REVIEW OF THE

2015 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, Inc.	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 their load forecast assumptions based on 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, 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 a utility's Ten-Year Site Plan is produced as the culmination of the IRP process. Commission Rules also require the utilities to provide aggregate data which provides an overview of the State of Florida electric grid.

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

Pursuant to Section 186.801(1), Florida Statutes (F.S.), each generating electric utility must submit to the Florida Public Service Commission (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 ten-year planning horizon. The Ten-Year Site Plans of Florida's electric utilities summarize the results of each utility's IRP process and are designed to give state, regional, and local agencies advance notice of 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 2015 Ten-Year Site Plans for Florida's electric utilities, filed by eleven reporting utilities.[1]

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

[1] Investor-owned utilities filing 2015 TYSPs include Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). Municipal utilities filing 2015 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 2015 TYSP.

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

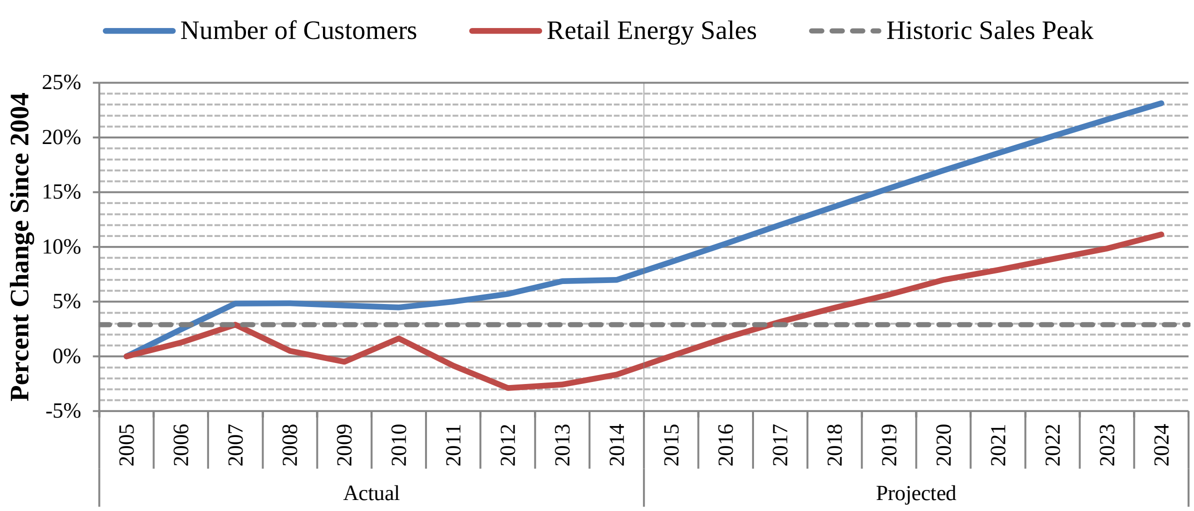
Review of the 2015 Ten-Year Site Plans

The Commission has divided this review into two portions: a Statewide Perspective, which covers the whole of Florida, and 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 the IRP process 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. The Commission, through its authority granted by Sections 366.80 through 366.85 and Section 403.519, F.S., otherwise known as the Florida Energy Efficiency and Conservation Act (FEECA), encourages demand-side management by establishing goals for the reduction of seasonal peak demand and annual energy consumption for those utilities under its jurisdiction. Based on current projections, Florida's electric utilities anticipate exceeding the historic 2007 peak by 2017. Figure 1 below, details these trends.

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



Source: 2015 FRCC Load and Resource Plan

[2] The 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 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

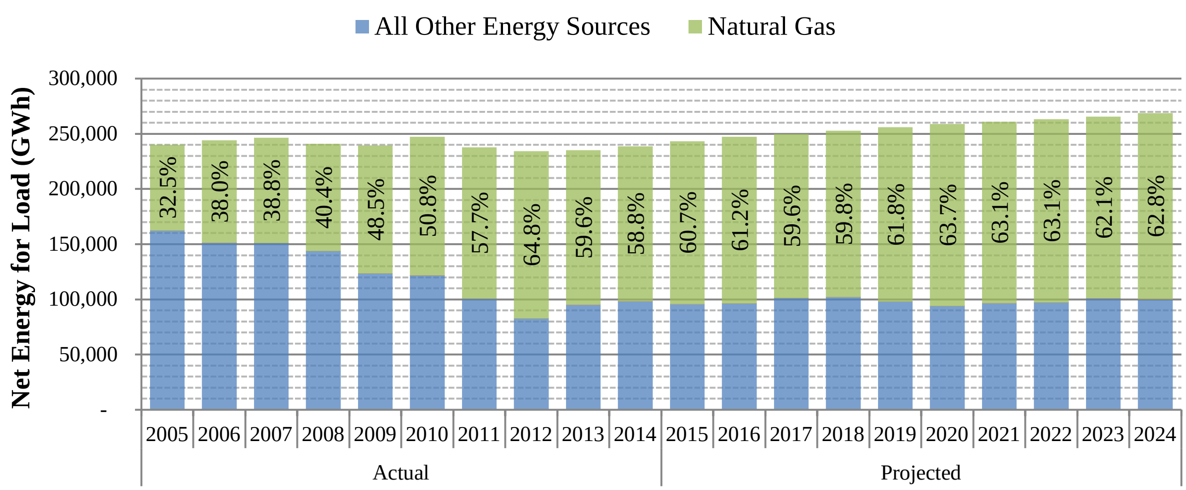
Renewable resources continue to expand in Florida, with approximately 1,640 MW of renewable generating capacity currently installed in Florida. The majority of installed renewable capacity is represented by biomass and municipal solid waste, making up approximately 60 percent of Florida's renewables. Other major renewable types, in order of capacity contribution, include waste, heat, solar, hydroelectric, and landfill gas. Notably, Florida had 80 MW of demand-side renewable energy systems installed and using net metering by the end of 2014, an increase in capacity of 27 percent from 2013.

Over the next 10 years, Florida's electric utilities have reported that 1,566 MW of additional renewable generation is planned in Florida, excluding any potential net metering additions. Over 1,100 MW of the projected capacity additions are solar facilities, which is the largest amount ever included in the utilities' Ten-Year Site Plans. Some utilities are including a portion of these solar resources as a firm resource for reliability considerations for the first time. Reasons given for these changes are a continued reduction in the price of solar facilities, availability of utility property with access to the grid, and actual performance data obtained from some pilot programs. If these conditions continue, cost-effective forms of renewable generation will continue to improve the state's fuel diversity and reduce dependence on fossil fuels.

Traditional Generation

Generating capacity within the State of Florida is anticipated to grow to meet the increase in customer demand, with approximately 11,548 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 12,570 MW new generation. Natural gas remains the dominant fuel over the planning horizon, with usage in 2014 at approximately 60 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. Natural gas usage is expected to grow slowly.

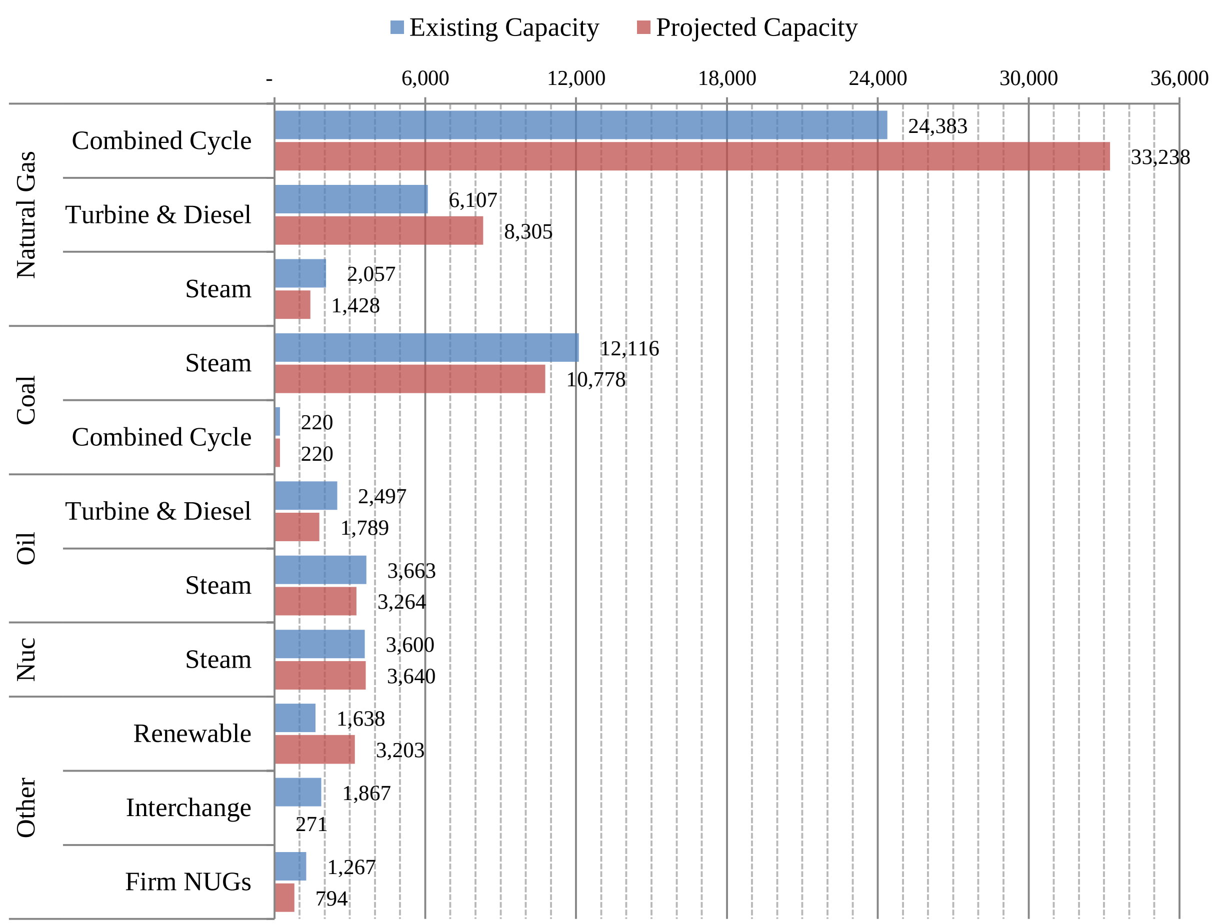
Figure 2: State of Florida - Natural Gas Contribution to Energy Consumption



Source:2005-2015 FRCC Load and Resource Plan

Based on the 2015 Ten-Year Site Plans, Figure 3, below illustrates the present and future aggregate capacity mix of the State of Florida. The capacity values in Figure 3 incorporate all proposed additions, changes, and retirements planned during the ten-year period. As in previous planning cycles, natural gas-fired generating units make up a majority of the generation additions and now represent a majority of capacity within the state.

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



Source:2015 FRCC Load and Resource Plan and TYSP Data Responses

As noted previously, the primary purpose of this review of the utilities' plans is to provide information regarding new electric power plants for local and state agencies to assist in the certification process. Table 1 below, displays those generation facilities that have not yet received from the Commission, a determination of need. A petition for a determination of need is generally anticipated at 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)	Notes
2019	FPL	Okeechobee	Natural Gas Combined Cycle	1,622	Docket No. 150196-EI
2021	SEC	Unnamed	Natural Gas Combined Cycle	649	
2023	FPL	Unknown	Natural Gas Combined Cycle	1,317	
2023	OUC	Unknown	Natural Gas Combined Cycle	285	

Source: 2015 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 or proposed several new rules in recent years that have a sizeable impact on Florida's existing generation fleet, as well as on its proposed new facilities.

Notably, the EPA finalized a rule in August 2015, associated with carbon pollution for existing power plants, also known as the Clean Power Plan. Because of the Clean Power Plan's implementation schedules, these EPA Rules, though they may have a significant effect on Florida's electric utilities, are not considered as part of this review. The Commission anticipates that the utilities' 2016 Ten-Year Site Plans will include more discussion of potential impacts from the Clean Power Plan.

Conclusion

The Commission has reviewed the 2015 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 2015 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

Integrated resource planning (IRP) is a term used to describe a utility planning process to insure reliable and affordable electric service. Each utility must periodically update their load forecast assumptions and combine demand-side and supply-side resources in various scenarios to decide which combination meets the need most cost-effectively. The Ten-Year Site Plans (TYSPs or Plans) of Florida's electric utilities are the culmination of an integrated resource plan which is designed to give state, regional, and local agencies advance notice of proposed power plants and transmission facilities. The Commission receives comments from these agencies regarding any issues with which they may have concerns. The Plans are planning documents that contain tentative data that is subject to change by the utilities upon written notification to the Commission.

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

Statutory Authority

All major generating electric utilities are required by Section 186.801, F.S., to submit at least every two years, for review a Ten-Year Site Plan to the Commission. Based on these filings, the Commission performs a preliminary study of each Plan and makes a non-binding determination as to whether it is suitable or unsuitable. The results of the Commission's study are contained in this report, the Review of the 2015 Ten-Year Site Plans, and are forwarded to the Florida Department of Environmental Protection for use in subsequent proceedings. In addition, Section 377.703(2)(e), F.S., requires the Commission to collect and analyze energy forecasts, specifically for electricity and natural gas, along with the Department of Agriculture and Consumer Services. The Commission has adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code (F.A.C.) in order to fulfill these statutory requirements and provide a solid framework for flexible, cost-effective utility resource planning. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving day-to-day planning and operations to utility management.

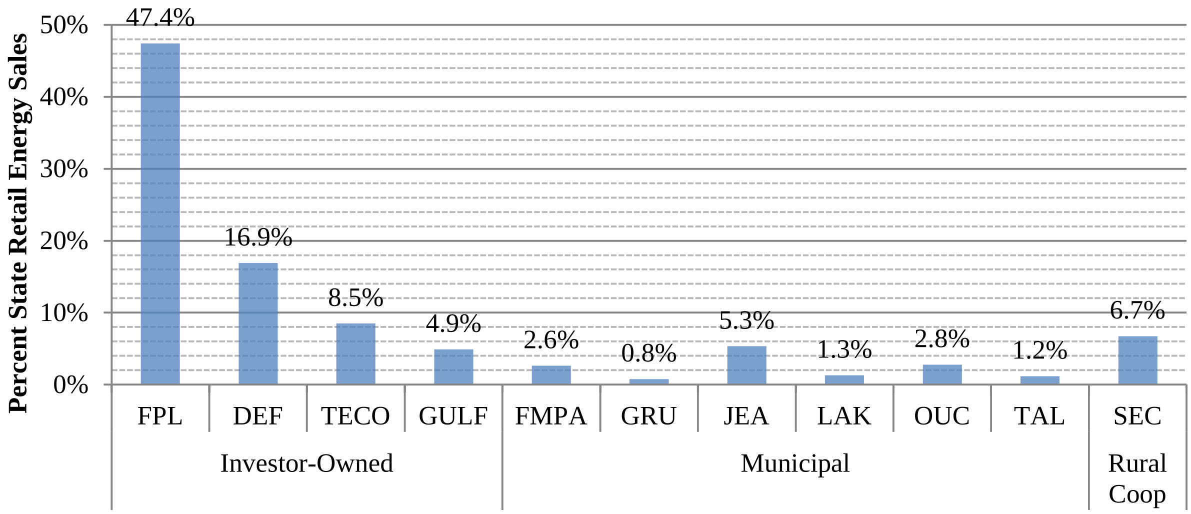
Applicable Utilities

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

In 2015, 11 utilities met these requirements and filed a Ten-Year Site Plan, including 4 investor-owned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). The municipal utilities, in alphabetical order, are Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). The sole rural electric cooperative filing a 2015 Plan is Seminole Electric Cooperative (SEC). Collectively, these utilities are referred to as the Ten-Year Site Plan Utilities (TYSP Utilities).

Figure 4 below, illustrates the comparative size of the TYSP Utilities, in terms of each utility's percentage share of the state's retail energy sales in 2014. Combined, the reporting investor-owned utilities account for 78.3 percent of the state's retail energy sales. Non-reporting utilities make up approximately 1.8 percent of the State's retail energy sales.

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



Source: 2015 Ten-Year Site Plans, 2015 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 ten-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 east of the Apalachicola River. The Florida Reliability Coordinating Council (FRCC) provides this aggregate data for the Commission's review. Each year, the FRCC publishes a Regional Load and Resource Plan, which contains historic and forecast data on demand and energy, capacity and reserves, and proposed new generating units and transmission line additions. In addition, the FRCC publishes an annual Reliability Report which is also relied upon by the Commission.

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

The Commission held a public workshop on September 15, 2015, to facilitate discussion of the annual planning process and allow for public comments. A presentation was conducted by the FRCC summarizing the 2015 Load and Resource Plan and other related matters, including fuel reliability, environmental regulations, and physical security of infrastructure. Presentations were also conducted by the four IOU's FPL, DEF, TECO and GPC, discussing upcoming solar installations. Public comments from Office of Public Counsel, Southern Alliance for Clean Energy and Sierra Club were also given at the workshop.

Structure of the Commission's Review

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

Conclusion

Based on its review, the Commission finds all 11 reporting utility's 2015 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

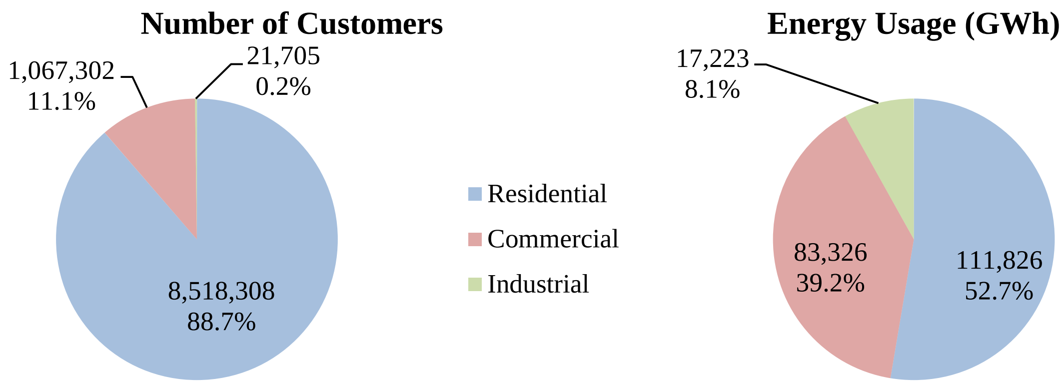
Load Forecasting

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

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

Figure 5: State of Florida - Electric Customer Composition in 2014

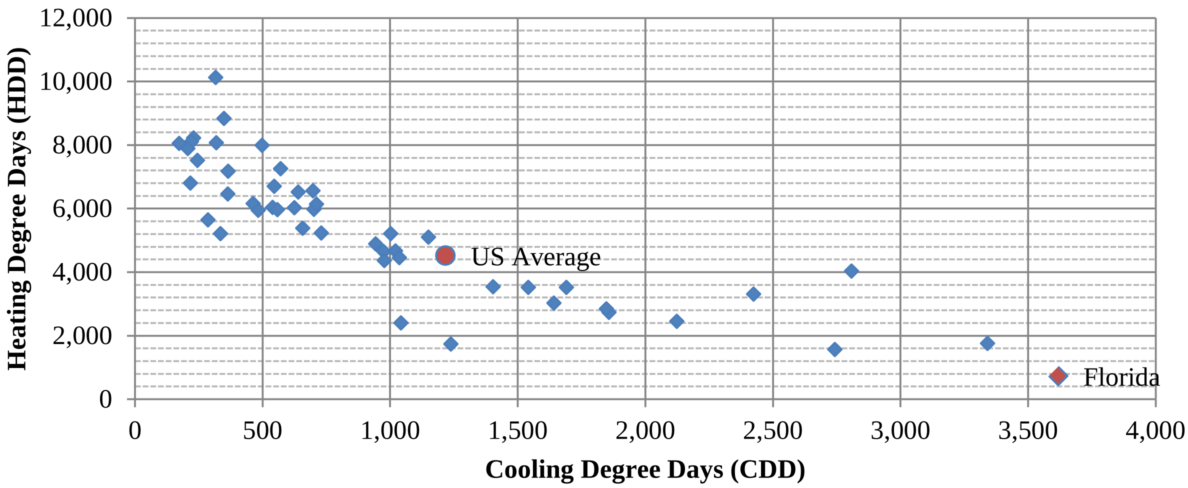


Source: FRCC 2015 Load and Resource Plan

Florida's residential customers make up a larger portion of retail energy sales than the United States as a whole, with a national average of 38 percent for residential retail sales. As a result, Florida's utilities are impacted more by trends in residential energy usage, which tend to be associated with weather conditions. Florida's residential customers rely more upon electricity for heating than the national average, with only a small portion using alternate fuels such as natural gas or oil for home heating needs.

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

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

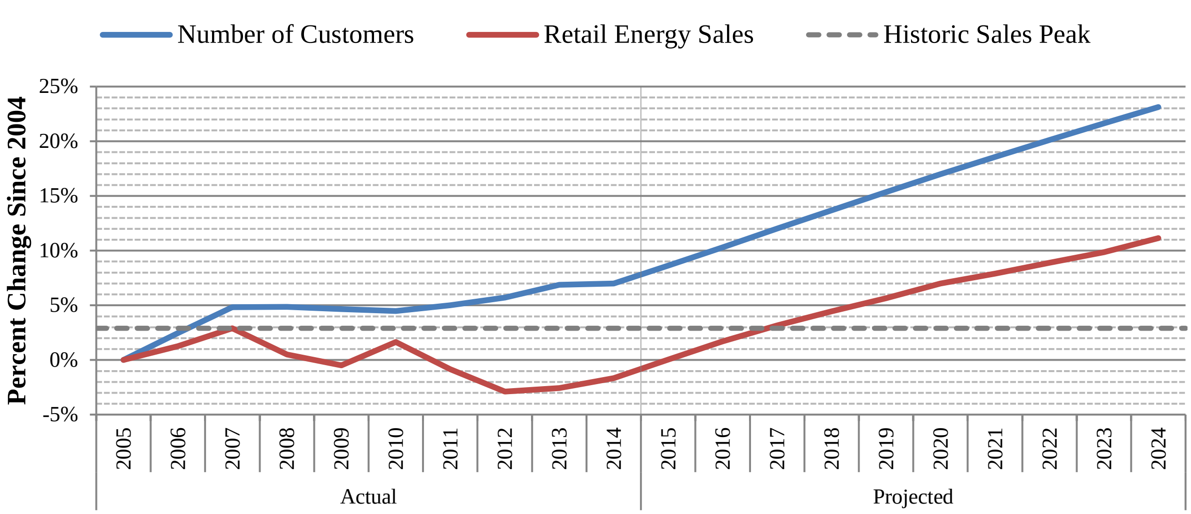


Source: National Oceanic & Atmospheric Administration, Historical Climatology Series 5-1 and 5-2

Growth Projections

For the next ten year period, Florida's customer base and retail sales are anticipated by the reporting utilities to grow at a faster pace than the last few years, reversing a trend of small population increases with declining retail sales. While this rate remains below those experienced before the financial crisis, it would set the State on track to exceed its previous 2007 retail sales peak in 2017. The current divide between customers and retail sales is anticipated to remain similar over the ten-year period, with customers growing at an average annual rate of 1.40 percent while retail sales increase by 1.18 percent annually. Florida's electric utilities are projecting an increase in economic growth in the state, but at levels below those experienced before the financial crisis. The trends are showcased in Figure 7 below.

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



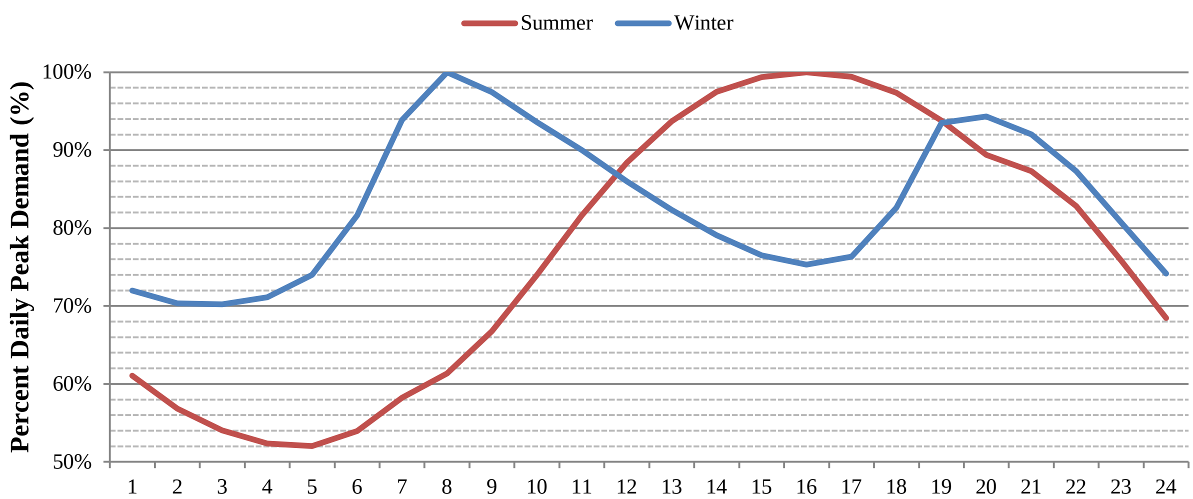
Source: FRCC 2015 Load and Resource Plan

Peak Demand

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

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

Figure 8: TYSP Utilities - Example Daily Load Curves

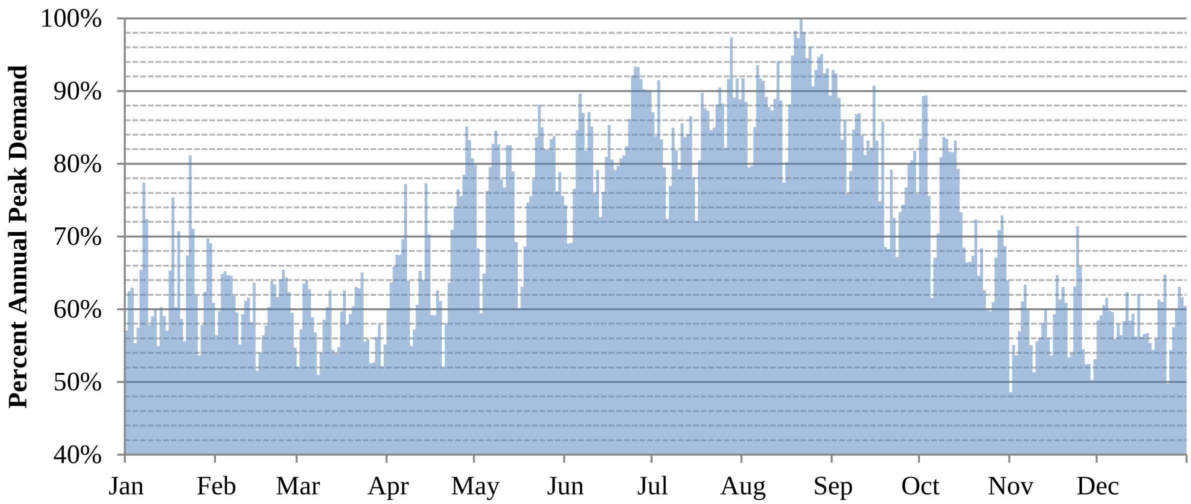


Source: TYSP Utilities Data Responses

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

As daily load varies, so do seasonal loads. Figure 9 below, illustrates this for 2014, showing the daily peak demand as a percentage of the annual peak demand for the reporting investor-owned utilities combined. Typically, winter peaks are short events while summer demand tends to stay at near peak levels for longer periods. The periods between seasonal peaks are referred to as shoulder months, in which the utilities take advantage of lower demand to perform maintenance without impacting their ability to meet daily peak demand.

