BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant	)))	DOCKET NO. ________________ Submitted for filing: May 27, 2014

<u>DUKE ENERGY FLORIDA, INC.'S NOTICE OF FILING</u>

Duke Energy Florida, Inc. ("DEF" or the "Company") hereby gives notice of filing the Need Determination Study as Exhibit BMHB-1 to the Direct Testimony of Benjamin M.H. Borsch in support of DEF's Petition for Determination of Need for the Citrus County Combined Cycle Power Plant.

Respectfully submitted this 27th day of May, 2014.

<u>/s/ James Michael Walls</u>

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NEED DETERMINATION STUDY

In Support of

**DUKE ENERGY FLORIDA'S
PETITION FOR DETERMINATION OF NEED
OF CITRUS COMBINED CYCLE UNIT**

REDACTED

1. Executive Summary.

Duke Energy Florida ("DEF" or the "Company") plans to add 1640 megawatts ("MW") of electrical generating resources to its system by May 2018 (820 MW) and November 2018 (the remaining 820 MW) in order to continue to provide reliable, adequate, and cost-effective service to its customers. The most cost-effective way for DEF to meet this need is to construct a 1640 MW (summer rating) state-of-the-art natural gas-fired, combined cycle power plant at site adjacent to DEF's existing Crystal River Energy Complex (CREC) in Citrus County, Florida. This unit is called the "Citrus County Combined Cycle Power Plant."

The Company has come to the decision to build the Citrus County Combined Cycle Power Plant ("Citrus CC") unit as the result of its ongoing Resource Planning process involving an extensive analysis of supply-side and demand-side alternatives, based on feasibility, economics, reliability, fuel diversity, and DEF's evaluation of the responses to its Request for Proposal ("RFP") for competitive supply-side alternatives. Duke Energy Florida needs additional generating capacity by the Summer 2018 to (1) maintain system reliability and integrity and continue to satisfy its 20 percent Reserve Margin commitment; (2) continue to provide adequate electricity at a reasonable cost; and (3) ensure appropriate natural gas fuel supply diversity in the Company's supply-side resource mix.

The Company has determined that the Citrus CC will best meet the Company's need for additional generating capacity in 2018. The need for additional generating capacity cannot be cost-effectively deferred or avoided by additional demand-side options. To ensure that DEF will be pursuing the best available alternative, the Company issued an RFP to solicit supply-side alternatives to building the Citrus CC. The Company carefully evaluated resulting proposals based on both price- and non-price attributes. After thorough evaluation, the Company concluded that the Citrus Combined Cycle unit was superior to the competing alternatives offered.

The Company is filing its petition for a determination of need with the Florida Public Service Commission ("PSC" or the "Commission") for approval to build the Citrus CC. This Need Determination Study ("Need Study" or "Study") has been prepared to support the Company's petition to the Commission for a determination of need in conjunction with DEF's application for authority to construct Citrus CC pursuant to the Power Plant Siting Act, sections 403.501 – 403.518, Florida Statutes.

2. Purpose and Overview of Need Study.

Duke Energy Florida is concurrently filing its petition for a determination of need with the Commission for approval to build the Citrus CC. This Need Study is being submitted in support of DEF's petition for a determination of need. It is composed of five main sections and supporting appendices.

The Introduction provides background information on DEF and its generation, transmission, and distribution facilities, as well as the purchased power contracts and demand-side management programs in which the Company is engaged.

The second section provides a description of the proposed Citrus CC. The projected cost and performance of Citrus CC is discussed, and fuel supply, environmental considerations, and transmission requirements are detailed.

The third section of this Need Study describes DEF's need for resources and the identification of the type of resources needed. The section starts with a discussion of the Company's reliability criteria and demonstrates the need for additional generating resources, based on the growing demand and energy requirements of DEF's customers. The Company's determination to seek approval to build Citrus CC is a direct result of the Resource Planning process, which is discussed next. The Company's load and energy forecast, which is an input to this process, is also discussed.

To demonstrate that Citrus CC is the most cost-effective generating alternative, the fourth section describes the Request for Proposals performed by DEF. This section discusses the RFP document, the bids received, and the evaluation performed by the Company.

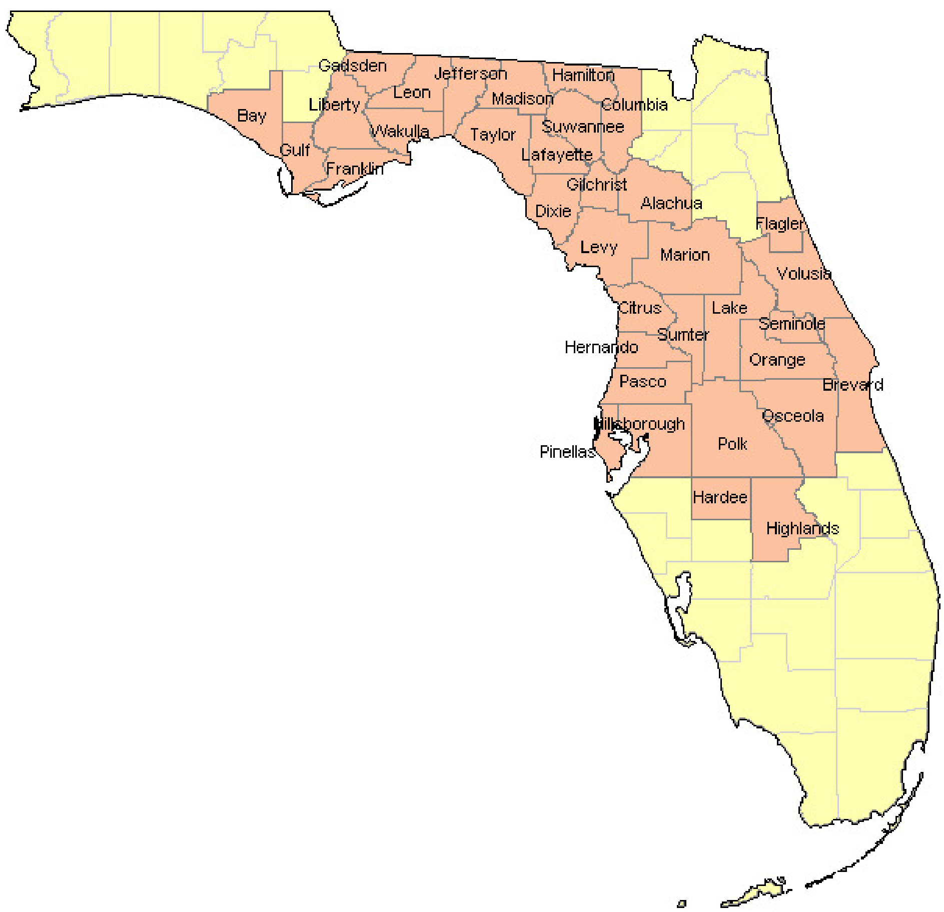
The final section of this Need Study, the Conclusion, summarizes the entire document and demonstrates the need for Citrus CC.

3. Company Description.

DEF is a wholly owned subsidiary of Duke Energy Corporation ("Duke Energy").
DEF is an investor-owned public utility, regulated by the PSC, with an obligation to provide electric service to approximately 1.7 million customers in its service area, which covers approximately 20,000 square miles in 29 of the state's 67 counties, as shown on the map in Figure 1. DEF supplies electricity at retail to approximately 350 communities and at wholesale to 22 municipalities, utilities, and power agencies in the State of Florida.

DEF serves what continues to be one of the faster growing areas of the country. Its forecasted annual customer growth is projected to be 1.4 percent over the next 10 years.

Figure 1
Map of Counties Served by DEF



a. Existing Facilities.

DEF currently owns and operates a mix of supply-side resources, consisting of generation from coal, oil, and natural gas, along with purchases from other utilities and purchases from non-utility generators such as cogenerators. The existing generating capacity is listed in Table 1. The Company's existing total summer net owned generating capability is 9,158 MW.

b. Purchased Power.

DEF purchases almost 2,500 MW of capacity from qualifying facilities, independent power producers and investor-owned utilities. The qualifying facilities from which the Company purchases power are fueled by a variety of sources, including natural gas, wood waste, and municipal waste. A full listing of qualifying facility contracts is provided in Table 2. DEF is also engaged in three long-term contracts for power. One contract is with The Southern Company, which sells the Company 414 MW from the coal-fired Scherer and natural gas fired Franklin Plants. DEF also has long term contracts for peaking capacity from the GE Shady Hills facility and the Northern Star Vandolah facility. Altogether, these purchased power resources account for approximately 20 percent of DEF's summer generation capacity, providing a significant amount of diversity in supply.

DUKE ENERGY FLORIDA
EXISTING GENERATING FACILITIES
AS OF MAY 31, 2014

PLANT NAME	UNIT NO.	LOCATION (COUNTY)	UNIT TYPE	FUEL PRI.	FUEL ALT.	NET CAPABILITY SUMMER MW
STEAM						
ANCLOTE	1	PASCO	ST	NG		501
ANCLOTE	2	PASCO	ST	NG		490
CRYSTAL RIVER	1	CITRUS	ST	BIT		370
CRYSTAL RIVER	2	CITRUS	ST	BIT		499
CRYSTAL RIVER	4	CITRUS	ST	BIT		712
CRYSTAL RIVER	5	CITRUS	ST	BIT		710
SUWANNEE RIVER	1	SUWANNEE	ST	NG		28
SUWANNEE RIVER	2	SUWANNEE	ST	NG		29
SUWANNEE RIVER	3	SUWANNEE	ST	NG		71
						3,410
COMBINED-CYCLE						
BARTOW	4	PINELLAS	CC	NG	DFO	1,160
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	462
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	490
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	488
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	472
TIGER BAY	1	POLK	CC	NG		205
						3,277
COMBUSTION TURBINE						
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	24
AVON PARK	P2	HIGHLANDS	GT	DFO		24
BARTOW	P1, P3	PINELLAS	GT	DFO		86
BARTOW	P2	PINELLAS	GT	NG	DFO	42
BARTOW	P4	PINELLAS	GT	NG	DFO	49
BAYBORO	P1-P4	PINELLAS	GT	DFO		174
DEBARY	P1-P6	VOLUSIA	GT	DFO		310
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	247
DEBARY	P10	VOLUSIA	GT	DFO		80
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	45
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	60
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		286
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	328
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		143
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	229
RIO PINAR	P1	ORANGE	GT	DFO		12
SUWANNEE RIVER	P1, P3	SUWANNEE	GT	NG	DFO	104
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		51
TURNER	P1-P2	VOLUSIA	GT	DFO		20
TURNER	P3	VOLUSIA	GT	DFO		53
TURNER	P4	VOLUSIA	GT	DFO		58
UNIV. OF FLA.	P1	ALACHUA	GT	NG		46
						2,471
						9,158

DUKE ENERGY FLORIDA FIRM RENEWABLES AND COGENERATION CONTRACTS AS OF MAY 31, 2014				
Facility Name	**Future Contract Start Dates**	**Contract Expiration Date**	**Summer Capacity (MW)**	**Firm Summer Capacity (MW)**
Lake County Resource Recovery		6/30/2014	12.8	12.8
Mulberry		8/8/2024	115	115
Orange Cogen (CFR-Biogen)		12/31/2025	74	74
Orlando Cogen		12/31/2023	115	115
Pasco County Resource Recovery		12/31/2024	23	23
Pinellas County Resource Recovery 1		12/31/2024	40	40
Pinellas County Resource Recovery 2		12/31/2024	14.8	14.8
Ridge Generating Station		12/31/2023	39.6	39.6
Florida Power Development		11/30/2033	60	60
Blue Chip Energy	12/1/2016	N/A	10	
National Solar - Gadsden	12/1/2017	N/A	50	
National Solar - Hardee	6/1/2016	N/A	50	
National Solar - Suwannee	12/1/2017	N/A	50	
National Solar - Highlands	12/1/2017	N/A	50	
National Solar - Osceola	12/1/2017	N/A	50	
Blue Chip Energy - Sorrento	12/1/2016	N/A	50	
E2E2 Inc.	1/1/2017	N/A	30	
US EcoGen Polk	1/1/2017	5/31/2043	60	
TOTAL				**494.2**

DUKE ENERGY FLORIDA PURCHASE POWER AGREEMENTS AS OF MAY 31, 2014			
Facility Name	**Future Contract Start Dates**	**Contract Expiration Date**	**Firm Summer Capacity (MW)**
Northern Star Generation (Vandolah)		5/31/2027	638.8
Shady Hills		4/30/2024	475.7
Southern Company (Scherer)		5/31/2016	342.0
Southern Company (Franklin)		5/31/2016	73.0
Southern Company (Franklin)	6/1/2016	5/31/2021	425.0
TOTAL			**1,954.6**

c. Demand-Side Management ("DSM").

To comply with the directives of the Florida Energy Efficiency and Conservation Act ("FEECA"), DEF must file with the PSC a DSM Plan to meet the conservation goals established by the PSC pursuant to FEECA. The PSC established conservation goals for DEF that span the ten-year period from 2010 through 2019 in Order No. PSC-09-0855-FOF-EG issued December 30, 2009 in Docket No. 080408-EG. The Company filed its DSM Plan on November 29, 2010. However, to avoid undue rate impact on DEF's customers, the Commission, in Order No. PSC-11-0347-PAA-EG, ordered the Company to continue its then-current DSM programs, which were approved as a result of the 2004 goal-setting proceeding. The Commission also approved the implementation of solar pilot programs. A description of Duke Energy Florida's DSM programs, as presented in the ongoing Energy Conservation Cost Recovery docket, is provided in Appendix B. A copy of Order No. PSC-11-0347-PAA-EG, Docket No. 100160-EG, issued on August 16, 2011 is provided in Appendix C.

The Company's residential Energy Management program represents a demand response type of program where participating customers help manage future growth and costs. Approximately 410,000 customers participated in the residential Energy Management program during 2013, contributing about 652 MW of winter peak-shaving capacity for use during high load periods. DEF'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.

DEF proposed new conservation goals for the ten year period from 2015 through 2024 in a filing with the Commission as part of Docket No. 130200-EI. Over the next five years (2015-2019) the proposed conservation goals are generally lower than the existing set of goals, reflecting less available savings from demand-side resources. The proposed conservation goals will lead to an increase in DEF's firm winter and summer peak demand. Therefore, if adopted by the Commission, DEF's proposed DSM goals further establish the need for the Citrus CC.

d. Committed Resources.

On August 1, 2013, the Company filed a Revised and Restated Stipulation and Settlement Agreement ("2013 Settlement Agreement") dated August 1, 2013, with the FPSC.

One of the Key Provisions of the 2013 Settlement was related to New Generation. Subject to a determination of need from the PSC and a prudence review of investment cost, Duke Energy Florida is permitted to:

- Recover prudently incurred costs to construct, acquire or uprate existing generation of up to 1,150 megawatts of capacity prior to the end of 2017.
- Establish a Generation Base Rate Adjustment (GBRA) to recover additional new generation needs in 2018 of up to 1,800 megawatts.

The Company has two capacity additions in its current Ten-Year Site Plan ("TYSP") prior to the planned in-service date of the Citrus CC.

- Two combustion turbines located at the Suwannee River Site available in June 2016; and
- Additional capacity at the Hines Energy Center through the installation of Inlet chilling that will be in service by 2017.

e. Retirements.

Crystal River Unit 3

On February 5, 2013, DEF announced that it was going to retire the Crystal River Nuclear Plant ("CR3"). The plant had been shut down since late 2009 when delaminations in the outer layer of the containment building's concrete wall occurred during a maintenance outage. The process of repairing the damage and restoring the unit to service resulted in additional delaminations in other sections of the containment structure in 2011. During the ensuing months, DEF evaluated the ability to successfully repair the unit, the risks associated with any repair and the repair scope as well as the likely costs and schedule. A report completed in late 2012 confirmed that repairing the plant was a viable option but that the nature and potential scope of repairs brought increased risks that could raise the cost dramatically and extend the schedule. Ultimately, DEF decided that retiring CR3 was in the best overall interests of its customers, investors, and the state of Florida.

Crystal River Units 1 and 2

Crystal River Units 1 and 2 are not capable of meeting the emissions requirements for the Mercury and Air Toxics Standards ("MATS") in their current configuration and using the current fuel. In addition, under the terms of the revised air permit, in accordance with the State Implementation Plan for compliance with the requirements of the Clean Air Visibility Rule ("CAVR"), these units are required to cease coal fired operation by the end of 2020 unless scrubbers are installed prior to the end of 2018.

DEF has received a one year extension of the deadline to comply with MATS for Crystal River Units 1 and 2 from the Florida Department of Environmental Protection ("FDEP"). This extension was granted to provide DEF sufficient time to complete projects necessary to enable interim operation of those units in compliance with MATS during the 2016 – 2020 period.

DEF anticipates burning MATS compliance coals in Crystal River Units 1 and 2 beginning no later than April 2016. To comply with MATS, the units must be de-rated to a collective 740 MW. Although specific dates have not been finalized, DEF anticipates retiring the Crystal River Units 1 and 2 in 2018 in coordination with the 2018 Citrus CC operations.

Other Units

DEF 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. Turner Unit P3 is projected to retire at the end of 2014. DEF also anticipates the retirement of the Avon Park, Rio Pinar and Turner P1 and P2 units. The three 60-year old Suwannee steam units are now projected to retire in the spring of 2016 consistent with the start of operation of the new Suwannee CT units. There are many factors which may impact these retirements including environmental regulations and permitting, the unit's age and maintenance requirements, local operational needs, their relatively small capacity size and system requirement needs. Current and projected retirements are listed in the table below.

Plant	Summer Capacity (MW)	Existing / Planned	Retirement Date
Crystal River 3	789	Existing	February 2013
Turner 3	53	Planned	December 2014
Turner 1 and 2	20	Planned	June 2016
Avon Park 1 and 2	48	Planned	June 2016
Rio Pinar	12	Planned	June 2016
Suwannee 1 – 3	128	Planned	June 201
Crystal River 1 and 2	740	Planned	April – October 2018 *
Higgins 1 – 4	105	Planned	June 2020

- The specific month of retirement of Crystal River 1 and 2 will be dependent on finalization of commissioning plans for the Citrus Combined Cycle.

f. Transmission and Distribution Facilities.

The Company is part of a nationwide interconnected power network that enables power to be exchanged between utilities. The DEF 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.

4. Description of the 2018 Citrus County Combined Cycle Power Plant.

The proposed Citrus CC will be a state-of-the-art, highly efficient combined cycle unit. Its beneficial heat rate, high availability and responsiveness, among other attributes will provide DEF customers with a low-cost, highly flexible source of power. Upon commencement of operation, the Citrus CC will be one of the most efficient natural gas fired units on the Company's system and within the State of Florida. This section outlines the technical characteristics of the proposed facility.

a. General description of the Citrus CC plant.

The Citrus CC will be a natural-gas fired, high efficiency plant that involves the generation of electricity in two stages, first by firing the combustion turbines ("CTGs"), and second by using the hot gas from the CTGs to produce steam through the heat recovery steam generators

("HRSGs") which is fed into the steam turbines ("STGs") to generate additional electricity. This combined-cycle capability makes the most of the input fuel, by burning it and using the waste heat from that process, to generate electricity and, therefore, is a very efficient plant design to produce electrical energy. The combined cycle generation technology is one of the most efficient base load power production technologies available today.

The Citrus CC will be an advanced class gas turbine, 4 by 2 combined cycle configuration, 1,640 MW plant built in stages of 820 MW each, with the first stage in commercial operation in May 2018 and the second stage in commercial operation by December 2018. DEF's technology review determined that use of proven advanced class gas turbines (GAC/H) in a 4X2 configuration will provide the best balance of efficiency, operational flexibility and reliability. The plant will have moderate duct firing capability, which means 50 to 100 MW of duct fired output of each 820MW block will be available as cost effective peaking capacity. The first advanced class turbines of this type in the United States have just been placed in service or are under construction. The Siemens H technology CC plant entered commercial operation in 2013 in Florida by FPL, and the first Mitsubishi GAC technology CC plant is expected to be commercial operation in 2014 in Virginia by Dominion.

The project will not include simple cycle bypass stacks which provide reliability but at a cost to unit efficiency. System reliability will be enhanced by the ability for independent operation of the two power blocks. One 820 MW CC block will connect to the 230kV transmission system and the other 820 MW block to the 500 kV transmission system. The project will take advantage of the existing transmission capacity that is and will be available due to the retirement of Crystal River Units 1, 2, and 3. The project will utilize sea water cooling towers with make-up supplied from the existing CREC intake canal and process makeup water from existing CREC fresh water wells.

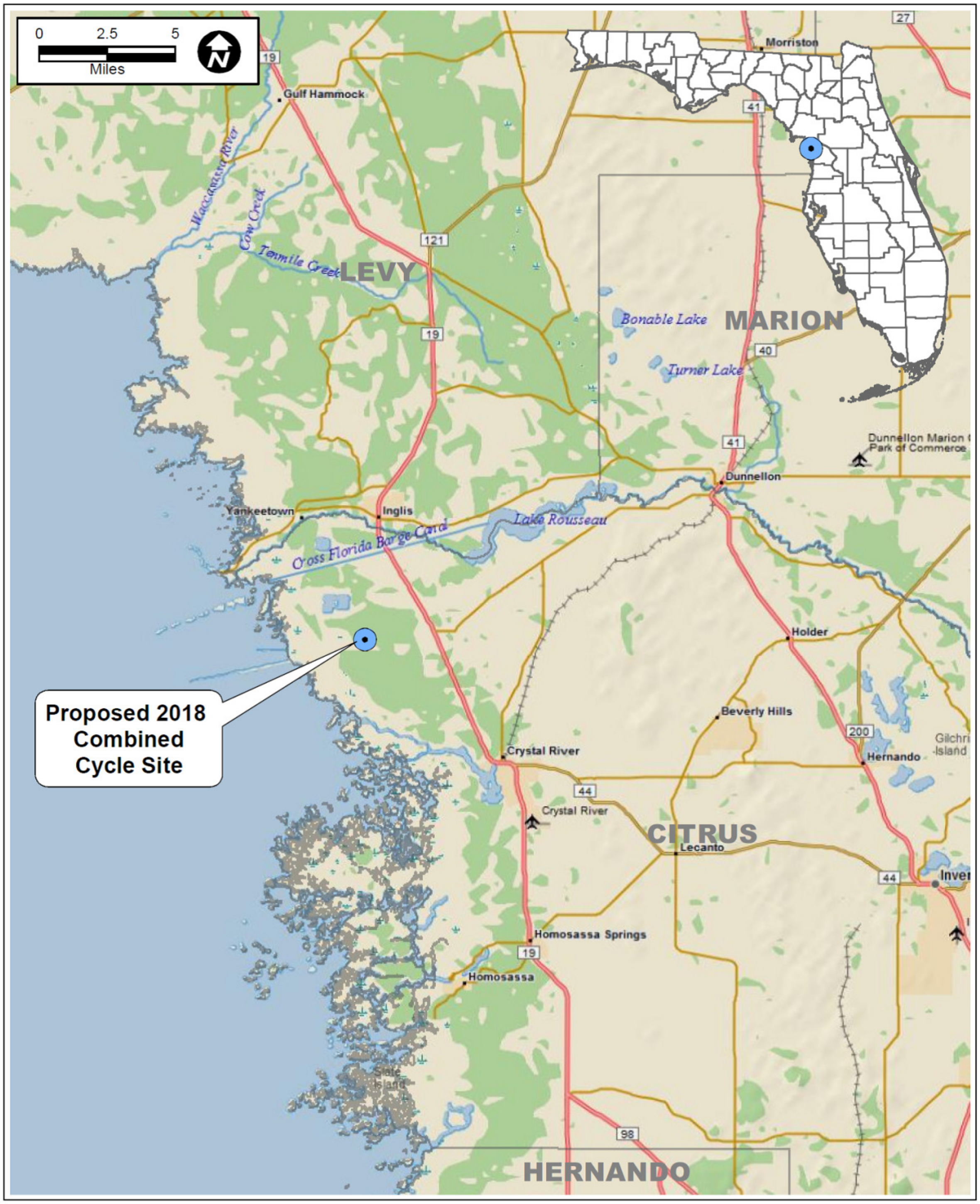
The Citrus CC project is designed for single fuel (natural gas only), with moderate duct-firing capability. Natural gas will be supplied via the new Sabal Trail Transmission LLC ("Sabal Trail") pipeline coming into central Florida from Alabama (Transco Station 85) and a new dedicated gas lateral pipeline (with proposed Florida Gas Transmission Company ("FGT") interconnect) to the Citrus CC facility.

b. Project Site.

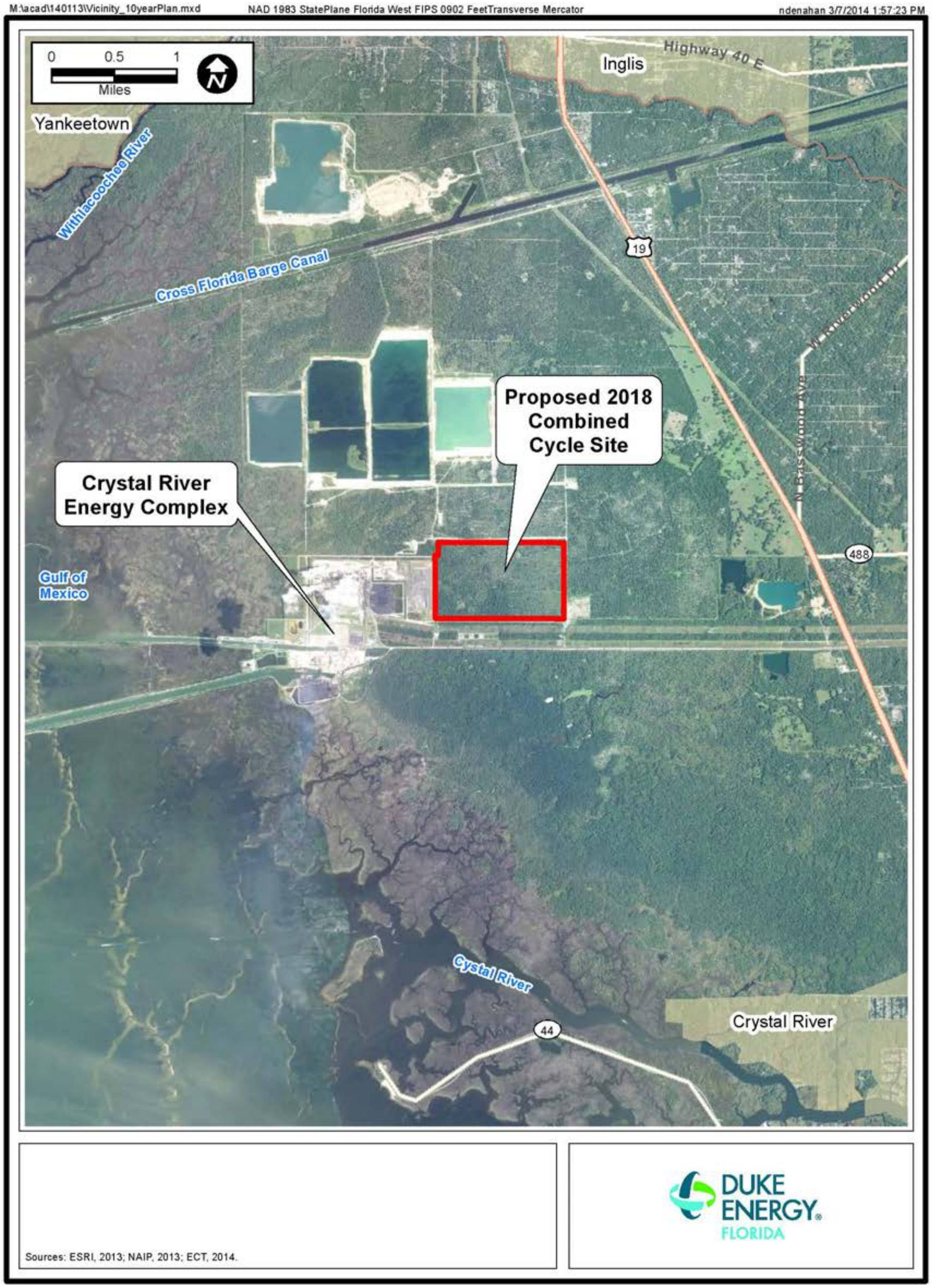
Siting analysis in 2013 determined the best site for a large combined cycle facility in DEF's territory was near the Crystal River Energy Complex ("CREC") and more specifically a 400 acre parcel, adjacent to CREC, to be purchased from Holcim (US), Inc. ("Holcim"). This location provided clear benefits in terms of the opportunity to utilize existing infrastructure resources including transmission, roads, and water resources. The Project Site is located at approximate latitude 26°58'00.84 north and approximate longitude 82°40'34.58 west.

The site consists of approximately 400 acres of property located immediately and north of the DEF Crystal River to Central Florida 500-/230-kV transmission line right-of-way and east of the Crystal River Units 4 and 5 coal ash storage area. The property consists of regenerating timber lands, forested wetlands, and rangeland. A new natural gas pipeline will be brought to the Project Site by the natural gas supplier on right of way provided by the supplier. The water pipelines and transmission lines will use existing DEF rights-of-way. No new rail spur is proposed and site access will be via existing roadways.

DEF's assessment of the Citrus site addressed whether any threatened and endangered species or archeological and cultural resources would be adversely impacted by the development of the site the facilities. No significant issues were identified in DEF's evaluations of the property. The new project is proposing to use the existing CR3 cooling water intake structure and a new discharge structure in the existing discharge canal.



Sources: DeLorme, 2014; ECT, 2014.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Crystal River
Energy Complex
Gulf of
Mexico
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Cystal River
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Crystal River
Sources: ESRI, 2013; NAIP, 2013; ECT, 2014.

c. Detailed Unit Description

The Citrus CC project is a 4x2 1,640 MW power plant using highly efficient advanced technology combined cycle units using natural gas as the fuel with salt water cooling towers as the heat sink. The proposed power block includes four (4) CTs; four (4) HRSGs and two (2) STGs. The power block will be split into two identical 2x1 units (2CTG's, 2 HRSG's, and 1 STG) that can operate as separate units with common infrastructure and provide backup to each other. The design incorporates auxiliary duct firing in the HRSGs to allow for additional steam generation.

The project will include:

- Two (2) units of 2 CT's on 2 HRSG's on 1 ST (2x2x1)
- Each unit has 100% steam by-pass (unfired condition).
- A common control room/administrative building between the two units.
- Separate cooling towers for each unit with common makeup water from the intake canal at CR3.

Major project equipment will include those items below. The description is on a per unit basis unless specified in the description as shared between units.

1. Combustion Turbine Generator Set
   - Advanced Class CT's [G or H]
   - Dry low NOx combustors (15-20 ppm NOx)
   - Hydrogen cooled generators

2. HRSG
   - 3 pressure reheat design
   - 1050F/1050F steam temperatures
   - 2350 PSIA maximum pressure
   - Duct firing capability
   - SCR catalysts
   - Oxidation catalyst for CO and VOC removal
   - Elevator for each unit.

