

REVIEW OF THE
2025 TEN YEAR SITE PLANS
OF FLORIDA'S ELECTRIC UTILITIES



**FLORIDA PUBLIC
SERVICE COMMISSION**

NOVEMBER 2025

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List of TYSP 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, Fuel, and Other 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
	Nuclear	NUC
Other	Ten Year Site Plan	TYSP

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 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 TYSPs is non-binding in accordance with Section 186.801(2), 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' TYSPs 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 TYSP 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 TYSPs 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 2025 TYSPs for Florida's electric utilities, as 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 Florida

¹ Investor-owned utilities filing 2025 TYSPs include Florida Power & Light Company, Duke Energy Florida, LLC, and Tampa Electric Company. Municipal utilities filing 2025 TYSPs 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 2025 TYSP.

Electrical Power Plant Siting Act or the Florida 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.

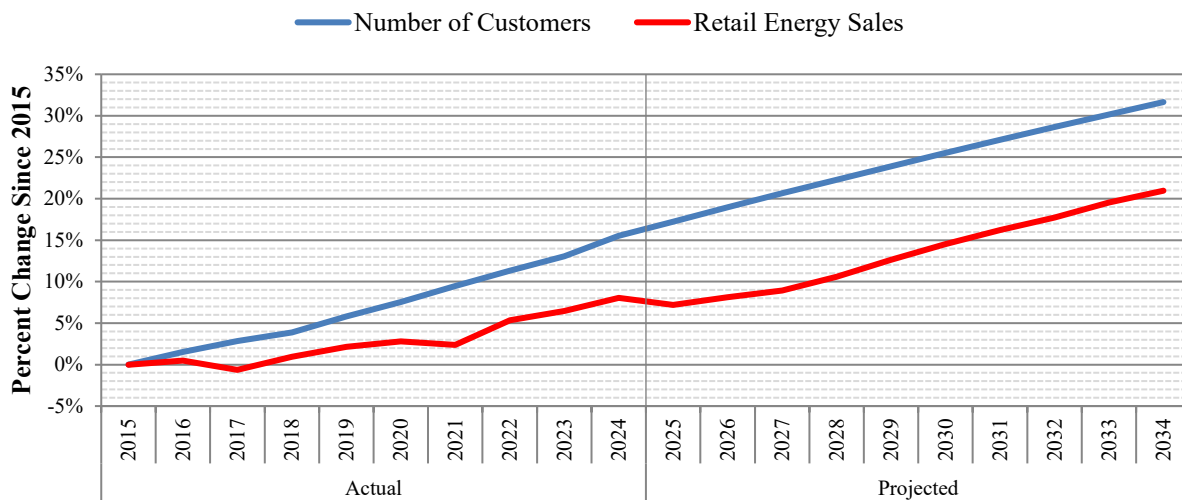
Review of the 2025 TYSPs

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. Normalized weather trends were used to forecast 2025 through 2034, which start slightly below the actual 2024 level but increase annually at 1.35 percent.

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



Source: Florida Reliability Coordinating Council (FRCC) 2025 Regional Load and Resource Plan

² The Florida Electrical Power Plant Siting Act is Sections 403.501 through 403.518, F.S. Pursuant to Section 403.519, F.S., and the Commission is the exclusive forum for the determination of need for an electrical power plant. The Florida Electric Transmission Line Siting Act is Sections 403.52 through 403.5365, F.S. Pursuant to Section 403.537, F.S., and 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 14,723 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 90 percent of Florida's existing renewables. Notably, Florida electric customers had installed 2,801 MW of demand-side renewable capacity by the end of 2024, an increase of 19 percent from 2023.

Florida's total renewable resources are expected to increase by approximately 26,228 MW over the 10-year planning period, excluding any potential demand-side renewable energy additions. Solar PV accounts for all of this increase. Table 1 provides a breakdown of each TYSP Utility's actual 2024 and projected 2034 generation from renewables, in gigawatt-hours (GWh) and as a percentage of the net energy for load (NEL). Renewable energy as a percentage of NEL is expected to increase from 7.8 percent in 2024 to 29.2 percent in 2034. On a statewide level, solar generation will account for 27.7 percent of NEL in 2034.

Table 1: State of Florida - Renewable Energy Generation

Utility	2024 Actual			2034 Projected		
	NEL	Renewables		NEL	Renewables	
	GWh	GWh	% NEL	GWh	GWh	% NEL
FPL	146,102	13,449	9.2%	160,473	56,831	35.4%
DEF	44,200	3,354	7.6%	46,359	13,250	28.6%
TECO	21,852	2,235	10.2%	23,374	5,870	25.1%
FMPA	7,172	161	2.2%	7,006	340	4.9%
GRU	1,903	253	13.3%	1,997	654	32.8%
JEA	13,254	507	3.8%	14,043	2,832	20.2%
LAK	3,509	28	0.8%	3,794	194	5.1%
OUC	8,206	408	5.0%	9,532	4,791	50.3%
TAL	2,849	96	3.4%	2,922	111	3.8%
SEC	17,359	383	2.2%	23,368	703	3.0%
STATE	266,406	20,874	7.8%	292,868	85,576	29.2%

Source: FRCC 2025 Regional Load and Resource Plan and TYSP Utilities' Data Responses

While solar makes notable contributions to NEL, it is not considered a firm resource and contributes only a portion of its capacity during the period of system peaks. Generally, solar makes a contribution toward summer peaks and no, or minimal, contribution to winter peaks. As the amount of solar generation in a utility system grows, this value is reduced as the net solar system peak is shifted further into the evening, when solar generation declines, increasing the need for non-solar generation to start or ramp up production. As a result, existing solar is considered firm towards summer peaks for approximately 35.4 percent of its capacity, while planned solar is considered firm for only 11.4 percent of its capacity.

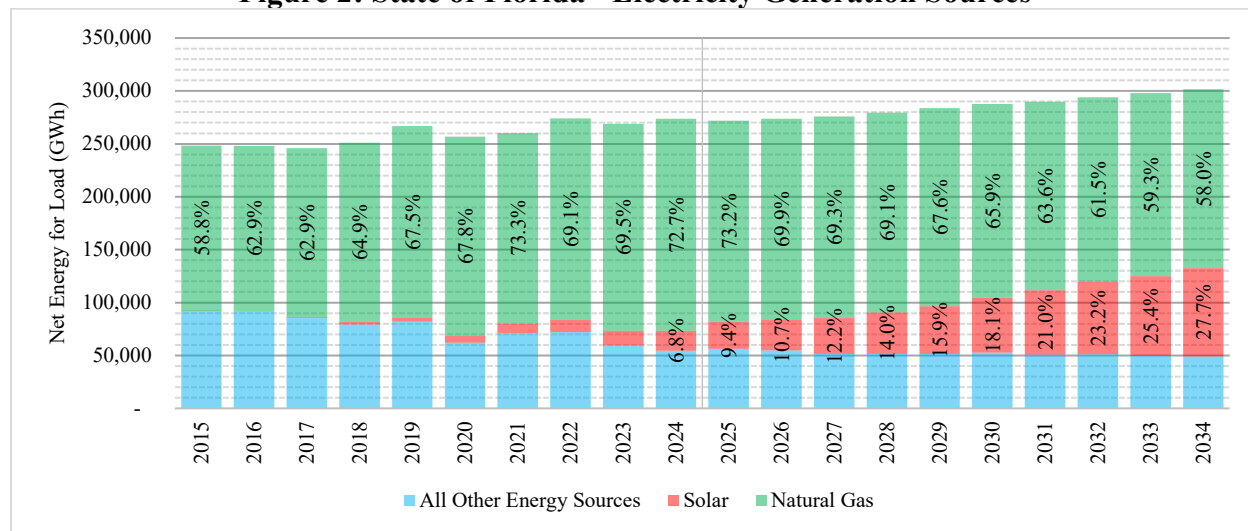
Battery Storage

Addressing this concern is a relatively new technological entry in Florida’s generation mix, energy storage, primarily in the form of batteries. While the first 1.5 MW pilot battery storage facility entered service in 2016, a total of 604 MW of battery storage was installed by 2024, and an additional 10,031 MW will enter service by 2034. Battery storage is a unique resource in that it can contribute to firm capacity and offers a fast ramp rate; however, it has a limited duration and requires charging from the grid, becoming load rather than generation. Battery storage can be charged by any generation resource. Given these characteristics, for reliability planning purposes, only 548 MW of existing battery storage and 5,673 MW of planned battery storage is considered firm for summer peaks. The Commission will continue to monitor technological developments in renewable generation and energy storage to cost-effectively address the state’s fuel diversity, reducing the dependence on fossil fuels, while still maintaining adequate resources to provide for customer loads.

Traditional Generation

Generating capacity within Florida is anticipated to grow to meet the increase in customer demand, with an approximate net increase of 1,715 MW of traditional generation over the planning horizon and 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 72.7 percent in 2024 to 58.0 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 2031.

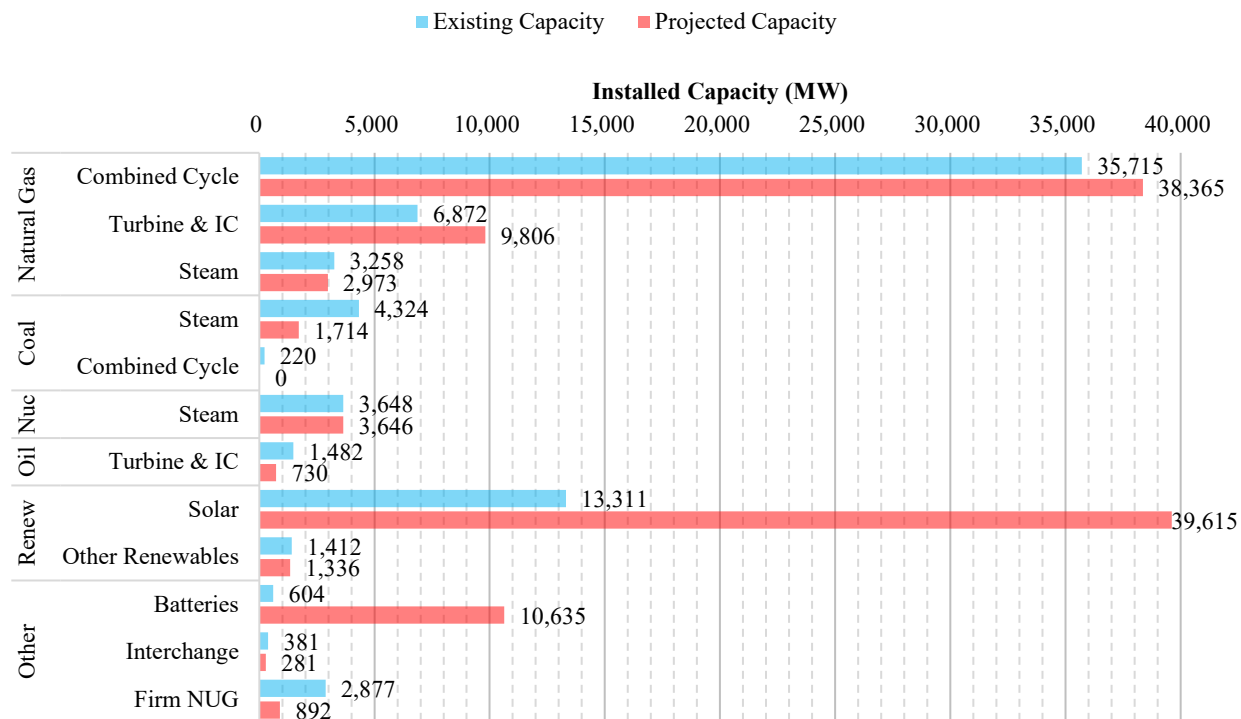
Figure 2: State of Florida - Electricity Generation Sources



Source: FRCC 2016-2025 Regional Load and Resource Plans

Figure 3 illustrates the present and future aggregate capacity mix of Florida based on the 2025 TYSPs. 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 2025 Regional Load and Resource Plan and TYSP Utilities' Data Responses

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 by JEA and SEC that may require a determination of need from the Commission pursuant to Section 403.519, F.S., both natural gas-fired combined cycles, in 2030 and 2032, respectively. The Commission can anticipate filings for need determinations sometime in 2026 and 2028 for these units, assuming a petition is filed four years before the in-service date.

Future Considerations

Florida's electric utilities must consider changes in environmental regulations associated with existing generators and planned generation to meet Florida's electric needs. Developments in the U.S. Environmental Protection Agency (EPA) regulations may impact Florida's existing

generation fleet and proposed new facilities. For example, on June 17, 2025, the EPA published a proposed rule to repeal all Greenhouse Gas (GHG) standards for fossil fuel-fired power plants, arguing that GHG emissions from these plants do not significantly contribute to dangerous air pollution. On March 12, 2025, the EPA also announced that it will undertake 31 actions to advance President Trump’s Executive Orders. These actions include the reconsideration of regulations on power plants and introducing the Clean Power Plan 2.0, and the reconsideration of limitations, guidelines, and standards for steam powered electric generating units. These and other relevant EPA actions are further discussed in the Traditional Generation section below.

Emerging Trends

Florida’s electric industry is experiencing heightened demand for power from customers influenced by the potential expansion of data centers. Florida utilities recognize the associated substantial increase in load to serve such customers and, to the extent such load materialize, they will require significant new infrastructure in both generation and transmission. As such, the utilities are actively assessing the potential impact of load growth driven by the advent of large data centers, including protections to their existing customers from the risks associated with potential stranded costs incurred to install new or upgraded facilities to serve a new large data center. Increased loads can be met on the utility side by improving existing generation and transmission infrastructure to allow more energy-efficient production and delivery of electricity or with the addition of new resources such as battery energy storage. Other developments, such as potential new nuclear generation in the form of small modular reactors, may have the potential to change Florida’s energy landscape in the future. As these new technologies evolve, the Commission will continue its oversight as these impacts are included in future electric utility TYSPs.

Conclusion

The Commission has reviewed the 2025 TYSPs 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 electric vehicle (EV) adoption, and the state’s dependence on natural gas for electricity production.

Based on its review, the Commission finds the 2025 TYSPs 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 TYSPs 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 TYSPs 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 TYSPs. 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 TYSPs 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 that all major generating electric utilities submit a TYSP to the Commission at least every two years. Based on these filings, the Commission performs a preliminary study of each TYSP and makes a non-binding determination as to whether the plan 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.

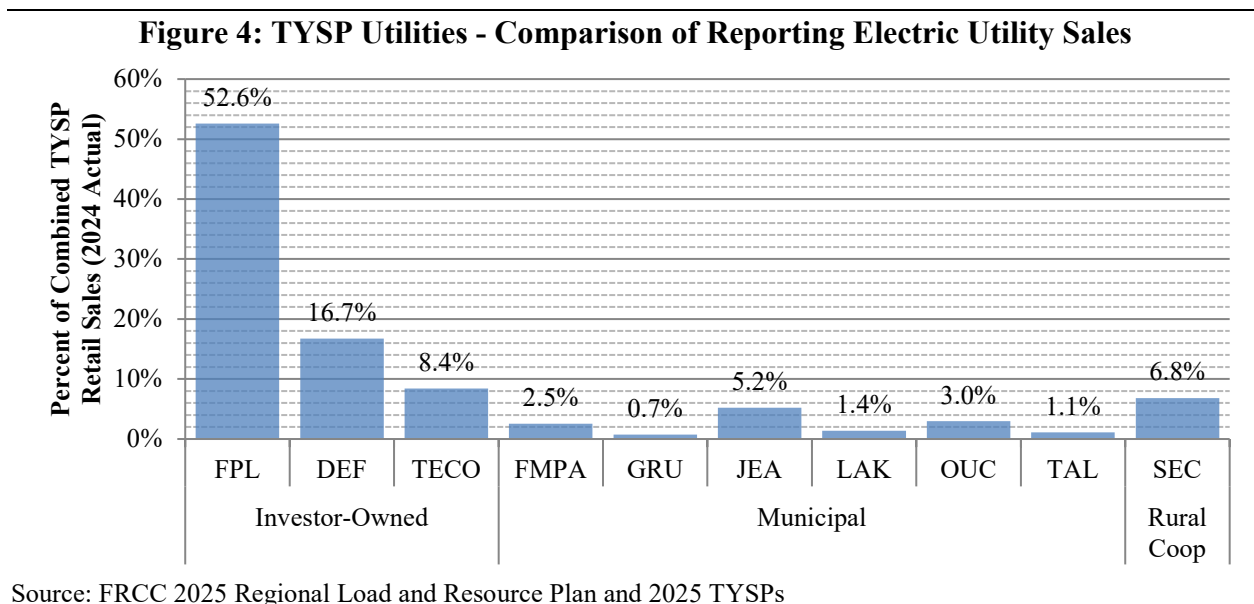
Applicable Utilities

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 TYSP with the Commission every year.

In 2025, 10 utilities met these requirements and filed a TYSP, 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 (FPL), Duke Energy Florida, LLC (DEF), and Tampa Electric Company (TECO). The municipal utilities, in alphabetical order, are Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of

Tallahassee Utilities (TAL). The sole rural electric cooperative filing a 2025 TYSP is Seminole Electric Cooperative (SEC). Collectively, these utilities are referred to as the 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 2024. Collectively, the reporting investor-owned utilities account for 77.7 percent of statewide retail energy sales, while the municipal and cooperative utilities make up approximately 20.8 percent of the statewide retail energy sales. The remainder is associated with non-reporting entities due to their limited size.



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 U. S. 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' 2025 TYSPs 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 TYSPs 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 TYSPs.

Statewide Perspective

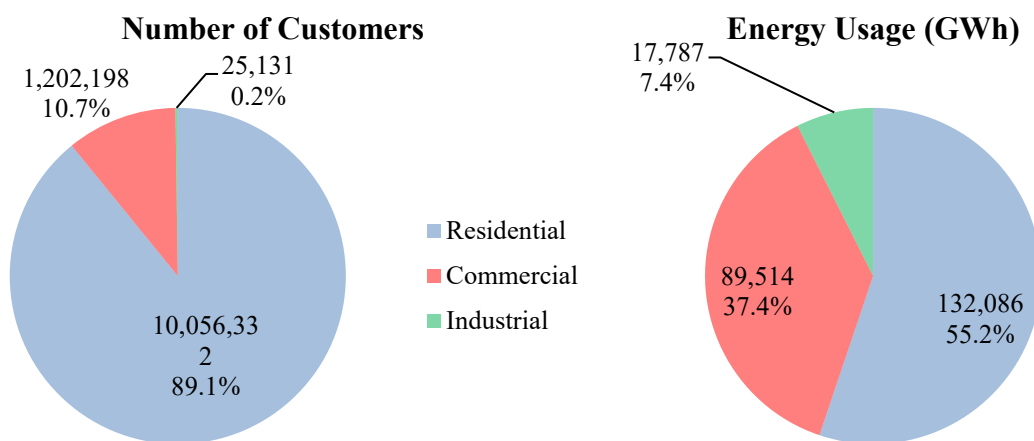
Load Forecasting

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 methodologies for preparing customer, energy, and peak demand forecasts.

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. Residential customers in Florida make up the largest portion of retail energy sales. Florida's residential customers accounted for 55.2 percent of retail energy sales in 2024, compared to a national average of approximately 37.4 percent in 2023.³

Figure 5: State of Florida - Electric Customer Composition in 2024



Source: FRCC 2025 Regional Load and Resource Plan

Growth Projections

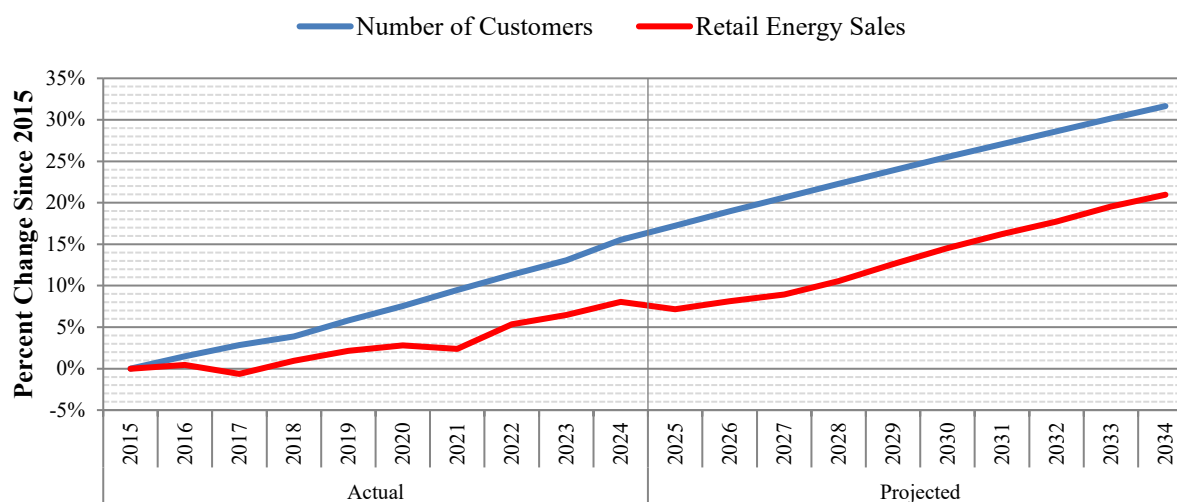
For the next 10-year period, Florida's weather normalized retail energy sales are projected to grow at 1.35 percent per year, compared to the 0.86 percent actual annual increase experienced during the 2015-2024 period. The number of Florida's electric utility customers is anticipated to grow at an average annual rate of about 1.30 percent for the next 10-year period, compared to the 1.62

³ U.S. Energy Information Administration – Electric Power Annual, released October 17, 2024.

percent actual annual increase experienced during the last decade. These trends are showcased in Figure 6.

As shown in Figure 6, Florida utilities' total retail energy sales reached a historical peak in 2024, surpassing the most recent peak that was reached in 2022. Several factors converged to contribute to this effect: continued growth in the number of retail customers as more people relocated to the state; warmer-than-normal weather conditions; and a surge in economic activity within the state's tourism and service sectors as they continued to recover from the COVID-19 pandemic, leading to increased electricity consumption across various industries. 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 (such as the addition of large load customers like data centers) as well as the expected increased level of adoption of EV vehicles.

Figure 6: State of Florida - Growth in Customers and Sales



Source: FRCC 2025 Regional Load and Resource Plan

The projected retail energy sales trend reflects the product of the utilities' forecasted number of customers and forecasted energy usage per customer (UPC). The key factor affecting utilities' number of customers is population growth. The key factors affecting utilities' average UPC includes weather variability, economic conditions, and changes in customer behavior or operations; hence, the corresponding information is utilized to develop the forecast models for projecting future growth of UPC. The projected growth rate of retail energy sales is impacted by these underlying key factors.

With respect to the UPC projection over the current forecast period, FPL's residential class UPC is expected to decline gradually over time, primarily driven by continued improvements in energy efficiency and increasing customer adoption of energy-saving behaviors and technologies. FPL's commercial class UPC is expected to be generally flat to slightly declining for similar reasons, and

its industrial UPC is predicted to increase modestly overall, driven by the additional usage by expected new large load customers.

Meanwhile, DEF reported that its residential and commercial UPC, respectively, decreased at a compounded annual growth rate of 0.7 percent and 0.8 percent. This decrease is primarily driven by fluctuations in price of electricity, end-use appliance saturation and efficiency improvements, more stringent building codes, housing type/size, and the energy source of air conditioning equipment. In addition, DEF is aware that more recently, the customer's ability to self-generate has begun to make an impact on the UPC numbers. For example, DEF noted 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. DEF also noted that, while the penetration of plug-in EVs has grown, working to increase residential UPC, rooftop solar generation continues to outweigh consumption from EV.

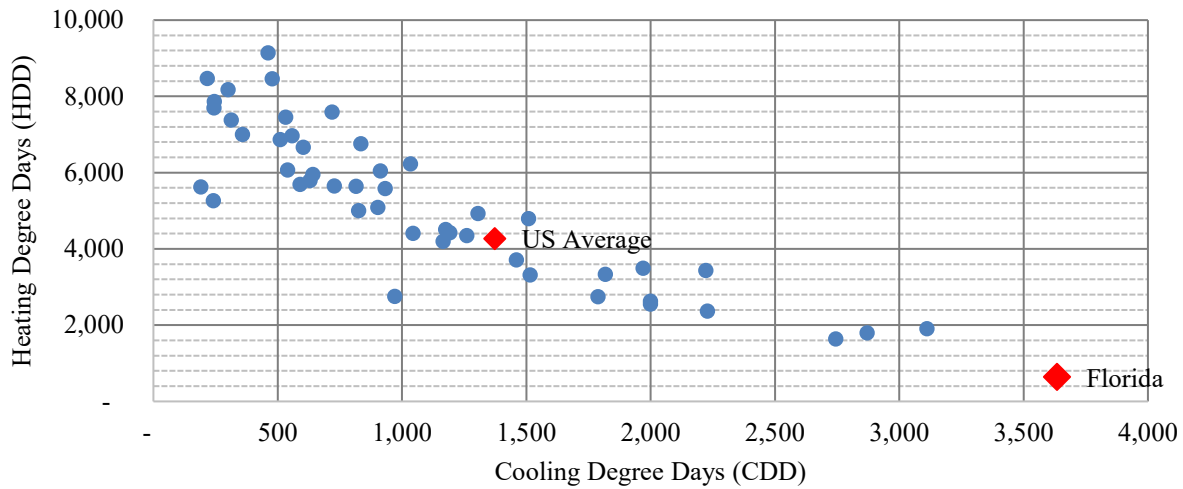
In west central Florida, TECO's residential class UPC is expected to decline at an average annual rate of 0.3 percent, primarily due to increases in appliance efficiencies, lighting efficiencies, energy efficiency in new homes, conservation efforts, and housing mix. TECO's commercial and industrial UPC are projected to decrease slightly at a rate of 0.1 percent and 0.2 percent a year, respectively. Likewise, other TYSP Utilities reported that the downward trend in UPC is due to advancements in technologies for energy efficiency, renewable generation, and alternative energy sources, with some TYSP Utilities expecting that increased residential at-home EV charging and the impact of anticipated energy-intensive commercial/industrial customers 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. As a result of the high contribution of residential customers to NEL, 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 continental United States, as shown in Figure 7. 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.

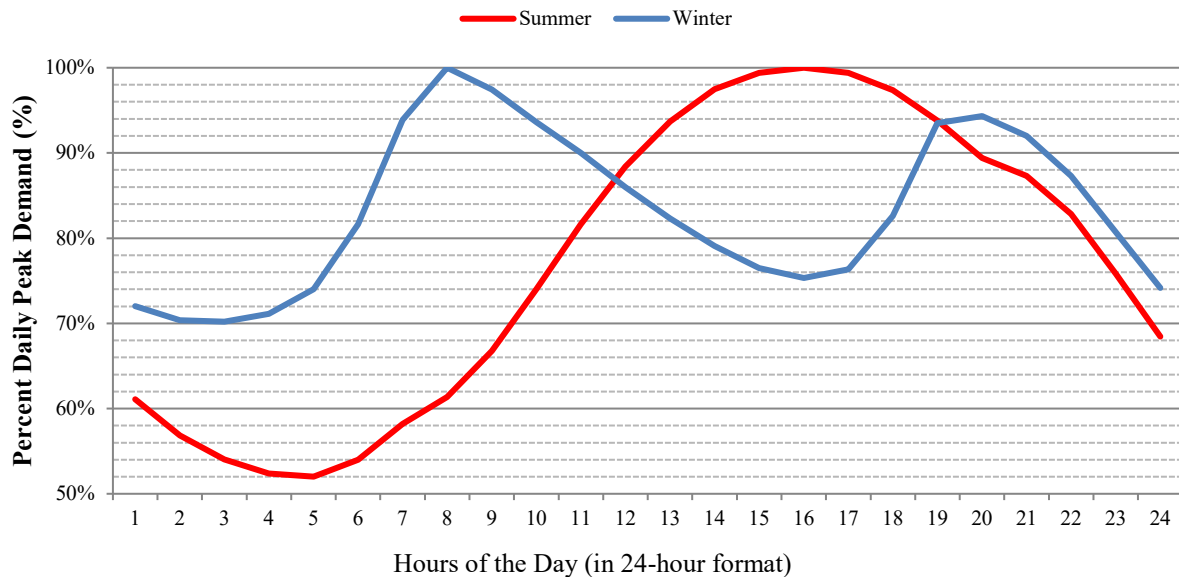
Figure 7: National - 20 Year Average Climate Data by State (Continental U.S.)



