REVIEW OF THE

2024 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

FLORIDA PUBLIC SERVICE COMMISSION

DECEMBER 2024

Table of Contents

List of Figures

List of Tables

List of Ten-Year Site Plan Utilities

Name	Abbreviation
Investor-Owned Electric Utilities	
Florida Power & Light Company	FPL
Duke Energy Florida, LLC	DEF
Tampa Electric Company	TECO
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

Unit Type and Fuel Abbreviations

Reference	Name	Abbreviation
Unit Type	Battery Storage	BAT
	Combined Cycle	CC
	Combustion Turbine	CT
	Hydroelectric	HY
	Internal Combustion	IC
	Photovoltaic	PV
	Steam Turbine	ST
Fuel Type	Bituminous Coal	BIT
	Distillate Fuel Oil	DFO
	Landfill Gas	LFG
	Natural Gas	NG

Executive Summary

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

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

Pursuant to Section 186.801, F.S., each generating electric utility must submit to the Commission a Ten-Year Site Plan which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a 10-year planning horizon. The Ten-Year Site Plans of Florida's electric utilities summarize the results of each utility's IRP process and identifies proposed power plants and transmission facilities. The Commission is required to perform a preliminary study of each plan and classify each one as either "suitable" or "unsuitable." This document represents the review of the 2024 Ten-Year Site Plans for Florida's electric utilities, filed by 10 reporting utilities.[1]

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

[1] Investor-owned utilities filing 2024 Ten-Year Site Plans include Florida Power & Light Company, Duke Energy Florida, LLC, and Tampa Electric Company. Municipal utilities filing 2024 Ten-Year Site Plans include Florida Municipal Power Agency, Gainesville Regional Utilities, JEA (formerly Jacksonville Electric Authority), Lakeland Electric, Orlando Utilities Commission, and City of Tallahassee Utilities. Seminole Electric Cooperative also filed a 2024 Ten-Year Site Plan.

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

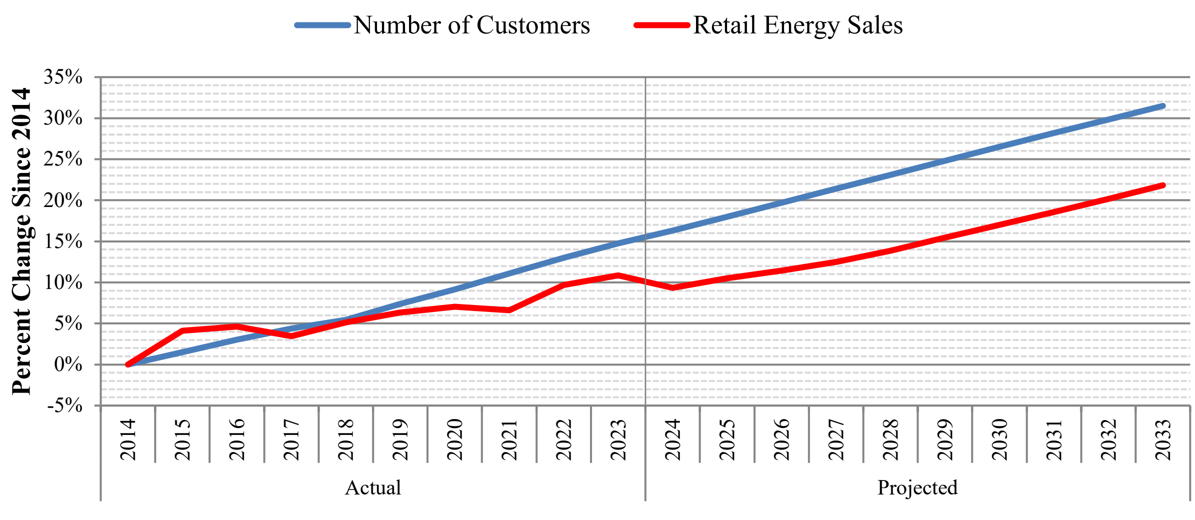
Review of the 2024 Ten-Year Site Plans

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

Load Forecasting

Forecasting customer energy needs or load is a fundamental component of electric utility planning. In order to maintain an adequate and reliable system, utilities must project and prepare for changes in overall electricity consumption patterns. These patterns are affected by the number and type of customers, and factors that impact customer usage including weather, economic conditions, housing size, building codes, appliance efficiency standards, new technologies, and demand-side management. Florida's utilities use well-known and tested forecasting methodologies, which are consistent with industrywide practices used in generation planning. Figure 1 provides the historical and forecasted trends in customer growth and energy sales. Forecasted retail energy sales in 2024 are lower than the actual retail energy sales in 2023. This is because of warmer weather conditions in 2023, and normalized weather trends were used to forecast 2024 through 2033.

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



Source: FRCC 2024 Regional Load and Resource Plan

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

Renewable Generation

Renewable resources continue to expand in Florida, with approximately 11,470 megawatts (MW) of renewable generating capacity currently in Florida. The majority of installed renewable capacity is represented by solar photovoltaic (PV) generation which makes up approximately 87 percent of Florida's existing renewables. Notably, Florida electric customers had installed 2,351 MW of demand-side renewable capacity by the end of 2023, an increase of 32 percent from 2022.

Florida's total renewable resources are expected to increase by an estimated 30,737 MW over the 10-year planning period, excluding any potential demand-side renewable energy additions. Solar PV accounts for all of this increase; however, only 8,007 MW of these new solar resources are considered as firm resources for summer peak reliability considerations. If these conditions continue, cost-effective forms of renewable generation will continue to improve the state's fuel diversity and reduce dependence on fossil fuels while having a lesser impact on system adequacy. Therefore, several utilities plan on adding battery storage totaling 5,305 MW during the planning period, which would increase firm capacity available during both seasonal system peaks.

Table 1 provides a breakdown of each TYSP Utility's actual 2023 and projected 2033 generation from renewables, in gigawatt-hours (GWh) and as a percentage of the net energy for load (NEL). Renewable energy as a percent of NEL is expected to increase from 6.8 percent in 2023 to 30.8 percent in 2033.

Table 1: State of Florida - Renewable Energy Generation

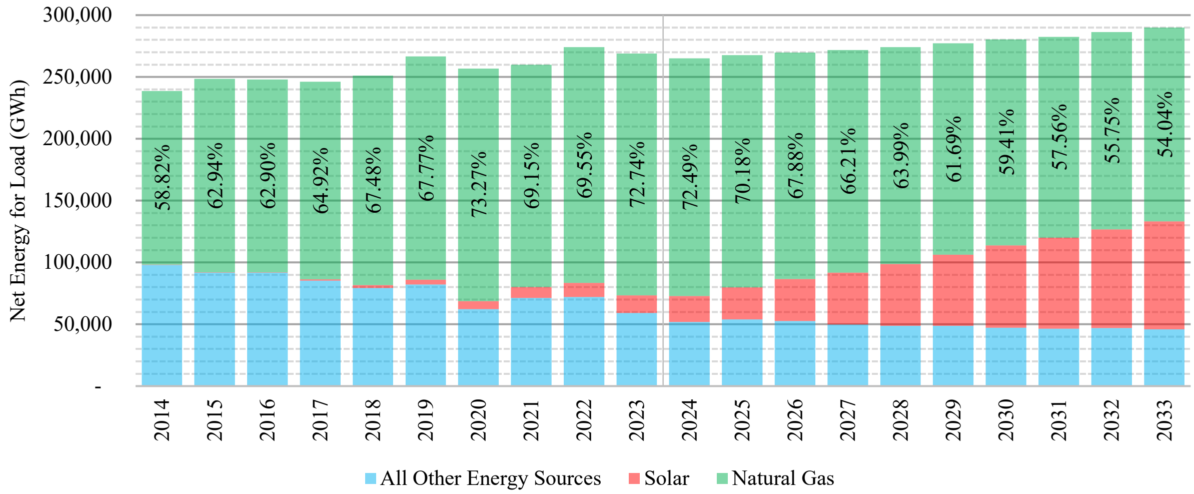
Utility	2023 Actual			2033 Projected		
	NEL	Renewables		NEL	Renewables	
	GWh	GWh	% NEL	GWh	GWh	% NEL
FPL	140,464	10,217	7.27%	153,681	59,440	38.68%
DEF	44,046	2,788	6.33%	47,094	13,408	28.47%
TECO	21,767	1,748	8.03%	23,224	6,191	26.66%
FMPA	7,174	143	1.99%	6,766	647	9.56%
GRU	1,861	296	15.90%	1,972	640	32.45%
JEA	12,722	412	3.24%	13,885	3,146	22.66%
LAK	3,442	25	0.73%	3,670	178	4.85%
OUC	7,972	396	4.97%	8,994	4,513	50.18%
TAL	2,753	107	3.89%	2,856	111	3.89%
SEC	16,312	423	2.59%	19,484	738	3.79%
State	268,898	18,217	6.77%	289,894	89,303	30.81%

Source: FRCC 2024 Regional Load and Resource Plan and TYSP Utilities' Data Responses

Traditional Generation

Generating capacity within Florida is anticipated to grow to meet the increase in customer demand, with an approximate net increase of 2,159 MW of traditional generation over the planning horizon, with natural gas plant additions offset by coal and oil retirements. Natural gas electric generation, as a percent of NEL, is expected to decline from 70 percent in 2023 to 54 percent over the planning horizon. Figure 2 illustrates the use of natural gas as a generating fuel for electricity production in Florida compared to solar and all other energy sources combined. The total energy produced by solar generation is projected to exceed all other sources combined excluding natural gas by 2028.

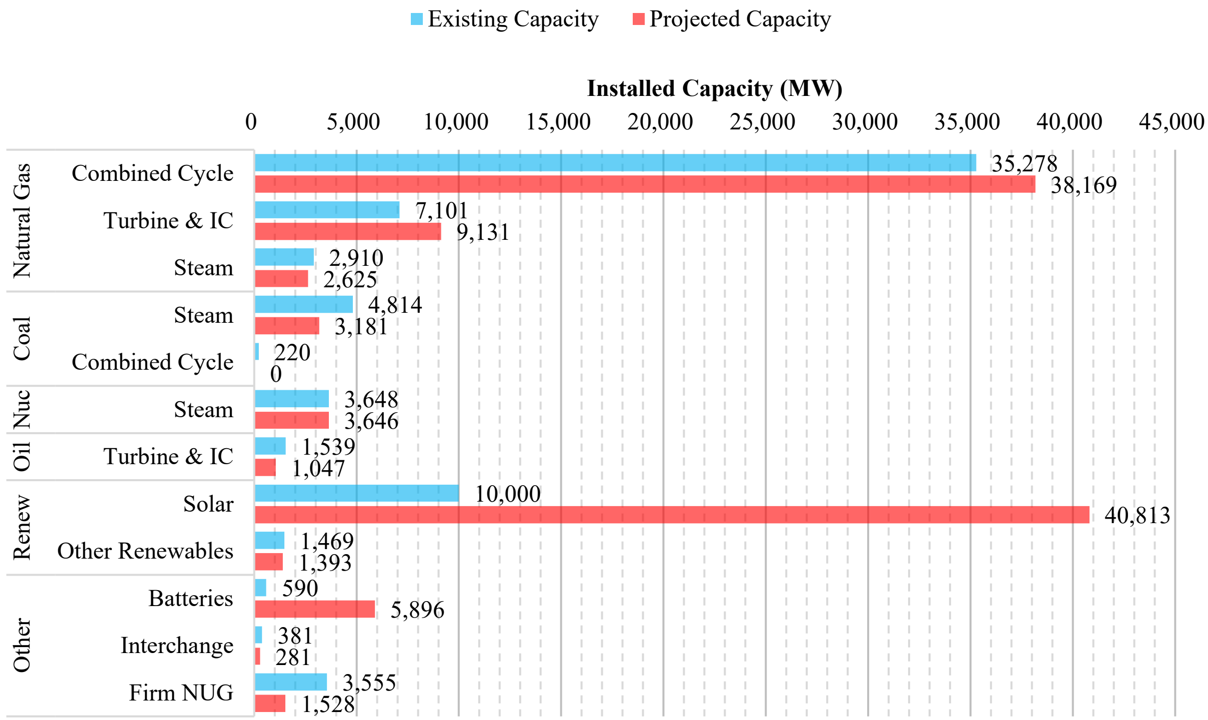
Figure 2: State of Florida - Electricity Generation Sources



Source: FRCC 2015-2024 Regional Load and Resource Plans

Figure 3 illustrates the present and future aggregate capacity mix of Florida based on the 2024 Ten-Year Site Plans. The capacity values in Figure 3 incorporate all proposed additions, changes, and retirements planned during the 10-year period. While natural gas-fired generating units represent a majority of capacity within the state, renewable capacity additions make up the majority of the projected net increase in generation capacity over the planning period. Solar generation is already the second highest category of installed capacity, and will exceed natural gas combined cycle nameplate capacity by the end of the 10-year planning period. As mentioned previously, not all of the installed solar capacity provides a firm resource that is available to serve peak demand.

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



Source: FRCC 2024 Regional Load and Resource Plan and TYSP Utilities' Data Responses

As noted previously, the primary purpose of this review is to provide information regarding proposed electric power plants for local, regional, and state agencies to assist in the certification process. During the next 10 years, there are two new units planned that may require a determination of need from the Commission pursuant to Section 403.519, F.S. JEA's TYSP includes a unit in 2030 and SEC's TYSP includes a unit in 2032.

Future Considerations

Florida's electric utilities must also consider changes in environmental regulations associated with existing generators and planned generation to meet Florida's electric needs. Developments in U.S. Environmental Protection Agency (EPA) regulations may impact Florida's existing generation fleet and proposed new facilities. For example, on May 9, 2024, the EPA released a final rule consisting of five separate actions under the Clean Air Act (CAA) Section 111, targeting greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs). These and other relevant EPA actions are further discussed in the Traditional Generation section.

Emerging Trends

In addition to changes in regulations, the electric utilities must also maintain an awareness of emerging trends in energy consumption and generation technologies, and their impacts on the industry. Trends, such as customer adoption of EVs, the potential for growth of data centers due to applications such as artificial intelligence, solar technologies, energy storage, and grid resilience, are important for the electric utilities to track both to determine future impacts and the best way to address them. One such area is advanced nuclear power technologies, such as small modular reactors. As directed by House Bill 1645, the Commission will be submitting a report evaluating the technical and economic feasibility of using these technologies, and recommendations to enhance nuclear technologies by April 1, 2025. While the information on these trends is limited in this Review of the Ten-Year Site Plans, the Commission will continue to monitor these trends and their impacts as they are included within the electric utilities' Ten-Year Site Plans each year.

Conclusion

The Commission has reviewed the 2024 Ten-Year Site Plans of Florida's electric utilities 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. The Commission will continue to monitor the impact of current and proposed EPA Rules, expansion of EV adoption, and the state's dependence on natural gas for electricity production.

Based on its review, the Commission finds the 2024 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.

Introduction

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

For any new proposed power plants and transmission facilities, certification proceedings under the Florida Electrical Power Plant Siting Act, Sections 403.501 through 403.518, F.S., or the Florida Electric Transmission Line Siting Act, Sections 403.52 through 403.5365, F.S., will include more detailed information than is provided in the Ten-Year Site 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 Ten-Year Site 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, regional, and local agencies to evaluate site-specific issues within their respective jurisdictions. Other regulatory processes may require the electric utilities to provide additional information as needed.

Statutory Authority

Section 186.801, F.S., requires all major generating electric utilities submit a Ten-Year Site Plan to the Commission at least every two years. Based on these filings, the Commission performs a preliminary study of each Ten-Year Site 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 and are forwarded to the Florida Department of Environmental Protection for use in subsequent proceedings. In addition, Section 377.703(2)(e), F.S., requires the Commission to collect and analyze energy forecasts, specifically for electricity and natural gas, and forward this information to the Department of Agriculture and Consumer Services. The Commission has adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code (F.A.C.) in order to fulfill these statutory requirements and provide a solid framework for flexible, cost-effective utility resource planning. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving day-to-day planning and operations to utility management.

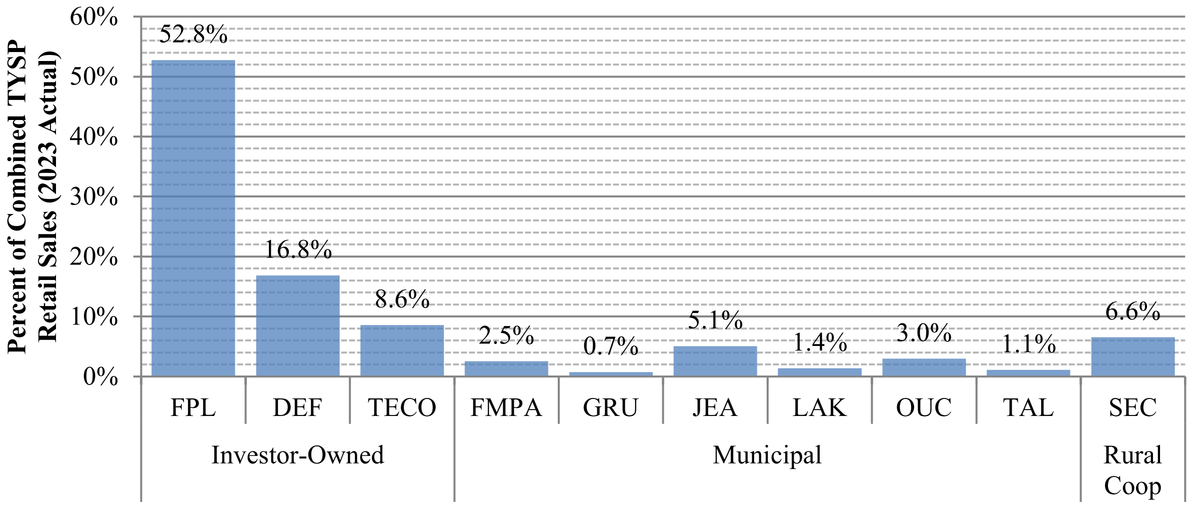
Applicable Utilities

Florida is served by 57 electric utilities, including 4 investor-owned utilities, 35 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only electric utilities with an existing generating capacity above 250 MW or a planned unit with a capacity of 75 MW or greater are required to file a Ten-Year Site Plan with the Commission every year.

In 2024, 10 utilities met these requirements and filed a Ten-Year Site Plan, including 3 investor-owned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company, Duke Energy Florida, LLC, and Tampa Electric Company. The municipal utilities, in alphabetical order, are Florida Municipal Power Agency, Gainesville Regional Utilities, JEA (formerly Jacksonville Electric Authority), Lakeland Electric, Orlando Utilities Commission, and City of Tallahassee Utilities. The sole rural electric cooperative filing a 2024 Ten-Year Site Plan is Seminole Electric Cooperative. Collectively, these utilities are referred to as the Ten-Year Site Plan Utilities (TYSP Utilities).

Figure 4 illustrates the comparative size of the TYSP Utilities, in terms of each utility's percentage share of the combined TYSP Utilities' retail energy sales in 2023. Collectively, the reporting investor-owned utilities account for 78.2 percent of the reported retail energy sales, while the municipal and cooperative utilities make up approximately 20.3 percent of the reported retail energy sales.

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



Source: FRCC 2024 Regional Load and Resource Plan and 2024 Ten-Year Site Plans

Required Content

The Commission requires each reporting utility to provide information on a variety of topics as required by Section 186.801(2) F.S. Schedules describe the utility's existing generation fleet, customer composition, demand and energy forecasts, fuel requirements, reserve margins, changes to existing capacity, and proposed power plants and transmission lines. The utilities also provide a narrative documenting the methodologies used to forecast customer demand and the identification of resources to meet that demand over the 10-year planning period. This information, supplemented by additional data requests, provides the basis of the Commission's review.

Additional Resources

The Florida Reliability Coordinating Council (FRCC) compiles utility data on both a statewide basis and for Peninsular Florida, which excludes the area west of the Apalachicola River. This provides 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. For certain comparisons, the Commission employs additional data from various government agencies, including the Energy Information Administration and the Florida Department of Highway Safety and Motor Vehicles.

Structure of the Commission's Review

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

Conclusion

Based on its review, the Commission finds all 10 reporting utilities' 2024 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.

The Commission notes that the Ten-Year Site Plans are non-binding, and a 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.

Statewide Perspective

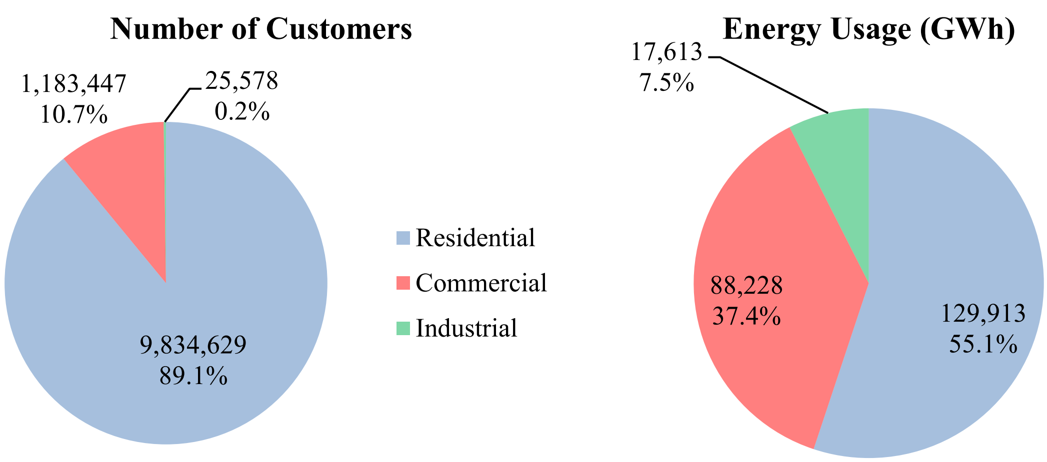
Load Forecasting

Forecasting customer energy needs or load is a fundamental component of electric utility planning. In order to maintain an adequate and reliable system, utilities must project and prepare for changes in overall electricity consumption patterns. These patterns are affected by the number and type of customers, and factors that impact customer usage including weather, economic conditions, housing size, building codes, appliance efficiency standards, new technologies, and demand-side management. Florida's utilities use well-known and tested forecasting methodologies, which are consistent with industrywide practices used in generation planning.

Electric Customer Composition

Utility companies categorize their customers by residential, commercial, and industrial classes. As illustrated in Figure 5, residential customers account for 89.1 percent of the total, followed by commercial (10.7 percent) and industrial (0.2 percent) customers. Commercial and industrial customers make up a sizeable percentage of energy sales due to their higher energy usage per customer.

Figure 5: State of Florida - Electric Customer Composition in 2023



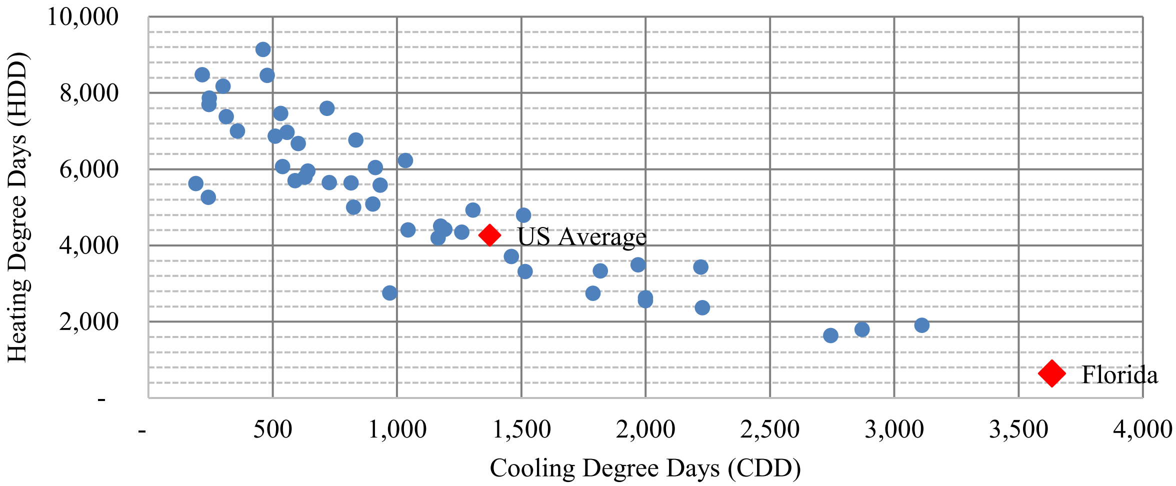
Source: FRCC 2024 Regional Load and Resource Plan

Residential customers in Florida make up the largest portion of retail energy sales. Florida's residential customers accounted for 55.1 percent of retail energy sales in 2023, compared to a national average of approximately 38.4 percent in 2022.[3] As a result, Florida's utilities are influenced more by trends in residential energy usage, which tend to be associated with weather conditions. Florida's unique climate plays an important role in electric utility planning, with the highest number of cooling degree days and lowest number of heating degree days within the

[3] U.S. Energy Information Administration – Sales and Direct Use of Electricity to Ultimate Customers.

continental United States, as shown in Figure 6. As such, most of Florida's utilities experience their peak demand during summer months. However, 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. Even with the low frequency of heating days required, such reliance can impact winter peak demand.

Figure 6: National - 20 Year Average Climate Data by State (Continental US)



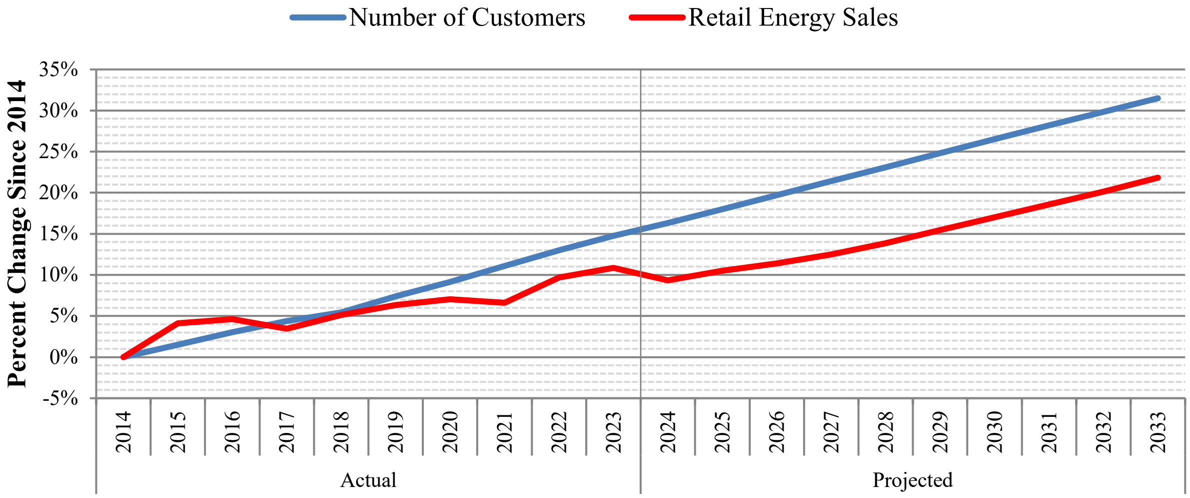
Source: National Oceanic and Atmospheric Administration Data

Growth Projections

For the next 10-year period, Florida's weather normalized retail energy sales are projected to grow at 1.21 percent per year, compared to the 1.15 percent actual annual increase experienced during the 2014-2023 period. The number of Florida's electric utility customers is anticipated to grow at an average annual rate of about 1.37 percent for the next 10-year period, compared to the 1.54 percent actual annual increase experienced during the last decade. These trends are showcased in Figure 7.

As shown in Figure 7, Florida utilities' total retail energy sales reached a historical peak in 2023 surpassing the most recent peak that was reached in 2020. Several factors converged to contribute to this effect: continued growth in the number of retail customers as more people move into the state, warmer than normal weather conditions, and a surge in economic activity in the state's vibrant tourism and service sectors as they further recover from the COVID-19 pandemic, which leads to increased electricity consumption across various industries. The second highest peak in energy sales occurred in 2020, which was mainly a result of residential customers working or schooling from home during the pandemic. Florida utilities' total retail energy sales are projected to continuously grow at a moderate annual average rate for the next 10 years. This sales growth is driven by an anticipated growth in customers and business activity, as well as the expected increased level of adoption of electric vehicles.

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



Source: FRCC 2024 Regional Load and Resource Plan

The projected retail energy sales trend reflects the product of the utilities' forecasted number of customers and forecasted energy consumption per customer. The key factor affecting utilities' number of customers is population growth. The key factors affecting utilities' use-per-customer includes weather, the economy, energy prices, and energy efficiency; hence, the corresponding information is utilized to develop the forecast models for projecting the future growth of use-per-customer. The projected growth rate of retail energy sales is impacted by these underlying key factors.

