REVIEW OF THE

2018 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

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 (TYSP or 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 2018 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 for its consideration at any subsequent certification proceeding pursuant to the

[1]Investor-owned utilities filing 2018 TYSPs include Florida Power & Light Company (FPL), Duke Energy Florida, LLC. (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). Municipal utilities filing 2018 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 2018 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.

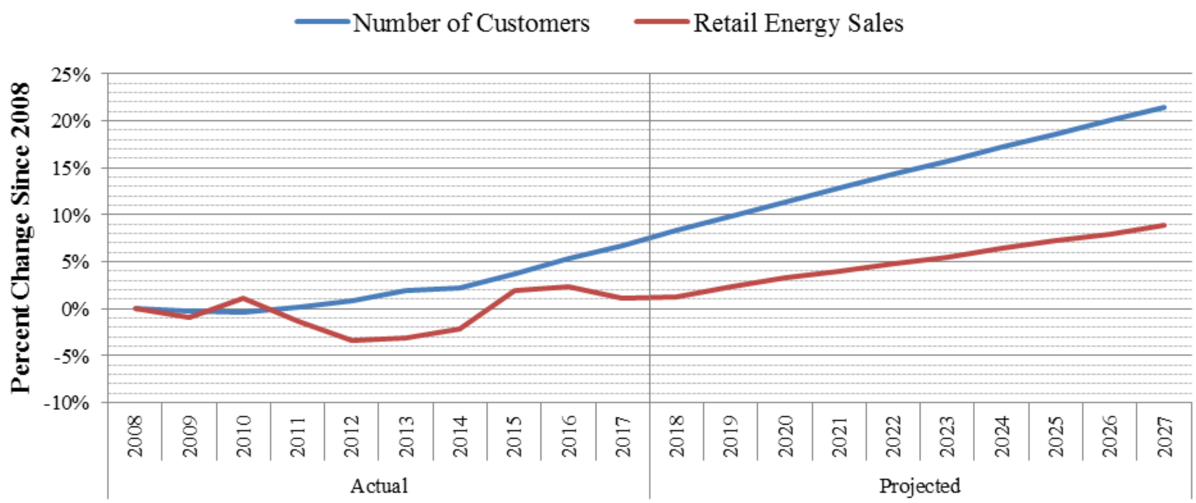
Review of the 2018 Ten-Year Site Plans

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 2010 peak by 2020. Figure 1 details these trends.

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



Source: 2018 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 Electric Transmission 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

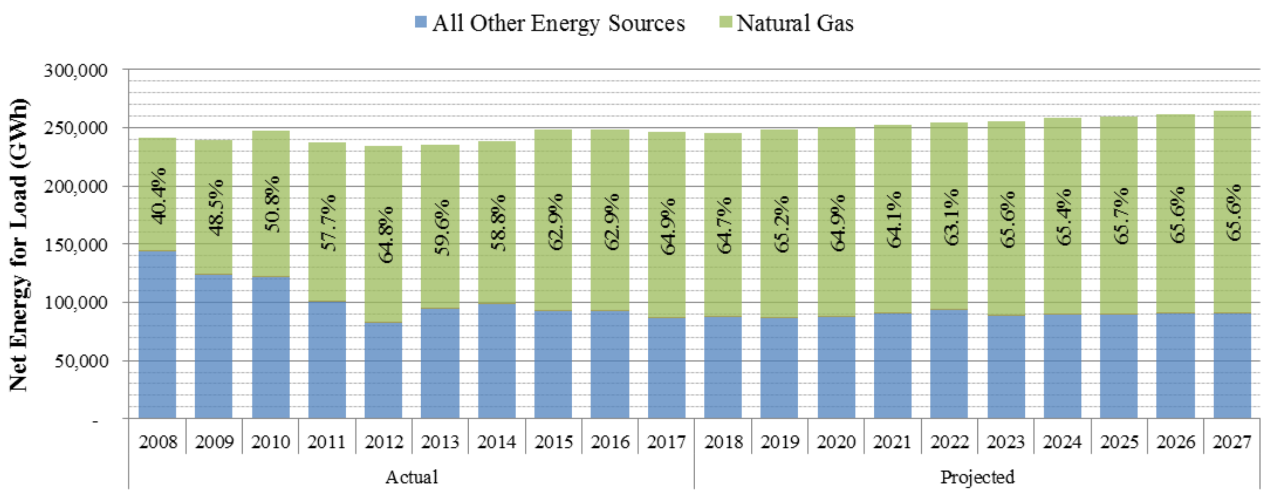
Renewable resources continue to expand in Florida, with approximately 2,583 MW of renewable generating capacity currently installed in Florida. The majority of installed renewable capacity is represented by biomass, solar, and municipal solid waste, making up approximately 73 percent of Florida's renewables. Other major renewable types, in order of capacity contribution, include waste heat, wind, landfill gas, and hydroelectric. Notably, Florida electric customers had installed 205 MW of demand-side renewable at the end of 2017, resulting in an increase in capacity of 45.4 percent from 2016.

Florida's total renewable resources are expected to increase by an estimated 7,049 MW over the 10-year planning period, 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 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 during 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 Florida is anticipated to grow to meet the increase in customer demand, with approximately 8,190 MW of new utility-owned generation added over the planning horizon. This figure represents a decrease from the previous year, which estimated the need for about 8,850 MW new generation. While natural gas usage is expected to grow slowly, natural gas remains the dominant fuel over the planning horizon, with usage in 2017 at approximately 65 percent of the state's net energy for load (NEL). Figure 2 illustrates the use of natural gas as a generating fuel for electricity production in Florida.

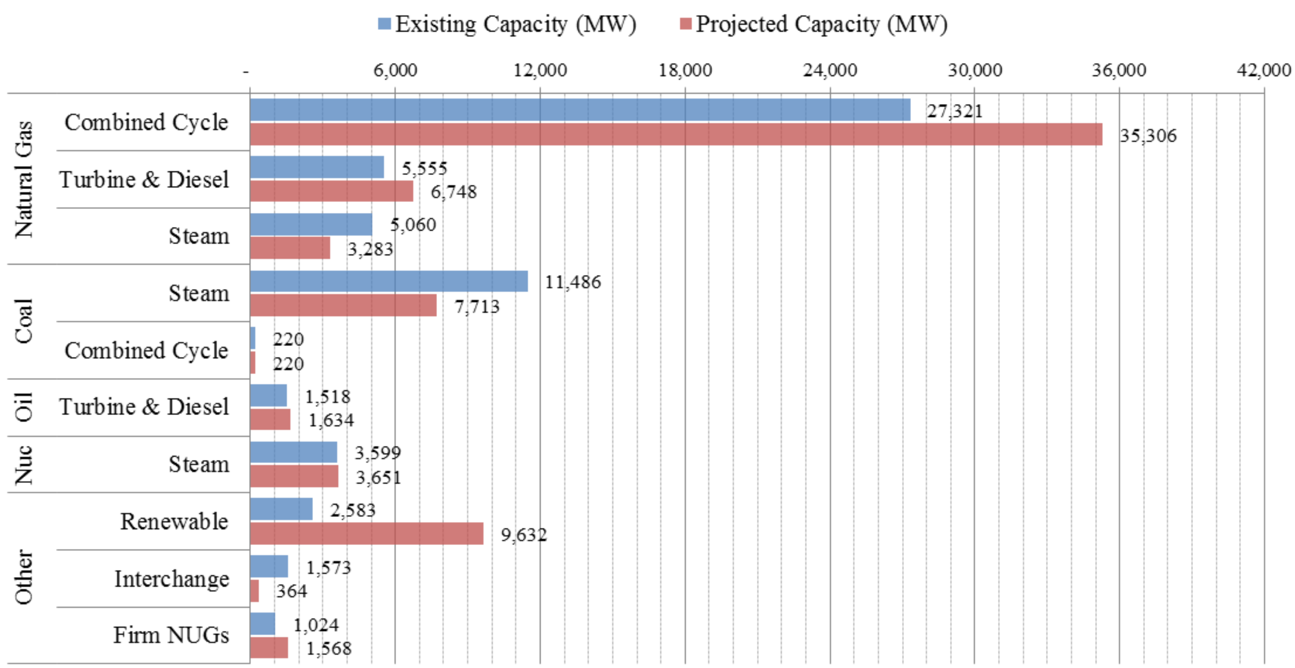
Figure 2: State of Florida - Natural Gas Contribution to Energy Consumption



Source: 2009-2018 FRCC Load and Resource Plan

Based on the 2018 Ten-Year Site Plans, Figure 3 illustrates the present and future aggregate capacity mix 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. However, this planning cycle differs from previous cycles in that renewable capacity is projected to surpass coal generation, becoming the second highest installed capacity source in the state.

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



Source: 2018 FRCC Load & Resource Plan and TYSP Data Responses

As noted previously, the primary purpose of this review is to provide information regarding proposed electric power plants for local and state agencies to assist in the certification process. Table 1 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)
2024	GPC	Unspecified CC	Natural Gas Combined Cycle	595

Source: 2018 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.

The 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, the EPA also published final rules setting carbon emissions limits for new facilities. On October 10, 2017, the EPA proposed a repeal of the Clean Power Plan. On August 21, 2018, as part of its proposed Affordable Clean Energy Rule, the EPA proposed updates to the New Source Review permitting program that may impact utility decisions regarding power plant modifications and reconstruction. These recent regulatory developments will be addressed in a subsequent Ten-Year Site Plan review, and the potential effects on Florida's electric utilities are not considered as part of this review

Conclusion

The Commission has reviewed the 2018 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 2018 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.

Introduction

The Ten-Year Site 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

Section 186.801, F.S., requires all major generating electric utilities submit a Ten-Year Site Plan to the Commission at least every two years. 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 2018 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.

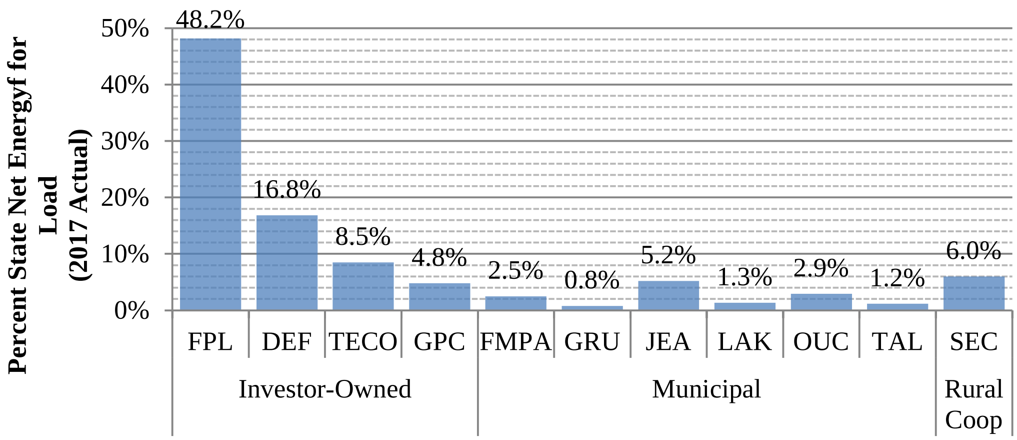
Applicable Utilities

Florida is served by 57 electric utilities, including 5 investor-owned utilities, 35 municipal utilities, and 17 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 2018, 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 2018 Plan is Seminole Electric Cooperative (SEC). Collectively, these utilities are referred to as the Ten-Year Site Plan Utilities (TYSP Utilities).

Figure 4 illustrates the comparative size of the TYSP Utilities, in terms of each utility's percentage share of the state's retail energy sales in 2017. Combined, the reporting investor-owned utilities account for 78.3 percent of the state's retail energy sales. The reporting municipal and cooperative utilities make up approximately 19.9 percent of the state's retail energy sales.

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



Source: 2018 Ten-Year Site Plans, 2018 FRCC 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 used for this review 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.

Commission staff held a public workshop on October 29, 2018, (previously scheduled for October 11, 2018), to facilitate discussion of the annual planning process and allow for public comments. A presentation was conducted by the FRCC summarizing the 2018 Load and Resource Plan and other related matters, including fuel supply reliability, environmental regulations, and physical security of infrastructure. Presentations were also provided by FPL and DEF, on battery storage.

Structure of the Commission's Review

The Commission's review is divided into multiple sections. The Statewide Perspective provides an overview 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. Comments collected from various review agencies, local governments, and other organizations are included in Appendix A.

Conclusion

Based on its review, the Commission finds all 11 reporting utilities' 2018 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.

Statewide Perspective

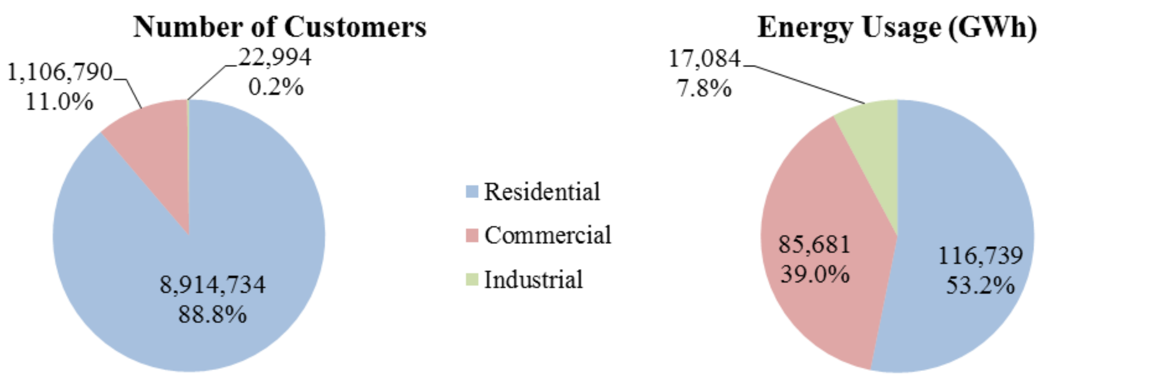
Load Forecasting

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

Utility companies categorize their customers by residential, commercial, and industrial classes. As of January 1, 2018, residential customers account for 88.8 percent of the total, followed by commercial (11.0 percent) and industrial (0.2 percent) customers, as illustrated in Figure 5 Commercial and industrial customers make up a sizeable percentage of energy sales, due to their higher energy usage per customer.

Figure 5: State of Florida - Electric Customer Composition in 2017



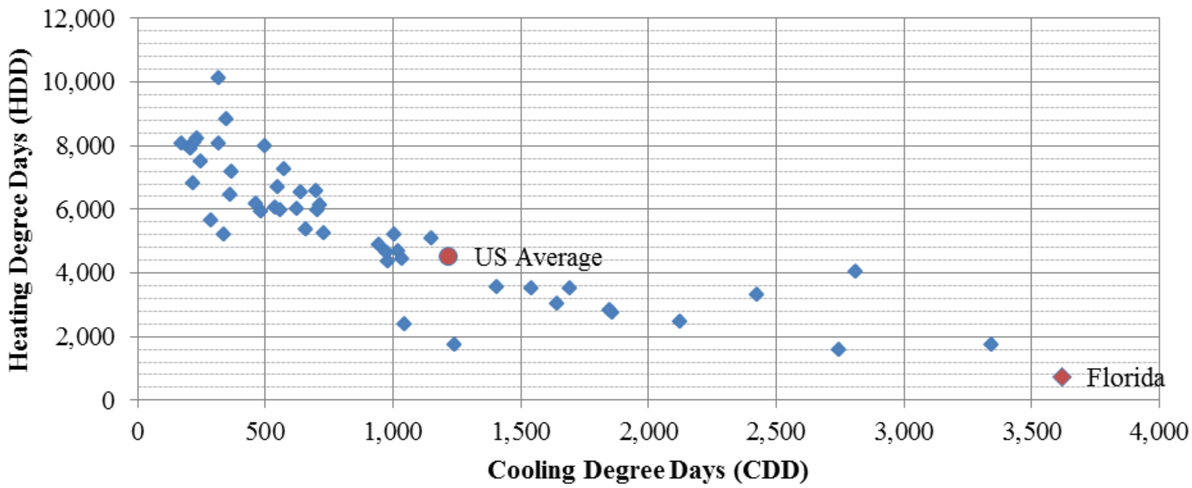
Source: FRCC 2018 Load & Resource Plan

Residential customers in Florida make up the largest portion of retail energy sales. Florida's residential customers accounted for 53.2 percent of retail energy sales in 2017, compared to a national average of 37.4 percent.[3] As a result, Florida's utilities are influenced more by trends in residential energy usage, which tend to be associated with weather conditions. In addition, 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.

[3] U.S. Energy Information Administration June 2018 Electric Power Monthly.

Florida's unique climate plays an important role in electric utility planning, with the highest number of cooling degree days and lowest number of heating degree days within the continental United States, as shown 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)

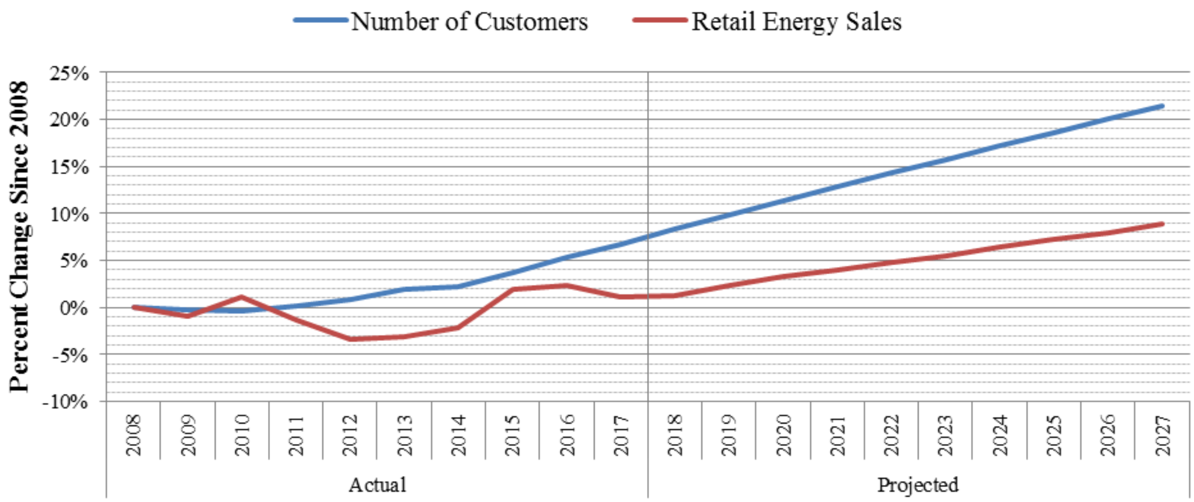


Source: National Oceanic & Atmospheric Administration, Historical Climatology Series 5-1 and 5-2

Growth Projections

For the next 10-year period, Florida's retail sales are anticipated to grow at a faster pace than the last few years, breaking a trend of flattening retail sales. While this rate remains below that experienced before 2007, it would set Florida on track to exceed its 2007 retail sales peak by 2020. 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 1.28 percent, while retail sales increase by about 0.81 percent annually. Florida's electric utilities are projecting an increase in economic growth in the state, but at levels below those experienced before 2007. The trends are showcased in Figure 7 below.

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



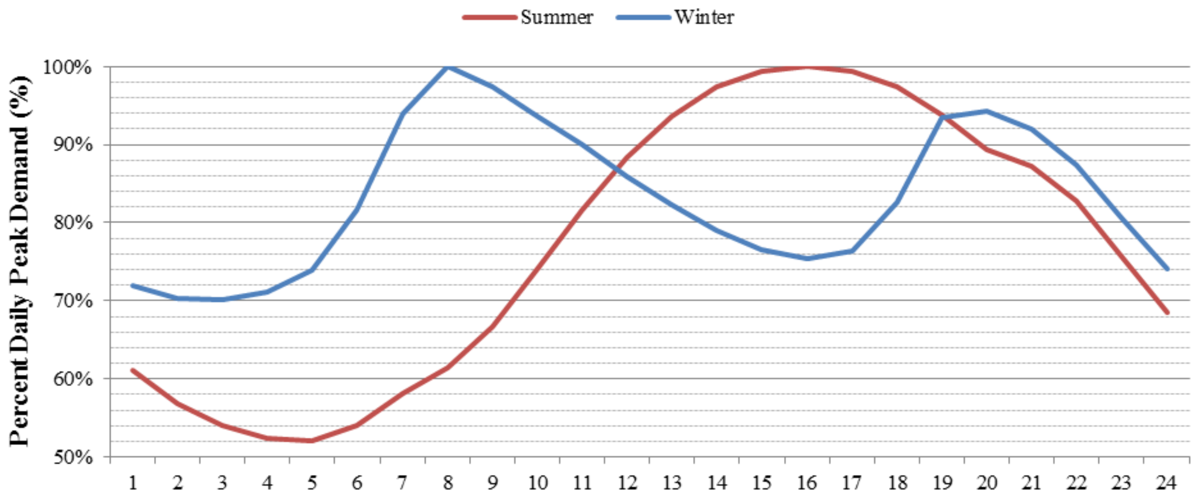
Source: FRCC 2018 Load & Resource Plan

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 dictate 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 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

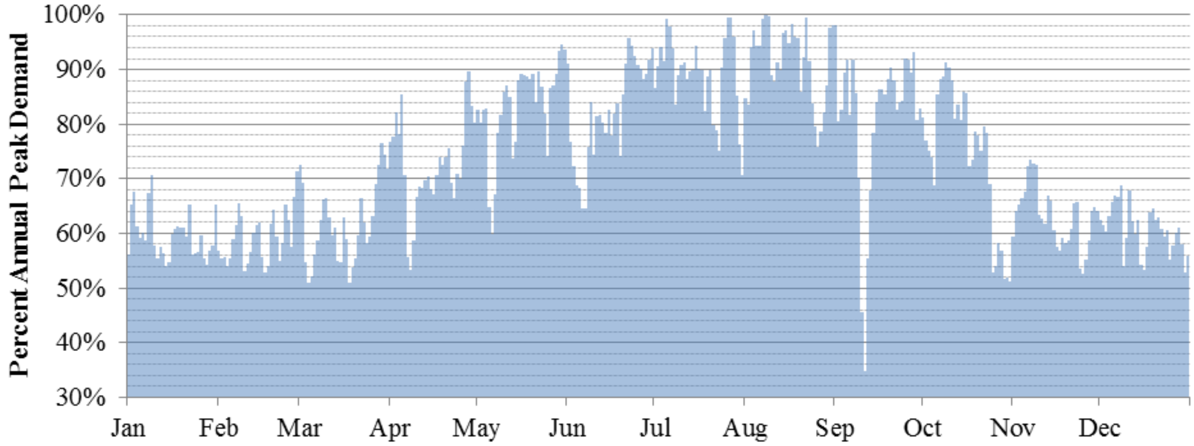


Source: TYSP Utilities Data Responses

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 shows the 2017 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 (2017 Actual)



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

Unusual events such as natural disasters can also impact load, due to evacuations and potential damage to infrastructure. These impacts, however, tend to be temporary, with system load quickly returning to season norms as infrastructure is repaired and customers return. Figure 9 exemplifies this in the loss of load shown during the first half of September, when Hurricane Irma caused widespread damage thoughout much of Florida.

Florida's utilities assume normalized weather in forecasts of peak demand. During operation of their systems, they continuously monitor 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 customer peak demand and energy consumption. These include new sources of energy consumption, such as electric vehicles, which can be considered analogous to home air conditioning systems in terms of system demand. At present, the reporting electric utilities estimate approximately 27,500 electric plug-in vehicles were operating in Florida at the end of 2017. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered automobiles, pickups, and buses in Florida, as of December 3, 2017, as 16.5 million vehicles, resulting in 0.17 percent penetration rate of electric vehicles.

