DUKE ENERGY®
FLORIDA

May 1, 2013

Phillip Ellis
Division of Engineering
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

*Re: 2013 TYSP Supplemental Data Request; Undocketed*

Dear Mr. Ellis:

Please find enclosed for filing on behalf of Duke Energy Florida, Inc., its response to questions #2-65 of the 2013 Supplemental TYSP Data Request issued by Staff on March 1, 2013. Pursuant to your request, DEF's response is provided in both electronic version (CD attached) and hard copy.

Please let me know if you have any questions. Thank you for your assistance in this matter.

Sincerely,

Dianne M. Triplett

DMT/emc
Enclosures

COM ____
AFD ____
APA ____
ECO ____
ENG CD
GCL ____
IDM ____
TEL ____
CLK ____

# DEF'S RESPONSE TO STAFF'S REVIEW OF THE 2013 TEN-YEAR SITE PLANS: DATA REQUEST #1

Please provide an electronic copy of all responses in Adobe PDF format or Microsoft Word (.doc or .docx), with tables to also be provided for in a Microsoft Excel (.xls or .xlsx file format) document, unless otherwise specified in the question.

Please respond to the following question by **April 1, 2013.**

1. Please provide an electronic copy of the Company's 2013 Ten-Year Site Plan (in PDF format) and Schedules 1 through 10 (in Excel format).

   **RESPONSE:** The PDF format of the DEF 2013 TYSP and Excel format of Schedules 1-through 10 were filed along with the DEF 2013 TYSP by April 1, 2013.

Please respond to all remaining questions by **May 1, 2013.**

## General Questions

2. Please provide all data requested in the attached forms labeled 'Appendix A,' **only** as an electronic copy in Microsoft Excel (.xls or .xlsx). Please do **not** provide a hardcopy of this response. If any of the requested data is already included in the Company's Ten-Year Site Plan, state so on the appropriate form.

   **RESPONSE:** Please the Excel file DEF 2013 TYSP Data Request - Appendix A.xls.

## Load & Demand Forecasting - General Questions

3. [Investor-owned Utilities Only] Please provide, on a system-wide basis, the hourly system load for the period January 1, 2012, through December 31, 2012. Please provide this **only** as an electronic copy in Microsoft Excel (.xls or .xlsx). Please do **not** provide a hardcopy of this response.

   **RESPONSE:** DEF's hourly system load for 2012 is provided in the Excel file Q3_DEF 2012 Hourly MW.xls.

4. Please discuss any recent trends in customer growth, by customer type (residential, commercial, industrial) and as a whole. Please explain the nature or reason for these trends, and identify what types of customers are most effected by these trends.

**RESPONSE:** In general, Duke Energy Florida retail customer growth has returned to solidly upward trending. The financial crisis turned customer growth negative for 21 straight months during the 2008-2010 period. Since then, positive growth has returned for 33 straight months ending December 2012. The residential and commercial classes have experienced gradually improving year over year customer growth trends reaching 0.9% in December 2012. An improved economy has boosted consumer confidence. Improved credit availability and the very low interest rates have spurred home buying.

The industrial class continues to experience a shrinking customer base which has now lasted eight years. The Duke Energy Florida service territory has always been characterized as more of a service-based economy than industrial and has seen some shrinkage in its rock mining and building products sectors. The 2012 customer count was 1.75% below the 2011 level.

Trends in the Public Authority class have been the least volatile the past several years. This class' customer growth, which never turned negative during the Great Recession, includes stable service-type categories like Federal, State and local government buildings, schools, post offices and public recreational accounts. Its growth rate, like the residential and commercial classes, has improved as the Florida economy has picked up steam. This class grew by 1.2% from 2011 to 2012.

5. Please provide the timing and temperature associated with the company's historic monthly peak demand for the period 2010 through 2012. Please also provide the day of the month, hour of the day, and system-average temperature at the time of each monthly peak. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Historic monthly peak demands for 2010, 2011 and 2012 are as follows and provided in tab 5 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls:

**Historic Peak Demand Timing & Temperature**

| Year | Month | Peak Demand (MW) | Date | Hour | Temperature (Degrees F) |
|---|---|---|---|---|---|
| 2010 | 1 | 11644 | 11 | 8 | 27.8 |
| | 2 | 8746 | 26 | 8 | 37.6 |
| | 3 | 8276 | 5 | 8 | 40.7 |
| | 4 | 6183 | 24 | 18 | 84.6 |
| | 5 | 8585 | 3 | 17 | 88.5 |
| | 6 | 9516 | 14 | 17 | 94.6 |
| | 7 | 9600 | 27 | 18 | 93.8 |
| | 8 | 9467 | 18 | 16 | 91.0 |
| | 9 | 8844 | 13 | 16 | 92.5 |
| | 10 | 7753 | 27 | 17 | 88.4 |
| | 11 | 6180 | 3 | 17 | 82.9 |
| | 12 | 10381 | 29 | 8 | 31.0 |
| 2011 | 1 | 9585 | 13 | 8 | 32.2 |
| | 2 | 7395 | 14 | 8 | 42.6 |
| | 3 | 6133 | 27 | 17 | 87.0 |
| | 4 | 8187 | 27 | 17 | 90.4 |
| | 5 | 8443 | 24 | 18 | 92.6 |
| | 6 | 9277 | 21 | 17 | 95.6 |
| | 7 | 8917 | 30 | 17 | 93.3 |
| | 8 | 9196 | 12 | 16 | 94.3 |
| | 9 | 8207 | 12 | 17 | 91.5 |
| | 10 | 7176 | 11 | 17 | 84.8 |
| | 11 | 5854 | 16 | 16 | 82.8 |
| | 12 | 5043 | 23 | 19 | 73.4 |
| 2012 | 1 | 8722 | 4 | 8 | 33.8 |
| | 2 | 8519 | 13 | 8 | 35.8 |
| | 3 | 6135 | 23 | 17 | 83.6 |
| | 4 | 7004 | 3 | 17 | 87.4 |
| | 5 | 7942 | 25 | 17 | 94.1 |
| | 6 | 8185 | 11 | 17 | 90.1 |
| | 7 | 9026 | 26 | 17 | 91.3 |
| | 8 | 8850 | 9 | 16 | 90.8 |
| | 9 | 8108 | 4 | 17 | 88.1 |
| | 10 | 7790 | 4 | 16 | 88.7 |
| | 11 | 5749 | 26 | 8 | 48.5 |
| | 12 | 6555 | 23 | 9 | 40.3 |

6. Please identify the weather station(s) used for calculation of the system-wide temperature for the utility's service territory. If more than one weather station is utilized, please describe how a system-wide average is calculated.

**RESPONSE:** For purposes of calculating heating and cooling degree days to project and weather adjust energy sales, DEF uses seven weather stations across Florida: Saint Petersburg, Tampa, Orlando, Winter Haven, Gainesville, Daytona Beach, and Tallahassee. A weighting based upon weather-sensitive energy sales around each station is calculated to develop a system average. For temperatures at time of peak, the Tampa, Orlando, and Tallahassee weather stations are used. The other weather stations are not used because enough historic hourly data is not available to develop a normal weather condition which requires temperatures at time of system peak. The three weather station aggregation also uses a weighting based on shares of energy sales from weather-sensitive classes tallied near each station.

7. Please provide the average cost of a residential customer bill, based upon a monthly usage of 1000 kilowatt-hours, for the period 2003 through 2012. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the table below and tab 7 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

| Typical Customer Bill Information | | |
|---|---|---|
| Year | | Residential Bill ($/1000-kWh) |
| Actual | 2003 | 82.87 |
| | 2004 | 83.71 |
| | 2005 | 95.83 |
| | 2006 | 109.56 |
| | 2007 | 110.34 |
| | 2008 | 109.15 |
| | 2009 | 128.82 |
| | 2010 | 126.94 |
| | 2011 | 119.34 |
| | 2012 | 123.19 |

## Load & Demand Forecasting - Electric Vehicles

8. Please discuss whether the company included plug-in electric vehicle loads in its demand and energy forecasts for the 2013 Ten-Year Site Plan.

   **RESPONSE:** DEF has not specifically assumed a MW or MWh impact in the 2013 Ten-Year Site Plan ("TYSP") for Plug-in Electric Vehicles (PEVs). Any estimates of plug-in vehicle adoption at this time are highly speculative from a DEF perspective. DEF has only seen the introduction of only a few mass-market models for PEV's in Florida in the previous two years. DEF continues to monitor the current market adoption and is assessing a range of models to help predict future vehicle adoption and resultant system load impact.

9. Please discuss the methodology (or, if applicable, the source(s) of the data) used to estimate the number of vehicles operating in the company's service territory and the methodology used to estimate the cumulative impact on system demand and energy consumption.

   **RESPONSE:** Although DEF has not specifically assumed a MW or MWh impact in the 2013 Ten-Year Site Plan ("TYSP") for Plug-in Electric Vehicles (PEVs), we are evaluating several models to assess potential future load impacts. One such model was derived from the Electric Power Research Institute (EPRI) and predicts future scenarios of plug-in vehicles penetration in our territory. EPRI recently published a public report titled Transportation Electrification: A Technology Overview that contains the high level summary of their prediction model at a national level along with the assumptions related to the low, medium, and high scenarios. DEF worked with EPRI to tailor the model to the utility's service territory level, including adjustments related to regional market introduction by the early plug-in vehicle manufacturers.

10. Please include the following information within the utility's service territory: an estimate of the number of electric vehicles, an estimate of the number of public EV charging stations, and the estimated demand and energy impacts of the electric vehicles by year.

    **RESPONSE:** Although DEF has not specifically assumed a MW or MWh impact in the 2013 Ten-Year Site Plan ("TYSP") for Plug-in Electric Vehicles (PEVs), we are evaluating several models to assess potential future load impacts. As noted in the previous answer, one such model is derived from the Electric Power Research and the medium adoption scenario is provided below. Note that there is considerable uncertainty surrounding the actual future adoption rates due to the many factors involved and this is only a scenario analysis based on one particular model. Furthermore, the cumulative impact of electric vehicle load on the system peak is also uncertain as there is not enough real-world charging profile data to understand the potential coincident impact to the system. Please see the table below and tab 10 of the Excel file DEF 2013 TYSP Data Request #1 – Tables.xls.

**Electric Vehicle Charging Impacts**

| Year | Number of Electric Vehicles | Number of Public EV Charging Stations | Cumulative Impact of Electric Vehicles | | |
|---|---|---|---|---|---|
| | | | Summer Demand | Winter Demand | Annual Energy |
| | (-) | (-) | (MW) | (MW) | (GWh) |
| 2012 | 238 | 13 | | | 1.3 |
| 2013 | 1,054 | 58 | | | 5.2 |
| 2014 | 2,361 | 130 | | | 10.7 |
| 2015 | 4,045 | 223 | | | 16.8 |
| 2016 | 6,274 | 345 | | | 23.7 |
| 2017 | 9,500 | 522 | | | 32.2 |
| 2018 | 13,816 | 760 | | | 43.6 |
| 2019 | 19,337 | 1,063 | | | 58.0 |
| 2020 | 26,204 | 1,441 | | | 75.7 |
| 2021 | 34,576 | 1,902 | | | 97.0 |
| 2022 | 45,184 | 2,486 | | | 122.8 |

11. Please describe any company programs or tariffs currently offered to customers relating to plug-in electric vehicles, and describe whether any new or additional programs or tariffs relating to plug-in electric vehicles will be offered to customers within the ten-year period?

**RESPONSE:** DEF currently does not offer any tariffs or load management programs specific to plug-in electric vehicles. The company is still evaluating the potential impact plug-in electric vehicles (PEVs) will have on the utility grid. Currently we are engaged in several research projects including an Electric Power Research Institute (EPRI) modeling tool to predict adoption and load impact, a detailed distribution circuit analysis to identify theoretical asset impact under various PEV adoption scenarios, and a charging station load research project. The charging station project will provide valuable information to understand when, where, and how early adopters of this new technology charge their vehicles and how that may impact the grid. Furthermore, we are monitoring the evolving communication standards and various load management technologies that may one day assist customers and the utility in minimizing peak impacts if necessary. The information provided by these research initiatives and industry working groups will help define the need, opportunity, design options, and timing for future plug-in vehicle programs/tariffs.

12. Please describe how the company monitors the installation of public charging stations in its service area? Please provide the number of "quick-charge" electric vehicle charging stations (i.e., charging stations requiring a service drop greater than 240 volts and/or using three-phase power) currently installed in the service area.

**RESPONSE:** DEF is currently treating charging infrastructure as any other load addition to the system. Current policies and procedures in place are expected to be sufficient to manage and support the addition of charging facilities as they do other load additions. As with any new load, commercial customers adding a significant potential load from charging stations are requested to contact our account managers or a specialized customer service group so we may assess the utility service impact. DEF is also actively engaged in the education of our customers and stakeholders related to the technology and impact to their electricity service to ensure a positive experience for all involved.

We are not currently aware of any Direct Current "quick-charge" charging infrastructure installed in our territory.

13. Please describe any instances since January 1, 2012 in which upgrades to the distribution system were made where electric vehicles were a contributing factor?

**RESPONSE:** We are not aware of any specific upgrades to our distribution system since 1/1/2012 that would be attributed to a plug-in electric vehicle. Distribution upgrades, when they do occur, are often a result of a combination of factors and determining the existence and contribution of a single source such as a plug-in vehicle would be difficult.

## Generation - Renewables Sources

14. Please identify and describe each existing utility-owned renewable resource as of December 31, 2012. Please include the facility's name, unit type, fuel type, whether it is a firm or non-firm resource, its net installed capacity, annual generation for 2012, capacity factor for 2012, and commercial in-service date. For small, distributed renewable resources, such as rooftop solar panels, please combine all under a single resource entry.

**RESPONSE:** Please see the table below and tab 14 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

**Existing Utility-Owned Renewable Resources**

| Facility Name | Unit Type | Fuel Type | Capacity Type | Net Capacity (MW) | | Annual Generation | Capacity Factor | Commercial In-Service Date |
|---|---|---|---|---|---|---|---|---|
| - | - | - | Firm/Non-Firm | Sum | Win | (MWh) | (%) | (MM/YYYY) |
| Econlockhatchee Photovoltaic Array | PV | SUN | Non-Firm | 0.007 | 0.007 | 10.4 | 17% | 01/1989 |

Note: please see related Q#17 Response.

15. Please identify and describe each planned utility-owned renewable resource for the period 2013 through 2022. Please include each proposed facility's name, unit type, fuel type, whether it will be a firm or non-firm resource, its net installed capacity, anticipated average annual generation, anticipated average capacity factor, and projected commercial in-service date. For small, distributed renewable resources, such as rooftop solar panels, please combine all under a single resource entry.

**RESPONSE:** DEF does not currently have any planned utility-owned renewable resources for the period 2013 through 2022.

16. Please refer to the list of planned utility-owned renewable resources for the period 2013 through 2022 above. Discuss the current status of each project.

**RESPONSE:** DEF does not currently have any planned utility-owned renewable resources for the period 2013 through 2022

17. Please list and discuss any planned utility-owned renewable resources within the past year that were cancelled, delayed, or reduced in scope. What was the primary reason for the changes? What, if any, were the secondary reasons?