3. Steam Turbine

   - Combined HP/IP Two-flow LP
   - 1050F/1050F steam temperatures
   - 2350 PSIA maximum pressure
   - Hydrogen cooled generator
   - Gantry Cranes for each STG

4. Condenser

   - 100% steam bypass capability for unfired steam flow
   - Deaerating condenser – no external deaerator

5. Cooling System

   - Closed loop salt water cooling tower – using the existing CR3 CW inlet system to supply makeup salt water to cooling towers (common system for the full power block)
   - Two 50% capacity circulating water pumps

6. Main Steam System

   - 100% steam turbine bypass design for unfired steam blow to condenser. Atmospheric vents will be used to minimize the opening of primary relief valves.

7. Feedwater System

   - Two 60% capacity motor operated BFW pumps per HRSG (60% capacity based on unfired case).

8. Condensate System

   - Three 50% capacity Condensate pumps to match cycle requirements
   - Use of the existing CR 1&2 fresh water wells as the source of process makeup water with new water treatment building.

9. Auxiliary Steam/Boiler

   - Single Auxiliary Boiler shared between two units for maintaining STG seals, condenser sparging, and ST prewarming
   - Electric superheaters at each steam turbine

- Auxiliary steam system cross-tied between units.

10. Controls

- Balance Of Plant (BOP) control system, integrated DCS (Emerson Ovation).
- CTG & STG Turbine controls provided by OEM
- Shared control room for the power block in a horseshoe configuration with each side dedicated to a single unit.
- Project includes a high-fidelity simulator system

11. Major Tanks

- Demineralized Water: Two tanks shared between the power block will provide storage for refill and startup of a unit following a single unit HRSG outage.
- Fire Water/Service Water: Two tanks shared between the power block as required to provide service water and fire water for both units. A single fire water supply and fire loop system will be shared by the power block.

12. Electrical Equipment

- GSU for each generator 18kV/230kV for one unit and 18kV/500kV for the other unit.
- UAT and generator breaker for each CTG train within power block
- 13.2 kV / 6,900 Volt medium voltage auxiliary power systems

13. Facilities

- One (1) combined Administration/Control/Maintenance Building with warehouse.
- Two personnel elevators (one on each 2x1) included for access drum-level of HRSG's.
- Drum-level catwalks between HRSG's within each unit.
- The major power equipment shall be outdoor construction.

Projected Citrus CC Costs.

d. Construction Costs.

$M	2013	2014	2015	2016	2017	2018	2019	Total
Engineering, Procurement, Construction, and Major Equipment	-	48.6	174.2	283.8	494.3	96.4	17.4	1,114.7
Owner Cost and BOP Equipment	2.8	11.8	14.3	24.2	89.1	44.1	0.1	186.5
Transmission Switchyard and Bus Line	-	-	-	4.9	41.2	2.4	-	48.5
Annual Cash Flow	**2.8**	**60.4**	**188.6**	**312.8**	**624.6**	**143.0**	**17.6**	**1,349.7**

There are a number of factors why Citrus CC is the most cost-effective alternative. First, DEF is able to take advantage of its prior investment in infrastructure at the CREC. Second, by virtue of its location in Citrus County adjacent to the CREC, the Citrus CC takes advantage of existing transmission capacity available as a result of the generation retirements at the CREC. Finally, DEF has as good, or better, credit rating than many of the IPPs today. Thus, the Company has a financing advantage.

e. O&M costs.

O&M Costs ($M)	2018	2019	2020	2021	2022
Fixed	$5.6	$11.3	$11.6	$12.0	$12.3
Variable (non-fuel)	$12.0	$24.8	$25.3	$26.0	$26.6
Total	$17.6	$36.1	$36.9	$38.0	$38.9

The estimated incremental annual fixed operation and maintenance ("O&M") cost for the Citrus CC is $6.79/kW-Yr (based on winter capacity of the plant and expressed in 2018 dollars). The largest fixed costs are wages and wage-related overheads for the permanent plant staff, as well as expenses for unplanned equipment maintenance. Estimated staffing for the Citrus plant is expected to be at least 40 permanent staff. Variable O&M costs, which vary as a function of plant generation, include consumables, chemicals, lubricants, water, and major maintenance costs such as planned equipment inspections and overhauls. The estimated non-fuel variable O&M cost is $2.41/MWh (expressed in 2018 dollars).

Projected Citrus CC Performance.

The proposed Citrus CC is a high efficiency combined cycle unit. with an expected average annual operational heat rate of approximately 6,625 BTU/kWh. Its heat rate approaches the lowest for generation units in operation today, meaning that it will generate more electricity per unit of fuel than many existing generating plants. The high reliability of the Citrus CC, with an expected equivalent forced outage rate of approximately two percent, will contribute to the Company's ability to provide adequate and reliable service to its customers. The plant's design also allows for greater flexibility in matching DEF's system operating requirements. The Citrus CC can be operated in baseload and load following service on the DEF system, depending on the needs of the system and the prevailing economic conditions. The Citrus CC is expected to operate in a capacity factor range of 50 percent to 90 percent, averaging 67 percent over its expected 35-year life. The Citrus CC will provide DEF and its customers with greater flexibility in the overall operation of its system at a low cost and a leading industry efficiency.

Heat Rate @ Maximum Load (Fully Fired)

Summer	6701	HHV
Winter	6669	HHV

New and clean without any margins applied.

Additional performance and operational characteristics of each unit include:

- Forced Outage Rate: 2%
- Operating ramp rate >20 MW/min
- Minimum load < 200 MW in 1x1 CC mode
- Stable cycle-down operation in 1x1x1 CC mode to obtain minimum load
- Simple-cycle CT operation that precludes combined cycle operation (the plant will be able to operate for a minimum of 30 minutes without the STG on-line bypassing to the condenser.)

The preliminary operational characteristics for the power block from recent production cost modeling are:

Annual Capacity Factor (%) Per Year – 4x2 CC Mode

Unit	**Min**	**Avg**	**High**
4x2 CC	50%	75%	90%

g. Fuel Supply and Transportation.

DEF analyzed the Citrus CC in terms of whether a secure, reliable primary fuel supply existed and could be expected to exist in the future for the plant. Natural gas has emerged as the fuel of choice for the current generation of new power plants because of its environmental advantages compared to coal or oil, its current lower cost and the projected adequate North American supplies available from shale rock sources. The lower level of environmental emissions from gas fueled generation (as compared to coal or oil) will assist DEF in complying with current and future environmental requirements. Recently promulgated and anticipated new regulations including the MATS, New Source Performance Standards for the emission of Greenhouse Gases, and Coal Combustions Residual rules will burden new and existing coal and oil facilities with increasingly larger costs compared to natural gas fired facilities. Federal and State environmental regulations will continue to cause cleaner burning fuels like natural gas to be more in demand as an alternative to coal and oil. Natural gas, therefore, will continue to be an attractive primary fuel source for DEF.

Adequacy of Fuel Supply

In addition to the well-developed conventional natural gas resources along the Gulf Coast and in western North America, in the last decade advances in natural gas production technology have provided natural gas producers access to unconventional gas supplies that previously were not economic production resources. These unconventional gas supplies are in tight gas sandstone structures and shale rock formations deep below the ground where natural gas in an abundant quantity is trapped within the rock. Improvements in drilling and well stimulation technologies now provide an economic method to drill and hydraulically fracture the rock and capture the large quantities of natural gas trapped in these impermeable rock formations. This advanced drilling technology is colloquially referred to as "fracking." Vast shale rock formations or "shale plays" extend across the United States and Canada. There are abundant shale plays in North America, providing a long-term source of supply of natural gas for natural gas users in the United States.

The ultimate size of the United States natural gas resource base has been estimated at 2,384 trillion cubic feet according to the latest report from the United States Potential Gas Committee 2013 Report from the United States Potential Gas Committee at the Colorado School of Mines. This estimate represents a 25% increase from their previous report in 2011 and at the current rate of United States consumption of approximately twenty five trillion cubic feet per year, the United States has ample domestic reserves.

As a result of the new drilling and completion technologies there has been a tremendous increase in United States unconventional gas production over the last five years. In the last five years the marketed production of United States natural gas has increased by 21% according to the Energy Information Administration ("EIA"). But an even more impressive statistic is the percentage of natural gas production from shale resources which has increased from about 11% of the national total in 2008 to over 35% by the end of 2012.

Shale resources are increasingly displacing conventional sources of gas in the Gulf of Mexico and elsewhere, and that has further implications on the reliability of supply. By moving on shore, producers are reducing the time it takes to bring new wells on line and those wells are less prone to disruption from hurricanes. The United States gas market is still subject to market volatility, in part due to the nature of the business where supply and demand must balance in real time and storage is finite and limited to certain regions by geology. However, short term price volatility arising from operational imbalances are not a significant threat to the value proposition of a natural gas combined cycle unit, the way long term fuel availability and price uncertainty is. The dramatic increase in the size of the gas resource base coupled with the speed at which it can be put in production has significantly improved the long term availability of natural gas and immensely improved the value proposition of natural gas as a fuel source for electric generation.

The United States power market will also benefit greatly from the distributed nature of the shale reserves being located much closer to major demand centers like the Northeast. The development of the Marcellus and Utica shale basins has freed up pipeline capacity across the Southeastern United States, which will also benefit future gas consumers in Florida in reduced transportation costs. This increase in the available gas supply and production of natural gas is expected to continue to favorably impact fuel prices with natural gas price projections being relatively economic to other fuels for energy production well into the future.

In part because of the expansion in natural gas supply in North America, and the forthcoming expansions of transportation into Florida, DEF was confident to design the Citrus CC without simple cycle bypass stacks or back up fuel oil which provide reliability but at costs to unit efficiency and capital construction.

Adequacy of Fuel Transportation

Sufficient and reliable firm gas transportation service for Florida natural gas customers can be expected. In addition to DEF's significant portfolio of firm transportation reservations from the two existing interstate pipelines, Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, L.L.C. ("Gulfstream"), DEF has a precedent agreement for firm transportation on the new Sabal Trail pipeline being constructed to serve the Florida market. Sabal Trail is a joint venture between affiliates of Spectra Energy Corp and NextEra Energy, Inc. The Sabal Trail Project will create a new pipeline system with a planned capacity to transport 1,100,000 dekatherms per day ("Dth/d") of natural gas. The Sabal Trail Project will have an initial capacity of 800,000 Dth/d with an in-service date beginning May 1, 2017. As part of the Sabal Trail Project, Sabal Trail will acquire by lease the mainline capacity to be created by Transcontinental Gas Pipe Line Company, LLC ("Transco"). Transco will expand the existing Transco system from Transco's Station 85 located in Choctaw County, Alabama to a location in Tallapoosa County, Alabama ("Transco Hillabee Project"). Sabal Trail will construct approximately 460 miles of greenfield mainline facilities from the interconnection with Transco in Tallapoosa County, Alabama to a point in Osceola County, Florida south of Orlando at the Central Florida Hub. At or near the Central Florida Hub, Sabal Trail will interconnect with Gulfstream and FGT. Information on Sabal Trail is based on the NEPA Pre-filing Process Request to FERC on

October 4, 2013 made by Sabal Trail for the Sabal Trail Project (Docket No. PF14-1). Additional information on Sabal Trail can be found on their website www.sabaltrailtransmission.com.

The Citrus CC site located in Citrus County, Florida currently is not interconnected with any natural gas pipeline. Sabal Trail will construct a 24-inch diameter gas lateral with an approximate length of 23 miles from Sabal Trail's mainline in Marion County, Florida to the Citrus CC site. The lateral will be capable of providing 300,000 MMBtu/day of firm gas transportation to the 2018CC with the ability to meet potential future additional gas generation needs up to 400,000 MMBtu/day. The gas lateral will have initial pressure above 1,000 psig at the mainline and Sabal Trail has a minimum pressure commitment of 650 psig at the custody transfer point, downstream of the M&R Station serving the Citrus CC. The target in-service date for Sabal Trail to complete the mainline, gas lateral, M&R station and associated facilities to support testing of the Citrus CC is October 1, 2017.

In addition to the previously planned bi-directional interconnections between Sabal Trail and FGT in Suwannee County, Florida and Orange County, Florida, DEF proposes an additional interconnect between Sabal Trail and FGT in Citrus County, Florida. DEF is in discussions with Sabal Trail for a 400,000 MMBtu/day receipt only meter. This interconnect will provide additional pipeline infrastructure diversity and reliability for the Citrus CC. In the event of a pipeline disruption or curtailment on Sabal Trail, this interconnect would allow DEF the ability to optimize FGT to deliver gas supply on a best efforts basis into the gas lateral interconnected with the Citrus CC.

Gas Supply

Sabal Trail provides direct upstream onshore contractual receipt points at Transco Station 85, Gulf South, Midcontinent Express Pipeline (MEP) and the Transco Zone 4 Pool. Gulf South and MEP combine for a receipt capacity of approximately 3.3 Bcf/day from the Mid-continent onshore production areas and can deliver to the proximity of Transco Station 85. These pipelines provide access to gas supplies from the Barnett Shale, Fayetteville Shale, Haynesville Shale, and Woodford Shale. In contrast to the traditional Gulf of Mexico and Mobile Bay offshore gas supplies, which have the risk of curtailment during storms, the "onshore points" at Transco

Station 85 have direct access to pipelines that have access to onshore supplies. This access provides the Citrus CC supply security, availability, supplier diversity, and flexibility. In addition, Sabal Trail provides access to receipt points in the Transco Zone 4 Pool through the lease with Transco which includes additional pipelines.

On average, the Citrus CC will use approximately 195,000 MMBtu (million British thermal units) per day of transportation service (with the capability to use up to 300,000 MMBtu per day in peak operation). DEF's precedent agreement with Sabal Trail, along with its existing agreements and its ongoing activity in the fuel transportation market will allow the Company to provide adequate and competitively priced natural gas transportation to serve the Citrus CC and DEF's fleet of natural gas generating units. The figures below show Florida's current natural gas pipeline network and the proposed path of the Sabal Trail Pipeline.

Fuel Supply Contracts

DEF's forecasted natural gas requirements are expected to be purchased primarily under term supply agreements based on market index pricing, with supplemental seasonal, monthly and daily purchases of natural gas being made as needed.

The FSO – DEF Long-Term Gas Supply RFP Process outlines the Long-Term RFP process by which DEF procures competitively priced natural gas to meet its longer-term projected fuel needs at its owned and tolled gas generation facilities in Florida. For clarity: 1) Long-Term RFP gas procurement activities typically are contract terms greater than one (1) year for periods that will typically begin for the next calendar period for which natural gas supplies are projected to be needed to meet DEF's annual, seasonal, monthly, and/or daily needs at its owned and tolled gas generation facilities; 2) DEF procures a portion of its projected fuel needs through the long-term RFP process and as needed will procure competitively priced natural gas supply through informal market solicitations based on the specific business opportunities and need. Binding commitments for long-term gas supply need to conform to this process and Duke Energy's Commodity Risk Policy, Credit Policy, Delegation of Authority and Approval of Business Transactions Policy.

Environmental Considerations

DEF places a strong emphasis on environmental quality in its planning process. While two resource alternatives may be economically competitive, their effects on the environment may be quite different, and DEF prefers not only the least cost resource but also one that satisfies DEF concerns for the quality of the environment. Accordingly, the technology and fuel type for a preferred generation alternative should be a relatively clean source. It must not only comply with current Clean Air Act and other environmental provisions, but must also provide substantial flexibility in the event of changes in environmental rules. Additionally, the generation technology should have a high efficiency (low heat rate). Efficient plants use less fuel per unit of electric service delivered and therefore create smaller environmental impacts per unit of service. Combined with the use of a clean combustion technology, efficient plants reduce the exposure of DEF to new environmental rules, constraints, or environmentally related taxes.

The Citrus CC will have a low environmental impact under all standard operating conditions. Combined cycle power plants operating on natural gas are one of the cleanest sources of fossil fuel power generation. Natural gas is a low sulfur, low nitrogen oxide, low particulate emission power plant fuel. Nitrogen oxide emissions will further be controlled by a selective catalytic reduction system located in the HRSGs. The Citrus CC will burn a relatively clean fuel and have a low environmental impact.

As a natural gas fired combined cycle power plant, the Citrus CC will be designed to comply with all current environmental regulations including anticipated additional regulations being proposed under the Clean Air Act. In addition to being low in sulfur, air toxics, and nitrogen oxide emissions, combined cycle natural gas plants produce approximately half of the CO2 emissions of a similarly sized conventional coal plant. The Citrus CC is designed to comply with the anticipated requirements of the New Source Performance Standards for Greenhouse Gas

Emissions. In addition, combined cycle facilities have a much lower thermal discharge impact compared to conventional steam generation and produce negligible streams of solid waste.

DEF's assessment of the Citrus CC site addressed whether any threatened and endangered species or archeological and cultural resources would be adversely impacted by the development of the site the facilities. No significant issues were identified in DEF's evaluations of the property. The site will be certified by the State of Florida under the Power Plant Siting Act. Federal permits for the development of the site will include a National Pollution Discharge Elimination System ("NPDES") permit, Title V Air Operating Permit and a Clean Water Act Section 404 Permit. The site will require Land Use Approval from Citrus County. The Citrus CC project will use the existing CR3 intake structure and a new discharge structure in the existing discharge canal.

The table below lists the required environmental permits for the Citrus CC along with the anticipated permitting schedule.

Item	Not Required	Required	To Be Applied For (Date)	Expected Receipt (Date)
Water Discharge to Surface Waters (NPDES) Permit		X	Jun-2014	Nov-2015
404 Permit / 401 Water Quality Certification		X	Jun-2014	Nov-2015
Domestic Wastewater		X(1)	Jun-2014	Oct-2015
Industrial Wastewater (non-NPDES)		X(1)	Jun-2014	Oct-2015
Water Use		X(1)	Jun-2014	Oct-2015
Water Use Area Restrictions (e.g. SWUCA, MIA) Applicability	X			
Corps of Engineers Permit(s): wetlands / aerial crossings		X	Jun-2014	Nov-2015
Environmental Resource Permit (ERP) for Wetlands		X(1)	Jun-2014	Nov-2015
ERP: Surface Water Management (MSSW)		X(1)	Jun-2014	Nov-2015
Solid Waste Disposal Permit	X			
Ash Disposal Permit	X			
Hazardous Waste Disposal Permit	X			
PSD (Air Construction) Permit		X(2)	Jun-2014	Nov-2015
Federal Aviation Administration License		X(3)	Sep-2016	Dec-2016
Certificate of Need		X(1)	Jun-2014	Dec-2017
Local Construction Permit		X(1)	Jun-2014	Dec-2015
Local Zoning Approval (Conditional Use Permit)		X	Mar-2014	Sep-2014
Spill Prevention Control Measures Permit		X	Aug-2016	Dec-2016
Section 10 (Wildlife) Permits	X			
Migratory Bird	X			
Department of Transportation		X(1)	Jun-2014	Oct-2015
Air: Title V Operating Permit		X	Jun-2014	Nov-2015
Electric and Magnetic Field (EMF) requirements: FDEP		X(1)	Jun-2014	Oct-2015
Title IV (Acid Rain) Permit		X(1)	Jun-2014	Nov-2015
Site Certification Application (includes state, local permitting and authorizations) or Supplemental SCA if existing site		X	Jun-2014	Oct-2015
Holcim Environmental Resource Permit (ERP) Modification		X	Jun-2014	Sep-2014
Holcim Department of Army Permit Modification		X	Jun-2014	Sep-2014
(1) Items will be addressed through the Site Certification Application (SCA)				
(2) Item will be coordinated with SCA				
(3) May be required for construction cranes				

j. Transmission requirements.

The Citrus CC siting review identified the Citrus County location as a favorable location from a transmission perspective both because of the availability of significant transmission resource in the area related to the CREC and because the construction of the Citrus CC would mitigate potential transmission upgrade needs triggered by the retirement of Crystal River Units 1, 2, and 3.

There are substantial Company transmission substation facilities, lines, and other structures and facilities in Citrus County and the surrounding area to transmit the generation at the CREC from the CREC across DEF's system to DEF's customers. At the beginning of 2013, there were over 3,000 MW of summer generation capacity from the Company's nuclear and coal-fired generation plants located at the CREC. All of this generation was supported by DEF transmission facilities, structures, and lines in the vicinity of the CREC.

In February 2013, the Company decided to retire CR3, its nuclear power plant, located at the CREC. CR3 alone accounted for almost 800 MW of the CREC's summer generation capacity. In addition, the Company's oldest coal-fired generation plants, its Crystal River Unit 1 ("CR1") and Unit 2 ("CR2") plants, cannot comply with the EPA MATS regulations in their current configuration and as they are currently operated, and face eventual retirement due to the EPA CAVR. As a result, the Company faced potential, additional generation plant retirements at the CREC in the immediate future. The existing and potential retirements of substantial CREC generation capacity freed up some of the existing transmission capacity that was built to support the CREC generation capacity. This existing transmission capacity was available to support new generation in Citrus County or the surrounding area.

The only transmission work that is necessary for the Citrus CC is the switchyard and transmission bus line work to actually connect that plant with the existing DEF transmission facilities that are already connected to DEF's transmission system and the electric power grid in Florida. One 820 MW block of the 1,640 MW Citrus CC will be connected to the existing 500 kV transmission system located at the CREC effectively replacing the generation from the retired

CR3 unit. The other 820 MW block will be connected to the existing CREC 230 kV transmission system effectively replacing the CR1 and CR2 generation when it is retired.

The transmission lines will use existing Duke Energy Florida rights-of-way.

Substation and Transmission design will have a multi-breaker substation configuration that will provide a reliable interconnection. Plant design will include allocations for interconnection at 500kV and 230kV and all transmission equipment installed will meet Federal Energy Regulatory Commission ("FERC"), North American Electric Reliability Corporation ("NERC") and DEF System Transmission Reliability Standards.

5. Resource Need and Identification.

a. Reserve Margin and Loss of Load Probability.

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. 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.

DEF 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 DEF's ability to meet its forecasted seasonal peak load with firm capacity. DEF 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 DEF, is a maximum of one day in ten years loss of load probability.

DEF 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. DEF'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, DEF'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. DEF has found that resource additions are typically triggered to meet the 20 percent Reserve Margin thresholds before LOLP becomes a factor.

Projected DEF Reserve Margins With and Without Citrus CC

		With Citrus CC		Without Citrus CC	
Year	Summer Firm Peak Demand	Summer Installed Capacity	Summer Reserve Margin (%)	Summer Installed Capacity	Summer Reserve Margin (%)
2014	8,812	11,024	25.1%	11,024	25.1%
2015	9,042	10,991	21.6%	10,991	21.6%
2016	9,149	11,012	20.4%	11,012	20.4%
2017	9,307	11,232	20.7%	11,232	20.7%
2018	9,439	11,362	20.4%	10,542	11.7%
2019	9,813	12,132	23.6%	10,492	6.9%
2020	9,935	12,027	21.1%	10,387	4.5%

DEF's needs in the period are driven not only by summer load growth (although growth in this period is projected at 1.8% per year due in part to expansion of wholesale contracts), but primarily due to recent and upcoming unit retirements. In addition to the 2013 retirement of CR3 (790 summer MW, DEF share), CR 1and CR2 will retire due to environmental restrictions (740 summer MW).

These capacity reductions and the additional peak demand translates into a capacity need of 840 MWs in year 2018, 1338 MW in 2019; and 1590 MW in 2020 as can be seen in the table above.

The Reserve Margin by 2018 is 20.4%. Without the addition of the Citrus CC in 2018, and the addition of the Suwannee CTs and the Hines Chillers prior to 2018, the Reserve Margin would have fallen below the minimum 20% requirement. The Suwannee CTs contribute 320 MWs and the Hines Chillers 220 MW.

b. Resource Planning Process.

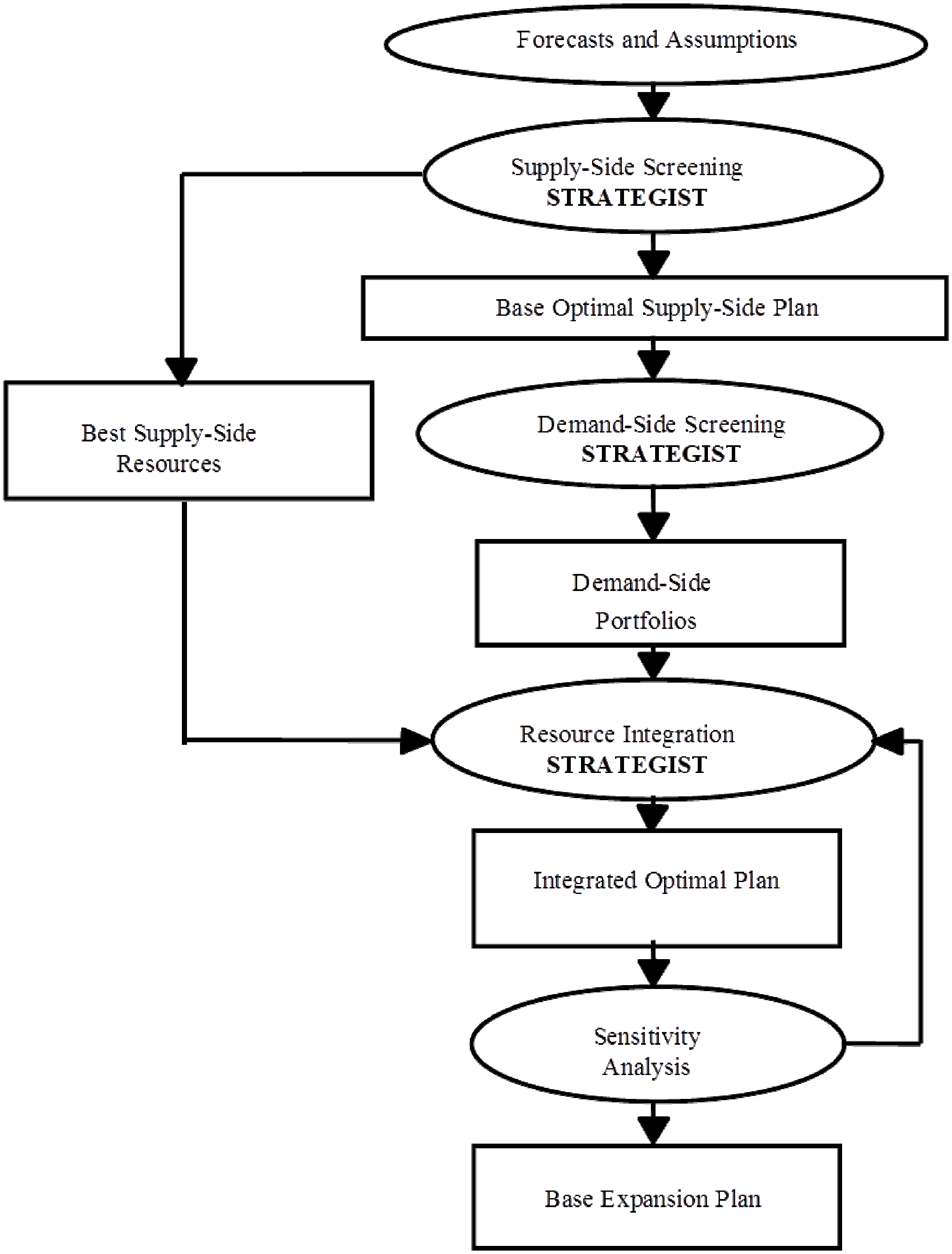
DEF employs an Integrated Resource Planning ("IRP") process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. DEF's IRP process incorporates state-of-the-art computer models to evaluate a wide range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

An overview of DEF'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 DEF 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 DEF 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



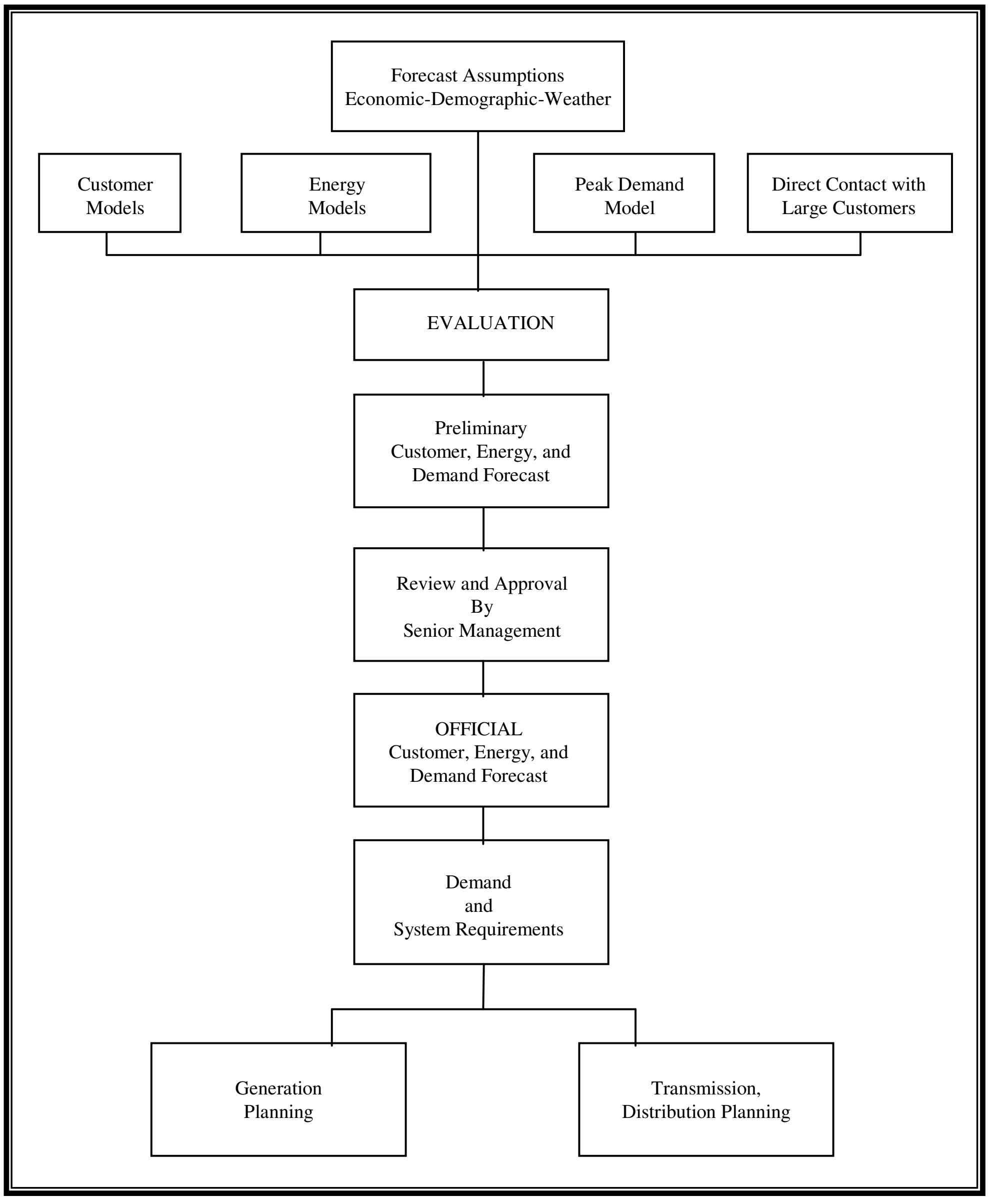
c. Forecasting methods and procedures.