Florida's electric utilities anticipate growth in the electric vehicle market, as illustrated in Table 2. Electric vehicle ownership is anticipated to grow rapidly throughout the planning period, resulting in approximately 420,000 electric vehicles operating within the electric service territories by the end of 2027.

Table 2: TYSP Utilities - Estimated Number of Electric Vehicles by Service Territory (Five-Year Rolling Average)

Year	FPL	DEF	TECO	GULF	JEA	OUC	TAL	Total
2017	17,753	4,945	2,008	449	968	485	1,365	27,488
2018	22,830	8,665	2,532	635	1,209	609	1,379	37,250
2019	29,076	12,327	2,866	809	1,527	757	1,392	47,997
2020	39,071	16,817	3,133	959	1,910	938	1,406	63,296
2021	52,564	22,573	3,385	1,094	2,351	1,160	1,420	83,387
2022	70,779	30,270	3,842	1,243	2,853	1,432	1,435	110,422
2023	95,370	40,096	4,490	1,412	3,412	1,767	1,449	146,229
2024	133,309	52,283	5,385	1,605	4,026	2,180	1,463	198,071
2025	179,786	67,271	6,899	1,861	4,698	2,690	1,478	261,993
2026	242,529	84,285	8,794	2,149	5,429	3,318	1,493	344,679
2027	290,930	103,071	11,170	2,498	6,219	4,093	1,508	419,489

Source: TYSP 2018 Data Responses

In terms of energy consumed by electric vehicles, Table 3 illustrates the estimates provided by the reporting utilities. The anticipated growth would result in an annual energy consumption of 1,697 GWh by 2027. Current estimates represent a less than 1 percent impact on net energy for load by 2027.

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

Year	FPL	DEF	TECO	GULF	JEA	OUC	TAL*	Total
2017	-	-	10.4	1.6	6.0	2.3	-	20.2
2018	30.0	4.6	13.7	2.2	7.2	2.9	-	60.6
2019	58.0	15.6	15.8	2.7	9.1	3.6	-	104.7
2020	103.0	29.7	17.5	3.2	11.4	4.4	-	169.2
2021	164.0	47.6	19.1	3.6	14.2	5.4	-	253.9
2022	246.0	71.4	22.0	4.0	17.6	6.7	-	367.7
2023	357.0	102.6	26.1	4.4	21.6	8.2	-	519.9
2024	528.0	142.8	31.7	4.9	26.1	10.1	-	743.7
2025	738.0	192.7	41.3	5.7	31.3	12.5	-	1,021.5
2026	1,021.0	252.6	53.2	6.6	37.2	15.4	-	1,386.0
2027	1,239.0	319.7	68.2	7.7	43.8	19.0	-	1,697.4

Source: TYSP 2018 Data Responses
*City of Tallahassee Utilities did not provide estimates of electric vehicle annual energy consumption.

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. As electric vehicle ownership increases, the projected impacts of electric vehicles on system peak demand should become clearer and electric utilities will be better positioned to respond accordingly.

In order to investigate potential unknowns associated with the electric vehicle energy market in Florida, several utilities have initiated Commission-approved electric vehicle pilot programs. The nature of these pilot programs vary among utilities, but include investments in vehicle charging infrastructure, research partnerships, and electric vehicle rebate programs. Utilities will note key findings and track metrics of interest within these pilot programs to help inform the Commission regarding the future power needs of electric vehicles in Florida.

Demand-Side Management

Florida's electric utilities also 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 2017 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 Utilities' proposed DSM Plans to comply with the established goals, approving the plans with some modifications in July 2015. The 2018 Ten-Year Site Plans incorporate the impacts of the DSM Plans established by the Commission for the planning period. The next FEECA goal-setting proceeding will occur in 2019, which will establish goals for the period 2020 through 2029.

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 2018, demand response available for reduction of peak load is 2,956 MW for summer peak and 2,762 MW for winter peak. Demand response is anticipated to increase to approximately 3,334 MW for summer peak and 3,124 MW for winter peak by the end of the planning period in 2027.[4]

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 2018, energy efficiency is responsible for peak load reductions of 4,333 MW for summer peak and 3,830 MW for winter peak. Energy efficiency is anticipated to increase to approximately 4,981 MW for summer peak and 4,431 MW for winter peak by the end of the planning period in 2027.[5]

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[4] TYSP Utilities Data Responses
[5] Id.

Forecast Load & Peak Demand

The historic and forecasted seasonal peak demand and annual energy consumption values for Florida are illustrated 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.

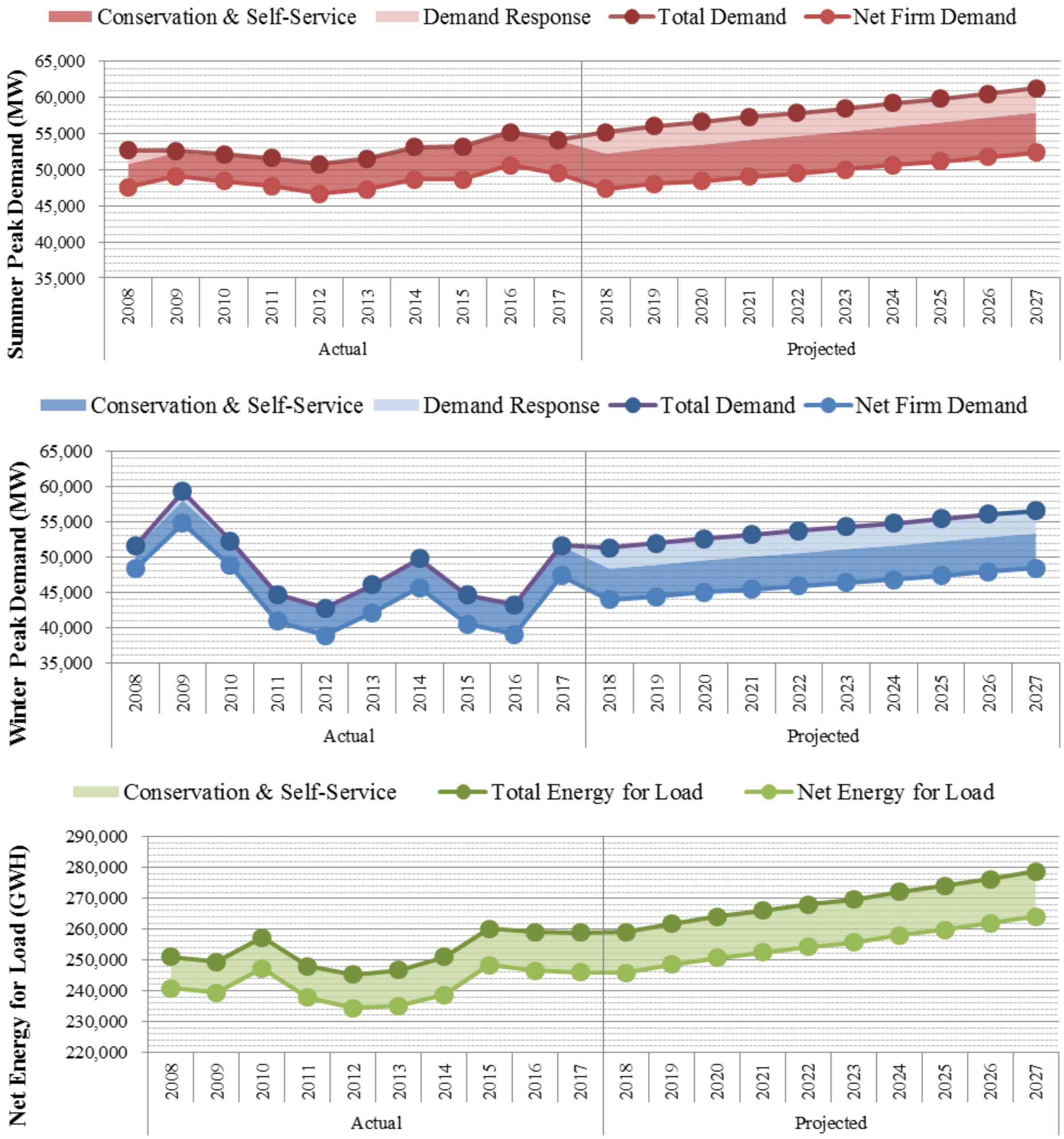
Demand-side management, including demand response and energy efficiency, along with self-service generation is included in each figure for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served if not for the impact 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, 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: 2018 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 2017 retail energy sales were compared to the forecasts made in 2012, 2013, and 2014. 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 2018 TYSPs, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2013 through 2017 to forecasts made between 2008 and 2014. As discussed previously, the period before the 2007 reccession, 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 were not included in these projections. Therefore, the use of a metric that compares pre-recession forecasts with pre-recession actual data has a high rate of error.

Table 4 shows that the forecast errors (the difference between the actual data and the forecasts made five years prior) were increasing with time starting in 2012 due to the unexpected impact of the 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 actual sales data provided in the 2017 TYSPs. The forecasting error rates (five-year rolling average and/or absolute average) derived from 2018 TYSPs show continued decreases.

Table 4: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts (Five-Year Rolling Average)

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	15.14%	15.14%
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%
2017	2016 - 2012	2013 - 2007	9.18%	9.18%
2018	2017 - 2013	2014 - 2008	6.08%	6.08%

Source: 2001-2018 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 provides the error rates for forecasts made between one to six years prior, along with the three-year average and absolute average error rates for the forecasting period of three- to five-year period used in the analysis in Table 4.

As displayed in Table 5 the utilities' retail energy sales forecasts show a consistent positive error rate beginning in 2007. The error rates reach a peak during the period 2009 through 2013. Starting in 2014, the error rates have declined considerably; and the error rates calculated based the recent years' TYSPs continue to show lower forecast error rates, compared to the peak value of the error rates related to 2009-2013 sales forecasts. Additionally, the last three years' one year ahead forecasts all bear negative error rates (under-forecast), with the current TYSPs showing an even smaller error rate.

Table 5: TYSP Utilities – Accuracy of Retail Energy Sales Forcasts – Annual Analysis (Analysis of Annual and Three-Year Average of Three- to Five- Prior Years)

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%
2016	4.49%	4.54%	2.44%	1.40%	0.35%	-0.82%	2.79%	2.79%
2017	6.99%	4.93%	3.59%	2.53%	1.57%	-0.07%	3.68%	3.68%

Source: 2001-2018 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 through 2017 in Table 5 than the significantly higher error rates shown in earlier years associated with the recession. 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 energy sales 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 2,583 MW of firm and non-firm generation capacity, which represents 4.3 percent of Florida's overall generation capacity of 59,948 MW in 2017. Table 6 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
Solar	804	31.1%
Biomass	592	22.9%
Municipal Solid Waste	484	18.7%
Waste Heat	306	11.8%
Wind*	272	10.5%
Landfill Gas	75	2.9%
Hydro	51	2.0%
Renewable Total	**2,583**	**100.00%**
*JEA's and Gulf's wind resources are not present in-state.		

Source: FRCC 2018 Load & Resource Plan and TYSP Utilities Data Responses

Of the total 2,583 MW of renewable generation, approximately 780 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 approximately 163 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 71 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 2017, approximately 205 MW of renewable capacity from over 24,000 systems has been installed statewide. Table 7 summarizes the growth of customer-owned renewable generation interconnections. Almost all installations are solar, with non-solar generation accounting for only 37 installations and 7.6 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	2010	2011	2012	2013	2014	2015	2016	2017
Number of Installations	2,833	3,994	5,302	6,697	8,581	11,626	15,994	24,166
Installed Capacity (MW)	19.9	28.4	42.2	63.0	79.8	107.5	141	205

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. However, several utilities are attributing firm capacity contributions to their solar installations based on the coincidence of solar generation and summer peak demand. Of the approximately 379 MW of existing utility-owned solar capacity, approximately 150 MW, or 40 percent, is considered firm.

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 discussed.

In 2016, the Commission approved a settlement agreement entered into by FPL that included a provision for a Solar Base Rate Adjustment (SoBRA) mechanism.[6] The SoBRA mechanism

[6] Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 20160021-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

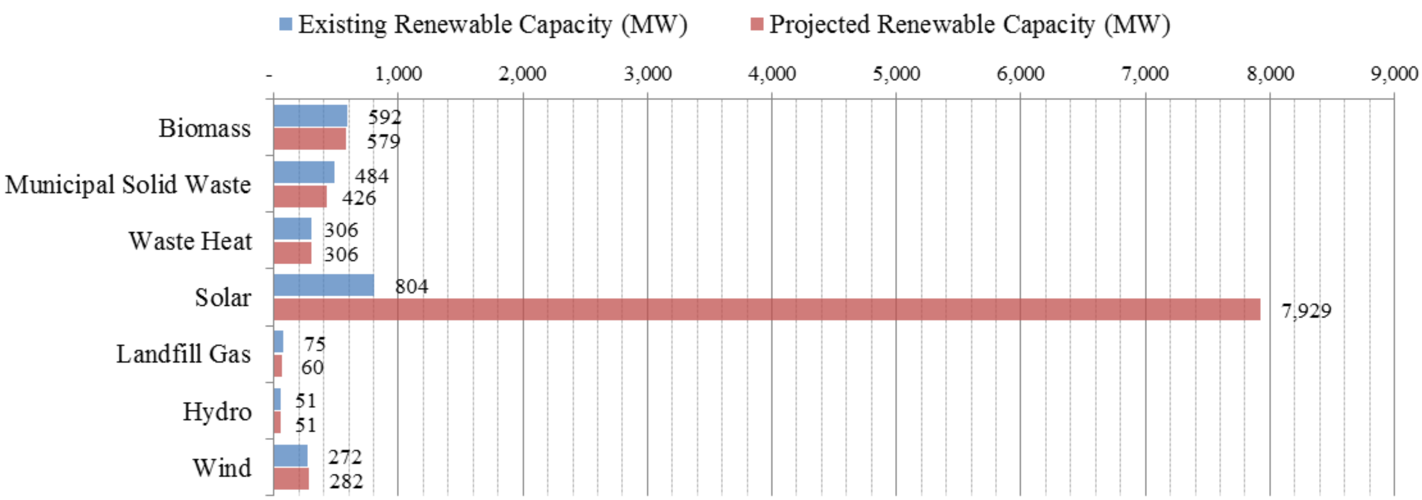
details a process by which FPL may seek approval from the Commission to recover costs for solar projects brought into service that meet certain project cost and operational criteria. In 2017, the Commission approved settlement agreements entered into by DEF and TECO that also included provisions for similar SoBRA mechanisms.[7,8] As of December 31, 2017, no solar capacity additions, through SoBRA mechanisms, have gone into commerical operation.

GPC 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 actually be delivered to GPC's system, the renewable attributes for their output are retained by GPC for the benefit of its customers.

Planned Renewable Resources

Florida's total renewable resources are expected to increase by an estimated 7,049 MW over the 10-year planning period, a significant increase from last year's estimated 4,204 MW projection. Figure 11 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[9]



Source: 2018 FRCC Load & Resource Plan, TYSP Utilities Data Responses

Of the 7,049 MW projected net increase in renewable capacity, firm resources contribute 3,155 MW, with 3,058 MW of that firm amount coming from solar generation. 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

[7] Order No. PSC-2017-0451-AS-EU, issued November 20, 2017, in Docket No. 20170183-EI, *In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC.*

[8] Order No. PSC-2017-0456-S-EI, issued November 27, 2017, in Docket No. 20170210-EI, *In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company.*

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

resources will once again be included in the state's capacity mix to serve future 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 7,125 MW to be installed. This consists of 5,551 MW of utility-owned solar and 1,574 MW of contracted solar. As a result of their settlement agreements, FPL, DEF, and TECO are projecting solar capacity additions through SoBRA mechanisms totalling 1,200 MW, 700 MW, and 600 MW, respectively. The Commission has already approved 596 MW of FPL's SoBRA capacity and 145 MW of TECO's SoBRA capacity. FPL and DEF are also projecting solar capacity additions throughout the remainder of the planning period outside of their respective SoBRA mechanisms. Table 8 lists some of the utility-scale (greater than 10 MW) solar installations with in-service dates within the planning period.

Table 8: TYSP Utilities - Planned Solar Installations

Year	Utility	Facility Name	Type	Capacity (MW)
2018	FPL	2018 Solar Projects	Utility Owned	597
2018	JEA	2018 Solar PPAs	Purchased	84
2018	TECO	Balm & Payne Creek	Utility Owned	144
			2018 Subtotal	**826**
2019	DEF	Hamilton Solar Power Plant	Utility Owned	75
2019	DEF	Solar 6, 7, & QF 3	Combined	270
2019	FPL	2019 Solar Projects	Utility Owned	300
2019	TAL	FL Solar 4 PPA	Purchased	40
2019	TECO	2019 Solar Projects	Utility Owned	279
2019	RCI	FL Solar 5 PPA	Purchased	50
			2019 Subtotal	**1014**
2020	DEF	Solar 8, 9, 10, 11, & QF 4	Combined	445
2020	FMPA	NextEra PPAs	Purchased	149
2020	FPL	Unsited Projects	Utility Owned	522
2020	OUC	Future Solar 1 & 2	Purchased	56
2020	TECO	Wimauma & Alafia	Utility Owned	125
			2020 Subtotal	**1296**
2021	DEF	Solar 12, 13, 14, & QF 5	Combined	360
2021	FPL	Unsited Projects	Utility Owned	596
2021	SECI	Tillman Solar Center	Purchased	40
2021	TECO	Lake Hancock	Utility Owned	50
			2021 Subtotal	**1045**
2022	DEF	Solar 15 & QF 6	Combined	150
2022	FPL	Unsited Projects	Utility Owned	298
2023	DEF	Solar 16 & QF 7	Combined	150
2023	FPL	Unsited Projects	Utility Owned	298
2024	DEF	Solar 17 & QF 8	Combined	150
2024	FPL	Unsited Projects	Utility Owned	298
2025	DEF	Solar 18 & QF 9	Combined	150
2025	FPL	Unsited Projects	Utility Owned	298
2026	DEF	Solar 19 & QF 10	Combined	150
2026	FPL	Unsited Projects	Utility Owned	298
2027	DEF	Solar 20 & QF 11	Combined	150
2027	FPL	Unsited Projects	Utility Owned	298
			2022 - 2027 Subtotal	**2687**
TBD	DEF	National Solar Projects	Purchased	250
			TBD Subtotal	**250**
			Total Installations	**7119**

Source: 2018 FRCC Load & Resource Plan, TYSP Utilities Data Responses

Renewable Outlook

Florida's renewable generation is projected to increase over the planning period. A significant portion of this increase can be attributed to growth in solar PV generation. As a result of the operational characteristics of these installations, namely the coincidence of solar generation and summer peak demand, some utilities are reporting a fraction of the nameplate capacity of these installations as firm resources for reliability considerations. However, emerging energy storage technologies have the potential to considerably increase not only the firm capacity contributions from solar PV installations, but their overall functionality as well.

A number of energy storage methodologies are currently being researched for utility-scale application. These include pumped hydropower, flywheels, compressed air, thermal storage, and electrochemical batteries. Among those listed, batteries are being extensively researched due to their declining costs, operational characteristics, scalability, and siting flexibility. A number of Florida utilities have developed pilot programs of varying sizes to explore where and how batteries can be incorporated into their systems. However, due to the infancy of the technology, firm capacity values are not being attributed to these programs. Nevertheless, these programs continue to explore the role battery storage can play in resource planning.

Traditional Generation

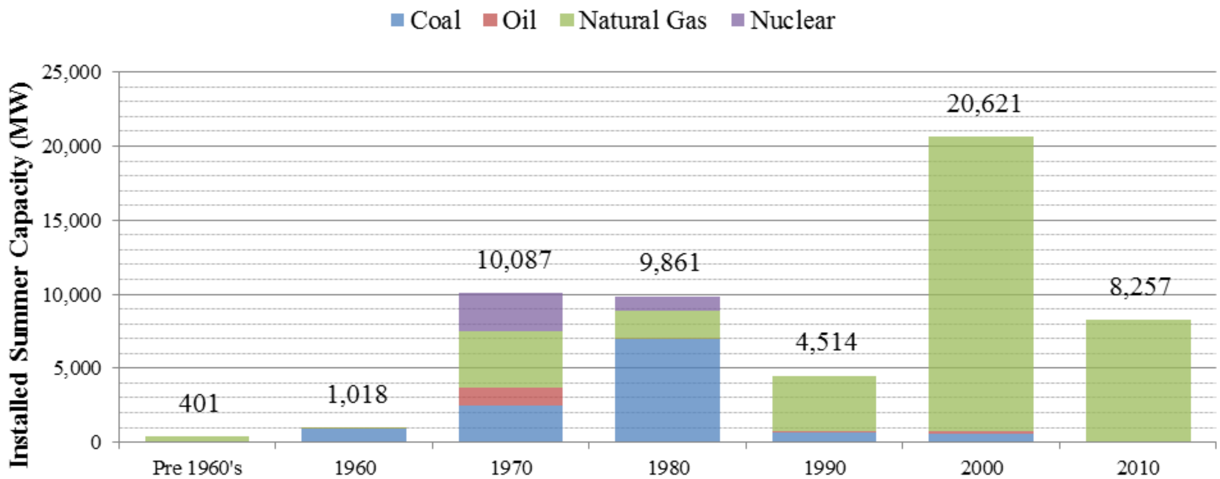
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and combustion turbine generators, that have been added to Florida's electric grid over the last several decades. 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 fuels powering 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 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: 2018 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 is currently under appeal. On August 21, 2018, as part of its proposed Affordable Clean Energy Rule, the EPA proposed updates to the New Source Review permitting program that may impact utility decisions regarding power plant modifications and reconstruction. These recent regulatory developments will be addressed in a subsequent Ten-Year Site Plan review.

- Carbon Pollution Emission Guideline for Existing Electric Generating Units (Clean Power Plan) - Requires each state to submit a plan to the 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. On October 10, 2017, the EPA proposed a repeal of the Clean Power Plan. On August 21, 2018, the EPA announced its Affordable Clean Energy Rule that replaces the Clean Power Plan. This recent regulatory development will be addressed in a subsequent Ten-Year Site Plan 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 conversions 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.[10] TECO is also modernizing its Big Bend Power Station through the conversion of Big Bend Unit 1, along with two planned combustion turbines, into a 2x1 combined cycle unit by 2023. Per the Florida Department of Environmental Protection, this conversion does not require a determination of need by the Commission. 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 lists the 6,056 MW of existing generation that is scheduled to be retired during the planning period. While the number of natural gas units scheduled for retirement (17) is greater than that of coal units (8), only 2,849 MW of natural gas-fueled capacity is being retired, as compared to 3,183 MW of coal-fueled capacity.

[10] Order No. PSC-13-0014-FOF-EI, issued January 8, 2013, in Docket No. 20120234-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)
					Summer
2018	DEF	Crystal River 1 & 2	Steam Turbine	Coal	766
2018	FPL	SJRPP 1 & 2	Steam Turbine	Coal	254
2018	FPL	Lauderdale 4 & 5	Combustion Turbine	Natural Gas	884
2018	FPL	Martin 1 & 2	Steam Turbine	Natural Gas	1626
2018	JEA	SJRPP 1 & 2	Steam Turbine	Coal	1002
2018	TAL	Purdom 2	Combustion Turbine	Natural Gas	10
2018	TAL	Hopkins 1	Steam Turbine	Natural Gas	76
		2018 Subtotal			**4,618**
2020	DEF	Avon Park 1	Combustion Turbine	Natural Gas	24
2020	DEF	Avon Park 2	Combustion Turbine	Distillate Fuel Oil	24
2020	DEF	Higgins 1 - 4	Combustion Turbine	Natural Gas	107
		2020 Subtotal			**155**
2021	TECO	Big Bend 2	Steam Turbine	Coal	385
		2021 Subtotal			**385**
2022	GRU	Deerhaven FS01	Steam Turbine	Natural Gas	75
		2022 Subtotal			**75**
2023	SECI	Seminole Generating Station 1 or 2*	Steam Turbine	Coal	626
		2023 Subtotal			**626**
2024	GPC	Crist 4	Steam Turbine	Coal	75
		2024 Subtotal			**75**
2025	GPC	Pea Ridge 1 - 3	Combustion Turbine	Natural Gas	12
		2025 Subtotal			**12**
2026	GRU	Deerhaven GT01 & GT02	Combustion Turbine	Natural Gas	35
2026	GPC	Crist 5	Steam Turbine	Coal	75
		2026 Subtotal			**110**
		Total Retirements			**6,056**

* SECI has not determined whether to retire SGS 1 (626 MW) or SGS 2 (634 MW) at this time.