Source: U.S. National Oceanic and Atmospheric Administration Data

Seasonal weather patterns are therefore a primary factor, with peak demands calculated separately for the summer and winter periods annually, based on 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

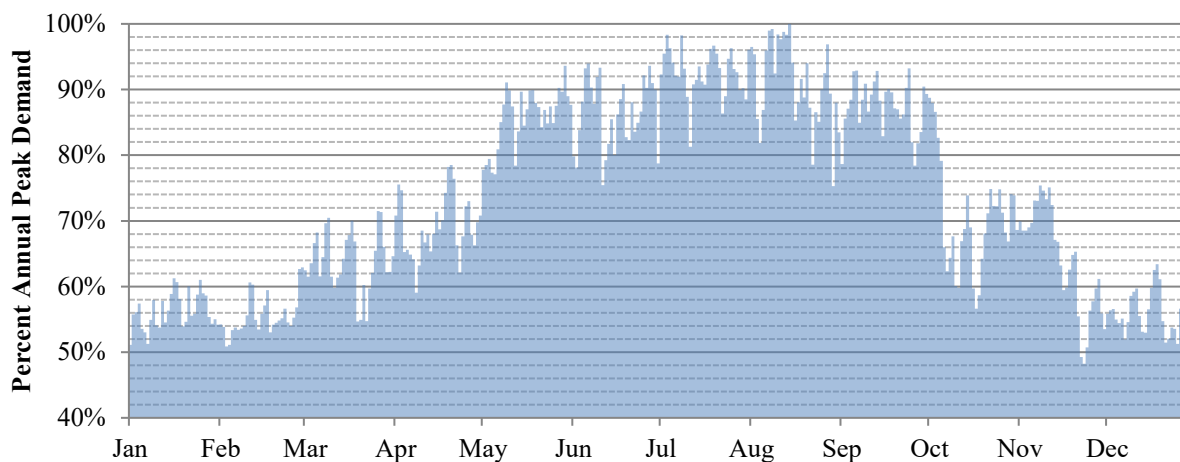


Source: TYSP Utilities' Data Responses

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 2024 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 (2024 Actual)



Source: 2025 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 EVs. The reporting TYSP Utilities estimate approximately 576,550 plug-in EVs will be operating in Florida by the end of 2025. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered automobiles, heavy trucks, and buses in Florida, as of January 5, 2025, at 18.88 million,

resulting in an approximate 3.05 percent penetration rate of electric vehicles, up from 2.30 percent last year.⁴

TYSP Utilities’ projections of EV ownership, public charging stations, and impacts to their electric grid are summarized in Table 2. Florida’s electric utilities anticipate continued growth in the EV market, albeit at a somewhat reduced rate from last year, with EV ownership anticipated to increase to 4,420,779 EVs operating within the reporting utilities’ electric service territories by the end of 2034. While approximately 40,000 charging stations are estimated to be available across the state by the end of 2025, more than 266,000 charging stations are anticipated by 2034. The projected EV charging station amounts listed in Table 2 include both normal and “quick-charge” public charging stations.⁵ EV annual energy consumption is expected to increase from 0.9 percent of retail energy sales in 2024 to 6.5 percent by 2034.

Table 2: TYSP Utilities - Electric Vehicle Projections

Year	EVs	EV Charging Stations	Grid Impacts		
			Annual Energy	Summer Peak	Winter Peak
	(-)	(-)	(GWh)	(MW)	(MW)
2025	576,550	39,887	2,109	401.5	166.9
2026	793,136	52,121	2,942	561.1	234.4
2027	1,054,941	69,641	3,983	763.8	316.7
2028	1,370,720	90,453	5,243	1,002.9	417.4
2029	1,744,984	115,023	6,743	1,290.7	536.5
2030	2,175,781	136,453	8,480	1,624.1	678.2
2031	2,670,121	167,087	10,561	2,029.9	846.4
2032	3,220,237	195,490	12,930	2,492.7	1,041.7
2033	3,805,844	230,430	15,367	2,980.4	1,243.0
2034	4,420,779	266,575	17,945	3,487.0	1,457.3

Source: TYSP Utilities’ Data Responses

A major factor driving EV growth in this state is reduced range anxiety due to the rapid expansion of charging infrastructure, with the reporting utilities projecting approximately 40,000 charging stations to be available by year-end 2025. 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.

In order to prepare and accommodate for the 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 rates, rebates on certain charging station installations, and programs designed to increase general outreach, education, and awareness of the EV market. The Commission will continue to closely monitor the status of the EV industry to ensure it is prepared to address any regulatory issues related to the future energy and demand impacts of EVs in Florida.

⁴ Florida Department of Highway Safety and Motor Vehicles January 2025 Vehicle and Vessel Reports and Statistics.

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

Data Centers

Existing Data Centers

The TYSP Utilities reported that there are some data centers currently in operation, as shown in Table 3. These existing data centers are relatively small, are being served by existing generation, and have no known negative impacts on reliability.

Table 3: TYSP Utilities - Data Centers by Utility

	Existing Data Centers*			
	No. of Data Centers	Total Energy Usage in 2024	Impact to Summer Peak Demand	Impact to Winter Peak Demand
		(GWhs)	(MWs)	(MWs)
FPL	62	283.0	30.2	30.2
DEF	5	48.0	14.5	7.0
TECO	14	71.4	11.0	10.5
JEA	4	38.1	6.3	6.2
LAK	1	4.1	---	---
Total	86	444.6	62.0	53.8

* FMPPA, GRU, OUC, SEC and TAL did not report any existing data centers.

Source: TYSP Utilities' data request responses.

As general practice, utilities currently do not separately identify data centers. FPL, for example, identified existing accounts associated with data centers through a web search of companies performing that service and then matched those companies to FPL records.

Emerging Data Centers

Most of the TYSP Utilities reported that they have received inquiries from potential new large-scale data centers. Some of these utilities have included the potential data center-related load requirements in their respective TYSPs. The scale of energy and demand use of such customers is much larger than the data centers the utilities reported are currently in operation. According to a 2025 report published by Electric Power Research Institute, titled "Grid Flexibility Needs and Data Center Characteristics," data centers range from small to large, or hyper-scale, with larger data centers having a greater impact on system-wide demand and flexibility needs.

FPL believes there is a potential for customers with significant new load requirements to be served beginning in 2028 and has included a projection of these additions in its forecasts through 2034. FPL has projected that the data center peak demand and total energy usage would grow, respectively, from 172 MW and 1,281 GWh in 2028 to 732 MW and 5,450 GWh in 2034.

Similar to FPL, DEF has received inquiries from a number of potential new customers, but the Utility indicated that none of these inquiries have progressed to the level of commitment that would warrant inclusion in the DEF 2025 TYSP load forecast. Meanwhile, TECO's 2025 TYSP does not include projections of the large data centers loads due to no firm end-use customer commitments. JEA stated that it has received numerous data center inquiries over the past year and that in order to serve them, JEA would need to construct more generating resources. OUC stated that it

anticipates having discussions with potential data centers to better understand the timing and magnitude of such new loads. Similarly, SEC reported that there has been increasing interest by data centers and developers in several member service territories. As such, SEC, as the generation provider to its member cooperatives, has begun issuing quarterly surveys with each member to identify potential new large loads.

Large data centers are unique types of energy consumption sources, given their significant and constant load requirements and the potential for high costs to extend service to them. Many of the potential issues associated with serving such customers will be directly related to the size and scope of the specific data center project in question. Any necessary system upgrades to accommodate incremental load, along with the deployment of generation resources to safely and reliably serve existing and new load, are also important concerns that must be addressed. Florida utilities recognize the associated substantial increase in load to serve such customers, and to the extent such loads materialize, they will require significant new infrastructure in both generation and transmission. As such, the TYSP Utilities are actively assessing the potential impact of load growth driven by the advent of large data centers, including protections to their existing customers from the risks associated with potential stranded costs incurred to install new or upgraded facilities to serve a new large data center.

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 unoccupied rooms, increasing thermostat settings during the summer, and purchasing appliances that exceed efficiency standards. While a certain portion of customers will engage in these activities without incentives due to economic, aesthetic, or environmental concerns, other customers may lack information or require additional incentives. Demand-Side Management (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 passed the Florida Energy Efficiency and Conservation Act (FEECA), which is codified in Sections 366.80 through 366.83, F.S., 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.⁶ Of the TYSP Utilities, these include the three investor-owned electric utilities, FPL, DEF, TECO, and two municipal electric utilities, JEA and OUC, and together represent approximately 86 percent of 2024 retail electric sales reported in the state. The FEECA Utilities offer DSM 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

⁶ FEECA also applies to Florida Public Utilities Company (FPUC), 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 TYSP.

measures customers can undertake themselves, and participation in utility-sponsored DSM programs.

In 2024, the Commission held a hearing and established goals for each of the FEECA Utilities for the period 2025 through 2034. In 2025, the Commission reviewed and approved DSM Plans for each FEECA electric utility designed to meet its goals. The Commission is scheduled to have its next goalsetting proceeding no later than 2029 for the period 2030 through 2039.

DSM Programs

DSM programs are generally 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 2025, the total amount of demand response resources available for reduction of peak load is 3,345 MW for summer peak and 3,127 MW for winter peak. Demand response is anticipated to increase only marginally to approximately 3,412 MW for summer peak and 3,157 MW for winter peak by 2034. 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 high efficiency appliances, customers can reduce both peak demand and annual energy consumption, resulting in lower energy bills. DSM 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, 2024, energy efficiency is responsible for peak load reductions of 4,732 MW for summer peak and 4,447 MW for winter peak. Energy efficiency is anticipated to increase to approximately 5,731 MW for summer peak and 5,231 MW for winter peak by 2034.

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.

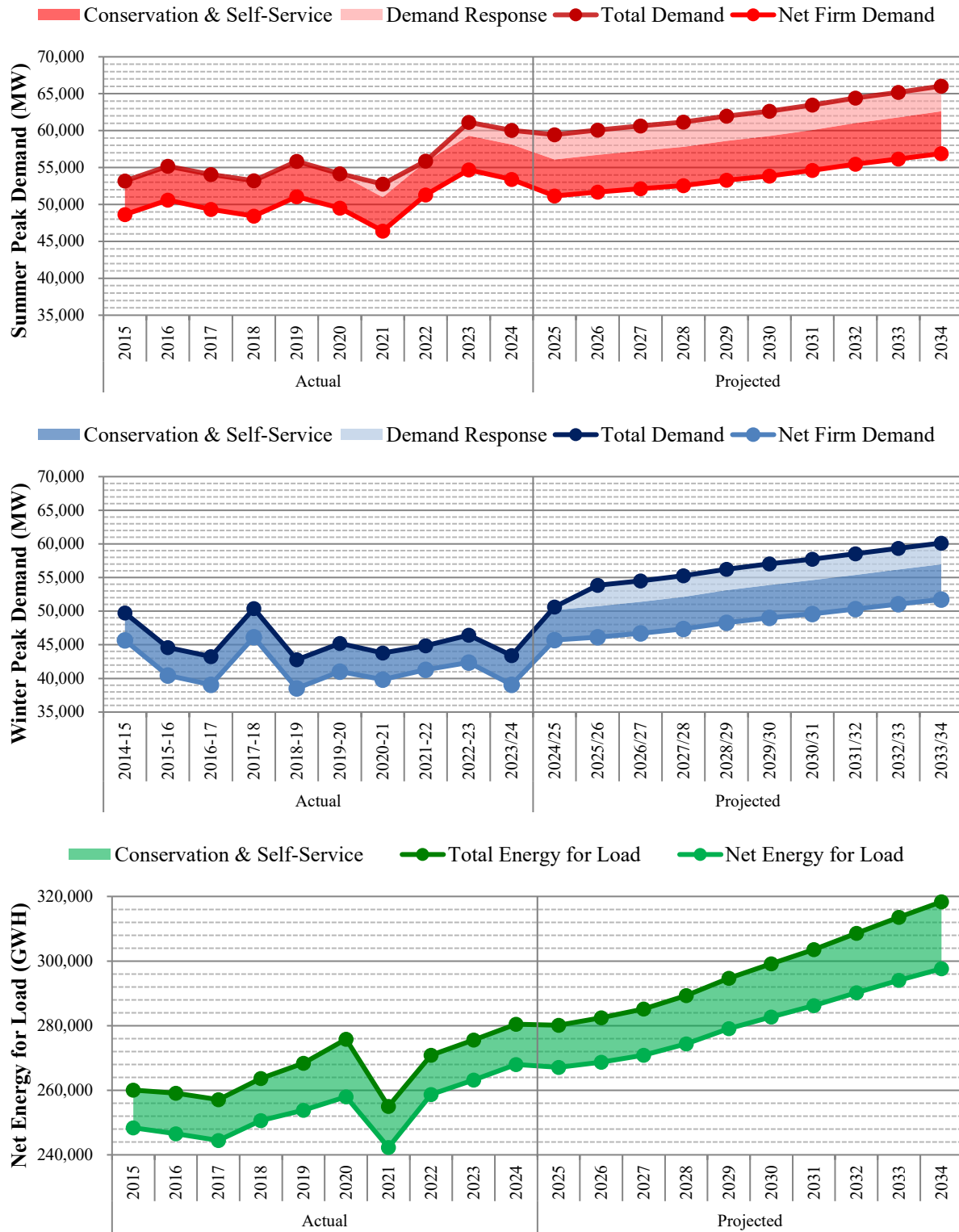
DSM, including demand response and energy efficiency, along with self-service generation, is included in each graph appearing in Figure 10 for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served if not for the impact 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 resources were available during the annual peak. Residential load management has been utilized to a limited extent during peak periods, with even less interruptible load being 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 future operating conditions, if an electric utility has sufficient generating capacity and it is economical to serve all customers loads, demand response would likely be inactive or only partially activated.

As previously discussed, Florida is normally a summer-peaking state and has been 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 2025 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 10 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 asset 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 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 customer's 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 EV and distributed generation. The forecasting models for energy sales must also take into account DSM.

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 that 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 cost-effectively. Again, for the 2025 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 TYSP Utility, the Commission reviewed the historic forecast accuracy of past retail energy sales forecasts. The standard methodology for the Commission's 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 2024 retail energy sales were compared to the forecasts made in 2019, 2020, and 2021. 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 2025 TYSPs, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2015 through 2024 to forecasts made between 2006 and 2020. These are summarized in Table 4.

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

TYSP Year	Five-Year Analysis Period	Forecast Years Analyzed	Forecast Error (%)	
			Average	Absolute Average
2016	2015 - 2011	2011 - 2006	12.5%	12.5%
2017	2016 - 2012	2012 - 2007	9.1%	9.1%
2018	2017 - 2013	2013 - 2008	6.0%	6.0%
2019	2018 - 2014	2014 - 2009	3.5%	3.5%
2020	2019 - 2015	2015 - 2010	2.1%	2.3%
2021	2020 - 2016	2016 - 2011	1.6%	2.0%
2022	2021 - 2017	2017 - 2012	1.0%	1.6%
2023	2022 - 2018	2018 - 2013	(0.1%)	1.4%
2024	2023 - 2019	2019 - 2014	(1.0%)	1.6%
2025	2024 - 2020	2020 - 2015	(1.8%)	2.0%

Source: 2006-2025 TYSPs

* 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 5 provides the error rates for forecasts made between one to six years prior, along with the three-year average and absolute average error rates for the forecasting period of a three to five-year period that was also used in the analysis in Table 4.

As displayed in Table 5, the TYSP 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 five years' four-year ahead, three-year ahead, two-year ahead, and one-year ahead forecasts all bear negative error rates (under-forecasts). Additionally, the last three years' six-year ahead and five-year ahead forecasts all render negative error rates as well. Note that all of the 2022-, 2023-, and 2024-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 the recent years.

**Table 5: 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	26.4%	26.1%	23.2%	8.6%	4.0%	3.8%	19.3%	19.3%
2013	28.6%	26.3%	10.0%	6.0%	5.6%	3.0%	14.1%	14.1%
2014	27.2%	9.7%	6.0%	5.6%	2.7%	2.1%	7.1%	7.1%
2015	7.2%	3.5%	3.1%	0.9%	(0.1%)	(1.3%)	2.5%	2.5%
2016	4.2%	4.3%	2.2%	1.1%	0.1%	(1.1%)	2.5%	2.5%
2017	6.9%	4.8%	3.5%	2.4%	1.5%	(0.2%)	3.6%	3.6%
2018	4.2%	2.7%	1.6%	0.6%	(1.3%)	(1.2%)	1.6%	1.6%
2019	2.8%	1.9%	0.8%	(1.4%)	(1.4%)	(2.0%)	0.4%	1.3%
2020	2.4%	1.3%	(1.0%)	(1.1%)	(1.9%)	(1.2%)	(0.3%)	1.1%
2021	2.6%	0.4%	0.0%	(0.8%)	(0.1%)	0.0%	(0.2%)	0.4%
2022	(1.6%)	(1.9%)	(2.9%)	(2.2%)	(2.1%)	(3.1%)	(2.3%)	2.3%
2023	(2.1%)	(3.3%)	(2.7%)	(2.5%)	(3.2%)	(2.6%)	(2.8%)	2.8%
2024	(3.9%)	(3.3%)	(3.3%)	(3.7%)	(3.2%)	(3.2%)	(3.4%)	3.4%

Source: 2006-2025 TYSPs

* 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 2024 in Table 5. However, all the major global and domestic events (e.g., the Russia-Ukraine war, intense conflicts in the Middle East, increased tariffs on foreign countries, supply chain issues, potential factors such as recession, increases in inflation rates, pandemic, etc.), individually or collectively, could inflict damage to the U.S. 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 over the next few years could differ from what Florida utilities projected in 2024 and earlier years. Consequently, average forecasted energy sales error rates during this period may deviate from the relatively low levels recorded since 2015. 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.

Renewables and Energy Storage

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 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. Section 366.91(2)(e), F.S., 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 14,723 MW of firm and non-firm generation capacity, which represents 20 percent of Florida’s overall generation capacity of 73,500 MW in 2024. Table 6 summarizes the contribution by renewable type of Florida’s existing renewable energy sources.

Table 6: State of Florida - Existing Renewable Resources

Renewable Type	MW	% Total
Solar	13,311	90.4%
Municipal Solid Waste	473	3.2%
Biomass	380	2.6%
Waste Heat	173	1.2%
Wind	272	1.8%
Landfill Gas	64	0.4%
Hydroelectric	51	0.3%
Renewable Total	14,723	

Source: FRCC 2025 Regional Load and Resource Plan and TYSP Utilities’ Data Responses

Of the total 14,723 MW of renewable generation, approximately 5,145 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 4,706 MW to this total, based upon the

coincidence of solar generation and summer peak demand, or about 35 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 1,412 MW of non-solar generation, only 439 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

Most renewable generation in Florida is utility-owned, with 9,988 MW of installed capacity, or 67.8 percent of total renewables, consisting primarily of 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 9,831 MW of existing utility-owned solar capacity, approximately 4,485 MW, or about 45.6 percent, is considered firm. All other renewable sources account for an additional 157 MW of utility-owned generation, which are all considered firm.

Non-Utility Renewable Generation

Approximately 1,934 MW, or 13.1 percent, of Florida's existing renewable capacity comes 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 U.S. 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 meets specified deliverability requirements, its capacity and energy output can be compensated 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 TYSP. 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 their financing requirements, and provides a basis from which negotiated contracts can be developed.

As previously discussed, large amounts of renewable energy is generated on an as-available basis. As-available energy is energy produced and sold by a renewable energy generator on an hour-by-hour basis for which contractual commitments as to the quantity and time of delivery are not

required. As-available energy is purchased at a rate equal to the utility’s hourly incremental system fuel cost, which reflects the highest fuel cost of generation each hour.

Customer-Owned Renewable Generation

Approximately 2,794 MW, or 19.0 percent, of renewable capacity is from small customer-owned renewable systems. As of the end of 2024, over 292,284 systems have been installed statewide. With respect to customer-owned renewable generation, Rule 25-6.065, F.A.C., requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer with renewable generation capability, to offset their energy usage. Table 7 summarizes the growth of customer-owned renewable generation interconnections. Almost all installations are solar. Non-solar generation, which accounts for only 25 installations and 7.1 MW of installed capacity includes wind turbines and anaerobic digesters.

Table 7: State of Florida - Customer-Owned Renewable Growth

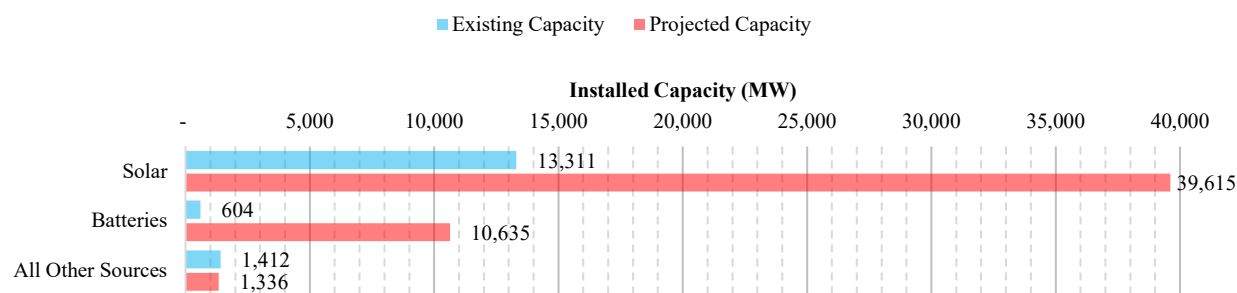
Year	2018	2019	2020	2021	2022	2023	2024
Number of Installations	37,862	59,508	90,552	130,947	189,952	249,521	292,284
Installed Capacity (MW)	317	514	835	1,177	1,780	2,351	2,801

Source: 2018-2024 Net Metering Reports

Planned Renewable Resources

Florida’s total renewable resources are expected to increase by an estimated 26,228 MW over the 10-year planning period, a decrease from last year’s estimated 30,737 MW projection. Solar generation, primarily utility-owned, is the sole renewable type projected to increase over the planning horizon, with non-solar renewables decreasing by 76 MW due to retirements or expired contracts. While solar generation is covered under the Florida Electrical 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. Figure 11 summarizes the existing and projected renewable capacity by generation type as well as energy storage capacity in the form of batteries.

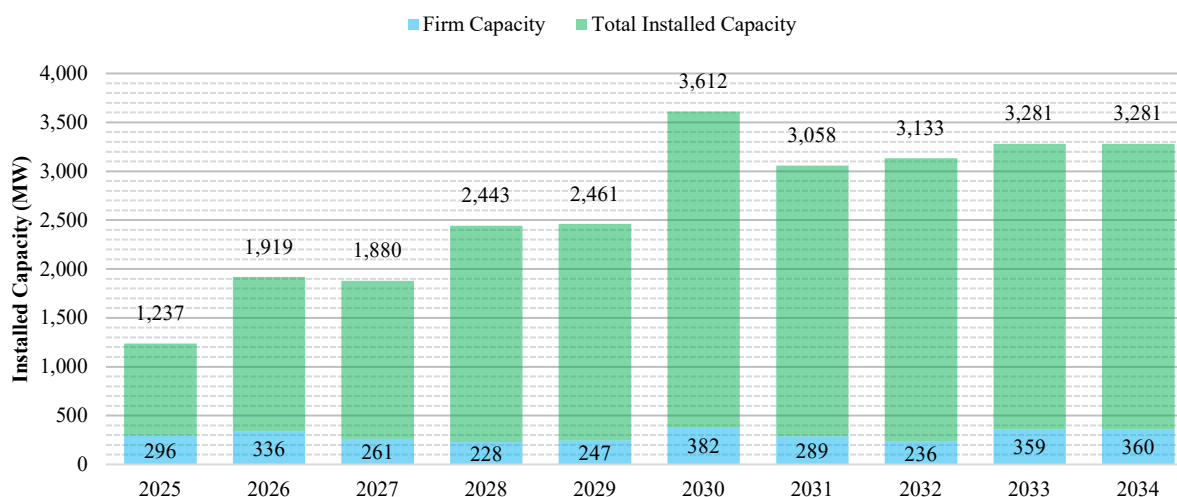
Figure 11: State of Florida – Current and Projected Renewables and Energy Storage



Source: FRCC 2025 Regional Load and Resource Plan and TYSP Utilities’ Data Responses

As noted previously, solar generation is anticipated to increase significantly over the 10-year period, with a net total of 26,304 MW to be installed, excluding solar degradation. This consists of 23,311 MW of utility-owned solar and 2,993 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. A total of 3,032 MW of solar additions are considered firm for summer peak, or about 11.4 percent of the total installed. 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.

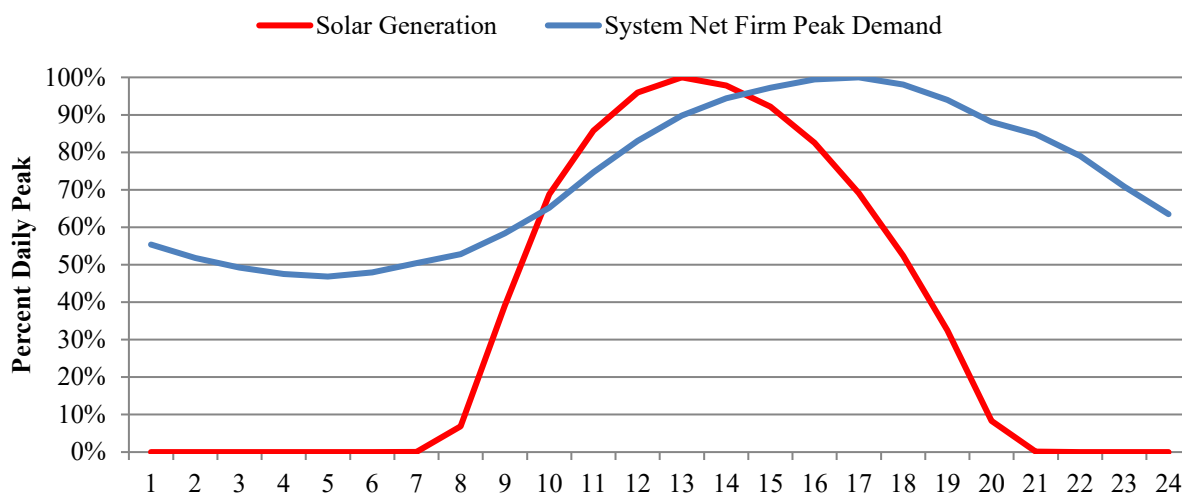
Figure 12: TYSP Utilities - Planned Solar Installations



Source: FRCC 2025 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 with traditional generation will become increasingly important to the grid. Solar generation cannot be dispatched on demand; instead, it is produced based on conditions at the plant site, which are 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 DSM 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

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 that are currently under research 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 for connection directly to the grid, behind the meter box (net metering) or integrated with 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.

Florida's utilities have 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, allowing customers to ride out outages (net metering), improving reliability and reducing line losses (distribution substations), or providing firm capacity to the grid (generating facilities). Currently, the TYSP Utilities have 604 MW of installed battery energy storage, with the single largest installation being FPL's 409 MW Manatee battery storage site. Battery storage is a unique resource in that it can contribute to firm capacity and offers a fast ramp rate, but it has a limited duration and requires charging from the grid, becoming a load to be served rather than generation serving load. Due to small inefficiencies in charging and discharging, batteries actually increase the total amount of energy that utilities must produce to serve customer load — affecting net load rather than net generation.

Over the next decade, utilities anticipate adding approximately 10,031 MW of energy storage, primarily directly on the transmission system or a specific power plant. While energy storage provides firming for intermittent solar facilities, grid connected batteries will not be restricted to charging from renewable sources. These units can be charged from any energy source during off-peak periods, including fossil fuel generation. To the extent solar generation is charging batteries

it is also not offsetting fossil fuel 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. Given these characteristics, for reliability planning purposes, 548 MW of existing battery storage and 5,673 MW for planned battery storage is considered firm for summer peaks.