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. DEF's forecasting framework utilizes a set of econometric models as well as the Itron statistically adjusted end-use ("SAE") approach 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 DEF's DSM programs.

Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of DEF'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.

FIGURE 2.1

Customer, Energy, and Demand Forecast



d. 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.

e. General Assumptions.

1. Normal weather conditions for energy sales are assumed over the forecast horizon using a sales-weighted 10-year average of conditions at the St Petersburg, Orlando, and Tallahassee weather stations. For billed kilowatt-hour (kWh) sales projections, the normal weather calculation begins with a historical 10-year average of the billing cycle weighted monthly heating and cooling degree-days. The expected consumption period read dates for each projected billing cycle determines the exact historical dates for developing the ten year average weather condition each month. Each class displays different weather-sensitive base temperatures from which degree day values begin to accumulate. Seasonal peak demand projections are based on a 30-year historical average of system-weighted temperatures at time of seasonal peak at the same three weather stations. The remaining months of the year may use less than 30 years if an historical monthly peak occurred during an unexpected time of day due to unusual weather.

2. Historical population, household and average household size estimates by Florida county produced by the BEBR at the University of Florida as published in "Florida Population Studies", Bulletin No. 65 (March 2013) are used. The projected change in Florida average household size from Moody's Analytics provided the basis for the 29 county household projection used in the development of the customer forecast. National and Florida economic projections produced by Moody's Analytics in their July 2013 forecast provided the basis for development of the DEF customer and energy forecast.

3. Within the DEF service area, the phosphate mining industry is the dominant sector in the industrial sales class. Three major customers accounted for exactly 33 percent of the industrial class MWh sales in 2013. 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 market price of the raw mined commodity often dictates production levels. Load and energy consumption at the DEF-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, global currency fluctuations and global stockpiles of farm commodities will determine the demand for fertilizers. The DEF forecast calls for an increase in annual electric energy consumption due to a new mine opening later in this decade. 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 DEF's rates versus competitors' rates play a role as to where a mining customer directs output from self-owned generation facilities. This can reduce DEF industrial sales.

4. DEF supplies load and energy service to wholesale customers on a "full" and "partial" 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) customers 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 and Homestead.

5. This forecast assumes that DEF 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 incorporates an increase of over 15 MW of self-service generation in 2013 from two customers. DEF will supply the supplemental

load of self-service cogeneration customers. While DEF 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 DEF 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.

f. Economic Assumptions.

The economic outlook for this forecast was developed in the summer of 2013 as the nation waited for stronger signs of growth. Most economic indicators pointed to better days ahead but Washington policy-makers continued to debate pro-growth versus deficit reduction strategies which prolonged uncertainty for consumers, employers and capital investment decision-makers. Consumer confidence and sentiment surveys improved, reflecting the lower unemployment rate and record setting stock market indexes. In Florida, these trends were tempered by continued high foreclosure rates and an expected sixth straight year of lower Statewide median household real income from its 2007 peak.

The DEF forecast incorporates the economic assumptions implied in the Moody's Analytics U.S. and Florida forecasts with some minor tempering to its short term optimism. This view suggests that 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. An improved manufacturing sector is well displayed in many parts across the U.S. The domestic economic picture will, however, continue to feel the drag from a weak Euro-Zone and other emerging economies. This will be reflected in lower short term growth from what has been a surprising source of U.S. GDP growth: American exports.

The debt bubble that set the conditions for the Great Recession and the lingering effects of the recession have created many economic imbalances that many now believe will result in a longer time to return to equilibrium than the ordinary recession. Signs of optimism do exist, however. DEF customer growth increased by more than 20,000 in December 2013 from December 2012. The anticipated influx of retiring baby-boomers may just be starting to be reflected in the data.

Energy prices are expected to remain in a tight range through the forecast due to increased supplies of both fossil fuels and renewables. The potential for a carbon tax or other monetization of carbon restrictions remains on the horizon in the 2020 period and is incorporated into this forecast's electric price projection. No disruption in global supplies of energy or new environmental findings over the safety of extracting fossil fuels are expected in the forecast horizon.

Also incorporated in this energy forecast is a projection of customer-owned solar photovoltaic generation and electric vehicle ownership. The net energy impact of both are expected to result in only marginal impacts to the forecasted energy growth.

g. Forecast Methodology.

The DEF forecast of customers, energy sales, and peak demand applies both an econometric and end-use methodology. The residential and commercial energy projections incorporate Itron's statistically adjusted end-use (SAE) approach while other classes use customer class-specific econometric models. These models are expressly designed to capture class-specific variation over time. 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.

h. 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 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. The incorporation of residential and commercial "end-use" energy have been modeled as well. Surveys of residential appliance saturation and average efficiency performed by the company's Market Research department and the EIA, along with trended projections of both by Itron, capture a significant piece of the changing future environment for electric energy consumption.

i. 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, DEF's coincident system peak is separated into five major components. These components consist of potential firm retail load, interruptible and curtailable tariff non-firm load, conservation and load management program capability, wholesale demand, company use demand, and interruptible demand.

Potential firm retail load refers to projections of DEF retail hourly seasonal net peak demand (excluding the non-firm interruptible/curtailable/standby services) before any historical activation of DEF's General Load Reduction Plan. The historical values of this series are constructed to show the size of DEF's firm retail net peak demand assuming no utility activated 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 retail customer levels and coincident weather conditions at the time of the peak without the impacts of year-to-year variation in load control reductions. Seasonal peaks are projected using the historical seasonal peak hour 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 DEF'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 DEF to other electric suppliers such as SECI, RCID, and other electric transmission and distribution entities. 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.

DEF "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 DEF'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.

j. Conservation.

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

The following tables show the 2010 through 2013 achievements from DEF's existing set of DSM programs.

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
2013	258	375	432

DEF'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 that will continue to be offered through 2014. 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 result of this process, including identified trends in customer growth, usage, net energy for load and winter and summer peak demands, making allowance for projected conservation efforts results in the final load forecast shown here and in Schedules 2.1, 2.2, 2.3, 3.1, 3.2, 3.3, and 4 of DEF's 2014 Ten Year Site Plan.

	LOAD FORECAST		
	Firm Peak Demand (MW)		Energy
	Winter	Summer	Requirements (GWH)
2014	8,170	8,812	39,801
2015	9,133	9,042	40,490
2016	9,370	9,149	41,098
2017	9,298	9,307	41,375
2018	9,544	9,439	41,995
2019	9,639	9,813	43,013
2020	9,971	9,935	43,998
2021	10,059	9,952	44,419
2022	10,144	10,067	44,870
2023	10,225	10,173	45,459

k. Other Planning Assumptions.

1. Fundamental Forecast.

All of DEF's long-term fundamental commodity prices are developed within the context of a comprehensive, internally consistent modeling process. The short term fuel forecast is based on available futures market prices, spot market prices, and short-term contract prices for the fuels used by the electric utilities. The short term natural gas fuels price forecast, for example, is based on the New York Mercantile Exchange ("NYMEX") futures contract prices for United States natural gas. The NYMEX natural gas futures market is an electric utility industry standard index of future market prices for United States natural gas. The Company transitions from its reliance on the short term fuels forecast to the Duke Energy Fundamental Forecast, or long term fuels forecast over a period between 3 and 5 years in the future.

Duke Energy starts its Fundamental Forecast with the assistance of an expert energy consultancy in the field of fuels forecasting in the industry. Duke Energy's current industry consultant is Energy Ventures Analysis, Inc. ("EVA"). EVA is an industry expert in fuel price forecast modeling and analysis.

Duke Energy relies on EVA to employ its industry leading modeling processes and databases to develop a long-term energy commodity price forecast that EVA provides Duke Energy. Duke Energy subject matter experts review the EVA assumptions and data inputs in the long-term energy commodity price forecast for consistency with Duke Energy's own internal planning assumptions and data inputs. Duke Energy works in a collaborative manner with EVA to discuss the input assumptions, model results, and corresponding conclusions in the EVA reference case.

The Fundamental Forecast is released each spring with an updated forecast typically in the fall of the year. The preparation of the Fundamental Forecast, however, is a continual process in the sense that Duke Energy routinely monitors and updates, when necessary, the assumptions underlying the Fundamental Forecast based on changes in the market and evolving conditions in the national and regional economies where the electric utilities are located, political and regulatory conditions, environmental conditions and other factors that have or may have an impact on the Fundamental Forecast.

The low and high natural gas forecasts in the Fundamental Forecast are developed by comparing the Duke Energy base natural gas price forecast in the Fundamental Forecast to contemporary, well-recognized industry natural gas price forecasts and applying statistically relevant standard deviations to the data. This methodology results in the calculation of the low and high natural

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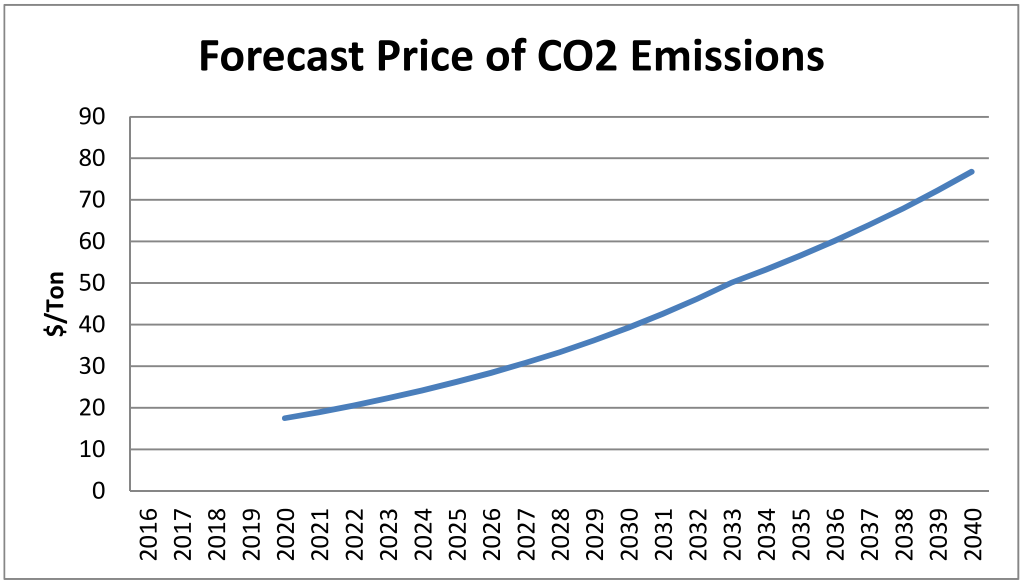
gas price forecasts around the Fundamental Natural Gas Forecast. Based on these calculations, the low natural gas forecast is 18 percent lower and the high natural gas forecast is 14 percent higher than the Duke Energy Fundamental Natural Gas Forecast, as shown in the table below. Duke Energy's methodology reasonably anchors its low and high natural gas price scenarios to contemporary industry natural gas price forecasts and ensures that the range of potential natural gas prices in the Duke Energy Fundamental Natural Gas Forecast is not out of line with industry forecasts.

[redacted]

Duke Energy has included a price on carbon within its base fundamentals outlook since 2006 as a way of capturing the potential impact of uncertain future policy. Although current legislative efforts to enact a policy that places a national price on carbon remain highly uncertain, it is still a possibility. Therefore, Duke Energy believes it is prudent to model a price on carbon as a way of capturing the risk of potential, but uncertain future legislation and pending EPA regulation of CO_2, and the impact of carbon policy at the national level within the context of its fundamental fuel price outlook. The carbon price Duke Energy currently uses in its fundamentals forecast is a direct input to the process and has been set at a level we believe to be a reasonable trajectory to represent the risk of federal climate change legislation or regulation given the current uncertainty surrounding such policy. The carbon price trajectory used is also in our view reflective of the pricing that policy makers might consider acceptable if or when they act.



Duke Energy also typically evaluates a scenario in which there is no monetized cost for carbon emissions and did so in the RFP evaluation.

2. Economic and Financial Assumptions.

Economic and Financial Assumptions

DEF's evaluation of its supply-side generation alternatives takes into account those economic and financial factors that affect the determination of the most economic generation expansion plan. DEF prepares and incorporates forecasts for key economic and financial factors such as the general inflation rate, construction cost escalation rate, and interest rates into its analysis of generation alternatives. These forecasts are based on DEF's annual assessment of regional and national economic factors and represent what DEF anticipates in support of its financial management process.

The values used in assessing alternatives in the selection of the Citrus CC are shown in the table below.

Financial Assumptions **Base Case**

AFUDC RATE		6.46	%
CAPITALIZATION RATIOS:			
	DEBT	50	%
	PREFERRED	0	%
	EQUITY	50	%
RATE OF RETURN			
	DEBT	3.75	%
	PREFERRED	0	%
	EQUITY	10.5	%
INCOME TAX RATE:			
	STATE	5.5	%
	FEDERAL	35	%
	EFFECTIVE	35.26	%
OTHER TAX RATE:		N/A	%
DISCOUNT RATE:		6.46	%

6. Future Demand-Side Management.

The Company's residential Energy Management program represents a demand response type of program where participating customers help manage future growth and costs. Approximately 410,000 customers participated in the residential Energy Management program during 2013, contributing about 652 MW of winter peak-shaving capacity for use during high load periods.

DEF'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. These programs contribute savings both in Energy Management and through conservation.

DEF projects the following annual savings through its DSM programs over the next ten years.

	Summer MW	Winter MW	

	Conservation	Energy Management	Conservation	Energy Management	Energy GWh
2014	37	-63	66	38	70
2015	31	11	58	29	60
2016	28	8	49	16	56
2017	25	41	47	34	49
2018	22	17	36	23	45
2019	21	56	34	58	43
2020	22	31	40	36	46
2021	20	10	34	15	43
2022	19	9	32	14	40
2023	18	9	31	14	39

DEF proposed new conservation goals for the ten year period from 2015 through 2024 in a filing with the Commission as part of Docket No. 130200-EI. Over the next five years (2015-2019) the proposed conservation goals are generally lower than the existing set of goals, reflecting less available savings from demand-side resources. The proposed conservation goals will lead to an increase in DEF's firm winter and summer peak demand. Therefore, if adopted by the Commission, DEF's proposed DSM goals further establish the need for the Citrus CC.

7. Supply Side Alternative Screening.

DEF includes conventional and renewable energy resources as potential capacity addition alternatives in its overall Resource Planning process. These resource alternatives are periodically reassessed and the performance characteristics updated to ensure that projections for new resource additions capture new and emerging technologies over the planning horizon. This analysis involves a preliminary screening of the generation resource alternatives based on commercial availability, technical feasibility, performance, and cost.

First, DEF examined the commercial availability of each technology for use in utility-scale applications. For a particular technology to be considered commercially available, the technology must be able to be built and operated on an appropriate commercial scale in continuous service by or for an electric utility. Reasonable levels of detail for emerging technologies were developed to allow DEF to screen the technology options and to stay abreast of potential economic benefits as they mature.

Second, technical feasibility for commercially available technologies was considered to determine if the technology met DEF's particular generation requirements and that it would integrate well into DEF's system. Evaluation of technical feasibility included the size, fuel type, and construction requirements of the particular technology and the ability to match the technology to the service it would be required to perform on DEF's system (e.g., baseload, intermediate, cycling, or peaking).

Finally, for each alternative, an estimate of the levelized cost of energy production, or "busbar" cost, accounting for capital, fuel, and O&M costs over the typical life expectancy of the unit, was developed. Busbar costs allow for comparison of fixed and operating costs of all technologies over different operating levels. The comparison considers the long-term economics of future power plants at varying levels of capacity factor. Data used to assess each technology includes fixed and variable O&M, fuel, construction costs, and the levelized fixed charge rate.

For the screening of alternatives, the data are generic in nature and thus not site specific. The costs and operating parameters are adjusted to reflect installation in the southeastern United States. The operating characteristics are based on state-of-the-art designs, and for most technologies, the performance and costs are based on a specific size unit. The cost and performance projections were made with Burns and McDonnell assistance and internal DEF resources.

Categories of capacity addition alternatives that were reviewed as potential resource options for in-service dates through 2018 included *conventional* technologies that utilize non-renewable resources and *alternative* technologies that utilize renewable sources of energy. In the most recent assessment, the following generation technologies were screened:

<u>Conventional Technologies</u>
Combustion Turbine (CT)
Combined Cycle (CC)

<u>Alternative Technologies</u>
Solar Photovoltaic (PV)
Wood (commercial)

These are mature, proven technologies.

Wind projects have high fixed costs but essentially no operating costs. Therefore, at high enough capacity factors they could become economically competitive with the lower-cost technologies identified. However, the geographic and atmospheric characteristics of Florida limit the ability of wind projects to achieve those capacity factors. Wind projects must be constructed in areas with high average wind speed. In general, wind resources in Florida, and throughout the southeast, are limited. The average wind speed in Florida is below 14 miles per hour and is not sufficient to be an economic alternative. Because a wind project would not be expected to operate above a 20-25 percent capacity factor in the Florida geographic area, it is not a viable alternative to the CC for intermediate duty. Further, because wind is not dispatchable, it is not a suitable alternative to the CT for peaking duty. As a result, wind was eliminated from consideration as a potential resource to meet future generation needs.

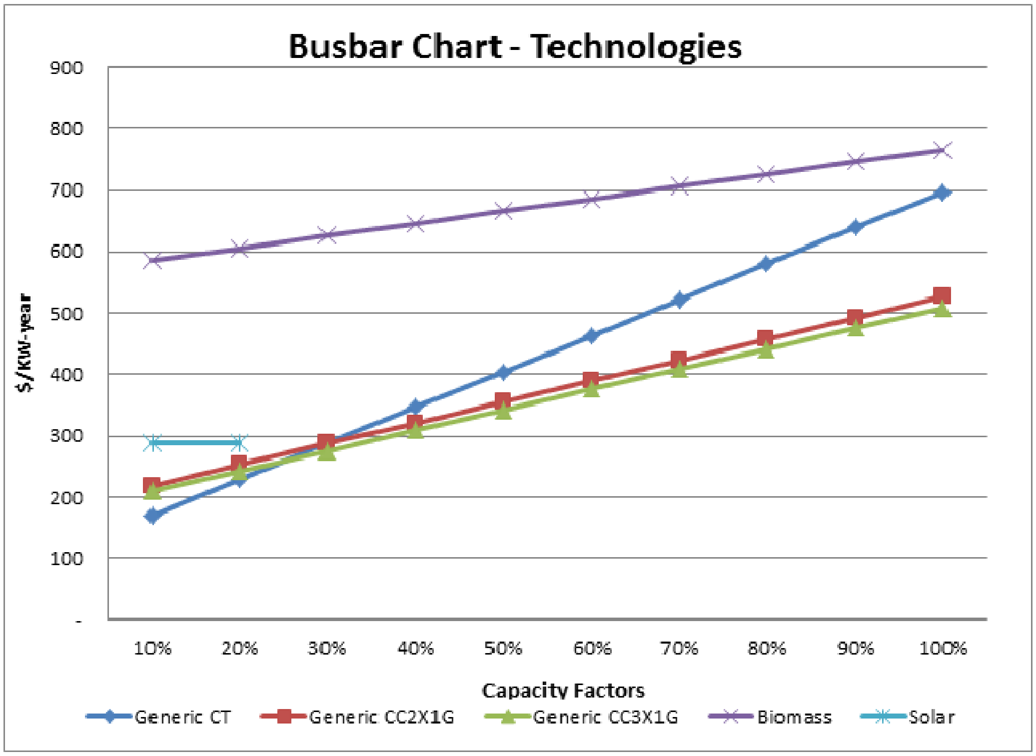
Solar photovoltaic (PV) projects are also technically constrained from achieving high capacity factors. In Florida they would be expected to operate at approximately 20 percent capacity factor making them unsuitable for intermediate or higher duty cycles. At the lower capacity factors, they, like wind, are not dispatchable and therefore not technically suited to provide reliable peaking capacity. In this evaluation, recognizing that the need for new generation was driven in large measure by the retirement of existing baseload units (Crystal River Units 1, 2, and 3), DEF recognized a system need for dispatchable, high capacity factor generation. Solar projects do not provide dependable dispatchable capacity and have not yet demonstrated economic competitiveness as an energy only resource. Similarly, biomass generation on a utility scale was eliminated because of high busbar costs, as well as potential environmental emission challenges.

Moderately high capital costs, as well as high operating cost, eliminated advanced nuclear technologies in the screening process. Long lead times led DEF to further forego nuclear as a viable means of satisfying its capacity needs during this planning period.

With solar photovoltaic and biomass technologies eliminated from further consideration, only three technologies were retained for the more detailed economic analysis phase of the evaluation. They included one simple cycle combustion turbine option and two combined cycle options.

The table below and the accompanying figure provide the busbar cost comparison of the four technologies identified as commercially available, technically feasible, and potentially cost-effective, making them viable generation alternatives in Florida. This graph illustrates that the combustion turbine (CT) is the most economical generation alternative for peaking duty cycles, and the combined cycle (CC) is the preference for intermediate and base load operation. Combustion turbines and combined cycles also have the lowest overnight capital costs.

Alternative	Summer Total Capacity (MW)	Overnight Generation Capital Costs 2016$ $/Kw	$M	Overnight Transmission Capital Costs 2016$ $/Kw	$M	O&M Costs 2016$ Fixed $/Kw	Variable $/Mwh	Summer Heat Rate Btu/Kwh	Equivalent FOR (%)	Fuel Type
Combustion Turbine	186.66	457	85	142	27	72	10.89	10,343	2.05%	Gas / Oil
Combined Cycle 2x1 G	792.97	904	717	392	311	72	5.72	6,800	6.36%	Gas / Oil
Combined Cycle 3x1 G	1,189.10	870	1,035	349	414	70	4.83	6,820	6.36%	Gas / Oil
Biomass	50.00	4,588	229	124	6	111	5.75	13,000		Wood
Solar Photovoltaic	25.00	1,956	49	124	3	89	-	-		Solar



DEF has historically considered both coal fired and nuclear generation. While neither of these is represented in the data above, DEF continues to monitor developments affecting cost and feasibility in both technologies.

New coal fired generation currently faces significant cost and feasibility challenges due to increasing environmental regulation. EPA's New Source Performance Standards for Control of Greenhouse Gas Emissions place stringent limits on the emission of CO_2 from coal fired plants and may require the use of carbon capture and sequestration (CCS). CCS is an emerging technology, not yet in full utility scale service in the United States. The examples of early integration of this technology have faced significant cost and operational challenges. In addition, successful implementation of CCS requires geology conducive to permanent sequestration of the CO_2. Adequate geology in Florida has not been demonstrated.

New nuclear generation also continues to face significant challenges from both licensing and cost pressures. DEF has for several years been pursuing development of a nuclear plant at DEF's site in Levy County. In the planning for the 2018 Need, DEF recognized that the development timeline for a nuclear facility including both licensing and construction, even with the investment made to date in the Levy Project, would not meet the in service needs for this time period.

Although the proposed Levy Nuclear Project is no longer an option for meeting energy needs within the originally scheduled time frame, Duke Energy Florida continues to regard the Levy site as a viable option for future nuclear generation and understands the importance of fuel diversity in creating a sustainable energy future. Because of this the Company will continue to pursue the combined operating license outside of the Nuclear Cost Recovery Clause with shareholder dollars as set forth in the 2013 Settlement Agreement. The Company will make a final decision on new nuclear generation in Florida in the future based on, among other factors, energy needs, project costs, carbon regulation, natural gas prices, existing or future legislative provisions for cost recovery, and the requirements of the NRC's combined operating license.

8. Resource Integration

Once the range of supply-side and demand-side alternatives has been screened, an integration assessment is conducted to determine the optimum supply-side expansion plan, given the portfolio of cost-effective DSM programs identified, as previously described. In this phase, DEF screens expansion plan alternatives comprised of the viable generation technologies using the Strategist resource optimization model. The results of the economic screening in Strategist showed the combined cycle and combustion turbine generation technologies were consistently selected in the top ranked plans. The top plans include the same resource additions through the ten-year planning horizon. The top ranked plan includes the addition of two combustion turbines at the Suwannee River Plant in 2016, addition of inlet chilling to supply additional summer capacity from the combined cycle units at the Hines Energy Center by 2017, the Citrus CC in 2018 and the addition of an undesignated future combined cycle unit in 2021. This plan was chosen by DEF as the Integrated Optimal Plan and was also published as the Base Expansion Plan in the Company’s 2014 TYSP filed with the FPSC on April 1, 2014 as shown in the table below.

DEF considered the option of increased DSM as an alternative to allow deferral of the Citrus CC. Because of the large size of the need for capacity in the 2018 timeframe, it was recognized that

DSM programs of such a scale necessary to defer this large block of capacity could not be developed, approved and implemented in the necessary timeframe. In addition, DEF has screened the current DSM programs, identified as the most cost effective programs available, against a generic CC unit in the timeframe of the Citrus CC and found that no cost effective DSM programs were available to defer the Citrus CC.

9. Resource Selection: 2018 RFP.

DEF Request For Proposal ("RFP"or the "DEF 2018 RFP") General Description:

Prior to filing its petition for determination of need for the Citrus CC pursuant to Section 403.519, Florida Statutes, DEF issued the DEF 2018 RFP to evaluated supply-side alternatives to the Citrus CC as its Next Planned Generating Unit ("NPGU"). DEF developed the 2018 RFP consistent with Rule 25-22.082 of the Florida Administrative Code ("Bid Rule") and complied with the Bid Rule in the 2018 RFP process and evaluation.

The DEF 2018 RFP included three key components: the Solicitation Document, the Bidder Response Package, and the Bidder Response Schedules and Forms. Attachments to the 2018 RFP included DEF's key Terms and Conditions and DEF's 2013 TYSP.

The DEF 2018 RFP Solicitation Document was divided into five parts. Part I was an introduction of the 2018 RFP, the objectives of the 2018 RFP, DEF's 2018 resource needs, the 2018 RFP schedule, and the 2018 RFP Official Contact. Part II provided potential bidders the instructions for responding to the 2018 RFP Solicitation Document and described the information and responsibilities for the potential bidders. Part III described the 2018 RFP evaluation process. Part IV described the Company's NPGU. Part V provided DEF's system specific conditions, which was information about DEF's system that was important for potential bidders to respond to the 2018 RFP. A copy of the 2018 RFP Solicitation Document and all attachments, including the Bidder Response Package and Bidder Response Schedules and Forms in included as an appendix to this Need Study.

The purpose of the DEF 2018 RFP was to solicit competitive proposals for supply-side alternatives to the Company's NPGU, the Citrus CC. The Citrus CC is approximately 1,640

MW (summer rating) 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. Accordingly, DEF sought a minimum of 820 MW in service no later than May 1, 2018 with the balance of the capacity available no later than December 1, 2018. DEF invited offers for all resource types as long as they were from a dispatchable, supply-side resource and considered to be firm capacity with firm deliverability into DEF's system. DEF allowed bidders to propose both existing and new capacity, and tolling and purchase power arrangements, including system power sales. Potential bidders were allowed up to two variations (such as power augmentation, operating reliability impacts or financing terms) in project term and/or pricing at no additional cost in their proposals. DEF requested creative responses which employed innovative or inventive technologies or processes. DEF sought resources that offered the maximum value, based on price and non-price attributes, to the Company's customers.

DEF specifically explained in its System Specific Conditions in the 2018 RFP Solicitation Document that the preferred Bulk Electric System ("BES") location for new DEF generation capacity was is in Citrus County. DEF explained that the Citrus County location was preferred because the new capacity was replacing generation that was being retired in the area. DEF even explained that this location or other areas in proximity to Citrus County provided transmission reliability benefits for DEF as well as neighboring transmission systems within the Florida Region. Finally, DEF explained that if the new generation capacity was not located in the vicinity of Citrus County, DEF expected significant Transmission Network Upgrades would be needed on DEF's transmission system as well as neighboring transmission systems within the Florida Region. In other words, DEF explained that if the bidders located their proposed generation in Citrus County they would take advantage of the available transmission capacity that was available on the BES due to DEF's generation retirements in the area.

DEF 2018 RFP Pre-Issuance and 2018 RFP Issuance.

On September 24, 2013, DEF notified potential bidders about the issuance of the DEF 2018 RFP by publishing public notices in major newspapers, periodicals and trade publications with statewide and national circulation including Megawatt Daily, SNL, the Tampa Tribune, the Orlando Sentinel, Energy Biz, and Power Engineering. The Company set up a 2018 RFP website that was publicly available the same day and that contained the information in the public notice. The public notice provided a general description of the Company's NPGU, the name and address of the contact person from whom an RFP package could be requested, the Company's website address at which an RFP package could be obtained, and the schedule of critical dates for the RFP process. A press release was also published that contained the same information in the public notice and that contained the 2018 RFP website address and link. The Company's press release about the 2018 RFP was referred to in articles by a number of news services, both in print and on-line, including the Tampa Bay Times, the Wall Street Journal, the Citrus County Chronicle, Yahoo Finance, and various industry trade journals.

Also on September 24, 2013, DEF issued a pre-release version of the RFP. The pre-release RFP documents were made available on the 2018 RFP website for dowloading. The pre-release RFP documents were also available to registrants on Power Advocate, a web-based RFP interface tool that DEF used for the 2018 RFP. DEF provided instructions for registration on Power Advocate and 33 individuals with 27 companies registered on Power Advocate. A copy of the 2018 RFP was also provided to the Florida Office of Public Counsel and filed with the Commission.

DEF held a public 2018 RFP pre-Issuance meeting on October 2, 2013 to review the information in the pre-release RFP documents and to receive feedback on the RFP. Over 20 people attended the pre-Issuance meeting in person in Tampa, Florida or via a conference call line or the live web presentation set up for the pre-Issuance meeting. DEF made a presentation at the meeting regarding the RFP objectives, the types of resource alternatives DEF sought in the RFP, the 2018 RFP documents, the RFP process, and other requirements of bidders. Potential bidder questions about the RFP documents and process were invited and any answers to questions were provided and posted on the 2018 RFP website.

The DEF 2018 RFP was officially released on October 8, 2013. DEF held a Bidders Conference for all potential bidders on October 18, 2013. The purpose of the Bidders Conference was to allow interested parties the opportunity to ask questions and seek additional information or clarification about the RFP solicitation process. DEF made another presentation at the bidders meeting regarding the RFP objectives, the types of resource alternatives DEF sought in response to the RFP, the 2018 RFP documents, the RFP process, and other bidder requirements. Over 12 people attended the Bidders Conference in person in Tampa, Florida or via a conference call line or the live web presentation set up for the meeting. Potential bidder questions about the RFP documents and process were invited and any answers to questions were provided and posted on the 2018 RFP website. DEF also notified the Office of Public Counsel and the Commission Staff of the 2018 RFP pre-Issuance meeting and Bidders Conference.