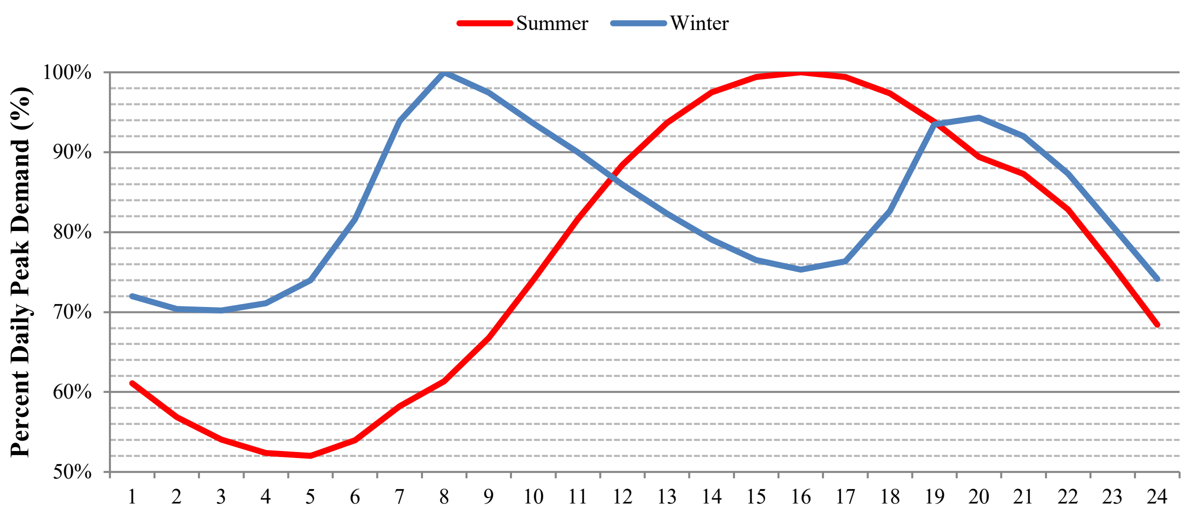
With respect to the energy consumption per customer forecasts, FPL forecasted that its residential use per customer will be flat or slightly grow (as high as 0.4 percent on average) due to economic growth as well as increased adoptions of electric vehicles. The utility expects that its commercial use per customer will decline between 0.1 to 0.7 percent per year over the forecast horizon due to continued improvements to equipment efficiencies. DEF reported that its per customer usage for both residential and commercial classes are primarily driven by fluctuations in electric price, end-use appliance saturation and efficiency improvement, more stringent building codes, housing type/size, and space conditioning equipment energy source. In addition, the utility is aware that more recently, the customer's ability to self-generate has begun to make an impact. A small percentage of industrial/commercial customers have chosen to install their own natural gas generators, reducing energy consumption from the power grid. Similarly, residential and some commercial accounts have reduced their utility requirements by installing solar panels behind the meter. However, DEF also noted that the penetration of plug-in electric vehicles has grown, leading to an increase in residential use per customer, all else being equal. Each of these stated items is directly or indirectly incorporated in DEF's sales forecast. TECO echoed that increases in appliance/lighting efficiencies, energy efficiency in new homes, conservation efforts and changes of its customer housing mix are also the primary drivers affecting the decrease in per customer usage. Other TYSP Utilities likewise reported that the downward pressure to the growth trend in per customer energy consumption is due to advancements in technologies for energy efficiency, renewable generation, and alternative energy sources, with some utilities expecting that the increased electric vehicle charging will mitigate this downward pressure to some extent.

Peak Demand

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

Seasonal weather patterns are a primary factor, 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 cooling (summer) and heating (winter) demand. Figure 8 illustrates a daily load curve for a typical day for each season. In summer, air-conditioning needs increase throughout the day, climbing steadily until a peak is reached in the late afternoon and then declining into the evening. In winter, electric heat and electric water heating produce a higher base level of usage, with a spike in the morning and an additional spike in the evening.

Figure 8: TYSP Utilities - Example Daily Load Curves

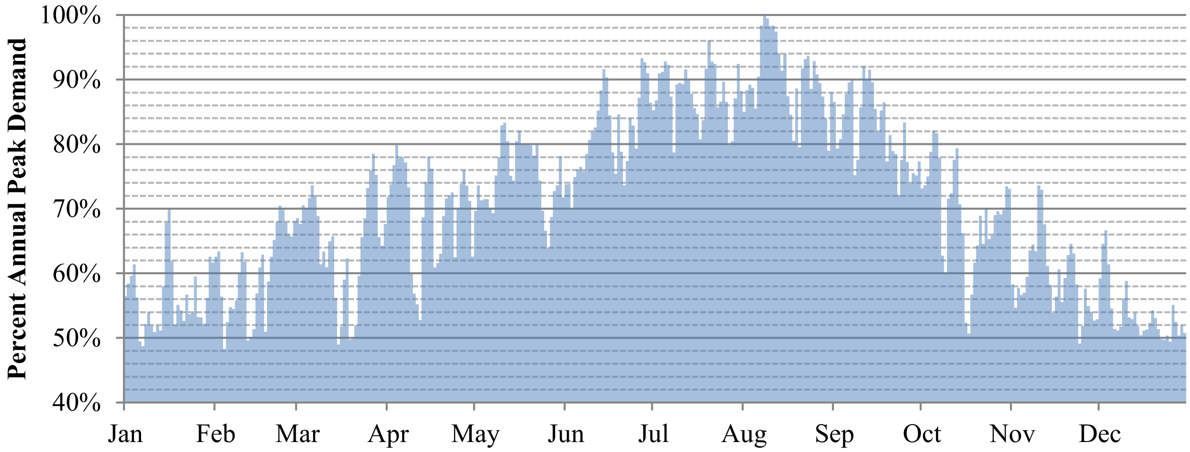


Source: TYSP Utilities' Data Responses

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

As daily load varies, so do seasonal loads. Figure 9 shows the 2023 daily peak demand as a percentage of the annual peak demand for the reporting investor-owned utilities combined. Typically, winter peaks are short events while summer demand tends to stay at near annual peak levels for longer periods. The periods between seasonal peaks are referred to as shoulder months, in which the utilities take advantage of lower demand to perform maintenance without impacting their ability to meet daily peak demand.

Figure 9: TYSP Utilities - Daily Peak Demand (2023 Actual)



Source: 2024 TYSP Utilities' Data Responses (Investor-Owned Utilities Only)

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

Electric Vehicles

Other trends that may impact customer peak demand and energy consumption are also examined by utilities, including new sources of energy consumption, such as electric vehicles (EVs). The reporting TYSP Utilities estimate approximately 428,607 electric plug-in vehicles will be operating in Florida by the end of 2024. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered automobiles, heavy trucks, and buses in Florida, as of January 7, 2024 at 18.64 million vehicles, resulting in an approximate 2.30 percent penetration rate of electric vehicles, up from 1.52 percent last year.[4]

TYSP Utilities responded to a data request regarding projections of electric vehicle ownership, public charging stations, and impacts to their electric grid, and the details appear in Tables 2 through 5. As it relates to the responses received, OUC did not provide projections of EVs,

[4] Florida Department of Highway Safety and Motor Vehicles January 2024 Vehicle and Vessel Reports and Statistics.

charging stations, or EV demand/energy. Florida's retail electric utilities anticipate continued growth in the electric vehicle market, as illustrated in Table 2. Electric vehicle ownership is anticipated to grow rapidly throughout the planning period, resulting in approximately 4,312,553 EVs operating within the reporting utilities' electric service territories by the end of 2033.

Table 2: TYSP Utilities - Estimated Number of Electric Vehicles

Year	FPL	DEF	TECO	GRU	JEA	LAK	TAL	Total
2024	293,845	68,488	47,374	13,467	1,812	1,844	1,777	428,607
2025	428,132	104,185	67,251	16,526	2,226	2,379	2,220	622,919
2026	590,749	157,228	89,559	19,881	2,690	2,983	2,727	865,817
2027	787,129	234,412	114,145	23,577	3,211	3,650	3,331	1,169,455
2028	1,018,957	339,524	140,948	27,665	3,793	4,382	3,990	1,539,259
2029	1,287,414	474,718	169,854	32,169	4,440	5,183	4,731	1,978,509
2030	1,589,148	636,557	200,304	37,114	5,159	6,024	5,568	2,479,874
2031	1,929,264	822,895	231,346	42,493	5,951	6,873	6,442	3,045,264
2032	2,300,764	1,029,188	263,294	48,347	6,824	7,735	7,467	3,663,619
2033	2,695,021	1,242,094	295,772	54,689	7,781	8,595	8,601	4,312,553

Source: TYSP Utilities' Data Responses

The major drivers of EV growth include a combination of the following: increased availability of charging infrastructure, lower fuel costs and emissions, increased commitment from auto manufacturers, broadened public outreach, expanded vehicle availability (makes and models), and strong government policy support at the local, state, and federal levels. Government agencies, private entities, municipalities, and electric utilities continue to work together to expand charging infrastructure throughout the state to meet this expected growth in EVs as well as to promote electric vehicle ownership.

Table 3 illustrates the reporting electric utilities' projections of public EV charging stations through 2033. While approximately 16,000 charging stations are estimated to be available across the state by the end of 2024, more than 136,000 charging stations are anticipated by 2033. The estimated EV charging station counts listed in Table 3 include both normal and "quick-charge" public charging stations.[5]

[5] "Quick-charge" public EV charging stations are those that require a service drop greater than 240 volts and/or use three-phase power.

Table 3: TYSP Utilities - Estimated Number of Public EV Charging Stations

Year	FPL	DEF	TECO	GRU	JEA	LAK	TAL	Total
2024	12,770	1,905	710	200	94	25	135	15,839
2025	20,601	2,498	810	232	148	30	136	24,455
2026	29,392	3,246	916	266	179	40	137	34,176
2027	38,516	4,209	1,028	302	214	50	139	44,458
2028	48,807	5,395	1,147	341	253	55	140	56,138
2029	60,490	6,819	1,272	384	296	60	141	69,462
2030	72,659	8,450	1,404	430	344	65	142	83,494
2031	86,389	10,311	1,542	479	397	70	143	99,331
2032	100,511	12,397	1,687	532	455	75	145	115,802
2033	118,956	14,574	1,838	589	519	80	147	136,703

Source: TYSP Utilities' Data Responses

Table 4 illustrates the TYSP Utilities' projections of energy consumed by EVs through 2033. Across the TYSP Utilities, anticipated growth would result in an annual energy consumption of 14,862.4 GWh by 2033, which represents an impact of approximately 5.2 percent of net energy for load.[6]

Table 4: TYSP Utilities - Estimated Electric Vehicle Annual Energy Consumption (GWh)

Year	FPL	DEF	TECO	GRU	JEA	LAK	TAL	Total
2024	351.5	49.6	263.8	45.5	8.7	1.5	2.6	723.1
2025	816.1	143.2	352.8	58.2	10.7	1.5	3.5	1,386.0
2026	1,387.8	285.6	454.2	72.2	12.9	2.9	4.7	2,220.4
2027	2,092.6	496.1	564.9	87.6	15.4	4.4	6.3	3,267.4
2028	2,945.3	791.7	683.2	104.7	18.2	4.4	8.8	4,556.2
2029	3,957.4	1,182.5	810.4	123.5	21.3	4.4	12.0	6,111.4
2030	5,123.6	1,662.6	944.2	144.2	24.8	7.3	15.8	7,922.4
2031	6,523.6	2,220.8	1,080.8	166.8	28.6	7.3	20.0	10,047.9
2032	8,117.9	2,845.7	1,221.9	191.3	32.8	8.8	24.9	12,443.2
2033	9,696.5	3,506.0	1,365.5	218.0	37.3	8.8	30.3	14,862.4

Source: TYSP Utilities' Data Responses

Table 5 illustrates the TYSP Utilities' estimates of the effects of EV ownership on summer and winter peak demand through 2033. Across the TYSP Utilities, anticipated growth results in an impact to summer peak demand of approximately 3,503.4 MW and an impact to winter peak demand of approximately 1,319.6 MW by 2033. Current estimates represent a cumulative impact

[6] Estimate assumes a state-wide net energy for load of approximately 285,404 GWH by 2033, as discussed later in the Forecast Load and Peak Demand section of this TYSP.

of approximately 6.3 percent on summer peak demand and a 2.6 percent on winter peak demand by 2032.[7]

Table 5: TYSP Utilities – Estimated Electric Vehicle Impact – Seasonal Peak Demand

Summer Peak Demand (MW)

Year	FPL	DEF	TECO	GRU	JEA	LAK	TAL	Total
2024	86.3	13.7	50.1	3.9	7.7	1.0	0.5	163.3
2025	200.5	33.6	66.3	5.0	9.2	1.0	0.7	316.3
2026	340.9	63.0	84.9	6.2	11.0	2.0	0.9	508.9
2027	514.0	105.6	105.0	7.5	13.1	3.0	1.2	749.5
2028	723.5	164.1	126.5	9.0	15.5	3.0	1.7	1,043.3
2029	972.1	293.4	149.6	10.6	18.1	3.0	2.3	1,449.1
2030	1258.5	331.4	173.8	12.4	21.1	5.0	3.1	1,805.2
2031	1602.4	531.1	198.5	14.3	24.3	5.0	3.9	2,379.6
2032	1994.0	668.6	224.1	16.4	27.9	6.0	4.8	2,941.8
2033	2381.8	809.1	250.1	18.7	31.8	6.0	5.9	3,503.4

Winter Peak Demand (MW)

Year	FPL	DEF	TECO	GRU	JEA	LAK	TAL	Total
2024	37.3	0.4	16.8	1.0	7.7	1.0	0.1	64.3
2025	86.7	3.4	21.3	1.3	9.2	1.0	0.1	123.1
2026	147.4	8.3	26.9	1.6	11.0	2.0	0.2	197.5
2027	222.3	16.0	32.7	2.0	13.1	3.0	0.3	289.4
2028	312.9	27.8	38.8	2.3	15.5	3.0	0.5	400.9
2029	420.5	44.6	45.3	2.8	18.1	3.0	0.6	534.8
2030	544.4	67.4	52.0	3.2	21.1	5.0	0.9	694.0
2031	693.1	96.0	58.9	3.7	24.3	5.0	1.2	882.3
2032	862.5	130.9	66.1	4.3	27.9	6.0	1.5	1,099.2
2033	1030.2	171.4	73.4	4.9	31.8	6.0	1.9	1,319.6

Source: TYSP Utilities' Data Responses

In order to prepare for and to accommodate the inevitable increase in EV ownership, several utilities now offer programs or tariffs applicable to EV customers. While the nature of these programs/tariffs vary among utilities, many include Time-of-Use (TOU) rates, rebates on certain

[7] Estimate assumes a state-wide net firm summer peak demand of approximately 55,956 MW and a net firm winter peak demand of approximately 51,076 MW by 2033, as discussed later in the Forecast Load and Peak Demand section of this TYSP.

charging station installations, and programs designed to increase general outreach, education, and awareness of the EV market.

In addition to the increase in general outreach, etc. for EV market awareness and education, some utilities currently operate specific EV pilot programs in order to investigate potential unknowns associated with the market. These programs have been established either as independently initiated programs or as part of rate case settlement agreements. Most of the programs are multi-year pilot programs which include extensive investments in electric vehicle charging infrastructure and market research. EV Pilot programs serve to provide the utilities insight for assessment as to whether such programs/tariffs should be continued, expanded, made permanent, or discontinued. These pilot programs also provide the Commission with valuable information, such as individual charging session data, peak EV charging hours, and impacts to peak demand - via annual updates from the utilities with regard to their respective pilot programs. The Commission will continue to closely monitor the key findings and metrics of interest within these pilot programs in order to be prepared to address any regulatory issues associated with the future energy and demand impacts of electric vehicles in Florida.

Demand-Side Management (DSM)

Florida's electric utilities also consider how the efficiency of customer energy consumption changes over the planning period. Changes in government mandates, such as building codes and appliance efficiency standards, reduce the amount of energy consumption for new construction and electric equipment. Electric customers, through the power of choice, can elect to engage in behaviors that decrease peak load or annual energy usage. Examples include: turning off lights and fans in vacant rooms, increasing thermostat settings in the summer, 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. DSM programs 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)

In 1980, the Florida Legislature established FEECA, which consists of Sections 366.80 through 366.83 and Section 403.519, F.S. Under FEECA, the Commission is required to set appropriate goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems for electric utilities of a certain size, known as the FEECA Utilities.[8] Of the TYSP Utilities, these include the three investor-owned electric utilities, FPL, DEF, TECO, and two municipal electric utilities, JEA and OUC. The FEECA Utilities represented approximately 86.2 percent of 2023 retail electric sales reported by the TYSP Utilities.

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.

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[8] FEECA also applies to Florida Public Utilities Company, a non-generating investor-owned electric utility. As FPUC purchases power from other generating entities and does not own or operate its own generation resources, it is not required to file a Ten-Year Site Plan.

In 2024, the Commission held a hearing and established goals for each of the FEECA Utilities for the period 2025 through 2034. Each FEECA electric utility will be required to submit a proposed DSM Plan, designed to meet its goals within 90 days of the final order establishing the goals. These proceedings are anticipated to be completed during 2025. The Commission is scheduled to have its next goalsetting proceeding no later than 2029 for the period 2030 through 2039.

DSM Programs

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

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

Load management is similar to interruptible load, but focuses on smaller customers and targets individual appliances. The utility installs a device on an electric appliance, such as a water heater or air conditioner, which allows for remote deactivation for a short period of time. Load management activations tend to have less advanced notice than those for interruptible customers, but tend to be activated only for short periods and are cycled through groups of customers to reduce the impact to any single customer. Due to the focus on specific appliances, certain appliances would be more appropriate for addressing certain seasonal demands. For example, load management programs targeting air conditioning units would be more effective to reduce a summer peak, while water heaters are more effective for reducing a winter peak. As of 2024, the total amount of demand response resources available for reduction of peak load is 3,151 MW for summer peak and 2,965 MW for winter peak. Demand response is anticipated to decline to approximately 3,082 MW for summer peak and 2,937 MW for winter peak by 2033. Residential load management is anticipated to decline slightly, while interruptible load is level and commercial/industrial demand response has a slight increase.

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 December 31, 2023, energy efficiency is responsible for peak load reductions of 4,617 MW for summer peak and 4,084 MW for winter peak. Energy efficiency is anticipated to increase to approximately 5,967 MW for summer peak and 5,235 MW for winter peak by 2033.

Forecast Load and Peak Demand

The historic and forecasted seasonal peak demand and annual energy consumption values for Florida are illustrated in Figure 10. 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. Forecasted net energy for load in 2024 is lower than the actual net energy for load in 2023. This is because of warmer weather conditions in 2023, and normalized weather trends were used to forecast 2024 through 2033.

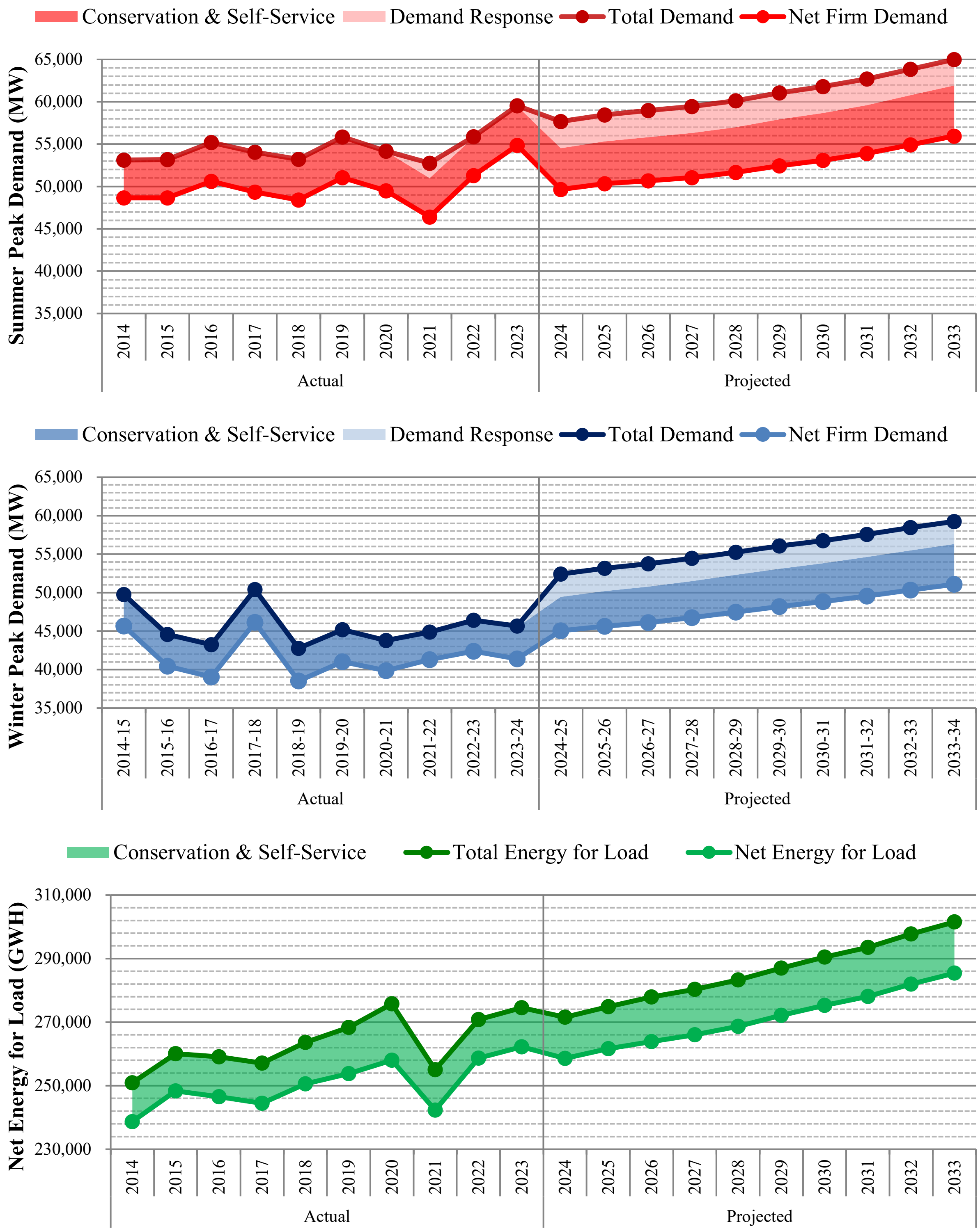
Demand-side management, including demand response and energy efficiency, along with self-service generation, is included in each graph appearing in Figure 10 for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served if not for the impact of these programs and self-service generators. The net firm demand is used as a planning number for the calculation of generating reserves and determination of generation needs for Florida's electric utilities.

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

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

As previously discussed, Florida is normally a summer-peaking state and was for the past 10 years. This trend is anticipated to continue, with the next 10 forecasted years all anticipated to be summer peaking. Based upon current forecasts using normalized weather data, Florida's electric utilities anticipate a gradual increase in both summer and winter net firm demand during the planning period.

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



Source: FRCC 2024 Regional Load and Resource Plan

Forecast Methodology

Load forecasting is an essential requirement of all electric utility companies for purposes of system planning. In order for utilities to reliably and cost-effectively serve their respective customers, they must be able to accurately determine their energy and demand requirements. Thus, the load forecast function facilitates the ongoing balance between system demand and system supply.

Load forecasting can be divided into three types depending on the forecasting horizon: short, medium and long-term. Short-term load forecasting denotes forecast horizons of up to one week ahead. Medium-term load forecasting ranges from one week to one year ahead. Long-term load forecasting typically targets forecast horizons of one to ten years, and sometimes up to several decades. Long-term load forecasting provides the essential load requirement data that a utility must have in order to effectively modify its system of generation, transmission, and distribution assets. Load forecasts directly impact the timing, type, and location of expansions, replacements, and retirements. Hence, the load forecast function plays a vital role in an electric utility's system planning and, in Florida, serves as the foundation of a utility's Ten-Year Site Plan (TYSP).

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

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

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

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

Historically, the various forecast models and techniques used by Florida's electric utilities are commonly used throughout the industry, and each utility has developed its own individualized approach to project load. The models have relied upon dependent and independent variable data to project energy sales and demand amounts that exist within a probabilistic range. The resulting forecasts allow each electric utility to evaluate its individual needs for new generation, transmission, and distribution resources to meet customers' current and future needs reliably and affordably. Again for the 2024 TYSPs, Florida's electric utilities used these same types of models and techniques to prepare their forecasts.

Accuracy of Retail Energy Sales Forecast

For each reporting electric utility, the Commission reviewed the historic forecast accuracy of past retail energy sales forecasts. The standard methodology for our review involves comparing actual retail energy sales for a given year to energy sales forecasts made three, four, and five years prior. For example, the actual 2023 retail energy sales were compared to the forecasts made in 2018, 2019, and 2020. The resulting differences, expressed as a percentage error rate, are used to determine each utility's historic forecast accuracy by applying 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 2024 TYSPs, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2014 through 2023 to forecasts made between 2005 and 2020. These are summarized in Table 6.

Table 6: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts
(Five-Year Rolling Average)

Year	Five-Year Analysis Period	Forecast Years Analyzed	Forecast Error (%)	
			Average	Absolute Average
2014	2014 - 2010	2011 - 2005	14.95%	14.95%
2015	2015 - 2011	2012 - 2006	12.48%	12.48%
2016	2016 - 2012	2013 - 2007	9.11%	9.11%
2017	2017 - 2013	2014 - 2008	5.96%	5.96%
2018	2018 - 2014	2015 - 2009	3.47%	3.47%
2019	2019 - 2015	2016 - 2010	2.13%	2.32%
2020	2020 - 2016	2017 - 2011	1.58%	2.04%
2021	2021 - 2017	2018 - 2012	1.04%	1.61%
2022	2022 - 2018	2019 - 2013	-0.13%	1.36%
2023	2023 - 2019	2020 - 2014	-1.02%	1.59%

Source: 2005-2024 Ten-Year Site Plans
* Inputs used including utilities' revisions to the corresponding prior TYSP-reported actual and/or projected data.

To verify whether more recent forecasts lowered the error rates, an additional analysis was conducted to determine, with more detail, the source of high error rates in terms of forecast timing. Table 7 provides the error rates for forecasts made between one to six years prior, along with the three-year average and absolute average error rates for the forecasting period of a three to five-year period that was also used in the analysis in Table 6.

As displayed in Table 7, the utilities' retail energy sales forecasts show large positive error rates during the recession-impacted period 2012 through 2015. Starting in 2015, the error rates have declined considerably; and, the error rates calculated based on recent years' TYSPs continue to show lower forecast error rates, compared to the peak value of the error rates related to 2012-2014 sales forecasts. Most of the last four years' four-year ahead forecasts and the last five years' three-year ahead forecasts all bear negative error rates (under-forecasts). Additionally, the last six years' two-year ahead forecasts and one-year ahead forecasts render negative error rates as well. Note that all of the 2022- and 2023-related forecasts made between one to six years prior show relatively higher negative error rates. This is due to the respective annual retail energy sales achieved which is largely attributable to the very hot weather Florida experienced in 2022 and 2023.

Table 7: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts - Annual Analysis
(Analysis of Annual and Three-Year Average of Three- to Five- Prior Years)*

Year	Annual Forecast Error Rate (%)						3-5 Year Error (%)	
	Years Prior						Average	Absolute Average
	6	5	4	3	2	1		
2012	26.43%	26.12%	23.16%	8.58%	4.01%	3.81%	19.29%	19.29%
2013	28.58%	26.29%	10.00%	5.98%	5.58%	2.97%	14.09%	14.09%
2014	27.15%	9.69%	6.00%	5.62%	2.73%	2.11%	7.10%	7.10%
2015	7.18%	3.53%	3.13%	0.92%	-0.10%	-1.27%	2.52%	2.52%
2016	4.22%	4.27%	2.18%	1.14%	0.10%	-1.07%	2.53%	2.53%
2017	6.87%	4.82%	3.48%	2.42%	1.45%	-0.18%	3.57%	3.57%
2018	4.16%	2.65%	1.64%	0.64%	-1.25%	-1.19%	1.64%	1.64%
2019	2.77%	1.86%	0.75%	-1.40%	-1.42%	-2.03%	0.40%	1.34%
2020	2.44%	1.27%	-0.97%	-1.07%	-1.91%	-1.22%	-0.25%	1.10%
2021	2.58%	0.35%	0.02%	-0.80%	-0.05%	0.03%	-0.15%	0.39%
2022	-1.60%	-1.87%	-2.85%	-2.23%	-2.13%	-3.06%	-2.32%	2.32%
2023	-2.09%	-3.27%	-2.68%	-2.45%	-3.16%	-2.63%	-2.80%	2.80%

Source: 2005-2024 Ten-Year Site Plans
*Inputs used include utilities' revisions to the corresponding prior TYSP-reported actual and/or projected sales data.

Barring any unforeseen economic crises or atypical weather patterns, average forecasted energy sales error rates in the next few years are likely to be more reflective of the error rates shown for 2015 through 2022 in Table 7. However, all the major global and domestic events (e.g., the Russo-Ukrainian War, pandemic, supply chain issues, high inflation rates, potential recession, etc.), individually or collectively, could inflict damage to the US economy. As such, there remains uncertainty as to what the economic impacts of such events will be going forward. Therefore, the actual retail energy sales of the next few years could be different from what Florida utilities projected in 2023 and prior years. Consequently, the average forecasted energy sales error rates in the next few years may deviate from the lower levels recently recorded. It is important to recognize that the dynamic nature of the economy, the weather, and even global health, political and economic issues present a degree of uncertainty for Florida utilities' load forecasts, ultimately impacting the accuracy of retail energy sales forecasts.