Figure 9: TYSP Utilities - Daily Peak Demand (2014 Actual)



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

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

Electric Vehicles

Utilities also examine other trends that may impact the amount of customer peak demand and energy consumption. This includes new sources of energy consumption, such as electric vehicles, which can be considered analogous to a home air conditioning system in terms of system load. At present, the reporting electric utilities estimate approximately 12,000 electric plug-in vehicles were operating in Florida by the end of 2014. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered vehicles in Florida as of December 31, 2014, as 13.9 million vehicles, resulting in 0.047 percent penetration rate of electric vehicles of Florida's registered vehicle fleet.

Florida's electric utilities anticipate growth in the electric vehicle market, as illustrated in Table 2.below Electric vehicles are anticipated to grow rapidly throughout the planning period, resulting in almost a quarter-million electric vehicles operating within the electric service territories by the end of 2024. The projected increase in electric vehicle ownership would result in approximately 2 percent share of Florida's vehicles being fueled by electricity.

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

Year	FPL	DEF	TECO	GULF	JEA	OUC	TAL	Total
2014	6,576	2,099	827	219	248	2,355	36	**12,360**
2015	9,395	4,194	1,432	453	372	4,504	43	**20,393**
2016	13,341	6,922	1,909	864	532	6,470	52	**30,090**
2017	17,702	10,701	2,328	1,443	733	8,409	67	**41,383**
2018	22,658	15,722	2,907	2,226	978	10,496	88	**55,075**
2019	29,002	22,321	3,273	3,227	1,263	12,428	114	**71,628**
2020	39,153	30,888	3,580	4,471	1,588	14,343	148	**94,171**
2021	52,857	41,801	3,879	5,972	1,950	16,278	192	**122,929**
2022	71,357	55,198	4,398	7,733	2,347	18,439	260	**159,732**
2023	96,332	70,992	5,076	9,720	2,777	20,762	351	**206,010**

Source: TYSP 2015 Data Responses

In terms of energy consumed by electric vehicles, Table 3 below, illustrates the estimates provided by the reporting utilities. The anticipated growth would result in an annual energy consumption of 765.6 GWh.

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

Year	FPL	DEF	TECO	GULF	JEA	OUC	TAL	Total
2014	3.1	4.4	3.3	1.0	1.6	2.7	0.1	**16.2**
2015	17.4	10.9	5.8	2.0	2.5	5.2	0.2	**43.9**
2016	36.3	20.7	7.7	3.8	3.7	7.2	0.2	**79.5**
2017	57.1	33.8	9.3	6.4	5.4	9.2	0.2	**121.3**
2018	80.7	50.6	11.7	9.8	7.5	11.4	0.3	**172.0**
2019	111.0	72.0	13.1	14.3	10.3	13.5	0.4	**234.6**
2020	159.5	99.4	14.4	19.8	13.6	15.6	0.5	**322.8**
2021	224.9	133.2	15.6	26.4	17.5	17.7	0.7	**435.9**
2022	313.2	173.4	17.7	34.2	22.0	20.1	0.9	**581.4**
2023	432.4	218.7	20.4	43.0	27.2	22.7	1.2	**765.6**

Source: TYSP 2015 Data Responses

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

Demand-Side Management

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

Florida Energy Efficiency and Conservation Act (FEECA)

The Florida Legislature has directed the Commission to encourage utilities to decrease the growth in seasonal peak demand and annual energy consumption by FEECA, which consists of Sections 366.80 through 366.85 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 86.5 percent of 2014 retail sales in Florida.

The FEECA utilities currently offer demand-side management programs for residential, commercial, and industrial customers which are integral to the utilities' IRP process. 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. The 2015 Ten-Year Site Plans incorporate the impacts of the goals established by the Commission for the planning period. During 2015, the Commission reviewed the FEECA Utility's proposed DSM Plans to comply with the established goals, approving the plans with some modifications in July, 2015.

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 customers is curtailable customers, 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 customers, 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 that 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 2015, demand response available for reduction of peak load is 3,110 MW for summer peak and 2,985 MW for winter peak. Demand response is anticipated to increase to approximately 3,458 for summer peak and 3,263 for winter peak by the end of the planning period in 2024.

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 2015, energy efficiency is responsible for peak load reduction of 3,970 MW for summer peak and 3,611 MW for winter peak. Energy efficiency is anticipated to increase to approximately 4,757 MW for summer peak and 4,361 MW for winter peak by the end of the planning period in 2024.

Forecast Load & Peak Demand

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

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

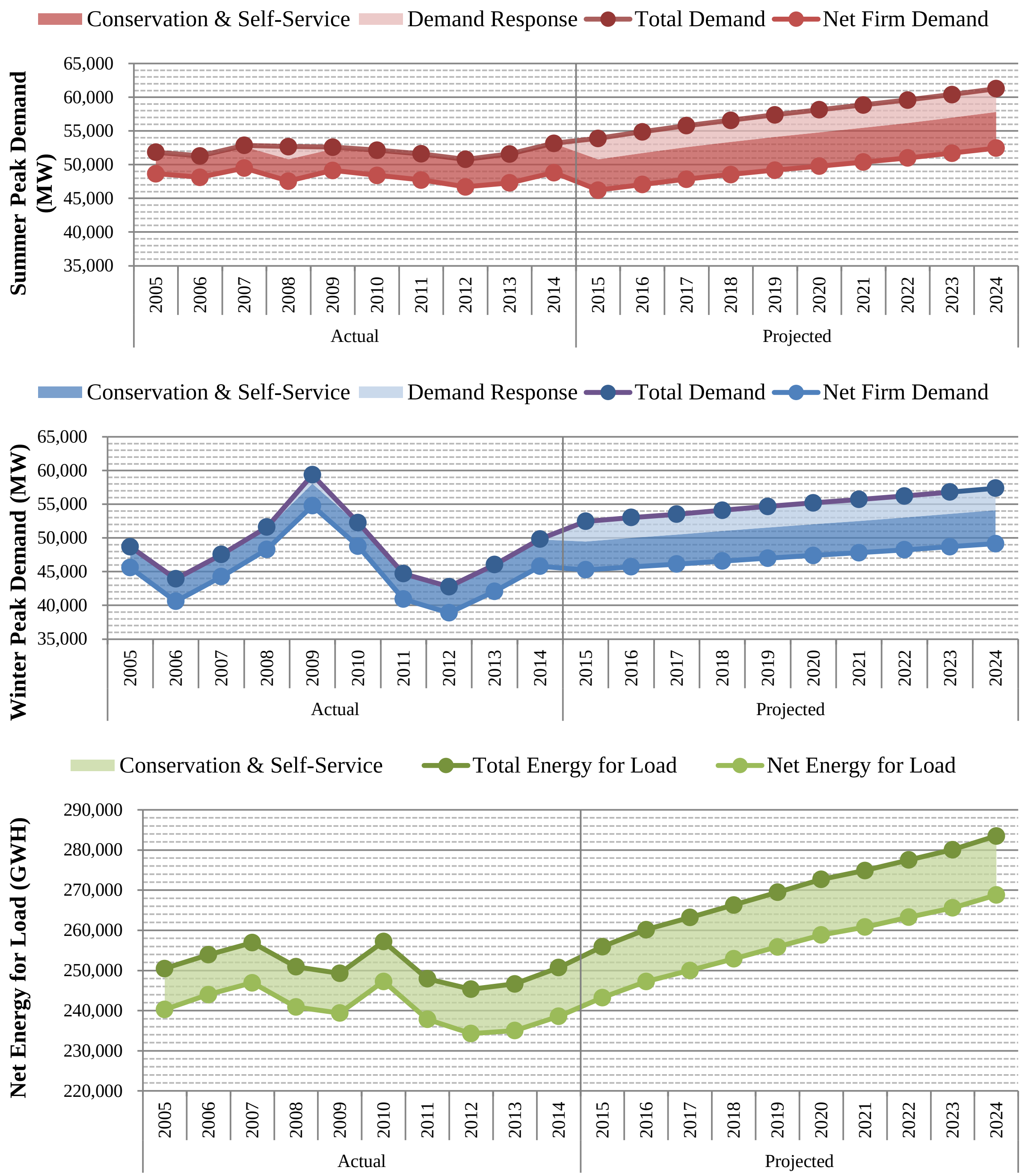
Demand response is included in Figure 10 below, in two different ways based upon the time period considered. For historic values of seasonal demand, the actual rates of demand response activation are shown, not the full amount demand response that was available at the time.

Overall, demand response has only been partially activated as sufficient generation assets were available during the annual peak. Residential load management has been called upon to a limited degree during peak periods, with a lesser amount of interruptible load activated. The primary exception to this trend was the summer of 2008 and winter of 2009, when a larger portion of the available demand response resources were called upon.

For forecast values of seasonal demand, it is assumed that all demand response resources will be activated during peak. The assumption of all demand response being activated reduces generation planning need. Based on operating conditions in the future, if an electric utility has sufficient generating units, and it is economical to serve all customer 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 10 years have had higher winter net firm demand than summer, and all 10 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: 2015 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 customer's expectations for their own future electricity consumption. 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 often 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.

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.

Historic Forecast Accuracy

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 2014 retail energy sales were compared to the forecasts made in 2011, 2010, and 2009. 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 2015 Ten-Year Site Plans, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2014 through 2010 to forecasts made between 2011 and 2005. As discussed previously, the period before the financial crisis experienced a higher annual growth rate for retail energy sales than the post-crisis period. As most electric utilities and macroeconomic forecasters did not predict the financial crisis, the economic impact and its resulting effect on retail energy sales of Florida's electric utilities was not included in these projections. Therefore, the use of a metric that compares pre-crisis forecasts with post-crisis actual data has a high rate of error.

Table 4 below, shows that the forecast error is increasing with time starting 2010 due to the unexpected impact of the financial crisis on retail energy sales in Florida due to decreased population growth, decreased economic growth, and decreased usage of electricity per capita. However, the forecast error should start to return to its historically normal lower levels as utility retail sales forecasts include more years after the financial crisis. This has been confirmed by the most recent data provided in the current TYSP. The forecasting errors (both average and absolute average) generated by comparing actual 2014 retail energy sales to the 2013 forecast of 2014 energy sales are reduced.

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

TYSP Year	Five Year Analysis Period	Forecast Years Analyzed	Forecast Error (%)	
			Average	Absolute Average
2010	2009 - 2005	2006-2000	4.98%	5.70%
2011	2010 - 2006	2007-2001	8.28%	8.29%
2012	2011 - 2007	2008-2002	11.93%	11.93%
2013	2012 - 2008	2009-2003	15.13%	15.13%
2014	2013 - 2009	2010-2004	16.16%	16.16%
2015	2014 - 2010	2011-2005	14.90%	14.90%

Source: 2000-2015 Ten-Year Site Plans

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

As displayed in Table 5 below, the companies' retail energy sales forecasts show a consistent positive error rate beginning in 2007 and extending through 2014, for forecasts prepared two to six years prior. However, 2014 sales forecasted in 2010 and 2011, reveal that three and four year error rates (6.10 percent and 5.73 percent, respectively) have declined considerably compared to the three and four year forecast error rates associated with 2010-2013 sales. The fact that three and four year forecast errors started to decline in 2009 and 2010 forecasts is not surprising because, by 2009, the inputs to the utilities' forecast models reflected the impacts of the financial crisis and population growth decline.

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

Year	Annual Forecast Error Rate (%)						3-5 Year Error (%)	
	Years Prior						Average	Absolute Average
	6	5	4	3	2	1		
2005	-5.82%	-4.03%	-0.69%	-0.64%	0.71%	0.90%	**-1.79%**	**1.79%**
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	27.285%	9.8%	6.10%	5.73%	2.84%	2.21%	**7.21%**	**7.21%**

Source: 2000-2015 Ten-Year Site Plans

On a going forward basis (2015 and beyond), average forecasted energy sales error rates for forecasts prepared three to five years prior, are likely to continue to decline as the older forecasts drop out of the analysis. For several years, Florida's electric utilities responded to the declines in customer load growth by delaying and cancelling new generation, and by taking opportunities to modernize existing plants, as discussed in previous annual reviews of the Ten-Year Site Plans. The dynamic nature of the state and national economies, actual and projected, continue to exert a significant impact on Florida utilities' load forecasts and, ultimately, the accuracy of such forecasts.

Renewable Generation

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

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

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

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

Existing Renewable Resources

Currently, renewable energy facilities provide approximately 1,638 MW of firm and non-firm generation capacity, which represents 2.8 percent of Florida's overall generation capacity of 58,148 MW in 2014. Table 6 below, summarizes the contribution by renewable type of Florida's existing renewable energy sources.

Table 6: State of Florida - Existing Renewable Resources

Renewable Type	MW	% Total
Biomass	581	35.5%
Municipal Solid Waste	400	24.4%
Waste Heat	308	18.8%
Solar	228	13.9%
Hydro	64	3.9%
Landfill Gas	47	2.9%
Wind	10	0.6%
Renewable Total	**1,638**	**100.0%**

Source: FRCC 2015 Load & Resource Plan and TYSP Utilities Data Responses

Of the total 1,638 MW of renewable generation, approximately 570 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 33 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 87 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 qualifying 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 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 2014, approximately 80 MW of renewable capacity from nearly 8,600 systems has been installed statewide. Table 7 below, summarizes the growth of customer owned renewable generation interconnections. Almost all installations under net metering are solar, with non-solar generation accounting for only 35 installations and 5.7 MW of installed capacity. The renewable generators in this category include wind turbines and anaerobic digesters.

Table 7: State of Florida - Net Metering Growth

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

Source: Annual Net Metering Reports

Utility-Owned Renewable Generation

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

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

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

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

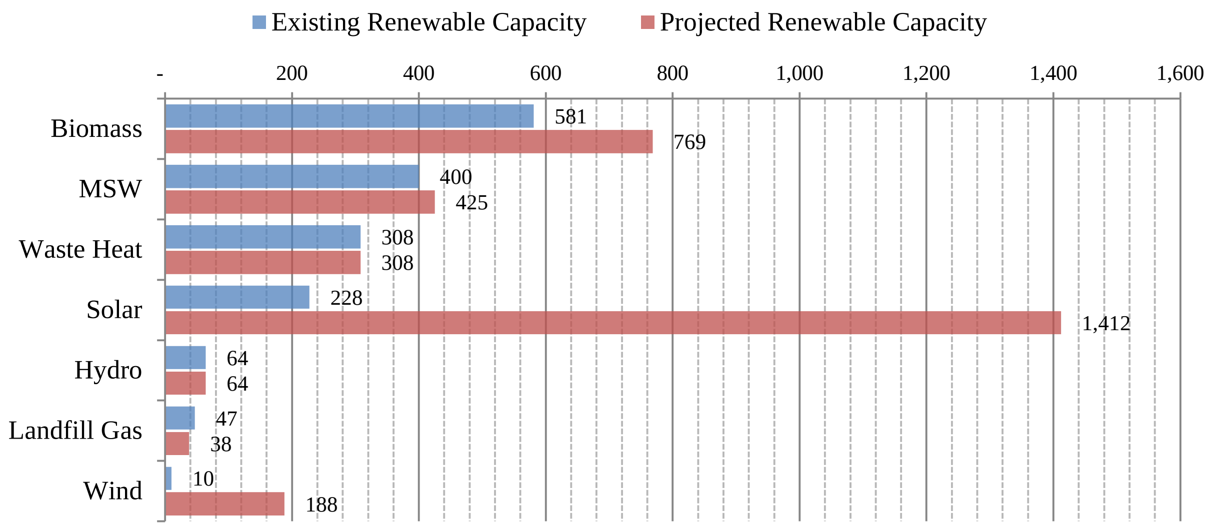
Based on actual data provided by FPL, the combined cost of generation of the three solar facilities was $0.37/kWh in 2014. These facilities make up a significant portion of the utility owned renewable generation. Since full operation began, the two solar PV facilities have operated largely as expected; however, the solar thermal facility has experienced multiple outages which have hindered its performance. In FPL's 2015 TYSP, FPL claims that the Desoto and Space Coast solar facilities contributed approximately 46 percent and 32 percent, respectively, of the system's installed capacity to summer peak demand. No contribution to winter peak demand as determined from either facility.

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

Planned Renewable Resources

Florida's utilities plan to construct or purchase an additional 1,566 MW of renewable generation over the ten-year planning period, a significant increase from last year's estimated 722 MW projection. Figure 11 below, summarizes the existing and projected renewable capacity by generation type. Solar generation is projected to have the greatest increase over the planning horizon.

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



Source: 2015 FRCC Load & Resource Plan, TYSP Utilities Data Responses

Of the 1,566 MW of planned renewable capacity, 432 MW is projected to be from firm resources, including 116 MW from solar generation. The projected firm capacity additions are from a combination of renewable contracts with non-utility generators, primarily biomass, and several utility-owned solar facilities. The remaining planned capacity from renewable resources is projected to be from non-firm resources.

For some existing renewable facilities, contracts for firm capacity are projected to expire within the ten-year planning. If new contracts are signed in the future to replace those that expire, these resources will once again be included in the state's capacity mix to serve future 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 ten-year period, with a total of 1,185 MW to be installed. This consists of 730 MW of utility-owned solar, 155 MW of contracted solar and 300 MW of as-available energy contract solar facilities. Table 8 below, lists some of the utility-scale (greater than 2 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)
2015	LAK	SunEdison Sutton	Purchased	6.0
2015	LAK	SunEdison East Main	Purchased	6.0
2015	DEF	Solar 1 & 2	Utility Owned	5.0
2015	LAK	SunEdison Airport	Purchased	3.2
			2015 Subtotal	**20.2**
2016	FPL	Babcock Solar Energy Center	Utility Owned	74.5
2016	FPL	Citrus Solar Energy Center	Utility Owned	74.5
2016	FPL	Manatee Solar	Utility Owned	74.5
2016	OUC	Stanton Solar Phase 2	Purchased	12.0
2016	DEF	Solar 3, 4 & 5	Utility Owned	10.0
			2016 Subtotal	**245.5**
2017	GULF	Gulf Coast Solar Center I Eglin	Purchased	30.0
2017	GULF	Gulf Coast Solar Center II Holley	Purchased	40.0
2017	GULF	Gulf Coast Solar Center III Saufley	Purchased	50.0
2017	DEF	Solar 6 & 7	Utility Owned	10.0
			2017 Subtotal	**130.0**
2018	DEF	Solar 8	Utility Owned	10.0
			2018 Subtotal	**10.0**
2019	DEF	Solar 9	Utility Owned	50.0
			2019 Subtotal	**50.0**
2020	DEF	Solar 10 & 11	Utility Owned	130.0
			2020 Subtotal	**130.0**
2021	DEF	Solar 12	Utility Owned	35.0
			2021 Subtotal	**35.0**
2022	DEF	Solar 13	Utility Owned	50.0
			2022 Subtotal	**50.0**
2023	DEF	Solar 14 & 15	Utility Owned	75.0
			2023 Subtotal	**75.0**
2024	DEF	Solar 16 & 17	Utility Owned	125.0
			2024 Subtotal	**125.0**
TBD	DEF	Blue Chip Energy Lake Mary	Purchased	10.0
TBD	DEF	Blue Chip Energy Sorrento	Purchased	40.0
TBD	DEF	National Solar Gadsden	Purchased	50.0
TBD	DEF	National Solar Hardee	Purchased	50.0
TBD	DEF	National Solar Suwannee	Purchased	50.0
TBD	DEF	National Solar Highlands	Purchased	50.0
TBD	DEF	National Solar Osceola	Purchased	50.0
			TBD Subtotal	**300.0**

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

Renewable Outlook

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

Traditional Generation

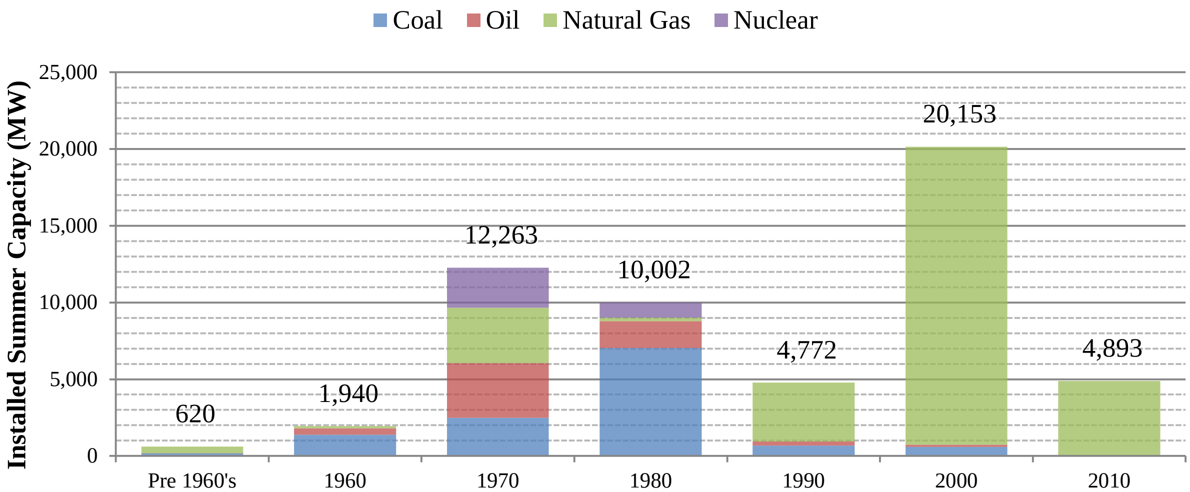
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and turbine generators, that have been added to Florida's electric grid over the last several decades. Due to forecasted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

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

Existing Generation

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

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



Source: 2015 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 changing environmental requirements. During the past several years, the U.S. Environmental Protection Agency (EPA) has finalized or proposed several rules which will impact both existing and planned generating units in the state. Environmental requirements and associated costs must be considered to fully evaluate any new supply-side resources, as well as the operation of existing generating units.

Six EPA rules are anticipated to affect electric generation in Florida:

- Carbon Pollution Emissions Standards for Modified and Reconstructed Secondary Sources: Electric Utility Generating Units – Sets carbon dioxide emission limits for modified or reconstructed electric generators. These limits vary by type of fuel (coal/IGCC or natural gas), size of unit (less than or above approximately 100 megawatts), and whether the unit is modified or reconstructed. EPA issued the final rule on August 3, 2015, and published in the *Federal Register* on October 23, 2015.

- Carbon Pollution Emission Guideline for Existing Electric Generating Units – Requires each state to submit a plan to EPA that outlines how the state's existing electric generation fleet 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 will apply to a statewide average of all generating units over 25 megawatts. EPA issued the final rule on August 3, 2015,and published in the *Federal Register* on October 23, 2015

- 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. On June 29, 2015, the U.S. Supreme Court found in a 5-4 decision that the EPA acted improperly by not considering the costs of compliance in deciding whether regulation of mercury and air toxics is appropriate and necessary. The court did not explicitly vacate the rule, and remanded the case back to the U.S. Court of Appeals for the D.C. Circuit for further proceedings consistent with its opinion.

- Cross-State Air Pollution Rule (CSAPR) - Requires 28 states, including Florida, 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 these states. Florida is only subject to the rule's seasonal NOx emissions requirements. On July 28, 2015, the U.S. Court of Appeals for the D.C. Circuit issued its opinion on the remaining issues raised with respect to CSAPR, keeping CSAPR in place.

- 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 existing electric generators that use water 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 (entrainment). The rule became effective on October 14, 2014.