Companies are continuing to explore different forms of energy storage even as they expand their construction of battery storage, such as storage with longer duration or superior ability to address operational needs. The Commission will continue to monitor technological developments in energy storage to cost-effectively address the state's fuel diversity, reducing the dependence on fossil fuels, while still maintaining adequate resources to provide for customer loads.

Traditional Generation

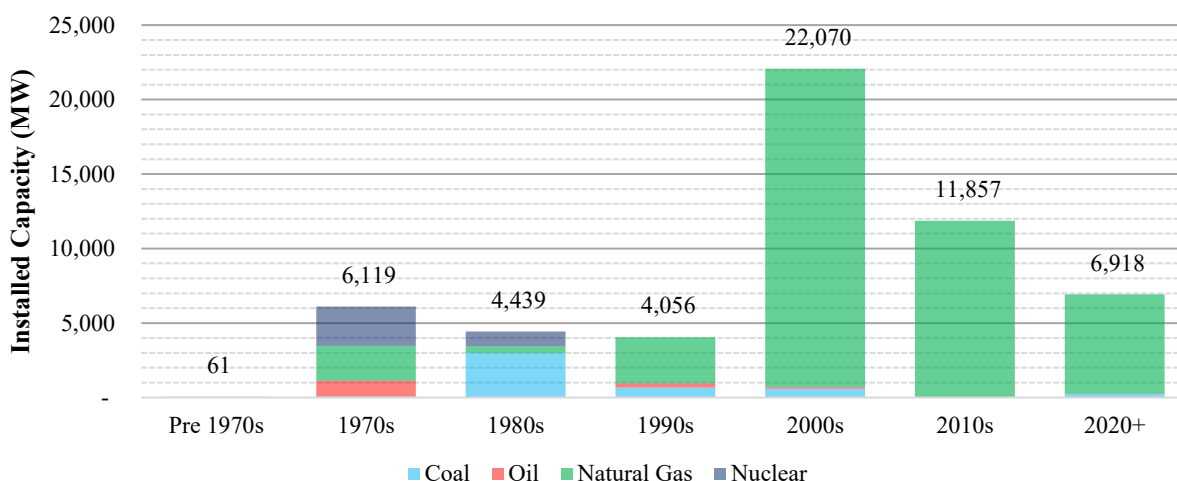
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and combustion turbine generators that have been added to Florida's electric grid over the last several decades. 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 cost-effectively 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 22 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 2025 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 implementing uprates at existing facilities to improve power output. Lastly, retirements of units which can no longer be operated and maintained economically or that fail to meet environmental requirements will reduce existing generation.

Impact of the EPA Rules

Over the summer, the EPA has issued three proposed rules that, if finalized and implemented as proposed, would significantly change the current environmental regulatory landscape affecting energy generation.

On June 11, 2025, the EPA Administrator announced a proposal to repeal all greenhouse gas (GHG) emission standards for electric generating units (EGUs) under Section 111 of the Clean Air Act. The EPA argues that GHG emissions from these facilities do not contribute significantly to dangerous air pollution.

Also on June 11, 2025, the EPA announced a proposal to repeal amendments to the 2024 Mercury and Air Toxics Standards that directly result in coal-fired power plants shutting down. The MATS Proposed Rule seeks to repeal recent amendments that tightened filterable particulate matter emission standards and mercury emission standards for certain existing coal-fired EGUs that use lignite, instead of bituminous coal. There are no lignite coal-firing units in Florida at this time. This proposal would reverse three key regulatory changes: the stricter filterable particulate matter emission standard for existing coal-fired EGUs, the more restrictive compliance demonstration requirements that limited monitoring options to only particulate matter continuous emission monitoring systems, and the tightened mercury emission standard for lignite-fired EGUs.

On July 29, 2025, the EPA issued a proposal to rescind the 2009 Endangerment Finding, which would have sweeping effects on GHG regulations for the transportation sector. If finalized, the proposal would repeal all GHG emission regulations for motor vehicles and engines. The Endangerment Finding Proposed Rule could also undermine the legal basis for GHG regulations across the power sector.

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 have converted oil-fired and coal-fired steam units to natural gas-fired combined cycle units, or converted or upgraded them 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 in 2025.

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, 490 MW of additional summer firm capacity is from upgrades 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, 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.⁷

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 8 lists the 3,848 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 2,067 MW of capacity to be retired by 2034, followed by oil combustion turbines, with five units totaling 753 MW by 2034, and natural gas-fired steam generation, with four units totaling 750 MW of capacity to be retired by 2030.

⁷ 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*.

Table 8: State of Florida - Electric Generating Units to be Retired

Year	Utility	Plant Name	Net Capacity
	Name	& Unit Number	(Sum MW)
Coal Steam Retirements			
2025	FMPA/OUC	Stanton Energy Center Unit 1	451
2034	FPL	Scherer Unit 3	215
2034	DEF	Crystal River 4 & 5	1,422
		Subtotal	2,067
Oil Combustion Turbine Retirements			
2026	DEF	Bayboro Units P1-P4	137
2027	DEF	Debary Units P2-P6	227
2027	DEF	Bartow Units P1 & P3	82
2028	FPL	Lansing Smith Unit 3A	32
2034	DEF	Intercession City P1-P6	275
		Subtotal	753
Natural Gas Steam Retirements			
2027	GRU	Deerhaven Unit FS01	76
2029	FPL	Gulf Clean Energy Center 4 & 5	150
2030	JEA	Northside Unit 3	524
		Subtotal	750
Natural Gas Combustion Turbine Retirements			
2026	FPL	Pea Ridge 1-3	12
2031	GRU	Deerhaven Unit GT1 & GT2	35
2034	DEF	Bartow Units P2 & P4	86
2034	DEF	Suwannee P1-P3	145
		Subtotal	278
Total Retirements			3,848

Source: 2025 TYSPs

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 forecasted customer demand.

Reserve Margin

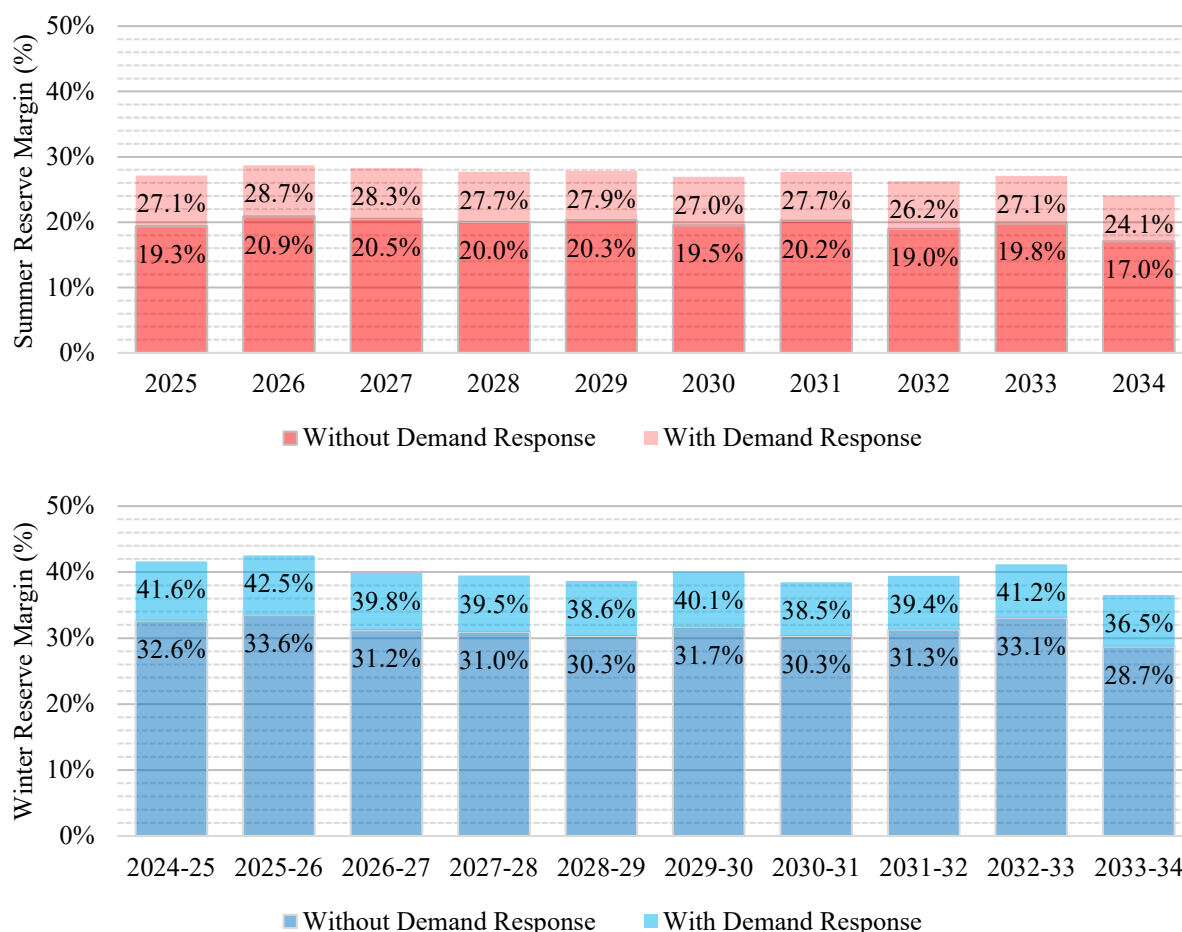
One reliability metric commonly used by the TYSP Utilities is a seasonal planning reserve margin. Each utility annually compares their forecasted seasonal peak demand after activation of demand response resources with the total amount of firm generation available at the seasonal peak hour. The difference between these values is the reserve margin, which is expressed in both megawatts and as a percentage of the net firm peak demand. Pursuant to Rule 25-6.035, F.A.C., electric utilities within Florida must maintain a minimum reserve margin of 15 percent for planning purposes, although certain utilities have elected to use a higher planning 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.⁸ As a whole, Florida typically has a lower summer reserve margin than winter, but individual utilities may be more impacted by winter peaks.

Regarding demand response, while participants receive discounted rates or credits paid for by all ratepayers regardless of activation, the concern exists that as activations increase, participation could decrease. While large interruptible customers typically have notice period requirements, small load management customers usually do not have an advanced notice requirement. Historically, activations of demand response have almost exclusively been of the smaller load management customers, and typically for off-peak periods. As illustrated in Figure 15, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin in all years. Even without demand response, the statewide reserve margin is anticipated to remain 17 percent or above throughout the planning period. On average, demand response contributes 7.5 percent toward the summer reserve margin, and 8.4 percent toward the winter reserve margin.

⁸ 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*.

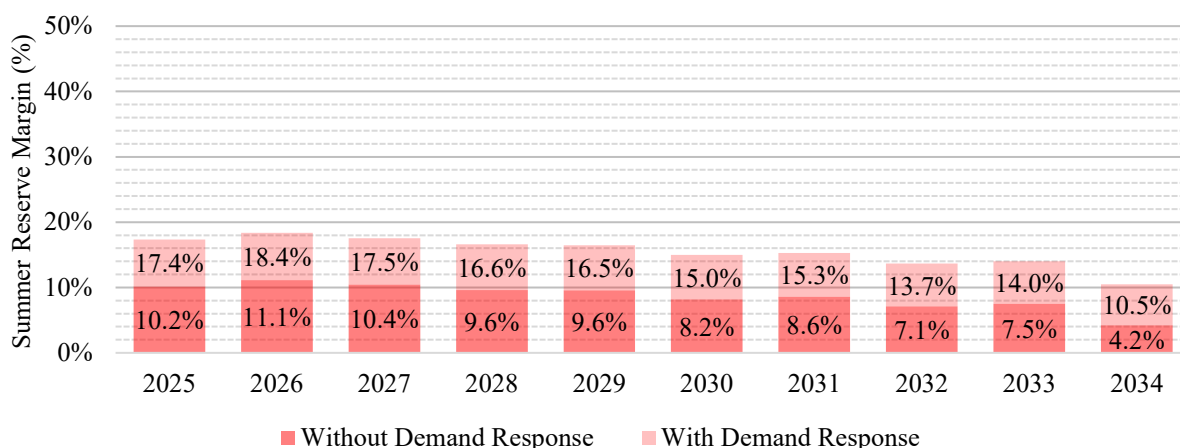
Figure 15: State of Florida - Projected Reserve Margin by Season



Source: FRCC 2025 Regional Load and Resource Plan - Revised Form 10

As discussed above, the reserve margin calculation is based upon the hour of highest peak demand and compared to the available firm generation. With the increase in the amount of non-dispatchable generation, primarily solar, the highest peak hour may no longer represent the time of highest dispatchable generation need especially for the summer peak period. One potential approach to address this would be to evaluate a net-solar peak hour, treating solar as a reduction to load similar to demand response. Alternatively, the firm contribution of solar could be removed from the reserve margin analysis to determine the contribution only of dispatchable resources, such as demand response or traditional generation. On average, solar contributes approximately 11.7 percent towards the summer reserve margin over the planning period. As illustrated by Figure 16, even without any contribution from solar at time of system peak, the statewide reserve margin would remain above the 15 percent threshold until 2032.

Figure 16: State of Florida - Projected Summer Reserve Margin without Solar



Source: FRCC 2025 Load & Resource Plan, 2025 TYSP Data Responses

Loss of Load Probability

In addition to reserve margin, Florida's utilities have used multiple indices to determine the reliability of their electric supplies. 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. A maximum LOLP of no more than 0.1 days per year, or approximately 1 day of outage per 10 years is a frequently used metric. Between the two reliability indices, LOLP and reserve margin, the reserve margin requirement has typically been the controlling factor for the addition of capacity for several decades.

Similar to reserve margin, with an increase in non-dispatchable generation, a LOLP analysis that looks at all days or hours of the year provides additional information regarding the reliability of the system. Based on the 2025 Load and Resource Reliability Assessment Report, the FRCC details how it conducted a statewide LOLP analysis for the period 2025 through 2029 using a system planning model that considered all hours of the year, using probabilistic methods to simulate various weather and unit outages, producing several thousand scenarios, and performing sensitivities with no imports, no demand response activations, and high load conditions. Overall, in the base case and in each sensitivity the FRCC determined that the planned resources are more than adequate to meet the 0.1 LOLP requirement by at least three orders of magnitude in the base case, and two orders of magnitude for the highest sensitivity. The results of the scenarios are provided in Table 9.

Table 9: FRCC Loss of Load Probability Study Results

Year	Scenario Results (Days/Year)			
	Base Case	No Availability of Imports	No Availability of Demand Response	High Load Case
2025	0.0001844	0.0003500	0.0007738	0.0010250
2026	0.0000514	0.0000318	0.0003046	0.0003964
2027	0.0000153	0.0000132	0.0001546	0.0002870
2028	0.0001177	0.0001135	0.0004745	0.0010767
2029	0.0002925	0.0002562	0.0014651	0.0028279

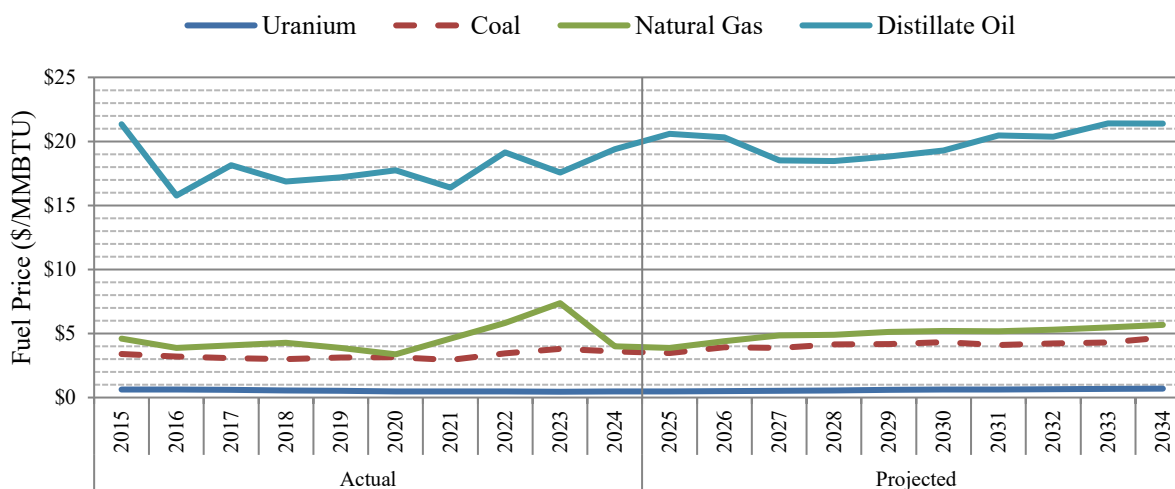
Source: 2025 TYSP Workshop FRCC Studies and Reports

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, uranium, and coal. Natural gas remains the most widely used fuel statewide, projected to account for between 73.2 percent and 58.0 percent of electric generation (in GWh) from 2025 through 2034.

As shown on Figure 17, the forecasted weighted average price per million British Thermal Units (MMBTUs) for natural gas, uranium, and coal are all expected to increase over the next 10 years. The highest forecasted increase in price over the forecast horizon is for natural gas, which is expected to increase from \$3.98 per MMBTU to \$6.10 per MMBTU by 2034. Meanwhile uranium, easily the lowest price fuel of the three, is projected to increase in price from \$0.51 MMBTU to \$0.75 MMBTU. Coal is projected to increase in price from \$3.29 MMBTU to \$4.78 MMBTU. Distillate oil is the most expensive fuel, with forecasted prices ranging between \$17.43 and \$21.24 per MMBTU from 2025 through 2034. Its high cost helps explain why it is used primarily for backup and peaking purposes.

Figure 17: TYSP Utilities - Average Fuel Price of Reporting Electric Utilities

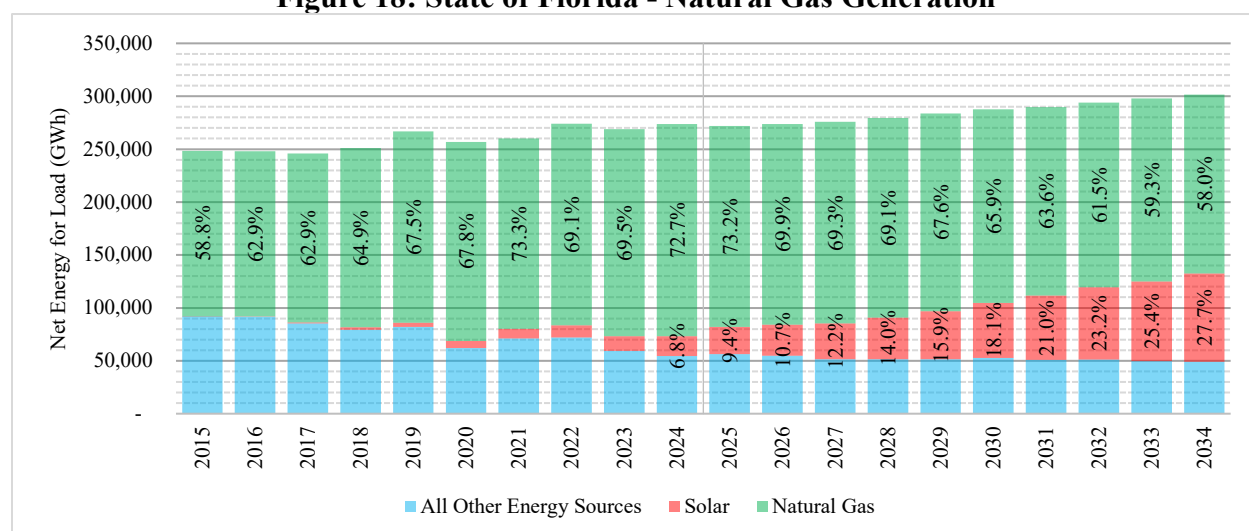


Source: TYSP Utilities' Data Responses

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 18 illustrates, natural gas was the source of approximately 72.7 percent of electric energy consumed in Florida in 2024. 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 2031.

Figure 18: State of Florida - Natural Gas Generation

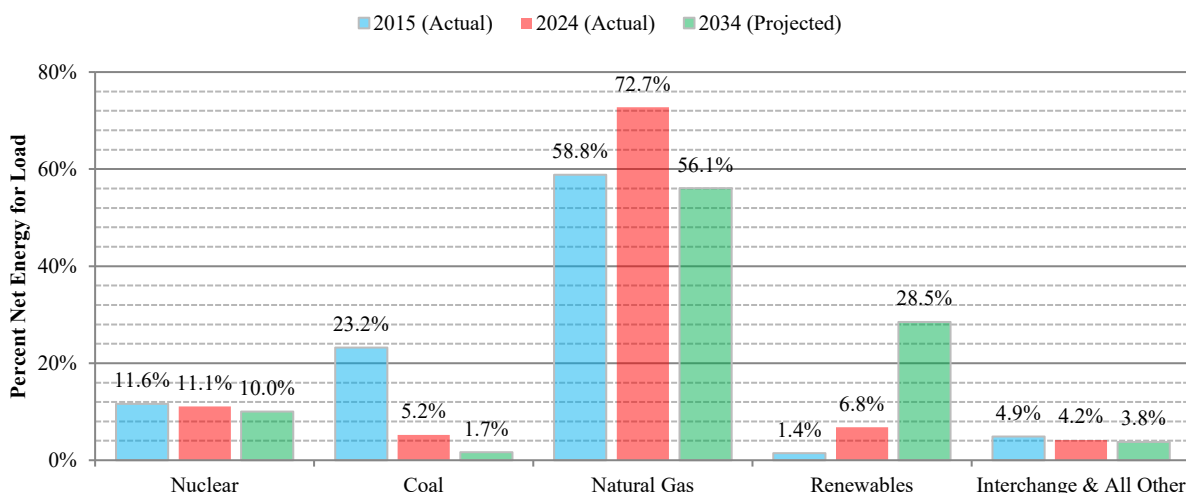


Source: FRCC 2015-2034 Regional Load and Resource Plans

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 related to environmental compliance requirements, making it unlikely that they could be permitted without novel emissions control technologies.

Figure 19 shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2015 and 2024, and forecast year 2034. 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, but this trend is anticipated to slightly decrease during the planning period. Renewables are expected to exceed all other generation sources except for natural gas by 2030.

Figure 19: State of Florida - Historic and Forecast Generation by Fuel Type



Source: FRCC 2015-2034 Regional Load and Resource Plan

Based on 2023 U.S. 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, representing 5 percent of national gas consumption.⁹ For volume of natural gas consumed for electric generation, Florida ranks second, behind Texas, representing 10.9 percent of national gas consumption for electric generation. Approximately 86.0 percent of natural gas consumed in Florida was for electric generation in 2023. 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.

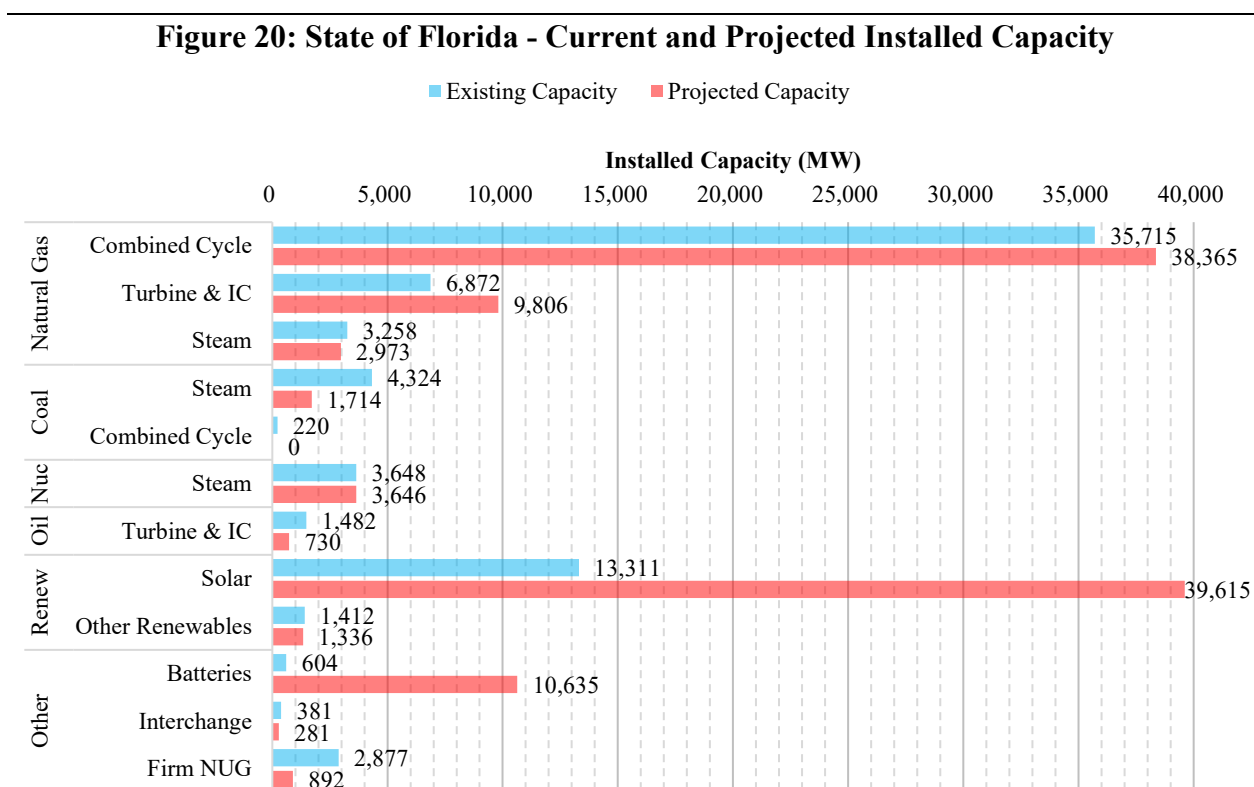
⁹ U.S. Energy Information Administration Natural Gas Annual Report.

New Generation Planned

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

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

Figure 20 illustrates the present and future aggregate capacity mix. The capacity values in Figure 20 incorporate all proposed additions, retirements, fuel switching, uprates and derates, and changes in operational or contract status contained in the reporting utilities' 2025 TYSPs and the FRCC's 2025 Regional Load and Resource Plan.



Source: FRCC 2025 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 Florida Electrical Power Plant Siting Act (PPSA), contained in Sections 403.501 through 403.518, F.S. The Commission has 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. When all parties stipulate that there are no disputed issues of material fact or law involved, the applicant may request that the Secretary of the Florida Department of Environmental Protection approve or deny certification, pursuant to Sections 403.508(6)(a) and 403.509(1)(a), F.S. Otherwise, the Governor and Cabinet sitting as the Siting Board ultimately must approve or deny the overall certification of a proposed line when there is a disputed issue of material fact or law, pursuant to Section 403.509(1)(b), F.S. There are only two planned units, both natural gas-fired combined cycles, requiring certification under the PPSA: a 576 MW unit with an in-service date of 2030 for JEA, and a 559 MW unit with an in-service date of 2032 for SEC. Based on these in-service dates, petitions are anticipated in 2026 and 2028 for JEA and SEC, respectively.

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 TYSP.

Florida is proactively exploring Small Modular Reactors (SMRs) to meet rising energy demands, though no units are currently operating. The state's efforts include a March 2025 feasibility report from the Commission and a related lawsuit filed by the Florida Attorney General against the U.S. Nuclear Regulatory Commission in April 2025. Major utilities like FPL and DEF are also considering SMR technology for their long-term power generation plans. In addition, the March 2025 feasibility report looked into military installations in partnership with a public utility.

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 units (also called reciprocating engines), 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 PPSA. Table 10 summarizes the approximately 4,233 MW of additional capacity from new natural gas-fired generating units proposed by the 2025 TYSP Utilities.

