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October 8, 2013

Ms. Ann Cole, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

ELECTRONIC FILING

Re: Duke Energy Florida, Inc. Request for Proposals

Dear Ms. Cole:

Pursuant to Rule 25-22.082, Florida Administrative Code, Duke Energy Florida, Inc. is filing herewith Duke Energy Florida, Inc.'s Request for Proposals for Long-term Power Supply Resources with an In-service Year of 2018 with Attachments.

If you or your Staff have any questions regarding this filing, please contact me at (813) 229-4257.

Sincerely,

James Michael Walls on behalf of
Duke Energy Florida, Inc.

Attachment

Duke Energy Florida, Inc.

10/8/13

Request for Proposals

For Long-term Power Supply Resources
With an In-service Year of 2018

DEF 2018 RFP

DEF 2018 RFP Document

TABLE OF CONTENTS

Attachments:

DEFINITIONS

Presented below are DEF definitions of critical terms used in this RFP and solicitation process. Other definitions are included in the Key Terms & Conditions.

Area Control Error (ACE): The difference between scheduled and actual interchange measured by a control area, taking into account the effects of frequency bias including a correction for meter error.

Automatic Generation Control (AGC): AGC is the automated regulation, within predetermined limits, of the power output of electric generators within a prescribed geographic area in response to changes in system frequency, tie-line loading, or the relation of these to each other, so as to maintain the scheduled system frequency and/or the established interchange with other geographic areas. This regulation will be accomplished through communication links between DEF's Energy Control Center dispatch computer and each generator equipped with such AGC control.

Availability Adjustment Factor (AAF): A measure of a Facility's or Bidder's ability to provide capacity in the amount requested by DEF. The Availability Adjustment Factor is defined in Section 2 of the Key Terms and Conditions (Attachment A).

Bidder: Any entity that submits a proposal to DEF in response to this RFP.

Block Schedule: A transaction where the generator or sending control area adjusts its generation on a 10 minute ramp to accommodate a static amount of capacity represented by an energy profile which is scheduled to flow to a load or sink control area.

Dynamic Schedule: A telemetered reading that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling generation to or from another control area.

Equivalent Availability Factor (EAF): Sum of the Equivalent Unplanned Derated Hours (EUDH) and Equivalent Planned Derated Hours (EPDH) subtracted from Available Hours (AH) and divided by Period Hours (PH). The method for calculating the Equivalent Availability Factor is defined in the discussion of Section II.H of the Response Package.

Equivalent Forced Outage Rate (EFOR): Sum of Forced Outage Hours (FOH) and Equivalent Forced Derated Hours (EFDH) divided by the sum of Forced Outage Hours (FOH) and Service Hours (SH). The method for calculating the Equivalent Forced Outage Rate is defined in the discussion of Section II.H of the Response Package.

Existing Unit Proposal: A bid to provide capacity and energy from a specific generating unit already in commercial operation and identified by the Bidder.

Facility: All of the equipment, property, buildings, and generation and transmission-interconnection facilities necessary to allow the Bidder to fulfill its proposal to provide capacity and energy to DEF pursuant to this RFP.

Forced Outage: An unplanned component failure (immediate, delayed, postponed, or start failure) or other condition that requires the unit be removed from service immediately, within six hours, or before the end of the next weekend, consistent with industry standards.

Frequency Control: The capability of a generator to automatically respond to frequency deviations by increasing or decreasing its gross real power output as a result of governor action.

For generation resources located inside the DEF control area or dynamically telemetered into the DEF control area:
The Bidder's generator(s) shall be equipped with fully functional governors with droop adjustable from 2% to 6% and nominally set at 4%. The governors will be fully responsive to frequency deviations exceeding 0.036 Hertz (Hz).

For generation resources located outside the DEF control area:
The Bidder shall comply with the frequency response requirements of the host control area.

Fully Dispatchable: A generating resource is Fully Dispatchable when DEF makes the sole decision to dispatch/operate the unit with exceptions granted for maintenance and testing. For generating resources located in DEF's control area and to qualify as Fully Dispatchable, the generator must be equipped with and controllable through an AGC link with DEF's Energy Control Center. For offers relating to a unit-contingent generating resource located outside of DEF's control area and to qualify as Fully Dispatchable, the generator must provide Dynamic or a combination of Dynamic/Block scheduling that is tied into DEF's Energy Control Center. Fully Dispatchable generating facilities must be available for DEF's dispatch instructions and control, in accordance with specific operating parameters (minimum load, ramp rates, start time, maximum starts per year, annual operating hour limit, and minimum run time) with the specifications for such parameters set forth by the Bidder in its proposal. Unit-contingent resources committed to DEF but not dispatched by DEF for a particular period will not be available to other market participants.

Fully Schedulable: A System Power Proposal is Fully Schedulable when its output is controlled and determined by a schedule specified by DEF. While such specific schedule would be established under the terms of an agreement with DEF, DEF expects that a schedule would be tentatively established on a day-ahead basis (i.e., by 4:00 p.m. for deliveries on the following day) and revised as necessary on a day-to-day basis to respond to unanticipated operating requirements subject to normal utility practice.

Minimum Technical Requirements: The minimum technical requirements that all proposals are required to meet and with which a Bidder's compliance will be assessed in Step 3 of the evaluation process (see Section III.B.3.b.i). Minimum Technical Requirements must be met to proceed beyond Step 3 of the evaluation process.

New Unit Proposal: A bid to provide capacity and energy from a new unit or block of units which is not currently in commercial operation and which is specifically identified by the Bidder.

Official Contacts: The DEF representative, and designee, identified in Section I.E of this RFP to whom all contact regarding this solicitation process must be made.

Power System: Physically connected generation and transmission facilities operated as an integrated unit under one central management or operating supervision.

Response Package: The second section of this RFP that identifies the information and schedules that Bidders are required to provide in their proposals to DEF.

RFP Project Team: A group of individuals with backgrounds in a number of disciplines necessary to conduct a thorough evaluation of each proposal. The individuals may be Duke Energy employees or consultants.

Seasonal Contract Capacity (SCC): The Summer Contract Capacity and the Winter Contract Capacity, as applicable, with the summer and winter seasons as defined in Section II.E of the Response Package (attachment C). For New and Existing Unit Proposals, the capacities are the values specified by the Bidder in Schedule 1 of the Response Package in the section labeled "Seasonal Contract Capacity." For System Power Proposals, the capacities are the values specified by the Bidder in Schedule 2 of the Response Package.

Self-Build Option: The proposal that will be developed by DEF and submitted to the RFP process along the same schedule as any other offers submitted in response to the RFP. Certain filing requirements do not apply to the Self-Build Option, including for example, acceptance of Key Terms and Conditions (since there would be no power purchase agreement for a Self-Build Option), and informational requirements regarding Bidder experience and credit quality.

Summer Contract Capacity: The maximum capacity (MW) the Facility can sustain during the Summer period, less the capacity utilized for station service or auxiliaries, and adjusted for losses to the delivery point in the DEF control area.

System Power Proposal: A bid to provide capacity and energy from a Power System.

Technical Criteria: Attributes of proposals that go beyond the Minimum Technical Requirements and which offer value to DEF's customers, as evaluated in Step 3 and as described in Section III.B.3.b.ii.

Threshold Requirements: The minimum requirements that all proposals are required to meet and with which a Bidder's compliance will be assessed in Step 1 of the evaluation process (reference Section III.B.1).

Unit Reliability Program: The program for unit operations and maintenance identified by Bidders. This program may take the form of identification of plans to conclude one or more

Long Term Service Agreements (LTSA) with equipment vendors, description of a self-performed maintenance plan, demonstration of a track record of unit availability in units committed to this proposal or other similar units.

Voltage Control: The ability to modify generator terminal voltage by varying the current in the generator's field winding either automatically by appropriate control mechanisms or manually by the operator.

For generation resources located inside the DEF control area or dynamically telemetered into the DEF control area:
The Bidder's generator(s) shall be equipped with fully functional automatic voltage regulators that will control the generator terminal voltage according to a Voltage Schedule provided by DEF unless directed otherwise by the DEF Energy Control Center.

For generation resources located outside the DEF control area:
The Bidder shall comply with the voltage control requirements of the host control area.

Winter Contract Capacity: The maximum capacity (MW) the Facility can sustain during the Winter period, less the capacity utilized for station service or auxiliaries, and adjusted for losses to the delivery point in the DEF control area.

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I. INTRODUCTION

A. Overview of DEF 2018 Request for Proposals ("RFP" or "DEF 2018 RFP")

Duke Energy Florida ("DEF" or "Company") is seeking proposals from potential suppliers of electric generating capacity and associated energy as described herein. In this RFP, DEF is soliciting proposals for alternatives to the Company's next planned generating unit ("NPGU"), which is approximately 1,640 MW (summer) in 2018 with a minimum of 820 MW in service no later than May 1, 2018 with the balance of the capacity to be in service no later than December 1, 2018.

DEF invites all potential participants to submit bids in accordance with the terms and conditions of this RFP. DEF's NPGU is a natural gas-fired combined-cycle ("CC") resource generally described in Section IV of this RFP. However, the Company will consider other resource types. Proposals received shall be evaluated in accordance with applicable rules, regulations, and statutes. The following are summaries of the RFP documents along with some Key RFP information.

This DEF 2018 RFP document includes the following four Attachments:

- Attachment A: Key Terms and Conditions
- Attachment B: DEF 2013 Ten-Year Site Plan ("TYSP")
- Attachment C: Bidders Response Package (Instructions)
- Attachment D: Bidders Response Schedules/Forms (Excel Version)

Summary of some key DEF 2018 RFP information:

- Capacity and energy must be from a dispatchable supply-side resource.
- The RFP allows for creative responses which employ innovative or inventive technologies or processes.
- Resources must be considered firm capacity including firm deliverability into DEF.
- The RFP allows for both Tolling and Purchase Power arrangements.
- Existing and new capacity, including system power sales, are acceptable.
- In addition to their base proposal, Bidders may supply up to two variations (such as power augmentation, operating reliability impacts or financing terms) in project term and/or pricing at no additional cost.
- The DEF NPGU is a Combined Cycle with a capacity of 1,640 MW (summer) in Citrus County, FL.
- A minimum of 820 MW (summer) are required to be in service no later than May 1, 2018 with the balance of the capacity available no later than December 1, 2018.
- DEF will not accept external bid projects on DEF properties.
- Acceptable bid proposal must not exceed a maximum of 1,640 MW (net summer).
- DEF is seeking delivery terms in the range of 15 to 35 years.

DEF will utilize a Third Party Independent Monitor throughout the RFP process. Also, DEF will utilize Power Advocate as the web-base interface tool for posting and responding to the RFP. Power Advocate is a nationally recognized RFP web tool that is commonly used by Duke Energy ("DE") for various types and sizes of RFPs. All documents for this RFP will be maintained on Power Advocate's web site ("RFP web site'). DE will also provide a link from the Duke Energy RFP home page to the Power Advocate web site for this RFP as shown below. This DEF link will contain initial RFP documents and related bidder material prior to a bidder registering with Power Advocate. In addition, DEF reserves the right to post to the Power Advocate website written responses to questions from potential participants if DEF, in its sole discretion, deems it necessary to ensure that all potential participants have equal access to certain information.

DEF initial RFP information and link to Power Advocate RFP web site for RFP registration:

htpp://www.duke-energy.com/floridarfp

B. Objectives of the RFP

The purpose of the RFP is to solicit competitive proposals for supply-side alternatives to DEF's NPGU. DEF's intent is to select resources that offer the maximum value, based on price and non-price attributes, to the Company's customers. During its normal course of business, DEF regularly evaluates resource alternatives to fulfill its need for long-term system resources. As a result, DEF has identified as its NPGU the natural gas fired combined cycle resource generally described in Section IV of this RFP. DEF, however, reserves the right to cancel, modify or withdraw the RFP, to reject any or all responses, and to terminate negotiations at any time during the RFP process.

C. DEF's Year 2018 Resource Needs

DEF has a need for 1,640 MW (summer) in the year 2018, a minimum of 820 MW of which must be in service no later than May 1, 2018 with the balance of the capacity available no later than December 1, 2018. DEF's NPGU, subject to approval under the conditions specified in Rule 25-22.082 Florida Administrative Code, is the Citrus CC1, located in Citrus County Florida.

A detailed technical description, as well as the financial assumptions and parameters associated with the Citrus CC1, are provided in Section IV of this RFP.

D. Schedule

A schedule for critical dates for the solicitation, evaluation, screening of proposals, and subsequent negotiations follow:

A. Solicitation	
Pre-Release of RFP	9/24/2013
Pre-Release Meeting	10/2/2013
Issuance of RFP	**10/8/2013**
Bidders Meeting	10/18/2013
Submission of Proposals	**12/9/2013 by 3:00 pm**
B. Evaluation and Screening of Proposals	
Selection of Short List	Expected by 3/2014
Selection of Finalist(s)	**Expected by 5/2014**
C. Negotiations	
Initiate Negotiations	Expected by 5/2014
Clarifications and Adjustments	Expected by 6/2014
Award Announcement	Expected by 8/2014
D. Regulatory Filings	
File for certification	Expected by 9/2014

DEF reserves the right to revise the schedule at any time, at DEF's sole discretion. Depending on DEF's requirements to review the proposals, DEF may shorten or lengthen the schedule and revise the dates associated with the schedule.

The Pre-Release and Bidder meetings are scheduled for October 2 and October 18, respectively, at the Tampa Marriott Westshore, 1001 N Westshore Blvd, Tampa, Florida 33607 (1:00 – 3:00pm, each day in conference room Cotillion-Terrace).

E. Official Contact Persons

All inquiries or contact regarding this RFP, including questions of clarification and requests for additional information must be submitted to both the DEF RFP Contact and the Independent Monitor/Evaluator ("IM/E") Contact as listed below.

DEF RFP Contact and	**Independent Monitor/Evaluator Contact**
Benjamin Borsch	
Duke Energy Florida (DEF16)	Sedway Consulting, Inc.
299 1st Ave North	821 15th St,
St. Petersburg, FL 33701	Boulder, Colorado 80302
Telephone number: (727) 820-4781	Telephone number: (303) 581-4172
E-mail address:	E-mail address:
DEF2018RFP@duke-energy.com	Alan.Taylor@sedwayconsulting.com

Unsolicited contact with other DEF personnel or employees of DEF affiliated companies concerning the RFP is not allowed and will constitute grounds for disqualification. DEF reserves the right to provide written responses to all Bidders on the Power Advocate DEF 2018 RFP web site (www.duke-energy.com/floridarfp) if DEF, at its sole discretion, deems it necessary to ensure that all Bidders have equal access to certain information.

II. INFORMATION AND RESPONSIBILITIES FOR BIDDERS

A. General Instructions

Bidders to this RFP are required to meet all of the terms and conditions of the RFP to be eligible to compete in the solicitation process. In submitting their proposals, Bidders are required to follow all instructions contained in the RFP. Bidders must respond to all questions contained in the Response Package (Attachment C), use the provided Microsoft Excel schedules (Attachment D), organize their proposals according to the structure specified in the Response Package (*i.e.*, organized by chapter and section in the order specified by DEF), and provide supporting documentation in the format requested.

Bidders should include the Project Name, chapter and section numbers, and page number on each attachment. If a question is not applicable to the type of proposal submitted, Bidders should so indicate and specify why the requested information is not applicable to a particular proposal. This requirement is in place to assist the Bidders and DEF in assuring that no question has been overlooked and to provide all relevant information needed to evaluate the proposals. It is the Bidder's responsibility to advise DEF's Official Contacts of any conflicting requirements, omissions of information, or the need for clarification before bids are due. Bidders should clearly organize and identify all information submitted in their proposals to facilitate review and evaluation.

A Bidder's failure to provide all of the information for a proposal as requested in this solicitation process or to demonstrate that the proposal satisfies all of the Threshold Requirements and Minimum Technical Requirements identified in Section III will be grounds for disqualification.

Bidders should identify and clearly mark all confidential and proprietary information contained in its proposals as "Confidential". DEF and the IM/E will use its best efforts to protect the confidentiality of such information and only release such information on a need-to-know basis to the members of the RFP Project Team, management, agents and contractors, and, as necessary and consistent with applicable laws and regulations, to its affiliates and regulatory commissions. DEF's and the IM/E use of confidential information will be for the purpose of evaluating resource options for DEF. In no event shall DEF or the IM/E be liable to a Bidder for any damages of whatsoever kind resulting from DEF's or the IM/E failure to protect the confidentiality of the Bidder's information. By submitting a proposal, the Bidder agrees to allow

DEF and the IM/E to use all information provided and the results of the evaluation as evidence in any proceeding before the Florida Public Service Commission ("FPSC" or "Commission"). To the extent DEF and the IM/E wishes to use information before the FPSC that a Bidder considers confidential, DEF or the IM/E, as applicable, will request that the Commission treat such information as confidential and to limit its dissemination, but DEF and the IM/E cannot and will not make any assurance of the outcome of any such request.

All correspondence between potential Bidders and DEF must be through both the Official Contact Persons (DEF and IM/E) and all questions concerning this RFP must be submitted in writing. DEF will attempt to respond within a reasonable length of time to Bidders' requests and questions. Written responses, as determined appropriate by DEF, may be posted via the RFP web site. Potential bidders are responsible for periodically checking the DEF RFP website to see whether new questions and answers regarding the RFP have been posted.

B. Submission of Proposals

All proposals **must be received by DEF by 3:00 PM EST on December 9, 2013**. Proposals must be submitted to the DEF Official Contact through the Power Advocate web tool.

For each proposal, Bidders must submit a complete bid package consisting of all of the information required as described on the Power Advocate RFP web site for this DEF2018RFP by December 9, 2013. Additionally, a copied version of the submitted proposal in electronic format and provided on a flash-drive should be delivered to the IM/E at the Sedway Consulting address listed for the Official Contacts in Section I.E. no later than December 10, 2013.

The Response Package in Attachment C contains directions regarding the type and form of information Bidders are required to provide on the Power Advocate web site.

C. Proposal Fees/ Proposal Variations

Proposals Fees: Bidders may submit as many proposals as they desire. To help defray the cost of performing the proposal evaluations, including necessary internal DEF Transmission evaluations, Bidders are required to submit for each proposal a submittal fee of $20,000. All such submitted fees shall be non-refundable. The fee should be in the form of a check payable to "Duke Energy Florida, Inc." and delivered to the Official DEF Contact at the St. Petersburg address shown in I.E. no later than December 10, 2013.

Additional Federal Energy Regulatory Commission ("FERC") related Transmission Feasibility, Transmission Impact, and Transmission Facility Requests will follow related FERC Transmission processes and costs (see Section F below).

Variations: Bidders are allowed to propose up to a total of two variations (such as power augmentation, operating reliability impacts, commercial operation date, or financing terms) in project term and/or pricing at no additional cost. Bidders must submit a complete electronic version of the Response Package for each variation.

D. *Proposal Terms and Conditions*

As discussed above and provided within this document, DEF is seeking proposals for power supply resources to meet a need of 1,640 MW (summer) in 2018 with a minimum of 820 MW in service no later than May 1, 2018 with the balance of the capacity to be in service no later than December 1, 2018. Consistent with DEF's need, the maximum size of proposal should be approximately 1,640 MW (summer).

Capacity and energy proposed to DEF under this proposal should be available no earlier than March 1, 2018 with a minimum of 820 MW in service no later than May 1, 2018 with the balance of the capacity to be in service no later than December 1, 2018. The earliest contract end date for the delivery of capacity and energy should be May 1, 2033 (15 years). The latest contract end date for the delivery of capacity and energy to DEF should be May 1, 2053 (35 years).

Terms and Conditions ("T&C") are provided in Attachment A. As part of a Bidder's proposal, the Bidder shall provide comments (in electronically redlined form), to the T&C form(s) that is/are applicable to such Bidder's proposal(s).

E. *Contract Flexibility Provisions*

DEF is interested in creative responses that employ innovative or inventive technologies or processes that can meet the RFP requirements. Also, bidders are encouraged to offer contract flexibility provisions within their proposals. Possible provisions include, but are not limited to, contract term extension options in which bidders propose an initial contract term and provide DEF the option to extend the contract at predefined prices, options to terminate or buy out the contract, or options to shorten or terminate the contract in the event of any federal or state legislative or regulatory actions, including but not limited to amendments to the Florida Power Plant Siting Act, new North American Electric Reliability Corporation ("NERC") Standards or revisions to existing Standards, or new FRCC Standards or revisions to existing FRCC Standards that represent a material change to the contract or the electric utility industry in Florida. Within the context of any particular proposal, for the purpose of payment of proposal fees, as described in Section II.C, above, the offering of such flexibility provisions will not constitute another offer.

DEF has ongoing requests for power for Renewable and Qualifying Facility resources and suppliers who wish to offer such resources are encouraged to use this process at the following web site:

https://www.progress-energy.com/florida/home/renewable-energy/sell.page

F. *Generator Interconnection Requests and Transmission System Analyses*

DEF requires that all resources procured through the RFP process be deliverable via Firm Transmission Service to serve loads during the term of the agreement. Therefore, resources need to be either (a) located within and interconnected to DEF's transmission system, with any Generator interconnection facilities and/or transmission upgrades necessary to allow the resource to qualify as a designated network resource pursuant to the DEF Open Access Transmission Tariff ("OATT"), or (b) located outside DEF's system, with any interconnection facilities and/or transmission upgrades necessary to allow the resource to be deliverable to the DEF interface on a firm point-to-point basis as well as transmission upgrades necessary to allow the resource to qualify as a designated network resource pursuant to the DEF OATT.

As noted in Section II.E of the Response Package in Attachment C, Bidders who offer resources located outside of the DEF system will be responsible for coordinating with other transmission system owners, as appropriate, for securing firm point to point transmission service for delivery of the resource capacity and energy to the DEF system interface. If Bidders desire DEF to pay for any transmission-related costs, including interconnection, wheeling and upgrade costs of other transmission systems, then Bidders must include any such transmission-related costs in Schedule 1 (or Schedule 2, as applicable) of the Response Package.

As part of their submissions in response to this RFP, Bidders must complete the Transmission Information Schedule (Schedule 7 of the Response Package) and provide the data and information needed for DEF to conduct the analyses.

DEF 2018 RFP and DEF OATT Transmission bidder Information:

A summary of the procedures to be followed during the DEF 2018 RFP with respect to the DEF OATT bidder information is provided below. For reference, the DEF OATT can be accessed via the following internet link:

http://www.ferc.duke-energy.com/Joint_OATT.pdf

1. New Unit Proposals Inside the DEF System

a. Generator Interconnection Request

- New Unit Proposals physically located inside the DEF system will be required to submit a complete Large Generator Interconnect Agreement ("LGIA") application and a $10,000 deposit (refundable) pursuant to the DEF OATT in order to participate in the RFP. If site control is not demonstrated then an additional $10,000 deposit (non-refundable) is also required pursuant to the DEF OATT. Once DEF has reviewed the submitted application and deemed it complete, a generator queue position will be assigned and posted on the DEF Open Access Same-Time Information System ("OASIS").
- DEF plans to utilize the option within the DEF OATT LGIA process that allows DEF and the interconnection customer to delay the scheduling of the scoping meeting for the LGIA request. The provision will allow the LGIA queue request process to pause until such time as it is clear that the new unit proposal has been selected for the RFP short list. (See DEF OATT attachment J, 3.3.4.)

- If the bidder is selected for the short list, DEF will schedule the LGIA scoping meeting and the DEF OATT LGIA process will proceed forward. Additional studies and deposits are required and those will proceed sequentially pursuant to the DEF OATT. DEF will use the results of the previously completed RFP screening studies to the extent possible to defray the work (and cost) involved. The remainder of the OATT LGIA process requires an Interconnection Feasibility Study, Interconnection System Impact Study, and Interconnection Facilities Study with deposits of $10,000, $50,000 and $100,000 respectively. The deposits are intended to cover the actual study costs and any balances are refundable to the interconnection customer. If a New Unit Proposal falls out of contention for the RFP, DEF will consider the LGIA request as withdrawn and refund the deposit balance to the customer.
- Bidders of New Unit Proposals that will interconnect to DEF's system will be required to complete all forms and processes included in Schedule 7 of the Response Package.

2. All Other Proposals

- All other proposals (New Unit Proposals outside the DEF system, Existing Unit Proposals inside or outside the DEF system, and System Power Proposals) will be required to complete all forms and processes included in Schedule 7 of the Response Package. Bidders of New Unit Proposals to be located on another system will be required to complete all forms and processes included in Schedule 7 of the Response Package.

3. Transmission Service Requests

- Ultimately, DEF as the load serving entity is the DEF system transmission customer and will be responsible for making the formalized request(s) to designate the selected options as designated network resource(s) pursuant to the DEF OATT. The bidders themselves do not have to request transmission service on the DEF system for any of the types of proposals that are described in this document. DEF as the load serving entity will make the appropriate Transmission service request for DNR status for the option(s) that proceed to the RFP negotiation stage (See section I, item D above).
- The bidders are responsible for making requests for transmission service on other transmission systems as needed to obtain service to deliver to the DEF interface.

G. Credit/Security Requirements

DEF will require financial security to ensure the project is completed on schedule and is operated effectively and reliably.

The amount of security required from the seller is a function of the credit rating of the Seller, the structure of the capacity payments, and DEF's market exposure related to the agreement. In general, the amount required increases during the development of the facility and decreases during the term of the agreement, subject to variation based on future market conditions.

Security required for new projects to be developed is shown in the table below.

SECURITY SCHEDULE – NEW PROJECTS		
Timing	Amount	Cumulative Amount
30 days after contract signing	$40/kW	$40/kW
12 months after contract signing	$20/kW	$60/kW
24 months after contract signing	$20/kW	$80/kW
Earlier of 36 months after contract signing or within 30 days after commercial operation	$20/kW	$100/kW [(a)]
10 years after c/o	($50/kW)	$50/kW [(a)]
15 years after c/o	($20/kW)	$30/kW [(a)]
During contract term, based on market exposure [(b)]	Up to $100/kW	Up to $200/kW

The following table shows the security required for existing facilities.

SECURITY SCHEDULE – EXISTING FACILITIES		
Timing	Amount	Cumulative Amount
30 days after contract signing	$40/kW	$40/kW
Within 10 business days after beginning of term	$60/kW	$100/kW [(a)]
10 years after beginning of term	($50/kW)	$50/kW [(a)]
15 years after beginning of term	($20/kW)	$30/kW [(a)]
During contract term, based on market exposure [(b)]	Up to $100/kW	Up to $200/kW

Notes:

(a) Cumulative amount shown excludes the impact of any additional security required based on market exposure – see note (b).

(b) Additional security will be required in the event that DEF's market exposure exceeds the operational security that is otherwise required. DEF's market exposure represents the additional cost that would be required to replace the capacity and energy in the wholesale electric power markets or by constructing a new generation facility.

DEF will assign a Credit Limit to qualified Sellers based on the table below. In order to qualify for a Credit Limit, a Seller must maintain a credit rating from Standard & Poor's (S&P) or Moody's Investors Service (Moody's). A Seller may elect to provide a parent guarantee from a rated entity, in which case the assessment will be based on the guarantor's creditworthiness.

The Credit Limit will be calculated as a percentage of the Seller’s Tangible Net Worth, subject to a maximum amount as shown under Credit Limit Cap. If the S&P and Moody’s ratings are not equivalent, then the lower of the two will be used. The total required cash and letter of credit security as determined per above will be reduced by the Credit Limit amount as determined by reference to the table below. If at any time during the term of the agreement, the credit rating changes, then the amount of cash or letter of credit security will be adjusted accordingly.

Credit Rating from S&P / Moody's *	Percentage of TNW	Credit Limit Cap
A-/A3 or better	16%	$50,000,000
BBB+/Baa1	10%	$40,000,000
BBB/Baa2	10%	$30,000,000
BBB-/Baa3	8%	$30,000,000
Below BBB-	0%	$0

If during the term of the agreement DEF becomes entitled to terminate the agreement due to an event of default and if operation of the facility is not assumed by its lender(s) or its permitted assignee, then, in lieu of terminating the agreement, DEF will require the right to assume operational responsibility for the Facility to complete construction, continue operation, complete any necessary repairs, or take such other steps as are appropriate in the circumstances, or DEF may designate a third party or parties to do the same, so as to assure uninterrupted availability of capacity and deliverability of electric energy from the facility. Please see Section 3 of the T&C’s in Attachment A for further explanation of DEF’s rights upon default. (This provision will not apply to system sales.)