- Coal Combustion Residuals (CCR) - Requires liners and ground monitoring to be installed on new landfills in which coal ash is deposited. On December 19, 2014, the EPA Administrator signed the Disposal of Coal Combustion Residuals from Electric Utilities final rule. The rule will become effective on October 14, 2015

For many of the units that will remain in operation, these new rules will result in an increased cost of operations. Each utility will need to evaluate whether these additional costs or new operational limitations allow the continued economic operation of each affected unit, and whether installation of emissions control equipment, fuel switching, or retirement is the proper course of action.

Modernization and Efficiency Improvements

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

The Commission has previously granted determinations of need for several conversations of oil-fired steam units to natural gas-fired combined cycle units, including FPL's Cape Canaveral, Riviera, and Port Everglades power plants. DEF has also recently 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. An example is 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. FPL plans on upgrades to its existing combined cycle fleet by improving the performance of the integrated combustion turbines at many of its current and planned power plants.

Planned Retirements

Power plant retirements occur when the electric utility is unable to economically operate or maintain a generating unit due to environmental, economic, or technical concerns. Table 9 below, lists the 4,252 MW of existing generation that is scheduled to be retired during the planning period, a majority of which are natural gas-fired peaking units. Approximately 1,260 MW of the planned retirements are three dozen small peaking units at two power plant sites operated by FPL.

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

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

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

Year	Utility Name	Unit Name	Fuel & Unit Type	Net Capacity (Sum MW)
2015	GPC	Scholz 1 & 2	Coal Steam	92.0
2015	DEF	G. E. Turner P1 - P4	Distillate Oil Combustion Turbine	132.0
			2015 Subtotal	**224.0**
2016	FPL	Cedar Bay	Coal Steam	250.0
2016	GPC	Lansing Smith 2	Coal Steam	0.0
2016	FPL	Turkey Point 1 [Condensor]	Residual Oil Steam	396.0
2016	JEA	Northside 3 [Reserve Storage]	Natural Gas Steam	524.0
2016	DEF	Avon Park 2	Distillate Oil Combustion Turbine	24.0
2016	DEF	Rio Pinar 1	Distillate Oil Combustion Turbine	12.0
2016	FPL	Ft. Myers 1 - 10	Distillate Oil Combustion Turbine	540.0
2016	DEF	Avon Park 1	Natural Gas Combustion Turbine	24.0
2016	FPL	Lauderdale 1 - 22	Natural Gas Combustion Turbine	754.0
2016	FPL	Port Everglades 1 - 12	Natural Gas Combustion Turbine	408.0
2016	TAL	Hopkins GT1	Natural Gas Combustion Turbine	12.0
2016	TAL	Purdom GT1 & GT2	Natural Gas Combustion Turbine	20.0
			2016 Subtotal	**2,964.0**
2017	DEF	Suwannee River 1 - 2	Natural Gas Steam	57.0
2017	TAL	Hopkins GT2	Natural Gas Combustion Turbine	24.0
			2017 Subtotal	**81.0**
2018	DEF	Crystal River 1 & 2	Coal Steam	740.0
2018	DEF	Suwannee River 3	Natural Gas Steam	71.0
2018	GPC	Pea Ridge 1 - 3	Natural Gas Combustion Turbine	12.0
			2018 Subtotal	**823.0**
2020	DEF	Higgins 1 - 4	Natural Gas Combustion Turbine	109.0
			2020 Subtotal	**109.0**
2021	TAL	Hopkins 1	Natural Gas Steam	76.0
			2021 Subtotal	**76.0**
2022	GRU	Deerhaven FS01	Natural Gas Steam	75.0
			2022 Subtotal	**75.0**
			Total Retirements	**4,352**

Source: 2015 Ten-Year Site Plans

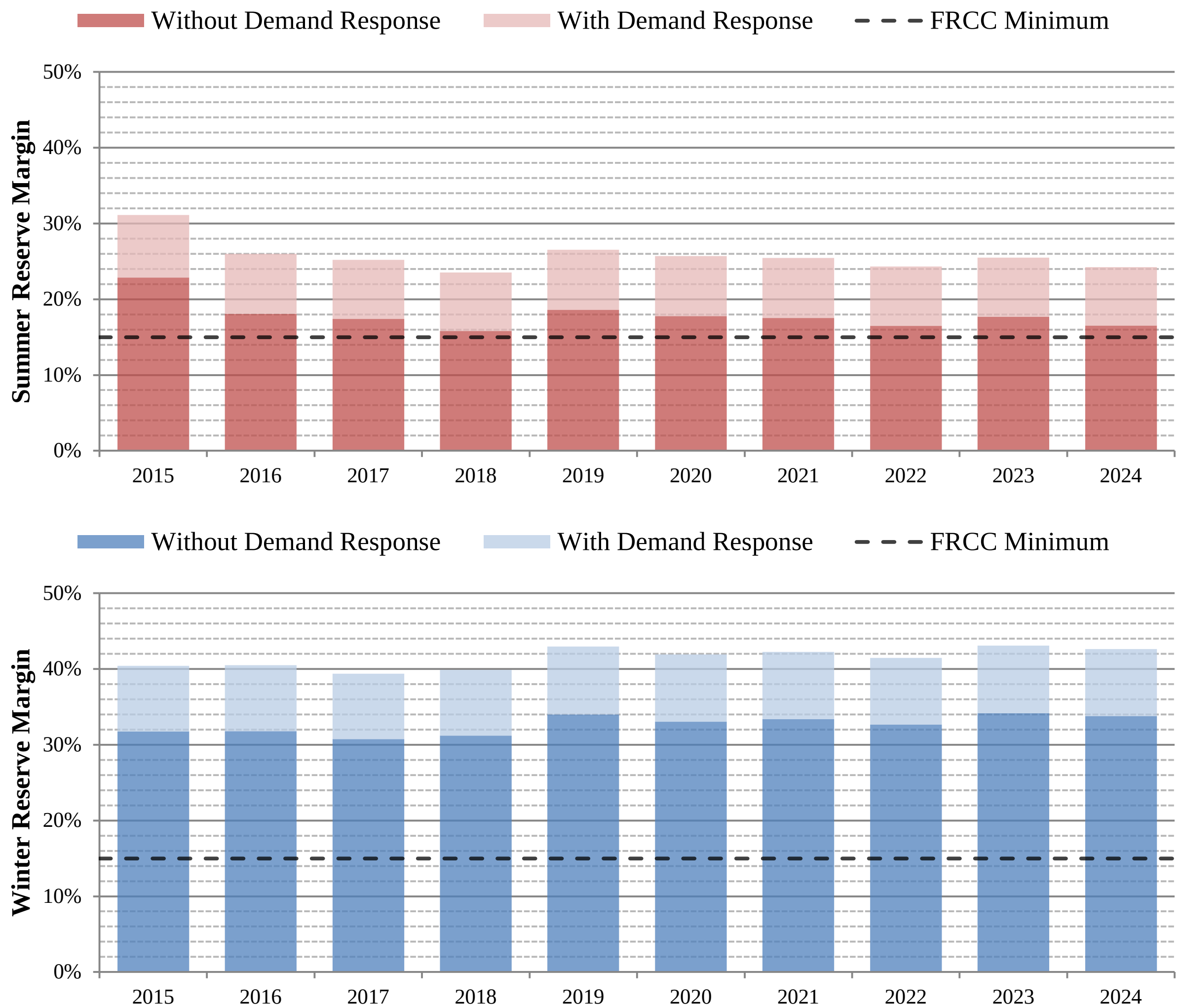
Reliability Requirements

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, potential instabilities could occur if customer demand exceeds the forecast, or if generating units are unavailable due to maintenance or forced outages. To address these circumstances, utilities are required to maintain additional planned generating capacity above the forecast customer demand, referred to as the reserve margin.

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

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

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



Source: 2015 FRCC Load & Resource Plan

Role of Demand Response in Reserve Margin

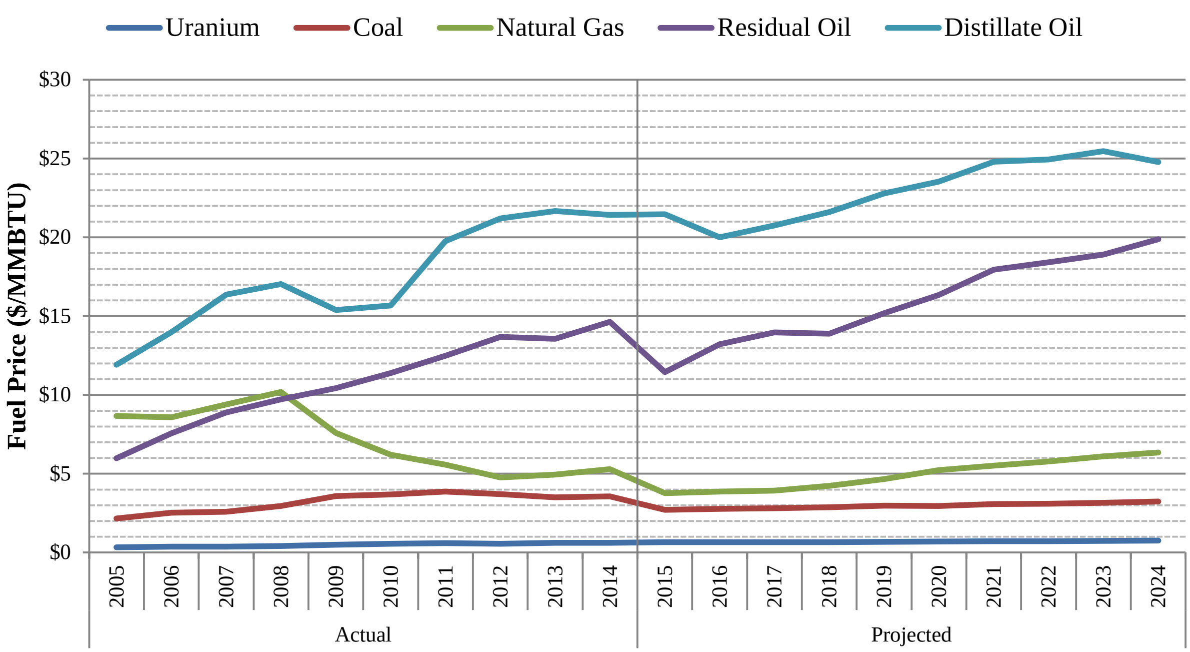
The Commission also considers the planning reserve margin without demand response. As illustrated in Figure 13 above, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin without activation of demand response. Demand response activation increases the reserve margin in summer by 8 percent on average, and represents 30 percent of the planning reserve margin.

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

Fuel Price Forecast

Fuel price is an important economic factor affecting the dispatch of the existing generating fleet and the selection of new generating units. In general, the capital cost of a power plant is inversely proportional to the cost of the fuel used to generate electricity from that unit. The major fuels consumed by Florida's electric utilities are natural gas, coal, uranium, and oil. Figure 14 below, illustrates the weighted average fuel price history and forecasts for the reporting electric utilities.

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

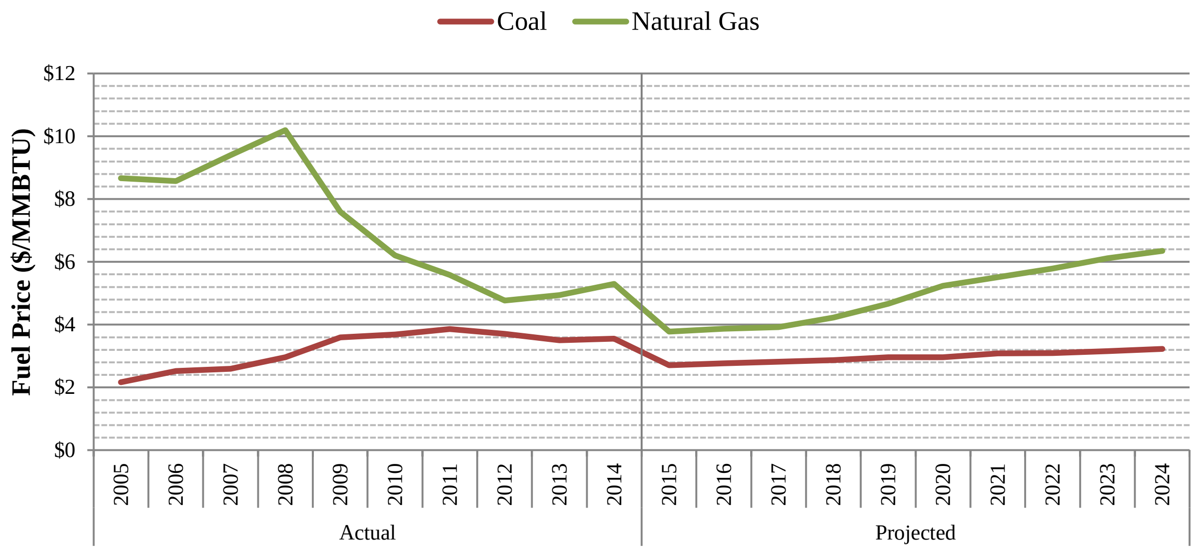


Source: TYSP Utilities Data Responses

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

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

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

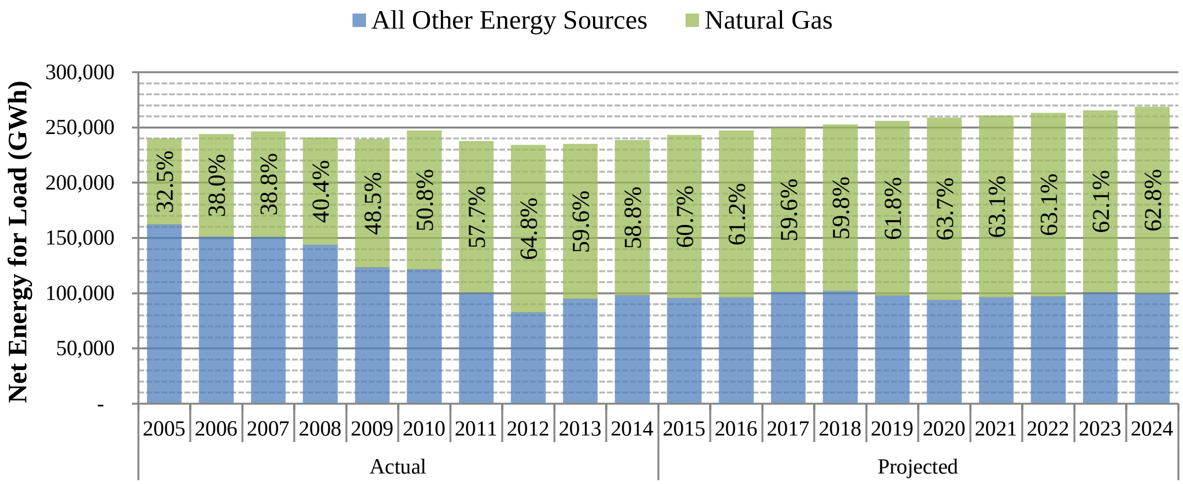


Source: TYSP Utilities Data Responses

Fuel Diversity

Natural gas has risen to become the dominant fuel in Florida within the last ten years, displacing coal, and since 2010 has generated more net energy for load than all other fuels combined. As Figure 16 below illustrates, natural gas is the source of approximately 60 percent of electric energy consumed in Florida, down from its peak in 2012 of 65 percent. The 2012 spike in usage was associated with extended outages at FPL's nuclear plants for uprates. Natural gas generation is anticipated to remain somewhat steady at its current level until the end of the planning period.

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

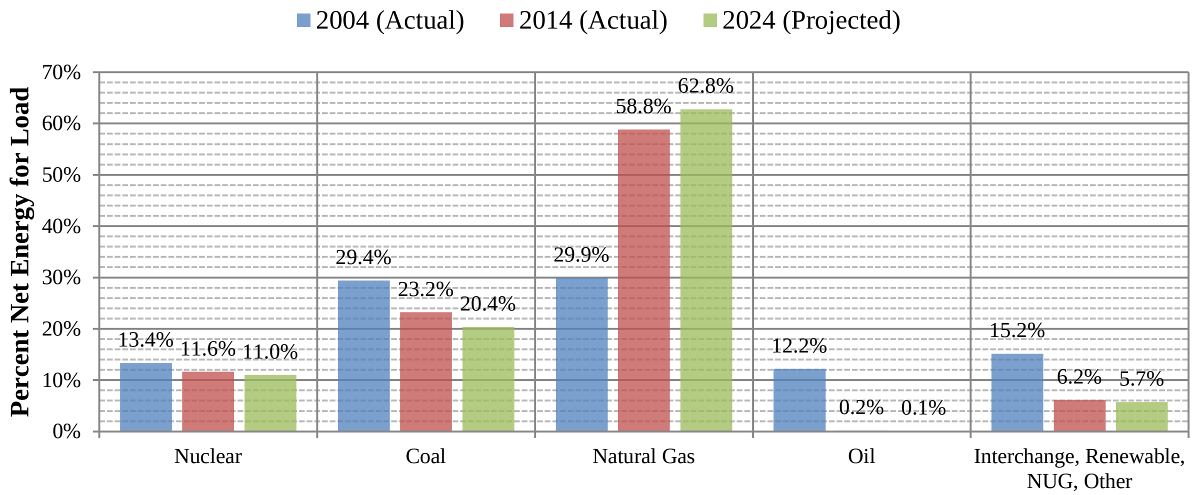


Source: 2006-2015 FRCC Load & Resource Plans

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

Figure 17 below shows, Florida's historic and forecast percent net energy for load by fuel type for the actual years 2004 and 2014, and forecast year 2024. Oil has declined significantly, with its uses reduced to start-up fuel, peaking, and back-up for dual-fuel units in case of a fuel outage. Nuclear generation was reduced beginning in 2010 by the outage and eventual retirement of Crystal River 3 and extended outages for uprates at FPL's St. Lucie and Turkey Point power plants. The resulting capacity leaves Florida's contribution from nuclear approximately the same even with the loss of one of five nuclear units. While coal generation has declined somewhat, it is expected to rebound slightly and remain at a plateau throughout the planning period. Natural gas has been the primary fuel used to meet the growth energy consumption, and this trend is anticipated to continue throughout the planning period.

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



Source: 2005-2015 FRCC Load & Resource Plans

Based on 2012 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 86 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 30th, while natural gas consumption for electricity ranks 6th. Natural gas is not used as a heating fuel in most of Florida's homes and businesses, which rely instead upon electricity that is increasingly being generated by natural gas. This leads to Florida's per capita consumption of natural gas being 15 percent less than the national average, but twice the national average per capita consumption of natural gas for electricity. As Florida has very little natural gas production and no gas storage capacity, the State is reliant upon out-of-state production and storage to satisfy the growing electric demands of the state.

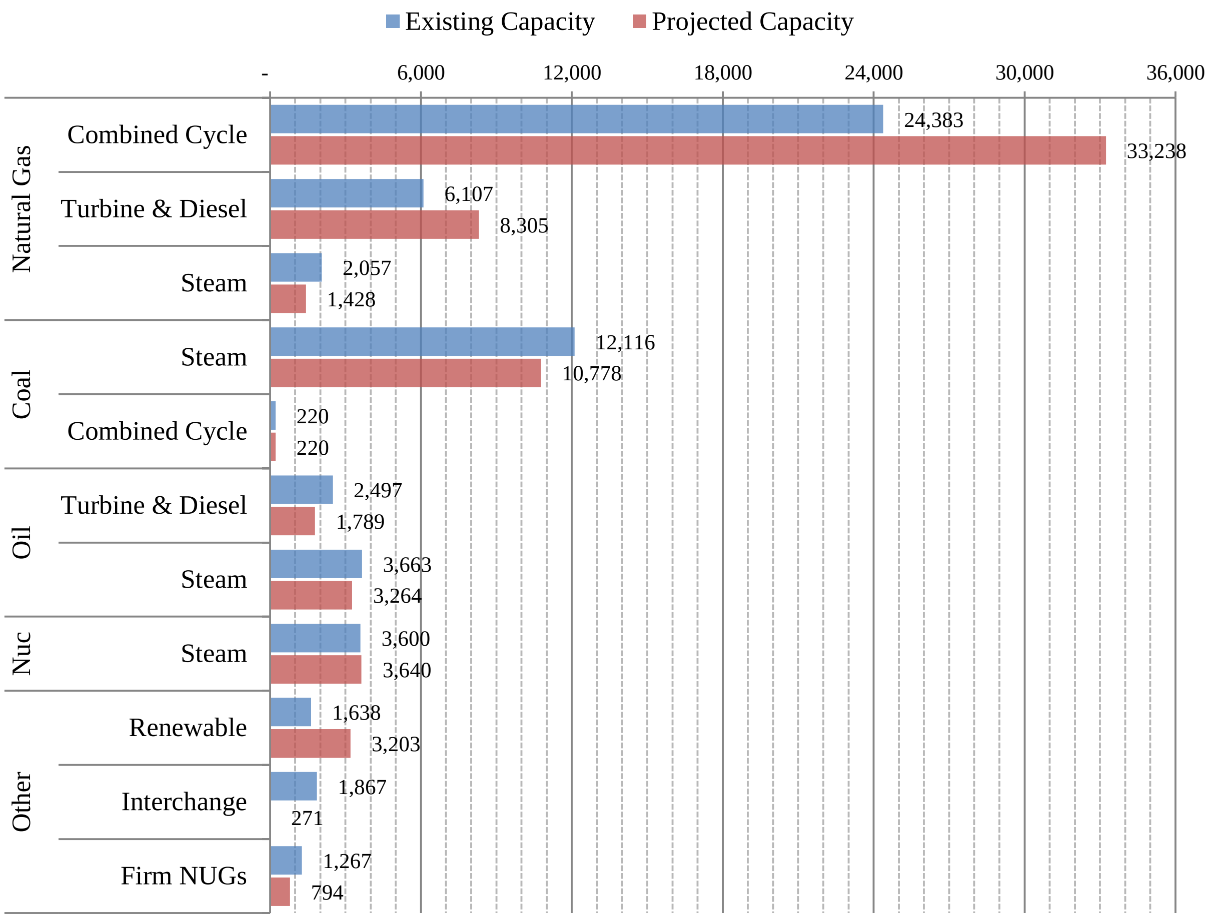
New Generation Planned

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

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

Figure 18 below, illustrates the present and future aggregate capacity mix. The capacity values in Figure 18 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2015 Ten-Year Site Plans and the FRCC's 2015 Load and Resource Plan.

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



Source: 2015 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. Previously, FPL had two nuclear projects at Turkey Point that have moved out of the planning horizon for the 2015 TYSP. Florida Power & Light had previously uprated its existing four nuclear generating units, with the last uprate completed in early 2013. While Duke Energy Florida had previously projected the addition of two nuclear units, Levy 1 and 2, it has discontinued this project but continues its efforts to obtain a combined operating license from the Nuclear Regulatory Commission.

Natural Gas

Excluding renewable and nuclear generation, all remaining new power plants are natural gas-fired combustion turbines or combined cycle units. Combustion turbines run in simple cycle mode as peaking units represent the third most abundant type of generating capacity, behind only coal-fired steam generation. Because combustion turbines are not a form of steam generation, unless part of a combined cycle unit, they do not require siting under the Power Plant Siting Act. Table 10 below, summarizes the approximately 11,548 MW of proposed new natural gas-fired generation included in the 2015 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 Power Plant Siting Act, contained in Sections 403.501 through 403.518, F.S. Any proposed steam or solar generating unit of at least 75 MW requires a certification under the Power Plant Siting Act. 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, ultimate must approve or deny the overall certification of a proposed power plant.