Table 10: 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 Unit 1	CC	546	Docket No. 20170267-EI
Subtotal				546	
New Units Requiring PPSA Approval					
2030	JEA	Advanced Class 1x1 CC	CC	576	
2032	SEC	Unnamed CC	CC	559	
Subtotal				1,135	
New Units Not Requiring PPSA Approval					
2025	TECO	South Tampa Resiliency Project	IC	75	4 Units
2025	LAK	Mcintosh Units MREP 1-3	IC	60	3 Units
2028	SEC	Unnamed CT 1	CT	393	
2030	SEC	Unnamed CT 2	CT	393	
2031	TECO	Future CT 1	CT	222	
2032	FPL	2x0 Manatee CT	CT	469	2 Units
2033	DEF	Undesignated CT 1 & 2	CT	491	2 Units
2034	DEF	Undesignated CT 3 & 4	CT	449	2 Units
Subtotal				2,552	
Total				4,233	

Source: 2025 TYSPs

In addition to the new generation listed in Table 10, multiple utilities are either acquiring existing natural gas-fired merchant generation facilities or are upgrading transmission to allow full capacity benefits from previously purchased resources. These include DEF's Osprey Energy Center (371 MW), FMPA's Orange facility (104 MW), and OUC's Osceola Generation Station (471 MW).

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 Florida Electric Transmission Line Siting Act (TLSA), contained in Sections 403.52 through 403.5365, F.S. To require certification under 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, pursuant to Section 403.537, F.S. The Commission is the sole forum for determinations of 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 with the PPSA, when all parties stipulate that there are no disputed issues of material fact or law involved, the applicant may request that the Secretary of the Florida Department of Environmental Protection approve or deny certification, pursuant to Sections 403.527(6)(a) and 403.529(1)(a), F.S. Otherwise, the Governor and Cabinet sitting as the

Siting Board ultimately must approve or deny the overall certification of a proposed line when there is a disputed issue of material fact or law, pursuant to Section 403.529(1)(b), F.S.

The Commission is also monitoring new technologies and trends associated with transmission. The use of advanced conductors that are being designed to operate at higher temperatures with less sag compared to traditional conductors allows for higher current flow and increased transmission line capacity within existing rights-of-way. Using new sensors and control systems with real-time data allows the potential for dynamic line rating systems to assess and adjust the carrying capacity of transmission lines based on loading and weather conditions. Advanced power flow controllers that enable active control and optimization of power flow across the transmission network, potentially reduce congestion, improve system stability, and enhance the integration of renewable energy sources.

Table 11 lists all proposed transmission lines in the 2025 TYSPs and the FRCC 2025 Regional Load and Resource Plan that require TLSA certification. The only planned lines have already received the approval of the Commission.

Table 11: State of Florida - Planned Transmission Lines

Utility	Transmission Line	Line Length	Nominal Voltage	Date Need Approved	Date TLSA Certified	In-Service Date
		(Miles)	(kV)			
FPL	Sweatt to Whidden	79	230	05/2022	09/2022	06/2026
DEF	DeLand West – Dona Vista	26.5	230	07/2025	TBD	01/2030

Source: 2025 TYSPs and FRCC 202 Regional Load and Resource Plan

Utility Perspectives

Florida Power & Light Company (FPL)

FPL is an investor-owned, 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 the FPL 2025 TYSP suitable for planning purposes.

Load and Energy Forecasts

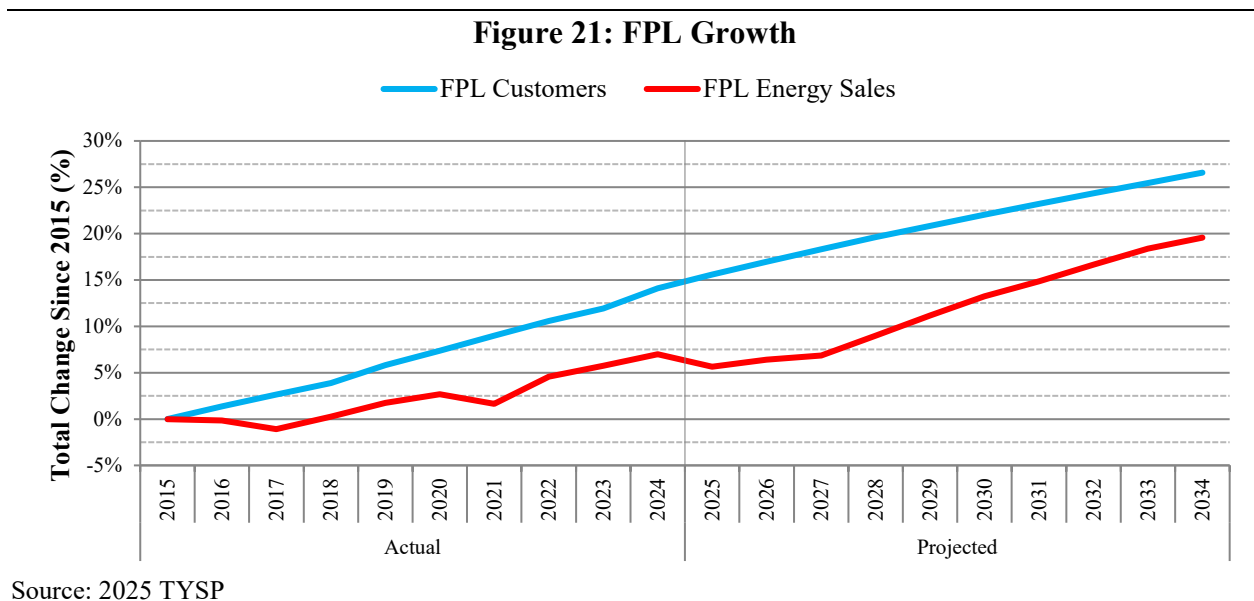
In 2024, FPL's service area had approximately 5,959,750 customers and annual retail energy sales of 129,386 GWh, accounting for approximately 52.6 percent of Florida's annual retail energy sales. The total number of customers and total retail energy sales grew by approximately 2.0 percent and 1.2 percent, respectively, in 2024.

Over the past 10 years, FPL's customer base has increased by 14.1 percent, while retail energy sales have grown by approximately 7.0 percent. For the 2025 TYSP forecast horizon, customers for the FPL system are forecasted to grow by 1.0 percent per year, with the residential and commercial classes accounting for the majority of the increase. According to the Utility, growth is closely linked to Florida's expanding population, housing market, and business activity, all of which are projected to remain positive.

FPL's historical underlying trends affecting average energy UPC across all customer classes include weather variability, economic conditions, and changes in customer behavior or operations. The residential UPC has ranged from relatively flat to slightly increasing in recent years. The change in residential consumption is attributable to the relative increased usage of electronics and equipment within residences, which is offset, in part, by continued improvements in energy efficiency, such as higher efficiency building codes, appliances, lighting, and HVAC systems. The trend in commercial UPC has been relatively flat over the past couple of years. Industrial UPC appeared relatively flat to slow but had a steady decline in the most recent years. The historical decline may be linked to shifts in the local industrial base, customer migration, increased energy efficiency, or operational changes among key industrial customers.

In the forecast period, residential UPC is forecasted to decline gradually over time, primarily driven by continued improvements in energy efficiency, such as higher efficiency building codes, appliances, lighting, and HVAC systems. In addition, increasing customer adoption of energy-saving behaviors and technologies (e.g., smart thermostats, solar panels) is expected to further reduce UPC. The commercial UPC is also expected to be generally flat to slightly declining for similar reasons. Energy efficiency standards, advanced building systems, and retrofits are expected to reduce consumption on a per-customer basis though some commercial customers may see stable or even increasing UPC due to higher operational loads and continued expansion. Industrial UPC is forecasted to increase modestly overall, driven by the expected addition of usage by large load customers.

Over the current TYSP forecast horizon, FPL’s total energy sales to ultimate customers are forecasted to increase steadily, driven primarily by customer growth. Florida’s strong population growth, housing development, and economic expansion continue to be the main drivers of rising energy demand across the state. Figure 21 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that FPL filed in its 2025 TYSP.



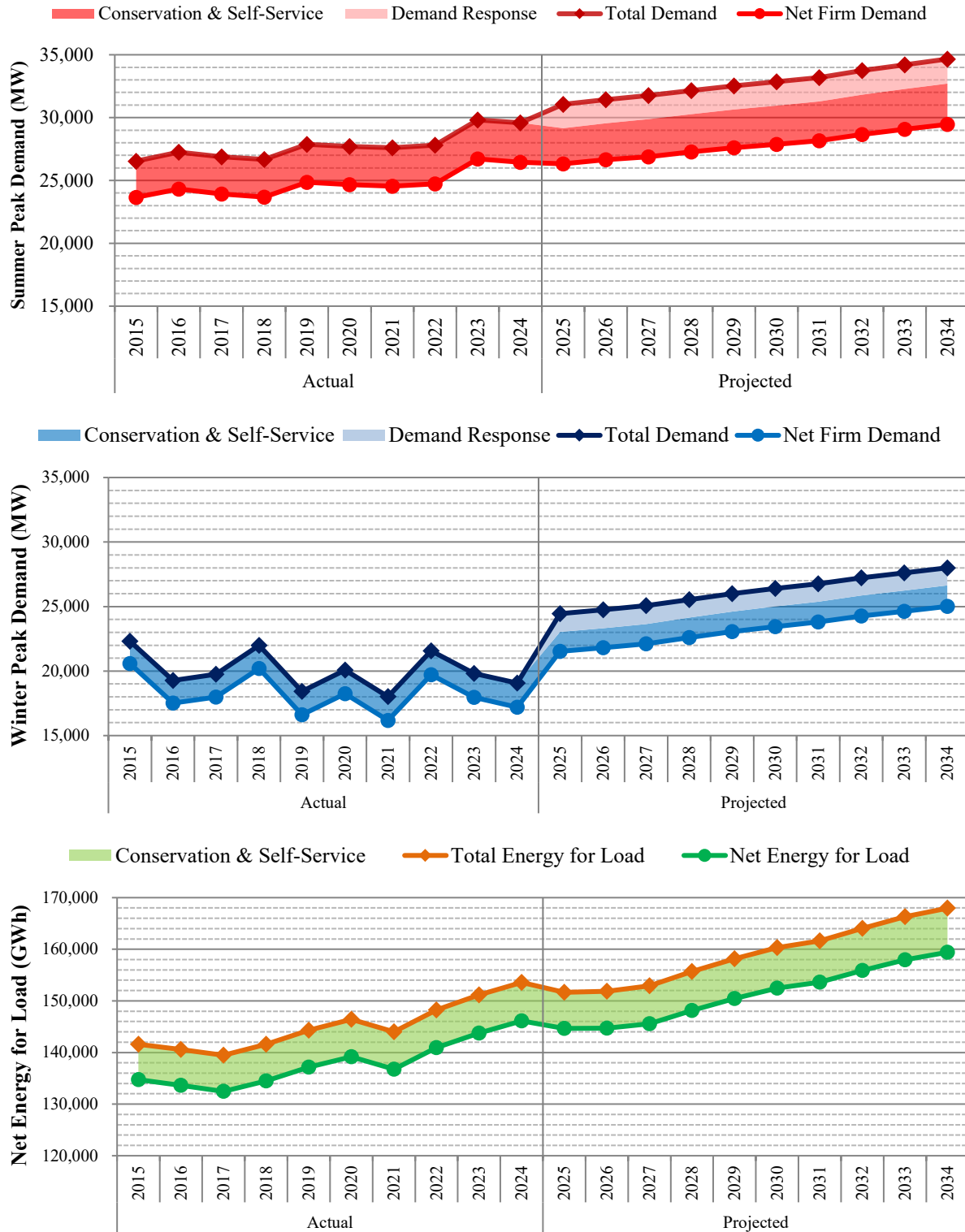
As stated earlier, on January 1, 2019, GPC became a subsidiary of NextEra Energy, Inc., FPL’s parent company, and the systems were integrated into a single electric system, effective January 1, 2022. The three graphs in Figure 22 show FPL and GPC’s combined seasonal peak demand, summer and winter, and net energy for load, for the historic years 2015 through 2021, and integrated FPL/GPC historical data for 2022 through 2024, and forecast data 2025 through 2034.

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 reviewed and established energy conservation goals for FPL and approved FPL’s 2025-2034 DSM Plan with modifications.^{10,11} In preparing its 2025 TYSP seasonal peak demand and energy forecasts, FPL reflects these Commission-approved FEECA goals through the forecast period (through 2034), as shown in Figure 22. These graphs include the impact of DSM, 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.

¹⁰ Order No. PSC-2024-0505-FOF-EG, issued on December 18, 2024, in Docket No. 20240012-EI, *In re: Commission review of numeric conservation goals (Florida Power & Light Company)*

¹¹ Order No. PSC-2025-0292-PAA-EG, issued on July 29, 2025, in Docket No. 20250048-EG, *In re: Petition for approval of proposed DSM plan, by Florida Power & Light Company.*

Figure 22: FPL Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 12 shows FPL’s actual net energy for load by fuel type for 2024 and the projected fuel mix for 2034. FPL relies primarily upon natural gas for energy generation, making up 71 percent of net energy for load in 2024. FPL is projected to use natural gas for less than half of its energy generation by 2033. Only three utilities, FPL, GRU, and OUC, are anticipated to reach this level of reduced natural gas consumption by the end of the planning period. By 2034, natural gas will remain FPL’s primary fuel source at approximately 46 percent, while renewables will account for 35 percent, followed by nuclear at 18 percent.

Table 12: FPL Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	104,335	71.4%	73,448	45.8%
Coal	533	0.4%	738	0.5%
Nuclear	28,009	19.2%	29,136	18.2%
Oil	116	0.1%	1	0.0%
Renewable	13,449	9.2%	56,831	35.4%
Interchange	0	0.0%	0	0.0%
NUG & Other	(340)	(0.2%)	319	0.2%
Total	146,102		160,473	

Source: 2025 TYSP

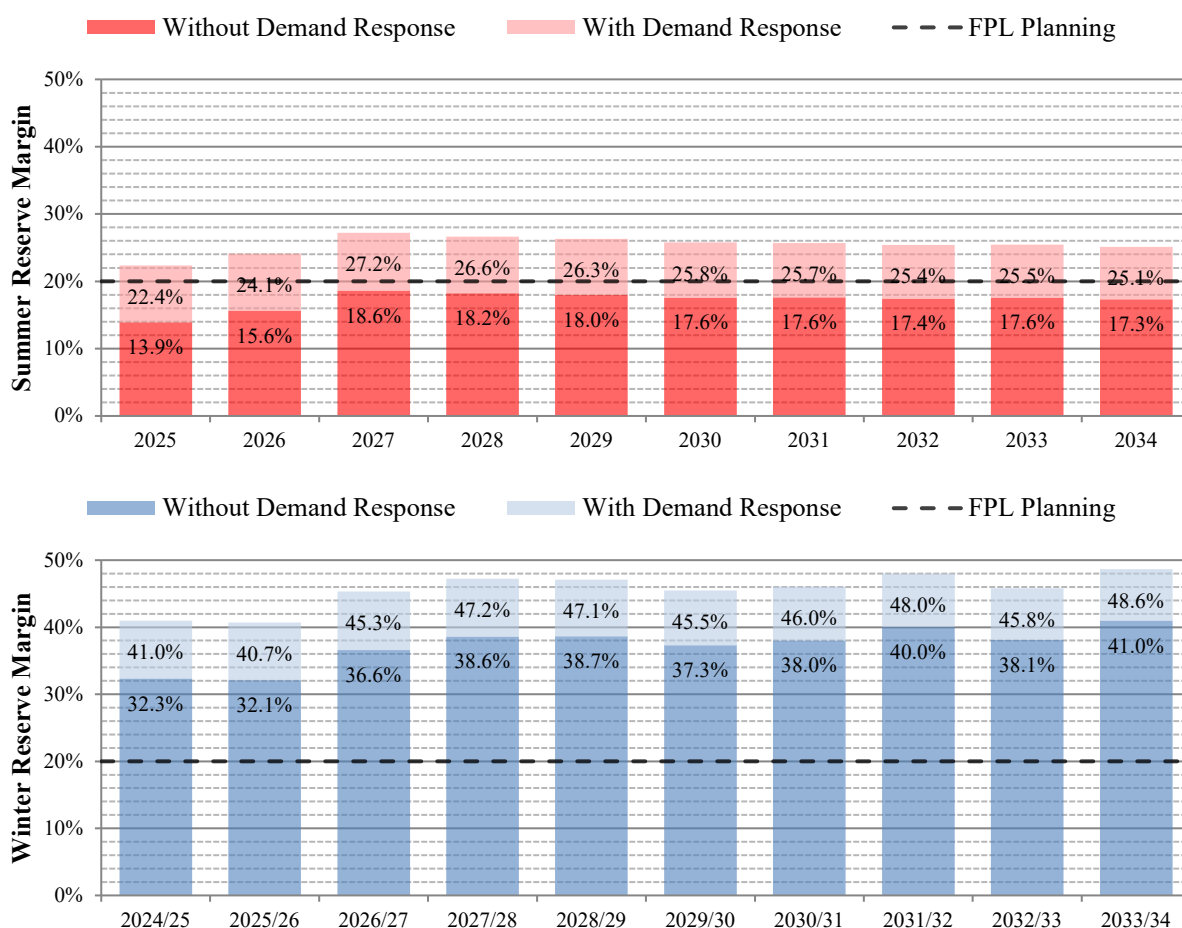
Reliability Requirements

Traditionally, FPL has used three methods for its reliability review. The three methods are a planning reserve margin, a generation-only planning reserve margin, and a LOLP. Since 1999, FPL has utilized a 20 percent planning reserve margin criterion based on a stipulation approved by the Commission.¹² FPL also elects to maintain a generation-only planning reserve margin of 10 percent. The Commission has yet to approve the 10 percent generation-only planning criteria, and it has not been the controlling factor for any unit additions. Figure 23 displays the forecast planning reserve margin with and without the use of demand response. As shown, in the future FPL’s generation needs are controlled by its summer peak.

For its reserve margin planning, FPL has considered only a portion of its solar facilities to be firm for seasonal peak planning purposes, primarily for summer. Of its 6,993 MW of existing utility-owned solar generation, it treats it as contributing 3,194 MW or 45.7 percent in summer, and 92 MW or 1.3 percent in winter. Planned solar generation additions of 17,508 MW are only considered firm for an additional 1,201 MW or 6.9 percent in summer, and 85 MW or 0.5 percent in winter. Therefore, existing utility-owned solar contributes 12.1 percent of its planned summer reserve margin in 2025, with new solar generation increasing the contribution to 14.9 percent in 2034.

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 23: FPL Reserve Margin Forecast



Source: 2025 TYSP

In addition to reserve margin, FPL uses 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 has historically been the controlling factor for the addition of capacity.

In its 2025 TYSP, FPL is shifting from its prior usage of a probabilistic model that evaluated daily peaks for the year to determine its LOLP value, to a new stochastic model to simulate various weather and unit outages, producing several hundred scenarios. FPL's 2025 TYSP only contained a summary of this methodology and did not provide a majority of the inputs or results. Using this analysis, FPL projected significant resource shortfalls primarily in off-peak periods, and is the controlling factor in generation additions. The use of this new methodology is at issue in FPL's current rate case before the Commission in Docket No. 20250011-EI, and any future Commission decision(s) associated with it will be addressed in FPL's next TYSP filing.

Generation Resources

FPL plans multiple unit retirements and additions during the planning period as are described in Table 13. Over the planning period, FPL will retire its remaining coal unit, Scherer Unit 3, which it acquired from its purchase of GPC. This and other retirements are partially offset by planned upgrades of its existing natural gas combined cycle generating units over the planning period, which increases summer capacity by 80 MW.

FPL plans a single new fossil fuel generating addition over the 10-year period, a pair of natural gas-fired combustion turbines in 2032 with a combined capacity of 469 MW. All other generation additions consist of solar and battery facilities, some of which may be constructed in a combined manner. Overall, FPL is planning a total of 17,508 MW and 7,605 MW of solar and battery storage capacity, respectively. For planning purposes, these are only considered to contribute towards summer firm peak a portion of their capacity, or 1,201 MW and 3,585 MW for solar and battery storage, respectively. None of these additions requires a need determination pursuant to the PPSA.

Table 13: FPL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Firm Capacity (MW)	Notes
			Sum	Sum	
Retiring Units					
2026	Pea Ridge 1-3	GT NG	12		3 Units Total
2028	Lansing Smith 3A	CT LO	32		
2029	Gulf Clean Energy Center 4 & 5	ST NG	150		2 Units Total
2030	Perdido 1 & 2	IC LFG	3		2 Units Total
2034	Scherer 3	BIT ST	215		
Total Retirements			412	-	
New Units					
2025	Gulf Battery Storage	BS	522	349	
2026	Sited Solar Plants	PV SUN	894	113	12 Sites
2026	Unsited Energy Storage	BS	1,420	997	
2027	Sited Solar Plants	PV SUN	1,192	64	16 Sites
2027	Unsited Energy Storage	BS	820	432	
2028	Unsited Solar Plants	PV SUN	1,490	79	20 Sites
2028	Unsited Energy Storage	BS	596	298	
2029	Unsited Solar Plants	PV SUN	1,788	95	24 Sites
2029	Unsited Energy Storage	BS	596	247	
2030	Unsited Solar Plants	PV SUN	2,235	119	30 Sites
2030	Unsited Energy Storage	BS	596	244	
2031	Unsited Solar Plants	PV SUN	2,235	119	30 Sites
2031	Unsited Energy Storage	BS	596	244	
2032	Unsited Solar Plants	PV SUN	2,235	119	30 Sites
2032	2x0 Manatee CT	CT NG	469		2 Units
2033	Unsited Solar Plants	PV SUN	2,235	119	30 Sites
2033	Unsited Energy Storage	BS	1,192	424	
2034	Unsited Solar Plants	PV SUN	2,235	119	30 Sites
2034	Unsited Energy Storage	BS	1,267	350	
Total New Units			24,613	4,531	
Net Additions			24,207		

Source: 2025 TYSP

Duke Energy Florida, LLC (DEF)

DEF is an investor-owned utility and Florida's second largest electric utility. The Utility's service territory is within the FRCC region and is primarily located in central and west central Florida. As an investor-owned utility, the Commission has regulatory authority over all aspects of utility operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds DEF's 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

In 2024, DEF had approximately 2,009,470 customers and annual retail energy sales of 41,132 GWh, accounting for approximately 16.7 percent of Florida's annual retail energy sales. DEF's total customers and total retail energy sales respectively grew approximately 2.1 percent and 0.7 percent in 2024. Over the last 10 years, DEF's customer base has increased by 16.7 percent, while retail energy sales have grown by 6.7 percent.

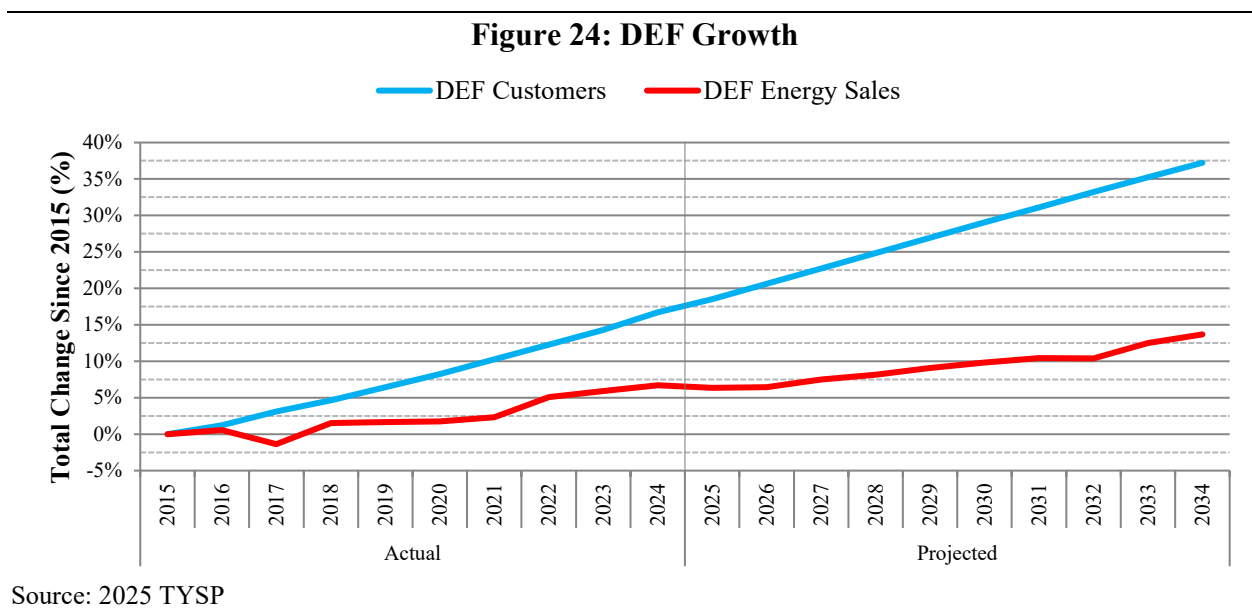
Historically, DEF's customer growth has always been dominated by the residential and commercial customer classes. Customer growth trends are driven by broad economic and demographic factors such as population growth, migration, retirement, housing, mortgage rates, and job growth. More recent information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

DEF reported that, from 2015 to 2024, its respective residential and commercial UPC annual growth rates decreased by approximately of 0.7 percent and 0.8 percent. These declines are primarily driven by fluctuations in price of electricity, end-use appliance saturation and efficiency improvement, more stringent building codes, housing type/size, and energy source of the air conditioning equipment. In addition, the Utility is aware that more recently, the customer's ability to self-generate has begun to make an impact on average usage. 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. DEF also noted that the penetration of plug-in EVs has grown, yielding an increase in residential UPC; however, the impact of rooftop solar generation on UPC continues to exceed the impact of EVs. In contrast, for the same historical period of 2015 to 2024, DEF's industrial UPC increased at an annual growth rate of 3.3 percent due to flat load combined with declining customer counts.

For 2025 to 2034, DEF is expecting its respective residential and commercial UPC to decrease by 1.0 percent and 0.4 percent per year. According to the Utility, the disparity between the going forward rates of residential and commercial UPC is the result of the anticipated growing residential behind the meter solar adoption. DEF is also expecting its industrial UPC to increase 0.7 percent annually, reflecting relatively flat sales and customer growth.

For the 2025 TYSP forecast horizon, DEF's customer base is projected to grow at an average annual rate of 1.6 percent approximately, and its retail energy sales amount is projected to grow at an average annual rate of 0.7 percent approximately.

Figure 24 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan DEF filed in its 2025 TYSP.

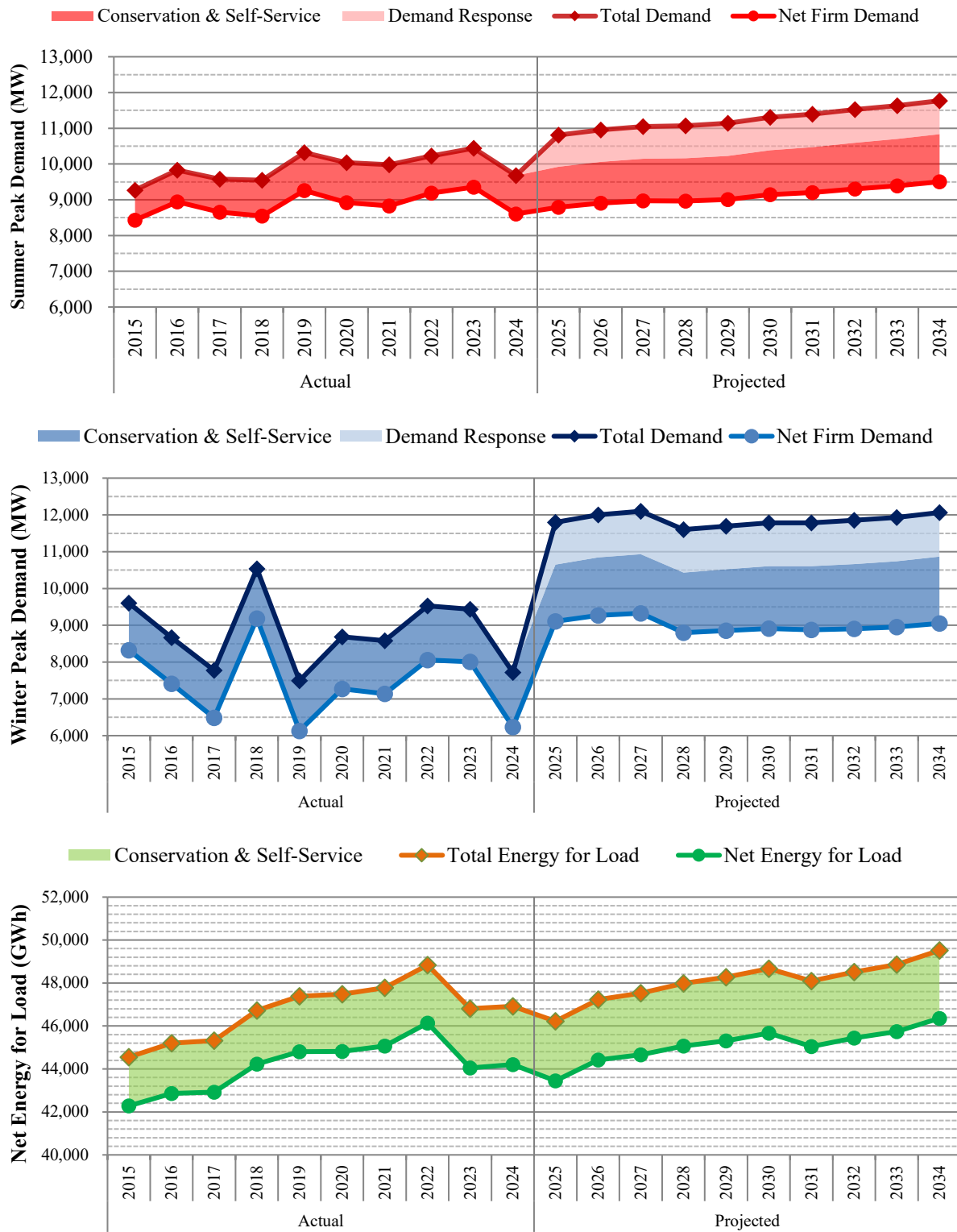


The three graphs in Figure 25 show DEF’s seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. These graphs include the full impact of DSM and assume that all available demand response resources will be activated during the seasonal 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. The Commission reviewed and established energy conservation goals for DEF and approved DEF’s 2025-2034 DSM Plan.^{13,14} In preparing its 2025 TYSP seasonal peak demand and energy forecasts, DEF reflects these Commission-approved FEECA goals through the forecast horizon (through 2034), as shown in Figure 25.