H. Permitting Responsibility

The Bidder(s) whose proposal is (are) selected will be responsible for acquiring in a timely fashion all necessary licenses, permits, certifications, and approvals required by federal, state and local government laws, regulations and policies for the design, construction, and operation of the project. In addition, the Bidder shall fully support all of DEF’s regulatory requirements associated with this potential power supply arrangement. The Bidder is also completely and solely responsible for securing financing for its project. DEF shall have no responsibility in identifying or securing any licenses, permits, or regulatory approvals (other than being a co-applicant in a Determination of Need filing and a co-applicant in the Certificate of Need proceeding under the Florida Electric Power Plant Siting Act) or in securing any financing required for the construction or operation of the project.

I. Regulatory Provisions

Any negotiated contract between DEF and the Bidder will be conditioned upon approval or acceptance without substantial change by any and all regulatory authorities that have, or claim to have, jurisdiction over any or all of the subject matter of this solicitation, including, without limitation, the FPSC, Florida Department of Environmental Protection ("FDEP") and the FRCC. Any such negotiated contract will be further conditioned upon favorable regulatory action without substantial condition or qualification (including but not limited to temporal or other conditions or limitations on cost recovery) by any and all regulatory authorities from which regulatory approval may be required for the contract or for the development or effectuation of the power supply project and related activities (including but not limited to a Determination of Need by the FPSC).

For new unit proposals, in accordance with Rule 25-22.082 of the Florida Administrative Code, each participant [Bidder] is required

> … to publish a notice in a newspaper of general circulation in each county in which the participant proposes to build an electrical power plant. The notice shall be at least one-quarter of a page and shall be published no later than 10 days after the date that the proposals are due. The notice shall state that the participant has submitted a proposal to build an electric power plant, and shall include the name and address of the participant submitting the proposal, the name and address of the public utility that solicited proposals, and a general description of each proposed power plant and its location.

Bidders are required to upload electronic copies of these actual published notices to the DEF Power Advocate Website and email a copy to the IM/E within seven (7) days of the notice appearing in the newspaper. The copy of this notice shall clearly indicate the name of the newspaper and the date on which the notice was published.

J. Reservation of Rights

DEF reserves the right to reject any, all, or portions of the proposals received for failure to meet any criteria set forth in this RFP. The Company also reserves the right in its sole discretion to decline to enter into a definitive, written agreement with any Bidder, or to abandon this RFP in its entirety. DEF reserves the right to revise the capacity need forecast at any point during the RFP process or during negotiations; any such change may reduce, eliminate, or increase the amount of power sought to be procured through this RFP.

Bidders should be aware that the following, without limitation, will be classified as non-responsive and may not be considered or evaluated if submitted:

- proposals offering non-firm capacity or energy;
- demand-side proposals;
- substantively incomplete, inaccurate, conditional, deceptive, misleading, ambiguous, exaggerated, or non-specific offers; or
- Proposals that are not in conformance with the requirements and instructions

contained herein.

Bidders that submit proposals do so without recourse against DEF or Duke Energy, Inc. or any of Duke Energy, Inc.'s subsidiary companies for either rejection of their proposal(s) or for failure to execute a definitive, written agreement for any reason.

III. DEF 2018 RFP PROCESS

The solicitation process is a multi-phase process consisting of four general phases and several sub-phases or steps. This Section III of the RFP describes the process in detail and outlines Bidder requirements and alternatives for each phase and step of the process.

DEF will also utilize Sedway Consulting, Inc as an independent monitor throughout the RFP process, including the Evaluation and Screening Process.

This Section III of the RFP is organized chronologically according to the sequence of steps in DEF's solicitation process. Specifically, the areas to be discussed are the (A) Solicitation activities, (B) Evaluation and Screening process, (C) Negotiations, and (D) Regulatory Process. Discussed as part of the evaluation process are the minimum requirements that all proposals must meet as well as the evaluation criteria that will be used to identify the most attractive proposals.

A. Solicitation

The solicitation activities phase of the process includes the period from issuance of the RFP to the submission of proposals by Bidders.

1. Notice of Intent to Bid and RFP Registration

Bidders are asked to submit a courtesy Notice of Intent to Bid ("NOI Form") in order to assist DEF in preparing for the Pre-Issuance meeting, the Bidders meeting, and the RFP process. Bidders are encouraged (but not required) to submit the NOI Form by October 2, 2013. Submitting a NOI Form does not commit a prospective Bidder to submitting a proposal to DEF.

Please submit an electronic copy of the NOI via the Power Advocate RFP web site or to the DEF RFP Official Contacts by email.

The NOI Form along with Power Advocate registration instructions are provided at the following website:

htpp://www.duke-energy.com/floridarfp

2. Pre-Release and Bidders Meetings

Pre-Release Meeting:

DEF will conduct a Pre-Release Meeting for interested potential Participants on October 2, 2013 at 1:00 PM at the Tampa Marriott Westshore, 1001 N. Westshore Blvd, Tampa, Florida 33607. If this time or location changes, DEF will provide notice on the RFP website. The purpose of the Pre-Release Meeting is to allow interested potential participants the opportunity to ask questions and seek additional information or clarification about the solicitation process. **To make the meeting as productive and informative as possible, Bidders are encouraged to submit a written list of questions concerning this RFP to the DEF RFP Official Contacts prior to October 2, 2013.**

Bidders Meetings:

DEF will conduct a Bidders Meeting for interested Bidders **on October 18, 2013** at 1:00 PM at the Tampa Marriott Westshore, 1001 N. Westshore Blvd, Tampa, Florida 33607. If this time or location changes, DEF will provide notice on the RFP website. The purpose of the Bidders Meeting is to allow interested Bidders the opportunity to ask questions and seek additional information or clarification about the solicitation process. **To make the meeting as productive and informative as possible, Bidders are encouraged to submit a written list of questions concerning this RFP to the DEF RFP Official Contacts prior to October 18, 2013.**

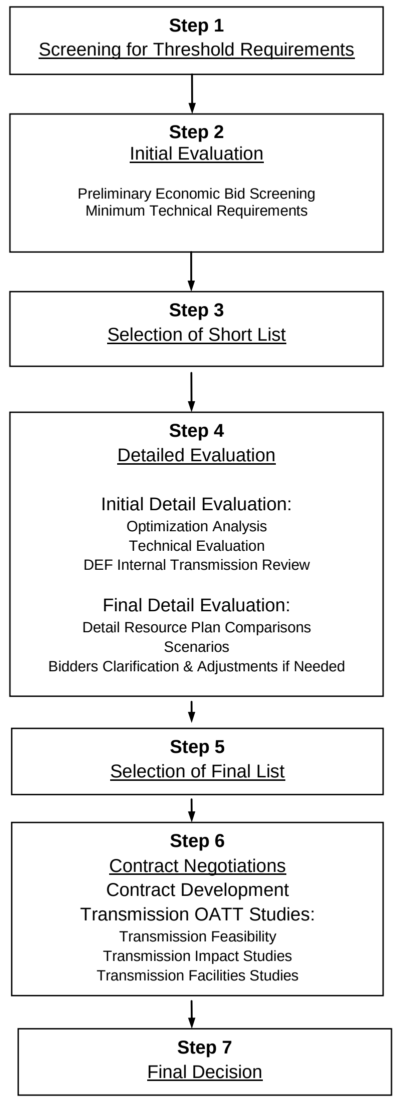
3. Submission of Proposals

The last step during this phase of the process is the submission of proposals. As noted, all proposals **must be received By the DEF Power Advocate web tool by 3:00 PM EST on December 9, 2013**. Additionally, a copied version of the submitted proposal in electronic format and provided on a flash-drive should be delivered to the IM/E at the Sedway Consulting address listed for the Official Contacts in Section I.E. no later than December 10, 2013. Proposals must remain valid for acceptance by DEF until DEF either (i) releases a proposal (by DEF informing the Bidder that its proposal was not approved to proceed to a next step in the evaluation process), (ii) accepts the proposal, or (iii) negotiates different terms during the Negotiation phase, whichever is earlier. **Failure to submit the proposal by the specified time will be grounds for disqualification.**

B. Evaluation Process

DEF will use a seven-step evaluation and screening process to review proposals and to select the best alternative. Figure III-1 illustrates the evaluation process, starting with the receipt of proposals to the final decision. The evaluation process is described more fully below.

FIGURE III-1
Evaluation Process



1. Step 1: Screening for Threshold Requirements

Subsequent to the receipt of the Bidders' proposals, DEF will thoroughly review and assess each proposal to ensure that it meets the Threshold Requirements listed in the RFP. Threshold Requirements represent the minimum requirements that all proposals are required to meet and with which a Bidder's compliance can be easily assessed. DEF may, at its sole discretion, seek clarification and/or modification of a Bidder's proposal at this stage of the evaluation process. Each Bidder should ensure that a contact person is available to DEF and Sedway Consulting throughout the Evaluation Process.

DEF views Threshold Requirements to be an important aspect of the evaluation process. The Bidder should ensure that its proposal satisfies the Threshold Requirements listed in FIGURE III-2 to be eligible for further consideration in the evaluation process. Bidders should also review and provide comments to the Key Terms & Conditions in Attachment A, because they are the terms and conditions that will be used to evaluate the Bidder's conformance with certain Threshold Requirements in this RFP. The information Bidders are required to provide to demonstrate their compliance with the Threshold Requirements is specified in greater detail in the Response Package.

Bidders must ensure that their proposals contain sufficient documentation to demonstrate that they meet all Threshold Requirements. **Failure to conform to the Threshold Requirements will be grounds for disqualification.** Proposals that are disqualified will not be evaluated further.

FIGURE III-2
Threshold Requirements

A. General Requirements

- The proposal is received on time.
- The proposal submittal fee is received by DEF.
- The pricing schedules are properly specified and the proper price indices are used.
- Power must be available for delivery under the contract May 1, 2018
- The proposed contract end date is no earlier than April 30, 2033

B. Operating Performance Thresholds

- If the project is located in DEF's system, the Bidder's proposal will be required to show documentation that the following operational criteria can be meet:
  - to operate the project to conform with DEF's ***Voltage Control*** requirements.
  - to operate the project to conform with DEF's ***Frequency Control*** requirements.
  - to be ***Fully Dispatchable*** and install ***Automatic Generator Control*** ("AGC") that is tied into DEF's Energy Control Center **[New and Existing Unit Proposals]**.
- If the project is located outside of DEF's system, New and Existing Unit Proposals must provide documentation to show that the proposal is ***Fully Dispatchable*** and provide ***Dynamic*** or a combination of ***Dynamic/Block*** scheduling that is tied into DEF's Energy Control Center.
- The Bidder must show documentation they are willing to ***coordinate the project's maintenance scheduling*** with DEF.
- System Power Proposals must show documentation that the proposal is ***Fully Schedulable*** (i.e., operate according to a day-ahead schedule but with schedule changes subject to normal utility practices). System Power Proposals must also provide D***ynamic*** or a combination of ***Dynamic/Block*** scheduling that is tied into DEF's Energy Control Center.

C. Terms & Conditions Thresholds

- Bidders must agree to each of the Terms & Conditions identified in Attachment A.

  \- OR -
- If Bidder has any objections to the Terms & Conditions, the Bidder must:
  - Identify the language which is objectionable;
  - Provide revised language.

D. Site Control Thresholds [New and Existing Unit Proposals]

- Identification of the site location on a USGS map.
- At a minimum, a Letter of Intent to negotiate a lease for the full contract term or term necessary for financing (whichever is greater), or to purchase the site **[New Unit Proposals]**. A copy of the title (or long term lease) and legal description of the property is required for **Existing Unit Proposals**.

E. Transmission Threshold

- If the proposal is for resources located outside of DEF's system, the Bidder must provide a transmission plan that exclusively utilizes firm transmission service from the host system to the DEF system. Bidders must provide evidence that the host system is willing to grant DEF the right to dispatch the output of New and Existing Unit Proposals or the right to schedule power from System Power Proposals. Bidders must provide host utility documentation that the results of a generator feasibility study and/or a host transmission system impact study performed by the host system will be completed or documentation such as a transmission study agreement showing that the results will be available no later than 30 days following the bid submittal date.
- For New Unit Proposals physically located inside the DEF system, documentation that the required Large Generator Interconnect Agreement ("LGIA") application and a $10,000 deposit (refundable) pursuant to the DEF OATT has been submitted to DEF **[New Unit Proposals]**.
- The Transmission Information Schedule (Schedule 7 of the Response Package) is properly completed for **All Proposals**.

2. Step 2: Initial Evaluations

Generation Economic Screening:

In the preliminary economic screening evaluation, DEF will evaluate each proposal based on its proposed prices. DEF's pricing parameters for New and Existing Unit Proposals are specified in the Response Package. The requirements for pricing bids for System Power Proposals are also specified in the Response Package. See Figure III-3 for additional pricing parameters.

FIGURE III-3
New and Existing Unit Proposal Pricing Parameters

Fixed Payment		• The monthly fixed payment to Bidders will be based on the product of the Seasonal Contract Capacity, one-twelfth (1/12) of the Bidder-specified annual charges (the possible components of which are detailed below). • Bidders must complete the applicable Pricing Schedules in the Response Package • If Bidders desire, they may propose alternative methods of distributing annual payments on a monthly basis.
	Generation Capital Component	• Bidders must specify a generation capital charge for each year of the proposal.
	Transmission Component	• Bidders must specify a transmission charge for each year of the proposal. • This charge must include all interconnection and, if applicable, wheeling costs, and upgrade costs of other transmission systems required for delivery of Firm Power to the DEF system. • During the Initial Evaluation (Step 3) and the Detailed Evaluation of proposals (Step 5), DEF will estimate transmission system upgrade costs for the DEF system and other affected systems needed to integrate the proposed power into the DEF transmission network. • The Bidders' transmission charge and DEF's estimate of any additional transmission system upgrade costs will be included in DEF's economic evaluation.
	Fixed O&M Component	• Bidders must specify annual fixed O&M charges for each year of the proposal.
	Fixed Pipeline Demand / Reservation Component	• Bidders must specify a fixed pipeline demand/reservation charge (if appropriate to the technology being proposed). Bidders must specify a charge for each year of the proposal. • Bidders may propose a fuel transportation tariff as the price. • DEF reserves the right to negotiate fuel transportation provisions with the Bidder if benefits can be derived for DEF and its customers.
Variable Payment		▪ The variable payment to Bidders will be based on the following components: fuel price and variable O&M price components. ▪ Bidders must complete the applicable Pricing Schedules in the Response Package.
	Fuel Price Component	Bidders must specify commodity prices and variable transportation prices for the primary (and, if appropriate, secondary) fuels. Bidders have three options for proposing fuel prices: 1. the Bidder may specify a series of firm prices or a price that escalates at a Bidder-specified rate. These prices will be used for evaluation and payment purposes. 2. the Bidder may propose to use a price index or propose a formula based on an index. 3. the Bidder may propose to use a fuel tolling arrangement whereby DEF will supply fuel tolling services to the project. If the Bidder selects this option, DEF will determine the appropriate price to use for the evaluation. • Formulas and escalation rates, if used, must be specified by the Bidder • DEF will not allow Bidders to merely state that fuel is a pass-through. DEF may allow a pass-through as a result of the negotiation process and, as a condition for this, would reserve the right to participate in the management of the project's fuel supply, but reserves the right to accept the base price and index or fixed escalation rate specified by the Bidder.

		• Bidders must specify the months in which the primary (and, if appropriate, secondary) fuels will be expected to be used and be prepared to be evaluated and paid on that basis.
	Variable O&M Component	• Bidders should specify in Schedule 1 annual variable O&M prices for each year of the proposal. Variable O&M may be stated in $/MWh, $/hour, or both.
Start Payment Component		• Bidders should specify annual start prices for each year of the proposal. Start payments will be paid only for those starts actually exercised by DEF. The cost to start the Facility for test starts, following a forced outage, or after unplanned maintenance will not be included in DEF's payments to the Bidder.

In the preliminary economic screening, DEF will use a spreadsheet model to compare the costs of each proposal to the other proposals at an appropriate capacity factor(s) as needed to evaluate the competitive rankings of each proposal. Such capacity factors may include, but are not limited to, capacity factors based on the anticipated dispatch of the resource within the DEF system of resources for the proposal. **DEF reserves the right to use the preliminary economic screening to eliminate proposals with high costs (relative to other proposals) from consideration without performing further analyses.**

Minimum Technical Criteria Evaluation:

Proposals will be evaluated on an initial technical basis to assess the feasibility and viability of each proposal. As part of this Minimum Technical Evaluation, proposals will be reviewed to ensure that they conform to the Minimum Technical Requirements described below.

i. Minimum Technical Requirements

DEF will apply Minimum Technical Requirements as a step in the initial evaluation process. These Minimum Technical Requirements, identified in Table III-4, are the technical "must have" elements of a proposal. The information Bidders are required to provide to demonstrate their compliance with these Minimum Technical Requirements is specified in greater detail in the Response Package. Each Minimum Technical Requirement will be evaluated on a "Pass/Fail" or "Go/No Go" basis.

Bidders must ensure that their proposals contain sufficient documentation to demonstrate that they meet all the Minimum Technical Requirements. **Failure to demonstrate conformance to these Minimum Technical Requirements will be grounds for disqualification.**

FIGURE III-4
Minimum Technical Requirements

A. Environmental

* Preliminary environmental analysis performed and submitted to DEF [New Unit Proposals].

* Reasonable schedule for securing permits presented with evidence provided that it is reasonable to expect that permits can be secured in a timely fashion [New Unit Proposals].

B. Engineering and Design

* The project technology is capable of achieving the operating targets specified by the Bidder [New Unit and Existing Unit Proposals].

* Operation and Maintenance Plan provided that indicates the project will be operated and maintained in a manner adequate to allow the project to satisfy its contractual commitments [New Unit and Existing Unit Proposals].

C. Fuel Supply and Transportation Plan

* Preliminary fuel supply plan provided which describes the Bidder's plan for securing fuel supply and transportation for delivery to the project. The plan shall provide a description of the fuel delivery system to the site, the terms and conditions of any existing or proposed fuel supply and transportation arrangements, and the status of such arrangements [New Unit and Existing Unit Proposals].

D. Project Financial Viability

* For New Unit Proposals, evidence provided that it is reasonable to expect that the project is financially viable (assuming a power purchase agreement is in place with DEF) [New Unit Proposals].

* Demonstration that the Bidder has sufficient credit standing and financial resources to satisfy its contractual commitments [All Proposals].

E. Project Management Plan

* For a New Unit Proposal, critical path diagram and schedule for the project provided which specify the items on the critical path and demonstrate the project would achieve commercial within the time frame requirements of this RFP [New Unit Proposals].

Generator Interconnection and Transmission Integrated Screening

For New and Existing Unit Proposals inside the DEF system, the Transmission Screening study will consist of a power flow analysis by the Transmission Group. For proposals in which the project is not interconnected with the DEF transmission system, preliminary transfer analyses will be performed to examine the impact on the DEF transmission system of a transfer from the host system of the project to the DEF system.

The transmission screening study will assess the impacts to the DEF transmission system and will result in a list of transmission facilities, and an estimate of the cost of the facilities.

Preliminary Total Cost Generation and Transmission Economic Screening

The combined screening results of the Generation, Interconnection and Transmission Integration costs provide the input to develop a total cost review and analysis for developing a mix of resources for Step 3 below.

3. Step 3: Selection of Short List

DEF's objective is to select a Short List of proposals which includes a mix of proposals that make up the best resources to allow further review as a system resource plan. Those proposals which are substantially inferior to other proposals will be eliminated from further consideration. DEF reserves the right to select as many proposals as needed for the Short List to develop reasonable resource plans for system evaluations, as DEF deems appropriate in its sole discretion. DEF will notify all short-listed Bidders that they have been selected for the Short List.

4. Step 4: Detailed Evaluation

Proposals that are included on the Short List will be subjected to a more detailed assessment and will be compared to DEF's self-build alternative. Consistent with Florida PSC rules, DEF encourages participants to formulate creative responses to the RFP. Without knowing the details of the proposals that may be submitted, DEF is not able to identify or describe all the detailed analyses that may be needed to determine which alternative is the most cost-effective alternative.

The Detailed Evaluation will consist of the Initial Detailed Evaluation followed by a Final Detailed Evaluation as follows:

Initial Detailed Evaluation

The next phase of the evaluation process is the Initialed Detailed Evaluation of proposals. In this step, the estimated costs from the initial screening study for the short list Bidders' proposals will be converted to Initial Resource Plans for further evaluations.

The Initial Detailed Evaluation will consist of several analyses conducted in parallel:

a. Optimization Analyses,
b. Technical Criteria Evaluation, and
c. Transmission Reviews.

a. Optimization Analyses

In the Optimization Analyses, DEF will analyze each short list bidder proposal's value by developing an optimal resource plan around each proposal and determining the cumulative present value of revenue requirements ("CPVRR") of the plan developed around the particular proposal. The Strategist optimization model will be used to develop the optimal plans and DEF will assess the impacts of each proposal on system costs over DEF's planning horizon. Generic combustion turbine and combined cycle plants will be available technologies from which the optimization model can select to develop the optimal plans. Depending on the nature of the proposals received, DEF may also examine combinations of proposals in the development of the portfolios which will be screened to identify optimal resource plans. Proposals with different capacity duration terms will be backfilled by the available generic resource technologies. The economic impact of the resource plans will be evaluated for both transmission and generation. For the generation portion, the production costs will be calculated using Energy Portfolio Management ("EPM") our detailed production cost tool. The Transmission Analyses will provide Transmission Capital Costs. The value of the proposal will be the CPVRR for its portfolio and will include Generation and Transmission Capital Revenue Requirements and Production Costs.

b. Technical Criteria

Technical Criteria are characteristics (non-price attributes) DEF desires that will increase the relative attractiveness of proposals that otherwise meet the Minimum Technical Requirements. DEF will use three major attributes to evaluate proposals' Technical Criteria: (1) expected operational quality; (2) expected development and commercial feasibility; and (3) estimated project value (non-price). Each of the evaluation criteria that are contained within these evaluation attributes are identified in FIGURE III-5 and discussed below. Proposals will be ranked relative to each other for each of the Technical Criteria.

Bidders will need to include information in their proposals that will support the Bidder's statements with respect to these technical criteria. Further, Bidders should assume that there will be provisions in any definitive, written agreement that DEF signs that reinforce the representations made by the Bidder with respect to these Technical Criteria. **Inability of a Bidder to adequately substantiate the basis for any representation will be grounds for a downward revision of its proposal's ranking or, in the event of misrepresentation, disqualification from this bidding process.**

FIGURE III-5
Technical Criteria

Operational Quality	Development and Commercial Feasibility	Project Value (non-price)
♦ Minimum Load (N, E)	♦ Permitting Certainty (N)	♦ Acceptance of Key Terms and Conditions (N,E,S)
♦ Start Time (N, E)	♦ Financial Viability of the Project (N)	♦ Fuel Supply and Transportation Plans (N,E,S)
♦ Ramp Rate (N, E)	♦ Credit Quality of Bidder (N,E,S)	♦ Generation Reliability Impact (N,E,S)
♦ Maximum Allowable Starts per Year (N, E)	♦ Commercial Operation Date Certainty (N)	♦ Unit Reliability Practices (N,E,S)
♦ Minimum Run-Time Constraint (N, E)	♦ Bidder Experience (N,E,S)	♦ Flexibility Provisions (N,E,S)
♦ Minimum Down-Time Constraint (N, E)		
♦ Annual Operating Hour Limit (N, E)		

N = New Unit Proposals, E = Existing Unit Proposals, S = System Power Proposals

Operational Quality

There are seven evaluation criteria that are considered as part of the operational quality attribute: (1) minimum load; (2) start time; (3) ramp rate; (4) maximum allowable starts per year; (5) minimum run-time constraint; (6) minimum down-time constraint, and (7) annual operating hour limit. DEF will expect that any definitive, written agreement for New and Existing Unit Proposals will include provisions requiring tests to be conducted periodically during the contract term to ensure that the Bidder's project conforms to the start time and ramp rate operating parameters claimed in its proposal. Failure to conform to these operating parameters will subject Bidders to performance penalties under any definitive, written agreement with DEF entered into as a result of this RFP.

The minimum load is the lowest capacity level at which the project may be continuously operated. DEF prefers projects that show flexibility by allowing operation at less than full load. The minimum loading level while on AGC should also be provided if different from plant local operation.

Start time assesses the amount of notice required to bring the unit, under normal operations, from a cold start to minimum synchronized load. DEF prefers proposals that have short start times.

Ramp rate assesses the megawatt (MW) increase per minute that can be provided by the project once the unit is at or above the minimum loading level. DEF prefers proposals that offer a high ramp rate. The ramp rate while on AGC should also be provided if different from plant local operation.

A maximum start per year assesses the maximum number of times that DEF will be allowed to start the Bidder's project. Test starts, starts after a forced outage, and starts after unplanned maintenance will not be included when determining the number of starts requested by DEF. DEF prefers proposals in which there is no limit on the number of times that DEF can start a project.

Minimum run-time constraint assesses the number of hours that the project is required to be operated at or above its minimum operating level once it has been dispatched on line. DEF prefers proposals that have no minimum run-time constraints.

The minimum down-time constraint assesses the number of hours that the project is required to remain out of service once it has been taken off-line for economic dispatch, maintenance outage, or forced outage. DEF prefers proposals that have no minimum down time constraints.

The annual operating hour limit assesses the number of hours during a year that DEF would be allowed to operate the Facility. DEF prefers proposals that have no operating hour limits.

Development and Commercial Feasibility

There are five evaluation criteria that are considered as part of the development and commercial feasibility attribute: (1) permitting certainty; (2) financial viability of the project; (3) Bidder credit quality; (4) commercial operation date certainty; and (5) Bidder experience. All five of these evaluation criteria will be considered for New Unit Proposals. Existing Unit and System Power Proposals will be evaluated based on two criteria: the Bidder's credit quality and Bidder experience.

The permitting certainty evaluation criterion assesses the degree to which the Bidder is able to demonstrate that it has identified and can secure all of the required major permits, approvals, certificates, and licenses within the period indicated on the project's critical path schedule. Relative to other proposals, DEF prefers proposals that provide well-conceived plans for securing all required permits, approvals, etc., demonstrate a thorough understanding of the permitting process, have realistic permitting and approval schedules, and have made greater progress in securing permits and approvals.

The project financial viability evaluation criterion assesses the financial viability of the Bidder's proposal, while Bidder's credit quality assesses the financial capability and credit of the Bidder. For New Unit proposals for which the Bidder is proposing to obtain project financing for its proposal, DEF's evaluation will focus on the financial viability of the proposal, and will evaluate project pro-forma financial statements based on the assumptions and capital structure in the proposal. To show financial viability, the Bidder needs to demonstrate that the project is, or eventually becomes, free cash flow positive (not every year must show positive free cash flows but, in general, the project should be positive more than it is negative). There is no specific cash flow hurdle. If the Bidder indicates that it will be providing equity to the project or will self-finance the project, DEF will also assess the Bidder's ability to provide the required equity or financing through the credit review. For New Unit Proposals, DEF prefers proposals for which the Bidder is able to demonstrate that there is a high likelihood of the project securing financing. For System Power and Existing Unit Proposals, DEF's evaluation will focus on the financial resources and credit quality of the Bidder.

DEF will also evaluate the Bidders' creditworthiness to assess the Bidders' financial ability to fulfill their obligations to DEF over the term of the contract.

DEF will require credit support as described in section II.G.If a respondent plans on providing a parent guarantee, and then financial information for the guarantor should be provided.

Commercial operation date certainty assesses the degree to which the Bidder is able to demonstrate that it will be able to bring the project to commercial operation of approximately 1,640 MW (summer) in 2018 with a minimum of 820 MW in service no later than May 1, 2018 with the balance of the capacity to be in service no later than December 1, 2018. For New Unit Proposals, DEF will evaluate the reasonableness of the following aspects of the Bidder's proposed schedule: permitting and approvals, fuel supply and transportation arrangements, construction or upgrades of necessary transmission facilities, engineering design, project financing, equipment procurement, project construction, and start-up and testing. DEF evaluation will consider the evidence presented by the Bidder that the proposed schedule for each of these project elements is achievable. DEF prefers proposals for which the Bidder is able to demonstrate that there is a reasonable likelihood that the project will be able to achieve the commercial operation date requirement. DEF will expect that any definitive, written agreement it signs for a proposal resulting from this RFP will include penalty provisions for delays in the commercial operating date.

