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.

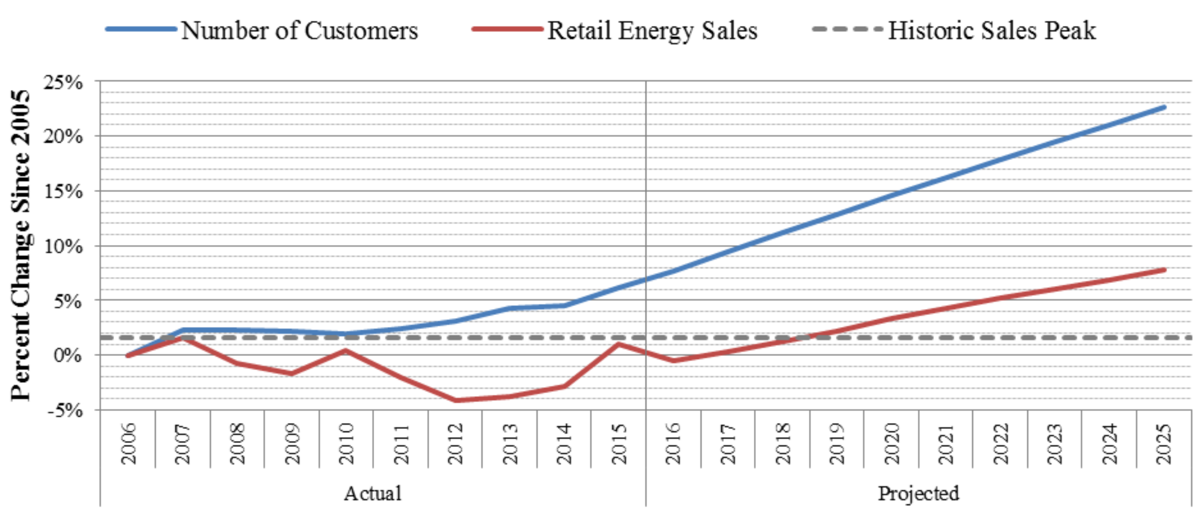
Review of the 2016 Ten-Year Site Plans

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

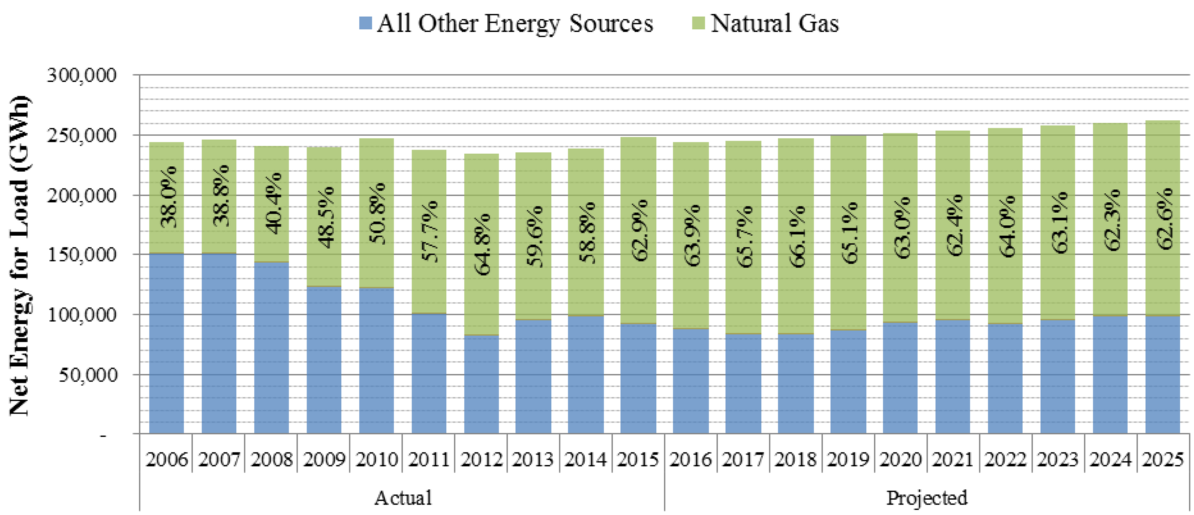
Renewable resources continue to expand in Florida, with approximately 1,860 MW of renewable generating capacity currently installed in Florida. The majority of installed renewable capacity is represented by biomass and municipal solid waste, making up approximately 60 percent of Florida's renewables. 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.

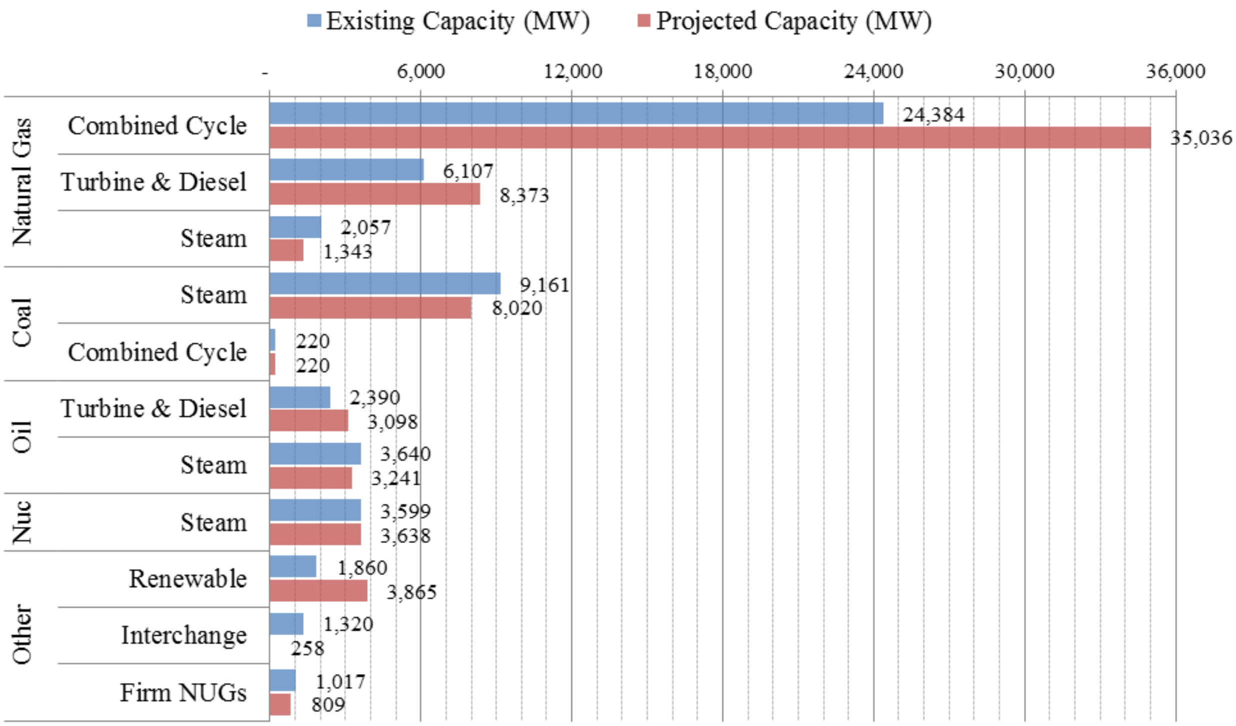
Figure 2: State of Florida - Natural Gas Contribution to Energy Consumption



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

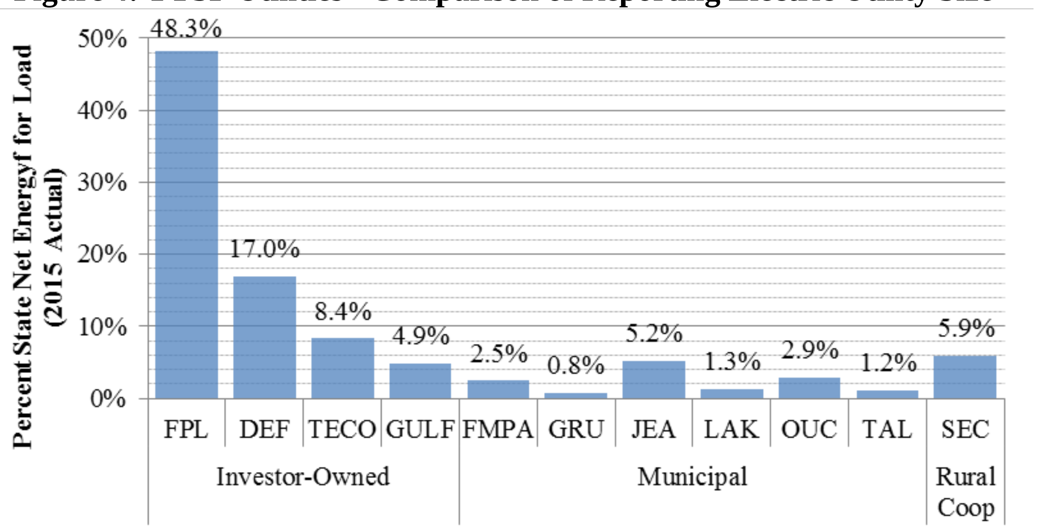
Florida is served by 58 electric utilities, including 5 investor-owned utilities, 35 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 megawatts (MW) or a planned unit with a capacity 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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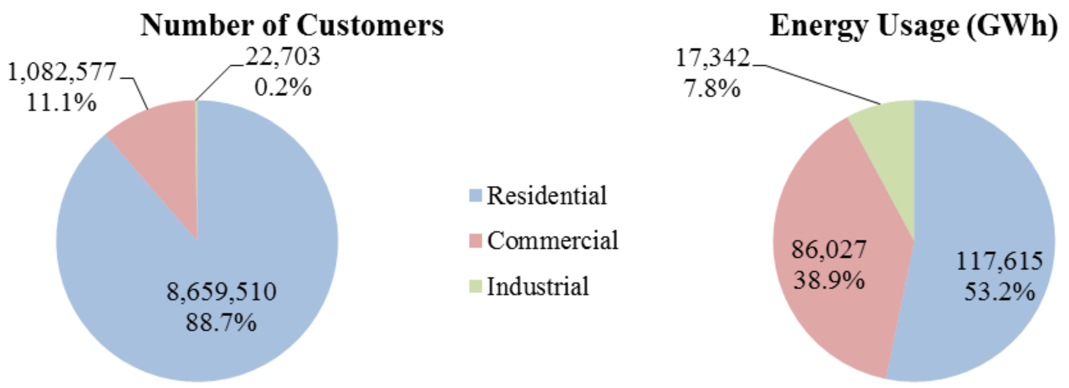
Load Forecasting

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

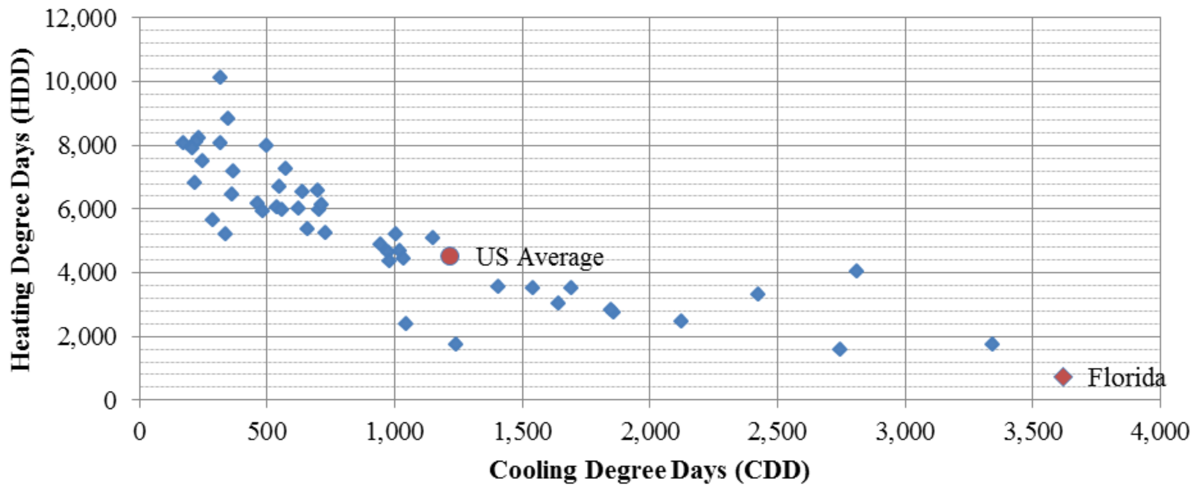


Source: FRCC 2016 Load and Resource Plan

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)

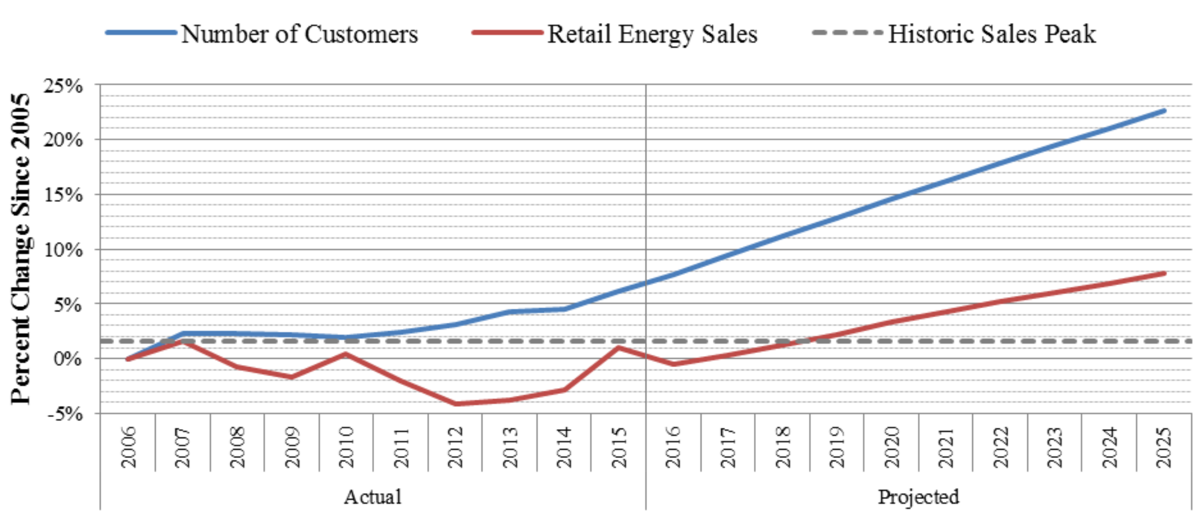


Source: National Oceanic & Atmospheric Administration, Historical Climatology Series 5-1 and 5-2

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



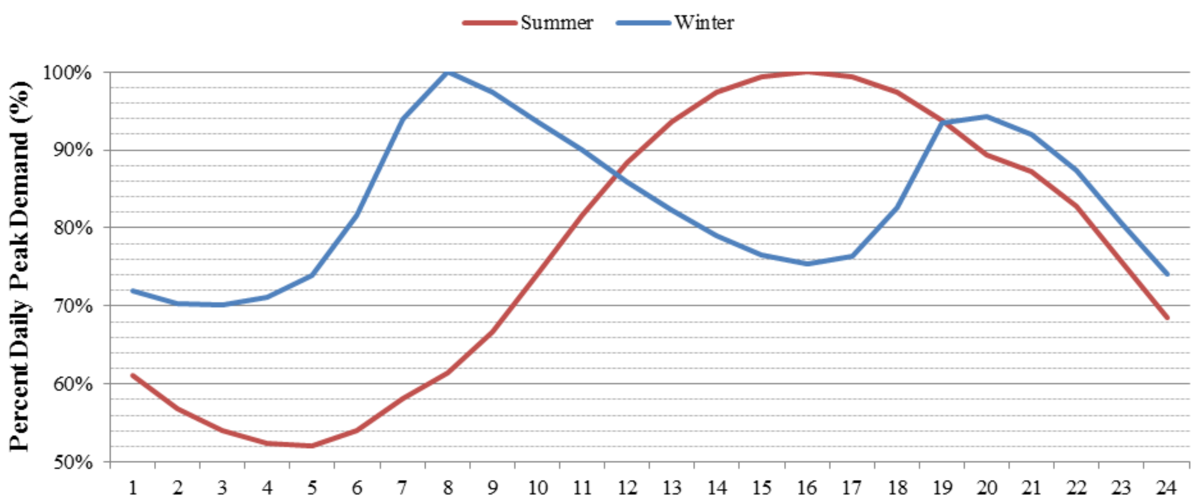
Source: FRCC 2016 Load and Resource Plan

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

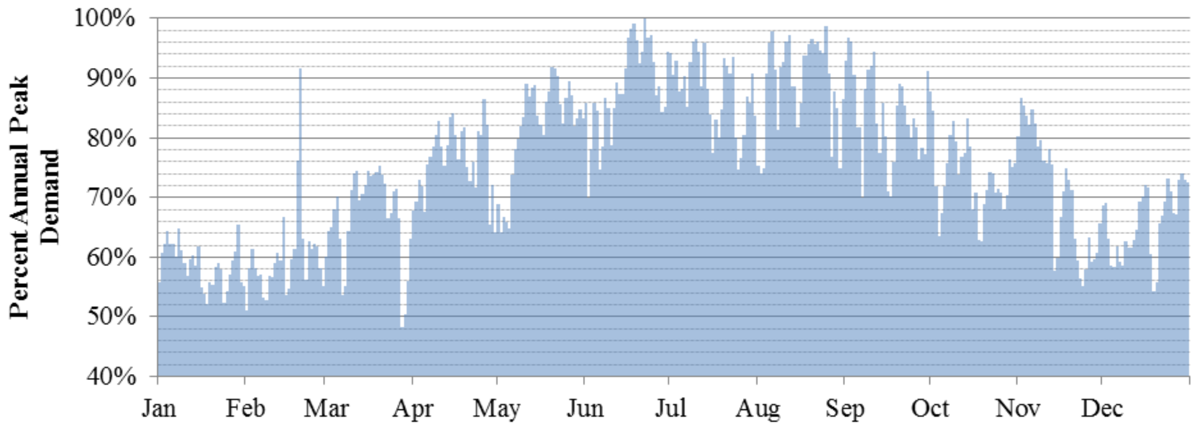


Source: TYSP Utilities Data Responses

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.

