REVIEW OF THE

2026 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES



FLORIDA PUBLIC
SERVICE COMMISSION

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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 2026 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 2026 TYSPs include Florida Power & Light Company, Duke Energy Florida, LLC, and Tampa Electric Company. Municipal utilities filing 2026 TYSPs include Florida Municipal Power Agency, Gainesville Regional Utilities, JEA, Lakeland Electric, Orlando Utilities Commission, and City of Tallahassee Utilities. Seminole Electric Cooperative also filed a 2026 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 2026 TYSPs

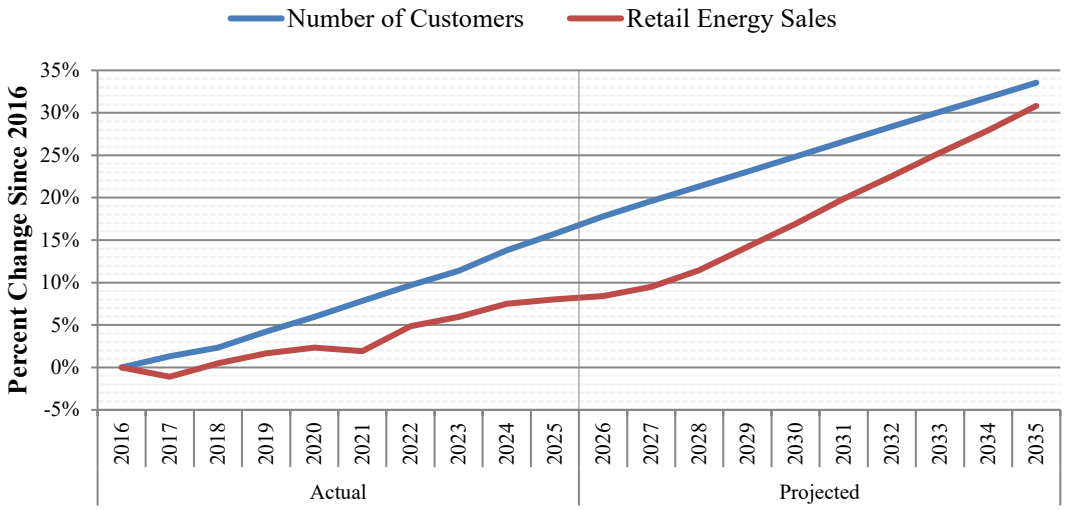
The Commission has divided this review into two portions: (1) a Statewide Perspective, which covers the whole of Florida; and (2) Utility Perspectives, which address each of the reporting utilities. From a statewide perspective, the Commission has reviewed the implications of the combined trends of Florida's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

Load Forecasting

Forecasting customer energy needs or load is a fundamental component of electric utility planning. 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. Figure 1 provides the historical and forecasted trends in customer growth and retail energy sales. Normalized weather trends were used to forecast 2026 through 2035 energy sales, which start slightly above the actual 2025 level and increase annually at 2.1 percent on average.

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

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



Source: FRCC 2026 Regional Load and Resource Plan

Data Centers

Florida utilities currently serve approximately 65 small data centers, none of which have raised reliability concerns due to their demand generally being individually below 10 MW. However, utilities are receiving increased interest from large data center developers with hundreds of MW each, creating the potential for significant future electric load growth. Recently enacted Section 366.043, F.S., defines a large load customer as a customer with an anticipated monthly peak load of 50 MW or more, which would include these large data centers. While some utilities have incorporated anticipated large data center developments into their load forecasts, others have received inquiries without sufficient firm commitments to include substantial new loads in their forecasts. Notably, while SEC included one large load customer addition in its 2026 TYSP, it has since been cancelled, and an adjustment will be made in its 2027 TYSP filing to reflect the cancellation. The methodology used to decide whether to include large load customers varies between utilities, with some reliant upon particular agreements while others use a probabilistic approach. The Commission will continue to monitor how large load customers are included and impact utility forecasts in future TYSPs.

Large data centers may require significant investments in generation and transmission interconnection infrastructure due to their high electricity demand and unique locations. Accordingly, the TYSP utilities are evaluating the potential impacts of data center-driven load growth, including measures to protect existing customers from the risks of potentially stranded costs associated with new or upgraded facilities constructed to serve large data centers.

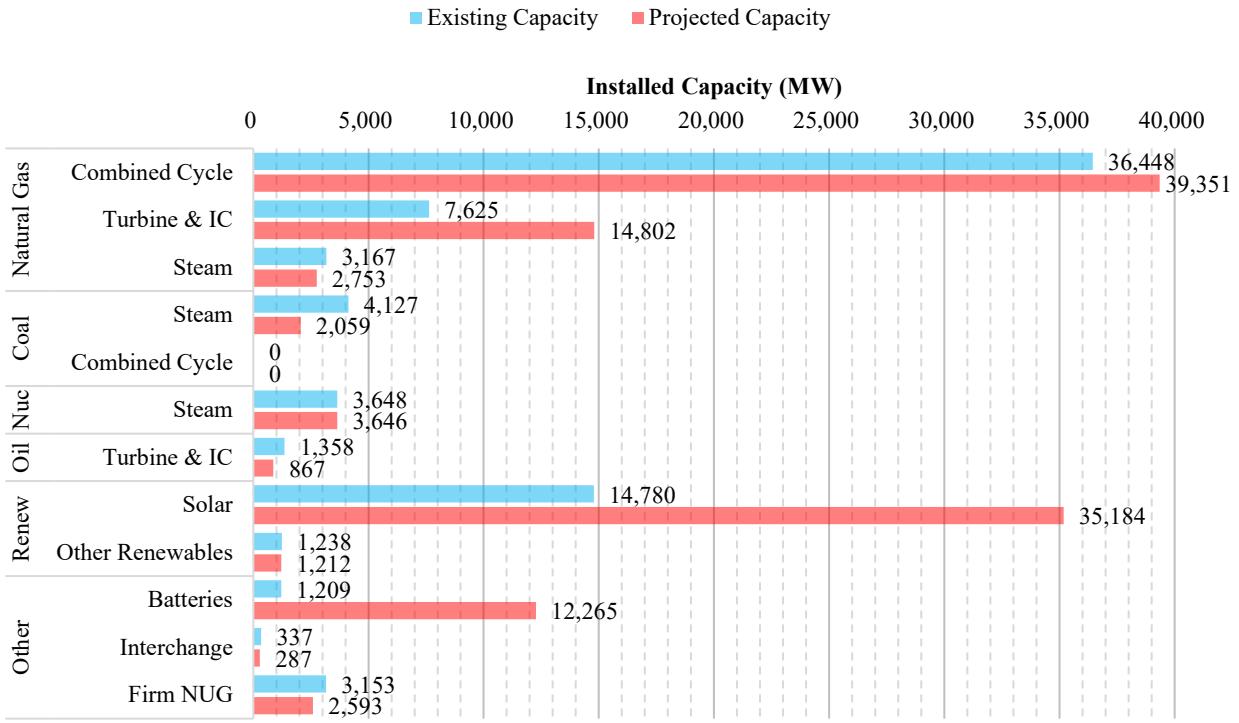
Demand Side Renewables

Florida's electric customers, pursuant to Section 366.91, F.S., have the opportunity to generate their own energy to offset their usage through demand-side renewable energy resources. As of the end of 2025, 319,068 customer installations with a total capacity of 3,150 megawatts (MW) were installed statewide, with the vast majority being solar photovoltaic systems.