Bidder experience assesses the relative experience of the Bidder in developing and operating projects that are of an equivalent size and technology as the Bidder proposes in response to this RFP. For a New Unit Proposal, DEF will evaluate the Bidder's relevant experience in six areas: permitting and approvals, engineering, financing, fuel procurement, project construction, and operations and maintenance, including environmental compliance. DEF prefers Bidders that have a history of successfully developing comparable projects. For proposals that rely on project teams composed of more than one firm to develop the projects, DEF prefers project teams that have a history of working together to successfully complete projects. DEF will review the Unit Reliability Program as the relative strength of the proposal to maintain operation at full capacity. DEF will evaluate the Bidder's plan for performing operations and maintenance including proposed O&M spending, planned engagement of an Long-Term Service Agreement ("LTSA"), allowance for capital spares, levels of redundancy in Balance of Plant ("BOP") equipment, major equipment technology selections and any unit identified restrictions. DEF prefers proposals that identify robust maintenance programs. DEF will consider Bidders demonstrated history of reliable operations for unit proposals in this response and other units operated by the Bidder. For a Bidder that proposes to supply DEF's capacity requirements from existing capacity, DEF will only evaluate the Bidder's fuel procurement and operations and maintenance experience. DEF will also examine the litigation history of all Bidders.

Project Value (Non-Price)

The project value (non-price) attribute considers the following four evaluation criteria: (1) the Bidder's degree of acceptance of the Terms & Conditions provided in Attachment A; (2) the reliability of the Bidder's fuel supply and transportation plan; (3) the impact of the proposed project on DEF's generation system reliability; (4) any flexibility provisions proposed by the Bidder.

Attachment A to this Solicitation Document contains Key Terms & Conditions, which will be used as the basis for this RFP and any possible negotiations of any final definitive, written agreement between DEF and one or more Bidders. DEF will evaluate the Bidder's acceptance of the Key Terms & Conditions by assessing the degree to which exceptions identified by the Bidder shift risk from the Bidder to DEF or its customers. DEF prefers Bidders which request no changes to the Terms & Conditions or which request only minor changes that have no material effect on the allocation of risk within any contract ultimately executed.

DEF will evaluate the reliability of the Bidder's fuel supply and transportation plans by assessing the status of its fuel supply and transportation arrangements, the strength of the proposed fuel supplier (and fuel transportation options), and the relative risk of (or flexibility among) the Bidder's proposed fuel supply and transportation arrangements. DEF prefers proposals that have well developed fuel supply and transportation arrangements, rely on a major fuel supplier that offers a diverse mix of potential fuel supplies and access to a number of different transportation alternatives, and have minimal fuel supply and transportation risks.

DEF will evaluate the impact on generation system reliability of the project proposed by Bidders, primarily through an examination of outage rate information provided by the Bidder. Depending on the proposals received, additional analyses may be required. DEF prefers bids that provide high levels of reliability – defined in terms of level of availability (tied to planned and unplanned outage rates). It is expected that unit-contingent proposals will have availability rates less than 100%. However, Bidders of System Power Proposals must guarantee 100% availability for the capacity and energy offered to DEF. Should curtailments be necessary for System Power Proposals, DEF prefers proposals that curtail delivery only on a pro-rata basis simultaneously and proportionately along with the Bidder's other firm sales, including primary public service obligations.

DEF reserves the right to take into consideration any unique flexibility provisions offered by a Bidder that are not considered elsewhere, such as in the economic evaluation. DEF favors bids which provide flexibility for meeting its projected requirements. DEF will finalize the Technical Criteria Evaluation of the short-listed proposals, after seeking clarification on any outstanding issues that resulted from the Technical Criteria Evaluation in the Initial Detailed Evaluation.

DEF will finalize the Technical Criteria Evaluation of the short-listed proposals, after seeking clarification, as DEF deems necessary, on any outstanding issues that resulted from the Technical Criteria Evaluation in the Initial Detailed Evaluation.

c. Transmission Reviews

DEF will incorporate the results of the Transmission Screening Study along with the preliminary information from the generation optimization and technical review, to assess the feasibility of the proposals that could be combined to form a preliminary Transmission Group for the DEF transmission system. A Transmission Group could be a single or multiple RFP proposals that would be studied together for overall transmission impact to the Bulk Electric System (BES).

In the initial detailed evaluation phase, DEF may perform detailed transmission cost estimates as well as an estimate of the time to construct the required facilities for each Transmission Group. If in DEF's judgment, the transmission cost estimates are determined to be a decisive factor in the overall Final Detailed Evaluation, then detailed transmission cost estimates will be performed. A detailed transmission cost estimate would go beyond previous cost estimates to more closely represent the actual cost expected of the Transmission Group.

In evaluating alternative proposals, DEF will include the costs of any necessary transmission network upgrades necessary to deliver the output of the new generator and/or power transfers from existing generation sources to DEF load. If the Response Package includes costs on other third party systems then those costs will be included in the evaluation.

The transmission network upgrade costs are based on all modifications (new facilities and facility upgrades) to the DEF transmission system that are necessary to physically transfer the proposed power from the DEF system receipt point to the load center consistent with reliability standards for 2018 Summer and 2018/19 Winter conditions. The latest available Florida Reliability Coordinating Council ("FRCC") peak load flow case (updated as necessary to reflect the latest available information) will be used as the basis for determining the transmission network upgrade modifications needed. Once these modifications are determined, costs for these modifications will be estimated and assigned to the appropriate Transmission Group.

The process of determining the needed transmission network upgrade modifications generally consists of two steps as follows:

Step One - The transmission studies performed to determine the deliverability of the various proposals to DEF load will be considered screening type studies and will not be as comprehensive as studies done for a request for service pursuant to DEF's OATT. The transmission screening studies will be sufficient to provide reasonable estimates of the transmission impacts to integrate the proposals into the DEF system and will involve the same reliability criteria for comparison purposes. The transmission service studies will be done consistent with NERC, FRCC and DEF standards to insure that DEF can serve its customers and meet its transmission service obligations in the years 2018 and beyond. Each of the Transmission Groups will be subjected to contingency screening of all transmission elements and generators, and the transmission system is monitored for violations of NERC, FRCC, and DEF standards. Contingency screening tests will be performed at Summer and Winter peak load conditions with all DEF generators/facilities assumed available and economically dispatched. Further, the generator deemed most critical to each Transmission Group will be assumed to be unavailable and the remaining DEF generators dispatched to mitigate if practicable, violation of reliability criteria for all contingencies tested. Violations of reliability criteria found on the DEF 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. If the transmission reviews reveal that a Transmission Group causes a potential violation on a third party affected system that was not identified in the response package, DEF will inform the Bidder(s) that they must communicate with the operator of the affected system and provide estimates of the attendant cost of resolving the violation. It is possible that a potential violation could be attributable in part to the Transmission Group being evaluated and would require a coordinated effort of multiple parties.

Step 2 - Once a list of network upgrades on the DEF system required for integration is identified, the second step of the transmission review evaluation process is developing cost estimates for the new and upgraded transmission facilities. Based on the need for incremental transmission network upgrades identified in each Transmission Group, a cost estimate for the facilities is developed in a consistent manner for each Transmission Group. The estimates will be based on engineering judgment and readily available cost information, including cost information previously obtained from third party entities and equipment manufacturers for transmission reinforcements of the type and capacity required for each portfolio.

Summary of Initial Detailed Evaluation

DEF will combine the three steps, (a) the Optimization Analyses, (b) Technical Criteria Evaluation and (c) the Transmission Reviews, for a combined review of initial competing alternative plans against the self-build alternative. Adjustment may be necessary to further optimize the Resource Plans when the combined results are reviewed.

Final Detailed Evaluation

DEF will further review the short list bidder proposals that satisfy the Initial Detailed Evaluation in a robust review of competing alternative plans against the self-build alternative. DEF plans to use EPM and a detailed financial model to further compare the short-listed proposals to DEF's self-build alternative. Using the optimal plans for the short listed proposals developed in the initial evaluation, the final evaluation will assess the impact of each alternative on the CPVRR over the planning horizon compared to a Base Case plan.

In order to treat all alternatives the same in the economic analysis, all cases will be compared to a Base Case optimal plan. The results of the production costing analyses will be incorporated into the detailed financial analysis of each alternative. In addition to the direct costs associated with each alternative (that is, the energy charges of the proposals and the operating costs of the self-build alternative), the change in system production costs compared to the Base Case will also be a part of the financial analysis. The fixed costs associated with each alternative (the fixed charges of the proposals and the construction costs and fixed O&M of the self-build alternative) will be included in the analysis as an add-on to the production costs. The cost impacts of the changes in the resource plan will be reflected in the financial analysis through charges or credits representing the revenue requirements of units added, accelerated, or deferred.

DEF will apply the cost of imputed debt to Bidders' proposals to assure that the total costs of proposals include the marginal impact of the fixed future commitment on DEF's capital structure. The annual additional equity cost of imputed debt on a revenue requirements basis is calculated as:

Annual Additional Equity Cost =
Risk Factor * Present Value of Future Fixed Payments
* (Cost of Equity Rate – After Tax Cost of Debt Rate)
* Equity Ratio / (1 – Tax Rate)

where the Risk Factor and Present Value of Future Fixed Payments are calculated consistent with the S&P Standard Methodology.

This additional cost is the direct result of having the transaction cause DEF to incur fixed future payment obligations. Rating agencies make these adjustments to a utility's balance sheet to reflect the existence of debt-like commitments. The Risk Factor is the percentage of the future fixed payments to be added to balance sheet debt and depends on a number of factors, including the conditions of a purchased power proposal, counterparty risk, and regulatory cost recovery risk. The biggest factor in selecting a risk factor is the degree of certainty and timeliness of regulatory recovery by the utility. Based on Standard & Poor's recommendation, utilities in supportive regulatory jurisdictions with a regulatory precedent for timely and full cost recovery of fuel and purchased-power costs, may use a risk factor as low as 25%.

Based on the team's review of the proposals submitted, DEF may deem it appropriate to perform scenario analyses (e.g., to examine flexibility options proposed by a Bidder), sensitivity analyses of key costs and performance characteristics (such as, but not limited to, heat rate, outage rate, construction cost, O&M costs, and energy costs), and/or any other type of analysis that DEF deems appropriate.

DEF may elect to schedule meetings or conference calls with each short-listed Bidder to review and clarify its proposal. DEF reserves the right to seek clarification or additional information from each Bidder regarding its proposal and develop appropriate adjustment in order to thoroughly evaluate a proposal.

5. Step 5: Selection of Final List

DEF may develop a Final List based on the detailed evaluation of the short-listed proposals. This Final List will not necessarily be composed of the lowest cost proposals since the combination of price and non-price terms may provide greater value to customers than the lowest cost proposals. DEF will exercise professional judgment in performing the analyses and in making the final selection of the RFP process. DEF's objective is to select resources that offer the maximum value, based on price and non-price attributes, to the Company and its customers. The final-listed Bidders will be those Bidders with which DEF will begin contract negotiations.

DEF will not necessarily put any Bidder proposals on the Final List. In the event DEF's self-build alternative is superior to the short-listed proposals, a Final List will not be selected and an appropriate announcement will be made.

6. Step 6: Negotiations and Transmission Facilities Studies

Immediately after the Final List announcement, DEF will begin negotiations with Bidders on the Final List. As previously noted, DEF has included T&C in the RFP to allow Bidders to identify their exceptions, thereby expediting negotiations and allowing DEF to assess the significance of the changes requested by Bidders. Inclusion of a proposal in the Final List does not indicate DEF's acceptance of the exceptions identified by the Bidder. DEF reserves the right to negotiate any terms and conditions which provide value to DEF and its customers. Also, if in DEF's view the negotiations are not proceeding on a reasonable schedule to ensure achievement of the in-service date requirement, DEF has the right to terminate negotiations with that Bidder.

7. Step 7: Final Decision

DEF will make its final decision related to this RFP once all definitive, written agreements have been fully negotiated and are ready to be executed by the parties, and any required Interconnection and Transmission Facilities Studies have been completed. For a winning Bidder whose proposal is for a New Unit in the DEF system, the results of the respective facilities study will be incorporated into a Large Generator Interconnection Agreement to be executed between the winning Bidder and DEF.

C. Regulatory Filings

Determination of Need and/or Cost Recovery Filings with the Florida Public Service Commission may be required of selected proposals. Proposals that require an application for certification by the Florida Siting Board under the Florida Electrical Power Plant Siting Act will require a Determination of Need by the Florida Public Service Commission. In that event, DEF will be the applicant, and the Bidder will be the co-applicant in proceedings before the Florida Public Service Commission (which will determine the need for the project), the Florida Department of Environmental Protection (which will make a recommendation to the Florida Siting Board concerning site certification), and the Florida Siting Board. Cost Recovery Filings are annual filings associated with the fuel and purchased power clauses and are made after the execution of the applicable written agreement and will be required for all selected proposals. In the case of a proposal that does not require a need determination, pre-approval of such written agreement, as determined by DEF, may be required. The expected regulatory filing date of September, 2014 in the RFP schedule (presented on page 3) is for the Determination of Need Filing, if required, or the written agreement pre-approval filing, if desired. DEF will also require that an application for site certification be filed on or before the PSC need filing date for any project that will require site certification by the Florida Siting Board.

IV. DEF'S "NPGU"

The following data represent preliminary cost and performance estimates for DEF's NPGU and are provided for information purposes only. The final actual cost of the project could be greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals.

1. Combined cycle generating unit to be located near DEF's existing Crystal River site in Citrus County, Florida (Citrus CC1).
2. Approximately 1,820 MW (net winter) and 1,640 MW (net summer).
3. Commercial Operation of the facility is proposed to be May 1, 2018.
4. The only fuel source to the unit is natural gas.
5. The estimated total direct cost excluding AFUDC is $ 1,240 million (2013$). This estimate includes the plant interconnection (electrical generator radial connections to the Bulk Electric System) costs identified in Item 11 below but does not include transmission network upgrade costs (or network system impacts associated with the Bulk Electric Systems).
6. The estimated annual levelized capital revenue requirement with AFUDC, excluding transmission system integration related capital costs, is $145.5 million over 35 years.
7. The estimated annual value of deferral of this unit is $63.3/kw-yr (2013$) based on summer fired capacity, which includes plant generation and interconnection construction costs and fixed O&M.
8. The estimated annual fixed O&M is $6.00/kW-yr (2013$). The estimated variable O&M is $2.13/MWh (2013$).
9. The Henry Hub estimated natural gas commodity cost is $3.96/mmBtu (2013$).
10. The following are planning estimates for the first year of operations:

Planned outage rate	8.0 %
Forced outage rate	2.0 %
Minimum load	200 MW
Ramp Rate	50 MW/minute (from minimum to full load)
Summer Fired Capacity	1,640 MW
Summer Unfired Capacity	1,464 MW
Summer Fired Heat Rate	6,850 Btu/kWh (HHV)
Summer Unfired Heat Rate	6,580 Btu/kWh (HHV)
Summer Conditions	90^{o}F, 60% R.H.
Winter Fired Capacity	1,820 MW
Winter Conditions	45^{o}F, 60% R.H.

11. The estimated plant transmission interconnection cost for this unit is $44 million (2013$), excluding AFUDC. The cost associated with the gas lateral will be included in the negotiated fixed transportation contract rate. All costs not provided through this rate are included in the plant capital cost identified in Item 5.

12. A Site Certification as well as an Air Construction/PSD Permit will be required for this unit.

It is DEF's plan to comply with all environmental standards of Local, Regional, State and Federal governments.

13. The major financial assumptions in the development of these numbers were:

General Inflation:	2.5 % per year
Capital structure:	50% debt @ 3.75%
	50% equity @ 10.5%
Discount rate:	6.46%

V. DEF'S SYSTEM SPECIFIC CONDITIONS

During the timeframe of this RFP, the following DEF system conditions are relevant to the responses to this RFP:

- The preferred Bulk Electric System (BES) location for the new DEF (DEF) capacity is in Citrus County. The Citrus County location is preferred because the new capacity is replacing generation that is being retired in the area. In addition this location for new generation is expected to provide transmission reliability benefits for DEF as well as neighboring transmission systems within the Florida Region.

- Other areas in the proximity of Citrus County are expected to have similar reliability benefits but may require additional Transmission Network Upgrades. If the new capacity is not located in the Citrus County vicinity, it is expected that significant Transmission Network Upgrades will need to be constructed within DEF as well as neighboring transmission systems within the Florida Region.

- The connection of the new capacity in Citrus County should be such that it takes advantage of the available transmission capacity that will become available on the BES due to generation retirements in the area.

DEF's long-term 10-year expansion plan was updated in the Summer of 2013 in which the 2018 Citrus County CC was selected as DEF's NPGU. With regards to the Summer 2013 Resource Plan evaluations, the following projected 10 year System Reserve Margins are being provided as follows:

DEF 2013 Ten Year Forecast of Firm Demand, Capacity, and Reserve Margins										
	MW	MW	MW	%			MW	MW	MW	%
	Firm Peak Demand	Installed Capacity	Installed Reserve	Reserve Margin			Firm Peak Demand	Installed Capacity	Installed Reserve	Reserve Margin
	Summer						Winter			
2013	8,944	10,999	2,055	23		**2013**	8,989	12,408	3,419	38
2014	9,005	10,959	1,954	22		**2014**	9,092	12,220	3,128	34
2015	9,164	10,952	1,788	20		**2015**	9,710	12,207	2,497	26
2016	9,169	11,287	2,118	23		**2016**	9,843	12,106	2,262	23
2017	9,230	11,406	2,176	24		**2017**	9,666	12,435	2,769	29
2018	9,400	11,359	1,958	21		**2018**	9,814	12,445	2,631	27
2019	9,823	12,179	2,355	24		**2019**	9,966	13,390	3,424	34
2020	9,994	12,074	2,079	21		**2020**	10,363	13,390	3,027	29
2021	10,063	12,442	2,378	24		**2021**	10,514	13,274	2,760	26
2022	10,229	12,442	2,213	22		**2022**	10,665	13,715	3,050	29

ATTACHMENT A

Key Terms, Conditions and Definitions

KEY TERMS & CONDITIONS

This Attachment A represents some of the Key Terms and Conditions that Duke Energy Florida will require in a Power Purchase Agreement (PPA). The Key Terms & Conditions were developed assuming the Bidder's resources are physically located in the DEF control area. For System Power Proposals, or to the extent the resources are off-system, some definitions, terms, and conditions may not apply or may need to be revised to reflect the location of the resource. This attachment reflects only some of the primary terms and conditions that DEF will require and is not intended to be exhaustive or all-inclusive of the terms and conditions DEF will require in an executed PPA. Bidders should refer to DEF's OATT for specific terms and conditions in the Standard Large Generator Interconnection Agreement that govern the transmission interconnection for New Unit Proposals interconnected to the DEF control area.

SECTION 1. RIGHT OF FIRST REFUSAL

Duke Energy Florida (DEF) shall have the Right of First Refusal to purchase the Facility or to purchase any capacity expansions during the term of the Agreement, upon substantially the same terms and purchase price as that offered to any third party, which option shall be held open for a period of ninety (90) days after Seller's presentation of the terms of such offer to DEF. Notwithstanding the foregoing, any transfer of the Facility or any expansion thereof to any third party shall be permitted only with the prior written approval of DEF, and only upon agreement by a third party to assume all of Seller's obligations under the Agreement. This Right of First Refusal is not applicable to System Power Proposals.

SECTION 2. ADJUSTMENTS TO` FIXED PAYMENTS

Subsequent to the Commercial Operation Date of the Facility and subject to the Seller's meeting all other obligations under the Agreement (including availability requirements), DEF shall accept, purchase, and pay for the Seasonal NDC (as applicable) to be delivered under the Agreement based on the Contract Capacity, subject to the following:

a. If the tested Seasonal NDC is greater than or equal to the Seasonal Contract Capacity, DEF will pay Seller for capacity delivered based on the Seasonal Contract Capacity.

b. If tested Seasonal NDC is lower than the Seasonal Contract Capacity, DEF will pay Seller based on the Seasonal Contract Capacity, after subtracting the daily liquidated damages as specified in Section 3.5, until a re-test of the Facility shows a Seasonal NDC at least equal to the applicable Seasonal Contract Capacity.

c. If Seller fails to achieve an eighty-five percent (85%) EAF on a 12-month rolling average, starting in the second contract year, then the proposed Fixed Payments (Generation Capital, Transmission, Fixed O&M, and Fixed Pipeline Demand/Reservation as specified in Schedule 1 of the Response Package-Attachment C) will be reduced on a sliding-scale basis.

d. No Fixed Payments will be made for those months in which the 12-month rolling average EAF is less than 60%.

e. In any month, if the actual EFOR is greater than the EFOR guarantee, the proposed Fixed Payment will also be reduced by the Availability Adjustment Factor (AAF), where

$$AAF = (1 - EFOR_{actual}) / (1 - EFOR_{guarantee}).$$

The AAF shall not be greater than 1.0.

f. The monthly fixed payment shall thus be
Actual Fixed Payment (AFP) = proposed Fixed Payment * EAF adjustment * AAF.

Fixed Payment Adjustments are not applicable to System sales.

SECTION 3. DEFAULT AND SECURITY

3.1 Operation by DEF Following Event of Default by Seller

a. If during the term of the Agreement DEF becomes entitled to terminate the Agreement due to an Event of Default, then, in lieu of terminating the Agreement, DEF may, in its sole discretion, but without any obligation to do so, assume operational responsibility for the Facility to complete construction, continue operation, complete any necessary repairs, or take such other steps as are appropriate in the circumstances, or may designate a third party or parties to do the same, so as to assure uninterrupted availability of capacity and deliverability of electric energy from the Facility. Seller agrees to fully cooperate with DEF in providing access to the Facility, and permitting DEF to operate the Facility as provided herein. Any payments to Seller shall be made only after any and all costs and expenses (including liquidated damages) of DEF in exercising its rights hereunder are deducted.

b. DEF's exercise of its rights hereunder to operate the Facility and Seller's Interconnection Facilities shall not be deemed an assumption by DEF of any liability of Seller.

c.

Operation by DEF Following Event of Default by Seller is not applicable to System sales.

3.2 Establishment of Security Funds

Seller agrees to establish, fund, and maintain the Security Fund as specified below:

- The Security Fund shall be maintained at Seller's expense, shall be originated by a financial institution or company ("Issuer") acceptable to DEF, and shall be in the form of either of the following, or combination of both:

  (1) An irrevocable standby letter of credit drawn on an Issuer acceptable to DEF; or
  (2) Cash in U.S. Dollars to be held by DEF.

- The amount of security to be required from Seller will be determined based on the following:

Security required for new projects to be developed is shown in the table below.

SECURITY SCHEDULE – NEW PROJECTS		
Timing	Amount	Cumulative Amount
30 days after contract signing	$40/kW	$40/kW
12 months after contract signing	$20/kW	$60/kW
24 months after contract signing	$20/kW	$80/kW
Earlier of 36 months after contract signing or within 30 days after commercial operation	$20/kW	$100/kW [a]
10 years after c/o	($50/kW)	$50/kW [a]
15 years after c/o	($20/kW)	$30/kW [a]
During contract term, based on market exposure [b]	Up to $100/kW	Up to $200/kW

The following table shows the security required for existing facilities.

SECURITY SCHEDULE – EXISTING FACILITIES		
Timing	Amount	Cumulative Amount
30 days after contract signing	$40/kW	$40/kW
Within 10 business days after beginning of term	$60/kW	$100/kW [a]
10 years after beginning of term	($50/kW)	$50/kW [a]
15 years after beginning of term	($20/kW)	$30/kW [a]

During contract term, based on market exposure [b]	Up to \$100/kW	Up to \$200/kW

Notes:
(a) Cumulative amount shown excludes the impact of any additional security required based on market exposure – see note (b).
(b) Additional security will be required in the event that DEF's market exposure exceeds the operational security that is otherwise required. DEF's market exposure represents the additional cost that would be required to replace the capacity and energy in the wholesale electric power markets or by constructing a new generation facility.

DEF will assign a Credit Limit to qualified Sellers based on the table below. In order to qualify for a Credit Limit, a Seller must maintain a credit rating from Standard & Poor's (S&P) or Moody's Investors Service (Moody's). A Seller may elect to provide a parent guarantee from a rated entity, in which case the assessment will be based on the guarantor's creditworthiness.

The Credit Limit will be calculated as a percentage of the Seller's Tangible Net Worth (TNW), subject to a maximum amount as shown under Credit Limit Cap. If the S&P and Moody's ratings are not equivalent, then the lower of the two will be used. The total required cash and letter of credit security as determined per above will be reduced by the Credit Limit amount as determined by reference to the table below. If at any time during the term of the agreement, the credit rating changes, then the amount of cash or letter of credit security will be adjusted accordingly.

Credit Rating from S&P / Moody's *	Percentage of TNW	Credit Limit Cap
A-/A3 or better	16%	\$50,000,000
BBB+/Baa1	10%	\$40,000,000
BBB/Baa2	10%	\$30,000,000
BBB-/Baa3	8%	\$30,000,000
Below BBB-	0%	\$0

The credit support amount resulting from DEF's market exposure will reflect the expected cost to replace the energy and capacity to be provided under the Agreement in the then-current market environment. A replacement price analysis will be performed using statistical methodologies reflective of prevailing market prices and volatilities at the time of the analysis, and other available market information, in the reasonable determination of DEF.

- To the extent a Security Fund is established in the form of a letter of credit, such letter of credit must be an irrevocable, non-transferable standby letter of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank (which is not an Affiliate of either Party) with such bank having a credit rating of at least A- from S&P and A3 from Moody's and acceptable to the receiving Party in its commercially reasonable discretion, and otherwise being in a form acceptable to DEF. The letter of credit should automatically renew on an annual basis and must be maintained in place for the duration of the Agreement. The letter of credit must specify that it can be drawn upon by DEF if (i) Seller is required to maintain the letter of credit or other form of security under the Agreement, (ii) Seller has failed to replace the letter of credit or provide other acceptable security, and (iii) less than thirty days remain until the expiration date of the letter of credit. If at any time, the issuing bank fails to meet the requirements of this section, Seller is required to replace the letter of credit within 10 business days with an acceptable letter of credit or other allowable form of security, and if Seller fails to do so, DEF may draw on the letter of credit and hold the cash as security until such time as Seller provides a replacement letter of credit. At such time as Seller's obligation to provide security expires, DEF shall, within a reasonable period of time, cooperate with Seller in canceling the letter of credit and/or returning such amounts.

- A Security Fund shall be maintained until such time as (a) the end of the term of the Agreement, or until termination of the Agreement; and (b) all amounts payable from the Security Fund have been paid.

3.3 Liquidated Damages for Seller's Failure to Meet Commercial Operation

a. If Seller fails to achieve Commercial Operation by the Scheduled Commercial Operation Date, Seller shall pay liquidated damages to DEF as specified below:

Event	Liquidated Damages
Failure to attain Commercial Operation by the Scheduled Commercial Operation Date	AFP/30*

* Based on the Seasonal Contract Capacity

Liquidated damages shall be paid for each calendar day of delay until the facility achieves Commercial Operation or until twelve (12) months shall pass, as liquidated damages and not as a penalty. Liquidated damages shall begin accruing the day after failure to meet the scheduled Commercial Operation Date. Liquidated damages shall be payable monthly within ten (10) days of Seller's receipt from DEF of a bill covering the applicable period and shall continue until the Commercial Operation Date is achieved or twelve (12) months have passed. If Seller fails to make such payment within such ten (10) days, DEF may draw on the Security to cover such payment. In the event that Seller fails to achieve Commercial Operation within twelve (12) months of the Scheduled Commercial

Operation Date, DEF shall have the right to terminate the Agreement. If DEF exercises its right to terminate the Agreement, the entire amount of Security plus any accrued interest shall be retained by DEF as liquidated damages. DEF shall also have any and all remedies specified in the Agreement, or as provided by law.

b. If Seller fails to achieve Commercial Operation by the Scheduled Commercial Operation Date, Seller shall be liable for damages to DEF for the costs of replacing the capacity and energy over and above what DEF would have paid Seller for the capacity and energy under the Agreement, and the transactional costs of obtaining the replacement capacity and energy, in addition to any liquidated damages payable under Section 3.3.a.

c. If Seller provides written notice to DEF or it is otherwise determined by DEF at any time after the Effective Date that Seller will not be able to complete the Facility to a state of Commercial Operation, DEF may terminate the Agreement, and Seller shall pay liquidated damages as specified by the following formula, in addition to any liquidated damages payable under Section 3.3a through the date of termination:

$$\left[(\$20/\text{kW} \times \text{Contract Capacity}) + (\$40/\text{kW} \times \text{Contract Capacity}) \times \frac{\text{(No. of days from contract execution to date of notice)}}{\text{(No. of days from contract execution to Scheduled Com. Oper. Date)}} \right]$$

Upon such notice given by DEF, the Agreement shall terminate and Seller waives any rights it may have under the Agreement.