Source: 2018 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 has 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. Another notable retirement is the St. Johns River Power Park (SJRPP) Units 1 and 2. The SJRPP is a large coal-fired generation facility that is jointly owned by both JEA and FPL and should be fully retired by 2019. Finally, TECO's retirement of its Big Bend Unit 2 in 2021 is part of the previously mentioned modernization of its Big Bend Power Station.

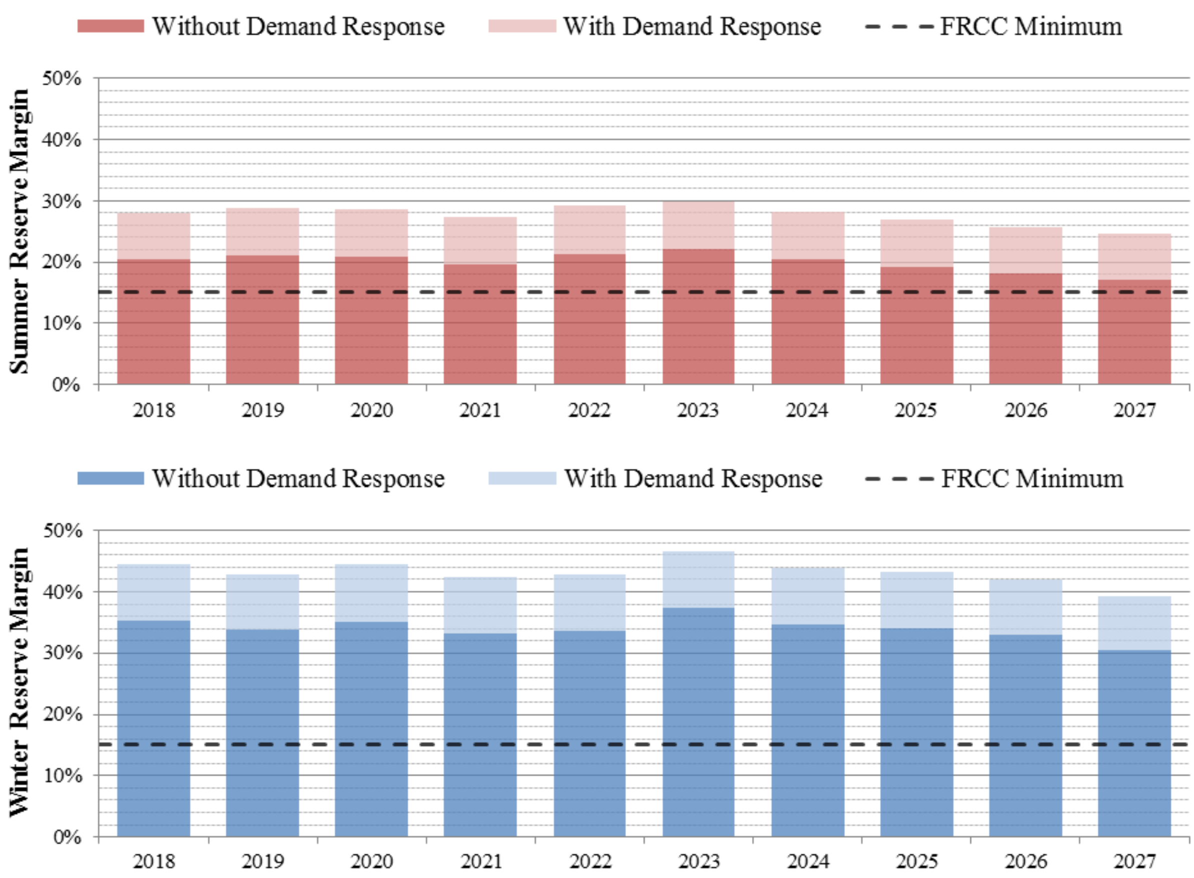
Reliability Requirements

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 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: 2018 FRCC Load & Resource Plan

Role of Demand Response in Reserve Margin

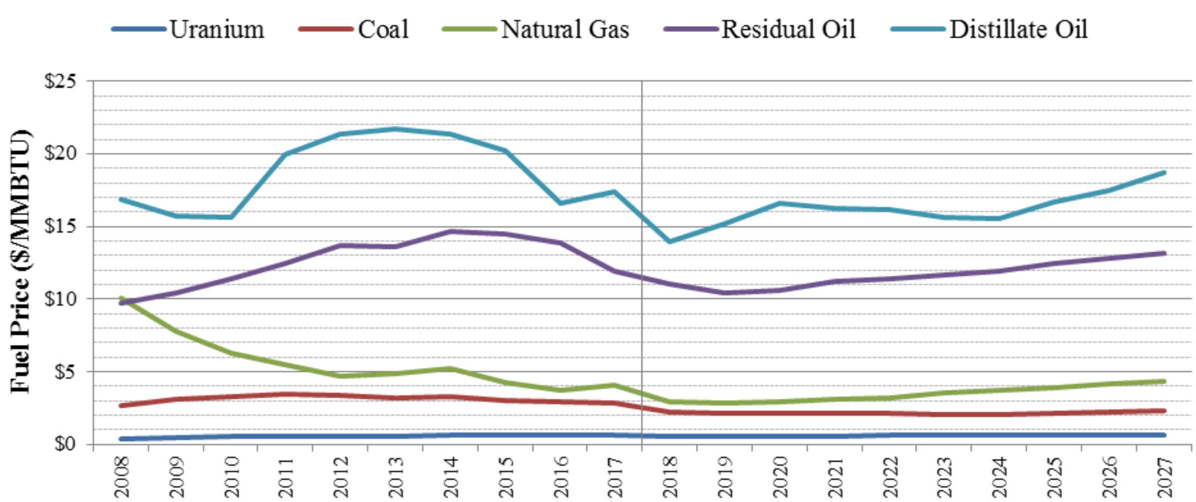
The Commission also considers the planning reserve margin without demand response. As illustrated above in Figure 13, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin without activation of demand response. Demand response activation increases the reserve margin in summer by 7.7 percent on average, and represents 28 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 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

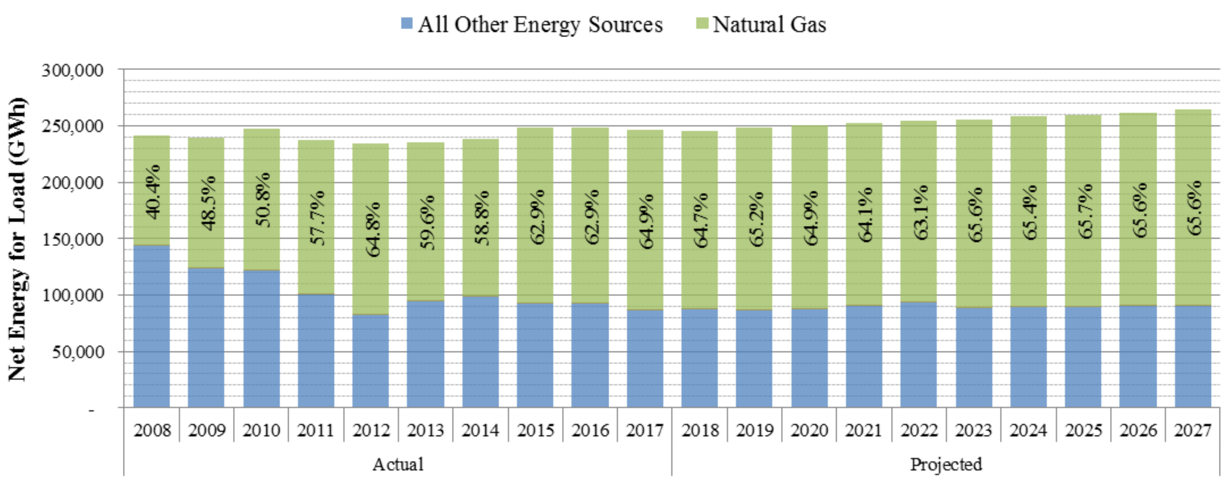
From 2003 to 2005, the price of natural gas was substantially higher than utilities had forecast. This natural gas price volatility led to concern regarding escalating customer bills and an expectation that natural gas prices would remain high. As a result, Florida's electric utilities began making plans 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 not to 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.

The price of natural gas declined rapidly after 2008, 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.

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 15 illustrates, natural gas is the source of approximately 65 percent of electric energy consumed in Florida. Natural gas generation is anticipated to remain somewhat steady at its current level until the end of the planning period.

Figure 15: State of Florida - Natural Gas Contribution to Energy Consumption

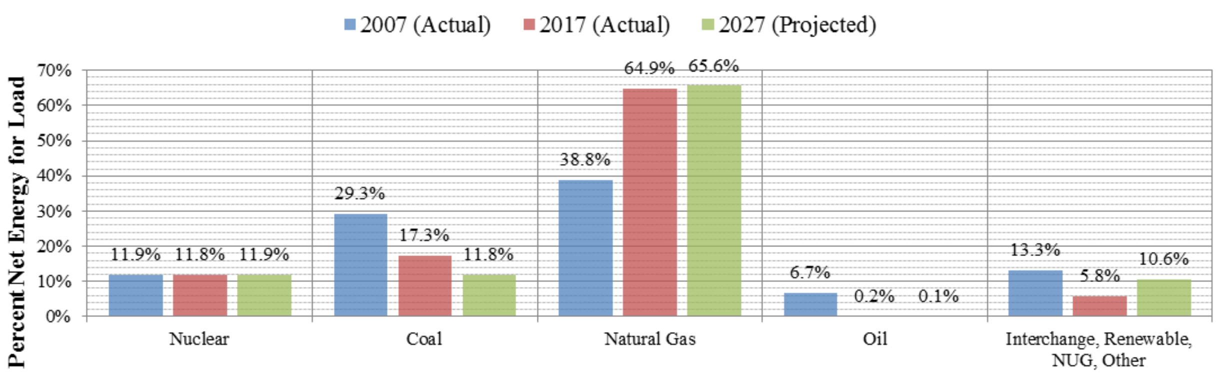


Source: 2008-2018 FRCC Load & Resource Plans

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 16 shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2007 and 2017, and forecast year 2027. 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. Coal generation is expected to continue its downward trend well into the planning period. Natural gas has been the primary fuel used to meet the growth of energy consumption, and this trend is anticipated to continue throughout the planning period.

Figure 16: State of Florida - Historic and Forecast Fuel Consumption



Source: 2008-2018 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.

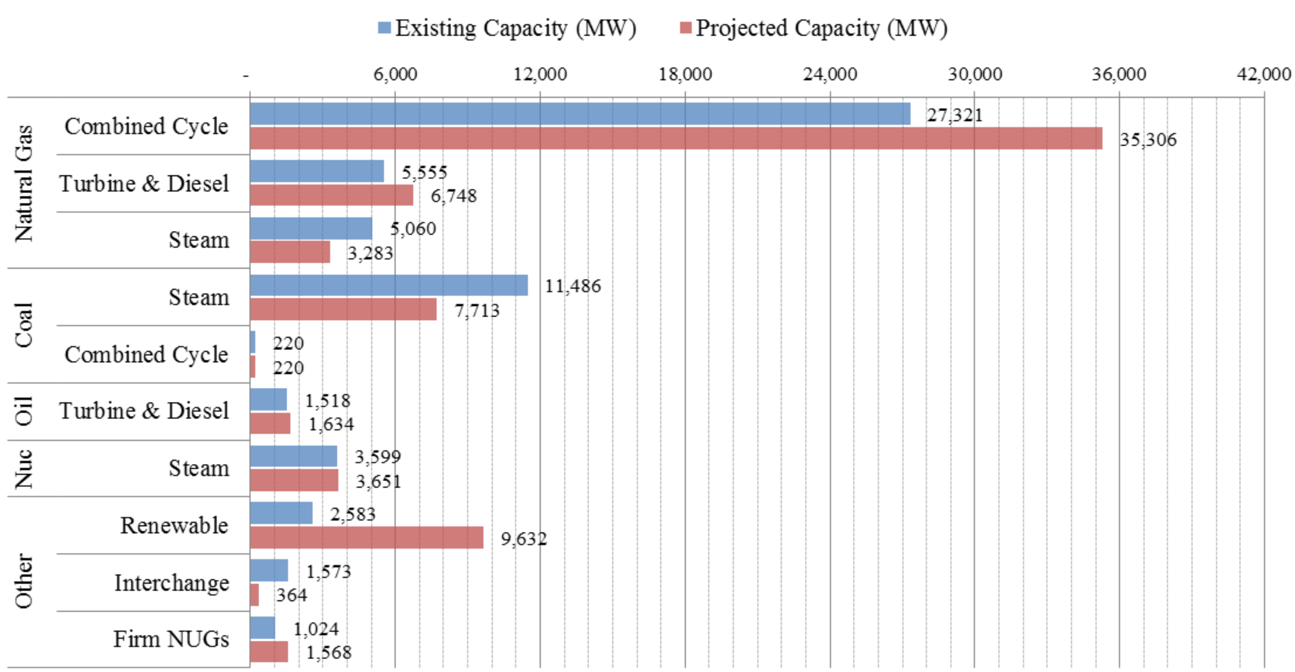
New Generation Planned

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 17 illustrates the present and future aggregate capacity mix. The capacity values in Figure 17 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2018 Ten-Year Site Plans and the FRCC's 2018 Load and Resource Plan.

Figure 17: State of Florida - Current and Projected Installed Capacity by Fuel



Source: 2018 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 have minimal uprates planned for 2018 and 2019. FPL had previously uprated its existing four nuclear generating units, with the last uprate completed in early 2013.

Natural Gas

Excluding renewables and minor nuclear and coal generation uprates, all remaining new power plants are natural gas-fired combustion turbines, internal combustion units, 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. As 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 summarizes the approximately 8,190 MW of proposed new natural gas-fired generation included in the 2018 Ten-Year Site Plans. Of this amount, approximately 6,441 MW are already under construction or have been previously certified.

Table 10: State of Florida - Planned Natural Gas Units

In-Service Year	Utility Name	Plant Name & Unit Number	Net Capacity (MW)	Notes
Previously Approved New Units				
2018	DEF	Citrus	1,640	Docket No. 20140110-EI
2019	FPL	Okeechobee Energy Center	1,778	Docket No. 20150196-EI
2022	FPL	Dania Beach Energy Center	1,163	Docket No. 20170225-EI
2022	SEC	Seminole CC Facility*	1,108	Docket No. 20170266-EI
			Subtotal	**5,689**
New Units Requiring PPSA Approval				
2024	GPC	Unspecified CC	595	
			Subtotal	**595**
New Units Not Requiring PPSA Approval				
2018	TAL	Sub 12 IC 1-2	18	
2018	TAL	Hopkins IC 1-4	74	
2021	TEC	Big Bend CT5 & CT6	660	Convert to CC in 2023
2023	TEC	Future CT 1	229	Not under construction
2025	TAL	Hopkins IC 5	18	
2026	TEC	Future CT 2	229	
2027	DEF	Undesignated CT P1	226	
2027	DEF	Undesignated CT P2	226	
2027	DEF	Undesignated CT P3	226	
			Subtotal	**1,906**
			Total Planned Natural Gas Capacity	**8,190**
* The Seminole CC Facility's Determination of Need is currently under appeal.				

Source: 2018 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 595 MW of generation that would require certification under the PPSA. Based on the unit type, GPC may be filing a need determination sometime in 2019.

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 lists all proposed transmission lines in the 2018 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	06/01/2019
FPL	Duval - Raven	45	230	02/25/2016	06/29/2016	12/01/2018
TECO	Thonotosassa Wheeler	8	230	06/21/2007	08/07/2008	TBD
TECO	Wheeler to Willow Oak	17	230	06/21/2007	08/07/2008	TBD

Source: 2018 Ten-Year Site Plans

Utility Perspectives

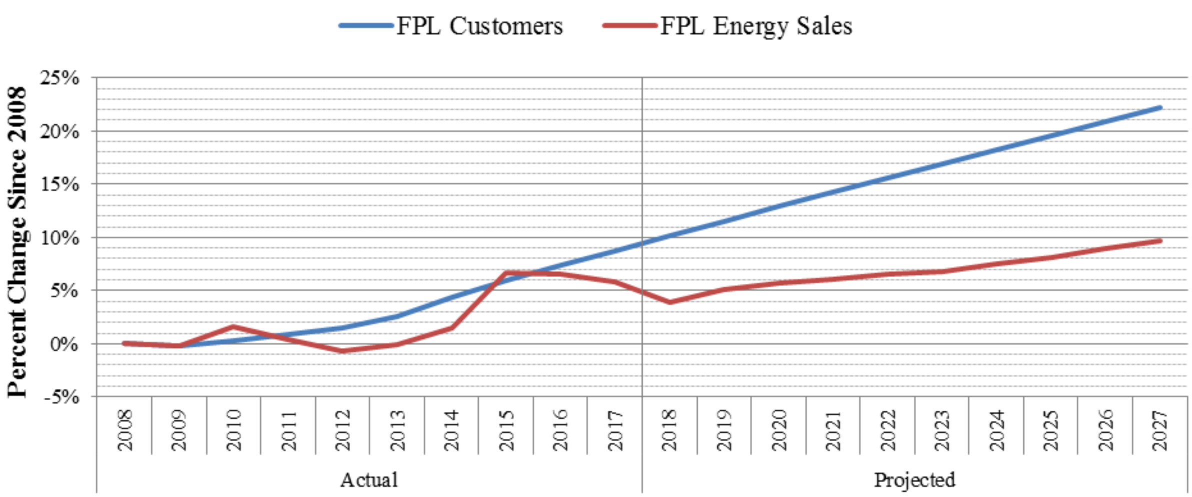
Florida Power & Light Company (FPL)

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 2018 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2017, FPL had approximately 4,901,886 customers and annual retail energy sales of 108,871 GWh or approximately 48.2 percent of Florida's annual retail energy sales. Figure 18 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the past 10 years, FPL's customer base has increased by 8.70 percent, while retail sales have grown by 5.78 percent. As illustrated, FPL's retail energy sales are anticipated to exceed its historic 2015 peak in 2023. Since 2009, FPL has been outperforming the state average in retail energy sales growth, a trend it projects to continue into the future.

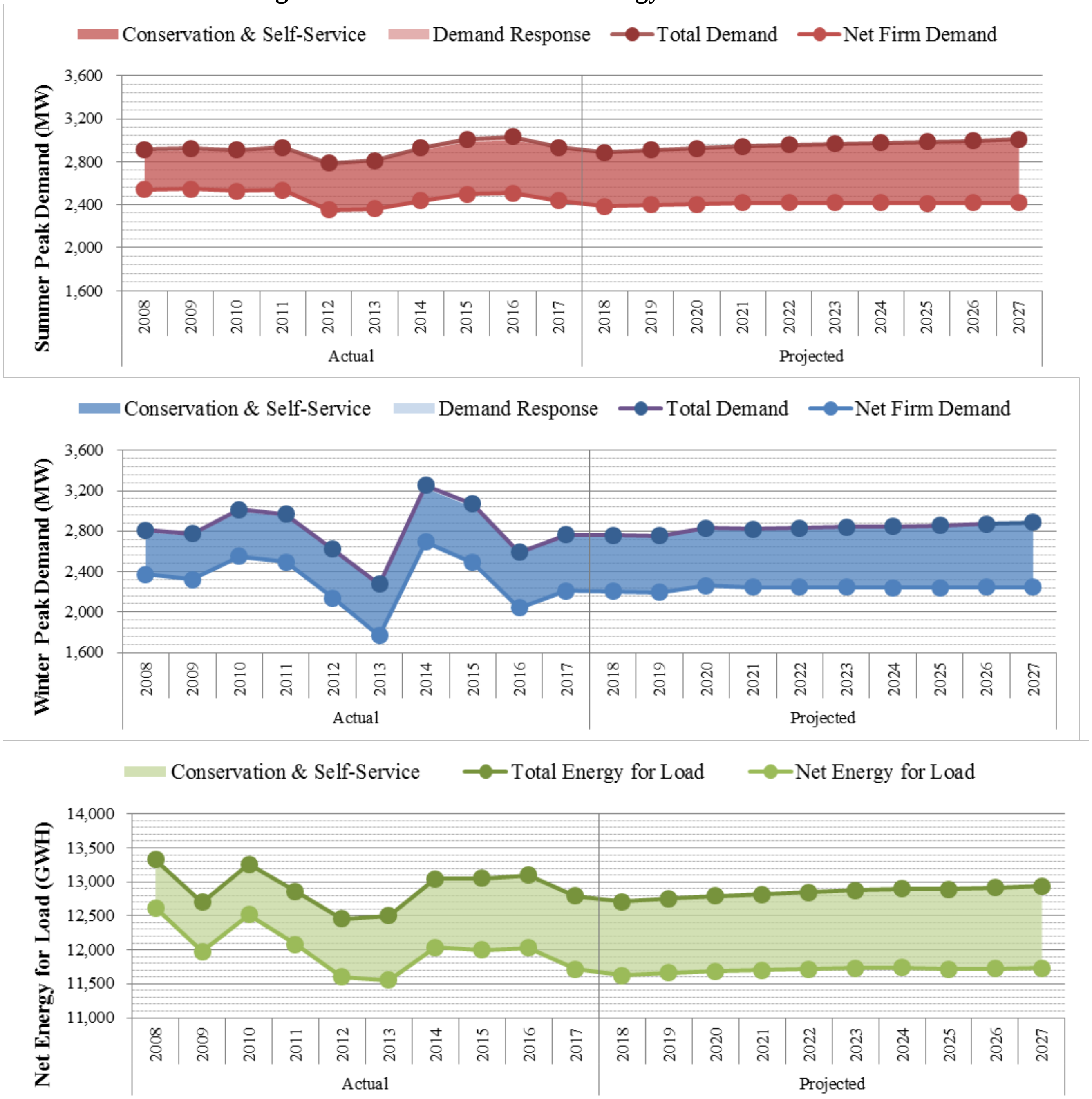
Figure 18: FPL Growth Rate



Source: 2018 Ten-Year Site Plan

The three graphs in Figure 19 show FPL's seasonal peak demand and net energy for load, for the historic years 2008 through 2017 and forecast years 2018 through 2027. 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 has not been 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 2018 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Figure 19: FPL Demand and Energy Forecasts



Source: 2018 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 12 shows FPL's actual net energy for load by fuel type for 2017, and the projected fuel mix for 2027. FPL relies primarily upon natural gas and nuclear for energy generation, making up 95 percent of net energy for load. Consistent with its previously discussed SoBRA, FPL projects that renewable energy will provide over 7 percent of generation by 2027.