<u>**RESPONSE:**</u> The Service Plaza Wind information project installed a 2.4kW small-scale wind turbine in January 2010 to analyze the viability of wind power in DEF's service territory. This research project site was located in Okahumpka at a Florida Turnpike service plaza and after two years of data collection was removed in January 2012. The Econolockhatchee Substation solar photovoltaic array provided in Q#14 was originally installed in 1988 to evaluate the performance and potential impacts from distributed solar generation and placed into service in 1989. In 2005 the system was evaluated and many panels were found to be no longer operational. A new research project was established to refurbish the existing panels and install two new technologies. These three, individually interconnected arrays, each 3.5 kW DC rated, allowed for comparison of performance, cost and benefits through 2010. In 2011 the remaining panels from the originally array installed in 1988 failed and were disconnected. The remaining two arrays total 7kW. The system, designed by FSEC, is optimally sited with a southern exposure and near latitude angle.

18. Please identify and describe each existing and planned co-fired renewable fuel source. Please include the name of the fuel production facility, the source of the renewable fuel, the type of fuel produced, what unit co-fires the fuel and its type, the amount of energy generated by the co-fired fuel, what percent of the co-firing unit's fuel is renewable, and the start and end dates of the agreement (if any).

<u>**RESPONSE:**</u> DEF does not currently have any planned co-fired renewable fuel source for the period 2013 through 2022.

19. Please identify and describe each purchased power agreement with a renewable generator that delivered energy during 2012. Please include the name of the facility, fuel type, whether the contract is for firm capacity, the contracted capacity (if firm), the energy delivered in 2012, the capacity factor for 2012, and the start and end dates of the purchased power agreement.

**RESPONSE:** Please see the tables below and tab 19 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

**Existing Renewable Purchased Power Agreements (2012)**

| Facility Name | Fuel Type | Capacity Type | Contracted Capacity (MW) | | Energy Delivered | Capacity Factor | Contract Term (MM/YYYY) | |
|---|---|---|---|---|---|---|---|---|
| - | - | Firm/Non-Firm | Sum | Win | (MWh) | (%) | Start | End |
| Lake County Resource Recovery | MSW | Firm | 12.75 | 12.75 | 88,074 | 83.6% | 1/1/1995 | 6/30/2014 |
| Metro-Dade County | MSW | Firm | 43.00 | 43.00 | 330,137 | 92.9% | 11/1/1991 | 11/30/2013 |
| Pasco County Resource Recovery | MSW | Firm | 23.00 | 23.00 | 183,015 | 96.8% | 1/1/1995 | 12/31/2024 |
| Pinellas County Resource Recovery | MSW | Firm | 54.75 | 54.75 | 339,028 | 75.1% | 1/1/1995 | 12/31/2024 |
| Ridge Generating Station | WDS | Firm | 39.60 | 39.60 | 226,109 | 84.7% | 8/1/1994 | 12/31/2023 |
| Swift Creek | WH | Non-Firm | N/A | N/A | 2,036 | N/A | N/A | N/A |
| White Springs | WH | Non-Firm | N/A | N/A | 2,727 | N/A | N/A | N/A |

* Overall Capacity Factor is affected by contractual curtailments per each Agreement

20. Please identify and describe each purchased power agreement with a renewable generator that is anticipated to begin delivering renewable energy to the Company during the period 2013 and 2022. Please include the name of the facility, fuel type, whether the contract is for firm capacity, the contracted capacity (if firm), the average annual energy to be delivered, the average capacity factor, and the start and end dates of the purchased power agreement.

**RESPONSE:** Please see the table below and tab 20 of the Excel file DEF 2013TYSP Data Request #1 - Tables.xls.

**Renewable Purchased Power Agreements (2013 - 2022)**

| Facility Name | Fuel Type | Capacity Type | Contracted Capacity (MW) | | Energy Delivered | Capacity Factor | Contract Term (MM/YYYY) | |
|---|---|---|---|---|---|---|---|---|
| | - | Firm/Non-Firm | Sum | Win | (MWh) | (%) | Start | End |
| FB Energy | Biomass | Firm | 60 | 60 | 467,787 | 89 | 12/1/2013 | 11/30/2033 |
| US EcoGen | Biomass | Firm | 60 | 60 | 494,067 | 94 | 1/1/2014 | 5/31/2043 |
| TransWorld Energy | Biomass | Firm | 40 | 40 | 329,373 | 94 | 7/1/2013 | 6/30/2033 |
| E2E2 Inc. | Biomass | Non-Firm | N/A | N/A | 249,700* | 95* | 1/1/2014 | N/A |
| Waste to Energy Partners LLC | Biomass | Non-Firm | N/A | N/A | 140,200* | 80* | 12/31/2013 | N/A |
| Waste to Energy Partners LLC | Biomass | Non-Firm | N/A | N/A | 140,200* | 80* | 12/31/2013 | N/A |
| Blue Chip Energy Lake Mary | PV Solar | Non-Firm | N/A | N/A | 17600 * | 20* | 11/30/2010 | N/A |
| Blue Chip Energy Sorrento | PV Solar | Non-Firm | N/A | N/A | 70,100* | 20* | 1/1/2013 | N/A |
| National Solar Gadsden | PV Solar | Non-Firm | N/A | N/A | 87,600* | 20* | 12/31/2013 | N/A |
| National Solar Hardee | PV Solar | Non-Firm | N/A | N/A | 87,600* | 20* | 12/31/2013 | N/A |
| National Solar Suwannee | PV Solar | Non-Firm | N/A | N/A | 87,600* | 20* | 12/31/2013 | N/A |
| National Solar Highlands | PV Solar | Non-Firm | N/A | N/A | 87,600* | 20* | 12/31/2013 | N/A |
| National Solar Osceola | PV Solar | Non-Firm | N/A | N/A | 87,600* | 20* | 12/31/2013 | N/A |

* Due to lack of assurances to the quantity, time or reliability of delivery of energy these values are best estimates

21. Please refer to the list of renewable purchased power agreements that are anticipated to begin delivering capacity and/or energy to the Company during the period 2013 through 2022. Discuss the current status of each project.

**RESPONSE:** Please see the table below for a status update for each agreement:

| Duke Energy Florida's planned Renewable Energy facilities as of December 31, 2012 | | | | | |
|---|---|---|---|---|---|
| Counterparty | County | In-Service Date | Contract End | MW | Status of Project |
| FB Energy | Hernando | 12/1/2013 | 2033 | 60 | Site has been moved to repower the former Central Power & Lime coal facility using biomass. Construction is underway and is scheduled to be complete on time. |
| TransWorld Energy | Citrus | 7/1/2013 | 2033 | 40 | DEF has expressed concerns regarding this project's ability to meet its in service date. Discussions are on going. |
| US EcoGen | Polk | 1/1/2014 | 2043 | 60 | DEF has expressed concerns regarding this project's ability to meet its in service date. Discussions are on going. |
| E2E2 | Polk | TBD | N/A | 30 | Duke has stalled but E2E2 remains optimistic about project completion |
| Waste to Energy Partners LLC | n/a | TBD | N/A | 20 | Duke has stalled but Waste to Energy Partners remain optimistic about project completion |
| Waste to Energy Partners LLC | n/a | TBD | N/A | 20 | Duke has stalled but Waste to Energy Partners remain optimistic about project completion |
| Blue Chip | Lake - Sorrento Project | TBD | N/A | 40 | Installation of posts has begun and the installation of panels is expected to begin in 2013 |
| Blue Chip | Seminole | TBD | N/A | 10 | Blue Chip has chosen to net meter its 1.5 MW of roof top PV panels. The remainder of the buildout is on hold until the Sorrento project is complete. |
| National Solar | Gasden | TBD | N/A | 50 | Project development phase for land acquisition, financing, and all associated permitting. |
| National Solar | Hardee | TBD | N/A | 50 | Project development phase for land acquisition, financing, and all associated permitting. |
| National Solar | Suwannee | TBD | N/A | 50 | Project development phase for land acquisition, financing, and all associated permitting. |
| National Solar | Highlands | TBD | N/A | 50 | Project development phase for land acquisition, financing, and all associated permitting. |
| National Solar | Osceola | TBD | N/A | 50 | Project development phase for land acquisition, financing, and all associated permitting. |

22. Please list and discuss any renewable purchased power agreements within the past year that were cancelled, expired, delayed, or modified. What was the primary reason for the changes? What, if any, were the secondary reasons?

**RESPONSE:** Please see the table below for a status update for each agreement:

**Planned Renewables for 2013 through 2022**

| Terminated Contracts | Reason |
|---|---|
| National Solar - Columbia | Customer Request |
| National Solar - Gilchrist | Customer Request |
| National Solar - Hamilton | Customer Request |

23. Please identify and describe each existing and planned renewable generator, including both interconnected and self-service generators, within the Company's service territory. Please include the facility's name, unit type, fuel type, the installed capacity of the generator, the commercial in-service date of the unit, and whether the renewable generator is contracted by the Company or another utility. Please do not include customer-owned distributed renewable generation in this response.

**RESPONSE:** Please see the tables below and tab 23 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

| Existing Renewable Generators in the Company's Service Territory | | | | | | |
|---|---|---|---|---|---|---|
| Facility Name | Unit Type | Fuel Type | Net Capacity (MW) | | Commercial In-Service Date | Contract Status |
| - | - | - | Sum | Win | (MM/YYYY) | - |
| Lake County Resource Recovery | CC | MSW | 12.75 | 12.75 | 1/1/1995 | PPA with DEF |
| Metro-Dade County Resource Recovery | CC | MSW | 43.00 | 43.00 | 11/1/1991 | PPA with DEF |
| Pasco County Resource Recovery | CC | MSW | 23.00 | 23.00 | 1/1/1995 | PPA with DEF |
| Pinellas County Resource Recovery | CC | MSW | 54.75 | 54.75 | 1/1/1995 | PPA with DEF |
| Ridge Generating Station | CC | WDS | 39.60 | 39.60 | 8/1/1994 | PPA with DEF |
| Swift Creek | ST | WH | 0.10 | 0.10 | 11/1/1980 | Delivering As-Available to DEF |
| White Springs | ST | WH | 0.10 | 0.10 | 11/1/1980 | Delivering As-Available to DEF |
| G2 | IC | LFG | 3.54 | 3.54 | 12/1/2008 | PPA with another utility |
| Telogia | ST | WDS | 8.00 | 8.00 | 7/1/1989 | PPA with another utility |
| Buckeye | ST | WDS/BL | 0.10 | 0.10 | 3/1/1993 | Delivering As-Available to DEF |

| Planned Renewable Generators in the Company's Service Territory | | | | | | |
|---|---|---|---|---|---|---|
| Facility Name | Unit Type | Fuel Type | Net Capacity (MW) | | Commercial In-Service Date | Contract Status |
| - | - | - | Sum | Win | (MM/YYYY) | - |
| **Firm:** | | | | | | |
| FB Energy | ST | WDS | 60 | 60 | 12/2/2013 | Construction |
| US Ecogen | ST | WDS | 60 | 60 | 1/1/2014 | Executed |
| TransWorld Energy | ST | WDS | 40 | 40 | 7/1/2013 | Executed |
| E2E2 Inc. | ST | WDS | 30 | 30 | TBD | Executed |
| **Non-Firm:** | | | | | | |
| Waste to Energy Partners LLC | ST | MSW | 20 | 20 | TBD | Executed |
| Waste to Energy Partners LLC | ST | MSW | 20 | 20 | TBD | Executed |
| Blue Chip - Sorrento | PV | Solar | 50 | 50 | TBD | Executed |
| Blue Chip - Seminole | PV | Solar | 10 | 10 | TBD | Executed |
| National Solar - Gasden | PV | Solar | 50 | 50 | TBD | Executed |
| National Solar - Hardee | PV | Solar | 50 | 50 | TBD | Executed |
| National Solar - Suwannee | PV | Solar | 50 | 50 | TBD | Executed |
| National Solar - Highlands | PV | Solar | 50 | 50 | TBD | Executed |
| National Solar - Osceola | PV | Solar | 50 | 50 | TBD | Executed |

24. Pease provide the annual output for the company's renewable resources, including utility-owned firm resources, utility-owned non-firm resources, firm renewable PPAs, non-firm renewable purchases (such as as-available energy purchases), or customer-owned generation, for the period 2012 through 2022. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the table below and tab 24 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

| Renewable Generation by Source | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Annual Output | Actual | Projected | | | | | | | | | |
| (GWh) | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| Firm Utility | - | - | - | - | - | - | - | - | - | - | - |
| Non-Firm Utility | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Firm PPA[1] | 1,148.3 | 1,345.9 | 1,840.0 | 1,840.0 | 1,840.0 | 1,840.0 | 1,840.0 | 1,840.0 | 1,840.0 | 1,840.0 | 1,840.0 |
| Non-Firm Purchase[1] | 22.8 | 92.9 | 1,061.0 | 1,061.0 | 1,061.0 | 1,061.0 | 1,061.0 | 1,061.0 | 1,061.0 | 1,061.0 | 1,061.0 |
| Customer Owned* | 128.1 | 184.6 | 230.6 | 292.0 | 322.4 | 276.2 | 311.0 | 341.0 | 370.8 | 400.0 | 430.0 |
| Total | 1,299.2 | 1,623.4 | 3,131.6 | 3,193.0 | 3,223.4 | 3,177.2 | 3,212.0 | 3,242.0 | 3,271.8 | 3,301.0 | 3,331.0 |

[1] Totals include signed contracts that have not yet met contractual milestones and may not be included in the TYSP Schedules

25. [Investor-owned Utilities Only] Provide, on a system-wide basis, the historical annual average as-available energy rate in the Company's service territory for the period 2003 through 2012. If the Company uses multiple areas for as-available energy rates, please provide a system-average rate as well. Also, provide the forecasted annual average as-available energy rate in the Company's service territory for the period 2013 through 2022. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the table below and tab 25 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

| As-Available Energy Rates | | | | |
|---|---|---|---|---|
| Year | | As-Available Energy ($/MWh) | On-Peak Average ($/MWh) | Off-Peak Average ($/MWh) |
| Actual | 2003 | $ 43.38 | $ 56.91 | $ 33.24 |
| | 2004 | $ 41.83 | $ 50.96 | $ 33.71 |
| | 2005 | $ 62.98 | $ 77.79 | $ 51.74 |
| | 2006 | $ 53.15 | $ 65.74 | $ 43.60 |
| | 2007 | $ 50.44 | $ 62.57 | $ 41.37 |
| | 2008 | $ 62.23 | $ 73.98 | $ 53.20 |
| | 2009 | $ 33.04 | $ 37.22 | $ 29.67 |
| | 2010 | $ 40.52 | $ 47.08 | $ 35.49 |
| | 2011 | $ 35.95 | $ 41.16 | $ 32.03 |
| | 2012 | $ 27.41 | $ 31.72 | $ 23.75 |
| Projected | 2013 | $ 36.59 | $ 40.88 | $ 32.96 |
| | 2014 | $ 38.52 | $ 43.56 | $ 34.25 |
| | 2015 | $ 41.66 | $ 48.08 | $ 36.22 |
| | 2016 | $ 43.27 | $ 50.09 | $ 37.50 |
| | 2017 | $ 43.71 | $ 49.40 | $ 38.89 |
| | 2018 | $ 45.63 | $ 51.86 | $ 40.37 |
| | 2019 | $ 48.97 | $ 56.52 | $ 42.59 |
| | 2020 | $ 51.24 | $ 60.58 | $ 43.34 |
| | 2021 | $ 53.59 | $ 63.79 | $ 44.97 |
| | 2022 | $ 56.95 | $ 69.03 | $ 46.73 |

## **Generation - Traditional Sources**

26. Please provide the cumulative present worth revenue requirement of the Company's Base Case for the 2013 Ten-Year Site Plan. If available, please provide the cumulative present worth revenue requirement of any sensitivities studied as well.

