REVIEW OF THE

2016 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

FLORIDA PUBLIC SERVICE COMMISSION

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List of Ten-Year Site Plan Utilities

Name	Abbreviation
Investor-Owned Electric Utilities	
Florida Power & Light Company	FPL
Duke Energy Florida, LLC.	DEF
Tampa Electric Company	TECO
Gulf Power Company	GPC
Municipal Electric Utilities	
Florida Municipal Power Agency	FMPA
Gainesville Regional Utilities	GRU
JEA	JEA
Lakeland Electric	LAK
Orlando Utilities Commission	OUC
City of Tallahassee Utilities	TAL
Rural Electric Cooperatives	
Seminole Electric Cooperative	SEC

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Executive Summary

Integrated resource planning (IRP) is a utility process that includes a cost-effective combination of demand-side resources and supply-side resources. While each utility has slightly different approaches to IRP, some things are consistent across the industry. Each utility must update its load forecast assumptions based on Florida Public Service Commission (Commission) decisions in various dockets, such as demand-side management goals. Changes in government mandates, such as appliance efficiency standards, building codes and environmental requirements, must also be considered. Other input assumptions such as demographics, financial parameters, generating unit operating characteristics, fuel costs, etc. are more fluid and do not require prior approval by the Commission. Each utility then conducts a reliability analysis to determine when resources may be needed to meet expected load. Next, an initial screening of demand-side and supply-side resources is performed to find candidates that meet the expected resource need. The demand-side and supply-side resources are combined in various scenarios to decide which combination meets the need most cost-effectively. After the completion of all these components, utility management reviews the results of the varying analyses and the utility's Ten-Year Site Plan is produced as the culmination of the IRP process. Commission Rules also require the utilities to provide aggregate data which provides an overview of the State of Florida electric grid.

The Commission's annual review of utility Ten-Year Site Plans is non-binding but it does provide state, regional, and local agencies advance notice of proposed power plants and transmission facilities. Any concerns identified during the review of the utilities' Ten-Year Site Plans may be addressed by the Commission at a formal public hearing, such as a power plant need determination proceeding. While Florida Statutes and Commission Rules do not specifically define IRP, they do provide a solid framework for flexible, cost-effective utility resource planning. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving day-to-day planning and operations to utility management.

Pursuant to Section 186.801, Florida Statutes (F.S.), each generating electric utility must submit to the Commission a Ten-Year Site Plan which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a 10-year planning horizon. The Ten-Year Site Plans of Florida's electric utilities summarize the results of each utility's IRP process and identifies proposed power plants and transmission facilities. The Commission is required to perform a preliminary study of each plan and classify each one as either "suitable" or "unsuitable." This document represents the review of the 2016 Ten-Year Site Plans for Florida's electric utilities, filed by 11 reporting utilities.[1]

All findings of the Commission are made available to the Florida Department of Environmental Protection (DEP) for its consideration at any subsequent certification proceeding pursuant to the

[1]Investor-owned utilities filing 2016 TYSPs include Florida Power & Light Company (FPL), Duke Energy Florida, LLC. (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). Municipal utilities filing 2016 TYSPs include Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). Seminole Electric Cooperative (SEC) also filed a 2016 TYSP.

Electrical Power Plant Siting Act or the Electric Transmission Line Siting Act.[2] In addition, this document is sent to the Florida Department of Agriculture and Consumer Services pursuant to Section 377.703(2)(e), F.S., which requires the Commission provide a report on electricity and natural gas forecasts.

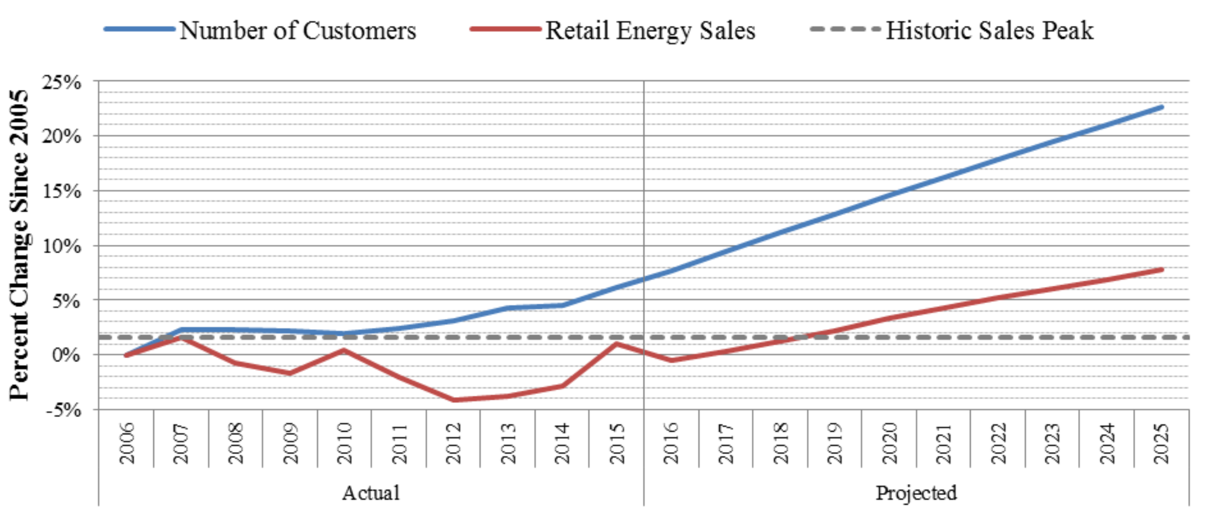
Review of the 2016 Ten-Year Site Plans

The Commission has divided this review into two portions: (1) a Statewide Perspective, which covers the whole of Florida; and (2) Utility Perspectives, which address each of the reporting utilities. From a statewide perspective, the Commission has reviewed the implications of the combined trends of Florida's electric utilities regarding load forecasting, renewable generation, and traditional generation.

Load Forecasting

Forecasting load growth is an important component of system planning for Florida's electric utilities. Florida's electric utilities reduce the rate of growth in customer peak demand and annual energy consumption through demand-side management programs. The Commission, through its authority granted by Sections 366.80 through 366.83 and Section 403.519, F.S., otherwise known as the Florida Energy Efficiency and Conservation Act (FEECA), encourages demand-side management by establishing goals for the reduction of seasonal peak demand and annual energy consumption for those utilities under its jurisdiction. Based on current projections, Florida's electric utilities anticipate exceeding the historic 2007 peak by 2019. Figure 1 below details these trends.

Figure 1: State of Florida - Growth in Customers and Sales



Source: 2016 FRCC Load and Resource Plan

[2]The Electrical Power Plant Siting Act is Sections 403.501 through 403.518, F.S. Pursuant to Section 403.519, F.S., the Commission is the exclusive forum for the determination of need for an electrical power plant. The ElectricTransmission Line Siting Act is Sections 403.52 through 403.5365, F.S. Pursuant to Section 403.537, F.S., the Commission is the sole forum for the determination of need for a transmission line.

Renewable Generation

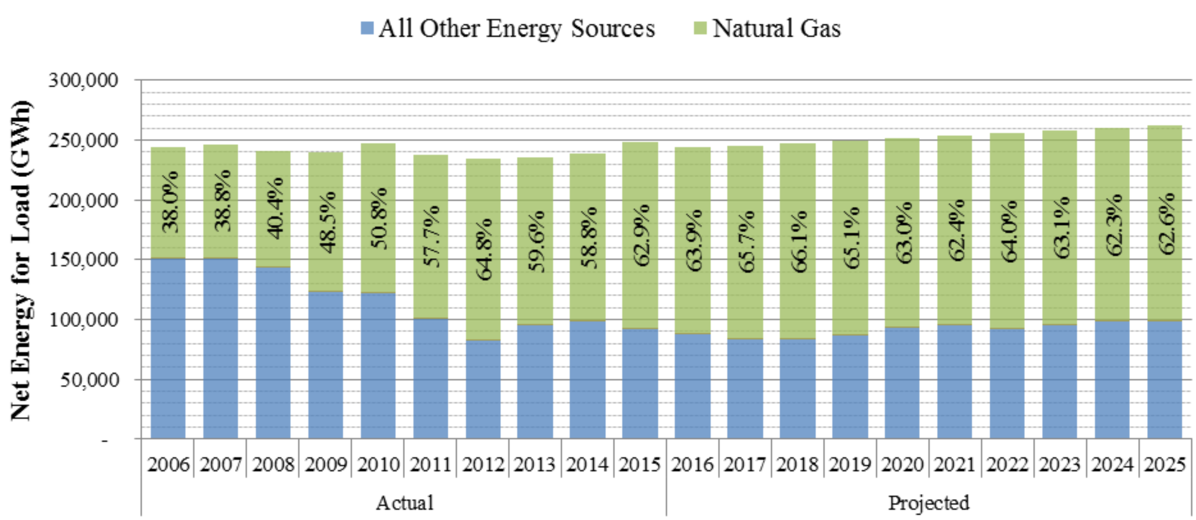
Renewable resources continue to expand in Florida, with approximately 1,860 MW of renewable generating capacity currently installed in Florida. The majority of installed renewable capacity is represented by biomass and municipal solid waste, making up approximately 60 percent of Florida's renewables. Other major renewable types, in order of capacity contribution, include waste heat, solar, hydroelectric, and landfill gas. Notably, Florida had 108 MW of demand-side renewable energy systems installed and using net metering at the end of 2015, an increase in capacity of 34.7 percent from 2014.

Over the next 10 years, Florida's electric utilities have reported that 2,005 MW of additional renewable generation is planned in Florida, excluding any potential demand-side renewable energy additions. Over three-quarters of the projected capacity additions are solar photovoltaic generation. Some utilities are including a portion of these solar resources (124 MW) as a firm resource for reliability considerations. Reasons given for these additions are a continued reduction in the price of solar facilities, availability of utility property with access to the grid, and actual performance data obtained solar demonstration projects. If these conditions continue, cost-effective forms of renewable generation will continue to improve the state's fuel diversity and reduce dependence on fossil fuels.

Traditional Generation

Generating capacity within the State of Florida is anticipated to grow to meet the increase in customer demand, with approximately 12,127 MW of new utility-owned generation added over the planning horizon. This figure represents an increase from the previous year, which estimated the need for about 11,548 MW new generation. Natural gas remains the dominant fuel over the planning horizon, with usage in 2015 at approximately 63 percent of the state's net energy for load (NEL). Figure 2 below illustrates the use of natural gas as a generating fuel for electricity production in Florida. Natural gas usage is expected to grow slowly.

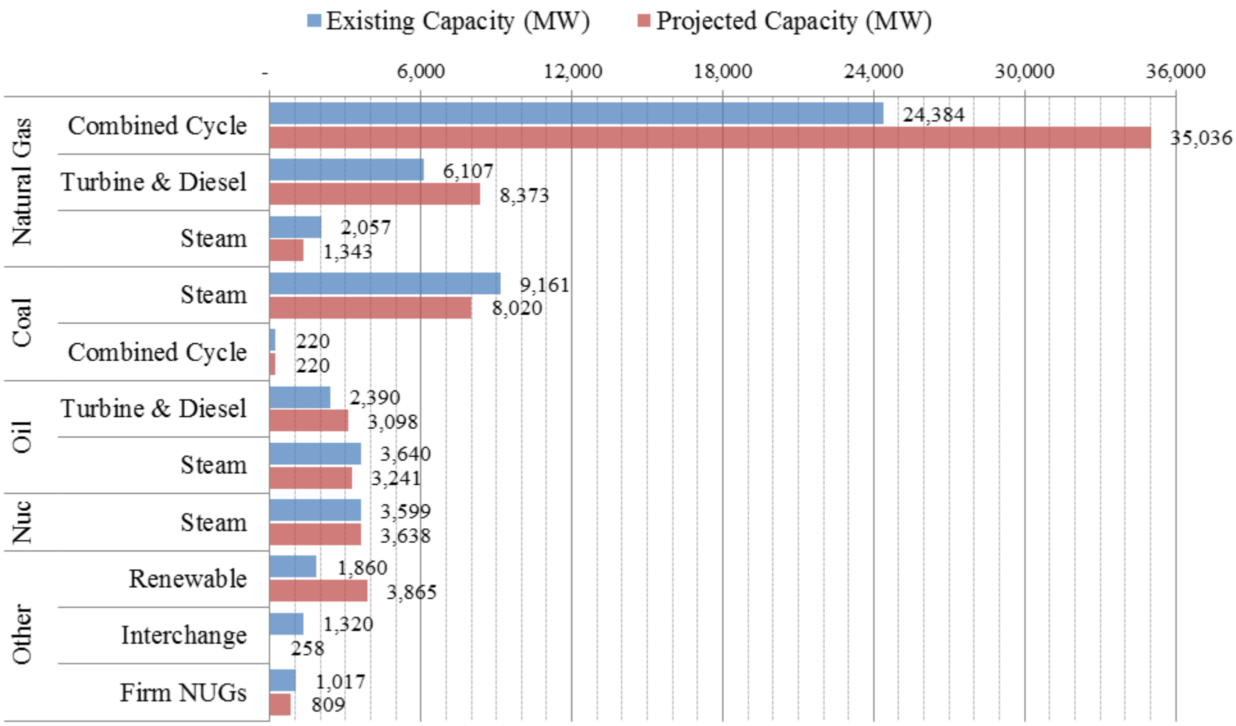
Figure 2: State of Florida - Natural Gas Contribution to Energy Consumption



Source: 2006-2016 FRCC Load and Resource Plan

Based on the 2016 Ten-Year Site Plans, Figure 3 below illustrates the present and future aggregate capacity mix of the State of Florida. The capacity values in Figure 3 incorporate all proposed additions, changes, and retirements planned during the 10-year period. As in previous planning cycles, natural gas-fired generating units make up a majority of the generation additions and now represent a majority of capacity within the state.

Figure 3: State of Florida - Current and Projected Installed Capacity by Fuel



Source: 2016 FRCC Load and Resource Plan and TYSP Data Responses

As noted previously, the primary purpose of this review of the utilities' plans is to provide information regarding proposed electric power plants for local and state agencies to assist in the certification process. Table 1 below displays those planned generation facilities that have not yet received a determination of need from the Commission. A petition for a determination of need is generally anticipated four years in advance of the in-service date for a natural gas-fired combined cycle unit.

Table 1: State of Florida - Planned Units Requiring a Determination of Need

Year	Utility Name	Unit Name	Fuel & Unit Type	Net Capacity (Sum MW)
2021	SEC	Unnamed CC	Natural Gas Combined Cycle	649
2023	OUC	Unspecified CC	Natural Gas Combined Cycle	300
2024	FPL	Combined Cycle Unit	Natural Gas Combined Cycle	1,317

Source: 2016 Ten-Year Site Plans

Future Concerns

Florida's electric utilities must also consider environmental concerns associated with existing generators and planned generation to meet Florida's electric needs. The U.S. Environmental Protection Agency (EPA) has finalized several new rules that are expected to have a sizeable impact on Florida's existing generation fleet, as well as on its proposed new facilities.

Notably, EPA published final rules in October 2015 associated with carbon pollution for existing power plants, also known as the Clean Power Plan. On the same date, EPA also published final rules setting carbon emissions from new facilities. These rules have been appealed. The U.S. Supreme Court has stayed the Clean Power Plan during the appeal process. Consequently, the potential effects on Florida's electric utilities are not considered as part of this review.

Conclusion

The Commission has reviewed the 2016 Ten-Year Site Plans and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. The Commission will continue to monitor the impact of current and proposed EPA Rules and the state's dependence on natural gas for electricity production.

Based on its review, the Commission finds the 2016 Ten-Year Site Plans to be suitable for planning purposes. Since the Plans are not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing.

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Introduction

The Ten-Year Site Plans (TYSPs or Plans) of Florida's electric utilities are the culmination of an integrated resource plan which is designed to give state, regional, and local agencies advance notice of proposed power plants and transmission facilities. The Commission receives comments from these agencies regarding any issues with which they may have concerns. The Plans are planning documents that contain tentative data that is subject to change by the utilities upon written notification to the Commission.

For any new proposed power plants and transmission facilities, certification proceedings under the Florida Electrical Power Plant Siting Act, Sections 403.501 through 403.518, Florida Statutes (F.S.), or the Florida Electric Transmission Line Siting Act, Sections 403.52 through 403.5365, F.S., will include more detailed information than is provided in the Plans. The Commission is the exclusive forum for determination of need for electrical power plants, pursuant to Section 403.519, F.S., and for transmission lines, pursuant to Section 403.537, F.S. The Plans are not intended to be comprehensive, and therefore may not have sufficient information to allow regional planning councils, water management districts, and other reviewing state and local agencies to evaluate site-specific issues within their respective jurisdictions. Other regulatory processes may require the electric utilities to provide additional information as needed.

Statutory Authority

All major generating electric utilities are required by Section 186.801, F.S., to submit at least every two years, for review, a Ten-Year Site Plan to the Commission. Based on these filings, the Commission performs a preliminary study of each Plan and makes a non-binding determination as to whether it is suitable or unsuitable. The results of the Commission's study are contained in this report, the Review of the 2016 Ten-Year Site Plans, and are forwarded to the Florida Department of Environmental Protection for use in subsequent proceedings. In addition, Section 377.703(2)(e), F.S., requires the Commission to collect and analyze energy forecasts, specifically for electricity and natural gas, along with the Department of Agriculture and Consumer Services. The Commission has adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code (F.A.C.) in order to fulfill these statutory requirements and provide a solid framework for flexible, cost-effective utility resource planning. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving day-to-day planning and operations to utility management.

Applicable Utilities

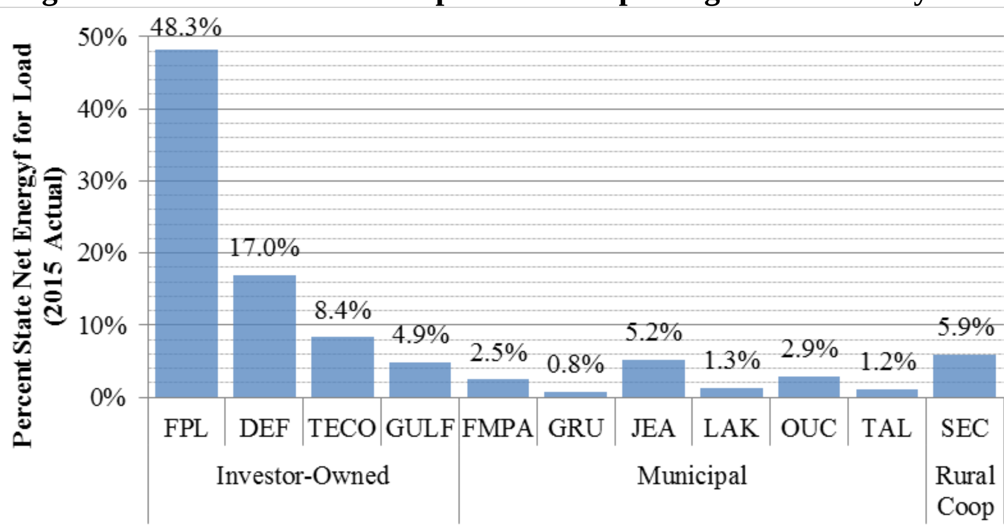
Florida is served by 58 electric utilities, including 5 investor-owned utilities, 35 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 megawatts (MW) or a planned unit with a capacity of 75 MW or greater are required to file with the Commission a Ten-Year Site Plan every year.

In 2016, 11 utilities met these requirements and filed a Ten-Year Site Plan, including 4 investor-owned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company (FPL), Duke Energy Florida, LLC

(DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). The municipal utilities, in alphabetical order, are Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). The sole rural electric cooperative filing a 2016 Plan is Seminole Electric Cooperative (SEC). Collectively, these utilities are referred to as the Ten-Year Site Plan Utilities (TYSP Utilities).

Figure 4 below illustrates the comparative size of the TYSP utilities, in terms of each utility's percentage share of the state's retail energy sales in 2015. Combined, the reporting investor-owned utilities account for 78.6 percent of the state's retail energy sales. The reporting municipal and cooperative utilities make up approximately 19.8 percent of the State's retail energy sales.

Figure 4: TYSP Utilities - Comparison of Reporting Electric Utility Size



Source: 2016 Ten-Year Site Plans, 2016 Load & Resource Plan

Required Content

The Commission requires each reporting utility to provide information on a variety of topics. Schedules describe the utility's existing generation fleet, customer composition, demand and energy forecasts, fuel requirements, reserve margins, changes to existing capacity, and proposed power plants and transmission lines. The utilities also provide a narrative documenting the methodologies used to forecast customer demand and the identification of resources to meet that demand over the 10-year planning period. This information, supplemented by additional data requests, provides the basis of the Commission's review.

Additional Resources

The Commission's Rules also task the reporting electric utilities with collecting information on both a statewide basis and for Peninsular Florida, which excludes the area west of the Apalachicola River. The Florida Reliability Coordinating Council (FRCC) provides this aggregate data for the Commission's review. Each year, the FRCC publishes a Regional Load and Resource Plan, which contains historic and forecast data on demand and energy, capacity and reserves, and proposed new generating units and transmission line additions. In addition, the FRCC publishes an annual Reliability Report which is also relied upon by the Commission.

For certain comparisons additional data from various government agencies is relied upon, including the Energy Information Administration and the Florida Department of Highway Safety and Motor Vehicles.

The Commission held a public workshop on September 14, 2016, to facilitate discussion of the annual planning process and allow for public comments. A presentation was conducted by the FRCC summarizing the 2016 Load and Resource Plan and other related matters, including fuel reliability, environmental regulations, and physical security of infrastructure. Presentations were also conducted by the four IOU's FPL, DEF, TECO, and GPC to discuss their planning process. Comments from Southern Alliance for Clean Energy and Sierra Club were also given at the workshop.

Structure of the Commission's Review

The Commission's review is divided into multiple sections. The Statewide Perspective provides an overview of the State of Florida as a whole, including discussions of load forecasting, renewable generation, and traditional generation. The Utility Perspectives provides more focus, discussing the various issues facing each electric utility and its unique situation. Lastly, the comments collected from various review agencies, local governments, and other organizations are included as Appendix A.

Conclusion

Based on its review, the Commission finds all 11 reporting utility's 2016 Ten-Year Site Plans to be suitable for planning purposes. During its review, the Commission has determined that the projections for load growth appear reasonable and that the reporting utilities have identified sufficient generation facilities to maintain an adequate supply of electricity at a reasonable cost.

The Commission notes that, as the Ten-Year Site Plans are non-binding, the classification of suitable does not constitute a finding or determination in any docketed matter before the Commission, nor an approval of all planning assumptions contained within the Ten-Year Site Plans. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing.

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Statewide Perspective

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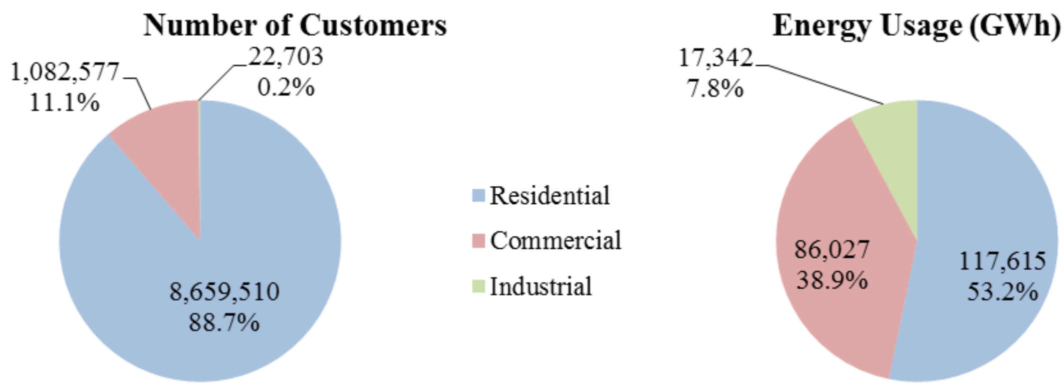
Load Forecasting

Forecasting load growth is an important component of the IRP process for Florida's electric utilities. In order to maintain system reliability, utilities must be prepared for future changes in electricity consumption, including changes to the number of electric customers, customer usage patterns, building codes and appliance efficiency standards, new technologies such as electric vehicles, and the role of demand-side management.

Electric Customer Composition

Residential customers represent the majority in terms of number of customers at 88.7 percent of customers, and retail energy sales for the three major customer classes, as illustrated in Figure 5 below. Both commercial and industrial customers make up a sizeable percentage of energy sales, due to each class' higher energy usage per customer account.

Figure 5: State of Florida - Electric Customer Composition in 2015

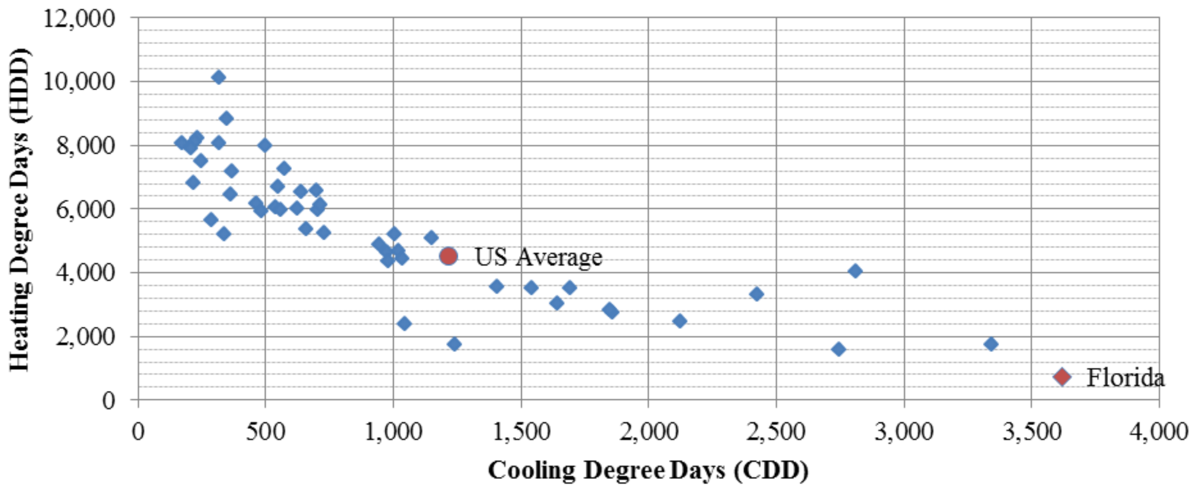


Source: FRCC 2016 Load and Resource Plan

Florida's residential customers make up a larger portion of retail energy sales than the United States as a whole, with a national average of 36 percent for residential retail sales. As a result, Florida's utilities are impacted more by trends in residential energy usage, which tend to be associated with weather conditions. Florida's residential customers rely more upon electricity for heating than the national average, with only a small portion using alternate fuels such as natural gas or oil for home heating needs.

Florida's unique climate plays an important role in electric utility planning. Florida is an outlier in terms of climate, with the highest number of cooling degree days and lowest number of heating degree days within the continental United States, as shown below in Figure 6. Other states tend to rely upon alternative fuels for heating, but Florida's heavy use of electricity results in high winter peak demand.

Figure 6: National - Climate Data by State (Continental US)

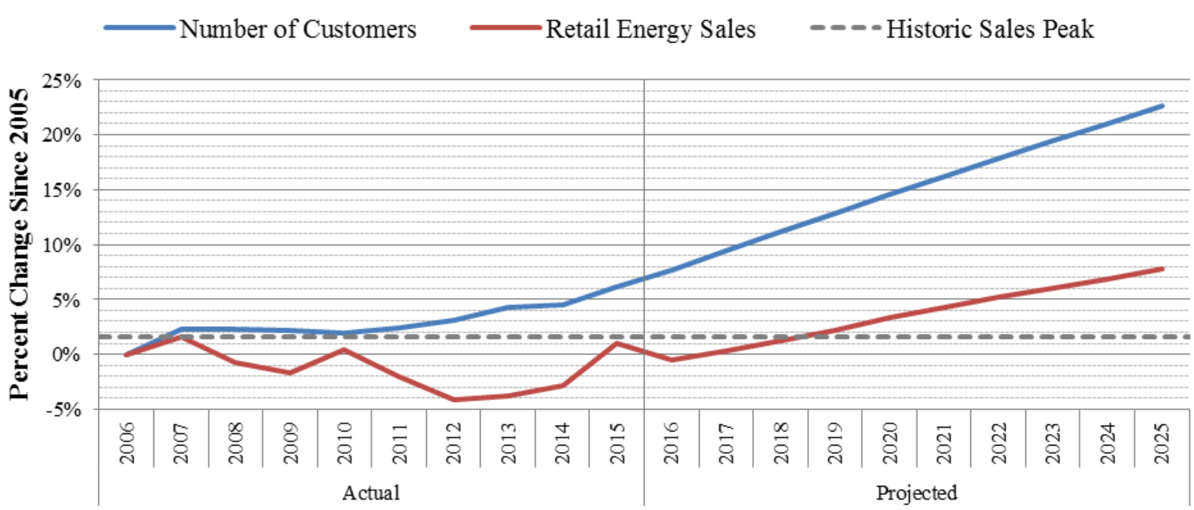


Source: National Oceanic & Atmospheric Administration, Historical Climatology Series 5-1 and 5-2

Growth Projections

For the next 10-year period, Florida's customer base and retail sales are anticipated by the reporting utilities to grow at a faster pace than the last few years, reversing a trend of small population increases with declining retail sales. While this rate remains below those experienced before the financial crisis, it would set the State on track to exceed its previous 2007 retail sales peak in 2019. The current divide between customers and retail sales is anticipated to remain similar over the 10-year period, with customers growing at an average annual rate of about 1.6 percent while retail sales increase by about 0.90 percent annually. Florida's electric utilities are projecting an increase in economic growth in the state, but at levels below those experienced before the financial crisis. The trends are showcased in Figure 7 below.

Figure 7: State of Florida - Growth in Customers and Sales



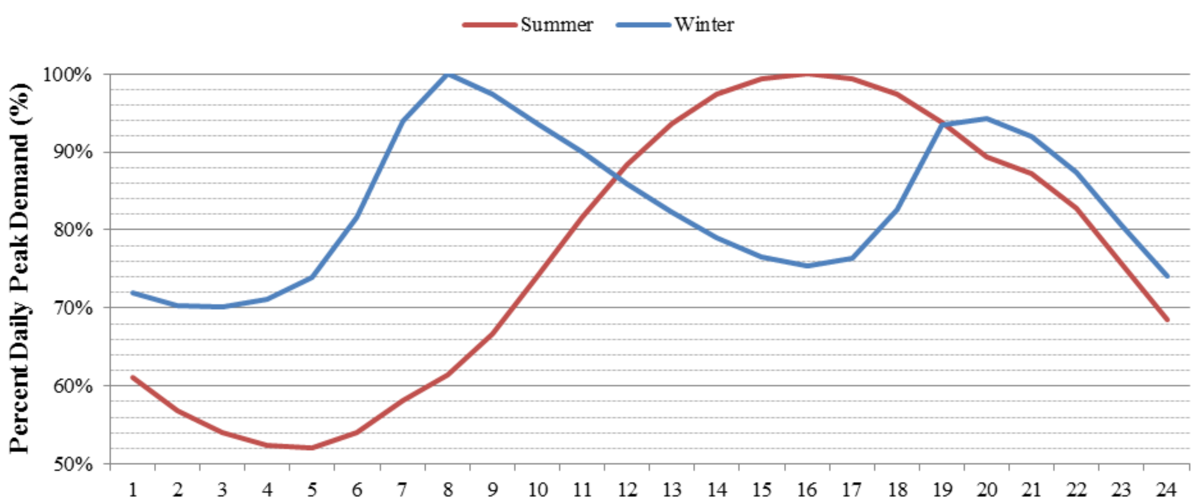
Source: FRCC 2016 Load and Resource Plan

Peak Demand

The aggregation of each individual customer's electric consumption must be met at all times by Florida's electric utilities to ensure reliable service. The time at which customers demand the most energy simultaneously is referred to as peak demand. While retail energy sales primarily vary the amount of fuel consumed by the electric utilities to deliver energy, peak demand determines the amount of generating capacity required to deliver that energy at a single moment in time.

A primary factor in this is seasonal weather patterns, with peak demands calculated separately for the summer and winter periods annually. The influence of residential customers is evident in the determination of these seasonal peaks, as they correspond to times of increased usage to meet home heating (winter) and cooling (summer) demand. Figure 8 below illustrates a daily load curve for a typical day for each season. In summer, air-conditioning needs increase throughout the day, climbing steadily until a peak is reached in the late afternoon and then declining into the evening. In winter, electric heat and electric water heating produce a higher base level of usage, with a large spike in the morning and a smaller spike in the evening.

Figure 8: TYSP Utilities - Example Daily Load Curves

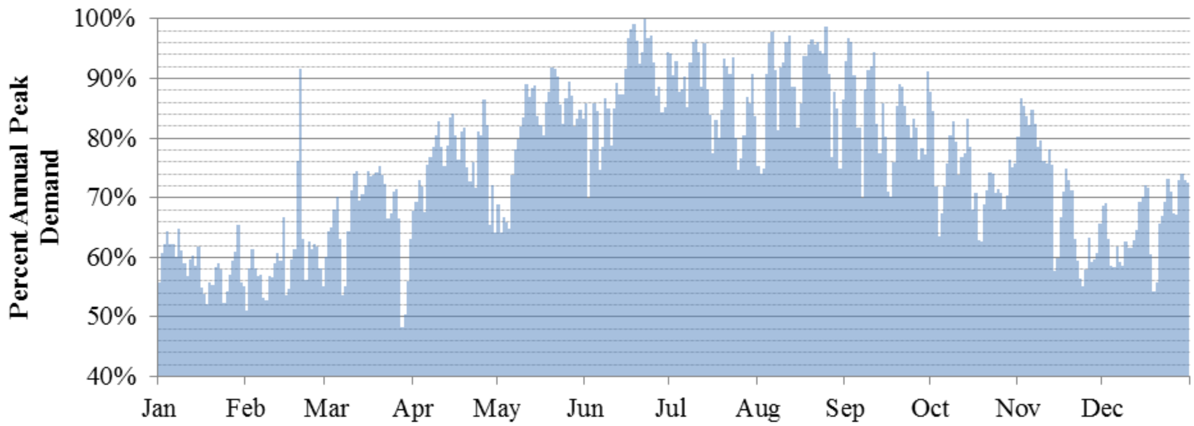


Source: TYSP Utilities Data Responses

Florida is typically a summer-peaking state, meaning that the summer peak demand generally exceeds winter peak demand, and therefore controls the amount of generation required. Higher temperatures in summer also reduce the efficiency of generation, with high water temperatures reducing the quality of cooling provided, and can sometimes limit the quantity as units may be required to operate at reduced power or go offline based on environmental permits. Conversely, in winter, utilities can take advantage of lower ambient air and water temperatures to produce more electricity from a power plant.

As daily load varies, so do seasonal loads. Figure 9 below illustrates this for 2015, showing the daily peak demand as a percentage of the annual peak demand for the reporting investor-owned utilities combined. Typically, winter peaks are short events while summer demand tends to stay at near peak levels for longer periods. The periods between seasonal peaks are referred to as shoulder months, in which the utilities take advantage of lower demand to perform maintenance without impacting their ability to meet daily peak demand.

Figure 9: TYSP Utilities - Daily Peak Demand (2015 Actual)



Source: TYSP Utilities Data Responses (Investor-Owned Utilities Only)

While the utilities assume normalized weather in forecasts of peak demand, during operation of the system, utilities continuously monitor the short-term weather patterns. Utilities adjust maintenance schedules to ensure the highest unit availability during the utility's projected peak demand, bringing units back online if necessary or delaying maintenance until after a weather system has passed.

Electric Vehicles

Utilities also examine other trends that may impact the amount of customer peak demand and energy consumption. This includes new sources of energy consumption, such as electric vehicles, which can be considered analogous to a home air conditioning system in terms of system load. At present, the reporting electric utilities estimate approximately 15,300 electric plug-in vehicles were operating in Florida at the end of 2015. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered vehicles in Florida as of December 31, 2015, as 19.7 million vehicles, resulting in 0.077 percent penetration rate of electric vehicles of Florida's registered vehicle fleet.

Florida's electric utilities anticipate growth in the electric vehicle market, as illustrated in Table 2 below. Electric vehicles are anticipated to grow rapidly throughout the planning period, resulting in over 300,000 electric vehicles operating within the electric service territories by the end of 2025. The projected increase in electric vehicle ownership would result in approximately 2 percent share of Florida's vehicles being fueled by electricity.

Table 2: TYSP Utilities - Estimated Number of Electric Vehicles by Service Territory

Year	FPL	DEF	TECO	GULF	JEA	OUC	TAL	Total
2015	10,466	2,819	1,052	450	386	-	88	**15,261**
2016	15,474	3,982	1,176	860	520	-	106	**22,118**
2017	23,683	5,683	1,345	1,450	683	-	137	**32,981**
2018	41,035	8,194	1,680	2,290	861	-	178	**54,238**
2019	61,552	11,626	1,820	3,410	1,066	-	232	**79,706**
2020	83,094	16,205	1,890	4,910	1,297	-	302	**107,698**
2021	108,023	21,732	1,941	6,900	1,558	-	392	**140,546**
2022	135,029	28,217	2,193	9,500	1,850	-	529	**177,318**
2023	167,437	35,502	2,633	12,910	2,175	-	715	**221,372**
2024	209,295	43,490	3,316	17,410	2,537	-	965	**277,013**
2025	251,154	52,180	4,615	23,660	2,938	-	1,351	**335,898**

Source: TYSP 2016 Data Responses

In terms of energy consumed by electric vehicles, Table 3 below illustrates the estimates provided by the reporting utilities. The anticipated growth would result in an annual energy consumption of 1,424.3 GWh.

Table 3: TYSP Utilities - Estimated Electric Vehicle Annual Energy Consumption (GWh)

Year	FPL	DEF	TECO	GULF	JEA	OUC	TAL	Total
2015	5.6	10.3	4.4	2.0	2.7	0.1	0.4	**25.5**
2016	28.2	14.3	5.0	3.8	3.8	-	0.5	**55.6**
2017	65.2	19.8	5.7	6.4	5.2	-	0.6	**102.9**
2018	143.4	27.9	7.1	10.1	6.9	-	0.8	**196.2**
2019	235.9	38.9	7.7	15.1	8.9	-	1.1	**307.6**
2020	333.0	53.5	8.0	21.7	11.4	-	1.4	**429.0**
2021	445.4	70.9	8.2	30.5	14.4	-	1.9	**571.3**
2022	567.2	91.8	9.3	42.0	17.9	-	2.5	**730.7**
2023	713.3	115.6	11.2	57.0	21.9	-	3.4	**922.4**
2024	902.0	142.3	14.1	76.9	26.7	-	4.6	**1,166.6**
2025	1,090.7	171.0	19.6	104.5	32.2	-	6.4	**1,424.3**

Source: TYSP 2016 Data Responses

The effect of increased electric vehicle ownership on peak demand is more difficult to determine. While comparable in electric demand to a home air conditioning system, the time of charging and whether charging would be shifted away from periods of peak demand are uncertainties that must be clarified to determine impact on system peak. As electric vehicle ownership increases, the effects of electric vehicles on system peak should become clearer and be able to be addressed by electric utilities.

Demand-Side Management

Florida's electric utilities also must consider how the efficiency of customer energy consumption changes over the planning period. Changes in government mandates, such as building codes and appliance efficiency standards, reduce the amount of energy consumption for new construction and electric equipment. Electric customers, through the power of choice, can elect to engage in behaviors that decrease peak load or annual energy usage. Examples include, turning off lights and fans in vacant rooms, increasing thermostat settings, and purchasing appliances that go beyond efficiency standards. While a certain portion of customers will engage in these activities without incentives due to economic, aesthetic, or environmental concerns, other customers may lack information or require additional incentives. Demand-side management represents an area where Florida's electric utilities can empower and educate its customers to make choices that reduce peak load and annual energy consumption.

Florida Energy Efficiency and Conservation Act (FEECA)

The Florida Legislature has directed the Commission to encourage utilities to decrease the growth rates in seasonal peak demand and annual energy consumption by FEECA, which consists of Sections 366.80 through 366.83 and Section 403.519, F.S. Under FEECA, the Commission is required to set goals for seasonal demand and annual energy reduction for seven electric utilities, known as the FEECA Utilities. These include the five investor-owned electric utilities (including Florida Public Utility Company, which is a non-generating utility and therefore does not file a Ten-Year Site Plan) and two municipal electric utilities (JEA and OUC). The FEECA utilities represented approximately 86 percent of 2015 retail sales in Florida.

The FEECA utilities currently offer demand-side management programs for residential, commercial, and industrial customers. Energy audit programs are designed to provide an overview of customer energy usage and to evaluate conservation opportunities, including behavioral changes, low-cost measures customers can undertake themselves, and participation in utility-sponsored DSM programs.

The last FEECA goal-setting proceeding was completed in December 2014, establishing goals for the period 2015 through 2024. During 2015, the Commission reviewed the FEECA Utility's proposed DSM Plans to comply with the established goals, approving the plans with some modifications in July 2015. The 2016 Ten-Year Site Plans incorporate the impacts of the DSM Plans established by the Commission for the planning period.

DSM Programs

DSM Programs generally are divided into three categories: interruptible load, load management, and energy efficiency. The first two are considered dispatchable, and are collectively known as demand response, meaning that the utility can call upon them during a period of peak demand or other reliability concerns, but otherwise they are not utilized. In contrast, energy efficiency measures are considered passive and are always working to reduce customer demand and energy consumption.

Interruptible load is achieved through the use of agreements with large customers to allow the utility to interrupt the customer's load, reducing the generation required to meet system demand. Interrupted customers may use back-up generation to fill their energy needs, or cease operation until the interruption has passed. A subtype of interruptible load is curtailable load, which allow the utility to interrupt only a portion of the customer's load. In exchange for the ability to interrupt these customers, the utility offers a discounted rate for energy or other credits which are paid for by all ratepayers.

Load management is similar to interruptible load, but focuses on smaller customers and targets individual appliances. The utility installs a device on an electric appliance, such as a water heater or air conditioner, which allows for remote deactivation for a short period of time. Load management activations tend to have less advanced notice than those for interruptible customers, but tend to be activated only for short periods and are cycled through groups of customers to reduce the impact to any single customer. Due to the focus on specific appliances, certain appliances would be more appropriate for addressing certain seasonal demands. For example, load management programs targeting air conditioning units would be more effective to reduce a summer peak, while water heaters are more effective for reducing a winter peak.

As of 2016, demand response available for reduction of peak load is 2,924 MW for summer peak and 2,885 MW for winter peak. Demand response is anticipated to increase to approximately 3,304 for summer peak and 3,178 for winter peak by the end of the planning period in 2025.

Energy efficiency or conservation measures also have an impact on peak demand, and due to their passive nature do not require activation by the utility. Conservation measures include improvements in a home or business' building envelope to reduce heating or cooling needs, or the installation of more efficient appliances. By installing additional insulation, energy-efficient windows or window films, and more efficient appliances, customers can reduce both their peak demand and annual energy consumption, leading to reductions in customer bills. Demand-side management programs work in conjunction with building codes and appliance efficiency standards to increase energy savings above the minimum required by local, state, or federal regulations. As of 2016, energy efficiency is responsible for peak load reduction of 4,024 MW for summer peak and 3,597 MW for winter peak. Energy efficiency is anticipated to increase to approximately 4,799 MW for summer peak and 4,165 MW for winter peak by the end of the planning period in 2025.

Forecast Load & Peak Demand

The historic and forecasted seasonal peak demand and annual energy consumption values for the State of Florida are illustrated below, in Figure 10. It should be noted, that the forecasts shown below are based upon normalized weather conditions, while the historic demand and energy values represent the actual impact of weather conditions on Florida's electric customers. Florida relies heavily upon both air conditioning in the summer and electric heating in the winter, so both seasons experience a great deal of variability due to severe weather conditions.

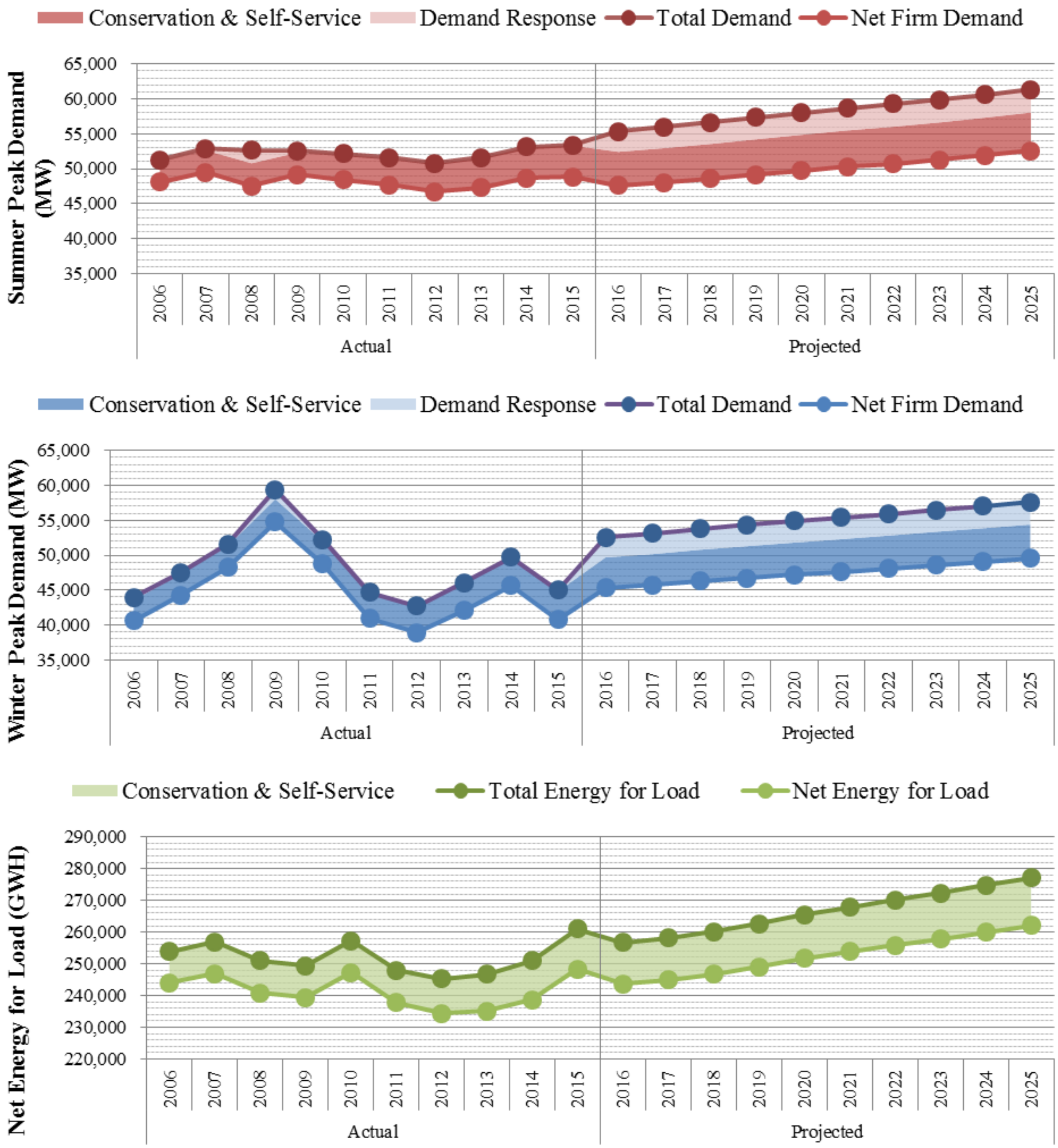
Demand-side management, including demand response and energy efficiency, along with self-service generation is included in each figure for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served if not for the impact of these programs and self-service generators. The net firm demand is used as a planning number for the calculation of generating reserves and determination of generation needs for Florida's electric utilities.

Demand response is included in Figure 10 below, in two different ways based upon the time period considered. For historic values of seasonal demand, the actual rates of demand response activation are shown, not the full amount demand response that was available at the time. Overall, demand response has only been partially activated as sufficient generation assets were available during the annual peak. Residential load management has been called upon to a limited degree during peak periods, with a lesser amount of interruptible load activated. The primary exception to this trend was the summer of 2008 and winter of 2009, when a larger portion of the available demand response resources were called upon.

For forecast values of seasonal demand, it is assumed that all demand response resources will be activated during peak. The assumption of all demand response being activated reduces generation planning need. Based on operating conditions in the future, if an electric utility has sufficient generating units, and it is economical to serve all customers load demand, response would not be activated or only partially activated in the future.

As previously discussed, Florida is normally a summer-peaking state. Only three of the past ten years have had higher winter net firm demand than summer, and all ten of the forecast years are anticipated to be summer peaking. Based upon current forecasts using normalized weather data, Florida’s electric utilities do not anticipate exceeding the winter 2009 peak during the planning period.

Figure 10: State of Florida - Historic & Forecast Seasonal Peak Demand & Annual Energy



Source: 2016 FRCC Load & Resource Plan

Forecast Methodology

Florida's electric utilities perform forecasts of peak demand and annual energy sales using various forecasting models, including econometric and end-use models, and other forecasting techniques such as surveys. In the development of econometric models, the utilities use historical data sets including dependent variables (e.g. summer peak demand per customer, residential energy use per customer) and independent variables (e.g. cooling degree days, real personal income, etc.) to infer relationships between the two types of variables. These historical relationships, combined with available forecasts of the independent variables and the utilities' forecasts of customers, are then used to forecast the peak demand and energy sales. For some customer classes, such as industrial customers, surveys may be conducted to determine the customers' expectations for their own future electricity consumption.

The forecasts also account for demand-side management programs. Sales models are prepared by revenue class (e.g. residential, small and large commercial, small and large industrial, etc.). Commonly, the results of the models must be adjusted to take into account exogenous impacts, such as the impact of the recent growth in plug-in electric vehicles and distributed generation.

End-use models are sometimes used to project energy use in conjunction with econometric models. End use models are used to capture trends in appliance and equipment saturation and efficiency, as well as building size and thermal efficiency, on residential and commercial energy use. If such end use models are not used, the econometric models for energy often include an index comprised of efficiency standards for air conditioning, heating, and appliances, as well as construction codes for recently built homes and commercial buildings.

Florida's electric utilities rely upon data sourced from public and private entities for historic and forecast values of specific independent variables used in econometric modeling. Public resources such as the University of Florida's Bureau of Economic and Business Research, which provides county-level data on population growth, and the U.S. Department of Commerce's Bureau of Labor Statistics, which publishes the Consumer Price Index, are utilized along with private forecasts for economic growth from macroeconomic experts, such as Moody's Analytics. By combining historic and forecast macroeconomic data with customer and climate data, Florida's electric utilities project future load conditions.

The various forecast models and techniques used by Florida's electric utilities are commonly used throughout the industry, and each utility has developed its own individualized approach to projecting load. The resulting forecasts allow each electric utility to evaluate its individual needs for new generation, transmission, and distribution resources to meet customers' current and future needs reliably and affordably.

For each reporting electric utility, the Commission reviewed the historic forecast accuracy of past retail energy sales forecasts. The review methodology, previously used by the Commission, involves comparing actual retail sales for a given year to energy sales forecasts made three, four, and five years prior. For example, the actual 2015 retail energy sales were compared to the forecasts made in 2012, 2011, and 2010. These differences, expressed as a percentage error rate, are used to determine each utility's historic forecast accuracy using a five-year rolling average. An average error with a negative value indicates an under-forecast, while a positive value represents an over-forecast. An absolute average error provides an indication of the total magnitude of error, regardless of the tendency to under or over forecast.

For the 2016 Ten-Year Site Plans, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2015 through 2011 to forecasts made between 2012 and 2006. As discussed previously, the period before the financial crisis, known as the Great Recession, experienced a higher annual growth rate for retail energy sales than the post-crisis period. As most electric utilities and macroeconomic forecasters did not predict the financial crisis, the economic impact and its resulting effect on retail energy sales of Florida's electric utilities was not included in these projections. Therefore, the use of a metric that compares pre-crisis forecasts with post-crisis actual data has a high rate of error.

Table 4 below shows that the forecast errors are increasing with time starting in 2011 due to the unexpected impact of the Great Recession and its impact on retail energy sales in Florida. However, the forecast errors have started to return to lower levels as utility retail sales forecasts include more post-recession years. This was indicated by the data provided in last year's TYSPs; and it is confirmed by the data provided in the current TYSPs. The forecasting error rates (both average and absolute average) generated by comparing actual 2015 retail energy sales to the 2014 forecast of 2015 energy sales are further reduced from the error rates generated by comparing actual 2014 sales to the 2013 forecast of 2014 sales.

Table 4: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts

TYSP Year	Five-Year Analysis Period	Forecast Years Analyzed	Forecast Error (%)	
			Average	Absolute Average
2011	2010 - 2006	2007-2001	8.28%	8.29%
2012	2011 - 2007	2008-2002	11.93%	11.93%
2013	2012 - 2008	2009-2003	15.13%	15.13%
2014	2013 - 2009	2010-2004	16.16%	16.16%
2015	2014 - 2010	2011-2005	14.90%	14.90%
2016	2015 - 2011	2012-2006	12.48%	12.48%

Source: 2001-2016 Ten-Year Site Plans

To verify whether more recent forecasts lowered the error rates, an additional analysis was conducted to determine with more detail, the source of high error rates in terms of forecast timing. Table 5 below provides the forecast error rate for forecasts made between one and six years prior, along with the average and absolute average error rates for the three- to five-year period used in the analysis above.

As displayed in Table 5 below the companies' retail energy sales forecasts show a consistent positive error rate beginning in 2007 and extending through 2014 for forecasts prepared two to six years prior. However, 2014 sales forecasted in 2010 and 2011, reveal that three and four year error rates (6.10 percent and 5.73 percent, respectively) have declined considerably compared to the three and four year forecast error rates associated with 2010-2013 sales. The error rates calculated based on the data provided in the current TYSPs continues showing across the board declines in forecast error rates made between one and six years prior, with the one-year ahead forecast showing a negative error rate (under-forecast).

Table 5: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts – Annual Analysis

Year	Annual Forecast Error Rate (%)						3-5 Year Error (%)	
	Years Prior						Average	Absolute Average
	6	5	4	3	2	1		
2006	-3.29%	-0.03%	1.03%	2.30%	2.43%	2.37%	**1.10%**	**1.12%**
2007	0.57%	2.26%	3.49%	3.59%	4.20%	3.05%	**3.11%**	**3.11%**
2008	7.02%	8.40%	8.56%	9.97%	9.24%	8.34%	**8.98%**	**8.98%**
2009	11.95%	12.15%	14.48%	13.91%	12.68%	10.18%	**13.51%**	**13.51%**
2010	12.93%	15.57%	14.89%	13.70%	10.55%	-0.73%	**14.72%**	**14.72%**
2011	21.56%	20.79%	20.09%	17.02%	3.79%	0.08%	**19.30%**	**19.30%**
2012	26.31%	25.97%	23.04%	8.47%	3.90%	3.71%	**19.16%**	**19.16%**
2013	28.55%	26.29%	10.00%	5.98%	5.58%	2.97%	**14.09%**	**14.09%**
2014	27.28%	9.80%	6.10%	5.73%	2.84%	2.21%	**7.21%**	**7.21%**
2015	7.29%	3.63%	3.23%	1.02%	0.00%	-1.17%	**2.63%**	**2.63%**

Source: 2001-2016 Ten-Year Site Plans

Barring any unforeseen economic crises or atypical weather patterns, average forecasted energy sales error rates in the next few years are likely to be more reflective of the error rates shown for 2015 in Table 5 than the significantly higher error rates shown in earlier years. It is important to recognize that the dynamic nature of the economy and the weather continue to present a degree of uncertainty for Florida utilities' load forecasts, ultimately impacting the accuracy of such forecasts.

Renewable Generation

Pursuant to Section 366.91, F.S., it is in the public interest to promote the development of renewable energy resources in Florida. Section 366.91(2)(d), F.S., defines renewable energy in part, as follows:

> "Renewable energy" means electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power.

Although not considered a traditional renewable resource, some industrial plants take advantage of waste heat, produced in production processes, to also provide electrical power via cogeneration. Phosphate fertilizer plants, which produce large amounts of heat in the manufacturing of phosphate from the input stocks of sulfuric acid, are a notable example of this type of renewable resource. The Section 366.91(2)(d), F.S., definition also includes the following language which recognizes the aforementioned cogeneration process:

> The term [Renewable Energy] includes the alternative energy resource, waste heat, from sulfuric acid manufacturing operations and electrical energy produced using pipeline-quality synthetic gas produced from waste petroleum coke with carbon capture and sequestration.

Existing Renewable Resources

Currently, renewable energy facilities provide approximately 1,860 MW of firm and non-firm generation capacity, which represents 3.1 percent of Florida's overall generation capacity of 58,421 MW in 2015. Table 6 below summarizes the contribution by renewable type of Florida's existing renewable energy sources.

Table 6: State of Florida - Existing Renewable Resources

Renewable Type	MW	% Total
Biomass	582	31.3%
Municipal Solid Waste	545	29.3%
Waste Heat	310	16.7%
Solar	263	14.2%
Landfill Gas	87	4.7%
Hydro	63	3.4%
Wind[3]	10	0.5%
Renewable Total	**1,860**	**100.00%**

Source: FRCC 2016 Load & Resource Plan and TYSP Utilities Data Responses

[3]JEA's wind resources are not present in-state.

Of the total 1,860 MW of renewable generation, approximately 598 MW are considered firm, based on either operational characteristics or contractual agreement. Firm renewable generation can be relied on to serve customers and can contribute toward the deferral of new fossil fueled power plant construction. Solar generation contributes 34 MW to this total, based upon the coincidence of solar generation and summer peak demand. Changes in timing of peak demand may influence the firm contributions of renewable resources such as solar and wind.

The remaining renewable generation can generate energy on an as-available basis or for internal use (self-service). As-available energy is considered non-firm, and cannot be counted on for reliability purposes; however, it can contribute to the avoidance of burning fossil fuels in existing generators. Self-service generation reduces demand on Florida’s utilities.

Non-Utility Renewable Generation

The majority of Florida’s existing renewable energy generation, approximately 89 percent, comes from non-utility generators. In 1978, the US Congress enacted the Public Utility Regulatory Policies Act (PURPA). PURPA requires utilities to purchase electricity from cogeneration facilities and renewable energy power plants with a capacity no greater than 80 MW (collectively referred to as Qualifying Facilities or QFs). PURPA required utilities to buy electricity from QFs at the utility’s full avoided cost. These costs are defined in Section 366.051, F.S., which provides in part that:

> A utility’s “full avoided costs” are the incremental costs to the utility of the electric energy or capacity, or both, which, but for the purchase from cogenerators or small power producers, such utility would generate itself or purchase from another source.

If a renewable energy generator can meet certain deliverability requirements, it can be paid for its capacity and energy output under a firm contract. Rule 25-17.250, F.A.C., requires each IOU to establish a standard offer contract with timing and rate of payments based on each fossil-fueled generating unit type identified in the utility’s TYSP. In order to promote renewable energy generation, the Commission requires the IOUs to offer multiple options for capacity payments, including the options to receive early (prior to the in-service date of the avoided-unit) or levelized payments. The different payment options allow renewable energy providers the option to select the payment option that best fits its financing requirements, and provides a basis from which negotiated contracts can be developed.

As previously discussed, large amounts of renewable energy is generated on an as-available basis. As-available energy is energy produced and sold by a renewable energy generator on an hour-by-hour basis for which contractual commitments as to the quantity and time of delivery are not required. As-available energy is purchased at a rate equal to the utility’s hourly incremental system fuel cost, which reflects the highest fuel cost of generation each hour.

Customer Owned Renewable Generation

With respect to customer-owned renewable generation, Rule 25-6.065, F.A.C., requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer, with renewable generation capability, to offset their energy usage. In 2008, the effective year of Rule 25-6.065, F.A.C., customer owned renewable generation accounted for 3 MW of renewable capacity. As of the end of 2015, approximately 108 MW of renewable capacity from nearly 11,650 systems has been installed statewide. Table 7 below summarizes the growth of customer owned renewable generation interconnections. Almost all installations are solar, with non-solar generation accounting for only 35 installations and 5.7 MW of installed capacity. The renewable generators in this category include wind turbines and anaerobic digesters.

Table 7: State of Florida - Customer-Owned Renewable Growth

Year	2008	2009	2010	2011	2012	2013	2014	2015
Number of Installations	577	1,625	2,833	3,994	5,302	6,697	8,581	11,626
Installed Capacity (MW)	2.8	13.0	19.9	28.4	42.2	63.0	79.8	107.5

Source: Annual Utility Reports

Utility-Owned Renewable Generation

Utility-owned renewable generation also contributes to the state's total renewable capacity. The majority of this generation is from solar facilities. Due to the intermittent nature of solar resources, capacity from these facilities has previously been considered non-firm for planning purposes.

In 2008, Section 366.92(4), F.S., was enacted and provides, in part, the following:

> In order to demonstrate the feasibility and viability of clean energy systems, the commission shall provide for full cost recovery under the environmental cost-recovery clause of all reasonable and prudent costs incurred by a provider for renewable energy projects that are zero greenhouse gas emitting at the point of the generation, up to a total of 110 MW statewide.

In 2008, the Commission approved a petition by FPL seeking installation of the full 110 MW across three solar energy facilities. The solar projects consisted of, a pair of solar PV facilities and a single solar thermal facility. In response to staff interrogatories, FPL estimated that the three solar facilities would cost an additional $573 million, above traditional generation costs over the life of the facilities. In 2012, Section 366.92, F.S., was revised and no longer includes the passage described above.

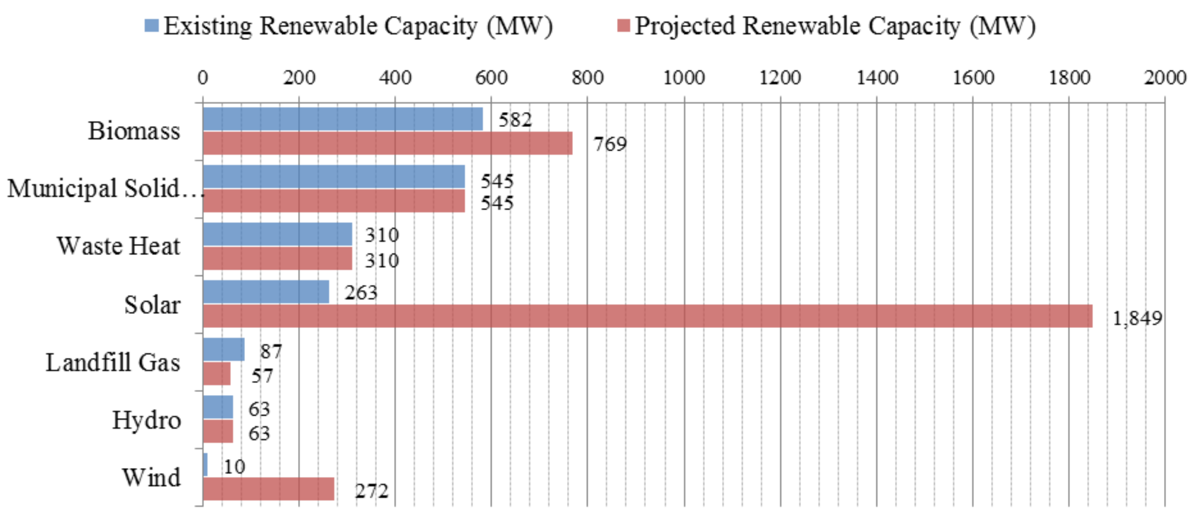
Based on actual data provided by FPL, the combined cost of generation of the three solar facilities was $0.41/kWh in 2016. These facilities make up a significant portion of the utility owned renewable generation. Since full operation began, the two solar PV facilities have operated largely as expected; however, the solar thermal facility has experienced multiple outages which have hindered its performance. In FPL's 2016 TYSP, FPL included that the Desoto and Space Coast solar facilities contributed approximately 46 percent and 32 percent, respectively, of the system's installed capacity to summer peak demand. No contribution to winter peak demand as determined from either facility.

Hydroelectric units at two sites, one owned by the City of Tallahassee Utilities, and one operated by the federal government, supply 63 MW of renewable capacity. Due to operational constraints, the City of Tallahassee does not consider its 12.3 MW of hydroelectric generation firm. Because of Florida's geography, however, new hydroelectric power generation is largely limited.

Planned Renewable Resources

Florida's utilities plan to construct or purchase an additional 2,005 MW of renewable generation over the 10-year planning period, an increase from last year's estimated 1,566 MW projections. Figure 11 below summarizes the existing and projected renewable capacity by generation type. Solar generation is projected to have the greatest increase over the planning horizon.

Figure 11: State of Florida - Current and Projected Renewable Resources[4]



Source: 2016 FRCC Load & Resource Plan, TYSP Utilities Data Responses

Of the 2,005 MW of planned renewable capacity, 365 MW is projected to be from firm resources with 124 MW of that firm amount coming from solar generation. The projected firm capacity additions are from a combination of renewable contracts with non-utility generators, primarily biomass, and several utility-owned solar facilities. The remaining planned capacity from renewable resources is projected to be from non-firm resources.

For some existing renewable facilities, contracts for firm capacity are projected to expire within the 10-year planning horizon. If new contracts are signed in the future to replace those that expire, these resources will once again be included in the state's capacity mix to serve future

[4]JEA and Gulf's wind resources are not present in-state.

demand. If these contracts are not extended, the renewable facilities could still deliver energy on an as-available basis.

As noted above, solar generation is anticipated to increase significantly over the 10-year period, with a total of 1,586 MW to be installed. This consists of 1,102 MW of utility-owned solar, 184 MW of contracted solar and 300 MW of as-available energy contract solar facilities. Table 8 below lists some of the utility-scale (greater than 10 MW) solar installations with in-service dates within the planning period.

Gulf has entered into purchase power agreements linked to 272 MW of wind energy produced by facilities located in Oklahoma. While the energy from the facilities may not be delivered to Gulf's system, the renewable attributes for their output are retained by the utility for the benefit of Gulf's customers.

Table 8: TYSP Utilities - Planned Solar Installations

Year	Utility	Facility Name	Type	Capacity (MW)
2016	FPL	Babcock Solar Energy Center	Utility Owned	74.5
2016	FPL	Citrus Solar Energy Center	Utility Owned	74.5
2016	FPL	Manatee Solar	Utility Owned	74.5
2016	OUC	Stanton Solar Phase 2	Purchased	12
			2016 Subtotal	**235.5**
2017	GULF	Gulf Coast Solar Center I Eglin	Purchased	30
2017	GULF	Gulf Coast Solar Center II Holley	Purchased	40
2017	GULF	Gulf Coast Solar Center III Saufley	Purchased	50
2017	DEF	Solar 3	Utility Owned	10
2017	DEF	Solar 4	Utility Owned	10
2017	TAL	Airport 1	Purchased	20
2017	TECO	Big Bend	Utility Owned	18
			2017 Subtotal	**178**
2018	DEF	Solar 5	Utility Owned	10
			2018 Subtotal	**10**
2019	DEF	Solar 6&7	Utility Owned	50
			2019 Subtotal	**50**
2020	DEF	Solar 8 & 9	Utility Owned	130
2020	FPL	Unsited Projects	Utility Owned	300
			2020 Subtotal	**430**
2021	DEF	Solar 10	Utility Owned	35
			2021 Subtotal	**35**
2022	DEF	Solar 11	Utility Owned	50
			2022 Subtotal	**50**
2023	DEF	Solar 12	Utility Owned	75
			2023 Subtotal	**75**
2024	DEF	Solar 13 & 14	Utility Owned	125
			2024 Subtotal	**125**
2025	DEF	Solar 15	Utility Owned	50
			2025 Subtotal	**50**
TBD	DEF	Blue Chip Energy Lake Mary	Purchased	10
TBD	DEF	Blue Chip Energy Sorrento	Purchased	40
TBD	DEF	National Solar Gadsden	Purchased	50
TBD	DEF	National Solar Hardee	Purchased	50
TBD	DEF	National Solar Suwannee	Purchased	50
TBD	DEF	National Solar Highlands	Purchased	50
TBD	DEF	National Solar Osceola	Purchased	50
			TBD Subtotal	**300**

Source: 2016 FRCC Load & Resource Plan, TYSP Utilities Data Responses

Renewable Outlook

Florida’s renewable generation is projected to increase over the planning period. Some utilities are including a portion of solar capacity as a firm resource for reliability considerations. Reasons given for these additions are the continued reduction in price of solar facilities, availability of utility property with access to the grid, and actual performance data from FPL’s pilot program. If these conditions remain, the cost-effective forms of renewable generation will continue to improve the state’s fuel diversity and reduce dependence on fossil fuels.

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Traditional Generation

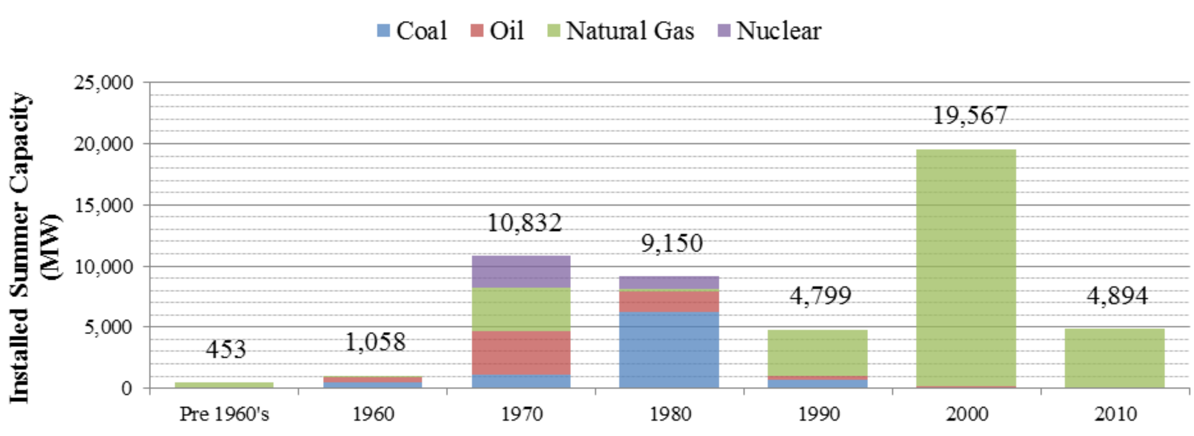
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and turbine generators, that have been added to Florida's electric grid over the last several decades. Due to forecasted increases in peak demand, further traditional resources are anticipated over the planning period.

