REVIEW OF THE

2014 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

List of Acronyms

Acronym	Term
CC	Combined Cycle
CT	Combustion Turbine
DACS	Florida Department of Agriculture and Consumer Services
DEP	Florida Department of Environmental Protection
DSM	Demand-Side Management
EIA	Energy Information Administration
EPA	Environmental Protection Agency
F.A.C.	Florida Administrative Code
F.S.	Florida Statutes
FEECA	Florida Energy Efficiency & Conservation Act
FRCC	Florida Reliability Coordinating Council
GWh	Gigawatt-hour
LFG	Landfill Gas
MMBtu	Million British Thermal Units
MSW	Municipal Solid Waste
MW	Megawatt
NSB	Utilities Commission of New Smyrna Beach
NEL	Net Energy for Load
NUG	Non-Utility Generator
OBS	Other Biomass Solids
PPSA	Power Plant Siting Act
QF	Qualifying Facilities
RPS	Renewable Portfolio Standard
TLSA	Transmission Line Siting Act
TYSP	Ten-Year Site Plan
WDS	Wood and Wood Waste Solids

Executive Summary

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 (TYSP or 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 are designed to give state, regional, and local agencies advance notice of proposed power plants and transmission facilities. In accordance with Section 186.801(2), 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 study of the 2014 Ten-Year Site Plans for Florida's electric utilities, filed by 11 reporting utilities.[1]

All findings of the Commission are made available to the Florida Department of Environmental Protection for its consideration at any subsequent certification proceedings pursuant to the Power Plant Siting Act or the Transmission Line Siting Act.[2] In addition, this document is forwarded 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 2014 Ten-Year Site Plans

The Commission has divided this review into two portions: a Statewide Perspective, which covers the whole State 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.

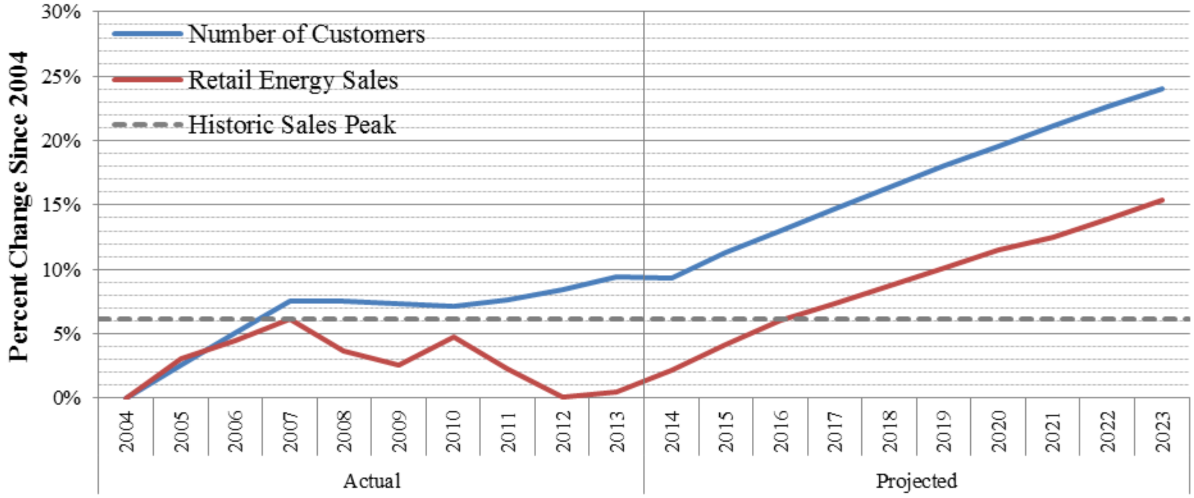
Load Forecasting

Forecasting load growth is an important component of system planning for Florida's electric utilities. Over the past ten years, the total number of electric customers has increased by 9.46 percent above 2004. However, growth in the number of customers has not necessarily resulted in growth in customer load. As of 2013, retail energy sales have only increased 0.52 percent above 2004, down from a historic 2007 peak. Florida's electric utilities project the economy to recover over the planning period, with growth remaining slower than before the financial crisis. Based on current projections, Florida's electric utilities anticipate exceeding the historic 2007 peak by 2017. Figure 1 below, details these trends.

[1] Investor-owned utilities filing 2014 TYSPs include Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). Municipal utilities filing 2014 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 2014 TYSP.

[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.

Figure 1: Florida Growth in Customers and Sales



Source: FRCC 2014 Load & Resource Plan

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. The Commission establishes goals at least once every five years, and is scheduled to establish goals by the end of 2014, which would be reflected in the 2015 Ten-Year Site Plans.

Based on current proposals, Florida's electric utilities project that by 2023 demand-side management programs will reduce the system's total summer peak demand by approximately 8,000 megawatts (MW), and annual energy consumption by over 11,000 gigawatt-hours (GWh). Including these reductions, Florida is forecasted to experience by 2023 a net firm summer peak demand of 52,633 MW and annual net energy for load of 270,773 GWh.

Renewable Generation

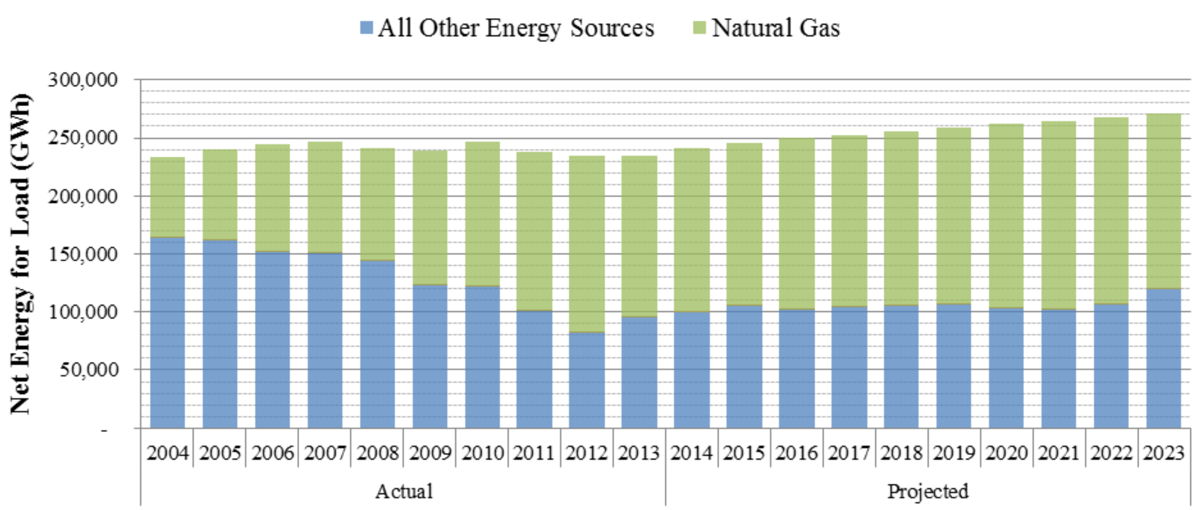
Renewable resources continue to expand in Florida, with approximately 1,620 MW of renewable generating capacity currently installed in Florida. The majority of installed renewable capacity is represented by biomass and municipal solid waste, making up approximately 60 percent of Florida's renewables. Other major renewable types, in order of capacity contribution, include waste heat, solar, hydroelectric, and landfill gas. Notably, Florida had 63 MW of demand-side renewable energy systems installed and using net metering by the end of 2013, an increase in capacity of 50 percent from 2012.

Over the next ten years, Florida's electric utilities have reported that 722 MW of additional renewable generation is planned in Florida, excluding any potential net metering additions. Almost half of the projected capacity additions are solar generation, the remainder consisting of solid biomass, municipal solid waste, and landfill gas. While these new projects represent a significant increase from the existing total, renewable generation continues to provide a relatively small contribution towards the reduction of the state's reliance upon fossil fuels.

Traditional Generation

Natural gas remains the dominant fuel over the planning horizon, with usage in 2013 at approximately 60 percent of the state's net energy for load (NEL). Figure 2 below, illustrates the use of natural gas as a generating fuel for electricity production in Florida. Natural gas usage is expected to remain approximately at its current level, on a percentage basis, and decline somewhat at the end of the planning period due to an increase in nuclear generation.

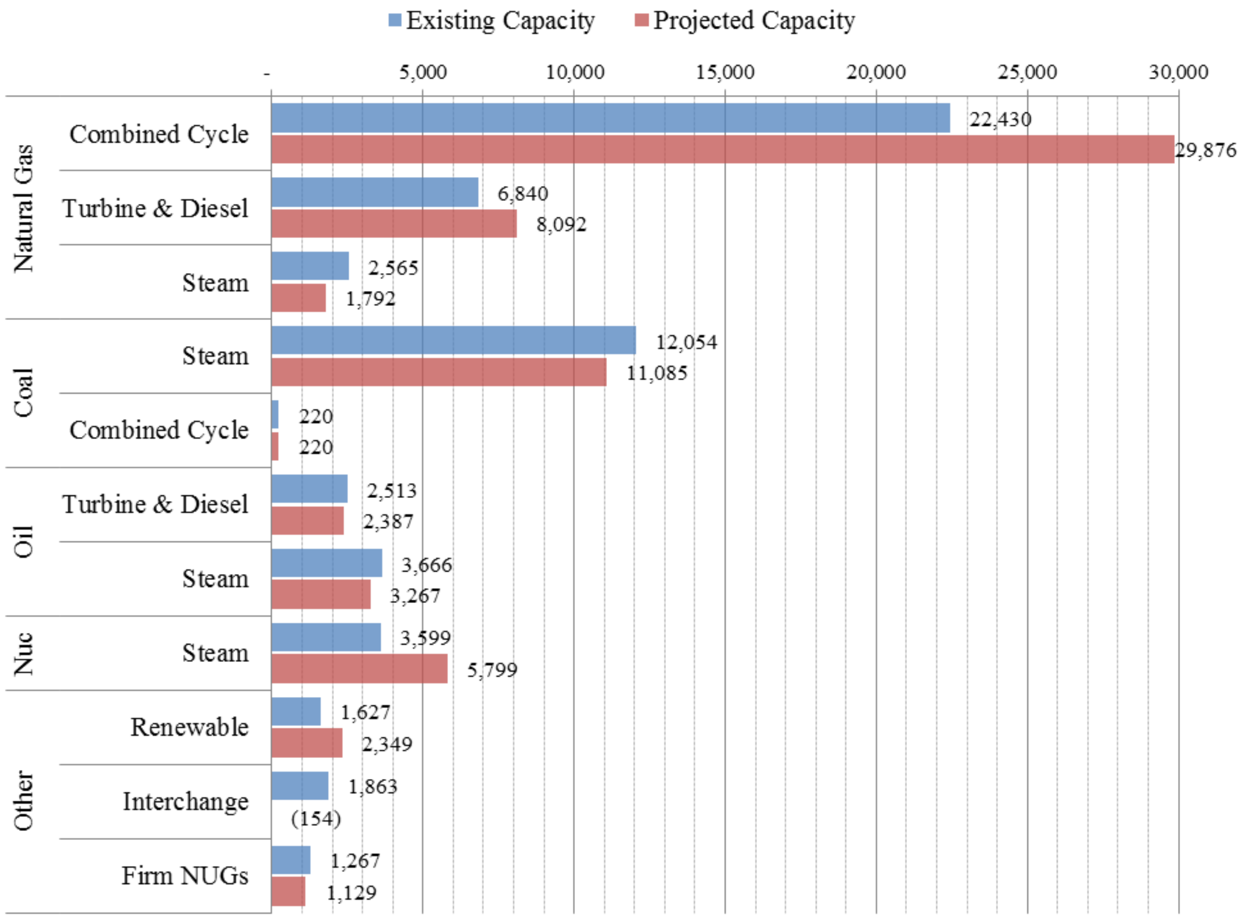
Figure 2: Natural Gas Contribution to Florida Energy Consumption



Source: 2005-2014 FRCC Load & Resource Plans

Generating capacity within the state of Florida is anticipated to grow to meet the increase in customer demand, with approximately 12,570 MW of new utility-owned generation added over the planning horizon. This figure represents an increase from the previous year, which estimated the need for about 9,960 MW new generation. Based on the 2014 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: Florida Current and Projected Installed Capacity by Fuel and Technology



Source: 2014 FRCC Load & Resource Plan and TYSP Utilities 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 had not yet received from the Commission a certification under the Power Plant Siting Act. 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. The Commission most recently approved a determination of need for DEF's proposed Citrus plant, which will still have to seek approval from DEP and the Siting Board.

Table 1: Planned Units Requiring a Determination of Need

In-Service Year	Utility Name	Plant Name & Unit Number	Unit Type	Net Capacity (MW)		Notes
				Sum	Win	
2018	DEF	Citrus	Combined Cycle	1,640	1,820	See Order No. PSC-14-0557-FOF-EI
2019	FPL	Unsited	Combined Cycle	1,269	1,429	
2020	SEC	Unsited	Combined Cycle	440	523	
2021	DEF	Unsited	Combined Cycle	793	866	

Source: 2014 Ten-Year Site Plans

While the Commission certifies transmission lines under the Transmission Line Siting Act (TLSA), there are none projected during the planning period that have not already been approved by the Commission.

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 proposed a rule in June 2014 associated with carbon pollution for existing power plants, also known as the Clean Power Plan. Due to the timing of the Ten-Year Site Plan filings, these proposed EPA Rules, though they may have a large effect on Florida's electric utilities, are not considered as part of this review. The Commission anticipates that the 2015 Ten-Year Site Plan will include more discussion of potential impacts to Florida's electric utilities from the Clean Power Plan, but uncertainty would remain as Florida's implementation plan would not be completed.

Regarding reliability, FPL is proposing using a third reliability criterion, a generation only planning reserve margin that excludes the benefits of demand response and incremental energy efficiency programs. While the proposed criterion has only a minor effect in the 2014 TYSP, it generally would result in higher installed or purchased capacity requirements for FPL to meet summer peak demand. At this time, FPL has not requested approval of this criterion, nor has the Commission approved its use. The Commission will continue to monitor annually FPL's reserve margin, demand response, and energy efficiency accomplishments. The Commission will have an opportunity to review FPL's proposed metric if it becomes a controlling factor for a determination of need of a new electrical power plant.

Conclusion

The Commission has reviewed the 2014 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 2014 Ten-Year Site Plans to be suitable for planning purposes. Since the Plans are not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing.

Introduction

The Ten-Year Site Plans of Florida's electric utilities are 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 annually submit 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 2014 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 Department of Agriculture and Consumer Services in consultation with the Commission to collect and analyze energy forecasts. 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.

Applicable Utilities

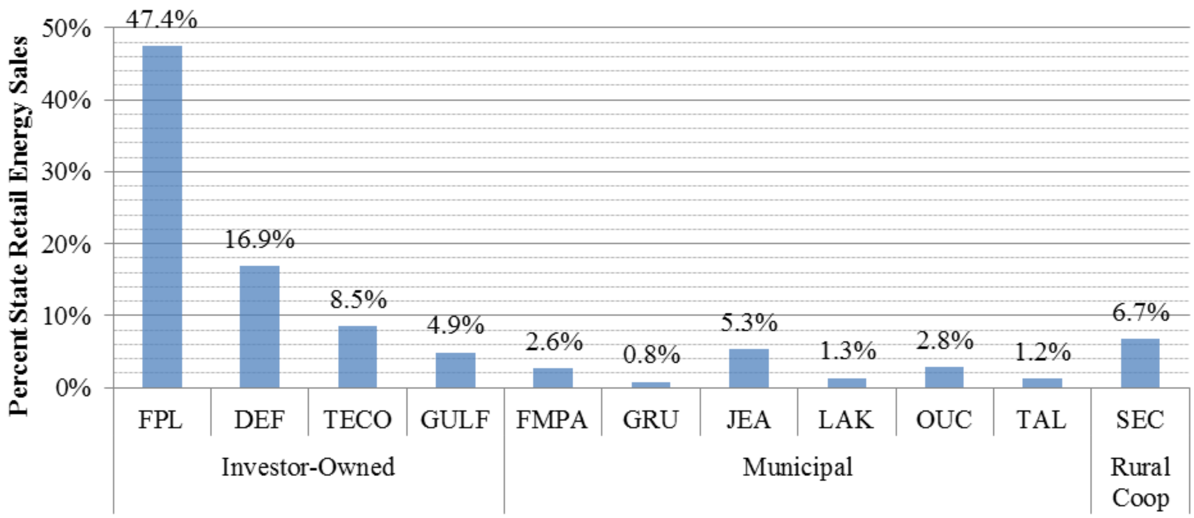
Florida is served by 58 electric utilities, including 5 investor-owned utilities, 35 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 megawatts (MW) or a planned unit with a capacity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

In 2014, 11 utilities met these requirements and filed a Ten-Year Site Plan, including 4 investor-owned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). The municipal utilities, in alphabetical order, are Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric

(LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). The sole rural electric cooperative filing a 2014 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 2013. Combined, the reporting investor-owned utilities account for 77.7 percent of the state's retail energy sales. Non-reporting utilities make up approximately 1.5 percent of the State's retail energy sales.

Figure 4: Comparison of Reporting Electric Utility Size



Source: 2014 Ten-Year Site Plans, 2014 Load & Resource Plan

<u>Required Content</u>

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 Rule 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 governmental 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 August 12, 2014, to facilitate discussion of the annual planning process and allow for public comments. A presentation was conducted by the FRCC summarizing the 2014 Load and Resource Plan and other related matters, including fuel reliability, environmental regulations, and physical security of infrastructure. Public comments were provided by the Sierra Club, which focused on the need to evaluate alternative energy options, planning for compliance with existing and future environmental regulations, and fuel diversity.

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 provide 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 utilities' 2014 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

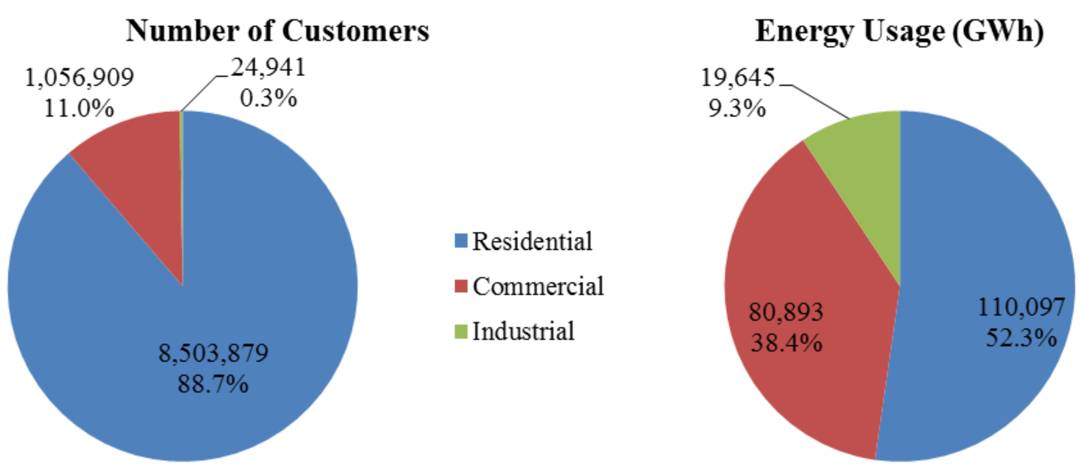
Load Forecasting

Forecasting load growth is an important component of system planning 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, at 52.3 percent of 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: Florida Electric Customer Composition in 2013

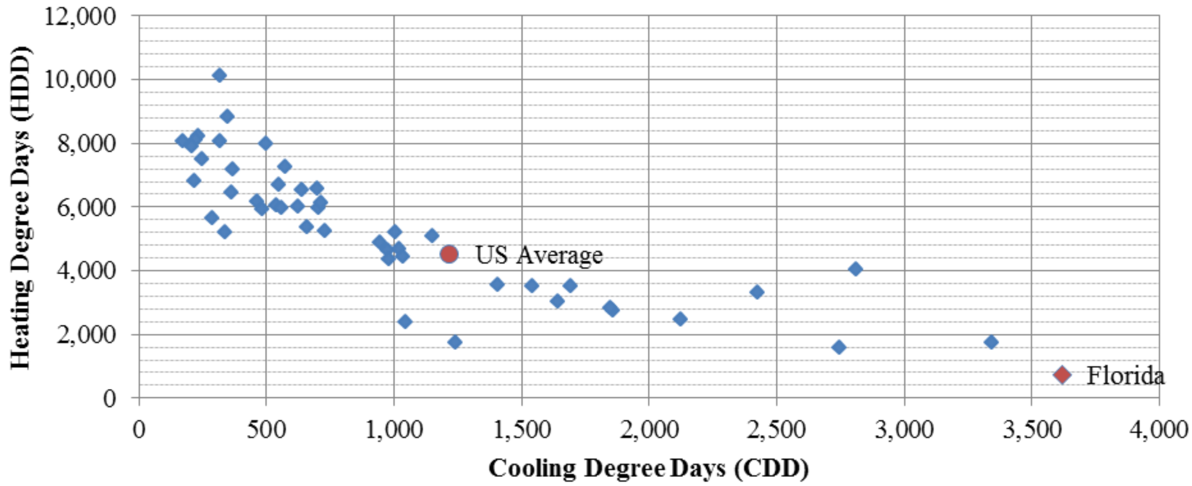


Source: FRCC 2014 Load & Resource Plan

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 by 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: Climate Data by State (Continental US)

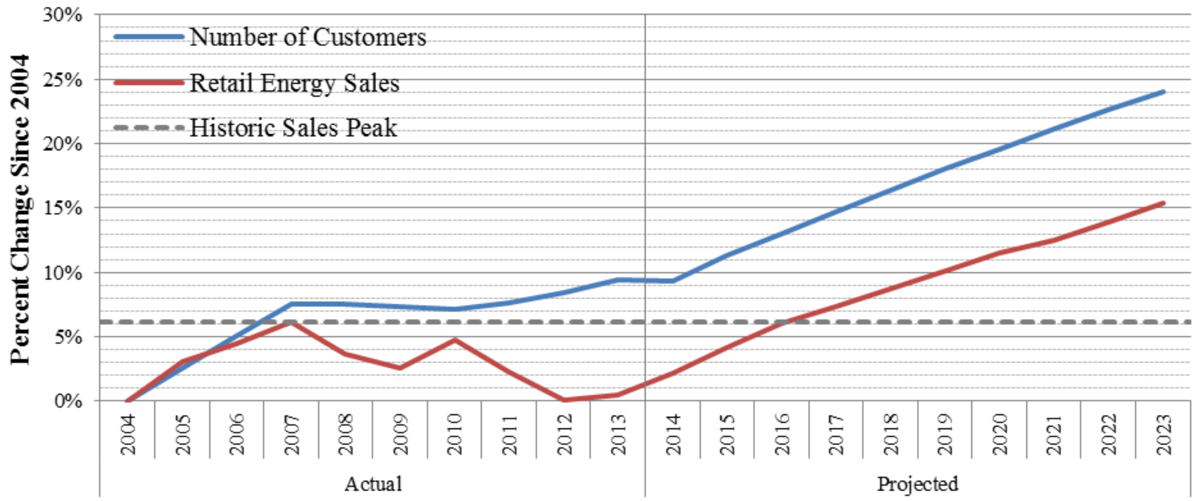


Source: National Oceanic & Atmospheric Administration, Historical Climatology Series 5-1 and 5-2 (30 year period)

Growth Projections

Florida traditionally has been a high growth state, with significant annual increases in both customers and retail energy sales. The financial crisis and resulting economic impact to Florida resulted in a freezing of customer growth and decline in retail energy sales from the 2007 peak. While customer growth has resumed, albeit at a slower pace, retail sales have declined since 2007 excluding a spike in usage associated with extreme winter weather in 2010. The result of both of these trends has been that over the last ten year period, the number of Florida's electric customers have risen 9.46 percent, while retail energy sales have risen only 0.52 percent. Since 2004, the effective average annual growth rate for electric sales during the past ten years was 0.06 percent. These trends are illustrated in Figure 7, below.

