements totaling approximately 37 MW of coal-fired capacity. These agreements are now projected to run through the end of 2017 instead of 2016 as projected in FPL's 2013 Site Plan. In addition, FPL now projects that Internal Revenue Service (IRS) regulations regarding the amount of energy that FPL can receive under its purchase agreement with Jacksonville Electric Authority (JEA) for St. Johns Regional Power Park (SJRPP)-based capacity and energy will not result in the suspension of the delivery of capacity and energy receipts to FPL until April 2019. [4]

None of the other purchase projections has changed from those in the 2013 Site Plan. FPL's current projection includes an additional 70 MW from the Palm Beach Solid Waste Authority (SWA) starting in year 2015. In addition, FPL projects that it will begin receiving a total of 180 MW of firm capacity in 2021 from biomass-based power purchase agreements with EcoGen.

In total, the projected firm capacity purchases are from a combination of utility and independent power producers. Details, including the annual total capacity values for these purchases, are presented in Chapter I in Tables I.B.1 and I.B.2. These purchased capacity amounts were incorporated in FPL's resource planning work.

The third set of assumptions involves a projection of the amount of additional DSM that is anticipated to be implemented annually over the ten-year period. A key aspect of FPL's IRP process is the evaluation of DSM resources. Since 1994, FPL's resource planning work has assumed that, at a minimum, the DSM MW called for in FPL's FPSC-approved DSM Plan will be achieved. In 2014, FPL is required to propose new DSM Goals for the 2015 through 2024 time period. Those proposed goals will be filed with the FPSC on April 2, 2014; i.e., one day after this 2014 Site Plan is filed with the FPSC. FPL's filing to support its proposed DSM goals provides extensive detail regarding how DSM resources were evaluated in FPL's most current IRP planning

[4] FPL's projected suspension date for the SJRPP purchase is based on a system reliability perspective and represents the earliest projected date at which the suspension of capacity and energy could occur.

analyses. The DSM assumptions presented in this 2014 Site Plan, and which are assumed in the analyses whose results are reflected in the Site Plan, are consistent with FPL's proposed goals. The FPSC is expected to make a decision regarding FPL's 2015 – 2024 DSM Goals later in 2014.

The Three Reliability Criteria Used to Determine FPL's Projected Resource Needs:

These key assumptions, plus the other updated information described above, are then applied in the first fundamental step: the determination of the magnitude and the timing of FPL's future resource needs. This determination is accomplished by system reliability analyses which for FPL have traditionally been based on dual planning criteria of a minimum peak period reserve margin of 20% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 day per year. Both of these criteria are commonly used throughout the utility industry. Beginning this year, FPL is also using a third reliability criterion: a 10% generation-only reserve margin (GRM) criterion.

Historically, two types of methodologies, deterministic and probabilistic, have been utilized in system reliability analysis. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements such as the impact of individual unit failures. For example: two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time. Probabilistic methods also recognize the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Among the most widely used is loss-of-load probability (LOLP) which FPL utilizes. Simply stated, LOLP is an index of how well a generating system may be able to meet its firm 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 terms of the projected probability that a utility will be unable to meet its entire firm load at some point during a year. The probability of not being able to meet the entire firm load is calculated for each day of the year using the daily peak hourly load. These daily probabilities are then summed to develop an annual probability value. This annual probability value is commonly expressed as "the number of days per year" that the entire system firm load could not be met. FPL's standard for LOLP, commonly accepted throughout the industry, is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does the reserve margin analysis. LOLP analyses are typically carried out using computer software models such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

FPL's recent integrated resource planning work has resulted in FPL's resource plans showing a significant shift in the mix of generation and DSM resources over the next 10 years in regard to the relative contribution of these resources to system reliability. In order to gauge the extent of this shift and its potential implications for FPL's system reliability, FPL developed a new metric: a generation-only reserve margin (GRM). This GRM metric reflects reserves that would be provided only by actual generating resources. The GRM value is calculated by setting to zero all incremental energy efficiency (EE) and load management (LM), plus all existing LM, in a reserve margin calculation. The resulting GRM value provides an indication of how large a role generation is projected to play in each year as FPL maintains its 20% Summer and Winter "total" reserve margins (which account for both generation and DSM resources).

FPL has been reporting the GRM metric in its Site Plans since 2011 when it presented projections of its Summer GRM for the years 2011-2020. The 2011 projection showed a steady decrease in GRM values from a "balanced" 11.5% in 2011 to much reduced 7.2% by 2020. In its 2012 Site Plan, FPL's projected GRM values steadily decreased over the 10-year period from 16.2% in 2012 to 5.5% in 2021. The projected pattern in the 2013 Site Plan was similar: a steady decrease from 16.3% in 2013 to 6.9% in 2021. (The projected GRM value for 2022 presented in the 2013 Site Plan increased to 8.9% due to the planned addition of the new Turkey Point 6 nuclear unit in 2022.) Thus FPL's resource planning projections over the last 3 years have each shown a general downwards trend in projected GRM in the latter portion of this decade. This indicates increasing reliance on DSM resources, particularly EE resource additions, and decreasing reliance on generation resources, to maintain system reliability. As a result, FPL has analyzed what impact(s) this trend could have on system reliability. Two types of evaluations were conducted. One of these evaluations is from the perspective of FPL's system operators who are responsible for operating the bulk electric system. The other evaluation is from a resource planning perspective.

The first evaluation examined what impact an increasing reliance on EE resource additions was projected to have on the amount and type of reserves that operators would have at their disposal to meet load on a system peak hour. FPL first used a "looking back" perspective at a recent actual peak load day of January 11, 2010 to see how the system actually operated. Then, assuming a "what if" situation in which the system was assumed to have been designed to have an identical total reserve margin, but higher and lower GRM respectively, FPL analyzed what the impact would have been on FPL's ability to serve its customers on that peak day with these alternative assumed systems.

FPL also performed analyses taking a "looking forward" perspective at the projected year of 2021. Three scenarios were analyzed: (i) the system with its projected GRM and total reserve margin values consistent with the 2013 Site Plan; (ii) a system with an identical total reserve margin, but a higher GRM; and (iii) a system with an identical total reserve margin, but a lower GRM. Recognizing that the impacts from EE resource additions will already have been accounted for in the peak load that system operators must react to on an actual peak day, the analyses assumed an adverse peak day situation which consisted of significantly higher load and significantly less available generation than projected. The results from both the "looking back" and "looking forward" analyses were similar. For resource plans with identical total reserve margins, but different GRM levels, system operators were projected to have significantly higher levels (MW) of reserves, either generation and/or load management reserves, available on the peak days with a resource plan that had a higher GRM level than with a resource plan that had a lower GRM level. Thus a resource plan with a higher GRM, compared with a lower GRM, results in better system reliability for customers due to a greater likelihood of meeting customers' firm demand on peak load days, despite unexpected conditions or events. Better system reliability to customers translates to a reduced risk of shedding firm load.

The second evaluation was from the resource planning perspective of loss-of-load-probability (LOLP). For this evaluation, FPL also analyzed resource plans with identical total reserve margins, but higher and lower GRM levels. The results of these analyses for the FPL system showed that a resource plan with a higher GRM resulted in a projection of lower LOLP values than a resource plan with a lower GRM.

Based on these operational and resource planning evaluations, FPL has concluded that resource plans for its system with identical total reserve margins, but different GRM values, are not equal in regard to system reliability. A resource plan with a higher GRM value is projected to result in more MW being available to system operators on adverse peak load days, and in lower LOLP values, than a resource plan with a lower GRM value, even though both resource plans have an identical total reserve margin. Therefore, FPL has applied a minimum GRM criterion as a third reliability criterion in its resource planning process.

Based on the expertise and experience of FPL's system operators regarding the amount of generation MW needed for reliable operations, the GRM criterion is set at a minimum of 10% for Summer and Winter. From an operational perspective, FPL believes it is necessary to have approximately 2,650 MW of generation reserves. These reserves will allow FPL to address a variety of operational considerations including: (i) unplanned generation unavailability; (ii) the deployment of real-time operating reserves to meet its 15-minute obligations as part of the Florida Reserve Sharing Group; (iii) the requirement pursuant to NERC Reliability Standards to replace with other resources within 30 minutes following the unplanned loss of a large generation unit; and (iv) higher-than-forecasted loads. The sum of the operational reserves to cover for these requirements and considerations is approximately 2,650 MW. This MW value is consistent with a 10% GRM for the foreseeable future. FPL is planning its system so that the minimum 10% GRM criterion is met beginning in the Summer of 2019.

The 10% minimum Summer and Winter GRM criterion augments the two existing reliability criteria used by FPL: a 20% total reserve margin criterion for Summer and Winter, and a 0.1 day/year LOLP criterion. The total reserve margin and LOLP criteria continue to identify the timing and magnitude of FPL's future resource needs. The GRM criterion provides direction regarding the mix of generation and DSM resources that should be added to maintain and enhance FPL's system reliability.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, preliminary economic screening analyses of new capacity options that are identical, or virtually identical, in regard to certain key characteristics may be conducted to determine which new capacity options appear to be the most competitive on FPL's system. This preliminary analysis work can also help identify capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. Similarly, preliminary economic screening analyses of new DSM options and/or evaluation of existing DSM options are often conducted in this second fundamental IRP step.

FPL typically utilizes the P-MArea production cost model and a Fixed Cost Spreadsheet, and/or an optimization models and spreadsheet analyses, to perform the preliminary economic screening of generation resource options. For the preliminary economic screening analyses of DSM resource options, FPL typically uses its DSM CPF model which is an FPL spreadsheet model utilizing the FPSC's approved methodology for performing preliminary economic screening of individual DSM measures and programs. In addition, a years-to-payback screening test based on a two-year criterion is also used in the preliminary economic screening of individual DSM measures and programs. Then, as the focus of DSM analyses progresses from analysis of individual DSM measures to the development of DSM portfolios, FPL uses two additional models. One of these models is FPL's non-linear programming model that is used for analyzing the potential for lowering system peak loads through additional load management/demand response capability. The other model that FPL typically utilizes is its linear programming model with which FPL develops DSM portfolios.

The individual new resource options, both Supply options and DSM portfolios, emerging from these preliminary economic screening analyses are then typically "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's projected new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet and/or dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans in Regard to System Economics and Non-Economic Factors:

At the completion of fundamental steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for evaluating these resource options and resource plans in system economic analyses that aim to account for all of the impacts to the FPL system from the competing resource options/resource plans. In FPL's 2013 and early 2014 resource planning work, once the resource plans were developed, FPL utilized the P-MArea production cost model and a Fixed Cost Spreadsheet, and/or the Strategist model, to perform the system economic analyses. Other spreadsheet models may also be used to further analyze the resource plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM methodology). In analyses in which the DSM contribution has already been determined through the same IRP process and FPSC approval, and therefore the only competing options were new generating units and/or purchase options, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and resource plans in such cases can be evaluated on a system cumulative present value revenue requirement (CPVRR) basis.

Other factors are also included in FPL's evaluation of resource options and resource plans. While these factors may have an economic component or impact, they are often discussed in quantitative, but non-economic, terms such as percentages, tons, etc. rather than in terms of dollars. These factors are often referred to by FPL as "system concerns" that include (but are not limited to) maintaining/enhancing fuel diversity in the FPL system, system emission levels, and maintaining a regional balance between load and generating capacity, particularly in the Southeastern Florida counties of Miami-Dade and Broward. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL's system, the non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan. These, and other, factors are discussed later in this chapter in section III.C.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps are typically used to develop FPL's current resource plan. The current resource plan is presented in the following section.

III.B Projected Incremental Resource Additions/Changes in the Resource Plan

FPL's projected incremental generation capacity additions/changes for 2014 through 2023 are depicted in Table III.B.1. These capacity additions/changes include the 5 generation additions/changes previously discussed. The table shows three more generation changes: a CC unit being added in 2019, a short-term PPA of 129 MW being added in 2020, and a short-term PPA of 168 MW being added in 2021. The CC unit is added in 2019 to meet the Summer total reserve margin criterion and the two PPAs are added in 2020 and 2021 to meet the GRM criterion.

Although FPL's projected DSM additions that are developed in the IRP process are not explicitly presented in this table, these DSM additions have been fully accounted for in all of FPL's resource planning work reflected in this document. The projected MW reductions from these DSM additions are also reflected in the projected total reserve margin values shown in the table below and in Schedules 7.1 and 7.2 presented later in this chapter. DSM is further addressed later in this chapter in section III.D.

III.C Discussion of the Projected Resource Plan and Issues Impacting FPL's Resource Planning Work

As indicated in the Executive Summary, FPL's resource planning efforts in 2013 and early 2014 were influenced by a number of factors. These factors are expected to continue to influence FPL's resource planning work for the foreseeable future. In addition, other factors may also influence FPL's on-going resource planning work in the future and may result in changes to the resource plan discussed in this document. Eight (8) of these factors are discussed below (in no particular order of importance).

1) Maintaining/enhancing fuel diversity in the FPL system;
2) Maintaining a balance between load and generating capacity in Southeastern Florida, particularly in Miami-Dade and Broward Counties;
3) Updated projections of Federal and state energy efficiency codes and standards;
4) Decline in the projected cost-effectiveness of utility DSM measures and programs;
5) FPL's growing dependence upon DSM resources to maintain system reliability;
6) The schedule for the new Turkey Point Nuclear Units 6 & 7;
7) Environmental regulation and/or legislation; and,
8) Possible establishment of a Florida standard for renewable energy or clean energy.

These 8 factors, and their various impacts on FPL's resource planning efforts including the current resource plan that is presented in this Site Plan, are briefly discussed below.

1. Maintaining/Enhancing System Fuel Diversity:

FPL currently uses natural gas to generate approximately 2/3 of the total electricity it delivers to its customers. In the future, the percentage of FPL's electricity that is generated by natural gas is projected to remain at a high level. For this reason, and due to evolving environmental regulations, FPL is continually seeking opportunities to economically maintain and enhance the fuel diversity of its system.

In 2007, following express direction by the FPSC to do so, FPL sought approval from the FPSC to add two new advanced technology coal units to its system. These two new units would have been placed in-service in 2013 and 2014. However, in part due to concerns over potential greenhouse gas emission legislation/regulation, FPL was unable to obtain approval for these units. Several other factors are currently unfavorable to new coal units compared to new CC units. The first of these factors is a significant reduction in the fuel cost difference between coal and natural gas compared to the fuel cost difference projected in 2007 that favored coal; i.e., the projected fuel cost advantage of coal versus natural gas has been significantly reduced. Second is the continuation of significantly higher capital costs for coal units compared to capital costs for CC units. Third is the increased fuel efficiency of new CC units compared to projected CC unit efficiencies in 2007. Fourth are existing and proposed environmental regulations, including those that address greenhouse gas emissions, that are unfavorable to new coal units when compared to new CC units. Consequently, FPL does not believe that new advanced technology coal units are currently economically, politically, or environmentally viable fuel diversity enhancement options in Florida.

Therefore, FPL has turned its attention to nuclear energy and renewable energy to enhance its fuel diversity, to diversifying the sources of natural gas, to diversifying the gas transportation paths used to deliver natural gas to FPL's generating units, and to using natural gas more efficiently. In regard to nuclear energy, in 2008 the FPSC approved the need to increase capacity at FPL's four existing nuclear units and authorized FPL to recover project-related expenditures that are approved as a result of annual nuclear cost recovery filings. FPL has now successfully completed the nuclear capacity uprate project. Approximately 520 MW of additional nuclear capacity were delivered by the project which represents an increase of approximately 30% more capacity than was originally forecasted when the project began. FPL's customers are already benefitting from lower fuel costs and reduced system emissions provided by this additional nuclear capacity.

FPL is continuing its work to obtain all of the licenses, permits, and approvals that would be necessary to construct and operate two new nuclear units at its Turkey Point site in the future. These licenses, permits, and approvals will provide FPL with the opportunity to construct these nuclear units at Turkey Point for a time expected to be up to 20 years from the time the licenses and permits are granted, and then to operate the units for at least 40 years thereafter. The earliest deployment dates for the two new nuclear units, Turkey Point Units 6 & 7, remain 2022 and 2023, respectively.

FPL also has been involved in activities to investigate adding or maintaining renewable resources as a part of its generation supply. One of these activities is a variety of discussions with the owners of existing facilities aimed at maintaining or extending current agreements. In addition, FPL considers new cost-effective renewable energy projects such as the power purchase agreements with EcoGen that will result in FPL receiving 180 MW of firm capacity from biomass facilities beginning in 2021.

FPL also sought and received approval from the FPSC in 2008 to add 110 MW through three new FPL-owned solar facilities: one solar thermal facility and two photovoltaic (PV) facilities.

One 25 MW PV facility began commercial operation in 2009. The remaining two solar facilities, a 10 MW PV facility and a 75 MW solar thermal steam generating facility, began commercial operation in 2010. The addition of these renewable energy facilities was made possible due to enabling legislation from the Florida Legislature in 2008. FPL remains strongly supportive of federal and/or state legislation that enables electric utilities to add renewable energy resources and authorize the utilities to recover appropriate costs for these resources. FPL is planning to introduce two new PV-based solar programs in 2014. These are discussed further in section III.F.4 of this chapter.

In regard to using natural gas more efficiently, FPL received approvals in 2008 from the FPSC to modernize the existing Cape Canaveral and Riviera Beach plant sites with new, highly efficient CC units that replace the former steam generating units on each of those sites. The Cape Canaveral modernization was commissioned on April 24, 2013 and the Riviera Beach modernization is projected to go in-service on/near the April 1, 2014 date this 2014 Site Plan is filed with the FPSC. On April 9th, 2012, FPL received FPSC approval to proceed with a similar modernization project at the Port Everglades site which is scheduled for completion in mid-2016. The modernization of the Port Everglades site will retain the capability of receiving water-borne delivery of oil as a backup fuel.

In regard to diversity in natural gas sourcing and delivery, in 2013 FPL was granted approval from the FPSC to build a new 3rd natural gas pipeline into Florida and FPL's service territory. The process to obtain approval for the new pipeline from the Federal Energy Regulatory Commission (FERC) is underway. The new pipeline will utilize a new route that will result in a more reliable, more economic, and more diverse natural gas supply for FPL's customers and the state of Florida.

In the future, FPL will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity. In this regard, FPL is maintaining the ability to utilize fuel oil at existing units that have that capability. For this purpose, FPL has installed electrostatic precipitators (ESPs) at its two 800 MW steam generating units at the Manatee site and at one of its two 800 MW steam generating units at the Martin site. FPL is in the process of installing ESPs on its remaining 800 MW steam generating unit at the Martin site. These installations will enable FPL to retain the ability to burn oil, as needed, at these sites while retaining the flexibility to use natural gas when economically attractive.

2. Maintaining a Balance Between Load and Generation in Southeastern Florida:

An imbalance has existed between regionally installed generation and regional peak load in Southeastern Florida. As a result of that imbalance, a significant amount of energy required in the Southeastern Florida region during peak periods is provided by operating less efficient generating units located in Southeastern Florida out of economic dispatch, by importing the energy through the transmission system from plants located outside the region, or by a combination of the two. FPL's prior planning work concluded that, as load inside the region grows, either additional installed generating capacity in this region, or additional installed transmission capacity capable of delivering more electricity from outside the region, would be required to address this imbalance.

Partly because of the lower transmission-related costs resulting from their location, four recent capacity addition decisions (Turkey Point Unit 5 and WCEC Units 1, 2, & 3) were determined to be the most cost-effective options to meet FPL's capacity needs in the near-term. In addition, FPL has added increased capacity at FPL's existing two nuclear units at Turkey Point as part of the previously mentioned nuclear capacity uprates project. The Port Everglades modernization project scheduled for completion in 2016 will also assist in addressing this imbalance. Adding the additional generation capacity through the projects mentioned above contributes to addressing the imbalance between generation, transmission capacity, and load in Southeastern Florida for approximately the remainder of this decade.

The planned addition of two new nuclear units at FPL's Turkey Point site, Turkey Point Unit 6 in 2022 and Turkey Point Unit 7 in 2023, will also address the imbalance issue for an additional period of time beginning in the next decade. Due to forecasted steadily increasing load in the Southeastern region, the Southeastern Florida imbalance issue will remain an important consideration in FPL's on-going resource planning work in future years.

3. Projections of Federal and State Energy Efficiency Codes and Standards:

As discussed in Chapter II, FPL's load forecast includes projected impacts from federal and state energy efficiency codes and standards. The magnitude of energy efficiency that is now projected to be delivered to FPL's customers through these codes and standards is significant.

In FPL's 2013 Site Plan, the projected cumulative Summer peak impact for the year 2022 from the codes and standards since 2005 was 2,898 MW compared to what the projected load would have been without the codes and standards. The current projection of cumulative Summer peak impact for the year 2023 from the codes and standards since 2005 is 3,477 MW.

In addition to lowering FPL's load forecast from what it otherwise would have been, and thus serving to lower FPL's projected resource needs, this projection of efficiency from the codes and standards also affects FPL's resource planning in another way. The projected impacts from the efficiency codes and standards lower the potential for utility DSM programs to deliver energy efficiency for the appliances and equipment that are directly addressed by the codes and standards. This effect is taken into account in FPL's proposed DSM Goals for the 2015 – 2024 time period and it is one reason why FPL's resource plan shows a diminished role for utility DSM for the years addressed by this 2014 Site Plan.

4. Decline in the Projected Cost-Effectiveness of Utility DSM Measures and Programs: There is another important reason why FPL's resource plan currently shows a diminished role for utility DSM: a decline in the projected cost-effectiveness of utility DSM measures and programs. The supporting testimony that FPL is filing in the DSM Goals proceeding discusses in detail the reasons for the declining cost-effectiveness of DSM. One portion of that discussion is summarized here for illustrative purposes.

The cost-effectiveness of DSM is driven in large part by the potential benefits that the kw (demand) reduction and kwh (energy) reduction characteristics of DSM programs are projected to provide. This discussion focuses solely on the current projection of potential benefits that DSM's kwh reductions can provide. At least three factors are each resulting in projections of lower kwh reduction-based benefits and thus projections of lower DSM cost-effectiveness.

The first factor is lower fuel costs. For example, comparing current fuel cost forecasts with those forecasted in 2009 – the year when FPL's DSM Goals were last set by the FPSC – shows that current forecasted fuel costs are now much lower than those forecasted in 2009, particularly in the near-term. This can be seen by comparing the 2009 and current forecasted costs ($/mmBTU) for natural gas for two specific years addressed in this Site Plan and which were addressed in the 2009 DSM goals-setting: 2015 and 2019:

Year	2009 Forecast	Current Forecast
2015	$9.64	$4.26
2019	$12.63	$6.15

As shown from these values, natural gas prices are currently forecast to be less than 50% of what they were forecast to be in 2009 when DSM goals were last set. Although lower forecasted natural gas costs are a very good thing for FPL's customers, lower fuel costs also result in lower potential fuel savings benefits from the kWh reductions of DSM measures. These lowered benefit values result in DSM being less cost-effective.

A second factor contributing to the decline in the cost-effectiveness of utility DSM is the steadily increasing efficiency with which FPL generates electricity. FPL's generating system has steadily gotten more efficient in regard to its ability to generate electricity using less fossil fuel. For example, FPL used 20% less fossil fuel to generate the same number of kwh in 2012 than it did in 2001. This is a very good thing for FPL's customers because it helps to significantly lower fuel costs.

The improvements in generating system efficiency affect DSM cost-effectiveness in much the same way that lower forecasted fuel costs do: both lower the fuel costs of energy delivered to FPL's customers. Therefore, the improvements in generating system efficiency further reduce the potential fuel savings benefits from the kWh reduction impacts of DSM, thus lowering potential DSM benefits and DSM cost-effectiveness.

A third factor for declining cost-effectiveness of utility DSM is due to significant changes in projected carbon dioxide (CO_2) compliance costs. For example, comparing CO_2 compliance forecasts with those forecasted in 2009 – the year when FPL's DSM Goals were last set by the FPSC – shows that current forecasted compliance costs are much lower than those forecasted in 2009, particularly in the near-term. This can be seen by comparing the 2009 and current forecasted costs ($/ton) for two specific years addressed in this Site Plan and which were addressed in the 2009 DSM goals-setting: 2015 and 2019:

Year	2009 Forecast	Current Forecast
2015	$17.00	$0.00
2019	$25.00	$0.00

(FPL's current forecast does not project non-zero CO_2 compliance costs until the year 2023.) While lower forecasted CO_2 compliance costs are again a good thing for FPL's customers, lower compliance costs also result in lower compliance cost savings benefits from the kWh reductions of DSM measures. These lower potential DSM benefits again result in lowering DSM cost-effectiveness.

Each of these three factors discussed above – lower forecasted fuel costs, greater efficiency in FPL's electricity generation, and lower forecasted CO_2 compliance costs – are good for FPL's customers because they will result in lower electric rates. Although good for FPL's customers, these factors also contribute to lowering the cost-effectiveness of utility DSM programs. Therefore, these factors (and other factors not discussed above), plus the growing impacts of energy efficiency codes and standards, lead to FPL's resource plan showing a diminished role for utility DSM.

5. **FPL's Increasing Dependence On DSM Resources to Maintain System Reliability:**

   As discussed earlier in section III.A of this chapter, FPL's 2011, 2012, and 2013 Site Plans each projected that FPL's system was becoming increasingly dependent upon DSM resources to maintain system reliability. FPL's analyses of this projected trend showed that, from an operational perspective, there can be significant differences between resources plans on the peak day even though the resource plans have identical total reserve margins. For this reason, FPL has begun using a 10% minimum generation-only reserve margin (GRM) in its resource planning work to complement its existing 20% total reserve margin and 0.1 day/year LOLP reliability criteria. FPL will begin applying the GRM criterion in the year 2019.

6. **The Schedule for the New Turkey Point Nuclear Units 6 & 7:**

   At the time the 2014 Site Plan is being finalized, the schedule for the project is under review. Several items will be considered that potentially influence the project schedule, including the Nuclear Regulatory Commission's (NRC's) schedule for reviewing the Combined Operating License Application (COLA), the impacts of the recently amended nuclear cost recovery clause (NCRC) statute, and the ongoing feasibility analyses that are part of the NCRC process.

7. **Environmental Regulation and/or Legislation:**

   The seventh factor is environmental regulation. As developments occur in regard to either new environmental regulations, and/or in how environmental regulations are interpreted and applied, the potential exists for such developments to affect FPL's resource plan that is presented in this document. For example, FPL is aware of potential impacts to generating units of recent EPA changes to the National Ambient Air Quality Standards that include shorter duration 1-hour standards for nitrogen dioxide (NO_2) and sulfur dioxide (SO_2). As a consequence, FPL filed in mid-2013 for FPSC approval to recover costs through the environmental cost recovery clause for removing all of its existing gas turbines (GTs) and partially replacing that peaking unit capacity with new combustion turbines (CTs). Although FPL withdrew its filing in December 2014 pending further analyses including on-site monitoring, FPL believes that the results of the monitoring and analyses will require that the Broward GTs be replaced. Therefore, FPL is currently projecting the retirement of all GTs in Broward County; i.e., at its existing Lauderdale and Port Everglades plant sites (a decrease in generating capacity of 1,260 MW Summer), and the installation of 5 new 201 MW CTs at its existing Lauderdale plant site (an increase of 1,005 MW Summer), both by the end of 2018.

8. **Possible establishment of a Florida standard for renewable energy or clean energy:** Although no such legislation has been enacted to-date, Renewable Portfolio Standards (RPS) or Clean Energy Portfolio Standard (CPS) legislation, or other legislative initiatives regarding renewable or clean energy contributions, may occur in the future at either the state or national level. If such legislation is enacted, FPL would then determine what steps need to be taken to address the legislation.

Each of these 8 factors will continue to be examined in FPL's on-going resource planning work during the rest of 2014 and in future years.

III.D Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978 and DSM has been a key focus of FPL's IRP process for decades. During that time FPL's DSM programs have included numerous energy efficiency and load management initiatives. FPL's DSM efforts through 2013 have resulted in a cumulative Summer peak reduction of approximately 4,753 MW (Summer) at the generator and an estimated cumulative energy saving of approximately 66,782 Gigawatt Hour (GWh) at the generator. After accounting for the 20% total reserve margin requirement, FPL's DSM efforts through 2013 have eliminated the need to construct the equivalent of approximately 14 new 400 MW power plants.

FPL has consistently been among the leading utilities nationally in DSM achievement. For example, according to the U.S. Department of Energy's 2012 data (the last year for which the DOE data was available at the time this Site Plan is being developed), FPL ranked # 2 nationally in cumulative DSM demand reduction. And, importantly, FPL has achieved these significant DSM accomplishments while minimizing the DSM-based impact on electric rates for all of its customers.

In 2014, new DSM Goals for the years 2015 through 2024 will be set for FPL by the FPSC. As part of this goals-setting process, FPL must propose new DSM Goals for this time period based on its most recent resource planning analyses. The results of those analyses are reflected in this 2014 Site Plan and FPL is filing its proposed new DSM Goals on April 2, 2014 (i.e., one day after the 2014 Site Plan is filed). As discussed in the previous section of this chapter, two factors have influenced the analyses that led to the amount of DSM that FPL is proposing as its new DSM Goals: (i) increased energy efficiency that will be delivered to FPL's customers through Federal and state energy efficiency codes and standards; and (ii) a decline in the projected cost-effectiveness of DSM measures.

Based on these factors and FPL's most recent resource planning analyses, FPL is proposing that its DSM Goals be set at 337 MW of Summer MW reduction. After accounting for the 20% total reserve margin requirements, this represents the elimination of the need to construct the equivalent of another 400 MW power plant. The resource plan presented in this 2014 Site Plan accounts for the proposed amount of annual DSM implementation through the year 2023 and the DSM contribution is shown in Schedules 7.1 and 7.2 that appear later in this chapter. The FPSC is expected to make its decision regarding what FPL's DSM Goals will be for 2015 through 2024 later this year.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy to FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV bulk transmission lines that must be certified under the Transmission Line Siting Act.

Table III.E.1: List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	St. Johns 1/	Pringle	25	Dec – 18	230	759
FPL	Manatee 2/	Bob White	30	Dec – 14	230	1195

1/ Final order certifying the corridor was issued on April 21, 2006. This project is to be completed in two phases. Phase I consisted of 4 miles of new 230 kV line (Pringle to Pellicer) and was completed in May-2009. Phase II consists of 21 miles of new 230 kV line (St. Johns to Pellicer) and is scheduled to be completed by Dec-2018.

2/ Final order certifying the corridor was issued on November 6, 2008. This project consists of 30 miles of new 230 kV line (Manatee to Bob White) and is scheduled to be completed by Dec-2014

In addition, there will be transmission facilities needed to connect several of FPL's projected generating capacity additions to the system transmission grid. These transmission facilities (described on the following pages) are for the Port Everglades modernization, the planned Lauderdale gas turbine replacements, and the planned new nuclear capacity addition at the Turkey Point site from Turkey Point Units 6 & 7.[5] Please see discussion in the Turkey Point Preferred Site section, subsection r, of the possibility of a transmission corridor/land swap between FPL and the National Park Service. At the time the 2014 Site Plan is being prepared, no

[5] Please see discussion in the Turkey Point Preferred Site section, subsection r of the possibility of a transmission corridor/land sway between FPL and National Park Service.

site has been selected for the planned addition of a CC unit in 2019. Therefore, no transmission information for this new unit is presented.

II.E.1 Transmission Facilities for Port Everglades Next Generation Clean Energy Center (Modernization)

The work required to connect the Port Everglades Next Generation Clean Energy Center in 2016 to the FPL grid is projected to be:

I. Substation:

1. Construct two string busses to connect two combustion turbines (CT) to the Port Everglades 138 kV Substation.
2. Construct two string busses to connect one CT, and one steam turbine (ST) to the Port Everglades 230 kV Substation.
3. Add four main step-up transformers (3-450 MVA, 1- 580 MVA), one for each CT, and one for the ST.
4. Replace ten (10) 138 kV breakers.
5. Replace eight (8) 230 kV breakers.
6. At Port Everglades Switchyard replace twenty-two 138 kV disconnect switches. Also upgrade associated jumpers, bus work, and equipment connections.
7. Expand switchyard relay vault and add relays and other protective equipment.

II. Transmission:

1. Upgrade of existing transmission facilities:
   - An ampacity upgrade up to 1905 amps on the Port Everglades-Port Everglades Tap 138kV line section.
   - An ampacity upgrade up to 1905 amps on the Port Everglades Tap-Port Everglades Tap 2 138 kV line section.
   - An ampacity upgrade up to 1695 amps on the Port Everglades Tap 1-Dania 138 kV line section.
   - An ampacity upgrade up to 1695 amps on the Dania-Hollywood 138 kV line section.

III.E.2 Transmission Facilities for the Lauderdale GT Replacement Project

The work required to connect the five Lauderdale combustion turbines (CT) in 2018 to the FPL grid is projected to be:

I. Substation:

1. Construct a collector switchyard for the five (5) CTs at Lauderdale Plant.
2. Install five (5) main step-up transformers (5 - 320 MVA), one for each CT.
3. Construct one 230 kV collector buss to connect two (2) CT step-up transformers to collector switchyard.
4. Construct one 138 kV collector buss to connect two (2) CT step-up transformers to collector switchyard.
5. Construct Cable Termination Structures (CTS) in the collector switchyard and the Lauderdale 138 kV Substation to connect the 138 kV collector buss for the two CTs to the Lauderdale 138 kV Substation Outside Bus.
6. Construct CTS in the collector switchyard and the Lauderdale 138 kV Substation to connect the fifth CT to the Lauderdale 138 kV Substation Inside Bus.
7. Add relays and other protective equipment.

II. Transmission:

1. Construct overhead 230 kV string bus to connect the 230 kV collector buss to the Lauderdale 230 kV Substation Inside Bus.
2. Construct two (2) underground 138 kV cables connecting the collector switchyard to the Lauderdale Substation Inside and Outside Busses.

III.E.3 Transmission Facilities for Turkey Point Nuclear Unit 6

The work required to connect the Turkey Point Nuclear Unit 6 by Summer 2022 to the FPL grid is projected to be:

I. Substation:

1. Build new Clear Sky 500/230kV Switchyard with six (6) bays on the 230 kV section for generator main step-up transformer connection, reserve auxiliary transformer connections, four (4) 230 kV line terminals, two (2) autotransformers and two (2) 500 kV line terminals.
2. At Turkey Point Switchyard add a new bay to accommodate the Turkey Point-Clear Sky 230 kV line terminal.
3. At Pennsuco Substation install a fourth line terminal to accommodate the Pennsuco-Clear Sky 230 kV line by converting the ring bus to a breaker and a half scheme and adding four (4) 230 kV breakers.
4. At Davis Substation construct two (2) new 230kV line terminals for the Clear Sky-Davis 230 kV line and the Davis-Miami 230 kV line.
5. At Levee Substation expand 500 kV section to accommodate the two (2) Levee-Clear Sky 500 kV lines.
6. At Andytown Substation install two (2) 5-Ohm inductors combined with external shunt capacitors on the 230kV side of the 500/230 autotransformers (one per auto).
7. At Miami Substation expand the 230kV section to a double bus configuration and add a new 230kV line terminal for Davis line and replace one (1) autotransformer.
8. Breaker replacements:
   Flagami Substation – Replace five (5) 230 kV breakers and three (3) 138 kV breakers
   Miami Substation – Replace one (1) 230 kV breaker and four (4) 138 kV breakers
   Davis Substation - Replace two (2) 230 kV breakers

II. Transmission:

1. FPL will design and construct two (2) 500kV transmission lines from the new Clear Sky Substation to the existing FPL Levee 500kV Substation switchyard. The lines will be approximately 43 miles long.
2. Construct a new Clear Sky-Davis 230kV line (approximately 19 miles) with a rating of 2990 Amperes.
3. Construct a new Clear Sky-Pennsuco 230kV line (approximately 52 miles) with a rating of 2990 Amperes.
4. Construct a new Davis-Miami 230kV line (approximately 18 miles) with a rating of 2297 Amperes.
5. Construct a new Clear Sky-Turkey Point 230kV line (approximately 0.5 miles) with a rating of 2990 Amperes.

III.E.4 Transmission Facilities for Turkey Point Nuclear Unit 7

The work required to connect the Turkey Point Nuclear Unit 7 by Summer 2023 to the FPL grid is projected to be:

I. Substation:

1. At Gratigny Substation install a second 230/138 kV autotransformer with one (1) 230 kV breaker and one (1) 138 kV breaker.
2. At Davis Substation construct a switch-able inductor to be installed on the Davis-Miami 230 kV line.
3. At Flagami Substation install a small inductor on one end of the Flagami-Miami 230kV #2 circuit.
4. Breaker replacements:
   Dade Substation - Replace seven (7) 230 kV breakers
   Court Substation – Replace one (1) 138 kV breaker.

II. Transmission:

1. The transmission line facilities required for Turkey Point Unit 7 will be constructed with the transmission line facilities needed for Turkey Point Unit 6, as described above in section III. E.3.

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to effectively utilize renewable energy technologies to serve its customers. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. For purposes of discussing FPL's renewable energy efforts in this document, those efforts will be placed into five categories.

Two of these categories are Supply-Side Efforts – Power Purchases, and Supply-Side Efforts – FPL Facilities. Since 2011, the energy (MWh) total output from these renewable energy sources has been greater than the energy produced from oil-fired generation. The renewable energy information is presented in Schedule 11.1, and the oil-based energy information is presented in Schedule 6.1 and in Schedule 11.1. Both of these schedules are presented at the end of this chapter.

1) <u>Early Research & Development Efforts:</u>

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970s in demonstrating the first residential photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10-kilowatt (kW) system was placed into operation in 1984. (The system was removed in 1990 at the conclusion of the PV testing to make room for substation expansion.)

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant Site. This FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site became the home for PV capacity which was installed as a result of other FPL renewable energy initiatives.

2) <u>Demand Side & Customer Efforts:</u>

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers who chose solar water heaters. Before the program ended (due to the fact that it was no longer projected to be cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for six passive home designs with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building Code (Code). This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code was one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the FPSC to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test were deemed to be solvable, particularly when new pools are constructed. However, challenges included the significant percentage of sites with unacceptable shading and various customer satisfaction issues.

FPL has since continued to analyze and promote the utilization of PV. These efforts have included PV research, development, and education, as well as development and implementation of the FPL Next Generation Solar Station Program. This initiative also delivers teacher training and curriculum that is tied to the Sunshine Teacher Standards in Florida. The program provides teacher grants to promote and fund projects in the classrooms.

In addition, FPL assists customers who are interested in installing PV equipment at their facilities. Consistent with Florida Administrative Code Rule 25-6.065, Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned PV systems. Through December 2013, approximately 2,565 customer systems (predominantly residential) have been interconnected.

As part of its 2009 DSM Goals decision, the FPSC imposed a requirement for Florida's investor-owned utilities to spend up to a set, not-to-exceed amount of money annually to facilitate demand side solar water heater and PV applications. FPL's not-to-exceed amount of money for these applications is approximately $15.5 million per year through 2014. In regard to this direction, FPL received approval from the FPSC in 2011 to initiate a solar pilot portfolio that consists of three PV-based programs and three solar water heating-based programs, plus Conservation Research and Development. These programs are currently projected to be offered through 2014. FPL's analyses of the results to-date from these programs shows that none of these programs are projected to be cost-effective using any of the three cost-effectiveness screening tests used by the State of Florida. The fate of these solar programs, including their potential replacement with new solar initiatives, will be determined later in 2014 as part of the FPSC's 2014 DSM Goals docket.

FPL has also been investigating fuel cell technologies through monitoring of industry trends, discussions with manufacturers, and direct field trials. From 2002 through the end of 2005, FPL conducted field trials and demonstration projects of Proton Exchange Membrane (PEM) fuel cells with the objectives of serving customer end-uses while evaluating the technical performance, reliability, economics, and relative readiness of the PEM technology. The demonstration projects were conducted in partnership with customers and included five locations. The research projects were useful to FPL in identifying specific issues that can occur in field applications and the current commercial viability of this technology. FPL will continue to monitor the progress of these technologies and conduct additional field evaluations as significant developments in fuel cell technologies occur.

3) <u>Supply Side Efforts – Power Purchases:</u>

FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy, and as-available energy, have been purchased by FPL from these types of facilities. (Please refer to Tables I.B.1, I.B.2, and I.C.1 in Chapter I).

FPL issued Renewable Requests for Proposals (RFPs) in 2007 and 2008 soliciting proposals to provide firm capacity and energy, and energy only, at or below avoided costs, from renewable generators. FPL also promptly responds to inquiries for information from prospective renewable energy suppliers either by e-mail or phone.

On April 22, 2013 in Order No. PSC-13-1064-PAA-EQ, the FPSC approved three 60 MW power purchase agreements with affiliates of U.S. EcoGen for biomass-fired renewable energy facilities. These facilities are expected to begin service in 2019, and to begin providing firm renewable energy and capacity to FPL's customers in 2021.

With regard to existing contracts that have recently ended, FPL and the Solid Waste Authority of Palm Beach (SWA) agreed to extend their contract that expired March 31, 2010 for a 20-

year term beginning in April 1, 2012 through April 1, 2032. However, the SWA refurbished their generating unit ahead of schedule and, as of January 2012, this unit began delivering firm capacity to FPL. In 2011, the FPSC approved a contract for an additional 70 MW between FPL and SWA for a new unit to be constructed and to begin delivering firm capacity and energy beginning on January 1, 2015. At the end of December 2011, the contract between FPL and Okeelanta (New Hope) expired. However, Okeelanta continues to deliver energy to FPL as an as-available, non-firm supplier of renewable energy.

4) <u>Supply Side Efforts – FPL Facilities:</u>

With regard to solar generating facilities, FPL has three such facilities: (i) a 75 MW steam generation solar thermal facility in Martin County (the Martin Next Generation Solar Energy Center); (ii) a 25 MW PV electric generation facility in DeSoto County (the DeSoto Next Generation Solar Energy Center); and (iii) a 10 MW PV electric generation facility in Brevard County at NASA's Kennedy Space Center (the Space Coast Next Generation Solar Energy Center). The DeSoto County project was completed in 2009 and the other two projects were completed in 2010. These three solar facilities were constructed in response to the Florida Legislature's House Bill 7135 which was signed into law by the Governor in June 2008.

House Bill 7135 was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in the State of Florida. Specifically, the bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land, zoning, and transmission rights in place. FPL's three solar projects met the specified criteria, and were granted approval for cost recovery in 2008. Each of the three solar facilities is discussed below.

a. <u>The Martin Next Generation Solar Energy Center:</u>

This facility began commercial operation in 2010 and provides 75 MW of solar thermal capacity in an innovative way that directly displaces fossil fuel usage on the FPL system. This facility consists of solar thermal technology which generates steam that is integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired CC plant. This project is the first "hybrid" solar plant in the world, and, at the time the facility came in-service, was the second largest solar facility in the world and the largest solar plant of any kind in the U.S. outside of California.

b. <u>The DeSoto Next Generation Solar Energy Center:</u>

This PV facility began commercial operation in 2009 and provides 25 MW of non-firm capacity and energy, making it one of the largest PV facilities in the U.S. The facility utilizes a tracking PV array that is designed to follow the sun as it traverses across the sky.

c. <u>The Space Coast Next Generation Solar Energy Center:</u>

Located at the Kennedy Space Center, this facility is part of an innovative public/private partnership with NASA. This non-tracking PV facility began commercial operation in 2010 and provides 10 MW of non-firm capacity and energy.

At the time the 2014 Site Plan is being prepared, FPL considers the output from these renewable facilities to be "as available," non-firm energy only. This is due to several factors. First, the Martin solar thermal facility is a "fuel-substitute" facility, not a facility that provides additional capacity and energy. The solar thermal facility displaces the use of fossil fuel to produce steam on the FPL system when the solar thermal facility is operating. Second, in regard to the two PV facilities, the intermittent nature of the solar resource has made it difficult to-date to accurately determine what contribution the PV facilities at these specific locations can consistently make at FPL's late Summer afternoon and early Winter morning peak load hours. This is, in part, due to the fact that at least several years worth of Summer and Winter peak load periods are needed to accurately gauge the actual output of these PV facilities during system peak hours. FPL is now evaluating what portion, if any, of the PV facilities' output can be projected as firm capacity at the projected peak hours in FPL's resource planning work.

In addition to these three solar facilities, FPL is currently in the process of identifying other potential sites in the state for central station PV facilities. FPL is evaluating existing FPL generation sites along with potential Greenfield sites within FPL's service territory. These sites are discussed further in Chapter IV.

In regard to PV distributed generation (DG), FPL is planning to implement two PV DG solar programs in 2014. The first program is a voluntary customer participation program that will be pursued on a pilot basis. FPL will file for FPSC approval of this program near the April filing date of the 2014 Site Plan. The second program is designed to research the effects of increasing PV DG on the FPL system. This program will be introduced later in 2014. A brief description of the two programs follows.

d. <u>Voluntary, Community-based Solar Partnership Pilot Program</u>

FPL will be filing for FPSC approval of a tariff that provides customers an opportunity to make voluntary contributions toward the construction of PV facilities on a local level throughout FPL's service territory. The pilot program will provide all customers the opportunity to support the use of solar energy at a community scale, and is designed to be especially attractive for customers who do not wish, or are not able, to place solar equipment on their roof.

d. C&I Solar Partnership Program:

This is also a PV-focused research program that will be conducted in partnership with interested commercial and industrial (C&I) customers. Limited investments will be made in rooftop PV facilities in selected geographic areas in order to examine the effect of PV DG on FPL's distribution system. FPL will attempt to site these PV facilities in areas where PV DG already exists to better study feeder loading impacts. The PV facilities will be located on C&I customer property near the targeted feeders. The objective of the program is to gather data that will result in a better understanding of the effects of high PV DG penetrations on FPL's system.

5) Ongoing Research & Development Efforts:

FPL has developed alliances with several Florida universities to promote development of emerging technologies. For example, FPL has an alliance has been established with the newly formed Southeast National Marine Renewable Energy Center (SNMREC) at Florida Atlantic University (FAU), which will focus on the commercialization of ocean current, ocean thermal (i.e., energy conversion as well as cold water air conditioning), and hydrogen technologies. FPL has been supporting FAU with the discussions being held with the U.S. Department of the Interior's Minerals Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE). BOEMRE is working to establish the permitting process for ocean energy development on the outer continental shelf.

FPL has also developed a "Living Lab" to demonstrate FPL's solar energy commitment to employees and visitors at its Juno Beach office facility. To-date, FPL has installed five different PV arrays (different technologies) of rooftop PV totaling 24 kW at the Living Lab. In addition, two PV-covered parking structures with a total of approximately 90 kW of PV are in use at the FPL Juno office parking lot. Through these Living Lab projects, FPL is able to evaluate multiple solar technologies and applications for the purpose of developing a renewable business model resulting in the most cost-effective and reliable uses of solar energy for FPL's customers. FPL plans to continue to expand the Living Lab as new solar products come to market.

FPL has also been in discussions with several private companies on multiple emerging technology initiatives including ocean current, ocean thermal, hydrogen, fuel cell technology, biomass, biofuels, and energy storage

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980s, FPL relied primarily on a combination of fuel oil, natural gas, and nuclear energy to generate electricity with significant reliance on oil–fired generation. In the early 1980s, FPL began to purchase "coal-by-wire." In 1987, coal was first added to the fuel mix through FPL's partial ownership (20%) and additional purchases (30%) from the St. Johns River Power Park (SJRPP). This allowed FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources were added with the partial acquisition (76%) of Scherer Unit 4 which began serving FPL's customers in 1991.

The trend since the early 1990s has been a steady increase in the amount of natural gas that is used by FPL to provide electricity due, in part, to the introduction of highly efficient and cost-effective CC generating units and the ready availability of natural gas. Most recently, FPL placed into commercial operation two new gas-fired CC units at the West County Energy Center (WCEC) site in 2009. A third new CC unit was added to the WCEC site in 2011. In addition, FPL finished modernization of its Cape Canaveral and Riviera Beach plant sites and is currently modernizing its existing Port Everglades plant site by removing the steam generating units previously on the site and replacing them with one highly efficient new CC unit. The new CC units at each of these three sites will provide highly efficient generation that will dramatically improve the efficiency of FPL's generation system in general and, more specifically, the efficiency at which natural gas is utilized.

In addition, FPL increased its utilization of nuclear energy through capacity uprates of its four existing nuclear units. With these uprates, more than 520 MW of additional nuclear capacity have been added to the FPL system. FPL is also pursuing plans to obtain licenses, permits, and approvals to construct and operate two new nuclear units at its existing Turkey Point site that, in total, would add approximately 2,200 MW of new nuclear generating capacity. The earliest dates by which these two new nuclear units could practically be deployed remain 2022 and 2023, respectively.

In regard to utilizing renewable energy, FPL has a 110 MW of solar generating capacity through a 75 MW solar thermal steam generating facility at FPL's existing Martin site, a 25 MW PV facility in DeSoto County, and a 10 MW PV facility in Brevard County. The DeSoto facility was placed into commercial operation in 2009. The other two solar facilities were placed into commercial operation in 2010.

FPL's future resource planning work will continue to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance FPL's long-term fuel diversity. These fuel diverse alternatives may include: the purchase of power from renewable energy facilities, additional FPL-owned renewable energy facilities, obtaining additional access to diversified sources of natural gas such as liquefied natural gas (LNG) and natural gas from the Mid-Continent unconventional reserves, preserving FPL's ability to utilize fuel oil at its existing units, and increased utilization of nuclear energy. (As previously discussed, new advanced technology coal generating units are not currently considered as viable options in Florida in the ten-year reporting period of this document due, in part, to current projections of relatively small differences in fuel costs between coal and natural gas, significantly higher capital costs for coal units compared to CC units, greater efficiencies of CC units, and concerns over environmental regulations that would impact coal units more negatively than CC units.) The evaluation of the feasibility and cost-effectiveness of these, and other possible fuel diversity alternatives, will be part of FPL's on-going resource planning efforts.

FPL's current use of various fuels to supply energy to customers, plus a projection of this "fuel mix" through 2023 based on the resource plan presented in this document, is presented in Schedules 5, 6.1, and 6.2 later in this chapter.

FPL's Fossil Fuel Cost Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used in evaluating alternatives for meeting future resource needs. FPL's forecasts are generally consistent with other published contemporary forecasts. An October 2013 fuel cost forecast was used in the analyses whose results led to the resource plan presented in this 2014 Site Plan.

Future oil and natural gas prices, and to a lesser extent, coal and petroleum coke prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, coal, and petroleum coke. These drivers include U.S. and worldwide demand, production capacity, economic growth, environmental legislation, and politics.

The inherent uncertainty and unpredictability in these factors today and tomorrow clearly underscores the need to develop a set of plausible oil, natural gas, and solid fuel (coal and petroleum coke) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, FPL developed and utilized Low, Medium, and High price forecasts for fossil fuels in some of its 2013 and early 2014 resource planning work, particularly in regard to analyses conducted as part of the nuclear cost recovery filing work.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

a. For 2014 through 2015, the methodology used the October 7, 2013 forward curve for New York Harbor 1% sulfur heavy oil, U. S. Gulf Coast 1% sulfur heavy oil, ultra low sulfur diesel fuel oil, and Henry Hub natural gas commodity prices;

b. For the next two years (2016 and 2017), FPL used a 50/50 blend of the October 7, 2013 forward curve and the most current projections at the time from The PIRA Energy Group;

c. For the 2018 through 2030 period, FPL used the annual projections from The PIRA Energy Group; and,

d. For the period beyond 2030, FPL used the real rate of escalation from the Energy Information Administration (EIA). In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal and petroleum coke prices. Coal and petroleum coke prices were based upon the following approach:

a. Delivered price forecasts for Central Appalachian (CAPP), Illinois Basin (IB), Powder River Basin (PRB), and South American coal and petroleum coke were provided by JD Energy; and,

b. The coal price forecast for SJRPP and Plant Scherer assume the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for oil, natural gas, coal, and petroleum coke prices were based on the historical volatility of the 12-month forward price, one year ahead. FPL developed these forecasts to account for the uncertainty which exists within each commodity as well as across commodities. These forecasts reflect a range of reasonable forecast outcomes.

3. Natural Gas Storage

FPL was under contract through March 2013 for 2 billion cubic feet (Bcf) of firm natural gas storage capacity in the Bay Gas storage facility located in Alabama. The Bay Gas storage facility is interconnected with the Florida Gas Transmission (FGT) pipeline. Starting on April 1, 2013, FPL entered into a new deal with Bay Gas Storage for one year for 2.5 billion cubic feet (Bcf) of firm natural gas storage capacity. In December 2013, FPL elected to extend this transaction for an additional three years which resulted in a lower annual cost for Bay Gas. FPL has predominately utilized natural gas storage to help mitigate gas supply problems caused by severe weather and/or infrastructure problems. Over the past several years, FPL has acquired upstream transportation capacity on several pipelines to help mitigate the risk of off-shore supply problems caused by severe weather in the Gulf of Mexico. While this transportation capacity has reduced FPL's off-shore exposure, a portion of FPL's supply portfolio remains tied to off-shore natural gas sources. Therefore, natural gas storage remains an important tool to help mitigate the risk of supply disruptions. For these reasons, FPL has typically maintained nearly full natural gas inventory during normal operations from June through November (hurricane season). From December through March, FPL typically maintains lower levels of natural gas inventory compared to Summer peak months.