3.4 Damages for Event of Default After Commercial Operation

If a termination of the Agreement occurs as a result of an Event of Default of Seller after attaining Commercial Operation, Seller, for four (4) years subsequent to the date of default, shall be liable for DEF's damages, including, but not limited to, damages to DEF for the costs of replacing the capacity and energy over and above what DEF would have paid Seller for the capacity and energy under the Agreement, and the transactional costs of obtaining the replacement capacity and energy.

3.5 Penalties for Seasonal Contract Capacity Deficiencies

Seller shall pay to DEF an amount to be determined, based on factors that include, without limitation, the difference between the Seasonal Contract Capacity and the tested Seasonal NDC as determined through Facility testing, for each day that the Seasonal NDC remains below the Seasonal Contract Capacity. Assessed penalties shall be paid monthly. Penalties for Seasonal Contract Capacity Deficiencies are not applicable to System sales.

3.6 Penalties for Start Time Deficiencies

If Seller fails to meet the agreed upon Start Time requirements when tested in accordance with agreed upon provisions at any time during the term of the Agreement, then for each failure Seller shall pay DEF an amount to be determined, based on factors that include, without limitation, the applicable Seasonal Contract Capacity for the Facility, until the deficiency is corrected and satisfactorily re-tested. Assessed penalties shall be paid monthly.

3.7 Penalties for Ramp Rate Deficiencies

If Seller fails to meet the agreed upon Ramp Rate requirements when tested in accordance with agreed upon provisions at any time during the term of the Agreement, then for each failure Seller shall pay DEF an amount to be determined, based on factors that include, without limitation, the applicable Seasonal Contract Capacity for the Facility, until the deficiency is corrected and satisfactorily re-tested. Assessed penalties shall be paid monthly.

3.8 Penalties for Reactive Capability Deficiencies

Seller shall pay to DEF an amount to be determined, based on factors that include, without limitation, the difference between the nameplate reactive capability and the tested reactive capability as determined through facility testing, for each day that the capability remains below the posted capability. Assessed penalties shall be paid monthly or the Seller may be billed for the cost incurred by DEF to replace the reactive output of the unit. Penalties for Reactive Capability Deficiencies are not applicable to System Power proposals or units outside the DEF system.

3.9 Payments from Security Funds

In addition to any other remedy available to it, DEF may draw appropriate amounts from the Security Funds to recover the damages owing to it under the Agreement, including but not limited to the recovery of liquidated damages payable under the contract. Seller will be required to refresh Security Funds to maintain such funds at levels established under the contract. No less than two (2) years after the end of the term of the Agreement, the remaining balance of the Security Funds shall be returned to Seller within a reasonable period of time if any funds are remaining in the Security Funds and if no funds are owed to DEF under the Agreement.

SECTION 4. OPERATION OF THE FACILITY

4.1 General

Seller shall operate, maintain, and repair the Facility in a safe, prudent, reliable, and efficient manner in accordance with Good Utility Practice.

4.2 Establishment of Operating Procedures

Seller and DEF shall each appoint an Operating Representative who shall be the primary point of contact between the parties for purposes of this Section within thirty (30) days after the Effective Date. Seller and DEF shall mutually develop written operating procedures no later than ninety (90) days prior to the Scheduled Commercial Operation Date. The operating procedures will be established by mutual agreement based on the design of the Facility and the design of the Interconnection Facilities. The operating procedures will be intended as a guide on how to integrate the Facility into the control area operator's transmission system. Topics covered shall include, but not be limited to, method of day-to-day communications; key personnel list for applicable DEF and Seller operating centers; clearances and switching practices; outage scheduling; daily capacity and energy reports; unit operations log; and reactive power support. In no event shall the operating procedures to be established hereunder be considered as a modification, amendment or waiver of any of the terms and conditions of the Agreement.

4.3 Certification of Maintenance

a. Seller shall obtain at its sole expense an independent engineering review of the entire Facility (including the Interconnection Facilities), its operation and maintenance to assist DEF in monitoring compliance with Good Utility Practice. This review shall also include a review of the environmental compliance of the Facility and its operation and maintenance plan. The independent review will be conducted by an engineering firm other than the firm chosen by Seller to design, construct, operate or maintain the Facility, and furthermore, selection of this engineering firm is subject to DEF's approval. The independent review will be conducted according to the following schedule:

    (1) Once every other year for the first ten (10) years following the Commercial Operation Date.

    (2) For the remainder of the term of the Agreement, once every calendar year.

b. Seller shall cause the independent engineer to issue a written report to DEF before June 1 of every year in which the independent review has been conducted assessing Facility operation and maintenance and compliance with all applicable environmental licenses, approvals, and permits and stipulating any related remedial or other actions consistent with Good Utility Practice. Such report shall be made available to DEF as soon as it is available to Seller. Seller shall cause these recommendations to be implemented as soon as practical unless Seller and DEF agree otherwise. Seller shall provide written certification of implementation of these recommendations to DEF as soon as they are completed.

c. DEF or its designated agent shall have the right to verify such recommendations by reviewing all pertinent Facility records and by inspecting the Facility, provided that such review and inspection shall not unreasonably interfere with Seller's operations at the Facility.

d. Seller and DEF shall use all reasonable efforts to resolve any disputes between them as to whether any maintenance deficiency exists and/or whether a particular remedy is reasonably necessary to correct a purported deficiency.

e. Seller agrees to undertake promptly and complete any undisputed deficiencies in maintenance and any disputed deficiencies in maintenance as ultimately agreed by Seller and DEF.

4.4 DEF Inspections

Seller shall allow DEF, at any time and with reasonable prior notice, to visit the Facility, including the control room and Interconnection Facilities, to inspect the Facility, review Seller's operating practices, and examine the operating logs. These visits may be made during weekends and nights as well as normal business hours. In exercising such rights, DEF shall not unreasonably interfere with or disrupt the operation of the Facility and DEF shall comply with all of Seller's reasonable safety regulations at the Facility.

SECTION 5. COMPLIANCE WITH LAWS

5.1 General

Seller agrees that it will at all times comply with all federal, state, and local statutes, laws, regulations and public ordinances of any nature relating in any way to the construction, modification, ownership, maintenance and operation of the Facility, and shall procure all necessary governmental permits, licenses, and inspections, and shall pay all fees and charges in connection therewith. Seller shall indemnify and defend DEF from and against any liability, fines, damages, costs, or expenses arising from Seller's failure to comply with the requirements of this Section. Seller further agrees that it will be responsible for all costs of complying with all current laws and any future change(s) in laws.

5.2 Safety and Health

Seller shall comply with all federal, state and local laws and regulations pertaining to health, safety, sanitary facilities and waste disposal. Seller shall meet all requirements of the Occupational Safety and Health Act of 1970 (OSHA), including all amendments. Seller shall also comply with any standards, rules, regulations and orders promulgated under OSHA and particularly with the agreement for state development and enforcement of occupational health and safety standards as authorized by Section 18 of the Act.

5.3 Equal Employment Opportunity

Unless the rules, regulations or orders of the United States Secretary of Labor exempt the Agreement from the provisions of Section 202 of Executive Order No. 11246, dated September 24, 1965, relating to equal employment opportunity, those provisions are, to the extent applicable, made a part of the Agreement.

5.4 NERC and FRCC

Seller shall comply with all standards pertaining to operation, maintenance and planning of the bulk electric system. Compliance penalties assessed to DEF directly due to non-compliance of the Seller shall be passed in full to the Seller for reimbursement.

SECTION 6. ASSIGNMENT

Seller shall not sell or transfer the Facility or any part thereof, and shall not sell, transfer or assign the Agreement or any rights or obligations thereunder, without the prior written consent of DEF, which DEF may withhold in its sole discretion if Seller is unable to demonstrate that the replacement seller and/or operator will not adequately meet the requirements under the contract. A request to sell or transfer the Facility, or to sell, transfer or assign the Agreement must contain the name and location of individuals or firms to whom it is to be assigned, and a detailed description of the proposed transaction. Consent by DEF to sell or transfer the Facility, or to sell, transfer or assign the Agreement shall not relieve the Seller of responsibility for the performance of all obligations under the Agreement. Any sale or transfer of the Facility, and any transfer or assignment of the Agreement shall not jeopardize any of the security given by Seller as provided in Section 3. For purposes of this Section, a transfer or assignment shall include but not be limited to a sale of all or a material interest in the stock of Seller.

SECTION 7. ENVIRONMENTAL REPORTING AND INDEMNITY

7.1 Environmental Compliance

Seller shall construct, maintain and operate the Facility in accordance with all state, federal and local environmental laws, regulations, ordinances, and permits. Seller shall disclose to DEF, as soon as and to the extent known to Seller, any actual or alleged violation of any environmental laws or regulations arising out of or in connection with the construction, operation or maintenance of the Facility, or the alleged presence of environmental contamination at or in connection with the Facility, or the existence of any past or present enforcement, legal or regulatory action or proceeding relating to such alleged violation or alleged presence of environmental contamination. Environmental contamination means the presence of hazardous wastes, hazardous substances, hazardous materials, toxic substances, hazardous air or other hazardous pollutants, and toxic pollutants, as those terms are used in the Resource Conservation and Recovery Act; the Comprehensive Environmental Response, Compensation and Liability Act; the Hazardous Materials Act; the Toxic Substances Control Act; the Clean Air Act; the Safe Drinking Water Act; the Oil Pollution and Hazardous Substances Control Act; and any and all other applicable federal, state, and local laws and regulations as amended, at such levels or quantities or location, or of such form or character, to be in violation of said federal, state, and local laws and regulations.

7.2 Environmental Indemnity

Seller shall indemnify, defend and hold DEF harmless against any and all claims, demands, losses, liabilities, expenses, fines and penalties, including interest and attorney fees, resulting from any alleged violation of applicable federal, state or local environmental laws or regulations arising out of Seller's construction, operation, maintenance or ownership of the Facility or the Facility site, or the presence of any environmental contamination at or in connection with the Facility.

SECTION 8. REGULATORY OUT

Notwithstanding anything to the contrary in the Agreement, if DEF, at any time during the term of the Agreement, fails to obtain or is denied the authorization of the Florida Public Service Commission ("FPSC"), or the authorization of any other legislative, administrative, judicial or regulatory body which now has, or in the future may have, jurisdiction over DEF's rates and charges, to recover from its customers all of the payments required to be made to the Seller under the terms of the Agreement or any subsequent amendment hereto, DEF may, at its sole option, adjust the payments made under the Agreement to the amount(s) which DEF is authorized to recover from its customers. In the event that DEF so adjusts the payments to which the Seller is entitled under the Agreement, then, without limiting or otherwise affecting any other remedies which the Seller may have hereunder or by law, the Seller may, at its sole option, terminate the Agreement upon (180) days written notice to DEF. If such determination of disallowance is ultimately reversed and such payments previously disallowed are found to be recoverable, DEF shall pay all withheld payments, with interest as set for refunds under the Federal Power Act pursuant to 18 C.F.R. §35.19a. Seller acknowledges that any amounts initially received by DEF from its ratepayers, but for which recovery is subsequently disallowed and charged back to DEF, may be offset or credited, with interest as set for refunds under the Federal Power Act pursuant to 18 C.F.R. §35.19a, against subsequent payments to be made by DEF to the Seller under the Agreement.

If, at any time, DEF receives notice that the FPSC or any other legislative, administrative, judicial or regulatory body seeks or will seek to prevent full recovery by DEF from its customers of all payments required to be made under the terms of the Agreement or any subsequent amendments to the Agreement, then DEF shall, within five business days of such action, give written notice thereof to the Seller. DEF shall use its best efforts to defend and uphold the validity of the Agreement and its right to recover from its customers all payments required to be made by DEF hereunder, and will cooperate in any effort by the Seller to intervene in any proceeding challenging, or to otherwise be allowed to defend, the validity of the Agreement and the right of DEF to recover from its customers all payments to be made by it hereunder.

The Parties do not intend this Section 8 to grant any rights or remedies to any third party(ies) or to any legislative, administrative, judicial or regulatory body; and this Section 8 shall not operate to release any person from any claim or cause of action which the Seller may have relating to, or to preclude the Seller from asserting, the validity or enforceability of any other obligation undertaken by DEF under the Agreement.

DEFINITIONS – FOR PURPOSES OF THIS RFP ONLY

"Agreement" means the Power Purchase Agreement entered into between Duke Energy Florida (DEF) and the "Seller."

"Commencement Date" means the date power is first accepted under this Agreement, but no later than May 1, 2018.

"Commercial Operation" means operation of the Facility commencing on the Commercial Operation Date and continuing until termination or expiration of the Agreement.

"Commercial Operation Date" means the later of (a) first day of the month following the date that the Facility has been satisfactorily completed and tested by Seller, or (b) the Commencement Date.

"Delivery Point" means the point at which deliveries of capacity and energy under the Agreement are required to be made and shall be measured which, for any Facility located within DEF's control area, shall be the Point of Interconnection; and, for any Facility located outside DEF's control area, shall be the physical point at which connection is made between DEF's system and the system of the Wheeling utility adjacent to DEF's control area which will deliver the capacity and energy to such point from the Facility or from other Wheeling utilities, as the case may be.

"Effective Date" means the date set forth in the preamble to the Agreement; generally, the contract execution date.

"Equivalent Availability Factor" or "EAF" shall have the meaning given in the Definitions Section of the RFP Solicitation Document.

"Equivalent Forced Outage Rate" or "EFOR" shall have the meaning given in the Definitions Section of the RFP Solicitation Document.

"Facility" or "Project" means the equipment, spare parts inventory, lands, property, buildings, generators, step-up transformers, boilers, output breakers, transmission lines and facilities used to connect to the Delivery Point or to the Facility's point of interconnection with the Wheeling utility, protective and associated equipment, improvements, and other tangible and intangible assets, property rights and contract rights reasonably necessary for the construction, operation and maintenance of the Facility.

"FRCC" means the Florida Reliability Coordinating Council.

"Good Utility Practice" means the practices, methods and acts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with law, regulation, codes, standards, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy and expedition. With respect to the Facility, Good Utility Practice(s) include, but are not limited to, taking reasonable steps to ensure that:

1. adequate equipment, materials, resources and supplies, including Primary Fuel and Secondary Fuel (with minimum inventory levels) are available to meet the needs of the Facility;

2. sufficient management and operating personnel are available at all times and are adequately experienced and trained and licensed as necessary to operate the Facility properly, efficiently and in coordination with the transmission system control area operator and are capable of responding to reasonably foreseeable emergency conditions whether caused by events on or off the site of the Facility;

3. preventive, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable long term and safe operation, and are performed by knowledgeable, trained and experienced personnel utilizing proper equipment and tools;

4. appropriate monitoring and testing is done to ensure equipment is functioning as designed;

5. equipment is not operated in a negligent or reckless manner, or in a manner unsafe to workers, the general public or the transmission system control area operator or contrary to environmental laws or regulations or without regard to defined limitations such as steam pressure, temperature and moisture content, chemical content of make-up water, safety inspection requirements, operating voltage, current, volt-ampere reactive (VAR) loading, frequency, rotational speed, polarity, synchronization and/or control system limits; and

6. the equipment will function properly under both normal and emergency conditions at the Facility and/or the transmission system.

<u>"Interconnection Facilities"</u> means all land, easements, materials, equipment and facilities installed for the purpose of interconnecting the Facility to the Delivery Point to facilitate the transfer of electric energy in either direction, including but not limited to connection, transformation, switching, metering, relaying, communications equipment, safety equipment, and any necessary additions and reinforcements to the control area operator's transmission system required for safety or system security as a result of the interconnection between the Facility and the control area operator's transmission system.

<u>"Milestone Date"</u> means the date by which the Seller is required to complete a specified task in accordance with the Milestone Schedule.

"Milestone Schedule" means the Milestone Schedule set forth in the Agreement, as such Milestone Schedule may be revised in accordance with the terms and conditions of the Agreement.

"MW" means megawatt or megawatts.

"NERC" means the North American Electric Reliability Council.

"Net Dependable Capacity" or "NDC" means the maximum net sustainable output of the Facility in MW that can be delivered to the Delivery Point (after deducting plant auxiliary loads and other losses), based on a performance test.

"Net Electrical Output" means all of the Facility's electric generating output after deducting plant auxiliary loads and any transmission losses between the Facility and the Delivery Point, as measured by metering devices owned by DEF.

"Point of Interconnection" shall mean the point where the Seller's Interconnection Facilities connect to the Company's transmission system.

"Project Lender" means the lender or lenders providing the initial construction and/or permanent debt financing for the Facility, and any fiscal agents, trustees, or other nominees acting on their behalf.

"Ramp Rate" means the minimum rate change in Net Electrical Output per minute over the period beginning at the time when the Seller is instructed to change the Facility's Net Electrical Output, and ending at the time that such Net Electrical Output is achieved, based on performance testing.

"Reactive Capability" means the lesser of the maximum reactive power (MVar) output at full load real power (MW) output based on manufacturer ratings or the reactive power output associated with meeting the voltage schedule contained in the generator interconnect agreement with the transmission provider.

"Scheduled Commercial Operation Date" means the Milestone Date by which Seller is required to achieve Commercial Operation.

"Seasonal Contract Capacity" shall have the meaning given in the Definitions Section of the RFP Solicitation Document.

"Seasonal NDC" means the Summer NDC and/or the Winter NDC, as applicable.

"Security Funds" means the security fund as defined in Section 3.2.

"Seller" means the party that is obligated to sell and deliver power to Duke Energy Florida as specified in this Agreement.

“Start Time” means the maximum time required to synchronize the Facility to the control area operator’s transmission system and achieve minimum load beginning when DEF instructs the Seller to start the Facility from a cold shut-down condition.

“Summer Contract Capacity” shall have the meaning given in the Definitions Section of the RFP Solicitation Document.

“Summer NDC” means the NDC for the Summer Period, corrected for ambient conditions.

“Summer Period” shall be the months specified in Section II.E of the Response Package.

“System” means Power System as defined in the RFP Solicitation Document.

“Wheeling” means the transmission of electric power from the electrical system of one utility to the electrical system of another utility, either directly or through the system of one or more other utilities.

“Winter Contract Capacity” shall have the meaning given in the Definitions Section of the RFP Solicitation Document.

“Winter NDC” means the NDC for the Winter Period, corrected for ambient conditions.

“Winter Period” shall be the months specified in Section II.E of the Response Package.

Progress Energy Florida, Inc.
Ten-Year Site Plan

April 2013

2013-2022

Submitted to:
Florida Public Service Commission

Progress Energy

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LIST OF REQUIRED SCHEDULES

LIST OF

TABLES AND FIGURES

CODE IDENTIFICATION SHEET

Generating Unit Type

ST - Steam Turbine - Non-Nuclear
NP - Steam Power - Nuclear
GT - Gas Turbine
CT - Combustion Turbine
CC - Combined Cycle
SPP - Small Power Producer
COG - Cogeneration Facility

Fuel Type

NUC - Nuclear (Uranium)
NG - Natural Gas
RFO - No. 6 Residual Fuel Oil
DFO - No. 2 Distillate Fuel Oil
BIT - Bituminous Coal
MSW - Municipal Solid Waste
WH - Waste Heat
BIO - Biomass

Fuel Transportation

WA - Water
TK - Truck
RR - Railroad
PL - Pipeline
UN - Unknown

Future Generating Unit Status

A - Generating unit capability increased
D – Generating unit capability decreased
FC - Existing generator planned for conversion to another fuel or energy source
P - Planned for installation but not authorized; not under construction
RP - Proposed for repowering or life extension
RT - Existing generator scheduled for retirement
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

INTRODUCTION

Section 186.801 of the Florida Statutes requires electric generating utilities to submit a Ten-Year Site Plan (TYSP) to the Florida Public Service Commission (FPSC). The TYSP includes historical and projected data pertaining to the utility's load and resource needs as well as a review of those needs. Florida Power Corporation doing business as (d/b/a) Progress Energy Florida, Inc.'s (PEF) TYSP is compiled in accordance with FPSC Rules 25-22.070 through 22.072, Florida Administrative Code.

PEF's TYSP is based on the projections of long-term planning requirements that are dynamic in nature and subject to change. These planning documents should be used for general guidance concerning PEF's planning assumptions and projections, and should not be taken as an assurance that particular events discussed in the TYSP will materialize or that particular plans will be implemented. Information and projections pertinent to periods further out in time are inherently subject to greater uncertainty.

This TYSP document contains four chapters as indicated below:

- **CHAPTER 1 - DESCRIPTION OF EXISTING FACILITIES**

  This chapter provides an overview of PEF's generating resources as well as the transmission and distribution system.
- **CHAPTER 2 - FORECAST OF ELECTRICAL POWER DEMAND AND ENERGY CONSUMPTION**

  Chapter 2 presents the history and forecast for load and peak demand as well as the forecast methodology used. Demand-Side Management (DSM) savings and fuel requirement projections are also included.
- **CHAPTER 3 - FORECAST OF FACILITIES REQUIREMENTS**

  The resource planning forecast, transmission planning forecast as well as the proposed generating facilities and bulk transmission line additions status are discussed in Chapter 3.
- **CHAPTER 4 - ENVIRONMENTAL AND LAND USE INFORMATION**

  Preferred and potential site locations along with any environmental and land use information are presented in this chapter.

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF or the Company) is a wholly owned subsidiary of Duke Energy Corporation (Duke Energy). Congress enacted legislation in 2005 repealing the Public Utilities Holding Company Act of 1935 (PUHCA) effective February 8, 2006. Subsequent to that date, Duke Energy is no longer subject to regulation by the Securities and Exchange Commission as a public utility holding company.

AREA OF SERVICE

PEF has an obligation to serve approximately 1.6 million customers in Florida. Its service area covers approximately 20,000 square miles in west central Florida and includes the densely populated areas around Orlando, as well as the cities of Saint Petersburg and Clearwater. PEF is interconnected with 22 municipal and nine rural electric cooperative systems. PEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), and the Florida Public Service Commission (FPSC). PEF's Service Area is shown in Figure 1.1.

TRANSMISSION/DISTRIBUTION

The Company is part of a nationwide interconnected power network that enables power to be exchanged between utilities. The PEF transmission system includes approximately 5,000 circuit miles of transmission lines. The distribution system includes approximately 18,000 circuit miles of overhead distribution conductors and approximately 13,000 circuit miles of underground distribution cable.

ENERGY MANAGEMENT and ENERGY EFFICIENCY

The Company's residential Energy Management program represents a demand response type of program where participating customers help manage future growth and costs. Approximately 405,000 customers participated in the residential Energy Management program at the end of

2012, contributing about 639 MW of winter peak-shaving capacity for use during high load periods. PEF's currently approved DSM programs consist of six residential programs, eight commercial and industrial programs, one research and development program and six solar pilot programs.

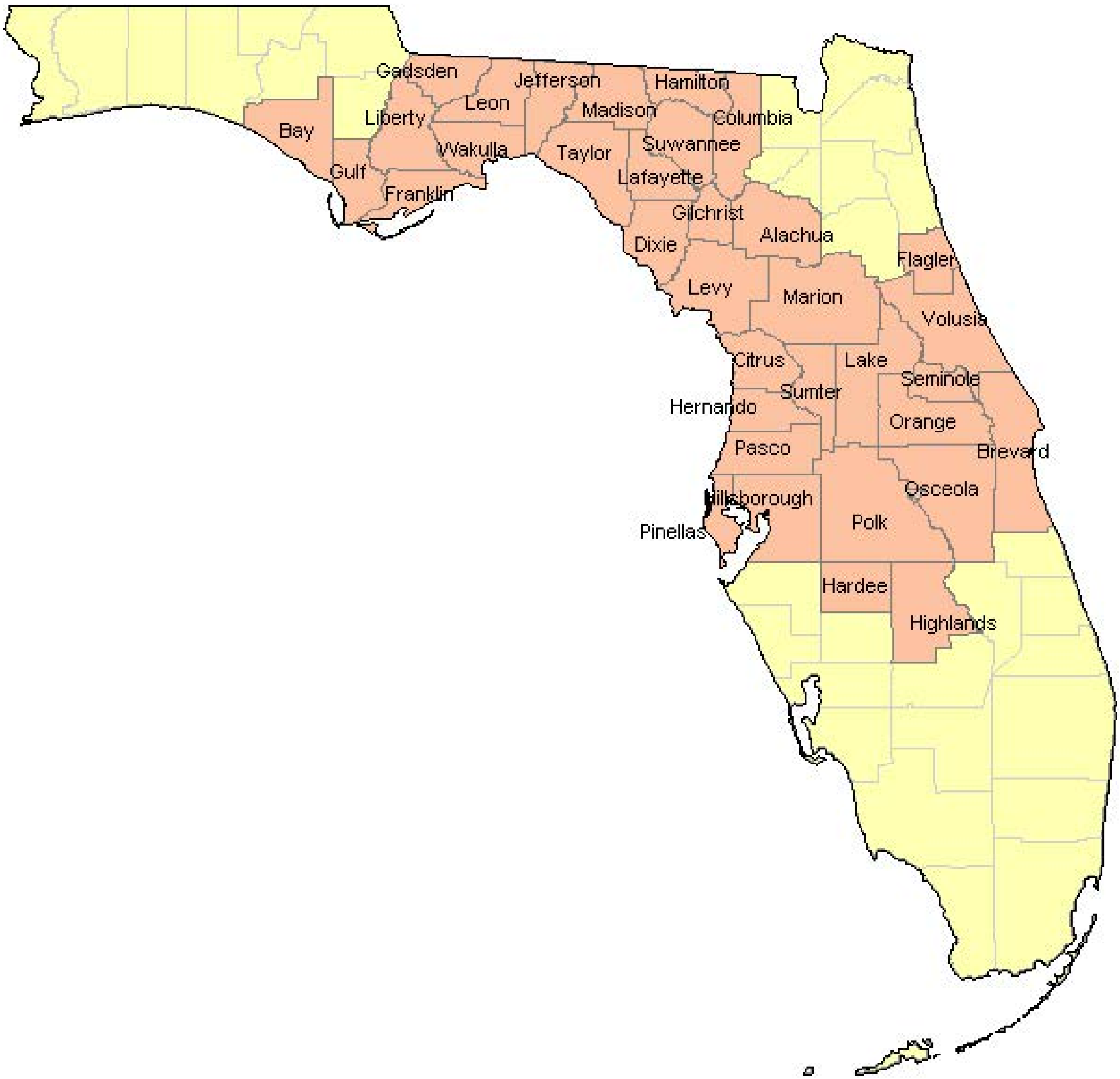
TOTAL CAPACITY RESOURCE

As of December 31, 2012, PEF had total summer capacity resources of 12,092 MW consisting of installed capacity of 9,884 MW (excluding Crystal River Unit 3 joint ownership) and 2,208 MW of firm purchased power. Additional information on PEF's existing generating resources can be found in Schedule 1 and Table 3.1.