Figure 7: Florida Growth in Customers and Sales



Source: FRCC 2014 Load & Resource Plan

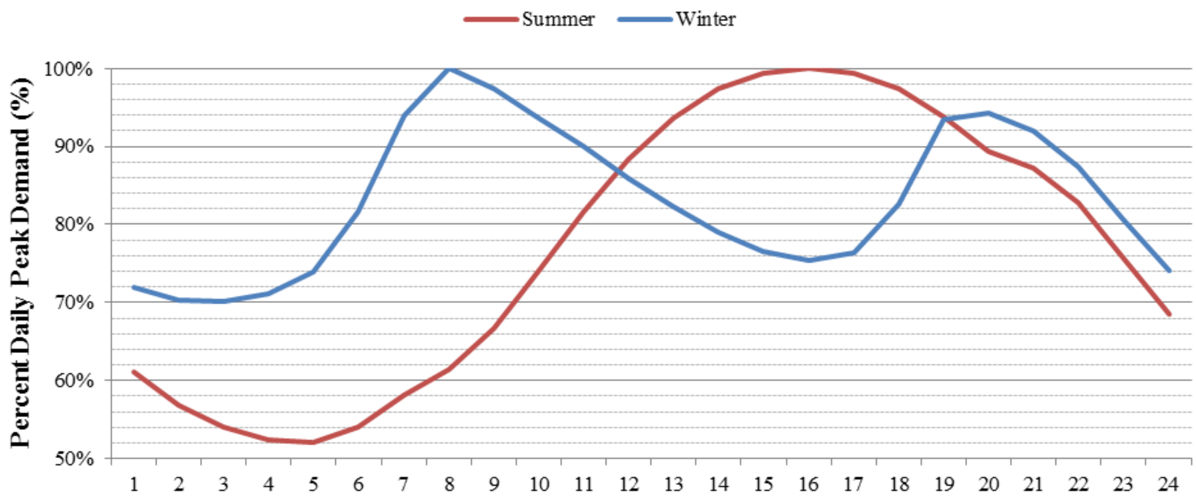
For the next ten-year period, Florida's customer base and retail sales are anticipated by the reporting utilities to grow at a faster pace than the last few years, reversing a trend of small population increases with declining retail sales. While this rate remains below those experienced before the financial 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 1.41 percent while retail sales increase by 1.36 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.

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 the 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 the winter, electric heat and electric water heating produces a higher base level of usage, with a large spike in the morning and a smaller spike in the evening.

Figure 8: Example Daily Load Curves

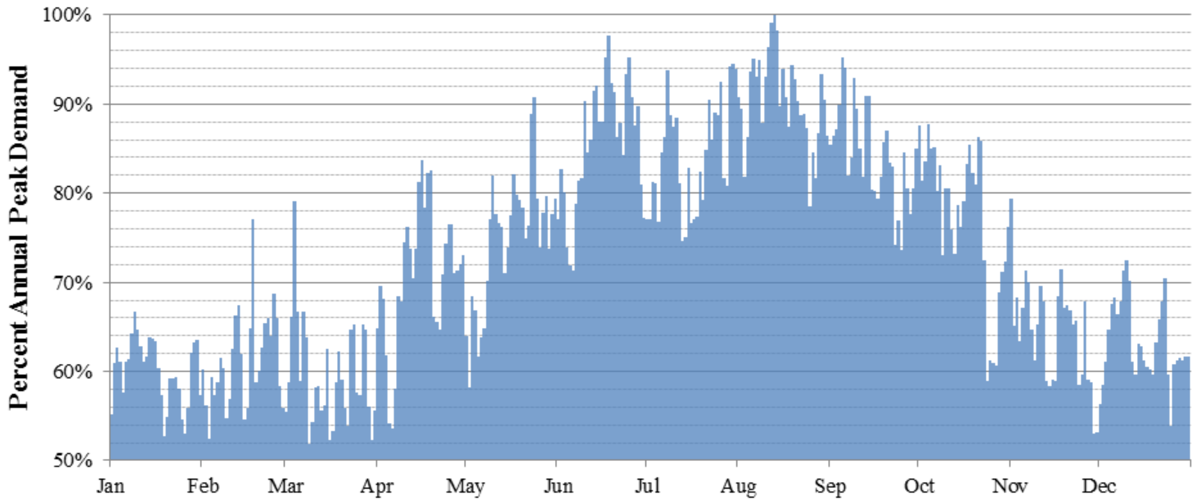


Source: TYSP Utility Data Responses

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. Weather conditions impact generation capacity in ways that cause summer demand to control. Higher temperatures in the summer 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 the 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 2013, showing the daily peak demand as a percentage of the annual peak demand for the reporting investor-owned utilities combined. As 2013 featured a mild winter, so summer peak demand set the annual peak demand. 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: Daily Peak Demand (2013 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. The reporting electric utilities estimate approximately 8,000 electric plug-in vehicles were operating in Florida by the end of 2013. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered vehicles in Florida as of December 31, 2013, as 18.9 million vehicles, resulting in 0.042 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 half-million electric vehicles operating within the electric service territories by the end of 2023. The projected increase in electric vehicle ownership would result in approximately 2 percent share of Florida's vehicles being fueled by electricity.

Table 2: Estimated Number of Electric Vehicles by Service Territory

Year	FPL	DEF	TECO	GPC	JEA	OUC	TAL	Total
2013	4,603	1,647	382	196	111	1,030	24	7,993
2014	8,787	3,125	N/A	445	173	1,624	36	14,190
2015	14,662	5,256	N/A	873	212	2,689	45	23,737
2016	22,628	8,273	N/A	1,442	282	4,037	54	36,716
2017	35,374	12,273	N/A	2,053	385	5,685	65	55,835
2018	48,200	17,482	N/A	2,836	520	7,646	84	76,768
2019	64,525	24,228	N/A	3,693	689	9,937	110	103,182
2020	97,425	32,893	N/A	4,626	891	12,574	142	148,551
2021	146,771	43,882	N/A	5,684	1,156	15,570	185	213,248
2022	220,792	57,338	N/A	6,872	1,485	18,859	250	305,596
2023	331,824	73,187	N/A	8,111	1,879	22,630	325	437,956

Source: TYSP Utilities 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 2,266 GWh, or approximately 0.9 percent of retail sales for the state of Florida.

Table 3: Estimates for Electric Vehicle Annual Energy Consumption (GWh)

Year	FPL	DEF	TECO	GPC	JEA	OUC	TAL	Total
2013	22	9	N/A	1	1	0	8	41
2014	42	21	N/A	2	1	1	12	79
2015	70	41	N/A	4	1	2	15	133
2016	108	70	N/A	7	2	2	18	207
2017	169	107	N/A	10	3	3	22	314
2018	230	152	N/A	13	5	5	28	433
2019	309	207	N/A	17	7	6	37	583
2020	466	273	N/A	21	9	8	48	825
2021	702	349	N/A	26	13	9	62	1,162
2022	1,056	421	N/A	32	17	11	84	1,621
2023	1,587	495	N/A	37	23	14	110	2,266

Source: TYSP Utilities 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 able to be addressed by the 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 percent of 2013 retail sales in Florida.

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

The last FEECA goal-setting proceeding was completed in December 2009, establishing goals for the period 2010 through 2019. As the Commission is required to establish goals once every five years, the Commission opened dockets in 2013 to begin the review process, and held a hearing in July 2014, with a final decision on annual goals reached on November 25, 2014. Each FEECA Utility's 2014 Ten-Year Site Plan includes either a continuation of existing programs or the utility's proposed goals. The 2015 Ten-Year Site Plans should reflect the impact of the goals established by the Commission for the period 2015 through 2024.

Demand Side Management 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 2014, demand response available for reduction of peak load is 3,105 MW for summer peak and 2,987 MW for winter peak. Demand response is anticipated to increase to approximately 3,500 for summer peak and 3,300 for winter peak by the end of the planning period in 2023.

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 2014, energy efficiency is responsible for peak load reduction of 3,766 MW for summer peak and 3,519 MW for winter peak. Energy Efficiency is anticipated to increase to approximately 4,454 MW for summer peak and 4,223 MW for winter peak by the end of the planning period in 2023.

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.

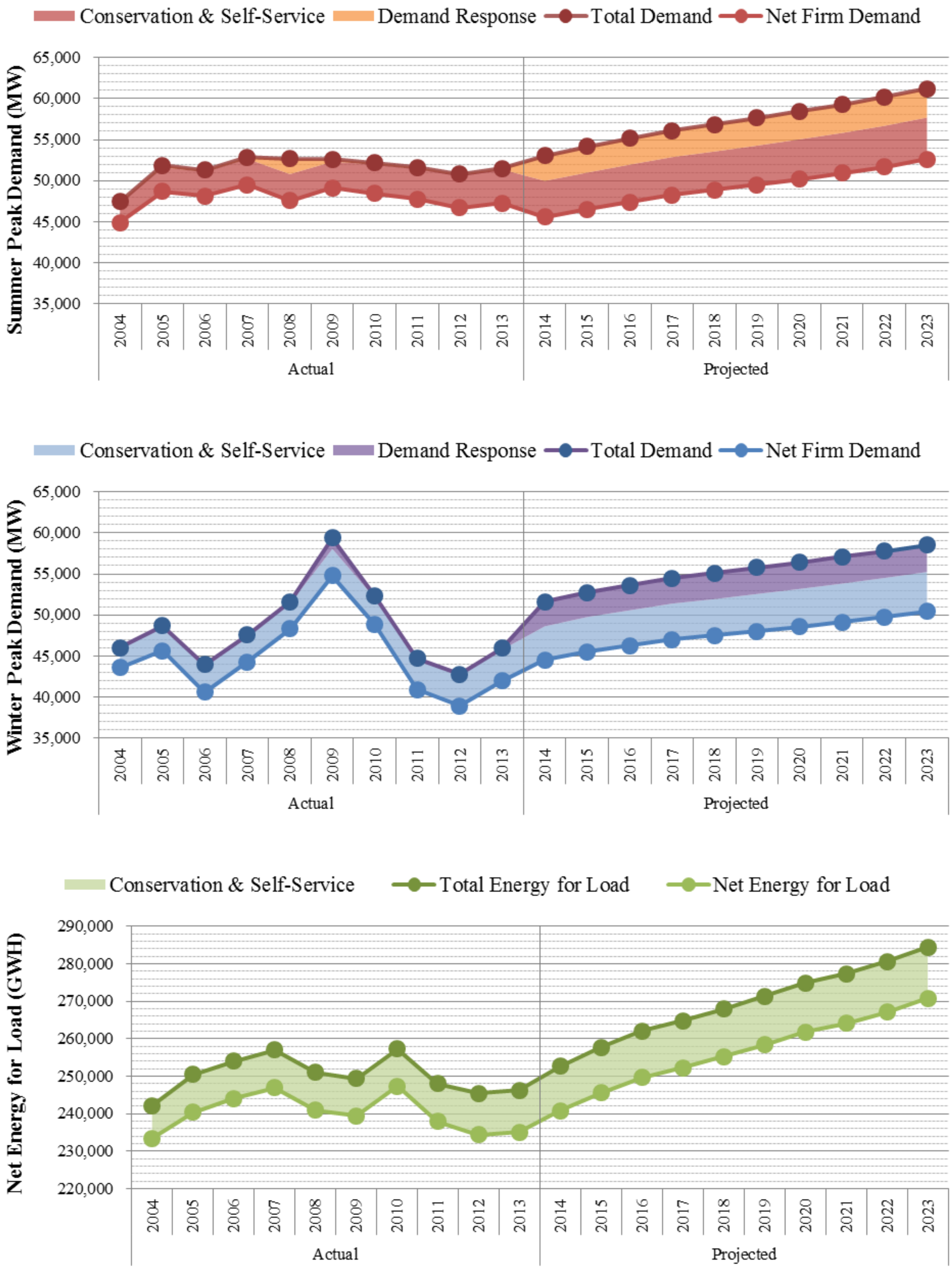
Demand-side management, including demand response and energy efficiency, along with self-service generation is included in each figure for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served if not for the impact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

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

Figure 10: Historic and Forecast for Statewide Seasonal Peak Demand and Annual Energy



Source: 2014 FRCC Load & Resource Plan

Forecast Methodology

Florida's electric utilities perform forecasts of peak demand and annual energy sales using historical data from several variables to infer relationships through multiple linear regressions. These variables include historic energy consumption, customer data such as square footage of housing, climate data such as cooling-degree-days or heating-degree days, and economic indicators such as income and employment. For some customer classes, such as industrial customers, surveys may periodically be conducted to determine the customer's expectations for their own future electricity consumption.

Florida's electric utilities rely upon econometric techniques for load forecasting, incorporating a variety of tools such as advanced software and analysis from independent experts from public and private sources for historic and forecast values of specific variables. Public resources such as the University of Florida's Bureau of Economic and Business Research, which provides data on population growth, and the Bureau of Labor Statistics, which publishes the Consumer Price Index, are utilized along with private forecasts for economic growth from macroeconomic experts. By combining historic and forecast macroeconomic data with customer and climate data, Florida's electric utilities project future load conditions.

Through multiple linear regressions, Florida's electric utilities demonstrate historical relationships between dependent variables such as load and retail energy sales, and independent variables such as economic conditions and climate. Projecting peak loads is more mathematically complicated and depends on the interrelationships between these variables.

Overall, while each of Florida's electric utilities forecast peak load and retail energy sales differently, the econometric techniques utilized appear to be sound. The 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 2013 retail energy sales were compared to the forecasts made in 2010, 2009, and 2008. 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 2014 Ten-Year Site Plans, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2013 through 2009 to forecasts made between 2010 and 2004. 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, confirms that the forecast error is increasing with time 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.

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

TYSP Year	Five Year Analysis Period	Forecast Years Analyzed	Forecast Error (%)	
			Average	Absolute Average
2009	2008 - 2004	2005-1999	1.74%	3.56%
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%

Source: 1999-2014 Ten-Year Site Plans

To verify whether more recent forecasts lowered these 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.

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		
2004	-	-5.08%	-3.18%	0.19%	-0.59%	0.93%	**-2.69%**	**2.81%**
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%**

Source: 1999-2014 Ten-Year Site Plans

As displayed in Table 5, the companies retail energy sales forecasts show a consistent positive error rate beginning in 2007 and extending through 2013 for forecasts prepared two to six years prior. However, 2013 sales forecasted in 2009 and 2010 reveal that three and four year error rates (5.98 percent and 10.00 percent, respectively) have declined considerably compared to the three and four year forecast error rates associated with 2009-2012 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.

On a going forward basis (2014 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. Florida's electric utilities, however, have responded to the recent 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.

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 1,617 MW of firm and non-firm generation capacity, which represents 2.8 percent of Florida’s overall generation capacity of 57,375 MW in 2013. Table 6 below, is a table that summarizes Florida’s existing renewable energy sources.

Table 6: State of Florida - Existing Renewable Resources

Renewable Type	MW	% Total
Municipal Solid Waste	398	24.6%
Waste Heat	308	19.0%
Solar	218	13.5%
Hydro	64	3.9%
Wind	0	0.0%
Solid Biomass	581	35.9%
Landfill Gas	49	3.1%
Total of All	**1,617**	**100.0%**

Source: FRCC 2014 Load & Resource Plan and TYSP Utilities Data Responses

Of the total 1,617 MW of renewable generation, approximately 490 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.

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 84 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 by 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. On July 8, 2014, the Commission approved standard offer contracts resulting in the continuous offering of nearly 3,484 MW for Florida's four largest IOUs.

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.

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 is 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 $.45/kWh in 2013. 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. Based on actual data collected from the three facilities, the maximum output does not appear to be coincident with the system's peak demand.

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. Because of Florida's geography, however, new hydroelectric power generation is largely limited.

Customer Owned Renewable Generation

With respect to customer owned renewable generation, Rule 25-6.065, F.A.C., requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer, with renewable generation capability, to offset their energy usage. In 2008, the effective year of the discussed Rule, customer owned renewable generation accounted for 3 MW of renewable capacity. As of 2013, approximately 63 MW of renewable capacity from nearly 6,700 systems has been installed statewide. Table 7 below, summarizes the growth of customer owned renewable generation interconnections.

Table 7: State of Florida - Net Metering Growth

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

Source: Annual Net Metering Reports

Planned Renewable Additions

Florida's utilities plan to construct or purchase an additional 722 MW of renewable generation over the ten-year planning period. Table 8 below, summarizes the planned renewable capacity increases by generation type.

Table 8: State of Florida - Planned Renewable Resources

Renewable Type	MW	% Total
Municipal Solid Waste	90	12.4%
Waste Heat	0	0.0%
Solar	332	46.1%
Hydro	0	0.0%
Wind	0	0.0%
Solid Biomass	272	37.6%
Landfill Gas	28	3.9%
Total of All	**722**	**100%**

Source: FRCC 2014 Load & Resource Plan and TYSP Utilities Data Responses

Of the 722 MW of planned renewable capacity, 361.5 MW is projected to be from firm resources. All of the projected firm capacity additions are from renewable contracts with non-utility generators. Table 9 below, summarizes the firm capacity renewable resources that are planned over the ten-year planning horizon. The remaining planned capacity from renewable resources is projected to be from non-firm resources including several 50 MW solar facilities.

Table 9: Planned Firm Renewables

Purchasing Utility	Facility Name	Fuel Type	Capacity (MW)	In-Service Date
JEA	Trailridge	LFG	9.0	2014
JEA	Sarasota County	LFG	6.4	2014
RCI	Harvest Power	OBS	2.4	2014
GPC	Perdido	LFG	1.5	2015
JEA	New River	LFG	3.2	2015
OUC	Shaw Environmental	LFG	9.0	2015
FPL	Solid Waste Authority of Palm Beach County	MSW	90.0	2015
DEF	Unknown - US EcoGen	WDS	60.0	2017
FPL	Ecogen Clay	OBS	60.0	2021
FPL	Ecogen Martin	OBS	60.0	2021
FPL	Ecogen Okeechobee	OBS	60.0	2021
Total of All			**361.5**	

Source: FRCC 2014 Load & Resource Plan and TYSP Utilities Data Responses

More than 170 MWs of contracted firm renewable 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.

Renewable Outlook

The Commission, in conjunction with the U.S. Department of Energy and the Lawrence Berkeley National Laboratory, retained Navigant Consulting, Inc. (Navigant) to prepare a detailed assessment of Florida's renewable potential in 2008. Navigant's assessment identified several key drivers that impact renewable energy development in Florida. Three of the "key drivers" were the cost of the natural gas, the cost of CO2, and the adoption of a Renewable Portfolio Standard (RPS).

Under the scenario considered to be favorable in fostering renewable generation, Navigant assumed natural gas prices between $11-$14/MMBTU, CO2 emission costs ($2/ton initially, then scaling to $50/ton by 2020) and the adoption of an RPS in Florida. At this time, natural gas prices are projected at $4.40/MMBTU in 2014, there is no current federal pricing for CO2 emissions, and no RPS legislation has been enacted. Therefore, current market conditions do not favor the development of renewable generation.

Even with these difficulties, Florida's renewable generation is projected to increase over the planning period. Renewable generation contributes to the state's fuel diversity and reduces dependence on fossil fuels. While current economic conditions may prevent more expensive forms of renewable generation, those cost-effective forms of renewable generation will continue to increase the state's share of renewable generation.

Traditional Generation

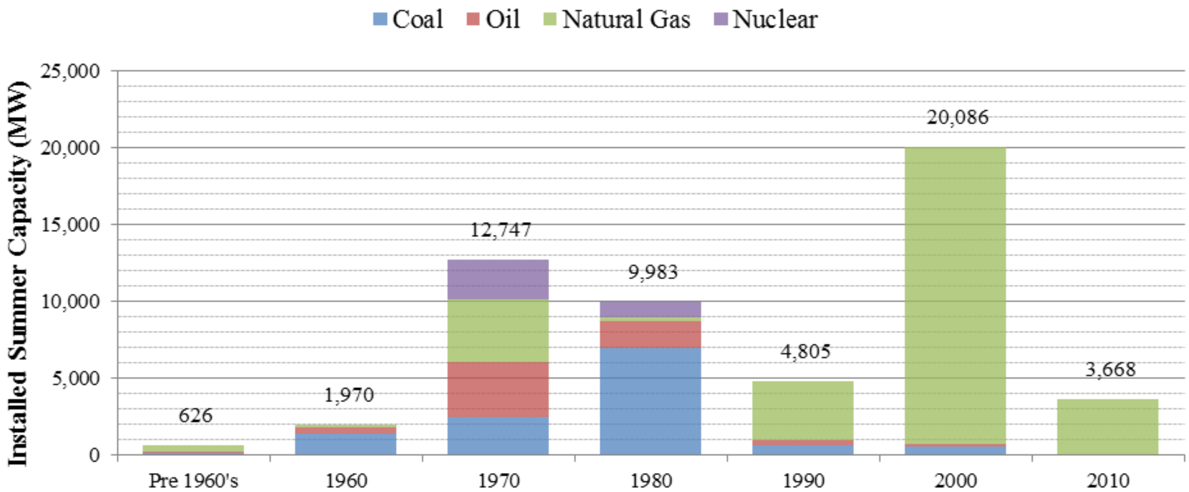
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and turbine generators that have been added to Florida's electric grid over the last several decades. Due to forecasted 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 to 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 11 below, illustrates the decade currently operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

Figure 11: Florida Electric Utility Installed Capacity by Decade



Source: 2014 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 emissions 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. This rule was proposed by the EPA on June 18, 2014, and has not yet been finalized.

- 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 proposed this rule on June 18, 2014, and anticipates finalizing it by June 2015, with state plans to be filed by June 2016, with possible one-year extensions. The Commission has sought comments from interested parties to be filed with the EPA, which has extended the period to file comments until December 1, 2014.

- 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 April 15, 2014, U.S. Court of Appeals for the D.C. Circuit fully upheld the rule. This decision will not become active, however, until all appeals have been resolved.

- 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 April 29, 2014, the U.S. Supreme Court upheld the rule by a 6-2 vote. On June 26, 2014, EPA asked the U.S. Court of Appeals for the D.C. Circuit to lift its stay on the rule. The court has not yet acted on this request, and it is not clear at this time if or when the stay will be lifted.

- 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). On May 28, 2014, the final rule was published in the *Federal Register*.

- Coal Combustion Residuals (CCR) - Requires liners and ground monitoring to be installed on new landfills in which coal ash is deposited. A Consent Decree, filed January 29, 2014, in the U.S. District Court for the District of Columbia, requires EPA to publish notice of a final action by December 19, 2014.

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. DEF plans to upgrade the capacity of its Hines combined cycle units by installing chiller modules.

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 10 below, lists the 4,252 MW of existing generation that is scheduled to be retired during the planning period and a majority of which is 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 10: Electric Generating Units to be Retired

Year	Utility Name	Plant Name & Unit Number	Unit Type	Fuel Type	Net Summer Capacity (MW)
2014	NSB	Smith (3-4,6-11)	Internal Combustion	Oil	13
2014	NSB	Swoope Station (2-4)	Internal Combustion	Oil	5
2014	DEF	G. E. Turner P3	Combustion Turbine	Oil	53
2014	JEA	Girvin Landfill	Internal Combustion	Landfill Gas	1
				2014 Subtotal	72
2015	FPL	Municipal Plant 1 & 3-4	Steam	Natural Gas	94
2015	JEA	Northside	Steam	Natural Gas	524
2015	TAL	Hopkins GT1	Combustion Turbine	Natural Gas	12
2015	TAL	Purdom GT1&2	Combustion Turbine	Natural Gas	20
2015	FPL	Putnam 1 & 2	Combined Cycle	Natural Gas	498
2015	GULF	Scholz 1 & 2	Steam	Coal	92
				2015 Subtotal	1,240
2016	DEF	Avon Park P2	Combustion Turbine	Oil	24
2016	DEF	Rio Pinar P1	Combustion Turbine	Oil	12
2016	DEF	G. E. Turner P1&2	Combustion Turbine	Oil	20
2016	DEF	Avon Park	Combustion Turbine	Natural Gas	24
				2016 Subtotal	80
2017	FPL	Turkey Point 1	Steam	Oil	396
2017	TAL	Hopkins GT2	Combustion Turbine	Natural Gas	24
				2017 Subtotal	420
2018	DEF	Crystal River 1 & 2	Steam	Coal	740
2018	DEF	Suwannee River 1-3	Steam	Natural Gas	128
2018	GPC	Pea Ridge 1-3	Combustion Turbine	Natural Gas	12
2018	FPL	Lauderdale 1-24	Combustion Turbine	Natural Gas	840
2018	FPL	Port Everglades 1-12	Combustion Turbine	Natural Gas	420
2018	FPL	Municipal Plant 2&5	Combined Cycle	Natural Gas	44
				2018 Subtotal	2,184
2020	DEF	Higgins P1-4	Combustion Turbine	Natural Gas	105
2020	TAL	Hopkins	Steam	Natural Gas	76
				2020 Subtotal	181
2022	GRU	Deerhaven	Steam	Natural Gas	75
				2022 Subtotal	75
				Total Retirements	**4,252**

Source: 2014 FRCC Load & Resource Plan, 2014 Ten-Year Site Plans

JEA’s Northside 5, a natural gas and oil-fired steam unit, was scheduled for retirement in 2019 in the utility’s Ten-Year Site Plan, but subsequently JEA announced that the retirement would be accelerated by four years to 2015.