Florida's electric utilities have historically relied upon several different fuel types to serve customer load. Previous to the oil embargo, Florida used oil-fired generation as its primary source of electricity until the increase in oil prices made this undesirable. Since that time, Florida's electric utilities have sought a variety of other fuel sources to diversify the state's generation fleet and more reliably and affordably serve customers. Numerous factors, including swings in fuel prices, availability, environmental concerns, and other factors have resulted in a variety of capacity on Florida's electric grid. Solid fuels, such as coal and nuclear, increased during the shift away from oil-fired generation, and more recently natural gas has emerged as the dominant fuel type in Florida.

Existing Generation

Florida's generating fleet includes incremental new additions to a historic base fleet, with units retiring as they become uneconomical to operate or maintain. Currently, Florida's existing capacity ranges greatly in age and fuel type, and legacy investments continue. The weighted average age of Florida's generating units is 23 years. While the original commercial in-service date may be in excess of 60 years for some units, they are constantly maintained as necessary in order to ensure safe and reliable operation, including uprates from existing capacity, which may have been added after the original in-service date. Figure 12 below illustrates the decade current operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

Figure 12: State of Florida - Electric Utility Installed Capacity by Decade



Source: 2016 FRCC Load & Resource Plan

The existing generating fleet will be impacted by several events over the planning period. New and proposed environmental regulations may require changes in unit dispatch, fuel switching, or installation of pollution control equipment which may reduce net capacity. Modernizations will allow more efficient resources to replace older generation, while potentially reusing power plant assets such as transmission and other facilities, switching to more economic fuel types, or uprates at existing facilities to improve power output. Lastly, retirements of units which can no longer be economically operated and maintained or meet environmental requirements will reduce the existing generation.

Impact of EPA Rules

In addition to maintaining a fuel efficient and diverse fleet, Florida's utilities must also comply with environmental requirements that impose incremental costs or operational constraints. During the planning period, six EPA rules were anticipated to affect electric generation in Florida:

- Carbon Pollution Emissions Standards for New, Modified and Reconstructed Secondary Sources: Electric Utility Generating Units - Sets carbon dioxide emissions limits for new, modified or reconstructed electric generators. These limits vary by type of fuel (coal or natural gas). New units are those built after January 18, 2014. Units that undergo modifications or reconstructions after June 18, 2014, that materially alter their air emissions are subject to the specified limits. This rule has been appealed.

- Carbon Pollution Emission Guideline for Existing Electric Generating Units (Clean Power Plan) - Requires each state to submit a plan to EPA that outlines how the state's existing electric generation fleet over 25 megawatts will meet a series of goals, in terms of pounds of carbon dioxide emitted per generated megawatt-hour, to reduce the state's carbon dioxide emissions. The guidelines include increased use of renewable generation and decreased use of coal-fired generation by 2030. This rule has been stayed pending an appeal review.

- Mercury and Air Toxics Standards (MATS) - Sets limits for air emissions from existing and new coal- and oil-fired electric generators with a capacity greater than 25 megawatts. Covered emissions include: mercury and other metals, acid gases, and organic air toxics for all generators, as well as particulate matter, sulfur dioxide, and nitrogen oxide from new and modified coal and oil units.

- Cross-State Air Pollution Rule (CSAPR) - Requires certain states to reduce air emissions that contribute to ozone and/or fine particulate pollution in other states. The rule applies to all fossil-fueled (i.e., coal, oil, and natural gas) electric generators with a capacity over 25 megawatts within the upwind states. Originally, the Rule included Florida, however, the final Rule, issued September 7, 2016, removes North Carolina, South Carolina, and Florida from the program because modeling for the final Rule indicates that these states do not contribute significantly to ozone air quality problems in downwind states.

- Cooling Water Intake Structures (CWIS) - Sets impingement standards to reduce harm to aquatic wildlife pinned against cooling water intake structures at electric generating facilities. All electric generators that use state or federal waters for cooling with an intake velocity of at least two million gallons per day must meet impingement standards. Generating units with higher intake velocity may have additional requirements to reduce the damage to aquatic wildlife due to entrapment in the cooling water system.

- Coal Combustion Residuals (CCR) - Requires liners and ground monitoring to be installed on new landfills in which coal ash is deposited.

Each utility will need to evaluate whether these additional costs or operational limitations allow the continued economic operation of each affected unit, and whether installation of emissions control equipment, fuel switching, or retirement is the proper course of action.

Modernization and Efficiency Improvements

Modernizations involve removing existing generator units that may no longer be economical to operate, such as oil-fired steam units, and reusing the power plant site's transmission or fuel handling facilities with a new set of generating units. The modernization of existing plant sites, allows for significant improvement in both performance and emissions, typically at a lower price than new construction at a greenfield site. Not all sites are candidates for modernization due to site layout and other concerns, and to minimize rate impacts, modernization of existing units should be considered along with new construction at greenfield sites.

The Commission has previously granted determinations of need for several conversations of oil-fired steam units to natural gas-fired combined cycle units, including FPL's Cape Canaveral, Riviera, and Port Everglades power plants. DEF has also conducted a conversion of its Bartow power plant, but this did not require a determination of need from the Commission.

Utilities also plan several efficiency improvements to existing generating units. For example, the conversion of existing simple cycle combustion turbines into a combined cycle unit, which captures the waste heat and uses it to generate additional electricity using a steam turbine. The Commission has granted a determination of need for the conversion of TECO's Polk Units 2 through 5 to a single combined cycle unit.[5] FPL plans on upgrading its existing combined cycle fleet by improving the performance of the integrated combustion turbines at many of its current and planned power plants. By 2018, DEF plans to increase the summer capacity rating at the Hines Energy Center through the installation of Inlet Chilling.

Planned Retirements

Power plant retirements occur when the electric utility is unable to economically operate or maintain a generating unit due to environmental, economic, or technical concerns. Table 9 below lists the 4,610 MW of existing generation that is scheduled to be retired during the planning period, a majority of which are natural gas-fired peaking units. Approximately 1,160 MW of the planned retirements are three dozen small peaking units at two power plant sites operated by FPL.

[5] Order No. PSC-13-0014-FOF-EI, issued January 8, 2013, in Docket No. 120234-EI, *In re: Petition to determine need for Polk 2-5 combined cycle conversion, by Tampa Electric Company.*

Table 9: State of Florida - Electric Generating Units to be Retired

Year	Utility Name	Plant Name & Unit Number	Unit Type	Fuel Type	Net Capacity (MW)
					Sum
2016	DEF	G. E. Turner P1 - P4	CT	Distillate Fuel Oil	132.0
2016	GPC	Lansing Smith 2	Steam	Coal	0.0
2016	FPL	Turkey Point 1	Steam	Residual Fuel Oil	396.0
2016	DEF	Rio Pinar 1	CT	Distillate Fuel Oil	12.0
2016	FPL	Ft. Myers 1 - 10	CT	Distillate Fuel Oil	540.0
2016	FPL	Lauderdale 1 - 22	CT	Natural Gas	754.0
2016	FPL	Port Everglades 1 - 12	CT	Natural Gas	408.0
		2016 Subtotal			**2,242.0**
2017	DEF	Suwannee River 1 - 2	Steam	Natural Gas	57.0
2017	FPL	Cedar Bay	Steam	Coal	250.0
2017	TAL	Hopkins GT1	CT	Natural Gas	12.0
2017	TAL	Purdom GT1 & GT2	CT	Natural Gas	20.0
		2017 Subtotal			**339.0**
2018	DEF	Crystal River 1 & 2	Steam	Coal	740.0
2018	DEF	Suwannee River 3	Steam	Natural Gas	71.0
2018	GPC	Pea Ridge 1 - 3	CT	Natural Gas	12.0
2018	TAL	Hopkins GT2	CT	Natural Gas	24.0
		2018 Subtotal			**847.0**
2019	JEA	Northside 3 [Reserve Storage]	Steam	Natural Gas	524.0
		2019 Subtotal			**524.0**
2020	DEF	Higgins 1 - 4	CT	Natural Gas	459.0
2020	DEF	Avon Park 1	CT	Natural Gas	24.0
2020	DEF	Avon Park 2	CT	Distillate Fuel Oil	24.0
		2020 Subtotal			**507.0**
2021	TAL	Hopkins 1	Steam	Natural Gas	76.0
		2021 Subtotal			**76.0**
2022	GRU	Deerhaven FS01	Steam	Natural Gas	75.0
		2022 Subtotal			**75.0**
		Total Retirements			**4,610**

Source: 2016 Ten-Year Site Plans

A notable retirement is DEF's Crystal River Units 1 and 2. Originally scheduled to retire in 2016, the retirement of these units have been delayed until 2018. This delay is due in part to a temporary averaging of emissions across the existing four units at the Crystal River site to meet environmental regulations, as Crystal River Units 4 and 5 have pollution controls installed.

Some retired units will continue operation in a different form. FPL intends to retire Turkey Point 1, a large oil-fired steam unit, and convert it to a synchronous condenser to support the transmission system and provide voltage regulation. FPL previously converted Turkey Point 2 to operate as a synchronous condenser.

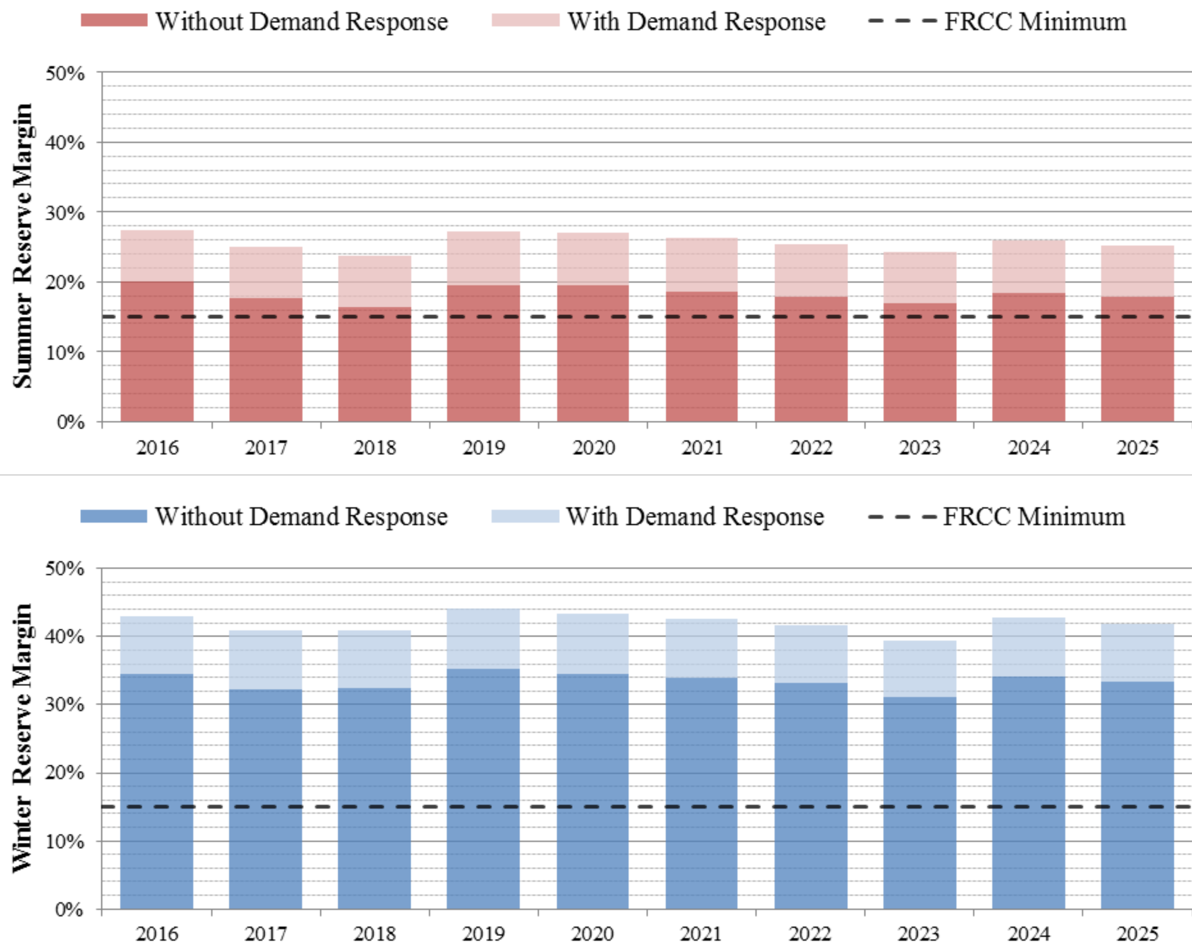
Reliability Requirements

Florida's electric utilities are expected to have enough generating assets available at the time of peak demand to meet forecasted customer demand. If utilities only had sufficient generating capacity to meet forecasted peak demand, then potential instabilities could occur if customer demand exceeds the forecast, or if generating units are unavailable due to maintenance or forced outages. To address these circumstances, utilities are required to maintain additional planned generating capacity above the forecast customer demand, referred to as the reserve margin.

Electric utilities within the Florida Reliability Coordinating Council region, which consists of Peninsular Florida, must maintain a minimum of 15 percent reserve margin for planning purposes. Certain utilities have elected to have a higher reserve margin, either on an annual or seasonal basis. The three largest reporting electric utilities, FPL, DEF, and TECO, are party to a stipulation approved by the Commission that utilizes a 20 percent reserve margin for planning.

While Florida's electric utilities are separately responsible for maintaining an adequate planning reserve margin, a statewide view illustrates the degree to which capacity may be available for purchases during periods of high demand or unit outages. Figure 13 below is a projection of the statewide seasonal reserve margin including all proposed power plants.

Figure 13: State of Florida - Projected Reserve Margin by Season



Source: 2016 FRCC Load & Resource Plan

Role of Demand Response in Reserve Margin

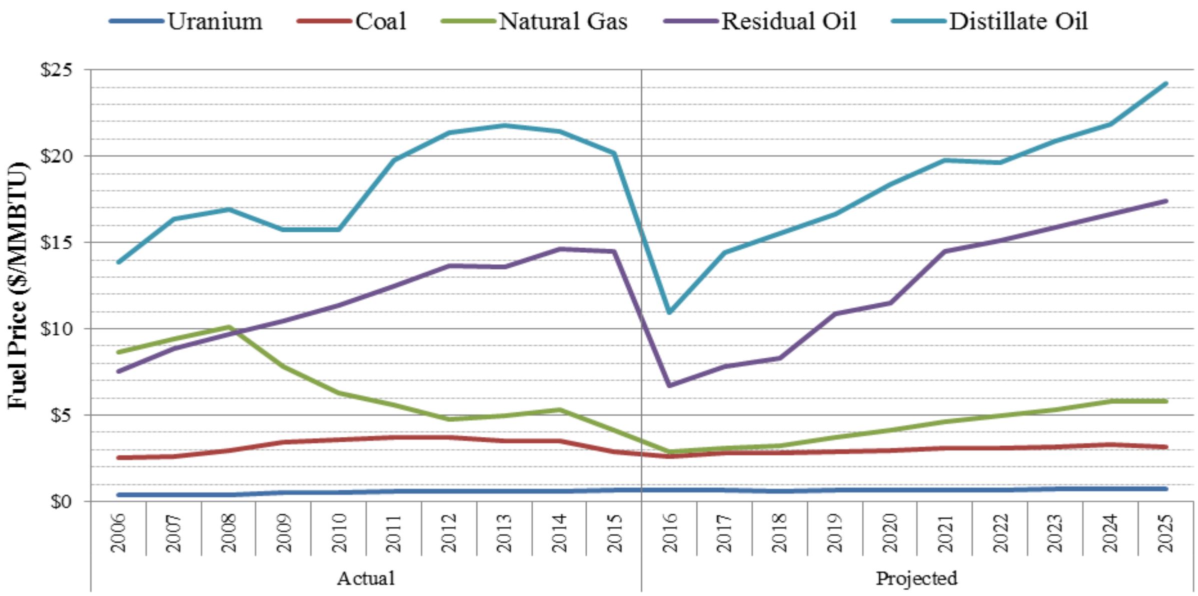
The Commission also considers the planning reserve margin without demand response. As illustrated above in Figure 13, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin without activation of demand response. Demand response activation increases the reserve margin in summer by 7.5 percent on average, and represents 25 percent of the planning reserve margin.

Demand response participants receive discounted rates or credits regardless of activation, with these costs recovered from all ratepayers. Because of the voluntary nature of demand response, a concern exists that a heavy reliance upon this resource would make participants eschew the discounted rates or credits for firm service. For interruptible customers, participants must provide notice that they intend to leave the demand response program, with a notice period of three or more years being typical. For load management participants, usually residential or small commercial customers, no advanced notice is typically required to leave. Historically, demand response participants have rarely been called upon during the peak hour, but are more frequently called upon during off-peak periods due to unusual weather conditions.

Fuel Price Forecast

Fuel price is an important economic factor affecting the dispatch of the existing generating fleet and the selection of new generating units. In general, the capital cost of a power plant is inversely proportional to the cost of the fuel used to generate electricity from that unit. The major fuels consumed by Florida's electric utilities are natural gas, coal, uranium, and oil. Figure 14 below illustrates the weighted average fuel price history and forecasts for the reporting electric utilities. While there has been a recent projected decrease in fuel oil prices, it remains the most expensive fuel and suitable primarily for backup and peaking purposes only.

Figure 14: TYSP Utilities - Average Reporting Electric Utility Fuel Price

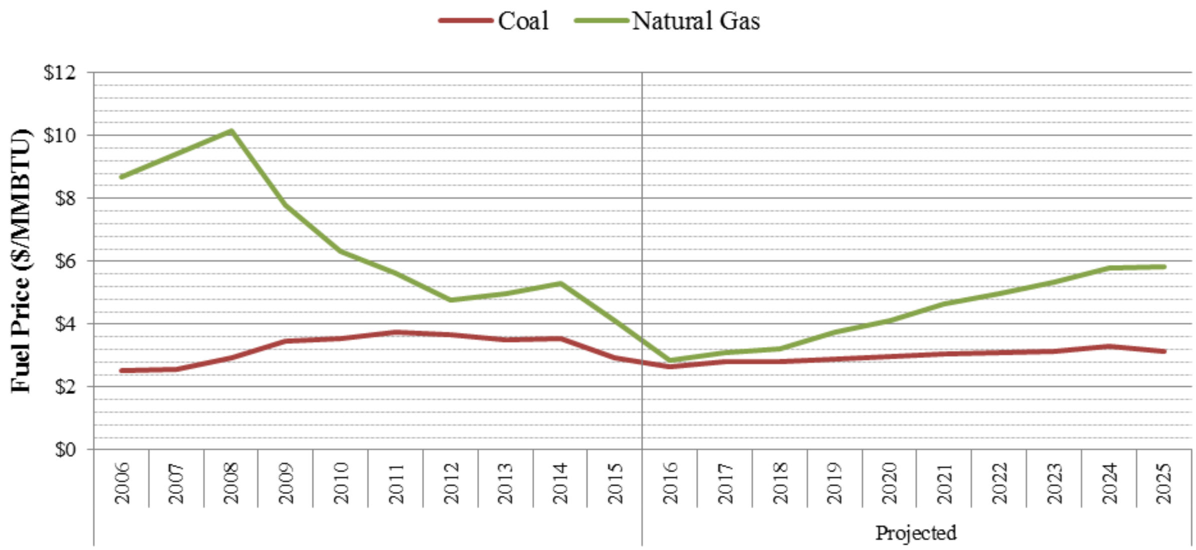


Source: TYSP Utilities Data Responses

From 2003 to 2005, the price of natural gas was substantially higher than utilities had forecast. This natural gas price volatility led to concern regarding escalating customer bills and an expectation that natural gas prices would remain high. As a result, Florida's electric utilities began making plans to build coal-fired units rather than continuing to increase the reliance on natural gas. Concerns regarding potential environmental regulations, and other projected costs, lead to this coal-fired generation to not materialize. Traditionally, coal was the lowest cost fuel besides uranium and was dispatched before most natural gas-fired units. While natural gas-fired units have the advantage of a lower heat rate, and therefore consume less units of thermal energy per unit of electrical energy produced, the fuel price differential allowed coal to remain dominant until 2008.

As shown below in Figure 15, the price of natural gas declined rapidly after the financial crisis, and is forecasted to remain at historically low levels. The smaller differential and higher efficiency of natural gas has shifted the dispatch order, with natural gas units displacing some coal units. The trend has also encouraged utilities to modify existing units to be capable of burning natural gas, either as a starter fuel, supplemental fuel, or primary fuel.

Figure 15: TYSP Utilities - Fuel Price Comparison for Coal and Natural Gas

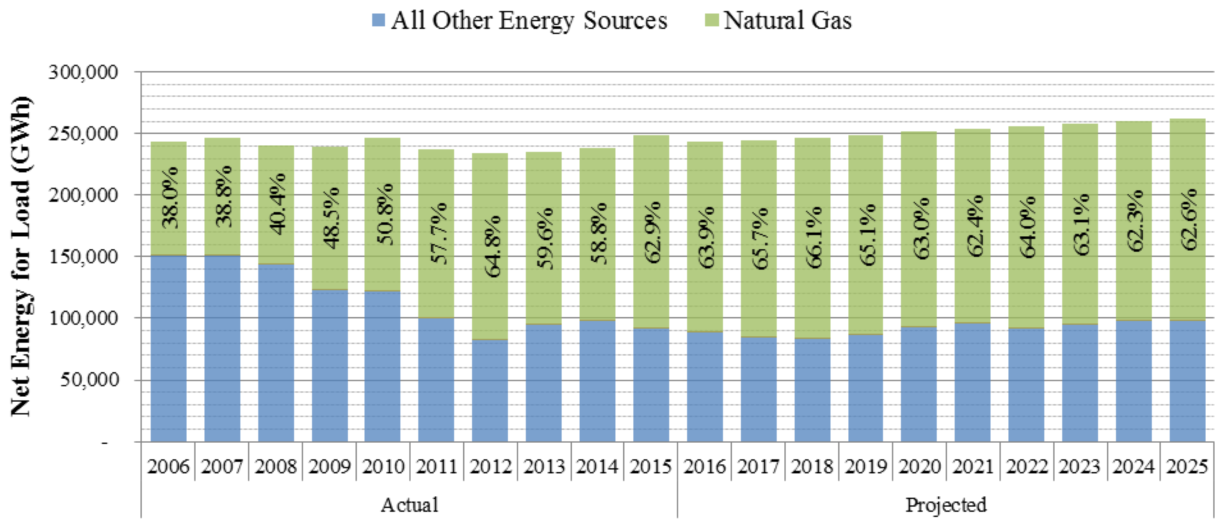


Source: TYSP Utilities Data Responses

Fuel Diversity

Natural gas has risen to become the dominant fuel in Florida within the last 10 years, displacing coal, and since 2010 has generated more net energy for load than all other fuels combined. As Figure 16 below illustrates, natural gas is the source of approximately 63 percent of electric energy consumed in Florida, down from its peak in 2012 of 65 percent. The 2012 spike in usage was associated with extended outages at FPL’s nuclear plants for uprates. Natural gas generation is anticipated to remain somewhat steady at its current level until the end of the planning period.

Figure 16: State of Florida - Natural Gas Contribution to Energy Consumption

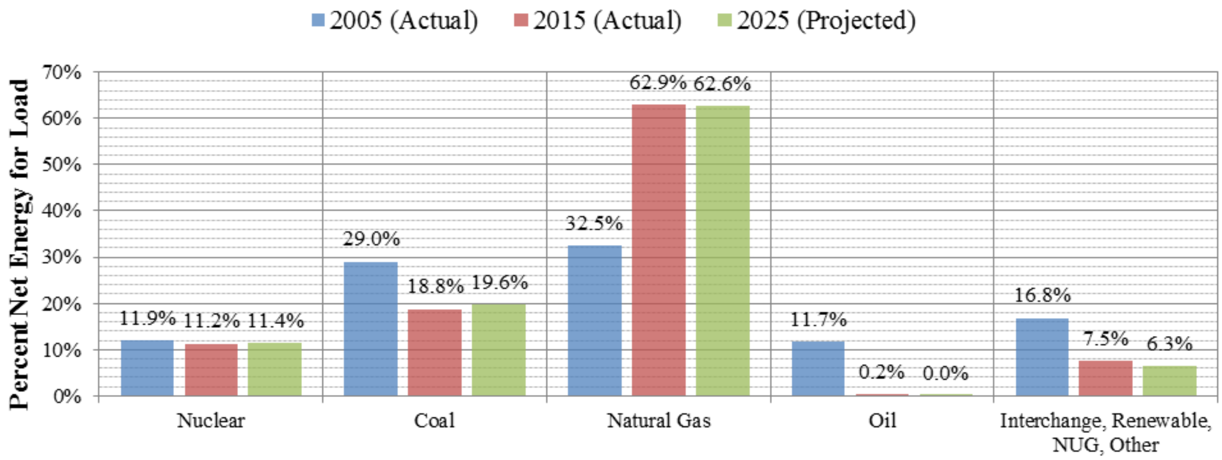


Source: 2006-2016 FRCC Load & Resource Plans

Because a balanced fuel supply can enhance system reliability and mitigate the effects of volatility in fuel price fluctuations, it is important that utilities have a level of flexibility in their generation mix. Maintaining fuel diversity on Florida's system faces several difficulties. Existing coal units will require additional emissions control equipment leading to reduced output, or retirement if the emissions controls are uneconomic to install or operate. New solid fuel generating units such as nuclear and coal have long lead times and high capital costs. New coal units face challenges relating to new environmental compliance requirements, making it unlikely they could be permitted without novel emissions control technology.

Figure 17 below shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2005 and 2015, and forecast year 2025. Oil has declined significantly, with its uses reduced to start-up fuel, peaking, and back-up for dual-fuel units in case of a fuel outage. Nuclear generation was reduced beginning in 2010 by the outage and eventual retirement of Crystal River 3 and extended outages for uprates at FPL's St. Lucie and Turkey Point power plants. The resulting capacity leaves Florida's contribution from nuclear approximately the same even with the loss of one of five nuclear units. While coal generation has declined somewhat, it is expected to rebound slightly and remain at a plateau throughout the planning period. Natural gas has been the primary fuel used to meet the growth energy consumption, and this trend is anticipated to continue throughout the planning period.

Figure 17: State of Florida - Historic and Forecast Fuel Consumption



Source: 2006-2016 FRCC Load & Resource Plans

Based on 2014 Energy Information Administration (EIA) data, Florida ranks fourth place in terms of the total volume natural gas consumption compared to the rest of the United States. For volume of natural gas consumed for electric generation, Florida ranks second, behind Texas.

Florida's percentage of natural gas consumption for electric generation is the highest in the country, with 90 percent of all natural gas consumed in the state for electricity. However, these figures do not consider population. On a per capita basis, Florida's total consumption of natural gas ranks thirtieth, while natural gas consumption for electricity ranks sixth. Natural gas is not used as a heating fuel in most of Florida's homes and businesses, which rely instead upon electricity that is increasingly being generated by natural gas. This leads to Florida's per capita consumption of natural gas being 15 percent less than the national average, but twice the national average per capita consumption of natural gas for electricity. As Florida has very little natural gas production and no gas storage capacity, the State is reliant upon out-of-state production and storage to satisfy the growing electric demands of the state.

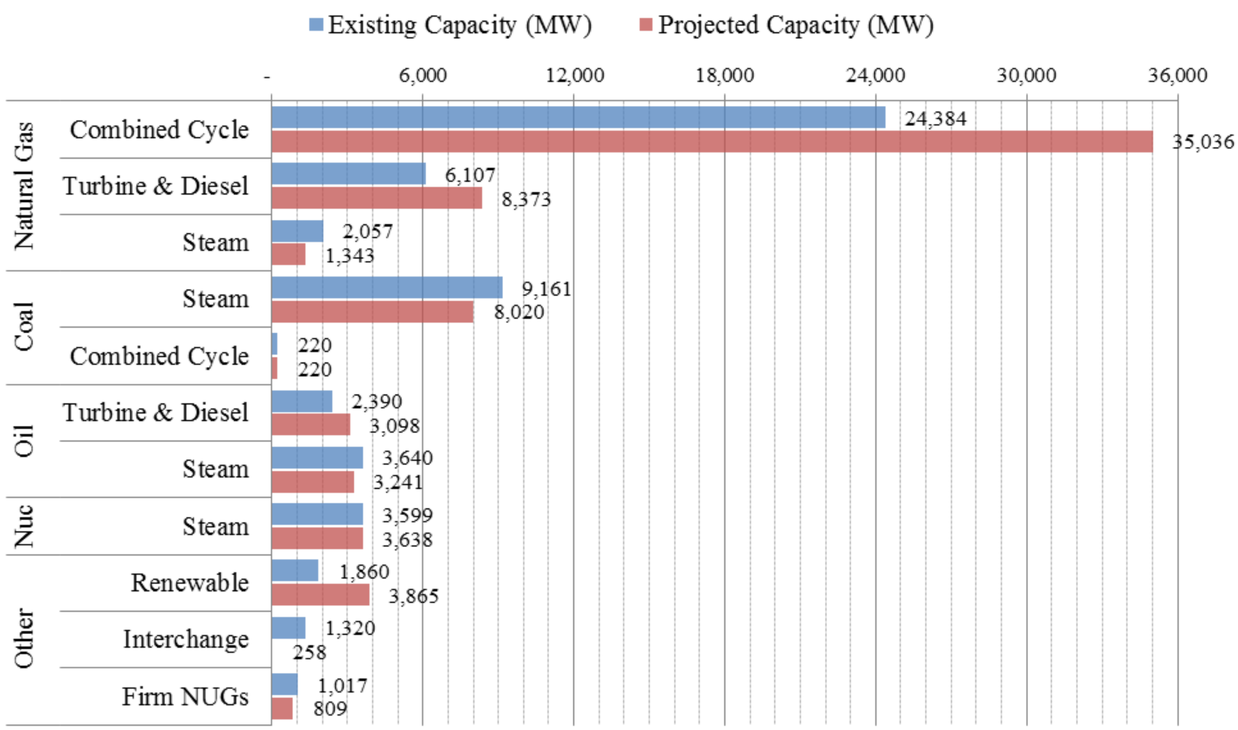
New Generation Planned

Current demand and energy forecasts continue to indicate that in spite of increased levels of conservation, energy efficiency, renewable generation, and existing traditional generation resources, the need for additional generating capacity still exists. While reductions in demand have been significant, the total demand for electricity is expected to increase, making the addition of traditional generating units necessary to satisfy reliability requirements and provide sufficient electric energy to Florida's consumers. Because any capacity addition has certain economic impacts based on the capital required for the project, and due to increasing environmental concerns relating to solid fuel-fired generating units, Florida's utilities must carefully weigh the factors involved in selecting a supply-side resource for future traditional generation projects.

In addition to traditional economic analyses, utilities also consider several strategic factors, such as fuel availability, generation mix, and environmental compliance prior to selecting a new supply-side resource. Limited supplies, access to water or rail delivery points, pipeline capacity, water supply and consumption, land area limitations, cost of environmental controls, and fluctuating fuel costs are all important considerations to the utilities' IRP process.

Figure 18 below illustrates the present and future aggregate capacity mix. The capacity values in Figure 18 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2016 Ten-Year Site Plans and the FRCC's 2016 Load and Resource Plan.

Figure 18: State of Florida - Current and Projected Installed Capacity by Fuel



Source: 2016 FRCC Load & Resource Plan and TYSP Utilities Data Responses

New Power Plants by Fuel Type

Nuclear

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. FPL has two nuclear projects at Turkey Point that were moved out of the planning horizon for the 2016 TYSP. FPL had previously uprated its existing four nuclear generating units, with the last uprate completed in early 2013. DEF obtained a combined operating license from the Nuclear Regulatory Commission, for two nuclear units, Levy 1 and 2, but has not included them in their planning at this time.

Natural Gas

Excluding renewable and nuclear generation uprates, all remaining new power plants are natural gas-fired combustion turbines or combined cycle units. Combustion turbines run in simple cycle mode as peaking units represent the third most abundant type of generating capacity, behind only coal-fired steam generation. Because combustion turbines are not a form of steam generation, unless part of a combined cycle unit, they do not require siting under the Power Plant Siting Act. Table 10 below summarizes the approximately 12,127 MW of proposed new natural gas-fired generation included in the 2016 Ten-Year Site Plans.

Table 10: State of Florida - Planned Natural Gas Units

In-Service Year	Utility Name	Plant Name & Unit Number	Fuel & Unit Type	Net Capacity (MW)	Notes
Previously Approved New Units					
2016	FPL	Port Everglades Modern.	Natural Gas CC	1,237	Docket No. 110309-EI
2017	TEC	Polk CC Conversion	Natural Gas CC	459	Docket No. 120234-EI
2018	DEF	Citrus	Natural Gas CC	1,640	Docket No. 140110-EI
2019	FPL	Okeechobee Energy Center	Natural Gas CC	1,622	Docket No. 150196-EI
Previously Approved New Units Subtotal				**4,958**	
New Units Requiring Approval					
2021	SEC	Unnamed CC	Natural Gas CC	649	
2023	OUC	Unspecified CC	Natural Gas CC	300	
2024	FPL	Combined Cycle Unit	Natural Gas CC	1,622	
New Units Requiring Approval Subtotal				**2,571**	
New Units Not Requiring PPSA Approval					
2016	FPL	Ft. Myers 4A & 4B	Natural Gas CT	462	
2016	FPL	Lauderdale 6A through 6E	Natural Gas CT	1,155	
2018	GRU	South Energy Center	Natural Gas CC	8	
2018	TAL	Sub 12 DG	Natural Gas CT	18	
2021	TAL	Hopkins	Natural Gas CT	37	
2021	TAL	Purdom	Natural Gas CT	37	
2021	TEC	Future CT 1	Natural Gas CT	204	
2022	SEC	Unnamed CT 1	Natural Gas CT	201	
2023	SEC	Unnamed CT 2	Natural Gas CT	201	
2023	GPC	Combustion Turbines	Natural Gas CT	654	
2023	TEC	Future CT 2	Natural Gas CT	204	
2024	SEC	Unnamed CT 3 & CT 4	Natural Gas CT	402	
2024	DEF	Unknown P1 - P4	Natural Gas CT	812	
2025	DEF	Unknown P5	Natural Gas CT	203	
New Units Not Requiring PPSA Approval Subtotal				**4,598**	
Total Planned Natural Gas Capacity				**12,127**	

Source: 2016 Ten-Year Site Plans

Commission's Authority over Siting

The Commission has been given exclusive jurisdiction to determine the need for new electric power plants by the Legislature, through the Electrical Power Plant Siting Act (PPSA), contained in Sections 403.501 through 403.518, F.S. Any proposed steam or solar generating unit greater than 75 MW requires a certification under the PPSA. Upon receipt of a determination of need, the electric utility would then seek approval from the Florida Department of Environmental Protection, which addresses land use and environmental concerns. Finally, the Governor and

Cabinet, sitting as the Siting Board, ultimately must approve or deny the overall certification of a proposed power plant. As shown in Table 10 above, there is approximately 2,571 MW of generation that would require certification under the PPSA in the years 2021–2024.

Transmission

As generation capacity increases, the transmission system must grow accordingly to maintain the capability of delivering energy to end users. The Commission has been given broad authority pursuant to Chapter 366, F.S., to require reliability within Florida's coordinated electric grid and to ensure the planning, development, and maintenance of adequate generation, transmission, and distribution facilities within the state.

The Commission has authority over certain proposed transmission lines under the Electric Transmission Line Siting Act (TLSA), contained in Sections 403.52 through 403.5365, F.S. To require certification under Florida's TLSA, a proposed transmission line must meet the following criteria: a nominal voltage rating of at least 230 kV, crossing a county line, and a length of at least 15 miles. Proposed lines in an existing corridor are also exempt from TLSA requirements. The Commission determines the reliability need and the proposed starting and end points for lines requiring TLSA certification. The proposed corridor route is subsequently determined by the Florida Department of Environmental Protection during the certification process. Much like the PPSA, the Governor and Cabinet sitting as the Siting Board ultimately must approve or deny the overall certification of a proposed line.

Table 11 below lists all proposed transmission lines in the 2016 Ten-Year Site Plans that require TLSA certification. All planned lines have already received the approval of the Commission, either independently or as part of a PPSA determination of need.

Table 11: State of Florida - Planned Transmission Lines

Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
FPL	St Johns – Pringle	25	230	05/13/2005	04/21/2006	12/01/2018
FPL	Levee-Midway	150	500	05/28/1988	04/20/1990	06/01/2023
FPL	Duval - Raven	45	230	02/25/2016	In Progress	12/01/2019
TECO	Thonotosassa Wheeler	8.0	230	06/21/2007	08/07/2008	TBD
TECO	Wheeler to Willow Oak	17.0	230	06/21/2007	08/07/2008	TBD

Source: 2016 Ten-Year Site Plans

Utility Perspectives

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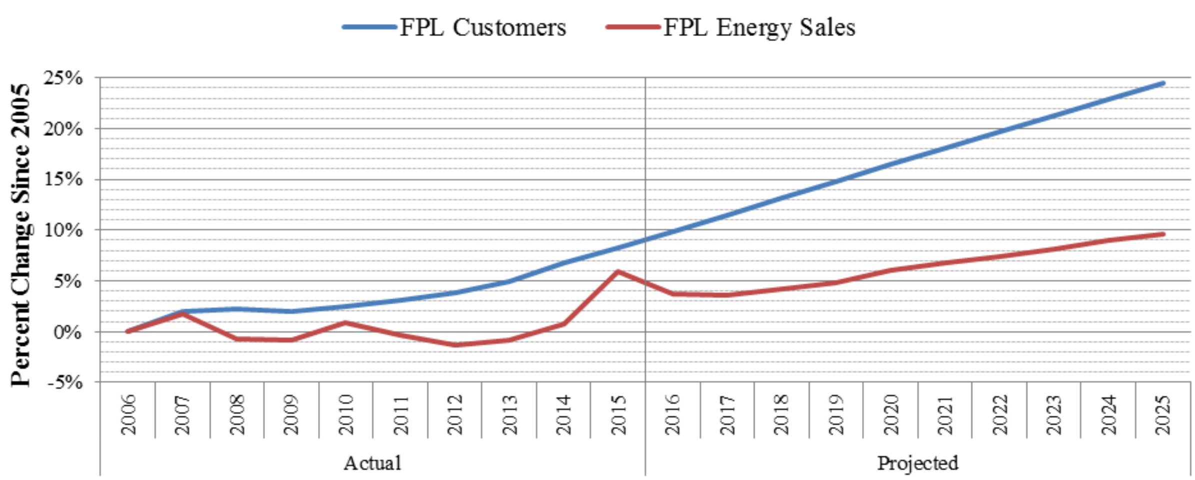
Florida Power & Light Company (FPL)

FPL is an investor-owned utility and Florida's largest electric utility. The Utility's service territory is within the FRCC region and is primarily in south Florida and along the east coast. As an investor-owned utility, the Commission has regulatory authority over all aspects of FPL's operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds FPL's 2016 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2015, FPL had approximately 4,775,382 customers and annual retail energy sales of 109,820 GWh or approximately 48.3 percent of Florida's annual retail energy sales. Figure 19 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the past 10 years, FPL's customer base has increased by 8.30 percent, while retail sales have grown by 5.94 percent. FPL exceeded its 2007 peak in 2015. FPL expects a slight decline before exceeding its 2015 peak in 2020. Since 2009, FPL has been outperforming the state average in retail energy sales growth, a trend it projects to continue into the future.

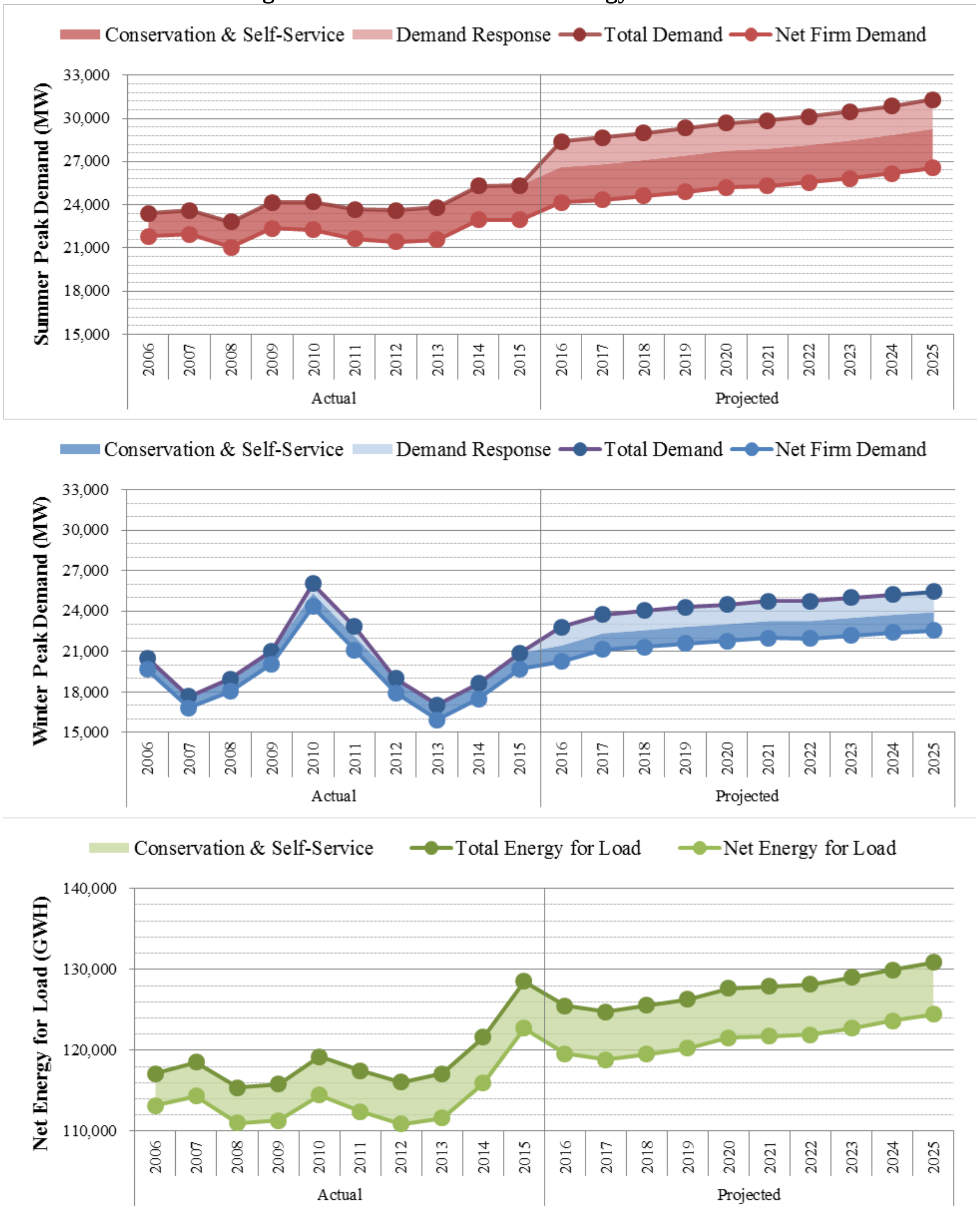
Figure 19: FPL Growth Rate



Source: 2016 Ten-Year Site Plan

The three graphs in Figure 20 below shows FPL's seasonal peak demand and net energy for load, for the historic years 2006 through 2015 and forecast years 2016 through 2025. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. Historically, demand response was not activated during the seasonal peak demand, excluding the winters of 2010 and 2011. As an investor owned utility, FPL is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2016 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Figure 20: FPL Demand and Energy Forecasts



Source: 2016 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 12 below shows FPL's actual net energy for load by fuel type for 2015, and the projected fuel mix for 2025. FPL relies primarily upon natural gas and nuclear for energy generation, making up approximately 90 percent of net energy for load.

Table 12: FPL Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	85,797	**69.9%**	87,435	**69.9%**
Coal	5,275	**4.3%**	3,388	**2.7%**
Nuclear	27,045	**22.0%**	28,871	**23.1%**
Oil	462	**0.4%**	49	**0.0%**
Renewable	157	**0.1%**	1,362	**1.1%**
Interchange	4,730	**3.9%**	0	**0.0%**
NUG & Other	-710	**-0.6%**	3,956	**3.2%**
Total	**122,757**		**125,062**	

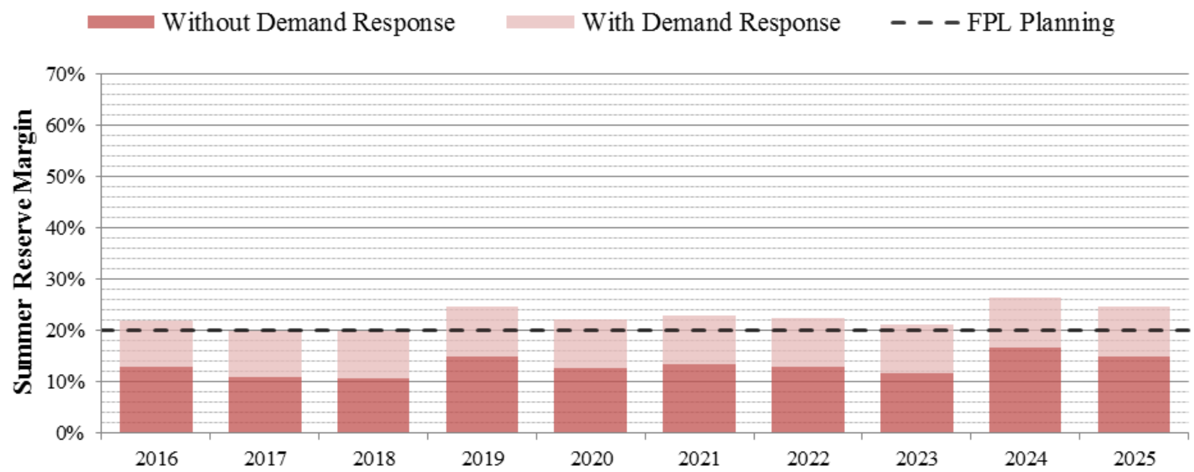
Source: 2016 Ten-Year Site Plan

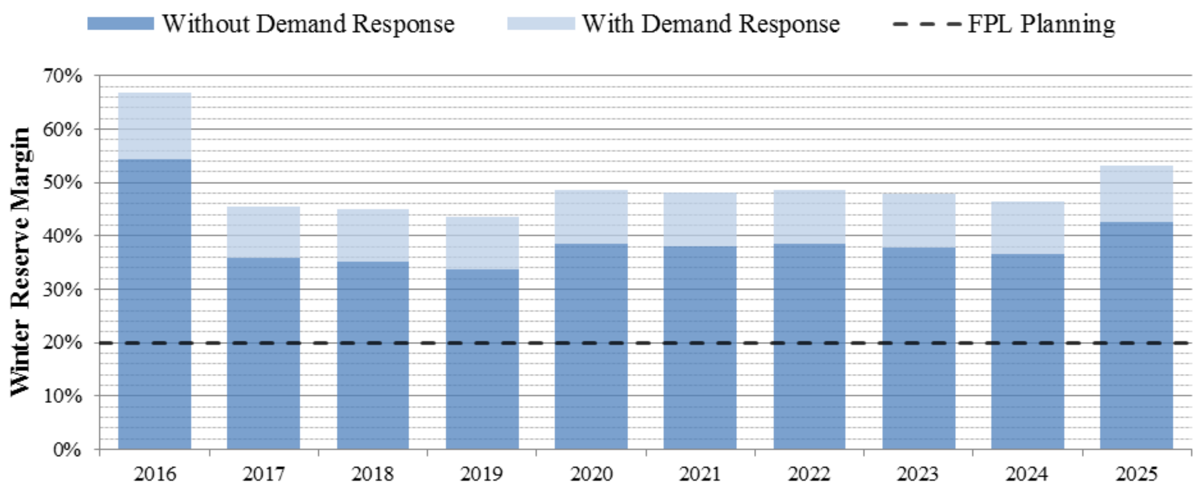
Reliability Requirements

While previously only reserve margin has been discussed, Florida's utilities use multiple indices to determine the reliability of the electric supply. An additional metric is the Loss of Load Probability (LOLP), which is a probabilistic assessment of the duration of time electric customer demand will exceed electric supply, and is measured in units of days per year. FPL uses a maximum LOLP of no more than 0.1 days per year, or approximately 1 day of outage per 10 years. Between the two reliability indices, LOLP and reserve margin, the reserve margin requirement is typically the controlling factor for the addition of capacity.

Since 1999, FPL has utilized a 20 percent planning reserve margin criterion. Figure 21 below displays the forecast planning reserve margin for FPL through the planning period for both seasons, with and without the use of demand response. As shown in the figure, FPL's generation needs are controlled by its summer peak throughout the planning period.

Figure 21: FPL Reserve Margin Forecast





Source: 2016 Ten-Year Site Plan

In addition to LOLP and the reserve margin, FPL utilizes a third reliability criterion. FPL's criterion would be to have available firm capacity 10 percent greater than the sum of customer seasonal demand, without consideration of incremental energy efficiency and all existing and incremental demand response resources. FPL refers to this as its 10 percent generation-only reserve margin. Currently, no other utility utilizes this same metric. While TECO includes a minimum supply-side contribution in its planning methodology, TECO uses a lower value of 7 percent and incremental energy efficiency is included in its calculation. FPL's generation-only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20 percent reserve margin will be realized.

While FPL does not include incremental energy efficiency resources and cumulative demand response in its resource planning for the generation-only reserve margin criterion, the Utility would remain subject to FEECA and the conservation goals established by the Commission. FPL would continue paying rebates and other incentives to participants, which are collected from all ratepayers through the Energy Conservation Cost Recovery Clause, but would not consider the potential capacity reductions of any future participation in energy efficiency or demand response programs during the 10-year planning period for planning purposes with this new reliability criterion only.

Energy efficiency, which includes installation of equipment designed to reduce peak demand and annual energy consumption, is considered a passive resource. While demand response must be activated by the utility, energy efficiency provides benefits consistently for the duration of the installation, reducing annual energy consumption, and if usage is coincident with system peak, peak demand. Customers do not remove building envelope improvements or newly installed equipment until the end of its service life for replacement.

As noted in the Statewide Perspective, the Commission does review the impact on reserve margin of demand response resources. At this time, FPL offers two types of demand response programs. The first type is interruptible and curtailable load programs, consisting of the Commercial/Industrial Load Control Program (CILC) and Commercial/Industrial Demand Reduction Rider (CDR) tariffs. The second type is load management programs, including the Residential On-Call and Business On-Call Programs. FPL utilizes load management programs on residential customers more often than commercial/industrial customers.

Generation Resources

FPL plans multiple unit retirements and additions during the planning period, as described in Table 13 below. The projected in-service dates of FPL's new planned nuclear units are now outside the 10-year planning period. FPL included the addition of three new natural gas-fired combined cycle units and also plans to partially replace its older gas turbine peaking capacity with new combustion turbine capacity at its Lauderdale and Fort Myers sites. On September 3, 2015, FPL filed a need determination with the Commission for the Okeechobee Unit which was granted on January 19, 2016.

As highlighted during the 2016 Ten-Year Site Plan Workshop, FPL's lower peak demand, natural gas, and CO2 price forecasts all have the impact of reducing the need for additional generation or reducing the cost-effectiveness of non-fossil fueled generation over the planning horizon. However, FPL's 2016 TYSP includes an additional 300 MW of solar generation capacity in 2020 that was not included in its 2015 TYSP. Since FPL's current planning assumptions suggest a reduction in the cost-effectiveness for adding solar generation, additional information may be needed to assess the reasonableness of such unit additions at this time.

Table 13: FPL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2016	FT. Myers GT 2-7,10-12	Distillate Oil Gas Turbine	486	
2016	Lauderdale GT 1-2, 4, 6-22	Natural Gas Gas Turbine	755	
2016	Port Everglades 1 - 12	Natural Gas Gas Turbine	412	
2016	Turkey Point 1	Residual Oil Steam Turbine	396	
2017	Cedar Bay 1	Coal Steam Turbine	250	
Total Retirements			**2,299**	
New Units				
2016	Babcock Solar Energy Center	Photovoltaic	75	
2016	Citrus Solar Energy Center	Photovoltaic	75	
2016	Ft. Myers 4A & 4B	Natural Gas Combustion Turbine	462	
2016	Lauderdale 6A-6E	Natural Gas Combustion Turbine	1,155	
2016	Manatee Solar Energy Center	Photovoltaic	75	
2016	Port Everglades Modern.	Natural Gas Combined Cycle	1,237	Docket No. 110309-EI
2019	Okeechobee Energy Center	Natural Gas Combined Cycle	1,633	Docket No. 150196-EI
2020	Unsited Solar	Photovoltaic	300	
2024	Unsited Unit	Natural Gas Combined Cycle	1,622	Requires PPSA
Total New Units			**6,633**	
Net Additions			**4,334**	

Source: 2016 Ten-Year Site Plan

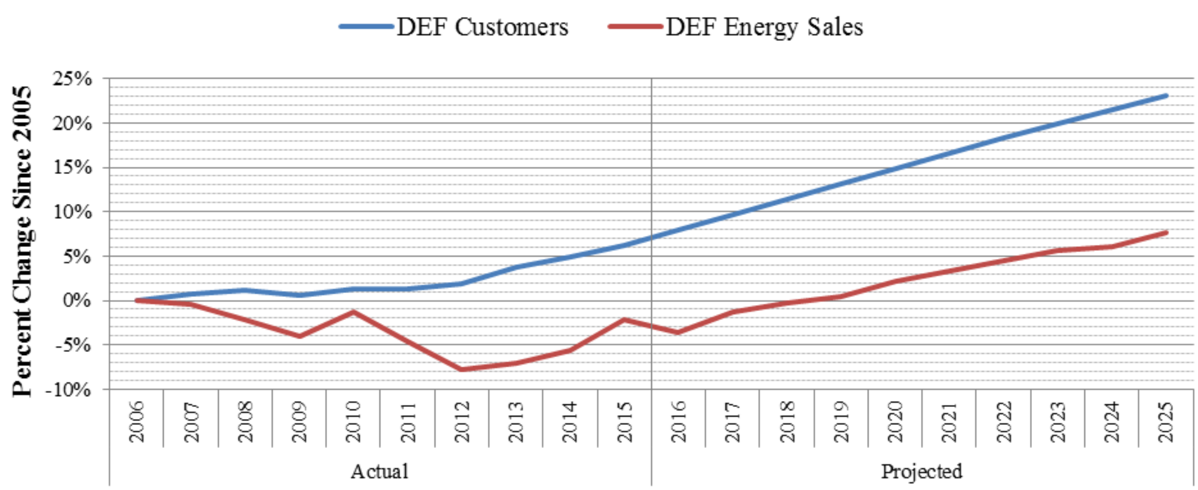
Duke Energy Florida, LLC (DEF)

DEF is an investor-owned utility and Florida's second largest electric utility. The Utility's service territory is within the FRCC region and is primarily in central and west central Florida. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds DEF's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, DEF had approximately 1,721,861 customers and annual retail energy sales of 38,553 GWh or approximately 17 percent of Florida's annual retail energy sales. Figure 22 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, DEF's customer base has increased by 6.26 percent, while retail sales have declined by 2.23 percent. As illustrated, retail energy sales are anticipated to exceed the historic 2006 peak by 2019, the same time as the state as a whole.

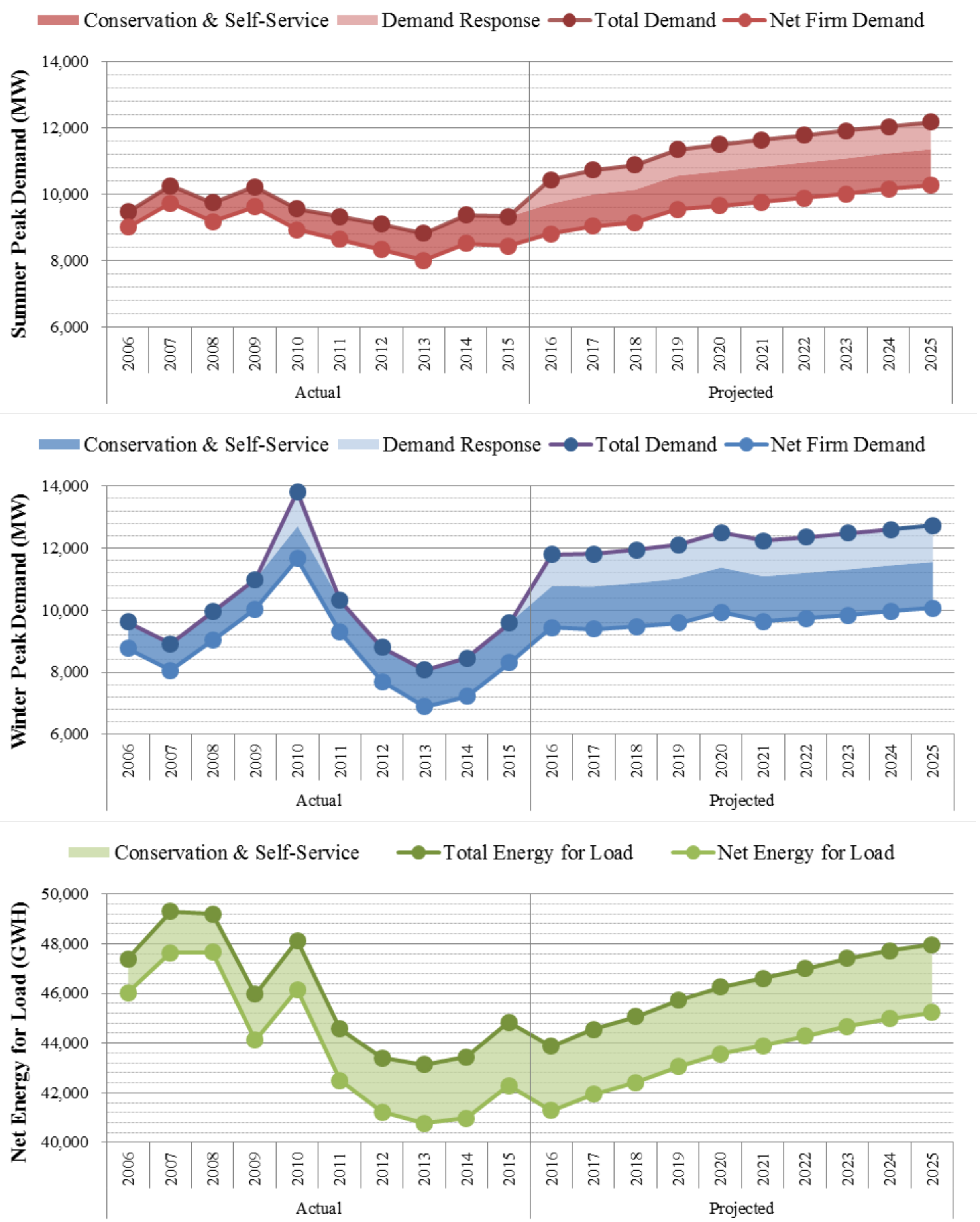
Figure 22: DEF Growth Rate



Source: 2016 Ten-Year Site Plan

The three graphs in Figure 23 below show DEF's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. These graphs include the full impact of demand-side management and assume that all available demand response resources were or will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand, excluding extreme weather events. As an investor-owned utility, DEF is subject to FEECA, and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2016 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Figure 23: DEF Demand and Energy Forecasts



Source: 2016 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 14 below shows DEF's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. DEF relies primarily upon natural gas and coal for energy generation, making up approximately 80 percent of net energy for load. DEF plans to substantially reduce coal usage over the planning period, but coal usage will be greater than all other energy types excluding natural gas.

Table 14: DEF Energy Consumption by Fuel Type

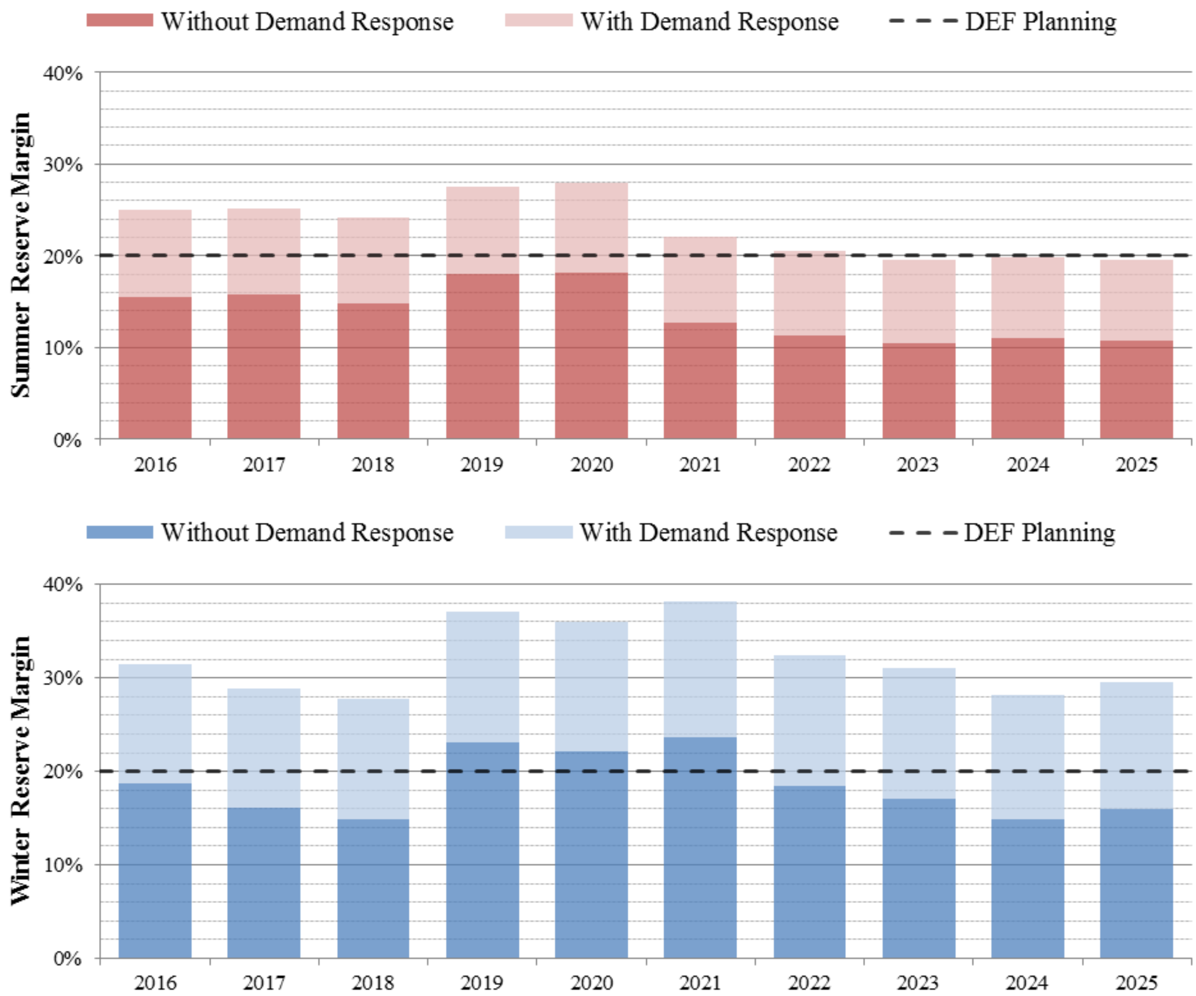
Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	25,227	**59.7%**	36,828	**81.4%**
Coal	9,718	**23.0%**	5,704	**12.6%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	73	**0.2%**	2	**0.0%**
Renewable	1,063	**2.5%**	2,243	**5.0%**
Interchange	2,390	**5.7%**	62	**0.1%**
NUG & Other	3,809	**9.0%**	389	**0.9%**
Total	**42,280**		**45,228**	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion. Figure 24 below displays the forecast planning reserve margin for DEF through the planning period for both seasons, with and without the use of demand response. As shown in the figure, DEF's generation needs are controlled by its summer peaking throughout the planning period. The Utility's summer peak percentage is projected to be slightly below its 20 percent planned reserve margin during the last three years of the planning period. The deficiency is approximately 0.5 percent which is reasonable for planning purposes.

Figure 24: DEF Reserve Margin Forecast



Source: 2016 Ten-Year Site Plan

Generation Resources

DEF plans multiple unit retirements and additions during the planning period, as described below in Table 15. DEF's 2016 Ten-Year Site Plan includes the retirement of the coal-fired Crystal River Units 1 and 2, to be replaced by a pair of natural gas-fired combined cycle units. In addition to the units discussed above, DEF includes the retirement of seven gas-fired units at multiple power plant sites. DEF's planned additions include a combined cycle facility in 2018 in Citrus County, a purchase and proposed acquisition of the Calpine Osprey Energy Combined Cycle Unit in Auburndale and five planned Combustion Turbine Units at an undesignated site(s) with four units in 2024 and one unit in 2025.

Table 15: DEF Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2016	Turner P1-2, 4	Distillate Oil Combustion Turbine	79	
2016	Suwannee River 1-3	Natural Gas Steam Turbine	128	
2016	Rio Pinar P1	Distillate Oil Combustion Turbine	12	
2018	Crystal River 1 & 2	Coal Steam Turbine	773	
2020	Avon Park P1-2	Distillate Oil Combustion Turbine	48	
2020	Higgins P1-4	Natural Gas Combustion Turbine	109	
Total Retirements			**1,149**	
New Units				
2017	Osprey CC 1	Natural Gas Combined Cycle	244	Docket No. 150043-EI
2018	Citrus	Natural Gas Combined Cycle	1,640	Docket No. 140110-EI
2018	Solar 5	Photovoltaic	10	
2019	Solar 6 & 7	Photovoltaic	50	
2020	Solar 8 & 9	Photovoltaic	130	
2021	Solar 10	Photovoltaic	35	
2022	Solar 11	Photovoltaic	50	
2023	Solar 12	Photovoltaic	75	
2024	Solar 13 & 14	Photovoltaic	125	
2024	Unknown P1 - P4	Natural Gas Combustion Turbine	849	
2025	Solar 15	Photovoltaic	50	
2025	Undesignated CT P5	Natural Gas Combustion Turbine	212	
Total New Units			**3,470**	
Net Additions			**2,321**	

Source: 2016 Ten-Year Site Plan

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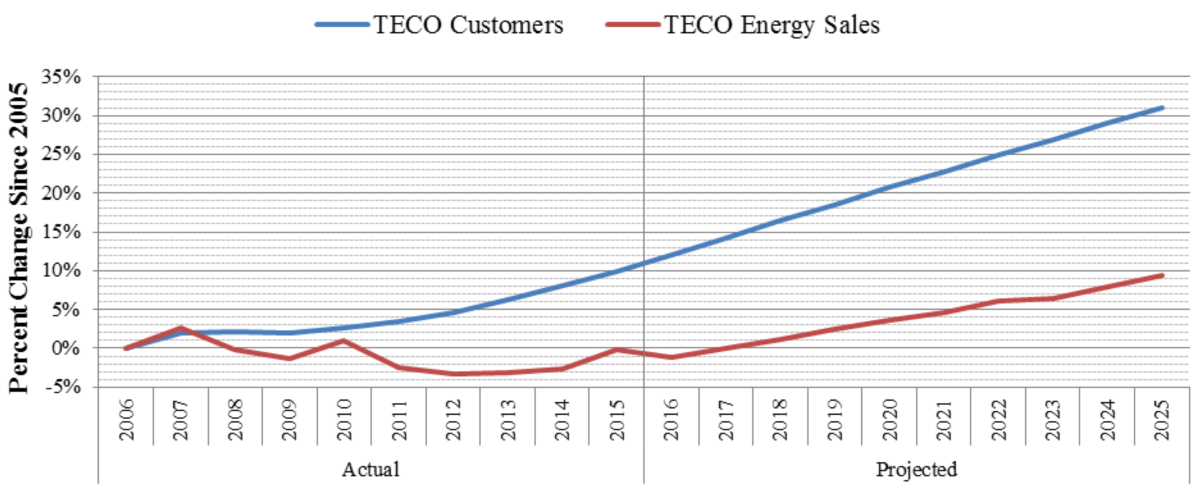
Tampa Electric Company (TECO)

TECO is an investor-owned utility and Florida's third largest electric utility. The Utility's service territory is within the FRCC region and consists primarily of the Tampa metropolitan area. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds TECO's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, TECO had approximately 718,713 customers and annual retail energy sales of 19,006 GWh or approximately 8.4 percent of Florida's annual retail energy sales. Figure 25 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, TECO's customer base has increased by 9.9 percent, while retail sales have declined by 0.10 percent. As illustrated, retail energy sales are anticipated to exceed the historic 2007 peak by 2020, one year later than the state as a whole.

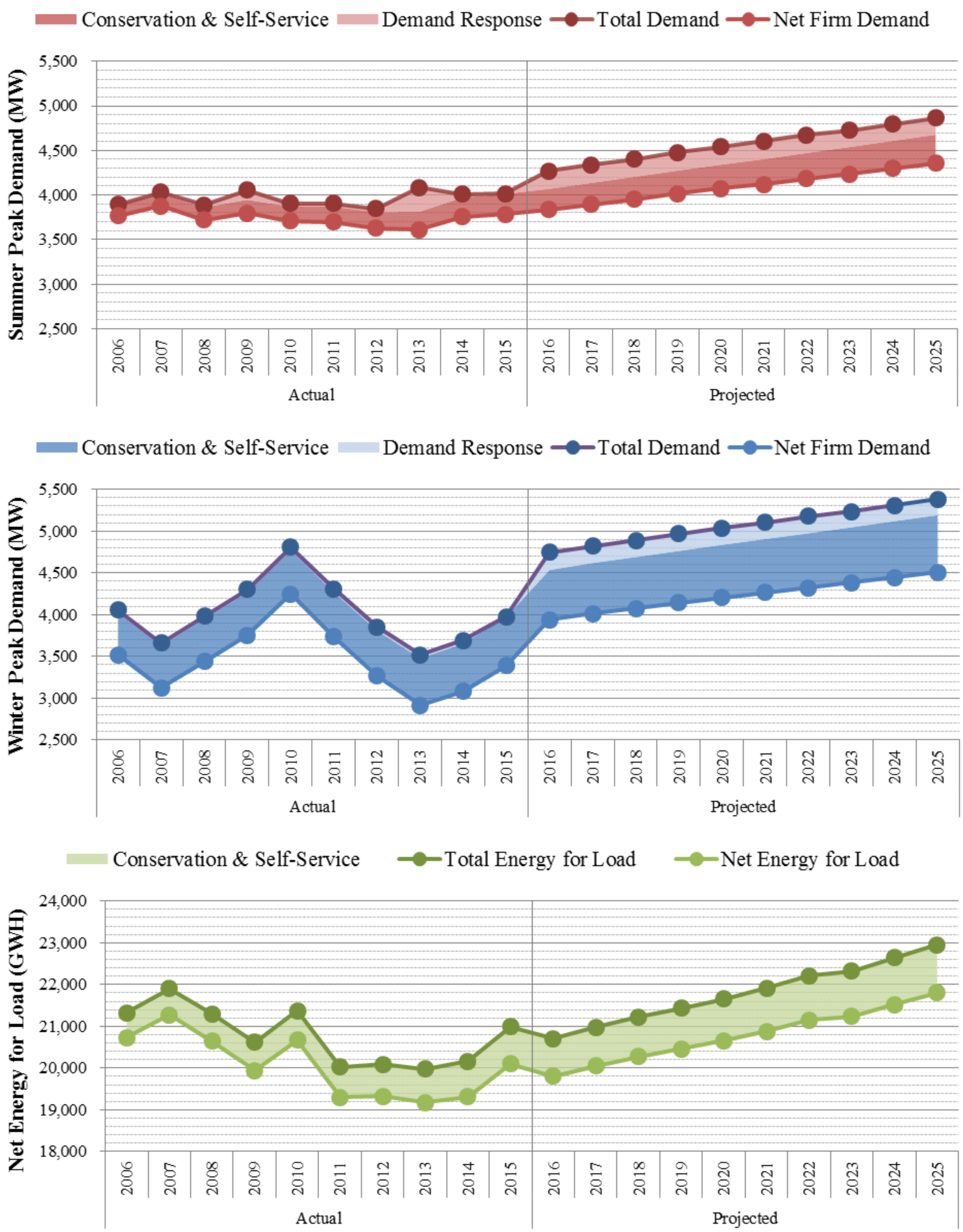
Figure 25: TECO Growth Rate



Source: 2016 Ten-Year Site Plan

The three graphs in Figure 26 below show TECO's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. These graphs include the full impact of demand-side management, and assume that all available demand response resources were or will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand excluding extreme weather events.