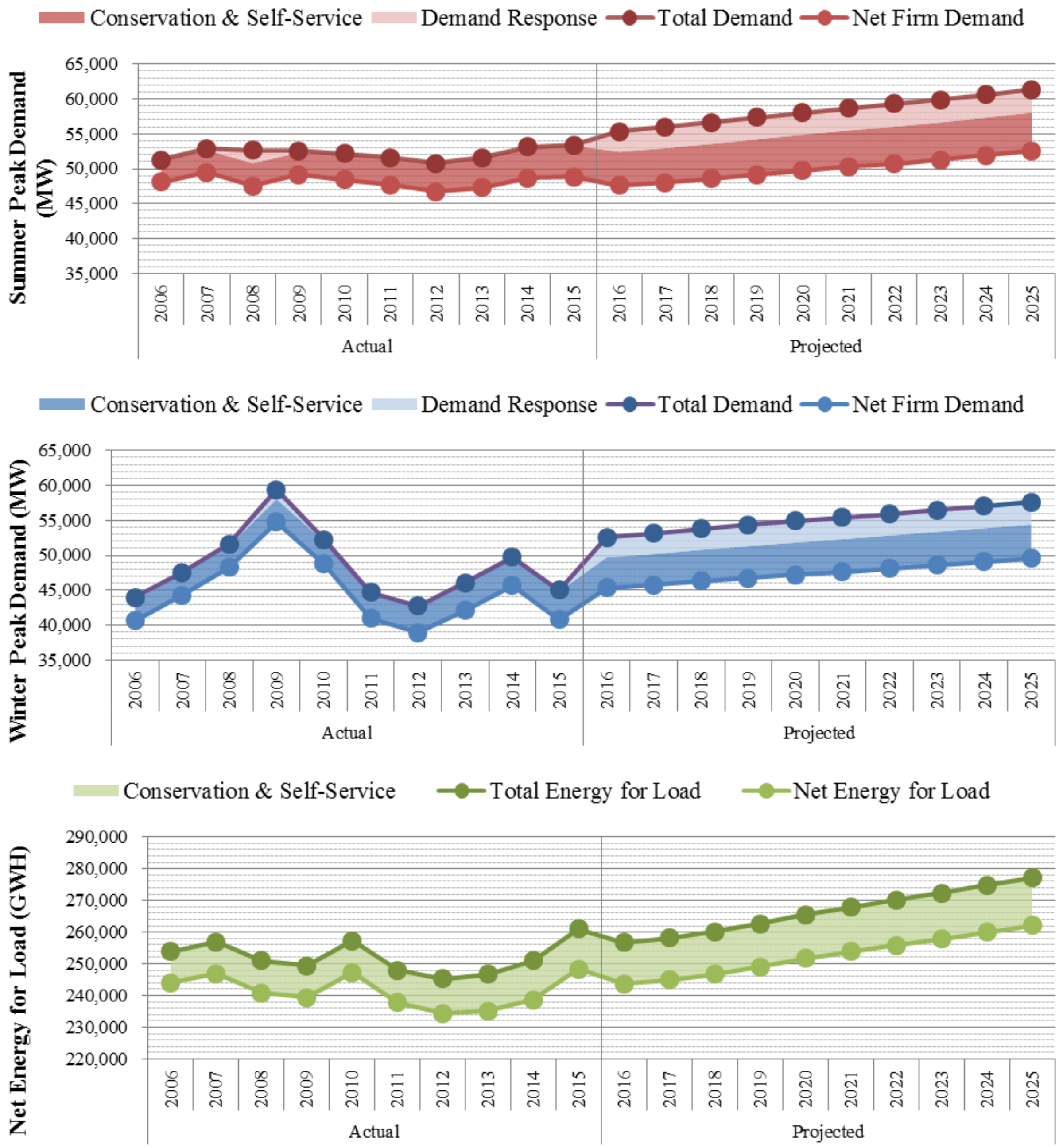
Demand-side management, including demand response and energy efficiency, along with self-service generation is included in each figure for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served if not for the impact 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.

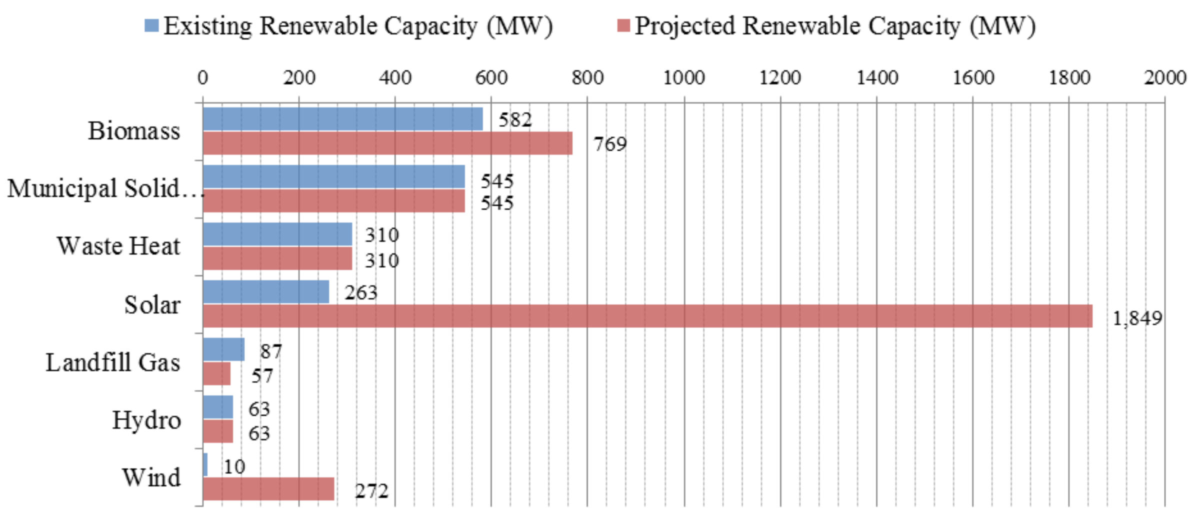
Based on actual data provided by FPL, the combined cost of generation of the three solar facilities was $0.41/kWh in 2016. These facilities make up a significant portion of the utility owned renewable generation. Since full operation began, the two solar PV facilities have operated largely as expected; 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

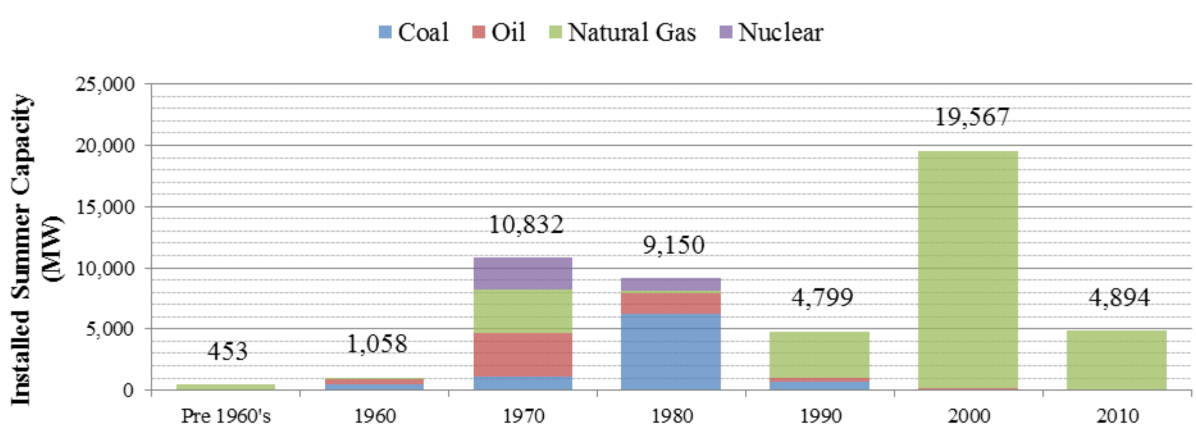
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and turbine generators, that have been added to Florida's electric grid over the last several decades. Due to forecasted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

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[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.

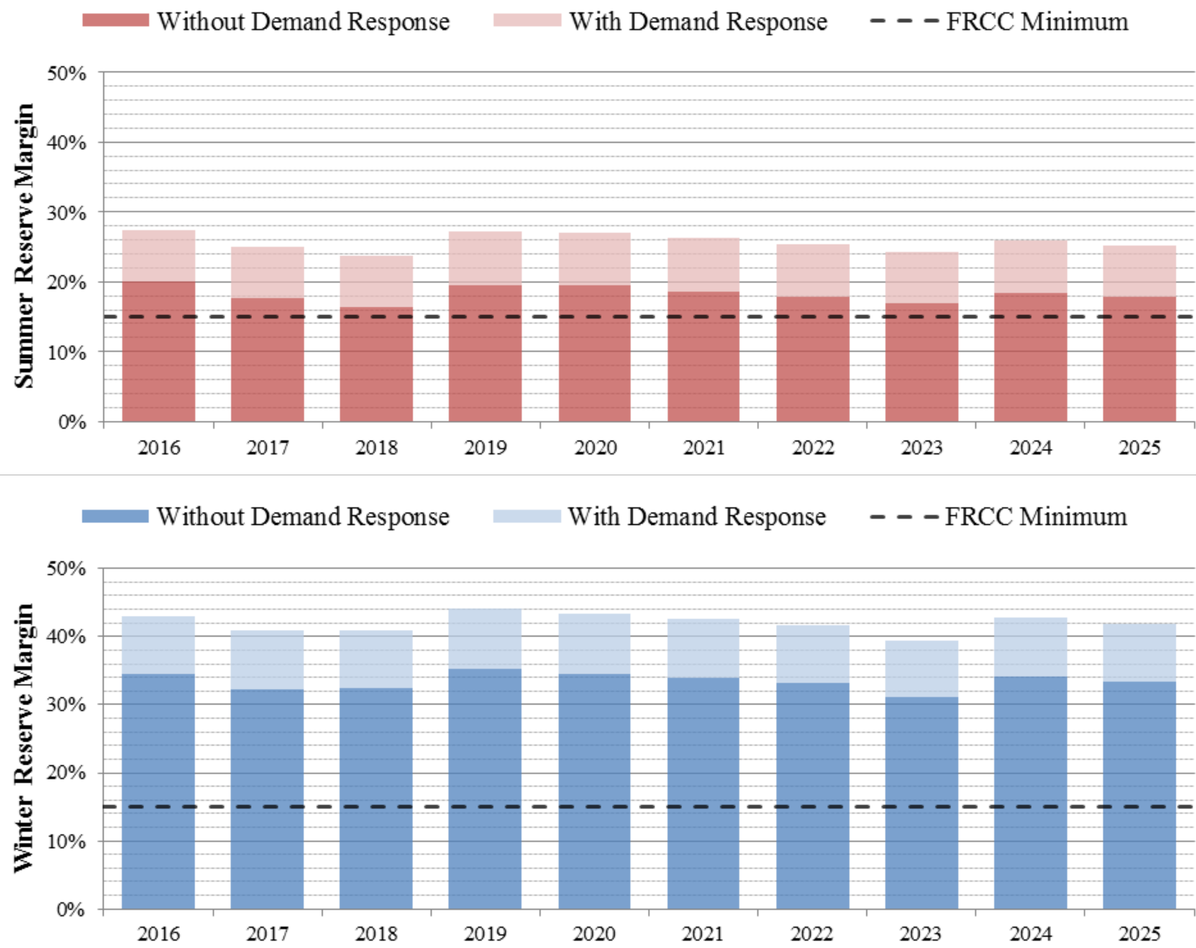
Reliability Requirements

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

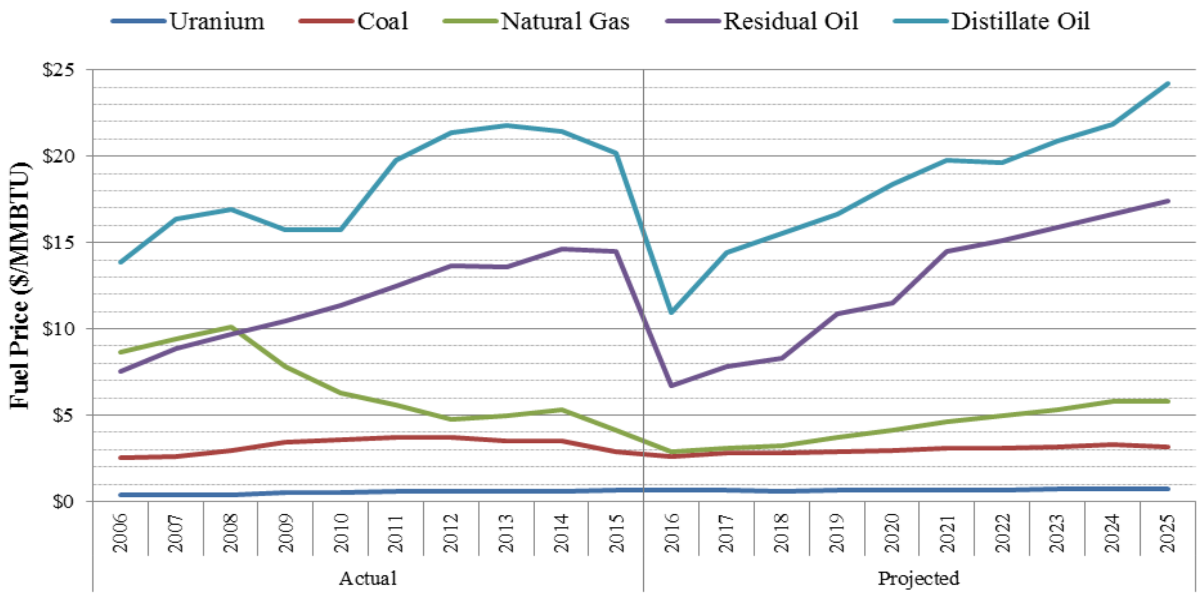
The Commission also considers the planning reserve margin without demand response. As illustrated above in Figure 13, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin without activation of demand response. Demand response activation increases the reserve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