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. 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 forecasted customer demand, referred to as the reserve margin.

Electric utilities within the FRCC 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.

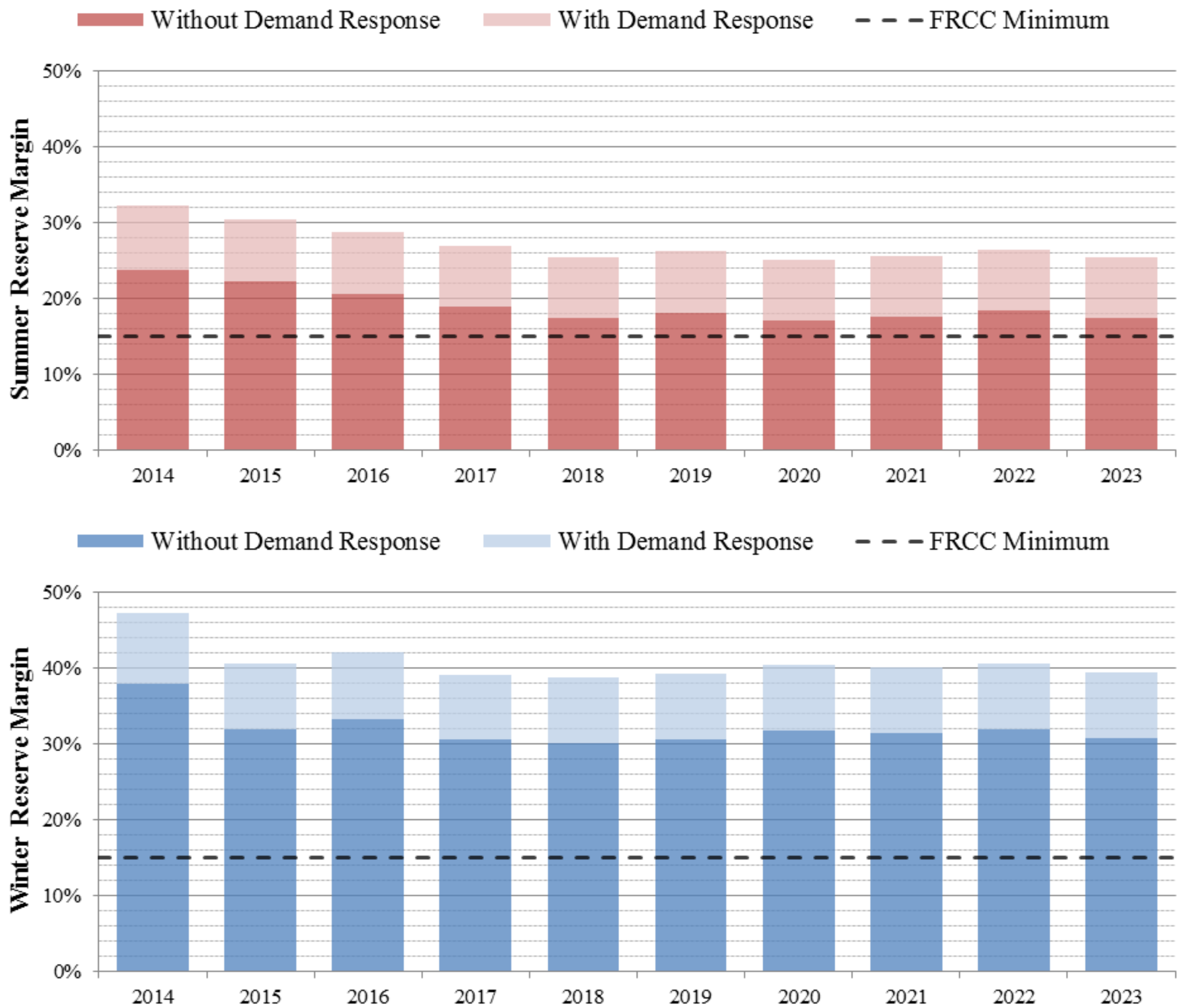
While Florida’s electric utilities are separately responsible for maintaining an adequate planning reserve margin, a statewide view illustrates the degree to which capacity may be available for purchases during periods of high demand or unit outages. Figure 12 below, is a projection of the statewide seasonal reserve margin including all proposed power plants.

<u>Role of Demand Response in Reserve Margin</u>

The Commission also considers the planning reserve margin without demand response. As illustrated in Figure 12 below, 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 the 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 hours, but are more frequently called upon during off-peak periods due to other reliability concerns. This trend is assumed to continue during the planning period.

Figure 12: State of Florida Reserve Margin with New Units

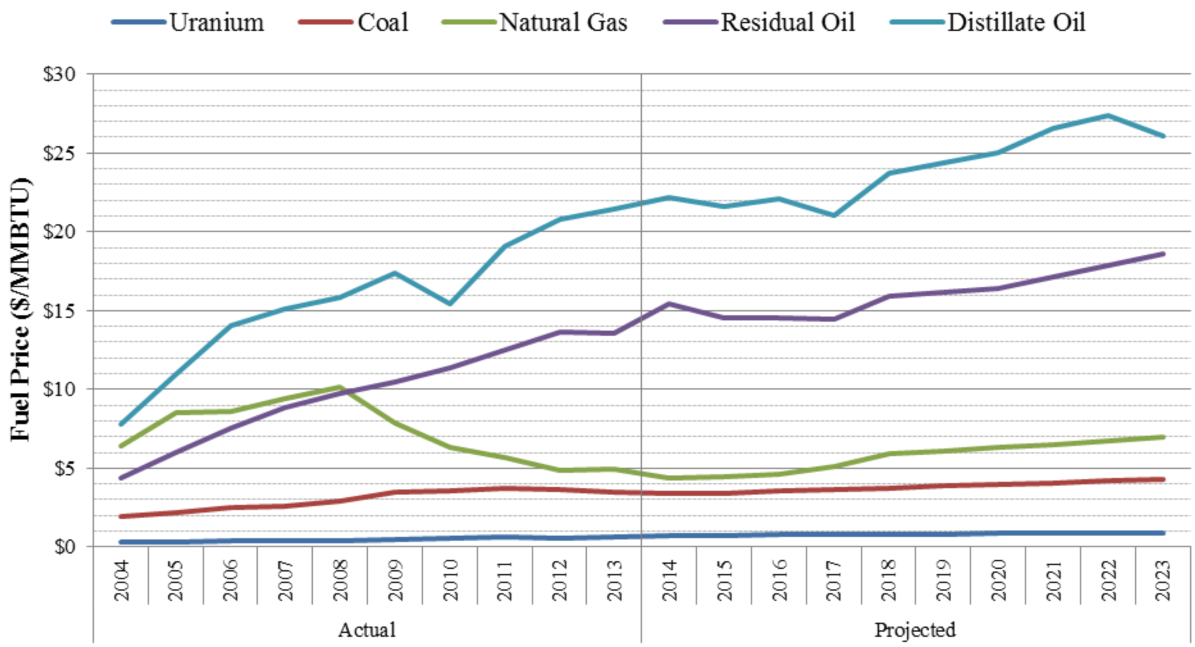


Source: 2014 FRCC Load & Resource Plan

Fuel Price Forecast

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. However, fuel price is an important economic factor affecting the dispatch of the existing generating fleet and the selection of new generating units. The major fuels consumed by Florida's electric utilities are natural gas, coal, uranium, and oil. Figure 13 below, illustrates the weighted average fuel price history and forecasts for the reporting electric utilities.

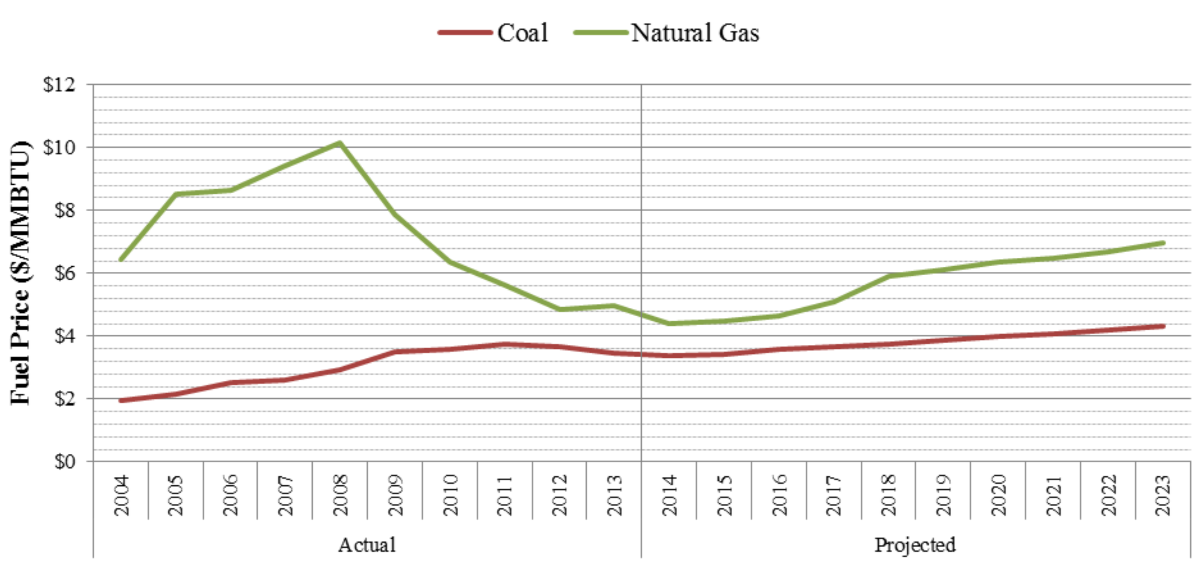
Figure 13: Average Reporting Electric Utility Fuel Price



Source: 2014 TYSP Utilities Data Responses

As Figure 14 below, shows the price of natural gas declined rapidly after the financial crisis, and is forecasted to remain near historically low levels. The smaller differential and higher efficiency of natural gas has shifted the dispatch order, with natural gas units displacing 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 14: Fuel Price Comparison for Coal and Natural Gas

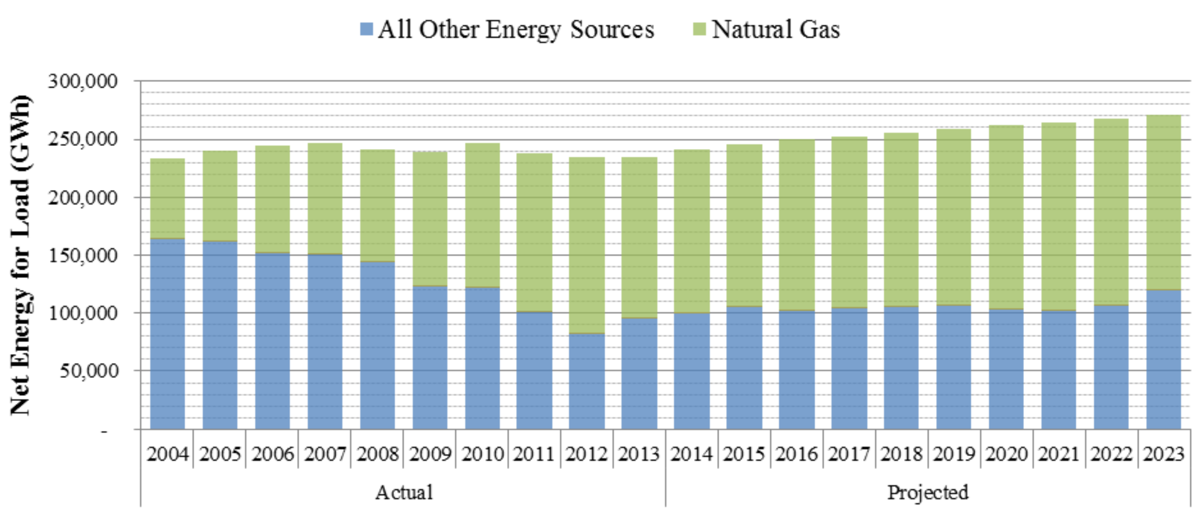


Source: 2014 TYSP Utilities Data Responses

Fuel Diversity

The volatility of natural gas in the early 2000s led to concern regarding escalating customer bills and an expectation that natural gas prices would remain high. While Florida's electric utilities made 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 cancellation of new coal-fired generation. Traditionally, coal was the lowest cost fuel besides nuclear and was dispatched before most natural gas-fired units. Natural gas has since 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 15 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 natural gas usage was associated with extended outages at FPL's nuclear plants for uprates, with gas usage decreasing as the nuclear units returned to operation. Natural gas generation is anticipated to serve future growth until the end of the planning period, when additional nuclear generation comes online.

Figure 15: Natural Gas Contribution to Florida Energy Consumption

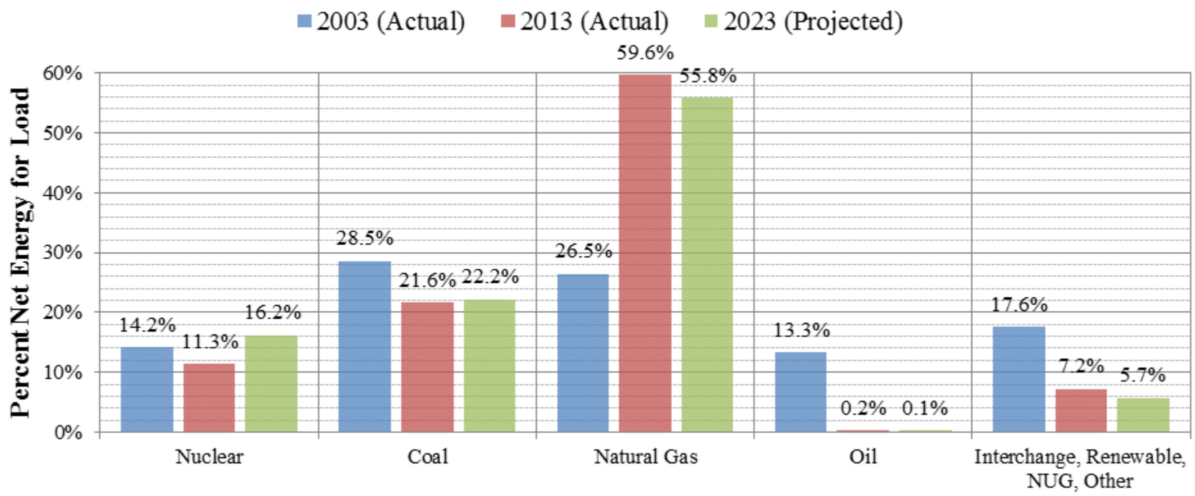


Source: 2005-2014 FRCC Load & Resource Plans

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

Figure 16 below, shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2003 and 2013, and forecast year 2023. 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 uprates of Florida's four remaining nuclear units were completed by 2013, and added approximately 520 MW of capacity, reducing the impact of the loss of Crystal River 3. While coal generation has declined somewhat, it is expected to rebound slightly and remain at a plateau throughout the planning period. This rebound was based upon the Utility's filings before the announcement of the EPA's Clean Power Plan. The 2015 Ten-Year Site Plans should include some considerations of the potential impacts of this regulation on each utility's fuel consumption. 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 16: Florida Historic and Forecast Fuel Consumption



Source: 2005-2014 FRCC Load & Resource Plans

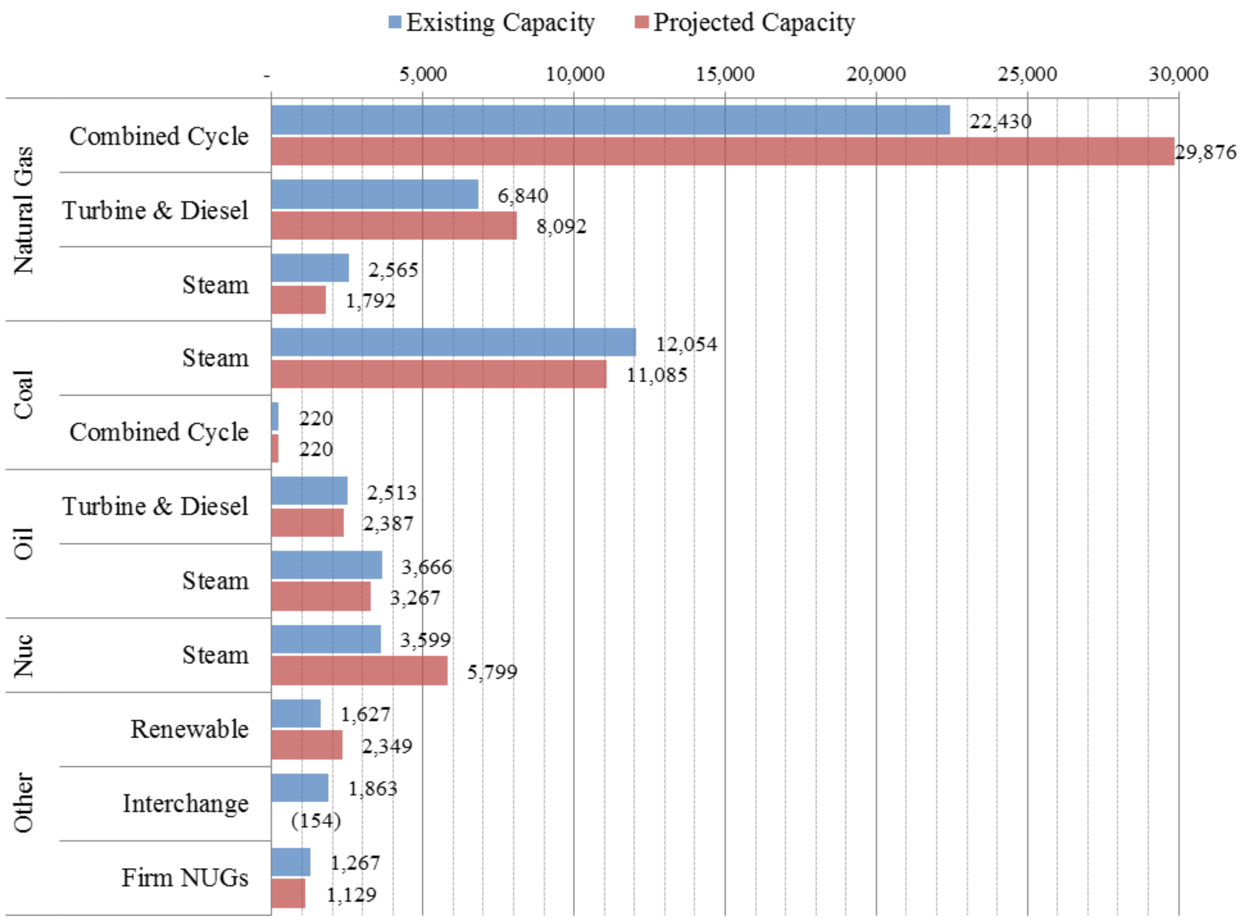
New Generation Planned

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.

Figure 17 below, illustrates the present and future aggregate capacity mix. The capacity values in Figure 17 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2014 Ten-Year Site Plans and the FRCC's 2014 Load and Resource Plan.

Figure 17: Florida Current and Projected Installed Capacity by Fuel and Technology



Source: 2014 FRCC Load & Resource Plan and TYSP Utilities Data Responses

New Power Plants by Fuel Type

<u>Nuclear</u>

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. Only a single Florida electric utility, FPL, is projecting additional nuclear power plants during the planning period. Table 11 below, lists the two new nuclear units anticipated in the planning period, Turkey Point Units 6 and 7. FPL had previously uprated its existing four nuclear generating units, with the last uprate completed in early 2013. While DEF had previously projected the addition of two nuclear units, Levy Units 1 and 2, it has discontinued this project but continues its efforts to obtain a combined operating license from the Nuclear Regulatory Commission.

Table 11: Planned Nuclear Units

In-Service Year	Utility Name	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	
				Sum	Win
2022	FPL	Turkey Point 6	Nuclear Steam	1,100	1,100
2023	FPL	Turkey Point 7	Nuclear Steam	1,100	1,100

Source: 2014 Ten-Year Site Plans

Natural Gas

All remaining new utility-owned power plants are natural gas-fired combustion turbines or combined cycle units. Natural gas-fired combined cycle units represent 39.1 percent of installed capacity in 2013. Combustion turbines, which 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, they do not require siting under the Power Plant Siting Act. Table 12 below, lists the approximate 10,363 MW net summer capacity of proposed new natural gas-fired generation included in the 2014 Ten-Year Site Plans.

Table 12: Planned Natural Gas Units

In-Service Year	Utility Name	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	
				Sum	Win
2014	FPL	Riviera Beach	Combined Cycle	1,212	1,344
2016	FPL	Port Everglades	Combined Cycle	1,237	1,346
2017	TECO	Polk	Combined Cycle	459	463
2018	DEF	Citrus	Combined Cycle	1,640	1,820
2019	FPL	Unsited	Combined Cycle	1,269	1,429
2020	SEC	Unsited	Combined Cycle	440	523
2021	DEF	Unsited	Combined Cycle	793	866
			Combined Cycle Subtotal	7,050	7,791
2016	DEF	Suwannee River 3 & 4	Combustion Turbine	316	375
2019	FPL	Lauderdale CT1-5	Combustion Turbine	1,005	1,000
2020	TAL	Hopkins 5	Combustion Turbine	46	48
2020	TECO	Future CT1	Combustion Turbine	190	220
2020	SEC	Unsited CT 1 & 2	Combustion Turbine	402	450
2021	SEC	Unsited CT 3-7	Combustion Turbine	1,005	1,125
2023	GPC	Unsited CT	Combustion Turbine	349	360
			Combustion Turbine Subtotal	3,313	3,578
			Total Planned Natural Gas Units	**10,363**	**11,369**

Source: 2014 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 (PPSA) at Section 403.519, F.S. Any proposed steam or solar generating unit of at least 75 MW requires a certification under the PPSA. Upon receipt of a determination of need, the electric utility would then seek approval from the Florida Department of Environmental Protection, which addresses land use and environmental concerns. Finally, the Governor and Cabinet, sitting as the Siting Board, must approve or deny the overall certification of a proposed power plant.

Approximately 12,565 MW of new utility-owned generating units are planned to enter service over the next ten-year period, with 74 percent of that capacity, 9,250 MW, subject to the PPSA. However, a majority of the proposed units have already received a determination of need from the Commission. The Commission most recently approved the determination of need for DEF's proposed Citrus plant, which will still have to seek approval from DEP and the Siting Board. A total of 2,502 MW still requires a determination of need, as shown in Table 13 below.