FIGURE 1.1

PROGRESS ENERGY FLORIDA

County Service Area Map



PROGRESS ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2012

(1) PLANT NAME	(2) UNIT NO.	(3) LOCATION (COUNTY)	(4) UNIT TYPE	(5) FUEL PRI.	(6) FUEL ALT.	(7) FUEL TRANSPORT PRI.	(8) FUEL TRANSPORT ALT.	(9) ALT. FUEL DAYS USE	(10) COM'L IN-SERVICE MO./YEAR	(11) EXPECTED RETIREMENT MO./YEAR	(12) GEN. MAX. NAMEPLATE KW	(13) NET CAPABILITY SUMMER MW	(14) NET CAPABILITY WINTER MW
STEAM													
ANCLOTE	1	PASCO	ST	RFO	NG	PL	PL	***	10/74		556,200	501	517
ANCLOTE	2	PASCO	ST	RFO	NG	PL	PL	***	10/78		556,200	510	530
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		10/66	****	440,550	370	372
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		11/69	****	523,800	499	503
CRYSTAL RIVER	3 *	CITRUS	NP	NUC		TK			3/77	1/2013	890,460	789	805
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA	RR		12/82		739,260	712	721
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA	RR		10/84		739,260	710	721
SUWANNEE RIVER	1	SUWANNEE	ST	NG	RFO	PL	TK/RR	***	11/53	*****	34,500	28	28
SUWANNEE RIVER	2	SUWANNEE	ST	NG	RFO	PL	TK/RR	***	11/54	*****	37,500	30	30
SUWANNEE RIVER	3	SUWANNEE	ST	NG	RFO	PL	TK/RR	***	10/56	*****	75,000	71	73
												4,220	**4,300**
COMBINED-CYCLE													
BARTOW	4	PINELLAS	CC	NG	DFO	PL	TK	***	6/09		1,253,000	1,074	1,235
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	***	4/99		546,500	462	528
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK	***	12/03		548,250	490	563
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK	***	11/05		561,000	488	564
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	PL	TK	***	12/07		610,000	472	544
TIGER BAY	1	POLK	CC	NG		PL			8/97		278,100	205	231
												3,191	**3,665**
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	***	12/68	******	33,790	24	35
AVON PARK	P2	HIGHLANDS	GT	DFO		TK		***	12/68	******	33,790	24	35
BARTOW	P1, P3	PINELLAS	GT	DFO		WA		***	5/72, 6/72		111,400	85	108
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	***	6/72		55,700	43	57
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	***	6/72		55,700	49	61
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA		***	4/73		226,800	174	232
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK		***	12/75-4/76		401,220	309	381
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	PL	TK	***	10/92		345,000	247	287
DEBARY	P10	VOLUSIA	GT	DFO		TK		***	10/92		115,000	80	95
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK	***	3/69, 4/69	******	67,580	45	45
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	PL	TK	***	12/70, 1/71	******	85,850	60	71
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK		***	5/74		340,200	286	372
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	***	10/93		460,000	328	379
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		PL,TK		***	1/97		165,000	143	161
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	***	12/00		345,000	229	276
RIO PINAR	P1	ORANGE	GT	DFO		TK		***	11/70	******	19,290	12	15
SUWANNEE RIVER	P1, P3	SUWANNEE	GT	NG	DFO	PL	TK	***	10/80, 11/80		122,400	104	127
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK		***	10/80		61,200	51	66
TURNER	P1-P2	VOLUSIA	GT	DFO		TK		***	10/70	******	38,580	20	26
TURNER	P3	VOLUSIA	GT	DFO		TK		***	8/74		71,200	53	77
TURNER	P4	VOLUSIA	GT	DFO		TK		***	8/74		71,200	61	78
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			1/94		43,000	46	47
												2,473	**3,031**
											TOTAL RESOURCES (MW)	**9,884**	**10,996**

* REPRESENTS PEF OWNERSHIP OF UNIT WHICH IS APPROXIMATELY 91.8%. IN FEBRUARY 2013, PEF ANNOUNCED PLANS TO RETIRE CR3 AND NOT RETURN THE UNIT TO SERVICE FROM AN EXTENDED OUTAGE.
** THE 143 MW SUMMER CAPABILITY (JUNE THROUGH SEPTEMBER) IS OWNED BY GEORGIA POWER COMPANY
*** APPROXIMATELY 2 TO 8 DAYS OF OIL USE TYPICALLY TARTGETED FOR ENTIRE PLANT. RFO TO BE PHASED OUT WITH UNIT RETIREMENTS OR UNIT GAS CONVERSIONS.
**** CRYSTAL RIVER UNITS 1 & 2 ESTIMATED TO BE SHUTDOWN BY 4/2016; PEF CONTINUES TO EVALUATE OPTION FOR CONTINUED OPERATIONS, SEE CHAPTER 3.
***** SUWANNEE STEAM UNITS ESTIMATED TO BE SHUTDOWN BY 6/2018.
****** PEAKERS at AVON PARK, HIGGINS, RIO PINAR, TURNER P1 & P2 ARE ESTIMATED TO BE PUT IN COLD STAND-BY OR RETIRED BY 6/2016.

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

Progress Energy

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

OVERVIEW

The information presented in Schedules 2, 3, and 4 represents PEF's history and forecast of customers, energy sales (GWh), and peak demand (MW). PEF's customer growth is expected to average 1.5 percent between 2013 and 2022, which is more than the ten-year historical average of 1.0 percent. County population growth rate projections from the University of Florida's Bureau of Economic and Business Research (BEBR) were incorporated into this projection. The severe housing crisis witnessed both nationwide and in Florida since 2007 has dampened the PEF historical ten-year growth rate significantly as total customer growth turned negative for a twenty-one month period during 2008, 2009 and 2010. Economic conditions going forward look more amenable to improved customer growth due to lower housing prices, improved housing affordability and a large retiring baby-boomer population.

Net energy for load (NEL) dropped by an average -0.7 percent per year between 2003 and 2012 due primarily to the economic recession and the weak economic recovery that followed. Milder than normal weather conditions during 2012 also contributed to the weak results. The 2013 to 2022 period is expected to improve by an average growth rate of 1.5 percent per year due to expected higher economic growth that drives the retail jurisdiction back to more normal NEL growth rates. Going forward, projected NEL growth continues to reflect the FPSC approved DSM energy savings targets. Wholesale NEL is expected to nearly double over this time period.

Summer net firm demand grew an average 0.8 percent per year during the last ten years. The projected ten year period summer net firm demand growth rate of 1.5 percent is primarily driven by a stronger economy improving net firm retail demand.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

The below schedules have been provided on the following pages:

SCHEDULE	DESCRIPTION
2.1, 2.2 and 2.3	History and Forecast of Energy Consumption and Number of Customers by Customer Class
3.1	History and Forecast of Summer Peak Demand (MW)
3.2	History and Forecast of Winter Peak Demand (MW)
3.3	History and Forecast of Annual Net Energy for Load (GWh)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month

PROGRESS ENERGY FLORIDA

SCHEDULE 2.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	PEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
HISTORY:								
2003	3,264,521	2.451	19,429	1,331,914	14,587	11,553	154,294	74,876
2004	3,339,365	2.447	19,347	1,364,677	14,177	11,734	158,780	73,898
2005	3,428,268	2.454	19,894	1,397,012	14,240	11,945	161,001	74,190
2006	3,504,907	2.448	20,021	1,431,743	13,983	11,975	162,774	73,568
2007	3,532,104	2.448	19,912	1,442,853	13,800	12,184	162,837	74,821
2008	3,561,743	2.458	19,328	1,449,041	13,339	12,139	162,569	74,669
2009	3,564,397	2.473	19,399	1,441,325	13,459	11,883	161,390	73,632
2010	3,621,408	2.495	20,524	1,451,466	14,140	11,896	161,674	73,579
2011	3,623,873	2.495	19,238	1,452,454	13,245	11,892	162,071	73,374
2012	3,636,514	2.493	18,251	1,458,690	12,512	11,723	163,297	71,792
FORECAST:								
2013	3,683,572	2.490	18,959	1,479,346	12,816	11,569	165,511	69,899
2014	3,719,750	2.480	19,405	1,499,899	12,938	11,776	168,050	70,074
2015	3,770,309	2.475	19,877	1,523,357	13,048	11,956	171,170	69,849
2016	3,818,679	2.470	20,287	1,546,024	13,122	12,068	174,439	69,182
2017	3,868,716	2.465	20,700	1,569,459	13,189	12,145	177,706	68,343
2018	3,919,678	2.460	21,107	1,593,365	13,247	12,202	181,060	67,392
2019	3,970,810	2.455	21,514	1,617,438	13,301	12,263	184,458	66,481
2020	4,029,595	2.455	21,904	1,641,383	13,345	12,328	187,857	65,624
2021	4,087,465	2.455	22,303	1,664,955	13,396	12,393	191,218	64,811
2022	4,144,418	2.455	22,712	1,688,154	13,454	12,458	194,526	64,043

PROGRESS ENERGY FLORIDA

SCHEDULE 2.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
HISTORY:							
2003	4,001	2,643	1,513,810	0	29	2,946	37,958
2004	4,069	2,733	1,488,840	0	28	3,016	38,194
2005	4,140	2,703	1,531,632	0	27	3,171	39,176
2006	4,160	2,697	1,542,455	0	27	3,249	39,432
2007	3,819	2,668	1,431,409	0	26	3,341	39,282
2008	3,786	2,587	1,463,471	0	26	3,276	38,555
2009	3,285	2,487	1,320,869	0	26	3,230	37,824
2010	3,219	2,481	1,297,461	0	26	3,260	38,925
2011	3,243	2,408	1,346,761	0	25	3,200	37,598
2012	3,160	2,372	1,332,209	0	25	3,221	36,381
FORECAST:							
2013	3,294	2,343	1,405,890	0	25	3,137	36,984
2014	3,270	2,340	1,397,436	0	25	3,207	37,683
2015	3,300	2,340	1,410,256	0	25	3,312	38,470
2016	3,308	2,340	1,413,675	0	25	3,381	39,069
2017	3,341	2,340	1,427,778	0	24	3,433	39,643
2018	3,413	2,340	1,458,547	0	24	3,484	40,230
2019	3,490	2,340	1,491,453	0	24	3,532	40,823
2020	3,568	2,340	1,524,786	0	24	3,580	41,404
2021	3,596	2,340	1,536,752	0	24	3,612	41,928
2022	3,575	2,340	1,527,778	0	24	3,641	42,410

PROGRESS ENERGY FLORIDA

SCHEDULE 2.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1) YEAR	(2) SALES FOR RESALE GWh	(3) UTILITY USE & LOSSES GWh	(4) NET ENERGY FOR LOAD GWh	(5) OTHER CUSTOMERS (AVERAGE NO.)	(6) TOTAL NO. OF CUSTOMERS
HISTORY:					
2003	3,359	2,594	43,911	21,665	1,510,516
2004	4,301	2,773	45,268	22,437	1,548,627
2005	5,195	2,507	46,878	22,701	1,583,417
2006	4,220	2,389	46,041	23,182	1,620,396
2007	5,598	2,753	47,633	24,010	1,632,368
2008	6,619	2,484	47,658	24,738	1,638,935
2009	3,696	2,604	44,124	24,993	1,630,195
2010	3,493	3,742	46,160	25,212	1,640,833
2011	2,712	2,180	42,490	25,228	1,642,161
2012	826	4,007	41,214	25,480	1,649,839
FORECAST:					
2013	1,410	2,392	40,786	25,818	1,673,018
2014	1,474	2,408	41,565	26,193	1,696,482
2015	1,627	2,452	42,549	26,664	1,723,531
2016	1,822	2,530	43,421	27,205	1,750,008
2017	1,705	2,476	43,824	27,744	1,777,249
2018	1,675	2,547	44,452	28,351	1,805,116
2019	1,630	2,584	45,037	28,966	1,833,202
2020	1,637	2,613	45,654	29,582	1,861,162
2021	1,609	2,642	46,179	30,191	1,888,704
2022	1,610	2,669	46,689	30,792	1,915,812

PROGRESS ENERGY FLORIDA

SCHEDULE 3.1
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
BASE CASE

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
HISTORY:										
2003	8,881	887	7,994	300	355	169	44	161	75	7,776
2004	9,583	1,071	8,512	531	331	185	39	163	110	8,224
2005	10,350	1,118	9,232	448	310	203	38	166	110	9,074
2006	10,147	1,257	8,890	329	307	222	37	170	66	9,016
2007	10,931	1,544	9,387	334	291	239	45	177	110	9,735
2008	10,592	1,512	9,080	500	284	255	66	192	110	9,186
2009	10,853	1618	9,235	262	291	271	84	211	110	9,624
2010	10,238	1272	8,966	271	304	296	96	232	110	8,929
2011	9,968	934	9,034	227	317	327	97	255	110	8,636
2012	9,783	402	9,381	267	326	355	100	278	124	8,333
FORECAST:										
2013	10,462	937	9,525	271	330	382	103	287	124	8,964
2014	10,572	871	9,702	274	335	408	107	298	124	9,026
2015	10,773	873	9,901	277	340	432	110	306	124	9,185
2016	11,066	977	10,089	276	345	452	113	314	124	9,441
2017	11,189	894	10,295	286	368	470	116	320	124	9,504
2018	11,391	894	10,497	288	373	486	120	326	124	9,674
2019	11,607	894	10,713	303	378	501	123	332	124	9,846
2020	11,823	894	10,929	318	383	518	126	337	124	10,017
2021	11,928	794	11,134	326	388	533	129	341	124	10,086
2022	12,121	794	11,327	326	393	548	133	345	124	10,252

Historical Values (2003 - 2012):
Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.
Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) =Customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).
Projected Values (2013 - 2022):
Cols. (2) - (4) = forecasted peak witiout load control, conservation, and customer-owned self-service cogeneration.
Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.2
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2002/03	11,553	1,538	10,015	271	795	312	27	122	191	9,833
2003/04	9,323	1,167	8,156	498	788	342	26	123	262	7,284
2004/05	10,830	1,600	9,230	575	779	371	26	123	283	8,673
2005/06	10,698	1,467	9,231	298	762	413	26	124	239	8,835
2006/07	9,896	1,576	8,320	304	671	453	26	126	262	8,055
2007/08	10,964	1,828	9,136	234	763	487	34	132	278	9,036
2008/09	12,092	2,229	9,863	268	759	522	71	147	291	10,034
2009/10	13,698	2,189	11,509	246	651	567	80	162	322	11,670
2010/11	11,347	1,625	9,722	271	661	633	94	179	214	9,295
2011/12	9,715	905	8,810	186	639	681	96	202	210	7,702
FORECAST:										
2012/13	11,203	909	10,294	254	672	735	100	216	239	8,987
2013/14	11,386	942	10,445	256	681	786	103	230	240	9,090
2014/15	12,081	1,445	10,636	259	690	836	106	239	242	9,709
2015/16	12,274	1,447	10,828	258	699	877	109	246	243	9,841
2016/17	12,423	1,394	11,029	267	717	917	113	254	245	9,910
2017/18	12,624	1,394	11,230	269	750	947	116	260	247	10,036
2018/19	12,840	1,394	11,446	283	759	975	119	267	250	10,188
2019/20	13,055	1,394	11,661	297	768	1,009	122	273	252	10,335
2020/21	13,263	1,394	11,869	305	777	1,040	126	276	254	10,485
2021/22	13,459	1,394	12,065	305	786	1,069	129	279	256	10,635

Historical Values (2003 - 2012):
Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.
Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).
Projected Values (2013 - 2022):
Cols. (2) - (4) forecasted peak without load control and conservation.
Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.3
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
BASE CASE

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
HISTORY:									
2003	45,234	402	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,834	426	360	780	38,193	4,301	2,774	45,268	56.5
2005	48,475	455	363	779	39,177	5,195	2,506	46,878	52.3
2006	47,399	484	365	509	39,432	4,220	2,389	46,041	52.1
2007	49,310	511	387	779	39,282	5,598	2,753	47,633	52.3
2008	49,208	543	442	565	38,556	6,619	2,483	47,658	53.1
2009	45,978	583	492	779	37,824	3,696	2,604	44,124	44.5
2010	48,135	638	558	779	38,925	3,493	3,742	46,160	45.3
2011	44,580	687	624	779	37,597	2,712	2,181	42,490	46.7
2012	43,396	733	669	780	36,381	826	4,007	41,214	51.7
FORECAST:									
2013	43,146	778	718	864	36,984	1,410	2,392	40,786	51.8
2014	43,995	821	745	864	37,683	1,474	2,408	41,565	52.2
2015	45,039	857	769	864	38,470	1,627	2,452	42,549	50.0
2016	45,970	891	792	866	39,069	1,822	2,530	43,421	50.2
2017	46,418	918	812	864	39,643	1,705	2,476	43,824	50.5
2018	47,091	944	831	864	40,230	1,675	2,547	44,452	50.6
2019	47,720	969	850	864	40,823	1,630	2,584	45,037	50.5
2020	48,384	996	868	866	41,404	1,637	2,613	45,654	50.3
2021	48,950	1,021	886	864	41,928	1,609	2,642	46,179	50.3
2022	49,500	1,044	903	864	42,410	1,610	2,669	46,689	50.1

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration.

** Load Factors for historical years are calculated using the actual winter peak demand except the 2004, 2007 & 2012 historical load factors which are based on the actual summer peak demand which became the annual peak for the year.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2)

PROGRESS ENERGY FLORIDA

SCHEDULE 4
PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	A C T U A L 2012		F O R E C A S T 2013		F O R E C A S T 2014	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	8,722	3,097	10,128	3,060	10,246	3,152
FEBRUARY	8,519	2,799	8,741	2,722	8,836	2,774
MARCH	6,135	3,128	7,708	2,959	7,804	2,990
APRIL	7,004	3,164	8,022	3,050	8,075	3,080
MAY	7,942	3,780	8,973	3,661	9,036	3,706
JUNE	8,185	3,699	9,389	4,006	9,456	4,093
JULY	9,026	4,278	9,564	4,123	9,636	4,212
AUGUST	8,850	4,218	9,669	4,213	9,742	4,296
SEPTEMBER	8,103	3,797	8,969	3,866	9,026	3,958
OCTOBER	7,790	3,478	8,473	3,265	8,544	3,342
NOVEMBER	5,749	2,739	7,081	2,812	7,104	2,855
DECEMBER	6,555	3,036	8,038	3,051	8,658	3,107
TOTAL		41,213		40,788		41,565

NOTE: Recorded Net Peak demands and System requirements including off-system wholesale contracts.

FUEL REQUIREMENTS AND ENERGY SOURCES

PEF's actual and projected nuclear, coal, oil, and gas requirements (by fuel unit) are shown in Schedule 5. PEF's two-year actual and ten-year projected energy sources by fuel type are presented in Schedules 6.1 and 6.2, in GWh and percent (%) respectively. PEF's fuel requirements and energy sources reflect a diverse fuel supply system that is not dependent on any one fuel source. Near term natural gas consumption is projected to increase as plants and purchases with tolling agreements are added to meet future load growth and natural gas generation costs reflect relatively attractive natural gas commodity pricing.

PROGRESS ENERGY FLORIDA

SCHEDULE 5
FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
		FUEL REQUIREMENTS	UNITS	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1,000 TON	4,663	4,543	5,381	5,369	5,484	4,925	4,951	4,726	4,497	4,030	3,843	3,814
(3)	RESIDUAL	TOTAL	1,000 BBL	380	89	0	0	0	0	0	0	0	0	0	0
(4)		STEAM	1,000 BBL	380	89	0	0	0	0	0	0	0	0	0	0
(5)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	256	160	316	325	402	846	835	517	458	236	168	241
(9)		STEAM	1,000 BBL	61	60	63	39	39	18	12	11	14	10	10	10
(10)		CC	1,000 BBL	8	1	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	187	99	253	286	363	827	823	506	444	226	157	231
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	183,363	187,251	177,253	188,213	192,618	185,192	174,966	194,327	206,682	230,055	241,711	245,067
(14)		STEAM	1,000 MCF	23,033	26,837	25,055	32,353	35,813	31,908	29,034	26,936	28,087	25,910	26,650	25,709
(15)		CC	1,000 MCF	151,176	155,717	142,259	145,347	144,571	138,185	131,519	155,331	167,608	195,979	207,251	209,755
(16)		CT	1,000 MCF	9,154	4,697	9,939	10,512	12,234	15,100	14,413	12,060	10,986	8,167	7,810	9,603
	OTHER (SPECIFY)														
(17)	OTHER, DISTILLATE	ANNUAL FIRM INTERCHANGE	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(18)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CC	1,000 MCF	0	0	8,494	9,464	10,165	31,831	45,266	32,360	25,945	14,297	9,113	9,411
(18.1)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CT	1,000 MCF	0	0	6,773	6,681	8,633	12,078	11,481	9,360	10,294	6,000	5,592	6,018
(19)	OTHER, COAL	ANNUAL FIRM INTERCHANGE, STEAM	1,000 TON	0	0	229	223	244	80	0	0	0	0	0	0

PROGRESS ENERGY FLORIDA

SCHEDULE 6.1
ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	1,917	1,558	663	654	845	4,490	6,449	4,231	3,175	1,252	409	458
(2)	NUCLEAR		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	10,809	10,003	11,761	11,758	12,003	10,882	10,952	10,456	9,926	8,777	8,336	8,288
(4)	RESIDUAL	TOTAL	GWh	187	46	0	0	0	0	0	0	0	0	0	0
(5)		STEAM	GWh	187	46	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	81	104	84	95	123	281	273	167	146	81	57	88
(10)		STEAM	GWh	2	63	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	4	1	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	75	39	84	95	123	281	273	167	146	81	57	88
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	23,571	23,997	23,159	24,423	24,855	23,478	22,124	25,481	27,531	31,592	33,532	33,946
(15)		STEAM	GWh	1,826	2,175	2,075	2,849	3,198	2,744	2,433	2,307	2,465	2,244	2,327	2,251
(16)		CC	GWh	20,775	21,469	20,204	20,644	20,580	19,504	18,539	22,168	24,140	28,612	30,498	30,818
(17)		CT	GWh	970	353	879	931	1,077	1,230	1,152	1,006	926	736	707	878
(18)	OTHER 2/														
	QF PURCHASES		GWh	2,423	2,767	2,174	1,571	1,565	1,657	1,656	1,652	1,640	1,577	1,522	1,523
	RENEWABLES		GWh	1,243	1,183	1,286	1,290	1,243	1,267	1,265	1,262	1,252	1,182	1,107	1,131
	IMPORT FROM OUT OF STATE		GWh	2,275	1,559	1,659	1,775	1,917	1,365	1,104	1,202	1,368	1,193	1,216	1,255
	EXPORT TO OUT OF STATE		GWh	-16	-4	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	42,490	41,213	40,786	41,565	42,549	43,421	43,824	44,452	45,037	45,654	46,179	46,689

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.
2/ NET ENERGY PURCHASED (+) OR SOLD (-).

PROGRESS ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	ANNUAL FIRM INTERCHANGE 1/		%	4.5%	3.8%	1.6%	1.6%	2.0%	10.3%	14.7%	9.5%	7.1%	2.7%	0.9%	1.0%
(2)	NUCLEAR		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	COAL		%	25.4%	24.3%	28.8%	28.3%	28.2%	25.1%	25.0%	23.5%	22.0%	19.2%	18.1%	17.8%
(4)	RESIDUAL	TOTAL	%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		STEAM	%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	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)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	0.2%	0.3%	0.2%	0.2%	0.3%	0.6%	0.6%	0.4%	0.3%	0.2%	0.1%	0.2%
(10)		STEAM	%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.2%	0.1%	0.2%	0.2%	0.3%	0.6%	0.6%	0.4%	0.3%	0.2%	0.1%	0.2%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	55.5%	58.2%	56.8%	58.8%	58.4%	54.1%	50.5%	57.3%	61.1%	69.2%	72.6%	72.7%
(15)		STEAM	%	4.3%	5.3%	5.1%	6.9%	7.5%	6.3%	5.6%	5.2%	5.5%	4.9%	5.0%	4.8%
(16)		CC	%	48.9%	52.1%	49.5%	49.7%	48.4%	44.9%	42.3%	49.9%	53.6%	62.7%	66.0%	66.0%
(17)		CT	%	2.3%	0.9%	2.2%	2.2%	2.5%	2.8%	2.6%	2.3%	2.1%	1.6%	1.5%	1.9%
(18)	OTHER 2/														
	QF PURCHASES		%	5.7%	6.7%	5.3%	3.8%	3.7%	3.8%	3.8%	3.7%	3.6%	3.5%	3.3%	3.3%
	RENEWABLES		%	2.9%	2.9%	3.2%	3.1%	2.9%	2.9%	2.9%	2.8%	2.8%	2.6%	2.4%	2.4%
	IMPORT FROM OUT OF STATE		%	5.4%	3.8%	4.1%	4.3%	4.5%	3.1%	2.5%	2.7%	3.0%	2.6%	2.6%	2.7%
	EXPORT TO OUT OF STATE		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

2/ NET ENERGY PURCHASED (+) OR SOLD (-).

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

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

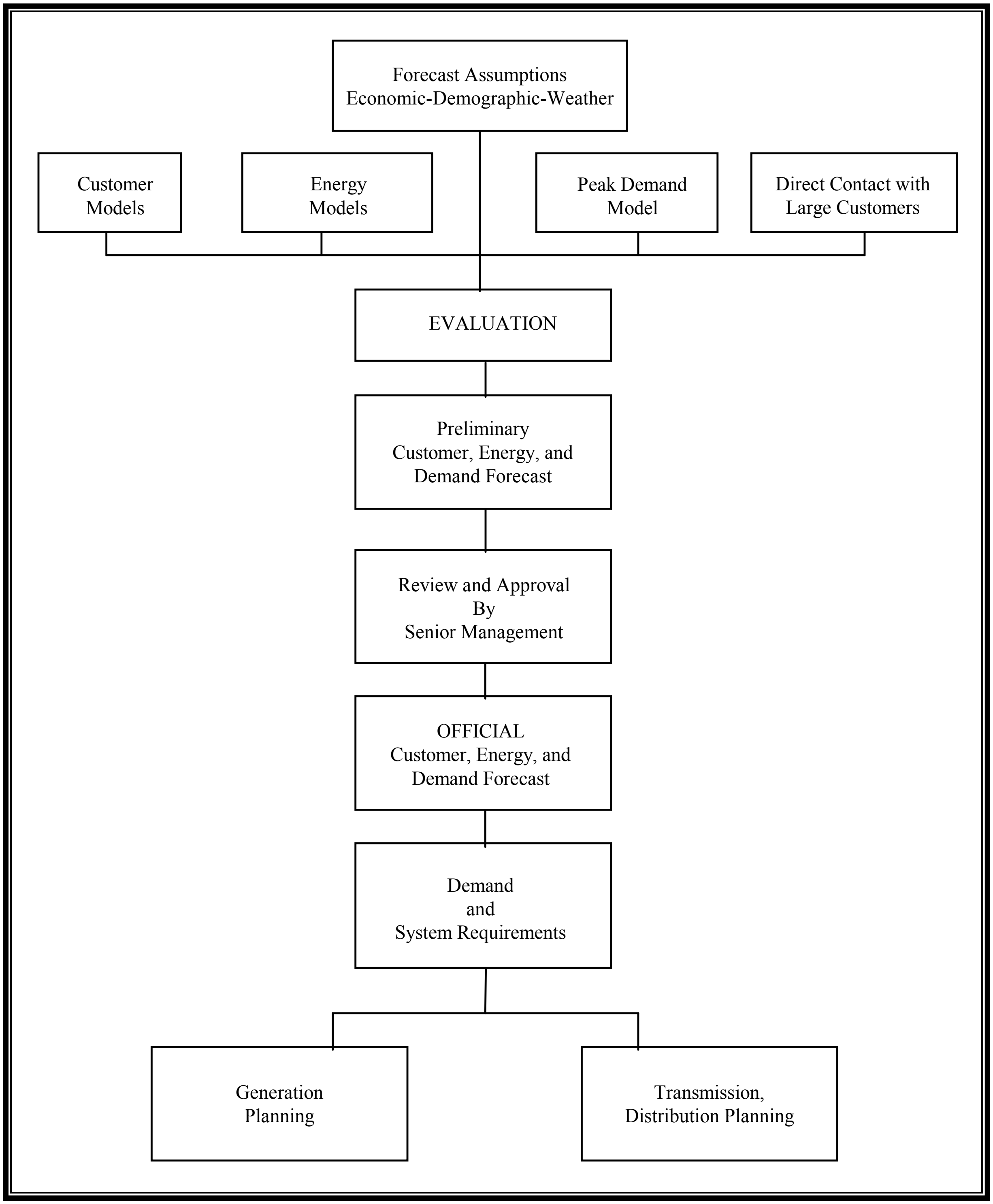
Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of PEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage, as well as customer growth, based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the tools needed to frame the most likely scenario of the Company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. A collaborative internal Company effort develops these assumptions including the research efforts of a number of external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions forms the basis for the forecast presented in this document.

FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

1. Normal weather conditions for energy sales are assumed over the forecast horizon using a sales-weighted "modified" 20-year average of conditions at seven weather stations across Florida (Saint Petersburg, Tampa, Orlando, Winter Haven, Gainesville, Daytona Beach, and Tallahassee). For kilowatt-hour (kWh) sales projections, the normal weather calculation begins with a historical 20-year average of the service area weighted billing month degree-days then removes the two largest outliers from this average for each of the 12 months for both the heating season and cooling season. Seasonal peak demand projections are based on a 30-year historical average of system-weighted temperatures at time of seasonal peak at the Tampa, Orlando, and Tallahassee weather stations; the other weather stations are not used in developing the historic average because they lack the historic hourly data needed for peak-weather normalization.

2. The population projections produced by the BEBR at the University of Florida as published in "Florida Population Studies," Bulletin No. 162 (March 2012) provided the basis for development of the customer forecast. The projection incorporated the results of the 2010 decennial census for Florida counties which includes a historical review of the years 1991-2009 for each county. The PEF methodology aggregates a 29 county area representative of the retail service territory. National and Florida economic projections produced by Moody's Analytics in their August 2012 forecast provided the basis for development of the energy forecast.