Generation Resources

Florida's electric utilities have historically relied upon several different fuel types to serve customer load. 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. Natural gas combined cycle generation is and will remain the single largest source of capacity, with simple cycle and internal combustion gas-fired units approximately doubling over the planning period to maintain their place as the third largest capacity resource. The largest nameplate generation additions are in solar generation and energy storage, which will become the second and fourth largest capacity resources by the end of the planning period. Figure 2 illustrates the current and projected mix of generation resources at the end of 2025 and 2035.[3]

Figure 2: State of Florida - Current and Projected Installed Capacity



Source: FRCC 2026 Regional Load and Resource Plan and TYSP Utilities' Data Responses

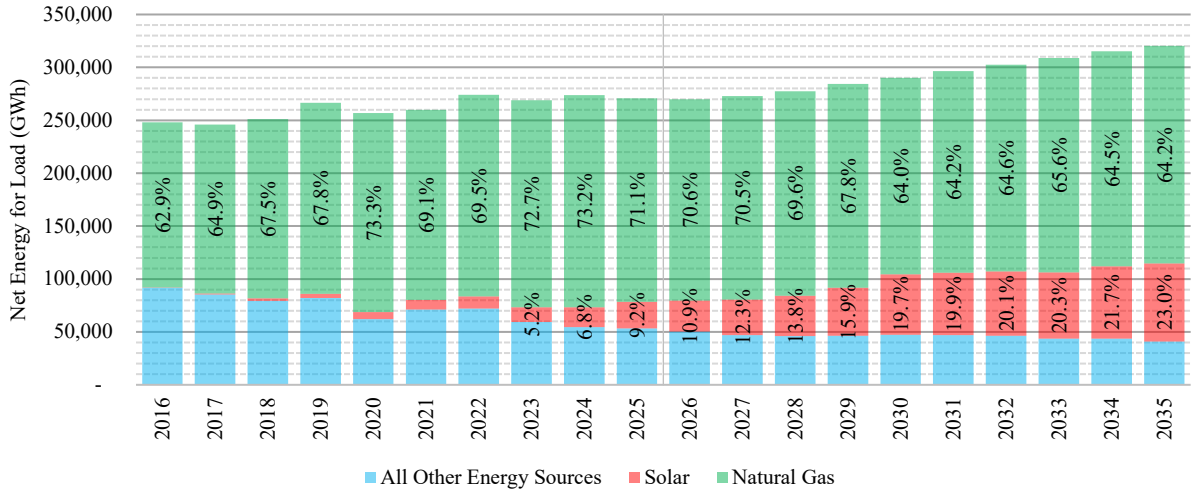
The primary purpose of this review is to provide information regarding proposed electric power plants for local, regional, and state agencies to assist in the certification process. There are two planned units that require a determination of need from the Commission pursuant to Section 403.519, F.S. These units are a pair of 559 MW natural gas-fired combined cycles planned by SEC, with in-service dates in 2032 and 2035. The Commission anticipates a petition for these units no later than 2028 and 2031, respectively.

[3] The installed capacity values include net metering installations, including 3,143.7 MW of solar and 6.3 MW of other renewable capacity.

Fossil Fuels

Generating capacity within Florida is anticipated to grow to meet the increase in customer demand, with an approximate net increase of 7,104 MW of traditional generation over the planning horizon and with natural gas plant additions offset by coal and oil retirements. This is a significant increase from the 2025 TYSPs projections, which was 1,715 MW and is associated with an increase in net firm summer peak demand. Natural gas electric generation, as a percent of Net Energy for Load (NEL), is expected to decline from 71.1 percent in 2025 to 64.2 percent over the planning horizon. Figure 3 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 2030. Solar generation previously exceeded all other renewables combined in 2019, and coal in 2023.

Figure 3: State of Florida - Electricity Generation Sources



Source: FRCC 2017-2026 Regional Load and Resource Plans

Nuclear

Florida's electric industry could experience significant future load growth from the expansion of large data centers, or hyperscalers, potentially requiring substantial investments in new generation and transmission infrastructure. Utilities are actively evaluating the impacts of this growth while also monitoring emerging technologies, including small modular reactors (SMRs), that could shape Florida's future energy landscape.

FPL is actively engaged in advanced nuclear development and plans to begin early site permitting in 2026–2027 for a potential SMR adjacent to an existing nuclear facility, although any resulting unit would be beyond the current 10-year planning period. FPL is also monitoring initiatives by the U.S. Department of Energy and Nuclear Regulatory Commission while recognizing the current costs and uncertainties associated with SMR development. Other TYSP Utilities are similarly monitoring SMRs, citing their long lead times, permitting requirements, and costs.

In the 2026 TYSPs, nuclear electric generation, as a percent of NEL, is expected to decline from 11.3 percent in 2025 to 9.4 percent over the planning horizon. Nationally, the 2026 Annual Energy Outlook projects relatively flat nuclear capacity, with nuclear generation declining from approximately 17 percent of total generation in 2025 to 12 to 15 percent by 2050. As data center demand and emerging generation technologies continue to develop, the Commission will monitor their impacts on resource planning and incorporate material changes into future electric utility TYSPs.

Renewables

Renewable resources continue to expand in Florida, with approximately 16,018 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 92 percent of Florida's existing renewables. Florida's total renewable resources are expected to increase by approximately 20,378 MW over the 10-year planning period, excluding any potential demand-side renewable energy additions. Solar PV accounts for all of this increase.

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 contributes 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 34.9 percent of its capacity, while planned solar is considered firm for only 11.6 percent of its capacity.

Energy Storage

While the first 1.5 MW pilot battery storage facility entered service in 2016, a total of 1,209 MW of battery storage was installed by 2025, and an additional 11,056 MW will enter service by 2035. 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 1,203 MW of existing battery storage and 8,568 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.

Environmental Regulations

Florida's electric utilities must navigate an evolving array of state and federal environmental regulations that could affect existing and planned generation resources. Recent Federal Environmental Protection Agency (EPA) actions have altered the federal greenhouse gas (GHG) regulatory landscape, including proposed repeals of GHG standards for fossil-fuel-fired power plants and the February 2026 rescission of the 2009 GHG Endangerment Finding. Most Florida utilities do not incorporate carbon dioxide (CO_2) compliance costs into resource planning and report no material impacts from current GHG regulations, while FPL includes projected costs beginning in 2036. Utilities remain subject to regulatory uncertainty regarding GHG and some,

such as FPL and JEA, have incorporated GHG compliance considerations into their generation planning. Solar PV and battery storage also may reduce fleet-wide GHG emissions and potential exposure to future environmental regulations.

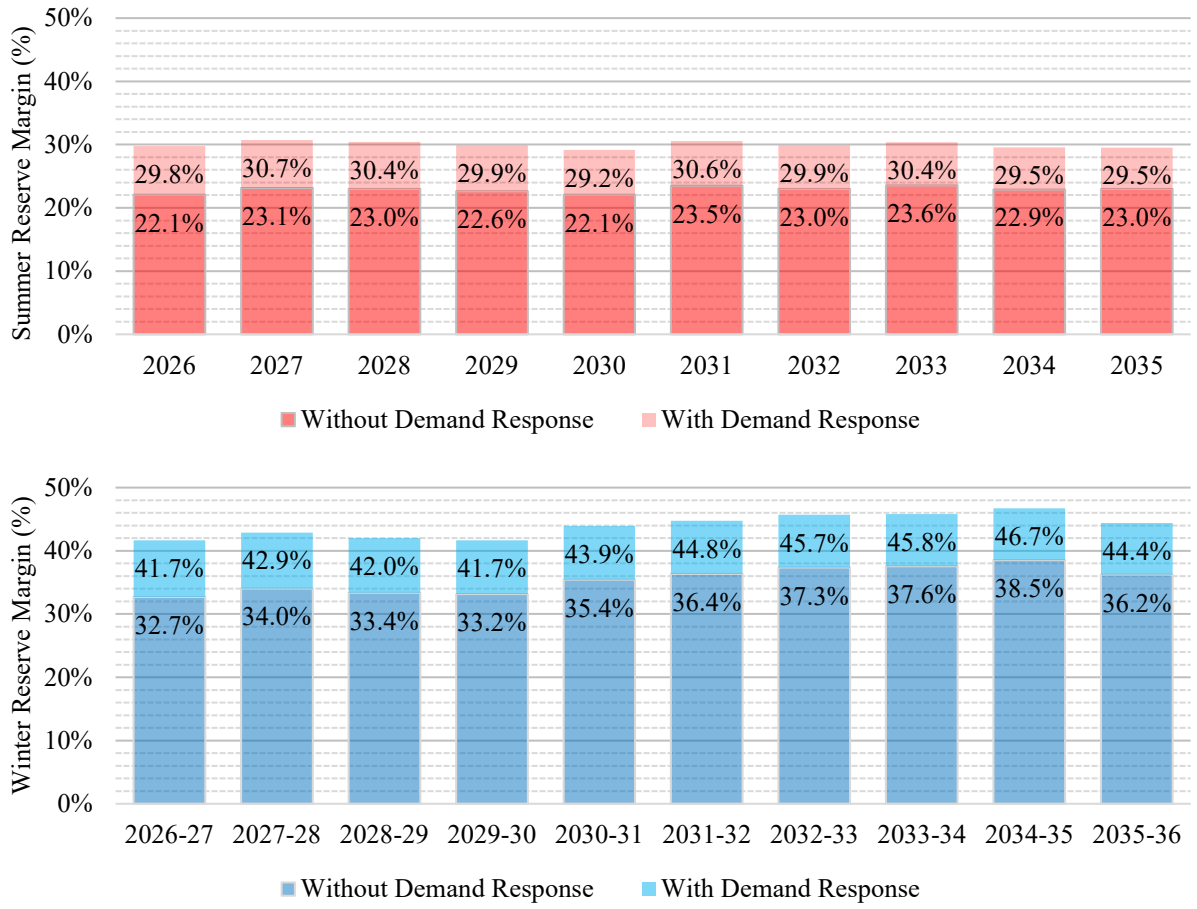
Throughout 2025 and into early 2026, several proposals were issued that may impact Florida's energy and environmental compliance landscape. On September 16, 2025, the EPA proposed amendments to the GHG Reporting Program that would remove reporting obligations for most source categories and suspend them until 2034. On February 12, 2026, the EPA finalized rescission of the 2009 GHG Endangerment Finding and repeal of federal GHG vehicle emission standards. On February 19, 2026, the EPA finalized the repeal of the 2024 Mercury and Air Toxics Standards (MATS) amendments, which required lower emissions for mercury and other hazardous air pollutants, returning standards to 2012 levels. Further environmental regulations include a proposal to revise the technology-based effluent limitations guidelines and standards (ELGs) promulgated in the 2024 "Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category" (2024 ELG) and revisions, which are final, to certain provisions of the 2024 oil and natural gas methane rules.