Table 12: FPL Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2017		2027	
	GWh	%	GWh	%
Natural Gas	86,706	**71.8%**	82,601	**66.3%**
Coal	4,057	**3.4%**	1,966	**1.6%**
Nuclear	27,971	**23.2%**	28,363	**22.8%**
Oil	400	**0.3%**	19	**0.0%**
Renewable	658	**0.5%**	9,391	**7.5%**
Interchange	1,598	**1.3%**	0	**0.0%**
Other	-642	**-0.5%**	2,215	**1.8%**
Total	**120,748**		**124,555**	

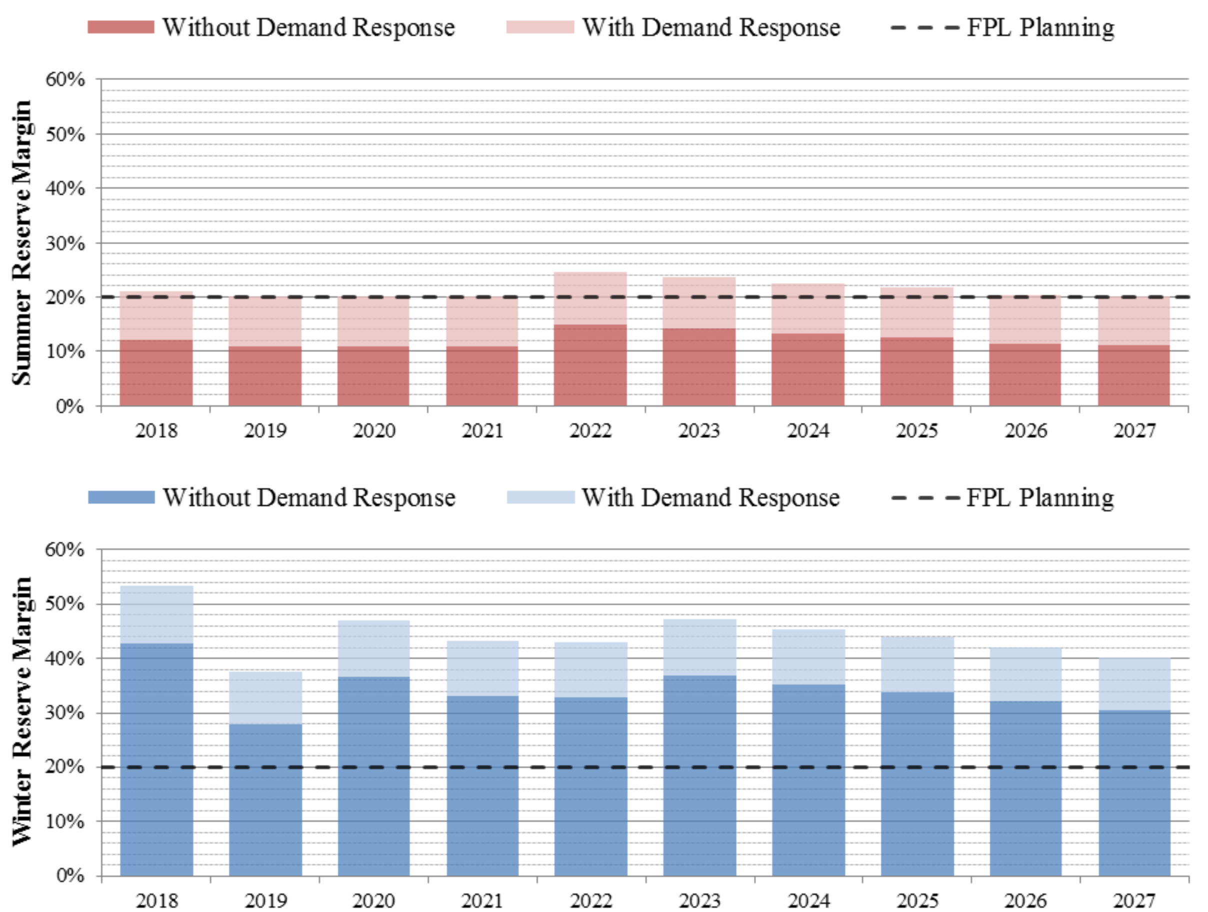
Source: 2018 Ten-Year Site Plan

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 20 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 20: FPL Reserve Margin Forecast



Source: 2018 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. 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. The projected in-service dates of FPL's new planned nuclear units are now outside the 10-year planning period. On September 3, 2015, FPL filed a need determination with the Commission for the Okeechobee Unit which was granted on January 19, 2016. The Okeechobee Unit is expected to be in-service by 2019. At the hearing on September 25, 2017, the Commission approved the Stipulation and Settlement Agreement which included FPL's proposal for early shutdown of SJRPP.[11] The SJRPP Units 1 & 2 are set to retire in 2018. FPL also plans to retire Martin Units 1 & 2 in 2018 due to the units' age and inefficiency in regards to converting natural gas or oil into electricity. Additionally, FPL is planning to retire Lauderdale Units 4 & 5 and replace them with the Dania Beach Clean Energy Center, a natural gas-fired combined cycle unit, consistent with the Commission approved need determination for the Dania Beach facility.[12] The Dania Beach Clean Energy Center is expected to be in-service by 2022.

FPL plans to increase the amount of planned solar projects by approximately 300 MW per calendar year, consistent with its last base rate case settlement.[13] FPL has included planned solar additions of 3,204 MW outside of the 596 MW of SoBRA additions approved in the fuel and purchased power cost recovery clause dockets.[14] FPL plans to conduct further economic analysis before reaching a decision to proceed with these additions. The planned solar additions make up approximately 56 percent of FPL's planned future units.

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[11]Document No. 07922-2017, filed September 26, 2017, in Docket No. 20170123-EI, *In re: Petition for approval of arrangement to mitigate unfavorable impact of St. Johns River Power Park, by Florida Power & Light Company.*
[12]Order No. PSC-2018-0150-FOF-EI, issued March 19, 2018, in Docket No. 20170225-EI, *In re: Petition of determination of need for Dania Beach Clean Energy Center Unit 7, by Florida Power & Light Company.*
[13]Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 20160021-EI, *In re: Petition for rate increase by Florida Power & Light Company.*
[14]Order No. PSC-2018-0028-FOF-EI, issued January 8, 2018, in Docket No. 20180001-EI, I*n re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

Table 13: FPL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Solar Firm Capacity (Summer)	Notes
			Sum	Sum	
Retiring Units					
2018	Lauderdale 4 & 5	Natural Gas Combustion Turbine	884		
2018	SJRPP 1 & 2	Coal Steam Turbine	254		
2018	Martin 1 & 2	Natural Gas Steam Turbine	1,626		
Total Retirements			**2,764**		
New Units					
2018	Coral Farms	Photovoltaic	75	40	
2018	Horizon	Photovoltaic	75	40	
2018	Indian River	Photovoltaic	75	40	
2018	Wildflowerr	Photovoltaic	75	40	
2018	Barefoot Bay	Photovoltaic	75	40	
2018	Blue Cypressr	Photovoltaic	75	40	
2018	Hammock	Photovoltaic	75	40	
2018	Loggerhead	Photovoltaic	75	40	
2019	Interstate	Photovoltaic	75	41	
2019	Miami-Dade	Photovoltaic	75	41	
2019	Okeechobee	Natural Gas Combined Cycle	1,778		Docket No. 20150196-EI
2019	Pioneer Trail	Photovoltaic	75	41	
2019	Sunshine Gateway	Photovoltaic	75	41	
2020	SoBRA PV Unsited	Photovoltaic	298	165	
2020	Unsited Solar	Photovoltaic	224	124	
2021	Unsited Solar	Photovoltaic	596	330	
2022	Dania Beach	Natural Gas Combined Cycle	1,163		Docket No. 20170225-EI
2022	Unsited Solar	Photovoltaic	298	165	
2023	Unsited Solar	Photovoltaic	298	165	
2024	Unsited Solar	Photovoltaic	298	165	
2025	Unsited Solar	Photovoltaic	298	155	
2026	Unsited Solar	Photovoltaic	298	131	
2027	Unsited Solar	Photovoltaic	298	116	
Total New Units			**6,741**	**2,003**	
Percentage of Solar Units Planned of Total New Units			**56.4%**		
Net Additions			**3,977**		

Source: 2018 Ten-Year Site Plan

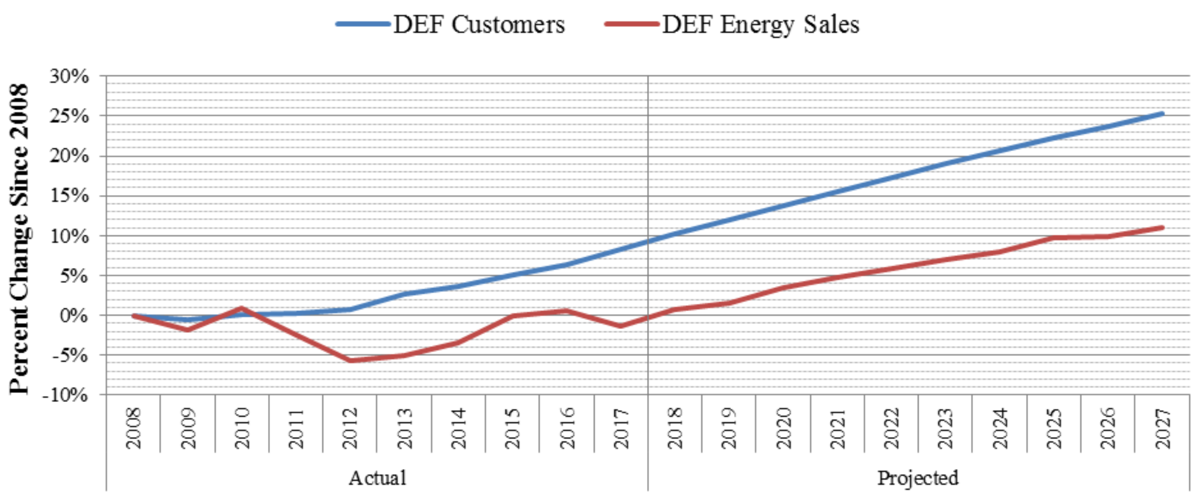
Duke Energy Florida, LLC (DEF)

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 2018 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2017, DEF had approximately 1,775,340 customers and annual retail energy sales of 38,023 GWh or approximately 16.8 percent of Florida's annual retail energy sales. Figure 21 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, DEF's customer base has increased by 8.32 percent, while retail sales have declined by 1.38 percent. As illustrated, DEF's retail energy sales are anticipated to exceed its historic 2010 peak in 2019.

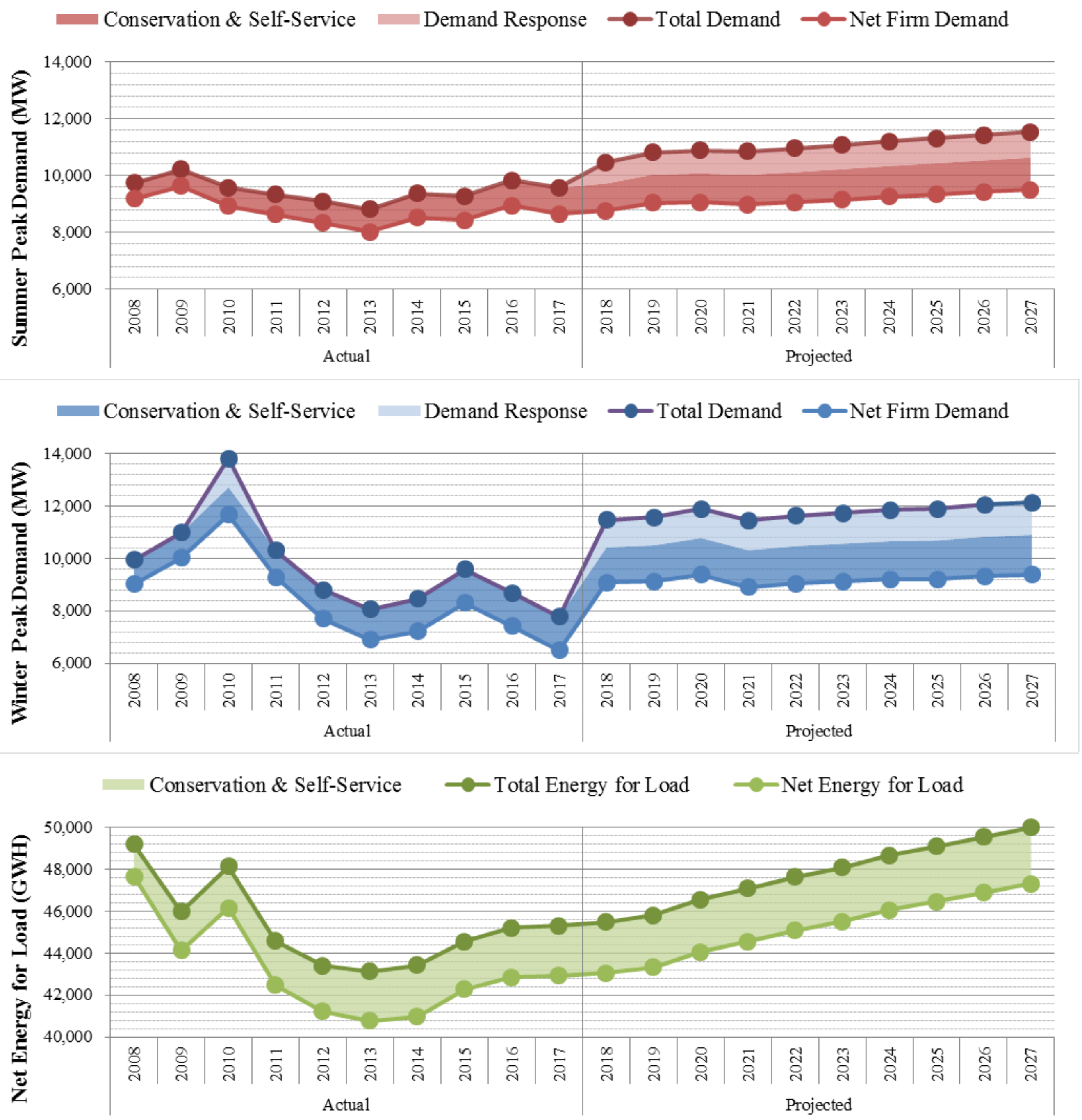
Figure 21: DEF Growth Rate



Source: 2018 Ten-Year Site Plan

The three graphs in Figure 22 show DEF's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. 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 2018 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Figure 22: DEF Demand and Energy Forecasts



Source: 2018 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 14 shows DEF's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. DEF relies primarily upon natural gas and coal for energy generation, making up approximately 84 percent of net energy for load. DEF plans to reduce coal usage over the planning period, and to increase renewable energy generation, making natural gas and renewable energy DEF's primary sources of generation by 2027. DEF projects the highest percentage of renewable energy generation in 2027 of the Ten-Year Site Plan utilities.

Table 14: DEF Energy Consumption by Fuel Type

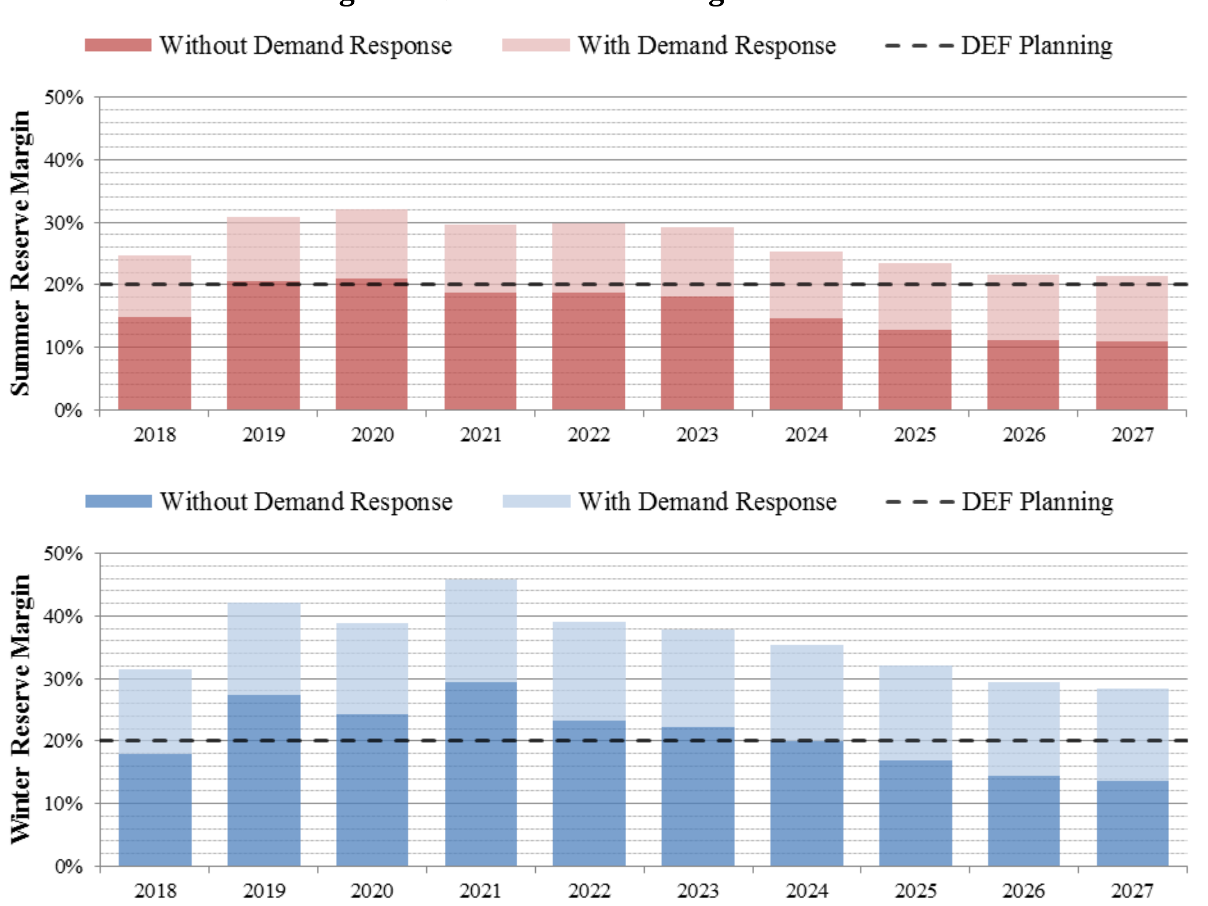
Fuel Type	Net Energy for Load			
	2017		2027	
	GWh	%	GWh	%
Natural Gas	27,307	**63.6%**	36,552	**77.3%**
Coal	8,722	**20.3%**	3,908	**8.3%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	62	**0.1%**	102	**0.2%**
Renewable	1,496	**3.5%**	6,504	**13.7%**
Interchange	2,037	**4.7%**	248	**0.5%**
NUG & Other	3,295	**7.7%**	2	**0.0%**
Total	**42,919**		**47,316**	

Source: 2018 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion. Figure 23 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.

Figure 23: DEF Reserve Margin Forecast



Source: 2018 Ten-Year Site Plan

Generation Resources

DEF plans multiple unit retirements and additions during the planning period, as described in Table 15. DEF's 2018 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 five gas-fired units at multiple power plant sites. DEF's planned additions include a combined cycle facility in 2018 in Citrus County, and three planned Combustion Turbine Units at an undesignated site(s) in 2024, 2025, and 2026.

DEF also anticipates increasing the amount of planned solar projects by approximately 175 MW per calendar year, not to exceed 700 MW, consistent with its 2017 Second Revised and Restated Settlement Agreement.[15] DEF has included 450 MW of planned solar additions outside of the 700 MW cap. Currently, DEF is petitioning the Commission for approval of 149.8 MW of solar

[15]Order No. PSC-2017-0451-AS-EU, issued November 20, 2017, in Docket No. 20170183-EI, *In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC.*

additions as part of its first SoBRA.[16] As a result of forecasts that show the continued reduction in the price of solar PV technology, DEF has incorporated this energy source as a supply-side resource in both its near-term and long-term generation plans. The solar additions make up approximately 33 percent of DEF's planned future units.

Table 15: DEF Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Solar Firm Capacity (Summer) Sum	Notes
Retiring Units					
2018	Crystal River 1 & 2	Coal Steam Turbine	766		
2020	Avon Park P1	Natural Gas Combustion Turbine	24		
2020	Avon Park P2	Distillate Oil Gas Turbine	24		
2020	Higgins P1-4	Natural Gas Combustion Turbine	107		
Total Retirements			**921**		
New Units					
2018	Citrus CC	Natural Gas Combined Cycle	1,640		Docket No. 20140110-EI
2019	Hamilton	Photovoltaic	75	43	
2019	Solar 6 & 7	Photovoltaic	120	68	
2020	Solar 8, 9, 10, & 11	Photovoltaic	295	168	
2021	Solar 12, 13, & 14	Photovoltaic	210	120	
2022	Solar 15	Photovoltaic	75	43	
2023	Solar 16	Photovoltaic	75	43	
2024	Solar 17	Photovoltaic	75	43	
2025	Solar 18	Photovoltaic	75	43	
2026	Solar 19	Photovoltaic	75	43	
2027	Unknown CT P1, P2, & P3	Natural Gas Combustion Turbine	678		
2027	Solar 20	Photovoltaic	75	43	
Total New Units			**3,468**	**655**	
Percentage of Solar Units Planned of Total New Units			**33%**		
Net Additions			**2,547**		

Source: 2018 Ten-Year Site Plan

[16]Document No. 049910-2018, filed July 31, 2018, in Docket No. 20180149-EI, *In re: Petition for a limited proceeding to approve first solar base rate adjustment, by Duke Energy Florida, LLC.*

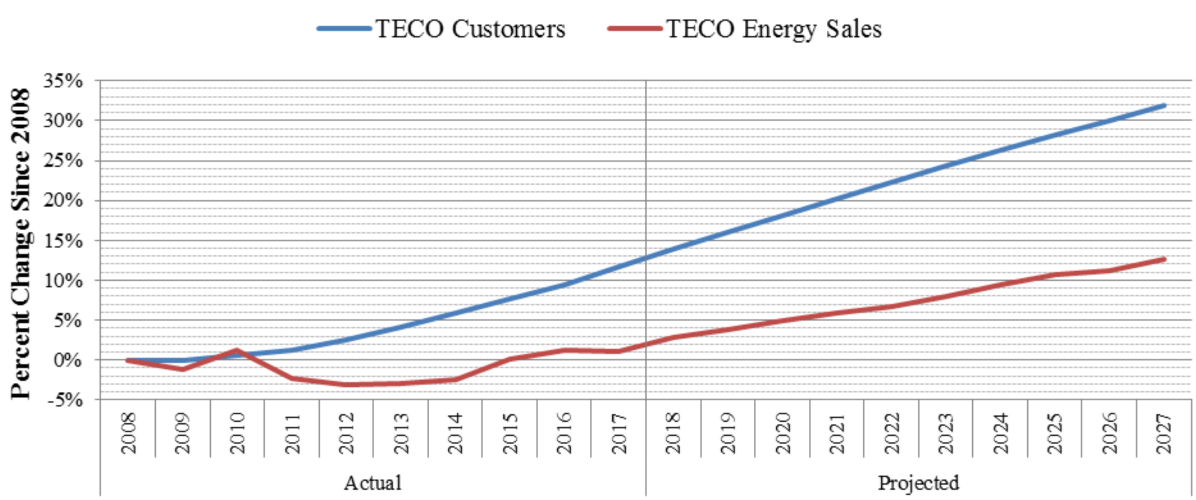
Tampa Electric Company (TECO)

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 2018 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2017, TECO had approximately 744,690 customers and annual retail energy sales of 19,186 GWh or approximately 8.5 percent of Florida's annual retail energy sales. Figure 24 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, TECO's customer base has increased by 11.6 percent, while retail sales have increased by 1.03 percent. As illustrated, TECO's retail energy sales are anticipated to exceed its historic 2016 peak in 2018.