Table 10: State of Florida - Planned Natural Gas Units

Year	Utility Name	Plant Name & Unit Number	Fuel & Unit Type	Net Capacity (MW)	Notes
Previously Approved New Units					
2016	FPL	Port Everglades	Natural Gas Combined Cycle	1,237	Docket No. 110309-EI
2017	TEC	Polk CC Conversion	Natural Gas Combined Cycle	459	Docket No. 120234-EI
2018	DEF	Citrus	Natural Gas Combined Cycle	1,640	Docket No. 140110-EI
New Units Requiring PPSA Approval					
2019	FPL	Okeechobee	Natural Gas Combined Cycle	1,622	Docket No. 150196-EI
2021	SEC	Unnamed CC	Natural Gas Combined Cycle	649	
2023	FPL	Combined Cycle Unit	Natural Gas Combined Cycle	1,317	
2023	OUC	Unknown	Natural Gas Combined Cycle	285	
New Units Not Requiring PPSA Approval					
2016	FPL	Ft. Myers 4A & 4B	Natural Gas Combustion Turbines	462	
2016	FPL	Lauderdale 6A - 6E	Natural Gas Combustion Turbines	1,155	
2021	TAL	Hopkins	Natural Gas Combustion Turbines	46	
2021	TEC	Future CT 1	Natural Gas Combustion Turbines	204	
2022	PEC	Mcintosh	Natural Gas Combined Cycle	191	Outside Florida
2022	SEC	Unnamed CT 1	Natural Gas Combustion Turbines	201	
2023	SEC	Unnamed CT 2	Natural Gas Combustion Turbines	201	
2023	GPC	Combustion Turbines	Natural Gas Combustion Turbines	866	
2024	SEC	Unnamed CT 3	Natural Gas Combustion Turbines	201	
2024	DEF	Unknown P1 - P4	Natural Gas Combustion Turbines	812	

Source: 2015 Ten-Year Site Plans

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

Table 11 below, lists all proposed transmission lines in the 2015 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	-	04/21/2006	12/01/2018
FPL	Levee - Midway	150	500		04/20/1990	06/01/2023

Source: 2015 Ten-Year Site Plans

Utility Perspectives

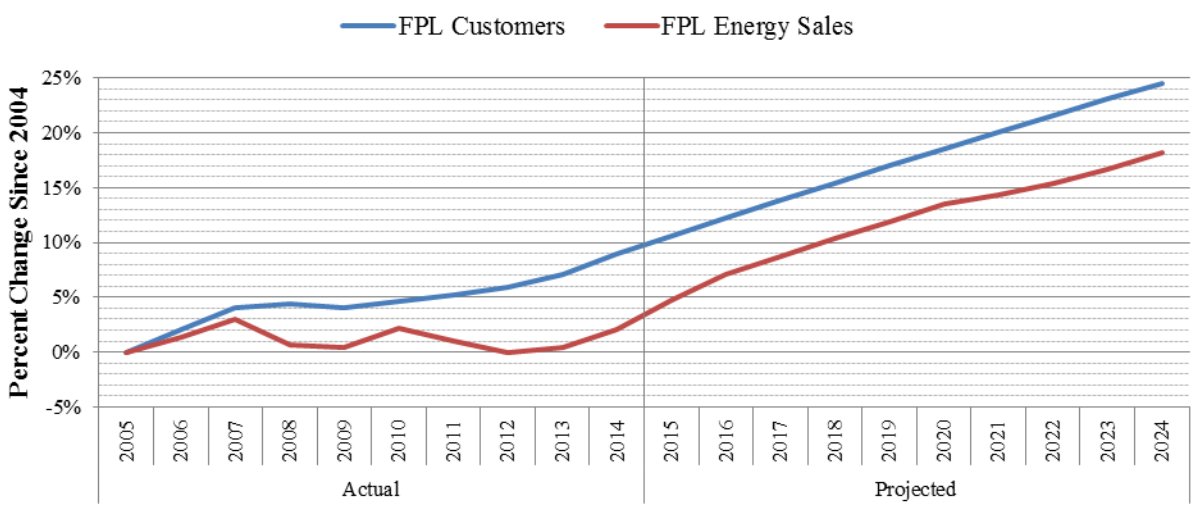
Florida Power & Light Company (FPL)

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 operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds FPL's 2015 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2014, FPL had approximately 4,708,829 customers and annual retail energy sales of 104,389 GWh or approximately 47.7 percent of Florida's annual retail energy sales. Figure 19 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2005. Over the past ten years, FPL's customer base has increased by 8.95 percent, while retail sales have grown by 2.05 percent. Since 2009, FPL has been outperforming the state average in retail energy sales growth, a trend it projects to continue into the future.

Figure 19: FPL Growth Rate

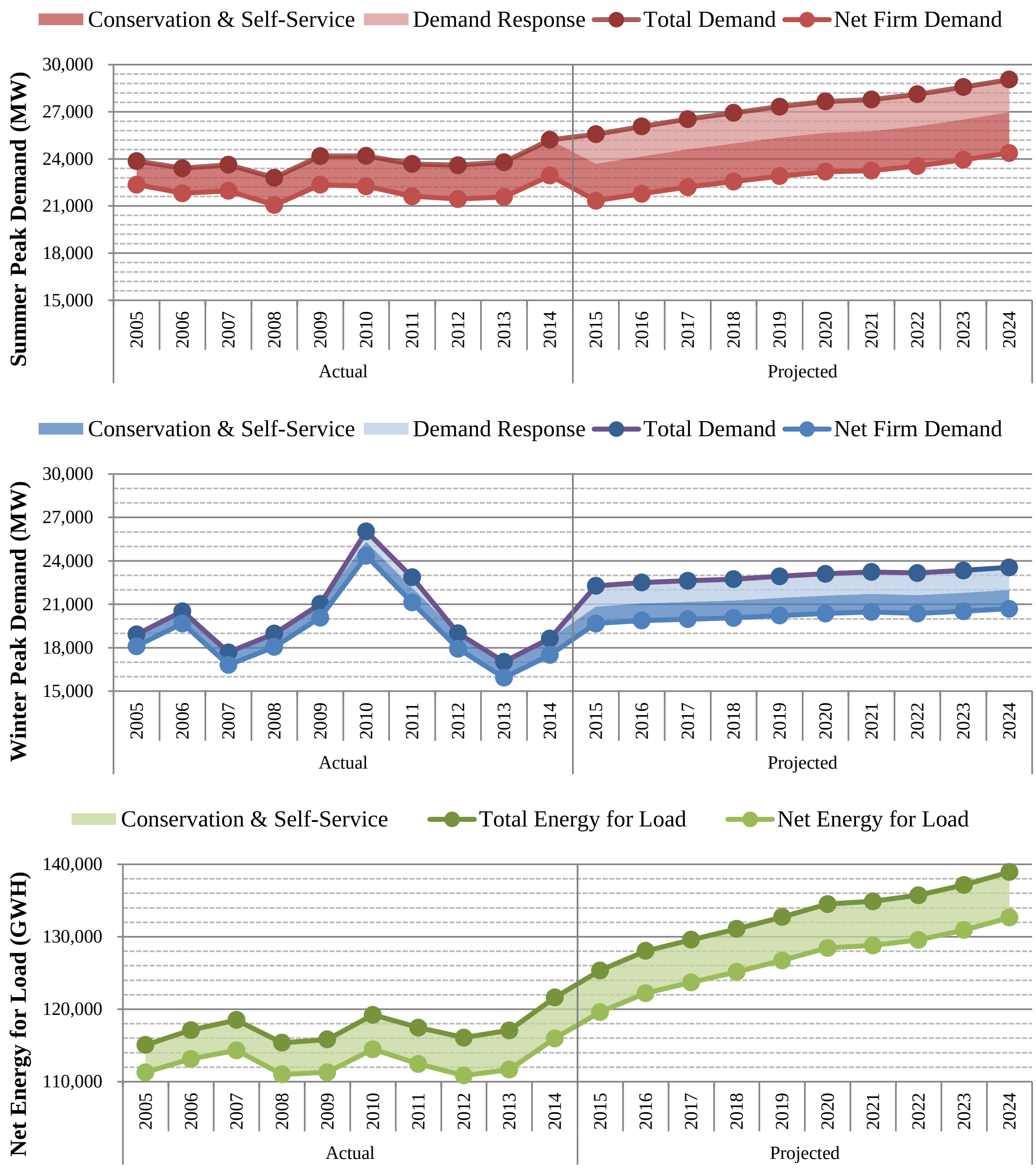


Source: 2015 Ten Year Site Plan

The three graphs in Figure 20 below, show's FPL's seasonal peak demand and net energy for load, for the historic years 2005 through 2014 and forecast years 2015 through 2024. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. Historically, demand response was not activated during the seasonal peak demand, excluding the winters of 2010 and 2011.

As an investor owned utility, FPL is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The utility's 2015 Ten-Year Site Plan reflects the recently revised demand-side management goals established by the Commission in December 2014.

Figure 20: FPL Demand and Energy Forecasts



Source: 2015 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 12 below, shows FPL's actual net energy for load for fuel type for 2014, and the projected fuel mix for 2024. FPL relies primarily upon natural gas and nuclear for energy generation, making up approximately 90 percent of net energy for load.

Table 12: FPL Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2014		2024	
	GWh	%	GWh	%
Natural Gas	79,102	**68.2%**	96,618	**72.5%**
Coal	4,482	**3.9%**	3,087	**2.3%**
Nuclear	26,812	**23.1%**	28,637	**21.5%**
Oil	359	**0.3%**	136	**0.1%**
Renewable	177	**0.2%**	691	**0.5%**
Interchange	4,908	**4.2%**	0	**0.0%**
NUG & Other	127	**0.1%**	4,107	**3.1%**
Total	**115,968**		**133,276**	

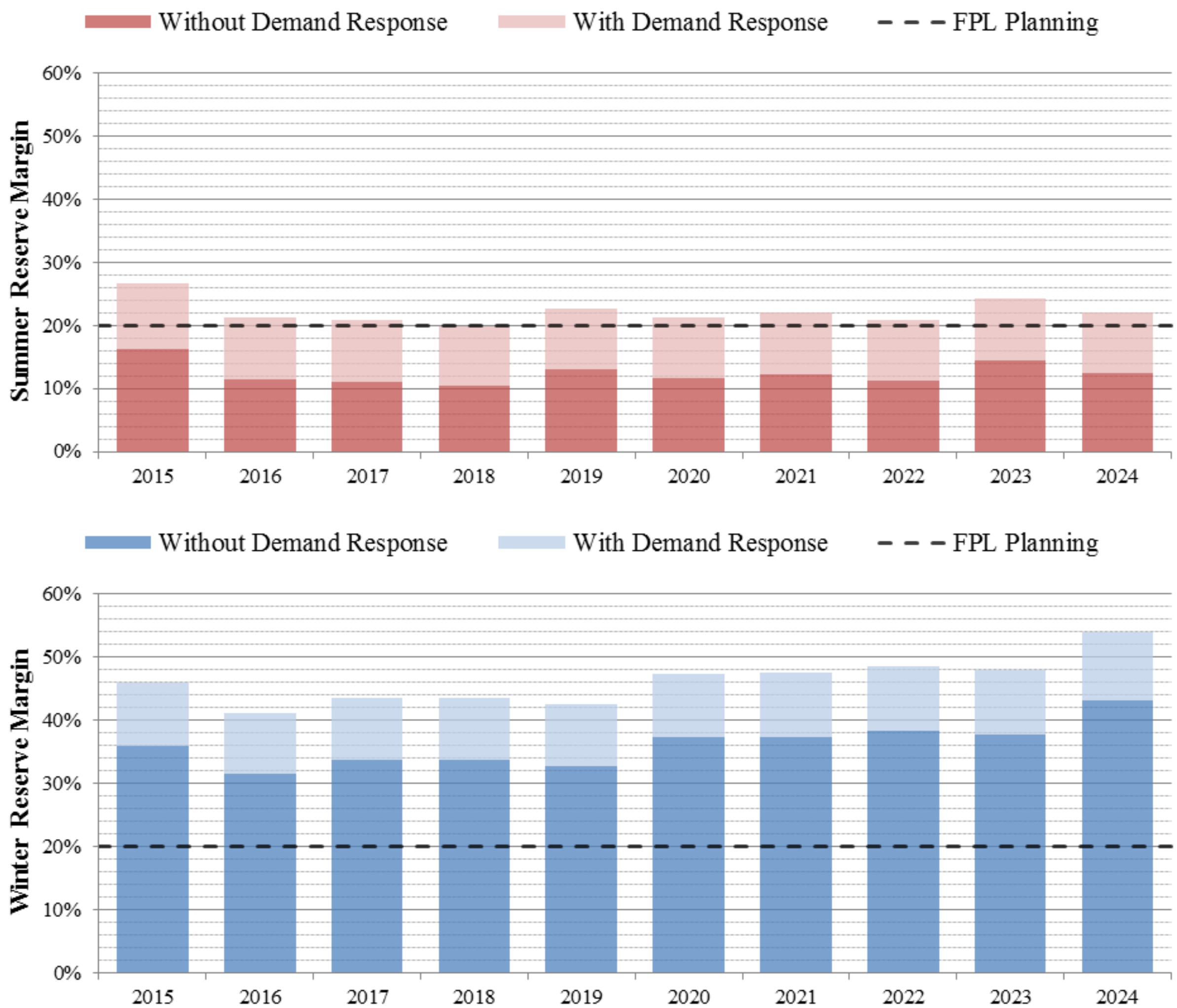
Source: 2015 Ten Year Site Plan

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 ten years. Between the two reliability indices, LOLP and reserve margin, the reserve margin requirement is typically the controlling factor for the addition of capacity.

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

Figure 21: FPL Reserve Margin Forecast



Source: 2015 Ten Year Site Plan

In addition to LOLP and the reserve margin, FPL utilizes a third reliability criterion. FPL's criterion would be to have available firm capacity 10 percent greater than the sum of customer seasonal demand, without consideration of incremental energy efficiency and all existing and incremental demand response resources. FPL refers to this as its 10 percent generation-only reserve margin. Currently, no other utility utilizes this same metric. While TECO includes a minimum supply-side contribution in its planning methodology, TECO uses a lower value of seven percent and incremental energy efficiency is included in its calculation.

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 ten-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.

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% reserve margin will be realized.

Generation Resources

FPL plans multiple unit retirements and additions during the planning period, as described in Table 13 below. FPL's 2014 Ten Year Site Plan included the acquisition of Vero Beach's generating units. FPL's 2015 plan does not include this acquisition. The projected in-service dates of FPL's new planned nuclear units are now outside the 10-year planning period of 2015's Ten Year Site Plan. FPL included the addition of three new natural gas-fired combined cycle unit. Port Everglades combined cycle is expected to come online in 2016. FPL filed a need determination with the Commission for the Okeechobee Unit on September 3, 2015.

Table 13: FPL Generation Resource Changes

Year	Unit Name	Fuel & Unit Type	Net Capacity (Sum MW)	Notes
Retiring Units				
2016	Turkey Point 1	Residual Oil Steam	396	Synchronous Condenser
2016	Ft. Myers 1 - 10	Distillate Oil Combustion Turbine	540	
2016	Cedar Bay	Coal Steam	250	Docket 150075-EI
2016	Lauderdale 1 - 22	Natural Gas Combustion Turbine	754	
2016	Port Everglades 1 - 12	Natural Gas Combustion Turbine	408	
		Retiring Units Total	**2,348**	
New Units				
2016	Ft. Myers 4A & 4B	Natural Gas Combustion Turbine	462	
2016	Lauderdale 6A - 6E	Natural Gas Combustion Turbine	1,155	
2016	Port Everglades	Natural Gas Combined Cycle	1,237	Docket No. 110309-EI
2019	Okeechobee	Natural Gas Combined Cycle	1,622	Docket No. 150196-EI
2023	Unsited Unit	Natural Gas Combined Cycle	1,317	Requires PPSA
		New Units Total	**5,793**	
		Net Additions	**3,445**	

Source: 2015 Ten Year Site Plan

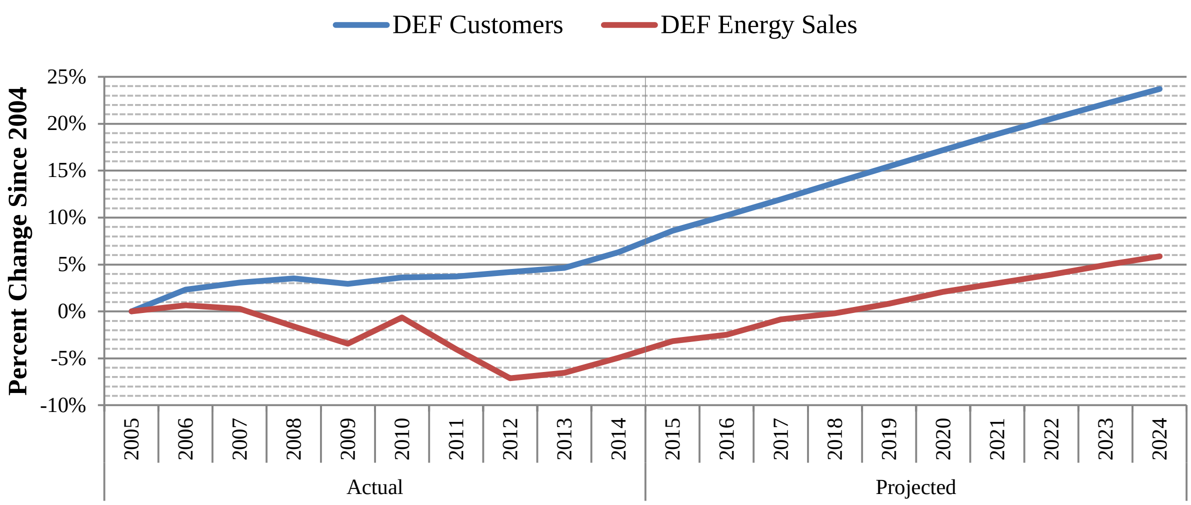
Duke Energy Florida, Inc. (DEF)

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 2015 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2014, DEF had approximately 1,683,454 customers and annual retail energy sales of 37,240 GWh or approximately 16.9 percent of Florida's annual retail energy sales. Figure 22 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2005. Over the last ten years, DEF's customer base has increased by 6.88 percent, while retail sales have declined by 4.13 percent. As illustrated retail energy sales are anticipated to exceed the historic 2006 peak by 2020, three years later than the state as a whole.

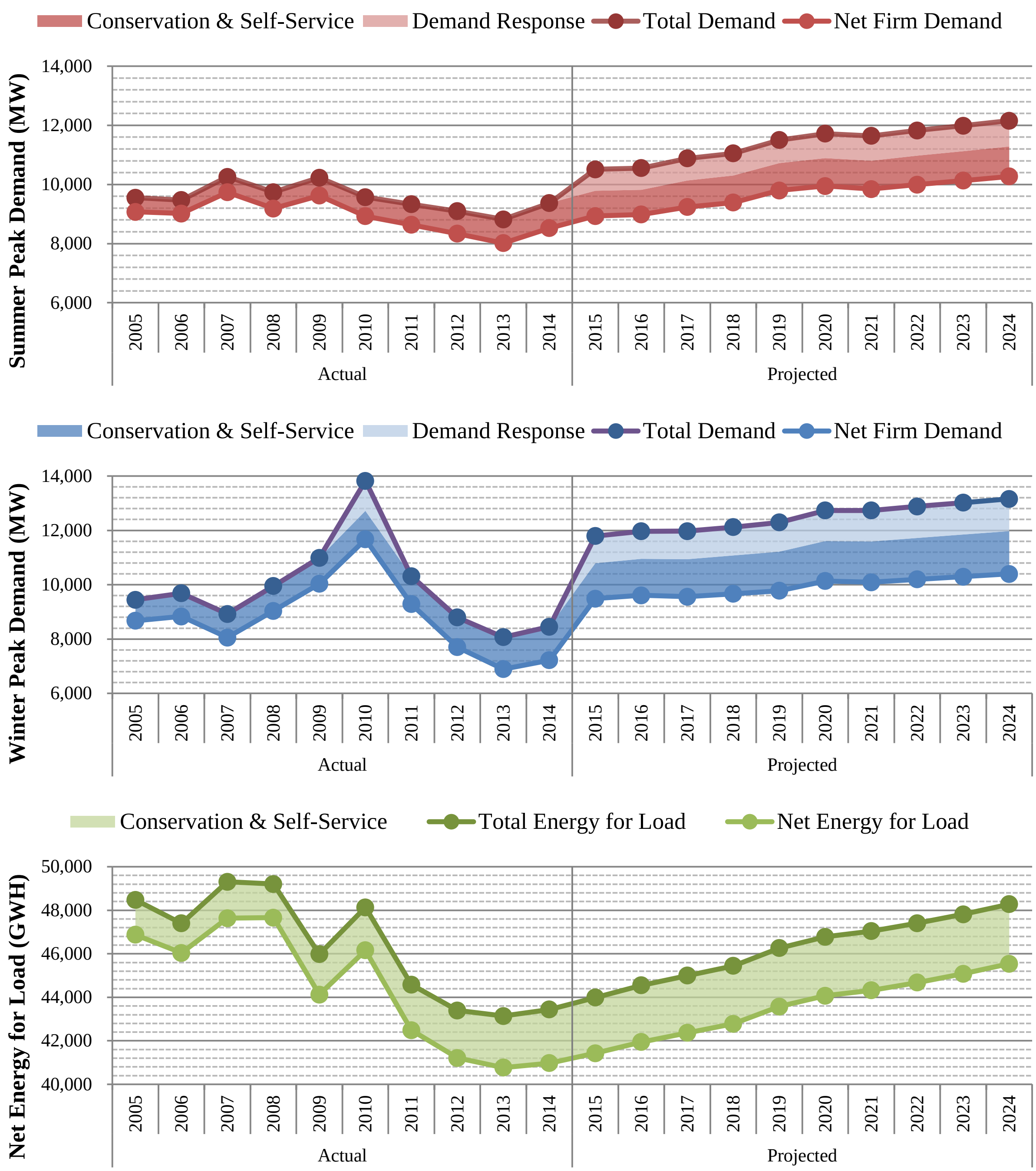
Figure 22: DEF Growth Rate



Source: 2015 Ten-Year Site Plan

The three graphs in Figure 23 below shows, DEF's seasonal peak demand and net energy for load for the historic years of 2005 through 2014 and forecast years 2015 through 2024. 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 2015 Ten-Year Site Plan reflects the recently revised demand-side management goals established by the Commission in December 2014.

Figure 23: DEF Demand and Energy Forecasts



Source: 2015 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 14 below shows, DEF’s actual net energy for load by fuel type as of 2014 and the projected fuel mix for 2024. DEF relies primarily upon natural gas and coal for energy generation, making up approximately 80 percent of net energy for load. DEF plans to substantially reduce coal usage over the planning period, but coal usage will be greater than all other energy types excluding natural gas.

Table 14: DEF Energy Consumption by Fuel Type

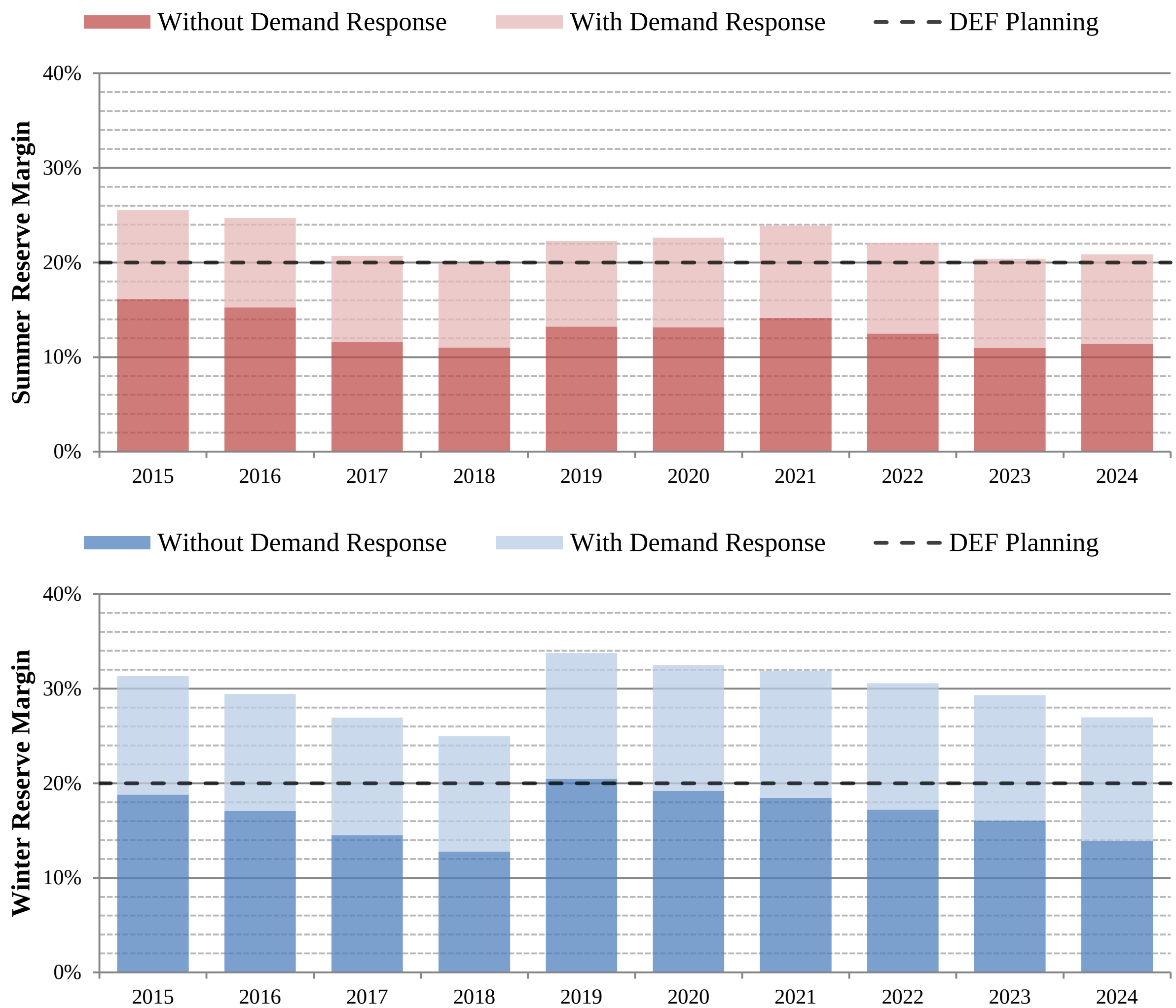
Fuel Type	Net Energy for Load			
	2014		2024	
	GWh	%	GWh	%
Natural Gas	22,962	**56.0%**	36,559	**80.3%**
Coal	11,760	**28.7%**	5,214	**11.4%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	38	**0.1%**	24	**0.1%**
Renewable	927	**2.3%**	2,152	**4.7%**
Interchange	1,755	**4.3%**	183	**0.4%**
NUG & Other	3,533	**8.6%**	1,412	**3.1%**
Total	**40,975**		**45,543**	

Source: 2015 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion. Figure 24 below displays, the forecast planning reserve margin for DEF through the planning period for both seasons, with and without the use of demand response. As shown in the figure, DEF's generation needs are controlled by its summer peaking throughout the planning period. While the utility's summer planning reserve margin dips below 20 percent in 2018, the deficiency is only 19.6 MW and is anticipated to be resolved by 2019.

