BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination that the Osprey Plant Acquisition and, alternatively, the Suwannee Simple Cycle Project is the most Cost Effective Generation Alternative to meet the Remaining Need Prior to 2018 for Duke Energy Florida, Inc.	DOCKET NO. ________________ Submitted for filing: January 30, 2015

DUKE ENERGY FLORIDA, INC.'S NOTICE OF FILING

Duke Energy Florida, Inc. ("DEF" or the "Company") hereby gives notice of filing the Direct Testimony of Benjamin M.H. Borsch with Exhibit BMHB-1 in support of DEF's Petition for Determination that the Osprey Plant Acquisition and, Alternatively, the Suwannee Simple Cycle Project is the Most Cost Effective Generation Alternative to Meet the Remaining Need Prior to 2018 for Duke Energy Florida, Inc.

Respectfully submitted this 30th day of January, 2015.

/s/ James Michael Walls

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REDACTED

DIRECT TESTIMONY
OF BENJAMIN M. H. BORSCH

ON BEHALF OF
DUKE ENERGY FLORIDA, INC.

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IN RE: PETITION FOR DETERMINATION THAT THE OSPREY PLANT ACQUISITION AND, ALTERNATIVELY, THE SUWANNEE SIMPLE CYCLE PROJECT IS THE MOST COST EFFECTIVE GENERATION ALTERNATIVE TO MEET THE REMAINING NEED PRIOR TO 2018 FOR DUKE ENERGY FLORIDA, INC.

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. ________

DIRECT TESTIMONY OF BENJAMIN M. H. BORSCH

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name, employer, and business address.

A. My name is Benjamin M. H. Borsch and I am employed by Duke Energy Corporation ("Duke Energy"). My business address is 299 1st Avenue North, St. Petersburg, Florida.

Q. Please tell us your position with Duke Energy and describe your duties and responsibilities in that position.

A. I am the Director, IRP & Analytics – Florida. In this role, I am responsible for resource planning for Duke Energy Florida, Inc. ("DEF" or the "Company"). I am responsible for directing the resource planning process in an integrated approach to finding the most cost-effective alternatives to meet the Company's obligation to serve its customers in Florida. As a result, we examine both supply-side and demand-side resources available and potentially available to the Company over its planning horizon, relative to the Company's load forecasts, and prepare and present the annual Duke Energy Florida Ten-Year Site Plan ("TYSP") documents that are filed with the Florida Public Service Commission ("FPSC" or the "Commission"), in accordance with the applicable statutory and regulatory requirements. In my capacity as the Director, IRP & Analytics – Florida, I oversaw the completion of the Company's 2013 and 2014 TYSP. I was also responsible for the Company's evaluation of options to meet its needs for reliable electric power prior to 2018.

Q. Please summarize your educational background and employment experience.

A. I received a Bachelor's of Science and Engineering degree in Chemical Engineering from Princeton University in 1984. I joined Progress Energy in 2008 supporting the project management and construction department in the development of power plant projects. In 2009 I became Manager of Generation Resource Planning for Progress Energy Florida, and following the 2012 merger with Duke Energy I accepted my current position. Prior to joining Progress Energy, I was employed for more than five years by Calpine Corporation where I was Manager (later Director) of Environmental Health and Safety for Calpine's Southeastern Region. In this capacity, I supported development and operations and oversaw permitting and compliance for several gas fired power plant projects in nine states. I was also employed for more than eight years as an environmental consultant with projects including development, permitting and compliance of power plants and transmission facilities. I am a professional engineer licensed in Florida and North Carolina.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your testimony in this proceeding?

A. I am testifying on behalf of the Company in support of its Petition. I will provide an overview of DEF's acquisition of the Osprey Plant from Osprey Energy Center, LLC, as the assignee of Calpine Construction Finance Company, L.P. ("Calpine"), and the Company's Suwannee Simple Cycle Project. I will explain that these generation alternatives meet DEF's remaining need prior to 2018 in the most cost-effective manner for its customers. I will set forth the reasons why the Company selected the Osprey Plant acquisition and the Suwannee Simple Cycle Project as alternative most cost-effective generation resources to meet that need, with the final generation resource addition dependent on regulatory approvals of the Osprey Plant acquisition, including Federal Energy Regulatory Commission ("FERC") approval in accordance with the terms of the Asset Purchase and Sale Agreement ("APA") between DEF and Calpine. I will also explain the Company's decision to proceed with its Petition to obtain a determination by the Commission that the Osprey Plant acquisition and, alternatively, the Suwannee Simple Cycle Project is the most cost-effective generation alternative to meet DEF's remaining need prior to 2018.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (BMHB-1), a composite exhibit of (i) my direct testimony and exhibits and (ii) the direct testimony and exhibits of DEF's expert Julie Solomon, who performed the FERC Competitive Analysis Screen qualitative analysis for DEF's evaluation of generation alternatives to meet its need prior to 2018, filed with the Commission in Docket No. 140111-EI on May 27, 2014;
- Exhibit No. ___ (BMHB-2), a composite exhibit of (i) my rebuttal testimony and exhibits and (ii) the rebuttal testimony and exhibits of DEF's expert Julie Solomon, who performed the FERC Competitive Analysis Screen qualitative analysis for DEF's evaluation of generation alternatives to meet its need prior to 2018, filed with the Commission in Docket No. 140111-EI on August 5, 2014;
- Exhibit No. ___ (BMHB-3), the Company's final detailed economic analysis results that demonstrate the Osprey Plant acquisition is a more cost-effective generation alternative than the Suwannee Simple Cycle Project, if the requisite regulatory approvals for the Osprey Plant acquisition are obtained in accordance with the terms of the Asset Purchase and Sale Agreement ("APA") between DEF and Calpine; and
- Exhibit No. ___ (BMHB-4), the Company's forecast of summer peak demands and reserves with and without the Osprey Plant acquisition and,

alternatively, with and without the Suwannee Simple Cycle Project additional generation capacity prior to 2018.

The portions of the composite exhibits containing my prior direct and rebuttal testimony and exhibits in Docket No. 140111-EI and Exhibits Nos. ___ (BMHB-3) and ___ (BMHB-4) were prepared under my direction and control, and each is true and accurate. The portions of the composite exhibits containing the direct and rebuttal testimony and exhibits of Julie Solomon were prepared at DEF's request and relied upon by DEF as true and accurate in the course of DEF's Integrated Resource Planning ("IRP") process and generation resource planning decisions.

Q. Please summarize your testimony.

A. DEF needs the Osprey Plant acquisition and, alternatively, the Suwannee Simple Cycle Project by the summer of 2017 to meet its 20 percent Reserve Margin commitment and to serve its customers' future electrical power needs in a reliable and cost-effective manner. As I explained in my direct testimony in Docket No. 140111-EI, included as part of Composite Exhibit No. ___ (BMHB-1) to my direct testimony in this docket, DEF's remaining need for additional generation in 2017 is driven by generation plant retirements and additional customer and peak load demand. The Company initially determined in its IRP process that the Suwannee Simple Cycle Project -- together with the Hines Chillers Power Uprate Project -- was superior to any other alternative, including additional renewable energy resources and conservation measures, to meet the Company's generation capacity needs prior to 2018.

As also explained in the direct testimony and exhibits in Docket No. 140111-EI included as Composite Exhibit No. ___ (BMHB-1), the Company evaluated the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project against power purchase agreements and generation facility acquisition proposals from third-party generators, and none of these proposals initially compared more favorably, on a quantitative and qualitative basis, to the Company's Projects. As a result, DEF initially petitioned the Commission for a determination of need for the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost effective generation alternatives to meet DEF's need prior to 2018. The Commission approved DEF's petition with respect to the Hines Chillers Power Uprate Project in Order No. PSC-14-0590-FOF-EI.

As I explained in my rebuttal testimony in Docket No. 140111-EI, included as part of Composite Exhibit No. ___ (BMHB-2) to my direct testimony in this docket, DEF entertained additional generation facility acquisition proposals even after it filed its petition and direct testimony in Docket No. 140111-EI. On the first day of the evidentiary hearing in Docket No. 140111-EI, Calpine ultimately submitted an offer that closed the gap between the cost-effectiveness of the Osprey Plant acquisition and the Suwannee Simple Cycle Project. As a result, DEF and Calpine reached an agreement in principle for the Osprey Plant acquisition on terms more cost effective for DEF's customers than the Suwannee

Simple Cycle Project, pending DEF and Calpine's agreement to an APA and conditioned upon regulatory approval of the acquisition. That same day DEF withdrew its petition with respect to the Suwannee Simple Cycle Project in Docket No. 140111-EI.

DEF and Calpine have now agreed to an APA for the Osprey Plant. DEF and Calpine agreed that DEF's acquisition of the Plant to meet DEF's remaining need for additional generation capacity by the summer of 2017 is conditioned upon the timely receipt of all required regulatory approvals for the acquisition. If the requisite regulatory approvals are timely received, as defined in the APA, by [redacted], DEF will purchase the Osprey Plant as the most cost-effective generation alternative to meet its remaining need prior to 2018. If the requisite regulatory approvals are not timely received, then DEF cannot purchase the Osprey Plant and DEF will move forward with the Suwannee Simple Cycle Project as the most cost effective generation alternative to meet DEF's remaining generation capacity need by the summer of 2017.

For this reason, DEF petitions the Commission to approve the Osprey Plant acquisition and, alternatively, the Suwannee Simple Cycle Project as the most cost effective generation alternative to meet DEF's remaining need for additional generation capacity prior to 2018. The Osprey Plant acquisition is the most cost effective alternative to maintain DEF's electric system reliability and integrity, and provide DEF's customers with adequate electricity at a reasonable cost, by the summer of 2017. If, however, DEF cannot purchase the Osprey Plant because DEF does not receive timely regulatory approvals for that acquisition, the

Suwannee Simple Cycle Project is the most cost effective alternative to maintain DEF's electric system reliability and integrity, and provide DEF's customers with adequate electricity at a reasonable cost, by that summer. DEF must proceed with this petition now because DEF will not have sufficient time to petition the Commission for approval of the Suwannee Simple Cycle Project before DEF must recommence that Project to place it in service to meet DEF's remaining generation need, if DEF does not receive the requisite regulatory approvals for the Osprey Plant acquisition and, therefore, is unable to purchase the Osprey Plant. We, accordingly, have provided the Commission the information needed to approve both the Osprey Plant acquisition and the Suwannee Simple Cycle Project alternative now and request that the Commission approve the Osprey Plant acquisition and, alternatively, the Suwannee Simple Cycle Project as the most cost-effective alternatives to meet the Company's remaining need for additional generation capacity by the summer of 2017.

III. DEF'S REMAINING GENERATION NEED PRIOR TO 2018.

Q. Can you generally explain the Company's remaining need for additional generation capacity prior to 2018?

A. Yes. DEF still has a need for additional generation capacity prior to 2018 consistent with what I described in my direct testimony in Docket No. 140111-EI. See Composite Exhibit No. ___ (BMHB-1). As I explained there, the Company faced resource planning decisions leading up to and early in 2013 that affected the Company's near-term need in the ten-year planning period for generation capacity to meet customer energy and reliability needs. As a result, during the Company's annual IRP analysis, the Company identified near-term substantial generation capacity needs. This analysis was first reflected in the Company's 2013 TYSP and the Company's continuing IRP process and analysis that resulted in its 2014 TYSP confirmed this need. The IRP process that led to the identification of the Company's need prior to 2018 is explained in detail in my direct testimony and exhibits, including the 2014 TYSP, in Composite Exhibit No. ___ (BMHB-1) to my direct testimony.

Basically, the generation plant retirements and load growth that I described in Docket No. 140111-EI contribute to the Company's generation capacity needs prior to 2018 to reliably serve DEF's customers. See Composite Exhibit No. ___ (BMHB-1). In Commission Order No. PSC-14-0590-FOF-EI, the Commission approved the Company's Hines Chillers Power Uprate Project to meet part of that need. The Company's remaining need for additional generation capacity in the summer of 2017 is approximately 180 Megawatts ("MW") and grows to over 300 MW in the summer of 2018.

Q. What is the Company's plan to meet its remaining generation capacity needs prior to 2018?

A. The most cost-effective resource plan to meet the Company's generation capacity need prior to 2018 is the acquisition of the Calpine Osprey Plant in accordance with the terms of the APA between DEF and Calpine. The Osprey Plant (or Osprey Energy Center) is an existing 599 MW (nominal) natural gas-fired, combined cycle generation plant located in Polk County, Florida. DEF will close on the Osprey Plant acquisition in January 2017 if the requisite regulatory approvals in accordance with the terms of the APA are received. DEF cannot purchase the Osprey Plant to fulfill its remaining generation capacity needs prior to 2018 if these regulatory approvals are not obtained. If DEF cannot purchase the Osprey Plant, there will be no closing, and DEF must recommence the Suwannee Simple Cycle Project to meet DEF's remaining need for additional generation capacity by the summer of 2017. The Suwannee Simple Cycle Project involves the construction of a new 320 MW simple cycle combustion turbine plant consisting of two F class combustion turbine units at the Company's existing Suwannee River power plant site. These units would come into service prior to the summer of 2017 if DEF recommences the Suwannee Simple Cycle Project by [redacted] This is the most cost-effective generation resource plan that is available to the Company to meet the Company's remaining generation capacity needs for its customers prior to 2018.

Q. Does this plan satisfy the Company's remaining need for generation capacity prior to 2018?

A. Yes. DEF still needs additional generation capacity by the summer of 2017 to fulfill its Reserve Margin obligations and reliably serve customers even with the Commission's approval of the Hines Chillers Power Uprate Project in Order No. PSC-14-0590-FOF-EI to meet part of DEF's need for generation capacity prior to 2018. The Company's current plan to meet its remaining generation capacity need by the summer of 2017 with either the Osprey Plant, if the requisite regulatory approvals for that acquisition are timely obtained, or the Suwannee Simple Cycle Project, if those approvals are not obtained, does not materially change DEF's remaining need for additional generation capacity prior to 2018. In other words, DEF needs additional generation capacity by the summer of 2017 regardless whether the source of that generation capacity is the Osprey Plant or the Suwannee Simple Cycle Project.

Q. In Docket No. 140111-EI, the Suwannee Simple Cycle Project was proposed to meet a 2016 need. What has changed?

A. When DEF prepared its analysis presented in Docket No. 140111-EI, DEF recognized that there was additional engineering required to confirm the schedule for the installation of the Hines Chillers Power Uprate Project. By comparison, the Suwannee Simple Cycle Project is a well-defined project of a type which DEF has substantial experience. Thus, DEF decided to schedule the Suwannee Simple Cycle Project for the earlier in-service date and allow additional time for the Hines Chillers Power Uprate Project to be completed. In the interim, engineering of the Hines Chillers Power Uprate Project has proceeded to a level that DEF is confident of its completion and availability for service before the summer of 2016. This and DEF's agreement to a PPA with Calpine for firm capacity and energy from the Osprey Plant commencing in October 2014 gave DEF the flexibility to delay the in-service date of the Suwannee Simple Cycle Project to the spring of 2017, allowing DEF and Calpine the opportunity to seek regulatory approvals necessary to complete the Osprey Plant acquisition while preserving the opportunity to meet the capacity need through completion of the Suwannee Simple Cycle Project in the event DEF and Calpine are unable to receive the necessary regulatory approvals for the acquisition.

Q. Is the Company's current decision with respect to its generation needs prior to 2018 consistent with the 2013 Settlement Agreement?

A. Yes. The Osprey Plant acquisition and, alternatively, the Suwannee Simple Cycle Project are the types of generation options specifically contemplated in the 2013 Settlement Agreement to meet the Company's generation capacity needs prior to 2018. The parties to the 2013 Settlement Agreement agreed that DEF could seek Commission approval for the costs of this additional generation in the 2013 Settlement Agreement. The Osprey Plant acquisition, and the Suwannee Simple Cycle Project in the event the Osprey Plant is not acquired, is the most cost-effective generation option to meet that remaining need prior to 2018.

As I explained in my direct testimony in Docket No. 140111-EI, DEF met with the parties to the 2013 Settlement Agreement to explain DEF's approach to its generation needs prior to 2018 and, ultimately, DEF's analyses and decision to meet that need consistent with the terms of the 2013 Settlement Agreement. See Composite Exhibit No. ___ (BMHB-1). DEF continued to explain its approach to meet its generation needs prior to 2018 when DEF presented its direct and rebuttal testimony and exhibits in Docket No. 140111-EI, which the parties to the 2013 Settlement Agreement received. See Composite Exhibits Nos. ___ (BMHB-1) and ____ (BMHB-2). No party to the 2013 Settlement Agreement expressed to DEF that DEF has not complied with the 2013 Settlement Agreement.

Q. Did the Company petition the Commission for approval of the Osprey Plant acquisition in Docket No. 140111-EI to meet its need prior to 2018?

A. No. DEF petitioned the Commission for approval of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project to meet its need for additional generation capacity prior to 2018 in Docket No. 140111-EI. DEF explained in detail its IRP process and the results of the Company's evaluation of the generation resource alternatives that led DEF to initially select the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost effective generation alternatives to meet its need prior to 2018 in the direct testimony and exhibits in Docket No. 140111-EI. See Composite Exhibit No. ___ (BMHB-1).

DEF, nevertheless, continued to discuss its need prior to 2018 with Calpine and NRG Florida LP ("NRG"), who had both made power purchase agreement ("PPA") and generation facility acquisition proposals to meet that Company need, even after DEF filed its petition and direct testimony and exhibits in Docket No. 140111-EI. DEF explained to Calpine and NRG the impediments to selecting their proposals to meet DEF's need and encouraged them to make final and best offers because DEF was genuinely interested in their proposals to meet DEF's need if they offered superior customer value compared to DEF's Suwannee Simple Cycle Project.

After DEF filed its petition in Docket No. 140111-EI, DEF received several offers from them that DEF evaluated and ultimately rejected because they did not provide customers a more cost effective generation alternative, on a quantitative and qualitative basis, than the Suwannee Simple Cycle Project to meet DEF's need prior to 2018. DEF's quantitative and qualitative evaluations of the cost effectiveness of these offers are discussed in detail and explained in the rebuttal testimony and exhibits in Docket No. 140111-EI. See Composite Exhibit No. ___ (BMHB-2). As a result, DEF proceeded to hearing on the cost effectiveness of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project to meet its need for additional generation capacity prior to 2018.

Q. Can you explain what occurred at the hearing in Docket No. 140111-EI?

A. Yes. On the first day of the evidentiary hearing, Calpine made an additional offer that "closed the gap" between the cost effectiveness of the Osprey Plant acquisition proposal and the Suwannee Simple Cycle Project. Calpine presented DEF with a term sheet that addressed the quantitative and qualitative factors that had resulted in DEF's rejection of Calpine's prior offers for the reasons described in the rebuttal testimony and exhibits included in Composite Exhibit No. ___ (BMHB-2). In brief, Calpine's term sheet addressed the acquisition price and other key terms affecting the economic value to DEF to acquire the Osprey Plant and the regulatory approvals that potentially precluded DEF from purchasing the Plant. The term sheet is included as an exhibit to the direct testimony of Mr. Palasek in this proceeding.

DEF agreed to the term sheet and moved to withdraw the Suwannee Simple Cycle Project from Docket No. 140111-EI. DEF explained to the Commission that DEF and Calpine had reached an agreement in principle for DEF to purchase the Calpine Plant subject to DEF's due diligence review of the Osprey Plant and DEF and Calpine agreeing to the terms and conditions of an APA for that Plant acquisition. DEF further explained that DEF would present the most cost effective alternative to meet DEF's remaining need for generation capacity prior to 2018 in a later Commission proceeding. The Commission granted DEF's motion. DEF has now completed its due diligence reviews, executed an APA with Calpine to acquire the Osprey Plant, and is petitioning the Commission to determine that the Osprey Plant and, alternatively, the Suwannee Simple Cycle Project, is the most cost effective generation alternative to meet DEF's remaining need prior to 2018, depending on timely requisite regulatory approval for the Osprey Plant acquisition.

Q. Did the Company receive any additional offers from NRG after DEF announced that it had reached an agreement in principle for the Osprey Plant acquisition with Calpine?

A. No. The last offer NRG made to DEF for the acquisition of the NRG plant was prior to the hearing in Docket No. 140111-EI and it was rejected because it was not quantitatively and qualitatively the most cost effective generation alternative to meet DEF's need prior to 2018. The reasons DEF rejected NRG's last offer are explained in detail in the rebuttal testimony in Docket No. 140111-EI attached as

Composite Exhibit No. ___ (BMHB-2).

Q. Have DEF and Calpine executed a final agreement for DEF's acquisition of the Osprey Plant?

A. Yes. DEF completed its due diligence reviews and found no material impediments to DEF's acquisition of the Osprey Plant. DEF therefore executed an APA with Calpine for the Osprey Plant on December 17, 2014. The APA incorporates and expands upon the term sheet provisions between DEF and Calpine and it includes terms and conditions that address the requisite regulatory approvals and DEF's due diligence reviews. The results of DEF's due diligence reviews of the Osprey Plant acquisition are addressed in more detail in the direct testimony of Mr. Edmondson. The APA terms and conditions are explained in more detail in the direct testimony of Mr. Palasek and the APA is included as an exhibit to Mr. Palasek's testimony in this proceeding.

Q. Can you please generally describe the terms of the APA between DEF and Calpine for DEF's acquisition of the Osprey Plant?

A. Yes. DEF agrees to purchase the Osprey Plant from Calpine for $166 million, subject to certain specified adjustments, and close on this transaction if the requisite regulatory approvals for the acquisition are timely obtained and the Plant passes DEF's final due diligence assessment prior to closing, currently planned in the APA for January 2017. The requisite regulatory approvals include FERC and DOJ approvals of DEF's acquisition of the Osprey Plant and Commission approval of this Petition. DEF agreed to request all requisite regulatory approvals for its purchase of the Osprey Plant pursuant to the terms of the APA. DEF and Calpine also agreed to a PPA from October 2014 to January 2017 for the purchase of firm capacity and energy that the Osprey Plant can provide DEF. Calpine agreed in the APA to continue to operate and maintain the Plant consistent with good utility practice and in accordance with applicable laws, regulations, orders, and permits for the Plant during this PPA period.

If the requisite regulatory approval is not timely obtained DEF cannot purchase the Osprey Plant, there is no closing, and [redacted]. In that event, [redacted], DEF will close on the Osprey Plant, acquire the Plant, and Calpine will assign its firm gas transportation contracts and firm partial path transmission rights to DEF. These are the principle terms of the APA between DEF and Calpine. The terms and conditions of the APA are further explained in the direct testimony of Mr. Palasek and the APA is included as an exhibit to Mr. Palasek's testimony.

IV. DEF'S PLAN TO MEET ITS REMAINING GENERATION CAPACITY NEED: THE OSPREY PLANT ACQUISITION AND, ALTERNATIVELY, THE SUWANNEE SIMPLE CYCLE PROJECT.

Q. Please describe the Osprey Plant.

A. The Osprey Plant is an existing natural gas-fired, combined cycle generation plant with a nominal baseload capacity of approximately 534 MW and duct firing capability to produce up to 599 MW for approximately 60 MW of cost-effective peaking capacity. The Osprey Plant was placed in commercial service in 2004.

The Osprey Plant contains two Siemens Westinghouse combustion turbines and one steam turbine with two heat recovery steam generators in a 2 by 1 combined cycle plant configuration. The Osprey Plant generates electricity in two stages, first by firing the combustion turbines, and second by using the hot gas from the combustion turbines to produce steam through the heat recovery steam generators, which is fed into the steam turbine to generate additional electricity. The combined cycle plant configuration makes the most of the input fuel, by burning it and using the waste heat from that process to generate electricity and, therefore, the combined cycle technology is an efficient plant design to produce electrical energy.

The Osprey Plant technology and equipment vintage also is similar to the technology and equipment at other DEF generation units. The Plant location is geographically close to some of these DEF generation units at DEF's Intercession City and Hines Energy Center power plant sites. As a result, the Osprey Plant provides DEF the opportunity to leverage the existing Plant equipment and infrastructure to provide DEF customers a cost effective generation resource.

Natural gas is the single fuel source for the Osprey Plant. The natural gas is supplied by Gulfstream Natural Gas System, L.L.C. ("Gulfstream") under an existing long-term firm natural gas transportation contract. There is no dual fuel capability for the Osprey Plant. The majority of DEF's existing combined cycle and combustion turbine power plants, however, have dual fuel capability and this existing dual fuel capability on DEF's system provides adequate fuel resource reliability for DEF's customers even without dual fuel capability at the Osprey Plant.

The Osprey Plant is located in the Tampa Electric Company ("TEC") Balancing Area Authority ("BAA") and it is currently interconnected with TEC. There currently is partial path firm point-to-point transmission service for 249 MW of the Osprey Plant generation capacity across the TEC BAA to DEF's system. If DEF's acquisition of the Osprey Plant is approved in accordance with the terms of the APA, DEF currently plans to build transmission network upgrades to directly connect the Osprey Plant to DEF's system to obtain the full output from the Osprey Plant. These transmission interconnection costs have been and continue to be included in DEF's evaluation of the cost effectiveness of the Osprey Plant acquisition. The planned transmission network upgrades and costs to directly connect the Osprey Plant to DEF's system are explained in more detail in the direct testimony of Mr. Scott.

Q. You explained that the Osprey Plant was placed in commercial service in 2004. Did DEF account for the age of the Osprey Plant in its evaluation of the cost effectiveness of acquiring the Plant?

A. Yes. DEF understands that the Osprey Plant is now ten years old and that it will be another two years older before it is purchased by DEF. Because DEF is buying a "used" Plant, DEF has consistently included expected capital maintenance and operation and maintenance ("O&M") costs based on the age and condition of the Plant in its evaluation of the Plant acquisition price and the cost effectiveness of the Plant. DEF also conducted a detailed due diligence review of the Plant condition and performance before DEF executed the APA. Based on this detailed due diligence review, DEF developed a better understanding of the Plant condition and the necessary capital and O&M maintenance costs upon acquiring the Plant to incorporate it into DEF's system consistent with DEF's combined cycle fleet program maintenance practices and procedures. These capital and O&M costs were included in the evaluation of the cost effectiveness of the Osprey Plant acquisition to meet DEF's remaining need for additional generation capacity prior to DEF's decision to acquire the Plant.

Q. Please describe the Suwannee Simple Cycle Project.

A. The Suwannee Simple Cycle Project consists of two F class combustion turbine generators, two generator step-up transformers, fuel oil and demineralized water storage tanks, and related balance of plant facilities that will be installed at the Company's existing Suwannee River power plant site in Suwannee County, Florida.

The Suwannee power plant site has existing infrastructure to support the Suwannee Simple Cycle Project. The Suwannee plant site has existing gas- and oil-fired combustion turbines, steam units, and a transmission switchyard, among other facilities. The new F class combustion turbine generators will be connected via a gas lateral to the Florida Gas Transmission gas pipeline and to the existing site metering and regulating station. One combustion turbine will be connected to the existing 115 kv transmission switchyard and the other combustion turbine will be connected to the existing 230 kv transmission switchyard. This existing infrastructure at the Suwannee site reduces the cost of the Suwannee Simple Cycle Project.

The estimated cost of the Suwannee Simple Cycle Project, including the Allowance for Funds Used during Construction ("AFUDC"), is $195.1 million. The Suwannee Simple Cycle Project is explained in more detail in the direct testimony of Mr. Landseidel in this proceeding.

Q. What are the benefits of the Suwannee Simple Cycle Project that make this Project the most cost-effective DEF self-build generation option to meet DEF's remaining need for additional generation capacity prior to 2018, if DEF cannot purchase the Osprey Plant?

A. There are customer benefits associated with the location of the Suwannee Simple Cycle Project at an existing Company power plant site. First, there are limited transmission system network upgrades and costs for the Suwannee Simple Cycle Project associated with the transmission interconnection of the combustion turbines at the existing Suwannee site. These transmission costs and benefits are explained in the direct testimony of Mr. Scott in this proceeding. Second, the location of the Suwannee Simple Cycle Project at an existing brownfield, power plant site means there are limited to no additional environmental impacts associated with this additional generation capacity. This Project provides DEF the ability to substantially increase its summer generation capacity to meet customer energy demand while maintaining its compliance with current and future environmental regulations.

These benefits make the Suwannee Simple Cycle Project more economically beneficial to customers than similar generation capacity installed at a greenfield site. For these reasons, DEF's IRP process demonstrated that the economics favored the Suwannee Simple Cycle Project over other available options to meet its need prior to 2018. The results of this process and the Company's evaluation that led the Company to conclude that, based on price and non-price attributes, the Suwannee Simple Cycle Project was the most cost-effective self-generation alternative to meet DEF's need prior to 2018 are explained in detail in the direct testimony included as Composite Exhibit No. ___ (BMHB-1).

Q. Why did DEF select the Osprey Plant over the Suwannee Simple Cycle Project to meet DEF's remaining need for generation capacity prior to 2018?

A. DEF and Calpine reached an agreement in principle in the term sheet and later agreed to an APA for DEF to acquire the Osprey Plant on a cost-effective basis for DEF's customers, subject to timely requisite regulatory approvals for the Plant acquisition and Calpine continuing to prudently operate and maintain the Plant prior to DEF purchasing it. DEF updated its Cumulative Present Value Revenue Requirements ("CPVRR") analysis based on the APA and DEF's due diligence reviews and determined that the Osprey Plant acquisition was more cost effective than the Suwannee Simple Cycle Project. The updated CPVRR analysis includes the updated purchase price in the APA, the capital and O&M costs required to acquire the Osprey Plant and incorporate that Plant into and operate it on DEF's system, and other necessary adjustments to reflect changes in DEF's system. The results of this CPVRR analysis demonstrate that the Osprey Plant acquisition is more cost effective than the Suwannee Simple Cycle Project for DEF's customers. The Osprey Plant acquisition has a favorable CPVRR differential of about $61 million in this evaluation compared to the Suwannee Simple Cycle Project. A summary of that CPVRR analysis is included as Exhibit No. ___ (BMHB-3) to my direct testimony.

Q. Were the same evaluation methods used to determine the most cost effective generation alternative in Docket No. 140111-EI used in the evaluation of the Osprey Plant acquisition APA?

A. Yes. DEF evaluated the acquisition of the Osprey Plant under the APA using the same evaluation methods that DEF used to determine the most cost effective generation alternative in Docket No. 140111-EI. See Composite Exhibit No. ___ (BMHB-1). DEF conducted an economic evaluation based on the fixed and variable Plant acquisition costs and economic resource optimization analyses were performed. DEF also evaluated the technical feasibility and viability of the Osprey Plant acquisition through an analysis of such factors as the operating, maintenance, and physical conditions of the Plant, insurance, project risk, environmental impacts and compliance, and regulatory feasibility, among other factors, through its due diligence reviews of the Plant condition and performance. These due diligence reviews are explained in more detail in the direct testimony of Mr. Edmondson.

The Company conducted a detailed economic evaluation of the Osprey Plant acquisition compared to DEF's Suwannee Simple Cycle Project. This detailed economic evaluation included all costs, including gas transportation and transmission cost impacts, in an optimization analysis of the optimal resource plan for the Osprey Plant acquisition and the Suwannee Simple Cycle Project for a period of thirty years to capture all costs associated with each proposal and the type of units that make up the optimal resource plan including each proposal.

Other inputs in the optimization model include the load and energy forecast and the costs and characteristics (such as heat rates, outage rates, and maintenance requirements) of the Company's existing generating units and power purchase agreements. Costs and operating characteristics of potential future supply-side resources, which could be generating units or purchases, are included in the resource optimization model. The resource optimization model runs develop alternative resource plans to meet the projected future customer requirements using all possible combinations of resources, and it calculates the CPVRR for each combination. The model then sorts each alternative from lowest to highest cost. From an economics-only perspective, the lowest cost plan is the optimal plan. The optimization analysis was performed using the same process combining the outputs of the Strategist optimization and Energy Portfolio

Manager ("EPM") production cost models used to evaluate the generation options in Docket No. 140111-EI. See Composite Exhibit No. ___ (BMHB-1).

The resource optimization analysis assessed the impact of the Osprey Plant acquisition on total system costs and compared those costs to the costs of the Company's base case self-build generation plan including the Suwannee Simple Cycle Project. The optimization analysis shows the net impact of the Osprey Plant acquisition and the impact the Osprey Plant acquisition has on system capital revenue requirements and fixed and operating costs. The analysis explicitly examines the relative impacts on system costs for fuel and variable O&M of the other units on DEF's system and any impact on DEF's purchased power costs. The objective function of the resource optimization model is to minimize the CPVRR for the DEF generation system, subject to the 20 percent Reserve Margin constraint. As shown in Exhibit No. ___ (BMHB-3), the Osprey Plant acquisition has a favorable CPVRR of about $61 million.

Q. Did the Company perform any sensitivity analyses in its evaluation of the cost-effectiveness of the Osprey Plant acquisition?

A. Yes. DEF performed high gas price and no carbon ("CO_2") price sensitivity analyses to establish the robustness of DEF's conclusion and to indicate how the results will vary based on variation in fuel and emission pricing, typically two of the most sensitive inputs to the production cost model. DEF determined that the Osprey Plant acquisition was even more cost effective in the high gas price sensitivity. Although the Osprey Plant acquisition is less cost effective in the no

CO_2 price sensitivity than the base generation plan including the Suwannee Simple Cycle Project, DEF continues to believe that some form of greenhouse gas regulation imposing an effective price on CO_2 emissions is the more likely long term scenario. Overall, based on the detailed economic evaluation results, the cost sensitivity and due diligence quantitative and qualitative factors, the most cost effective generation alternative for DEF's customers is the Osprey Plant acquisition, if the requisite regulatory approvals for the acquisition are timely obtained. See Exhibit No. ___ (BMHB-3).

Q. What impact will the addition of the Osprey Plant have upon DEF's Reserve Margin and its ability to provide reliable service to its customers?

A. As shown in Exhibit No. ___ (BMHB-4), the addition of the Osprey Plant to DEF's system will increase DEF's summer peak Reserve Margin to 20.6 percent in the summer of 2017. This is because DEF only has firm transmission rights to 249 MW of the Osprey Plant generation capacity until the transmission network upgrades necessary to directly connect the Osprey Plant to DEF's system are completed. DEF estimates that the transmission network upgrades will not be complete until 2020. The exhibit shows that DEF will have a total generating capability of approximately 11,222 MW by the summer of 2017 if DEF closes on the Osprey Plant acquisition following the regulatory approvals for the acquisition in accordance with the terms of the APA. The total generation capability includes the installation of the Hines Chillers Power Uprate Project previously approved by the Commission. DEF's Reserve Margin will decrease to 18 percent in the summer of 2017 if the Osprey Plant acquisition is not added to DEF's system. The Osprey Plant acquisition allows DEF to satisfy its commitment to maintain a minimum 20 percent Reserve Margin in 2017 to provide DEF's customers with reliable electric service.

Q. What is the impact of the Suwannee Simple Cycle Project on the Company's Reserve Margin?

A. If DEF does not close the Osprey Plant acquisition in accordance with the terms of the APA, the addition of the Suwannee Simple Cycle Project to DEF's system will increase DEF's summer peak Reserve Margin to 20.7 percent in the summer of 2017. See Exhibit No. ___ (BMHB-4). The exhibit shows that DEF will have a total generating capability of approximately 11,230 MW by the summer of 2017 if the Suwannee Simple Cycle Project is installed because DEF could not purchase the Osprey Plant. The total generation capability includes the installation of the Hines Chillers Power Uprate Project previously approved by the Commission. DEF's Reserve Margin will decrease to 18 percent in the summer of 2017 if the Suwannee Simple Cycle Project is not added to DEF's system. DEF needs this alternative, additional generation capacity in the summer of 2017 to satisfy its minimum 20 percent Reserve Margin obligation to provide reliable electric service to its customers.

V. THE MOST COST-EFFECTIVE GENERATION ALTERNATIVE.

Q. What is the most cost-effective alternative for meeting the Company's remaining reliability needs prior to 2018?

A. The most cost effective generation alternative to meet DEF's remaining reliability need prior to 2018 is the acquisition of the Osprey Plant if that acquisition is approved after the required regulatory reviews. The Osprey Plant will provide DEF's customers with beneficial combined-cycle generation fuel efficiency and emissions costs at a favorable acquisition price even with the necessary capital maintenance, O&M, and transmission interconnection investment in the Plant to incorporate it into DEF's system. On a CPVRR basis, the Osprey Plant acquisition is about $61 million more cost effective for DEF's customers than the Suwannee Simple Cycle Project. See Exhibit No. ___ (BMHB-3).

If FERC approves the Osprey Plant acquisition [redacted] and DEF timely receives the other requisite regulatory approvals, DEF will purchase the Osprey Plant and close on that transaction in January 2017. The parties negotiated [redacted] If FERC [redacted] or the other regulatory approvals are not obtained, however, DEF cannot purchase the Osprey Plant and, under these circumstances, the Suwannee

Simple Cycle Project is the most cost-effective generation alternative to meet DEF's remaining need for additional generation capacity prior to 2018. See Composite Exhibit No. ___ (BMHB-1).

Q. Did DEF evaluate the Osprey Plant acquisition based on the same fundamental modeling data that DEF used to evaluate the most cost effective generation alternative in Docket No. 140111-EI?

A. Yes. As I explained above, the term sheet was executed on August 25, 2014 at the start of the hearing in Docket No. 140111-EI. DEF had shared with Calpine the results of DEF's CPVRR evaluation of Calpine's offers to sell DEF the Osprey Plant using the same fundamental modeling data DEF used to evaluate the cost effectiveness of all generation capacity alternatives, including the Suwannee Simple Cycle Project, to meet its need for additional generation capacity prior to 2018. See Composite Exhibit Nos. ___ (BMHB-1) and ___ (BMHB-2). As a result, Calpine understood the economic gap between its offers and the Suwannee Simple Cycle Project and the qualitative factors that had to be addressed to make the Osprey Plant acquisition more cost effective on a quantitative and qualitative basis than the Suwannee Simple Cycle Project. Because the August 25, 2014 term sheet addressed the economic gap and redressed the qualitative factors that DEF had identified, DEF readily determined from the face of the term sheet that the Osprey Plant acquisition appeared to be a more cost effective alternative than the Suwannee Simple Cycle Project, on a quantitative and qualitative basis, to meet DEF's remaining need for reliable generation capacity prior to 2018, subject to DEF's due diligence and agreement to an asset purchase agreement for the Plant.

Q. Were there any updates to the CPVRR evaluation of the Osprey Plant acquisition after DEF and Calpine agreed to the term sheet?

A. Yes. DEF refined the CPVRR evaluation after the term sheet was executed to include changes in the revenue requirements for the Osprey Plant acquisition based on the capital and O&M maintenance costs derived from the Company's due diligence reviews of the Osprey Plant condition and performance that were conducted between execution of the term sheet and execution of the APA. These changes and other intervening resource plan modeling adjustments are reflected in the CPVRR evaluation included in Exhibit No. ____ (BMHB-3) that was used to determine that the Osprey Plant acquisition was the most cost effective generation alternative to meet DEF's need for additional generation capacity prior to 2018 before DEF and Calpine agreed to and executed the APA for the Osprey Plant acquisition.

Q. Were there any changes to the fundamental modeling data used in the CPVRR evaluation of the Osprey Plant acquisition based on DEF's ongoing IRP process before DEF executed the APA to acquire the Osprey Plant?