    **RESPONSE:** DEF's Resource Planning Base Case cumulative present worth revenue requirement for the 2013 TYSP is $36.8B.

27. Please illustrate what the Company's generation expansion plan would be as a result of sensitivities to the base case demand, as provided in Appendix A. Include impacts on unit in-service dates for any possible delays, cancellations, accelerated completion, or new additions as a result.

    **RESPONSE:** Duke Energy Florida did not produce demand and fuel price sensitivities for the April 2013 Ten-Year Site Plan, and therefore did not evaluate any expansion plans based on such sensitivities.

28. Please complete the following table detailing unit specific information on capacity and fuel consumption for 2012. For each unit on the Company's system, provide the following data based upon historic data from 2012; the unit's capacity, annual generation, capacity factor, estimated annual availability factor, unit average heat rate, and average energy cost for the unit's production. For dual fuel units, please report each fuel separately. Please complete the table below and provide an electronic copy (in Excel).

    **RESPONSE:** Please see the table below and tab 28 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

| Utility-Owned Generation | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Plant | Unit # | Unit Type | Fuel Type | Net Capacity (MW) | | 2012 Annual Generation | Capacity Factor | Avail. Factor | In-Service Date | Avg. Heat Rate | Unit Fuel Cost |
| | | | | Sum | Win | (MWh) | (%) | (%) | | (BTU/kWh) | (¢/kWh) |
| Crystal River Nuclear | 3 | Nuclear | Uranium | 789 | 805 | 0 | 0.00 | 0.00 | 3/1977 | 0 | 0.0 |
| Anclote | 1 | Steam | Gas | 501 | 517 | 812,405 | 18.69 | 91.32 | 10/1974 | 12,558 | 6.5 |
| | | | Oil | | | 23,374 | | | | | 15.3 |
| Anclote | 2 | Steam | Gas | 510 | 530 | 849,762 | 19.08 | 88.01 | 10/1978 | 12,273 | 6.3 |
| | | | Oil | | | 21,698 | | | | | 14.8 |
| Crystal River | 1 | Steam | Coal | 370 | 372 | 1,085,567 | 32.91 | 94.29 | 10/1966 | 10,889 | 5.0 |
| Crystal River | 2 | Steam | Coal | 499 | 503 | 1,417,718 | 32.41 | 87.42 | 11/1969 | 10,694 | 5.1 |
| Crystal River | 4 | Steam | Coal | 712 | 721 | 4,372,520 | 69.48 | 94.63 | 12/1982 | 10,503 | 3.7 |
| Crystal River | 5 | Steam | Coal | 710 | 721 | 3,188,963 | 50.74 | 78.46 | 10/1984 | 10,669 | 3.8 |
| Suwannee River | 1 | Steam | Gas | 28 | 28 | 63,417 | 25.89 | 85.05 | 11/1953 | 14,952 | 7.7 |
| | | | Oil | | | 259 | | | | | 12.8 |
| Suwannee River | 2 | Steam | Gas | 30 | 30 | 114,155 | 43.37 | 95.05 | 11/1954 | 15,071 | 7.7 |
| | | | Oil | | | 144 | | | | | 14.2 |
| Suwannee River | 3 | Steam | Gas | 71 | 73 | 336,492 | 53.25 | 90.78 | 10/1956 | 11,827 | 6.1 |
| | | | Oil | | | 256 | | | | | 14.3 |
| Avon Park | 1~2 | Gas Turbine | Gas | 48 | 70 | 166 | 0.09 | 81.58 | 12/1968 | 20,016 | 10.6 |
| | | | Oil | | | 313 | | | | | 34.7 |
| Bartow CC | 4 | CC | Gas | 1074 | 1235 | 6,856,959 | 65.96 | 84.73 | 6/2009 | 7,552 | 4.3 |
| | | | Oil | | | 1,094 | | | | | 15.3 |
| Bartow Peaker | 1~4 | Gas Turbine | Gas | 177 | 226 | 1,925 | 0.22 | 34.42 | 05/1972-06/1972 | 11,947 | 6.3 |
| | | | Oil | | | 1,899 | | | | | 22.1 |
| Bayboro | 1~4 | Gas Turbine | Oil | 174 | 232 | 4,995 | 0.28 | 98.29 | 04/1973 | 13,725 | 27.4 |
| DeBary | 1~10 | Gas Turbine | Gas | 636 | 763 | 44,334 | 0.83 | 91.66 | 12/1975-10/1992 | 13,967 | 7.2 |
| | | | Oil | | | 6,881 | | | | | 24.6 |
| Higgins | 1~4 | Gas Turbine | Gas | 105 | 116 | 699 | 0.09 | 90.24 | 03/1969-01/1971 | 21,021 | 10.9 |
| | | | Oil | | | 133 | | | | | 35.7 |
| Hines Energy Complex | 1~4 | CC | Gas | 1912 | 2199 | 12,998,510 | 72.02 | 86.95 | 04/1999-11/2005 | 7,151 | 4.1 |
| Intercession City | 1~14 | Gas Turbine | Gas | 986 | 1188 | 294,415 | 3.20 | 88.12 | 05/1974-12/2000 | 13,356 | 7.6 |
| | | | Oil | | | 10,605 | | | | | 24.5 |
| Rio Pinar | 1 | Gas Turbine | Oil | 12 | 15 | 31 | 0.03 | 100.00 | 11/1970 | 19,146 | 35.8 |
| Suwannee River Peaker | 1~3 | Gas Turbine | Gas | 155 | 193 | 11,410 | 0.83 | 82.17 | 10/1980-11/1980 | 14,246 | 7.4 |
| | | | Oil | | | 1,499 | | | | | 22.4 |
| Tiger Bay | 1 | CC | Gas | 205 | 231 | 1,252,357 | 66.02 | 81.91 | 08/1997 | 7,596 | 3.9 |
| Turner | 1~4 | Gas Turbine | Oil | 134 | 182 | 13,647 | 0.98 | 89.27 | 10/1970-08/1974 | 15,387 | 31.3 |
| University of Florida | 1 | Gas Turbine | Gas | 46 | 47 | 361,306 | 88.46 | 88.56 | 01/1994 | 9,388 | 4.5 |

29. Please complete the following table detailing planned unit additions, including information on capacity and in-service dates. Please include only planned conventional units with an in-service date past January 1, 2013, and including nuclear units, nuclear unit uprates, combustion turbines, and combined-cycle units. For each planned unit, provide the date of the Commission's Determination of Need and Power Plant Siting Act certification (if applicable), and the anticipated in-service date. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the table below and tab 29 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

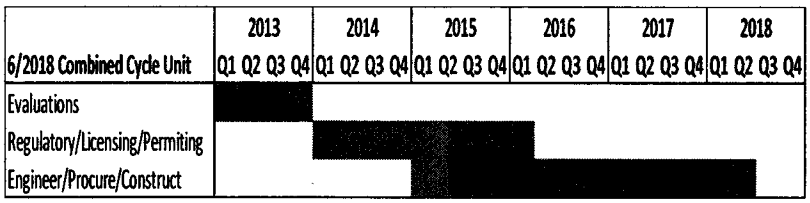
**Planned Unit Additions for 2013 through 2022**

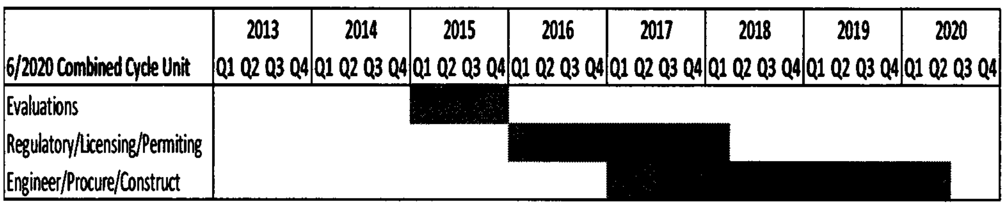
| Generating Unit Name | Summer Capacity (MW) | Certification Dates (if Applicable) | | In-Service Date |
|---|---|---|---|---|
| | | Need Approved (Commission) | PPSA Certified | |
| **Nuclear Unit Additions / Uprates** | | | | |
| n/a | | | | |
| **Combustion Turbine Unit Additions** | | | | |
| Unknown | 187 | | | 6/2022 |
| **Combined Cycle Unit Additions** | | | | |
| Unknown | 1189 | | | 6/2018 |
| Unknown | 1189 | | | 6/2020 |
| **Steam Turbine Unit Additions** | | | | |
| n/a | | | | |

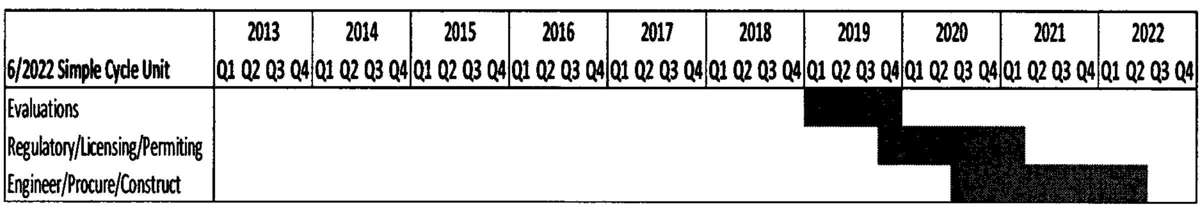
30. For each of the planned generating units contained in the Company's Ten-Year Site Plan, please discuss the drop dead date for a decision on whether or not to construct each unit. Provide a time line for the construction of each unit, including regulatory approval, and final decision point.

**RESPONSE:** In the Duke Energy Florida April 2013 Ten-Year Site Plan, the in-service dates for future combined cycle units were projected for June 2018 and 2020. The in-service date for a future simple cycle unit was projected for June 2022.

DEF anticipates an approximate 54 month window for developing a combined cycle power plant. Major equipment lead times are approximately 24 to 36 months depending on vendor workloads. A "drop dead" decision date to proceed with the combined cycle (CC) project would typically occur about 36 months before the in-service date for the Combined Cycle Units and 24 months for the Simple Cycle Unit. The major components of the 6/2018 and 6/2020 combined cycle power plant schedules are shown below as well as the simple cycle schedule for 6/2022:




31. For each existing and planned unit on the Company's system, provide the following data based upon historic data from 2011 and forecasted capacity factor values for the period 2012 through 2021. Please complete the tables below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the table below and tab 31 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

| Projected Unit Information – Capacity Factor (%) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Plant | Unit # | Unit Type | Fuel Type | Actual | Projected | | | | | | | | | |
| | | | | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| Anclote | 1 | Steam | Oil/Gas | 18.7 | 20.0 | 28.2 | 33.3 | 25.5 | 22.4 | 23.8 | 26.3 | 24.3 | 24.6 | 22.9 |
| Anclote | 2 | Steam | Oil/Gas | 19.1 | 17.6 | 29.8 | 31.8 | 28.3 | 24.4 | 26.0 | 29.3 | 26.2 | 28.0 | 27.9 |
| Crystal River | 1 | Steam | Coal | 32.9 | 27.0 | 27.6 | 24.9 | 12.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Crystal River | 2 | Steam | Coal | 32.4 | 31.4 | 30.9 | 30.0 | 27.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Crystal River | 4 | Steam | Coal | 69.5 | 77.5 | 78.9 | 84.6 | 84.6 | 85.5 | 89.1 | 78.3 | 71.1 | 71.7 | 69.5 |
| Crystal River | 5 | Steam | Coal | 50.7 | 75.2 | 73.9 | 74.1 | 83.3 | 90.3 | 78.8 | 81.0 | 69.4 | 62.1 | 63.5 |
| Suwannee River | 1 | Steam | Oil/Gas | 25.9 | 28.3 | 23.1 | 25.7 | 31.4 | 32.9 | 18.1 | 0.0 | 0.0 | 0.0 | 0.0 |
| Suwannee River | 2 | Steam | Oil/Gas | 43.4 | 46.8 | 24.9 | 26.5 | 32.4 | 32.1 | 20.3 | 0.0 | 0.0 | 0.0 | 0.0 |
| Suwannee River | 3 | Steam | Oil/Gas | 53.3 | 35.1 | 25.7 | 29.2 | 30.5 | 30.9 | 22.8 | 0.0 | 0.0 | 0.0 | 0.0 |
| Avon Park | 1-2 | Gas Turbine | Oil/Gas | 0.1 | 3.2 | 3.2 | 3.4 | 3.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Bartow CC | 4 | CC | Oil/Gas | 66.0 | 91.3 | 88.2 | 86.1 | 81.0 | 82.8 | 72.4 | 65.1 | 60.2 | 53.5 | 54.3 |
| Bartow Peaker | 1-4 | Gas Turbine | Oil/Gas | 0.2 | 4.0 | 3.9 | 6.1 | 8.4 | 7.9 | 5.9 | 6.1 | 3.1 | 2.6 | 3.2 |
| Bayboro | 1-4 | Gas Turbine | Oil | 0.3 | 0.0 | 0.0 | 0.1 | 0.3 | 0.1 | 0.1 | 0.0 | 0.2 | 0.1 | 0.3 |
| DeBary | 1-10 | Gas Turbine | Oil/Gas | 0.8 | 4.5 | 4.2 | 5.5 | 6.8 | 6.4 | 4.7 | 4.2 | 2.7 | 2.6 | 2.9 |
| Higgins | 1-4 | Gas Turbine | Oil/Gas | 0.1 | 0.4 | 0.5 | 0.8 | 1.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hines Energy Complex | 1-4 | CC | Oil/Gas | 72.0 | 61.7 | 67.1 | 67.1 | 63.6 | 58.1 | 54.8 | 49.2 | 46.7 | 41.1 | 42.1 |
| Intercession City | 1-14 | Gas Turbine | Oil/Gas | 3.2 | 8.6 | 9.0 | 10.6 | 13.0 | 12.1 | 10.4 | 9.9 | 6.4 | 6.1 | 5.7 |
| Rio Pinar | 1 | Gas Turbine | Oil | 0.0 | 2.5 | 2.4 | 3.0 | 2.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Suwannee River Peaker | 1-3 | Gas Turbine | Oil/Gas | 0.8 | 1.3 | 0.9 | 1.5 | 2.1 | 1.3 | 0.5 | 0.7 | 0.7 | 1.5 | 1.9 |
| Tiger Bay | 1 | CC | Gas | 66.0 | 75.8 | 65.5 | 72.7 | 66.4 | 57.5 | 57.2 | 53.2 | 56.4 | 46.7 | 57.0 |
| Turner | 1-4 | Gas Turbine | Oil | 1.0 | 1.6 | 1.8 | 2.3 | 6.4 | 6.9 | 4.0 | 3.4 | 1.4 | 1.1 | 1.4 |
| University of Florida | 1 | Gas Turbine | Gas | 88.5 | 75.8 | 87.8 | 87.6 | 83.9 | 83.9 | 88.0 | 74.7 | 84.0 | 80.9 | 77.5 |

32. Please complete the table below, providing a list of all of the Company's steam units or combustion turbines that are potential candidates for repowering. As part of this response, please provide the unit's fuel and unit type, summer capacity rating, in-service date, and what potential conversion/repowering would be most applicable. Also include a description of any major obstacles that could affect repowering efforts at any of these sites, such as unit age, land availability, or other requirements. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Duke Energy Florida repowered the P.L. Bartow Plant in 2009 and could potentially repower the units identified in the table below and provided in tab 32 of the Excel file DEF 2013 TYSP Data Request - Tables.xls. Possible repowering major obstacles include but are not limited to transmission upgrades, fuel transportation, site constraints, and obtaining necessary permits.