Table 13: Planned Units Requiring a Determination of Need

In-Service Year	Utility Name	Plant Name & Unit Number	Unit Type	Net Capacity (MW)		Notes
				Sum	Win	
2018	DEF	Citrus	Combined Cycle	1,640	1,820	See Order No. PSC-14-0557-FOF-EI
2019	FPL	Unsited	Combined Cycle	1,269	1,429	
2020	SEC	Unsited	Combined Cycle	440	523	
2021	DEF	Unsited	Combined Cycle	793	866	

Source: 2014 Ten-Year Site Plans

Transmission

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. 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 sole jurisdiction to determine the need for new electric transmission lines by the Legislature through the Florida Electric Transmission Line Siting Act (TLSA) at Section 403.537, 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 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 DEP 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 14 below, lists all proposed transmission lines in the 2014 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 14 : Planned Transmission Lines

Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
FPL	Manatee – Bobwhite	30	230	8/28/2006	11/06/2008	12/01/2014
FPL	St Johns – Pringle	25	230	5/13/2005	4/01/2006	12/01/2018
TECO	Thonotosassa - Wheeler	8	230	6/22/2007	8/08/2008	TBD
TECO	Wheeler - Willow Oak	17	230	6/23/2007	8/09/2008	TBD

Source: 2014 Ten-Year Site Plans

UTILITY PERSPECTIVES

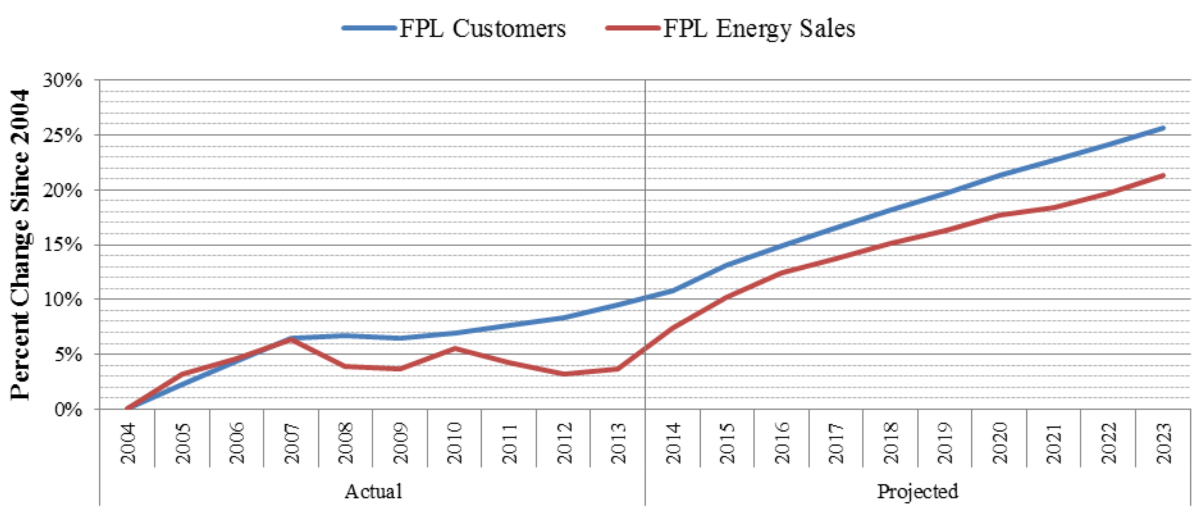
Florida Power & Light Company (FPL)

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 2014 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2013, FPL had approximately 4,627,000 customers and annual retail energy sales of 102,784 GWh, or approximately 47.4 percent of Florida's annual retail energy sales. Figure 18 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2004. Over the last ten years, FPL's customer base has increased by 9.5 percent, while retail sales have grown by only 3.7 percent. Since 2009, FPL has been outperforming the state average in retail energy sale growth, a trend it projects to continue into the future. As illustrated below, retail energy sales are anticipated to exceed their historic 2007 peak in 2014, three years faster than the state as a whole. This forecast includes FPL's acquisition of the Vero Beach electric system beginning in 2015, which is estimated to represent 0.6 percent of FPL's 2023 net energy for load.

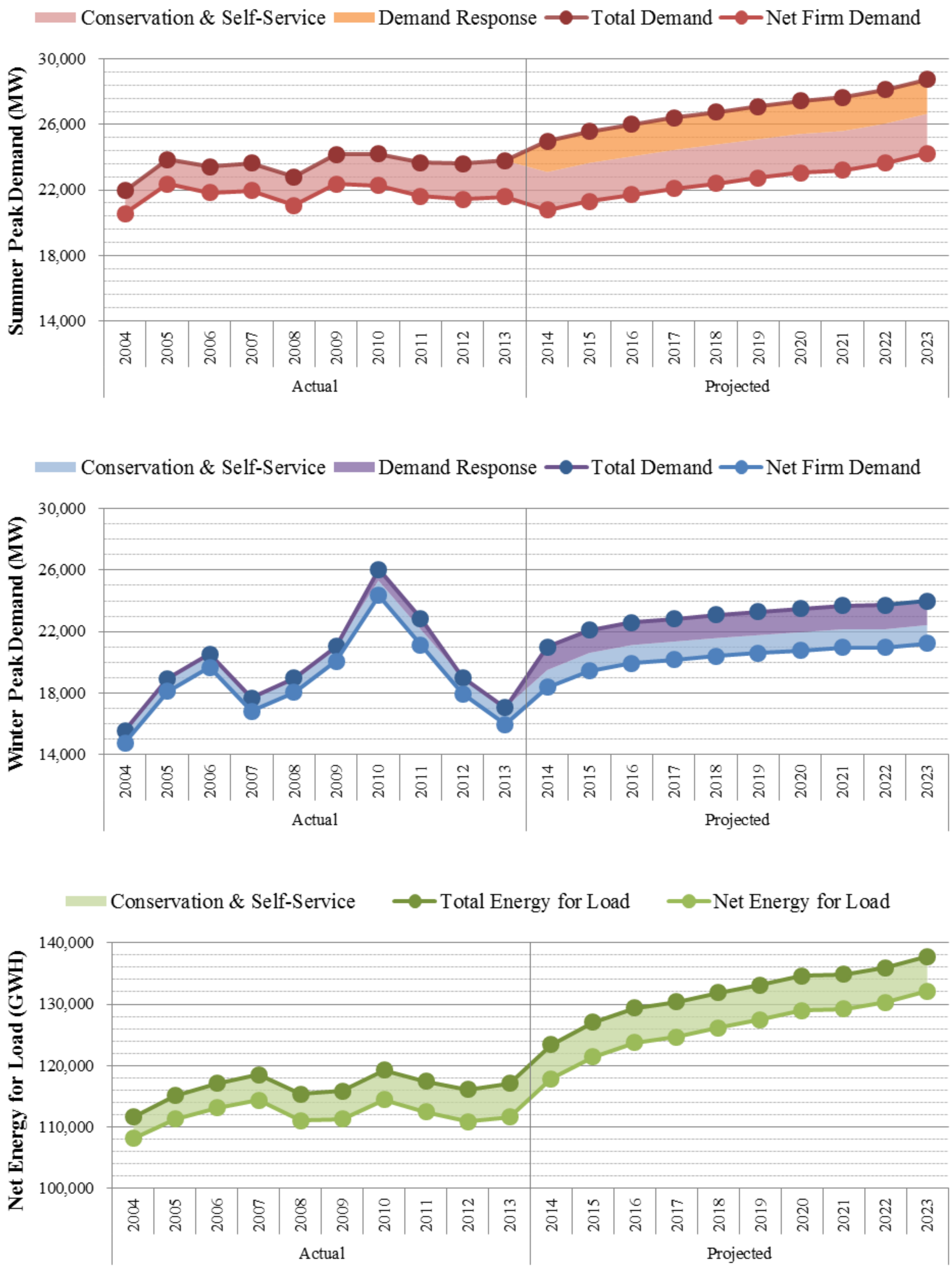
Figure 18: FPL Growth Rate



Source: 2014 Ten-Year Site Plan

The three graphs in Figure 19 below, shows FPL's seasonal peak demand and net energy for load for the historic years of 2004 through 2013 and forecast years 2014 through 2023. 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.

Figure 19: FPL Demand and Energy Forecasts



Source: 2014 Ten-Year Site Plan and Data Responses

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. For planning purposes, FPL utilized its proposed demand-side management goals for the forecast period. The utility's 2015 Ten-Year Site Plan should include revised values that would reflect the Commission's decision in the currently open FEECA goal-setting Docket No. 130199-EI.

Fuel Diversity

Table 15 below, shows FPL's actual net energy for load by fuel type as of 2013, and the projected fuel mix for 2023. FPL relies primarily upon natural gas and nuclear for energy generation, making up approximately 90 percent of net energy for load.

Table 15: FPL Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2013		2023	
	GWh	%	GWh	%
Natural Gas	75,208	**67.4%**	76,379	**57.7%**
Coal	5,981	**5.4%**	6,779	**5.1%**
Nuclear	25,243	**22.6%**	42,915	**32.4%**
Oil	196	**0.2%**	123	**0.1%**
Renewable	155	**0.1%**	192	**0.1%**
Interchange	4,445	**4.0%**	0	**0.0%**
NUG & Other	428	**0.4%**	5,968	**4.5%**
Total	**111,656**		**132,356**	

Source: 2014 Ten-Year Site Plan and Data Responses

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 20 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 20: FPL Reserve Margin Forecast

Source: 2014 Ten-Year Site Plan

Proposed Third Reliability Requirement

In addition to these two reliability indices, FPL is proposing in its 2014 Ten-Year Site Plan to introduce a third reliability criterion. FPL's proposed requirement 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 has proposed a similar 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 proposes to not include incremental energy efficiency resources and cumulative demand response in its resource planning for the proposed metric, 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 expresses an over-reliance upon demand response will result in frequent customer interruptions, which will in turn, cause customers to end their voluntary participation, which could negatively impact reliability. FPL addresses this concern for large commercial and industrial customers by including minimum noticing requirements for customers to leave the CILC and CDR tariffs. Customers must provide five years notice before the customer is able to end participation, excluding special provisions. This is sufficient time for a utility to plan a unit to provide firm capacity. In contrast, the Residential On-Call and Business On-Call programs have only a seven day advanced notice requirement. However, each individual customer’s demand reduction for these programs is much smaller.

As previously noted, FPL has historically not activated demand response customers during seasonal peaks, excluding two winter peaks in which only CILC and CDR customers were activated. Regardless of whether or not demand response capacity is activated, participants receive bill credits or discounted rates. It should be noted that peak reductions during annual peaks, which is the focus of a reserve margin, are not the only use for demand response. In fact, FPL reports a total of 144 activations within the past ten years of its demand response resources, with an average 11 activations per summer and 4 activations per winter. Only seven of the 144 activations included CILC and CDR participants.

While FPL’s proposed generation-only reserve margin would increase the amount of capacity required for all years of the planning period, based upon the timing of other unit additions, it is the controlling factor for two years of the ten-year planning period. In 2020 and 2021, FPL would increase firm capacity purchases by 113 MW and 130 MW, respectively, to meet the proposed metric. At this time, FPL has not yet entered into purchased power agreements for this additional capacity. Without these additional purchases, FPL's generation only reserve margin, excluding demand response and incremental energy efficiency would be 9.6 percent in 2020 and 9.5 percent in 2021. During the years of 2020 and 2021, the statewide summer reserve margin would be in excess of 17 percent without activating demand response, so it is likely that additional power would be available for purchase in case of high demand.

As part of FEECA, the Commission annually publishes a report on the accomplishments of the FEECA Utilities, of which FPL is one, towards meeting conservation goals established by the Commission. The Commission monitors and tracks the anticipated and actual program participation and savings associated with the utility's conservation programs, including energy efficiency and demand response. If participation in a program is less than anticipated, the utility has the opportunity to respond by modifying the program. This annual review mechanism would therefore alert the Commission if a utility were not meeting its conservation goals and allow steps to be taken to adjust as necessary.

At this time, while FPL has noted its use of this metric in several dockets before the Commission, the utility has not requested approval to use this metric or its value, nor does the Commission's suitability finding of FPL's 2014 Ten-Year Site Plan constitute approval. The Commission will have an opportunity to review FPL's proposed metric if it becomes a controlling factor for a determination of need of a new electrical power plant.

Generation Resources

FPL plans multiple unit retirements and additions during the planning period, as described below in Table 16. Three dozen of the retirements are small natural gas-fired combustion turbines used as peakers, to be replaced by five new units that will offer superior efficiency and emissions profiles. FPL's 2014 Ten-Year Site Plan includes the acquisition of Vero Beach's generating units, which are all planned for retirement by 2018. Lastly, FPL is converting Turkey Point 1 to operate as a synchronous condenser to support the transmission system in South Florida.

In addition to the peaking units discussed above, FPL included the addition of three new natural gas-fired combined cycle units and two new nuclear steam units. Only one of the combined cycles has yet to receive a determination of need from the Commission, with a filing anticipated sometime during 2015.

Table 16: FPL Unit Retirements and Additions

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)		Notes
			Sum	Win	
Retiring Units					
Oil					
2017	Turkey Point 1	Steam	396	398	Synchronous Condenser
Natural Gas					
2015	Municipal Plant 1 & 3-4	Steam	94	98	From Vero Beach
2015	Putnam 1 & 2	Combined Cycle	498	529	
2018	Lauderdale 1-24	Combustion Turbine	840	917	
2018	Port Everglades 1-12	Combustion Turbine	420	458	
2018	Municipal Plant 2&5	Combined Cycle	44	46	From Vero Beach
New Units					
Natural Gas					
2014	Riviera Beach Energy Center	Combined Cycle	1,212	1,344	In Service
2016	Port Everglades Modernization	Combined Cycle	1,237	1,346	Previously Approved
2019	Unsited Combined Cycle	Combined Cycle	1,269	1,429	Requires Approval
2019	Lauderdale CT1-5	Combustion Turbine	1,005	1,000	
Nuclear					
2022	Turkey Point 6	Steam	1,100	1,100	Previously Approved
2023	Turkey Point 7	Steam	1,100	1,100	Previously Approved

Source: 2014 Ten-Year Site Plan and Data Responses

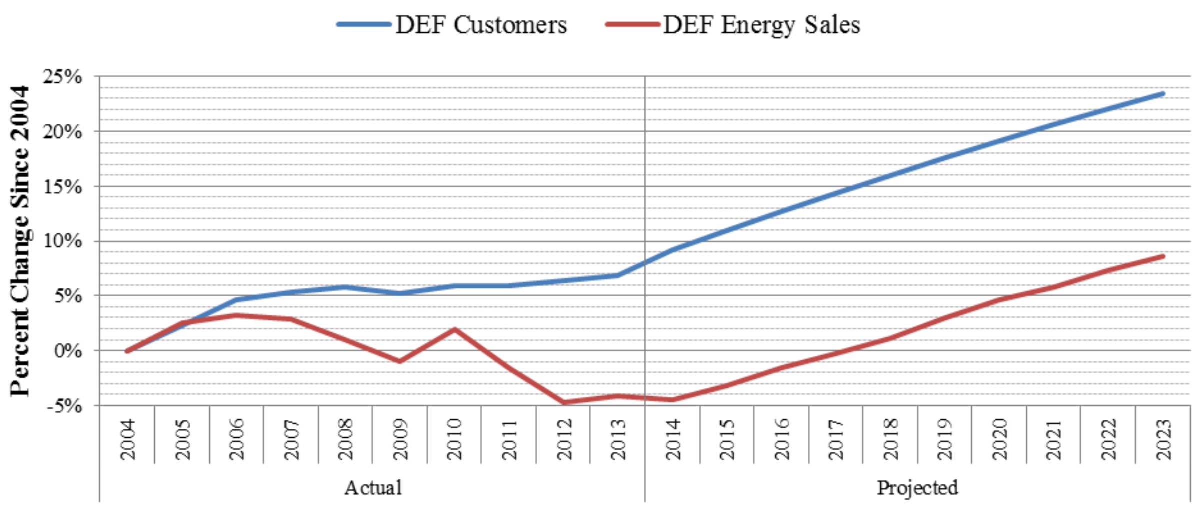
Duke Energy Florida, Inc. (DEF)

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 2014 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2013, DEF had approximately 1,657,000 customers and annual retail energy sales of 36,616 GWh, or approximately 16.9 percent of Florida's annual retail energy sales. Figure 21 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2004. 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 below, retail energy sales are anticipated to exceed the historic 2006 peak by 2020, three years later than the state as a whole.

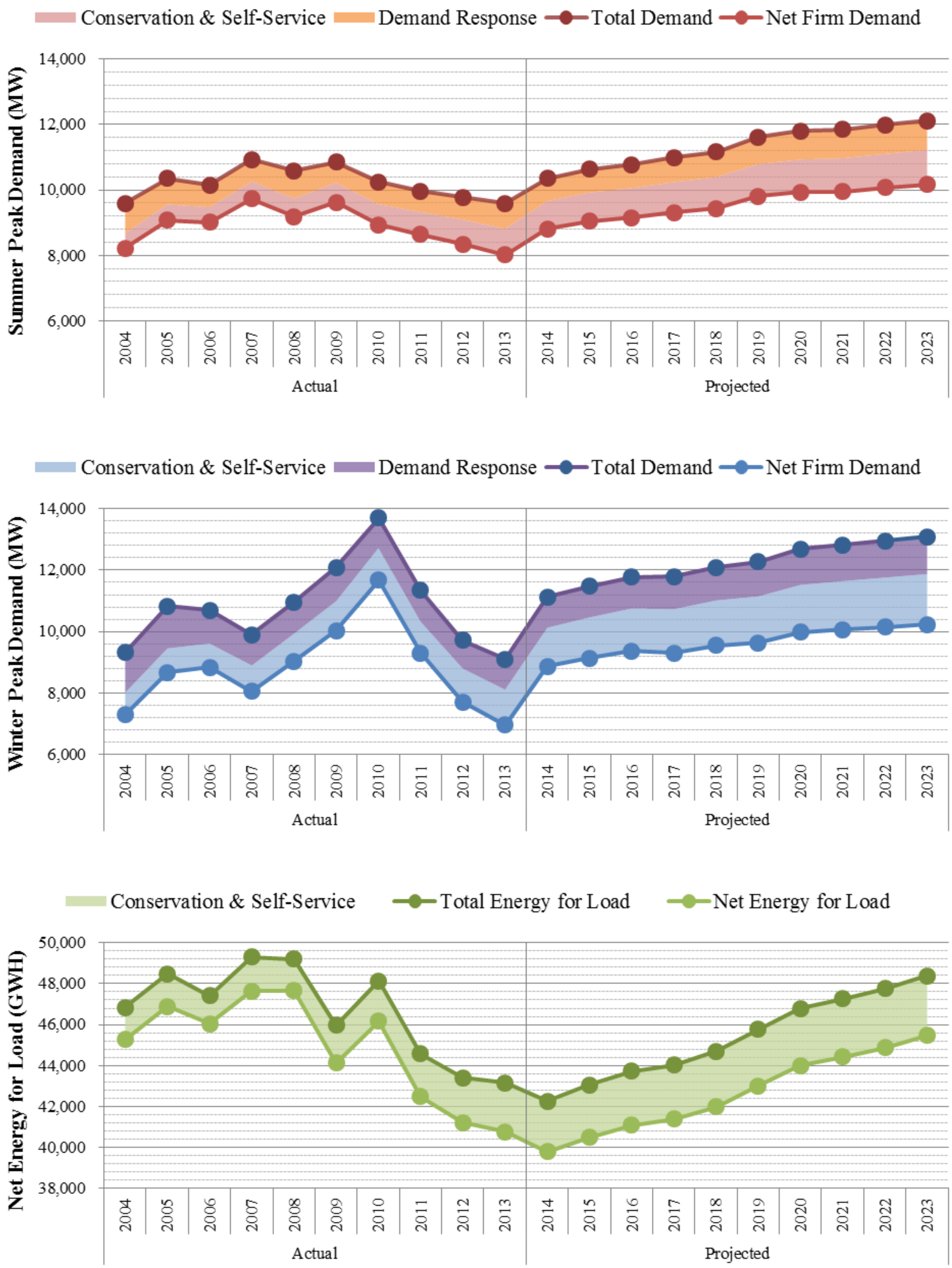
Figure 21: DEF Growth Rate



Source: 2014 Ten-Year Site Plan

The three graphs in Figure 22 below, show DEF's seasonal peak demand and net energy for load for the historic years of 2004 through 2013 and forecast years 2014 through 2023. 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. DEF based its estimated conservation values off of its existing demand-side management portfolio. The utility's 2015 Ten-Year Site Plan should include revised values that would reflect the Commission's decision in the currently open FEECA goal-setting docket.

Figure 22: DEF Demand and Energy Forecasts



Source: 2014 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 17 below, shows DEF's actual net energy for load by fuel type as of 2014 and the projected fuel mix for 2023. 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 17: DEF Energy Consumption by Fuel Type

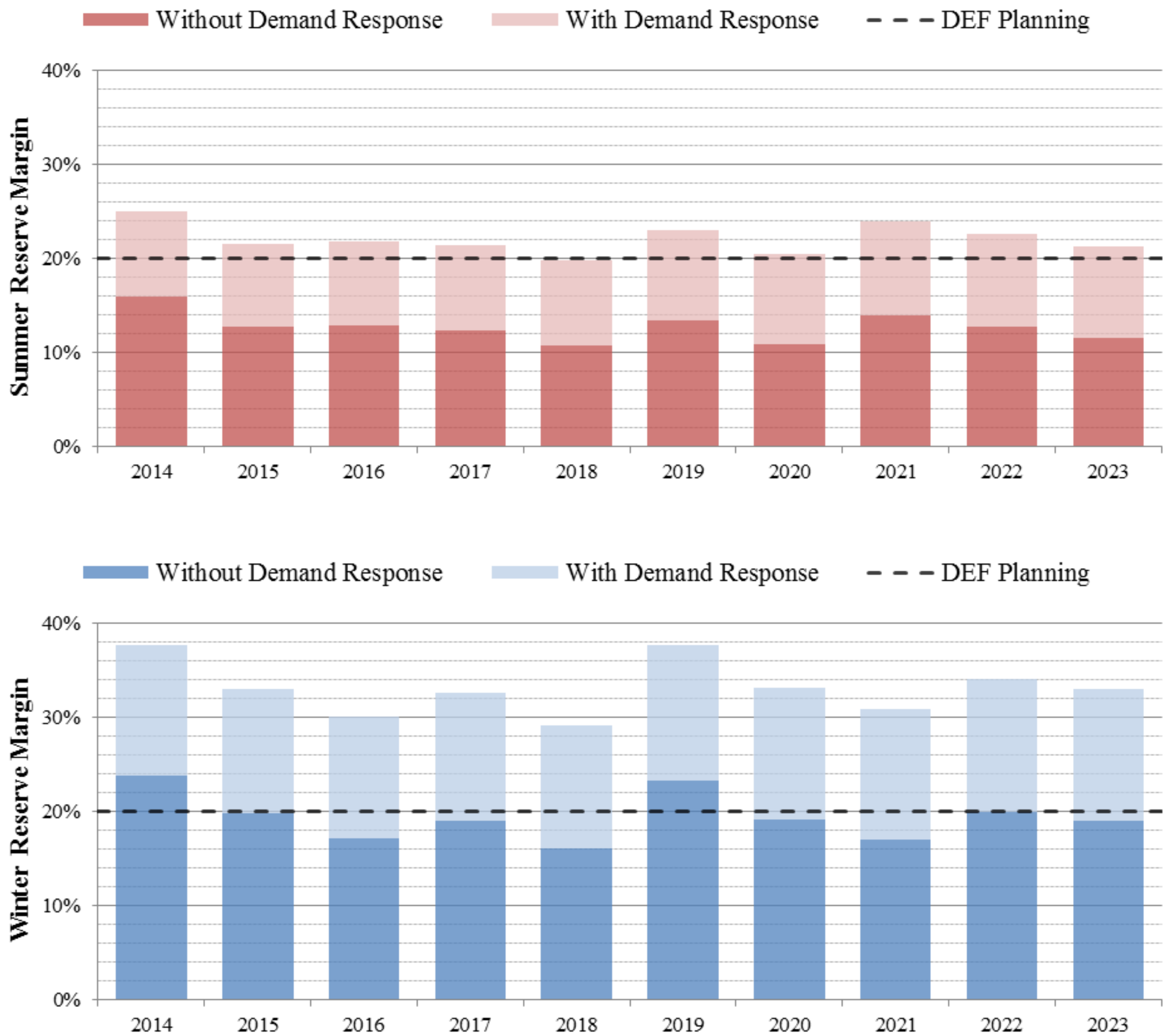
Fuel Type	Net Energy for Load			
	2013		2023	
	GWh	%	GWh	%
Natural Gas	23,061	**56.6%**	35,370	**77.8%**
Coal	10,577	**25.9%**	6,585	**14.5%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	220	**0.5%**	57	**0.1%**
Renewable	1,132	**2.8%**	1,256	**2.8%**
Interchange	1,409	**3.5%**	687	**1.5%**
NUG & Other	4,373	**10.7%**	1,505	**3.3%**
Total	**40,772**		**45,459**	

Source: 2014 Ten-Year Site Plan and Data Responses

Reliability Requirements

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



Source: 2014 Ten-Year Site Plan

Generation Resources

DEF plans multiple unit retirements and additions during the planning period, as described below in Table 18. DEF's 2014 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. DEF's Plan also includes the addition of two combustion turbines at the Suwannee River plant site, but this is subject to change based upon the outcome of a potential purchase of merchant capacity.