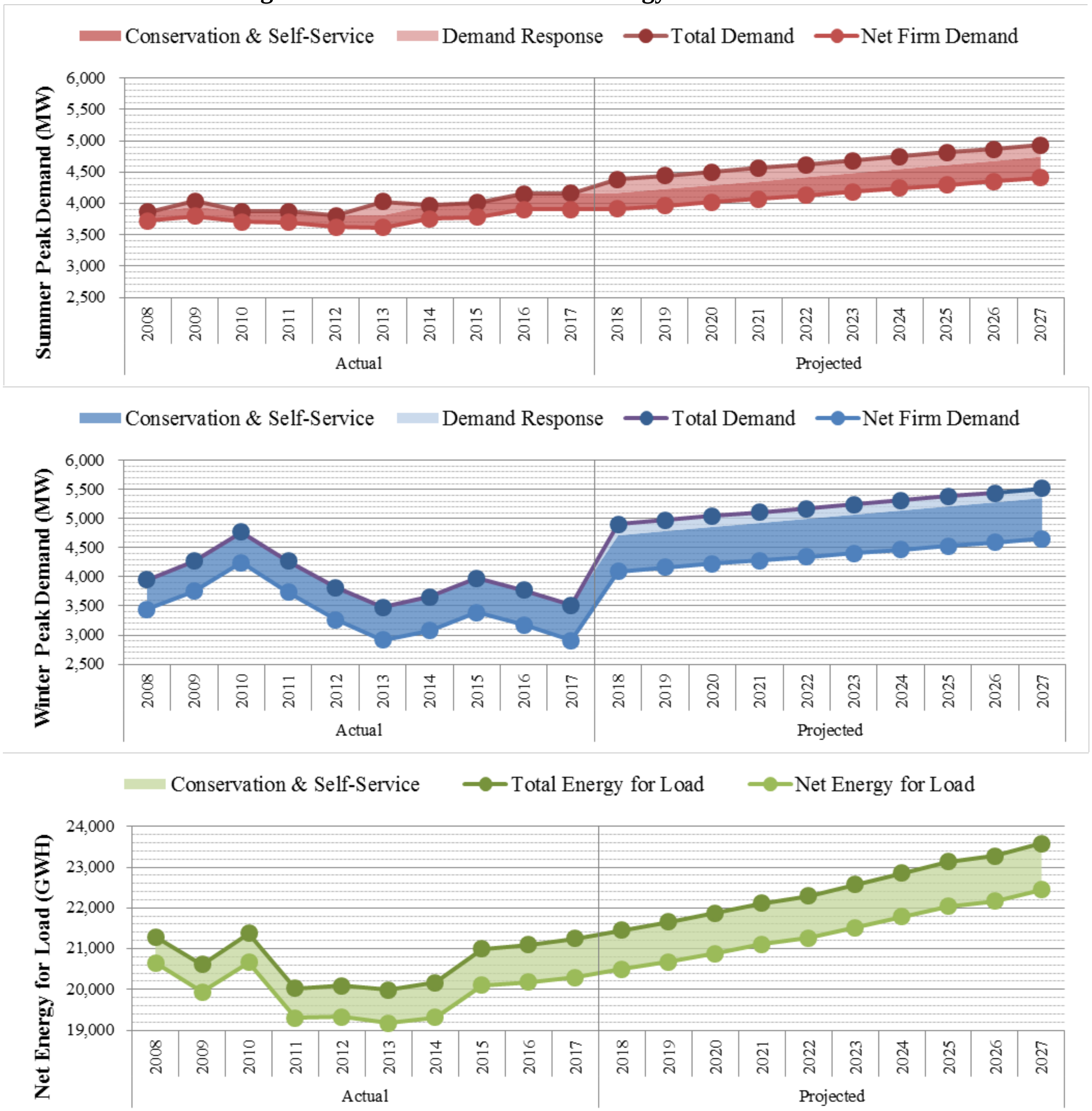
Figure 24: TECO Growth Rate



Source: 2018 Ten-Year Site Plan

The three graphs in Figure 25 show TECO's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. 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 25: TECO Demand and Energy Forecasts



Source: 2018 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 2018 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Fuel Diversity

Table 16 shows TECO's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. Based on its 2018 Ten-Year Site Plan, natural gas is used for the majority of TECO's energy generation. Natural gas accounts for approximately 67 percent of net energy for load. In the future, TECO projects that energy from coal will slightly decrease and energy from natural gas will increase. TECO projects that renewable energy will increase from 0.2 percent to 6.2 percent of generation by 2027.

Table 16: TECO Energy Consumption by Fuel Type

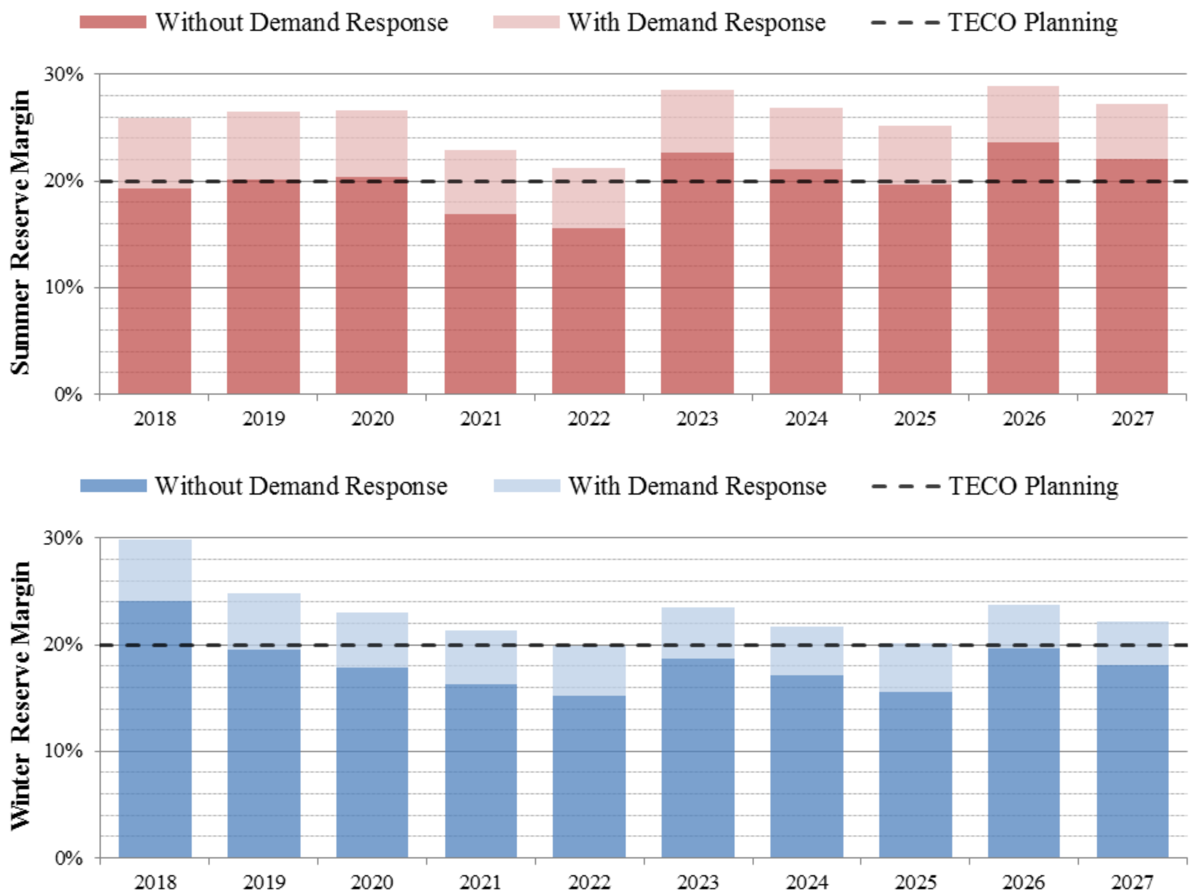
Fuel Type	Net Energy for Load			
	2017		2027	
	GWh	%	GWh	%
Natural Gas	13,685	**67.4%**	16,379	**73.0%**
Coal	4,949	**24.4%**	3,430	**15.3%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	45	**0.2%**	1,387	**6.2%**
Interchange	122	**0.6%**	0	**0.0%**
NUG & Other	1,496	**7.4%**	1,256	**5.6%**
Total	**20,298**		**22,452**	

Source: 2018 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 26 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. 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 26: TECO Reserve Margin Forecast



Source: 2018 Ten-Year Site Plan

Generation Resources

TECO plans a unit retirement and multiple unit additions during the planning period, as described in Table 17. TECO's 2018 Ten-Year Site Plan includes the retirement of the coal-fired Big Bend Unit 2 in 2021. TECO also plans to convert its coal-fired Big Bend Unit 1 steam turbine into a natural gas-fired combined cycle unit by 2023. The Florida Department of Environmental Protection has determined that a determination of need is not necessary for this conversion. TECO also plans the addition of two natural gas-fired combustion turbine peaking units in 2023 and 2026, and anticipates increasing the amount of planned solar projects over the planning period.

TECO's planned solar projects are consistent with its 600 MW cap, included in its 2017 Stipulation and Settlement Agreement.[17] In TECO's first SoBRA, 144.7 MW were approved.[18] Currently, TECO is petitioning the Commission for approval of 260.3 MW of solar additions as part of its second SoBRA.[19] The solar additions make up approximately 35 percent of TECO's planned future units.

[17]Order No. PSC-2017-0456-S-EI, issued November 27, 2017, in Docket No. 20170210-EI, *In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company.*

[18]Order No. PSC-2018-0288-FOF-EI, issued July 5, 2018, in Docket No. 20170260-EI, *In re: Petition for limited proceeding to approve first solar base rate adjustment (SoBRA), effective September 1, 2018, by Tampa Electric Company.*

[19]Document No. 04469-2018, filed June 29, 2018, in Docket No. 20180133-EI, *In re: Petition for limited proceeding to approve second solar base rate adjustment (SoBRA), effective January 1, 2019, by Tampa Electric Company.*

Table 17: TECO Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Solar Firm Capacity (Summer)
			Sum	Sum
Retiring Units				
2021	Big Bend 2	Coal Steam Turbine	385	
Total Retirements			**385**	
New Units				
2018	Balm Solar	Photovoltaic	74	38
2018	Payne Creek Solar	Photovoltaic	70	36
2019	Bonnie Mine Solar	Photovoltaic	35	18
2019	Grange Hall Solar	Photovoltaic	61	32
2019	Lithia Solar	Photovoltaic	75	39
2019	Mountain View Solar	Photovoltaic	55	28
2019	Peace Creek Solar	Photovoltaic	57	29
2020	Alafia Solar	Photovoltaic	50	26
2020	Wimauma Solar	Photovoltaic	75	38
2021	Big Bend 5 & 6	Natural Gas Combustion Turbine	660	
2021	Lake Hancock Solar	Photovoltaic	50	26
2023	Future CT 1	Natural Gas Combustion Turbine	229	
2026	Future CT 2	Natural Gas Combustion Turbine	229	
Total New Units			**1,719**	**311**
Percentage of Solar Units Planned of Total New Units			**35%**	
Net Additions			**1,334**	

Source: 2018 Ten-Year Site Plan

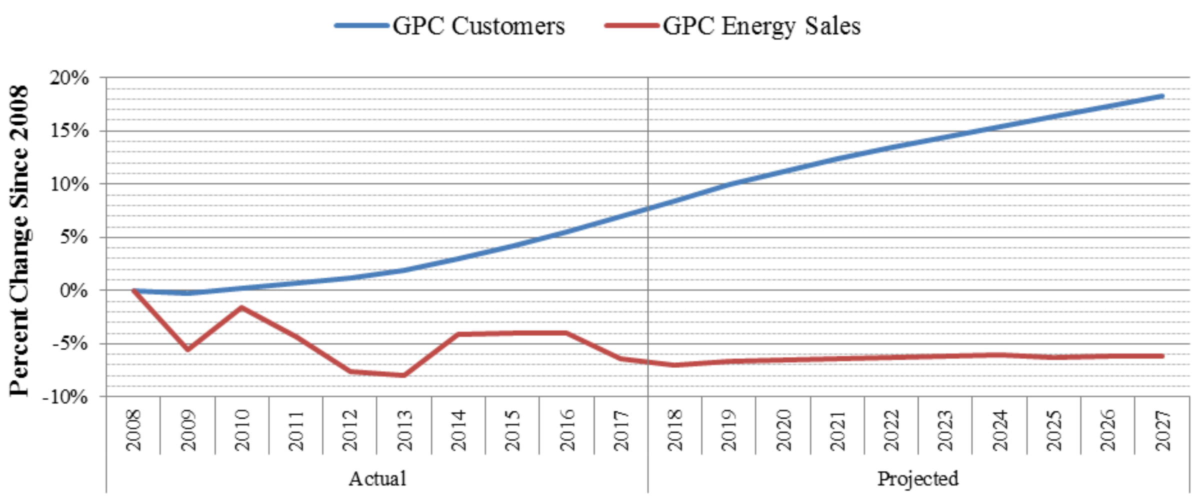
Gulf Power Company (GPC)

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. NextEra Energy Inc., FPL's parent company, plans to acquire GPC through a purchase, subject to federal approval, expected to close during the first half of 2019. The effects, if any, to future TYSP is unknown at this time. 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 2018 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2017, GPC had approximately 459,050 customers and annual retail energy sales of 10,809 GWh or approximately 4.8 percent of Florida's annual retail energy sales. Figure 27 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, GPC's customer base has increased by 6.93 percent, while retail sales have declined by 6.36 percent. As illustrated, GPC's retail energy sales are not anticipated to exceed its historic 2008 peak during the planning period.

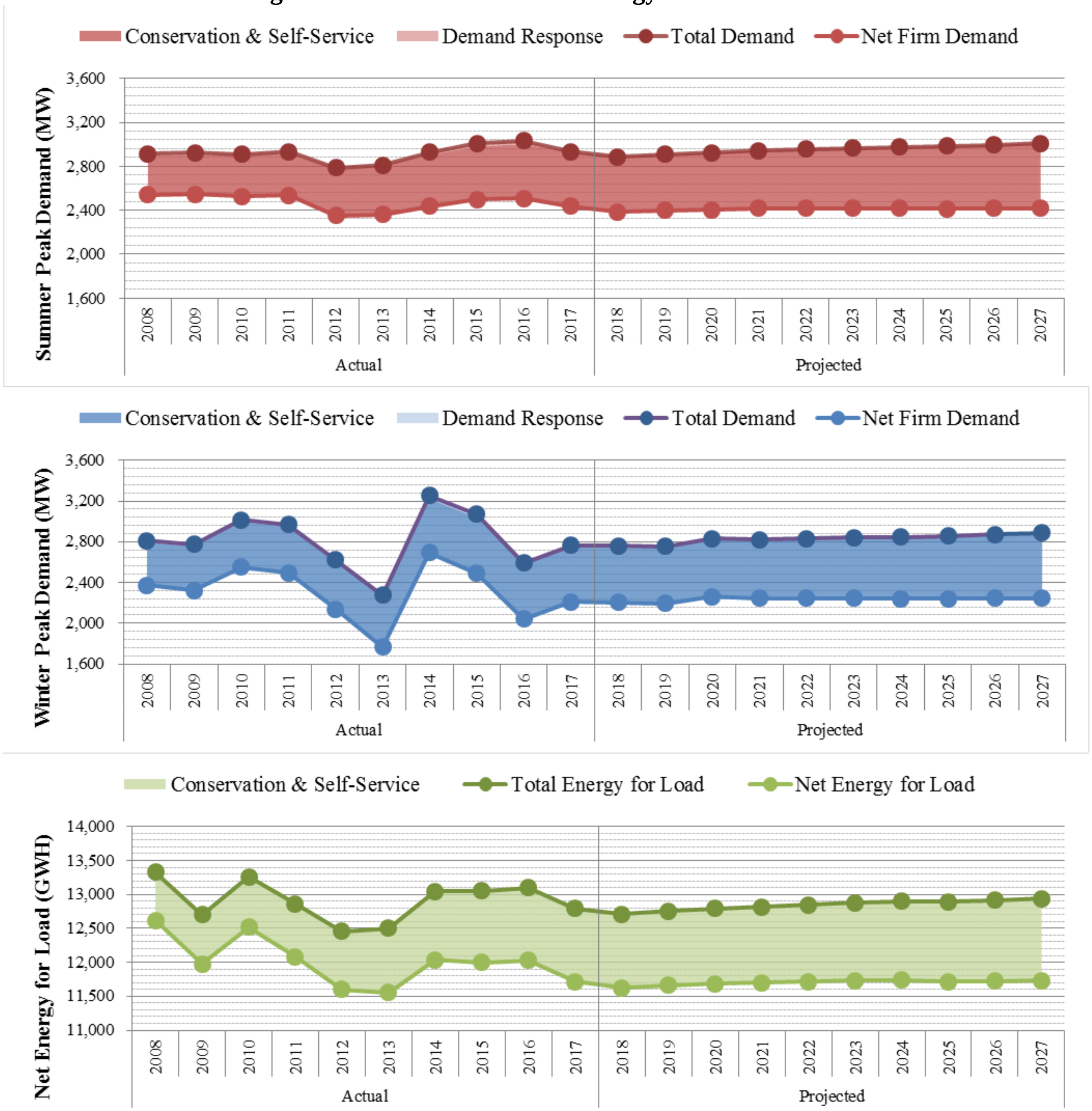
Figure 27: GPC Growth Rate



Source: 2018 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 2018 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014. The three graphs in Figure 28 shows GPC's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. These graphs include the full impact of demand-side management.

Figure 28: GPC Demand and Energy Forecasts



Source: 2018 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 18 shows GPC's actual net energy for load by fuel type as of 2017, and the projected fuel mix for 2027. GPC is an energy exporter, producing approximately 31 percent more energy than it requires for native load. While natural gas was the dominant fuel source in 2017, coal was the second most utilized fuel source. By 2027, GPC's 2018 Ten-Year Site Plan projects a decrease in export to Southern Company Services that will be 29.7 percent of native load, with coal representing approximately 53 percent of system energy. GPC projects the second highest percentage of energy consumption from coal in 2027 of the Ten-Year Site Plan utilities.

Table 18: GPC Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2017		2027	
	GWh	%	GWh	%
Natural Gas	8,983	**76.6%**	7,527	**64.2%**
Coal	4,973	**42.4%**	6,205	**52.9%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	1	**0.0%**
Renewable	1,214	**10.4%**	1,285	**11.0%**
Interchange	-3,633	**-31.0%**	-3,485	**-29.7%**
NUG & Other	188	**1.6%**	196	**1.7%**
Total	**11,725**		**11,729**	

Source: 2018 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 16.25 percent summer reserve margin beginning in 2021. Figure 29 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 Figure 29, GPC is reporting a near-zero reserve margin for Summer 2023 and a 7.7 percent reserve margin for Winter 2023 through 2024. This is due to the expiration of a purchased power agreement with Shell Energy North America (Shell PPA) for 885 MW of firm capacity in May 2023. GPC currently anticipates replacing a portion of this lost capacity with a 595 MW 1x1 combined cycle unit in June 2024. GPC expects to manage its reserve margin requirements in the interim, between the expiration of the Shell PPA and the in-service date of its anticipated new combined cycle unit, with short-term arrangements that are available through the Intercompany Interchange Contract's reserve sharing mechanism or through capacity purchases from the market. The Intercompany Interchange Contract's reserve sharing mechanism is a benefit afforded to GPC from its association with the Southern electric system. However, while GPC expects that these purchases will serve to meet its reserve margin requirements, it has not included any contributed capacity from the purchases into its reserve margin projections due to their nature as market purchases. The FRCC's reserve margin is projected to be 30 percent in 2023 at the time of summer peak, and is projected to be 47 percent in 2023/24 at the time of winter peak. GPC will provide an update on its reserve margin for the specified timeframe in its next Ten-Year Site Plan. As shown below, GPC's generation needs are typically determined by its summer peak.

Figure 29: GPC Reserve Margin Forecast

Source: 2018 Ten-Year Site Plan

Generation Resources

GPC plans unit retirements and additions during the planning period, as described in Table 19. Three natural gas-fired combustion turbines will be retired during the planning period. GPC has also indicated that the coal-fired units Crist 4 & 5 are tentatively scheduled for retirement in 2024 and 2026, respectively. GPC has indicated these retirement dates borrow from end-of-life depreciation calculations and do not represent results from an operational evaluation of the units.

Based on its 2018 Ten-Year Site Plan, GPC plans to add a natural gas-fired combined cycle unit in 2024, after the expiration of a purchased power agreement. The planned combined cycle addition will require a determination of need from the Commission.

Table 19: GPC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum
Retiring Units			
2024	Crist 4	Coal Fossil Steam Turbine	75
2025	Pea Ridge 1 - 3	Natural Gas Combustion Turbine	12
2026	Crist 5	Coal Fossil Steam Turbine	75
Total Retirements			**162**
New Units			
2024	Combined Cycle 2	Natural Gas Combined Cycle	595
Total New Units			**595**
Net Additions			**433**

Source: 2018 Ten-Year Site Plan

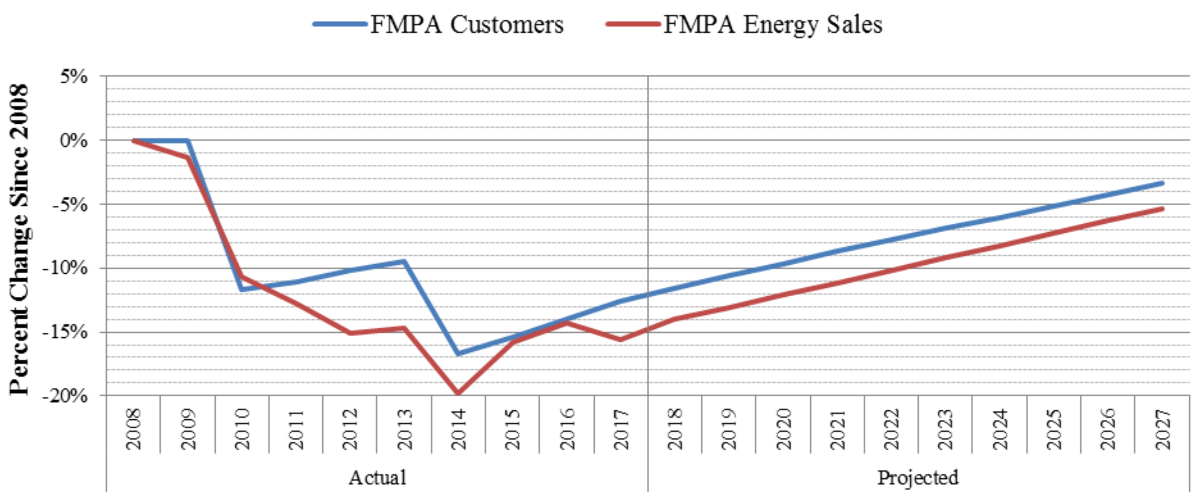
Florida Municipal Power Agency (FMPA)

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 2018 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2017, FMPA had approximately 257,698 customers and annual retail energy sales of 5,629 GWh or approximately 2.5 percent of Florida's annual retail energy sales. Figure 30 illustrates the Utility's historic and forecast number of customers and retail energy sales in terms of percentage growth from 2008. Over the last 10 years, FMPA's customer base has decreased by 12.59 percent, while retail sales have decreased by 15.66 percent. As illustrated, FMPA's retail energy sales are not anticipated to exceed its historic 2008 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, the City of Fort Meade in 2015, and the City of Green Cove Springs in 2019.