Figure 26: TECO Demand and Energy Forecasts



Source: 2016 Ten-Year Site Plan and Data Responses

As an investor-owned utility, TECO is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2016 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Fuel Diversity

Table 16 below shows TECO's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. Based on its 2016 Ten-Year Site Plan, natural gas is used for the majority of TECO's energy generation. Natural gas accounts for approximately 50 percent of net energy for load. In the future, TECO projects that energy from coal and gas will remain approximately the same.

Table 16: TECO Energy Consumption by Fuel Type

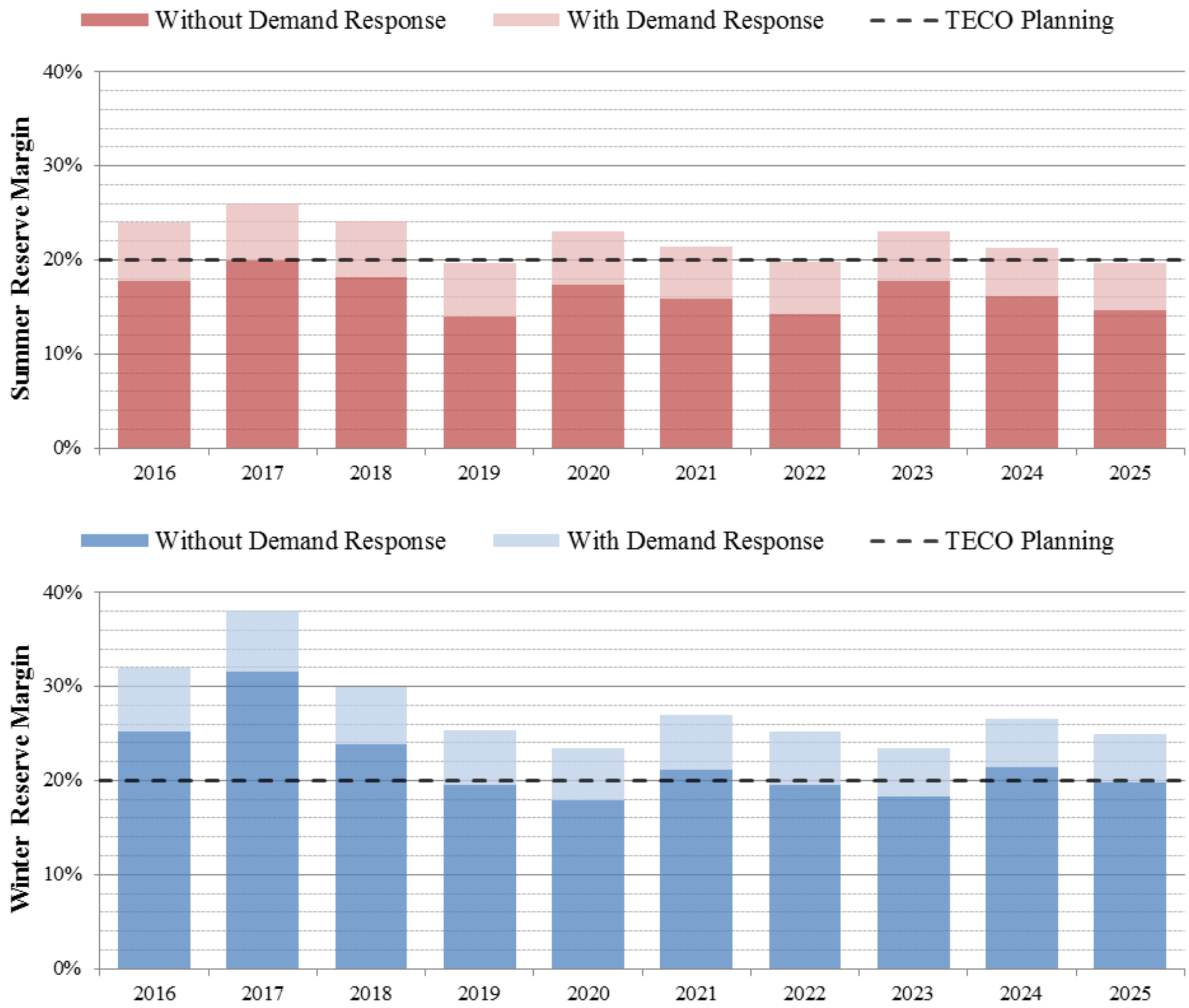
Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	9,919	**49.3%**	11,321	**51.9%**
Coal	8,208	**40.8%**	9,078	**41.6%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	341	**1.7%**	136	**0.6%**
Interchange	438	**2.2%**	0	**0.0%**
NUG & Other	1,200	**6.0%**	1,272	**5.8%**
Total	**20,105**		**21,807**	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion. TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 27 below displays the forecast planning reserve margin for TECO through the planning period for both seasons, with and without the use of demand response. As shown in the figure, TECO's generation needs are controlled by its summer peak throughout the planning period. The Utility's summer peak percentage is projected to be slightly below its 20 percent planned reserve margin in 2025. The deficiency is only 0.4 percent which is reasonable for planning purposes. TECO's 7 percent supply-side only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20 percent reserve margin will be realized.

Figure 27: TECO Reserve Margin Forecast



Source: 2016 Ten-Year Site Plan

Generation Resources

TECO plans three unit additions during the planning period, as described in Table 17 below. TECO plans to convert a set of four natural gas-fired simple cycle combustion turbines at its Polk power plant to combined cycle operation. The additional capacity associated with the modernization is listed below and has already been certified through the Power Plant Siting Act. TECO also plans the addition of two natural gas-fired combustion turbine peaking units in 2020 and 2023.

Table 17: TECO Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum
New Units			
2017	Big Bend Solar	Photovoltaic	18
2017	Polk 2 CC Conversion	Natural Gas Combined Cycle	459
2020	Future CT 1	Natural Gas Combustion Turbine	204
2023	Future CT 2	Natural Gas Combustion Turbine	204
Total New Units			**885**
Net Additions			**885**

Source: 2016 Ten-Year Site Plan

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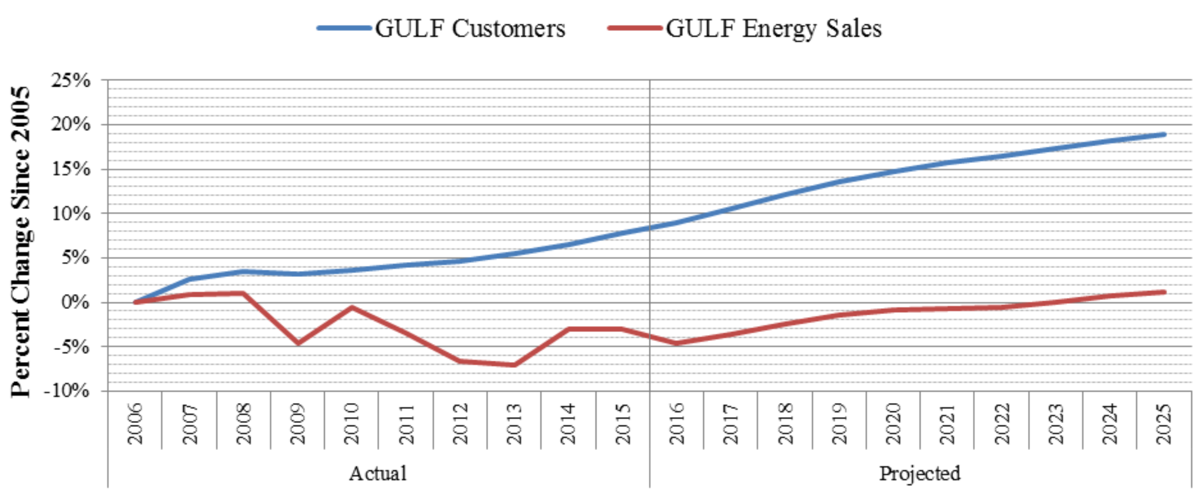
Gulf Power Company (GPC)

GPC is an investor owned utility, and is Florida's sixth largest electric utility. It represents the smallest of the generating investor-owned utilities, and the only one inside the Southern Company electric system. As GPC plans and operates its system in conjunction with the other Southern Company utilities, not all of the energy generated by GPC is consumed within Florida. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds GPC's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, GPC had approximately 447,557 customers and annual retail energy sales of 11,086 GWh or approximately 4.9 percent of Florida's annual retail energy sales. Figure 28 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, GPC's customer base has increased by 7.8 percent, while retail sales have declined by 3.0 percent. As illustrated, retail energy sales are anticipated to exceed the historic 2008 peak by 2025, six years later than the state as a whole.

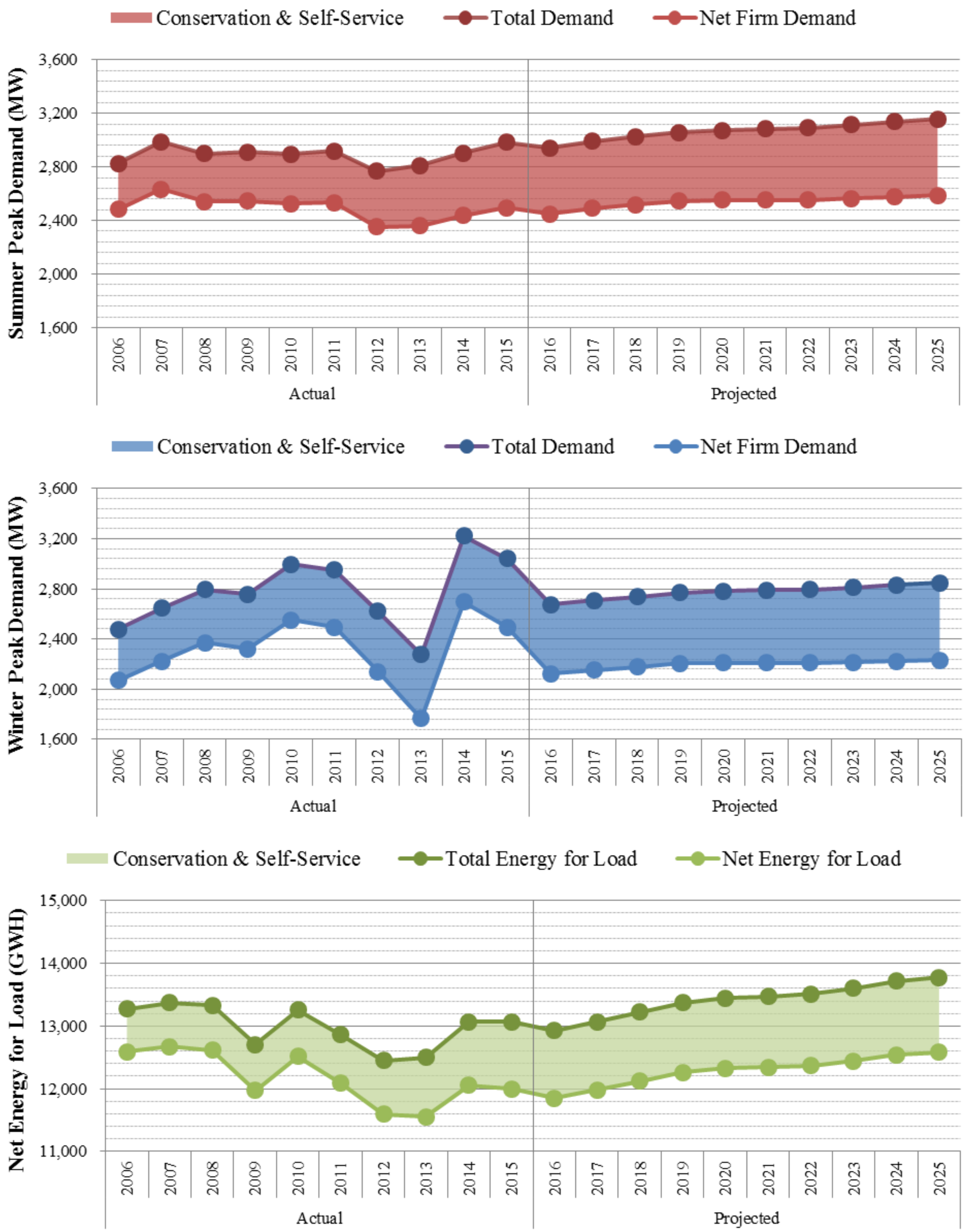
Figure 28: GPC Growth Rate



Source: 2016 Ten-Year Site Plan

As an investor-owned utility, GPC is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2016 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014. The three graphs in Figure 29 below shows GPC's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. These graphs include the full impact of demand-side management.

Figure 29: GPC Demand and Energy Forecasts



Source: 2016 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 18 below shows GPC's actual net energy for load by fuel type as of 2015, and the projected fuel mix for 2025. GPC is an energy exporter, producing over 7.5 percent more energy than it requires for native load. While natural gas was the dominant fuel source in 2015, coal was the second most utilized fuel source. By 2025, GPC's 2016 Ten-Year Site Plan projects an increase in export to Southern Company Services that will be 8.1 percent of native load, with coal representing approximately 85 percent of system energy. GPC projects a greater percent of energy consumption from coal in 2025 than any of the other TYSP Utilities.

Table 18: GPC Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	7,787	**64.9%**	1,828	**14.5%**
Coal	4,876	**40.6%**	10,687	**84.9%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable[6]	235	**2.0%**	1,091	**8.7%**
Interchange	-903	**-7.5%**	-1,023	**-8.1%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**11,996**		**12,583**	

Source: 2016 Ten-Year Site Plan and Data Responses

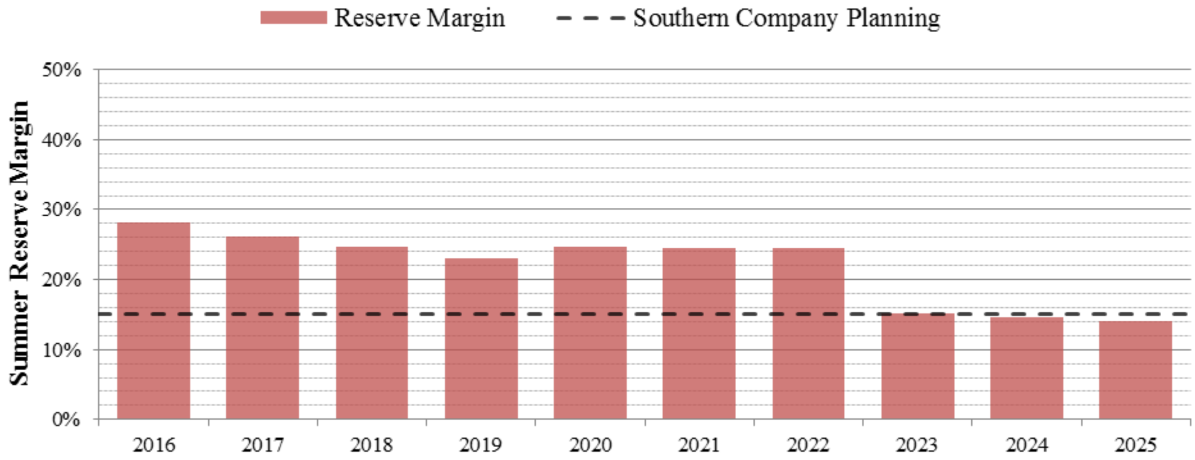
Reliability Requirements

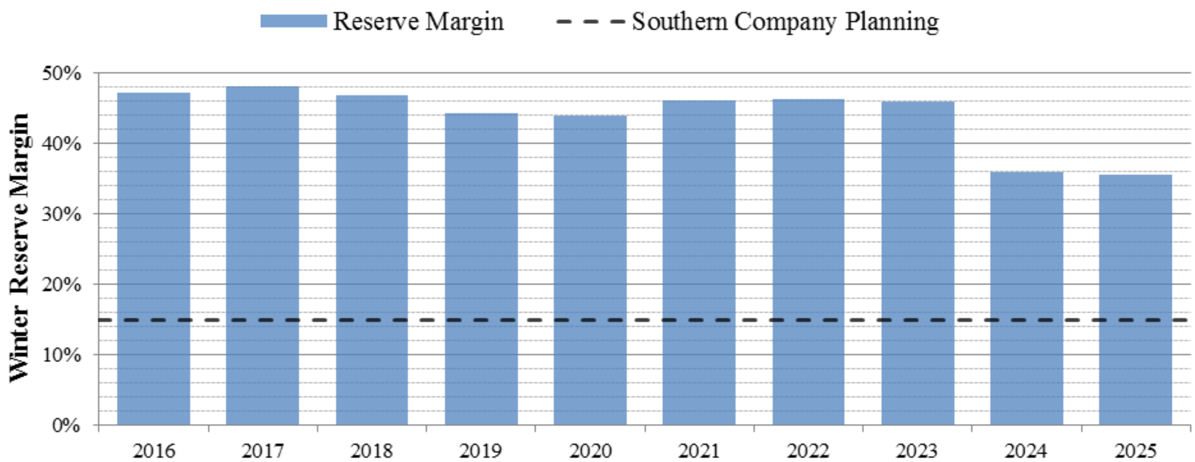
As previously noted, GPC is the only Ten-Year Site Plan utility outside of the FRCC region. As part of Southern Company's electric system, GPC plans to maintain a 15 percent seasonal planning reserve margin beginning in 2017. Figure 30 below displays the forecast planning reserve margin for GPC through the planning period for both seasons, including the impact of energy efficiency programs. As shown in the figure, GPC's generation needs are typically determined by its summer peak. It is anticipated that GPC would either construct additional generation or contract for purchased power to meet its planning reserve requirement in 2025.

GPC also recently filed a petition requesting that formal action is taken to recognize its ownership in Plant Scherer Unit No. 3 as being in service to retail customers. In Figure 30 below the summer reserve margin forecasts with and without Plant Scherer Unit No. 3 are shown. The winter reserve margin for Plant Scherer Unit No. 3 remained relatively unaffected. This issue will be further addressed in GPC's rate case (Docket No. 160186-EI).

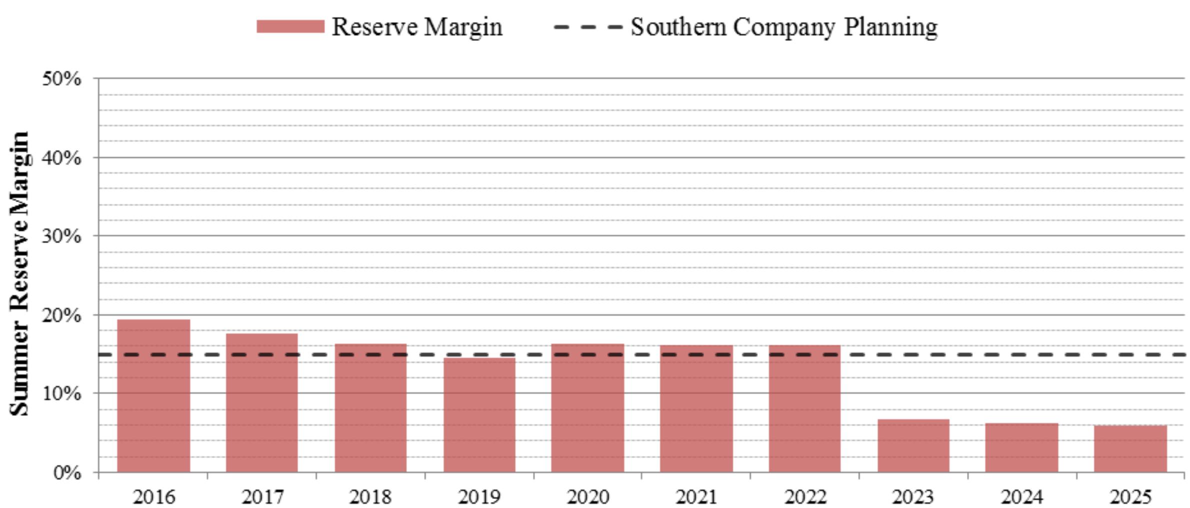
[6] Gulf has entered into purchase power agreements linked to 272 MW of wind energy produced by facilities located in Oklahoma. While the energy from the facilities may not be delivered to Gulf's system, the renewable attributes for their output are retained by the utility for the benefit of Gulf's customers.

Figure 30: GPC Reserve Margin Forecast
With Plant Scherer Unit No. 3





Without Plant Scherer Unit No. 3



Source: 2016 Ten-Year Site Plan

Generation Resources

GPC plans multiple unit retirements and additions during the planning period, as described in Table 19 below. A coal-fired steam unit and three natural gas-fired combustion turbines will be retired during the planning period. Based on its 2016 Ten-Year Site Plan, GPC plans to add a single natural gas-fired combustion turbine in 2023, after the expiration of a purchased power agreement. In addition, GPC plans on the addition of utility-owned renewable generation from a landfill gas-fired internal combustion unit, which would provide firm capacity.

Table 19: GPC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)
			Sum
Retiring Units			
2016	Lansing Smith 2	Coal Steam	195
2018	Pea Ridge 1 - 3	Natural Gas Combustion Turbine	12
Total Retirements			**207**
New Units			
2023	Combustion Turbines	Natural Gas Combustion Turbine	654
Total New Units			**654**
Net Additions			**447**

Source: 2016 Ten-Year Site Plan

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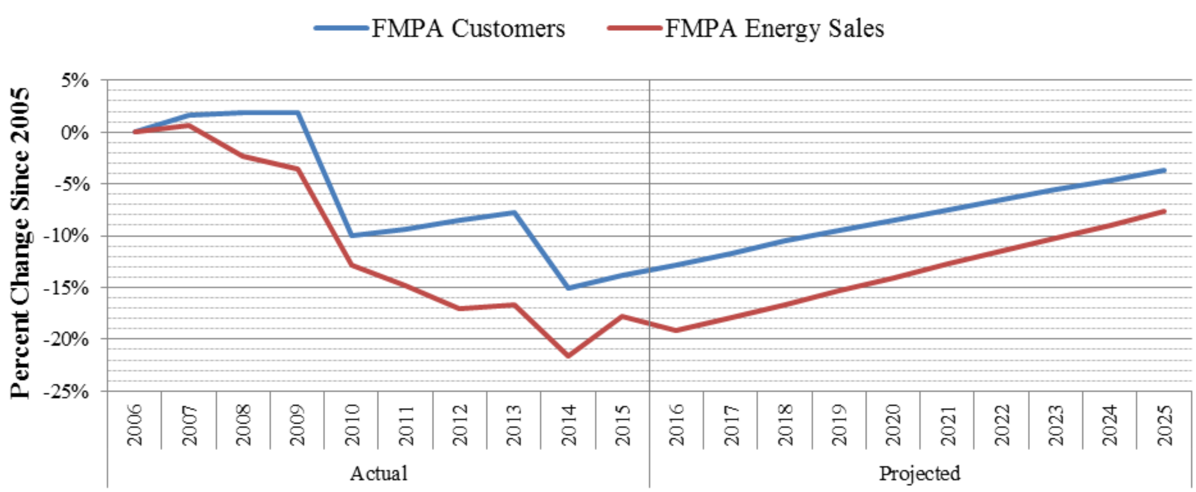
Florida Municipal Power Agency (FMPA)

FMPA is a governmental wholesale power company owned by several Florida municipal utilities throughout Florida. Collectively, FMPA is Florida's eighth largest electric utility and third largest municipal electric utility. While FMPA has 31 member systems, only those members who are participants of the All-Requirements Power Supply Project (ARP) are addressed in the Utility's Ten-Year Site Plan. FMPA is responsible for planning activities associated with ARP member systems. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds FMPA's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, FMPA had approximately 249,318 customers and annual retail energy sales of 5,617 GWh or approximately 2.5 percent of Florida's annual retail energy sales. Figure 31 below illustrates the Utility's historic and forecast number of customers and retail energy sales in terms of percentage growth from 2006. Over the last 10 years, FMPA's customer base has decreased by 13.8 percent, while retail sales have decreased by 17.8 percent. As illustrated, retail energy sales are not anticipated to exceed the historic 2007 peak during the planning period. The reduction in sales is associated with several ARP member systems modifying their contractual agreements with FMPA, such that FMPA no longer provides for the system's capacity and energy needs. Those member systems modifying agreements include the City of Vero Beach in 2010, the City of Lake Worth in 2014, and the City of Fort Meade in 2015.

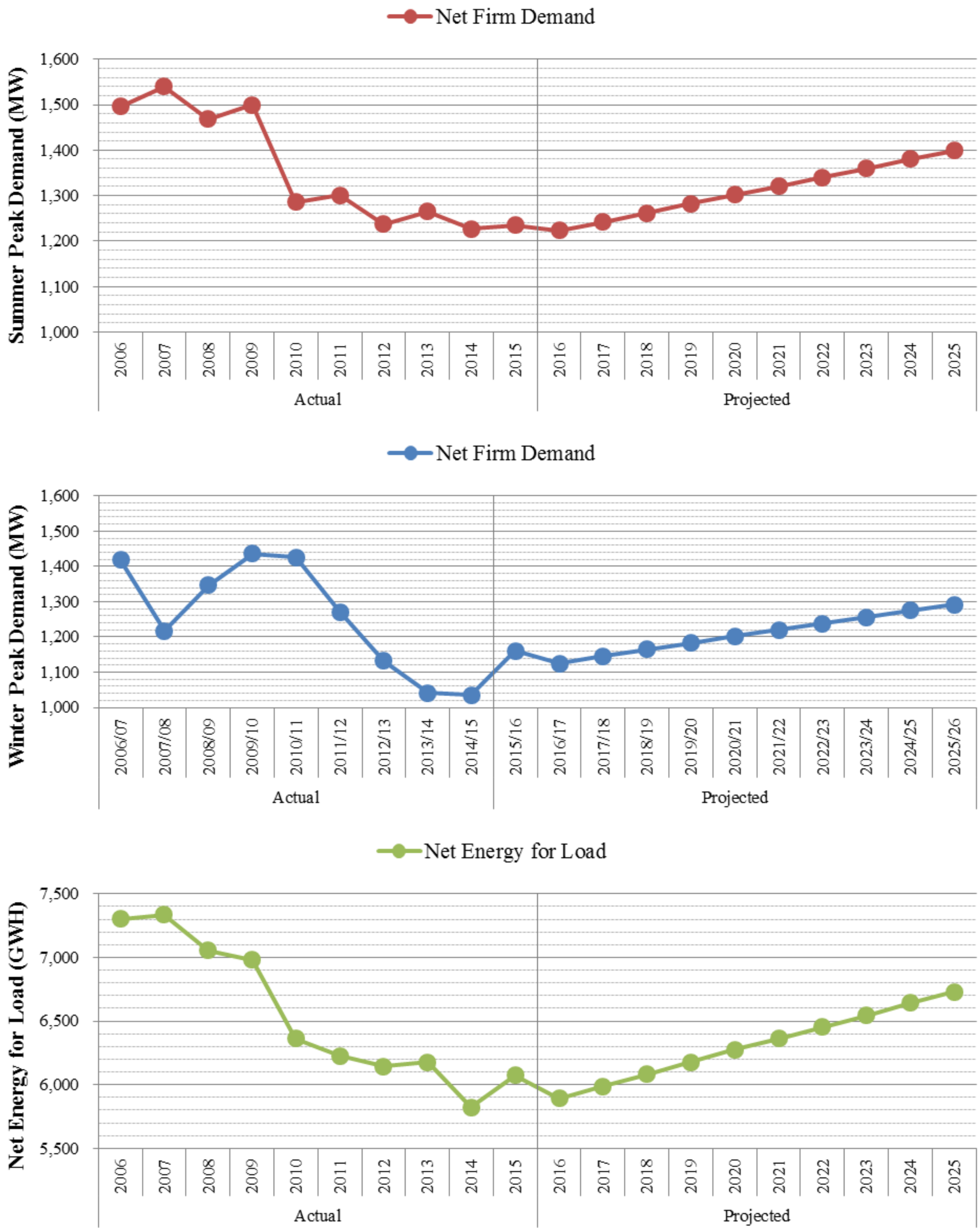
Figure 31: FMPA Growth Rate



Source: 2016 Ten-Year Site Plan

The three graphs in Figure 32 below show FMPA's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer demand-side management programs, the impacts of which are included in the graphs below.

Figure 32: FMPA Demand and Energy Forecasts



Source: 2016 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 20 below shows FMPA's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects an increase in purchased power and energy from coal in 2025, but approximately 86 percent of energy would still be sourced from natural gas and nuclear.

Table 20: FMPA Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	5,021	**82.7%**	5,500	**81.7%**
Coal	726	**12.0%**	914	**13.6%**
Nuclear	273	**4.5%**	269	**4.0%**
Oil	5	**0.1%**	0	**0.0%**
Renewable	42	**0.7%**	46	**0.7%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	6	**0.1%**	0	**0.0%**
Total	**6,072**		**6,729**	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

FMPA utilizes an 18 percent planning reserve margin criterion for summer peak demand, and a 15 percent planning reserve margin criterion for winter peak demand. Figure 33 below displays the forecast planning reserve margin for FMPA through the planning period for both seasons, with the impact of energy efficiency programs. As shown in the figure, FMPA's generation needs are controlled by its summer peak throughout the planning period.

Figure 33: FMPA Reserve Margin Forecast

Source: 2016 Ten-Year Site Plan

Generation Resources

FMPA plans no unit additions or retirements during the planning period. However, as discussed above, several ARP member systems have elected to modify their contractual agreements with FMPA, such that FMPA no longer utilizes the member system's generation resources.

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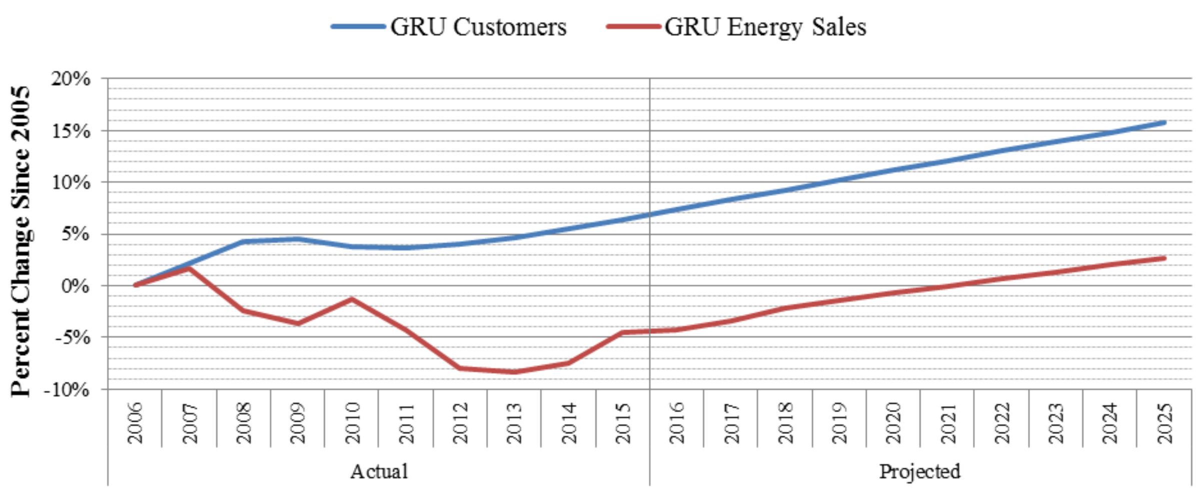
Gainesville Regional Utilities (GRU)

GRU is a municipal utility and the smallest electric utility required to file a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and consists of the City of Gainesville and its surrounding area. GRU also provides wholesale power to the City of Alachua and Clay Electric Cooperative. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds GRU's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, GRU had approximately 94,628 customers and annual retail energy sales of 1,765 GWh or approximately 0.8 percent of Florida's annual retail energy sales. Figure 34 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, GRU's customer base has increased by 6.33 percent, while retail sales have decreased by 4.49 percent. As illustrated, retail energy sales are anticipated to exceed their historic 2007 peak in 2024, five years later than the state as a whole.

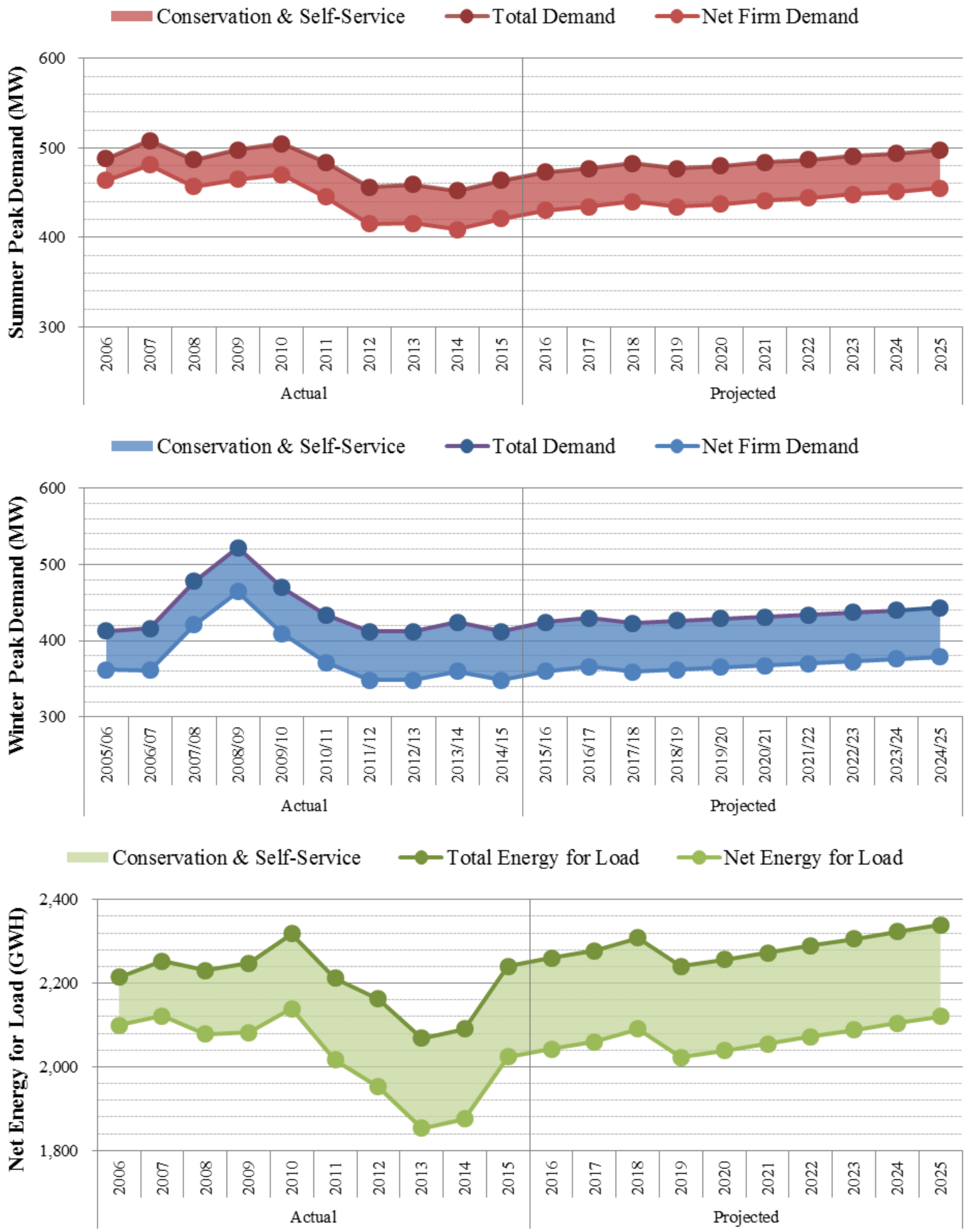
Figure 34: GRU Growth Rate



Source: 2016 Ten-Year Site Plan

The three graphs in Figure 35 below show GRU's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 35 include the impact of these demand-side management programs.

Figure 35: GRU Demand and Energy Forecasts



Source: 2016 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 21 below shows GRU's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. In 2014, coal was approximately two times natural gas in terms of contribution to net energy for load, with the remaining energy split between renewable generation and non-utility generators. But, in 2015, natural gas became GRU's primary fuel source. By 2025, GRU projects a slight increase in natural gas, approximately a 10 percent increase in coal, and approximately an 8 percent decrease in renewable energy.

Table 21: GRU Energy Consumption by Fuel Type

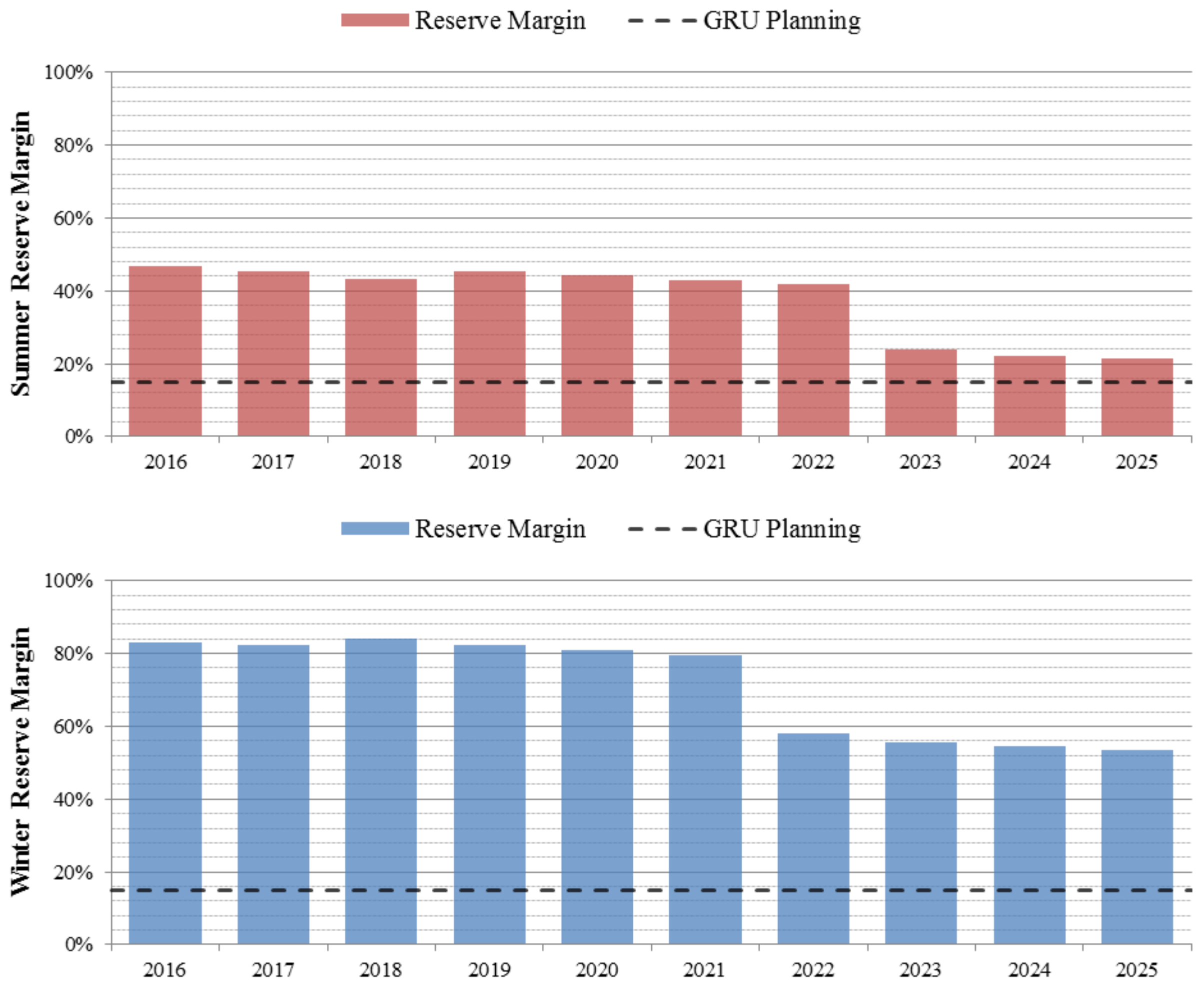
Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	771	**38.1%**	921	**43.4%**
Coal	663	**32.8%**	895	**42.2%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	374	**18.5%**	217	**10.2%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	215	**10.6%**	87	**4.1%**
Total	**2,024**		**2,120**	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 36 below displays the forecast planning reserve margin for GRU through the planning period for both seasons, including the impacts of demand-side management. As shown in the figure, GRU's generation needs are controlled by its summer peak throughout the planning period. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, GRU's largest single unit, Deerhaven 2, a coal-fired steam unit, represented 44.2 percent of summer net firm peak demand in 2016, almost the entirety of the Utility's reserve margin.

Figure 36: GRU Reserve Margin Forecast



Source: 2016 Ten-Year Site Plan

Generation Resources

GRU currently plans to retire a natural gas-fired steam unit towards the end of the planning period, as described in Table 22 below. As a smaller utility, single units can have a large impact upon reserve margin. GRU does not plan to add additional generating capacity during the planning period.

Table 22: GRU Generation Resource Changes

Year	Unit Name	Fuel & Unit Type	Net Capacity (MW) Sum
Retiring Units			
2022	Deerhaven FS01	Natural Gas Steam	75
		Retiring Units Total	75
		Net Additions	**(75)**

Source: 2016 Ten-Year Site Plan

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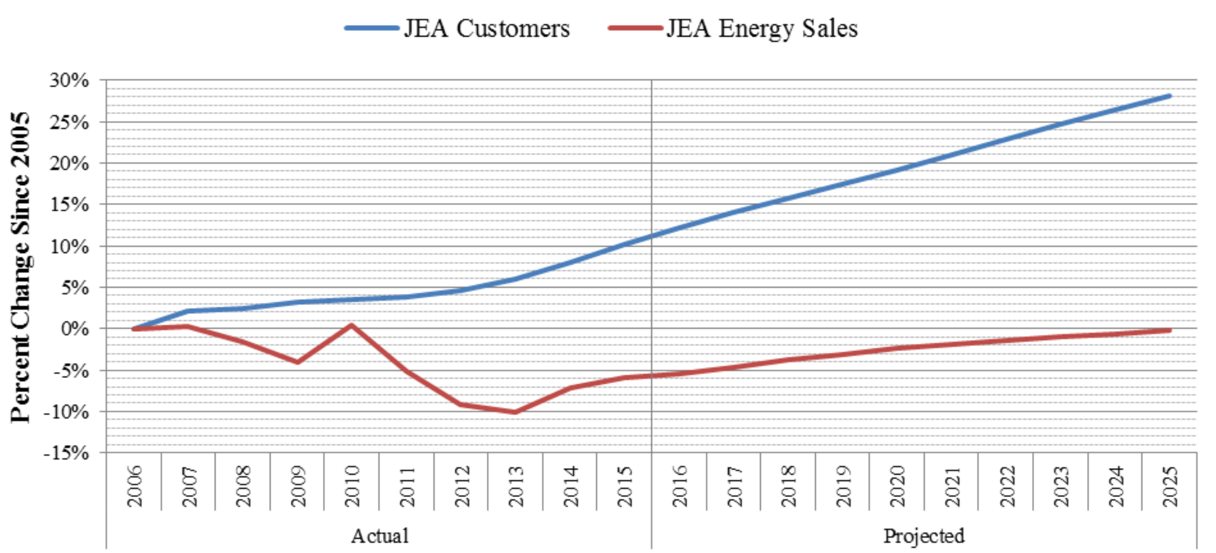
JEA

JEA, formerly known as Jacksonville Electric Authority, is Florida's largest municipal utility and fifth largest electric utility. JEA's service territory is within the FRCC region, and includes all of Duval County as well as portions of Clay and St. Johns Counties. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds JEA's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, JEA had approximately 442,249 customers and annual retail energy sales of 11,864 GWh or approximately 5.2 percent of Florida's annual retail energy sales. Figure 37 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, JEA's customer base has increased by 10.21 percent, while retail sales have declined by 5.96 percent. As illustrated, JEA exceeded its 2007 peak for retail energy sales in 2010, but does not forecast returning to that level of energy sales during the planning period.

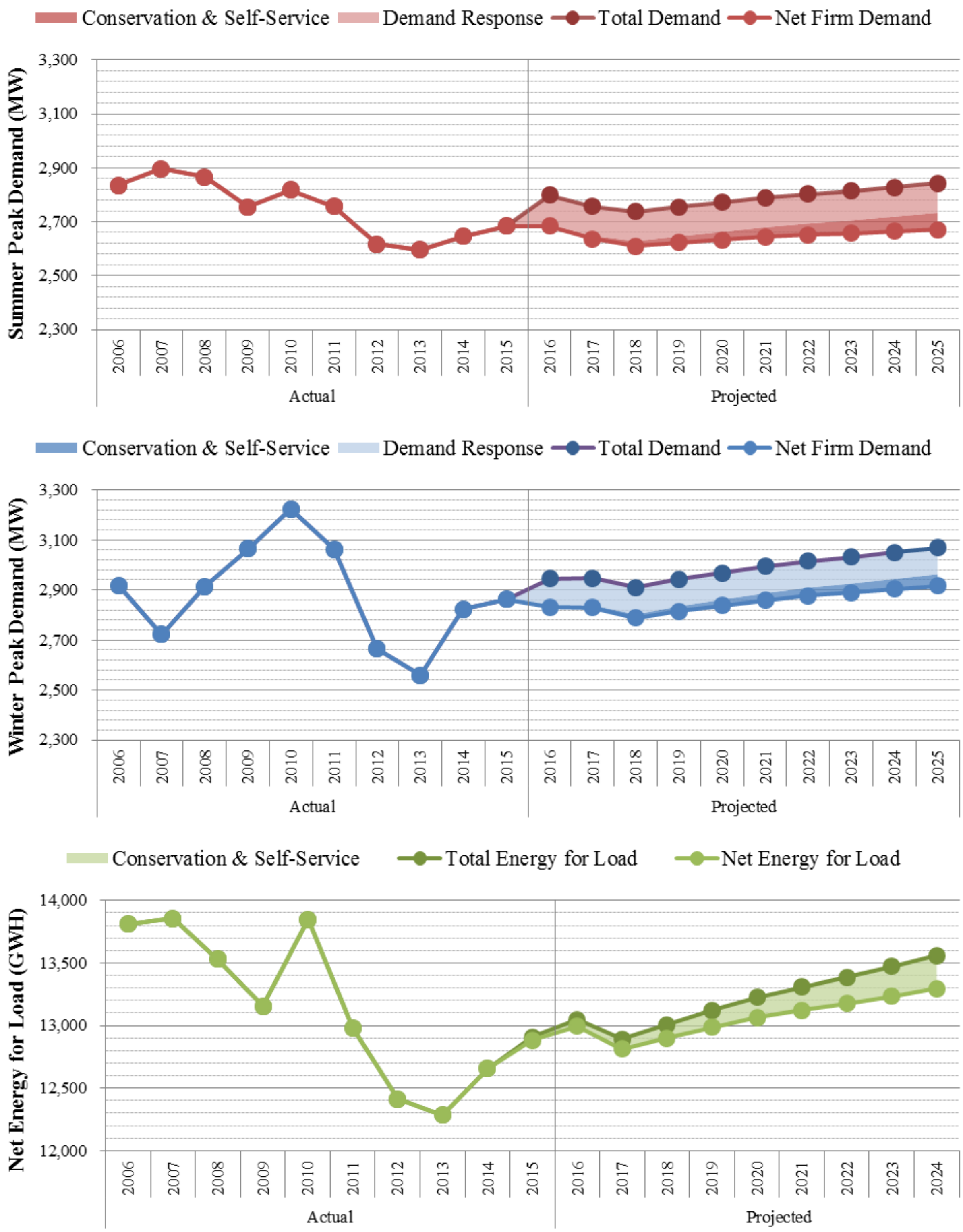
Figure 37: JEA Growth Rate



Source: 2016 Ten-Year Site Plan and 2016 FRCC Load & Resource Plan

The three graphs in Figure 38 below show JEA's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. These graphs include the full impact of demand-side management, and assume that all available demand response resources were or will be activated during the seasonal peak.

Figure 38: JEA Demand and Energy Forecasts



Source: 2016 Ten-Year Site Plan and Data Responses

While a municipal utility, JEA is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2016 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Fuel Diversity

Table 23 below shows JEA's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. In 2025, a majority JEA's net energy for load will come from coal. JEA projects the second highest percent energy consumption from coal in 2025 of the Ten-Year Site Plan utilities.

Table 23: JEA Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	5,209	**40.5%**	1,486	**11.2%**
Coal	5,132	**39.9%**	7,782	**58.5%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	14	**0.1%**	0	**0.0%**
Renewable[7]	101	**0.8%**	126	**0.9%**
Interchange	935	**7.3%**	1,606	**12.1%**
NUG & Other	1,475	**11.5%**	2,294	**17.3%**
Total	**12,866**		**13,294**	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 39 below displays the forecast planning reserve margin for JEA through the planning period for both seasons, with and without the use of demand response. As shown in the figure, JEA's generation needs are controlled by its summer peak throughout the planning period.

[7] JEA's renewables include out of state wind resources.

Figure 39: JEA Reserve Margin Forecast

Source: 2016 Ten-Year Site Plan

Generation Resources

JEA plans to retire one unit during the planning period, as described in Table 24 below. The Northside Unit 3, a natural gas-fired steam unit is planned for retirement in 2017 based on the Utility's Ten-Year Site Plan.

Table 24: JEA Generation Resource Changes

Year	Unit Name	Fuel & Unit Type	Net Capacity (MW)	Notes
			Sum	
Retiring Units				
2017	Northside 3	Natural Gas Steam	524	Reserve Storage
		Retiring Units Total	524	
		Net Additions	**(524)**	

Source: 2016 Ten-Year Site Plan

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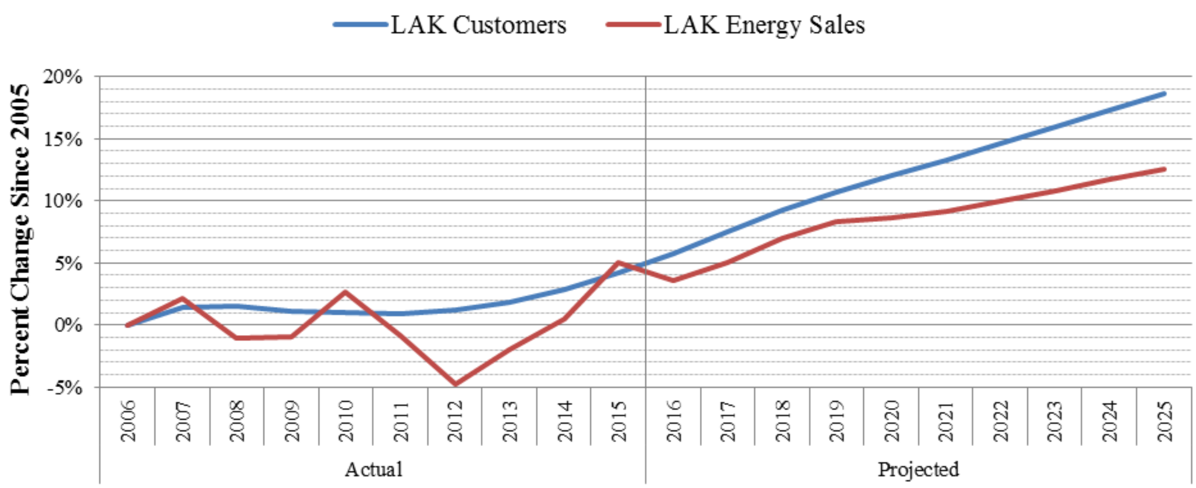
Lakeland Electric (LAK)

LAK is a municipal utility and the state's third smallest electric utility required to file a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and consists of the City of Lakeland and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds LAK's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, LAK had approximately 125,670 customers and annual retail energy sales of 3,034 GWh or approximately 1.3 percent of Florida's annual retail energy sales. Figure 40 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, LAK's customer base has increased by 4.19 percent, while retail sales have grown by 5.06 percent. As illustrated, retail energy sales exceeded their historic 2007 peak in 2010 and 2015.

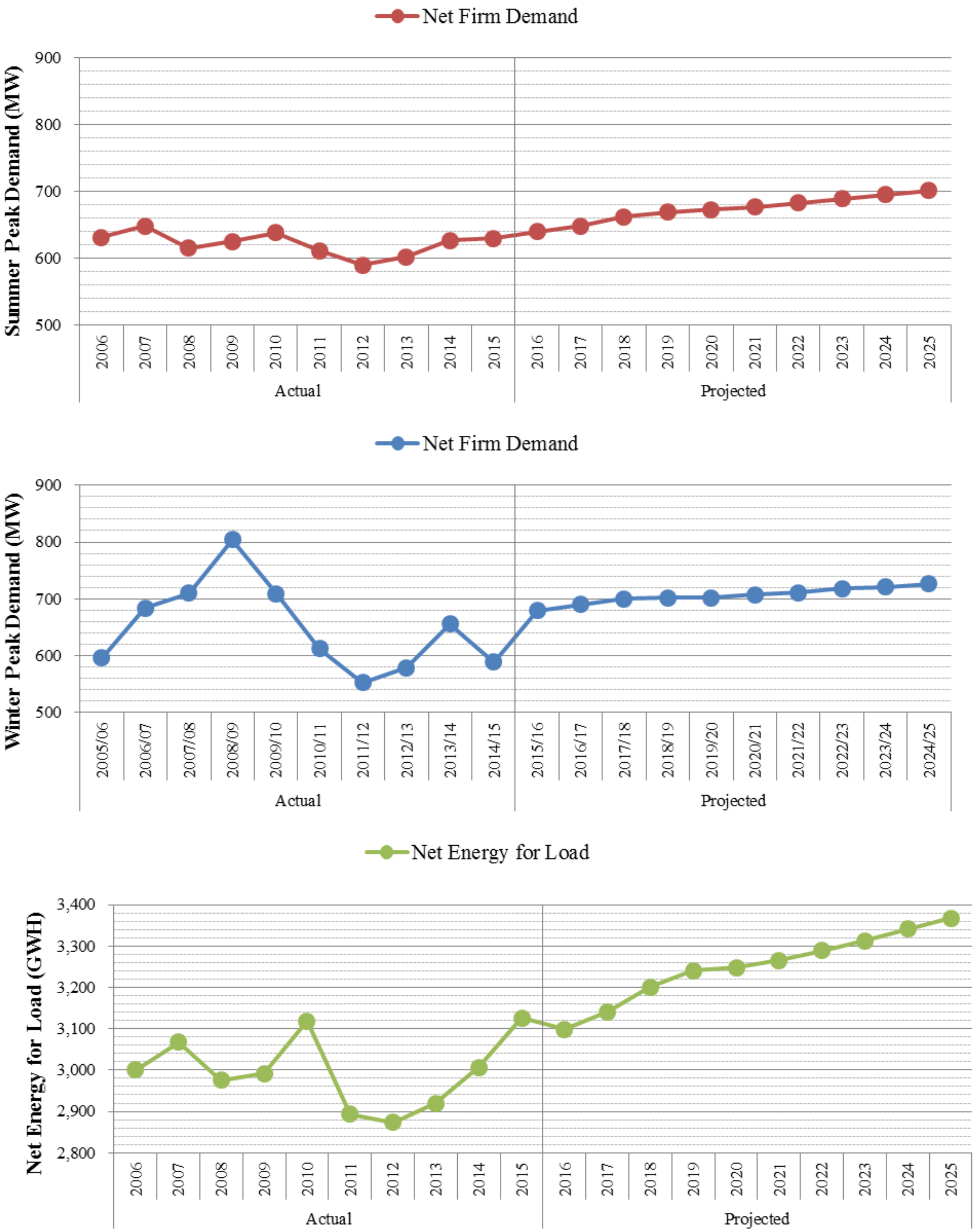
Figure 40: LAK Growth Rate



Source: 2016 Ten-Year Site Plan

The three graphs in Figure 41 below show LAK's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. LAK offers energy efficiency programs, the impacts of which are included in the graphs below.

Figure 41: LAK Demand and Energy Forecasts



Source: 2016 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 25 below shows LAK's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. LAK uses natural gas as its primary fuel type for energy, with coal representing about 25 percent net energy for load. While natural gas usage is anticipated to increase somewhat as a percent of net energy for load, coal is projected to decrease by 2025.

Table 25: LAK Energy Consumption by Fuel Type

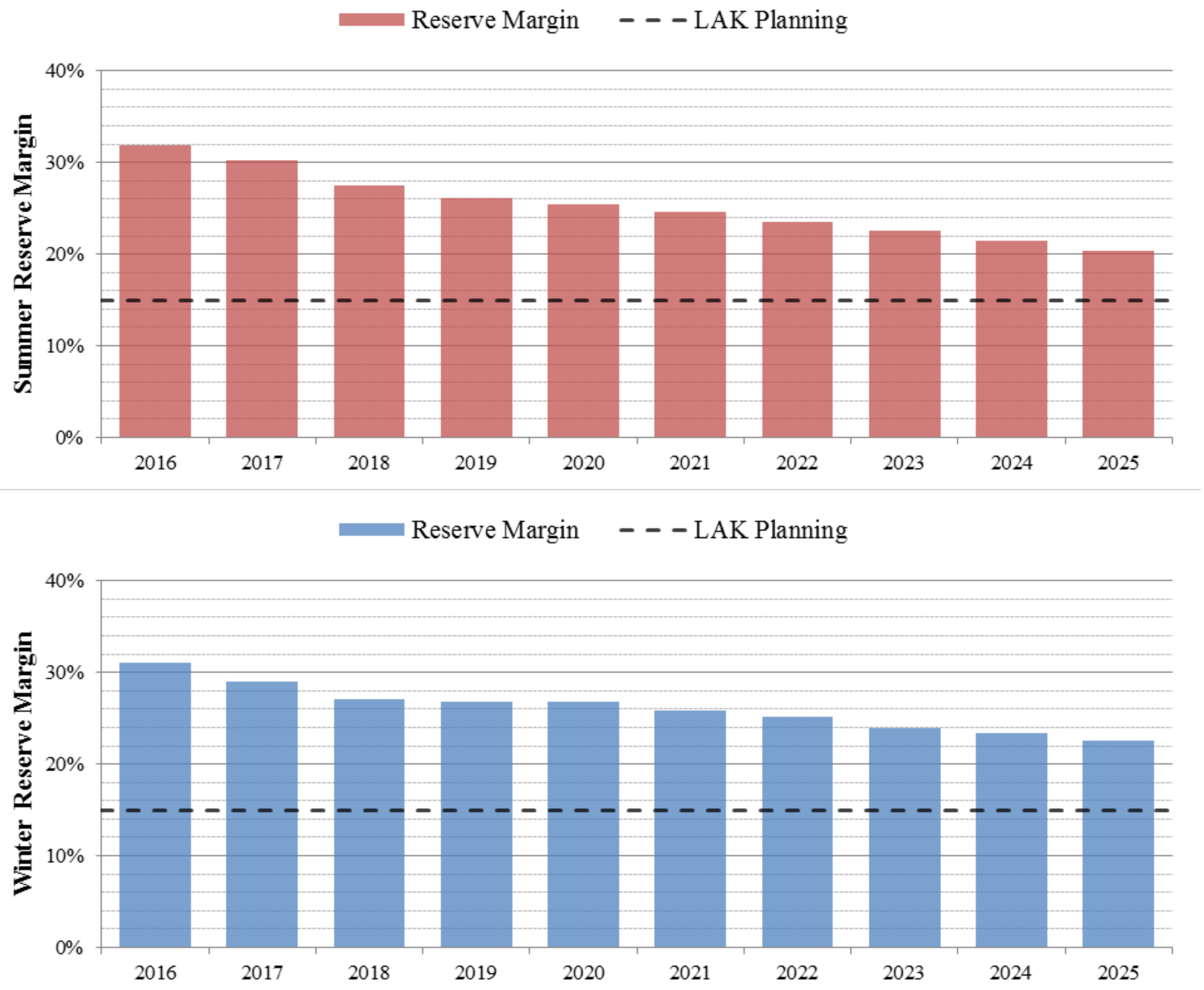
Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	2,204	**70.5%**	2,812	**83.5%**
Coal	788	**25.2%**	624	**18.5%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	1	**0.0%**
Renewable	16	**0.5%**	38	**1.1%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	118	**3.8%**	-107	**-3.2%**
Total	**3,126**		**3,368**	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 42 below displays the forecast planning reserve margin for LAK through the planning period for both seasons, including the impacts of demand-side management. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, LAK's largest single unit, McIntosh 5, a natural gas-fired combined cycle unit, represents 30.1 percent of winter net firm peak demand in 2015, in excess of the Utility's reserve margin.

Figure 42: LAK Reserve Margin Forecast



Source: 2016 Ten-Year Site Plan

Generation Resources

LAK plans no unit additions or retirements during the planning period.

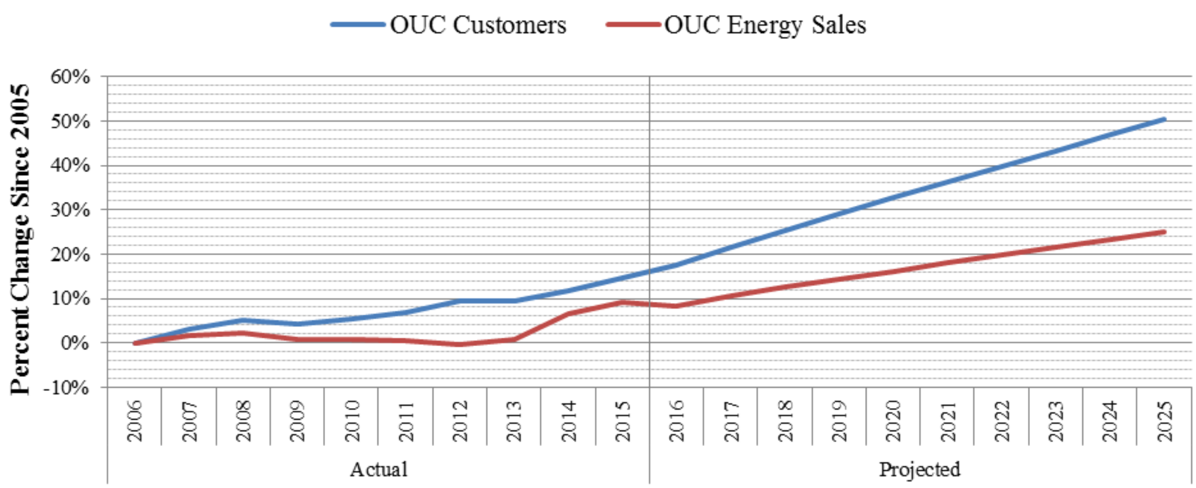
Orlando Utilities Commission (OUC)

OUC is a municipal utility and Florida's seventh largest electric utility and second largest municipal utility. The Utility's service territory is within the FRCC region and primarily consists of the Orlando metropolitan area. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds OUC's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, OUC had approximately 225,105 customers and annual retail energy sales of 6,536 GWh or approximately 2.9 percent of Florida's annual retail energy sales. Figure 43 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, OUC's customer base has increased by 14.57 percent, while retail sales have grown by 9.22 percent. As illustrated, retail energy sales reached a new historic peak in 2015 and are anticipated to exceed that peak in 2017.

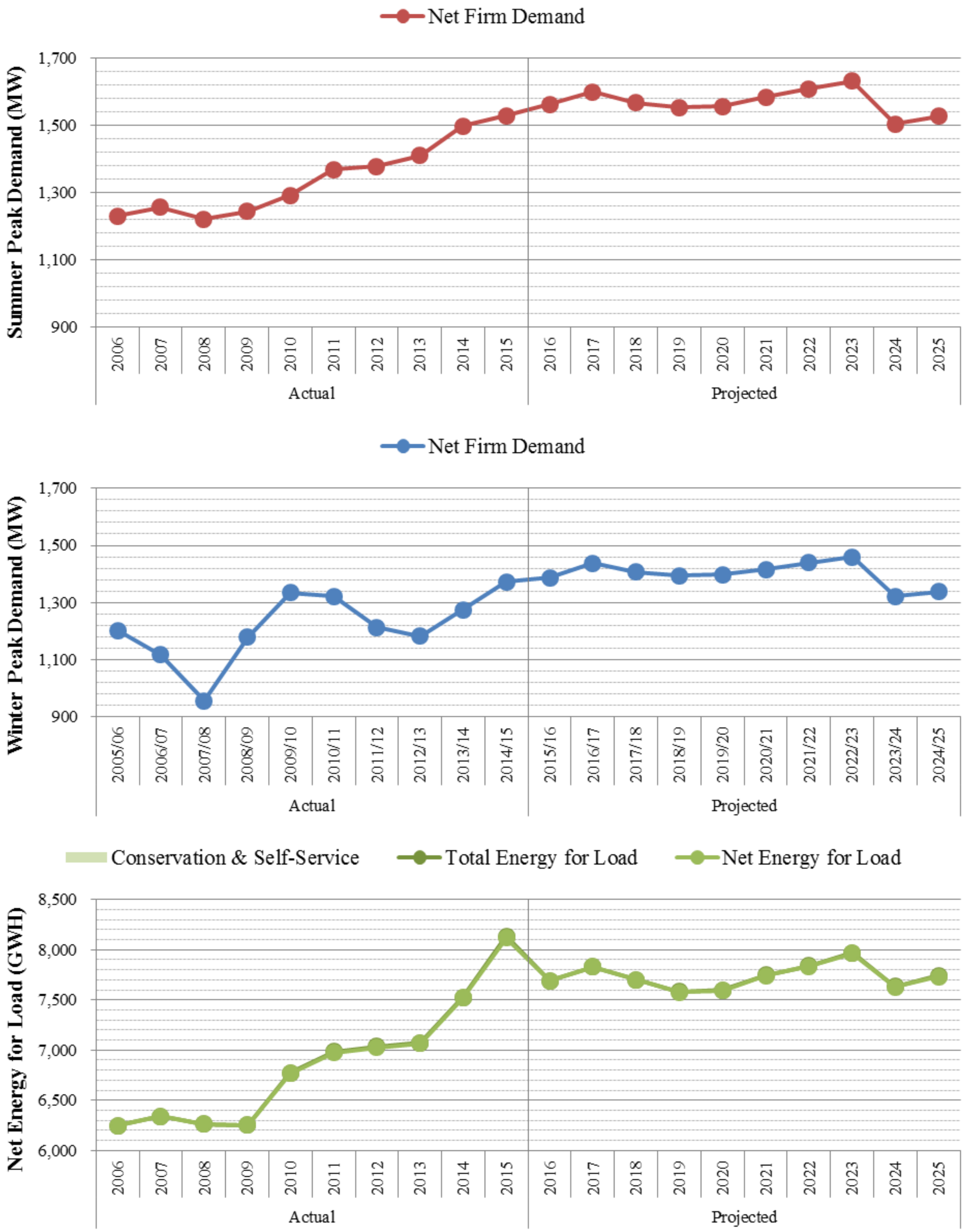
Figure 43: OUC Growth Rate



Source: 2016 Ten-Year Site Plan

The three graphs in Figure 44 below show OUC's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. These graphs include the impact of the Utility's demand side management programs. While a municipal utility, OUC is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption.

Figure 44: OUC Demand and Energy Forecasts



Source: 2016 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 26 below shows OUC's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. In 2015, OUC primarily used natural gas as fuel to meet its net energy for load at 56 percent, with coal as the second most used fuel at 37 percent. However, OUC projects an increase in the quantity of energy consumed from coal by approximately 20 percent, making coal its primary fuel source by 2025. Natural gas usage is planned to decrease by about 24 percent by 2025. Based upon this projection, OUC, as a percent of net energy for load, would be the third largest user of coal in Florida by 2025.