Recent FERC actions also affected Florida's regulatory and planning environment. These actions included streamlined permitting for natural-gas infrastructure, and approval of new grid reliability standards. FERC's 2025–2026 Winter Energy Market and Reliability Assessment confirmed that Florida has sufficient generation resources to meet winter demand under normal conditions. Overall, while the regulatory environment remains dynamic, Florida's utilities generally do not anticipate material generation curtailments, retirements, or reliability impacts from environmental regulations during their planning periods. The Commission will continue to monitor these developments and incorporate material impacts into future TYSPs.

Reliability

Florida's electric utilities are expected to have enough generating assets available at the time of peak demand to meet forecasted demand. On a statewide basis, generating capacity is projected to be no less than 29 percent higher than the forecasted summer net firm peak demand, and 41 percent higher than the forecasted winter net firm peak demand. Without activating load management resources like demand response programs, including interruptible and curtailable load, the state would still have more reserves of more than 22 percent during summer peak and 32 percent during winter peak. Figure 4 provides the annual values over the planning horizon with and without activating demand response for each season.

Figure 4: State of Florida - Projected Reserve Margin by Season



Source: FRCC 2026 Regional Load and Resource Plan - Form 10

Conclusion

The Commission has reviewed the 2026 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 state and federal regulations, electric vehicle adoption, the state's dependence on natural gas for electricity production, and emerging trends such as large load customers and potential new nuclear generation.

Based on its review, the Commission finds the 2026 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 any docketed matter(s) 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

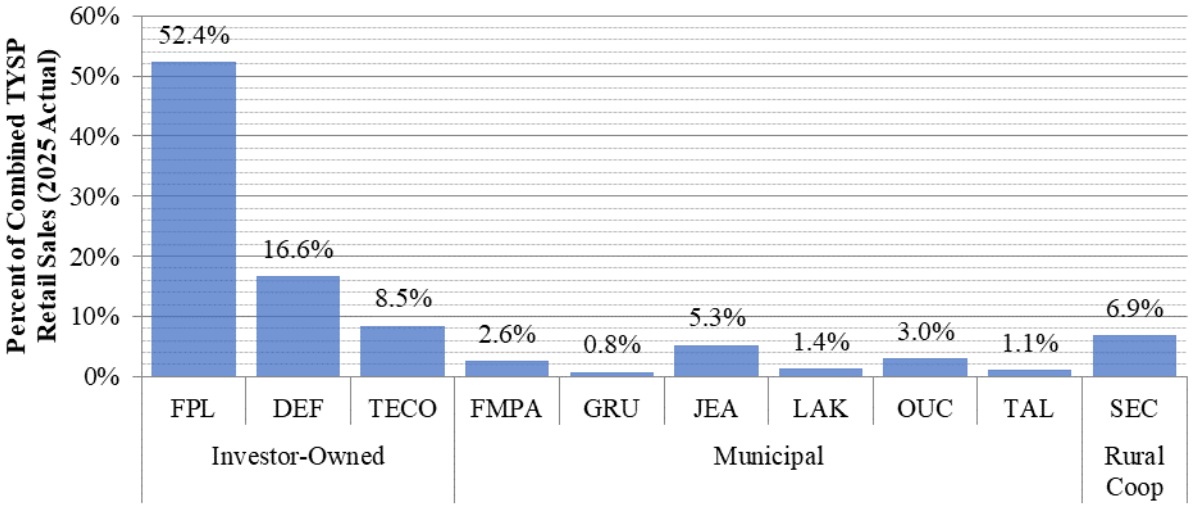
Florida is served by 57 electric utilities, including 4 investor-owned utilities, 35 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only electric utilities with an existing generating capacity above 250 MW or a planned unit with a capacity of 75 MW or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

In 2026, 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 2026 TYSP is Seminole Electric Cooperative (SEC). Collectively, these utilities are referred to as the TYSP Utilities.

Figure 5 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 2025. Collectively, the reporting investor-owned utilities account for 77.5 percent of statewide retail energy sales, while the municipal and cooperative utilities make up approximately 21.1 percent of the statewide retail energy sales. The remainder is associated with non-reporting entities due to their limited size.

Figure 5: TYSP Utilities - Comparison of Reporting Electric Utility Sales



Source: FRCC 2026 Regional Load and Resource Plan and 2026 TYSPs

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.

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 and generation resources, including their associated components topics such as forecast methodology, load management, fuel diversity, and reliability. 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 of reporting utilities' 2026 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

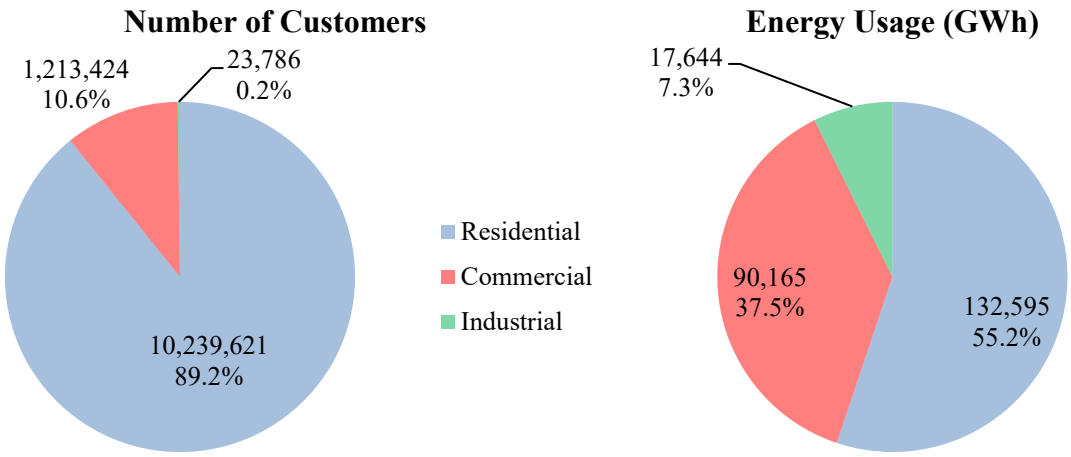
Load Forecasting

Forecasting customer energy needs or load is a fundamental component of electric utility planning. 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 6, residential customers account for 89.2 percent of the total, followed by commercial (10.6 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 2025, compared to a national average of approximately 37.3 percent in 2024.[4]