Figure 24: DEF Reserve Margin Forecast



Source: 2015 Ten-Year Site Plan

Generation Resources

DEF plans multiple unit retirements and additions during the planning period, as described below in Table 15. DEF's 2015 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 oil-fired units and eight natural gas-fired units at multiple power plant sites. An additional new combined cycle is planned for 2021 which will require a determination of need from the Commission

Table 15: DEF Generation Resource Changes

Year	Unit Name	Fuel & Unit Type	Net Capacity (Sum MW)	Notes
Retiring Units				
2015	G. E. Turner P1 - P4	Distillate Oil Combustion Turbine	132	
2016	Avon Park 2	Distillate Oil Combustion Turbine	24	
2016	Rio Pinar 1	Distillate Oil Combustion Turbine	12	
2016	Avon Park 1	Natural Gas Combustion Turbine	24	
2017	Suwannee River 1 - 2	Natural Gas Steam	57	
2018	Suwannee River 3	Natural Gas Steam	71	
2018	Crystal River 1 & 2	Coal Steam	740	
2020	Higgins 1 - 4	Natural Gas Combustion Turbine	109	
		Retiring Units Total	**1,169**	
New Units				
2018	Citrus	Natural Gas Combined Cycle	1,640	Docket No. 140110-EI
2024	Unknown P1 - P4	Natural Gas Combustion Turbine	812	
		New Units Total	**2,452**	
		Net Additions	**1,283**	

Source: 2015 Ten-Year Site Plan

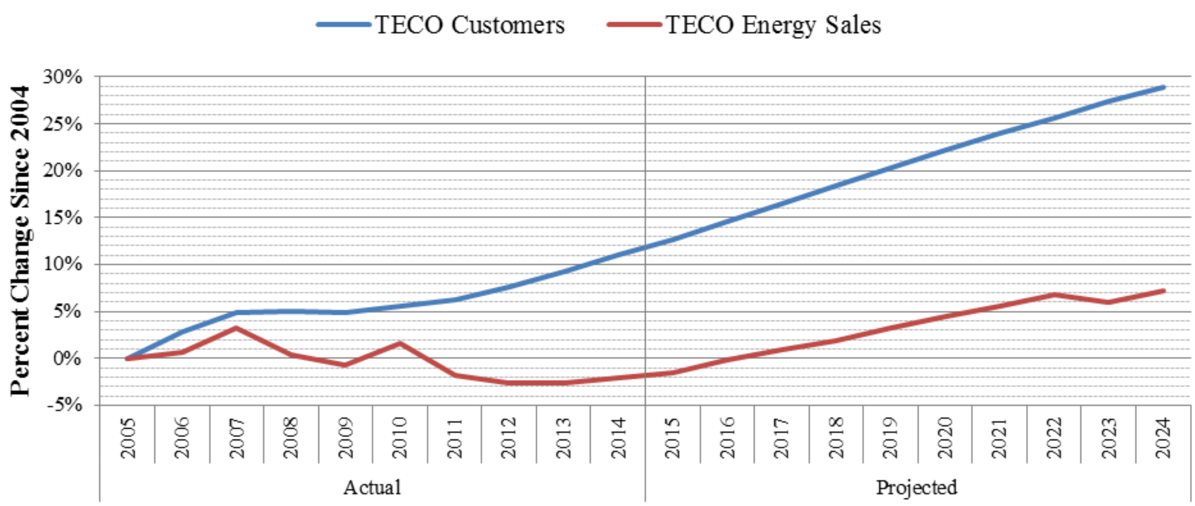
Tampa Electric Company (TECO)

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 2015 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2014, TECO had approximately 706,161 customers and annual retail energy sales of 18,526 GWh or approximately 8.5 percent of Florida's annual retail energy sales. Figure 25 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2005. Over the last 10 years, TECO's customer base has increased by 11 percent, while retail sales have declined by 2.06 percent. As illustrated retail energy sales are anticipated to exceed the historic 2007 peak by 2020, three years later than the state as a whole.

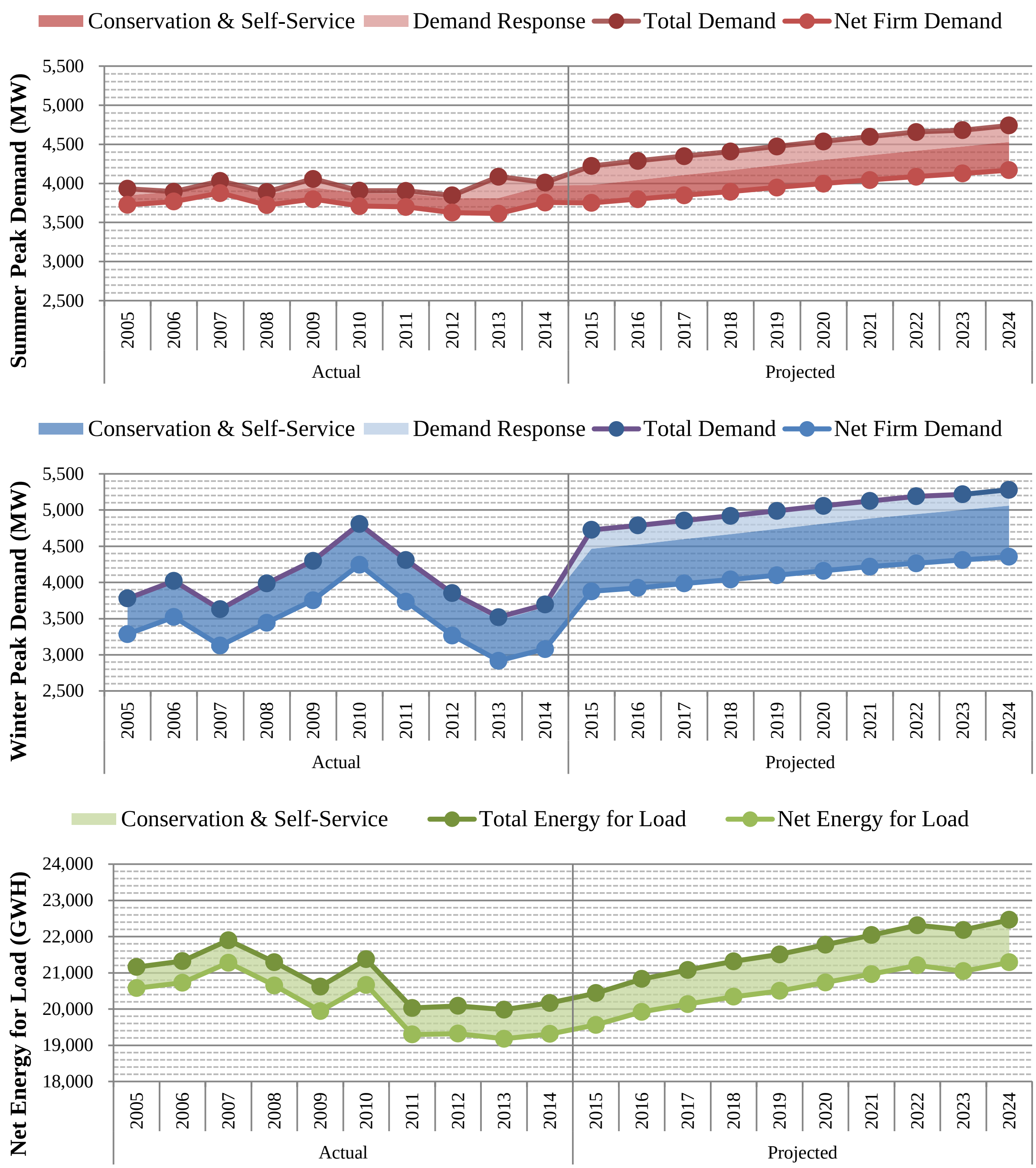
Figure 25: TECO Growth Rate



Source: 2015 Ten-Year Site Plan

The three graphs in Figure 26 below, shows TECO's seasonal peak demand and net energy for load for the historic years of 2005 through 2014 and forecast years 2015 through 2024. These graphs include the full impact of demand-side management, and assume that all available demand response resources were or will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand excluding extreme weather events.

Figure 26: TECO Demand and Energy Forecasts



Source: 2015 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 2015 Ten-Year Site Plan reflects the recently revised demand-side management goals established by the Commission in December 2014.

Fuel Diversity

Table 16 below, shows TECO's actual net energy for load by fuel type as of 2014 and the projected fuel mix for 2024. TECO uses coal for a majority of energy generation, and based on the 2015 Ten-Year Site Plan, actual energy from coal equal to all other sources combined. Natural gas is the second largest source of energy for the utility, at approximately 40 percent of net energy for load. In the future, TECO projects that energy from coal and gas will be approximately the same.

Table 16: TECO Energy Consumption by Fuel Type

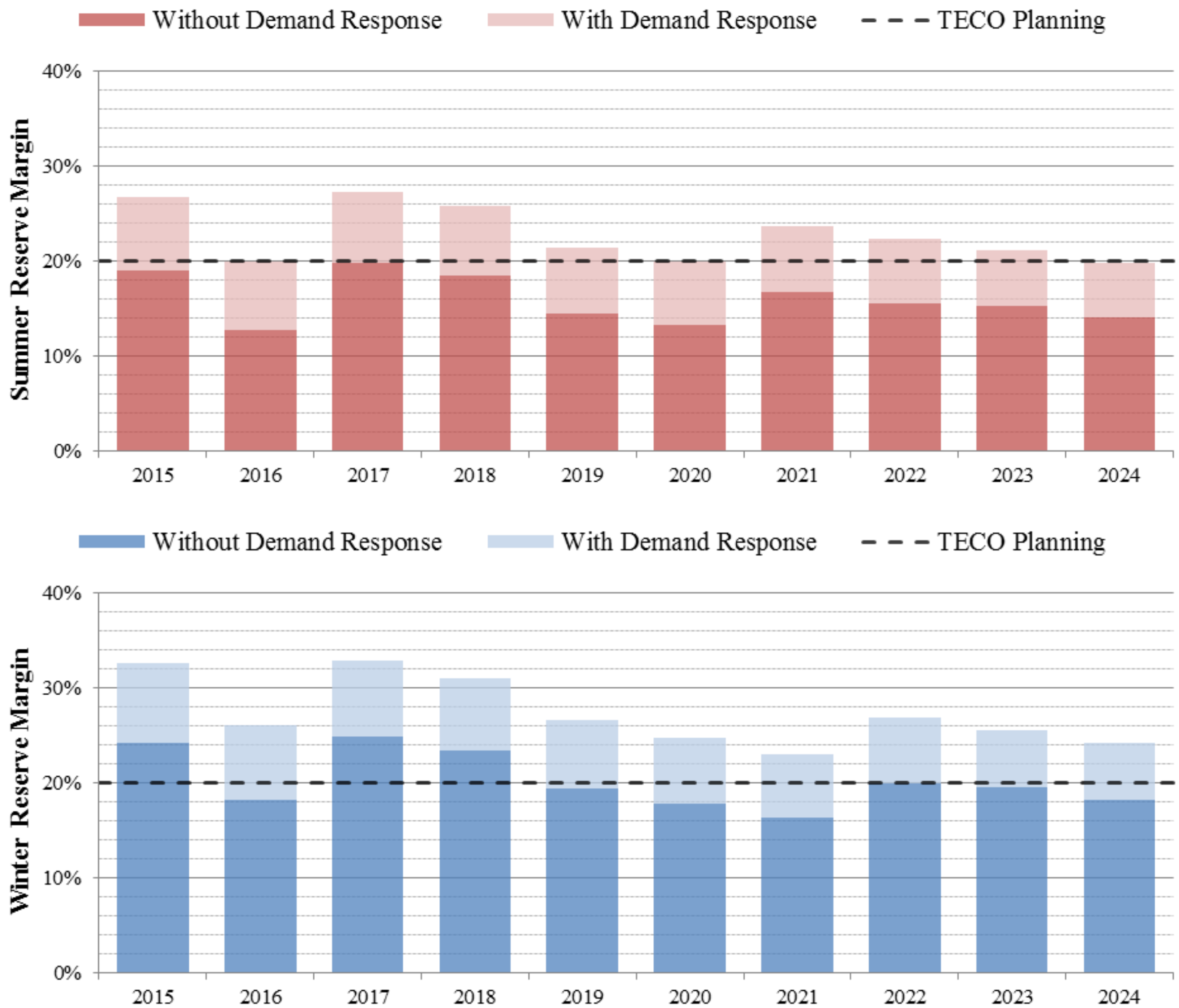
Fuel Type	Net Energy for Load			
	2014		2024	
	GWh	%	GWh	%
Natural Gas	7,116	**36.8%**	10,197	**47.9%**
Coal	10,383	**53.8%**	9,755	**45.8%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	272	**1.4%**	183	**0.9%**
Interchange	194	**1.0%**	0	**0.0%**
NUG & Other	1,351	**7.0%**	1,153	**5.4%**
Total	**19,315**		**21,288**	

Source: 2015 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion. TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 27 below, displays the forecast planning reserve margin for TECO through the planning period for both seasons, with and without the use of demand response. As shown in the figure, TECO's generation needs are controlled by its summer peaking throughout the planning period.

Figure 27: TECO Reserve Margin Forecast



Source: 2015 Ten-Year Site Plan

Generation Resources

TECO plans a pair of unit additions during the planning period, as described in Table 17 below. TECO plans to convert a set of four natural gas-fired simple cycle combustion turbines at its Polk power plant to combined cycle operation. The additional capacity associated with the modernization is listed below, and has already been certified through the Power Plant Siting Act. TECO also plans the addition of a peaking unit, a natural gas-fired combustion turbine in 2021.

Table 17: TECO Generation Resource Changes

Year	Unit Name	Fuel & Unit Type	Net Capacity (Sum MW)	Notes
New Units				
2017	Polk CC Conversion	Natural Gas Combined Cycle	459	Docket No. 120234-EI
2021	Future CT 1	Natural Gas Combustion Turbine	204	
		New Units Total	**663**	
		Net Additions	**663**	

Source: 2015 Ten-Year Site Plan

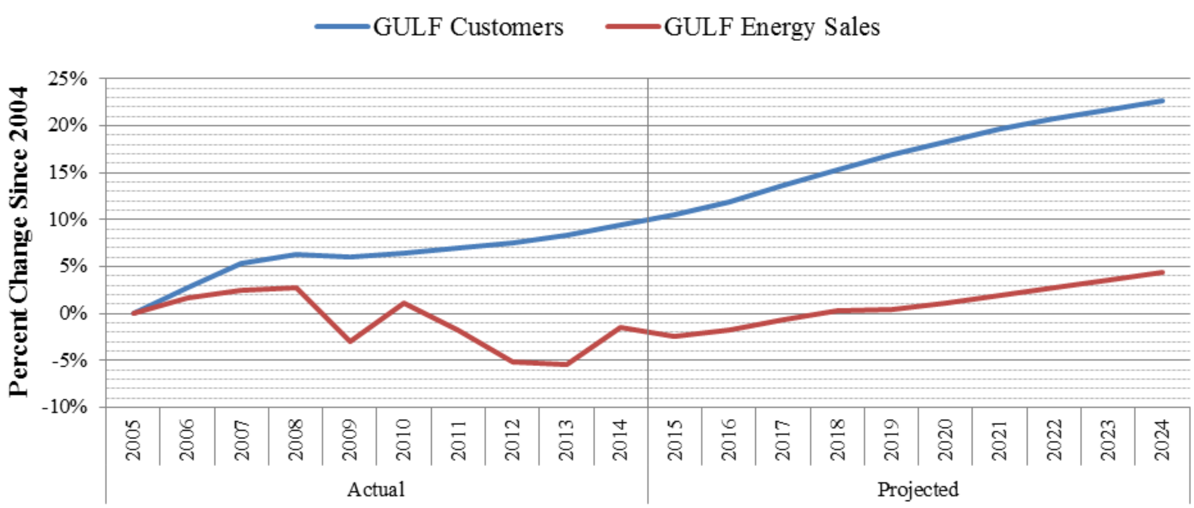
Gulf Power Company (GPC)

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. 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 2015 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2014, GPC had approximately 442,370 customers and annual retail energy sales of 11,075 GWh or approximately 5.1 percent of Florida's annual retail energy sales. Figure 28 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2005. Over the last ten years, GPC's customer base has increased by 9.47 percent, while retail sales have declined by 1.46 percent. As illustrated retail energy sales are anticipated to exceed the historic 2008 peak by 2022, six years later than the state as a whole.

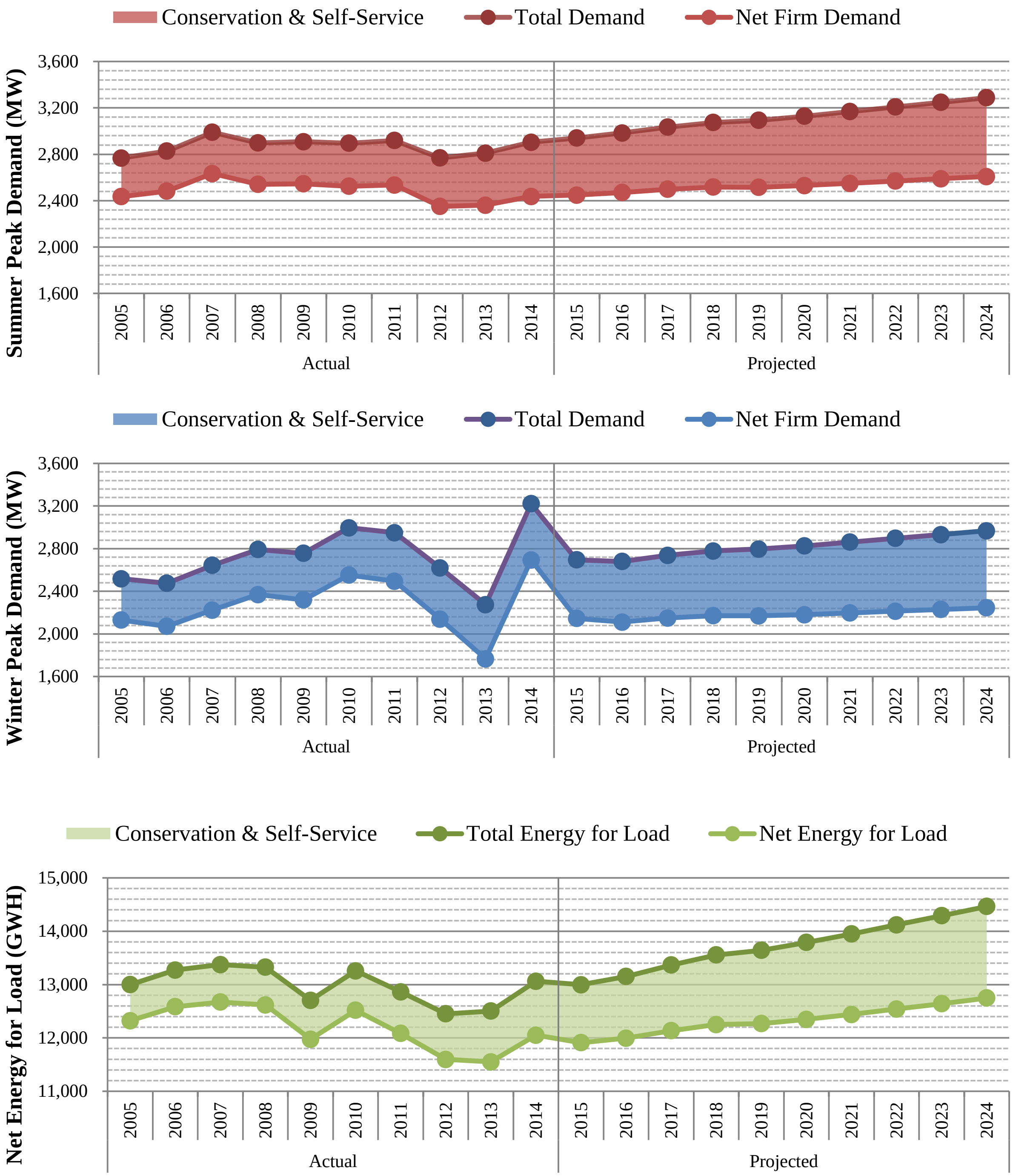
Figure 28: GPC Growth Rate



Source: 2015 Ten-Year Site Plan

The three graphs in Figure 29 below, shows GPC's seasonal peak demand and net energy for load for the historic years of 2005 through 2014 and forecast years 2015 through 2024. These graphs include the full impact of demand-side management.

Figure 29: GPC Demand and Energy Forecasts



Source: 2015 Ten-Year Site Plan and Data Responses

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 2015 Ten-Year Site Plan reflects the recently revised demand-side management goals established by the Commission in December 2014.

Fuel Diversity

Table 18 below, shows GPC's actual net energy for load by fuel type as of 2014, and the projected fuel mix for 2024. GPC is an energy exporter, producing over a quarter more energy than it requires for native load. While natural gas was the dominant fuel source in 2014, coal made up approximately half of energy produced. By 2024, GPC's 2015 Ten-Year Site Plan projects a decline in sales to only 10.2 percent of native load, with coal representing approximately 84 percent of system energy. GPC projects a greater percent of energy consumption from coal in 2024 than any other investor-owned utility and all but two other TYSP Utilities, JEA and OUC.

Table 18: GPC Energy Consumption by Fuel Type

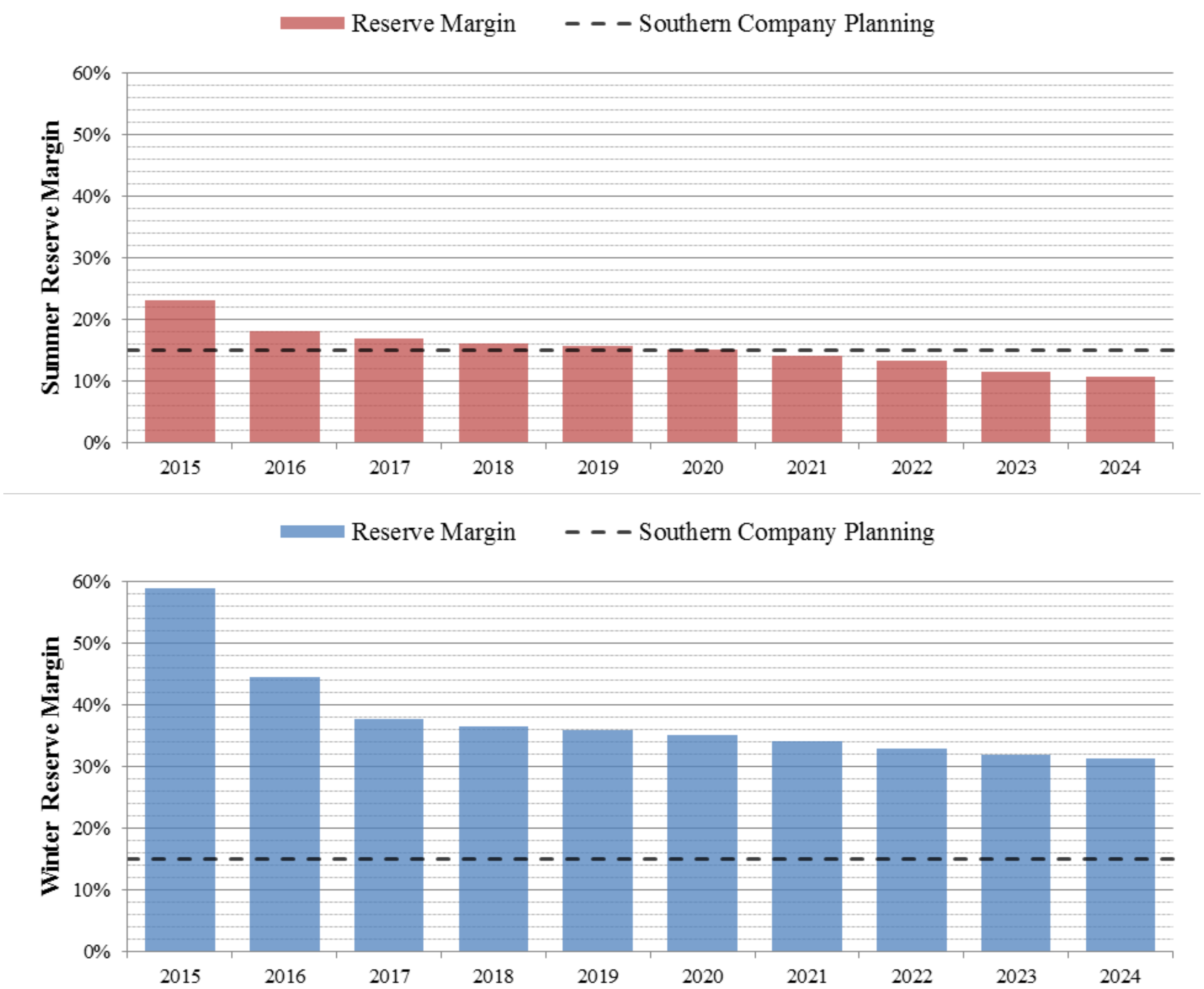
Fuel Type	Net Energy for Load			
	2014		2024	
	GWh	%	GWh	%
Natural Gas	8,207	**68.1%**	3,116	**24.4%**
Coal	7,394	**61.4%**	10,714	**84.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	1	**0.0%**
Renewable	0	**0.0%**	0	**0.0%**
Interchange	-3,760	**-31.2%**	-1,296	**-10.2%**
NUG & Other	210	**1.7%**	214	**1.7%**
Total	**12,052**		**12,749**	

Source: 2015 Ten-Year Site Plan and Data Responses

Reliability Requirements

As previously noted, GPC is the only Ten-Year Site Plan utility outside of the FRCC region. As part of Southern Company's electric system, GPC plans to maintain a 15 percent seasonal planning reserve margin beginning in 2017. Figure 30 below, displays the forecast planning reserve margin for GPC through the planning period for both seasons, including the impact of energy efficiency programs. As shown in the figure, GPC's generation needs are typically determined by its summer peak. It is anticipated that GPC would either construct additional generation beyond the units identified above or contract for purchased power to meet its planning reserve requirement in 2024.