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 18: DEF Unit Retirements and Additions

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)		Notes
			Sum	Win	
Retiring Units					
Coal					
2018	Crystal River 1 & 2	Steam	740	743	
Oil					
2014	G. E. Turner P3	Combustion Turbine	53	77	
2016	Avon Park P2	Combustion Turbine	24	35	
2016	Rio Pinar P1	Combustion Turbine	12	15	
2016	G. E. Turner P1&2	Combustion Turbine	20	26	
Natural Gas					
2016	Avon Park	Combustion Turbine	24	35	
2018	Suwannee River 1-3	Steam	128	129	
2020	Higgins P1-4	Combustion Turbine	105	116	
New Units					
Natural Gas					
2016	Suwannee River	Combustion Turbine	316	375	Docket No. 140111-EI
2018	Citrus Combined Cycle	Combined Cycle	1,640	1,820	Docket No. 140110-EI
2021	Unsited Combined Cycle	Combined Cycle	793	866	Requires Approval

Source: 2014 Ten-Year Site Plan

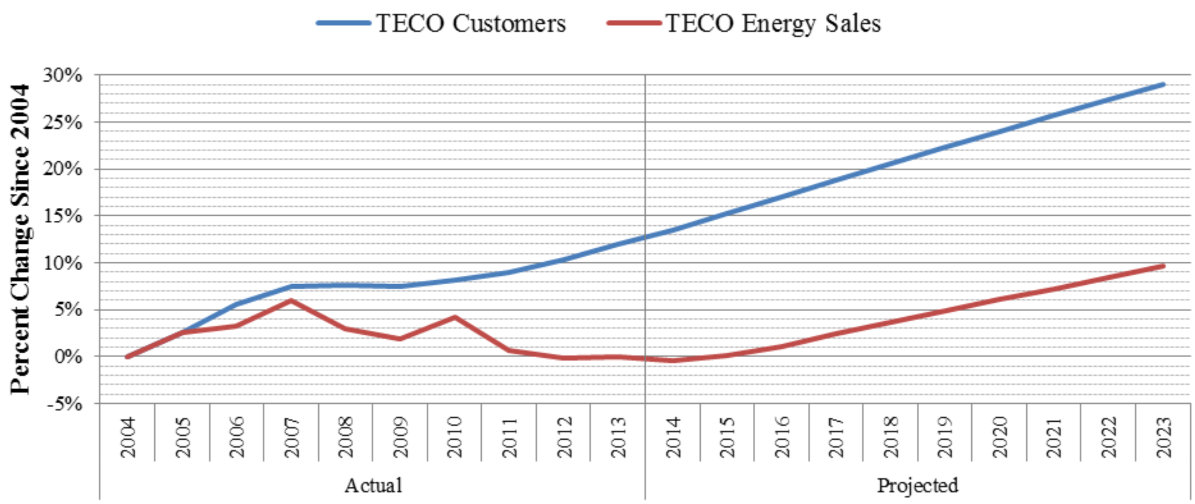
Tampa Electric Company (TECO)

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 2014 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2013, TECO had approximately 695,000 customers and annual retail energy sales of 18,418 GWh, or approximately 8.5 percent of Florida's annual retail energy sales. Figure 24 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2004. Over the last ten years, TECO's customer base has increased by 12.01 percent, while retail sales have declined by 0.10 percent. As illustrated below, retail energy sales are anticipated to exceed the historic 2007 peak by 2020, three years later than the state as a whole.

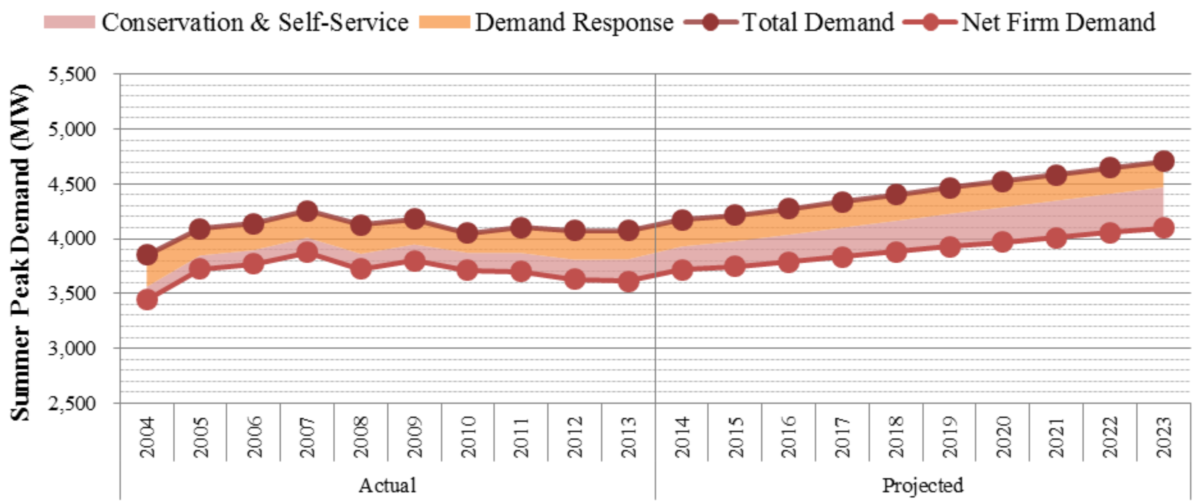
Figure 24: TECO Growth Rate

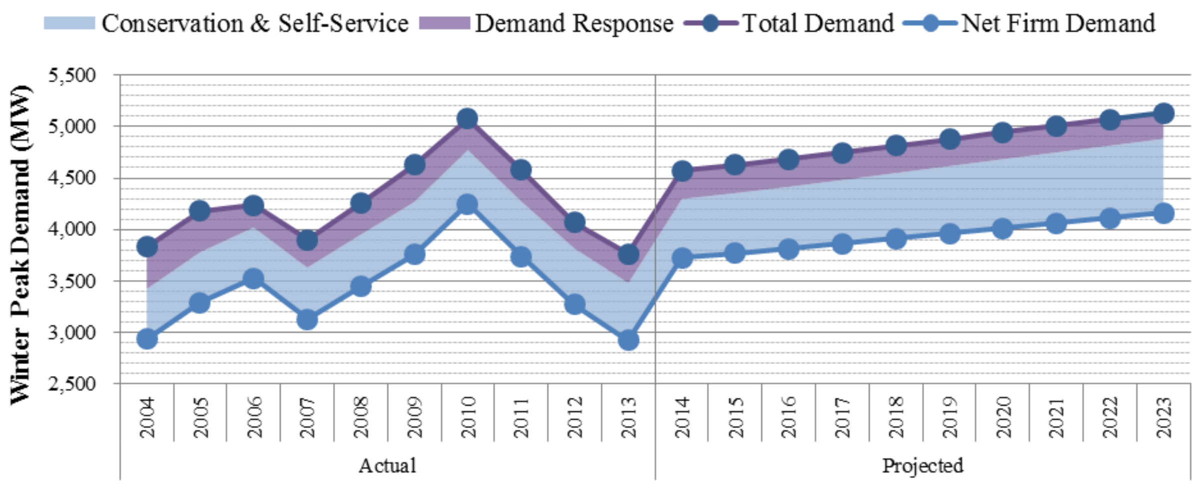


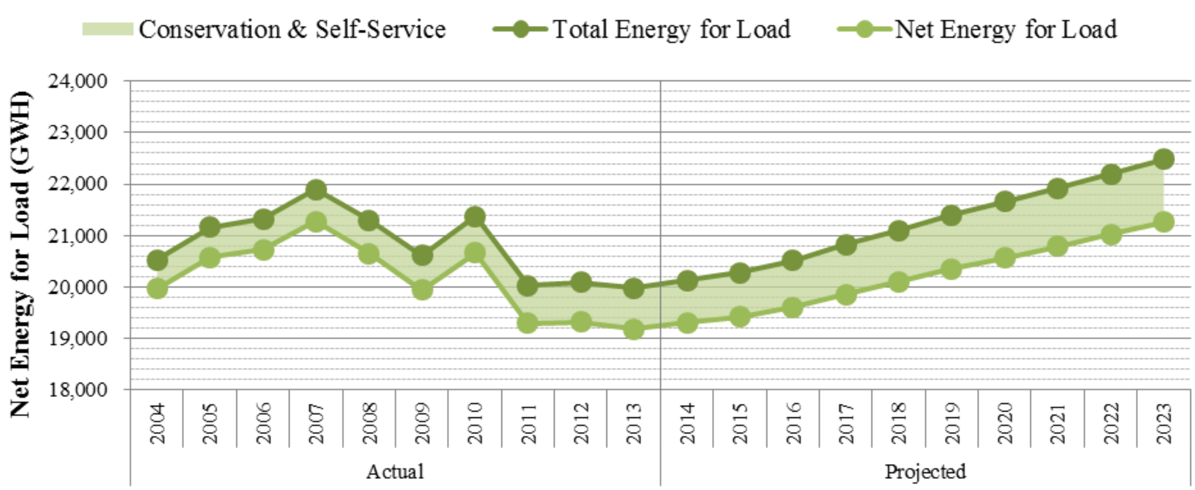
Source: 2014 Ten-Year Site Plan

The three graphs in Figure 25 below, shows TECO's seasonal peak demand and net energy for load for the historic years of 2004 through 2013 and forecast years 2014 through 2023. These graphs include the full impact of demand-side management, and assume that all available demand response resources were or will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand excluding extreme weather events.

Figure 25: TECO Demand and Energy Forecasts







Source: 2014 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 should include revised values that would reflect the Commission's decision in the currently open FEECA goal-setting docket.

Fuel Diversity

Table 19 below, shows TECO's actual net energy for load by fuel type as of 2014 and the projected fuel mix for 2023. TECO uses coal for a majority of energy generation, and based on the 2014 Ten-Year Site Plan, energy from coal is anticipated to be 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.

Table 19: TECO Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2013		2023	
	GWh	%	GWh	%
Natural Gas	7,601	**39.6%**	9,009	**42.4%**
Coal	9,647	**50.3%**	10,650	**50.1%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	8	**0.0%**	0	**0.0%**
Renewable	0	**0.0%**	0	**0.0%**
Interchange	200	**1.0%**	0	**0.0%**
NUG & Other	1,720	**9.0%**	1,604	**7.5%**
Total	**19,177**		**21,263**	

Source: 2014 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion. TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 26 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 26: TECO Reserve Margin Forecast

Source: 2014 Ten-Year Site Plan

Generation Resources

TECO plans a pair of unit additions during the planning period, as described below in Table 20. 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 2020.

Table 20: TECO Unit Additions

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)		Notes
			Sum	Win	
New Units					
Natural Gas					
2017	Polk CC Conversion	Combined Cycle	459	463	Previously Approved
2020	Future CT1	Combustion Turbine	190	220	

Source: 2014 Ten-Year Site Plan

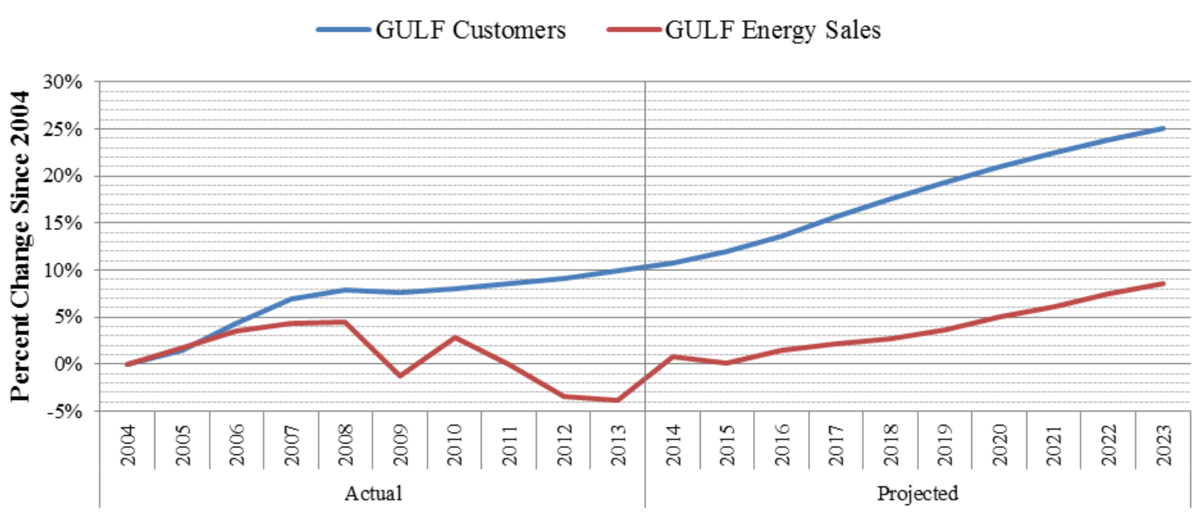
Gulf Power Company (GPC)

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 2014 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2013, GPC had approximately 438,000 customers and annual retail energy sales of 10,620 GWh, or approximately 4.9 percent of Florida's annual retail energy sales. Figure 27 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2004. Over the last ten years, GPC's customer base has increased by 9.90 percent, while retail sales have declined by 3.86 percent. As illustrated below, retail energy sales are anticipated to exceed the historic 2008 peak by 2020, three years later than the state as a whole.

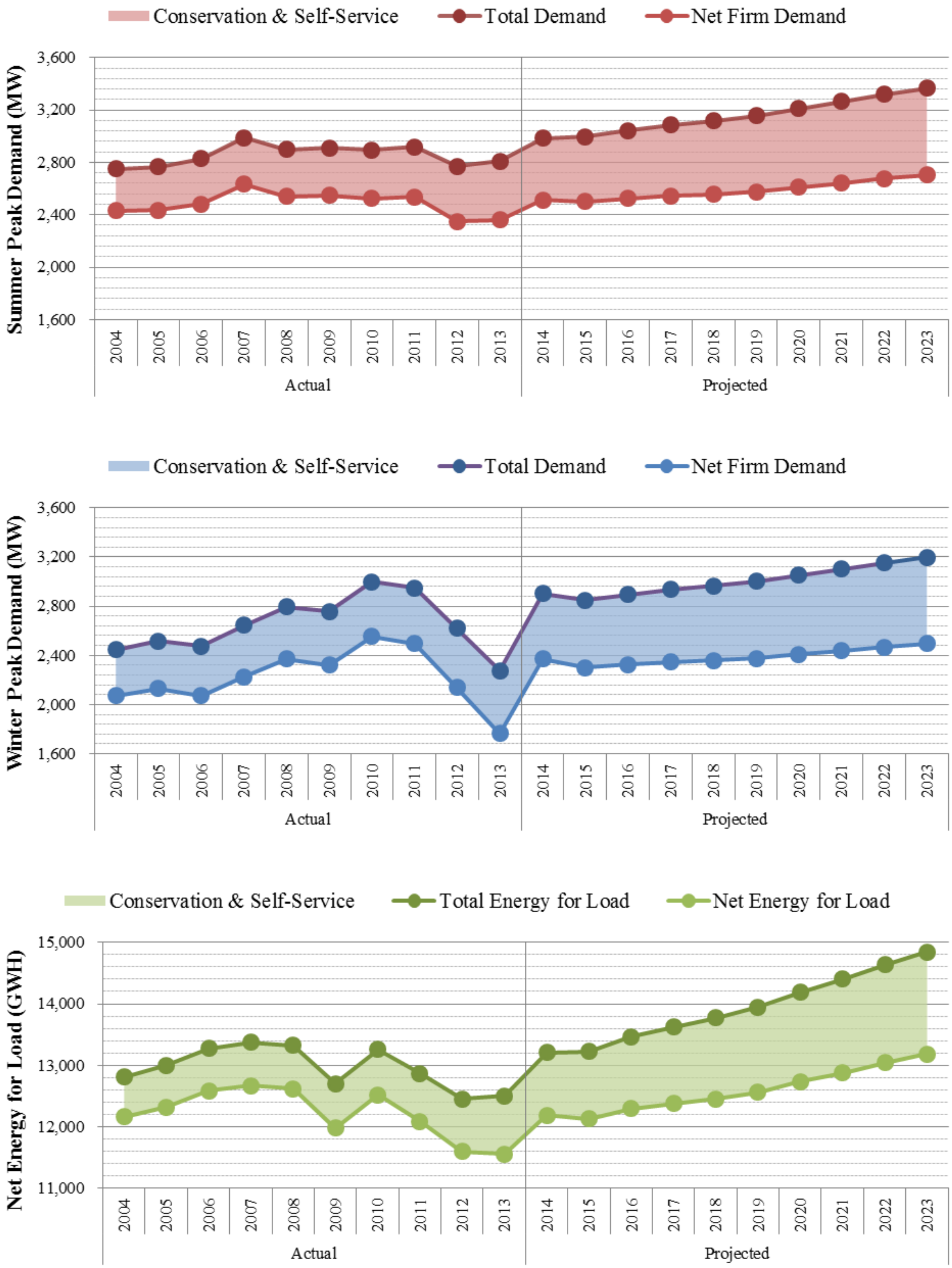
Figure 27: GPC Growth Rate



Source: 2014 Ten-Year Site Plan

The three graphs in Figure 28 below, shows GPC's seasonal peak demand and net energy for load for the historic years of 2004 through 2013 and forecast years 2014 through 2023. These graphs include the full impact of demand-side management.

Figure 28: GPC Demand and Energy Forecasts



Source: 2014 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 should include revised values that would reflect the Commission's decision in the currently open FEECA goal-setting docket.

Fuel Diversity

Table 21 below, shows GPC's actual net energy for load by fuel type as of 2013, and the projected fuel mix for 2023. 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 2013, coal made up approximately half of energy produced. By 2023, GPC's 2014 Ten-Year Site Plan projects a decline in sales to only 11.1 percent of native load, with coal representing approximately 70 percent of system energy. GPC projects a greater percent of energy consumption from coal in 2023 than any other investor-owned utility and all but two other TYSP Utilities, JEA and OUC.

Table 21: GPC Energy Consumption by Fuel Type

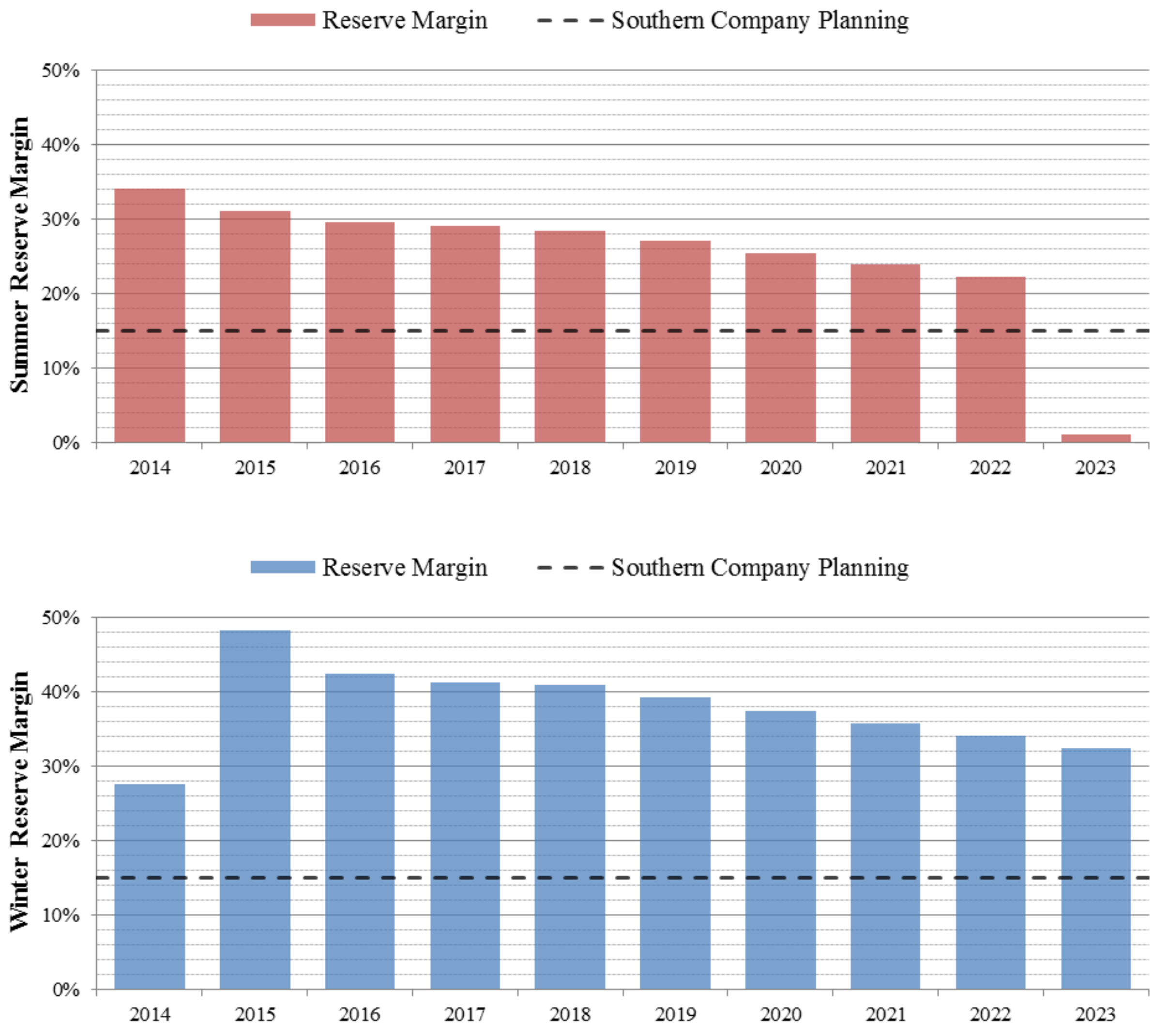
Fuel Type	Net Energy for Load			
	2013		2023	
	GWh	%	GWh	%
Natural Gas	8,834	**76.5%**	5,258	**39.9%**
Coal	5,601	**48.5%**	9,078	**68.9%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	1	**0.0%**
Renewable	0	**0.0%**	0	**0.0%**
Interchange	-3,174	**-27.5%**	-1,469	**-11.1%**
NUG & Other	290	**2.5%**	311	**2.4%**
Total	**11,552**		**13,179**	

Source: 2014 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 29 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, but in 2014 the winter peak is the controlling factor. Notably, GPC's 2014 Ten-Year Site Plan projects a low reserve margin for its summer 2023 period, with a reserve margin of only 1.1 percent. The decline in reserve margin is associated with the expiration of a purchased power agreement of approximately 885 MW of natural gas-fired generation in June 2023. 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 2023.