No potential participants filed objections to the 2018 RFP documents with the Commission within 10 days of the issuance of the 2018 RFP. DEF provided potential bidders 60 days to respond to the 2018 RFP between the issuance of the 2018 RFP on October 8, 2013 and the due date for proposals on December 9, 2013.

DEF also employed Alan Taylor with Sedway Consulting, Inc. as an Independent Monitor and Independent Evaluator for the 2018 RFP. Mr. Taylor assisted the Company with the development of the 2018 RFP documents and associated website, reviewed DEF's solicitation process, and performed a parallel and independent economic evaluation of DEF's NPGU and the proposals DEF received in response to the 2018 RFP. His contact information was provided to potential bidders in the RFP Solicitation Document and on the 2018 RFP webiste. Potential bidders were asked in the 2018 RFP Solicitation Document and solicitation process to contact Mr. Taylor and the Company's contact with any questions or comments regarding the 2018 RFP. Mr. Taylor's role as an Independent Monitor was to ensure the 2018 RFP process was fair and impartial and that the 2018 RFP documents were clear, fair, and consistent with the Bid Rule. Mr. Taylor determined that the 2018 RFP documents were reasonable and that the 2018 RFP solicitation process was fair to all participants.

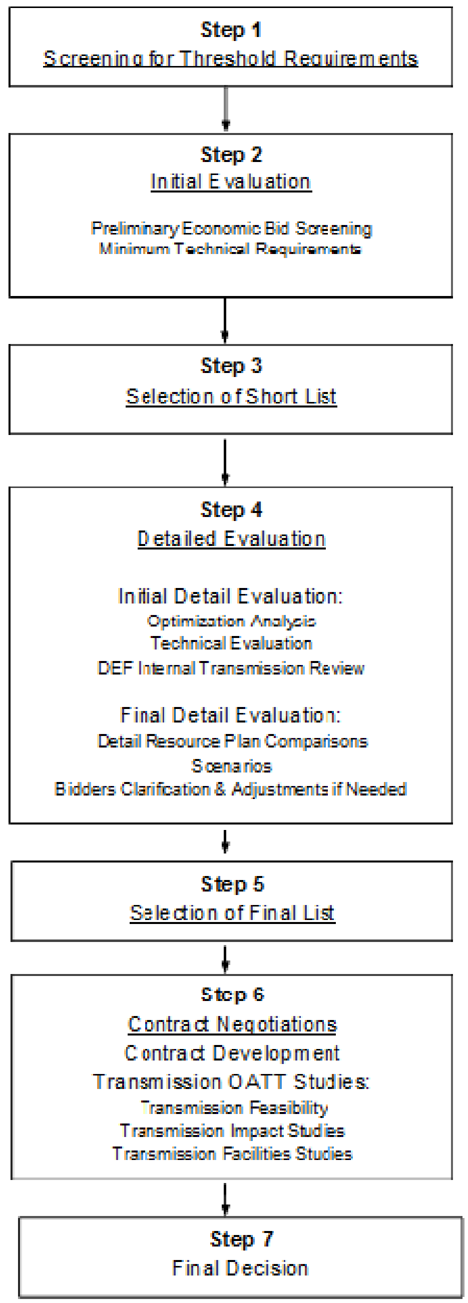
DEF 2018 RFP Proposals:

On December 9, 2013, in addition to the self-build proposal, DEF received 6 alternative Bidder proposals with an additional 5 variations on proposals for a total of 12 proposals (including the self-build proposal) in response to the 2018 RFP. A total of 1,332 MW of alternative capacity resources were proposed in response to the Company's 1,640 MW reliability need in 2018. Of the 1,332 MW of alternative capacity proposals, two were located within DEF's control area and the remaining proposals were located outside DEF's service area. Proposals outside DEF's transmission area required additional transmission studies by the host transmission providers. All but one of the alternative proposals were from existing sites. All but one of the alternative proposals relied on natural gas as the fuel for the proposed resource. The alternative capacity proposals varied in MW capacity and proposal contract term lengths; none of the alternative proposals equaled the 35-year life of the Citrus County CC NPGU. Even if all alternative proposals were combined together, DEF was still required to build generation in 2018/19 to meet its reliability need and to build generation again after the alternative proposal terms expired. A confidential summary of the proposals is included in Appendix D to this Need Study.

DEF 2018 RFP Evaluation Process:

DEF utilized a seven-step evaluation and screening process to review proposals to the 2018 RFP and to select the best alternative on price and non-price attributes for DEF's customers. Figure III-1 illustrates the evaluation process, starting with the receipt of proposals to the final decision. DEF's evaluation of the proposals to the 2018 RFP consistent with this process is described more fully below.

FIGURE III-1
Evaluation Process



Step 1: Screening for Threshold Requirements.

Subsequent to the receipt of the Bidders' proposals, DEF thoroughly reviewed and assessed each proposal to ensure that it met the Threshold Requirements listed in the RFP. Threshold Requirements represent the minimum requirements that all proposals are required to meet. Bidders were required to include sufficient documentation in their proposals to demonstrate that they met all Threshold Requirements. Failure to conform to the Threshold Requirements was grounds for disqualification. The Bidder Threshold Requirements are listed in FIGURE III-2.

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**.

Threshold Requirements Screening Results:

None of the Bidder proposals initially passed the Threshold Requirements screen without any deficiencies. All proposals required clarifying questions to obtain additional information to assist DEF in determining if the proposals met the Threshold Requirements. DEF sent clarifying questions to the bidders on December 26, 2013. All bidders responded to the clarifying questions. Four bidder proposals required additional threshold transmission information about the status of their host utility transmission study and about their ability to obtain a host transmission agreement within the required timeframe. All of these bidders responded with a willingness to pursue the required transmission information, but they all had issues with obtaining the transmission information by required date. Because these bidders proposed to supply DEF with capacity from existing units DEF knew their host transmission utility and had a working relationship with and some knowledge about the host utility. As a result of this information, and because DEF had received a limited number of proposals in response to the 2018 RFP, DEF elected to continue with the next steps in the RFP process and to evaluate these deficiencies later in the qualitative assessment of the proposals after completion of the quantitative evaluation of the proposals, if a qualitative assessment was necessary. DEF, accordingly, did not disqualify these bidder proposals for failure to meet the 2018 RFP Threshhold Requirements.

Another bidder proposal failed to satisfy the Operating Performance and Site Control Threshold Requirements. DEF sent clarifying questions, again on December 26, 2013, and the bidder supplied additional information regarding the Operating and Site Control Threshold Requirements for the bidder's proposal. The additional information included an expressed willingness to pursue operating delivery alternatives to the Operating Performance Threshold Requirements, however, the information supplied did not meet this Threshold Requirements. Again, because DEF had received a limited number of proposals in response to the 2018 RFP, DEF elected to continue with the next steps in the RFP process and to evaluate these deficiencies later in the qualitative assessment of the proposal after completion of the quantitative evaluation of the proposals, if a qualitative assessment was necessary. DEF, accordingly, did not disqualify this bidder proposal for failure to meet the 2018 RFP Threshhold Requirements.

DEF discussed its approach to the Threshold Requirements deficiencies in some of the bidder proposals with Mr. Taylor and Mr. Taylor agreed with the Company's approach. Mr. Taylor agreed that DEF's decision to defer the assessment of these Threshold Requirements deficiencies to the qualitative evaluation of the proposals, if a qualitative assessment was required after the economic evaluation of the proposals, was a fair approach to the evaluation of the proposals even though DEF had the right under the 2018 RFP to disqualify the non-conforming proposals from further evaluation in the RFP evaluation process.

The following Table summarizes that DEF checked all Threshold Requirements for all bidder proposals. As explained above, despite Threshold Requirement deficiencies with some bidder proposals, DEF elected to continue with the economic evaluation of the proposals. All Threshold Requirements deficiencies would be evaluated in the qualitative evaluation of the proposals if a qualitative assessment was necessary after DEF completed the economic evaluation of the proposals.

Final "Over All" Threshold Requirements Review

Proposal #	A	B	C	D	E	F
Accepetd (√) Rejected (X)	√	√	√	√	√	√

Threshold Requirement - Proposal Reviews By Sections

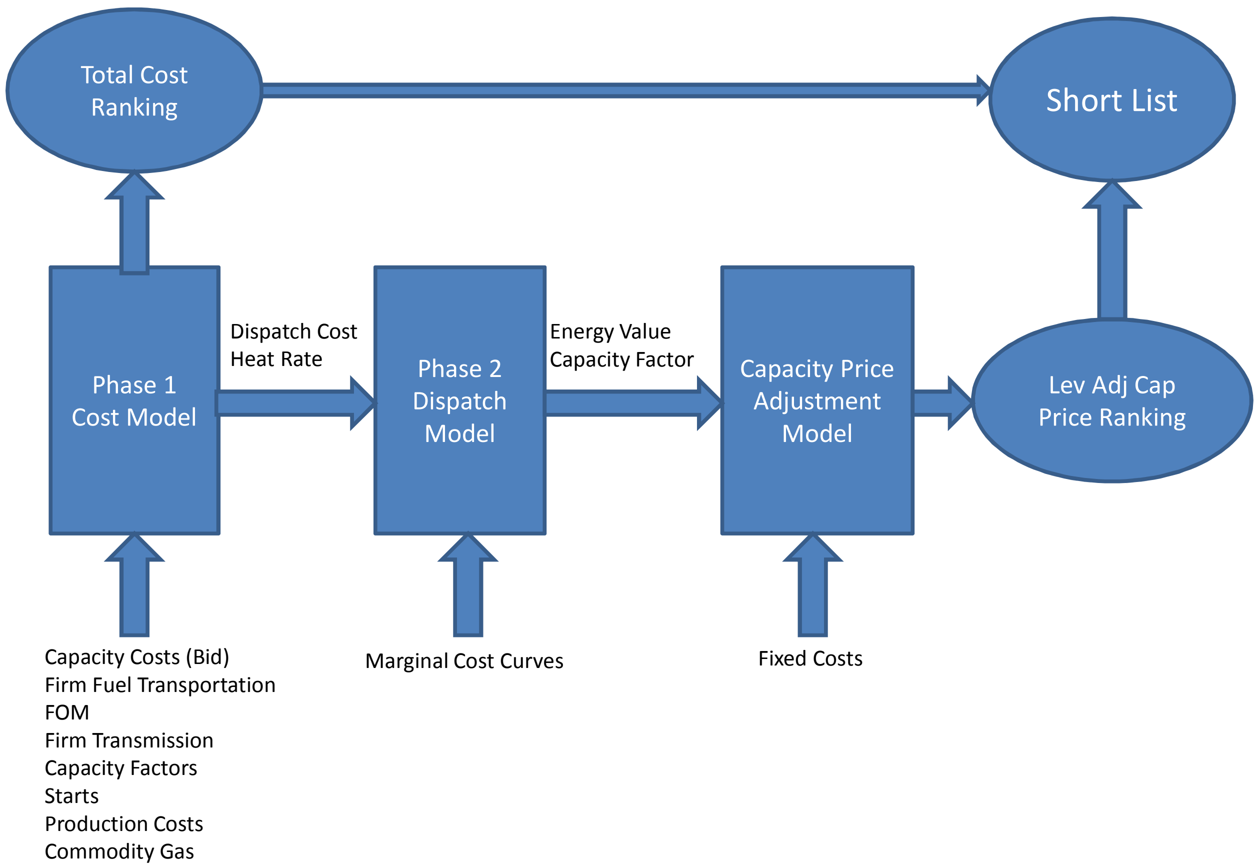
Proposal #	A	B	C	D	E	F	Threshold Requirement Review Sections
Accepetd (√) Rejected (X)	√	√	√	√	√	√	A. General Requirements
Proposal #	A	B	C	D	E	F	B. Operating Performance Thresholds
Accepetd (√) Rejected (X)	√	√	√	√	√	√	
Proposal #	A	B	C	D	E	F	C. Terms & Conditions Thresholds
Accepetd (√) Rejected (X)	√	√	√	√	√	√	
Proposal #	A	B	C	D	E	F	D. Site Control Thresholds [New and Existing Unit Proposals]
Accepetd (√) Rejected (X)	√	√	√	√	√	√	
Proposal #	A	B	C	D	E	F	E. Transmission Threshold
Accepetd (√) Rejected (X)	√	√	√	√	√	√	

Note: Although various concerns were identified by Review Leads and addressed in DEF 12/26/13 Clarifyng Questions, bidders responses to the 12/26/13 Clarifying Questions were adequate for continued evaluation and review beyond Step 1 - Threshold Requirements

Step 2: Initial Evaluations

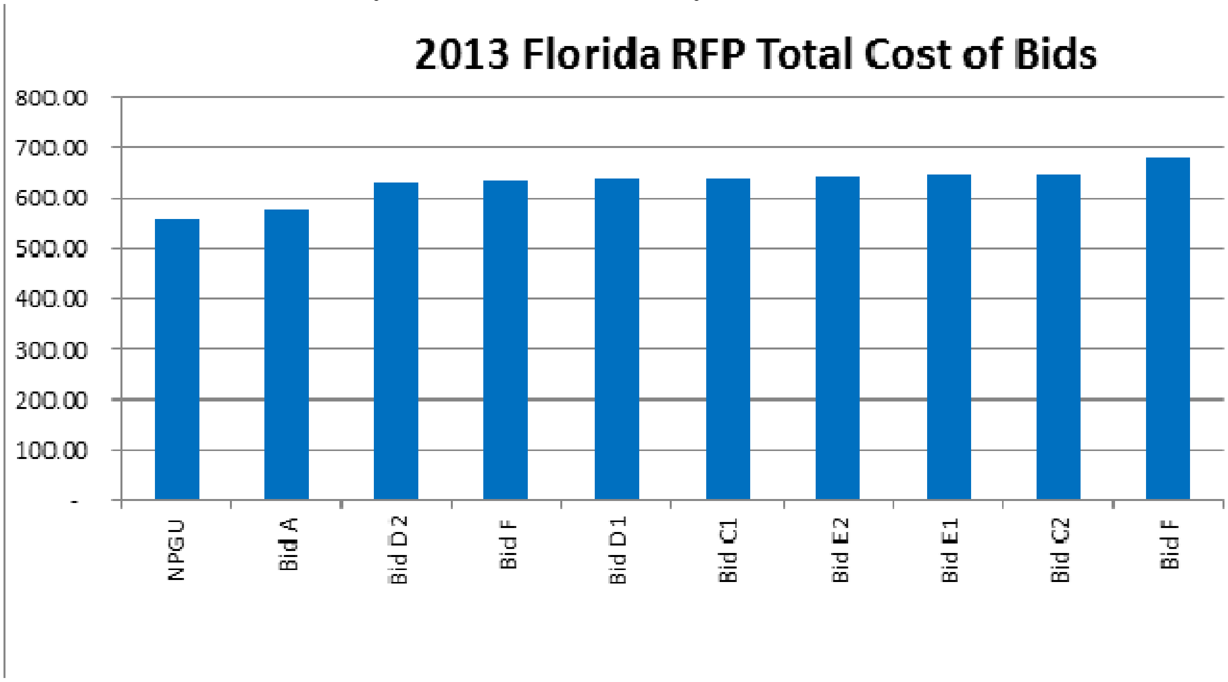
Initial Economic Screening

The initial economic screen was performed in two phases, one in which the operational cost of each bid was evaluated on a standalone basis and a second phase in which each unit was evaluated against the DEF system to evaluate the total fixed and energy costs for that unit. The initial screening process is outlined in the figure below.



The Phase 1 Screening uses assumed capacity factors and associated number of starts (in this evaluation 70% for the combined cycle units and 90% for the renewable bid). Using the bid values and DEF data for gas price, bid VOM, and bid start costs, a total energy cost is developed. That value is combined with a total fixed cost developed using DEF and bid data for capacity prices, fixed gas transportation, and firm transmission. Bids shorter than the study period (26 years for the screening) were back filled with energy and fixed costs equal to the self build on a $/kw basis. In this evaluation, transmission costs were not used since the transmission portfolios and their costs had not yet been developed.

Results of the Phase 1 Analysis (Total Cost in $/kwyr Levelized)



Final Screening Results

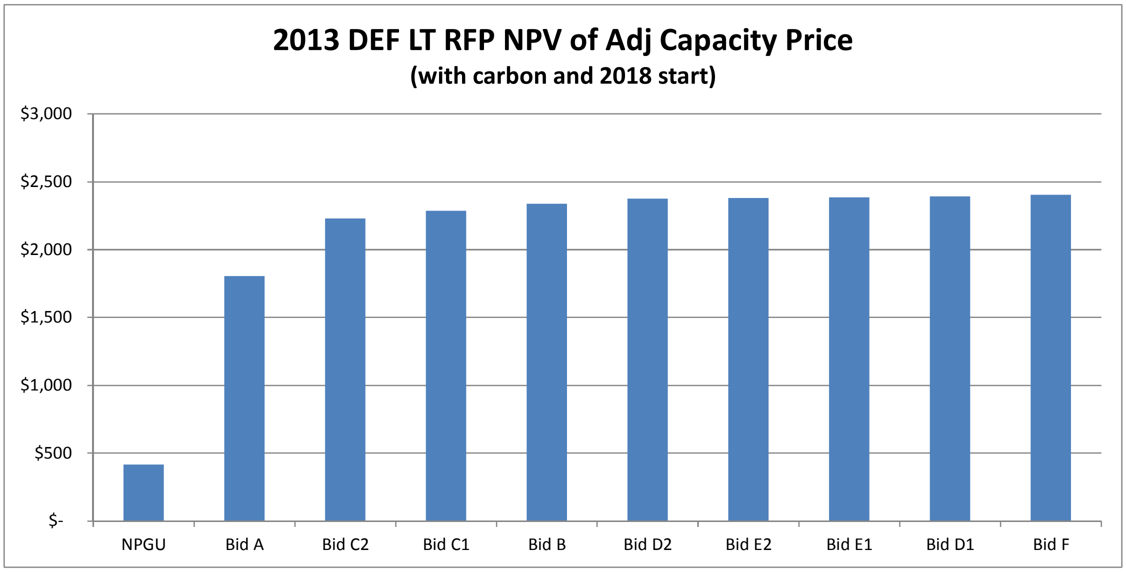
In the Phase 2 evaluation, fixed and variable costs for each unit were calculated. A proxy system in which required capacity was filled with a high dispatch cost unit (15,000 btu/kw heat rate) was developed to establish an hourly system dispatch price. Energy values for each bid were then calculated based on a comparison to a system marginal cost. Because of the variation in bid sizes, generic fillers were added (on a $/kw basis scaled to the size of the bids). Generic CC units were used to "back fill" (at the end of contracts), and generic CT units were used to "side fill" (add necessary capacity to equal the 1640 requested in the bid).

The analysis proceeded as described here with all calculations summed annually.

1. Calculate the dispatch cost for each unit based on bid data for heat rates, variable O&M, and energy charges.
2. Calculate a capacity factor for each unit by comparing the dispatch price to the hourly marginal cost for each hour in the period. Units were assigned a 4 hour minimum run time. (Except for Bid C which was 8 hours per the bid)
3. Calculate an "energy value" for each bid by calculating the difference between the marginal cost curve and bid dispatch cost when the bid is dispatched (considering minimum run times).
4. Calculate an energy value for any back fill and side fill capacity.
5. Calculate fixed costs for each unit including cost assigned for the sidefill and backfill capacities.
6. Calculate the total annual adjusted capacity price equal to the difference between the fixed costs of each bid and the energy value.
7. Calculate the NPV of the total annual adjusted capacity price for each bid.

The Final Screening Results involved combining individual bids into a resource plan which could meet DEF's system resource needs and then combining system requirements needs along with transmission screening costs into the Final Screening Results. The final economic screening did not eliminate any proposal but reflected a screening ranking of resource plans.

Results of the final (Phase 2) screening are shown in the figure below.



Minimum Technical Criteria Evaluation:

Bidder proposals were evaluated on an initial technical basis to assess the feasibility and viability of each proposal. As part of this technical evaluation, proposals were reviewed to ensure that they conformed to the Minimum Technical Requirements. The Minimum Technical Requirements are the technical "must have" elements of a proposal. The plan was to evaluate each Minimum Technical Requirement on a "Pass/Fail" or "Go/No Go" type basis. The Minimum Technical Requirements are identified in Table III-4 below.

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].

Minimum Technical Requirements Evaluation Results.

DEF reviewed the Minimum Technical Requirements of each bidder proposal to ensure that the proposal contained sufficient documentation to demonstrate that they met all Minimum Technical Requirements. DEF established separate teams staffed with personnel with expertise in the areas of development and construction, engineering operations, environmental, financial viability, fuel, key terms and conditions, and transmission to review the bidder proposals for compliance with the Minimum Technical Requirements. Each team received the executive summaries of the proposals and only the portions of the proposals that dealt with its area of expertise. The economic evaluation team was the only team that had access to the pricing of the bidder proposals because the other evaluation teams did not need to know the pricing to perform the evaluation of the proposals on technical merits. This resulted in an impartial technical evaluation of the bidder proposals.

DEF's technical requirements evaluation uncovered issues that needed further clarification from all of the bidders. Clarifying questions were sent to the bidders and responses were received. While all bidders attempted to respond to the clarifying questions, the information provided did not resolve all the issues identified in the technical criteria review. Again, because DEF had a limited number of bidder proposals to evaluate, DEF elected not to disqualify any proposal from further evaluation, and DEF decided to consider the remaining technical criteria issues, as necessary, in any final qualitative evaluation of the proposals. If the Company's economic analysis in the RFP evaluation process eliminated the proposals with these technical criteria issues from further consideration, there was no need to resolve them. DEF decided that it could always seek to resolve the technical criteria issues later in the qualitative evaluation process or through negotiations with the bidders, if necessary.

The following Table summarizes that Minimum Technical Requirements review, indicating that DEF checked all bidder proposals for compliance with the Minimum Technical Requirements. DEF further evaluated all bidder proposals on the same based for the more detailed technical criteria review at the same time, again, because of the limited number of bidder proposals DEF received in response to the 2018 RFP.

Final "Over All" Minimum Technical Requirements (MTR) Review

Proposal #	A	B	C	D	E	F
Accepetd (√) Rejected (X)	√	√	√	√	√	√

Minimum Technical Requirements - Proposal Reviews By Sections

Proposal #	A	B	C	D	E	F	MTR Review Sections
Accepetd (√) Rejected (X)	√	√	√	√	√	√	A. Environmental
Proposal #	A	B	C	D	E	F	
Accepetd (√) Rejected (X)	√	√	√	√	√	√	B. Engineering & Design
Proposal #	A	B	C	D	E	F	
Accepetd (√) Rejected (X)	√	√	√	√	√	√	C. Fuel Supply Transportation Plan
Proposal #	A	B	C	D	E	F	
Accepetd (√) Rejected (X)	√	√	√	√	√	√	D. Project Financial Viability
Proposal #	A	B	C	D	E	F	
Accepetd (√) Rejected (X)	√	√	√	√	√	√	E. Project Management Plan

Note: Although various concerns were identified by Review Leads and addressed in DEF 12/26/13 Clarifyng Questions, bidders responses to the 12/26/13 Clarifying Questions were adequate for continued evaluation and review beyond the Minimum Technical Requirements

Preliminary Total Cost Economic Screening with Generator Interconnection and Transmission Integration.

DEF conducted a preliminary total cost economic screening that incorporated generator interconnection and transmission integration for the bidder proposals. Because none of the bidder proposals satisfied DEF's 2018 reliability need, DEF had to develop resource plans that combined bidder proposals together, with generic CC or CT units, and that included individual bidder proposals with generic units. In this way, the preliminary economic screening combined bidder proposals into a resource plan that could meet DEF's system resource needs with appropriate generation interconnection and transmission integration screening costs. The preliminary economic screening did not eliminate any bidder proposal. It reflected a screening ranking of the bidder proposal resource plans.

To develop the generation interconnection and transmission integration costs, for new and existing unit bidder proposals located inside the DEF system, the transmission screening study consisted of a power flow analysis by the Transmission Group. For the bidder proposals with projects that were not interconnected with the DEF transmission system, preliminary transfer analyses were performed to examine the impact on the DEF transmission system of a transfer from the host system of the proposal output to the DEF system. The transmission screening study assessed the impacts to the DEF transmission system and resulted in a list of required transmission facilities, and an estimated cost of the required facilities, for the bidder proposal resource plans.

A more detailed discussion of the resource plans with a chart of the plans used for transmission evaluation is presented below in the detailed evaluation discussion.

Step 3: Selection of Short List.

DEF did not select a Short List. There were threshold requirements and technical criteria issues with the bidder proposals and the necessary bidder proposal resource plans that prevented DEF from selecting a short list.

DEF understood from receipt of the bidder proposals that all of the bidder proposals required generic units to fulfill the reliability need for the Company. As a result, the technical criteria review of a resource plan including some or all of the bidder proposals involved the assessment of unplanned and undeveloped generic units. Each of these unplanned and undeveloped generic units presented technical requirement and criteria issues in addition to the issues with the bidder's proposed units. These issues for the generic units included, among other factors, the need to site, license, obtain environmental permits, engineer, design, and construct the unplanned and undeveloped generic units in the bidder proposal resource scenarios. Because of these issues, as explained in more detail below, the Company was not sure that it could even plan and build the generic units in time to meet its reliability need. Consequently, the Citrus County CC NPGU clearly ranked ahead of all the bidder proposals resource scenario alternatives for all the 2018 RFP technical requirements and criteria.

Because of the limited number of bidder proposals, however, DEF elected to continue to evaluate the bidder proposals subject to all requirements of the 2018 RFP. DEF decided to continue the economic evaluation of all the bidder proposals to determine if there was some combination of them with generic units that offered superior value to DEF's customers than the Citrus CC NPGU. If the economic evaluation revealed such a favorable bidder resource plan proposal, DEF would then evaluate the qualitative risks associated with the generic units in the bidder proposal resource plan to determine if they could be overcome or satisfactorily mitigated. If the economic evaluation revealed that no bidder proposal resource plan was superior to the Citrus CC NPGU, there was no need to address the qualitative risks associated with the technical requirements and issues with the bidder proposal resource plans. DEF informed the bidders of this decision explaining that, because of the limited number of proposals DEF received in response to the 2018 RFP, DEF was continuing to evaluate all proposals utilizing all steps of the RFP process as may be necessary in its evaluation of their proposals.

Step 4: Detailed Evaluation

Introduction.

Due to the fact that (1) DEF received a limited number of proposals; (2) each individual proposal was at least 1,000 MW below the proposed RFP Citrus CC capacity of 1,640 MW; and (3) the total bid capacity was over 300 MW shy of the proposed RFP 1,640 MW of capacity need, DEF determined that it was required to build DEF generation in any and all combinations of the proposals that were provided. Originally in the development of the RFP, DEF selected the

Citrus CC as the least cost, self-build generation alternative from all internal resources available to DEF. Thus, the RFP was seeking competitive proposals to the Citrus CC unit as outlined in the DEF 2018 RFP. The DEF Citrus CC proposal of 1,640 MW was the only proposal that reliably meet the RFP bid requirements.

As stated in the RFP, DEF's analyses would utilize Generic CT and CC plants to complete the resource plans. Often in RFPs, DEF would use the Generic Units to backfill proposals that did not extend out the entire planning review period. Typically, the generic units would be place holders for future DEF resources so that DEF could insure a reliable resource plan given a bidder(s) shortfall in capacity due to a proposal(s) term(s) of service years. By nature, the future forecasting of DEF generic units would allow DEF significant enough time to develop the Generic Units into feasible, site specific alternatives that could be refined so that the required regulatory and environmental permits could be obtained for those future resources.

Due to the 2018 in-service requirements of the RFP (and thus DEF's need to seek viable market alternatives to DEF's Citrus CC), DEF does not believe that it could easily and adequately develop and obtain regulatory approval for such smaller generic combined cycle unit that would be required to supplement individual bid proposals for a 2018 in-service date. However, DEF believes it could successfully develop generic combustion turbine units into a feasible alternative that could obtain the required regulatory and environmental permits, although additional developmental time would be required.

Despite potential feasibility concerns, DEF allowed both the Generic CC and Generic CT as available resource options to determine if the detailed evaluation results would produce enough system benefits to justify continued evaluation of an alternative resource portfolio that could potentially benefit DEF even though, as discussed above, such a portfolio inherently had permitting and construction risks associated with DEF's own generic unit. DEF commenced with the Detailed Evaluation of all submitted proposals subject to the continued evaluation of all proposals utilizing all steps of the RFP process as necessary.

Detailed Evaluation

The Detailed Evaluation consisted of the Initial Detailed Evaluation followed by a Final Detailed Evaluation. In the Initial Detailed Evaluation, DEF combined 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.

As contemplated in the RFP, none of the bids received was directly comparable to the NPGU in capacity or in duration. As a result, DEF created a series of portfolios utilizing the proposal bids and generic units in combination to meet the required need. DEF also used these portfolios as the basis for transmission studies to establish the transmission system upgrade costs associated with each alternative.

In addition, because the evaluation was conducted over the 35 year period corresponding to the projected life of the NPGU, capacity was required to "back fill" at the conclusion of the proposed contracts. DEF used a hypothetical 450 MW future combined cycle as to provide necessary capacity to balance the portfolios. In each case, the back fill unit was put into service at the end of a given contract.

Finally, in constructing the portfolios, because three of the bids were submitted by a single corporate owner (Bids D, E, and F), and each bid was for a capacity of 150MW or less, these bids were evaluated as a group.. This grouped bid (made up of Bids D1, E1 and F) was designated Bid G.

Bid B was for only 40 MW. This capacity is not large enough to cause a deferral of future capacity in the resource plans used for this evaluation. Bid B was combined with other bids in some portfolios and was separately evaluated in combination with the NPGU to demonstrate whether the energy value derived from this resource would produce value in the portfolio above the proposed capacity and energy charges.

Fuel gas for each of the bidding and generic units was assumed to be supplied via existing contracts where available and from available pipeline capacity as needed. Transportation pricing was adjusted to provide access to onshore and unconventional (shale resources) for all portfolios.

a. Optimization Analyses

In the Optimization Analyses, DEF analyzed each short list bidder proposal's value by developing an optimal resource plan around each proposal as shown below:

Scenario	Bid Units	Generic 2018 Units	Backfill Units
1	Citrus CC (NPGU)	None	None
3	Bid C1 Bid A Bid G Bid F	2 CT (188MW each)	2034 450 MW CC 2043 450 MW CC 2044 450 MW CC
5	Bid A Bid G	2x1 CC (793 MW)	2043 450 MW CC 2044 450 MW CC
6	Bid C1 Bid A	2x1 CC (793 MW)	2034 450 MW CC 2043 450 MW CC
7	Bid C1 Bid G Bid B	2x1 CC (793 MW)	2034 450 MW CC 2043 450 MW CC
8	Bid A	2x1 CC (793 MW) 2 CT (188MW each)	2043 450 MW CC
9	Bid G	2x1 CC (793 MW) 2 CT (188MW each)	2044 450 MW CC
10	Bid C1	2x1 CC (793 MW) 2 CT (188MW each)	2034 450 MW CC
11	Citrus CC (NPGU) Bid B	None	None

The objective of the portfolio development, in each case was to create a portfolio of approximately 1,640 MW that could be evaluated in comparison with the NPGU. Discrete sized generic units (as identified in the table above) were used, so each portfolio was slightly different in total capacity, but the differences were small enough that DEF believes these differences did not produce any material bias in the results. These portfolios were developed both for use in the evaluation of system costs and for use in the transmission evaluations described earlier.