Figure 30: GPC Reserve Margin Forecast



Source: 2015 Ten-Year Site Plan

Generation Resources

GPC plans multiple unit retirements and additions during the planning period, as described in Table 19 below. A pair of coal-fired steam units and three natural gas-fired combustion turbines would be retired during the planning period. Based on its 2015 Ten-Year Site Plan, GPC plans to add a single natural gas-fired combustion turbine in 2023, after the expiration of a purchased power agreement expires. In addition, GPC plans on the addition of utility-owned renewable generation from a landfill gas-fired internal combustion unit, which would provide firm capacity.

Table 19: GPC Generation Resource Changes

Year	Unit Name	Fuel & Unit Type	Net Capacity (Sum MW)	Notes
Retiring Units				
2015	Scholz 1 & 2	Coal Steam	92	
2016	Lansing Smith 2	Coal Steam	195	
2018	Pea Ridge 1 - 3	Natural Gas Combustion Turbine	12	
		Retiring Units Total	**299**	
New Units				
2023	Combustion Turbines	Natural Gas Combustion Turbine	866	
		New Units Total	**866**	
		Net Additions	**567**	

Source: 2015 Ten-Year Site Plan

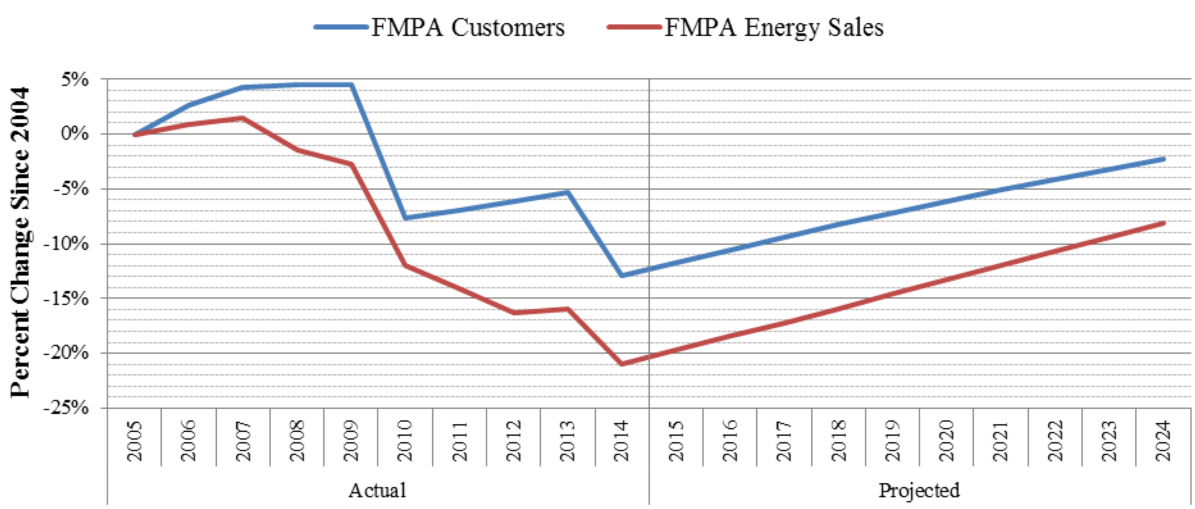
Florida Municipal Power Agency (FMPA)

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 2015 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

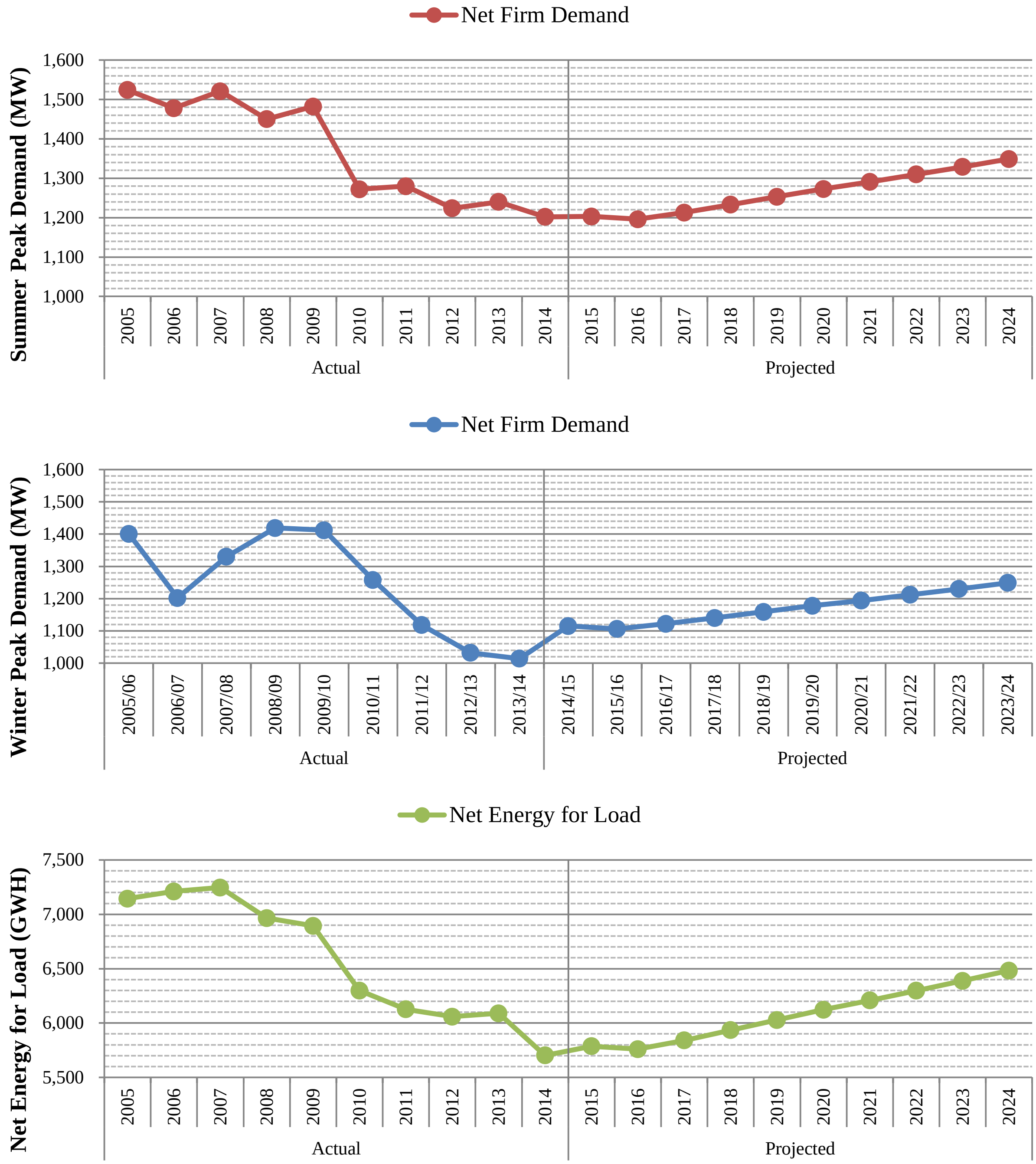
In 2014, FMPA had approximately 245,664 customers and annual retail energy sales of 5,353 GWh or approximately 2.4 percent of Florida's annual retail energy sales. Figure 31 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2005. Over the last ten years, FMPA's customer base has decreased by 12.95 percent, while retail sales have decreased by 20.97 percent. As illustrated retail energy sales are not anticipated to exceed the historic 2007 peak during the planning period, and will, in fact, be below 2004 retail energy sale levels by 7.56 percent. The reduction in sales is associated with several ARP member systems modifying their contractual agreements with FMPA, such that FMPA no longer provides for the system's capacity and energy needs. Those member systems modifying agreements include the City of Vero Beach in 2010, the City of Lake Worth in 2014, and the City of Fort Meade in 2015.

Figure 31: FMPA Growth Rate



Source: 2015 Ten-Year Site Plan

Figure 32: FMPA Demand and Energy Forecasts



Source: 2015 Ten-Year Site Plan and Data Responses

The three graphs in Figure 32 above, shows FMPA's seasonal peak demand and net energy for load for the historic years of 2005 through 2014 and forecast years 2015 through 2024. 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 above.

Fuel Diversity

Table 20 below, shows FMPA's actual net energy for load by fuel type as of 2014 and the projected fuel mix for 2024. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects an increase in purchased power and energy from coal in 2024, but 85 percent of energy would still be sourced from natural gas and nuclear.

Table 20: FMPA Energy Consumption by Fuel Type

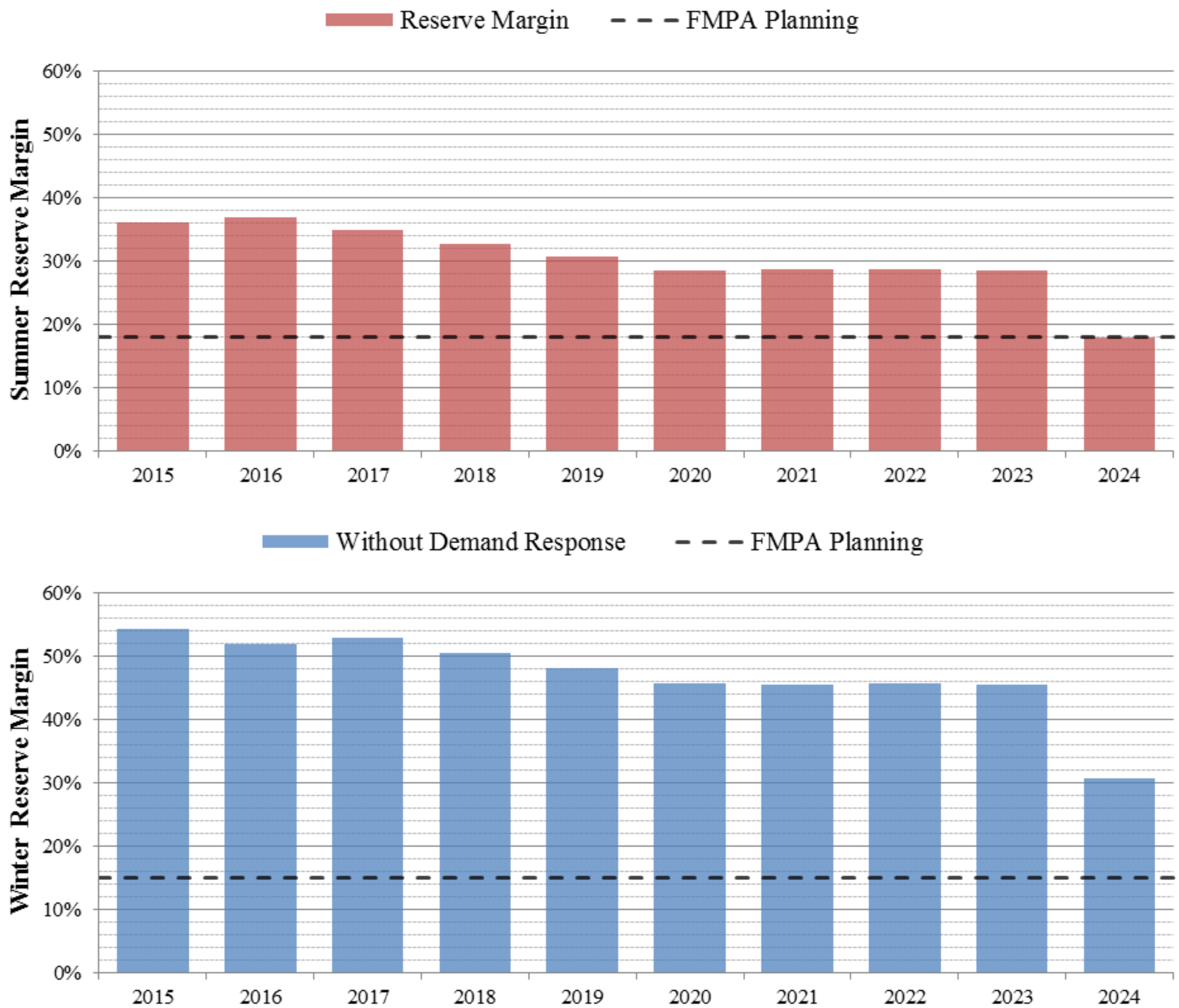
Fuel Type	Net Energy for Load			
	2014		2024	
	GWh	%	GWh	%
Natural Gas	4,596	**79.3%**	5,273	**80.0%**
Coal	837	**14.4%**	1,011	**15.3%**
Nuclear	286	**4.9%**	286	**4.3%**
Oil	3	**0.1%**	0	**0.0%**
Renewable	32	**0.6%**	23	**0.3%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	42	**0.7%**	0	**0.0%**
Total	**5,796**		**6,593**	

Source: 2015 Ten-Year Site Plan and Data Responses

Reliability Requirements

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

Figure 33: FMPA Reserve Margin Forecast



Source: 2015 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.

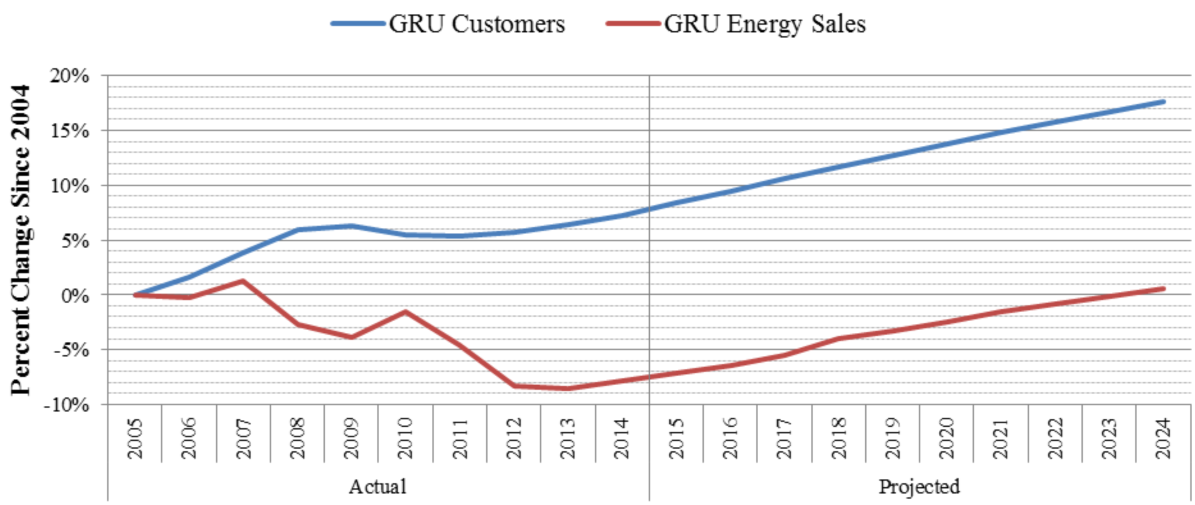
Gainesville Regional Utilities (GRU)

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 2015 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2014, GRU had approximately 93,855 customers and annual retail energy sales of 1,709 GWh or approximately 0.8 percent of Florida's annual retail energy sales. Figure 34 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2005. Over the last ten years, GRU's customer base has increased by 7.19 percent, while retail sales have decreased by 7.81 percent. As illustrated retail energy sales are not anticipated to exceed their historic 2007 peak during the planning period.

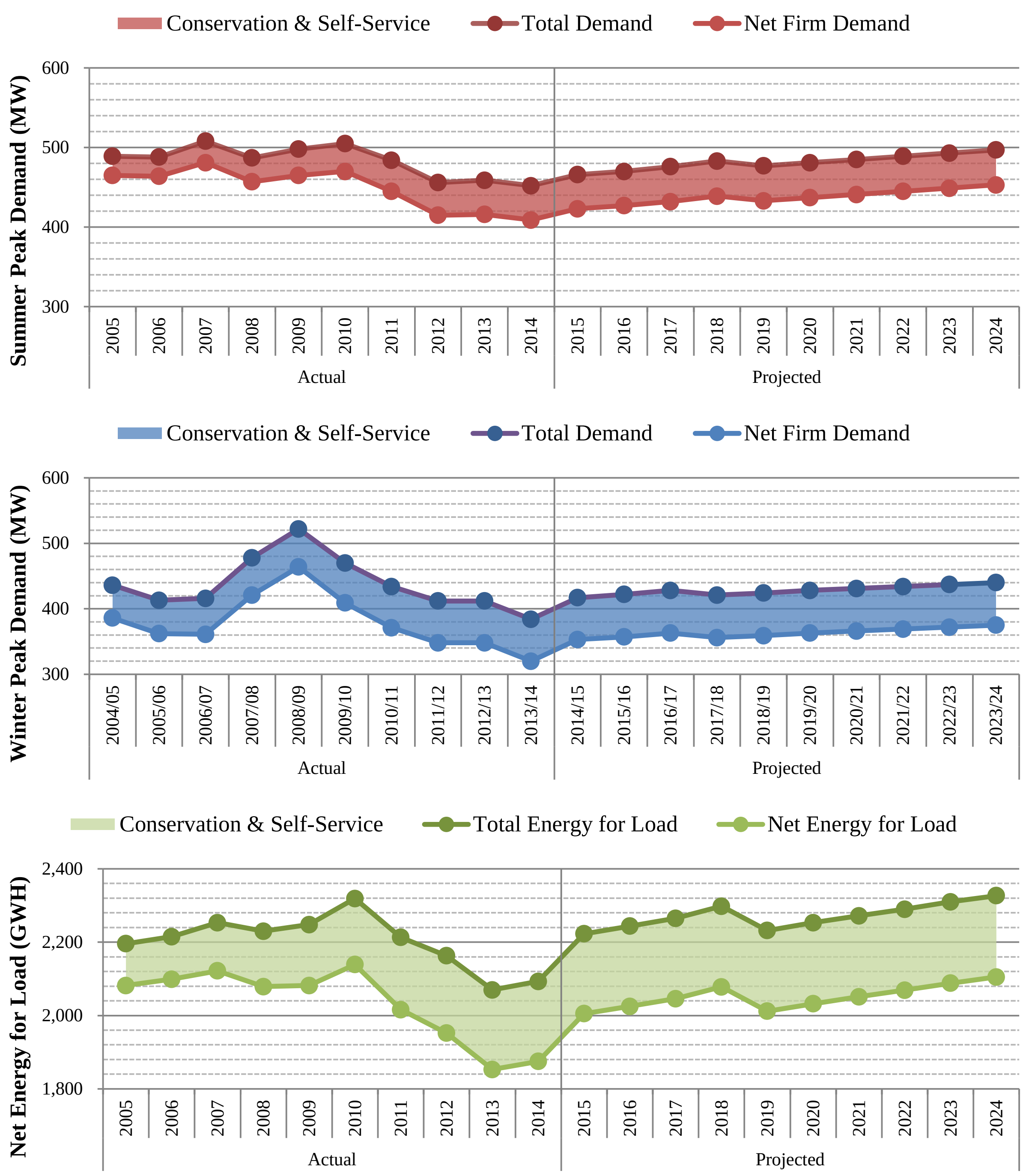
Figure 34: GRU Growth Rate



Source: 2015 Ten-Year Site Plan

The three graphs in Figure 35 below, shows GRU's seasonal peak demand and net energy for load for the historic years of 2005 through 2014 and forecast years 2015 through 2024. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 35 include the impact of these demand-side management programs.

Figure 35: GRU Demand and Energy Forecasts



Source: 2015 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 21 below, shows GRU's actual net energy for load by fuel type as of 2014 and the projected fuel mix for 2024. 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. By 2024, GRU projects a decline in natural gas and an increase in renewable energy to almost 40 percent of net energy for load. This increase in renewables is primarily associated with the Gainesville Renewable Energy Center, a biomass facility that GRU has a long-term purchased power agreement with for approximately 100 MW of firm capacity and energy.

Table 21: GRU Energy Consumption by Fuel Type

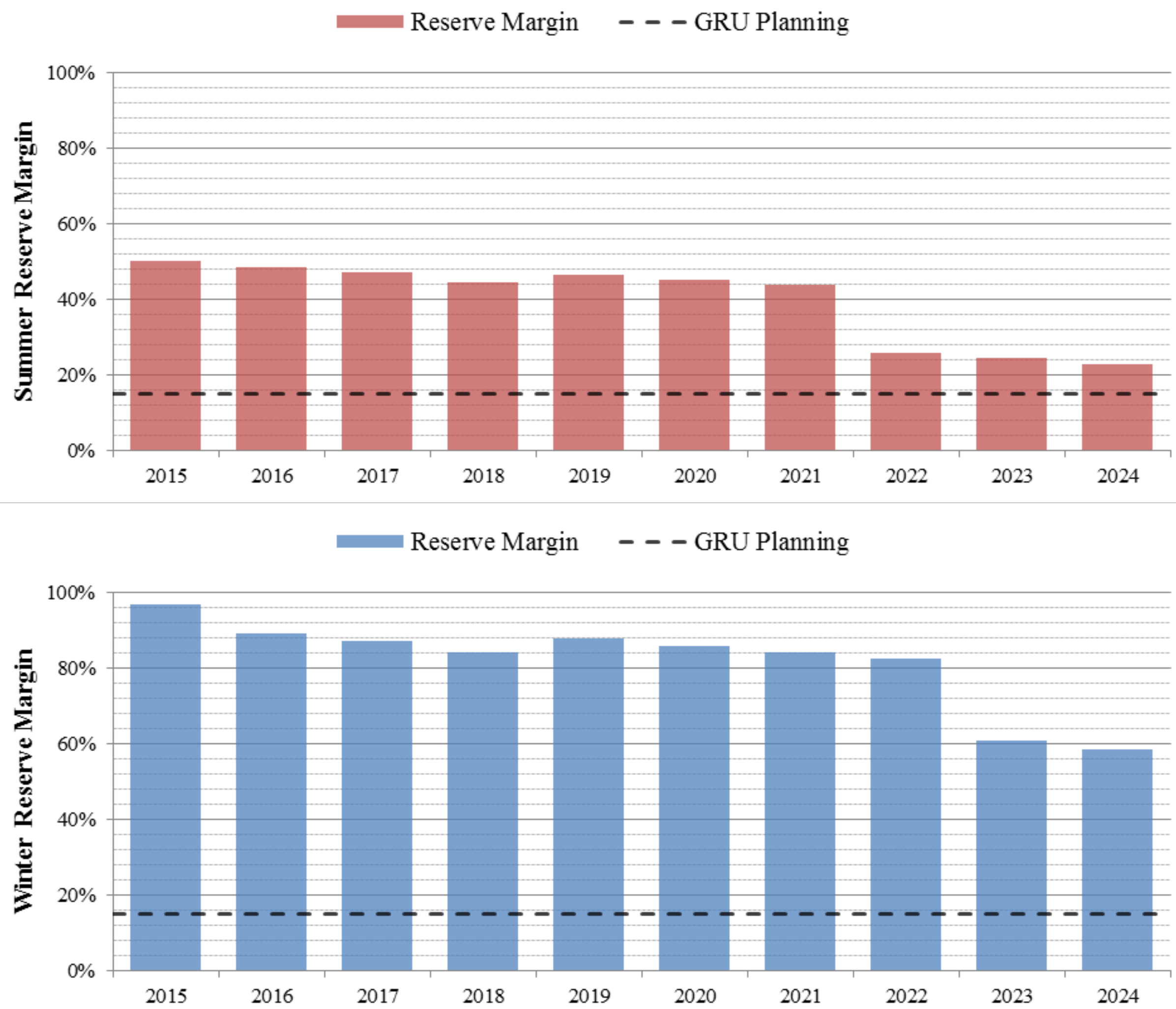
Fuel Type	Net Energy for Load			
	2014		2024	
	GWh	%	GWh	%
Natural Gas	315	**16.8%**	284	**13.5%**
Coal	820	**43.7%**	820	**39.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	635	**33.9%**	835	**39.7%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	105	**5.6%**	166	**7.9%**
Total	**1,875**		**2,105**	

Source: 2015 Ten-Year Site Plan and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 36 below, displays the forecast planning reserve margin for GRU through the planning period for both seasons, including the impacts of demand-side management. As shown in the figure, GRU's generation needs are controlled by its summer peak throughout the planning period. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, GRU's largest single unit, Deerhaven 2, a coal-fired steam unit, represents 56.3 percent of summer net firm peak demand in 2014, almost the entirety of the utility's reserve margin.