Renewable Generation

Pursuant to Section 366.91, F.S., the Legislature has found that it is in the public interest to promote the development of renewable energy resources in Florida. Section 366.91(2)(e), 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 or resulting 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)(e), 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 11,470 MW of firm and non-firm generation capacity, which represents 16 percent of Florida's overall generation capacity of 71,505 MW in 2023. Table 8 summarizes the contribution by renewable type of Florida's existing renewable energy sources.

Table 8: State of Florida - Existing Renewable Resources

Renewable Type	MW	% Total
Solar	10,000	87.2%
Municipal Solid Waste	473	4.1%
Biomass	380	3.3%
Waste Heat	227	2.0%
Wind	272	2.4%
Landfill Gas	67	0.6%
Hydroelectric	51	0.4%
Renewable Total	**11,470**	100.0%

Source: FRCC 2024 Regional Load and Resource Plan and TYSP Utilities' Data Responses

Of the total 11,470 MW of renewable generation, approximately 3,937 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 fuel power plants. Solar generation contributes approximately 3,499 MW to this total, based upon the coincidence of solar generation and summer peak demand, or about 34 percent of its installed capacity. Changes in timing of peak demand may influence the firm contributions of renewable resources such as solar and wind.

Of the 1,470 MW of non-solar generation, only 438 MW is treated as firm because of contractual commitments. 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.

Utility-Owned Renewable Generation

Utility-owned renewable generation also contributes to the state's total renewable capacity, including 7,410 MW of installed capacity. The majority of this generation is from solar facilities. Due to the intermittent nature of solar resources, capacity from these facilities has previously been considered non-firm for planning purposes. However, several utilities are attributing firm capacity contributions to their solar installations based on the coincidence of solar generation and summer peak demand. Of the approximately 7,254 MW of existing utility-owned solar capacity, approximately 3,628 MW, or about 48 percent, is considered firm. All other renewable sources account for an additional 157 MW of utility-owned generation.

Non-Utility Renewable Generation

Approximately 4,059 MW, or 35 percent of Florida's existing renewable capacity is not owned by utilities, either from large supply-side non-utility generators or small distributed customer owned generation. Approximately 1,708 MW of that comes from supply side resources from non-utility generators such as cogeneration facilities and renewable energy power plants with a capacity no greater than 80 MW (collectively referred to as Qualifying Facilities or QFs). In 1978, the US Congress enacted the Public Utility Regulatory Policies Act (PURPA), which requires utilities to purchase electricity from QFs at the utility's full avoided cost. These costs are defined in Section 366.051, F.S., which provides in part that:

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

If a renewable energy generator can meet certain deliverability requirements, its capacity and energy output can be paid for under a firm contract. Rule 25-17.250, F.A.C., requires each investor-owned utility 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 Ten-Year Site Plan. In order to promote renewable energy generation, the Commission requires the investor-owned utilities to offer multiple options for capacity payments, including the options to receive early (prior to the in-service date of the avoided-unit) or levelized payments. The different payment options allow renewable energy providers the option to select the payment option that best fits its financing requirements, and provides a basis from which negotiated contracts can be developed.

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

Demand-Side Renewable Generation

Approximately 2,351 MW, or 21 percent of existing renewable capacity is from customer-owned systems, also referred to as demand-side renewable systems. Rule 25-6.065, F.A.C., requires the investor-owned utilities to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer with renewable generation capability, to offset their energy usage. In 2008, the effective year of Rule 25-6.065, F.A.C., customer-owned renewable generation accounted for 3 MW of renewable capacity. As of the end of 2023, approximately 2,351 MW of renewable capacity from over 249,521 systems has been installed statewide. Table 9 summarizes the growth of customer-owned renewable generation interconnections. Almost all installations are solar, with non-solar generation accounting for only 28 installations and 7 MW of installed capacity. The renewable generators in this category include wind turbines and anaerobic digesters.

Table 9: State of Florida - Customer-Owned Renewable Growth

Year	2017	2018	2019	2020	2021	2022	2023
Number of Installations	24,166	37,862	59,508	90,552	103,947	189,952	249,521
Installed Capacity (MW)	205	317	514	835	1,177	1,780	2,351

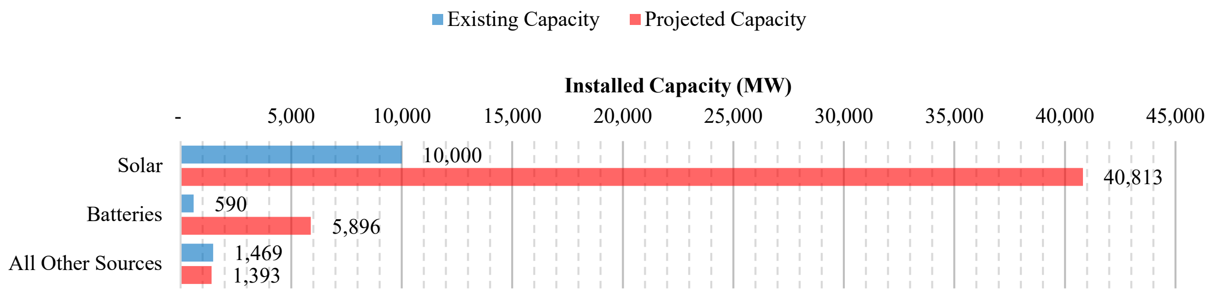
Source: 2017-2024 Net Metering Reports

Planned Renewable Resources

Florida's total renewable resources are expected to increase by an estimated 30,737 MW over the 10-year planning period, an increase from last year's estimated 27,630 MW projection. Figure 11 summarizes the existing and projected renewable capacity by generation type as well as energy storage capacity in the form of batteries. Solar generation, primarily utility-owned, is the sole renewable type projected to increase over the planning horizon. While solar generation is covered under the Power Plant Siting Act, all future solar projects are below the 75 MW threshold, and therefore are not required to seek approval from the Commission prior to construction.

Of the 30,737 MW projected net increase in renewable capacity, firm resources contribute 4,351 MW, or about 14 percent, of the total. This net increase value takes into account that for some existing renewable facilities are retired or contracts for firm capacity are projected to expire within the 10-year planning horizon, decreasing renewable capacity by 76 MW. 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.

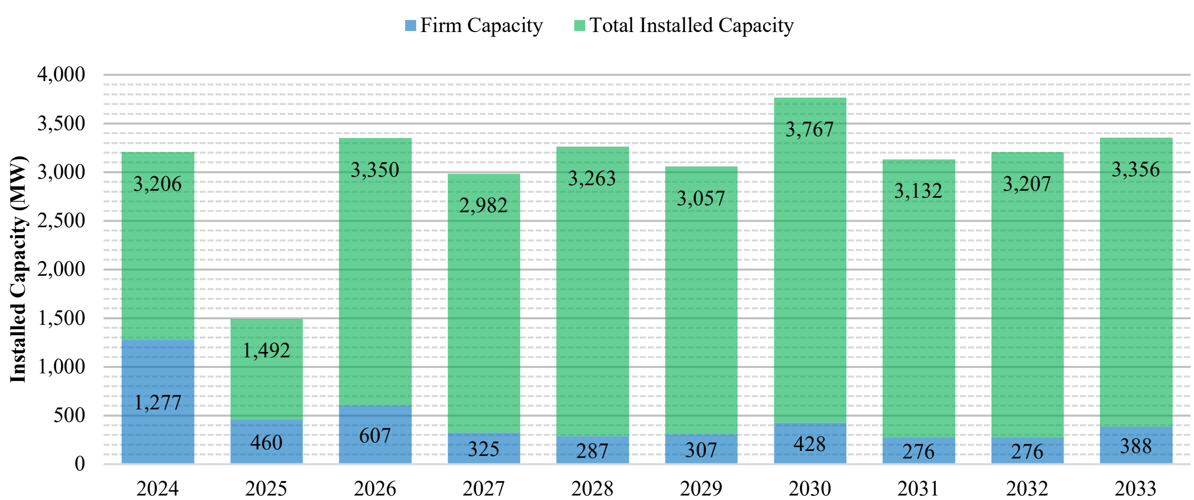
Figure 11: State of Florida - Current and Projected Renewable Resources



Source: FRCC 2024 Regional Load and Resource Plan and TYSP Utilities' Data Responses

As noted above, solar generation is anticipated to increase significantly over the 10-year period, with a net total of 30,813 MW to be installed. This consists of 27,366 MW of utility-owned solar and 3,447 MW of contracted solar. The firm contribution of solar varies by utility, with some having a set percentage value for all projects over the planning period, and others having a declining value as projects are added. Figure 12 provides an overview of the additional solar capacity generation planned within the next 10 years, as well as the amount considered firm for summer reserve margin planning.

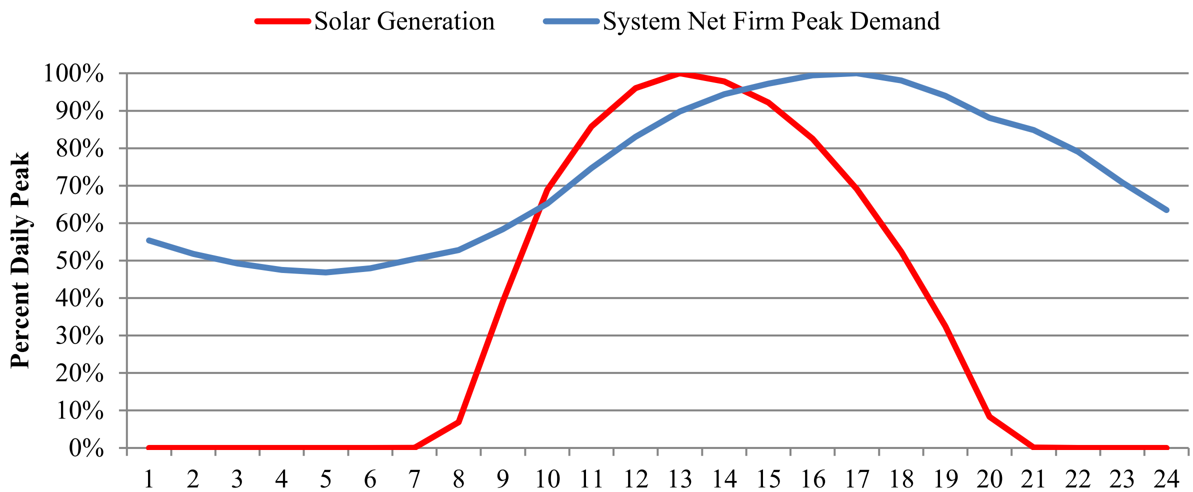
Figure 12: TYSP Utilities - Planned Solar Installations



Source: FRCC 2024 Regional Load and Resource Plan and TYSP Utilities' Data Responses

As the amount of solar increases in the state, the difference in how it operates compared to traditional generation will have an increasing importance to the grid. Solar generation cannot be dispatched as needed, but is produced based upon the conditions at the plant site, influenced by variations in daylight hours, cloud cover, and other environmental factors. Generally speaking, the peak hours for production of a solar facility are closer to noon, whereas the peak in system demand tends to be in the early evening in summer and early morning in winter. Figure 13 illustrates this with example data from FPL's 2023 TYSP hourly dispatch model for their 2024 summer peak day. While solar generation peaks at 1:00 p.m., the net firm system demand peaks at 5:00 p.m., when solar generation is only at 69 percent of its daily peak. By 6:00 p.m., demand remains high, at 98 percent of its daily peak, while solar generation falls to 52 percent. Energy storage and other technologies to shift load, such as demand-side management programs or demand response, can be used to offset these characteristics.

Figure 13: FPL 2024 Summer Peak Day Hourly Dispatch



Source: 2023 FPL Data Response

Energy Storage Outlook

In addition to a number of electric grid related applications, emerging energy storage technologies have the potential to considerably increase not only the firm capacity contributions from solar PV installations, but their overall functionality as well. Energy storage technologies currently being researched include pumped hydropower, flywheels, compressed air, thermal storage, and battery storage. Of these technologies, battery storage is primarily planned and used by utility companies. Battery storage has been proposed to be connected directly to the grid, behind the meter box (net metering) or connected directly to a Solar/PV unit. Battery storage technology has continued to advance, and the cost of storage is projected to continue to decline over the long-term, aided, in part, by continued tax credits from the Inflation Reduction Act.

Currently, Florida's utilities have primarily engaged in small pilot programs to determine the best placement and usage for energy storage technologies, including behind the customer's meter, at distribution substations, and at generating facilities. Each use case has its own benefits, to allow customers to ride out outages (net metering), improve reliability and decrease line losses (distribution substations), or provide firm capacity to the grid (at generating facilities). Currently, the TYSP Utilities have 590 MW of installed energy storage, primarily batteries, with the single largest installation being FPL's 409 MW Manatee battery storage site.

Over the next decade, utilities are anticipating adding approximately 5,305 MW of energy storage, primarily directly on the transmission system or connected to a specific power plant. While energy storage is discussed here within the context of renewables, as they provide firming for intermittent solar facilities, grid connected batteries will not be restricted to charging from renewable sources. These units can be charged using any source during off-peak periods, either from solar or fossil generation. To the extent solar generation is charging batteries it is also not offsetting fossil generation that otherwise would be occurring on the grid during the same period. Some energy storage will be directly connected to a specific renewable power plant however. For example, DEF will be constructing combined solar and energy storage systems, with 40 MW of planned energy storage capacity per 74.9 MW solar site. As these systems are associated with a particular facility, the improved firm contribution has already been included in the prior discussion regarding solar firm capacity.

Traditional Generation

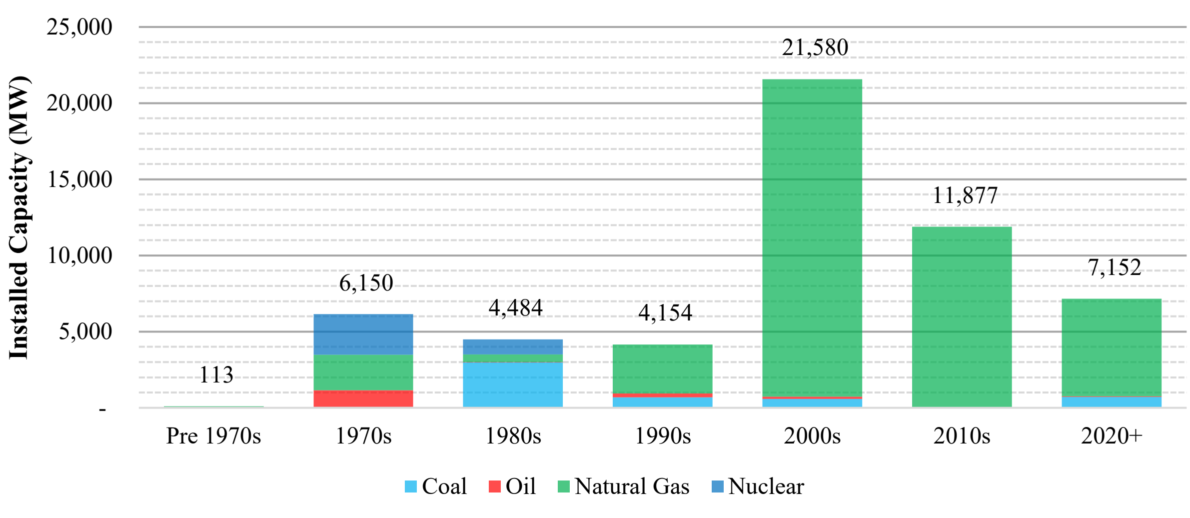
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and combustion turbine generators that have been added to Florida's electric grid over the last several decades.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

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

Existing Generation

Florida's generating fleet includes incremental new additions to a historic base fleet, with units retiring as they become uneconomical to operate or maintain. Currently, Florida's existing capacity ranges greatly in age and fuel type, and legacy investments continue. The weighted average age of Florida's traditional generating units is 21 years. While the original commercial in-service date may be in excess of 50 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 14 illustrates the decade in which current operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

Figure 14: State of Florida - Electric Utility Installed Capacity by Decade



Source: FRCC 2024 Regional Load and 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

On April 24, 2024, the EPA published the final rule, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants. Section 111 of the CAA directed the EPA to determine the best system of emission reduction (BSER), determine the degree of emission limitation achievable through the application of that system, and impose an emissions limit on new stationary sources that reflected that amount.

For existing coal-fired units, the final EPA rule identifies three subcategories based on how far into the future these plants plan to operate. Plants that plan to permanently cease operation prior to January 1, 2032, have no emission reduction guidelines under the final ruling. Plants that plan to cease operation by January 1, 2039, will be assigned a numeric emission rate limit based on 40 percent natural gas co-firing that they must meet by January 1, 2030. Plants that plan to operate past January 1, 2039, will be assigned a numeric emission rate limit based on application of carbon capture and sequestration (CCS) with 90 percent capture that must be met by January 1, 2032.

For new combustion turbines, the final rule establishes three subcategories based on how intensively they are operated: baseload, intermediate load, and low load. Baseload is defined as units with a capacity factor of at least 40 percent. Compliance for new base load turbines is broken down into two phases. Phase One includes highly efficient generation. Phase Two requires utilization of CCS with 90 percent capture by January 1, 2032. Intermediate load is defined as units with a capacity factor between 20 to 40 percent. For new intermediate load turbines, the BSER has been identified as highly efficient simple cycle generation. Low load is defined as units with a capacity factor less than 20 percent (peaking units). For new low load turbines, the BSER is the use of lower-emitting fuels.

Prior to the final rule, the EPA had published a proposed rule on May 11, 2023. Perhaps the most controversial aspect of the proposed rule dealt with emission standards for existing natural gas EGUs. However, in the final rule the EPA has declined to impose emission standards on existing natural gas power plants at this time.

The final rule has relied solely on a BSER of CCS for existing coal and new baseload natural gas EGUs. CCS has not been sufficiently demonstrated to be technically feasible and may be cost-prohibitive to implement. As a result, the final rule is likely to limit the feasibility of operating existing coal units until CCS technology has been demonstrated to be technically and economically deployable, a timeframe for which does not currently exist.

On February 15, 2024, the New York Attorney General, Letitia James, led a coalition of 16 states in filing a motion to intervene with the Supreme Court against the EPA's final rule, arguing that the EPA lacks authority to establish these regulations. On April 18, 2024, the Florida Attorney General, Ashley Moody, joined and filed a lawsuit to block the new EPA emissions rule.

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.

Several utilities converted of oil-fired and coal-fired steam units to natural gas-fired combined cycle units, or converted or upgraded to run on natural gas for all or a majority of their fuel. This trend continues, with direct coal-fired steam to natural gas-fired steam, such as OUC's conversion of Stanton Unit 2 by 2027. Additional planned conversions from coal or other solid fuels are planned by the TYSP Utilities, including TECO's conversion of the Polk Unit 1 integrated gasification combined cycle unit, the only petcoke fueled combined cycle within the State, to a natural gas-fired combustion turbine.

Utilities also plan several efficiency improvements to existing generating units. For example, the conversion of existing simple cycle combustion turbines into a combined cycle unit, which captures the waste heat and uses it to generate additional electricity using a steam turbine. Overall, 560 MW of additional summer firm capacity is from uprates to existing natural gas fired combined cycle units. In addition, DEF and OUC plan transmission upgrades that will allow them improved access to capacity from existing natural gas units at the Osprey and Osceola plant sites in 2025. While these do not change the amount of capacity available in the state as a whole, it improves the ability to deliver capacity where needed on the system.

Utilities are also investigating potential future conversions or dual-firing with hydrogen. For example, FPL's hydrogen pilot at its Okeechobee natural gas-fired combined cycle facility, approved as part of FPL's 2021 Settlement Agreement,[9] involves using a solar powered electrolyzer to produce hydrogen from water and replacing up to 5 percent of the fuel mix with hydrogen in the unit's combustion turbines.

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 lists the 2,456 MW of existing generation that is scheduled to be retired during the planning period. A majority of the retirements are coal-fired steam generators, with four units totaling 1,167 MW of

[9] Order No. PSC-2021-0446-S-EI, issued December 2, 2021, in Docket No. 20210015-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

capacity to be retired by 2029, followed by natural gas-fired steam generation, with four units totaling 750 MW of capacity to be retired by 2030.

Table 10: State of Florida - Electric Generating Units to be Retired

Year	Utility Name	Plant Name & Unit Number	Net Capacity (MW) Summer
Coal Steam Retirements			
2024	FPL	Daniel 1&2	502
2025	FMPA-OUC	Stanton Unit 1	450
2029	FPL	Scherer Unit 3	215
		Coal Steam Subtotal	**1,167**
Oil Combustion Turbine Retirements			
2026	DEF	Bayboro Units P1-P4	151
2027	DEF	Debary Units P2-P6	227
2027	DEF	P L Bartow Units P1 & P3	82
2027	FPL	Lansing Smith Unit A	32
		Oil CT Subtotal	**492**
Natural Gas Steam Retirements			
2024	FPL	Gulf Clean Energy Center 4	75
2026	FPL	Gulf Clean Energy Center 5	75
2027	GRU	Deerhaven FS01	76
2030	JEA	Northside Unit 3	524
		Gas Steam Subtotal	**750**
Natural Gas Combustion Turbine Retirements			
2025	FPL	Pea Ridge 1-3	12
2031	GRU	Deerhaven GT1 & GT2	35
		Gas CT Subtotal	**47**
		Total Retirements	**2,456**

Source: 2024 Ten-Year Site Plans

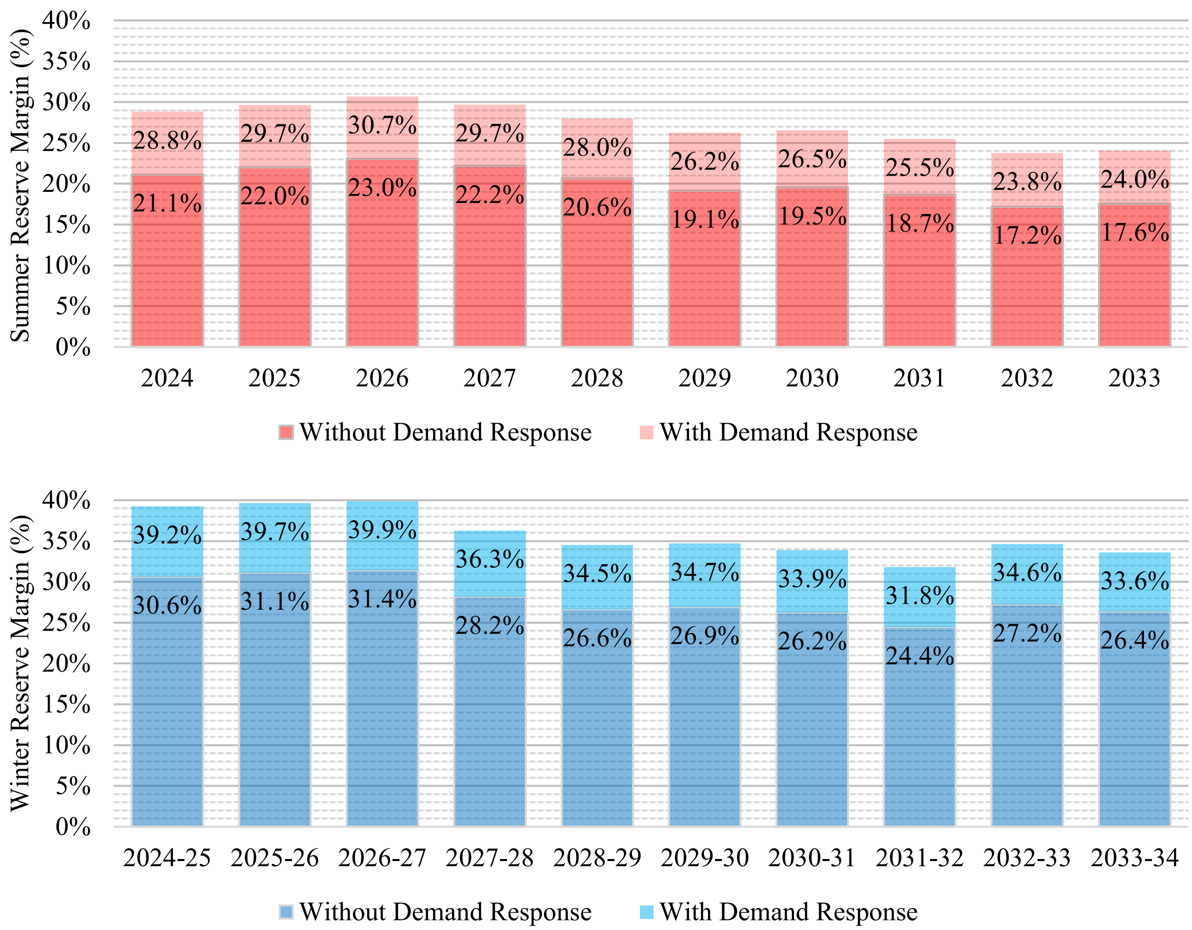
Reliability Requirements

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

On July 1, 2019, the SERC Reliability Corporation (formerly the Southeastern Electric Reliability Council) became the new Compliance Enforcement Authority for all electric utilities previously registered with the FRCC. Electric utilities within Florida must maintain a minimum reserve margin of 15 percent 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 15 is a projection of the statewide seasonal reserve margin including all proposed power plants.

Figure 15: State of Florida - Projected Reserve Margin by Season



Source: FRCC 2024 Regional Load and Resource Plan - Revised Form 10

Role of Demand Response in Reserve Margin

The Commission also considers the planning reserve margin without demand response. As illustrated above in Figure 15, 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 on average 7.2 percent in summer and 7.9 percent in winter.

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 reconsider the value of the discounted rates or credits. For interruptible customers, participants must provide notice that they intend to leave the demand response program, with a notice period of three or more years being typical. For load management participants, usually residential or small commercial customers, no advanced notice is typically required to leave. Historically, demand response participants have rarely been called upon during the peak hour, but are more frequently called upon during off-peak periods due to unusual weather conditions.

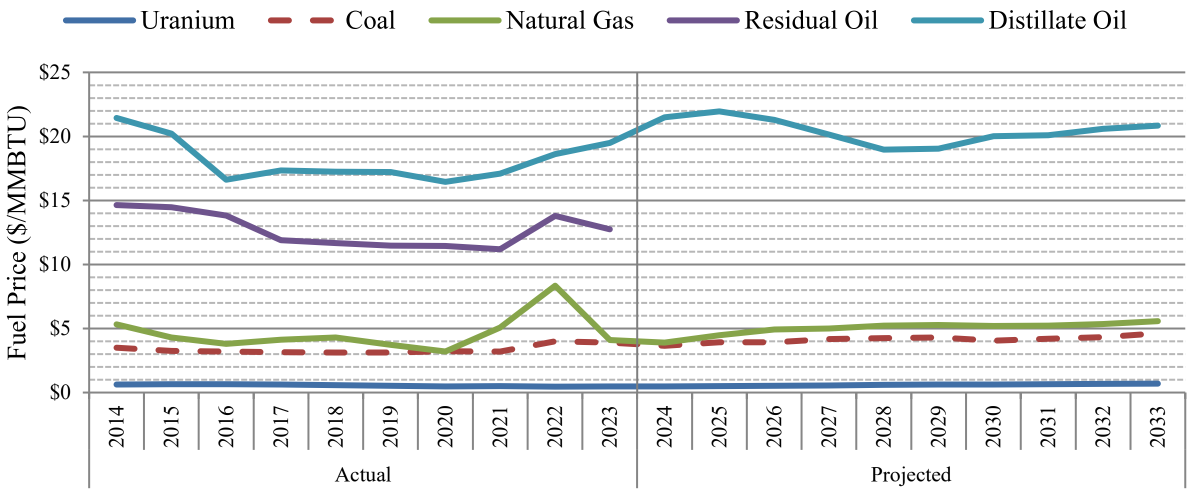
Fuel Price Forecast

Fuel price is an important economic factor affecting the dispatch of the existing generating fleet and the selection of new generating units. In general, the capital cost of a fuel-based power plant is inversely proportional to the cost of the fuel used to generate electricity from that unit. The major fuels consumed by Florida's electric utilities are natural gas, coal, and uranium. Distillate oil also factors into Florida utilities' fuel mix, albeit minimally, when compared to historical levels. Figure 16 illustrates the weighted average fuel price history and forecasts for the reporting electric utilities.

Natural gas remains the most intensively used fuel state-wide on a per GWh basis, accounting for 72.7 percent of electric generation in 2023. As shown in Figure 16, the price of natural gas continued to decline from 2014 until 2020. However, the weighted average natural gas prices saw a sizable increase from 2020 through 2022, with a peak of $8.00 per million British Thermal Units (MMBTUs) in 2022, before returning to a price of approximately $4.00/MMBTU in 2023. The price of natural gas is forecast to stabilize in 2024, and then increase slightly through 2033. Meanwhile, the price of coal was stable from 2014 through 2022. Even so, forecasts anticipate coal prices to increase gradually from $3.64 in 2024 to $4.62 in 2033. It should be noted that the use of coal is projected to decrease substantially through 2033.