A. No. As I explained above, DEF continued to evaluate the cost effectiveness of the Osprey Plant acquisition based on the same fundamental modeling data that was used to determine the cost effectiveness of the generation alternatives in Docket

No. 140111-EI and the term sheet for the Osprey Plant acquisition between DEF and Calpine. DEF's IRP update process continued in 2014, ultimately for preparation of the Company's 2015 TYSP, but that process was not complete by the time the APA was approved by the Board of Directors on December 8, 2014. Final information for updates to the Company's key corporate forecasts in its IRP process – DEF's load, economic, and financial forecasts – used to prepare the 2015 TYSP was not available by December 8, 2014. The decision to enter into the APA for the Osprey Plant acquisition was based on 2014 TYSP IRP process information because that was the best resource planning information available to the Company at the time that decision was made. See Exhibit No. ___ (BMHB-3).

Q. Did DEF consider its Demand Side Management Program in its evaluation of the most cost effective generation to meet DEF's remaining need prior to 2018?

A. Yes, energy conservation and direct load control programs are always a part of the Company's IRP process and they were considered in connection with our continuing evaluation of the Company's remaining near-term generation capacity need. The Company's current demand-side management ("DSM") programs were included in the Company's CPVRR evaluation included in Exhibit No. ___ (BMHB-3). A detailed description of the Company's DSM programs is contained in the Company's 2014 TYSP attached to my direct testimony included as part of Composite Exhibit No. ___ (BMHB-1) to my direct testimony. These DSM programs cannot replace or defer the Company's remaining need for additional generation capacity on its system prior to 2018.

Although the final order was received too late to include it in the updated CPVRR, DEF did consider the Commission's decision in Docket No. 130200-EI. In the Company's DSM goals docket the Commission voted on November 25, 2014 to approve DEF's future DSM goals for the period 2015 to 2024. Over the next ten years DEF's DSM goals are generally lower than the existing DSM goals. All other things being equal, then, the Company's near-term DSM goals will cause an increase in DEF's firm summer peak demand prior to 2018. Based on these DSM goals, there are no additional DSM measures or programs that can replace or defer the Company's remaining need for additional generation capacity prior to 2018 to reliably serve DEF's customers. The Company's remaining need for additional generation capacity by the summer of 2017 is not affected by the outcome of Docket No. 130200-EI.

Q. Are there any recent renewable energy sources and technologies that can meet DEF's remaining need for additional generation capacity prior to 2018?

A. No. The Company does evaluate the timeline for new technologies, including renewable energy sources and technologies, on a continuing basis as part of its IRP process and as part of its evaluation of responses to its Request for Renewables ("RFR") that continuously solicits proposals for renewable energy projects. However, no commercially available, economically feasible renewable generation resource or resource proposal currently exists to displace or defer DEF's remaining generation capacity needs prior to 2018.

VI. CONSEQUENCES OF DELAY.

Q. What is the impact of delaying Commission approval of DEF's Petition?

A. DEF needs Commission approval for the Osprey Plant acquisition, and, alternatively, the Suwannee Simple Cycle Project at this time to ensure that DEF meets its remaining reliability needs prior to 2018 in the most cost effective manner for DEF's customers. DEF cannot delay its petition to this Commission because there is insufficient time before DEF must recommence the Suwannee Simple Cycle Project to preserve the benefits of that cost effective Project for customers to meet DEF's remaining need for generation capacity by the summer of 2017, if DEF does not obtain the requisite regulatory approvals to purchase the Osprey Plant.

DEF must recommence the Suwannee Simple Cycle Project by [redacted] for that Project to be in commercial service by the summer of 2017. As I explained above, if DEF cannot buy the Osprey Plant the Suwannee Simple Cycle Project is the most cost effective generation alternative to meet DEF's remaining need for additional generation capacity by the summer of 2017. To preserve this generation alternative for customers DEF must request all requisite regulatory approvals for the Osprey Plant acquisition and have an adequate determination of those regulatory approvals by [redacted]

DEF and Calpine agreed that this is the fundamental principle of the regulatory approval conditions precedent to DEF's obligation to purchase the Osprey Plant in the APA. To this end, Calpine and DEF agreed to cooperate with all requests for regulatory approval, including this Petition, to obtain a decision from the requisite regulatory bodies on approval of the Osprey Plant acquisition by [redacted]. Ensuring that DEF can provide customers the benefits of one of these two most cost effective generation alternatives to meet its need prior to 2018, whichever alternative the circumstances warrant, is central to the deal between DEF and Calpine in the APA.

DEF and Calpine agreed in the APA to preserve the benefits of the most cost-effective generation alternative for customers to meet DEF's remaining need prior to 2018, regardless of the outcome of the requisite regulatory approvals for the Osprey Plant acquisition. DEF and Calpine structured the deal in the APA for both generation capacity projects, with DEF proceeding to close on the Osprey Plant acquisition in the event of timely regulatory approval, and with DEF proceeding with the Suwannee Simple Cycle Project in the event regulatory approval for the acquisition is not timely obtained. In this way, DEF mitigates the risk to customers of regulatory approvals beyond DEF's and Calpine's control. For this reason, the Osprey Plant acquisition and the Suwannee Simple Cycle Project are inextricably intertwined in the APA and they cannot logically or practicably be evaluated separately by the Commission. As a result, DEF cannot present, and the Commission cannot consider one project without the other in determining the most cost-effective generation alternative to meet DEF's remaining need prior to 2018.

DEF has provided the Commission the information necessary to approve its Petition to alternatively purchase the Osprey Plant or build the Suwannee Simple Cycle Project to ensure that DEF's customers receive the benefits of the most cost effective generation alternative to meet their reliability needs by the summer of 2017 regardless of the outcome of the requisite regulatory reviews. This decision will allow DEF to add additional generation capacity to meet its reliability commitment to customers without any risk of interruption of service in the event of unanticipated forced outages or other contingencies for which DEF maintains reserves.

VII. CONCLUSION.

Q. Please summarize DEF's request for relief from the Commission in this Petition.

A. DEF needs the Osprey Plant and, alternatively, the Suwannee Simple Cycle Projects to maintain its electric system reliability and integrity and to provide its customers with adequate electricity at a reasonable cost. DEF will not both buy the Osprey Plant and build the Suwannee Simple Cycle Project. DEF will build the Suwannee Simple Cycle Project only if DEF cannot buy the Osprey Plant. DEF will realistically know if it can obtain the requisite regulatory approvals to purchase the Osprey Plant by [redacted], the deadline for DEF to recommence the Suwannee Simple Cycle Project to place that Project in commercial service by the summer of 2017. DEF, therefore, will either purchase the Osprey Plant or build the Suwannee Simple Cycle Project to meet its commitment to maintain a 20 percent Reserve Margin by the summer of 2017.

The Osprey Plant acquisition or, alternatively, the Suwannee Simple Cycle Project will satisfy DEF's generation reliability commitment by improving not just the quantity, but also preserving the quality of DEF's total reserves, maintaining an appropriate portion of physical generating assets in the Company's overall resource mix. The Company has exhausted conservation measures cost effectively available to the Company and there are no reasonably available renewable energy resources or technologies to meet the Company's remaining near-term reliability needs in the summer of 2017. The Osprey Plant acquisition and, alternatively, the Suwannee Simple Cycle Project is the most cost-effective resource to meet customer reliability needs in this time period. We, accordingly, request that the Commission approve the Osprey Plant acquisition and, alternatively, the Suwannee Simple Cycle Project as the most cost-effective alternatives to meet the Company's remaining need for additional generation capacity prior to 2018.

Q. **Does this conclude your testimony?**

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.

DOCKET NO. ____________
Submitted for filing:
May 27, 2014

**DIRECT TESTIMONY
OF BENJAMIN M. H. BORSCH**

**ON BEHALF OF
DUKE ENERGY FLORIDA, INC.**

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IN RE: PETITION FOR DETERMINATION OF COST EFFECTIVE GENERATION ALTERNATIVE TO MEET NEED PRIOR TO 2018 FOR DUKE ENERGY FLORIDA, INC.

BY DUKE ENERGY FLORIDA, INC.

FPSC DOCKET NO. ________

DIRECT TESTIMONY OF BENJAMIN M. H. BORSCH

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name, employer, and business address.

A. My name is Benjamin M. H. Borsch and I am employed by Duke Energy Corporation. My business address is 299 1st Avenue North, St. Petersburg, Florida.

Q. Please tell us your position with Duke Energy and describe your duties and responsibilities in that position.

A. I am the Director, IRP & Analytics – Florida. In this role, I am responsible for resource planning for Duke Energy Florida, Inc. ("DEF" or the "Company"). I am responsible for directing the resource planning process in an integrated approach to finding the most cost-effective alternatives to meet the Company's obligation to serve its customers in Florida. As a result, we examine both supply-side and demand-side resources available and potentially available to the

Company over its planning horizon, relative to the Company's load forecasts, and prepare and present the annual Duke Energy Florida Ten-Year Site Plan ("TYSP") documents that are filed with the Florida Public Service Commission ("FPSC" or the "Commission"), in accordance with the applicable statutory and regulatory requirements. In my capacity as the Director, IRP & Analytics – Florida, I oversaw the completion of the Company's most recent TYSP document filed in April 2014 and the Company's 2013 TYSP. I was also responsible for the Company's evaluation of options to meet its needs for reliable electric power prior to 2018.

Q. Please summarize your educational background and employment experience.

A. I received a Bachelor's of Science and Engineering degree in Chemical Engineering from Princeton University in 1984. I joined Progress Energy in 2008 supporting the project management and construction department in the development of power plant projects. In 2009 I became Manager of Generation Resource Planning for Progress Energy Florida, and following the 2012 merger with Duke Energy accepted my current position. Prior to joining Progress Energy, I was employed for more than 5 years by Calpine Corporation where I was Manager (later Director) of Environmental Health and Safety for Calpine's Southeastern Region. In this capacity, I supported development and operations and oversaw permitting and compliance for several gas fired power plant projects in nine states. I was also employed for more than 8 years as an environmental consultant with projects including development, permitting and compliance of power plants and transmission facilities. I am a professional engineer licensed in Florida and North Carolina.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your testimony in this proceeding?

A. I am testifying on behalf of the Company in support of its Petition for Determination of Cost Effective Alternative to Meet Need prior to 2018 for Duke Energy Florida. I will provide an overview of the generation alternatives that the Company proposes to build to meet its need prior to 2018 in the most cost-effective manner for its customers. I will discuss the resource planning process and how that led the Company to identify this need prior to 2018 and I will explain the steps the Company took to identify available, potentially superior supply-side alternatives. Next, I will explain the Company's evaluation of these generation alternatives and set forth the reasons why the Company's self-build generation options are the most cost-effective resource options to meet the Company's need prior to 2018. I will conclude my testimony by explaining the Company's decision to proceed with its self-build generation options to meet its need prior to 2018 in the most cost-effective manner for the Company's customers.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (BMHB-1), a copy of the Florida Reliability Coordinating Council ("FRCC") Evaluation of Transmission Impact of the United States Environmental Protection Agency ("EPA") Mercury and Air Toxics Standard ("MATS") --- Transmission Impact Study for Shutdown of Crystal River Unit 1 ("CR1") and Crystal River Unit 2 ("CR2") with retirement of Crystal River Unit 3 ("MATS Study");
- Exhibit No. ___ (BMHB-2), the Company's current, April 2014 TYSP;
- Exhibit No. ___ (BMHB-3), the Company's near-term summer and winter load forecast;
- Exhibit No. ___ (BMHB-4), the Company's forecast of summer peak demands and reserves with and without additional generation capacity in the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-5), the Company's forecast of physical and dispatchable demand-side resource reserves through the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-6), the generation options evaluated to contribute to the Company's capacity needs in the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-7), a confidential chart of the supply-side generation proposals evaluated by the Company to meet its capacity needs in the summers of 2016 and 2017;
- Exhibit No. ___ (BMHB-8), the Company's initial detailed economic analysis results for the most cost-effective generation option to meet the Company's capacity needs in the summers of 2016 and 2017;

- Exhibit No. ___ (BMHB-9), the Company's cost sensitivity analysis results based on the initial detailed economic analysis;
- Exhibit No. ___ (BMHB-10), the Company's final detailed economic analysis results for the most cost-effective generation option to meet the Company's capacity needs in the summer of 2016 and 2017; and
- Exhibit No. ___ (BMHB-11), the Company's analysis of natural gas price and carbon cost ("CO2") sensitivities to the final detailed economic analyses.

Each of these exhibits was prepared under my direction and control, and each is true and accurate.

Q. Please summarize your testimony.

A. DEF needs the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project by the summer of 2016 and 2017, respectively, to meet its 20 percent Reserve Margin commitment and to serve its customers' future electrical power needs in a reliable and cost-effective manner. Faced with generation plant retirements and additional customer and peak load demand, the Company determined in its resource planning process that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project were superior to any other alternative, including additional renewable energy resources and conservation measures, to meet the Company's near-term generation capacity needs.

The Company further evaluated these projects against power purchase agreement and generation facility acquisition proposals from third-party generators, and none of these proposals compared more favorably, on a quantitative and qualitative basis, to the Company's Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project. DEF has demonstrated that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the best alternatives for maintaining DEF's electric system reliability and integrity, and providing its customers with adequate electricity at a reasonable cost, by the summer of 2016 and 2017, respectively. We, accordingly, request that the Commission approve the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost-effective alternatives to meet the Company's need in 2016 and 2017.

III. OVERVIEW OF THE COMPANY'S NEED AND PETITION.

Q. Can you generally explain the Company's need that led to this Petition?

A. Yes. The Company faced resource planning decisions leading up to and early in 2013 that affected the Company's near-term need in the ten-year planning period for generation capacity to meet customer energy needs. As a result, during the Company's annual integrated resource planning analysis, the Company identified substantial generation capacity needs in the near term, beginning in 2016. This analysis was first reflected in the Company's 2013 TYSP. The Company's continuing resource planning process and analysis that resulted in its 2014 TYSP confirmed this need beginning in 2016.

Q. What were these resource planning decisions?

A. In February 2013, the Company decided to retire its Crystal River Unit 3 nuclear power plant ("CR3"). The Company also decided to retire its CR1 and CR2 (also "CRS" for "Crystal River South"), coal plants earlier than originally planned. These generation retirements account for over 1,500 MegaWatts ("MW") of summer generation capacity on DEF's system.

The Company planned to retire its CR1 and CR2 coal plants in 2020. The issuance of new EPA environmental regulations under the Clean Air Act affected the Company's planned retirement of CR1 and CR2. As a result of these new environmental regulations, the Company faced the retirement of CR1 and CR2 as soon as 2015, but, as explained in more detail below, the Company now plans to retire CR1 and CR2 in 2018. Still, these and other retirement decisions and the Company's response to them, coupled with the Company's load growth, create a near term need for generation, commencing in 2016.

Q. What were the environmental regulations that impacted the Company's planned retirement of its Crystal River South coal plants?

A. The EPA issued its MATS regulations in December 2011 and these regulations became effective in April 2012. The EPA MATS regulations are designed to reduce mercury, other metals, and acid gas emissions from coal- and oil-fired power plants. Compliance with MATS is required three years after the effective date, or by April 2015. A one-year MATS compliance extension is available under certain conditions from the Florida Department of Environmental

Protection ("FDEP"). The Crystal River Units 1 and 2 coal-fired units cannot meet the emissions requirements for MATS as currently configured and without changes in the coal fuel source for the units.

Q. What impact did these EPA regulations have on the Company's retirement decision for its Crystal River South coal plants?

A. Initially, the Company faced the retirement of CR1 and CR2 as early as 2015, with a possible extension to 2016. This extension was granted by the FDEP earlier this year, based on the time DEF needed to complete modest upgrades to the CR1 and CR2 units under a plan the Company developed for limited continued operation of CR1 and CR2 in compliance with MATS. The FDEP also recognized that continued operation of CR1 and CR2 deferred or resolved significant Florida electric grid reliability issues identified by the FRCC in its MATS study completed in 2013.

The FRCC MATS Study evaluated the impact of a MATS-required shutdown of CR1 and CR2 on the reliability of the Florida Bulk Electric System ("BES"). The FRCC is responsible for ensuring that the Florida BES is reliable and adequate. The FRCC concluded, based on its analysis in 2013, that shutting down CR1 and CR2 in 2015 as a result of MATS would result in significant, adverse transmission impacts to the BES. The FRCC found that, at a minimum, the one-year extension of the MATS compliance deadline was needed to provide time to alleviate the significant transmission reliability issues that the FRCC identified in the MATS Study. The FDEP considered the FRCC conclusions in its decision to grant the one-year extension to 2016 for CR1 and CR2 to comply with MATS. A copy of the FRCC MATS Study is attached as Exhibit No. ___ (BMHB-1) to my direct testimony.

During 2013, the Company further evaluated the continued operation of Crystal River South in compliance with MATS and other environmental regulations and determined that the Company could continue to operate CR1 and CR2 beyond 2016 with certain modifications to the units and a change to lower sulfur coal blends burned at the plants. The Company evaluated this plan against other options, concluded that the plan was the most cost-effective option, and presented this plan to the Commission in December 2013 as a modification to its Integrated Clean Air Compliance Plan. More detail on the Company's compliance strategy for CR1 and CR2 in response to MATS and other environmental regulations is provided in the Company's petition to modify its Integrated Clean Air Compliance Plan filed in Docket No. 130007-EI. The Commission approved this modification to its Integrated Clean Air Compliance Plan in Order No. PSC-14-0173-PAA-EI (consummating Order No. PSC-14-0218-CO-EI issued May 9, 2014).

The Company now plans to continue commercial operation of CR1 and CR2 until 2018 in compliance with the Commission-approved modification to its Integrated Clean Air Compliance Plan. This decision reduces the generation capacity the Company needs prior to 2018, but the Company still needs generation capacity to reliably serve its customers commencing in this time period.

Q. What were the Company's other generation retirement decisions?

A. The Company projected the retirement of some of its oldest combustion turbines in its fleet in 2014 and 2016. These projected retirements were identified in the Company's resource planning process in the late 2000's and continued to be part of the Company's resource plans in its 2013 and 2014 TYSPs. These combustion turbines were installed in the late 1960's and early 1970's at Avon Park, Turner, and Rio Pinar. They collectively provide 133 MW of summer generation capacity to DEF's system. They are smaller, less efficient combustion turbines and they are increasingly more costly to operate and maintain. The Company will retire all of these combustion turbine units by 2016.

The Company also plans to retire its three 1950's vintage oil- and gas-fired steam generation plants at the Company's Suwannee power plant site by 2016. These are small units, collectively providing 128 MW of summer capacity to DEF's system. These units were slated for retirement in 2018 as they approach the end of their life cycle. DEF will retire these units in 2016 to reduce the cost of the transmission upgrades needed for installation of the proposed peakers.

These generation plant retirements contribute to the Company's generation capacity needs prior to 2018. Coupled with load growth identified in the Company's 2013 and 2014 TYSPs, the Company needs additional generation capacity prior to 2018 to reliably serve customers.

Q. What did the Company do in response to this identified need in 2016?

A. The Company evaluated several alternative generation options to meet this need including (i) construction of new generation; (ii) purchases from or acquisitions of existing generation plants owned by other companies; and (iii) power uprate projects at existing generation plants on the Company's system. The Company identified a need up to 1,150 MegaWatts ("MW") of additional generation capacity beginning in 2016 and established a process for Commission review of the Company's evaluation of this need in its Revised and Restated Stipulation and Settlement Agreement ("2013 Settlement"). In the 2013 Settlement, the Company agreed to evaluate and compare the most cost effective alternative to satisfy its generation capacity needs prior to year end 2017 through its Integrated Resource Planning ("IRP") methodology and to present this evaluation to the Commission.

Q. Does the Company still need up to 1,150MW of generation commencing in 2016?

A. No. As I explained above, the Company's decision to complete projects necessary to permit the continued operation of CR1 and CR2 with alternative, low sulfur coal fuel sources and site averaging to comply with MATS extends the operation of CR1 and CR2 to 2018. This decision reduces the Company's generation capacity needs commencing in 2016. As a result, the Company no longer needs up to 1,150 MW of generation capacity commencing in 2016. The Company's need now is approximately 280 MW of summer generation capacity commencing in 2016 that increases to 470 MW in the summer of 2017.

Q. What is the Company's plan to meet its generation needs commencing in 2016?

A. The most cost-effective resource plan to meet the Company's summer generation capacity needs commencing in 2016 includes the construction of a new 320 MW simple cycle combustion turbine plant consisting of two F class combustion turbine units at the Company's Suwannee power plant site. This is called the Suwannee Simple Cycle Project. This plan also includes the installation of a 220 MW chillers power uprate project for the Company's existing natural gas-fired, combined cycle power blocks at the Company's Hines Energy Complex ("HEC"). This is called the Hines Chillers Power Uprate Project. This is the most cost-effective generation resource plan available to the Company for its customers to meet the Company's near-term generation needs commencing in 2016 based on both price and non-price attributes.

Q. Is the Company's decision with respect to its generation needs prior to 2018 consistent with the 2013 Settlement Agreement?

A. Yes. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the types of generation options specifically contemplated in the 2013 Settlement Agreement to meet the Company's generation capacity needs prior to 2018. The Company's decision to select these projects to meet its reliability need is the result of the IRP methodology that the Company agreed in the 2013 Settlement Agreement to use to evaluate and compare the most cost effective alternative to satisfy its generation capacity needs prior to year end 2017 and present to the Commission for approval. Indeed, the parties to the 2013 Settlement Agreement agreed that DEF could seek Commission approval for the costs of additional generation to meet a need up to 1,150 MW in the 2013 Settlement Agreement, however as I explained above, the Company's ability to cost-effectively comply with MATS and extend the commercial operation of Crystal River South has reduced the Company's estimated need prior to 2018 from up to 1,150 MW to approximately 500 MW. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project are the most cost-effective generation options to meet that need.

DEF has met with the parties to the 2013 Settlement Agreement several times to explain DEF's approach to its generation needs prior to 2018 and, ultimately, DEF's analyses and decision to meet that need consistent with the terms of the 2013 Settlement Agreement. No party to the 2013 Settlement Agreement has expressed to DEF that DEF has not complied with the 2013 Settlement Agreement.

IV. THE COMPANY'S RESOURCE PLANNING PROCESS.

Q. Please explain the Company's Resource Planning Process.

A. The IRP process is an integrated process in which the Company seeks to optimize its supply-side and demand-side options into an integrated optimal plan designed to deliver reliable, cost-effective power to DEF's customers. On an annual basis, and when circumstances materially affecting the Company's current resource plan change, we evaluate the relationship of demand and supply against the

Company's reliability criteria to determine if additional capacity is needed. Based on that evaluation, we develop the most cost-effective overall plan, which becomes the Company's Integrated Optimal Plan. This Integrated Optimal Plan is typically presented to the Commission in April each year in the Company's annual TYSP filing. The Company's current 2014 TYSP is included as Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. What reliability standards does the Company use to determine the need for additional resources?

A. DEF plans its resources in a manner consistent with utility industry resource planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. The Company plans its resources to satisfy a minimum Reserve Margin criterion and a maximum Loss of Load Probability ("LOLP") criterion. DEF has used dual reliability criteria since the early 1990s in its IRP process and this practice has been accepted by the Commission. DEF uses both the Reserve Margin and LOLP planning criteria to ensure that its resource plan has sufficient capacity available to meet customer peak demand, and to provide reliable generation service under all expected load conditions in the Company's service territory.

Q. Why are reserves needed?

A. Utilities require reserves to provide a margin of generating capacity above the firm demands of their customers in order to provide reliable electric service.

Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment. Also, at any given time during the year, some plants will be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserves 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. For all these reasons, DEF plans generating capacity reserves into its optimal resource plan.

Q. What is DEF's Reserve Margin in its Integrated Resource Plan?

A. DEF's current minimum Reserve Margin threshold is 20 percent. The Reserve Margin is a deterministic measure of reliability. Reserve margin is the amount of capacity that a utility maintains above the peak forecast load expressed as a percentage of the load. The Commission approved this minimum Reserve Margin threshold for the investor-owned utilities in peninsular Florida in Commission Order No. PSC -99-2507-S-EU.

Q. What is LOLP and what does it measure?

A. The LOLP is a probabilistic criterion that measures the probability that a utility company will be unable to meet its load throughout the year. Where Reserve Margin considers only the peak load and amount of installed resources, LOLP also takes into account a utility's load shape, generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard LOLP 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. In most cases, however, the need for additional generation capacity is triggered by the 20 percent Reserve Margin requirement before the LOLP criterion is considered. DEF's need for additional generation capacity prior to 2018 is also based on DEF's 20 percent Reserve Margin requirement.

Q. How did you start your resource plan that led to the identification of your need beginning in 2016 based on your reliability criteria?

A. As I explained above, there were certain retirement decisions, in particular, the retirement of the Company's CR3 nuclear plant, and the planned retirement of the Company's Crystal River South coal plants around changing environmental requirements, that drove the Company's near-term reliability needs as the Company entered 2013. The generation capacity need resulting from these decisions was coupled with additional load growth as a result of the Company's routine update of its forecast of system load growth for the next ten years as part of the normal IRP process. The Company's load forecast draws on the collection of certain input data, such as population growth, fuel prices, and interest and inflation rates. The load forecast is then developed based on economic and demographic assumptions that impact future energy sales and customer demand. The Company's load forecast is another key driver of the Company's resource plan in the IRP process. The Company's load forecast methodology is described in detail in Chapter 2 of the Company's 2014 TYSP, which is Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. Can you generally describe DEF's system demand and energy forecasts?

A. Yes. The Company's summer firm demand is expected to grow to 9,149 MW by the summer of 2016, which represents approximately a 3.8 percent growth rate from 2014. The net energy for load is projected to grow to 41,098 GWh in 2016, which represents approximately a 3.3 percent growth rate from 2014. The demand and energy forecasts are discussed in more detail in Chapter 2 of the Company's 2014 TYSP, which is Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. What is the impact of the Company's load forecast on the Company's generation resource needs?

A. The Company will experience load growth as the Florida economy recovers from the last recession. DEF expects both more customers and growth in energy demand in the near term, through 2017, albeit at a slower pace than customer and energy demand growth before the recession. This is a change from the loss of customers and reduced demand at the height of the recession in 2009. The Company has slowly recaptured the ground lost during the recession and expects continued growth in customers and demand. This growth, especially in summer peak demand on the Company's system, is one driver of the need for additional generation. Additionally, as I explained above, the need for additional generation is driven by the Company's decisions to retire generation capacity on its system. Together, the Company's projected capacity needs resulting from the Company's projected load growth, and existing and planned retirements, among other factors, demonstrate a need for additional capacity of approximately 280 MW in the summer of 2016 increasing to a need for 470 MW by the summer of 2017. Exhibit No. ____ (BMHB-3) is a summary of the Company's summer load forecast during this period.

Q. What is the impact on the Company's Reserve Margin?

A. DEF needs additional generation in the summer of 2016 and 2017 to meet its 20 percent minimum Reserve Margin requirement. Exhibit No. ___ (BMHB-4) shows DEF's forecast of summer peak demand and reserves, with and without any summer capacity additions. For the period from the summer of 2015 to the summer of 2017, DEF projects that the growth in firm summer peak demand will average approximately 132 MW a year with a projected peak in 2016 of 9,149 MW and in 2017 of 9,307 MW. The exhibit also shows that DEF will have a total generating capability of approximately 11,012 MW by the summer of 2016 and 11,232 MW by the summer of 2017. This capacity includes the installation of the Suwannee Simple Cycle Project in 2016 and the Hines Chillers Power Uprate Project in 2017.

As demonstrated in this exhibit, without these capacity additions, DEF's Reserve Margin will decrease to 16.9 percent in the summer of 2016 and 14.9

percent by the summer of 2017. DEF maintains its Reserve Margin for its summer (and winter) peak demands to ensure reliable electric service to its customers. DEF needs additional generation capacity in the summer of 2016 and the summer of 2017 to meet its obligation to provide reliable electric service to its customers.

Q. Did the Company consider non-generating alternatives to meet the Company's capacity need commencing in 2016?

A. Yes, energy conservation and direct load control programs are always a part of the Company's IRP process and they were considered in connection with the Company's near-term generation capacity need commencing in 2016. The Company's current demand-side management ("DSM") programs were included in the Company's Base Generation Expansion Plan that contains the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate project. As evidenced by the inclusion of these projects in the Company's Base Generation Expansion Plan, however, The Company's current DSM programs cannot replace or defer the Company's need for additional generation on its system to meet the Company's generation capacity needs commencing in 2016.

Q. What are the Company's current DSM programs?

A. DEF's current DSM programs were essentially set forth in the DSM Plan approved by the Commission in Order No. PSC-11-0347-PAA-EG in August 2011. In this Order, the Commission modified the Company's DSM Plan, effectively approving the Company's DSM programs that were in effect in August 2011. In 2012, additional revisions to four Company DSM programs resulting from changes in the Florida Building Code were approved, otherwise the Company's current DSM programs are the same as the programs the Commission approved in Order No. PSC-11-0347-PAA-EG. With these revisions, DEF's Commission-approved DSM Plan consists of six residential programs, eight commercial and industrial programs, one research and development program, and six solar pilot programs. These DSM programs will continue to be offered to the Company's customers through 2014 as the Company's current DSM Plan extends through the end of the year. A more detailed description of the Company's DSM programs is contained in the Company's 2014 TYSP attached as Exhibit No. ___ (BMHB-2) to my direct testimony.

Q. Did the Company's continuing IRP planning process in 2014 reveal new or revised DSM programs or measures that satisfied or deferred the Company's generation capacity needs commencing in 2016?

A. No. DEF performed the DSM evaluations necessary for the Commission's current DSM goals docket that will set DEF's future DSM goals for the period 2015 to 2024. Based on the results of that evaluation, there are no additional DSM measures or programs that can replace or defer the Company's need for additional generation capacity prior to 2018 to reliably serve DEF's customers. There is no reason to conclude, then, that the Company's determination that it needs additional supply-side generation capacity commencing in 2016 will be affected by the outcome of the current DSM goals docket.

Over the next ten years the Company's proposed conservation goals are generally lower than the existing DSM goals. All other things being equal, then, the Company's near-term DSM goals cause an increase in DEF's firm summer peak demand in 2016 and 2017, and, therefore, further establish the need for the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project to meet DEF's reliability needs in 2016 and 2017.

DEF's proposed DSM Plan reflects the successful implementation of cost-effective DSM programs by the Company for the past thirty years to reduce energy demand and energy consumption and therefore avoid the need for new generation. Through 2011, DEF's Commission-approved DSM programs have achieved more than 5,000 GWh reductions in energy consumption and over 1,645 MW in demand savings, effectively eliminating the need for the Company to build and operate approximately eighteen (18) new peaking power plants. The elimination of the need to build additional generation plants has resulted in over $1.2 billion in customer energy savings.

Substantial reductions in energy consumption and demand already have been achieved by the Company in its service territory, necessarily resulting in diminishing future energy consumption and demand reductions from future energy efficiency programs and measures. It is simply more difficult to achieve additional reductions in energy consumption and demand, and more costly to do so too, with continued or new DSM programs. More simply put, DEF's past success with its DSM programs makes it more difficult to get more "bang for the buck" with new or revised DSM programs.

In addition, DEF's new DSM programs are competing with increasing gains in energy efficiency by measures implemented by customers themselves, either independently or as a result of other, non-utility incentives, such as building code changes for new customer construction. The Commission recognized this impact in its 2014 Florida Energy Efficiency and Conservation Act ("FEECA") report to the Florida Legislature, explaining to the Florida Legislature that such changes reduce the amount of incremental energy available to count toward utility savings through utility DSM programs. These impacts also make it more difficult and more costly to achieve each incremental increase in energy efficiency or demand reduction through DEF's DSM programs.

For all these reasons, as more fully explained by the Company in Docket No. 130200-EI, DEF's proposed DSM goals for the next ten years are lower than the Company's current DSM goals. As a result, the Company's proposed DSM goals have no impact on the Company's reliability need in 2016 and 2017. There simply are no cost-effective DSM measures or programs that can offset or defer the need for additional generation capacity beginning in 2016.

Q. Would the Company's reliability need in 2016 and 2017 be impacted if the results of the current DSM goals docket are different from what the Company expects them to be?

A. No. The Company firmly believes that its proposed DSM goals in Docket No.

130200-EI are reasonable, cost-effective goals for the Company and its customers, and that they will be accepted by the Commission. Even if the Commission for some reason departed from these proposed DSM goals, however, for several reasons the resulting goals would have no impact on the Company's reliability need in 2016 and 2017.

First, the future DSM goals will not even be established by Commission Order until the fall of 2014, at the earliest. The Company will then need time to evaluate, develop, and implement new or revise existing DSM programs and measures in an attempt to meet the new DSM goals. After these new or revised DSM programs and measures are implemented, there naturally will be a period of time before any results are observed in the Company's load and peak demand. The Company cannot obtain the new DSM goals, evaluate them, develop and implement new or revised DSM programs or measures to achieve those goals, and see the full results of these new or revised DSM programs or measures by the summers of 2016 and 2017 when the Company has a reliability need for new generation. Accordingly, even if the current DSM goals docket results in different, higher DSM goals for DEF than DEF has proposed in that docket, those DSM goals would have no impact on DEF's reliability need for additional generation capacity in the summer of 2016 and 2017.

Q. Are there other considerations in balancing demand- and supply-side resources?

A. Yes. The Company calculates its Reserve Margin based on the relationship between firm load and total capacity available to serve that load. Firm load represents firm customer load after all DSM capability is implemented. While dispatchable demand-side resources provide important and cost-effective resources to reduce load, they cannot be used as often or as long as physical generation without eventually affecting customer participation levels. Prolonged use of dispatchable DSM resources to meet customer load demand, especially in the summer months, will result in customer attrition in the dispatchable DSM program. Based on the Company's experience, when interruptions in customer service increase in frequency, customers are less willing to accept such service for lower rates. For this reason, DEF carefully evaluates increasing reliance on dispatchable DSM programs to meet load with additional physical reserves to meet that load. In the case of the Company's additional capacity needs in the summers of 2016 and 2017, based on projected load growth and the Company's existing and planned generation retirements, the planned addition of generation projects will increase the Company's share of physical reserves to approximately 54 percent of total reserve capacity (which includes DSM) in the summer of 2017. See Exhibit No. ___ (BMHB-5) to my direct testimony. This level of physical reserves, in the Company's view, is, at a minimum, necessary to maintain coverage of an unplanned outage of the fleet's largest unit or to maintain coverage in an extreme weather event.

Q. Were supply-side alternatives identified and considered to meet the Company's capacity needs commencing in 2016?

A. Yes, in fact, the Company's optimization of its resource plan to meet its capacity needs commencing in 2016 in its IRP process determined that supply-side generation alternatives were necessary to cost-effectively meet customer capacity needs beginning in this time period. DEF examined several alternative generation expansion plans to meet this need, however, the alternative generation expansion plans that could be evaluated were limited by the need to place generation in-service in 2016 and 2017. With this limitation in mind, the Company evaluated generation options to determine those options that were the most cost-effective, screening the options based on cost, fuel sources and availability, technological maturity, and overall resource feasibility within the Company's system.

Generation alternatives that passed this screen were included in the Company's economic evaluation in the EPM production cost computer model. The primary output of EPM is a Cumulative Present Value Revenue Requirements ("CPVRR") comparison of the generation resource options that satisfied DEF's reliability requirements. The most cost-effective supply-side resources were evaluated and ranked by system revenue requirements. The Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project had the lowest CPVRR and were chosen by the Company as its Base Generation Plan to meet the Company's reliability needs in 2016 and 2017.

Q. Did the Company consider supply resources from other generation suppliers in its planning process to meet its capacity needs commencing in 2016?

A. Yes. DEF always takes into account the potential future supply of firm capacity from purchased power contracts during the study period in its evaluation. In fact, DEF determined that a short-term power purchase agreement ("PPA") with Southern Company over the limited transmission import interface was cost effective and included this purchase in its Base Generation Plan to meet its generation capacity needs commencing in 2016. DEF also evaluated several, other PPAs, and even acquisitions of generation facilities, to determine if they were more cost effective, considering all price and non-price attributes, than the Company's self-build new generation Suwannee Simple Cycle and Hines Chillers Power Uprate Projects to meet the Company's capacity needs commencing in 2016. These other, potential generation alternatives, and the Company's evaluation of them, are discussed in more detail later in my direct testimony.

Q. Did the Company consider renewable energy sources and technologies to meet its capacity needs in 2016?

A. Yes. The Company evaluates the timelines for new technologies including renewable energy source and technologies on a continuing basis as part of its IRP process. The Company also has a Request for Renewables ("RFR") that continuously solicits proposals for renewable energy projects. The Company will continue to evaluate the development or purchase of renewable energy in the future to potentially reduce DEF's use of fossil fuels or to defer or eliminate the need to construct more conventional, fossil-fueled generation resources.

Q. Were renewable energy sources or technologies reasonably available to the Company to meet its capacity needs commencing in 2016?

A. No. No commercially available, economically feasible renewable generation resource currently exists to displace or defer DEF's generation capacity needs commencing in the summer of 2016. DEF has a contract with U.S. Ecogen for a 60 MW plant that will use an energy crop as a fuel source with a planned in-service date of January 2017, however, that in-service date is uncertain and, even if this plant achieves commercial operation in January 2017, it does not address DEF's generation capacity need commencing in the summer of 2016, and it does not defer the need for generation capacity in the summer of 2017. Additionally, no other proposal for renewable energy projects have been received in response to the Company's RFR that will displace or defer the Company's generation capacity needs in 2016 and 2017.

V. THE SUWANNEE SIMPLE CYCLE AND HINES CHILLERS POWER UPRATE PROJECTS.

Q. Please explain the Company's plan to meet its capacity needs commencing in 2016.

A. The Company's plan includes the Suwannee Simple Cycle Project in the summer of 2016 and the Hines Chillers Power Uprate Project by the summer of 2017. As

I mentioned above, the Company also executed a short term PPA with the Southern Company for generation capacity commencing in 2016 as part of its base generation plan with the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project. Both Company projects are necessary to meet the Company's summer Reserve Margin requirement in 2016 and 2017 to deliver reliable electric service to the Company's customers.

The Suwannee Simple Cycle Project consists of two F class combustion turbine generators, two generator step-up transformers, fuel oil and demineralized water storage tanks, and related balance of plant facilities installed by June 2016 at the Company's existing Suwannee power plant site in Suwannee County, Florida. The Suwannee power plant site has existing infrastructure to support the Suwannee Simple Cycle Project. The Suwannee plant site has existing gas- and oil-fired combustion turbines, steam units and a transmission switchyard among other facilities. The new F class combustion turbine generators will be connected via a gas lateral to the Florida Gas Transmission gas pipeline and to the existing site metering and regulating station. One combustion turbine will be connected to the existing 115 kv transmission switchyard and the other combustion turbine will be connected to the existing 230 kv transmission switchyard. This existing infrastructure at the Suwannee site reduces the cost of the Suwannee Simple Cycle project. The estimated cost of the Suwannee Simple Cycle project, including the Allowance for Funds Used during Construction ("AFUDC"), is $197 million. The Suwannee Simple Cycle Project is explained in more detail in the testimony of Mr. Landseidel in this proceeding.