As FPL's reliance on natural gas has increased, its ability to manage the daily "swings" that can occur on its system due to weather and unit availability changes has become more challenging, particularly from oversupply situations. Natural gas storage is a valuable tool to help manage the daily balancing of supply and demand. From a balancing perspective, injection and withdrawal rights associated with gas storage have become an increasingly important part of the evaluation of overall gas storage requirements.

As FPL's system grows to meet customer needs, it must maintain adequate gas storage capacity to continue to help mitigate supply and/or infrastructure problems and to provide FPL the ability to manage its supply and demand on a daily basis. FPL continues to evaluate its gas storage portfolio and is likely to subscribe for additional gas storage capacity to help increase reliability, provide the necessary flexibility to respond to demand changes, and diversify the overall portfolio.

4. Securing Additional Natural Gas:

The recent trend of increasing reliance upon natural gas to produce electricity for FPL's customers is projected to continue due to FPL's growing load. The addition of highly fuel-efficient CC units at Cape Canaveral and Riviera Beach due to completed modernization projects, and the on-going Port Everglades modernization project, will serve to reduce the growth in natural gas use from what it otherwise might have been due to the high fuel-efficiency levels of these new CC units. However, these efficiency gains do not fully offset the effects of FPL's growing load. Therefore, FPL will need to secure more natural gas supply and more firm gas transportation capacity in the future as fuel requirements dictate. The issue is how to secure these additional natural gas resources in a manner that is economical for FPL's customers and which maintains and/or enhances the reliability of natural gas supply and deliverability to FPL's generating units.

FPL has historically purchased the gas transportation capacity required for new natural gas supply from two existing natural gas pipeline companies. As more natural gas is delivered through these two pipelines, the impact of a supply disruption on either pipeline becomes more problematic. Therefore, FPL issued a Request for Proposals (RFP) in December 2012 for gas transportation capacity to meet FPL's system natural gas requirements beginning in 2017. The RFP encouraged bidders to propose new gas transportation infrastructure to meet Florida's growing need for natural gas. A third pipeline would have benefits for FPL and its customers by increasing the diversity of FPL's fuel supply sources, increasing the physical reliability of the pipeline delivery system, and enhancing competition among pipelines. The RFP process was completed in June 2013 and the winning bidders, Sabal Trail Transmission, LLC (Sabal Trail) and Florida Southeast Connection, LLC (FSC), have begun the Federal Energy Regulatory Commission approval process with a planned in-service date of May 2017. The contracts with Sabal Trail and FSC were reviewed by the FPSC and were approved for cost recovery in late 2013. The order approving this cost recovery became final in January 2014.

5. Nuclear Fuel Cost Forecast

This section reviews the various steps needed to fabricate nuclear fuel for delivery to the nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

a) Steps Required for Nuclear Fuel to be delivered to FPL's Plants

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

(1) Mining: Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U_3O_8 (sometimes referred to as yellowcake).

(2) Conversion: During the second step, the U_3O_8 is chemically converted into UF_6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

(3) Enrichment: The third step is called enrichment. Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to almost five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 2.2% to as high as 4.95%). The output of this enrichment process is enriched uranium in the form of UF6.

(4) Fabrication: During the last step, fuel fabrication, the enriched UF6 is changed to a UO2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion in a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) Mining: The impact of the earthquake and tsunami that struck the Fukushima nuclear complex in Japan in March 2011 is still being felt in the uranium market. Current demand has declined and several of the production facilities have announced delays. Factors of importance are:

- Hedge funds are still very active in the market. This causes more speculative demand that is not tied to market fundamentals and causes the market price to move up or down just based on news that might affect future demand.

- Some of the uranium inventory from the U.S. Department of Energy (DOE) is finding its way into the market periodically to fund cleanup of certain Department of Energy facilities.

- Although a limited number of new nuclear units are scheduled to start production in the U.S. during the next 5 to 10 years, other countries, more specifically China, have announced an increase in construction of new units which may cause uranium prices to trend up in the near future.

Over a 10-year horizon, FPL expects the market to be more consistent with market fundamentals. The supply picture is more stable, with laws enacted to resolve the import of Russian-enriched uranium, by allowing some imports of Russian-enriched uranium to meet about 20-25% of needs for currently operating units, but with no restriction on the first core for new units and no restrictions after 2020. New and current uranium production facilities continue to add capacity to meet demands. Actual demand tends to grow over time because of the long lead time to build nuclear units. However, FPL cannot discount the possibility of future periodic sharp increase in prices, but believes such occurrences will likely be temporary in nature.

(2) Conversion: The conversion market is also in a state of flux due to the Fukushima events. Planned production after 2016 is currently forecasted to be insufficient to meet the higher demand scenario, but it is projected to be sufficient to meet most reference case scenarios. As with additional raw uranium production, supply will expand beyond current level once more firm commitments are made including commitments to build new nuclear units. FPL expects long term price stability for conversion services to support world demand.

(3) Enrichment: As a result of the Fukushima events in March 2011, the near-term price of enrichment services has been declining for the last three years. However, plans for construction of several new facilities that were expected to come on-line in the next few years have been delayed. Also, some of the existing high operating cost diffusion plants have shut down. As with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand. Meanwhile, world supply and demand will continue to be balanced such that FPL expects adequate supply of enrichment services. The current supply/demand profile will most likely result in the price of enrichment services remaining stable or declining for the next few years before starting to increase.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the Nuclear Regulatory Commission (NRC), not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand is expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies. The calculations for the nuclear fuel cost forecasts used in FPL's 2013 and early 2014 resource planning work were performed consistent with the method then used for FPL's Fuel Clause filings, including the assumption of refueling outages every 18 months and plant operation at power uprate levels. The costs for each step to fabricate the nuclear fuels were added to come up with the total costs of the fresh fuel to be loaded at each refueling (acquisition costs). The acquisition cost for each group of fresh fuel assemblies were then amortized over the energy produced by each group of fuel assemblies. FPL also added 1 mill per kilowatt hour net to reflect payment to DOE for spent fuel disposal.

Schedule 5
Fuel Requirements
(for FPL only)

	Fuel Requirements	Units	Actual 1/ 2012	Actual 1/ 2013	Forecasted 2014	Forecasted 2015	Forecasted 2016	Forecasted 2017	Forecasted 2018	Forecasted 2019	Forecasted 2020	Forecasted 2021	Forecasted 2022	Forecasted 2023
(1)	Nuclear	Trillion BTU	188	273	298	300	306	303	300	306	302	300	357	455
(2)	Coal	1,000 TON	2,692	3,540	3,414	3,778	2,124	3,076	3,574	3,791	3,835	3,803	3,756	3,756
(3)	Residual (FO6) - Total	1,000 BBL	459	150	715	1,130	1,139	561	546	164	176	188	111	52
(4)	Steam	1,000 BBL	459	150	715	1,130	1,139	561	546	164	176	188	111	52
(5)	Distillate (FO2) - Total	1,000 BBL	23	152	37	35	226	61	293	247	284	282	184	126
(6)	Steam	1,000 BBL	4	0	0	0	0	0	0	0	0	0	0	0
(7)	CC	1,000 BBL	15	140	7	30	88	6	186	144	160	153	100	76
(8)	CT	1,000 BBL	4	12	30	6	139	56	107	104	124	129	84	51
(9)	Natural Gas - Total	1,000 MCF	595,396	550,350	550,782	544,663	584,056	578,902	581,638	580,361	596,131	600,152	570,533	518,693
(10)	Steam	1,000 MCF	46,112	30,348	4,413	8,395	10,562	9,343	8,967	2,912	3,104	3,280	2,021	1,001
(11)	CC	1,000 MCF	546,386	514,793	544,967	534,847	571,277	567,674	568,822	575,025	590,083	593,852	566,719	516,379
(12)	CT	1,000 MCF	2,899	5,208	1,403	1,421	2,216	1,884	3,849	2,424	2,944	3,020	1,793	1,313

1/ Source: A Schedules.
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual [1/] 2012	2013	Forecasted 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	Annual Energy Interchange 2/	GWH	5,186	4,445	3,539	3,876	2,165	2,316	2,640	962	0	0	0	0
(2)	Nuclear	GWH	16,916	25,243	27,792	27,981	28,593	28,279	27,959	28,550	28,177	27,971	33,464	42,915
(3)	Coal	GWH	4,745	5,981	6,020	6,662	3,827	5,486	6,488	6,850	6,923	6,867	6,778	6,779
(4)	Residual(FO6) -Total	GWH	378	75	437	722	684	333	327	104	111	118	69	32
(5)	Steam	GWH	378	75	437	722	684	333	327	104	111	118	69	32
(6)	Distillate(FO2) -Total	GWH	54	120	13	26	104	17	208	177	203	200	131	91
(7)	Steam	GWH	2	2	0	0	0	0	0	0	0	0	0	0
(8)	CC	GWH	49	114	6	25	72	5	148	115	128	122	80	60
(9)	CT	GWH	4	5	7	1	32	12	60	63	75	78	51	31
(10)	Natural Gas -Total	GWH	80,505	75,208	78,228	77,979	84,154	83,812	84,144	84,899	87,546	88,092	83,914	76,379
(11)	Steam	GWH	5,543	2,472	381	724	932	817	789	249	267	283	172	84
(12)	CC	GWH	74,668	72,308	77,722	77,131	83,029	82,833	82,978	84,412	86,994	87,519	83,567	76,167
(13)	CT	GWH	295	428	125	124	194	163	377	238	285	291	176	129
(14)	Solar [3/]	GWH	159	155	191	176	195	194	194	194	194	188	192	192
(15)	PV	GWH	71	68	72	71	71	70	70	69	69	68	68	67
(16)	Solar Thermal	GWH	89	87	119	104	125	124	124	124	125	119	124	124
(17)	Other [4/]	GWH	2,922	428	1,782	4,185	4,220	4,475	4,435	5,936	6,032	6,015	5,967	5,968
	Net Energy For Load [5/]	GWH	110,866	111,656	118,002	121,606	123,942	124,914	126,395	127,670	129,184	129,451	130,515	132,356

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report
2/ The projected figures are based on estimated energy purchases from SJRPP, the Southern Companies (UPS contract), and other utilities.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
5/ Net Energy For Load values for the years 2014- 2023 are also shown in Col. (19) on Schedule 2.3.

Schedule 6.2
Energy Sources % by Fuel Type

	Energy Source	Units	Actual [1/] 2012	2013	Forecasted 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	Annual Energy Interchange [2/]	%	4.7	4.0	3.0	3.2	1.7	1.9	2.1	0.8	0.0	0.0	0.0	0.0
(2)	Nuclear	%	15.3	22.6	23.6	23.0	23.1	22.6	22.1	22.4	21.8	21.6	25.6	32.4
(3)	Coal	%	4.3	5.4	5.1	5.5	3.1	4.4	5.1	5.4	5.4	5.3	5.2	5.1
(4)	Residual (FO6) -Total	%	0.3	0.1	0.4	0.6	0.6	0.3	0.3	0.1	0.1	0.1	0.1	0.0
(5)	Steam	%	0.3	0.1	0.4	0.6	0.6	0.3	0.3	0.1	0.1	0.1	0.1	0.0
(6)	Distillate (FO2) -Total	%	0.0	0.1	0.0	0.0	0.1	0.0	0.2	0.1	0.2	0.2	0.1	0.1
(7)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	CC	%	0.0	0.1	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.0
(9)	CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0
(10)	Natural Gas -Total	%	72.6	67.4	66.3	64.1	67.9	67.1	66.6	66.5	67.8	68.1	64.3	57.7
(11)	Steam	%	5.0	2.2	0.3	0.6	0.8	0.7	0.6	0.2	0.2	0.2	0.1	0.1
(12)	CC	%	67.3	64.8	65.9	63.4	67.0	66.3	65.7	66.1	67.3	67.6	64.0	57.5
(13)	CT	%	0.3	0.4	0.1	0.1	0.2	0.1	0.3	0.2	0.2	0.2	0.1	0.1
(14)	Solar [3/]	%	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1
(15)	PV	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(16)	Solar Thermal	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(17)	Other [4/]	%	2.6	0.4	1.5	3.4	3.4	3.6	3.5	4.6	4.7	4.6	4.6	4.5
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report
2/ The projected figures are based on estimated energy purchases from SJRPP, the Southern Companies (UPS contract), and other utilities.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled
Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Reserve Margin MW	Generation Reserve Margin % of Peak
2014	25,488	1,303	0	635	27,426	22,768	1,992	20,777	6,649	32.0	826	5,823	28.0	3,831	16.8
2015	25,121	1,450	0	595	27,165	23,356	2,057	21,298	5,867	27.5	0	5,867	27.5	3,810	16.3
2016	26,358	522	0	595	27,474	23,778	2,082	21,696	5,779	26.6	0	5,779	26.6	3,697	15.5
2017	25,962	522	0	595	27,078	24,190	2,108	22,082	4,996	22.6	0	4,996	22.6	2,888	11.9
2018	25,916	485	0	595	26,996	24,544	2,136	22,408	4,587	20.5	0	4,587	20.5	2,452	10.0
2019	26,930	110	0	595	27,635	24,896	2,165	22,731	4,904	21.6	0	4,904	21.6	2,739	11.0
2020	26,930	239	0	595	27,764	25,239	2,195	23,044	4,720	20.5	0	4,720	20.5	2,524	10.0
2021	26,930	278	0	775	27,983	25,439	2,227	23,212	4,770	20.6	0	4,770	20.6	2,544	10.0
2022	28,117	110	0	775	29,002	25,908	2,259	23,649	5,353	22.6	0	5,353	22.6	3,094	11.9
2023	29,272	110	0	775	30,157	26,528	2,292	24,236	5,921	24.4	0	5,921	24.4	3,628	13.7

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2013 load forecast without incremental DSM or cumulative load management.
Col. (8) represents cumulative load management capability, plus incremental conservation,and load management, from 9/2013-on intended for use with the 2013 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period; i.e., Martin Unit 2's planned outage in Summer 2014 for the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)
Col. (15) =Col. (6) - Col. (7)
Col. (16) = Col.(15) / Col.(7)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
January of Year	Firm Installed Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Reserve Margin MW	Generation Reserve Margin % of Peak
2014	25,671	1,311	0	635	27,617	19,875	1,502	18,373	9,243	50.3	832	8,411	45.8	6,910	34.8
2015	26,597	1,458	0	595	28,649	20,971	1,530	19,442	9,208	47.4	0	9,208	47.4	7,678	36.6
2016	26,653	530	0	595	27,777	21,490	1,543	19,947	7,831	39.3	0	7,831	39.3	6,287	29.3
2017	27,601	530	0	595	28,725	21,731	1,558	20,173	8,552	42.4	0	8,552	42.4	6,994	32.2
2018	27,557	493	0	595	28,645	21,968	1,573	20,396	8,249	40.4	0	8,249	40.4	6,676	30.4
2019	27,295	493	0	595	28,383	22,180	1,588	20,592	7,790	37.8	0	7,790	37.8	6,203	28.0
2020	28,724	239	0	595	29,558	22,383	1,603	20,780	8,777	42.2	0	8,777	42.2	7,174	32.1
2021	28,724	278	0	775	29,777	22,584	1,619	20,966	8,811	42.0	0	8,811	42.0	7,192	31.8
2022	28,724	110	0	775	29,609	22,601	1,634	20,967	8,642	41.2	0	8,642	41.2	7,007	31.0
2023	29,910	110	0	775	30,795	22,891	1,651	21,241	9,554	45.0	0	9,554	45.0	7,903	34.5

Col. (2) represents capacity additions and changes projected to be in-service by January 1st. These MW are generally considered to be available to meet winter peak loads which are forecasted to occur during January of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2013 load forecast without incremental DSM or cumulative load management. 2013 load is an actual load value.
Col. (8) represents cumulative load management capability, plus incremental conservation and load management,, from 9/2013-on intended for use with the 2013 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Winter peak period; i.e., Martin Unit 1's planned outage during the Winter of 2014 for the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)
Col. (15) =Col. (6) - Col. (7)
Col. (16) = Col.(15) / Col.(7)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (1)

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability (2)		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2014														
Sanford CT Upgrade	5B	Volusia County	CC	NG	No	PL	No	Aug-13	Sep-13	Unknown	188,190	10	9	OT
Turkey Point CT Upgrade	5A	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	---	7	OT
Turkey Point CT Upgrade	5B	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	---	7	OT
Turkey Point CT Upgrade	5C	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	---	7	OT
Turkey Point CT Upgrade	5D	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	---	7	OT
Martin (3)	1	Martin County	ST	FO6	NG	PL	PL	Jun-13	Mar-14	Unknown	934,500	(832)	823	ESP
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	TK	WA	Jun-12	Apr-14	Unknown	1,295,400	---	1,212	U
Martin (3)	2	Martin County	ST	FO6	NG	PL	PL	Mar-14	Dec-14	Unknown	934,500	---	(826)	OT
											2014 Changes/Additions Total:	**(822)**	**1,247**	
2015														
Turkey Point CT Upgrade	5A	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	8	---	OT
Turkey Point CT Upgrade	5B	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	8	---	OT
Turkey Point CT Upgrade	5C	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	8	---	OT
Turkey Point CT Upgrade	5D	Miami Dade County	CC	NG	FO2	PL	TK	---	Mar-14	Unknown	188,190	8	---	OT
Martin (3)	1	Martin County	ST	FO6	NG	PL	PL	Jun-13	Mar-14	Unknown	934,500	832	---	ESP
Manatee CT Upgrade	3A	Manatee County	CC	NG	No	PL	No	Aug-14	Oct-14	Unknown	188,190	9	8	OT
Manatee CT Upgrade	3B	Manatee County	CC	NG	No	PL	No	Aug-14	Oct-14	Unknown	188,190	9	8	OT
Manatee CT Upgrade	3C	Manatee County	CC	NG	No	PL	No	Apr-14	Oct-14	Unknown	188,190	9	8	OT
Manatee CT Upgrade	3D	Manatee County	CC	NG	No	PL	No	Apr-14	Oct-14	Unknown	188,190	9	8	OT
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	TK	WA	Jun-12	Jun-14	Unknown	188,190	1,344	---	U
Vero Beach Combined Cycle	1	Indian River	CC	NG	DFO	PL	TK	---	Jan-15	Unknown	---	44	46	OT
Martin (3)	2	Martin County	ST	FO6	NG	PL	PL	Mar-14	Dec-14	Unknown	934,500	---	823	ESP
Putnam	1	Putnam County	CC	NG	FO2	PL	TK	---	---	Jun-15	290,004	(265)	(249)	
Putnam	2	Putnam County	CC	NG	FO2	PL	TK	---	---	Jun-15	290,004	(265)	(249)	
Ft. Myers CT Upgrade	2A	Lee County	CC	NG	No	PL	No	---	Jun-15	Unknown	188,190	---	9	OT
Ft. Myers CT Upgrade	2B	Lee County	CC	NG	No	PL	No	---	Mar-15	Unknown	188,190	---	9	OT
Ft. Myers CT Upgrade	2C	Lee County	CC	NG	No	PL	No	---	Jun-15	Unknown	188,190	---	9	OT
Ft. Myers CT Upgrade	2D	Lee County	CC	NG	No	PL	No	---	May-15	Unknown	188,190	---	9	OT
Ft. Myers CT Upgrade	2E	Lee County	CC	NG	No	PL	No	---	May-15	Unknown	188,190	---	9	OT
Ft. Myers CT Upgrade	2F	Lee County	CC	NG	No	PL	No	---	Mar-15	Unknown	188,190	---	9	OT
											2015 Changes/Additions Total:	**1,758**	**456**	
2016														
Ft. Myers CT Upgrade	2B	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	188,190	9	---	OT
Ft. Myers CT Upgrade	2F	Lee County	CC	NG	No	PL	No	Feb-15	Mar-15	Unknown	188,190	9	---	OT
Ft. Myers CT Upgrade	2D	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	188,190	9	---	OT
Ft. Myers CT Upgrade	2E	Lee County	CC	NG	No	PL	No	May-15	Jun-15	Unknown	188,190	9	---	OT
Ft. Myers CT Upgrade	2A	Lee County	CC	NG	No	PL	No	Jun-15	Jul-15	Unknown	188,190	9	---	OT
Ft. Myers CT Upgrade	2C	Lee County	CC	NG	No	PL	No	Jul-15	Aug-15	Unknown	188,190	9	---	OT
Port Everglades Next Generation Clean Energy Center	1	City of Hollywood	CC	NG	FO2	TK	WA	Jun-14	Jun-16	Unknown	Unknown	---	1,237	U
											2016 Changes/Additions Total:	**55**	**1,237**	

(1) Schedule 8 shows only planned and prospective changes to generating facilities and does not reflect changes to existing purchases. Those changes are reflected on Tables ES-1, I.B.1 and I.B.2.
The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring after August each year will be picked up for reserve margin calculation purposes in the following year.
(2) This generating unit is currently serving as a synchronous condenser and is not included in reserve margin calculation.
(3) Outages for ESP work.

Schedule 8

Planned And Prospective Generating Facility Additions And Changes (1)

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability (2)		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
2017														
Port Everglades Next Generation Clean Energy Center	1	City of Hollywood	CC	NG	FO2	TK	WA	Jun-14	Jun-16	Unknown	Unknown	1,346	---	U
Turkey Point Synchronous Condenser	1	Miami Dade County	ST	FO6	NG	WA	PL	---	---	Jun-17	402,050	(398)	(396)	OT
											2017 Changes/Additions Total:	**948**	**(396)**	
2018														
Vero Beach Combined Cycle	1	Indian River	CC	NG	DFO	PL	TK	---	---	Jan-18	---	(44)	(46)	OT
											2018 Changes/Additions Total:	**(44)**	**(46)**	
2019														
Lauderdale GT	1-12	Broward County	GT	NG	FO2	PL	PL	---	---	Dec-18	410,734	(459)	(420)	P
Lauderdale GT	12-24	Broward County	GT	NG	FO2	PL	PL	---	---	Dec-18	410,734	(459)	(420)	P
Port Everglades GT	1-12	Broward County	GT	NG	FO2	PL	PL	---	---	Dec-18	410,734	(459)	(420)	P
Lauderdale CT	1-5	Broward County	CT	NG	FO3	PL	PL	---	Jan-19	Unknown	Unknown	1,115	1,005	P
Unsited 3x1 CC unit	1	---	CC	NG	FO2	TK	WA	Jun-17	Jun-19	Unknown	Unknown	---	1,269	P
											2019 Changes/Additions Total:	**(262)**	**1,014**	
2020														
Unsited 3x1 CC unit			CC	NG	FO2	TK	WA	Jun-17	Jun-19	Unknown	Unknown	1,429	---	P
											2020 Changes/Additions Total:	**1,429**	**0**	
2021														
												---	---	
											2021 Changes/Additions Total:	**0**	**0**	
2022														
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	TK	---	Jun-22	Unknown	1,295,400	---	87	P
Turkey Point	6	Miami Dade County	ST	NP	No	TK	No	2014	Jun-22	Unknown	Unknown	---	1,100	T
											2022 Changes/Additions Total:	**0**	**1,187**	
2023														
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	TK	---	Jun-22	Unknown	1,295,400	87	---	P
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	TK	WA	Jun-12	Apr-14	Unknown	1,295,400	---	55	P
Turkey Point	6	Miami Dade County	ST	NP	No	TK	No	2014	Jun-22	Unknown	Unknown	1,100	---	L
Turkey Point	7	Miami Dade County	ST	NP	No	TK	No	2015	Jun-23	Unknown	Unknown	---	1,100	L
											2022 Changes/Additions Total:	**1,187**	**1,155**	

(1) Schedule 8 shows only planned and prospective changes to generating facilities and does not reflect changes to existing purchases. Those changes are reflected on Tables ES-1, I.B.1 and I.B.2.
(2) The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occuring after August each year will be picked up for reserve margin calculation purposes in the following year.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Vero Beach Combined Cycle Capacity

(2) **Capacity**

a. Summer	46	MW
b. Winter	44	MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**

a. Field construction start-date: Not Applicable - See Note 1 below.
b. Commercial In-service date: 2015

(5) **Fuel**

a. Primary Fuel Gas
b. Alternate Fuel Oil

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 16 Acres

(9) **Construction Status:** See note 1 below

(10) **Certification Status:** See note 1 below

(11) **Status with Federal Agencies:** See note 1 below

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	20.5%	
Forced Outage Factor (FOF):	0.0%	
Equivalent Availability Factor (EAF):	72.5%	
Resulting Capacity Factor (%):	3.88%	
Average Net Operating Heat Rate (ANOHR):	9,397	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data**

Book Life (Years):	TBD	years
Total Installed Cost ($/kW):	Not Applicable	
Direct Construction Cost ($/kW):	Not Applicable	
AFUDC Amount ($/kW):	Not Applicable	
Escalation ($/kW):	Not Applicable	
Fixed O&M ($/kW-Yr): ($)	Not Applicable	
Variable O&M ($/MWH): ($)	Not Applicable	
K Factor:	Not Applicable	

NOTE 1: The combined cycle capacity consists of two existing units. This existing unit is being acquired by FPL as part of the arrangement for FPL to serve Vero Beach's load beginning in January 2015. FPL is also taking ownership of three steam units.The three steam units will be retired as soon as they aquired. FPL plans to retire the CC unit at the end of 2017.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Port Everglades Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,237 MW
b. Winter 1,429 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2014
b. Commercial In-service date: 2016

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas,
0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** Existing Site Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.5%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	95.4%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,330	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2016 $/kW):	928	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	87	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2016 $)	30.00	
Variable O&M ($/MWH): (2016 $)	0.10	
K Factor:	1.51	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing plant are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Lauderdale CT's (5 CTs will be added)

(2) **Capacity (for each CT)**

a. Summer	201	MW
b. Winter	223	MW

(3) **Technology Type:** Combustion Turbine

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2017
b. Commercial In-service date: 2018

(5) **Fuel**
a. Primary Fuel — Natural Gas
b. Alternate Fuel — Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Water to Air Heat Exchangers

(8) **Total Site Area:** Existing Site Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	1.6%	
Forced Outage Factor (FOF):	1.0%	
Equivalent Availability Factor (EAF):	97.4%	
Resulting Capacity Factor (%):	3%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	10,057	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2018 $/kW):	547	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	56	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2018 $)	17.63	
Variable O&M ($/MWH): (2018 $)	0.07	
K Factor:	1.59	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing GTs are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited 3x1 CC

(2) **Capacity**
a. Summer 1,269 MW
b. Winter 1,429 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2017
b. Commercial In-service date: 2019

(5) **Fuel**
a. Primary Fuel — Natural Gas
b. Alternate Fuel — Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.5%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	95.4%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,334	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2019 $/kW):	968	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	95	
Escalation ($/kW):	872.79	
Fixed O&M ($/kW-Yr): (2019 $)	22.25	
Variable O&M ($/MWH): (2019 $)	0.72	
K Factor:	1.51	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas lateral, transmission interconnection and integration, escalation, and AFUDC.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point Nuclear Unit 6

(2) **Capacity**
a. Summer 1,100 MW
b. Winter 1,100 MW

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2015
b. Commercial In-service date: 2022

(5) **Fuel**
a. Primary Fuel Uranium Dioxide
b. Alternate Fuel N/A

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** Mechanical Draft Cooling Towers

(8) **Total Site Area:** 211 Acres

(9) **Construction Status:** L (Regulatory approval pending.Not under construction)

(10) **Certification Status:** L (Regulatory approval pending.Not under construction)

(11) **Status with Federal Agencies:** L (Regulatory approval pending.Not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	TBD	
Forced Outage Factor (FOF):	TBD	
Equivalent Availability Factor (EAF):	TBD	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	TBD	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	TBD	years
Total Installed Cost ($/kW):	TBD	
Direct Construction Cost ($/kW):	TBD	
AFUDC Amount ($/kW):	TBD	
Escalation ($/kW):	TBD	
Fixed O&M ($/kW-Yr): ($)	TBD	
Variable O&M ($/MWH): ($)	TBD	
K Factor:	TBD	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point Nuclear Unit 7

(2) **Capacity**

a. Summer	1,100	MW
b. Winter	1,100	MW

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2015
b. Commercial In-service date:	2023

(5) **Fuel**

a. Primary Fuel	Uranium Dioxide
b. Alternate Fuel	N/A

(6) **Air Pollution and Control Strategy:** N/A

(7) **Cooling Method:** Mechanical Draft Cooling Towers

(8) **Total Site Area:** 211 Acres

(9)	**Construction Status:**	L	(Regulatory approval pending.Not under construction)
(10)	**Certification Status:**	L	(Regulatory approval pending.Not under construction)
(11)	**Status with Federal Agencies:**	L	(Regulatory approval pending.Not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	TBD	
Forced Outage Factor (FOF):	TBD	
Equivalent Availability Factor (EAF):	TBD	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	TBD	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	TBD	years
Total Installed Cost ($/kW):	TBD	
Direct Construction Cost ($/kW):	TBD	
AFUDC Amount ($/kW):	TBD	
Escalation ($/kW):	TBD	
Fixed O&M ($/kW-Yr): ($)	TBD	
Variable O&M ($/MWH): ($)	TBD	
K Factor:	TBD	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Vero Beach Existing Combined Cycle Capacity

The Vero Beach existing combined cycle capacity that FPL is projected to take ownership of starting January 1, 2015 does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Port Everglades Next Generation Clean Energy Center

The Port Everglades Next Generation Clean Energy Center which will result from the modernization of the Port Everglades power plant site does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Lauderdale Combustion Turbine Project

The Lauderdale Combustion Turbine (CT) project, which will result in the retirement of 36 aero-derivative combustion gas turbines at the Lauderdale and Port Everglades plant sites, and their replacement with 5 simple-cycle combustion turbines at the Lauderdale site, does not require any "new" transmission lines.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Unsited Combined Cycle in 2019

No projection of a new transmission line(s) can be made until a site is selected for this unit.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 6

The Turkey Point New Nuclear Project starting with the addition of Turkey Point Unit 6 will require a new substation and five new transmission lines terminating at existing substations.

(1)	Point of Origin and Termination:	New Clear Sky Substation – Levee Substation
(2)	Number of Lines:	2
(3)	Right-of-way	FPL Owned
(4)	Line Length:	43 miles
(5)	Voltage:	500 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Levee Substation
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	New Clear Sky Substation – Pennsuco Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	52 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Pennsuco Substation
(9)	Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 6 (continued)

(1)	Point of Origin and Termination:	New Clear Sky Substation – Davis Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	19 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Davis Substation
(9)	Participation with Other Utilities:	None

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(1)	Point of Origin and Termination:	Davis Substation – Miami Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	18 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	Davis Substation and Miami Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 6 (continued)

(1)	Point of Origin and Termination:	New Clear Sky Substation – Turkey Point Substation
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	0.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBD End date: TBD
(7)	Anticipated Capital Investment: (Trans.and Sub.)	$ TBD
(8)	Substations:	New Clear Sky Substation and Turkey Point Substation
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Turkey Point Nuclear Unit 7

The transmission lines required for Turkey Point Unit 7 will be constructed with Turkey Point Unit 6 and are listed in the Schedule 10 for Turkey Point Nuclear Unit 6.

Schedule 11.1

Existing FIRM and NON-FIRM Capacity and Energy by Primary Fuel Type
Actuals for the Year 2013

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Net (MW) Capability				NEL	Fuel Mix
	Generation by Primary Fuel	**Summer (MW)**	**Summer (%)**	**Winter (MW)**	**Winter (%)**	**GWh [2]**	**%**
(1)	Coal	897	3.4%	911	3.3%	5,981	5.4%
(2)	Nuclear	3,453	13.2%	3,550	12.8%	25,243	22.6%
(3)	Residual	3,666	14.0%	3,700	13.4%	75	0.1%
(4)	Distillate	648	2.5%	710	2.6%	120	0.1%
(5)	Natural Gas	15,575	59.4%	16,785	60.6%	75,208	67.4%
(6)	Solar (Non-Firm)	35	0.1%	35	0.1%	155	0.1%
(7)	***FPL Existing Units Total [1] :***	***24,274***	***92.6%***	***25,691***	***92.8%***	***106,782***	***95.6%***
(8)	Renewables (Purchases)- Firm	61.0	0.2%	112.0	0.4%	43	0.0%
(9)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	362	0.3%
(10)	***Renewable Total:***	61.0	0.2%	112.0	0.4%	405	0.36%
(11)	***Purchases Other :***	1,883.0	7.2%	1,891.0	6.8%	4,468	4.0%
(12)	***Total :***	*26,218.0*	*100.0%*	*27,694.0*	*100.0%*	*111,655*	*100.0%*

Note:
(1) FPL Existing Units Total values on row (7), columns (2) and (4), match the System Firm Generating Capacity values found on Schedule 1 for Summer and Winter.
(2) Net Energy for Load GWh values on row (12), column (6), matches Schedule 6.1 value for 2013.

Schedule 11.2

Existing NON-FIRM Self-Service Renewable Generation Facilities
Actuals for the Year 2013

(1)	(2)	(3)	(4)	(5)	(6) = (3)+(4)-(5)
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh)	Annual Energy Purchased from FPL (MWh)	Annual Energy Sold to FPL (MWh)	Projected Annual Energy Used by Customers
Customer-Owned Renewable Generation (0 kW to 10 kW)	12.86	16,142	111,831	465	127,508
Customer-Owned Renewable Generation (> 10 kW to 100 kW)	6.69	8,758	197,171	376	205,553
Customer-Owned Renewable Generation (> 100 kW - 2 MW)	7.94	10,475	62,050	177	72,348
	27.49	35,375	371,052	1,018	405,409

Notes:

(1) There were 2,565 customers with renewable generation facilities interconnected with FPL on December 31, 2013.
(2) The Installed Capacity value is the sum of the nameplate ratings (DC MW) for all of the customer-owned renewable generation facilities connected as of Dec. 31,2013. One system does not have a DC rating. The AC valued of 0.75 MW was included in the (> 100 - 2 MW) row.
(3) The Projected Annual Output value is based on NREL's PV Watts 1 program and the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.
(4) The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2013.
(5) The Annual Energy Sold to FPL is an actual value from FPL's metered data for 2013.
(6) The Projected Annual Energy Used by Customers is a projected value that equals:
(Renewable Projected Annual output + Annual Energy Purchased) minus the Annual Energy Sold to FPL.

CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

Florida is a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered or threatened plant and animal species. Florida's residents, wildlife, and ecosystems require the same air, land, and water resources that are necessary to meet the demand for the generation, transmission, and distribution of electricity. The general public has an expectation that a large corporation, such as FPL, will conduct their business in an environmentally responsible manner that minimizes impacts to the natural environment.

FPL has been recognized for many years as one of the leaders among electric utilities for its commitment to the environment. Being responsible stewards of the environment is ingrained in FPL's corporate culture. FPL has one of the lowest emissions profiles among U.S. utilities and in 2013 its carbon dioxide (CO_2) emission rate was 35% lower (better) than the industry average.

FPL's environmental leadership and that of its parent company, NextEra Energy, Inc., has been heralded by many outside organizations as demonstrated by a few recent examples.

FPL's responsible tree care practices across its 35-county service area have been recognized for almost a decade. FPL has been the recipient of the Tree Line USA award annually from 2003 - 2013. This award is sponsored by the Arbor Day Foundation in cooperation with the National Association of State Foresters. The recognition is given to utilities that demonstrate quality tree care practices, annual worker training, and public education programs.

In 2013, FPL continued to support the Loggerhead Marinelife Center with a $21,500 donation toward the acquisition of a larger tank to assist in sea turtle rehabilitation. Two FPL employees serve as members of the Loggerhead Marinelife Center and are committed to its success. In addition, through a "Power to Care" charity event an additional $500 was collected by FPL staff and given to the Center. In past years, FPL has won the Loggerhead Marinelife Center's "Blue Business of the Year" award, which is given to those who are leading the way in raising awareness about, and have made significant contributions to improve and protect, South Florida's oceans, beaches, and wildlife. The award recognized FPL's protection and conservation of the endangered Florida manatee and the fostering of public and employee education and support.

FPL employees serve as board members for many organizations that focus on environmental restoration, preservation, and stewardship. A partial list of these organizations includes: Audubon Florida, the Everglades Foundation, the Arthur R. Marshall Foundation, The Nature Conservancy, and the Palm Beach Zoo.

IV.B FPL's Environmental Statement

At FPL and its parent company, NextEra Energy, Inc., we are committed to being an industry leader in environmental protection and stewardship, not only because it makes business sense, but because it is the right thing to do. Our commitment to compliance, conservation, communication, and continuous improvement fosters a culture of environmental excellence and drives the sustainable management of our business planning, operations, and daily work.

In accordance with our commitments to environmental protection and stewardship, FPL and NextEra Energy, Inc. endeavor to:

Comply

- Comply with all applicable environmental laws, regulations, and permits
- Proactively identify environmental risks and take action to mitigate those risks
- Pursue opportunities to exceed environmental standards
- Participate in the legislative and regulatory process to develop environmental laws, regulations, and policies that are technically sound and economically feasible
- Design, construct, operate, and maintain our facilities in an environmentally sound and responsible manner

Conserve

- Prevent pollution, minimize waste, and conserve natural resources
- Avoid, minimize, and/or mitigate impacts to habitat and wildlife
- Promote the efficient use of energy, both within our company and in our communities

Communicate

- Communicate this policy to all employees and publish it on the corporate website
- Invest in environmental training and awareness to achieve a corporate culture of environmental excellence
- Maintain an open dialogue with stakeholders on environmental matters and performance

Continuously Improve

- Establish, monitor, and report progress toward environmental targets
- Review and update this policy on a regular basis
- Drive continuous improvement through ongoing evaluations of our environmental management system to incorporate lessons learned and best practices.

This statement was updated in 2013 by FPL's parent company, NextEra Energy, Inc. to reflect changing expectations and ensure that employees are doing the utmost to protect the environment. FPL complies with all environmental laws, regulations, and permit requirements. FPL designs, constructs, and operates its facilities in an environmentally sound and responsible manner. It also responds immediately and effectively to any known environmental hazards or non-compliance situations. FPL's commitment to the environment does not end there. It proactively pursue opportunities to exceed current environmental standards, including reducing waste and emission of pollutants, recycling materials, and conserving natural resources throughout its operations and day-to-day work activities. FPL also encourages the efficient use of energy, both within the Company and in communities served by FPL. These actions are just a few examples of how FPL is committed to the environment.

To ensure that FPL is adhering to its environmental commitment, it has developed rigorous environmental governance procedures and programs. These include its Environmental Assurance Program and Corporate Environmental Governance Council. Through these programs, FPL conducts periodic environmental self-evaluations to verify that its operations are in compliance with environmental laws, regulations, and permit requirements. Regular evaluations also help identify best practices and opportunities for improvement.

IV.C Environmental Management

In order to successfully implement the Environmental Statement, FPL has developed a robust Environmental Management System program to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program. Other components of the system include: executive management support and commitment, a dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

As part of its commitment to excellence and continuous improvement, FPL began implementing an enhanced environmental data management information system (EDMIS) in 2013. Environmental data management software systems are increasingly viewed as an industry best-management practice to ensure environmental compliance. FPL's top goals for this project are to: 1) improve the flow of environmental data between site operations and corporate services to ensure compliance, and 2) improve operating efficiencies. In addition, the EDMIS will help standardize environmental data collection, thus improving external reporting to the public.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities that are designed to evaluate environmental performance, verify compliance with corporate policy as well as legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and FPL policies. In addition to FPL facility audits, the Environmental Assurance Program performs audits of third-party vendors used for recycling and/or disposal of waste generated by FPL operations. Vendor audits provide information used for selecting candidates or incumbent vendors for disposal and recycling needs.

FPL has also implemented a Corporate Environmental Governance System, in which quarterly reviews are performed by each business unit deemed to have significant environmental exposures. Quarterly reviews evaluate operations for potential environmental risks and consistency with the company's Environmental Policy. Items tracked during the quarterly reviews include processes for the identification and management of environmental risks, metrics, and indicators and progress / changes since the most recent review.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and in public education. Some of FPL's 2013 environmental outreach activities are summarized in Table IV.E.1.

Table IV.E.1: 2013 FPL Environmental Outreach Activities

Activity	Count (#)
Visitors to FPL's Energy Encounter at St. Lucie	2,900
Visitors to Manatee Park, Ft. Myers	>210,000
Number of website visits to FPL's Environmental & Corporate Responsibility Websites	245,630
Visitors to Barley Barber Swamp (Treasured Lands Partnership)	1,492
Martin Energy Center Solar Tours	~850
Solar Schools Program (# of schools actively generating)	24 schools 5 demo sites An additional 67 schools will come online by the end of 2014

IV.F Preferred and Potential Sites

Based upon its projection of future resource needs, FPL has identified six (6) Preferred Sites and four (4) Potential Sites for future generation additions. Preferred Sites are those locations where FPL has conducted significant reviews and has either taken action, is currently committed to take action, or is likely to take action, to site new generating capacity. Potential Sites are those sites that have attributes that support the siting of generation and are under consideration as a location for future generation. Some of these sites are currently in use as existing generation sites and some are not. The identification of a Potential Site does not indicate that FPL has made a definitive decision to pursue generation (or generation expansion or modernization in the case of an existing generation site) at that location, nor does this designation indicate that the size or technology of a generator has been determined. Analyses of any modernization candidates would include evaluation of numerous factors including: fuel delivery, transmission, permitting, etc. The Preferred Sites and Potential Sites are discussed in separate sections below.

IV.F.1 Preferred Sites

The modernization of FPL's Riviera Beach site was scheduled to be completed on/near April 1, 2014 (the filing date for this 2014 Site Plan). Therefore, the Riviera Beach modernization is not discussed further in this chapter. FPL currently has identified six (6) Preferred Sites. Four of these are existing plant sites: Port Everglades, Lauderdale, Putnam and Turkey Point; two of these would be new plant sites: Hendry County and Northeast (NE) Okeechobee County.

The Port Everglades site is a location where modernization work, to replace the former steam generating units with new combined cycle (CC) technology, is in progress. The modernization work is scheduled to be completed in mid-2016. The existing gas turbines (GTs) at the Port Everglades and the Lauderdale sites are projected to be removed by the end of 2018. Five new combustion turbines (CTs) are projected to be added at the Lauderdale site by the end of 2018 to partially replace the capacity from existing GTs at Port Everglades and at the Lauderdale sites. These actions will aid in addressing compliance with new air emissions standards. The Hendry County, NE Okeechobee County, and Putnam sites are the likely next locations for new CC units after the Port Everglades and Lauderdale projects mentioned above have been completed. In addition, the Hendry County and Okeechobee County sites are also likely sites for new photovoltaic (PV) facilities.

In regard to the Turkey Point site, the nuclear capacity uprate project was successfully completed in 2013. The new Turkey Point nuclear Units 6 & 7 are currently projected to come in-service in 2022 and 2023, respectively.

The first two Preferred Sites discussed below are in general chronological order with respect to when the capacity additions are projected to occur. The remaining four Preferred Sites are discussed in alphabetical order.

Preferred Site # 1: Port Everglades Plant, Broward County

This site is located on the existing FPL Port Everglades Plant property within the City of Hollywood, Broward County. The site is surrounded by the Port of Port Everglades. The site has barge access via the Port of Port Everglades. A rail line is located near the plant.

The previous site generating capacity was made up of two 200 MW (approximate) steam generating units (Units 1 & 2) and two 400 MW (approximate) steam generating units (Units 3 & 4). The four units have been taken out of service and dismantled as part of the modernization of the plant site.

The Port Everglades Plant site has been listed as a Preferred or Potential Site in previous FPL Site Plans for both CC and CT generation options. On April 9, 2012, the FPSC issued the final need order for the modernization of the existing Port Everglades Plant. As a result of the modernization of the site, the new generating unit - to be renamed the Port Everglades Next Generation Clean Energy Center (PEEC) – will replace the existing steam generating units with modern, highly efficient, lower-emission next-generation advanced CC technology. The existing four steam units have been removed from the site and will be replaced by a single new CC unit.

a. U.S. Geological Survey (USGS) Map

A USGS map of the PEEC site is found at the end of this chapter.

b. Proposed Facilities Layout

A general layout of the PEEC generating facilities is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing Port Everglades Plant formerly consisted of two 200 MW (approximate) and two 400 MW (approximate) generating units with conventional dual-fuel fired steam boilers and steam turbine units. These generating units have now been removed as part of the modernization project. The plant site includes minimal vegetation. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of facilities related to electric power generation for the former Port Everglades Plant generating units. The site is located adjacent to the Intracoastal Waterway. The site provides warm water as required for manatees pursuant to the facility's Manatee Protection Plan.

2. Listed Species

No adverse impacts to federally or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species. The warm water discharges from the plant attract manatees, an endangered species. FPL continues to work closely with state and federal wildlife agencies to ensure protection of the manatees during the modernization process and upon operation of the new plant. FPL plans to install a temporary heating system to provide warm water for manatees as required pursuant to the facility's Manatee Protection Plan. FPL also anticipates complying with other manatee-related conditions of certification to ensure the protection of the manatees during the modernization work and during future operations of PEEC.

3. Natural Resources of Regional Significance Status

The construction and operation of a natural gas-fired CC generating facility at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option is to replace the former units (Units 1 through 4) with one new approximately 1,237 MW (Summer) unit consisting of three new CTs, three new heat recovery steam generators (HRSG), and a new steam turbine. The new CC unit is projected to be in service in mid-2016. Natural gas delivered via an existing pipeline is the primary fuel type for the unit with ultra-low sulfur light fuel oil serving as a backup fuel.

In addition, all of the existing GTs at the Port Everglades site are projected to be removed by the end of 2018.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is a combination of "Electrical Generating Facility" and "Utilities Use". A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Port Everglades site has been selected for modernization due to consideration of various factors including system load, ability to provide generation in the Miami-Dade/Broward region to help balance load and generation in the region, and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity or other environmental issues. However, there are environmental benefits of replacing the former steam units with a new CC unit including a significant reduction in system air emissions, improved aesthetics at the site, and continued warm water discharge for the manatees as required pursuant to the facility's Manatee Protection Plan. Further, modernizing this existing facility reduces the impact on natural resources by not requiring new land or new water resources.

i. Water Resources

Water from the Intracoastal Waterway via the Port of Port Everglades Slip No. 3 is currently used for once-through cooling water supply. The new plant will utilize portions of the existing once-through cooling water intake and discharge structures. Process and potable water for the modernized plant will come from the existing City of Ft. Lauderdale potable water supply.

j. Geological Features of Site and Adjacent Areas

FPL's Port Everglades Plant site is underlain by the surficial aquifer system. The surficial aquifer system in eastern Broward County is primarily composed of sand, sandstone, shell, silt, calcareous clay (marl), and limestone deposited during the Pleistocene and Pliocene ages. The sediments forming the aquifer system are the Pamlico Sand, Miami Oolite, Anastasia Formation, Key Largo Formation, and Fort Thompson Formation (Pleistocene) and the Tamiami Formation (Pliocene). The sediments in the eastern portion of the county are appreciably more permeable than in the west.

The surficial aquifer is underlain by at least 600 feet of the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Approximately 600 mgd of cooling water would be cycled through the once-through cooling water system which is a reduction of more than 51% from the previous fossil steam unit's capability. Potable water demand is expected to average .001 mgd.

l. Water Supply Sources by Type

The modernized plant will continue to use the Intracoastal Waterway as the source of once-through cooling water. Process and potable water for the new plant will come from the existing City of Ft. Lauderdale potable water supply.

m. Water Conservation Strategies Under Consideration

No additional water resources will be required as a result of the modernization project. CC technology uses less water by design than traditional steam generation units.

n. Water Discharges and Pollution Control

The modernized plant will utilize portions of the existing once-through cooling water system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's once-through cooling water system prior to discharge. Stormwater runoff will be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for the new unit would be transported to the site via an existing natural gas pipeline to the site. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit will be installed either at the existing site or off-site. Ultra-low sulfur light fuel oil would be received by truck, pipeline, or barge and stored in a new above-ground storage tank.

p. Air Emissions and Control Systems

The regulated air emission rates at the new plant would be approximately 90 percent lower than the previous Port Everglades Plant's emission rates, resulting in significant annual emissions reductions and air quality benefits per unit of energy produced. The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Using these fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x) and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. CC facility emissions of greenhouse gas emissions (GHGs) from combustion of natural gas achieve an emission rate substantially lower than the EPA proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of PEEC would incorporate features that will make it among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. Status of Applications

FPL filed a need determination with the FPSC on November 21, 2011. The FPSC's final need order was issued on April 9, 2012. The Site Certification Application (SCA) was submitted January 24, 2012 resulting in the issuance of Final Order PA 12-57 on October 9, 2012. Concurrent with the SCA filing, FPL submitted applications for a Greenhouse Gas (GHG) permit, a Prevention of Significant Deterioration (PSD) permit, and an Industrial Wastewater Facility permit revision. The revised Industrial Wastewater Facility permit was issued

December 16, 2012. The GHG permit was issued December 26, 2013 and the PSD permit was issued May 1, 2012.

Preferred Site # 2: Lauderdale Plant, Broward County

This site is located at and situated within the existing FPL Lauderdale Plant property, approximately 392 acres, within the Cities of Dania Beach and Hollywood in Broward County, Florida. The jurisdiction for the City of Hollywood is a small area south of SW 42nd Street in the eastern portion of the property. The remainder of the Plant property is located in the City of Dania Beach. The Plant property is located east of U.S. Highway 441, north of Griffin Road, west of SW 30th Avenue, and south of Interstate 595. The existing accesses to the Plant are from SW 24th Avenue and SW 42nd Street. The adjacent properties include residential properties to the south, the South Broward County Resource Recovery Facility to the west, Pond Apple Slough to the north and commercial properties to the east.

The Lauderdale Plant includes two banks of 12 simple cycle gas turbines (GTs) that began operation in the early 1970s. These GTs are first generation GTs that are used to serve peak and emergency demands in a quick-start manner. Each bank of GTs has a net capacity of 420 (Summer) megawatts (MWs), and are authorized to operate on natural gas and distillate oil. Due to new nitrogen dioxide (NO_2) environmental regulations, FPL filed in June 2013 for FPSC approval to recover costs for removing all of its existing GTs and replacing a portion of the GT capacity with new CTs. In December 2013, FPL withdrew this request pending additional environmental monitoring and analyses. Computer modeling of the emissions from the GTs projected that the GTs would exceed the new NO_2 limit. FPL believes this monitoring and analyses will confirm that the operation of its existing GTs in Broward County will not comply with the new NO_2 regulations. Therefore, for planning purposes, FPL has assumed that all of its existing Broward County GTs will be removed (a loss of 1,260 MW Summer) and that this capacity will be partially replaced by 5 new CTs that would be sited in Broward County (an increase of 1,005 MW Summer). This GT removal and CT partial replacement is assumed to occur by the end of 2018.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Lauderdale site is found at the end of this chapter.

b. Proposed Facilities Layout

A general layout of the Lauderdale generating facilities is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing Lauderdale Plant includes two combined cycle units (Units 4 and 5) and two banks of 12 simple cycle gas turbines (GT1 through GT12 and GT13 through GT24). Units 4 and 5 have net capacity of 442 (Summer) MW each. Each bank of GTs has a net capacity of 420 (Summer) MW. The northern portion of the property is comprised of a forested wetland area adjacent to the Pond Apple Slough.

The adjacent properties to the Lauderdale Site include residential properties to the south, the South Broward County Resource Recovery Facility to the west, Pond Apple Slough to the north and commercial properties to the east. The Dania Cut-off Canal is located along the southern boundary and the South New River Canal is located along the western and northern boundaries.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

FPL Lauderdale Plant property consists of approximately 392 acres, within the Cities of Dania Beach and Hollywood in Broward County, Florida. The Project area comprises approximately 20 acres in the northern portion of the existing Plant site, and includes the approximately 6-acre north gas turbine site containing 12 gas turbines as well as approximately 14 acres of surrounding forested wetlands and upland spoil piles.

2. Listed Species

No negative impacts to threatened or endangered species are anticipated as a result of the CT Project.

Based upon the field assessment conducted in 2013, review of United States Fish and Wildlife (USFWS) and Florida Fish and Wildlife Conservation Commission (FWC) literature and databases, the Florida Natural Areas Inventory (FNAI) database of documented listed species occurrences, and the lack of suitable habitat, federally listed species are not anticipated to utilize the CT Project area. The potential occurrence of listed flora and fauna within the CT Project area is limited due to the surrounding land uses (industrial, commercial, and residential areas, as well as Ft. Lauderdale-Hollywood International Airport), and lack of suitable habitat within and surrounding the CT Project area to support partial or full life-cycle requirements of federally listed species known to occur within Broward County.