Distillate oil remains the most expensive fuel, which partially explains why it is used for backup and peaking purposes only. Also of note is a phasing out of residual oil, with no forecast for purchasing residual oil after 2023. The truncated graph on Figure 16 reflects this phasing out of residual oil.

Figure 16: TYSP Utilities - Average Fuel Price of Reporting Electric Utilities



Source: TYSP Utilities' Data Responses

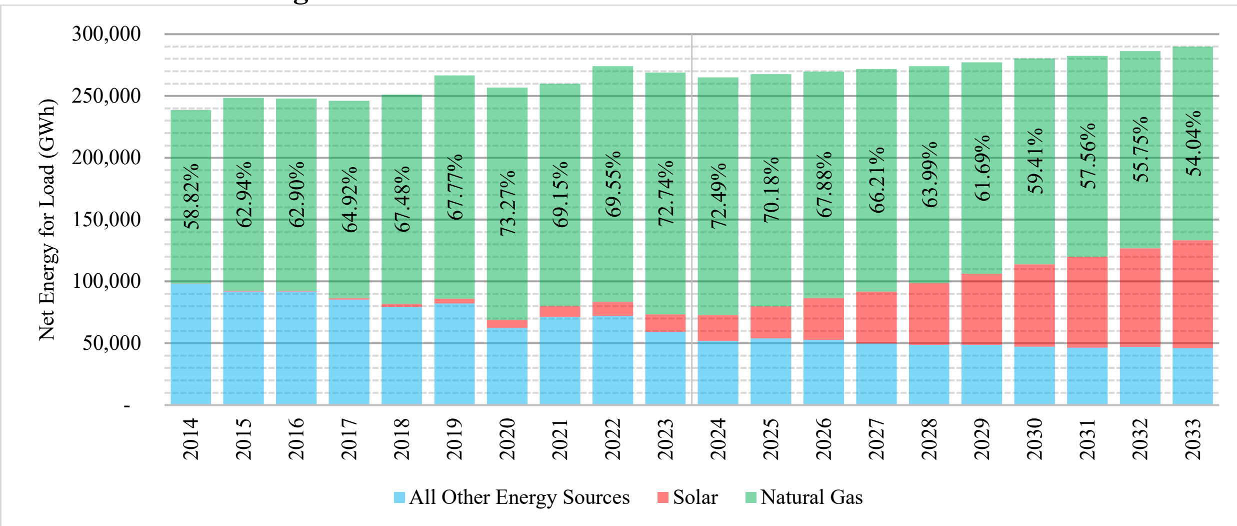
As shown in Figure 16, the price of natural gas continued to decline from 2014 until 2020. Even though current forecasts project the price of natural gas to remain relatively stable over the long term, there remains some degree of natural gas price volatility over the short and medium term. For instance, natural gas price volatility was reflected in the 2024 requests for fuel factor mid-course corrections (increases or decreases in customer fuel charges) filed by FPL, DEF, and TECO. FPL's mid-course correction was approved by the Commission on April 10, 2024, and DEF and TECO's were approved on May 24, 2024.[10]

Fuel Diversity

Natural gas has risen to become the dominant fuel in Florida and since 2011 has generated more net energy for load than all other fuels combined. As Figure 17 illustrates, natural gas was the source of approximately 69.6 percent of electric energy consumed in Florida in 2023. Natural gas electric generation, as a percent of net energy for load, is anticipated to decline throughout the remainder of the planning period, offset by solar generation. Solar generation is anticipated to exceed all non-natural gas energy sources combined by 2028.

[10] Docket No. 20240001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

Figure 17: State of Florida - Natural Gas Generation

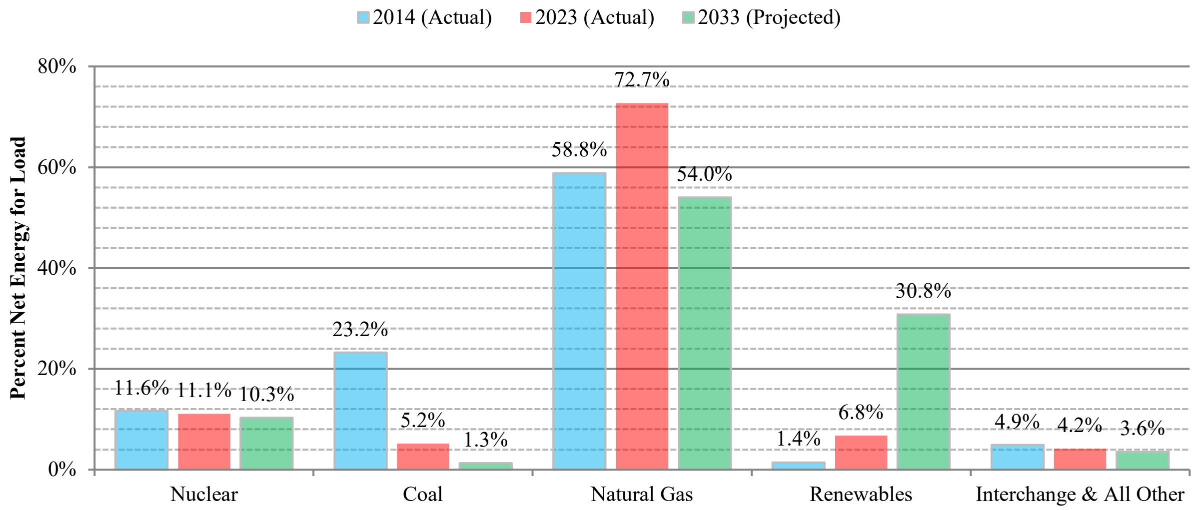


Source: FRCC 2015-2024 Regional Load and Resource Plans

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 18 shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2014 and 2023, and forecast year 2033. Nuclear generation is expected to remain steady throughout the planning period. Coal generation is expected to continue its downward trend well into the planning period. Natural gas has been the primary fuel used to meet the growth of energy consumption, and this trend is anticipated to continue throughout the planning period. Renewables are expected to exceed all other generation sources except for natural gas by 2028.

Figure 18: State of Florida - Historic and Forecast Generation by Fuel Type



Source: FRCC 2015-2024 Regional Load and Resource Plan

Based on 2020 Energy Information Administration data, Florida ranks fifth in terms of the total volume of natural gas consumed compared to the rest of the United States.[11] For volume of natural gas consumed for electric generation, Florida ranks second, behind Texas. Natural gas is not used as a heating fuel in most of Florida's homes and businesses, which rely instead upon electricity that is increasingly being generated by natural gas. As Florida has very little natural gas production and limited gas storage capacity, the state is reliant upon out-of-state production and storage to satisfy the growing electric demands of the state.

New Generation Planned

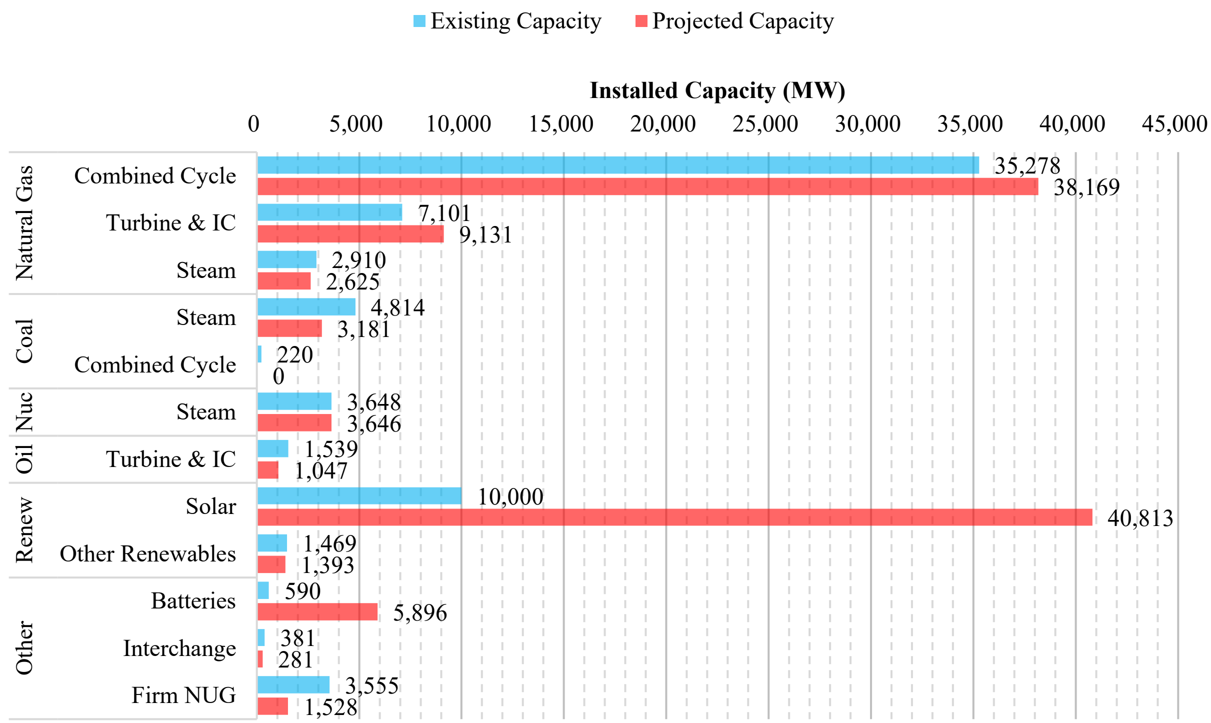
Current demand and energy forecasts continue to indicate that in spite of increased levels of conservation, energy efficiency, renewable generation, and existing traditional generation resources, the need for additional generating capacity still exists. While reductions in demand have been significant,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

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

[11] U.S. Energy Information Administration natural gas consumption by end-use annual report.

Figure 19 illustrates the present and future aggregate capacity mix. The capacity values in Figure 19 incorporate all proposed additions, retirements, fuel switching, uprates and derates, and changes in operational or contract status contained in the reporting utilities' 2024 Ten-Year Site Plans and the FRCC's 2024 Regional Load and Resource Plan.

Figure 19: State of Florida - Current and Projected Installed Capacity



Source: FRCC 2024 Regional Load and Resource Plan and TYSP Utilities' Data Responses

Commission's Authority Over Siting

Any proposed steam or solar generating unit greater than 75 MW requires a certification under the Electrical Power Plant Siting Act (PPSA), contained in Sections 403.501 through 403.518, F.S. The Commission has been given exclusive jurisdiction to determine the need for new electric power plants through Section 403.519, F.S. Upon receipt of a determination of need, the electric utility would then seek approval from the Florida Department of Environmental Protection, which addresses land use and environmental concerns. Finally, the Governor and Cabinet, sitting as the Siting Board, ultimately must approve or deny the overall certification of a proposed power plant. There are two planned units, both natural gas-fired combined cycles, requiring certification under the PPSA; a 571 MW unit with an in-service date of 2032 for SEC, and a 518 MW unit with an in-service date of 2030 for JEA. While solar generation is covered under the Power Plant Siting Act, all future solar projects are below the 75 MW threshold, and therefore are not required to seek approval from the Commission prior to construction.

New Power Plants by Fuel Type

Nuclear

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. In April 2018, FPL received Combined Operating Licenses from the Nuclear Regulatory Commission for two future nuclear units, Turkey Point Units 6 and 7. These units are planned to be sited at FPL's Turkey Point site, the location of two existing nuclear generating units. The earliest possible in service date for these two units are outside the scope of the Ten-Year Site Plan.

Natural Gas

Several new natural gas-fired combustion turbines, internal combustion units, and combined cycle units are planned over the next 10 years. While combined cycle systems are the dominant generating unit type, combustion turbines that run only in simple cycle mode and internal combustion (also called reciprocating engines) units, taken together, represent the third most abundant type of generating capacity, behind installed solar generation as well. As combustion turbines and internal combustion units are not a form of steam generation, unless part of a combined cycle unit, they do not require siting under the Power Plant Siting Act. Table 11 summarizes the approximately 3,287 MW of additional capacity from new natural gas-fired generating units proposed by the 2024 Ten-Year Site Plan utilities. In addition to the new generation listed below, FMPA is acquiring three existing merchant facilities, all natural gas-fired combined cycle units, for a total of 332 MW.

Table 11: TYSP Utilities - Planned Natural Gas Units

In-Service Year	Utility Name	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Notes
PPSA Approved Units					
2026	SEC	Shady Hills Energy Center	CC	546	
			Subtotal	**546**	
New Units Requiring PPSA Approval					
2030	JEA	Advanced 1x1 CC	CC	576	
2032	SEC	Unnamed CC	CC	571	
			Subtotal	**1,147**	
New Units Not Requiring PPSA Approval					
2024	LAK	Mcintosh ME1-ME6	IC	120	6 Units
2025-2026	TECO	South Tampa Resiliency Project	IC	75	2 Phases – 4 Units Total
2029	SEC	Unnamed CT	CT	317	
2030	TECO	Future CT 1	CT	222	
2032	DEF	Undesignated CT 1 & 2	CT	430	2 Units
2033	DEF	Undesignated CT 3 & 4	CT	430	2 Units
			Subtotal	**1,594**	
			Total	**3,287**	

Source: 2024 Ten-Year Site Plans

Transmission

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

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

Table 12 lists all proposed transmission lines in the 2024 Ten-Year Site Plans and the FRCC 2024 Regional Load and Resource Plan that require TLSA certification. The only planned line has already received the approval of the Commission.

Table 12: State of Florida - Planned Transmission Lines

Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
FPL	Sweatt to Whidden	79	230	05/2022	09/2022	06/2026

Source: 2024 Ten-Year Site Plans and FRCC 2024 Regional Load and Resource Plan

Utility Perspectives

Florida Power & Light Company (FPL)

FPL is an investor-owned utility and Florida's largest electric utility. FPL's service territory previously was solely in the FRCC Region and consisted of South Florida and the east coast. FPL's parent company, NextEra Energy Inc., acquired Gulf Power Company (GPC) in January 2019. Resource planning is now being done for the single entity of FPL, with the former GPC territory referred to as FPL's Northwest Florida Division (FPL NWFL). As an investor-owned utility, FPL, is subject to the regulatory authority of the Commission over all aspects of utility operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds FPL 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2023, FPL's service area had approximately 5,845,160 customers and annual retail energy sales of 127,904 GWh, or approximately 54.7 percent of Florida's annual retail energy sales. The total number of customers grew by approximately 1.2 percent in 2023 which is in line with FPL's normal growth rates.

Over the past 10 years, FPL's customer base has increased by 13.5 percent, while retail energy sales have grown by approximately 10.8 percent. For the 2024 TYSP forecast horizon, customers for the FPL system are forecasted to grow by 1.2 to 1.3 percent per year. According to FPL, its total customer growth is being driven primarily by growth in residential customer numbers.

FPL's weather-normalized energy consumption per customer for residential and commercial customers reflect the impacts of the pandemic and the resulting return to more normal conditions. In 2023, residential usage decreased by 0.1 percent as, according to the Company, a strong economy led to customers spending less time at home (i.e. returning to work-place/school). Commercial usage, on the other hand, increased by 0.4 percent due to rebounding commercial activity. FPL's industrial use per customer declined by 11.6 percent, but this decline was attributable to strong growth in the number of small industrial customers with low average usage.

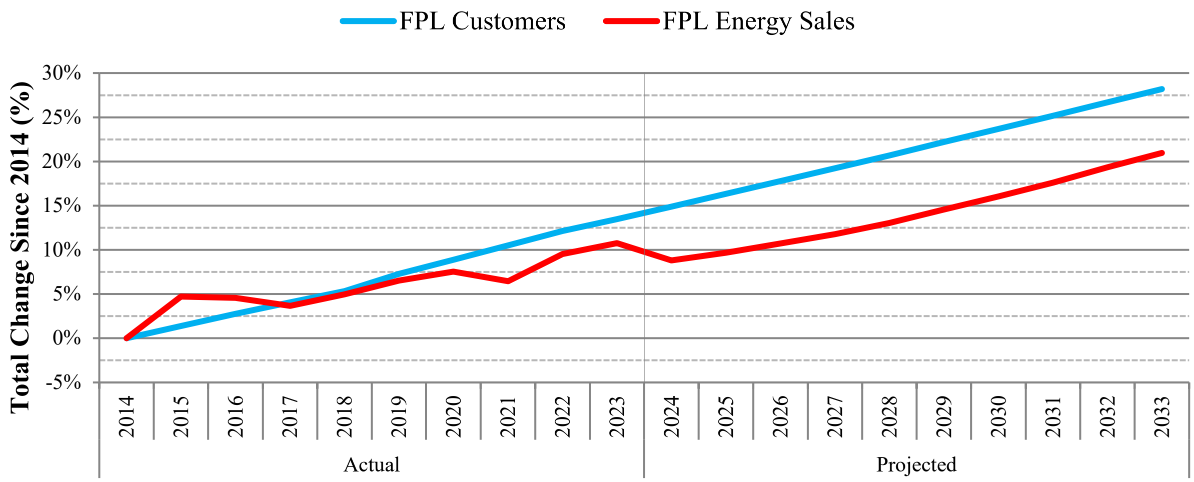
Over the current TYSP forecast horizon, residential use per customer is forecasted to be flat or slightly grow up to 0.6 percent due to continued economic growth as well as increased adoptions of electric vehicles. Commercial usage is forecast to decline between 0.1 to 0.7 percent per year over the forecast horizon due to continued improvements to equipment efficiencies.

FPL's weather-normalized annual retail energy sales increased by 0.8 percent in 2023, driven by growth in the residential class. Residential energy sales increased by 1.1 percent due to continued customer growth. Commercial energy sales increased due to both customer and usage growth. Industrial energy sales decreased but had a negligible impact on total retail energy sales because the industrial class sales are a small proportion of total retail energy sales.

For the 2024 TYSP forecast horizon, FPL's total retail energy sales are forecasted to grow by 0.8 to 1.3 percent per year. This projected retail energy sales growth is driven by sales growth in the residential class and commercial class, and these class-level energy sales increases are driven by growth in the number of customers.

Figure 20 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan FPL filed in its 2024 TYSP.

Figure 20: FPL Growth

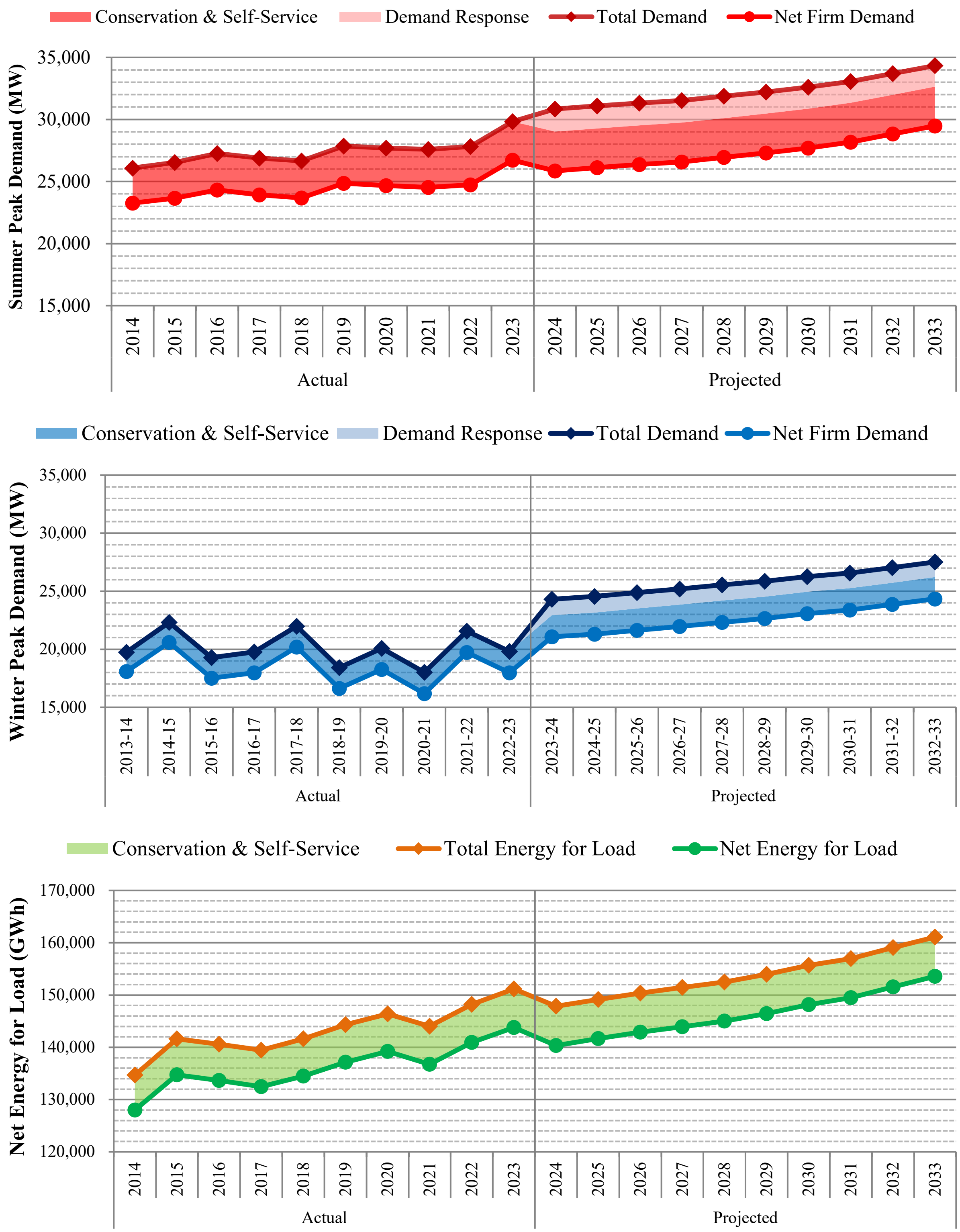


Source: 2024 Ten-Year Site Plan

As mentioned earlier, on January 1, 2019, GPC became a subsidiary of NextEra, FPL's parent company. FPL and GPC integrated the two systems into a single electric system, effective January 1, 2022. The three graphs in Figure 21 show FPL and GPC's combined seasonal peak demand, summer and winter, and net energy for load, for the historic years 2014 through 2021, with the integrated FPL/GPC historical data for 2022 and 2023, and forecast for years 2024 through 2033.

As an investor-owned utility, FPL is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Commission is currently reviewing FPL's 2025-2034 DSM goals. These goals are scheduled to be voted on at the December 3, 2024 Commission Conference and, in 2025, the Commission will review FPL's plan designed to achieve those goals. In preparing its 2024 Ten-Year Site Plan seasonal peak demand and energy forecasts, FPL assumes the trends in these goals will be extended through the forecast period (through 2033), as reflected in Figure 21. 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. During the past 10 years, demand response has not been activated during seasonal peak demand.

Figure 21: FPL Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 13 shows FPL's actual net energy for load by fuel type for 2023 and the projected fuel mix for 2033. FPL relies primarily upon natural gas for energy generation, making up 75 percent of net energy for load in 2023. FPL is projected to use natural gas for less than half of its energy generation by 2033. Only two utilities, FPL and OUC, are anticipated to reach this level of reduced natural gas consumption by the end of the planning period. By 2033, natural gas will still be the highest individual fuel at 42 percent, while renewables will account for 39 percent, followed by nuclear at 19 percent.

Table 13: FPL Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	105,854	**75.4%**	64,551	**42.0%**
Coal	472	**0.3%**	0	**0.0%**
Nuclear	28,767	**20.5%**	28,830	**18.8%**
Oil	233	**0.2%**	2	**0.0%**
Renewable	10,217	**7.3%**	59,440	**38.7%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	(5,079)	**-3.6%**	857	**0.6%**
Total	**140,464**		**153,681**	

Source: 2024 Ten-Year Site Plan

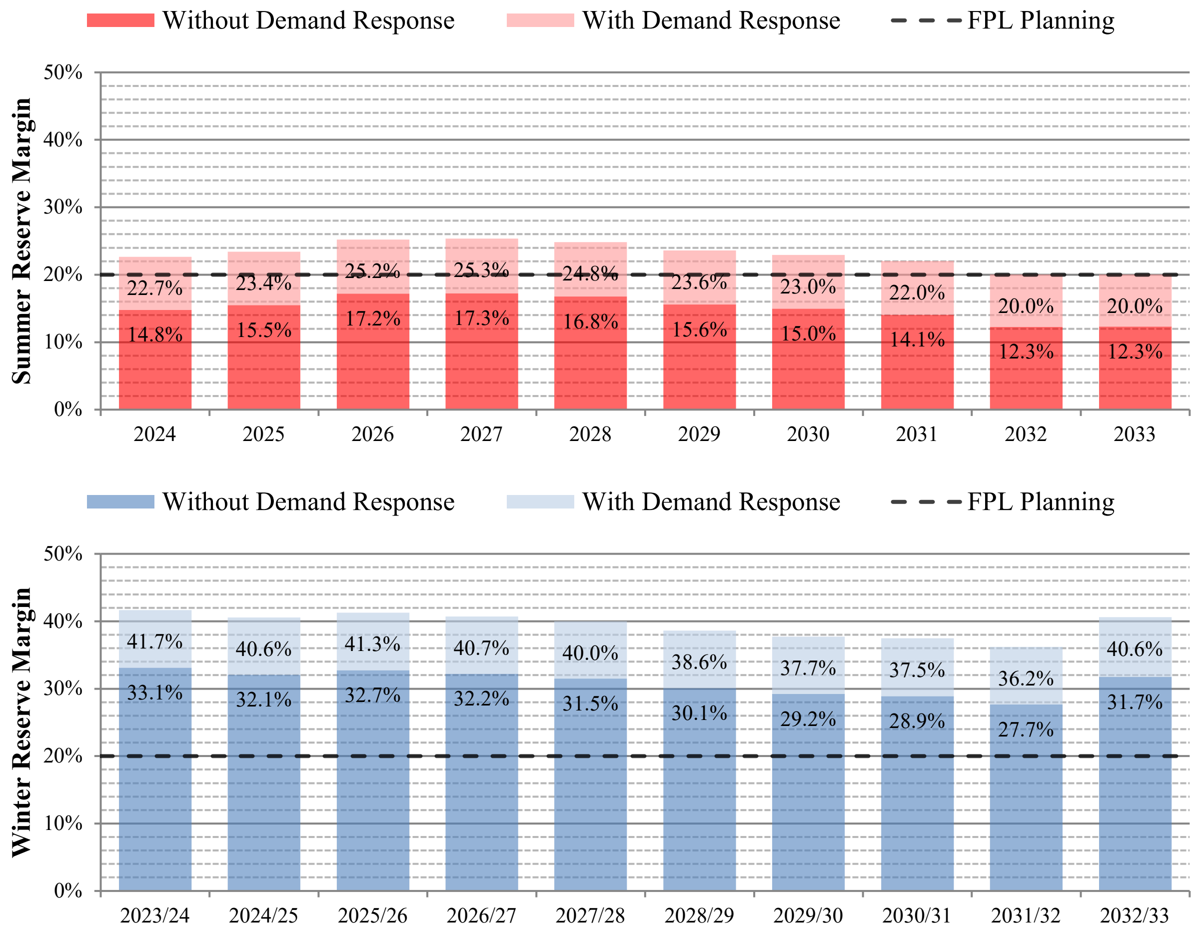
Reliability Requirements

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

Since 1999, FPL has utilized a 20 percent reserve margin criterion for planning based on a stipulation approved by the Commission.[12] Figure 22 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.

[12] Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 19981890-EU, *In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.*

Figure 22: FPL Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

In addition to LOLP and the reserve margin, FPL utilizes a third reliability criterion which it refers to as its 10 percent generation-only reserve margin. This criterion requires that available firm capacity be 10 percent greater than the sum of customer seasonal demand, without consideration of incremental energy efficiency and all existing and incremental demand response resources. Currently, no other utility utilizes this same metric. FPL's generation-only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20 percent reserve margin will be realized.

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

Generation Resources

FPL plans multiple unit retirements and additions during the planning period as are described in Table 14. Particularly noteworthy is the Company's plan to retire its three remaining coal units, totaling 717 MW, which consist of FPL's partial ownership of Scherer Unit 3 and Daniel Units 1 and 2, all assets which it acquired from its purchase of GPC. FPL also plans the retirement of another 197 MW of assets, primarily natural gas-fired steam plants. These retirements are partially offset by planned upgrades to its existing natural gas combined cycle generating units over the planning period, which increase summer capacity by 123 MW.

FPL does not plan any new fossil generating unit additions over the next 10-year period, only solar and battery facilities. The majority of changes on FPL's system are from new solar photovoltaic plants, with a planned 282 sites totaling 21,009 MW in capacity, of which 2,742 MW are considered firm for the summer peak. In addition, FPL anticipates adding a total of 4,022 MW of battery storage, of which 2,159 MW will be considered firm for purposes of summer peak. None of these additions require a need determination pursuant to the PPSA.