The Hines Chillers Power Uprate Project involves the installation of a chiller system designed to cool gas turbine inlet air to 50 degrees F and, therefore, increase the summer capacity of the combustion turbines for all four existing power blocks at the HEC. The HEC contains four natural gas-fired combined cycle units or power blocks with approximately 1,900 MW of total installed capacity. The Hines Chillers Power Uprate Project is projected to increase the total HEC power block summer output by approximately 220 MW. The Hines Chillers Power Uprate Project involves the installation of chiller modules and a large chilled water storage tank, auxiliary power system, pumps and chilled water supply and return piping, and gas turbine air inlet chiller coils including modification of the air inlet ducts on the existing power blocks. The estimated cost of the Hines Chillers Power Uprate Project, including AFUDC, is $160 million. The Hines Chillers Power Uprate Project is also explained in more detail in Mr. Landseidel's testimony in this proceeding.

Q. What impact will the addition of the Suwannee Simple Cycle and Hines Chillers Power Uprate projects have upon DEF's Reserve Margin and its ability to provide reliable service to its customers?

A. As shown in Exhibit No. ___ (BMHB-4), the addition of the Suwannee Simple Cycle Project will increase DEF's summer peak Reserve Margin to 20.4 percent in the summer of 2016. The addition of the Hines Chillers Power Uprate Project by the following summer will increase DEF's 2017 summer peak Reserve Margin to 20.7 percent. See Exhibit No. ___ (BMHB-4). The Suwannee Simple Cycle and Hines Chillers Power Uprate Projects allow DEF to satisfy its commitment to maintain a minimum 20 percent Reserve Margin.

Q. Why did DEF select the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects as the Company's generation options to meet its need in the summers of 2016 and 2017?

A. DEF's resource planning analyses show that the economics favor these projects over other Company generation options that were available to meet its near-term capacity needs in the summers of 2016 and 2017. The Company evaluated new generation, existing plant uprate projects, and existing generation life extension projects to meet this need. This evaluation included the fixed project capital costs, fixed and variable O&M costs, fuel and consumable costs, transmission costs, and the technical feasibility of these generation options. Based on this evaluation, the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects were the most cost-effective generation options, based on price and non-price attributes, to meet the Company's reliability needs in the summers of 2016 and 2017. Exhibit No. ___ (BMHB-6) to my direct testimony shows the range of projects considered. I will note that at this point in the Company's evaluation, the Hines Chillers Power Uprate Project was considering chilling systems on only 3 of the 4 HEC power blocks (Power Blocks 2, 3, and 4). Further evaluation on Power Block 1 was centered around the thermal performance uprate ("TPU"). The TPU was not deemed to be economically favorable and was later dropped for consideration.

Q. What are the transmission impacts and benefits of the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects?

A. There are no additional transmission costs associated with transmission enhancements or modifications for the Hines Chillers Power Uprate Project. These are power uprates to the existing HEC power blocks which are supported by the existing transmission system connecting the HEC to DEF's system. There are limited transmission system network upgrades and costs for the Suwannee Simple Cycle Project associated with the transmission interconnection of the combustion turbines at the existing Suwannee site. These are added customer benefits from installing these projects at existing power plant sites on the Company's system compared to generation at a Greenfield site. These transmission costs and benefits are also explained in the direct testimony of Mr. Ed Scott in this proceeding.

Q. Are there environmental benefits associated with the Suwannee Simple Cycle and Hines Chillers Power Uprate projects?

A. Yes. Both projects are located at existing brown field, power plant sites. Both projects have limited to no additional environmental impact at the existing sites. As a result, the Company is able to add over 500 MW of additional summer generation capacity by the summer of 2017 with little to no additional environmental impact. These projects provide the Company with the ability to substantially increase its summer generation capacity to meet customer energy demand while maintaining the Company's compliance with current and future environmental regulations.

VI. DEF'S GENERATION RESOURCE OPTIONS ASSESSMENT .

Q. Did DEF evaluate other supply-side alternatives to meet its generation needs in the summers of 2016 and 2017?

A. Yes. The Company evaluated PPAs from other utilities and non-utility generators and the acquisition of existing, non-utility generation plants in addition to the Company's self-build generation options. These are the same options that the Company said it was going to evaluate in the 2013 Settlement Agreement approved by the Commission.

Q. Please describe DEF's efforts to solicit proposals from other supply-side providers to meet its capacity needs commencing in the summer of 2016.

A. DEF first contacted other utilities and non-utility generators with the capability of supplying some or all of the Company's near-term capacity needs in September 2012. DEF issued a solicitation for proposals for PPAs. Bids were initially received in October 2012, evaluated in November 2012, and a short list was identified and negotiations over draft PPAs commenced in January and February 2013. Changes with the Company's resource plan, in particular with the decision to retire CR3 and the potential early retirement of CR1 and CR2 in this same time period, required the Company to re-evaluate its resource plan and its generation capacity needs. This re-evaluation led the Company to identify a potential near-term generation capacity need of up to 1,150 MW in the 2013 Settlement Agreement. At the same time, however, the Company was evaluating a plan to continue commercial operation of Crystal River South in compliance with MATS through site averaging for another two years. As I explained above, the Company ultimately determined that it could operate Crystal River South until 2018 under a MATS compliance plan and it has implemented that plan with Commission approval. The implementation of this plan to continue the operation of Crystal River South to 2018 substantially reduced the Company's summer generation capacity needs prior to 2018.

DEF requested renewed proposals for PPAs and solicited interest in potential generation facility acquisitions from the potential generation suppliers who responded to the Company's earlier RFP. These potential suppliers submitted renewed bids for PPAs and generation facility acquisition offers to meet DEF's near-term generation capacity needs in September and October 2013. The Company evaluated these proposals and followed up with the bidders regarding additional information, issues, and potential supplemental offers from October 2013 through February 2014.

Q. Please explain the supply-side proposals you received.

A. The Company invited alternative proposals that offered superior customer value to the Company's self-build generation options to meet the Company's near-term capacity needs prior to 2018. We sought reliable, dispatchable, and financially sound proposals that would provide the Company generation capacity by the summer of 2016 and/or the summer of 2017. We received nine proposals for PPAs or generation facility acquisitions from seven participants. We evaluated all of these proposals by systematically following a structured, orderly evaluation process that evaluated all proposals, including the Company's self-build generation projects, on price and non-price attributes.

After initial screening, DEF evaluated both generation facility acquisition and PPA proposals from two participants. There was one system PPA proposal from another investor-owned utility, two PPA proposals from non-utility generators and three additional generation facility acquisition proposals. A confidential chart of these supply-side generation proposals that were received and evaluated by the Company to meet its capacity needs commencing in the summer of 2016 is included in Exhibit No. ___ (BMHB-7) to my direct testimony.

Q. Please describe the evaluation process.

A. The evaluation process involved an analysis of the price and non-price attributes on all the supply-side generation proposals received and the Company's self-build generation options. The proposals were first segregated into categories distinguished by the type of proposal and term to ensure a consistent and fair evaluation by categorizing and evaluating "like type" proposals. Next, the Company conducted an economic evaluation of the proposals. In this step, the proposals were screened based on the fixed and variable payments or costs and economic optimization screening analyses were performed.

The Company also preliminarily evaluated the technical feasibility and viability of the proposed acquisitions through an analysis of such factors as the operating, maintenance, and physical conditions of the plants. Other non-price attributes, including insurance, project risk, environmental impacts and compliance, and regulatory feasibility, among other factors, were also considered. This preliminary qualitative assessment was undertaken to determine if there were any proposals that were such outliers from a qualitative risk perspective that further economic evaluation was unnecessary. Upon the completion of the economic evaluation, however, a more detailed qualitative evaluation was necessary, assuming that one or more proposals were economic, before the Company could conclude that a proposal was the most cost effective generation capacity option for DEF's customers.

Finally, the Company conducted a detailed economic evaluation of each proposal compared to DEF's self-build generation alternatives, the Suwannee Simple Cycle and the Hines Chillers Power Uprates projects. This detailed economic evaluation included all costs, including transmission cost impacts, in the analysis.

Q. How did the Company perform the detailed economic evaluation?

A. The Company performed a detailed economic optimization analysis of the alternative and Company supply-side generation proposals to meet its capacity needs beginning in the summer of 2016. The purpose of the optimization analysis was to develop an optimal resource plan for each proposal for the detailed economic analysis. The optimization analyses were performed for a period of thirty years to capture all costs associated with each proposal and, in particular, to determine the type of units that make up the optimal resource plan including a proposal.

The optimization analysis was performed using the Strategist optimization model. While the economic screening analysis compared 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 total system costs and compared those costs to the costs of the Company's base case self-build generation plan. The optimization analysis, therefore, shows the net impact of both the proposal cost and the impact the proposal has on system capital revenue requirements and fixed and 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 any impact on DEF's purchased power costs. DEF integrates the resource plan optimization and fixed cost results including capital revenue requirements for generation and transmission from Strategist with the detailed production cost results from the EPM model in its detailed economic evaluations.

Q. What was the Company's base case generation plan in its detailed economic evaluation?

A. The base case was the Suwannee Simple Cycle and Hines Chillers Power Uprate projects in the summers of 2016, and 2017, respectively, followed by the other planned generation units included in the Company's 2014 TYSP. The base case or "self-build" option included chillers at only three Hines power blocks at this stage of the analysis. See Exhibit No. ___ (BMHB-2).

Q. Please explain what the Strategist optimization model is and what it does.

A. The Strategist optimization model is an industry-recognized utility system production cost model that we use to develop optimal resource plans. Strategist is a detailed, chronological production costing model that simulates each generating resource on the DEF system, both existing and future, and how each resource is used to serve the forecasted peak demand and energy requirements of DEF's customers. The objective function of the Strategist model is to minimize the cumulative present value of revenue requirements ("CPVRR") for the DEF generation system, subject to the 20 percent Reserve Margin constraint.

Thus, for each resource proposal evaluated, the Strategist model provides the optimal generation expansion plan for the 30-year study period, if the proposed resource was selected. Inputs to the model include the load and energy forecast and the costs and characteristics (such as heat rates, outage rates, and maintenance requirements) of the Company's existing generating units and purchase power agreements. Costs and operating characteristics of potential future supply-side resources, which could be generating units or purchases, are also included in the model. Strategist model runs develop alternative resource plans to meet the projected future customer requirements using all possible combinations of resources, and it calculates the CPVRR for each combination. The model then sorts each alternative from lowest to highest cost. From an economics-only perspective, the lowest cost plan is the optimal plan.

Q. How were the results of the Strategist model optimization analysis used?

A. The results of the Strategist optimization cost analyses were used to identify optimal resource plans corresponding to each of the proposals or self-build options selected for evaluation. DEF reviewed the best plans produced by Strategist for each option and selected the plan with the lowest CPVRR for each that was feasible given constraints of transmission, construction, permitting, and other factors. The fixed cost output from Strategist was then incorporated into the financial analysis of each alternative proposal.

Q. How were the production costs associated with each alternative proposal determined?

A. After using Strategist to identify the lowest cost plan candidates, DEF uses the Planning and Risk module of the Energy Portfolio Manager ("EPM") software to further evaluate the production cost results. EPM is a detailed production cost model which evaluates the fleet dispatch in each hour over the period of the study taking into consideration both costs and projected operating constraints such as unit start times, minimum up and down times, reliability must run requirements, and projections of planned and unplanned outages. The analysis must capture these costs because each alternative proposal, due to, for example, its size, heat rate (if relevant), proposed pricing, and other factors, causes the other resources on the DEF generation system to operate in a different manner, resulting in different total system production costs. Production cost results from EPM were combined with fixed cost calculations from Strategist to calculate total 30-year production costs for each proposal and a resulting CPVRR for each proposal alternative. The cost results and CPVRR for each proposal is reviewed individually and then compared to the self build case.

Q. Were any other cost impacts included in the analysis?

A. Yes. The fixed costs of the alternatives, that is, the fixed charges of the proposals and the construction costs and fixed O&M costs of the Company's self-build generation projects, were captured in the financial analysis. The transmission construction costs to integrate each of the proposals and the Company's self-build generation projects into the transmission system were also included in the detailed economic analysis. The annual cash flow pattern of these transmission construction costs was based on typical expenditure patterns. All these costs were captured in the Strategist modeling analysis. Finally, we also evaluated the cost of imputed debt by determining the additional equity cost related to the purchased power proposals. The cost of imputed debt is typically applied to PPA proposals to ensure that the total costs of the PPA proposals include the marginal impact of the fixed future commitment on DEF's capital structure. This additional cost is the direct result of incurring fixed future payment obligations. The cost of imputed debt is a real cost associated with a PPA proposal and it therefore needs to be considered by the utility in determining the most cost-effective resource to meet its customers' reliability needs. In this case, because the term of the PPAs evaluated was five years or less, the impact of the imputed debt was found to be less than $5 million and was deemed to be not material in the results.

Q. What were the results of the detailed economic analysis?

A. In CPVRR terms, the Company's base generation plan --- the Suwannee Simple Cycle and Hines Chillers Power Uprate projects --- was found to be less expensive or more cost effective than all of the PPA proposals and all but one of the potential generation facility acquisition proposals. The Company's base generation plan was only marginally more expensive than one of the acquisition proposals, but in CPVRR terms over the 30-year study period they were nearly equivalent on an economic basis to the Company. Another potential generation facility acquisition proposal ranked third behind this generation facility acquisition and the Company's base generation plan by almost $200 million. Exhibit No. ___ (BMHB-8) to my direct testimony show the results of the initial detailed economic analysis.

Q. Did DEF consider combining one of the self-build projects with the alternative proposals?

A. Yes. DEF tested the proposals with and without the Hines Chillers. Initially, this was because some of the proposals (e.g. Acquisitions 4 and 5) did not supply sufficient MWs to meet DEF's need. During the course of testing alternatives, DEF modeled several of the proposals with and without the Hines Chillers. In each case, addition of the Hines Chillers made the project more favorable from a

CPVRR perspective, even when the capacity of the Chillers was not required to meet the reserve margin. As a result, all of the resource plans represented in Exhibit No. __ (BMBH-8) include inlet chilling on three Hines Power Blocks.

Q. What was DEF's next step in the analysis?

A. Following review of the initial detailed economic results, DEF quantified a number of sensitivity risks around the proposals evaluated. Included in these risks were construction cost sensitivity around the Suwannee and Hines projects, gas transportation contract risks, plant condition and maintenance risks, and transmission cost risks. Exhibit No. ___ (BMHB-9) shows the results of the cost risk sensitivity analysis.

Given the range of values, DEF looked closely at two acquisition proposals as alternatives to the DEF self-build project. These were Acquisitions 1 and 2. In the case of Acquisition 1, while the option had an apparently positive CPVRR relative to the self-build option, DEF recognized that there were a number of costs that might not be fully developed. Chief among these undeveloped costs was the fact that the option had been evaluated based on its existing fuel purchase arrangements. DEF recognized that these existing arrangements provided less firm gas transportation than would be typical for a DEF facility of this type. While this might be suitable for an Independent Power Producer like Acquisition 1, further evaluation would be warranted to determine if this would provide adequate reliability for a utility asset.

In the case of Acquisition 2, DEF had made conservative assumptions regarding the cost of transmission upgrades required to deliver the power from Acquisition 2 to DEF. DEF recognized that further analysis might yield a lower cost solution. For this reason, DEF looked more closely at Acquisition 2. However, in all the acquisition cases, DEF recognized the risk that due diligence might identify differences in maintenance practices, spares stocking, or issues around unit condition, among other factors, that would add cost to these acquisition alternatives. Based on the results of these initial economic analyses, DEF concluded that there was potential for two of the acquisitions to be competitive to the self-build and that it would be prudent to proceed with an evaluation of the FERC market screen risks associated with the two acquisitions before concluding the economic analysis and proceeding to the due diligence evaluation of the potential acquisition options.

Q. What additional analyses with respect to these proposals did DEF perform?

A. Because the cost sensitivities showed that two generation facility acquisition proposals had the possibility of being close in the CPVRR analyses to the Company's base generation plan the Company took the next step in determining the feasibility of any proposed generation facility acquisition by conducting a Federal Energy Regulatory Commission ("FERC") market screen analysis.

The FERC market screen analysis is a required step in obtaining FERC approval under section 203 of the Federal Power Act ("FPA") for any public utility acquisitions of jurisdictional generation facilities. Pursuant to FPA section 203, the FERC must determine that a public utility generation facility acquisition transaction is in the public interest. To make this determination, FERC reviews the proposed transaction to assess its effect on competition in the wholesale market, wholesale rates, and regulation. The FERC market screen, or Competitive Analysis Screen, is part of this review under the Antitrust Agencies' Horizontal Merger Guidelines adopted by FERC. FERC must approve any potential generation facility acquisition by the Company before the Company can complete that acquisition.

Q. How did the Company assess the competitive impact of its proposed generation facility acquisition under the FERC market screen test?

A. The Company retained Julie Solomon with Navigant Consulting, Inc. to perform the FERC market screen analysis. Julie Solomon and Navigant are well-recognized industry experts in this area. Julie Solomon has performed the FERC market screen analysis dozens of times for potential mergers or generation facility acquisitions and she has filed testimony many times at FERC regarding the implementation and application of the FERC market screen to such transactions.

Q. What were the results of the FERC market screen analysis?

A. Both potential generation facility acquisitions that were evaluated failed the FERC Competitive Analysis Screen. Failure of the FERC Competitive Analysis Screen means that FERC likely will not approve the generation facility acquisition transaction without mitigation efforts by the Company to eliminate the screen failures. The FERC market screen analysis and the results of that analysis are explained in more detail in the direct testimony of Julie Solomon filed on the Company's behalf in this proceeding.

Q. What did the Company do with the FERC market screen analysis results?

A. The Company decided, based on these results, that the potential generation facility acquisitions were not cost effective for the Company's customers and should not be considered further by the Company. The Company determined that the Company's base generation plan was the most cost-effective resource plan to meet customer reliability needs in the summers of 2016 and 2017.

Q. Why did the Company make this decision?

A. Both potential generation facility acquisitions failed the FERC Competitive Analysis Screen. As explained by Julie Solomon in her testimony, failure of the FERC Competitive Analysis Screen means that FERC likely will not approve the generation facility acquisition without structural mitigation to mitigate the screen failures. There are two potential FERC-approved mitigation measures. One is for the Company to sell its own generation facilities to reduce DEF's owned or controlled generation capacity in the market. This mitigation measure makes no sense for the Company. DEF cannot sell off generation because DEF needs additional generation capacity to provide reliable electric service to its customers. This remedy is not a reasonable mitigation measure for the Company.

Another FERC-approved mitigation measure is adding transmission import capability to reduce DEF's share of the generation capacity in the market by increasing the total supply of generation in the market. This means the Company must build additional transmission facilities to expand the transmission import capability. The Company cannot rely on currently planned transmission system facility upgrades for this mitigation. The additional transmission must be net new facilities to the DEF system.

Increasing the transmission import capability by building net new transmission facilities is not a reasonable mitigation measure to eliminate the screen failures for these potential generation facility acquisitions. As explained by Julie Solomon in her direct testimony, a range of 600 MW to 800 MW of additional transmission import capacity must be added to DEF's system to mitigate the FERC screen failures for the lowest cost potential generation facility acquisition, and a minimum of 1,000 MW of additional transmission import capacity must be added to DEF's system for the other generation facility acquisition to mitigate its FERC screen failures. Based on our experience with our transmission system and the costs to add transmission facility upgrades, the transmission system facility upgrades -- and the cost of the upgrades -- to provide an additional 600 MW to 800 MW of transmission import capacity would be substantial, in the realm of hundreds of millions of dollars, and, therefore, easily far in excess of any benefits that the potential generation facility acquisitions provide DEF's customers.

The best generation facility acquisition proposal was only marginally more cost-effective on a CPVRR basis over the 20-year study period than the Company's self-build base generation plan. This marginal benefit does not warrant hundreds of millions of dollars in transmission system facility upgrades that DEF and its customers must incur to mitigate the FERC screen failures for this potential acquisition. The other potential generation facility acquisition evaluated under the FERC market screen analysis was already almost $200 million less cost-effective on a CPVRR basis than the Company's self-build generation plan, largely due to transmission system upgrades already required to incorporate the generation facility into DEF's system. The additional transmission system facility upgrades to provide a minimum of 1,000 MW of additional transmission import capability to mitigate the FERC screen failures for this potential generation facility acquisition clearly render this acquisition uneconomic for DEF and its customers.

Q. Were there any other factors that led the Company to determine that pursuit of FERC approval for these potential generation facility acquisitions was not in the best interest of the Company's customers?

A. Yes. Apart from the quantitative factors that render the potential generation facility acquisitions uneconomic, they are also qualitatively not the most cost effective options for DEF and its customers. DEF must still seek FERC approval for the generation facility acquisitions even if DEF elected to pursue mitigation, which as I explained above, is not an economically viable option for the Company. At a minimum, this means the Company must incur the cost and spend the time necessary to retain experts and develop the analyses for the case for FERC approval, and then initiate the FERC proceeding to obtain that approval, which is uncertain. The FERC proceeding, at a minimum, will take six months before the Company obtains a FERC decision. This is unacceptable to DEF and its customers. Setting aside the cost of the expert analyses and the FERC proceeding itself and the uncertainty of the outcome of that proceeding, DEF must make investment decisions now to ensure that it can reliably provide its customers with additional generation capacity in 2016.

Qualitatively too, there were other risks associated with these potential generation facility acquisitions that likely would have rendered them not cost-effective for DEF and its customers. DEF deployed a step-wise approach and evaluated these generation facility acquisitions first on the bases of CPVRR and FERC market screen analyses. Until DEF determined: (1) whether a potential acquisition was economically competitive; and (2) whether or not a potential acquisition could pass the FERC market screen, it did not make sense for DEF to complete its due diligence on these plant acquisitions, or engage in negotiations over the terms of the plant acquisitions. The condition of the plants; the environmental conditions of the plant sites; plant performance history, warranties and guarantees; financial guarantees; insurance and indemnity obligations, among other factors, would be fully evaluated only if the potential acquisition was shown to be economically competitive and capable of passing the FERC market screens. These additional qualitative factors, however, represent additional, unmitigated risk associated with the potential generation facility acquisitions that preclude the Company from determining that they are cost effective for customers.

As a result of the Company's economic and FERC market screen analyses and its evaluation of the qualitative risks associated with the proposed generation facility acquisitions, the Company determined that further review of the generation facility acquisition proposals was unnecessary. The most cost effective generation option to meet customer reliability needs prior to 2018 is the Company's self-build generation plan.

Q. Did you perform additional economic analyses following the results of the FERC market screen?

A. Yes. DEF updated the results of the most favorable remaining alternatives, adjusting the modeling case to the latest assumptions consistent with the 2014 TYSP. While this did not have a significant effect on the results, the results are shown in Exhibit __ (BMBH-10). This exhibit shows the difference in total system CPVRR associated with each supply-side generation alternative proposal compared to the Company's Base Generation Plan. DEF evaluated the highest ranking of the PPA options from the previous review and the remaining PPA-acquisition hybrid that DEF believed would pass the market screen. Both of these were significantly less cost effective than the self-build option. Prior to this point, all analyses had been done assuming that the chillers would be added only to Power Blocks 2, 3, and 4 at HEC. During this period, DEF engineering had concluded that it would be feasible to extend the chiller project to Power Block 1. The results in Exhibit __ (BMHB-10) continue to use the Suwannee project along with the three inlet chillers as the base case, but also shows the evaluation of the project with four chillers, and a resource plan in which the chillers were omitted and replaced by a third combustion turbine at Suwannee in addition to the comparison with the remaining PPA alternatives. These results support the conclusion that the most cost effective plan is the construction of the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project at all four Hines power blocks.

Q. Did you perform any sensitivity analyses?

A. Yes. DEF performed sensitivity analyses of the final alternatives in our High Gas Price sensitivity case and with no CO_2 price. These cases are typically run to establish the robustness of a conclusion and to indicate how the results will vary based on variation in fuel and emission pricing, typically two of the most sensitive inputs to the production cost model. The results of these analyses are shown in Exhibit __ (BMHB-11). Comparison of the results follow generally expected patterns, favoring portfolios with higher proportions of combined cycle in the high gas case and the reverse in the no CO2 case. Since the alternatives are all gas fired, the variations between cases are relatively small. The results of these sensitivity analyses support the conclusion that the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project together form the most cost effective selection for DEF's need in 2016, 2017, and beyond.

VII. THE MOST COST-EFFECTIVE GENERATION ALTERNATIVE.

Q. Is the Company's base generation plan the most cost-effective alternative for meeting the Company's reliability needs in the summers of 2016 and 2017?

A. Yes, it is. The Company conducted a careful screening of various other supply-side alternatives as part of its IRP process before identifying the Suwannee Simple Cycle and Hines Chillers Power Uprate projects as its base generation plan to meet its reliability needs by the summers of 2016 and 2017. Further, through the Company's evaluation of market proposals for alternative generation, the Company determined that the Suwannee Simple Cycle and Hines Chillers Power Uprate projects were more cost-effective, on a quantitative and qualitative basis, than any of alternative supply-side generation proposal on the market.

Q. What caused the Company's Base Generation Plan to be more cost effective than any of the other alternatives?

A. The Suwannee Simple Cycle Project is a new, state-of-the-art combustion turbine plant with higher fuel efficiency than existing combustion turbine PPAs or the acquisition of existing combustion generation facilities. As I explained above and as explained in more detail in the direct testimony of Mr. Landseidel, there are also economic benefits associated with its location at an existing Company power plant site. Further, there are no FERC market screen issues with new generation in the market. FERC is concerned with removing generation or the ability to remove generation from the market. For all these reasons, the Suwannee Simple Cycle Project proved to be a cost-effective part of the Company's base generation plan to meet its reliability needs in 2016.

The Hines Chillers Power Uprate Project is the most cost-effective generation option in every generation alternative scenario. This project adds summer generation capacity with additional combined cycle power generation. As a result, the Company obtains additional summer peaking generation at combined cycle generation efficiency and cost. The fuel efficiency and relatively low cost of the Hines Chillers Power Uprate project make it a highly cost-effective generation option to meet DEF's customer reliability needs.

VIII. CONSEQUENCES OF DELAY

Q. What will be the impact of delaying implementation of the Suwannee Simple Cycle and the Hines Chillers Power Uprate projects?

A. If the Suwannee Simple Cycle and Hines Chillers Power Uprate projects are delayed, DEF would not be able to satisfy its minimum 20 percent Reserve Margin planning criterion by the summer of 2016 and 2017, respectively, in the most reliable and cost-effective manner. This would expose DEF's customers to a risk of interruption of service in the event of unanticipated forced outages or other contingencies for which DEF maintains reserves. Even without an interruption in service, without the Suwannee Simple Cycle and Hines Chillers Power Uprate projects, DEF would be forced to enter into more costly PPAs to meet this near-term reliability need. As a result, DEF's customers would be subject to higher costs to serve their reliability needs in the summer of 2016 and 2017.

IX. CONCLUSION

Q. Please summarize the benefits of the Suwannee Simple Cycle and the Hines Chillers Power Uprate projects.

A. DEF needs the Suwannee Simple Cycle and Hines Chillers Power Uprate Projects to maintain its electric system reliability and integrity and to provide its customers with adequate electricity at a reasonable cost. By building these projects the Company will be able to meet its commitment to maintain a 20 percent Reserve Margin, and it will do so by improving not just the quantity, but also preserving the quality of its total reserves, maintaining an appropriate portion of physical generating assets in the Company's overall resource mix. The Company has exhausted conservation measures reasonably available to the Company and there are no reasonably available renewable energy resources or technologies to meet the Company's near-term reliability needs in the summers of 206 and 2017. The Suwannee Simple Cycle and Hines Chillers Power Uprate Projects are the most cost-effective resources to meet customer reliability needs in this time period. We, accordingly, request that the Commission approve the Suwannee Simple Cycle Project and the Hines Chillers Power Uprate Project as the most cost-effective alternatives to meet the Company's need in 2016 and 2017.

Q. Does this conclude your testimony?

A. Yes, it does.

Docket No. _______
Duke Energy Florida
Exhibit No. ____ (BMHB-1)

FRCC
Florida Reliability Coordinating Council, Inc.

FRCC's Evaluation of Transmission Impact of the EPA's Mercury and Air Toxics Standard (MATS)

(Transmission Impact Study for Shutdown of Crystal River Units 1 & 2, with retirement of Crystal River Unit 3)

Performed by the FRCC TWG

Prepared by TWG	**June 3, 2013**
Accepted by MSPC	**February 4, 2014**

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Summary

The FRCC TWG, under direction of the FRCC PC, has performed a study to determine the transmission reliability impact to the FRCC Region of the EPA MATS regulation. In order to comply with the MATS regulation, Duke Energy Florida's ("DEF") Crystal River 1 & 2 ("CR 1 & 2") coal-fired units are subject to shutdown in April 2015 (or April 2016 if a one year extension is granted). In addition to the potential impacts of the MATS regulation, DEF announced in early 2013 that it would retire the Crystal River 3 nuclear unit ("CR 3"). The impact of shutting down CR 1 & 2, the retirement of CR 3, and replacing this generation with DEF reserves (as was analyzed in this evaluation) is a significant shift in power flow patterns causing reliability concerns in areas not previously identified.

The FRCC TWG finds the following with respect to the three MATS Study deliverables:

- An extension of at least one year on the EPA's MATS compliance deadline is needed for Crystal River 1 & 2. This will alleviate significant reliability issues that would begin in the summer 2015 timeframe (without such extension), ensuring BES reliability in the FRCC Region as various transmission projects and operational mitigation procedures are implemented.

- In 2016 and 2017, significant reliability issues continue to exist with the retirement/shutdown of the Crystal River units. The TWG requests that All entities with unresolved thermal and/or voltage criteria exceptions further investigate and develop mitigation plans.

- The results of the summer 2018 analysis for the potential addition of a combined cycle facility of 1,179 MW in the vicinity of the existing Crystal River plant, combined with the accelerated projects and previously identified operating solutions, finds that the reliability issues that are created by the potential shutdown of CR 1 & 2 and announced retirement of CR 3 are resolved.

Purpose of Study

On December 16, 2011 the Environmental Protection Agency ("EPA") issued their Mercury and Air Toxics Standards ("MATS") regulation. The MATS regulation is designed to reduce mercury, other metals and acid gas emissions from coal- and oil-fired power plants. The MATS regulation became effective on April 16, 2012, and the initial compliance deadline is three years after the effective date, or April 16, 2015. In order to comply with the MATS rule, Duke Energy Florida's ("DEF") Crystal River 1 & 2 ("CR 1 & 2") coal-fired units are subject to shutdown in April 2015 (or April 2016 if a one year extension is granted). The MATS rule does offer a one year extension, to be approved by the state permitting authority (Florida Department of Environmental Protection), if reliability issues warrant an extension.

In addition to the potential impacts of the MATS rule, DEF announced in early 2013 that it would retire the Crystal River 3 nuclear unit ("CR 3"), instead of repairing it as previously planned. The unit has been off-line since 2009, and has been previously modeled in the FRCC Databank as returning to service in 2015.
As a result of these events, and their potential impact(s) to the FRCC Region, the FRCC Planning Committee ("PC") directed the Transmission Working Group ("TWG") to perform an analysis determining the impact(s) to the Bulk Electric System ("BES") and the 69 kV transmission system within the FRCC.

The primary deliverables of the evaluation were:

- Determine whether a one year extension on the EPA's MATS compliance deadline is needed to ensure reliability.
- Assess the transmission reliability impact for the 2015 through 2017 timeframe and develop potential solutions.
- Evaluate the potential reliability benefits of a new combined cycle constructed in the vicinity of the existing Crystal River site, starting operations in summer of 2018.

<u>Case Description and Sensitivities</u>

The initial load flow cases selected for the evaluation were the 2012 FRCC Load Flow Databank (LFDB) cases (revision 1B), which were utilized for the FRCC's 2012 Long Range Study. These cases were slightly modified to reflect known assumptions and information about the system, including long-term resource and transmission plans, as well as correcting any issues that were identified during the Long Range Study effort.

The following years and loading conditions were selected for the analysis:

- Summer - 2015, 2016 (Peak and 60%), 2017, 2018
- Winter - 2015/16, 2016 /17

The following scenarios and sensitivities were analyzed:

- Base/Study scenarios – Generation economically dispatched by respective Balancing Authority area
  - Base cases include CR 1 & 2 and CR 3 on-line and fully dispatched
  - Study cases model CR 1 & 2 and CR 3 off-line with generation replaced with DEF available reserves. Minority owners of CR 3 replaced the generation from other resources.

- Base/Study scenarios – System response at the Florida / Southern import limit
  - Timeframe - summer 2016
  - Increased Southern to Florida transfer beyond firm commitments to 3,700 MW limit with remaining resources dispatched economically

- Polk Firm sensitivity – Stress Central Florida area
  - Timeframe - winter 2016/17 and summer 2017
  - Maximize all firm resources in the Polk area
    - FPL's Manatee unit evaluated at both economic dispatch and full output

- Crystal River site combined cycle sensitivity – DEF self-build alternative
  - Model a new 1,179 MW combined cycle resource assumed in-service by the summer of 2018, this correlates to DEF's latest Ten-Year Site Plan filed at the FPSC. The location is not specified in the Ten-Year Site Plan, so based on the FRCC PC study directive the unit was placed at the Crystal River plant with the combustion turbines connected to the 230 kV bus and the steam turbine connected to the 500 kV bus, with remaining DEF generation resources economically dispatched

- Unit Out scenarios (C3-Gens analysis)
  - Bayside 2, Crystal River 4, Crystal River 5, Fort Myers 2, Sanford 5 and Stanton 2, for winter 2015 and summer 2016.

Study Methodology

The TWG analysis was performed by conducting a power flow analysis under normal and various contingency conditions using Siemens Power System Simulator for Engineering ("PSS/E") and PowerGEM's Transmission Adequacy and Reliability Assessment ("TARA") software program. All system elements 69 kV and above within the FRCC region were modeled for NERC Category A, B, and selected C contingency events using steady state methods. All branches' (including transformers and ties) thermal loadings were monitored to be within System Operating Limits ("SOL"). Thermal loadings greater than 100% of a facility's applicable rating that were materially aggravated (more than 3%) when compared to the reference case or thermal overloads that did not exist in the reference case, for the same contingency, are attributed to the impact of the CR 1 & 2 shutdowns and the CR 3 retirement. Similarly, all system busses were monitored for applicable voltage criteria, including nuclear plant interface requirements. Voltages outside of transmission owner criteria that were materially lower (more than 2%) when compared to the reference case, for the same contingency, are attributed to the impact of the CR 1 & 2 shutdowns and the CR 3 retirement.

The TWG performed the following steps for the analysis:

- Verified that under normal operating conditions (NERC Category A criteria), all facilities remained within applicable ratings.

- Performed a "Rate C" contingency screening in order to identify any conditions that would indicate potential SOL limitations which would require pre-contingency mitigation measures. Any potential limitation required a remedy before any further analysis, in order to represent the pre-contingency condition.

- Performed a NERC Category B contingency analysis on all Base and Study cases and sensitivities using the criteria described above.

- Performed NERC Category C (C2, C5, C3 Gen and C3 Lines) event analysis on all Base and Study cases and sensitivities using the criteria described above.

General Findings

The impact of shutting down CR 1 & 2, the retirement of CR 3, and replacing this generation with DEF reserves (as was analyzed in this evaluation) is generally to reduce the two power injections from (1) the north to the Tampa Bay load area, and from (2) west central Florida to the western portions of the Orlando load area. Utilizing DEF's available reserves causes a shift in the power flow patterns with issues. The specific findings for the timeframes analyzed are discussed in subsequent sections.

Deliverable 1 - Findings and potential solutions for summer 2015 & winter 2015/16

DEF's System

The summer and winter of 2015 results indicate that with CR 1 & 2, and CR 3 retirement, the flow of power from the DEF Central Florida Substation into the Greater Orlando Area is reduced significantly. That coupled with the operation of the base load units at FPL's Sanford Plant and DEF's dispatch of Debary, results in significantly increased flows in the 230 kV corridor between the generation at Debary and Sanford, and the load to the south (West Greater Orlando Area). With the previously described conditions, this path experiences significant pre-contingency loading (99% of Rate A) and post-contingency thermal overloads. Additional post-contingency thermal overloads were also observed on other elements within DEF's system, which can be resolved using various switching mitigation procedures.

A combination of the previously stated 230 kV line rebuilds, significant 69 kV and 230 kV switching (sectionalizing), and significant re-dispatch is required to resolve the corridor overloads identified above. Since this corridor is used to transfer bulk power and to serve area load, switching alternatives are limited, and clearance windows would be short, making it very unlikely that the 230 kV rebuild lines could be completed prior to April 2015. In addition, re-dispatch options are also very limited due to the absence of the three base load resources at Crystal River that results in utilizing nearly all available reserves. What remains of the identified mitigations is a less desirable option to address the identified post-contingency corridor issues: a severe combination of 69 kV and 230 kV switching (sectionalizing), combined with limited re-dispatch at Debary.

If DEF were granted an extension to delay the shutdown of CR 1 & 2, the ability to run these units will resolve these significant issues on the system through April 2016.

Seminole Electric Cooperative, Inc.'s (SECI) System

During the 2012 Long Range Study, Seminole's 69 kV transmission line located in north Sumter County was projected to experience thermal overload conditions starting in the summer of 2016 and increasing slightly through the end of the planning horizon. Seminole's plan was to reconductor the 0.3 miles of 336 ACSR with 556 ACSR prior to the start of the summer of 2016 season. However, with the loss of CR 1 & 2, the thermal overload on the respective Seminole facility begins in the summer of 2015.

Seminole's original plan was to reconductor the 0.3 miles prior to the start of the summer 2016 season; however, with the assumption that CR 1 & 2 will be shutdown by 2015, Seminole would need to accelerate the reconductor project to be complete prior to the start of the summer 2015 season. This project could remain on its current schedule per the 2012 Long Range Study if DEF was granted an extension to delay the shutdown of CR1 & 2.

Tampa Electric Company's (TEC) System
Prior to proceeding with the study analysis, the cases were assessed for potential Rate C overloads by running all contingencies (B, C2, C5 & C3 Gens) against the Rate C. TEC addressed potential BES screening overloads using one of four possible methods: pre-contingency switching, pre-contingency dispatch adjustment, documentation of a higher Rate C or automatic action schemes (i.e., SPS, UVLS, etc.).

The results for the summer 2015 and winter of 2015/16 indicate significant overloads in the corridor flowing power from east to west towards the Lake Tarpon area. While numerous thermal overloads appear to be satisfactorily resolved using various switching mitigations, additional TEC transmission lines resulted in Rate B overloads under contingency events that are still outstanding. Each is fully mitigated with the ability to run CR 1 & 2.

Running CR 1 & 2 at the current generation capacity, as it had been projected in the 2012 LFDB models, resolves the overloads on many of the effected TEC facilities or reduces the impact on the thermal overloads on the remaining facilities, so that switching solutions would resolve the remaining overloads.

Determination

The TWG has determined that in the summer 2015 and winter 2015/16 scenarios, with the order to comply with the MATS regulation and subsequent shutdown of Crystal River unit 1 and unit 2, in addition to the announced retirement of Crystal River 3, severe reliability issues exist. The shutdown of CR 1 & 2 will cause new overloads and increase the magnitude of known contingency overloads, many of which cannot be remedied by existing operational procedures. These post-contingency overloads will require new transmission facilities to be constructed and/or existing transmission facilities to be rebuilt or re-conductored in order to accommodate new flow patterns that have not been previously observed.