¹³ Order No. PSC-2024-0429-FOF-EG, issued September 20, 2024, in Docket No. 20240013-EI, *In re: Commission review of numeric conservation goals (Duke Energy Florida, LLC)*.

¹⁴ Order No. PSC-2025-0088-PAA-EG, issued March 24, 2025, in Docket No. 20240169-EG, *In re: Petition for approval of proposed demand-side management plan and demand-side management program standards, by Duke Energy Florida, LLC*.

Figure 25: DEF Demand and Energy Forecasts



Source: 2025 TYSP and Data Responses

Fuel Diversity

Table 14 shows DEF’s actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. DEF relies primarily upon natural gas for energy generation, making up approximately 85 percent of net energy for load in 2024. DEF plans to increase renewable energy generation over the planning period, offsetting both natural gas and coal usage. DEF projects that renewable energy will provide 29 percent of its generation by 2034, which is the fourth highest percentage of renewable energy generation in 2034 of the TYSP Utilities. Natural gas would remain the primary fuel, at 70 percent in 2034.

Table 14: DEF Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	37,494	84.8%	32,440	70.0%
Coal	3,262	7.4%	657	1.4%
Nuclear	0	0.0%	0	0.0%
Oil	30	0.1%	3	0.0%
Renewable	3,354	7.6%	13,250	28.6%
Interchange	(541)	(1.2%)	9	0.0%
NUG & Other	601	1.4%	0	0.0%
Total	44,200		46,359	

Source: 2025 TYSP and Data Responses

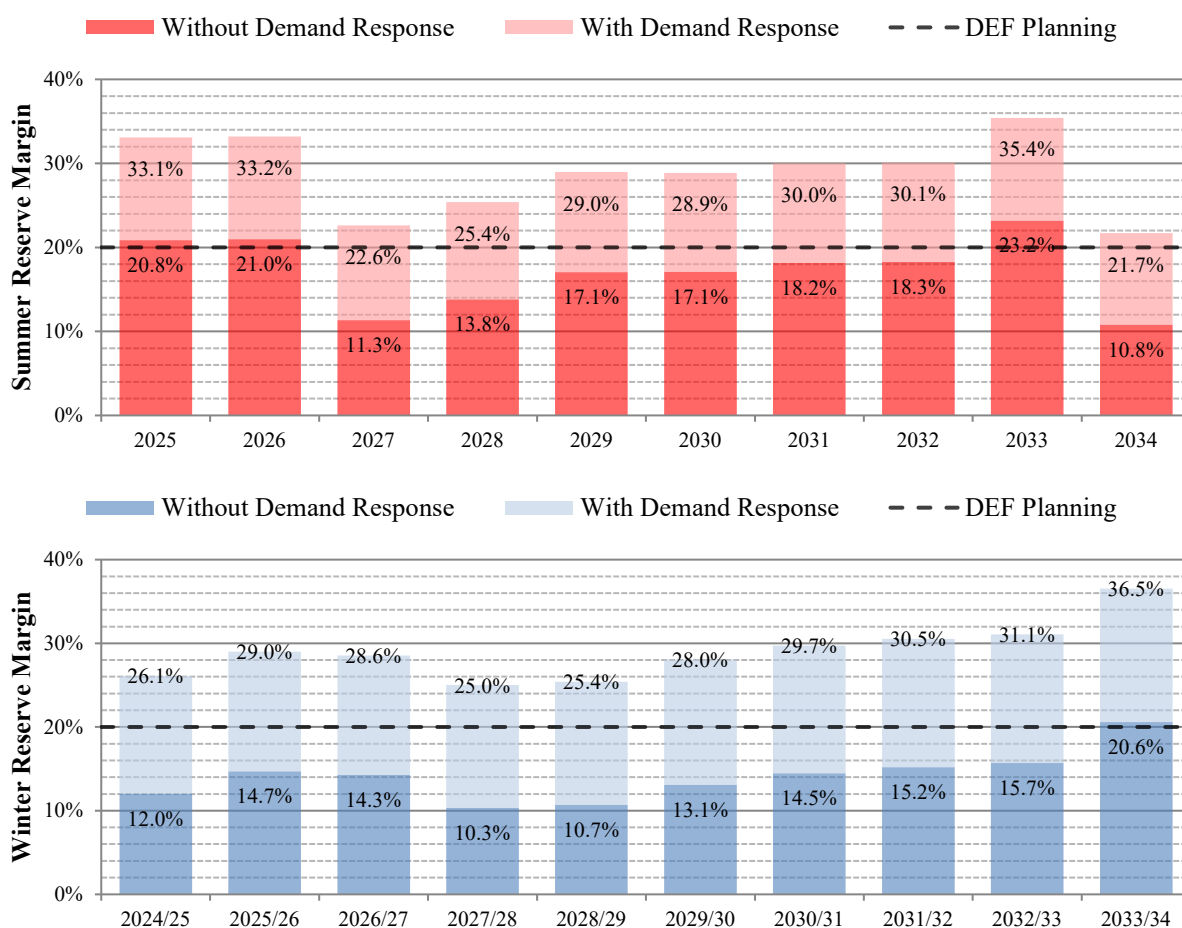
Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion based on a stipulation approved by the Commission.¹⁵ Figure 26 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.

As part of its evaluation of its system reliability, DEF also conducted an evaluation of the contribution of its existing and planned solar generation assets towards its seasonal peaks. The methodology selected by DEF, Effective Load Carrying Capacity (ELCC), determined that DEF’s existing solar capacity has a reduced benefit for summer peaks than previously calculated, from 54.7 percent to 53.7 percent and that the facilities also contribute approximately 5 percent to the winter peak. The ELCC methodology also provides that as additional resources are added to the system, the net contribution will decrease, similar to observed trends in prior planning methodologies. DEF plans to perform future ELCC studies to account for new solar and battery additions. The Commission will have an opportunity to review this methodology during a future proceeding.

¹⁵ 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 26: DEF Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

DEF projects multiple unit retirements and additions during the planning period, as described in Table 15. Over the planning period, DEF will retire its only remaining coal-fired units, Crystal River Units 4 and 5, in addition to several simple cycle combustion turbines fueled by oil or natural gas. This is partially offset by planned upgrades to its existing natural gas combined cycle generating units, which increase summer capacity by 256 MW, and improved transmission facilities that will allow DEF to fully utilize the acquired Osprey plant, which increases its firm contribution to 371 MW. DEF also plans on several solar QF purchases, totaling an additional 225 MW.

DEF identified two new fossil fuel generating addition over the 10-year period, each a pair of natural gas-fired combustion turbines, with combined capacities of 491 MW in 2033 and 449 MW in 2034. All other generation additions consist of solar and battery facilities, with a majority of the storage facilities constructed in combination with the solar additions. Overall, DEF is planning a total of 4,463 MW and 1,330 MW of solar and battery storage capacity, respectively. For planning purposes, these are only considered to contribute towards summer firm peak a portion of their capacity, or 873 MW and 1,088 MW for solar and battery storage, respectively. None of these additions requires a need determination pursuant to the PPSA.

Table 15: DEF Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Firm Capacity (MW)	Notes
			Sum	Sum	

Retiring Units					
2026	Bayboro Units P1-P4	CT DFO	137		4 Units
2027	Debary Units P2-P6	CT DFO	227		5 Units
2027	Bartow Units P1 & P3	CT DFO	82		2 Units
2034	Intercession City P1-P6	CT DFO	275		6 Units
2034	Bartow P2, P4	CT NG	86		2 Units
2034	Suwannee P1-P3	CT NG	145		3 Units
2034	Crystal River 4 & 5	ST BIT	1,422		2 Units
Total Retirements			2,374	0	

New Units					
2025	Sundance Solar Plant	PV SUN	75	26	
2026	Sited Solar Plants	PV SUN	524	186	7 Sites
2027	Unsited Solar Plants	PV SUN	300	100	4 Sites
2027	Powerline Energy Storage	BAT	100	90	
2028	Unsited Solar Plants	PV SUN	225	62	3 Sites
2028	Unsited Solar Plus Storage	PV SUN	150	32	2 Sites
2028	Unsited Solar Plus Storage	BAT	100	90	
2029	Unsited Solar Plant	PV SUN	225	62	3 Sites
2029	Unsited Battery Storage	BAT	225	203	
2029	Unsited Solar Plus Storage	PV SUN	150	32	2 Sites
2029	Unsited Solar Plus Storage	BAT	100	90	
2030	Unsited Solar Plants	PV SUN	225	48	3 Sites
2030	Unsited Solar Plus Storage	PV SUN	150	32	2 Sites
2030	Unsited Solar Plus Storage	BAT	100	90	
2031	Unsited Solar Plants	PV SUN	449	74	6 Sites
2031	Unsited Solar Plus Storage	PV SUN	150	23	2 Sites
2031	Unsited Solar Plus Storage	BAT	100	90	
2032	Unsited Solar Plants	PV SUN	449	48	6 Sites
2032	Unsited Solar Plus Storage	PV SUN	150	14	2 Units
2032	Unsited Solar Plus Storage	BAT	100	85	
2033	Unsited Solar Plants	PV SUN	449	43	6 Sites
2033	Undesignated CT P1 & P2	CT NG	491		2 Units
2033	Unsited Solar Plus Storage	PV SUN	150	14	2 Sites
2033	Unsited Solar Plus Storage	BAT	100	70	
2034	Undesignated CT P3 & P4	CT NG	449		2 Units
2034	Unsited Battery Storage	BAT	300	210	
2034	Unsited Solar Plus Storage	PV SUN	150	14	2 Units
2034	Unsited Solar Plus Storage	BAT	100	70	
Total New Units			6,236	1,898	

Net Additions			3,862		
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Source: 2025 TYSP

Tampa Electric Company (TECO)

TECO is an investor-owned utility and Florida's third largest electric utility. The Utility's service territory is within the FRCC region and consists primarily of the Tampa metropolitan area. As an investor-owned utility, the Commission has regulatory authority over all aspects of utility operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds TECO's 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

In 2024, TECO had approximately 849,877 customers and annual retail energy sales of 20,702 GWh, accounting for approximately 8.4 percent of Florida's annual retail energy sales. Over the last 10 years, TECO's customer base has increased by approximately 18.3 percent, while retail energy sales have increased by approximately 9.0 percent.

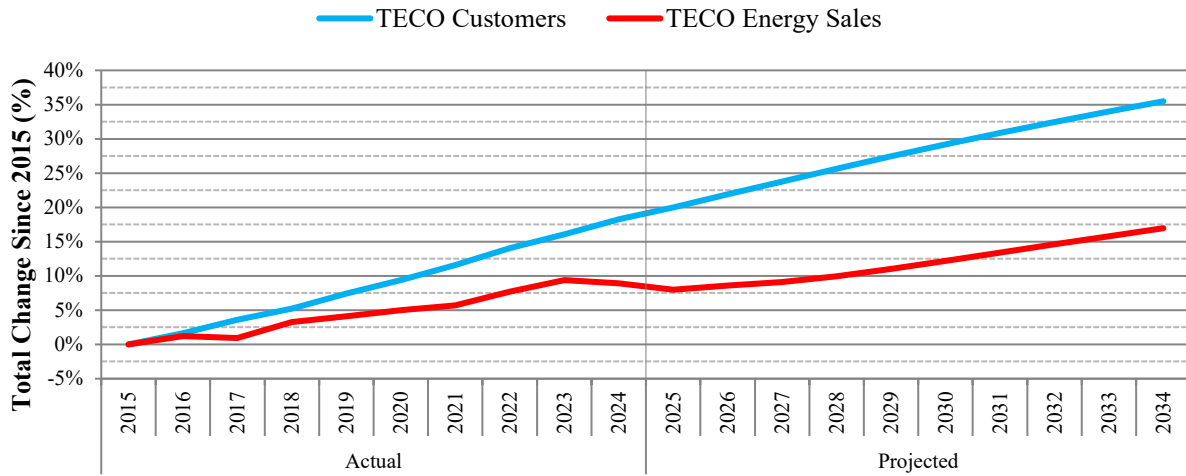
TECO's total customer growth in 2024 averaged 1.9 percent approximately with the residential class being the engine behind the growth. Over the next 10 years customer growth is expected to increase at an average rate of 1.4 percent annually.

TECO's residential UPC and commercial UPC growth rates were both slightly lower in 2024 than in 2023, primarily due to the record-breaking heat in 2023. TECO's industrial UPC declined by 1.4 percent in 2024 and is expected to be flat for 2025. Over the forecast horizon, TECO's residential UPC is expected to decline at an average annual rate of 0.3 percent over the TYSP's forecast horizon. The primary drivers behind the decline in per-customer usage are increases in appliance efficiencies, lighting efficiencies, energy efficiency in new homes, conservation efforts, and housing mix. TECO's commercial and industrial UPC is projected to decrease slightly, at an annual rate of 0.1 percent and 0.2 percent, respectively.

In 2024, TECO's retail energy sales were 0.4 percent lower than in 2023. For the next 10 years, the Utility'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 declines in UPC, as well as declines in the phosphate sector as the mining industry continues to move south and out of TECO's service territory.

Figure 27 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that TECO filed in its 2025 TYSP.

Figure 27: TECO Growth



Source: 2025 TYSP

The three graphs in Figure 28 show TECO’s seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. These graphs include the full impact of DSM, 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. The Commission reviewed and established energy conservation goals for TECO and approved TECO’s 2025-2034 DSM Plan.^{16,17} In preparing its 2025 TYSP seasonal peak demand and energy forecasts, TECO reflects these Commission-approved FEECA goals through the forecast period (through 2034), as shown in Figure 28.

¹⁶ Order No. PSC-2024-0430-FOF-EG, issued September 20, 2024, in Docket No. 20240014-EI, *In re: Commission review of numeric conservation goals (Tampa Electric Company)*.

¹⁷ Order No. PSC-2025-0093-PAA-EG, issued March 24, 2025, in Docket No. 20240163-EG, *In re: Petition for approval of proposed demand-side management plan and demand-side management program standards, by Tampa Electric Company*.

Figure 28: TECO Demand and Energy Forecasts



Source: 2025 TYSP and Data Responses

Fuel Diversity

Table 16 shows TECO's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. Natural gas is used for the majority of TECO's energy generation, and accounts for approximately 82 percent of net energy for load in 2024 and is projected to account for approximately 72 percent in 2034. Renewables, primarily solar, are anticipated to increase from 10 percent in 2024 to 25 percent in 2034.

Table 16: TECO Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	17,999	82.4%	16,864	72.1%
Coal	58	0.3%	323	1.4%
Nuclear	0	0.0%	0	0.0%
Oil	4	0.0%	0	0.0%
Renewable	2,235	10.2%	5,870	25.1%
Interchange	33	0.2%	281	1.2%
Other	1,523	7.0%	36	0.2%
Total	21,852		23,374	

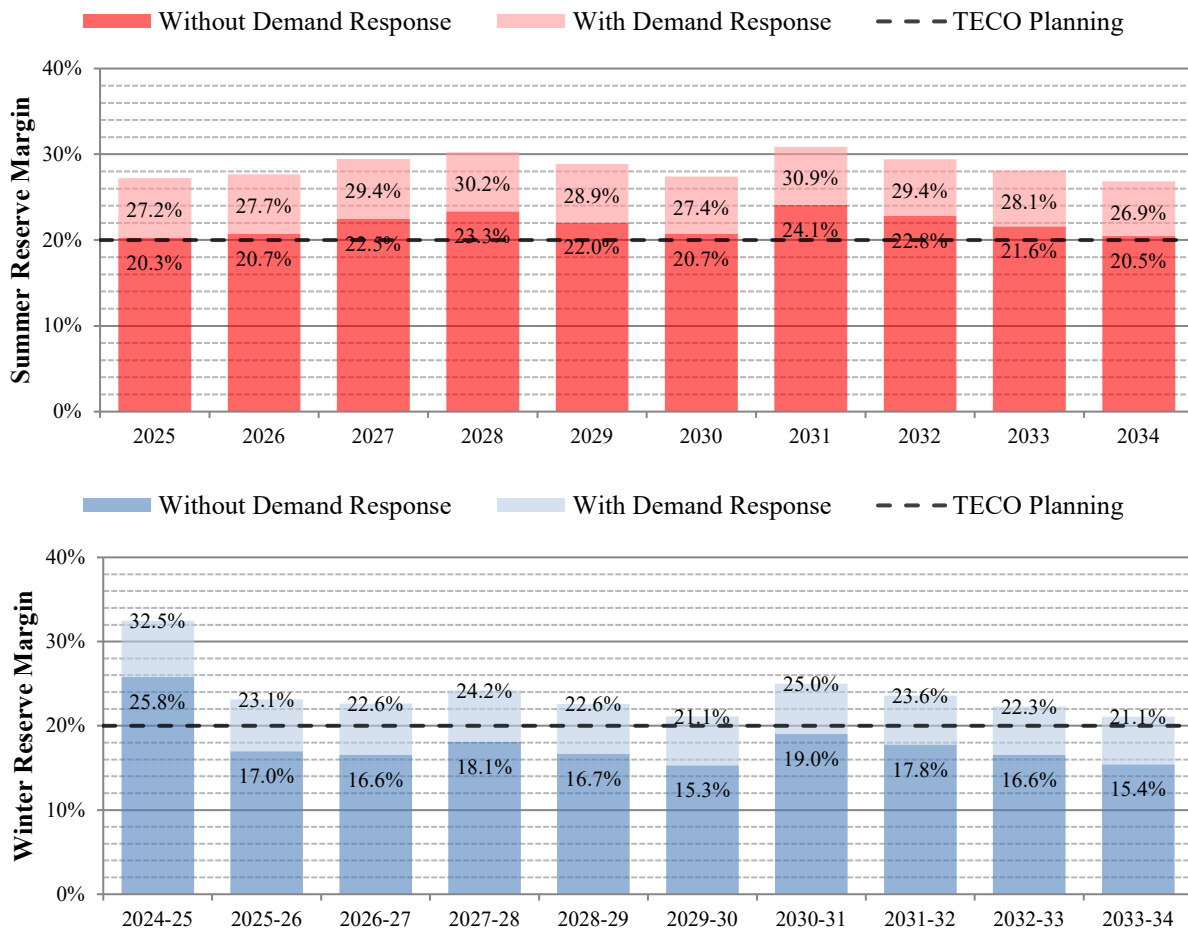
Source: 2025 TYSP and Data Responses

Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion based on a stipulation approved by the Commission.¹⁸ TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 29 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.

¹⁸ 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 29: TECO Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

TECO projects multiple unit additions during the planning period, as described in Table 15. While TECO does not plan to retire any generating units, it is converting Polk Unit 1 from a petcoke-fired combined cycle system to a natural gas-fired simple cycle combustion turbine, which reduces its output by approximately 30 MW. This is offset by planned upgrades to its existing natural gas combined cycle generating units, which increase summer capacity by 140 MW.

TECO plans two new fossil fuel generating additions over the 10-year period, all natural gas-fired, including a set of four reciprocating engines in 2025 with a capacity of 75 MW, and a simple cycle turbine in 2031 with a capacity of 222 MW. All other generation additions consist of solar and battery facilities. Overall, TECO is planning a total of 1,340 MW and 195 MW of solar and battery storage capacity, respectively. For planning purposes, the batteries are assumed to contribute their full capacity, while the solar facilities are only considered to contribute towards summer firm peak a portion of their capacity, 26 MW. None of these additions requires a need determination pursuant to the PPSA.

Table 17: TECO Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacit y (MW)	Firm Capacit y (MW)	Notes
			Sum	Sum	

Retiring Units					
	None				
Total Retirements			0	0	

New Units					
2025	South Tampa Resilience Project	IC NG	75		4 Units
2025	Sited Solar Plants	PV SUN	149	7	2 Sites
2025	Sited Energy Storage	BAT	100	100	3 Sites
2026	Sited Solar Plants	PV SUN	227	8	4 Sites
2027	Brewster Solar Plant	PV SUN	16	0	1 Site
2027	Unsited Solar Plant	PV SUN	149	2	2 Sites
2027	Unsited Energy Storage	BAT	95	95	2 Sites
2028	Unsited Solar Plants	PV SUN	204	3	3 Sites
2029	Unsited Solar Plants	PV SUN	149	2	2 Sites
2030	Unsited Solar Plants	PV SUN	149	2	2 Sites
2031	Future CT 1	CT NG	222		
2031	Unsited Solar Plant	PV SUN	75	1	1 Site
2032	Unsited Solar Plant	PV SUN	75	1	1 Site
2033	Unsited Solar Plant	PV SUN	75	1	1 Site
2034	Unsited Solar Plant	PV SUN	75	1	1 Site
Total New Units			1,835	223	

Net Additions			1,835	223	
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Source: 2025 TYSP

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 31 member systems, only those members that are participants in the All-Requirements Power Supply Project (ARP) are addressed in the Utility's TYSP. 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 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

In 2024, FMPA had approximately 293,231 customers and annual retail energy sales of 6,254 GWh, accounting for approximately 2.5 percent of Florida's annual retail energy sales. Over the last 10 years, FMPA's customer base has increased by 17.6 percent, while energy sales have increased by 11.3 percent.

In 2024, FMPA's total customer growth averaged 2.5 percent approximately. It noticed strong customer count gains in certain areas of the ARP participant service territories where residential sector expansion is the primary driver of customer gains. Florida in-migration has continued to be the leading driver of ARP customer growth.

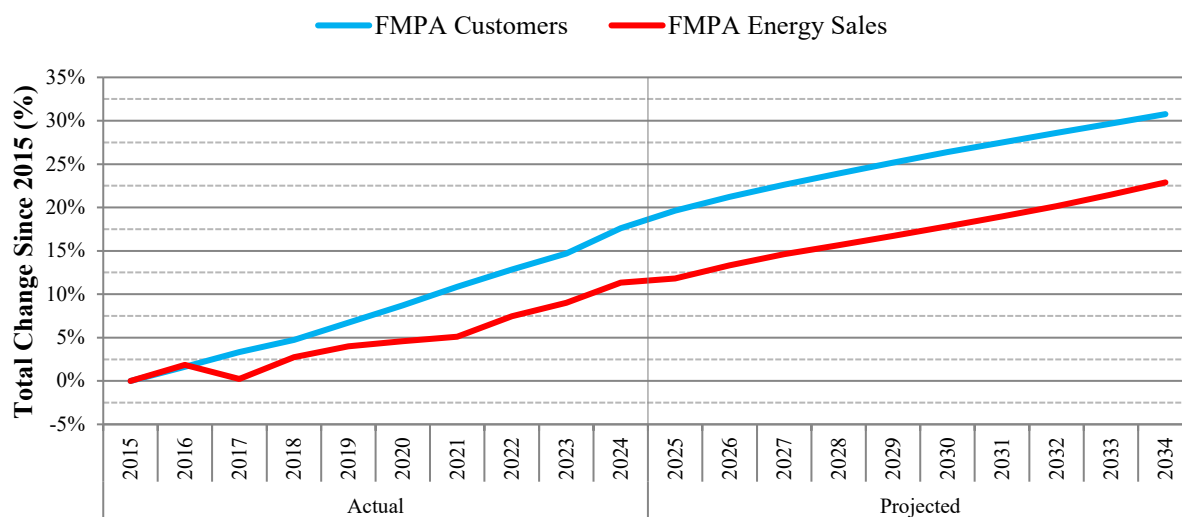
FMPA's annual increase in energy sales was 2.1 percent in 2024, higher than the 1.5 percent increase recorded in 2023. According to the Utility, this is due to an increase in seasonal firm capacity and energy sales that did not take place in the year prior.

FMPA noted that, in aggregate, its UPC has been relatively flat in both the residential and non-residential sectors after controlling for weather variation from normal conditions. The Utility noted that a continued orientation toward conservation and continued improvement in energy efficiency, driven primarily from technological advances, equipment standards, and enhanced building codes, place downward pressure on average usage.

FMPA acknowledged that, over the last several years, EVs adoption has steadily increased in Utility's service areas. Given the significance of this trend, FMPA's 2025 load forecast includes a projection of the future impact of EV charging energy.

For the current 10-year forecast horizon, FMPA is projecting an average annual growth rate of approximately 1.0 percent for its customer base, and a 1.1 percent average annual growth rate for energy sales. Figure 30 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that FMPA filed in its 2025 TYSP.

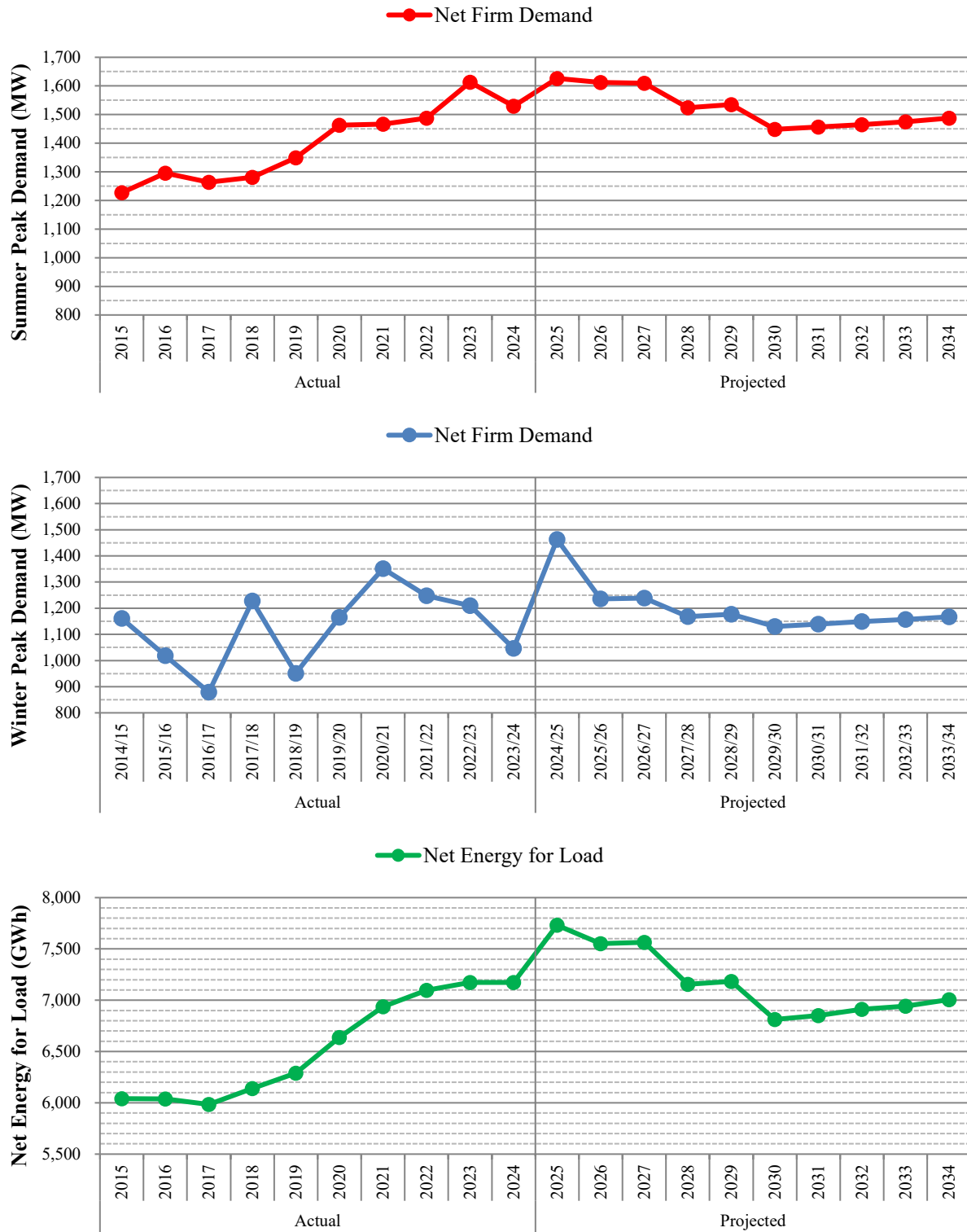
Figure 30: FMPA Growth



Source: 2025 TYSP

The three graphs in Figure 31 show FMPA's seasonal peak demand and net energy for load for the historic years 2015 through 2024 and forecast years 2025 through 2034. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer DSM programs, the impacts of which are included in the graphs.