3. Within the PEF service area, the phosphate mining industry is the dominant sector in the industrial sales class. Four major customers accounted for over 30 percent of the industrial class MWh sales in 2012. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. The supply and demand (price) for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. The price of the raw mined commodity often dictates production levels. Load and energy consumption at the PEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by these global as well as the local conditions, including environmental regulations. Going forward, a weaker U.S. currency

value on the foreign exchange is expected to help the industry in two ways. First, American farm commodities have become more competitive overseas which has contributed to higher crop production at home. Second, a weak U.S. dollar results in U.S. fertilizer producers to become more price competitive relative to foreign producers. The PEF forecast calls for an increase in annual electric energy consumption levels for fertilizer producers. A risk to this projection lies in the price of energy, which is a major cost of both mining and producing phosphoric fertilizers. Fuel charges embedded in PEF's rates versus competitors' rates play a role as to where a mining customer directs output from self-owned generation facilities. This can reduce load for the utility.

4. PEF supplies load and energy service to wholesale customers on a "full," "partial," and "supplemental" requirement basis. Full requirements (FR) customers' demand and energy are assumed to grow at a rate that approximates their historical trend. However, the impact of the current recession has reduced short term growth expectations. Contracts for this service include the cities of Chattahoochee, Mt. Dora and Williston. Partial requirements (PR) customer load is assumed to reflect the current contractual obligations reflected by the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for PR service included in this forecast are with the Reedy Creek Improvement District (RCID), Seminole Electric Cooperative, Inc. (SECI), and the cities of New Smyrna Beach, Gainesville, Homestead and Winter Park.

   PEF has negotiated several power sales agreements with SECI beginning in various years over the ten-year horizon. An existing contractual arrangement is a "supplemental" service contract providing energy over and above stated levels they commit to supply themselves. This contract terminates in December 2013. Stratified partial requirements agreements over the next ten years include base strata, intermediate strata, a seasonal peaking strata and a system average sale. Finally, an agreement to provide interruptible service at a SECI metering site has also been included in this projection.

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

6. This forecast incorporates demand and energy reductions expected to be realized through currently offered DSM programs.

7. Expected energy and demand reductions from customer-owned self-service cogeneration facilities are also included in this forecast. This projection assumes an increase of over 15 MW of self-service generation beginning in 2013 from two customers. PEF will supply the supplemental load of self-service cogeneration customers. While PEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for power at time of peak.

8. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the forecast does not plan for generation resources unless a long-term contract is in place. FR customers are typically assumed to renew their contracts with PEF except those who have termination provisions and have given their notice to terminate. PR contracts are typically projected to terminate as terms reach their expiration date.

SHORT-TERM ECONOMIC ASSUMPTIONS

The economic outlook for this forecast was developed in the summer of 2012 as the nation displayed positive signs of growth. Most economic indicators pointed to better days ahead but Washington policy-makers continued to debateover pro-growth versus deficit reduction strategies which prolong uncertainty for consumers, employers and capital investment decision-makers. Consumer confidence and sentiment surveys have bounced back as the unemployment rate has dropped and stock market indexes are at double the levels reached at the trough of the recession.

This forecast tried to weigh two opposing opinions of future economic outlooks. One view sees continued improvement in several economic series. This view suggests that eventually, a de-leveraging American consumer will begin to spend again, feeling more secure about the outlook. The newfound abundance of American energy supplies, creating additional job growth and low natural gas prices, is expected to improve the country's competitive advantage in several manufacturing sectors. Manufacturing activities returning to the U.S. have been reported. An alternative view anticipates an increasingly weaker national picture driven by weak demand from the debt-laden Euro-Zone economies. Policies requiring severe austerity measures to reduce sovereign debt levels are expected to lead to weak growth in Europe as well as in the U.S. This view suggests that a continued de-leveraging of the American consumer, lower job growth and tight credit standards dim hopes for a healthy short-term recovery. The commencement of the Affordable Care Act in 2014 continues to drive uncertainty for employers as a lack of understanding still remains.

The Federal Reserve Board policy of "quantitative easing" can claim some success for the improved housing market. Low mortgage rates have led to very low inventories of homes for sale and prices have begun to rise. Higher home prices help both homeowners and lenders by improving their financial security. Probably the best test that the economy has turned the corner will come as job growth reaches over 200,000 jobs per month and gains in "earned" income out-grow inflation.

In summary, the short term assumptions underlying this forecast are based on an economic outlook that involves a slower than normal recovery. Financial instability, whether it is called the "Fiscal Cliff", "sequestration" or "deficit reduction", will likely reduce economic growth from the public sector as well as stifle private sector decision-making in the near term.

LONG-TERM ECONOMIC ASSUMPTIONS

The long term economic outlook assumes that changes in economic and demographic conditions, as well as technological change impacting the electric utility industry, will follow a historical behavior pattern. The main focus involves identifying these trends. No attempt is made to predict business cycle fluctuations or rapid penetration of a significant technological breakthrough impacting electric utility energy sales during this period.

Population Growth Trends

This forecast assumes Florida will experience higher near-term population growth as economic recovery takes hold, as reflected in the BEBR projections. Florida's climate and low cost of living have historically attracted a major share of the retirement population from the eastern half of the United States. Florida is expected to continue to be an attractive state for the increasing population of baby-boom generation retirees. Working against this significant trend will be several aesthetic and economic factors. First, the enormous growth in population and corresponding development of the 1980s, 1990s, and early 2000s made portions of Florida less desirable and less affordable for retirement living. This perceived diminished quality of retiree life, along with increasing competition from neighboring states, will cause a slight decline in Florida's share of these prospective new residents over the long term. Second, and to a lesser extent, there is a lingering fear for safety and expense from hurricane damage.

Economic Growth Trends

The Florida economy has always relied upon agriculture, tourism and development to serve as its economic growth engine. Recent efforts have been made to further diversify into the bioscience-related industries with some success. Setbacks, such as the severe financial crisis and the ending of a large piece of NASA's space flight industry, however, have left Florida significantly challenged. Declining revenues have forced budget cutbacks in most government departments and delays or cancelation of many state-supported projects. As with every previous recession, however, conditions are anticipated to improve and economic growth is assumed to return.

As a state with growing energy needs and a rapidly increasing average-aged population, Florida stands to benefit from strides currently being made in the health, technology and energy sectors. The nation has also realized the economic benefits that come from trade. Several Florida ports are being expanded to handle larger shipping vessels that will travel through an expanded Panama Canal. Florida has developed close trading ties with South America which has several countries that have developed into major emerging markets. Renewing economic ties with Cuba is now a reasonable possibility that could benefit the state. These trends along with an eventual turnaround in the state housing sector will lead to the assumed level of economic growth in the forecast.

FORECAST METHODOLOGY

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

ENERGY AND CUSTOMER FORECAST

In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and annual data for customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting concerns. The external sources of data include Moody's Analytics and the University of Florida's BEBR. Internal company forecasts are used for projections of electricity price, weather conditions, and the length of the billing month. Normal weather, which is assumed throughout the forecast horizon, is based on a twenty-year modified average of heating and cooling degree-days by month as measured at several weather stations throughout Florida for energy projections and temperatures around the hour of peak for the firm retail demand forecast. Projections of PEF's demand-side management (conservation) programs are also incorporated as reductions to the forecast. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled as a function of real median household income, cooling degree-days, heating degree-days, the real price of electricity to the residential class and the average number of billing days in each sales month. This equation captures significant variation in residential usage caused by economic cycles, weather fluctuations, electric price movements, and sales month duration. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating annual customer growth with PEF service area population growth. County level population projections for counties in which PEF serves residential customers are provided by the BEBR.

Commercial Sector

Commercial MWh energy sales are forecast based on commercial sector (non-agricultural, non-manufacturing and non-governmental) employment, the real price of electricity to the commercial class, the average number of billing days in each sales month and heating and cooling degree-days. The measure of cooling degree-days utilized here differs slightly from that used in the residential sector reflecting different temperature base sensitivities, when heating and cooling load become observable. Commercial customers are projected as a function of the number of residential customers served.

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use is consumed by the phosphate mining industry. Because this one industry is such a large share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted significantly by changes in economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using Florida manufacturing employment and a Florida industrial production index, the real price of electricity to the industrial class, and the average number of sales month billing days.

The industrial phosphate mining industry is modeled using customer-specific information with respect to expected market conditions. Since this sub-sector is comprised of only four customers, the forecast is dependent upon information received from direct customer contact. PEF industrial customer representatives provide specific phosphate customer information regarding customer production schedules, inventory levels, area mine-out, start-up predictions, and changes in self-service generation or energy supply situations over the forecast horizon.

Street Lighting

Electricity sales to the street and highway lighting class have remained flat for years but have declined recently. A continued decline is expected as improvements in lighting efficiency are projected. The number of accounts, which has dropped by more than one-third since 1995 due to most transferring to public authority ownership, is expected to decline further before leveling off in the intermediate term. A simple time-trend was used to project energy consumption and customer growth in this class.

Public Authorities

Energy sales to public authorities (SPA), comprised mostly of government operated services, is also projected to grow with the size of the service area. The level of government services, and thus energy, can be tied to the population base, as well as to the state of the economy. Factors affecting population growth will affect the need for additional governmental services (i.e. public schools, city services, etc.) thereby increasing SPA energy consumption. Government employment has been determined to be the best indicator of the level of government services provided. This variable, along with heating and cooling degree-days (class specific), the real price of electricity and the average number of sales month billing days, results in a significant level of explained variation over the historical sample period. Adjustments are also included in this model to account for the large change in school-related energy use in the billing months of January, July, and August. The SPA customer forecast is projected linearly as a function of a time-trend. Recent budget issues have also had an impact on the near-term pace of growth.

Sales for Resale Sector

The Sales for Resale sector encompasses all firm sales to other electric power entities. This includes sales to other utilities (municipal or investor-owned) as well as power agencies (rural electric authority or municipal).

Seminole Electric Cooperative, Inc. (SECI) is a wholesale, or sales for resale, customer of PEF on both a supplemental contract basis and contract demand basis. Under the supplemental contract, PEF provides service for those energy requirements above the level of generation capacity served by either SECI's own facilities or its firm purchase obligations. Monthly supplemental energy is developed using an average historical load shape of total SECI load in the PEF control area, subtracting out the level of SECI "committed" capacity from each hour. Beyond supplemental service, PEF has several agreements with SECI to serve various types of stratified demand levels deemed by their resource planners as necessary to meet their load characteristics and reserve requirements.

The municipal sales for resale class includes a number of customers, divergent not only in scope of service, (i.e. full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. Three customers in this class, Chattahoochee, Mt. Dora and Williston are municipalities whose full energy requirements are supplied by PEF. The full requirement customers' energy projections grow at a rate that approximates their historical trend with additional information coming from the respective city officials. PEF serves partial requirement service (PR) to municipalities such as New Smyrna Beach, Homestead, Gainesville and Winter Park, and another power provider Reedy Creek Improvement District (RCID). In each case, these customers contract with PEF for a specific level and type of demand needed to provide their particular electrical system with an appropriate level of reliability. The energy forecast for each contract is derived using its historical load factors where enough history exists, or typical load factors for a given type of contracted stratified load.

PEAK DEMAND FORECAST

The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, PEF's coincident system peak is separated into five major components. These components consist of potential firm retail load, conservation and load management program capability, wholesale demand, company use demand, and interruptible demand.

Potential firm retail load refers to projections of PEF retail hourly seasonal net peak demand (excluding the non-firm interruptible/curtailable/standby services) before any historical cumulative effects of company-aided conservation activity or the activation of PEF's General Load Reduction Plan. The historical values of this series are constructed to show the size of PEF's firm retail net peak demand assuming no utility induced conservation or load control had ever taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to total system customer levels and coincident weather conditions at the time of the peak without the impacts of year-to-year variation in conservation activity or load control reductions. Seasonal peaks are projected using historical seasonal peak data regardless of which month the peak occurred. The projections become the potential retail demand projection for the months of January (winter) and August (summer) since this is typically when the seasonal peaks occur. The non-seasonal peak months are projected the same as the seasonal peaks, but the analysis is limited to the specific month being projected.

Energy conservation and direct load control estimates are consistent with PEF's DSM goals that have been established by the FPSC. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM impacts are subtracted from the projection of potential firm retail demand resulting in a projected series of retail monthly peak demand figures.

Sales for Resale demand projections represent load supplied by PEF to other electric suppliers such as SECI, RCID, and other electric transmission and distribution entities. The SECI supplemental demand projection is based on SECI's projection of total load in the PEF control area. The level of MW to be served by PEF is dependent upon the amount of generation resources SECI supplies itself or contracts from others. For Partial Requirement demand projections, contracted MW levels dictate the level of monthly demands. The Full Requirement municipal demand forecast is estimated for individual cities using historically trended growth rates adjusted for current economic conditions.

PEF "company use" at the time of system peak is estimated using load research metering studies and is assumed to remain stable over the forecast horizon as it has historically. The interruptible and curtailable service (IS and CS) load component is developed from historic trends, as well as the incorporation of specific information obtained from PEF's large industrial accounts by account executives.

Each of the peak demand components described above is a positive value except for the DSM program MW impacts and IS and CS load. These impacts represent a reduction in peak demand and are assigned a negative value. Total system firm peak demand is then calculated as the arithmetic sum of the five components.

CONSERVATION

On August 16, 2011, the PSC issued Order No. PSC-11-0347-PAA-EG, Modifying and Approving the Demand Side Management Plan of PEF. In this Order, the FPSC modified PEF's DSM Plan to consist of those existing programs in effect as of the date of the Order.

The following tables show the 2010, 2011 and 2012 achievements from PEF's existing set of DSM programs.

Residential Conservation Savings Cumulative Achievements

Year	Summer MW	Winter MW	GWh Energy
	Achieved	Achieved	Achieved
2010	43	85	58
2011	82	160	110
2012	115	229	156

Commercial Conservation Savings Cumulative Achievements

Year	Summer MW	Winter MW	GWh Energy
	Achieved	Achieved	Achieved
2010	36	32	66
2011	65	61	132
2012	92	81	196

Total Conservation Savings Cumulative Achievements

Year	Summer MW	Winter MW	GWh Energy
	Achieved	Achieved	Achieved
2010	79	116	124
2011	148	221	242
2012	208	310	352

PEF's currently approved DSM programs consist of six residential programs, eight commercial and industrial programs, one research and development program, and six solar pilot programs. The programs are subject to periodic monitoring and evaluation for the purpose of ensuring that all demand-side resources are acquired in a cost-effective manner and that the program savings are durable. The following is a brief description of these programs. In 2012, PEF received administrative approval of revisions to four programs as a result of changes to the Florida Building Code: Home Energy Improvement, Residential New Construction, Business New Construction and Better Business. The Building Code changes resulted in increased minimum efficiency levels which resulted in an increase in the baseline efficiency level from which PEF provides incentives. The revisions to the programs are incorporated in the descriptions below.

RESIDENTIAL PROGRAMS

Home Energy Check

This energy audit program provides customers with an analysis of their current energy use and recommendations on how they can save on their electricity bills through low-cost or no-cost energy-saving practices and measures. The Home Energy Check program offers PEF customers the following types of audits: Type 1: Free Walk-Through Audit (Home Energy Check); Type 2: Customer-Completed Mail-In Audit (Do It Yourself Home Energy Check); Type 3: Online Home Energy Check (Internet Option)-a customer-completed audit; Type 4: Phone Assisted Audit – a customer assisted survey of structure and appliance use; Type 5: Computer Assisted Audit; Type 6: Home Energy Rating Audit (Class I, II, III); Type 7: Student Mail In Audit - a student-completed audit. The Home Energy Check program serves as the foundation of the

Home Energy Improvement program in that the audit is a prerequisite for participation in the energy saving measures offered in the Home Energy Improvement program.

Home Energy Improvement

This is the umbrella program to increase energy efficiency for existing residential homes. It combines efficiency improvements to the thermal envelope with upgrades to electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, and high efficiency electric heat pumps. Additional measures within this program include spray-in wall insulation, central AC 14 Seasonal Energy Efficiency Ratio (SEER) non-electric heat, and proper sizing of high efficiency Heating, Ventilation and Air Conditioning (HVAC) systems, HVAC commissioning, reflective roof coating for manufactured homes, reflective roof for single-family homes, window film or screen, and replacement windows.

Residential New Construction

This program promotes energy efficient new home construction in order to provide customers with more efficient dwellings combined with improved environmental comfort. The program provides education and information to the design and building community on energy efficient equipment and construction. It also facilitates the design and construction of energy efficient homes by working directly with the builders to comply with program requirements. The program provides incentives to the builder for high efficiency electric heat pumps and high performance windows. The highest level of the program incorporates the U.S. Environmental Protection Agency's Energy Star Homes Program and qualifies participants for cooperative advertising. Additional measures within the Residential New Construction program include HVAC commissioning, window film or screen, reflective roof for single-family homes, attic spray-on foam insulation, conditioned space air handler, and energy recovery ventilation.

Low Income Weatherization Assistance

This umbrella program seeks to improve energy efficiency for low-income customers in existing residential dwellings. It combines efficiency improvements to the thermal envelope with upgrades to electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, HVAC maintenance, high efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters.

Neighborhood Energy Saver

This program consists of 12 measures including compact fluorescent bulb replacement, water heater wrap and insulation for water pipes, water heater temperature check and adjustment, low-flow faucet aerator, low-flow showerhead, refrigerator coil brush, HVAC filters, and weatherization measures (i.e. weather stripping, door sweeps, etc.). In addition to the installation of new conservation measures, an important component of this program is educating families on energy efficiency techniques and the promotion of behavioral changes to help customers control their energy usage.

Residential Energy Management (EnergyWise)

This program allows PEF to reduce peak demand and thus defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio-controlled switches installed on the customer's premises. These interruptions are at PEF's option, during specified time periods, and coincident with hours of peak demand. Participating customers receive a monthly credit on their electricity bills prorated above 600 kWh per month.

COMMERCIAL/INDUSTRIAL (C/I) PROGRAMS

Business Energy Check

This energy audit program provides commercial and industrial customers with an assessment of the current energy usage at their facilities, recommendations on how they can improve the environmental conditions of their facilities while saving on their electricity bills, and information on low-cost energy efficiency measures. The Business Energy Check consists of a free walk-through audit and a paid walk-through audit. Small business customers also have the option to complete a Business Energy Check online at Progress Energy's website. In most cases, this program is a prerequisite for participation in the other C/I programs.

Better Business

This is the umbrella efficiency program for existing commercial and industrial customers. The program provides customers with information, education, and advice on energy-related issues as well as incentives on efficiency measures. The Better Business program promotes energy efficient HVAC, building retrofit measures (in particular, ceiling insulation upgrade, duct leakage test and repair, energy-recovery ventilation, and Energy Star cool roof coating products), demand-control ventilation, efficient compressed air systems, efficient motors, efficient indoor lighting, green roof, occupancy sensors, packaged AC steam cleaning, roof insulation, roof-top unit recommissioning, thermal energy storage and window film or screen.

Commercial/Industrial New Construction

The primary goal of this program is to foster the design and construction of energy efficient buildings. The new construction program: 1) provides education and information to the design community on all aspects of energy efficient building design; 2) requires that the building design, at a minimum, surpass the State of Florida energy code; 3) provides financial incentives for specific energy efficient equipment; and 4) provides energy design awards to building design teams. Incentives are available for high efficiency HVAC equipment, energy recovery ventilation, Energy Star cool roof coating products, demand-control ventilation, efficient compressed air systems, efficient motors, efficient indoor lighting, green roof, occupancy sensors, roof insulation, thermal energy storage and window film or screen.

Innovation Incentive

This program promotes a reduction in demand and energy by subsidizing energy conservation projects for PEF customers. The intent of the program is to encourage legitimate energy efficiency measures that reduce peak demand and/or energy, but are not addressed by other programs. Energy efficiency opportunities are identified by PEF representatives during a Business Energy Check audit. If a candidate project meets program specifications, it may be eligible for an incentive payment, subject to PEF approval.

Commercial Energy Management (Rate Schedule GSLM-1)

This direct load control program reduces PEF's demand during peak or emergency conditions. As described in PEF's DSM Plan, this program is currently closed to new participants. It is applicable to existing program participants who have electric space cooling equipment suitable for interruptible operation and are eligible for service under the Rate Schedule GS-1, GST-1, GSD-1, or GSDT-1. The program is also applicable to existing participants who have any of the following electrical equipment installed on permanent structures and utilized for the following purposes: 1) water heater(s), 2) central electric heating systems(s), 3) central electric cooling system(s), and or 4) swimming pool pump(s). Customers receive a monthly credit on their bills depending on the type of equipment in the program and the interruption schedule.

Standby Generation

This demand control program reduces PEF's demand based upon the indirect control of customer generation equipment. This is a voluntary program available to all commercial, industrial, and agricultural customers who have on-site generation capability of at least 50 kW, and are willing to reduce their demand when PEF deems it necessary. Customers participating in the Standby Generation program receive a monthly credit on their electric bills according to their demonstrated ability to reduce demand at PEF's request.

Interruptible Service

This direct load control program reduces PEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to have their power interrupted. PEF will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. In return for the ability to interrupt load, customers participating in the Interruptible Service program receive a monthly credit applied to their electric bills.

Curtailable Service

This load control program reduces PEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to curtail 25 percent of their average monthly billing demand. Customers participating in the Curtailable Service program receive a monthly credit applied to their electric bills.

RESEARCH AND DEVELOPMENT PROGRAMS

Technology Development

The primary purpose of this program is to establish a system to "Aggressively pursue research, development and demonstration projects jointly with others as well as individual projects" (Rule 25-17.001(5)(f), Florida Administration Code). In accordance with the rule, the Technology Development program facilitates the research of innovative technologies and continued advances within the energy industry. PEF will undertake certain development, educational and demonstration projects that have potential to become DSM programs. Examples of such projects include the evaluation of Premise Area Networks that provide an increase in customer awareness of efficient energy usage while advancing demand response capabilities. Additional projects include the evaluation of off-peak generation with energy storage for on-peak demand consumption, small-scale wind and smart charging for plug-in hybrid electric vehicles. In most cases, each demand reduction and energy efficiency project that is proposed and investigated under this program requires field-testing with customers.

DEMAND-SIDE RENEWABLE PORTFOLIO

Solar Water Heating for the Low-income Residential Customers Pilot

This pilot program is designed to assist low-income families with energy costs by incorporating a solar thermal water heating system in their residence while it is under construction. PEF will collaborate with non-profit builders to provide low-income families with a residential solar thermal water heater. The solar thermal system will be provided at no cost to the non-profit builders or the residential participants.

Solar Water Heating with Energy Management

This program represents an updated version of the previous residential Renewable Energy Program. It encourages residential customers to install new solar thermal water heating systems on their residence with the requirement for customers to participate in our residential Energy

Management program (EnergyWise). Participants will receive a one-time $550 rebate designed to reduce the upfront cost of the renewable energy system, plus a monthly bill credit associated with their participation in the residential Energy Management program.

Residential Solar Photovoltaic Pilot

This pilot encourages residential customers to install new solar photovoltaic (PV) systems on their home. A PEF audit is required prior to system installation to qualify for this rebate. Participating customers will receive a one-time rebate of up to $20,000 to reduce the initial investment required to install a qualified renewable solar PV system. The rebate is based on the wattage of the PV (DC) power rating.

Commercial Solar Photovoltaic Pilot

This pilot encourages commercial customers to install new solar PV systems on their facilities. A PEF energy audit is required prior to system installation to qualify for this rebate. The program provides participating commercial customers with a tiered rebate to reduce the initial investment in a qualified solar PV system. The rebate is based on the PV (DC) power rating of the unit installed. The total incentives per participant will be limited to $130,000, based on a maximum installation of 100 kW.

Photovoltaic For Schools Pilot

This pilot is designed to assist schools with energy costs while promoting energy education. This program provides participating public schools with new solar photovoltaic systems at no cost to the school. The primary goals of the program are to:

- Eliminate the initial investment required to install a solar PV system
- Increase renewable energy generation on PEF's system
- Increase participation in existing residential Demand Side Management measures through energy education
- Increase solar education and awareness in PEF communities and schools

The program will be limited to an annual target of one system with a rating up to 100 KW installed on a post secondary public school and ten 10 KW systems with battery backup option installed on public K-12 schools, preferably serving as emergency shelters.

Research and Demonstration Pilot

The purpose of this program is to research technology and establish Research and Design initiatives to support the development of renewable energy pilot programs. Demonstration projects will provide real-world field testing to assist in the development of these initiatives. The program will be limited to a maximum annual expenditure equal to 5% of the total Demand-Side Renewable Portfolio annual expenditures.

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

As of December 31, 2012 PEF had a summer total capacity resource of 12,092 MW (see Table 3.1). This capacity resource includes nuclear (in February 2013 PEF announced the retirement of CR3, 789 MW), fossil steam (3,431 MW), combined-cycle plants (3,191 MW), combustion turbines (2,473 MW; 143 MW of which is owned by Georgia Power for the months June through September), utility purchased power (412 MW), independent power purchases (1,113 MW), and non-utility purchased power (683 MW). Table 3.2 presents PEF's firm capacity contracts with Renewable and Cogeneration Facilities.

Demand-Side Programs

Total DSM resources are presented in Schedules 3.1 and 3.2 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources.

Capacity and Demand Forecast

PEF's forecasts of capacity and demand for the projected summer and winter peaks can been found in Schedules 7.1 and 7.2, respectively. PEF's forecasts of capacity and demand are based on serving expected growth in retail requirements in its regulated service area and meeting commitments to wholesale power customers who have entered into supply contracts with PEF. In its planning process, PEF balances its supply plan for the needs of retail and wholesale customers and endeavors to ensure that cost-effective resources are available to meet the needs across the customer base.

Base Expansion Plan

PEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as PEF's Base Expansion Plan. This plan includes the retirement of Crystal River 3 in 2013, expected retirement of Crystal River 1 & 2 in 2016, planned power purchases from 2016 through 2020 and planned installation of combined cycle facilities in 2018 and 2020 at undesignated sites. The addition of Levy Unit 1 and Unit 2 are not included in this ten-year planning horizon but have planned in-service dates of 2024 and 2025, respectively. These additions depend, in part, on projected load growth, and obtaining all necessary state and federal permits under current schedules. Changes in these or other factors could impact PEF's Base Expansion Plan.

PEF's Base Expansion Plan projects the need for additional capacity with proposed in-service dates during the ten-year period from 2013 through 2022. The planned capacity additions, together with purchases from Qualifying Facilities (QF), Investor Owned Utilities, and Independent Power Producers help the PEF system meet the energy requirements of its customer base. The capacity needs identified in this plan may be impacted by PEF's ability to extend or replace existing purchase power, cogeneration and QF contracts and to secure new renewable purchased power resources in their respective projected timeframes. Status reports and specifications for the planned new generation facilities are included in Schedule 9. The planned transmission lines associated with PEF Bulk Electric System (BES) are shown in Schedule 10.

PEF announced the retirement of Crystal River Unit 3 effective January 31, 2013. This has been reflected in this TYSP.

The promulgation of the Mercury and Air Toxics Standards (MATS) by EPA in April of 2012 presents new environmental requirements for the PEF units at Anclote, Suwannee and Crystal River.

- The three steam units at Suwannee are capable of operation on both natural gas and residual oil. These units will be able to comply with the MATS rule by ceasing operation on residual oil prior to the April 2015 compliance date.
- PEF has begun a project at the Anclote facility to convert the two residual oil fired units there to 100% firing on natural gas. This project is expected to be complete by early second quarter of 2014. The project will result in no change to the output of the two units.

- NOx and SO_2 control equipment was added to Units 4 and 5 at Crystal River in 2009 and 2010. These environmental control upgrades are expected to enable these two units to operate in compliance with the requirements of the MATS, but PEF is conducting tests to confirm expected performance levels.
- Crystal River Units 1 and 2 are not capable of meeting the emissions requirements for MATS in their current configuration and using the current fuel. In addition, under the terms of the revised air permit, subject to approval of the State Implementation Plan for compliance with the requirements of the Clean Air Visible Haze Rule, these units are required to cease coal fired operation by the end of 2020 unless scrubbers are installed prior to the end of 2018. PEF anticipates retiring these units prior to 2020.
    - In this TYSP, PEF anticipates retiring these units in April of 2016 following the receipt of a one year MATS compliance extension from the Florida Department of Environmental Protection due to the need to make transmission grid upgrades to maintain reliability. PEF continues to evaluate alternatives that would allow these units to operate in compliance with MATS during the period 2015 – 2020.