3. Natural Resources of Regional Significance Status

The construction and operation of the CT Project at this location is consistent with the existing use at the site and is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands. No named wetlands, named surface waters, Outstanding Florida Waters, or Aquatic Preserves would be impacted by the proposed Project.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

In the event monitoring confirms that emissions from operation of the existing GTs would not comply with the NO_2 regulations, the design option is to remove 24 gas turbines (GTs) at the existing Lauderdale Plant, and an additional 12 simple cycle GTs at their nearby Port Everglades Plant, and replace them with five new highly efficient simple cycle combustion turbines (CTs). The CTs operate in simple cycle mode with associated stacks and produce electrical energy by direct connection to an electric generator. The CTs will operate using natural gas and ultra-low sulfur distillate (ULSD) oil as fuel.

g. Local Government Future Land Use Designations

The site is zoned General Industrial by the City of Dania Beach, a designation intended to provide for light and medium intensity industrial, research, and assembly fabrication uses. Electrical power plants are permitted within a General Industrial zoning designation as a special exception use only.

A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Lauderdale Plant site has been selected as a "Preferred" for the location of peaking unit facilities due to consideration of various factors including maximizing opportunities to utilize existing utility infrastructure, system load, transmission interconnection, and economics.

i. Water Resources

The Project will require a marginal increase in demineralized water that will be obtained from the existing Lauderdale Plant's water treatment system.

j. Geological Features of Site and Adjacent Areas

According to the Natural Resource Conservation Service (NRCS) Soil Survey of Broward County, the Project area is dominated by Okeelanta muck, with Udorthents, shaped as a minor association.

The Okeelanta series consists of very deep, very poorly drained, rapidly permeable soils in large fresh water marshes and small depressional areas. They formed in decomposed hydrophytic non-woody organic material overlying sand. Slopes range from zero to two percent. In un-drained areas the water table is at depths of less than ten inches below the surface or the soil is covered by water 6 to 12 months during most years. Areas of Okeelanta muck within the Project area support a mixed native and exotic hardwood wetland community.

k. Projected Water Quantities for Various Uses

The CT Project consists of CTs that are operated in simple cycle mode and do not require a heat dissipation system. As a result, there are no associated cooling water uses, cooling water discharges, or other heat dissipation impacts.

l. Water Supply Sources by Type

The CT Project would continue to acquire water from existing water contracts with Broward County. Therefore, the Project will have no adverse impact to groundwater. The CT Project would not use onsite groundwater or a new groundwater source for any purpose. The CT Project would have no adverse impact to surface water.

The CT Project would continue to use municipal potable water from the City of Hollywood to provide drinking water for employees. There is no projected increase in employment at the Lauderdale Plant as a result of the CT Project and no associated potable water use increase for that purpose. Therefore, there would be no impact to drinking water sources from the CT Project.

m. Water Conservation Strategies Under Consideration

No additional water resources would be required as a result of the CTs project.

n. Water Discharges and Pollution Control

There would be no surface water discharges required for the operation of the CT Project, other than storm water discharges from non-contact areas. Operation of the CT Project would not generate leachate and the stormwater management system has been designed to prevent direct discharge to surface waters. Therefore, there would be no adverse impact to water supplies due to runoff or leachate from the CT Project.

The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The fuel to be used in the CTs is natural gas and ULSD oil. Natural gas will be transported to the facility via existing pipeline. No onsite storage is provided for natural gas. ULSD oil would be trucked or piped to the facility and stored in double walled ULSD oil tanks.

p. Air Emissions and Control Systems

Air emission rates for NOx with the CT Project would be approximately 90 percent lower than the existing GT emission rates, resulting in significantly lower air quality impacts. In addition to lower air emissions, the maximum total air quality impacts for the CT Project are predicted to be well below and in compliance with the National Ambient Air Quality Standards (NAAQS). For pollutants such as NO_2, the CT Project's total air quality impacts are predicted to be significantly reduced by 40 percent or more compared to the existing GTs.

The use of clean fuels (natural gas and ULSD oil) and combustion controls would minimize air emissions of SO_2, sulfuric acid mist (SAM), particulates (PM/PM10/PM2.5), and other fuel-bound contaminants and ensure compliance with applicable emission-limiting standards. Combustion controls will minimize the formation of NOx and the formation of CO and VOCs by combustor design. Further NOx reduction will be achieved by water injection during oil firing.

q. Noise Emissions and Control Systems

It is not expected that noise from the CT Project would exceed the maximum permissible sound levels in Section 17-86 of the City of Dania Beach noise ordinance. The operation of the CTs is not expected to exceed the City of Dania Beach maximum permissible sound levels in residential areas.

The design of the CT Project includes components that mitigate noise from being emitted to the surrounding environment. The majority of the noise sources, such as the CTs, are located within enclosures that mitigate sounds emitted by equipment.

Noise expected to be caused by unit construction at the site is expected to be below current noise levels for the residents nearest the site.

r. Status of Applications

No licenses or permits have been issued for the CT Project. FPL has submitted applications to: the Florida Department of Environmental Protection (FDEP) for the Prevention of Significant Deterioration (PSD) air permit; U.S. Environmental Protection Agency (EPA) for the Greenhouse Gas air permit; and to the U. S. Army Corps of Engineers (USACE) for the 404 dredge and fill permit. These applications are currently in review with the respective agencies.

Preferred Site # 3: Hendry County, Hendry County

FPL has acquired an approximately 3,120-acre site in southeast Hendry County, off CR 833. The Hendry County site has been listed as a Preferred or Potential Site in previous FPL Site Plans as a possibility for a future PV facility and/or natural gas-fired CC generation. FPL currently views the Hendry site as one of the most likely sites to be used for future large-scale generation.

a. Geological Survey (USGS) Map

A USGS map of the site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the property owned by FPL is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The existing and future land uses on the site are zoned Planned Unit Development (PUD). The PUD is currently being challenged. The existing land uses that are adjacent to the site are predominately agricultural. The property to the south is the Seminole Big Cypress Reservation.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The natural environment adjacent to the north, east, and west of the site are used predominately for agricultural activities such as improved, unimproved, and woodland pasture. The majority of the pasture lands includes upland scrub, pine, and hardwoods. The Seminole Big Cypress Reservation lies to the south.

2. Listed Species

FPL strives to have no adverse impacts on federal- or state-listed terrestrial plants and animals. Much of southwest Florida is considered habitat for the endangered Florida

Panther. Although few or no impacts are expected in association with future construction at the site, FPL anticipates minimizing or mitigating for unavoidable wildlife or wetland impacts.

3. Natural Resources of Regional Significance Status

Future construction and operation of a solar and/or a natural gas-fired CC generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

Options include construction of CC and/or solar power generation technologies. Mitigation for unavoidable impacts may occur through a combination of on- and off-site mitigation.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is Utility. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Hendry County site has been selected as "Preferred" due to consideration of various factors including system load, transmission interconnection, and economics.

i. Water Resources

Groundwater is anticipated to supply water to the Hendry County site.

j. Geological Features of Site and Adjacent Areas

The site is at an approximate elevation of 10 to 12 feet above mean sea level (msl) and is located on the Immokalee Rise and the Big Cypress Spur considered terraces created by high sea level events. The terraces are composed of fine quartz sands that lie discontinuously upon the surficial aquifer system whose sediments are the Fort Thompson (Pleistocene), Caloosahatchee Marl (Pleistocene and Pliocene), and Tamiami Formations (Pliocene). Other soil types in the area include limestone rock, calcareous muds, sands, organic materials, and mixed solids.

The surficial aquifer is underlain by the Hawthorn formation (confining unit). The Floridan Aquifer System underlies the Hawthorn formation.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for processing at a CC unit is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Potable water demand is expected to average .001 mgd. Minimal amounts of water would be required for a PV facility. Approximately 7.5 mgd of cooling water would be used in cooling towers for one CC unit.

l. Water Supply Sources by Type

Potential water supply source is groundwater. Additional evaluations are necessary to determine the exact source. Process and potable water for the new plant will come from the existing potable water supply.

m. Water Conservation Strategies Under Consideration

CC and cooling tower technologies utilize less water by design than traditional steam generation units. PV facilities have minimal water demands. Specific water conservation strategies will be evaluated and selected during the detailed design phase of any development project.

n. Water Discharges and Pollution Control

A CC unit at the site would utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's cooling water flow prior to discharge. Wastewater disposal is anticipated via discharge to an Underground Injection Control well system. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ a Best Management Practices (BMP) plan and Spill Prevention, Control, and Countermeasure (SPCC) plan to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral to the site. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary Ultra-low sulfur light fuel oil will be received by truck or pipeline and stored in an above-ground storage tank.

p. Air Emissions and Control Systems

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize regulated air emissions from a CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of SO_2, PM, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of NO_x and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra low sulfur fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA's proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida. PV generation does not produce air emissions.

q. <u>Noise Emissions and Control Systems</u>

Noise anticipated to be caused by unit construction at the site is expected to be minimal.

r. <u>Status of Applications</u>

FPL has not submitted any application associated with the Hendry County site.

<u>Preferred Site # 4: NE Okeechobee County, Okeechobee County</u>

FPL has purchased a site of approximately 2,800 acres in Northeast Okeechobee County. The site is in an unincorporated, rural area and is predominantly used for agricultural production. FPL's transmission lines intersect the property. The Northeast Okeechobee County site has been listed as a Preferred or Potential Site in previous FPL Site Plans as a possibility for a natural gas-fired CC generation and/or future PV facility. Natural gas-fired CC generation will be made possible by the May,2017 projected commercial operating date of the Florida Southeast Connection (FSC) natural gas pipeline. FSC is within 3 miles of the NE Okeechobee County site. FPL currently views the Okeechobee site as one of the most likely sites to be used for future large-scale generation.

a. <u>U.S. Geological Survey (USGS) Map</u>

A USGS map of the Northeast Okeechobee site is found at the end of this chapter.

b. <u>Proposed Facilities Layout</u>

A map of the property owned by FPL is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The Northeast Okeechobee County site is predominantly used for agricultural production (cattle and citrus). Adjacent land uses include primarily agriculture and conservation.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is comprised of lands dedicated to agricultural production.

2. Listed Species

Minimal impacts to federal- or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species.

3. Natural Resources of Regional Significance Status

The construction and operation of a power generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

Options include construction of PV or CC technologies. Mitigation for unavoidable impacts may occur through a combination of on- and off-site mitigation.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is predominantly unimproved pasture. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Northeast Okeechobee County site has been selected as a Preferred Site due to consideration of various factors including system load, transmission interconnection, the proximity of the proposed FSC natural gas pipeline, and economics. Environmental issues were not a deciding factor since this site does not exhibit significant environmental sensitivity.

i. Water Resources

Groundwater is anticipated to supply water to the Northeast Okeechobee County site.

j. Geological Features of Site and Adjacent Areas

The hydrostratigraphy of the Northeast Okeechobee County site is similar to that of most of South Florida. In general, the groundwater system underlying Okeechobee County consists of the Surficial Aquifer System (SAS), the Intermediate Confining Unit (ICU), and the Floridan Aquifer System (FAS). The SAS consists of approximately 100 to 250 feet of undifferentiated deposits of sand, shell, clay and silt. The ICU consists of approximately 200 feet of carbonate rocks interbedded with sandy and silty clay. The multiple layers of the FAS extend thousands of feet below the ICU.

k. Projected Water Quantities for Various Uses

Potable water demand is expected to average .001 mgd. The estimated quantity of water required for processing at a CC unit is approximately 0.24 million gallons per day (mgd) for uses such as process water and service water. Approximately 7.5 mgd of cooling water would be used in cooling towers for a CC unit. Minimal amounts of water would be required for a PV facility.

l. Water Supply Sources by Type

Potential water supply source is groundwater. Additional evaluations are necessary to determine the exact source. Process and potable water for the new plant will come from the existing a potable water supply.

m. Water Conservation Strategies Under Consideration

CC technology utilizes less water by design than traditional steam generation units. PV facilities have minimal water demands. Specific water conservation strategies will be evaluated and selected during the detailed design phase of any development project.

n. Water Discharges and Pollution Control

A CC plant is anticipated to utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's cooling water flow prior to discharge. Wastewater disposal is anticipated via discharge to an Underground Injection Control well system. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ Best

Management Practices (BMP) and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o. <u>Fuel Delivery, Storage, Waste Disposal, and Pollution Control</u>

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary. Back-up fuel supplies of ultra-low sulfur light fuel oil will be received by truck or pipeline and stored in an above-ground storage tank to ensure reliability of operations.

p. <u>Air Emissions and Control Systems</u>

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize regulated air emissions from a CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of SO_2, PM, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of NO_x and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra-low sulfur light fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA's proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions, and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida. PV generation does not produce air emissions.

q. <u>Noise Emissions and Control Systems</u>

Noise anticipated to be caused by unit construction at the site is expected to be minimal.

r. <u>Status of Applications</u>

FPL has not filed any applications associated with the Northeast Okeechobee County site.

<u>Preferred Site # 5: Putnam Site, Putnam County</u>

FPL is currently evaluating the existing Putnam Plant site for future natural gas-fired generation as part of a potential modernization project. This 66 acre site is located on the east side of Highway 100 opposite the former FPL Palatka Plant in East Palatka. The Putnam site has been listed as a Potential Site in previous FPL Site Plans as a possibility for future natural gas-fired CC generation.

FPL currently views the Putnam site as one of the most likely sites to be used for future large-scale generation.

a. U.S. Geological Survey (USGS) Map

A USGS map of the Putnam site is found at the end of this chapter.

b. Proposed Facilities Layout

A map of the property owned by FPL is found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

The Putnam site is designated as Industrial land use. Adjacent land uses include power generation and associated facilities (the former Palatka Plant) as well as Mixed Wetland Hardwoods, Residential, and Hardwood-Coniferous Mixed.

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

The majority of the site is developed and has facilities necessary for power plant operations. No significant environmental features have been identified at this time.

2. Listed Species

Minimal impacts to federal- or state-listed terrestrial plants and animals are expected in association with construction at the site, due to the existing developed nature of the site and lack of suitable onsite habitat for listed species.

3. Natural Resources of Regional Significance Status

The construction and operation of a power generating facility at this location is not expected to have any adverse impacts on parks, recreation areas, or environmentally sensitive lands.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

Options include construction of CC technology. Mitigation for unavoidable impacts may occur through a combination of on- and off-site mitigation.

g. Local Government Future Land Use Designations

Local government future land use designation for the site is Industrial. A land use map of the site and adjacent areas is also found at the end of this chapter.

h. Site Selection Criteria Process

The Putnam site has been selected as a Preferred Site due to consideration of various factors including system load, transmission interconnection, and economics.

i. Water Resources

The St John's River and/or regional water supply initiatives are potential water sources.

j. Geological Features of Site and Adjacent Areas

The hydrostratigraphy of the Putnam site is similar to that of most of North Florida. In general, the groundwater system underlying Putnam consists of the Surficial Aquifer System (SAS), and the Floridan Aquifer System (FAS).

k. Projected Water Quantities for Various Uses

Potable water demand is expected to average .001 million gallons per day (mgd). The estimated quantity of water required at a CC unit is approximately 0.24 mgd for uses such as process water and service water. Approximately 7.5 mgd of cooling water would be used in cooling towers for a CC unit.

l. Water Supply Sources by Type

Potential water supply source is the St. John's River. Additional evaluations are necessary to determine the exact source. Process and potable water for the new plant will come from the existing a potable water supply.

m. Water Conservation Strategies Under Consideration

CC and cooling tower technologies utilize less water by design than traditional steam generation units. Specific water conservation strategies will be evaluated and selected during the detailed design phase of the project development.

n. Water Discharges and Pollution Control

A CC plant is anticipated to utilize a closed cycle cooling (towers) system for heat dissipation. The heat recovery steam generator blowdown will be reused to the maximum extent practicable or mixed with the cooling water flow before discharge. Reverse osmosis (R/O) reject will be mixed with the plant's cooling water flow prior to discharge. Wastewater disposal is anticipated via discharge to surface and/or ground water as is the case with the existing Putnam Plant. Stormwater runoff would be collected and routed to stormwater ponds. The facility will employ Best Management Practices (BMP) and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

Natural gas for a new CC unit will be transported to the site via a new natural gas pipeline lateral. New gas compressors to raise the gas pressure of the pipeline to the appropriate level for the new unit may be necessary. Back-up fuel supplies of ultra-low sulfur light fuel oil will be received by water-borne delivery, truck, or pipeline and stored in an above-ground storage tank to ensure reliability of operations.

p. Air Emissions and Control Systems

The use of natural gas, ultra-low sulfur light fuel oil, and combustion controls would minimize regulated air emissions from a CC unit and ensure compliance with applicable emission limiting standards. Using these clean fuels minimizes emissions of SO_2, PM, and other fuel-bound contaminates. Combustion controls similarly minimize the formation of NO_x and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during operations when using ultra- low sulfur light fuel oil as backup fuel. CC facility emissions of GHGs from combustion of natural gas achieve an emission rate substantially lower than the EPA's proposed new source performance standards for GHGs. These design alternatives are equivalent to the Best Available Control Technology for air emissions and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of a CC unit would incorporate features that would make it among the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise anticipated to be caused by unit construction at the site is expected to be minimal.

r. Status of Applications

FPL has not submitted any applications associated with the Putnam site.

Preferred Site # 6: Turkey Point Plant, Miami-Dade County

The Turkey Point Plant (Turkey Point) is located on the west side of Biscayne Bay, 25 miles south of Miami. Turkey Point is directly on the shoreline of Biscayne Bay and is geographically located approximately 9 miles east of Florida City on Palm Drive. The land surrounding Turkey Point is owned by FPL and acts as a buffer zone. Turkey Point is comprised of two natural gas/oil conventional steam units (Units 1 & 2), two nuclear units (Units 3 & 4), one combined cycle natural gas unit (Unit 5), nine small diesel generators, and the cooling canals. A capacity uprate project for the two nuclear units was successfully completed in 2013. The Everglades Mitigation Bank (EMB), an approximately 13,000 acre, FPL-maintained natural wildlife and wetlands area that has been set aside, is located to the south and west of the site.

In regard to Turkey Point Units 6 & 7, FPL is pursuing licensing for two new nuclear units at Turkey Point. Each of these two units would provide 1,100 MW of capacity. The current projections for the earliest in-service dates for the two new units remain 2022 (for Turkey Point Unit 6) and 2023 (for Turkey Point Unit 7). In addition to the two generating units, supporting buildings, facilities, and equipment will be located on the Turkey Point Units 6 & 7 site, along with a construction laydown area. Proposed associated facilities include: a nuclear administration building, a training building, a parking area, an FPL reclaimed water treatment facility and reclaimed water pipelines, radial collector wells and delivery pipelines, an equipment barge unloading area, transmission lines (and transmission system improvements elsewhere within Miami-Dade County), access roads and bridges, and potable water pipelines.

a. U.S. Geological Survey (USGS) Map

USGS maps of the Turkey Point area, with the proposed location of Turkey Point Units 6 & 7 identified, are found at the end of this chapter.

b. Proposed Facilities Layout

Maps of the general layout of Turkey Point Units 6 &7 are found at the end of this chapter.

c. Map of Site and Adjacent Areas

Land Use / Land Cover overview maps of the Turkey Point Units 6 & 7 site and adjacent areas are also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

Turkey Point Plant is currently home to five generating units and support facilities that occupy approximately 150 acres of the approximately 9,400-acre Turkey Point property. Prominent features beyond the power block area include the intake system, cooling canal system, switchyard, spent fuel storage facilities, and technical and administrative support facilities The cooling canal system occupies approximately 5,900 acres.

The two 400-megawatt (MW) (nominal) fossil fuel-fired steam electric generation units at Turkey Point have been in service since 1967 (Unit 1) and 1968 (Unit 2). These units have historically burned residual fuel oil and/or natural gas with a maximum equivalent sulfur content of one percent. Unit 2 is currently serving, not as a power generating unit, but as a synchronous condenser to provide voltage support to the southeastern end of FPL's transmission system. The two original 700-MW (nominal) nuclear units have been in service since 1972 (Unit 3) and 1973 (Unit 4) and were uprated to a total of approximately 1,632 (Summer) MW's in 2013. Turkey Point Units 3 and 4 are pressurized water reactor (PWR) units. Turkey Point Unit 5 is a net 1,148 (Summer) MW natural gas-fired combined cycle unit that began operation in 2007. The site for the new Units 6 & 7 is south of existing Units 3 and 4 and occupies approximately 300 acres within the existing cooling canal system.

Properties adjacent to Turkey Point property are almost exclusively undeveloped land. The FPL-owned EMB is adjacent to most of the western and southern boundaries of Turkey Point property. The South Florida Water Management District (SFWMD) Canal L-31E is also situated to the west of Turkey Point property. The eastern portions of Turkey Point property are adjacent to Biscayne Bay, the Biscayne National Park (BNP), and Biscayne Bay Aquatic Preserve. The southeastern portion of Turkey Point property is bounded by state-owned land located on Card Sound. The Homestead Bayfront Park, owned and operated by Miami-Dade County, is situated to the north of the Turkey Point property.

e. <u>General Environment Features On and In the Site Vicinity</u>

1. <u>Natural Environment</u>

Turkey Point is located directly on the northwest, west, and southwest shoreline of Biscayne Bay and the Biscayne National Park, 25 miles south of Miami. Biscayne National Park was first established in 1968 as a National Monument and was expanded in 1980 to approximately 173,000 acres of water, coastal lands, and 42 keys. A portion of Biscayne Bay Aquatic Preserve, a state-owned preserve, is adjacent to the eastern boundary of the Turkey Point plant property. The Biscayne Bay Aquatic Preserve is a shallow, subtropical lagoon consisting of approximately 69,000 acres of submerged State land that has been designated as an Outstanding Florida Water.

The approximately 300-acre Turkey Point Units 6 & 7 site consists of the plant area and adjacent areas designated for laydown and ancillary facilities. The site includes hypersaline mud flats, man-made active cooling canals, man-made remnant canals, previously filled areas/roadways, mangrove heads associated with historical tidal channels, dwarf mangroves, open water /discharge canal associated with the cooling canals on the western portion of the site, wet spoil berms associated with remnant canals, and upland spoil areas.

2. Listed Species

Threatened, endangered, and/or animal species of special concern known to occur at the site, transmission line corridors, or in the nearby Biscayne National Park, include the peregrine falcon *(Falco peregrinus)*, wood stork *(Mycteria americana)*, American crocodile *(Crocodylus acutus)*, roseate spoonbill (*Ajaja ajaja)*, little blue heron *(Egretta caerulea),* snowy egret *(Egretta thula),* American oystercatcher *(Haematopus palliates),* least tern *(Sterna antillarum)*, the white ibis *(Eudocimus albus)*, Florida manatee (Trichechus manatus latirostris), eastern indigo snake (Drymarchon couperi), snail kite (Rostrhamus sociabilis plumbeus), white-crowned pigeon (Patagioenas leucocephala), and bald eagle *(Haliaeetus leucocephalus)*. No bald eagle nests are known to exist in the vicinity of the site. The federally listed, threatened American crocodile thrives at Turkey Point, primarily in and around the southern end of the cooling canals which lie south of the Turkey Point Unit 6 & 7 area. The majority of Turkey Point is considered American crocodile habitat due to the mobility of the species and use of the site for foraging, traversing, and basking. FPL manages a program for the conservation and enhancement of the American Crocodile and the program is credited with survival improvement and contributing to the downlisting of the American Crocodile from endangered to threatened.

Some listed flora species likely to occur at the site or vicinity include pinepink (Bletia purpurea), Florida brickell-bush (Brickellia mosieri), Florida lantana (Lantana depressa var. depressa), mullien nightshade (Solanum donianum), and lamarck's trema (Trema lamarckianum).

The construction, and operation after construction, of Turkey Point Unit 6 & 7 project is not expected to adversely affect any rare, endangered, or threatened species.

3. Natural Resources of Regional Significance Status

Significant features within the vicinity of the site include Biscayne National Park, the Biscayne Bay Aquatic Preserve, Miami-Dade County Homestead Bayfront Park, and Everglades National Park. The portion of Biscayne Bay adjacent to the site is included within the Biscayne National Park. Biscayne National Park contains 180,000 acres, approximately 95 percent of which is open water interspersed with more than 40 keys. The Biscayne National Park headquarters is located approximately two miles north of Turkey Point and is adjacent to the Miami-Dade County Homestead Bayfront Park, which contains a marina and day-use recreational facilities.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

For Turkey Point Units 6 & 7, the technology proposed is the Westinghouse AP1000 pressurized water reactor (PWR). This design is certified by the Nuclear Regulatory Commission (NRC) under 10 CFR 52 and incorporates the latest technology and more advanced safety features than today's nuclear plants that have already achieved record safety levels. The Westinghouse AP1000 unit consists of the reactor, steam generators, pressurizer, and steam turbine/electric generator. Condenser cooling for the Units 6 & 7 steam turbines will be accomplished using six circulating water cooling towers. The makeup water reservoir is the reinforced concrete structure beneath the circulating water system cooling towers that will contain reserve reclaimed water capacity to be used for the circulating water system. The structures for the Westinghouse AP1000 are the nuclear island (containment building, shield building, and auxiliary building), turbine building, annex building, diesel generator building, and radwaste building. The plant area will also contain the Clear Sky substation (switchyard) that will connect Units 6 & 7 to FPL's transmission system.

g. Local Government future Land Use Designations

The Turkey Point Plant site is designated by the Miami-Dade County Comprehensive Development Management Plan as an IU-3 (Industrial, Utilities, and Communications) Unlimited Manufacturing District that carries a dual designation of MPA (Mangrove Protection Area) in portions of the property. There are also areas designated GU – "Interim District." Designations for the surrounding area are primarily GU – "Interim District."

h. Site Selection Criteria Process

For Turkey Point Units 6 & 7, FPL conducted an extensive site selection analysis leading to the selection of the Turkey Point site as the site that, on balance, provided the most favorable location for developing new nuclear generation to serve FPL's customers. The Site Selection Study employed the principles of the Electric Power Research Institute (EPRI) siting guidelines and is modeled upon applicable NRC site suitability and National Environmental Policy Act (NEPA) criteria regarding the consideration of alternative sites. The study convened a group of industry and FPL subject matter experts to develop and assign weighting factors to a broad range of site selection criteria. Twenty-three candidate sites were then ranked using the siting criteria. This review allowed the list of candidates to be reduced until the best site emerged. Key factors contributing to the selection of the Turkey Point site include the existing transmission and transportation infrastructure to support new generation, the large size and seclusion of the site while being relatively close to the load center, and the long-standing record of safe and secure operation of nuclear generation at the site since the early 1970s.

i. Water Resources

In regard to Turkey Point Units 6 & 7, the primary source of cooling water makeup will be reclaimed water from the Miami-Dade County Water and Sewer Department (MDWASD), with potable water also from MDWASD. When reclaimed water is not available in sufficient quantity and quality of water needed for cooling, makeup water will be saltwater supplied by radial collector wells that are recharged from the marine environment of Biscayne Bay. Horizontal collector wells (radial collector wells) have become widely used for the purpose of inducing infiltration from surface water bodies into hydraulically-connected aquifer systems in order to develop moderate to high capacity water supplies. Turkey Point Units 6 & 7 wastewater will be discharged via on-site deep injection wells.

j. Geological Features of Site and Adjacent Areas

Turkey Point lies upon the Floridian Plateau, a partly-submerged peninsula of the continental shelf. The peninsula is underlain by approximately 4,000 to 15,000 feet of sedimentary rocks consisting of limestone and associated formations that range in age from Paleozoic to Recent. Little is known about the basement complex of Paleozoic igneous and metamorphic rocks due to their great depth.

Generally in Miami-Dade County, the surficial aquifer (Biscayne Aquifer) consists of a wedge-shaped system of porous clastic and carbonate sedimentary materials, primarily limestone and sand deposits of the Miocene to late Quaternary age. The Biscayne Aquifer is thickest along the eastern coast and varies in thickness from 80 to 200 feet thick. The surficial aquifer is typically composed of Pamlico Sand, Miami Limestone (Oolite), the Fort Thompson and Anastasia Formations (lateral equivalents), Caloosahatchee Marl, and the Tamiami formation. The lower confining layers below the surficial aquifer range in thickness from 350 to 600 feet and are composed of the Hawthorn Group. Beneath the Hawthorn Group, the Floridan Aquifer System ranges from 2,800 to 3,400 feet thick and consists of Suwannee Limestone, Avon Park Limestone, and the Oldsmar Formations.

k. Projected Water Quantities for Various Uses

The estimated quantity of water required for the new Turkey Point Units 6 & 7 for industrial processing is approximately 936 gallons per minute (gpm) for uses such as process water and service water. Approximately 55.3 million gallons per day (mgd) of cooling water would be cycled through the cooling towers. Water quantities needed for other uses such as potable water are estimated to be approximately 50,400 gallons per day (gpd) for Units 6 & 7.

l. Water Supply Sources and Type

The water for the various water needs of Turkey Point 6 & 7 will be obtained from a reclaimed water supply, a saltwater supply, and a potable water supply. Reclaimed water will be used as makeup water to the cooling water system with saltwater from radial collector wells as a back-up water source to be used when reclaimed water is not available in sufficient quantity or quality.

Potable water will be used as makeup water for the service water system. The potable water supply will also provide water to the fire protection system, demineralized water treatment system, and other miscellaneous uses.

m. Water Conservation Strategies

Use of reclaimed water from MDWASD Turkey Point Units 6 & 7 is a beneficial and cost-effective means of increasing the use of reclaimed water. This use of reclaimed water helps Miami-Dade County meet approximately half of its wastewater reuse goals and will provide environmental benefits by reducing the volume of wastewater discharged by the County. In the absence of reuse opportunities, this treated domestic wastewater would likely continue to be discharged to the ocean or into deep injection wells.

Miami-Dade County is required to eliminate ocean outfalls and increase the amount of water that is reclaimed for environmental benefit and other beneficial uses. Turkey Point Units 6 & 7 will use reclaimed water 24 hours per day, 365 days per year when operating and when the reclaimed water is available in sufficient quantity and quality.

n. Water Discharges and Pollution Control

Turkey Point Units 6 & 7 will dissipate heat from the power generation process using cooling towers. Blowdown water or discharge from the cooling towers, along with other wastestreams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Storm water runoff will be released to the closed-loop cooling canal system.

Turkey Point Units 6 & 7 will employ Best Management Practices (BMP) plans and Spill Prevention, Control, and Countermeasure (SPCC) plans to prevent and control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The Turkey Point Units 6 & 7, reactors will contain enriched uranium fuel assemblies. A fuel assembly consists of 264 fuel rods, 24 guide thimbles, and 1 instrumentation tube in a 17-by-

17 square array. The fuel rods consist of enriched uranium, in the form of cylindrical pellets of sintered uranium dioxide contained in ZIRLO™ tubing.

New fuel assemblies will be transported to Turkey Point for use in Units 6 & 7 by truck from a fuel fabrication facility in accordance with U.S. Department of Transportation (DOT) and NRC regulations. Spent fuel assemblies being discharged will remain in the spent fuel pool while short half-life isotopes decay.

After a sufficient decay period, the fuel would be transferred to an on-site independent spent fuel storage installation facility or an off-site disposal facility. Packaging of the fuel for off-site shipment will comply with the applicable DOT and NRC regulations for transportation of radioactive material.

The U.S. Department of Energy (DOE) is responsible for spent fuel transportation from reactor sites to a repository under the Nuclear Waste Policy Act of 1982, as amended. FPL has executed a standard spent nuclear fuel disposal contract with DOE for fuel used in Units 6 & 7.

p. <u>Air Emissions and Control Systems</u>

Turkey Point Units 1, 2, and 5, and the emergency diesel generators associated with Units 3 and 4, are classified as a major source of air pollution. FDEP has issued a separate Title V Air Operating Permit for the fossil units at Turkey Point and for the emergency diesel generators associated with the nuclear units. There are no operating limits for the emergency generators or diesel engines. Emergency diesel generators are limited to use ultra-low sulfur diesel fuel (0.0015% sulfur). NO_x emissions are regulated under Reasonably Available Control Technology (RACT) requirements in Rule 62-296.570(4) (b) 7 F.A.C., which limit NO_x emissions to 4.75 lb/MMBtu. The use of 0.05 percent sulfur diesel fuel and good combustion practices serve to keep NO_x emissions under this limit.

Regarding Turkey Point Units 6 & 7, the units will also minimize FPL system air pollutant emissions by using nuclear fuel to generate electric power. This includes avoiding emissions of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), carbon dioxide (CO_2), and volatile organic compounds (VOC). The circulating water cooling towers will be equipped with high-efficiency drift or mist eliminators to minimize emissions of PM to 0.0005 percent of the circulating water; which represents 99.99-percent control of potential drift emissions based on the circulating water flow.

The diesel engines necessary to support Turkey Point Units 6 & 7 and fire pump engines will be purchased from manufacturers whose engines meet the EPA's New Source Performance Standards (NSPS) Subpart IIII emission limits.

q. <u>Noise Emissions and Control Systems</u>

Field surveys and impact assessments of noise expected to be caused by activities associated with the Turkey Point Units 6 & 7 project were conducted. Predicted noise levels associated with these projects are not expected to result in adverse noise impacts in the vicinity of the site.

r. <u>Status of Applications</u>

The Turkey Point Units 6 & 7 Site Certification Application (SCA), under the Florida Electrical Power Plant Siting Act, was filed in June 2009 and a final order is anticipated in mid-2014. The FPSC issued the final order approving the need for this additional nuclear capacity in April 2008.

A Combined License Application for Units 6 & 7 was submitted to the NRC in June 2009. There are two components to that application; one is the Environmental Assessment (EA) and the other is the Safety component. The Application is still in process.

Besides the certification and the license, additional approvals have been issued for Turkey Point Units 6 & 7 including Miami-Dade County Unusual Use approvals that were issued in 2007 and 2013 and a Land Use Consistency Determination that was issued in 2013. The Prevention of Significant Deterioration (Air permit) was issued in 2009. In addition, a permit to construct an exploratory well and a dual zone monitoring well, under the Underground Injection Control Program, was issued in 2010, and a permit to convert the exploratory well, to an injection well and to operationally test the system, was issued in 2013. Permits from the Federal Aviation Administration (FAA) for the containment structure were originally issued in 2009 and renewed in 2012.

The western transmission lines associated with Units 6 & 7 (2 500 kV New Clear Sky Substation – Levee Substation and 1 230 kV New Clear Sky Substation – Pennsuco Substation) will utilize the existing approximately 40-mile-long transmission line right-of-way acquired by FPL in the 1960s and early 1970s between the Turkey Point plant property and Levee Substation. A 7.4 mile long segment of that existing right-of-way became surrounded by the Everglades National Park in 1989 when the East Everglades Expansion Area south of Tamiami Trail (US-41) was added to the Park. The National Park Service and several other federal, state and local agencies entered into contingent agreements in 2008 to exchange

FPL's fee-owned property within the Park for an alternative right-of-way along the Park's eastern boundary (the Exchange Right-of-Way). That land exchanges was authorized by the U.S. Congress in the 2009 Omnibus Public Lands Management Act, and the National Park Service is currently engaged in a National Environmental Policy Act (NEPA) review of the proposed exchange. The Recommended Order to be considered by the Siting Board in 2014 recommends for approval FPL's West Preferred Corridor, which includes the Exchange Right-of-Way, as a back-up western transmission line corridor to another corridor. The primary western corridor recommended for approval is the West Consensus Corridor (comprising an alternate corridor proposed by the Miami-Dade Limestone Products Association and a portion of FPL's West Preferred Corridor). Both of those western transmission line corridors recommended for certification use the Exchange Right-of-Way. In the event the pending land exchange with the National Park Service and other agencies is not consummated on a timely basis, FPL will need to evaluate other potential western corridors for the western transmission lines associated with Units 6 & 7, including its existing fee-owned right-of-way in the Park, and seek necessary approvals for construction of the required transmission facilities.

IV.F.2 <u>Potential Sites for Generating Options</u>

Four (4) sites are currently identified as Potential Sites for future generation additions to meet FPL's projected capacity and energy needs.[6] These sites have been identified as Potential Sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are suitable for different capacity levels and technologies, including both renewable energy and non-renewable energy technologies for various sites.

Each of these Potential Sites offer a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has different characteristics that will require further definition and attention.

Permits are presently considered to be obtainable for each of these sites. No significant environmental constraints are currently known for any of these sites. The Potential Sites briefly discussed below are presented in alphabetical order. At this time, FPL considers each site to be equally viable.

[6] As has been described in previous FPL Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites and other Greenfield sites. Greenfield sites that FPL currently does not own, or for which FPL has not currently secured the necessary rights to, are not specifically identified as Potential Sites in order to protect the economic interests of FPL and its customers.

Potential Site # 1: Babcock Ranch, Charlotte County

This site is located within the proposed Babcock Ranch Community on the north side of Tuckers Grade, approximately 10.5 miles north of the intersection of SR-80 and SR-31 and 1.1 miles east of SR-31. The project is bordered on the north by the Babcock Ranch Preserve owned by the State of Florida. This site is a possibility for an FPL PV facility. FPL has received all permits necessary to construct a 74 MW PV facility at this location.

a. U.S. Geological Survey (USGS) Map

A map of this site is found at the end of this chapter.

b. Land Uses

Existing land use on the site is the Babcock Ranch Overlay District, and it is zoned as the Babcock Ranch Overlay Zoning District. This land use and zoning allows for solar facilities.

c. Environmental Features

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

d. Water Quantities

Minimal amounts of water, if any, would be required for a PV facility.

e. Supply Sources

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water may be brought to the site by truck.

Potential Site # 2: DeSoto Solar Expansion, DeSoto County

The DeSoto site is located at 4051 Northeast Karson Street which is approximately 0.3 miles east of U.S. Highway 17 and immediately north of Bobay Road in Arcadia, Florida. The site is located in Sections 26, 27, & 35, Township 36 South, and Range 25 East. FPL owns an approximate 13,000 acre parcel in DeSoto County. FPL has designated approximately 5,177 acres for development of a PV facility.

The DeSoto site is home to a 25 MW PV facility that has been operational since 2009. Up to an additional 275 MW of PV generation could be constructed in phases on the remaining undeveloped land. FPL has initiated permitting for the additional PV facilities.

a. U.S. Geological Survey (USGS) Map

A map of this site is found at the end of this chapter.

b. Land Uses

Existing land use on the site is agricultural. The future land use is Electric Generating Facility.

c. Environmental Features

There are no significant environmental features on the site.

d. Water Quantities

Minimal amounts of water would be required for a future expansion of the existing PV facility.

e. Supply Sources

Minimal water would be required for an expanded PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall. Potable water will be required in the administration building and maintenance building. FPL would propose to utilize existing wells onsite to accommodate water needs.

Potential Site # 3: Manatee Plant Site, Manatee County

The existing FPL Manatee Plant 9,500-acre site is located in unincorporated north-central Manatee County. The existing power generating facilities are located in all or portions of Sections 18 and 19 of Township 33S, Range 20-E. The plant site lies approximately 5 miles east of Parrish, Florida. It is approximately 5 miles east of U.S. Highway 301 and 9.5 miles east of Interstate Highway 75 (I-75). The existing plant is approximately 2.5 miles south of the Hillsborough-Manatee County line. A portion of the north property boundary of the plant site abuts the county line. State Road 62 (SR 62) is about 0.7 mile south of the plant, with the plant entrance road going north from that highway. This site is a possible location for an FPL PV facility. FPL has received the federal and state permits required to construct approximately 50 MW of PV at this location.

a. U.S. Geological Survey (USGS) Map

A map of the site is found at the end of this chapter.

b. Land Uses

Existing land use on the site is agricultural. The property is zoned Planned Development / Public Interest (PD-PI), which will allow for electrical generation.

c. Environmental Features

FPL anticipates mitigating for unavoidable wildlife and/or wetland impacts as needed as a result of a PV project constructed at this site.

d. Water Quantities

Minimal amounts of water would be required for a PV facility.

e. Supply Sources

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall. Panel cleaning water source may be existing potable water or water tank trucked to the site.

Potential Site # 4: Martin County, Martin County

FPL is currently evaluating potential sites in Martin County for a future PV facility. No specific locations have been selected at this time.

a. U.S. Geological Survey (USGS) Map

A USGS map of the county has been included at the end of this chapter.

b. Land Uses

This information is not available because a specific site has not been selected at this time.

c. Environmental Features

This information is not available because a specific site has not been selected at this time.

d. Water Quantities

Minimal amounts of water would be required for a PV facility.

e. Supply Sources

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the PV panels in the absence of sufficient rainfall.

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CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information." These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints: external limitations and internal limitations. External limitations deal with FPL's ties to its neighboring systems. Internal limitations deal with the flow of electricity within the FPL system.

The external limitations are important since they affect the development of assumptions for the amount of external assistance that is available to the FPL system as well as the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In the loss of load probability (LOLP) portion of its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed by identifying potential geographic locations for potential new generating units that minimize adverse impacts to the flow of electricity within FPL's system. The internal transmission limitations are also addressed by developing the direct costs for siting new units at different locations, by evaluating the cost impacts created by the new unit/unit location combination on the operation of existing units in the FPL system, and/or by evaluating the costs of transmission additions that may be needed to address regional concerns regarding an imbalance between load and generation in a given region. Both of these site- and system-related transmission costs are developed for each different unit/unit location option or groups of options. When analyzing DSM portfolios, such as in a DSM Goals docket, FPL also examines the potential of utility DSM energy efficiency programs to avoid/defer regional transmission expenditures that would otherwise be needed to import power into that region by lowering electrical load in Southeastern Florida. In addition, transfer limits for capacity and energy that can be imported into the Southeastern Florida region (Miami-Dade and Broward Counties) of FPL's system are also developed for use in FPL's production costing analyses. (A further discussion of the Southeastern Florida region of FPL's system, and the need to maintain a regional balance between generation and transmission contributions to meet regional load, is found in Chapter III.)

FPL's annual transmission planning work determines transmission additions needed to address limitations and to maintain/enhance system reliability. FPL's planned transmission facilities to interconnect and integrate generating units in FPL's resource plans, including those transmission facilities that must be certified under the Transmission Line Siting Act, are presented in Chapter III.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL typically performs economic analyses of competing resource plans using as an economic criterion FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach). In addition, for analyses in which DSM levels are not changed, FPL uses the equivalent criterion of the cumulative present value of revenue requirements for the FPL system.[7]

The load forecast that is presented in FPL's 2014 Site Plan was developed in October 2014. The only load forecast sensitivities analyzed during 2013/early 2014 were high load forecast sensitivities developed to analyze FPL's potential future natural gas needs and to analyze the quality of FPL's future reserves.

[7] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis (i.e., when only new generating options are considered), the lowest electric rate basis approach and the lowest system cumulative present value of revenue requirements basis approach yield identical results in terms of which resource options are more economic. In such cases FPL evaluates resource options on the simpler-to-calculate (but equivalent) lowest cumulative present value system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its fuel price forecasts are discussed in Chapter III of this document. FPL used three fuel cost, and three environmental compliance cost, forecasts in analyses supporting its 2013 nuclear cost recovery filing. Also, in response to a request from the FPSC Staff, FPL used three fuel cost forecasts in sensitivity case analyses for the 2014 DSM Goals docket.

A Medium fuel cost forecast is developed first. Then the Medium fuel cost forecast is adjusted upwards (for the High fuel cost forecast), or downwards (for the Low fuel cost forecast), by multiplying the annual cost values from the Medium fuel cost forecast by a factor of (1 + the historical volatility in the 12-month forward price, one year ahead) for the High fuel cost forecast, or by a factor of (1 – the historical volatility of the 12-month forward price, one year ahead) for the Low fuel cost forecast.

The resource plan presented in this Site Plan is based, in part, on those prior analyses. For that reason, this resource plan has not been further tested for different fuel cost forecasts.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

As described above in the answer to Discussion Item # 3, FPL used up to three fuel cost forecasts in its 2013/early 2014 resource planning analyses. While these forecasts did not represent a constant cost differential between oil/gas and coal, a variety of fuel cost differentials were represented in these forecasts.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 in Chapter I and Schedule 8 in Chapter III present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are generally consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options in its resource planning work. A summary of this information for the new capacity options FPL currently projects to add over the reporting horizon for this document is presented on the Schedule 9 forms in Chapter III.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

During 2013, FPL used the following financial assumptions: i) a capital structure of 40.38% debt and 59.62% equity; (ii) a 4.79% cost of debt; (iii) a 10.5% return on equity; and (iv) an after-tax discount rate of 7.45%. In early 2014, the cost of debt and the after-tax discount rate changed slightly to 5.14% and 7.54%, respectively. The other assumptions did not change. No sensitivities of these financial assumptions were used in FPL's 2013/early 2014 resource planning work.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the objective generally being to minimize FPL's projected levelized system average electric rate (i.e., a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item # 2, both the electricity rate perspective and the cumulative present value of system revenue requirement perspective yield identical results in terms of which resource options are more economic when DSM levels are unchanged between competing resource plans. Therefore, in planning work in which DSM levels were unchanged, the equivalent, but simpler-to-calculate, cumulative present value of revenue requirements perspective was utilized.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses three system reliability criteria in its resource planning work that addresses generation, purchase, and DSM options. One criterion is a minimum 20% Summer and Winter reserve margin. Another reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). The third criterion is a minimum 10% generation-only reserve margin (GRM) criterion. These three reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability analysis work, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the Reliability Standards established by the North American Electric Reliability Council (NERC). The *NERC Reliability Standards* are available on the internet site (http://www.nerc.com/).

In addition, FPL has developed a *Facility Connection Requirements* (FCR) document as well as a *Facility Rating Methodology* document that are also available on the internet under the Interconnection Request Information, and FPL Facility Ratings Methodologies, directories respectively at https://www.oatioasis.com/FPL/index.html.

Generally, FPL limits its transmission facilities to 100% of the applicable thermal rating. The normal and contingency voltage criteria for FPL stations are provided below:

	Normal/Contingency	
Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95/0.95	1.05/1.07
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.09
Turkey Point (*)	1.01/1.01	1.06/1.06
St. Lucie (*)	1.00/1.00	1.06/1.06

(*) Voltage range criteria for FPL's Nuclear Power Plants

There may be isolated cases for which FPL may have determined that it is acceptable to deviate from the general criteria stated above. There are several factors that could influence these criteria, such as the overall number of potential customers that may be impacted, the probability of an outage actually occurring, or transmission system performance, as well as others.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The projected impacts of FPL's DSM programs on demand and energy consumption are revised periodically. Engineering models, calibrated with current field-metered data, are updated at regular intervals. Participation trends are tracked for all of FPL's DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants. For its load management programs, FPL conducts periodic tests of the load control equipment to ensure that the equipment is functioning correctly. These tests, plus actual, non-test load management events, also allows FPL to gauge the MW reduction capabilities of its load management programs on an on-going basis.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The Executive Summary and Chapter III provide a discussion of a variety of system concerns/issues that influence FPL's resource planning process. Please see those chapters for a discussion of those concerns/issues.

In addition to these system concerns/issues, there are other strategic factors FPL typically considers when choosing between resource options. These include the following: (1) technology risk; (2) environmental risk, and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects.

Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology, which has not achieved general commercial acceptance, has a higher risk than a technology in wide use and, therefore, assuming all else equal, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the FPL system, including environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for FPL's resource plan are those which minimize environmental impacts for the FPL system as a whole through highly efficient fuel use, state of the art environmental controls, generating technologies that do not utilize fossil fuels (such as nuclear and solar), etc.

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with few barriers to successful development.

All of these factors play a part in FPL's planning and decision-making, including its decisions to construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As shown in this 2014 Site Plan, FPL's resource plan currently reflects the following major supply-side resource additions: the on-going modernization at Port Everglades, on-going upgrading of CTs in several CCs throughout FPL's system, the projected addition of CTs at FPL's Lauderdale plant site, the implementation of the previously executed EcoGen PPA, a projected new CC unit (at a site that has not yet been selected), and the projected Turkey Point Units 6 & 7.

In regard to the above capacity additions for which a need determination has already been granted, Turkey Point Units 6 & 7, did not lend themselves to a request for proposal (RFP) approach involving bids from third parties who would build new nuclear generation capacity. In addition, nuclear capacity additions are exempted from the Commission's Bid Rule by section 403.519 (4) (c). For nuclear projects, FPL's procurement activities are conducted to ensure the best combination of quality and cost for the delivered products. In regard to the modernization project at Port Everglades, the project received a Commission waiver from the Bid Rule due to attributes specific to the Port Everglades site and to modernization projects in general (such as use of existing land, water, transmission, etc.) plus other economic benefits to FPL's customers. This waiver from the Bid Rule was granted in Order No. PSC-11-0360-PAA-EI for Port Everglades.

CT upgrades are currently taking place at several CC units throughout the FPL system. FPL was approached by the original equipment manufacturer (OEM) of the CTs regarding the possibility of upgrading these units. Following negotiations with the OEM, and economic analyses that showed that upgrading was cost-effective for FPL's customers, the decision was made to proceed with the CT upgrades. That process is underway and is scheduled to be completed in 2015.

In regard to the addition of five new CTs at FPL's Lauderdale plant site, FPL anticipates selecting the CTs through negotiations with, and/or competitive solicitation of, CT manufacturers. The EcoGen PPA, which was approved by the Commission in Order No. PSC-13-0205-CO-EQ dated 5/21/13, was the result of negotiations between EcoGen and FPL.

Identification of projected self-build options, beyond those units already approved by the FPSC and Governor and Siting Board or units, such as the 2019 CC unit presented in this Site Plan, is required of FPL in its Site Plan filings and represents FPL's current view of alternatives that appear to be FPL's best, most cost-effective self-build options at present. FPL reserves the right to refine its planning analyses and to identify and evaluate other options before making decisions regarding future capacity additions. Such refined analyses have the potential to yield a variety of self-build options, some of which might not require an RFP. If an RFP is issued for Supply options, FPL reserves the right to choose the best alternative for its customers, even if that option is not an FPL self-build option.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

(1) FPL has identified the need for a new 230 kV transmission line that required certification under the Transmission Line Siting Act which was issued in April 2006. The new line is to be completed in two phases connecting FPL's St. Johns Substation to FPL's Pringle Substation (shown on Table III.E.1 in Chapter III). Phase 1 was completed in May 2009 and consisted of a new line connecting Pringle to a new Pellicer Substation. Phase 2 is planned to connect St. Johns to Pellicer and is scheduled to be completed by December 2018. The construction of this line is necessary to serve existing and future customers in the Flagler and St. Johns areas in a reliable and effective manner.

(2) FPL has identified the need for a new 230 kV transmission line (by December 2014) that required certification under the Transmission Line Siting Act which was issued on November 2008. The new line will connect FPL's Manatee Substation to FPL's proposed Bob White Substation (also shown on Table III.E.1 in Chapter III). The construction of this line, scheduled to be completed in 2014, is necessary to serve existing and future customers in the Manatee and Sarasota areas in a reliable and effective manner.

APPENDIX B

Power Purchase Agreement Key Conditions

Attachment B

Power Purchase Agreement Key Conditions

These Power Purchase Agreement Key Conditions supplement Florida Power & Light Company's ("FPL") 2015 Request for Proposals to Meet Generation Capacity Needs Beginning in 2019 (the "RFP") and sets forth certain minimum conditions (the "Conditions") that will be incorporated in any Power Purchase Agreement (the "Contract") that would be executed by and between a Proposer and FPL. The Conditions are specified below and are in addition to any other RFP requirements that a Proposer in the RFP (the "Proposer") must satisfy. Satisfaction of the Conditions, standing alone, does not ensure a Proposer's eligibility for participation in the RFP, other RFP eligibility requirements specified in the RFP must also be satisfied. (Note: In the text below, the term "Facility" refers, as applicable, to both an individual generating unit, and a system of generating units, upon which the Proposal is based.)

I. Conditions Precedent

- The Florida Public Service Commission ("FPSC") shall have issued a final Determination of Need for the Facility (if applicable), which order is not subject to appeal.
- The FPSC shall have issued a final order approving the Contract and finding that FPL is entitled to recover all costs under the Contract from its customers, which order is not subject to appeal.
- The Federal Energy Regulatory Commission ("FERC") shall have issued a final order authorizing the Proposer to make the sales contemplated by the Contract, which order is not subject to appeal.
- Each Governmental Authority having jurisdiction over the Contract shall have issued a final order of approval, which order is no longer subject to appeal.

II. Completion Security, Performance Security

- Proposer shall provide Completion Security and Performance Security in the amount, form, and in accordance with the schedule set forth in the RFP.

III. Capacity Payment

- Capacity Payments will be on a sliding scale, based upon the Facility's annual capacity billing Factor ("ACBF").
- The Facility's ACBF will be determined by FPL and calculated based on (i) the Facility's availability measured on a rolling twelve month average, and (ii) weighted based on the Facility's Peak Period availability (60%) and Non-Peak

availability (40%). "Peak Period" means those hours (i) from 12:00 p.m. to 9:00 p.m. during the months of April through October, and (ii) from 6:00 am to 10:00 am and from 6:00 pm to 10:00 pm during the months January through March and November and December. "Non-Peak" means all other hours. Additionally, the average Peak Period availability will be weighted 70% for the months of December through February and June through September, with all other months weighted 30%.

- Within a band of 94% to 70% ACBF, for each 1% that the Facility's ACBF drops below 94%, then the Capacity Payment with respect to the Facility will be reduced by 4% (*i.e.*, for each 1% drop in ACBF the Capacity Payment is reduced by 4%).
- If the Facility's AFBC falls below the 70% band, no Capacity Payment shall be made with respect to the Facility.