Figure 29: GPC Reserve Margin Forecast



Source: 2014 Ten-Year Site Plan

Generation Resources

GPC plans multiple unit retirements and additions during the planning period, as described below in Table 22. A pair of coal-fired steam units and three natural gas-fired combustion turbines would be retired during the planning period. Based on its 2014 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 22: GPC Unit Retirements and Additions

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Net Capacity (MW) Win	Notes
Retiring Units					
Coal					
2015	Scholz 1 & 2	Steam	92	92	
Natural Gas					
2018	Pea Ridge 1-3	Combustion Turbine	12	15	
New Units					
Natural Gas					
2023	Unsited CT	Combustion Turbine	349	360	
Landfill Gas					
2015	Perdido	Internal Combustion	2	2	

Source: 2014 Ten-Year Site Plan

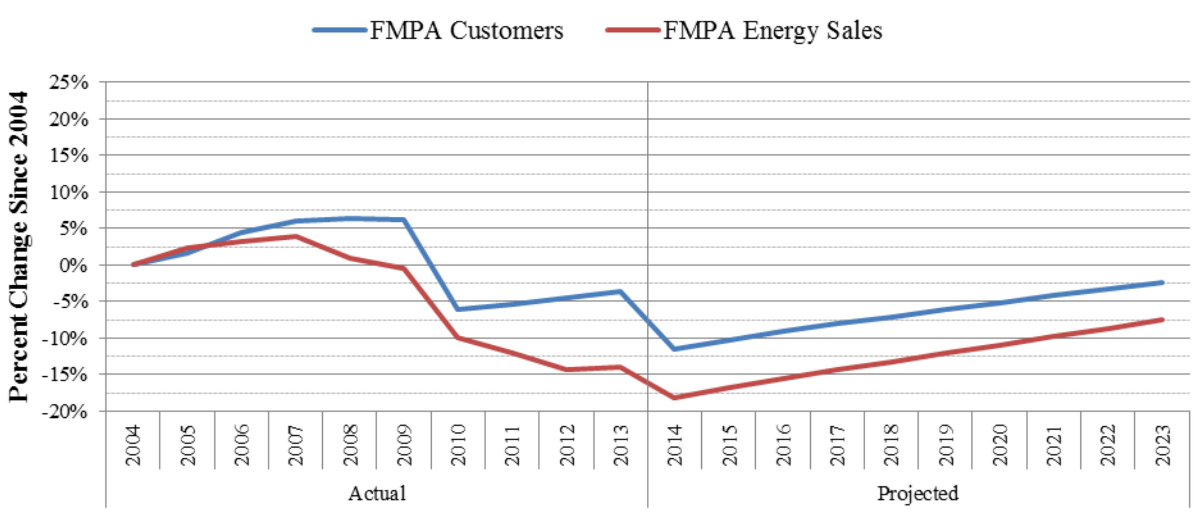
Florida Municipal Power Agency (FMPA)

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 2014 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

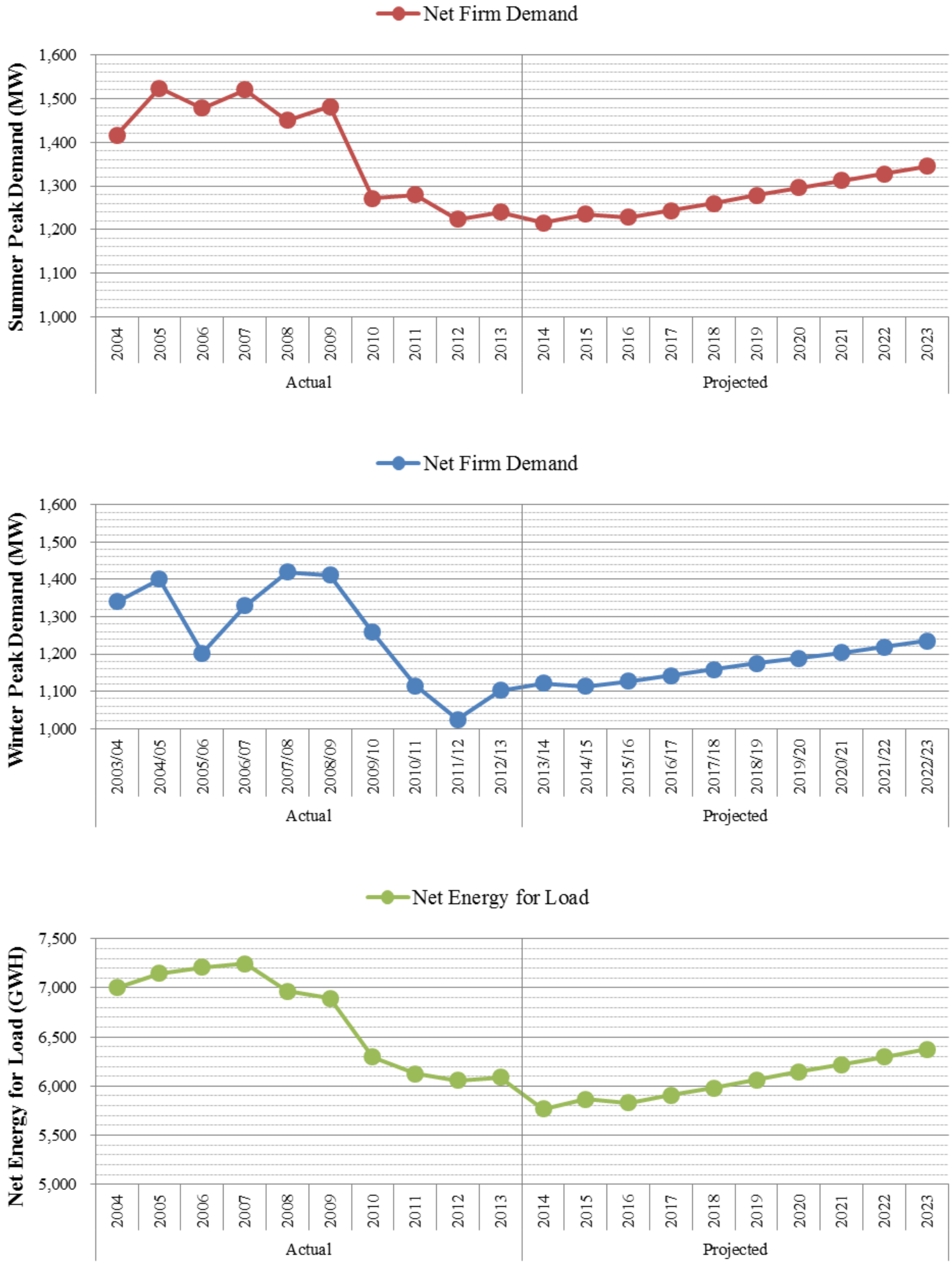
In 2013, FMPA had approximately 267,000 customers and annual retail energy sales of 5,688 GWh, or approximately 2.6 percent of Florida's annual retail energy sales. Figure 30 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2004. Over the last ten years, FMPA's customer base has decreased by 3.68 percent, while retail sales have decreased by 14.04 percent. As illustrated below, 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 30: FMPA Growth Rate



Source: 2014 Ten-Year Site Plan

Figure 31: FMPA Demand and Energy Forecasts



Source: 2014 Ten-Year Site Plan and Data Responses

The three graphs in Figure 31 above, shows FMPA's seasonal peak demand and net energy for load for the historic years of 2004 through 2013 and forecast years 2014 through 2023. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer demand-side management programs, the impacts of which are included in the graphs below.

Fuel Diversity

Table 23 below, shows FMPA's actual net energy for load by fuel type as of 2014 and the projected fuel mix for 2023. 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 2023, but 70 percent of energy would still be sourced from natural gas and nuclear.

Table 23: FMPA Energy Consumption by Fuel Type

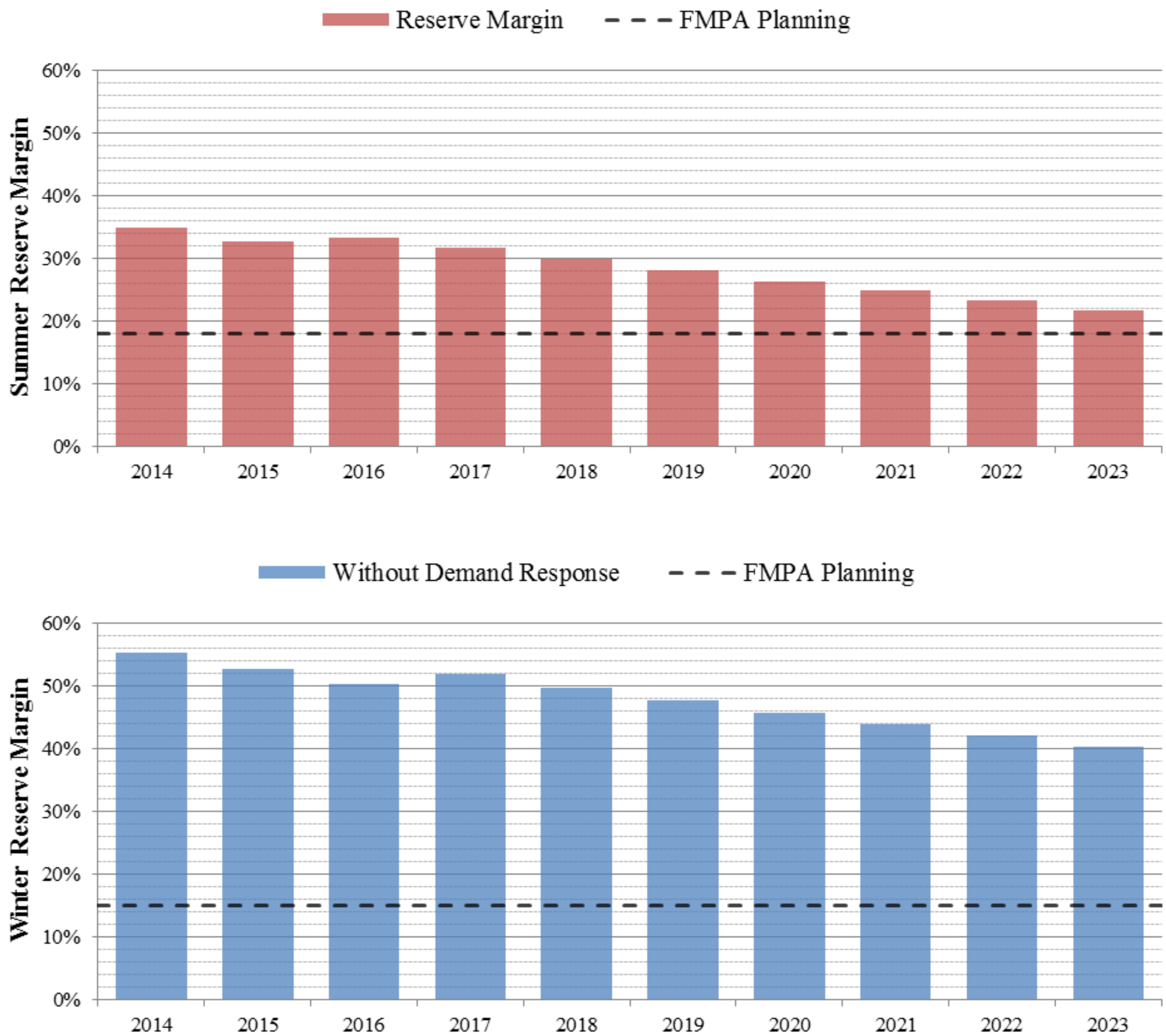
Fuel Type	Net Energy for Load			
	2013		2023	
	GWh	%	GWh	%
Natural Gas	4,527	**73.8%**	4,336	**66.8%**
Coal	734	**12.0%**	960	**14.8%**
Nuclear	618	**10.1%**	287	**4.4%**
Oil	2	**0.0%**	1	**0.0%**
Renewable	46	**0.8%**	23	**0.4%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	206	**3.4%**	881	**13.6%**
Total	**6,133**		**6,488**	

Source: 2014 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 32 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 32: FMPA Reserve Margin Forecast



Source: 2014 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.

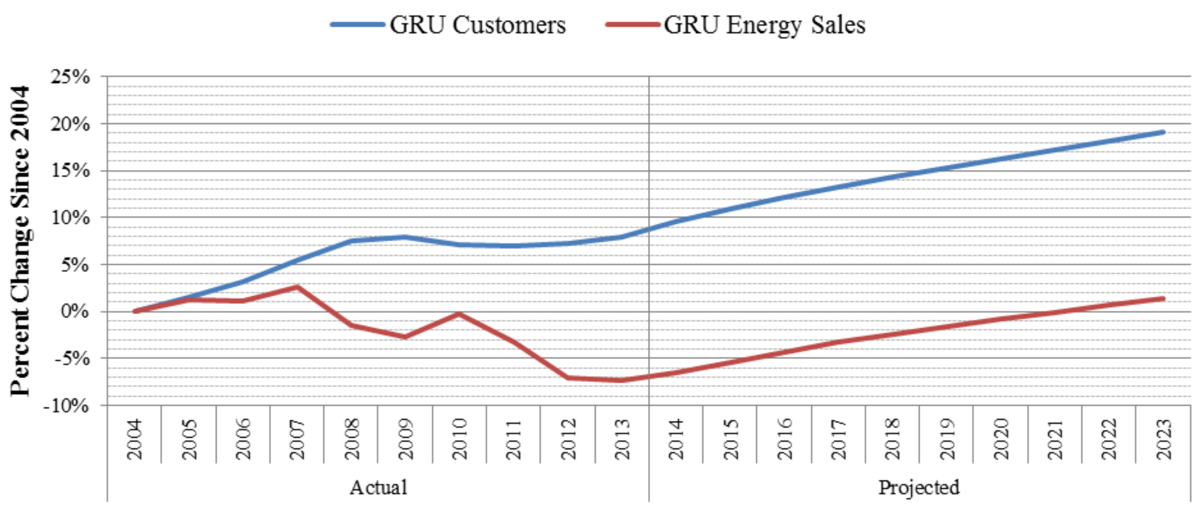
Gainesville Regional Utilities (GRU)

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 2014 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2013, GRU had approximately 93,000 customers and annual retail energy sales of 1,694 GWh, or approximately 0.8 percent of Florida's annual retail energy sales. Figure 33 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2004. Over the last ten years, GRU's customer base has increased by 7.96 percent, while retail sales have decreased by 7.41 percent. As illustrated below, retail energy sales are not anticipated to exceed their historic 2007 peak during the planning period.

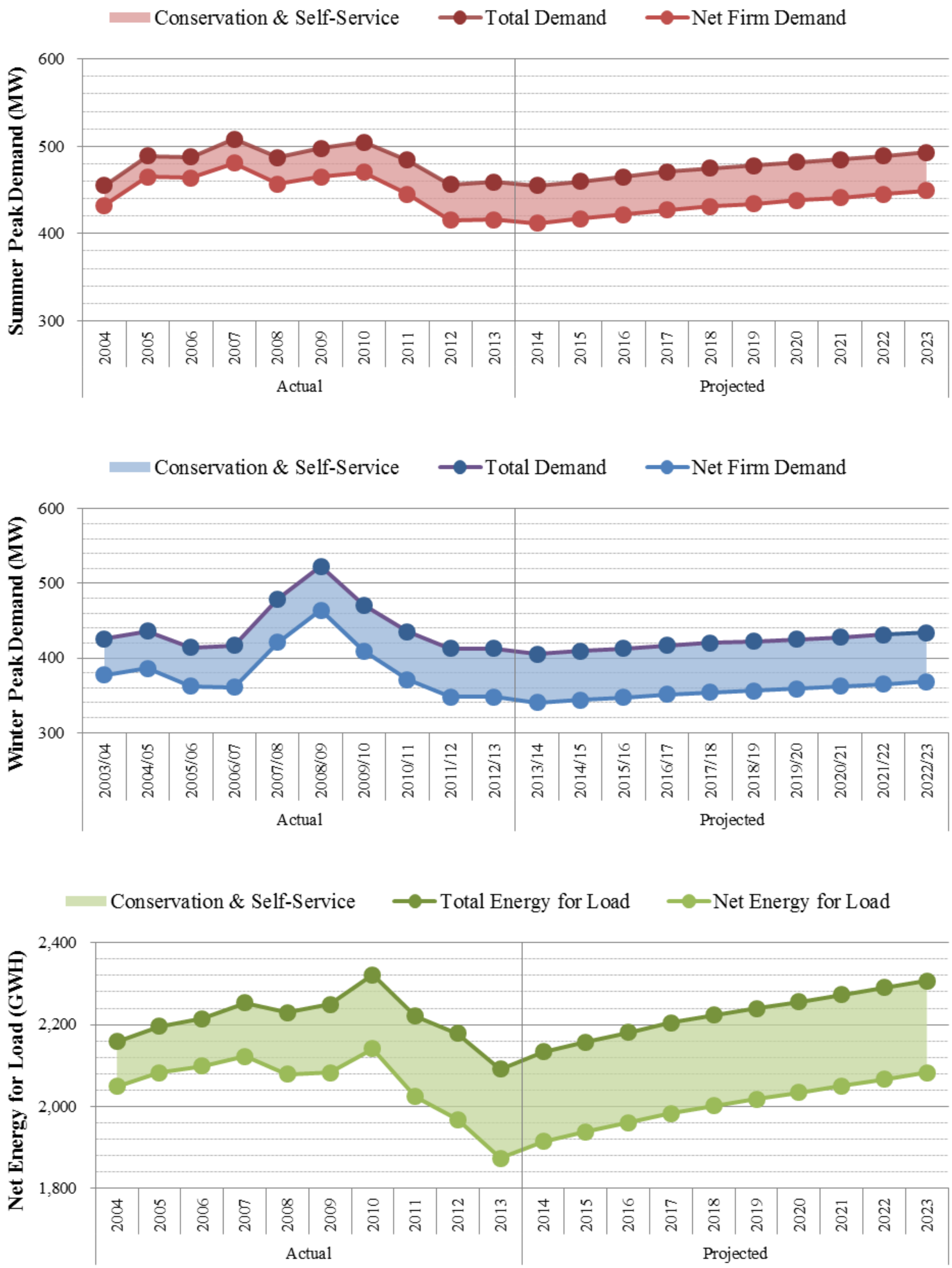
Figure 33: GRU Growth Rate



Source: 2014 Ten-Year Site Plan

The three graphs in Figure 34 below, shows GRU's seasonal peak demand and net energy for load for the historic years of 2004 through 2013 and forecast years 2014 through 2023. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 34 include the impact of these demand-side management programs.

Figure 34: GRU Demand and Energy Forecasts



Source: 2014 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 24 below, shows GRU's actual net energy for load by fuel type as of 2013 and the projected fuel mix for 2023. In 2013, natural gas and coal were approximately equal in terms of contribution to net energy for load, with the remaining energy split between renewable generation and non-utility generators. By 2023, GRU projects a decline in natural gas and an increase in renewable energy to over 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 24: GRU Energy Consumption by Fuel Type

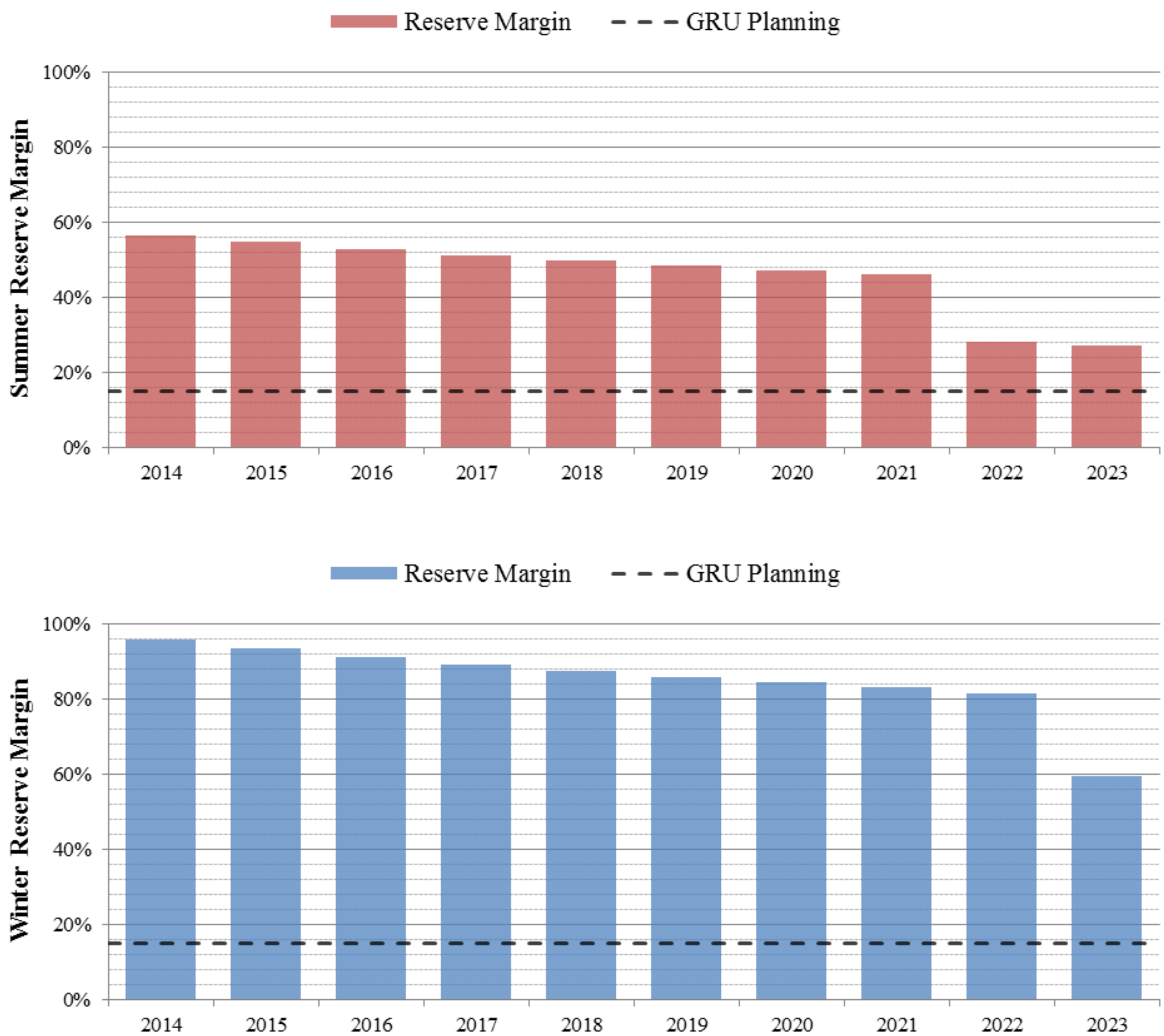
Fuel Type	Net Energy for Load			
	2013		2023	
	GWh	%	GWh	%
Natural Gas	696	**37.1%**	426	**20.5%**
Coal	626	**33.4%**	756	**36.3%**
Nuclear	81	**4.3%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	215	**11.5%**	901	**43.3%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	255	**13.6%**	0	**0.0%**
Total	**1,873**		**2,083**	

Source: 2014 Ten-Year Site Plan and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 35 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 35: GRU Reserve Margin Forecast



Source: 2014 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 below in Table 25. 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 25: GRU Unit Retirements

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)		Notes
			Sum	Win	
Retiring Units					
Natural Gas					
2022	Deerhaven	Steam	75	75	

Source: 2014 Ten-Year Site Plan

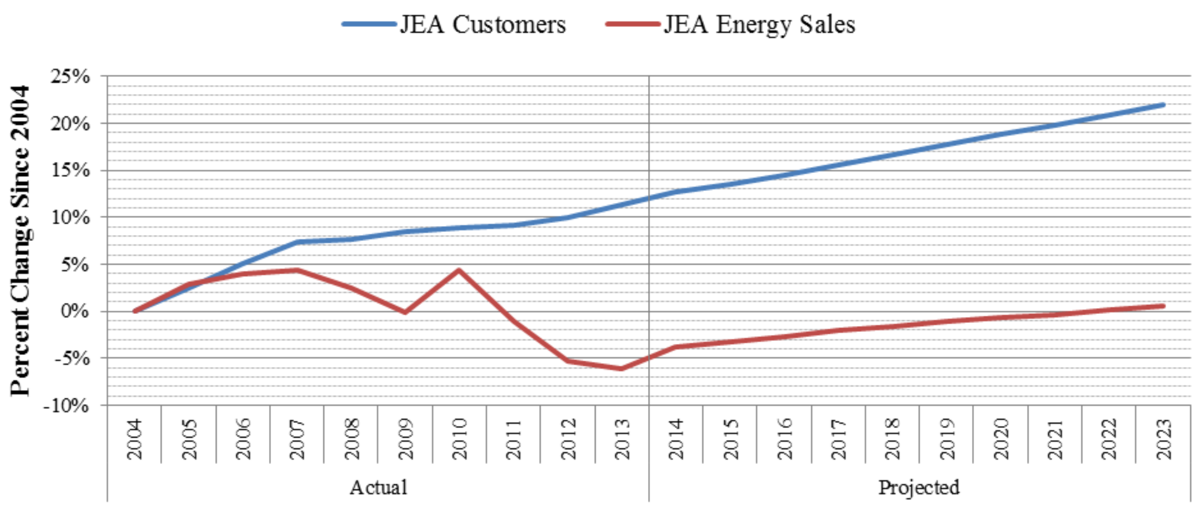
JEA

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 2014 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2013, JEA had approximately 425,000 customers and annual retail energy sales of 11,556 GWh, or approximately 5.3 percent of Florida's annual retail energy sales. Figure 36 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2004. Over the last ten years, JEA's customer base has increased by 11.36 percent, while retail sales have declined by 6.14 percent. As illustrated below, 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.