The development of the above Generation Scenario Plans were then combined with the items B and C above to determine the cumulative present value of revenue requirements ("CPVRR") of each plan as shown in the Summary of Initial Detailed Evaluation section.

b. Transmission Reviews

As discussed in the RFP, DEF recognized that a reduction in the available generation in the immediate vicinity of the Crystal River Energy Center related to the retirements of Crystal River Units 1, 2, and 3 would result in a need for significant transmission upgrades on the DEF system. As a result, transmission studies with evaluations of the portfolios and the specific locations of the units, both bidders and generic units in each portfolio, to identify the costs of transmission projects required was a critical part of the overall evaluation. In order to minimize the impacts of transmission on the results, DEF assumed that the generic units would be sited in locations deemed to partially mitigate the impact of the Crystal River unit retirements, i.e. near Crystal River or near DEF's Central Florida Substation. These selections are reflected in the portfolios.

Each of the portfolios was evaluated for transmission impacts. As identified in the RFP, retiring generation at Crystal River made Citrus County a preferred location for the new generation. It was anticipated that location of generation away from this area would cause additional transmission impacts. However, the impacts associated with each portfolio had be evaluated based on transmission modeling based on the specific locations of each bid and selected locations for generic units as shown in the Table above. Actual transmission modeling work for the transmission analyses was performed by Power Grid Engineering LLC ("Power Grid"), an independent engineering company, under the supervision of the DEF Transmission Planning Group. Power Grid is a recognized electric utility engineering company with substantial expertise in modeling transmission systems and performing the standard electric utility transmission system analyses for any proposed generation additions to a transmission system.

Power Grid used industry-leading transmission planning engineering tools similar to our own transmission planning engineering tools to perform these analyses and DEF transmission planning staff reviewed and validated their models and model results.

DEF initially performed a transmission screening study for all proposals to the 2018 RFP. For the 2018 RFP proposals within DEF's system, a power flow analysis was performed. For the 2018 RFP proposals that were not interconnected with DEF's transmission system, preliminary transfer analyses were performed. Both sets of transmission screening studies assessed the impacts to the DEF transmission system by providing a list of required transmission facility additions or modifications and an estimate of the cost of the transmission facility additions or modifications. These transmission screening studies were industry-standard studies consistent with DEF's internal standards and both FRCC and NERC reliability standards. For example, the latest available FRCC peak load flow case, including the latest available information, was used as the baseline to determine what transmission system network upgrade facilities or modifications were needed. The cost estimates were also based on industry-standard transmission facility estimation standards consistent with DEF's experience with such transmission facilities. DEF employed the same industry-standard transmission facility cost estimation standards to the 2018 RFP proposals that DEF uses for all of its planned or projected transmission facility additions or upgrades on its own transmission system. All potential solutions were then subsequently introduced into the appropriate case and tested in order to verify the completeness of the solution.

All of the 2018 RFP proposals, except the Company's self-build next planned generating unit proposal, were evaluated in the portfolios identified above, also referred to as transmission groups. The transmission groups are shown below. As noted, the groupings of units are the same as those identified in the generation portfolios above.

Resource Plan Alternative	Gen Plan #s (Trans Plan #s)	Description	MW	Units	Location
I) Self Build Only	1	NPGU	1,640	Citrus 4x2 CC	500 Kv 1st & CR1&2 on for summer/230 Kv Wtr
	2	NPGU	1,640	Citrus 4x2 CC	230 Kv 1st & CR1&2 off for summer/500 Kv Wtr
II) Total Non DEF Proposals	3 (2B)	A, B, C, G		Bids	Bidder Sites
+ DEF Generic Units		DEF Generic		2-CTs	Central Florida Sub
		Total MW	1,715		
	4 (2C)	A, B, C, G		Bids	Bidder Sites
		DEF Generic		2-CTs	Citrus
		Total MW	1,715		
III) Approx 900 Block Proposals	5 (3A)	A, G		Bids	Bidder Sites
+ DEF Generic Units		DEF Generic		2x1 CC	Citrus
		Total MW	1,693		
	6 (3B)	A, C		Bids	Bidder Sites
		DEF Generic		2x1 CC	Citrus
		Total MW	1,689		
	7 (3C)	B, C, G		Bids	Bidder Sites
		DEF Generic		2x1 CC	Citrus
		Total MW	1,729		
IV) Individual Proposals	8 (4A)	A		Bid	Bidder Site
+ DEF Generic Units		DEF Generic		2x1 CC	Citrus
		DEF Generic		2-CTs	Central Florida Sub
		Total MW	1,688		
	9 (4B)	G		Bid	Bidder Site
		DEF Generic		2x1 CC	Citrus
		DEF Generic		2-CTs	Central Florida Sub
		Total MW	1,572		
	10 (4C)	C		Bids	Bidder Sites
		DEF Generic		2x1 CC	Citrus
		DEF Generic		2-CTs	Central Florida Sub
		Total MW	1,568		
	11	B		Bids	Bidder Sites
		NPGU		4x2 CC	Citrus
		Total MW	1,680		

In reviewing Transmission Groups, DEF included the costs of any necessary transmission network upgrades that were determined to be necessary to deliver the output of the new generator and/or power transfers from existing generation sources to DEF load. If the individual proposal Response Package included costs on other third party systems as a DEF responsibility, then those costs would 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) was used as the basis for determining the transmission network upgrade modifications needed.

The Final Summary Results of the Transmission Economic Reviews are as follows:

Summary of Estimated Transmission Cost by Scenario				
Scenario				
3	2B - Combined Transmission Cost	$	186.6	Million
4	2C - Combined Transmission Cost	$	190.3	Million
5	3A - Combined Transmission Cost	$	146.0	Million
6	3B - Combined Transmission Cost	$	161.9	Million
7	3C - Combined Transmission Cost	$	145.7	Million
8	4A - Combined Transmission Cost	$	129.8	Million
9	4B - Combined Transmission Cost	$	202.4	Million
10	4C - Combined Transmission Cost	$	135.3	Million

Values are nominal dollars for 2018 in service projects

Implementing DEF Transmission BES upgrades may impact other host utility BES networks and would require additional detailed transmission impact and facility reviews if an individual or combination of bids were selected to the Final List(s). DEF recognized a qualitative risk around the potential that transmission engineering and construction might result in project delays beyond the May 2018 in service date. The nominal costs shown above were assumed to be spread over the years 2015 through 2018 to mimic a typical construction schedule and converted to revenue requirements for use in the economic analysis.

Economic Evaluation

While the screening analysis of the proposals compared the cost of the proposals to each other based simply on the cost of the proposals in isolation, the optimization analyses assessed the impact of each proposal on the total DEF system cost compared to a Base Case. The impact on total system costs is important because it shows the net impact on the customer of choosing an alternative, including both the project cost and the impact the alternative would have on system operating costs. Such an analysis explicitly examines the relative impacts on system costs for fuel and variable O&M of the other units on DEF's system, and the impact the alternative would have on DEF's other purchased power operating costs.

DEF combined the above 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.

Each portfolio was evaluated over the 35 year period corresponding to the projected life of the NPGU. DEF used the Planning and Risk module of Ventyx's Energy Portfolio Manager (EPM) modeling software to derive the production costs including fuel, non-fuel O&M, emissions and reagent costs for the full portfolio. Planning and Risk uses Ventyx's PROSYM calculation engine to calculate hourly dispatch, performance and costs for each unit on the DEF system. Fixed costs including capital revenue requirements, fixed gas transmission charges, capacity payments and fixed O&M were calculated. These two sets of results were combined to develop total portfolio costs expressed as Cumulative Present Value Revenue Requirements for each portfolio.

Summary of Initial Detailed Evaluation Results

DEF determined the cumulative present value of revenue requirements ("CPVRR") of each scenario developed around the resource plans described. The results of the initial detailed evaluation are based on detailed production cost modeling and fixed cost analysis of the RFP plan scenarios over a 35 year study period. The results are shown as differential CPVRR comparing each of the plan scenarios with TP1 – the Self-Build NPGU. Negative differentials indicate that a scenario is more expensive (less favorable).

Initial Detailed Evaluation Results

		Differential vs. NPGU $M CPVRR		
	Transmission Plan Scenarios	**Reference Case**	**High Gas Price Case**	**No CO2 Price Case**
TP 1	Self-Build NPGU	$0	$0	$0
TP 3	Bids A, B, C1 and G + 2 Generic CTs	($951)	($908)	($773)
TP 5	Bids A and G + Generic CC	($583)	($569)	($438)
TP 6	Bids A and C1 + Generic CC	($512)	($510)	($466)
TP 7	Bids B, C1, and G + Generic CC	($685)	($646)	($620)
TP 8	Bid A + 2 Generic CTs + Generic CC	($376)	($366)	($171)
TP 9	Bid G + 2 Generic CTs + Generic CC	($647)	($631)	($403)
TP 10	Bid C1 + 2 Gen CTs + Generic CC	($457)	($444)	($308)
TP 11	Self-Build NPGU and Bid B	($20)	($4)	($50)

Final Detailed Evaluation

DEF further reviewed the proposals from the Initial Detailed Evaluation in a robust review of competing alternative plans against the self-build alternative. DEF utilized a High Gas Price Case and a No CO2 Price Case for this review. DEF determined the cumulative present value of revenue requirements ("CPVRR") of each scenario developed around the resource plans for; (1) Reference Case (as shown above and utilized here for reference purposes); (2) High Gas Price Case; (3) No CO2 Price Case. A summary of these differential vs. NPGU (Citrus CC1) CPVRR in millions of dollars are shown below.

Rule 25-22.081(7) requires utilities to include a discussion of the potential for increases or decreases in its cost of capital should a purchase power agreement with a nonutility generator by made. Since entering into a purchase power agreement is similar to taking on additional debt, the cost of imputed debt was applied to proposals to ensure 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% of which DEF used for this analyses.

Results of analysis

The results of the final detailed evaluation are based on detailed production cost modeling and fixed cost analysis of the RFP plan scenarios over a 35 year study period. The results are shown as differential CPVRR comparing each of the plan scenarios with TP1 – the Self-Build NPGU. Negative differentials indicate that a scenario is more expensive (less favorable).

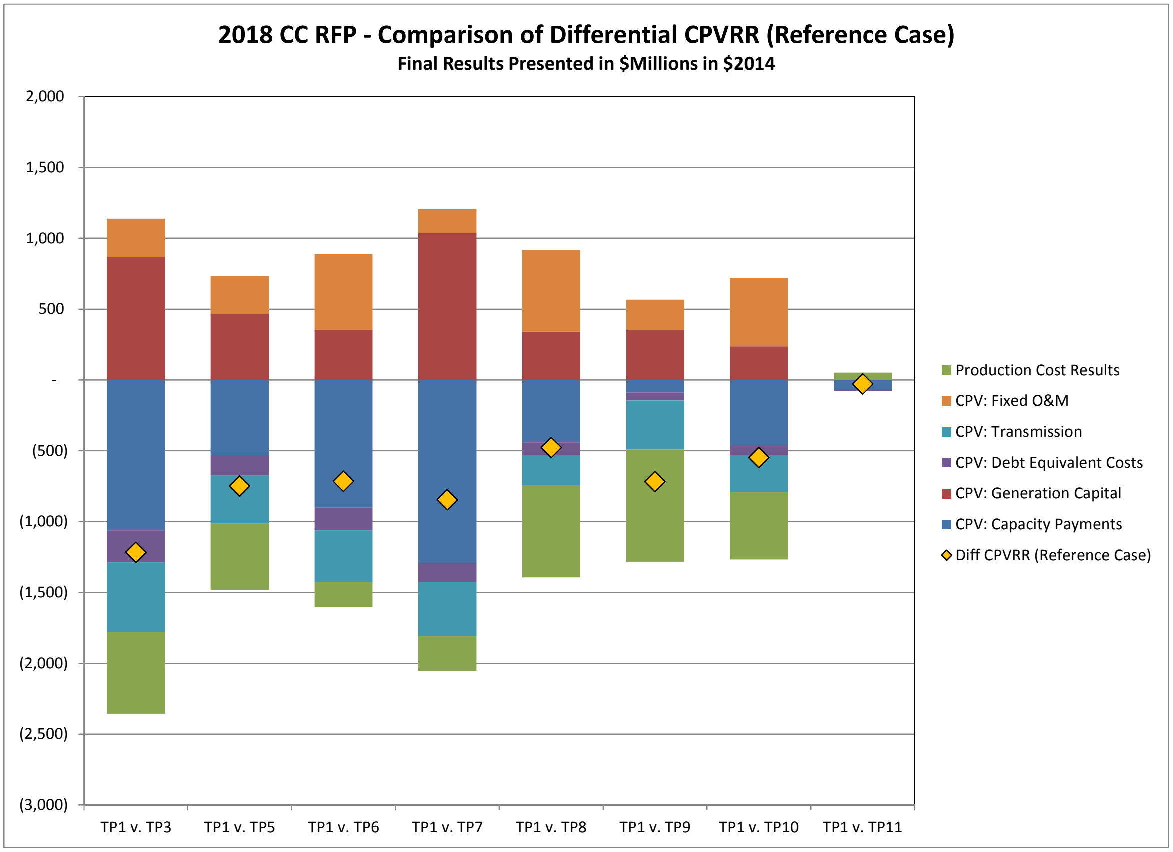
		Differential CPVRR $2014 in $Millions		
	Transmission Plan Scenarios	**Reference Case**	**High Gas Price Case**	**No CO2 Price Case**
TP 1	Self-Build NPGU	$0	$0	$0
TP 3	Bids A, B, C1 and G + 2 Generic CTs	($1,218)	($1,171)	($1,037)

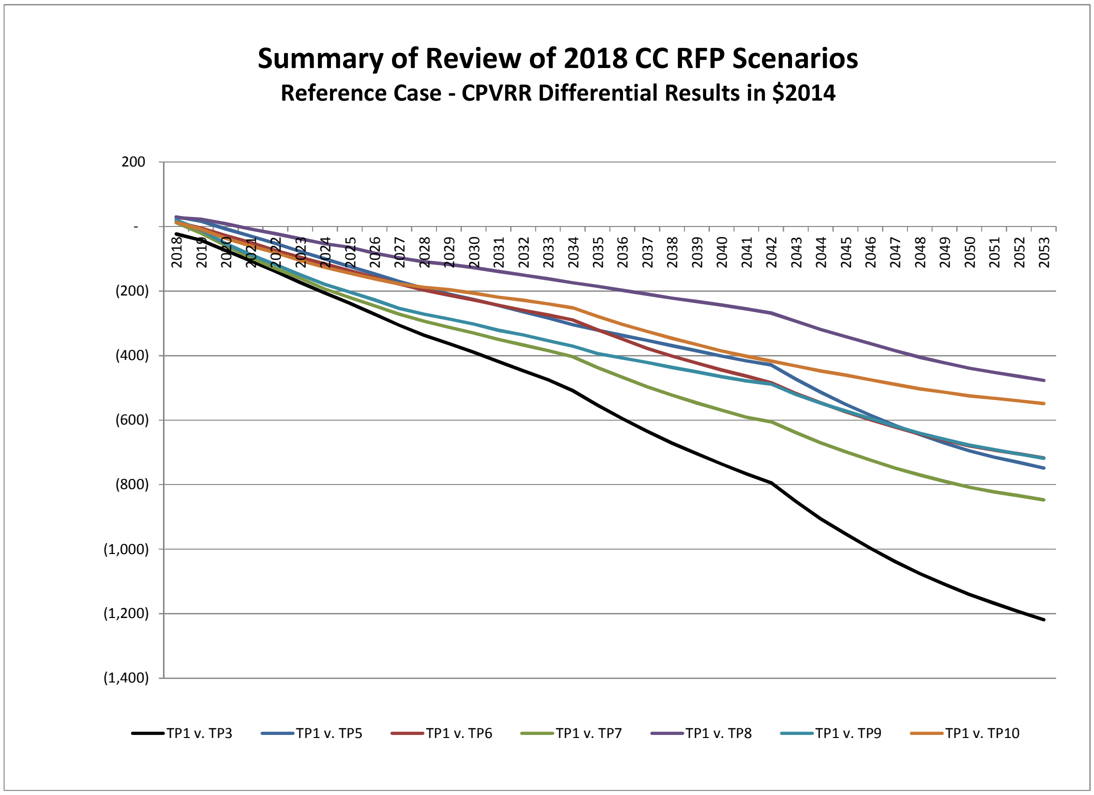
TP 5	Bids A and G + Generic CC	($748)	($731)	($600)
TP 6	Bids A and C1 + Generic CC	($705)	($699)	($655)
TP 7	Bids B, C1, and G + Generic CC	($847)	($811)	($784)
TP 8	Bid A + 2 Generic CTs + Generic CC	($477)	($464)	($269)
TP 9	Bid G + 2 Generic CTs + Generic CC	($718)	($693)	($464)
TP 10	Bid C1 + 2 Gen CTs + Generic CC	($548)	($535)	($399)
TP 11	Self-Build NPGU and Bid B	($29)	($13)	($59)

In terms of cumulative present value of revenue requirements (CPVRR), the Citrus CC was found to be was found to be approximately $477 million less expensive than the least cost alternative portfolio in which Citrus was not constructed. The charts below, Figures XX and YY along with the table above, show the results of the analysis. The table shows the total differential CPVRR between the Citrus CC (NPGU) and the other portfolios. Figure XX shows the difference in the total CPVRR with a breakdown into major components of the difference. Figure 12 shows the results on an annual basis.

Bid B in combination with the Citrus CC did not provide a lower CPVRR over the period compared to the Citrus CC alone. This demonstrated that Bid B did not provide value as an energy resource in the portfolio at the capacity and energy rates proposed.

The results of the detailed financial analysis of the proposals and the alternate scenarios demonstrate that the Citrus CC is clearly the most cost-effective alternative for supplying generation to meet the needs of the DEF customer.


2018 CC RFP - Comparison of Differential CPVRR (Reference Case)
Final Results Presented in $Millions in $2014
2,000
1,500
1,000
500
-
(500)
(1,000)
(1,500)
(2,000)
(2,500)
(3,000)
TP1 v. TP3
TP1 v. TP5
TP1 v. TP6
TP1 v. TP7
TP1 v. TP8
TP1 v. TP9
TP1 v. TP10
TP1 v. TP11
Production Cost Results
CPV: Fixed O&M
CPV: Transmission
CPV: Debt Equivalent Costs
CPV: Generation Capital
CPV: Capacity Payments
Diff CPVRR (Reference Case)

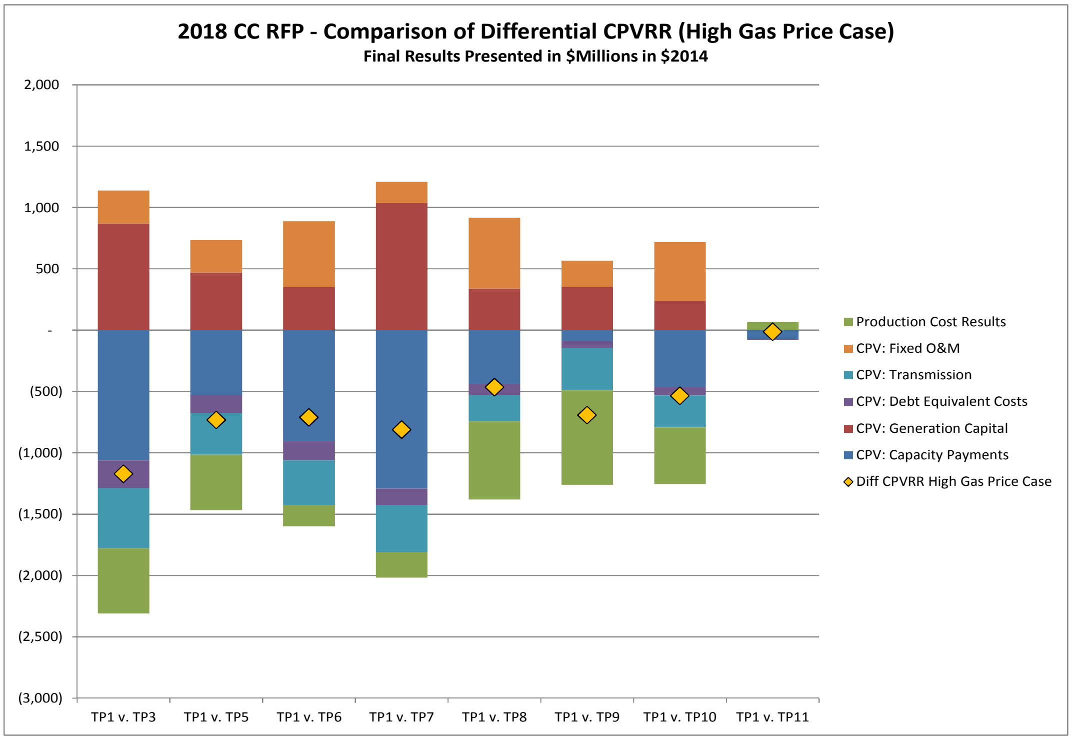


Sensitivities

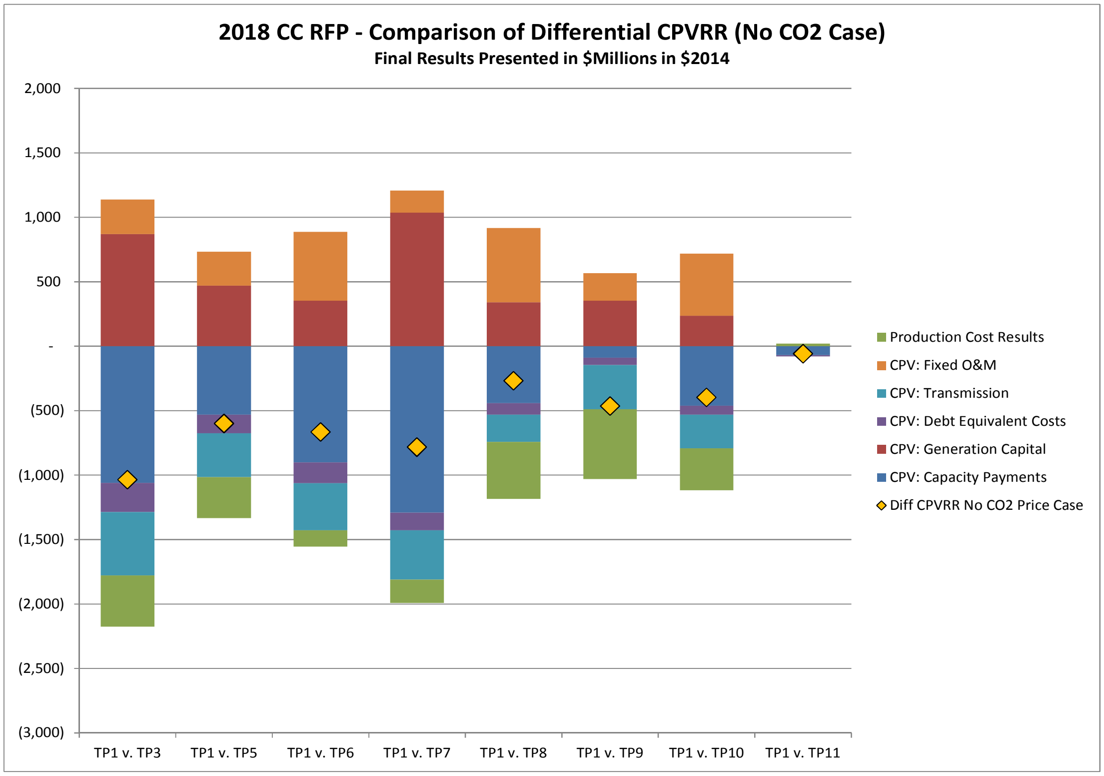
To confirm the results and establish that the selection of the Citrus CC as the most cost effective alternative to meet the needs of DEF customers is robust, DEF ran two sensitivities a high gas price case, and a no CO2 price case. Results of these sensitivities are shown in the Table and in the figures below.

In general, the application of the high gas price to the cases caused the alternate cases to have a smaller differential from the Citrus CC than in the reference case. This result is somewhat counter intuitive since in general the Citrus CC is the most efficient generator analyzed. A detailed review of the results showed that most of the difference in the cases is actually attributable to increased operation of the coal fired Crystal River Units 4 and 5 displacing operation of the marginal CC unit from the proposals. This confirms that the result is robust for two reasons (1) the shift in the values is very small and the Citrus CC is still preferred over any of the portfolios without Citrus by over $400 million and (2) since the differential is caused in part by increase in the coal fired utilization and that generation is close to its maximum availability, a further rise in the gas price is not anticipated to make significant further reductions in the differentials.

The high gas price produced more value for Bid B in combination with the Citrus CC (TP11), but did not produce sufficient value to offset the proposed energy and capacity charges.



DEF also examined a case in which there was no CO2 regulation. The CO2 price from the base reference case was set to zero and no emissions restrictions were adopted for greenhouse gases. This sensitivity reduced the differential between the Citrus CC portfolio and all the portfolios in which the Citrus CC was not constructed. The Citrus CC was still preferred by over$250 million in CPVRR compared to the next most favorable alternative portfolio. This change in the differentials results from the effective removal of an efficiency penalty in the form of a charge for emissions rate. Since the comparison of portfolios is between different gas fired alternatives, the emissions rate for each portfolio is effectively a measure of portfolio efficiency. A secondary effect observed here is the increase in coal fired generation in many of the competing portfolios as the emissions penalty for the coal fired emissions is removed.



Selection of Final List

DEF stated in its RFP that it would develop a Final List based on the detailed evaluation of the short-listed proposals, but that in the event that the Citrus CC was found to be clearly superior to the other alternative, a Final List would not be selected. Based on the results of the detailed analysis, the Citrus CC was found to be clearly superior to the other alternatives. Thus, DEF announced on May 13, 2014 that the Citrus CC was the most cost-effective alternative for adding electric generation to serve its customers' needs. This announcement concluded the RFP process.

10. Conclusions—The Need for The Citrus CC

The Citrus CC unit will be a state-of-the-art, highly efficient, environmentally benign unit, and it will be built at a site that is well-suited to accommodate the planned expansion of DEF's generation system. The plant is the most cost-effective alternative available to DEF. It will provide needed efficiency and cost-effectiveness to DEF, enabling DEF to achieve substantial savings for its ratepayers over the life of the plant.

For these reasons, DEF seeks an affirmative determination of need for the Citrus CC unit and associated transmission facilities to meet DEF's needs for electric system reliability and integrity and to enable DEF to continue to provide adequate electricity to its ratepayers at a reasonable cost. DEF determined to seek this approval only after conducting a rigorous internal review of supply-side and demand-side options, and after soliciting and evaluating competing proposals submitted by interested third party suppliers. The need for additional generating capacity cannot be cost-effectively deferred or avoided by additional demand-side options.

The addition of the Citrus CC capacity is necessary for the Company to meet its commitment to provide an adequate and reliable power supply. The Citrus CC will allow the Company to satisfy its Reserve Margin and loss of load probability criteria while maintaining an appropriate level of physical reserves for the DEF system.

The Citrus CC is designed to be a highly efficient state-of-the-art combined cycle unit with minimal environmental impact. It will be fired with natural gas, a clean and environmentally friendly fuel that will be supplied from a new natural gas transportation resource and will be able to access the new sources of unconventional gas from on-shore North America. The Citrus CC will be sited on land contiguous with the existing Crystal River Energy Center and will achieve synergy savings in transmission, water, and transportation resources.
The Citrus CC unit will meet the Company's need to be able to provide adequate electric service at a reasonable cost to its customers.

Adverse Consequences of Not Building the Citrus CC

If the Citrus CC unit is delayed, DEF would not be able to satisfy its minimum 20 percent Reserve Margin planning criterion by the summer of 2018 in the most reliable and cost-effective manner. This would expose the Company's customers to a greater risk of interruption of service in the event of unanticipated forced outages or other contingencies for which DEF maintains reserves. To illustrate, DEF has retired CR3 and currently must retire CR1 and CR2 and will do so by 2018. DEF, therefore, faces a need for reliable generation in 2018. In addition, these retirements lead to DEF and Florida electric grid reliability issues in the event the addition of combined cycle generation in the vicinity of Citrus County is delayed beyond 2018. To avoid reliability issues for the Florida grid, the Citrus CC needs to be built and placed in commercial operation in 2018. Even without an interruption in service, without the efficient Citrus CC unit, DEF's customers would be subject to higher fuel costs as less efficient units are used to serve their needs. Delaying the Citrus CC beyond 2018, delays these benefits to customers. For all these reasons, DEF needs to move forward with and place the Citrus CC in commercial operation in 2018.

APPENDIX A

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

DUKE ENERGY®

DEF 2018 RFP Document
TABLE OF CONTENTS

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.