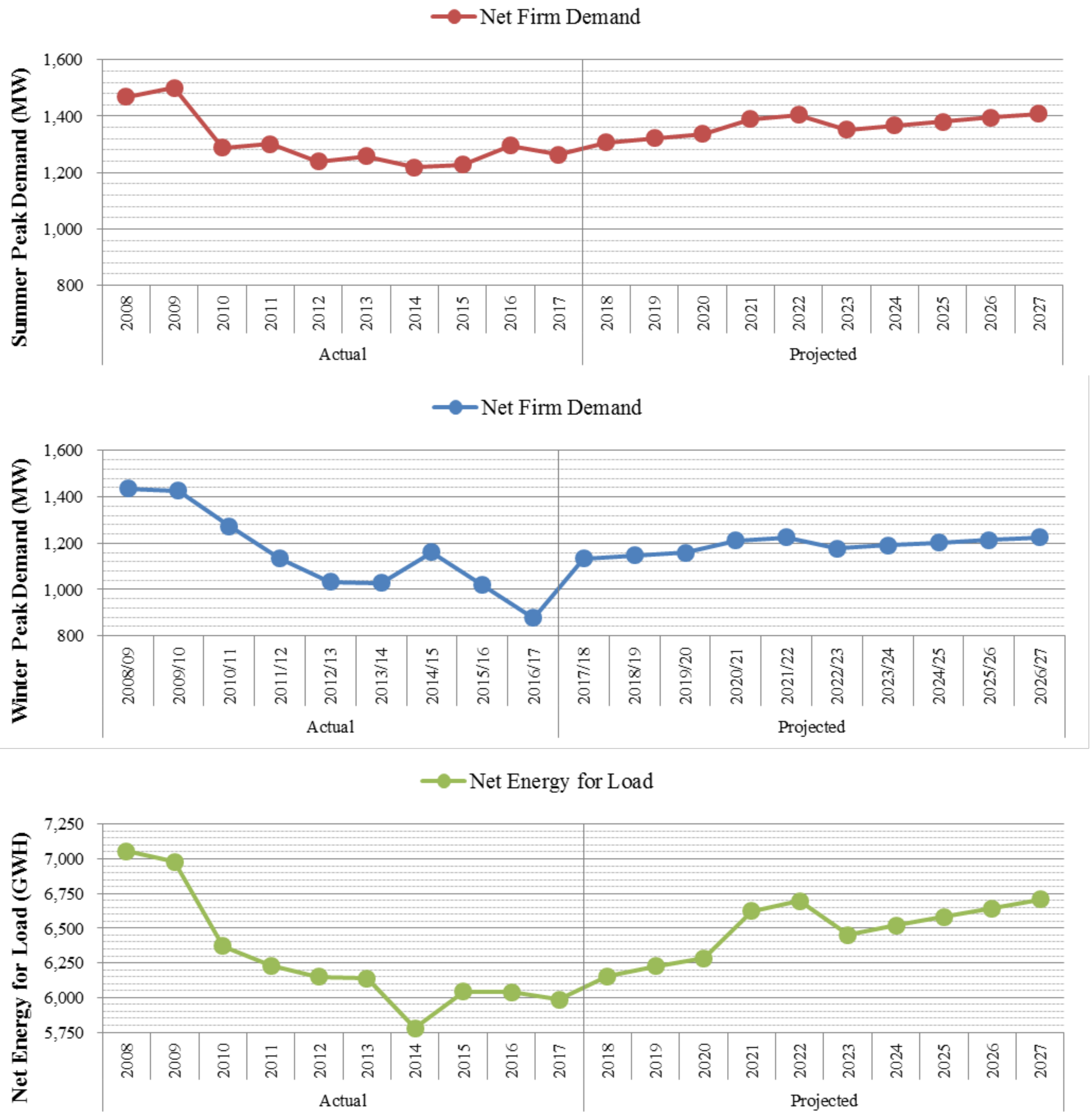
Figure 30: FMPA Growth Rate



Source: 2018 Ten-Year Site Plan

The three graphs in Figure 31 show FMPA's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. 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.

Figure 31: FMPA Demand and Energy Forecasts



Source: 2018 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 20 shows FMPA's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects a decrease in energy generation from coal in 2027, but approximately 93 percent of energy would still be sourced from natural gas and nuclear.

Table 20: FMPA Energy Consumption by Fuel Type

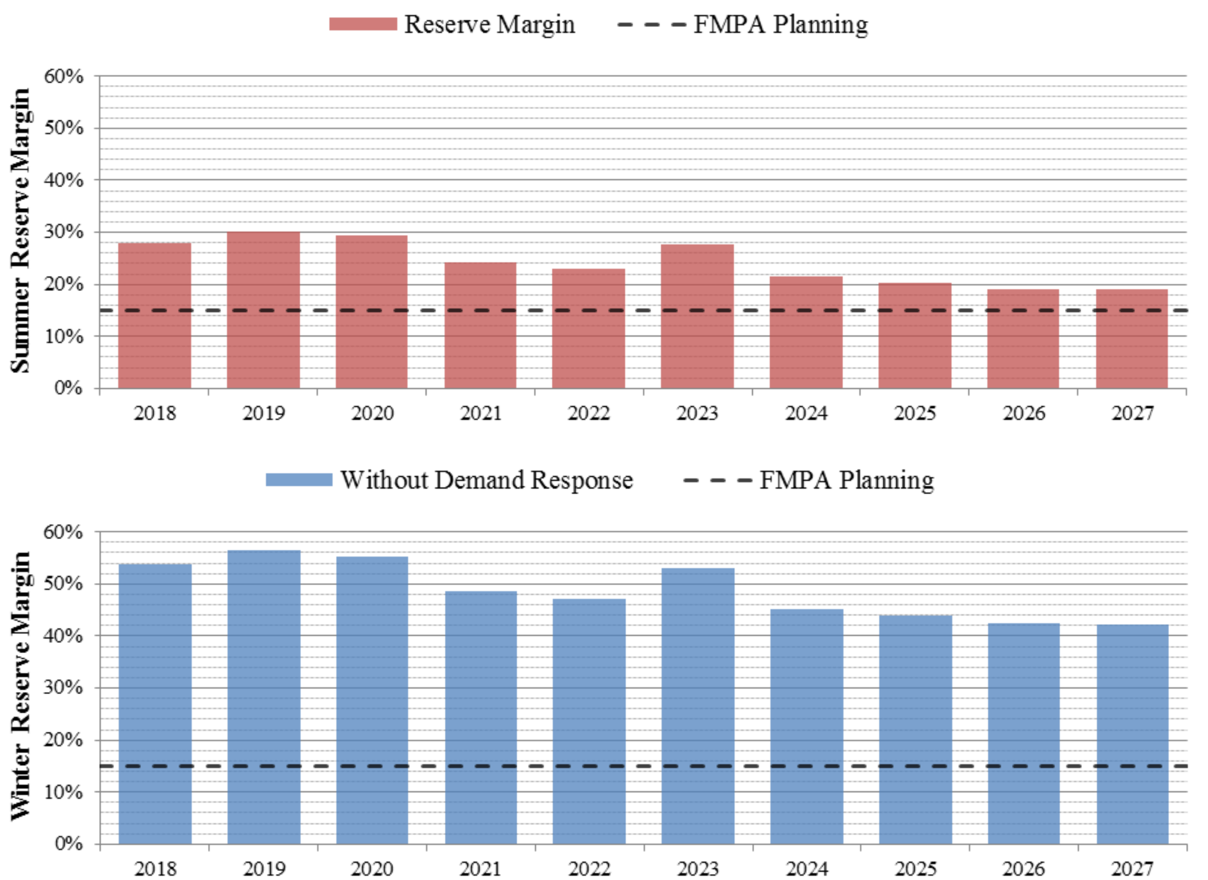
Fuel Type	Net Energy for Load			
	2017		2027	
	GWh	%	GWh	%
Natural Gas	4,741	**79.2%**	5,828	**86.9%**
Coal	915	**15.3%**	472	**7.0%**
Nuclear	294	**4.9%**	376	**5.6%**
Oil	1	**0.0%**	1	**0.0%**
Renewable	33	**0.6%**	32	**0.5%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**5,984**		**6,708**	

Source: 2018 Ten-Year Site Plan and Data Responses

Reliability Requirements

FMPA utilizes a 15 percent planning reserve margin criterion. Figure 32 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 32: FMPA Reserve Margin Forecast



Source: 2018 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.

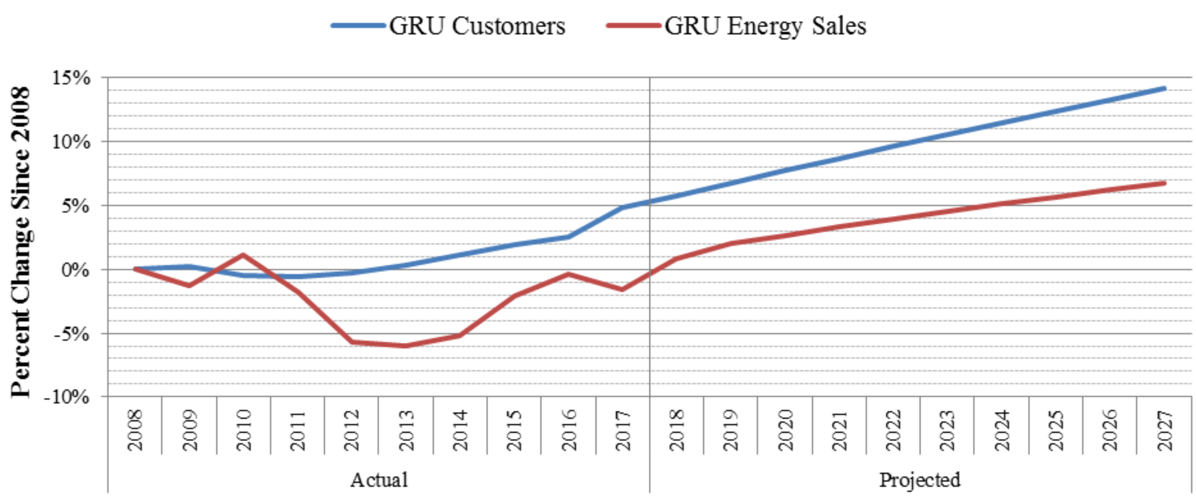
Gainesville Regional Utilities (GRU)

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 2018 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2017, GRU had approximately 97,245 customers and annual retail energy sales of 1,774 GWh or approximately 0.8 percent of Florida's annual retail energy sales. Figure 33 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, GRU's customer base has increased by 4.8 percent, while retail sales have decreased by 1.61 percent. As illustrated, GRU's retail energy sales are anticipated to exceed its historic 2010 peak in 2019.

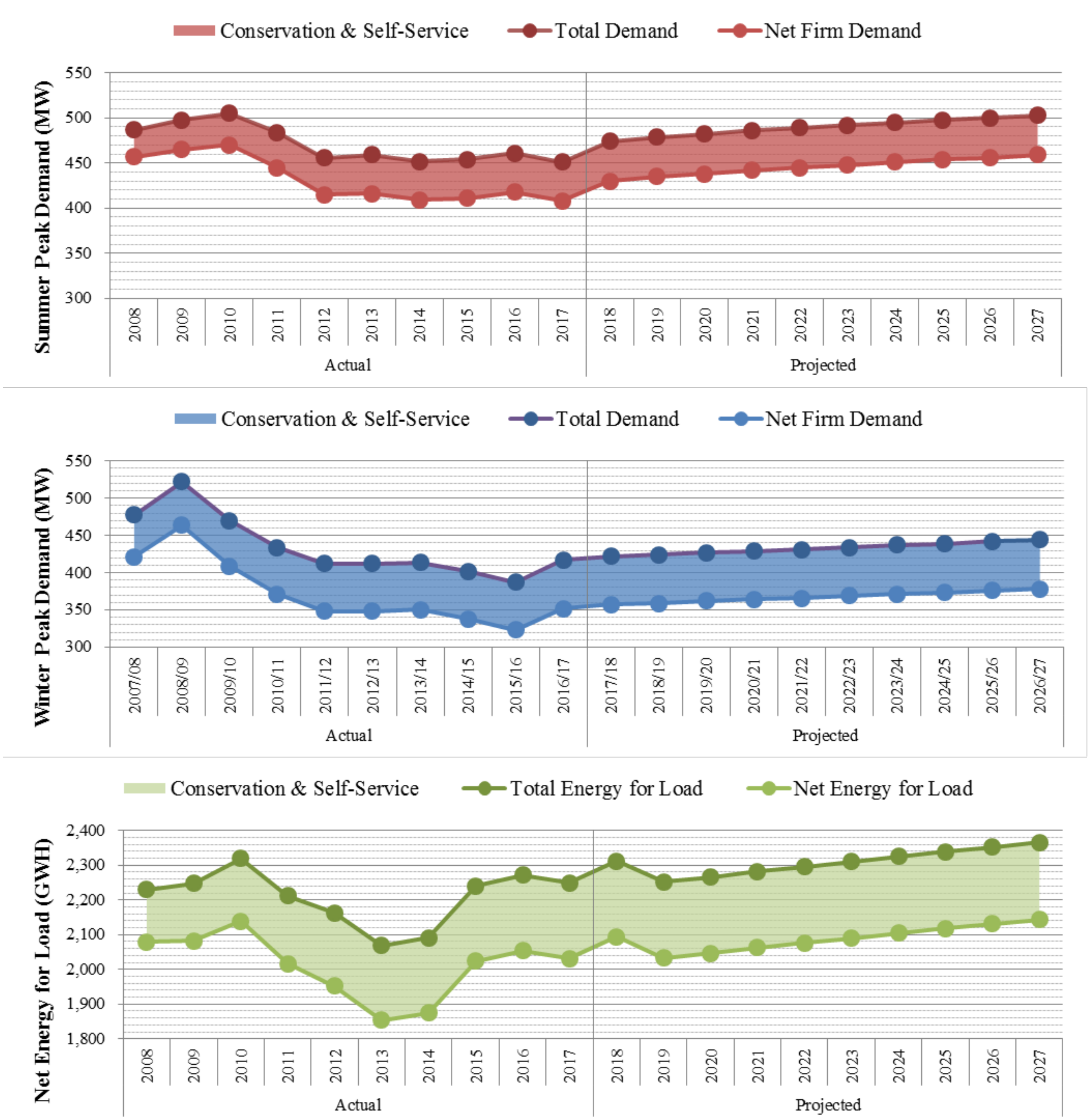
Figure 33: GRU Growth Rate



Source: 2018 Ten-Year Site Plan

The three graphs in Figure 34 show GRU's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. 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 34: GRU Demand and Energy Forecasts



Source: 2018 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 21 shows GRU's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. 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. In 2015, natural gas became GRU's primary fuel source which has continued into 2017. By 2027, GRU projects an increase in natural gas, approximately an increase from 25 percent to 33 percent in coal, and an approximate decrease from 18 percent to 15 percent in renewable energy.

Table 21: GRU Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2017		2027	
	GWh	%	GWh	%
Natural Gas	800	**39.4%**	980	**45.7%**
Coal	501	**24.7%**	696	**32.5%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	2	**0.1%**	0	**0.0%**
Renewable	373	**18.4%**	315	**14.7%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	355	**17.5%**	153	**7.1%**
Total	**2,031**		**2,144**	

Source: 2018 Ten-Year Site Plan and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 35 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 36.4 percent of summer net firm peak demand in 2017, almost the entirety of the Utility's reserve margin.

Figure 35: GRU Reserve Margin Forecast

Source: 2018 Ten-Year Site Plan

Generation Resources

GRU currently plans to retire a natural gas-fired steam unit in 2022, and a two natural gas-fired combustion turbines in 2026, as described in Table 22. As a smaller utility, single units can have a large impact upon reserve margin.

Table 22: GRU Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum
Retiring Units			
2022	Deerhaven FS01	Natural Gas Steam Turbine	75
2026	Deerhaven GT01 & GT02	Natural Gas Combustion Turbine	35
Total Retirements			**110**
Net Additions			**(110)**

Source: 2018 Ten-Year Site Plan

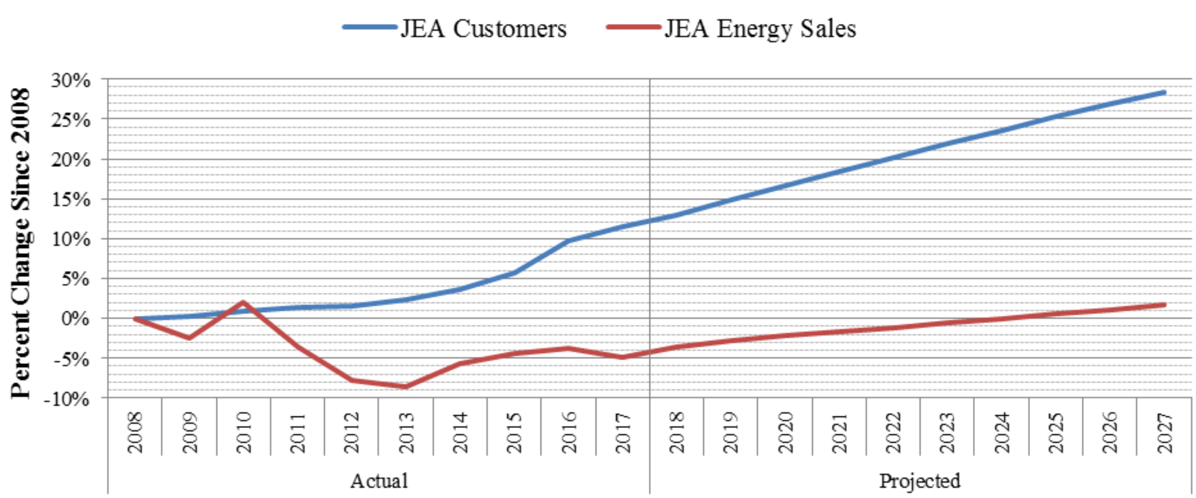
JEA

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 2018 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2017, JEA had approximately 456,981 customers and annual retail energy sales of 11,805 GWh or approximately 5.2 percent of Florida's annual retail energy sales. Figure 36 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, JEA's customer base has increased by 11.44 percent, while retail sales have declined by 4.9 percent. As illustrated, JEA's retail energy sales are not anticipated to exceed its historic 2010 peak during the planning period.

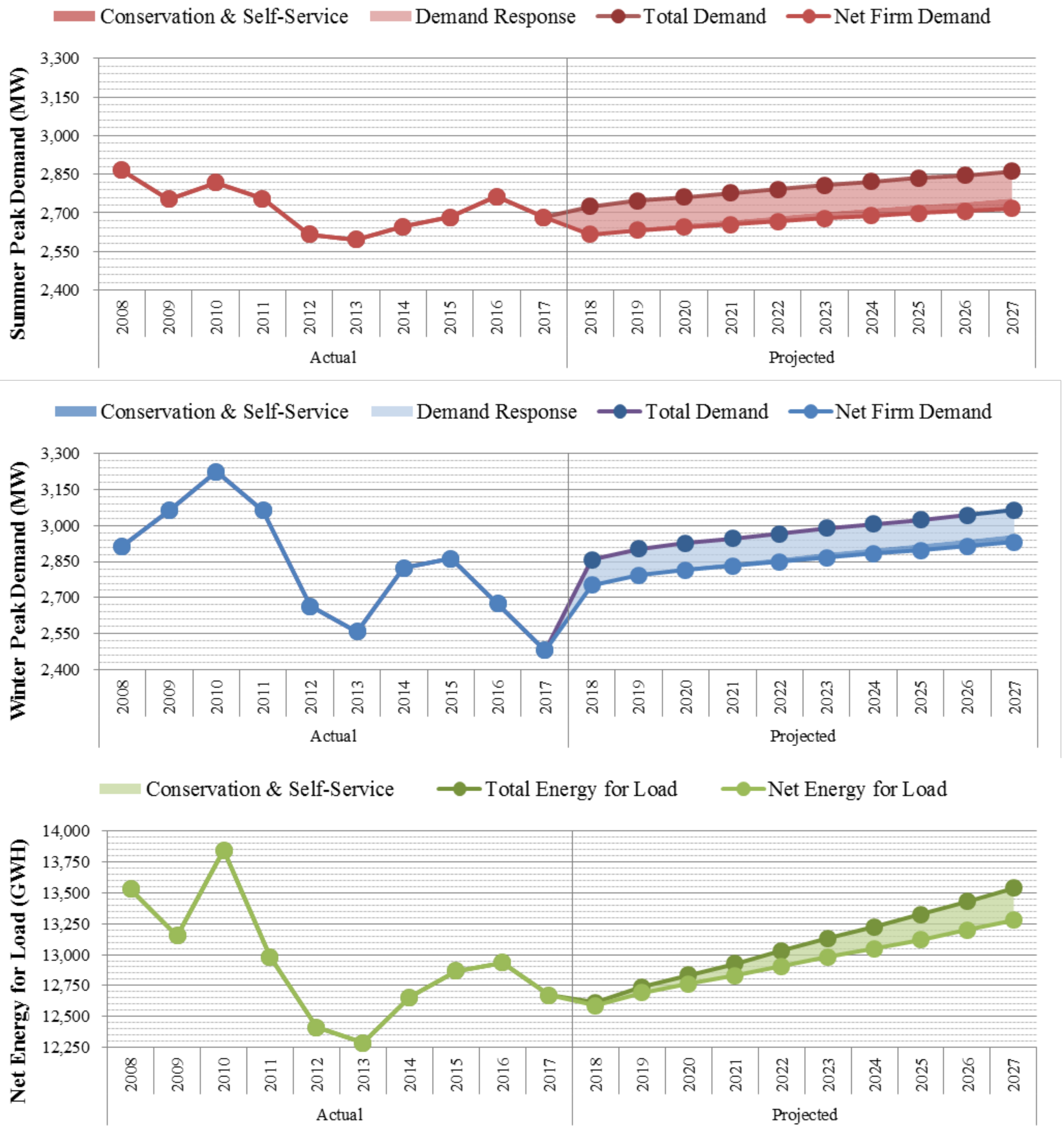
Figure 36: JEA Growth Rate



Source: 2018 Ten-Year Site Plan

The three graphs in Figure 37 show JEA's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. 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 37: JEA Demand and Energy Forecasts



Source: 2018 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 2018 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Fuel Diversity

Table 23 shows JEA's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. While natural gas was the dominant fuel source in 2017, coal was JEA's second most utilized fuel source. JEA's 2018 Ten-Year Site plan projects a majority of its net energy for load will continue to come from natural gas and coal in 2027. JEA projects the third highest percentage of energy consumption from coal in 2027 of the Ten-Year Site Plan utilities.