Table 14: FPL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Firm Capacity (MW) Sum	Notes
Retiring Units					
2024	Daniel 1 & 2	BIT ST	502		2 Units Total
2024	Gulf Clean Energy Center 4	NG ST	75		
2025	Pea Ridge 1-3	NG GT	12		3 Units Total
2026	Gulf Clean Energy Center 5	NG ST	75		
2027	Lansing Smith 3A	DFO GT	32		
2028	Scherer 3	BIT ST	215		
2029	Perdido 1 & 2	LFG IC	3		2 Units Total
		Total Retirements	**914**	**-**	
New Units					
2024	Sited Solar Plants	SUN PV	2,235	982	30 Sites
2025	Sited Solar Plants	SUN PV	894	351	12 Sites
2025	Unsited Energy Storage	BAT	522	349	
2026	Sited Solar Plants	SUN PV	2,235	429	30 Sites
2027	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2027	Unsited Energy Storage	BAT	300	219	
2028	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2028	Unsited Energy Storage	BAT	300	213	
2029	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2029	Unsited Energy Storage	BAT	300	201	
2030	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2030	Unsited Energy Storage	BAT	300	191	
2031	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2031	Unsited Energy Storage	BAT	300	186	
2032	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2032	Unsited Energy Storage	BAT	300	150	
2033	Unsited Solar Plant	SUN PV	2,235	140	30 Sites
2033	Unsited Energy Storage	BAT	1,700	650	
		Total New Units	**25,031**	**4,901**	
		Net Additions	**24,117**		

Source: 2024 Ten-Year Site Plan

Duke Energy Florida, LLC (DEF)

DEF is an investor-owned utility and Florida's second largest electric utility. The Company's service territory is within the FRCC region and is primarily located 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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2023, DEF had approximately 1,968,221 customers and annual retail energy sales of 40,832 GWh, or approximately 17.4 percent of Florida's annual retail energy sales. DEF's total customers and total retail energy sales respectively grew approximately 1.8 percent and 0.8 percent in 2023. Over the last 10 years, DEF's customer base has increased by 15.8 percent, while retail energy sales have grown by 9.6 percent.

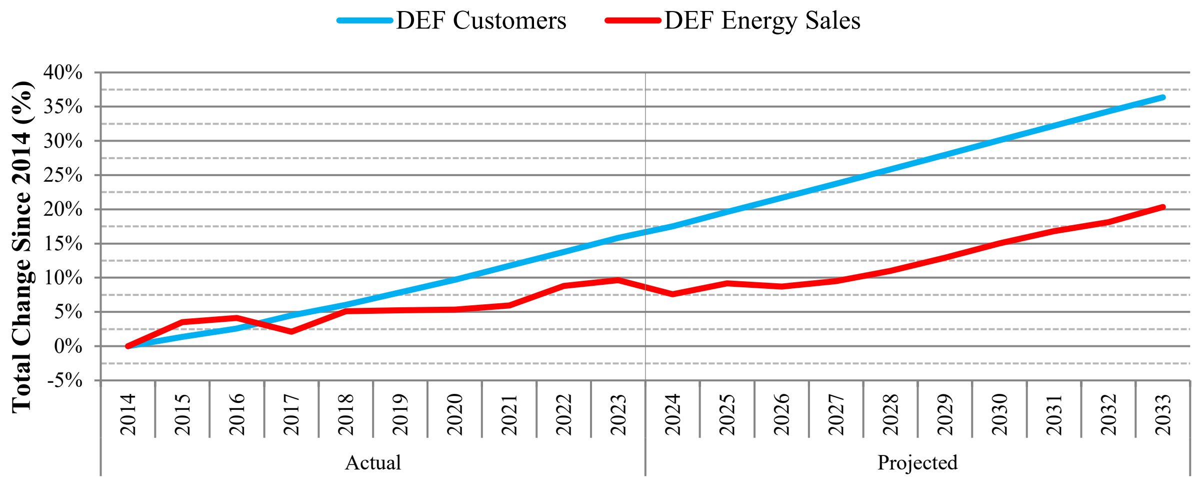
DEF's customer growth has always been dominated by the residential and commercial customer classes. Customer growth trends are driven by broad economic and demographic factors such as population growth, migration, retirement, affordable housing, mortgage rates and job growth. More recent information reflects a return to the long-term trend of population migration into Florida. Commercial customer growth typically tracks residential growth supplying needed services.

DEF's projected retail energy sales trend reflects the product of the Company's forecasted number of customers and forecasted energy consumption per customer. Fluctuations of per customer usage for DEF's residential and commercial classes are primarily driven by variations in electricity price, end-use appliance saturation and efficiency improvement, housing type/building size, improved building codes, and space conditioning equipment fuel type. With respect to the average energy consumption per customer, the Company is aware that the ability to self-generate recently has begun to make an impact. A small percentage of industrial/commercial customers have chosen to install their own natural gas generation, reducing energy consumption from the power grid. Similarly but more significantly, residential and some commercial accounts have reduced their utility requirements by installing solar panels behind their meters. The Company also noted that the penetration of plug-in electric vehicles has grown, leading to an increase in residential use per customer, all else being equal.

For the 2024 TYSP forecast horizon, DEF's forecast results indicate that the Company's customer base is projected to grow at an average annual rate of 1.7 percent approximately, and its retail energy sales are projected to grow at an average annual rate of 1.3 percent approximately.

Figure 23 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan DEF filed in its 2024 TYSP.

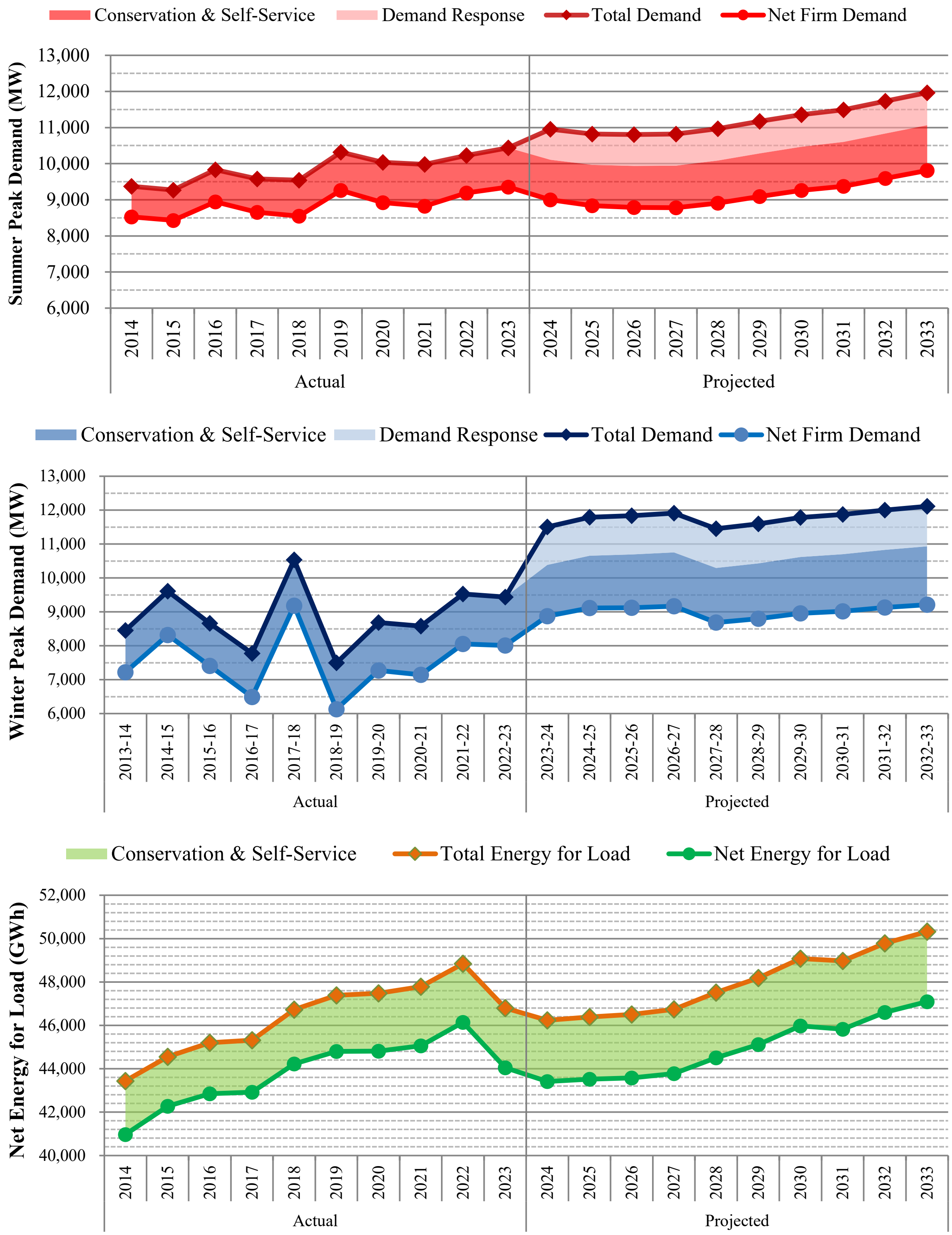
Figure 23: DEF Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 24 show DEF's seasonal peak demand and net energy for load for the historic years of 2014 through 2023 and forecast years 2024 through 2033. These graphs include the full impact of demand-side management and assume that all available demand response resources will be activated during the seasonal peak. During the past 10 years, demand response has not been activated during seasonal peak demand. 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. In August 2024, the Commission established demand side management goals for DEF for the years 2025 through 2034. In 2025, the Commission will review DEF's plan designed to achieve the Company's DSM goals. In preparing its 2024 Ten-Year Site Plan seasonal peak demand and energy forecasts, DEF assumes trends in these goals will be extended through the forecast horizon (through 2033).

Figure 24: DEF Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 15 shows DEF's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. DEF relies primarily upon natural gas for energy generation, making up approximately 81 percent of net energy for load in 2023. DEF plans to increase renewable energy generation over the planning period, somewhat offsetting natural gas and coal usage. DEF projects that renewable energy will provide 29 percent of its generation by 2033, which is the fourth highest percentage of renewable energy generation in 2033 of the TYSP Utilities. Natural gas would remain the primary fuel, at 68 percent in 2033.

Table 15: DEF Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	35,526	**80.7%**	31,801	**67.5%**
Coal	3,829	**8.7%**	1,873	**4.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	29	**0.1%**	10	**0.0%**
Renewable	2,788	**6.3%**	13,408	**28.5%**
Interchange	60	**0.1%**	2	**0.0%**
NUG & Other	1,814	**4.1%**	0	**0.0%**
Total	**44,046**		**47,094**	

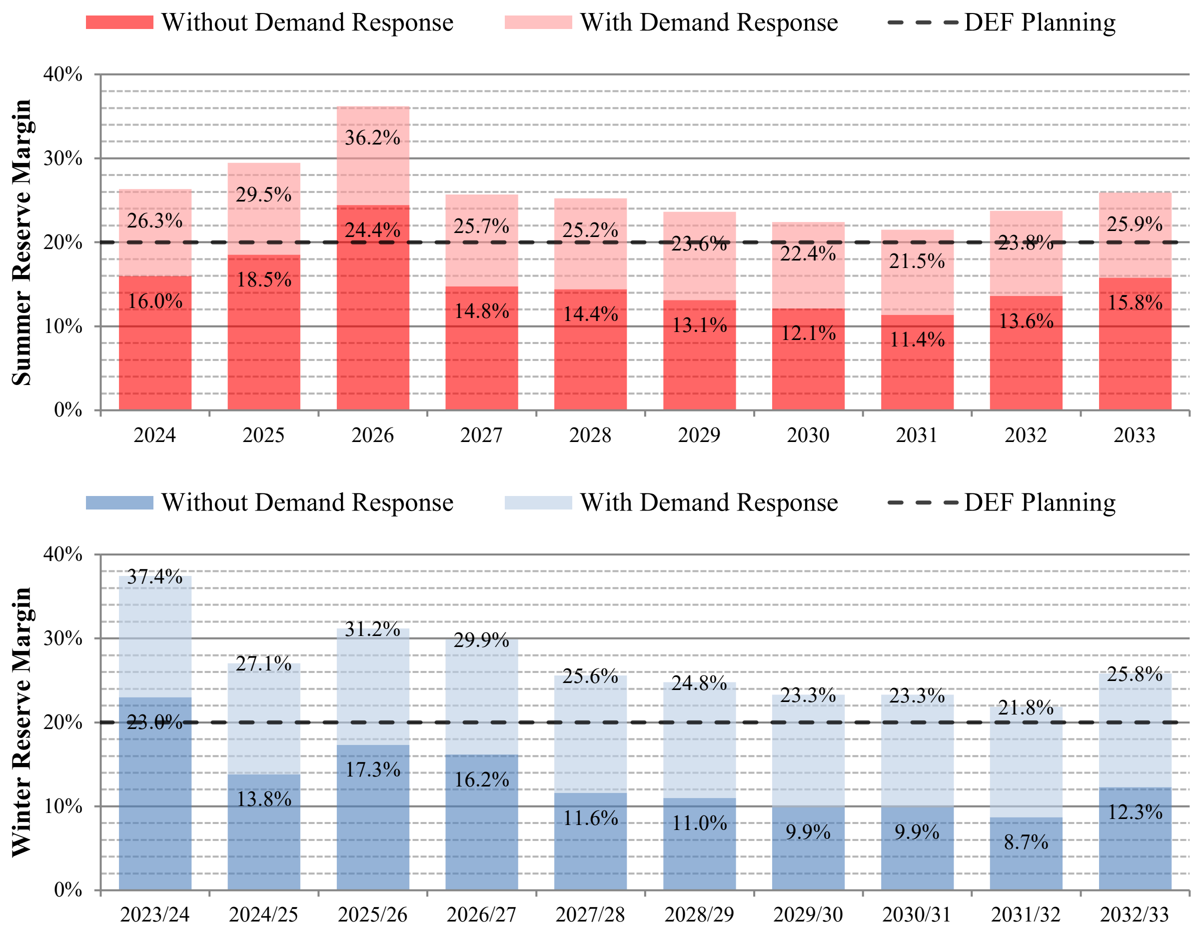
Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion based on a stipulation approved by the Commission.[13] Figure 24 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 mostly controlled by its summer peaking throughout the planning period.

[13] Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 19981890-EU, *In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.*

Figure 25: DEF Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

DEF projects multiple unit retirements and additions during the planning period, as described in Table 16. DEF plans to retire 460 MW of oil-fired combustion turbines by 2027 across three sites. These retirements are completely offset by modifications to its existing natural gas-fired combined cycle facilities. Uprates to the combustion turbines will increase their summer peak capacity by 389 MW, and improved transmission facilities will allow DEF to fully utilize the acquired Osprey plant, which increases its firm contribution to 347 MW.

DEF plans additions of fossil, renewable, and storage technologies over the planning period. For new fossil generation, DEF plans a total of four new natural gas-fired combustion turbines, with a pair of 215 MW units installed in 2032 and 2033, each. For renewables, DEF plans on 63 solar sites totaling 4,718 MW in capacity, of which 891 MW are considered firm for the summer peak. In addition, DEF plans on constructing 100 MW of independent battery storage, of which 90 MW are considered firm for summer peak. DEF also plans on collocating an additional 240 MW of battery storage at 6 of the solar sites, with 40 MW per site. DEF has designated these sites as Solar Plus Storage, and included the firm contribution of the battery as part of the solar facility. None of the solar and battery additions require a need determination pursuant to the PPSA.

Table 16: DEF Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Firm Capacity (MW)	Notes
			Sum	Sum	
Retiring Units					
2026	Bayboro P1 - P4	DFO CT	151		4 Units
2027	Debary P2 - P6	DFO CT	227		5 Units
2027	Bartow P1, P3	DFO CT	82		2 Units
Total Retirements			**460**	**0**	
New Units					
2024	Sited Solar Plants	PV SUN	300	171	4 Sites
2025	Sited Solar Plants	PV SUN	300	75	4 Sites
2026	Unsited Solar Plants	PV SUN	374	94	5 Sites
2027	Unsited Solar Plants	PV SUN	374	94	5 Sites
2027	Unsited Energy Storage	BAT	100	90	
2028	Unsited Solar Plant	PV SUN	300	30	4 Sites
2028	Unsited Solar Plus Storage	PV SUN	150	55	2 Sites
2029	Unsited Solar Plant	PV SUN	374	37	5 Sites
2029	Unsited Solar Plus Storage	PV SUN	150	55	2 Sites
2030	Unsited Solar Plant	PV SUN	449	45	6 Sites
2030	Unsited Solar Plus Storage	PV SUN	150	55	2 Sites
2031	Unsited Solar Plant	PV SUN	599	60	8 Sites
2032	Unsited Solar Plant	PV SUN	599	60	8 Sites
2032	Undesignated CTs 1 & 2	NG CT	430		2 Units
2033	Unsited Solar Plant	PV SUN	599	60	8 Sites
2033	Undesignated CTs 3 & 4	NG CT	430		2 Units
Total New Units			**5,678**	**981**	
Net Additions			**5,218**		

Source: 2024 Ten-Year Site Plan

Tampa Electric Company (TECO)

TECO is an investor-owned utility and Florida's third largest electric utility. The Company'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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

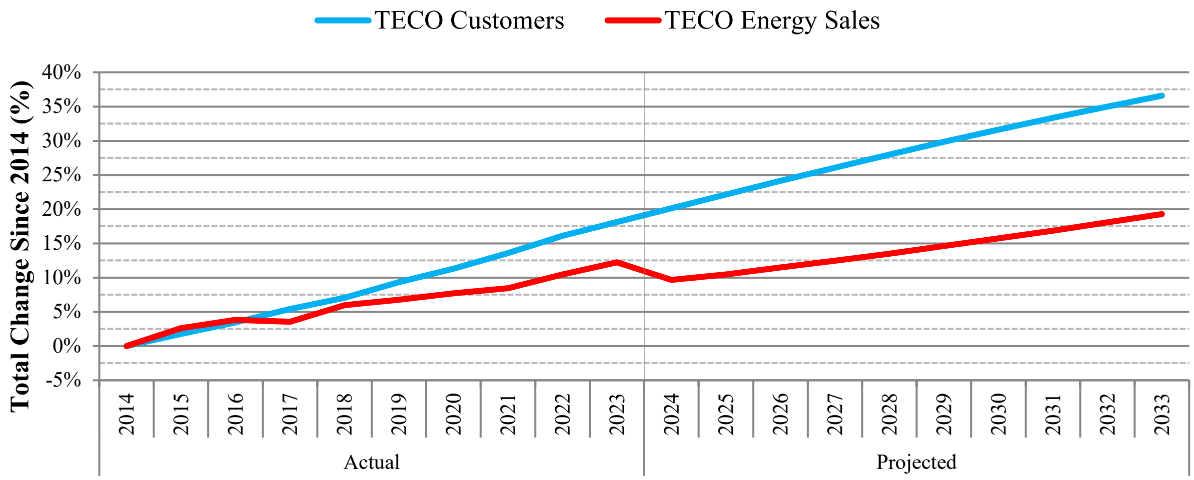
In 2023, TECO had approximately 834,144 customers and annual retail energy sales of 20,791 GWh or approximately 8.9 percent of Florida's annual retail energy sales. Over the last 10 years, TECO's customer base has increased by approximately 18.1 percent, while retail energy sales have increased by approximately 12.2 percent.

TECO's total customer growth in 2023 averaged 1.8 percent approximately with the residential class being the engine behind the growth. Over the next 10 years customer growth is expected to increase at an average rate of 1.5 percent annually. The primary driver of customer growth in the residential sector will be new construction and increasing net in-migration to the Company's service area.

TECO's average annual energy consumption per residential customer is slightly higher in 2023 than in 2022, primarily due to the record-breaking heat in 2023. Likewise, the Company's commercial per customer usage was slightly higher in 2023 than in 2022 due to the record-breaking heat. TECO's industrial per customer usage in 2023 was also higher than in 2022. The primary driver of this increase, in addition to hotter weather, was the industrial phosphate sector had less self-serving generation and more energy purchases from TECO. Over the next 10 years, TECO expects average energy consumption per residential customer to decline at an average annual rate of 0.2 percent. The main drivers behind the decline are the increases in the energy efficiencies of the appliances, lighting, and new homes, as well as the conservation efforts and changes in housing mix. The Company also expects average energy consumption per commercial and industrial customer to decline 0.2 and 0.1 percent, respectively.

For the next 10 years, TECO's retail energy sales are projected to grow at an annual average rate of approximately 0.9 percent. This is below the projected customer growth rate of 1.4 percent primarily due to continued per customer energy consumption declines, as well as declines in the phosphate sector as the mining industry continues to move south and out of the Company's service territory. Figure 26 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan TECO filed in its 2024 TYSP.

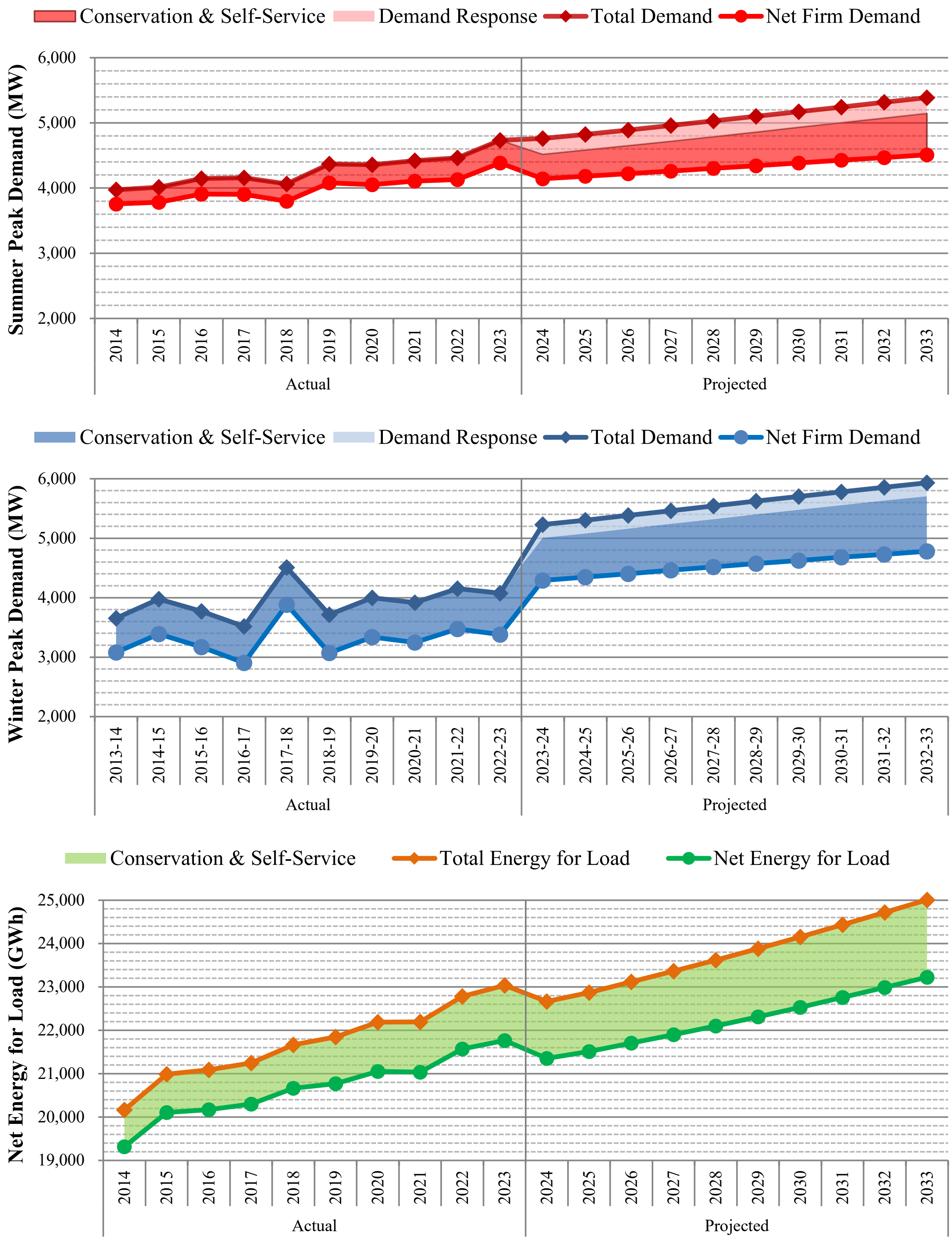
Figure 26: TECO Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 27 show TECO's seasonal peak demand and net energy for load for the historic years of 2014 through 2023 and forecast years 2024 through 2033. These graphs include the full impact of demand-side management, and assume that all available demand response resources will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand, excluding the summer of 2013 and winters of 2017-2018 and 2018-2019. 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. In August 2024, the Commission established demand side management goals for TECO for the years 2025 through 2034. In 2025, the Commission will review TECO's plan designed to achieve the Company's DSM goals. In preparing its 2024 Ten-Year Site Plan seasonal peak demand and energy forecasts, TECO assumes the trends in these goals will be extended through the forecast period (through 2033).

Figure 27: TECO Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 17 shows TECO's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. Based on its 2024 Ten-Year Site Plan, natural gas is used for the majority of TECO's energy generation. Natural gas accounts for approximately 82 percent of net energy for load in 2023 and is projected to account for approximately 72 percent in 2033. In the future, TECO projects that energy from coal will decrease and energy from renewables will increase. TECO projects that renewable energy will increase from 8 percent to 27 percent by 2033.

Table 17: TECO Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	17,814	**81.8%**	16,721	**72.0%**
Coal	769	**3.5%**	139	**0.6%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	2	**0.0%**	0	**0.0%**
Renewable	1,748	**8.0%**	6,191	**26.7%**
Interchange	21	**0.1%**	150	**0.6%**
Other	1,412	**6.5%**	23	**0.1%**
Total	**21,767**		**23,224**	

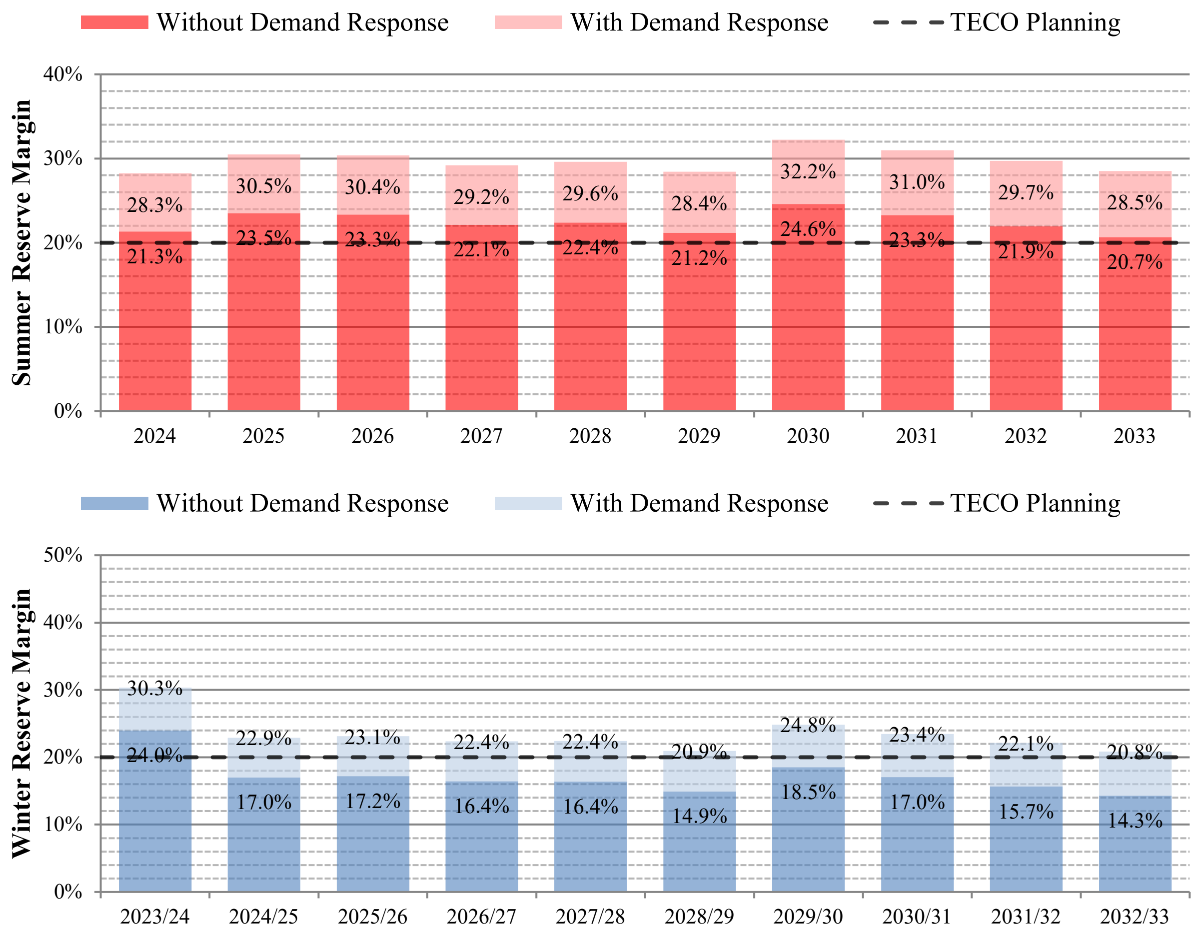
Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion based on a stipulation approved by the Commission.[14] TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 28 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 being controlled by its winter peak. TECO's current and planned investments in solar generation contribute to this shift in planning because solar resources provide coincident capacity during the summer peak but not the winter peak. TECO's 7 percent supply-side only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20 percent reserve margin will be realized.