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.**

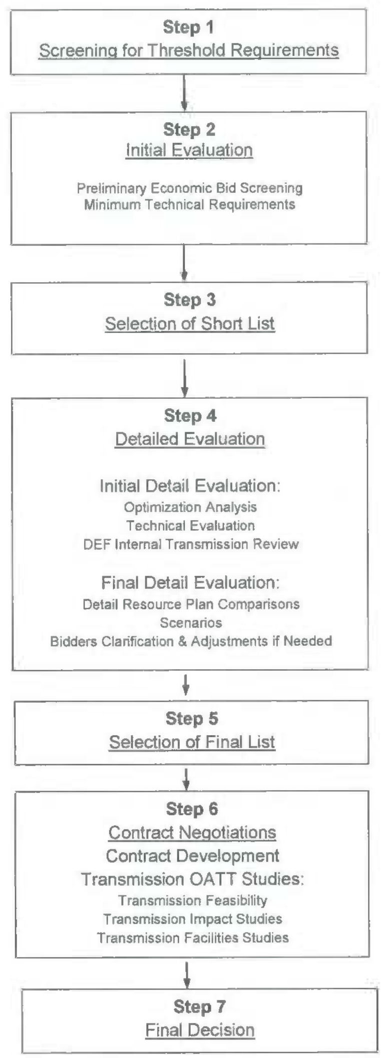
3. Submission of Proposals

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°F, 60% R.H.
Winter Fired Capacity	1,820 MW
Winter Conditions	45°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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TABLE OF CONTENTS (Continued)

LIST OF REQUIRED SCHEDULES

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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

Progress Energy

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

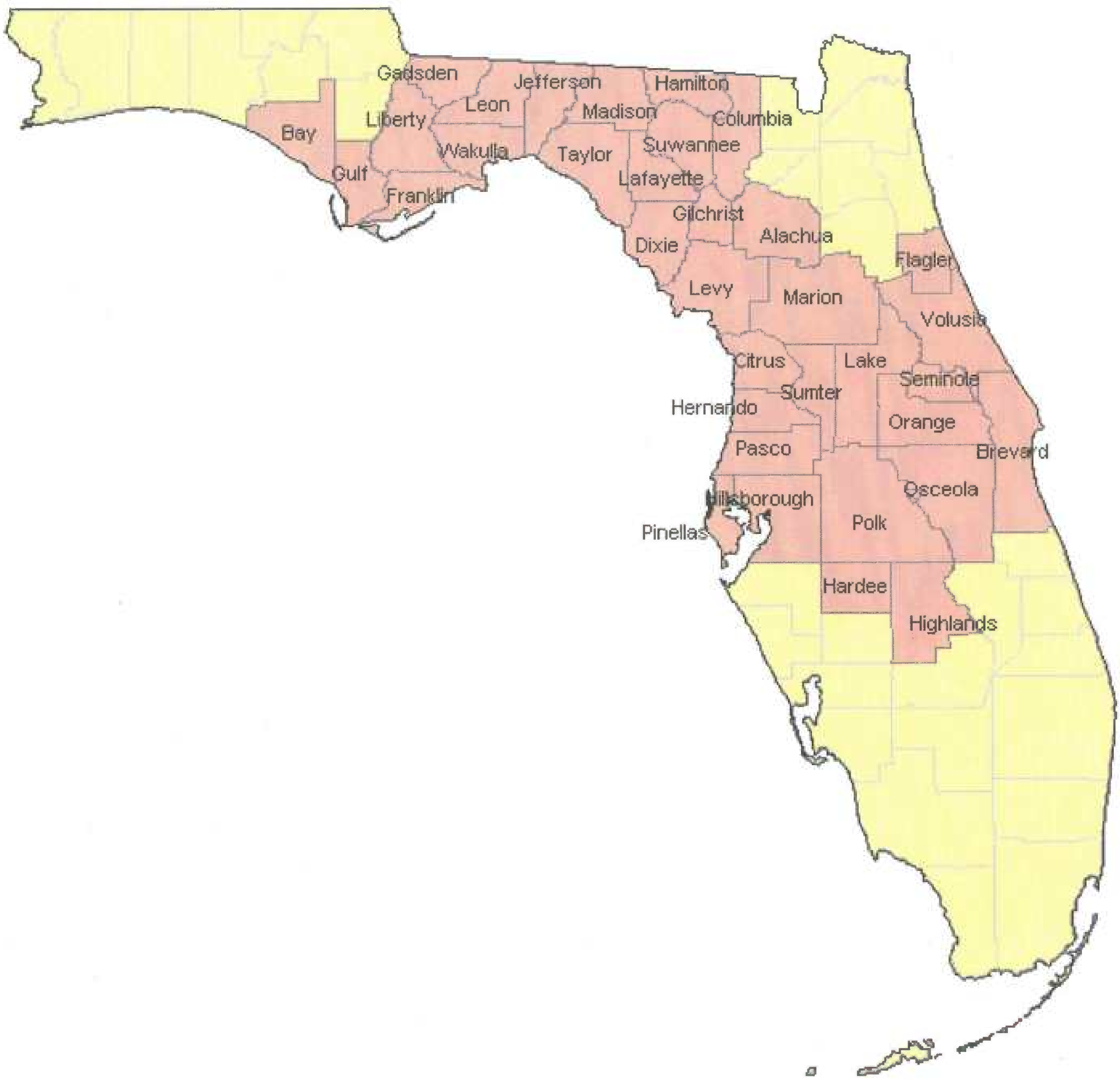
The Company's residential Energy Management program represents a demand response type of program where participating customers help manage future growth and costs. Approximately 405,000 customers participated in the residential Energy Management program at the end of

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) 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:										
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)
	ACTUAL 2012		FORECAST 2013		FORECAST 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.

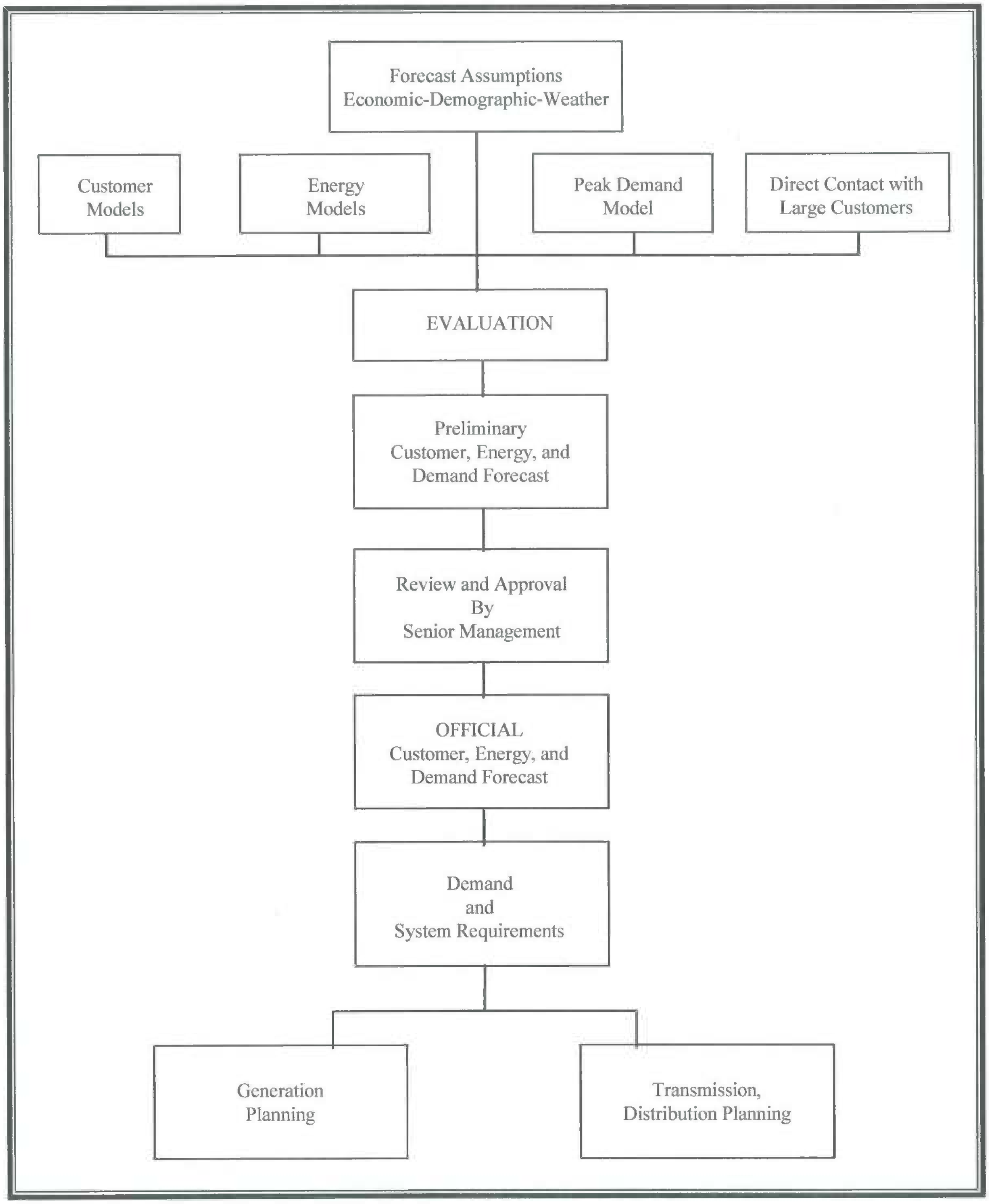
Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of PEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage, as well as customer growth, based on a specific set of assumptions for 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

Progress Energy

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 desigiated 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

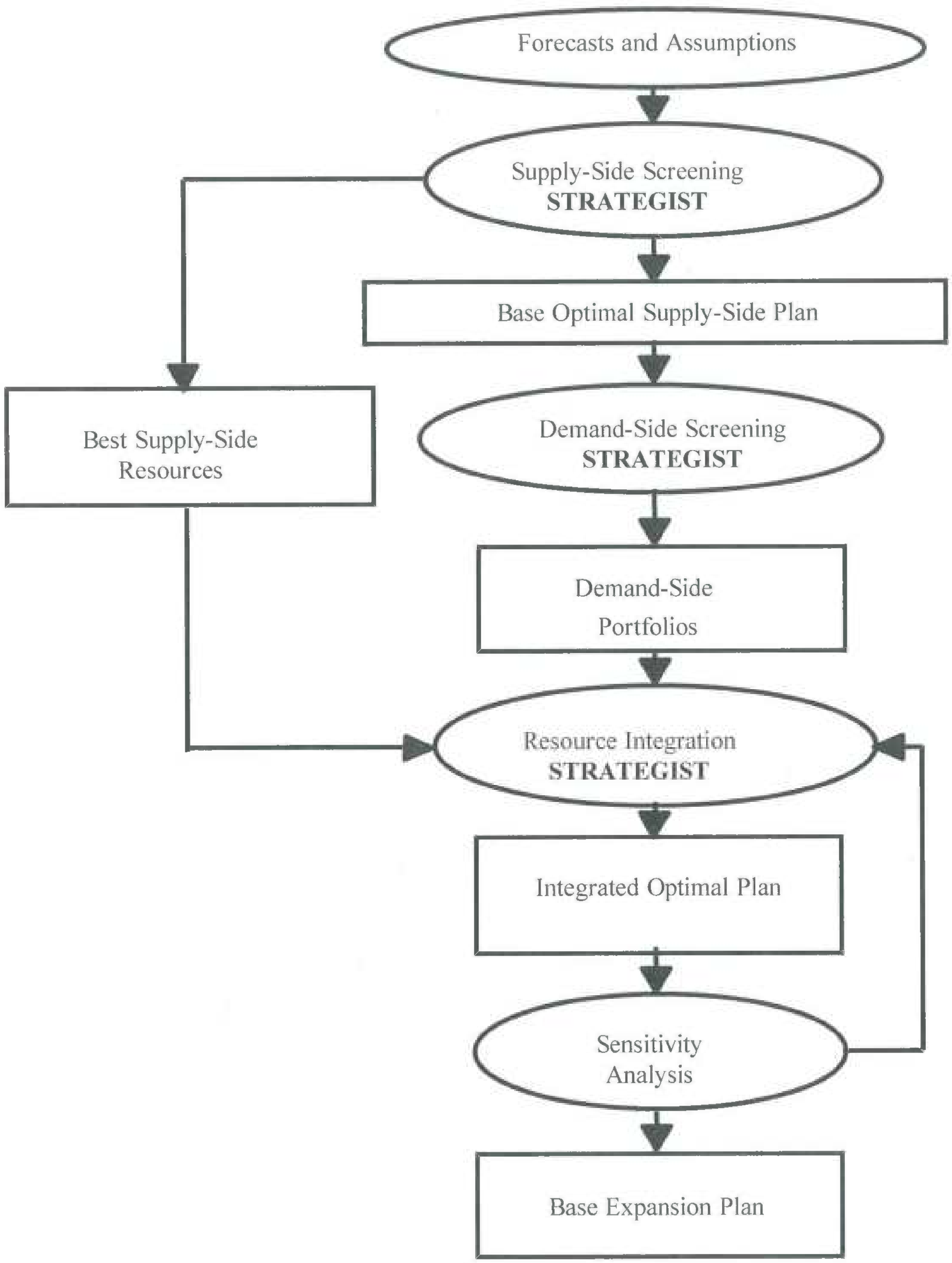
PEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. PEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide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

ATTACHMENT C
Response Package (Instructions)

10-8-13

DEF2018RFP

DUKE ENERGY®

Attachment C - Response Package
TABLE OF CONTENTS

I. General Instructions

This Response Package contains the information required of Bidders and reviews the required organizational structure and contents of the proposals submitted in response to DEF's RFP for Power Supply Resources. Prior to developing their proposals, Bidders are requested to carefully read Duke Energy Florida's RFP and the instructions in this Response Package.

DEF will be utilizing PowerAdvocate (www.PowerAdvocate.com for further basic information on PowerAdvocate) RFP web tool to download, communicate and upload RFP information. There are no associated charges or specific registration restrictions associated with the registration process. In order to download the DEF 2018 RFP, an interested party must register with PowerAdvocate as a user to access their site which will require basic registration information. To access the DEF 2018 RFP registration process the following link should be used:

www.duke-energy.com/floridarfp

In most cases, the confirmation and acceptance of the registration process should occur within 1 to 4 hours, or within an 8 hr business day window, and an associate email with a link to access the DEF 2018 RFP information will be sent to the user.

Proposals in response to this RFP must be submitted in electronic version via the PowerAdvocate RFP web tool. 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 I.E. no later than one day after the DEF December 9, 2013 deadline, or by December 10, 2013. Text portions of the responses must be in Microsoft Word or Adobe Acrobat and schedules are in Microsoft Excel. Preprinted materials such as maps, annual reports, etc. should be submitted in electronic format through the website as well. Bidders must ensure that the proposals are delivered on time.

The PowerAdvocate web site is designed for bidders to upload their complete response package associated with each bid utilizing the three basic tab categories designated by PowerAdvocate as Commercial, Technical and Pricing. Please note the tab names are generic PowerAdvocate tab names and each tab may include various aspects of information relating to technical or pricing information without restrictions to the tab name.

Specific individual bid responses should be uploaded to these three tabs (Commercial, Technical and Pricing) as follows:

(1) **Commercial (or the Commercial tab)[Word Type Files]:** All word related text documents should be uploaded to the commercial tab. Basically, this will consist of the Bidders text responses to Chapters (Executive Summary and Chapters 1 through 12) as one Word document (not individual chapter documents).
(2) **Technical (or the Technical tab)[Non-Word or Non-Excel Files]:** All non-Word or non-Excel files such as .pdf or .jpg should be uploaded to the Technical tab. Basically, this will

consist of the Bidders' referenced information from the Word or Excel files which are cumbersome to include within those Word or Excel files.

(3) **Pricing (or Pricing tab)[excel Type Files]:** All Excel file documents should be uploaded to the Pricing tab. Basically, this will consist of one Excel File with the nine associated RFP schedules as tabs within the Excel file.

Submissions on flash-drives also should be structured in three folders in accordance with the above.

Bidders are required to use the schedules provided. The schedules (as well as the format of the entire Response Package) have been designed to facilitate the evaluation of the proposals in an expedient manner. Failure to use the schedules will be grounds for disqualification.

II. Organization and Contents of Bidders' Proposals

A. Overview

Bidders' proposals **must** be organized according to the structure specified below. If a particular chapter or section is not relevant to a Bidder's proposal, then the Bidder should include the chapter or section and indicate why it is not relevant. Where DEF has included a schedule that is to be completed by the Bidder, the schedules must be completed or the Bidder must indicate why the schedule is not relevant. This requirement is in place to assist the Bidder and DEF in assuring that no question has been overlooked and to provide all relevant information needed to evaluate the proposals.

B. Proposal Outline

The outline that Bidders **must** use to organize their proposals is presented below. Also specified in each section of this Response Package are the chapter number and section number that should be used for all proposals. The specific information that is to be included in each chapter is described below. However, because the information requested may not be relevant to all types of proposals, DEF has indicated in bold the type of proposal to which each question applies. **Where no specific type of proposal is indicated, the Bidder should assume that the information is required for all types of proposals. The Executive Summary and Chapters 1 – 12 word documents should be uploaded to the Power Advocate Commercial tab (and included in the Commercial folder on flash-drive submissions) as one word document when completed.**

- Proposal Executive Summary
- Chapter 1: Project Summary
- Chapter 2: Proposal Pricing
- Chapter 3: Operating Performance
- Chapter 4: Permitting Plans
- Chapter 5: Engineering and Design Plans
- Chapter 6: Site Control
- Chapter 7: Transmission Plan
- Chapter 8: Fuel Supply and Transportation Plan
- Chapter 9: Project Financing Plan
- Chapter 10: Commercial Operation Date Certainty

- Chapter 11: Bidder Experience
- Chapter 12: Acceptance of key Terms & Conditions

This Response Package is organized around a series of schedules. The matrix presented below indicates which schedules apply to different types of proposals. These schedules are provided in an Excel workbook included as part of this Response Package. If a schedule applies to the type of proposal that the Bidder is submitting, the Bidder is **required** to complete the schedule. **Inconsistencies between the electronic and hard copies will be grounds for disqualification. The Excel File with the associated Schedule A tab and 1 – 9 schedules should be uploaded to the Power Advocate Commercial tab as one Excel document when completed.**

Schedules To Be Completed By Bidder

Schedule No. and Name	New Unit	Existing Unit	System Power
Schedule A: Project Summary	X	X	X
Schedule 1: Pricing Schedule for New and Existing Unit Proposals	X	X	
Schedule 2: Pricing Schedule for System Power Proposals			X
Schedule 3: Capacity States and Heat Rates for New and Existing Unit Proposals	X	X	
Schedule 4: Operating Performance Schedule	X	X	X
Schedule 5: Environmental and Regulatory Permit Status Schedule	X		
Schedule 6: Air Emissions Schedule	X	X	
Schedule 7: Transmission Information Schedule	X	X	X
Schedule 8: Project Pro Forma Schedule	X		
Schedule 9: Project Milestone Schedule	X		

All other non Word or Excel files should be referenced to their associated Word or Excel file, uploaded to the Power Advocate Technical tab, and included in the Technical Folder in the flash-drive submissions.

C. *Proposal Executive Summary*

The Bidder is required to provide a brief summary of its proposal (no more than two pages). The summary should include at a minimum a brief overview of the technology and equipment proposed, amount of capacity offered, project location and point of delivery, proposed project pricing, power delivery period, proposed fuel supply arrangements, experience with key project elements, financing plan/arrangements, permitting schedule, and conformance with the key Terms & Conditions (reference Attachment A to the RFP).

D. *Chapter 1: Project Summary*

Chapter 1 of the Bidder's proposal must consist of a completed Project Summary (Schedule A). Bidders should complete Schedule A after they have completed all other schedules; data must be consistent with the detailed schedules. The information in this form will be treated as non-confidential and non-proprietary and may be released to the public.

E. Chapter 2: Proposal Pricing

Introduction

Bidders are required to complete all the applicable pricing schedules referenced in this chapter of the Response Package and to provide a complete description of the components of the charges. Duke Energy Florida has included price schedules for New and Existing Unit Proposals (Schedule 1) and System Power Proposals (Schedule 2) in the Response Package forms as part of this package. Bidders should only complete those schedules that are pertinent to the type of bid submitted (reference "Schedules to be Completed by Bidder" table on Page C2). Bidders should note that contract year one is a partial year. Therefore, a "15-year" contract will cover one partial year and fourteen full years, for example, May 1, 2018 through December 31, 2032.

Price Schedule for New and Existing Unit Proposals

Bidders offering New or Existing Unit Proposals must complete all relevant sections of Schedule 1 as described in this section of the Response Package. Bidders should ensure that the pricing components of their proposals conform to the requirements described in Figure III-3 (New and Existing Unit Proposal Pricing Parameters) of the DEF 2018 RFP Document. **All costs to be paid by DEF must be reflected in the proposed pricing. DEF will not accept any charges other than those identified in Schedule 1.** Bidders must specify the pricing for their proposals in terms of the following components and units, to the degree that each component is relevant to the particular bid:

- Fixed Payment
  - Generation Capital Charge ($/kW-Yr)
  - Fixed Operation and Maintenance (O&M) Charge ($/kW-Yr)
  - Transmission Charge ($/kW-Yr)
  - Pipeline Reservation Charge ($/mmBtu-day)
- Variable Payment
  - Fuel Commodity ($/mmBtu)
  - Variable Transportation ($/mmBtu)
  - Variable O&M Price ($/MWh, $/hour, or both)
- Start Payment
  - Start Price Per Facility ($/start/facility).

In addition to completing the schedule, Bidders should include back-up sheets that clearly describe their pricing proposals in terms of the pricing components, any indices proposed to adjust the prices, and the frequency of change in the indices for payment purposes.

The first entries in Schedule 1 are the Contract Start Month, the Contract Start Year, and the Contract End Year, which represent the term for which capacity and energy will be provided to DEF by the Bidder. Bidders must then specify the proposed Contract Capacity for both the Winter and Summer Seasons for each year of the proposed term.

CAPACITY SPECIFICATION CRITERIA

- Summer: 90°F, 60% R.H.
- Winter: 40°F, 60% R.H.

SEASONAL DEFINITIONS

Summer	Winter
May through October	November through April

Bidders then enter the annual fixed payment items in Schedule 1 for every year of the term of the proposal. The annual fixed payments must be based on the Seasonal Contract Capacities. Therefore, Bidders must take into account the difference in Summer and Winter Contract Capacities and enter **annualized** $/kW values for every year, including the start year when the proposal does not include all 12 months of the calendar year. Since the Summer and Winter Periods each contain six (6) months, this can easily be achieved by using the average Summer and Winter Contract Capacities when developing $/kW values. Bidders will be paid monthly based on the product of the Bidder-specified seasonal capacity and one-twelfth (1/12) of the Bidder-specified annual charges, and will be subject to adjustments based on actual operating performance (the adjustments for operating performance are described in the key Terms & Conditions included as Attachment A to the DEF 2018 RFP Document).

Generation capital charges are to be consistent with the generation equipment costs specified in Section 9.0 of the Bidder's proposal. Fixed O&M charges should reflect the fixed costs associated with operating and maintaining the project.

A transmission charge must be specified by the Bidder in Schedule 1 for each year of the proposal. These charges should represent the Bidder's Interconnection Facilities and wheeling (if applicable) costs to DEF's Delivery Point and must be based on the Seasonal Contract Capacities. The transmission charges specified are to be consistent with the transmission equipment costs specified in Section 9.0 of the Bidder's proposal. If the proposed project is not located in the DEF system, any costs related to an upgrade of other transmission systems required for delivery of Firm Power from the Facility to the delivery point in the DEF system must be included in the price proposal by the Bidder. Costs for any necessary upgrades to integrate the project into the DEF transmission system will be estimated by DEF during the Initial Detailed and Final Detailed Evaluations of proposals and the costs for the upgrades on the DEF system and other affected utility systems will be included in the evaluation of the proposal.

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 in $/mmBtu-day and must specify the amount of transportation proposed to be reserved (in Chapter 8 of the proposal). Bidders may specify a fixed pipeline demand/reservation 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.

Bidders must provide fuel price proposals for the primary and secondary fuels. The primary fuel is the fuel that the Bidder expects to use for the majority of the generation in the year, and the secondary fuel is the fuel that the Bidder expects to use for the remaining generation. If desired, the Bidder may propose to use only one fuel throughout the year and not specify a secondary fuel (the primary and secondary fuels are specified on Schedule A). 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. The escalation rate used must be outlined in the Bidder's proposal.
2. the Bidder may propose to use a price index or combination of indices or propose a formula based on an index or combination of indices. Reference price forecasts are provided in Schedule 1 for the Bidder to use as an index to formulate prices. The Bidder should enter the formula in the appropriate cells (in Rows 29-30 and 32-33 of Schedule 1) and also describe the formula in Chapter 2 of its proposal. The Bidder shall enter the name of the proposed index (e.g., "Gas Daily Henry Hub", "Gas Daily Florida Citygate", etc.) in the space provided on Rows 48 and 49 of Schedule 1.
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.

If the Bidder selects option 2 above, the DEF fuel price forecast will be used as an index to evaluate proposals; however, the Bidder will be paid based on the actual values of the index(es) at the time of payment. The DEF fuel price forecast assumptions are based on recent forecasts for the fuels; however, DEF reserves the right to update these forecasts during the evaluation period if they no longer reflect DEF's current expectations.

The index selected for each pricing component should be consistent with market-based indices that are appropriate for that component. For example, if a Bidder proposes to use natural gas as its primary fuel, a gas commodity index is appropriate to choose. If a Bidder proposes to use a secondary fuel, the Bidder should select an appropriate index for that fuel. The Bidder must identify the pricing point for the index selected, if appropriate.

Bidders must enter annual prices for variable O&M. Although Bidders may specify two fuels (Primary and Secondary) to be used during a year, Bidders should enter only one annual price for each of the O&M components. These prices should reflect the weighted average annual O&M, based on the proposed fuels. Bidders may propose variable O&M prices in terms of $/MWh or $/hour of operation, or both.

Bidders are also required to enter annual start prices. The start price component is designed to compensate the Bidder for the cost of starting the Facility. Payment will only be made for starts required and initiated by DEF. DEF will not reimburse the Bidder for test starts or starts arising from a forced outage or from an unplanned maintenance outage. DEF will estimate the number of starts for evaluation purposes but pay the Bidder based on the actual number of successful starts.

Schedule 1 provides an area for other costs to be specified by the Bidder. Any other costs the Bidder expects DEF to pay must be identified in this area. **DEF will not accept any charges other than those identified in Schedule 1.**

Bidders should include back-up sheets which clearly describe their pricing proposals in terms of the pricing components and the index(es) proposed to adjust the prices.

Price Schedule For System Power Proposals

Bidders who are proposing System Power Proposals are required to complete Schedule 2. **All costs to be paid by DEF must be reflected in the proposed pricing. DEF will not accept any charges other than those identified in Schedule 2.**

The first entries in Schedule 2 are the Contract Start Month, the Contract Start Year, and the Contract End Year, which represent the term for which capacity and energy will be provided to DEF by the Bidder. Bidders must then specify the proposed Contract Capacity for both the winter and Summer Seasons for each year of the proposed term.

Bidders next enter capacity and transmission charges, fuel and non-fuel energy prices, and start prices in Schedule 2 for every year of the term of the proposal. The capacity charge should represent fixed costs associated with the generation system from which power is being provided. For the transmission charge, the Bidder should enter the total price of transmission, including wheeling and system upgrade costs as appropriate, to deliver the system power to the delivery point at the DEF system. Costs for any necessary upgrades to integrate the proposed power flow into the DEF transmission system will be estimated by DEF during the Initial and Detailed Evaluations of proposals, and the costs for the upgrades on the DEF system and other affected utility systems will be included in the evaluation of the proposal.

The capacity and transmission charges must be based on the Seasonal Contract Capacities and must be entered as **annualized** values for every year, including the start year when the proposal does not include all twelve months of the calendar year. Bidders will be paid monthly based on the product of the Seasonal Contract Capacity and one-twelfth (1/12) of the Bidder-specified annual capacity and transmission charges, and will be subject to adjustments based on the actual availability of capacity under the agreement.

Bidders of System Power Proposals must guarantee 100% availability for the capacity and energy offered to DEF. In the event that DEF signs a power purchase agreement (PPA) with a Bidder to supply System Power, and that supplier fails to deliver the capacity and energy committed to in the PPA, then DEF will only pay for the capacity and energy actually received and will also charge the supplier for DEF's cost of replacement capacity and energy. DEF prefers proposals that, when curtailments are necessary, the Bidder curtails delivery only on a pro-rata basis simultaneously and proportionately along with the Bidder's other firm sales, including primary public service obligations.

The system fuel energy price should reflect the fuel costs associated with providing energy from the Bidder's generation system. Bidders have three options for proposing fuel-related system energy 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. The escalation rate used by the Bidder must be outlined in the Bidder's proposal.
2. the Bidder may propose to use a price index or combination of indices or propose a formula based on an index or combination of indices. Reference price forecasts are provided in

Schedule 2 for the Bidder to use as an index to formulate prices. The Bidder should enter the formula in the appropriate cells (in Row 27 of Schedule 2) and also describe the formula in Chapter 2 of its proposal. The Bidder shall enter the proposed index(es) (e.g., "Gas Daily Henry Hub", "Gas Daily Florida Citygate", etc.) in the space provided on Row 40 of Schedule 2.

3. the Bidder may propose a "true-up" arrangement whereby the fuel price will be trued-up to the Bidder's regulatory jurisdiction's system average fuel price. If the Bidder selects this option, the bidder must provide a series of prices to be used for evaluation purposes, as well as evidence that the series of prices are reasonable.

If the Bidder selects option 2 above, the DEF fuel price forecast will be used as an index to evaluate the proposal; however, the Bidder will be paid based on the actual values of the index(es) at the time of payment. The DEF fuel price forecast assumptions are based on recent forecasts for the fuels; however, DEF reserves the right to update these forecasts during the evaluation period if they no longer reflect DEF's current expectations.

The index selected for each pricing component should be consistent with market-based indices that are appropriate for that component. For example, if a Bidder proposes to use natural gas as its primary fuel, a gas commodity index is appropriate to choose. If a Bidder proposes to use a secondary fuel, the Bidder should select an appropriate index for that fuel. The Bidder must identify the pricing point for the index selected, if appropriate.

The non-fuel energy costs should represent the non-fuel variable costs associated with providing energy from the Bidder's system. The non-fuel energy costs can be represented in terms of $/MWh or $/hour scheduled, or both.

The Bidder may also provide annual start prices. The start price component is designed to compensate the Bidder for the cost of starting various facilities when DEF schedules power for delivery. DEF will estimate the number of starts for evaluation purposes but pay the Bidder based on the actual number of times DEF schedules power for delivery.

Schedule 2 provides an area for other costs to be specified by the Bidder. Any other costs the Bidder expects DEF to pay must be identified in this area. **DEF will not accept any charges other than those identified in Schedule 2.**

Bidders should include back-up sheets which clearly describe their pricing proposals in terms of the pricing components and the index(es) proposed to adjust the prices.

Contract Flexibility Provisions

Also pursuant to Section II.E of the DEF 2018 RFP Document, DEF is encouraging Bidders to offer contract flexibility provisions. For example, Bidders may propose an initial contract term and provide DEF options to extend the term at predefined prices. If Bidders would like to provide such options, the pricing schedules should be used to convey the prices. The initial term should be entered as the Contract Term, and the extension provisions should be explained by the Bidder. Other flexibility provisions could also be proposed. Bidders should clearly and completely explain their proposals, including appropriate pricing information.

F. Chapter 3: Operating Performance

In this chapter of its proposal, each Bidder must demonstrate how its proposal complies with all of the operating performance requirements specified in Section III of the DEF 2018 RFP Document and the degree to which it is consistent with DEF's preferences for the operational Technical Criteria outlined in Section III.B.3.b.ii of the RFP. In Attachment A of the DEF 2018 RFP Document, DEF has provided key Terms & Conditions that provide several of the key operating performance requirements which will be used to ensure that the Bidder's generating resource provides DEF with its required level of operating performance. Bidders are required to answer the questions presented in Schedules 3 and 4 and to provide all necessary data to support the answers provided.

Bidders must specify in Schedule 3 the proposed project's heat rate information for the proposed primary fuel and secondary fuel. The heat rate data must be provided by specifying seasonal capacity states and heat rates for each fuel based on the Capacity Specification Criteria and Seasonal Capacity Specification Criteria provided in Attachment A (key Terms & Conditions). <u>Capacity states must be specified at net generation levels at the delivery point of the DEF system.</u> In addition, the Bidder should specify the elevation at which the unit is (would be) be sited. The heat rate data provided will be used for both evaluation and contract purposes.