Table 23: JEA Energy Consumption by Fuel Type

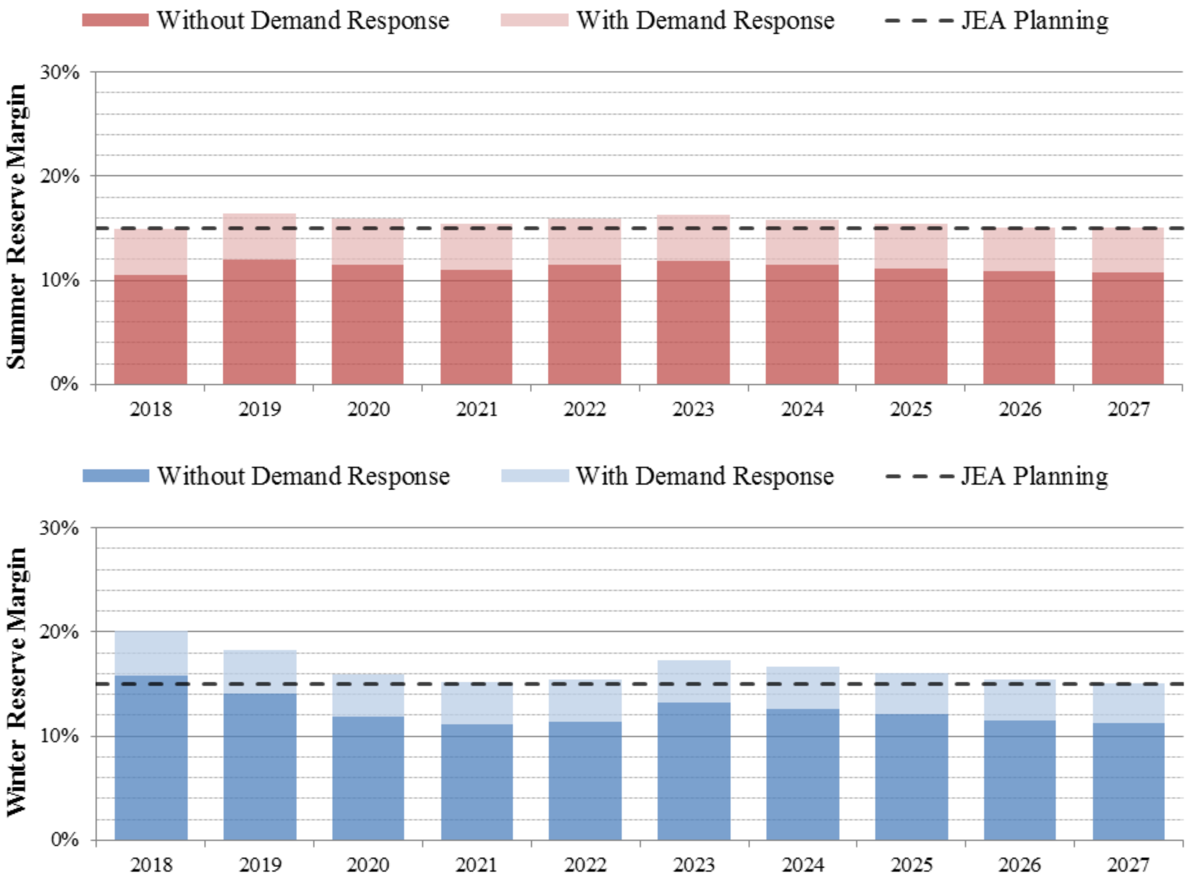
Fuel Type	Net Energy for Load			
	2017		2027	
	GWh	%	GWh	%
Natural Gas	5,697	**45.0%**	6,471	**48.7%**
Coal	5,416	**42.7%**	5,115	**38.5%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	5	**0.0%**
Renewable	111	**0.9%**	79	**0.6%**
Interchange	1,447	**11.4%**	1,611	**12.1%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**12,672**		**13,281**	

Source: 2018 Ten-Year Site Plan and Data Responses

Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 38 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.

Figure 38: JEA Reserve Margin Forecast



Source: 2018 Ten-Year Site Plan

Generation Resources

JEA plans to retire two units during the planning period, as described in Table 24. As discussed in FPL's section, the coal-fired steam SJRPP Units 1 & 2 are set to retire in 2018, based on the Utility's Ten-Year Site Plan.

Table 24: JEA Generation Resource Changes

Year	Unit Name	Fuel & Unit Type	Net Capacity (MW)
			Sum
Retiring Units			
2018	SJRPP 1 & 2	Coal Steam Turbine	1,002
Total Retirements			1,002
Net Additions			**(1,002)**

Source: 2018 Ten-Year Site Plan

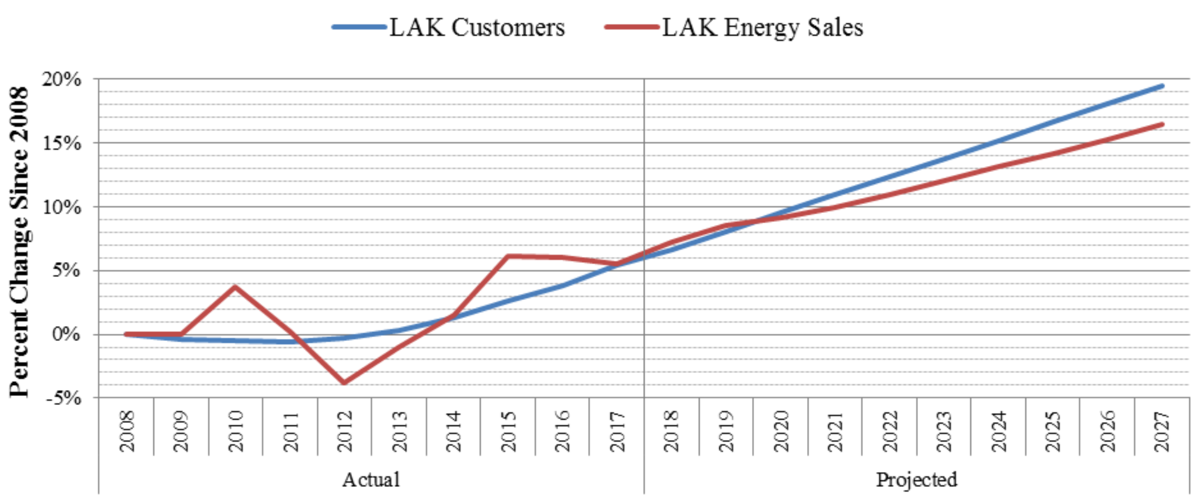
Lakeland Electric (LAK)

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 2018 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2017, LAK had approximately 129,113 customers and annual retail energy sales of 3,018 GWh or approximately 1.3 percent of Florida's annual retail energy sales. Figure 39 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, LAK's customer base has increased by 5.46 percent, while retail sales have grown by 5.56 percent. As illustrated, LAK's retail energy sales are anticipated to exceed its historic 2015 peak in 2018.

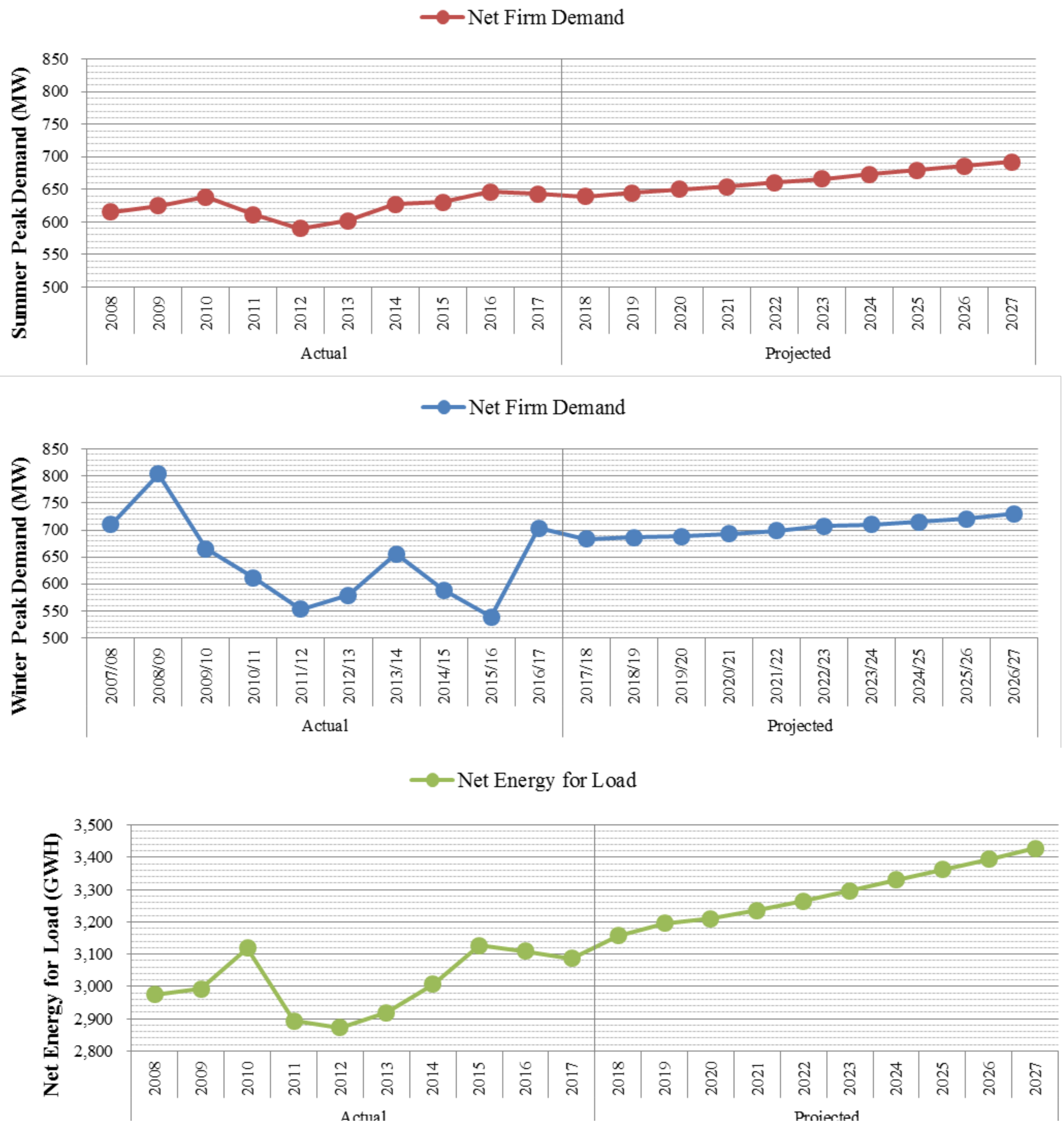
Figure 39: LAK Growth Rate



Source: 2018 Ten-Year Site Plan

The three graphs in Figure 40 show LAK's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. LAK offers energy efficiency programs, the impacts of which are included in the graphs.

Figure 40: LAK Demand and Energy Forecasts



Source: 2018 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 25 shows LAK's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. LAK uses natural gas as its primary fuel type for energy, with coal representing about 27 percent net energy for load. While natural gas usage is anticipated to increase as a percent of net energy for load, coal is projected to decrease by 2027.

Table 25: LAK Energy Consumption by Fuel Type

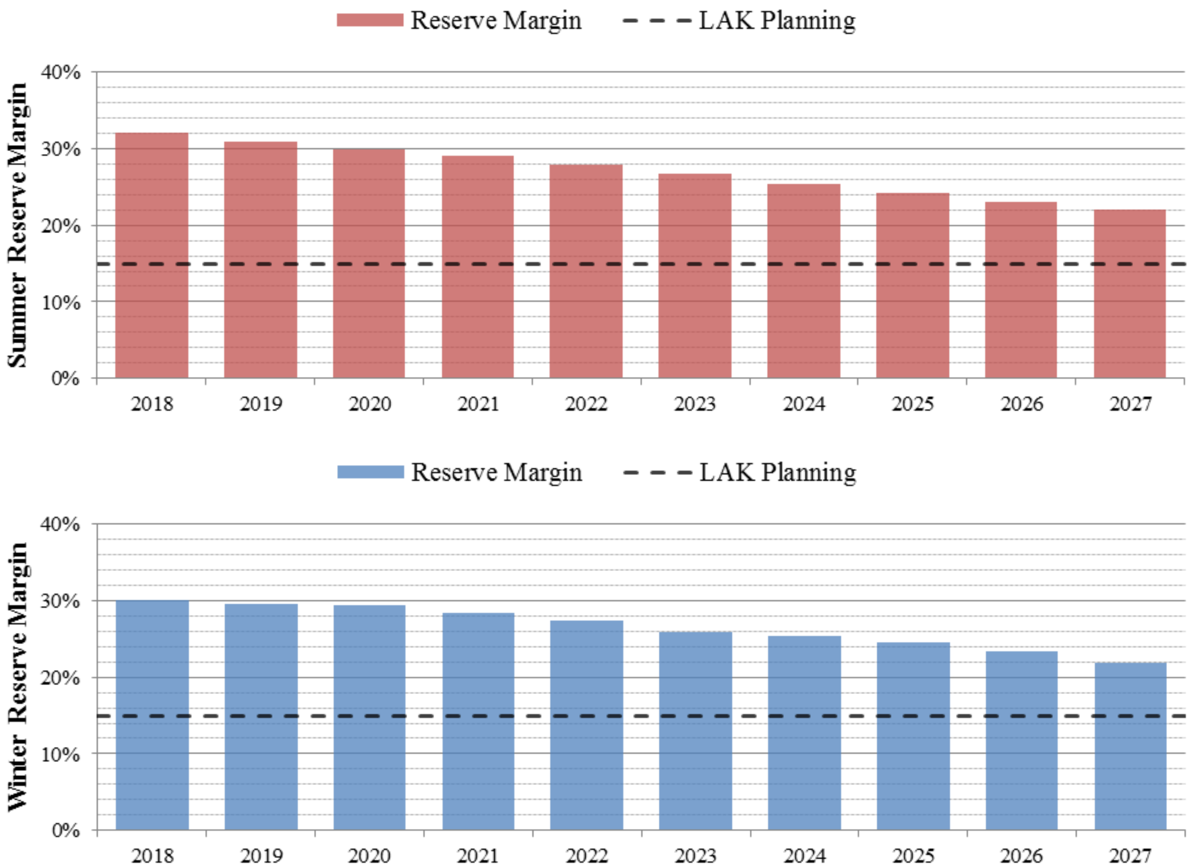
Fuel Type	Net Energy for Load			
	2017		2027	
	GWh	%	GWh	%
Natural Gas	1,589	**51.5%**	2,667	**77.8%**
Coal	846	**27.4%**	474	**13.8%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	1	**0.0%**
Renewable	27	**0.9%**	37	**1.1%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	624	**20.2%**	248	**7.2%**
Total	**3,086**		**3,427**	

Source: 2018 Ten-Year Site Plan and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 41 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 25.2 percent of winter net firm peak demand in 2017, in excess of the Utility's reserve margin.

Figure 41: LAK Reserve Margin Forecast



Source: 2018 Ten-Year Site Plan

Generation Resources

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

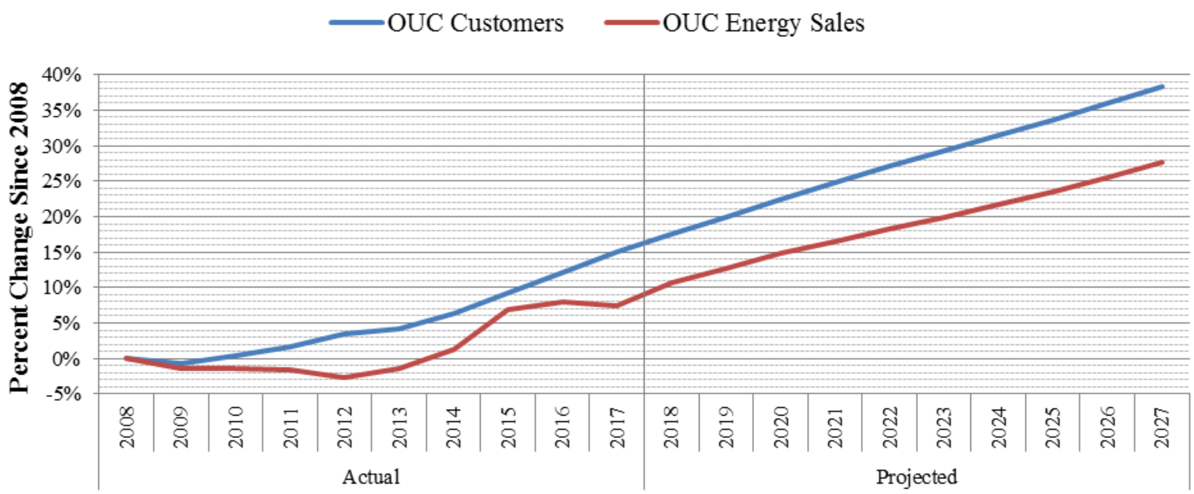
Orlando Utilities Commission (OUC)

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 2018 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2017, OUC had approximately 237,121 customers and annual retail energy sales of 6,568 GWh or approximately 2.9 percent of Florida's annual retail energy sales. Figure 42 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, OUC's customer base has increased by 15 percent, while retail sales have grown by 7.41 percent. As illustrated, OUC's retail energy sales are anticipated to exceed its historic 2016 peak in 2018.

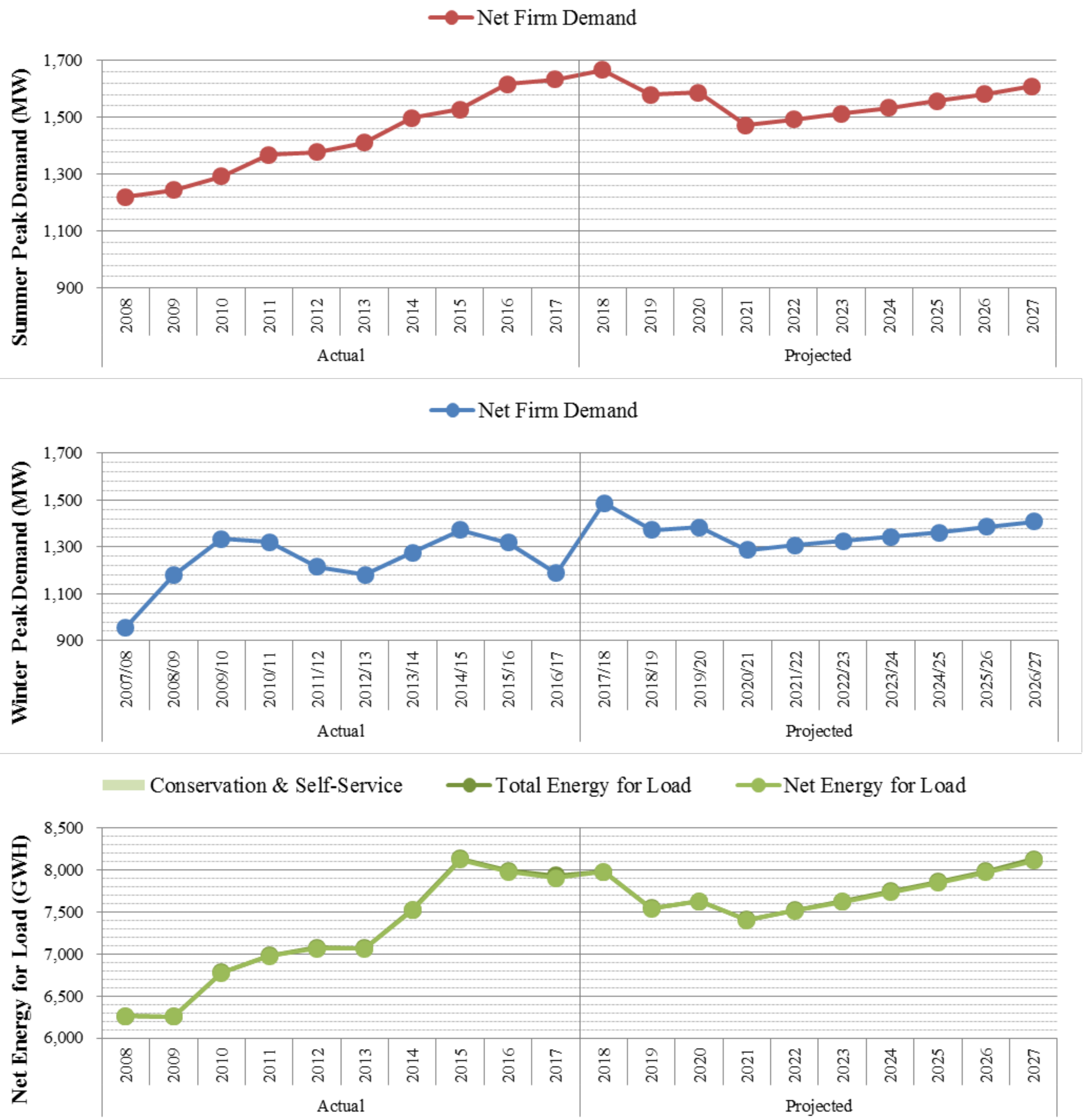
Figure 42: OUC Growth Rate



Source: 2018 Ten-Year Site Plan

The three graphs in Figure 43 show OUC's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. 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 43: OUC Demand and Energy Forecasts



Source: 2018 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 26 shows OUC's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. In 2017, OUC primarily used coal as fuel to meet its net energy for load at approximately 50 percent, with natural gas as the second most used fuel at approximately 42 percent. OUC projects an increase in the quantity of energy consumed from coal by 2027. Natural gas usage is planned to decrease to about 24 percent by 2027. Based upon this projection, OUC, as a percent of net energy for load, would be the largest user of coal of the Ten-Year Site Plan Utilities by 2027.