[14] Order No. PSC-99-2507-S-EU, issued December 22, 1999, in Docket No. 19981890-EU, *In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.*

Figure 28: TECO Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

For its existing generating units, TECO plans uprates at its existing Bayside combined cycle facilities for an additional 72 MW of capacity, offset by the conversion of the petcoke fueled Polk 1 integrated gasification combined cycle to a natural gas-fired simple cycle system, which reduces its net firm capacity by 30 MW.

TECO plans additions of fossil, renewable, and storage technologies over the planning period, as described in Table 18. For natural gas-fired capacity, TECO plans on four 18.5 MW internal combustion units in 2025, and a single 222 MW combustion turbine in 2030. TECO plans on adding 23 solar sites for 1,585 MW of solar capacity, of which only 35 MW will be considered firm for purposes of summer peak. The Company will also be installing five battery sites with a total of 185 MW of capacity, all of which is considered to contribute to the system peak.

Table 18: TECO Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Firm Capacity (MW)	Notes
			Sum	Sum	
Retiring Units					
	None				
Total Retirements			**0**	**0**	
New Units					
2024	Sited Solar Plants	PV SUN	97	5	2 Units
2024	Sited Energy Storage	BAT	15		1 Unit
2025	South Tampa Resilience Project	NG IC	75		4 Units
2025	Sited Solar Plants	PV SUN	149	7	2 Sites
2025	Sited Energy Storage	BAT	100		3 Sites
2026	Sited Solar Plants	PV SUN	242	8	4 Sites
2027	Sited Solar Plant	PV SUN	74	1	1 Site
2027	Unsited Solar Plant	PV SUN	74	1	1 Site
2028	Sited Solar Plants	PV SUN	130	2	2 Sites
2028	Unsited Solar Plant	PV SUN	74	1	1 Site
2028	Unsited Energy Storage	BAT	70	-	1 Site
2029	Unsited Solar Plant	PV SUN	149	2	2 Sites
2030	Unsited CT 1	NG CT	222	-	
2030	Unsited Solar Plant	PV SUN	149	2	2 Sites
2031	Unsited Solar Plant	PV SUN	149	2	2 Sites
2032	Unsited Solar Plant	PV SUN	149	2	2 Sites
2033	Unsited Solar Plant	PV SUN	149	2	2 Sites
Total New Units			**2,067**	**35**	
Net Additions			**2,067**	**35**	

Source: 2024 Ten-Year Site Plan

Florida Municipal Power Agency (FMPA)

FMPA is a governmental wholesale power company owned by several Florida municipal utilities throughout the state. Collectively, FMPA is Florida's seventh largest electric utility and third largest municipal electric utility. While FMPA has 33 member systems, only those members that are participants in the All-Requirements Power Supply Project (ARP) are addressed in the Company's Ten-Year Site Plan. FMPA is responsible for planning activities associated with ARP member systems. For 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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

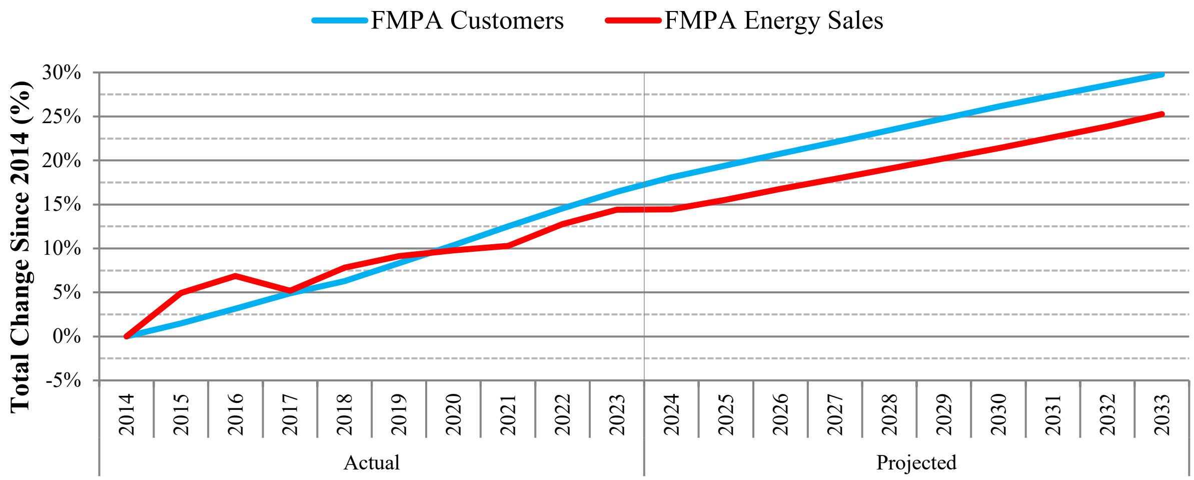
In 2023, FMPA had approximately 286,046 customers and annual retail energy sales of 6,124 GWh or approximately 2.6 percent of Florida's annual retail energy sales. Over the last 10 years, FMPA's customer base has increased by 16.4 percent, while energy sales have increased by 14.4 percent.

FMPA noted that, in aggregate, its energy usage has been relatively flat in both the residential and non-residential sectors after controlling for weather variation from normal conditions. There are countervailing factors that influence usage. In general, declines in electricity prices and population growth led to a small upward impact on usage. Concurrently, a continued orientation to conservation and continued improvement in energy efficiency place downward pressure on average usage. Both the continued conservation focus and energy efficiency improvements are driven primarily from technological advances, equipment standards, and enhanced building codes. These impacts have been offset by strong customer count gains in certain areas of the ARP Participant service territories

FMPA acknowledged that over the last several years, EVs have been adopted in increasing numbers in the Company's service area. Given the significance of this trend, the Company's 2024 load forecast includes a projection of the future impact of EV charging energy.

For the current 10-year forecast horizon, FMPA is projecting approximately a 1.1 percent average annual growth rate for its customer base, and a 1.0 percent average annual growth rate for energy sales. Figure 29 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan FMPA filed in its 2024 TYSP.

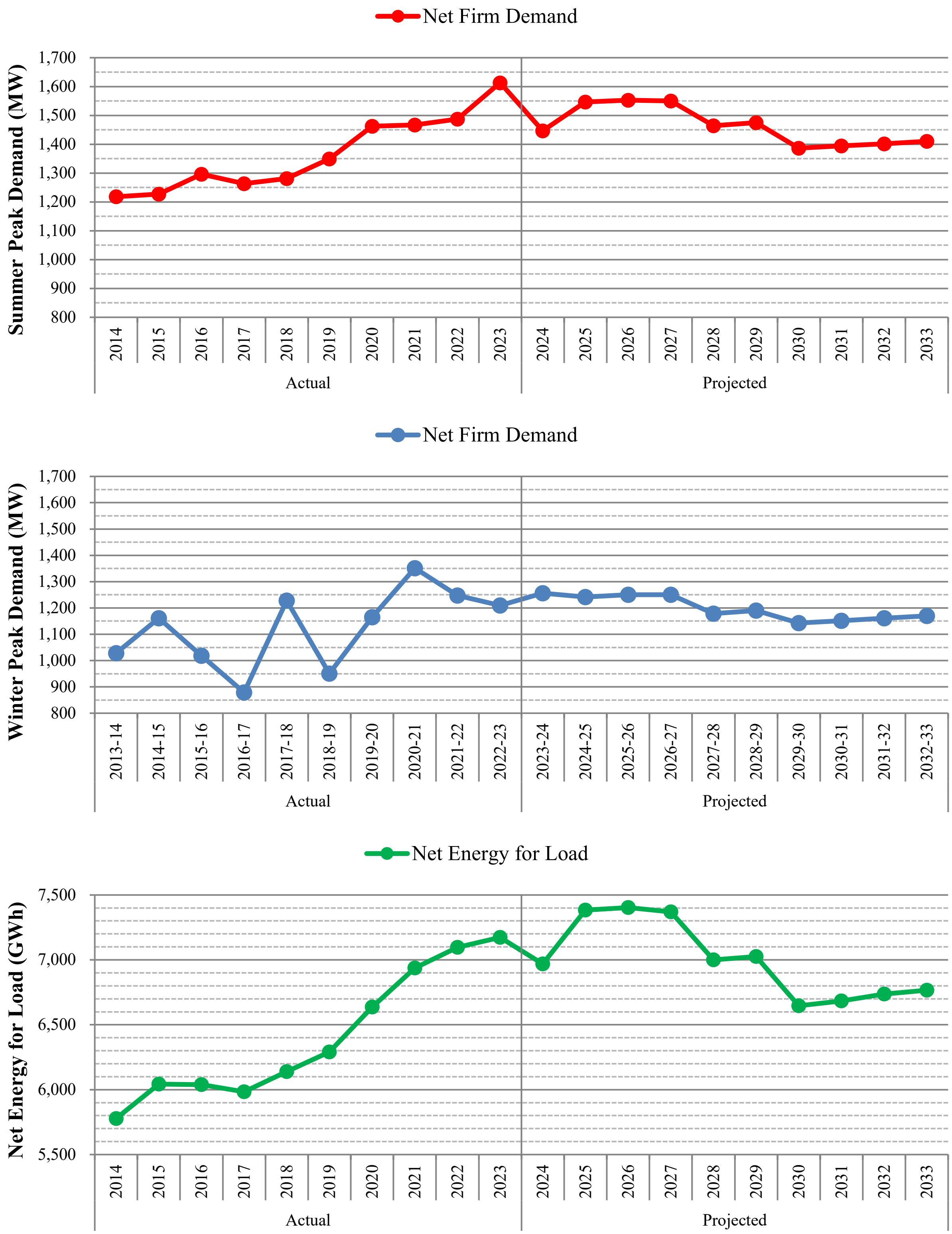
Figure 29: FMPA Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 30 show FMPA's seasonal peak demand and net energy for load for the historic years 2014 through 2023 and forecast years 2024 through 2033. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer demand-side management programs, the impacts of which are included in the graphs.

Figure 30: FMPA Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 19 shows FMPA's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects to end energy generation from coal, but approximately 90 percent of energy would still be sourced from natural gas and nuclear. FMPA projects serving 10 percent of its net energy for load with renewable resources by the end of the planning period.

Table 19: FMPA Energy Generation by Fuel Type

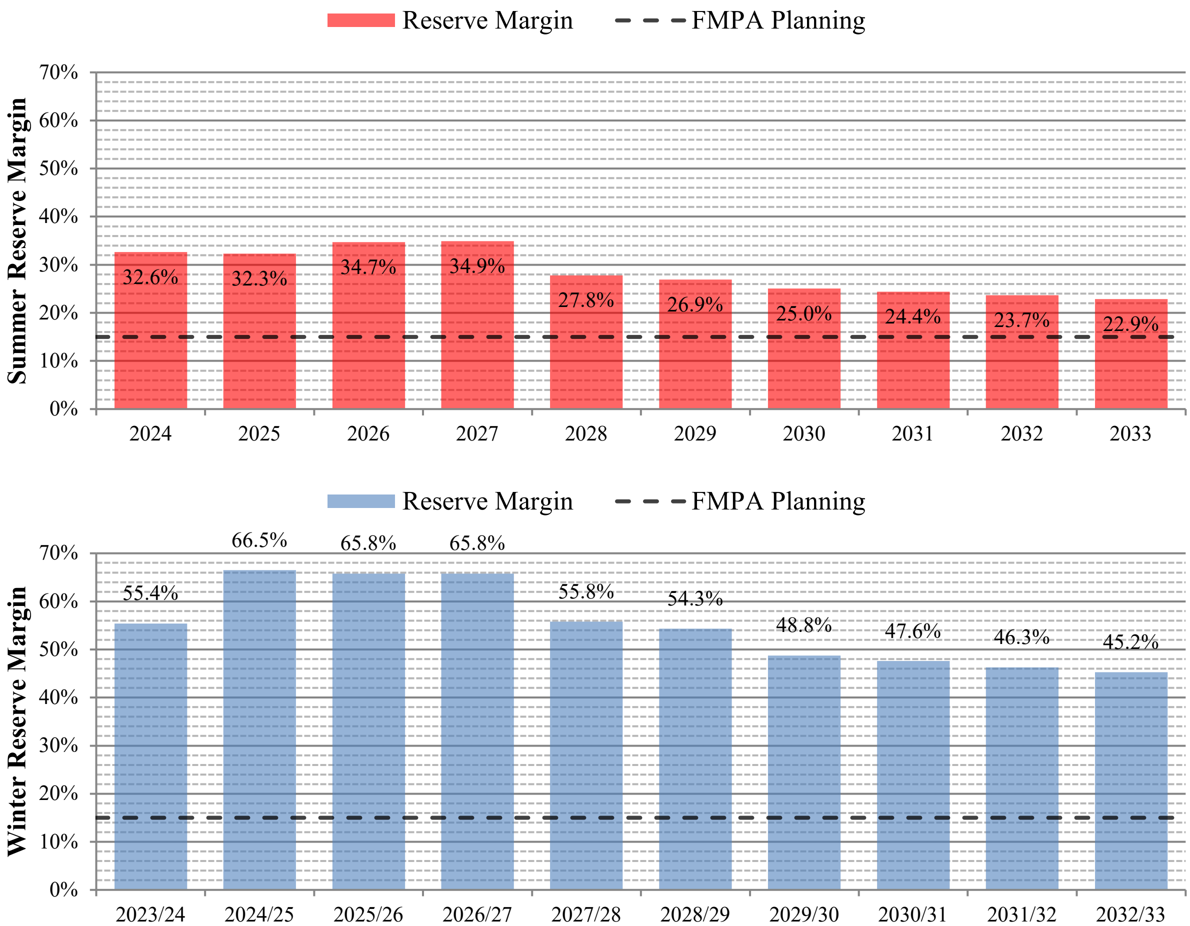
Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	5,853	**81.6%**	5,743	**84.9%**
Coal	769	**10.7%**	0	**0.0%**
Nuclear	406	**5.7%**	376	**5.6%**
Oil	3	**0.0%**	1	**0.0%**
Renewable	143	**2.0%**	647	**9.6%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**7,174**		**6,766**	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

FMPA utilizes a 15 percent planning reserve margin criterion. Figure 31 displays the forecast planning reserve margin for FMPA through the planning period for both seasons. As shown in the figure, FMPA's generation needs are controlled by its summer peak throughout the planning period.

Figure 31: FMPA Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

FMPA plans on retiring one unit and adding three new units during the planning period, as described in Table 20. FMPA plans on retiring the Stanton Energy Center Unit 1, a coal steam unit, in 2025. The three additions are all acquisitions of existing merchant natural gas-fired combined cycle facilities, two completed in 2024 and one projected for 2026. In addition, FMPA has entered into multiple purchased power agreements (PPAs) that will add a total of 193 MW of solar capacity by the end of 2026.

Table 20: FMPA Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2025	Stanton Unit 1	Coal ST	119	Jointly Owned Unit
		Total Retirements	**119**	
New Units				
2024	Sand Lake Energy Center	NG CC	120	Merchant Acquisition
2024	Mulberry	NG CC	108	Merchant Acquisition
2026	Orange Cogeneration	NG CC	104	Merchant Acquisition
		Total New Units	**332**	
		Net Additions	**213**	

Source: 2024 Ten-Year Site Plan

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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

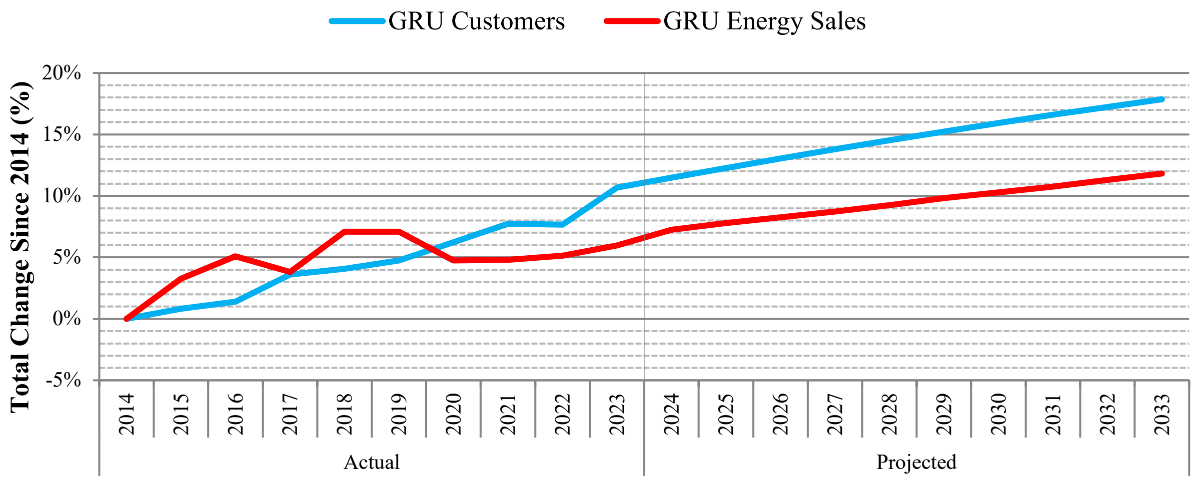
In 2023, GRU had approximately 103,865 customers and annual retail energy sales of 1,811 GWh, or approximately 0.8 percent of Florida's annual retail energy sales. Over the last 10 years, GRU's customer base has increased by approximately 10.7 percent, while retail energy sales have increased by approximately 6.0 percent.

GRU acknowledged that over the past 10 years, its residential energy consumption per customer declined approximately 0.2 percent per year, while its non-residential consumption per customer declined approximately 0.5 percent per year. For the next 10 years, the Utility projects that its residential energy usage per customer will stay relatively constant, and non-residential energy usage per customer will decline at a rate of approximately 0.3 percent per year. GRU recognized some of the factors that effect the usage per customer which include increasing electricity prices, improved building code, energy efficiency standards and regulations, and Utility-sponsored conservation measures. The Utility also anticipated that in future years, loads associated with EV charging are anticipated to support usage per customer for all classes, most significantly in the residential sector with at-home charging.

For the current 10-year forecast horizon, GRU's number of customers and retail energy sales will grow at an annual average rate of approximately 0.6 and 0.5 percent, respectively. The Utility indicated that its projected growth of retail energy sales is supported by its projected increase in the number of customers and offset negatively by flat or declining energy usage per customer. The Utility also noted that load associated with electric vehicle charging is anticipated to support energy sales more in this forecast than in past forecasts.

Figure 32 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan GRU filed in its 2024 TYSP.

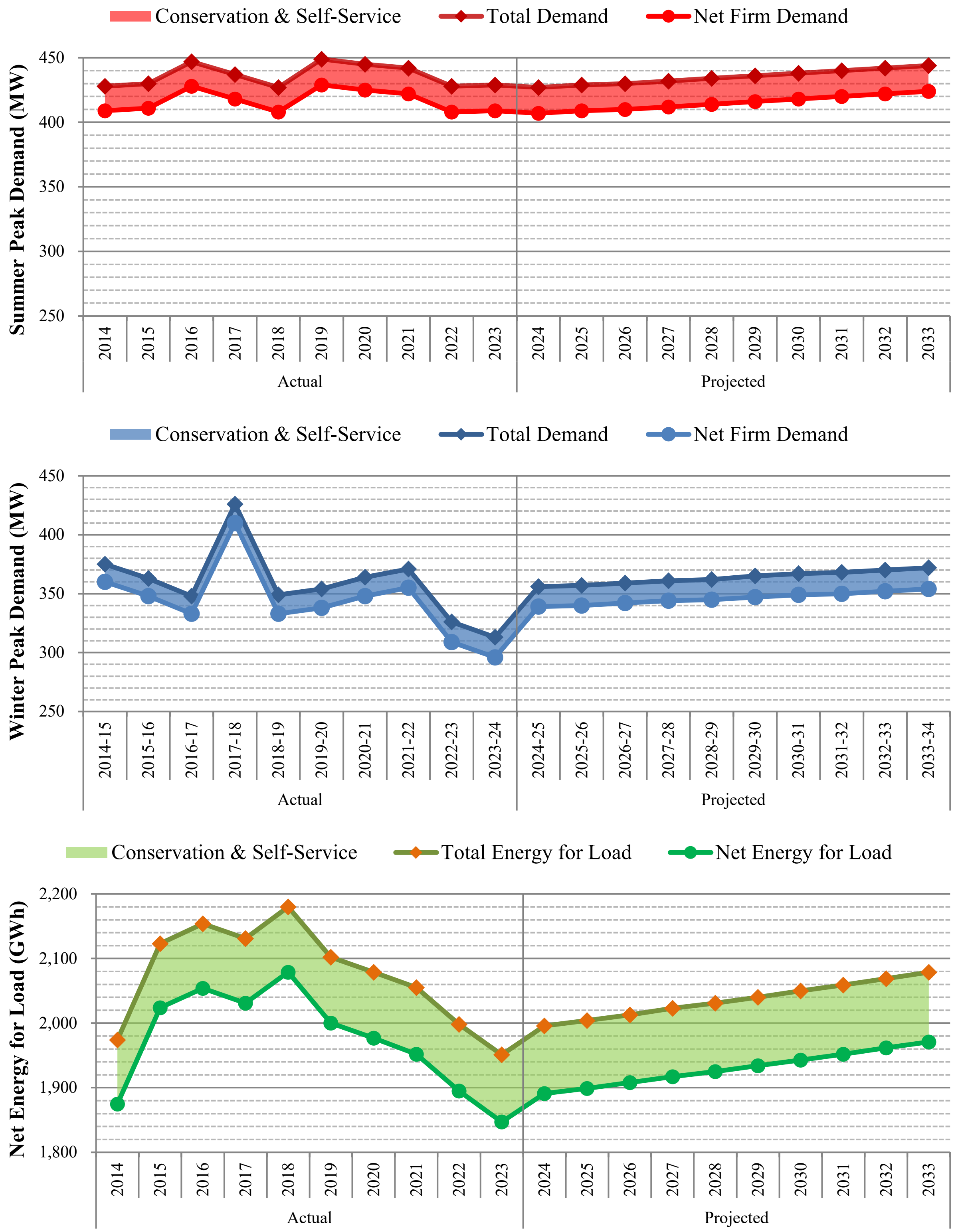
Figure 32: GRU Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 33 show GRU's seasonal peak demand and net energy for load for the historic years of 2014 through 2023 and forecast years 2024 through 2033. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 33 include the impact of these demand-side management programs.

Figure 33: GRU Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 21 shows GRU's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. In 2022, natural gas and renewables were the primary fuel for energy generation, making up approximately 100 percent of net energy for load. GRU currently has the highest percentage contribution of renewables in Florida for net energy for load, but will fall behind FPL and JEA by 2033.

Table 21: GRU Energy Generation by Fuel Type

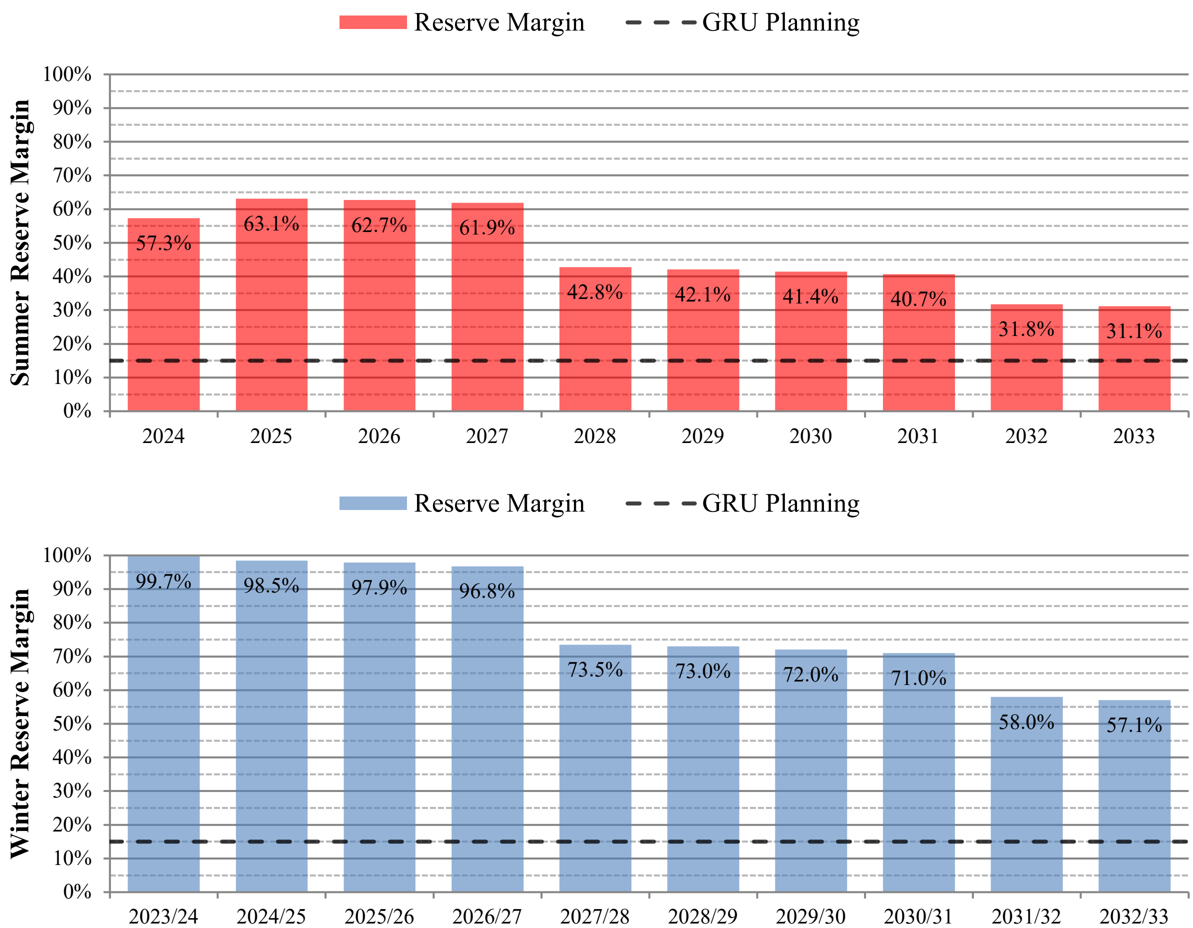
Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	1,574	**84.6%**	1,266	**64.2%**
Coal	20	**1.1%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	296	**15.9%**	640	**32.5%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	(29)	**-1.6%**	66	**3.3%**
Total	**1,861**		**1,972**	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 34 displays the forecast planning reserve margin for GRU through the planning period for both seasons. As shown in the figure, GRU's generation needs are controlled by its summer peak throughout the planning period.

Figure 34: GRU Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

GRU currently plans on retiring three natural gas-fired units, as described in Table 22. All three units, a pair of combustion turbines and a steam turbine, are located at GRU's Deerhaven plant. In addition, GRU entered into a 20 year contract that is expected to deliver an additional 75 MW of solar capacity through a PPA with an expected in-service year of 2025, including a 12 MW battery installation.

Table 22: GRU Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2027	Deerhaven Unit FS01	NG ST	76	
2031	Deerhaven Unit GT01 & GT02	NG CT	35	2 Units Total
		Total Retirements	**111**	
New Units				
	None			
		Total New Units	**0**	
		Net Additions	**(111)**	

Source: 2024 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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

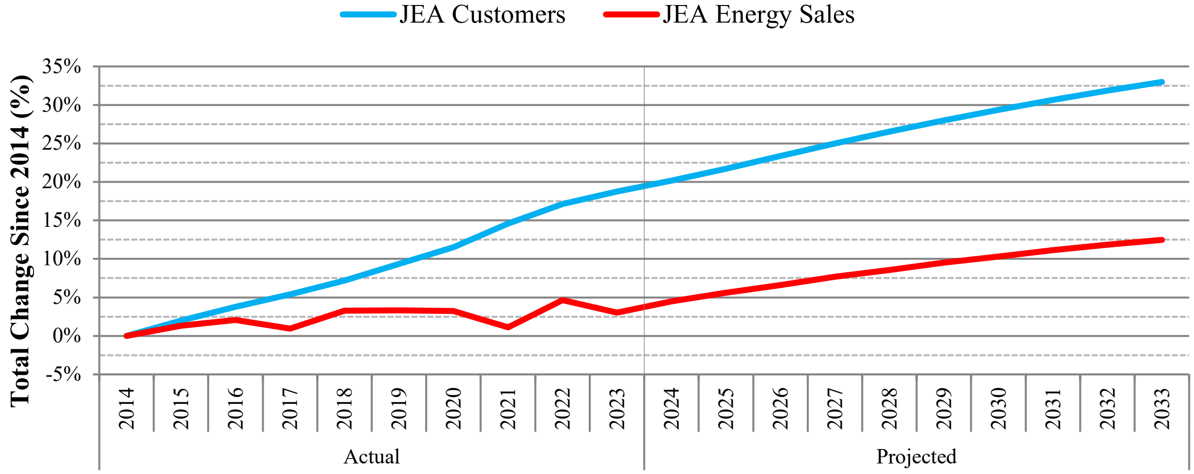
In 2023, JEA had approximately 514,909 customers and annual retail energy sales of 12,295 GWh or approximately 5.3 percent of Florida's annual retail energy sales. Over the last 10 years, JEA's customer base has increased by approximately 18.8 percent, while retail energy sales have increased by approximately 3.0 percent.