Heat rates must be expressed in terms of the higher heating value of the fuel and must be the average (not incremental) heat rate for the capacity state. Heat rates must incorporate any margin for degradation during the term of the contract. Degradation may be incorporated over the term or annually. Bidders are required to provide heat rate data for the minimum load and full load operating points (the full load capacity values must be equal to the Seasonal Contract Capacity values and are carried over from Schedule 1). Bidders may provide heat rates for up to three additional capacity states to better represent the operational characteristics of the proposed project.

In Schedule 4, the Bidder must provide responses to all items that apply to the type of proposal being offered. Answer yes or no for each Operating Performance threshold by entering an "X" in the appropriate box for each item in the first part of Schedule 4. In the second part of Schedule 4, Bidders must provide operating performance evaluation criteria responses and outage information.

G. Chapter 4: Permitting Plans

In this chapter of its proposal, each Bidder should demonstrate how its proposal complies with all of the permitting requirements specified in Section III of the RFP Solicitation Document, and the degree to which it is consistent with DEF's preferences for a high level of certainty that the proposed project will receive its required permits within the time indicated on the project's critical path schedule. Each Bidder is required to answer the questions presented below and provide all necessary data to support these answers. For sections that require responses to several bullet items, the Bidder must always precede its response with the bullet item, verbatim, as shown below.

<u>Section</u>

4.0 In Schedule 5, the Environmental and Regulatory Permit Status Schedule, identify which items would be required for the project to be constructed and operated by placing an "X" in the "Not Required" or "Required" column by each item. If a permit has been applied for, indicate the date that the permit was applied for in the column marked "Applied For" and the date that the permit is likely to be issued in the column labeled "Expected Receipt." Some of the required items are pre-printed in Schedule 5. However, if additional permits would be required, add them to the schedule in the blank cells provided.

The Bidder should indicate why the project is likely to receive each required permit, license, or approval. **[New Unit Proposals]**

4.1 Provide specific information for the project site as identified below. **[New Unit Proposals]**

- List any new rights-of-way required for the project for fuel pipelines, water pipelines, rail spurs, roadways, or electric transmission lines.
- Identify the total acreage of wetlands on the proposed site or rights-of-way before and after construction and the acreage disturbed, lost, or converted during construction.
- Provide a copy of a map showing any portions of the proposed site or rights-of-way that are in a local or state designated Coastal Zone Management Area (CZMA).
- Provide evidence that the existing zoning for the site is compatible with the proposed use and, if not, provide a plan for changing the zoning.
- Provide evidence that a Phase I Environmental Assessment has been completed and that the proposed site or rights-of-way are not contaminated. If the proposed site or rights-of-way are contaminated, indicate the clean-up measures planned, their estimated costs, schedules for completion, and status of reviews by appropriate federal or state agencies.
- Identify any environmentally sensitive areas (*i.e.*, wetlands, water use caution areas, state lands (including submerged), CZMA, wildlife refuge, public parks, critical habitats for endangered species) within a one-mile radius of the proposed plant location and any mitigation measures for these areas.
- Identify any sites of historical or archaeological significance within a one-mile radius of the proposed plant location and any mitigation measures for these areas.

4.2 Describe the current and recent past land use and development of the site and adjacent lands, discussing the compatibility of the project with adjacent and nearby land uses. **[New Unit Proposals]**

4.3 Provide a waste disposal plan for the proposed project which identifies the solid or hazardous wastes that would be generated by the project and identifies how they would be disposed. **[New Unit Proposals]**

4.4 Indicate the quantity and source of cooling, injection, steam make-up, and general use water that would be needed for the project. This information should include the characteristics of the water to be used, necessary treatment processes, and a discussion of competing uses for the water. Provide a water supply plan for securing water supply and delivery to the project. Include the source of the water, a description of the water delivery system, the terms and conditions of any existing water supply transportation arrangements, and the status of such arrangement. **[New Unit Proposals, Existing Unit Proposals]**

4.5 Provide the following information concerning the wastewater generated by the project **[New Unit Proposals]**:

- The sources, composition, and expected quantity of wastewater to be generated by the project, the disposal method to be employed, including any waste treatment methods, and the water composition after treatment.

- The classification of any surface waters or groundwaters to which wastewater effluent is discharged and the name of the surface water.

4.6 Describe any hydrologic alterations, (*e.g.*, dredging, filling, diking, outfall structure, or impoundment) of any surface waters that would be required by the project, identifying the affected resource, the significance of the alteration, and the mitigation measures proposed. **[New Unit Proposals]**

4.7 Provide the following information regarding the impact of the project on the air quality of the surrounding area **[New Unit Proposals, Existing Unit Proposals]**:

- Identify the air quality management area where the project is (would be) located and indicate the attainment status of this area for each of the criteria pollutants.

- Identify whether there are any Class 1 areas within 100 kilometers of the proposed project site. If so, indicate whether any visibility modeling has been performed and the visibility impacts on the Class 1 areas projected by the model.

- Indicate the removal efficiency of any pollution control equipment that is (would be) employed for NO_x, SO_2, PM, CO, Hg, or hazardous air pollutants (HAPs).

- Complete Schedule 6, the Air Emissions Schedule, for both the primary and secondary fuel.

- If BACT or LAER would apply to the project, indicate how the Bidder proposes to comply with these requirements.

- Describe plans for obtaining any required offsets and allowances for the project, including SO_2 and NO_x allowances.

- Address levels of NH_3 (ammonia) emissions and requirements for handling/storage, if used.

- Describe the strategy for compliance with the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and the Clean Air Visibility Rule (CAVR).

4.8 Indicate the expected incremental ambient noise level during the daytime and nighttime hours that would result from the operation of the project at the nearest property boundary and any planned mitigation measures. Also, indicate the distance of the nearest residence from the project and define the expected daytime and nighttime ambient noise levels at the nearest residence. **[New Unit Proposals]**

H. Chapter 5: Engineering and Design Plans

In this chapter of the proposal, the Bidder should demonstrate how its proposal complies with all of the engineering and design requirements specified in Section III of the RFP Solicitation Document. The Bidder is required to provide the information requested below and all data necessary to support the answers provided. **[New Unit Proposals, Existing Unit Proposals]**

Section

5.0 This section is used to describe, at the highest level, the project's facilities. The discussion should clearly describe the assumptions as to what degree, if any, the new facilities will interface and rely on or enhance existing facilities.

- Layout and Location—Describe the location of the new facilities on site using a conceptual layout drawing. If existing facilities are present, show them in relation to the new units. The drawing(s) should show the location and size of the units and auxiliaries, stacks, fuel and water delivery systems, fuel and water storage tanks, waste water handling and disposal systems, water treatment systems, sanitary waste treatment systems, site storm water management systems, effluent storage system and tanks, etc. The site layout shall also identify wetland boundaries, buffers, etc. The drawing(s) should show the plant access for operations and construction, construction lay down and parking as well as security and buffer arrangements. The drawing(s) shall also show, in phantom, the location for future build-out reserve areas.

- Offices, Control Room, Shops and Warehousing—Describe what facilities are going to be built or added, either to existing or as standalone facilities. With regard to office and shop space, describe the number of individuals to be housed in offices, and the assumption on the level of maintenance work to be done in the shop.

- Transmission and Substation—Describe in general terms how the unit(s) are, or are proposed to be, interconnected to the Duke Energy Florida transmission system. Describe conceptually the substation arrangement (e.g. breaker and a half scheme) and at what voltage level the units are to be tied in to the substation. Describe the step up transformer including the MVA rating. Supply a single line diagram.

- 15 kV and Higher Equipment up to the Step up Transformer—Describe the 15kV equipment from the generator leads to the step up transformer. This description shall include the iso-phase bus work, generator breaker and connected auxiliary transformers and equipment. This equipment should be described on a single line diagram.

- Less than 15kV Electrical System—Describe the lesser voltage electrical systems to be installed. Indicate any interface or tie in to existing systems. Redundant systems should be defined. The uninterruptible power source for the plant shall also be described. Include appropriate single line diagrams.

- Plant Control Room Philosophy—Describe in general terms the overall control room philosophy as to the balance of plant DCS and the interface with the unit specific control system. Describe any tie-ins or interface with existing plant systems. Describe the interface of the DCS unit controls to the RTU connection to the DEF Energy Control Center.

- Raw, Service and Potable Water Facilities—Describe any new and/or existing facilities and any interconnection between the facilities, if applicable. The description shall include the capability of the systems and the storage requirements.

- Demineralized Water Facilities—Describe demineralized water facilities. Include the throughput and the amount of waste water to be rejected. Describe the storage facilities and the amount of capacity available in hours of operation. Describe the nature of the demineralizer arrangement as to whether it is leased and if it includes pre-filtration and reverse osmosis. If buildings are required describe them as well.

5.1 Provide an operations and maintenance plan (O&M Plan) which demonstrates that the project will be operated and maintained in a manner to allow the project to satisfy its contractual commitments. This O&M Plan should indicate proposed project staffing levels, the schedule for major maintenance activities, plans for inspecting and testing of major equipment, entities responsible for operating and maintaining the project, and status and schedule for securing a maintenance agreement.

5.2 Provide an engineering design plan that identifies the following:

- generation technology, including the make/model/supplier's name
- emission control equipment, including the make/model/supplier's name
- major equipment to be employed, including the make/model/supplier's name
- major equipment vendors
- whether new or refurbished equipment will be used
- commercial in-service date **[Existing Unit Proposals only]**

5.3 Provide historic operating performance data (heat rate, EFOR, summer and winter MDC, number of starts) for the proposed projects that demonstrate that they will be able to achieve the operating targets specified. **[Existing Unit Proposals only]**

Provide historic operating performance data (heat rate, EFOR, summer and winter MDC, number of starts) for projects of similar technology that demonstrate that the proposed technology will be able to achieve the operating targets specified. **[New Unit Proposal only]**

5.4 Provide a heat and material balance diagram.

5.5 Specify any limitations the proposed project will have regarding the start-up fuel system. If the project has or will have a secondary fuel, please specify whether the project will be able to start on either fuel independent of other fuel systems being completely out of service. Please specify whether the project will be able to switch fuel sources "on the fly."

5.6 Provide the following projected unit performance information:

- Equivalent Forced Outage Rate (EFOR)

  EFOR = [(FOH + EFDH)/(FOH + SH)]

  Where:

  FOH = Forced Outage Hours: The sum of all hours experienced during forced outages.

  EFDH = Equivalent Forced Derated Hours: The summation of the products of the Forced Derated Hours (FDH) and size (MW) of reduction for each event, divided by the Seasonal Contract Capacity (SCC).

  FDH = Forced Derated Hours: The number of hours experienced during a forced derated event.

  SH = Service Hours: The total number of hours a unit was electrically connected to the transmission system.

- Equivalent Availability Factor (EAF)

  EAF = [(AH - (EUDH + EPDH)) / PH]

  Where:

  AH = Available Hours: Period Hours (PH) less Planned Outage Hours (POH), Forced Outage Hours (FOH) and Maintenance Outage Hours (MOH).

  PH = Period Hours: Number of hours in the period (month).

  POH = Planned Outage Hours: The sum of all hours experienced during planned outages and planned outage extensions.

  FOH = Forced Outage Hours: The sum of all hours experienced during forced outages.

  MOH = Maintenance Outage Hours: The sum of all hours experienced during maintenance outages and maintenance outage extensions.

  EUDH = Equivalent Unplanned Derated Hours: The summation of the products of Unplanned Derated Hours (UDH) and size (MW) of reduction for each event, divided by Seasonal Contract Capacity (SCC).

  UDH = Unplanned Derated Hours: The number of hours experienced during a forced derated event, a maintenance derated event, or scheduled derated extension of a maintenance derated event.

  EPDH = Equivalent Planned Derated Hours: The summation of the products of the Planned Derated Hours (PDH) and size (MW) of reduction for each event, divided by the Seasonal Contract Capacity (SCC).

  PDH = Planned Derated Hours: The number of hours experienced during planned derated event or scheduled derated extension of a planned derated event.

I. Chapter 6: Site Control

In this chapter of the proposal, the Bidder should demonstrate how its proposal complies with all of the site control requirements specified in Section III of the RFP Solicitation Document. Bidders are required to provide the information requested below and all necessary data to support the answers provided. **[New Unit Proposals, Existing Unit Proposals]**

Section

6.0 Provide a USGS map (7.5 minute scale) that indicates the project site location and the surrounding area of at least two (2) miles from the site center, identifies all generation, substation, and other equipment, and all new rights-of-way that would be required for the project, including critical dimensions. Show proximity to and identify the nearest DEF substation and/or transmission line. Provide a recent aerial photograph showing the site location and surrounding area for at least one (1) mile from each site boundary.

6.1 Demonstrate site control either in the form of an agreement demonstrating ownership of the site, lease of the site for the term of the proposal, or at a minimum, an executed letter of intent to negotiate a lease for the site for the full contract term or term necessary for financing (whichever is greater) or to purchase the site. Provide a copy of a letter of intent or contract that demonstrates that the Bidder's proposal satisfies DEF's site control threshold. If the property is fee owned, a copy of the Title and Legal Description of the property is required.

6.2 If off-site rights-of-way are required for gas, electrical, water, or rail service, demonstrate site control either in the form of an executed letter of intent to negotiate a lease for the rights-of-way for the full contract term or term necessary for financing (whichever is greater) or to purchase the rights-of-way.

J. Chapter 7: Transmission Plan

In this chapter of the proposal, the Bidder should demonstrate how its proposal complies with all of the transmission requirements specified in Section III of the RFP Solicitation Document. Bidders are required to provide the information requested below and all necessary data to support the answers provided .

Section

7.0 Bidders are required to provide a completed Transmission Information Schedule (Schedule 7). **[All Proposals]**

7.1 If the proposed project or power source is located outside of DEF's system, provide a transmission plan that identifies the project's proposed transmission path, including delivery point. Also provide evidence that the host system utility and all wheeling utilities are willing to grant DEF the right to dispatch the output of New and Existing Unit Proposals or the right to schedule the power from System Power Proposals. Identify the DEF interface utility that would be used to deliver the power to DEF. **[Existing Unit Proposals, New Unit Proposals]**

For New Unit Proposals located outside of the DEF system, bidders are required to provide one of the following from the host system utility:

- A Transmission System Impact study agreement from the host system's Transmission Provider that indicates that the output of the New Unit can be delivered to the DEF interface.
- Confirmed Transmission Service to the DEF interface

In addition, for New Unit Proposals located outside of the DEF system, bidders are required to provide the information in Schedule 7 of Attachment D.

- Bidders are required to provide the contact information of a transmission planner from the host system utility.

For Existing Unit Proposals located outside the DEF system, bidders are required to provide the information in Schedule 7 of Attachment D.

7.2 For projects located inside of the DEF system, bidders are required to the information in Schedule 7 of Attachment D.

K. Chapter 8: Fuel Supply and Transportation Plan

In this chapter of the proposal, the Bidder should demonstrate how its proposal complies with all of the fuel supply and transportation plan requirements specified in Section III of the RFP Solicitation Document and the degree to which it is consistent with DEF's requirements for a reliable fuel supply for the proposed project. Bidders are required to provide a preliminary fuel supply plan and all necessary data to support the answers provided regarding this plan. **[New Unit Proposals, Existing Unit Proposals]** Bidders interested in having DEF provide fuel tolling services should complete Section 8.1 rather than Section 8.0.

Section
8.0 The preliminary fuel supply plan for both primary and secondary fuels must specify or provide the information listed below.

- Provide a map of the fuel supply and transportation infrastructure for the proposed project and a description of supply and transportation alternatives available to the project. If natural gas is proposed as a fuel (primary or secondary), identify the proposed main pipeline source, the length of any lateral from the main pipeline to the site, and the size and pressure of the lateral. If oil is proposed as a fuel (primary or secondary), provide the fuel quality requirements, proposed on-site storage capacity (total usable volume and number of tanks), the proposed transport means to the site, and the distance from the expected supply source.

- Provide copies of all fuel supply and transportation agreements in place for the proposed project. If fuel supply and transportation contracts are not in place, provide a description of the types and quality of service for fuel supply and transportation sought, the pricing and operational requirements, the contract terms and conditions required, and the status of such arrangements including the date that such arrangements will be in place. If the Bidder has received proposals from fuel and transportation providers, the Bidder should include the preferred proposal as well as a description of the experience of the Bidder in developing similar supply arrangements.

- Specify the criteria that would be used to select the ultimate fuel supplier and transportation service providers.

- If a secondary fuel is to be used, provide supporting information for the periods over which the primary and secondary fuel supply are expected to be used. The Bidder must specify any months in which the usage of the primary fuel is expected to be curtailed and the conditions under which the primary fuel is expected to be curtailed.

- Indicate whether transportation would be provided from existing capacity or whether new construction would be required. If new construction is required, provide an assessment of the availability of rights-of-way.

- If natural gas is being proposed, indicate the required gas pressure for the proposed project and confirm the capability of the pipeline to deliver natural gas to the project at or above that pressure.

- If natural gas is being proposed, indicate the amount of fixed pipeline demand/reservation (in mmBtu per day) on which the pricing is based.

- Describe the liquid fuel unloading facilities. This should include the number of truck or rail unloading stations and the unloading rate for the unloading facility. Describe the amount of existing storage and any new oil storage required. Describe if the storage is single or double walled and the amount of fuel oil storage dedicated to any new units. Describe whether a storage tank fire protection system is, or will be installed.

8.1 DEF is willing to consider tolling proposals. If the Bidder is interested in DEF providing fuel tolling services, the following information must be included in its proposal:

- Provide a map of the fuel supply and transportation infrastructure for the proposed project and a description of supply and transportation alternatives available to the project. If natural gas is proposed as a fuel (primary or secondary), identify the proposed main pipeline source, the length of any lateral from the main pipeline to the site, and the size and pressure of the lateral. If oil is proposed as a fuel (primary or secondary), provide the fuel quality requirements, proposed on-site storage capacity (total usable volume and number of tanks), the proposed transport means to the site, and the distance from the expected supply source.

- If a secondary fuel can be used, provide information for the periods over which the primary and secondary fuel supply is expected to be used.

[Existing Unit Proposals]

- The name of gas pipeline(s) with which the project is interconnected
- Location of the interconnection/meter
- Flow capability of each meter at the plant and the pressure requirement
- The name of the Operator Account
- Specify whether there are other units at the site that serve other customers such that a balancing agreement would need to be developed with a third party.

[New Unit Proposals]

- The name of gas pipeline(s) with which the project will be interconnected
- Location of the proposed interconnection/meter
- Specify whether the facility will serve only DEF such that the meter could be added to DEF's Operator Account.

L. Chapter 9: Project Financing Plan and Bidder Financial Information

The Bidder is required to provide evidence that the project is financially viable, that the project will likely be able to attract funds from investors, and that the Bidder has the financial ability to fulfill their obligations to DEF over the term of the contract. In this section of the proposal, the Bidder should demonstrate how its proposal complies with all of the project financial viability requirements specified in Section III of the RFP Solicitation Document and the degree to which it is consistent with DEF's preferences for proposals for which the Bidder is able to demonstrate that there is a high likelihood of the project securing funding. Bidders are required to provide the information requested below and all necessary data to support the answers provided.

Section

9.0 The financing plan must specify or provide the following: **[New Unit Proposals]**

- The projected cost of the project, broken down into the following major cost elements:

  Equipment
    Generation facilities
    Transmission Interconnection facilities
    Fuel facilities (e.g. pipeline interconnection, oil storage tanks, rail spurs)
  EPC Contractor
  Contingency
  Licensing, permits and site certificates
  Interest During Construction
  Other Costs.

- How the proposed project would be financed, including likely lenders and investors, the terms under which funds would be provided, and the respective percentage of funding represented by debt and equity.

- The timing for securing financing.

- A description of the project from a legal and financial standpoint indicating the actual ownership structure, the entities that will have ownership interests and their percentage interests in the project, their responsibilities for the development of the project, and their responsibilities for funding of project development expenses.
- Provide documentation demonstrating the relevant experience of the Bidder (or partner responsible for securing financing) in obtaining financing for other power generation projects.

9.1 The Bidder is required to provide sufficient financial information to enable DEF to assess the financial strength and credit of the entity that would execute a contract with DEF. Bidders should provide information on their corporate structure (including identification of any parent companies), a copy of the respondent's most recent quarterly report containing unaudited consolidated financial statements that is signed and verified by an authorized officer of respondent attesting to its accuracy, a copy of respondent's most recent annual report containing audited consolidated financial statements and a summary of respondent's relevant experience. Financial statements should include all associated footnotes. Financial statements, annual reports and other large documents may be referenced via a web site address. If the proposed contracting entity is not the same legal entity for which financial information is furnished, the respondent should state whether a parent guarantee will be provided to cover the obligations of the contracting entity.

9.2 The Bidder is required to include a discussion of the potential for increases or decreases in DEF's cost of capital and any competitive advantage the Bidder's financing arrangements may give the Bidder. **[All Proposals]**

9.3 For proposals that will be seeking to obtain project financing, Bidders are required to provide full project financial Pro Formas that supply, at a minimum, the information outlined in Schedule 8, Project Pro Formas Schedule, for the proposed financing term. For purposes of completing this pro forma, Bidders should assume an appropriate project capacity factor for the technology being proposed (10% for peaking duty, 50% for intermediate duty, and 80% for baseload duty). Actual project capacity factors will vary. The assumed capacity factor is used only to review the project's financial viability as indicated by the Bidder's project pro forma. DEF reserves the right to request project pro formas from all short-listed proposals. **[New Unit Proposals]**

M. Chapter 10: Commercial Operation Date Certainty

The Bidder is required to demonstrate that its New Unit Project will be able to achieve the commercial operation date requirements. As part of this demonstration, the Bidder is required to provide a critical path diagram and schedule for the project that conforms to the requirements specified below. DEF will evaluate the reasonableness of the following aspects of the Bidder's proposed schedule: permitting, securing the project site, fuel supply and transportation arrangements, engineering design, equipment procurement, project financing, project construction, and start-up and testing. DEF's evaluation will consider the evidence presented by the Bidder that the proposed schedule for each of these project elements is reasonable. For the purposes of developing this schedule only, the Bidder should assume that negotiations are finalized by August, 2014. However, specifying this date should not be construed as a commitment by DEF to finalize negotiations by this date.

Section

10.0 Provide a critical path diagram and schedule for the project that specifies the critical path for each of the elements of the project development cycle including but not limited to, the following: permitting, securing the project site, fuel supply and transportation arrangements, engineering design, equipment procurement, construction and permanent financing, project construction, and start-up and testing. **[New Unit Proposals]**

10.1 Complete Schedule 9, the Project Milestone Schedule, which will be included as part of an executed contract. **[New Unit Proposals]**

10.2 The Bidder should provide a summary of its current and planned electric power resources including such information as the source of supply, contract terms, and accessibility to the DEF system. For proposals that require new resources be built to maintain a reliable supply on the host system, Bidders are required to state the type of capacity to be built and provide evidence that the required construction can be completed in time to maintain a reliable supply. **[System Power Proposals]**

10.3 If the proposed project will be providing steam or electricity to a host customer, indicate the name of the entity to whom this service will be provided, the type and amount of energy to be provided, and the status of negotiations regarding the terms and conditions under which such service will be provided, including appropriate documentation of such contracts. **[New Unit Proposal, Existing Unit Proposal]**

N. Chapter 11: Bidder Experience

The Bidder is required to provide evidence regarding its relevant experience in developing projects that are of an equivalent size and technology. DEF will evaluate each Bidder's relevant experience in six areas: permitting, engineering, financing, fuel procurement, project construction, and operations and maintenance, including environmental compliance. For proposals that rely on a project team composed of more than one firm to develop the project, the Bidder should indicate its relevant experience in working with other team members to develop projects.

Section

11.0 Provide for at least five comparable projects a project reference not affiliated with the Bidder. For each reference, specify a contact name, title, company, address, and phone number.

For each project, indicate the utility or company served and provide a description of the project, including project location, the size and type of project, the scheduled and actual in-service date, and the availability factor achieved. **[New Unit Proposals, Existing Unit Proposals]**

11.1 For each of the project participants, provide an experience statement which lists the relevant experience of the firm, including other projects of a similar type, size, and technology. Describe the experience in the following six areas: permitting, engineering, financing, fuel procurement, project construction, and operations and maintenance, including environmental compliance. **[New Unit Proposals, Existing Unit Proposals]**

11.2 Provide documentation regarding the contractual relationship between the Bidder and all additional project participants and vendors. If this contractual relationship has not been finalized, specify the schedule for doing so. **[New Unit Proposals]**

11.3 Indicate if the Bidder has failed to perform under any contracts or agreements for power supplies. If so, please explain. **[All Proposals]**

11.4 Provide a summary of current litigation activity, with supporting explanatory information as necessary, related to (1) provision of energy products and services (fuel, power, ancillary services, engineering, on-site services); (2) lease option arrangements for assets; (3) purchases of energy products and services (as above); or (4) industrial construction projects (power plants, industrial plants, cogeneration facilities, etc.). **[All Proposals]**

O. Chapter 12: Acceptance of key Terms & Conditions

[All Proposals]
Attachment A to the DEF RFP Solicitation Document contains key Terms & Conditions that DEF will utilize during this RFP and any possible contract negotiations. The key Terms & Conditions were developed assuming the resources are in the DEF System.

Bidders willing to accept DEF's key Terms & Conditions (Attachment A to the DEF RFP Solicitation Document) without exceptions should indicate this in their proposals. Bidders with exceptions to the key Terms & Conditions should indicate all exceptions in red-lined form. Each exception should be clearly described and the requested change clearly identified. Bidders may provide the red-lined form using the Word version that was included in the RFP Package. Red-lined versions of the key Terms & Conditions should be accompanied by a textual discussion which provides the reason for the exception.

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																	
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																		
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)																		
[illegible]																		
[illegible]																		
[illegible]																		

	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																	
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)																	
[illegible]																	
[illegible]																	
[illegible]																	

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
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	12.06	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	22.52	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	34.62	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 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
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
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
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)												
[illegible]												
[illegible]												
[illegible]												

	Contract Year											
Number	13	14	15	16	17	18	19	20	21	22	23	24
Beginning	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
Ending	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
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)												
[illegible]												
[illegible]												
[illegible]												

	Contract Year										
Number	25	26	27	28	29	30	31	32	33	34	35
Beginning	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	12/31/42	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)											
[illegible]											
[illegible]											
[illegible]											

Proposed fuel energy price index(es) ____________________

Reference Price Forecasts[3] ($/mmBtu)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Natural Gas, Henry Hub	5.61	5.94	6.70	7.12	7.49	7.74	8.07	8.41	8.76	9.12	9.50	9.89
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	22.52	23.42	24.26	25.11
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

Reference Price Forecasts[3] ($/mmBtu)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Natural Gas, Henry Hub	10.29	10.71	11.14	11.59	12.05	13.23	14.65	15.76	16.68	17.60	18.53	19.45
No. 2 Oil, .5% S. delivered to Florida Gulf Coast	26.00	26.71	27.72	28.77	29.86	31.00	32.17	33.39	34.52	35.65	36.79	37.92
Coal	5.19	5.35	5.54	5.72	5.91	5.11	6.30	6.50	6.70	6.89	7.09	7.28

Reference Price Forecasts[3] ($/mmBtu)	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Natural Gas, Henry Hub	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	39.05	40.19	41.32	42.45	43.59	44.72	45.86	46.99	48.12	49.26	50.39
Coal	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 Contact**	Bidder Name	____________
	Contact Name	____________
	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

APPENDIX B

Program Description and Progress

Program Title: Home Energy Check

Program Description: The Home Energy Check program is a comprehensive residential energy evaluation (audit) program. The program provides Duke Energy Florida, Inc.'s (DEF) residential customers with an analysis of energy consumption and recommendations on energy efficiency improvements. It acts as a motivational tool to identify, evaluate, and inform consumers on cost effective energy saving measures. It serves as the foundation of the residential Home Energy Improvement program and is a program requirement for participation. There are seven types of the energy audit: the free walk-thru, the paid walk-thru ($15 charge), the energy rating (Energy Gauge), the mail-in audit, an internet option, a phone assisted audit, and a student audit.

Program Accomplishments for January 2013 through December 2013:
31,643 customers participated in Home Energy Checks.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $7,631,853.

Program Progress Summary: To-date 778,295 customers have participated in Home Energy Check. Duke Energy Florida will continue to use the Home Energy Check to inform and motivate consumers to implement cost effective energy efficiency measures and qualify for Home Energy Improvement incentives.

APPENDIX B

Program Description and Progress

Program Title: Home Energy Improvement

Program Description: Home Energy Improvement is an umbrella program for residential customers with existing homes. This program combines thermal envelope efficiency improvements with upgraded equipment and appliances. The Home Energy Improvement program includes incentives for measures such as duct testing, duct leakage repair, attic insulation, injected wall insulation, replacement windows, window film, reflective roofing, high efficiency heat pump replacing resistance heat, high efficiency heat pump replacing a heat pump, high efficiency A/C replacing A/C with non-electric heat, HVAC commissioning, plenum sealing, proper sizing and supplemental bonuses.

Program Accomplishments for January 2013 through December 2013: There were 29,724 measures implemented under this program.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $6,138,247.

Program Progress Summary: To-date 573,246 Home Energy Improvement measures have been implemented. This program will continue to be offered to residential customers through the Home Energy Check to provide opportunities for improving the energy efficiency of existing homes.

APPENDIX B

Program Description and Progress

Program Title: Residential New Construction

Program Description: The Home Advantage Program promotes energy-efficient construction which exceeds the building code. Information, education, and consultation are provided to homebuilders, contractors, realtors and home buyers on energy-related issues and efficiency measures. This program is designed to encourage single, multi, and manufactured home builders to build more energy efficiently by encouraging a whole house performance view including the installation of climate effective windows, reflective roof materials, upgraded insulation, conditioned space air handler placement, energy recovery ventilation, and highly efficient HVAC equipment. Incentives are awarded to the builder based on the level of efficiency they choose.

Program Accomplishments for January 2013 through December 2013: There were 23,469 measures implemented through this program.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $3,863,861.

Program Progress Summary: To-date 264,788 measures have been implemented through the Residential New Construction program. This program is tied to the building industry's economic health and these forces will dictate the number of homes built during any given year.

APPENDIX B

Program Description and Progress

Program Title: Neighborhood Energy Saver

Program Description: The Neighborhood Energy Saver Program was designed to assist low-income families with managing energy costs. The goal of this program is to implement a comprehensive package of electric conservation measures at no cost to eligible customers. Additionally, Duke Energy Florida will endeavor to educate the participating families to better manage their energy usage through efficiency techniques and practices.

Program Accomplishments for January, 2013 through December, 2013: There were 2,911 customers who participated in the Neighborhood Energy Saver program.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $1,283,067.

Program Progress Summary: To-date 17,833 customers have benefited from the Neighborhood Energy Saver Program. This program will continue to be offered to low-income neighborhoods in Duke Energy Florida's service territories.

APPENDIX B

Program Description and Progress

Program Title: Low-Income Weatherization Assistance Program (LIWAP)

Program Description: The program goal is to integrate DEF's DSM program measures with the Department of Economic Opportunity (DEO) and local weatherization providers to deliver energy efficiency measures to low-income families. Through this partnership Duke Energy Florida will assist local weatherization agencies by providing energy education materials and financial incentives to weatherize the homes of low-income families.