**Repowering Candidate Units**

| Plant Name | Unit Type | Fuel Type | Summer Capacity (MW) | In-Service Date | Potential Conversion |
|---|---|---|---|---|---|
| Anclote | Steam | NG/RFO | 501 | 10/74 | CC |
| Anclote | Steam | NG/RFO | 510 | 10/78 | CC |
| Crystal River | Steam | BIT | 370 | 10/66 | CC/IGCC |
| Crystal River | Steam | BIT | 499 | 11/69 | CC/IGCC |
| Crystal River | Steam | BIT | 712 | 12/82 | CC/IGCC |
| Crystal River | Steam | BIT | 710 | 10/84 | CC/IGCC |
| Suwannee River | Steam | NG/RFO | 28 | 11/53 | CC/RF |
| Suwannee River | Steam | NG/RFO | 30 | 11/54 | CC/RF |
| Suwannee River | Steam | NG/RFO | 71 | 10/56 | CC/RF |
| Avon Park | Gas Turbine | DFO/NG | 48 | 12/68 | CC |
| Bartow Peaker | Gas Turbine | DFO/NG | 177 | 6/72-4/73 | CC |
| Bayboro | Gas Turbine | DFO/NG | 174 | 4/73 | CC |
| DeBary | Gas Turbine | DFO/NG | 636 | 12/75-10/92 | CC |
| Higgins | Gas Turbine | DFO/NG | 105 | 3/69-1/71 | CC |
| Intercession City | Gas Turbine | DFO/NG | 986 | 5/74-12/00 | CC |
| Suwannee River Peaker | Gas Turbine | DFO/NG | 155 | 10/80-11/80 | CC |
| Turner | Gas Turbine | DFO | 134 | 10/70-8/74 | CC |
| University of Florida | Gas Turbine | NG | 46 | 1/94 | CC |

33. Please complete the following table detailing the Company's planned changes to summer capacity. In addition to providing the net change for the current year's Ten-Year Site Plan, please also provide the net change based on last year's Ten-Year Site Plan. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the table below and tab 33 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

**System Capacity Changes by Fuel & Unit Type**

| Fuel Type | Unit Type | Summer Capacity Changes (MW) 2012 TYSP (2012-2021) | Summer Capacity Changes (MW) 2013 TYSP (2013-2022) |
|---|---|---|---|
| Natural Gas | Combined Cycle | 767 | 2378 |
| | Combustion Turbine | -185 | 187 |
| | Steam | -109 | -129 |
| Coal | Steam | | -869 |
| | Integrated Coal Gasification | | 0 |
| Oil | Combustion Turbine & Diesel | | -185 |
| | Steam | | 0 |
| Nuclear | Steam | 2035 | -789 |
| Firm Purchases | Independent Power Producer (IPP) | | 0 |
| | Interchange | | -1 |
| | Non-Utility Generator (NUG) | | -65 |
| | Renewables | | 4 |
| **NET CAPACITY ADDITIONS** | | **2508** | **531** |

34. [Investor-Owned Utilities Only] Please complete the table below describing the status of the company's generating units during each month's peak demand, for the year 2012. As part of this response, include the actual values at monthly peak for installed capacity, scheduled maintenance, forced outages, available capacity, and net firm peak demand. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the table below and tab 34 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

**Available Capacity at Time of Peak Demand**

| Capacity / Demand at Time of Monthly Peak (MW) | | | | | | |
|---|---|---|---|---|---|---|
| **Year** | **Month** | **Installed Capacity** | **Scheduled Maintenance** | **Forced Outages** | **Available Capacity** | **Peak Demand** |
| 2012 | 1 | 12,933 | 343 | 1,445 | 11,145 | 8,722 |
| | 2 | 12,933 | 471 | 979 | 11,483 | 8,519 |
| | 3 | 12,933 | 3,249 | 1,214 | 8,470 | 6,135 |
| | 4 | 12,933 | 1,827 | 1,140 | 9,966 | 7,004 |
| | 5 | 12,003 | 733 | 913 | 10,357 | 7,942 |
| | 6 | 12,003 | 406 | 889 | 10,708 | 8,185 |
| | 7 | 12,003 | 418 | 1,030 | 10,555 | 9,026 |
| | 8 | 12,003 | 207 | 1,431 | 10,365 | 8,850 |
| | 9 | 12,003 | 355 | 925 | 10,723 | 8,103 |
| | 10 | 12,003 | 664 | 889 | 10,450 | 7,790 |
| | 11 | 12,933 | 2,181 | 1,519 | 9,233 | 5,749 |
| | 12 | 12,933 | 1,215 | 981 | 10,737 | 6,555 |

## Generation - Energy Purchases / Sales

35. Please identify each of the Company's existing and planned power purchase contracts, including firm capacity imports reflected in Schedule 7 of the Company's Ten-Year Site Plan. Provide the seller, capacity, associated energy, and term of each purchase, and provide unit information if a unit power purchase. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the table below and tab 35 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

**Existing Purchased Power Agreements as of January 1, 2013**

| Seller | Contract Term | | Contract Capacity (MW) | | Annual Generation | Capacity Factor | Primary Fuel | Description |
|---|---|---|---|---|---|---|---|---|
| | Begins | Ends | Summer | Winter | (MWh) | (%) | (if any) | |
| City of Chattahoochee | 1/20/2004 | 1/20/2014 | 5 | 5 | 0 | 0 | Diesel | Call Option |
| Shady Hills Power Company | 4/1/2007 | 4/30/2024 | 485 | 516 | 480 | 18.7 | NG | GT |
| Southern Company Services | 6/1/2010 | 5/31/2016 | 73 | 73 | 516 | 80.7 | Coal | Steam |
| Southern Power | 6/1/2010 | 5/31/2016 | 350 | 350 | 1,317 | 42.9 | NG | CC |
| Caithness | 7/1/94 | 12/31/13 | 114.2 | 114.2 | 969,792 | 84.0 | GAS | GT - Auburndale Facility |
| Caithness | 7/1/93 | 7/31/13 | 110 | 110 | 603,028 | 63.0 | GAS | GT - Lake Cogen Facility |
| Northern Star Generation | 6/1/95 | 12/31/15 | 74 | 74 | 248,858 | 46.0 | GAS | GT -Orange Cogen Facility |
| | 1/1/16 | 12/31/25 | 104 | 104 | 464,600 | | GAS | |
| Northern Star Generation | 10/1/93 | 12/31/13 | 79.2 | 79.2 | 653,244 | 94.0 | GAS | GT- Orlando Cogen Facility |
| | 1/1/14 | 12/31/23 | 115 | 115 | 987,300 | | GAS | |
| Northern Star Generation | 7/1/94 | 8/31/24 | 115 | 115 | 411,911 | 52.0 | GAS | GT - Mulberry Cogen Facility |
| Northern Star Generation | 6/1/12 | 5/31/27 | 635 | 678 | 693,400 | 15.0 | GAS | GT- Vandolah Facility |

**Planned Purchased Power Agreements for 2013 through 2022**

| Seller | Contract Term | | Contract Capacity (MW) | | Annual Generation | Capacity Factor | Primary Fuel | Description |
|---|---|---|---|---|---|---|---|---|
| | Begins | Ends | Summer | Winter | (MWh) | (%) | (if any) | |
| SERC Region | 6/1/2016 | 5/31/2021 | 412 | 412 | 1,155 | 34 | NG | CC |
| Unkown | 4/1/2016 | 3/31/2019 | 480 | 480 | 228 | 7 | NG | GT |
| Unkown | 4/1/2016 | 3/31/2019 | 500 | 500 | 1,720 | 49 | NG | CC |
| Unkown | 4/1/2016 | 3/31/2019 | 500 | 500 | 2,089 | 71 | NG | CC |

36. Please identify each of the Company's existing and planned power sales, including firm capacity exports reflected in Schedule 7 of the Company's Ten-Year Site Plan. Provide the purchaser, capacity, associated energy, and term of each purchase, and provide unit information if a unit power sale. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the table below and tab 36 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

**Existing Power Sales as of January 1, 2013**

| Purchaser | Contract Term | | Contract Capacity (MW) | | Annual Generation | Capacity Factor | Primary Fuel | Description |
|---|---|---|---|---|---|---|---|---|
| | Begins | Ends | Summer | Winter | (MWh) | (%) | (if any) | |
| City of Chattahoochee | 1/1/2003 | 12/31/2017 | 6 | 5 | 29,107 | 61.00% | System | Average |
| Gainesville Regional Utilities | 4/1/2009 | 12/31/2013 | 50 | 50 | 20,000 | 4.60% | System | Base |
| City of Homestead | 11/1/2007 | 12/31/2019 | 40 | 40 | 113,880 | 36.30% | System | Base, Intermediate |
| City of Mount Dora | 1/1/2013 | 12/31/2016 | 21 | 18 | 92,904 | 53.00% | System | Average |
| City of New Smyrna Beach | 1/1/2013 | 12/31/2016 | 44 | 25 | 43,800 | 41.80% | System | Average, Peaking |
| Seminole Electric Cooperative | 10/13/1983 | 12/31/2013 | 0 | 0 | 0 | 0.00% | System | System Peaking |
| Seminole Electric Cooperative | 1/1/2011 | 12/31/2013 | 150 | 150 | 58,217 | 26.60% | Natural Gas | Combined Cycle |
| Seminole Electric Cooperative | 1/1/1999 | 12/31/2013 | 300 | 300 | 21,753 | 0.80% | System | Intermediate |
| Seminole Electric Cooperative | 1/1/2012 | 12/31/2013 | 150 | 150 | 71,107 | 5.40% | System | Base |
| Seminole Electric Cooperative | 1/1/1999 | 12/31/2013 | 15 | 15 | 76,103 | 57.90% | System | Interruptible Average |
| Reedy Creek Energy Services | 1/1/2013 | 12/31/2016 | 60 | 60 | 270,029 | 51.40% | System | Combined Cycle |
| Reedy Creek Energy Services | 1/1/2013 | 12/31/2016 | 53 | 20 | 4,403 | 1.80% | System | Base |
| City of Winter Park | 1/1/2011 | 12/31/2013 | 40 | 40 | 186,020 | 53.10% | Natural Gas | Combined Cycle |
| City of Williston | 1/1/2013 | 12/31/2016 | 7 | 6 | 29,195 | 51.30% | System | Average |

**Planned Power Sales for 2013 through 2022**

| Purchaser | Contract Term | | Contract Capacity (MW) | | Annual Generation (MWh) | Capacity Factor (%) | Primary Fuel (If any) | Description |
|---|---|---|---|---|---|---|---|---|
| | Begins | Ends | Summer | Winter | | | | |
| Seminole Electric Cooperative | 1/1/2014 | 5/31/2016 | 250 | 250 | 1,680,679 | 76.70% | System | Base |
| Seminole Electric Cooperative | 1/1/2014 | 5/31/2016 | 150 | 150 | 522,612 | 39.80% | System | Average |
| Seminole Electric Cooperative | 6/1/2016 | 12/31/2024 | 200-500 | 200-500 | 653,658-1,047,152 | 40.0%-59.7% | Natural Gas | Combined Cycle |
| Seminole Electric Cooperative | 1/1/2014 | 12/31/2020 | 150 | 150 | 207,612 | 15.80% | System | Intermediate |
| Seminole Electric Cooperative | 1/1/2014 | 12/31/2020 | 100 | 100-600 | 19,392-61,200 | 4.00% | System | Peaking |

37. Please discuss and identify the impacts on the Company's capacity needs of all known firm power purchases and sales over the planning horizon. As part of this discussion, please include whether options to extend purchases or sales exist, and the potential effects of expiration of these purchase or sales.

**RESPONSE:** Capacity sales extensions and expirations are based upon the individual terms of their respective contracts. For example, full requirements contracts with municipal utilities are assumed to renew unless a new supplier has been identified. This ensures that a utility has capacity committed to the municipal customer. Other contracts may have extensions or "evergreen" provisions that assume that the contract will continue. In the event that a customer selects another supplier, DEF would attempt to sell that capacity to a different wholesale customer or use the capacity to satisfy a retail customer requirement. The Company has been successful in extending many of our expiring wholesale agreements, including full requirements sales to Williston and Mount Dora.

38. Please list and discuss any long-term power sale or purchase agreements within the past year that were cancelled, expired, or modified. What was the primary reason for the changes? What, if any, were the secondary reasons?

**RESPONSE:** DEF's purchase and sales agreements end due to natural expiration, economic climate or market conditions. The agreements that ended during 2012 were:

A. DEF and City of Tallahassee jointly agreed to terminate a sale of 11.4 MW from DEF's Base resources to Tallahassee at the end of 2012.

B. DEF had a System Intermediate sale of varying amounts to Reedy Creek Improvement District that expired at the end of 2012. A replacement agreement between the Parties began January 1, 2013.
C. DEF had a System Intermediate sale to Seminole Electric Cooperative that expired at the end of 2012.
D. DEF's Full Requirements sale to City of Mount Dora was scheduled to expire at the end of 2012, but was extended through 2016.
E. DEF's Full Requirements sale to City of Williston was likewise extended through 2016.
F. DEF's 316 MW capacity purchase from GenOn expired on May 31, 2012.
G. DEF's 650 MW capacity purchase from Northern Star began on June 1, 2012.
H. DEF contract with Mount Dora ended 2012 and replaced with a new 2013 – 2016 contract with new rates.
I. DEF contract with Williston terminated in 2012 and replaced with a new contract through 2016 with new rates.

## Generation - Environmental

39. Provide a narrative explaining the impact of any existing environmental regulations relating to air emissions and water quality or waste issues on the Company's system during the 2012 period. As part of your discussion, please include the potential for existing environmental regulations to impact unit dispatch, curtailments or retirement during the 2013 through 2022 period.

**RESPONSE:** Crystal River Units 1 and 2 continue to be subject to the potential for derate in order to meet the surface water discharge effluent thermal limit imposed by the Crystal River Units 1, 2, and 3 National Pollution Discharge Elimination System (NPDES) permit. No derates were required in 2012. The Crystal River Units 1 and 2 air emissions are governed by a permit that will require the units to comply with the Best Available Retrofit Technology (BART) for particulate matter by the end of 2013. One option to meet the permit limits includes de-rating the units; however, the extent of these potential derates is not known at this time.