JEA utilized various economic and demographic forecasts from Moody's Analytics as the inputs to the Utility's forecasting models. Overall, Moody's Analytics inputs resulted in a forecasted percentage growth for all parameters utilized in JEA's 2024 TYSP which is very similar as compared to the 2023 forecasts. As a result, JEA projected a 1.1 percent growth for residential customers, and 0.3 percent growth for both commercial and industrial customers.

JEA indicated that the Utility-funded demand-side management programs continue to be a contributor to the usage decrease in annual energy use per residential customer. The other contributing factors include customer behavioral changes, increased electric rates, more multifamily housing constructions compared to single-family housing constructions that use less energy per customer. The Utility noted that the US Government's SEER Requirement Changes for 2015, that required new split system central air conditioners to be a minimum 14 SEER, had contributed to the majority of decrease in electricity use per customer over the past years. It further indicated that the new 2023 SEER rating standards, now requiring new air conditioners in Southern states to be a minimum 15 SEER, will continue to contribute to the decrease in electricity usage per customer. For the 2024 TYSP forecasting horizon, JEA expected that the average energy consumption per customer will stay flat for residential customers, decrease for commercial customers with an annual growth rate of negative 0.9 percent, and increase slightly for industrial customers with a rate of 0.2 percent.

For the next 10 years, JEA's forecasting results indicate that the customer numbers will grow at an average annual rate of 1.1 percent; and the retail energy sales will grow at an average annual rate of 0.8 percent. Figure 35 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan JEA filed in its 2024 TYSP.

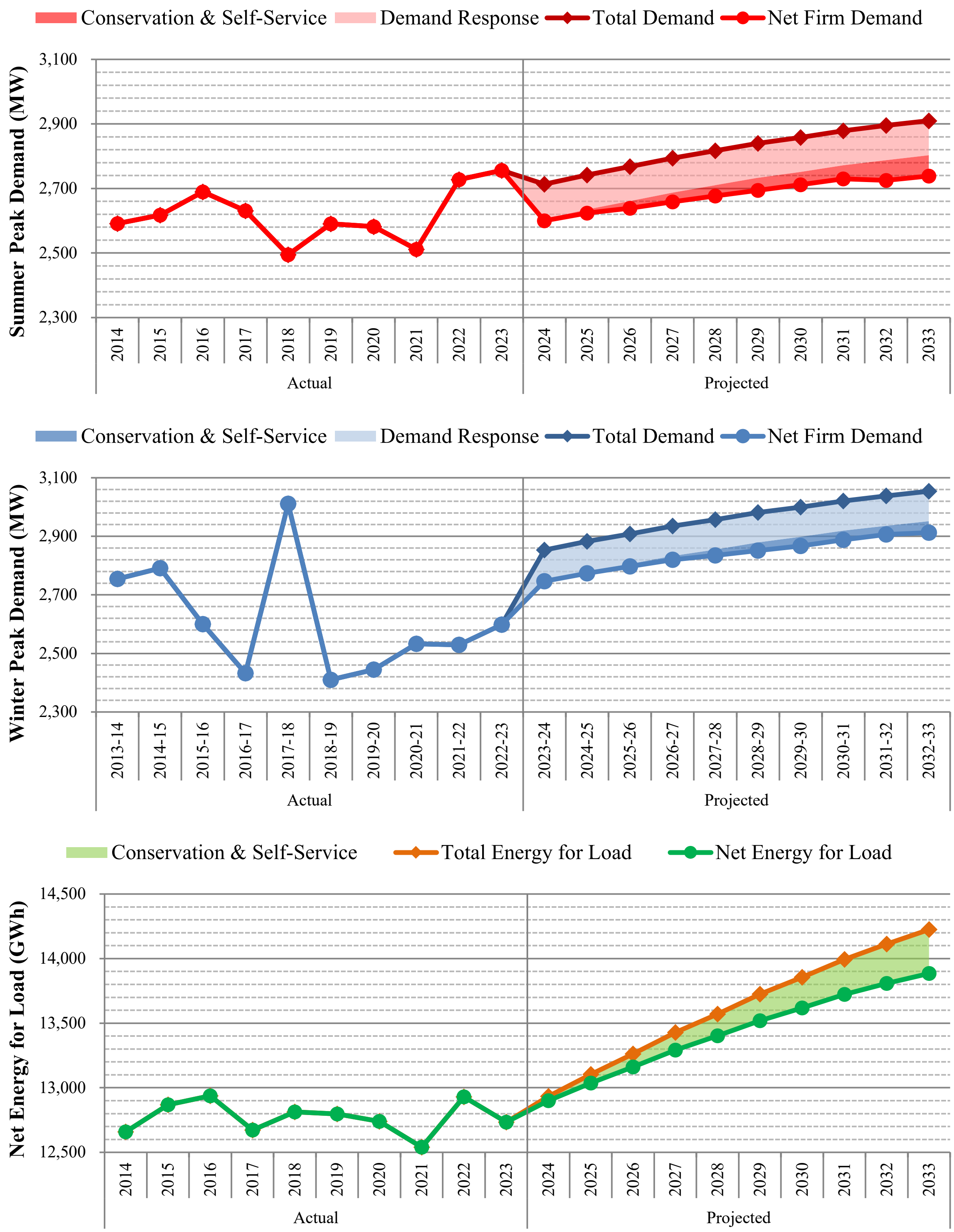
Figure 35: JEA Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 36 show JEA's seasonal peak demand and net energy for load for the historic years of 2014 through 2023 and forecast years 2024 through 2033. 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. These graphs include the full impact of demand-side management, and assume that all available demand response resources will be activated during the seasonal peak. In August 2024, the Commission established demand side management goals for JEA for the years 2025 through 2034. In 2025, the Commission will review JEA's plan designed to achieve the Utility's DSM goals. In preparing its 2024 Ten-Year Site Plan seasonal peak demand and energy forecasts, JEA assumes the trends in these goals will be extended through the forecast period (through 2033).

Figure 36: JEA Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 23 shows JEA's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. While natural gas was the dominant fuel source in 2023, purchases through the Interchange was JEA's second most utilized energy source. JEA has the highest percentage of energy from other utilities (interchange), primarily from a contract with the Municipal Electric Authority of Georgia for 200 MW from the Vogtle nuclear Units 3 and 4. JEA's 2024 Ten-Year Site plan projects that a JEA will reduce its use of coal while increasing its renewable fuel source.

Table 23: JEA Energy Generation by Fuel Type

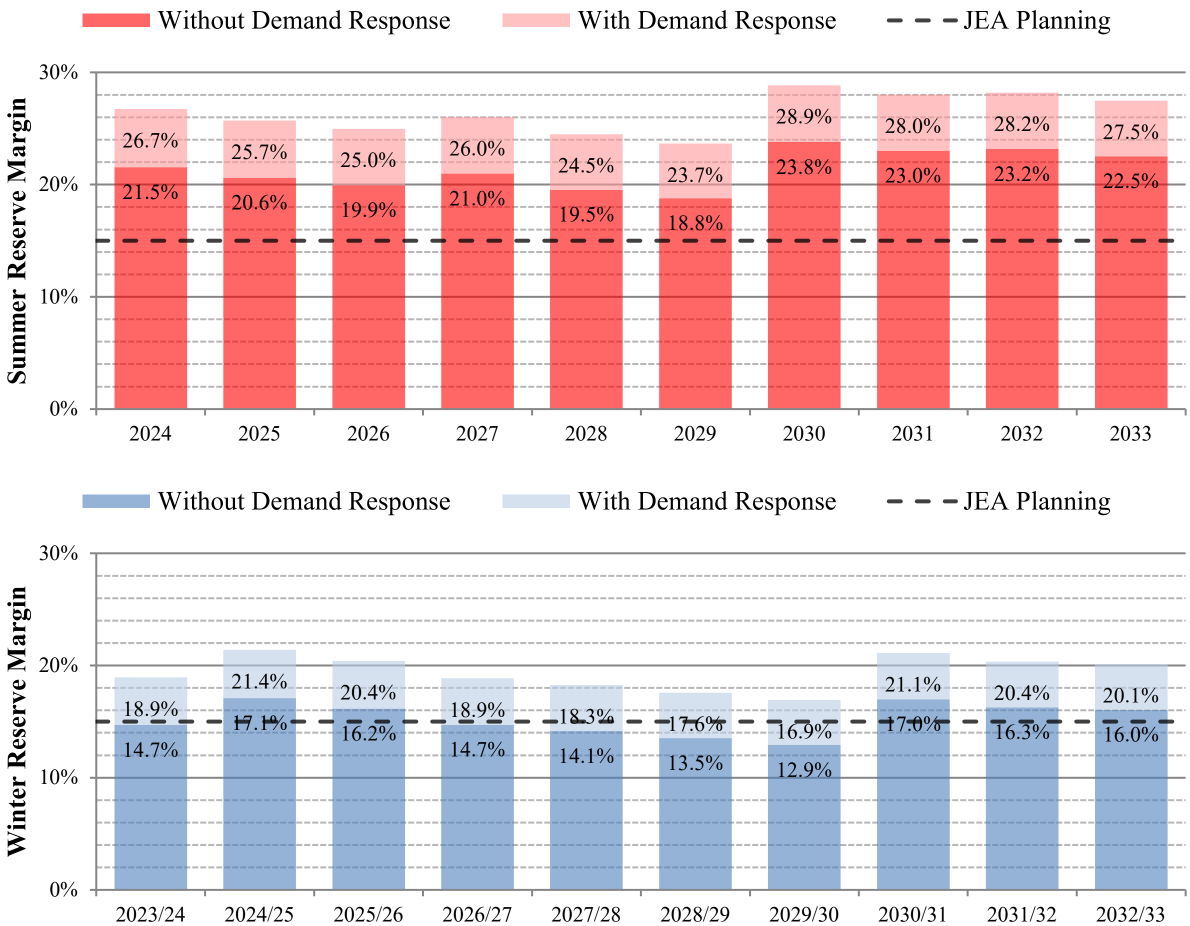
Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	7,268	**57.1%**	8,192	**59.0%**
Coal	1,231	**9.7%**	397	**2.9%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	3	**0.0%**	5	**0.0%**
Renewable	412	**3.2%**	3,146	**22.7%**
Interchange	3,763	**29.6%**	2,080	**15.0%**
NUG & Other	46	**0.4%**	65	**0.5%**
Total	**12,722**		**13,885**	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 37 displays the forecast planning reserve margin for JEA through the planning period for both seasons, with and without the use of demand response. JEA's current and planned purchased power agreements with solar generators contribute to this shift in planning because solar resources provide coincident capacity during the summer peak but not the winter peak.

Figure 37: JEA Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

As detailed in Table 24, JEA is retiring Northside Unit 3 and adding an unnamed natural gas-fired combined cycle unit. JEA has entered into a PPA with Municipal Electric Authority of Georgia for firm nuclear capacity, and is currently receiving 100 from Vogtle Unit 3, and anticipates receiving an additional 100 MW from Vogtle Unit 4 in 2024. In addition, JEA is planning to enter into several solar PPAs totaling 1,134 MW. JEA has already entered into PPAs for 420 MW of new solar to be constructed through 2027, and 150 MW of existing solar capacity from FPL. A majority of the PPAs, totaling 559 MW, are planned for 2030. JEA also reported that approximately 140 MW of battery storage would be associated with the solar PPAs.

Table 24: JEA Energy Generation by Fuel Type

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2030	Northside Unit 3	NG ST	524	
		Total Retirements	**524**	
New Units				
2030	Advanced-Class 1x1 CC	NG CC	576	PPSA Approval Needed
		Total New Units	**576**	
		Net Additions	**52**	

Source: 2024 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 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2023, LAK had approximately 141,106 customers and annual retail energy sales of 3,311 GWh or approximately 1.4 percent of Florida's annual retail energy sales. Over the last 10 years, LAK's customer base has increased by 13.8 percent, while retail energy sales have grown by 14.1 percent approximately.

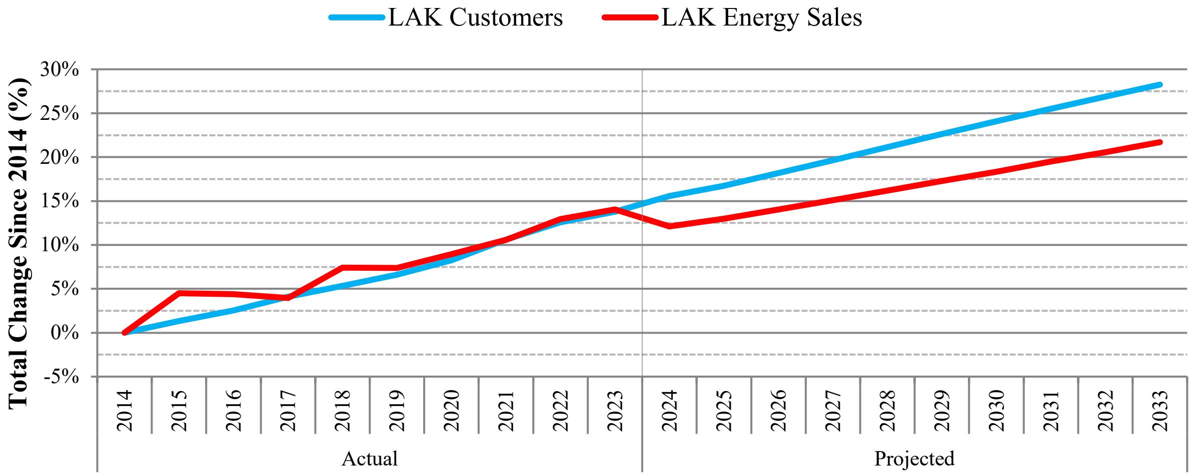
In recent years, LAK's service area in Polk County has seen a boom in e-commerce warehouse development. Notably, Amazon moved its air-hub from Tampa to the Utility's service area in the summer of 2020 and it is continuing to expand. As a result, LAK experienced 1.1 percent total customer growth in 2023, with the commercial rate class growing by 4.3 percent and industrial class growing by 2.0 percent.

Despite customer growth, LAK noted that its residential average energy consumption per customer has been declining and this trend is expected to continue. The main factors that contribute to the decline include increased appliance energy efficiency, improved building shell insulation, and changes in mix residential building type. The Utility's commercial average energy consumption per customer has also been declining, and this trend is expected to continue. Main contributors to the decline are lighting upgrades, appliance energy efficiency improvements, and the customer adoption of energy management systems. LAK expects a flattening of the trend of LAK's industrial average energy consumption mainly because the industrial customers that are projected to be added are expected to be mostly classified in the "small demand" industrial category.

LAK noted that, although the average energy consumption per customer is declining or flat for all three main rate classes, positive customer growth rates are expected to compensate for average energy use declines. The Utility assumed the impact of conservation programs are already included in the energy sales history and made no additional assumptions regarding their impact.

For the next 10 years, the Utility's forecasts indicate that LAK's number of customers are projected to grow at an average annual rate of approximately 1.2 percent, and its retail energy sales are projected to grow at an average annual rate of approximately 0.9 percent. Figure 38 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan LAK filed in its 2024 TYSP.

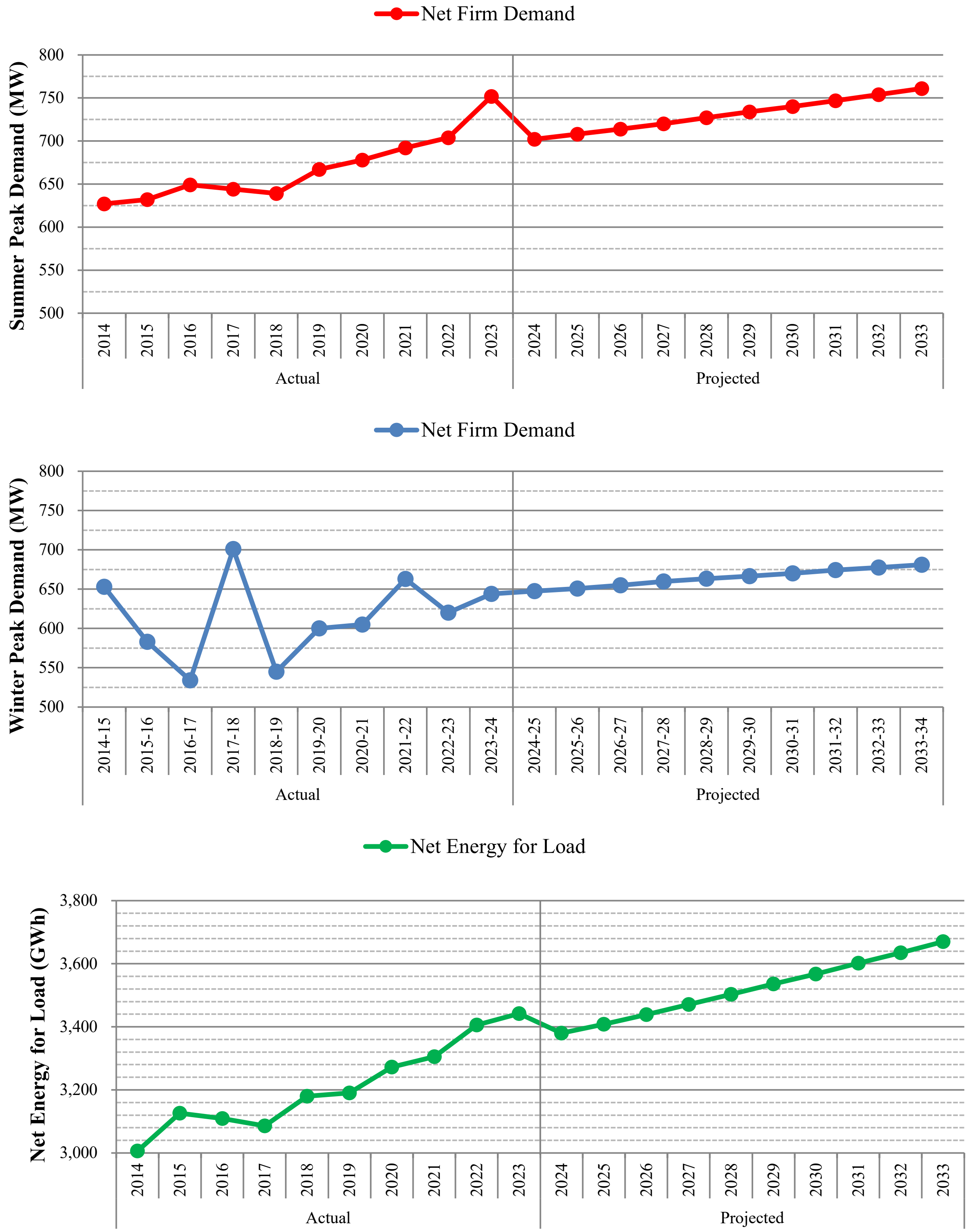
Figure 38: LAK Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 39 show LAK's seasonal peak demand and net energy for load for the historic years of 2014 through 2023 and forecast years 2024 through 2033. LAK offers energy efficiency programs, the impacts of which are included in the graphs.

Figure 39: LAK Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 25 shows LAK's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. LAK uses natural gas as its primary fuel type for energy, with purchases (listed in the NUG & Other category below) representing about 42 percent net energy for load. While natural gas generation is anticipated to increase over the next 10 years, interchange purchases are projected to decrease to about 33 percent, while renewables increase to 5 percent by 2033.

Table 25: LAK Energy Generation by Fuel Type

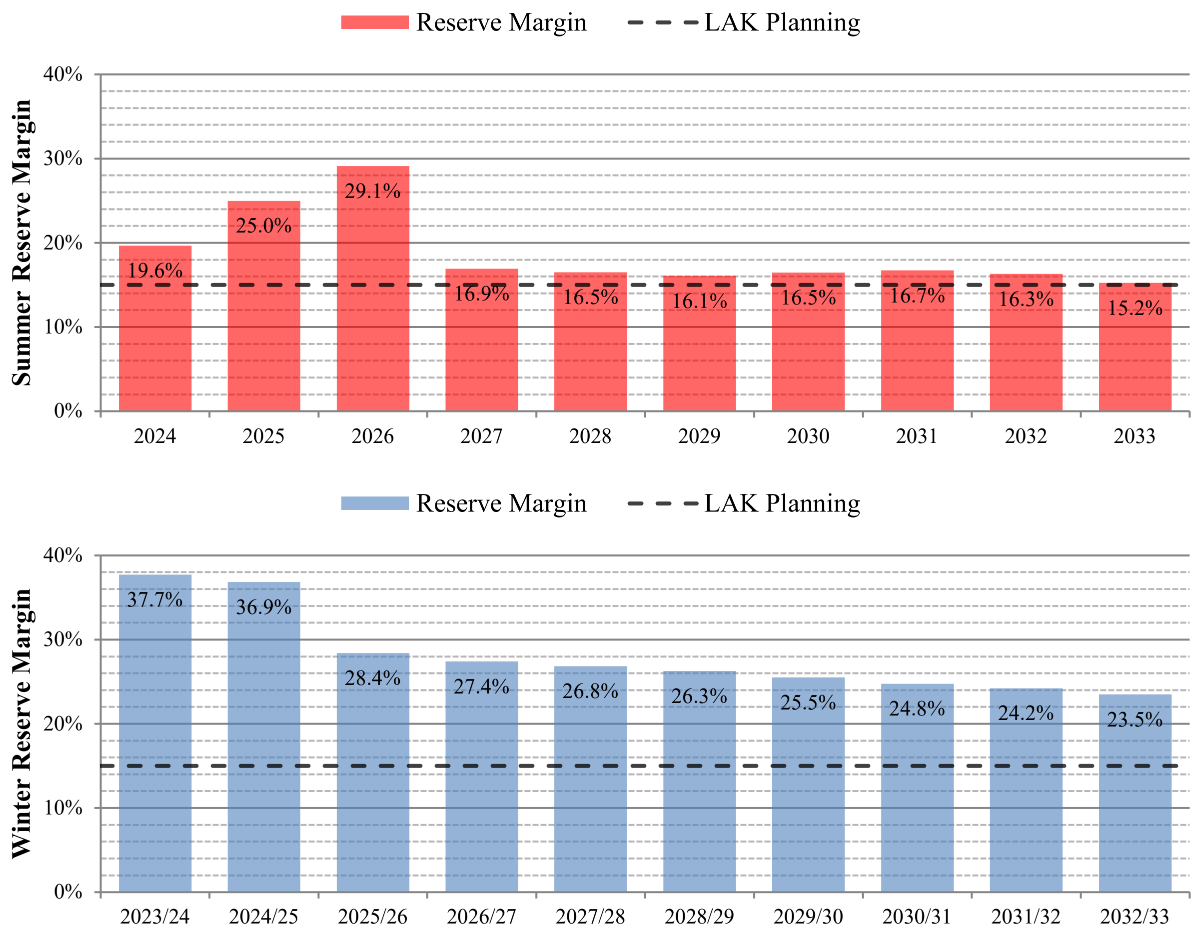
Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	1,976	**57.4%**	2,283	**62.2%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	1	**0.0%**
Renewable	25	**0.7%**	178	**4.9%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	1,441	**41.9%**	1,208	**32.9%**
Total	**3,442**		**3,670**	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 40 displays the forecast planning reserve margin for LAK through the planning period for both seasons. The Utility does not offer demand response programs at this time. As illustrated by Figure 40, summer peak demand is the controlling factor for reliability planning for almost all years of the planning period.

Figure 40: LAK Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

LAK plans to add six units during the planning period, as described in Table 26, all natural gas-fired internal combustion engines. LAK is in negotiations for a PPA with Edge Solar for a 75 MW solar facility by 2026.

Table 26: LAK Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
	None			
		Total Retirements	**0**	
New Units				
2024	McIntosh Units ME1 –ME6	NG IC	120	6 Units Total
		Total New Units	**120**	
		Net Additions	**120**	

Source: 2024 Ten-Year Site Plan and Data Responses

Orlando Utilities Commission (OUC)

OUC is a municipal utility and Florida's sixth 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 2024 Ten-Year Site Plan suitable for planning purposes.

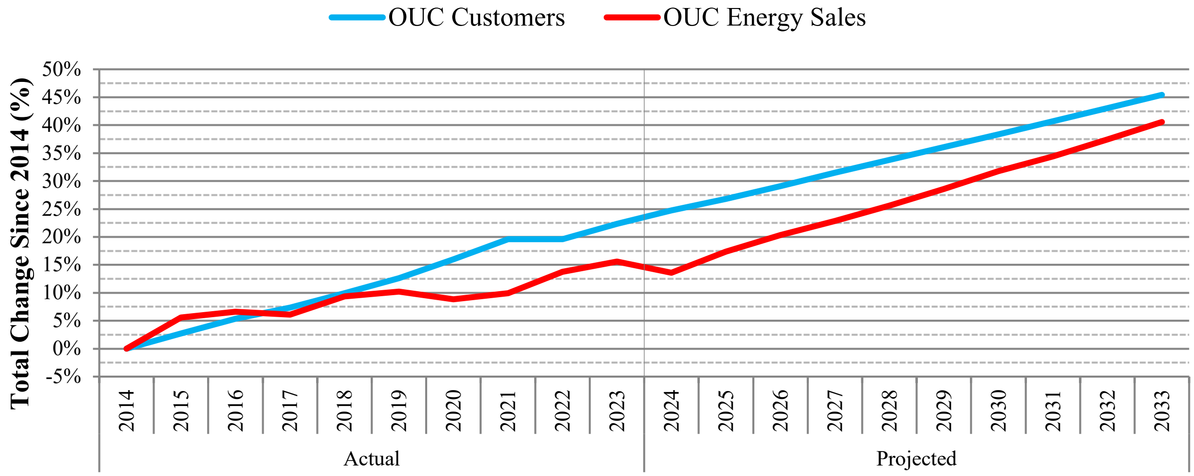
Load and Energy Forecasts

In 2023, OUC had approximately 275,339 customers and annual retail energy sales of 7,155 GWh or approximately 3.1 percent of Florida's annual retail energy sales. Over the last 10 years, OUC's customer base has increased by 22.3 percent, while its retail energy sales have increased by 15.6 percent, approximately.

OUC experienced a continued decline in weather-normalized average use per residential customer in 2023. The Utility noted that such decline has tapered dramatically since the beginning of the 10-year historic period due to the increased saturation of more efficient HVAC equipment and other electrical devices, as well as customer conservation efforts. OUC's forecasted residential average usage per customer is expected to remain relatively flat as increased electric vehicle charging mitigates further saturation of more efficient electrical equipment and conservation efforts. The Utility's average use per commercial customer also experienced a slight, long-term decline, which was greatly exacerbated by the impacts of the pandemic in 2020, but is expected to return to pre-pandemic levels. The Utility's industrial average use per customer increased approximately 1.4 percent annually over the last 10-year period.

Over the forecast horizon, OUC is projecting growth in the number of customers at an average annual rate of 1.7 percent, and retail energy sales at an average annual rate of 2.4 percent approximately. OUC noted that the main contributors to the projected customer growth include the increased population and household numbers in its service area. The main drivers for the projected growth of the energy sales include the recovery from COVID-19 pandemic effects, the projected growth in electric vehicle charging load, and major commercial expansions by Universal Studios and the Orlando International Airport that are largely outside of normal growth. Figure 41 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan OUC filed in its 2024 TYSP.