Figure 31: FMPA Demand and Energy Forecasts



Source: 2025 TYSP and Data Responses

Fuel Diversity

Table 18 shows FMPA's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. FMPA uses natural gas as its primary fuel, producing 85 percent of energy in 2024 and increasing to 90 percent of energy by 2034. FMPA projects to end energy generation from coal beginning in 2028 with the conversion of the Stanton Energy Center Unit 2 from coal to natural gas-fired generation. Overall, coal-generated energy is being replaced by a combination of increased natural gas, nuclear, and renewable energy sources.

Table 18: FMPA Energy Generation by Fuel Type

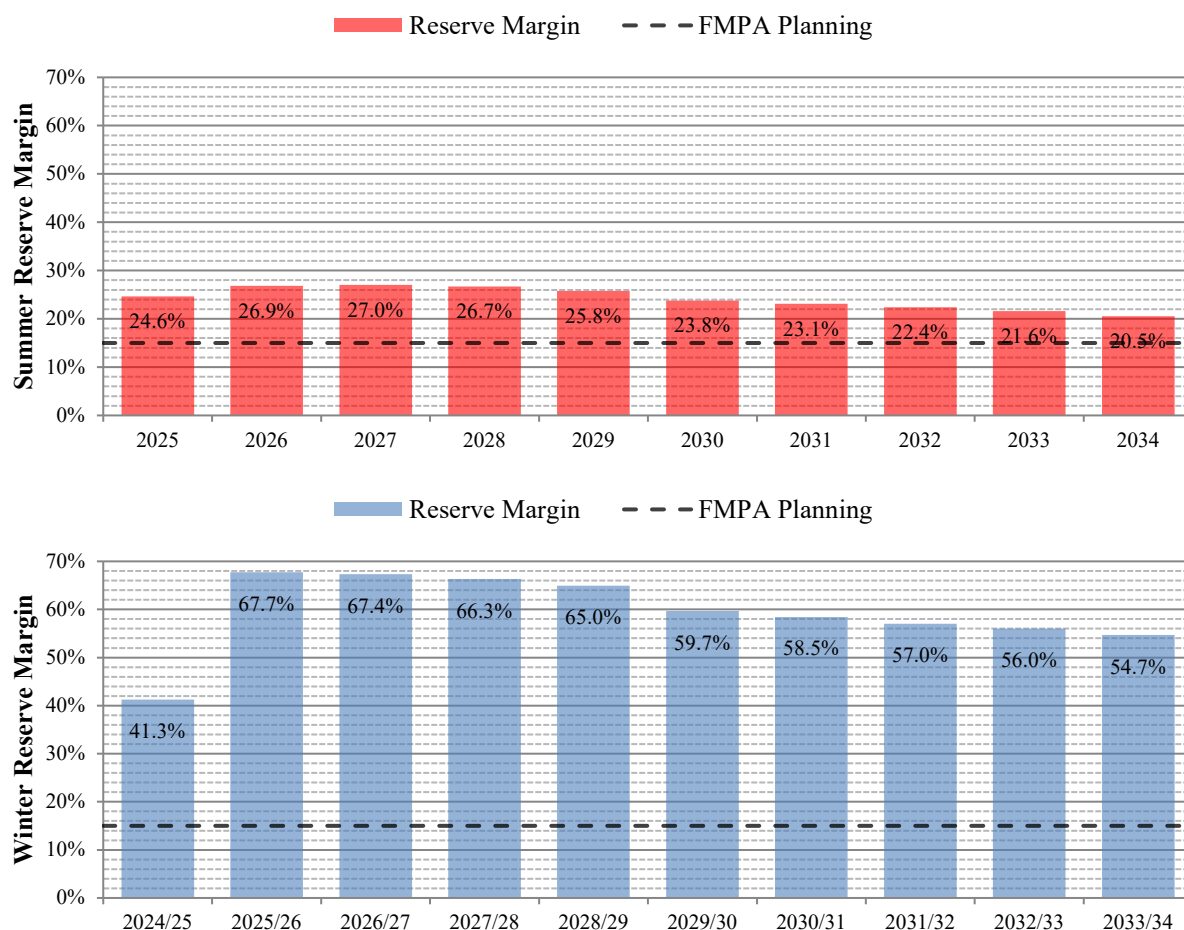
Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	6,073	84.7%	6,275	89.6%
Coal	582	8.1%	0	0.0%
Nuclear	353	4.9%	390	5.6%
Oil	3	0.0%	1	0.0%
Renewable	161	2.2%	340	4.9%
Interchange	0	0.0%	0	0.0%
NUG & Other	0	0.0%	0	0.0%
Total	7,172		7,006	

Source: 2025 TYSP and Data Responses

Reliability Requirements

FMPA utilizes a 15 percent planning reserve margin criterion. Figure 32 displays the forecast planning reserve margin for FMPA through the planning period for both seasons. As shown in the figure, FMPA's generation needs are controlled by its summer peak throughout the planning period.

Figure 32: FMPA Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

FMPA plans on retiring and adding one unit each during the planning period, as illustrated in Table 19. The Stanton Energy Center Unit 1, a coal steam unit which is jointly owned with OUC and others, is scheduled for retirement in 2025. In 2028, the Stanton Energy Center Unit 2 is scheduled for conversion from a coal-fired to a natural gas-fired steam unit. FMPA is acquiring the existing Orange Cogeneration 104 MW natural gas-fired combined cycle merchant facility in 2026. In addition to its utility-owned generation, FMPA has entered into multiple purchased power agreements (PPAs) for additional solar capacity.

Table 19: FMPA Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Notes
			Sum	
Retiring Units				
2025	Stanton Energy Center Unit 1	ST BIT	118	Jointly Owned Unit
Total Retirements			118	
New Units				
2026	Bartow Energy Center	CC NG	104	Merchant Acquisition
Total New Units			104	
Net Additions			(14)	

Source: 2025 TYSP

Gainesville Regional Utilities (GRU)

GRU is a municipal utility and the smallest electric utility by sales required to file a TYSP. 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 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

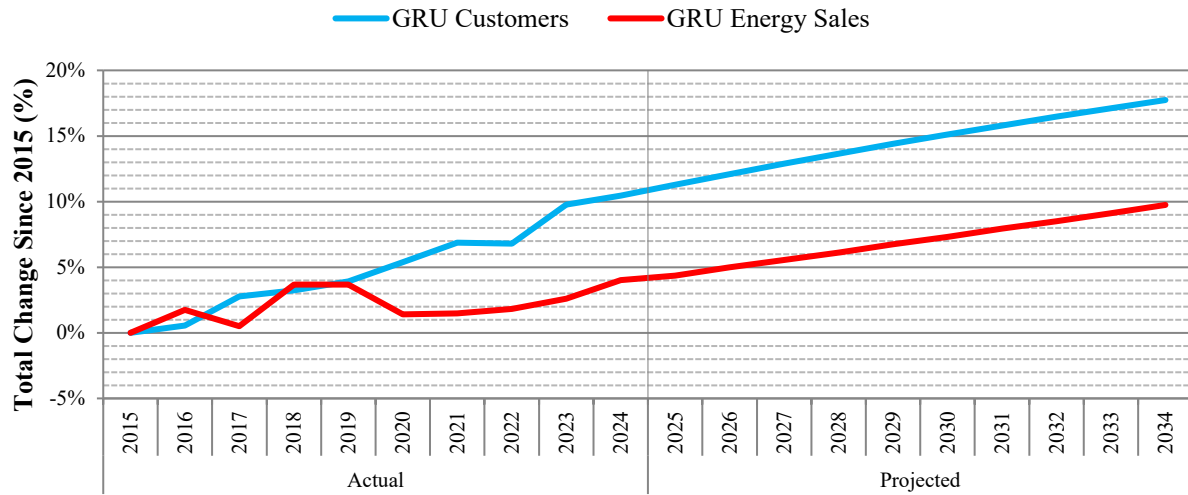
In 2024, GRU had approximately 104,510 customers and annual retail energy sales of 1,836 GWh, accounting for approximately 0.8 percent of Florida's annual retail energy sales. In the same year, the Utility's total customer growth and total retail sales growth were approximately 0.6 percent and 1.4 percent, respectively. Over the last 10 years, GRU's customer base has increased by approximately 10.4 percent with an annual growth rate of 1.1 percent, while retail energy sales have increased by approximately 4.0 percent with an annual growth rate of 0.4 percent.

Over the past 10 years, GRU's residential UPC declined approximately 0.2 percent per year, while its non-residential UPC declined approximately 0.8 percent per year. Some of the factors that influence these UPC declines include energy efficiency standards, improved building codes, increasing electricity prices, and growing participation in behind-the-meter solar energy. For the forecast period, GRU projected its residential UPC will remain flat. In the non-residential sectors, increasing real price of electricity is projected to play a large role such that UPC will decline at a rate of approximately 0.2 percent per year.

For the current 10-year forecast horizon, GRU's number of customers and retail energy sales will both grow nearly the same at an annual average rate of approximately 0.6 percent. 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 UPC.

Figure 33 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that GRU filed in its 2025 TYSP.

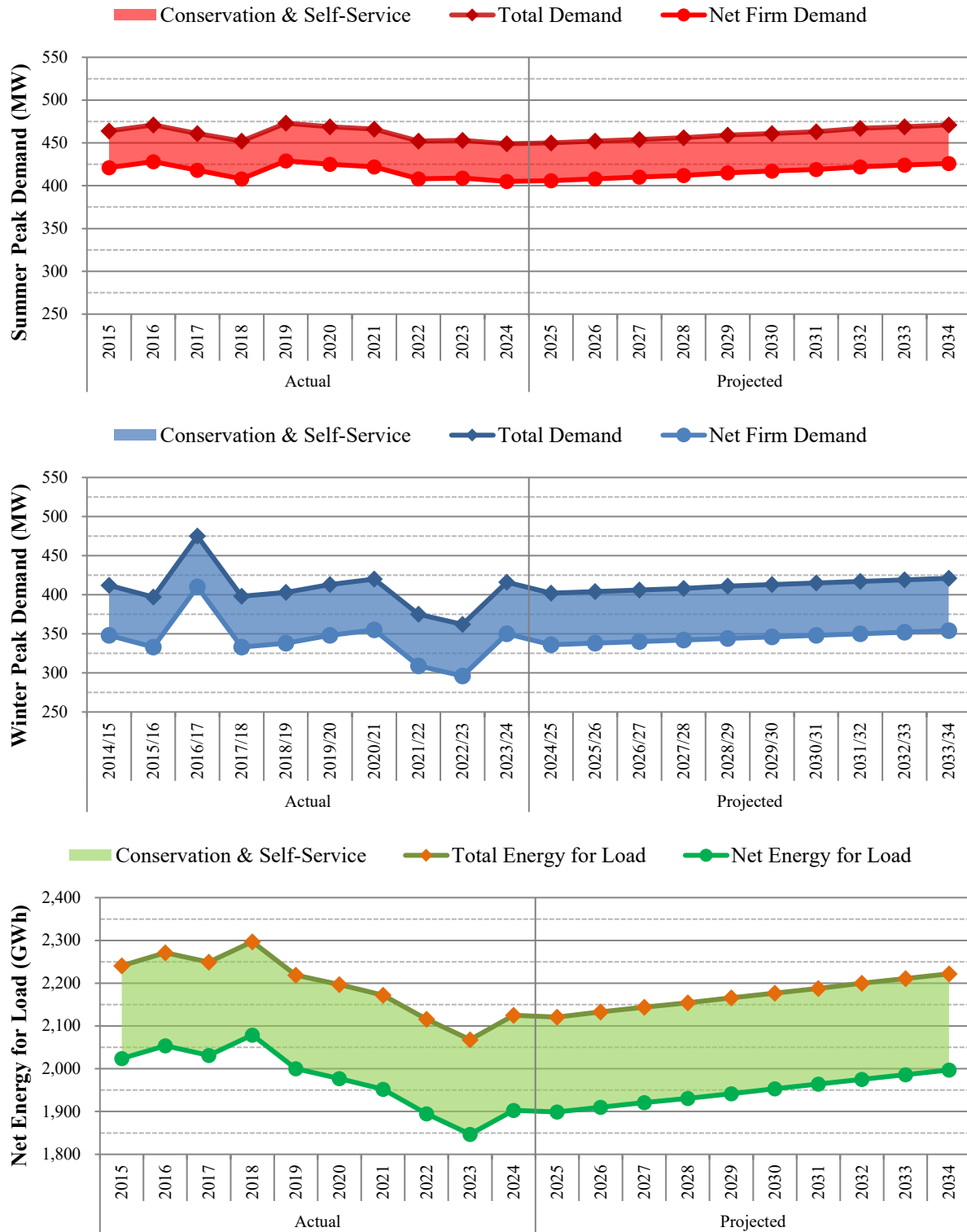
Figure 33: GRU Growth



Source: 2025 TYSP

The three graphs in Figure 34 show GRU's seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 34 include the impact of these DSM programs.

Figure 34: GRU Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 20 shows GRU's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. GRU relies primarily upon natural gas for energy generation, making up 82 percent of net energy for load in 2024. GRU is projected to use natural gas for less than half of its energy generation by 2034. Only three utilities, FPL, GRU, and OUC, are anticipated to reach this level of reduced natural gas consumption by the end of the planning period. By 2034, natural gas will remain GRU's primary fuel source at 48 percent, while renewables will account for 33 percent. Coal generation is anticipated to increase from approximately 0 percent in 2024 to 16 percent in 2034, with the increase being associated with the co-firing of coal and natural gas at Deerhaven Unit FS02, GRU's only remaining unit capable of burning coal.

Table 20: GRU Energy Generation by Fuel Type

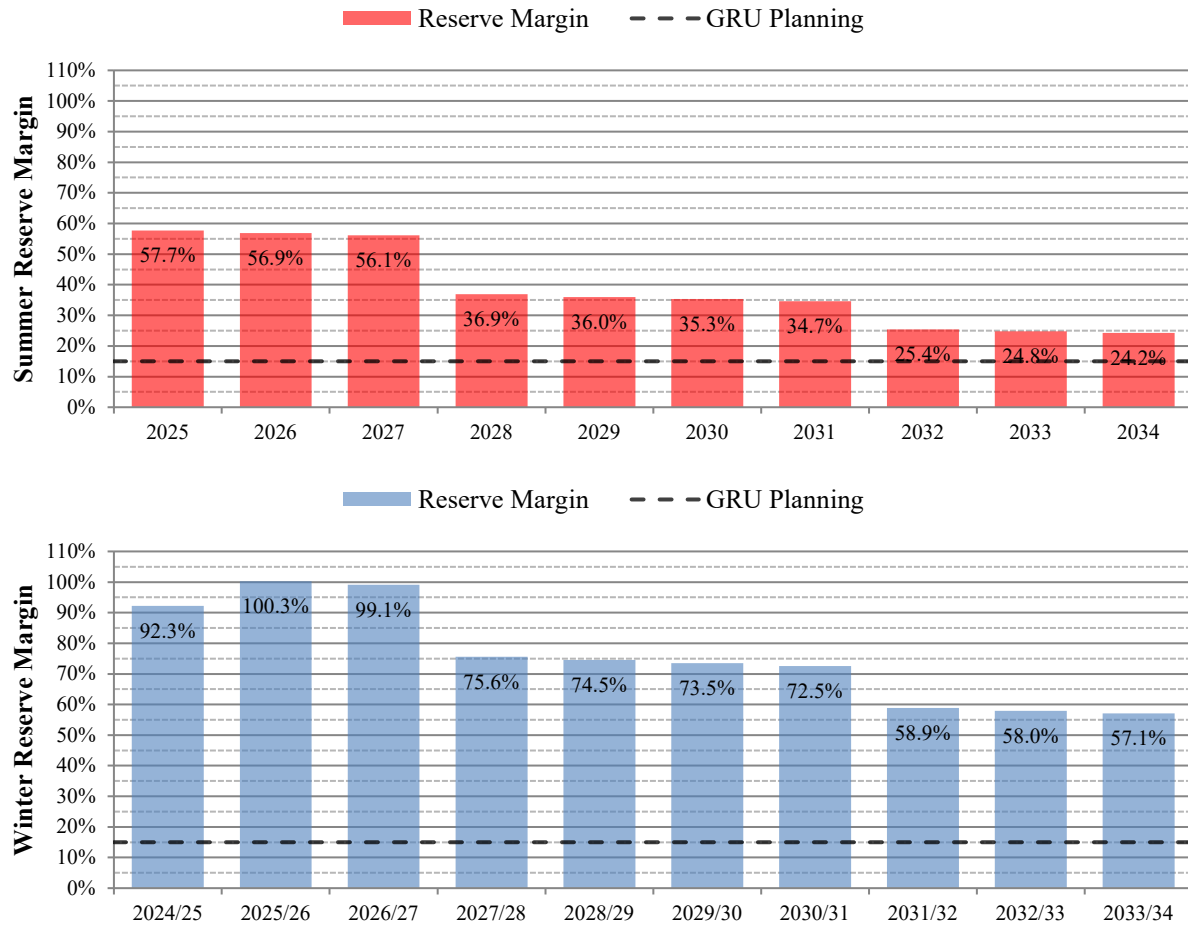
Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	1,562	82.1%	959	48.0%
Coal	2	0.1%	316	15.8%
Nuclear	0	0.0%	0	0.0%
Oil	0	0.0%	0	0.0%
Renewable	253	13.3%	654	32.7%
Interchange	0	0.0%	0	0.0%
NUG & Other	86	4.5%	68	3.4%
Total	1,903		1,997	

Source: 2025 TYSP and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 35 displays the forecast planning reserve margin for GRU through the planning period for both seasons. As shown in the figure, GRU's generation needs are controlled by its summer peak throughout the planning period.

Figure 35: GRU Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

GRU currently plans on retiring three natural gas-fired units, as described in Table 21. All three units, a pair of combustion turbines and a steam turbine, are located at GRU's Deerhaven plant.

Table 21: GRU Generation Resource Changes

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

Source: 2025 TYSP

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 2025 TYSP suitable for planning purposes.

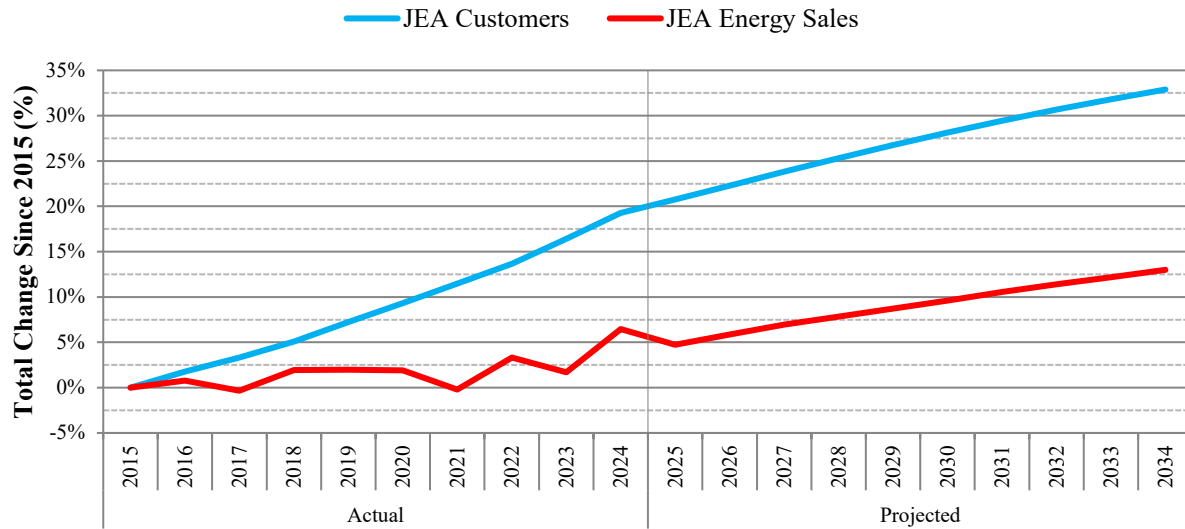
Load & Energy Forecasts

In 2024, JEA had approximately 527,491 customers and annual retail energy sales of 12,873 GWh, accounting for approximately 5.2 percent of Florida's annual retail energy sales. Over the last 10 years, JEA's customer base has increased by approximately 19.3 percent, while retail energy sales have increased by approximately 6.5 percent.

JEA indicated that the utility-funded DSM programs continue to be a contributor to the decrease in residential UPC. The other contributing factors include customer behavioral changes, increased electric rates, and more multifamily housing construction (such housing features lower UPC compared to single-family housing). The Utility noted that the U.S. Government's SEER Requirement Changes for 2015 requiring new split system central air conditioners to be a minimum 14 SEER was the primary reason for the decrease in electricity UPC in years subsequent to the new standard. The Utility 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 UPC. For the 2025 TYSP forecasting horizon, JEA expects that residential UPC will stay flat with an average growth rate of 0.4 percent, commercial UPC will decrease by 1.1 percent per year, and industrial UPC will decrease by 0.2 percent per year.

For the next 10 years, JEA's customer base is forecasted to grow at an average annual rate of 1.1 percent; while its retail energy sales are projected to increase at an average annual rate of 0.9 percent. Figure 36 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that JEA filed in its 2025 TYSP.

Figure 36: JEA Growth



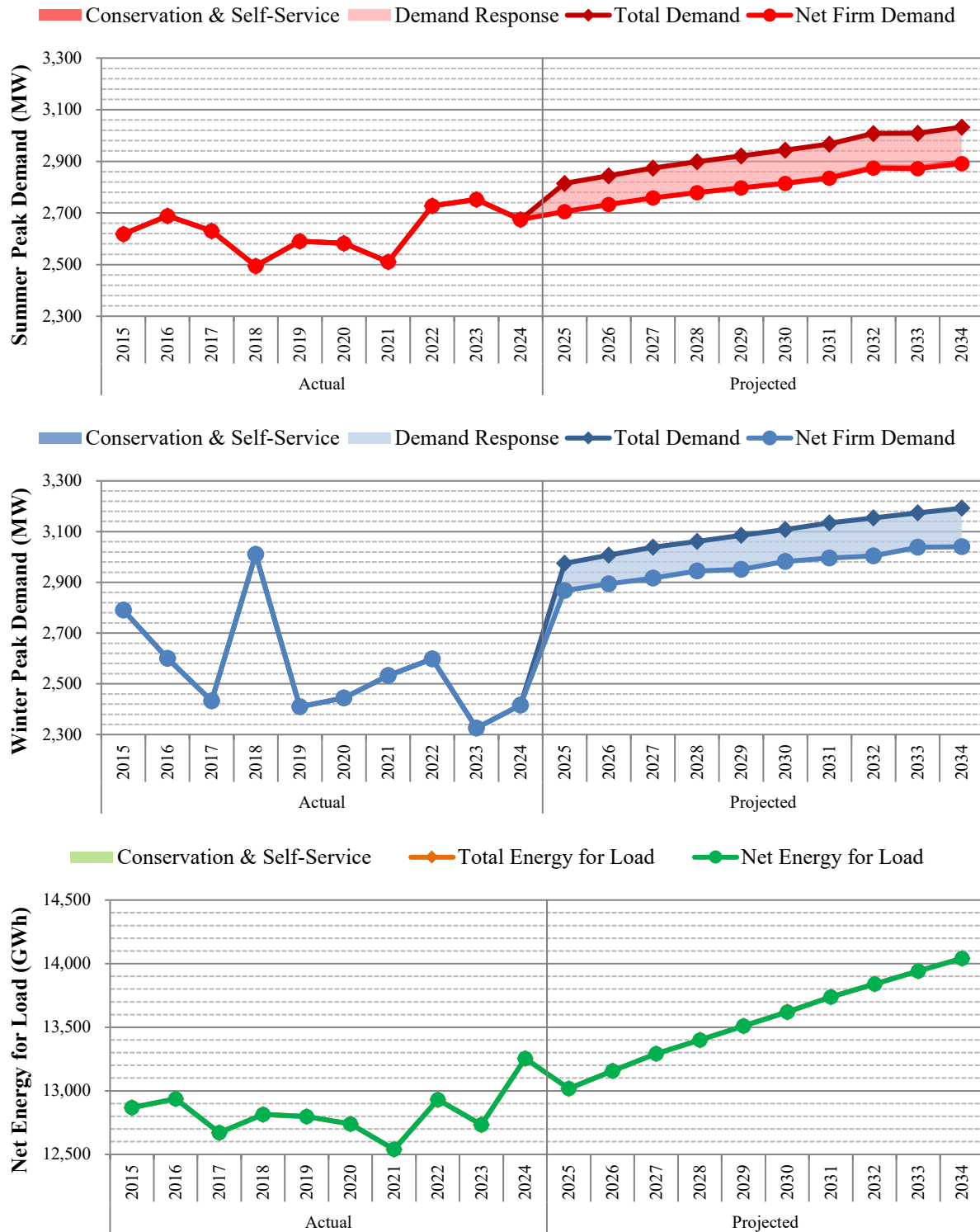
Source: 2025 TYSP

The three graphs in Figure 37 show JEA’s seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. Even though JEA is a municipal utility, it 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 DSM, and assume that all available demand response resources will be activated during the seasonal peak. The Commission reviewed and established energy conservation goals for JEA and approved JEA’s 2025-2034 DSM Plan.^{19,20} In preparing its 2025 TYSP seasonal peak demand and energy forecasts, JEA reflects these Commission-approved FEECA goals through the forecast period (through 2034), as shown in Figure 37.

¹⁹ Order No. PSC-2024-0432-FOF-EG, issued September 20, 2024, in Docket No. 20240016-EI, *In re: Commission review of numeric conservation goals (JEA)*.

²⁰ Order No. PSC-2025-0094-PAA-EG, issued March 24, 2025, in Docket No. 20240167-EG, *In re: Petition for approval of demand-side management plan, by JEA*.

Figure 37: JEA Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 22 shows JEA's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. While natural gas was the dominant fuel source in 2024, purchases from other utilities, through the Interchange, was JEA's second most utilized energy source. JEA has the highest percentage of energy from other utilities, primarily from a contract with the Municipal Electric Authority of Georgia for 200 MW from the Vogtle nuclear Units 3 and 4. JEA is projected to reduce its Interchange purchases from approximately 28 percent in 2024 to 15 percent in 2034, primarily offset by an increase in renewables, which will represent 20 percent of energy by 2034.