Figure 6: State of Florida - Electric Customer Composition in 2025



Source: FRCC 2026 Regional Load and Resource Plan

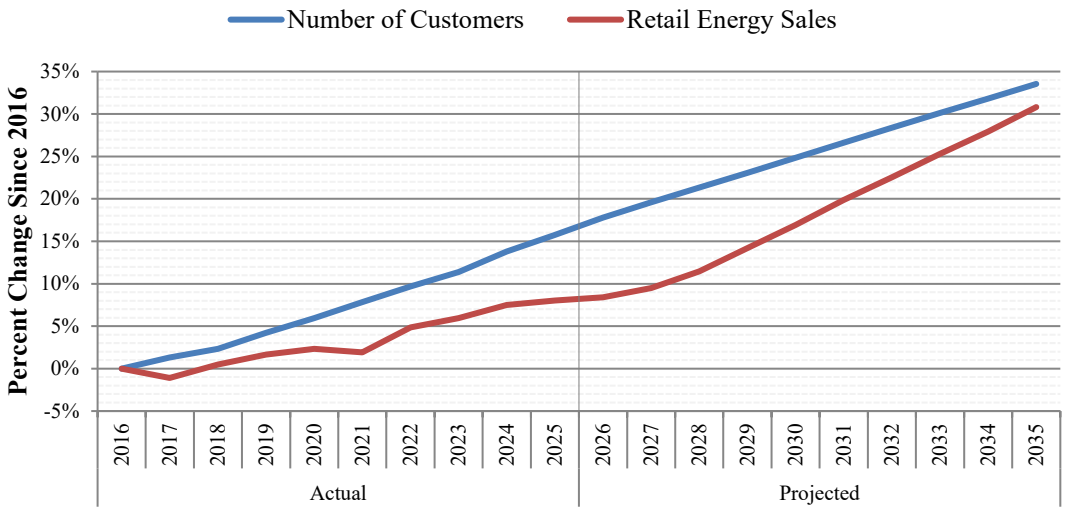
Growth Projections

For the next 10-year period, Florida's weather normalized retail energy sales are projected to grow at 2.1 percent per year, compared to the 0.9 percent actual annual increase experienced during the 2016-2025 period. The number of Florida's electric utility customers is anticipated to grow at an

[4] U.S. Energy Information Administration – Electric Power Annual, Table 2.2, Sales to Ultimate Customers, released October 16, 2025.

average annual rate of about 1.4 percent for the next 10-year period, compared to the 1.6 percent actual annual increase experienced during the last decade. These trends are shown in Figure 7.

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



Source: FRCC 2026 Regional Load and Resource Plan

As shown in Figure 7, Florida utilities' total retail energy sales reached a historical peak in 2025 surpassing the most recent peak that was reached in 2024. Compared to 2024, the statewide total retail energy grew a half percent in 2025. The chief contributors to this growth in retail energy sales include the continued growth in the number of retail customers and weather conditions. In 2025, FPL's total customers increased by 1.7 percent, which is lower than the 2.0 percent increase in 2024. However, this 1.7 percent increase in customers is still higher than the long-term historical average and reflects continued growth to FPL's service territory. Additionally, DEF's customer growth is determined by factors such as population growth, population migration, and the retirement demographic. DEF reported that housing market issues such as affordability, mortgage rates, and job growth have always applied a significant influence on customer growth dynamics. The Utility noted that more recent site plans reflect a return to the long-term trend of population migration into Florida; and, commercial customer growth typically tracks residential growth, due to its role of supplying needed services to the residential customer group.

Florida utilities' total retail energy sales are projected to continuously grow for the next 10 years. This sales growth is driven by an anticipated growth in customers and business activity, the expected increased level of adoption of electric vehicles, and the addition of large load customers such as data centers especially after 2028.

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, new technologies, and changes in customer behavior or operations; hence, the corresponding information is utilized to develop the forecast

models for projecting the future growth of usage per customer. 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, most TYSP utilities reported a downward trend due to advancements in technologies for energy efficiency, renewable generation, and alternative energy sources. However, some utilities, such as FPL and DEF, are expecting that increased residential at-home electric vehicle charging and the impact of anticipated energy-intensive commercial/industrial customers will mitigate this downward pressure to a certain extent. FPL also forecasted its industrial UPC to increase significantly supported by the addition of large load customers expected to enter the system in 2028.

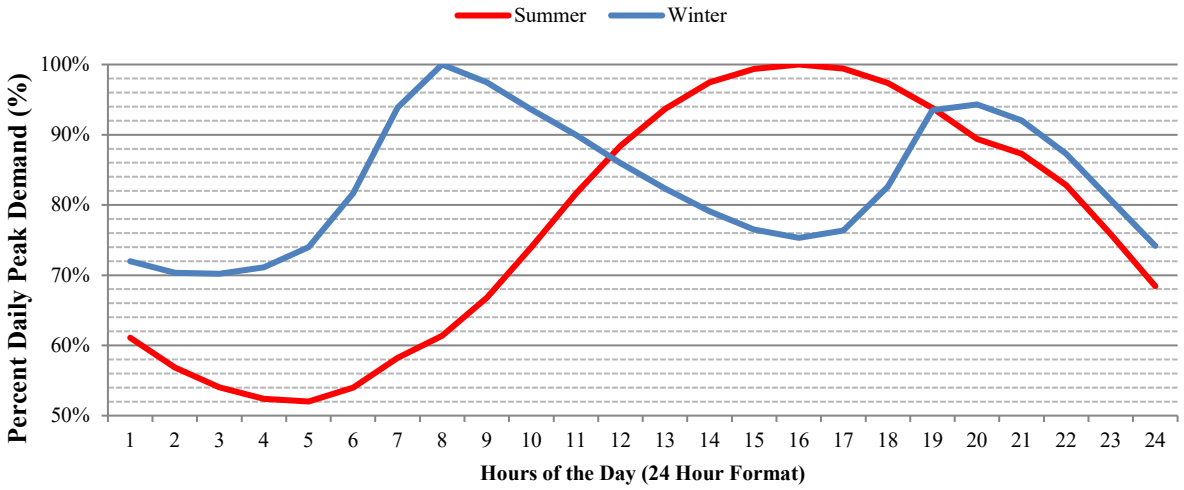
Peak Demand

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. While most of Florida's utilities experience their peak demand during summer months, 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.

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

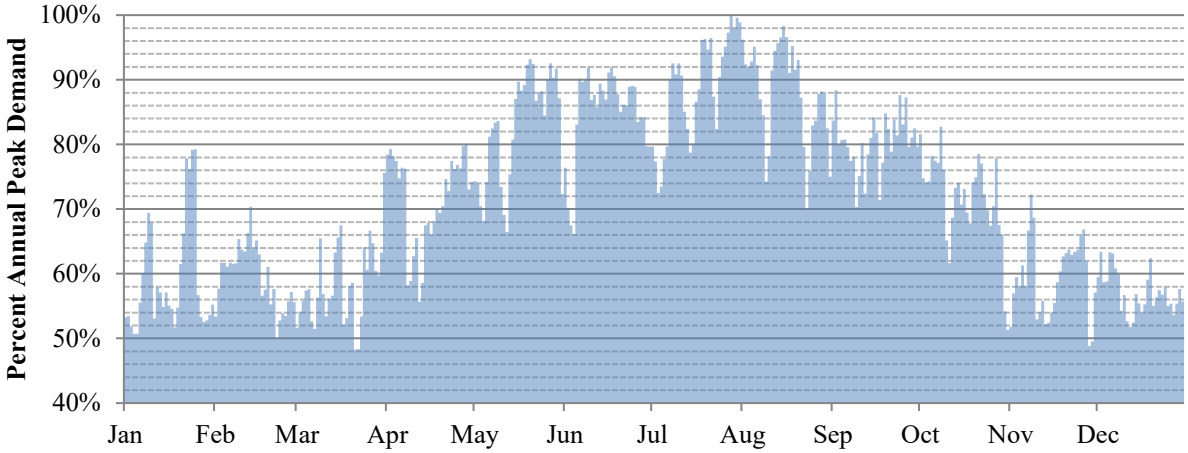


Source: TYSP Utilities' Data Responses

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 2025 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 (2025 Actual)



Source: 2026 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

The reporting TYSP Utilities estimate approximately 696,650 plug-in EVs will be operating in Florida by the end of 2026, which represents approximately 3.6 percent of registered automobiles, heavy trucks, and buses, an increase from 3.05 percent in 2025. TYSP Utilities' projections of EV ownership, public charging stations, and impacts to their electric grid are summarized in Table 1. Florida's electric utilities continue to anticipate growth in the EV market; however, projected growth has moderated in recent years due to factors such as affordability pressures, economic uncertainty, and the repeal of EV purchase incentives.[5] EV ownership is now projected to increase to 3.5 million EVs and 187,000 EV charging stations operating within the reporting utilities' electric service territories by the end of 2035, down from last year's estimate of 4.4 million EVs and 267,000 EV charging stations by 2034. The projected EV charging station amounts listed in Table 1 include both normal and "quick-charge" public charging stations.[6] EV annual energy consumption is expected to increase from 0.9 percent of retail energy sales in 2026 to 4.7 percent by 2035. In terms of seasonal peak demand, EVs have a greater impact upon summer peak than winter, this is expected to increase from 1.0 percent of net firm summer peak demand in 2026 to 4.8 percent by 2035.