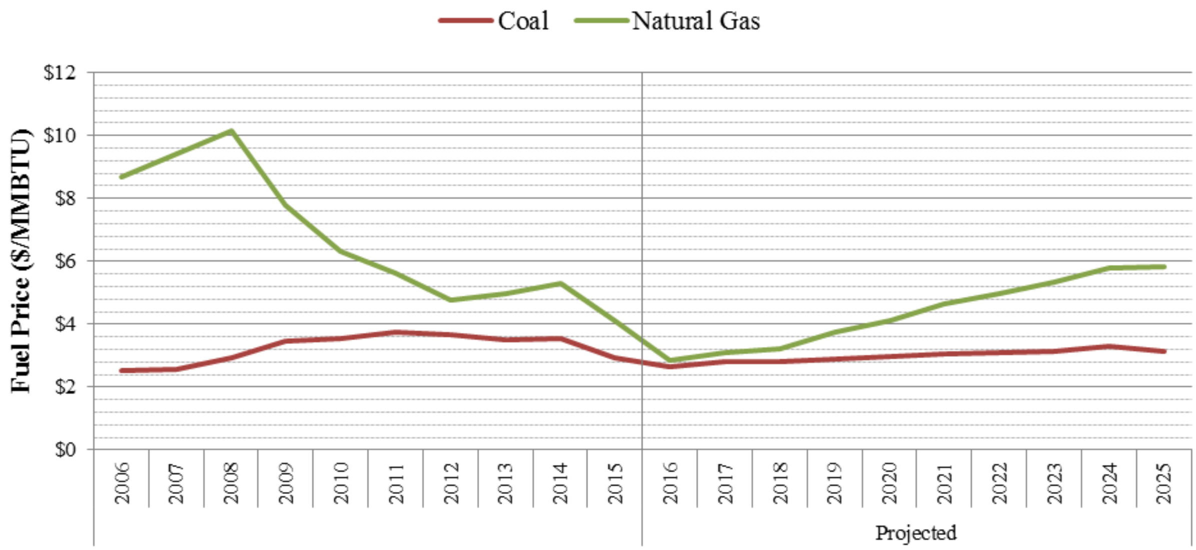


Source: TYSP Utilities Data Responses

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

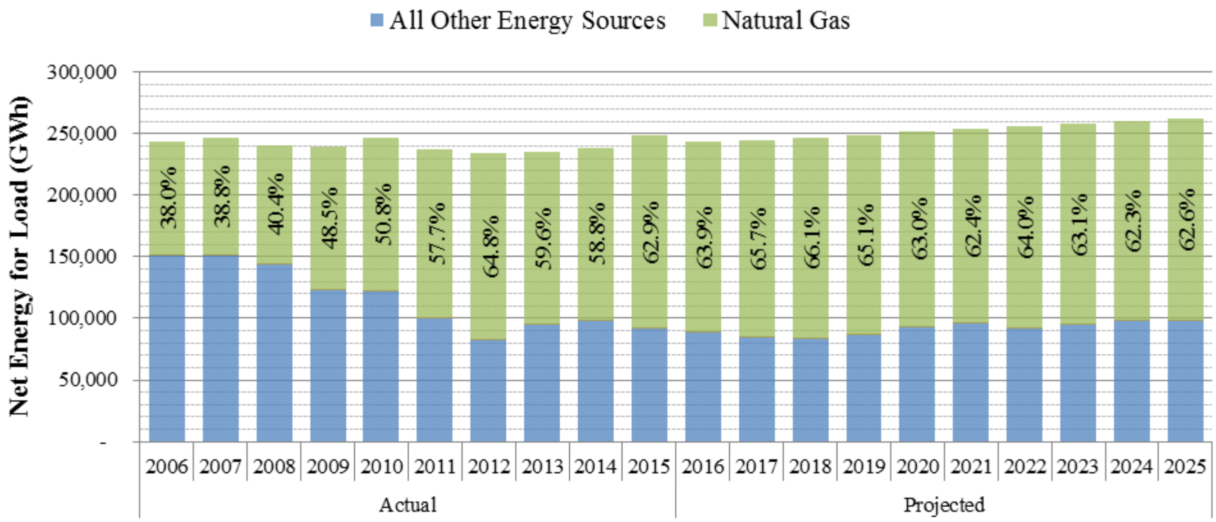


Source: TYSP Utilities Data Responses

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

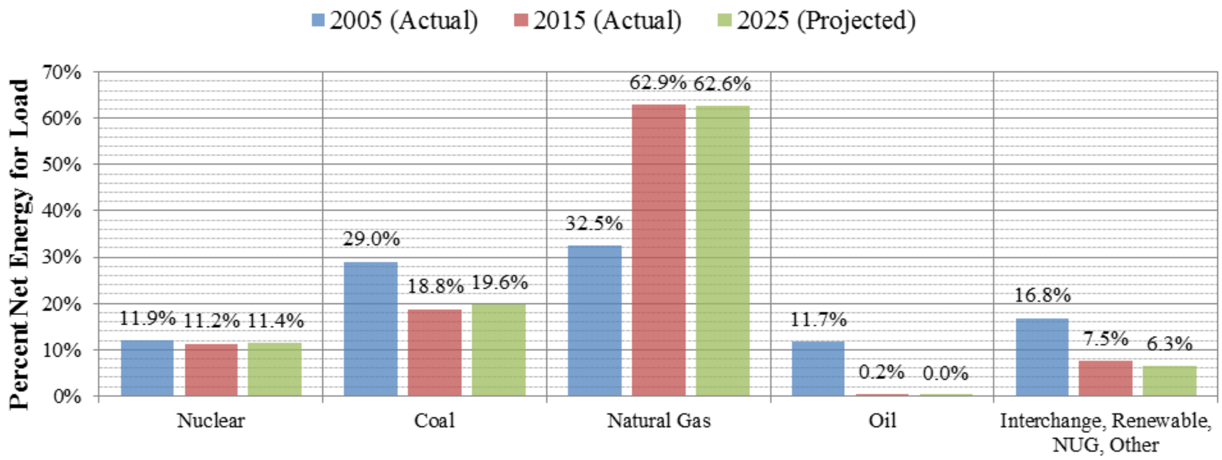


Source: 2006-2016 FRCC Load & Resource Plans

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.

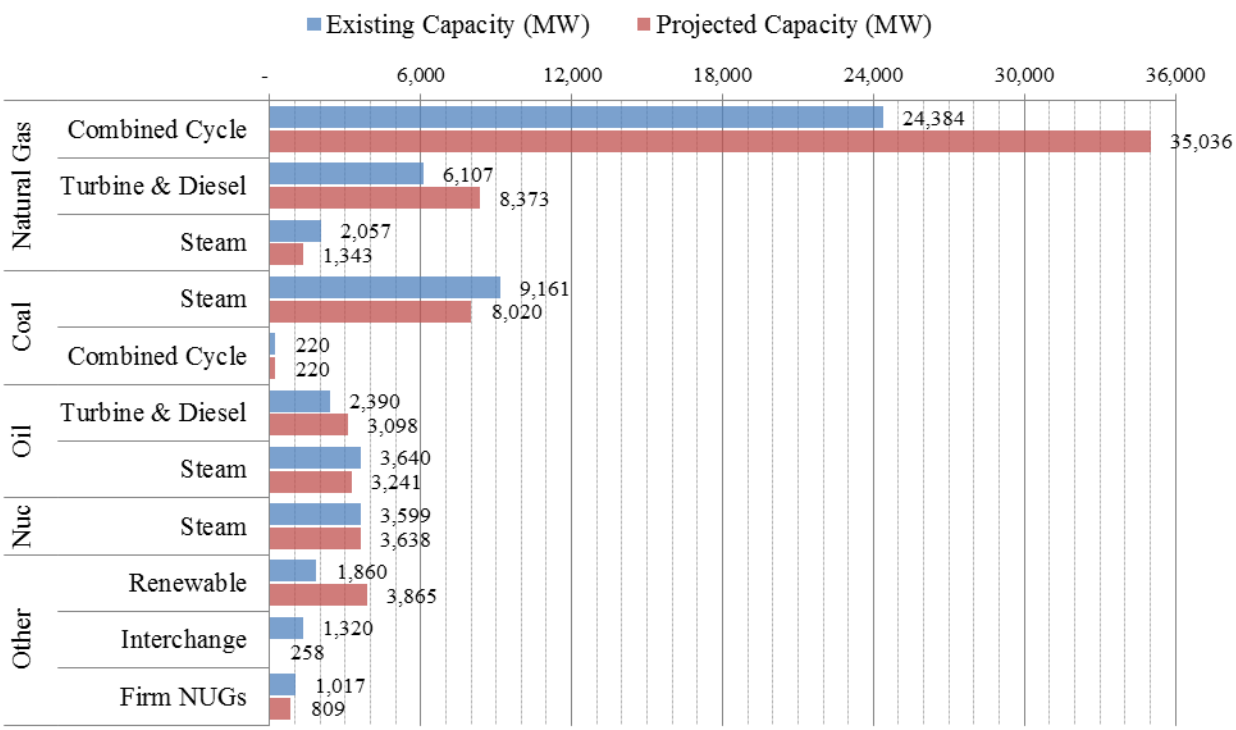
New Generation Planned

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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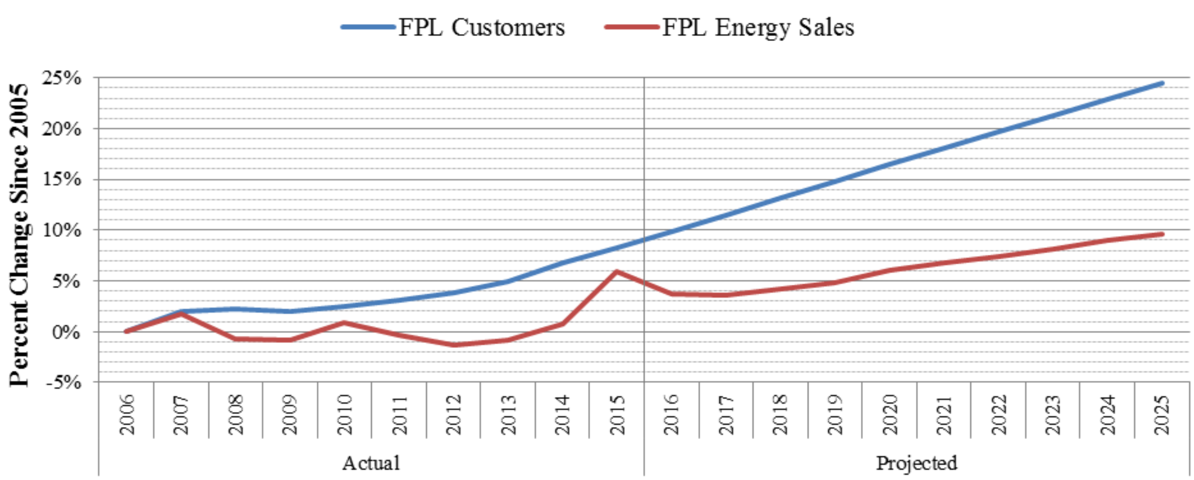
Florida Power & Light Company (FPL)

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.

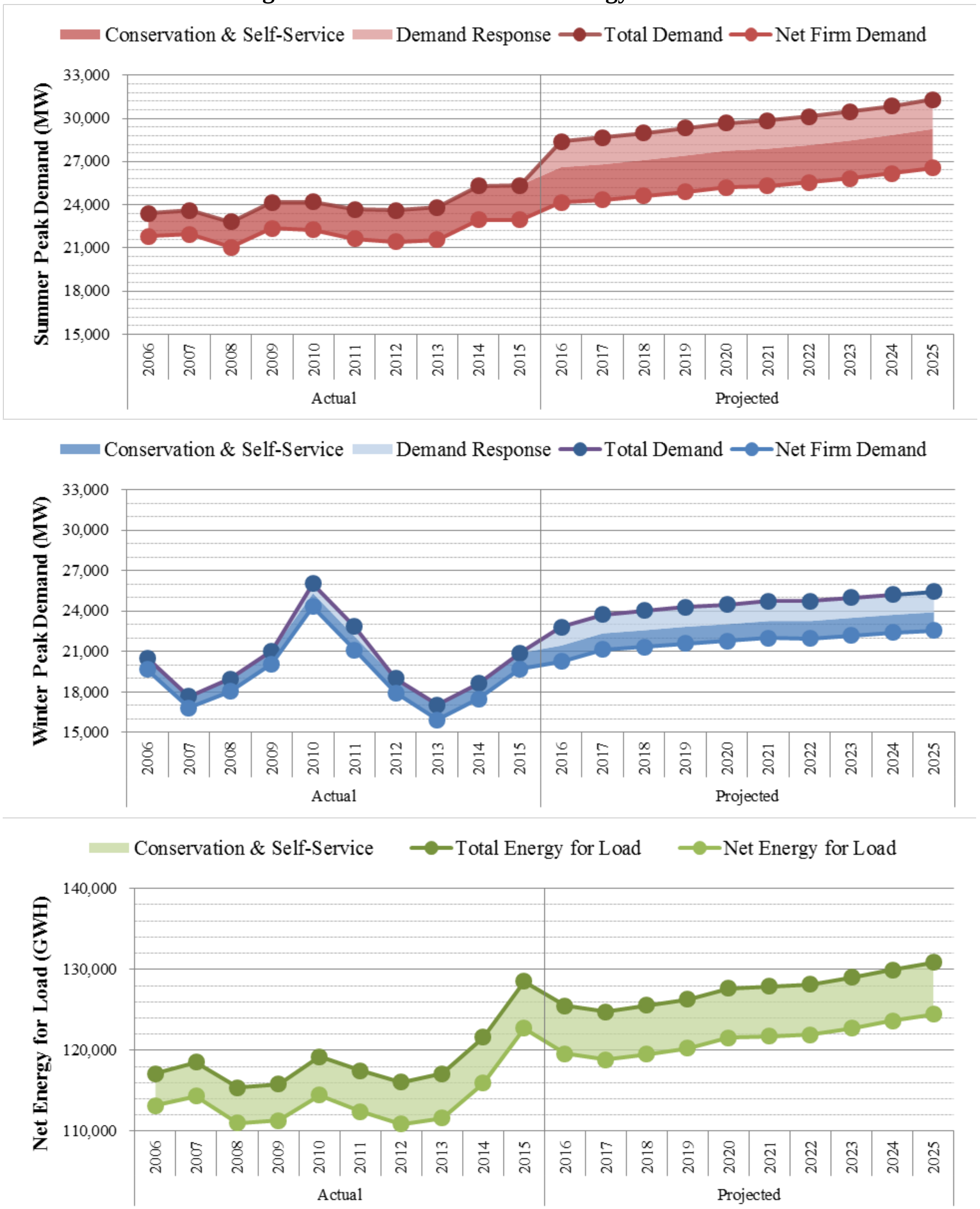
Figure 19: FPL Growth Rate



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

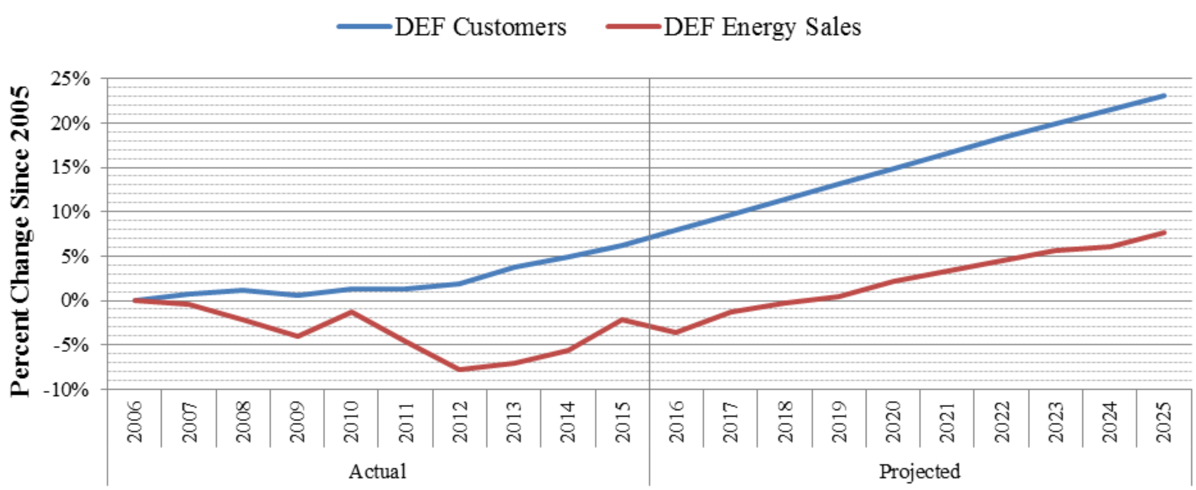
Duke Energy Florida, LLC (DEF)

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.