Figure 36: GRU Reserve Margin Forecast



Source: 2015 Ten-Year Site Plan

Generation Resources

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

Table 22: GRU Generation Resource Changes

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

Source: 2015 Ten-Year Site Plan

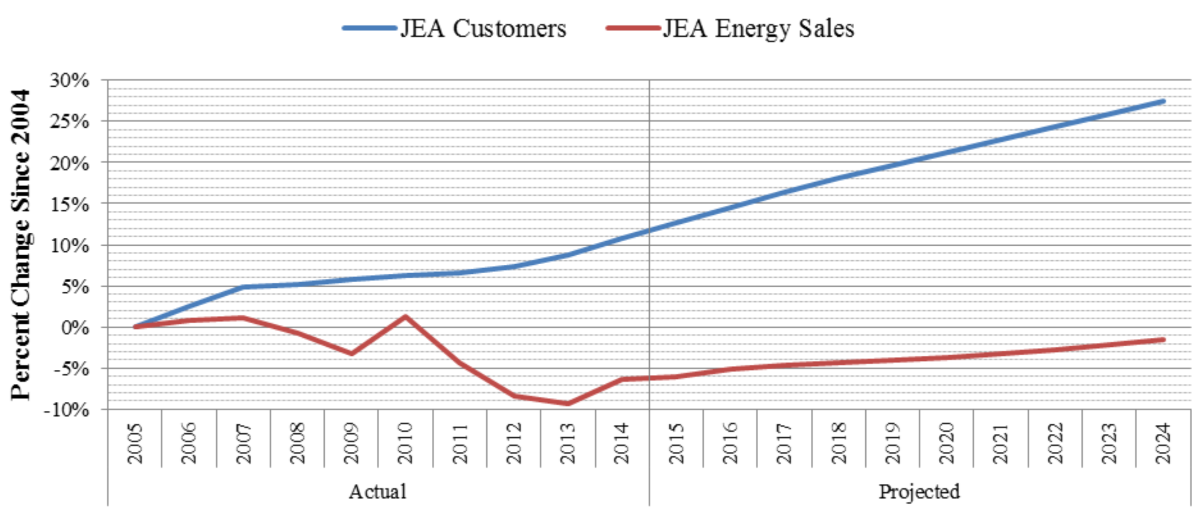
JEA

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 2015 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2014, JEA had approximately 433,578 customers and annual retail energy sales of 11,713 GWh or approximately 5.3 percent of Florida's annual retail energy sales. Figure 37 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2005. Over the last ten years, JEA's customer base has increased by 10.85 percent, while retail sales have declined by 6.36 percent. As illustrated JEA exceeded its 2007 peak for retail energy sales in 2010, but does not forecast returning to that level of energy sales during the planning period.

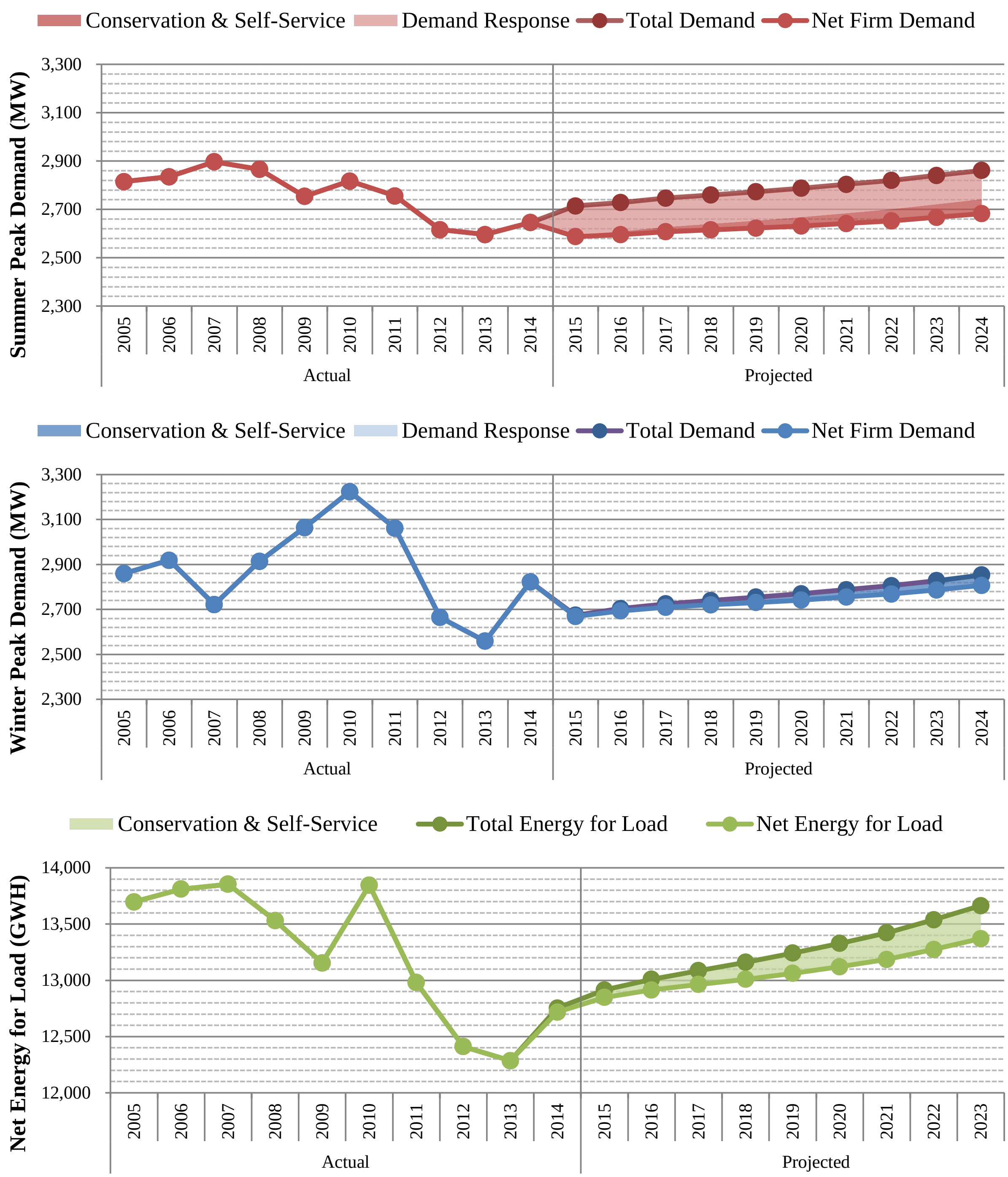
Figure 37: JEA Growth Rate



Source: 2015 Ten-Year Site Plan and 2015 FRCC Load & Resource Plan

The three graphs in Figure 38 below, shows JEA's seasonal peak demand and net energy for load for the historic years of 2005 through 2014 and forecast years 2015 through 2024. These graphs include the full impact of demand-side management, and assume that all available demand response resources were or will be activated during the seasonal peak.

Figure 38: JEA Demand and Energy Forecasts



Source: 2015 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 2015 Ten-Year Site Plan reflects the recently revised demand-side management goals established by the Commission in December 2014.

Fuel Diversity

Table 23 below, shows JEA's actual net energy for load by fuel type as of 2014 and the projected fuel mix for 2024. In 2014, a majority JEA's net energy for load came from coal and petroleum coke, which is listed in the "NUG & Other" category in Table 23. While the utility plans on eliminating petroleum coke usage over the planning period, JEA projects the highest percent energy consumption from coal in 2024 of the Ten-Year Site Plan utilities.

Table 23: JEA Energy Consumption by Fuel Type

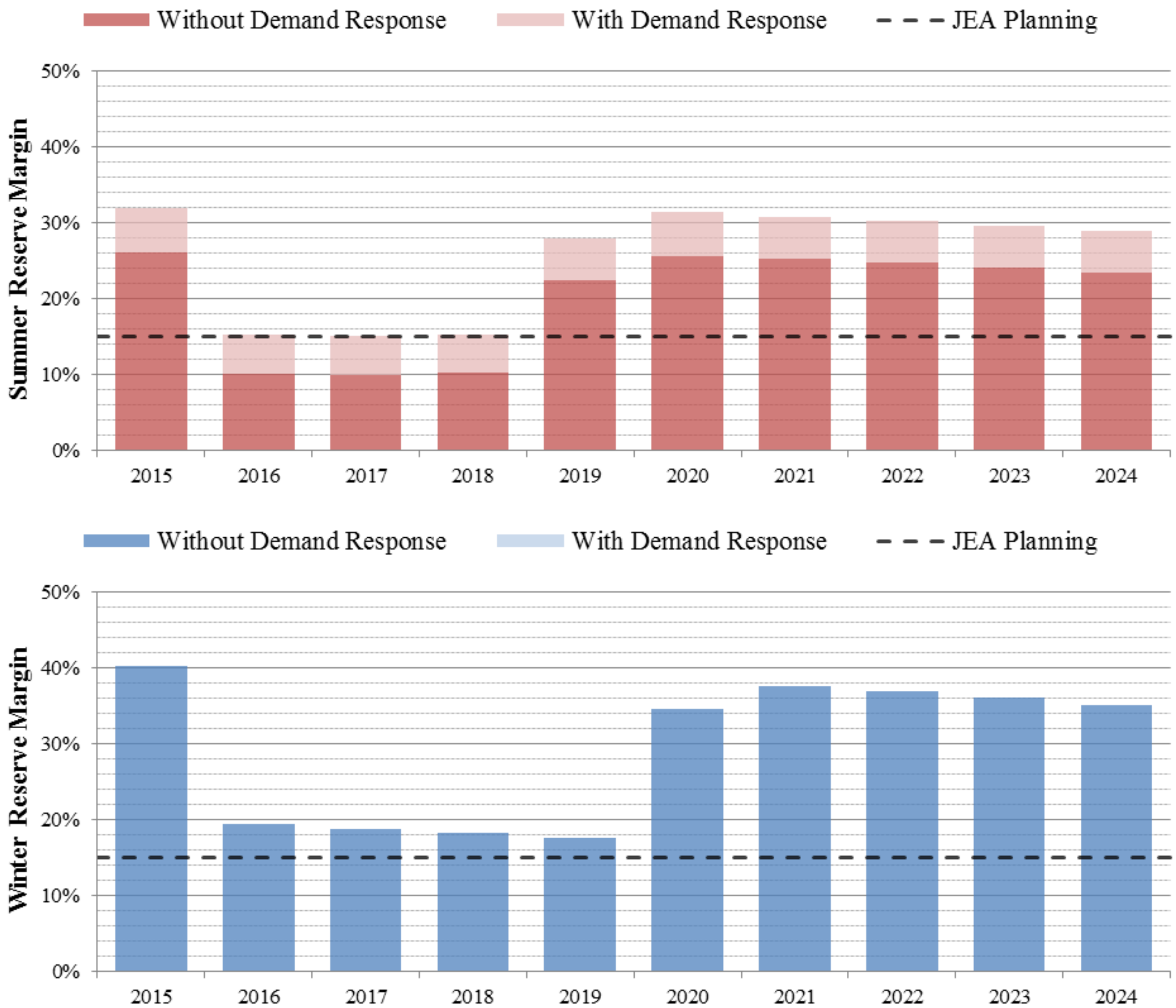
Fuel Type	Net Energy for Load			
	2014		2024	
	GWh	%	GWh	%
Natural Gas	3,993	**31.5%**	1,128	**8.4%**
Coal	7,012	**55.4%**	8,301	**62.1%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	9	**0.1%**	2	**0.0%**
Renewable	91	**0.7%**	72	**0.5%**
Interchange	477	**3.8%**	1,610	**12.0%**
NUG & Other	1,075	**8.5%**	2,258	**16.9%**
Total	**12,656**		**13,371**	

Source: 2015 Ten-Year Site Plan and Data Responses

Reliability Requirements

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

Figure 39: JEA Reserve Margin Forecast



Source: 2015 Ten-Year Site Plan

Generation Resources

JEA plans to retire one unit during the planning period, as described in Table 24 below. The Northside Unit 3, a natural gas-fired steam unit is planned for retirement in 2016 based on the utility's Ten-Year Site Plan.

Table 24: JEA Generation Resource Changes

Year	Unit Name	Fuel & Unit Type	Net Capacity (Sum MW)	Notes
Retiring Units				
2016	Northside 3	Natural Gas Steam	524	Reserve Storage
		Retiring Units Total	524	
		Net Additions	**(524)**	

Source: 2015 Ten-Year Site Plan

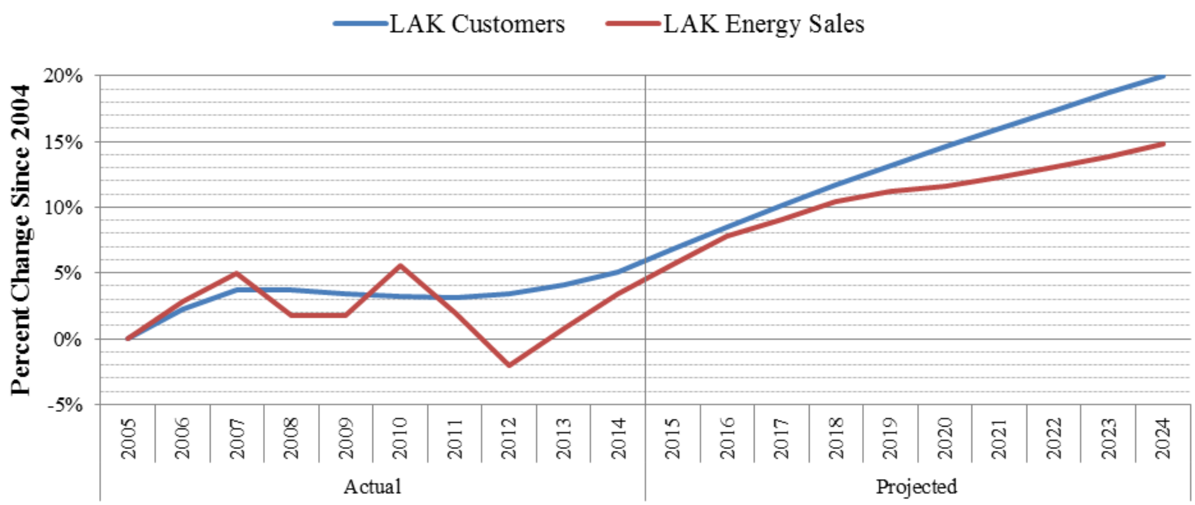
Lakeland Electric (LAK)

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 2015 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2014, LAK had approximately 124,021 customers and annual retail energy sales of 2,904 GWh or approximately 1.3 percent of Florida's annual retail energy sales. Figure 40 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2005. Over the last 10 years, LAK's customer base has increased by 5.10 percent, while retail sales have grown by 3.38 percent. As illustrated below, retail energy sales exceed their historic 2007 peak in 2010, and are anticipated to again exceed this value in 2015.

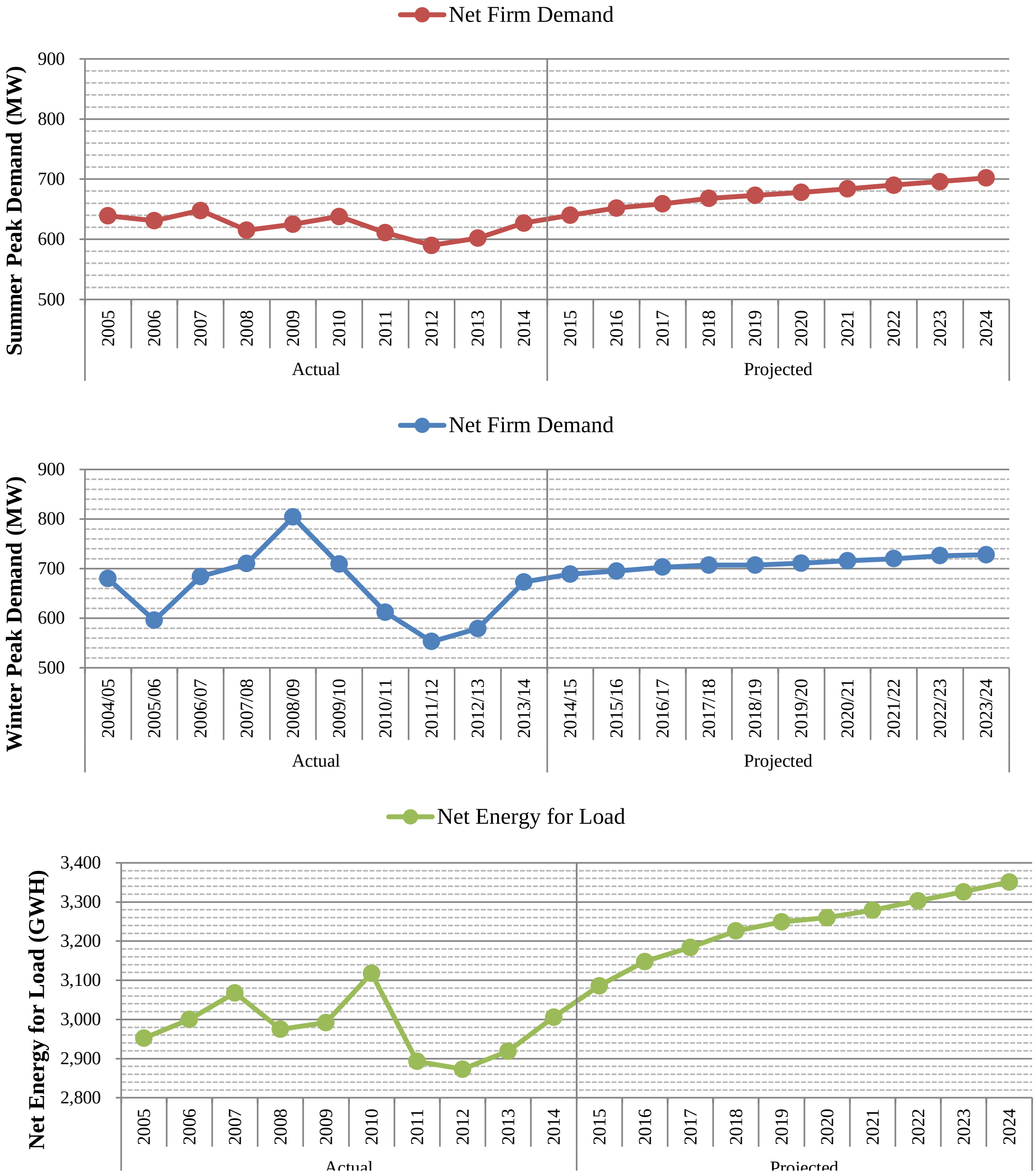
Figure 40: LAK Growth Rate



Source: 2015 Ten-Year Site Plan

The three graphs in Figure 41 below, shows LAK's seasonal peak demand and net energy for load for the historic years of 2005 through 2014 and forecast years 2015 through 2024. LAK offers energy efficiency programs, the impacts of which are included in the graphs below.

Figure 41: LAK Demand and Energy Forecasts



Source: 2015 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 25 below, shows LAK's actual net energy for load by fuel type as of 2014 and the projected fuel mix for 2024. LAK uses natural gas as its primary fuel type for energy, with coal representing about 10 percent net energy for load. While natural gas usage is anticipated to increase somewhat as a percent of net energy for load, coal is projected triple in 2024.

Table 25: LAK Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2014		2024	
	GWh	%	GWh	%
Natural Gas	1,714	**57.0%**	2,524	**75.3%**
Coal	278	**9.2%**	1,131	**33.8%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	1	**0.0%**
Renewable	12	**0.4%**	37	**1.1%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	1,002	**33.3%**	-342	**-10.2%**
Total	**3,006**		**3,351**	

Source: 2015 Ten-Year Site Plan and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 42 below, displays the forecast planning reserve margin for LAK through the planning period for both seasons, including the impacts of demand-side management. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, LAK's largest single unit, McIntosh 5, a natural gas-fired combined cycle unit, represents 51.4 percent of winter net firm peak demand in 2014, in excess of the utility's reserve margin.

Figure 42: LAK Reserve Margin Forecast

Source: 2015 Ten-Year Site Plan

Generation Resources

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

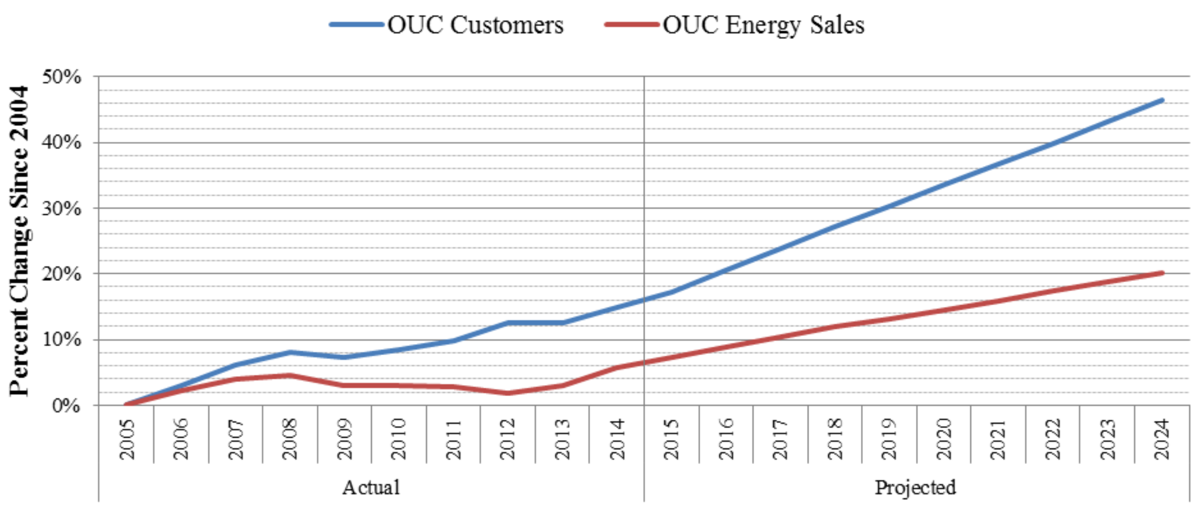
Orlando Utilities Commission (OUC)

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 2015 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2014, OUC had approximately 219,272 customers and annual retail energy sales of 6,191 GWh or approximately 2.8 percent of Florida's annual retail energy sales. Figure 43 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2005. Over the last 10 years, OUC's customer base has increased by 14.94 percent, while retail sales have grown by 5.79 percent. As illustrated retail energy sales are anticipated to exceed their historic 2008 peak in 2015.

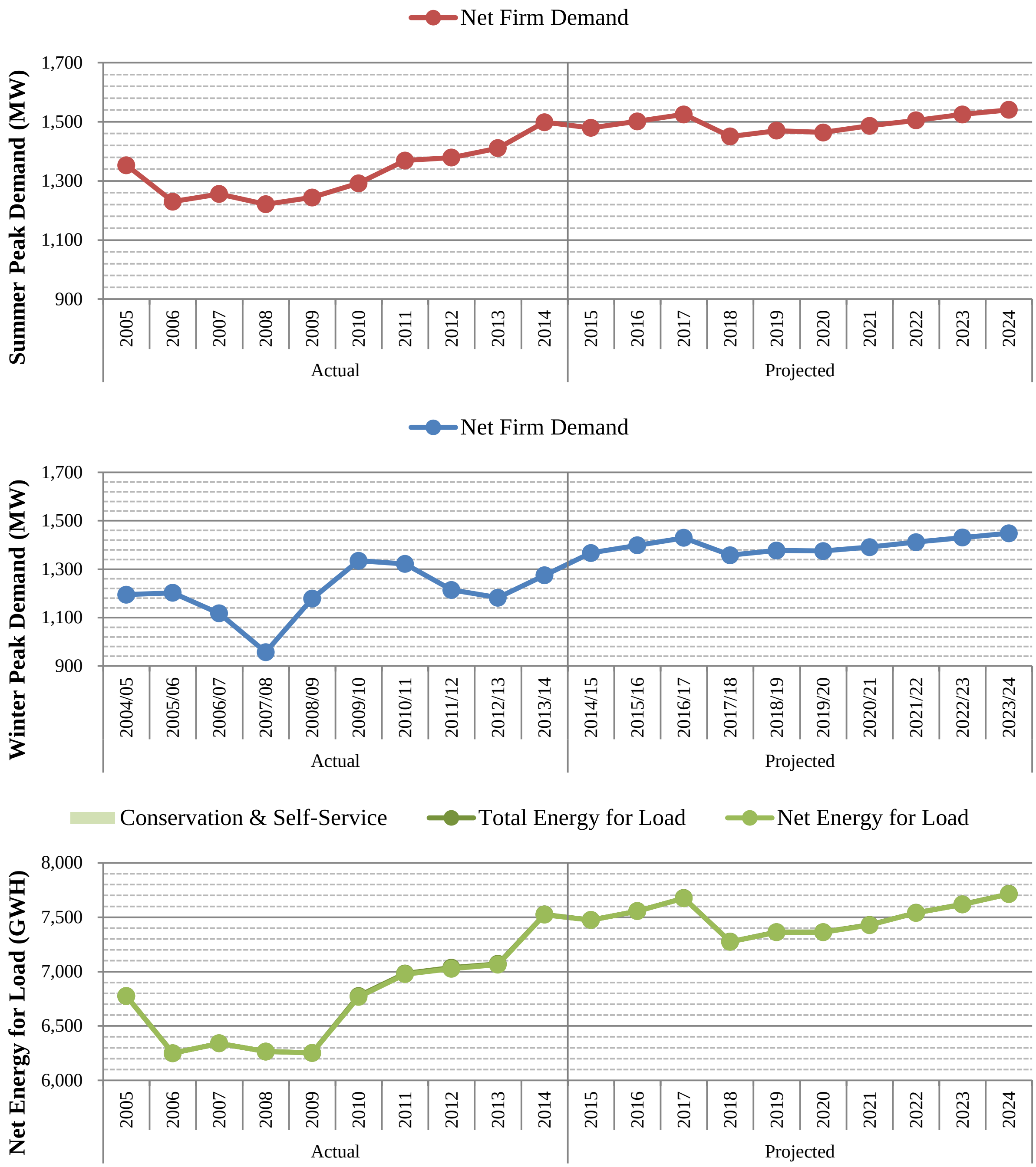
Figure 43: OUC Growth Rate



Source: 2015 Ten-Year Site Plan

The three graphs in Figure 44 below, shows OUC's seasonal peak demand and net energy for load for the historic years of 2005 through 2014 and forecast years 2015 through 2024. These graphs include the impact of the utility's demand side management programs. While a municipal utility, OUC is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption.