[5] The federal New Clean Vehicle Credit (IRC § 30D) was terminated under the One Big Beautiful Bill Act, effective for vehicles acquired after September 30, 2025. *One Big Beautiful Bill Act*, Pub. L. No. 119-21, § 70502, 139 Stat. 72 (2025).

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

Table 1: TYSP Utilities - Electric Vehicle Projections

Year	EVs	EV Charging Stations	Grid Impacts		
			Annual Energy	Summer Peak	Winter Peak
	(-)	(-)	(GWh)	(MW)	(MW)
2026	696,650	39,845	2,499	522.7	267.3
2027	868,788	49,894	3,211	664.6	340.3
2028	1,068,035	61,539	4,043	806.4	367.6
2029	1,300,862	75,066	5,024	996.8	455.9
2030	1,575,854	90,947	6,196	1,225.6	573.5
2031	1,892,487	109,301	7,627	1,508.8	706.2
2032	2,249,987	125,309	9,281	1,836.2	853.2
2033	2,639,562	146,274	11,013	2,180.8	1,011.1
2034	3,057,711	167,991	12,880	2,554.1	1,178.9
2035	3,518,471	187,359	14,924	2,976.3	1,362.0

Source: TYSP Utilities' Data Responses

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.

Data Centers

Many TYSP utilities reported that they have received inquiries from potential new large load data centers that require hundreds of MW each. Table 2 shows the projected number of large load data centers, and their load impacts included in the 2026 TYSPs. In terms of peak demand, large data centers have a greater impact upon summer peak than winter, and this is expected to represent 4.9 percent of net firm summer peak demand by 2035. Only two TYSP Utilities, FPL and SEC, have included the potential data center-related load requirements in their respective TYSPs. However, SEC notes that its one projected data center project, totaling 162 MW of summer peak demand by 2035, has been cancelled.

Table 2: TYSP Utilities - Projected Large Load Data Centers and System Impacts

Year	No. of Data Centers	Grid Impacts		
		Annual Energy	Summer Peak	Winter Peak
	(-)	(GWh)	(MW)	(MW)
2026	-	-	-	-
2027	-	-	-	-
2028	2	1,520	248	25
2029	3	4,968	695	395
2030	3	8,049	1,100	724
2031	3	11,314	1,526	1,073
2032	3	14,138	1,898	1,369
2033	3	16,899	2,270	1,664
2034	3	19,691	2,642	1,960
2035	3	22,483	3,014	2,255

Source: 2026 TYSP Utilities' Data Responses

Florida TYSP utilities identified concerns regarding this level of large-load growth which include: (1) the timing and certainty of when individual projects will materialize; (2) the need to plan and construct incremental generation and transmission infrastructure to reliably serve these loads; and (3) ensuring that the costs to serve large-load customers are appropriately assigned. FPL, specifically, indicated that it is addressing these issues through ongoing customer engagement, system impact and interconnection studies, and integration of expected large-load additions into its long-term resource planning processes.

Large data centers are unique types of energy consumption sources due to 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 Renewables

Under Rule 25-6.065, F.A.C., investor-owned utilities (IOUs) must offer net metering for renewable generation systems up to 2 MW, allowing customers to offset energy usage and reducing utility-served energy and, in some cases, peak demand. Florida's customer-sited or demand-side renewable generation, primarily behind-the-meter rooftop solar PV, continues to grow and is an increasingly important consideration in utility load forecasting. As of the end of 2025, more than 319,068 demand-side systems totaling approximately 3,150 MW were installed statewide, with nearly all consisting of solar; non-solar systems account for only 27 installations totaling 6.3 MW.

Table 3 summarizes the growth of demand-side renewable generation interconnections.

Table 3: State of Florida – Demand-Side Renewable Growth

Year	2019	2020	2021	2022	2023	2024	2025
Number of Installations	59,508	90,552	130,947	189,952	249,521	292,284	319,068
Installed Capacity (MW)	514	835	1,177	1,780	2,351	2,801	3,150

Source: 2019-2025 Net Metering Reports

For the 2026–2035 planning period, utilities generally incorporate demand-side generation as a reduction to forecasted net energy for load and peak demand, although methodologies vary. FPL uses Wood Mackenzie solar market data and NREL's PVWatts Calculator to forecast solar growth and its impacts on energy and seasonal peak demand, while DEF, TECO, SEC, GRU, FMPA, LAK, and TAL use combinations of historical data, adoption trends, EIA forecasts, and net-metering data. OUC uses NREL adoption curves, projecting an average annual growth rate of 8.1 percent, while JEA uses a more detailed hourly model incorporating rooftop solar and paired battery storage. SEC projects incremental demand-side solar generation to increase from 167 GWh in 2026 to 1,154 GWh in 2035, and FMPA projects demand-side generation units to grow from approximately 7,400 to 12,000 by 2035. Overall, the continued growth of demand-side renewable generation, particularly rooftop solar, is becoming an increasingly significant factor in Florida's load forecasts, with utilities differing in their treatment of peak demand, energy storage, and the level of detail used to model future adoption.

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 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, etc.) and independent variables (e.g., peak day

minimum temperature, real personal income, heating degree days and cooling degree days, etc.) to infer relationships between the two types of variables. These historical relationships, combined with available forecasts of the independent variables and the utilities' forecasts of customers, are then used to forecast the peak demand and energy sales. For some customer classes, such as industrial customers, surveys may be conducted to determine the customers' specific expectations for their own future electricity consumption.

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

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

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

Historically, the various forecast models and techniques used by Florida's electric utilities are commonly used throughout the industry, and each utility has developed its own individualized approach to project load. The models have relied upon dependent and independent variable data to project energy sales and demand amounts that exist within a probabilistic range. The resulting forecasts allow each electric utility to evaluate its individual needs for new generation, transmission, and distribution resources to meet customers' current and future needs reliably and affordably. Again, for the 2026 TYSPs, Florida's electric utilities used these same types of models and techniques to prepare their forecasts.

Accuracy of Retail Energy Sales Forecast

For each reporting electric utility, the Commission reviewed the historic forecast accuracy of past retail energy sales forecasts. The standard methodology for our review involves comparing actual retail energy sales for a given year to energy sales forecasts made three, four, and five years prior. For example, the actual 2025 retail energy sales were compared to the forecasts made in 2020, 2021, and 2022. 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 2026 TYSPs, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2016 through 2025 to forecasts made between 2007 and 2021. 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
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%
2026	2025 - 2021	2021 - 2016	(2.3%)	2.4%

Source: 2007-2026 TYSPs
* Inputs used include 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 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 four years' six-year ahead and five-year ahead forecasts all render negative error rates as well. Note that all the 2023-, 2024- and 2025-related forecasts made between two 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%)	(3.1%)	(3.7%)	(3.2%)	(3.2%)	(3.4%)	3.4%
2025	(2.9%)	(2.7%)	(3.2%)	(2.6%)	(2.3%)	(1.3%)	(2.9%)	2.9%

Source: 2006-2026 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 2016 through 2025 in Table 5. However, all the major global and domestic events (e.g. the Russia-Ukraine war, intense conflicts in the Middle East, significant changes in 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 US economy. As such, there remains uncertainty as to what the economic impacts of such events will be going forward.

Further, as discussed earlier, new and emerging technologies may also have an impact on the accuracy of a utility's long-term forecast. DEF indicated that the most significant non-weather impact on its load and demand, which is the broader saturation of self-generation, particularly solar PV, is only beginning to be felt. DEF stated this impact is reflected more in the forecast than the historic trend data. Impacts of demand-side renewables have been modest thus far, but the trend of increasing adoption indicates that there will be significant and growing impacts especially to the annual energy sales in the near future. Similarly, the Utility also pointed out that impact from Plug-in Electric Vehicles (PEVs) and data centers is reflected more in the future data than that in the historic trend data for the same reasons. The Utility explained that forecast accuracy impacts are more likely to be associated with changes in the timing and magnitude of large, discrete loads (such as data center additions or expansions) or changes in the pace of PEV adoption.

Therefore, the actual retail energy sales of the next few years could be different from what Florida utilities projected in 2025 and prior years. Consequently, the average forecasted energy sales error

rates in the next few years may deviate from the relatively lower levels recorded since 2016. That possible deviation is the case because of the compounding effects of emerging technologies, self generation, political and international trade challenges, major regional conflicts worldwide, and global health issues in addition to the standard sources of forecasting error such as weather and the national economy.