The TWG finds that a one year extension for the operation of CR units 1 & 2 is justified and necessary to maintain the integrity and the reliability of the BES within the FRCC. This extension will allow additional time to construct transmission projects to resolve many of the issues and aid in mitigating significant post-contingency overloads allowing for operational procedures to be implemented.

Deliverable 2 - Transmission impacts and potential solutions in 2016 & 2017

DEF's System
The results for the summer and winter of 2016 and 2017 indicate significant overloads in:

- The 230 kV tie-line between Lakeland Electric (LAK) and DEF.
- The 230 kV corridor between the generation in the area of Debary (DEF) and Sanford (FPL) and the load to the south.

By summer 2016, DEF plans to rebuild the LAK / DEF 230 kV tie-line and remove the limiting elements to resolve the worst overloads in this area, although DEF will still need to use some switching mitigation procedures for other issues downstream. DEF also plans to eliminate its most limiting elements on the addition LAK / DEF 230 kV tie-line by April 2016.

DEF is currently developing plans to have the corridor located north of Orland in southwest Seminole County rebuilt by summer of 2016. The rebuild of these segments in this corridor will improve area conditions, but until the last rebuild project is completed along this corridor, DEF will still have to depend on some combination of 69 kV and 230 kV switching and limited re-dispatch at Debary. If generation were made available by some means in the Crystal River area, this could resolve most, if not all, of the issues on this corridor and significantly reduce the negative impact in many other areas as well.

As observed in the summer 2015 and winter 2015/16, some additional less significant thermal overloads remain in DEF's system, but can be satisfactorily resolved using various switching mitigation procedures.

TEC's System

Similar to the summer of 2015 and winter of 2015/16 cases, the summer of 2016 & 2017 and winter of 2016/17 cases were assessed for possible Rate C overloads. TEC addressed potential BES screening overloads using one of four possible methods: pre-contingency switching, pre-contingency dispatch adjustment, documentation of a higher Rate C or automatic protection system (i.e., SPS, UVLS, etc.). s:

In addition to the BES Rate C overloads, the 69 kV system is also assessed for any potential Rate C overloads that may potentially impact the BES, but not required to be resolved prior to proceeding with the study analysis.. TEC would be able to address the 69 kV overloads by choosing to uneconomically increase the Pasco Cogen generation to its maximum as pre-contingency in all the cases.

The results for the summer of 2016 & 2017 and winter of 2016/17 indicate significant overloads in the corridor flowing power from east to west towards the Lake Tarpon area. While numerous thermal overloads appear to be satisfactorily resolved using various switching mitigations, additional TEC transmission lines resulted in Rate B overloads that remain outstanding. If generation were made available by some means in the Crystal River area, this could resolve most, if not all, of the issues and significantly reduce the negative impact in other areas as well.

Determination

In the 2016 and 2017 timeframe, severe reliability issues exist with the shutdown of CR 1 & 2. The most severe issues revolve around the Polk Firm and the Unit Out scenarios (most notably, Bayside 2). In these scenarios TWG has identified Rate C overloads and numerous post-contingency overloads in the TEC area for which mitigations have not yet been developed.

Deliverable 3 - Reliability impact of a new combined cycle built at Crystal River in 2018

TEC's System

The results for the summer of 2018 show the elimination of the Rate B and Rate C overloads shown in the previous cases with the exception of one 230 kV transmission line under a double contingency event in the Study scenario.

The effect of installing a combined cycle facility of 1,179 MW by the summer of 2018 in the Crystal River vicinity partially alleviates the thermal overload on TEC's 230 kV transmission line to 101% and a switching solution would resolve the remaining overload.

Determination

The TWG's evaluation of the transmission impact associated with the addition of a combined cycle facility of 1,179 MW by summer 2018 in the vicinity of the existing Crystal River plant, combined with the accelerated projects and previously identified operating solutions, finds that the reliability issues that are created by the potential shutdown of CR 1 & 2 and announced retirement of CR 3 are resolved

Effect on future studies

This study identified several concerns without providing firm resolutions for various contingency types and system conditions. For future studies that will have to incorporate the Crystal River shutdowns and retirements, including the FRCC Long Range Study, the issues identified in this analysis will need to have adequate remedies. Additionally, any future TSR/NITS or GISR/NRIS studies will be much more complex when starting with unresolved issues. There is one GISR already underway, and it is anticipated that more will be coming in the near future.

Duke Energy Florida, Inc.
Ten-Year Site Plan

April 2014

2014-2023

Submitted to:
Florida Public Service Commission

DUKE ENERGY.
FLORIDA

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LIST OF REQUIRED SCHEDULES

LIST OF
TABLES AND FIGURES

CODE IDENTIFICATION SHEET

Generating Unit Type

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

Fuel Type

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

Fuel Transportation

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

Future Generating Unit Status

A - Generating unit capability increased
D – Generating unit capability decreased
FC - Existing generator planned for conversion to another fuel or energy source
P - Planned for installation but not authorized; not under construction
RP - Proposed for repowering or life extension
RT - Existing generator scheduled for retirement
T - Regulatory approval received but not under construction
U - Under construction, less than or equal to 50% complete
V - Under construction, more than 50% complete

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Duke Energy Florida

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. Duke Energy Florida, Inc.'s TYSP is compiled in accordance with FPSC Rules 25-22.070 through 22.072, Florida Administrative Code.

DEF'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 DEF'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 DEF'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.

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

Duke Energy Florida, Inc. (DEF or the Company) is a wholly owned subsidiary of Duke Energy Corporation (Duke Energy).

AREA OF SERVICE

DEF has an obligation to serve approximately 1.7 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. DEF is interconnected with 22 municipal and nine rural electric cooperative systems. DEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), and the FPSC. DEF'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 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.

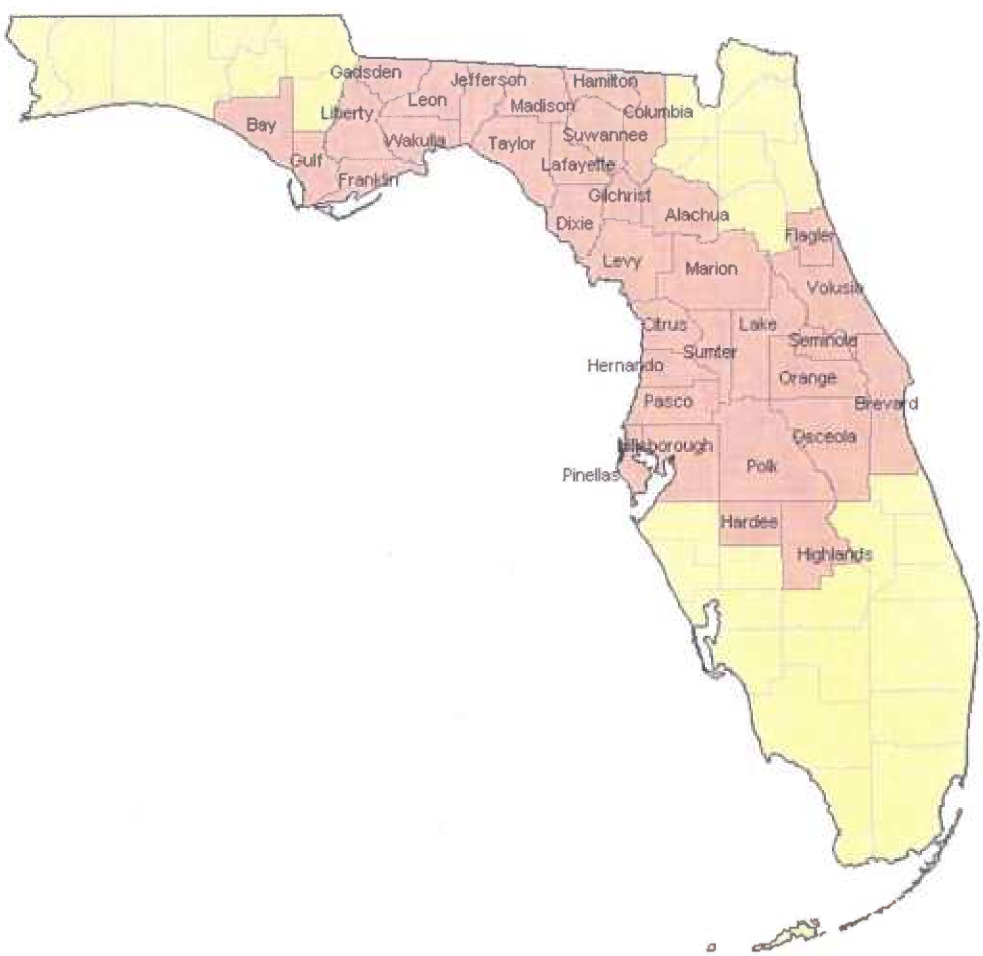
ENERGY MANAGEMENT and ENERGY EFFICIENCY

The Company's residential Energy Management program represents a demand response type of program where participating customers help manage future growth and costs. Approximately 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.

TOTAL CAPACITY RESOURCE

As of December 31, 2013, DEF had total summer capacity resources of 11,258 MW consisting of installed capacity of 9,141 MW and 2,117 MW of firm purchased power. Additional information on DEF's existing generating resources can be found in Schedule 1 and Table 3.1 (Chapter 3).

FIGURE 1.1
DUKE ENERGY FLORIDA
County Service Area Map



DUKE ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
									COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		ALT. FUEL	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	DAYS USE	MO./YEAR	MO./YEAR	KW	MW	MW
STEAM													
ANCLOTE	1	PASCO	ST	NG		PL			10/74		556,200	484	506
ANCLOTE	2	PASCO	ST	NG		PL			10/78		556,200	490	511
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	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		PL		***	11/53	*****	34,500	28	28
SUWANNEE RIVER	2	SUWANNEE	ST	NG		PL		***	11/54	*****	37,500	29	28
SUWANNEE RIVER	3	SUWANNEE	ST	NG		PL		***	10/56	*****	75,000	71	73
												3,393	**3,463**
COMBINED-CYCLE													
BARTOW	4	PINELLAS	CC	NG	DFO	PL	TK	***	6/09		1,253,000	1,160	1,185
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
												3,277	**3,615**
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	86	108
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	***	6/72		55,700	42	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	310	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	58	78
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			1/94		43,000	46	47
												2,471	**3,031**
											TOTAL RESOURCES (MW)	**9,141**	**10,109**

** 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.

***** SUWANNEE STEAM UNITS ESTIMATED TO BE SHUTDOWN BY 6/2018.

****** PEAKERS at AVON PARK, RIO PINAR, TURNER P1 & P2 ARE ESTIMATED TO BE PUT IN COLD STAND-BY OR RETIRED BY 6/2016 WITH TURNER P3 BY 12/2014 AND HIGGINS BY 6/2020.

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

OVERVIEW

The information presented in Schedules 2, 3, and 4 represents DEF's history and forecast of customers, energy sales (GWh), and peak demand (MW). DEF's customer growth is expected to average 1.4 percent between 2014 and 2023, which is more than the ten-year historical average of 0.8 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 DEF 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 1.2 percent per year between 2004 and 2013 due primarily to the economic recession and the weak economic recovery that followed. Sales for Resale in 2013 were only 35% of their 2004 level. Mild winter weather conditions early in 2013 and above normal rainfall over the summer also contributed to the results. The 2014 to 2023 period is expected to improve by an average growth rate of 1.5 percent per year due to expected higher population and 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 increase by 33% over the ten year horizon.

Summer net firm demand declined an average 0.3 percent per year during the last ten years, mostly driven by a wholesale load that was nearly 50% below the average of the previous nine summers. The projected ten year period summer net firm demand growth rate of 1.6 percent is primarily driven by higher population improving net firm retail demand.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

The below schedules have been provided:

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 Base Summer Peak Demand (MW)
3.2	History and Forecast of Base Winter Peak Demand (MW)
3.3	History and Forecast of Base Annual Net Energy for Load (GWh)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month

DUKE 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	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
2004	3,339,460	2.447	19,347	1,364,677	14,177	11,734	158,780	73,898
2005	3,427,860	2.454	19,894	1,397,012	14,240	11,945	161,001	74,190
2006	3,505,058	2.448	20,021	1,431,743	13,983	11,975	162,774	73,568
2007	3,531,483	2.448	19,912	1,442,853	13,800	12,184	162,837	74,821
2008	3,561,727	2.458	19,328	1,449,041	13,339	12,139	162,569	74,669
2009	3,564,937	2.473	19,399	1,441,325	13,459	11,883	161,390	73,632
2010	3,621,407	2.495	20,524	1,451,466	14,140	11,896	161,674	73,579
2011	3,623,813	2.495	19,238	1,452,454	13,245	11,892	162,071	73,374
2012	3,633,611	2.491	18,251	1,458,690	12,512	11,723	163,297	71,792
2013	3,633,838	2.480	18,508	1,465,169	12,632	11,718	163,671	71,594
2014	3,700,173	2.471	18,574	1,497,280	12,405	11,617	167,106	69,519
2015	3,736,060	2.456	18,840	1,520,916	12,387	11,766	169,628	69,364
2016	3,777,512	2.446	19,179	1,544,620	12,417	12,015	172,186	69,779
2017	3,818,761	2.435	19,494	1,568,452	12,429	12,200	174,750	69,814
2018	3,861,879	2.427	19,833	1,591,324	12,463	12,297	177,209	69,393
2019	3,906,298	2.422	20,086	1,612,908	12,453	12,499	179,511	69,628
2020	3,949,461	2.417	20,351	1,634,061	12,454	12,735	181,753	70,068
2021	3,992,349	2.413	20,605	1,654,509	12,454	12,939	183,909	70,355
2022	4,033,775	2.409	20,906	1,674,417	12,486	13,239	185,998	71,178
2023	4,075,604	2.407	21,199	1,693,168	12,520	13,457	187,949	71,599

DUKE 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
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
2013	3,206	2,370	1,352,743	0	25	3,159	36,616
2014	3,153	2,324	1,356,713	0	24	3,123	36,491
2015	3,173	2,307	1,375,379	0	24	3,145	36,948
2016	3,188	2,293	1,390,318	0	24	3,178	37,584
2017	3,158	2,277	1,386,913	0	23	3,198	38,073
2018	3,251	2,259	1,439,132	0	23	3,220	38,624
2019	3,503	2,241	1,563,141	0	23	3,239	39,350
2020	3,618	2,224	1,626,799	0	22	3,257	39,983
2021	3,564	2,208	1,614,130	0	22	3,274	40,404
2022	3,535	2,192	1,612,682	0	22	3,289	40,991
2023	3,490	2,176	1,603,860	0	22	3,301	41,469

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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
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	1,768	3,065	41,214	25,480	1,649,839
2013	1,488	2,668	40,772	25,543	1,656,753
2014	936	2,374	39,801	25,904	1,692,614
2015	974	2,568	40,490	26,079	1,718,930
2016	1,024	2,490	41,098	26,233	1,745,332
2017	795	2,507	41,375	26,369	1,771,848
2018	767	2,604	41,995	26,489	1,797,281
2019	1,046	2,617	43,013	26,596	1,821,256
2020	1,270	2,745	43,998	26,689	1,844,727
2021	1,243	2,772	44,419	26,772	1,867,398
2022	1,244	2,635	44,870	26,847	1,889,454
2023	1,244	2,746	45,459	26,913	1,910,206

DUKE ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
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	1,618	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	1080	8,703	262	326	355	100	278	124	8,338
2013	9,581	581	9,000	334	332	384	101	297	124	8,008
2014	10,359	804	9,555	254	337	411	105	308	132	8,812
2015	10,631	806	9,825	256	342	434	110	316	132	9,042
2016	10,775	658	10,117	255	347	455	114	323	132	9,149
2017	10,998	587	10,411	256	383	473	118	330	132	9,307
2018	11,169	587	10,582	263	388	488	122	336	132	9,440
2019	11,620	837	10,783	310	393	503	127	342	132	9,813
2020	11,795	837	10,958	332	398	520	131	346	132	9,935
2021	11,842	737	11,104	333	403	536	135	351	132	9,952
2022	11,985	738	11,247	333	408	550	139	355	132	10,067
2023	12,118	738	11,380	333	413	564	143	359	132	10,173

Historical Values (2004 - 2013):

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 (2014 - 2023):

Cols. (2) - (4) = forecasted peak without load control, cumulative 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).

DUKE ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
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	206	7,706
2012/13	9,105	831	8,274	248	652	744	97	219	193	6,952
2013/14	11,126	895	10,231	237	661	796	101	233	228	8,870
2014/15	11,476	1,376	10,099	238	670	845	105	241	243	9,133
2015/16	11,779	1,378	10,401	238	679	887	110	249	246	9,371
2016/17	11,788	1,088	10,700	238	706	927	114	256	249	9,298
2017/18	12,093	1,088	11,005	245	715	956	118	263	252	9,544
2018/19	12,281	1,088	11,193	288	724	984	122	269	254	9,639
2019/20	12,690	1,338	11,351	309	733	1,018	127	275	256	9,972
2020/21	12,827	1,338	11,489	310	742	1,049	131	278	257	10,059
2021/22	12,958	1,339	11,619	310	751	1,079	135	281	258	10,143
2022/23	13,083	1,339	11,745	310	760	1,106	139	285	259	10,224

Historical Values (2004 - 2013):

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 (2014 - 2023):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

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).

DUKE 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 (%) **
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	1,768	3,065	41,214	52.0
2013	43,150	778	736	864	36,616	1,488	2,668	40,772	53.0
2014	42,249	821	763	864	36,491	936	2,374	39,801	51.2
2015	43,047	857	787	913	36,948	974	2,568	40,490	50.6
2016	43,714	890	810	916	37,584	1,024	2,490	41,098	49.9
2017	44,037	918	831	913	38,073	795	2,507	41,375	50.8
2018	44,702	944	850	913	38,624	767	2,604	41,995	50.2
2019	45,763	969	868	913	39,350	1,046	2,617	43,013	50.9
2020	46,797	996	887	916	39,983	1,270	2,745	43,998	50.2
2021	47,258	1,021	905	913	40,404	1,243	2,772	44,419	50.4
2022	47,749	1,044	922	913	40,991	1,244	2,635	44,870	50.5
2023	48,377	1,067	938	913	41,469	1,244	2,746	45,459	50.8

* 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 and 2013 historical load factors which are based on the actual summer peak demand which became the annual peaks for the year.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2)

DUKE 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 2013		FORECAST 2014		FORECAST 2015	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	5,877	2,881	9,973	3,166	10,257	3,213
FEBRUARY	8,032	2,746	8,454	2,713	9,127	2,766
MARCH	7,856	3,031	7,479	2,879	8,188	2,936
APRIL	7,153	3,166	7,537	2,954	7,781	3,008
MAY	7,863	3,460	8,467	3,560	8,694	3,616
JUNE	8,524	3,965	9,021	3,749	9,246	3,810
JULY	8,352	3,983	9,327	3,953	9,562	4,012
AUGUST	8,776	4,283	9,509	3,993	9,750	4,058
SEPTEMBER	8,446	3,861	8,778	3,728	8,984	3,790
OCTOBER	7,645	3,517	8,192	3,330	8,472	3,390
NOVEMBER	6,418	2,912	6,697	2,738	6,902	2,804
DECEMBER	5,826	2,967	8,764	3,038	8,879	3,087
TOTAL		40,772		39,801		40,490

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

FUEL REQUIREMENTS AND ENERGY SOURCES

DEF's actual and projected nuclear, coal, oil, and gas requirements (by fuel unit) are shown in Schedule 5. DEF'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. DEF'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.

DUKE 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	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1,000 TON	4,543	4,792	4,521	5,099	4,709	5,443	4,951	4,431	3,314	3,253	2,863	3,230
(3)	RESIDUAL	TOTAL	1,000 BBL	89	251	0	0	0	0	0	0	0	0	0	0
(4)		STEAM	1,000 BBL	89	251	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	160	132	128	145	159	116	117	66	96	69	93	166
(9)		STEAM	1,000 BBL	60	55	61	61	54	49	31	12	31	33	45	39
(10)		CC	1,000 BBL	1	8	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	99	69	66	84	105	67	86	54	64	36	48	126
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	187,251	177,196	185,946	183,135	188,841	185,881	196,042	211,855	232,439	245,117	258,700	256,669
(14)		STEAM	1,000 MCF	26,837	23,404	31,406	37,531	36,652	26,744	25,644	26,128	23,891	24,146	24,876	28,004
(15)		CC	1,000 MCF	155,717	150,875	148,761	138,981	142,519	149,678	160,865	177,949	200,579	213,835	226,668	219,394
(16)		CT	1,000 MCF	4,697	2,917	5,779	6,623	9,669	9,459	9,533	7,778	7,969	7,135	7,156	9,271
	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	12,711	12,734	18,515	14,152	13,659	13,607	14,812	5,519	0	0
(18.1)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CT	1,000 MCF	0	0	7,403	8,894	10,318	6,071	6,028	5,518	5,312	4,373	4,938	7,123
(19)	OTHER, COAL	ANNUAL FIRM INTERCHANGE, STEAM	1,000 TON	0	0	221	225	105	0	0	0	0	0	0	0

DUKE 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	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	1,558	1,409	709	854	989	578	577	529	495	408	457	687
(2)	NUCLEAR		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	10,003	10,577	9,816	11,072	10,078	11,776	10,826	9,272	6,772	6,617	5,802	6,585
(4)	RESIDUAL	TOTAL	GWh	46	127	0	0	0	0	0	0	0	0	0	0
(5)		STEAM	GWh	46	127	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	104	93	27	35	43	27	35	23	27	16	21	57
(10)		STEAM	GWh	63	58	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	1	7	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	39	28	27	35	43	27	35	23	27	16	21	57
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	23,997	23,061	24,337	23,621	24,374	24,194	25,818	28,468	31,855	33,840	35,846	35,370
(15)		STEAM	GWh	2,175	1,951	2,738	3,349	3,264	2,235	2,159	2,240	2,006	2,038	2,136	2,430
(16)		CC	GWh	21,469	20,893	21,037	19,641	20,183	21,038	22,732	25,465	29,061	31,087	32,998	32,032
(17)		CT	GWh	353	217	562	631	927	921	927	763	788	715	711	908
(18)	OTHER 2/														
	QF PURCHASES		GWh	2,767	2,886	1,421	1,444	1,529	1,527	1,533	1,526	1,506	1,507	1,498	1,505
	RENEWABLES		GWh	1,183	1,132	1,301	1,260	1,277	1,279	1,285	1,280	1,254	1,253	1,245	1,256
	IMPORT FROM OUT OF STATE		GWh	1,559	1,546	2,191	2,203	2,809	1,995	1,921	1,915	2,089	777	0	0
	EXPORT TO OUT OF STATE		GWh	-4	-59	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	41,213	40,772	39,801	40,490	41,098	41,375	41,995	43,013	43,998	44,419	44,870	45,459

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

DUKE 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	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	ANNUAL FIRM INTERCHANGE 1/		%	3.8%	3.5%	1.8%	2.1%	2.4%	1.4%	1.4%	1.2%	1.1%	0.9%	1.0%	1.5%
(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		%	24.3%	25.9%	24.7%	27.3%	24.5%	28.5%	25.8%	21.6%	15.4%	14.9%	12.9%	14.5%
(4)	RESIDUAL	TOTAL	%	0.1%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		STEAM	%	0.1%	0.3%	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	%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%
(10)		STEAM	%	0.2%	0.1%	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	%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%
(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	%	58.2%	56.6%	61.1%	58.3%	59.3%	58.5%	61.5%	66.2%	72.4%	76.2%	79.9%	77.8%
(15)		STEAM	%	5.3%	4.8%	6.9%	8.3%	7.9%	5.4%	5.1%	5.2%	4.6%	4.6%	4.8%	5.3%
(16)		CC	%	52.1%	51.2%	52.9%	48.5%	49.1%	50.8%	54.1%	59.2%	66.1%	70.0%	73.5%	70.5%
(17)		CT	%	0.9%	0.5%	1.4%	1.6%	2.3%	2.2%	2.2%	1.8%	1.8%	1.6%	1.6%	2.0%
(18)	OTHER 2/														
	QF PURCHASES		%	6.7%	7.1%	3.6%	3.6%	3.7%	3.7%	3.6%	3.5%	3.4%	3.4%	3.3%	3.3%
	RENEWABLES		%	2.9%	2.8%	3.3%	3.1%	3.1%	3.1%	3.1%	3.0%	2.8%	2.8%	2.8%	2.8%
	IMPORT FROM OUT OF STATE		%	3.8%	3.8%	5.5%	5.4%	6.8%	4.8%	4.6%	4.5%	4.7%	1.7%	0.0%	0.0%
	EXPORT TO OUT OF STATE		%	0.0%	-0.1%	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. 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.

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.

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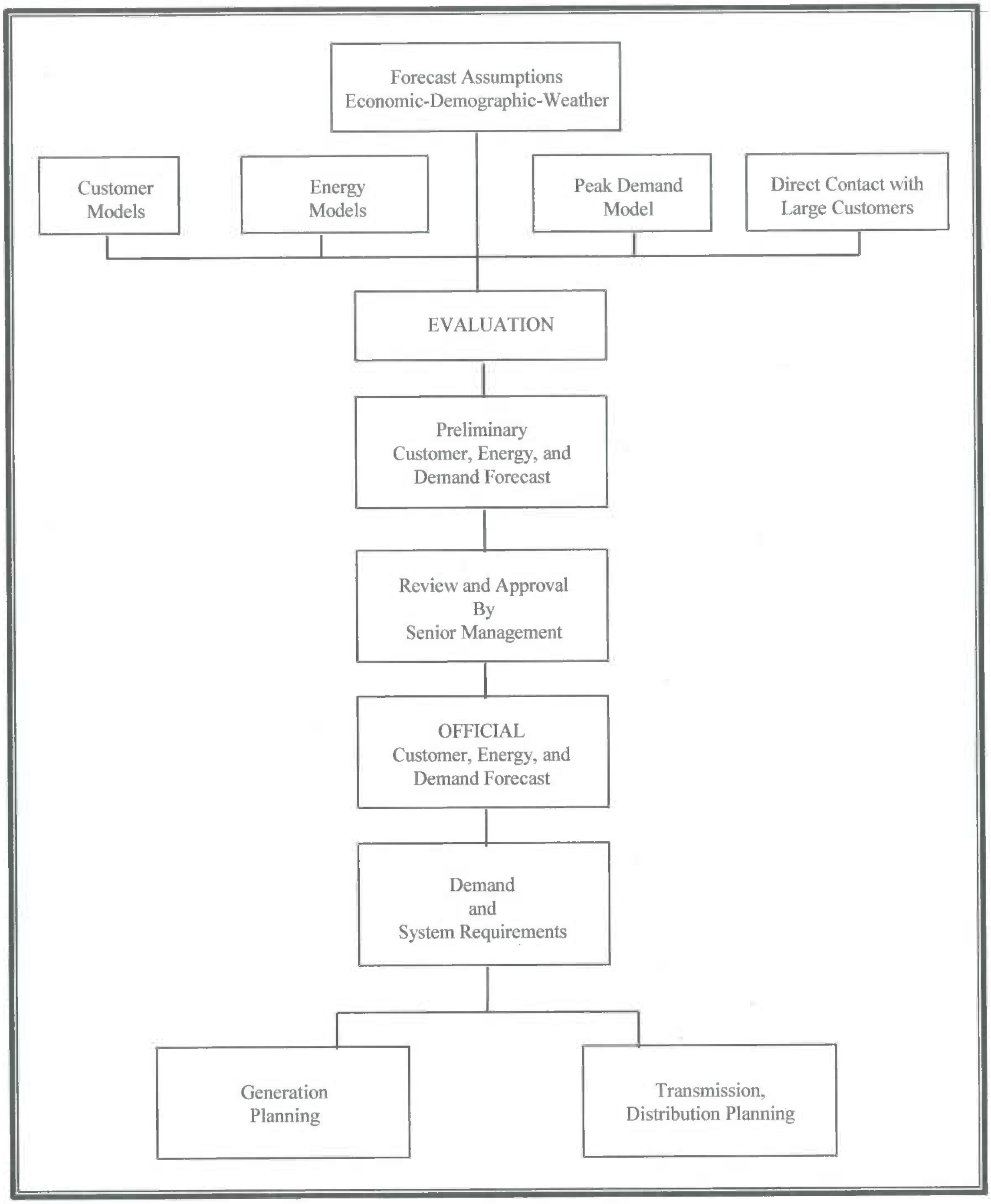
FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

1. Normal weather conditions for energy sales are assumed over the forecast horizon using a sales-weighted 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). 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.

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.

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 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.

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 Energy Information Agency (EIA), along with trended projections of both by Itron capture a significant piece of the changing future environment for electric energy consumption. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled using the SAE framework. This approach explicitly introduces trends in appliance saturation and efficiency, dwelling size and thermal efficiency. It allows for an easier explanation of usage levels and changes in weather-sensitivity over time. The "bundling" of 19 residential appliances into "heating", "cooling" and "other" end uses form the basis of equipment-oriented drivers that are interacted with the typical exogenous factors as 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 structure captures significant variation in residential usage caused by changing appliance efficiency and saturation levels, economic cycles, weather fluctuations, electric price, 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 monthly residential customers with households within DEF's 29 county service area. County level population projections for counties in which DEF 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. As in the residential sector, these variables are interacted with the commercial end-use equipment (listed below) after trends in equipment efficiency and saturation rates have been projected.

- Heating
- Cooling
- Ventilation

- Water heating
- Cooking
- Refrigeration
- Outdoor Lighting
- Indoor Lighting
- Office Equipment (PCs)
- Miscellaneous

The SAE model contains indices that are based on end-use energy intensity projections developed from EIA's commercial end-use forecast database. Commercial energy intensity is measured in terms of end-use energy use per square foot. End-use energy intensity projections are based on end-use efficiency and saturation estimates that are in turn driven by assumptions in available technology and costs, energy prices, and economic conditions. Energy intensities are calculated from the Annual Energy Outlook (AEO) commercial database. End-use intensity projections are derived for eleven building types. The energy intensity (EI) is derived by dividing end-use electricity consumption projections by square footage:

$$EI_{bet} = Energy_{bet} / sqft_{bt}$$

Where:

$Energy_{bet}$ = energy consumption for building type b, end-use e, year t

$Sqft_{bt}$ = square footage for building type b in year t

Commercial customers are modeled using the projected level of residential customers.

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 interacted with the Florida industrial production index, 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 three customers, the forecast is dependent upon information received from direct customer contact. DEF 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 of late. 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 within the size of the service area. The level of government services, and thus energy, can be tied to the population base, as well as the amount of tax revenue collected to pay for these services. 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 cooling degree-days 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).

SECI is a wholesale, or sales for resale, customer of DEF contracting to purchase base, intermediate and peaking stratified load over varying time periods over the forecast horizon. 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 DEF. Energy projections for full requirement customers grow at a rate that approximates their historical trend with additional information coming from the respective city officials. DEF serves partial requirement service (PR) to municipalities such as New Smyrna Beach, Homestead, and another power provider, RCID. In each case, these customers contract with DEF for a specific level and type of stratified capacity 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 and expected fuel prices.

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.

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 (formerly known as Progress Energy Florida, Inc.). 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.

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
2013	140	274	195

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
2013	118	101	237

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. A brief description of each of the currently offered DSM programs is provided below.

In 2012, DEF 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 DEF provides incentives. The revisions to the four programs are incorporated in the descriptions below.

In 2013, the increased efficiency standards impacted participation in DEF's approved DSM programs as measures that previously were eligible for incentives became required standards ineligible for incentives. The higher performance requirements established by the changes to the Florida Building Code, along with the state and federal minimum efficiency standards for residential appliances and commercial equipment, resulted in a reduction of demand and energy savings from DEF's DSM programs. As the U.S. Department of Energy (DOE) continues the implementation of increased energy efficiency standards for residential and commercial end-uses, the amount of demand and energy savings captured by DEF's DSM programs will decrease. As DEF continues its planning process in the ongoing DSM goals docket, the impacts of future implementation of state building code and federal appliance standards will be incorporated into its DSM goal proposals.

DEF's CURRENTLY APPROVED DSM PROGRAMS:

RESIDENTIAL PROGRAMS

Home Energy Check

This energy audit program provides residential customers with an analysis of their current energy use and provides 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 DEF 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); and 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

The Home Energy Improvement Program is the umbrella program that serves 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 DEF 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 DEF'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. 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 DEF 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 DEF representatives during a Business Energy Check audit. If a candidate project meets program specifications, it may be eligible for an incentive payment, subject to DEF approval.

Commercial Energy Management (Rate Schedule GSLM-1)

This direct load control program reduces DEF's demand during peak or emergency conditions. As described in DEF'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 system(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 DEF'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 DEF 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 DEF's request.

Interruptible Service

This direct load control program reduces DEF'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. DEF 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 DEF'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. DEF 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 have included 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. DEF collaborates with non-profit builders to provide low-income families with a residential solar thermal water heater. The solar thermal system is provided at no cost to the non-profit builders or the residential participants.

Solar Water Heating with Energy Management

This pilot program 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 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 DEF 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 DEF 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 DEF's system
- Increase participation in existing residential Demand Side Management measures through energy education
- Increase solar education and awareness in DEF 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 pilot 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

DUKE ENERGY. FLORIDA

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

As of December 31, 2013 DEF had a summer total capacity resource of 11,258 MW (see Table 3.1). This capacity resource includes fossil steam (3,393 MW), combined-cycle plants (3,277 MW), combustion turbines (2,471 MW; 143 MW of which is owned by Georgia Power for the months June through September), utility purchased power (413 MW), independent power purchases (1,114 MW), and non-utility purchased power (590 MW). Table 3.2 presents DEF'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

DEF's forecasts of capacity and demand for the projected summer and winter peaks can been found in Schedules 7.1 and 7.2, respectively. DEF'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 DEF. In its planning process, DEF 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

DEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as DEF's Base Expansion Plan. This plan includes two combustion turbines located at the Suwannee River Site in 2016, additional summer capacity at the Hines Energy Center through the installation of Inlet Chilling, a combined cycle facility in 2018 at Citrus County (DEF issued an RFP on October 8, 2013 to seek competitive alternatives to the 2018 Citrus Combined Cycle project; bids to this RFP were closed on December 9, 2013 and the RFP is currently under evaluation), and a 2021 Combined Cycle facility at an undesignated site. DEF continues to seek market supply-side resource alternatives to enhance DEF's resource plan and has extended a purchase power agreement with Southern Power Company beginning in 2016. Other short and long-term power resources from 2016 through 2020 are also under evaluation and may impact the proposed Base Expansion Plan. DEF continues to evaluate alternatives to the base plan, including the 2018 Citrus Combined Cycle, through IRP resource evaluations that include RFP alternative bid reviews and 2013 rate settlement reviews. DEF expects to file formal petitions regarding resource selections resulting from these evaluations during 2014.

The promulgation of the Mercury and Air Toxics Standards (MATS) by EPA in April of 2012 presents new environmental requirements for the DEF 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. Residual oil was removed from the site in 2013.
- DEF is continuing to execute projects at the Anclote facility to convert the two residual oil fired units there to 100% firing on natural gas. These environmental control upgrades are expected to enable these two units to operate in compliance with the requirements of the MATS. Following completion of the project in 2014, DEF will conduct final tests to confirm 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, in accordance with 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.
- 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. 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. 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 Combined Cycle operations.
- Additional details regarding DEF's compliance strategies in response to the MATS rule are provided in DEF's annual update to the Integrated Clean Air Compliance Plan filed in Docket No. 140007-EI.

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. The Avon Park, Rio Pinar and Turner Units P1 and P2 continue to show anticipated retirement dates in 2016. The three Suwannee steam units are projected to retire by the spring of 2018. Operation of the peaking units at Higgins units is being extended to 2020. 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.

DEF's Base Expansion Plan projects the need for additional capacity with proposed in-service dates during the ten-year period from 2014 through 2023. The planned capacity additions, together with purchases from Qualifying Facilities (QF), Investor Owned Utilities, and Independent Power Producers help the DEF system meet the energy requirements of its customer base. The capacity needs identified in this plan may be impacted by DEF'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. The additions in the Base Expansion Plan 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 DEF's Base Expansion Plan. Status reports and specifications for the planned new generation facilities are included in Schedule 9. The planned transmission lines associated with DEF Bulk Electric System (BES) are shown in Schedule 10.

TABLE 3.1

DUKE ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2013

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)
Fossil Steam		
Crystal River	4	2,291
Anclote	2	974
Suwannee River	3	128
Total Fossil Steam	9	3,393
Combined Cycle		
Bartow	1	1,160
Hines Energy Complex	4	1,912
Tiger Bay	1	205
Total Combined cycle	6	3,277
Combustion Turbine		
DeBary	10	637
Intercession City	14	986 *(1)*
Bayboro	4	174
Bartow	4	177
Suwannee	3	155
Turner	4	131
Higgins	4	105
Avon Park	2	48
University of Florida	1	46
Rio Pinar	1	12
Total Combustion Turbine	47	2,471
Total Units	**62**	
Total Net Generating Capability		**9,141**

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

Purchased Power		
Firm Qualifying Facility Contracts	11	590
Investor Owned Utilities	2	413
Independent Power Producers	2	1,114
TOTAL CAPACITY RESOURCES		**11,258**

TABLE 3.2

DUKE ENERGY FLORIDA
FIRM RENEWABLES
AND COGENERATION CONTRACTS

AS OF DECEMBER 31, 2013

Facility Name	Firm Capacity (MW)
El Dorado*	114.2
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
Florida Power Development	60
TOTAL	**589.6**

* El Dorado, LFC Jefferson and LFC Madison expire 12/31/13.