IV. Step-In Rights, FPL's First Lien

- In addition to FPL's other remedies under the Contract, upon failure of the Proposer to meet any agreed upon milestone date, or upon any event of default by the Proposer (and failure by the Proposer to cure such default), FPL or its designee shall have the right, but not the obligation, to enter upon and complete the licensing, permitting, construction, start-up, testing, and commissioning, or operate and maintain the Facility as agent for the Proposer. FPL's step-in right shall continue until the earlier of (i) the Proposer demonstrating to FPL's reasonable satisfaction that reasons for Proposer's failure no longer applies; (ii) FPL elects in its sole discretion to cease exercising Step-In rights, or (iii) expiration or termination of the Contract.
- As security for Proposer's performance of its obligations, Proposer or FPL shall execute and record a Mortgage and Security Agreement to provide FPL with a fully perfected subordinated security interest and mortgage lien in any and all real and personal property, contractual rights, or other rights the necessary for the development, procurement, construction, operation, and maintenance of the Facility.

V. Exclusivity, Payment

- Proposer shall have no right to sell energy, capacity, or ancillary services (the "Products") generated by or attributable to the Facility to any entity except FPL during the term of the Contract. Payments under the Contract will represent a combined charge for the sale of all Products of any type provided by the Facility.

VI. Testing, Capacity Rating, Heat Rate

- In addition to a required capacity test to demonstrate Commercial Operation, FPL has the right, but not the obligation, to require Proposer to perform a capacity test once per each Summer Period, and once per each Winter Period, at FPL's sole discretion. Additionally, a capacity test will be required if Proposer is unable to comply with any material obligation under the Contract for a period of 30 days or more as a consequence of an event of Force Majeure, or at any time when the Proposer fails two consecutive times to satisfy the operating levels set by FPL dispatch instructions. Upon completion of a capacity test, the Available Capacity will be set at a level not less than the Minimum Capacity and not more than the lower of the Committed Capacity or the Continuous Capability demonstrated in the most recent capacity test.

- Consistent with the RFP, (i) the Proposer will guarantee the Facility's heat rate levels reflected in its proposal, (ii) the Facility will be subject to heat rate testing administered by FPL, and (iii) a heat rate adjustment payment will be due from Proposer in the event the Facility fails to achieve the guaranteed heat rate levels.

VII. Dispatch, Control, Operation, and Maintenance of the Facility

- Proposer shall at all times operate the Facility consistent with FPL's dispatch and control rights. Control shall be either by Proposer's manual control pursuant to FPL's oral or written directions, or by Automated Generation Control by FPL's system control center, as determined by FPL.

- During the term, Proposer shall employ qualified and trained personnel for managing, operating, and maintaining the Facility and shall ensure that such personnel are on-duty 24 hours per day, each day, throughout the term of the Contract.

- Proposer shall be responsible for compliance with all applicable NERC regulations and requirements.

- Proposer shall operate and maintain the Facility in accordance with good engineering and operating practices, including compliance with all environmental laws, regulations, and permits. Proposer shall operate the Facility with all automatic controls (except Automatic Generation Control) and protection equipment in service whenever the Facility is connected to or operating in parallel with FPL's system. Automatic Generation Control shall be operated by FPL's system control center as determined by FPL.

- Key replacement and maintenance components (Gas Turbine hot path components, for example) may be obtained only from the Original Equipment Manufacturer.
- On an annual basis, the Proposer shall submit preliminary desired outage schedules for the following five years and a detailed plan for the next year. FPL shall notify Proposer if the outage schedule is accepted, or cooperate reasonably with Proposer to agree upon an acceptable schedule. Under no circumstances will outages be scheduled during the Peak Months.

VIII. Regulatory Out

- Notwithstanding anything contrary in the Contract, if at any time FPL fails to obtain, or is denied, the authorization of the FPSC or any other legislative, judicial, or regulatory body which now has, or may have in the future, jurisdiction over FPL's rates and charges, to recover from its customers all of the payments required to be made under the terms of this Contract, or any amendment thereto, FPL may, at its sole discretion, adjust the payments made under the Contract to the amounts which FPL is authorized to recover from its customers. In this event, Proposer shall have the option to terminate the Contract upon ninety days' notice to FPL.

IX. Variable Interest Entity (VIE)

- From the effective date through the end of the term of the contract, Proposer shall covenant that from its perspective and due to any of its actions, FPL will not be required by any legal requirement or an accounting standard to consolidate Proposer or any of its affiliates or permitted assigns as a VIE in FPL's or any of its affiliates' financial statements. Proposer shall promptly notify FPL following any determination made by Proposer or its independent auditor that Proposer constitutes a VIE for which FPL is the primary beneficiary as a result of the Contract. At the time of execution of the Contract and annually thereafter, Proposer shall provide certification of compliance with this provision by the chief financial officer of the Proposer.
- If a Proposer fails to provide the required certification, or if at any time Proposer becomes a VIE and FPL becomes the Primary Beneficiary, such an event shall constitute an event of default under the Contract.

X. Greenhouse Gas (GHG) Emission Costs

- Whether FPL would pay the Proposer for their proposed unit's (or system's) share of "annual GHG emission costs for FPL total energy" calculated as reflected in the proposal evaluation would be a subject of PPA negotiations. However, FPL and its customers will not agree to pay the Proposer for any GHG emission costs due to GHG emission rates higher than submitted by the Proposer.

- In the event of a future change in law or regulation that would have the effect of shifting to or imposing upon FPL GHG emission costs not agreed to in the PPA, FPL would have the right to terminate the PPA if such additional costs were not found to be prudent and approved for FPL cost recovery by the FPSC.

APPENDIX C

Forms for Proposers

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Forms for Proposers

A. Overview of the Required Ten (10) Forms

There are ten (10) forms that all Proposers must complete and return to FPL's RFP Contact Person by 4:00 p.m. EDT on the Proposal Due Date. These completed forms, requested attachments to these forms, and RFP Evaluation Fee will, collectively, represent a proposal. If a Proposer is submitting more than one proposal, a separate set of forms and the appropriate RFP Evaluation Fee must be submitted for each proposal. These ten forms are described in the remainder of this Appendix. If a Proposer is also submitting a variation of a proposal in which a different price and/or term (but no changes in any other attributes) is offered for a proposal, then Form # 1, Form # 4 (page 3 of 14), Form # 5 (pages 1 of 4 and 2 of 4, or 3 of 4, as appropriate), Form # 9, and Form # 10 must be completed and submitted (along with the Variation Fee).

The Proposer must submit five (5) bound hard copies of each proposal that contains the forms and requested information, and an electronic copy of the completed forms on a CD, along with the RFP Evaluation Fee and, if applicable, the Variation Fee.

As discussed in Section II.C.2 of the RFP document, FPL will treat as confidential all information contained in proposals which is clearly identified as Proprietary and Confidential except for the information to be submitted on Form # 1, Public Information Regarding Proposal. To clearly identify confidential information, the Proposer must (1) stamp each such page with "**Confidential Information**" <u>and</u> (2) highlight/shade the specific confidential information on the pages stamped "**Confidential Information**". (A blanket statement that an entire page, or the entire proposal, is proprietary and confidential will <u>not</u> be considered clear identification.)

Please refer to Section II.C.2 of the RFP document for a full discussion of Proposal Confidentiality.

B. Form # 1: Public Information Regarding Proposal

In order to provide general information to the public about the proposals received in response to this RFP, FPL requires that all proposal submittals include a completed Public Information Regarding Proposal form that includes a list of projects undertaken (constructed and/or operated) by the Proposer that are similar to the project now being proposed. The information contained in this form will be treated as non-confidential and non-proprietary and may be released to the public at the sole discretion of FPL.

C. Form # 2: Executive Summary of the Proposal

A one (1) page summary of the proposed project and the Proposer is sought on this form. This executive summary should highlight any major value-added features of the proposal.

D. Form # 3: Financial Information

To mitigate risk, FPL will examine the Proposer's and, if applicable, the parent/affiliate guarantor's credit/corporate profile and financial guarantees. The credit/corporate profile information includes the corporate bond rating, the commercial paper rating, and the Dunn & Bradstreet Credit Appraisal Rating.

If a Proposer will be relying on any parent/affiliate guarantees, the Proposer shall also include a description of the corporate relationship between the Proposer and the guarantor and provide a description regarding the proposed guarantor's willingness to guarantee the Proposer's obligations and the terms of the guarantee.

In addition, the proposal shall include audited financial statements for the last two years for the Proposer and, if the Proposer is relying on any parent/affiliate guarantees, for the guarantor.

E. Form # 4: Operations & Engineering Information

Form # 4 requests a variety of information that will be used in the economic evaluation and/or non-economic evaluation of proposals. The requested information is to be filled in, as applicable, on the following 9 information categories of this form:

1. Power Generation Proposal Type
2. Technology/Configuration
3. Operational Considerations: Availability, Reliability, & Operating Time Limitations
4. Fuel Information & Barometric Pressure
5. Guaranteed Firm Capacity
6. Guaranteed Heat Rates
7. Emission Rate Information[1]

[1] If the proposal is based on a system sale, the emission rate information in section 7 is to be provided for each year in the proposed term of service by attaching a separate page(s) to the Proposal.

8. Natural Gas Pipeline Connection(s)
9. Generating Units' Operating & Maintenance Experience/Performance

In response to this capacity RFP, FPL envisions that it may receive power purchase agreement (PPA) proposals based on a specific existing generating unit(s) or a new generating unit(s). In either of these cases, FPL is requesting specific information regarding the following four aspects of the proposal:

- OEM replacement parts for hot gas path (HGP) components
- Availability and reliability
- Guaranteed capacity
- Guaranteed heat rates

For proposals based on an existing generating unit, FPL is seeking the following information regarding the above mentioned four aspects of the proposal:

a) OEM: Proposers will be required to state to what extent OEM parts have been used in the "proposal" unit to-date. Proposers will be required – as part of their proposal – to explicitly state that, if selected, the proposed unit will install and continue to use OEM replacement parts for such components, and that OEM maintenance schedules will be observed. A selected Proposer will have to annually obtain from the OEM a certification that OEM replacement parts have been installed and have been maintained in accordance with the OEM schedules. If a selected Proposer fails to install, use, and properly maintain OEM parts, or fails to obtain the OEM's certification, it will be in default, and will have 120 days to cure; if not cured, FPL may terminate the PPA and/or collect damages as specified in the PPA.

b) Availability & Reliability, Peak Capacity, and Heat Rates: Proposers will be required to state to what extent the proposed unit has achieved the availability and reliability, peak capacity, and heat rate levels reflected in the proposal during the last five years, and provide evidence that demonstrates that such availability and reliability, peak capacity, and heat rate levels have been achieved (such as through the results of annual heat rate tests, capacity tests, etc.) If selected, the Proposer must guarantee in the PPA that the proposed unit will continuously achieve the availability and reliability, peak capacity, and heat rate levels reflected in the proposal. If the unit in a selected proposal fails to achieve the availability and reliability, peak capacity, and/or heat rate levels reflected in the proposal and guaranteed in the PPA, the Proposer would be subject to liquidated damages. The selected Proposer will have 120 days to cure the problem. If not cured, FPL may terminate the PPA.

c) In regard to Availability & Reliability: If the average actual or proposed (as per the calculation performed in Form # 4) EAF for a proposal based on an existing combined cycle unit is less than 80% for any year, or if the average actual (or proposed as per the calculation performed in Form # 4) EFOR for a proposal based on an existing combined cycle unit is more than 4.2% for any year, or if the average actual or proposed (as per the calculation performed in Form # 4) FOF for a proposal based on an existing combustion turbine is more than 2.6% for any year, as applicable, the proposal will be rejected.

d) In regard to Heat Rates: If a heat rate test has not been performed within the last two years, the Proposer must perform a new test and submit the results as part of the proposal.

For proposals based on a new generating unit, FPL is seeking the following information regarding the above mentioned four aspects of the proposal:

a) OEM: Proposers will be required to state to what extent OEM parts have been used in existing units operated by the Proposer. Proposers will be required – as part of their proposal – to explicitly state that, if selected, the proposed unit will use OEM replacement parts for such components, and that OEM maintenance schedules will be observed. A selected Proposer will have to annually obtain from the OEM a certification that OEM replacement parts have been installed and have been maintained in accordance with the OEM schedules. If a selected Proposer fails to install, use, and properly maintain OEM parts, or fails to obtain the OEM's certification, it will be in default, and will have 120 days to cure; if not cured, FPL may terminate the PPA and/or collect damages as specified in the PPA.

b) Availability & Reliability, Peak Capacity, and Heat Rates: Proposers will be required to state to what extent the Proposer's similar existing units have achieved the availability and reliability, peak capacity, and heat rate levels reflected in the proposal during the last five years, and provide evidence that demonstrates that such availability and reliability, peak capacity, and heat rate levels have been achieved (such as through the results of annual heat rate tests or capacity tests). If selected, a Proposer must guarantee in the PPA that the proposed unit will continuously achieve the availability and reliability, peak capacity, and heat rate levels reflected in the proposal. If the unit in a selected proposal fails to achieve the availability and reliability, peak capacity, and/or heat rate levels reflected in the proposal and guaranteed in the PPA, the Proposer would be subject to liquidated damages. The selected Proposer will have 120 days to cure the problem. If not cured, FPL may terminate the PPA.

c) In regard to Availability & Reliability: If the proposed (as per the calculation performed in Form # 4) EAF for a proposal based on a new combined cycle unit is less than 80% for any year, or if the proposed (as per the calculation performed in Form # 4) EFOR for a proposal based on a new combined cycle unit is more than 4.2% for any year, or if the proposed (as per the calculation performed in Form # 4) FOF for a proposal based on a new combustion turbine is more than 2.6% for any year, as applicable, the proposal will be rejected.

d) In regard to Heat Rates: If selected, a winning Proposer must guarantee in the PPA to provide results of annual heat rate tests for the proposed unit.

For purposes of the RFP evaluation, FPL is using the following formulae for calculating availability and reliability of proposals and the NPGU:

- Availability = (8760 - POH – FOH)/8760

- EFOR = FOH/(Service Hours + FOH) in which Service Hours are calculated based on the type of proposed unit. For example, a CC unit's Service Hours are calculated to be 8760 hours x 0.80 and a CT unit's Service Hours are calculated to be 8760 hours x 0.15.

- FOF = FOH/8760

F. Form # 5: Pricing Information for Purchased Power or System Sale Proposals

Pricing for firm capacity and energy proposals that offer power purchases or system sales must be presented on Pricing Information Form # 5. **(Note that Proposers should not include projected greenhouse gas (GHG) costs in their proposal payment values. GHG cost values, in the form of FPL's projected CO2 annual cost values in $/ton, will be addressed in FPL's evaluation based upon CO2 emission rates provided in each proposal. This evaluation approach is discussed further in Appendix D.)**

Note that FPL requires actual prices to be filled in for each year of the proposed term-of-service. Proposals indicating a first-year price followed only by a note stating that a formula is to be used for escalating that price from year-to-year are not acceptable and constitute grounds for declaring a proposal ineligible. Please refer to Section F.5 (below) for an explanation of acceptable pricing approaches a Proposer may utilize in developing the annual price values to be presented on Form # 5.

1) Guaranteed Capacity Payments

The Proposer must provide Guaranteed Capacity Payment values for the term of the proposed contract on Form # 5, page 1 of 5. Guaranteed Capacity Payment values in terms of $/kw-month must be supplied for each operational mode (*e.g.,* base operation, Incremental Level 1, or Incremental Level 2, etc.) as specified on Form # 4. Proposals must include all costs of delivering capacity and energy to the FPL System including delivery over intervening transmission systems and the cost of gas pipeline laterals, if applicable, connecting the generator to the appropriate natural gas pipeline. Proposals must utilize the Guaranteed Firm Capacity rating for Summer (temperature of 95 degrees F.), the relative humidity specified, and the appropriate barometric pressure value from the chart supplied on Form # 4 in developing the denominator for the $/kw–month values.

2) <u>Guaranteed Energy Pricing & Payments</u>

a) Fuel Prices (for Non-System sales) & Energy Charges (for System Sales)

<u>For Proposals Not Based on System Sales:</u>
On Form # 5, page 2 of 5, the Proposer may submit a Guaranteed Fuel Transportation Reservation Price (\$/mmBTU per Day) for the proposed term of the contract. The Proposer must designate the pipeline (FGT, Gulfstream, Sabal Trail, Sabal Trail / Florida Southeast Connection, etc.) that will serve the facility. FPL will base the variable costs and fuel on the current (or proposed as in the case of Sabal Trail and Sabal Trail / Florida Southeast Connection) tariff rates of the pipeline selected by the Proposer. If the Proposer does not wish to provide Guaranteed Fuel Transportation Reservation Prices, and the project can be connected to Sabal Trail or Florida Southeast Connection, FPL will use its own fuel transportation cost projections (which are based on Sabal Trail and Florida Southeast Connection), plus the Proposer's lateral and meter costs (provided on Form # 5, page 5 of 5), for the purposes of proposal evaluation. If the project must be connected to FGT, Gulfstream, etc., FPL will evaluate the cost of securing additional transportation capacity on those pipelines and incorporate that cost in the evaluation of the proposal.

If the Proposer has elected to submit a Guaranteed Fuel Transportation Reservation Price, the Proposer must also submit a Guaranteed Fuel Transportation Quantity (mmBTU/day) for the proposed term of the contract. For proposals with no Guaranteed Fuel Transportation Reservation Price, FPL will base its evaluation on the value for gas quantity that must be obtained on a firm basis as identified in Form # 4, page 13 of 14, in item (8) (f).

If the Proposer has elected to submit a Guaranteed Fuel Transportation Reservation Price, the Proposer may choose to submit a Guaranteed Fuel Commodity Price (\$/mmBTU per Day) for the proposed term of the contract. If the Proposer elects to not provide Guaranteed Fuel Commodity Prices, FPL will use its own fuel commodity cost projections.

FPL's projected fuel commodity costs that will be used in the RFP economic evaluations will be presented on FPL's RFP website once this RFP is issued.

For Proposals Based on System Sales:
In regard to proposals based on system sales, the Proposer must submit a Guaranteed Energy Price value for each year of the proposed term-of-service. Actual annual values must be entered on Form 5, page 3 of 5. These annual values may be based on a formula based on FPL's projected fuel commodity price forecast that is discussed above. **The formula(e) applied by the Proposer to develop the energy charge payment values must be provided and fully described on a page to be developed by the Proposer and attached to Form # 5**. This formula, combined with future actual values for each forecasted fuel cost used in the formula, will be the basis for payments that the Proposer would receive if the proposal is selected.

b) Variable O&M Payments

In addition, the Guaranteed Variable O&M Prices (in \$/MWh) of the proposal for each year of the proposed term-of-service for the base operational mode and for any other operational mode must be provided for all types of proposals. This information is to be provided on Form # 4, page 2 of 5 (for non-system sale proposals) or page 3 of 5 (for system sale proposals).

In calculating these values, assume an annual capacity factor of 80% for a system sale or a baseload generating proposal and 15% for peaking capacity proposals.

3) Startup Fuel Amounts and Startup Costs

The amount of fuel needed per startup (mmBTU per startup) must be provided on Form # 5, page 4 of 5.

Startup costs (other than fuel needed for startup as discussed above) should be included, at the Proposer's choice, in either of the Proposer's Guaranteed Capacity Payments or Variable O&M Payments, and are not to be entered separately on Form # 5.

4) <u>Costs and Information Included in the Payments</u>

Proposals that are based on generators that need to be constructed and connected to the transmission system must include transmission interconnection costs in their Guaranteed Capacity Pricing in Form # 5, page 1 of 5.

These proposals, plus proposals that are based on existing generating units, must also include the cost of third party transmission service (if applicable) for delivery to the FPL Receipt Point, including the impact of third party transmission service losses, if appropriate, in their Guaranteed Capacity Pricing on Form # 5, page 1 of 5.

On Form # 5, page 4 of 5, each Proposer must also <u>separately provide</u> the specific costs of transmission interconnection that are the basis for these transmission-related costs that are included in the Guaranteed Capacity Pricing values. The Proposer must also provide information related to third party transmission service (if applicable). The Proposer must also <u>separately provide</u> the specific costs of the gas pipeline lateral and meter, if applicable, regarding the connection of the generator to the appropriate natural gas pipeline on Form # 5, page 5 of 5.

The information that follows pertains to these transmission interconnection costs, third party transmission service information, and the costs of the gas pipeline lateral.

a) <u>Transmission Interconnection Costs:</u>

- All proposals that are based on generators that need to be constructed and connected to the transmission system must demonstrate that they have a valid completed application for Generator Interconnection Service (GIS) in the FPL GIS Queue, or with the applicable third party to the extent the new generator is connected to a third party's transmission system.

- The process for requesting GIS and having a completed GIS application on the FPL system is delineated on FPL's Open Access Transmission Tariff (OATT).

- To the extent the generator(s) is connecting to the FPL system, and a transmission interconnection study has been performed and completed by FPL Transmission providing cost estimates is available, the Proposer shall provide an interconnection cost estimate based on the transmission interconnection study, along with a copy of this study. This cost estimate shall include all materials, labor, land, permitting, and overhead adders associated with upgrades of existing facilities and construction of incremental facilities required as a result of the connection, plus thermal, short circuit, and stability impacts on the transmission system. Note that if a new transmission switchyard must be constructed to connect the proposed generator(s), the cost of the transmission switchyard, including land, all necessary permits, filling, and grading must be included in the cost estimate.

To the extent a completed transmission interconnection study is not available, and the generator(s) for which the capacity is being offered is to be connected to the FPL system, the Proposer must provide a cost estimate for the interconnection along with a written explanation of the basis for this estimate. Such cost estimate shall include all materials, labor, land, permitting, and overhead adders associated with upgrades of existing facilities and construction of incremental facilities required as a result of the connection, and short circuit and stability impacts on the transmission system. Note that if a new transmission switchyard must be constructed to connect the proposed generator(s), the cost of the transmission switchyard, including land, all necessary permits, filling, and grading, must be included in this cost estimate.

Form # 5, page 4 of 5, instructs proposers to provide the "basis for this (interconnection cost) estimate". FPL reserves the right to review such cost estimates for reasonableness. To the extent that FPL determines that this cost estimate is materially incorrect or incomplete, FPL reserves the right to adjust this cost estimate as it deems necessary during the evaluation process in order to reflect an acceptable interconnection arrangement. (The actual cost of connecting the generator to the FPL system would be based on the specific GIS Queue process and the attendant studies. These actual costs will need to be addressed if the Proposer is ultimately selected.)

- To the extent the generator(s) for which the capacity is being offered is not directly connected to the FPL system, the Proposer shall provide the best available cost estimate and a written explanation of the assumptions or studies upon which this cost estimate was based on Form # 5, page 4 of 5. Such cost estimate shall include all materials, labor, land, permitting, and overhead adders associated with upgrades of existing facilities and construction of incremental facilities required as a result of the connection, plus thermal, short circuit, and stability impacts on the transmission system.

b) <u>Third Party Transmission Service Information:</u>

To the extent the generator(s) is connected to the transmission system of a third party, the Proposer shall state whether third party transmission rights have been requested and/or already procured for a portion of or all of the generation capacity being offered. To the extent a request for such long-term firm transmission right have been requested, but not yet procured, provide all available studies associated with the request.

c) <u>Transmission Losses:</u>

On Form # 5, page 5 of 5, provide the projected transmission losses (MW) associated with the third party transmission service that are accounted for in the Total Guaranteed Firm Capacity values on Form # 4.

d) <u>Gas Pipeline Lateral and Meter Costs:</u>

On Form # 5, page 5 of 5, provide the total cost of the lateral pipeline and meter station for the lateral that connects the generator to the appropriate natural gas pipeline. (This cost is to be included in the Guaranteed Capacity Payment values provided on Form # 4.)

5) <u>Guidance for Developing Annual Capacity Payment and Variable O&M Payment Values for Form # 5</u>

a) Background

FPL's 2015 RFP requires potential Proposers to provide annual values for Capacity Payments (that inherently may include a fixed O&M component) and Variable O&M Payments. These annual values may reflect assumed escalation over the term of a proposed contract. Proposers may either submit fixed annual values or have components of their proposal prices be subject to escalation.

In the former instance, the Proposer would be guaranteeing the actual prices for each year (*i.e.*, those are the set annual prices that would be incorporated directly into a PPA if the Proposer were selected by FPL). In so doing, a Proposer would be choosing to assume the risk/benefit of costs deviating from the annual values provided.

In the latter case, a Proposer may submit prices that are subject to future adjustment based on a formula that includes one or more of three approved indices (described below). For example, a Proposer might propose a Variable O&M charge that entails a 2019 starting value that escalates thereafter at some portion or all of the actual change in a specific index. In summary, Proposers can choose the level of risk they would assume by applying a formulaic approach or guaranteeing specific annual values.

The following describes how this can be accomplished by Proposers in response to FPL's 2015 RFP (and how FPL developed, in part, the fixed O&M and variable O&M values for its NPGU.)

b) Process

The following is provided to clarify requirements for data submitted in response to FPL's 2015 RFP as pertains to proposal pricing components that may be either fixed or subject to escalation. The approach offers Proposers the opportunity to declare the annual values that will be used to evaluate their proposal and (if the proposal is subject to escalation) the method of applying FPL-authorized indices to develop the values to be evaluated.

A Proposer must submit payment <u>values</u>, not formulae, for all years for Capacity Payment and Variable O&M Payment as described in FPL's 2015 RFP. Thus, even if a Proposer decides to base a price component on a formula/index, the Proposer must still calculate and populate the RFP Form # 5 with specific annual values (so that the proposal evaluation team can verify its understanding of the Proposer's formula) and utilize the Proposer's own values in its evaluation.

Fixed Price Procedure

If the values on Form # 5 represent fixed, guaranteed payment values, then simply completing the RFP forms as described in the RFP is sufficient. These firm, guaranteed annual payment values would be used in the evaluation and then included unchanged in the PPA should the proposal be selected.

Formulaic/Indexing Procedure for Guaranteed Capacity and Variable O&M Payments

If a Proposer chooses to develop payment values based on the use of FPL-authorized indices, and desires this method to be the basis of the evaluation and a potential PPA with FPL, the Proposer must use the following approach.

For actual payment purposes if a proposal is selected, FPL's authorized indices for the Guaranteed Capacity Payments and Variable O&M Payments are from IHS Global Insight (Global Insight), a leading economic forecasting firm. The authorized indices are presented in Table C – 1 below and consist of:

- The Global Insight escalation index for Consumer Price Index – All Urban Consumers (CPI).
- The Global Insight escalation index for Producer Price Index – All Commodities (PPI); and,
- The Global Insight escalation index for Compensation Per Hour – Non-Farm Business Sector (CPH)

Or, alternatively, a Proposer may use a formula for these two payment values based on:

- A constant escalation rate per year.

Only the indices in Table C – 1, or a formula based on a constant escalation rate, are authorized for use in submitting formulaic/indexed prices for Guaranteed Capacity Payments and Variable O&M Payments in response to this RFP.

The formula(e) applied by the Proposer to develop the payment values must be provided and fully described on an attached page to Form # 5. This formula, combined with future actual values for each index from Table C – 1 used in the formula, will be the basis for payments that the Proposer would receive if the proposal is selected. **Note that if a constant escalation rate is used in a formulaic approach, the annual values supplied in the Proposal will then be included unchanged in the PPA should the proposal be selected (*i.e.*, this formulaic approach becomes a Fixed Price Procedure as previously described).**

A Proposer may also deem that some portion of a payment is not indexed, while another segment of the payment is. For example, a Proposer's Guaranteed Capacity Payment may entail one portion that is fixed (or that escalates at a set percentage) throughout the term of the contract while another portion (*i.e.*, a fixed O&M component) may be subject to annual adjustment based on a formula that includes one or more of the FPL-authorized indices or a constant escalation rate.

In addition to a thorough description of the formula/indexing process that is proposed, a Proposer must fill out the annual values for every year of the proposed transaction

Note that if a proposal that is based on a formulaic/indexing approach using the indices presented in Table C – 1 is selected, the Proposer will not be bound by these specific annual values that will be supplied on Form # 5 – only by the formulaic/indexing process behind them. However, the annual values are essential and will be used to confirm that the proposal evaluation team understands and correctly applies the Proposer's formula/indexing process.

Formulaic/Indexing Procedure for Energy Pricing of System Sale Proposals

Similar to the discussion above, the Proposer must provide annual values for each year of the proposed term-of-service for Guaranteed Energy Pricing Payments for system sale-based proposals. These annual values may be based on formulaic approach using one or more of the FPL Fuel Commodity Cost forecast that will be posted on the RFP website once the RFP is issued. The Proposer is required to provide an explanation of this formulaic approach.

Note that if such a proposal is selected, the Proposer will not be bound by these specific annual values that will be supplied on Form # 5 – only by the formulaic/indexing process behind them. However, the annual values are essential and will be used to confirm that the proposal evaluation team understands and correctly applies the Proposer's formula/indexing process.

c) FPL's Methodology for Developing NPGU Costs

In its NPGU analyses, FPL used projections of specific annual costs for Fixed O&M (FOM), Variable O&M (VOM), and Capital Replacement. The annual values for each of these three cost categories are presented in in Table VI.B-2 in the main body of the RFP document. The FOM, VOM and capital replacement are projections from a model that utilizes as inputs constant annual escalation rates of 2.5% for FOM and VOM, and 2.0% for Capital Replacement.

Table C - 1

Price Indices
(based on Global Insight's July & August 2014 Forecasts)

Year	Consumer Price Index (CPI) (Urban All Consumers)	% Change	Producer Price Index (PPI) (All Commodities)	% Change	Compensation per Hour (Nonfarm Business Sector)	% Change
2000	1.7267	---	1.3277	---	0.7398	---
2001	1.7723	2.6%	1.3421	1.1%	0.7728	4.5%
2002	1.8032	1.7%	1.3112	-2.3%	0.7905	2.3%
2003	1.8426	2.2%	1.3812	5.3%	0.8200	3.7%
2004	1.8940	2.8%	1.4665	6.2%	0.8572	4.5%
2005	1.9585	3.4%	1.5737	7.3%	0.8884	3.6%
2006	2.0193	3.1%	1.6473	4.7%	0.9233	3.9%
2007	2.0807	3.0%	1.7268	4.8%	0.9631	4.3%
2008	2.1524	3.4%	1.8956	9.8%	0.9895	2.7%
2009	2.1499	-0.1%	1.7297	-8.8%	1.0002	1.1%
2010	2.1841	1.6%	1.8480	6.8%	1.0195	1.9%
2011	2.2548	3.2%	2.0108	8.8%	1.0421	2.2%
2012	2.2993	2.0%	2.0218	0.5%	1.0706	2.7%
2013	2.3321	1.4%	2.0341	0.6%	1.0827	1.1%
2014	2.3782	2.0%	2.0679	1.7%	1.1204	3.5%
2015	2.4124	1.4%	2.0931	1.2%	1.1576	3.3%
2016	2.4507	1.6%	2.1189	1.2%	1.1998	3.6%
2017	2.4961	1.9%	2.1639	2.1%	1.2460	3.9%
2018	2.5471	2.0%	2.2079	2.0%	1.2955	4.0%
2019	2.5976	2.0%	2.2371	1.3%	1.3469	4.0%
2020	2.6506	2.0%	2.2789	1.9%	1.3991	3.9%
2021	2.7093	2.2%	2.3238	2.0%	1.4526	3.8%
2022	2.7678	2.2%	2.3715	2.1%	1.5072	3.8%
2023	2.8271	2.1%	2.4212	2.1%	1.5643	3.8%
2024	2.8856	2.1%	2.4889	2.8%	1.6240	3.8%
2025	2.9445	2.0%	2.5460	2.3%	1.6856	3.8%
2026	3.0046	2.0%	2.5837	1.5%	1.7500	3.8%
2027	3.0647	2.0%	2.6266	1.7%	1.8160	3.8%
2028	3.1244	1.9%	2.6668	1.5%	1.8831	3.7%
2029	3.1838	1.9%	2.7074	1.5%	1.9519	3.7%
2030	3.2432	1.9%	2.7423	1.3%	2.0230	3.6%
2031	3.3056	1.9%	2.7877	1.7%	2.0954	3.6%
2032	3.3703	2.0%	2.8317	1.6%	2.1700	3.6%
2033	3.4384	2.0%	2.8755	1.5%	2.2465	3.5%
2034	3.5069	2.0%	2.9163	1.4%	2.3254	3.5%
2035	3.5770	2.0%	2.9693	1.8%	2.4083	3.6%
2036	3.6489	2.0%	3.0123	1.4%	2.4947	3.6%
2037	3.7230	2.0%	3.0586	1.5%	2.5830	3.5%
2038	3.7998	2.1%	3.1059	1.5%	2.6754	3.6%
2039	3.8787	2.1%	3.1541	1.6%	2.7711	3.6%
2040	3.9588	2.1%	3.2018	1.5%	2.8694	3.5%
2041	4.0406	2.1%	3.2495	1.5%	2.9713	3.6%
2042	4.1240	2.1%	3.2991	1.5%	3.0771	3.6%
2043	4.2092	2.1%	3.3501	1.5%	3.1870	3.6%
2044	4.2962	2.1%	3.4035	1.6%	3.3021	3.6%
2045	4.3849	2.1%	3.4578	1.6%	3.4214	3.6%
2046	4.4755	2.1%	3.5129	1.6%	3.5449	3.6%
2047	4.5679	2.1%	3.5689	1.6%	3.6729	3.6%
2048	4.6623	2.1%	3.6257	1.6%	3.8056	3.6%
2049	4.7586	2.1%	3.6835	1.6%	3.9430	3.6%

G. Form # 6: Environmental & Permitting Information

In order to fully evaluate the environmental and permitting aspects of proposals, Form # 6 requests a variety of information from 12 major categories that will be used to evaluate proposals. Each Proposer should be more inclusive rather than exclusive when responding to the information requested. If the category or information requested does not apply to the proposal, an explanation must be provided. The following are the 12 major information categories of this form:

1. Proposed Community Outreach Activities and Experience
2. Required Permits or Approvals to License or Permit the Facility
3. Description of Air Pollution Control Equipment
4. PSD/NSR Permitting
5. Water Supply Strategy
6. Water Discharge Strategy
7. Strategy to Address Land Use Issues
8. Solid/Hazardous Waste / Material Management Strategy
9. Other Infrastructure Needs or Requirements
10. Protected Species Impacts
11. Permitting Experience in Florida of Proposer and Environmental Support Contractors and Consultants
12. Proposer Compliance History (Last 5 years, i.e., 2010 – 2014)

H. Form # 7: Key Milestones

FPL's ability to maintain a certain level of system reliability for its customers will be dependent upon a selected Proposer's ability to meet the contracted Capacity Delivery Date (CDD). Because there is a possibility that the Proposer will not meet this date, FPL may have to make alternate arrangements to cover the capacity and energy shortfall. This will require FPL to monitor the Proposer's progress. Therefore, the Proposer must provide the expected completion dates for certain key project milestones on this form. When providing these key project milestones, a Proposer should carefully review the Minimum Requirements regarding Project Milestone Schedule for the specific milestones listed in Section III, part 20, of the main body of the RFP document.

A proposal that requires new power plant construction falling under the Siting Act will have to demonstrate permitting, construction, etc. schedules that allow the new plant to be in-service on or before FPL's needed in-service date of June 1, 2019.

I. Form # 8: Receipt Point(s) to FPL

Information on this form will identify the location of the receipt point(s) of each proposed capacity source(s) including a listing of the nearest substation(s).

The Proposer must also attach a readable transmission map (8.5 x 11 inches) highlighting the receipt point(s) identified above.

J. Form # 9: Proposer Exceptions

All Proposers must complete and return this Proposer Exceptions form as part of their proposal submittal. On this form, the Proposer must either indicate that they take no exceptions to any of the terms, conditions, or other facets of the RFP or must indicate that they do take exception(s). In the case in which one or more exception is taken, then for each term, condition, or other facets of the RFP to which an exception is taken, the Proposer must provide their desired revised language.

FPL will consider the number and significance of exceptions in its non-economic evaluation. FPL will not consider proposed exceptions to the RFP's Minimum Requirements for Proposals or Minimum Requirements Pursuant to Purchase Agreement.

K. Form # 10: Proposal Certification

All Proposers must complete and return this Proposal Certification form as part of their proposal submittal. An Officer of the proposing company is to certify that: (i) all information contained in the Proposer's proposal is complete and accurate and that the pricing contains all applicable costs for the proposed full term of service; (ii) that the terms, conditions, and other facets of the RFP are acceptable, except as specifically noted by the Proposer on Form # 9; (iii) the Completion Security and Performance Security described in Section IV of the main body of the RFP document are acceptable and there are no pending legal or civil actions that would affect the ability of the Proposer and/or its guarantor to maintain these security amounts; (iv) the proposal has been submitted in the legal name of the entity which would be bound by any resulting contract; (v) and that the proposal is binding, definitive, and firm and will remain open for 180 days from the Proposal Due Date.

The copies of this form that are included in the five (5) bound hard copies of the proposal must each be signed by an Officer of the proposing company.

M. Proposer's Forms

The forms that follow on the remaining pages of this Appendix are the required forms which must be completed by all Proposers for each individual proposal they wish to offer. If a variation to a proposal is offered, in which either price or term only is offered, then only forms applicable to this variation may be presented.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 1: Public Information Regarding Proposal

Facility Name: ______________________________

1) **Name of Proposing Company:** ______________________________

2) **Type of Generating Unit:** ______________________________

3) **Type of Project (Select One):**
Purchased Power from Existing Unit: ________
Purchased Power from New Unit: ________
System Sale: ________
Qualifying Facility: ________
Other(Specify): ________

4) **Generating Facility Location (City/Co./State):** ______________________________

5) **Fuel:** Primary: ________________
Secondary/Backup: ________________

6) **Proposer Classification (Select One):**
Utility (retail serving): ________
Independent Power Producer: ________
Small Power Producer: ________
Cogenerator: ________
Other (explain): ________

7) **Proposed Total Guaranteed Firm Capacity (Net MW) Delivered to FPL system** (must match information on Form # 4, item 5, Guaranteed Firm Capacity, MW):

Summer (95F): __________ Winter (35F): __________

8) **Proposed Capacity Delivery Start Date:** ______________ (Month/Day/Year)

9) **Proposed Capacity Delivery End Date:** ______________ (Month/Day/Year)

10) **Use the space below, or a separate sheet, to list all major projects undertaken (constructed and/or operated) by the Proposer or Proposer's affiliates/parent company during the last five (5) years which are similar to the project being proposed by the Proposer in response to FPL's RFP.**

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 2: Executive Summary of the Proposal

Facility Name: ____

Please provide a one (1) page summary of the proposed project and the Proposer.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 3: Financial Information

Facility Name: ____________________

1) **Proposer's Legal Name:** ____________________

2) **Physical Address:** ____________________
____

3) **Financial/Credit Contact Person:**

Name: ____________________
Position Title: ____________________
Telephone: ____________________
Fax: ____________________
E-Mail: ____________________

4) **Federal Tax Identification Number:** ____________________

5) **Proposer is (Select all that apply):**

________ Corporation	________ Sole Proprietorship
________ Partnership	________ Limited Liability Company
________ Joint Venture	________ Limited Liability Partnership
	________ Other (attach description)

6) **State in which Proposer is incorporated or organized:** ____________________

7) **Proposer Information:**

a) Dunn & Bradstreet Identification Number: ____________________

b) Corporate Bond Ratings: ________ Sources: ________
________ ________

c) Commercial Paper Ratings: ________ Sources: ________
________ ________

d) Dunn & Bradstreet Credit Appraisal Rating: ________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 3: Financial Information

Facility Name: ____

8) (If applicable) Parent/Affiliate Guarantor Information:

a) Name of parent/affiliate guarantor: ______________________

b) Dunn & Bradstreet Identification Number: ______________________

c) Corporate Bond Ratings: ____________ Sources: ____________
____________ ____________

d) Commercial Paper Ratings: ____________ Sources: ____________
____________ ____________

e) Dunn & Bradstreet Credit Appraisal Rating: ______________

9) If Proposer is relying on any parent/affiliate guarantees, use the space below to describe the corporate relationship between the Proposer and the guarantor. Also, provide a statement regarding the proposed guarantor's willingness to guarantee the Proposer's obligation pursuant to the form of guarantee that is to be attached to the PPA.

____
____
____
____
____
____

10) Provide audited financial statements for the last two years for the Proposer and, if applicable, the proposed guarantor.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____________________

1) **Power Generation Proposal Type: (Select one):**

a) Purchased Power from Existing Unit: _____
b) Purchased Power from New Unit: _____
c) System Sale: _____ Provide an attachment detailing the proposed system sale including an explanation of how the proposing utility will maintain its reserve margin/reliability requirements in regard to commitments to its Public Service Commission.

d) Qualifying Facility: _____
e) Other: _____ Provide details:

____

____

2) **Technology/Configuration:**

a) Type of Generating Unit: Select Appropriate Number from the List Below: 1
Combined Cycle = 1
Combustion Turbine = 2
All Other = 3
(Note: if "All Other = 3" is chosen, FPL will develop Proposal-specific values for calculating EFOR and EAF on Form # 4, page 3 of 14)

b) Configuration:(*e.g Combined Cycle Unit with 2 CTG/HRSG trains w/duct firing and 1 Steam Turbine, Cooling Tower with makeup water from Source A; etc):*

____

____

c) Major Equipment Technology, Supplier, Model: (*Combustion Turbine, Steam Turbine; Boiler/HRSG/Catalyst Systems):*

____

____

d) Generation/Operation Modes: (*Specify/describe basis for proposed Generation/Operation Mode(s)):*
Base Operation: ____________________
Incremental Level 1: ____________________
Incremental Level 2: ____________________
Other(s): ____________________

e) Design/Operational capabilities for extreme events (e.g. hurricanes)
Design Criteria:
i) Building Code ____________________
ii) Wind Speed: ____________________
iii) Importance Factor: ____________________
Operating Criteria - specificy the maximum wind speed above which the Operator(s) will shut down the generating unit: ____________________
Special Design/Operational Features - identify plant system(s) and capabilities
i) safe shutdown of unit with readiness for rapid restart: ____________________
ii) blackstart unit w/o offsite power: ____________________

____

f) General Equipment Specifications
Nominal Ratings (at rated temperature and pressure of the generator cooling medium):

____

Capability Curves (at rated temperature and pressure of the generator cooling medium): Provide as an attachment.
Nominal Power Factor: ____________________
GSU Transformer impedances: ____________________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

2) Technology/Configuration (Continued):

g) Existing Unit(s) and OEM Replacement Parts for Hot Gas Path Components:

- For a proposal based on an existing generating unit(s), please explain to what extent OEM replacement parts for hot gas path (HGP) components have been used in the unit(s):

____

____

- If the proposal is accepted, the winning Proposer must install OEM replacement HGP parts prior to the start of delievery of capacity and energy to FPL, then continue to utilize OEM replacement HGP parts for the duration of the PPA, and agree in the PPA to annually obtain from the OEM a certification that OEM replacement have been installed and have been maintained in accordance with the OEM schedules. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

h) Proposed New Unit(s) and OEM Replacement Parts for Hot Gas Path Components:

- For a proposal based on a new generating unit(s), please explain to what extent OEM replacement parts for hot gas path (HGP) components have been used in existing unit(s) operated by the Proposer:

____

____

- If the proposal is accepted, the winning Proposer must utilize OEM replacement HGP parts for the duration of the PPA, and agree in the PPA to annually obtain from the OEM a certification that OEM replacement have been installed and have been maintained in accordance with the OEM schedules. (Check One):

Agree ________ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

i) Historical Outage Hours for Existing Unit(s) Operated by Propser that are Similar to the New Unit being proposed: (Provide requested data below for all such existing units)

	Base Operational Mode		Other Operational Modes	
Year	Actual Annual Planned Outage Hours	Actual Annual Forced Outage Hours	Actual Annual Planned Outage Hours	Actual Annual Forced Outage Hours
2010				
2011				
2012				
2013				
2014				

Note: Do not include Maintenance Outage Hours in these projections.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____________________

1 = Type of Generating Unit (from Form 4_1).

0.85 = Projected service hours for purposes of projecting EFOR and FOF.

3) Operational Considerations: Availability, Reliability, & Operating Time Limitations:

a) Outage Hours:

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Base Operational Modes					Other Operational Modes				
			FPL Calculations for RFP Analyses					FPL Calculations for RFP Analyses		
Contract Year	Annual Forced Outage Hours	Annual Planned Outage Hours	EAF (%)	EFOR (%)	FOF (%)	Annual Forced Outage Hours	Annual Planned Outage Hours	EAF (%)	EFOR (%)	FOF (%)
2019			100%	0.00%	0.00%			100%	0.00%	0.00%
2020			100%	0.00%	0.00%			100%	0.00%	0.00%
2021			100%	0.00%	0.00%			100%	0.00%	0.00%
2022			100%	0.00%	0.00%			100%	0.00%	0.00%
2023			100%	0.00%	0.00%			100%	0.00%	0.00%
2024			100%	0.00%	0.00%			100%	0.00%	0.00%
2025			100%	0.00%	0.00%			100%	0.00%	0.00%
2026			100%	0.00%	0.00%			100%	0.00%	0.00%
2027			100%	0.00%	0.00%			100%	0.00%	0.00%
2028			100%	0.00%	0.00%			100%	0.00%	0.00%
2029			100%	0.00%	0.00%			100%	0.00%	0.00%
2030			100%	0.00%	0.00%			100%	0.00%	0.00%
2031			100%	0.00%	0.00%			100%	0.00%	0.00%
2032			100%	0.00%	0.00%			100%	0.00%	0.00%
2033			100%	0.00%	0.00%			100%	0.00%	0.00%
2034			100%	0.00%	0.00%			100%	0.00%	0.00%
2035			100%	0.00%	0.00%			100%	0.00%	0.00%
2036			100%	0.00%	0.00%			100%	0.00%	0.00%
2037			100%	0.00%	0.00%			100%	0.00%	0.00%
2038			100%	0.00%	0.00%			100%	0.00%	0.00%
2039			100%	0.00%	0.00%			100%	0.00%	0.00%
2040			100%	0.00%	0.00%			100%	0.00%	0.00%
2041			100%	0.00%	0.00%			100%	0.00%	0.00%
2042			100%	0.00%	0.00%			100%	0.00%	0.00%
2043			100%	0.00%	0.00%			100%	0.00%	0.00%
2044			100%	0.00%	0.00%			100%	0.00%	0.00%
2045			100%	0.00%	0.00%			100%	0.00%	0.00%
2046			100%	0.00%	0.00%			100%	0.00%	0.00%
2047			100%	0.00%	0.00%			100%	0.00%	0.00%
2048			100%	0.00%	0.00%			100%	0.00%	0.00%
2049			100%	0.00%	0.00%			100%	0.00%	0.00%

Notes: 1) The specified forced outage hour values **must** reflect realistic values **over the life of the proposed capacity, not**"new & clean" unit values for all years.
2) If the EAF, EFOR, or FOF values are worse than the respective values discussed in Appendix C, Section E in any year, the bid will be rejected.

b) Operating Time Limitations:

- Provide explanation (s) for any operating time limitations attributable to facility design, permits, environmental regulations, maintenance, and/or other factors.
- Note that FPL requires that the Guaranteed Firm Capacity value quoted on Form 4_7 be capacity without run-time limitations.

Generation Operation Mode	Run-Time Limitations (e.g. hrs/yr.)	Explanation
Base Operation:		
Incremental Level 1:		
Incremental Level 2:		
Other(s):		

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

3) **Operational Considerations: Availability & Reliability (Continued):**

c) Existing Unit(s) and Availability & Reliability:

- For a proposal based on an existing generating unit(s), please state to what extent this generating unit(s) has achieved the outage hours reflected in the proposal during the last five years (and provide evidence that demonstrates that these outage hour levels have been achieved.)

____

- If the proposal is accepted, the winning Proposer must guarantee in the PPA that the unit will achieve outage hour levels reflected in the proposal so that the calculated EA, EFOR, and FOF levels are no worse than those projected on Form # 4, page 3 of 14. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

d) Proposed New Unit(s) and Availability & Reliability:

- For a proposal based on a new generating unit(s), please state to what extent existing units operated by the Proposer have achieved the calculated EA, EFOR, and FOF levels projected during the past five years (and provide evidence that demonstrates that such availability and reliability levels have been achieved).

____
____

- If the proposal is accepted, the winning Proposer must guarantee in the PPA that the unit will achieve EA, EFOR, and FOF levels equal to, or better, than those calculated on Form # 4, page 3 of 14. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the bid will be rejected.)*

4) **Fuel Information and Barometric Pressure:**

a) Primary Type of Fuel: ______________

b) Secondary/Backup Type of Fuel: ______________

c) Total operating time that unit can run at full capacity using actual on-site Secondary/Backup fuel without this stored fuel being replenished. = ______________ Hrs.
(See Minimum Requirements for Proposals, Section III)

d) Total Quantity of Secondary/Backup Fuel Stored On-Site:
Storage capacity = ______________________________
Typical On-Site Inventory for Operations = ______________________________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

4) Fuel Information and Barometric Pressure (continued):

c) Natural Gas Fuel -Typical Properties *(for specifying unit performance values)*

Proposer's facility shall be designed to handle the expected range of fuels from its source(s). However, all specified unit performance values provided by Proposer shall be based on the "Average Fuel Analysis" that follows below:

Wide Range Fuel Data - Natural Gas

Property Constituents (Mole%)	Average
Methane	93.56%
Ethane	3.90%
Propane	1.00%
Normal Butane	0.23%
Iso Butane	0.23%
Normal Pentane	0.05%
Iso Pentane	0.03%
Hexane	0.10%
Carbon Dioxide	0.50%
Nitrogen	0.40%
TOTAL (MOLE %)	100%
Specific Gravity	0.601
Wobbe Index	1,376.7
Btu/SCF (HHV)	1,067
Btu/SCF (LHV)	962
HHV/LHV Ratio	1.109

Notes:
1 The constituent mole % values are normalized from the AVERAGE.
2 All constituent heating values are from the 1981 GPSA Engineering Data Book.
3 FPL does not warrant or guarantee that this fuel information is the actual that will be received during operation.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

4) <u>Fuel Information and Barometric Pressure (continued):</u>

d) Barometric Pressure Conditions (for specifying performance values):

The generating unit performance values specified hereinafter shall be based on barometric pressure conditions as follows:

Ambient Barometric Pressure Chart

Centerline of CTG inlet bell mouth elevation (ft.)	Barometric Pressure (PSIA)
Sea Level	14.696
25	14.687
50	14.674
75	14.661
100	14.648
150	14.622
200	14.596
250	14.5704
300	14.5445

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____________________

5) **Guaranteed Firm Capacity** **(Net MW @ GSU Transformer High Side unless otherwise noted *):**

a) On Primary Fuel

	Generation/Operation Mode				
Ambient Conditions	Base Operation **	Incremental Level 1 *,***	Incremental Level 2 *,***	Other(s) (Specify) *,***	Total Guaranteed Firm Capacity
95F,50%RH					
35F,60%RH					
95F,50%RH ***					
35F,60%RH ***					

b) On Secondary Fuel

	Generation/Operation Mode				
Ambient Conditions	Base Operation **	Incremental Level 1 *,***	Incremental Level 2 *,***	Other(s) (Specify) *,***	Total Guaranteed Firm Capacity
95F,50%RH					
35F,60%RH					
95F,50%RH ***					
35F,60%RH ***					

* As delivered to FPL's system adjusted for any 3rd Party transmission system losses (if applicable).

** Guaranteed firm capacity must be capacity without run-time limitations

*** Generation/Operation Mode: "Incremental Level 1" values shall be specified as incremental to "Base Operation" values; "Incremental Level 2" values shall be specified as incremental to "Incremental Level 1 values; and so forth. (Example: Base Operation may be combined cycle w/o HRSG duct burners in operation. "Incremental 1" may be the incremental performance from use of HRSG duct burners.)

Note: The guaranteed capcity values shown above **must reflect "average" capacity values over the proposed term-of-service to FPL, not** "new & clean" unit values.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

5) **Guaranteed Firm Capacity (Continued):**

c) Existing Unit(s) and Guaranteed Firm Capacity:

- For a proposal based on an existing generating unit(s), please state to what extent this generating unit(s) has achieved the peak capacity levels reflected in the proposal during the last five years (and provide evidence that demonstrates that such peak capacity levels have been achieved.)

____

____

- If the proposal is accepted, the winning Bidder must guarantee in the PPA that the unit will continuously achieve the peak capacity levels reflected in the bid and provide results on annual tests of capacity. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the bid will be rejected.)*

d) Proposed New Unit(s) and Guaranteed Firm Capacity:

- For a proposal based on a new generating unit(s), please explain to what extent existing units operated by the Proposer have achieved the peak capacity levels reflected in the proposal during the past five years (and provide evidence that demonstrates that such peak capacity levels have been achieved).