Load Management

Florida's electric utilities also consider how the efficiency of customer energy consumption changes over the planning period. Changes in government mandates, such as building codes and appliance efficiency standards, reduce the amount of energy consumption for new construction and electric equipment. Electric customers, through the power of choice, can elect to engage in behaviors that decrease peak load or annual energy usage. Examples include turning off lights and fans in 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 represent 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.[7] 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 2025 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 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

[7] 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 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 commercial/industrial 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 allows 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.

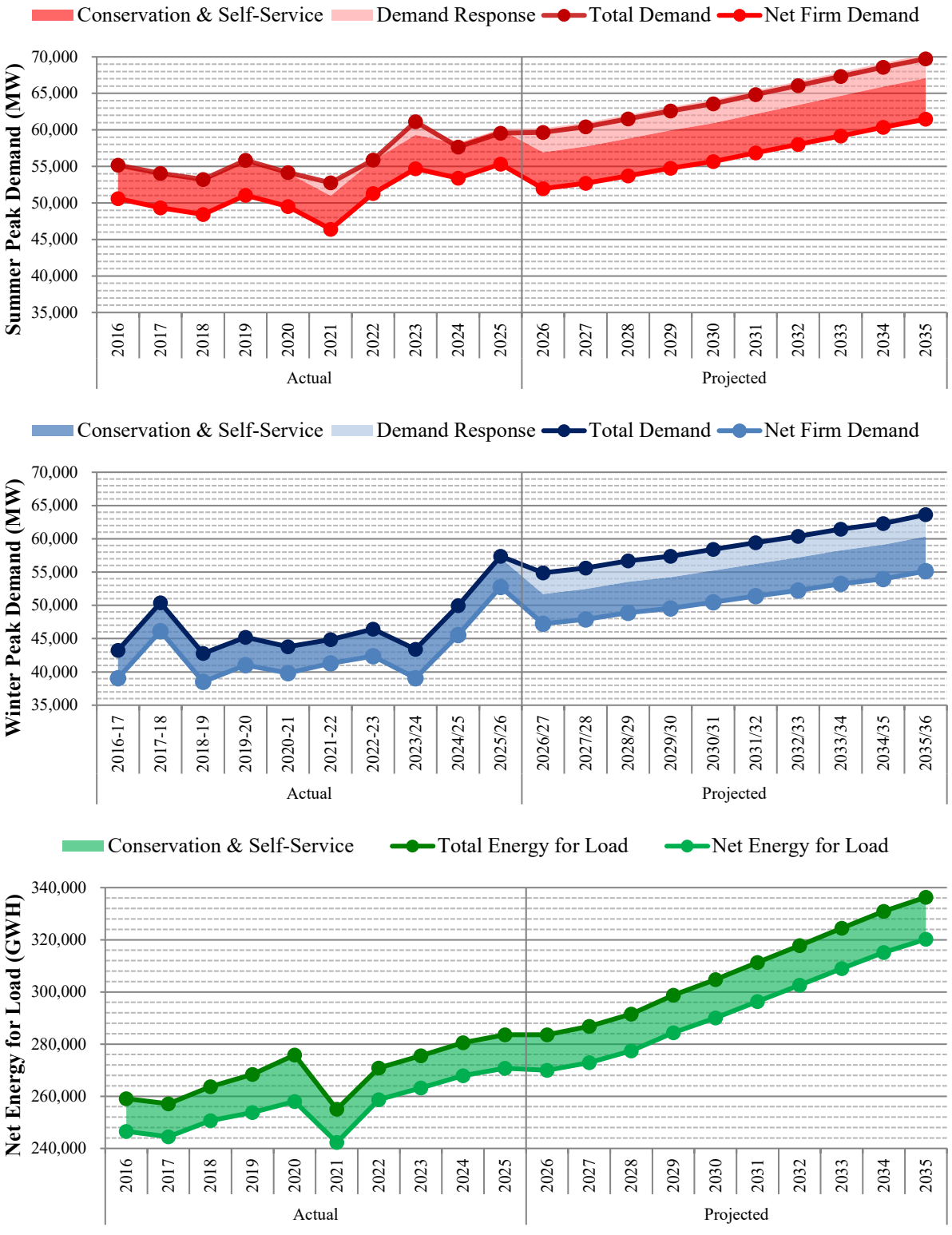
Load management is similar to interruptible load but focuses on smaller customers and targets individual appliances. The utility installs a device on an electric appliance, such as a water heater or air conditioner, which allows for remote deactivation for a short period of time. Load management activations 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 2026, the total amount of demand response resources available for reduction of peak load is 3,283 MW for summer peak and 3,048 MW for winter peak. Demand response is anticipated to decrease only marginally to approximately 3,270 MW for summer peak and increase to approximately 3,168 MW for winter peak by 2035. 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, 2025, energy efficiency is responsible for peak load reductions of 4,746 MW for summer peak and 4,468 MW for winter peak. Energy efficiency is anticipated to increase to approximately 5,605 MW for summer peak and 5,195 MW for winter peak by 2035.

Forecast Load & 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.

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



Source: FRCC 2026 Regional Load and Resource Plan

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.

The forecasts also reflect differences among utilities in how anticipated large load customers are incorporated into their load forecasts. Some utilities have included expected large load customers in their forecasts, while others have not included such customers due to the uncertainty regarding the timing, size, or likelihood of the associated load materializing during the forecast period. Under section 366.043(2)(d), F.S., a large load customer is a customer with an anticipated monthly peak load of 50 MW or more, calculated as the highest average load over a 15-minute interval at a single location. Consequently, differences in how utilities account for anticipated large load customers should be considered when comparing individual utility load forecasts and evaluating changes in statewide demand.

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.

Generation Resources

Florida's electric utilities have historically relied upon several different fuel types to serve customer load. Before 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. Renewable resources continue to expand within Florida, the majority being represented by solar PV generation, but also include sources such as waste heat and solid waste. Renewables are expected to exceed all other generation sources except for natural gas by 2030.

Generation by Type

Fossil fuel generation provides a constant supply of generation but requires usage of solid fuels which are affected by fuel prices. Nuclear capacity serves as an alternative to natural gas fueled generation, but the necessary facilities are capital-intensive and require long lead times to construct. Renewable generation provide power without the use of fossil fuels, which must be imported into the state. However, solar generation is not considered a firm resource and contributes only a portion of its capacity during the period of system peaks. Generally, solar contributes 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. Energy 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.

Renewables

Renewable energy is an increasing share of generation within the state, primarily displacing natural gas consumption. Table 6 provides a breakdown of each TYSP Utility's actual 2025 and projected 2035 generation from renewables, in gigawatt-hours (GWh) and as a percentage of NEL. Renewable energy as a percentage of NEL is expected to increase from 10.1 percent in 2025 to 23.7 percent in 2035. On a statewide level, solar generation will account for 23.0 percent of NEL in 2035.

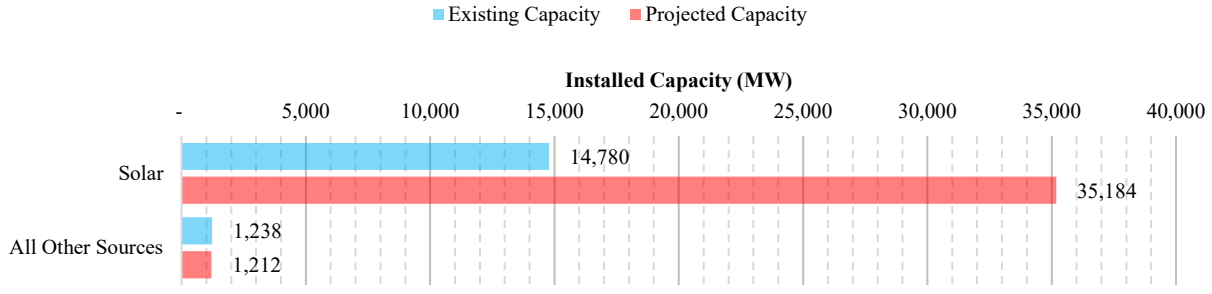
Table 6: State of Florida - Renewable Energy Generation

Utility	2025 Actual			2035 Projected		
	NEL	Renewables		NEL	Renewables	
	GWh	GWh	%	GWh	GWh	% NEL
FPL	147,260	17,617	12.0%	180,677	47,798	26.5%
DEF	43,580	3,659	8.4%	46,632	14,780	31.7%
TECO	21,798	2,419	11.1%	23,619	5,436	23.0%
FMPA	7,804	290	3.7%	7,197	339	4.7%
GRU	1,910	453	23.7%	2,028	350	17.3%
JEA	13,479	536	4.0%	15,219	364	2.4%
LAK	3,531	30	0.8%	3,918	204	5.2%
OUC	8,222	588	7.2%	9,556	4,356	45.6%
TAL	2,877	108	3.8%	2,998	103	3.4%
SEC	17,778	932	5.2%	24,543	700	2.9%
STATE	270,665	27,311	10.1%	320,229	75,741	23.7%