** Lake County Resource Recovery expires 6/1/2014

*** Orlando Cogen increases contract capacity by 35.8MW to 115MW on 1/1/2014

DUKE 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
2014	9,015	1,831	0	177	11,024	8,812	2,211	25%	0	2,211	25%
2015	8,982	1,831	0	177	10,991	9,042	1,949	22%	0	1,949	22%
2016	9,089	1,873	0	177	11,140	9,149	1,991	22%	0	1,991	22%
2017	9,254	1,873	0	177	11,305	9,307	1,998	21%	0	1,998	21%
2018	9,206	1,923	0	177	11,307	9,439	1,868	20%	0	1,868	20%
2019	10,026	1,873	0	177	12,077	9,813	2,264	23%	0	2,264	23%
2020	9,921	1,873	0	177	11,972	9,935	2,037	21%	0	2,037	21%
2021	10,714	1,448	0	177	12,340	9,952	2,388	24%	0	2,388	24%
2022	10,714	1,448	0	177	12,340	10,067	2,273	23%	0	2,273	23%
2023	10,714	1,448	0	177	12,340	10,173	2,167	21%	0	2,167	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

DUKE 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
2013/14	10,109	1,916	0	190	12,215	8,870	3,345	38%	0	3,345	38%
2014/15	10,062	1,916	0	177	12,155	9,133	3,022	33%	0	3,022	33%
2015/16	10,062	1,946	0	177	12,185	9,370	2,815	30%	0	2,815	30%
2016/17	10,194	1,958	0	177	12,330	9,298	3,032	33%	0	3,032	33%
2017/18	10,194	1,958	0	177	12,330	9,544	2,786	29%	0	2,786	29%
2018/19	11,142	1,958	0	177	13,278	9,639	3,639	38%	0	3,639	38%
2019/20	11,142	1,958	0	177	13,278	9,971	3,306	33%	0	3,306	33%
2020/21	11,026	1,958	0	177	13,162	10,059	3,103	31%	0	3,103	31%
2021/22	11,892	1,533	0	177	13,603	10,144	3,459	34%	0	3,459	34%
2022/23	11,892	1,533	0	177	13,603	10,225	3,378	33%	0	3,378	33%

Notes:

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

b. QF includes Firm Renewables

DUKE ENERGY FLORIDA

SCHEDULE 8
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2014 THROUGH DECEMBER 31, 2023

(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[a]	NOTES[b]
ANCLOTE	1	PASCO	ST	NG		PL			5/2014			17	11	FC/A	(1) and (2)
ANCLOTE	2	PASCO	ST	NG		PL			12/2014			20	19	FC/A	(1) and (2)
TURNER	3	VOLUSIA	GT							12/2014		(53)	(77)	RT	(2)
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		4/2016			(50)	(52)	FC	(2)
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		4/2016			(79)	(80)	FC	(2)
TURNER	P 1-2	VOLUSIA	GT							6/2016		(20)	(26)	RT	(2)
AVON PARK	P 1-2	HIGHLANDS	GT							6/2016		(48)	(70)	RT	(2)
RIO PINAR	P1	ORANGE	GT							6/2016		(12)	(15)	RT	(2)
SUWANNEE RIVER	P 4-5	SUWANNEE	GT					12/2014	06/2016			316	375	P	(2) and (3)
HINES	2-4	POLK	CC	NG		PL			3/2017			165	0	RP	(2) and (3)
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		10/1966	4/2018		(320)	(320)	RT	(2)
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		11/1969	4/2018		(420)	(423)	RT	(2)
SUWANNEE RIVER	1-3	SUWANNEE	ST							6/2018		(129)	(131)	RT	(2)
CITRUS	1	CITRUS	CC					11/2015	05/2018			1640	1820	P	(2), (3), and (4)
HIGGINS	P 1-4	PINELLAS	GT							6/2020		(105)	(116)	RT	(2)
UNKNOWN	1	UNKNOWN	CC					01/2018	06/2021			793	866	P	(2)

a. See page v. for Code Legend of Future Generating Unit Status.
b. NOTES
(1) Capability was reduced after gas conversion due to FD fan limitations. FD Fan replacement increases the capability to what it was before the Gas Conversion.
(2) Planned, Prospective, or Committed project.
(3) DEF continues to evaluate alternatives to the base plan, including the 2018 Citrus Combined Cycle, through IRP resource evaluations that include RFP alternative bid reviews and 2013 rate settlement reviews
(4) Approximately 50% of plant capacity is planned in service 5/2018 with the balance in service 11/2018

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2014

(1)	Plant Name and Unit Number:	**Suwannee CTs (Units 4 and 5)**	
(2)	Capacity		
	a. Summer:	316	
	b. Winter:	375	
(3)	Technology Type:	COMBUSTION TURBINE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	12/2014	
	b. Commercial in-service date:	6/2016	(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:	N/A	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 (%):	9.3	%
	e. Average Net Operating Heat Rate (ANOHR):	10,197	BTU/kWh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	35	
	b. Total Installed Cost (In-service year $/kW):	661.57	
	c. Direct Construction Cost ($/kW): ($2014)	605.36	
	d. AFUDC Amount ($/kW):	45.97	
	e. Escalation ($/kW):	10.23	
	f. Fixed O&M ($/kW-yr): ($2014)	3.86	
	g. Variable O&M ($/MWh): ($2014)	3.26	
	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

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2014

(1)	Plant Name and Unit Number:		**Citrus Combined Cycle**
(2)	Capacity		
	a. Summer:		1640
	b. Winter:		1820
(3)	Technology Type:		COMBINED CYCLE
(4)	Anticipated Construction Timing		
	a. Field construction start date:		11/2015
	b. Commercial in-service date:		5/2018 - 11/2018 (EXPECTED)
(5)	Fuel		
	a. Primary fuel:		NATURAL GAS
	b. Alternate fuel:		N/A
(6)	Air Pollution Control Strategy:		SCR and CO Catalyst
(7)	Cooling Method:		Cooling Tower
(8)	Total Site Area:		410 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):		8.00 %
	b. Forced Outage Factor (FOF):		2.00 %
	c. Equivalent Availability Factor (EAF):		90.16 %
	d. Resulting Capacity Factor (%):		76.6 %
	e. Average Net Operating Heat Rate (ANOHR):		6,624 BTU/kWh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):		35
	b. Total Installed Cost (In-service year $/kW):		924.19
	c. Direct Construction Cost ($/kW):	($2014)	774.74
	d. AFUDC Amount ($/kW):		99.90
	e. Escalation ($/kW):		49.55
	f. Fixed O&M ($/kW-yr):	($2014)	6.15
	g. Variable O&M ($/MWh):	($2014)	2.03
	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

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2014

(1)	Plant Name and Unit Number:	**Undesignated CC**	
(2)	Capacity		
	a. Summer:	793	
	b. Winter:	866	
(3)	Technology Type:	COMBINED CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	1/2018	
	b. Commercial in-service date:	6/2021	(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 (%):	75.6 %	
	e. Average Net Operating Heat Rate (ANOHR):	6,741 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	35	
	b. Total Installed Cost (In-service year $/kW):	1,613.11	
	c. Direct Construction Cost ($/kW): ($2014)	1,281.90	
	d. AFUDC Amount ($/kW):	146.84	
	e. Escalation ($/kW):	184.37	
	f. Fixed O&M ($/kW-yr): ($2014)	6.60	
	g. Variable O&M ($/MWh): ($2014)	5.45	
	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

DUKE ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

DEF does not anticipate having any Directly Associated Lines with the designated units in Schedule 8

INTEGRATED RESOURCE PLANNING OVERVIEW

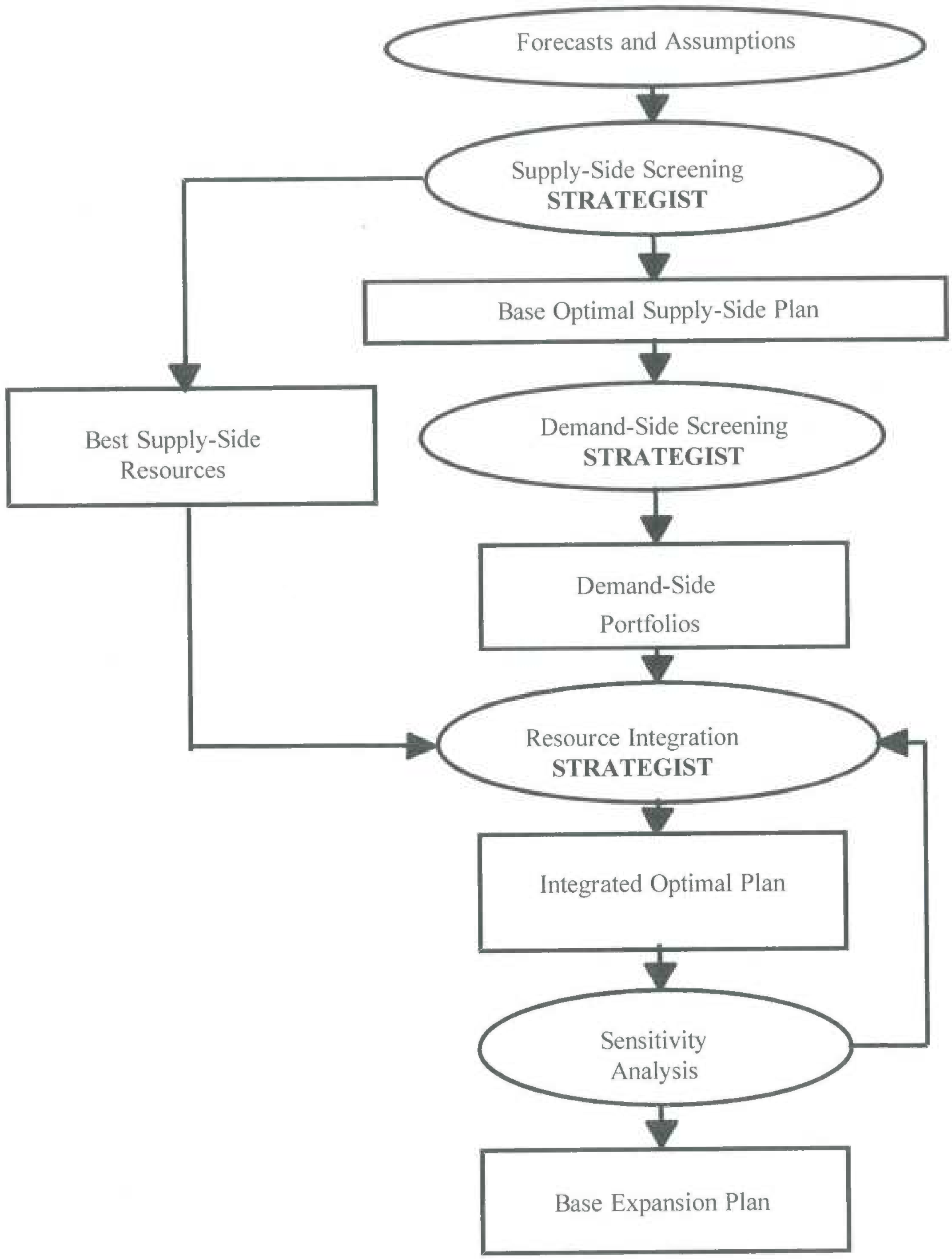
DEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. DEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide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

An overview of 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



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 DEF'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 DEF'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.

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.

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 DEF'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 DEF'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 DEF'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 DEF 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 DEF's most recent planning studies were 50 percent debt and 50 percent equity capital structure, projected cost of debt of 3.75 percent, and an equity return of 10.5 percent. The assumptions resulted on a weighted average cost of capital of 7.13 percent and an after-tax discount rate of 6.46 percent.

TEN-YEAR SITE PLAN (TYSP) RESOURCE ADDITIONS

This plan includes two combustion turbines located at the Suwannee River Site in 2016, additional summer capacity at the Hines Energy Center through the installation of Inlet Chilling, a combined cycle facility in 2018 at Citrus County (DEF issued an RFP on October 8, 2013 to seek competitive alternatives to the 2018 Citrus Combined Cycle project; bids to this RFP were closed on December 9, 2013 and the RFP is currently under evaluation), and a 2021 Combined Cycle facility at an undesignated site.

DEF continues to seek market supply-side resource alternatives to enhance DEF's resource plan and has extended a purchase power agreement with Southern Power Company beginning in 2016. Other short and long-term power resources from 2016 through 2020 are also under evaluation and may impact the proposed Base Expansion Plan.

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.The Avon Park, Rio Pinar and Turner Units P1 and P2 continue to show anticipated retirement dates in 2016. The three Suwannee steam units are projected to retire by the spring of 2018. Operation of the peaking units at Higgins units is being extended to 2020. 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.

Through its ongoing planning process, DEF 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, 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

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

Municipal Solid Waste Facilities:

Lake County Resource Recovery (12.8 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

DEF owned installations (approximately 930 kW)

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

In addition, DEF has contracts with U.S. EcoGen (60 MW) and Florida Power Development (60 MW). U.S. Ecogen will utilize an energy crop, while the Florida Power Development facility utilizes wood products as its fuel source.

DEF 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	
Pasco County Resource Recovery	23	Yes	
Pinellas County Resource Recovery	54.8	Yes	
Ridge Generating Station	39.6	Yes	
PCS Phosphate	As Avail	Yes	
Florida Power Development, LLC	60	Yes	
U.S. EcoGen Polk	60	No	1/1/17
DEF 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.

DEF continues to seek out renewable suppliers that can provide reliable capacity and energy at economic rates. DEF continues to keep an open Request for Renewables (RFR) soliciting proposals for renewable energy projects. DEF's open RFR continues to receive interest and to date has logged over 315 responses. DEF 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 DEF'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

DEF'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 DEF, 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. DEF 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, transmission 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 DEF 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.

DEF 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_Posted_Rev2.docx.
- http://www.oatioasis.com/FPC/FPCdocs/TRMID_3.docx

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

- http://www.oatioasis.com/FPC/FPCdocs/CBMID_rev2.docx

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

TABLE 3.3
DUKE ENERGY FLORIDA
LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS
2014 – 2023

MVA RATING WINTER	LINE OWNERSHIP	TERMINALS		LINE LENGTH (CKT-MILES)	COMMERCIAL IN-SERVICE DATE (MO./YEAR)	NOMINAL VOLTAGE (kV)
1000	DEF	DEBARY	ORANGE CITY	6	11/30/2015	230

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

DUKE ENERGY.
FLORIDA

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

DEF's 2014 TYSP Preferred Sites include Citrus County for Combined Cycle natural gas generation (and adjacent to the DEF Crystal River Site) and Suwannee County for Simple Cycle natural gas generation. DEF's expansion plan beyond this TYSP planning horizon includes potential nuclear power at the Levy County greenfield. The Citrus County, Suwannee County and Levy County Preferred Sites are discussed below.

SUWANNEE COUNTY

DEF has identified the existing Suwannee River Energy Center site in Suwannee County for simple cycle CTs (see Figure 4.1.a below). The proposed power block includes two (2) dual fuel CTs using F-class technology. The project area totals approximately 68 acres and is located west of River Road, south of U.S. 90. The project area consists of a naturally occurring pine-oak community of the subject parcel and has a canopy primarily composed of longleaf and slash pine as well as turkey and laurel oak. There are no wetlands within the limits of the project area.

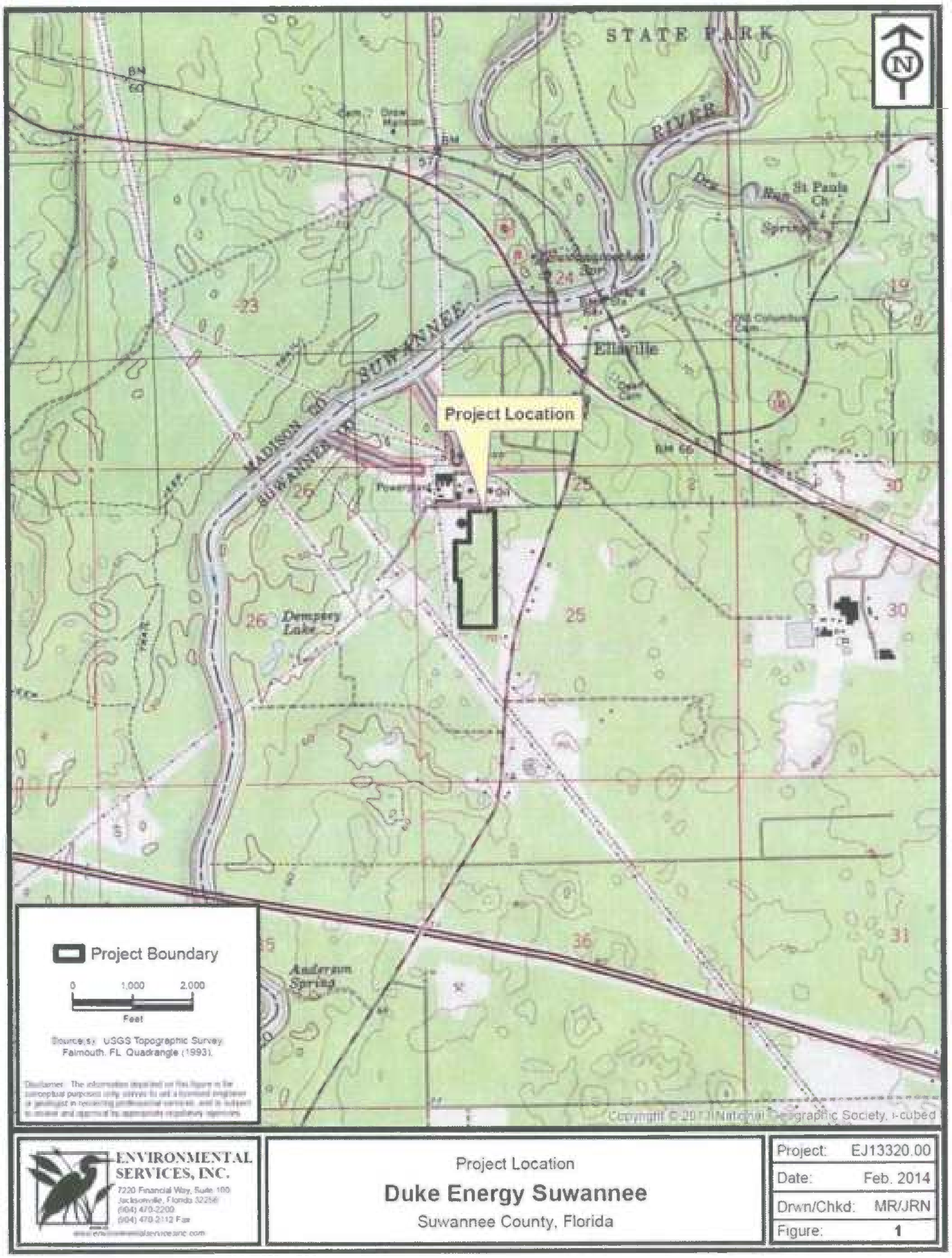
DEF's assessment of the Suwannee site addressed whether any threatened and endangered species or archeological and cultural resources would be adversely impacted by the development of the site the facilities. Gopher tortoises, a state listed species, may be impacted by the development of the project. DEF will acquire a permit from the Florida Fish and Wildlife Conservation Commission to relocate any gopher tortoises from the project area prior to construction. No archaeological or cultural resources will be adversely impacted by the project.

The new project will not require an increase of water use beyond what is already permitted to be used by the site from the Suwannee River Water Management District. Development of the project site will also require an Environmental Resource Permit and Air Permit from the Florida

Department of Environmental Protection. Suwannee County requires a special exception approval to construct the project on the property.

FIGURE 4.1.a

Suwanee County Preferred Site Location



CITRUS COUNTY

DEF has identified a site in Citrus County as a preferred site for new combined cycle generation (see Figure 4.1.b below). The Company is planning for the construction of a new combined cycle facility on the property with the unit coming on line during 2018. The Citrus site consists of approximately 400 acres of property located immediately north of the Crystal River Energy Center (CREC) transmission line right-of-way and east of the Crystal River Units 4 and 5 coal ash storage area and north of the DEF Crystal River to Central Florida 500-/230-kV transmission line right-of-way. The property consists of regenerating timber lands, forested wetlands, and rangeland bounded to the south by the CREC North Access Road. The site is currently part of the Holcim mine. 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 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 new project is proposing to use the existing CR3 intake structure and a new discharge structure in the existing discharge canal.

FIGURE 4.1.b

Citrus County Preferred Site Location

LEVY COUNTY NUCLEAR POWER PLANT – LEVY COUNTY

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.

The Levy County site is shown in Figures 4.1.c below:

FIGURE 4.1.c

Levy County Nuclear Power Plant (Levy County)

DEF's Near Term Summer and Winter Load Forecast

Year	LOAD FORECAST		
	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

DEF's Forecast of Summer Peak Demands and Reserves With and Without Additional Generation Capacity in the Summers of 2016 and 2017

		Including Suwannee CTs and Hines Inlet Chillers		Excluding Suwannee CTs and Hines Inlet Chillers	
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%	10,696	16.9%
2017	9,307	11,232	20.7%	10,696	14.9%

DEF's Forecast Of Physical And Dispatchable Demand-Side Resource Reserves Through the Summers of 2016 And 2017

Year	Summer				
	Peak Demand Before DR	Dispatchable Demand Side Resources	Net Firm Demand	Total Installed Capacity	Reserve Margin
2014	9,641	829	8,812	11,024	25.1%
2015	9,882	840	9,042	10,991	21.5%
2016	9,997	848	9,149	11,012	20.4%
2017	10,196	889	9,307	11,232	20.7%

GENERATION OPTIONS EVALUATED TO CONTRIBUTE TO DEF'S CAPACITY NEEDS IN THE SUMMERS OF 2016 AND 2017

New Simple Cycle Units: Suwannee River Plant preferred location (*Selected*)

Thermal Power Uprates: Update compressor, turbine and controls components in the combustion turbines to current design and firing temperatures.

- Bartow 4 Combined Cycle – 4 CT's
- Hines PB1 Combined Cycle – 2 CT's
- Hines PB2 Combined Cycle – 2 CT's
- Hines PB3 Combined Cycle – 2 CT's
- Hines PB4 Combined Cycle – 2 CT's

Inlet Chilling: Install electric driven chillers and thermal storage systems to cool inlet air to the combustion turbines during the warm summer months

- Bartow 4 Combined Cycle – 4 CT's
- Hines PB1 Combined Cycle – 2 CT's (*Selected*)
- Hines PB2 Combined Cycle – 2 CT's (*Selected*)
- Hines PB3 Combined Cycle – 2 CT's (*Selected*)
- Hines PB4 Combined Cycle – 2 CT's (*Selected*)

Other operations-focused options evaluated and implemented at the Bartow 4 Combined Cycle Plant:

- Replace the steam turbine LP L-0 row turbine blades at the with the OEM's current design

REDACTED

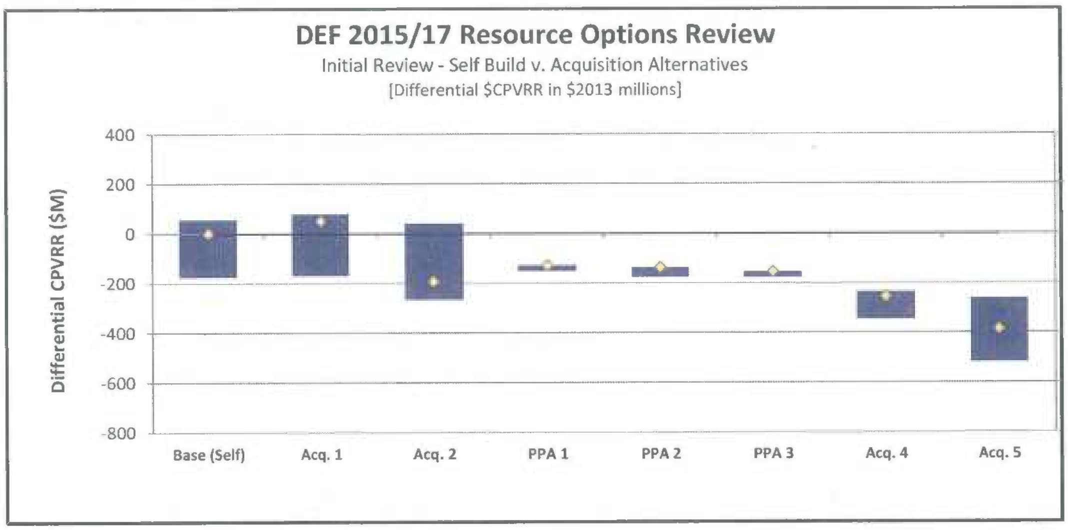
[redacted]

INITIAL DETAILED ECONOMIC ANALYSIS RESULTS FOR THE MOST COST-EFFECTIVE GENERATION OPTION TO MEET THE COMPANY'S CAPACITY NEEDS IN THE SUMMERS OF 2016 AND 2017

Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build									
$M 2013	PPA 1	PPA 2	PPA 3	Acquisition 2	Acquistion 1	Acquisition - PPA Mix 1	Acquisition - PPA Mix 2	Acquistion 3	Acquistion 4
Capital Costs	37	90	90	(49)	204	101	101	23	(35)
Fuel	395	141	45	(50)	16	(12)	260	7	(3)
Emissions	19	23	19	(71)	(47)	(3)	15	13	1
Variable Costs	19	(4)	(9)	113	34	(4)	10	(0)	1
Fixed Costs	(36)	(122)	(122)	(148)	(162)	(129)	(129)	(310)	(351)
PPAs	(567)	(270)	(184)	44	10	(65)	(375)	9	2
Cogens	(1)	5	6	(36)	(9)	0	(2)	0	1
Emergency Energy	4	2	0	4	2	2	2	3	(2)
Total	(129)	(136)	(155)	(193)	49	(110)	(118)	(255)	(386)

Docket No. ______
Duke Energy Florida
Exhibit No. _____ (BMHB-9)
Page 1 of 1

COMPANY'S COST SENSITIVITY ANALYSIS RESULTS BASED ON THE INITIAL DETAILED ECONOMIC ANALYSIS



DETAILED ECONOMIC ANALYSIS RESULTS FOR THE MOST COST-EFFECTIVE GENERATION OPTION TO MEET THE COMPANY'S CAPACITY NEEDS IN THE SUMMERS OF 2016 AND 2017.

Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build				
$M 2014	Acquisition - PPA Mix 1	PPA 1	Self Build No Hines Chillers	Self Build plus Hines 1 Chillers
Capital Costs	88	83	52	(33)
Fuel	50	227	(36)	68
Emissions	16	29	(24)	19
Variable Costs	(9)	2	13	(2)
Fixed Costs	(141)	(129)	(7)	5
PPAs	(143)	(332)	(27)	(29)
Cogens	1	3	(0)	(2)
Emergency Energy	(1)	(1)	3	1
Total	(139)	(118)	(26)	26

COMPANY'S ANALYSIS OF GAS PRICE AND CO2 COST SENSITIVITIES TO THE FINAL DETAILED ECONOMIC ANALYSES

High Gas Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build (3 Chillers)			
$M 2014	Acquisition _PPA Mix 1	PPA 1	Self Build plus Hines 1 Chillers
Capital Costs	88	83	(33)
Fuel	35	267	53
Emissions	15	29	21
Variable Costs	(10)	2	(4)
Fixed Costs	(141)	(129)	5
PPAs	(123)	(364)	(1)
Cogens	1	3	(1)
Emergency Energy	(1)	(1)	1
Total	(138)	(110)	41

No CO2 Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build (3 Chillers)			
$M 2014	Acquisition _PPA Mix 1	PPA 1	Self Build plus Hines 1 Chillers
Capital Costs	88	83	(33)
Fuel	23	205	46
Emissions	(13)	(12)	(1)
Variable Costs	(9)	3	(2)
Fixed Costs	(141)	(129)	5
PPAs	(117)	(311)	(2)
Cogens	(0)	1	(1)
Emergency Energy	(1)	(1)	1
Total	(170)	(161)	14

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.

DOCKET NO. ______
Submitted for filing:
May 27, 2014

DIRECT TESTIMONY
OF JULIE SOLOMON

ON BEHALF OF
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IN RE: PETITION FOR DETERMINATION OF COST EFFECTIVE GENERATION ALTERNATIVE TO MEET NEED PRIOR TO 2018 FOR DUKE ENERGY FLORIDA, INC.

BY DUKE ENERGY FLORIDA, INC.
FPSC DOCKET NO. ________

DIRECT TESTIMONY OF JULIE SOLOMON

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name, employer, and business address.

A. My name is Julie Solomon. I am employed by Navigant Consulting, Inc. ("Navigant"). My business address is 1200 19th Street, NW, Washington, DC 20036.

Q. What is your job with Navigant Consulting, Inc.?

A. I am a Managing Director in Navigant's Energy Practice. My consulting practice primarily focuses on regulatory issues involving mergers, asset transactions, and market based rate matters, mostly in the context of Federal Energy Regulatory Commission ("FERC") proceedings. I frequently file testimony in this regard.

Q. Please summarize your educational background and employment experience.

A. I have a bachelor's degree in Economics from Connecticut College, and a Masters in Business Administration from the Wharton School of the University of Pennsylvania. Since 1986, I have worked for firms involved in consulting in regulatory and economics matters within the energy industry, and joined Navigant in 2010. I have been involved as either an expert witness or consultant on many of the mergers and acquisitions that have occurred in recent years. Among these, I was a consultant to Duke Energy in connection with the merger of Duke Energy and Progress Energy. I submitted testimony to FERC on more than 30 mergers or asset purchases since 2010. I also often analyze potential transactions prior to entities entering into a purchase and sale agreement. A copy of my curriculum vitae is attached as Exhibit No. ___ (JS-1) to my direct testimony.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your testimony in this proceeding?

A. I am testifying on behalf of Duke Energy Florida, Inc. ("DEF" or the "Company"), to explain the results of an analysis that I performed in connection with the Company's evaluation of the most cost-effective generation alternative to meet the Company's capacity need prior to 2018. I was retained by the Company to perform the FERC Competitive Analysis Screen for potential generation facility acquisitions that the Company was considering as part of its evaluation. The Competitive Analysis Screen is also referred to as a Delivered Price Test ("DPT") or an Appendix A analysis (referring to Appendix A of FERC's Merger Policy Statement).

The Competitive Analysis Screen is part of the FERC framework to evaluate the competitive effects of proposed public utility mergers and public utility acquisitions (or disposals) of generation facilities. FERC authorization is required for all proposed public utility acquisitions of generation facilities under section 203 of the Federal Power Act ("FPA"). The Competitive Analysis Screen is one the elements required by FERC to evaluate potential horizontal market power effects in approving public utility acquisitions of generation facilities. I will explain the results of the Competitive Analysis Screen.

The testimony that I provide addresses the FERC framework and, in particular, the Competitive Analysis Screen, and seeks to be helpful to the Florida Public Service Commission ("FPSC" or the "Commission") to understand this framework, the Competitive Analysis Screen, and the results of this analysis of the potential public utility acquisitions of generation facilities.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to my testimony:

- Exhibit No. ___ (JS-1), a copy of my curriculum vitae;
- Exhibit No. ___ (JS-2), a schematic showing DEF's Balancing Authority Area ("BAA") and other BAAs in the Florida Reliability Coordinating Council ("FRCC");
- Exhibit No. ___ (JS-3), sample Herfindahl-Hirschman Index ("HHI") calculations of market concentration;
- Exhibit No. ___ (JS-4), a table depicting the metrics FERC uses to define market concentration and acceptable levels of HHI changes under the Competitive Analysis Screen;
- Exhibit No. ___ (JS-5), a table of the ten periods that are evaluated in the Competitive Analysis Screen;
- Exhibit No. ___ (JS-6), a table of the "Available Economic Capacity ("AEC") calculations derived for DEF in the Competitive Analysis Screen evaluation;
- Exhibit No. ___ (JS-7), a table of the AEC calculations derived for DEF with a ten percent increase in the market price;

- Exhibit No. ___ (JS-8), a table summarizing the differences between the AEC for DEF from Exhibit No. ___ (JS-6) and Exhibit No. ___ (JS-7);
- Exhibit No. ___ (JS-9), results of the Competitive Analysis Screen for potential Acquisition 1;
- Exhibit No. ___ (JS-10), results of the Competitive Analysis Screen for potential Acquisition 2;
- Exhibit No. ___ (JS-11), results of the Competitive Analysis Screen price increase and decrease sensitivity analyses for potential Acquisition 1; and
- Exhibit No. ___ (JS-12), results of the Competitive Analysis Screen price increase and decrease sensitivity analyses for potential Acquisition 2.

Each of these exhibits was prepared under my direction and control, and each is true and accurate.

Q. Please summarize your testimony.

A. The Company cannot acquire either potential Acquisition 1 or potential Acquisition 2 without FERC approval. A necessary step in obtaining FERC approval is the FERC Competitive Analysis Screen, which is the analytical tool FERC requires to evaluate the competitive effects of potential plant acquisitions. I performed the FERC Competitive Analysis Screen for both potential plant acquisitions. Acquisition 1 and Acquisition 2 failed the FERC Competitive Analysis Screen. FERC-required and additional sensitivities confirmed these Competitive Analysis Screen results. In my opinion, there is a reasonable risk that FERC would not approve either Acquisition 1 or Acquisition 2 without mitigation by the Company to eliminate the Competitive Analysis Screen failures. The only potential, workable structural mitigation available to the Company is building additional transmission facilities to expand the transmission import capability to increase supply in the market and offset the competitive effect of an acquisition. My calculations show that substantial, additional MegaWatts ("MW") of transmission import capability from 600 MWs to over 1,000 MWs, respectively, are required to eliminate the Competitive Analysis Screen failures for these potential plant acquisitions.

III. OVERVIEW OF FERC ANALYSIS IN COMPANY EVALUATION OF POTENTIAL GENERATION FACILITY ACQUISITIONS.

Q. What were you asked to do?

A. I was asked by the Company to assist it with its evaluation of the potential acquisition of existing generation facilities to meet the Company's near-term, future generation capacity needs. In particular, I was asked to perform an analysis required to obtain FERC approval of such acquisitions should they prove to be the most cost-effective generation capacity alternatives to meet the Company's needs. I was not asked to perform and did not perform any analyses or evaluation to determine if in fact these potential generation facility acquisitions were the most cost-effective generation for the Company and its customers.

Q. Who evaluated the potential generation facility acquisitions to determine if they were the most cost-effective alternative generation option for the Company?

A. The Company conducted that evaluation. My understanding is that Mr. Ben Borsch is providing testimony in this proceeding to explain the Company's evaluation and the results of that evaluation. I understand that potential generation facility acquisitions were one of the generation options to meet the Company's generation capacity needs in that evaluation. The other options were power purchase agreements ("PPAs") with utility and non-utility generators and self-build Company generation projects.

Q. What generation facility acquisitions did you evaluate?

A. I analyzed the Company's potential acquisition of the Acquisition 1 facility and the Acquisition 2 facility. These were the potential generation facility acquisitions that the Company asked me to evaluate under the FERC Competitive Analysis Screen. Acquisition 1 is a combustion turbine ("CT") facility located in DEF's BAA. Acquisition 2 is a combined cycle ("CC") facility located outside DEF's BAA. I used the ratings from EIA Form 860, see http://www.eia.gov/electricity/data/eia860/, which is the plant ratings source typically used by FERC for Acquisition 1 and Acquisition 2.

Q. What is a balancing authority area?

A. A BAA is a term used by the North American Electric Reliability Corporation ("NERC"), and represents a collection of generation, transmission, and loads within its boundaries. The Balancing Authority operator maintains load-resource balance within this area. The BAA typically roughly follows the boundary of a franchise retail service territory for utilities such as DEF, but it could also include generation that is physically located outside of the service territory that is dynamically scheduled into the BAA. In the context of FERC's Competitive Analysis Screen, a BAA represents the default relevant geographic market for evaluating wholesale market power. FERC requires the Competitive Analysis Screen analysis to examine the effect on competition in the BAA where the generation is interconnected and, for transmission-owning utilities such as DEF, in any interconnected (i.e., "first-tier") BAA. An excerpt from NERC's "bubble map" of BAAs in the FRCC is graphically illustrated in Exhibit No. ___ (JS-2) to my direct testimony.

Q. What is the FERC Competitive Analysis Screen?

A. The FERC Competitive Analysis Screen is the analytical tool that must be employed in the FERC framework to evaluate the competitive effects of a potential public utility generation facility acquisition. This framework was adopted by FERC to evaluate the competitive effects of potential mergers, but FERC applies the same framework to evaluate the competitive effects of potential public utility acquisitions of generation facilities. Under section 203 of the FPA, FERC authorization is required for acquisitions of generation facilities owned by public utilities.

The Competitive Analysis Screen is used to determine if the generation facility acquisition would significantly increase market concentration. Market concentration is a measure of market structure (how many and the relative size of market participants), and FERC uses market concentration and the change in market concentration as a means to evaluate market power, which is defined as the ability to sustain an increase in the market price through unilateral action or collusion to the detriment of potential customers in the market. Market power can be exercised by withholding generation from the market by taking it out of service, thus, restricting supply and increasing the market price at that time, or by raising market prices through offers at higher prices (such actions are referred to as physical and economic withholding, respectively).

Passing the FERC Competitive Analysis Screen typically leads to a conclusion that a transaction is unlikely to present competitive problems. If the Competitive Analysis Screen is "failed", i.e. the changes in market concentration exceed the allowed level, the proposed merger or acquisition is deemed likely to have an adverse impact on competition and FERC will look more closely at the transaction before making its final determination. As FERC has stated: "When there is a screen failure, applicants must provide evidence of relevant market conditions that indicate a lack of a competitive problem or they should propose mitigation." In re: Revised Filing Requirements under Part 33 of the Commission's Regulations, Order 642 FERC Stats. & Regs., ¶31,11, at page 62 (2000).

Evidence of relevant market conditions that may indicate a lack of a competitive problem include "demand and supply elasticity, ease of entry and market rules, as well as technical conditions, such as the types of generation involved." (Id.). No facts such as these have been relied on by FERC in previous orders or have been identified in the acquisitions at issue and, as a result, the FERC inquiry likely would be on any proposed mitigation.

Q. Why did FERC adopt the Competitive Analysis Screen?

A. FERC adopted its merger filing requirements, including the Competitive Analysis Screen, to provide regulatory certainty to the industry in obtaining approval for mergers or generation transactions. The Competitive Analysis Screen is intended to provide a conservative standard to allow parties to identify mergers or generation facility acquisitions that are unlikely to present competitive problems.

The FERC focus in the Competitive Analysis Screen is on the effect of the proposed merger or generation facility acquisition on the wholesale market or wholesale customers in the market. FERC's regulatory authority does not extend to whether the generation facility acquisition, for example, is a cost-effective or "good" deal for the public utility and its retail customers or the owner who is selling the generation facility to the public utility. FERC's concern in approving or disapproving the acquisition is on whether the transaction is in the public interest. The three factors in making such a determination are the impact of a transaction on competition in the wholesale market, the effect on wholesale rates, and the effect on regulation.

Q. How do you use the FERC Competitive Analysis Screen?

A. The FERC Competitive Analysis Screen is a forward-looking analysis because the impact of the proposed generation facility acquisition will occur in the future. Therefore, the Screen analysis is applied to a relatively near-term future year view of the market. Implementation of the FERC Competitive Analysis Screen requires: (i) identification of the relevant products, i.e., capacity, energy, or both for potential customers in the market; (ii) identification of customers in the market who may be affected by the acquisition; (iii) identification of the potential suppliers to each identified customer in the market; and (iv) the analysis of the market concentration using the appropriate HHI thresholds.

Q. What is the Herfindahl-Hirschman Index?

A. The HHI is a widely accepted measure of market concentration. FERC, the United States Department of Justice, and the Federal Trade Commission all use HHI metrics to evaluate market concentration. Because market concentration is a metric that captures the number of entities and their respective shares of relevant supply in a particular market, the HHI is calculated by squaring the market share of each entity competing in the market and summing the results for all market participants. Exhibit No. ___ (JS-3) to my direct testimony provides a sample HHI calculation that demonstrates how the sum of squares of market shares for the market participants is calculated. The fewer the number of entities in the market and the larger certain entities' market share, the higher the HHI. This effect can be readily seen in Exhibit No. ___ (JS-3) by comparing Market X with one supplier on the left side of the Exhibit, Market Y with 4 equal suppliers in the middle of the Exhibit, and Market Y with the proposed merger of entities "B" and "C" on the right side of the Exhibit.

Based on the HHI, markets are categorized as either "unconcentrated," "moderately concentrated," or "highly concentrated." The magnitude of acceptable changes in the HHI, and the corresponding potential merger or acquisition effect on competition in the market, differs depending on the market concentration. The standards FERC applies in this regard are depicted in the HHI market concentration table included as Exhibit No. ___ (JS-4) to my direct testimony. In Exhibit No. ___ (JS-4) any change in the HHI as a result of the potential generation facility acquisition in an unconcentrated market, for example, is unlikely to have any adverse competitive effects. In a highly concentrated market, however, any change greater than 100 points in the HHI as a result of the proposed acquisition is considered an adverse effect on competition in the market because it likely creates or enhances the acquiring entity's market power.