Additional details regarding PEF's compliance strategies in response to the MATS rule are provided in PEF's annual update to the Integrated Clean Air Compliance Plan filed in Docket No. 130007-EI.

PEF continues to look ahead to the projected retirements of several of the older units in the fleet, particularly combustion turbines at Higgins, Avon Park, Turner and Rio Pinar as well as the three steam units at Suwannee. The Suwannee units are anticipated to have their operational lives extended to the spring of 2018. The other units continue to show anticipated retirement dates in 2016.

Given the retirements and anticipated retirements discussed above, particularly at the Crystal River Energy Complex, along with expected load growth, PEF is preparing to add additional resources in the period beginning in 2016.

- PEF is currently negotiating with a number of counterparties including cogenerators, independent power producers and neighboring utilities to purchase energy and firm capacity to supplement PEF's current owned generation and contracted resources. Based on PEF's current projected needs, these contracts will vary in capacity and length, projected to be principally 2, 4 and 5 year contracts. Anticipated energy and capacity supplied by these contracts are reflected in this TYSP. Specific counterparties are not identified as commercial negotiations are ongoing.

- PEF is preparing for the addition of two new combined cycle units, one in service beginning in 2018 and the other in 2020. Early development of the 2018 unit including site selection and preliminary engineering is currently underway. A preferred site for this unit has not yet been selected and thus is not reflected in Chapter 4.

TABLE 3.1

PROGRESS ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF
POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2012

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)	
Nuclear Steam			
Crystal River	1	789	*(1)*
Total Nuclear Steam	1	789	
Fossil Steam			
Crystal River	4	2,291	
Anclote	2	1,011	
Suwannee River	3	129	
Total Fossil Steam	9	3,431	
Combined Cycle			
Bartow	1	1,074	
Hines Energy Complex	4	1,912	
Tiger Bay	1	205	
Total Combined cycle	6	3,191	
Combustion Turbine			
DeBary	10	636	
Intercession City	14	986	*(2)*
Bayboro	4	174	
Bartow	4	177	
Suwannee	3	155	
Turner	4	134	
Higgins	4	105	
Avon Park	2	48	
University of Florida	1	46	
Rio Pinar	1	12	
Total Combustion Turbine	47	2,473	
Total Units	**63**		
Total Net Generating Capability		**9,884**	

(1) Adjusted for sale of approximately 8.2% of total capacity

(2) Includes 143 MW owned by Georgia Power Company (Jun-Sep)

Purchased Power			
Firm Qualifying Facility Contracts	13	683	
Investor Owned Utilities	2	412	
Independent Power Producers	2	1,113	
TOTAL CAPACITY RESOURCES		**12,092**	

TABLE 3.2

PROGRESS ENERGY FLORIDA
FIRM RENEWABLES
AND COGENERATION CONTRACTS

AS OF DECEMBER 31, 2012

Facility Name	Firm Capacity (MW)
Dade County Resource Recovery	43
El Dorado	114.2
Lake Cogen	110
Lake County Resource Recovery	12.8
LFC Jefferson	8.5
LFC Madison	8.5
Mulberry	115
Orange Cogen (CFR-Biogen)	74
Orlando Cogen	79.2
Pasco County Resource Recovery	23
Pinellas County Resource Recovery 1	40
Pinellas County Resource Recovery 2	14.8
Ridge Generating Station	39.6
TOTAL	**682.6**

PROGRESS ENERGY FLORIDA

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)
	TOTAL[a] INSTALLED CAPACITY	FIRM[b] CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF[c]	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2013	8,952	1,926	0	173	11,052	8,965	2,087	23%	0	2,087	23%
2014	8,952	1,831	0	177	10,960	9,026	1,935	21%	0	1,935	21%
2015	8,952	1,871	0	177	11,000	9,185	1,816	20%	0	1,816	20%
2016	7,898	3,340	0	177	11,415	9,442	1,974	21%	0	1,974	21%
2017	7,898	3,340	0	177	11,415	9,504	1,911	20%	0	1,911	20%
2018	8,958	2,840	0	177	11,975	9,674	2,301	24%	0	2,301	24%
2019	8,958	2,840	0	177	11,975	9,846	2,129	22%	0	2,129	22%
2020	10,147	1,860	0	177	12,185	10,017	2,168	22%	0	2,168	22%
2021	10,147	1,860	0	177	12,185	10,086	2,099	21%	0	2,099	21%
2022	10,334	1,860	0	177	12,371	10,252	2,119	21%	0	2,119	21%

Notes:

a. Total Installed Capacity does not include the 143 MW to Southern Company from Intercession City, P11.

b. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

c. QF includes Firm Renewables

PROGRESS ENERGY FLORIDA

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)
	TOTAL INSTALLED CAPACITY	FIRM[a] CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF[b]	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2012/13	10,996	2,121	0	173	13,290	8,987	4,303	48%	805	3,498	39%
2013/14	10,191	1,915	0	190	12,297	9,090	3,207	35%	0	3,207	35%
2014/15	10,191	1,915	0	177	12,284	9,710	2,574	27%	0	2,574	27%
2015/16	10,191	1,945	0	177	12,314	9,842	2,472	25%	0	2,472	25%
2016/17	9,089	3,424	0	177	12,691	9,910	2,781	28%	0	2,781	28%
2017/18	9,089	3,424	0	177	12,691	10,036	2,655	26%	0	2,655	26%
2018/19	10,265	2,924	0	177	13,366	10,188	3,178	31%	0	3,178	31%
2019/20	10,265	2,924	0	177	13,366	10,335	3,031	29%	0	3,031	29%
2020/21	11,571	1,944	0	177	13,693	10,485	3,208	31%	0	3,208	31%
2021/22	11,571	1,944	0	177	13,693	10,635	3,058	29%	0	3,058	29%

Notes:

a. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

b. QF includes Firm Renewables

PROGRESS ENERGY FLORIDA

SCHEDULE 8
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2013 THROUGH DECEMBER 31, 2022

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY[a]			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS[b]	NOTES[c]
CRYSTAL RIVER	3	CITRUS	NP	BIT		RR	WA		10/1966	1/2013		(789)	(805)	RT	(1)
ANCLOTE	1	PASCO	ST	NG		PL			4/2013			0	0	FC	(1)
ANCLOTE	2	PASCO	ST	NG		PL			12/2013			0	0	FC	(1)
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		10/1966	4/2016		(370)	(372)	RT	(1)
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		11/1969	4/2016		(499)	(503)	RT	(1)
HIGGINS	P1-4	PINELLAS	GT							d.		(105)	(116)	P	(1)
TURNER	P1-2	VOLUSIA	GT							d.		(20)	(26)	P	(1)
AVON PARK	P1-2	HIGHLANDS	GT							d.		(48)	(70)	P	(1)
RIO PINAR	P1	ORANGE	GT							d.		(12)	(15)	P	(1)
SUWANNEE RIVER	1-3	SUWANNEE	ST							e		(129)	(131)	P	(1)
UNKNOWN	1	UNKNOWN	CC					01/2015	06/2018			1189	1307	P	(1)
UNKNOWN	2	UNKNOWN	CC					01/2017	06/2020			1189	1307	P	(1)
UNKNOWN	1	UNKNOWN	CT					06/2020	06/2022			187	214	P	(1)

a. Net capability of Crystal River 3 represents approximately 91.8% PEF Ownership.
b. See page v. for Code Legend of Future Generating Unit Status.
c. NOTES
(1) Planned, Prospective, or Committed project.
d. Higgins P1-4, Turner P1-2, Avon Park P1-2, Rio Pinar P1 are expected to be shut down by 6/2016.
e. Suwannee 1-3 are expected to be shut down by 5/2018.

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2013

(1)	Plant Name and Unit Number:		**Undesignated CC1**	
(2)	Capacity			
	a. Summer:		1189	
	b. Winter:		1307	
(3)	Technology Type:		COMBINED CYCLE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		1/2015	
	b. Commercial in-service date:		6/2018	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		NATURAL GAS	
	b. Alternate fuel:		DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:		SCR and CO Catalyst	
(7)	Cooling Method:		Cooling Tower	
(8)	Total Site Area:		UNKNOWN	ACRES
(9)	Construction Status:		PLANNED	
(10)	Certification Status:		PLANNED	
(11)	Status with Federal Agencies:		PLANNED	
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		6.66	%
	b. Forced Outage Factor (FOF):		6.36	%
	c. Equivalent Availability Factor (EAF):		87.40	%
	d. Resulting Capacity Factor (%):		86.1	%
	e. Average Net Operating Heat Rate (ANOHR):		6,703	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		25	
	b. Total Installed Cost (In-service year $/kW):		1,403.25	
	c. Direct Construction Cost ($/kW):	($2013)	1,181.33	
	d. AFUDC Amount ($/kW):		127.95	
	e. Escalation ($/kW):		93.97	
	f. Fixed O&M ($/kW-yr):	($2013)	4.89	
	g. Variable O&M ($/MWh):	($2013)	4.19	
	h. K Factor:		NO CALCULATION	

NOTES
. Total Installed Cost includes gas expansion, transmission interconnection and integration
. $/kW values are based on Summer capacity
. Fixed O&M cost does not include firm gas transportation costs

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2013

(1)	Plant Name and Unit Number:		**Undesignated CC2**	
(2)	Capacity			
	a. Summer:		1189	
	b. Winter:		1307	
(3)	Technology Type:		COMBINED CYCLE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		1/2017	
	b. Commercial in-service date:		6/2020	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		NATURAL GAS	
	b. Alternate fuel:		DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:		SCR and CO Catalyst	
(7)	Cooling Method:		Cooling Tower	
(8)	Total Site Area:		UNKNOWN	ACRES
(9)	Construction Status:		PLANNED	
(10)	Certification Status:		PLANNED	
(11)	Status with Federal Agencies:		PLANNED	
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		6.66	%
	b. Forced Outage Factor (FOF):		6.36	%
	c. Equivalent Availability Factor (EAF):		87.40	%
	d. Resulting Capacity Factor (%):		81.5	%
	e. Average Net Operating Heat Rate (ANOHR):		6,720	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		25	
	b. Total Installed Cost (In-service year $/kW):		1,066.64	
	c. Direct Construction Cost ($/kW):	($2013)	858.74	
	d. AFUDC Amount ($/kW):		97.53	
	e. Escalation ($/kW):		110.37	
	f. Fixed O&M ($/kW-yr):	($2013)	1.84	
	g. Variable O&M ($/MWh):	($2013)	4.19	
	h. K Factor:		NO CALCULATION	

NOTES
. Total Installed Cost includes gas expansion, transmission interconnection and integration
. $/kW values are based on Summer capacity
. Fixed O&M cost does not include firm gas transportation costs

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2013

(1)	Plant Name and Unit Number:		**Undesignated CT1**	
(2)	Capacity			
	a. Summer:		187	
	b. Winter:		214	
(3)	Technology Type:		SIMPLE CYCLE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		1/2020	
	b. Commercial in-service date:		6/2022	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		NATURAL GAS	
	b. Alternate fuel:		DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:		Dry Low NOx Combustion	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		UNKNOWN	ACRES
(9)	Construction Status:		PLANNED	
(10)	Certification Status:		PLANNED	
(11)	Status with Federal Agencies:		PLANNED	
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		3.85	%
	b. Forced Outage Factor (FOF):		2.05	%
	c. Equivalent Availability Factor (EAF):		94.18	%
	d. Resulting Capacity Factor (%):		10.9	%
	e. Average Net Operating Heat Rate (ANOHR):		10,649	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		25	
	b. Total Installed Cost (In-service year $/kW):		715.02	
	c. Direct Construction Cost ($/kW):	($2013)	567.83	
	d. AFUDC Amount ($/kW):		30.95	
	e. Escalation ($/kW):		116.24	
	f. Fixed O&M ($/kW-yr):	($2013)	3.00	
	g. Variable O&M ($/MWh):	($2013)	10.13	
	h. K Factor:		NO CALCULATION	

NOTES
. Total Installed Cost includes gas expansion, transmission interconnection and integration
. $/kW values are based on Summer capacity
. Fixed O&M cost does not include firm gas transportation costs

PROGRESS ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

PEF has not designiated a site for this CC1, CC2 or CT1 in Schedule 8 and therefore does not have any Directly Associated Lines with these units.

INTEGRATED RESOURCE PLANNING OVERVIEW

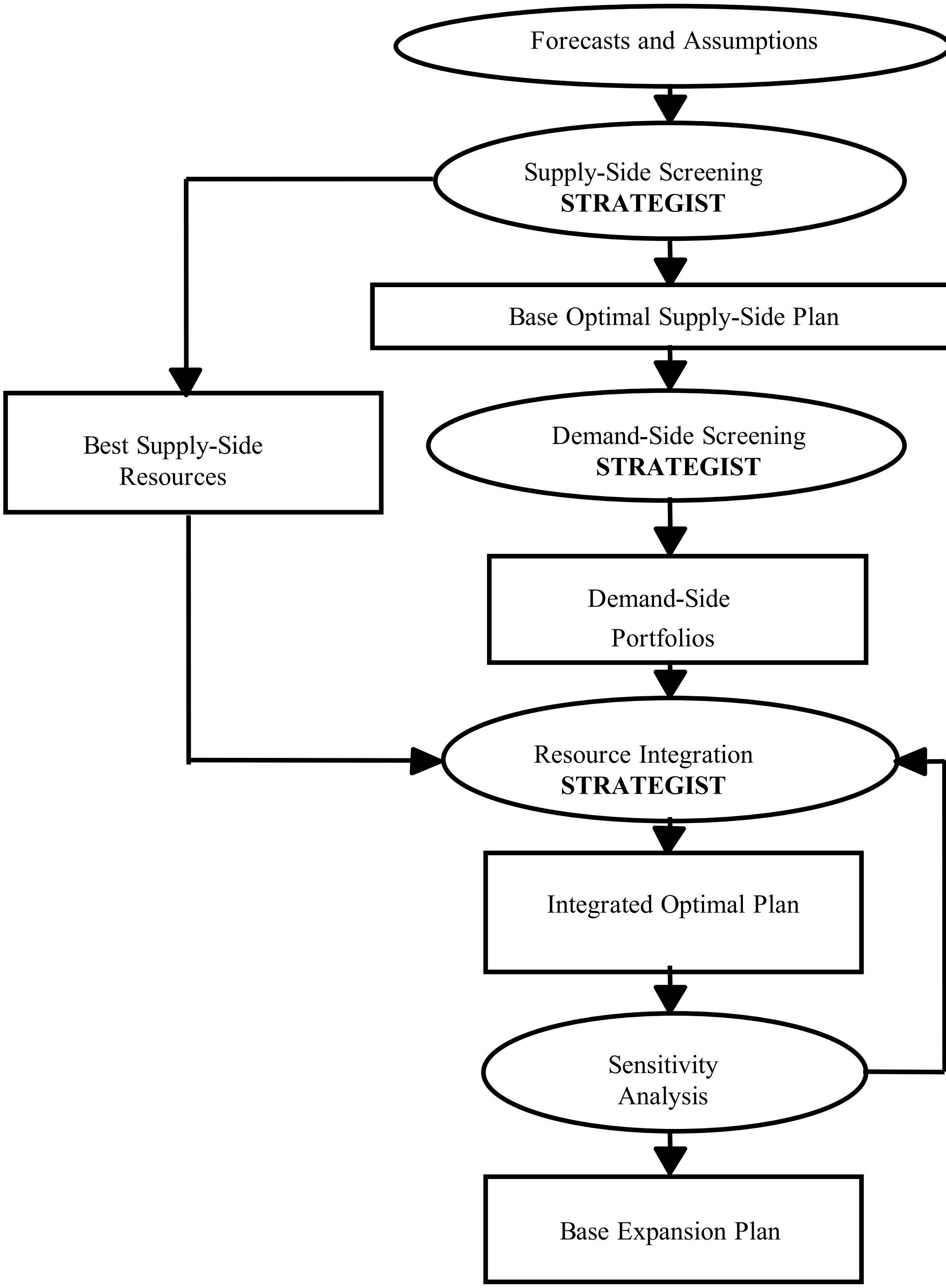
PEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. PEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide range of future generation alternatives and cost-effective conservation and dispatchable demand-side management programs on a consistent and integrated basis.

An overview of PEF's IRP Process is shown in Figure 3.1. The process begins with the development of various forecasts, including demand and energy, fuel prices, and economic assumptions. Future supply- and demand-side resource alternatives are identified and extensive cost and operating data are collected to enable these to be modeled in detail. These alternatives are optimized together to determine the most cost-effective plan for PEF to pursue over the next ten years to meet the Company's reliability criteria. The resulting ten-year plan, the Integrated Optimal Plan, is then tested under different relevant sensitivity scenarios to identify variances, if any, which would warrant reconsideration of any of the base plan assumptions. If the plan is judged robust and works within the corporate framework, it evolves as the Base Expansion Plan. This process is discussed in more detail in the following section titled "The Integrated Resource Planning (IRP) Process".

The IRP provides PEF with substantial guidance in assessing and optimizing the Company's overall resource mix on both the supply side and the demand side. When a decision supporting a significant resource commitment is being developed (e.g. plant construction, power purchase, DSM program implementation), the Company will move forward with directional guidance from the IRP and delve much further into the specific levels of examination required. This more detailed assessment will typically address very specific technical requirements and cost estimates, detailed corporate financial considerations, and the most current dynamics of the business and regulatory environments.

FIGURE 3.1

Integrated Resource Planning (IRP) Process Overview



THE INTEGRATED RESOURCE PLANNING (IRP) PROCESS

Forecasts and Assumptions

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

Reliability Criteria

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

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

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

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

Supply-Side Screening

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

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

Demand-Side Screening

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

The Base Optimal Supply-Side Plan is used to establish avoidable units for screening future demand-side resources. Each future demand-side alternative is individually tested in this plan over the ten-year planning horizon to determine the benefit or detriment that the addition of this demand-side resource provides to the overall system. Strategist® calculates the benefits and costs for each demand-side measure evaluated and reports the appropriate ratios for the Rate Impact Measure (RIM), the Total Resource Cost Test (TRC), and the Participant Test.

Resource Integration and the Integrated Optimal Plan

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

Developing the Base Expansion Plan

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

KEY CORPORATE FORECASTS

Load Forecast

The assumptions and methodology used to develop the base case load and energy forecast are described in Chapter 2 of this TYSP.

Fuel Forecast

The base case fuel price forecast was developed using short-term and long-term spot market price projections from industry-recognized sources. The base cost for coal is based on the existing contracts and spot market coal prices and transportation arrangements between PEF and its various suppliers. For the longer term, the prices are based on spot market forecasts reflective of expected market conditions. Oil and natural gas prices are estimated based on current and expected contracts and spot purchase arrangements as well as near-term and long-term market forecasts. Oil and natural gas commodity prices are driven primarily by open market forces of supply and demand. Natural gas firm transportation cost is determined primarily by pipeline tariff rates.

Financial Forecast

The key financial assumptions used in PEF's most recent planning studies were 47 percent debt and 53 percent equity capital structure, projected cost of debt of 3.05 percent, and an equity return of 10.5 percent. The assumptions resulted on a weighted average cost of capital of 7.00 percent and an after-tax discount rate of 6.47 percent.

TEN-YEAR SITE PLAN (TYSP) RESOURCE ADDITIONS

The planned units in this TYSP result in a robust plan that includes the retirement of the Crystal River Nuclear Unit No. 3 in January 2013, retirement of Crystal River Units 1 & 2 in 2016, the installation of combined cycle units in 2018 and 2020 at locations that has not yet been chosen, as well as purchases in years 2016 through 2020. Levy Units 1 & 2 are beyond this ten-year planning horizon but are planned for the years 2024 and 2025, respectively. Additionally, PEF anticipates the retirements of older, smaller combustion turbines and steam units in the year 2016 and 2018, respectively.

Through its ongoing planning process, PEF will continue to evaluate the timetables for all projected resource additions and assess alternatives for the future considering, among other things, projected load growth, fuel prices, and lead times in the construction marketplace, project development timelines for new fuels and technologies, and environmental compliance considerations. The Company will continue to examine the merits of new generation alternatives and adjust its resource plans accordingly to ensure optimal selection of resource additions based on the best information available.

RENEWABLE ENERGY

PEF continues to make purchases from the following facilities listed by fuel type:

Municipal Solid Waste Facilities:

Lake County Resource Recovery (12.8 MW)

Metro-Dade County Resource Recovery (43 MW)

Pasco County Resource Recovery (23 MW)

Pinellas County Resource Recovery (54.8 MW)

Waste Heat from Exothermic Processes:

PCS Phosphate (As Available)

Waste Wood, Tires, and Landfill Gas:

Ridge Generating Station (39.6 MW)

Photovoltaics

PEF owned installations (approximately 930 kW)

PEF's Net Metering Tariff includes over 12.5 MW of solar PV

In addition, PEF has contracts with U.S. EcoGen (60 MW), TransWorld Energy (40 MW), and FB Energy (60 MW). U.S. Ecogen will utilize an energy crop, while the FB Energy facility and the TransWorld Energy facility will utilize wood products as their fuel source.

PEF has also signed several As-Available contracts utilizing biomass and solar PV technologies. A summary of renewable energy resources is below.

Supplier	Size (MW)	Currently Delivering?	Anticipated In-Service Date
Lake County Resource Recovery	12.8	Yes	
Metro-Dade Resource Recovery	43	Yes	
Pasco County Resource Recovery	23	Yes	
Pinellas County Resource Recovery	54.8	Yes	
Ridge Generating Station	39.6	Yes	
PCS Phosphate	As Avail	Yes	
FB Energy	60	No	12/1/13
U.S. EcoGen Polk	60	No	1/1/14

Trans World Energy	40	No	7/1/13
PEF owned Photovoltaics	1	Yes	
Net Metered Customers (1,118)	12.5	Yes	
Blue Chip Energy - Sorrento	As Avail	No	See Note Below
National Solar - Gadsden	As Avail	No	See Note Below
National Solar - Hardee	As Avail	No	See Note Below
National Solar - Highlands	As Avail	No	See Note Below
National Solar - Osceola	As Avail	No	See Note Below
National Solar - Suwannee	As Avail	No	See Note Below

Note: As Available purchases are made on an hour-by-hour basis for which contractual commitments as to the quantity, time, or reliability of delivery are not required.

PEF continues to seek out renewable suppliers that can provide reliable capacity and energy at economic rates. PEF continues to keep an open Request for Renewables (RFR) soliciting proposals for renewable energy projects. PEF's open RFR continues to receive interest and to date has logged over 310 responses. PEF will continue to submit renewable contracts in compliance with FPSC rules.

Depending upon the mix of generators operating at any given time, the purchase of renewable energy may reduce PEF's use of fossil fuels. Non-intermittent renewable energy sources also defer or eliminate the need to construct more conventional generators.

PLAN CONSIDERATIONS

Load Forecast

In general, higher-than-projected load growth would shift the need for new capacity to an earlier year and lower-than-projected load growth would delay the need for new resources. The Company's resource plan provides the flexibility to shift certain resources to earlier or later in-service dates should a significant change in projected customer demand begin to materialize.

TRANSMISSION PLANNING

PEF's transmission planning assessment practices are developed to test the ability of the planned system to meet the reliability criteria as outlined in the FERC Form 715 filing, and to assure the system meets PEF, Florida Reliability Coordinating Council, Inc. (FRCC), and North American Reliability Corporation (NERC) criteria. This involves the use of load flow and transient stability programs to model various contingency situations that may occur, and determining if the system response meets the reliability criteria. In general, this involves running simulations for the loss of any single line, generator, or transformer. PEF normally runs this analysis for system peak and off-peak load levels for possible contingencies, and for both summer and winter. Additional studies are performed to determine the system response to credible, but less probable criteria. These studies include the loss of multiple generators, lines or combinations of each (some load loss is permissible under the more severe disturbances). These credible, but less probable scenarios are also evaluated at various load levels, since some of the more severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs.

As noted in the PEF reliability criteria, some remedial actions are allowed to reduce system loadings, in particular, sectionalizing is allowed to reduce loading on lower voltage lines for bulk system contingencies, but the risk to load on the sectionalized system must be reasonable (it would not be considered prudent to operate for long periods with a sectionalized system). In addition, the number of remedial action steps and the overall complexity of the scheme are evaluated to determine overall acceptability.

PEF presently uses the following reference documents to calculate and manage Available Transfer Capability (ATC), Total Transfer Capability (TTC) and Transmission Reliability Margin (TRM) for required transmission path postings on the Florida Open Access Same Time Information System (OASIS):

- http://www.oatioasis.com/FPC/FPCdocs/ATCID.docx.

- http://www.oatioasis.com/FPC/FPCdocs/TRMID.docx

PEF uses the following reference document to calculate and manage Capacity Benefit Margin (CBM):

- http://www.oatioasis.com/FPC/FPCdocs/CBMID.docx

PEF proposed bulk transmission line additions are summarized in the following Table 3.3. PEF has listed only the larger transmission projects. These projects may change depending upon the outcome of PEF's final corridor and specific route selection process.

TABLE 3.3
PROGRESS ENERGY FLORIDA
LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS
2013 - 2022

MVA RATING WINTER	LINE OWNERSHIP	TERMINALS		LINE LENGTH (CKT-MILES)	COMMERCIAL IN-SERVICE DATE (MO./YEAR)	NOMINAL VOLTAGE (kV)
1370	PEF	INTERCESSION CITY	Gifford	13	5/31/2013	230
1000	PEF	KATHLEEN	ZEPHYRHILLS N	12	5/31/2013	230

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

Progress Energy

CHAPTER 4
ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

PEF's expansion plan beyond this TYSP planning horizon includes nuclear power at the Levy County greenfield site with the first unit planned for in 2024 and a second unit in 2025. PEF continues to evaluate available options for future supply alternatives. Appropriate permitting requirements for PEF's preferred Levy Site are discussed in the following site description.

LEVY COUNTY NUCLEAR POWER PLANT – LEVY COUNTY

PEF has named a site in southern Levy County as the preferred location for construction of new generation. The Company is planning the construction of nuclear generation at this site with the first unit planned in 2024 and a second unit in 2025 which are both beyond the planning horizon for this TYSP.

The Levy County site (see Figures 4.1 a & b) is approximately 3,100 acres and located eight miles inland from the Gulf of Mexico and roughly ten miles north of the existing PEF Crystal River Energy Complex.

The site is about 2.5 miles from the Cross Florida Barge Canal, from which the Levy units may draw their makeup water to supply the on-site cooling water system. The Levy County Plant, together with the necessary associated site facilities, will occupy approximately ten percent of the 3,100 acre site and the remaining acreage will be preserved as an exclusionary boundary around the developed plant site and a buffer preserve. PEF purchased an additional 2,100 acre tract contiguous with the southern boundary of the Levy site that secures access to a water supply for the site from the Cross Florida Barge Canal as well as transmission corridors from the plant site. The property for many years had been used for cultivation of forest trees and was designated as Forestry/Rural Residential. The surrounding area land use is predominantly vacant, commercial forestry lands.

This site was chosen based on several considerations including availability of land and water resources, access to the electric transmission system, and environmental considerations. First, the Levy County site had access to an adequate water supply. Second, the site is at a relatively high elevation, which provides additional protection from wind damage and flooding. Third, unlike a number of other sites considered, the Levy site has more favorable geotechnical qualities, which are critical to siting a nuclear power plant. Fourth, the Levy site provides geographical separation from other electrical generating facilities. This site separation decreases the likelihood of a significant generation loss from a single event and a potential large-scale impact on the PEF system. The Levy County location also would assist in avoiding a potential loss from a single significant transmission system event that might result in a large-scale impact on the PEF system.

PEF's assessment of the Levy County site addressed whether any threatened and endangered species or archeological and cultural resources would be adversely impacted by the development of the site for nuclear generation units and related facilities. No significant issues were identified in PEF's evaluations of the property.

The Levy unit will be located on a greenfield site where site and transmission infrastructure must be constructed along with the buildings necessary for the power units. The site will include cooling towers, intake and discharge structures, containment buildings, auxiliary buildings, turbine buildings, diesel generators, warehouses, related site work and infrastructure, including roads, transmission lines, and a transmission substation. The proximity of the Levy County site to the PEF's existing Crystal River Site may provide opportunities for efficiencies in support functions with the existing Crystal River infrastructure. The Company submitted a Site Certification Application (SCA) to the Florida Department of Environmental Protection (FDEP) on June 2, 2008, for the entire site, including plants and associated facilities for the units. Site certification hearings were completed in March 2009, and the Siting Board approved the final certification in August 2009.