Table 26: OUC Energy Consumption by Fuel Type

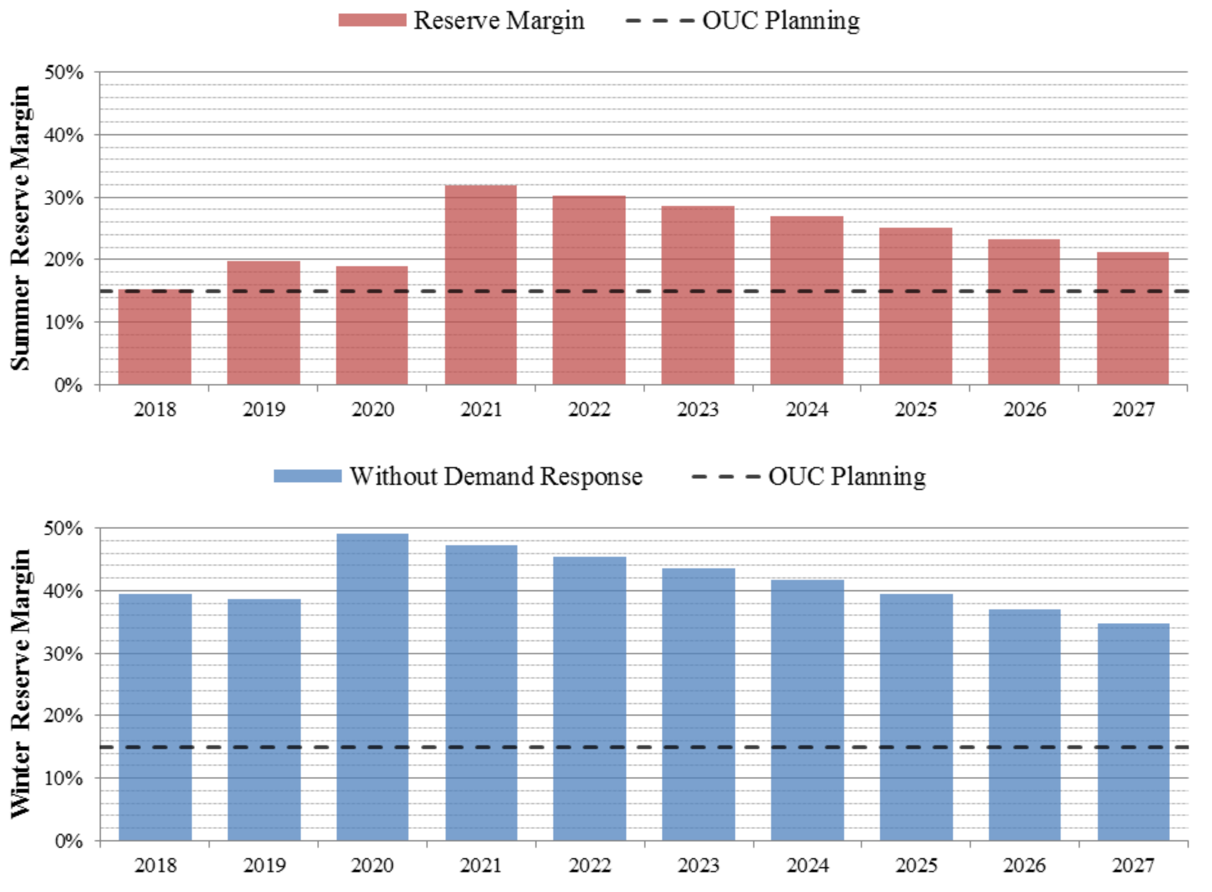
Fuel Type	Net Energy for Load			
	2017		2027	
	GWh	%	GWh	%
Natural Gas	3,326	**42.1%**	1,944	**24.0%**
Coal	3,955	**50.1%**	4,920	**60.6%**
Nuclear	467	**5.9%**	560	**6.9%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	154	**1.9%**	689	**8.5%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**7,902**		**8,113**	

Source: 2018 Ten-Year Site Plan and Data Responses

Reliability Requirements

OUC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 44 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 44: OUC Reserve Margin Forecast



Source: 2018 Ten-Year Site Plan

Generation Resources

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

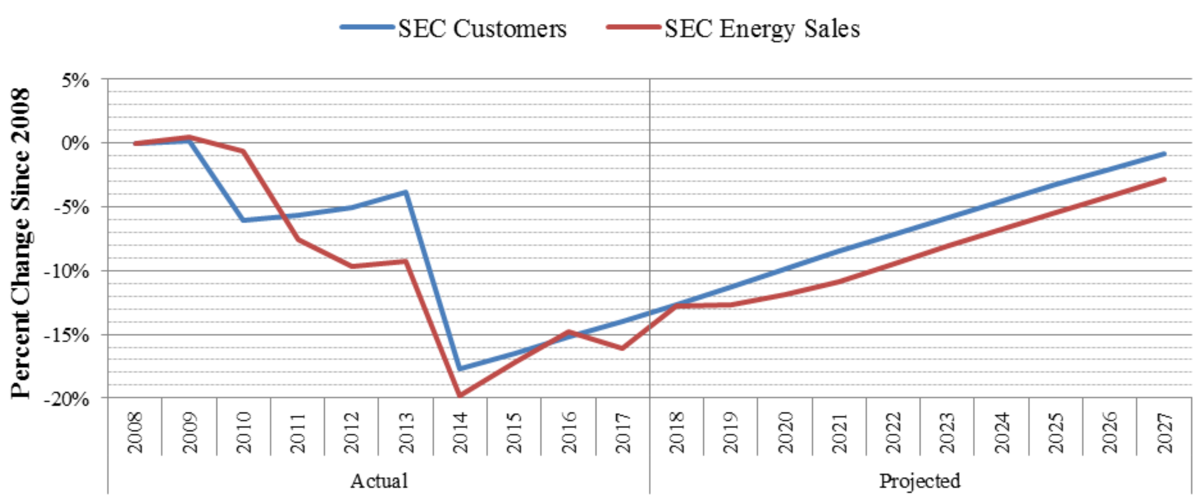
Seminole Electric Cooperative (SEC)

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 2018 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2017, SEC had approximately 774,337 customers and annual retail energy sales of 13,563 GWh or approximately 6 percent of Florida's annual retail energy sales. Figure 45 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, SEC's customer base has decreased by 13.97 percent, and retail sales have decreased 16.08 percent. As illustrated, SEC's retail energy sales are not anticipated to exceed its historic 2009 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.

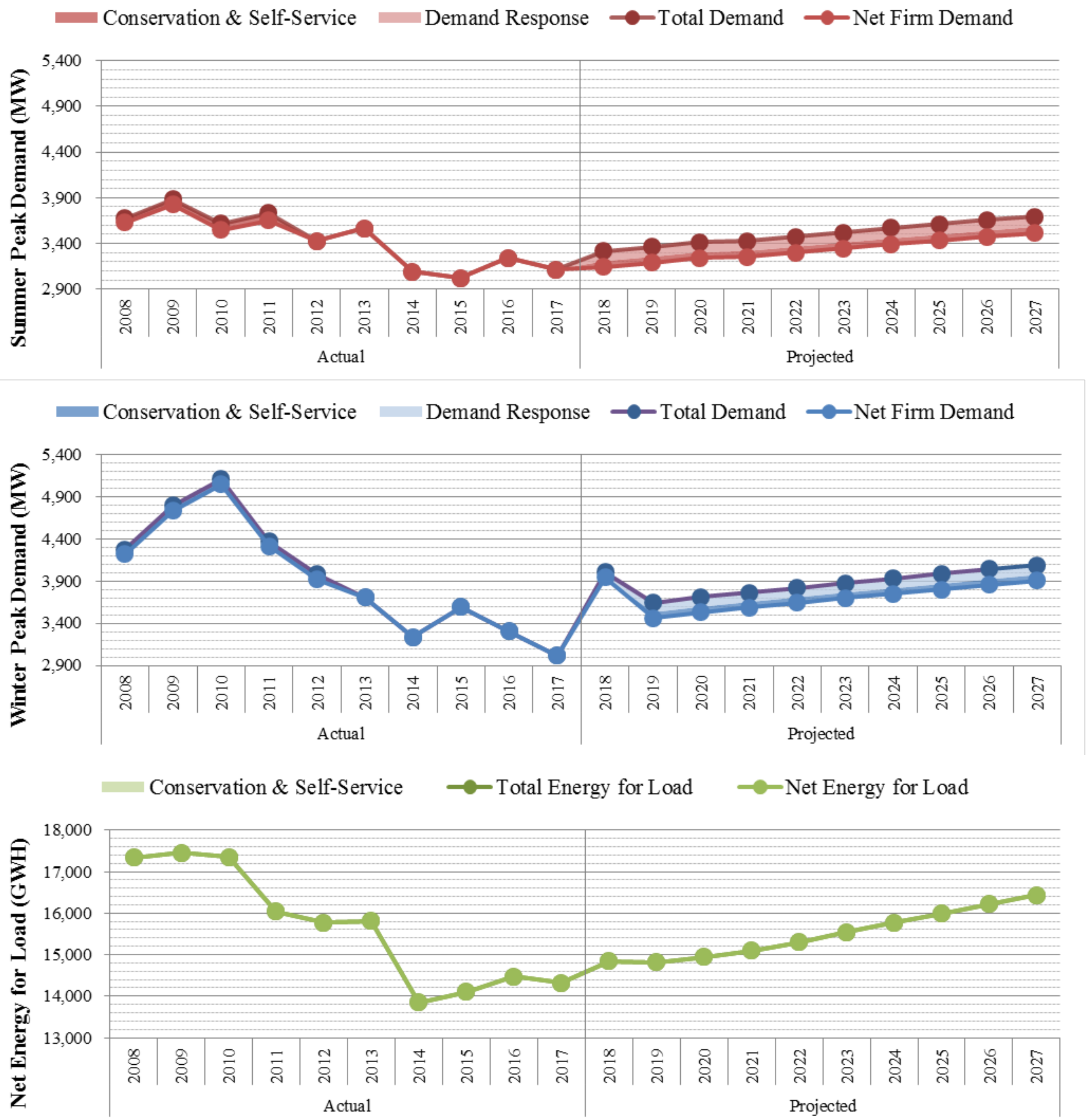
Figure 45: SEC Growth Rate



Source: 2018 Ten-Year Site Plan

The three graphs in Figure 46 show SEC's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. 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 46: SEC Demand and Energy Forecasts



Source: 2018 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 27 shows SEC's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. In 2017, SEC used a combination of coal and natural gas to meet its member cooperatives' net energy for load, with coal use exceeding all other combined sources. By 2027, SEC projects this to reverse, with natural gas usage higher than coal.

Table 27: SEC Energy Consumption by Fuel Type

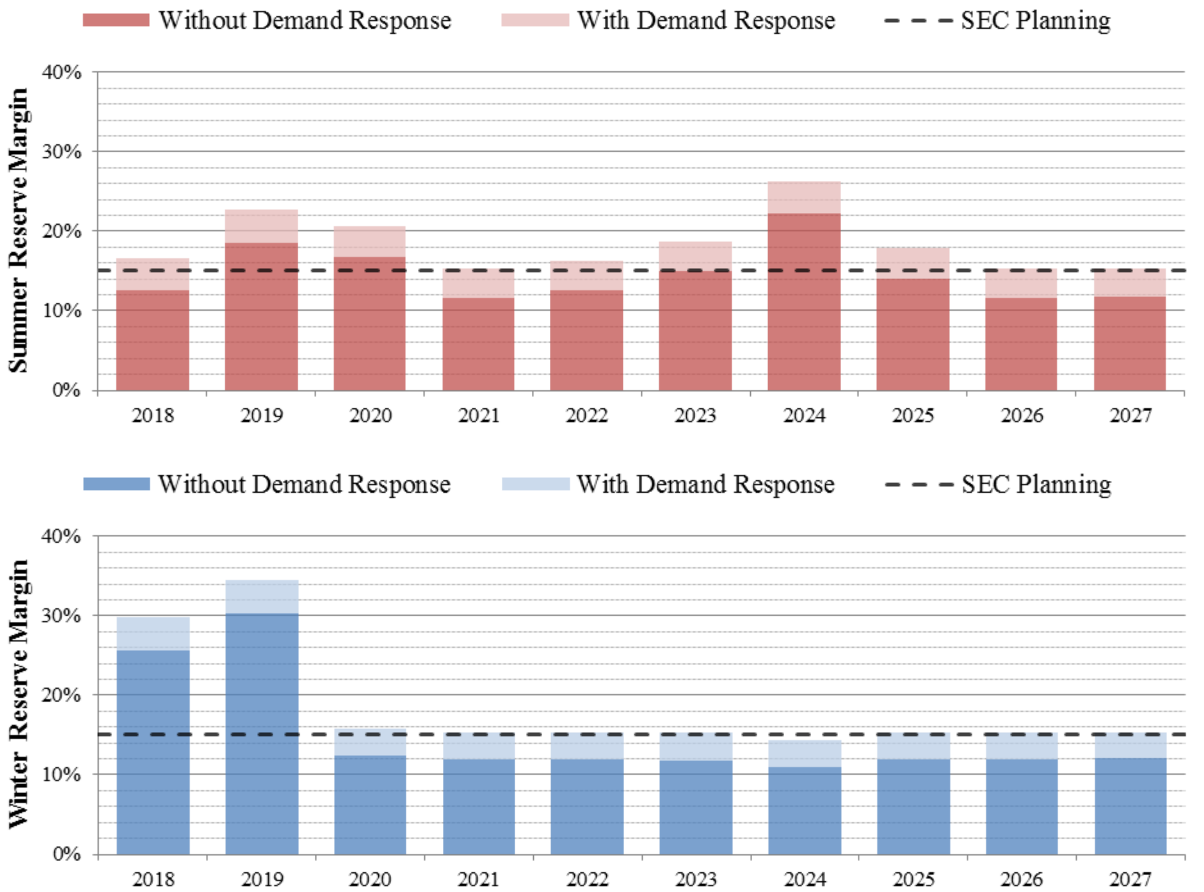
Fuel Type	Net Energy for Load			
	2017		2027	
	GWh	%	GWh	%
Natural Gas	3,299	**23.0%**	9,863	**60.0%**
Coal	7,508	**52.4%**	3,040	**18.5%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	17	**0.1%**	8	**0.0%**
Renewable	581	**4.1%**	113	**0.7%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	2,920	**20.4%**	3,413	**20.8%**
Total	**14,325**		**16,437**	

Source: 2018 Ten-Year Site Plan and Data Responses

Reliability Requirements

SEC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 47 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 47: SEC Reserve Margin Forecast



Source: 2018 Ten-Year Site Plan

Generation Resources

SEC plans to retire one unit and add one unit during the planning period, as described in Table 28. On December 21, 2017, SEC filed a need determination with the Commission for the Seminole CC Facility which was granted on May 25, 2018.[20] Consistent with its need determination filing, SEC plans to retire one of its coal-fired SGS units in 2023, and the Seminole CC Facility is expected to be in-service by 2022. However, this need determination is currently under appeal.

Table 28: SEC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2023	SGS Unit	Coal Steam Turbine	630	
Total Retirements			**630**	
New Units				
2022	Seminole CC Facility	Natural Gas Combined Cycle	1,108	Docket No. 20170266-EC
Total New Units			**1,108**	
Net Additions			**478**	

Source: 2018 Ten-Year Site Plan

[20] Order No. PSC-2018-0262-FOF-EC, issued May 25, 2018, in Docket No. 20170266-EC, *In re: Petition to determine need for Seminole combined cycle facility,by Seminole Electric Cooperative, Inc.*

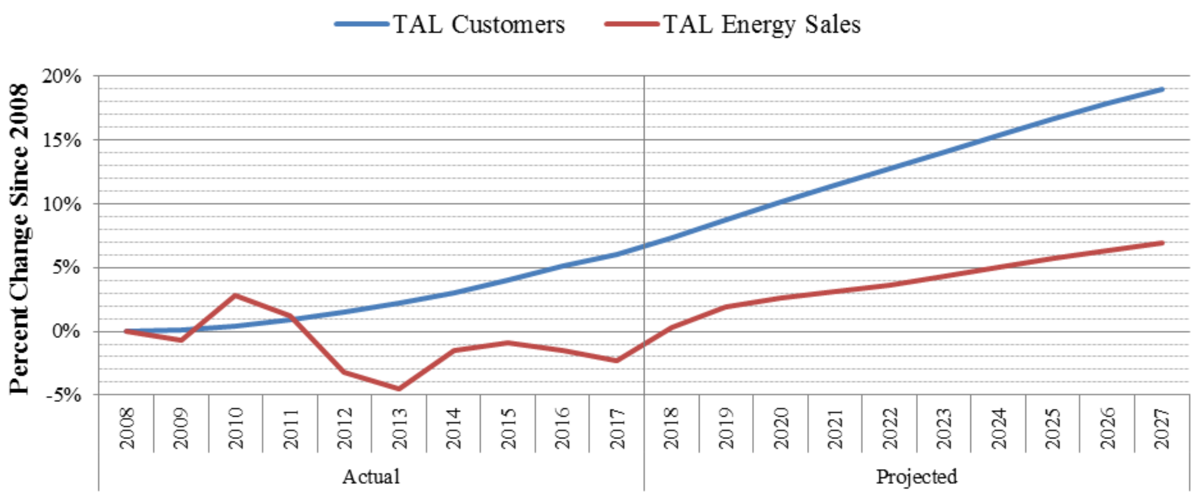
City of Tallahassee Utilities (TAL)

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 2018 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2017, TAL had approximately 120,051 customers and annual retail energy sales of 2,617 GWh or approximately 1.2 percent of Florida's annual retail energy sales. Figure 48 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, TAL's customer base has increased by 6.02 percent, while retail sales have declined by 2.31 percent. As illustrated, TAL's retail energy sales are not anticipated to exceed its historic 2010 peak until 2021.

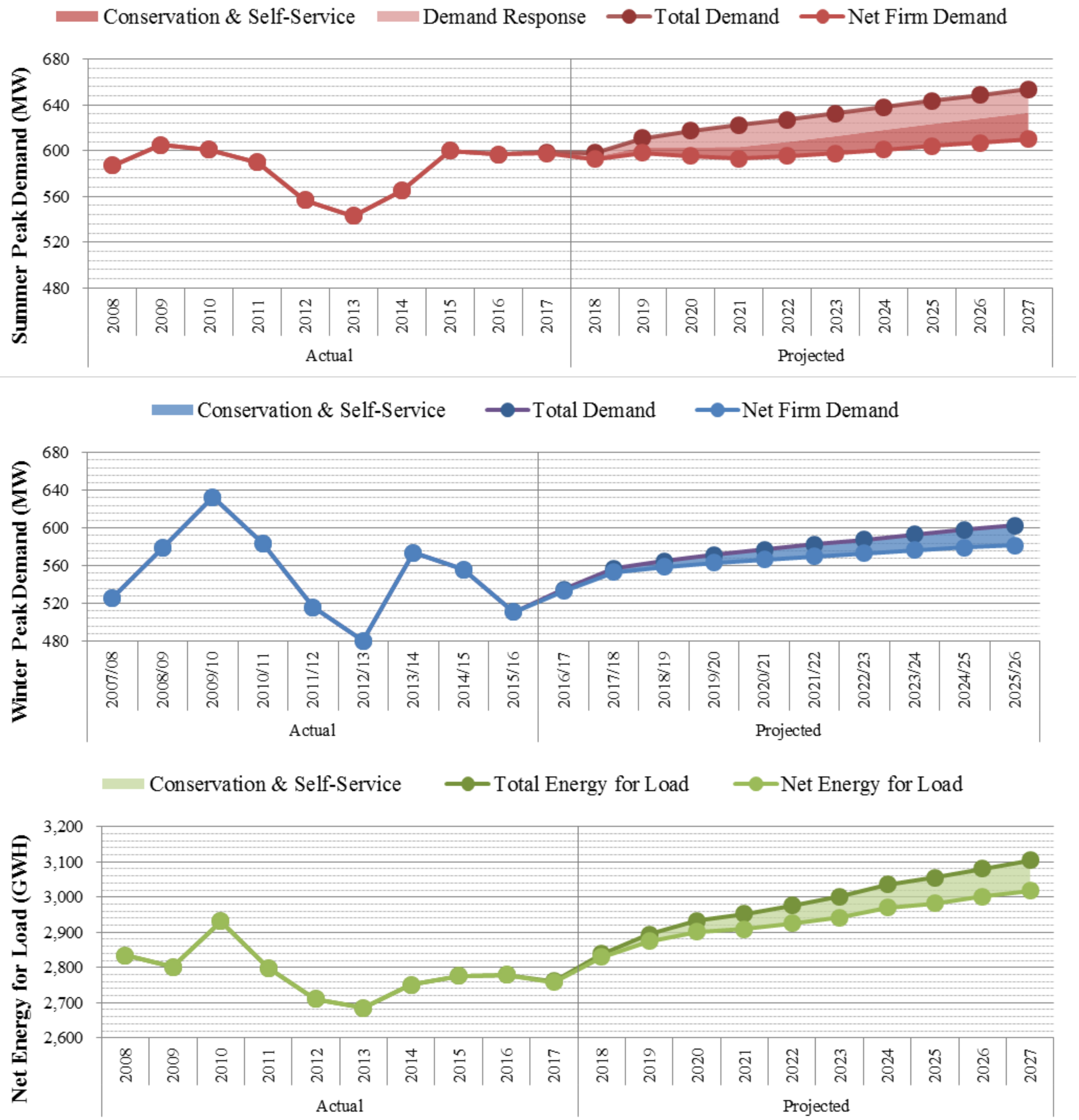
Figure 48: TAL Growth Rate



Source: 2018 Ten-Year Site Plan

The three graphs in Figure 49 shows TAL's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. 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 49: TAL Demand and Energy Forecasts



Source: 2018 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 29 shows TAL's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. 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 29: TAL Energy Consumption by Fuel Type

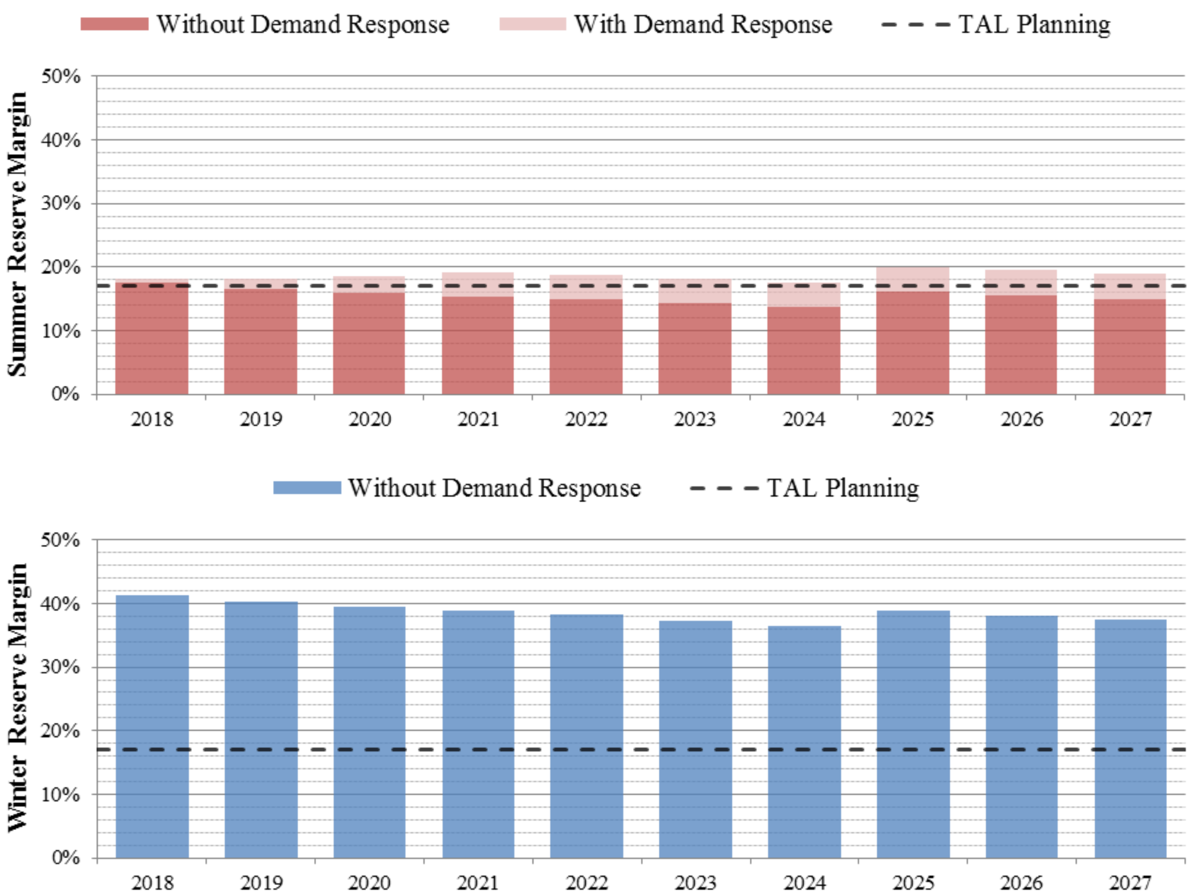
Fuel Type	Net Energy for Load			
	2017		2027	
	GWh	%	GWh	%
Natural Gas	2,635	**95.5%**	2,907	**96.3%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	13	**0.5%**	132	**4.4%**
Interchange	110	**4.0%**	-21	**-0.7%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**2,758**		**3,018**	

Source: 2018 Ten-Year Site Plan and Data Responses

Reliability Requirements

TAL utilizes a 17 percent planning reserve margin criterion for seasonal peak demand. Figure 50 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 50: TAL Reserve Margin Forecast



Source: 2018 Ten-Year Site Plan

Generation Resources

TAL plans multiple unit retirements and additions during the planning period, as described in Table 30. A natural gas-fired steam unit and a natural gas-fired combustion turbine unit are anticipated to be retired during the planning period. Based upon its current planning, TAL intends to add several natural gas-fired internal combustion units.

Table 30: TAL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum
Retiring Units			
2018	Hopkins 1	Natural Gas Steam Turbine	76
2018	Purdom CT-2	Natural Gas Combustion Turbine	10
Total Retirements			**86**
New Units			
2018	Hopkins IC 1-4	Natural Gas Internal Combustion	74
2018	Substation 12 IC 1 & 2	Natural Gas Internal Combustion	18
2025	Hopkins IC 5	Natural Gas Internal Combustion	18
Total New Units			**110**
Net Additions			**24**

Source: 2018 Ten-Year Site Plan