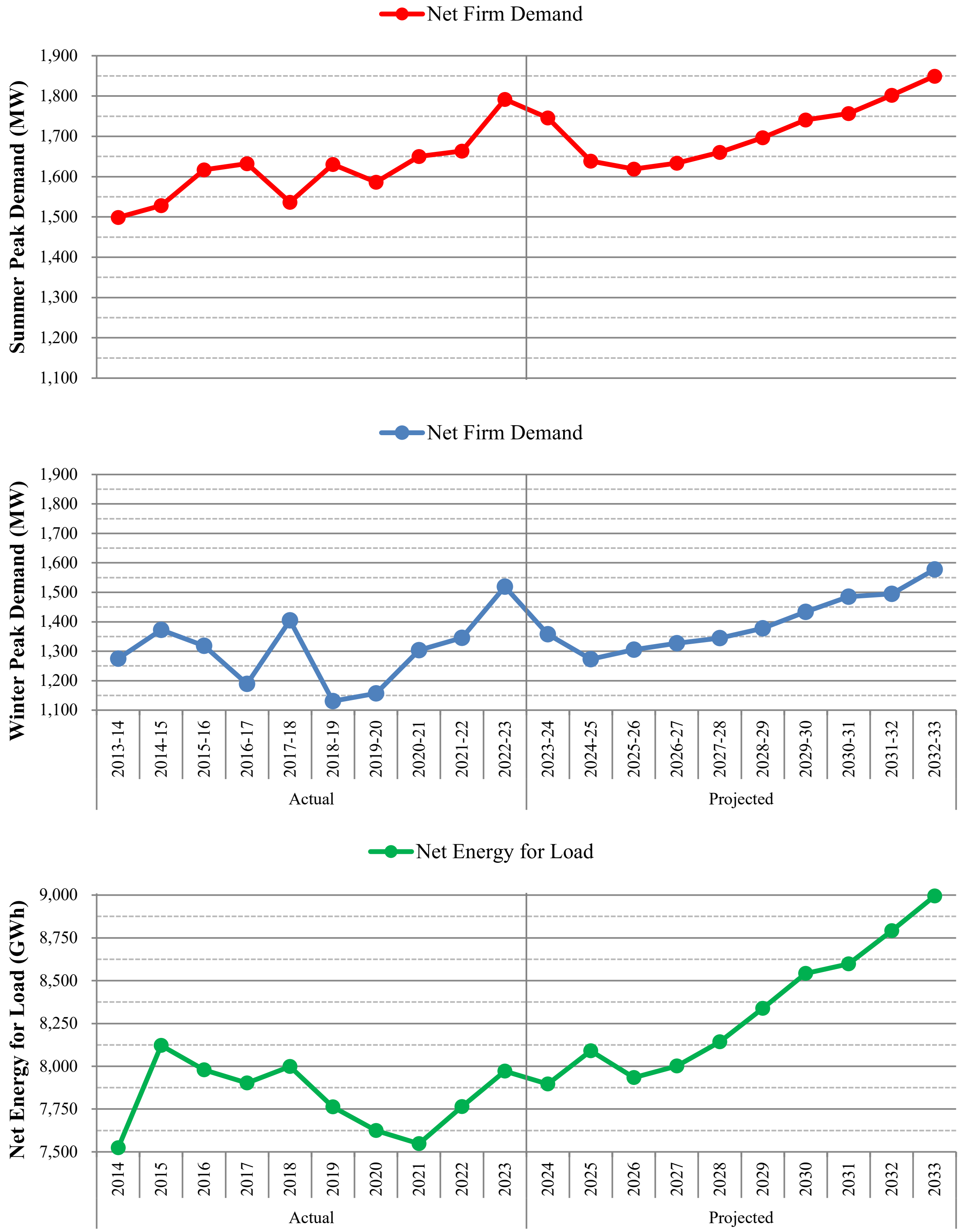
Figure 41: OUC Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 42 show OUC's seasonal peak demand and net energy for load for the historic years of 2024 through 2023 and forecast years 2024 through 2033. 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 programs to customers to reduce peak demand and annual energy consumption. In August 2024, the Commission established demand side management goals for OUC for the years 2025 through 2034. In 2025, the Commission will review OUC's plan designed to achieve the Utility's 2025-2034 DSM goals. In preparing its 2024 Ten-Year Site Plan seasonal peak demand and energy forecasts, OUC assumes the trends in these goals will be extended through the forecast period (through 2033).

Figure 42: OUC Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 27 shows OUC's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. In 2023, approximately 65 percent of OUC's net energy for load was met with natural gas, while coal, the second most-used fuel, met approximately 24 percent of the demand. By 2033, OUC projects an increase in renewable energy generation from 5 percent to 50 percent, the second highest in the state. The remainder of energy primarily comes from natural gas and nuclear, with coal generation completely eliminated.

Table 27: OUC Energy Generation by Fuel Type

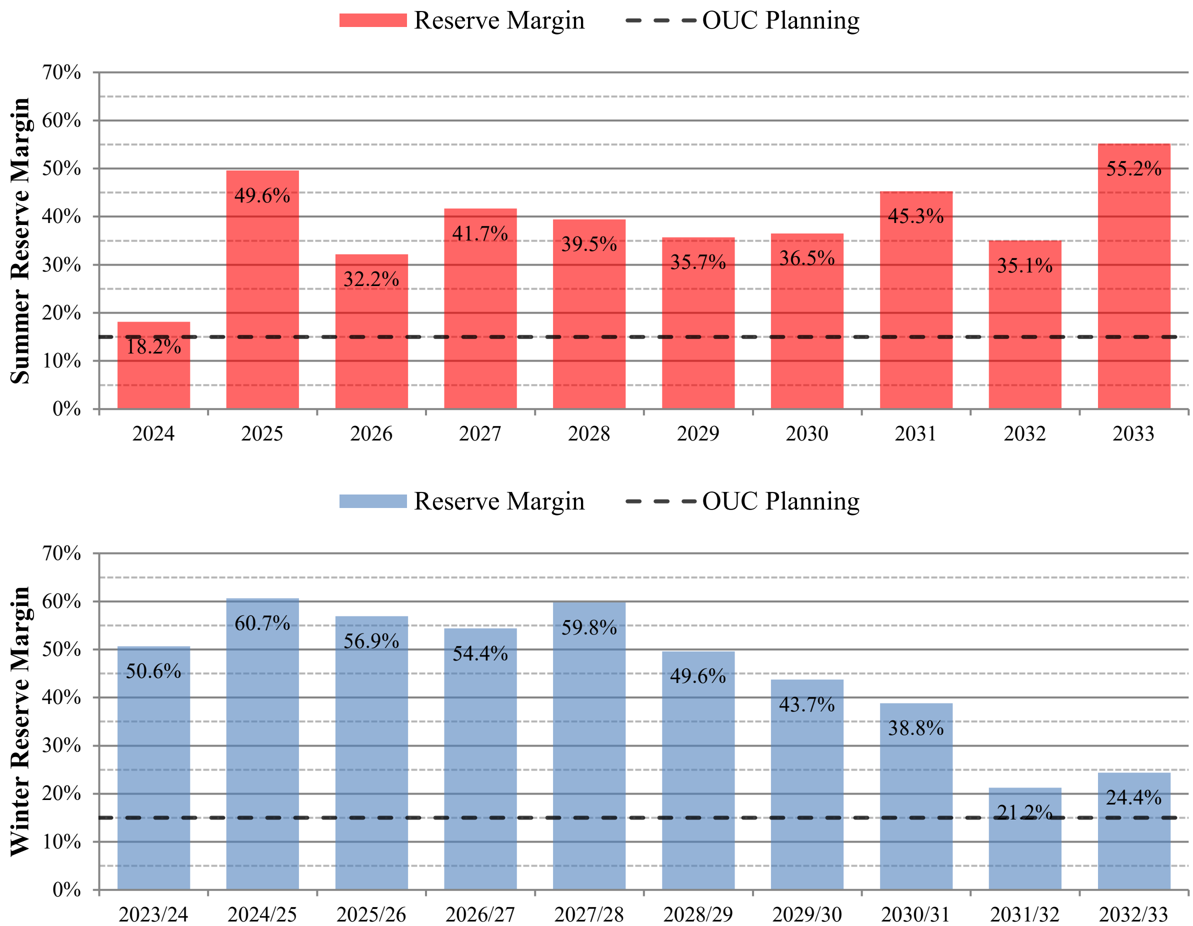
Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	5,144	**64.5%**	4,002	**44.5%**
Coal	1,938	**24.3%**	0	**0.0%**
Nuclear	494	**6.2%**	479	**5.3%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	396	**5.0%**	4,513	**50.2%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**7,972**		**8,994**	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

OUC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 43 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.

Figure 43: OUC Reserve Margin Forecast



Source: 2024 Ten-Year Site Plan

Generation Resources

As detailed in Table 28, OUC plans on retiring Stanton Energy Center Unit 1, OUC's oldest coal-fired unit, in 2025. OUC will convert the remaining coal-fired Stanton Energy Center Unit 2 to a natural gas-fired unit by the end of 2027. Transmission upgrades planned for 2025 will allow OUC full access to the firm capacity of their existing Osceola generating unit. OUC anticipates entering into PPAs for a total of 1,267 MW of solar net capacity and 600 MW of battery storage. These PPAs are projected to contribute 559 MW and 600 NW to firm summer peak, respectively. OUC has already signed two of these PPAs, with NextEra for a total of 149 MW of solar capacity with a planned in-service year of 2024.

Table 28: OUC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2025	Stanton Energy Center Unit 1	Coal ST	311	Jointly Owned Unit
		Total Retirements	**311**	
New Units				
	None			
		Total New Units	**0**	
		Net Additions	**(311)**	

Source: 2024 Ten-Year Site Plan

Seminole Electric Cooperative (SEC)

SEC is a generation and transmission rural electric cooperative that serves its member cooperatives, and is collectively Florida's fourth largest utility. SEC's generation and member cooperatives are within the FRCC region, with member cooperatives located in central and north Florida. As a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds SEC's 2024 Ten-Year Site Plan suitable for planning purposes.

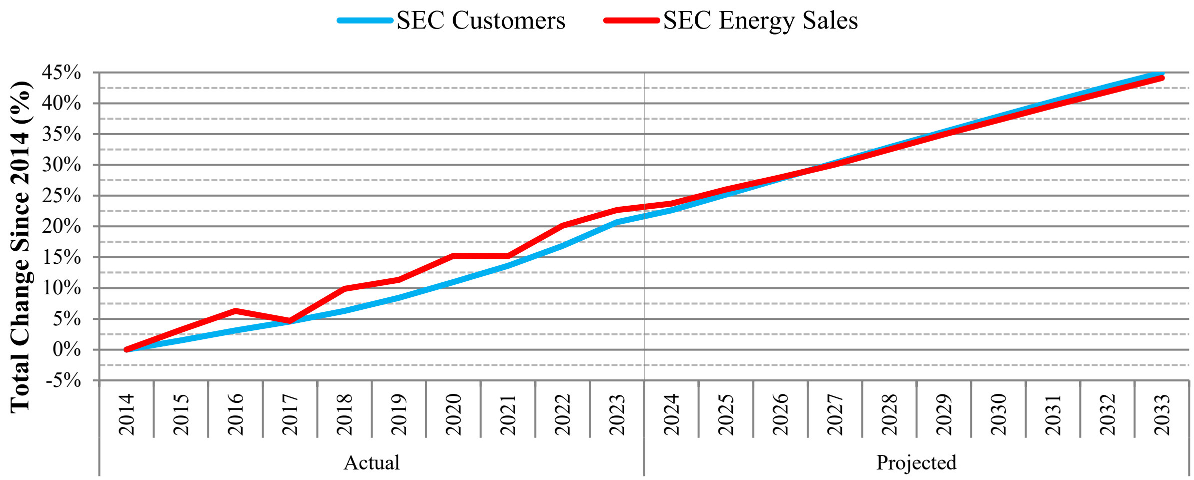
Load and Energy Forecasts

In 2023, SEC member cooperatives had approximately 893,826 customers and annual retail energy sales of 15,895 GWh or approximately 6.8 percent of Florida's annual retail energy sales. Over the last 10 years, SEC's customer base has increased by 20.7 percent, while its retail energy sales have increased by 22.7 percent, approximately.

SEC states that, historically, the consumer base of its Seminole-Member system has grown at a faster rate than the State of Florida as a whole, and this trend is expected to continue. The Utility noted that the leading indicators for load growth are Florida's expanding economy and net migration prospects into the state, especially from "baby boomer" retirees, and migration impacts during the COVID-19 pandemic. Customer growth and business activity are expected to drive growth of retail energy sales in a positive direction, while downward pressure is also anticipated. The downward pressure is expected to come from flattening and declining residential end-use which is due to growth in efficient technologies, renewable generation, and alternative resources.

Over the current 10-year forecast horizon, SEC is projecting an average annual growth rate in its customer base of 1.9 percent, and an average annual growth rate in its retail energy sales of 1.7 percent. Figure 44 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan SEC filed in its 2024 TYSP.

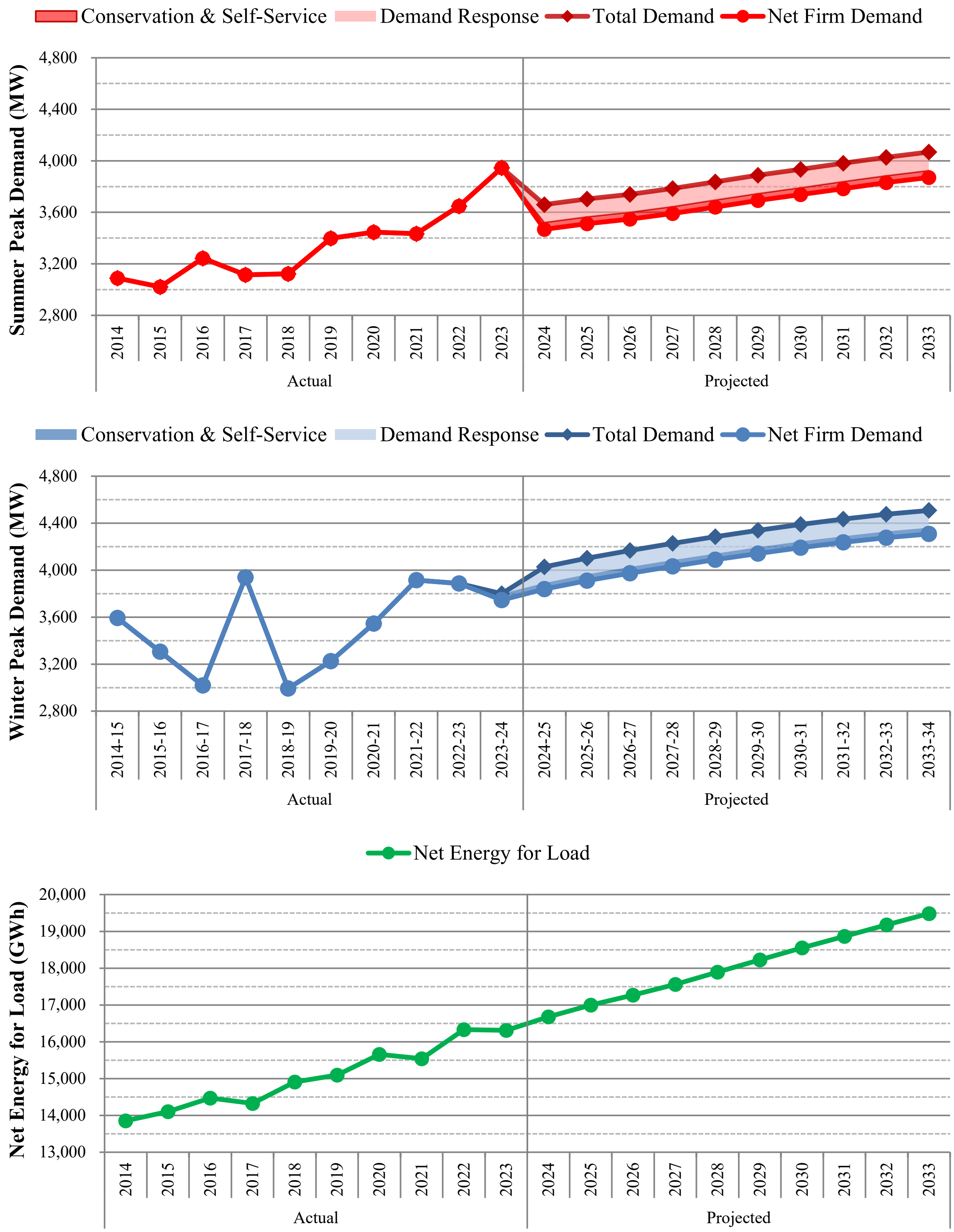
Figure 44: SEC Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 45 show SEC's seasonal peak demand and net energy for load for the historic years 2014 through 2023 and forecast years 2024 through 2033. As SEC is a generation and transmission utility, it does not directly engage in energy efficiency or demand response programs. Member cooperatives do offer demand-side management programs, the impacts of which are included in Figure 45.

Figure 45: SEC Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 29 shows SEC's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. In 2023, SEC used a mix of natural gas, coal and purchases to meet demand requirements. However, during the planning period, SEC will be switching to mostly self-generation by increasing natural gas usage while reducing coal and purchases. By 2033, natural gas will represent approximately 87 percent of SEC's fuel usage.

Table 29: SEC Energy Generation by Fuel Type

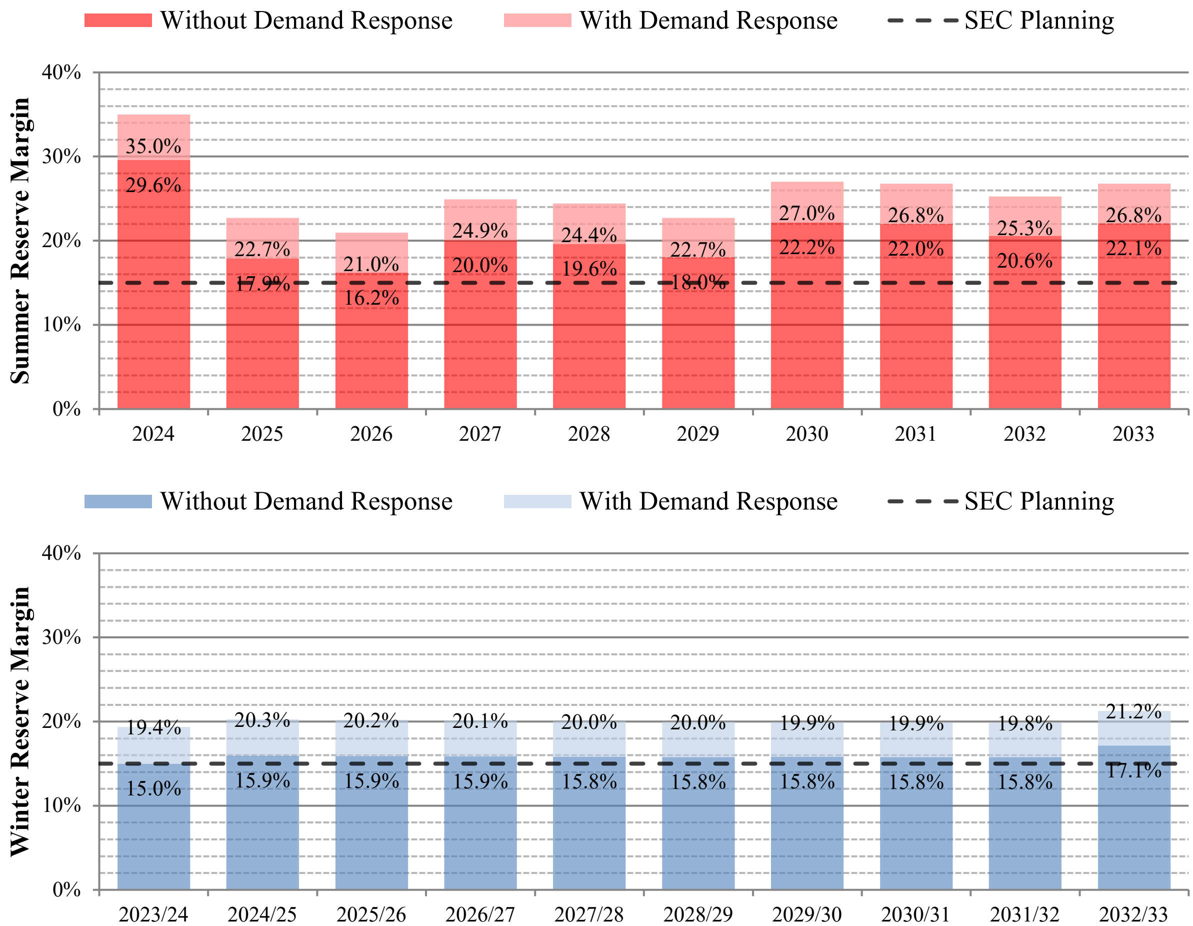
Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	8,920	**54.7%**	16,881	**86.6%**
Coal	4,896	**30.0%**	1,366	**7.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	18	**0.1%**	4	**0.0%**
Renewable	423	**2.6%**	738	**3.8%**
Interchange	141	**0.9%**	0	**0.0%**
NUG & Other	1,914	**11.7%**	495	**2.5%**
Total	**16,312**		**19,484**	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

SEC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 46 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 46: SEC Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

SEC plans to add three units during the planning period, as described in Table 30, all natural gas-fired generation. SEC plans to add two combined cycles and one combustion turbine during the planning period. SEC anticipates an additional 300 MW of solar generation through PPAs to become commercially operational by the end of 2024, of which 119 MW will be considered firm for summer peak.

Table 30: SEC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
	None			
Total Retirements			**0**	
New Units				
2026	Shady Hills	NG CC	546	PPSA Approved
2029	Unnamed CT	NG CT	317	
2032	Unnamed CC	NG CC	571	PPSA Approval Needed
Total New Units			**1,434**	
Net Additions			**1,434**	

Source: 2024 Ten-Year Site Plan

City of Tallahassee Utilities (TAL)

TAL is a municipal utility and the second smallest electric utility that files a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and primarily consists of the City of Tallahassee and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds TAL's 2024 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2023, TAL had approximately 119,140 customers and annual retail energy sales of 2,694 GWh or approximately 1.2 percent of Florida's annual retail energy sales. Over the last 10 years, TAL's customer base has increased by approximately 2.1 percent, while retail energy sales have increased by approximately 2.4 percent.

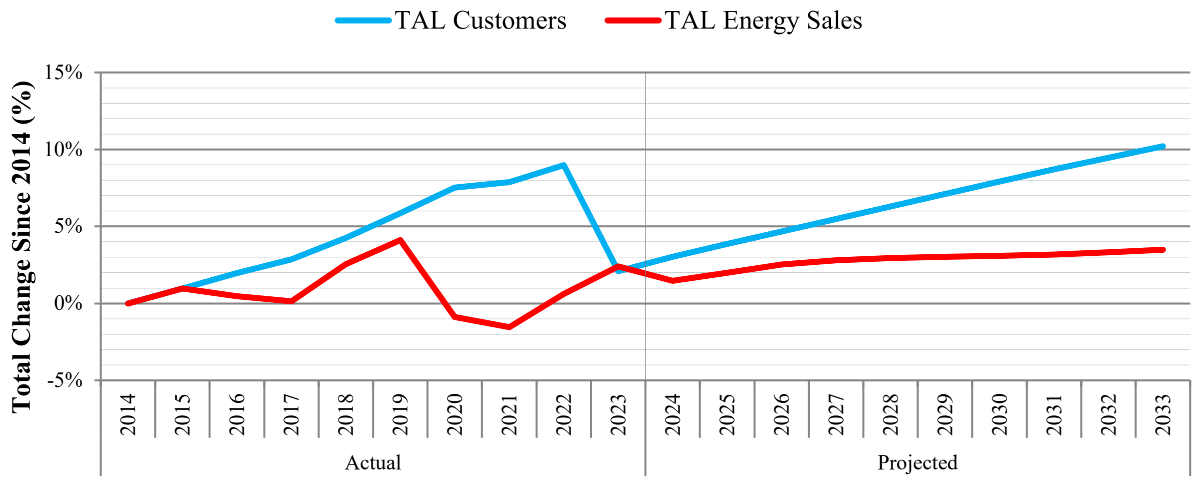
TAL's customer base consists of residential and commercial classes. The total energy consumption associated with the commercial class is higher than that associated with the residential class. The Utility's customer count growth correlates well to the rate of change in Leon County's population, household formation, and economic activity; and, the historical trend and 10 year forecast predict steady growth in its customer counts.

The Utility indicated that its energy efficiency and demand-side management programs have decreased the average residential and commercial demand and energy requirements and are projected to somewhat offset the increased growth from population in residential and commercial customers. Additionally, the Clean Energy Plan, which promotes accelerated installation of distributed solar PV and heightened energy efficiency investment through 2030, is also projected to somewhat offset the Utility's increased load growth from emerging electrification efforts such as electric vehicle charging. The net effect is the average consumption for residential and commercial customers may be approaching its minimum and leveling out over time.

Over the current forecast horizon, TAL is projecting an average annual growth rate of approximately 0.8 percent in its total customer counts, and an average annual growth rate of approximately 0.2 percent in its annual retail energy sales. Figure 47 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan TAL filed in its 2024 TYSP.

TAL implemented a new customer management software in 2022 and completed the transition in 2023. The new software positively affected the customer experience in how they are able to view and pay bills. The side effects of this implementation included some data impacts, such as transitioning from bill-based customer counts to meter-based customer counts, which overall reduced the number of customers in the billing system, and reclassifying some non-demand small commercial to residential classifications. TAL noted that the data collection issues should not persist in 2024 as the software implementation is complete.

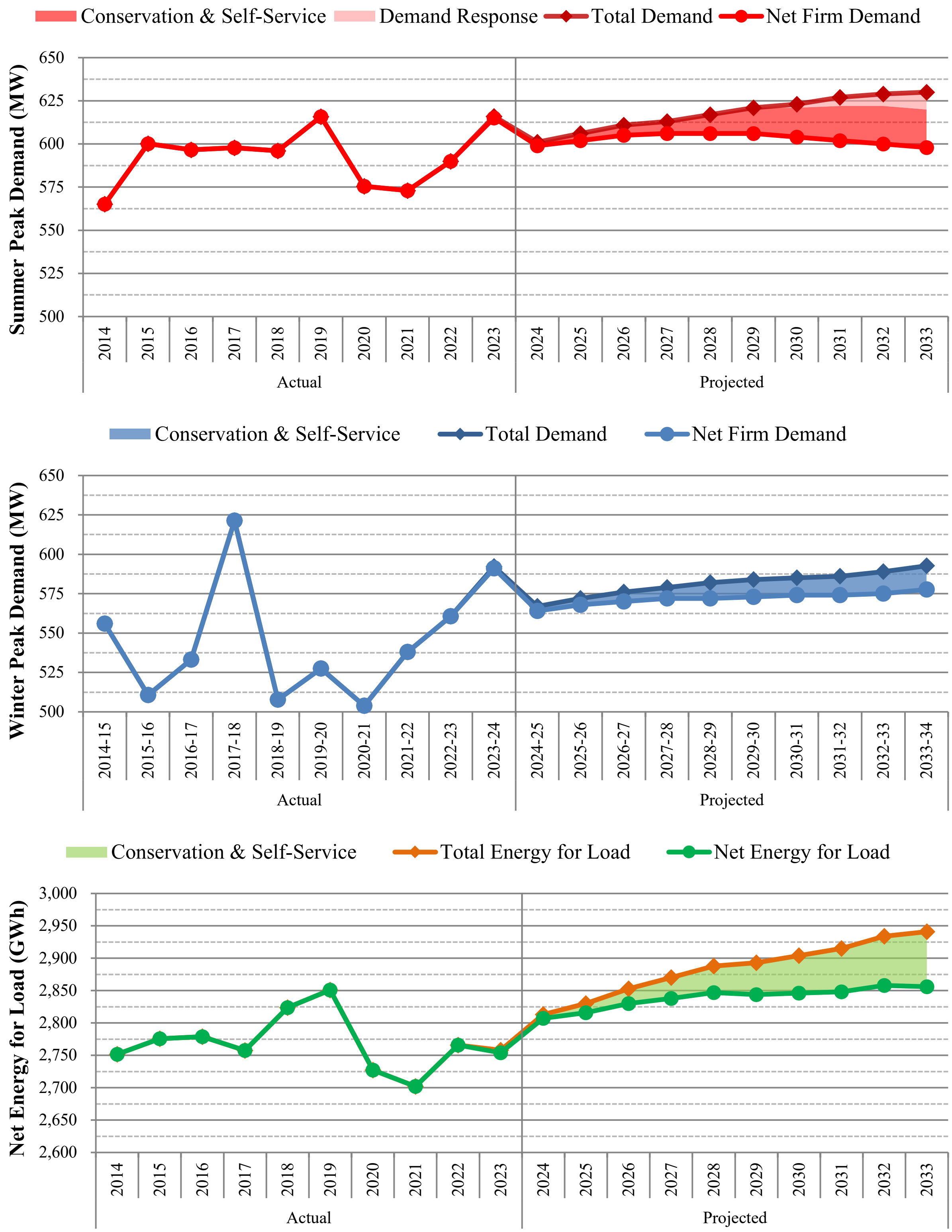
Figure 47: TAL Growth



Source: 2024 Ten-Year Site Plan

The three graphs in Figure 48 show TAL's seasonal peak demand and net energy for load for the historic years of 2014 through 2023 and forecast years 2024 through 2033. 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 48: TAL Demand and Energy Forecasts



Source: 2024 Ten-Year Site Plan

Fuel Diversity

Table 31 shows TAL's actual net energy for load by fuel type as of 2023 and the projected fuel mix for 2033. TAL relies almost exclusively on natural gas for its generation, excluding some purchases from other utilities and qualifying facilities. Natural gas is anticipated to remain the primary fuel source on the system. TAL projects it will continue to be a net exporter of energy, primarily of off-peak power during shoulder months due to its generation's operating characteristics.

Table 31: TAL Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2023 Actual		2033 Projected	
	GWh	%	GWh	%
Natural Gas	3053	**110.9%**	2,780	**97.3%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	2	**0.1%**	0	**0.0%**
Renewable	107	**3.9%**	111	**3.9%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	(409)	**-14.9%**	(35)	**-1.2%**
Total	**2,753**		**2,856**	

Source: 2024 Ten-Year Site Plan and Data Responses

Reliability Requirements

TAL utilizes a 17 percent planning reserve margin criterion for seasonal peak demand. Figure 49 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 49: TAL Reserve Margin Forecast

Source: 2024 Ten-Year Site Plan

Generation Resources

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