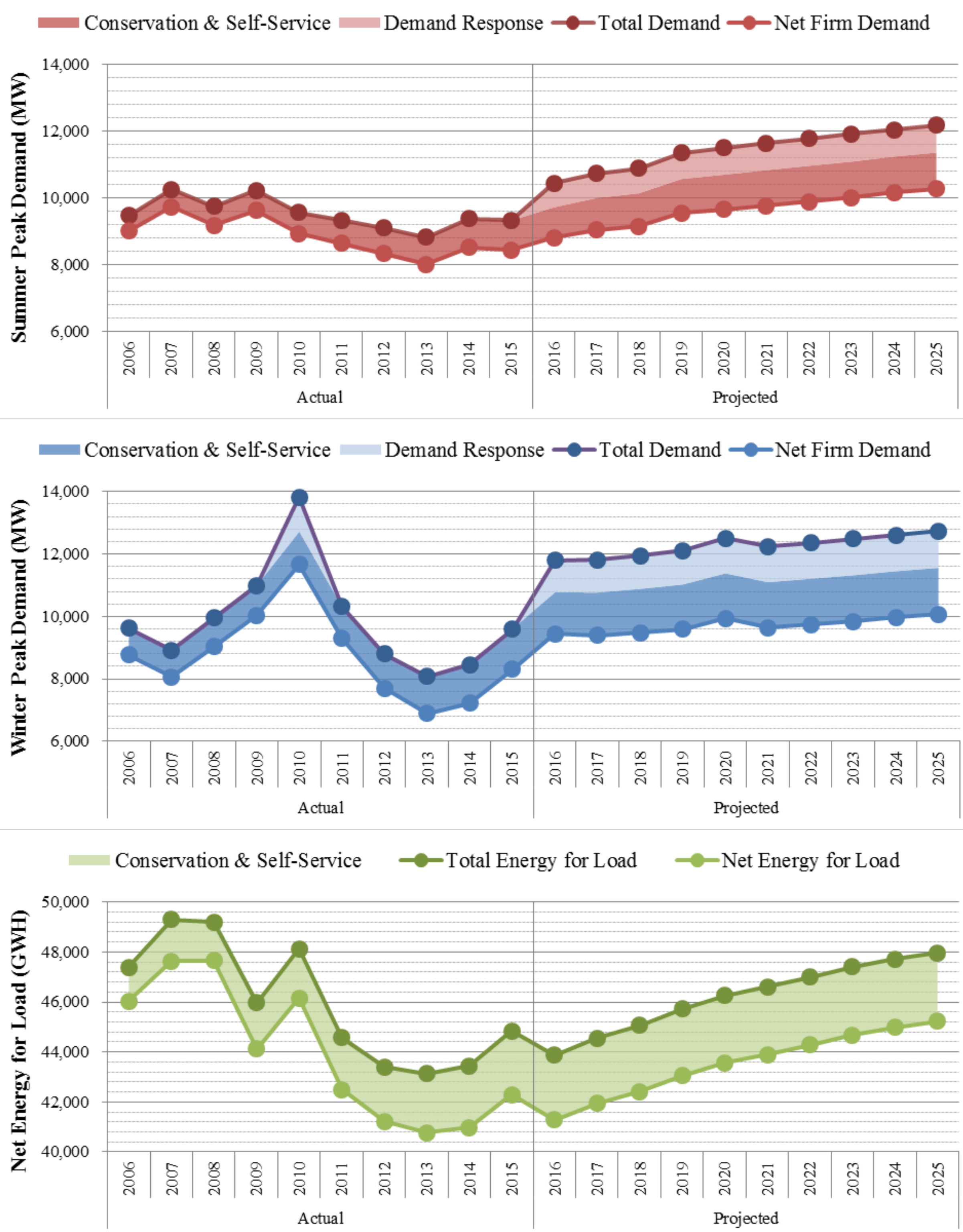
Figure 22: DEF Growth Rate



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

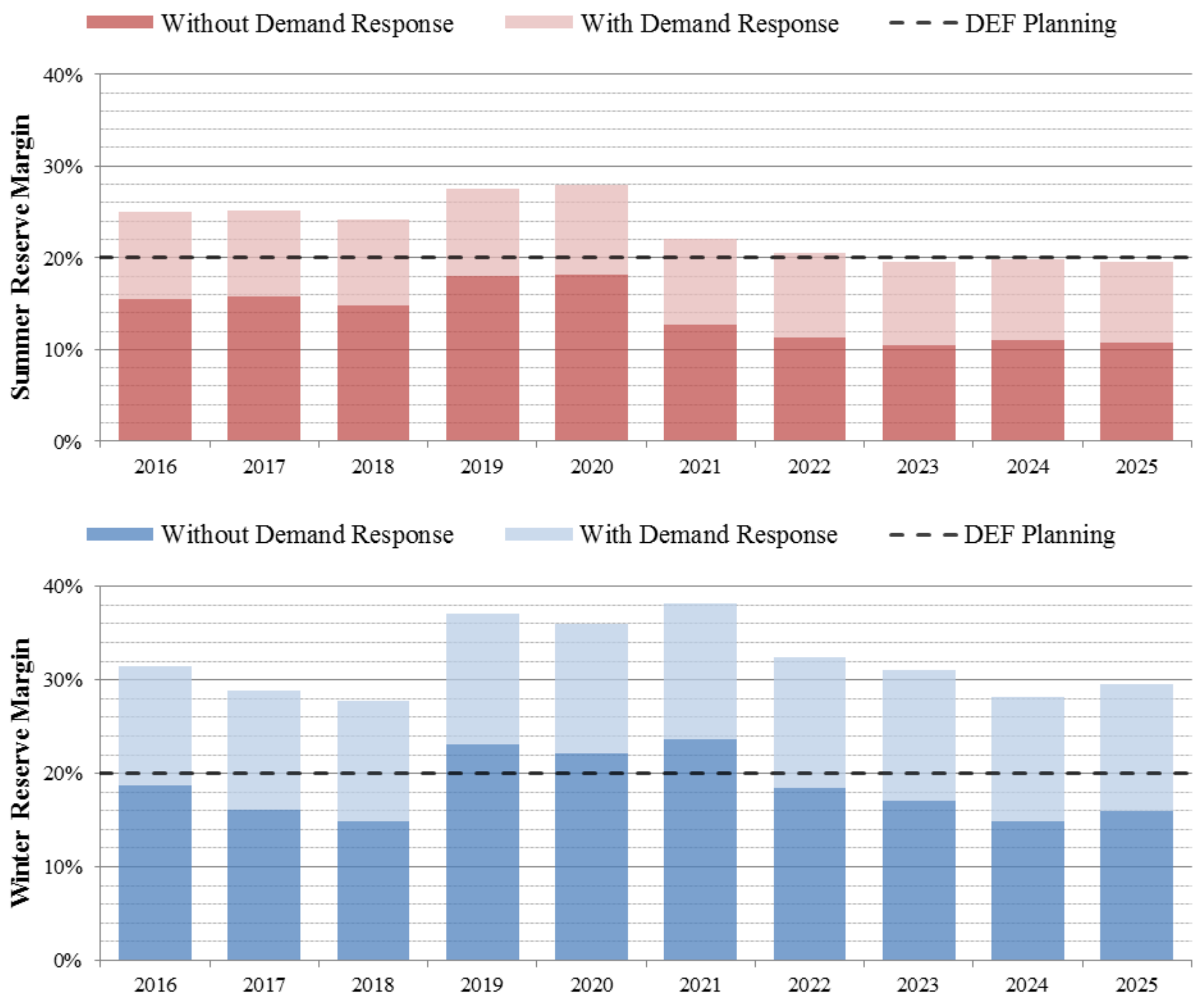
Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	25,227	**59.7%**	36,828	**81.4%**
Coal	9,718	**23.0%**	5,704	**12.6%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	73	**0.2%**	2	**0.0%**
Renewable	1,063	**2.5%**	2,243	**5.0%**
Interchange	2,390	**5.7%**	62	**0.1%**
NUG & Other	3,809	**9.0%**	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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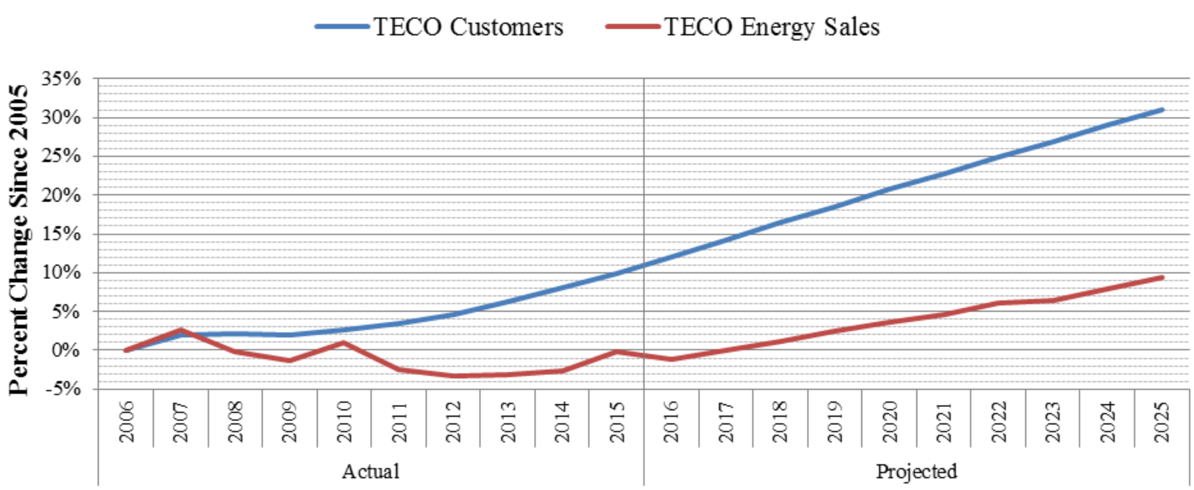
Tampa Electric Company (TECO)

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.

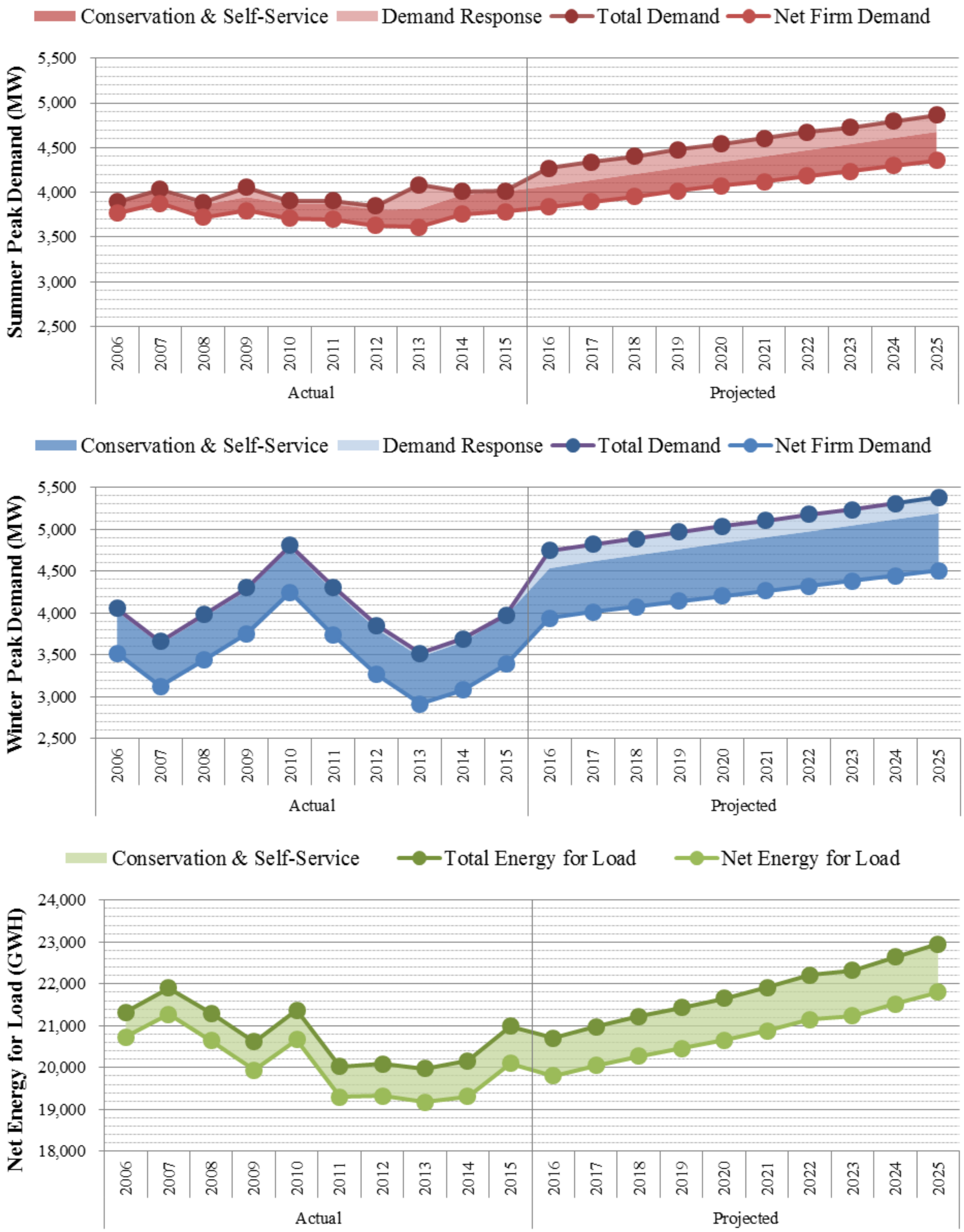
Figure 25: TECO Growth Rate



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

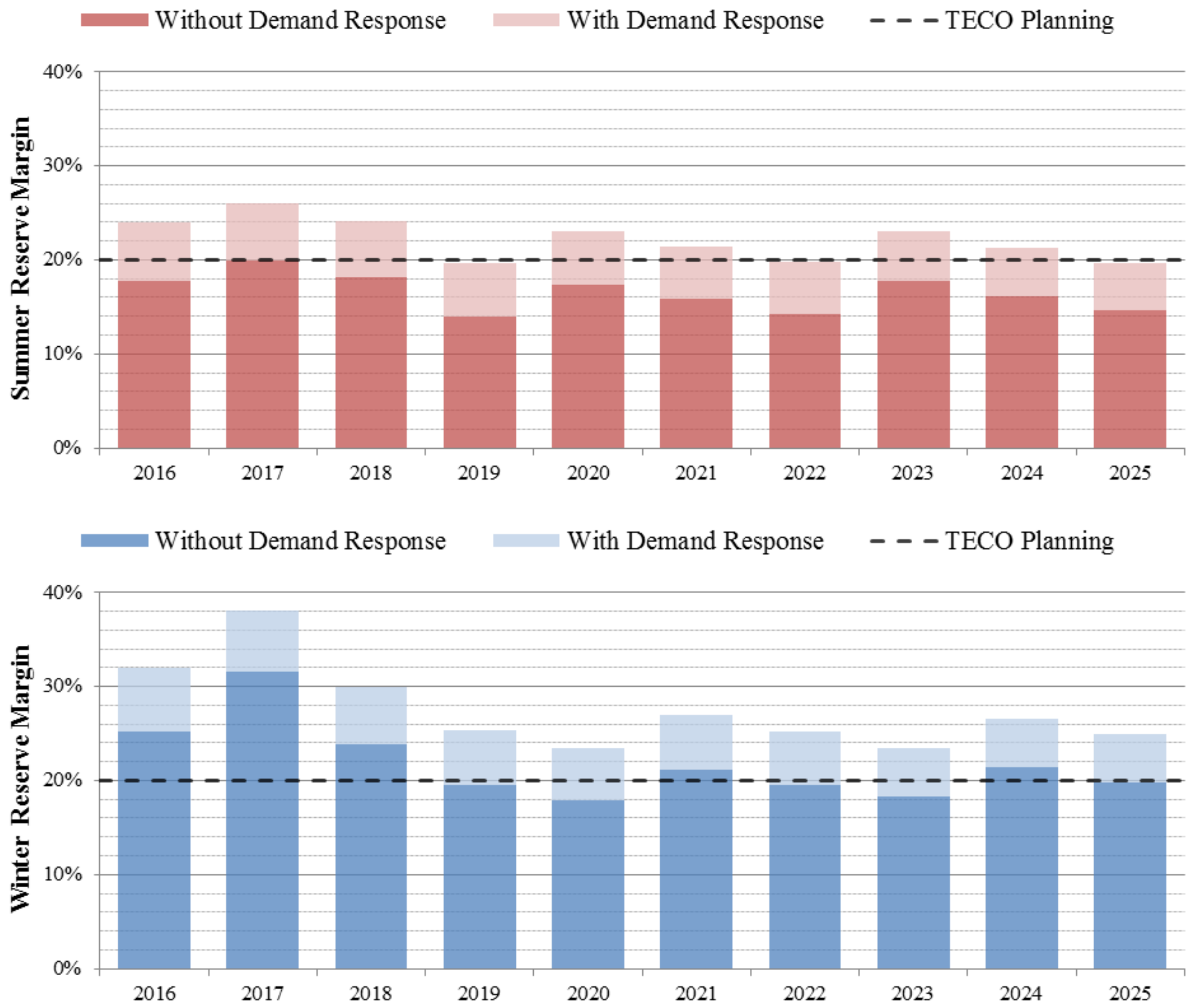
Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	9,919	**49.3%**	11,321	**51.9%**
Coal	8,208	**40.8%**	9,078	**41.6%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	341	**1.7%**	136	**0.6%**
Interchange	438	**2.2%**	0	**0.0%**
NUG & Other	1,200	**6.0%**	1,272	**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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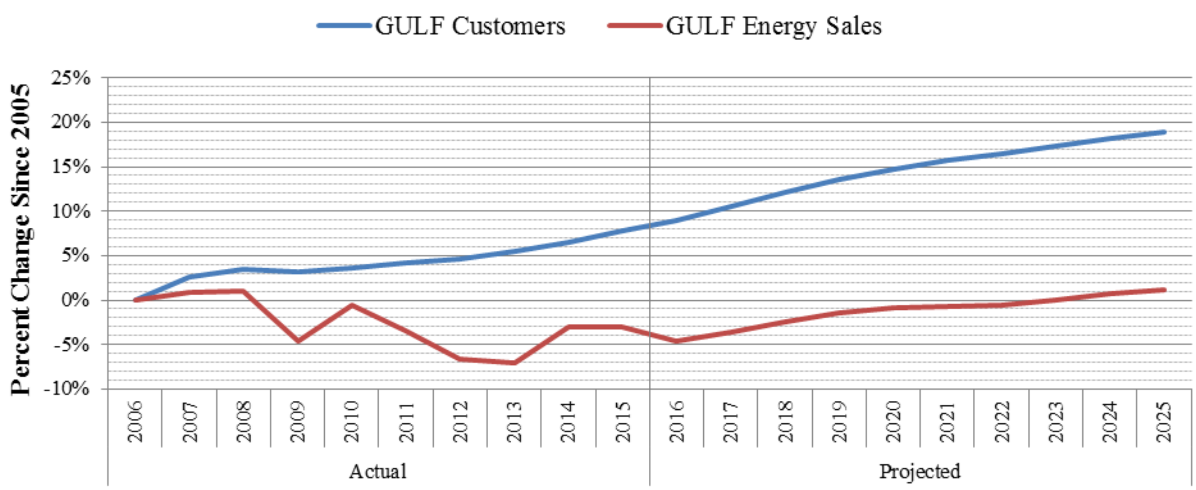
Gulf Power Company (GPC)

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.