____

____

- If the proposal is accepted, the winning Proposer must guarantee in the PPA that the unit will continuously achieve the peak capacity levels reflected in the proposal and provide results on annual tests of capacity. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

6) **Guaranteed Heat Rates (BTU/kWh (HHV) @ Guaranteed Firm Capacity as delivered to FPL system adjusted for any 3rd Party transmission system losses):**

a) On Primary Fuel:

	Generation/Operation Mode			
Ambient Conditions	Base Operation	Incremental Level 1 *	Incremental Level 2 *	Other(s) (Specify)*
95F,50%RH				
75F,60%RH				

b) On Secondary Fuel:

	Generation/Operation Mode			
Ambient Conditions	Base Operation	Incremental Level 1 *	Incremental Level 2 *	Other(s) (Specify)*
95F,50%RH				
75F,60%RH				

* Generation/Operation Mode: "Incremental Level 1" values shall be specified as incremental to "Base Operation" values; "Incremental Level 2" values shall be specified as incremental to "Incremental Level 1 values; and so forth. (Example: Base Operation may be combined cycle w/o HRSG duct burners in operation. "Incremental 1" may be the incremental performance from use of HRSG duct burners.)

Note: The guaranteed heat rates values shown above **must reflect "average" values over the proposed term-of-service to FPL, not** "new & clean" unit values.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

6) **Guaranteed Heat Rates (Continued):**

c) Existing Unit(s) and Guaranteed Heat Rates:

- For a proposal based on an existing generating unit(s), please state to what extent this generating unit(s) has achieved the heat rate levels reflected in the proposal during the last five years (and provide evidence that demonstrates that such heat rate levels have been achieved.)

____

____

- In regard to this evidence of actual heat rates, if a heat rate test acceptable to FPL has not been performed within the last two years, the Proposer must perform a new test and submit the results as part of the proposal. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

- If the proposal is accepted, the winning Proposer must guarantee in the PPA that the unit will achieve the heat rate levels reflected in the proposal and provide results of annual heat rate tests (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

d) Proposed New Unit(s) and Guaranteed Heat Rates:

- For a proposal based on a new generating unit(s), please explain to what extent similar existing units operated by the Proposer have achieved the heat rate levels reflected in the proposal during the past five years (and provide evidence that demonstrates that such peak capacity levels have been achieved).

____

- In regard to this evidence of actual heat rates, if a heat rate test acceptable to FPL has not been performed for such existing units within the last two years, the Proposer must perform a new test(s) and submit the results as part of the proposal. (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

- If the proposal is accepted, the winning Proposer must guarantee in the PPA that the unit will achieve the heat rate levels reflected in the proposal and provide results of annual heat rate tests (Check One):

Agree ______ Disagree ______ *(If marked "Disagree, the proposal will be rejected.)*

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ______________________________

7) **Emission Rate Information:** **(For System Sales, please see directions in the Appendix C text on page C-4.)**

Provide the emission rate information requested below for the incremental MW supplied by each applicable operational mode on both the primary and secondary fuel.

a) On Primary Fuel

	Base Operation @ Full Load	Incremental Level 1	Incremental Level 2	Other
NO_x emission rate: lbs./mmBTU =				
SO_2 emission rate:lbs./mmBTU =				
PM_{10} emission rate:lbs./mmBTU =				
CO emission rate:lbs./mmBTU =				
CO_2 emission rate:lbs./mmBTU =				
Hg emission rate:lbs./trillion BTU =				

b) On Secondary Fuel

	Base Operation @ Full Load	Incremental Level 1	Incremental Level 2	Other
NO_x emission rate: lbs./mmBTU =				
SO_2 emission rate:lbs./mmBTU =				
PM_{10} emission rate:lbs./mmBTU =				
CO emission rate:lbs./mmBTU =				
CO_2 emission rate:lbs./mmBTU =				
Hg emission rate:lbs./trillion BTU =				

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

7) **Emission Rate Information (Continued):**

Provide the emission rate information requested below for the incremental MW supplied by each applicable operational mode on both the primary and secondary fuel.

a) On Primary Fuel

	Base Operation @ Full Load	Incremental Level 1	Incremental Level 2	Other
NO_x (ppmvd @ 15% oxygen) =	________	________	________	________
CO (ppmvd @ 15% oxygen) =	________	________	________	________
VOC (ppmvd @ 15% oxygen) =	________	________	________	________
SO_2 (ppmvd @ 15% oxygen) =	________	________	________	________
SO_2 (lbs per hour) =	________	________	________	________
PM (lbs per hour) =	________	________	________	________
PM_{10} (lbs per hour) =	________	________	________	________
$PM_{2.5}$ (lbs per hour) =	________	________	________	________
H_2SO_4 mist (lbs per hour) =	________	________	________	________

b) On Secondary Fuel

	Base Operation @ Full Load	Incremental Level 1	Incremental Level 2	Other
NO_x (ppmvd @ 15% oxygen) =	________	________	________	________
CO (ppmvd @ 15% oxygen) =	________	________	________	________
VOC (ppmvd @ 15% oxygen) =	________	________	________	________
SO_2 (ppmvd @ 15% oxygen) =	________	________	________	________
SO_2 (lbs per hour) =	________	________	________	________
PM (lbs per hour) =	________	________	________	________
PM_{10} (lbs per hour) =	________	________	________	________
$PM_{2.5}$ (lbs per hour) =	________	________	________	________
H_2SO_4 mist (lbs per hour) =	________	________	________	________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

8) **Natural Gas Pipeline Connection(s):**

a) Identify the projected source of natural gas supply (FGT, Gulfstream, Sabal Trail, or Sabal Trail / Florida Southeast Connection, etc.)

____

b) Designate the power generating facility, proposed gas pipeline delivery point, and any proposed lateral line facilities on a hard copy submittal of marked-up U.S. Geological Survey Map(s) indicating the Section(s), Township(s) and Range(s). Include one hard copy of this USGS map(s) in each of the five bound hard copies of these completed forms.

c) Provide a written description of these proposed lateral line and metering facilities to connect the interstate or intrastate gas pipeline to the generating facility, including the size of the pipe and the distance (in miles) of the generating facility from the appropriate natural gas interstate or intrastate mainline (name the mainline) that will supply the facility's gas and a detailed description of the metering facilities.

____
____
____
____

d) Provide the minimum acceptable natural gas delivery pressure at each of the following locations: (i) at the interconnection with the interstate gas pipeline, (ii) at the end of the proposed lateral line, and (iii) at the generating facility inlet.

e) Provide the Maximum Daily Natural Gas Consumption Requirement at Generating Facility:
____________________ (mmBTU/day)

f) Provide the portion of the Maximum Daily Natural Gas Consumption Requirement identified in e) above that must be obtained on a firm basis: _________ (mmBTU/day)

g) Provide the Maximum Hourly Natural Gas Consumption Requirement at Generating Facility:
____________________ (mmBTU/hour)

h) Provide the portion of the Maximum Hourly Natural Gas Consumption Requirement identified in g) above that must be obtained on a firm basis: _________ (mmBTU/hour)

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 4: Operations & Engineering Information

Facility Name: ____

9) **Generating Units' Operating & Maintenance Experience/Performance:**

Use attachment(s) to specify the name, address, etc. of the responsible Operating & Maintenance Group/ Company and pertinent U.S. experience/performance information (i.e., Actual Performance Track-Record):

For all generating plants in its U.S. domestic portfolio, provide a listing of individual generating unit names, location, state, guaranteed/demonstrated MW capacity, in-service year, technology type, primary fuel, start year of Operating Entity experience with the unit. From these, provide composite experience summaries as follows:

General - Cumulative MW-years of experience through December 2014 with ALL present generating capacity

Specific - Cumulative MW-years of experience through December 2014 with SPECIFIC generating technologies being proposed (e.g. Combined Cycle, Peaking CT/GT, Coal-Steam).

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 5: Pricing Information for Purchased Power or System Sale Proposals

Facility Name: ______________________________

1) **Guaranteed Capacity Payments: *,****

Provide guaranteed total capacity pricing for each operational mode identified on Form # 4. Please insert "NA" for operational modes that are not applicable to your proposal.

	for: Base Operational Mode	for: Incremental Level 1 Operational Mode	for: Incremental Level 2 Operational Mode	for: Other (specify) Operational Mode
Contract Year	Guaranteed Capacity Payment **($/kw-month)**	Guaranteed Capacity Payment **($/kw-month)**	Guaranteed Capacity Payment **($/kw-month)**	Guaranteed Capacity Payment **($/kw-month)**
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				
2039				
2040				
2041				
2042				
2043				
2044				
2045				
2046				
2047				
2048				
2049				

* Guaranteed capacity pricing values must include all proposed payments for at least the following:
- generation capital, fuel delivery capital including lateral from the appropriate natural gas pipeline, and infrastructure capital;
- fixed O&M and capital replacement;
- transmission interconnection and 3rd party transmission service (as applicable) over another utility system(s). (See pages 3 of 4 and 4 of 4 of this form.)

**** Please refer to instructions in Section F of this Appendix.**

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 5: Pricing Information for Non-System Sale Proposals

Facility Name: ______________________________

2) **Guaranteed Energy Pricing Payments:**

Pipeline: ________________ *

Contract Year	Guaranteed Fuel Transportation Reservation Price (if applicable) ** **($/mmBTU per Day)**	Guaranteed Fuel Transportation Quantity (if applicable) *** **(mmBTU per Day)**	Guaranteed Fuel Commodity Price (if applicable) **** **($/mmBTU per Day)**	(for Base Operational Modes) Guaranteed Variable O&M Payment ***** **($/MWH)**	(for all Other Operational Modes) Guaranteed Variable O&M Payment ***** **($/MWH)**
2019					
2020					
2021					
2022					
2023					
2024					
2025					
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					
2036					
2037					
2038					
2039					
2040					
2041					
2042					
2043					
2044					
2045					
2046					
2047					
2048					
2049					

* In regard to the "Pipeline" entry, please fill in the blank with one of the following: "FGT", "Gulfstream", "Sabal Trail", or "Sabal Trail / Florida Southeast Connection (FSC)".

** If $/mmBTU per Day values are not entered for each year, FPL will use its own fuel transportation forecast, plus any incremental lateral costs, for evaluation purposes for any project capable of connecting to Sabal Trail or FSC. For projects which must be connected to FGT or Gulfstream, FPL will have to evaluate the cost of acquiring additional capacity on the applicable pipeline. If $/mmBTU per Day values are entered, FPL will use those values for evaluation purposes and will use the applicable pipeline's tariff to determine the appropriate variable costs and fuel per mmBTU per Day.

*** A Guaranteed Fuel Transportation Quantity must be included for proposals with a Guaranteed Fuel Transportation Reservation Price.

**** If left blank, FPL will use its own fuel price forecast for purposes of proposal evaluation.

***** **Please refer to instructions in Section F of this Appendix.**

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 5: Pricing Information for System Sale Proposals

Facility Name: ____________________

2) Guaranteed Energy Pricing Payments:

Contract Year	Guaranteed Variable O&M Payment * (\$/MWH)	Guaranteed Energy Payment * (\$/MWH)
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		
2046		
2047		
2048		
2049		

* Please refer to instructions in Section F of this Appendix.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 5: Pricing Information for Purchased Power or System Sale Proposals

Facility Name: ____

3) **Startup Fuel Amount Required:**

______________________ **(mmBTU per startup)**

4) **Costs and Information Included in the Payments:**

a) (For proposals that are based partially or totally on generators that need to be constructed and connected to the transmission system) Attach a copy of the completed and submitted application for Generator Interconnection Service (GIS) in the FPL GIS Queue, or which the applicable third party if the new generator is to be connected to a third party's transmission system.

b) Transmission Interconnection Costs:

Total transmission interconnection cost included in the Guaranteed Capacity Payment values provided on page 1 of 4 of this form = ________________________ (millions, 2019$)

Basis for this cost estimate is : ______________________________________
____
____
____

c) Third Party Transmission Service Information:

State whether third party transmission service rights have been requested and/or already procured for a portion of or all of the generation capacity being offered. To the extent a request for such long-term firm transmission rights have been requested, but not yet procured, provide all available studies associated with such requests.

____
____
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 5: Pricing Information for Purchased Power or System Sale Proposals

Facility Name: ____

4) **Costs and Information Included in the Payments (Continued):**

d) Transmission Losses:

Transmission losses (MW) associated with the third party transmission service (which are accounted for in developing the Total Guaranteed Firm Capacity (As Delivered to FPL's System) values on Form # 4):

____

____

____

____

e) Gas Pipeline Lateral and Meter Costs:

Total lateral pipeline and meter cost = ______________ (millions, 2019$).

Are the lateral pipeline and meter station cost included in the Guaranteed Capacity Payment values provided on page 1 of 4 of this form or, if applicable, in the Guaranteed Fuel Transportation Reservation Price provided on page 2 of 4 of this form? Please indicate below with an "X":

In the Guaranteed Capacity Payment ________
In the Guaranteed Fuel Transportation Reservation Price ________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

1) **Proposed Community Outreach Activities and Experience:**

Describe experience with Community Outreach Plans, identify community benefits, and identify the proposed outreach activities for the proposed facilities.

____
____
____

2) **Required Permits or Approvals to License or Permit the Facility:**

Provide a listing of all required permits or approvals (federal, state, and local) to license or permit the construction and operation of the facility.
Include a major milestone permitting schedule *:

____
____
____

* FPL is requiring that a Proposer's Site Certification Application must be filed within 39 months of the proposed Capacity Delivery Date. **(See Section III of the RFP document.)**

Identify any studies, surveys, and/or analyses necessary to support the permititng, licensing, and certification of the facility:

____
____
____

Identify the need for any Variances or Exceptions to substantive standards and other requirments along with the strategy to obtain same:

____
____
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

3) **Description of Air Pollution Control Equipment:**
Provide sufficient detail to characterize pollution reduction effectiveness and maturity at size/scale proposed, e.g. mature, emerging, or new application):

____
____
____

a) Industry Experience:
# of Units in operation: ________
Years Experience: ________
Operational Issues: ______________________________
____
Other: ______________________________
____

b) Proposer Experience:
# of Units in operation: ________
Years Experience: ________
Operational Issues: ______________________________
____
Other: ______________________________
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

4) **PSD/NSR Permitting:**

Provide anticipated emission rates for each regulated pollutant or emission emitted from the facility (including CO_2).

Lbs./hr ________
Lbs./mmBTU ________
ppm ________
TPY ________

Describe the overall strategy for permitting the proposed Pollution Control Technology for all regulated pollutants.

____
____
____

Describe the emissions credit strategy (if applicable):

____
____
____

Describe the basis for all regulated pollutant emission rates (e.g., vendor guarantee, EPA emissions factor, operating experience, etc.):

____
____
____

Provide the expected cooling tower emission rates for regulated pollutants (lbs.hr. & TPY):

____
____
____

Describe treatment/maintenance chemicals (including cycles of concentration):

____
____
____

Describe compliance with applicable AAQS, PSD increments and AQRVs:

____
____
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

5) **Water Supply Strategy:**

Identify source(s), quantity, and quality (monthly or seasonal differences):

____

____

Describe agreement(s) or authorization status (timetable or plan to acquire water supply):

____

____

Identify any conflicts with regional Water Management District (WMD), or other local water authority, goals or plans:

____

____

6) **Water Discharge Strategy:**

Location(s) of discharge(s) - water body, city/town, and latitude and longitude:

____

____

Quality and quantity (monthly or seasonal differences):

____

____

List of any required agreements or permits and provide status (timetable or work plan to acquire same):

____

____

Identify any conflicts with WMD goals and FDEP rules:

____

____

Wetlands Impacts:

____

____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ______________________________

6) **Water Discharge Strategy (Continued):**

TMDLs (if applicable):

____
____
____

Surface Water Impacts

____
____
____

Groundwater Water Impacts

____
____
____

7) **Strategy to Address Land Use Issues:**

Comprehensive Plan/Amendment (current and proposed changes, if any; status or work plan required):

____
____
____

Identify the need for Variances or Exceptions and the strategy to obtain same:

____
____
____

Compatibility with adjacent land uses:

____
____
____

Distance and direction of nearest residence to plant boundary:

____
____
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

7) **Strategy to Address Land Use Issues (Continued):**

Describe the strategy for compliance with noise standards:

____
____
____

Describe the strategy for compliance with other standards:

____
____
____

Identify any zoning issues, the need for Variances or Exceptions, and the strategy to obtain same:

____
____
____

Summary of Phase I/Phase II environmental site assessment findings, if any; and status of required work plan.

____
____
____

Description of Archaeological or Historic Site Impacts, if any;
status of work plan required:

____
____
____

8) **Solid/Hazardous Waste/Material Management Strategy:**

____
____
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ____

9) **Other Infrastructure Needs or Requirements:**

Water supply or discharge line Right of Way (ROW) and easements - and the strategy to obtain same:

____
____
____

Fuel supply ROW and easements - and the strategy to obtain same:

____
____
____

Transmission line ROW and easements - and the strategy to obtain same:

____
____
____

Transportation access ROW & easements - and strategy to obtain same:

____
____
____

10) **Protected Species Impacts:**

____
____
____

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 6: Environmental & Permitting Information

Facility Name: ______________________________

11) **Permitting Experience in Florida of Proposer and Environmental Support Contractors and Consultants:**

____
____
____
____
____
____

12) **Proposer Compliance History (Last 5 years, i.e., 2010-2014):**

Total and type of violation/non-compliance: ______________________________
____

Total dollars in:
Fines: ____________
Penalties: ____________
Payments or other in-kind contribution for settlement: ____________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 7: Key Milestones

Facility Name: ____

Key Milestones (as applicable):	**Projected Date:**
a) Site Certification Application Filed	____________
b) Air Permit Application Filed	____________
c) Interconnection Application Filed	____________
d) Granted Site Certification	____________
e) Granted Air Permit	____________
f) Irrevocable Order Placed for All Major Equipment	____________
g) Firm Fuel Transportation Arrangement(s) Executed	____________
h) Contractor Mobilized, Financing Closed	____________
i) Construction Start	____________
j) Major Equipment Deliveries (specify all)	____________
k) Acceptance Testing (specify all)	____________
l) Capacity Delivery Date	____________

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 8: Receipt Point(s) to FPL

Facility Name: ____

1) State the receipt point(s) to the FPL system including nearest substation(s):

____

____

____

2) Attach a readable transmission map (8.5x11) highlighting the receipt point(s) listed above.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 9: Proposer Exceptions *

Facility Name: ____

*** Note: FPL will not consider proposed exceptions to the RFP's Minimum Requirements for Proposals or to the Minimum Requirements Pursuant to Puchase Agreement.**

1) With regard to this proposal, the Proposer takes no exception to terms, conditions, or other facets of the RFP (Check One): ________ Agrees ________ Disagrees

2) If the answer to item (1) above is "Disagrees", then for each term, condition, or other facet of the RFP which the Proposer takes exception to, use the space below to:

   a) identify the language (citing page and paragraph) in the RFP for which an exception is made; and,

   b) write out the Proposer's desired revised language.

Florida Power & Light Company's
2015 Request for Proposal for 2019 Capacity

Form # 10: Proposal Certification

Facility Name: ____

The undersigned certifies that: (i) all of the information submitted in its proposal to FPL is complete and accurate, and that the pricing includes all of the following applicable costs for the proposal for the proposed full term of service including, but not limited to, the following costs:

- generator construction;
- generator operation and maintenance;
- transmission interconnection and 3rd party transmission service;
- gas pipeline interconnection including lateral pipeline (or other fuel delivery capital and O&M costs); and
- cost of fuel (as applicable);

(ii) the terms, conditions, and other facets of the RFP are acceptable, except as specifically noted on Form # 9; (iii) the Completion Security and Performance Security described in Section IV of the RFP document are acceptable and there are no pending legal or civil actions that would affect the ability of the Proposer and/or it guarantor to maintain these security amounts; (iv) the proposal has been submitted in the legal name of the entity which would be bound by any resulting contract; and (v) the proposal is binding, definitive, and firm and will remain open for 180 days from the Proposal Due Date.

Name of Legal Entity: ____

State of Incorporation: ____

Business Address: ____

Name of Person Certifying Proposal: ____

Title: ____

Date: ____

Telephone: ____

Signature:* ____

E-Mail: ____

(* An Officer of the proposing company must sign a copy of this form which is included in each of the five (5) bound hard copies of the proposal.)

APPENDIX D

D.1 Evaluation Methodology – Overall Process

D.2 Transmission Integration & Losses

D.3 Net Equity Adjustment

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D.1. Evaluation Methodology - Overall Process

A. Overview

The objective of the evaluation methodology is to determine the best generation capacity option(s) that meet the RFP eligibility requirements and FPL's RFP capacity need requirements that start in June 2019. The determination will be made after analyses of eligible proposals received in response to this RFP and FPL's next planned generating unit (NPGU) that is presented in the main body of this RFP.

An individual proposal may meet the 2019 need requirement by itself (as FPL's NPGU will do). Individual proposals that only partially satisfy the 2019 need requirement may be paired with other proposals in a portfolio of proposals that together meet the 2019 need requirement. Once portfolios have been developed that each meet FPL's 2019 need requirement, the next step is to develop multi-year resource plans. Each resource plan will incorporate: an individual proposal that fully meets FPL's 2019 resource need, FPL's NPGU that also fully meets FPL's 2019 resource need, or one of the portfolios of smaller proposals. Filler units will then be added in each resource plan to meet FPL's projected annual resource needs after 2019.

These resource plans will then be evaluated using a multi-year analysis approach that allows examination of both short-term and long-term impacts to FPL's system from the generation options. These analyses will utilize both economic and non-economic perspectives.

The economic analyses will provide a total system perspective including economic impacts related to: new generation costs, system fuel costs, transmission costs, environmental compliance costs, and FPL's cost of capital. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the intent of minimizing FPL's levelized system average rate (*i.e.*, a Rate Impact Measure or RIM methodology). However, in cases such as a generation-only RFP evaluation in which FPL's demand side management (DSM) plans are unchanged, comparisons of competing resource plans' impacts on a levelized system average electric rate basis and on a cumulative present value system revenue requirements (CPVRR) basis will yield identical rankings of the options being evaluation. For this reason, and because it is a simpler process to perform CPVRR-based analyses than it is to perform levelized system average electric rate analyses, the economic analyses for this RFP competing resource plans evaluated in the RFP analyses will be evaluated on a CPVRR basis.

The economic analyses of proposals received in response to this capacity RFP will use a similar process to that used in analyses that led to the identification of FPL's NPGU. In its economic evaluation, FPL plans to use the UPLAN production costing model for detailed production costing work. If a large number of eligible proposals are received in response to this RFP, FPL may also use the EGEAS optimization model to perform rankings of the resource plans. The highest ranking (*i.e.*, lowest CPVRR cost) resource plans would then be evaluated using the UPLAN production costing model and FPL's Fixed Cost Spreadsheet. The Fixed Cost Spreadsheet is used to develop the fixed costs associated with each of the resource plans. These fixed costs include costs (as applicable) for: capital for new generation, fixed O&M, capital replacement, firm gas transportation, capacity payments, etc. If the number of eligible proposals received is relatively small, FPL may elect to not utilize the EGEAS model. In addition, the analyses will also utilize various spreadsheets that are discussed later in this Appendix.

All economic analyses steps will use consistent assumptions regarding fuel costs, environmental compliance costs, load growth, and generation expansion plan addition options. A designated FPL Fossil Fuel Price Forecast and the FPL Environmental Compliance Cost Forecast will be utilized in these economic analyses. (The FPL Fossil Fuel Price Forecast and the FPL Environmental Compliance Cost Forecast will be posted on the RFP website once the RFP document is issued.) In addition, load growth will be modeled using FPL's current Load Forecast and FPL's approved DSM Goals. The resulting projected firm peak load growth will require additional generation beginning in 2019, and in years beyond 2019, to maintain FPL's required reserve margin levels.

Some of the forecasts and assumptions that will be utilized in the economic analyses are different from those presented in, and utilized in the development of FPL's 2014 Ten Year Site Plan (Site Plan). Appendix E presents a list of some of the key forecasts that have changed from those used in developing the resource plan that was previously presented in the 2014 Site Plan. (FPL will file its 2015 Site Plan on April 1, 2015, *i.e.*, after the release of this RFP.) Largely as a result of these updated forecasts, FPL's current resource plan is different from that presented in the 2014 Site Plan. Appendix E also discusses key changes in FPL's resource plan through the year 2019.

Non-economic analyses will be performed to evaluate certain risks for each portfolio. These analyses will include, but not necessarily be limited to, examining the following: 1) risks associated with an eligible proposal, 2) projected FPL system emissions for each portfolio, and 3) projected FPL system fuel mix for each portfolio. The results of the non-economic analyses will then be combined with the results of the economic analyses in order to determine the best overall portfolio with which to serve FPL's customers.

The economic analysis will be coordinated and largely conducted by FPL's Resource Assessment & Planning Department. An external consultant, Sedway Consulting (Sedway), will serve as an Independent Evaluator and conduct parallel economic evaluations using a different model(s). Both FPL and Sedway will evaluate FPL's NPGU and eligible proposals received in response to the RFP. Other external consultants may be used in analyzing impacts or costs regarding transmission integration, transmission losses, and/or natural gas delivery aspects of the evaluation depending upon the number and/or complexity of the proposals received.

The non-economic analysis will be conducted by several FPL departments which may also utilize other independent consultants in their assessments. The coordination of the non-economic analysis work, and the integration of the results of the economic and non-economic analyses, will be performed by FPL's Resource Assessment & Planning Department.

The evaluation of eligible proposals, the NPGU, and the resulting resource plans will be conducted using an eight (8) step process that is summarized below.

Step 1: Initial Screening for Eligibility

This initial step determines whether proposals satisfy the Minimum Requirements for Proposals and the Minimum Requirements Pursuant to Purchase Agreement (Sections III and IV, respectively, of the main body of the RFP). Proposals that do not satisfy these Minimum Requirements will be deemed ineligible and will be returned to the Proposer, along with 50% of the RFP Evaluation Fee, and will not be evaluated further.

Step 2: Economic Evaluation of Individual Proposals (if applicable)

In order to assist in the analysis of a potentially large number of eligible proposals that might be received in response to this RFP, an economic ranking of individual eligible proposals may be made based on their individual impact to the FPL system. The results of such an analysis would be used to rank proposals based on their individual economic merit. If there are significant differences in the projected economic impacts to the FPL system among the proposals, these results may be used to reduce the number of proposals that are carried forward to the next steps of the economic evaluation. Proposals that are not evaluated beyond this step will have been shown to be non-competitive by comparison of their results to the results of other proposals that do proceed in the evaluation.

The Step 2 analyses, if applicable, will likely be performed utilizing the EGEAS optimization model. These analyses of individual proposals will address FPL system cost impacts such as capital, capacity payments, fixed and variable O&M, capital replacement, firm gas transportation, system fuel, system environmental compliance costs, and other impacts effects from a resource plan perspective, including the ability of a proposal to help meet post-2019 resource needs.

If there are a relatively small number of eligible proposals, FPL may choose to forego this step of evaluating individual proposals and proceed to the creation and evaluation of portfolios and/or resource plans.

Step 3: Creation and Initial Evaluation of Portfolios and/or Resource Plans

Eligible proposals that remain after Step 1 (and, if applicable, Step 2) will then be incorporated into resource plans for further analyses. If a proposal is large enough by itself to meet FPL's 2019 resource needs, this proposal will be the only generation addition assumed to be added in 2019. Smaller proposals that cannot, by themselves, fully meet FPL's 2019 resource needs, would be combined, if possible, into a portfolio of proposals that in combination meets the 2019 resource need. Then large proposals and portfolios of smaller proposals will be incorporated into separate multi-year resource plans that address 30 years beyond 2019. In addition, a separate resource plan will assume the NPGU alone is added in 2019.

Each resource plan will then be evaluated for all system cost impacts, such as capital and other fixed costs, fuel and other variable costs, transmission interconnection and integration costs, system losses, and system environmental costs. These analyses will be performed utilizing FPL's Fixed Cost Spreadsheet and the UPLAN production costing model. FPL will utilize its Fixed Cost Spreadsheet to develop the fixed costs associated with each of the resource plans. These fixed costs include costs for: capital, fixed O&M, capital replacement, firm gas transportation, and capacity payments.

The UPLAN production costing model will be used to develop the variable annual costs of system operation for the resource plans. (The UPLAN model will be used by FPL in FPL's fuel cost recovery filings beginning in 2015, as well as in other production cost applications, and was used in the identification of FPL's NPGU for this capacity RFP.) This detailed, hourly production costing model will develop the projected annual fuel and variable O&M costs for each of the resource plans. This production costing model will also account for limitations on the amount of power that can be imported into the Southeastern Florida area and the corresponding impacts on the operation of FPL generating units located in Southeastern Florida. The UPLAN model, and potentially additional spreadsheet analysis, will be used to develop the environmental compliance costs of each portfolio.

Step 4: Development of Additional System Costs for Resource Plans

At the conclusion of Step 3, competitive resource plans will then undergo additional economic analyses as well as a non-economic evaluation. In Step 4, four additional system cost areas will be specifically developed for each resource plan, as applicable. These system costs are: (a) transmission-related costs, (b) fuel system-related costs, (c) greenhouse gas (GHG) emission-related costs, and (d) the net impact on FPL's cost of capital. In regard to the first two of these cost items, the specific siting of the proposed generation will be a key factor.

4a. Transmission-Related Costs

The following transmission-related costs will be calculated:

- transmission integration costs;
- costs related to system capacity (MW) losses at FPL's system peak hour and costs related to system annual energy (MWh) losses; and,
- impacts of the resource plans on maintaining a balance between load and generation in the Southeastern Florida region (*i.e.*, Miami-Dade and Broward counties).

The transmission integration facilities that are needed for each resource plan will be determined first. Next, costs for these integration facilities will be calculated. A transmission system analysis will then be conducted of each resource plan assuming that these integration facilities are in place. This analysis will serve as the basis to estimate the transmission system capacity losses at the system peak hour and annual energy losses associated with the resource plan. Costs will be assigned to these projected losses. In addition, the location of proposed generation capacity in each resource plan will be evaluated in regard to how it is projected to affect FPL's ability to maintain a balance between load and generation in the Southeastern Florida region consisting of Miami-Dade and Broward counties. Proposed generation capacity that is located in that region may be credited with the benefit of avoiding/deferring the costs of transmission projects projected to maintain this balance. (In addition, the production costing analyses will automatically account for the impact of the location of proposed generation capacity on the dispatch of FPL's generation system.)

Other transmission-related costs, including transmission interconnection costs and the costs of 3rd party transmission services (if applicable), are to be included in the price provided for each individual proposal. These items are discussed in more detail in Section D.2. below. (The cost of the NPGU presented in the main body of this RFP includes both transmission interconnection and integration costs.)

4b. Fuel System-Related Costs

As applicable, a more detailed analysis of the fuel system-related costs for each resource plan will be developed. Such an analysis will utilize the specific location of the generator(s) contained in the portfolio and the designated natural gas pipeline(s) to provide a more definitive estimate of the firm fuel transportation costs required to provide the necessary firm transportation at the appropriate pressures and volume to the portfolio consistent with FPL's normal fuel system management practices.

In addition, FPL will be evaluating the portfolio and resource plan to identify if "upstream" capital costs associated with additional natural gas pipeline and/or compression facilities will be needed to supply the proper volume and pressure of natural gas to the units in the portfolio.

4c. GHG Emission-Related Costs

For evaluation purposes, carbon dioxide (CO2) emission will serve to represent GHG emissions. All proposals will be required to provide the CO2 emission rates (lbs/MMBtu) of each proposed individual unit or, in the case of a system sale, the projected annual system emission rates (tons/MWh), for CO2 emissions. FPL will use these emission rates to calculate FPL's total projected annual system CO2 system emissions (tons) for each resource plan that includes one or more proposals. This approach will also apply to the resource plan with the NPGU. FPL and Sedway will then apply FPL's current projection of annual CO2 emission costs ($/ton) to these annual CO2 emissions so that the total annual emission costs that could be attributable to all energy generated to meet FPL customers' needs ("annual CO2 emission costs for FPL total energy") are calculated for each resource plan. FPL's projection of annual CO2 emission costs ($/ton) will be posted on the RFP website once the RFP is issued. From these annual CO2 emission costs, FPL will calculate a CPVRR CO2 emission cost value for the length of the analysis period for each resource plan. This CPVRR CO2 emission cost value will then be added to the projected fixed and variable CPVRR cost for the resource plan in the same way that CPVRR costs for transmission integration, losses, and net equity adjustment (see below) will be added. Together, the sum of all of these CPVRR costs will represent the total CPVRR cost for the resource plan.

4d. Net Equity Adjustment

FPL will also estimate the impact to FPL's cost of capital associated with entering into a new purchased power agreement(s). The costs of the resulting impact on FPL's capital structure are referred to as an equity adjustment. It is also recognized that a power purchase agreement also has the potential to mitigate completion and/or performance risks that would otherwise be borne by FPL if FPL were to construct a new generating unit. FPL assigns a cost savings to these "mitigating factors" and subtracts these values from the equity adjustment amount to derive a net equity adjustment. An explanation of the net equity adjustment evaluation, including an example calculation, is presented in Section D.3. below.

Step 5: Detailed Evaluation of Total System Costs

In Step 5, the CPVRR costs for each resource plan calculated in Step 3 are added to the additional system costs developed in Step 4 to produce a total system CPVRR cost for each resource plan. This total cost value represents the result of the full economic evaluation for each resource plan. The results for each resource plan, presented in CPVRR form, will be compared to the results for all other resource plans.

Step 6: Non-Economic Evaluation of Portfolios

A non-economic evaluation will be conducted on parameters that, by their nature, are unable to be integrated into the economic evaluation. These parameters describe factors that represent elements of risk that FPL must evaluate in all generation addition scenarios as well as other non-economic factors such as projections of system emissions and system fuel mix. Detailed information requirements designed to assist FPL in certain aspects of the non-economic evaluation are outlined in the submittal forms in this RFP that are presented and discussed in Appendix C. These submittal forms will be used to evaluate specific risk-related parameters that can be summarized as falling into one or more of the following three areas:

6a. Environmental Area

- Items related to the Proposer's ability to successfully complete the permitting and siting aspects of the project as proposed and maintain compliance with applicable rules and regulations.

6b. Technical/Operational Area

- Items related to the long-term operational performance, reliability, and maintainability of the proposed generating alternatives.

6c. Project Execution Area

- Items related to the exceptions stated to the RFP and the impact of those exceptions.
- Items that relate to the Proposer's ability to complete the development, construction, and operational aspects of the project as proposed.

Proposals that exhibit strong potential in the economic evaluation, but are unclear in certain non-economic evaluation areas, may be considered for a Panel Review. The Panel Review, if necessary, would provide for an exchange between the Proposer(s) and FPL panelists regarding the non-economic evaluation areas. This would allow for a more complete exchange of information in the important areas. Proposers will be notified individually if a need for a Panel Review is indicated, and a mutually convenient time will be arranged.
The specific key parameters for each of these 3 areas are presented in Tables D.1 - 1 through D.1 – 3 that follow.

Table D.1 - 1 Environmental Area Parameters

Compliance Experience
Control Technology
Violation/Non - Compliance
Proposed Project
Licensing/Permitting
PPSA/Permitting Issues
PSD/NSR Issues
Land Use Issues
Protected Species Issues
Zoning Issues
Variance Required
Exceptions Required
Community Outreach Plan
Water Supply Strategy
Water Discharge Strategy
FL Permitting Experience
PPSA
Non - PPSA
Other Infrastructure
Water Supply or Discharge Easements
Transportation Access
Fuel Supply Easements
Transmission Line Easements

Table D.1 - 2 Technical/Operational Area Parameters

Technology
Configuration
Operational Limitations
Fuel
Guaranteed Firm Capacity
Guaranteed Heat Rate
Commercial Availability
Generating Units' Operating & Maintenance Experience

Table D.1 - 3 Project Execution Area Parameters

Nature of Exceptions
Impact to Risk Profile
Departure from Scope
Probability of Resolution
Development Experience
Design/Construct Experience
Operational Experience

Step 7: Best and Final Offer Evaluation

After the economic results from Step 5 and the non-economic results from Step 6 are developed, the overall economic and non-economic profile of each resource plan based on a single proposal or portfolio of proposals will be examined and compared to the resource plan that includes FPL's NPGU. At that time, FPL will decide whether it will select a Short List of Proposers. If so, FPL may request from these Short Listed Proposers a Best and Final Offer ("BAFO"). In this case, FPL would then evaluate these BAFOs to develop the final economic and non-economic evaluations.

If the results of the evaluation indicate that the additional step of selecting a Short List of Proposers is not necessary or appropriate, FPL will base its decision on the evaluation (economic and non-economic) performed on the original proposals.

Step 8: Final Selection

The results of FPL's economic and non-economic evaluation will be presented to an FPL Management Review Team. The Management Review Team will then make a selection based on sound business practices and the best interests of FPL's customers.

D.2 Transmission Integration and Losses

A. Overview

In its evaluation of proposals received in response to this RFP, FPL will be evaluating five transmission-related costs associated with FPL's transmission system for individual proposals or for portfolios of proposals. These five costs are:

1) transmission interconnection costs (as applicable);
2) third party transmission service costs (as applicable);
3) transmission integration costs;
4) costs of transmission system losses; and
5) cost impacts of the resource plans on maintaining a balance between load and generation in the Southeastern Florida region (*i.e.*, Miami-Dade and Broward counties).

Noting that the transmission interconnection and third party transmission service costs are to be provided by each Proposer for their individual proposal(s), each of these 5 categories of transmission-related costs are discussed below.

1. Transmission Interconnection Costs (as applicable)

As discussed in Appendix C, Form # 5, a Proposer whose proposal is based partially or totally on generators that need to be constructed and connected to a transmission system must include all costs of this interconnection in the proposal's Guaranteed Capacity Payment. In addition, these interconnection costs must be separately broken out on Form # 5 so that FPL may judge the reasonableness of this estimate. FPL reserves the right to review and, if it deems necessary, to adjust this estimate accordingly to provide a more accurate interconnection cost based on FPL's knowledge and experience with the transmission system. Proposers will be notified of any such adjustments affecting their proposal(s).

All proposals that are based partially or totally on generators that need to be constructed and connected to the transmission system must also demonstrate per instructions on Form # 5 that they have a valid completed application for Generator Interconnection Service ("GIS") in the FPL GIS Queue, or with the applicable third party if the new generator is to be connected to a third party's transmission system.

The process for requesting GIS and having a completed GIS application on the FPL system is delineated in FPL's Open Access Transmission Tariff.

2. Third Party Transmission Service Costs (as applicable)

As discussed in Appendix C, regarding Form # 5, to the extent the generator(s) is connected to the transmission system of a third party, the Proposer shall include any and all third party transmission service costs in the Guaranteed Capacity Payment.

In addition, the Proposer shall state on Form # 5 whether such long-term transmission rights for third party transmission service has been requested and/or already procured for a portion of or all of the generation capacity being offered. To the extent a request for such long – term firm transmission rights has been made, but not yet procured, the Proposer shall provide all available studies and information associated with such request(s).

Finally, the Proposer shall also state on Form # 5 the transmission losses associated with the third party transmission service which are accounted for as the Proposer developed the Total Guaranteed Firm Capacity (as delivered to FPL's system) values on Form # 4.

3. Transmission Integration Costs

The transmission integration costs are based on all modifications (new facilities and facility upgrades) to the FPL transmission system that are necessary to physically transfer the proposed power from the FPL System Receipt Point to the load center consistent with reliability standards for 2019 conditions. The latest available Florida Reliability Coordinating Council (FRCC) peak load flow case representing the year 2019 (updated as necessary to reflect the latest available information) will be used as the basis for determining the transmission integration modifications needed. Once these modifications are determined, costs for these modifications will be estimated. These costs will then be assigned to the resource plan in question. The process of determining the needed transmission integration modifications generally consists of three steps.

Integration Cost Step 1: Identify Needed New/Upgraded Facilities

The first step is to perform screening studies to identify new facilities and facility upgrades that would be needed to integrate the proposals, portfolios of proposals, and/or the NPGU in each resource plan into the transmission system as a network resource for FPL. The type of studies that will be performed are considered screening type studies since they are not as comprehensive as studies that are normally performed for a specific request for transmission service. However, the screening type studies are sufficient to provide a reasonable estimate of the upgrades and facilities necessary to integrate each portfolio into the FPL system meeting the same reliability standards for comparison purposes. The analysis will assure that the FPL transmission system is planned with sufficient capability such that FPL can serve its customers and meet its transmission service obligations beginning in the year 2019 consistent with NERC, FRCC, and FPL standards.

Each of the resource plans will be subjected to contingency screening of all transmission elements and generators, and the transmission system is monitored for violations of NERC, FRCC, and FPL standards. Contingency screening tests will be performed at summer peak load conditions with all FPL generators/facilities assumed available and economically dispatched. Further, the generator deemed most critical to that case will be assumed to be unavailable, and the remaining FPL generators will be dispatched to mitigate, if practicable, violation of reliability criteria for all contingencies tested. Violations of reliability criteria found on the FPL system are resolved by acceptable remedial action (*e.g.*, switching), facility upgrades, or by new facilities, as appropriate. All proposed solutions will be subsequently introduced into the appropriate case and tested in order to verify the completeness of the solution.

During these studies, potential violations may be noticed on third party transmission systems. Should that occur, the following actions will be taken. The observance of such potential violations and the details surrounding these events will be communicated to the Proposer whose proposal is associated with the third party transmission system in question. Since the mitigation measures employed for the potential violations on third party systems will be at the discretion of, and based on the expertise of, third parties for their own transmission systems, identified potential violations will need to be communicated by the Proposer to the third party transmission system owner. Resolution of potential violations will be necessary if the proposal is selected to potentially meet FPL's need. As a result, any upgrades or facilities required on a third party system and attendant costs must be developed and provided by the Proposer so that they may be taken into consideration in the final evaluation. It is possible that a potential violation could be attributable in part to the portfolio combination of proposals being reviewed (*e.g.*, violation on transmission system X of Proposal A is aggravated by existence of Proposal B on FPL system). Analysis of this type would require a coordinated effort and the involvement of multiple parties.

Integration Cost Step 2: Determine Total Cost of Needed Facilities

Once a list of new facilities and upgrades on the FPL system required for integration is identified, the second step of the evaluation process of developing cost estimates for the new and upgraded transmission facilities commences. Based on the need for incremental transmission facilities identified in each resource plan, a cost estimate for the facilities is developed in a consistent manner for each resource plan. The estimates will be based on engineering judgment and readily available cost information, including cost information previously obtained from equipment manufacturers for transmission reinforcements of the type and capacity required. The estimates do not involve any field inspections, or detailed analysis of the type that would be performed in response to a specific request for interconnection or transmission service, but are adequate for their intended purpose.

Integration Cost Step 3: Develop Monthly Cash Flows

The final step in the process involves transforming the total transmission integration cost for resource plan developed in Step 2 into an estimated monthly cash flow (including AFUDC, as appropriate) of the costs for the transmission projects. This will allow projected annual integration costs to be accounted for each resource plan.

4. Costs of Transmission System Losses

Each proposal, portfolio of proposals, and/or the NPGU in the resource plans will contain capacity additions at specific locations in relation to the FPL transmission system. Therefore, each resource plan will present a unique transmission loss impact when combined with the existing FPL transmission system. The difference in the economic impacts between resource plans related to losses will be estimated and applied in the economic comparison of resource plans.

There are two types of losses that comprise total transmission losses for the system. In the analysis of the first type of loss, the generation capacity required to compensate for transmission losses is based on losses during peak load conditions. The second type of loss, energy losses that occur over the entire year, will be estimated based on losses during peak load and average system load conditions.

Transmission losses will vary from year-to-year with load growth, transmission system additions, and resource additions. It is not practicable to predict the amount of such variations due to the almost infinite combinations of future scenarios. It is, however, both certain and practical to assess the impact each portfolio would have in the 2019 time frame of operation. Losses for all future years are calculated based on expected 2020 system conditions, while only accounting for term-of-service-related changes in a particular resource plan over time as discussed below.

The losses for a given resource plan are determined, and costs are assigned to these losses, in a 3-step procedure discussed below. This discussion utilizes a hypothetical example to explain the loss evaluation and cost assignment methodologies. In this example, it is assumed that a hypothetical resource plan has a 1,200 MW proposed purchase for 20 years starting in 2019. At the end of the 20-year purchase term, the proposed 1,200 MW purchase capacity is replaced by filler units.

Cost of Losses Step 1: Calculation of Peak Load and Average Load Losses

a) <u>Peak Load Losses</u>

The required FPL transmission system integration upgrades will be incorporated into the FRCC load flow base case (updated with the latest available information), resulting in a modified, resource plan-specific load flow case. The modified load flow case is set up with the proposal, portfolio of proposals, and/or the NPGU on-line at full output, and the remaining system resources are dispatched economically. The losses (MW) <u>at the peak load hour</u> on the FPL transmission system (Peak Load Losses) are then calculated.

The resource plan associated with the lowest system Peak Load Losses for the year 2019 will be designated as the "reference" resource plan for both the 2019 Peak Load Losses and Average Load Losses analyses. The difference between system Peak Load Losses associated with each resource plan and with the reference resource plan will be calculated for 2019.

Starting with the year 2019, the total losses will remain constant for each resource plan for the 2019 – on time period until one of the components (proposal, portfolio of proposals, and/or the NPGU) reaches the end of its proposed term-of-service. If there are no changes to the reference resource plan during this period, the difference in transmission losses between the specific resource plan being evaluated and the reference resource plan will also be unchanged over this period.

In the example, the MW differences in system Peak Load Losses associated with the hypothetical resource plan and with the reference resource plan can be seen in Column (8) of Table D.2 – 1 below.

For resource plans (including the actual reference resource plan) that have components whose proposed terms-of-service end prior to the end of the analysis period (as is the case with this hypothetical resource plan), the resource plan-specific load flow case mentioned above will be further modified. This additional modification will reflect the termination of a specific component along with a corresponding adjustment to the FPL load. The system Peak Load Losses associated with only the resource plan's remaining components are first calculated. Then, in order to compensate for the loss of the expired component's capacity, an equal amount of Filler unit capacity and load is introduced. This Filler unit capacity is assumed to have losses equal to FPL's current system average transmission losses (1.85%).[1]

The losses associated with the reference resource plan are subtracted from the system Peak Load Losses associated with the remaining resource plan components, plus the Filler unit losses. The resulting system Peak Load Loss value associated with the resource plan is carried forward until another component of the resource plan reaches the end of its proposed term-of-service (if applicable).

[1] Note that the FPL system average transmission losses mentioned here are not the same as the Average Load Losses discussed later in this section.

Table D.2 - 1

Peak Load Losses Calculation for:

Example: For 2019, a 1,200 MW proposal for 20 years

		(1)	(2)	(3)	(4) =(2) * (3)	(5)	(6) =(4) + (5)	(7)	(8) =(6) - (7)
	Year	Proposal 1 (1200 MW)	Filler Capacity Needed to replace Resource Plan's Expired Components (MW)	Filler Capacity Losses (%)	Filler Capacity Losses (MW)	FPL Transmission System Losses with Resource Plan's Remaining Components (MW)	FPL Transmission System Losses with Resource Plan's Remaining Components + Filler Capacity Losses (MW)	FPL Transmission System Losses with the Reference Resource Plan (MW)	Difference in FPL Transmission System Losses between Resource Plan In Question and Reference Resource Plan (MW)
1	2019	1,200	-	1.85%	0	475	475	466	9
2	2020	1,200	-	1.85%	0	494	494	474	20
3	2021	1,200	-	1.85%	0	486	486	483	3
4	2022	1,200	-	1.85%	0	514	514	507	7
5	2023	1,200	-	1.85%	0	567	567	546	21
6	2024	1,200	-	1.85%	0	567	567	574	(7)
7	2025	1,200	-	1.85%	0	567	567	574	(7)
8	2026	1,200	-	1.85%	0	567	567	574	(7)
9	2027	1,200	-	1.85%	0	567	567	574	(7)
10	2028	1,200	-	1.85%	0	567	567	574	(7)
11	2029	1,200	-	1.85%	0	567	567	574	(7)
12	2030	1,200	-	1.85%	0	567	567	574	(7)
13	2031	1,200	-	1.85%	0	567	567	574	(7)
14	2032	1,200	-	1.85%	0	567	567	574	(7)
15	2033	1,200	-	1.85%	0	567	567	574	(7)
16	2034	1,200	-	1.85%	0	567	567	574	(7)
17	2035	1,200	-	1.85%	0	567	567	574	(7)
18	2036	1,200	-	1.85%	0	567	567	574	(7)
19	2037	1,200	-	1.85%	0	567	567	574	(7)
20	2038	1,200	-	1.85%	0	567	567	574	(7)
21	2039	-	1,200	1.85%	22	567	589	574	16
22	2040	-	1,200	1.85%	22	567	589	574	16
23	2041	-	1,200	1.85%	22	567	589	574	16
24	2042	-	1,200	1.85%	22	567	589	574	16
25	2043	-	1,200	1.85%	22	567	589	574	16
26	2044	-	1,200	1.85%	22	567	589	574	16
27	2045	-	1,200	1.85%	22	567	589	574	16
28	2046	-	1,200	1.85%	22	567	589	574	16
29	2047	-	1,200	1.85%	22	567	589	574	16
30	2048	-	1,200	1.85%	22	567	589	574	16
31	2049	-	1,200	1.85%	22	567	589	574	16

b) <u>Average Load Losses</u>

Another separate set of load flow cases is then created for each resource plan. This second set of load flow cases represent specific portfolios in 2019 - on, under FPL's average system load (*i.e.*, 60% of peak) and typical operation of FPL's system (*e.g.*, peaking generation type components off-line). For each resource plan, the transmission system is modified to include the same transmission upgrades required for that resource plan as applied to the load flow cases used for the Peak Load Losses evaluation. This system representation is used to calculate the transmission system losses on the FPL system at average system load (Average Load Losses) for each resource plan including the reference resource plan defined in the Peak Load Losses calculations for years 2019 - on.

The difference between system Average Load Losses of each evaluated resource plan and the reference resource plan will be calculated for 2019. Thereafter, the difference amount is carried forward for each year until one of the components making up the resource plan (or one of the components in the reference resource plan) reaches the end of its proposed term-of-service.

In the example, the differences between the system Average Load Losses associated with the hypothetical resource plan and with the reference resource plan can be seen in Column (8) of Tables D.2 – 2 below.

For resource plans that have components whose proposed terms-of-service end prior to the end of the analysis period, and which would have been on-line in the typical operation of the system at FPL's system average load, that component would be replaced with Filler unit capacity. The loss calculations in these instances will be based on the same 2019 load flow case, but with the FPL load reduced by the amount of expired capacity and the existing FPL resources and the remaining resource components dispatched to represent typical operation of FPL's system (*e.g.*, peaking type components off-line at this load level). In those circumstances in which a component is not typically in operation at FPL's average system load and whose term-of-service ends prior to the end of the analysis period, no Filler unit capacity is introduced for this analysis.

Table D.2 - 2

Average Load Losses Calculation for:

Example: For 2019, a 1,200 MW proposal for 20 years

		(1)	(2)	(3)	(4) = (2) * (3)	(5)	(6) = (4) + (5)	(7)	(8) = (6) - (7)
	Year	Proposal 1 (1200 MW)	Filler Capacity Needed to replace Resorce Plan's Expired Components (MW)	Filler Capacity Losses (%)	Filler Capacity Losses (MW)	FPL Transmission System Losses with Resource Plan's Remaining Components (MW)	FPL Transmission System Losses with Resource Plan's Remaining Components Filler Capacity Losses (MW)	FPL Transmission System Losses with the Reference Resource Plan (MW)	Difference in FPL Transmission System Losses between Resource Plan in Question and Rdference Resource Plan (MW)
1	2019	1,200	-	1.85%	0	248	248	238	10
2	2020	1,200	-	1.85%	0	248	248	248	0
3	2021	1,200	-	1.85%	0	248	248	241	7
4	2022	1,200	-	1.85%	0	246	246	251	(5)
5	2023	1,200	-	1.85%	0	246	246	272	(26)
6	2024	1,200	-	1.85%	0	246	246	273	(27)
7	2025	1,200	-	1.85%	0	246	246	273	(27)
8	2026	1,200	-	1.85%	0	246	246	273	(27)
9	2027	1,200	-	1.85%	0	246	246	273	(27)
10	2028	1,200	-	1.85%	0	246	246	273	(27)
11	2029	1,200	-	1.85%	0	246	246	273	(27)
12	2030	1,200	-	1.85%	0	246	246	273	(27)
13	2031	1,200	-	1.85%	0	246	246	273	(27)
14	2032	1,200	-	1.85%	0	246	246	273	(27)
15	2033	1,200	-	1.85%	0	246	246	273	(27)
16	2034	1,200	-	1.85%	0	246	246	273	(27)
17	2035	1,200	-	1.85%	0	246	246	273	(27)
18	2036	1,200	-	1.85%	0	246	246	273	(27)
19	2037	1,200	-	1.85%	0	246	246	273	(27)
20	2038	1,200	-	1.85%	0	246	246	273	(27)
21	2039	-	1,200	1.85%	22	246	268	273	(5)
22	2040	-	1,200	1.85%	22	246	268	273	(5)
23	2041	-	1,200	1.85%	22	246	268	273	(5)
24	2042	-	1,200	1.85%	22	246	268	273	(5)
25	2043	-	1,200	1.85%	22	246	268	273	(5)
26	2044	-	1,200	1.85%	22	246	268	273	(5)
27	2045	-	1,200	1.85%	22	246	268	273	(5)
28	2046	-	1,200	1.85%	22	246	268	273	(5)
29	2047	-	1,200	1.85%	22	246	268	273	(5)
30	2048	-	1,200	1.85%	22	246	268	273	(5)
31	2049	-	1,200	1.85%	22	246	268	273	(5)

Cost of Losses Step 2: Calculation of Peak Hour Capacity Loss Costs:

The cost of peak hour capacity losses associated with a resource plan is the product of the annual difference in the Peak Load Losses between a resource plan and the reference resource plan (calculated in Step 1) multiplied by a proxy purchase cost ($5/kw-month), and then escalated annually throughout the analysis period. This proxy purchase cost represents the economic value needed to bring this reference plan into equivalence with the reference resource plan.