Q. How concentrated is the DEF BAA?

A. Focusing on the AEC metric, as described below, the DEF BAA falls into the moderately concentrated to highly concentrated ranges, depending on the time period analyzed. This means that the target HHI change is no more than 100 points when the market is moderately concentrated and no more than 50 points when the market is highly concentrated. As explained in the bottom row of Exhibit No. ___ (JS-4), if the HHI change exceeds 100 points in the moderately concentrated market, the potential transaction potentially raises significant competitive concerns. If the market is highly concentrated, a HHI change of more than 50 points also means the potential transaction potentially raises significant competitive concerns, and a HHI change of more than 100 points means the potential transaction is likely to create or enhance market power. Market concentration of such levels is not atypical for vertically integrated public utilities in a non-restructured, state-regulated electricity market.

Q. What do you mean by Available Economic Capacity?

A. FERC's Competitive Analysis Screen considers two metrics, Economic Capacity ("EC") defined as energy that can be delivered into a market at a delivered cost less than 105 percent of the presumed market price; and Available Economic Capacity ("AEC"), defined as EC over and above that required to meet native load and other long-term obligations that meet the delivered price test. That is, AEC = EC – native load. Because AEC (as well as EC) is measured under a range of system conditions, and takes into account generation economics, even if a utility has capacity equal to its peak load plus its planning reserve margin requirement, there may be significant AEC available under some market conditions. It is well established that in non-restructured markets where vertically-integrated utilities maintain load-serving obligations, AEC is the more relevant measure under the Competitive Analysis Screen. In contrast, in restructured markets, for example, in most of the markets operated by Regional Transmission Organizations ("RTO") or Independent System Operators ("ISO"), EC is the more relevant measure.

Q. How are market prices determined for the AEC calculations?

A. FERC requires that the market prices for the Competitive Analysis Screen be based on data in the Electric Quarterly Reports ("EQRs"), except when analyzing RTO or ISO markets where historical hourly data are reported by the governing entities. EQRs are quarterly, historical wholesale price reports that each utility must file with FERC. Remember, however, that the screen is forward-looking so the expected future market price for energy, not the historical energy market price, must be used. The EQRs, therefore, are the starting point for calculating the forecasted market price.

There are some inherent limitations in prices reported in the EQRs for BAAs such as DEF's BAA. Often transactions are limited, because wholesale sales activity is limited. Until very recently, non-FERC jurisdictional entities were not required to file EQRs, thus, the data excluded transactions by non-FERC-jurisdictional entities, and therefore, most of the data reported in the historical EQRs for the DEF BAA is limited to DEF's sales and any wholesale sales made by FERC-jurisdictional entities. As noted, adjustments to the historical energy prices from the EQRs must be made to move prices from historical to expected future prices, primarily consisting of adjustments to reflect changes in fuel costs. This analysis requires a review of historical and future fuel prices and related marginal costs. FERC also requires testing the sensitivity of the Competitive Screen Analysis results to higher or lower expected market prices.

Other factors must be considered to test the sensibility of the future energy market price. For example, if one finds that the Competitive Screen Analysis using a specific set of prices leads to capacity factors for generation that are significantly different than historically (e.g., plants are not economic at the market price during seasonal periods when one would expect them to be), then the market prices might need to be adjusted. To illustrate, if the future energy price calculation in a certain time period implies that a CC unit is not dispatched in a peak period, but historically CC units have been dispatched in that time period, an adjustment may need to be made to the estimated market price. Thus, determining future market energy prices for the DPT is not a purely quantitative calculation, and qualitative adjustments may be required to ensure a robust Competitive Analysis Screen.

Q. Has FERC accepted such qualitative considerations in determining market prices in the Competitive Analysis Screen?

A. Yes. Although FERC is very specific about the need to use EQRs as the basis for market prices, in appropriate circumstances, FERC has accepted qualitative adjustments to the prices. One example is a transaction involving the Bluegrass generating facility in Kentucky, where EQR-based prices implied that a CT would be economic in far too many hours (almost 30 percent of the time) when its actual capacity factor was more like 3 percent. In re: Bluegrass Generation Company, L.L.C., Louisville Gas and Electric Co., Kentucky Utilities Co., 139 FERC ¶61,094 (2012). In that example, the qualitative adjustments to the price "improved" the Competitive Analysis Screen results. Certainly, qualitative adjustments also can lead to more conservative results under the Competitive Analysis Screen.

Q. How are transmission capability and imports reflected in the Competitive Analysis Screen?

A. Transmission capability is another important input into the Competitive Analysis Screen. The Competitive Analysis Screen is a measure of competitive supply in the market, which consists of internal generation as well as external generation that can be imported into the market, taking into account generation economics, transmission costs, and the market price. FERC refers to this transmission import capability as the Simultaneous Import Limit ("SIL").

Q. What happens if a proposed generation facility acquisition fails the Competitive Analysis Screen?

A. As I referenced earlier, if the proposed generation facility acquisition fails the Competitive Analysis Screen, and a party cannot demonstrate other market factors limiting market power concerns -- which have not been identified here -- mitigation must be considered if the public utility wants to pursue FERC approval of the acquisition. FERC has demonstrated a preference for "structural" as opposed to "behavioral" mitigation and, to the extent structural mitigation is required, such mitigation must eliminate the screen failures identified in the Competitive Analysis Screen. Typical types of structural mitigation include the divestiture (sale) of owned or controlled generation or the addition of transmission (e.g., transmission upgrades, or new transmission that has not already been included in any planning studies). Selling generation reduces market concentration by reducing the selling party's market share. Adding transmission reduces market concentration by increasing the size of the market (i.e., imports, or the SIL).

IV. RESULTS OF FERC COMPETITIVE ANALYSIS SCREEN EVALUATION.

Q. How did you evaluate the Company's proposed generation facility acquisitions?

A. I evaluated these proposed acquisitions using the FERC Competitive Analysis Screen that I have just described. My focus was on the competitive effect of the potential acquisitions on the DEF BAA. Both proposed generation facility acquisitions failed the Competitive Analysis Screen. In my opinion, based on my evaluation, it is unlikely that DEF would pass the FERC Competitive Analysis Screen if DEF tries to acquire the Acquisition 1 plant located in DEF's BAA. Also based on my evaluation, it is even less likely that DEF would pass the FERC Competitive Analysis Screen if DEF tries to acquire the Acquisition 2 plant located outside DEF's BAA and incorporate that plant as a DEF network resource on DEF's system.

Q. How did you develop the data underlying the FERC Competitive Analysis Screen?

A. I started by identifying DEF's generation portfolio, including its own generation and PPAs, and then I identified the seasonal capacity ratings and generated estimates of the marginal costs for each generation resource, relying generally on third-party sources for data drawn from public (e.g., Energy Information Administration) filings or third-party databases (e.g., Ventyx). In identifying the DEF generation resources, generation under long-term PPAs with DEF were assigned to DEF while third-party generation resources located in the DEF BAA, but under long-term PPAs with other entities outside DEF's BAA, were considered "moved out" of the DEF BAA and assigned to the buyer under the PPA.

Next, I used DEF's peak load forecast and built an hourly-load shape based on historical hourly load data. This information was used to define load conditions in ten time periods identified by FERC. FERC determined in a series of FERC orders and regulations addressing the Competitive Analysis Screen evaluation that these time periods appropriately represented the range of relevant system conditions that must be considered in the Competitive Analysis Screen. See, e.g., In re: Market-Based Rates for Wholesale Sales of Electric Energy, Capacity, and Ancillary Services by Public Utilities, 119 FERC ¶ 61,296, p. 106, n.92 (2007); In re: Analysis of Horizontal Market Power under the Federal Power Act, 138 FERC ¶ 61,109 (2012). Exhibit No. ___ (JS-5) to my direct testimony is a table of the ten time periods.

Market prices are another important input to the Competitive Analysis Screen. As I described above, the EQRs were the starting point for the future market prices. The forward-looking period for the market prices here was 2015, when the acquired generation facilities would be added to DEF's system, if the acquisitions took place.

Finally, I included an estimate for the SIL into DEF's BAA. No new SIL analysis was conducted for the purpose of my analysis. Instead, for purposes of my Competitive Analysis Screen, I started with SIL data for the DEF BAA for a 2008-2009 time period that was accepted by FERC in 2012 in connection with market-based rate proceedings before FERC at that time. (In the analysis of potential Acquisition 2, I assumed the output was fully importable into the DEF BAA). Along with the SIL data, I made an assumption about how many potential suppliers would receive an allocation of imports into the market. Typically, for a full-blown FERC analysis, both a SIL study and modeling of first-tier supplies would be undertaken. Here, in addition to using previous SIL calculations, I merely estimated a number of potential suppliers that were allocated shares of the SIL. These assumptions, while necessary to complete the inputs for the Competitive Analysis Screen, had no material effect on the results of my evaluation.

Before I actually conducted the Competitive Analysis Screen, I completed an interim analysis that I refer to as the "AEC Facts." This analysis merely extracts some key data from the Competitive Analysis Screen insofar as it reflects DEF's ability to participate in the relevant market. These AEC facts are included in the table in Exhibit No. ___ (JS-6) to my direct testimony. The table in Exhibit No. ___ (JS-6) reflects DEF's total generation, its load, its Economic Capacity, which as you recall is the AEC before native load commitments are removed, and its AEC prior to the generation facility acquisition in all ten time periods.

Q. Why did you use the existing SIL study in your Competitive Analysis Screen evaluation?

A. Absent conducting a new SIL study, this is the best available SIL study information. Conducting a SIL study is a complex, time-consuming undertaking, so while such an analysis would be necessary for any actual filing to obtain FERC approval of a public utility merger or generation facility acquisition, it is not necessary to perform the study, where, as here, one can demonstrate that the results of the Competitive Analysis Screen do not turn on the specific SIL level. I often use the existing FERC-accepted SIL studies to determine if the proposed merger or acquisition likely can pass the Competitive Analysis Screen before asking a client to develop its own studies. That is the approach that I reasonably took in my Competitive Analysis Screen evaluation of the Company's proposed generation facility acquisitions. As discussed below, I also tested the sensitivity of using different SIL levels.

Q. What conclusions do you draw from the AEC facts in the table in Exhibit No. ___ (JS-6) to your direct testimony?

A. The last row of the table of AEC facts in Exhibit No. ___ (JS-6) shows that, based on these market prices, DEF has AEC in only two of the ten time periods. These are the Winter Super Peak and the Winter Peak. I also examined the underlying data and tested whether the AEC results are "knife edge", that is whether, with slightly higher prices, a significant amount of additional capacity becomes economic. This is evident by looking at market prices 10% higher, as shown in Exhibit No. ___ (JS-7), and by a comparison of the amount of AEC that DEF has between the two sets of market prices, as shown in Exhibit No. ___ (JS-8). With prices 10% higher, DEF has AEC in six, rather than just two, of the ten time periods. DEF's AEC ranges from 452 MW to 3,077 MW. Prices do not have to be 10% higher across the board to see some of this "knife-edge" effect. For example, increasing the Winter Off-Peak price by only $2/MWh results in DEF having 1,164 MW additional AEC in that time period. This sensitivity analysis is important, not simply because FERC requires price sensitivities, but because it provides the means to challenge or "test" the validity of the results using the base EQR prices, i.e. whether the

EQR price results are a reasonable reflection of the market price. More typically, my experience is that the +10% and -10% price sensitivities required by FERC do not yield such different results as I found here. These results suggest that the EQR prices understate expected market prices and lead to the conclusion that the 10% higher price results may more accurately reflect a better "base case."

More AEC available in more time periods increases the opportunity that the DEF AEC will coincide with economic supply from the potential generation facility that is the subject of the potential acquisition. The relevant time periods of overlap will differ for a CT such as the Acquisition 1 plant and a CC such as the Acquisition 2 plant. Where there are overlaps, there is more opportunity for increases in market concentration that the FERC Competitive Analysis Screen seeks to identify.

Q. What were the results of your Competitive Analysis Screen?

A. The results of the Competitive Analysis Screen for potential Acquisition 1 are shown in Exhibit No. ___ (JS-9) to my direct testimony. In the base case, using prices based solely on the EQRs (adjusted to a 2015 price), the Acquisition 1 plant capacity is economic in only three time periods, the two Summer Peak periods and the Winter Super Peak period. This is demonstrated in column five in Exhibit No. ___ (JS-9) where the Acquisition 1 plant has economic supply available in these time periods. Only one of these time periods overlaps a time period when DEF has AEC, that is the Winter Super Peak time period, which can be seen by comparing column three and column five in Exhibit No. ___ (JS-9). The HHI change in the far right hand column in Exhibit No. ___ (JS-9) for this time period is 1,221, in a very highly concentrated market where any HHI change above 100 points indicates the potential transaction is likely to create or enhance market power. As a result, potential Acquisition 1 does not pass the FERC Competitive Analysis Screen. Further, as I discuss below, the results are similar in the required FERC -10% price sensitivity and significantly worse in the FERC +10% price sensitivity.

Q. What were the results of your Competitive Analysis Screen for potential Acquisition 2?

A. The results of the Competitive Analysis Screen for potential Acquisition 2 are shown in Exhibit No. ___ (JS-10) to my direct testimony. In this base case, again using prices based solely on the EQRs, potential Acquisition 2 plant capacity is economic in all but two of the time periods. This is not a surprising outcome; potential Acquisition 2 is a CC plant, and therefore it is more efficient than the CTs in the Acquisition 1 plant and should have economic capacity in more time periods than the Acquisition 1 plant. The only time periods where potential Acquisition 2 plant capacity is not economic are the Shoulder Off-Peak period and the Winter Off-Peak period. This is depicted in column five in Exhibit No. ___ (JS-10). There are periods of overlap with DEF's AEC, however, only in the Winter Super Peak and Winter Peak time periods. This can be seen by comparing column three and column five in Exhibit No. ___ (JS-10). The HHI changes in the far right hand column in Exhibit No. ___ (JS-10) for these time periods is 540 and 1,357, respectively, again, in a very highly concentrated market where any HHI change above 100 points indicates the potential transaction is likely to create or enhance market power. Thus, potential Acquisition 2 does not pass the FERC Competitive Analysis Screen.

Q. Was this the end of your evaluation?

A. No. FERC also requires that you perform price sensitivities around the base case in the Competitive Analysis Screen. I performed the FERC-required sensitivities at a ten percent decrease and increase in price. The results of these sensitivity analyses for the potential Acquisition 1 are contained in the tables in Exhibit No. ___ (JS-11) to my direct testimony. The 10% sensitivity is typically what I use to meet FERC's requirement that price sensitivities be submitted. Here, however, because the EQR prices proved to be so "knife-edge", as I discussed previously, I believed that the base case prices might be understating DEF's AEC. As a result, I believe that the +10% price increase sensitivity might be closer to a base case and, accordingly, I looked at a +20% price increase sensitivity as well.

As shown in the first table in Exhibit No. ___ (JS-11), at a ten percent increase in price, the DEF AEC increases substantially from two to six time periods with a substantial increase in MWs; the economic time periods for Acquisition 1 plant capacity increase from three to four; and the overlap between DEF AEC and Acquisition 1 plant capacity increases from one to two time periods, at the Summer Super Peak 2 period in addition to the Winter Super Peak. There are now two changes in HHI well above the 100 point change limit. Thus, the screen failures increase with a ten percent increase in price.

The screen failures increase further with a twenty percent increase in price. The second table in Exhibit No. ___ (JS-11) contains the 20 percent price increase sensitivity results for potential Acquisition 1. With this price increase, there is DEF AEC in every time period (see column 3 in the second table). There is now an overlap with DEF AEC in five time periods. Only one of these overlapping time periods is below the HHI change target of 50 points. The other four overlapping time periods have HHI changes well above the 100 HHI point change limit, as shown in the far right column in the second table in Exhibit No. ___ (JS-11). The result is there are four screen failures. As prices increase, therefore, the screen failures increase.

I also conducted the required FERC reduced price sensitivity analysis, using -10%. The third table in Exhibit No. ___ (JS-11) contains the results of this sensitivity analysis. With a ten percent decrease in price, DEF has AEC in only one time period, the Winter Super Peak, where this is an overlap with economic Acquisition 1 plant capacity and a HHI change well above the HHI change limit of 100 points at 1,363. Even in the price decrease sensitivity analysis potential Acquisition 1 fails the Competitive Analysis Screen.

Q. Did you perform the same price sensitivity analyses for potential Acquisition 2?

A. Yes. The results of the ten percent and twenty percent price increase sensitivity analyses, and the ten percent price decrease sensitivity analysis, for potential Acquisition 2 are contained in the tables in Exhibit No. ___ (JS-12) to my direct testimony. The first table in Exhibit No. __ (JS-12) contains the ten percent price increase sensitivity results; the second table contains the twenty percent price increase sensitivity results; and the third table contains the ten percent price decrease sensitivity results. Starting with the ten percent price increase sensitivity results, the fifth column of the first table shows that potential Acquisition 2 has economic capacity in all ten time periods. The DEF AEC in column three increases from two to six time periods with a ten percent increase in price.

That means there is an overlap of the DEF AEC and the economic potential Acquisition 2 plant capacity in six time periods. The HHI change for all six time periods in the far right column of the first table is well over the HHI 100 point change limit. All six overlapping time periods are screen failures.

The screen failures grow with a further increase in price from ten to twenty percent. In the second table in Exhibit No. ___ (JS-12), with a twenty percent increase in price, there is DEF AEC and potential Acquisition 2 economic plant capacity in all ten time periods. As depicted in the far right column in the second table in Exhibit No. ___ (JS-12), nine of the ten overlapping DEF AEC and potential Acquisition 2 economic capacity time periods are screen failures. All nine screen failure time periods are well over the HHI 100 point change limit.

Now, turning to the ten percent price decrease sensitivity analysis results in the third table, DEF has AEC in only one time period, the Winter Super Peak, and potential Acquisition 2 also has economic capacity in that time period, resulting in a HHI change of 701, as shown in the far right column of the third table. This HHI change exceeds the HHI 100 point change limit and, as a result, this potential transaction also fails the Competitive Analysis Screen even when prices decrease.

The FERC required price sensitivity calculations in the Competitive Analysis Screen further confirm that neither potential Acquisition 1 nor potential Acquisition 2 pass the Competitive Analysis Screen.

Q. Were there any other sensitivities that were performed as part of your evaluation?

A. Yes. I also tested my results using significantly higher SILs. Using higher SILs assumes that transmission import capability has increased relative to the earlier SIL studies accepted by FERC. Higher SILs, therefore, dilute DEF's market share, makes the market less concentrated (lower total HHI), and reduces the HHI changes resulting from a proposed acquisition transaction. Higher SILs increase the possibility that the potential acquisitions may pass the Competitive Analysis Screen. The results of these significantly higher SIL calculation sensitivities did lower the HHI changes for the potential acquisitions, however, they did not result in a change in the outcome of the base case or price sensitivity Competitive Analysis Screen analyses. Both Acquisition 1 and Acquisition 2 still failed the Competitive Analysis Screen even with the higher SILs.

Q. Why did you perform a sensitivity case with higher SILs?

A. Even though the SIL data and study I used in my base case and price sensitivity Competitive Analysis Screen analyses is the best SIL information for the DEF BAA available at this time, I understand that new SIL data likely will become available later this summer when market-based rate filings are made with FERC for the Southeast Region. The FERC likely will not approve any new SIL studies until sometime next year. Nevertheless, I wanted to perform a sensitivity analysis that considered higher import levels. Even assuming significantly higher SILs, the results are directionally the same. Neither potential generation facility acquisition passed the Competitive Analysis Screen. This additional sensitivity analysis provides further confirmation that the results of my Competitive Analysis Screen for these potential acquisitions are conservative.

Q. In your opinion will potential Acquisition 1 pass the Competitive Analysis Screen at FERC?

A. No. As I have explained above, I conservatively evaluated potential Acquisition 1 under the FERC Competitive Analysis Screen and the acquisition fails the screen. The additional sensitivity analyses that I performed that I have described above confirm this result. In my opinion, there is a reasonable risk that FERC would not approve this generation facility acquisition without mitigation by the Company. These are the kinds of risks I typically evaluate for parties considering asset transactions requiring FERC approval. As a result, there is a risk that FERC would require mitigation.

Q. In your opinion will potential Acquisition 2 pass the Competitive Analysis Screen at FERC?

A. No. As I have also explained above, I conservatively evaluated potential Acquisition 2 under the FERC Competitive Analysis Screen and that acquisition also fails the screen. The additional sensitivity analyses that I performed that I have described above confirm this result too. In my opinion, and for the same reasons discussed above with respect to Acquisition 1, there is a reasonable risk that FERC would not approve this generation facility acquisition without mitigation by the Company.

Q. What mitigation, if any, is available to the Company to mitigate these Competitive Analysis Screen failures?

A. As I explained above, there are two typical structural remedial measures, reducing DEF owned or controlled generation capacity in the market by selling off its generation facilities or expanding the market by increasing its overall transmission import capability. Selling off generation to alleviate the Competitive Analysis Screen failure makes no sense for DEF because DEF needs additional generation capacity to meet its reliability need. Indeed, that is the reason DEF is considering these acquisitions in the first place, namely that DEF needs additional capacity. The only potential, workable structural mitigation available to DEF to alleviate the Competitive Analysis Screen failures for these potential generation facility acquisitions is increasing the transmission import capability. This means DEF must build additional transmission facilities to expand the transmission import capability (i.e. the SIL).

Q. Were you asked to evaluate potential transmission mitigation for the Competitive Analysis Screen failures?

A. Yes. Once it became clear that both potential generation facility acquisitions failed the FERC Competitive Analysis Screen and additional transmission import capability was the only potential, workable mitigation, the Company asked me to determine what additional transmission import capability would be required to mitigate the screen failures. I used the same FERC-approved SIL study and data that I used in the FERC Competitive Analysis Screen evaluation as well as additional DEF and market generation and transmission information to perform calculations to estimate the additional transmission import capability (SIL) to mitigate the FERC Competitive Analysis Screen failures. In the case of potential Acquisition 1, I estimated, based on my analysis, that approximately 600 MWs to 800 MWs of additional transmission import capability were necessary to mitigate the Competitive Analysis Screen failures. In the case of potential

Acquisition 2, the increase in transmission import MW capability was even higher, with in excess of 1,000 MWs of additional transmission import capability mitigation required. The results of my transmission import capability mitigation analyses were provided to the Company.

It is important to note that increased transmission capability requires an increase in the SIL, not just an increase on any particular transmission line. Because where the transmission limit occurs can differ in each season, increasing transmission across one interface may or may not increase the SIL in each season. This further complicates the determination of how much transmission is needed. In addition, DEF cannot rely on already planned transmission upgrades or improvements to increase the SIL. Such planned upgrades or improvements cannot be considered as mitigation to address the Competitive Analysis Screen failures and, therefore, they cannot be counted as part of the structural remedy by DEF.

Q. In your opinion, are the results of your mitigation evaluations for the Company's potential generation facility acquisitions reasonable?

A. Yes. These results are based on detailed calculations using reasonable data and analyses under these circumstances where there are substantial Competitive Analysis Screen failures under conservative FERC Competitive Analysis Screen base case and sensitivity analyses.

Q. Can FERC waive the requirements to file a Competitive Analysis Screen?

A. No. FERC's regulations contain limited exemptions from filing a Competitive Analysis

Screen under specific circumstances, but such exemptions are not applicable here. The Competitive Analysis Screen need not be filed if the applicant can demonstrate that they do not conduct business in the same geographic market or the extent of business transactions in the same geographic market is *de minimis* (and no intervenor has alleged that the parties are perceived potential competitors in the same geographic market). There is no procedure to seek a waiver of filing an analysis, absent meeting these limited exemptions.

Q. Can FERC simply ignore failures of the Competitive Analysis Screen?

A. No. When there is a screen failure, applicants are required to provide evidence of relevant market conditions that indicate a lack of a competitive problem, which as I explained above are not present here, or propose mitigation. There are limited circumstances in which FERC may determine that screen failures do not lead to a conclusion that there is a competitive concern, but that of course, means FERC has addressed the Competitive Analysis Screen failure results in a proceeding before FERC and reached that conclusion based on the evidence presented in that proceeding.

Q. Does this conclude your direct testimony?

A. Yes.

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Professional History

- Managing Director, Navigant Consulting - 2010-Present
- Vice President, Charles River Associates - 2001-2010
- Senior Vice President, Putnam, Hayes and Bartlett, Inc. and PHB Hagler Bailly, Inc., Washington, DC - 1986-2000
- Economist, Economic Consulting Services, Inc., Washington, DC - 1979-1986
- Economist, U.S. Department of Labor, Washington, DC - 1976-1979

Education

- M.B.A. Finance, The Wharton School University of Pennsylvania
- B.A. Economics, Connecticut College

Testimony

- Written testimony provided in more than 150 regulatory proceedings

Julie Solomon is a Managing Director at Navigant Consulting, Inc. in the Energy Practice's Power Systems, Markets & Pricing group. She has more than 20 years of consulting experience, specializing in the areas of regulatory and utility economics, financial analysis and business valuation. Ms. Solomon has participated in analysis of proposed regulatory reforms, supply options and utility industry restructuring in the gas and electric industries. She also has advised utility clients in corporate strategy and corporate restructuring, and consulted to legal counsel on a variety of litigation and regulatory matters, including antitrust litigation and contract disputes. She has filed testimony in numerous proceedings before the Federal Energy Regulatory Commission. Much of her current practice focuses on regulatory and market power issues concerning mergers and acquisitions and compliance filings in the electricity market.

» Advised clients in the electric and gas utility industry on competition issues, including the impact of mergers on competition. Directed a large number of analytic studies relating to obtaining merger approval from regulatory authorities.

» Advised clients in the electric utility industry on restructuring strategies, including potential mergers and acquisitions, functional unbundling and cost savings.

» Consulted in the electric and gas utility industries in a variety of regulatory and competition matters, including rate proceedings, prudence reviews, proposed regulatory reforms, analysis of supply options, privatization and restructuring.

» Advised utility and non-utility clients on many aspects of the competitive independent power industry, including strategic and financial consulting assignments.

» Consulted legal counsel on a variety of litigation matters, including the development of expert testimony on liability issues and the calculation of damages in a variety of industries.

» Provided strategic and economic analyses for clients in trade regulatory proceedings such as dumping and subsidies.

» Provided financial and business valuation analyses in a number of transactions, including fair market value for taxation purposes and valuation of family-owned businesses.

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Professional Experience

Electric and Gas Utilities

Mergers and Acquisitions (Market Power and Competition Issues)

» Advised clients and conducted analytic studies in connection with a large number of major electric and electric-gas mergers and asset transactions of regulated companies. Provided testimony to FERC for a number of these types of transactions.

» Advised clients and provided confidential pre-screening analyses for potential mergers and acquisitions.

» Conducted numerous analytic studies in connection with FERC market-based rate applications and compliance filings for electricity sellers. Provided testimony to FERC for a number of these types of transactions.

» Conducted numerous analytic studies in connection with FERC market-based rate applications and compliance filings for gas storage facilities. Provided testimony to FERC for a number of these types of transactions.

Utility Restructuring and Stranded Cost

» Conducted analytic studies and provided litigation support in connection with state stranded cost proceedings in Ohio (Cincinnati Gas & Electric and Dayton Power & Light); West Virginia (Monongahela Power and Potomac Edison); Maryland (Potomac Edison) and Pennsylvania (West Penn Power).

» Provided analytic support evaluating the benefits of Public Service of Colorado's proposed DC transmission line between Colorado and Kansas in support of a regulatory proceeding.

» Assisted in studies relating to privatization of the electricity industry in the United Kingdom, including development of a computer model to simulate electricity dispatch and project future prices, capacity needs and utility revenues under various scenarios. During temporary assignment to London office.

» Participated in antitrust litigation involving a utility and a cogenerator, including preparation of an expert report on liability and damage issues, preparation of expert witnesses for deposition, and assistance in preparation for depositions of opposing expert and in-house witnesses.

» Assisted in the valuation of the interests of several firms in various cogeneration projects for the purpose of combining these interests into a new entity or selling interests to third parties.

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- Analyzed the financial feasibility and viability of a large number of cogeneration projects, assisted in the preparation of presentations and filings and presented testimony to the relevant public utility commission. Ms. Solomon also assisted in the development of a PC-based financial model to analyze various cogeneration projects.
- Participated in a study to analyze the financial effects of a variety of restructuring options for a utility, including transfer and/or sale of assets and subsequent sale-leasebacks, and debt restructuring alternatives. In addition, she developed a PC-based financial model with applications to utility restructuring plans.
- Provided litigation support in major utility rate proceedings, including assisting in the preparation of responses to interrogatories and data requests, preparation of company and outside expert witnesses for deposition and hearings, and assistance in the deposition and cross-examination of intervenor witnesses.
- Participated in proceedings involving regulation of an oil pipeline, which included evaluating the business risks faced by the company.

Business Valuation

- Participated in a valuation study involving the fair market value of a privately held company for purposes of an IRS proceeding.
- Participated in a valuation study in a divorce proceeding, where the assets being valued included a privately held business.
- Participated in two strategic engagements that developed business plans and identified potential acquisition candidates for the client.
- Provided advice to a client concerning the benefits and potential risks of developing a partnership with a competitor.

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Testimony or Expert Report Experience

- Affidavit on behalf of NatGen Southeast Power LLC, Docket No. EC14-81, application for authorization of disposition of jurisdictional facilities, April 28, 2014.
- Surrebuttal Testimony on Behalf of Commonwealth Edison Company, Illinois Commerce Commission, Application for a Certificate of Public Convenience and Necessity, No. 13-0657, April 9, 2014.
- Affidavit on behalf of KMC Thermo, LLC, Docket No. ER14-1468, market-based rate application, March 12, 2014.
- Affidavit on behalf of Trailstone Power, LLC, Docket No. ER14-1439, market-based rate application, March 6, 2014.
- Affidavit on behalf of MACH Gen, LLC et al., Docket No. EC14-61, application for authorization of disposition of jurisdictional facilities, March 4, 2014.
- Affidavit on behalf of MidAmerican Geothermal, LLC, et al., Docket No. EC14-59, application for authorization of disposition of jurisdictional facilities, February 20, 2014.
- Affidavit on behalf of Green Mountain Power Corporation, Docket No. ER11-1933, market-based rate triennial filing, February 7, 2014.
- Affidavit on behalf of NorthWestern Corporation, et al., Docket No. EC14-41, application for authorization of disposition of jurisdictional facilities, January 10, 2014.
- Affidavit on behalf of NorthWestern Corporation, Docket No. ER11-1858, notification of change in status, January 10, 2014.
- Affidavit on behalf of MidAmerican Energy, Docket No. ER10-2475, notification of change in status, January 2, 2014.
- Affidavit on behalf of Powerex Corp., Docket No. ER11-2664, market-based rate triennial filing, December 31, 2013.
- Affidavit on behalf of TransAlta, Docket No. ER10-2847, market-based rate triennial filing, December 31, 2013.
- Affidavit on behalf of Duquesne Light Company, Docket No. ER10-1910, market-based rate triennial filing, December 31, 2013.
- Affidavit on behalf of Constellation Energy Nuclear Group, Docket No. ER10-2179, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Exelon, Docket No. ER12-2178, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Dominion, Docket No. ER13-434, market-based rate triennial filing, December 30, 2013.

» Affidavit on behalf of Brookfield Companies, Docket No. ER10-2895, market-based rate triennial filing, December 30, 2013.

» Affidavit on behalf of Oklahoma Gas & Electric, Docket No. ER14-882, notification of change in status/tariff filing, December 30, 2013.

» Affidavit on behalf of AES Corp, Docket No. ER10-3415, market-based rate triennial filing, December 26, 2013.

» Affidavit on behalf of JPMorgan, Docket No. ER10-2331, market-based rate triennial filing, December 23, 2013.

» Affidavit on behalf of Northeast Utilities, Docket No. ER10-1801, market-based rate triennial filing, December 20, 2013.

» Affidavit on behalf of Iberdrola, Docket No. ER10-2822, market-based rate triennial filing, December 20, 2013.

» Affidavit on behalf of PHI, Docket No. ER10-2997, market-based rate triennial filing, December 20, 2013.

» Affidavit on behalf of Essential Power, Docket No. ER12-952, market-based rate triennial filing, December 20, 2013.

» Affidavit on behalf of Empire District, Docket No. ER14-793, notification of change in status/tariff filing, December 20, 2013.

» Affidavit on behalf of Westar Energy, Inc., Docket No. ER14-724, notification of change in status/tariff filing, December 19, 2013.

» Affidavit on behalf of Alpha Gen Power, LLC, Docket No. ER14-630, market-based rate application, December 16, 2013.

» Affidavit on behalf of Black Bear Hydro Partners, LLC, Docket No. EC14-28, application for authorization of disposition of jurisdictional facilities, November 14, 2013.

» Affidavit on behalf of Sierra Pacific Power Company, Docket No. ER10-2474, notification of change in status, November 4, 2013.

» Affidavit on behalf of ECP, Docket No. ER11-3859, notification of change in status, September 30, 2013.

» Affidavit on behalf of Steele Flats Wind Project, LLC, Docket No. ER13-2474, market-based rate application, September 27, 2013.

» Affidavit on behalf of Tuscola Wind II, LLC, Docket No. ER13-2458, market-based rate application, September 26, 2013.

» Affidavit on behalf of Pheasant Run Wind, LLC and Pheasant Run Wind II, LLC, Docket Nos. ER13-2461-2, market-based rate applications, September 26, 2013.

- Affidavit on behalf of TPF II and USPG Holdings, LLC, Docket No. EC13-154, application for authorization of disposition of jurisdictional facilities, September 25, 2013.
- Affidavit on behalf of Seneca Generation, LLC et al., Docket Nos. ER13-2316-9, market-based rate applications, September 4, 2013.
- Affidavit on behalf of Seneca Generation, LLC et al., Docket No. EC13-143, application for authorization of disposition of jurisdictional facilities, September 4, 2013.
- Supplemental Affidavit on behalf of MidAmerican Energy (Silver Merger Sub, Inc.), Docket No. EC13-128, application for authorization of disposition of jurisdictional facilities, August 17, 2013.
- Affidavit on behalf of Desert Sunlight 250, LLC and Desert Sunlight 300, LLC, Docket Nos. ER13-1991-2, market-based rate applications, July 17, 2013.
- Affidavit on behalf of MidAmerican Energy (Silver Merger Sub, Inc.), Docket No. EC13-128, application for authorization of disposition of jurisdictional facilities, July 12, 2013.
- Affidavit on behalf of Calpine Southwest MBR Sellers, Docket No. ER10-1942, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of NextEra Companies, Docket No. ER10-1847, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of Wayzata Entities, Docket No. ER10-1777, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of AES MBR Affiliates, Docket No. ER10-3415, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of Sierra Pacific Power Company, *et al.* under ER10-2474, Docket No. ER10-24744, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of NorthWestern Corporation, Docket No. ER11-1858, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of SGOC Southwest MBR Sellers, Docket No. ER10-2864, market-based rate triennial filing, June 28, 2013.
- Affidavit on behalf of GWF Energy LLC, et al. Docket No. ER10-3301, market-based rate triennial filing, June 28, 2013.
- Affidavit on behalf of NV Energy, Inc., application for approval of internal reorganization, Docket No. EC13-113, May 31, 2013.
- Affidavit on behalf of Midwest Generation, LLC, Docket No. EC13-103, application for authorization of disposition of jurisdictional facilities, May 6, 2013.
- Affidavit of behalf of Nevada Power Company (with Matthew E. Arenchild), Docket No. EC13-96, application for authorization of disposition of jurisdictional facilities, April 17, 2013.

- Affidavit of behalf of Dynegy Inc., Docket No. EC13-93, application for authorization of disposition of jurisdictional facilities, April 16, 2013.
- Application on behalf of Florida Power & Light Company, Docket No. EC13-91, application for authorization of disposition of jurisdictional facilities, April 12, 2013.
- Affidavit on behalf of Blythe Energy LLC, et al., Docket No. EC13-89, application for authorization of disposition of jurisdictional facilities, April 2, 2013.
- Affidavit on behalf of New Harquahala Generating Company, LLC, Docket No. ER10-3310, market-based rate triennial filing, March 29, 2013.
- Affidavit on behalf of Dominion Energy Brayton Point, et al., Docket No. EC13-82, application for authorization of disposition of jurisdictional facilities, March 21, 2013.
- Affidavit on behalf of Duke Energy Carolinas, LLC et al., Docket No. ER10-2566, et al., notice of change in status, January 29, 2013.
- Affidavit on behalf of CCI Roseton LLC, Docket No. ER13-773, market-based rate application, January 17, 2013.
- Affidavit on behalf of CCI Roseton LLC, Docket No. EC13-63, application for authorization of disposition of jurisdictional facilities, January 16, 2013.
- Affidavit on behalf of Calpine Oneta Power, LLC, Docket No. ER11-3777, et al., market-based rate triennial filing, December 31, 2012.
- Affidavit on behalf of NextEra Energy Companies, Docket No. ER12-569, et al., market-based rate triennial filing, December 27, 2012.
- Affidavit on behalf of Nevada Power Company, Docket No. ER10-2474, market-based rate triennial filing, December 26, 2012.
- Testimony on behalf of Powerex Corp re Puget Sound Energy, Inc v. All Jurisdictional Sellers of Energy & Capacity, Docket No. EL01-10, December 17, 2012.
- Affidavit on behalf of AES Beaver Valley, LLC, Docket No. ER13-442, market-based rate application, November 21, 2012.
- Affidavit on behalf of Broad River Energy LLC, et al., Docket No. EC13-42, application for authorization of disposition of jurisdictional facilities, November 16, 2012.
- Affidavit on behalf of Westar Energy, Inc., Docket No. ER10-2507, notice of change in status, October 29, 2012.
- Affidavit on behalf of Homer City Generation, L.P., Docket No. ER13-55, market-based rate application, October 9, 2012.
- Affidavit on behalf of Homer City Generation, L.P., et al., Docket No. EC13-9, application for authorization of disposition of jurisdictional facilities, October 9, 2012.

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» Affidavit on behalf of GenOn Marsh Landing, LLC, Docket No. ER12-2545, market-based rate application, August 29, 2012.

» Affidavit on behalf of High Mesa Energy, LLC, Docket No. ER12-2528, market-based rate application, August 27, 2012.

» Affidavit on behalf of Brandon Shores LLC, et al., Docket No. EC12-137, application for authorization of disposition of jurisdictional facilities, August 23, 2012.

» Affidavit on behalf of North Sky River Energy, LLC, Docket No. ER12-2444, market-based rate application, August 14, 2012.

» Affidavit on behalf of Duke Energy Carolinas, LLC et al., Docket No. ER10-2566, et al., notice of change in status, August 1, 2012.

» Affidavit on behalf of Canandaigua Power Partners, LLC et al., Docket No. ER10-2460, notice of change in status, July 16, 2012.

» Affidavit on behalf of Limon Wind I and Limon Wind II, LLC, Docket Nos. ER12-2225 and -2226, market-based rate application, July 10, 2012.

» Affidavit on behalf of Ensign Wind, LLC, Docket No. ER12-2227, market-based rate application, July 10, 2012.