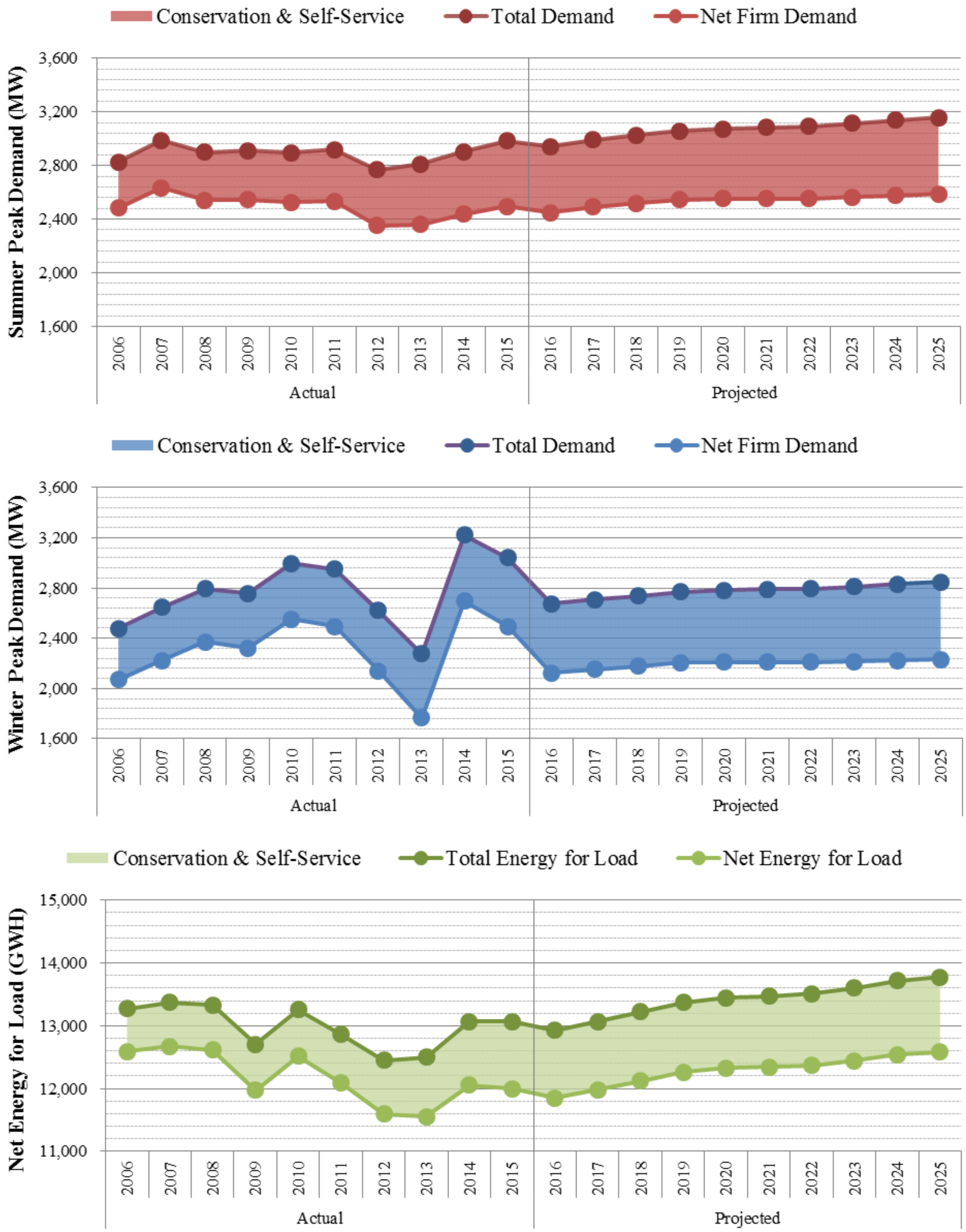
Figure 28: GPC Growth Rate



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

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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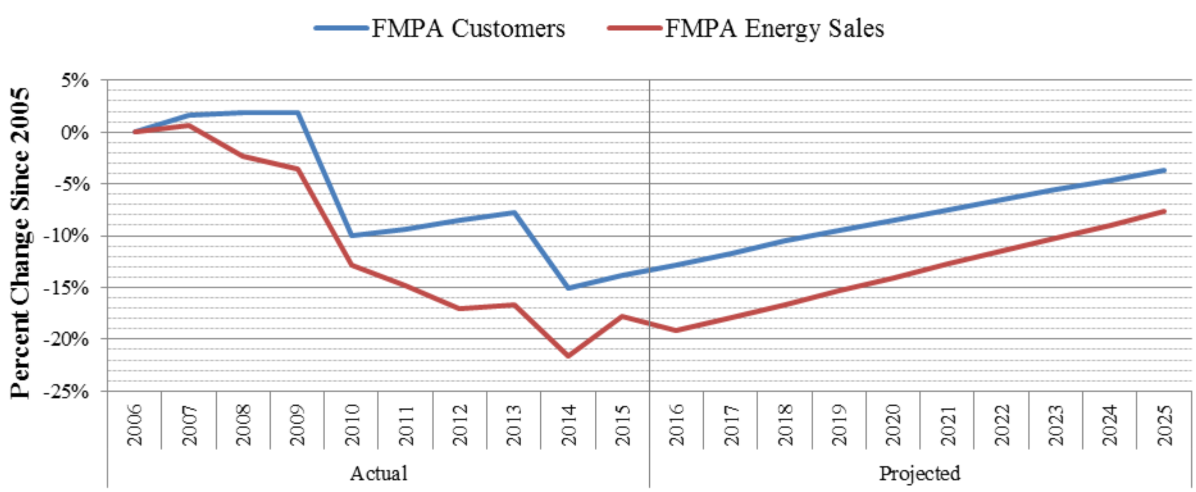
Florida Municipal Power Agency (FMPA)

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.

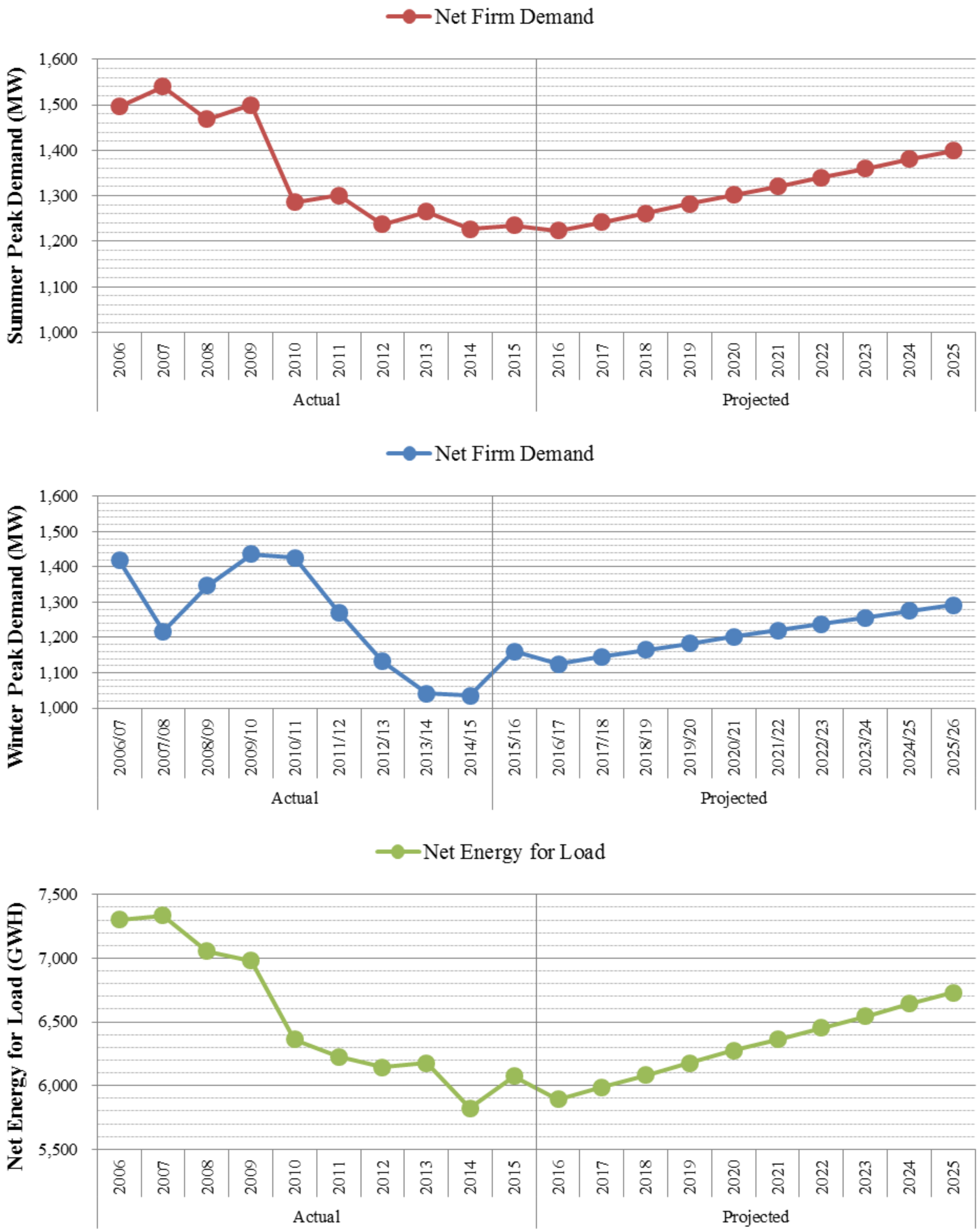
Figure 31: FMPA Growth Rate



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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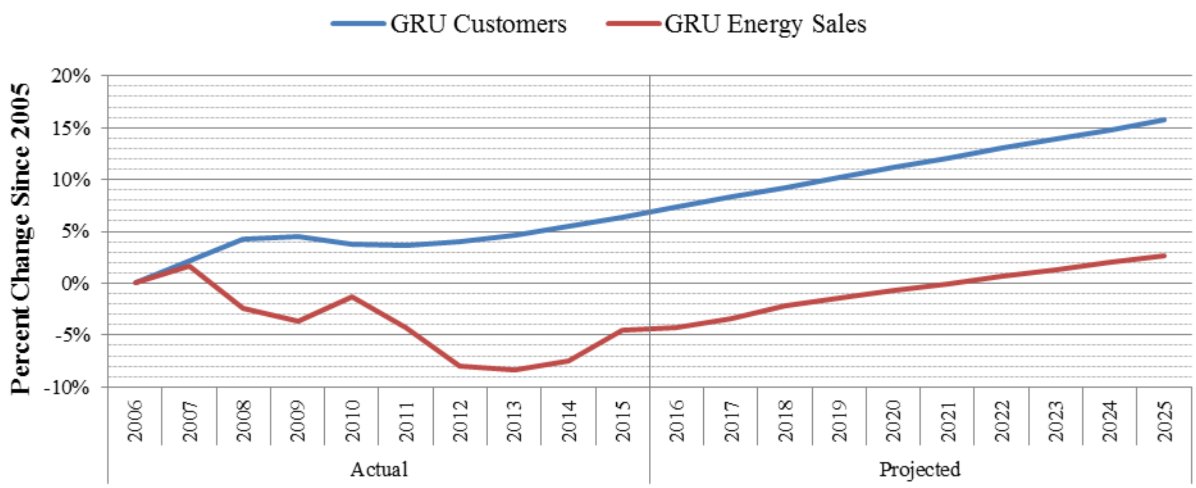
Gainesville Regional Utilities (GRU)

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.