Table 26: OUC Energy Consumption by Fuel Type

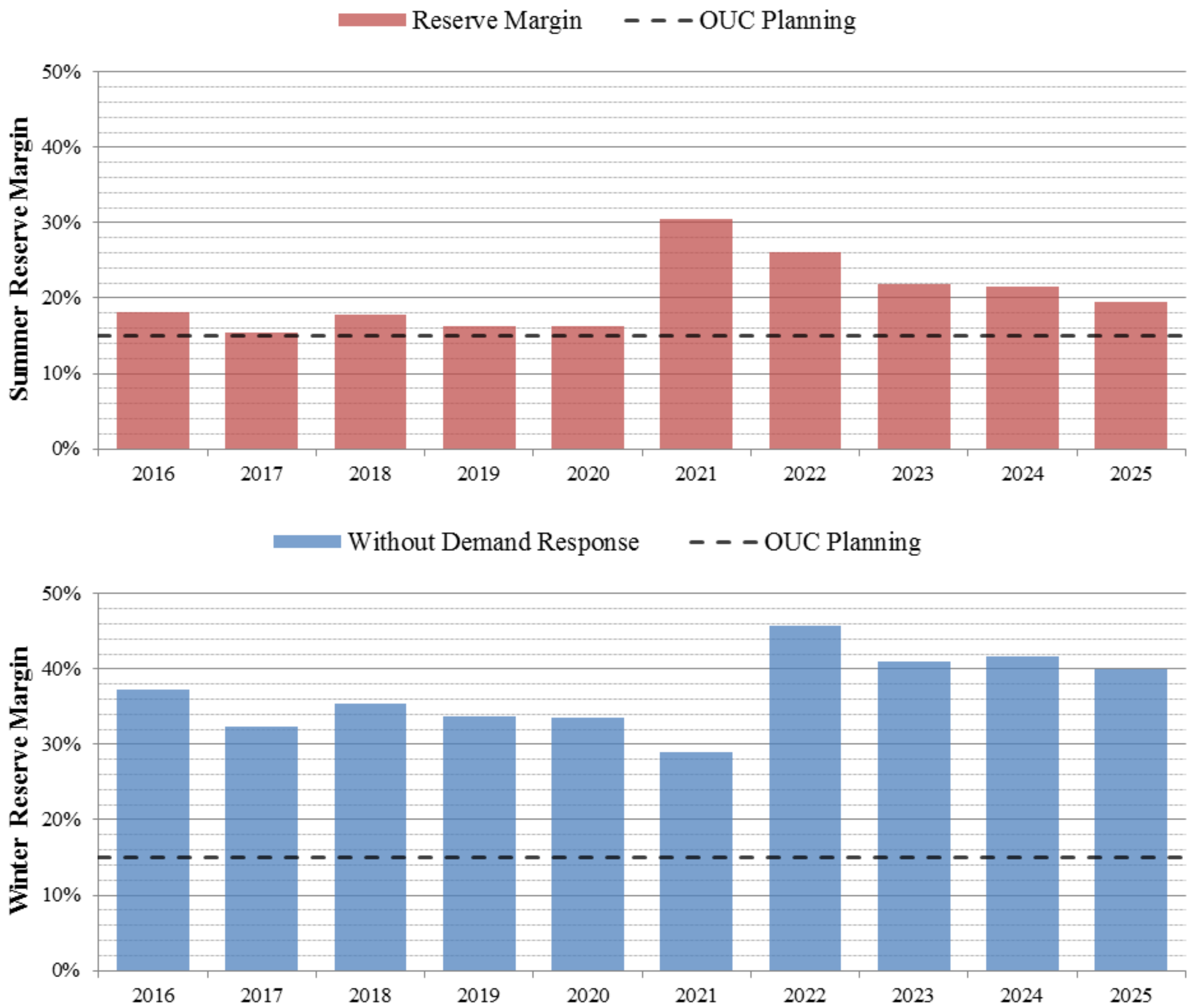
Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	4,578	**56.4%**	2,512	**32.5%**
Coal	2,990	**36.8%**	4,287	**55.4%**
Nuclear	450	**5.5%**	586	**7.6%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	102	**1.3%**	347	**4.5%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**8,121**		**7,732**	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

OUC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 45 below displays the forecast planning reserve margin for OUC through the planning period for both seasons, including the impact of demand-side management programs. As shown in the figure, OUC's generation needs are controlled by its summer peak demand throughout the planning period.

Figure 45: OUC Reserve Margin Forecast



Source: 2016 Ten-Year Site Plan

Generation Resources

Based upon current planning OUC is adding a combined cycle in 2021 using natural gas. The unit as shown in Table 27 below will be a 300 MW Natural Gas Unit and will require a determination of need from the Commission.

Table 27: OUC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
New Units				
2021	Unknown	Natural Gas Combined Cycle	300	Requires PPSA
Total New Units			**300**	
Net Additions			**300**	

Source: 2016 Ten-Year Site Plan

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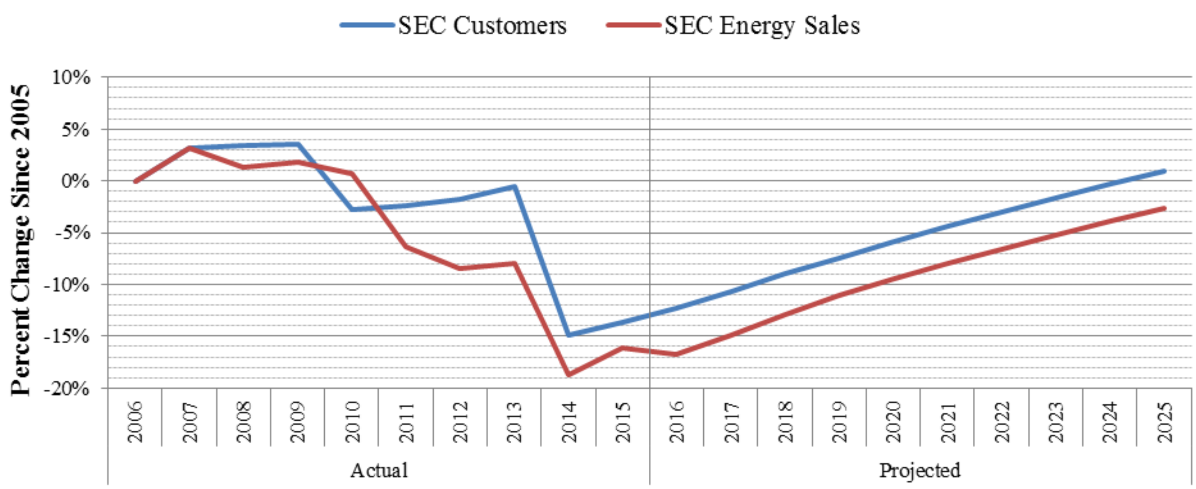
Seminole Electric Cooperative (SEC)

SEC is a generation and transmission rural electric cooperative that serves its member cooperatives, and is collectively Florida's fourth largest utility. SEC's generation and member cooperatives are within the FRCC region, with member cooperatives located in central and north Florida. As a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds SEC's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, SEC had approximately 751,848 customers and annual retail energy sales of 13,374 GWh or approximately 5.9 percent of Florida's annual retail energy sales. Figure 46 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, SEC's customer base has decreased by 13.59 percent, and retail sales have decreased 16.12 percent. As illustrated, retail energy sales are not anticipated to exceed their historic 2007 peak during this planning period. The decline shown in 2014 is associated with one member cooperative, Lee County Electric Cooperative, electing to end its membership with SEC.

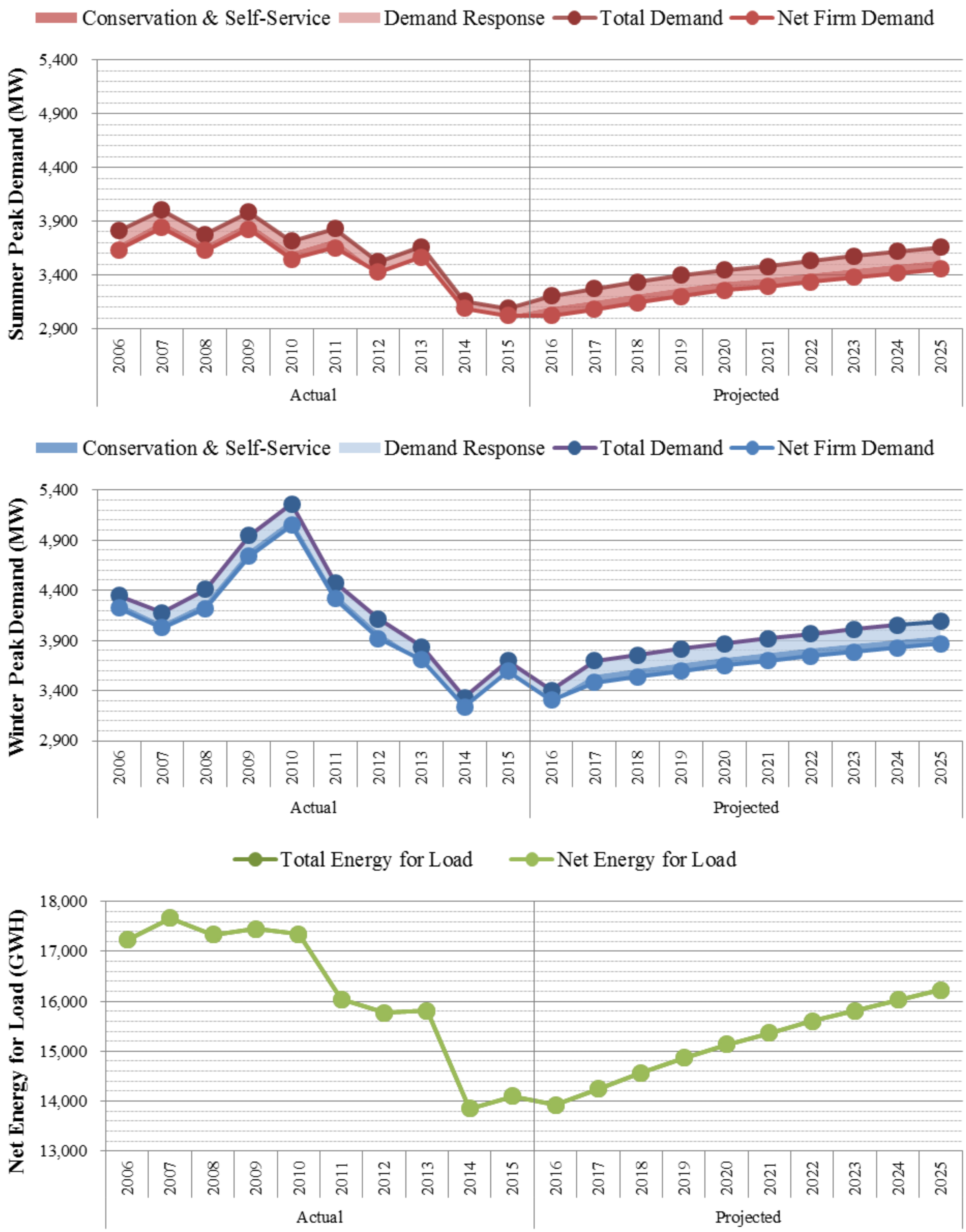
Figure 46: SEC Growth Rate



Source: 2016 Ten-Year Site Plan

The three graphs in Figure 47 below show SEC's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. As SEC is a generation and transmission company, it does not directly engage in energy efficiency or demand response programs. Member cooperatives do offer demand-side management programs, the impacts of which are included in Figure 47.

Figure 47: SEC Demand and Energy Forecasts



Source: 2016 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 28 below shows SEC's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. In 2015, SEC uses a combination of coal and natural gas to meet its member cooperatives' net energy for load, with coal use slightly higher than natural gas. By 2025, SEC projects this to reverse, with natural gas usage somewhat higher than coal.

Table 28: SEC Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	5,333	**37.8%**	8,625	**53.2%**
Coal	7,803	**55.3%**	7,363	**45.4%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	36	**0.3%**	50	**0.3%**
Renewable	932	**6.6%**	186	**1.1%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**14,104**		**16,224**	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

SEC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 48 below displays the forecast planning reserve margin for SEC through the planning period for both seasons, with and without the use of demand response. Member cooperatives allow SEC to coordinate demand response resources to maintain reliability. As shown in the figure, SEC's generation needs are determined by winter peak demand more often than summer peak demand during the planning period.

Figure 48: SEC Reserve Margin Forecast

Source: 2016 Ten-Year Site Plan

Generation Resources

SEC plans the addition of several generating units during the planning period, as described in Table 29 below. All unsited natural gas-fired units, SEC plans the addition of a total of four combustion turbines and a single combined cycle unit over the planning period.

Table 29: SEC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
New Units				
2021	Unnamed CC	Natural Gas Combined Cycle	649	Requires PPSA
2021	Unnamed CT 1	Natural Gas Combustion Turbine	201	
2022	Unnamed CT 2	Natural Gas Combustion Turbine	201	
2024	Unnamed CT 3 & 4	Natural Gas Combustion Turbine	201	
Total New Units			**1,252**	

Source: 2016 Ten-Year Site Plan

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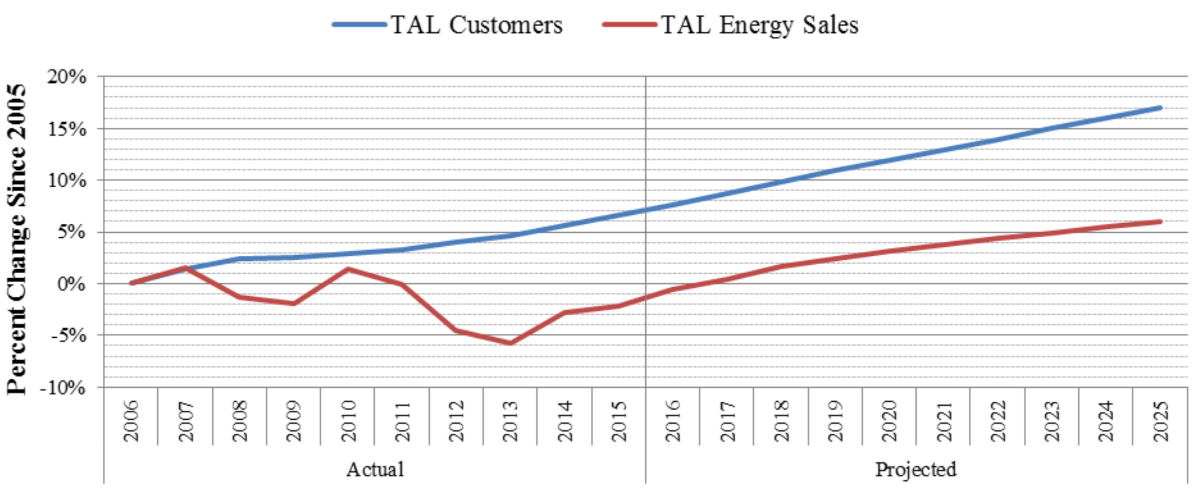
City of Tallahassee Utilities (TAL)

TAL is a municipal utility and the second smallest electric utility which files a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and primarily consists of the City of Tallahassee and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds TAL's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, TAL had approximately 117,827 customers and annual retail energy sales of 2,655 GWh or approximately 1.2 percent of Florida's annual retail energy sales. Figure 49 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, TAL's customer base has increased by 6.58 percent, while retail sales have declined by 2.17 percent. As illustrated, retail energy sales are not anticipated to exceed their historic 2007 peak until 2018.

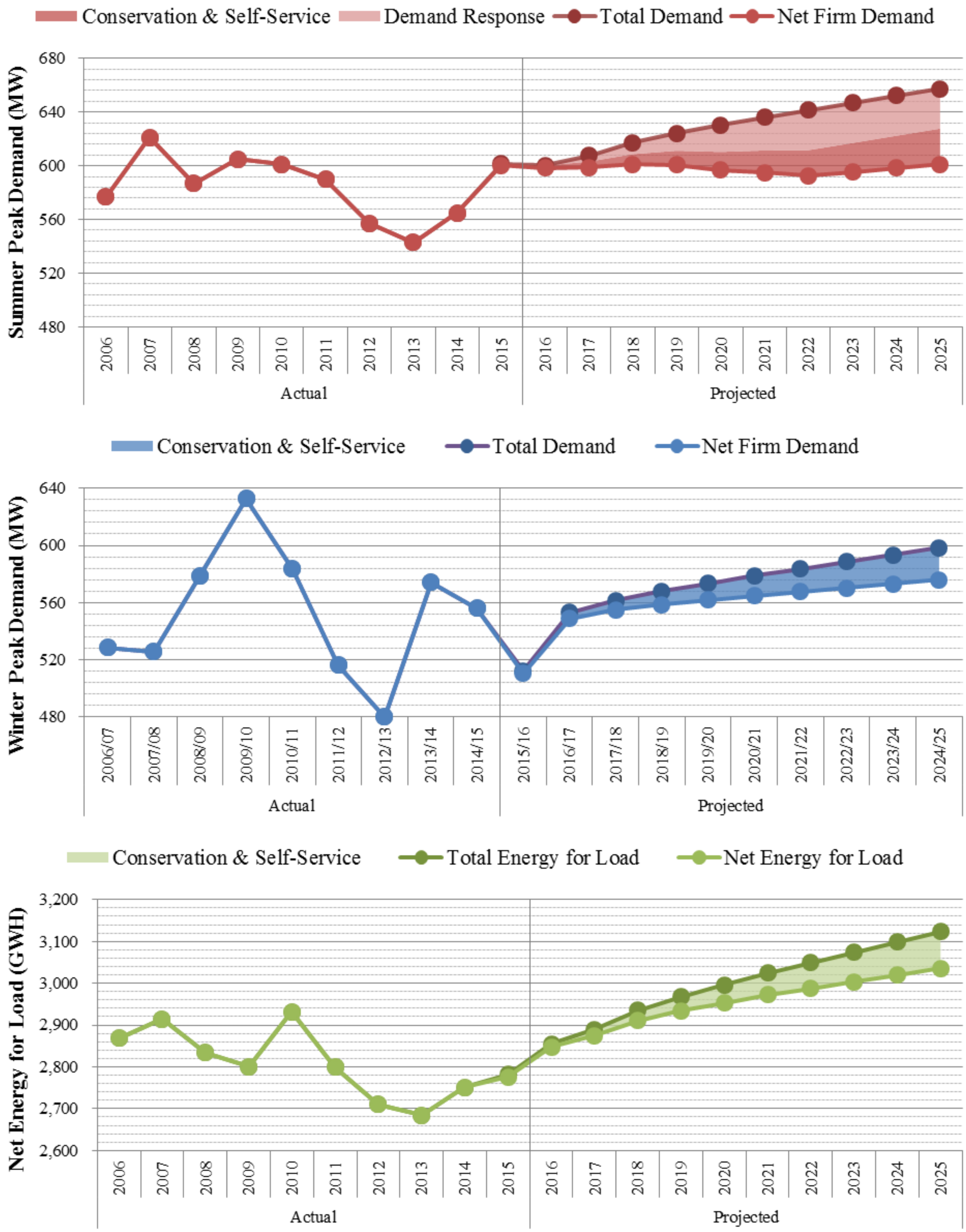
Figure 49: TAL Growth Rate



Source: 2016 Ten-Year Site Plan

The three graphs in Figure 50 below show TAL's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. TAL offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. Currently TAL only offers demand response programs targeting appliances that contribute to summer peak, and therefore have no effect upon winter peak.

Figure 50: TAL Demand and Energy Forecasts



Source: 2016 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 30 below shows TAL's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. TAL relies almost exclusively on natural gas for its generation, excluding some purchases from other utilities and qualifying facilities and the use of oil as a backup fuel. Natural gas is anticipated to remain the primary fuel source on the system.

Table 30: TAL Energy Consumption by Fuel Type

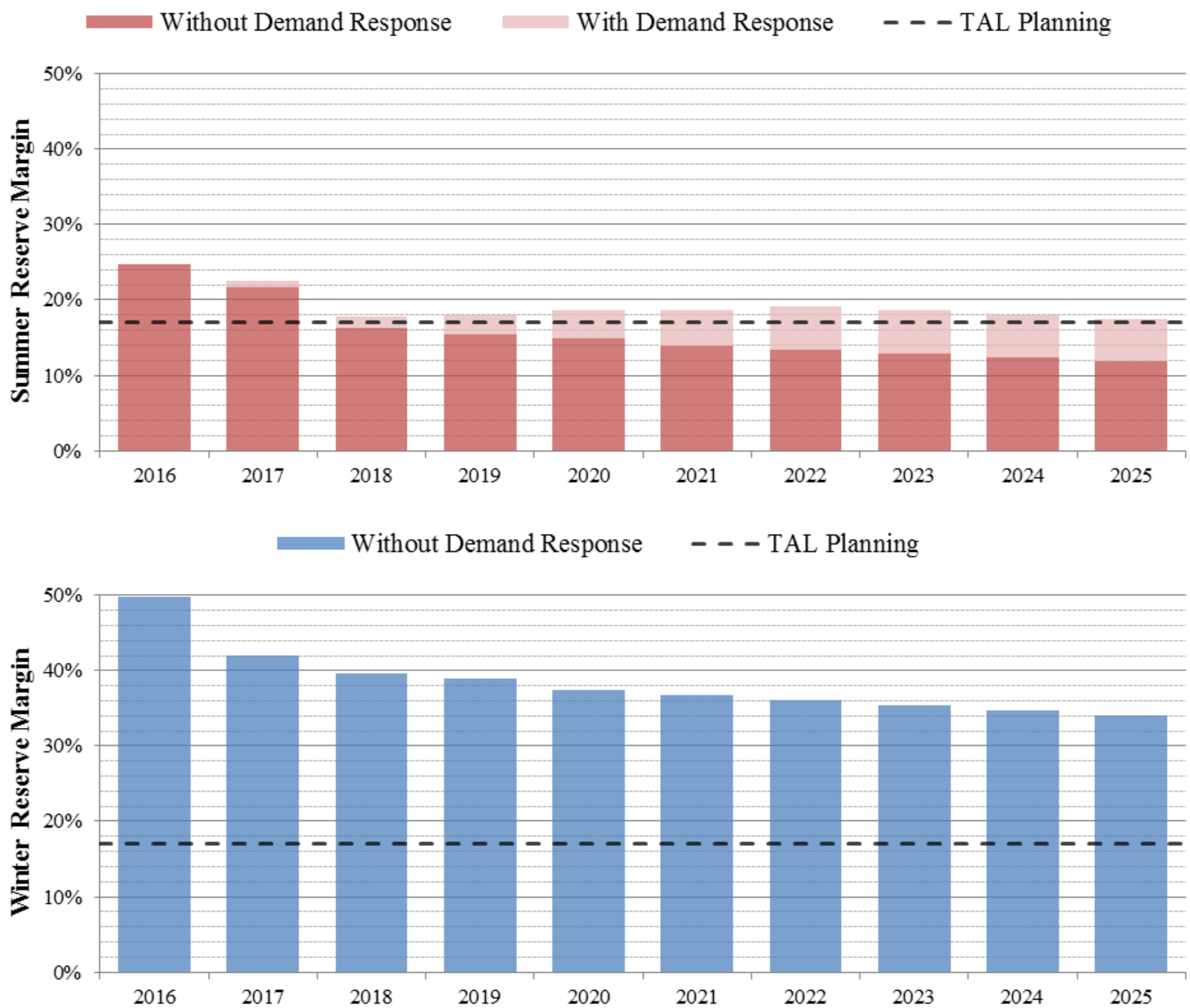
Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	2,704	**97.4%**	3,001	**98.9%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	16	**0.6%**	53	**1.7%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	55	**2.0%**	-20	**-0.7%**
Total	**2,775**		**3,035**	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

TAL utilizes a 17 percent planning reserve margin criterion for seasonal peak demand. Figure 51 below displays the forecast planning reserve margin for TAL through the planning period for both seasons, with and without the use of demand response. As discussed above, TAL only offers demand response programs applicable to the summer peak. As shown in the figure, TAL's generation needs are controlled by its summer peak throughout the planning period.

Figure 51: TAL Reserve Margin Forecast



Source: 2016 Ten-Year Site Plan

Generation Resources

TAL plans multiple unit retirements and a single addition during the planning period, as described in Table 31 below. Several older combustion turbines at two plant sites and a single steam unit, all natural gas-fired, are anticipated to be retired during the planning period. Based upon its current planning, TAL intends to add a new natural gas-fired combustion turbine in 2018.

Table 31: TAL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum
Retiring Units			
2017	Hopkins CT-1	Natural Gas Gas Turbine	12
2017	Purdom CT-1 & CT-2	Natural Gas Gas Turbine	20
2018	Hopkins CT-2	Natural Gas Gas Turbine	24
2021	Hopkins 1	Natural Gas Steam Turbine	76
Total Retirements			**132**
New Units			
2018	Substation 12 IC 1-2	Natural Gas Internal Combustion	9
Total New Units			**9**
Net Additions			**(123)**

Source: 2016 Ten-Year Site Plan

APPENDIX A

REVIEW OF THE

2016 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

FLORIDA
PUBLIC
SERVICE
COMMISSION

NOVEMBER 2016

Ten-Year Site Plan Comments

State Agencies

- Fish and Wildlife Conservation Commission- General
- Fish and Wildlife Conservation Commission- Gulf
- Department of Environmental Protection

Regional Planning Councils

- Treasure Coast Regional Planning Council

Water Management Districts

- Southwest Florida Water Management District
- St. Johns Water Management District

Local Governments

- Charlotte County

Environmental Groups

- Southern Alliance for Clean Energy
- Sierra Club

Florida Fish and Wildlife Conservation Commission

Office of the Executive Director
Nick Wiley
Executive Director

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(850) 921-5786 FAX

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MyFWC.com

June 21, 2016

Moniaishi Mtenga
Division of Engineering
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
mmtenga@psc.state.fl.us

RE: 2016 Ten-Year Power Plant Site Plans

Dear Mr. Mtenga:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the 2016 Ten-Year Power Plant Site Plans submitted to the Public Service Commission (PSC). We will be providing comments on the Gulf Power Company (GULF) Ten-Year Site Plan in a subsequent letter. However, we are submitting this letter to notify you that we have reviewed the following plans and have no comments regarding fish and wildlife resources:

Gainesville Regional Utilities (GRU)
Orlando Utilities Commission (OUC)
City of Tallahassee Utilities (TAL)
Jacksonville Energy Authority (JEA)
Florida Municipal Power Agency (FMPA)
Florida Power and Light Company (FPL)
Seminole Electric Cooperative (SEC)
Lakeland Electric (LAK)
Tampa Electric Company (TECO)
Duke Energy Florida (DEF)

We appreciate the opportunity to review the Ten-Year Site Plans, as provided by the PSC. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or by email at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions, please contact Jason Hight either by phone at (850) 413-6966 or by email at Jason.Hight@MyFWC.com.

Sincerely,

Jennifer D. Goff

Jennifer D. Goff
Land Use Planning Program Administrator
Office of Conservation Planning Services

jdg/jh
ENV 2-11-3
2016 Ten-Year Site Plans_30912, 30917, 30910, 30916, 30921, 30925, 30911, 30914, 30923, 30924_062416

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July 6, 2016

Moniaishi Mtenga
Division of Engineering
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
mmtenga@psc.state.fl.us

RE: Gulf Power 2016 10-Year Site Plan, Multi-County

Dear Mr. Mtenga:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the Gulf Power 2016 10-Year Site Plan and provides the following comments and recommendations.

Project Description

Section 186.801, Florida Statutes, requires electric generating facilities to submit a ten-year site plan to the Florida Public Service Commission. Gulf Power owns and operates five plants in Northwest Florida: Plant Crist (Escambia County); Plant Lansing Smith (Bay County); Plant Scholz (Jackson County); Pea Ridge (Santa Rosa County); and Perdido (Escambia County). Gulf Power has continued to evaluate the construction of generating facilities or the acquisition of equivalent capacity resources in coordination with other Southern Electric System (SES) operating companies. Gulf Power indicates that it has satisfied its need for firm capacity through the May 2023 time period. Any new facility construction is deferred during the 2016-2025 planning cycle. Gulf Power will consider future additional capacity at its existing sites at the Plant Crist, Plant Lansing Smith, Plant Scholz, or on the identified Gulf Power sites at the Shoal River property in Walton County, Caryville property in Holmes and Washington counties, or the North Escambia County property.

Potentially Affected Fish and Wildlife Resources

FWC staff previously provided comments to Gulf Power on the potentially affected resources at the proposed facility expansion sites during the 2010 and 2012 Plan Reviews, with the exception of the proposed North Escambia County Site (see enclosure). Since that time, the listing status of several species has changed which affects the discussion of unique or significant environmental features that are discussed under each site description in the Ten-Year Site Plan. We are providing the following information as technical assistance at the request of Gulf Power staff so that they may update these descriptions.

Plant Crist (Escambia County) is located adjacent to the Escambia River. FWC GIS analysis found that this site is located near, within, or adjacent to:

- U.S. Fish and Wildlife Service Critical Habitat for the:
  - Gulf sturgeon (*Acipenser oxyrinchus desotoi*, Federally Threatened (FT)

- Potential habitat for the:
  - Harlequin darter (*Etheostoma histrio*, State Species of Special Concern [SSC])

Plant Scholz (Jackson County) is located adjacent to the Apalachicola River. FWC GIS analysis found that this site is located near, within, or adjacent to:

- U.S. Fish and Wildlife Service Critical Habitat for the:
  - Gulf sturgeon (*Acipenser oxyrinchus desotoi*, FT)
  - Purple bankclimber (*Elliptoides sloatianus*, FT)
  - Fat three-ridge (*Amblema neislerii*, Federally Endangered [FE])

- Potential habitat for the:
  - Barbour's map turtle (*Graptemys barbouri*, SSC)

The undeveloped Shoal River Site (Walton County) is located on the Shoal River approximately 3 miles northwest of Mossy Head, Florida. The property is predominantly in pine plantation. FWC GIS analysis found that this site is located near, within, or adjacent to:

- U.S. Fish and Wildlife Service Consultation Area for the:
  - Red-cockaded woodpecker (*Picoides borealis*, FE)

- U.S. Fish and Wildlife Service Critical Habitat for the:
  - Southern sandshell mussel (*Hamiota australis*, FT)
  - Choctaw bean (*Villosa choctawensis*, FE)
  - Narrow pigtoe (*Fusconaia escambia*, FT)
  - Fuzzy pigtoe (*Pleurobema strodeanum*, FT)

- Potential habitat for the:
  - Gopher tortoise (*Gopherus polyphemus*, State Threatened [ST])
  - Blackmouth shiner (*Notropis melanostomus*, ST)
  - Bluenose shiner (*Pteronotropis welaka*, SSC)
  - Alligator snapping turtle (*Macrochelys temminckii*, SSC)
  - Eastern indigo snake (*Drymarchon couperi*, FT)
  - Pine barrens treefrog (*Hyla andersonii*, SSC)
  - Florida black bear (*Ursus americanus floridanus*)

The undeveloped Caryville Site (Holmes and Washington counties) is approximately 1.5 miles northeast of Caryville, Florida, and adjacent to the Choctawhatchee River. The property is predominantly in agriculture and pine plantation. FWC staff conducted a GIS analysis and found that this site is located near, within, or adjacent to:

- U.S. Fish and Wildlife Service Critical Habitat for the:
  - Gulf sturgeon (*Acipenser oxyrinchus desotoi*, FT)
  - Southern sandshell mussel (*Hamiota australis*, FT)
  - Choctaw bean (*Villosa choctawensis*, FE)

- Southern kidneyshell (*Ptychobranchus jonesi*, FE)
- Tapered pigtoe (*Fusconaia burki*, FT)
- Fuzzy pigtoe (*Pleurobema strodeanum*, FT)

- Potential habitat for the:
  - Gopher tortoise (*Gopherus polyphemus*, ST)
  - Barbour's map turtle (*Graptemys barbouri*, SSC)
  - Bluenose shiner (*Pteronotropis welaka*, SSC)
  - Eastern indigo snake (*Drymarchon couperi*, FT)
  - Pine barrens treefrog (*Hyla andersonii*, SSC)
  - Alligator snapping turtle (*Macrochelys temminckii*, SSC)
  - Florida black bear (*Ursus americanus floridanus*)

The undeveloped North Escambia Property Site (Escambia County) is approximately 5 miles southwest of Century, Florida near County Road 4 and U.S. Highway 29. The site contains part of the Mitchell Creek drainage basin. FWC GIS analysis found that this site is located near, within, or adjacent to:

- Potential habitat for the:
  - Gopher tortoise (*Gopherus polyphemus*, State Threatened [ST])
  - Harlequin darter (*Etheostoma histrio*, SSC)
  - Sherman's fox squirrel (*Sciurus niger shermani*, SSC)

With the addition of the information provided above, FWC finds that Gulf Power's 2016 10-year Site Plan 2016-2025 document is suitable for planning purposes and the plan proposes no significant impacts to fish and wildlife resources as written. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions regarding the content of this letter, please contact Theodore Hoehn at (850) 488-8792 or by email at ted.hoehn@MyFWC.com.

Sincerely,

Jennifer D. Goff

Jennifer D. Goff
Land Use Planning Program Administrator
Office of Conservation Planning Services

jdg/th
ENV 2-11-4/3
Gulf Power Company 2016 Ten-Year Site Plan_ 30922_070616
Enclosure

cc: Robert McGee, Jr., Gulf Power, RLMMCGEE@southernco.com

Florida Fish and Wildlife Conservation Commission

Office of the Executive Director
Nick Wiley
Executive Director

(850) 487-3796
(850) 921-5786 FAX

620 South Meridian Street
Tallahassee, Florida
32399-1600
Voice: (850) 488-4676

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MyFWC.com

June 7, 2012

Mr. Phillip Ellis
Division of Regulatory Analysis
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
pellis@psc.statea.fl.us

RE: Gulf Power 2012 10-Year Site Plan, Multi-County

Dear Mr. Ellis:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the Gulf Power 2012 10-Year Site Plan and provides the following comments and recommendations for your consideration.

Project Description

Section 186.801, Florida Statutes requires electric generating facilities to submit a ten-year site plan to the Florida Public Service Commission. Gulf Power owns and operates five plants in Northwest Florida: Plant Crist (Escambia County); Plant Lansing Smith (Bay County); Plant Sholtz (Jackson County); Pea Ridge (Santa Rosa County); and Perdido (Escambia County). Gulf Power has continued to evaluate the construction of generating facilities or the acquisition of equivalent capacity resources in coordination with other Southern Electric System (SES) operating companies. Gulf Power indicates that it has satisfied its need for firm capacity through the May 2023 time period. Any new facility construction is deferred during the 2012-2021 planning cycle. Gulf Power will consider additional capacity at its existing sites at the Plant Crist, Plant Lansing Smith, Plant Scholtz, or at the identified sites on the Shoal River property in Walton County or the Caryville property in Holmes and Washington Counties.

Potentially Affected Resources

Plant Crist (Escambia County) is located adjacent to the Escambia River, which has been designated as Critical Habitat for the Gulf Sturgeon [*Acipenser oxyrinchus desotoi* – Federal Threatened (FT)]. The undeveloped portion of the site includes mixed hardwoods/pines and mixed scrub.

Plant Lansing Smith (Bay County) is located along North Bay of the St. Andrews Bay system. The undeveloped portion of the site is predominantly pine plantation with some wetland areas. The site is adjacent to areas identified for conservation under the Bay County Sector Plan.

Plant Scholtz (Jackson County) is located adjacent to the Apalachicola River. The site consists of a mixture of pine and hardwood forests. Plant Scholtz is adjacent to the Apalachicola River, which has designated critical habitat for the Gulf Sturgeon

[*Acipenser oxyrinchus desotoi* (FT)], and critical habitat for the purple bankclimber [*Elliptoides sloatianus* (FT)] and fat three-ridge [*Amblema neislerii* - Federal Endangered (FE)].

The undeveloped Shoal River Site (Walton County) is located on the Shoal River approximately 3 miles northwest of Mossy Head, Florida. The property is predominantly in pine plantation. The site falls within a federally designated red-cockaded woodpecker consultation area; and contains primary and secondary habitat for the Florida black bear [*Ursus americanus floridanus* – State Threatened (ST)]. This site is also within close proximity to known occurrences of southern sandshell mussel (*Hamiota australis* – Federal, Candidate Endangered), blackmouth shiner [*Notropis melanostomus* – State Endangered (SE)], bluenose shiner [*Pteronotropis welaka* – State Species of Special Concern (SSC)], Eastern indigo snake [*Drymarchon couperi* – (FT)], alligator snapping turtle [*Macrochelys temminckii* (State SSC)], gopher tortoise [*Gopherus polyphemus* – (ST)], and pine barrens treefrog [*Hyla andersonii* (State SSC)].

The undeveloped Caryville Site (Holmes/Washington County) is approximately 1.5 miles northeast of Caryville, Florida. The property is predominantly in agriculture and pine plantation. The site may contain gopher tortoise [*Gopherus polyphemus* (ST)], pine barrens treefrog [*Hyla andersonii* (State SSC)], and the Eastern indigo snake [*Drymarchon couperi* (FT)]. The site is also within close proximity to the Choctawhatchee River, which contains critical habitat for the Gulf Sturgeon [*Acipenser oxyrinchus desotoi* (FT)] and known occurrences of Barbour's Map Turtle [*Graptemys barbouri* (State SSC)], Fuzzy Pigtoe (*Pleurobema strodeanum* – Federal, Candidate Endangered), and bluenose shiner [*Pteronotropis welaka* (State SSC)].

FWC appreciates the opportunity to review Gulf Power's 2012 10-year Site Plan 2012-2021 document and extends an offer to assist Gulf Power in further identifying fish and wildlife resources within their planning area. Based on our review, we have determined that there are no development plans proposed in this Gulf Power Planning document that appear to pose significant fish and wildlife resource issues or potential conflicts for this planning period. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions regarding the content of this letter, please contact Theodore Hoehn at 850-488-8792 or by email at ted.hoehn@myfwc.com.

Sincerely,

for, Scott Sanders, Director
Office of Conservation Planning Services

ss/bg/th
ENV 2-11-4/3
Gulf Power Company 2012 10-year Site Plan_16170_060712
cc: Susan Ritenour, Gulf Power, SDRITENO@southernco.com

From: Bull, Robert (Bobby)
To: Moni Mtenga
Cc: Mulkey, Cindy; Seiler, Ann
Subject: DEP-Siting Coordination Office TYSP Review
Date: Thursday, June 30, 2016 2:00:44 PM

Good afternoon,

The Department of Environmental Protection's Siting Coordination Office has reviewed the 2016 Ten-Year Site Plans for Florida's Electric Utilities and found the documents to be adequate for planning purposes. Thank you for the opportunity to review and comment on the plans.

Bobby Bull, P.E.
Siting Coordination Office
2600 Blair Stone Road MS 5500
Tallahassee, FL 32399
Robert.Bull@dep.state.fl.us
850/717-9111

TREASURE COAST REGIONAL PLANNING COUNCIL

Report on the

Florida Power & Light Company Ten Year Power Plant Site Plan 2016-2025

July 15, 2016

Introduction

Each year every electric utility in the State of Florida produces a ten year site plan that includes an estimate of future electric power generating needs, a projection of how those needs will be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The Florida Public Service Commission (FPSC) has requested that Council review the most recent ten year site plan prepared by Florida Power & Light Company (FPL). The purpose of this report is to summarize FPL's plans for future power generation and provide comments for transmittal to the FPSC.

Summary of the Plan

The plan indicates that total summer peak demand is expected to grow by 9.9 percent from 24,170 megawatts (MW) in 2016 to 26,572 MW in 2025. During the same period, FPL is expecting to reduce electrical use through demand side management programs, which include a number of conservation, energy efficiency, and load management initiatives. FPL's demand side management programs are expected to grow by 26.7 percent from 1,842 MW in 2016 to 2,334 MW in 2025. After FPL's demand side management efforts are factored in, FPL will still require additional capacity from conventional power plants to meet future electrical demand (Exhibit 1). FPL is proposing to add a total of about 2,989 MW of summer capacity to its system from 2016 to 2025. FPL plans to obtain additional electricity through: 1) power purchases from qualifying facilities, utilities, and other entities; 2) upgrades to existing facilities; 3) modernization of existing FPL facilities; and 4) construction of new generating units. Major additions of new generating capacity are as follows:

- 2016 – place in service the Port Everglades Next Generation Clean Energy Center (1,237 MW) in the City of Hollywood;
- 2017 – place in service five new combustion turbines to replace gas turbines at the Lauderdale site (1,155 MW) in Broward County;
- 2019 – place in service the Okeechobee Next Generation Clean Energy Center (1,633 MW) in Okeechobee County; and
- 2024 – place in service a new combined cycle power plant (1,317 MW) (not sited).

Based on the projection of future resource needs, FPL has identified the following seven preferred sites for future power generating facilities:

1. Babcock Ranch Solar Energy Center, Charlotte County
2. Citrus Solar Energy Center, DeSoto County

3. Manatee Solar Energy Center, Manatee County
4. Lauderdale Plant Peaking Facilities, Broward County
5. Fort Myers Plant Peaking Facilities, Lee County
6. Okeechobee Site, Okeechobee County
7. Turkey Point Plant, Miami-Dade County

Also, FPL has identified six potential sites for new or expanded power generating facilities. The identification of potential sites does not represent a commitment by FPL to construct new power generating facilities at these sites. The potential sites include:

1. Alachua County
2. Hendry County
3. Martin County
4. Miami-Dade County
5. Putnam County
6. Volusia County

The ten year site plan describes five factors that have impacted or could impact FPL's resource plan. These factors include:

1. Maintaining/enhancing fuel diversity in the FPL system.
2. Maintaining a balance between load and generating capacity in southeastern Florida, particularly in Miami-Dade and Broward counties.
3. Maintaining an appropriate balance of demand side management and supply resources to achieve system reliability.
4. The impact of federal and state energy efficiency codes and standards on FPL's forecasted future demand and energy requirements.
5. The increasing cost competitiveness of utility-scale photovoltaic (PV) facilities due to the continued decline of the cost of PV modules and the recent extension of federal tax credits.

Evaluation

One of the main purposes of preparing the ten year site plan is to disclose the general location of proposed power plant sites. The FPL ten year site plan identifies no preferred sites and one potential site for future power generating facilities in the Treasure Coast Region (Exhibit 2). The only potential site identified in the Treasure Coast Region is Martin County. The plan indicates FPL is currently evaluating potential sites in Martin County for a future PV facility. No specific locations have been selected at this time.

One preferred site, the Okeechobee site is located in northeastern Okeechobee County directly adjacent to Indian River County. Natural gas is expected to be supplied by an existing pipeline as well as a future pipeline. The FPSC issued a determination of need order approving this unit on January 19, 2016. The Florida Department of Environmental Protection has recently issued a final order approving certification of this facility. Indian River County was a party to the site certification proceeding and FPL coordinated with Indian River County regarding possible impacts to the county. The conditions of certification for the new Okeechobee Next Generation Clean Energy Center address impacts to Indian River County related to traffic, traffic impact fees, and emergency services.

The ten year site plan indicates that fossil fuels will be the primary source of energy used to generate electricity by FPL during the next 10 years (Exhibit 3). The plan indicates fossil fuels will account for 72.6 percent (3.3 percent from coal, 1.5 percent from oil, and 67.8 percent from natural gas) of FPL's electric generation in 2016. The plan predicts fossil fuels will account for 72.6 percent (2.7 percent from coal, 0 percent from oil, and 69.9 percent from natural gas) of FPL's electric generation in 2025. During the same period, nuclear sources are predicted to change from 23.9 percent in 2016 to 23.1 percent in 2025. Solar sources are predicted to increase from 0.1 percent in 2016 to 1.0 percent in 2025.

Renewable Energy

The 10 year site plan indicates FPL is increasing its efforts to implement cost-effective renewable energy. The factors driving these efforts are: 1) the price of PV modules has declined in recent years; 2) FPL has developed a methodology with which it can assign a firm capacity benefit for meeting FPL's summer peak load to PV; and 3) FPL has concluded from its implementation and analyses of utility-scale PV and PV demand side pilot programs that utility-scale PV applications are the most economical way to utilize solar energy. FPL's efforts to increase use cost-effective renewable energy include the use of utility-scale PV facilities and distributed generation PV pilot programs, which are described below.

Utility-scale PV Facilities. FPL is planning to add three new PV facilities by the end of 2016. These are the Babcock Ranch Solar Energy Center in Charlotte County, Citrus Solar Energy Center in DeSoto County, and Manatee Solar Energy Center in Manatee County. Each of the PV facilities will be approximately 74.5 MW. These new facilities will be in addition to the existing Martin Next Generation Solar Energy Center (75 MW) in Martin County, the DeSoto Next Generation Solar Energy Center (25 MW) in DeSoto County, and the Space Coast Next Generation Solar Energy Center (10 MW) in Brevard County. The new facilities will increase FPL's solar generation capacity from its current 110 MW to approximately 333 MW. Also, FPL is projecting the addition of another approximately 300 MW of PV that will be added by the year 2021. This will result in an approximate doubling of FPL's PV generation from the 333 MW level by the end of 2016 to approximately 633 MW by 2021. A final determination of the siting of this 300 MW of additional PV has not yet been made.

Distributed Generation PV Pilot Programs. FPL has three types of distributed generation (DG) PV programs. First is the *Community-based Solar Partnership Pilot Program*, which is a voluntary solar pilot program to provide customers with an additional and flexible opportunity to support development of solar power in Florida. This pilot program will provide all customers the opportunity to support the use of solar energy at a community scale and is designed for customers who do not wish, or are not able, to place solar equipment on their roof. Customers can participate in the program through voluntary contributions of $9/month. The voluntary contribution is required, because the cost per MW to construct this type of distributed generation scale facility is approximately double the cost of utility scale facilities. Also, the operation and maintenance costs of these facilities are expected to be three times as much as for utility-scale PV systems. The first 175 kW of DG PV projects under this pilot program are located in the City of West Palm Beach and in Broward County. Additional PV facilities under this program will be built when the projected voluntary contributions are sufficient to cover on-going program costs without increasing electric rates for all customers. The locations of additional PV facilities have not yet been determined.

The second type of DG PV program is the *Commercial and Industrial Partnership Pilot Program*. This pilot program will be conducted in partnership with interested commercial and industrial customers over about a five year period. Limited investments will be made in PV facilities located at customer sites in selected geographic areas of FPL's service territory. The primary objective of this program is to examine the effect of high penetration of DG PV on FPL's distribution system and to determine how best to address any problems that may be identified. FPL will site approximately 4 MW of PV facilities on circuits that experience specific loading conditions to better study impacts. PV installations at Daytona International Speedway, Daytona Kennel Club and Poker Room, and Florida International University’s Engineering Center campus in West Miami-Dade County have been selected based on their interconnection with targeted circuits.

The third type of DG PV program is the *Battery Storage Pilot Program*. The purpose of this pilot program is to demonstrate and test a wide variety of battery storage grid applications. In addition, the pilot program is designed to help FPL learn how to integrate battery storage into the grid. Under this pilot program, FPL is installing a 1.5 MW battery storage system in Miami-Dade County. In addition, a battery storage system of 1.5 MW is also being installed in Monroe County for backup power and voltage support. Several smaller kilowatt-scale systems are also being installed at other locations to study distributed storage reliability applications.

Conclusion

Council is encouraged that FPL will have tripled its solar capacity by building three more 74.5 MW solar energy centers by the end of 2016. The amount of electricity generated by FPL’s six solar plants will be the equivalent of 65,000 residential rooftop solar installations. FPL is preparing to build even more large scale solar projects in the next 5 years, while at the same time constructing and operating highly efficient natural gas plants that have decreased dependence on foreign oil and saved energy costs. This has resulted in FPL having the lowest rates of all electric utilities in the State of Florida and among the lowest rates in the nation.

Council recommends that FPL continue to make progress toward adopting a more balanced portfolio of fuels that includes a significant component of renewable energy sources. This is important to reduce vulnerability to fuel price increases and supply interruptions. Council continues to encourage the Florida Legislature to adopt a Renewable Portfolio Standard in order to provide a mechanism to expand the use of renewable energy in Florida.

Council supports FPL’s existing and proposed solar projects and encourages FPL to develop additional projects based on renewable resources. FPL should consider developing other programs to install, own, and operate PV units on the rooftops of private and public buildings.

The shift to rooftop PV systems distributed throughout the area of demand could reduce reliance on large transmission lines and reduce costs associated with owning property; purchasing fuel; and permitting, constructing, and maintaining a power plant. Another advantage of this strategy is that PV systems do not require water for cooling. The incentive for owners of buildings to participate in this strategy is they could be offered a reduced rate for purchasing electricity. Also, FPL should consider expanding solar rebate programs for customers who install PV and solar water heating systems on their homes and businesses. These rebates should be coordinated with other programs, such as the Solar and Energy Loan Fund (SELF) and Property-Assessed Clean Energy (PACE) programs, to provide participants in these programs the option of receiving a rebate. SELF is a low interest rate loan program that provides financing for clean energy solutions. PACE programs allow property owners to finance energy retrofits by placing an additional tax assessment on the property in which the investment is made.

Council urges FPL and the State of Florida to continue developing new programs to: 1) reduce the reliance on fossil fuels as future energy sources; 2) increase conservation activities to offset the need to construct new power plants; and 3) increase the reliance on renewable energy sources to produce electricity. The complete costs of burning fossil fuels, such as the costs to prevent environmental pollution and costs to the health of the citizens, need to be considered in evaluating these systems. State legislators should amend the regulatory framework to provide financial incentives for the power providers and the customers to increase conservation measures and to rely to a greater extent on renewable energy sources. Also, the state should reconsider the currently used test for energy efficiency and choose a test that will maximize the potential for energy efficiency and renewable energy sources. The phasing in of PV and other locally available energy sources will help Florida achieve a sustainable future.

Attachments

Exhibit 1

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

Year *	Projected Capacity & Firm Purchase Power Changes	Summer MW	Date	Summer Reserve Margin **
2016	Fort Myers 2	8	January 2016	
	Fort Myers 3A	25	June 2016	
	Martin 4	15	April 2016	
	Martin 8	(5)	March 2016	
	Port Everglades Next Generation Clean Energy Center	1,237	April 2016	
	Total of MW changes to Summer firm capacity:	**1,280**		**22.0%**
2017	Babcock Solar Energy Center (Charlotte) ***	38	December 2016	
	Citrus Solar Energy Center (DeSoto) ***	38	December 2016	
	Manatee Solar Energy Center ***	38	December 2016	
	Unspecified Short-Term Purchase	53	April 2016	
	Turkey Point Unit 1 synchronous condenser	(396)	December 2016	
	Port Everglades GTs	(412)	October 2016	
	Cedar Bay	(250)	January 2017	
	Lauderdale GT 1-12	(343)	October 2016	
	Lauderdale GT 13-22	(412)	October 2016	
	Lauderdale GTs - 5 CT	1,155	December 2016	
	Fort Myers - 2 CT	462	December 2016	
	Fort Myers 3B	25	July 2016	
	Fort Myers GT 1- 12	(486)	June 2016	
	Martin 3	27	August 2016	
	Martin 4	13	April 2016	
	Martin 8	(5)	March 2016	
	Manatee 3	(11)	May 2017	
	Total of MW changes to Summer firm capacity:	**(465)**		**20.0%**
2018	Unspecified Short-Term Purchase	324	April 2018	
	Sanford 4	(1)	September 2017	
	Sanford 5	(1)	July 2017	
	Turkey Point Nuclear Unit #5	(15)	January 2018	
	Total of MW changes to Summer firm capacity:	**307**		**20.0%**
2019	Turkey Point Nuclear Unit #3	20	Fall 2018	
	Turkey Point Nuclear Unit #4	20	Spring 2019	
	Okeechobee Next Generation Clean Energy Center	1,633	June 2019	
	Total of MW changes to Summer firm capacity:	**1,673**		**24.6%**
2020	SJRPP suspension of energy	(382)	4th Qtr 2019	
	Unsited Solar (PV)	156	June 2020	
	Total of MW changes to Summer firm capacity:	**156**		**22.2%**
2021	Eco-Gen PPA firm capacity	180	January 2021	
	Cape Next Generation Clean Energy Center	88	Spring 2021	
	Total of MW changes to Summer firm capacity:	**268**		**23.0%**
2022	Riviera Beach Next Generation Clean Energy Center	86	Spring 2022	
	Total of MW changes to Summer firm capacity:	**86**		**22.5%**
2023	---	---	---	
	Total of MW changes to Summer firm capacity:	**0**		**21.2%**
2024	Unsited CC	1,622	June 2024	
	Total of MW changes to Summer firm capacity:	**1,622**		**26.5%**
2025	---	---	---	
	Total of MW changes to Summer firm capacity:	**0**		**24.7%**

* Year shown reflects when the MW change begins to be accounted for in Summer reserve margin calculations.

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

*** MW values shown for the PV facilities represent the firm capacity assumptions for the PV facilities.

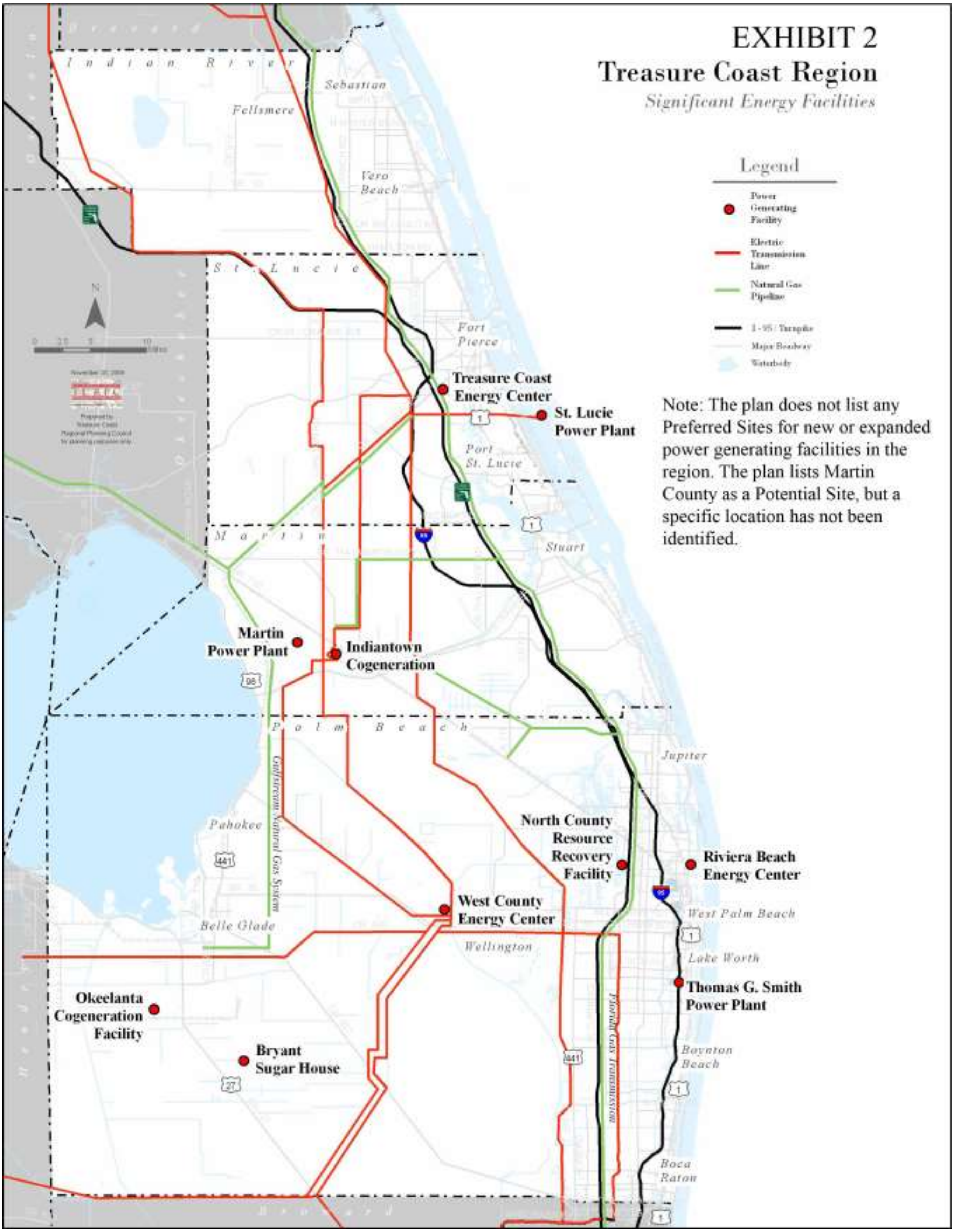
EXHIBIT 2
Treasure Coast Region
Significant Energy Facilities
Legend
Power Generating Facility
Electric Transmission Line
Natural Gas Pipeline
I - 95 / Turnpike
Major Roadway
Waterbody
Treasure Coast Energy Center
St. Lucie Power Plant
Martin Power Plant
Indiantown Cogeneration
North County Resource Recovery Facility
Riviera Beach Energy Center
West County Energy Center
Thomas G. Smith Power Plant
Okeelanta Cogeneration Facility
Bryant Sugar House
Sebastian
Fellsmere
Vero Beach
Fort Pierce
Port St. Lucie
Stuart
Jupiter
Pahokee
Belle Glade
Wellington
West Palm Beach
Lake Worth
Boynton Beach
Boca Raton
Indian River
St. Lucie
Martin
Palm Beach
Gulfstream Natural Gas System
Florida Gas Transmission
Note: The plan does not list any Preferred Sites for new or expanded power generating facilities in the region. The plan lists Martin County as a Potential Site, but a specific location has not been identified.

Exhibit 3

Schedule 6.2
Energy Sources % by Fuel Type

Energy Source	Units	Actual [1] 2014	2015	Forecasted 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
(1) Annual Energy Interchange [2]	%	4.2	3.9	1.1	0.7	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0
(2) Nuclear	%	23.1	22.0	23.9	23.8	23.6	24.0	23.4	23.2	23.6	23.0	22.9	23.1
(3) Coal	%	3.9	4.3	3.3	2.3	2.2	2.6	2.4	2.8	2.8	2.7	2.9	2.7
(4) Residual (FO6) -Total	%	0.2	0.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5) Steam	%	0.2	0.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6) Distillate (FO2) -Total	%	0.1	0.1	1.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
(7) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8) CC	%	0.1	0.1	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9) CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10) Natural Gas -Total	%	68.2	69.9	67.8	70.8	70.7	69.9	71.2	70.2	69.6	69.9	69.9	69.9
(11) Steam	%	1.6	3.5	1.7	1.8	0.9	0.5	0.3	0.3	0.4	0.4	0.1	0.1
(12) CC	%	66.3	66.0	66.1	68.6	69.6	69.3	70.7	69.8	69.1	69.3	69.8	69.7
(13) CT	%	0.3	0.4	0.0	0.4	0.2	0.1	0.1	0.1	0.1	0.2	0.1	0.1
(14) Solar [3]	%	0.2	0.1	0.1	0.5	0.5	0.5	1.0	1.0	1.0	1.0	1.0	1.0
(15) PV	%	0.1	0.1	0.1	0.5	0.5	0.5	1.0	1.0	1.0	1.0	1.0	1.0
(16) Solar Thermal	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(17) Other [4]	%	0.1	-0.6	2.2	2.0	2.1	2.1	1.9	2.6	2.8	3.1	3.2	3.2
		100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report
2/ The projected figures are based on estimated energy purchases from SJRPP.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales.

Southwest Florida Water Management District
2379 Broad Street, Brooksville, Florida 34604-6899
(352) 796-7211 or 1-800-423-1476 (FL only)
WaterMatters.org

An Equal Opportunity Employer

Bartow Service Office
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Sarasota, Florida 34240-9711
(941) 377-3722 or
1-800-320-3503 (FL only)

Tampa Service Office
7601 U.S. 301 North (Fort King Highway)
Tampa, Florida 33637-6759
(813) 985-7481 or
1-800-836-0797 (FL only)

June 24, 2016

Mr. Moniaishi Mtenga, Engineering Specialist
Division of Engineering
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Subject: Electric Utility 2016 Ten-Year Site Plans

Dear Mr. Mtenga:

In response to your request, the Southwest Florida Water Management District (District) has completed its review of the 2016 Ten-Year Site Plans for Duke Energy Florida, Florida Power & Light Company, Seminole Electric Cooperative and Tampa Electric Company. The District's review is being conducted pursuant to Section 186.801(2)(e), Florida Statutes, which requires the Public Service Commission to consider "the views of the appropriate water management district as to the availability of water and its recommendation as to the use by the proposed plant of salt water or fresh water for cooling purposes." Based on our review, all four utilities are proposing to construct new combustion turbine or combined cycle facilities at undesignated sites within the ten-year planning horizon.

The District offers the following technical assistance comments for consideration:

- The most water conserving practices must be used in all processes and components of the power plant's water use that are environmentally, technically and economically feasible for the activity, including reducing water losses, recycling, and reuse. If a lower quality water is available and is environmentally, technically and economically feasible for all or a portion of the proposed use, this lower quality water must be used.

- For new generating facilities proposed in the southern and much of the central portions of the District, there are additional water use constraints. These areas have been designated as Water Use Caution Areas. This designation has occurred in response to water resource impacts, such as salt water intrusion, lowered water levels in lakes and wetlands, and reduced stream flows, which have been caused by excessive ground water withdrawals. Regional recovery strategies are being implemented to address these adverse water resource impacts. Consequently, the District has heightened concerns regarding potential impacts due to additional water withdrawals.

Early coordination with the District's Water Use Permit (WUP) staff is encouraged prior to submittal of any Site Certification or WUP applications. For assistance or additional information concerning the District's WUP program, please contact Darrin Herbst, WUP bureau chief in the District's Tampa office, at (813) 985-7481, extension 2014, or darrin.herbst@watermatters.org.

We appreciate this opportunity to participate in the review process. If you have any questions or require further assistance, please do not hesitate to contact me at (352) 796-7211, extension 4790, or james.golden@watermatters.org.

Sincerely,

James J. Golden, AICP
Senior Planner

JG

St. Johns River Water Management District

Ann B. Shortelle, Ph.D., Executive Director

Date: July 1, 2016

From: Richard Burklew, Bureau Chief, Water Use Regulation

To: Florida Public Service Commission

Subject: Review of 2016 Ten-Year Power Plant Site Plan for Electric Utilities

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The relevant statute for ten-year review of Site Plans is Section 186.801, F.S.. The portion of this statute relevant to District review includes the following:

…In its preliminary study of each 10-year site plan, the commission shall consider such plan as a planning document and shall review:

(c) The anticipated environmental impact of each proposed electrical power plant site.….

(e) The views of appropriate local, state, and federal agencies, including the views of the appropriate water management district as to the availability of water and its recommendation as to the use by the proposed plant of salt water or fresh water for cooling purposes….

Individual Site Plan Reviews:

Florida Power & Light – The Site Plan includes the addition of the Okeechobee Clean Energy Center (OCEC), which is a proposed new facility planned for operation in 2019. OCEC will be authorized to use approximately 9 mgd of groundwater. However, the certification will require conversion to lower quality water sources when feasible. The Site Plan reflects information submitted and reviewed by the District during the site certification review process. District staff considered this information and recommended approval of the project to the District's Governing Board. The Governing Board approved its agency report regarding OCEC in March 2016. The Site Plan discusses two other potential sites in Alachua and Volusia Counties. Both of these sites are proposed as photovoltaic plants with minimal water resource needs. Beyond these three sites, no additional new significant resource needs until 2024 and 2025. The submitted Site Plan is suitable as a planning document.

Seminole Electric Cooperative – The Site Plan discusses addition of a total of 1700 MW by 2025, including four 224 MW natural gas Combustion Turbine (CT) units, one 741 MW natural gas Combined Cycle (CC) unit, and an additional 2 MW photovoltaic (PV) plant. Of these facilities, only the CC unit is proposed for wet cooling and the CT units will be air-cooled. None of the CC or CT units have been sited yet and water sources are not discussed. Potential site locations are in Gilchrist County and at the existing Seminole Generating Station (SGS) in Putnam County. The existing SGS uses surface water from the St. Johns River for cooling and, presumably, if this site is selected for the proposed CC unit, could potentially be a source of cooling water for this unit.

The preferred future site for PV generation is at the existing Midulla Generating Station (Hardee County). This plant would have minimal water use obtained by water trucks or from existing onsite permitted resources. Submitted Site Plan is suitable as a planning document.

JEA – The Site Plan discusses continuation of the existing generating facilities, expiration of the agreement between JEA and Florida Power & Light for the joint ownership of the St. Johns River Power Park and expiration of the wholesale power agreement to supply Florida Public Utilities. The plan forecasts additional power purchased from two new nuclear units at the Plant Vogtle in Georgia. Based on expiration of wholesale and joint ownership agreements and the commitment to purchase nuclear power, there is no anticipated expansion of water use at the existing power generation facilities beyond what is currently permitted. The submitted Site Plan is suitable as a planning document

Orlando Utilities Commission (OUC) – The OUC Site plan discusses continued operation of existing facilities, power purchase and sales contracts, renewable energy and sustainability initiatives and future demand projections. Consideration of OUC's existing generating resources and OUC's current base case load forecast indicates that OUC is expecting to have adequate capacity to satisfy forecast reserve margin requirements until the summer of 2021. Based on the magnitude and timing of OUC's projected need for capacity, it has been assumed for purposes of the Ten-Year Site Plan that OUC will have to add combined cycle capacity to meet the projected capacity requirements. It was noted that OUC's existing Stanton Energy Center and Indian River sites may accommodate future generating unit additions. However, OUC has not made any commitments to new capacity additions, and will continue to evaluate its power supply requirements and alternatives as part of its planning processes. There is no defined or declared expansion of water use at the existing power generation facilities beyond what is currently permitted. The submitted Site Plan is suitable as a planning document.

MEMORANDUM

Date: July 1, 2016

To: Shaun Cullinan, Planning and Zoning Official

From: Matt Trepal, Principal Planner and Ken Quillen, Planner III

Subject: Review of *Ten Year Power Plant Site Plan 2016-2025* for Florida Power and Light

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The Comprehensive Planning Division has completed their review of the Florida Power and Light's *Ten Year Power Plant Site Plan 2016-2025* and has the following comments.

This ten year Plan includes the Babcock Solar Energy Center, which is a new 74.5 MW photovoltaic (PV) electric generating plant in Charlotte County near the developing Babcock Ranch Community in East County. Related facilities include the Tuckers substation, located near the Babcock Solar Energy Center, and the Hercules substation, located near Fire Station No. 9 and the Babcock Ranch Community. Transmission lines are also being constructed linking these two substations. Charlotte County has been aware of this proposed new power generation plant for some time. These facilities are now under construction and are intended to be completed and in service by December of this year. This facility will serve the planned Babcock Ranch Community, which is now under construction.

Planning staff believes that this is a suitable planning document which describes its existing electric generation and distribution capacity (owned or purchased) as well as projected future resource needs. This planning document states that it was designed to focus on projected supply side additions of electric generation capability and the locations for these additions. We believe that FPL has done a good job of calculating future needs, or load, and generating capacity based on past and present demand by traditional land uses, such as, residential, commercial, industrial uses. However, there is an emerging new demand for electricity from plug-in electric vehicles.

Staff understands that it may be difficult to anticipate how fast this new demand may grow in the next five to ten years and this is a subject of much discussion and speculation today in the planning field. This new market could create a tremendous new demand for electricity. The Plan has taken this into account and does forecast an additional load of approximately 1,091 GWh by 2025 from new plug-in vehicles. The only suggestion our planning staff would make regarding this Plan is that more information regarding how the anticipated future demand for plug-in electric vehicles is being calculated. Maybe the Florida Department of Motor Vehicles can use licensing information to determine the number of plug-in electric vehicles there are each year so that the rate of increase in numbers, and therefore demand, could be watched and monitored accordingly.

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October 3, 2016

Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399

Re: 2015 Ten Year Site Plans

Dear Commissioners and Staff:

Thank you for the opportunity to Southern Alliance for Clean Energy (SACE) to provide written comments on the utilities' 2016 Ten Year Site Plans and opportunities for providing additional customer value.

SACE is a non-profit, non-partisan clean energy group that advocates for lower cost, lower risk resources in meeting electricity demand. That includes moving away from high risk, high cost resources such as coal, and diversifying the state's energy mix into resources with vast potential – such as capturing more energy efficiency and integrating higher levels of clean, abundant and low cost solar power.

SACE supports policies and plans that meaningfully increase rooftop solar, larger commercial installations, and utility-scale solar. They are all part of a healthy solar market. Solar energy benefits Florida by diversifying its resource mix to include a resource that presents no long-term cost risk, an important hedge against the likelihood that natural gas fuel prices will increase over time. Furthermore, solar arrays require no water for generation and produce no emissions subject to regulatory abatement.

All forms of solar power are seeing continuing price drops, with utility scale power purchase agreements now being signed at 3.5 to 5 cents per kilowatt hour (kWh).[i] Even though Florida is one of the largest states, it ranked just 18th in total megawatts of solar installed in 2015.[ii] As it relates to utility-scale solar, there is a significant and growing opportunity to expand and bring Florida to the forefront of this industry where it belongs.

SACE recommends that the Commission require the utilities to study supply-side solar as a resource, and provide for more market entry for supply-side solar projects. To that end, we offer several recommendations below.

Require utilities to study solar as a supply-side resource in the resource planning process

To establish effective market competition and Commission regulatory oversight of solar energy supply decisions, the Commission should reform resource planning rules. Florida's current planning requirements include four steps: the Ten-Year Site Plan (TYSP); Request for Proposal (RFP) process; Need Determination; and Site Certification. Solar power projects under 75 MW are effectively exempt from these steps, except for a requirement to revise the TYSP to include those projects (but there is no clear deadline for such revisions as discussed below).

Utility resource plans are required to be described in an annual TYSP, which has extensive information and data requirements. The TYSP is submitted to the Florida PSC annually by electric generation utilities with a generating capacity greater than 250 MW.[iii] The Commission reviews the plans within nine months following submission and reports its findings, along with any comments or recommendations, to the Florida Department of Environmental Protection and the utilities filing a plan. The Commission also creates a statewide TYSP from the provided information.

The Commission makes a preliminary study of each plan and classifies it as "suitable" or "unsuitable." It should be noted that "suitability" has not been defined in statute or rule, but unsuitability may be remedied by the utility providing additional data.[iv] The Commission may suggest alternatives to the plan. It is recognized that 10-year site plans submitted by an electric utility are *tentative information* for planning purposes only and may be *amended at any time* at the *discretion of the utility*.[v]

For any planned generating unit over 75 MW, the utility initiates regulatory oversight when the unit is identified as the utility's next planned generating unit in a TYSP revision. Until that point, any discussion of a planned generating unit is merely informational and does not appear to have any regulatory significance. Identification of the next planned generating unit is important for a number of reasons, including the practice of basing the avoided capacity rate in standard offer contracts on the next unit (and not, for example, on the opportunity to defer subsequent units or change the type of the next unit). Even more important is that Commission rules identify this unit as the benchmark for the alternatives analysis.

The only requirement for a Florida utility to consider alternatives to the next planned generating unit is the Commission's rule requiring a RFP process for projects over 75 MW. According to that rule, "The use of a RFP process is an appropriate means to ensure that a public utility's selection of a proposed generation addition is the most cost-effective alternative available."[vi] The Commission's rules do not provide for any public review of the alternatives analysis.

However, by benchmarking alternatives against the "price and non-price attributes of its next planned generating unit," the RFP rule effectively excludes any requirement for the utility to consider alternative configurations of technology that might be more cost-effective in the long-term. FPL's RFP for 1,052 MW (March 16, 2015) provides a good example of how alternative resources are disadvantaged by such a benchmark process. Under the terms of the RFP, any proposed resources were compared to FPL's Next Planned Generating Unit, the Okeechobee Clean Energy Center, a 1,622 MW combined cycle natural gas plant.[vii]

According to the RFP, the "firm capacity and energy proposed" must be "fully dispatchable under the operational control of FPL" which would operationally exclude solar PV resources from providing even a portion of the energy, not to mention any firm summer capacity.[viii] In short, the RFP process is not capable of evaluating any alternative that is not a one-for-one replacement of the company's next planned generating unit and thus does not ensure that the selected resource is the most cost-effective means to meet the utility's identified resource needs.