40. Please provide the amount of regulated air pollutants and carbon dioxide emitted, on an annual and per megawatt-hour basis, for the Company's generation fleet during the period 2003 through 2022. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the table below and tab 40 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

**Emissions of Registered Air Pollutants & CO2**

| | Year | SOX | | NOX | | Mercury | | Particulates | | CO2e | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | lb/MWh | Tons | lb/MWh | Tons | lb/MWh | Tons | lb/MWh | Tons | lb/MWh | Tons |
| Actual | 2003 | 9.0 | 162,586 | 2.7 | 48,733 | 0.000015 | 0.27 | 0.25 | 4,481 | 1510 | 27,215,023 |
| | 2004 | 7.5 | 140,378 | 2.4 | 45,533 | 0.000014 | 0.26 | 0.29 | 5,398 | 1444 | 26,881,428 |
| | 2005 | 7.4 | 139,506 | 2.5 | 46,325 | 0.000015 | 0.28 | 0.26 | 4,989 | 1496 | 28,245,706 |
| | 2006 | 6.7 | 122,930 | 2.2 | 40,411 | 0.000013 | 0.24 | 0.15 | 2,729 | 1392 | 25,390,219 |
| | 2007 | 7.1 | 133,170 | 2.5 | 46,663 | 0.000013 | 0.24 | 0.24 | 4,465 | 1363 | 25,515,743 |
| | 2008 | 5.8 | 110,452 | 2.2 | 41,100 | 0.000012 | 0.23 | 0.20 | 3,761 | 1256 | 23,972,817 |
| | 2009 | 4.4 | 79,685 | 1.3 | 23,891 | 0.000010 | 0.18 | 0.14 | 2,722 | 1202 | 21,739,872 |
| | 2010 | 2.5 | 47,264 | 0.8 | 15,999 | 0.000010 | 0.19 | 0.15 | 2,789 | 1325 | 25,421,640 |
| | 2011 | 1.6 | 28,529 | 0.7 | 11,271 | 0.000005 | 0.08 | 0.12 | 2,238 | 1358 | 23,526,029 |
| | 2012 | 1.5 | 27,259 | 0.6 | 11,233 | 0.000004 | 0.07 | 0.15 | 2,582 | 1277 | 22,719,631 |
| Projected | 2013 | 1.7 | 30,029 | 0.7 | 12,391 | 0.000007 | 0.12 | 0.15 | 3,080 | 1360 | 23,810,628 |
| | 2014 | 1.7 | 29,929 | 0.8 | 13,635 | 0.000007 | 0.12 | 0.15 | 3,139 | 1348 | 24,447,056 |
| | 2015 | 1.6 | 29,362 | 0.8 | 14,620 | 0.000007 | 0.12 | 0.15 | 3,213 | 1353 | 25,021,193 |
| | 2016 | 0.8 | 13,483 | 0.6 | 11,178 | 0.000005 | 0.08 | 0.15 | 3,279 | 1350 | 23,382,132 |
| | 2017 | 0.6 | 10,057 | 0.6 | 10,033 | 0.000004 | 0.07 | 0.15 | 3,309 | 1368 | 22,809,261 |
| | 2018 | 0.5 | 9,223 | 0.5 | 9,104 | 0.000004 | 0.07 | 0.15 | 3,357 | 1290 | 23,289,791 |
| | 2019 | 0.5 | 8,752 | 0.5 | 8,966 | 0.000003 | 0.07 | 0.15 | 3,401 | 1248 | 23,456,031 |
| | 2020 | 0.4 | 7,589 | 0.4 | 8,028 | 0.000003 | 0.06 | 0.15 | 3,448 | 1169 | 23,643,323 |
| | 2021 | 0.3 | 7,186 | 0.4 | 7,908 | 0.000003 | 0.06 | 0.15 | 3,487 | 1138 | 23,865,467 |
| | 2022 | 0.3 | 7,203 | 0.4 | 7,968 | 0.000003 | 0.06 | 0.15 | 3,526 | 1136 | 24,033,048 |

41. Please indicate if your company will be materially affected by the new or proposed rules listed below. If the company will be affected by the rules, identify any compliance strategies the company intends to employ for each rule. If a compliance strategy has not been completed, explain the timeline for completion of the compliance strategy, including any regulatory approvals, for each rule.

    a. Mercury and Air Toxics Standards (MATS) Rule

    b. Cross-State Air Pollution Rule (CSAPR) or Clean Air Interstate Rule (CAIR) Rule

    c. Cooling Water Intake Structures Rule (CWIS)

    d. Coal Combustion Residuals Rule (CCR), both for classification of coal ash as a "Non-Hazardous Waste" and as a "Special Waste"

    e. Florida's State Implementation Plan for Regional Haze

    f. Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units

**RESPONSE:** DEF has provided its compliance strategy for MATS, CSAPR, and the Regional Haze Rule in the Integrated Clean Air Compliance Plan submitted to the Commission on April 1, 2013 in Docket 130007. Because the CWIS, CCR, and GHG rules have not been finalized, there are no compliance plans yet developed.

42. Please identify, for each unit affected by one or more of EPA's new or proposed rules, what the impact is for each Rule, including; unit retirement, curtailment, installation of additional emissions controls, fuel switching, or other impacts identified by the Company. As part of this response, please also provide the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the table below and tab 42 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

As discussed in the company's Integrated Clean Air Compliance Plan filed April 1, 2013, evaluations for MATS compliance at Crystal River units 1 and 2 are ongoing. Thus far, the company has determined that installation of controls for long term operation (e.g. scrubber and SCR) would not be economical compared to retiring the units and replacing the generation. Evaluation of options to continue the operation of the units for a limited term utilizing an alternate fuel and site wide pollutant averaging are ongoing. Final decisions about dates for unit retirement or the cessation of coal fired operations will be made at the conclusion of these evaluations expected to be late in 2013.

It is anticipated that Crystal River Units 4 and 5 will comply with MATS utilizing the emissions controls currently in place. Additional testing and evaluation to ensure the capability of the units to comply on a continuous basis is ongoing.

**Unit Impacts of EPA's New and Proposed Rules**

| Unit Impacts of EPA's New and Proposed Rules | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Unit | Unit Type | Fuel Type | Net Summer Capacity | Type of New and Proposed EPA Rule Impacts | | | | | Anticipated Impacts |
| | | | (MW) | MATS | CSAPR/CAIR | CWIS | CCR Non-Hazardous Waste | CCR Special Waste | |
| Anclote 1 | Steam | Oil/NG | 501 | Convert to NG Steam | NG Conversion, Dispatch Changes | Impacted | NA | NA | None |
| Anclote 2 | Steam | Oil/NG | 510 | Convert to NG Steam | | Impacted | NA | NA | None |
| Bartow PB4 | Combined Cycle | NG | 1,074 | NA | Dispatch changes | Impacted | NA | NA | None |
| Crystal River 1 | Steam | Coal | 370 | Impacted - Compliance TBD | Dispatch changes | Impacted | Impacted | Impacted | None |
| Crystal River 2 | Steam | Coal | 499 | Impacted - Compliance TBD | | Impacted | Impacted | Impacted | None |
| Crystal River 4 | Steam | Coal | 712 | Impacted - Compliance TBD | FGD/SCR Optimization | Impacted | Impacted | Impacted | None |
| Crystal River 5 | Steam | Coal | 710 | Impacted - Compliance TBD | | Impacted | Impacted | Impacted | None |
| Suwannee 1 | Steam | Oil/NG | 28 | Only use NG | Use Natural Gas, Dispatch Changes | Impacted | NA | NA | None |
| Suwannee 2 | Steam | Oil/NG | 30 | Only use NG | | Impacted | NA | NA | None |
| Suwannee 3 | Steam | Oil/NG | 71 | Only use NG | | Impacted | NA | NA | None |
| HEC PB 1-4 | Combined Cycle | NG | 1,912 | NA | Dispatch changes | NA | NA | NA | None |
| Other Units - CTs, Smaller CC units | Simple Cycle CTs & Cogeneration | Oil/NG | Various | NA | Dispatch changes | NA | NA | NA | None |

43. Please identify, for each unit impacted by one or more of the EPA's new or proposed rules, what the estimated cost is for implementing each Rule over the course of the planning period. As part of this response, please provide the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Many of these rules are not final, and in the case of the CSAPR, the rule has been vacated by the court with ongoing litigation and no indication of the final outcome. As such, the estimates provided below are at a very high-level and are listed as cost ranges based on the various potential compliance options that may be required. In some cases, the costs cannot be attributed to a specific unit, but to a group of units that share similar compliance points, such as cooling water intake structures. Also note that these costs estimates only include the capital requirements and do not include on-going O&M costs. The O&M costs will be highly variable and dependent on the technology choices employed.

In the case of Crystal River Units 1 and 2, as discussed above, evaluations of the options for MATS compliance are not yet final. While it is not expected that these options will include investment in long term emissions controls, it appears that retirement and replacement of the generation is a likely outcome although the specific date is uncertain. Significant costs will be incurred due to transmission system upgrades and replacement generation costs. These costs are not reflected at this time.

Please see the table below and tab 43 of the Excel file DEF 2012 TYSP Data Request #1 - Tables.xls.

**Estimated Unit Cost of EPA's New and Proposed Rules**

| Unit | Unit Type | Fuel Type | Net Summer Capacity (MW) | Estimated Cost of New or Proposed EPA Rules Impacts (2013 $ millions) | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | MATS | CSAPR/CAIR | CWIS | CCR: Non-Hazardous Waste | CCR: Special Waste | Total |
| Anclote 1 | Steam | Oil/NG | 501 | ~$100M | $0 | $15 - 130M | NA | NA | $105M - $230M |
| Anclote 2 | Steam | Oil/NG | 510 | | $0 | | NA | NA | |
| Bartow PB4 | Combined Cycle | NG | 1,074 | NA | $0 | $10 - 170M | NA | NA | $10 - 170M |
| Crystal River 1 | Steam | Coal | 370 | TBD | $0 | $45 - 780M | Included with CR 4 & 5 | Included with CR 4 & 5 | $45 - 780M plus MATS Compliance Costs |
| Crystal River 2 | Steam | Coal | 499 | TBD | $0 | | | | |
| Crystal River 3 | Nuclear | Nuclear | 789 | NA | NA | | NA | NA | |
| Crystal River 4 | Steam | Coal | 712 | $5 - 50M | $0 | $2 - 5M | TBD | TBD | $7 - 55M plus CCR |
| Crystal River 5 | Steam | Coal | 710 | | $0 | | | | |
| Suwannee 1 | Steam | Oil/NG | 28 | -- | $0 | $5 - 75M | NA | NA | $5 - 75M |
| Suwannee 2 | Steam | Oil/NG | 30 | -- | $0 | | NA | NA | |
| Suwannee 3 | Steam | Oil/NG | 71 | -- | $0 | | NA | NA | |
| HEC PB 1-4 | Combined Cycle | NG | 1,912 | NA | $0 | NA | NA | NA | $0 |
| Other Units - CTs, Smaller CC units | Simple Cycle CTs & Cogeneration | Oil/NG | Various | NA | $0 | NA | NA | NA | $0 |

44. Please identify, for each unit impacted by one or more of EPA's new or proposed rules, when and for what duration units would be required to be offline due to retirements, curtailments, installation of additional controls, or additional maintenance related to emission controls. Also include important dates relating to each rule. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Since the Cooling Water Intake Structure Rule and the CCR have not been finalized, there is no definitive determination on what would be required. Therefore, it is difficult to determine when units must be offline for control installations or for how long, as this would be highly dependent on compliance and technology choices. Outages required for maintenance will also be highly dependent on technology choice. For example, FGD and SCR maintenance outages are required approximately every 18 months. They are scheduled to occur concurrently with boiler outages and can range from 4 to 6 weeks.

Please see the table below and tab 44 of the Excel file DEF 2012 TYSP Data Request #1 - Tables.xls.

**Estimated Timing of Unit Impacts of EPA's New and Proposed Rules**

| Unit | Unit Type | Fuel Type | Net Summer Capacity (MW) | Estimated Timing of New and Proposed EPA Rule Impacts (Month/Year - Duration) | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | MATS | CSAPR/CAIR | CWIS | CCR Non-Hazardous Waste | CCR Special Waste |
| Anclote 1 | Steam | Oil/NG | 501 | April 2013 (10 wks) | Dispatch Changes | TBD | NA | NA |
| Anclote 2 | Steam | Oil/NG | 510 | October 2013 (10 wks) | Dispatch Changes | | NA | NA |
| Bartow PB4 | Combined Cycle | NG | 1,074 | NA | None | TBD | NA | NA |
| Crystal River 1 | Steam | Coal | 370 | TBD | Dispatch Changes | TBD | None | TBD |
| Crystal River 2 | Steam | Coal | 499 | | | | | |
| Crystal River 4 | Steam | Coal | 712 | TBD | Dispatch Changes | TBD | None | TBD |
| Crystal River 5 | Steam | Coal | 710 | | | | | |
| Suwannee 1 | Steam | Oil/NG | 28 | -- | Dispatch Changes | TBD | NA | NA |
| Suwannee 2 | Steam | Oil/NG | 30 | -- | | | NA | NA |
| Suwannee 3 | Steam | Oil/NG | 71 | -- | | | NA | NA |
| HEC PB 1-4 | Combined Cycle | NG | 1,912 | NA | None | NA | NA | NA |
| Other Units - CTs, Smaller CC units | Simple Cycle CTs & Cogeneration | Oil/NG | Various | NA | Dispatch Changes | NA | NA | NA |

45. From a system-wide perspective, provide a preliminary estimate of the cost associated with each EPA Rule over the planning period, 2013 through 2022 expressed in 2013 dollars. As part of this response, please include the estimated additional capital cost expenditures, O&M costs, and impact on generation costs associated with each rule. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** The capital, O&M and differential fuel costs are dependent in part on the eventual technology choices employed. The preliminary capital estimates provided may not be inclusive of all actual compliance related capital future costs. Please see the table below and tab 45 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

| Estimated Cost of EPA's New and Proposed Rules | | | | |
|---|---|---|---|---|
| EPA Rule | Estimated Cost of New or Proposed EPA Rules Impacts (2013 $ millions) | | | |
| | Capital Costs | O&M Costs | Fuel Costs | Total Costs |
| Mercury and Air Toxics Standards (MATS) Rule | $85 - 130* | TBD | TBD | TBD |
| Cross-State Air Pollution Rule (CSAPR) | $0 | TBD | TBD | TBD |
| Cooling Water Intake Structures Rule (CWIS) | $80 - 1,200 | TBD | TBD | TBD |
| Coal Combustion Residuals Rule (CCR) | TBD | TBD | TBD | TBD |

* Exclusive of costs related to Crystal River Units 1 and 2.

46. Explain any expected reliability impacts resulting from each of the EPA Rules listed below. As part of this discussion, include the impact of transmission constraints and units not modified by the rule, that may be required to maintain reliability if unit retirements, curtailments, additional emissions control upgrades, or longer outage times are impacts of the EPA Rules.

    a. Mercury and Air Toxics Standards (MATS) Rule

    b. Cross-State Air Pollution Rule (CSAPR) or CAIR Rule

    c. Cooling Water Intake Structures Rule (CWIS)

    d. Coal Combustion Residuals Rule (CCR)

    e. Florida's State Implementation Plan for Regional Haze

**RESPONSE:** DEF is continuing to assess the impacts on both generation and transmission reliability of alternate compliance scenarios. In the case of MATS, DEF recognizes that there may be a need to request additional compliance time as allowed by the rule to maintain reliability. Specific scenarios involving projects and interactions, including the generation reliability impacts of new controls strategies and changing dispatch scenarios that would necessitate this additional compliance time are under review and development. In the case of CSAPR, DEF's initial plan was not considered to have immediate reliability impacts. With the uncertainty generated by the delay in rule implementation and the potential for changes in the rule requirements, this conclusion remains under review. Both the CCR and the CWIS rules have a variety of impacts depending on the final scope of the regulations. DEF is committed to maintain reliability and is working with regional and national reliability organizations to maintain compliance with reliability standards.

47. If applicable, identify any currently approved costs for environmental compliance investments made by your company which would mitigate the need for future investments to comply with recently finalized or proposed EPA regulations.