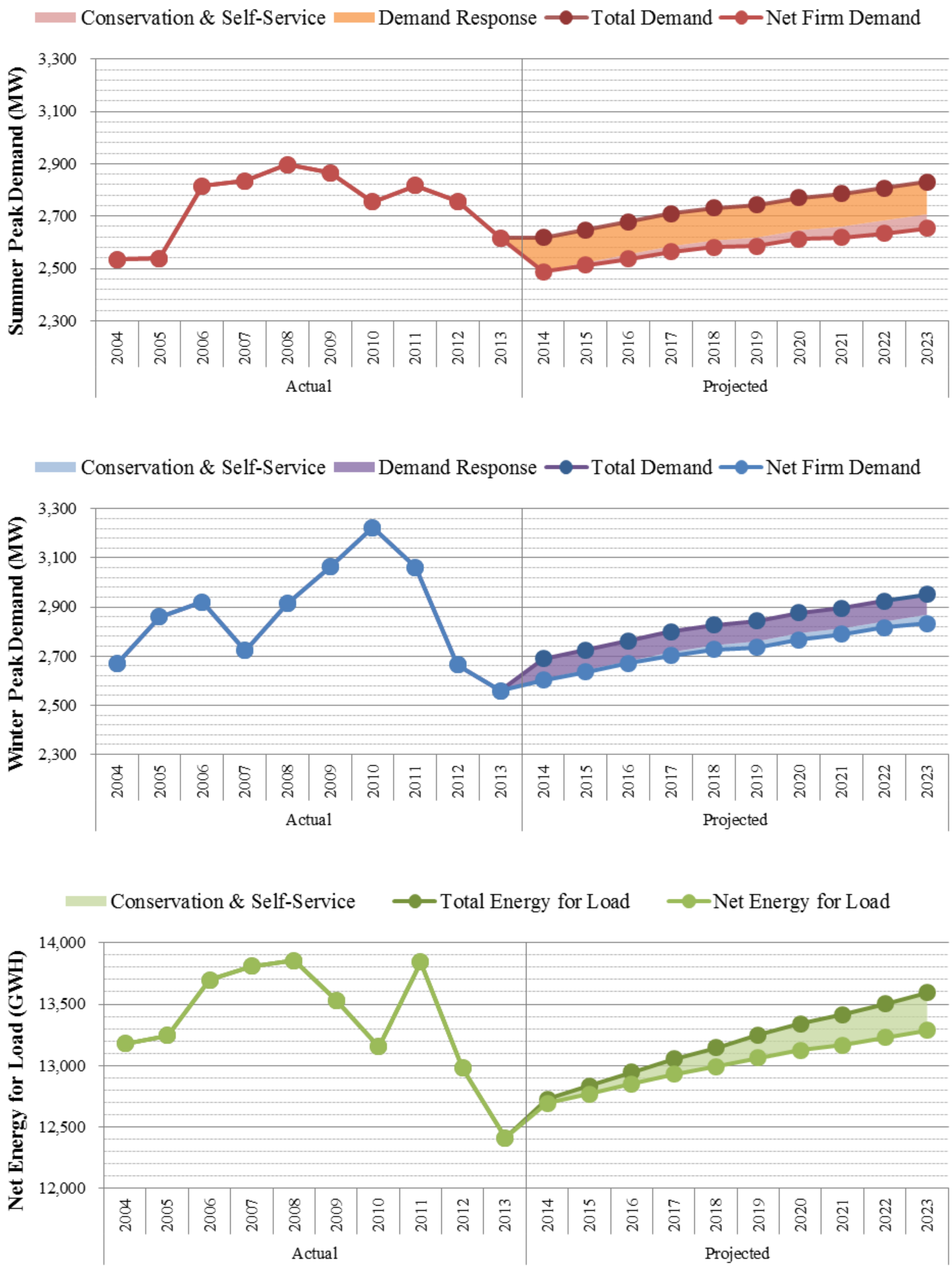
Figure 36: JEA Growth Rate



Source: 2014 Ten-Year Site Plan and 2014 FRCC Load & Resource Plan

The three graphs in Figure 37 below, shows JEA's seasonal peak demand and net energy for load for the historic years of 2004 through 2013 and forecast years 2014 through 2023. These graphs include the full impact of demand-side management, and assume that all available demand response resources were or will be activated during the seasonal peak.

Figure 37: JEA Demand and Energy Forecasts



Source: 2014 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 should include revised values that would reflect the Commission's decision in the currently open FEECA goal-setting docket.

Fuel Diversity

Table 26 below, shows JEA's actual net energy for load by fuel type as of 2013 and the projected fuel mix for 2023. In 2013, a majority JEA's net energy for load came from coal and petroleum coke, which is listed in the "NUG & Other" category in Table 26. While the utility plans on eliminating petroleum coke usage over the planning period, JEA projects the highest percent energy consumption from coal in 2023 of the Ten-Year Site Plan utilities, almost doubling its usage of the solid fuel.

Table 26: JEA Energy Consumption by Fuel Type

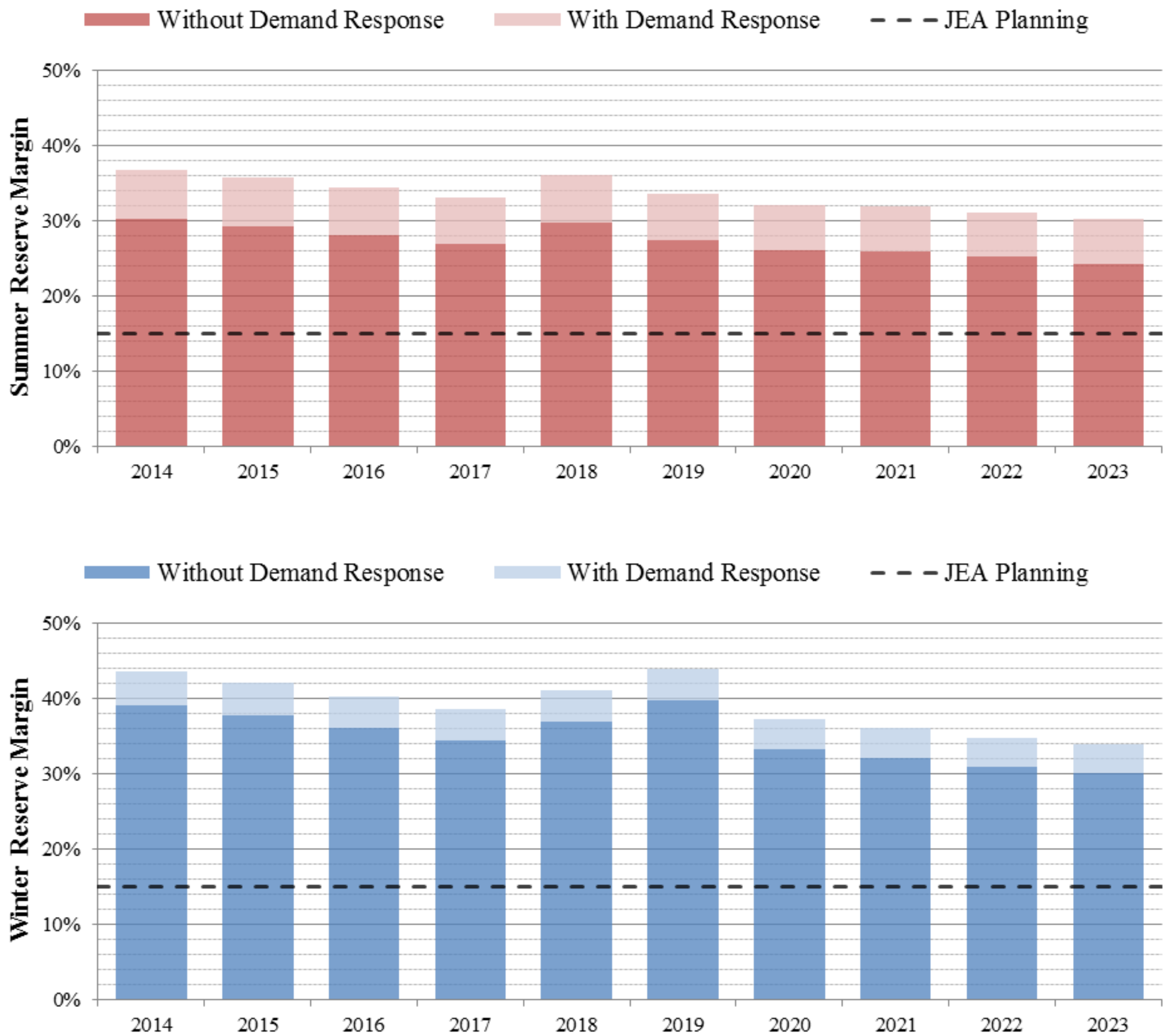
Fuel Type	Net Energy for Load			
	2013		2023	
	GWh	%	GWh	%
Natural Gas	3,890	**31.7%**	1,090	**8.2%**
Coal	5,376	**43.8%**	10,440	**78.6%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	3	**0.0%**	2	**0.0%**
Renewable	92	**0.7%**	101	**0.8%**
Interchange	841	**6.8%**	1,654	**12.4%**
NUG & Other	2,084	**17.0%**	0	**0.0%**
Total	**12,286**		**13,286**	

Source: 2014 Ten-Year Site Plan and Data Responses

Reliability Requirements

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



Source: 2014 Ten-Year Site Plan

Generation Resources

JEA plans to retire a pair of units during the planning period, as described below in Table 27. The Northside Unit 3, a natural gas-fired steam unit is planned for retirement in 2019 based on the utility's Ten-Year Site Plan, but JEA subsequently announced that its retirement would be accelerated to 2015. JEA also has retired its Girvin landfill units due to a decline in gas flows.

Table 27: JEA Unit Retirements

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)		Notes
			Sum	Win	
Retiring Units					
Natural Gas					
2019	Northside	Steam	524	524	Accelerated to 2015
Landfill Gas					
2014	Girvin Landfill	Internal Combustion	1	1	2014

Source: 2014 Ten-Year Site Plan

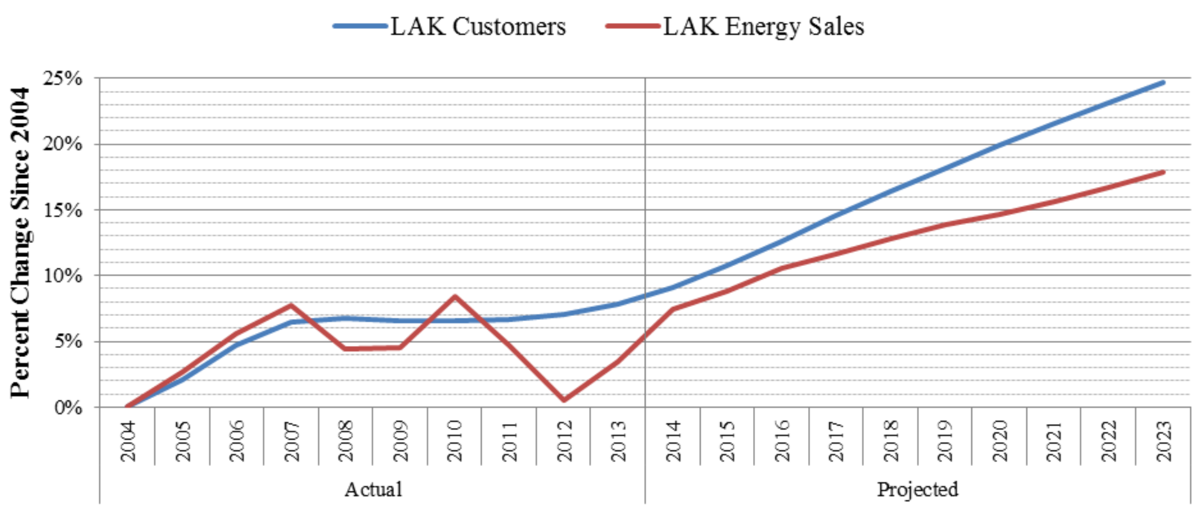
Lakeland Electric (LAK)

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 2014 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2013, LAK had approximately 123,000 customers and annual retail energy sales of 2,831 GWh, or approximately 1.3 percent of Florida's annual retail energy sales. Figure 39 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2004. Over the last ten years, LAK's customer base has increased by 7.82 percent, while retail sales have grown by 3.47 percent. As illustrated below, retail energy sales exceed their historic 2007 peak in 2010, and are anticipated to again exceed this value in 2015.

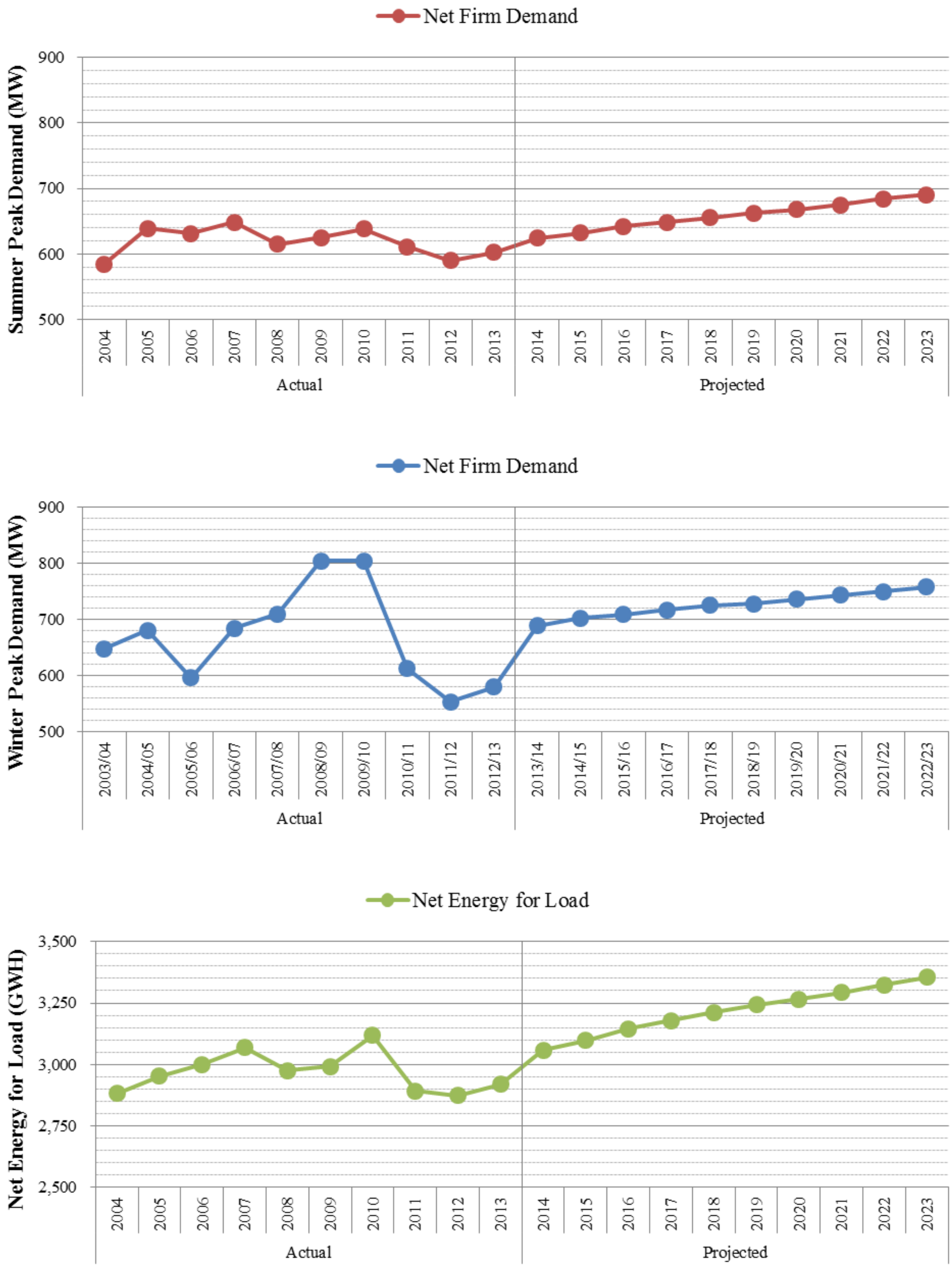
Figure 39: LAK Growth Rate



Source: 2014 Ten-Year Site Plan

The three graphs in Figure 40 below, shows LAK's seasonal peak demand and net energy for load for the historic years of 2004 through 2013 and forecast years 2014 through 2023. LAK offers energy efficiency programs, the impacts of which are included in the graphs below.

Figure 40: LAK Demand and Energy Forecasts



Source: 2014 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 28 below, shows LAK's actual net energy for load by fuel type as of 2013 and the projected fuel mix for 2023. LAK uses natural gas as its primary fuel type for energy, with coal representing slightly more than a quarter of net energy for load. While natural gas usage is anticipated to increase somewhat as a percent of net energy for load, coal is projected to remain at a similar level to 2013.

Table 28: LAK Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2013		2023	
	GWh	%	GWh	%
Natural Gas	2,018	**69.1%**	2,705	**80.6%**
Coal	786	**26.9%**	926	**27.6%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	6	**0.2%**	21	**0.6%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	109	**3.7%**	-297	**-8.9%**
Total	**2,919**		**3,355**	

Source: 2014 Ten-Year Site Plan and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 41 below, displays the forecast planning reserve margin for LAK through the planning period for both seasons, including the impacts of demand-side management. As shown in the figure, LAK's generation needs are controlled by its winter 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, 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 41: LAK Reserve Margin Forecast

Source: 2014 Ten-Year Site Plan

New Units

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

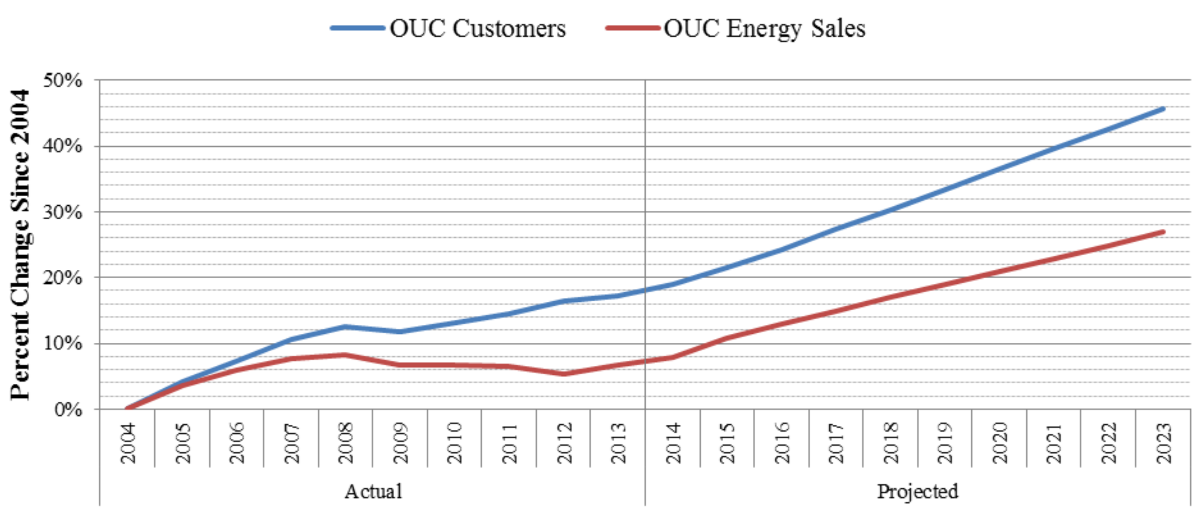
Orlando Utilities Commission (OUC)

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 2014 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2013, OUC had approximately 215,000 customers and annual retail energy sales of 6,025 GWh, or approximately 2.8 percent of Florida's annual retail energy sales. Figure 42 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2004. Over the last ten years, OUC's customer base has increased by 17.28 percent, while retail sales have grown by 6.62 percent. As illustrated below, retail energy sales are anticipated to exceed their historic 2008 peak in 2015.

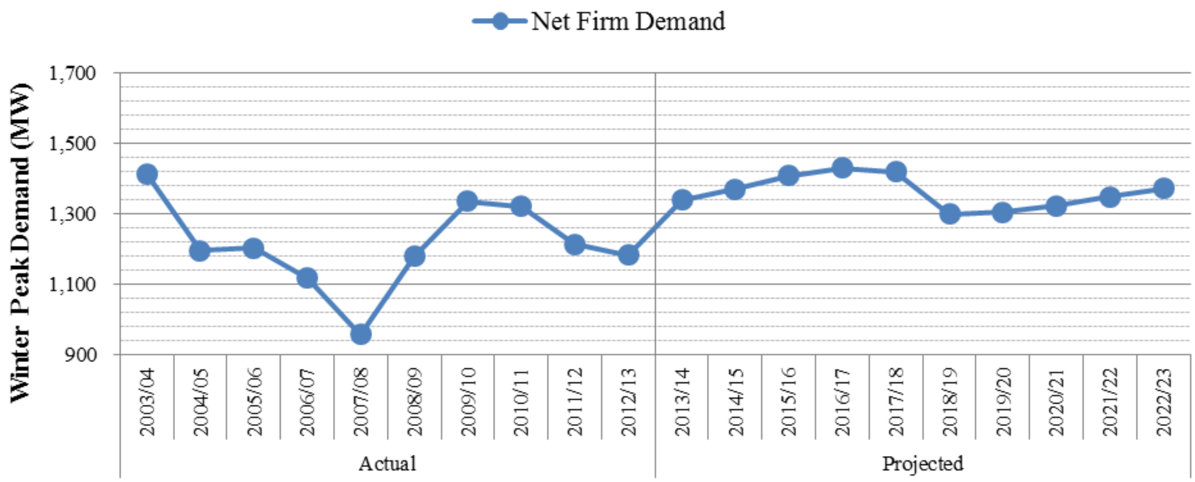
Figure 42: OUC Growth Rate

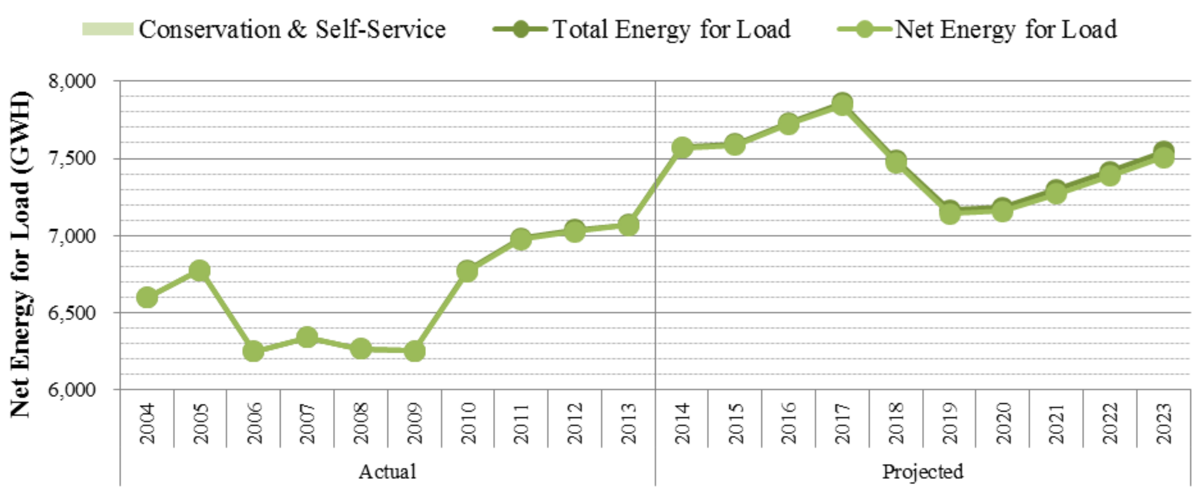


Source: 2014 Ten-Year Site Plan

The three graphs in Figure 43 below, shows OUC's seasonal peak demand and net energy for load for the historic years of 2004 through 2013 and forecast years 2014 through 2023. 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. The utility's 2015 Ten-Year Site Plan should include revised values that would reflect the Commission's decision in the currently open FEECA goal-setting docket.