Of course, Florida's utilities do undertake a more comprehensive analysis of resource needs beyond that in the RFP, utilizing what is *presumed* to be a thorough IRP analysis including consideration of resource alternatives through a computer model optimization process. However, this process is not available to the public for review during either the TYSP or the RFP process. It is only when the results of the RFP process are made known,[ix] and a request for a need determination is made, that the utility's assumptions and methods for considering alternatives can be evaluated by interested parties and the Commission.

This review is ill-timed. By the time that a utility files a request for a need determination, the utility has likely waited until what it views as the last possible moment for building the power plant. At this point, the utility has constrained its options due to schedule and potentially missed opportunities. While significant changes can and have been made, they are typically substitutions of like resources, such as the recent Duke Energy Florida substitution of a purchase of an existing combined cycle gas plant for construction of a new combined cycle gas plant.

Together these policies form a less than coordinated state planning process. The assumptions used in the utility resource planning process are only revealed through intervention and discovery in a need determination (or FEECA) proceeding. Moreover, the Ten Year Site Plan process does not provide opportunities for stakeholder input of the type found in other Southeastern states' IRP processes. The benefit of an integrated resource plan (IRP) is that it allows for meaningful stakeholder involvement and the consideration of alternate planning scenarios, which tends to place all resources on a "level playing field." Hence, Florida customers may be shouldering unnecessary costs from a less than optimal resource planning process, and the policies and programs recommended here would help to ensure that utilities are pursuing the most effective, least-cost options for electricity generation.

In order to promote the development of supply-side solar systems, the Commission could initiate a rulemaking to revise the Ten-Year Site Plan process to incorporate best practices for integrated resource planning.[x] Of particular interest would be the opportunity to ensure that the characterization of the cost and performance of solar resources is reasonable and unbiased, that the study methods are also themselves free of unreasonable bias, and that the Company leverages the resource planning process to properly evaluate a variety of market-supplied and self-build resource alternatives. To effectuate such reforms, the Commission could revise its rules to require a periodic review of the utility's entire IRP (such as every two years) or could require a utility to submit its IRP for review at least two years in advance of an anticipated certification proceeding.

Establish a process for selecting cost-effective solar resource projects, including RFPs

Even if a Florida utility determines that solar resources are the most cost-effective available, it is not clear under what Commission rules a utility would request a determination of need. As discussed above, for any solar facility 75 MW or greater, §403.503, Fla. Stat. requires a determination of need by the Commission. However, Commission rules only prescribe the content of petitions for "Fossil, Integrated Gasification Combined Cycle, or Nuclear Fuel Electric Plants."[xi]

SACE recommends that the Commission initiate a rulemaking proceeding to revise Chapter 25-22 to incorporate a process for a need determination for renewable energy resources, particularly solar, taking into consideration differing performance characteristics. For example, a utility may reasonably wish to seek a determination of need for a large solar (or other renewable resource) facility solely on the basis that the capital investment will result in a more cost-effective method of supplying electricity to its customers, even in the absence of a need for capacity. The investment may help to defer fuel, operating and maintenance costs, or free up energy for resale to other utilities during peak periods, resulting in an overall cost savings. We also recommend that the Commission identify best practices, such as long-term contracts, similar to the Gulf Power solar PPAs, that ensure the competitive solicitation process results in the most cost-effective outcome. For example, in order to meet a need (or cost-effective opportunity) for solar power in excess of 75 MW, a utility might choose a reverse auction mechanism to, as SEIA describes it, "ensure that developers are paid a price that is sufficient to bring projects online, but also provide ratepayer protection against "overpayment."[xii]

Furthermore, we would recommend that the Commission make this RFP process available, and encourage its use, for all utility-scale solar projects. Economies of scale for utility-scale projects are often achieved at 20 MW, and few projects are constructed over 100 MW in scale (particularly in a landscape with as much land use variety and constraint as Florida). Thus, the 75 MW threshold for a need determination is an unwieldy threshold for triggering the opportunity to utilize a RFP process or obtain clear approval from the Commission for the costs and prudence of a substantial generation facility.

Solar standard offer contract

We recommend the establishment of a solar-specific standard offer contract, including a contract avoided cost rate, for solar Qualifying Facilities with a capacity of up to 5 MW. Florida rules and utility practice effectively exclude small solar projects from realizing the benefits of the standard offer contract available to other small power generators under the federal Public Utility Regulatory Policies Act (PURPA). PURPA is meant to increase energy independence in the United States by requiring states to establish the prices retail utilities must pay to third-party renewable energy developers – thus giving small developers a market for their power.

Yet, in practice in Florida, solar Qualifying Facilities are ineligible for any capacity payment due to the minimum performance standards for the delivery of firm capacity.

The system size in the standard offer contract is limited to a mere 100 kW.[xiii] Developers tell us that there is great interest for projects larger than this limit. In fact, it is not unusual for business customers to install larger systems, either through a developer or with their own financing. However, these customers may not wish to enter into expensive negotiations with the utility, and will desire a streamlined process such as a meaningful standard offer contract may provide.

If a solar developer does wish to negotiate a contract for a solar project over 100 kW, such contracts are entirely at the utility's discretion. There is limited legal basis for any party to challenge a utility's decision to refuse a contract, even if it is at the same time negotiating another similar contract at a higher price.

Policies such as these will help Florida realize more solar potential at the utility scale level. The Florida Reliability Coordinating Council's (FRCC) presentation during the Ten Year Site Planning Workshop show solar expanding in Florida by only 1445 MW in the next ten years. By comparison, nearly half that amount is already installed on Georgia Power's system, and up to 1900 MW more of renewable energy may be added by 2021. Florida has greater solar potential than our neighbor to the north, and we ought to ensure that this state's policies do not create an unnatural barrier to taking advantage of our vast potential.

Moving away from coal

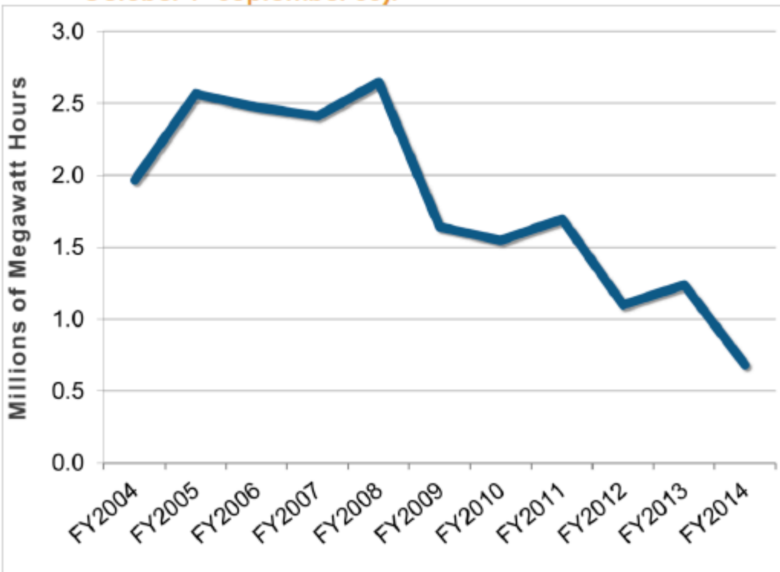
Many of the state's coal-fired power plants remain in the utilities' Ten Year Site Plans through the planning period.

This assumption is worth taking another look at, as keeping coal plants online is actually subject to a number of risks. There is good reason to plan for the case that the end of a unit's useful life falls within the next ten years. Utilities should demonstrate that they have factored these risks in, and publicly disclose scenarios in which coal-fired units are taken offline, including the relative costs of retirement compared with the continued costs and associated ratepayer risks of maintaining a coal-fired unit.

Coal is becoming a more costly choice. Coal-fired power plants have been dispatched less frequently for a number of reasons, but primarily because they are not cost-effective relative to natural gas-fired power plants. Yet many operational costs of coal plants accrue whether the plant runs or not. As a result, the cost per megawatt-hour (MWh) tends to increase when plants are run less frequently.

C.D. McIntosh Unit 3, a coal-fired unit operated by Lakeland Electric (and co-owned with Orlando Utilities Commission), exemplifies this trend. In a report commissioned by SACE, David Schlissel provides the following chart showing declining power production at the plant.[xiv]

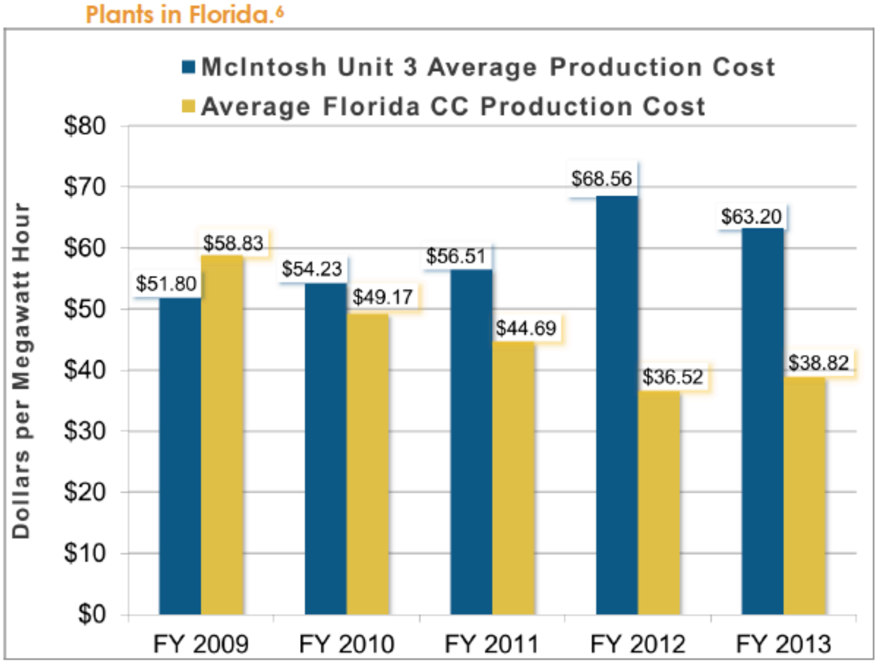
Figure 1: McIntosh Unit 3 Annual Generation in Megawatt Hours, 2004-2014 (Fiscal Years October 1- September 30).[1]



[1] The October 1 through September 30 Fiscal Years shown in Figures 1 and 2 are used in the annual utility reports published by Lakeland Electric and OUC.

The report also compares the rising cost of operating the plant with the falling cost of power available on the Florida market from natural gas.

Figure 11: Average Production Costs - McIntosh Unit 3 vs. Natural Gas-Fired Combined Cycle Plants in Florida.[6]



Competition may not fully explain the reduced dispatch rate. The report also notes that the Equivalent Forced Outage Rate for the plant is unusually high; this suggests substantial maintenance issues, and in fact subsequent to the publication of this report, Lakeland Electric took the plant out of service for maintenance for months. While these issues may be plant-specific; their significant presence at this plant, one of Florida's newer coal-fired plants, adds to the need for caution in relying on coal-fired plants far into the future.

Adding to the lack of cost competitiveness are regulatory compliance liabilities. The regulations provide much needed public health and environmental protections for Floridians. Yet, in order to comply with these standards, many plants will need significant upgrades.

For example, Gulf's Crist units 4 and 5 and JEA's Northside units use once-through cooling systems that suck massive amounts of water from the river and return most of it to the water body at a higher temperature. Both should anticipate that in the plant's next water permitting cycle, that the plants will need to make provisions to reduce thermal impacts, likely by adding a cooling tower, upgrades with costs in the hundreds of millions of dollars.[xv]

A cooling tower would also help meet modern standards for prevention of fish, fish eggs, and other wildlife from getting caught or sucked into the plant's intake, another regulatory obligation under section 316b of the Clean Water Act (CWA), which will apply upon renewal of the units' NPDES permits.

Meanwhile, Tampa Electric has already applied for cost recovery of $400,000,[xvi] just to study what will be needed to bring its Big Bend plant into compliance with new Effluent Limitation Guidelines (ELGs), which will come into play in its next CWA permit cycle. With such significant costs just for the studies, one can safely anticipate that the cost of actually converting to dry ash handling, and controlling heavy metals in the discharge water, will be significant, possibly enough to make retirement a more cost-effective option.

Coal cost risks are further increased by the need to comply with the federal Coal Combustion Residuals Rule (CCR Rule or Coal Ash Rule), which is a particular challenge for Florida coal plant operators. By 2018, operators will need to show their ash storage is not compromised by locational factors such as sinkhole-prone geology, proximity to aquifers, or being in a floodplain. Many Florida plants may be unable to comply due to Florida's geology, and may face the costly alternative of shipping the ash out of peninsular Florida.

Plant McIntosh is once again a salient example. Although dry ash storage is already in use at the site, a recent hydrogeological study found the likelihood that at a sinkhole will form under the ash landfill. Such a sinkhole could drop ash and contaminated groundwater into the Floridan aquifer. Groundwater flows in the area, as well as the presence of nearby sinkholes including at least two on the plant property, were used to determine this likelihood.[xvii,xviii]

Utilities' and FRCC's presentations at the Ten Year Site Plan workshop on September 14, 2016 indicated that impacts of the Clean Power Plan on generation choices would be addressed in the future, once federal courts resolve the challenge of the rule. We strongly urge utilities not to wait, as there are no-regrets clean energy choices that can be made now. Nevertheless, the Clean Power Plan is just one of many upcoming public health and environmental protection rules that utilities will need to address; as we outline here, there are others that will impact prudent decision-making in the resource planning process.

Conclusion

It is prudent to investigate these risks now, and research alternatives. Piecemeal decision-making needlessly exposes Florida's families and business to higher priced power while also robbing them of the wide-ranging benefits of clean water and clean energy resources that are at record low prices.

SACE appreciates the opportunity to offer these comments and looks forward to working with the Commission and its staff in the resource planning process and associated dockets to reduce customer risk and realize additional value for customers.

Sincerely,

/s/ George Cavros

Florida Energy Policy Attorney,
Southern Alliance for Clean Energy

/s/ Amelia Shenstone

Campaigns Director,
Southern Alliance for Clean Energy

[i] Solar Energy Industries Association/GTM Research, *Solar Market Insights 2016, Q3*, September 12, 2016, at http://www.seia.org/research-resources/solar-market-insight-report-2016-q3
[ii] *Id.*
[iii] R. 25-22.071, F.A.C. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 megawatts (MW) or a planned unit with a capacity of 75 MW or greater are required to file with the Commission a Ten-Year Site Plan, at least once every two years. In 2014, 11 utilities met these requirements and filed a Ten-Year Site Plan, including 4 investor-owned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). The municipal utilities, in alphabetical order, are Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric 8 (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). The sole rural electric cooperative filing a 2015 Plan is Seminole Electric Cooperative (SEC). Collectively, these utilities are referred to as the Ten-Year Site Plan Utilities (TYSP Utilities).
[iv] *Id.*
[v] § 186.801(2), Fla. Stat.
[vi] R. 25-22.082, F.A.C.
[vii] Florida Power & Light Company, *2015 Request for Proposals to Meet Generation Capacity Needs Beginning in 2019*, p. 40.
[viii] *Id.*, p. 5.
[ix] A utility's IRP analysis may also be obtained during the goal-setting proceeding under the Florida Energy Efficiency and Conservation Act (FEECA), which occurs every five years. However, utility-scale solar generation is not within the scope of that proceeding.
[x] Rachel Wilson and Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans*, Regulatory Assistance Project (June 2013).
[xi] R. 25-22.081, F.A.C.
[xii] Solar Energy Industries Association website. For example, California Public Utilities Commission's Renewable Auction Mechanism.
[xiii] R. 25-17.250, F.A.C. *See also* R. 25-17.0825(1)(b), F.A.C. (Those qualifying facilities wishing to negotiate a contract for the sale of firm capacity and energy with terms different from those in a utility's standard offer contract may do so pursuant to subsection 25-17.0832(2), F.A.C. Where parties cannot agree on the terms and conditions of a negotiated contract, either party may apply to the Commission for relief pursuant to Rule 25-17.0834, F.A.C.)
[xiv] Schlissel, David, *The Time is Right to Retire C.D. McIntosh Unit 3*. Institute for Energy Economics and Financial Analysis, October, 2015, at: http://ieefa.org/study-concludes-costly-coal-plant-in-lakeland-fla-should-be-retired-in-favor-of-solar-expansion-and-energy-efficiency-initiatives/. Attached.
[xv] Section 316a, Clean Water Act
[xvi] Tampa Electric Company, *Petition of Tampa Electric Company for approval of a new environmental program for cost recovery through the Environmental Cost Recovery Clause*, Florida PSC Docket No.160027. Filed Feb. 2, 2016.
[xvii] Diana Csank, *Memorandum to Joel Ivy, General Manager, Lakeland Electric Re: Lakeland Electric Should Cease Burning Coal and Clean Up the CCR at McIntosh Unit 3 for Economic, Regulatory, and Public Health Reasons*, January 25, 2016. Attached.
[xviii] Stewart, Mark. *Preparing for the U.S. Environmental Protection Agency's Coal Combustion Residuals Rule: Technical Assessment of the C.D. McIntosh, Jr. Power Plant CCR Storage and Disposal Facilities*, January 25, 2016. Attached.

October 10, 2016

Via electronic filing and electronic mail

Chairman Brown, Comm'rs. Brisé, Edgar, Graham, Patronis
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Re: Planning for least-cost electric service in Florida

Dear Commissioners:

Rapid changes in the electric sector make integrated resource planning more important than ever. Yet Florida electric utilities, especially the investor-owned utilities (IOUs), barely have any plans at all—besides adding natural gas-burning generation, which dwarfs everything else in their plans.[1] Sierra Club respectfully urges the Commission to reject them and require revised plans for four main reasons:

1. Florida law requires utilities to provide least-cost service, but the utilities are unprepared to do so because they fail to perform options analyses; the utilities thus never try to (nor could they) square their gas-laden plans with the alternatives available to them in the market.[2]

2. The proposed gas generation violates the least-cost standard because this generation is inherently high cost and high risk.

3. The proposed gas generation also violates the least-cost standard because it reduces fuel diversity and foregoes cost-effective renewables and energy efficiency, thereby pushing Florida's all-time high gas reliance, 71% of the state generation total, even higher, to 74%.

4. With no shortage of cost-effective alternatives in the market, especially renewables and energy efficiency, the only way to explain the utilities' gas generation proposals is that they aim to benefit entities other than customers.

[1] Unless stated otherwise, "plans" refers to ten-year site plans, and "utilities" refers to those that file them.

[2] To their credit, Staff issued extensive data requests. The responses, however, cannot cure the unlawful plans.

By now, it is unmistakable; the IOUs/their affiliates are investing heavily in every aspect of gas generation and infrastructure with a perverse incentive to continue to do so. They pass the resulting added cost of service onto their captive customers, and the resulting windfall profits to shareholders.

It is imperative that the Commission intervene and reject all of the unlawful plans. Revised plans should follow as soon as practicable. For the IOUs, this should be no later than April 1, 2017, the annual deadline for revised plans, to minimize the fallout from their conflict-ridden plans.

As we discuss below, at least one Florida utility, Lakeland Electric, recently undertook an assessments of its options under different scenarios, showing this is eminently doable. Moreover, practically all of the Florida utilities, with the glaring exception of the IOUs, have issued requests for proposals (RFPs) for renewables and found no shortage of cost-effective solar generation options in the Florida market. When done well, market assessments like these promote competition, stakeholder participation, and ultimately transparent, data-driven options analyses to guide utilities to least-cost investments.

The stakes are high. Every year that passes without plans for least-cost electric service further jeopardizes the competitiveness of Florida's economy and the wellbeing of its residents. This includes the millions of low-income/fixed-income Floridians who already face a disproportionate energy burden.

DISCUSSION

The Commission should reject the plans because they violate the least-cost standard under Florida law; the revised plans should include robust options analyses focusing on renewables and energy efficiency.

We divided this discussion into three parts: First, we discuss the applicable least-cost standard under Florida law. Second, we show that the utility plans violate this standard, and the Commission should reject them. Finally, we conclude by urge the Commission to obtain revised plans, including the chronically missing options analyses, as soon as practicable, so that the Commission can meaningfully audit the utilities and ensure they are prepared to achieve least-cost service.

I. Under Florida's least-cost standard, electric utilities must develop robust options analyses focusing on renewables and energy efficiency to guide the utilities to least-cost investments to serve their customers.

Florida law requires electric utility service to be least-cost. As the Florida Supreme Court affirmed, under this standard, the state's electric utilities must "t[ake] every reasonably available prudent action to minimize [their cost of service].”[3] Planning is the critical first step. Per Commission rules, the utilities must develop and disclose “sufficient information to reassure the Commission that an adequate and reliable supply of electricity at the lowest cost possible is planned.”[4]

A. Utilities must develop robust options analyses to guide them to least-cost investments.

Options analyses are routine in the business world, and essential for the utilities to meet the least-cost standard under Florida law. This is a matter of Commission precedent and common sense.[5][6] Options typically available to utilities include but are not limited to:

- ◊ Alternatives to conventional generation, such as renewables[7] and energy efficiency;[8]
- ◊ Alternatives identified through market assessments such as the request for proposal process under Rule 25-22.082, F.A.C (i.e., the Commission’s competitive “bid rule”);[9]

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[3] *Gulf Power Co. v. Florida pub. Service Com’n*, 453 So.2d 799, 802 (Fla. 1984).

[4] Rule 25-22.072(1), F.A.C., incorporating by reference Form PSC/RAD 43-E (11/97), at 4; *cf.* Section 366.82(5)(b)(requiring “analysis of various policy options … to achieve least-cost strategy”).

[5] Order No. PSC-11-0547-FOF-EI, at 82, issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause; *See also* Order No. PSC-11-0547-FOF-EI (redacted Final Order) (noting approval of utility’s rate increase request upon finding “no practical alternative”) issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause; *cf.* Order No. PSC-11-0547-FOF-EI (redacted Final Order), at 6 (reviewing whether utilities properly considered “all available” demand-side and supply-side conservation and efficiency measures) issued on December 16, 2014, in Docket No. 130205-EI, In re: Commission review of numeric conservation goals (Florida Public Utilities Company).

[6] Order No. PSC-11-0547-FOF-EI, at 82 (noting the review of “all available options” is “routine procedure in the business world,” including the electric utlity industry as it undertakes “long-term, complex project[s]”) issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause.

[7] Unless otherwise noted, the terms “renewables” and “renewable energy” refer to the same energy resources. *See generally* Section 366.91(2)(d), F.S, (defining “renewable energy” in pertinent part as “electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power”).

[8] *See, e.g.,* Order No. PSC-14-0696-FOF-EU, at 39, issued on December 16, 2014, in Docket No. 130205-EI, In re: Commission review of numeric conservation goals (Florida Public Utilities Company) (“demand-side management is an alternative resource to generation plants and should be evaluated similarly for reliability and economic impacts.”); *See also* Order No. PSC-16-0032-FOF-EI, at 13−15, issued on January 19, 2016, in Docket No. 150196-EI, In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company; *See also* Order No. PSC-11-0547-FOF-EI, issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause (“In 2006, we stated that utilities should not assume the automatic approval of natural gas-fired plants.”).

◊ Incremental capacity increases;[10]

◊ Earlier or later extremes of commercial operations date;[11] and

◊ Retaining one vendor, retaining multiple vendors, or building the generation itself ("self-build").[12]

Robust options analyses are those that develop information on the economics of these wide ranging options under various scenarios.[13] A simple comparison of the status quo and one option is indefensible.[14]

B. Utilities must focus on renewables and energy efficiency.

Florida Statutes brim with directives to diversify the fuels and the technologies the utilities use to serve customers.[15] More specifically, they emphasize and reiterate that Florida's reliance on inherently risky natural gas imports is a problem, and that cost-effective renewables and energy efficiency are solutions that are in the public interest. As the utilities perform options analysis, they must therefore focus on renewables and energy efficiency as part of their plan to serve customers at the least-cost.

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[9] *See*, *e.g.*, Order No. PSC-06-0779-PAA-EI, at 3, issued on September 19, 2006, in Docket No. 060426-E1, In re: Petition for exemption under Rule 25-22.082(18), F.A.C., from issuing request for proposals (RFPs), by Florida Power & Light Company ("the RFP process provides us with valuable information on the available capacity alternatives and is a valid tool for evaluating the cost-effectiveness of proposed generating units.").

[10] *See*, *e.g.*,Order No. PSC-13-0505-PAA-EI, at 13, issued on October 28, 2013, in Docket No. 130198-EI, In re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company; *See also* Florida Public Service Commission, *States' Electric Resurfacing Activities* (1997); *See also* F.L. House of Representatives, Committee on Utilities and Communications, *Overview of the Electric Industry*, 27 (2000), *available at* https://goo.gl/uKDBP6.

[11] *See*, *e.g.*, Order No. PSC-11-0547-FOF-EI, at 82.

[12] *See*, *e.g.*, Order No. PSC-08-0749-FOF-E, issued on Nov. 12, 2008, in Docket No. 080009-EI, In re: Nuclear cost recovery clause; *See also* Order No. PSC-09-0783-FOF-EI, issued on Nov. 19, 2009, in Docket No. 090009-EI, In re: Nuclear cost recovery clause; *See also* Order No. PSC-11-0547-FOF-EI.

[13] *See* Sierra Club Comments (Oct. 16, 2013) (hereinafter "Sierra Club 2013 Comments") (discussing best practices in integrated resource planning including options analysis), *available at* http://goo.gl/h9RHeT.

[14] *Gulf Power Co. v. Florida pub. Service Com'n*, 453 So.2d 799 (Fla. 1984) (affirming Commission disallowance of costs incurred pursuant to utility's failure to review other other options beyond its preferred proposal for years).

[15] For a recap of the relevant provisions in Florida Statutes, see Sierra Club Post-Hearing Brief in Docket No. 160021 (Sept. 19, 2016), *available at* https://goo.gl/X6QJ91.

II. The Commission should reject the plans because they are in no way least-cost.

The plans fail to meet the least-cost standard under Florida law for many reasons. The most glaring one is that the utilities failed to present any options analyses. The utilities thus failed to reconcile their inherently high-cost, high-risk gas generation with the abundant, competitive renewables and energy efficiency in the market available to them, and in the case of the IOUs, plainly have a conflict of interest behind the omission.

A. The utilities failed to present any options analyses in their plans.

This year, the utilities continued their practice[16] of presenting the Commission just their preferred generation proposals and asserting they considered/will continue to consider their options.[17] This violates the unambiguous requirement in Florida Statutes that the Commission "shall review"—"possible alternatives to the proposed plan[s]" of the utilities.[18] If the utilities present no data or analyses on the options/alternatives available to them in the market, they preclude the Commission from performing its plain duty under Florida Statutes.

To be sure, the utility responses to Staff data requests do not cure the unlawful plans. For all of the planned generating units, Staff asked the utilities to "identify the next best alternative that was rejected for each unit."[19] The fact that Staff had to ask for this information underscores how devoid the plans are of options analyses. The utility responses do, too. They are high-level comparisons between each <u>planned ***gas*** generating unit</u> and <u>another ***gas*** generating unit</u>. That is all. That is the sum total of the options analyses before the Commission.

No one can square the dearth of information presented by the utilities with the least-cost standard under Florida law. As discussed in Section I (above), the standard requires the utilities to conduct robust options analyses, focusing on renewables and energy efficiency, so that they are prepared to take <u>every</u> reasonably available prudent action to minimize cost of

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16 *See* Sierra Club 2013 Comments (noting the unlawful practice), *available at* http://goo.gl/h9RHeT; Sierra Club Comments (Dec. 15, 2015) (hereinafter "Sierra Club 2015 Comments") (noting the same), *available at* https://goo.gl/IWbsDH.

17 *See e.g.*, Florida Power & Light Company's 2016 Ten-Year Power Plant Site Plan (hereinafter "FPL 2016 TYSP"), Chapter III.C (noting "significant factors that either influenced the current resource plan presented in this document or which may result in changes in this resource plan in the future" but omitting data on or comparative analysis of those factors/ changes; i.e., options analysis); *available at* https://goo.gl/wgWn9Y; *see generally* 2016 Ten-Year Site Plans (similar omissions) *available at* https://goo.gl/1y17w9.

18 Section 186.801(2), F.S.

19 Staff data request no. 42.

service, and Florida's reliance on inherently risky natural gas imports. Working up the details of just one gas generation plan and then, at Staff's prodding, working up another is nowhere near the robust options analysis that is routine and essential to prepare electric utilities to provide least-cost service. The Commission therefore should reject the plans.

B. The utilities failed to reconcile their inherently high-cost, high-risk gas generation proposals with the abundant, cost-effective renewables and energy efficiency in the market available to them.

The plans are indefensible and the Commission should reject them for the additional reason that they would increase gas generation, which is inherently high cost and high risk, especially as demand is down. The utilities never tried to (nor could they) reconcile their plans with the abundant, cost-effective renewables and energy efficiency in the market available to them.

1. Demand is down and the growth projected by utilities has not materialized for eight straight years, a trend no one can square with adding gas generation in large, inflexible increments.

Since it peaked in 2005, demand for electricity across Florida is down. This is not due to the Recession alone, as the Commission itself noted.[20] Previous utility load forecasts required downward revisions due to slower-than-projected growth <u>for eight straight years</u>, including the last three.[21] The utilities themselves acknowledge that usage per customer is down.[22]

Yet the utilities project peak demand will somehow grow faster than one percent annually between 2016 and 2025 (net firm peak demand)—more than half again the rate experienced between 2004 and 2015 (0.76 percent CAAGR). This is inconsistent with, for example, the U.S. Energy Information Administration's lower projection of a 0.7 percent annual growth rate through 2025.[23]

More importantly and obviously, demand projections are never as good as verified actual data, and the actuals have shown a consistent downward trend. The best options for

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[20] FPSC, Review of the 2015 TYSPs, at 22, *available at* https://goo.gl/DTGoX1.

[21] *Compare* FRCC 2014 Presentation, at 7 ("Forecasted energy sales and winter firm peak demands are lower in 2014 TYSP compared to 2013 TYSP and forecasted summer firm peak demands are higher from 2017 forward."), *available at* https://goo.gl/ACqiVT; FRCC 2015 Presentation, at 7, ("forecasted energy sales and firm peak demands are lower in 2015 TYSP compared to 2014 TYSP"), *available at* https://goo.gl/mn4gUf; and FRCC 2016 Presentation, at 8 "forecasted energy sales and firm peak demands are lower in 2016 TYSPs compared to 2015 TYSPs"), *available at* https://goo.gl/UScXlk.

[22] Utility responses to Staff data request no. 10.

[23] This is EIA's projection for Florida as well as other South Atlantic states.

Florida therefore are those that (1) keep demand down to reduce cost (i.e., demand-side management), and (2) meet any growth in demand with incremental supply that closely matches the growth (i.e., flexible supply). The utilities failed to present any such options. The only option the utilities did present—large, inflexible gas generation additions—flies in the face of the market reality just described. It is indefensible also because the additional capacity maintained by the IOUs consistently exceeds the levels needed for an adequate and reliable supply of electricity.[24]

2. Gas generation is inherently high cost and high risk.

The Commission should not accept the utilities' complacency about the costs and risks of gas generation, especially as the state's reliance on natural gas is already at an all-time high—71% of the total generation.[25] The utilities propose to add another five gigawatts—pushing that up to 74% by 2025.[26] Even the smallest proposed increment exceeds 180 MW,[27] with projected capital costs measured in millions of dollars, and book lives in decades. Moreover, with the exception of Orlando Utilities Commission (OUC) and Florida Power & Light Company (FPL), the utilities propose inherently less efficient peaking generation—gas combustion turbines (CTs).[28]

All of the proposed gas generation raises stranded asset risk, but the utilities fail to mention that fact. This is a glaring omission as it is the judgment of Florida's largest utility FPL that in four years, 2020, gas peakers will be obsolete compared to energy storage and renewables.[29] It is even more troubling then that the utilities never present any options analyses for the proposed gas peakers. Nor even the basic data to allow for such a

[24] *See* the detailed briefing by Public Counsel, filed July 15, 2015, in Docket No. 160096-EI, Joint petition for approval of modifications to risk management plans by DEF, FPL, Gulf and TECO; *See also* joint petition filed by Public Council, filed Dec 9., 2015, in Docket No. 150196-EI, In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company, *available at* https://goo.gl/wBgl2S.

[25] FRCC, 2016 Presentation, at 22.

[26] *Id.*

[27] Tampa Electric Company's 2016 Ten-Year Site Plan (hereinafter "TECO 2016 TYSP") (planning to add 180 MW CT in 2019), *available at* https://goo.gl/zGh1Id.

[28] OUC and FPL propose gas combined cycle generation (CCs) with 2021 and 2024 in-service dates respectively. Like CTs, the CCs involve massive costs and risks, and the utilities can only add them in large, inflexible increments. Thus, beyond the marginal efficiency improvement of CCs over CTs, our discussion of the CTs applies equally to the CCs.

[29] NextEra on Storage: 'Post 2020, There May Never Be Another Peaker Built in the US,' Sept. 30, 2015, GreenTech Media [hereainafter "NextEra on Storage"], https://goo.gl/rQDK0H (referring to judgment of team including FPL executives).

comparison. In response to Staff data requests, for instance, the utilities omitted the inputs and workbooks that would allow independent verification of their summary comparisons between two gas generation options, discussed in Section II.B.1 above, and provided virtually no data on other, non-gas options, as discussed further below in Section II.B.3.

As the Commission maintains separate dockets on the operation and maintenance costs and risks of gas generation, it knows how astronomically high those costs and risks have proven to be. With gas prices at all-time lows—levels so low they are widely expected to only go up from here—Floridians have already lost billions of dollars on risk hedging programs.[30] Still, the hedging programs themselves are mere half-measures against the price and supply risks of Florida's reliance on natural gas imports—and useless against stranded asset risk. The FPL rate case underscores this.[31] FPL supported its request for a $1.3 billion annual rate increase and a 100 basis point return on equity increase with sworn testimony on all the costs and risks associated with managing its out-sized gas generation fleet.

Adding more gas generation is thus indefensible because it would exacerbate the burden on customers who essentially bear all the costs and risks. This includes the tremendous capital outlays required at the outset to add gas generation (recovered through base rates), and the tremendous operations and maintenance, including hedging expenses, over the 30 or more years these plants are supposed to be in service (recovered through separate clauses).

3. Renewables and energy efficiency are abundantly available to meet peak demand, and they can achieve deep cost-savings—unlike gas generation—through their flexible and diverse applications across the electric grid's generation, transmission, and distribution functions.

For alternatives to meet peak demand, such as renewables and energy efficiency, the market is better than ever. Yet the utilities only propose relatively modest amounts of solar, and even less amounts of other alternatives, despite these technologies' maturity, competitiveness, and widespread adoption in neighboring states. Moreover, these technologies can achieve deep cost-savings—unlike gas generation—through their flexible and diverse applications to the grid's electric generation, transmission, and distribution functions. As we discuss below, this is borne out by RFPs and integrated resource plans (IRPs) across our region and the country. We also discuss how the IOUs' refusal to conduct RFPs for renewables makes them particularly unprepared to deliver least-cost service.

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[30] *See* the detailed briefing by Public Counsel, filed July 15, 2015, in Docket No. 160096-EI, Joint petition for approval of modifications to risk management plans by DEF, FPL, Gulf and Tampa Electric Company.

[31] FPSC Docket No. 160021.

a. Solar

Solar generation technologies, especially solar photovoltaics (PV) can meet peak demand[32] and achieve deep cost savings as a hedge against natural gas price volatility.[33] Solar PV is also a flexible resource, precisely what Florida needs as discussed in Section II.B.1 above. With an abundant solar resource—consistently ranked third best in the country for solar generation potential[34]—and ample support for developing it in Florida Statutes, discussed above in Section I.B, the utilities should be planning to "make Florida a leader in [this] new and innovative technolog[y]."[35]

Florida's tremendous solar potential, however, remains largely untapped because, in essence, the IOUs—with their overwhelming control of the state's energy market—sit on the tap. FPL is the sitter in chief. Florida's largest utility has not issued an RFP for renewable energy since 2007 and 2008, and never explains this omission, even though FPL acknowledges the cost of solar PV has since "plunged."[36] Likewise, DEF, the second largest utility, admits that it received "436 inquiries" from third parties interested in developing in-state renewables.[37] As Sierra Club has consistently highlighted, and as the Southern Alliance for Clean Energy (SACE) comments discuss in more detail, a disturbing lack of transparency shrouds such inquiries. This includes the modest solar power purchase agreements (PPAs) that DEF has negotiated to date. DEF refuses to disclose details, even such basic ones as the in-service, start, and end dates of the PPAs.[38] Gulf Power Company (Gulf) and Tampa Electric Company (TECO) are no better.[39]

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[32] *See, e.g.,* FPL 2016 TYSP, at 49-50 (crediting solar PV with 52% nameplate capacity at summer peak).

[33] Lawrence Berkeley National Laboratory, *Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (Sept. 2015) at ii ("At these low levels – which appear to be robust, given the strong response to recent utility solicitations – PV compares favorably to just the fuel costs (i.e., ignoring fixed capital costs) of natural gas-fired generation, and can therefore potentially serve as a [']fuel saver['] alongside existing gas-fired generation (and can also provide a hedge against possible future increases in fuel prices).") (hereinafter "Utility-Scale Solar 2014"), *available at* https://goo.gl/0L2dDOU.

[34] *See, e.g.*, AEE, *Advanced Energy in Florida* (Jun. 11, 2015), *available at* https://goo.gl/BBL5M4.

[35] Section 366.91(1), F.S.

[36] NextEra on Storage, https://goo.gl/eIVoSL.

[37] DEF response to Staff data request no. 35.

[38] DEF response to Staff data request no. 28 (stating "n/a" or "TBD" for in-service, start, and end dates).

[39] *See generally* Gulf Power Company's 2016 Ten-Year Site Plan (hereinafter "Gulf 2016 TYSP"), *available at* https://goo.gl/PE1qbW; Gulf 2016 TYSP Workshop Presentation, *available at* https://goo.gl/GH9rME; TECO 2016 TYSP; TECO 2016 TYSP Workshop Presentation, *available at ht*tps://goo.gl/rQNeYF.

Collectively, the IOUs plan to add in ten years as much solar generation as Gulf's sister subsidiary, Georgia Power, will add by next year—more than a gigawatt.[40] Moreover, through additional RFPs, Georgia Power plans to double its installed capacity again in five years with more solar PV, battery storage, and other renewables.[41] Georgia Power is hardly alone. In 2015, 100% of Alabama Power's new generation came from solar, and that utility just gained approval to issue RFPs for 500 MW more.[42] In fact, RFPs in every single state in the Southeast have returned abundant, cost-effective solar PV bids.[43] These are widely reported precedents, which reputable entities such as the U.S. Department of Energy also verify and publish in market reports.[44] Yet the IOUs never mention them; much less reconcile their refusal to issue RFPs with the relatively modest amounts of solar they propose to build themselves.

Indeed, the utilities present no data or analyses whatsoever to justify the relatively modest amount of solar generation they propose. The RFPs of other Florida utilities, however, confirm there is no shortage of cost-effective solar PV in Florida.[45] As we highlighted last year, on a per customer basis these utilities have already installed far more solar capacity than the IOUs.[46]

The IOUs' proposals to add solar are also mere placeholders. Unlike the solar PV contracts that other utilities are negotiating with third parties, the IOUs have identified no particular process to set the terms of the solar they would build, such as the timing, sizing, siting, sourcing of inputs, and the costs. This gives the Commission—and the public—no reassurance whatsoever that the IOU investments in solar generation will in fact be optimally timed, sized, sited, etc. to achieve least-cost service. [47]

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[40] Georgia Power, Utility-Scale RFP Program, *available at* https://goo.gl/yEKHAu.

[41] Georgia Power 2016 Integrated Resource Plan, at 10-101, *available at* https://goo.gl/CdMFiZ.

[42] *See* Top 10 Solar States (2015), https://goo.gl/F3jIVu; *See also* Alabama Power's plan for 500 MW of renewables approved by regulators, Utility Dive, Sept. 3, 2015, https://goo.gl/uf5Ffm.

[43] *See* Exhibit A: Southeast RFPs for renewables.

[44] *See, e.g.,* Utility-Scale Solar 2014, at 37; *See also* Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States (2016), *available at* https://goo.gl/SpUJY2.

[45] *See* Exhibit B: Florida RFPs for solar.

[46] *See* Sierra Club 2015 Comments, at 12.

[47] Sierra Club supports SACE's comments and shares SACE's concern that, beyond ten-year site plan reviews, the Commission may not get another opportunity to conduct fact-finding until after the utilities have already built whatever solar generation they unilaterally selected.

b. Energy storage

Energy storage is another competitive alternative to gas generation. Tellingly, the states that already use energy storage want to add more of it. This includes Alabama,[48] Georgia,[49] West Virginia,[50] Tennessee,[51] and California.[52] Other states with energy storage market studies, such as Texas and Massachusetts, also report that this technology can provide immense improvements to the electric grid—and deep cost-savings relative to the status quo.

In contrast, there is a glaring omission of energy storage from the Florida utility plans. At the planning workshop, DEF explained that it lumps energy storage with offshore wind,[53] but that technology came online for the first time this summer.[54] Energy storage projects in contrast have been operational for decades. The first advanced compressed air energy storage (CAES) plant came online in 1978, and the first one in the US, in 1991, in

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[48] As noted above, Alabama Power recently gained approval to issue additional RFPs for renewables. The company built the country's first compressed air energy storage CAES plant, 110-MW McIntosh plant, in 1991. PowerSouth Energy Cooperative, https://goo.gl/idGTAz. ("The unit captures off-peak energy at night, when utility system demand and costs are lowest. […] PowerSouth uses the stored energy during intermediate and peak energy demand periods to generate electricity.").

[49] As of September of 2015, Georgia has the largest Southern Company battery storage research project, which is testing a 1 MW/2 MWh lithium-ion battery storage system at a solar facility. Southern Company: Cedartown Battery Energy Storage Project, Sept. 17, 2015, https://goo.gl/MvLO7a; Southern Company also has a partnership with Tesla to test energy-storage products for commercial customers. Southern Co. goes all in on solar, storage, smart homes, EnergyWire, May 28, 2015, https://goo.gl/LjxEwD.

[50] In West Virginia, AES Energy Storage installed the Laurel Mountain Energy Storage Project at the Laurel Mountain wind plant, which delivers 32 MW of regulation and wind smoothing. The World's Largest Lithium-Ion Battery Farm Comes Online, Forbes, Oct. 27, 2011, https://goo.gl/L5g8K9.

[51] The Tennessee Valley Authority (TVA) operates the Raccoon Mountain Pumped-Storage Plant in Marion County, Tennessee. With capacity of 1,616 MW, it is TVA's largest hydroelectric facility and "provides critical flexibility." 2015 Tennessee Valley Authority Integrated Resource Plan (hereinafter "2015 TVA IRP"), at 40, *available at* https://goo.gl/GiURX3.

[52] World's Largest Storage Battery Will Power Los Angeles, Scientific American, July 7. 2016, https://goo.gl/cvGXzD; CNBC, Tesla tackles California energy woes with massive energy-storage deal, Sept. 16, 2016, https://goo.gl/z1YELb; California Dreaming: 5,000MW of Applications for 74MW of Energy Storage at PG&E, GreenTech Media, May 28, 2015, https://goo.gl/nuZRT4.

[53] Duke Energy has relegated energy storage has into a third category of "Emerging Technologies," along with offshore wind technologies. Duke Energy, A Brief Overview of DEF Planning. Duke Presentation, given at the Sept. 14, 2016 Ten-Year Site Plan Workshop, *available at* https://goo.gl/STKM0q.

[54] Offshore Wind Arrives in America, Energy.gov, Sept. 9, 2016, https://goo.gl/sqjxpr.

Alabama.[55] Now, as utilities across the country are rapidly procuring storage, Florida utilities are behind, without even a plan to explore procurements of their own.

As noted above, FPL itself acknowledges that energy storage is a competitive alternative to peakers. Market studies commissioned by state energy regulators and by other utilities agree: energy storage investments can save hundreds of millions, if not billions of dollars.[56] These projected savings stem from the wide-ranging applications of this technology, spanning electric generation (on and off peak), transmission, and distribution.

Peak generation is of course the most expensive generation, and storage allows utilities to reduce or avoid that generation altogether by redeploying surplus energy from lower cost, off-peak hours. A 2016 report by the state of Massachusetts concluded that this application alone could save customers in that state more than a billion dollars. Other studies document the cost savings from energy storage's ability to reduce transmission and distribution-related maintenance, as well as defer and even avoid huge capital expenditures.[57] In 2014, Texas utility, Oncor, announced it would seek approval to build 5,000 MW of energy storage citing over $625 million of projected customer savings.[58]

Storage can also reduce risk by providing both flexibility and reliability. Energy storage is in fact highly accommodating with sizing, siting, permitting, and construction time. Because this technology does not produce direct air emissions, or have large land requirements, the permitting and siting processes are far easier.[59] Because individual storage systems are modular, one system can consist of many modules operating simultaneously, and can take on additional modules incrementally, so the system will not fail from the breakdown of one module.[60] Additionally, several types of advanced storage technologies are commercially viable,[61] including batteries, compressed air energy storage, liquid air energy storage, pumped hydroelectric storage, and flywheels.[62] They are also readily available. A

55 PowerSouth Energy Cooperative, https://goo.gl/idGTAz.

56 A 2016 report by the state of Massachusetts concludes that 600 megawatts of storage capacity installed by 2025 would save ratepayers $800 million in system costs. Massachusetts Energy Storage Initiative Study (2016), at xvi-xvii, *available at* https://goo.gl/D3zviD.

57 *Id.* at 86-89.

58 The Value of Distributed Electricity Storage in Texas Proposed Policy for Enabling Grid-Integrated Storage Investments (2014), at 14, *available at* https://goo.gl/fv2mYF.

59 Massachusetts Energy Storage Initiative Study, at 9.

60 Massachusetts Energy Storage Initiative Study, at 10.

61 This is evidenced by their widespread use in competitive markets without subsidies. *Id.* at 2.

62 Energy Storage Technologies, https://goo.gl/5vcJTb.

2016 study found utilities could procure these advanced technologies within months—four to six times faster than conventional technologies.[63]

The value of energy storage is also apparent in California's use of it to solve the emergency that resulted from the massive gas facility failure at Aliso Canyon. That failure put the entire region at high risk of far-reaching power outages. State regulators directed utilities to speed up the deployment of large-scale, grid-connected storage. As of August, California utilities have proposed three large-scale battery installations[64]—one with an in-service date just five months after it was proposed.[65]

c. Energy efficiency

Energy efficiency is the lowest-cost energy resource available,[66] and is essential to deliver least-cost electric service. More specifically, the wide-ranging technologies labeled as energy efficiency are part of the demand-side management that Florida needs to keep demand down and electric bills low, as noted in Section II.B.1 above. Yet the utilities continue their practice of ignoring any incremental energy efficiency additions beyond the levels set by the Commission based on information three or more years old.[67] This cannot be squared with the more recent market assessments, including those in other Southeast states, consistently showing that energy efficiency is not only cost-effective, but a critical resource to meet peak demand,[68] reduce risk, and save customers money.[69]

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[63] *Id.* at 10.

[64] They proposed two 20 MW (80 MWh) facilities from SCE and a 37.5 MW (150 MWh) project from SDG&E. 'Eyes wide open': Despite climate risks, utilities bet big on natural gas, Utility Dive, Sept. 27, 2016, https://goo.gl/697hYh.

[65] As Aliso Canyon Gas Shortage Looms, Southern California Looks to Energy Storage, Greentech Media, Jun. 02, 2016, https://goo.gl/JrI0O4; *See also* California Utilities Are Fast-Tracking Battery Projects to Manage Aliso Canyon Shortfall, GreenTech Media, Aug. 18, 2016, https://goo.gl/9XyYx1. (stating that the projects must be grid-ready by year's end, in SCE's case, or by Jan. 31, 2017, in SDG&E's case.).

[66] SEE, Guide For States: Energy Efficiency As A Least-Cost Strategy To Reduce Greenhouse Gases And Air Pollution, And Meet Energy Needs In The Power Sector (2016), *available at* https://goo.gl/ZtQ7pc; *See also* ClimateWorks & Fraunhofer ISI, How Energy Efficiency Cuts Costs for a 2°C Future (2015), *available at* https://goo.gl/fjf0xR; *See also* The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs (2014), *available at* https://goo.gl/GPYhzU.

[67] Here, "utilities" refers to the utilities subject to the Florida Energy Efficiency and Conservation Act (FEECA). The other Florida utilities also have an obligation to provide least-cost service and to that end should develop and disclose robust options analyses focusing on energy efficiency.

[68] At very low cost and risk, efficiency offers flexibility in meeting peak demand. Florida utilities can quickly ramp up efficiency to meet demand growth and thereby reduce or entirely avoid costly infrastructure improvements and expansion. RAP, Recognizing the Full Value of Energy Efficiency (What's Under the Feel-

Energy efficiency programs are inherently less risky since they consist of many discrete resources that will not fail all at once.[70] Additionally, efficiency increases system reliability by reducing the stress on it. Many utilities give energy efficiency resources a risk credit, meaning the risk reduction effects of implementing efficiency reduced the cost of energy efficiency.[71] Thus, efficiency is a highly predictable and reliable cost-effective resource that enables the utility system to avoid the risk of surpluses, shortages, and periodic outages.

The utilities' refusal to consider incremental energy efficiency additions is even more alarming given the highly publicized, rapid changes in the market, and the billions of dollars that other utilities reported saving in recent years from geographically targeted energy efficiency programs, especially those that defer or avoid large transmission and distribution expenditures.[72] This Commission itself stated that, "at any time," it is ready to "reexamine and then adopt new [energy efficiency/demand-side management] goals or changes to those goals."[73] It is the responsibility of the utilities to develop data and analysis to allow the Commission to do so.

Indeed, if the utilities and the Commission are serious about closing the gap that minority and low-income households spend on energy, then they will rapidly develop plans to increase investment in energy efficiency, as leading energy efficiency experts have recommended.[74]

Good Frosting of the World's Most Valuable Layer Cake of Benefits) (2013) (hereinafter "2013 RAP Energy Efficiency Report"), at 41, *available at* https://goo.gl/APjr2s.

[69] Because efficiency reduces all pollutants, it can also save ratepayers money by satisfying environmental regulations without building new power plants, which require huge, inflexible capital outlays.

[70] 2013 RAP Energy Efficiency Report, at 41.

[71] The 2013 PacifiCorp IRP and the Northwest Power Council both give energy efficiency resources risk credit. ACEEE Comments on 2015 Tennessee Valley Authority Draft Integrated Resource Plan, at 3.

[72] For instance, in 2011, Consolidated Edison estimated that including the effects of geographically-targeted efficiency programs in its 10-year forecast reduced costs by over $1 billion. Additionally, since 2012, ISO New England identified over $400 million in deferred transmission investments due to efficiency. NEEP Northeast Energy Efficiency Partnerships: Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically (2015), at 12 available at https://goo.gl/AXRf3m.

[73] FPSC Transcript Document No. 06614-14, at 21, Order No. PSC-14-0696-FOF-EU, filed Dec. 5, 2014, in Docket No. 130205-EI.

[74] ACEE, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low-Income and Underserved Communities, Apr. 20, 2016, at 3-4. (For African-American, Latino, and renting households, 42%, 68%, and 97% of their excess energy burdens, respectively, could be eliminated by raising household efficiency to the median.).

C. Rather than minimize cost of service to customers, the plans pave the way for windfalls for the IOUs/their affiliates at the expense of the captive customer base; it is imperative for the Commission to intervene and reject the plans.

As discussed above, the plans are in no way least-cost from an electric utility customer perspective. Others, however, certainly profit from these gas-laden proposals. The most obvious profiteers are the shareholders of the IOUs/their affiliates—together they are heavily investing in gas generation and infrastructure, such as inter-state pipelines. This gives the IOUs a perverse incentive to increase their reliance on and subsidize the inefficient production and distribution of natural gas as they pass increases in fuel costs directly to customers.

In his testimony before the Senate Energy and Natural Resources Committee, Jonathan Peress highlights "a disturbing trend of utilities pursuing a capacity expansion strategy by imposing transportation contract costs on state-regulated retail utility ratepayers so that affiliates of those same utilities can earn shareholder returns as pipeline developers. . . . Thus ratepayer costs which may not be justified by ratepayer demand are being converted into shareholder return."[75] Mr. Peress further explains, "the effect of these affiliate transactions, whereby utilities commit their captive customers to pay for pipelines being developed by the same corporate group, is that customers are saddled with risky 20 year financial obligations to provide nearly risk free shareholder returns of 14% per year or more."[76]

Ultimately, Mr. Peress warns, affiliate transactions can hurt not only customers but also market participants. In Florida, this includes business, large or small, that lose opportunities to provide efficient solutions for electric service due to the control that the IOUs/their affiliates exert over the state's energy market. This is the rub, for instance, in FPL and DEF's decision to import more gas through the Southeast Market Pipeline Project instead of less costly, Florida-made solutions for them to provide an adequate and reliable supply of electricity.

In recent years, mergers between the IOUs and pipeline companies have proliferated[77]—growing the potential for the fallout described by Mr. Peress. Again, the Southeast Market Pipeline Project [78] is case in point: FPL and DEF back this pipeline even

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[75] Jonathan Peress, Testimony Before the Senate Energy and Natural Resources Committee (June 14, 2016), at 5, https://goo.gl/rPoudE.

[76] *Id.*

[77] *See* Exhibit C: Mergers between pipeline companies and IOUs/their affiliates.

[78] Sabal Trail is part of multiple pipeline expansions and a joint venture of DEF's parent, Duke Energy Corporation, and FPL's parent, NextEra.

though it would more than double the amount of natural gas that FPL and Duke themselves project needing.[79]

Coupled with the utilities' hedging programs, the recent mergers and affiliate transactions raise an acute threat of improper subsidization of pipeline companies by Florida electric utility customers.[80] Between 2002 and 2015, the four IOUs saddled their customers with more than a $6 billion bill for fuel costs higher than market price.[81] Public Counsel has protested this, citing the IOUs' own estimates of another $559 million in losses-borne again by customers.[82] If the Commission were to allow the utilities, now merged with pipeline companies, to increase their gas generation, customer bill could soar even higher.

As the Antitrust Division of the United States Department of Justice recognizes, this type of vertical integration "may be used by monopoly public utilities subject to rate regulation as a tool for circumventing that regulation. The clearest example is the acquisition by a regulated utility of a supplier of its fixed or variable inputs. After the merger, the utility would be selling to itself and might be able arbitrarily to inflate the prices of internal transactions. Regulators may have great difficulty in policing these practices, particularly if there is no independent market for the product (or service) purchased from the affiliate."[83] Vertical integration of the retail distribution and generation markets plus financial hedging of natural gas thus presents a clear conflict of interest whereby self-dealing practices can rampantly exploit the captive customer base.

To protect customers and diverse businesses in Florida, it is imperative for the Commission to reject the plans, and put all the utilities on a path to reduce, not increase, Florida's generation.

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[79] FPL admitted that it would only require 400,000 Dth/day by 2017 and 600,000 Dth/day by 2020, yet it moved forward with the construction of Sabal Trail, which will ship double that amount—800,000 Dth/day by 2017 and 1.1 billion Dth/day by 2020. *Compare* Testimony of Heather C. Stubblefield on behalf of the Florida Power & Light Co., FPSC Docket No. 130198, July 26, 2013 at 9:10-13, (testifying that FPL requested these amounts "based on FPL's analyses of its future gas transportation requirements"); Application by Florida Southeast Connection, LLC ("FSC") to FERC for a Certificate of Public Convenience and Necessity and for Related Authorizations, Sept, 26, 2014 at 2, (stating amount that Sabal Trail will ship).

[80] For example, the $3 billion Atlantic Sunrise gas pipeline expansion proposal pending before the Federal Energy Regulatory Commission (Docket No. CP15-138) would connect to delivery points in Florida, and FPL and DEF have intervened in the FERC proceeding, indicating they have a material interest in this pipeline.

[81] Office of Public Counsel Protest, Document No. 05102-16, at 2, filed July 15, 2016, in Docket No. 160096-EI (hereinafter "Public Counsel Protest of Hedging Losses").

[82] Public Counsel Protest of Hedging Losses, at 2.

[83] United States Department of Justice, Antitrust Division, Non-Horizontal Merger Guidelines § 4.3 Evasion of Rate Regulation, *available at* https://goo.gl/9xw0QB.

D. The utilities acknowledge they can wait many months, even years before committing resources to add any gas generation, so they have time to pursue alternatives instead.

The utilities cite no reason to move forward now with their proposals to add gas generation.[84] Indeed, the purpose of this generation is mainly to meet projected growth in peak demand.[85] We reiterate that this growth may never materialize. Even if it did, the utilities acknowledge they can wait many months, even years, before committing any resources to adding gas generation.[86] More specifically, November 2017 is the earliest "drop dead" date (for a 200 MW CT with a May 2020 in-service date), and that could be pushed back by six months.[87] The utilities thus have ample time to complete the missing RFPs and options analyses and revise their plans to pursue cost-effective alternatives instead.

E. Florida's high-cost, high-risk coal generation reinforces the need for revised plans including the chronically missing options analyses.

While the utilities are not proposing any new coal generation, their existing coal burning generation undermines their ability to provide least-cost service. Burning coal to generate electricity lost whatever economic edge it once had, as evidenced by the overwhelming national coal divestment trend.[88] To be sure, coal is a terrible deal: Not only is burning coal one of the priciest[89] and most polluting[90] ways to generate electricity, importing coal from out of state also stunts local economic growth.[91]

With no shortage of low-cost, low-risk alternatives in the market, all remaining coal owners and operators owe their regulators robust options analyses focusing on options for transitioning to the alternatives as soon as practicable. The regulators, in turn, are wise to

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[84] Staff data request no. 42.

[85] As noted above, OUC and FPL propose adding CCs as well.

[86] *See* response to Staff data request no. 40; *See also* 2016 TYSP Schedule 9s.

[87] TECO 2016 TYSP; *See also* TECO response to Staff data request no. 40.

[88] *See*, *e.g.*, EIA, 'Coal made up more than 80% of retired electricity generating capacity in 2015' (Mar. 8, 2016) available at https://goo.gl/b0xcAq; *See also* Sierra Club, Open letter to coal industry: United States and the world are moving away from coal, toward clean energy (Apr. 21. 2016) *available at* http://goo.gl/kE94J6.

[89] *See* 2016 TYSP Comments, *supra* n. 3 (citing sources on how coal generation costs compare to alternatives).

[90] *See* Mother Jones, 'Environmentalists Hate Fracking. Are They Right?' (May 11, 2016) *available at* http://goo.gl/dGtFju.

[91] *See* Union of Concerned Scientists, Burning Coal, Burning Cash: 2014 Update; Fact Sheet: Florida's Dependence on Imported Coal (Jan. 2014) *available at* http://goo.gl/Y3Yw21.

disallow further expenditures on uncompetitive coal generation, as the Georgia Public Service Commission just did in the integrated resource planning proceeding it recently concluded for that state's largest electric utility Georgia Power.[92]

Yet in Florida, the utilities have continued their practice of presenting no options analyses regarding their existing coal generation. This is a grave omission, as we have consistently warned, because the utilities' own, incomplete regulatory compliance cost estimates for this generation range in the hundreds of millions to billions of dollars.[93] Moreover, when Staff asked for up-to-date information—underscoring the dearth of information in the plans—the utilities indicated that their analyses are still incomplete, and they failed to provide any estimate whatsoever for several existing regulations.[94]

One glaring omission concerns the Effluent Limitations Guidelines (ELGs), the new U.S. Environmental Protection Agency rule to protect our waters from the toxic pollutants in the discharge of coal generators. The ELGs became effective on January 4, 2016, and the default deadline is November 2018. As it took EPA decades to issue this rule, utilities have long anticipated and planned for it.[95] Indeed, the IOUs must report their compliance estimates under federal financial disclosure rules, and have in fact reported such estimates for ELGs, which are as high as $50 million for just one of a dozen Florida coal plants.[96]

With such massive costs looming over them, it is unacceptable for the utilities to continue to delay studying their options to transition to non-fossil generation.[97] Indeed, as we highlighted last year, Lakeland Electric stands out as the one Florida utility that already commissioned such a study. Lakeland compared several retrofit and retirement scenarios for its aging coal plant, showing that the analysis itself is eminently doable.[98] Predictably, Lakeland's conclusion, which the utility is now refining with further studies, is that

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[92] *See* Exhibit D – Georgia Power IRP Stipulation, at 3 ("minimiz[ing] all capital expenditures" on two large coal generation facilities); *See also* GPSC Docket No. 40161, Direct Testimony of T. Newsome and P. Hayet, at 7 and 51 (Commission staff expert recommending "all capital investment" on costly coal plants be "minimize[d].") (May 6, 2016) *available at* http://goo.gl/SF9rba.

[93] *See* Sierra Club 2015 Comments, at 7.

[94] *See generally* Utility responses to Staff data requests nos. 50-62.

[95] *See* Exhibit E – Sierra Club Comments to Florida Dep't of Environmental Protection (FDEP) re: ELGs.

[96] *See* Exhibit F – Sierra Club Comments to FDEP re: Crystal River Energy Center.

[97] To be clear, Sierra Club does not support new nuclear generation as it extremely high cost and high risk and thus a nonsensical choice given all of the better alternatives available in the market.

[98] nFront Consulting LLC, "Strategic Resource Plan, Lakeland Electric,"(Mar. 2015), *available at* http://goo.gl/B2BmRK.

renewables and energy efficiency will meet its load growth over the next 20 years more cost-effectively than all three fossil fuel expansion scenarios studied.[99]

III. The Commission should require the utilities to file revised plans as soon as practicable.

For all the foregoing reasons, the Commission should reject the plans and require all the utilities to file revised plans as soon as practicable, including the chronically missing options analyses. The IOUs should file revised plans no later April 1, 2017, the annual deadline for plan revisions, to minimize the fallout from their conflict-ridden plans.

Thank you for your consideration.

Respectfully submitted,

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[99] *Id.* at 3-13, 3-24.

EXHIBIT A

Exhibit A: RFPs for Renewables in the Southeast

The following is an illustrative list of RFPs for renewables in the Southeast.

Alabama

- The Alabama Public Service Commission (PSC) approved a proposal from Southern Company subsidiary Alabama Power, the state's dominant electricity provider, to procure up to 500 MW of renewable energy from 80 MW or smaller facilities. The utility's proposal cited both a need for renewables to meet Clean Power Plan emissions reductions requirements and customer demand. The utility's request for proposals (RFP) requires renewables projects to be priced below what it would expect to pay for other generation sources, unless the off-taker agrees to pay the difference.[1]
- On September 27, 2016, Alabama Power issued a request for proposals (RFP) for renewable energy resources. For a proposed project to be considered under this RFP, the generation resource must be either a renewable resource, as identified in Section 40-18-1(30), Code of Alabama (1975), or an environmentally specialized generating resource. Eligible projects include solar, wind, geothermal, tidal or ocean current, low-impact hydro and biomass.[2]

Georgia

- Georgia Power Company's 2015/2016 Advanced Solar Initiative Distributive Generation Program sought proposals and applications for solar photovoltaic generation. The Georgia public Service Commission has given approval to Georgia Power Co., a unit of Southern Co., to release a request for proposal for 495 MW of new solar power generation. The commission approved 425 MW of the requested amount on July 12, 2013 as part of the 2013 Georgia Power Co. Integrated Resource Plan and 70 MW as part of the utility's Advanced Solar Initiative November 20, 2012.[3]

Kentucky

- East Kentucky Power Cooperative RFP sought to obtain up to 300 MW of generation, including renewable resources with a capacity of 5 MW or larger. EKPC will retain all environmental attributes associated with the renewable resources.[4] (Closed August 30, 2012)

Mississippi

- The South Mississippi Electric Power Association RFP sought capacity and/or related energy from wind resources with up to 250 MW of nameplate capacity.[5] (Closed August 31, 2015)

Tennessee

- State of Tennessee RFP sought proposals for design, delivery, installation, operation and maintenance of renewable energy systems using solar photovoltaic electric generating technologies to supply energy to the State at multiple sites.[6] (Closed August 9, 2016).

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[1] https://goo.gl/dnY5Ea.
[2] https://goo.gl/XXCQAh.
[3] https://goo.gl/FkAz21.
[4] https://goo.gl/7GhgcP.
[5] https://goo.gl/OS1kKz.
[6] https://goo.gl/CsM2QY.

Virginia

- EPB RFP sought proposals from qualified contractors for the labor and materials needed to build the first of two community solar power generation facilities under its Solar Share pilot project. The first project will be built in the Bakewell community of northern Hamilton County and the second one is planned near existing EPB facilities in Chattanooga. The two projects will provide a combined 1.35 megawatt generation capacity.[7] (Closed May 15, 2016)
- The Council of Independent Colleges in Virginia (CICV) RFP sought proposals to construct and finance up to 37.8 MW solar photovoltaics (PV) systems at the campuses of some of its member colleges. The project is supported by the U.S. Department of Energy's SunShot Initiative. Bidders shall propose the construction of different types of PV systems under various financing mechanisms that creates net cost savings to participating colleges.[8] (Closed January 22, 2016)
- Solarize Harrisonburg RFP sought a single price/kW installed for a group of residential homeowners in Harrisonburg, Virginia. This price will be offered to all homeowners participating in the group. The PV projects are to be installed on the roofs of each of the properties and will be owned by the individual property owners.[9] (Closed September 11, 2014)
- Appalachian Power Company RFP sought proposals to solicit and subsequently pre-qualify companies who have an interest in participating in the company's RFP for obtaining up to 10 MW (AC) of ground-mounted solar energy resources via either an asset purchase with 100% ownership or 20-year PPA. Proposed projects must be located within Virginia, be interconnected to the PJM Regional Transmission Operator or Appalachian Power's distribution system, and have a minimum nameplate rating of 5 MW (AC).[10] (Closed February 5, 2016)

North Carolina

- The City of Raleigh RFP sought proposals from qualified solar energy developers to own, install, operate, and maintain solar systems on approximately 53 acres of city-owned land near the Neuse River Resource Recovery Facility.[11] (Closed January 8, 2016)
- NC GreenPower RFP sought proposals for up to 60,000 MWh of renewable energy through a purchase with either a one- or two-year term. The potential generator of renewable energy will be required to enter into a Power Purchase Agreement with a North Carolina electric utility and the generated power will be delivered to North Carolina's electrical supply.[12] (Closed January 6, 2016)
- NC GreenPower RFP sought proposals for up to 40,000,000 kWh of Renewable Energy Certificates (RECs) generated in North Carolina through one- or two-year terms from qualifying renewable energy projects.[13] (Closed November 25, 2014)

South Carolina

- Duke Energy Carolinas and Duke Energy Progress RFP sought approximately 40 MW and 13 MW of eligible photovoltaic generation capacity and all associated renewable attributes located in and

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[7] https://goo.gl/y0a1sk.
[8] https://goo.gl/Ay3DUh.
[9] https://goo.gl/mWiAcl.
[10] https://goo.gl/vNNFbr.
[11] https://goo.gl/1fZ1sQ.
[12] https://goo.gl/Yrjj3M.
[13] https://goo.gl/2iZOSd.

directly interconnected to its retail service areas in South Carolina via a combination of Power Purchase Agreements and turnkey proposals with engineering, procurement and construction agreements in the form of Design-Build-Transfer Asset Purchase proposals.[14] (Closed October 27, 2015)

- Duke Energy Carolinas and Duke Energy Progress RFP sought approximately 4 MW and 1 MW of eligible photovoltaic generation capacity and all associated renewable attributes located in and directly interconnected to its retail service areas in South Carolina via a combination of Power Purchase Agreements and turnkey proposals with engineering, procurement and construction agreements in the form of Design-Build-Transfer Asset Purchase proposals. Proposals must comply with Duke Energy's "Shared Solar Program" requirements under the South Carolina Distributed Energy Resource Program Act and be in service by December 31, 2016.[15] (Closed October 27, 2015)
- South Carolina Electric & Gas Company RFP seeking bidders to provide solar power to the utility through purchased power agreements. SCE&G intends to work with solar developers to locate the solar farms on company-owned property in North Charleston (up to 500 kW) and Cayce (up to 4 MW).[16] (Closed October 3, 2014)

Louisiana

- State of Louisiana Department of Education RFP seeking bids for the installation of solar panels at Andrew Jackson Elementary School located in New Orleans, LA.[17] (Closed June 26, 2012)
- AEP Southwestern Electric Power Company (SWEPCO) RFP seeking long-term renewable energy to help fulfill energy-supply requirements for its customers. The request was issued as part of the Louisiana Public Service Commission's Renewable Energy Pilot Program. Proposals for approximately 31 megawatts of new renewable-energy resources deliverable to the Southwest Power Pool (SPP). Resources must be able to begin operating by Dec. 31, 2014, and have a minimum 10-year PPA.[18] (Closed June 15, 2011)

Multiple States in the Southeast Involved

- Southern Alliance for Clean Energy RFP sought a contractor to perform a transmission analysis for gigawatt-scale offshore wind energy off North Carolina, South Carolina and Georgia. (Phase 2C - Offshore Wind Energy Transmission Study).[19] (Closed February 16, 2011)
- Appalachian Power RFP sought up to 150 megawatts of wind power. Proposals should allow Appalachian Power to own one or more wind projects or purchase the output from wind projects under one or more 20-year renewable energy power purchase agreements. Qualified projects must be located within Virginia, West Virginia, eastern Indiana, Kentucky, Maryland, North Carolina, Ohio or Pennsylvania, be interconnected to the PJM Regional Transmission Operator, and have a minimum nameplate rating of 40 MW.[20] (Closed April 1, 2016)

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[14] https://goo.gl/uv2Mj8; https://goo.gl/K5U7TY.
[15] https://goo.gl/b4dpPR.
[16] https://goo.gl/toZd3Q.
[17] https://goo.gl/l2hDuK.
[18] https://goo.gl/iu1fM6.
[19] https://goo.gl/fLSBAe.
[20] https://goo.gl/8S6l5C.

EXHIBIT B

Exhibit B: Florida RFPs for solar

The following is an illustrative list of recent RFPs in Florida.