**RESPONSE:** The installation of the flue gas desulfurization (FGD) systems in 2010, also known as wet scrubbers, and the SCR systems on Crystal River 4 and 5 reduce mercury and other air toxic emissions and therefore, will be a key component of DEF's MATS compliance strategy. The cost of this project was approximately $1.2 billion.

The conversion of Anclote Units 1 and 2 to natural gas firing has been approved and is ongoing. This conversion will remove the Anclote units from regulation under MATS. The cost of this conversion is approximately $94 million.

48. Please indicate if your company has filed any comments with EPA during EPA's rule development proceedings for the following:

a. Mercury and Air Toxics Standards (MATS) Rule
b. Cross-State Air Pollution Rule (CSAPR) or CAIR Rule
c. Cooling Water Intake Structures (CWIS) Rule
d. Coal Combustion Residuals (CCR) Rules
e. Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units

**RESPONSE:** Comment letters for the above listed rule development proceedings filed in 2012 are included in Attachment Q#48. DEF previously submitted these letters for years prior to 2012 in response to the 2012 data request. The letters attached here represent comments made by DEF as an individual company. DEF also contributes to comments on various rulemakings through participation in industry groups including FCG, UARG, EEI, and EPRI.

49. On August 21, 2012, the U.S. Circuit Court of Appeals decided to vacate the CSAPR Rule. Has the Court's order to vacate the CSAPR Rule and require EPA to continue administering the CAIR Rule impacted your compliance strategies? If so, how?

<u>**RESPONSE:**</u> Along with vacating the CSAPR, the court ruled that CAIR remains in effect until EPA successfully promulgates a new rule that corrects the deficiencies earlier identified by the court in CAIR. DEF will continue to implement its CAIR strategy as laid out in the Integrated Clean Air Compliance Plan. With the controls investment at Crystal River Units 4 & 5, the repowering of the Bartow plant and banked allowances, DEF is in a good position for continued compliance with CAIR.

DEF's Cross-State Rule compliance strategy development will be resumed and revised as necessary in response to resolution of the litigation and/or the proposal and promulgation of the replacement rule. In addition, DEF has committed to work with FDEP to develop a state-based implementation plan (SIP) for Regional Haze. With the *vacatur* of the CSAPR, and EPA's previous statement that CAIR no longer satisfies BART, $SO_2$ and $NO_x$ compliance will need to be addressed in FDEP's revised BART SIP for Crystal River Units 1 & 2 and Anclote Units 1 & 2. The details of this permitting are still being negotiated with FDEP and EPA. The final outcome of the Cross-State Rule litigation (i.e. if CAIR remains in effect) and/or promulgation of a replacement rule could alter the SIP outcome.

50. Please discuss the impacts, if any, the Stationary Reciprocating Internal Combustion Engines (RICE) Rule will have on your company.

<u>**RESPONSE:**</u> The rule places limitations on use and participation associated with our commercial and industrial demand response programs, as currently designed. Impact to our existing standby generator program may include a change to the dispatch order, which may reduce potential use and associated value. Additionally, our interruptible and curtailable programs will require customers to review their plans for participation, as well as customers testing and potential emission control enhancements to their equipment. Alternatively, customers may decide to reduce their participation.

As such, DEF is evaluating the rule, monitoring customer and utility responses and may consider changes to our standby generation program, such as the development of both emergency only and non-emergency program offerings. DEF does not expect to implement any changes to the operability in our interruptible or curtailable program, and recognize this will require customers to evaluate their participation of our programs and manage associated compliance as applicable.

51. Please discuss your company's current coal residual disposal practices for each coal generating facility.

**RESPONSE:** Duke Energy Florida's only coal-fired generation site is the Crystal River Energy Complex (CREC). The CREC consists of five generating units. Units 1, 2, 4, & 5 are coal-fired steam units capable of producing a combined 2,313 megawatts. Unit 3 is a nuclear-powered unit excluded from the site ash management system. CREC coal combustion residuals (CCRs) include dry fly ash and bottom ash, as well as gypsum. The CREC manages CCRs generated at the facility in dry storage areas including: an ash storage/disposal area for both fly ash and bottom ash; and a temporary storage pad for gypsum. The ash storage area at the CREC is located east of Units 4 & 5 and incorporates the following separate management piles: fly ash (Units 1, 2, 4, 5), Units 1 & 2 bottom ash, Units 4 & 5 bottom ash, comingled materials, and high chloride ash. Gypsum is stored on a concrete temporary storage pad before being sent offsite for reuse or disposal. DEF is committed to the safety and well-being of our employees, our communities and the environment. These objectives are implemented through management plans and environmental permits designed to ensure that ash is handled with a primary focus on safety and protection of the environment. Management of CCRs at CREC is governed by a wide spectrum of environmental permits/authorizations including: 1) September 2010 Coal Combustion Product/Solid Waste Materials Management Plan; 2) Site Certification Application Conditions of Certification (COC) PA79-09O; 3) FDEP Industrial Wastewater Permit Number FLA016960; 4) FDEP NPDES Permit – Permit No. FL0036366; and 5) Duke Energy Florida Site Specifications for Storage of Fly Ash and Bottom Ash. DEF's ash storage area is operated in compliance with all applicable local, state and federal environmental permitting regulations.

An important part of DEF's ash handling objectives is the minimization of disposal through a strong beneficial use program. A primary ash contractor supports DEF with the transportation, spreading, compacting, pile maintenance, and final disposition of ash. To the extent that this contractor is unable to use or sell these materials, it transfers temporarily unsalable fly ash to the existing on-site ash storage area.

52. Please briefly discuss your company's efforts to facilitate the recycling of coal waste into beneficial products. What percentage of your company's coal waste is used for beneficial purposes?

**RESPONSE:** The Byproducts and Reagents Group, in collaboration with Power Operations, is responsible for development and execution of a comprehensive Coal Combustion Products (CCP) Marketing Strategy. These efforts are tailored to each individual site and are driven by the distinct dynamics occurring within each market area. Specifically at the Crystal River Energy Complex (CERC), the company utilizes a multi-tiered marketing approach employing a combination of independent third-party marketing groups and internal company sales and marketing resources in an attempt to maximize the opportunities for beneficial reuse. Through continual involvement in targeted commercial outlets Duke Energy is able to effectively identify and evaluate existing and emerging end-use markets to provide suitable beneficial reuse options for CREC. In 2012, DEF's beneficial reuse of Coal Combustion Products was approximately 98.5%.

## Fuel Supply & Reliability

53. Please provide, on a system-wide basis, the historic annual fuel usage (in GWh) and historic average fuel price (in nominal $/MMBTU) for each fuel type utilized by the company in the period 2003 through 2012. Also, provide the forecasted annual fuel usage (in GWh) and forecasted annual average fuel price (in nominal $/MMBTU) for each fuel type forecasted to be used by the Company in the period 2013 through 2022. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the tables below and tab 53 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

**Average Fuel Price Comparison**

| | Year | Uranium | | Coal | | Natural Gas | | Residual Oil | | Distillate Oil | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | GWh | $/MMBTU | GWh | $/MMBTU | GWh | $/MMBTU | GWh | $/MMBTU | GWh | $/MMBTU |
| Actual | 2003 | 6039 | 0.36 | 16111 | 2.37 | 6155 | 6.02 | 6785 | 4.12 | 405 | 6.22 |
| | 2004 | 6703 | 0.36 | 15063 | 2.27 | 7516 | 6.40 | 6981 | 4.36 | 361 | 8.09 |
| | 2005 | 5829 | 0.37 | 15834 | 2.65 | 8236 | 8.53 | 6618 | 5.40 | 414 | 11.19 |
| | 2006 | 6382 | 0.36 | 15293 | 3.14 | 9657 | 7.41 | 4656 | 6.36 | 258 | 14.42 |
| | 2007 | 6124 | 0.36 | 14457 | 3.27 | 10579 | 8.51 | 4575 | 7.99 | 307 | 15.16 |
| | 2008 | 6425 | 0.37 | 14219 | 3.71 | 14239 | 10.03 | 2534 | 8.69 | 168 | 15.83 |
| | 2009 | 4945 | 0.39 | 11089 | 4.19 | 18457 | 8.43 | 974 | 9.49 | 261 | 17.28 |
| | 2010 | 0 | 0 | 12115 | 4.05 | 23692 | 6.27 | 683 | 10.95 | 381 | 16.19 |
| | 2011 | 0 | 0 | 10809 | 3.83 | 23571 | 5.43 | 187 | 10.97 | 81 | 18.31 |
| | 2012 | 0 | 0 | 10003 | 3.83 | 23997 | 5.56 | 46 | 12.12 | 104 | 20.35 |
| Projected | 2013 | 0 | 0 | 11,761 | 2.90 | 23,159 | 4.31 | 0 | 0 | 84 | 22.49 |
| | 2014 | 0 | 0 | 11,758 | 2.99 | 24,423 | 4.62 | 0 | 0 | 95 | 21.99 |
| | 2015 | 0 | 0 | 12,003 | 3.19 | 24,855 | 4.79 | 0 | 0 | 123 | 21.65 |
| | 2016 | 0 | 0 | 10,882 | 2.93 | 23,478 | 5.28 | 0 | 0 | 281 | 20.22 |
| | 2017 | 0 | 0 | 10,952 | 2.89 | 22,124 | 5.56 | 0 | 0 | 273 | 20.53 |
| | 2018 | 0 | 0 | 10,456 | 2.95 | 25,481 | 5.89 | 0 | 0 | 167 | 20.62 |
| | 2019 | 0 | 0 | 9,926 | 3.02 | 27,531 | 6.24 | 0 | 0 | 146 | 20.70 |
| | 2020 | 0 | 0 | 8,777 | 3.08 | 31,592 | 6.64 | 0 | 0 | 81 | 20.83 |
| | 2021 | 0 | 0 | 8,336 | 3.16 | 33,532 | 7.03 | 0 | 0 | 57 | 21.37 |
| | 2022 | 0 | 0 | 8,288 | 3.24 | 33,946 | 7.43 | 0 | 0 | 88 | 21.91 |

54. Please discuss how the Company compares its fuel price forecasts to recognized, authoritative independent forecasts.

**RESPONSE:** DEF's coal price forecast is developed based on the forward market price for the first three years and based on a third party forecast prepared by Energy Ventures Analysis (EVA) for the long term. DEF's oil forecast is developed based on the NYMEX Forward Price curve for first three years. The long term oil forecast is based on third party forecast provided by EVA. The first three years of DEF's natural gas forecast is based on the NYMEX Forward Price curve. The long term natural gas forecast is based on third party forecasts provided by EVA. EVA is a nationally recognized energy consultancy based in Arlington, VA. The forecast is consistent with their "2012 Fuelcast".

55. Please identify and discuss expected industry trends and factors for each fuel type (coal, natural gas, nuclear fuel, oil, etc.) that will affect the Company during the period 2013 through 2022.

**RESPONSE:** Over the planning horizon, there are a number of developments that could impact natural gas prices. The first is the continued success of domestic unconventional supply growth. Second, there are on- going supply and demand developments for natural gas. Third, on-going developments in environmental and climate change legislation could impact natural gas prices and demand over the planning horizon.

On-shore natural gas shale production continues to demonstrate tremendous success and growth in the lower-48 states and has more than made up for production declines from the Gulf of Mexico. With increasing natural gas production driven by access to U.S. shale gas resources, EIA projects Henry Hub gas prices to remain below $4.00/MMbtu through 2018. In the Energy Information Administration Annual Energy Outlook 2013 Reference Case, US natural gas production is projected to be higher throughout the reference case than in the previous AEO 2012 reference case. EIA predicts that US production of natural gas is expected to exceed consumption by the year 2020.

Prior to the realization of the unconventional supply growth and its potential, LNG was viewed as a key supply resource to fill the incremental future needs of the U.S. However, given the success in unconventional supply growth, forecasters have reduced their forecasts for LNG imports due to the growth in unconventional domestic supply. EIA now expects the US to become a net LNG exporter starting in 2016 and an overall net exporter of LNG and pipeline natural gas by 2020. According to EIA's Annual Energy Outlook 2013, ("AEO 2013") Early Release Overview, LNG is expected to increase as a fuel source serving global markets outside the US with growth in global liquefaction capacity additions in Western

Canada and conversion of existing US Import facilities to LNG export facilities to meet greater world regasification capacity outside the U.S. To date, one US Export LNG Project has been approved and is currently under construction at Cheniere's Sabine Pass facility. The Sabine Pass facility is expected to be placed in-service during the 4th quarter of 2015. There continues to be a great deal of interest in constructing Export LNG facilities at a number of the existing Import LNG facilities located in the US.

In addition to the growth in supply and on-going developments, domestic demand and the makeup of demand may be impacted over the next ten years with the potential growth in renewable and more stringent environmental requirements and efficiency programs that could be developed. A push to renewables and energy efficiency programs could have some impact on electric generation demand. Also, any new greenhouse gas legislation that may be implemented during the planning period could have the potential to increase natural gas demand for electric generation. In addition, conversions and retirements of older, less efficient coal plants to burn natural gas have been announced. As such, natural gas fired generation may become a larger component of the overall generation mix of fuels. The cleaner natural gas-fired generation will produce less $CO_2$ than that of the equivalent amount of coal-fired generation would have produced.

With respect to fuel oil, with the growth in DEF's and the State of Florida's natural gas generation, DEF's use of heavy oil and distillate oil for its generation fleet is expected to decline over the planning horizon. With respect to industry trends, per the EIA 2013 Early Annual Release (EIA), West Texas Intermediate ("WTI") spot prices averaged $92.50 per barrel for 2012. Per the EIA, crude oil prices are expected to rise to $96.00 per barrel in 2017 as pipeline capacity from Cushing, Oklahoma, to the Gulf Coast increases, the world economy recovers, and global demand grows more rapidly than the available supplies of liquids from producers outside the Organization of the Petroleum Exporting Countries (OPEC). In 2035, the average real price of WTI in the Reference case is about $143 per barrel in 2011 dollars, or about $217 per barrel in nominal dollars. As fuel oil remains a critical peaking fuel and backup fuel, DEF will continue to monitor oil prices, trends and its fuel forecast over time and will ensure it procures the needed competitive supply and transportation services to meets its generation fleet needs over the planning horizon.

With respect to coal, high-sulfur Illinois basin coal prices remain in the upper $30's to mid $40's per ton and Central Appalachia coal prices remain in the low to mid $60's. Market drivers for these prices are low natural gas prices and published reports of surplus coal inventories in stockpile at most U.S. power plants. Near term, we see (a) lower demand for U.S. steam coal supplies, (b) continued interest in exporting to the global coal market, (c) natural gas prices remain low as compared to historical values, but have increased slightly recently, (d) healthy utility coal inventories, and (e) volatile power prices. Coal markets are likely to be relatively stable in the near term; however, looking forward, we see potential for market volatility as market uncertainties continue and coal suppliers continue to cut production and bring supply into balance with demand.

56. Please identify and discuss steps that the Company has taken to ensure natural gas supply availability and transportation over the 2013 through 2022 planning period.

**RESPONSE:** DEF has broad contacts and relationships with natural gas suppliers and pipeline service providers. DEF performs periodic short-term and long-term fuel forecasts to estimate expected fuel usage for future periods. The fuel forecasts includes items such as load forecasts, fuel and emission prices, operational specifics of the generation and tolling fleet, contracted resources, wholesale power sales agreements, unit maintenance schedules, and current and future generation resource plans. The short-term forecast is performed approximately four times per year for a five year period and currently covers years 2013 through 2018. The long-term forecast is performed two times per year and currently covers years 2019-2032.