Nuclear power is a clean source of electric power generation. Electric power generation from nuclear fuel produces no sulfur dioxide (SO_2), nitrogen oxide (NO_x), green house gases (GHG), or other emissions. Therefore, it will have a positive effect on the surrounding air quality.

Water discharged from nuclear plants must meet federal Clean Water Act requirements and state water-quality standards. Before operating, a nuclear plant's licensing process requires an environmental impact statement that carefully examines and resolves all potential impacts to water quality from the operation of the plant. These issues include concerns about the discharge of waste water and the impacts on aquatic life in cooling water used by the plant.

Transmission modifications will be required to accommodate the Levy County Nuclear Power Plant.

FIGURE 4.1.a.

Levy County Nuclear Power Plant (Levy County)

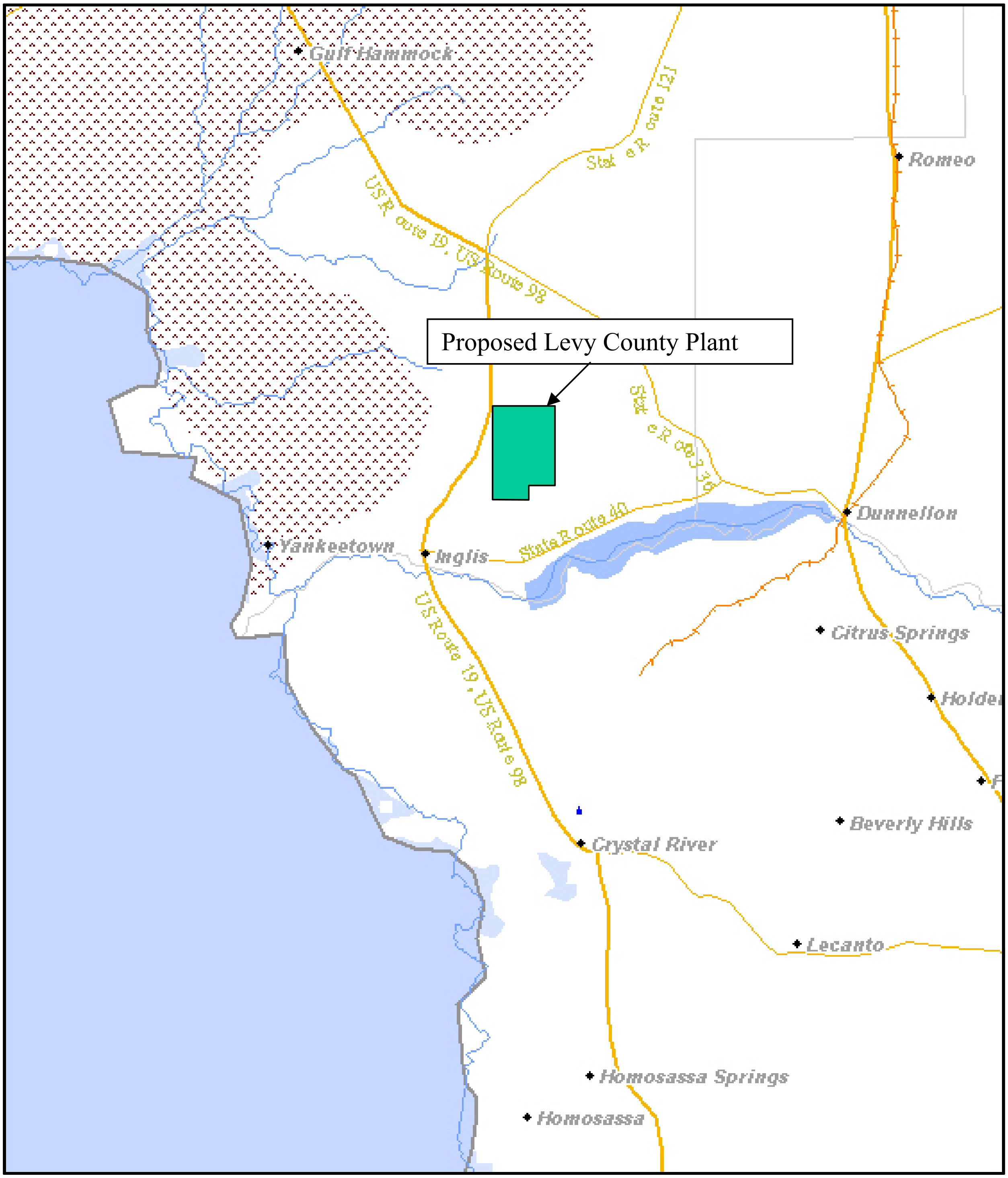


FIGURE 4.1.b.

Levy County Nuclear Power Plant (Levy County) – Aerial View

Duke Energy Florida
RFP for Power Supply Resources

Notice of Intent to Bid - Non Binding

Name of Bidder	Bidder Name	________________
	Contact Name	________________
Bidder Contact	Address	________________
		________________
	Telephone	________________
	Fax	________________
	E-mail address	________________
Bidder Representatives Attending Bidders Conference	Names:	________________
		________________

All potential Bidders are requested to submit an email Notice of Intent to Bid to Duke Energy Florida's Official Contacts by the Bidders Meeting.

E-mail to the Official Contacts:

DEF RFP Contact

DEF2018RFP@duke-energy.com

and

Independent Monitor/Evaluator Contact

Alan.Taylor@sedwayconsulting.com

Schedule A

Project Summary		
Name of Bidder		______
Bidder Contact	Name	______
	Address	______
		______
		______
	Telephone	______
	Fax	______
	e-mail address	______
Project Name		______
Project Location	County	______
	State	______
Contract Start Month/Year		______
Term of Proposal	Years	______
Seasonal Contract Capacity (MW)	Summer	______
	Winter	______
Proposal Type	Check One	New Unit ☐
		Existing Unit ☐
		System Power ☐
Generation Technology	Technology	______
Fuel Type	Primary	______
	Secondary	______
Heat Rate @ Max Load	Summer	______ HHV
	Winter	______ HHV

Schedule 1[1]
Pricing Schedule for New and Existing Unit Proposals

Contract Start Month	
Contract Start Year	
Contract End Year	

						Contract Year									Contract Year										Contract Year										
Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
Beginning	05/01/18	01/01/19	01/01/20	01/01/21	01/01/22	01/01/23	01/01/24	01/01/25	01/01/26	01/01/27	01/01/28	01/01/29	01/01/30	01/01/31	01/01/32	01/01/33	01/01/34	01/01/35	01/01/36	01/01/37	01/01/38	01/01/39	01/01/40	01/01/41	01/01/42	01/01/43	01/01/44	01/01/45	01/01/46	01/01/47	01/01/48	01/01/49	01/01/50	01/01/51	01/01/52
Ending	12/31/18	12/31/19	12/30/20	12/31/21	12/31/22	12/31/23	12/30/24	12/31/25	12/31/26	12/31/27	12/30/28	12/31/29	12/31/30	12/31/31	12/30/32	12/31/33	12/31/34	12/31/35	12/30/36	12/31/37	12/31/38	12/31/39	12/30/40	12/31/41	12/31/42	12/31/43	12/31/44	12/31/45	12/31/46	12/31/47	12/31/48	12/31/49	12/31/50	12/31/51	12/31/52
Seasonal Contract Capacity (MW net)																																			
Winter (Jan, Feb, Mar, Apr, Nov, Dec)																																			
Summer (May, Jun, Jul, Aug, Sep, Oct)																																			
Annual Charges/Prices																																			
Fixed Payment																																			
Generation Capital Charges ($/kW-year)[2]																																			
Fixed O&M Charges ($/kW-year)[2]																																			
Transmission Charges ($/kW-year)[2]																																			
Total Fixed Charges ($/kW-year)																																			
Pipeline Demand/Reservation Charges ($/mmBtu-day)																																			
Variable Payment																																			
Primary Fuel Commodity Price ($/mmBtu)																																			
Primary Fuel Variable Transportation Price ($/mmBtu)																																			
Total Primary Fuel Price ($/mmBtu)																																			
Secondary Fuel Commodity Price ($/mmBtu)																																			
Secondary Fuel Variable Transportation price ($/mmBtu)																																			
Total Secondary Fuel Price ($/mmBtu)																																			
Variable O&M Prices																																			
$/MWh																																			
$/hour																																			
Start Payment																																			
Start Prices ($/Start)																																			
Enter other charges here																																			
Enter other charges here																																			
Enter other charges here																																			

Desired Primary Fuel Price Index ____________________
Desired Secondary Fuel Price Index ____________________

Reference Price Forecasts[3] ($/mmBtu)	**2018**	**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**	**2050**	**2051**	**2052**
Natural Gas, Henry Hub	5.51	5.94	6.70	7.12	7.49	7.74	8.07	8.41	8.76	9.12	9.50	9.89	10.29	10.71	11.14	11.59	12.05	13.23	14.65	15.76	16.68	17.60	18.53	19.45	20.37	21.30	22.22	23.14	24.07	24.99	25.91	26.84	27.76	28.68	29.61
No. 2 Oil, .5% S, delivered to Florida Gulf Coast	18.54	18.66	18.82	19.39	19.97	20.58	21.20	21.85	22.62	23.42	24.25	25.11	26.00	26.71	27.72	28.77	29.86	31.00	32.17	33.39	34.52	35.65	36.79	37.92	39.05	40.19	41.32	42.45	43.59	44.72	45.86	46.99	48.12	49.26	50.39
Coal	3.82	3.93	3.80	3.90	3.99	4.15	4.28	4.42	4.57	4.72	4.87	5.03	5.19	5.35	5.54	5.72	5.91	6.11	6.30	6.50	6.70	6.89	7.09	7.28	7.47	7.67	7.86	8.05	8.25	8.44	8.63	8.83	9.02	9.22	9.41

Notes:
1. For instructions on completing this schedule, refer to Response Package, Section II.E.
2. Even though first year will be a partial year, input the ANNUALIZED charges here.
3. Reference Price forecasts are for reference purposes only and may be used to represent an index; they are not firm prices. Forecasts are subject to change.

Schedule 2[1]
Pricing Schedule for System Proposals

Contract Start Month	
Contract Start Year	
Contract End Year	

	Contract Year																	
Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Beginning	05/01/18	01/01/19	01/01/20	01/01/21	01/01/22	01/01/23	01/01/24	01/01/25	01/01/26	01/01/27	01/01/28	01/01/29	01/01/30	01/01/31	01/01/32	01/01/33	01/01/34	01/01/35
Ending	12/31/18	12/31/19	12/30/20	12/31/21	12/31/22	12/31/23	12/30/24	12/31/25	12/31/26	12/31/27	12/30/28	12/31/29	12/31/30	12/31/31	12/30/32	12/31/33	12/31/34	12/31/35
Seasonal Contract Capacity (MW net)																		
Winter (Jan, Feb, Mar, Apr, Nov, Dec)																		
Summer (May, Jun, Jul, Aug, Sep, Oct)																		
Annual Charges/Prices																		
Fixed Payment																		
Capacity Charges ($/kW-year)[2]																		
Transmission Charges ($/kW-year)[2]																		
Total Fixed Charges ($/kW-year)																		
Variable Payment																		
System Fuel Energy Price ($/MWh)																		
Non-Fuel Energy Price																		
$/MWh																		
$/hour																		
Start Payment																		
Start Prices ($/Start)																		
Enter other charges here																		
Enter other charges here																		
Enter other charges here																		

	Contract Year																
Number	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
Beginning	01/01/36	01/01/37	01/01/38	01/01/39	01/01/40	01/01/41	01/01/42	01/01/43	01/01/44	01/01/45	01/01/46	01/01/47	01/01/48	01/01/49	01/01/50	01/01/51	01/01/52
Ending	12/30/36	12/31/37	12/31/38	12/31/39	12/30/40	12/31/41	12/31/42	12/31/43	12/31/44	12/31/45	12/31/46	12/31/47	12/31/48	12/31/49	12/31/50	12/31/51	12/31/52
Seasonal Contract Capacity (MW net)																	
Winter (Jan, Feb, Mar, Apr, Nov, Dec)																	
Summer (May, Jun, Jul, Aug, Sep, Oct)																	
Annual Charges/Prices																	
Fixed Payment																	
Capacity Charges ($/kW-year)[2]																	
Transmission Charges ($/kW-year)[2]																	
Total Fixed Charges ($/kW-year)																	
Variable Payment																	
System Fuel Energy Price ($/MWh)																	
Non-Fuel Energy Price																	
$/MWh																	
$/hour																	
Start Payment																	
Start Prices ($/Start)																	
Enter other charges here																	
Enter other charges here																	
Enter other charges here																	

Proposed fuel energy price index(es) ____________________

Reference Price Forecasts[3] ($/mmBtu)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Natural Gas, Henry Hub	5.51	5.94	6.70	7.12	7.49	7.74	8.07	8.41	8.76	9.12	9.50	9.89	10.29	10.71	11.14	11.59	12.05	13.23
No. 2 Oil, .5% S, delivered to Florida Gulf Coast	18.54	18.66	18.82	19.39	19.97	20.58	21.20	21.85	22.62	23.42	24.25	25.11	26.00	26.71	27.72	28.77	29.86	31.00
Coal	3.82	3.93	3.80	3.90	3.99	4.15	4.28	4.42	4.57	4.72	4.87	5.03	5.19	5.35	5.54	5.72	5.91	6.11

Reference Price Forecasts[3] ($/mmBtu)	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**
Natural Gas, Henry Hub	14.65	15.76	16.68	17.60	18.53	19.45	20.37	21.30	22.22	23.14	24.07	24.99	25.91	26.84	27.76	28.68	29.61
No. 2 Oil, .5% S, delivered to Florida Gulf Coast	32.17	33.39	34.52	35.65	36.79	37.92	39.05	40.19	41.32	42.45	43.59	44.72	45.86	46.99	48.12	49.26	50.39
Coal	6.30	6.50	6.70	6.89	7.09	7.28	7.47	7.67	7.86	8.05	8.25	8.44	8.63	8.83	9.02	9.22	9.41

Notes:
1. For instructions on completing this schedule, refer to Response Package, Section II.E.
2. Even though first year will be a partial year, input the ANNUALIZED charges here.
3. Reference Price forecasts are for reference purposes only and may be used to represent an index; they are not firm prices. Forecasts are subject to change.

Schedule 3
Capacity States and Heat Rates for New and Existing Unit Proposals[1]

Specify Capacity States (MW)[2] and Net Heat Rates (Btu/kWh)[3] for each Season.
Winter is defined as January, February, March, April, November, and December.
Summer is defined as May, June, July, August, September, and October.

Plant elevation ________ feet

							Contract Year										Contract Year									
	Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
	Beginning	05/01/18	01/01/19	01/01/20	01/01/21	01/01/22	01/01/23	01/01/24	01/01/25	01/01/26	01/01/27	01/01/28	01/01/29	01/01/30	01/01/31	01/01/32	01/01/33	01/01/34	01/01/35	01/01/36	01/01/37	01/01/38	01/01/39	01/01/40	01/01/41	01/01/42
	Ending	12/31/18	12/31/19	12/30/20	12/31/21	12/31/22	12/31/23	12/30/24	12/31/25	12/31/26	12/31/27	12/30/28	12/31/29	12/31/30	12/31/31	12/30/32	12/31/33	12/31/34	12/31/35	12/30/36	12/31/37	12/31/38	12/31/39	12/30/40	12/31/41	12/31/42
Required	**Winter Full Load Capacity (MW)**																									
	Net Heat Rate--Primary Fuel																									
	Net Heat Rate--Secondary Fuel																									
	Summer Full Load Capacity (MW)																									
	Net Heat Rate--Primary Fuel																									
	Net Heat Rate--Secondary Fuel																									
	Winter Minimum Load (MW)[4]																									
	Net Heat Rate--Primary Fuel																									
	Net Heat Rate--Secondary Fuel																									
	Summer Minimum Load (MW)																									
	Net Heat Rate--Primary Fuel																									
	Net Heat Rate--Secondary Fuel																									
Optional	Winter--Capacity State 2 (MW)																									
	Net Heat Rate--Primary Fuel																									
	Net Heat Rate--Secondary Fuel																									
	Summer--Capacity State 2 (MW)																									
	Net Heat Rate--Primary Fuel																									
	Net Heat Rate--Secondary Fuel																									
	Winter--Capacity State 3 (MW)																									
	Net Heat Rate--Primary Fuel																									
	Net Heat Rate--Secondary Fuel																									
	Summer--Capacity State 3 (MW)																									
	Net Heat Rate--Primary Fuel																									
	Net Heat Rate--Secondary Fuel																									
	Winter--Capacity State 4 (MW)																									
	Net Heat Rate--Primary Fuel																									
	Net Heat Rate--Secondary Fuel																									
	Summer--Capacity State 4 (MW)																									
	Net Heat Rate--Primary Fuel																									
	Net Heat Rate--Secondary Fuel																									

Notes:
1. For instructions on completing this schedule, refer to Response Package, Section II.F.
2. Capacity must be specified at net generation levels at the Delivery Point.
3. All heat rates must be expressed in Btu/kWh, higher heating value (HHV). Heat rates for capacity states must be average, not incremental, heat rates.
   Heat rates must incorporate any margin for degradation during the term of the contract. Degradation may be incorporated as an average over the term or annually.
4. The Minimum Load point is considered Capacity State 1.

Schedule 4
Operating Performance Schedule[1]

	Yes	No
Greenfield and Unit Proposals will have a direct communication link with Duke Energy Florida's Control Center that enables Duke Energy Florida to control the operation of the unit under automatic generator control (in DEF's control area) or a combination of dynamic/block scheduling (outside of DEF's control area) **[New Unit Proposal, Existing Unit Proposal]**		
Duke Energy Florida will be able to operate the unit to provide voltage support for the DEF system: **[New Unit Proposal, Existing Unit Proposal] in DEF's control area**		
Duke Energy Florida will be able to operate the unit to provide frequency control for the DEF system: **[New Unit Proposal, Existing Unit Proposal] in DEF's control area**		
The proposed project will be Fully Dispatchable by Duke Energy Florida. **[New Unit Proposal, Existing Unit Proposal]**		
The proposed project will be Fully Schedulable by Duke Energy Florida. **[System Power Proposal]**		
The Bidder agrees to coordinate its maintenance schedule with Duke Energy Florida. **[New Unit Proposal, Existing Unit Proposal]**		
The level of on-site fuel storage (equivalent hours of operation at full load without refilling). **[New Unit Proposal, Existing Unit Proposal]**		

Schedule 4
Operating Performance Schedule[1]
(Continued)

Operating Performance Evaluation Criteria [New Unit Proposal, Existing Unit Proposal]

The maximum capacity level at which each unit may be operated while on AGC ______ MW

The minimum capacity level (MW) at which each unit may be operated ______ MW
The minimum capacity level (MW) while on AGC ______ MW

The guaranteed start time required to bring each unit from a cold start to minimum load would be: ______ minutes

The guaranteed ramp rate for each unit from the minimum loading level: ______ MW/min (facility)
The ramp rate for each unit from the minimum loading level while on AGC ______ MW/min (facility)

The maximum number of starts (per unit) that DEF would be allowed per year: ______ starts/year (unit)
(Test starts and starts after a forced outage or unscheduled maintenance will not be included when determining the number of starts requested by DEF.)

The minimum run time when each unit has been dispatched on line would be: ______ hours

The minimum down time when each unit has been taken off-line would be: ______ hours

The maximum number of hours during a year that DEF would be allowed to operate the facility (air permit limit): ______ hours (facility)

Outage Information [New Unit Proposal, Existing Unit Proposal]

The Equivalent Forced Outage Rate Guarantee is ________

Specify the average number of days per year of scheduled maintenance for each unit, consistent with Schedule 3.

Unit	Maintenance days per year

Notes:
[1] For instructions on completing this schedule, refer to Response Package, Section II.F.

Schedule 5
Environmental and Regulatory Permit Status Schedule

Item	Not Required	Required	Applied For (Date)	Expected Receipt (Date)
Water Discharge to Surface Waters (NPDES) Permit				
404 Permit / 401 Water Quality Certification				
Domestic Wastewater				
Industrial Wastewater (non-NPDES)				
Water Use				
Water Use Area Restrictions (e.g. SWUCA, MIA) Applicability				
Corps of Engineers Permit(s): wetlands / aerial crossings				
Environmental Resource Permit (ERP) for Wetlands				
ERP: Surface Water Management (MSSW)				
Solid Waste Disposal Permit				
Ash Disposal Permit				
Hazardous Waste Disposal Permit				
PSD (Air Construction) Permit				
Federal Aviation Administration License				
Certificate of Need				
Local Construction Permit				
Local Zoning Approval (Conditional Use Permit)				
Spill Prevention Control Measures Permit				
Section 10 (Wildlife) Permits				
Migratory Bird				
Department of Transportation				
Air: Title V Operating Permit				
Electric and Magnetic Field (EMF) requirements: FDEP				
Title IV (Acid Rain) Permit				
Site Certification Application (includes state, local permitting and authorizations) or Supplemental SCA if existing site				

Schedule 6
Air Emissions Schedule

Primary Fuel						
Fuel Type:	0		Maximum Hours of Operation:			
Pollutant	Facility at Maximum Load Conditions				Facility Total (Including all sources at ISO conditions)	
	ppm	lbs/MMBtu	lbs/hr	Tons/yr	lbs/hr	Tons/yr
NOx						
VOCs						
SO2						
CO						
PM						
Sulfuric Acid Mist						
Hazardous Air						

Secondary Fuel						
Fuel Type:	0		Maximum Hours of Operation:			
Pollutant	Facility at Maximum Load Conditions				Facility Total (Including all sources at ISO conditions)	
	ppm	lbs/MMBtu	lbs/hr	Tons/yr	lbs/hr	Tons/yr
NOx						
VOCs						
SO2						
CO						
PM						
Sulfuric Acid Mist						
Hazardous Air						

Maximum Hours of Operation: ______ hours
(sum of all fuels; consistent with Schedule 4, page 2)

Schedule 7
Transmission Information Schedule

Check the appropriate box and provide the requested information:

☐ **New Unit Proposal (Unit Inside DEF)**

1 Interconnection Request Queue Position and Date ____________________

2 Submit all information requested in the Interconnection Request for a Large Generating Facility (see Appendix 1 of Attachment J (LGIP) in DEF's OATT), which can be found at http://www.ferc.duke-energy.com/Joint_OATT.pdf.

3 Customer to confirm agreement that the Large Generator scoping meeting will be delayed until such time that DEF determines the LGIA interconnection studies should move forward. Refer to attachment J section 3.3.4 in the DEF OATT.

4 Non binding good faith estimate of the directly assignable interconnection facilities costs associated with the proposed interconnecion

☐ **New Unit Proposal (Unit Outside DEF)**

1 Host/Source system ____________________

2 Submit a completed transmission interconnection feasibility study report or a transmission service agreement study report from the host utility.

3 Submit all information requested in the Interconnection Request for a Large Generating Facility as submitted to the Host system (see Appexdix 1 of Attachment J (LGIP) in DEF's OATT), which can be found at http://www.ferc.duke-energy.com/Joint_OATT.pdf.

4 Non binding good faith estimate of the directly assignable interconnection facilities costs associated with the proposed interconnecion

☐ **Existing Unit Proposals (Unit Inside DEF)**

1 Nothing required for the generator queue process since the unit is already interconnected to the DEF system.

☐ **Existing Unit Proposals (Unit Outside DEF)**

1 Host/Source System ____________________

2 Submit a completed transmission system impact study agreement from the host system or a confirmed point to point transmission reservation from the host system.

☐ **System Power Proposal (Outside DEF)**

1 Host/Source system ____________________

Submit a completed transmission system impact study agreement from the host system or a confirmed point to point transmission reservation from the host system. ____________________

Contact information for transmission planner from the host system utility:
[New and Existing Unit Proposals Outside DEF, System Power Proposals]

Company: ____________________
Name: ____________________
Street Address: ____________________
P.O. Box: ____________________
City, State, Zip Code: ____________________
Phone Number: ____________________
Fax: ____________________
Email: ____________________

Schedule 8
Project Pro Forma Schedule[1]
($ 000's)

Schedule 8
Project Pro Formas Schedule[1]
($ 000's)

PROJECT ASSUMPTIONS

Total Project Capital Cost ($ 000's) ➔	
Debt Ratio (%) ➔	
Debt Cost (%) ➔	
Debt Term (yrs) ➔	

Line No.		2018	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	2050	2051	2052
	Operating Revenues																																			
1	Capacity Payments ➔																																			
2	Fixed O&M Payments ➔																																			
3	Energy Payments ➔																																			
4	Other Revenues (explain) ➔																																			
5	Total Revenues (1+2+3+4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Operating Expenses																																			
6	Fuel - Commodity Costs ➔																																			
7	Fuel - Transportation Costs ➔																																			
8	Variable Operation & Maintenance Costs ➔																																			
9	Fixed Operation & Maintenance Costs ➔																																			
10	Wheeling Charges ➔																																			
11	Insurance ➔																																			
12	Property Taxes ➔																																			
13	Administration ➔																																			
14	Other Expenses (identify) ➔																																			
15	Total Operating Expenses (6+7+8+9+10+11+12+13+14)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Net Operating Income - Before Tax (5-15)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Income Taxes																																			
17	Tax Depreciation and Amortization ➔																																			
18	Interest Expense ➔																																			
19	Other Income / (Deductions) - Net ➔																																			
20	Taxable Income (16-17-18+19)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	State Income Taxes Payable ➔																																			
22	Federal Income Taxes Payable ➔																																			
23	Income Taxes Payable (21+22)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	After-Tax Cash Flow																																			
24	Principal Payments ➔																																			
25	Reserve Deposits / (Withdrawals) - Net ➔																																			
26	Net After Tax Cash Flow (16-18+19-23-24-25)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Debt Service Coverage Ratio (16)/(18+24)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Notes
[1] Bidders should enter data by each line item marked with an arrow. Shaded cells will be automatically calculated by the spreadshee

Notes
[1] Bidders should enter data by each line item marked with an arrow. Shaded cells will be automatically calculated by the spreadsheet.

Schedule 9
Project Milestone Schedule

For all items other than Commercial Operation Date, specify the number of months prior to Scheduled Commercial Operation Date

Site Acquisition:	
Fuel Supply Contract:	
Facility Contracts:	
Public Service Commission Approval:	
Air Permit:	
Commencement of Construction:	
Delivery of Turbine-Generator Equipment:	
Wheeling Agreements:	
Financial Closing:	
Commercial Operation Date:	

The Bidders meeting is scheduled for October 18 at the Marriott Tampa Westshore, 1001 N Westshore Blvd, Tampa, Florida 33607 (1:00 – 3:00pm Westshore Room).

Bidders Meeting

Join the meeting

AUDIO INFORMATION

Telephone Conferencing

Choose one of the following:

- Dial the conferencing service directly, and enter the participant code shown below:
  Toll-free: +1-8887465325
  Participant Code: 3997449

Schedule

A schedule for critical dates for the solicitation, evaluation, screening of proposals, and subsequent negotiations follow:

A. Solicitation

Pre-Release of RFP	9/24/2013
Pre-Release Meeting	10/2/2013
Issuance of RFP	**10/8/2013**
Bidders Meeting	10/18/2013
Submission of Proposals	**12/9/2013 by 3:00 pm**

B. Evaluation and Screening of Proposals

Selection of Short List	Expected by 3/2014
Selection of Finalist(s)	**Expected by 5/2014**

C. Negotiations

Initiate Negotiations	Expected by 5/2014
Clarifications and Adjustments	Expected by 6/2014
Award Announcement	Expected by 8/2014

D. Regulatory Filings

File for certification	Expected by 9/2014

DEF reserves the right to revise the schedule at any time, at DEF's sole discretion. Depending on DEF's requirements to review the proposals, DEF may shorten or lengthen the schedule and revise the dates associated with the schedule.

Duke Energy Florida
RFP for Power Supply Resources

Notice of Intent to Bid - Non Binding

Name of Bidder	Bidder Name	______________________
	Contact Name	______________________
Bidder Contact	Address	______________________
		______________________
	Telephone	______________________
	Fax	______________________
	E-mail address	______________________

Bidder Representatives Attending Bidders Conference	Names:	______________________
		______________________

All potential Bidders are requested to submit an email Notice of Intent to Bid to Duke Energy Florida's Official Contacts by the Bidders Meeting.

E-mail to the Official Contacts:

DEF RFP Contact

DEF2018RFP@duke-energy.com

and

Independent Monitor/Evaluator Contact

Alan.Taylor@sedwayconsulting.com