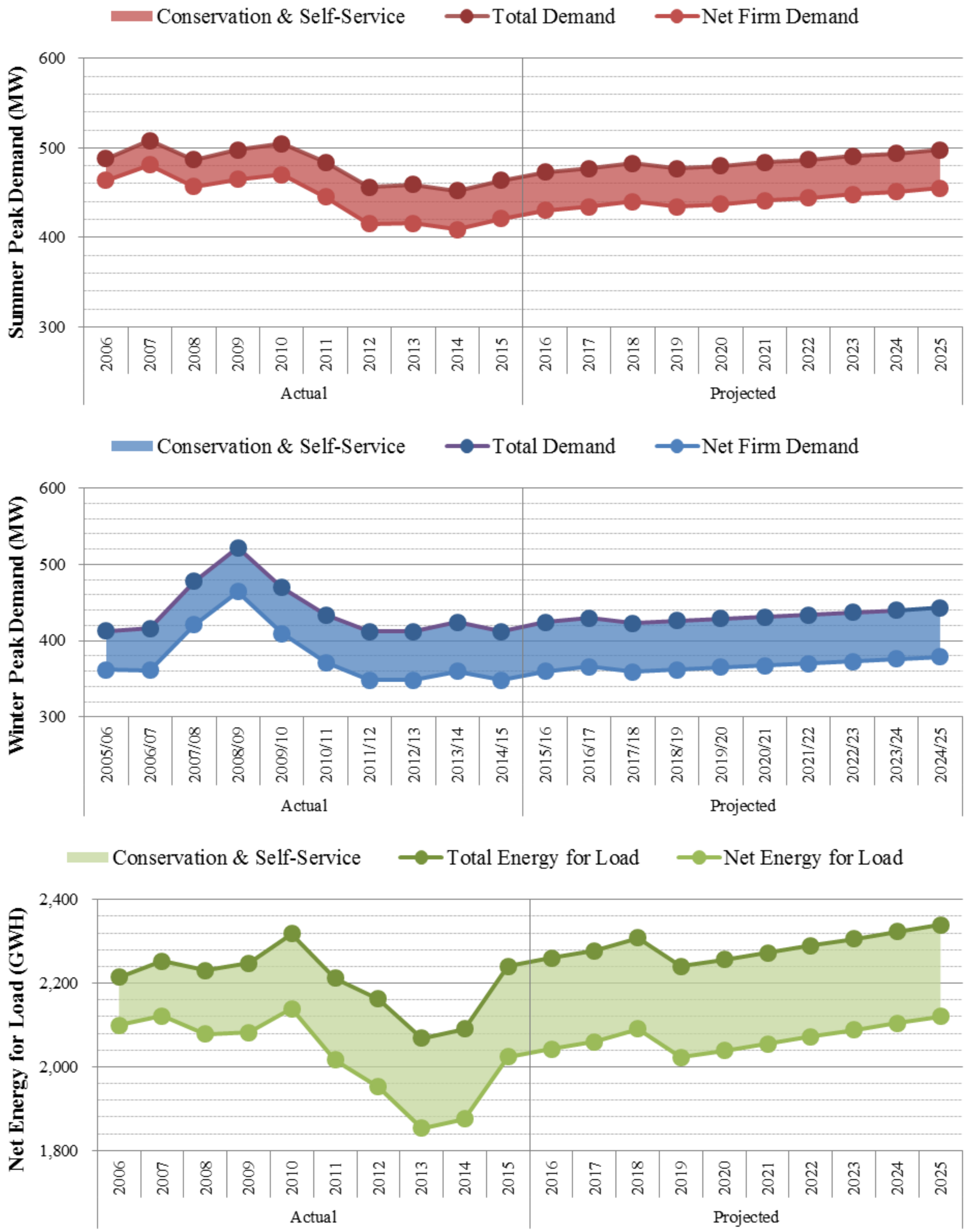
Figure 34: GRU Growth Rate



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

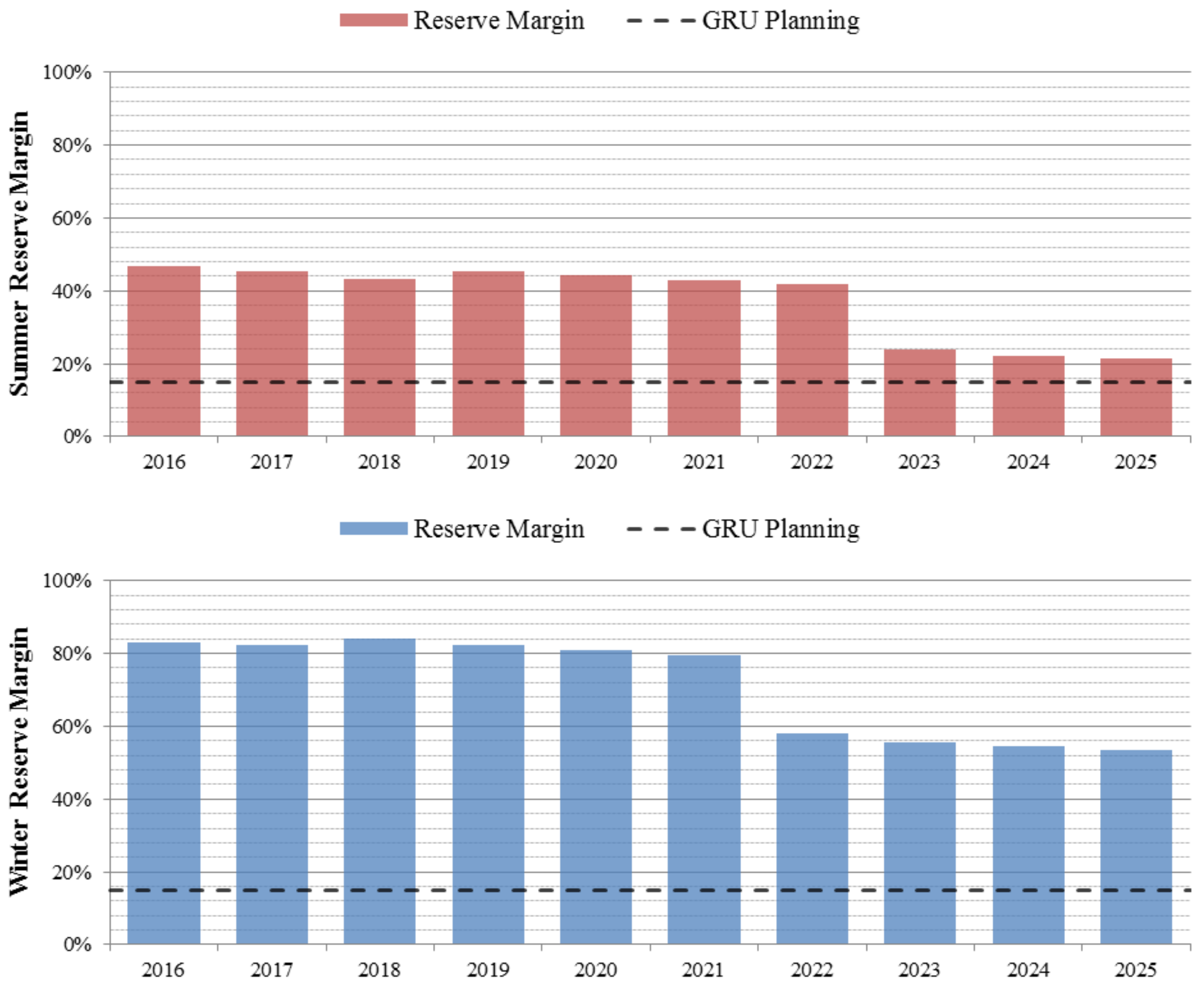
Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	771	**38.1%**	921	**43.4%**
Coal	663	**32.8%**	895	**42.2%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	374	**18.5%**	217	**10.2%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	215	**10.6%**	87	**4.1%**
Total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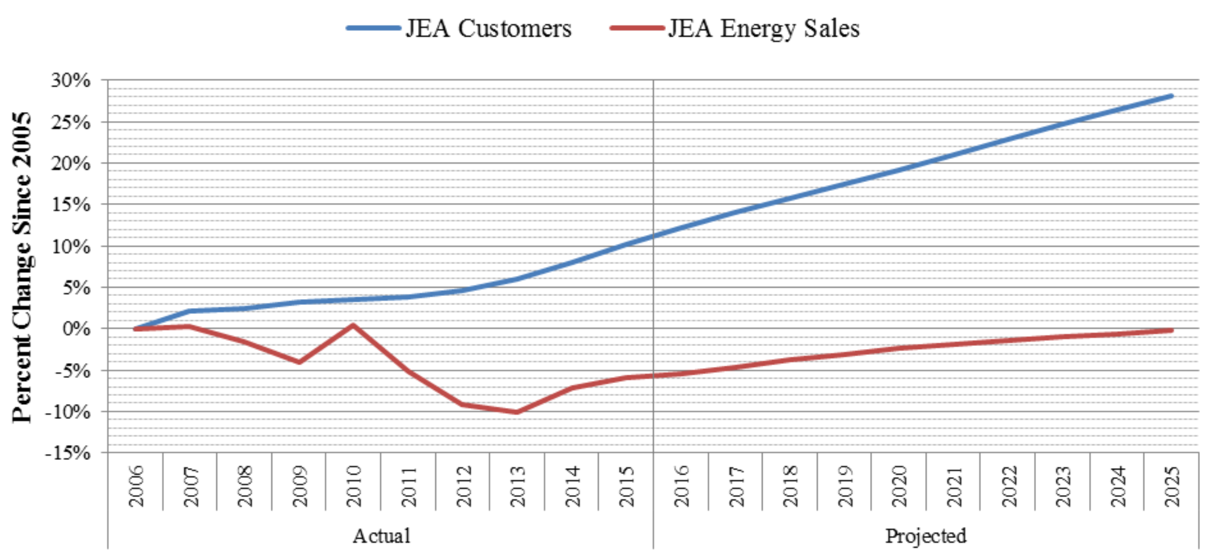
JEA

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.

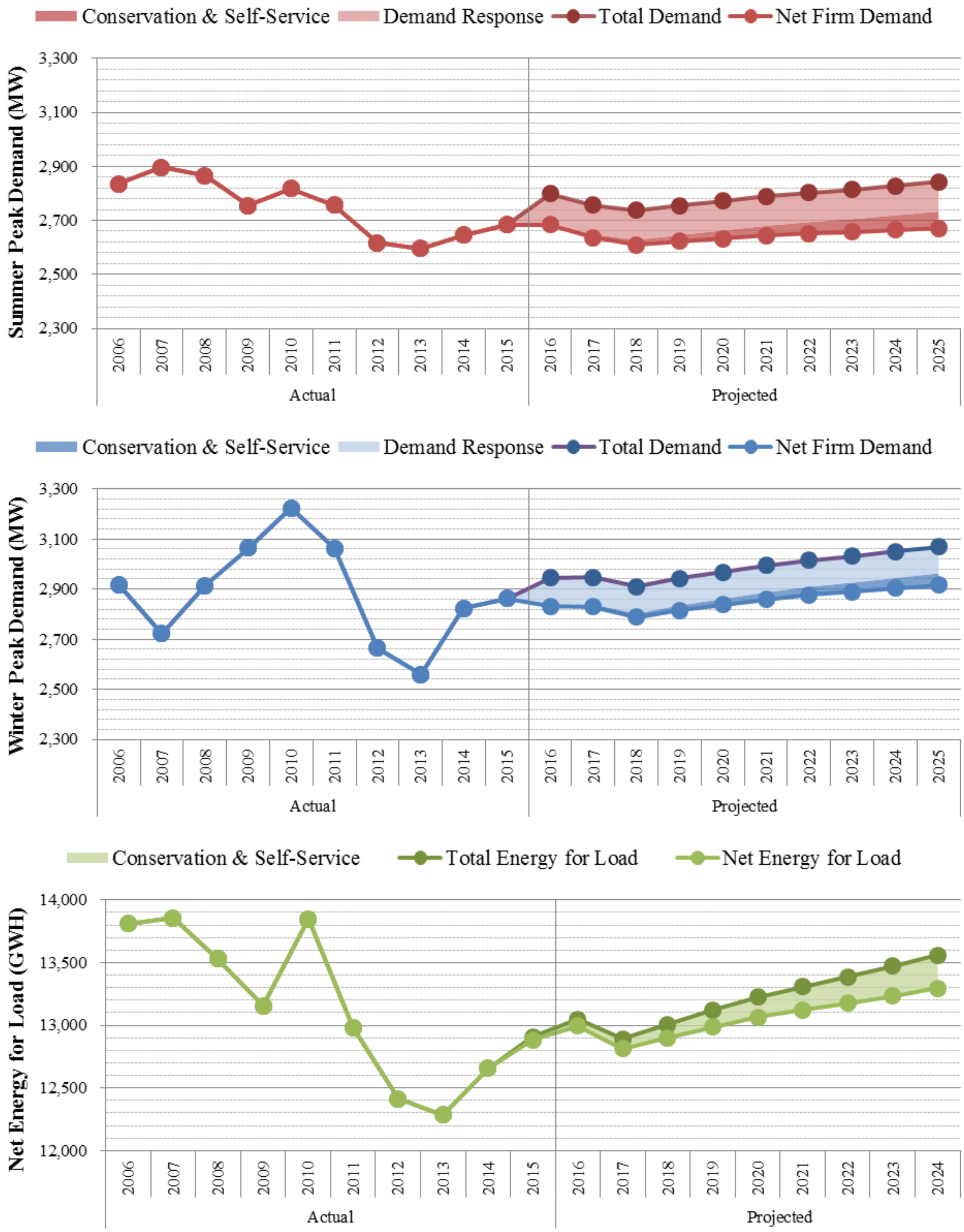
Figure 37: JEA Growth Rate



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**	

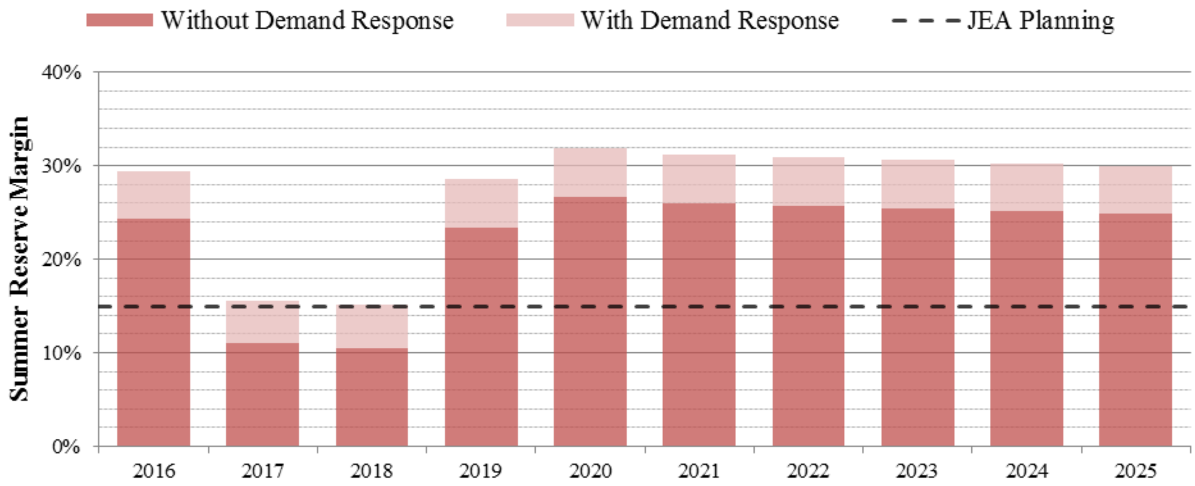
Source: 2016 Ten-Year Site Plan and Data Responses

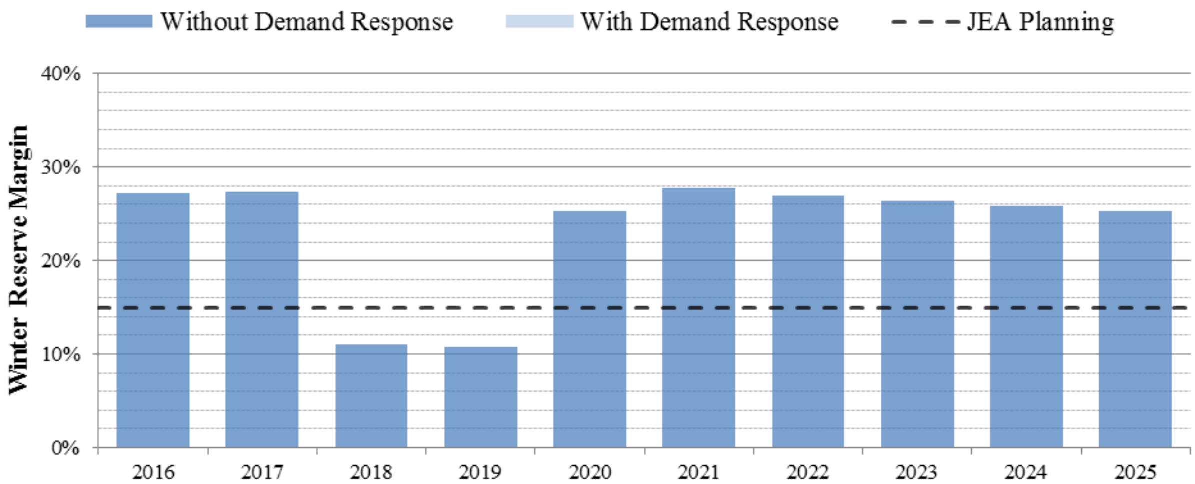
Reliability Requirements

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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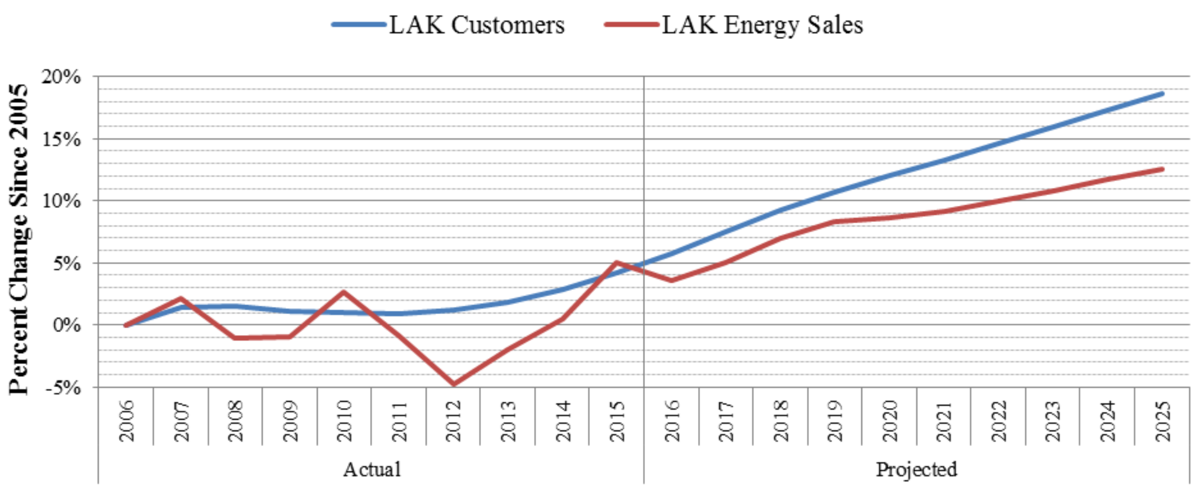
Lakeland Electric (LAK)

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.