Source: FRCC 2026 Regional Load and Resource Plan and TYSP Utilities' Data Responses

Currently, renewable energy facilities provide approximately 16,018 MW of firm and non-firm generation capacity, which represents 21.1 percent of Florida's overall generation capacity of 75,881 MW in 2025. This value includes existing demand-side renewable resources with net metering agreements, totaling 3,150 MW, discussed earlier. Florida's total renewable resources are expected to increase by an estimated 20,378 MW over the 10-year planning period, a decrease from last year's estimated 26,228 MW projection, excluding solar degradation. Solar generation, primarily utility-owned, is the sole renewable type projected to increase over the planning horizon, with non-solar renewables decreasing by 26 MW due to retirements or expired contracts. Solar generation is anticipated to more than double over the 10-year period, with a net total of 20,404 MW to be installed, consisting of 18,265 MW of utility-owned solar and 2,138 MW of contracted solar. Figure 11 summarizes the existing and projected renewable capacity by generation type.

Figure 11: State of Florida - Current and Projected Renewables



Source: FRCC 2026 Regional Load and Resource Plan and TYSP Utilities' Data Responses

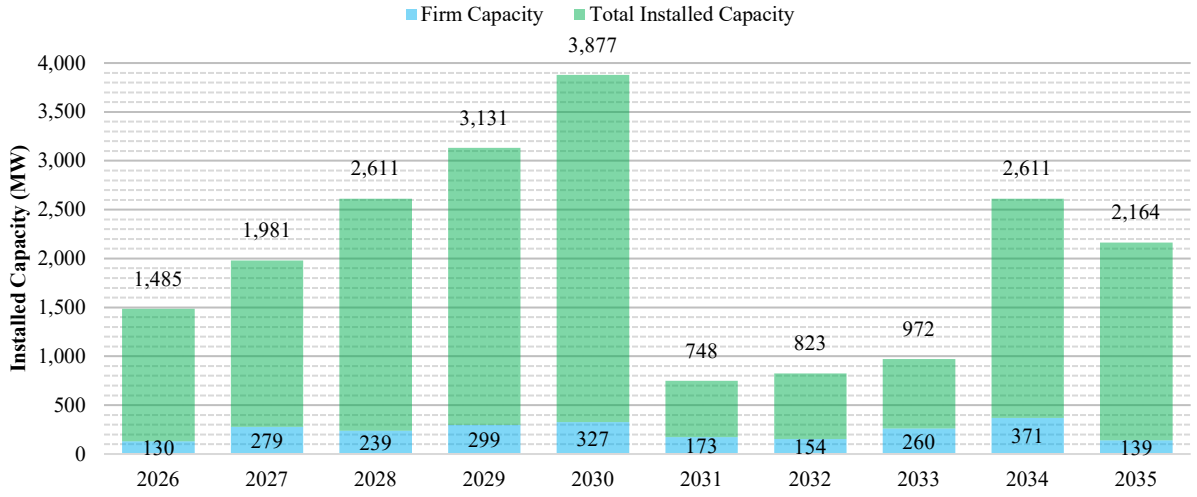
Renewable Capacity and Peak Contribution

Of the total existing renewable capacity, only approximately 5,545 MW of existing renewable generation is 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. Changes in timing of peak demand may influence the firm contributions of renewable resources such as solar and wind. 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. Solar generation contributes approximately 5,157 MW to this total, based upon the coincidence of solar generation and summer peak demand, or about 35 percent of its installed capacity. Of the 1,238 MW of non-solar generation, only 388 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.

As the number of solar installations increases in the state, the difference in how solar operates compared with traditional generation will become increasing important to the grid. 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 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. A total of 2,370 MW of solar additions are considered firm for summer peak, or about 11.6 percent of the total projected to be installed.

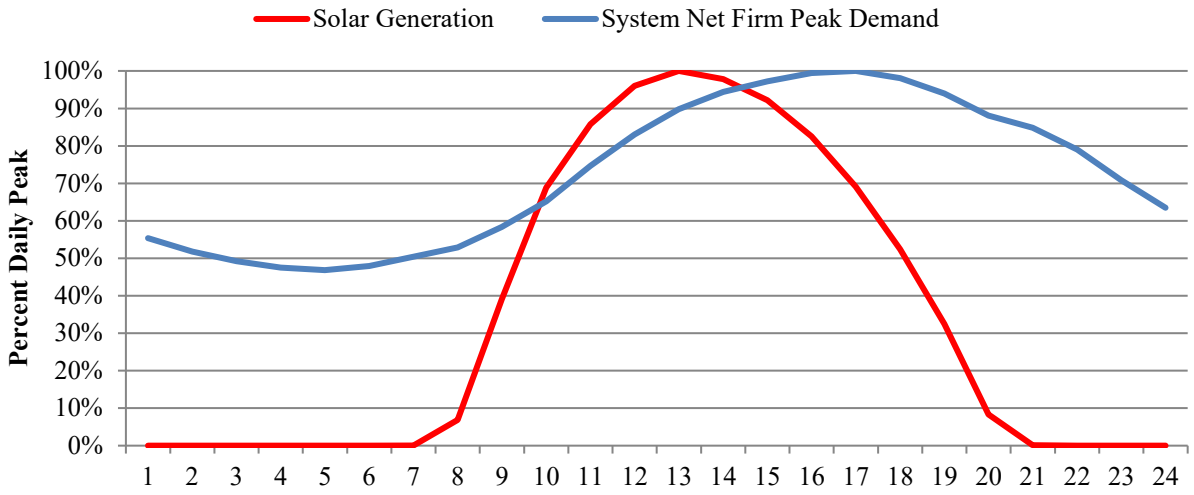
Figure 12: TYSP Utilities - Planned Solar Installations



Source: FRCC 2026 Regional Load and Resource Plan and TYSP Utilities' Data Responses

As solar generation cannot be dispatched on demand, it is produced based on conditions at the plant site, which are influenced by variations in daylight hours, cloud cover, and other environmental factors. 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 pm, the net firm system demand peaks at 5:00 pm 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 Responses

Non-Utility Owned Renewable Generation

Approximately 1,609 MW, or 10 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 are 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.

Nuclear

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. Florida has had three nuclear plants with five units total; two units each at Turkey Point and St. Lucie, both operated by FPL and still active, and a single now retired unit at Crystal River, formerly operated by DEF. In addition, several utilities jointly own or purchase capacity from nuclear units, including FMPA and OUC with FPL's St. Lucie Unit 2, and JEA from Vogtle Units 3 and 4 in Georgia.

Florida's electric utilities are taking varied approaches to existing and potential future nuclear resources, while evolving state and federal regulations may influence the timing and feasibility of advanced nuclear generation. FPL remains the most proactive, having received Nuclear Regulatory Commission Combined Operating Licenses in 2018 for potential Turkey Point Units 6 and 7, although their earliest possible in-service dates fall outside the current planning period for this report. FPL is also evaluating SMRs and plans to begin early site permitting by 2027 for a potential SMR adjacent to an existing nuclear facility, with any resulting unit likewise expected beyond the 10-year planning horizon. The remaining TYSP Utilities do not currently include any new nuclear development during the planning period but are monitoring the technology. The State of Florida is also proactively evaluating SMRs, including through a Commission feasibility report issued in March 2025 and related state efforts to clarify regulatory requirements for SMR deployment. The Commission will continue to monitor advancements in nuclear technology and changes to federal and state regulations and incorporate material impacts into future TYSPs.