Table 22: JEA Energy Generation by Fuel Type

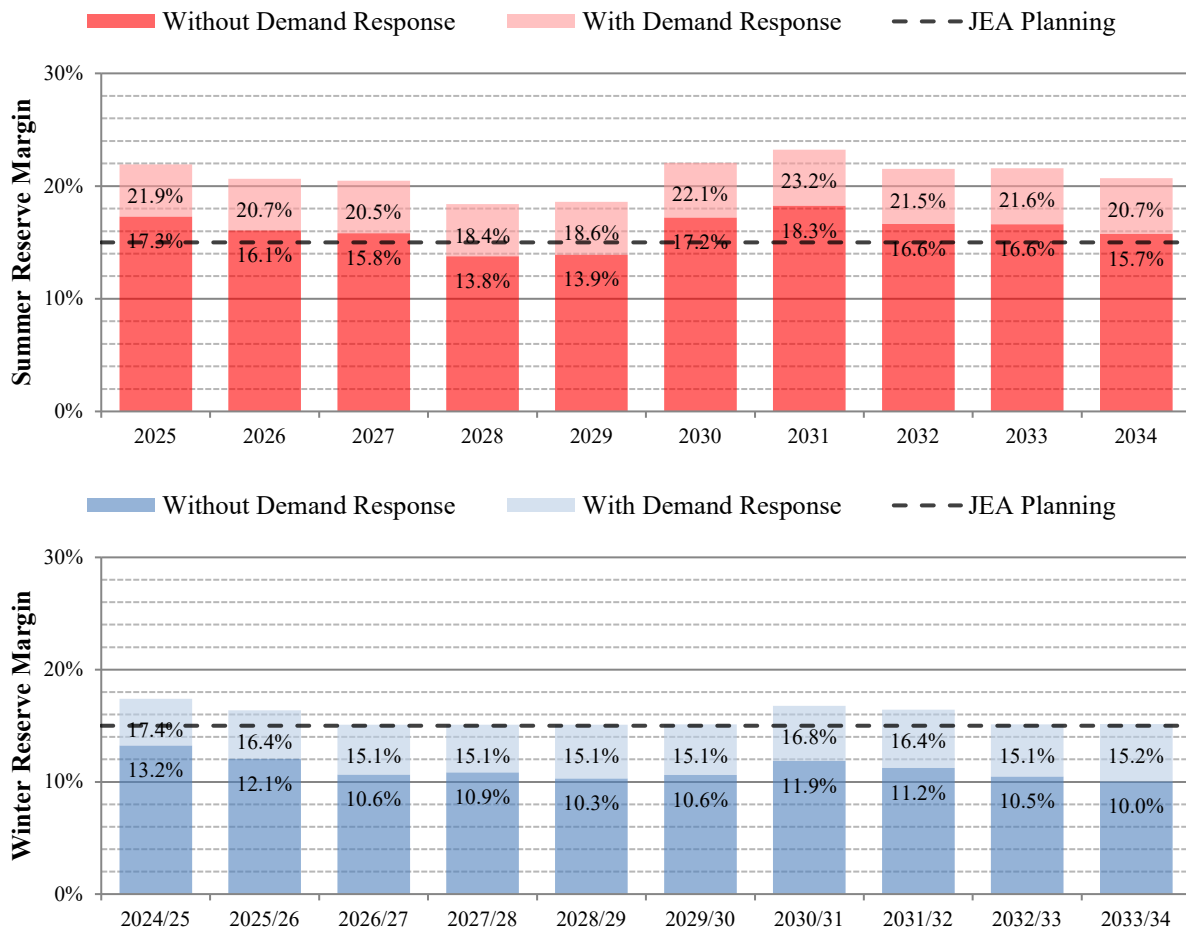
Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	8,257	62.3%	8,172	58.2%
Coal	774	5.8%	986	7.0%
Nuclear	0	0.0%	0	0.0%
Oil	8	0.1%	9	0.1%
Renewable	507	3.8%	2,832	20.2%
Interchange	3,676	27.7%	2,044	14.6%
NUG & Other	32	0.2%	0	0.0%
Total	13,254		14,043	

Source: 2025 TYSP and Data Responses

Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 38 displays the forecast planning reserve margin for JEA through the planning period for both seasons, with and without the use of demand response. JEA's current and planned PPA with solar generators contribute to this shift in planning because solar resources provide coincident capacity during the summer peak but not the winter peak. Over the planning horizon, JEA's winter reserve margin is lower than its summer reserve margin.

Figure 38: JEA Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

JEA projects one unit retirement and one unit addition during the planning period, as described in Table 23. JEA plans on retiring Northside Unit 3 and adding an unnamed natural gas-fired combined cycle unit in 2030. The unnamed combined cycle would be subject to PPSA approval and it is anticipated a filing with the Commission would occur in 2026. JEA also includes in its resource planning PPAs with 18 solar facilities totaling 1,129 MW, including 2 with collocated batteries totaling 100 MW, over the planning period.

Table 23: JEA Energy Generation by Fuel Type

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

Source: 2025 TYSP

Lakeland Electric (LAK)

LAK is a municipal utility and the state's third smallest electric utility required to file a TYSP. 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 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

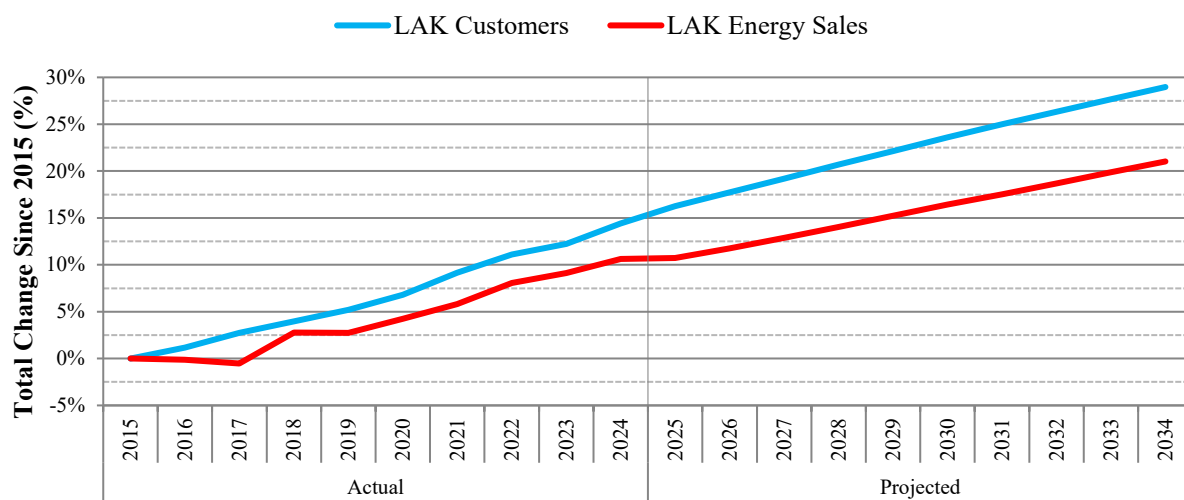
In 2024, LAK had approximately 143,790 customers and annual retail energy sales of 3,356 GWh, accounting for approximately 1.4 percent of Florida's annual retail energy sales. In the same year, the Utility's total customer growth and total retail sales growth were approximately 1.9 percent and 1.4 percent, respectively. Historically, the Utility has experienced a steady growth in residential and commercial customers due to a rise in population in the Lakeland area. The number of industrial customers are relatively stable with most industry being manufacturing or distribution centers. Over the last 10 years, LAK's customer base has increased by 14.4 percent, while retail energy sales have grown by approximately 10.6 percent.

LAK's residential UPC has slightly increased as more customers continue to work from home, leading to higher daytime energy consumption which is an ongoing trend that emerged following the COVID-19 pandemic. Both LAK's commercial and industrial UPCs decreased slightly which is attributed to energy efficient buildings and appliances. Additionally, customer's movement to rooftop solar has contributed in offsetting the energy usage from the grid. LAK projects that the UPC of each rate class and the total UPC will continue to decrease, and perceived that the factors contributing to the decline is appliance efficiency improvement and new homes being built to be more efficient.

For the next 10 years, LAK's forecasts indicate that its 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 1.0 percent. The Utility identified the factors contributing to the growth of sales are continuous population increase and economic development. Also contributing to the sales growth is the warmer weather expected.

Figure 39 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that LAK filed in its 2025 TYSP.

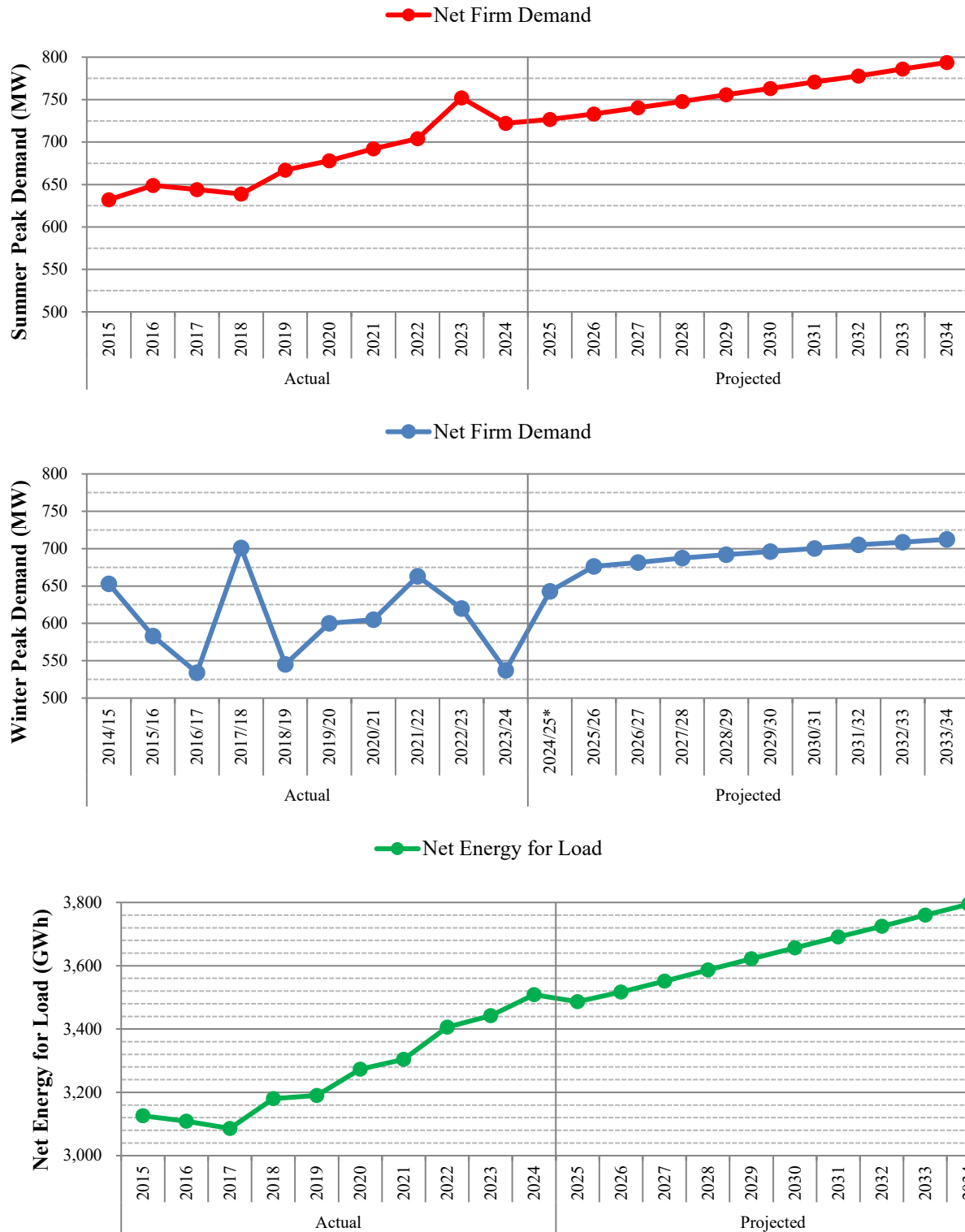
Figure 39: LAK Growth



Source: 2025 TYSP

The three graphs in Figure 40 show LAK's seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. LAK offers energy efficiency programs, the impacts of which are included in the graphs.

Figure 40: LAK Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 24 shows LAK’s actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. LAK uses natural gas as its primary fuel type for energy, 75 percent in 2024, with purchases (listed in the NUG & Other category) representing 24 percent net energy for load, and the remaining 1 percent from renewables. By 2034, natural gas is expected to be reduced to 64 percent, offset by purchases and renewables, which would represent 31 and 5 percent, respectively. LAK, in the actual and projected period, is the utility most reliant upon energy purchases.

Table 24: LAK Energy Generation by Fuel Type

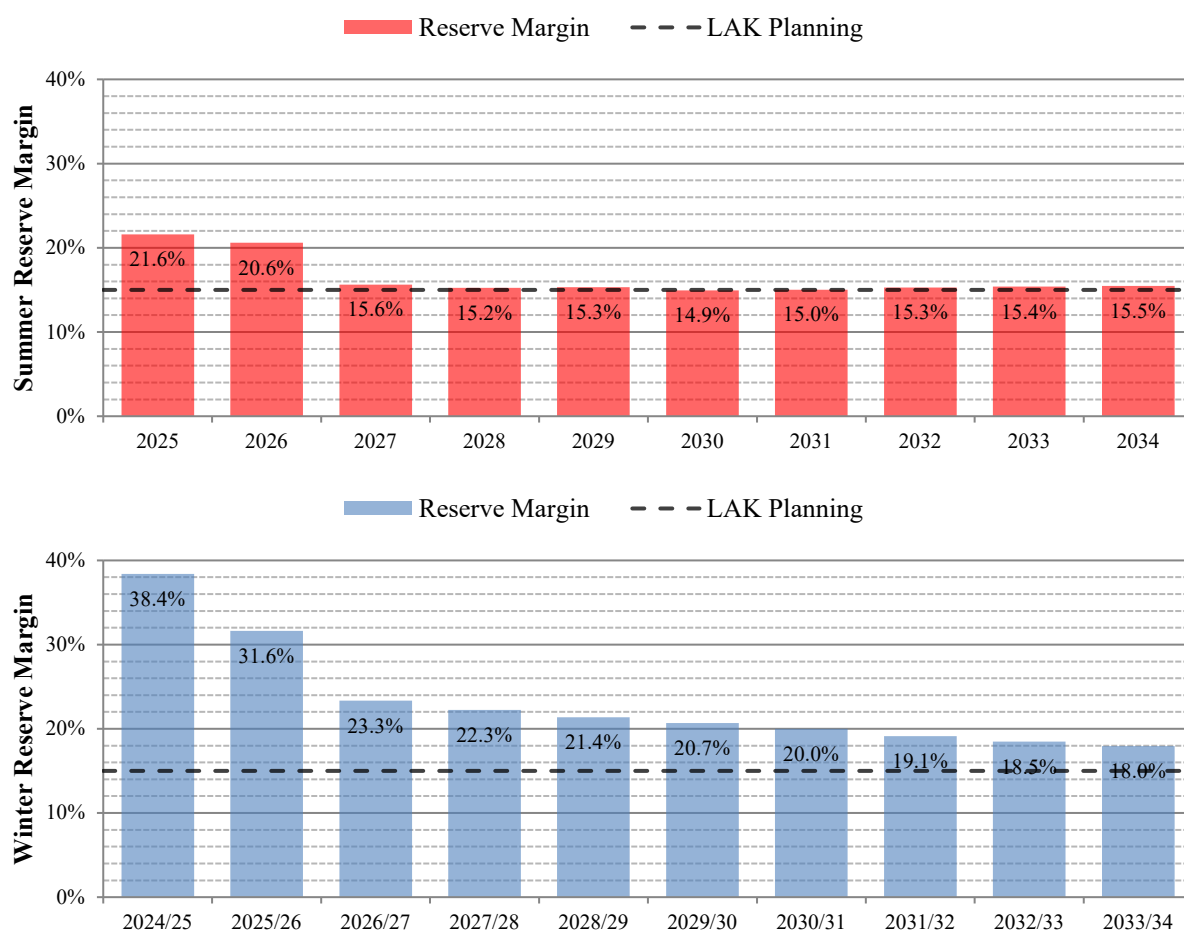
Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	2,643	75.3%	2,408	63.5%
Coal	0	0.0%	0	0.0%
Nuclear	0	0.0%	0	0.0%
Oil	0	0.0%	0	0.0%
Renewable	28	0.8%	194	5.1%
Interchange	0	0.0%	0	0.0%
NUG & Other	838	23.9%	1,192	31.4%
Total	3,509		3,794	

Source: 2025 TYSP and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 41 displays the forecast planning reserve margin for LAK through the planning period for both seasons. LAK does not offer demand response programs at this time. As illustrated by Figure 41, summer peak demand is the controlling factor for reliability planning for almost all years of the planning period.

Figure 41: LAK Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

LAK projects three unit additions during the planning period, as described by Table 25. The additions are all natural gas-fired internal combustion engines, with a capacity of 20 MW and an in-service date of 2025. Three similar units entered service in 2024. LAK is in negotiations for a PPA with Edge Solar for a 74.8 MW solar facility by 2026. None of these additions requires a need determination pursuant to the PPSA.

Table 25: LAK Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Notes
			Sum	
Retiring Units				
	None			
Total Retirements			0	
New Units				
2025	McIntosh Units MREP 1-3	IC NG	60	3 Units
Total New Units			60	
Net Additions			60	

Source: 2025 TYSP 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 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

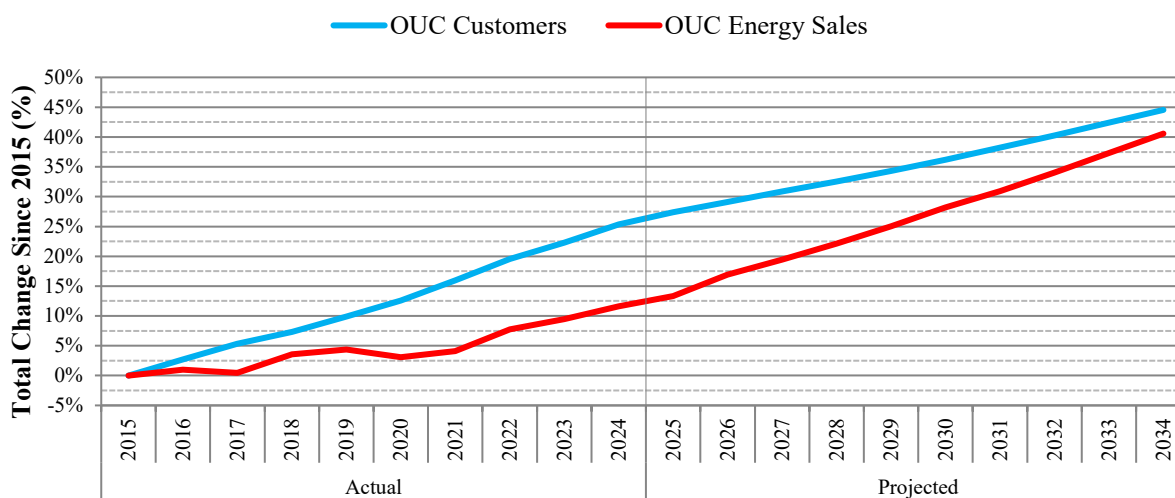
In 2024, OUC had approximately 282,179 customers and annual retail energy sales of 7,295 GWh, accounting for approximately 3.0 percent of Florida's annual retail energy sales. Over the last 10 years, OUC's customer base has increased by 25.4 percent, while its retail energy sales have increased by 11.6 percent, approximately.

OUC acknowledged that over the past 10 years, its UPC has been essentially flat for both the residential and commercial customer segments. For the next 10 years, OUC's residential UPC is expected to grow 1.9 percent annually. The main driver of this increase is the projected adoption of EVs. The Utility's commercial UPC is expected to grow 1.2 percent annually. This increase is driven by large customer expansions which increase overall commercial sales.

Over the forecast horizon, OUC is projecting growth in the number of customers at an average annual rate of 1.4 percent, and growth in retail energy sales at an average annual rate of 2.4 percent, approximately. The Utility indicates that this projected increase is driven by large commercial expansions and residential EV adoption.

Figure 42 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that OUC filed in its 2025 TYSP.

Figure 42: OUC Growth



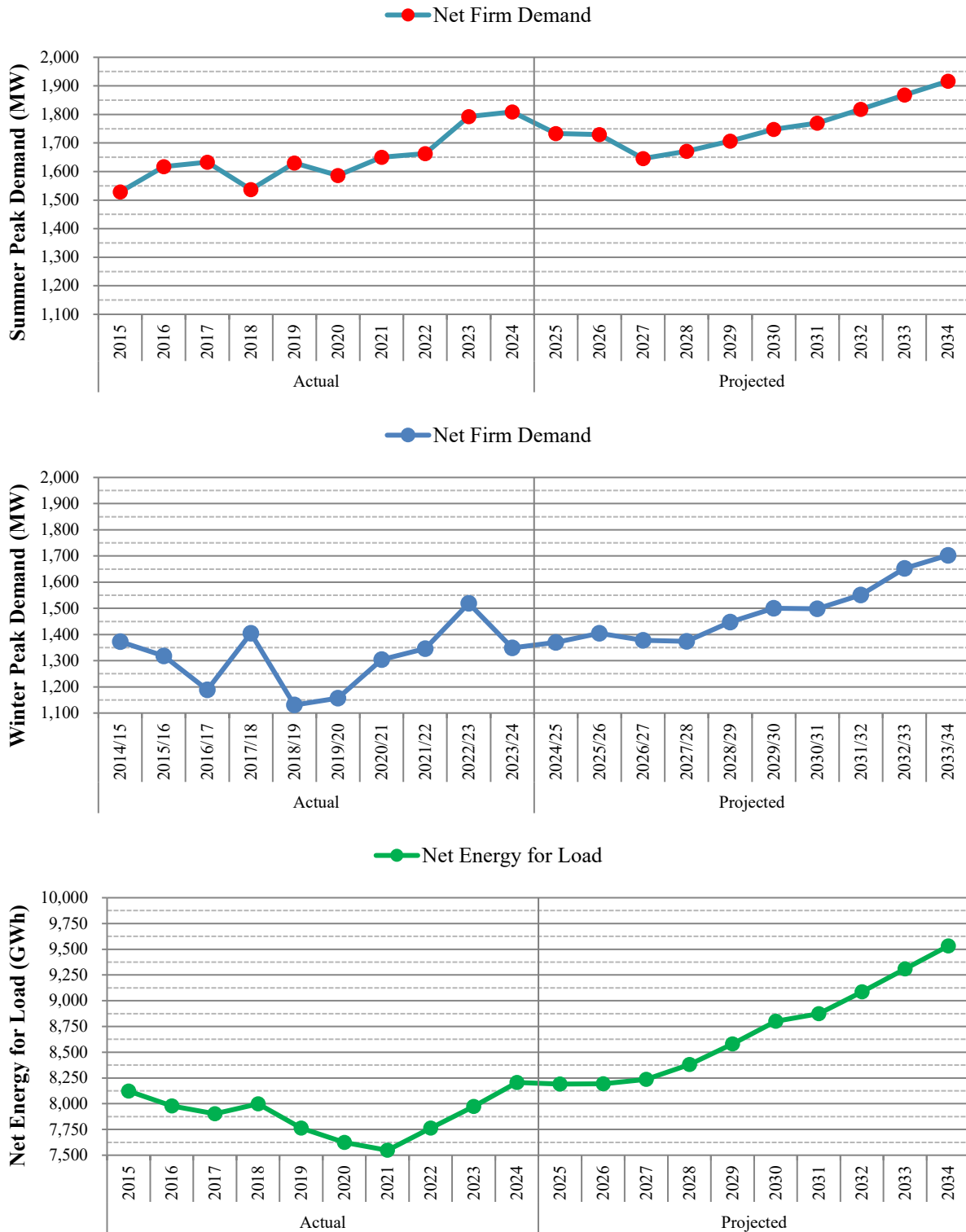
Source: 2025 TYSP

The three graphs in Figure 43 show OUC’s seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. These graphs include the impact of the Utility’s DSM 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. The Commission reviewed and established energy conservation goals for OCU and approved OUC’s 2025-2034 DSM Plan.^{21,22} In preparing its 2025 TYSP seasonal peak demand and energy projects, OUC reflects these Commission-approved FEECA goals will be extended through the forecast period (through 2034), as shown in Figure 43.

²¹ Order No. PSC-2024-0433-FOF-EG, issued September 20, 2024, in Docket No. 20240017-EI, *In re: Commission review of numeric conservation goals (Orlando Utilities Commission)*.

²² Order No. PSC-2025-0086-PAA-EG, issued March 24, 2025, in Docket No. 20240166-EG, *In re: Petition for approval of 2025 demand-side management plan, by Orlando Utilities Commission*.

Figure 43: OUC Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 26 shows OUC's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. In 2024, approximately 70 percent of OUC's net energy for load was met with natural gas, while coal, the second most-used fuel, met approximately 20 percent of the demand. By 2034, OUC will be one of three utilities, along with FPL and GRU, to use natural gas for less than half of its energy generation, and the only utility to use renewable energy for a majority of its energy generation.

Table 26: OUC Energy Generation by Fuel Type

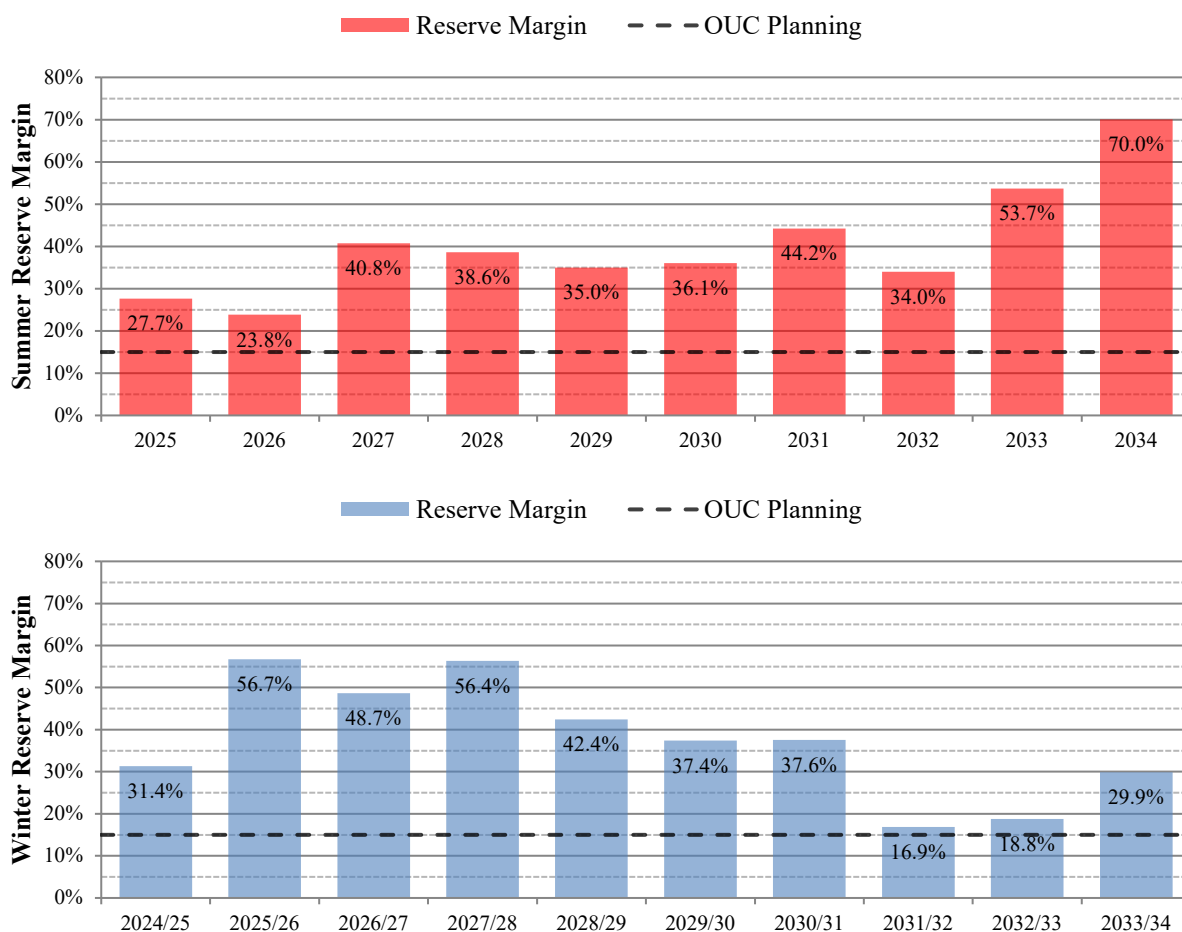
Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	5,753	70.1%	4,230	44.4%
Coal	1,608	19.6%	0	0.0%
Nuclear	433	5.3%	511	5.4%
Oil	4	0.0%	0	0.0%
Renewable	408	5.0%	4,791	50.3%
Interchange	0	0.0%	0	0.0%
NUG & Other	0	0.0%	0	0.0%
Total	8,206		9,532	

Source: 2025 TYSP and Data Responses

Reliability Requirements

OUC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 44 displays the forecast planning reserve margin for OUC through the planning period for both seasons, including the impact of DSM programs. As shown in the figure, OUC's generation needs are controlled by its summer peak demand.