Figure 44: OUC Demand and Energy Forecasts



Source: 2015 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 26 below, shows OUC's actual net energy for load by fuel type as of 2014 and the projected fuel mix for 2024. In 2014, OUC used approximately equal portions of natural gas and coal as fuel to meet the utility's net energy for load. However, OUC projects to significantly increase the quantity of energy consumed from coal, while decreasing natural gas usage by 2024. Based upon this projection, OUC as a percent of net energy for load would be the second largest user of coal in Florida by 2024.

Table 26: OUC Energy Consumption by Fuel Type

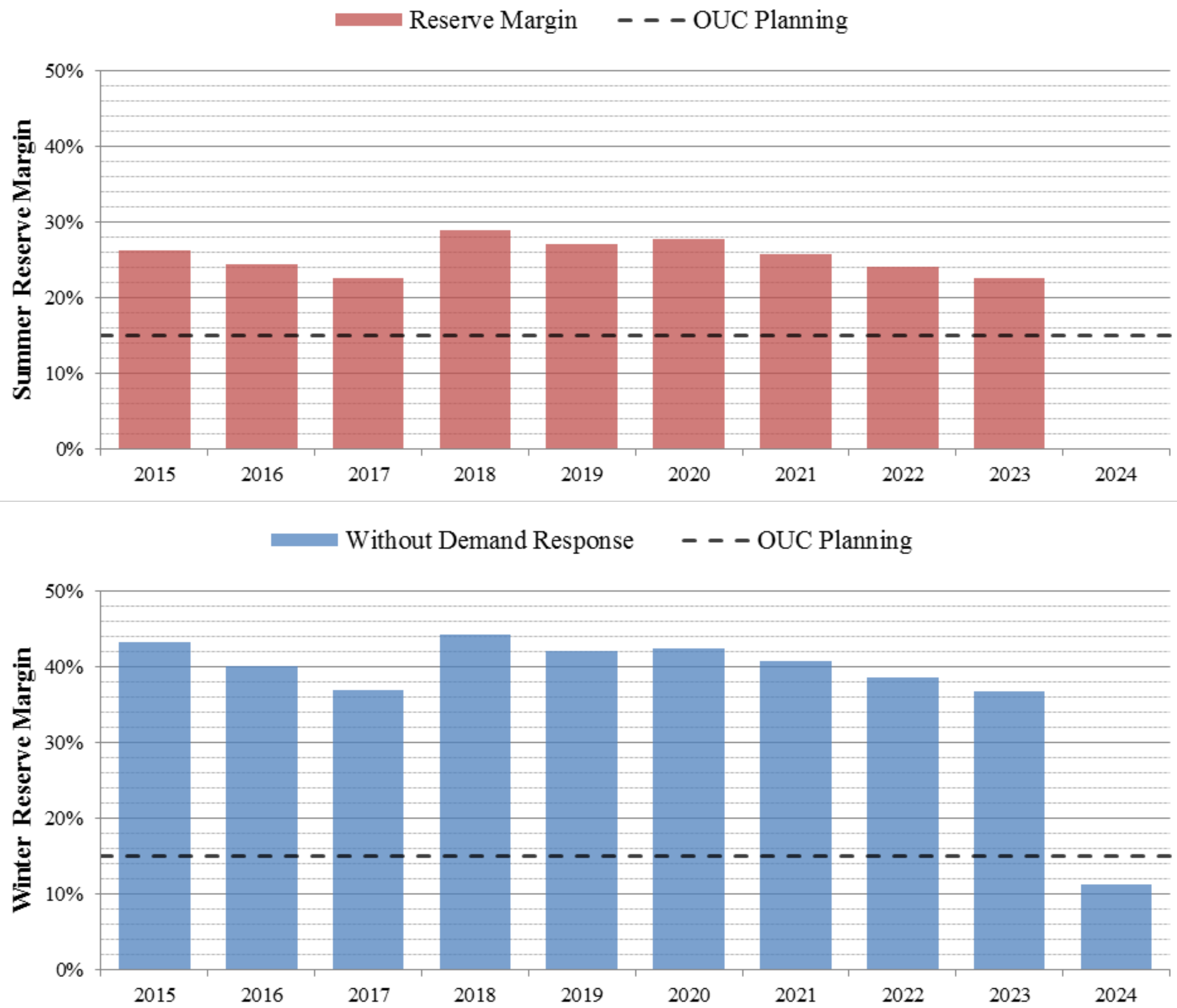
Fuel Type	**Net Energy for Load**			
	2014		**2024**	
	GWh	**%**	GWh	**%**
Natural Gas	3,405	**45.3%**	443	**5.7%**
Coal	3,534	**47.0%**	6,644	**86.1%**
Nuclear	472	**6.3%**	459	**6.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	109	**1.4%**	168	**2.2%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**7,521**		**7,714**	

Source: 2015 Ten-Year Site Plan and Data Responses

Reliability Requirements

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

Figure 45: OUC Reserve Margin Forecast



Source: 2015 Ten-Year Site Plan

Generation Resources

Based upon current planning OUC is adding a combined cycle in 2023 using natural gas. The unit as shown, in Table 27 below, will be a 285 MW Natural Gas Unit and will require a determination of need from FPSC.

Table 27: OUC Generation Resource Changes

Year	Unit Name	Fuel & Unit Type	Net Capacity (Sum MW)	Notes
New Units				
2023	Unknown	Natural Gas Combined Cycle	285	Requires PPSA
		New Units Total	**285**	
		Net Additions	**285**	

Source: 2015 Ten-Year Site Plan

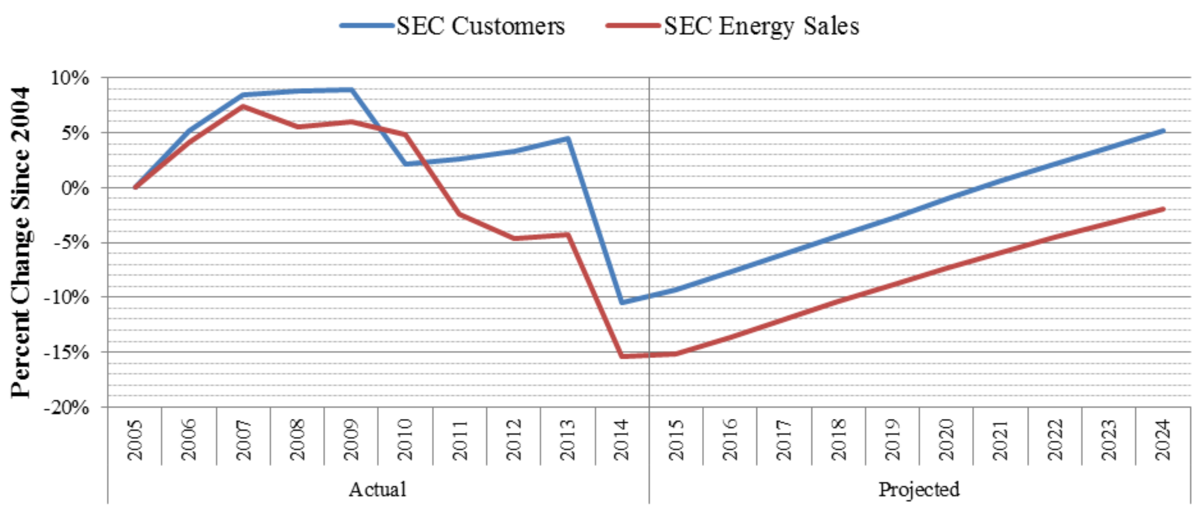
Seminole Electric Cooperative (SEC)

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 2015 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

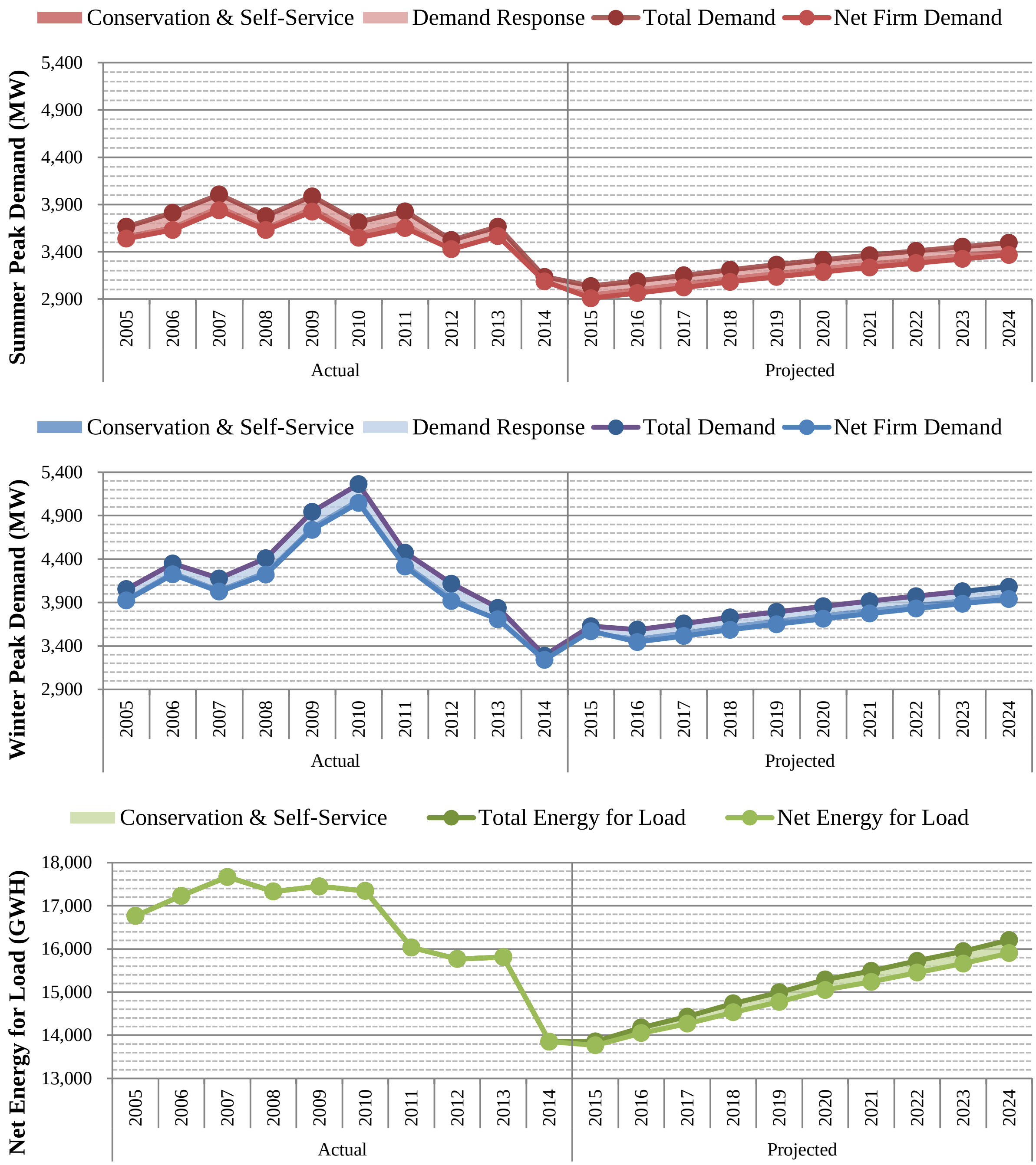
In 2014, SEC had approximately 740,566 customers and annual retail energy sales of 12,960 GWh or approximately 6.7 percent of Florida's annual retail energy sales. Figure 46 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2005. Over the last 10 years, SEC's customer base has decreased by 10.5 percent, while retail sales have decreased 5.39 percent. As illustrated retail energy sales are anticipated to exceed their historic 2007 peak by 2022, approximately five years later than Florida as a whole. The decline shown in 2014 is associated with one member cooperative, Lee County Electric Cooperative, electing to end its membership with SEC.

Figure 46: SEC Growth Rate



Source: 2015 Ten-Year Site Plan

Figure 47: SEC Demand and Energy Forecasts



Source: 2015 Ten-Year Site Plan and Data Responses

The three graphs in Figure 47 above, shows SEC's seasonal peak demand and net energy for load for the historic years of 2005 through 2014 and forecast years 2015 through 2024. 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 the graphs below.

Fuel Diversity

Table 28 below, shows SEC's actual net energy for load by fuel type as of 2014 and the projected fuel mix for 2024. In 2014, SEC uses a combination of coal and natural gas to meet its member cooperatives' net energy for load, with coal use slightly higher than natural gas. By 2024, SEC projects this to reverse, with natural gas usage somewhat higher than coal.

Table 28: SEC Energy Consumption by Fuel Type

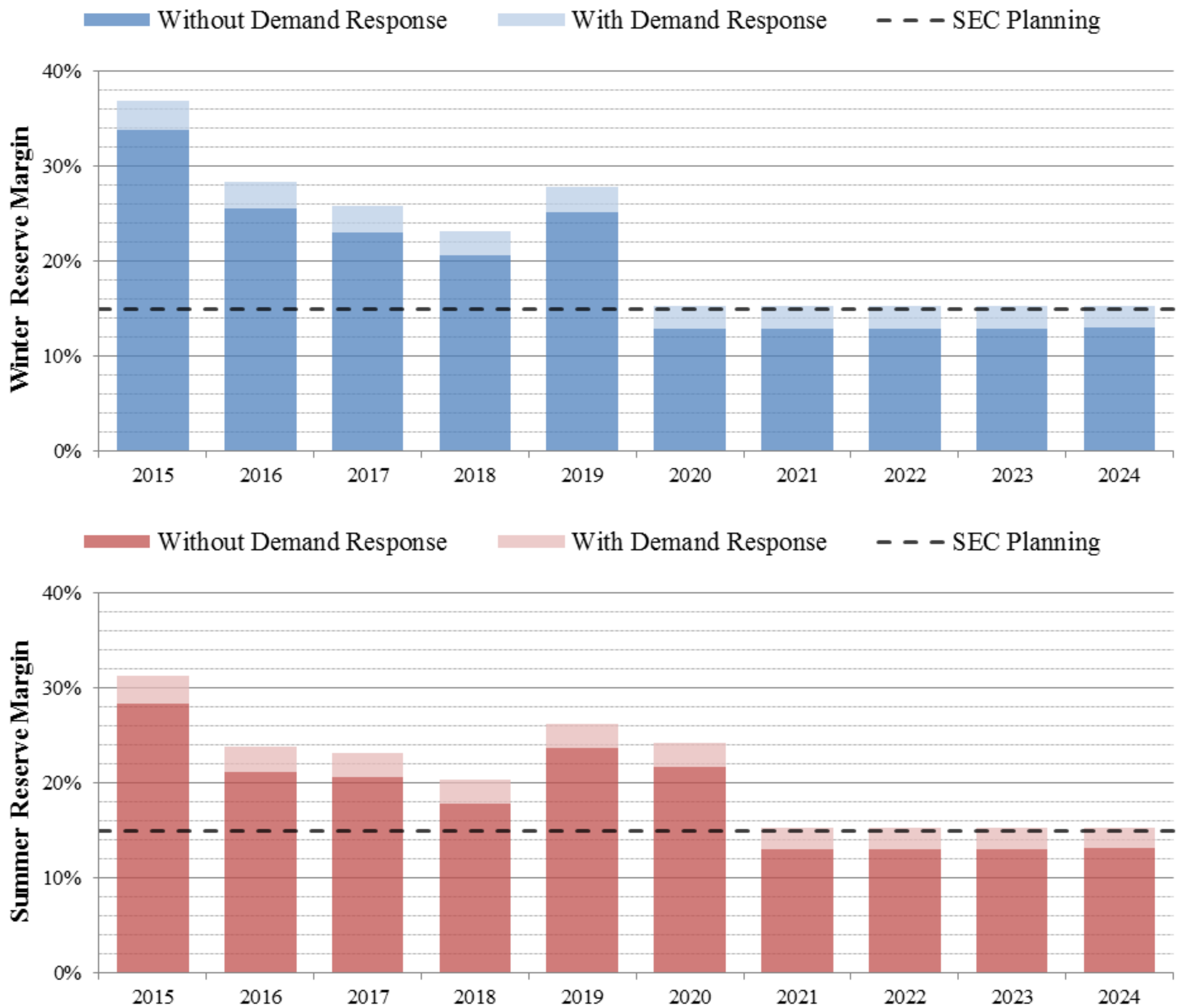
Fuel Type	Net Energy for Load			
	2014		2024	
	GWh	%	GWh	%
Natural Gas	4,737	**34.2%**	7,504	**47.2%**
Coal	8,159	**58.9%**	7,571	**47.6%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	35	**0.3%**	48	**0.3%**
Renewable	923	**6.7%**	780	**4.9%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**13,854**		**15,903**	

Source: 2015 Ten-Year Site Plan and Data Responses

Reliability Requirements

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

Figure 48: SEC Reserve Margin Forecast



Source: 2015 Ten-Year Site Plan

Generation Resources

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

Table 29: SEC Generation Resource Changes

Year	Unit Name	Fuel & Unit Type	Net Capacity (Sum MW)	Notes
New Units				
2021	Unnamed CC	Natural Gas Combined Cycle	649	Requires PPSA
2022	Unnamed CT 1	Natural Gas Combustion Turbine	201	
2023	Unnamed CT 2	Natural Gas Combustion Turbine	201	
2024	Unnamed CT 3	Natural Gas Combustion Turbine	201	
		New Units Total	**1,252**	
		Net Additions	**1,252**	

Source: 2015 Ten-Year Site Plan

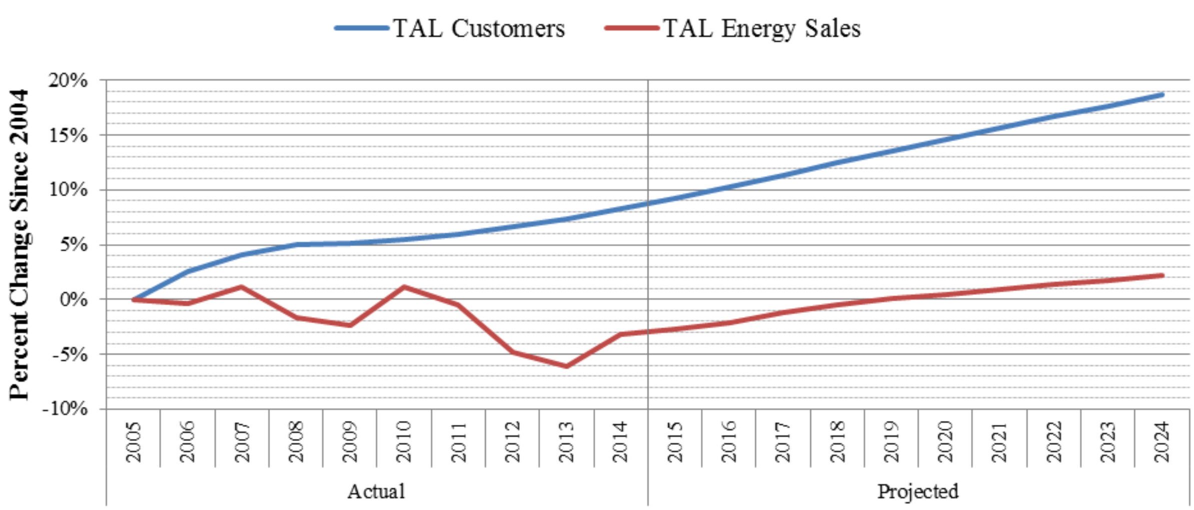
City of Tallahassee Utilities (TAL)

TAL is a municipal utility and the second smallest electric utility and municipal electric utility. 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 2015 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2014, TAL had approximately 116,708 customers and annual retail energy sales of 2,638 GWh or approximately 1.2 percent of Florida's annual retail energy sales. Figure 49 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2005. Over the last 10 years, TAL's customer base has increased by 8.28 percent, while retail sales have declined by 3.16 percent. As illustrated retail energy sales are not anticipated to exceed their historic 2007 peak until 2023, six years later than the state as a whole.

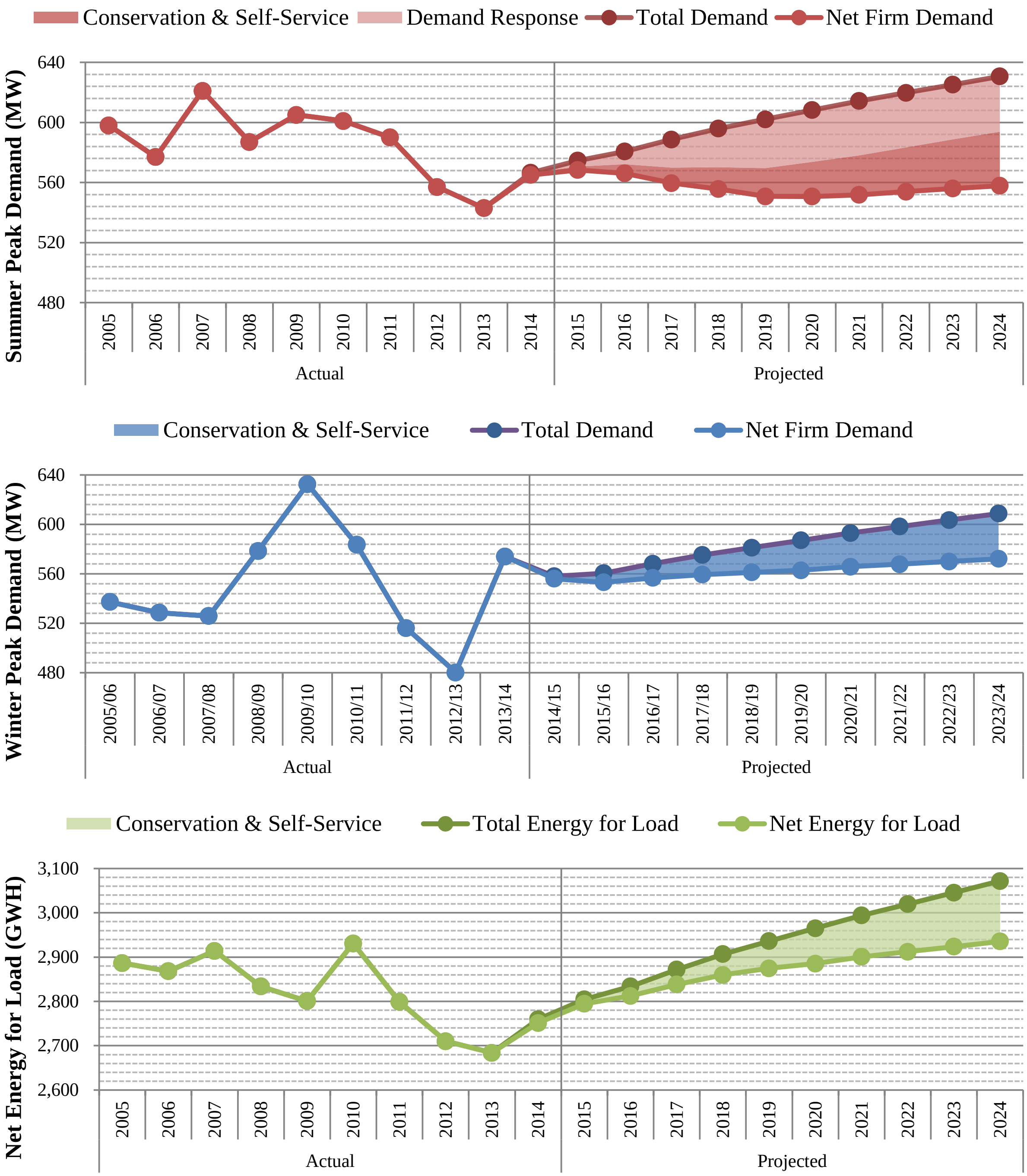
Figure 49: TAL Growth Rate



Source: 2015 Ten-Year Site Plan

The three graphs in Figure 50 below, shows TAL's seasonal peak demand and net energy for load for the historic years of 2005 through 2014 and forecast years 2015 through 2024. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. TAL offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. Currently TAL only offers demand response programs targeting appliances that contribute to summer peak, and therefore have no effect upon winter peak.

Figure 50: TAL Demand and Energy Forecasts



Source: 2015 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 30 below, shows TAL's actual net energy for load by fuel type as of 2013 and the projected fuel mix for 2023. 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 sole fuel on the system, with only natural gas-fired generation to be added.

Table 30: TAL Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2014		2024	
	GWh	%	GWh	%
Natural Gas	2,788	**101.3%**	2,917	**99.4%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	20	**0.7%**	14	**0.5%**
Interchange	0	**0.0%**	29	**1.0%**
NUG & Other	-56	**-2.0%**	-24	**-0.8%**
Total	**2,751**		**2,935**	

Source: 2015 Ten-Year Site Plan and Data Responses

Reliability Requirements

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

Figure 51: TAL Reserve Margin Forecast

Source: 2015 Ten-Year Site Plan

Generation Resources

TAL plans multiple unit retirements and a single addition during the planning period, as described in Table 31 below. Several older combustion turbines at two plant sites and a single steam unit, all natural gas-fired, are anticipated to be retired during the planning period. Based upon its current planning, TAL intends to add a new natural gas-fired combustion turbine in 2020.

Table 31: TAL Generation Resource Changes

Year	Unit Name	Fuel & Unit Type	Net Capacity (Sum MW)	Notes
Retiring Units				
2016	Hopkins GT1	Natural Gas Combustion Turbine	12	
2016	Purdom GT1 & GT2	Natural Gas Combustion Turbine	20	
2017	Hopkins GT2	Natural Gas Combustion Turbine	24	
2021	Hopkins 1	Natural Gas Steam	76	
		Retiring Units Total	**132**	
New Units				
2021	Hopkins	Natural Gas Combustion Turbine	46	
		New Units Total	**46**	
		Net Additions	**(86)**	

Source: 2015 Ten-Year Site Plan