Figure 43: OUC Demand and Energy Forecasts





Source: 2014 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 29 below, shows OUC's actual net energy for load by fuel type as of 2013 and the projected fuel mix for 2023. In 2013, 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 2023. Based upon this projection, OUC as a percent of net energy for load would be the second largest user of coal in Florida by 2023.

Table 29: OUC Energy Consumption by Fuel Type

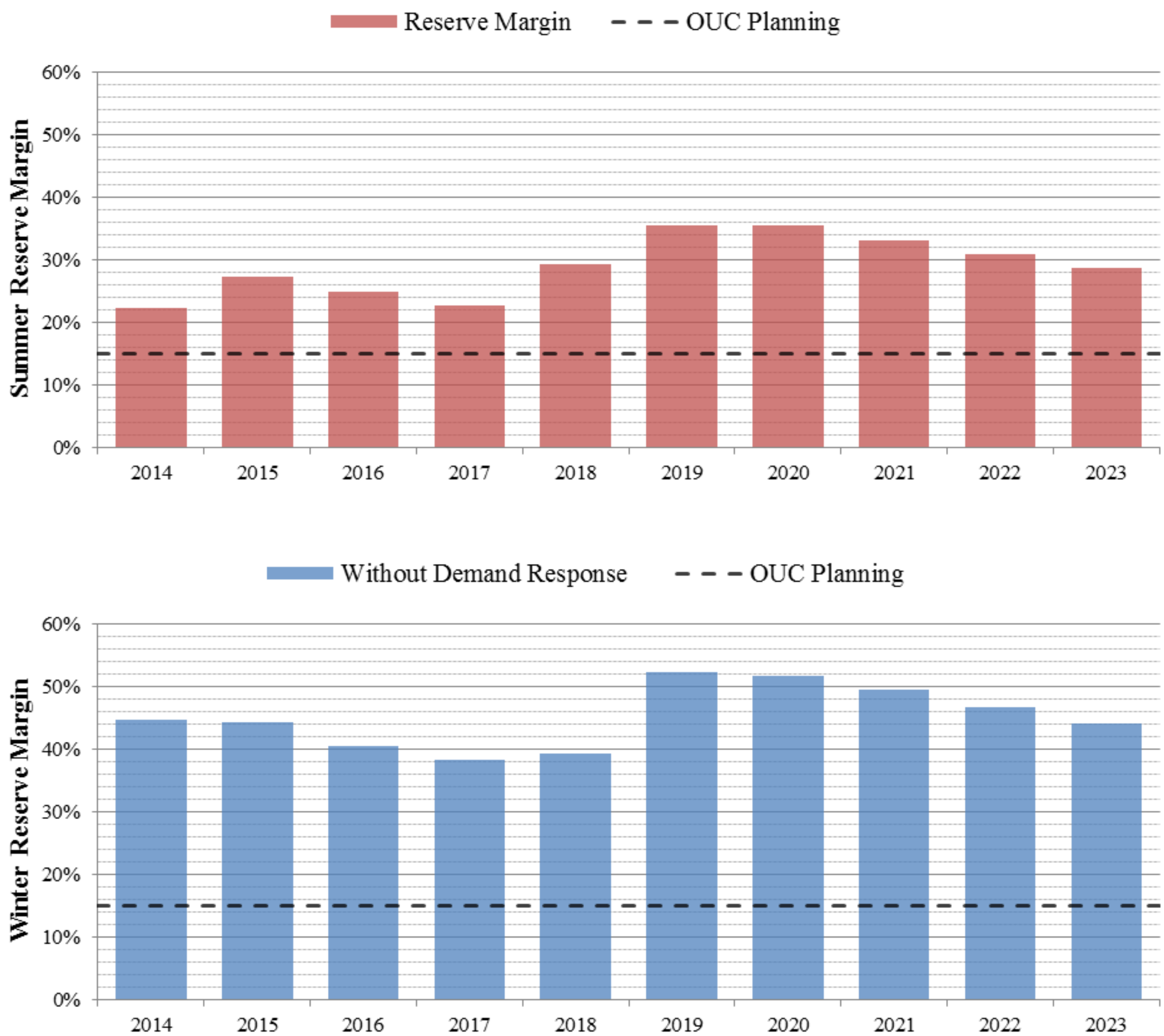
Fuel Type	Net Energy for Load			
	2013		2023	
	GWh	%	GWh	%
Natural Gas	3,040	**43.0%**	839	**12.4%**
Coal	3,030	**42.9%**	5,284	**77.9%**
Nuclear	569	**8.1%**	462	**6.8%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	91	**1.3%**	194	**2.9%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	336	**4.8%**	0	**0.0%**
Total	**7,065**		**6,779**	

Source: 2014 Ten-Year Site Plan and Data Responses

Reliability Requirements

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



Source: 2014 Ten-Year Site Plan

Generation Resources

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

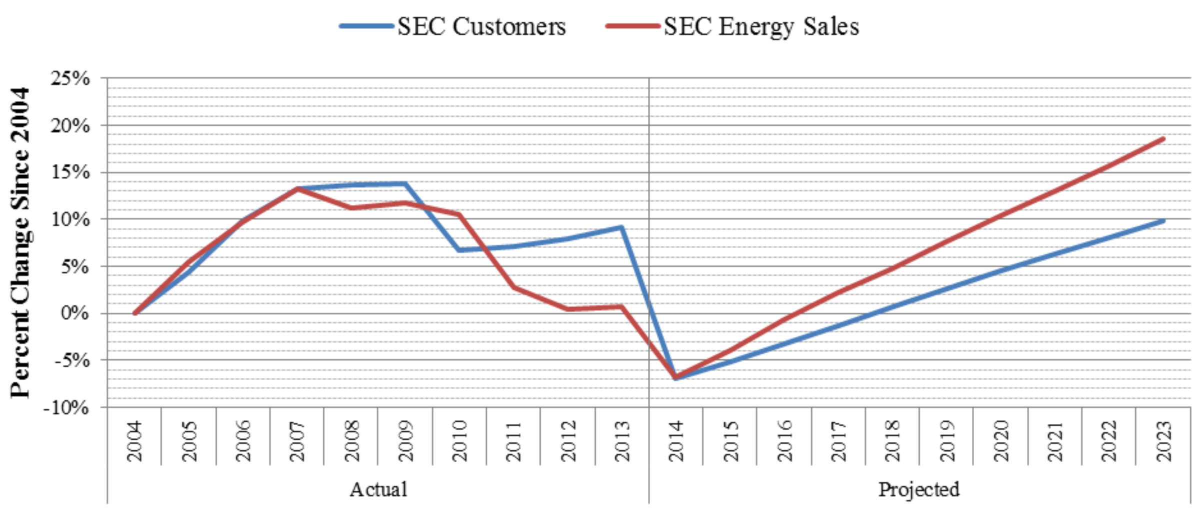
Seminole Electric Cooperative (SEC)

SEC is a generation and transmission rural electric cooperative that serves its member cooperatives, and is collectively Florida's fourth largest utility. SEC's generation and member cooperatives are within the FRCC region, with member cooperatives located in central and north Florida. As a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds SEC's 2014 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

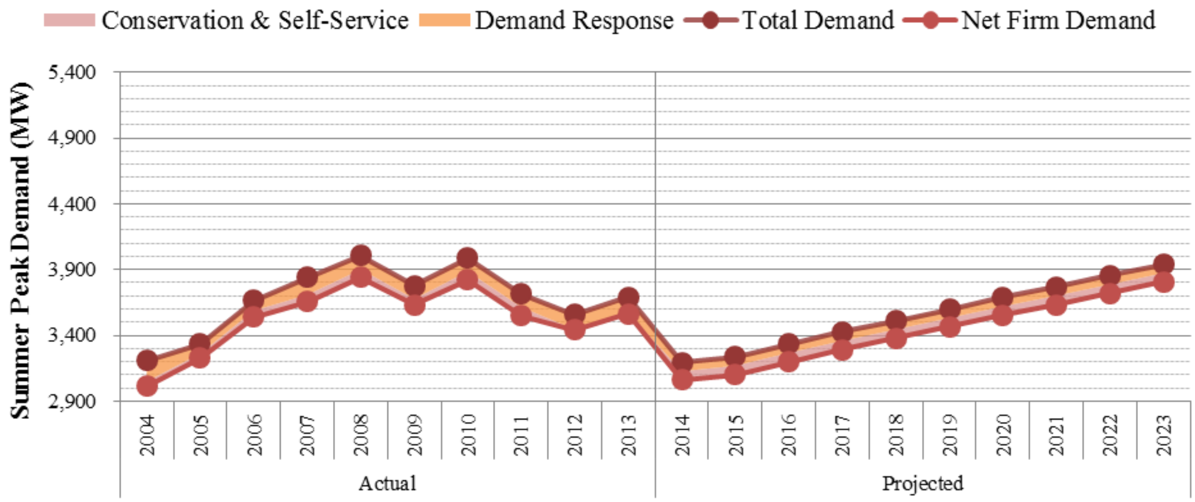
In 2013, SEC had approximately 865,000 customers and annual retail energy sales of 14,631 GWh, or approximately 6.7 percent of Florida's annual retail energy sales. Figure 45 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2004. Over the last ten years, SEC's customer base has increased by 9.15 percent, while retail sales have grown by only 0.67 percent. As illustrated below, 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.

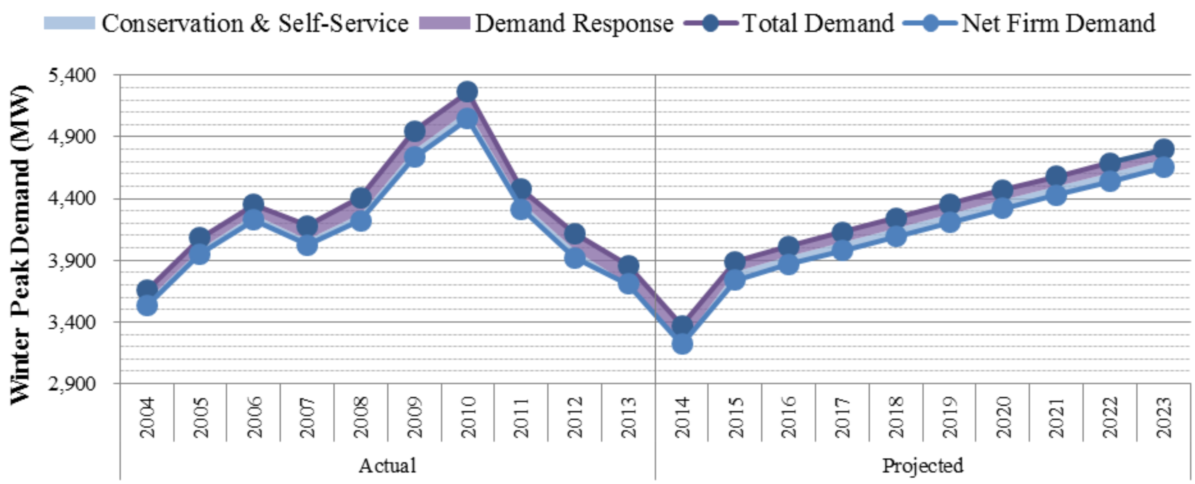
Figure 45: SEC Growth Rate

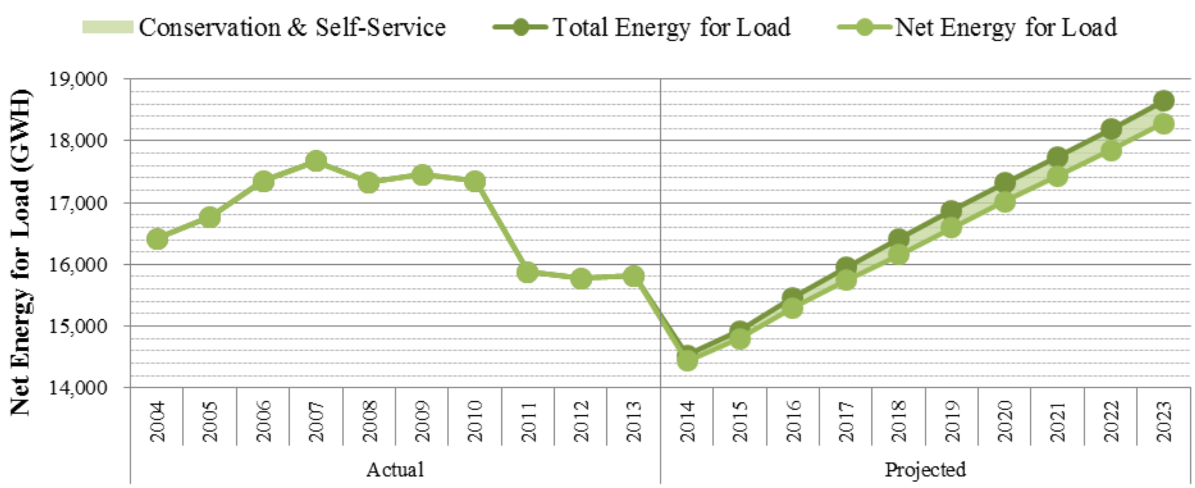


Source: 2014 Ten-Year Site Plan

Figure 46: SEC Demand and Energy Forecasts







Source: 2014 Ten-Year Site Plan and Data Responses

The three graphs in Figure 46 above, shows SEC's seasonal peak demand and net energy for load for the historic years of 2004 through 2013 and forecast years 2014 through 2023. 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 30 below, shows SEC's actual net energy for load by fuel type as of 2013 and the projected fuel mix for 2023. In 2013, 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 2023, SEC projects this to reverse, with natural gas usage somewhat higher than coal.

Table 30: SEC Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2013		2023	
	GWh	%	GWh	%
Natural Gas	7,071	**44.7%**	9,814	**53.7%**
Coal	7,725	**48.9%**	7,859	**43.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	54	**0.3%**	61	**0.3%**
Renewable	962	**6.1%**	550	**3.0%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**15,812**		**18,284**	

Source: 2014 Ten-Year Site Plan and Data Responses

Reliability Requirements

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

Source: 2014 Ten-Year Site Plan

Generation Resources

SEC plans the addition of several generating units during the planning period, as described below in Table 31. 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 31: SEC Unit Retirements and Additions

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)		Notes
			Sum	Win	
New Units					
2020	Unsited Combined Cycle	Combined Cycle	440	523	Requires Approval
2020	Unsited CT 1 &2	Combustion Turbine	402	450	
2021	Unsited CT 3-7	Combustion Turbine	1,005	1,125	

Source: 2014 Ten-Year Site Plan

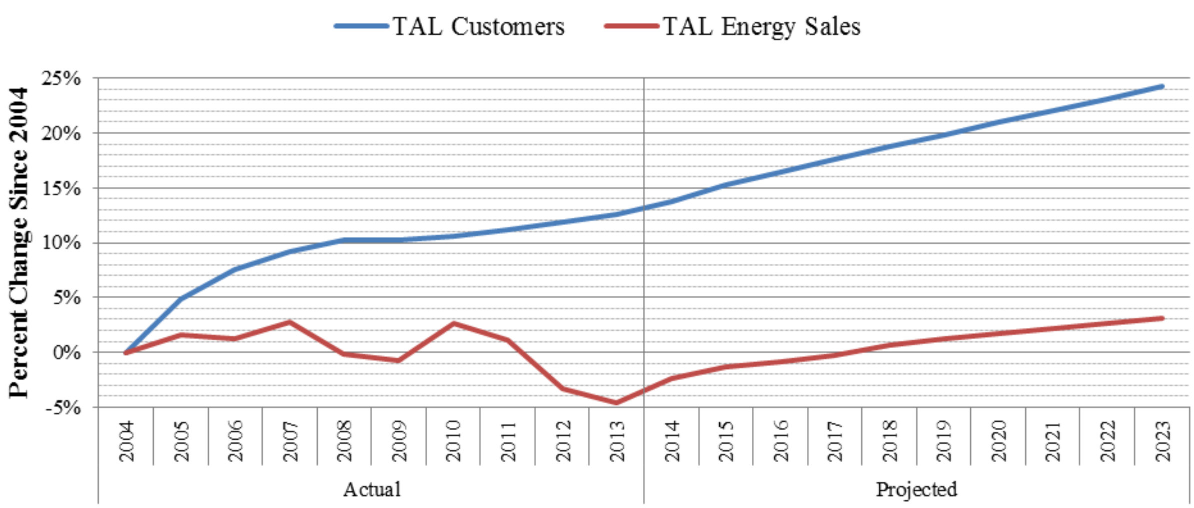
City of Tallahassee Utilities (TAL)

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 2014 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2013, TAL had approximately 116,000 customers and annual retail energy sales of 2,558 GWh, or approximately 1.2 percent of Florida's annual retail energy sales. Figure 48 below, illustrates the company's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2004. Over the last ten years, TAL's customer base has increased by 12.59 percent, while retail sales have declined by 4.63 percent. As illustrated below, retail energy sales are not anticipated to exceed their historic 2007 peak until 2023, six years later than the state as a whole.

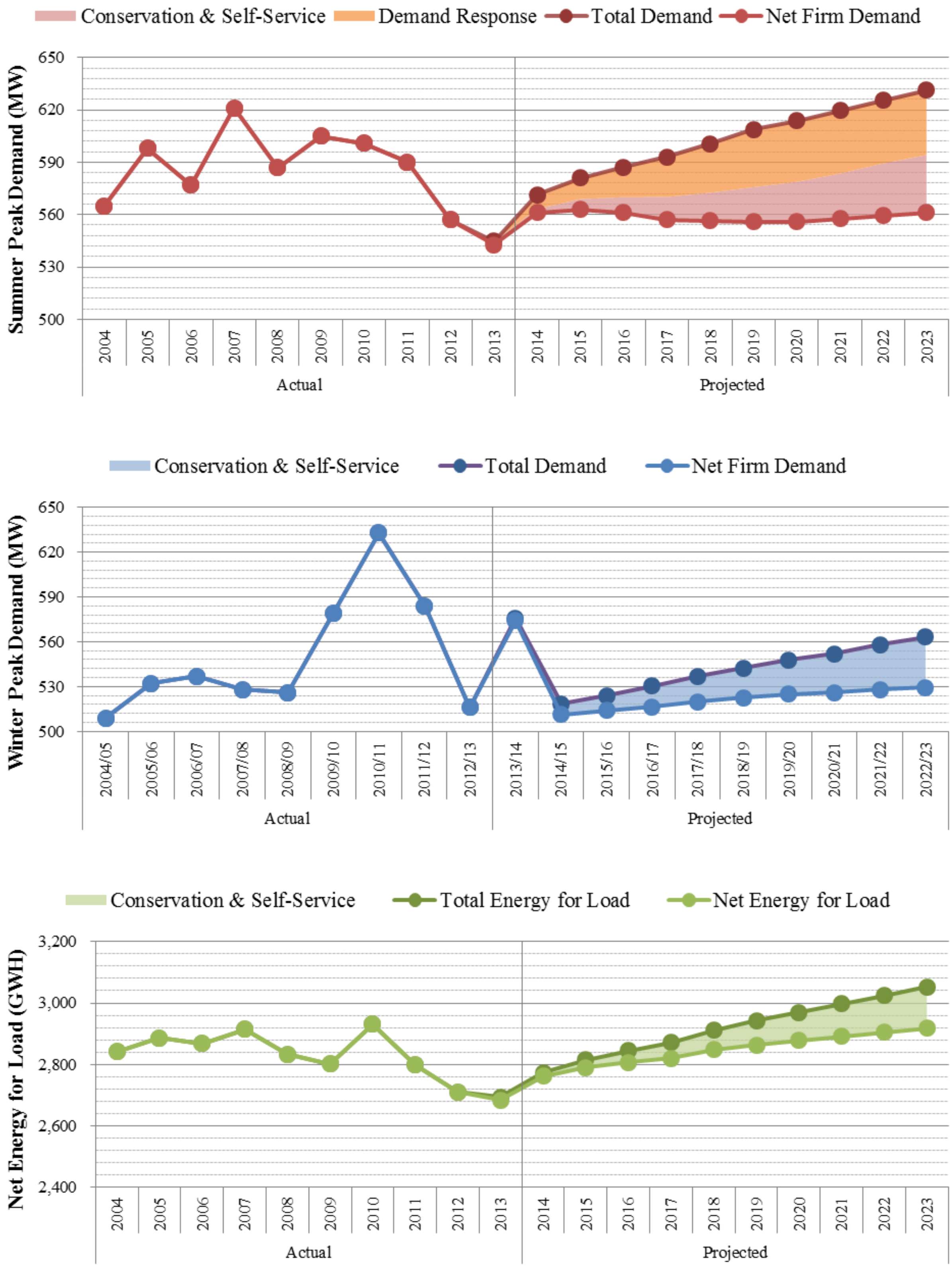
Figure 48: TAL Growth Rate



Source: 2014 Ten-Year Site Plan

The three graphs in Figure 49 below, shows TAL's seasonal peak demand and net energy for load for the historic years of 2004 through 2013 and forecast years 2014 through 2023. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. TAL offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. Currently TAL only offers demand response programs targeting appliances that contribute to summer peak, and therefore have no effect upon winter peak.

Figure 49: TAL Demand and Energy Forecasts



Source: 2014 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 32 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 32: TAL Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2013		2023	
	GWh	%	GWh	%
Natural Gas	2,662	**99.2%**	2,903	**99.5%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	2	**0.1%**	0	**0.0%**
Renewable	23	**0.8%**	11	**0.4%**
Interchange	1	**0.0%**	27	**0.9%**
NUG & Other	-3	**-0.1%**	-23	**-0.8%**
Total	**2,684**		**2,918**	

Source: 2014 Ten-Year Site Plan and Data Responses

Reliability Requirements

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

Source: 2014 Ten-Year Site Plan

Generation Resources

TAL plans multiple unit retirements and a single addition during the planning period, as described below in Table 33. 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 33: TAL Unit Retirements and Additions

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)		Notes
			Sum	Win	
Retiring Units					
Natural Gas					
2015	Hopkins GT1	Combustion Turbine	12	14	
2015	Purdom GT1&2	Combustion Turbine	20	20	
2017	Hopkins GT2	Combustion Turbine	24	26	
2020	Hopkins	Steam	76	78	
New Units					
Natural Gas					
2020	Hopkins 5	Combustion Turbine	46	48	

Source: 2014 Ten-Year Site Plan