An example of this calculation for the hypothetical resource plan is shown below in Table D.2 – 3.

An annual peak hour capacity loss cost is calculated for all years starting in 2019 and the annual costs are then present valued and summed. The sum of these present valued costs represents the difference in CPVRR cost of peak hour capacity losses associated with the resource plan relative to the reference resource plan.

Cost of Losses Step 3: Calculation of Annual Energy Loss Costs:

Both the differences for the Peak Load Losses and Average Load Losses between a resource plan and the reference resource plan (calculated in Step 1) are first converted to energy (MWh) values. The Peak Load Loss value is multiplied by 876 hours each year (representing 10% of the annual 8,760 hours) to derive an "on-peak" energy loss (MWh) value. These on-peak MWh values are then multiplied by projected on-peak marginal energy prices to derive on-peak energy loss costs for each resource plan relative to the reference resource plan.

Similarly, the Average Load Losses value is multiplied by an appropriate (to the type of capacity being offered in the resource plan) number of hours to derive an "off-peak" energy loss (MWh) value. These off-peak MWh values are then multiplied by projected off-peak marginal energy prices to derive off-peak energy loss costs for each resource plan relative to the reference resource plan.

These annual on-peak and off-peak energy loss costs are then summed to derive a total annual energy loss cost for each resource plan relative to the reference resource plan. This total annual energy loss cost is calculated for all years starting in 2020. These annual costs are then present valued and summed. The sum of these present valued costs represents the difference in the CPVRR cost of energy losses associated with the resource plan relative to the reference resource plan.

Tables D.2 – 3 and D.2 - 4 present an example of this calculation for the hypothetical resource plan. In Table D.2 – 4, a set of marginal energy costs based on FPL's designated Fossil Fuel Price Forecast is used in this example.

Table D.2 - 3

Calculation of Costs for Peak Hour Capacity Losses (MW) for:

Example: For 2019, a 1,200 MW Proposal for 20 years

Discount Rate =	7.51%
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	2.5%

		(1)	(2)	(3)	(4)	(5)
					=(1)*(3)*12	=(2)*(4)
	Year	Proxy Purchase Cost ($/kw-mo)	Discount Factor	Peak Load Loss (MW)	Peak Hour Capacity Loss Cost Nominal ($ 000)	Peak Hour Capacity Loss Cost NPV ($ 000)
	2015	$0.00	1.000	0	$0	$0
	2016	$0.00	0.930	0	$0	$0
	2017	$0.00	0.865	0	$0	$0
	2018	$0.00	0.805	0	$0	$0
1	2019	$5.00	0.749	9	$553	$414
2	2020	$5.13	0.696	20	$1,215	$846
3	2021	$5.25	0.648	3	$196	$127
4	2022	$5.38	0.602	7	$463	$279
5	2023	$5.52	0.560	21	$1,403	$786
6	2024	$5.66	0.521	(7)	($441)	($230)
7	2025	$5.80	0.485	(7)	($452)	($219)
8	2026	$5.94	0.451	(7)	($464)	($209)
9	2027	$6.09	0.419	(7)	($475)	($199)
10	2028	$6.24	0.390	(7)	($487)	($190)
11	2029	$6.40	0.363	(7)	($499)	($181)
12	2030	$6.56	0.337	(7)	($512)	($173)
13	2031	$6.72	0.314	(7)	($525)	($165)
14	2032	$6.89	0.292	(7)	($538)	($157)
15	2033	$7.06	0.272	(7)	($551)	($150)
16	2034	$7.24	0.253	(7)	($565)	($143)
17	2035	$7.42	0.235	(7)	($579)	($136)
18	2036	$7.61	0.219	(7)	($593)	($130)
19	2037	$7.80	0.203	(7)	($608)	($124)
20	2038	$7.99	0.189	(7)	($623)	($118)
21	2039	$8.19	0.176	16	$1,544	$271
22	2040	$8.40	0.164	16	$1,582	$259
23	2041	$8.61	0.152	16	$1,622	$247
24	2042	$8.82	0.142	16	$1,662	$235
25	2043	$9.04	0.132	16	$1,704	$224
26	2044	$9.27	0.122	16	$1,746	$214
27	2045	$9.50	0.114	16	$1,790	$204
28	2046	$9.74	0.106	16	$1,835	$194
29	2047	$9.98	0.099	16	$1,881	$185
30	2048	$10.23	0.092	16	$1,928	$177
31	2049	$10.49	0.085	16	$1,976	$168

					NPV Total ($000) =	$2,308
					NPV Total ($millions) =	$2.31

Table D.2 - 4

Calculation of Costs for Annual Energy Losses (MW) for:

Example: For 2019, a 1,200 MW Proposal for 20 years

On-Peak Hours =	876	(or 10% of all hours)
Off-Peak Hours =	6,570	
Discount Factor =	7.51%	

		(1)	(2)	(3)	(4)	(5) = (4)*On-Peak Hours	(6) = (1)*(5)/1000	(7)	(8) = (7)*Off-Peak Hours	(9) = (2)*(8)/1000	(10) = (6) + (9)	(11) = (3)*(10)
	Year	On-Peak Marginal Energy Cost ($/mwh)	Off-Peak Marginal Energy Cost ($/mwh)	Discount Factor	Peak Load Loss from Table D.2-1 (MW)	On - Peak Hours Annual Energy Loss (MWH)	On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Average Load Loss from Table D.2-2 (MW)	Off - Peak Hours Annual Energy Loss (MWH)	Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost NPV ($ 000)
	2015	0	0	1.000	0	0	$0	0	0	$0	$0	$0
	2016	0	0	0.930	0	0	$0	0	0	$0	$0	$0
	2017	0	0	0.865	0	0	$0	0	0	$0	$0	$0
	2018	0	0	0.805	0	0	$0	0	0	$0	$0	$0
1	2019	$55.94	$35.12	0.749	9	8,077	$452	10	64,715	$2,273	$2,725	$2,039
2	2020	$49.82	$40.20	0.696	20	17,301	$862	0	1,708	$69	$931	$648
3	2021	$55.81	$41.42	0.648	3	2,724	$152	7	47,895	$1,984	$2,136	$1,383
4	2022	$63.48	$47.75	0.602	7	6,272	$398	(5)	(35,281)	($1,685)	($1,286)	($775)
5	2023	$70.21	$50.90	0.560	21	18,554	$1,303	(26)	(173,645)	($8,838)	($7,536)	($4,222)
6	2024	$62.85	$48.98	0.521	(7)	(5,694)	($358)	(27)	(178,967)	($8,766)	($9,124)	($4,755)
7	2025	$63.53	$50.28	0.485	(7)	(5,694)	($362)	(27)	(180,018)	($9,050)	($9,412)	($4,562)
8	2026	$58.11	$50.38	0.451	(7)	(5,694)	($331)	(27)	(180,018)	($9,068)	($9,399)	($4,238)
9	2027	$60.67	$51.82	0.419	(7)	(5,694)	($345)	(27)	(180,018)	($9,328)	($9,673)	($4,057)
10	2028	$58.85	$51.01	0.390	(7)	(5,694)	($335)	(27)	(180,018)	($9,183)	($9,518)	($3,713)
11	2029	$62.76	$52.04	0.363	(7)	(5,694)	($357)	(27)	(180,018)	($9,367)	($9,725)	($3,528)
12	2030	$66.32	$59.18	0.337	(7)	(5,694)	($378)	(27)	(180,018)	($10,653)	($11,030)	($3,723)
13	2031	$68.73	$62.46	0.314	(7)	(5,694)	($391)	(27)	(180,018)	($11,243)	($11,634)	($3,652)
14	2032	$70.61	$65.36	0.292	(7)	(5,694)	($402)	(27)	(180,018)	($11,766)	($12,169)	($3,553)
15	2033	$74.01	$69.32	0.272	(7)	(5,694)	($421)	(27)	(180,018)	($12,478)	($12,900)	($3,504)
16	2034	$76.25	$71.98	0.253	(7)	(5,694)	($434)	(27)	(180,018)	($12,957)	($13,391)	($3,383)
17	2035	$78.95	$74.66	0.235	(7)	(5,694)	($450)	(27)	(180,018)	($13,441)	($13,890)	($3,264)
18	2036	$83.21	$78.73	0.219	(7)	(5,694)	($474)	(27)	(180,018)	($14,174)	($14,647)	($3,201)
19	2037	$85.80	$82.38	0.203	(7)	(5,694)	($489)	(27)	(180,018)	($14,831)	($15,319)	($3,114)
20	2038	$89.87	$85.82	0.189	(7)	(5,694)	($512)	(27)	(180,018)	($15,448)	($15,960)	($3,018)
21	2039	$92.94	$89.87	0.176	16	13,753	$1,278	(5)	(34,164)	($3,070)	($1,792)	($315)
22	2040	$97.35	$94.34	0.164	16	13,753	$1,339	(5)	(34,164)	($3,223)	($1,884)	($308)
23	2041	$100.71	$98.61	0.152	16	13,753	$1,385	(5)	(34,164)	($3,369)	($1,984)	($302)
24	2042	$105.53	$103.07	0.142	16	13,753	$1,451	(5)	(34,164)	($3,521)	($2,070)	($293)
25	2043	$110.41	$108.38	0.132	16	13,753	$1,518	(5)	(34,164)	($3,703)	($2,184)	($288)
26	2044	$115.07	$113.55	0.122	16	13,753	$1,583	(5)	(34,164)	($3,879)	($2,297)	($281)
27	2045	$119.92	$118.96	0.114	16	13,753	$1,649	(5)	(34,164)	($4,064)	($2,415)	($275)
28	2046	$124.98	$124.63	0.106	16	13,753	$1,719	(5)	(34,164)	($4,258)	($2,539)	($269)
29	2047	$130.25	$130.57	0.099	16	13,753	$1,791	(5)	(34,164)	($4,461)	($2,669)	($263)
30	2048	$135.75	$136.80	0.092	16	13,753	$1,867	(5)	(34,164)	($4,674)	($2,807)	($257)
31	2049	$141.48	$143.32	0.085	16	13,753	$1,946	(5)	(34,164)	($4,896)	($2,951)	($252)
											NPV Total ($000) =	($59,295)
											NPV Total ($millions) =	($59)

5. Cost Impacts Regarding Maintaining a Balance Between Load and Generation in the Southeastern Florida Region

The location of proposed generation capacity in each resource plan will be evaluated in regard to how it is projected to affect FPL's ability to maintain a balance between load and generation in the Southeastern Florida region consisting of Miami-Dade and Broward counties. The analysis approach that will be used is the same as has been utilized in a number of FPL's filings over the last several years including nuclear cost recovery and DSM. The projected costs of maintaining this balance solely through new transmission expenditures will first be developed. Then each resource plan will be analyzed to determine if the proposed location of the generation resources would avoid/defer any of these projected transmission expenditures. If so, then the resource plan may be credited with the benefit of avoiding/deferring the costs of these transmission projects.

D.3 Net Equity Adjustment

A. Explanation of Equity Adjustment

In order to fairly evaluate the total cost of competing resource plans, FPL will consider the impact that the potential selection of each resource plan would have on FPL's overall capital structure. FPL's NPGU assumes financing of incremental costs at 59.62% equity, 40.38% debt, and these financing costs are included in the total cost of FPL's NPGU.

Consistent with that approach, an adjustment will be made to the total cost of other resource plans containing purchased power obligations to reflect the fact that such obligations draw upon the debt capacity of FPL and, all other things being equal, must be offset by increasing the ratio of equity in FPL's capital structure. This is necessary to ensure that resource plans are compared against one another in a manner that is neutral relative to FPL's capital structure. Rating agencies explicitly evaluate purchase power obligations and, based on that examination, the rating agencies attribute a portion of the net present value (NPV) of the obligations under each power purchase agreement to the utility's balance sheet as a debt equivalent. The effect of this adjustment is to increase the relative share of debt and debt-like instruments in the capital structure. Therefore, FPL will calculate the incremental cost of the equity required to rebalance the capital structure at 59.62% equity, 40.38% debt to obtain a complete assessment of the related costs to FPL associated with each resource plan.

Standard & Poor's ("S & P") methodology will be used to calculate the debt equivalent that would be added to FPL's capital structure. S & P begins by taking the NPV of the annual capacity payments over the life of the power purchase contract using a 7% discount factor. To determine the debt equivalent, the NPV is then multiplied by a risk factor. Based on the guidelines provided by S & P for utilities with a clause recovery mechanism (such as is the case for FPL), a 25% risk factor will be used to calculate the debt equivalent.

Once the debt equivalent has been determined, the amount of equity required to rebalance the capital structure will be calculated. The equity adjustment represents the net present value of the incremental cost of equity (versus debt) required to rebalance the capital structure. A detailed example of the calculation of the equity adjustment is presented in Table D.3 – 1 at the end of this section.

B. Mitigating Factors

While the S & P methodology takes a broad look at the debt equivalence of purchase power obligations, there may be other factors which may be considered as mitigating the effect of such purchased power obligations. The following subsections discuss those factors that, in FPL's review, may offer some mitigation and can be quantified. These factors will be reflected as credits in the development of a modified or net equity adjustment factor.

1) Mitigation Offered by Completion Security

When FPL enters into a purchased power agreement (PPA) associated with a new unit to be constructed, the Proposer will provide Completion Security to address the delivery risks associated with completing the project. Many of these risks can be combined and represented as the risk of delivering less capacity than that proposed, and upon which the selection was made and a PPA was executed. Under an FPL self-build option, there is some small probability that such an event might occur, and that impact might not be mitigated by FPL's contractual arrangements. If this occurred and it was determined by the FPSC that FPL was not imprudent, any incremental cost caused by such a delivery shortage may be allowed to be recovered from FPL's customers.

If this same sequence of events occurred under a PPA associated with a unit to be constructed, in the form contemplated by FPL, the Completion Security could mitigate the impact of those costs on FPL's customers. This would be the source of mitigation provided by the PPA Completion Security that is different from an FPL self-build option.

In order to assess a quantitative value that could be assigned to this mitigation, both the risk of occurrence and the economic magnitude of the occurrence of a delivery shortage must be estimated.

FPL reviewed the history of FPL self-build projects relevant to this RFP to determine the probability of a delivery shortage. These combined cycle projects represented approximately 6,745 MW of planned capacity. The data showed that some projects over-delivered while others under-delivered. As a conservative approach, overages were not allowed to offset shortages. On this basis, a total shortage of 14 MW was seen over the projected approximately 6,745 MW resulting in a probability of delivery shortage of 0.21%.

The economic impact of a delivery shortage can be identified as represented by the Completion Security amount established by FPL. It is noted that this amount could be mitigated by many factors for specific occurrences; *e.g.*, component performance guarantees, engineering - procurement - construction (EPC) guarantees and Liquidated Damages (LD's), but represents a "worst case" value that is conservatively derived and applied to the favor of the Proposer in developing the mitigation credit.

The value of the mitigation provided by a PPA would be the product of the probability of delivery shortage (risk) and the Completion Security amount (magnitude) identified in Section IV of the RFP document.

The following example demonstrates the Completion Security mitigating factor calculation for a proposal based on a new generating unit:

P_{DS} = Probability of FPL Delivery Shortage = 0.21%
CS = Completion Security = \$200,000 per MW

CS Mitigation = CS * (P_{DS}) = \$200,000* (0.0021) = \$420 per MW (Nominal \$)

2) Mitigation offered by Performance Security

FPL recognizes that PPA-based capacity, if selected instead of an FPL self-build option, has the <u>potential</u> to provide better performance than that projected for FPL's NPGU at certain times. Therefore, FPL has calculated a Performance Mitigating Factor that attributes an appropriate amount of credit to a PPA for this potential benefit.

The Performance Mitigating Factor is not dependent upon the type or nature of the PPA in question. Instead, it is based on the projected forced outage factor (FOF) of FPL's NPGU in this RFP compared to recent FPL experience with the type of new units installed and operated by FPL that are most similar to the NPGU of this RFP; *i.e.*, combined cycle units. The most recent FPL combined cycle units are: Martin units 3, 4, and 8, Manatee unit 3, Turkey Point unit 5, and West County units 1, 2, and 3.

The actual/projected annual average FOF for these units over their projected life is 1.56%. The projected average annual FOF for FPL's NPGU is 1.1%. Consequently, using the actual/projected annual average FOF for the previous FPL combined cycle units as a possible projection of the actual FOF for the similar, but different, technology of FPL's NPGU, yields a possible FOF annual differential of 0.46%.

This translates to approximately 40 hours per full year (8,760 hours/year x 0.0046 = 40 hours/year) in which the existing units on FPL's system might have to supply energy that is projected to be supplied by the NPGU. Then, using the same projection of FPL system marginal energy costs that is used in the calculation of the Costs of Transmission Losses in Section D.2 of this appendix, a calculation of the replacement energy costs for these 40 hours for each year is made. This annual nominal cost value is then present valued and added to the cumulative present value of these costs from prior years. This calculation is presented in Table D.3 – 2 at the end of this section.

As seen in Table D.3 – 2, the values calculated are on a per MW basis and can vary according to the proposed term of the PPA. The actual Performance Mitigating Factor that will be applied to a PPA will depend both upon the proposed capacity (MW) and the proposed term-of-service.

3) Application

Once the appropriate Performance Mitigating Factor is calculated for a PPA, this mitigating factor, plus the Completion Security Mitigating Factor discussed above, will be subtracted from the Equity Adjustment value to derive a Net Equity Adjustment value for the PPA. This net value will be included in the final economic evaluation of all resource plans that include this PPA.

An example application of the equity adjustment calculation, and the mitigating factors, to provide a net equity adjustment value is presented in the remainder of this section.

C. Example Net Equity Adjustment Calculations

The net equity adjustment calculations that FPL will use in its evaluation of purchased power Proposals received in response to this RFP are explained below using a hypothetical Proposal for 500 MW starting in June 2019 through the end of 2030 at a constant price of $60/kw-yr (or $5/kw-month).

Table D.3 -1 presents the equity adjustment calculation. This is preceded by an explanation by column of the values in Table D.3 - 1. The first of the two mitigating factors is then discussed. Then Table D.3 – 2 presents the calculation of the second of the two mitigating factors. The net equity adjustment value is then calculated.

Explanation of calculation by column:

Column [K] = Projected Annual Capacity Payments in $/kw-year (assuming a constant $5/kw-month payment.)

Column [L] = Projected Annual Capacity Payments in $000 (Projected Annual Capacity Payments in $/kw-year * Proposal's Firm Capacity (MW) * PPA's Firm Capacity Ratio) /12 * number of months capacity is delivered)

Column [M] = Net Present Value (NPV) of the total sum of remaining annual capacity payments with values discounted at the risk factor used by S&P's to value off-balance sheet purchase power obligations.

Example: For 2019: NPV of capacity payments for (2019-2030)
For 2020: NPV of capacity payments for (2020 – 2030)
For 2021: NPV of capacity payments for (2021 – 2030)
Etc:

Column [N] =Total imputed asset value (NPV of capacity payments in Column [3]* S&P Adjustment Factor)

Column [O] =Equity Replaced to Rebalance (Total imputed asset value in Column [4] * Equity ratio)

Column [P] = Equity Adjustment (Column [5]* Equity vs. Debt Cost Difference)
(Where Equity vs. Debt Cost Difference = ((Cost of Equity)/(1- Effective Tax Rate)) – Cost of Debt)

NPV Total is discounted back to the current year (2015 in this example) using the after tax cost of capital discount rate.

Table D.3 - 1

Equity Adjustment Calculation - Example Purchase

	Notes			Notes	
Adjustment Factor	A	25.00%	Disc Rate for Equity Adj (FPL 2014 WACC)	G	7.51%
Target Equity Ratio	B	59.62%	Equity vs. Debt Pre-Tax Cost Difference	H	12.0%
Effective Tax Rate	C	38.58%	Nameplate Capacity (MW)	I	500
Cost of Debt	D	5.05%	PPA Firm Capacity Ratio	J	100.0%
Discount Rate Applied to Capacity Charges	E	7.00%			
Cost of Equity (Allowed ROE)	F	10.50%			

Equity Adjustment Calculation

Period	K Projected Capacity Chg. ($/kw-yr)	L = I x J x K Projected Annual Capacity Payments ($000)	M NPV Capacity Payments @ 7% (E) ($000)	N = M x A Total Imputed Asset Value ($000)	O = N x B Equity Replaced to Rebalance ($000)	P = O x H Equity Adjustment ($000)
2015	-	-	-	-	-	-
2016	-	-	-	-	-	-
2017	-	-	-	-	-	-
2018	-	-	-	-	-	-
2019	60	17,500	226,598	56,650	33,774	4,068
2020	60	30,000	224,960	56,240	33,530	4,038
2021	60	30,000	210,707	52,677	31,406	3,783
2022	60	30,000	195,457	48,864	29,133	3,509
2023	60	30,000	179,139	44,785	26,701	3,216
2024	60	30,000	161,679	40,420	24,098	2,902
2025	60	30,000	142,996	35,749	21,314	2,567
2026	60	30,000	123,006	30,751	18,334	2,208
2027	60	30,000	101,616	25,404	15,146	1,824
2028	60	30,000	78,729	19,682	11,735	1,413
2029	60	30,000	54,241	13,560	8,085	974
2030	60	30,000	28,037	7,009	4,179	503
			CPVRR Equity Adjustment @ WACC (2015 $s) @ 59.6% =			$17,810

Notes:

A) Per Standard & Poor's methodology for utilities, such as FPL, that have a clause recovery mechanism
B) FPL target equity ratio
C) FPL effective tax rate
D) FPL average cost of debt
E) Discount applied to Capacity Charges per S&P
F) FPL's allowed ROE
G) FPL incremental WACC (based on B,C,D,F above)
H) Difference between FPL's pre-tax cost of equity and debt
I) Sum of capacity of PPA portfolio
J) Firm capacity ratio of PPAs
K) Annual capacity payments calculated by multiplying the capacity charge, by the project namplate capacity and the firm capacity ratio of 100%
L) Annual capacity payments of PPA's
M) PV of net capacity payments discounted at FPL's average cost of debt
N) Per S&P methodology, apply a 25% adjustment factor for utilities with clause recovery mechanisms to the NPV of capacity payments
O) Equity required to rebalance due to the additional imputed debt is calculated by multiplying the debt equivalence by the target equity ratio
P) The equity adjustment is calculated as the equity replaced to rebalance, multiplied by the difference between the cost of equity and the pre-tax debt cost
Q) The CPVRR of the equity adjustments discounted at WACC. Represents the additional equity required to maintain the capital structures ratio considering the PPA as debt.

Completion Security Mitigation Example:

The Completion Security Mitigating Factor would be credited by applying the amount previously calculated:

CS mitigation/MW * Capacity * Net Present Value Factor for the year 2019 = Completion Security Mitigation Factor

$420/MW * 500 MW = $210,000 (Nominal $) or
$210,000 * 0.749 = $157,290 (NPV $)

Performance Mitigation Example:

The Performance Mitigation value, in terms of $ per MW, is presented in the following table.
In the table above, a 500 MW PPA with an in-service date of 2019 and a term through the end of 2030 would have a Performance Mitigation amount of:

500 MW * $11,537/MW = $ 5,768,500 (NPV $)

Net Equity Adjustment Example:

In this example, the Completion Security Mitigation amount and the Performance Mitigation amount would be subtracted from the Equity Adjustment to yield a Net Equity Adjustment value for a resource plan that included this PPA of:

$17,810,000 - $157,290 - $5,768,500 = $11,884,210 (NPV $)

Table D.3 - 2

Performance Mitigating Factor Calculation: for Bid with 2019 In-Service Date
(Note: Values shown are "per MW" values)

Assumptions:

Capacity level (MW) =	1
Historical Average FOF value for CC units =	1.56%
Projected Annual FOF value for NPGU =	1.10%
Average Annual FOF "overage" for FPL CC's =	0.46%

		(1)	(2)	(3)	(4) = (2) x (3)	(5) = (1) x (3)	(6)
	Year	Discount Factor 7.51%	Average Annual Forced Outage "Overage" (MWH per MW)	Average Marginal Energy Cost ($/MWH)	Nominal Replacement Energy Cost ($/MW)	Annual NPV Replacement Energy Cost ($/MW)	Cumulative NPV Replacement Energy Cost ($/MW)
	2015	1.000	0	$31.55	$0	$0	$0
	2016	0.930	0	$35.50	$0	$0	$0
	2017	0.865	0	$31.44	$0	$0	$0
	2018	0.805	0	$33.90	$0	$0	$0
1	2019	0.749	23	$33.30	$781	$585	$585
2	2020	0.696	40	$39.64	$1,598	$1,113	$1,697
3	2021	0.648	40	$43.01	$1,729	$1,120	$2,817
4	2022	0.602	40	$45.94	$1,847	$1,113	$3,930
5	2023	0.560	40	$48.39	$1,945	$1,090	$5,020
6	2024	0.521	40	$49.99	$2,015	$1,050	$6,070
7	2025	0.485	40	$52.38	$2,106	$1,021	$7,091
8	2026	0.451	40	$53.14	$2,136	$963	$8,054
9	2027	0.419	40	$54.06	$2,173	$911	$8,965
10	2028	0.390	40	$56.51	$2,278	$889	$9,854
11	2029	0.363	40	$58.93	$2,369	$860	$10,714
12	2030	0.337	40	$60.69	$2,440	$823	$11,537
13	2031	0.314	40	$62.57	$2,516	$790	$12,327
14	2032	0.292	40	$65.23	$2,630	$768	$13,095
15	2033	0.272	40	$68.08	$2,737	$743	$13,838
16	2034	0.253	40	$69.67	$2,801	$708	$14,546
17	2035	0.235	40	$70.99	$2,854	$671	$15,217
18	2036	0.219	40	$72.38	$2,918	$638	$15,854
19	2037	0.203	40	$74.58	$2,999	$610	$16,464
20	2038	0.189	40	$77.31	$3,108	$588	$17,052
21	2039	0.176	40	$79.28	$3,187	$561	$17,612
22	2040	0.164	40	$82.61	$3,330	$545	$18,157
23	2041	0.152	40	$85.92	$3,454	$526	$18,683
24	2042	0.142	40	$89.12	$3,583	$507	$19,190
25	2043	0.132	40	$92.47	$3,718	$489	$19,679
26	2044	0.122	40	$96.31	$3,883	$475	$20,155
27	2045	0.114	40	$100.30	$4,033	$459	$20,614
28	2046	0.106	40	$104.47	$4,200	$445	$21,059
29	2047	0.099	40	$108.81	$4,375	$431	$21,490
30	2048	0.092	40	$113.33	$4,569	$419	$21,909
31	2049	0.085	40	$118.03	$4,746	$405	$22,314

APPENDIX E

Changes in Key Forecasts and FPL's Resource Plan from FPL's 2014 Ten-Year Site Plan

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FPL's 2014 Ten-Year Site Plan (Site Plan) was filed with the Florida Public Service Commission (FPSC) in April 2014. This Site Plan, presented in Appendix A of this RFP document, addressed FPL's resource planning work during the year 2013 and the first quarter of 2014. Since the first quarter of 2014, a number of changes have occurred in regard to the forecasts that are used in FPL's resource planning work. Largely as a result of these changes to forecasts, FPL's current resource plan has also changed. The changes to these forecasts and FPL's resource plan will be presented in FPL's 2015 Site Plan that will be filed with the Florida Public Service Commission on April 1, 2015.

For the benefit of potential bidders to this capacity RFP, two tables are presented below. Table E - 1 summarizes changes in key forecasts from those used in the 2014 Site Plan work. Table E – 2 summarizes key changes in FPL's resource plan through the year 2019 (the year for which capacity proposals are being sought with this RFP).

Table E - 1

Key Changes in Forecasts		
Item	**Ten Year Site Plan**	**Current**
Date of Load Forecast	10/1/2013	10/14/2014
Vero Beach load	Included in FPL's load forecast	Not Included in FPL's load forecast
Date of Fuel Forecast	10/7/2013	11/3/2014
Below are the forecasted firm gas prices for 2019 from the two fuel forecasts:		
- 2019 FGT Firm Gas Price	$6.15/MMBTU	$4.70/MMBTU
- 2019 Gulfstream Gas Price	$6.13/MMBTU	$4.65/MMBTU
- 2019 New Pipeline Gas Price	$6.14/MMBTU	$4.69/MMBTU

As shown in Table E – 1, the October 2014 load forecast has now replaced the October 2013 load forecast that was used in the resource planning work that led to the 2014 Site Plan. The new load forecast no longer assumes that FPL will serve the electrical load of Vero Beach. In regard to the Summer 2019 peak load, the new October 2014 load forecast is approximately 150 MW higher than the October 2013 load forecast.

Similarly, the November 2014 fuel cost forecast has now replaced the October 2013 fuel cost forecast that was used in the resource planning work that led to the

2014 Site Plan. As shown in the comparison of forecasted natural gas values for the year 2019, projected natural gas prices are now lower than previously forecast.

In addition, FPL's resource plan has changed from that presented in its 2014 Site Plan. Table E – 2 presents the key changes in FPL's resource plan through the year 2019.

Table E - 2

Key Changes in FPL's Resource Plan Through 2019
(presented in approximate chronologieal order)

Item	2014 Site Plan	Current
FPL DSM Additions (approx. MW/year)	34	53
Existing GT Replacement	Occurs by the end of 2018; Net effect of approx. 255 MW capability reduction	Occurs by the end of 2016; Net effect of approx. 40 MW capability reduction
Cedar Bay Expiration Date (250 MW)	12/31/2024	12/31/2016
New Utility Scale Solar	No additional solar	3 - 74 MW (nameplate AC) PV facilities by the end of 2016.
2019 Unit (Summer MW)	1,269 MW CC	1,622 MW CC (FPL's NPGU)

FPL's resource plan now shows an increase in annual DSM implementation (in terms of Summer MW peak load reductions) from approximately 34 MW/year assumed in FPL's 2014 Site Plan to approximately 53 MW/year. This is consistent with the FPSC's decision in the 2014 DSM Goals docket.

In its 2014 Site Plan, FPL projected that, for environmental reasons, it would have to retire all of its existing gas turbines (GTs) in Broward County and replace part of that capacity with new combustion turbines (CTs) by the end of 2018. The projected impact of this would have been a net loss of 255 MW. FPL currently projects that it is cost-effective to retire most of its existing GTs at its two Broward County sites (Lauderdale and Port Everglades) and its Lee County (Ft. Myers) site, and partially replace this peaking capacity with new CTs at its

Lauderdale and Ft. Myers sites. In addition, FPL's two existing CTs at its Ft. Myers site will be upgraded to produce more capacity. All of this "GT replacement" work is projected to be completed by the end of 2016.
FPL anticipates terminating its existing power purchase agreement for 250 MW of coal-fired capacity from the Cedar Bay generating facility at the end of August 2015 as a result of a Purchase and Sale Agreement between FPL and Cedar Bay Generating Company, L.P. FPL would then own the unit starting on September 1, 2015. FPL currently anticipates that it will not need the unit for economic purposes after 2016 and, if that proves to be the case, would retire the unit at that time. FPL filed for FPSC approval of the Purchase and Sale Agreement in the first quarter of 2015.

FPL will be adding three new photovoltaic (PV) facilities by the end of 2016. Each of the PV facilities will be approximately 74.5 MW (nameplate rating, AC). The new PV installations are projected to be sited in Manatee, Charlotte, and DeSoto counties. The economics of these specific PV projects are aided by the fact that the sites are located close to existing electric infrastructure including tranmission lines and electric substations.

Finally, in its 2014 Site Plan, FPL projected the addition of a 1,269 MW (Summer) combined cycle (CC) unit as a placeholder in 2019 to meet capacity needs beginning in 2019. At the time the 2014 Site Plan was filed, this represented FPL's best self-build generating option for that year. FPL now projects that a 1,622 MW (Summer) CC unit to be its best self-build generating option for 2019. That CC unit is presented in this RFP as FPL's next planned generating unit (NPGU) which will be evaluated with all eligible proposals received in response to this RFP.

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Projection of FPL's Resource Needs: 2015 through 2020

August of the Year	(1) Projected FPL Unit Capability * (MW)	(2) Projected Firm Capacity Purchases * (MW)	(3) Projected Scheduled Maintenance (MW)	(4) = (1) + (2) - (3) Projected Total Capacity (MW)	(5) Projected Peak Load (MW)	(6) Projected Summer DSM Capability ** (MW)	(7) = (5) - (6) Projected Firm Peak Load (MW)	(8) = (4) - (7) Projected Summer Reserves (MW)	(9) = (8) / (7) Projected Summer Total Reserve Margin w/o Additions in 2019 & 2020 (%)	(10) = ((7)*1.20)-(4) **Projected Total MW Needed to Meet 20% Total Reserve Margin*** (MW)**	(11) = ((4)-(5)) / (5) Projected Generation-Only Reserve Margin (GRM) w/o Additions in 2019 & 2020 (%)	(12) = ((5)*1.10)-(4) **Projected Total MW Needed to Meet 10% GRM**** (MW)**
-----	-----	-----		-----	-----	-----	-----	-----	-----	**-----**	-----	**-----**
2015	25,008	2,015	0	27,022	23,286	1,951	21,335	5,688	26.7%	(1,421)	---	---
2016	25,585	837	0	26,421	23,778	2,000	21,779	4,643	21.3%	(287)	---	---
2017	26,002	837	0	26,838	24,252	2,046	22,207	4,632	20.9%	(190)	---	---
2018	26,023	1,044	0	27,067	24,648	2,092	22,555	4,512	20.0%	(1)	---	---
2019	26,043	455	0	26,498	25,045	2,140	22,905	3,593	15.7%	**988**	5.8%	**1,052**
2020	26,043	455	0	26,498	25,369	2,188	23,181	3,316	14.3%	**1,320**	4.4%	**1,409**

* MW values shown in Columns (1) & (2) include, but are not limited to, the following: the completion of the Port Everglades modernization project in 2016, the retirement of 44 of the 48 existing GTs in late 2016, the addition of 5 new CTs at the Lauderdale site and 2 CTs at the Ft.Myers site in late 2016, the addition of 116 MW of firm PV in late 2016, the upgraded capacity of Ft.Myers 3A & 3B in late 2016, and the addition of an unspecified one-year 207 MW PPA in 2018.

** The DSM values shown in Column (6) account for incremental DSM additions as per the 2014 DSM Goals docket for 2015 through 2020, and for projected annual participant attrition in FPL's existing residential load management program.

*** MW values shown in Column (10) represent new generating capacity needed to meet the 20% total reserve margin criterion.

**** MW values shown in Column (12) represent new generating capacity needed to meet the 10% generation-only reserve margin criterion (GRM) which must be met beginning in 2019.

Evaluation of FPL Self-Build Options: A Representative List of CC and CT Generating Options at Two Sites Evaluated in the First Stage of the Analyses

Site	Type of Generation	Manufacturer	Model of CT	With Duct Firing ?	Summer Capacity (MW)
Okeechobee	3 x 1 CC	GE	7HA.02	Yes	1,523
Okeechobee	4 x 1 CC	Mitsubishi	J	No	1,749
Okeechobee	3 x 1 CC	GE	7HA.02	No	1,424
Okeechobee	3 x 1 CC	Mitsubishi	J	Yes	1,411
Okeechobee	3 x 1 CC	Mitsubishi	J	No	1,311
Okeechobee	7 x 0 CT	GE	7FA.05	No	1,419
Okeechobee	6 x 0 CT	GE	7FA.05	No	1,216
Putnam	3 x 1 CC	GE	7HA.02	Yes	1,524
Putnam	3 x 1 CC	GE	7HA.02	No	1,424
Putnam	3 x 1 CC	Siemens	H	Yes	1,321
Putnam	3 x 1 CC	Siemens	H	No	1,220
Putnam	3 x 1 CC	Mitsubishi	J	No	1,312
Putnam	5 x 0 CT	GE	7FA.05	No	1,014

Evaluation of FPL Self-Build Options: Results of Analyses of CC and CT Generating Options at Two Sites Evaluated in the First Stage of the Analyses

Site	Type of Generation	Manufacturer	Model of CT	With Duct Firing ?	Summer Capacity (MW)	Difference From Lowest Cost Resource Plan (CPVRR, millions)
-------	-------	-------	-------	-------	-------	-------
Okeechobee	3 x 1 CC	GE	7HA.02	Yes	1,523	---
Okeechobee	4 x 1 CC	Mitsubishi	J	No	1,749	$33
Okeechobee	3 x 1 CC	GE	7HA.02	No	1,424	$42
Putnam	3 x 1 CC	GE	7HA.02	Yes	1,524	$65
Okeechobee	3 x 1 CC	Mitsubishi	J	Yes	1,411	$73
Putnam	3 x 1 CC	GE	7HA.02	No	1,424	$81
Okeechobee	3 x 1 CC	Mitsubishi	J	No	1,311	$114
Okeechobee	7 x 0 CT	GE	7FA.05	No	1,419	$124
Putnam	3 x 1 CC	Siemens	H	Yes	1,321	$129
Putnam	3 x 1 CC	Mitsubishi	J	No	1,312	$238
Okeechobee	6 x 0 CT	GE	7FA.05	No	1,216	$259
Putnam	5 x 0 CT	GE	7FA.05	No	1,014	$265
Putnam	3 x 1 CC	Siemens	H	No	1,220	$322

Evaluation of FPL Self-Build Options: List of Generating Option Technologies Evaluated in the Second Stage of the Analyses and the Results of These Analyses

(1) First Step:

Site -------	CC Type -------	Manufacturer -------	Model of CT -------	With Duct Firing ? -------	Summer Capacity (MW) -------	Difference From Lowest Cost Resource Plan (CPVRR, millions) -------
Okeechobee	3 x 1	GE	7HA.02	Yes	1,582	-
Okeechobee	3 x 1	GE	7HA.02	No	1,482	$103
Okeechobee	3 x 1	GE	7HA.02	Yes	1,523	$109
Okeechobee	3 x 1	Mitsubishi	J	Yes	1,418	$191
Okeechobee	2 x 1	GE	7HA.02	Yes	1,054	$193
Okeechobee	3 x 1	Mitsubishi	J	No	1,317	$220
Okeechobee	3 x 1	Siemens	H	Yes	1,322	$238
Okeechobee	3 x 1	Mitsubishi	JAC	Yes	1,350	$265
Okeechobee	3 x 1	Siemens	H	No	1,221	$265
Okeechobee	3 x 1	Mitsubishi	JAC	No	1,251	$294

Evaluation of FPL Self-Build Options: List of Generating Option Technologies Evaluated in the Second Stage of the Analyses and the Results of These Analyses

(2) Second Step:

Site	CC Type	Manufacturer	Model of CT	With Duct Firing ?	With Peak Firing and Wet Compression ?	Summer Capacity (MW)	Difference From Lowest Cost Resource Plan (CPVRR, millions)
-------	-------	-------	-------	-------	-------	-------	-------
Okeechobee	3 x 1	GE	7HA.02	No	Yes	1,586	-
Okeechobee	3 x 1	GE	7HA.02	Yes	No	1,582	$42
Okeechobee	3 x 1	GE	7HA.02	No	No	1,482	$83

(3) Third Step:

Site	CC Type	Manufacturer	Model of CT	With Duct Firing ?	With Peak Firing and Wet Compression ?	Summer Capacity (MW)	Difference From Lowest Cost Resource Plan (CPVRR, millions)
-------	-------	-------	-------	-------	-------	-------	-------
Okeechobee	3 x 1	GE	7HA.02	No	Yes	1,622	-
Okeechobee	3 x 1	GE	7HA.02	No	Yes	1,586	$6

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

PETITION FOR DETERMINATION OF NEED

REGARDING OKEECHOBEE CLEAN ENERGY CENTER UNIT 1

DIRECT TESTIMONY OF JACQUELYN K. KINGSTON

DOCKET NO. 15____________-EI

SEPTEMBER 3, 2015

TABLE OF CONTENTS

I. INTRODUCTION 3

II. OVERVIEW OF COMBINED CYCLE TECHNOLOGY 8

A. Description of Technology 8

B. Operating Advantages 9

C. FPL's History of Building and Operating Combined Cycle Plants 10

III. OCEC UNIT 1 COMBINED CYCLE PROJECT 13

A. Site Description 13

B. Project Description 14

C. Water Supply - Access and Availability 18

D. Electric Transmission Interconnection Facilities 19

E. Proposed Construction Schedule 19

F. Estimated Construction Costs 20

G. Other Benefits 21

IV. CONSEQUENCES OF DELAY 22

V. CONCLUSION 23

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jacquelyn K. Kingston. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL or the Company) as a Manager of Project Development for fossil generation, including the proposed Okeechobee Clean Energy Center Unit 1 (OCEC Unit 1 or the Project).

Q. Please describe your duties and responsibilities in that position.

A. I manage the development of new power generation projects. I am responsible for overseeing the activities of the project team that collectively make the project successful, including early stage due diligence, permitting, and engineering. Ultimately, my goal is to ensure that the development project is transitioned to construction on schedule to support the required commercial operation date. I have overall responsibility for the development of OCEC Unit 1.

Q. Please describe your education and professional experience.

A. I received a Bachelor of Science in Biological Sciences from Florida Institute of Technology in 2004 and a Master of Science from Florida Atlantic University in 2006. Additionally, I am a certified Project Management Institute (PMI) Project Management Professional (PMP). PMI's PMP credential is the most important industry-recognized certification for project managers. Globally recognized and demanded, the PMP demonstrates that one has the experience, education, and competency to lead and direct projects.

Throughout my nine year career with FPL, I have been involved in the development, permitting, and construction of multiple fossil power plants. In addition to the development of OCEC Unit 1, I have been responsible for the permitting of three (3) combined cycle (CC) projects, construction compliance (ensuring projects were constructed in accordance with environmental permits and applicable regulations) for two (2) CC projects, and development of two (2) gas turbine peaker replacement projects (replacement of gas turbines with combustion turbines (CTs) for peaking capacity), totaling over 5,200 megawatts (MW) of electrical generating capacity. These projects include FPL's Cape Canaveral Next Generation Clean Energy Center, Riviera Beach Next Generation Clean Energy Center, West County Energy Center Unit 3, Lauderdale Gas Turbine Power Park, and Ft. Myers Gas Turbine Power Park.

I have also held responsibilities with Power Delivery, specifically environmental permitting, construction compliance, and environmental operations support for the FPL transmission system. This included overseeing completion of over 840 environmental assessments, obtaining over 130 environmental permits for transmission projects, and providing daily environmental support to transmission operations, construction, and engineering.

I have also held responsibilities with NextEra Energy providing oversight in obtaining environmental permits to construct two new natural gas pipelines in the United States under joint ventures with other companies. These two projects totaled over 800 miles in length.

Q. What is the purpose of your testimony?

A. The purpose of my direct testimony is three-fold. First, I discuss FPL's experience building and operating CC generating units. Second, I describe the proposed Project in detail, including a description of the site, the technology, engineering design parameters, operating characteristics, and overall project cost and schedule. I will demonstrate that the performance standards assumed for the OCEC Unit 1 are both reasonable and achievable. Third, I address the consequences if a determination of need for the OCEC Unit 1 was delayed.

Q. Please summarize your testimony.

A. FPL has performed an extensive assessment of what generating option is the best to meet its projected 2019 resource need. FPL witness Sim addresses how FPL determined its resource need and the multiple analyses performed by his department supporting the choice of a self-build generating alternative. Ultimately, FPL chose the best, most cost-effective generating technology and site for FPL's customers. The OCEC Unit 1 is FPL's best alternative to meet its need for maintaining system reliability and integrity and the need to provide adequate electricity at a reasonable cost.

FPL plans to construct and operate OCEC Unit 1, a 3-on-1 (3x1) CC unit at a greenfield site in Okeechobee County. The Project will consist of three advanced technology CTs, three heat recovery steam generators (HRSGs), and one steam turbine/electric generator. Natural gas will be the primary fuel for OCEC Unit 1. Ultra low-sulfur distillate (light fuel oil) will be used as a backup fuel for the CTs. The cooling water source for the Project will be groundwater from the Floridan Aquifer. The surficial aquifer will be used for potable and process water. By using natural gas as the primary fuel for OCEC Unit 1 and technology that is recognized by the Florida Department of Environmental Protection (FDEP) as the Best Available Control Technology (BACT) for minimizing air emissions, OCEC Unit 1 is projected to be the most fuel-efficient CC unit in the state of Florida and among the cleanest and most efficient fossil fuel-fired, electric-power generating units in the world.

OCEC Unit 1 is expected to have an in-service date of June 2019. The projected cost of the OCEC Unit 1 is $1,196.0 million. The Project is estimated to generate approximately $238.8 million in tax revenue from 2020 to 2049. The project will also result in a number of significant public welfare benefits, including the creation of an estimated 650 direct jobs at its peak during construction.

FPL has significant experience building and operating CC plants to achieve the best possible efficiencies. Accordingly, FPL is confident of the accuracy of its construction cost estimates and projected unit capabilities.

A delay in the determination of need for the OCEC Unit 1 would result in a delay in the power plant certification for OCEC Unit 1. Such a delay would defer the operation of this valuable asset that will maintain system reliability and provide an efficient reliable generating unit; ensuring customers have adequate electricity at a reasonable cost. In addition, it would result in a higher system heat rate and lower customer fuel savings than customers would enjoy if the unit were constructed on time.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibits JKK-1 through JKK-12. The titles to each exhibit are shown below, and they are all attached to my direct testimony.

Exhibit JKK-1	Typical 3x1 Combined Cycle Unit Schematic
Exhibit JKK-2	FPL Combined Cycle Power Plants
Exhibit JKK-3	History of FPL Combined Cycle Capital Construction Costs
Exhibit JKK-4	OCEC Unit 1 Site Regional Map
Exhibit JKK-5	OCEC Unit 1 Site Property Delineation
Exhibit JKK-6	Aerial Photo of Okeechobee FPL Property (January 2015)
Exhibit JKK-7	OCEC Unit 1 Proposed Site Plan Rendering

Exhibit JKK-8	OCEC Unit 1 Plant Specifications
Exhibit JKK-9	OCEC Unit 1 Water Balance
Exhibit JKK-10	Florida Reliability Coordinating Council Letter
Exhibit JKK-11	OCEC Unit 1 Expected Construction Schedule
Exhibit JKK-12	OCEC Unit 1 Plant Construction Cost Components

II. OVERVIEW OF COMBINED CYCLE TECHNOLOGY

A. Description of Technology

Q. Please describe the combined cycle technology that will be used for the OCEC Unit 1 Project.

A. The CC technology generates electric power in two cycles. As shown on Exhibit JKK-1, a CC unit is comprised of electric generators, CTs, HRSGs, and a steam-driven turbine generator (STG). During the first cycle of energy production, each of the CTs compresses outside air into a combustion area where fuel, typically natural gas or light fuel oil, is burned. The hot gases from the burning fuel-air mixture cause the turbine to rotate, which, in turn, directly rotates a generator to produce electricity. The exhaust gas produced by each turbine is passed through a HRSG where heat is extracted before exiting the stack. During the second cycle of energy production, the energy extracted by the HRSG converts water into steam, which then drives an STG. The residual steam is then cooled into water in a condenser and returned to the HRSG, beginning its cycle all over again.

The recovery of waste heat from the CTs for utilization in an STG improves the overall plant efficiency beyond that of just CTs or conventional steam electric generating units, because additional power is produced without burning additional fuel.

Each CT/HRSG combination is called a "train." The number of CT/HRSG trains used establishes the general size of the STG. For the proposed OCEC Unit 1 Project, three CT/HRSG trains will be connected to one STG, giving rise to the characterization of the Project as a 3x1 CC unit.

B. Operating Advantages

Q. What level of operating efficiency is anticipated for the OCEC Unit 1 Project?

A. In general, modern CC plants can be expected to achieve a fuel to electrical energy conversion rate (heat rate) of less than 7,000 British thermal units (Btu) per kilowatt hour (kWh), as opposed to values in the 10,000 Btu/kWh range for conventional steam-electric generating units or typical simple cycle units. FPL anticipates that OCEC Unit 1 will have an average base heat rate as low as 6,304 Btu/kWh (based on an average ambient air temperature of 75°F) over the life of this Project. The proposed 3x1 CC unit will therefore produce the same amount of energy as a similarly sized conventional steam plant using approximately 35% less fuel. The addition of this highly efficient unit to the FPL system is projected to improve the overall system heat rate.

The lower the heat rate, the more efficient the generating fleet is and the greater the fuel savings are for the benefit of FPL's customers.

Q. Are there other operational advantages to combined cycle technology?

A. Yes. An advantage of the multi-train CC arrangement is that it allows for greater flexibility in matching unit output to generation requirements over time. This is possible because each of the CTs and the steam turbine can be independently controlled, allowing the unit greater flexibility in matching the load requirements at any given point in time.

C. FPL's History of Building and Operating Combined Cycle Plants

Q. Does FPL have experience in building combined cycle plants?

A. Yes. FPL has extensive experience in building CC plants on time and within budget. FPL's first CC plant (Putnam Units 1 & 2) went into service in 1976 and was recently retired at the end of 2014 after 38 years of operations. More recently, FPL successfully constructed three new CC "greenfield" units at its West County Energy Center and two new CC modernizations at its Cape Canaveral and Riviera Beach sites. Currently, FPL is constructing a CC modernization project at its Port Everglades site.

Q. Please describe FPL's history of operating combined cycle plants.

A. Currently, there are 15 CC units in operation in FPL's service territory as shown in Exhibit JKK-2. These 15 existing CC units comprise 14,817 MW (net summer) of capacity in service, with an additional 1,237 MW currently under construction, for a total of over 16,000 MW.

In addition to its CC operating experience, FPL has extensive experience operating simple-cycle CTs, which comprise the front end of the CC train (*i.e.*, no HRSG or STG). FPL has operated CTs as simple-cycle units at its Fort Myers and Martin plant sites in Florida.

Q. Please describe FPL's track record in building and operating combined cycle units.

A. FPL has consistently demonstrated its ability to cost-effectively construct reliable and efficient plants that save money for customers over the project lives. Most recently, in December 2014, *Power Engineering* and *Renewable Energy World* magazines honored FPL's Riviera Beach Clean Energy Center with its "Project of the Year" award in the "Best Gas-Fired Project" category. The "Project of the Year" award recognizes the world's best power projects, honoring excellence in design, construction, and operation of power generation facilities. Examples of other FPL CC plants that have received similar recognitions include Martin Units 3 and 4, Sanford Units 4 and 5, Fort Myers Unit 2, Turkey Point Unit 5, and West County Energy Center Units 1, 2, and 3.

FPL's fossil fleet performance has consistently exceeded fossil industry performance averages and is frequently ranked "Top Decile" or "Best in Class" among FPL's large electric utility fossil fleet peers. Since 1990, as FPL transformed the fossil generating fleet, FPL substantially improved operating performance across key factors integral to generating electricity for its customers. These performance factor improvements include the reduction of system heat rate, forced outage rate, total non-fuel O&M costs, and air emissions.

With world-class operational skills, FPL maximizes the value of its existing and new assets to its customers. FPL's employment of operational best practices has resulted in its industry leading positions. FPL's fossil-fueled fleet has achieved an Equivalent Availability Factor (EAF) of 92.7% averaged over the past 10 years. This compares very favorably to the U.S. industry average EAF of 87.1%. EAF represents plant availability and is a measure of the percent capacity available from a generating unit to provide electricity throughout the year, regardless of whether the generating unit is actually called upon to operate.

Q. Please describe how FPL monitors the operational performance and reliability of its power plants.

A. FPL uses technology to optimize plant operations, gain process efficiencies, and leverage the deployment of technical skills as demand for services increases. For example, the Company's Fleet Performance and Diagnostics Center (FPDC) in Juno Beach, Florida, provides FPL with the capability to monitor every plant in its system. The FPDC uses advanced technology to troubleshoot problems when they happen and often prevent them before they occur. FPL can compare the performance of like components on similar generating units, determine how it can make improvements, and often avoid problems, ultimately saving customers money. Live video links can be established between the FPDC and plant control rooms to immediately discuss challenges that may arise, thus enabling FPL to prevent, mitigate, and/or solve problems.

Q. Please address FPL's record in constructing CC units at or below estimated budgets.

A. FPL has a proven track record of constructing CC power plants within budget. Since 2005, FPL has constructed eight CC units and all were completed on or below budget. Exhibit JKK-3 lists the CC projects constructed by FPL and the approved and actual construction costs.