1. JEA issued an RFP for solar PV Power Purchase Agreements (PPA) in April of 2015, and entered into seven PPAs.[1] In 2015, JEA awarded a total of 31.5 MW of solar PPAs. Agreements have been finalized for five projects for a total of 25.5 MW.[2] Additionally, in December of 2014, JEA issued a solar photovoltaic RFP. Earlier, in May of 2009, JEA entered into a PPA with Jacksonville Solar, LLC to receive up to 15 MW from the solar plant located in western Duval County. The facility consists of approximately 200,000 photovoltaic panels, and generated 20,132 MWh in 2015.[3]

2. Seminole issued a solar RFP in March 2015 for a minimum of 2 MW and maximum of 20 MW to be in operation before November 2, 2016. Seminole received seventeen different offers with photovoltaic technology to be in service by the end of 2016. Seminole also incorporated a 2 MW solar photovoltaic facility into Seminole's ten-year plan. Finally, on March 21, 2016, Seminole finalized agreements for a 2.2 MW solar facility to be constructed in Hardee County.[4]

3. The City of Tallahassee issued a RFP for a PPA for a 10 MW utility scale solar photovoltaic project.[5] During negotiations, the project developer offered double the capacity of the project, and the City Commission voted to authorize the PPA for 20 MW.[6]

4. Lakeland Electric issued an RFP in November of 2007, seeking an investor to purchase and install investor-owned photovoltaic systems totaling 24 megawatts. In October of 2008, the project was approved, and installed two years later. The projected reduction in annual fossil-fuel generation is expected to be 31,800 megawatt-hours. In addition, Lakeland Electric issued another RFP in November 2007 for the expansion of its Residential Solar Water Heating Program. Lakeland's proposal was for the installation and operation of 3,000 – 10,000 solar residential water heaters, and annual projected energy savings ranged between 7,500 and 25,000 megawatt-hours.[7]

[1] Solar Photovoltaic Power Purchase Agreements, Dec. 22, 2014, *available at* https://goo.gl/X4C2hu.
[2] *See* JEA 2016 Ten-Year Site Plan, at 12.
[3] *See id.* at 3.
[4] Seminole response to Staff data request no. 36; *See also* Seminole 2016 Ten-year site plan, at 25; *See also* Seminole Electric Cooperative Issues Request for Proposals for Solar Energy, Mar. 31, 2015, https://goo.gl/fkRXXg.
[5] 2015 Solar Procurement in the South, Oct. 6, 2015, https://goo.gl/jFaYnj.
[6] *See* City of Tallahassee 2016 Ten-year site plan, at 41-42; *see also* Tallahassee prepares to add solar power to portfolio, Mar. 24, 2015, https://goo.gl/47IWrv.
[7] *See also* Lakeland Electric's 2016 Ten-Year Site Plan.

EXHIBIT C

Exhibit C: Mergers between pipeline companies and IOUs/their affiliates.

The following is an illustrative list of mergers between pipeline companies and the IOUs/their affiliates.

1. AGL the largest natural gas distributor in the Southeast merged with Southern Company, which is the parent company of Gulf Power. The merger creates operations of more than 80,000 miles of pipelines.[1]

2. There is a pending merger between Duke Energy and Piedmont. Both are partners on a $5 billion Atlantic Coast Pipeline.[2]

3. NextEra Energy Partners, LP, parent company of Florida Power & Light, acquired NET Midstream, owner of seven long-term contracted natural gas pipeline assets.[3]

Mergers aside, Tampa Electric Company also has substantial stakes in gas infrastructure. TECO's subsidiary, SeaCoast Gas Transmission, L.L.C, operates a 25-mile pipeline system, which can deliver 100,000 MMBtus per day of natural gas to northeast Florida.[4] Another affiliate, New Mexico Gas Company, also owns and operates pipelines.[5]

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[1] Southern Company and AGL Resources complete merger, create a leading U.S. energy company, Southern Company, July 1, 2016, https://goo.gl/lHeHHU.

[2] North Carolina environmental groups oppose Duke-Piedmont merger, Crain's Raleigh-Durham, July 22, 2016, goo.gl/GSoCQ0

[3] NextEra Energy Partners, LP completes the acquisition of natural gas pipelines in Texas, PR Newswire, Oct. 5, 2015, goo.gl/WlaS4X.

[4] TECO Energy announces the formation of a new subsidiary, SeaCoast Gas Transmission, LLC, TECO Energy, Aug. 4, 2008, https://goo.gl/0ebj7J.

[5] Overview — New Mexico Gas Company, https://goo.gl/jQtnwL.

EXHIBIT D

STATE OF GEORGIA

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

IN RE:	)	
	)	
Georgia Power Company's 2016 Integrated Resource Plan and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT	)	Docket No. 40161
	)	
Georgia Power Company's Application for the Certification, Decertification, and Amended Demand Side Management Plan	)	Docket No. 40162

Stipulation

The Georgia Public Service Commission (the "Commission") Public Interest Advocacy Staff ("PIA Staff"), Georgia Power Company ("Georgia Power" or the "Company") and the undersigned intervenors (collectively the "Stipulating Parties") agree to the following stipulation as a resolution of the above-styled proceedings to consider the Company's 2016 Integrated Resource Plan (the "2016 IRP") and the Application for the Certification, Decertification, and Amended Demand Side Management Plan (the "2016 DSM Plan"). The Stipulation is intended to resolve all of the issues in these Dockets. The Stipulating Parties agree as follows:

Supply Side Plan

1. The 2016 IRP is approved as amended by this Stipulation.

2. Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1CT and Intercession City CT shall be decertified and retired as provided for in the 2016 IRP.

3. The Renewable Energy Development Initiative ("REDI") is approved and shall be increased such that it will procure 1,200 MW (150 MW of Distributed Generation ("DG") and 1,050 MW of utility scale resources). Utility scale procurement shall take place through two separate Requests For Proposals ("RFP"). The first RFP will be issued to the marketplace in 2017 and will seek 525 MW of renewables with in service dates of 2018 and 2019. The second RFP will be issued to the marketplace in 2019 and will seek 525 MW of renewables with in service dates of 2020 and 2021. No more than a total of 300 MW of wind resources shall be procured through REDI. Bid fees for the utility scale solicitation shall be set at five thousand dollars ($5,000) or three hundred dollars per MW

($300/MW), whichever is greater. The cost to implement and administer the REDI program shall be recovered through the fuel clause. Provided, however, that any costs recovery related to the ASI Prime Program in excess of ongoing ASI Prime costs shall be allocated to REDI and shall not be recovered through the fuel clause. All bid fees collected will be credited to the fuel clause.

4. In 2017, the Company shall issue an RFP for 100 MW of DG greater than 1kW but not more than 3 MW with a commercial operation date of 2018 or 2019. Contract terms will be up to 35 years and solar DG projects must interconnect at Georgia Power's owned distribution system. Bid fees for the DG solicitations shall be set at $4/kW.

5. By the end of 2018, the Company shall procure an additional 50 MWs of customer sited DG projects. Such projects shall be greater than 1kW but not more than 3 MW and must have an installed DC capacity that is less than or equal to 125% of the actual annual peak demand of the customer's Premises in 2015 and be a current GPC customer at the time of award. Procurement shall be done through an application process and if oversubscribed, a lottery will be conducted. Participant fees for the DG solicitations shall be set at $3/kW. Any MWs that are unsubscribed from the customer sited program shall be allocated to the DG RFP reserve list. Customer sited projects will be paid avoided costs using the process as described below in item 8(a).

6. The specific process that will be utilized for the evaluation (such as whether to use a project and/or portfolio analysis) for projects submitted into REDI will be finalized during the review and approval of the REDI RFP documents.

7. The Renewable Cost Benefit framework ("RCB") as provided in paragraph 8(a) shall be utilized in the evaluation of bids received through the REDI RFPs for utility scale and DG projects. The Company and Staff will work collaboratively to develop a process and recommendations for the continued implementation of RCB. Within (4) months from the issuance of the Final Order in this case, the Company and Staff will file their proposal with the Commission for implementation of RCB. If an agreement is reached between the Company and Staff on implementation of RCB, the Company and Staff can recommend to the Commission utilization of the full RCB in REDI.

8. The RCB shall be modified for use in the REDI program as follows:

(a) The Company shall evaluate the bids received in response to REDI RFPs using the RCB. The evaluation of REDI proposals will be limited to the consideration of Avoided Energy and Deferred Generation Capacity cost components consistent with the Framework methodology. Further, the Company will evaluate the appropriate transmission and distribution costs and benefits on a case by case basis as proposed in the Framework document.

(b) Once the evaluation in 8(a) is concluded the Company will conduct, for information purposes only, an evaluation using the entire RCB as filed by the Company to allow Staff and the Independent Evaluator ("IE") to gain familiarity with the RCB. The evaluation will include all aspects of the Framework including specifically, Generation Remix, Support Capacity, and Bottom Out Adjustments. The Company will file its results with the Commission.

9. The Additional Sum for utility scale resources procured through REDI shall be set at 8.5% of shared savings. This amount shall be levelized and recovered annually for the term of the PPA.

10. The Company's closed ash pond solar demonstration project is approved as filed by the Company. The Company will be required to file quarterly construction monitoring reports and will be required to demonstrate the reasonableness and prudency of any recovery in excess of the budget for this project filed in the 2016 IRP. The Simple Solar program is approved with the modifications to the sourcing of the program as recommended by Staff.

    In addition, the Company's High Wind Study is approved as filed. The Company agrees to file quarterly reports providing the status of the High Wind Study. The Staff and Company will collaborate on what, if any, information from the wind study will be made available to interested parties.

11. The Commission approves an additional 200 MW of self-build capacity for use by the Company to develop additional renewable projects in collaboration with customers, including potential projects at Robins Air Force Base and Fort Benning. The projects must be at or below the Company's avoided costs. No more than 75 MW of the 200 MWs provided for in this provision may be used for non-military customer projects. For the non-military customer projects, the Company must demonstrate that the project meets a special public interest need and could not reasonably be achieved using the competitive bid process. The RECs for the non-military customer projects shall accrue to the benefit of all customers.

12. The Company shall consider the development of a renewable Commercial and Industrial Program. No more than 200 MW shall be allocated for such a program and such program must be approved by the Commission before implementation. The Company shall only consider program options that will result in delivering value to all of its customers and will benchmark such programs to the last accepted proposal from the Company's utility scale REDI program.

13. Staff and the Company shall work together to address retirement study and other modeling issues. This process should begin within six months of the final order being issued in this proceeding and must conclude at least 12 months prior to the Company's filing of the 2019 IRP.

14. For purposes of the Company's IRP evaluations the long term Southern System planning reserve margin shall be raised to 16.25%. The Company shall meet with Commission Staff within 6 months of a final order in this case to discuss the timing of future Expected

Unserved Energy studies. The Company will report to Staff once all operating companies have approved for utilization the long term planning reserve margin adopted by this provision.

15. The Company agrees to minimize all capital expenditures on Plant McIntosh Unit 1 and Plant Hammond Units 1-4 through July 31, 2019. The Company agrees to annual limits on all capital expenditures of $1 million for McIntosh 1 and $5 million for Hammond 1-4[1]. The Company agrees to make a filing with the Commission prior to incurring expenditures that exceed the annual limit.

16. The measures taken to comply with the existing government imposed environmental mandates necessary for the Company to implement its environmental and compliance plan as presented in Technical Appendix Volume 2, Summary of Capital Expenditures, Closures, and O&M Expenses filed as part of the 2016 IRP are approved subject to the limits outlined in No. 15 above regarding Plant McIntosh Unit 1 and Hammond Units 1-4. This approval does not preclude the Commission from reviewing prudence of the actual expenditures made to effectuate the compliance plan.

17. The remaining net book values of Plant Mitchell Unit 3 shall be reclassified as a regulatory asset and the Company shall continue to provide for amortization expense at the same rate as determined in the Company's 2013 base rate case. Recovery of the remaining balance as of December 31, 2019 will be deferred for consideration in the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2019 base rate case.

Any unusable M&S inventory balance remaining at the date of the unit retirement shall be reclassified as a regulatory asset and deferred for consideration in the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2019 base rate case.

18. Any over or under recovered cost of removal balances for each Retirement Unit shall be deferred for consideration until the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the appropriate period in which the costs should be recovered. Parties may argue their respective positions on that issue in the 2019 base rate case.

[1] The Hammond Units 1-4 $5 million value represents the cumulative annual amount for all four units. This provision does not apply to expenditures required for retirement obligations.

19. The Company shall report to the Commission concerning progress on the dismantlement and remediation of the Plant Kraft generating plant site and the Company shall provide the Commission with appraised values of any land at that site that the Company would propose to donate to the Georgia Ports Authority, including information regarding whether the appraised value exceeds the Company's net book value of such land.

20. The decision whether to accept, modify or defer consideration of the Company's request for authority to capitalize additional costs to preserve new nuclear shall be a policy decision for the Commission. Adoption of this provision within this stipulation does not preclude any Party from making any argument for or against the Company's request in this regard, nor does this agreement or this provision within this agreement suggest that the Commission must or should (or should not) consider this question as part of this IRP.

21. When filing the 2019 IRP or when filing any updates to the IRP prior to the 2019 IRP filing, the Company agrees to provide the Commission Staff working copies of all models used in the development of that IRP, with each configured to replicate inputs used to derive results incorporated in its base case scenario within 10 days after the IRP or update to the IRP is filed.

22. In conjunction with the ongoing level of review and analysis required by this agreement, Georgia Power will agree to pay for any reasonably necessary specialized assistance to the Staff in an amount not to exceed $300,000 annually. This amount paid by Georgia Power under this paragraph shall be deemed as necessary cost of providing service and the Company shall be entitled to recover the full amount of any costs charged to the utility.

23. The Electric Transportation Initiatives and associated costs identified in the 2016 IRP are not, and have not been converted into, jurisdictional expenses that become the responsibility of ratepayers. Each party reserves the right to address these costs and the merits of the program through the Annual Surveillance Report process and future rate cases.

<u>**Demand Side Plan**</u>

1. The Company's 2016 Demand Side Management ("DSM") Plan and Application for Certification, Decertification and Amended DSM Plan is approved as amended by this Stipulation.

2. Georgia Power will continue to treat DSM as a priority resource in accordance with prior Commission precedent. For the calculation of long term percentage rate impacts, the Company will work with Commission Staff to come up with a methodology within 12 months of the issuance of the final order.

3. Georgia Power will enter discussions over the next three years with Staff and DSMWG members on the value of a Residential Mid-Stream Retail Products Program.

4. Georgia Power will develop a Technical Reference Manual prior to the Company's next IRP filing and will update it every three years thereafter. The Company will work closely with Staff and members of the DSMWG and DSMWG members may also propose new measures to be added at any point in the measure evaluation process. The DSM Program Planning Approach filed as Staff Exhibit BSK8 will otherwise remain unchanged other than "Technology Catalog" will be replaced with "Technical Reference Manual" and the dates will be updated to reflect 2017 through 2019.

5. Georgia Power will agree to the budget adjustments as provided in exhibit 8 attached to this Stipulation as amended.

6. Georgia Power will receive an Additional Sum equal to 8.5% of actual net benefits based on net energy savings from the Program Administrators Cost Test ("PACT"). Once the Additional Sum amount as calculated exceeds the annual program costs, the portion of the Additional Sum that exceeds the program cost shall be calculated based on 4% of the actual net benefits based on net energy savings from the PACT.

7. Georgia Power will work with Staff and the Company's implementation contractor for the Residential Behavioral Program to find ways to include more customers in the program.

8. The Company will make a concerted effort to obtain at least 25% of portfolio savings each year from the Residential sector.

9. Once a program implementer is selected and plans for all proposed programs are drafted and completed, the plans will be provided to Staff for review prior to implementation of the programs. The current review and approval process reached in an agreement between Staff and the Company in 2014 will continue, and the Company agrees to discuss further refinements and revisions to the process. In order to change the process both Staff and the Company must agree to the recommended changes.

10. The Company will provide detailed evaluation plans for each of the approved DSM programs within 120 days of the selection of Program Implementers for each of the certified programs. If necessary, the Company may request, and Staff may unilaterally grant, additional time to complete the detailed evaluation plans for each of the approved DSM proposals.

11. The Company will agree to a Commercial and Residential Building Usage Data awareness option at the cost of $300,000 for 2017 and $100,000 annually for 2018 and 2019, and such costs will be added to the DSM Consumer Awareness budget. This option will be available to customers within one year from the date of the final order in

this docket. There will be no assumed energy savings or goals attributed to this customer awareness option.

12. The Company and Staff agree to a $2.5 million annual pilot budget for DSM and energy efficiency pilot programs. Staff will be notified before the start of such pilots.

13. The Company agrees to the Staff recommendation for the Learning Power program annual budget to be $3 million.

14. The Company agrees to the Staff recommendation against shifting residential and commercial customer awareness to cross-cutting costs.

15. The current DSM true-up process filed in Docket No. 36499 on October 18, 2013, will continue through 2020. Although the DSM tariffs will remain at current levels until rates are adjusted in 2020, the true-up review process will continue on an annual basis.

Agreed to this 23rd day of June, 2016.

Jeffrey Stair

On behalf of the Georgia Public Service Commission
Public Interest Advocacy Staff

Brandon F. Marzo

On behalf of Georgia Power Company

[Additional Signatures]

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On behalf of Clean Line Energy Partners LLC

David Berry
authorized person

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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[Additional Signatures]

Chas. B. Jones, III
On behalf of Georgia Association
Of Manufacturers

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On behalf of Georgia Industrial
Group

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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12. The Company and Staff agree to a $2.5 million annual pilot budget for DSM and energy efficiency pilot programs. Staff will be notified before the start of such pilots.

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14. The Company agrees to the Staff recommendation against shifting residential and commercial customer awareness to cross-cutting costs.

15. The current DSM true-up process filed in Docket No. 36499 on October 18, 2013, will continue through 2020. Although the DSM tariffs will remain at current levels until rates are adjusted in 2020, the true-up review process will continue on an annual basis.

Agreed to this 23rd day of June, 2016.

Jeffrey Stair

On behalf of the Georgia Public Service Commission
Public Interest Advocacy Staff

Brandon F. Marzo

On behalf of Georgia Power Company

On behalf of Georgia Industrial Group

7

[Additional Signatures]

On behalf of The Georgia Large Scale Solar Association

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

[Additional Signatures]

On behalf of Georgia State Building and Construction Trades Council

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

[Additional Signatures]

Bruce W. Burcat

On behalf of Southern Wind Energy
Association

EXHIBIT E

February 29, 2016

Via Electronic Mail

Supervisor Marc Harris
Power Plant NPDES Permitting, Industrial Wastewater Section
Florida Department of Environmental Protection

Re: *Bringing Florida Coal Plants Into Compliance With The New Effluent Limitations Guidelines*

Dear Supervisor Harris:

As you know, the U.S. Environmental Protection Agency ("EPA") updated the Effluent Limitations Guidelines ("ELGs") for steam electric power plants to protect our waters from the toxic pollutants in these generators' discharges.[1] Reflecting decades of advances in water quality science and control technology,[2] the ELGs became effective on January 4, 2016. Now coal-burning[3] power plants across the country must come into compliance with the ELGs "as soon as possible;" for many plants the deadline is November 1, 2018.[4] The undersigned groups and our tens of thousands of Florida members therefore urge you, as the supervisor of power plant NPDES permitting, to:

1. Promptly issue draft revised NPDES permits and fact sheets for Florida coal plants to require these plants to comply with the ELGs by November 1, 2018, unless you conclude that a later date is appropriate based on a well-documented justification that is consistent with EPA's guidelines in the final rule and the public interest in securing vital water protections as soon as possible.

2. Take public comment for no less than 60 days on draft NPDES permits and fact sheets for Florida coal plants that include your ELGs compliance determinations.

3. Work with the operators of the three Florida coal plants without NPDES permits or announced plans for retirement, and other stakeholders, to ensure that these plants achieve timely compliance with the applicable requirements in the ELGs.

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[1] U.S. EPA, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 80 Fed. Reg. 67,837 (Nov. 3, 2015), codified at 40 C.F.R. part 423.
[2] *See* 80 Fed. Reg. at 67,840.
[3] *See* 80 Fed. Reg. at 67,839, n. 1 ("power plants covered by the ELGs use nuclear or fossil fuels, such as coal, oil, or natural gas, to heat water in boilers, which generate steam." [emphasis added]).
[4] *See, e.g.*, 40 C.F.R. § 423.13(g)(1)(i) (establishing deadline for compliance with FGD wastewater standards; identical language appears in the provisions for other regulated waste streams).

4. Work with all Florida coal plant operators, fellow regulators, and other stakeholders to determine compliance obligations and timelines for all other applicable water-side requirements.

As we discuss below, timing is critical. Through the permit renewal process, making prompt compliance determinations will help attain and maintain safe water quality in Florida. Prompt compliance determinations will also allow fellow regulators to assess whether it is more prudent to retire—rather than spend huge sums of public monies to retrofit—these aging coal plants in the rapidly evolving regulations and market conditions concerning coal and carbon.

<u>In short, our overarching request is that you take swift action to determine what it will take to bring *all* Florida coal plants into timely compliance with *all* applicable water-side requirements, set deadlines for the same, and meet with us to discuss the way forward</u>.

I. DEP Should Promptly Issue Draft Permits And Fact Sheets For Florida Coal Plants Incorporating The ELGs And Specifying The "As Soon As Possible" Compliance Deadline.

The ELGs impose stringent, technology-based effluent limitations on the discharges of several common types of effluent (i.e., waste streams) from coal plants, including fly ash and bottom ash transport waters, and wastewater from flue gas desulphurization ("FGD") systems.[5] Under the Clean Water Act, it is the responsibility of state permitting authorities to incorporate the ELGs into the NPDES permits for coal plants "as a floor or a minimum level of control."[6] Just as it is the responsibility of the coal plant operators to "immediately begin"—"even prior to the permit renewal process"—their ELGs compliance analyses, and convey to state authorities the information they need to complete independent evaluations.[7]

In particular, when revising permits for direct dischargers—facilities that discharge to surface waters—state permitting authorities must determine the compliance deadline for the ELGs, which is to be "as soon as possible beginning November 1, 2018, but no later than December 31, 2023." To be clear, the phrase "as soon as possible" means November 1, 2018, unless the permitting authority establishes a later date based on a well-documented justification and the

[5] *See* 40 C.F.R. § 423.13.
[6] 80 Fed. Reg. at 67,882.
[7] *Id.* at 67,882-83 ("Regardless of when a plant's NPDES permit is ready for renewal, the plant should <u>immediately begin</u> evaluating how it intends to comply with the requirements of the final ELGs. In cases where significant changes in operation are appropriate, the plant should discuss such changes with the permitting authority and evaluate appropriate steps and a timeline for the changes, <u>even prior to the permit renewal process</u>." [emphasis added]).

authority's case-by-case consideration of certain enumerated factors in the final rule, discussed further below.

The November 1, 2018, compliance deadline is achievable. EPA's rulemaking record shows that, depending on the scope of required retrofit at a particular coal plant, industry itself projects that the total time needed for fly ash and bottom ash system retrofits ranges from 27 to 36 months, from the start of conceptual engineering to final commissioning.[8] With appropriate planning and direction from state permitting authorities, many plants thus can and should be required to bring their operations into compliance by November 1, 2018, especially given that the updates to the ELGs were developed and thus anticipated by industry over several decades.

EPA rightly urges permitting authorities to "provide a well-documented justification for how [they] determined the 'as soon as possible' date in the fact sheet or administrative record for the permit," and to "explain why allowing additional time to meet the limitations is appropriate," if that is the authority's conclusion.[9] EPA specifies that any determination that a later date is appropriate should be substantiated by the public record and reflect consideration of the following factors:

◊ "Time to expeditiously plan (including time to raise capital), design, procure, and install equipment to comply with the requirements [in the ELGs]."[10] EPA explains that "the permitting authority should evaluate what operational changes are expected at the plant to meet the new BAT limitations for each waste stream, including the types of new treatment technologies that the plant plans to install, process changes anticipated, and the timeframe estimated to plan, design, procure, and install any relevant technologies."[11]

◊ Changes being made or planned to bring the coal plant into compliance with Clean Air Act requirements, as well as the requirements for the disposal of coal combustion residuals under Subtitle D of the Resource Conservation and Recovery Act.[12]

◊ For FGD wastewater requirements only, an initial commissioning period to optimize the installed equipment.[13] EPA explains that the "record demonstrates that plants installing

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[8] Utility Water Act Group, *Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Sept. 30, 2013), Attach. 11: Retrofitting Dry Bottom Ash Handling, Attach 13: Retrofitting Dry Fly Ash Handling.
[9] *See* U.S. EPA, Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Sept. 2015), at p. 14-11, *available at* http://goo.gl/PpzQ4F [hereinafter "TDD"].
[10] *Id.*
[11] *Id.*
[12] 40 C.F.R. § 423.11(t)(2).

the FGD technology basis spent several months optimizing its operation (initial commissioning period). Without allowing additional time for optimization, the plant would likely not be able to meet the limitations because they are based on the operation of optimized systems."[14]

◊ Other factors as appropriate.[15]

Consistent with these EPA guidelines and the public interest in securing vital water protections as soon as possible, you should incorporate the ELGs into the NPDES permits for eight Florida coal plants—Big Bend, Crist, Crystal River, Northside/St. Johns, Seminole, Stanton, Indiantown and Polk.

As you are aware, NPDES permits for the first six of these plants (Big Bend through Stanton) expire this year or next year. Therefore, you should be working with their operators to ensure that they do, in fact, "immediately begin" their ELGs compliance analyses, and are prepared to provide you and the public the information needed to evaluate and set the "as soon as possible" ELGs compliance deadline in their NPDES renewal permits.

Moreover, even if Indiantown and Polk's NPDES permits do not expire until 2019, their operators have the same responsibility to "immediately begin"—"even prior to the permit renewal process"—their ELGs compliance analyses, and, similarly, you should be working with these plant's operators to expeditiously set and achieve the "as soon as possible" ELGs compliance deadline.

Therefore, we urge you to make prompt compliance determinations for all eight coal plants, <u>first</u>, by collecting and making publicly available the information from their operators regarding their potential to comply with the ELGs by November 1, 2018, and, <u>second</u>, by closely scrutinizing and verifying this information as you revise NPDES permits and adjudicate any requests to extend the ELGs compliance deadline beyond November 1, 2018.

With respect to extension requests, we recognize that for other regulations, for instance, the Mercury and Air Toxics Standards, it has been the Department of Environmental Protection's ("DEP") practice to carefully review and grant such requests only in exceptional cases. Similarly, DEP should continue this practice here and use its broad information collection powers and stakeholder engagement process to help adjudicate the merits of any extension requests for ELGs compliance.

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[13] 40 C.F.R. § 423.11(t)(3).
[14] TDD at 14-11.
[15] 40 C.F.R. §423.11(t)(4).

II. DEP Should Take Public Comment For No Less Than 60 Days On Draft NPDES Permits And ELGs Compliance Determinations For Coal Plants.

Because of the significance of the water protections in the ELGs and the findings you must make regarding the compliance date, as discussed above, we urge you to take public comment for no less than 60 days on these draft NPDES renewal permits and compliance determinations for the ELGs. Doing so is entirely consistent with DEP's mission to serve the public interest and to conduct its environmental oversight responsibilities with transparency.[16]

III. DEP Should Work With Florida Coal Plant Operators That Do Not Have NPDES Permits, And Other Stakeholders, To Ensure That Their Plants Achieve Timely Compliance With The Applicable Requirements In The ELGs.

Three coal plants in Florida—C.D. McIntosh, Jr., Cedar Bay, and Deerhaven—are not covered by NPDES permits but nonetheless must assure that the toxic pollutants in their effluent are properly treated to meet the requirements in the ELGs. For example, the McIntosh plant in Lakeland discharges effluent containing toxic pollutants such as mercury to publicly owned treatment works. These discharges are subject to revised Pretreatment Standards for Existing Sources (PSES) in the ELGs.[17] The PSES are self-implementing, meaning these requirements apply directly, without the need for any permit revision, and must be met by the November 1, 2018, compliance deadline in the final rule.[18] Sierra Club provided McIntosh's operator, Lakeland Electric, with a compliance analysis specifying the implications of the PSES for this plant.[19] We urge you to work with the DEP PSES coordinator, the operators of all three plants, as well as other stakeholders, to ensure that they achieve timely compliance with the applicable requirements in the ELGs.

IV. Timing Is Critical.

As we noted above, timing is critical. Through the water permit renewal process, you should make prompt ELGs compliance determinations for three key reasons:

First, prompt ELGs compliance determinations, including setting the "as soon as possible" deadline, are needed to secure safe water for Floridians. EPA updated the ELGs to address the "outstanding public health and environmental problem" related to the discharge of effluent containing toxic and other pollutants from power plants, including Florida's aging coal plants.[20]

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[16] *See, e.g.*, FDEP Mission Statement & Objectives, *available at* http://goo.gl/tTk3mp.
[17] *See* 40 C.F.R. § 423.16.
[18] *Id.*
[19] *See* Sierra Club letter to General Manager Ivy of January 26, 2016 and exhibits, on file with DEP.
[20] 80 Fed. Reg. at 67,840-41.

Indeed, the "ELGs that EPA promulgated and revised in 1974, 1977, and 1982 are out of date" and, as a result, permits issued to coal plants under those previous, outdated ELGs "do not adequately control the pollutants (toxic metals and other) discharged by this industry, nor do they reflect relevant process and technology advances that have occurred in the last 30-plus years."[21]

Furthermore, as you know, NPDES permits have a maximum term of five years.[22] The limited permit duration and the anti-backsliding requirement in the Clean Water Act aim to achieve gradual, iterative, but continual progress towards restoring the nation's waters. As the D.C. Circuit has explained, "[t]he essential purpose of this series of progressively more demanding technology-based standards was not only to stimulate but to press development of new, more efficient and effective technologies."[23] As pollution control technologies improve, higher standards are incorporated into the NPDES permits of existing facilities upon renewal. This makes timely renewal of NPDES permits a linchpin of the Clean Water Act, and an essential part of your office's responsibilities.

Second, prompt ELGs compliance determinations will help assure that coal plant operators do, in fact, reduce as soon as possible the toxic discharges into our waters, thus avoiding regulatory uncertainty and any avoidable delay in achieving these vital water protections.

Third, prompt ELGs compliance determinations will help level the playing field between coal plants with NPDES permits and those without them, so that all Florida coal plants achieve compliance with the ELGs as soon as possible.

For all these reasons, we urge you to make prompt determinations of what it will take to bring Florida coal plants into compliance with the ELGs, and promptly adjudicate any requests to extend the compliance deadline beyond November 1, 2018.

V. DEP Should Do Its Part To Protect Consumers From Piecemeal Regulatory Compliance Decisions That Fail To Identify And Pursue Cost-Effective Alternatives To Spending Billions Of Dollars To Retrofit Florida's Aging Coal Plants.

As we noted above, fellow regulators are deciding whether to spend huge sums of public monies on retrofitting aging coal plants to meet several environmental regulations with fast-approaching compliance deadlines. Indeed, because burning coal is one of the most polluting and

[21] 80 Fed. Reg. at 67,840 [emphasis added].
[22] *See* 33 U.S.C. § 1342(b)(1)(B).
[23] *Natural Res. Def. Council v. U.S. Envtl. Prot. Agency*, 822 F.2d 104, 124 (D.C. Cir. 1987).

increasingly costly ways to generate electricity, regulators—and coal plant operators—will soon decide whether to take as much as 4 billion dollars from Floridian families and businesses for retrofits, alone, to these plants.[24] Yet there has not been any comprehensive accounting of just how much more Floridians may have to pay to rely on these plants to keep the lights on, much less a fair comparison to available alternatives such as retiring these plants and investing instead in modern clean energy resources such as solar, wind, energy efficiency, and storage that are at record low prices.[25] Indeed, while operators project coal plant retrofits may cost 4 billion dollars or more, they admit this huge sum does not account for all the costs and risks associated with relying on coal plants in the rapidly evolving regulations and market conditions concerning coal and carbon.[26]

We urge you to do your part to fill this acute information gap, first, by providing much needed clarity regarding ELGs compliance obligations and timelines for coal plants and, second, by providing the same for other applicable water-side requirements. For example, four Florida coal plants—Big Bend, Crist, Crystal River, Northside—use antiquated once-through cooling systems that needlessly harm millions of aquatic organisms, potentially including federally listed species. In fact, it has been unlawful to use such rudimentary cooling systems when building new power plants since 2001,[27] and generally none have been built since the 1980's precisely because of their adverse biological impacts.[28] To be sure, aging coal plants such as Big Bend, Crist, Crystal River, and Northside also must come into compliance with modern, species-protecting cooling standards under the Endangered Species Act and the Cooling Water Intake Structure Rule. Therefore, we urge you to work closely with the operators, fellow regulators, and other stakeholders to comprehensively identify Florida coal plants' water-side compliance obligations and timelines. The sooner, the better. As we discussed above, huge sums of public monies and vitally important water resources are at stake.

Thank you for your consideration, and we look forward to the opportunity to meet with you to discuss the way forward.

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[24] *See, e.g.,* Sierra Club letter of December 12, 2015, Table 1 (showing electric utilities' incomplete regulatory compliance costs estimates totaling 3-4 billion dollars through 2024), *available at* http://goo.gl/CT8l1j [hereinafter "2015 Letter"].
[25] *See generally id.*
[26] *See* 2015 TYSP First Supplemental Staff Data Request No. 38*, available at* http://goo.gl/nhBGEi; *see also* 2015 Letter, 7-8 (discussing incomplete nature of utility retrofit cost estimates).
[27] *See* 66 Fed. Reg. 65256 (2001) ("Phase I Rules"); *see also* 40 CFR §§125.80(a), 125.81(a) (2008).
[28] *See*, *e.g.*, 65 Fed. Reg. 49060, 49087 and 49094 (Aug. 10, 2000) ("Draft Phase I Rules") (noting that since the 1970's there has been extensive and increasing recycling and reuse of cooling water and that by the year 2000 most new industrial facilities used closed-cycle cooling systems).

Sincerely,

Diana Csank
Sierra Club

Alisa Coe
EarthJustice

Susan Glickman
Southern Alliance for Clean Energy

Kathleen E. Aterno
Clean Water Action

Jerry Phillips
Florida PEER

Dan Tonsmeire
Apalachicola Riverkeeper

Pete Harrison
Waterkeeper Alliance

Laurie Murphy
Emerald Coastkeeper

Neil A. Armingeon
Matanzas Riverkeeper

Justin Bloom
Suncoast Waterkeeper

Lisa Rinaman
St. Johns Riverkeeper

Rachel Silverstein, Ph.D.
Miami Waterkeeper

Harrison Langley
Collier County Waterkeeper

Cc: Paula Cobb, DEP
Greg Brown, DEP
Richard Tedder, DEP
Julie Brown, PSC
Mark Futrell, PSC
Tom Ballinger, PSC
J.R. Kelly, OPC

EXHIBIT F

SIERRA CLUB

September 26, 2016

Via email and postal mail

Supervisor Marc Harris
Power Plant NPDES Permitting, Industrial Wastewater Section
Florida Department of Environmental Protection
marc.harris@dep.state.fl.us

Re: Bringing coal burning operations at the Crystal Energy Generating Complex Units 4 and 5 into compliance with ground and surface water protection standards in the current NPDES permit renewal process (Permit No. FL0036366)

Dear Supervisor Harris:

On behalf of our tens of thousands of Florida members and supporters and the undersigned groups, the Sierra Club respectfully submits these comments on the Draft Permit issued by the Florida Department of Environmental Protection ("DEP") for National Pollutant Discharge Elimination System Permit ("NPDES") Permit No. FL0036366. This permit governs discharges from Units 4 and 5 at Duke Energy Florida's ("DEF") Crystal River Energy Generating Complex ("CREC") into Crystal Bay, a Class II marine water and part of the Gulf of Mexico.

As stated in our prior letter of February 29, 2016,[1] we have a vital interest in bringing the toxic coal burning operations in Florida into compliance with the applicable public health and safety standards. Our comments here focus on the necessary changes to Permit No. FL0036366 to bring CREC into compliance with the revised effluent limitation guidelines for steam electric power plants ("ELGs")[2] and the new standards for coal combustion residuals ("CCR") [3] storage and disposal (the "CCR Rule").[4]

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[1] Letter from Diana Csank, Sierra Club, to Marc Harris, Florida Department of Environmental Protection (February 29, 2016).

[2] U.S. EPA, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Final Rule*, 80 Fed. Reg. 67,838 (Nov. 3, 2015) (revising 40 C.F.R. Part 423) [hereinafter "ELGs"].

[3] Coal combustion residuals include "fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated from burning coal for the purpose of generating electricity by electric utilities and independent power producers." 40 C.F.R. § 257.53.

[4] U.S. EPA, *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities; Final Rule*, 80 Fed. Reg. 21,302 (Apr. 17, 2015), as amended by Technical Amendments to the Hazardous and Solid Waste

To support our comments, we enclose two exhibits: Exhibit 1, by one of the state's preeminent hydrogeologists, Dr. Mark Stewart, assesses the coal disposal at CREC including the pathways for toxic contaminants in the Ash Landfill and Percolation Pond to leach into the Floridan aquifer and Crystal Bay. Exhibit 2, by Dr. Ranajit Sahu— an expert with over twenty-five years of experience in environmental, mechanical, and chemical engineering, including coal-fired power plants— examines the timeline for CREC Units 4 and 5 to achieve compliance with a zero discharge standard for bottom ash.

As detailed below and in the enclosed exhibits, per the ELGs, by November 1, 2018, the final permit should require DEF to eliminate all discharges of bottom ash and flue gas mercury control ("FGMC") wastewaters, and meet new limitations for pollutants in flue gas desulfurization ("FGD") wastewater and combustion residual leachate for the following reasons, again, detailed further below:

◊ The final permit should set November 1, 2018, as the "as soon as possible" deadline for DEF to eliminate bottom ash wastewater discharges from Units 4 and 5. [5] It is well documented that a zero discharge best available technology economically achievable ("BAT") standard for bottom ash wastewater can be readily achieved in 27 to 30 months, rather than the 44 months that DEF proposed and DEP has endorsed in the Draft Permit.[6] In fact, the permitting record here indicates that DEF is well-positioned to meet the standard in even less time, such that the default, November 1, 2018, deadline should apply.

◊ The final permit should include the applicable ELG provisions for CREC's FGMC and FGD wastewaters as they are discharged to groundwater in Percolation Ponds and directly hydrologically connected to Crystal Bay and the Gulf of Mexico, "waters of the United States."[7]

◊ The final permit should set November 1, 2018, as the deadline for DEF to meet the zero discharge standard for CREC's discharges of FGMC wastewater.[8] Additionally, before that deadline, the permit should require DEF to meet the best practicable control technology available ("BPT") limitations for total suspended solids ("TSS") and oil and grease effluent limits and begin monitoring flows daily.[9]

◊ The final permit should require the FGD wastewater to meet strict BAT effluent limits

Management System; Disposal of Coal Combustion Residuals from Electric Utilities—Correction of the Effective Date, 80 Fed. Reg. 37,988 (Jul. 2, 2015) (revising 40 C.F.R. §§ 257 & 261) [hereinafter "CCR Rule"].

[5] *See* 40 C.F.R. § 423.11(t) (defining the phrase "as soon as possible" to mean Nov. 1, 2018, unless a later date is specifically justified); § 423.13(k)(1) (requiring compliance with bottom ash wastewater standards by Nov. 1, 2018 unless a later date up to Dec. 31, 2023 is specifically justified).

[6] *See* Exhibit 2.

[7] 33 U.S.C. §§ 1311(a), 1342(a), 1362(14); 40 C.F.R. § 423.13(g) and (i).

[8] 40 C.F.R. § 423.13(i)(1) (requiring compliance with FGMC wastewater standards by Nov. 1, 2018 unless a later date up to Dec. 31, 2023 is specifically justified).

[9] 40 C.F.R. § 423.12(b)(11).

for arsenic, mercury, selenium and nitrate/nitrite by December 2018, or even sooner if possible.[10] Additionally, the permit should require, effective immediately, FGD wastewater to meet the BPT TSS and oil and grease effluent limits and daily monitoring of the same.[11]

◊ The final permit should require combustion residual leachate to meet all applicable technology and water quality based effluent limits, not only for discharges that drain to the runoff collection system, but also for discharges to the seawater discharge canal and Crystal Bay.[12]

As detailed below and in the enclosed exhibits, per the CCR Rule, the final permit should require DEF to meet all of the applicable new safety standards for coal ash disposal. This includes the standards aimed at protecting groundwater and surface—here, most notably, the Floridan aquifer and Crystal Bay:

◊ Toxic coal ash contaminants associated with CCR—arsenic, boron, manganese, molybdenum, selenium, sulfate, and thallium—are exceeding state and federal safety limits at wells downgradient from the unlined Ash Landfill,[13] as DEP is aware and even predicted.[14] Because there is no protective barrier, CCR waste in the landfill is in direct contact with the Floridan aquifer and groundwater that is hydrologically connected to Crystal Bay.

◊ The CCR Rule requires cleanup of the CCR that has accumulated in the unlined Ash Landfill.[15] To prevent unauthorized discharges and further contamination, and to comply with federal and state waste and water quality regulations, the final permit should require DEF to take corrective action as soon as possible by removing all CCR from the Ash Landfill and decontaminating the site.

◊ CREC is in one of the country's most unstable areas, in karst terrain, and under the influence of multiple sinkholes, including 24 reported sinkholes within 5 miles of CREC. Siting CCR waste facilities here puts ground and surface waters at risk of releases of toxic CCR waste into the underlying aquifer, due to limestone dissolution and collapse.[16]

◊ DEF must comply with prohibitions, designed to protect public waters, on siting coal ash

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[10] *See* 40 C.F.R. §423.13(g)(1)(i) (requiring compliance with FGD wastewater standards by Nov. 1, 2018 unless a later date up to Dec. 31, 2023 is specifically justified).

[11] 40 C.F.R. § 423.12(b)(11).

[12] 40 C.F.R §§ 423.12(b)(11) and 423.13(l).

[13] *See* Exhibit 1 and Section G below; *see also* 40 C.F.R. §§ 141.62,141.66, 257.95(h); Fla. Admin. Code. R. 62-520.420 (2016).

[14] Memorandum from Don Kell to Hamilton Oven, Jr., July 15, 1981 at 3, 4, 7 (hereinafter "Ash Landfill Interoffice Memo").

[15] 40 C.F.R. §§ 257.95(g)(5); 257.96; 257.101(a).

[16] *See* Exhibit 1.

waste facilities in unstable areas (i.e., Florida's karst terrain).[17] To do so, DEF must move CCR disposal offsite if DEF fails to prove that the status quo—storing CCR in CREC's facilities—is somehow safe.[18] Because the Ash Landfill cannot meet the safety standards in the CCR Rule, and the facility cannot be effectively retrofitted, it cannot receive CCR after April 19, 2019. Instead, DEF will be required to close the landfill and move disposal offsite.

DEF applied to renew Permit No. FL0036366, governing surface water discharges from Units 4 and 5 in January 2016.[19] Notice of the Draft Permit was received by Sierra Club via email on Friday, August 26, 2016. The applicant's name is DEF Florida, LLC, and its address is 15760 Power Line St., Crystal River, FL 34428. The discharge covered by the proposed Draft Permit, File No. FL00036366-013-IW1S, is located in Citrus County.

We respectfully submit this material to help inform DEP's renewal of Crystal River's NPDES permit, to raise our concerns that the Draft Permit does not assure compliance with state and federal law, and to urge DEP to revise the Draft Permit and include requirements for CREC to comply with all applicable ground and surface water protection standards.

BACKGROUND

The Crystal River Energy Generating Complex ("CREC") is located in Citrus County, Florida and is owned and operated by DEF. CREC Units 4 and 5 are pulverized coal-burning steam electric generating units that were placed into service in 1982 and 1984 respectively. The 4,729-acre coastal site in Florida's Big Bend is connected to Crystal Bay, a Class II[20] marine water and part of the Gulf of Mexico, via a seawater discharge canal that releases the plant's wastewater.

Crystal Bay is a shallow embayment of the Gulf of Mexico, midway between the Withlacoochee River to the north and the Crystal River to the south. Undeveloped portions of CREC include wetlands and salt marshes. Crystal Bay includes a variety of habitats that support vital aquatic resources, including the federally-listed species identified below. Open water habitats in Crystal Bay cover saltwater, tidally-influenced water, and tidal freshwater areas and include artificial structures, coastal tidal rivers and streams, oyster reefs, salt marshes, subtidal unconsolidated marine/estuary sediment habitats, and submerged aquatic vegetation habitats such as seagrasses and algae. The bottom of Crystal Bay provides benthic habitats, with characteristics dictated by salinity, tides, and substrate type.[21]

[17] 40 C.F.R. § 257.64.

[18] 40 C.F.R. §§ 257.64(5), 257.101(b)(1) (surface impoundments), 257.101(d)(1) (landfills).

[19] *See* Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016.

[20] *See* Fla. Admin. Code. R. 62-302.400(16)(b)(9) (2016) (classifying "all coastal waters and tidal creeks" within Citrus County as Class II waters).. The Surface Water Quality Criteria are designed to to "protect fish consumption, recreation and the propagation and maintenance of a health, well-balanced population of fish and wildlife." Fla. Admin. Code. R. 62-302-400(4) (2016). Florida has set Surface Water Quality Criteria).

[21] U.S. Nuclear Regulatory Commission, Draft Environmental Impact Statement for Crystal River Unit 3, at 2-42

Water-related industries, such as commercial fishing and tourism, make up a large sector of the employment base in Citrus County.[22] These sectors of the local economy "depend upon the resources of the coastal fisheries and the West Indian (Florida) manatee."[23] Over ninety species of fish have been identified near CREC.[24]

Federally-listed threatened or endangered species in the vicinity of the CREC include, but are not limited to, the Gulf sturgeon, smalltooth sawfish, green turtle, hawksbill turtle, Kemp's ridley turtle, leatherback turtle, loggerhead turtle, the American alligator, the wood stork, the bald eagle, and the Florida manatee.[25] Manatees are known to dwell in Crystal River effluent and intake canals during the spring and fall[26] and nearby Crystal River/Kings Bay, an Outstanding Florida Water, is the largest winter refuge for manatees on the Florida Gulf Coast.[27]

As detailed in Exhibit 1, the CREC is located in one of the country's most unstable areas with 24 known sinkholes within a 5 mile distance. Indeed, coastal Citrus County is an active karst area with sandy sediment cover over limestone.[28] The near-surface limestone is deeply incised with solution channels and conduits that can cause additional sinkholes to form as surficial sands move into subsurface voids.[29] The permeable surficial sediments allow access to the shallow, unconfined aquifer below through solution cavities and along fractures. Groundwater at CREC flows towards Crystal Bay and the Gulf of Mexico via the seawater discharge canal, and tidal wetlands.

Wastewater from Units 4 and 5 includes runoff from coal, gypsum, and limestone storage handling areas and the Ash Landfill, overflow bottom ash sluice water, FGD wastewater, FGMC wastewater, and cooling tower blowdown. These wastewaters are combined and released into the seawater discharge canal, which connects the plant to Crystal Bay.

Bottom ash generated at CREC Units 4 and 5 is sluiced to handling tanks and dewatering bins, where bottom ash solids are separated out from the wastewater.[30] Overflow bottom ash

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(2011) (citing Florida Fish and Wildlife Conservation Commission (FWC, 2005)).).

[22] *See e.g.*, Tommy Thompson, *Time to Join the Crystal River Circus*, Florida Sportsman, February 1, 2006, *available at* http://www.floridasportsman.com/2006/02/01/fishing_crystal_river_powerplant/

[23] Citrus County Comprehensive Plan, Chapter 4, 4-13, October 28, 2014, *available at* https://www.citrusbocc.com/plandev/landdev/comp-plan/chapter-4.pdf.,

[24] U.S. Nuclear Regulatory Commission, Draft Environmental Impact Statement for Crystal River Unit 3, at 2-5.

[25] Duke Energy Florida, Inc. Crystal River Unit 3 Post-Shutdown Decommissioning Activities Report, at 25 (Dec. 2013) *available at* http://www.duke-energy.com/pdfs/3f1213-02_psdar.pdf.

[26] *See* Citrus County Comprehensive Plan, Chapter 13, October 28, 2014, *available at* https://www.citrusbocc.com/plandev/landdev/comp-plan/chapter-13.pdf.

[27] Southwest Florida Water Management District, *Crystal River/Kings Bay, Citrus County* https://www.swfwmd.state.fl.us/springs/kings-bay/

[28] See Exhibit 1.

[29] *Id.* at 4 (citing Dames and Moore 1994).

[30] Duke Energy Florida, Ash Storage/Disposal Area Operations Plan at 2, 5 (Dec. 2013); Duke Energy Florida, Response to Request for Additional Information, May 20, 2016 (hereinafter "RAI #2").

wastewater from the dewatering bins is permitted to flow through internal Outfall I-CH0, which is released through the main discharge canal at Outfall D-001 to Crystal Bay.

Fly ash and bottom ash solids from Units 4 and 5 are taken to CREC's Ash Landfill for disposal or storage. The 62-acre, unlined Ash Landfill began operating alongside Units 4 and 5 in the 1980's and receives a mixture of bottom ash, fly ash, gypsum, pyrites, FGD blowdown solids, mill rejects, and other CCR. [31] The Ash Landfill is unlined[32] as well as uncovered,[33] allowing water, such as precipitation, to enter and mix with the wastes inside, and subsequently leach CCR contaminants into the groundwater beneath the Ash Landfill, and then into the runoff collection system, the seawater discharge canal, and the waters of Crystal Bay.

Units 4 and 5 use a wet scrubber system for sulfur dioxide removal, which produces FGD wastewater as a byproduct. This wastewater is discharged to the plant's FGD Blowdown Ponds, two 1.5- and 4.5-acre solids settling ponds that became operational in 2010.[34] Solids are settled out in the FGD Blowdown Ponds and the remaining liquid is pumped to CREC's unlined Percolation Ponds to be absorbed into groundwater. FGMC wastewater is generated via the plant's mercury control system and is injected into the FGD absorber before also being discharged to the Percolation Ponds.[35] Gypsum solids are conveyed to the concrete-lined Gypsum Storage Pad and stored before disposal in the Ash Landfill or transport offsite for sale.

LEGAL REQUIREMENTS

The wastewater and solid waste byproducts of burning coal at CREC fall under two new U.S. Environmental Protection Agency ("EPA") rules: the ELGs and the CCR Rule. These rules advance vital public health and environmental safeguards against the toxic metals and other pollutants found in CREC's waste streams.

CREC Units 4 and 5 discharge wastewater into Crystal Bay and are therefore required, pursuant to section 402 of the Clean Water Act ("CWA"), to obtain a NPDES permit. In enacting the CWA, Congress established as a national goal the elimination of all discharges of pollution into waters of the United States.[36] To this end, the Act's implementing regulations establish the NPDES permitting program. Under the program, no pollutant may be discharged from any "point source" without a permit, and failure to comply with such a permit constitutes a violation of the CWA.[37] The CWA defines a "point source" as "any discernible, confined and

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[31] Ash Storage/Disposal Area CCR Landfill Annual Inspection Report, December 2015; Florida Department of Environmental Protection Inspection Report, July 28, 2015.

[32] The 62-acre landfill is unlined with the exception of a 5.5-acre horizontal expansion in June 2010 which used a geosynthetic clay liner. RAI #2.

[33] Approximately 11 acres of the landfill has been covered with a geosynthetic clay liner, 24-inches of protective soil cover, and sod. *Id.*

[34] Record Documentation of Units 4 and 5 FGD Blowdown Ponds Construction Quality Assurance (January 2010).

[35] RAI #2.1

[36] 33 U.S.C. § 1251(a)(1).

[37] 33 U.S.C. §§ 1311(a) and 1342(a); 40 C.F.R. § 122.41(a).

discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, [or] container … from which pollutants are or may be discharged."[38]

The CWA authorizes EPA to establish national, technology-based effluent limitations guidelines for discharges from categories of point sources, and requires that NPDES permits include effluent limits based on the performance achievable through the use of statutorily-prescribed levels of technology that "will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[39]

The ELGs became effective on January 4, 2016, and must be included in NPDES permits for such generators going forward. The ELGs impose technology-based effluent limitations—reflecting decades of advances in water quality science and control technology—on discharges of several common types of effluent (i.e., waste streams) from coal-burning power plants, including fly ash and bottom ash transport waters and wastewater from FGD and FGMC systems.

Under the CWA, it is the responsibility of state permitting authorities, such as DEP, to "incorporate the ELGs into NPDES permits as a floor or a minimum level of control."[40] November 1, 2018, is the default deadline for all coal-burning[41] power plants across the country.[42] Because we submitted comments to you in February detailing DEP's implementation responsibilities, we will not repeat ourselves here, but instead incorporate those comments by reference.[43]

EPA's CCR Rule, effective October 19, 2015, establishes national minimum requirements for the safe disposal of coal combustion residuals, or CCR, the solid waste byproducts of burning coal, commonly known as "coal ash." CCR contain toxic metals that for years have contaminated groundwater and put public drinking water supplies and surface waters at risk.[44] The CCR Rule advances public health and environmental safeguards, including enhanced groundwater monitoring, location restrictions for siting CCR waste facilities, liner and leachate collection requirements, and corrective action for cleaning up groundwater contamination.

Unlike the ELG requirements for direct dischargers, the CCR rule is self-implementing. EPA explains: "The federal standards apply directly to the facility (are self-implementing) and facilities are directly responsible for ensuring that their operations comply with these

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[38] 33 U.S.C. § 1362(4).

[39] 33 U.S.C. § 1311(b)(2)(A)(i), *see also* § 1311(b)(1)(A);)

[40] 80 Fed. Reg. at 67,882.

[41] *Id*. at 67,839, n. 1 ("power plants covered by the ELGs use nuclear or fossil fuels, such as <u>coal</u>, oil, or natural gas, to heat water in boilers, which generate steam." [emphasis added]).

[42] *See, e.g.*, 40 C.F.R. § 423.13(g)(1)(i).

[43] Letter from Sierra Club et al. to Supervisor Marc Harris, Power Plant NPDES Permitting, DEP Industrial Wastewater Section Re: *Bringing Florida Coal Plants Into Compliance With The New Effluent Limitations Guidelines*, (Feb. 29, 2016), *available at* http://blog.cleanenergy.org/files/2016/05/2016-02-29-Letter-re-Water-Side-Reqts-for-Fla-Coal-Plants-vfin.pdf.

[44] 80 Fed. Reg. 21,396; *see also* 80 Fed. Reg. 21,326: EPA identified 157 cases of proven or potential groundwater contamination from CCR in states across the nation.

requirements."[45] To ensure full and timely compliance with the CCR Rule, states can adopt the applicable standards in NPDES permits.[46] Likewise, states and citizens can enforce the federal standards under the citizen suit authority of the Resource Conservation and Recovery Act ("RCRA").

COMMENTS

In this section, we explain the changes DEP should make as it finalizes Permit No. FL0036366 to bring the CREC into compliance with the applicable public health and safety standards in the ELGs and the CCR Rule.

A. DEP Should Require Compliance with a Zero Discharge Standard for Bottom Ash Wastewater No Later Than November 1, 2018

Under the ELGs, the BAT standard for bottom ash wastewater is zero discharge. DEP should require the CREC to meet this zero discharge standard by November 1, 2018. As Dr. Sahu explains in his enclosed report, and we repeat here for emphasis, nothing in the permitting record justifies any later compliance deadline; in fact, the record shows that DEF is well-positioned to meet the default compliance deadline:

◊ DEF has already spent more than three years planning to convert to dry bottom ash handling at the CREC to comply with the ELGs, and has not documented any possible reason for needing additional time to plan, nor for why planning was slated to begin in June 2016 in the proposed schedule. DEF admits that compliance options are readily available.

◊ Duke Energy has publicly reported projected costs for ELG compliance at CREC Units 4 and 5 since at least 2014, which required conceptual or detailed engineering evaluations and studies in order to develop cost estimates. An additional 6 months for budget approval is unnecessary.

In fact, while DEF has long anticipated a "late 2018" compliance deadline,[47] DEF proposed almost five more years—to December 31, 2023—to reach compliance—without any justification for such a huge delay.[48] DEP should reject DEF's unsubstantiated and improper extension request.

As Dr. Sahu explains, it is clear that a November 1, 2018, compliance deadline for the BAT standard is readily achievable: most of the planning is finished, procurement should take little to no time and DEF admits construction takes 18 months.

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[45] 80 Fed. Reg. 21,311.

[46] Additionally, states can continue to enforce state regulations under their independent state enforcement authority.

[47] Exhibit 1.

[48] Response to RAI 2, Attachment 1

Dr. Sahu concludes that Units 4 and 5 can convert to dry bottom ash handling in approximately 27 to 30 months, instead of the 44 months projected by DEF, reaching compliance by August to November 2018 at the latest.

Indeed, EPA's rulemaking record and comments from the Utility Water Act Group ("UWAG")[49] show that, depending on the scope of the required conversions (a.k.a., retrofits) at a particular coal plant, industry itself projects that the total time needed for bottom ash system retrofits ranges from 27 to 36 months, from the start of conceptual engineering to final commissioning.[50]

At Duke Energy's own Mayo Plant in North Carolina, a wet-to-dry bottom ash handling system conversion was completed in under a year and a half.[51] At the South Carolina Electric & Gas Company Wateree plant, for example, conversion to a closed-loop bottom ash handling system was completed in two and a half years.[52] Conversion to a closed-loop bottom ash handling system was completed in two and a half years at the South Carolina Electric & Gas Company Wateree plant.[53] In 2010, the BL England Station retrofitted a recycle system on two coal burning units (one is 125-MW, the other is 155-MW) as well as a 170-MW oil-burning unit in less than two years from award of contract to operation of the new system.[54]

Delaying compliance with the zero discharge standard for bottom ash wastewater beyond November 1, 2018, is unnecessary and puts public and environmental health at risk. Bottom ash wastewaters are known to contain a number of toxic metals in both suspended and dissolved form, including arsenic, cadmium, chromium, copper, iron, lead, mercury, selenium, and zinc.[55] In one example of the public and environmental health threats posed by CCR waste, EPA estimates that reductions in arsenic loadings from the final ELGs will reduce cancer risks to humans that consume fish exposed to steam electric power plant discharges—such as those caught in Crystal Bay.[56] Against this backdrop, DEP has all the more reason to require CREC to comply with the zero discharge standard by the November 1, 2018, deadline.[57]

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[49] Duke Energy is a UWAG member.

[50] Utility Water Act Group, *Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Sept. 30, 2013), Attach. 11: Retrofitting Dry Bottom Ash Handling.

[51] *See* DEF Progress, Inc., Mayo Steam Electric Generating Plant, Quarterly Progress Report (January – March 2015) ("Dry bottom ash handling system began construction on December 14, 2012. As of March 31, 2014, construction of this system was 100% complete.").

[52] DCN SE03779. Final Notes from Site Visit at South Carolina Electric & Gas Company's Wateree Station on January 24, 2013, *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OW-2009-0819-1917.

[53] *See* Final Notes from Site Visit at South Carolina Electric & Gas Company's Wateree Station on January 24, 2013, EPA-HQ-OW-2009-0819-1917, at 2. Check, from SELC comments, change text

[54] Dennis Del Vecchio and Robert G. Walsh, Wet to Dry Bottom Ash Disposal Conversion Project - BL England Station, Power-Gen, December 2011, February 2008 - February 2010.

[55] *See e.g.*, U.S. EPA, *Steam Electric Power Generating Point Source Category: Final Detailed Study Report*, EPA 821-R-09-008, 3-19 (Oct. 2009), (hereinafter "EPA Detailed Study"); U.S. EPA, *Development Document for Final Effluent Limitations Guidelines, New Source Performance Standards, and Pretreatment Standards for the Steam Electric Point Source Category*, Table V-33 (Nov. 1982).

[56] 80 Fed. Reg. 67,874 (Nov. 8, 2015).

[57] 80 Fed. Reg. at 67,840-41.

B. The ELGs Apply to FGD Wastewater and FGMC Wastewater From Units 4 and 5, Which Discharge to Crystal Bay and the Gulf of Mexico via Hydrologically Connected Groundwater

Steam electric power plants must meet strict new standards in EPA's revised ELGs for contaminants in FGD wastewater—including arsenic, mercury, selenium, and nitrate/nitrite—and a zero discharge standard for FGMC wastewater. Because Unit 4 and 5's FGD and FGMC wastewaters discharge to waters of the United States, these waste streams must meet the standards in EPA's revised ELGs, and DEP must include permit limits in the renewed NPDES permit for CREC Units 4 and 5.

As Dr. Stewart explains in his enclosed report, contaminants from the unlined Percolation Ponds travel through the aquifer into Crystal Bay. FGD and FGMC wastewaters from Units 4 and 5 are thus discharged to the Percolation Ponds and absorbed into groundwater, as DEP is already aware.[58] The Percolation Ponds are unlined, in direct communication with the Upper Floridan aquifer, and connected to Crystal Bay and the Gulf of Mexico.[59] The Percolation Ponds recharge the shallow groundwater aquifer, which conveys pollutants into the seawater discharge canal, tidal wetlands, and Crystal Bay.[60]

The Percolation Ponds and groundwater are hydrologically connected to "waters of the United States"—that is, Crystal Bay and the Gulf of Mexico—and therefore, by discharging pollutants into the Percolation Ponds, DEF is discharging to waters of the United States *via* the Ponds and the groundwater. The Percolation Ponds and groundwater are conduits to waters of the United States. Discharging the FGD and FGMC wastewater to the Percolation Ponds puts these waste streams under the jurisdiction of the CWA, and the Units 4 and 5 NPDES Permit, because the wastewaters, and pollutants, migrate from the pond directly into Crystal Bay through an underground "conveyance" or "conduit."[61]

When groundwater is a conduit for pollutants, CWA liability may attach to a discharge to that groundwater.[62] "[I]t would hardly make sense for the CWA to encompass a polluter who discharges pollutants via a pipe running from the factory directly to the riverbank, but not a polluter who dumps the same pollutants into a man-made settling basin some distance short of the river and then allows the pollutants to seep into the river via the groundwater."[63] EPA has asserted that its authority under the CWA extends to hydrologically connected groundwater.[64]

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[58] See e.g., Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016; RAI #2,

[59] Exhibit 1 at 9.

[60] *Id*.

[61] 33 U.S.C. § 1362(14).

[62] *See Haw. Wildlife Fund v. Cnty. of Maui*, 24 F. Supp. 3d 980, 996 (D. Haw. 2014).

[63] *N. Cal. Riverwatch v. Mercer Fraser Co.*, No. C-04-4620 SC, 2005 U.S. Dist. LEXIS 42997, *7-*8 (N.D. Cal. Sep. 1, 2005).

[64] 66 Fed. Reg. 2960, 3015 (Jan. 12, 2001); 73 Fed. Reg. 70,418, 70,420 (Nov. 20, 2008); 55 Fed. Reg. 47990, 47997 (col. 3) (Nov. 16, 1990)

The courts agree and have held, definitively, that the CWA covers groundwater that is hydrologically connected to waters of the United States. [65] Eleventh Circuit jurisprudence, governing Florida, also suggests that CWA jurisdiction extends to discharges like those to CREC Percolation Ponds.[66]

In sum, the FGD and FGMC wastewaters from Units 4 and 5 are discharged to surface waters *through* groundwater, and since the groundwater under the Percolation Ponds is directly hydrologically connected to surface water, discharges to the percolation ponds are a discharge to waters of the United States and must be regulated under the CWA. Therefore— just as DEP has included ELG limits for leachate that migrates through groundwater to the runoff collection system (see Section E below)—the ELGs apply to discharges of FGD and FGMC wastewaters and must be included in the revised NPDES permit.

C. DEP Should Require Compliance with a Zero Discharge Standard for FGMC Wastewater No Later Than November 1, 2018

Under the ELGs, FGMC wastewater at CREC must be monitored and subject to new effluent limits. Effective immediately, this discharge is subject to a BPT TSS effluent limit of 100/30 mg/L (daily max./30 day avg.) and oil and grease effluent limit of 20/15 mg/L (daily max./30 day avg.) and after November 1, 2018, a zero discharge standard applies.[67]

As explained above in Section B, FGMC wastewater at the plant is discharged to waters of the United States—Crystal Bay and the Gulf of Mexico—through hydrologically connected groundwater and must be regulated under the ELGs. Although the FGMC wastewater combines with FGD wastewater at CREC Units 4 and 5, the zero discharge standard still applies: "Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the [zero] discharge limitation in this paragraph."[68]

The final permit therefore must include BPT limits for FGMC wastewater until a zero discharge BAT standard applies after November 1, 2018. Again, the revised ELGs apply starting

[65] *See e.g., Waterkeeper Alliance, Inc. v. U.S. EPA*, 399 F.3d 486, 514-515 (2d Cir. 2005) (upholding EPA's requirements for the discharge of pollutants to surface water via groundwater to be regulated, "as necessary, on a case-by-case basis."); *Dague v. City of Burlington*, 935 F.2d 1343, 1347 & 1355 (2d Cir. 1991), rev'd in part on other grounds, 505 U.S. 557 (1992) (finding the city liable for allowing groundwater to flow through a landfill and into a pond and wetlands that were waters of the United States); *U.S. Steel Corp. v. Train*, 556 F.2d 822, 852 (7th Cir. 1977) (the CWA "authorizes EPA to regulate the disposal of pollutants into deep wells, at least when the regulation is undertaken in conjunction with limitations on the permittee's discharges into surface waters"), overruled on other grounds by City of West Chicago v. U.S. Nuclear Regulatory Comm'n, 701 F.2d 632, 644 (7th Cir. 1983).

[66] *U.S. v Banks,* 115 F.3d 916 (11th Cir. 1997) (District Court not clearly erroneous in deciding that wetlands are adjacent to a waterbody because of a hydrological connection where a hydrological connection is largely through groundwater and a surface flow only appears during storms); *United States v. Tilton*, 705 F.2d 429, 431 (11th Cir. 1983) (a hydrological connection exists when flowing mainly through groundwater, even where surface water only connects at extreme high tides such as in hurricanes).

[67] 40 C.F.R. § 423.13(l).

[68] 40 C.F.R. § 423.13 (i)(1)(i).

November 1, 2018, or "as soon as possible" based on a well-documented justification of a later date and DEP's consideration of certain factors enumerated in the final rule.

Until the zero discharge BAT standard is met, DEP should incorporate monitoring requirements for the FGMC wastewater into revised NPDES permit and Conditions of Certification ("COC"). To meet both monthly average and daily maximum limits, quarterly monitoring is wholly inadequate. A daily maximum limit cannot be effectively enforced with monitoring conducted on a monthly basis. Monitoring frequency should be daily in order to effectively enforce these limits to meet both monthly average and daily maximum limits for TSS and oil and grease. Sampling should be performed prior to mixing with the FGD wastewater.

D. DEP Must Require Compliance with New Limits on FGD Wastewater Pollutants No Later Than December 2018

DEP must include effluent limits for FGD wastewater in the revised NPDES permit. Effective immediately, this discharge is subject to a BPT TSS effluent limit of 100/30 mg/L (daily max./30 day avg.) and oil and grease effluent limit of 20/15 mg/L (daily max./30 day avg.).[69] After November 1, 2018, DEF must meet strict new BAT effluent limits for arsenic, mercury, selenium, and nitrate/nitrite for the untreated FGD wastewater that is discharged to the Percolation Pond and waters of the United States. [70] DEP must incorporate the ELGs for FGD wastewater into the revised NPDES permit, immediately apply BPT and monitoring requirements, and ensure that DEF meets the BAT standard by December 2018 or as soon as possible.

The revised ELGs set daily maximum and monthly average limits on arsenic, mercury, selenium, and nitrate/nitrite in discharges of FGD wastewater.[71] These limits are based on technology using chemical precipitation and an anoxic/anaerobic fixed-film biological treatment system.[72] The chemical precipitation achieves most of the mercury and arsenic reductions, while the biological reactor removes selenium and nitrogen and other dissolved heavy metals.

DEF is currently completing "construction of a new wastewater treatment system that will use chemical precipitation and a bioreactor" for treatment of FGD wastewater from Units 4 and 5 and will complete the project by December 2018.[73] DEF "evaluated several treatment options…and selected a strategy that uses a physical/chemical treatment system with a bioreactor treatment system to treat Flue Gas Desulfurization ("FGD") blowdown wastewater with discharge to surface water or percolation ponds."[74]

[69] 40 C.F.R. § 423.12(b)(11).

[70] 40 C.F.R. § 423.13(g)(1)(i).

[71] *Id.*

[72] 80 Fed. Reg. at 67,850.

[73] Third Amendment to Consent Order, OGC No. 09-3463D, at ¶4; *see also* Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016 at Attachment 4 p.2.

[74] Duke Energy Florida's Petition for Approval of Environmental Cost Recovery True-Up and 2017 Environmental Cost Recovery Clause Factors, Docket No. 160007-EI, Environmental Cost Recovery Clause Form 42-SP at 7 (August 31, 2016). 07181-16, PSC ECRC filing

In November 2011, DEP entered into a Consent Order[75] with the former CREC owner Progress Energy Florida ("PEF") following exceedances of groundwater standards for gross alpha standard, radium 226/228, and arsenic. In the third amendment to the Consent Order in March 2016, DEF agreed to complete construction of a new wastewater treatment system using chemical precipitation and a bioreactor for treating FGD wastewater by December 31, 2018.[76] Within 30 days following completion of the treatment system, DEF will remove all accumulated CCR from the FGD Blowdown Ponds.[77]

The Consent Order constitutes an additional and separate legal obligation (from the ELGs) to complete construction of the FGD wastewater treatment system by December 2018. Nevertheless, DEP is required to include the new effluent limits in the revised NPDES and to ensure that DEF's new treatment system meets the federal BAT standards for arsenic, mercury, selenium, and nitrate/nitrite—which are not specified in the Consent Order— "as soon as possible beginning November 1, 2018."

It is imperative that DEP ensure that DEF meets this timeline and its legal obligations and begins operating the new system and treating toxic FGD wastewater by December 2018 at the latest. DEF is on its way to meeting these new standards and anticipated[78] meeting the revised ELG requirements for FGD wastewater, in addition to its Consent Order obligations.

Attachment H— Groundwater Monitoring, Operation, and Maintenance Requirements—of CREC COC authorizes DEF to discharge a variety of wastewaters, including FGD wastewater from Units 4 and 5, to the Percolation Ponds.[79] Quarterly reporting is required for FGD wastewater flows at sampling point EFF-2, the discharge pipe into the Percolation Ponds.[80] However, no limits are imposed on the FGD wastewater flows. DEP must incorporate monitoring requirements for arsenic, mercury, selenium, nitrate/nitrite, and TSS into the revised NPDES permit, as well as the COC. Monitoring should be required twice weekly. For final limits, where both monthly average and daily maximum limits are set, quarterly monitoring is wholly inadequate. A daily maximum limit cannot be effectively enforced with monitoring conducted on a monthly basis. Monitoring frequency should be daily to effectively enforce these limits.

E. Combustion Residual Leachate from the Ash Landfill is Subject to Technology and Water Quality Based Effluent Limits

[75] Consent Order, File No. 09-34652, Permit No. FLA016960, OGC File No. 09-3463 (Nov. 2011).

[76] Third Amendment to Consent Order, OGC No. 09-3463D ¶4 (March 22, 2016).

[77] Third Amendment to Consent Order, OGC No. 09-3463D ¶5 (March 22, 2016).

[78] Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016 at Attachment 4 p. 1.