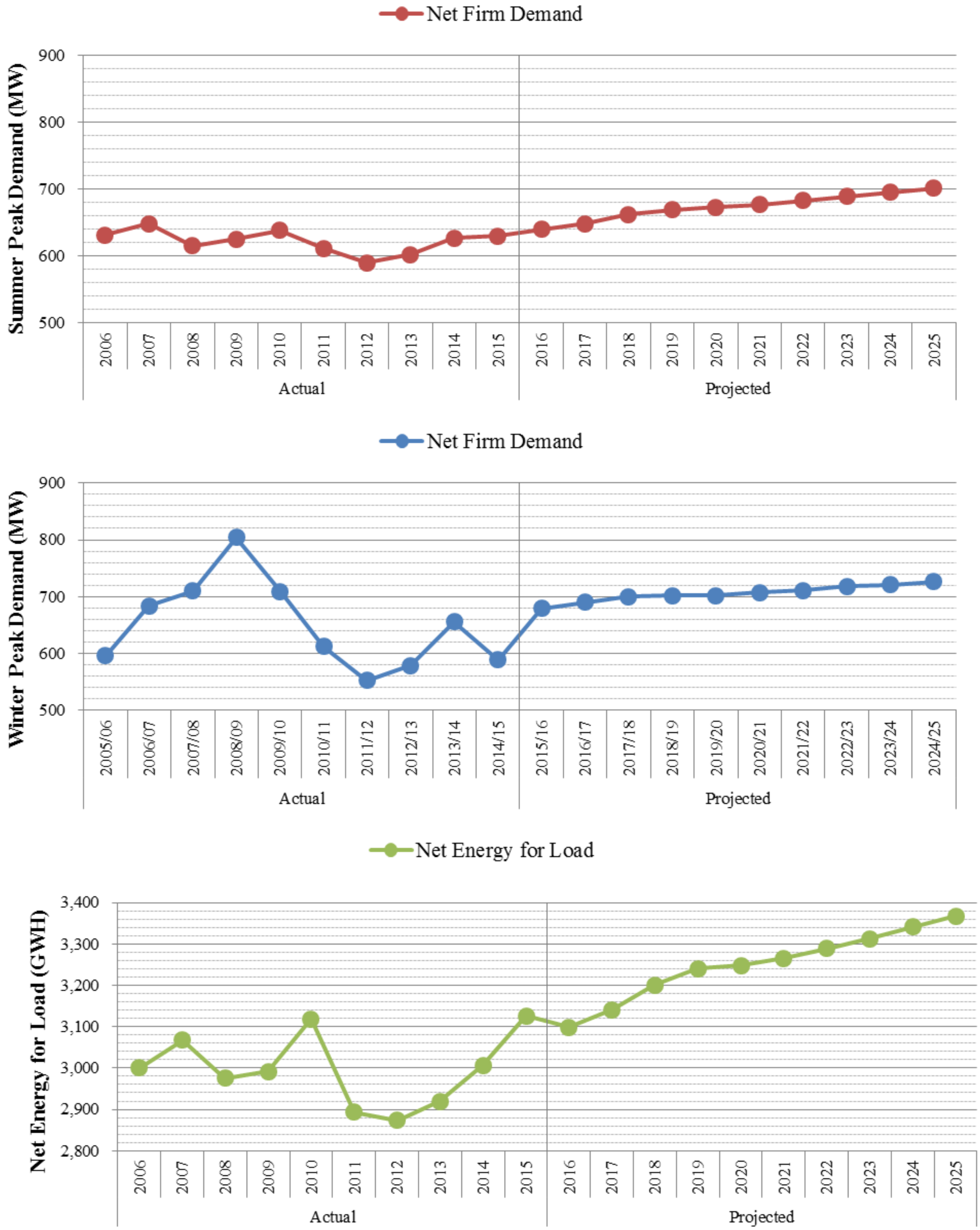
Figure 40: LAK Growth Rate



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

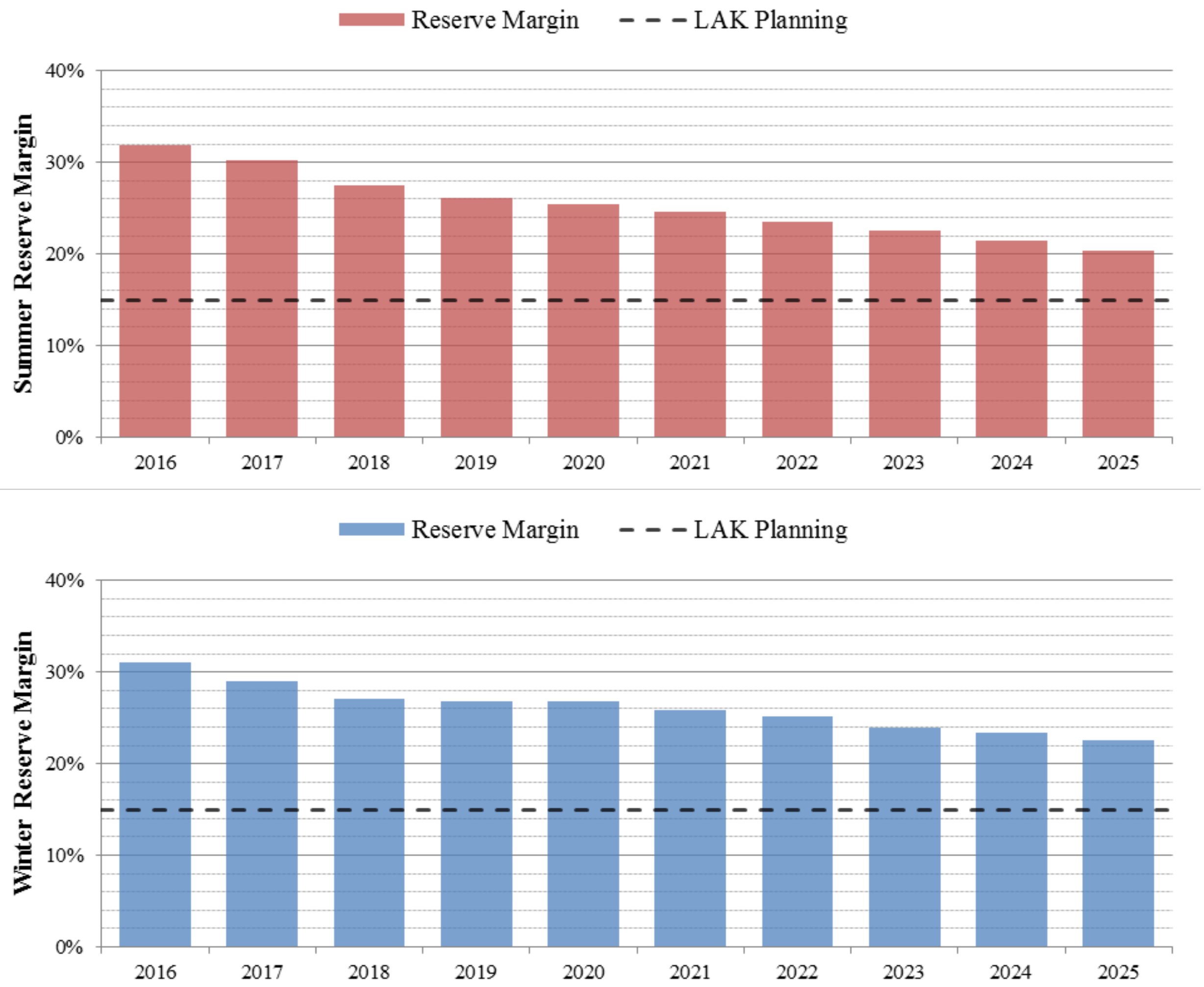
Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	2,204	**70.5%**	2,812	**83.5%**
Coal	788	**25.2%**	624	**18.5%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	1	**0.0%**
Renewable	16	**0.5%**	38	**1.1%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	118	**3.8%**	-107	**-3.2%**
Total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

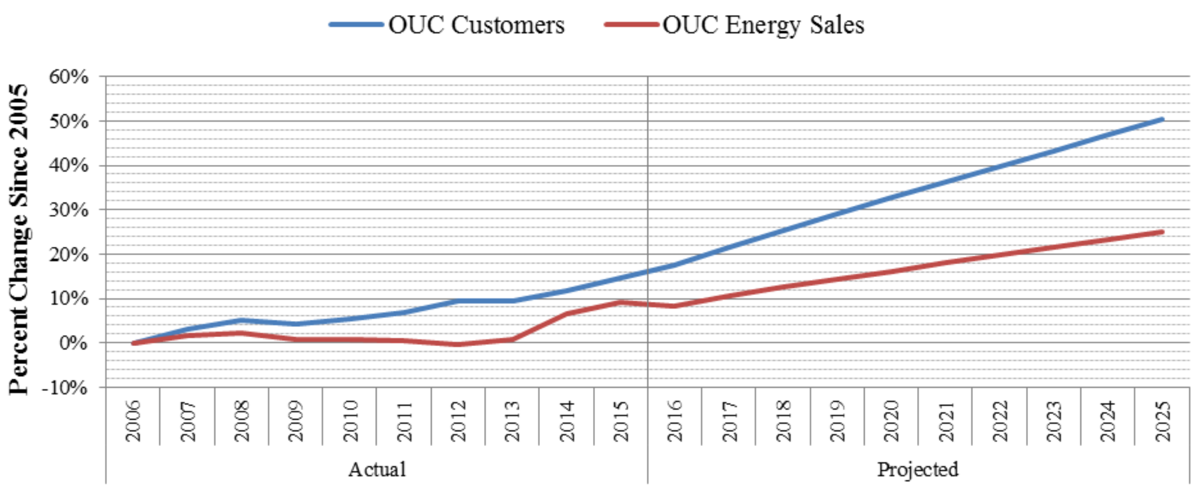
Orlando Utilities Commission (OUC)

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.

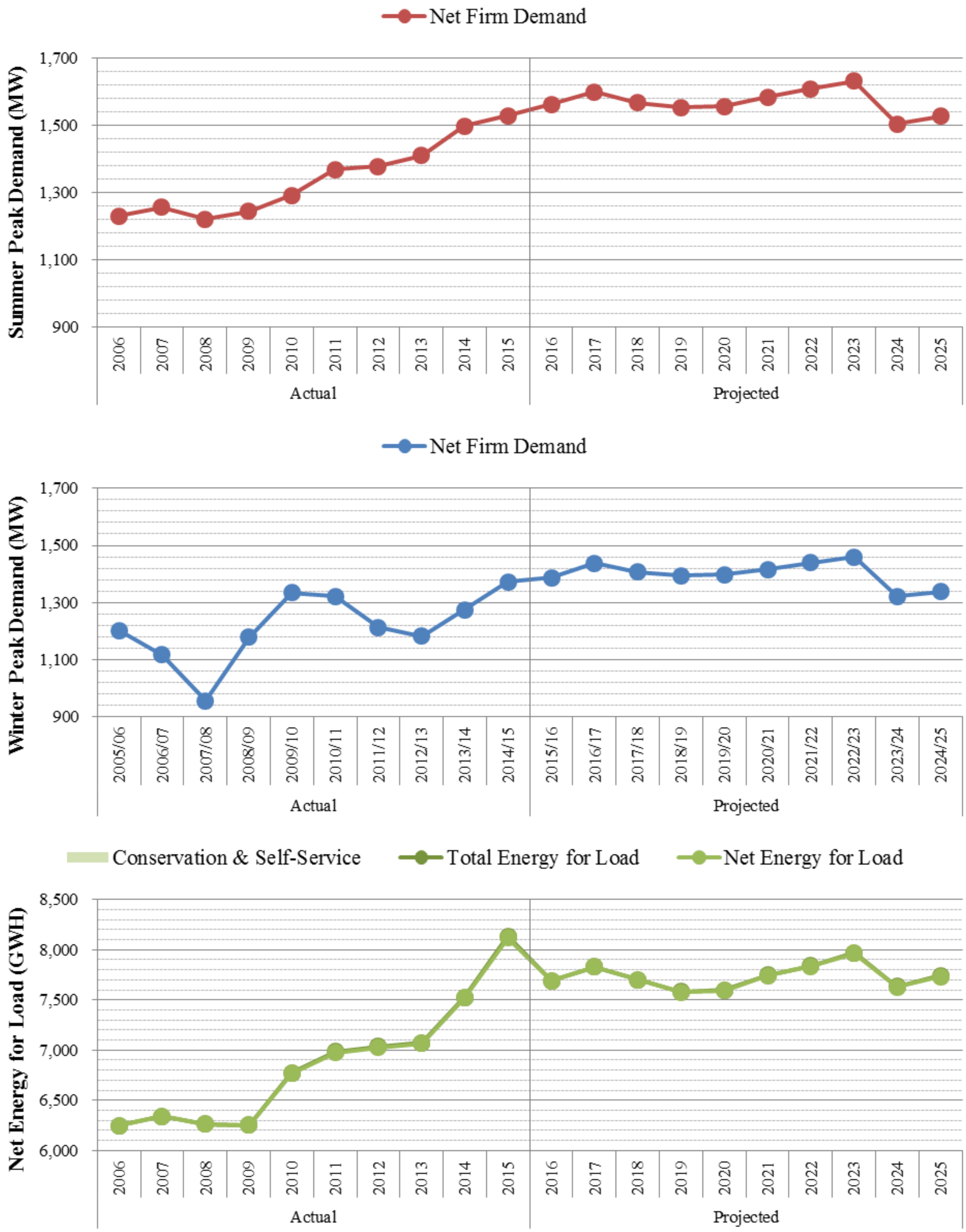
Figure 43: OUC Growth Rate



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

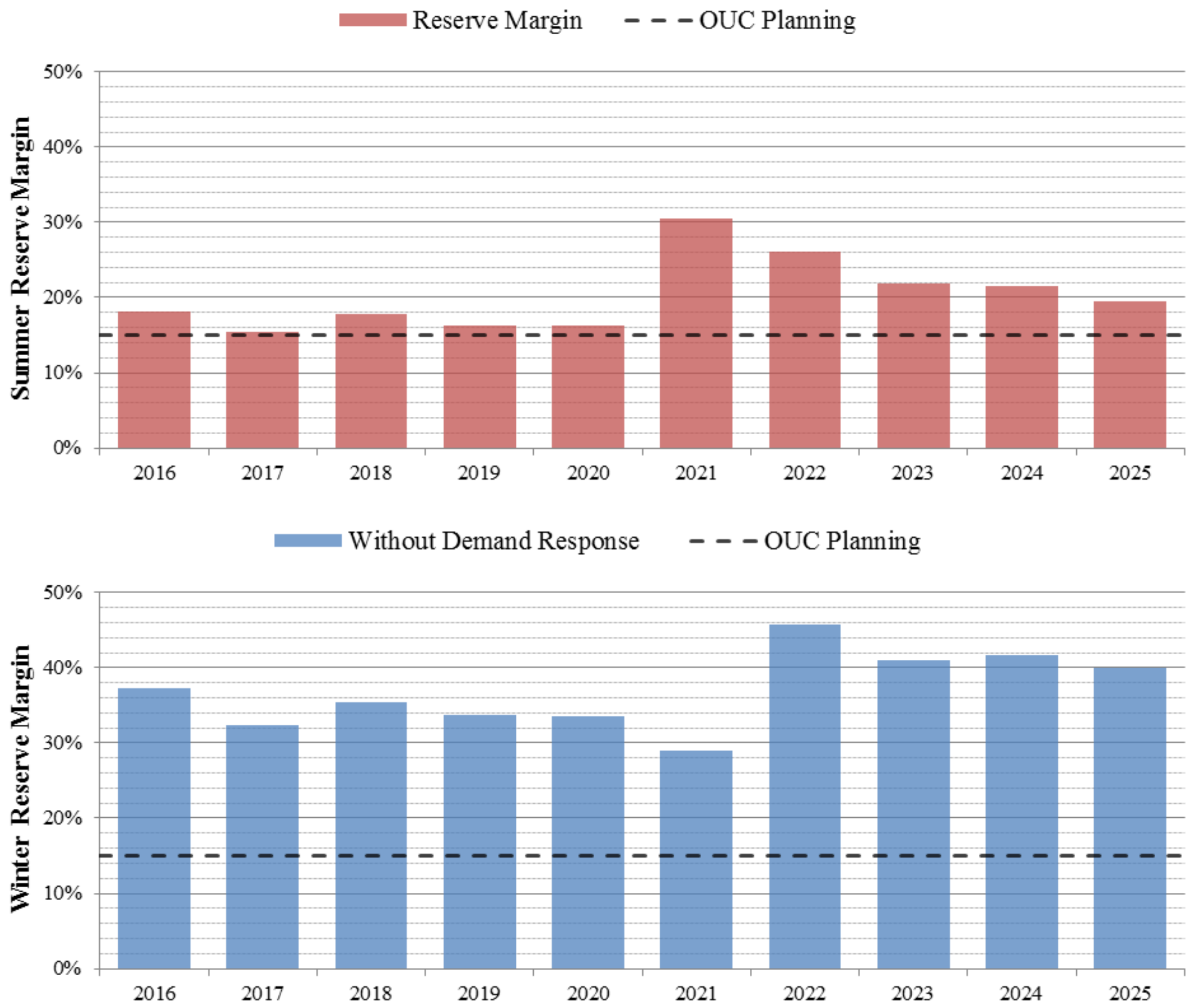
Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	4,578	**56.4%**	2,512	**32.5%**
Coal	2,990	**36.8%**	4,287	**55.4%**
Nuclear	450	**5.5%**	586	**7.6%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	102	**1.3%**	347	**4.5%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
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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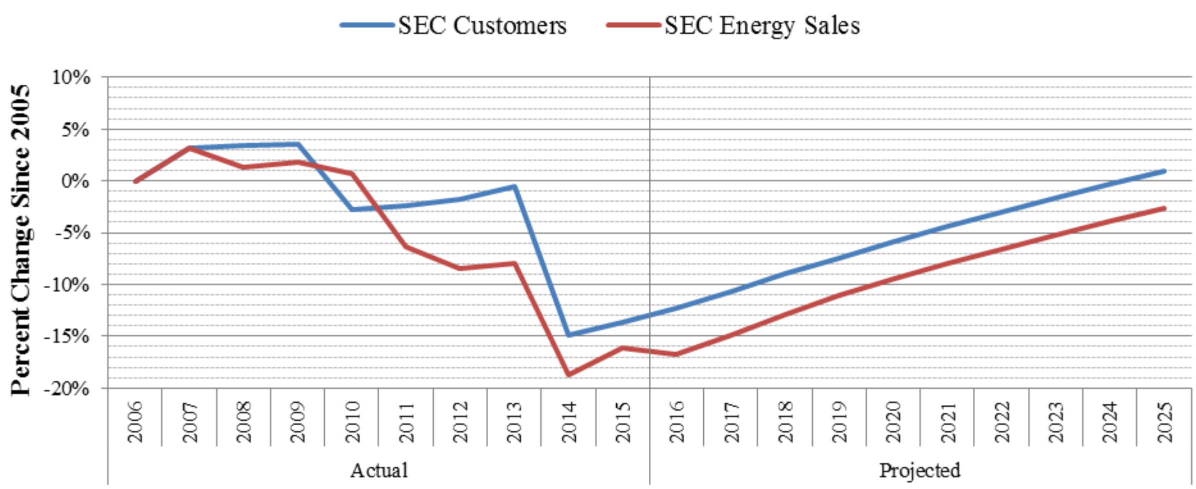
Seminole Electric Cooperative (SEC)