» Affidavit on behalf of NextEra Energy Companies, Docket No. ER10-1836, et al., market-based rate triennial filing, July 2, 2012.

» Affidavit on behalf of Iberdrola Renewables, LLC, et al., Docket No. ER10-2994, et al., market-based rate triennial filing, June 29, 2012.

» Affidavit on behalf of The Empire District Electric Company, Docket No. ER10-2738, market-based rate triennial filing, June 29, 2012.

» Affidavit on behalf of Wisconsin Electric Power Company, Docket No. ER10-2563, market-based rate triennial filing, June 29, 2012.

» Affidavit on behalf of Baltimore Gas and Electric Company, et al., Docket No. ER10-2172, et al., market-based rate triennial filing, June 29, 2012.

» Affidavit on behalf of Westar Energy, Inc., Docket No. ER12-2124, market-based rate triennial filing, June 28, 2012.

» Affidavit on behalf of Duke Energy Beckjord, LLC, et al., Docket No. ER12-1946 et al., market-based rate application, June 5, 2012.

» Affidavit on behalf of Minco Wind III, LLC, Docket No. ER12-1880, market-based rate application, May 31, 2012.

» Affidavit on behalf of Tuscola Bay Wind, LLC, Docket No. ER12-1660, market-based rate application, April 30, 2012.

- Affidavit on behalf of Powerex Corp., Docket No. ER11-2664, notice of change in status, April 13, 2012.
- Affidavit on behalf of Safe Harbor Water Power Corporation, Docket No. ER11-2780, notice of change in status, April 11, 2012.
- Affidavit on behalf of Hot Spring Power Company, LLC, Docket No. EC12-87, application for authorization of disposition of jurisdictional facilities, March 28, 2012.
- Affidavit on behalf of High Majestic Wind II, LLC, Docket No. ER12-1228, market-based rate application, March 8, 2012.
- Affidavit on behalf of Duke Energy Indiana, Inc. et al., Docket No. ER10-2034 et al., notice of change in status, January 31, 2012.
- Affidavit on behalf of CPV Cimarron Renewable Energy Company, LLC, Docket No. ER12-775, market-based rate application, January 6, 2012.
- Affidavit on behalf of LS Power Marketing, LLC, et al., Docket No. ER10-2739, et al., market-based rate triennial filing, January 3, 2012.
- Affidavit on behalf of Auburndale Peaker Energy Center, LLC, et al., Docket No. ER10-1945, et al., market-based rate triennial filing, January 3, 2012.
- Affidavit on behalf of Duke Energy Indiana, Inc., et al., Docket No. ER10-2034, et al., market-based rate triennial filing, December 28, 2011.
- Affidavit on behalf of Northern Indiana Public Service Company, Docket No. ER10-1781, market-based rate triennial filing, December 28, 2011.
- Affidavit on behalf of Baltimore Gas and Electric Company, et al., Docket No. ER10-2172, et al., market-based rate triennial filing, December 28, 2011.
- Affidavit on behalf of Duke Energy Carolinas, LLC Docket No. ER10-2566, notice of change in status, December 27, 2011.
- Affidavit on behalf of AEE2, L.L.C., et al., Docket No. ER10-3142, et al., market-based rate triennial filing, December 23, 2011.
- Affidavit on behalf of Exelon Generation Company, LLC, et al., Docket No. ER10-1144, et al., market-based rate triennial filing, December 23, 2011.
- Affidavit on behalf of AEE2, L.L.C., et al., Docket No. ER10-3142, et al., notice of change in status, December 23, 2011.
- Affidavit on behalf of Perrin Ranch, LLC, Docket No. ER12-676, market-based rate application, December 22, 2011.
- Affidavit on behalf of GenOn Energy Management, LLC, et al., Docket No. ER10-1869, et al., market-based rate triennial filing, December 16, 2011.

- Affidavit on behalf of Blackwell Wind, LLC, Docket No. ER12-569, market-based rate application, December 7, 2011.
- Affidavit on behalf of Bluegrass Generation Company, L.L.C. et al., Docket No. EC12-29, application for authorization of disposition of jurisdictional facilities, November 14, 2011.
- Affidavit on behalf of Dynegy Danskammer, L.L.C., et al., Docket No. EC12-27, application for authorization of disposition of jurisdictional facilities, November 8, 2011.
- Affidavit on behalf of LSP Energy Limited Partnership, et al., Docket No. EC12-19, application for authorization of disposition of jurisdictional facilities, November 1, 2011.
- Affidavit on behalf of Tenaska Power Management, LLC, Docket No. ER12-60, market-based rate application, October 11, 2011.
- Testimony on behalf of Florida Power & Light Company, Docket No. ER12-46, October 7, 2011.
- Affidavit on behalf of Montezuma Wind II, LLC and Vasco Winds, LLC, Docket No. ER11-4677 and ER11-4678, market-based rate applications, September 28, 2011.
- Affidavit of Amsterdam Generating Company, LLC, et al. under Docket No. EC11-118, application for authorization of disposition of jurisdictional facilities, September 9, 2011.
- Affidavit on behalf of Minco Wind II, LLC, Docket No. ER11-4428, market-based rate application, September 2, 2011.
- Affidavit on behalf of Osage Wind, LLC, Docket No. ER11-4363, market-based rate application, August 24, 2011.
- Affidavit on behalf of Baltimore Gas and Electric Company, et al., Docket No. ER10-2172, et al. and Calvert Cliffs Nuclear Power Plant, LLC, et al. Docket No. ER10-2179, et al. Notice of Change in Status, August 19, 2011.
- Affidavit on behalf of Michigan Wind II, LLC, Docket No. ER11-3989, market-based rate application, August 17, 2011.
- Affidavit on behalf of Morgan Stanley Capital Group, Docket No. EC11-97, application for authorization of disposition of jurisdictional facilities, July 22, 2011.
- Affidavit on behalf of Calpine Energy Services, L.P., et al., Docket No. ER10-2042, et al., Supplemental market-based rate filing, July 22, 2011.
- Affidavit on behalf of South Carolina Electric & Gas Co, Docket No. ER10-2498, market-based rate triennial filing, July 14, 2011.
- Affidavit on behalf of Duke Energy Carolinas, LLC, Docket No. ER10-2566, market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of North Allegheny Wind, LLC, Docket No. ER10-1330, et al.., market-based rate triennial filing, June 30, 2011.

- Affidavit on behalf of NextEra Energy Companies, Docket No. ER10-1838, market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of NextEra Energy Companies, Docket No. ER10-1852, market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of AES MBR Affiliates, Docket No. ER10-3142 et al., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of MATEP Limited Partnership, Docket No. ER10-3194, market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of Morgan Stanley Capital Group Inc., Docket No. ER94-1384 et al., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of Louisville Gas and Electric Company et al., Docket No. ER10-1511 et al., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of Progress Companies, Docket No. ER10-1760 et al., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of Mojave Solar, LLC, Docket No. ER11-3917, market-based rate application, June 29, 2011.
- Affidavit on behalf of GDF SUEZ Northeast MBR Sellers, Docket No. ER10-2670 et al., market-based rate triennial filing, June 24, 2011.
- Affidavit on behalf of Alcoa Companies, Docket No. ER10-3069 et al., market-based rate triennial filing, June 23, 2011.
- Affidavit on behalf of Northwestern Corporation, Docket No. EC11-88, application for authorization of disposition of jurisdictional facilities, June 6, 2011.
- Testimony, with Joe D. Pace, on behalf of Exelon Corporation and Constellation Energy Group, Inc., Docket No. EC11-83, merger application, May 20, 2011.
- Affidavit on behalf of The AES Corporation and DPL Inc., Docket No. EC11-81, application for authorization of disposition of jurisdictional facilities, May 18, 2011.
- Affidavit on behalf of Wildcat Power Holdings, LLC, Docket No. ER11-3336, market-based rate application, April 15, 2011.
- Affidavit on behalf of TPF Generation Holdings, LLC, University Park Energy, LLC, and LSP Park Generating, LLC, Docket No. EC11-61, application for authorization of disposition of jurisdictional facilities, April 4, 2011.
- Affidavit on behalf of Entegra Power Group LLC, Gila River Power, L.P., and Wildcat Power Holdings, LLC, Docket No. EC11-54, application for authorization of disposition of jurisdictional facilities, May 22, 2011.

- Affidavit on behalf of Safe Harbor Water Power Corporation, Docket No. ER11-2780, market-based rate triennial filing, January 28, 2011.
- Supplemental Affidavit on behalf of NorthWestern Corp et al., Docket No. ER03-329-010 et al., triennial market-based rate update, January 21, 2011.
- Affidavit on behalf of Mountain View Power Partners IV, LLC, Docket No. ER11-2701, market-based rate application, January 19, 2011.
- Affidavit on behalf of Calpine Energy Services, L.P., et al., Docket No. ER10-2042, et al., market-based rate triennial filing, January 3, 2011.
- Affidavit on behalf of J.P. Morgan Ventures Energy Corporation, Docket No. ER05-1232, market-based rate triennial filing, December 31, 2010.
- Affidavit on behalf of the Exelon MBR Companies, Docket No. ER10-1048, et al., market-based rate triennial filing, December 30, 2010.
- Affidavit on behalf of First Wind Energy Marketing, LLC, et al., Docket No. ER09-1549, et al. , market-based rate application, December 30, 2010.
- Affidavit on behalf of the IRI MBR Companies, Docket No. ER11-2462, et al., market-based rate triennial filing, December 29, 2010.
- Affidavit on behalf of Green Mountain Power Corporation, Docket No. ER01-989, market-based rate triennial filing, December 29, 2010.
- Affidavit on behalf of Baltimore Gas and Electric Company et al., Docket Nos. ER10-2172 et al., market-based rate triennial filing, December 29, 2010.
- Affidavit on behalf of Dominion Resources Services, Inc., on behalf of Virginia Electric and Power Company and affiliates, Docket No. ER01-468, et al., market-based rate triennial filing, December 27, 2010.
- Affidavit on behalf of NextEra Companies, Docket No. ER98-2494, et al., market-based rate triennial filing, December 27, 2010.
- Affidavit on behalf of Atlantic City Electric Company et al., Docket No. ER96-1351 et al., market-based rate triennial filing, December 27, 2010.
- Affidavit on behalf of Allegheny Companies, Docket No. ER11-2481 et al., market-based rate triennial filing, December 27, 2010.
- Affidavit on behalf of Red Mesa Wind, LLC, Docket No. ER11-2192, market-based rate application, November 25, 2010.
- Affidavit on behalf of Duke Energy Vermillion II, LLC; Duke Energy Hanging Rock II, LLC; Duke Energy Lee II, LLC; Duke Energy Washington II, LLC; Duke Energy Fayette II, LLC; Docket Nos. ER11- 2063-6 and 2069, market-based rate application, November 10, 2010.

- Affidavit on behalf of Elk City II Wind, LLC, Docket No. ER11-2037, market-based rate application, November 5, 2010.
- Affidavit on behalf of AES Laurel Mountain, LLC, Docket No. ER11-2036, market-based rate application, November 5, 2010.
- Supplemental Affidavit on behalf of GDF SUEZ S.A. and International Power Plc, Docket No. EC10-98, application for authorization of disposition of jurisdictional facilities, October 29, 2010.
- Supplemental Affidavit on behalf of NorthWestern Corp et al., Docket No. ER03-329-010 et al., triennial market-based rate update, October 18, 2010.
- Supplemental Affidavit on behalf of Fore River Development, LLC, et al., Docket No. EC10-85, application for authorization of disposition of jurisdictional facilities, October 8, 2010.
- Affidavit on behalf of Harbor Gen Holdings, LLC, et al., Docket No. EC11-3, application for authorization of disposition of jurisdictional facilities, October 6, 2010.
- Affidavit on behalf of Ashtabula Wind III, LLC, Docket No. ER11-26, market-based rate application, October 5, 2010.
- Affidavit on behalf of LSP Safe Harbor Holdings, LLC, Docket No. ER11-27, market-based rate application, October 5, 2010.
- Affidavit on behalf of Exelon Corporation, et al., Docket No. EC10-105, application for authorization of disposition of jurisdictional facilities, September 30, 2010.
- Supplemental Affidavit on behalf of Constellation Mystic Power, LLC, Docket No. ER10-2281, September 23, 2010.
- Affidavit on behalf of GDF SUEZ S.A. and International Power Plc, Docket No. EC10-98, application for authorization of disposition of jurisdictional facilities, September 23, 2010.
- Affidavit on behalf of Minco Wind, LLC, Docket No. ER10-2720, market-based rate application, September 17, 2010.
- Affidavit on behalf of Baldwin Wind, LLC, Docket No. ER10-2551, market-based rate application, September 7, 2010.
- Affidavit on behalf of Fore River Development, LLC, et al., Docket No. EC10-85, application for authorization of disposition of jurisdictional facilities, August 18, 2010.
- Affidavit on behalf of Constellation Mystic Power, LLC, Docket No. ER10-2281, market-based rate application, August 18, 2010.
- Affidavit on behalf of Calpine Mid-Atlantic Marketing, LLC, Docket No. ER10-2029, market-based rate application, July 29, 2010.
- Affidavit on behalf of Sundevil Power Holdings, LLC, Docket No. ER10-1777, market-based rate application, July 14, 2010.

- Supplemental affidavit on behalf of Shell Energy North America (US), Docket No. ER08-656, triennial market-based rate update, July 9, 2010.
- Affidavit on behalf of NextEra Companies, Docket No. ER02-2018 et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of NorthWestern Corp et al., Docket No. ER03-329 et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of Mirant, Docket No. ER01-1270 et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of CalPeak Entities and Tyr Energy, LLC, Docket No. ER06-1331, et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of Starwood Power-Midway, Docket No. LLC under ER08-110, triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of J.P. Morgan Ventures Energy Corporation and BE CA LLC in ER05-1232, et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of AES 2, L.L.C., et al. Docket No. ER99-2284, et al., triennial market-based rate update, June 29, 2010.
- Affidavit on behalf of Sierra Pacific Power Company and Nevada Power Company, Docket No. ER01-1527 et al., triennial market-based rate update, June 28, 2010.
- Affidavit on behalf of Dynegy Marketing and Trade, LLC, et al., Docket No. ER09-629, et al., triennial market power update, June 23, 2010.
- Affidavit on behalf of Mirant Corporation and RRI Energy, Inc., application for authorization to transfer jurisdictional facilities, Docket No. EC10-70, May 14, 2010.
- Affidavit on behalf of New Development Holdings, LLC et al., application for authorization to transfer jurisdictional facilities, Docket No. EC10-64, May 6, 2010.
- Supplemental affidavit on behalf of JPMorgan Chase, Docket No. ER07-1358 et al., notice of change in status regarding market-based rate authorization, April 16, 2010.
- Supplemental affidavit on behalf of Shell Energy North America (US), Docket No. ER08-656, triennial market-based rate update, April 12, 2010.
- Supplemental affidavit on behalf of Dogwood Energy LLC, Docket No. ER07-312, triennial market-based rate update, April 9, 2010.
- Affidavit on behalf of Big Horn Wind Project LLC and Juniper Canyon Wind Power LLC, Docket Nos. ER10-974 and 975, market-based rate application, March 31, 2010.
- Affidavit on behalf of CER Generation, LLC Docket No. ER10-662, market-based rate application, March 19, 2010.

- Affidavit on behalf of Calpine Corporation, Docket No. ER00-3562 et al., triennial market-based rate update, March 16, 2010.
- Affidavit on behalf of NV Energy, Docket No. ER01-1529 et al., triennial market-based rate update, March 8, 2010.
- Affidavit on behalf of Day County Wind, LLC, Docket No. ER10-825, market-based rate application, March 4, 2010.
- Affidavit on behalf of Dogwood Energy LLC, Docket No. ER07-312, triennial market-based rate update, March 1, 2010.
- Affidavit on behalf of NextEra Companies, Docket No. ER10-149 et al., triennial market-based rate update, March 1, 2010.
- Supplemental affidavit on behalf of The Empire District Company, Docket No. ER99-1757, triennial market-based rate update, February 22, 2010.
- Supplemental affidavit on behalf of Oklahoma Gas and Electric Company & OGE Energy Resources, Inc., Docket No. ER98-511 and ER97-4345, triennial market-based rate update, February 19, 2010.
- Supplemental affidavit on behalf of Westar Energy, Inc., ER98-2157 et al., triennial market-based rate update, February 18, 2010.
- Affidavit on behalf of AES ES Westover, LLC, Docket No. ER10-712, market-based rate application, February 5, 2010.
- Affidavit on behalf of RRI Florida MBR Companies, Docket No ER09-1110 et al. notice of change in status regarding market-based rate authorization, February 1, 2010.
- Affidavit on behalf of Wolverine Power Supply Cooperative, Inc. and FirstEnergy Generation Corp., Docket No. EC10-41, January 21, 2010.
- Affidavit on behalf of FPL Energy Illinois Wind, LLC, Docket No. ER10-402, market-based rate application, December 10, 2009.
- Affidavit on behalf of NextEra Companies, Docket No. ER09-832, et al., notice of change in status regarding market-based rate authorization, December 7, 2009.
- Affidavit on behalf of Garden Wind, LLC, Docket No. ER10-296 and Crystal Lake Wind III, LLC, Docket No. ER10-297, market-based rate application, November 23, 2009.
- Affidavit on behalf of Stateline II, LLC, Docket No. ER10-256, market-based rate application, November 16, 2009.
- Affidavit on behalf of Elk City Wind, LLC, Docket No. ER10-149, market-based rate application, November 2, 2009.
- Affidavit on behalf of Alcoa Power Generating, Inc. et al., Docket No. ER07-496 et al., triennial market-based rate update, October 30, 2009.

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Julie R. Solomon

» Affidavit on behalf of CPV Keenan II Renewable Energy Co, LLC, Docket No. ER10-64, market-based rate application, October 16, 2009.

» Supplemental Affidavit on behalf of Florida Power & Light Co et al., Docket No. ER97-3359 et al., triennial market-based rate update, October 7, 2009.

» Affidavit on behalf of High Majestic Wind Energy Center, LLC, Butler Ridge Wind Energy Center, LLC, and Wessington Wind Energy Center, LLC, Docket Nos. ER10-1-3, market-based rate applications, October 6, 2009.

» Affidavit on behalf of Powerex Corp. in State of California, ex rel. Lockyer v. British Columbia Power Exchange Corp., et al., Docket No. EL02-71, September 17, 2009.

» Affidavit on behalf of Alcoa Power Generating, Inc. et al., Docket No. ER07-496 et al., triennial market-based rate update, September 14, 2009.

» Affidavit on behalf of Powerex Corp. in State of California, ex rel. Edmund G. Brown, Attorney General for the State of California v. Powerex Corp. (f/k/a British Columbia Power Exchange Corp.), et al., Docket No. EL09-56, September 3, 2009.

» Affidavit on behalf of Ashtabula Wind II, LLC, Docket No. ER09-1656, market-based rate application, September 1, 2009.

» Affidavit on behalf of Oklahoma Gas and Electric Company et al., Docket No. ER98-511 et al., triennial market power update, July 30, 2009.

» Affidavit on behalf of Westar Energy, Inc & Kansas Gas and Electric Company, Docket No. ER98-2157 et al., triennial market power update, July 30, 2009.

» Affidavit on behalf of The Empire District Electric Company, Docket No .ER99-1757, triennial market power update, July 30, 2009.

» Affidavit on behalf of NextEra Companies, Docket No. ER08-1297, et al., triennial market power update, June 30, 2009.

» Affidavit on behalf of Calpine Energy Services, L.P., et al., Docket No. ER00-3562, et al. triennial market power update, June 30, 2009.

» Affidavit on behalf of Dominion Energy Kewaunee, Inc., Docket No. ER04-318, triennial market power update, June 30, 2009.

» Affidavit on behalf of CinCap IV, LLC, Docket No. ER05-1372 et al., triennial market power update, June 30, 2009.

» Affidavit on behalf of Wisconsin Electric Power Company, Docket No. ER98-855, triennial market power update, June 30, 2009.

» Affidavit on behalf of J.P. Morgan Ventures Energy Corporation, et al., Docket No. ER05-1232, et al., triennial market power update, June 30, 2009.

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- Affidavit on behalf of Iberdrola Renewables, Inc et al., Docket No. ER08-912 et al., triennial market power update, June 30, 2009.
- Affidavit on behalf of Exelon Generation Co, LLC et al., Docket No. ER00-3251 et al., triennial market power update, June 30, 2009.
- Affidavit on behalf of Dynegy Marketing and Trade, LLC, et al., Docket No. ER09-629, et al., triennial market power update, June 26, 2009.
- Affidavit on behalf of GenConn Middletown, LLC and GenConn Devon, LLC, Docket Nos. ER09-1300-1301, market-based rate application, June 15, 2009.
- Affidavit on behalf of Northern Colorado Wind Energy, Docket No. ER09-1297, market-based rate application, June 12, 2009.
- Affidavit on behalf of Fox Energy Company LLC, Docket No. ER03-983, triennial market power update, June 3, 2009.
- Affidavit on behalf of the KGen Companies, Docket No .ER04-1181 et al., market-based rate change in status filing, April 2, 2009.
- Affidavit on behalf of Victory Garden Phase IV, LLC, Sky River LLC, FPL Energy Cabazon Wind LLC, Docket Nos. ER09-900-902, market-based rate application, April 1, 2009.
- Affidavit on behalf of the KGen Companies, Docket No. EC07-30 et al., March 31, 2009.
- Affidavit on behalf of TransAlta Energy Marketing Corporation, Docket No. ER09-884, market-based rate application, March 25, 2009.
- Affidavit on behalf of NorthWestern Energy, Docket No. ER03-329, triennial market-based rate update, December 30, 2008.
- Affidavit on behalf of Calpine Corporation re Broad River Energy LLC et al., Docket No. ER00-38 et al., triennial market-based rate update, December 30, 2008.
- Affidavit on behalf of Constellation MBR Entities, Docket No. ER99-2948 et al., triennial market-based rate update, December 30, 2008.
- Affidavit on behalf of LS Power Marketing, LLC, Docket No. ER96-1947 et al., triennial market-based rate update, December 29, 2008.
- Affidavit on behalf of Tenaska Alabama Partners, L.P., et al., Docket No. ER00-840 et al., triennial market-based rate update, December 24, 2008.
- Affidavit on behalf of Bluegrass Generation Company, LLC., et al., Docket No. ER02-506 et al., triennial market-based rate update, December 24, 2008
- Affidavit on behalf of KGen Hinds, LLC, et al., Docket No. ER04-1181 et al., triennial market-based rate update, December 23, 2008
- Affidavit on behalf of Reliant SE MBR Entities, FERC Docket No. ER05-143 et al., triennial market-based rate update, December 23, 2008.

» Affidavit on behalf of Exelon Generation Company, LLC, Docket No. ER00-3251 triennial market-based rate update, December 18, 2008.

» Affidavit on behalf of Northern Indiana Public Service Co. et al., Docket No. ER00-2173 et al., triennial market-based rate update, December 18, 2008.

» Affidavit on behalf of Duke Energy Indiana, Inc., et al., Docket No. ER07-189 et al., triennial market-based rate update, December 17, 2008.

» Affidavit on behalf of Shady Hills Power Company, LLC, Docket No. ER02-527, triennial market-based rate update, December 4, 2008.

» Affidavit on behalf of Farmers City Wind, LLC, Docket No. ER09-31, market-based rate application, October 6, 2008.

» Affidavit on behalf of Elm Creek Wind, LLC, Docket No. ER09-30, market-based rate application, October 6, 2008.

» Affidavit on behalf of Dynegy Marketing and Trade, Docket No. ER09-20, market-based rate application, October 6, 2008.

» Affidavit on behalf of LS Power Development, LLC and Luminus Management, LLC, Docket No. EC08-126, September 24, 2008.

» Affidavit on behalf of Public Utility District 2 of Grant County, WA, in NorthWestern Corporation, in connection with market-based rates for ancillary services, Docket No. ER08-1529, September 12, 2008.

» Affidavit on behalf of LG&E Energy Marketing Inc. et al., Docket No. ER94-1188 et al., triennial market-based rate update, September 2, 2008.

» Affidavit on behalf of Alcoa Power Generating, Inc. et al., Docket No. ER07-496 et al., triennial market-based rate update, September 2, 2008.

» Affidavit on behalf of Calpine Corporation re Bethpage Energy Center 3, LLC et al., Docket No. ER04-1099 et al., September 2, 2008.

» Supplemental Affidavit on behalf of Virginia Electric and Power Co. et al., Docket No. ER01-468 et al., triennial market-based rate update, September 2, 2008.

» Affidavit on behalf of South Carolina Electric & Gas Company, Docket No. ER96-1085, triennial market-based rate update, September 2, 2008.

» Affidavit on behalf of Florida Power & Light Co et al., Docket No. ER97-3359 et al., triennial market-based rate update, September 2, 2008.

» Affidavit on behalf of Progress Energy Inc. et al., Docket No. ER99-2311 et al., triennial market-based rate update, September 2, 2008.

» Affidavit on behalf of the EME Companies, Docket No. ER96-2652 et al., triennial market-based rate update, August 29, 2008.

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- Affidavit on behalf of Bridgeport Energy, LLC et al., Docket No. ER98-2783. triennial market-based rate update, August 29, 2008.
- Affidavit on behalf of Duke Energy Carolinas, LLC, Docket No. ER07-188, triennial market-based rate update, August 29, 2008.
- Supplemental Affidavit on behalf of PHI Entities, Docket No. ER96-1361 et al., triennial market-based rate update, August 21, 2008.
- Supplemental Affidavit on behalf of Constellation MBR Entities, Docket No. ER99-2948 et al., triennial market-based rate update, August 18, 2008.
- Supplemental Affidavit on behalf of Exelon MBR Companies, Docket No. ER00-3251 et al., triennial market-based rate update, August 15, 2008.
- Affidavit on behalf of Fowler Ridge Wind Farm, LLC, Docket No. ER08-1323, application for market-based rates, August 1, 2008.
- Affidavit on behalf of FPL Energy, LLC, Docket No. ER08-1300 et al., application for market-based rates, July 24, 2008.
- Affidavit on behalf of Naturener Montana Wind Energy, LLC, Docket No. ER08-1261, application for market-based rates, July 15, 2008.
- Affidavit on behalf of FPLE Companies, FERC Docket No. ER02-2559 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Duke Energy MBR Companies, FERC Docket No. ER07-189 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Bear Energy LP et al., FERC Docket No. ER06-864 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Reliant NE MBR Entities, FERC Docket No. ER00-2129 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Noble Altona Windpark, LLC et al., FERC Docket No. ER06-1409 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of NRG Companies, FERC Docket No. ER97-4281 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of BG Dighton Power, LLC et al., FERC Docket No. ER06-1367 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Mirant Canal, LLC et al., FERC Docket No. ER01-1268 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of CPV Liberty, LLC, FERC Docket No. ER07-1193, triennial market-based rate update, June 30, 2008.

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- Affidavit on behalf of Tenaska Energy, Inc. et al., FERC Docket No. ER02-24 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Birchwood Power Partners LP et al., FERC Docket No. ER07-501 et al., triennial market-based rate update, June 27, 2008.
- Affidavit on behalf of Wisconsin Electric Power Company, FERC Docket No. ER08-1176, application for market-based rates, June 27, 2008.
- Affidavit on behalf of New Athens Generating Co., LLC and Millennium Power Partners, LP, triennial market-based rate update, FERC Docket No. ER98-830 et al., June 27, 2008.
- Affidavit on behalf of Granite Ridge Energy, LLC, FERC Docket No. ER05-287, triennial market-based rate update, June 27, 2008.
- Affidavit on behalf of Astoria Generating Co. LP et al., FERC Docket No. ER99-3168 et al., triennial market-based rate update, June 24, 2008.
- Affidavit on behalf of Duke Energy Carolinas, LLC, FERC Docket No. EC08-94, application for sale of jurisdictional assets, May 30, 2008.
- Supplemental Affidavit on behalf of Allegheny Energy Supply Company, LLC et al., triennial market-based rate update, FERC Docket No. ER98-1466, April 21, 2008.
- Supplemental Affidavit on behalf of Baltimore Gas and Electric Company et al., triennial market-based rate update, FERC Docket No. ER99-2948, April 21, 2008.
- Affidavit on behalf of JPMorgan Chase & Co. and The Bear Stearns Companies Inc., application for sale of jurisdictional assets, FERC Docket No. EC08-66, March 31, 2008.
- Affidavit on behalf of Oklahoma Gas & Electric Company, et al., application for sale of jurisdictional assets, FERC Docket No. EC08-58, March 20, 2008.
- Affidavit on behalf of NRG Southaven, LLC et al., FERC Docket No. EC08-57, March 20, 2008.
- Affidavit on behalf of Shell Energy North America (US), LP, application for market-based rates, FERC Docket No. ER08-656, March 11, 2008.
- Affidavit on behalf of EFS Parlin Holdings, LLC, application for market-based rates, FERC Docket No. ER08-649, March 10, 2008.
- Affidavit on behalf of Safe Harbor Power Corporation, application for market-based rates, FERC Docket No. ER08-537, February 5, 2008.
- Affidavit on behalf of Auburndale Peaker Energy Center, LLC et al., FERC Docket No. ER02-1633, change in status, January 31, 2008.
- Affidavit on behalf of Calpine Corp. and LS Power Development, LLC et al., FERC Docket No. EC08-39-000, January 22, 2008.
- Supplemental Affidavit on behalf of Langdon Wind, LLC, application for market-based rate authority, FERC Docket No. ER08-250-000, January 15, 2008.

» Affidavit on behalf of AES Western Wind MV Acquisition, Docket No. EC08-37, January 15, 2008.

» Affidavit on behalf of Dominion Energy Marketing, Inc. et al., application for market-based rate authority, FERC Docket No. ER01-468, January 14, 2008.

» Affidavit on behalf of Baltimore Gas and Electric Company et al., updated market-based rate filing, FERC Docket No. ER99-2948, January 14, 2008.

» Affidavit on behalf of Allegheny Energy Supply Company, LLC et al., updated market-based rate filing, FERC Docket No. ER98-1466, January 14, 2008.

» Affidavit on behalf of Exelon Generation Company, LLC et al., updated market-based rate filing, FERC Docket No. ER00-3251, January 14, 2008.

» Affidavit on behalf of Pepco Holdings, Inc., et al., updated market-based rate filing, FERC Docket No. ER96-1361, January 14, 2008.

» Affidavit on behalf of Green Mountain Power Corporation, updated market-based rate filing, FERC Docket No. ER01-0989, January 14, 2008.

» Affidavit on behalf of Duquesne Light Company et al., updated market-based rate filing, FERC Docket No. ER98-4159 et al., January 11, 2008.

» Affidavit on behalf of Central Hudson Gas and Electric Corporation, updated market-based rate filing, FERC Docket No. Docket No. ER97-2872 et al., January 11, 2008.

» Affidavit on behalf of Bicent (California) Malburg, LLC, application for market-based rate authority, FERC Docket No. ER08-314-000, December 7, 2007.

» Affidavit on behalf of Northern Indiana Public Service Co. and Broadway Gen Funding, LLC, application and related exhibits requesting authorization for a transaction to transfer a generating facility, FERC Docket No. EC08-21-000, December 6, 2007.

» Affidavit on behalf of Langdon Wind, LLC, application for market-based rate authority, FERC Docket No. ER08-250-000, November 21, 2007.

» Affidavit on behalf of Calpine Corp. and Harbinger Capital Partners Master Fund I, Ltd. et al., joint application for approval of the proposed distribution of common stock of a reorganized Calpine to Acquirors, FERC Docket No. EC08-15-000, November 16, 2007.

» Affidavit on behalf of Waterbury Generation, LLC, application for market-based rate authority, FERC Docket No. ER08-200-000, November 9, 2007.

» Affidavit on behalf of FPL Energy Oliver Wind II, LLC, application for market-based rate authority, FERC Docket No. ER08-197-000, November 8, 2007.

» Affidavit on behalf of Central Power & Lime, Inc., application for market-based rate authority, FERC Docket No. ER08-148-000, November 1, 2007.

» Affidavit on behalf of Gilberton Power Company, application for market-based rate authority, FERC Docket No. ER08-83-000, October 23, 2007.

NAVIGANT

Julie R. Solomon

- Affidavit on behalf of Black Bayou Storage, LLC, application for market-based rate authority for a natural gas storage facility, FERC Docket No. CP07-451, September 25, 2007.
- Affidavit on behalf of NedPower Mount Storm, LLC, application for market-based rate authority, FERC Docket No. ER07-1306-000, August 23, 2007.
- Affidavit on behalf of Sempra Energy Trading Corp. in connection with market-based rate authority, FERC Docket No. ER03-1413-005, July 25, 2007.
- Affidavit on behalf of KGen Acquisition I, LLC et al., application for disposition of jurisdictional facilities, FERC Docket No. EC07-116-000, July 13, 2007.
- Supplemental Affidavit on behalf of Williams Power Company, Inc., application for market-based rate authority, FERC Docket No. EC07-106-000, June 28, 2007.
- Affidavit on behalf of Williams Power Co, Inc and Bear Energy LP, joint application for authorization of the disposition of jurisdictional facilities, FERC Docket No. EC07-106-000, June 14, 2007.
- Affidavit on behalf of Bluegrass Generation Company, LLC et al., notice of non-material change in status, FERC Docket No. ER02-506-008 et al., May 31, 2007.
- Affidavit on behalf of BG Dighton Power, LLC et al., notice of non-material change in status, FERC Docket Nos. ER06-1367-003 et al., May 30, 2007.
- Affidavit on behalf of FPL Energy Point Beach, LLC, application for market-based rate authority, FERC Docket No. ER07-904-000, May 16, 2007.
- Affidavit on behalf of Copiah Storage, LLC, application for market-based rate authority for a natural gas storage facility, FERC Docket No, CP02-24, March 29, 2007.
- Affidavit on behalf of NRG Power Marketing, Inc. and thirty-one affiliates most of which own generating facilities, triennial market power update and notice of change in status, FERC Docket Nos. ER97-4281-016 et al., March 26, 2007.
- Affidavit on behalf of Egan Hub Storage, application for market-based rate authority for a natural gas storage facility, FERC Docket No. CP07-88, February 20, 2007.
- Affidavit on behalf of Wisconsin Electric Power Co. and FPL Energy Point Beach, LLC, joint application for authorization to dispose of jurisdictional facilities, FERC Docket No. EC07-57-000, February 1, 2007.
- Affidavit on behalf of Lake Road Generating Company, LP et al., joint application for authorization of the disposition of jurisdictional facilities pursuant to Section 203 of the Federal Power Act, FERC Docket No. EC07-50-000, January 22, 2007.
- Affidavit on behalf of Exelon Generation Company, LLC et al., notice of non-material change in status, FERC Docket Nos. ER00-3251-013 et al., December 15, 2006.
- Revised Affidavit on behalf of Calpine Energy Services, LP, triennial market analysis, FERC Docket No. ER00-3562-004, December 13, 2006.

NAVIGANT

Julie R. Solomon

- Affidavit on behalf of Dynegy Entities and LSP Entities, notice of non-material change in status, FERC Docket Nos. ER02-506-007 et al., November 2, 2006.
- Affidavit on behalf of Wisconsin Energy Corp.'s, Wisconsin Electric Power Co. et al. for authorization to dispose of jurisdictional facilities, FERC Docket No. ER07-14-000, November 2, 2006.
- Affidavit on behalf of Calpine Energy Services, LP, updated triennial market power analysis, FERC Docket No. ER00-3562-004, October 30, 2006.
- Affidavit on behalf of Dynegy, application for authorization of transactions pursuant to Section 203 of the Federal Power Act, FERC Docket No. EC07-9-000, October 26, 2006.
- Affidavit on behalf of Coral Power, LLC et al., triennial updated market analysis, FERC Docket Nos. ER96-25-028 et al., October 23, 2006.
- Affidavit on behalf of Westar Energy, Inc. and Kansas Gas and Electric, request for rehearing, FERC Docket Nos. ER03-9-007 et al., October 6, 2006.
- Affidavit on behalf of The Empire District Electric, request for rehearing, FERC Docket Nos. ER99-1757-011 et al., September 14, 2006.
- Joint Affidavit (with William H. Hieronymus) on behalf of Powerex Corp., errata to its 7/31/06 triennial market power update, FERC Docket No. ER01-48-007, September 11, 2006.
- Affidavit on behalf of FPLE Companies, joint triennial market power update, FERC Docket Nos. ER02-2559-007 et al., August 28, 2006.
- Affidavit on behalf of FPL Energy Oliver Wind, LLC application for market-based rates, FERC Docket No. ER06-1392-000, August 23, 2006.
- Affidavit on behalf of The Constellation MBR Entities, errata to their joint triennial market power update submitted on 8/14/06, FERC Docket Nos. ER99-2948-009 et al., August 16, 2006.
- Affidavit on behalf of Constellation MBR Entities, joint triennial market power update, FERC Docket Nos. ER99-2948-009 et al., August 14, 2006.
- Affidavit on behalf of Sempra Energy Trading Corp., updated market analysis, FERC Docket No. ER03-1413-005, August 1, 2006.
- Joint Affidavit (with William H. Hieronymus) on behalf of Powerex Corp, triennial market power analysis in support of its continued authority to sell power at market-based rates, FERC Docket No. ER01-48-007, July 31, 2006.
- Affidavit on behalf of Reliant Energy Power Supply, LLC, application for market-based rates, FERC Docket No. ER06-1272-000, July 20-21, 2006.
- Affidavit on behalf of Lincoln Generating Facility, LLC, fka Allegheny Energy Supply, updated generation market power study, FERC Docket No. ER05-524-001, June 19, 2006.

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- Affidavit on behalf of Alcoa Power Generating, Inc & Alcoa Power Marketing, Inc., amendment to triennial, updated market analysis under ER02-2074 et al., FERC Docket Nos. ER02-2074-002 et al., May 17, 2006.
- Affidavit on behalf of Alcoa Power Generating, Inc. and Alcoa Power Marketing, Inc., updated market analysis of the triennial review of market-based rate authority, FERC Docket Nos. ER02-2074-002 et al., April 13, 2006.
- Affidavit on behalf of Morgan Energy Center, LLC et al., Calpine Gilroy Cogen, LP, Los Medanos Energy Center, LLC, and KIAC Partners et al., market-based rate filings, FERC Docket Nos. ER06-741-000 et al., March 16, 2006.
- Affidavit on behalf of Midland Cogeneration Venture Limited Partnership, market-based rate application, FERC Docket No. ER06-733-000, March 15, 2006.
- Affidavit on behalf of Duke Power Co, LLC et al., notice of change in status filing, FERC Docket Nos. ER96-110-020 et al., March 1, 2006.
- Affidavit on behalf of Westar Energy Inc & ONEOK Energy Services Co, LP, answer to protests filed by Oklahoma Municipal Power Authority et al., FERC Docket No. ER06-48-000, February 21, 2006.
- Affidavit on behalf of Edgecombe Genco, LLC and Spruance Genco, LLC, market-based rate application, FERC Docket No. ER06-635-000 and ER06-634-000, February 13, 2006.
- Affidavit on behalf of NRG Energy, Inc. et al., joint application for authorization under Section 203 of the Federal Power Act to transfer jurisdictional facilities, FERC Docket No. EC06-66-000, January 20, 2006.
- Affidavit on behalf of Westar Energy, Inc. et al. joint application for authorization under Section 203 of the Federal Power Act for the disposition of jurisdictional facilities, FERC Docket No. EC06-48-000, December 21, 2005.
- Affidavit on behalf of Calpine Energy Center, LLC, joint updated market power analysis, FERC Docket Nos. ER02-2227-003 et al., August 30, 2005.
- Affidavit on behalf of Allegheny Power, Allegheny Energy Supply Co., LLC, Allegheny Energy Supply Gleason Generating Facility, Inc et al., combined triennial market power report, FERC Docket Nos. ER98-1466-003 et al., August 11, 2005.
- Affidavit on behalf of Hermiston Power Partnership et al., joint updated market power analysis, filed on 5/3/05, FERC Docket Nos. ER02-1257-003 et al., August 5, 2005.
- Affidavit on behalf of MidAmerican Energy Co., in connection with market-based rate update, FERC Docket No. ER96-719-006, August 1, 2005.
- Affidavit on behalf of Occidental Power Services Inc., updated market power analysis, FERC Docket No. ER02-1947-006, August 1, 2005.