With respect to ensuring that DEF has the needed natural supply gas and transportation needs over the planning horizon, DEF performs periodic competitive natural gas supply Request for Proposals to procure the needed competitive natural gas supply consistent with its procurement approach. In addition, DEF also monitors potential pipeline expansion projects that can access competitively priced and secure natural gas and provide delivery to DEF's facilities. DEF monitors potential pipeline expansions through on-going discussions and periodic meetings with suppliers, pipeline providers and end users, open seasons issued by the pipelines, industry events and publications.

57. Please identify and discuss any existing or planned natural gas pipeline expansion project, including new pipelines and those outside of the State of Florida, that would affect the Company for the period 2013 through 2022.

**RESPONSE:** The project descriptions outlined below are not intended to be an all inclusive list of all the upstream pipeline projects that are occurring or proposed in the Gulf Coast and Southeast Region but those that DEF believes could have an impact on the natural gas supply available for DEF and the State of Florida.

**Southeast Supply Header ("SESH") – In Service**

SESH is a 50/50 joint venture between Spectra Energy and Center Point Energy. In December 2006, SESH and DEF entered into a Precedent Agreement ("PA") for a total of 200,000 MMBtus/day of firm transportation service for 15 years to be phased in over three years targeted for in service on June 1, 2008.

In December 2006, SESH filed its original NGA 7c Needs Certificate Application with the FERC. SESH was a new greenfield natural gas pipeline system consisting of approximately 269 miles of pipe, three mainline compressor stations, two booster stations and other facilities. SESH interconnects with several pipelines including but not limited to Gulf South Pipeline Company ("Gulf South"), Center Point Energy Gas Transmission Company ("CEGT") and ETC's Tiger Pipeline ("Tiger Pipeline") expansion projects which access unconventional onshore shale gas and tight sands gas production along a pipeline corridor extending from Carthage (TX) to Perryville (LA) delivering to the Perryville Hub located near Delhi, Louisiana. SESH extends from the Perryville Hub area on a southeasterly direction and terminates at an interconnection with Gulfstream near Coden, Alabama. SESH expansion created approximately 1 Bcf/day of new transportation capacity. In September 2007, the FERC issued an Order approving the SESH request for needs certificate authorization. In this order, SESH indicated that they had entered into precedent agreements with five shippers for 945,000 MMBtus/day of firm transportation service or about 94.5% of the overall SESH project capacity. Based upon publicly available data, the five firm shippers included are, FPL at 500,000 MMBtus/day, DEF at 200,000 MMBtus/day, Southern Company Services at 175,000 MMBtus/day, EOG Resources at 50,000 MMBtus/day and Teco at 20,000 MMBtus/day

In addition, based on publically available data, Southern Natural Gas Company (SNG) will own 140,000 MMBtus/day of capacity in a jointly owned segment from the Perryville Hub to a point located in Gwinville, Mississippi interconnecting with the SNG system.

SESH connects with natural gas pipelines which provide access to onshore unconventional natural gas supply from the Barnett Shale, Bossier Sands, Arkoma, Haynesville and Fayetteville Shale basins. Also, SESH has multiple interconnections with interstate pipelines including Columbia Gulf, Texas Eastern, Sonat, Transco, Tennessee, Florida Gas Transmission and Gulfstream which provide it the ability to potentially reach markets in the Southeast, Atlantic, and Northeast regions of the United States. Also, SESH has direct or indirect access to numerous existing and proposed storage facilities, including Egan Hub Partners (via upstream pipelines), Moss Bluff Hub Partners (via upstream pipelines), Southern Pines Energy Center (a direct connect to existing storage), Petal Gas Storage (a direct connect to existing storage), Copiah Hub Partners (proposed project), and MoBay Storage Hub (proposed project). This expansion allows DEF to access a broader base of suppliers, significantly improves supply reliability and accesses competitively priced and growing onshore unconventional natural gas supply resources. SESH began providing service to DEF on or about September 6, 2008.

**Transcontinental Gas Pipe Line Corporation ("Transco") - Mobile Bay Phase I Expansion - In-Service**

Open Season – In October 2007, Transco announced a non-binding Open Season for up to 700,000 MMBtus/day of incremental capacity to be available from Transco's Station 85 Pool and other points that interconnect near Butler in Choctaw County, Alabama to points on its Mobile Bay Lateral as far south as the existing interconnect between Transco and Gulfstream near Coden in Mobile County, Alabama under Transco's proposed "Mobile Bay South Expansion". The expansion will also provide deliveries into FGT. The proposed target in-service date was May 1, 2010. The Open Season expired in November 2007.

In May 2008, DEF entered into Precedent Agreement ("PA") with Transco for firm transportation capacity on the Mobile Bay South Expansion. In September 2008, Transco filed its NGA 7c Needs Certificate Application with the FERC. The Certificate Application indicated that approval of the project by May 15, 2009, would enable Transco to complete construction of the proposed facilities and begin providing service by May 1, 2010. In addition, the Certificate Application indicated that Transco executed PA's with DEF and Southern Company Services, Inc. for a total firm transportation service capacity of approximately 253,000 MMBtus/day. The project facilities consist primarily of 9,470 HP of gas fired compression and 2,400 feet of 30-inch diameter piping.

DEF acquired the firm transportation to meet its long term natural gas needs. This project allows DEF to access the needed competitively priced and secure natural gas supply from the growing unconventional onshore supply that can be delivered on the Mobile Bay Lateral South to Florida Gas Transmission and Gulfstream. Phase I was placed in-service on May 1, 2010.

**Transco Mobile Bay South Phase II Expansion – In-Service**

Open Season – In January 2009, Transco announced that it was holding a Non-Binding Open Season for up to 550,000 MMBtus/day of year round firm transportation service available from Transco's Mobile Bay South Lateral near Butler in Choctaw County, Alabama to the point of interconnection between Transco and Gulfstream in Coden, Mobile County, Alabama, under Transco's proposed "Mobile Bay South II Expansion". The expansion provides deliveries into FGT and Gulfstream via the Mobile Bay Lateral. As part of its on-going efforts to evaluate potential options to access competitively priced and secure onshore natural gas from growing unconventional natural gas resources, DEF submitted a non-binding request in response to the Open Season.

In June 2009, DEF entered into a binding Precedent Agreement with Transco for firm transportation service on Phase II of the Mobile Bay South Project for 50,000 MMBtus/day. In November 2009, Transco filed its Certificate Application with the FERC. In its application, Transco acknowledged receiving binding commitments from shippers for approximately 380,000 MMBtus/day of firm transportation capacity. The scope of the project includes the installation of 8,100 hp of new compression at Station 85 in Choctaw County, AL and minor facility additions at an existing Compressor Station 83 located near Citronelle, AL. This project was placed in-service on May 1, 2011.

On April 27, 2011, DEF entered into an agreement with an existing shipper for a permanent release of 53,500 MMBtus/day of Mobile Bay South Phase II firm transportation capacity commencing on June 1, 2016 and extending for the remaining primary term of the base agreement expiring on November 1, 2026. On December 8, 2011, DEF entered into a FT Service Agreement with Transco following all Transco's FERC approved Tariff posting procedures governing a permanent pre-arranged capacity release for the permanently released capacity from the supplier.

DEF is a direct beneficiary of this project as it accesses onshore supply which will deliver into the Transco Mobile Bay Lateral and will tie into DEF's capacity on to delivery points into Florida Gas Transmission and Gulfstream.

**Transco Mobile Bay South Phase III Expansion (Proposed)**

Open Season – In July 2012, Transco announced that it was holding a Non-Binding Open Season for up to 325,000 MMBtus/day of year round firm transportation service available from Transco's Mobile Bay South Lateral near Butler in Choctaw County, Alabama to the point of interconnection between Transco and Bay Gas Storage, Mobile County, Alabama, under Transco's proposed "Mobile Bay South III Expansion". The expansion provides deliveries into FGT and Gulfstream via the Mobile Bay Lateral. Transco has a targeted in-service date as early as October 1, 2014. DEF would indirectly benefit from any additional expansion of Transco south as it would provide additional onshore gas supply access that could be potentially delivered into the existing Florida pipeline systems.

**CenterPoint Energy Gas Transmission ("CEGT") – Carthage to Perryville ("Line CP") Existing and Proposed Expansions – Phase I through Phase IV In-Service**

CEGT began service in March 2007 and continues to gauge market interest in an additional expansion of its existing 1.5 Bcf/day, 42 inch Line CP pipeline. This pipeline accesses unconventional onshore gas supplies produced in North Central Texas (Barnett Shale) and from Tight Sands (Bossier Sands) production located in East Texas through the Carthage receipt points with delivery to SESH and Columbia Gulf. CEGT has successfully completed the first four phases of Line CP expansions. The Line CP Phase IV expansion was placed in service on February 1, 2010, increasing Line CP overall capacity to approximately 1.9 Bcf/day.

Based upon publicly available data, key shippers that signed up for capacity on CenterPoint's Line CP project and expansions (Phase I through IV) included Chesapeake Energy Marketing, Cross Timbers Energy Services (XTO), EOG Resources, BP Energy, Samson Resources and Chevron USA.

CenterPoint continues to gauge interest in incremental capacity expansions of Line CP. On June 14, 2010, CenterPoint held a Non-Binding Open Season for a Line CP Phase V expansion. The Open Season closed on July 7, 2010, and there have been no indications that the Phase V expansion has moved beyond this Non-Binding Open Season.

DEF is a direct beneficiary of participating shippers bringing onshore supply which delivers into DEF's existing SESH firm transportation capacity at Perryville located in and around Delhi, Louisiana.

**Gulf Crossing Pipeline a Boardwalk Pipeline Company ("Gulf Crossing") In-Service**

Gulf Crossing is approximately a 1.7 Bcf/day capacity pipeline that was put in service March 2009. This greenfield pipeline expansion project consists of approximately 357 miles of 42-inch pipe that accesses onshore natural gas supply from the Barnett and Caney/Woodford Shales (unconventional production) located in North Central Texas and SE Oklahoma. This project provided incremental gas to serve the Southeast US markets (including Florida) by interconnecting with Transco in Choctaw County, Alabama and delivering into Transco's Mobile Bay South Expansion Projects Phase I (in-service May 1, 2010) and Phase II (in-service date May 1, 2011). It is delivering gas to SESH at the Perryville Hub located in Delhi, Louisiana. Based on publicly available data, key shippers that signed up for capacity on this project include Crosstex Gulf Coast Marketing, Ltd., Devon Gas Services, LP and Enterprise Gas Marketing, LP.

DEF is a direct beneficiary of participating shippers bringing onshore supply which delivers into DEF's firm transportation capacity on the Transco Mobile Bay South Lateral via participating shipper's Gulf South SE expansion capacity and DEF's SESH firm transportation capacity at the Perryville Hub located in and around Delhi, Louisiana.

**Gulf South Pipeline a Boardwalk Pipeline – East TX to Mississippi ("TX-MS") Expansion In - Service**

The Gulf South TX-MS expansion project is approximately a 1.7 Bcf/day capacity pipeline which was placed into service January 2008. This greenfield pipeline expansion project consists of approximately 242 miles of 42-inch pipe that accesses onshore natural gas supply from the Barnett Shale Haynesville Shale and Bossier Sands (unconventional onshore production) located in North Central Texas and Northern Louisiana. This expansion provides incremental gas to serve the Southeast US markets by interconnecting with Transco near Butler in Choctaw County, Alabama delivering into Transco's Mobile Bay South Expansion Projects Phase I (filed) and II (proposed). It also can deliver gas to SESH at the Perryville Hub located in Delhi, Louisiana. Based upon publicly available data, key shippers that signed up for capacity on this project include Chesapeake Energy Marketing, Devon Gas Services, LP, EOG Resources, Inc. and Kaiser-Francis Oil Company.

DEF is a direct beneficiary of this expansion as participating shippers are bringing growing unconventional onshore supply to Perryville which will deliver into DEF's firm transportation capacity on the Transco's Mobile Bay South Lateral via participating shipper's Gulf South SE expansion capacity and DEF's SESH firm transportation capacity at the Perryville Hub located in and around Delhi, Louisiana.

**Gulf South Pipeline SE Expansion In-Service**

The Gulf South SE expansion project is approximately a 1.9 Bcf/day capacity pipeline which was placed in-service in May 2008. This greenfield pipeline expansion project consists of approximately 111 miles of 42-inch pipe that accesses onshore natural gas supply from the Perryville Hub, Gulf Crossing and Gulf South. It provided incremental gas to serve the Southeast US markets in the future by interconnecting with Transco in Choctaw County, Alabama delivering into Transco's Mobile Bay South Expansion Projects Phase I (in service May 1, 2010) and Phase II (in-service date of May 1, 2011) and Destin Pipeline through direct connections with the SE Expansion project. In addition it accesses both FGT and Gulfstream via existing interconnects on the legacy Gulf South pipeline system. Based upon publicly available data, key shippers that signed up for capacity on this project include Chesapeake Energy Marketing, EOG Resources, Inc. and Oneok Energy Services Company, LP.

DEF is a direct beneficiary of this expansion as participating shippers are bringing growing unconventional onshore supply which delivers into DEF's firm transportation capacity on the Transco Mobile Bay Lateral via Gulf South's SE Expansion.

**Kinder Morgan's Mid-Continent Express In-Service**

The Mid-Continent Express ("MEP") expansion project is approximately 1.5 Bcf/day Capacity pipeline in Zone 1 (Ok to Delhi, LA) and 1.0 Bcf/day Capacity in Zone 2 (Delhi, LA to Butler, AL) which was placed in-service in August 2009. MEP is expandable by compression additions to approximately 1.8 Bcf/day in Zone 1 and 1.2 Bcf/day in Zone 2 which was placed in service sometime around July 1, 2010. This greenfield pipeline expansion project consists of approximately 507 miles of 30-inch, 36-inch and 42-inch pipe that routes From SE Oklahoma, across NE Texas, northern Louisiana, Central Mississippi and into western Alabama. This project accesses growing unconventional onshore natural gas supply from the Barnett Shale, Caney/Woodford Shale and Haynesville Shale formations (unconventional onshore production) located in North Central Texas, SE Oklahoma and North Louisiana and will provide new secure and competitively priced onshore unconventional natural gas to serve the Southeast US including Florida by interconnecting with Transco near Butler in Choctaw County, Alabama delivering into Transco's Mobile Bay South Expansion. Based upon publicly available data, key shippers that signed up for capacity on the Mid-Continent Express project include Chesapeake Energy Marketing and Newfield Exploration.

**ETC's Tiger Pipeline In-Service**

ETC Tiger Pipeline Company LLC ("Tiger Pipeline") is proposing to construct, own and operate a new interstate natural gas pipeline to provide takeaway capacity from the East Texas Carthage Hub area and the Haynesville Shale production are in NW

Louisiana. Tiger Pipeline will consist of 175 miles of 42" pipeline with four (4) compressor stations providing an estimated 2.0 Bcf/day of firm transportation capacity delivering to Columbia Gulf Transmission and SESH interconnects located near Delhi, LA in Richland Parish. Tiger Pipeline's FERC Certificate order, which was issued by the FERC in April 2010, identified five (5) producer shippers with firm transportation capacity commitments of approximately 2.0 Bcf/day. This project was placed in-service on December 1, 2010.