[79] Florida Department of Environmental Protection, Conditions of Certification: Duke energy Florida Crystal River Energy Complex, PA 77-09R, Attachment H, April 29, 2016.

[80] *Id.*

Combustion residual leachate ("CRL") is now a separately regulated waste stream under the revised ELGs. Leachate from coal ash and other CCRs that are discharged to waters of the United States must be included in the NPDES permit and subject BPT limits in TSS and oil and grease, as well as technology and water quality based effluent limits.

CREC has no leachate collection system for the unlined Ash Landfill, and instead of being discharged to surface waters through a permitted outfall, most leachate seeps into the groundwater, as discussed further below in Section G and in Exhibit 1. The "majority of the coal combustion residual leachate is discharged to ground water"[81] as "by design, the leachate generated in the [Ash Landfill] infiltrates to the groundwater underneath the [Ash Landfill]."[82] EPA correctly notes that "[u]nlined impoundments and landfills usually do not collect leachate, which would allow the leachate to potentially migrate to nearby ground waters, drinking water wells, or surface waters."[83]

Since groundwater beneath the Ash Landfill is hydrologically connected to surface waters, CRL wastewater discharging from the Ash Landfill to groundwater constitutes a discharge to waters of the United States. DEF's groundwater modeling shows that CRL from the unlined Ash Landfill at times flows towards portions of the runoff ditch at Units 4 and 5.[84] Following, DEP has incorporated new BPT limitations for oil and grease and TSS in the Draft Permit at monitoring well TWI-1R, in order to differentiate CRL from storm water collected in the runoff collection system.[85]

Additionally, as described in Dr. Stewart's assessment, groundwater under the Ash Landfill "flows toward the west-southwest and discharges into the seawater discharge canal, and ultimately into Crystal Bay."[86] Indeed, monitoring data shows that toxic pollutants from CCR leachate[87]—including arsenic, boron, manganese, molybdenum, selenium, and sulfate—are migrating from groundwater beneath the Ash Landfill and flowing to Crystal Bay.

Like CRL leachate that migrates through groundwater to the runoff collection system, and for the reasons articulated above in Section B for FGD and FGMC wastewater, the discharges of leachate to groundwater beneath the Ash Landfill and into the seawater discharge canal, and then Crystal Bay, are also subject to the CWA. The CWA prohibits the discharge of pollutants from a point source" — "any discernible, confined and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, [or] container … from which pollutants are or may be discharged"[88]—to waters of the United States, except as

[81] Draft Permit at 12.

[82] RAI #2 p. 9.

[83] 80 Fed. Reg. at 67,847.

[84] RAI #2.

[85] Draft Permit p. 12.

[86] Exhibit 1 at 6.

[87] *See* TDD Table 6-13. Pollutants of Concern – Combustion Residual Leachate.

[88] 33 U.S.C. § 1362(4); *see also, e.g.*, *Dague v. City of Burlington*, 935 F.2d 1343, 1347 & 1355 (2d Cir. 1991), rev'd in part on other grounds, 505 U.S. 557 (1992) (finding the city liable for allowing groundwater to flow through a landfill and into a pond and wetlands that were waters of the United States).

in compliance with a NPDES permit.[89] Thus, CRL from the Ash Landfill that is discharged to Crystal Bay via groundwater must be also regulated in the revised NPDES permit, and meet new BPT requirements as well as other water quality based requirements.

DEP must also conduct a reasonable potential analysis and determine whether additional water quality-based effluent limits ("WQBELs") are required for the CRL from the Ash Landfill, in order to protection of aquatic life and human health. After application of the most stringent treatment technologies available under the BAT standard, if a discharge causes or contributes, or has the reasonable potential to cause or contribute to a violation of water quality standards, the permitting agency must include any limits in the NPDES permits necessary to ensure that water quality standards (both narrative and numeric) are maintained and not violated.[90] EPA regulations require permitting authorities to characterize all effluents in order to determine the need for WQBELs in the permit.[91]

Ultimately, as explained below, the only way to prevent further contamination of ground and surface waters from the Ash Landfill is likely to remove all accumulated CCR from the Ash Landfill and decontaminate the site.

F. There is No Barrier Between the Unlined Ash Landfill and Percolation Ponds and the Underlying Groundwater, Allowing Toxic Coal Ash Contaminants to Pollute the Floridan Aquifer and Crystal Bay

The Ash Landfill and Percolation Ponds are unlined, with no protective barrier between toxic coal ash and wastewater and the underlying groundwater. Additionally, there is no intermediate confining unit between the highly permeable soils onsite and the Floridan aquifer, signifying an elevated risk of groundwater contamination. As a result, the toxic CCR waste and wastewaters that are disposed of in the unlined Ash Landfill and Percolation Ponds are in direct hydraulic connection with the Floridan aquifer and with groundwater draining into Crystal Bay.

Sierra Club retained one of the state's preeminent hydrogeologists, Dr. Mark Stewart, to evaluate conditions at CREC and application of the technical requirements in the CCR Rule. As explained in his accompanying report, Exhibit 1, the Floridan aquifer at CREC is unconfined and in direct hydraulic connection with the water table. The area is a recharge zone for the shallow aquifer. The underlying Floridan aquifer, one of the largest and most productive sources of fresh groundwater in the world,[92] lies within a few feet of the land surface. Thus, the unlined Ash Landfill sits less than 5 feet from the water table in the Floridan aquifer.[93] Because the Ash

[89] Section 301(a) of the Clean Water Act, 33 U.S.C. § 1311(a).

[90] *See* 40 C.F.R. § 122.44(d). "[T]he permit must contain effluent limits" for any pollutant for which the state determines there is a reasonable potential for the pollutant to cause or contribute to a violation. *Id.* 40 C.F.R. § 122.44(d)(1)(iii); *see also Am. Paper Inst. v. EPA*, 996 F.2d 346, 350 (D.C. Cir. 1993); *Waterkeeper Alliance, Inc. v. EPA*, 399 F.3d 486, 502 (2d. Cir. 2005).

[91] 40 CFR § 122.44(d).

[92] Exhibit 1 at 5 (citing Miller 1986).

[93] Exhibit 1..

Landfill and Percolation Pond are unlined, and because of the shallow, unconfined aquifer at CREC, these two facilities are in direct connection with underlying groundwater and Floridan aquifer.[94]

To protect groundwater from contamination from CCR wastes, the CCR Rule prescribes (a) a distance of at least 5 feet between the base of facilities containing CCR and the uppermost aquifer, or (b) other measures that eliminate the hydraulic connection between the base and the uppermost aquifer—safety standards that the Ash Landfill, a CCR landfill[95], does not meet. CCR surface impoundments and new or expanded landfills must be constructed with a base that is located no less than five feet above the upper limit of the uppermost aquifer, or must demonstrate that there will not be an intermittent, recurring, or sustained hydraulic connection between any portion of the base of the CCR unit and the uppermost aquifer due to normal fluctuations in groundwater elevations (including the seasonal high water table).[96] While the Ash Landfill is exempt from this common-sense restriction as an "existing landfill"—although any future expansions and new facilities would not be—and the Percolation Ponds do not fall under the CCR Rule,[97] it is clear why these safety standards have been promulgated and that the close proximity of the unlined facilities to the aquifer are contaminating the Floridan aquifer and Crystal Bay.

Groundwater monitoring data showing contamination at the unlined Ash Landfill and Percolation Pond are further evidence of a hydraulic connection between the unlined Ash Landfill and the underlying aquifer. Groundwater pollution at the site, as described next in Section G, indicates that the Ash Landfill is in direct hydraulic connection with a highly permeable fracture zone in the Upper Floridan aquifer and that toxic contaminants are leaching from the Ash Landfill, as well as the Percolation Ponds, into the groundwater beneath, and moving towards Crystal Bay.

G. The Unlined Ash Landfill and Percolation Ponds Are Leaching Coal Ash Contaminants Into Groundwater and Crystal Bay

Groundwater contamination from toxic coal ash contaminants has been repeatedly documented at wells downgradient from the Ash Landfill. In fact, data from DEF's own groundwater monitoring wells downgradient of the unlined Ash Landfill have consistently shown contamination at levels that far exceed background levels and federal, state, and permit limits.[98] This threatens the Floridan aquifer and waters of Crystal Bay and the Gulf of Mexico.

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[94] Exhibit 1.

[95] The CREC Ash Landfill is an "existing CCR landfill," subject to regulation under the CCR Rule. It is an "area of land or an excavation that receives CCR and which is not a surface impoundment, an underground injection well, a salt dome formation, a salt bed formation, an underground or surface mine, or a cave" that received CCR both before and after October 19, 2015. 40 C.F.R. § 257.53.

[96] 40 C.F.R. § 257.60.

[97] *See* 40 C.F.R. § 257.53.

[98] *See* Florida Department of Environmental Protection, Conditions of Certification: Duke energy Florida Crystal River Energy Complex, PA 77-09R, Attachment H, April 29, 2016; 40 C.F.R. §§ 141.62 and 141.66; Fla. Admin. Code. R. 62-520.420 (2016).

Wells downgradient from the unlined Ash Landfill have regularly exceeded regulatory for toxic coal ash contaminants—arsenic, boron, manganese, molybdenum, selenium, sulfate, and thallium—since 2012.[99] Levels of arsenic, boron, manganese, molybdenum, and sulfate, in particular, have trended upward since that time and continue to exceed protective groundwater standards. Concentration of arsenic at wells downgradient from the Ash Landfill are *five times* higher than at wells upgradient from the facility.

The presence of these common coal ash contaminants at monitoring wells downgradient from the unlined Ash Landfill, in combination with groundwater flow direction at the site and high permeability conduits, is, in Dr. Stewart's view, "overwhelming evidence" that contaminants have leached from the CCR materials have reached the water table and the Floridan aquifer.[100]

Contaminants from the unlined Percolation Ponds are also being absorbed to groundwater, which flows towards the Gulf of Mexico. Arsenic in groundwater near the ponds has been associated with the FGD wastewater that is discharged to the ponds, thus driving the installation of the new FGD wastewater treatment system.[101]

DEP is currently investigating groundwater contamination from the Ash Landfill.[102]A July 2015 DEP inspection noted adverse impacts to water quality from the operation of the Ash Landfill and that "[g]roundwater trending data for background and intermediate groundwater monitoring wells indicates impacts to groundwater, specifically for Arsenic, Boron, Manganese, and Molybdenum."[103] Steps have been taken to address contamination at the Percolation Ponds under CREC's November 2011 Consent Order.[104]

While alarming, the groundwater contamination at the Ash Landfill is not at all surprising given that the facility is unlined and lacks a protective barrier, that the CCR materials within it are in direct hydraulic connection with the Floridan aquifer, and given the shallow, unconfined aquifer. In fact, DEP predicted that serious groundwater contamination would occur from the operation of the Ash Landfill:

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[99] Exhibit 1; Florida Department of Environmental Protection ("DEP"), 2015. Groundwater Review, WAVS UD 97667, Amaury Betancourt, Nov. 30, 2015; Florida Department of Environmental Protection ("DEP"), 2016. FDEP Automated Data Evaluation. Duke Energy (FKA PEF) Crystal River Energy Complex. February 1, 2016

[100] Exhibit 1 at 9.

[101] Geosyntec, 2013. Arsenic and radionuclide plan of study addendum, Crystal River Energy Complex, Crystal River, Florida, Rpt. No. FR2061/03, April 2013; Consent Order No. 09-34652. This groundwater contamination (under NPDES Permit No. FLA016960) remains unresolved, five years later. Further review of arsenic contamination is required, but not until December 31, 2017, and a plan to evaluate arsenic impacts on downgradient surface waters is required by June 30, 2018. Full compliance with arsenic limits is required by December 31, 2019. DEP should reopen NPDES Permit No. FL0036366 pending results of the required studies and strictly enforce corrective action to clean up groundwater contamination at the CREC.

[102] Email from Amaury Betancourt, P.E., Florida Department of Environmental Protection to Mr. Bob Stafford, Duke Energy, February 15, 2016.

[103] *See* Florida Department of Environmental Protection Inspection Report, July 28, 2015.

[104] Consent Order No. 09-34652.

> 'The highly transmissive characteristic of the shallow aquifer zone should provide and environment for the rapid dispersion of leachate which might infiltrate from the ash disposal site into the shallow aquifer.'…
>
> [Former CREC owner and applicant] FPC's application demonstrates succinctly that point at which such economico-politico maneuvering leads to very serious consequences when 1000 tons per day of truly hazardous wastes, generated each day that Units 4 and 5 would operate (for 30 years or more), would be dumped, for all practical purposes into the Floridan aquifer. …
>
> Thus leachate from the proposed ash disposal area can (on the basis of the data implicating the existing dump as a source of ground water pollution) be expected to flow into the Floridan aquifer at such rates that a number of WQ standards would be violated short term. (Perhaps many more violations would occur long term as pollutant activities build up on the ecosystem). Should the leachate move through existing or through <u>induced</u> Karst structures into deeper zones of the aquifer where hydraulic head may be reduced (or only appear to equal or even "slightly exceed" shallow depth heads by reason of statistically inadequate data or by greater <u>density</u> due to higher salinity or loading of leachate itself), then so much the worse for the Floridan aquifer.[105]

As Dr. Stewart explains in his assessment, there is no adequate liner or natural barrier to prevent CCR constituents from seeping out of the Ash Landfill into the underlying aquifer and eventually into Crystal Bay and the Gulf of Mexico. Until DEF removes the existing CCR material from the Ash Landfill and decontaminates the site, it will continue to leach toxic CCR contaminants into ground and surface waters. Furthermore, as explained next in Section H, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated.

H. The CCR Rule Requires Corrective Action to Address the Groundwater Contamination from the Unlined Ash Landfill

Where coal ash contaminants from CCR units have leached into the environment in excess of federal regulatory limits, the CCR Rule requires corrective action to prevent further releases. Monitoring data at CREC show levels of arsenic, molybdenum, and thallium at wells downgradient from the Ash Landfill exceeding federal groundwater protection standards and triggering clean up requirements for DEF.

To ensure compliance with the CCR Rule and to prevent further releases of CCR constituents into Floridan waters, DEP should require DEF to immediately take action to remove the CCR that has accumulated and decontaminate the Ash Landfill.

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[105] Ash Landfill Interoffice Memo at 3, 4, 7 (emphasis original).

Owners and operators of CCR units must install a system of groundwater monitoring wells and establish a monitoring program to detect the presence of hazardous constituents and other monitoring parameters from covered CCR units.[106] Where groundwater monitoring shows exceedances of groundwater protection standards[107] for Appendix IV constituents—including arsenic, molybdenum, and thallium—the owner or operator must initiate corrective action, retrofit, and/or close the unit.[108]

For these Appendix IV CCR constituents of concern, "immediately upon detection of a release from a CCR unit" the owner/operator "must initiate an assessment of corrective measures to prevent further releases, to remediate any releases and to restore affected area [*sic*] to original conditions."[109] Then, the owner/operator must select and implement remedies certified by a qualified engineer to be consistent with the standards set out in the CCR Rule. Specifically, the "remedies must"

(1) Be protective of human health and the environment;

(2) Attain the groundwater protection standard as specified pursuant to §257.95(h);

(3) Control the source(s) of releases so as to reduce or eliminate, to the maximum extent feasible, further releases of constituents in Appendix IV to this part into the environment;

(4) Remove from the environment as much of the contaminated material that was released from the CCR unit as is feasible, taking into account factors such as avoiding inappropriate disturbance of sensitive ecosystems; and

(5) Comply with standards for management of wastes as specified in §257.98(d).[110]

The requirement to "immediately" initiate an assessment of corrective measures is triggered by the detection of a release at any time after the effective date of the CCR Rule, October 19, 2015. This includes but is not limited to detection pursuant to a pre-existing groundwater monitoring program and/or the enhanced groundwater monitoring program that is required by the CCR Rule. The "zone of discharge" exemption to water quality standards under Florida law do not apply; "the point of compliance is the waste boundary" of CCR units.[111]

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[106] 40 C.F.R. § 257.94(a).

[107] Groundwater protection standards for Appendix IV constituents detected are based on either (1) the maximum contaminant limit ("MCL") established at 40 C.F.R. §§ 141.62 and 141.66; or (2) the background concentration for the constituent, where there is no MCL or where the background concentrations are higher than the MCL. 40 C.F.R. § 257.95(h).

[108] 40 C.F.R. §§ 257.95(g)(5); 257.101(a).

[109] 40 C.F.R. § 257.96.

[110] 40 C.F.R. § 257.97.

[111] EPA, Comment Summary and Response Document, Docket #EPA-HQ-RCRA-2009-0640, Volume 9: Groundwater and Corrective Action at 47; *see also* 40 C.F.R. § 257.53 (defining "waste boundary"); § 257.91 (requiring groundwater

Groundwater monitoring data for the Ash Landfill following October 19, 2015, show exceedances of groundwater protection standards[112] for arsenic, molybdenum, and thallium, all Appendix IV constituents, at wells downgradient from the Ash Landfill, an existing CCR landfill under the CCR Rule. With this knowledge, DEF is obligated to immediately begin an assessment of corrective measures and implementation of appropriate remedies. To meet the corrective action requirements in the CCR Rule, and to "eliminate, to the maximum extent feasible, further releases of constituents," Dr. Stewart recommends ceasing onsite CCR storage and disposal, which can exacerbate the ongoing contamination problem. The only way to effectively prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

I. CREC is Located in Sinkhole-Prone Karst Terrain, Putting Ground and Surface Water Resources at (Further) Risk and Requiring Compliance with the CCR Rule's Location Restriction for Unstable Areas

Coastal Citrus County is an active karst area, marked by limestone and under the influence of sinkholes. As detailed in Dr. Stewart's assessment, the onsite and local hydrogeological conditions make CREC an inherently unstable area, under the influence of multiple sinkholes, including 24 reported sinkholes within 5 miles.

Most sinkholes in the region are cover subsidence sinkholes, whereby loose surficial sands migrate downward into solution cavities in the limestone and which can occur either slowly or abruptly. Because the Floridan aquifer is at or near land surface at CREC, sinkholes of any size would allow the movement materials under the CCR landfill into the voids, depressions, and caverns underneath, allowing materials, such as CCR waste in the Ash Landfill, to come into direct contact with the limestones and groundwater of the Floridan aquifer.

DEP is aware of the unstable nature of CREC and accompanying risks to ground and surface waters from the sinkhole-marked terrain. For example, in a staff analysis, DEP described CREC as "characterized by sinkholes and flowing springs" and concluded that:

> Due to the nature of the geologic formation under this area there <u>will always be a chance of a sinkhole forming under the plant or its related facilitie</u>s….
>
> It is not apparent that FPC has adequately considered the impact that future solution cavities may have on the operation of the coal piles, the ash disposal landfill, and related ditches. Acidic leachates can hasten formulation of solution<u> cavities which could result in</u>

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monitoring at the waste boundary); § 257.94 (requiring enhanced groundwater monitoring for detected increases in certain CCR constituents at the waste boundary).

[112] There is no MCL for molybdenum; instead the groundwater protection standard is the background level. A background well (MWB-30R) at the CREC shows molybdenum levels of 18 mg/L. In contrast, the intermediate monitoring well and temporary monitoring wells around the Ash Landfill have exhibited molybdenum levels ranging from 44.5 – 135 mg/L—*seven times higher* than background levels.

subsidence of the land surface and allow for rapid contamination of ground and surface waters.[113]

Later, DEP rightly questioned the sensibility of locating a coal ash landfill at CREC:

> Already a piece of heavy machinery has fallen into a sinkhole on site which collapsed beneath the weight of the machine. What would be the effect of the much greater loading due to 60 or more feet of stacked ash materials spread over some 100 acres? Even if a massive collapse did not take place, allowing direct introduction of the wastes into the aquifer, [studies] clearly indicate the high permeability of the upper …[114]

There is copious evidence, as documented in Dr. Stewart's assessment, DEP records[115], and other sources, showing sinkhole activity at and around CREC. There can be no question that CREC is in unstable, sinkhole terrain and that, as described next in Sections J and K, CREC cannot meet CCR Rule's safety standards for onsite storage and disposal.

J. After April 19, 2019, the CCR Rule Prohibits Adding—Even On a Temporary Basis—CCR To CCR Units in Unstable Areas, Such As Florida's Karst Terrain, Unless a Qualified Engineer Can Certify That it is Safe To Do So

After April 19, 2019, the CCR Rule prohibits adding, even on a temporary basis, CCR to CCR units in unstable areas, such as Florida's karst terrain, unless a qualified engineer can certify that it is safe to do so by October 17, 2018.[116] Specifically, this is a certification "that recognized and generally accepted good engineering practices have been incorporated into the design of the CCR unit to ensure that the integrity of the structural components of the CCR unit will not be disrupted."[117] This location restriction applies to all existing and new CCR units.

EPA defines unstable areas as:

> a location that is susceptible to natural or human-induced events or forces capable of impairing the integrity, including structural components of some or all of the CCR unit that are responsible for preventing releases from such unit. Unstable areas can include poor foundation conditions, areas susceptible to mass movements, and karst terrains.[118]

[113] "1978 Staff Analysis, at 44, (STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION, ELECTRIC POWER PLANT SITE CERTIFICATION REVIEW FOR FLORIDA POWER CORPORATION CRYSTAL RIVER UNITS 4 AND 5, CASE NO. PA 77-09, STAFF ANALYSIS. September 15, 1978) (emphasis added).

[114] Ash Landfill Interoffice Memo at 4.

[115] Florida Department of Environmental Protection, Conditions of Certification: Duke energy Florida Crystal River Energy Complex, PA 77-09R, Attachment H, April 29, 2016;; Ash Landfill Interoffice Memo; 1978 Staff Analysis; Terry Witt, Citrus County Chronicle, July 23, 2007 and July 30, 2007 articles, *in* "Proposed Haul Road Letter"; FGD Blowdown bond 2010 report.

[116] 40 C.F.R. §§ 257.101(b)(1) and 257.101(d)(1).

[117] 40 C.F.R. § 257.64(a).

[118] 40 C.F.R. § 257.53.

"Structural components" are defined as:

> liners, leachate collection and removal systems, final covers, run-on and run-off systems, inflow design flood control systems, and any other component used in the construction and operation of the CCR unit that is necessary to ensure the integrity of the unit and that the contents of the unit are not released into the environment."[119]

In the final CCR Rule, EPA enumerates safety factors that should be addressed in the certification of CCR units in Florida's karst terrain:

> For areas where the solution-weathered limestone is close to the surface (e.g., Florida) recognized and generally accepted good engineering practices dictate that there must be no conduits beneath the CCR unit that allow piping of groundwater into the karst aquifer, or shallow caves that could cause sudden collapse of the unit foundation. …
>
> Karst hydrogeology is complex, since contaminant flows can occur along paths and networks that are discreet and tortuous, and groundwater monitoring wells must be capable of detecting any contaminants released from the CCR unit into the karst aquifer. …
>
> Therefore, the owner or operator will need to ensure, with verification by a qualified professional engineer, that monitoring wells installed in accordance with § 257.91 will intercept these pathways. Verification will usually necessitate the use of tracers to track groundwater flow towards offsite seeps or springs from the uppermost aquifer beneath the facility. Any engineered solution employed to mitigate weak ground strength in karst areas must be able to prevent the kind of foundation collapse and settlement that could lead to sudden release to the environment of CCR with its toxic constituents and associated leachate. …
>
> However, such engineered solutions are complex and costly, and the best protection is not to site CCR landfills and surface impoundments in karst areas.[120]

In short, this safety certification is a tall order in Florida's karst terrain. Elsewhere in the rulemaking docket, EPA noted that it might even be "impossible" to obtain the safety certification for a CCR unit that has already been constructed without adequate safeguards.[121]

These safety standards were not incorporated into the design of the Ash Landfill when it was built, as discussed in Dr. Stewart's assessment. The Ash Landfill does not have structural reinforcements nor a liner that could help prevent movement of CCR materials into the

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[119] *Id.*

[120] 80 Fed. Reg. 21,368 (emphasis added).

[121] U.S. EPA, Comment Summary and Response Document, Volume 4: Location Restrictions, Docket # EPA-HQ-RCRA-2009-0640, December 2014, *available at* http://goo.gl/QVAXRi.

Floridan aquifer. Dr. Stewart explains that certain factors at the Ash Landfill even increase the risk of limestone dissolution and sudden collapse, such as including having no impermeable liner; having no cover to exclude precipitation from the exposed CCR waste; and CCR accumulating and increasing the static load on the underlying, unstable soils.

Moreover, the Ash Landfill cannot effectively, nor economically, be retrofitted using existing technologies to meet the CCR Rule's safety standards: it would be nearly impossible to ensure that all conduits, voids, and caves beneath the Ash Landfill were had been detected and intercepted. Attempting a retrofit of the Ash Landfill now could even trigger a sinkhole collapse.

CREC FGD Blowdown Ponds and Gypsum Storage Pad also lie on unstable karst terrain and a qualified professional engineer must make a demonstration showing "that recognized and generally accepted good engineering practices have been incorporated" into the design of these units by October 17, 2018 in order for them to continue operation. Although these units are at least lined, providing some measure of protection unlike the Ash Landfill, if a sinkhole were to rupture the liners or pipes at the FGD Blowdown Ponds, for example, the CCR wastes would be released into the Floridan aquifer, and flow into the seawater discharge canal, tidal wetlands, and Crystal Bay.

DEF reports that a preliminary assessment of the stability at the Ash Landfill has been performed and that the "preliminary conclusion is no karst remediation will be required."[122] This conclusion seems remarkable given the geological characteristics and history of the region and CREC site, as encapsulated above in Section I and in Dr. Stewart's review. Regardless of this conclusion, however a thorough evaluation must still be completed under the CCR Rule.

The CCR Rule location restriction and safety factors are designed to protect public waters from the risks of sinkhole and unstable terrain. To comply with federal regulations and protect the Floridan aquifer and waters of Crystal Bay, DEP must ensure that DEF completes the required engineering certifications. Because CREC's CCR units cannot be certified as safe under the CCR Rule, DEF will have to change its current practices of onsite CCR storage and disposal by the April 19, 2019 deadline in the CCR Rule.

K. DEP Should Extend The Proposed Schedule for Permit Issuance To Allow For Meaningful Consideration of Public Comments

Finally, we urge DEP to revise its own proposed schedule for permit issuance to allow for meaningful consideration of and response to public comments. Under the proposed schedule,[123] DEP would submit the proposed permit to EPA on September 30th, only *one day* after the close of the public comment period on September 29, 2016. This plainly is not enough time for the Department to review let alone meaningfully consider and respond to all comments

[122] Duke Energy Florida's Petition for Approval of Environmental Cost Recovery True-Up and 2017 Environmental Cost Recovery Clause Factors, Docket No. 160007-EI (August 31, 2016). Recent PSC filing – 07181-16

[123] Draft Permit at 14.

in writing.[124] As we explained in our February 29, 2016, letter, due to the importance of the water impacts and protections at issue in this permit renewal, DEP should go above and beyond its routine public participation practices, not truncate them.

CONCLUSION

For all the foregoing reasons, we respectfully ask that, in issuing Crystal River Unit 4 and 5's renewed NPDES permit, DEP:

1. Set a technology-based zero discharge standard for bottom ash wastewater and require compliance with the standard no later than November 1, 2018;

2. Set a technology-based zero discharge standard for FGMC wastewater and require compliance with the standard no later than November 1, 2018;

3. Set technology-based limits on arsenic, mercury, selenium and nitrate/nitrite in FGD wastewater and require compliance with the standard no later than December 2018;

4. Establish technology-based BPT effluent limits and daily monitoring requirements for FGD and FGMC wastewater flows, effective immediately;

5. Apply BPT limits to discharges of CRL from the Ash Landfill to the runoff collection system and to Crystal Bay, and conduct a reasonable potential analysis to determine whether WQBELs are needed for greater protection;

6. Require clean up and corrective action, as mandated by the CCR Rule, to swiftly address ongoing groundwater contamination from the unlined Ash Landfill and to take all measures necessary to protect against further leaching of toxic metals into ground and surface waters including, retrofitting or closing the unit; and

7. Require compliance with the CCR Rule's prohibition on siting CCR units in unstable areas, so as to further protect ground and surface waters.

Timing is critical: To meet the deadlines for implementing ground and surface water protections—which also protect the public use of those waters—DEF will have to undertake changes to coal operations at CREC Units 4 and 5. DEF must not delay, or be excused by DEP through extensions or deferrals to future permit renewal cycles, for which there is no justification let alone a well-documented one in this permitting record.

Thank you for your consideration.

Sincerely,

[124] Draft Permit at 15.

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EXHIBIT 1

Preparing for the U.S. Environmental Protection Agency's Coal Combustion Residuals Rule: Technical Assessment of Hydrogeologic Conditions and Groundwater Contamination at the Crystal River Energy Complex

August 28, 2016

By Mark Stewart, PhD, PG

1. EXECUTIVE SUMMARY

The Crystal River Energy Complex ("CREC") is located on unstable karst terrain, and the primary facility used for the storage and disposal of coal combustion residuals ("CCR") at CREC, the Ash Landfill, exhibits increasing contamination from toxic heavy metals associated with CCR waste. CCR disposal and storage at CREC puts local water resources at risk and fails to meet the new safety standards by the U.S. Environmental Protection Agency ("EPA") in December 2014 ("the CCR Rule") for several reasons:

- CREC is located in one of the country's most unstable areas, in karst terrain, and is under the influence of multiple sinkholes, including 24 reported sinkholes within 5 miles of CREC.

- The risk of limestone dissolution and sudden collapse beneath CREC's Ash Landfill is increased by many factors, including (a) having no impermeable liner; (b) having no cover to exclude precipitation from the exposed ash waste; and (c) CCR accumulating at the Ash Landfill increasing the static load on the underlying, unstable soils and rock.

- To assure the safety of CCR storage and disposal in such unstable areas, EPA's CCR Rule requires the detection and interception of (a) all of the possible conduits that allow piping of groundwater into underlying karst aquifers; (b) all of the possible shallow caves that could cause a sudden foundation collapse; and (c) all of the possible pathways for CCR constituents to be released from CCR storage and disposal facilities into karst aquifers. Consulting reports state that at CREC, "most [groundwater] flow is through solution cavities and conduits." These safety standards were not incorporated into the design of the Ash Landfill when it was built, and it is now nearly impossible to do so.

- The Ash Landfill was not built to structurally withstand the influence of sinkholes. It lacks the structural reinforcement that would be necessary, but may nevertheless be insufficient, to prevent a sudden foundation collapse. The Ash Landfill cannot be retrofitted now to be safe. Attempting a retrofit could trigger a sinkhole collapse that could rapidly spread CCR contamination in the underlying karst aquifers.

- To protect public waters, the CCR Rule requires (a) a distance of at least 5 feet between the base of CCR storage and disposal facilities and the uppermost aquifer, or (b) other measures that eliminate any hydraulic connection between CCR storage and disposal facilities and the aquifer—CREC Ash Landfill does not meet either standard. In fact, the available monitoring data are indicative of an ongoing hydraulic connection that allows CCR constituents, including arsenic and other heavy metals associated with CCR leachate, to reach the underlying karst aquifers.

- Water quality samples from wells downgradient from the Ash Landfill show consistent and increasing contamination since 2012 with toxic constituents associated with CCR, such as arsenic, boron, molybdenum, manganese, selenium, sulfate, and thallium, indicating that the Ash Landfill has contaminated the Surficial and Floridan Aquifer at the site.

- Groundwater beneath CREC Ash Landfill, FGD Blowdown Ponds, and Percolation Ponds flows towards the seawater discharge canal, tidal wetlands, and Crystal Bay.

For these reasons, discussed in detail in the full report, the Ash Landfill cannot meet the safety standards in the CCR Rule. Additionally, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated. The only way to prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

2. INTRODUCTION

This is an assessment of coal combustion residuals ("CCR") storage and disposal at the Crystal River Energy Complex ("CREC"). This assessment evaluates hydrogeologic conditions at the Ash Landfill, FGD Blowdown Ponds, Gypsum Storage Pad, and Percolation Ponds, existing groundwater contamination at CREC, and compliance with the U.S. Environmental Protection Agency's ("EPA") new rule on the disposal of CCR from electric utilities ("CCR Rule," U.S. EPA 2015). More specifically, this assessment considers whether CREC's CCR facilities satisfy the safety standards in the CCR Rule for CCR disposal in karst terrain and away from the uppermost aquifer and for preventing groundwater contamination.

The karst-specific safety factors under CCR Rule can be summarized as follows:

1. The historical record of local sinkhole development;
2. The presence of a local hydraulic gradient that points downward at shallow depths;
3. The presence of subsurface conduits that allow piping of groundwater into the karst aquifer, or shallow conduits or caves that could cause sudden collapse of the structure's foundation; and
4. The use of engineering solutions to "prevent the kind of foundation collapse and settlement that could lead to sudden release to the environment of CCR with its toxic constituents and associated leachate." (U.S. EPA 2015).

As discussed below, these factors support the conclusion that CREC Ash Landfill cannot continue to safely receive CCR, nor can it meet the requirements of the CCR Rule.

Additionally, the CCR Rule requires (a) a distance of at least 5 feet between the base of certain CCR storage and disposal facilities and the uppermost aquifer, or (b) other measures that eliminate any hydraulic connection between the facilities and the aquifer. As discussed below, the Ash Landfill does not meet either of these standards.

Water quality samples from wells downgradient from the Ash Landfill show consistent and increasing contamination from common CCR constituents, such as arsenic, boron, molybdenum, manganese, selenium, sulfate, and thallium, indicating that the Ash Landfill has already contaminated the Surficial and Floridan Aquifer at the site.

The Ash Landfill cannot meet the safety standards in the CCR Rule. Additionally, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated. The only way to prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

3. ASSESSMENT

A. CREC is in one of the country's most unstable areas, under the influence of multiple sinkholes

CREC is located in Citrus County, an active karst area under the influence of sinkholes (FGS 1985). The sandy sediment cover over the limestone in coastal Citrus County is thin, and sinkholes that form tend to be smaller, i.e., less than 10 feet ("ft") in diameter, and not as deep as in areas with thicker, more cohesive sediments covering the limestone. However, the near-surface limestone is deeply incised with solution channels and conduits that can cause small sinkholes to form as surficial sands move into the subsurface voids (Dames and Moore 1994).

a. Hydrogeology of coastal West Florida: Karst terrain, solution conduits, and sinkholes

Coastal Citrus County is a region that is underlain by a thick sequence of carbonate rocks, commonly called "limestone" (Miller 1986). These rocks can be dissolved by the chemical action of acidic groundwaters. This creates voids in the rock and a distinctive geologic terrain called karst.[1] Karst terrains are characterized by solution features such as caves and collapse features caused by surface materials falling into voids created by the solution of the underlying rocks. A vertical collapse or solution feature created by karst activity is called a sinkhole (Tihansky 2013).

Small sinkholes are common in western Citrus County (FGS 2016; Tihansky 2013). These voids or depressions at the surface are caused by the movement of unconsolidated surficial materials into pre-existing voids in the underlying limestone. Sinkholes can form rapidly by collapse or slowly by movement of surficial materials into underlying voids in the carbonate rock. Most sinkholes in coastal Citrus County are cover subsidence sinkholes. These sinkholes form when loose surficial sands migrate downward into solution cavities in the limestone. Cover subsidence sinkholes can form slowly, or abruptly, especially after heavy rainfall (Tihansky 2013).

[1] Geologists generally use the term "terrane" to refer to three-dimensional areas including the surface and subsurface, and "terrain" to refer to the surface configuration or topography only. This assessment uses "terrain" to refer to both surface and subsurface areas unless otherwise noted.

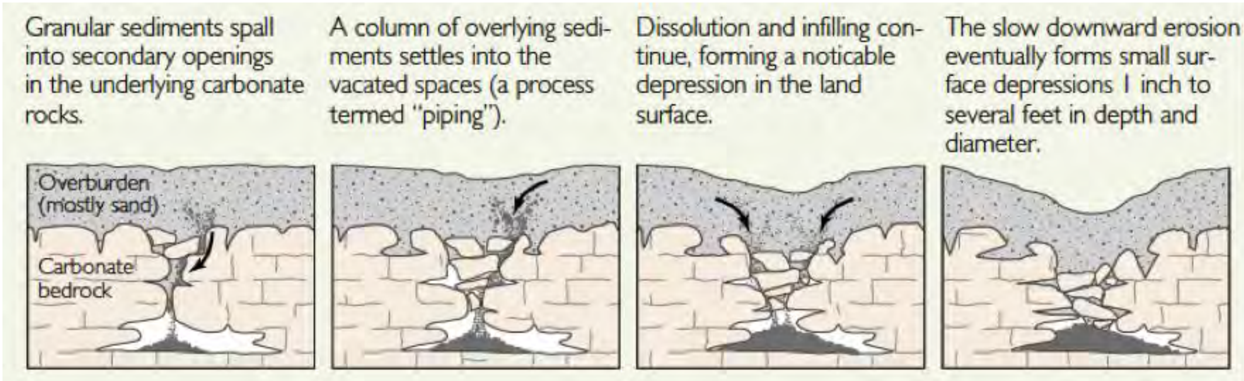

Figure 1. Cover subsidence sinkhole schematic (Tihansky 2013)

Paleosinks or paleo-sinkholes are also common in West Central Florida (Tihansky 2013). These are cover subsidence sinkholes that have been filled by sediments or water and do not have recognizable depressions at the surface. Such sediment-filled sinkholes can create a vertical column of permeable materials that allow contaminants introduced at the water table to reach the Floridan Aquifer. In addition to sinkholes, the limestone underlying CREC contains many solution enlarged fractures that form preferred conduits for groundwater flow and allow for downward movement of surficial sands into the underlying limestone (Dames and Moore 1994).

Groundwater, particularly groundwater in the Surficial and Floridan Aquifers,[2] supplies the region's public drinking water. The Floridan Aquifer is one of the largest and most productive sources of fresh groundwater in the world (Miller 1986). It is comprised of the carbonate rocks of Eocene to Miocene age in West Central Florida. In coastal western Citrus County, the Floridan Aquifer is unconfined and water table elevations represent the potentiometric surface of the Floridan Aquifer. This area is a recharge zone for the shallow Floridan Aquifer, which is at or within a few feet of land surface at CREC. More specifically, shallow groundwater flows downward from the water table and the shallow sands of the Surficial Aquifer into the Floridan Aquifer. Near CREC, the deeper and intermediate portions of the Floridan Aquifer are discharge zones, and groundwater has a component of flow toward the surface.

b. Hydrogeology of CREC site

The Florida Geological Survey ("FGS") sinkhole database (FGS 2016) documents 24 reported sinkholes within 5 miles of CREC site. As the FGS sinkhole data are self-reported, the 24 reported sinkholes are the minimum number of sinkholes that have occurred in recent years near CREC site. The FGS database is biased toward residential and commercial areas where sinkholes are more likely to be reported than in rural areas and industrial sites. Most of the reported sinkholes near CREC site are reported along the U.S. Highway 19 corridor east of CREC site and associated residential areas. The reported sinkholes are smaller than sinkholes that occur in central Florida, generally less than 10 ft in

[2] The Surficial and Floridan Aquifers are U.S. EPA designated Underground Sources of Drinking Water, and Florida Department of Environmental Protection ("DEP") designated Type G-II (Surficial) and G-I (Floridan) groundwaters.

diameter and up to 10 ft in depth. Using the 24 sinkholes as a representative data set, 95% (two standard deviations) of reported sinkholes within 5 miles of CREC have diameters less than 7 ft. They are indicative of the extensive karst solution cavities that are present in the shallow subsurface in western Citrus County.

Dames and Moore (1994) describe the geology and hydrogeology of CREC site. The following discussion is a summary of the geology and hydrogeology of CREC site from that report.

Dames and Moore report that the Upper Floridan Aquifer at CREC site contains abundant "solution enlarged fractures," "long linear depressions" in the limestone surface, and "underground channels and caverns." They also report that during removal of coal ash from the area of the former CREC south ash pond, "local superficial channels/sinkholes concealed by ash deposits had caused a continuous series of incidents and delayed removal/transportation activities." The report also states that "most flow is through the solution channels and cavities" and that the upper zone from the surface to a depth of about 30 feet contains many large interconnected solution cavities and channels that are highly permeable.

The surficial deposits at CREC consist of predominantly sandy, unconsolidated materials with some silt and clay. There is no distinct Surficial Aquifer at the site, and the Floridan Aquifer is within a few feet of the land surface. Water reaching the water table from the surface is effectively recharging the upper part of the Floridan Aquifer. The permeable surficial sediments are in direct hydraulic connection with the limestones of the Upper Floridan Aquifer. As a result of the lack of extensive low permeability surficial materials, the Floridan Aquifer at CREC site is an unconfined aquifer in direct hydraulic connection with the water table. Soils at the site typically have seasonal water tables within 1-2 ft of the land surface and are described as poorly drained. The undisturbed soils at CREC are subject to frequent and prolonged flooding.

The near-surface Floridan Aquifer units present at the site are the limestones of the Ocala Group, specifically the lower member of the Ocala Group, the Inglis Formation. The Inglis Formation is an Eocene limestone with extensive solution features. The Avon Park Formation underlies the Inglis Formation. The Avon Park Formation consists of limestones and dolostones and forms the bottom of the Upper Floridan Aquifer (Miller 1986). The permeability of the Avon Park decreases with depth. This results in enhancement of horizontal ground water flow in the Inglis Formation limestones. Dames and Moore (1994) report that most groundwater flow at the site is through "solution cavities and channels." In test borings that encountered voids, about 10% of the total aquifer volume is void space, generally within 50 ft of land surface. A zone in the Inglis Formation from land surface to a depth of about 30 ft consists of "many large solution cavities and channels that are highly permeable." A lower high permeable zone occurs between depths of about 40 to 60 ft at the contact between the Inglis and Avon Park Formations. Aquifer performance data suggest that the transmissivity of the Upper Floridan Aquifer at the site is about 2E05 ft^2/day, a very high value.

In a study to support installation of CREC Units 4 and 5 at CREC (ESE 1982), Dames and Moore (1994) report that test borings could be divided into "void" borings that encountered voids during drilling, and “non-void” borings that encountered solid limestone. The eight void wells responded faster to recharge events and tides and were assumed to connect with solution cavities and channels. The water levels for the void group wells were found to “form a trough running northeast to southwest under the ash disposal site…this trough roughly coincides with the known subsurface cavities in this area and likely reflects a fracture zone of high permeability.” The general groundwater flow direction under the Ash Landfill indicated by the void and non-void wells is northeast to southwest, toward CREC intake and discharge canals and wetlands to west of CREC. Groundwater that flows under the Ash Landfill through the “trough” delineated by Dames and Moore (1994) flows toward the west-southwest and discharges into the seawater discharge canal, and ultimately into Crystal Bay.

The water table “trough” under the Ash Landfill reported by Dames and Moore (1994) includes monitor wells MWI-2R2, TWI-5, and TWI-3 (Figures 2 and 3). These three monitor wells are located on the west side of the Ash Landfill. As described further below, groundwater monitoring reports (DEP 2015) indicate that these three wells have been contaminated with arsenic, sulfate, thallium, selenium, molybdenum, manganese, and boron, all of which are contaminants associated with CCR leachate. This indicates that the Ash Landfill is in direct hydraulic connection with a highly permeable fracture zone in the Upper Floridan Aquifer, and that contaminants associated with CCR wastes have entered the Upper Floridan Aquifer.

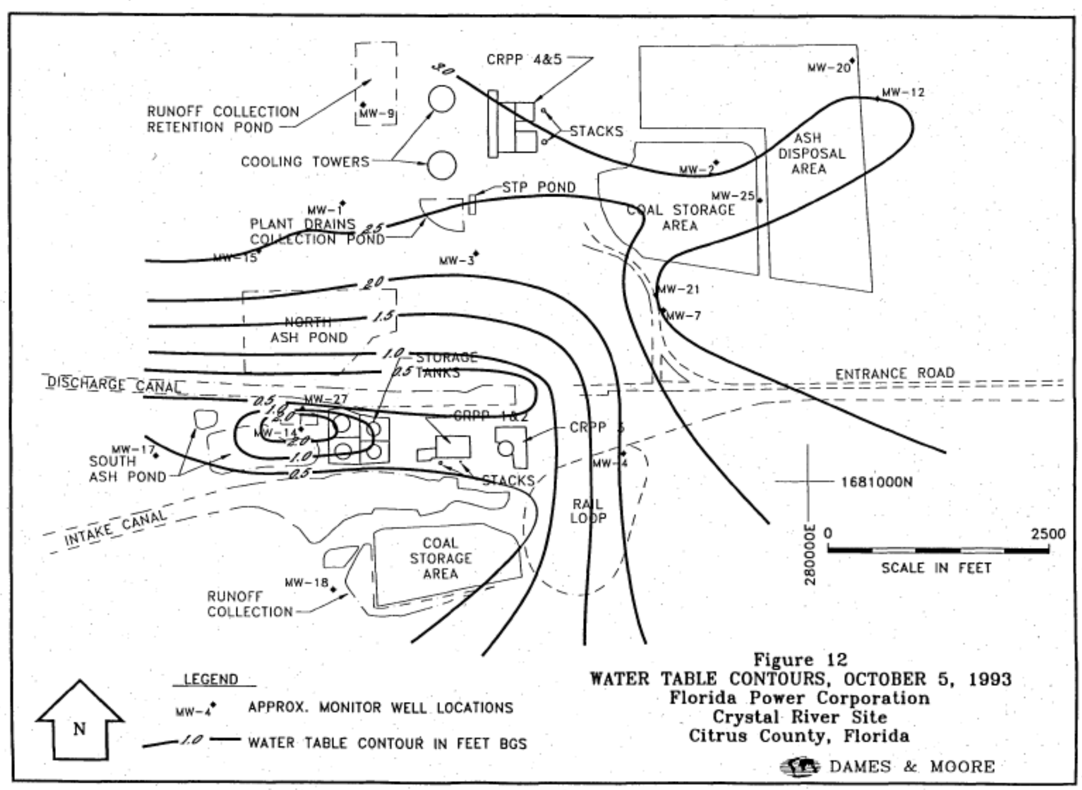

Figure 2. Water table elevations under the Ash Landfill (Dames and Moore 1994)

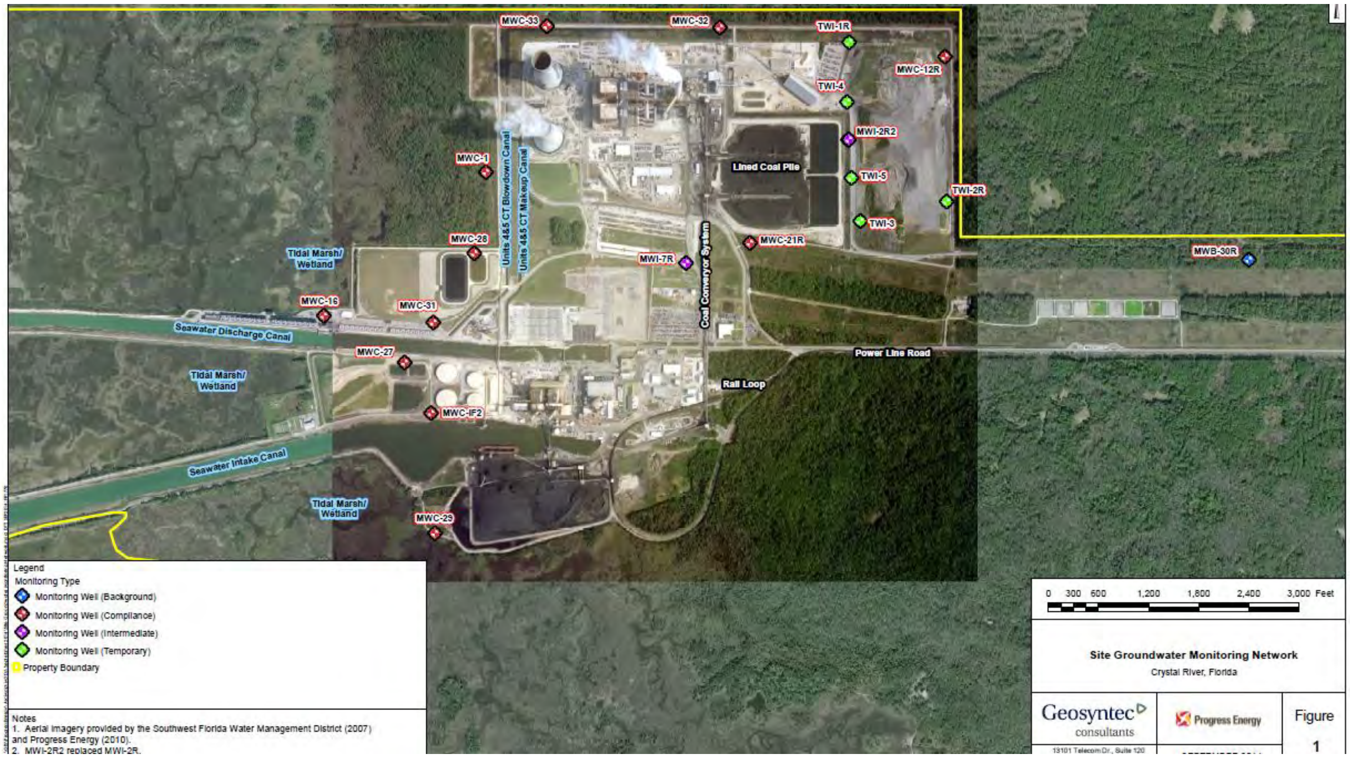

Figure 3. Groundwater Monitoring Network at CREC (Geosyntec 2013)

B. CREC Ash Landfill cannot meet the CCR Rule's safety standards for unstable areas

Historical records of sinkhole activity in the region and reports prepared for CREC site clearly indicate that the site is within an active karst zone, with numerous, unlocated channels and voids. Consulting reports (Dames and Moore 1984; ESE 1982) state that at CREC "most [groundwater] flow is through solution cavities and conduits" and these reports document that the site contains numerous solution enlarged channels, voids, and caves, with one documented high permeability conduit located directly under the Ash Landfill (Dames and Moore 1994). These channels, conduits, limestone surface depressions, and voids create a sinkhole hazard for the Ash Landfill.

The Floridan Aquifer is at or near land surface at CREC site (Dames and Moore 1994) and any size sinkhole is likely to allow movement of unconsolidated materials under the CCR landfill into the voids, depressions, and caverns under the landfill will, and likely has (ESE 1982), allowed CCR materials to come into direct contact with the limestones and groundwater of the Upper Floridan Aquifer. The Ash Landfill does not have structural reinforcements or a liner[3] to prevent vertical movement of CCR materials into the Upper Floridan Aquifer, as occurred at the site of the former CREC south ash pond (ESE 1982).

[3] Only 5.5 acres of the 62-acre Ash Landfill are lined.

To ensure the safety of CCR storage and disposal in unstable karst areas, the CCR Rule requires the detection and interception of (a) *all* of the possible conduits that allow piping of groundwater into the underlying karst aquifers; (b) *all* of the possible shallow caves that could cause a sudden foundation collapse; and (c) *all* of the possible pathways for CCR constituents to be released from CCR storage and disposal facilities, such as the Ash Landfill, into the karst aquifers (U.S. EPA 2015).

These safety standards were not incorporated into the design of the Ash Landfill when it was built. Detection and interception of *all* possible conduits, depressions, voids, and shallow caves in a complex karst terrain such as CREC site is extremely difficult technically, if not practically and economically infeasible. With any currently known sinkhole remediation technology, the Ash Landfill cannot be "upgraded" to meet the CCR Rule requirements for facilities in karst terrains as it would be nearly impossible to determine that all conduits, voids, and caves had been detected and intercepted. As the Ash Landfill does not meet the CCR Rule's safety standards and instructions for engineering practices in karst areas, the CCR materials currently onsite should be removed and the groundwater and soils decontaminated.

In addition to the Ash Landfill, CREC site contains a Gypsum Storage Pad, which receives gypsum solids before disposal in the Ash Landfill or transport offsite, and FGD Blowdown Ponds and Percolation Ponds on the west side of the site, adjacent to the seawater discharge canal, that receive waste and wastewater from coal operations. The FGD Blowdown Ponds are lined with synthetic impermeable liners. However, the FGD Blowdown Ponds, Percolation Ponds, and Gypsum Storage Pad are in the same unstable karst environment as the Ash Landfill. There is a potential for failure of the FGD Blowdown Pond liner system or piping as result of sinkhole activity. If a sinkhole punctured the liner or caused a FGD pipe to leak, the FGD wastes would be introduced directly into the Upper Floridan Aquifer, discharging to the seawater discharge canal, tidal wetlands, and ultimately Crystal Bay. The liner system would need to be able to span sinkholes 10 ft in diameter or greater without failing to avoid contaminating the Upper Floridan Aquifer with FGD wastes. The Percolation Ponds are unlined and are in direct communication with the Upper Floridan Aquifer. The Percolation Ponds recharge the shallow groundwater aquifer and discharge into the seawater discharge canal, tidal wetlands, and Crystal Bay (Figures 2 and 3).

C. The Upper Floridan Aquifer exhibits contamination from CCR Leachate at CREC

Contaminants such as sulfate, arsenic, selenium, thallium, boron, molybdenum, and manganese are common constituents of CCR leachate (EPRI 2004). The presence of several of these constituents, at any detectable level above background values, in groundwater downgradient from a CCR storage and disposal unit is overwhelming evidence that contaminants that have leached from the CCR materials have reached the water table and the aquifer. Groundwater sampling results from September 2012 for monitoring well MZ-3, which is in an upgradient, undisturbed area approximately one mile east of CREC facility, indicate that background arsenic concentrations in the shallow, intermediate, and deep portions of the aquifer are 2.1, 6.3, and <2.0 micrograms/liter, respectively (Geosyntec 2013). Arsenic levels in groundwater >10.0 micrograms/liter are indications of contamination of the aquifer system by CCR.

Dames and Moore (1994) state that the "void wells" near the Ash Landfill define a "trough" in the water table surface underneath the landfill (Figure 2). They attribute this water table trough to a "fracture zone of high permeability." Three monitor wells on the west side of the Ash Landfill are located in or near this high permeability fracture zone: wells MWI-2R2, TWI-5, and TWI-3 (Figure 3).

Water samples from these three wells have regularly exceeded federal and state regulatory levels for arsenic, sulfate, thallium, selenium, molybdenum, manganese, and boron since 2012. For arsenic, boron, manganese, and molybdenum levels of these contaminants in groundwater in this fracture zone have trended upward from 2012 to 2015 (Figures 4, 5, 6, and 7). Water quality data obtained in January 2016, continue to show levels of contaminants in excess of groundwater standards in wells downgradient of the Ash Landfill in wells MWI-2R2, TWI-1R, TWI-3, and TWI-5 (DEP 2016).

These supporting lines of evidence, the definition of the water table trough, the presence of high permeability conduits at the site, and the presence of common CCR leachate constituents at increasing concentrations in wells downgradient from the Ash Landfill are overwhelming evidence that the landfill has contaminated local groundwater with toxic materials associated with CCR leachate. As the purpose of the standards enumerated under the CCR Rule is to prevent groundwater contamination from CCR facilities, the presence of these contaminants at the existing site is evidence that that the existing Ash Landfill does not meet the conditions specified in the rule.

Geosyntec (2013) has prepared a report that maintains that the arsenic found in groundwater downgradient from the Ash Landfill is the result of complex geochemical conditions and a natural source of arsenic. They note that arsenic was detected in borings at a proposed coal ash storage site east, and upgradient, of the current Ash Landfill, suggesting a natural source of arsenic. However, the concentrations of arsenic detected downgradient of the Ash Landfill are up to five times as high as the concentrations detected upgradient. In addition, the associated CCR contaminants sulfate, selenium, thallium, boron, molybdenum, and manganese have been detected in wells downgradient of the Ash Landfill. The Geosyntec report does not explain the presence of these CCR associated contaminants.

To prevent such contamination, the CCR Rule prescribes (a) a distance of at least 5 feet between the base of facilities containing CCR and the uppermost aquifer, or (b) other measures that eliminate the hydraulic connection between the base and the uppermost aquifer—safety standards that the Ash Landfill does not meet. According to public records, the base of the Ash Landfill has an elevation of 4 to 8 feet above sea level, while the water table near the Ash Landfill has reported elevations greater than 3 feet (Geosyntec 2013). This indicates that the base of the Ash Landfill is within 5 feet of the water table in the Surficial/Floridan Aquifer. The Ash Landfill is unlined, meaning that the CCR materials are in direct hydraulic connection with the Floridan Aquifer. Furthermore, natural soils at CREC site are poorly drained and flood seasonally (Dames and Moore 1994), indicating that the water table seasonally approaches the land surface.

As the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site should be decontaminated.

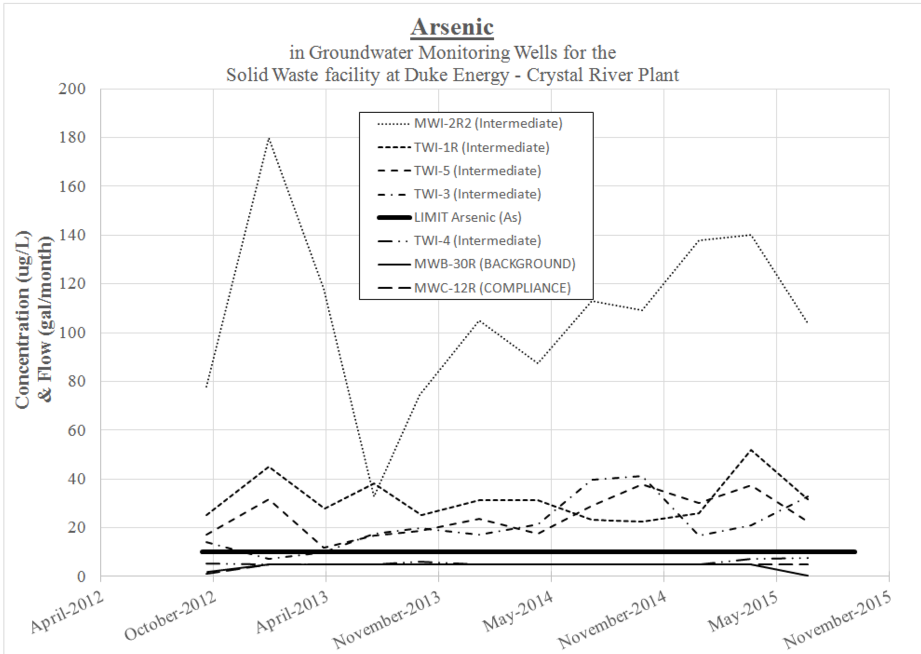

Figure 4. Arsenic levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)

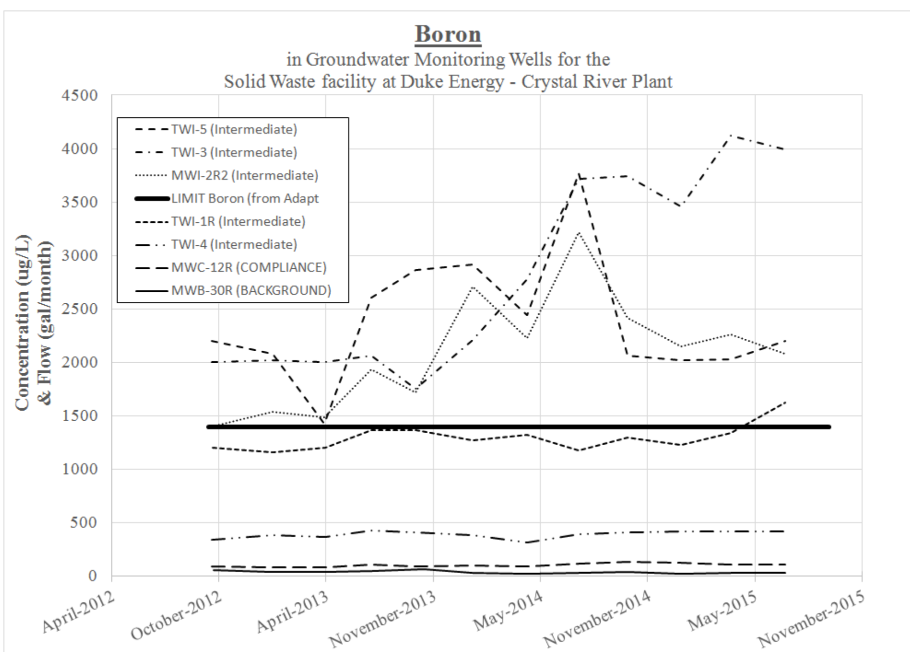

Figure 5. Boron levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)

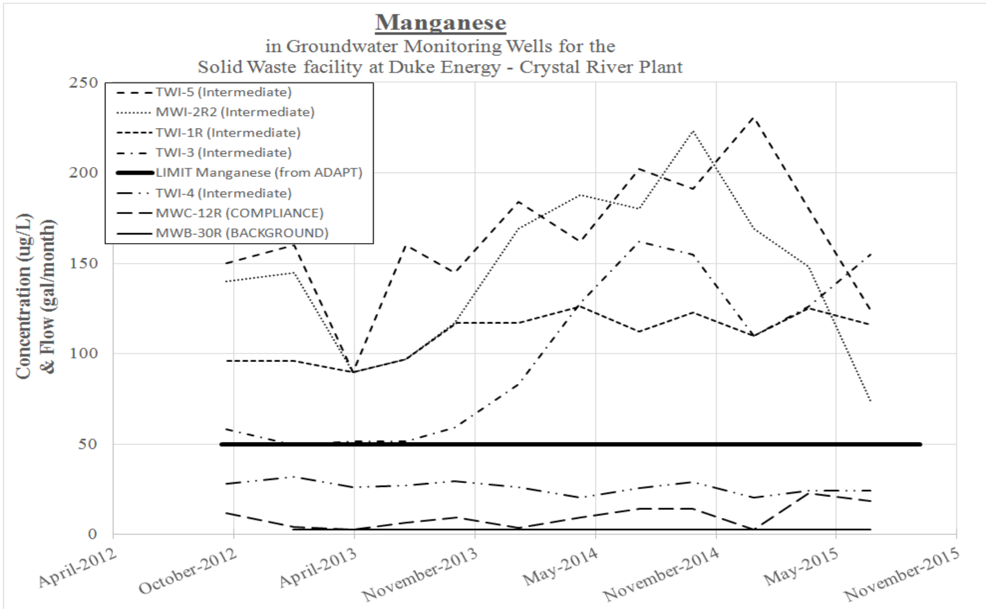

Figure 6. Manganese levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)

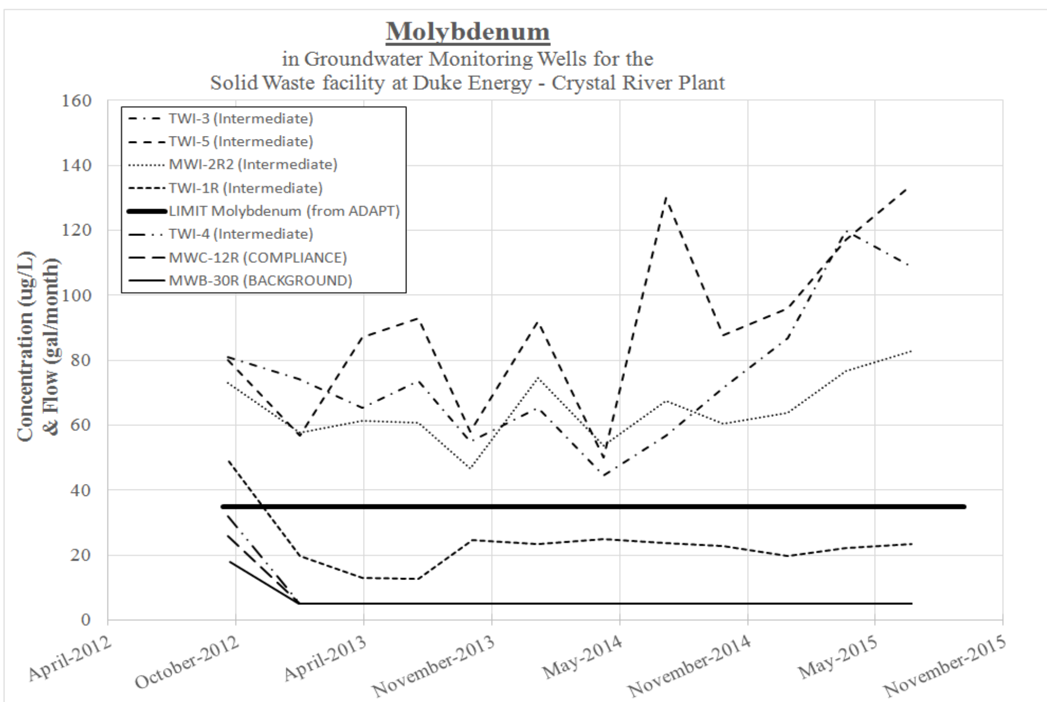

Figure 7. Molybdenum levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)

4. SUMMARY

CREC Ash Landfill does not meet the safety criteria for CCR landfills and impoundments enumerated in the EPA's CCR Rule. The facility is located in a documented unstable, karst area, putting local water resources at risk. It would be technically challenging, if not impossible to upgrade the Ash Landfill to meet the CCR Rule standards for active facilities in karst areas. In addition, there is overwhelming evidence that the Ash Landfill has contaminated local ground water with arsenic, selenium, molybdenum, manganese, boron, and thallium. The source of these contaminants is the Ash Landfill as documented by the presence of these contaminants in water samples from downgradient wells. The Ash Landfill is uncovered and open to infiltration of rainwater, the facility is unlined, and it is in direct hydraulic connection with the Upper Floridan Aquifer. The remedy to prevent further contamination of the aquifer and of Crystal Bay, is to remove the CCR materials currently on site and to decontaminate the Floridan Aquifer and local soils.

5. AUTHOR'S EXPERTISE AND QUALIFICATIONS

The author of this technical assessment, Dr. Mark Stewart, PhD, PG, is a Professor Emeritus at the University of South Florida School of Geosciences. Dr. Stewart is a registered Professional Geologist in the State of Florida. He has an extensive publication record and expertise in the hydrogeology of Florida, water resources management, karst hydrology, applied geophysics, and the geology of sinkholes. He has been qualified in hearings of the Division of Administrative Hearings and in State and Federal courts as an expert in hydrogeology, water resources management, karst hydrology, the geology of sinkholes, hydrologic modeling, and environmental geophysics. Dr. Stewart has an undergraduate degree in geological sciences from Cornell University, and graduate degrees in geology and water resources management from the University of Wisconsin-Madison.

The primary materials reviewed and used in the preparation of this assessment were Florida Department of Environmental Protection ("DEP") regulatory files, which include groundwater monitoring reports, reports on the geology and hydrogeology of CREC site, and reports on the construction and operation of waste material facilities and disposal of generated wastes, all of which were prepared by Duke/Progress Energy/FPC and their consultants and submitted to the DEP. Additional materials referenced for this report include: publications, data, and maps from the U.S. Geological Survey and Florida Geological Survey; peer-reviewed journal articles; and publically-available documents related to coal and coal combustion residuals, hydrogeology, sinkholes, and karst hydrology.

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EXHIBIT 2

Technical Assessment of Converting a Zero Discharge Standard for Bottom Ash Wastewater at the Crystal River Energy Complex:

Expert Report by Dr. Ranajit (Ron) Sahu

September 26, 2016

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

This is an assessment of Duke Energy Florida's ("DEF") plans for achieving compliance with the U.S. Environmental Protection Agency's ("EPA") revised effluent limitations guidelines ("ELGs") for bottom ash wastewater generated at DEF's Crystal River Energy Generating Complex ("CREC") Units 4 and 5. Specifically, this assessment evaluates DEF's contention that February 1, 2020, should be the deadline for these units under the ELGs.

DEF's 44-month schedule to achieve compliance with the bottom ash BAT standard is simply unsupported. CREC can achieve a zero discharge standard for bottom ash wastewater within 27 to 30 months, roughly August to November 2018.

Construction time for bottom ash retrofits at Units 4 and 5 are anticipated to take, with a built in contingency, only 18 months. Other, related, tasks for achieving compliance should take significantly less time than DEF proposes, particularly as DEF began planning for and evaluating strategies to comply with the revised ELGs as far back as 2012. Beginning in 2014, Duke Energy began publicly reporting projected compliance costs, suggesting that conceptual or detailed engineering evaluations and studies were undertaken and that Duke Energy's Board has been aware of these changes and costs for some time.

DEF does not need until February 1, 2020, to achieve compliance with a zero discharge standard for bottom ash wastewater at CREC Units 4 and 5. Rather, compliance can be achieved by November 2018 if not sooner. The Florida Department of Environmental Protection ("DEP") should carefully review the unsupported schedule provided by DEF and require that Units 4 and 5 comply with a zero discharge bottom ash standard by no later than November 2018.

2. INTRODUCTION

This is an assessment of Duke Energy Florida's ("DEF") plans for achieving compliance with the U.S. Environmental Protection Agency's ("EPA") revised effluent limitations guidelines ("ELGs") for bottom ash transport water[1] or "wastewater" generated at DEF's Crystal River Energy Generating Complex ("CREC") Units 4 and 5. Specifically, this assessment evaluates DEF's contention that February 1, 2020, should be the deadline for these units' under the ELGs.

3. BOTTOM ASH HANDLING AND WASTEWATER AT CREC UNITS 4 AND 5

[1] 40 C.F.R. § 423.11(f) (defining the term "bottom ash" as "the ash, including boiler slag, which settles in the furnace or is dislodged from furnace walls. Economizer ash is included in this definition when it is collected with bottom ash); § 423.11(p) (defining the term "transport water" as "any wastewater that is used to convey fly ash, bottom ash, or economizer ash from the ash collection or storage equipment, or boiler, and has direct contact with the ash. Transport water does not include low volume, short duration discharges of wastewater from minor leaks (e.g., leaks from valve packing, pipe flanges, or piping) or minor maintenance events (e.g., replacement of valves or pipe sections)."