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.

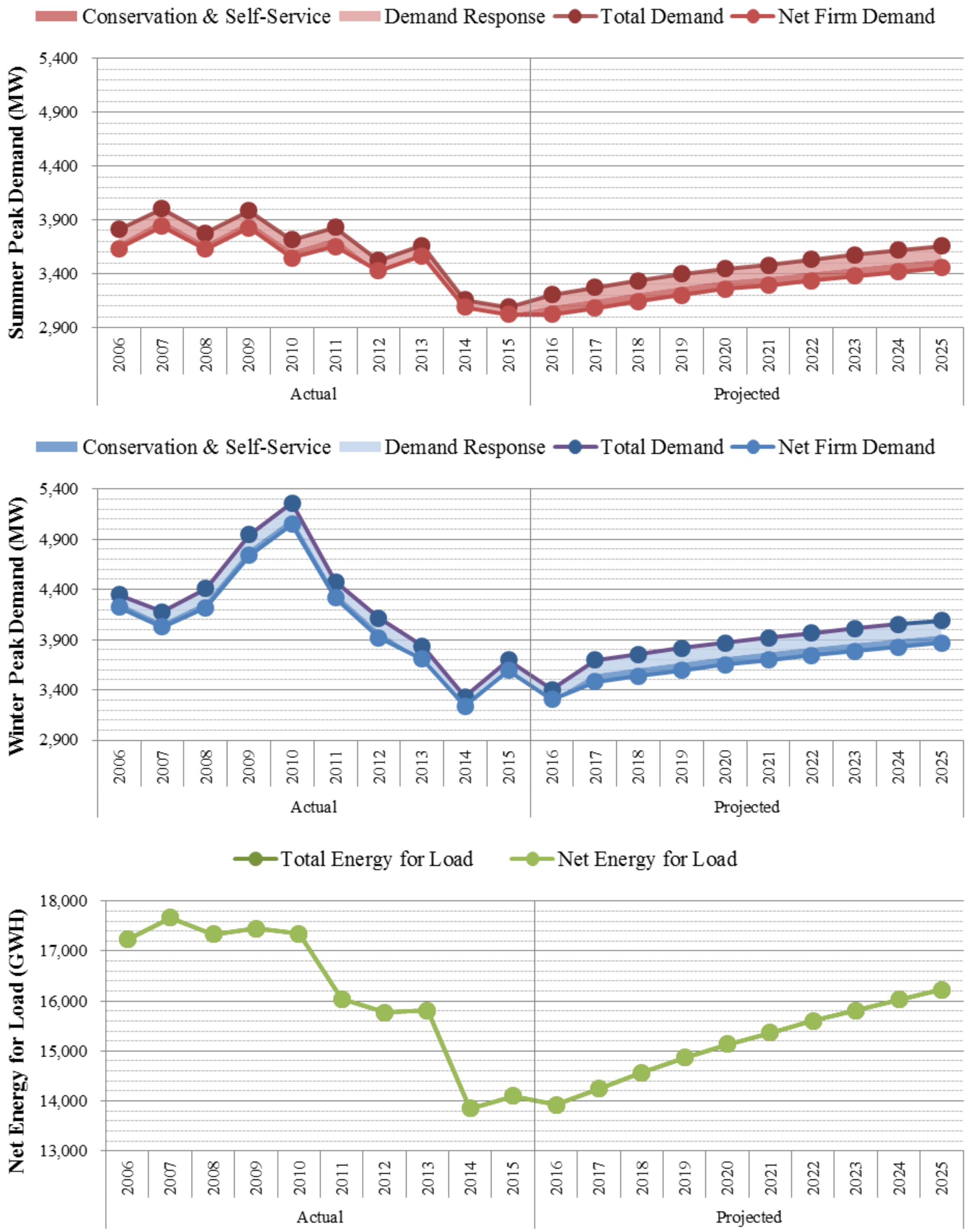
Figure 46: SEC Growth Rate



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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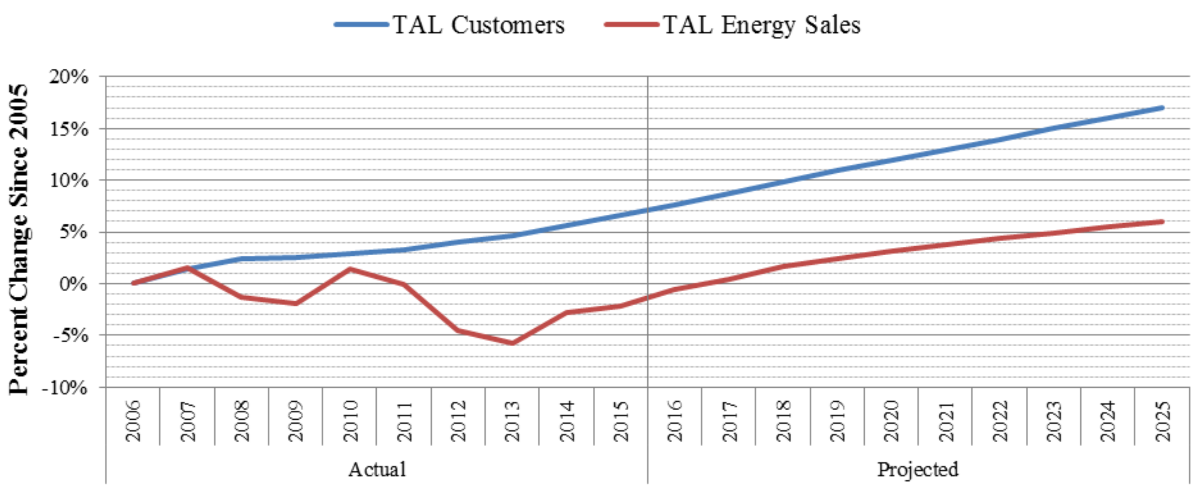
City of Tallahassee Utilities (TAL)

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.

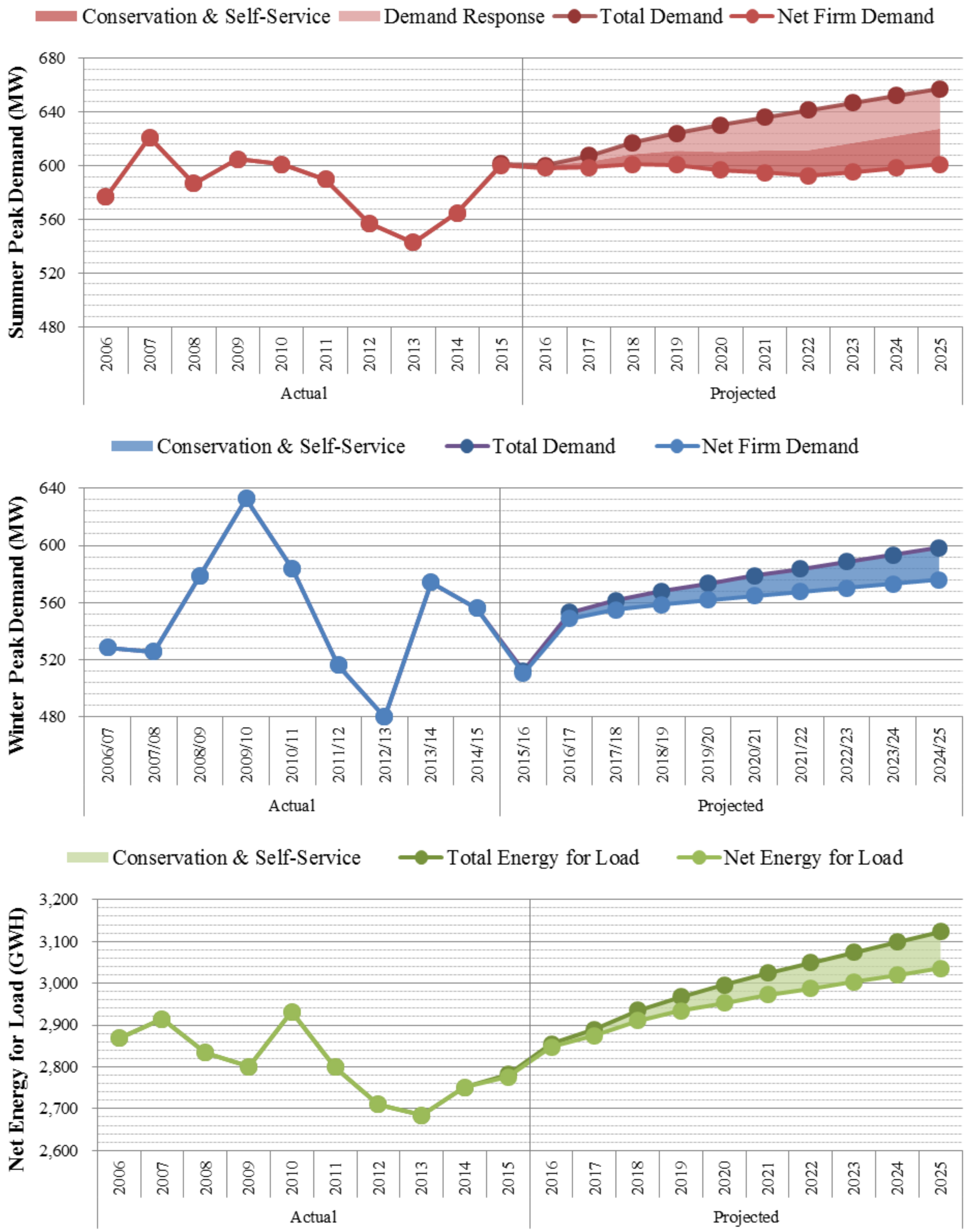
Figure 49: TAL Growth Rate



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

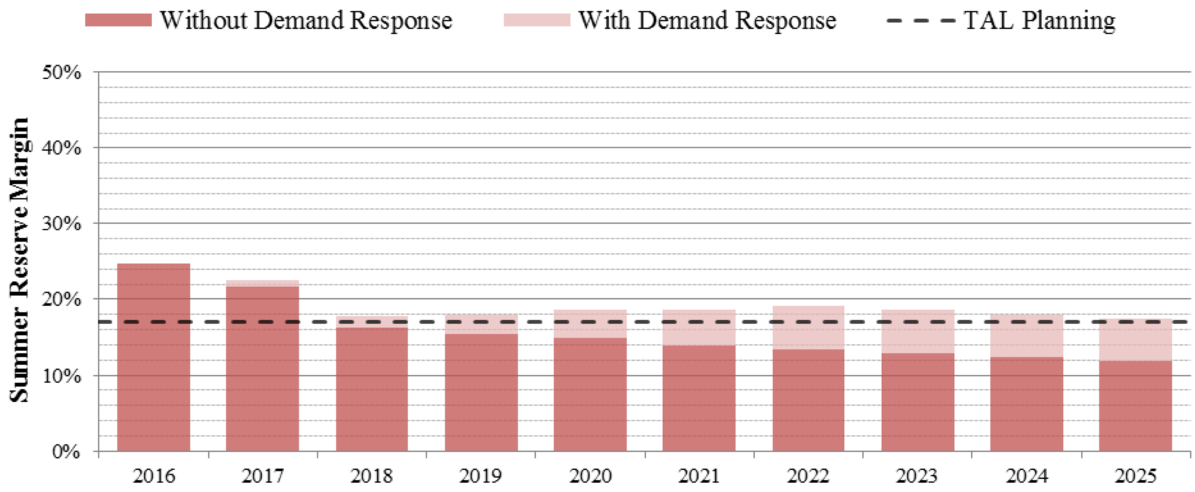
Fuel Type	Net Energy for Load			
	2015		2025	
	GWh	%	GWh	%
Natural Gas	2,704	**97.4%**	3,001	**98.9%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	16	**0.6%**	53	**1.7%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	55	**2.0%**	-20	**-0.7%**
Total	**2,775**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

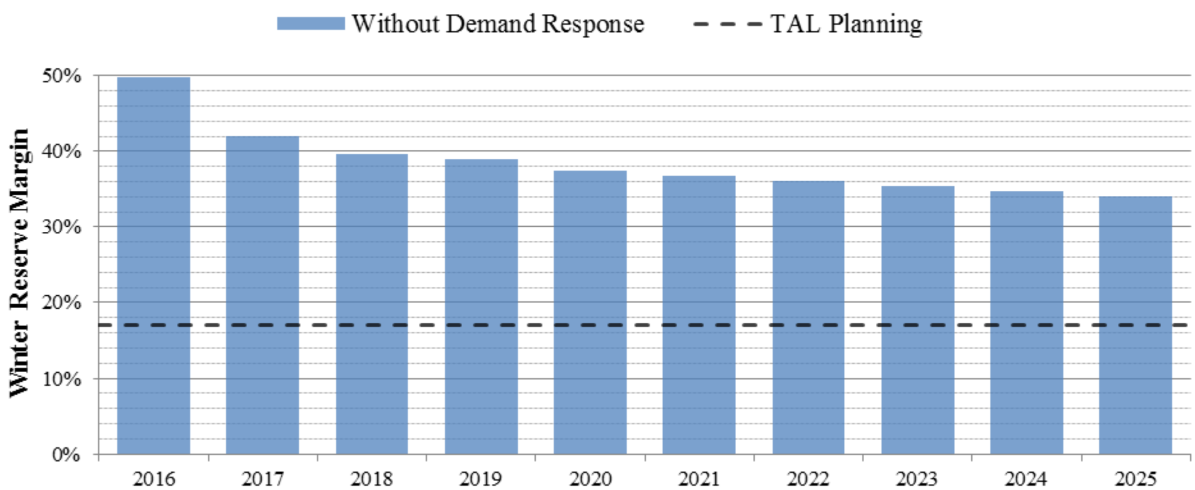
Source: 2016 Ten-Year Site Plan and Data Responses

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