NAVIGANT

Julie R. Solomon

- Affidavit on behalf of FPL Energy Duane Arnold LLC, joint application for approval of disposition of jurisdictional facilities, FERC Docket Nos. EC05-114-000 et al., July 29, 2005.
- Affidavit on behalf of FPL Energy Duane Arnold, LLC, authorization to sell at market-based rates, FERC Docket No. ER05-1281-000, July 29, 2005.
- Affidavit on behalf of MidAmerican Energy Holdings Co. et al., application for approval of disposition of jurisdictional facilities under Section 203 of the Federal Power Act, FERC Docket No. EC05-110-000, July 22, 2005.
- Affidavit on behalf of Calpine Entities, joint updated market power analysis, FERC Docket Nos. EC02-1367-003 et al., July 18, 2005.
- Affidavit on behalf of Bayonne Plant Holding, LLC, as successor in interest of Cogen Technologies NJ Venture et al.,, as successor in interest to Camden Cogen et al., triennial updated market analysis, FERC Docket Nos. EC02-1486-003 et al., July 15, 2005.
- Affidavit on behalf of Cabazon Wind Partners, LLC & Whitewater Hill Wind Partners, consolidated triennial updated market analysis, FERC Docket Nos. ER02-1695-003 et al., June 24, 2005.
- Affidavit on behalf of TransAlta Energy Marketing (U.S.) Inc. et al., in connection with market-based rate authority, FERC Docket Nos. ER05-1014-000 et al., May 24, 2005.
- Affidavit on behalf of Minergy Neenah, LLC, updated triennial market power analysis, FERC Docket No. ER99-3125-001, May 16, 2005.
- Affidavit on behalf of Hermiston Power Partnership et al., joint updated market power analysis, FERC Docket Nos. ER02-1257-002 et al., May 3, 2005.
- Affidavit on behalf of CES Marketing VI, LLC et al., market-based rate application, FERC Docket Nos. ER05-816-000 et al., April 13, 2005.
- Affidavit on behalf of Onondaga Cogeneration Limited Partnership, triennial updated market analysis, FERC Docket No. ER00-895-006, March 24, 2005.
- Affidavit on behalf of The Williams Entities' (Williams Power Co. Inc. et al.), joint triennial market power update, FERC Docket Nos. ER03-1331-004 et al., March 24, 2005.
- Affidavit on behalf of J Aron & Co and Power Receivable Finance LLC, errata to triennial updated market analysis submitted on 12/30/04, FERC Docket Nos. ER02-237-003 et al., February 25, 2005.
- Affidavit on behalf of Delta Energy Center, LLC, updated power analysis, FERC Docket No. ER02-600-003, February 14, 2005.
- Affidavit on behalf of Wisconsin Electric Power Company, market-based rate filing, FERC Docket No. ER05-540-000, February 4, 2005.
- Affidavit on behalf of J Aron & Co. and Power Receivable Finance, LLC, consolidated triennial updated market analysis, December 30, 2004.

- Affidavit on behalf MidAmerican Energy Co., supplement to 10/29/04 market-power update filing, FERC Docket No. ER96-719-004, November 23, 2004.
- Affidavit in connection with Comments of Cinergy Services, Inc. re Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority under RM04-14, FERC Docket No. RM04-14-000, November 15, 2004.
- Affidavit on behalf of Metcalf Energy Center, LLC and Pastoria Energy Center, LLC, market-based rate application, FERC Docket No. ER05-68-000 and ER05-67-000, October 25, 2004.
- Affidavit on behalf Calpine Bethpage 3, LLC and TBG Cogen Partners, market-based rate filing, FERC Docket No. ER05-48-000 and ER04-1100-000, August 4, 2004.
- Affidavit on behalf of The Empire District Electric Co., updated market power analysis, FERC Docket No. ER99-1757-005, September 27, 2004.
- Affidavit on behalf of Wisconsin Electric Power Co, revised generation market power portion of its pending three-year market power update, FERC Docket No. ER98-855-004, September 27, 2004.
- Affidavit on behalf of Duke Power, a Division of Duke Energy Corp., market power analysis, FERC Docket No. ER96-110-010, August 11, 2004.
- Affidavit on behalf of Virginia Electric & Power Co et al., application for the proposed transfer of substantially all of the assets of Multitrade to Dominion Power, FERC Docket No. EC04-139-000, July 30, 2004.
- Affidavit on behalf of Goldendale Energy Center, market-based rate application, FERC Docket No. ER04-1038-000, July 23, 2004.
- Affidavit on behalf of Calumet Energy Team, LLC, updated triennial market power analysis, FERC Docket No. ER01-389-001, July 20, 2004.
- Affidavit on behalf of Calpine Parlin, LLC, market-based rate filing, FERC Docket No. ER04-832-000, May 11, 2004.
- Affidavit on behalf of Calpine Newark, LLC, market-based rate filing, FERC Docket No. ER04-831-000, May 11, 2004.
- Affidavit on behalf of Virginia Electric & Power Co, application for market-based rates, FERC Docket No. ER04-834-000, May 11, 2004.
- Affidavit on behalf of Virginia Electric and Power Co., UAE Mecklenburg Cogeneration, LP et al., authorization for the proposed transfer of 100% of the ownership interests of Cogenco etc., FERC Docket No. EC04-104-000, May 6, 2004.
- Affidavit on behalf of Occidental Power Marketing, LP, triennial market power analysis, FERC Docket No. ER99-3665-004, April 14-15, 2004.
- Affidavit on behalf of The Williams Entities, joint triennial market power update, FERC Docket Nos. ER03-1331-003 et al., March 12, 2004.

» Affidavit on behalf of Wisconsin Electric Power Co., updated triennial market-power analysis, FERC Docket No. ER98-855-003, January 29, 2004.

» Affidavit on behalf of GEN~SYS Energy, triennial update market power analysis, FERC Docket No. ER97-4335-006, October 17, 2003.

» Affidavit on behalf of Calpine Energy Services LP, updated market power analysis, FERC Docket No. ER00-3562-001, September 22, 2003.

» Affidavit on behalf of Rocky Mountain Energy Center, LLC, application for market-based rates, FERC Docket No. ER03-1288-000, September 3, 2003.

» Affidavit on behalf of Fox Energy Co, LLC, application for market-based rates, FERC Docket No. ER03-983-000, June 24, 2003.

» Affidavit on behalf of Chehalis Power Generating Limited Partnership, application for market-based rates etc., FERC Docket No. ER03-717-000, April 7, 2003.

» Affidavit on behalf of Calpine Northbrook Energy Marketing, LLC, triennial updated market power analysis, FERC Docket No. ER03-717-000, October 23, 2002.

» Affidavit on behalf of Choctaw Generation Limited Partnership, updated triennial market power analysis, FERC Docket No. ER98-3774-001, October 17, 2002.

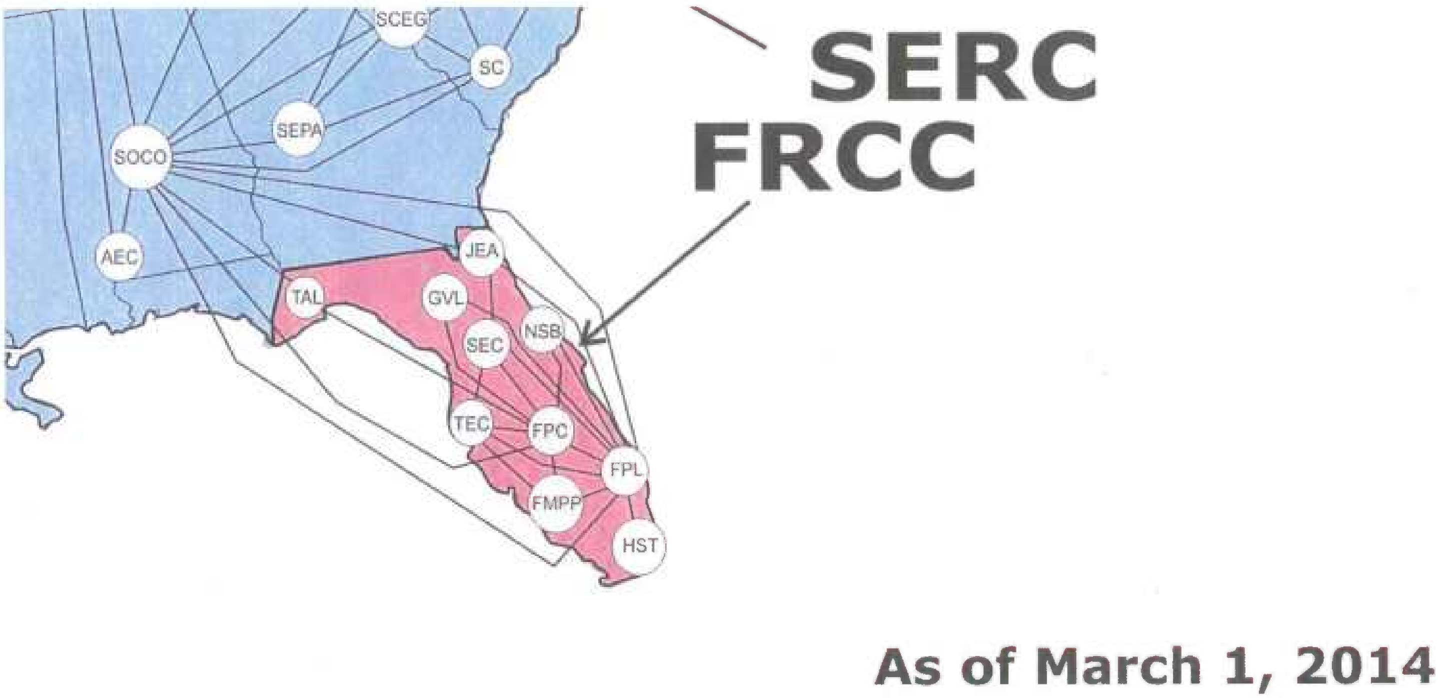
» Affidavit on behalf of Riverside Energy Center, LLC, market-based rate filing, FERC Docket No. ER03-49-000, October 16, 2002.

» Affidavit on behalf of Blue Spruce Energy Center, LLC, market-based rate filing, FERC Docket No. ER03-25-000, October 8, 2002.

» Prepared Responsive Testimony on behalf of Calpine Energy Services, LP et al. re: San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Services etc. under EL00-95 et al., FERC Docket Nos. EL00-95-045 et al., September 27, 2002.

» Affidavit on behalf of Duke Power Co., a division of Duke Energy Corp., market-based rate filing, FERC Docket No. ER96-110-007, December 17, 2001.

NERC "Bubble" Diagram of BAAs (Excerpt)



http://www.nerc.com/comm/OC/RS%20Agendas%20Highlights%20and%20Minutes%20DL/BA_Bubble_Map_20140305.jpg

Abbreviation	Utility	Abbreviation	Utility
JEA	JEA	FPC	DEF – Duke Energy Florida
GVL	Gainesville Regional Utilities	FPL	Florida Power & Light
TAL	City of Tallahassee	FMPP	Florida Municipal Power Pool
SEC	Seminole Electric Cooperative	HST	Homestead Energy Services
TEC	Tampa Electric Company	NSM	New Smyrna Beach

Illustrative HHI Calculations

Market X - 1 Supplier				Market Y - 4 Equal Suppliers				Market Y – B+C Merge			
	MW	Share	HHI		MW	Share	HHI		MW	Share	HHI
Co. A	12,000	100%	10,000	Co. B	3,000	25%	625	Co. B/C	6,000	50%	2500
				Co. C	3,000	25%	625				
				Co. D	3,000	25%	625	Co. D	3,000	25%	625
				Co. E	3,000	25%	625	Co. E	3,000	25%	625
Total	12,000	100%	10,000	Total	12,000	100%	2500	Total	12,000	100%	3750
								HHI Change:			1250

HHI Standards as Applied by FERC

	Unconcentrated	Moderately Concentrated	Highly Concentrated	
Post-Merger HHI	< 1000	1000-1800	>1800	
Change in HHI	Any change	>100	> 50	>100
Potential Merger Effect	Unlikely to have adverse competitive effects	Potentially raises significant competitive concerns	Potentially raises significant competitive concerns	Likely to create or enhance market power

Time Period Definitions Used in Competitive Analysis Screen

SUMMER (June-July-August)

Super Peak 1 (S_SP1):	Top load hour
Super Peak 2 (S_SP2):	Top 10% of peak load hours
Peak (S_P):	Remaining peak hours
Off-peak (S_OP):	All off-peak hours

WINTER (December-January-February)

Super Peak (W_SP):	Top 10% of peak load hours
Peak (W_P):	Remaining peak hours
Off-peak (W_OP):	All off-peak hours

SHOULDER (March-April-May-September-October-November)

Super Peak (SH_SP):	Top 10% of peak load hours
Peak (SH_P):	Remaining peak hours
Off-peak (SH_OP):	All off-peak hours

"AEC Facts" for DEF (EQR Prices)

Time Period	S_SP1	S_SP2	S_P	S_OP	W_SP	W_P	W_OP	SH_SP	SH_P	SH_OP
Load(MW)	9,185	8,360	6,264	5,070	5,956	4,501	3,786	7,374	5,174	4,195
Price	$200	$63	$47	$43	$70	$43	$38	$51	$39	$37
Price x 1.05	$210	$66	$49	$45	$74	$45	$40	$54	$41	$39
Total Generation & LT Purchases (MW)	10,228	10,228	10,228	10,228	10,460	10,460	10,460	9,651	9,651	9,651
Economic Capacity (MW)	9,117	8,210	6,113	5,037	9,032	5,055	2,220	5,552	3,675	2,072
Available Economic Capacity (MW)	-	-	-	-	3,077	554	-	-	-	-

"AEC Facts" for DEF (EQR Prices +10%)

Time Period	S_SP1	S_SP2	S_P	S_OP	W_SP	W_P	W_OP	SH_SP	SH_P	SH_OP
Load(MW)	9,185	8,360	6,264	5,070	5,956	4,501	3,786	7,374	5,174	4,195
Price	$220	$69	$52	$47	$77	$47	$42	$56	$43	$41
Price x 1.05	$231	$73	$54	$50	$81	$50	$44	$59	$45	$43
Total Generation & LT Purchases (MW)	10,228	10,228	10,228	10,228	10,460	10,460	10,460	9,651	9,651	9,651
Economic Capacity (MW)	9,117	9,005	6,121	6,113	9,032	6,047	5,055	7,293	4,647	4,647
Available Economic Capacity (MW)	-	645	-	1,044	3,077	1,546	1,269	-	-	452

"AEC Facts" for DEF (a comparison of EQR Prices and EQR Prices + 10%)

Time Period	S_SP1	S_SP2	S_P	S_OP	W_SP	W_P	W_OP	SH_SP	SH_P	SH_OP
Price	$200	$63	$47	$43	$70	$43	$38	$51	$39	$37
Available Economic Capacity (MW)	-	-	-	-	3,077	554	-	-	-	-
Price	$220	$69	$52	$47	$77	$47	$42	$56	$43	$41
Available Economic Capacity (MW)	-	645	-	1,044	3,077	1,546	1,269	-	-	452
Change in AEC (MW)	-	645	-	1,044	-	992	1,269	-	-	452

AEC Results for DEF (Acquisition 1 (EQR Prices))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 1				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 200	-	0.0%	436	17.0%	2,569	1,149	368	14.7%	2,501	1,125	(24)
S_SP2	$ 63	-	0.0%	436	17.0%	2,569	1,149	285	11.8%	2,418	1,111	(38)
S_P	$ 47	-	0.0%	-	0.0%	2,130	1,268	-	0.0%	2,130	1,268	-
S_OP	$ 43	-	0.0%	-	0.0%	2,130	1,268	-	0.0%	2,130	1,268	-
W_SP	$ 70	3,077	68.6%	400	8.9%	4,486	4,877	3,476	77.5%	4,486	6,098	1,221
W_P	$ 43	554	39.0%	-	0.0%	1,419	2,369	554	39.0%	1,419	2,369	-
W_OP	$ 38	-	0.0%	-	0.0%	712	3,034	-	0.0%	712	3,034	-
SH_SP	$ 51	-	0.0%	-	0.0%	2,392	1,830	-	0.0%	2,392	1,830	-
SH_P	$ 39	-	0.0%	-	0.0%	2,121	2,258	-	0.0%	2,121	2,258	-
SH_OP	$ 37	-	0.0%	-	0.0%	2,121	2,484	-	0.0%	2,121	2,484	-

AEC Results for DEF (Acquisition 2 (EQR Prices))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 2		DEF						
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 200	-	0.0%	70	2.7%	2,569	1,149	495	19.8%	2,501	1,190	40
S_SP2	$ 63	-	0.0%	70	2.7%	2,569	1,149	412	17.0%	2,418	1,144	(5)
S_P	$ 47	-	0.0%	59	2.8%	2,130	1,268	412	20.8%	1,980	1,226	(41)
S_OP	$ 43	-	0.0%	59	2.8%	2,130	1,268	531	25.3%	2,098	1,345	78
W_SP	$ 70	3,077	68.6%	4	0.1%	4,486	4,877	3,602	72.6%	4,960	5,416	540
W_P	$ 43	554	39.0%	3	0.2%	1,419	2,369	1,080	57.0%	1,893	3,726	1,357
W_OP	$ 38	-	0.0%	-	0.0%	712	3,034	-	0.0%	712	3,034	-
SH_SP	$ 51	-	0.0%	85	3.5%	2,392	1,830	-	0.0%	1,914	1,690	(140)
SH_P	$ 39	-	0.0%	85	4.0%	2,121	2,258	-	0.0%	1,643	2,179	(79)
SH_OP	$ 37	-	0.0%	-	0.0%	2,121	2,484	-	0.0%	2,121	2,484	-

AEC Results for DEF (Acquisition 1 (+10% Price Sensitivity))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 1				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 220	-	0.0%	436	17.0%	2,569	1,149	368	14.7%	2,501	1,125	(24)
S_SP2	$ 69	645	20.1%	436	13.6%	3,214	1,137	1,080	33.6%	3,214	1,681	544
S_P	$ 52	-	0.0%	-	0.0%	2,133	1,264	-	0.0%	2,133	1,264	-
S_OP	$ 47	1,044	32.9%	-	0.0%	3,174	1,652	1,044	32.9%	3,174	1,652	-
W_SP	$ 77	3,077	68.6%	400	8.9%	4,486	4,877	3,476	77.5%	4,486	6,098	1,221
W_P	$ 47	1,546	60.6%	-	0.0%	2,553	3,959	1,546	60.6%	2,553	3,959	-
W_OP	$ 42	1,269	59.5%	-	0.0%	2,134	3,910	1,269	59.5%	2,134	3,910	-
SH_SP	$ 56	-	0.0%	364	13.2%	2,759	1,549	282	10.5%	2,677	1,572	22
SH_P	$ 43	-	0.0%	-	0.0%	2,392	1,830	-	0.0%	2,392	1,830	-
SH_OP	$ 41	452	17.6%	-	0.0%	2,573	1,843	452	17.6%	2,573	1,843	-

AEC Results for DEF (Acquisition 1 (+20% Price Sensitivity))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 1				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 240	1,043	28.5%	436	11.9%	3,655	1,417	1,479	40.5%	3,655	2,097	680
S_SP2	$ 76	645	20.1%	436	13.6%	3,214	1,137	1,080	33.6%	3,214	1,681	544
S_P	$ 56	1,788	41.0%	436	10.0%	4,357	2,087	2,224	51.0%	4,357	2,908	821
S_OP	$ 52	1,051	33.0%	-	0.0%	3,184	1,657	1,051	33.0%	3,184	1,657	-
W_SP	$ 84	3,107	68.8%	400	8.8%	4,517	4,903	3,506	77.6%	4,517	6,120	1,217
W_P	$ 52	1,554	60.7%	-	0.0%	2,561	3,971	1,554	60.7%	2,561	3,971	-
W_OP	$ 46	2,261	69.2%	-	0.0%	3,268	4,965	2,261	69.2%	3,268	4,965	-
SH_SP	$ 61	31	1.1%	364	13.0%	2,790	1,494	394	14.1%	2,790	1,523	29
SH_P	$ 47	372	13.4%	-	0.0%	2,764	1,552	372	13.4%	2,764	1,552	-
SH_OP	$ 44	1,350	36.1%	-	0.0%	3,742	2,049	1,350	36.1%	3,742	2,049	-

AEC Results for DEF (Acquisition 1 (-10% Price Sensitivity))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 1				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 180	-	0.0%	436	17.0%	2,569	1,149	368	14.7%	2,501	1,125	(24)
S_SP2	$ 57	-	0.0%	436	17.0%	2,569	1,159	127	5.6%	2,260	1,158	(2)
S_P	$ 42	-	0.0%	-	0.0%	2,130	1,268	-	0.0%	2,130	1,268	-
S_OP	$ 39	-	0.0%	-	0.0%	1,822	1,612	-	0.0%	1,822	1,612	-
W_SP	$ 63	2,096	59.8%	400	11.4%	3,505	3,859	2,495	71.2%	3,505	5,222	1,363
W_P	$ 39	-	0.0%	-	0.0%	712	3,034	-	0.0%	712	3,034	-
W_OP	$ 34	-	0.0%	-	0.0%	699	3,142	-	0.0%	699	3,142	-
SH_SP	$ 46	-	0.0%	-	0.0%	2,392	1,830	-	0.0%	2,392	1,830	-
SH_P	$ 35	-	0.0%	-	0.0%	2,121	2,484	-	0.0%	2,121	2,484	-
SH_OP	$ 33	-	0.0%	-	0.0%	2,109	2,512	-	0.0%	2,109	2,512	-

AEC Results for DEF (Acquisition 2 (+10% Price Sensitivity))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 2				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 220	-	0.0%	70	2.7%	2,569	1,149	495	19.8%	2,501	1,190	40
S_SP2	$ 69	645	20.1%	70	2.2%	3,214	1,137	1,208	37.6%	3,214	1,896	759
S_P	$ 52	-	0.0%	59	2.8%	2,133	1,264	420	21.1%	1,990	1,229	(35)
S_OP	$ 47	1,044	32.9%	59	1.9%	3,174	1,652	1,607	50.6%	3,174	2,870	1,218
W_SP	$ 77	3,077	68.6%	4	0.1%	4,486	4,877	3,602	72.6%	4,960	5,416	540
W_P	$ 47	1,546	60.6%	3	0.1%	2,553	3,959	2,072	68.4%	3,027	4,892	932
W_OP	$ 42	1,269	59.5%	3	0.2%	2,134	3,910	1,795	68.8%	2,608	4,985	1,075
SH_SP	$ 56	-	0.0%	85	3.1%	2,759	1,549	397	14.8%	2,677	1,268	(282)
SH_P	$ 43	-	0.0%	85	3.5%	2,392	1,830	-	0.0%	1,914	1,690	(140)
SH_OP	$ 41	452	17.6%	85	3.3%	2,573	1,843	930	36.2%	2,573	2,196	352

AEC Results for DEF (Acquisition 2 (+20% Price Sensitivity))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 2				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 240	1,043	28.5%	70	1.9%	3,655	1,417	1,606	43.9%	3,655	2,319	902
S_SP2	$ 76	645	20.1%	70	2.2%	3,214	1,137	1,208	37.6%	3,214	1,896	759
S_P	$ 56	1,788	41.0%	59	1.4%	4,357	2,087	2,351	54.0%	4,357	3,176	1,088
S_OP	$ 52	1,051	33.0%	59	1.9%	3,184	1,657	1,614	50.7%	3,184	2,875	1,219
W_SP	$ 84	3,107	68.8%	4	0.1%	4,517	4,903	3,632	72.8%	4,990	5,439	535
W_P	$ 52	1,554	60.7%	3	0.1%	2,561	3,971	2,079	68.5%	3,034	4,901	930
W_OP	$ 46	2,261	69.2%	3	0.1%	3,268	4,965	2,787	74.5%	3,742	5,682	717
SH_SP	$ 61	31	1.1%	102	3.6%	2,790	1,494	509	18.3%	2,790	1,284	(210)
SH_P	$ 47	372	13.4%	85	3.1%	2,764	1,552	850	30.8%	2,764	1,756	205
SH_OP	$ 44	1,350	36.1%	85	2.3%	3,742	2,049	1,829	48.9%	3,742	2,830	780

AEC Results for DEF (Acquisition 2 (-10% Price Sensitivity))

		Pre-Transaction						Post-Transaction				
		DEF		Acquisition 2				DEF				
Period	Price	MW	Mkt Share	MW	Mkt Share	Market Size	HHI	MW	Mkt Share	Market Size	HHI	HHI Chg
S_SP1	$ 180	-	0.0%	70	2.7%	2,569	1,149	495	19.8%	2,501	1,190	40
S_SP2	$ 57	-	0.0%	59	2.3%	2,569	1,159	254	11.3%	2,260	1,106	(53)
S_P	$ 42	-	0.0%	59	2.8%	2,130	1,268	-	0.0%	1,567	1,264	(3)
S_OP	$ 39	-	0.0%	59	3.3%	1,822	1,612	-	0.0%	1,259	1,706	94
W_SP	$ 63	2,096	59.8%	4	0.1%	3,505	3,859	2,621	65.9%	3,979	4,560	701
W_P	$ 39	-	0.0%	-	0.0%	712	3,034	-	0.0%	712	3,034	-
W_OP	$ 34	-	0.0%	-	0.0%	699	3,142	-	0.0%	699	3,142	-
SH_SP	$ 46	-	0.0%	85	3.5%	2,392	1,830	-	0.0%	1,914	1,690	(140)
SH_P	$ 35	-	0.0%	-	0.0%	2,121	2,484	-	0.0%	2,121	2,484	-
SH_OP	$ 33	-	0.0%	-	0.0%	2,109	2,512	-	0.0%	2,109	2,512	-

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.	)))))	DOCKET NO. 140111-EI Submitted for filing: August 21, 2014

DUKE ENERGY FLORIDA, INC.'S NOTICE OF FILING ERRATA

Duke Energy Florida, Inc. ("DEF") hereby gives notice of filing errata to the May 27, 2014 testimony and exhibits and August 5, 2014 exhibits of Mr. Benjamin M.H. Borsch and to the May 27, 2014 testimony of Julie Solomon as more specifically described below:

- As previously corrected in DEF's Response to NRG's First Set of Interrogatories #89, served on July 7, 2014, in the **May 27, 2014 Direct Testimony of Benjamin M. H. Borsch Page 45, Line 22**, "20-year study period" should be changed to "30-year study period." This was a typo only and had no effect on the analysis. See corrected testimony page attached.

- As referenced in Mr. Borsch's Deposition on August 11, 2014, in **Exhibit No. __(BMHB-3) to Benjamin Borsch's May 27, 2014 Direct Testimony** the "Winter Firm Peak Demand 2014" number should be listed as "8870" versus "8170." This was a typo only and had no effect on the analysis. See corrected Exhibit No. ___(BMHB-3) attached.

- As previously corrected in DEF's Supplemental Response to NRG's First Document Request #8, served on July 11, 2014, in **Exhibit No. __(BMHB-8) to Benjamin Borsch's May 27, 2014 Direct Testimony** there was an error in a formula which transferred model results to the spreadsheet used to create the exhibit. The error caused double counting of some costs for the PPAs which were also accounted for in the fuels totals. The error affected PPA1 and PPA3. This has been corrected and the corrected values were supplied to all parties in response to the NRG Document Request referenced above. The change did not have a material impact on the conclusions. See corrected Exhibit No. ___(BMHB-8) attached.
    - Corrections include:
        - In Column "PPA1" Row "Fuel" the number was corrected from 395 to 394.
        - In Column "PPA1" Row "PPAs" the number was corrected from (567) to (562).
        - In Column "PPA1" Row "Total" the number was corrected from (129) to (126).
        - In Column "PPA3" Row "Fuel" the number was corrected from 45

to 63.
    - In Column "PPA3" Row "PPAs" the number was corrected from (184) to (175).
    - In Column "PPA3" Row "Total" the number was corrected from (155) to (128).
    - In Column "ACQ PPA MIX1" Row "Fuel" the number was corrected from (12) to (11).
    - In Column "ACQ PPA MIX1" Row "PPAs" the number was corrected from (65) to (62).
    - In Column "ACQ PPA MIX1" Row "Total" the number was corrected from (110) to (107).
    - In Column "ACQ PPA MIX2" Row "Fuel" the number was corrected from (260) to (258).
    - In Column "ACQ PPA MIX2" Row "PPAs" the number was corrected from (375) to (372).
    - In Column "ACQ PPA MIX2" Row "Total" the number was corrected from (118) to (117).

- In **Exhibit No. __(BMHB-10) to Benjamin Borsch's May 27, 2014 Direct Testimony** the cost of the 4th Chiller was incorrectly input. The value was $10 million (CPVRR equivalent) less than it should have been. This reduces the cost effectiveness of 4 chillers vs. the 3 chiller base case by $10 million, but it remains cost effective. All comparisons to the alternate bids was done on a 3 chiller basis, so this does not affect any of the differential outcomes to the alternative bids. See corrected Exhibit No. __(BMHB-10) attached.
  - Corrections include:
    - In Column "Self Build plus Hines 1 Chillers" Row "Capital Costs" the number was corrected from (33) to (43).
    - In Column "Self Build plus Hines 1 Chillers" Row "Total" the number was corrected from 26 to 16.

- In **Exhibit No. __(BMHB-11) to Benjamin Borsch's May 27, 2014 Direct Testimony** there was an error in the No CO2 price case. The CO2 price was left on for the first two generic CT units following the PPA expirations in the "PPA1" and "ACQ PPA MIX 1" cases. As a result, these cases were more costly because they included CO2 allowance costs for those units. These costs also affected the dispatch which resulted in a shift in other costs (Fuel, VOM, etc.). This error did not affect the rank order of the results or materially affect the conclusions. See corrected Exhibit No. ___(BMHB-11) attached. This update to Exhibit No. __ (BMHB-11) also incorporates the change in the capital cost of the 4th Hines Chiller discussed in reference to Exhibit No. ___(BMHB-10).
  - Corrections include:
    - In Table "High Gas" in Column "Self Build plus Hines 1 Chillers" Row "Capital Costs" the number was corrected from (33) to (43).
    - In Table "High Gas" in Column "Self Build plus Hines 1 Chillers" Row "Total" the number was corrected from 41 to 31.

  - In Table "No CO2" in Column "AQCPPA MIX1" Row "Fuel" the number was corrected from 23 to 28.
  - In Table "No CO2" in Column "AQCPPA MIX1" Row "Emissions" the number was corrected from (13) to 1.
  - In Table "No CO2" in Column "AQCPPA MIX1" Row "Variable Costs" the number was corrected from (9) to (7).
  - In Table "No CO2" in Column "AQCPPA MIX1" Row "PPAs" the number was corrected from (117) to (116).
  - In Table "No CO2" in Column "AQCPPA MIX1" Row "Total" the number was corrected from (170) to (149).
  - In Table "No CO2" in Column "PPA1" Row "Fuel" the number was corrected from 205 to 210.
  - In Table "No CO2" in Column "PPA1" Row "Emissions" the number was corrected from (12) to 3.
  - In Table "No CO2" in Column "PPA1" Row "Variable Costs" the number was corrected from 3 to 5.
  - In Table "No CO2" in Column "PPA1" Row "PPAs" the number was corrected from (311) to (309).
  - In Table "No CO2" in Column "PPA1" Row "Total" the number was corrected from (161) to (137).
  - In Table "No CO2", in Column "Self Build plus Hines 1 Chillers" Row "Capital Costs" the number was corrected from (33) to (43).
  - In Table "No CO2", in Column "Self Build plus Hines 1 Chillers" Row "Total" the number was corrected from 14 to 4.

- As referenced in Mr. Borsch's Deposition on August 11, 2014, the label in the top right corner for **Exhibit No. __(BMBHB-15) to Benjamin Borsch's August 5, 2014 Rebuttal Testimony** contained typos and should be labeled as "Exhibit No.__(BMHB-15)."

- As previously corrected in DEF's Response to Staff's First Set of Interrogatories #40a, served on July 15, 2014, in the **May 27, 2014 Direct Testimony of Julie Solomon Page 9, Line 14** the words "these" and "or" should have been deleted. See corrected testimony page attached.

/s/ Blaise N. Gamba

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY a true and correct copy of the foregoing has been furnished to counsel and parties of record as indicated below via electronic mail this 21st day of August, 2014.

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by increasing the total supply of generation in the market. This means the Company must build additional transmission facilities to expand the transmission import capability. The Company cannot rely on currently planned transmission system facility upgrades for this mitigation. The additional transmission must be net new facilities to the DEF system.

Increasing the transmission import capability by building net new transmission facilities is not a reasonable mitigation measure to eliminate the screen failures for these potential generation facility acquisitions. As explained by Julie Solomon in her direct testimony, a range of 600 MW to 800 MW of additional transmission import capacity must be added to DEF's system to mitigate the FERC screen failures for the lowest cost potential generation facility acquisition, and a minimum of 1,000 MW of additional transmission import capacity must be added to DEF's system for the other generation facility acquisition to mitigate its FERC screen failures. Based on our experience with our transmission system and the costs to add transmission facility upgrades, the transmission system facility upgrades -- and the cost of the upgrades -- to provide an additional 600 MW to 800 MW of transmission import capacity would be substantial, in the realm of hundreds of millions of dollars, and, therefore, easily far in excess of any benefits that the potential generation facility acquisitions provide DEF's customers.

The best generation facility acquisition proposal was only marginally more cost-effective on a CPVRR basis over the ~~20-year~~ 30 year study period than the Company's self-build base generation plan. This marginal benefit does not

DEF's Near Term Summer And Winter Load Forecast

Year	LOAD FORECAST		
	Peak Demand (MW)		Energy
	Winter	Summer	Requirements (GWH)
2014	8,8 70	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

INITIAL DETAILED ECONOMIC ANALYSIS RESULTS FOR THE MOST COST-EFFECTIVE GENERATION OPTION TO MEET THE COMPANY'S CAPACITY NEEDS IN THE SUMMERS OF 2016 AND 2017

Cumulative PV Revenue Requirements Comparison Acquisition Options vs Self Build									
$M 2013	PPA1	PPA2	PPA3	ACQ2	ACQ1	ACQ PPA MIX1	ACQ PPA MIX2	ACQ3	ACQ4
Capital Costs	37	90	90	(49)	204	101	101	23	(35)
Fuel	394	141	63	(50)	16	(11)	258	7	(3)
Emissions	19	23	19	(71)	(47)	(3)	15	13	1
Variable Costs	19	(4)	(9)	113	34	(4)	10	(0)	1
Fixed Costs	(36)	(122)	(122)	(148)	(162)	(129)	(129)	(310)	(351)
PPAs	(562)	(270)	(175)	44	10	(62)	(372)	9	2
Cogens	(1)	5	6	(36)	(9)	0	(2)	0	1
Emergency Energy	4	2	0	4	2	2	2	3	(2)
Total	(126)	(136)	(128)	(193)	49	(107)	(117)	(255)	(386)

DETAILED ECONOMIC ANALYSIS RESULTS FOR THE MOST COST-EFFECTIVE GENERATION OPTION TO MEET THE COMPANY'S CAPACITY NEEDS IN THE SUMMERS OF 2016 AND 2017

Cumulative PV Revenue Requirements Comparison Acquisition/PPA Options vs Self Build				
$M 2014	Acquisition - PPA Mix 1	PPA 1	Self Build No Hines Chillers	Self Build plus Hines 1 Chillers
Capital Costs	88	83	52	(43)
Fuel	50	227	(36)	68
Emissions	16	29	(24)	19
Variable Costs	(9)	2	13	(2)
Fixed Costs	(141)	(129)	(7)	5
PPAs	(143)	(332)	(27)	(29)
Cogens	1	3	(0)	(2)
Emergency Energy	(1)	(1)	3	1
Total	(139)	(118)	(26)	16

COMPANY'S ANALYSIS OF GAS PRICE AND CO2 COST SENSITIVITIES TO THE FINAL DETAILED ECONOMIC ANALYSES

High Gas			
Cumulative PV Revenue Requirements Comparison Acquisition Options vs Self			
$M 2014	ACQ PPA MIX1	PPA1	Self Build plus Hines 1 Chillers
Capital Costs	88	83	(43)
Fuel	35	267	53
Emissions	15	29	21
Variable Costs	(10)	2	(4)
Fixed Costs	(141)	(129)	5
PPAs	(123)	(364)	(1)
Cogens	1	3	(1)
Emergency Energy	(1)	(1)	1
Total	(138)	(110)	31

No CO2			
Cumulative PV Revenue Requirements Comparison Acquisition Options vs Self			
$M 2014	AQC PPA MIX1	PPA1	Self Build plus Hines 1 Chillers
Capital Costs	88	83	(43)
Fuel	28	210	46
Emissions	1	3	(1)
Variable Costs	(7)	5	(2)
Fixed Costs	(141)	(129)	5
PPAs	(116)	(309)	(2)
Cogens	(0)	1	(1)
Emergency Energy	(1)	(1)	1
Total	(149)	(137)	4

Passing the FERC Competitive Analysis Screen typically leads to a conclusion that a transaction is unlikely to present competitive problems. If the Competitive Analysis Screen is "failed", i.e. the changes in market concentration exceed the allowed level, the proposed merger or acquisition is deemed likely to have an adverse impact on competition and FERC will look more closely at the transaction before making its final determination. As FERC has stated: "When there is a screen failure, applicants must provide evidence of relevant market conditions that indicate a lack of a competitive problem or they should propose mitigation." In re: Revised Filing Requirements under Part 33 of the Commission's Regulations, Order 642 FERC Stats. & Regs., ¶31,11, at page 62 (2000).

Evidence of relevant market conditions that may indicate a lack of a competitive problem include "demand and supply elasticity, ease of entry and market rules, as well as technical conditions, such as the types of generation involved." (Id.). No facts such as ~~these~~ have been relied on by FERC in previous orders ~~or~~ have been identified in the acquisitions at issue and, as a result, the FERC inquiry likely would be on any proposed mitigation.

Q. Why did FERC adopt the Competitive Analysis Screen?

A. FERC adopted its merger filing requirements, including the Competitive Analysis Screen, to provide regulatory certainty to the industry in obtaining approval for mergers or generation transactions. The Competitive Analysis Screen is intended to provide a conservative standard to allow parties to identify mergers or generation facility acquisitions that are unlikely to present competitive problems.