Figure 44: OUC Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

OUC projects one unit retirement during the planning period, as described in Table 27. OUC plans on retiring Stanton Energy Center Unit 1, a jointly owned unit with FMPA and other utilities, in 2025. OUC is also converting its last remaining coal-fired Stanton Energy Center Unit 2 to a natural gas-fired unit in 2028. Transmission upgrades planned for 2025 and 2026 will allow OUC full access to the firm capacity of its existing three natural gas-fired combustion turbines acquired from the Osceola merchant plant, for a total of 471 MW. OUC also includes in its resource planning PPAs with several solar and battery facilities, including a total of 1,490 MW of solar and 800 MW of batteries over the planning period.

Table 27: OUC Generation Resource Changes

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

Source: 2025 TYSP

Seminole Electric Cooperative (SEC)

SEC is a generation and transmission rural electric cooperative that serves its member distribution 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 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

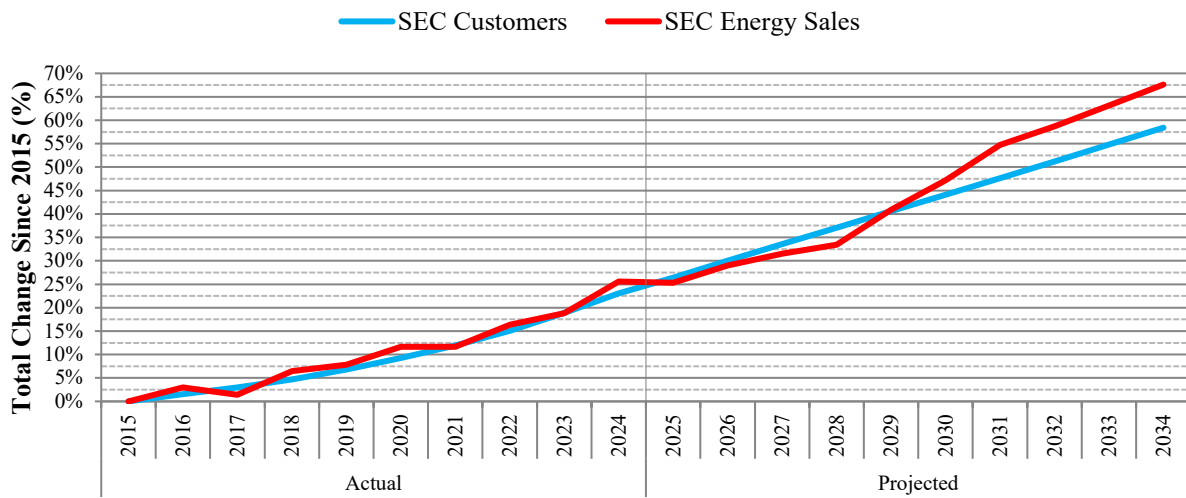
In 2024, SEC member cooperatives had approximately 925,329 customers and annual retail energy sales of 16,792 GWh, accounting for approximately 6.8 percent of Florida's annual retail energy sales. Over the last 10 years, SEC's customer base has increased by 23.1 percent, while its retail energy sales have increased by approximately 25.6 percent.

Over the past 10 years, for SEC's combined members (hereinafter the Membership), average UPC has remained relatively stable, with the residential sector increasing annually by 0.3 percent on average, and the commercial sector decreasing annually by 0.4 percent on average. These trends reflect the widespread adoption of more efficient residential and commercial appliances and equipment. For the next 10 years, across the Membership, the UPC is expected to increase by 2.4 percent annually in average, with diverging trends by customer type. Residential UPC is expected to decrease by 0.9 percent and commercial UPC is expected to increase by 3.2 percent annually. The forecasted slight decline in residential UPC is due primarily to the continued replacement of older appliances and equipment with more energy-efficient models. In contrast, the projected increase in commercial UPC is due to the expectation of more energy-intensive customers, which offset any efficiency-driven declines.

Over the current 10-year forecast horizon, SEC is projecting an average annual growth rate in its customer base of 2.5 percent. The major factors contributing to the growth are continued positive net migration and growth in regional housing. SEC's projected average annual growth rate in retail energy sales is 3.3 percent.

Figure 45 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that SEC filed in its 2025 TYSP.

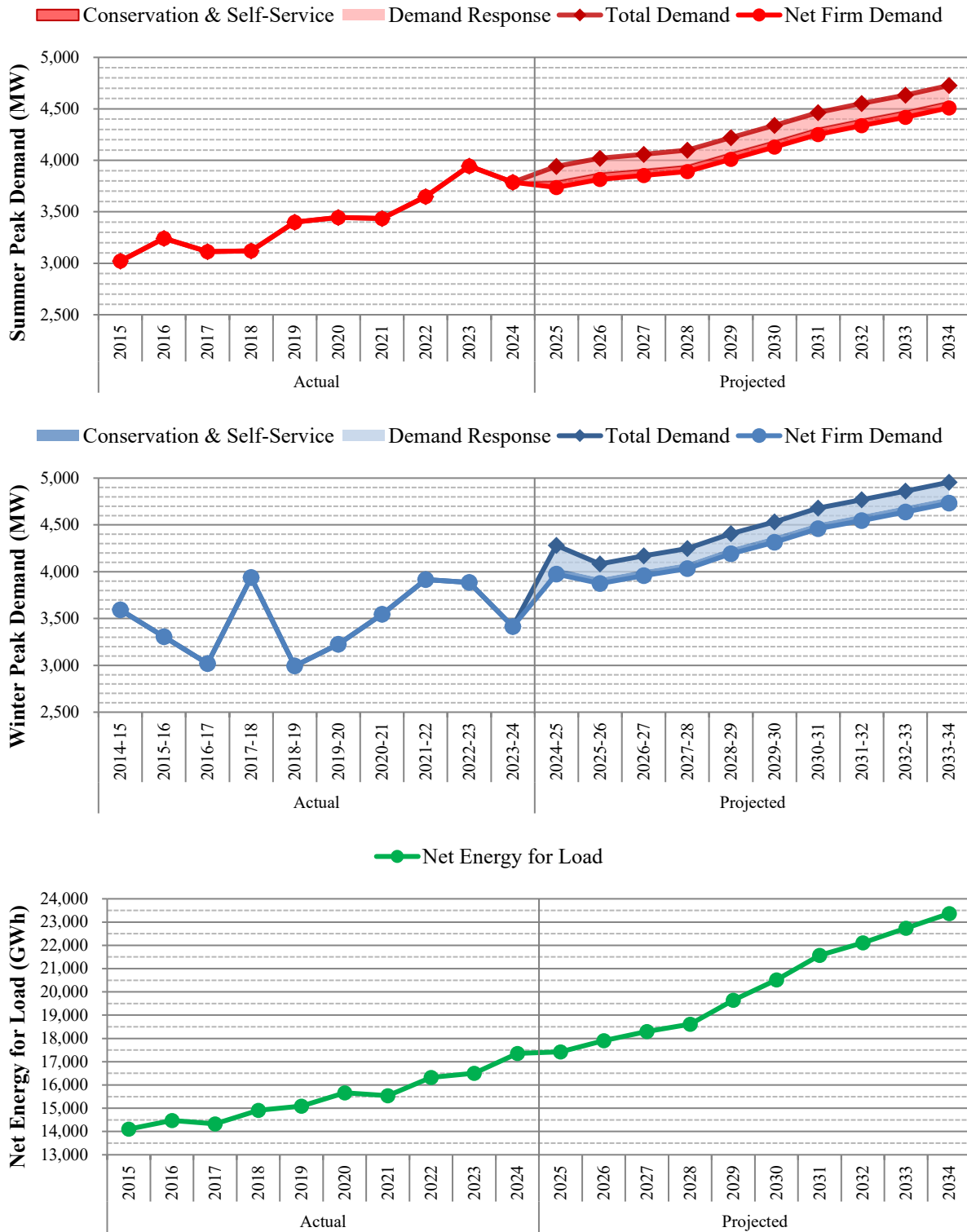
Figure 45: SEC Growth



Source: 2025 TYSP

The three graphs in Figure 46 show SEC’s seasonal peak demand and net energy for load for the historic years 2015 through 2024 and forecast years 2025 through 2034. As SEC is a generation and transmission company, it does not directly engage in energy efficiency or demand response programs. Member cooperatives do offer DSM programs, the impacts of which are included in Figure 46.

Figure 46: SEC Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 28 shows SEC's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. In 2024, natural gas was SEC's primary fuel, at 62 percent, with purchases making up approximately 20 percent, the second highest in the state. During the planning period, SEC is projected to increase its self-generation, primarily of natural gas, offsetting these purchases and coal generation. By 2034, natural gas will represent approximately 85 percent of SEC's fuel usage.

Table 28: SEC Energy Generation by Fuel Type

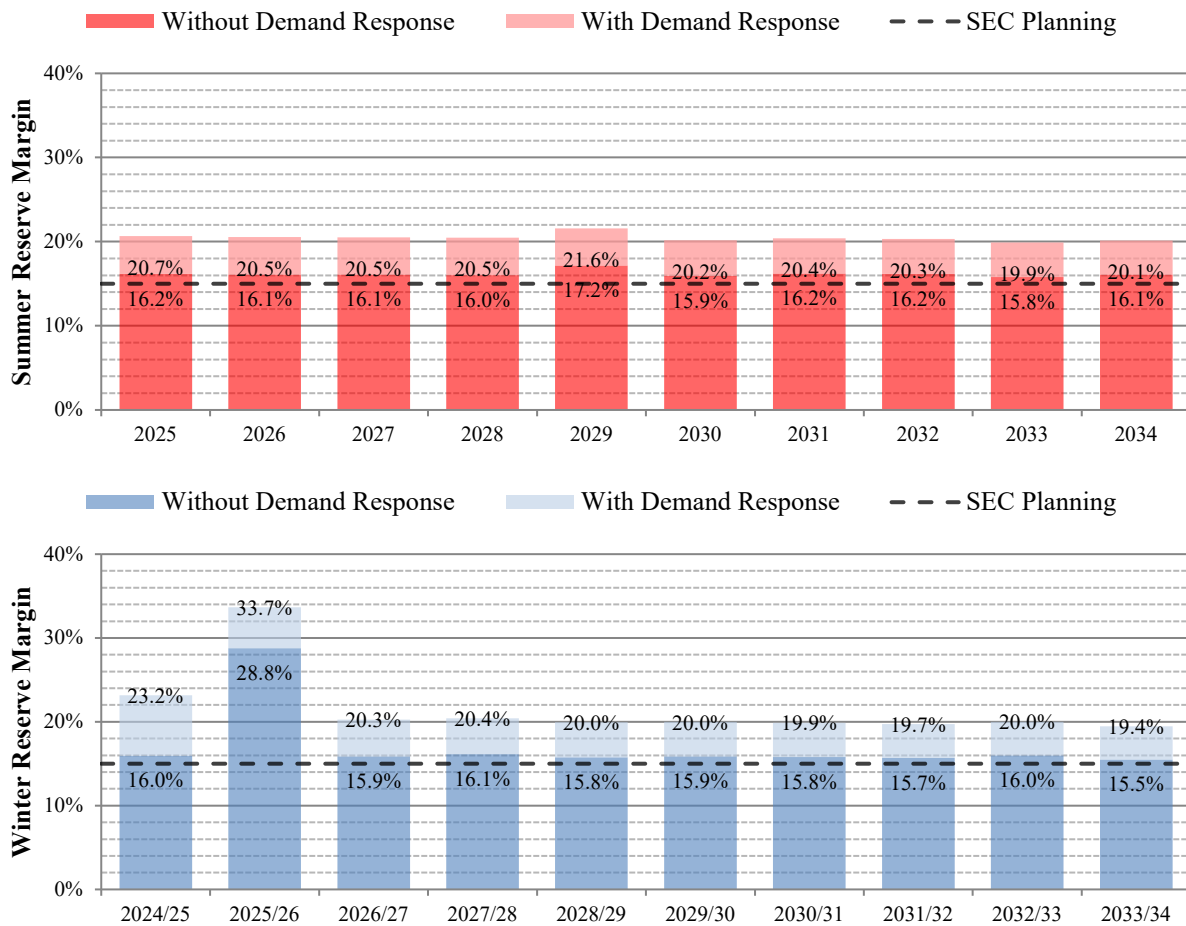
Fuel Type	Net Energy for Load			
	Actual 2024		Projected 2034	
	GWh	%	GWh	%
Natural Gas	10,840	62.4%	19,781	84.6%
Coal	2,197	12.7%	1,965	8.4%
Nuclear	0	0.0%	0	0.0%
Oil	14	0.1%	6	0.0%
Renewable	383	2.2%	703	3.0%
Interchange	455	2.6%	0	0.0%
NUG & Other	3,470	20.0%	913	3.9%
Total	17,359		23,368	

Source: 2025 TYSP and Data Responses

Reliability Requirements

SEC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 47 displays the forecast planning reserve margin for SEC through the planning period for both seasons, with and without the use of demand response. Member cooperatives allow SEC to coordinate demand response resources to maintain reliability. As shown in the figure, SEC's generation needs are determined by winter peak demand more often than summer peak demand during the planning period.

Figure 47: SEC Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

SEC projects four unit additions during the planning period, as described by Table 29. All are natural gas-fired units, including two combined cycle and two simple cycle combustion turbines. The first combined cycle, the Shady Hills Energy Center in 2026, has already received PPSA approval by the Commission. The second combined cycle has a capacity of 559 MW, with an estimated in-service date of 2032. This unnamed combined cycle unit would be subject to PPSA approval and it is anticipated a filing with the Commission would occur in 2028.

Table 29: SEC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Notes
			Sum	
Retiring Units				
	None			
Total Retirements			0	
New Units				
2026	Shady Hills Energy Center Unit 1	NG CC	546	PPSA Approved
2028	Unnamed CT	NG CT	393	
2030	Unnamed CT	NG CT	393	
2032	Unnamed CC	NG CC	559	PPSA Approval Needed
Total New Units			1,891	
Net Additions			1,891	

Source: 2025 TYSP

City of Tallahassee Utilities (TAL)

TAL is a municipal utility and the second smallest electric utility by sales that files a TYSP. 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 2025 TYSP suitable for planning purposes.

Load & Energy Forecasts

In 2024, TAL had approximately 124,241 customers and annual retail energy sales of 2,788 GWh, or approximately 1.1 percent of Florida's annual retail energy sales. Over the last 10 years, TAL's customer base has increased by approximately 5.4 percent, while retail energy sales have increased by approximately 5.0 percent.

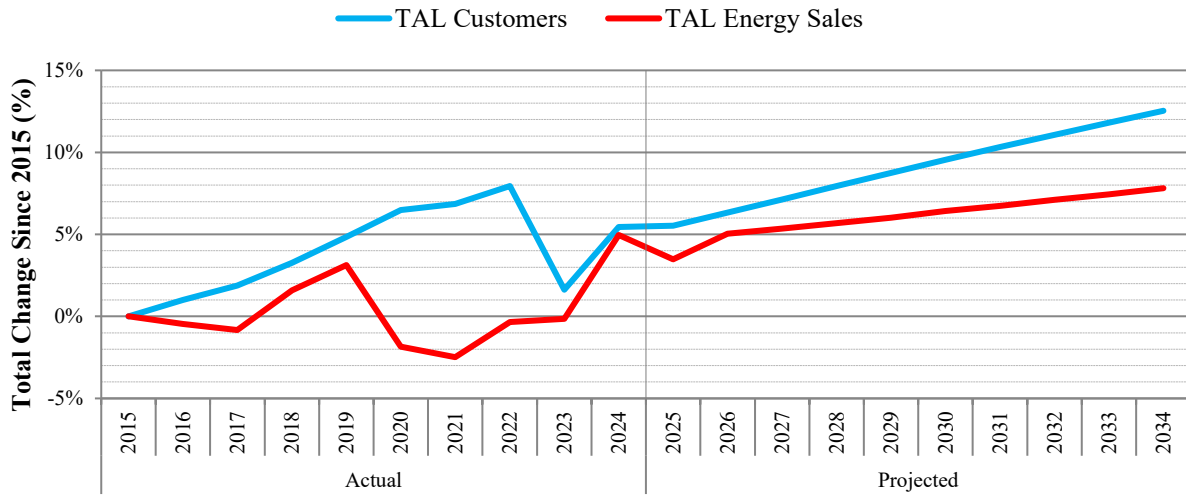
TAL noticed that, historically, both its residential and commercial UPC fluctuated slightly year-to-year but remained relatively steady over the 10-year period with one exception: a noticeable decrease for commercial customers in the year or two following the COVID-19 pandemic. Other major factors affecting UPC included growth in electrification (e.g., EV, customer-owned solar generation), market-driven efficiencies from upgrading HVAC, DSM incentives, and weather anomalies. Looking forward, TAL predicts that planning period trends in residential UPC will closely match the historical trends. The Utility indicates that the underlying economic factors that influence commercial growth in the planning period are often at odds with the gains from DSM and market-driven efficiencies. TAL is forecasting increased commercial activity, which will result in an increase in the commercial UPC, even with a slight offset from efficiency measures. The resulting trend in commercial UPC is increasing in the near future and then decreasing in later years as market-driven efficiencies and DSM measures build momentum over time.

In 2024, TAL's total customer growth and total retail sales growth are approximately 3.8 percent and 5.1 percent, respectively. Over the current forecast horizon, TAL is projecting an average annual growth rate of approximately 0.7 percent in its total customers, and an average annual growth rate of approximately 0.5 percent in its annual retail energy sales.

In 2023, TAL implemented new customer billing software, which changed the methodology of accounting for customer types and consolidated some service points. The resulting data anomaly showed an increase in average residential consumption, a decrease in average commercial consumption, and an overall reduction in service points. Since the software implementation is now complete, the Utility noted that its data collection issues should not persist on a going-forward basis. However, TAL indicates that with 2023 data remaining in the Utility's historical data as a step change, this anomaly or non-weather event-caused step change will continue to be noted in future reports.

Figure 48 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that TAL filed in its 2025 TYSP.

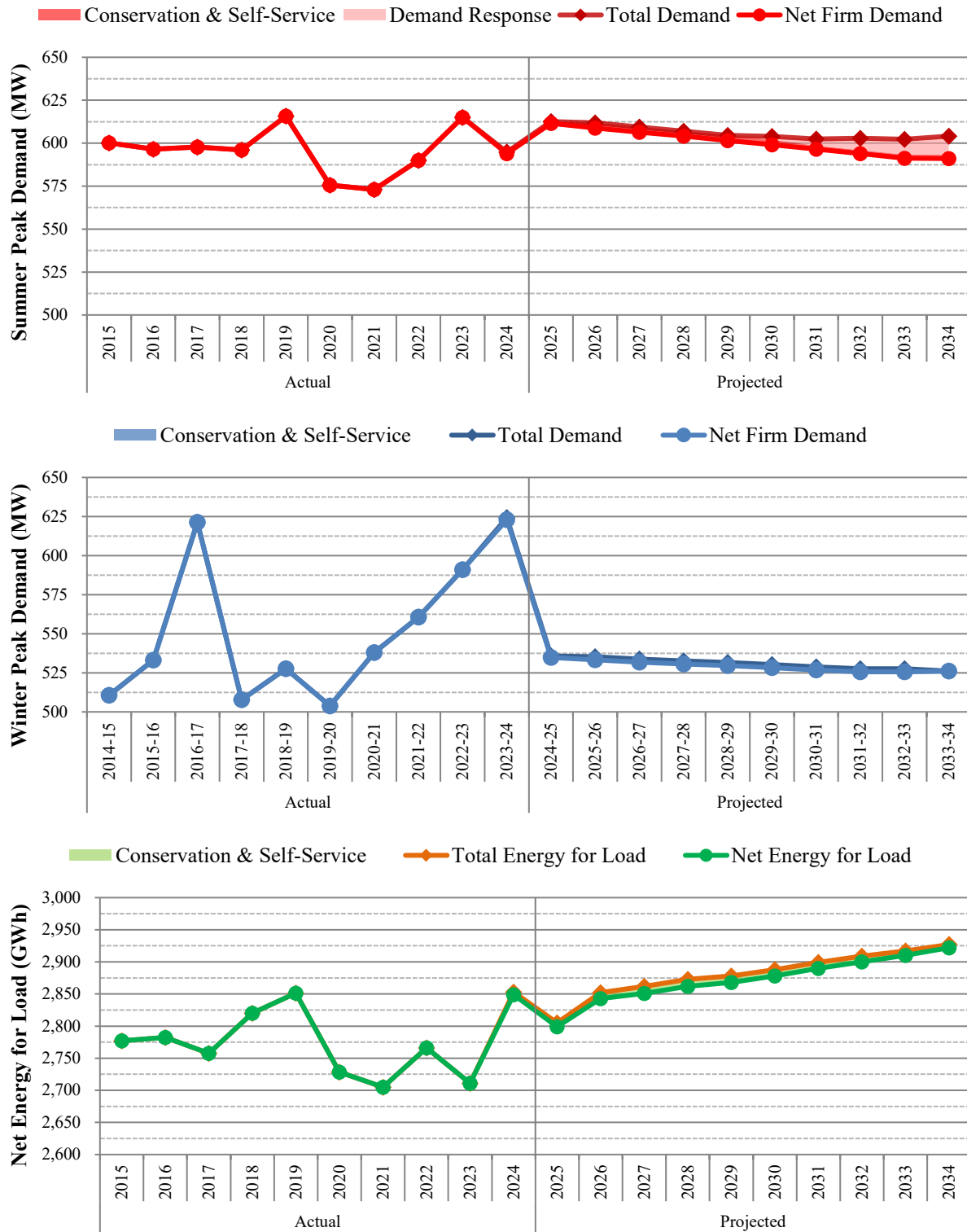
Figure 48: TAL Growth



Source: 2025 TYSP

The three graphs in Figure 49 show TAL's seasonal peak demand and net energy for load for the historic years of 2015 through 2024 and forecast years 2025 through 2034. These graphs include the impact of DSM, and for future years reflect 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 that target appliances contributing to summer peak, and therefore have no effect upon winter peak.

Figure 49: TAL Demand and Energy Forecasts



Source: 2025 TYSP

Fuel Diversity

Table 30 shows TAL's actual net energy for load by fuel type as of 2024 and the projected fuel mix for 2034. TAL relies almost exclusively on natural gas for its generation, excluding some purchases from other utilities and QF. In 2024, TAL produced more energy than required for its native load and was a net exporter by approximately 8 percent, primarily of off-peak power during shoulder months due to its generation's operating characteristics. Natural gas is anticipated to remain the primary fuel source on the system and TAL will continue to be a net exporter of energy throughout the period.

Table 30: TAL Energy Generation by Fuel Type

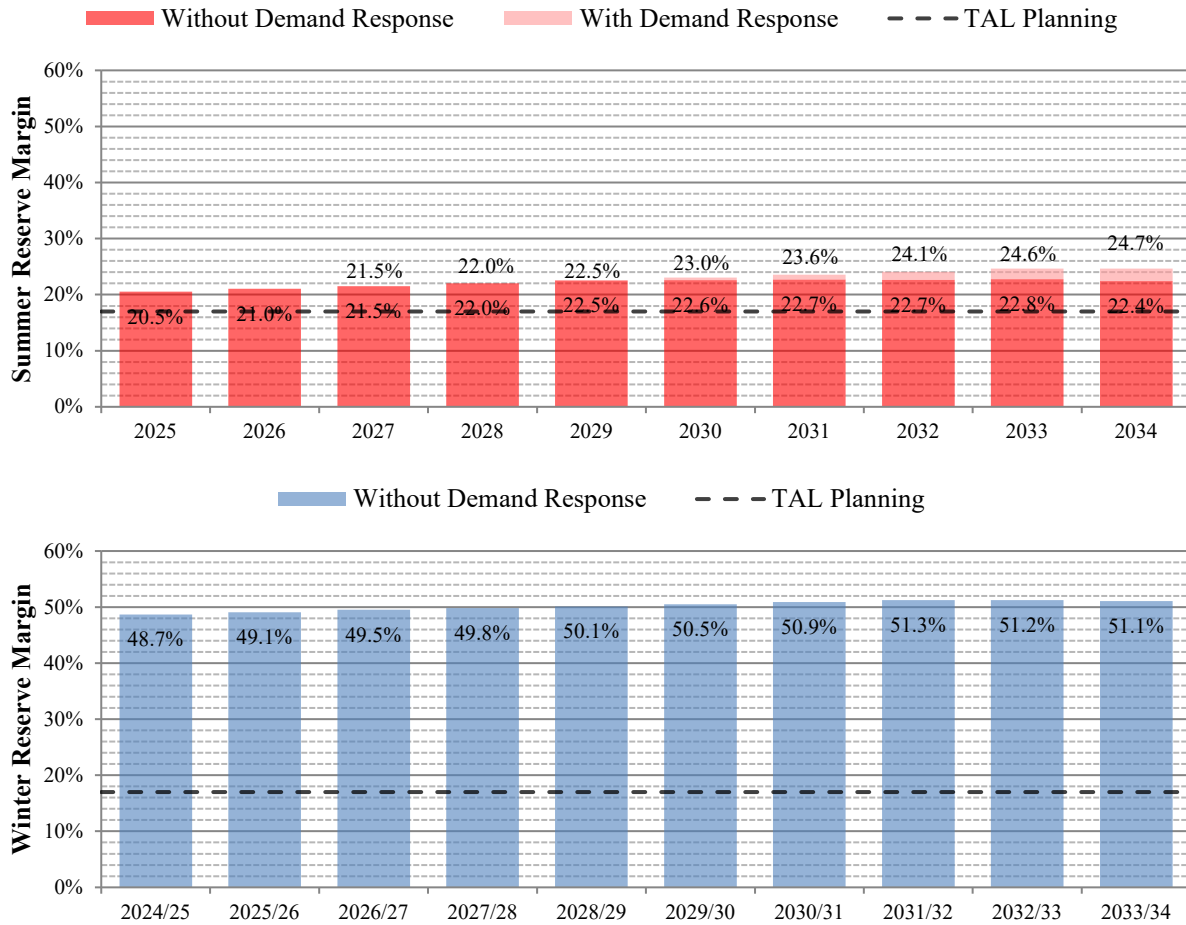
Fuel Type	Net Energy for Load			
	2024		2034	
	GWh	%	GWh	%
Natural Gas	2,985	104.8%	2,846	97.4%
Coal	0	0.0%	0	0.0%
Nuclear	0	0.0%	0	0.0%
Oil	0	0.0%	0	0.0%
Renewable	96	3.4%	111	3.8%
Interchange	0	0.0%	0	0.0%
NUG & Other	(232)	(8.1%)	(35)	(1.2%)
Total	2,849		2,922	

Source: 2025 TYSP and Data Responses

Reliability Requirements

TAL utilizes a 17 percent planning reserve margin criterion for seasonal peak demand. Figure 50 displays the forecast planning reserve margin for TAL through the planning period for both seasons, with and without the use of demand response. As discussed above, TAL only offers demand response programs applicable to the summer peak. As shown in the figure, TAL's generation needs are controlled by its summer peak throughout the planning period.

Figure 50: TAL Reserve Margin Forecast



Source: 2025 TYSP

Generation Resources

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