**ETC Tiger Phase I Expansion In-Service** – On June 15, 2010, Tiger filed an application with the FERC to expand its capacity by 400 MMcfd. This expansion was supported by one (1) producer shipper, Petrohawk Energy Corporation. With this expansion, total Tiger Pipeline capacity is approximately 2.4 Bcf/day. This project was placed in-service on August 1, 2011

DEF is a direct beneficiary of Tiger Pipeline and its Phase I expansion as participating shippers are bringing growing unconventional onshore supply which delivers into DEF's firm transportation capacity on SESH at Perryville, LA.

**Gulf South Pipeline Haynesville/Perryville Expansion In-Service**

The proposed Gulf South Pipeline Haynesville/Perryville expansion project was filed with the FERC in May 2009 as a .556 Bcf/day capacity expansion of an existing pipeline. The expansion was achieved by adding approximately 31,913 hp of compression at two locations in Louisiana. This pipeline expansion project was placed in service on October 22, 2010, and provides access to incremental onshore natural gas supply at the Perryville Hub. Based upon publicly available data, key shippers that signed up for capacity on this project include Petrohawk Energy Corporation, Questar Exploration and Production Company and EnCana Marketing (USA) Inc. These three (3) producer-shippers are new to the Gulf South Pipeline East Texas to Mississippi Expansion Facilities and have contracted to transport volumes from future receipt points in northwest Louisiana (Haynesville Shale Production) to delivery points in northeast Louisiana (Perryville Hub area).

DEF is a direct beneficiary of this expansion as participating shippers are bringing growing unconventional onshore supply which delivers into DEF's firm transportation capacity on SESH via the existing Gulf South Pipeline East TX to Mississippi Expansion.

**Gulf South Pipeline Southeast Market Expansion (Proposed)**

On June 29, 2012, Gulf South held a binding Open Season for expansion of its existing pipeline capacity extending from the Carthage Area or from the Perryville Area with deliveries into the Mobile Bay, Alabama area. The expansion was initially planned for a 400,000 MMBtu/day capacity addition. The expansion for the full volume of 400,000 MMBtu/day with a target in service date of late 2014. At this time, this project is expected to move forward. Additionally, in February 2013, Gulf South issued a new binding Open Season Notice for an incremental 100,000 MMBtu/day capacity. These expansion projects will provide access to additional onshore supply that can be delivered to customers on Gulf South and delivered into delivery points that are connected to Florida Gas Transmission to support the gas needs of Florida.

**Florida Pipeline Developments (Proposed)**

Florida Power & Light issued a Firm Gas Transportation Request for Proposals (RFP) on December 19, 2012 with bids due April 3, 2013. In summary, the purpose of the RFP was to identify and negotiate firm transportation to meet a portion of their increased transportation needs with volumes starting at 400,000 MMBtu/day beginning in May 2017, and an additional quantity of 200,000 MMBtu/day beginning in May 2020, with options for additional quantities in later years beyond 2020. The RFP indicated a strong preference for new, geographically diverse pipeline infrastructure. Potential bidders were invited to provide bids for two pipeline project segments, an Upstream Segment and a Downstream Segment. The Upstream Pipeline Project was requesting this segment originate from the vicinity of the Transco Station 85 and terminating at an interconnection with the Downstream Pipeline Project in Osceola County, Florida (Central Florida Interconnection). The Downstream Pipeline Project would originate at the Central Florida Interconnection and would terminate at FPL's Martin Plant located in Martin County, Florida. FPL summarized in the RFP that the Transco Station 85 supply receipt location was selected given its proximity to two large diameter pipelines, Midcontinent Express Pipeline and the Gulf South Pipeline, which provide access to onshore shale gas supplies. In addition, this location provides access to the Transco pipeline which can access both traditional and shale supplies. The Company is monitoring these pipeline developments to determine potential opportunities to support potential new DEF natural gas-fired generation in the planning horizon.

**Destin Pipeline Open Season – Existing Capacity (Proposed)**

On April 1, 2013, Destin Pipeline issued a notice for a binding Open Season for 360,000 MMBtus/day of existing unsubscribed capacity with receipts from interconnects in the Clarke Co., MS area and deliveries to interconnects located in the Pascagoula, MS area The target in-service date is November 1, 2014

In addition, on April 1, 2013, Destin Pipeline issued a notice for a binding Open Season for 380,000 MMBtus/day of incremental expansion capacity with receipts from interconnects located in the Clarke Co., MS area and deliveries to interconnects located in the Pascagoula, MS area. The targeted in-service date is May 1, 2015.

58. Please identify and discuss expected liquefied natural gas (LNG) industry factors and trends that will impact the Company, including the potential impact on the price and availability of natural gas, for the period 2013 through 2022.

**RESPONSE:** According to the EIA's early release of the 2013 Annual Energy Outlook ("AEO2013") published in December 2012, EIA expects that the rapid growth of shale gas production expected in the United States will continue to lessen the need for US imports and projects that net natural gas imports (Pipeline and LNG) will decrease from 7.8% (1.95 Tcf/yr) of the total US Supply in 2011 to a net import of -.0136Tcf/yr or -.05% in 2020 due to the growth in shale production and the forecast of LNG exports Competition for natural gas supplies in the worldwide market is expected to limit how much LNG will reach the U.S. markets. U.S. LNG imports are expected to decrease modestly in early years of the forecast projections. As additional worldwide liquefaction capacity comes on line, US LNG imports are now expected to peak at 0.17 Tcf/year in 2014 and remain at or below that level through 2016 when the US is expected to become a net exporter of LNG given global LNG prices and demand.

LNG infrastructure has experienced growth globally and in the United States. In EIA's most recent International Energy Outlook ("IEO2011") published in September 2011, EIA stated that net exports from the Middle East are expected to grow at an average annual rate of 3.6%/yr as flows from the region are expected to increase from 1.8 Tcf/yr in 2008 to 4.8 Tcf/yr in 2035. World natural gas liquefaction capacity is expected to nearly double increasing 1.875 times the 8.0 Tcf/year capacity in 2009 to 15.0 Tcf/year in 2035. Most of the continuing increase in liquefaction capacity is expected to be in the Middle East and Australia where a number of new liquefaction projects are expected to be developed, many of which will become operational between 2011 and 2020. From EIA's International Energy Statistics (updated January 2011), EIA reported that in early 2011, the capacity of LNG export facilities in Qatar reached a capacity of 3.6 Tcf/year which is more than three and a half times its 2005 level of 1.0 Tcf/year. Currently, Qatar is the world's largest LNG exporter. After the last in a series of six (6) liquefaction facilities came on stream in early 2011, Qatar's natural gas exports grew and are expected to continue growing by an estimated average of 12.5%/yr from 2008 to 2015. After 2015, Qatar's LNG exports are expected to slow to an average increase of 0.9%/yr. Utilization of liquefaction capacity is expected to remain high over the forecast period.

In the United States, import and vaporization capacity has grown and is projected to grow as existing terminals expand and new Greenfield facilities are placed in service. According to the FERC, as of late March 2013, there are twelve (12) existing U.S. LNG facilities with a total capacity of 19.035 Bcf/day (See Attachment No. 58-1). The existing US LNG Capacity does not include the 7.6 Bcf/day of federally approved U.S. projects that have not started construction (See Attachment No. 58-2). These developments will provide the United States more opportunities to import the growing worldwide supply of LNG when needed. In addition to the Gulf Coast, there continues to be ongoing discussion about a potential proposed project off the west coast of Florida. At this time, the proposed project is still in a developmental stage and the potential timing of any future development is uncertain.

To date, FERC has approved one (1) LNG Export facility which is currently under construction at the Cheniere Sabine Pass LNG Facility location. This LNG Export facility is expected to be in-service sometime in the 4th Quarter of 2015. LNG exports are expected to start at approximately 0.6 Bcf/year in 2016 and increase to 4.5 Bcf/year by 2027.

In the event LNG export projects receive all the necessary regulatory approvals and are ultimately brought on line within the 2013 through 2022 planning horizon, the amount of exports could put upward pressure on natural gas prices. Based on the EIA's early release overview of the AEO 2013, shows a rise in the Average Lower 48 wellhead prices (nominal dollars) from $3.25 /MMBtu in 2013 to $4.67/MMBtu in 2022

DEF will continue to monitor and evaluate potential LNG supply and infrastructure projects as part of its overall procurement strategy during the planning horizon. The future growth and trends of LNG supply, and U.S. LNG net exports and imports is difficult to predict as it can be impacted by several factors in both the U.S. and globally over the long-term period. These factors include, but are not limited to, U.S. natural gas prices and costs compared to global market prices in other regions, on-going developments in the fundamentals of supply and demand, storage levels, economic cycles and the number of potential U.S. export facilities that may be approved. As the global LNG supply grows, U.S. gas supply could compete with the global LNG markets given overall lower prices that have resulted due to the increase in shale gas production (and reserves).

59. Please identify and discuss the Company's plans for the use of firm natural gas storage for the period 2013 through 2022.

**RESPONSE:** DEF has executed agreements with SGRM Southern Pines Energy Center gas storage ("SGRM") and Bay Gas Storage Company for firm storage capacity. These gas storage projects were placed into service in May 2008. Both gas storage facilities are directly connected to pipelines (FGT, Gulfstream, SESH and Transco) on which DEF currently holds firm transportation. SGRM and Bay Gas both provide DEF with greater supply reliability, operational flexibility and price protection during weather events such as tropical storms and hurricanes and during pipeline operational flow orders. DEF expects high deliverability storage to be a key component of its overall gas contract portfolio for the planning period. DEF will continue to evaluate any additional needs for firm gas storage capacity throughout the planning period.

60. Please identify and discuss expected coal transportation industry trends and factors, for transportation by both rail and water, that will impact the Company during the period 2013 through 2022. Please include a discussion of actions taken by the Company to promote competition among coal transportation modes, as well as expected changes to terminals and port facilities that could affect coal transportation.

**RESPONSE:** DEF has always had a healthy, competitive atmosphere between its water and rail transportation suppliers. The ability to take coal from various coal regions promotes this competition between water and rail delivery of coal as well as allowing DEF to take advantage of differences in coal prices between coal regions.

With respect to transportation by rail, increased mining cost, declining productivity, declining coal reserves, lower quality coal from regions that DEF has purchased coal historically and natural gas pricing continues to apply pressure for coal transported by rail to be cost competitive. Additionally, any increases demand for coal in countries outside the US could put pressure on the railroads infrastructure to transport coal to the ports for shipment of coal overseas. DEF expects the coal market will remain volatile and that varying modes of transportation will provide valuable flexibility.

With respect to water transportation, as a result of the addition of scrubbers to many coal generation plants in the Midwest and Southeast, use of coal originating from the Illinois Basin has increased with the main mode of transportation from this region being via water. DEF has monitored this trend and continues to explore opportunities to increase water-delivered coal. DEF has negotiated replacement of four older tows with two new ocean tows. These changes will allow DEF to deliver coal shipments more efficiently and reliably. DEF expects the coal market will remain volatile and that varying modes of transportation will provide valuable flexibility. Terminal services in the Gulf will be critical to enable DEF to continue purchase waterborne coals. With limited terminal capacity in the Gulf and increased demand for coal in countries outside the US, terminal capacity is at a premium in the Gulf. DEF has secured a ten year contract with a Gulf terminal and has secured a contract to load coal directly from a river barge to an ocean barge which allows DEF to mitigate unfavorable weather and operational impacts while ensuring reliable loading operations. DEF continuously communicates with barge companies, terminal facilities and Gulf barge companies to share its strategies for coal transportation by water. In addition, DEF continuously seeks opportunities to diversify its water transportation and terminaling portfolio to ensure a reliable fuel supply. In response to this trend DEF expects that rail companies will look for opportunities to expand deliveries from this region. DEF is monitoring these trends and continues to explore opportunities maintain competition between water and rail delivery of coal.

61. Please identify and discuss any expected changes in coal handling, blending, unloading, and storage for any planned changes and construction projects at coal generating units for the period 2013 through 2022.

**RESPONSE:** The addition of scrubbers has allowed DEF to consider higher sulfur coals from all regions. Coal handling, blending, unloading, and storage requirements for coals from different regions must be considered when determining which coal to purchase to ensure a reliable fuel supply. Continuous communications with terminal facilities, river and gulf barge companies, and rail companies is critical for DEF's coal transportation strategy. As a part of this strategy, DEF is installing two new ship unloaders and a new conveyor in the fall of 2013. This will enable DEF to unload barges in shorter cycle times and with improved reliability.

62. Please identify and discuss the Company's plans for the storage and disposal of spent nuclear fuel for the period 2013 through 2022. As part of this discussion, please include the Company's expectation regarding short-term and long-term storage, dry cask storage, litigation involving spent nuclear fuel, and any relevant legislation.

**RESPONSE:** The United States Federal Government is legally obligated to take title and possession of all spent nuclear fuel. DEF will utilize existing spent fuel pools and, among other things, add on-site dry storage as needed until the government fulfills its contractual obligations. Reimbursement for costs incurred to store fuel on site is expected, if the storage is as a result of the DOE's breach of the standard contract for disposal of spent nuclear fuel. DEF cannot predict what future actions the government will take to fulfill its contractual obligations. The Nuclear Waste Policy Act of 1982, as amended cannot be changed except by an act of Congress.

63. Please identify and discuss expected uranium production industry trends and factors that will affect the Company during the period 2013 through 2022.

**RESPONSE:** Recent price movements in the uranium market have caused uranium producers to slow the expansion of their facilities due to a weak market price. The price is expected to eventually recover and supply is expected to continue to meet worldwide demand. There are enough proven reserves of uranium to supply all current and planned plants through the specified period of 2013-2022. If the price stays at the expected level, the Company should not be affected by uranium production trends.

64. Please identify and discuss expected fuel oil transportation industry trends and factors that will affect the Company during the period 2013 through 2022.

**RESPONSE:** With the growth in DEF's and the State of Florida's natural gas generation, DEF's use of heavy oil and distillate oil for its generation fleet is expected to decline over the planning horizon. With respect to industry trends, per the EIA 2013 Early Annual Release (EIA), West Texas Intermediate ("WTI") spot prices averaged $92.50 per barrel for 2012. Per the EIA, crude oil prices are expected to rise to $96 per barrel in 2017 as pipeline capacity from Cushing, Oklahoma, to the Gulf Coast increases, the world economy recovers, and global demand grows more rapidly than the available supplies of liquids from producers outside the Organization of the Petroleum Exporting Countries (OPEC). In 2035, the average real price of WTI in the Reference case is about $143 per barrel in 2011 dollars, or about $217 per barrel in nominal dollars. As fuel oil remains a critical peaking fuel and backup fuel, DEF will continue to monitor oil prices, trends and its fuel forecast over time and will ensure it procures the needed competitive supply and transportation services to meets its generation fleet needs over the planning horizon.

## Transmission

65. Please provide a list of all proposed transmission lines in the planning period that require certification under the Transmission Line Siting Act. Please also include those that have been approved, but are not yet in-service. Please complete the table below and provide an electronic copy (in Excel).

**RESPONSE:** Please see the table below and tab 65 of the Excel file DEF 2013 TYSP Data Request #1 - Tables.xls.

**Transmission Projects Requiring TLSA Approval**

| Transmission Line | Line Length | Nominal Voltage | Date Need Approved | Date TLSA Certified | In-Service Date |
|---|---|---|---|---|---|
| | (Miles) | (kV) | | | |
| Intercession City - Gifford | 12 | 230 | 9/12/2007 | 1/27/2009 | 8/31/2013 |