Program Accomplishments for January 2013 through December 2013: There were 1,750 measures implemented in the program in 2013.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $224,641.

Program Progress Summary: To-date 18,659 measures have been implemented through the Low-Income Weatherization Assistance Program (LIWAP). Duke Energy Florida participates in local, state-wide and national agency meetings to promote the delivery of LIWAP programs. Individual meetings with weatherization providers and other low income providers are conducted throughout DEF's territory to encourage customer participation in energy efficiency programs.

APPENDIX B

Program Description and Progress

Program Title: Energy Management (Residential & Commercial)

Program Description: The Load Management Program is a voluntary program that incorporates direct radio control of selected customer equipment to reduce system demand during winter and summer peak capacity periods and/or emergency conditions by temporarily interrupting selected customer appliances for specified periods of time. Customers have a choice of options and receive a credit on their monthly electric bills depending on the options selected and their monthly kWh usage.

Program Accomplishments for January 2013 through December 2013: During this period 4,321 customers were added to the residential program. The commercial program was closed to new participants in April 2001.

Program Fiscal Cost for January 2013 through December 2013: Residential program expenditures during this period were $50,369,626 and commercial expenditures were $596,873.

Program Progress Summary: As of December 31, 2013 there were 394,387 residential customers and 359 commercial customers participating in the Load Management program.

APPENDIX B

Program Description and Progress

Program Title: Business Energy Check

Program Description: The Business Energy Check is an audit for non-residential customers, and several options are available. The free audit provides a no-cost energy audit for non-residential facilities and can be completed at the facility by an auditor or online by the business customer. The paid audit provides a more thorough energy analysis for non-residential facilities. This program acts as a motivational tool to identify, evaluate, and inform consumers on cost effective energy saving measures for their facility. It serves as the foundation of, and is a requirement for participation in, the Better Business Program.

Program Accomplishments for January 2013 through December 2013: There were 2,070 customers who participated in this program.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $2,298,401.

Program Progress Summary: To-date 36,942 non-residential customers have participated in the Business Energy Check. This program will continue to inform and motivate consumers on cost effective energy efficiency improvements which result in implementation of energy efficiency measures. The program is required for participation in most of the company's other DSM Business incentive programs.

APPENDIX B

Program Description and Progress

Program Title: Better Business

Program Description: This umbrella efficiency program provides incentives to existing commercial and industrial customers for heating, air conditioning, motors, roof insulation upgrade, duct leakage and repair, window film, demand-control ventilation, lighting, occupancy sensors, green roof, cool roof, high efficiency energy recovery ventilation, compressed air, and HVAC optimization.

Program Accomplishments for January 2013 through December 2013: There were 992 measures implemented under this program.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $1,857,858.

Program Progress Summary: To-date 15,560 measures have been implemented through the Better Business Program. This program will continue to be offered to commercial customers through the Business Energy Check to provide opportunities for improving the energy efficiency of existing facilities.

APPENDIX B

Program Description and Progress

Program Title: Commercial/Industrial New Construction

Program Description: This is an umbrella efficiency program for new Commercial and Industrial facilities. This program provides information, education, and advice on energy-related issues and efficiency measures by involvement early in the building's design process. With the exception of ceiling insulation upgrade, duct test and leakage repair, HVAC steam cleaning and roof top HVAC unit recommissioning, the Commercial and Industrial New Construction program provides incentives for the same efficiency measures listed in the Better Business program for existing buildings.

Program Accomplishments for January 2013 through December 2013: There were 246 measures implemented in 2013.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $1,112,112.

Program Progress Summary: To-date 1,735 measures have been implemented through the Commercial/Industrial New Construction program. This program is tied to the building industries economic health and these forces will dictate the number of commercial facilities built during any given period.

APPENDIX B

Program Description and Progress

Program Title: Innovation Incentive

Program Description: Significant conservation efforts that are not supported by other Duke Energy Florida programs can be encouraged through Innovation Incentive. Major equipment replacement or other actions that substantially reduce DEF peak demand requirements are evaluated to determine their impact on Duke Energy Florida's system. Incentives are provided for customer-specific demand and energy conservation projects on a case-by-case basis, where cost-effective to all DEF customers. To be eligible, projects must reduce or shift a minimum of 10 kW of peak demand.

Program Accomplishments for January 2013 through December 2013: There were a total of 13 projects completed that qualified for incentives in 2013.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $64,858.

Program Progress Summary: To-date 190 projects have completed incentives through the Innovation Incentive program. This program continues to target specialized, customer specific energy efficiency measures not covered through the company's other DSM programs.

APPENDIX B

Program Description and Progress

Program Title: Standby Generation

Program Description: Duke Energy Florida provides an opportunity for commercial customers to voluntarily operate their on-site generators during times of system peak. Participants receive an incentive per kW available, as well as a kWh supplement for runtime during times of system peak.

Program Accomplishments for January 2013 through December 2013: There were 12 new accounts added to the program during this period.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $4,587,513.

Program Progress Summary: A total of 256 accounts are currently participating in this program.

APPENDIX B

Program Description and Progress

Program Title: Interruptible Service Program

Program Description: The Interruptible Service program is a rate tariff which allows Duke Energy Florida to switch off electrical service to customers during times of capacity shortages. The signal to operate the automatic switch on the customer's service is activated by the Energy Control Center. In return for this, the customers receive a monthly rebate on their kW demand charge.

Program Accomplishments for January 2013 through December 2013: There were 4 new participant added to the program under the IS-2 tariff during this period.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $24,703,515.

Program Progress Summary: The program currently has 134 active accounts with 105 IS-1 accounts, 23 IS-2 accounts, 4 SS-2 accounts, and two SECI-IS accounts. The original program filed as the IS-1 tariff is no longer cost-effective under the Commission approved test and was closed on April 16, 1996. Existing participants were grandfathered into the program. New participants are placed on the IS-2 tariff.

APPENDIX B

Program Description and Progress

Program Title: Curtailable Service Program

Program Description: The Curtailable Service is a dispatchable DSM program in which customers contract to curtail or shut down a portion of their load during times of capacity shortages. The curtailment is done voluntarily by the customer when notified by DEF. In return for this cooperation, the customer receives a monthly rebate for the curtailable portion of their load.

Program Accomplishments for January 2013 through December 2013: There were no new participants added to this program in 2013.

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $878,351.

Program Progress Summary: The program currently has 4 accounts with 3 CST-1 accounts and 1 SS-3 accounts. The original program filed as the CS-1 tariff is no longer cost-effective under the Commission approved test and was closed on April 16, 1996. Existing participants were grandfathered into the program. New participants are placed on the CS-2 tariff.

APPENDIX B

Program Description and Progress

Program Title: Solar Water Heating with Energy Management Program

Program Description: This program is part of DEF's Demand-Side Renewable Portfolio and encourages residential customers to install a solar thermal water heating system. Customers are required to complete a Home Energy Check before the solar thermal system is installed. To receive the one-time $550 incentive, the heating, air conditioning, and water heating systems must be on the Energy Management program and the solar thermal system must provide a minimum of 50% of the water heating load.

Program Accomplishments for January, 2013 through December, 2013: There were 259 customers that participated in the Solar Water Heater with Energy Wise.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $170,584.

Program Progress Summary: This program was implemented in 2011, along with a new online application process and will continue to be offered in Duke Energy Florida's service territories through 2014.

APPENDIX B

Program Description and Progress

Program Title: Solar Water Heating Low Income Residential Pilot

Program Description: The Solar Water Heating Low Income Residential Customers Pilot is part of DEF's Demand-Side Renewable Portfolio and designed to assist low income families with managing energy costs by incorporating a solar thermal water heating system in their residence while it is under construction. Duke Energy Florida 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.

Program Accomplishments for January, 2013 through December, 2013: There were 24 customers that participated in this program in 2013.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $123,594.

Program Progress Summary: This pilot program was implemented in 2011 and will continue to be offered in Duke Energy Florida's service territories through 2014.

APPENDIX B

Program Description and Progress

Program Title: Residential Solar Photovoltaic Pilot

Program Description: This pilot program is part of DEF's Demand-Side Renewable Portfolio and encourages residential customers to install new solar photovoltaic (PV) systems on their home. Customers are required to complete a Home Energy Check before the PV system is installed. The pilot program includes an annual reservation process for pre-approval to ensure the maximum incentive funds are available for participation. Participants can receive a rebate up to $2.00 per Watt of the PV dc power rating up to a $20,000 maximum for installing a new PV system.

Program Accomplishments for January, 2013 through December, 2013: There were 152 customers that participated in this program in 2013.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $2,445,475.

Program Progress Summary: This pilot program was implemented in 2011, along with an online application process. Duke Energy Florida will continue to offer this program in its service territories through 2014.

APPENDIX B

Program Description and Progress

Program Title: Commercial Solar Photovoltaic Pilot

Program Description: This pilot program is part of DEF's Demand-Side Renewable Portfolio and encourages commercial customers to install new solar photovoltaic (PV) systems on their facilities. Additionally, the pilot program promotes the installation of renewable energy on energy efficient businesses by requiring customers to complete a Business Energy Check prior to installation. The program design includes an annual reservation process for pre-approval to ensure the maximum incentive funds are available for participation. Participants can receive a rebate up to $2.00 per Watt of the PV DC power rating for the first 10 KW, $1.50 per Watt for 11KW to 50 KW, and $1.00 per Watt for 51 KW to 100 KW, up to a $130,000 maximum for installing a new PV system.

Program Accomplishments for January, 2013 through December, 2013: There were 12 customers that participated in this program in 2013.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $920,291.

Program Progress Summary: This pilot program was implemented in 2011, along with an online application process, and will continue to be offered in Duke Energy Florida's service territories through 2014.

APPENDIX B

Program Description and Progress

Program Title: Photovoltaic for Schools Pilot

Program Description: This pilot program is part of DEF's Demand-Side Renewable Portfolio and is designed to promote energy education and provide participating public schools with new solar photovoltaic (PV) systems at no cost to the school. The pilot program will be limited to an annual target of one system with a rating up to 100 kW installed on a post secondary school and up to ten (10) 10 kW systems with battery backup option installed on schools, preferably those serving as emergency shelters.

Program Accomplishments for January, 2013 through December, 2013: There were 11 customers that participated in this program in 2013.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $1,054,297.

Program Progress Summary: This pilot program was implemented in 2011 and will continue to be offered in Duke Energy Florida's service territories through 2014. Photovoltaic systems were started at ten primary and one post secondary public school. The post secondary school was completed in 2013 the remaining primary schools will be completed in 2014.

APPENDIX B

Program Description and Progress

Program Title: Research and Demonstration Pilot

Program Description: The purpose of this program component is to research technology and establish R&D 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 focus of this pilot is to establish associated impacts from increased solar PV penetration in order to enhance the program cost benefit study and incorporate mitigation, as necessary, within the program eligibility standards. Additional objectives include enhanced understanding on the performance variability from different solar PV technologies, and research on economic impact and funding mechanisms.

The program will be limited to a targeted annual expenditure cap of 5% of the total Demand-Side Renewable Portfolio annual expenditures.

Program Accomplishments for January, 2013 through December, 2013: Several research and development projects continued and/or launched in 2013.

- Enhanced and continued data collection to document solar resource on distribution feeders associated with our solar PV monitoring project
- Established a study to determine impacts from increased penetration of PV resources on distribution circuits utilizing data collected in our PV monitoring project
- Partnered with EPRI to evaluate Flat Plate PV arrays
- Participated in EPRI programs 84 and 174; Renewables, Economics, and Technology Status; and Integrating Renewables into Distribution

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $11,026.

Program Progress Summary: The Research and Demonstration Pilot was initiated during 2011 along with the Demand Side Renewable Portfolio of pilot programs. This research pilot will continue through 2014.

APPENDIX B

Program Description and Progress

Program Title: Technology Development

Program Description: This program allows Duke Energy Florida, Inc. to undertake certain development and demonstration projects which have promise to become cost-effective conservation and energy efficiency programs.

Program Accomplishments for January 2013 through December 2013:
Several research and development projects continued and/or launched in 2013.

- Continued battery storage technology analysis by evaluating two Li-Ion batteries associated with the Renewable SEEDS project; final report to be completed in 2013
- Data collection and evaluation of Variable Speed HPs with the potential of eliminating strip heat as a back-up heat source for heat pumps
- Participated in EPRI Program 94 and 18D, Energy Storage and Electric Transportation Systems Infrastructure and Utility Readiness
- Partnered with EPRI and other research organizations to evaluate energy efficiency, energy storage, and alternative energy / innovative technologies

Program Fiscal Cost for January 2013 through December 2013: Expenses for this program were $251,317.

Program Progress Summary:
In 2013, Duke Energy Florida continued to focus on advancing new technologies which have the potential to provide new programs and create new customer offerings that continue to focus on using energy responsibly. We will continue to study several technologies such as energy storage, energy efficiency, and control automation so that we can fully understand the impacts these will have to our grid and our customer programs. Accomplishments in 2013 included: evaluating and collecting the data from the heat pump energy efficiency product that will eliminate the need for strip heat, working with EPRI and other utilities to advance EVSE for demand response capabilities, and working with EPRI to study energy storage cost benefit analysis. All of this research is tied to our strategic objectives to provide customers cost effective conservation and energy efficiency programs.

APPENDIX B

Program Description and Progress

Program Title: Qualifying Facility

Program Description: Power is purchased from qualifying cogeneration, renewables and small power production facilities.

Program Accomplishments for January, 2013 through December, 2013: Duke Energy Florida met with many Qualified Facility developers interested in providing renewable generation within our service territory. On-going discussions with renewable and CHP developers continue to progress with market changes, an increase in interest in project development, as well as technology advances. As the number of potential developers grow, more in depth policy and analytics are required to support these purchased power negotiations. Discussions have been held with current Qualified Facilities to extend soon to expire purchase agreements. The contracts under development are being diligently monitored for construction milestones, financing status, permitting, transmission studies and agreements, insurance and Performance Security. Duke Energy Florida continues to successfully administer all executed contracts with Qualified Facilities for compliance. These contracts produced more than 3.98 Million MWHs for Duke Energy Florida customers during 2013. That's equal to the average annual electricity use of about 370,000 average households.

Program Fiscal Cost for January, 2013 through December, 2013: Expenses for this program were $858,618.

Program Progress Summary:
As of December 31, 2013, the total firm capacity from in-service Qualifying Facilities is approximately 529 MW with an additional 150 MW of firm capacity and 300 MW of As-Available energy contracts are being monitored for future service.

APPENDIX C

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for approval of demand-side management plan of Progress Energy Florida, Inc.	DOCKET NO. 100160-EG ORDER NO. PSC-11-0347-PAA-EG ISSUED: August 16, 2011

The following Commissioners participated in the disposition of this matter:

ART GRAHAM, Chairman
LISA POLAK EDGAR
RONALD A. BRISÉ
EDUARDO E. BALBIS
JULIE I. BROWN

NOTICE OF PROPOSED AGENCY ACTION
ORDER MODIFYING AND APPROVING DEMAND-SIDE MANAGEMENT PLAN

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

Case Background

As required by the Florida Energy Efficiency and Conservation Act (FEECA), Sections 366.80 through 366.85 and 403.519, Florida Statutes (F.S.), we have adopted annual goals for seasonal peak demand and annual energy consumption for the FEECA Utilities. These include Florida Power & Light Company (FPL), Progress Energy Florida, Inc. (PEF), Tampa Electric Company (TECO), Gulf Power Company (Gulf), Florida Public Utilities Company (FPUC), JEA, and Orlando Utilities Commission (OUC).

Pursuant to Rule 25-17.008, Florida Administrative Code (F.A.C.), in any conservation goal setting proceeding, we require each FEECA utility to submit cost-effectiveness information based on, at a minimum, three tests: (1) the Participants test; (2) the Rate Impact Measure (RIM) test, and (3) the Total Resource Cost (TRC) test. The Participants test measures program cost-effectiveness to the participating customer. The RIM test measures program cost-effectiveness to the utility's overall rate payers, taking into consideration the cost of incentives paid to participating customers and lost revenues due to reduced energy sales that may result in the need for a future rate case. The TRC test measures total net savings on a utility system-wide basis. In past goal setting proceedings, we established conservation goals based primarily on measures that pass both the Participants test and the RIM test.

The 2008 Legislative Session resulted in several changes to the FEECA Statutes, and our 2008 goal-setting proceeding was the first implementation of these modifications. By Order No. PSC-09-0855-FOF-EG, issued December 30, 2009, in Docket Number 080408-EG, we established annual numeric goals for summer peak demand, winter peak demand, and annual energy conservation for the period 2010 through 2019, based upon an unconstrained Enhanced-Total Resource test (E-TRC) for the investor-owned utilities (IOUs). The E-TRC test differs from the conventional TRC test by taking into consideration an estimate of additional costs imposed by the potential regulation of greenhouse gas emissions. In addition, the numeric impacts of certain measures with a payback period of two years or less were also included in the goals. Further, the IOUs subject to FEECA were authorized to spend up to 10 percent of their historic expenditures through the Energy Conservation Cost Recovery (ECCR) clause as an annual cap for pilot programs to promote solar water heating (Thermal) and solar photovoltaic (PV) installations.

On January 12, 2010, PEF filed a Motion for Reconsideration of our goal setting decision in Docket No. 080408-EG. Order No. PSC-10-0198-FOF-EG, issued March 31, 2010, granted, in part, PEF's reconsideration which revised PEF's numeric goals to correct a discovery response that caused a double-counting error. On March 30, 2010, PEF filed a petition requesting approval of its Demand-Side Management (DSM) Plan pursuant to Rule 25-17.0021, Florida Administrative Code (F.A.C.) (Docket No. 100160-EG). The Florida Industrial Users Group (FIPUG), White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (PCS Phosphate), the Southern Alliance for Clean Energy (SACE), the Florida Solar Energy Industry Association (FlaSEIA), and Wal-Mart Stores East, LP, and Sam's East, Inc. (Walmart) were all granted leave to intervene in the proceeding.

On July 14, 2010, SACE filed comments on the FEECA Utilities' DSM Plans. These comments were amended on August 3, 2010, to include comments regarding FPUC. No other intervenors filed comments. On July 28, and August 12, 2010, PEF and Gulf, respectively, filed responses to SACE's comments.

On September 1, 2010, our staff filed a recommendation, noting that the DSM Plan filed by PEF on March 30, 2010, did not meet all annual goals we set for PEF in Order No. PSC-10-0198-FOF-EG. On October 4, 2010, we issued Order No. PSC-10-0605-PAA-EG approving six solar pilot programs but denying the remainder of PEF's petition and directing the Company to modify its DSM Plan to meet the annual goals we originally set. During the discussion at the September 14, 2010, Commission Conference, we also encouraged PEF to provide an alternative DSM Plan to reduce the customer rate impact in addition to the DSM Plan to meet our original goals. Therefore, on November 29, 2010, the Company filed two DSM Plans: an Original Goal Scenario DSM Plan and a Revised Goal DSM Plan. For clarity and ease of reference, the Original Goal Scenario DSM Plan, which features programs designed to meet the full demand and energy savings goals, will be referred to throughout the remainder of this Order as the "Compliance Plan" and the Revised Goal DSM Plan, which has a lower rate impact, but reduced projected savings, will be referred to as the "Rate Mitigation Plan."

On December 22, 2010, SACE filed a letter offering comments on the DSM plans submitted by PEF and several of the other IOUs. The letter references the August 3, 2010, filing by SACE relating to the PEF's initial DSM filing, and updates several issues relating to the Company's new DSM Plans. On April 25, 2011, SACE filed another letter offering similar comments and recommendations with regard to PEF's new DSM Plans filed on November 29, 2010, and FPL's modified and alternate DSM Plans filed March 25, 2011. On May 9, 2011, SACE filed a letter providing its comparison of PEF's proposed DSM plans filed on November 29, 2010, with Progress Energy Carolina's DSM/energy efficiency cost recovery rider application filed on May 2, 2011, with the South Carolina Public Service Commission. We have jurisdiction over this matter pursuant to Sections 366.80 through 366.85, F.S.

PEF's Compliance Plan

As noted above, PEF's initial filing submitted March 30, 2010, was insufficient to meet several of the annual goals in multiple categories. We directed PEF, in Order No. PSC-10-0605-PAA-EG, to file a modified DSM Plan which would comply with the goal-setting Order. However, the Compliance Plan PEF filed on November 29, 2010, still failed to fully meet the goals we established. Specifically, PEF's filing failed to achieve the annual and cumulative summer and winter demand (MW) goals for the commercial sector. Consequently, our staff sent a data request[1] to PEF requesting an explanation for PEF's failure to comply with our Order. PEF responded that it had inadvertently developed the portfolio of commercial programs in the Compliance Plan based upon an estimate of the commercial summer and winter demand (MW) goals "at-the-meter" rather than targeting the actual Commission-established demand goals which are "at-the-generator." This resulted in the assumed commercial demand savings being less than the established demand goals. PEF modified anticipated participation levels for measures within its Better Business program which were sufficient to eliminate the deficiency. With the provision of these modifications, PEF's Compliance Plan satisfies our Order and features programs designed to fully meet the established demand and energy savings goals.

Compliance Plan Programs

PEF's Compliance Plan includes seven residential programs and ten commercial/industrial programs. One of the residential programs, Technical Potential, is new. Three of the commercial/industrial programs are new: Commercial Green Building, Business Energy Saver, and Business Energy Response. Modifications, such as adding new measures, have been made to most of the programs. The status of each program relative to PEF programs currently in effect is indicated in Table 1, below.

[1] Staff's 10th Data Request to PEF, Question Number 1 (a – d), issued December 9, 2010.

Table 1 – Compliance Plan Programs

Program Name	Program Status
Residential Portfolio	
1. Technical Potential	New
2. Home Energy Improvement	Modified
3. Residential New Construction	Modified
4. Neighborhood Energy Saver	Modified
5. Low Income Weatherization Assistance	Modified
6. Home Energy Check	Modified
7. Residential Energy Management	Existing
Commercial/Industrial Portfolio	
1. Business Energy Check	Modified
2. Commercial Green Building	New
3. Business Energy Saver	New
4. Commercial/Industrial New Construction	Modified
5. Better Business	Modified
6. Innovation Incentive	Modified
7. Business Energy Response	New
8. Interruptible Service	Modified
9. Curtailable Service	Modified
10. Standby Generation	Modified
Renewable Portfolio	
1. Qualifying Facilities	Existing
2. Technology Development	Modified

Rate Impact of Compliance Plan

The costs to implement a DSM program consist of administrative expenses, equipment costs, and incentive payments to the participants, all of which are recovered by the Company through its ECCR clause. This clause represents a monthly bill impact to customers as part of the non-fuel cost of energy on their bills. Utility incentive payments, not included in the E-TRC, are recovered through the utility's ECCR factor and have an immediate impact on customer rates.

Much like investments in generation, transmission, and distribution, investments in energy efficiency have an immediate rate impact but produce savings over time. Table 2 shows the ECCR Expenditures and Rate Impact on a typical residential customer's bill under the Compliance Plan over ten years. The monthly bill impact of PEF's ECCR factor would range from $11.28 in 2011 to $16.52 in 2014, when we are due to revisit the conservation goals as required by Section 366.82(6), F.S.

Table 2 - Estimated Rate Impact of PEF's Compliance Plan Associated with Goals
(1,200 kWh Residential Bill)

Year	ECCR Component ($/mo)	Estimated Residential Bill ($/mo)	Percent of Bill (% Bill)
2010	$3.24	$154.58	2.10%
2011	$11.17	$162.51	6.88%
2012	$12.59	$163.93	7.68%
2013	$13.31	$164.65	8.08%
2014	$14.28	$165.62	8.62%
2015	$16.34	$167.68	9.74%
2016	$16.20	$167.54	9.67%
2017	$16.94	$168.28	10.06%
2018	$16.46	$167.80	9.81%
2019	$16.20	$167.54	9.67%

We believe the increase to an average residential customer's monthly bill that would result from implementing PEF's Compliance Plan is disproportionately high and clearly constitutes an undue rate impact on PEF's customers. As will be discussed below, Florida Statutes provide a remedy for addressing such cases of conservation plans having an undue impact on customer rates.

PEF's Rate Mitigation Plan

As mentioned in the case background, due to the significant rate impact associated with the initial filing, we also encouraged PEF to submit an alternative DSM Plan to lessen the rate impact over the planning period. The Company's Rate Mitigation Plan does not project achievement of our approved goals for residential customers. Residential goal achievement is forecast at less than 70 percent for each category, including 64.4 percent for summer peak demand, 69.8 percent for winter peak demand, and 48.8 percent for annual energy. However, goals for commercial/industrial customers are projected to be achieved or exceeded in each category under the Rate Mitigation Plan. Even so, combining the savings from the residential and commercial/industrial categories fails to result in the Rate Mitigation Plan meeting the goals we set.

Mitigation Plan Programs

PEF's Rate Mitigation Plan contains the same programs as the Compliance Plan, except that the Technical Potential program in the residential portfolio has been replaced with three programs. Two of these programs, Residential Lighting and Appliance Recycling, were formerly measures within the Technical Potential program and have simply been converted to stand-alone programs. The third program, Residential Behavior Modification, is a newly designed program which will provide reports to customers that allow them to compare their energy use and consumption patterns with that of neighbors in similar homes.

Rate Impact of Mitigation Plan

As discussed above, the costs to implement a DSM program consist of administrative expenses, equipment costs, and incentive payments to the participants, which are recovered by the Company through its ECCR clause. This clause represents a monthly bill impact to customers as part of the non-fuel cost of energy on their bills. Table 4 shows the ECCR Expenditures and Rate Impact on a typical residential customer's bill under the Rate Mitigation Plan over ten years. Under the Rate Mitigation Plan, the monthly bill impact would range from $4.73 in 2011 to $6.13 in 2014, when we are due to revisit the conservation goals as required by Section 366.82(6), F.S.

Table 4 - Estimated Rate Impact of PEF's Rate Mitigation Plan Associated with Goals
(1,200 kWh Residential Bill)

Year	ECCR Component ($/mo)	Estimated Residential Bill ($/mo)	Percent of Bill (% Bill)
2010	$3.24	$154.58	2.10%
2011	$4.73	$156.07	3.03%
2012	$5.20	$156.54	3.32%
2013	$5.67	$157.01	3.61%
2014	$6.13	$157.47	3.89%
2015	$5.98	$157.32	3.80%
2016	$5.66	$157.00	3.60%
2017	$5.25	$156.59	3.35%
2018	$5.05	$156.39	3.23%
2019	$4.92	$156.26	3.15%

As with our finding regarding PEF's Compliance Plan, discussed above, we believe the increase to an average residential customer's monthly bill that would result from implementing PEF's Rate Mitigation Plan is also high and constitutes and undue rate impact on customers. As will be discussed below, Florida Statutes provide a remedy for addressing such cases of conservation plans having an undue impact on customer rates.

Modification and Approval of Demand-Side Management Plan

Section 366.82(7), Florida Statutes, states as follows:

Following adoption of goals pursuant to subsections (2) and (3), the commission shall require each utility to develop plans and programs to meet the overall goals within its service area. The commission may require modifications or additions to

> a utility's plans and programs at any time it is in the public interest consistent with this act. In approving plans and programs for cost recovery, the commission shall have the flexibility to modify or deny plans or programs that would have an undue impact on the costs passed on to customers. . . .

As we noted above, the Compliance Plan filed by PEF is projected to meet the goals we previously established, but at a significant increase in the rates paid by PEF customers. We further noted that PEF's Rate Mitigation Plan is not estimated to meet the goals we established, yet also has a substantial rate increase. After deliberation, we find that both Plans filed by PEF will have an undue impact on the costs passed on to consumers, and that the public interest will be served by requiring modifications to PEF's DSM Plan. Therefore, we hereby determine to exercise the flexibility specifically granted us by statute to modify the Plans and Programs set forth by PEF.

Currently, PEF has an approved Plan as a result of our 2004 goal setting process, and the programs contained in that Plan have yielded significant increases in conservation and decreases in the growth of energy and peak demand. As noted above, both the Compliance Plan and Rate Mitigation Plan substantially rely on these existing Programs, with some modifications, and only a few new programs. We therefore conclude that the Programs currently in effect, even without modification, are likely to continue to increase energy conservation and decrease seasonal peak demand. As further discussed above, the rate impacts of the existing Plan are relatively minor. We find that the Programs currently in effect, contained in PEF's existing Plan, are cost effective and accomplish the intent of the statute. Therefore, exercising the specific authority granted us by Section 366.82(7), F.S., we hereby modify PEF's 2010 Demand-Side Management Plan, such that the DSM Plan shall consist of those programs that are currently in effect today.

We do wish to specifically note that Order No. PSC-10-0605-PAA-EG, while denying the Petition to approve the DSM Plan, did specifically approve six solar pilot programs. Those programs have been implemented to date. Given that they are pilot programs, we believe they should be continued, and reaffirm that provision of Order No. PSC-10-0605-PAA-EG.

Financial Reward or Penalty under Section 366.82(8), Florida Statutes

Section 366.82(8), F.S., gives us the authority to financially reward or penalize a company based on whether its conservation goals are achieved, at our discretion. In Order No. PSC-09-0855-FOF-EG, we concluded that, "[w]e may establish, through a limited proceeding, a financial reward or penalty for a rate-regulated utility based upon the utility's performance in accordance with Section 366.82(8) and (9), F.S."

As a result of our decision to modify PEF's 2010 Plan, we wish to clarify that PEF shall not be eligible for any financial reward pursuant to these statutory sections unless it exceeds the goals set forth in Order No. PSC-09-0855-FOF-EG. Conversely, PEF shall not be subject to any financial penalty unless it fails to achieve the savings projections contained in the existing DSM plan, which is approved and extended today.

Closure of Docket

By our vote today, we have taken action to approve a DSM Plan and continue existing Programs for PEF. If no person whose substantial interests are affected by this proposed agency action files a protest within 21 days of the issuance of this Order, we will issue a Consummating Order, and the docket shall be closed. If a protest is filed within 21 days of the issuance of this Order, however, the docket shall remain open to resolve the protest.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Progress Energy Florida, Inc.'s November 29, 2010, Original Goal Scenario DSM Plan and Revised Goal DSM Plan are not approved as filed. It is further

ORDERED that a Modified DSM Plan, consisting of existing Programs currently in effect, as detailed in the body of this Order, is Approved. It is further

ORDERED that Progress Energy Florida, Inc. shall only be eligible for a financial reward or penalty pursuant to Section 366.82(8) and (9), Florida Statues as set forth in the body of this Order. It is further

ORDERED that the Solar Pilot Programs approved in Order No. PSC-10-0605-FOF-EG are continued. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that upon the issuance of a Consummating Order, this docket shall be closed.

By ORDER of the Florida Public Service Commission this 16th day of August, 2011.

/s/ Ann Cole
ANN COLE
Commission Clerk
Florida Public Service Commission
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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing that is available under Section 120.57, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on September 6, 2011.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this/these docket(s) before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

Appendix D - Descriptions of Proposals

(Pages 1 through 5)

REDACTED

This document is confidential in it’s entirety