III. OCEC UNIT 1 COMBINED CYCLE PROJECT

A. Site Description

Q. Please describe the OCEC Unit 1 Plant site.

A. OCEC Unit 1 will be located on 2,842 acres of FPL-owned land in northeast Okeechobee County (Exhibits JKK-4 and JKK-5). The site is approximately 8 miles southeast of Yeehaw Junction, 27 miles northeast of the city of Okeechobee, and approximately 24 miles west of the city of Vero Beach. The site, which was acquired in 2011, is predominately used for agriculture production (cattle and citrus). Exhibit JKK-6 includes an aerial photo of the site taken in January 2015. Once operational, OCEC Unit 1 will comprise approximately 250 acres of the site. The remainder of the site is being evaluated as a potential future location for up to approximately 200 MW nameplate of large-scale photovoltaic solar generation.

B. Project Description

Q. Please describe the proposed OCEC Unit 1 project in more detail.

A. An artist's rendering of OCEC Unit 1 is shown on Exhibit JKK-7. Unit 1 will be a 3x1 CC unit consisting of three nominal 350-MW GE 7HA.02 CTs, with dry low-NO_x combustors, peak-firing, inlet cooling, wet compression, and three HRSGs, which will use the waste heat from the CTs to produce steam to be utilized in a new steam turbine generator. The HRSG stacks will be approximately 149 feet tall.

Each CT is projected to utilize inlet air evaporative cooling. Evaporative coolers achieve cooling using water evaporation to remove heat from the inlet air. This increases the density of air flowing through the turbine, allowing additional power to be produced during periods of high ambient air temperature. The evaporative coolers normally would be utilized when the ambient air temperature is greater than 60°F. The base unit capacity at 95°F is 1,511 MW. For additional power production at peak periods, peak firing and wet compression, which sprays additional water in a fine mist into the gas turbine inlet air, can be turned on. Peak firing and wet compression can be utilized during peak demand periods to add about 111 MW of capacity to the unit, totaling 1,622 MW.

With its anticipated average heat rate as low as 6,304 Btu/kWh during baseload operation (based on an average ambient air temperature of 75°F), OCEC Unit 1 is projected to be the most fuel-efficient CC unit in the state of Florida. The unit will have an estimated EAF of approximately 96.7%, an estimated average forced outage factor of approximately 1.1%, and a planned outage factor of 2.2%. Plant specifications are shown in Exhibit JKK-8.

With OCEC Unit 1, FPL's system reliability and integrity will be maintained and even improved. Given its very low heat rate, the unit will improve FPL's overall system heat rate. This improvement in system heat rate means that the OCEC Unit 1 will be dispatched ahead of other efficient FPL combined cycle units, resulting in significant fuel savings to FPL's customers.

The OCEC Unit 1's EAF will also improve system reliability, making the unit available for dispatch up to 96.7% of the time. Having such an efficient unit available improves FPL system's operational reliability.

The performance level of CC plants continues to evolve and advance in the marketplace. As a result, FPL will continue to evaluate enhanced designs and models for the OCEC Unit 1's CTs, HRSGs, and steam turbine (collectively, the "Power Train Components") and other related equipment necessary for operation of the unit, as a part of FPL's continuing efforts to determine whether an enhanced design or model would provide even greater projected benefits to FPL's customers.

For example, FPL is continuing to evaluate the optimal steam cycle equipment configuration, which could have the potential for additional capital costs while at the same time providing overall system CPVRR cost savings benefits to FPL's customers, based on increased output and a lower heat rate resulting from the optimization. Similarly, if an enhanced design or model emerges as a result of continued evaluation, FPL will optimize the condenser and cooling towers needed for OCEC Unit 1 as a part of FPL's continuing efforts to provide the greatest benefits to its customers.

In the event that FPL selects an enhanced design or model for the Power Train Components and other related equipment other than the analyzed technology subsequent to the Commission having granted a determination of need for OCEC Unit 1, FPL would make an informational filing to the Commission, as discussed in the direct testimony of FPL witness Sim.

Q. Please describe the potential air emissions of the OCEC Unit 1 project.

A. The use of natural gas as a primary fuel source, with light fuel oil as a back-up fuel, combined with combustion control technologies, will minimize air emissions from the unit and ensure compliance with applicable emission limiting standards. Maximum total air quality impacts for OCEC Unit 1 are predicted to be below and in compliance with the National Ambient Air

Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) increments. The NAAQS are standards required by the Clean Air Act and established by the Environmental Protection Agency (EPA) that protect the public health of the most sensitive populations as well as public welfare. The PSD increments are levels of air pollutants established by the Clean Air Act and EPA that make sure "clean air remains clean." The low air quality impacts, well below these standards, are achieved by meeting BACT for regulated air pollutants that include particulate matter (PM), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), carbon dioxide (CO_2), volatile organic compounds (VOCs), and sulfuric acid mist. The use of natural gas and light fuel oil (with maximum sulfur content of 0.0015%) minimizes emissions of SO_2, PM, and other fuel-bound contaminants. Combustion controls similarly minimize the formation of NO_2, and the combustor design will limit the formation of CO and VOCs. When firing natural gas, NO_2 emissions will be controlled using dry-low NO_x combustion technology and Selective Catalytic Reduction (SCR). Water injection and SCR will be used to reduce NO_2 emissions during operations when using light fuel oil as back-up fuel. This emission control design is accepted by the FDEP and EPA as BACT for air emissions.

The design of OCEC Unit 1 will incorporate features that are projected to make it one of the most efficient and cleanest fossil generating units in Florida, if not the world. The use of the latest combustion turbine and combined cycle technology reduces the emissions of CO_2 by about 35% relative to conventional steam electric generating units. This will result in very low emissions of CO_2 for the amount of electric generation OCEC Unit 1 can produce.

Q. What types of fuel will OCEC Unit 1 be capable of burning?

A. The Project will use natural gas as the primary fuel source. As discussed in the testimony of FPL witness Stubblefield, a new pipeline lateral will be required to be constructed to transport natural gas to the site. OCEC Unit 1 also will be capable of using light fuel oil, more specifically a distillate fuel oil with a maximum sulfur content of 0.0015%, as a back-up fuel. The site design allows for operation at full capacity for seventy-two (72) hours of continuous operation using back-up fuel.

C. Water Supply - Access and Availability

Q. What are the water requirements for the OCEC Unit 1 project, and how will they be met?

A. The potential water supply source is groundwater from the surficial aquifer system and the Floridan Aquifer system. FPL is requesting authorization for a daily average withdrawal from the Floridan Aquifer of 9 million gallons per day (MGD) and a maximum daily allocation of 11 MGD. FPL is also requesting a daily allocation of 0.08 MGD from the surficial aquifer. Primary water uses will be for condenser cooling, combustion turbine evaporative coolers, steam cycle makeup, and service water. Water will also be used on a limited basis for NO_x control when using light fuel oil. Condenser cooling for the steam cycle portion will be accomplished using mechanical draft cooling towers. The overall water balance for OCEC Unit 1 is shown on Exhibit JKK-9.

D. Electric Transmission Interconnection Facilities

Q. How will the OCEC Unit 1 project be interconnected to FPL's transmission network?

A. OCEC Unit 1 will connect to a new 500 kV transmission switchyard on the OCEC property. Transmission lines from the existing Martin-Poinsett 500 kV line will be looped into the new switchyard to interconnect the facilities to the FPL transmission grid.

The Florida Reliability Coordinating Council (FRCC) has reviewed FPL's proposed interconnection and integration plan for the Project and determined that it will be reliable, adequate, and will not adversely impact the reliability of the FRCC transmission system. Please see Exhibit JKK-10.

E. Proposed Construction Schedule

Q. What is the proposed construction schedule for the OCEC Unit 1?

A. A summary of estimated construction milestone dates is shown on Exhibit JKK-11. FPL will commence construction upon receipt of the necessary regulatory approvals, which FPL anticipates will occur by December 2016.

Construction will require approximately 27 months, and the Project is expected to start commercial operations in June 2019.

Q. What is the current status of the certifications and permits required to begin construction of OCEC Unit 1?

A. Several local, state, and federal approvals are required prior to start of construction for OCEC Unit 1. FPL intends to file for FDEP site certification under the Florida Electrical Power Plant Siting Act in September 2015. Concurrently, FPL will file for a Prevention of Signification Deterioration air construction permit. In August 2015, FPL filed a U.S. Army Corps of Engineers (USACE) Section 404, Clean Water Act, Dredge & Fill Permit application for impacts to onsite wetlands. The USACE application is currently under agency review. In April 2015, FPL was issued a permit from FDEP to construct an exploratory well to investigate the geology and hydrogeology of the site, and the feasibility of disposal of non-hazardous fluids via deep well injection. No local rezoning with Okeechobee County is required for this Project.

F. Estimated Construction Costs

Q. What does FPL estimate that the OCEC Unit 1 will cost?

A. A summary of estimated costs is shown on Exhibit JKK-12. FPL estimates that the total cost will be $1,196.0 million. Principal components include the power block and generator transformers at $1,031.5 million, transmission interconnection and integration at $52.0 million, and Allowance for Funds

Used During Construction (AFUDC) at $112.5 million. FPL will annually report to the Florida Public Service Commission's (Commission or PSC) Director of Economic Regulation updates to the budgeted and actual cost of OCEC Unit 1, compared to the estimated total in-service cost.

Q. Are these estimated costs for OCEC Unit 1 the same as the estimated costs published in the 2015 Request for Proposals for 2019 Capacity Needs?

A. Yes.

G. Other Benefits

Q. What other benefits are associated with OCEC Unit 1?

A. Several additional benefits come to mind. First, the Project will result in additional property tax revenues to governmental agencies of some $238.8 million over the projected life of the unit. This will be a significant benefit to the local economy. Second, during construction of the unit there will be, at the peak of construction, some 650 additional jobs brought into the local economy. Third, there will be approximately 30 permanent positions at the OCEC Unit 1. Fourth, beyond the significant payroll and tax impacts on the local economy, there will be indirect economic effects on the local economy through additional demands for goods and services. These are significant economic benefits of the Project beyond the fuel savings and system reliability improvements.

IV. CONSEQUENCES OF DELAY

Q. What consequences with respect to licensing and construction of OCEC Unit 1 would be likely if the need determination for the project was delayed?

A. FPL has set an in-service date of June 2019 for OCEC Unit 1. FPL anticipates commencing site work following the receipt of all necessary approvals, anticipated by December 2016, which includes Site Certification from the FDEP. If the need determination for the project was delayed, this would delay issuance of the PSC Need Determination Agency Report which is required as part of the FDEP Site Certification process. A delayed issuance of an Agency Report suspends the Site Certification process from moving forward until the report is received which could have a trickle-down effect and result in a delayed FDEP Site Certification and ultimately a delayed start of construction resulting in an in-service date later than when the unit is needed. Such a delay would defer the operation of this valuable asset necessary to maintain system reliability and provide an efficient reliable generating unit that will contribute to ensuring customers have adequate electricity at a reasonable cost. In addition, it would result in a higher system heat rate and lower customer fuel savings than customers would enjoy if the unit were constructed on time.

V. CONCLUSION

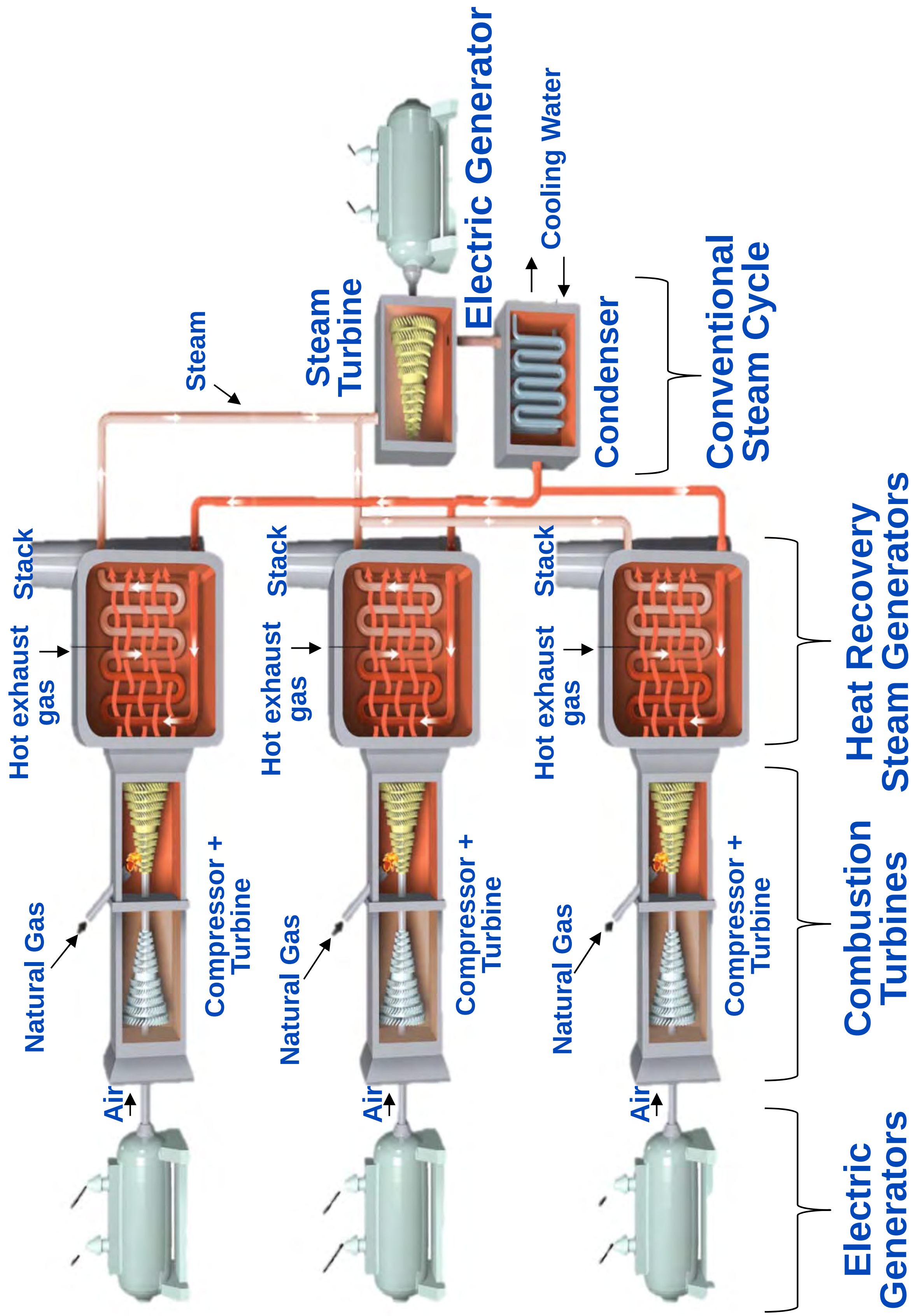
Q. What level of confidence does FPL have in the cost, projection and construction schedule for the unit discussed herein?

A. As previously discussed, FPL has a proven track record of constructing combined cycle power plants within budget and on schedule. Based on this experience, I am confident that the project will be completed on time and within the projected budget.

Q. Does this conclude your testimony?

A. Yes.

Typical 3x1 Combined Cycle Unit Schematic



FPL Operational Combined Cycle Power Plants

Facility[1]	In-Service Year	Technology	Summer Capacity (MW)
Riviera Beach Unit 5	2014	3x1 combined cycle	1,212
Cape Canaveral Unit 3	2013	3x1 combined cycle	1,210
West County Unit 3	2010	3x1 combined cycle	1,219
West County Unit 2	2009	3x1 combined cycle	1,219
West County Unit 1	2008	3x1 combined cycle	1,219
Turkey Point Unit 5	2007	4x1 combined cycle	1,192
Martin Unit 8	2005	4x1 combined cycle	1,135
Manatee Unit 3	2005	4x1 combined cycle	1,143
Sanford Unit 4	2003	4x1 combined cycle	1,005
Fort Myers Unit 2	2002	6x2 combined cycle	1,436
Sanford Unit 5	2002	4x1 combined cycle	1,005
Martin Unit 3	1994	2x1 combined cycle	469
Martin Unit 4	1994	2x1 combined cycle	469
Lauderdale Unit 4	1993	2x1 combined cycle	442
Lauderdale Unit 5	1993	2x1 combined cycle	442
TOTAL:			**14,817**

FPL Combined Cycle Power Plants in Construction

Facility[1]	Projected In-Service Year	Technology	Summer Capacity (MW)
Port Everglades Unit 5	2016	3x1 combined cycle	1,237
TOTAL:			**1,237**

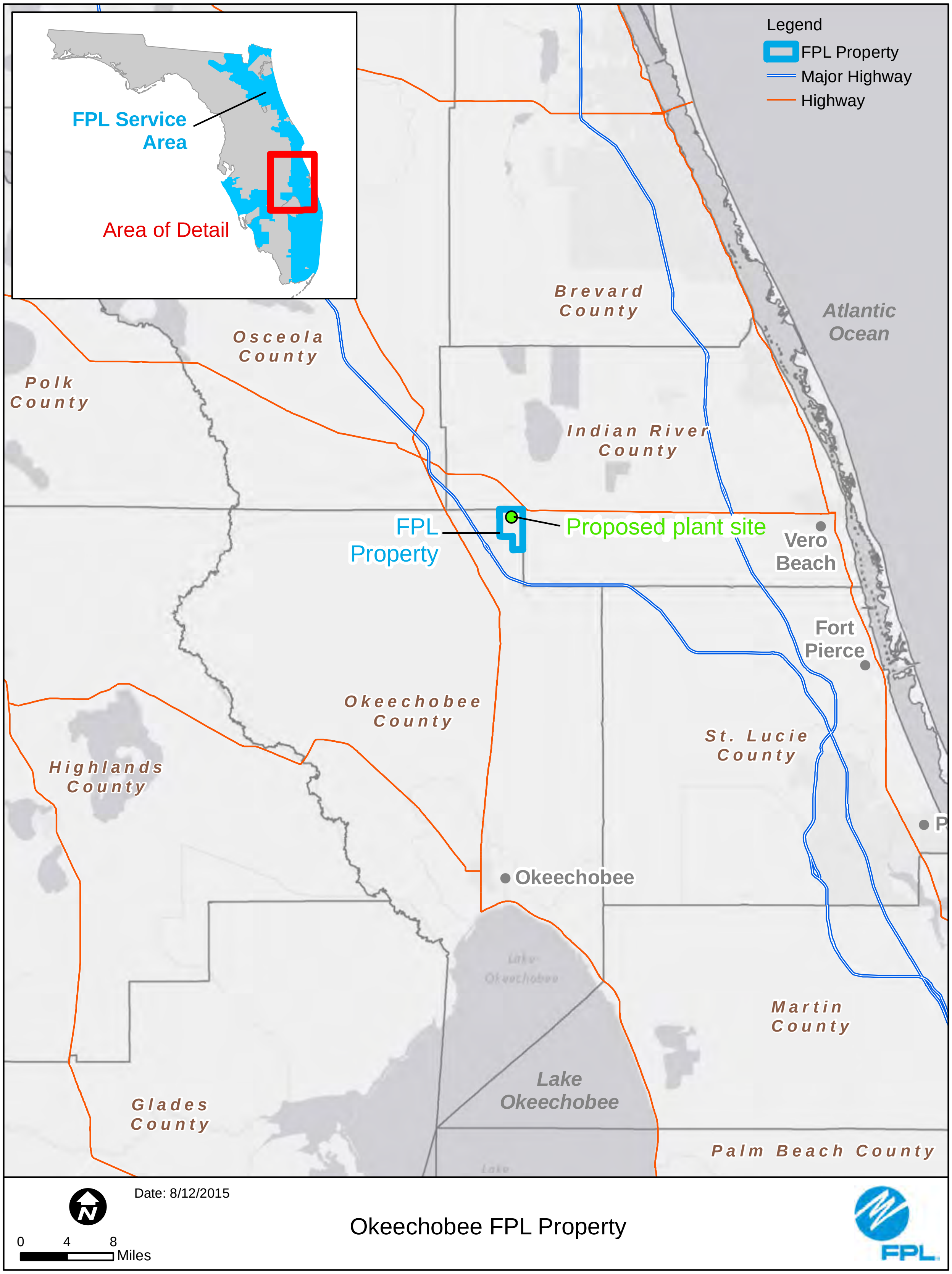
[1]All facilities are located in Florida. The primary fuel for all facilities is natural gas.

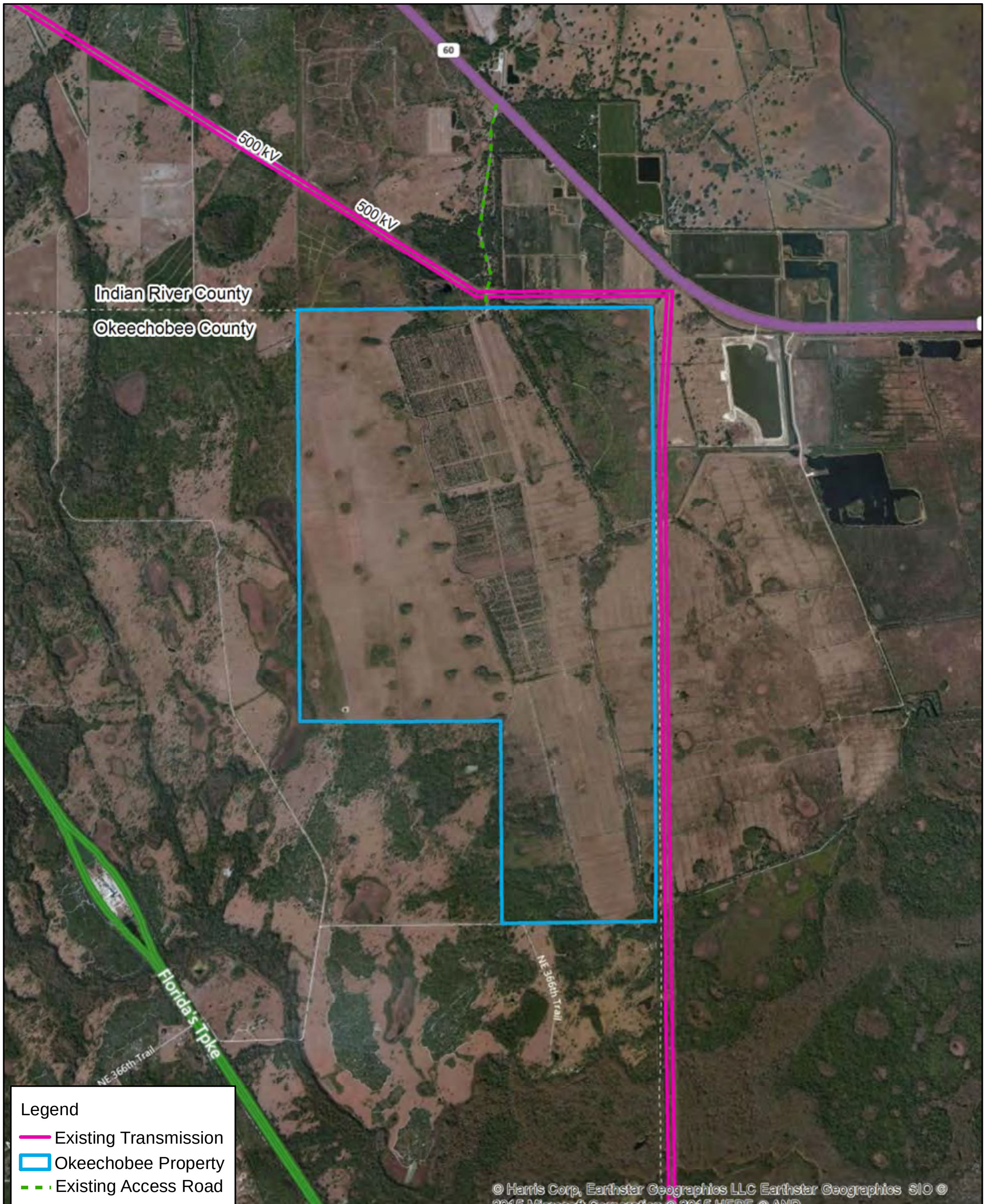
History of FPL Combined Cycle Capital Construction Costs

Project	Approved Plan ($ Millions)	Actual/Projected Cost ($ Millions)
Martin Unit 8	$462.7	$391.2
Manatee Unit 3	$552.8	$476.8
Turkey Point Unit 5	$580.3	$552.4
West County Units 1 & 2[1]	$1,321.0	$1,320.8
West County Unit 3	$864.7	$842.4
Cape Canaveral Unit 3[2]	$1,114.7	$968.6
Riviera Beach Unit 5[3]	$1,275.6	$1,275.6

[1] FPL considers the combined costs to be the most meaningful way to evaluate project costs because it best aligns in practical terms with how the construction was actually managed.
[2] Construction on the units is complete; however, there are limited warranty activities still ongoing which are expected to be complete by year-end 2015.
[3] Construction on the units is complete; however, there are activities still ongoing which are expected to be completed by year-end 2015.

Docket No. 15__________-EI
OCEC Unit 1 Site Regional Map
Exhibit JKK-4, Page 1 of 1





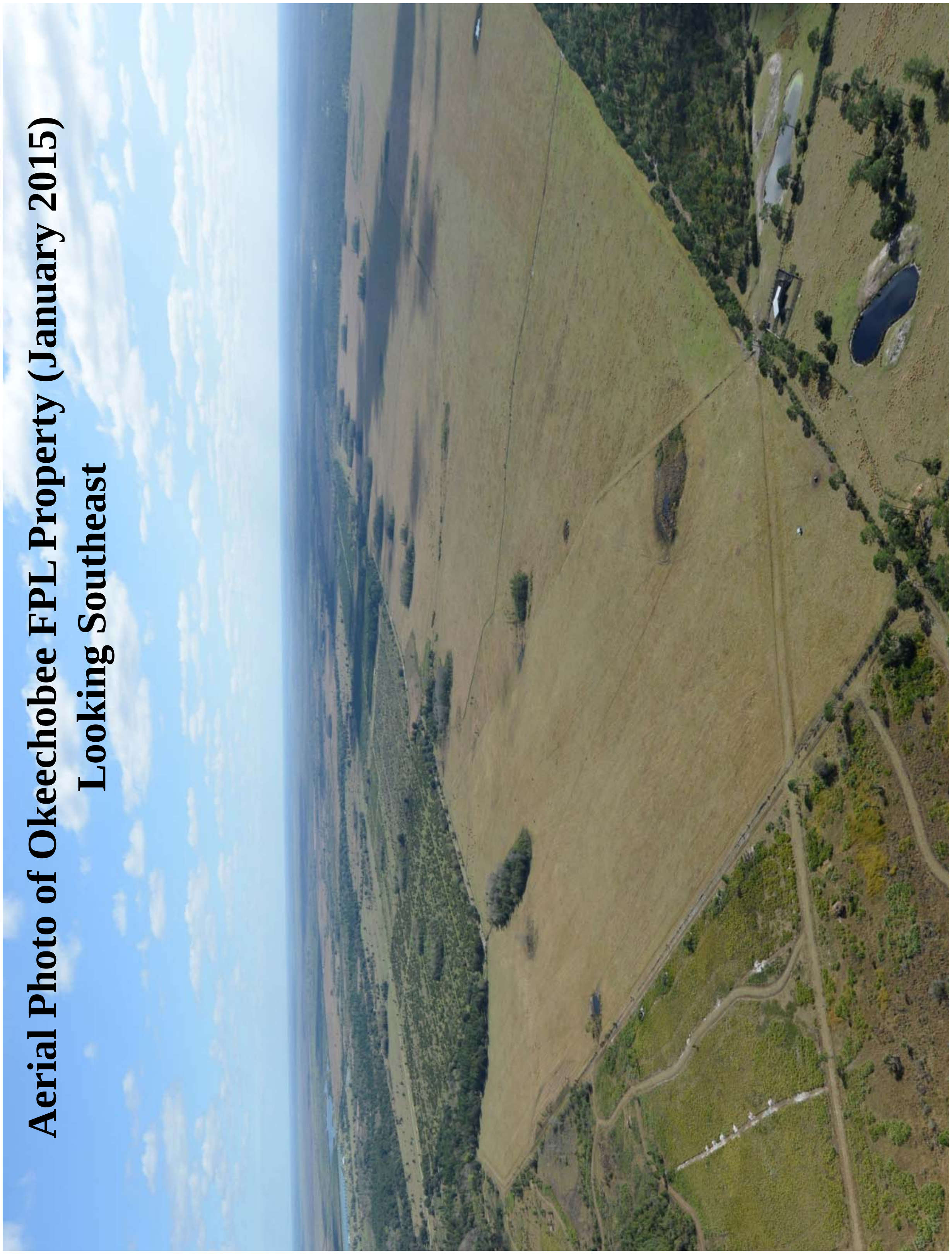
Date: 6/15/2015

0 0.25 0.5 Miles

Okeechobee FPL Property

FPL

Docket No. 15__________-EI
Aerial Photo of Okeechobee FPL Property
Exhibit JKK-6, Page 1 of 1



Docket No. 15________-EI
OCEC Unit 1 Proposed Site Plan Rendering
Exhibit JKK-7, Page 1 of 1

OCEC Unit 1 Proposed Site Plan Rendering

1. Cooling tower
2. Steam generators
3. Steam turbine
4. Combustion turbines
5. Collector yard
6. Maintenance work area
7. Switch yard
8. Power transmission lines
9. Storm water pond
10. Gas metering area
11. Contractor work area
12. Contractor parking
13. Employee parking
14. Administration & storage buildings
15. Back-up fuel tank
16. Demineralized water tank
17. Storm water ditch

OCEC Unit 1 Plant Specifications

Generating Technology – "Three on One" (3x1) Combined Cycle Configuration:

- Three (3) Advanced Combustion Turbines with Evaporative Coolers
- Three (3) Heat Recovery Steam Generators with Selective Catalytic Reduction System for NO_X control
- One (1) Single-Reheat Steam Turbine

Expected Plant Peak Capacity:

• Summer (95°F / 50% Relative Humidity (RH))	1,622 MW
• Winter (35°F / 60% RH)	1,595 MW

Projected Unit Performance Data:

• Planned Outage Factor	2.2%
• Forced Outage Factor	1.1%
• Equivalent Availability Factor	96.7%
• Resulting Capacity Factor (%)	Approx. 80%
• Avg. Net Operating Heat Rate (Base operation @ 75°F, 100%)	6,304 Btu/kWh
• Annual Fixed O&M[1]	$16.89/kW-yr
• Variable O&M - excluding fuel[2]	$0.28/MWh

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

• Primary Fuel	Natural Gas
• Natural Gas Consumption	9,432,429 scf/hr[3]
• On Site Back Up Fuel	Light Fuel Oil
• Light Fuel Oil Consumption	68,497 gal/hr

Expected Base Load Air Emissions Per Combustion Turbine/Heat Recovery Steam Generator @ 75°F (Baseload):

	Natural Gas	Light Fuel Oil
• NO_x (@15% O_2)	2 ppmvd[4]	8 ppmvd
• CO	5 ppmvd	10 ppmvd
• SO_2	< 0.0003 lb Sulfur/100 cubic feet	<0.0015% Sulfur

Water Balance:

- Primary Water Source – Floridan Aquifer

Linear Facilities:

- One (1) new natural gas pipeline lateral
- No new linear transmission facilities – connect into adjacent 500 kV corridor

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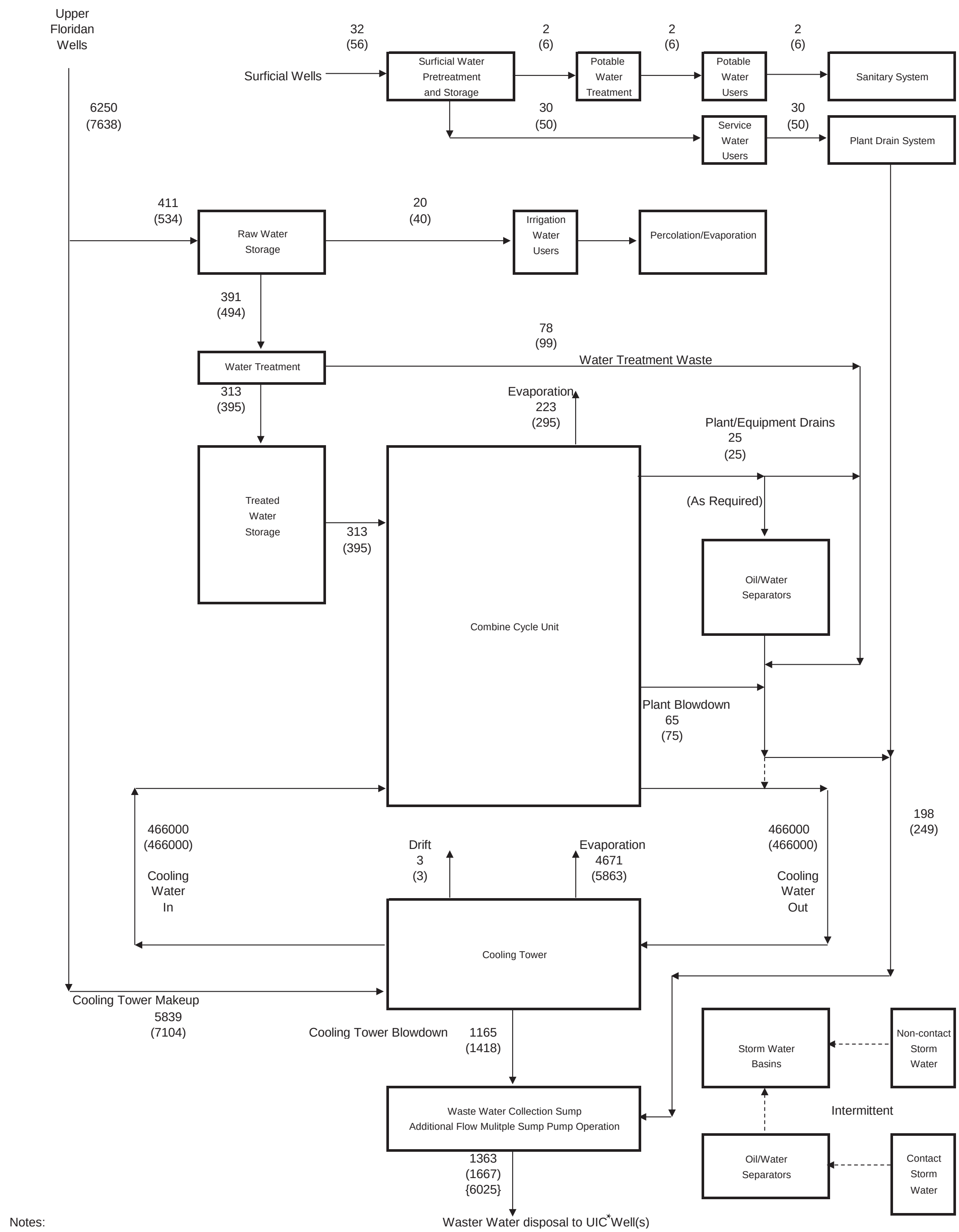
[1] Annual fixed O&M value includes capital replacement costs and fixed O&M presented as a levelized value to year 2019
[2] Variable O&M represents the value for year 2019
[3] Standard cubic feet per hour
[4] Parts per million volumetric dry

Jun-15 OCEC



Notes:
1 Flows are in gallons per minute (GPM).
2 Flows shown with no parenthesis [{ } or ()] are estimated annual average daily values - annual average basis.
3 Flows shown in () are hot weather daily values - monthly maximum basis.
4 Flows shown in { } are peak intermittent short duration values.
5 ----- Dashed lines indicate intermittent or alternate flow paths.
* Underground Injection Control

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.
3000 BAYPORT DRIVE, SUITE 600
TAMPA, FLORIDA 33607-8410
PHONE 813.289.5644 • FAX 813.289.5646
WWW.FRCC.COM

August 10, 2015

Mr. Pedro Modia
Director, Services and Planning
Florida Power and Light
4200 W. Flagler Street
Miami, FL 33134

Re: FRCC review of Florida Power and Light's Okeechobee County Energy Center Interconnection and Integration Request

Dear Pedro:

The Florida Reliability Coordinating Council's (FRCC) Transmission Working Group (TWG), and Stability Working Group (SWG) have evaluated and reviewed the Florida Power and Light (FPL) proposed Okeechobee Combined Cycle Unit Generation Interconnection Service Request (GISR) to serve FPL native load. The analyses conducted by the TWG, SWG and FPL for the interconnection and integration plan for FPL's Okeechobee County Energy Center (OCEC) are based on the 2014 FRCC databank, modified for planned facilities that resulted from the 2014 Long Range Study.

The OCEC, located in Okeechobee County, Florida, is comprised of three (3) natural gas fired Combustion Turbine (CT) generators and one (1) Steam Turbine (ST) generator with a total net output of 1652 MW for summer and 1625 MW for winter. The OCEC will be interconnected to the FPL transmission system by looping FPL's existing Martin-Poinsett 500kV line into a new 500 kV Okeechobee substation at the plant site. The project has a proposed in-service date of June 1, 2019.

The TWG evaluation found that FPL's steady state contingency analysis was comprehensive and complete. The analyses evaluated facilities 69 kV and above. Under normal operating conditions all facilities remained within applicable ratings. Both the FPL and the TWG contingency analyses identified potential 3rd party impacts of OCEC on the transmission system within the FRCC Region which have been addressed with appropriate remedies provided by the members of the TWG. A review of the short circuit analysis has also shown that there are no short circuit concerns from the OCEC.

In addition to the steady state and short circuit analyses, the SWG reviewed FPL's stability analyses. The dynamic simulations showed a stable response at both Peak and 50% load levels for planning events required to be analyzed by NERC Reliability Planning Standards.

FRCC
Florida Reliability Coordinating Council, Inc.

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.
3000 BAYPORT DRIVE, SUITE 600
TAMPA, FLORIDA 33607-8410
PHONE 813.289.5644 • FAX 813.289.5646
WWW.FRCC.COM

A Power transfer-Voltage (PV) sensitivity analysis was also performed to determine potential impacts on the Florida-Southern interface resulting from the loss of the entire combined cycle unit, and the results showed no impact on the future ability to import 3200 MW across the Florida-Southern interface with the addition of OCEC.

Based on the above review and analysis conducted by the TWG and SWG, the FRCC Planning Committee has determined that the proposed interconnection and integration plan for OCEC will be reliable, adequate and will not adversely impact the reliability of the FRCC transmission system.

Sincerely,

Vicente Ordax

VICENTE ORDAX
DIRECTOR OF PLANNING

OCEC Unit 1 Expected Construction Schedule

Milestone	Begin	End
Initiate sequence of HRSG orders (NTP[1] x 3)	Dec, 2015	-
Initiate NTP[1] for steam turbine	Dec, 2015	-
Initiate sequence of CT orders (NTP[1] x 3)	Jan, 2016	-
Receive approvals necessary to begin construction	-	Dec, 2016
Site preparation and install foundations	Mar, 2017	Dec, 2017
Balance of Plant	Mar, 2017	Sep, 2018
Erect HRSGs	Sep, 2017	Sep, 2018
Erect CTs	Sep, 2017	Sep, 2018
Erect steam turbine	Dec, 2017	Sep, 2018
Startup	Oct, 2018	Jun, 2019
Commercial Operation	-	Jun, 2019

[1] Notice to Proceed

OCEC Unit 1 Plant Construction Cost Components

Component	**Cost in millions (2019$)**
Power Block and Generator Transformers	$1,031.5
Land	$0
Transmission Interconnection and Integration	$52.0
Third Party Gas Infrastructure[1]	$0
Allowance for Funds Used During Construction (AFUDC)	$112.5
Total Plant Cost	**$1,196.0**

[1]Does not include cost to build gas pipeline or fuel charges

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

PETITION FOR DETERMINATION OF NEED

REGARDING OKEECHOBEE CLEAN ENERGY CENTER UNIT 1

DIRECT TESTIMONY OF RICHARD FELDMAN

DOCKET NO. 15____________-EI

SEPTEMBER 3, 2015

TABLE OF CONTENTS

I. INTRODUCTION 3

II. FPL'S EXISTING CUSTOMER BASE 6

III. LOAD FORECASTING PROCESS AND RESULTS 7

IV. CUSTOMER GROWTH FORECAST 9

V. SUMMER PEAK DEMAND FORECAST 11

VI. WINTER PEAK DEMAND FORECAST 21

VII. NET ENERGY FOR LOAD FORECAST 25

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Richard Feldman, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL or the Company) as a Production Analysis Lead in the Resource Assessment and Planning (RAP) department.

Q. Please describe your duties and responsibilities as a Production Analysis Lead.

A. I am responsible for developing the models and analysis supporting FPL's official peak demand, energy, and customer forecasts that are used in FPL's Ten Year Site Plans (TYSP) and long-term planning. I also develop risk adjusted forecasts for select forecasts which are used in various planning processes within the company. I produce reports for management on a regular basis and provide variance analysis on these forecasts. I also oversee the work of more junior analysts.

Q. Please describe your educational background and professional experience.

A. I hold a bachelor's degree (B.B.A.) in economics from the University of Miami, and I completed my coursework and thesis towards a master's degree in economics from the University of Miami along with additional graduate course work in statistics. I am also a certified Six Sigma Black Belt. As a Six Sigma Black Belt, I am trained in the use of statistical tools and techniques to document and improve existing processes. I am also tasked with assisting others in improving their processes through the use of Six Sigma methodologies and tools.

I began my career with FPL in 1982 as a Load Research Analyst. I have since held a variety of positions in the areas of market research and economics and forecasting. I spent ten-and-a-half years working for FPL Energy Services where I conducted tariff analysis and developed an electric pricing model for the Northeast U.S. I also managed an FPL real-time electric pricing program, and was the product manager for FPL Energy Services' insurance products and retail natural gas business, where I developed a retail natural gas pricing model and had profit and loss responsibility for the natural gas business. I assumed my current position in 2009.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibits RF-1 through RF-8, which are attached to my direct testimony.

Exhibit RF-1	Florida Population
Exhibit RF-2	Total Average Customers
Exhibit RF-3	Real Disposable Income per Household
Exhibit RF-4	Real Price of Gasoline Lagged
Exhibit RF-5	Summer Peak Load (MW)

Exhibit RF-6	Risk-Adjusted Summer Peak Forecast (MW)
Exhibit RF-7	Winter Peak Load (MW)
Exhibit RF-8	Calendar Net Energy for Load (GWh)

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe FPL's load forecasting process, identify the underlying methodologies and assumptions, and review the results of FPL's most current forecasts. These long-term forecasts include base case projections of customers, peak demands, and net energy for load. These base case forecasts are the same forecasts presented in FPL's 2015 TYSP, which was filed on April 1, 2015. My testimony expands upon the methodologies described in the 2015 TYSP filing. In addition, FPL's long-term forecasts include risk-adjusted projections of summer peak demands. FPL's risk-adjusted projections are designed to reflect the higher levels of summer peak demands that could occur in the future given the uncertainties inherent in the forecasting process. These uncertainties have been quantified based on analysis of the differences between actual and forecasted values of the summer peak that FPL has experienced historically.

Q. Please summarize your testimony.

A. My testimony addresses FPL's customer growth forecast, summer and winter peak demand forecasts, and the net energy for load forecast. My testimony explains how these forecasts are developed and why they are reasonable. As discussed in my testimony, FPL is expected to experience moderate growth in its customer base through 2024. By 2019, the number of FPL customer accounts (customers) is expected to surpass the five million mark, and by 2024, the cumulative increase in customers from 2014 is expected to reach almost 675,000. Summer peak demands are also projected to increase at a moderate rate. Although the percentage growth rates projected for the summer peak are somewhat lower than those experienced historically, the absolute increases will remain significant. By 2019, the summer peak is projected to reach 25,045 megawatts (MW), an increase of 2,110 MW relative to the 2014 summer peak, which equates to a cumulative increase of approximately 9%. Finally, my testimony explains that a 10% cumulative increase in FPL's net energy for load is also expected between 2014 and 2019, a net increase in excess of 11,000 gigawatt-hours (GWh).

II. FPL'S EXISTING CUSTOMER BASE

Q. Please describe FPL's service territory.

A. FPL's service territory covers approximately 27,650 square miles within peninsular Florida, which ranges from St. Johns County in the north to Miami-Dade County in the south, and westward to Manatee County. FPL serves customers in thirty-five counties within this region.

Q. How many customers receive their electric service from FPL?

A. FPL currently serves over 4.7 million customers, as shown on Exhibit RF-2. This amounts to a population of more than nine million people.

Q. Geographically, where is the largest concentration of FPL's load?

A. The largest concentration of load is in Southeast Florida. Although FPL's service area covers thirty-five counties, two counties, Miami-Dade and Broward, have recently accounted for 43% of the Company's summer peak load.

Q. What is the current economic outlook for Florida?

A. Florida's economy continues to expand at a moderate pace. After five years of positive employment growth, Florida has recently gained back all of the jobs lost during the recession. Likewise, the unemployment rate in Florida has fallen to its lowest level since early 2008. The real estate market has also improved although the amount of new construction remains modest by historical standards. Population growth has also recovered from the historic lows reached during the recent recession.

III. LOAD FORECASTING PROCESS AND RESULTS

Q. Please describe FPL's forecasting process.

A. FPL relies on econometrics as the primary tool for projecting future levels of customer growth, net energy for load, and peak demand. An econometric model is a numerical representation, obtained through statistical estimation techniques, of the degree of relationship between a dependent variable, *e.g.*, the level of net energy for load, and the independent (explanatory) variables. A change in any of the independent variables will result in a corresponding change in the dependent variable. On a historical basis, econometric models have proven to be highly effective in explaining changes in the level of customer or load growth. FPL has consistently relied on econometric models for various forecasting purposes, and the modeling results have been reviewed and accepted by the Florida Public Service Commission (Commission) in past proceedings, including Docket Nos. 130198-EI (Petition for prudence determination regarding new pipeline system) and 110309-EI (Petition to determine need for modernization of Port Everglades Plant).

Q. How does FPL determine the independent variables that should be used to forecast customer growth, net energy for load, and peak demand?

A. FPL has found that population growth, the economy, codes and standards, and weather are the primary drivers of future electricity needs. Accordingly, the models used to forecast customer growth, net energy for load, and peak demand rely on independent variables representing these various drivers. As discussed later in my testimony, the models used to forecast customer growth, net energy for load, and demand vary in terms of the specific independent variables used. However, a consistent set of assumptions regarding population growth, the economy, federal and state energy efficiency codes and standards, and weather are used throughout the load forecast.

Q. What sources does FPL rely on for projections of these independent variables?

A. FPL relies on leading industry experts for projections of these independent variables. Population projections are produced by the University of Florida's

Bureau of Economic and Business Research (BEBR) in conjunction with the Office of Economic and Demographic Research (EDR) of the Florida legislature. The projected economic conditions are from IHS Global Insight, a reputable economic forecasting firm. The weather factors are obtained from WSI, a division of The Weather Company, the world's leading provider of weather data and information. Estimates of the impact of codes and standards are provided by ITRON, one of the leading consultants on energy issues.

IV. CUSTOMER GROWTH FORECAST

Q. Please explain the development of FPL's customer growth forecast.

A. The growth of customers in FPL's service territory is a primary driver of the growth in the level of net energy for load and peak demand. In order to project the growth in the number of customers, FPL utilized the July 2014 population projections from EDR, the most current projections available at the time the forecast was developed.

Q. How do EDR's July 2014 population projections compare with its prior forecast?

A. Exhibit RF-1 shows that population growth rates are modestly higher but generally consistent with growth rates projected in the 2014 TYSP. While not expected to return to the growth rates experienced during the 1980s and 1990s, significant increases in the Florida population are projected through 2019.

Q. What is FPL's projected customer growth?

A. The number of customers is expected to increase moderately, averaging a 1.3% rate of increase between 2015 and 2024. As can be seen in Exhibit RF-2, by 2019, the number of customers is expected to surpass the five million mark, and by 2024, the cumulative increase in customers from 2014 is expected to reach almost 675,000. This level of growth in customers is consistent with EDR's population projections.

Q. How do FPL's projected customer growth rates compare with the growth rates experienced historically?

A. Customer growth is projected to average over 67,000 per year between 2015 and 2024, somewhat higher than the 65,000 customers per year FPL has averaged since 1990. It should be noted, however, that this historical time period included the recession during which customer growth slowed significantly. The forecast level of growth is comparable to that experienced during the 1990s but somewhat below the level of growth experienced during the boom of the early to mid-2000s. Customer growth has rebounded from the 2008 to 2010 time period when customer growth averaged less than 8,000 customers a year. Thus, the forecasted growth in customers represents a return to more historically typical growth rates.

Q. Is FPL's customer forecast reasonable?

A. Yes. The forecast incorporates the most recent EDR population projections available at the time the forecast was developed, relies on the sound and proven forecasting methods previously reviewed and accepted by the Commission, and is consistent with historical trends in customer growth.

V. SUMMER PEAK DEMAND FORECAST

Q. What are the factors that affect FPL's summer peak demand?

A. Variability in FPL's peak demand has been a function of a larger customer base, weather conditions, economic growth, codes and standards, and changing patterns of customer behavior.

Q. What weather information does FPL utilize?

A. FPL utilizes information from four weather stations scattered throughout its service territory. Composite estimates of the hourly temperatures representative of the FPL system as a whole are developed by weighting the values by weather station with the proportion of sales served in that area.

Q. How are weather conditions incorporated into the summer peak per customer model?

A. The summer peak per customer model is calibrated using historical data on two weather series: the maximum temperature on the day of the summer peak and the sum of the cooling degree hours two days prior to the peak day. In forecasting these weather variables, FPL relies on a normal weather outlook. Normal weather is based on historical averages over the last twenty years.

Q. How are economic conditions incorporated into the summer peak per customer model?

A. The impact of the economy is captured through a variable based on Florida real household disposable income. Real disposable income is based on the real (inflation-adjusted) level of income in Florida adjusted for taxes. Florida's real household disposable income is provided by IHS Global Insight. Exhibit RF-3 shows the actual and forecasted values for Florida's real household disposable income. Between 2015 and 2024, Florida's real household disposable income is expected to increase at an average annual rate of 2.0%, higher than the 1.4% projected in the 2014 TYSP forecast. By contrast, Florida's real household disposable income increased at an annual rate of 1.2% between 1990 and 2014. The 2.0% projected annual increase in this series between 2015 and 2024 is comparable to the growth rates experienced from the early 1990s until the start of the recession in 2007. Thus, the forecast anticipates that real household disposable income will return to a normal, pre-recession level of growth.

Q. How is the impact from codes and standards incorporated into the summer peak per customer model?

A. A variable is included for the impact of codes and standards based on end-use estimates developed by ITRON, a leading expert in this area. Included in ITRON's estimates are savings from federal and state codes and standards, including the Energy Policy Act of 2005, the Energy Independence and Security Act of 2007, and the savings occurring from the use of compact fluorescent and LED bulbs. This reduction is inclusive of ITRON's end-use engineering estimates and any resulting behavioral changes. By 2019, the cumulative savings, since 2005, from codes and standards are expected to reach 2,747 MW. It should be noted that the savings from codes and standards discussed here do not include the impact from incremental utility sponsored demand-side management (DSM) programs. As discussed in witness Sim's testimony, the impact of incremental DSM is addressed in the resource planning process.

Q. What assumptions regarding the impact of energy prices were used in the summer peak per customer model?

A. The real price of gasoline lagged one month was incorporated into the summer peak model as a proxy for energy prices. The price of gasoline is provided by IHS Global Insight. As gasoline prices fall, more income is available for the purchase of other commodities including electricity and vice versa. Exhibit RF-4 shows the historical real gasoline price along with its forecasted values. The forecast of real gasoline prices, through 2019, is lower than the price forecast used in the 2014 TYSP.

Q. How is the output from the summer peak per customer model incorporated into the summer peak forecast?

A. The output from the summer peak per customer model is multiplied by the forecasted number of customers. The result is a preliminary estimate of the forecasted summer peak. The forecasted summer peak is then adjusted for the impacts from incremental wholesale loads.

Q. Why is the forecast adjusted to include incremental wholesale loads?

A. The forecast is adjusted for incremental wholesale loads in order to reflect changes in load not otherwise reflected in FPL's historical load levels as a result of new, modified, or expanded wholesale contracts. The largest of these contracts is the power sales contract to Lee County, a not-for-profit electric distribution cooperative serving a five-county area in Southwest Florida. Other wholesale load is included, removed, or modified based on the contract terms for each wholesale customer.

Q. Are there any other adjustments to the summer peak forecast in addition to those for incremental wholesale load?

A. Yes. FPL includes an adjustment for the incremental load resulting from plug-in electric vehicles, for the new and incremental load resulting from its Economic Development Rider and Existing Facility Economic Rider, and for distributed solar generation.

Q. Why is an adjustment being made for plug-in electric vehicles?

A. The forecast is adjusted for plug-in electric vehicles in order to reflect additional load not otherwise captured in FPL's historical load levels. The current load from plug-in electric vehicles is estimated to be about 9 MW. The load from plug-in electric vehicles is expected to contribute 30 MW to the summer peak by 2019.

Q. How is the load from plug-in electric vehicles projected?

A. Projections on the number of plug-in electric vehicles in FPL's service territory were developed by the company's Customer Service Business Unit.