CREC is operated by DEF and is located adjacent to Crystal Bay, part of the Gulf of Mexico, in Citrus County, Florida. Units 1 (built in 1966, rated at 395 MW), 2 (built in 1969, rated at 520 MW), 4 (built in 1982, rated at 769 MW), and 5 (built in 1984, rated at 767 MW) are Duke Energy's only coal-fired units in Florida.[2] DEF applied to renew the NPDES Permit No. FL0036366 for Units 4 and 5 in January 2016.[3]

As described by DEF, Units 4 and 5 produce bottom ash wastewater that discharges from dewatering bins to an intenral canal and then to Crystal Bay via a discharge canal:

> The bottom ash handling system collects and removes bottom ash from Crystal River North Unit 4 & 5. Bottom ash collected in ash hoppers beneath the steam generator is periodically removed with ash sluice water to a transfer tank. From the transfer tank, an ash slurry pump transports slurry to a selected dewatering bin where bottom ash is separated from the transport water. When dewatered, bottom ash is either directly sent for beneficial reuse or deposited in an ash storage area for later beneficial reuse. All transport water from the dewatering bin is sent to a surge tank where it is pumped back to the ash hoppers to transport more bottom ash. Several process streams also feed into the bottom ash transport water system. While they provide needed make-up water, these sources may also, at times, cause the surge tank to overflow. The overflow runs into the coal area stormwater runoff ditch which discharges infrequently through NPDES internal outfall I-CHO.[4]

DEF further describes:

> The facility currently utilizes a wet-sluicing system for bottom ash, in which most of the bottom ash transport water is reused after exiting the dewatering basins. However, due to water balance issues at the facility, an overflow structure is used to discharge excess water from the dewatering basins into the runoff collection system, and then through Internal Outfall I-CHO to eventually Internal Outfall I-0CO, Outfall D-001 and waters of the State.[5]

Additional details are provided in the NPDES permit renewal application and other documents in the permitting record.[6]

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[2] *See Coal-Fired Plants*, Duke Energy, https://www.duke-energy.com/power-plants/coal-fired.asp (last visited Sep. 26, 2016).

[3] Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016.

[4] Duke Energy Florida, Response to Request for Additional Information, Attachment 1 at 1, May 20, 2016.

[5] Draft Permit at 12.

[6] *See e.g.*, DEF's Coal Combustion Product (CCP)/Solid Waste Materials Management Plan, Revision 6, December 2013.

4. THE ELGS

After many years of work,[7] EPA finalized the ELGs in November 2015.[8] The ELGs revise and strengthen technology-based effluent limitations guidelines and standards for wastewater discharges from steam electric power plants, including coal-fired units such as CREC Units 4 and 5.

The final ELGs set federal limits on the discharge toxic metals and other harmful pollutants from wastewater at steam electric power plants. The ELGs are based on technology improvements in the steam electric power industry over the last three decades and establish new requirements for wastewater streams from the following processes and byproducts associated with flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels such as coal and petroleum coke.

The ELGs require a zero discharge best available technology ("BAT") standard for bottom ash wastewater to be achieved by November 1, 2018, or "as soon as possible." [9] The phrase "as soon as possible" means November 1, 2018, unless permitting authorities, such as the Florida Department of Environmental Protection ("DEP"), establish a later date based on a well-documented justification.[10]

5. CONSULTATION WITH VENDORS AND INDUSTRY REGARDING BOTTOM ASH CONVERSIONS

A. Vendor Experience and Discussions During ELG Rulemaking

As EPA has stated, "to gather information on handling fly ash and bottom ash, EPA … contacted several ash handling and ash storage vendors. The vendors provided the following types of information for EPA's analyses:

- Type of fly ash and bottom ash handling systems available for reducing or eliminating ash transport water;
- Equipment, modifications, and demolition required to convert wet-sluicing fly ash and bottom ash handling systems to dry ash handling or closed-loop recycle systems;
- Equipment that can be reused as part of the conversion from wet to dry handling or in a closed-loop recycle system;

[7] As EPA noted in the preamble to the final ELG Rule, "….EPA initiated a steam electric ELG rulemaking following a detailed study in 2009. EPA published the proposed rule on June 7, 2013, and took public comments until September 20, 2013." 80 Fed. Reg. 67,844.

[8] The Final ELG Rule was published in the Federal Register on November 3, 2015. 80 Fed. Reg. 67,838.

[9] *See* 40 C.F.R. § 423.11(t) (defining the phrase "as soon as possible" to mean Nov. 1, 2018, unless a later date is specifically justified); § 423.13(k)(1) (requiring compliance with bottom ash wastewater standards by Nov. 1, 2018 unless a later date up to Dec. 31, 2023 is specifically justified).

[10] 40 C.F.R. § 423.11(t) (emphasis added).

- Outage time required for the different types of ash handling systems;
- Maintenance required for each type of system;
- Operating data for each type of system;
- Purchased equipment, other direct, and indirect capital costs for fly ash and bottom ash conversions;
- Specifications for the types of ash storage available (*e.g.*, steel silos or concrete silos) for the different types of handling systems;
- Equipment and installation capital costs associated with the storage of fly ash and bottom ash; and
- Operation and maintenance costs for fly ash and bottom ash handling systems."[11]

The vendor community has been well aware of the rule requirements and participated fully in the rulemaking. There are numerous well-qualified U.S. vendors (and foreign vendors that are active in the U.S. market) that are capable of providing equipment and services for ash handling and conversion of bottom ash transport water at coal-fired units such as Units 4 and 5. Major vendors include United Conveyer Corporation ("UCC"),[12] Clyde Bergemann,[13] and Magaldi.[14] Others such as GE, Veolia, Nalco, Aquatech, Heartland, LB Industrial Systems, and many others also have potential capabilities and solutions for specific aspects of ash handling. The ELGs docket shows that EPA consulted expensively with at least UCC and Clyde Bergemann with respect to bottom ash transport water and handling during rule development.[15].

That the vendor community is robust is not surprising given that the US coal-fired power plant fleet is over 800 units strong, with each one generating copious amounts of bottom ash that must be handled and managed. Further, as the ELGs rulemaking record shows, a significant portion of the U.S. coal fleet already meets the ELGs BAT standard for bottom ash wastewater and are dry systems. These vendors already have many technology solutions and offerings for achieving

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[11] Technical Development Document for the Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category, U.S. Environmental Protection Agency, EPA-821-R-15-007 at p. 3-21 and 3-22 (Sep. 2015).

[12] UCC offers various hydraulic, mechanical, pneumatic, and vibratory systems for dry bottom ash handling.

See Bottom Ash, United Conveyor Corporation, http://unitedconveyor.com/bottom_ash/ (last visited Sep. 26, 2016).

[13] Clyde Bergemann offers a trademarked "DRYCON" system for dry bottom ash handling.

See DRYCON, Clyde Bergemann Power Group, http://www.cbpg.com/en/products-solutions-materials-handling-bottom-ash/drycon%E2%84%A2 (last visited Sep. 26, 2016).

[14] Magaldi offers a dry ash handling system called MAC. A variant of this system appears to have been installed in either CREC Unit 1 or 2 or both.

See Magaldi Solutions for Ash Handling, Magaldi, http://www.magaldi.com/en/magaldi_solutions_for/Ash-Handling-Mac__9_11.php#tab_fototab (last visited Sep. 26, 2016).

[15] See, for example, EPA-HQ-OW-2009-0819-0580 (pertaining to EPA and its contractor's discussions with UCC) (*available at* https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-0580) and EPA-HQ-OW-2009-0819-6232 (pertaining to EPA and its contractor's discussions with Clyde Bergemann) (*available at* https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-6232).

a zero discharge bottom ash standard. As the preamble to the ELG Rule states:

> …technologies for control of bottom ash transport water are demonstrably available. Based on survey data, more than 80 percent of coal-fired generating units built in the last 20 years have installed dry bottom ash handling systems. In addition, EPA found that more than half of the entities that would be subject to BAT requirements for bottom ash transport water are already employing zero discharge technologies (dry handling or closed-loop wet ash handling) or planning to do so in the near future.[16]

Thus, DEF has a good selection of experienced vendors to select from to achieve compliance with the bottom ash ELGs. As discussed below, the record also shows that DEF and previous CREC owner Progress Energy Florida ("PEF") appear to have actively consulted with at least one vendor, UCC, with regards to bottom ash dry conversion systems, as far back as 2012.

B. Vendor Discussions Pertaining to DEF and CREC in the Rulemaking Docket

The ELG rulemaking docket indicates that DEF already consulted vendors regarding the conversion to bottom ash dry conversion systems. Specifically, the docket shows that DEF has a long-standing relationship with one of the vendors, Magaldi,[17] and has been discussions with another vendor DRYCON™.[18] In addition, the docket shows DEF has experience with other vendors through its pursuit of dry systems at its other plants/units. Moreover, DEF and its predecessor, Progress Energy Florida (PEF), have been engaged for years in developing a compliance strategy for bottom ash transport water for Units 4 and 5. As EPA notes in a memorandum provided by its contractor ERG in May 2012:

> UCC noted the wet to dry conversions in the recent past or in process:
>
> …
>
> - Duke Energy's Gibson plant is in the process of converting their wet sluicing system to a dry fly ash handling system;
>
> …
>
> - Progress Energy's Mayo plant is planning to convert their current bottom ash handling system to a PAX system (100 percent dry

[16] 80 Fed. Reg. 67,852.

[17] *See* Final Seminole Site Visit Notes, EPA-HQ-OW-2009-0819-1891 (Jan. 2013) (*available at* https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-1891).

[18] *See* Memorandum to the Steam Electric Rulemaking Record: Ash Handling Documentation from Comunications with Clyde Bergemann Power Group, EPA-HQ-OW-2009-0819-6232 (Sep. 2015) (*available at* https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-6232).

> vacuum), which is currently scheduled to be commissioned in 2013;
> …
>
> UCC explained that Duke Energy's plants (i.e., Marshall, Allen, Wabash, and Gibson) are going dry to avoid violations, or risks of violations, with NPDES permits. Additionally, Duke Energy is exploring ash handling technologies in anticipation of changing regulations. Additionally, UCC reports that Gibson engaged UCC for quotes for a bottom ash handling conversion.
>
> UCC also reported that Progress Energy wants to convert ash handling systems to dry to get ahead of the industry. UCC stated that Progress is likely going with a PAX bottom ash handling system for the plants that still operate wet sluicing systems. UCC stated that this system because [*sic*] operational at Crystal River 15 years ago.[19]

These notes show that DEF/PEF has already made significant progress on dry conversion for its plants/units, including not only installing such a system at its Mayo plant in 2013, but also for its other plants including CREC where only Units 4 and 5 use wet bottom ash sluicing. Moreover, the fact that these discussions took place in mid-2012 show that significant development work was completed on or before by that time—more than four years ago. The discussions also show significant preparations by DEF parent company to convert to dry handling systems in anticipation of the ELGs.

C. Utility Water Act Group (UWAG) Comments During the ELG Rule Development

Lastly, while numerous parties provided comments to the EPA during its ELG rulemaking, it is particularly important to note certain relevant portion of comments provided by the Utility water Act Group ("UWAG"), an industry consortium, which includes almost all utilities as its members.[20] Duke is a member of UWAG as was PEF.

In its comments, pertaining to bottom ash conversions, UWAG states that

[19] *See* Teleconference Notes Between Kevin McDonough & Mike Kippis, United Conveyor Corporation, Ron Jordan and Jezebele Alicea-Virella, USEPA, TJ Finseth, Elizabeth Sabol, ERG, Inc., EPA-HQ-OW-2009-0819-0580 (May 24, 2012) (*available at* https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-0580) (emphasis added).

[20] As UWAG's comment's note, "UWAG is a voluntary, *ad hoc*, non-profit, unincorporated group of 198 individual energy companies and three national trade associations of energy companies: the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association. The individual energy companies operate power plants and other facilities that generate, transmit, and distribute electricity to residential, commercial, industrial, and institutional customers." Utility Water Act Group Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, at 1 n.1.

> [I]n the case study presented in the attachment, it would take 30-36 months to convert from a wet bottom ash hopper to a dry bottom ash hopper for a large unit…..Another case study for adding a remote wet ash hopper and submerged flight conveyor would take 27-33 months.[21]

The project implementation timeframes referenced in this section, which are already considerably shorter than what DEF has proposed (i.e., 44 months, as discussed in Section 7), are relevant for situations in which no initial planning or assessment has been completed. However, since, as shown next, there are clear indications that Duke Energy and PEF have undertaken significant, multi-year efforts to begin planning for a conversion to dry bottom ash handling, and that the implementation schedule at CREC Units 4 and 5 should be shorter.

6. DUKE ENERGY'S PUBLIC STATEMENTS AND PLANNING TO COMPLY WITH THE BOTTOM ASH ELGS

Public statements from Duke Energy corroborate that DEF has already evaluated options and developed likely costs for compliance with the ELGs at CREC Units 4 and 5, and that implementation can and should occur more quickly than in the schedules proposed by DEF and DEP.

A. Duke Energy's 2013 Annual Report and SEC Form 10-K Filing

In a brief discussion in its 2013 Annual Report, Duke Energy provided the following general statement, (although no cost estimates) regarding compliance with the then-proposed revised ELGs for steam electric power plants:

> *Steam Electric Effluent Limitation Guidelines*
>
> On June 7, 2013, the EPA proposed Steam Electric Effluent Limitations Guidelines (ELGs). The EPA is under a court order to finalize the rule by May 22, 2014. The EPA has proposed eight options for the rule, which vary in stringency and cost. The proposed regulation applies to seven waste streams, including wastewater from air pollution control equipment and ash transport water. Most, if not all of the steam electric generating facilities the Duke Energy Registrants own are likely affected sources. Compliance is proposed as soon as possible after July 1, 2017, but may extend until July 1, 2022. The Duke Energy Registrants are unable to predict the outcome of the rulemaking, but the impact

[21] *Id.* at 84.

could be significant.[22]

B. Duke Energy's 2014 Annual Report and SEC Form 10-K Filing

Again in 2014, Duke Energy considered compliance with the proposed ELGs, this time offering cost estimates:

> *Steam Electric Effluent Limitation Guidelines*
>
> On June 7, 2013, the EPA proposed Steam Electric Effluent Limitations Guidelines. The EPA is under a revised court order to finalize the rule by September 30, 2015. The EPA has proposed eight options for the rule, which vary in stringency and cost. The proposed regulation applies to seven waste streams, including wastewater from air pollution control equipment and ash transport water. Most, if not all, of the steam electric generating facilities the Duke Energy Registrants own are likely affected sources. Requirements to comply with the Final rule may begin as early as late 2018 for some facilities.
>
> *Estimated Cost and Impacts of Rulemakings*
>
> …
>
> The following table provides estimated costs, excluding AFUDC, of new control equipment that may need to be installed on existing power plants, including conversion of plants to dry disposal of bottom ash and fly ash, to comply with the above regulations over the five years ended December 31, 2019
>
> …

(in millions)		Estimated 5 Year Cost
Duke Energy	$	1,850
Duke Energy Carolinas		675
Progress Energy		525
Duke Energy Progress		475
Duke Energy Florida		50
Duke Energy Ohio		75
Duke Energy Indiana		575

[23]

[22] Available at https://www.duke-energy.com/investors/financials-sec-filings/annual.asp.

Even though the ELGs had not yet been finalized, Duke Energy recognized that the rule would likely be final by September 2015 and had already developed cost estimates for compliance. Duke Energy necessarily would have had to complete considerable planning and engineering work in the 2013-2014 time period to be able to share such cost estimates.

The statement above also shows that Duke anticipated that compliance would be required "as early as late 2018" which is consistent with EPA's final compliance schedule beginning in November 2018.

Specific to CREC units, the cost estimate of $50 million presented to shareholders and the SEC for DEF relate directly to Units 4 and 5, since these are DEF's only non-retired coal units.

C. Duke Energy's 2015 Annual Report and SEC Form 10-K Filing

Finally, in 2015, Duke Energy again projected compliance dates and costs for the ELGs:

> *Steam Electric Effluent Limitations Guidelines*
>
> On January 4, 2016, the final Steam Electric Effluent Limitations Guidelines (ELG) rule became effective. The rule establishes new requirements for wastewater streams associated with steam electric power generation and includes more stringent controls for any new coal plants that may be built in the future. Affected facilities must comply between 2018 and 2023, depending on timing of new Clean Water Act permits. Most, if not all, of the steam electric generating facilities the Duke Energy Registrants own are likely affected sources. <u>The Duke Energy Registrants are well-positioned to meet the requirements of the rule due to current efforts to convert to dry ash handling.</u>
>
> *Estimated Cost and Impacts of Rulemakings*
>
> Duke Energy will incur capital expenditures to comply with the environmental regulations and rules discussed above. The following five-year table provides estimated costs, excluding AFUDC, of new control equipment that may need to be installed on existing power plants primarily to comply with the Coal Ash Act requirements for conversion to dry disposal of bottom ash and fly ash, MATS, Clean Water Act 316(b) and ELGs, through December 31, 2020.

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[23] Duke Energy 2014 Annual Report at 59 *available at* https://www.duke-energy.com/investors/financials-sec-filings/annual.asp.

(in millions)	Five-Year Estimated Costs
Duke Energy	**$ 1,350**
Duke Energy Carolinas	625
Progress Energy	350
Duke Energy Progress	300
Duke Energy Florida	50
Duke Energy Ohio	100
Duke Energy Indiana	275

"[24]

The 2015 filing does not change the 2014 cost estimate of $50 million for DEF's compliance with the ELGs, indicating no significant alterations in its compliance strategy. Notably, Duke Energy states that "[t]he Duke Energy Registrants are well-positioned to meet the requirements of the rule due to current efforts to convert to dry ash handling."[25] This statement is not surprising and is consistent with DEF's ability to meet a compliance deadline of late 2018.

7. CRITIQUE OF DEF'S PROPOSED COMPLIANCE SCHEDULE

As detailed above, Duke Energy and DEF have made considerable progress in preparations for compliance with the bottom ash wastewater provisions in the ELGs. Nothing in the record suggests that Units 4 and 5 cannot achieve compliance with the BAT requirements for bottom ash wastewater by November 1, 2018. Yet DEF has, surprisingly, proposed February 1, 2020, as the compliance deadline for the bottom ash BAT standard at CREC Units 4 and 5.

In its initial NPDES permit renewal application, DEF proposed the following schedule for "[e]valuation of the Dry Bottom Ash Dewatering system to eliminate the water overflows" and stated that "Duke Energy is in the process of conducting this evaluation:"[26]

- Complete evaluation of the Dry Bottom Ash Dewatering System and submit to the Department a list of actions with deadlines – July 31, 2018.
- Completion of actions and compliance with the ELG Rule no later than December 31, 2023.[27]

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[24] Duke Energy 2015 Annual Report at 63 *available at* https://www.duke-energy.com/investors/financials-sec-filings/annual.asp (emphasis added).

[25] *Id.*

[26] Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016, at attachment 4 p.1-2.

[27] *Id.*

In other words, DEF did not commit to compliance before December 31, 2023, the final deadline for compliance with the revised ELGs, nor provide any support for why it would take until late 2023, eight years after the finalization of the ELGs.

Subsequently, in reponse to Florida DEP's request for additional information, DEF amended its initial proposed schedule for compliance and stated that:

> DEF intends to promptly initiate the formal planning process on June 1, 2016, based on an assumption that the enclosed additional information will result in a complete application and no significant modification to DEF's compliance plans. Due to time needed for planning, procurement, permitting, construction and testing, DEF is requesting that the Department approve a date of completion February 1, 2020, 44 months from June 1, 2016.[28]

DEF now proposes February 1, 2020, as the compliance deadline for the zero discharge standard for bottom ash wastewater. While this is an improvement over the previous, unsupported December 31, 2023, compliance date proposal, this is still too long, and not supported by an justificaiton, as describe next.

As support for a project duration of 44 months, DEF provided a project schedule, shown below.[29]

Table 1- CRN Unit 4 & 5 : Dry Bottom Ash

Task Number	Task Name	Duration (Months)
1	Bottom Ash Water Balance	6
2	Review Bottom Ash Modification Options	2
3	Finalize Bottom Ash Modification Options	3
4	Project Budget Approval	6
5	Detailed Engineering of Selected Modifications	3
6	Implementation of Modifications	18
7	Review of Modifications/Contingency	6
Total (months - excluding task overlaps)		44

DEF's discussion of each Task Number, as shown in the schedule in F is provided below in

[28] Duke Energy Florida, Response to Request for Additional Information at 1, May 20, 2016.

[29] Duke Energy Florida, Response to Request for Additional Information, at attachment 1, May 20, 2016.

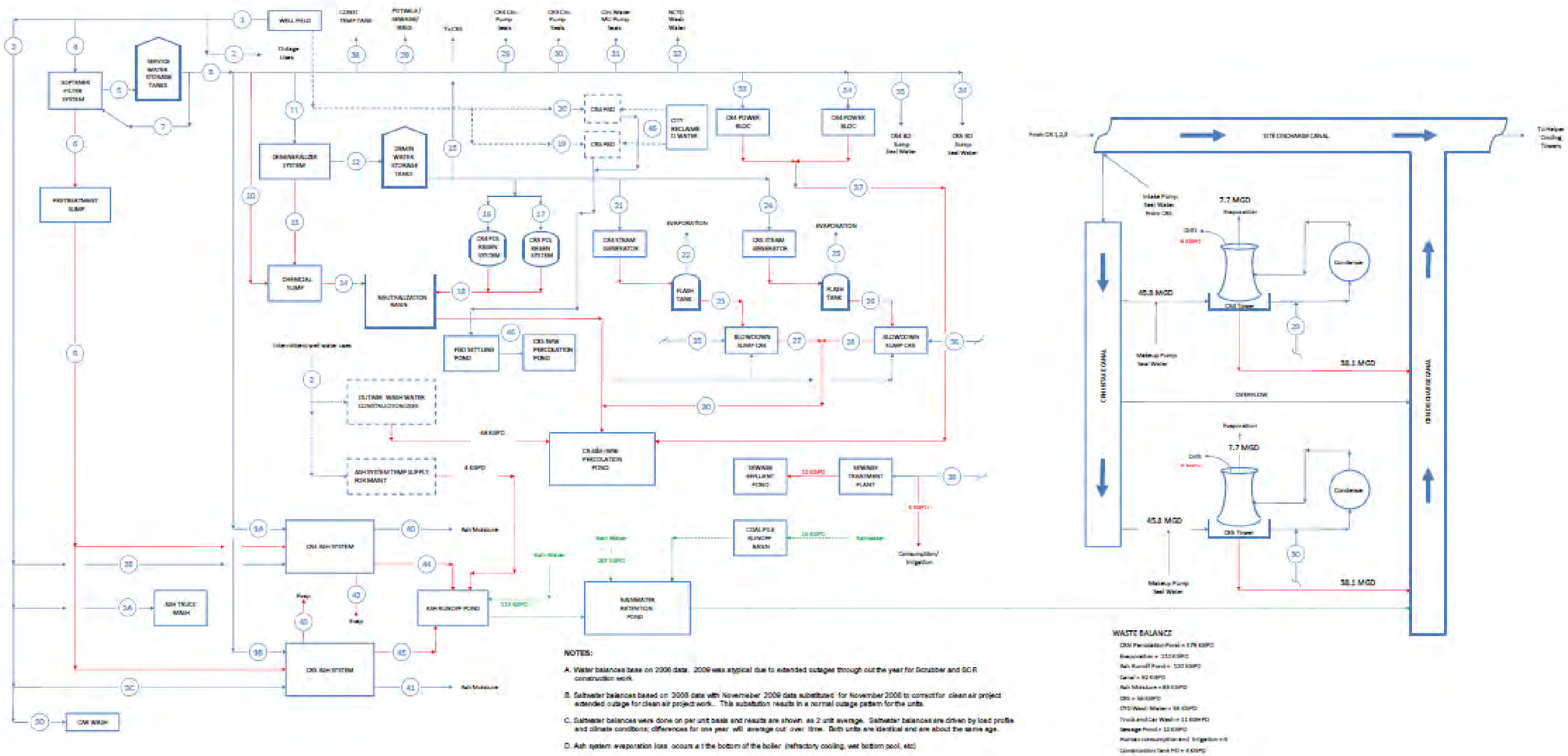
italics followed by critique and commentary:

- ***Task 1 - Bottom Ash Water Balance Review***

An internal water balance was developed on the bottom ash system several years ago and identified water streams and approximate amounts contributing to the bottom ash system. Review of the information on the on bottom ash system water balance will include verifying all streams indicated, data verification, and review of system as pertains to new ELG regulation. Approximately six (6) months are necessary to perform these actions, which provides time if additional information is required for the evaluation.

DEF asserts that an internal water balance must be developed, yet in its January 2016 application for NPDES permit renewal, just months ago, DEF provided a detailed water balance, as reproduced below.

The January 2016 renewal application was required be accurate and complete. Unless DEF failed to meet that requirement, which DEF has not indicated it has, DEF already has developed an accurate and complete water balance and should not need another six months to redevelop such a balance. Any verification needed can be made in a shorter time frame—and in parallel with the tasks described next. Thus, the six months built into the schedule for this task are a significant and unnecessary slack.



CRYSTAL RIVER UNITS 4 AND 5 WATER BALANCE

STREAM NO.	1	2	3	3A	3B	3C	3D	4	5	6	7	8	9A	9B	10	11	12	13
FLOW (KGPD)	1009	52	69	8	11	11	3	824	826	102	102	822	78	78	5	431	376	37
FLOW (GPM)	701	36	29	6	8	8	2	962	962	71	71	571	54	54	3	299	260	26

STREAM NO.	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
FLOW (KGPD)	4	86	15	15	42	1200	1200	145	86	79	145	64	79	82	82	35	35
FLOW (GPM)	3	59	10	10	31	834	834	101	60	55	101	45	55	57	57	25	24

STREAM NO.	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47
FLOW (KGPD)	22	38	4	6	5	5	92	8	14	92	88	39	31	58	58	850	690
FLOW (GPM)	15	26	3	3	3	3	64	6	10	63	60	27	21	40	40	594	480

- ***Task 2 - Review Bottom Ash Modification Options***

After review and finalization of a bottom ash water balance, a review of inputs and outputs will be performed. The review will indicate options available for managing the streams in the process. This could include a review of switching mechanical seals on pumps from wet to dry seals, evaluating rerouting streams to other locations, and system modifications required to meet the ELG regulations. The review of bottom ash modification options will last approximately two (2) months and will entail a review of possible pipe reroutes, potential changes in system operations, and system modifications required for ELG compliance.

- ***Task 3 - Finalize Bottom Ash Modification Options***

Once DEF outlines the modification options, the next step is to determine which modifications and piping reroutes will needed. A three (3) month schedule is proposed for this activity, which includes review of modifications and reroutes from an economical, operational, and environmental standpoint with DEF's management team members with responsibility over these different functional areas. Additional time is included to resolve unexpected questions or missing data that may arise when finalizing the modification options considered in Task 2.

DEF's proposed 5-month duration for Tasks 2 and 3 to review and finalize bottom ash modification options is inexplicably long. So much time may be reasonable for a plant that has never before undertaken such reviews, but that is not the case here. Duke Energy already reported costs to the SEC and its shareholders for such modifications. It would be inconsistent with Duke's SEC and shareholder reporting obligations to report such costs without analytic support. Similar to Task 1, any further confirmation of Duke's options can be done in much less time. More specifically, if such confirmation is done in parallel with Task 1, any competent consultant, in-house engineer, or vendor should be able to complete Tasks 1-3 in no more than 2 to 3 months, including development of a budget estimate, as discussed next.

- ***Task 4 - Budget Approval***

The final modification plan will include appropriate budgetary estimates. In accordance with company fiduciary duties, DEF will conduct an in-depth financial review of these budgetary estimates prior to securing the requested funds. Depending on the budgetary amount required and the number of modifications necessary, several review stages may be required prior to fund approval. The project budget approval time is anticipated to last six (6) months.

DEF has already developed a budget estimate and Duke Energy has publicly reported this estimate since 2014. It is therefore unnecessary to schedule 6 additional months for budget approval. As Duke Energy's filing indicates, its Board has long been aware of the need to spend $50 million for ELG compliance at CREC. Anticipated cost expenditures reported to shareholders are typically based on appropriate engineering and planning studies and analyses, including budgetary quotes obtained from vendors for equipment and labor. This is especially true for publicly traded corporations such as Duke

Energy, which have significant legal obligations in its SEC filings. As a result, it is unreasonable to allow six additional months for internal budget approval.

- ***Task 5 - Detailed Engineering of Modifications***

Once the modifications are selected and the budgetary approval finalized, the project will enter a detailed engineering design phase. This phase will likely include, but not limited to, pump sizing, pipe rerouting, vessel sizing, building additions or modifications, chemical sizing, system sizing, etc. An engineering firm may need to be identified and hired to help facilitate detailed engineering of the required modifications. DEF estimates it will take three (3) months to select an engineering firm with the requisite expertize and then work with the firm to finalize the detailed engineering design.

If DEF were to hire the same engineering firm or consultant to confirm Tasks 1, 2, and 3, Task 5 can be run in parallel with those tasks, saving more time. Alternatively, Duke could save as much if not even more time if DEF were to complete Tasks 1, 2, 3, and 5 with in-house engineering staff and/or Duke's corporate engineering staff.

- ***Task 6 - Implementation of Modifications***

Depending on bottom ash system modifications selected, construction or implementation may or may not be an extensive process. The ideal modifications selected would have minimal capital and operational and maintenance cost associated with them. However, lead times on components and routing of streams to alternative locations may nevertheless prolong the estimated duration, as well as, any unforeseen circumstances such as weather. Some modifications may require a unit outage to complete. Recognizing the current uncertainty associated with implementing plant modifications that have not yet been conceived, DEF conservatively estimates that eighteen (18) months will be required to retain a labor and construction firm to perform the selected modifications from Task 5 and includes time to implement modifications that may require a long term outage.

Depending on the option selected, "implementation may or may not be an extensive process…" Thus, the possibility that this task will take 18 months, is a worst case estimate, with enough contingency already built in. For example, if DEF chooses to not replace the current almost closed loop system with a complete dry system, and instead chooses to engineer and build additional margin so that there is no possibility of any overflow of the bottom ash transport water under any circumstances to receiving waters, then implementation will likely take significantly less time.

- ***Task 7 - Review of Modifications/Contingency***

Approximately six (6) months have been added to the compliance schedule for review of system modifications and/or contingency needed due to unforeseen events that may arise in other tasks. If the dry bottom ash system modifications have unintended or undesirable impacts on other processes or do not obtain satisfactory results, then additional modifications and reviews may be required to resolve.

DEF's proposal of six months of additional contingency, on top of the contingency already built into Task 6, is simply unjustified additional slack in the schedule.

In summary, Tasks 1-5 can be reasonably completed in 6 to 9 months, if not less. Even assuming that Task 6 takes all of 18 months, which is highly unlikely, and allowing for a reasonable contingency of 3 months in Task 7, the overall project duration should be in the range of 27 to 30 months, instead of the 44 months projected by DEF, a saving of 17 months. This would allow compliance to be achieved by roughly August to November 2018. DEP should carefully review the unsupported schedule provided by DEF and, reasonably, require that Units 4 and 5 achieve bottom ash wastewater BAT compliance by no later than November 2018.

8. COMPARISON OF DEF'S COMPLIANCE SCHEDULE WITH THAT OF OTHER LARGE PROJECTS

DEF's 44-month schedule to achieve compliance with the bottom ash wastewater BAT provisions of the ELGs is simply unsupported. In part, this is due to DEF's unjustified and long projected timelines for certain tasks, particularly given the strong evidence of DEF and Duke's prior planning for compliance with these provisions, which began as far back as mid-2012.

Additionally, in comparison to other major projects at coal-fired units, the 44-month schedule proposed by DEF for bottom ash ELG BAT compliance is simply unreasonable and too long. Here, comparisons are made using the expected timelines for implementing complex,air pollution control projects at coal-fired boilers. These include the installation of wet or dry flue gas desulfurization ("FGD") or scrubbers for SO_2 control and the installation of Selective Catalytic Reduction ("SCR") for NOx control. These projects, for units of similar size to CREC Units 4 and 5, often cost hundreds of million dollars. Yet, while often complex and challenging to implement, timelines for such projects are in the range of 3 to 5 years—starting from conceptual engineering through completion during scheduled outages.

Three example timelines are shown below—for dry FGD, wet FGD, and SCR projects, respectively—as developed by a contractor for MISO, the independent system operator for the U.S..[30] These timelines are generally conservative– i.e., the timelines shown are generally high, reflecting the most complex installations, with typical projects capable of implementation in less time. Nonetheless, as the charts below show, the expected durations for implementing dry FGD or SCR are around 46 months and the same for wet FGD is around 56 months.

Given the far greater complexity associated with these projects, DEF's assertion is untenable that the relatively much simpler conversion of Unit 4 and Unit 5's wet sluicing bottom ash system to a dry system will take 44 months. If DEF decides to achieve compliance without

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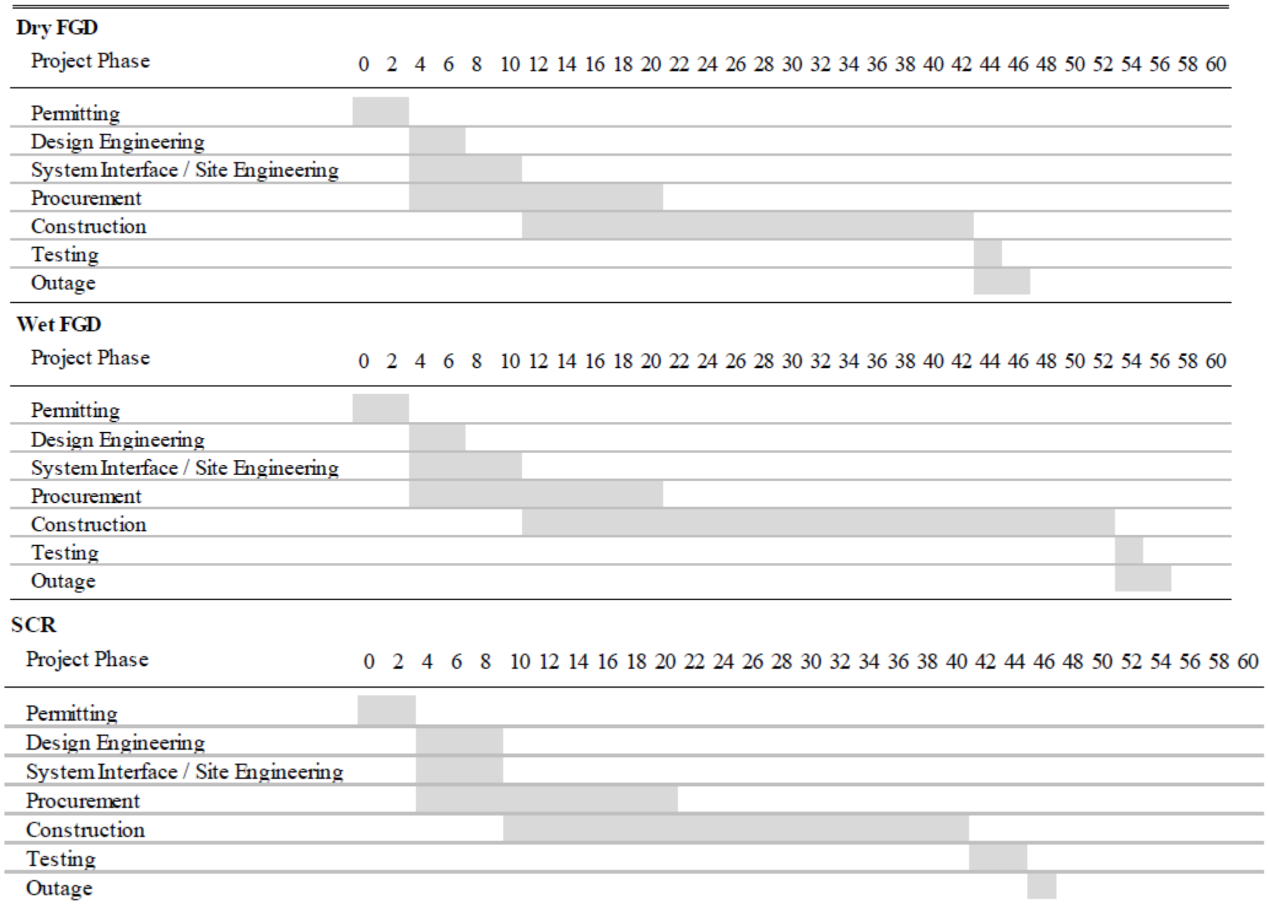
[30] The Brattle Group, *Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS*, Appendix A (May 2012) (available at http://www.brattle.com/news-and-knowledge/news/brattle-economists-identify-challenges-for-miso-s-coal-fleet-to-comply-with-epa-s-mats-rule).

switching to a dry system, implementation times will be even shorter.

Typical Timelines for Dry FGD, Wet FGD, DSI and ACI Retrofit Projects



9. CONCLUSIONS

DEF does not need till February 1, 2020 to achieve compliance with a zero discharge standard for bottom ash wastewater at CREC Units 4 and 5. Rather, compliance can be achieved by November 2018, if not sooner.

Construction for bottom ash retrofits at Units 4 and 5 is anticipated to take, with a built in contingency, only 18 months. Other proposed tasks for acheving compliance should take signficiantly less time than DEF forecasts, particularly as DEF began anticipating and planning for the revised ELGs as far back as 2012. Beginning in 2014, Duke Energy began publicly reporting projected compliance costs, suggesting that conceptual or detailed engineering evaluations and studies were undertaken and that Duke Energy's Board has been aware of these changes and costs for some time.

DEF's 44-month schedule to achieve compliance with the bottom ash BAT standard is simply unsupported. Comparisons to similar retrofits and other large-scale, more complex projects at coal-burning units show far shorter timelines and demonstrate that DEF's proposed schedule is inflated. Moreover, as DEF is aware, there is a robust vendor community with experience in handling the types of retrofits needed to achieve compliance.

The available evidence does not support a 44-month timeline for eliminating bottom ash wastewtater discharges at CREC Units 4 and 5. In renewing the NPDES permit for CREC Units 4 and 5, DEP should require DEF to achieve compliance with the bottom ash wastewater ELGs no later than November 2018.

10. AUTHOR'S EXPERTISE AND QUALIFICATIONS

Dr. Ranajit Sahu has over twenty-five years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment for a wide range of emissions sources; soils and groundwater remediation including landfills as remedy; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

Over the last twenty-three years, Dr. Sahu has consulted on several municipal landfill related projects addressing landfill gas generation, landfill gas collection, and the treatment/disposal/control of such gases in combustion equipment such as engines, turbines, and flares. In particular, Dr. Sahu has executed numerous projects relating to flare emissions from sources such as landfills as well as refineries and chemical plants. He has served as a peer-reviewer for EPA in relation to flare combustion efficiency, flare destruction efficiency, and flaring emissions.

A significant portion of Dr. Sahu's educational background and consulting experience deals with addressing environmental impacts due to coal-fired power plants including all aspects of air emissions from such plants but also environmental impacts from water/waste water, cooling water, and solid/hazardous wastes at such plants and impacts due to coal mining, transportation, and stockpiling.

Dr. Sahu holds a B.S., M.S., and Ph.D., in Mechanical Engineering, the first from the Indian Institute of Technology (Kharagpur, India) and the latter two from the California Institute of Technology (Caltech) in Pasadena, California. His research specialization was in the combustion of coal and, among other things, understanding air pollution aspects of coal combustion in power plants as well as the formation of ash during combustion.

The opinions expressed in the report are Dr. Sahu's and are based on the data and facts available at the time of writing. Should additional relevant or pertinent information become available, Dr. Sahu reservesthe right to supplement the discussion and findings.

ATTACHMENT A - RESUME

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EXPERIENCE SUMMARY

Dr. Sahu has over twenty five years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment for a wide range of emissions sources; soils and groundwater remediation including landfills as remedy; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

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He has over twenty-three years of project management experience and has successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public. Notably, he has successfully managed a complex soils and groundwater remediation project with a value of over $140 million involving soils characterization, development and implementation of the remediation strategy including construction of a CAMU/landfill and associated groundwater monitoring, regulatory and public interactions and other challenges.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past twenty three years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including EPA, the US Dept. of Justice, California DTSC, various municipalities, etc.). Dr. Sahu has performed projects in over 44 states, numerous local jurisdictions and internationally.

In addition to consulting, Dr. Sahu has taught numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past seventeen years. In this time period he has also taught at Caltech, his alma mater (various engineering courses), at the University of Southern California (air pollution controls) and at California State University, Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies.

EXPERIENCE RECORD

2000-present **Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.) public sector (such as the US Department of Justice) and public interest group clients with project management, air quality consulting, waste remediation and management consulting, as well as regulatory and engineering support consulting services.

1995-2000 Parsons ES, **Associate, Senior Project Manager and Department Manager for** Air Quality/Geosciences/Hazardous Waste Groups, Pasadena. Responsible for the management of a group of approximately 24 air quality and environmental professionals, 15 geoscience, and 10 hazardous waste professionals providing full-service consulting, project management, regulatory compliance and A/E design assistance in all areas.

Parsons ES, **Manager for Air Source Testing Services**. Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.

1992-1995 Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department. Responsibilities included multimedia regulatory compliance and permitting (including hazardous and nuclear materials), air pollution engineering (emissions from stationary and mobile sources, control of criteria and air toxics, dispersion modeling, risk assessment, visibility analysis, odor analysis), supervisory functions and project management.

1990-1992 Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department. Responsibilities included permitting, tracking regulatory issues, technical analysis, and supervisory functions on numerous air, water, and hazardous waste projects. Responsibilities also include client and agency interfacing, project cost and schedule control, and reporting to internal and external upper management regarding project status.

1989-1990 Kinetics Technology International, Corp. **Development Engineer.** Involved in thermal engineering R&D and project work related to low-NOx ceramic radiant burners, fired heater NOx reduction, SCR design, and fired heater retrofitting.

1988-1989 Heat Transfer Research, Inc. **Research Engineer**. Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

EDUCATION

1984-1988 Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.

1984 M. S., Mechanical Engineering, Caltech, Pasadena, CA.

1978-1983 B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

TEACHING EXPERIENCE

Caltech

"Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.

"Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.

"Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.

"Heat Transfer," - taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.

“Thermodynamics and Heat Transfer,” Fall and Winter Terms of 1996-1997.

U.C. Riverside, Extension

"Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.

"Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.

"Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.

"Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.

"Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992-2010.

"Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.

"Advanced Hazard Analysis - A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.

“Advanced Hazardous Waste Management” University of California Extension Program, Riverside, California. 2005.

Loyola Marymount University

"Fundamentals of Air Pollution - Regulations, Controls and Engineering," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1993.

"Air Pollution Control," Loyola Marymount University, Dept. of Civil Engineering, Fall 1994.

“Environmental Risk Assessment,” Loyola Marymount University, Dept. of Civil Engineering. Various years since 1998.

“Hazardous Waste Remediation” Loyola Marymount University, Dept. of Civil Engineering. Various years since 2006.

University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

International Programs

"Environmental Planning and Management," 5 week program for visiting Chinese delegation, 1994.

"Environmental Planning and Management," 1 day program for visiting Russian delegation, 1995.

"Air Pollution Planning and Management," IEP, UCR, Spring 1996.

"Environmental Issues and Air Pollution," IEP, UCR, October 1996.

PROFESSIONAL AFFILIATIONS AND HONORS

President of India Gold Medal, IIT Kharagpur, India, 1983.

Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992-present.

American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-present.

Air and Waste Management Association, West Coast Section, 1989-present.

PROFESSIONAL CERTIFICATIONS

EIT, California (# XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, since 2000.

CEM, State of Nevada (#EM-1699). Expiration 10/07/2017.

ATTACHMENT B – LIST OF PUBLICATIONS AND PRESENTATIONS

PUBLICATIONS (PARTIAL LIST)

"Physical Properties and Oxidation Rates of Chars from Bituminous Coals," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **67**, 275-283 (1988).

"Char Combustion: Measurement and Analysis of Particle Temperature Histories," with R.C. Flagan, G.R. Gavalas and P.S. Northrop, *Comb. Sci. Tech.* **60**, 215-230 (1988).

"On the Combustion of Bituminous Coal Chars," PhD Thesis, California Institute of Technology (1988).

"Optical Pyrometry: A Powerful Tool for Coal Combustion Diagnostics," *J. Coal Quality*, **8**, 17-22 (1989).

"Post-Ignition Transients in the Combustion of Single Char Particles," with Y.A. Levendis, R.C.Flagan and G.R. Gavalas, *Fuel*, **68**, 849-855 (1989).

"A Model for Single Particle Combustion of Bituminous Coal Char." Proc. ASME National Heat Transfer Conference, Philadelphia, **HTD-Vol. 106**, 505-513 (1989).

"Discrete Simulation of Cenospheric Coal-Char Combustion," with R.C. Flagan and G.R.Gavalas, *Combust. Flame*, **77**, 337-346 (1989).

"Particle Measurements in Coal Combustion," with R.C. Flagan, in "**Combustion Measurements**" (ed. N. Chigier), Hemisphere Publishing Corp. (1991).

"Cross Linking in Pore Structures and Its Effect on Reactivity," with G.R. Gavalas in preparation.

"Natural Frequencies and Mode Shapes of Straight Tubes," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Optimal Tube Layouts for Kamui SL-Series Exchangers," with K. Ishihara, Proprietary Report for Kamui Company Limited, Tokyo, Japan (1990).

"HTRI Process Heater Conceptual Design," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Asymptotic Theory of Transonic Wind Tunnel Wall Interference," with N.D. Malmuth and others, Arnold Engineering Development Center, Air Force Systems Command, USAF (1990).

"Gas Radiation in a Fired Heater Convection Section," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1990).

"Heat Transfer and Pressure Drop in NTIW Heat Exchangers," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1991).

"NOx Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

"From Puchase of Landmark Environmental Insurance to Remediation: Case Study in Henderson, Nevada," with Robin E. Bain and Jill Quillin, presented at the AQMA Annual Meeting, Florida, 2001.

"The Jones Act Contribution to Global Warming, Acid Rain and Toxic Air Contaminants," with Charles W. Botsford, presented at the AQMA Annual Meeting, Florida, 2001.

PRESENTATIONS (PARTIAL LIST)

"Pore Structure and Combustion Kinetics - Interpretation of Single Particle Temperature-Time Histories," with P.S. Northrop, R.C. Flagan and G.R. Gavalas, presented at the AIChE Annual Meeting, New York (1987).

"Measurement of Temperature-Time Histories of Burning Single Coal Char Particles," with R.C. Flagan, presented at the American Flame Research Committee Fall International Symposium, Pittsburgh, (1988).

"Physical Characterization of a Cenospheric Coal Char Burned at High Temperatures," with R.C. Flagan and G.R. Gavalas, presented at the Fall Meeting of the Western States Section of the Combustion Institute, Laguna Beach, California (1988).

"Control of Nitrogen Oxide Emissions in Gas Fired Heaters - The Retrofit Experience," with G. P. Croce and R. Patel, presented at the International Conference on Environmental Control of Combustion Processes (Jointly sponsored by the American Flame Research Committee and the Japan Flame Research Committee), Honolulu, Hawaii (1991).

"Air Toxics - Past, Present and the Future," presented at the Joint AIChE/AAEE Breakfast Meeting at the AIChE 1991 Annual Meeting, Los Angeles, California, November 17-22 (1991).

"Air Toxics Emissions and Risk Impacts from Automobiles Using Reformulated Gasolines," presented at the Third Annual Current Issues in Air Toxics Conference, Sacramento, California, November 9-10 (1992).

"Air Toxics from Mobile Sources," presented at the Environmental Health Sciences (ESE) Seminar Series, UCLA, Los Angeles, California, November 12, (1992).

"Kilns, Ovens, and Dryers - Present and Future," presented at the Gas Company Air Quality Permit Assistance Seminar, Industry Hills Sheraton, California, November 20, (1992).

"The Design and Implementation of Vehicle Scrapping Programs," presented at the 86th Annual Meeting of the Air and Waste Management Association, Denver, Colorado, June 12, 1993.

"Air Quality Planning and Control in Beijing, China," presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, Ohio, June 19-24, 1994.

ATTACHMENT C – PREVIOUS EXPERT WITNESS TESTIMONY

1. Occasions where Dr. Sahu has provided Written or Oral testimony before Congress:

(a) In July 2012, provided expert written and oral testimony to the House Subcommittee on Energy and the Environment, Committee on Science, Space, and Technology at a Hearing entitled "Hitting the Ethanol Blend Wall – Examining the Science on E15."

2. Matters for which Dr. Sahu has provided affidavits and expert reports include:

(b) Affidavit for Rocky Mountain Steel Mills, Inc. located in Pueblo Colorado – dealing with the technical uncertainties associated with night-time opacity measurements in general and at this steel mini-mill.

(c) Expert reports and depositions (2/28/2002 and 3/1/2002; 12/2/2003 and 12/3/2003; 5/24/2004) on behalf of the United States in connection with the Ohio Edison NSR Cases. *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (Southern District of Ohio).

(d) Expert reports and depositions (5/23/2002 and 5/24/2002) on behalf of the United States in connection with the Illinois Power NSR Case. *United States v. Illinois Power Co., et al.*, 99-833-MJR (Southern District of Illinois).

(e) Expert reports and depositions (11/25/2002 and 11/26/2002) on behalf of the United States in connection with the Duke Power NSR Case. *United States, et al. v. Duke Energy Corp.*, 1:00-CV-1262 (Middle District of North Carolina).

(f) Expert reports and depositions (10/6/2004 and 10/7/2004; 7/10/2006) on behalf of the United States in connection with the American Electric Power NSR Cases. *United States, et al. v. American Electric Power Service Corp., et al.*, C2-99-1182, C2-99-1250 (Southern District of Ohio).

(g) Affidavit (March 2005) on behalf of the Minnesota Center for Environmental Advocacy and others in the matter of the Application of Heron Lake BioEnergy LLC to construct and operate an ethanol production facility – submitted to the Minnesota Pollution Control Agency.

(h) Expert Report and Deposition (10/31/2005 and 11/1/2005) on behalf of the United States in connection with the East Kentucky Power Cooperative NSR Case. *United States v. East Kentucky Power Cooperative, Inc.*, 5:04-cv-00034-KSF (Eastern District of Kentucky).

(i) Affidavits and deposition on behalf of Basic Management Inc. (BMI) Companies in connection with the BMI vs. USA remediation cost recovery Case.

(j) Expert Report on behalf of Penn Future and others in the Cambria Coke plant permit challenge in Pennsylvania.

(k) Expert Report on behalf of the Appalachian Center for the Economy and the Environment and others in the Western Greenbrier permit challenge in West Virginia.

(l) Expert Report, deposition (via telephone on January 26, 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) in the Thompson River Cogeneration LLC Permit No. 3175-04 challenge.

(m) Expert Report and deposition (2/2/07) on behalf of the Texas Clean Air Cities Coalition at the Texas State Office of Administrative Hearings (SOAH) in the matter of the permit challenges to TXU Project Apollo's eight new proposed PRB-fired PC boilers located at seven TX sites.

(n) Expert Testimony (July 2007) on behalf of the Izaak Walton League of America and others in connection with the acquisition of power by Xcel Energy from the proposed Gascoyne Power Plant – at the State of Minnesota, Office of Administrative Hearings for the Minnesota PUC (MPUC No. E002/CN-06-1518; OAH No. 12-2500-17857-2).

(o) Affidavit (July 2007) Comments on the Big Cajun I Draft Permit on behalf of the Sierra Club – submitted to the Louisiana DEQ.

(p) Expert Report and Deposition (12/13/2007) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (Western District of Pennsylvania).

(q) Expert Reports and Pre-filed Testimony before the Utah Air Quality Board on behalf of Sierra Club in the Sevier Power Plant permit challenge.

(r) Expert Report and Deposition (October 2007) on behalf of MTD Products Inc., in connection with *General Power Products, LLC v MTD Products Inc*., 1:06 CVA 0143 (Southern District of Ohio, Western Division) .

(s) Expert Report and Deposition (June 2008) on behalf of Sierra Club and others in the matter of permit challenges (Title V: 28.0801-29 and PSD: 28.0803-PSD) for the Big Stone II unit, proposed to be located near Milbank, South Dakota.

(t) Expert Reports, Affidavit, and Deposition (August 15, 2008) on behalf of Earthjustice in the matter of air permit challenge (CT-4631) for the Basin Electric Dry Fork station, under construction near Gillette, Wyoming before the Environmental Quality Council of the State of Wyoming.

(u) Affidavits (May 2010/June 2010 in the Office of Administrative Hearings))/Declaration and Expert Report (November 2009 in the Office of Administrative Hearings) on behalf of NRDC and the Southern Environmental Law Center in the matter of the air permit challenge for Duke

Cliffside Unit 6. Office of Administrative Hearing Matters 08 EHR 0771, 0835 and 0836 and 09 HER 3102, 3174, and 3176 (consolidated).

(v) Declaration (August 2008), Expert Report (January 2009), and Declaration (May 2009) on behalf of Southern Alliance for Clean Energy in the matter of the air permit challenge for Duke Cliffside Unit 6. *Southern Alliance for Clean Energy et al., v. Duke Energy Carolinas, LLC*, Case No. 1:08-cv-00318-LHT-DLH (Western District of North Carolina, Asheville Division).

(w) Declaration (August 2008) on behalf of the Sierra Club in the matter of Dominion Wise County plant MACT.us

(x) Expert Report (June 2008) on behalf of Sierra Club for the Green Energy Resource Recovery Project, MACT Analysis.

(y) Expert Report (February 2009) on behalf of Sierra Club and the Environmental Integrity Project in the matter of the air permit challenge for NRG Limestone's proposed Unit 3 in Texas.

(z) Expert Report (June 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al.*

(aa) Expert Report (August 2009) on behalf of Sierra Club and the Southern Environmental Law Center in the matter of the air permit challenge for Santee Cooper's proposed Pee Dee plant in South Carolina).

(bb) Statements (May 2008 and September 2009) on behalf of the Minnesota Center for Environmental Advocacy to the Minnesota Pollution Control Agency in the matter of the Minnesota Haze State Implementation Plans.

(cc) Expert Report (August 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(dd) Expert Report and Rebuttal Report (September 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

(ee) Expert Report (December 2009) and Rebuttal reports (May 2010 and June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

(ff) Pre-filed Testimony (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(gg) Pre-filed Testimony (July 2010) and Written Rebuttal Testimony (August 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(hh) Expert Report (August 2010) and Rebuttal Expert Report (October 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana) – Liability Phase.

(ii) Declaration (August 2010), Reply Declaration (November 2010), Expert Report (April 2011), Supplemental and Rebuttal Expert Report (July 2011) on behalf of the United States in the matter of DTE Energy Company and Detroit Edison Company (Monroe Unit 2). *United States of America v. DTE Energy Company and Detroit Edison Company*, Civil Action No. 2:10-cv-13101-BAF-RSW (Eastern District of Michigan).

(jj) Expert Report and Deposition (August 2010) as well as Affidavit (September 2010) on behalf of Kentucky Waterways Alliance, Sierra Club, and Valley Watch in the matter of challenges to the NPDES permit issued for the Trimble County power plant by the Kentucky Energy and Environment Cabinet to Louisville Gas and Electric, File No. DOW-41106-047.

(kk) Expert Report (August 2010), Rebuttal Expert Report (September 2010), Supplemental Expert Report (September 2011), and Declaration (November 2011) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (District of Colorado).

(ll) Written Direct Expert Testimony (August 2010) and Affidavit (February 2012) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(mm) Deposition (August 2010) on behalf of Environmental Defense, in the matter of the remanded permit challenge to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(nn) Expert Report, Supplemental/Rebuttal Expert Report, and Declarations (October 2010, November 2010, September 2012) on behalf of New Mexico Environment Department (Plaintiff-Intervenor), Grand Canyon Trust and Sierra Club (Plaintiffs) in the matter of *Plaintiffs v. Public Service Company of New Mexico* (PNM), Civil No. 1:02-CV-0552 BB/ATC (ACE) (District of New Mexico).

(oo) Expert Report (October 2010) and Rebuttal Expert Report (November 2010) (BART Determinations for PSCo Hayden and CSU Martin Drake units) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(pp) Expert Report (November 2010) (BART Determinations for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(qq) Declaration (November 2010) on behalf of the Sierra Club in connection with the Martin Lake Station Units 1, 2, and 3. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Case No. 5:10-cv-00156-DF-CMC (Eastern District of Texas, Texarkana Division).

(rr) Pre-Filed Testimony (January 2011) and Declaration (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

(ss) Declaration (February 2011) in the matter of the Draft Title V Permit for RRI Energy MidAtlantic Power Holdings LLC Shawville Generating Station (Pennsylvania), ID No. 17-00001 on behalf of the Sierra Club.

(tt) Expert Report (March 2011), Rebuttal Expert Report (June 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (District of Colorado).

(uu) Declaration (April 2011) and Expert Report (July 16, 2012) in the matter of the Lower Colorado River Authority (LCRA)'s Fayette (Sam Seymour) Power Plant on behalf of the Texas Campaign for the Environment. *Texas Campaign for the Environment v. Lower Colorado River Authority,* Civil Action No. 4:11-cv-00791 (Southern District of Texas, Houston Division).

(vv) Declaration (June 2011) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.

(ww) Expert Report (June 2011) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).

(xx) Declaration (August 2011) in the matter of the Sandy Creek Energy Associates L.P. Sandy Creek Power Plant on behalf of Sierra Club and Public Citizen. *Sierra Club, Inc. and Public Citizen, Inc. v. Sandy Creek Energy Associates, L.P.,* Civil Action No. A-08-CA-648-LY (Western District of Texas, Austin Division).

(yy) Expert Report (October 2011) on behalf of the Defendants in the matter of *John Quiles and Jeanette Quiles et al. v. Bradford-White Corporation, MTD Products, Inc., Kohler Co., et al.,* Case No. 3:10-cv-747 (TJM/DEP) (Northern District of New York).

(zz) Declaration (February 2012) and Second Declaration (February 2012) in the matter of *Washington Environmental Council and Sierra Club Washington State Chapter v. Washington State Department of Ecology and Western States Petroleum Association,* Case No. 11-417-MJP (Western District of Washington).

(aaa) Expert Report (March 2012) and Supplemental Expert Report (November 2013) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.,* Civil Action No. 4:10-cv-4969 (Southern District of Texas, Houston Division).

(bbb) Declaration (March 2012) in the matter of *Center for Biological Diversity, et al. v. United States Environmental Protection Agency,* Case No. 11-1101 (consolidated with 11-1285, 11-1328 and 11-1336) (US Court of Appeals for the District of Columbia Circuit).

(ccc) Declaration (March 2012) in the matter of *Sierra Club v. The Kansas Department of Health and Environment*, Case No. 11-105,493-AS (Holcomb power plant) (Supreme Court of the State of Kansas).

(ddd) Declaration (March 2012) in the matter of the Las Brisas Energy Center *Environmental Defense Fund et al., v. Texas Commission on Environmental Quality,* Cause No. D-1-GN-11-001364 (District Court of Travis County, Texas, 261st Judicial District).

(eee) Expert Report (April 2012), Supplemental and Rebuttal Expert Report (July 2012), and Supplemental Rebuttal Expert Report (August 2012) on behalf of the states of New Jersey and Connecticut in the matter of the Portland Power plant *State of New Jersey and State of Connecticut (Intervenor-Plaintiff) v. RRI Energy Mid-Atlantic Power Holdings et al.,* Civil Action No. 07-CV-5298 (JKG) (Eastern District of Pennsylvania).

(fff) Declaration (April 2012) in the matter of the EPA's EGU MATS Rule, on behalf of the Environmental Integrity Project.

(ggg) Expert Report (August 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana) – Harm Phase.

(hhh) Declaration (September 2012) in the Matter of the Application of *Energy Answers Incinerator, Inc.* for a Certificate of Public Convenience and Necessity to Construct a 120 MW Generating Facility in Baltimore City, Maryland, before the Public Service Commission of Maryland, Case No. 9199.

(iii) Expert Report (October 2012) on behalf of the Appellants (Robert Concilus and Leah Humes) in the matter of Robert Concilus and Leah Humes v. Commonwealth of Pennsylvania Department of Environmental Protection and Crawford Renewable Energy, before the Commonwealth of Pennsylvania Environmental Hearing Board, Docket No. 2011-167-R.

(jjj) Expert Report (October 2012), Supplemental Expert Report (January 2013), and Affidavit (June 2013) in the matter of various Environmental Petitioners v. North Carolina

DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.

(kkk) Pre-filed Testimony (October 2012) on behalf of No-Sag in the matter of the North Springfield Sustainable Energy Project before the State of Vermont, Public Service Board.

(lll) Pre-filed Testimony (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.

(mmm) Expert Report (February 2013) on behalf of Petitioners in the matter of Credence Crematory, Cause No. 12-A-J-4538 before the Indiana Office of Environmental Adjudication.

(nnn) Expert Report (April 2013), Rebuttal report (July 2013), and Declarations (October 2013, November 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

(ooo) Declaration (April 2013) on behalf of Petitioners in the matter of *Sierra Club, et al., (Petitioners) v Environmental Protection Agency et al. (Resppondents),* Case No., 13-1112, (Court of Appeals, District of Columbia Circuit).

(ppp) Expert Report (May 2013) and Rebuttal Expert Report (July 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).

(qqq) Declaration (August 2013) on behalf of A. J. Acosta Company, Inc., in the matter of *A. J. Acosta Company, Inc., v. County of San Bernardino*, Case No. CIVSS803651.

(rrr) Comments (October 2013) on behalf of the Washington Environmental Council and the Sierra Club in the matter of the Washington State Oil Refinery RACT (for Greenhouse Gases), submitted to the Washington State Department of Ecology, the Northwest Clean Air Agency, and the Puget Sound Clean Air Agency.

(sss) Statement (November 2013) on behalf of various Environmental Organizations in the matter of the Boswell Energy Center (BEC) Unit 4 Environmental Retrofit Project, to the Minnesota Public Utilities Commission, Docket No. E-015/M-12-920.

(ttt) Expert Report (December 2013) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

(uuu) Expert Testimony (December 2013) on behalf of the Sierra Club in the matter of Public Service Company of New Hampshire Merrimack Station Scrubber Project and Cost Recovery, Docket No. DE 11-250, to the State of New Hampshire Public Utilities Commission.

(vvv) Expert Report (January 2014) on behalf of Baja, Inc., in *Baja, Inc., v. Automotive Testing and Development Services, Inc. et. al*, Civil Action No. 8:13-CV-02057-GRA (District of South Carolina, Anderson/Greenwood Division).

(www) Declaration (March 2014) on behalf of the Center for International Environmental Law, Chesapeake Climate Action Network, Friends of the Earth, Pacific Environment, and the Sierra Club (Plaintiffs) in the matter of *Plaintiffs v. the Export-Import Bank (Ex-Im Bank) of the United States*, Civil Action No. 13-1820 RC (District Court for the District of Columbia).

(xxx) Declaration (April 2014) on behalf of Respondent-Intervenors in the matter of *Mexichem Specialty Resins Inc., et al., (Petitioners) v Environmental Protection Agency et al.,* Case No., 12-1260 (and Consolidated Case Nos. 12-1263, 12-1265, 12-1266, and 12-1267), (Court of Appeals, District of Columbia Circuit).

(yyy) Direct Prefiled Testimony (June 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17319 (Michigan Public Service Commission).

(zzz) Expert Report (June 2014) on behalf of ECM Biofilms in the matter of the US Federal Trade Commission (FTC) v. ECM Biofilms (FTC Docket #9358).

(aaaa) Direct Prefiled Testimony (August 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of Consumers Energy Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17317 (Michigan Public Service Commission).

(bbbb) Declaration (July 2014) on behalf of Public Health Intervenors in the matter of *EME Homer City Generation v. US EPA* (Case No. 11-1302 and consolidated cases) relating to the lifting of the stay entered by the Court on December 30, 2011 (US Court of Appeals for the District of Columbia).

(cccc) Expert Report (September 2014), Rebuttal Expert Report (December 2014) and Supplemental Expert Report (March 2015) on behalf of Plaintiffs in the matter of *Sierra Club and Montana Environmental Information Center (Plaintiffs) v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and Pacificorp (Defendants)*, Civil Action No. CV 13-32-BLG-DLC-JCL (US District Court for the District of Montana, Billings Division).

(dddd) Expert Report (November 2014) on behalf of Niagara County, the Town of Lewiston, and the Villages of Lewiston and Youngstown in the matter of CWM Chemical Services, LLC New

York State Department of Environmental Conservation (NYSDEC) Permit Application Nos.: 9-2934-00022/00225, 9-2934-00022/00231, 9-2934-00022/00232, and 9-2934-00022/00249 (pending).

(eeee) Pre-filed Direct Testimony (March 2015) and Rebuttal Testimony (August 2015) on behalf of Friends of the Columbia Gorge in the matter of the Application for a Site Certificate for the Troutdale Energy Center before the Oregon Energy Facility Siting Council.

(ffff) Expert Report (March 2015) on behalf of Plaintiffs in the matter of *Conservation Law Foundation v. Broadrock Gas Services LLC, Rhode Island LFG GENCO LLC, and Rhode Island Resource Recovery Corporation (Defendants)*, Civil Action No. 1:13-cv-00777-M-PAS (US District Court for the District of Rhode Island).

(gggg) Direct Prefiled Testimony (May 2015) on behalf of the Michigan Environmental Council, the Natural Resources Defense Council, and the Sierra Club in the matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy and for Miscellaneous Accounting Authority, Case No. U-17767 (Michigan Public Service Commission).

(hhhh) Expert Report (July 2015) and Rebuttal Expert Report (July 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).

(iiii) Declaration (August 2015, Docket No. 1570376) in support of "Opposition of Respondent-Intervenors American Lung Association, et. al., to Tri-State Generation's Emergency Motion;" Declaration (September 2015, Docket No. 1574820) in support of "Joint Motion of the state, Local Government, and Public Health Respondent-Intervenors for Remand Without Vacatur," *White Stallion Energy Center, LLC v. US EPA*, Case No. 12-1100 (US Court of Appeals for the District of Columbia).

(jjjj) Expert Report (November 2015) on behalf of Appellants in the matter of *Sierra Club, et al. v. Craig W. Butler, Director of Ohio Environmental Protection Agency ey al.,* ERAC Case No. 14-256814.

3. Occasions where Dr. Sahu has provided oral testimony <u>in depositions, at trial or in similar proceedings</u> include the following:

(kkkk) Deposition on behalf of Rocky Mountain Steel Mills, Inc. located in Pueblo, Colorado – dealing with the manufacture of steel in mini-mills including methods of air pollution control and BACT in steel mini-mills and opacity issues at this steel mini-mill.

(llll) Trial Testimony (February 2002) on behalf of Rocky Mountain Steel Mills, Inc. in Denver District Court.

(mmmm) Trial Testimony (February 2003) on behalf of the United States in the Ohio Edison NSR Cases, *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (Southern District of Ohio).

(nnnn) Trial Testimony (June 2003) on behalf of the United States in the Illinois Power NSR Case, *United States v. Illinois Power Co., et al.*, 99-833-MJR (Southern District of Illinois).

(oooo) Deposition (10/20/2005) on behalf of the United States in connection with the Cinergy NSR Case. *United States, et* al. *v. Cinergy Corp., et al.*, IP 99-1693-C-M/S (Southern District of Indiana).

(pppp) Oral Testimony (August 2006) on behalf of the Appalachian Center for the Economy and the Environment re. the Western Greenbrier plant, WV before the West Virginia DEP.

(qqqq) Oral Testimony (May 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) re. the Thompson River Cogeneration plant before the Montana Board of Environmental Review.

(rrrr) Oral Testimony (October 2007) on behalf of the Sierra Club re. the Sevier Power Plant before the Utah Air Quality Board.

(ssss) Oral Testimony (August 2008) on behalf of the Sierra Club and Clean Water re. Big Stone Unit II before the South Dakota Board of Minerals and the Environment.

(tttt) Oral Testimony (February 2009) on behalf of the Sierra Club and the Southern Environmental Law Center re. Santee Cooper Pee Dee units before the South Carolina Board of Health and Environmental Control.

(uuuu) Oral Testimony (February 2009) on behalf of the Sierra Club and the Environmental Integrity Project re. NRG Limestone Unit 3 before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(vvvv) Deposition (July 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al.*

(wwww) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Coleto Creek coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(xxxx) Deposition (October 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(yyyy) Deposition (October 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

(zzzz) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Tenaska coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (April 2010).

(aaaaa) Oral Testimony (November 2009) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(bbbbb) Deposition (December 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(ccccc) Oral Testimony (February 2010) on behalf of the Environmental Defense Fund re. the White Stallion Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(ddddd) Deposition (June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

(eeeee) Trial Testimony (September 2010) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, State of Maryland, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case in US District Court in the Western District of Pennsylvania. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (Western District of Pennsylvania).

(fffff) Oral Direct and Rebuttal Testimony (September 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(ggggg) Oral Testimony (September 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(hhhhh) Oral Testimony (October 2010) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(iiiii) Oral Testimony (November 2010) regarding BART for PSCo Hayden, CSU Martin Drake units before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(jjjjj) Oral Testimony (December 2010) regarding BART for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(kkkkk) Deposition (December 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(lllll) Deposition (February 2011 and January 2012) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(mmmmm) Oral Testimony (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

(nnnnn) Deposition (August 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (District of Colorado).

(ooooo) Deposition (July 2011) and Oral Testimony at Hearing (February 2012) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.

(ppppp) Oral Testimony at Hearing (March 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(qqqqq) Oral Testimony at Hearing (April 2012) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).

(rrrrr) Oral Testimony at Hearing (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.

(sssss) Deposition (March 2013) in the matter of various Environmental Petitioners v. North Carolina DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.

(ttttt) Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

(uuuuu) Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).

(vvvvv) Deposition (February 2014) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

(wwwww) Trial Testimony (February 2014) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.,* Civil Action No. 4:10-cv-4969 (Southern District of Texas, Houston Division).

(xxxxx) Trial Testimony (February 2014) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

(yyyyy) Deposition (June 2014) and Trial (August 2014) on behalf of ECM Biofilms in the matter of the *US Federal Trade Commission (FTC) v. ECM Biofilms* (FTC Docket #9358).

(zzzzz) Deposition (February 2015) on behalf of Plaintiffs in the matter of *Sierra Club and Montana Environmental Information Center (Plaintiffs) v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and Pacificorp (Defendants)*, Civil Action No. CV 13-32-BLG-DLC-JCL (US District Court for the District of Montana, Billings Division).

(aaaaaa) Oral Testimony at Hearing (April 2015) on behalf of Niagara County, the Town of Lewiston, and the Villages of Lewiston and Youngstown in the matter of CWM Chemical Services, LLC New York State Department of Environmental Conservation (NYSDEC) Permit Application Nos.: 9-2934-00022/00225, 9-2934-00022/00231, 9-2934-00022/00232, and 9-2934-00022/00249 (pending).

(bbbbbb) Deposition (August 2015) on behalf of Plaintiff in the matter of *Conservation Law Foundation (Plaintiff) v. Broadrock Gas Services LLC, Rhode Island LFG GENCO LLC, and Rhode Island Resource Recovery Corporation (Defendants)*, Civil Action No. 1:13-cv-00777-M-PAS (US District Court for the District of Rhode Island).

(cccccc) Testimony at Hearing (August 2015) on behalf of the Sierra Club in the matter of *Amendments to 35 Illinois Administrative Code Parts 214, 217, and 225* before the Illinois Pollution Control Board, R15-21.

(dddddd) Deposition (May 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., (Plaintiffs) v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).

(eeeeee) Trial Testimony (October 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., (Plaintiffs) v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).