Projections of the U.S. market for plug-in electric vehicles were first developed based on a review of multiple forecasts from leading experts and discussions with knowledgeable professionals in the automotive industry. FPL's share of the U.S. market for plug-in electric vehicles was then estimated based on data from the Department of Motor Vehicles for registered plug-in vehicles in Florida. Using the same Department of Motor Vehicles data for counties served by FPL, FPL's share of plug-in vehicles is then estimated. The contribution to the summer peak load from plug-in electric vehicles was then derived from the vehicle forecast, an estimate of vehicle demand, and the proportion of vehicles expected to be charged during the summer peak.

Q. Why are adjustments being made for the Economic Development Rider and Existing Facility Economic Rider?

A. Under both the Economic Development Rider and Existing Facility Economic Rider, customers are provided discounts for adding new or incremental load. To qualify for either rider, customers are required to verify that the availability of the rider was a significant factor in their location or expansion decision. The Economic Development Rider and Existing Facility Economic Rider are expected to add incremental load to the summer peak not otherwise captured in FPL's historical load levels. Based on estimates developed by FPL's Economic Development group in conjunction with the Customer Service and Regulatory Business Units, the Economic Development Rider and Existing Facility Economic Rider are projected to add about 5 MW to the summer peak beginning in 2015. This figure is expected to rise to about 27 MW by 2019.

Q. Why is an adjustment being made for distributed solar generation?

A. The forecast is adjusted for distributed solar generation in order to reflect the load impact not otherwise captured in FPL's historical load levels. The impact of distributed solar generation is estimated to reduce the summer peak by about 46 MW by 2019. For clarification, distributed solar generation in this context is referring to photovoltaics, *e.g.*, rooftop solar.

Q. How are the projected adjustments made for distributed solar generation?

A. A forecast is obtained from Greentech Media (GTM), a leading source of news and research on green technology, for installed capacity of distributed solar generation for the state of Florida. FPL's share of the state forecast is determined based on actual 2014 FPL data for residential and commercial distributed solar generation. These shares along with GTM's state forecast are used to develop FPL's installed capacity of distributed solar generation. Megawatt hours (MWh) of distributed solar are derived using a capacity factor and hourly MWh values are then developed using solar profiles. The values at the hour of FPL's summer peak are used to adjust the summer peak forecast.

Q. Have adjustments to the summer peak forecast been incorporated into prior forecasts?

A. Yes. The 2014 TYSP forecast incorporated adjustments for incremental wholesale load, the Economic Development Rider and Existing Facility Economic Rider, and for new load resulting from plug-in electric vehicles. In fact, adjustments for incremental wholesale load and plug-in electric vehicles have been incorporated into FPL's long-term forecast since the 2009 TYSP. Adjustments for the Economic Development Rider and Existing Facility Economic Rider have been incorporated into FPL's forecast since the 2012 TYSP. Adjustments for distributed solar generation described previously were not incorporated into prior forecasts.

Q. What is FPL's projected summer peak demand?

A. As shown on Exhibit RF-5, FPL is projecting an annual increase of 1.6% in the summer peak demand between 2015 and 2024. While the projected percentage growth is lower than the long term rate experienced historically, the absolute level of growth remains very large. An annual increase of 387 MW is projected between 2015 and 2024. By 2019, the summer peak is projected to reach 25,045 MW, a cumulative increase of 2,110 MW relative to the actual 2014 summer peak.

Q. How does FPL's summer peak demand forecast compare with the 2014 TYSP?

A. As shown in Exhibit RF-5, under the current forecast the summer peak is expected to grow at an annual rate of 1.6% between 2015 and 2024, slightly lower than the 1.7% annual growth rate projected in the 2014 TYSP. The summer peak forecast is driven by economic conditions and population growth and the long-term growth in the summer peak forecast is comparable to the forecast growth rates in the 2014 TYSP.

Q. Is FPL's summer peak demand forecast based on an econometric model with a strong goodness of fit and a high degree of statistical significance?

A. Yes. Goodness of fit refers to how closely the predicted values of a model match the actual observed values. FPL's summer peak model has a strong goodness of fit as demonstrated by the model's adjusted R square of 92.1%. This means that 92.1% of the variability in the summer peak per customer is explained by the model. In addition, the coefficients for all of the variables have the expected sign (+/-) and are statistically significant. This indicates that the variables influencing the summer peak demand have been properly identified and their predicted impact is statistically sound. Additionally, there is no observable pattern in the residuals. Finally, the model has a Durbin-Watson statistic of 2.020 indicating the absence of significant autocorrelation. The absence of significant autocorrelation is a desirable quality in a well-constructed model. Overall, the summer peak model has excellent diagnostic statistics.

Q. In addition to its base case forecast, has FPL developed an alternative forecast of the summer peak demand?

A. Yes. As previously discussed, FPL has also developed a risk-adjusted forecast of the summer peak in order to address the uncertainty inherent in long-term projections. While the 2019 need is based on FPL's base case summer peak forecast, there is a probability that this 2019 need may be higher. The risk-adjusted summer peak forecast quantifies the probability and magnitude of this risk.

Q. How do FPL's base case and risk-adjusted forecasts of the summer peak differ?

A. FPL's base case forecast of the summer peak reflects the most likely future values of the summer peak. As such, the base case forecast is designed to reflect an approximately equal chance of under- or over-forecasting the summer peak. FPL's risk-adjusted forecast of summer peak is designed to reduce, but not eliminate the probability of under-forecasting the summer peak. The risk-adjusted forecast is designed to reflect the higher values of summer peak demands that could occur in the future given past differences between actual and forecasted values of the summer peak. Based on prior vintages of FPL's forecast, there is a 75% probability that the actual value of the summer peak in the future will be equal to or less than its risk-adjusted projections. Conversely, there is a 25% probability, based on past vintages of FPL's forecasted summer peak, that the actual future values of the summer peak will be higher than their risk-adjusted projections. The methodology used to develop the risk-adjusted forecasts was reviewed and accepted by this Commission in Docket No. 130198-EI where the Commission concluded that "we find it is a reasonable approach for controlling the risk of under forecasting future load growth."

Q. Does FPL develop a low band risk-adjusted forecast for summer peak?

A. No. From a capacity perspective, there is no need to develop a low band risk-adjusted forecast. If the base case need is met, by definition any low band risk-adjusted forecast would be met as well.

Q. What is FPL's risk-adjusted forecast for summer peak?

A. As shown in Exhibit RF-6, the summer peak reaches 26,188 MW by 2019 and 28,550 MW by 2024 under the risk-adjusted forecast. The risk-adjusted forecast indicates a cumulative increase in the summer peak of 4,815 MW between 2015 and 2024.

Q. How does the growth shown in FPL's risk-adjusted forecast for summer peak compare with historical growth rates?

A. FPL's risk-adjusted forecast shows an average annual increase of 2.1% in the summer peak demand between 2015 and 2024. These projected growth rates are comparable to the growth rate averaged over the last twenty-four years.

Q. How does FPL's risk-adjusted forecast of the summer peak compare with its base case forecast?

A. As shown in RF-6, the risk-adjusted forecast is 1.9% higher than the base forecast in 2015, the equivalent of 449 MW. By 2024, the delta between the risk-adjusted forecast and base case forecast increases to 6.6% or 1,779 MW.

Q. Are FPL's base case and risk-adjusted summer peak demand forecasts reasonable?

A. Yes. FPL's summer peak demand forecasts are based on reasonable assumptions developed by industry experts, are consistent with historical experience, and rely on the forecasting methods previously reviewed and accepted by the Commission. The model employed by FPL has a strong goodness of fit and a high degree of statistical significance. FPL's base case forecast is designed to reflect an approximately equal chance of under- or over-forecasting the summer peak, while the risk-adjusted forecast of summer peak is designed to reduce, but not eliminate the probability of under-forecasting the summer peak.

VI. WINTER PEAK DEMAND FORECAST

Q. What is FPL's process to forecast winter peak demand?

A. Like the summer peak model, the winter peak model is also an econometric model. The winter peak model is a per-customer model that includes two weather-related variables: the minimum temperature on the peak day and the square of heating degree hours from the prior day until 9:00 a.m. of the peak day. The model also has an economic term, housing starts per capita. In addition, the model includes a term for peaks occurring during the weekends as these tend to be lower than weekday peaks. The projected winter peak load per customer value is multiplied by the total number of customers to derive a preliminary estimate of the forecasted winter peak.

Q. Are the same line item adjustments made to the summer peak forecast also made to the winter peak forecast?

A. Yes. The winter peak forecast is adjusted for incremental wholesale loads, new load resulting from plug-in electric vehicles, incremental load resulting from the Economic Development Rider and Existing Facility Economic Rider, and the impact of distributed solar generation.

Q. How are codes and standards treated in the winter peak forecast?

A. ITRON developed end-use estimates of the codes and standards impacting the winter peak, similar to the estimates developed for the summer peak. As is the case in the development of the summer peak forecast, codes and standards do not include incremental utility-sponsored DSM programs as these are addressed in the resource planning process. Rather, codes and standards refer to national and state efficiency standards as well as the savings resulting from compact fluorescent and LED bulbs. The historical levels of the winter peak are first increased to remove the historical impact of codes and standards. The winter peak per customer model is based on these adjusted historical levels. The future impact from codes and standards is then treated as a line item adjustment reducing the level of the winter peak forecast.

Q. What is FPL's projected winter peak demand?

A. As shown in Exhibit RF-7, the winter peak is projected to increase at an annual rate of 0.7% between 2015 and 2024. The annual growth in the winter peak between 2015 and 2024 is expected to be 141 MW a year. By 2019, the winter peak is expected to reach 21,792 MW, an increase of 2,074 MW over the actual January 2015 winter peak of 19,718 MW.

Q. Why are FPL's projected winter peaks low relative to the 2010 winter peak?

A. The 2010 winter peak was the result of the extraordinary period of sustained cold weather experienced in January 2010. The day prior to the peak, January 10, 2010, was the third coldest day on record in the FPL service area based on records going back to 1948. Moreover, the cold weather had already been experienced almost continuously for more than a week prior to the January 2010 peak. Indeed, January 2010 holds the record for having the highest number of consecutive days below 40°F. Due to this period of sustained cold weather, a record peak of 24,346 MW was recorded on January 11, 2010. Projected winter peaks are based on the weather normally experienced on the day of the winter peak, as opposed to the record cold experienced in January 2010. As a result, the projected winter peaks through 2024 are not expected to exceed the 2010 winter peak. However, a peak of this magnitude while unlikely is still a possibility and outlines the risk associated with inadequate generating capacity.

Q. Is FPL's winter peak demand forecast based on an econometric model with a strong goodness of fit and a high degree of statistical significance?

A. Yes. Goodness of fit refers to how closely the predicted values of a model match the actual observed values. FPL's winter peak model has a strong goodness of fit as demonstrated by the model's adjusted R square of 94.6%.

This means that 94.6% of the variability in the winter peak per customer is explained by the model. In addition, the coefficients for all of the variables have the expected sign (+/-) and are statistically significant. This indicates that the variables influencing the winter peak demand have been properly identified and their predicted impact is statistically sound. Additionally, there is no observable pattern in the residuals. Finally, the model has a Durbin-Watson statistic of 1.808 indicating the absence of significant autocorrelation. The absence of significant autocorrelation is a desirable quality in a well-constructed model. Overall, the winter peak model has excellent diagnostic statistics.

Q. Is FPL's winter peak demand reasonable?

A. Yes. FPL's projected winter peak demand is based on reasonable assumptions developed by industry experts, is consistent with historical experience, and relies on the sound and proven forecasting methods previously reviewed and accepted by the Commission. The model employed by FPL has a strong goodness of fit and a high degree of statistical significance. FPL is confident that the relationship that exists between the level of winter peak demand, the weather, customers, and other variables have been properly assessed and numerically quantified.

VII. NET ENERGY FOR LOAD FORECAST

Q. How does FPL forecast energy sales?

A. FPL forecasts energy sales using an econometric model for total net energy for load. Net energy for load is a measure of electric sales that takes into account the MWh FPL generates and the net flow of interchange sales into and out of the FPL system. An econometric model for net energy for load is more reliable than models for billed energy sales because the explanatory variables can be better matched to usage. This is so because the net energy for load data do not have to be attuned to account for billing cycle adjustments, which might distort the real time match between the production and consumption of electricity.

Q. What inputs does the econometric model use to forecast net energy for load?

A. FPL has found that the customer base, weather, the economy, and codes and standards are the principal factors influencing net energy for load. Accordingly, a net energy per customer model has been developed incorporating these variables. The model output is multiplied by the number of customers to derive a preliminary net energy for load forecast.

Q. How are weather conditions incorporated into the net energy per customer model?

A. The weather variables included in the net energy for load per customer model are monthly cooling degree hours using a base of 72°F and monthly winter heating degree days using a base of 66°F. In addition, a second measure of heating degree days is included using a base of 45°F in order to capture the additional heating load resulting from sustained periods of unusually cold weather as occurred in January 2010.

Q. How are economic conditions incorporated into the net energy per customer model?

A. A composite variable based on Florida real per capita income weighted by the percent of the state's population employed is used as a measure of economic conditions. The impact of energy prices on electricity consumption is measured by the Consumer Price Index for energy prices, as forecasted by IHS Global Insight.

Q. How is the impact from codes and standards incorporated into the net energy per customer model?

A. A variable is included for the impact of codes and standards based on end-use estimates developed by ITRON. This variable is calculated as a net energy per customer impact of codes and standards and is inclusive of ITRON's end-use engineering estimates and any resulting behavioral changes.

Q. Are the same line item adjustments made to the summer and winter peak forecasts also made to the net energy for load forecast?

A. Yes. The net energy for load forecast is adjusted for incremental wholesale loads, new load resulting from plug-in electric vehicles, incremental load resulting from the Economic Development Rider and Existing Facility Economic Rider, and the impact of distributed solar generation.

Q. What is FPL's projected net energy for load?

A. As shown in Exhibit RF-8, FPL is projecting a 1.2% annual growth rate in net energy for load between 2015 and 2024. This projected annual growth in net energy for load reflects the impact of continued economic and population growth. The absolute level of increase in GWh, however, is expected to be lower than that experienced historically. The forecast shows an annual increase in net energy for load of 1,507 GWh between 2015 and 2024, resulting in a cumulative increase of 13,563 GWh.

Q. How does FPL's projected net energy for load compare with the 2014 TYSP?

A. As shown at the top of Exhibit RF-8, the projected long-run percentage growth rates are identical as those of the 2014 TYSP. The current forecast shows a 1.2% annual growth rate in net energy for load between 2015 and 2024, the same as the 2014 TYSP.

Q. Is FPL's net energy for load forecast based on an econometric model with strong goodness of fit and a high degree of statistical significance?

A. Yes. Goodness of fit refers to how closely the predicted values of a model match the actual observed values. FPL's net energy for load model has strong goodness of fit as demonstrated by the model's adjusted R square of 99.5%. This means that 99.5% of the variability in net energy for load per customer is explained by the model. In addition, the coefficients for all the variables have the expected sign (+/-) and are statistically significant. This indicates that the variables influencing net energy for load have been properly identified and their predicted impact is statistically sound. Additionally, there is no observable pattern in the residuals. Finally, the model has a Durbin-Watson statistic of 2.029 indicating the absence of significant autocorrelation. The absence of significant autocorrelation is a desirable quality in a well-constructed model. Overall, the net energy for load model has excellent diagnostic statistics.

Q. Is FPL's net energy for load forecast consistent with the forecasts for summer and winter peak demands?

A. Yes. All three forecasts rely on the same set of assumptions regarding population, weather, and economic growth and rely on similar modeling techniques. Additionally, similar out-of-model adjustments are made to all three forecasts.

Q. Is FPL's projected net energy for load reasonable?

A. Yes. FPL's projected net energy for load is based on assumptions developed by industry experts, is consistent with historical experience, and relies on the forecasting methods previously reviewed and accepted by the Commission. The model employed by FPL has a strong goodness of fit and high degrees of statistical significance. FPL is confident that the relationship that exists between the level of net energy for load and the economy, weather, customers, codes and standards, and other variables have been properly assessed and numerically quantified.

Q. In your testimony, you compare the 2014 and 2015 TYSP forecasts. Do these forecasts have a consistent methodology and rely on similar drivers?

A. Yes, both forecasts use consistent methodologies and rely on similar drivers. Econometric modeling is the tool used in developing each of these forecasts. Additionally, the same basic drivers obtained from the same independent experts are used as explanatory variables in each of these forecasts. Each TYSP forecast uses the best and most current assumptions available at the time the forecasts were developed, and result in models that have sound model statistics. Each forecast was reasonable for planning purposes at the time the forecasts were employed. As part of FPL's on-going commitment to process improvement, minor modifications are made at times to take advantage of more current data and recent learnings in order to make improvements to the models. However, the primary drivers of future electricity needs and the forecast methodologies remain the same in all forecast vintages.

Q. Does this conclude your direct testimony?

A. Yes.

FLORIDA POPULATION

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	273,721	1.7%
Based on 2014 TYSP (2015 to 2024)	268,995	1.3%
Based on 2015 TYSP (2015 to 2024)	277,262	1.3%

HISTORY

		Growth	
		Absolute	%
1990	12,938,071	390,341	3.1%
1991	13,258,732	320,661	2.5%
1992	13,497,541	238,809	1.8%
1993	13,730,115	232,574	1.7%
1994	14,043,757	313,642	2.3%
1995	14,335,992	292,235	2.1%
1996	14,623,421	287,429	2.0%
1997	14,938,314	314,893	2.2%
1998	15,230,421	292,107	2.0%
1999	15,580,244	349,823	2.3%
2000	15,982,824	402,580	2.6%
2001	16,305,100	322,276	2.0%
2002	16,634,256	329,156	2.0%
2003	16,979,706	345,450	2.1%
2004	17,374,824	395,118	2.3%
2005	17,778,156	403,332	2.3%
2006	18,154,475	376,319	2.1%
2007	18,446,768	292,293	1.6%
2008	18,613,905	167,137	0.9%
2009	18,687,425	73,520	0.4%
2010	18,801,332	113,907	0.6%
2011	18,905,070	103,738	0.6%
2012	19,074,434	169,364	0.9%
2013	19,259,543	185,109	1.0%
2014	19,507,369	247,826	1.3%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Absolute Growth	Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Monthly Rate	Absolute	%
2015	19,745,376	238,007	1.2%	19,769,010	261,641	1.3%	21,803	23,634	0.1%
2016	20,024,054	278,678	1.4%	20,051,547	282,537	1.4%	23,545	27,493	0.1%
2017	20,306,863	282,809	1.4%	20,338,444	286,897	1.4%	23,908	31,581	0.2%
2018	20,587,391	280,528	1.4%	20,622,557	284,113	1.4%	23,676	35,166	0.2%
2019	20,864,297	276,906	1.3%	20,906,670	284,113	1.4%	23,676	42,373	0.2%
2020	21,137,177	272,880	1.3%	21,185,476	278,806	1.3%	23,234	48,299	0.2%
2021	21,389,898	252,721	1.2%	21,460,260	274,784	1.3%	22,899	70,362	0.3%
2022	21,645,640	255,742	1.2%	21,731,097	270,837	1.3%	22,570	85,457	0.4%
2023	21,904,440	258,800	1.2%	21,998,833	267,736	1.2%	22,311	94,393	0.4%
2024	22,166,334	261,894	1.2%	22,264,368	265,535	1.2%	22,128	98,033	0.4%

TOTAL AVERAGE CUSTOMERS

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	64,584	1.7%
Based on 2014 TYSP (2015 to 2024)	65,543	1.3%
Based on 2015 TYSP (2015 to 2024)	67,178	1.3%

HISTORY

		Growth	
		Absolute	%
1990	3,158,817	94,381	3.1%
1991	3,226,455	67,638	2.1%
1992	3,281,238	54,783	1.7%
1993	3,355,794	74,556	2.3%
1994	3,422,187	66,393	2.0%
1995	3,488,796	66,609	1.9%
1996	3,550,747	61,951	1.8%
1997	3,615,485	64,738	1.8%
1998	3,680,470	64,985	1.8%
1999	3,756,009	75,539	2.1%
2000	3,848,350	92,341	2.5%
2001	3,935,281	86,931	2.3%
2002	4,019,805	84,523	2.1%
2003	4,117,221	97,416	2.4%
2004	4,224,509	107,289	2.6%
2005	4,321,895	97,386	2.3%
2006	4,409,563	87,667	2.0%
2007	4,496,589	87,027	2.0%
2008	4,509,730	13,141	0.3%
2009	4,499,067	-10,663	-0.2%
2010	4,520,328	21,261	0.5%
2011	4,547,051	26,723	0.6%
2012	4,576,449	29,398	0.6%
2013	4,626,934	50,486	1.1%
2014	4,708,829	81,895	1.8%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2015	4,782,469	73,640	1.6%	4,777,210	68,380	1.5%	-5,259	-0.1%
2016	4,852,827	70,358	1.5%	4,848,294	71,084	1.5%	-4,534	-0.1%
2017	4,922,918	70,090	1.4%	4,919,162	70,868	1.5%	-3,756	-0.1%
2018	4,991,659	68,741	1.4%	4,988,771	69,609	1.4%	-2,888	-0.1%
2019	5,058,945	67,286	1.3%	5,057,400	68,629	1.4%	-1,545	0.0%
2020	5,123,909	64,963	1.3%	5,124,436	67,036	1.3%	528	0.0%
2021	5,185,333	61,424	1.2%	5,190,185	65,748	1.3%	4,852	0.1%
2022	5,247,054	61,721	1.2%	5,254,820	64,635	1.2%	7,766	0.1%
2023	5,309,376	62,322	1.2%	5,318,608	63,788	1.2%	9,232	0.2%
2024	5,372,353	62,977	1.2%	5,381,815	63,207	1.2%	9,463	0.2%

REAL DISPOSABLE INCOME PER HOUSEHOLD (THOUSANDS 2009$)

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	0.94	1.2%
Based on 2014 TYSP (2015 to 2024)	1.36	1.4%
Based on 2015 TYSP (2015 to 2024)	2.00	2.0%

HISTORY

		Growth	
		Absolute	%
1990	67.1	-0.1	-0.2%
1991	66.4	-0.8	-1.2%
1992	67.2	0.9	1.3%
1993	68.4	1.2	1.8%
1994	69.3	0.9	1.3%
1995	71.0	1.6	2.4%
1996	71.4	0.4	0.5%
1997	72.1	0.8	1.1%
1998	75.2	3.1	4.2%
1999	76.1	0.9	1.2%
2000	78.2	2.1	2.7%
2001	79.2	1.1	1.4%
2002	80.6	1.4	1.7%
2003	81.9	1.4	1.7%
2004	84.7	2.8	3.4%
2005	86.6	1.8	2.2%
2006	90.1	3.5	4.1%
2007	90.8	0.7	0.8%
2008	89.7	-1.1	-1.2%
2009	86.9	-2.8	-3.2%
2010	88.7	1.9	2.2%
2011	88.8	0.0	0.1%
2012	89.4	0.7	0.7%
2013	89.1	-0.3	-0.4%
2014	89.7	0.6	0.7%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2015	91.9	2.1	2.4%	91.5	1.8	2.0%	-0.4	-0.4%
2016	93.9	2.0	2.2%	94.2	2.7	3.0%	0.4	0.4%
2017	96.1	2.2	2.3%	97.3	3.0	3.2%	1.2	1.2%
2018	97.5	1.4	1.5%	99.6	2.4	2.4%	2.1	2.2%
2019	98.9	1.4	1.4%	101.8	2.1	2.1%	2.9	2.9%
2020	99.9	1.0	1.0%	103.3	1.6	1.5%	3.5	3.5%
2021	100.7	0.8	0.8%	104.8	1.5	1.4%	4.1	4.1%
2022	101.6	0.9	0.9%	106.4	1.6	1.5%	4.8	4.7%
2023	102.7	1.1	1.1%	108.0	1.7	1.6%	5.3	5.2%
2024	104.1	1.4	1.4%	109.5	1.5	1.4%	5.4	5.2%

REAL PRICE OF GASOLINE LAGGED (CENTS/GALLON)

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	2.91	1.9%
Based on 2014 TYSP (2015 to 2024)	0.65	0.5%
Based on 2015 TYSP (2015 to 2024)	2.38	1.6%

HISTORY

		Growth	
		Absolute	%
1990	94.58	6.27	7.1%
1991	87.36	7.27	-7.6%
1992	87.04	-0.31	-0.4%
1993	80.31	-6.73	-7.7%
1994	79.50	-0.82	-1.0%
1995	82.05	2.56	3.2%
1996	84.64	2.59	3.2%
1997	80.99	-3.65	-4.3%
1998	69.40	-11.59	-14.3%
1999	77.49	8.09	11.7%
2000	93.18	15.69	20.2%
2001	87.88	-5.30	-5.7%
2002	83.34	-4.54	-5.2%
2003	90.04	6.71	8.0%
2004	104.58	14.54	16.1%
2005	133.50	28.92	27.7%
2006	143.00	9.50	7.1%
2007	139.22	-3.78	-2.6%
2008	178.64	39.41	28.3%
2009	116.50	-62.14	-34.8%
2010	127.41	10.91	9.4%
2011	162.84	35.44	27.8%
2012	161.91	-0.93	-0.6%
2013	156.49	-5.42	-3.3%
2014	149.90	-6.59	-4.2%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2015	139.64	-10.26	-6.8%	139.70	-10.20	-6.8%	0.06	0.0%
2016	140.85	1.21	0.9%	138.42	-1.28	-0.9%	-2.43	-1.7%
2017	142.30	1.45	1.0%	138.10	-0.32	-0.2%	-4.20	-2.9%
2018	143.98	1.68	1.2%	139.15	1.05	0.8%	-4.83	-3.4%
2019	145.20	1.22	0.8%	141.36	2.21	1.6%	-3.84	-2.6%
2020	145.79	0.59	0.4%	145.14	3.78	2.7%	-0.64	-0.4%
2021	145.99	0.21	0.1%	149.48	4.33	3.0%	3.49	2.4%
2022	145.80	-0.20	-0.1%	153.47	3.99	2.7%	7.67	5.3%
2023	145.58	-0.21	-0.1%	157.44	3.97	2.6%	11.85	8.1%
2024	145.45	-0.13	-0.1%	161.13	3.69	2.3%	15.68	10.8%

SUMMER PEAK LOAD (MW)

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	383	2.2%
Based on 2014 TYSP (2015 to 2024)	429	1.7%
Based on 2015 TYSP (2015 to 2024)	387	1.6%

HISTORY

		Growth	
		Absolute	%
1990	13,754	329	2.5%
1991	14,123	369	2.7%
1992	14,661	538	3.8%
1993	15,266	605	4.1%
1994	15,179	-87	-0.6%
1995	15,813	634	4.2%
1996	16,064	251	1.6%
1997	16,613	549	3.4%
1998	17,897	1,284	7.7%
1999	17,615	-282	-1.6%
2000	17,808	193	1.1%
2001	18,754	946	5.3%
2002	19,219	465	2.5%
2003	19,668	449	2.3%
2004	20,545	877	4.5%
2005	22,361	1,816	8.8%
2006	21,819	-542	-2.4%
2007	21,962	143	0.7%
2008	21,060	-902	-4.1%
2009	22,351	1,291	6.1%
2010	22,256	-95	-0.4%
2011	21,619	-637	-2.9%
2012	21,440	-179	-0.8%
2013	21,576	136	0.6%
2014	22,935	1,359	6.3%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2015	23,356	421	1.8%	23,286	351	1.5%	-70	-0.3%
2016	23,778	422	1.8%	23,778	493	2.1%	1	0.0%
2017	24,190	412	1.7%	24,252	474	2.0%	62	0.3%
2018	24,544	354	1.5%	24,648	395	1.6%	104	0.4%
2019	24,896	352	1.4%	25,045	397	1.6%	149	0.6%
2020	25,239	344	1.4%	25,369	324	1.3%	130	0.5%
2021	25,439	200	0.8%	25,497	128	0.5%	58	0.2%
2022	25,908	469	1.8%	25,833	336	1.3%	-75	-0.3%
2023	26,528	621	2.4%	26,286	453	1.8%	-242	-0.9%
2024	27,214	686	2.6%	26,771	485	1.8%	-444	-1.6%

RISK-ADJUSTED SUMMER PEAK FORECAST (MW)

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	383	2.2%
Base Case Forecast (2015 to 2024)	387	1.6%
Risk-Adjusted Forecast (2015 to 2024)	535	2.1%

HISTORY

		Growth	
		Absolute	%
1990	13,754	329	2.5%
1991	14,123	369	2.7%
1992	14,661	538	3.8%
1993	15,266	605	4.1%
1994	15,179	-87	-0.6%
1995	15,813	634	4.2%
1996	16,064	251	1.6%
1997	16,613	549	3.4%
1998	17,897	1,284	7.7%
1999	17,615	-282	-1.6%
2000	17,808	193	1.1%
2001	18,754	946	5.3%
2002	19,219	465	2.5%
2003	19,668	449	2.3%
2004	20,545	877	4.5%
2005	22,361	1,816	8.8%
2006	21,819	-542	-2.4%
2007	21,962	143	0.7%
2008	21,060	-902	-4.1%
2009	22,351	1,291	6.1%
2010	22,256	-95	-0.4%
2011	21,619	-637	-2.9%
2012	21,440	-179	-0.8%
2013	21,576	136	0.6%
2014	22,935	1,359	6.3%

FORECAST

	2015 TYSP Base Case Forecast	Growth Absolute	Growth %	2015 TYSP Risk-Adjusted Forecast	Growth Absolute	Growth %	Difference
2015	23,286	351	1.5%	23,735	800	3.5%	449
2016	23,778	493	2.1%	24,333	598	2.5%	555
2017	24,252	474	2.0%	24,922	589	2.4%	670
2018	24,648	395	1.6%	25,494	572	2.3%	847
2019	25,045	397	1.6%	26,188	694	2.7%	1,143
2020	25,369	324	1.3%	26,802	614	2.3%	1,433
2021	25,497	128	0.5%	27,127	325	1.2%	1,630
2022	25,833	336	1.3%	27,539	412	1.5%	1,707
2023	26,286	453	1.8%	28,042	502	1.8%	1,756
2024	26,771	485	1.8%	28,550	508	1.8%	1,779

WINTER PEAK LOAD (MW)

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	146	0.9%
Based on 2014 TYSP (2015 to 2024)	249	1.1%
Based on 2015 TYSP (2015 to 2024)	141	0.7%

HISTORY

		Growth	
		Absolute	%
1990	13,988	1,112	8.6%
1991	11,868	-2,120	-15.2%
1992	13,319	1,451	12.2%
1993	12,964	-355	-2.7%
1994	12,594	-370	-2.9%
1995	16,563	3,969	31.5%
1996	18,096	1,533	9.3%
1997	16,490	-1,606	-8.9%
1998	13,060	-3,430	-20.8%
1999	16,802	3,742	28.7%
2000	17,057	255	1.5%
2001	18,199	1,142	6.7%
2002	17,597	-602	-3.3%
2003	20,190	2,593	14.7%
2004	14,752	-5,438	-26.9%
2005	18,108	3,356	22.7%
2006	19,683	1,575	8.7%
2007	16,815	-2,868	-14.6%
2008	18,055	1,240	7.4%
2009	20,081	2,026	11.2%
2010	24,346	4,265	21.2%
2011	21,126	-3,220	-13.2%
2012	17,934	-3,192	-15.1%
2013	15,931	-2,003	-11.2%
2014	17,500	1,569	9.8%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2015	20,971	3,471	19.8%	21,136	3,636	20.8%	165	0.8%
2016	21,490	519	2.5%	21,369	233	1.1%	-122	-0.6%
2017	21,731	241	1.1%	21,485	116	0.5%	-246	-1.1%
2018	21,968	238	1.1%	21,598	113	0.5%	-370	-1.7%
2019	22,180	211	1.0%	21,792	194	0.9%	-388	-1.7%
2020	22,383	203	0.9%	21,965	173	0.8%	-418	-1.9%
2021	22,584	201	0.9%	22,096	131	0.6%	-488	-2.2%
2022	22,601	17	0.1%	22,026	-71	-0.3%	-575	-2.5%
2023	22,891	290	1.3%	22,202	176	0.8%	-689	-3.0%
2024	23,211	320	1.4%	22,408	206	0.9%	-803	-3.5%

CALENDAR NET ENERGY FOR LOAD (GWH)

AVERAGE ANNUAL GROWTH

History (1990 to 2014)	1,852	2.0%
Based on 2014 TYSP (2015 to 2024)	1,472	1.2%
Based on 2015 TYSP (2015 to 2024)	1,507	1.2%

HISTORY

		Growth	
		Absolute	%
1990	71,528	1,229	1.7%
1991	73,426	1,897	2.7%
1992	73,321	-105	-0.1%
1993	76,074	2,753	3.8%
1994	80,673	4,599	6.0%
1995	84,546	3,873	4.8%
1996	85,028	482	0.6%
1997	87,056	2,028	2.4%
1998	92,802	5,747	6.6%
1999	91,683	-1,119	-1.2%
2000	96,313	4,630	5.1%
2001	98,612	2,299	2.4%
2002	104,657	6,045	6.1%
2003	108,214	3,557	3.4%
2004	108,122	-93	-0.1%
2005	111,443	3,321	3.1%
2006	113,406	1,963	1.8%
2007	114,532	1,126	1.0%
2008	111,100	-3,432	-3.0%
2009	111,237	137	0.1%
2010	114,604	3,366	3.0%
2011	111,542	-3,061	-2.7%
2012	110,866	-677	-0.6%
2013	111,655	790	0.7%
2014	115,968	4,312	3.9%

FORECAST

	2014 TYSP	Growth		2015 TYSP	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2015	121,606	5,638	4.9%	119,713	3,745	3.2%	-1,893	-1.6%
2016	123,943	2,337	1.9%	122,407	2,694	2.3%	-1,536	-1.2%
2017	124,914	971	0.8%	123,946	1,539	1.3%	-968	-0.8%
2018	126,399	1,485	1.2%	125,433	1,487	1.2%	-966	-0.8%
2019	127,673	1,274	1.0%	127,070	1,637	1.3%	-603	-0.5%
2020	129,187	1,514	1.2%	128,851	1,782	1.4%	-336	-0.3%
2021	129,454	267	0.2%	129,237	386	0.3%	-216	-0.2%
2022	130,517	1,064	0.8%	130,077	839	0.6%	-441	-0.3%
2023	132,357	1,840	1.4%	131,495	1,419	1.1%	-862	-0.7%
2024	134,849	2,492	1.9%	133,276	1,780	1.4%	-1,573	-1.2%

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

PETITION FOR DETERMINATION OF NEED

REGARDING OKEECHOBEE CLEAN ENERGY CENTER UNIT 1

DIRECT TESTIMONY OF HEATHER C. STUBBLEFIELD

DOCKET NO. ____________-EI

SEPTEMBER 3, 2015

TABLE OF CONTENTS

I. **INTRODUCTION AND CREDENTIALS** **3**

II. **FUEL FORECAST** **5**

III. **FUEL TYPE AND FUEL TRANSPORTATION** **7**

I. INTRODUCTION AND CREDENTIALS

Q. Please state your name and business address.

A. My name is Heather C. Stubblefield. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Manager of Project Development in the Energy Marketing and Trading (EMT) Business Unit.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for evaluating gas transportation alternatives for FPL's gas-fired generation expansions. This includes evaluating proposals from pipeline companies, negotiating terms and conditions, and executing transportation agreements which are in the best interest of FPL's customers.

Q. Please describe your educational background and professional experience.

A. I graduated from Auburn University with a Bachelor of Arts degree in Business Administration in 1986. I joined Sonat, Inc. (NKA Kinder Morgan, Inc.) in 1988, where I held various positions in Human Resources, Internal Auditing, and the Sonat Marketing Company. In 2003, I joined FPL Group Resources as the Director of Marketing for liquefied natural gas initiatives. In 2005, I transferred to the EMT Business Unit of FPL where my duties include evaluating gas transportation alternatives for FPL's gas-fired generation expansions. This includes evaluating proposals from pipeline companies, negotiating terms and conditions, and executing gas transportation agreements that are in the best interest of FPL's customers.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit HCS-1, FPL's November 3, 2014 and October 7, 2013 Fuel Price Forecasts, which is attached to my direct testimony.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present and explain (1) the fossil fuel price forecasts used in the evaluation of FPL's Okeechobee Clean Energy Center Unit 1 (OCEC Unit 1); and (2) the proposed fuel and fuel transportation plan for OCEC Unit 1.

Q. Please summarize your testimony.

A. FPL's fuel price forecasts reflect the projected commodity and transportation costs for fuel oil, natural gas, and coal. The November 2014 Fuel Price Forecast is the same fuel price forecast that was used in FPL's 2015 Ten Year Site Plan (TYSP). In addition, the fuel price forecasts were developed using the same methodology that was presented in my testimony for the Determination of Need filings for West County Energy Center Unit 3 and the modernizations of Cape Canaveral Plant, Riviera Plant, and Port Everglades Plant; therefore, this forecast is reasonable for the evaluation of OCEC Unit 1.

OCEC Unit 1 will burn natural gas as its primary fuel. With the addition of the capacity FPL has contracted for on the Sabal Trail Transmission, LLC (Sabal

Trail) and the Florida Southeast Connection, LLC (FSC) pipelines beginning in 2017 (400,000 million Btu per day (MMBtu/day) increasing to 600,000 MMBtu/day in 2020), FPL will have sufficient natural gas transportation rights to meet the requirements of OCEC Unit 1. Only minor facilities modifications, such as a lateral connecting the OCEC Unit 1 to FSC and metering facilities, will be required to facilitate natural gas deliveries to OCEC Unit 1.

Finally, OCEC Unit 1 will utilize a form of light fuel oil known as ultra-low-sulfur distillate as a backup fuel source in the event of a natural gas supply disruption. Light fuel oil will be stored in sufficient quantities to allow OCEC Unit 1 to operate at full capacity for seventy-two (72) hours of continuous operation and can be resupplied with truck deliveries.

II. FUEL FORECAST

Q. Which fossil fuel price forecasts were used in the evaluation of FPL's proposed OCEC Project?

A. FPL's November 3, 2014 and October 7, 2013 long-term fuel price forecasts were used in the evaluation of OCEC Unit 1 and are provided in Exhibit HCS-1.

Q. What was FPL's methodology for developing the forecasts for fuel oil, natural gas, and coal?

A. For fuel oil and natural gas commodity prices, FPL's forecast applied the following methodology: (1) for the first two years, the methodology uses the forward curve for Henry Hub natural gas, New York Harbor 0.7% sulfur heavy oil, and ultra-low sulfur diesel fuel oil; (2) for the next two years, FPL uses a 50/50 blend of the forward curve and the most current projections from The PIRA Energy Group; (3) for years 5 through 20, FPL uses the annual projections from The PIRA Energy Group; (4) for the period beyond year 20, FPL used the real rate of escalation from the Energy Information Administration. In addition to the development of commodity prices, price forecasts were also prepared for fuel oil transportation and natural gas transportation costs. These transportation costs, when added to the projected commodity prices, resulted in the delivered price forecasts used to evaluate the cost effectiveness of OCEC Unit 1. Coal prices were based on mine-mouth and transportation costs provided by JD Energy, Inc. This methodology is consistent with the approach to fuel forecasting used in previous filings, including FPL's 2015 Ten Year Site Plan.

Q. Please identify the key drivers that affect the future price of fossil fuels.

A. Future fuel oil and natural gas prices, and to a much lesser extent coal prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short and long-term prices. These drivers include worldwide demand, production capacity, economic growth, environmental legislation, and politics.

Q. Are FPL's long-term fossil fuel price forecasts reasonable for the evaluation of capacity options such as OCEC Unit 1?

A. Yes. Each of the FPL long-term fossil fuel price forecasts was reasonable for the evaluation of OCEC Unit 1 at the time they were used. All of those FPL fuel price forecasts reflect the projected supply, demand and price for fuel oil, natural gas, and coal, as well as the transportation of these fuels to the existing and proposed sites.

III. FUEL TYPE AND FUEL TRANSPORTATION

Q. What is the primary fuel type that will be utilized in OCEC Unit 1?

A. OCEC Unit 1 will burn natural gas as the primary fuel source.

Q. Does FPL have sufficient gas transportation capacity to serve OCEC Unit 1?

A. Yes. As previously approved by the Florida Public Service Commission in Docket 130198-EI, Order No. PSC-13-0505-PAA-EI, FPL has contracted with Sabal Trail and FSC for incremental gas transportation capacity of 400,000 MMBtu/day beginning May 1, 2017 increasing to 600,000 MMBtu/day beginning May 1, 2020. This capacity is sufficient to meet FPL's system gas requirements including the addition of OCEC Unit 1 in 2019.

Q. Does FPL currently have natural gas delivery to OCEC Unit 1 site?

A. No. Because this is a greenfield site, there is currently no gas transportation service to the site. If OCEC Unit 1 is approved, FPL will work with FSC to construct the necessary facilities, including a lateral and metering equipment, which will be required to effectuate deliveries to OCEC Unit 1.

Q. Has the cost of the additional gas transportation facilities been included in the evaluation of OCEC Unit 1?

A. Yes, FPL has included the estimated cost of these facilities in the evaluation of OCEC Unit 1.

Q. Will OCEC Unit 1 have a backup fuel source in the event of a natural gas supply disruption?

A. Yes. OCEC Unit 1 will be capable of burning light fuel oil in the event of a natural gas supply disruption. Light fuel oil will be trucked to the site and stored on-site in sufficient quantities to allow the site to operate at full capacity for seventy-two (72) hours of continuous operation.

Q. Does this conclude your direct testimony?

A. Yes.

FPL'S NOVEMBER 3, 2014 FUEL PRICE FORECAST

	NATURAL GAS			OIL			COAL			
YEAR	FLORIDA GAS TRANSMISSION $/MMBTU	GULFSTREAM $/MMBTU	FLORIDA SOUTHEAST CONNECTION / SABAL TRAIL $/MMBTU	MARTIN PLANT RESIDUAL 0.7% $/MMBTU	MANATEE / TURKEY POINT PLANTS RESIDUAL 0.7% $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	SCHERER 4 $/MMBTU	INDIANTOWN COGEN $/MMBTU	CEDAR BAY $/MMBTU	ST. JOHNS $/MMBTU
2015	$4.02	$3.99		$12.79	$12.43	$19.76	$2.53	$5.12	$3.21	$3.25
2016	$4.11	$4.06		$13.29	$12.92	$19.92	$2.87	$5.25	$3.39	$3.45
2017	$4.10	$4.06	$4.11	$13.37	$13.01	$20.18	$3.00	$5.38	$3.59	$3.59
2018	$4.36	$4.31	$4.36	$13.58	$13.22	$20.80	$3.11	$5.52	$3.74	$3.74
2019	$4.70	$4.65	$4.69	$14.91	$14.55	$22.62	$3.14	$5.66	$3.86	$3.86
2020	$5.16	$5.11	$5.14	$16.16	$15.79	$24.19	$3.20	$5.80	$3.73	$3.73
2021	$5.56	$5.51	$5.53	$17.47	$17.11	$25.76	$3.27	$5.95	$3.77	$3.77
2022	$5.87	$5.81	$5.83	$17.81	$17.45	$26.60	$3.34	$6.10	$3.94	$3.94
2023	$6.11	$6.05	$6.06	$18.39	$18.03	$27.37	$3.41	$6.25	$4.07	$4.07
2024	$6.30	$6.23	$6.24	$19.32	$18.96	$28.37	$3.49	$6.41	$4.16	$4.16
2025	$6.49	$6.42	$6.43	$20.62	$20.26	$29.41	$3.57	$6.57	$4.24	$4.24
2026	$6.69	$6.62	$6.62	$21.43	$21.07	$30.41	$3.65	$6.74	$4.34	$4.34
2027	$6.89	$6.82	$6.82	$22.29	$21.92	$31.44	$3.73	$6.91	$4.44	$4.44
2028	$7.10	$7.02	$7.02	$23.14	$22.77	$32.46	$3.82	$7.08	$4.55	$4.55
2029	$7.32	$7.24	$7.23	$24.07	$23.71	$33.47	$3.91	$7.26	$4.66	$4.66
2030	$7.53	$7.45	$7.44	$25.05	$24.68	$34.53	$4.00	$7.44	$4.77	$4.77
2031	$7.76	$7.68	$7.66	$25.80	$25.43	$35.35	$4.09	$7.63	$4.92	$4.92
2032	$7.99	$7.90	$7.88	$26.56	$26.20	$36.18	$4.20	$7.83	$5.07	$5.07
2033	$8.22	$8.13	$8.11	$27.33	$26.97	$37.00	$4.31	$8.02	$5.22	$5.22
2034	$8.39	$8.30	$8.27	$28.10	$27.73	$37.82	$4.43	$8.23	$5.38	$5.38
2035	$8.55	$8.46	$8.43	$28.86	$28.50	$38.67	$4.55	$8.43	$5.55	$5.55
2036	$8.76	$8.66	$8.63	$29.31	$28.94	$39.32	$4.67	$8.65	$5.71	$5.71
2037	$8.97	$8.87	$8.83	$29.76	$29.39	$39.98	$4.80	$8.87	$5.87	$5.87
2038	$9.18	$9.08	$9.04	$30.21	$29.85	$40.66	$4.92	$9.09	$6.02	$6.02
2039	$9.40	$9.30	$9.26	$30.67	$30.31	$41.34	$5.05	$9.32	$6.17	$6.17
2040	$9.63	$9.52	$9.48	$31.14	$30.78	$42.04	$5.19	$9.56	$6.32	$6.32
2041	$9.86	$9.75	$9.70	$31.62	$31.26	$42.75	$5.32	$9.80	$6.48	$6.48
2042	$10.10	$9.99	$9.93	$32.11	$31.74	$43.47	$5.46	$10.05	$6.64	$6.64
2043	$10.34	$10.23	$10.17	$32.60	$32.24	$44.21	$5.61	$10.30	$6.80	$6.80
2044	$10.59	$10.47	$10.41	$33.10	$32.74	$44.96	$5.76	$10.56	$6.96	$6.96
2045	$10.84	$10.72	$10.65	$33.61	$33.24	$45.72	$5.91	$10.83	$7.13	$7.13
2046	$11.10	$10.98	$10.91	$34.12	$33.76	$46.49	$6.06	$11.10	$7.31	$7.31
2047	$11.37	$11.24	$11.16	$34.65	$34.29	$47.28	$6.22	$11.38	$7.49	$7.49
2048	$11.64	$11.51	$11.43	$35.18	$34.82	$48.08	$6.39	$11.67	$7.67	$7.67
2049	$11.92	$11.79	$11.70	$35.72	$35.36	$48.90	$6.56	$11.96	$7.86	$7.86

FPL'S OCTOBER 7, 2013 FUEL PRICE FORECAST

	NATURAL GAS			OIL						COAL			
YEAR	FLORIDA GAS TRANSMISSION $/MMBTU	GULFSTREAM $/MMBTU	FLORIDA SOUTHEAST CONNECTION / SABAL TRAIL $/MMBTU	MARTIN PLANT RESIDUAL 0.7% $/MMBTU	MANATEE / TURKEY POINT PLANTS RESIDUAL 0.7% $/MMBTU	TURKEY POINT DISTILLATE $/MMBTU	FORT MYERS DISTILLATE $/MMBTU	PORT EVERGLADES / LAUDERDALE DISTILLATE $/MMBTU	WCEC / PUTNAM / MARTIN / CANAVERAL / RIVIERA DISTILLATE $/MMBTU	SCHERER 4 $/MMBTU	INDIANTOWN COGEN $/MMBTU	CEDAR BAY $/MMBTU	ST. JOHNS $/MMBTU
2015	$4.26	$4.25		$14.61	$14.45	$22.70	$22.41	$22.13	$22.27	$2.48	$5.90	$3.80	$3.58
2016	$4.51	$4.50		$15.28	$15.12	$23.28	$22.98	$22.71	$22.84	$3.28	$6.05	$3.93	$3.69
2017	$4.93	$4.92	$4.92	$15.23	$15.08	$23.72	$23.42	$23.15	$23.28	$3.31	$6.20	$3.88	$3.88
2018	$6.00	$5.98	$5.99	$17.23	$17.08	$25.07	$24.77	$24.50	$24.64	$3.40	$6.35	$4.00	$4.00
2019	$6.15	$6.13	$6.14	$17.65	$17.49	$25.60	$25.30	$25.03	$25.16	$3.22	$6.52	$4.09	$4.09
2020	$6.31	$6.29	$6.30	$18.18	$18.03	$26.29	$26.00	$25.73	$25.86	$3.29	$6.68	$4.18	$4.18
2021	$6.41	$6.39	$6.40	$19.08	$18.92	$27.51	$27.21	$26.94	$27.08	$3.37	$6.85	$4.28	$4.28
2022	$6.62	$6.59	$6.60	$19.89	$19.74	$28.80	$28.51	$28.24	$28.37	$3.45	$7.02	$4.38	$4.38
2023	$6.93	$6.90	$6.91	$20.88	$20.72	$30.05	$29.76	$29.49	$29.62	$3.54	$7.20	$4.49	$4.49
2024	$7.34	$7.31	$7.33	$21.88	$21.73	$31.26	$30.96	$30.69	$30.83	$3.63	$7.38	$4.61	$4.61
2025	$7.65	$7.61	$7.63	$22.89	$22.73	$32.43	$32.13	$31.86	$32.00	$3.72	$7.57	$4.73	$4.73
2026	$7.96	$7.92	$7.94	$23.30	$23.14	$33.07	$32.77	$32.50	$32.64	$3.82	$7.76	$4.86	$4.86
2027	$8.26	$8.22	$8.25	$23.76	$23.60	$33.68	$33.38	$33.11	$33.25	$3.92	$7.96	$4.99	$4.99
2028	$8.68	$8.63	$8.66	$24.17	$24.01	$34.25	$33.95	$33.68	$33.81	$4.02	$8.16	$5.12	$5.12
2029	$8.99	$8.94	$8.97	$24.65	$24.49	$34.84	$34.54	$34.27	$34.41	$4.12	$8.36	$5.25	$5.25
2030	$9.19	$9.14	$9.18	$25.09	$24.93	$35.42	$35.13	$34.86	$34.99	$4.22	$8.58	$5.39	$5.39
2031	$9.54	$9.48	$9.53	$25.49	$25.34	$36.02	$35.72	$35.45	$35.59	$4.32	$8.79	$5.52	$5.52
2032	$9.90	$9.84	$9.89	$25.90	$25.74	$36.63	$36.33	$36.06	$36.20	$4.42	$9.01	$5.66	$5.66
2033	$10.27	$10.21	$10.26	$26.31	$26.16	$37.25	$36.95	$36.68	$36.81	$4.53	$9.24	$5.81	$5.81
2034	$10.66	$10.60	$10.65	$26.74	$26.58	$37.88	$37.58	$37.31	$37.44	$4.64	$9.48	$5.96	$5.96
2035	$11.06	$10.99	$11.05	$27.16	$27.01	$38.52	$38.22	$37.95	$38.08	$4.75	$9.72	$6.23	$6.23
2036	$11.48	$11.41	$11.47	$27.60	$27.44	$39.17	$38.87	$38.60	$38.74	$4.86	$9.96	$6.46	$6.46
2037	$11.92	$11.84	$11.90	$28.04	$27.88	$39.83	$39.53	$39.26	$39.40	$4.96	$10.21	$6.52	$6.52
2038	$12.37	$12.28	$12.35	$28.49	$28.33	$40.51	$40.21	$39.94	$40.08	$5.08	$10.47	$6.55	$6.55
2039	$12.83	$12.75	$12.82	$28.95	$28.79	$41.20	$40.90	$40.63	$40.76	$5.19	$10.74	$6.58	$6.58
2040	$13.32	$13.23	$13.31	$29.41	$29.26	$41.90	$41.60	$41.33	$41.46	$5.31	$11.01	$6.61	$6.61
2041	$13.82	$13.72	$13.81	$29.88	$29.73	$42.61	$42.31	$42.04	$42.18	$5.43	$11.29	$6.64	$6.64
2042	$14.35	$14.24	$14.33	$30.36	$30.21	$43.34	$43.04	$42.77	$42.90	$5.55	$11.57	$6.68	$6.68
2043	$14.89	$14.78	$14.88	$30.85	$30.70	$44.07	$43.78	$43.51	$43.64	$5.68	$11.86	$6.72	$6.72
2044	$15.45	$15.34	$15.44	$31.35	$31.19	$44.83	$44.53	$44.26	$44.39	$5.81	$12.16	$6.77	$6.77
2045	$16.04	$15.91	$16.02	$31.85	$31.69	$45.59	$45.30	$45.02	$45.16	$5.94	$12.47	$6.84	$6.84
2046	$16.64	$16.51	$16.63	$32.36	$32.21	$46.37	$46.07	$45.80	$45.94	$6.07	$12.79	$6.92	$6.92
2047	$17.27	$17.14	$17.26	$32.88	$32.73	$47.17	$46.87	$46.60	$46.73	$6.21	$13.11	$7.03	$7.03
2048	$17.92	$17.78	$17.91	$33.41	$33.26	$47.97	$47.68	$47.40	$47.54	$6.35	$13.44	$7.16	$7.16
2049	$18.60	$18.46	$18.59	$33.95	$33.79	$48.80	$48.50	$48.23	$48.36	$6.50	$13.78	$7.30	$7.30