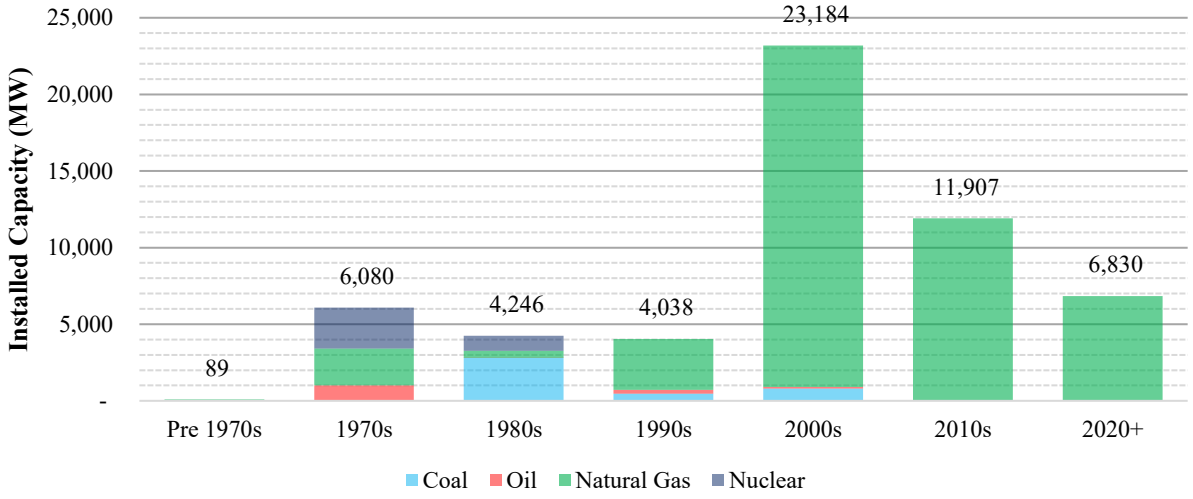
Fossil Fuels

While renewable generation increases its contribution to the state's generating capacity, most of the 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 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 23 years. While the original commercial in-service date

may be more than 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.[8]

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



Source: FRCC 2026 Regional Load and Resource Plan

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 1,209 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

[8] The values for historic periods may vary from prior reports due to capacity uprates or derates of the generating units included in the age cohort, in addition to retirements.

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 increase the total amount of energy that utilities must produce to serve customer load, affecting net load rather than net generation.

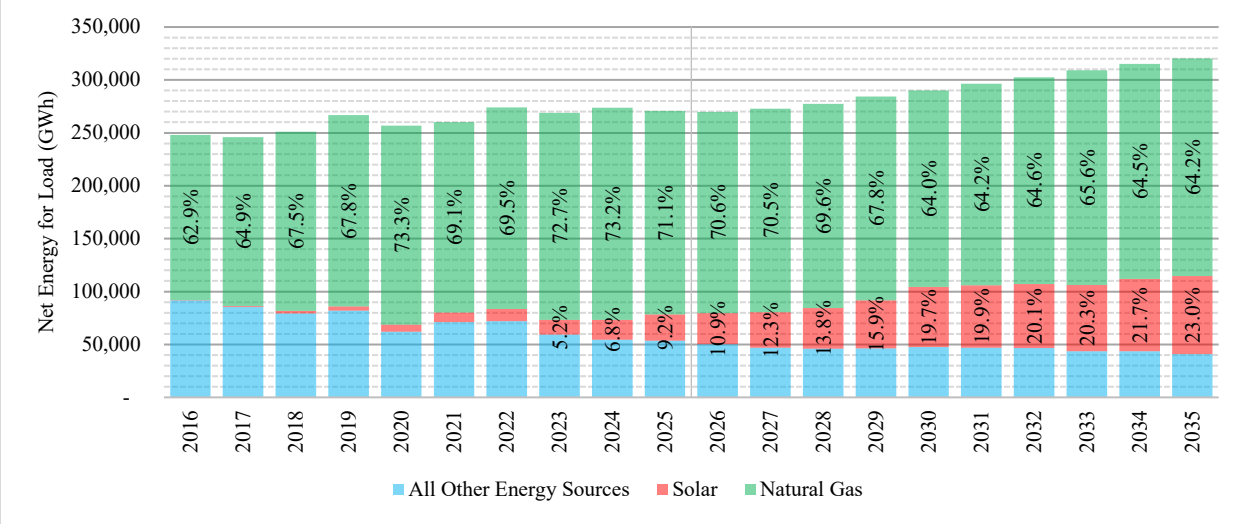
Over the next decade, utilities anticipate adding approximately 11,056 MW of energy storage, primarily directly on the transmission system or a specific power plant. While energy storage provides firming for intermittent solar facilities, grid connected batteries will not be restricted to charging from 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, 1,203 MW of existing battery storage and 8,568 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.

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 15 illustrates, natural gas was the source of approximately 71.1 percent of electric energy consumed in Florida in 2025. 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 2030.

Figure 15: State of Florida - Natural Gas Generation

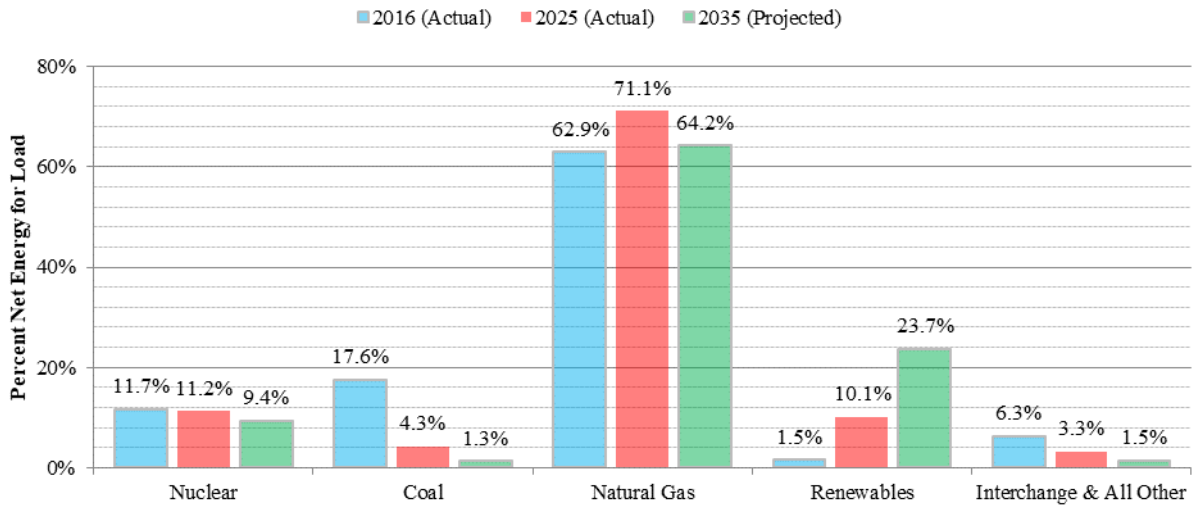


Source: FRCC 2016-2035 Regional Load and Resource Plans

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 16 shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2016 and 2025, and forecast year 2035. 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.

Figure 16: State of Florida - Historic and Forecast Generation by Fuel Type

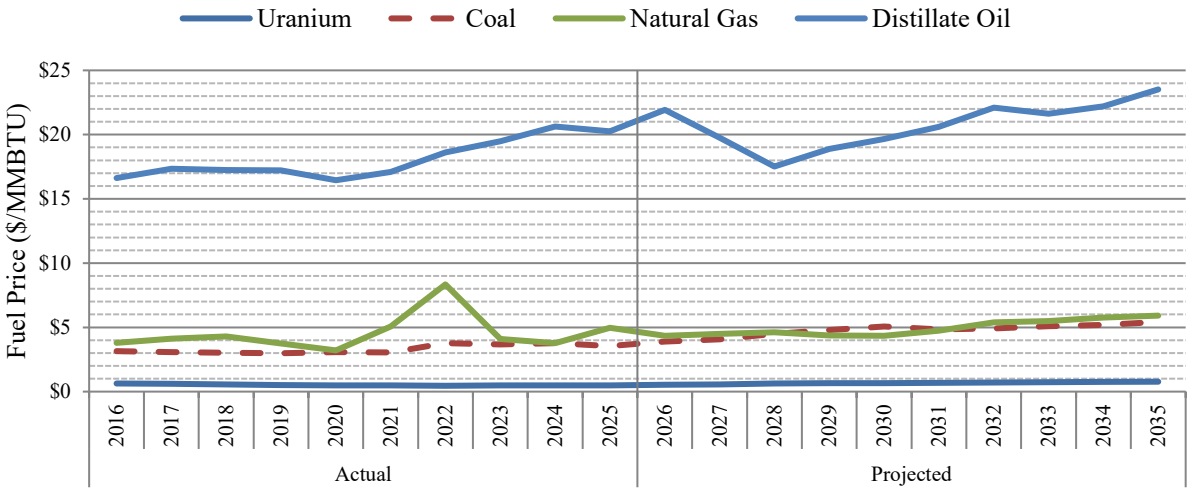


Source: FRCC 2016-2035 Regional Load and Resource Plan

Fuel Price Forecast

Fuel price is an important economic factor affecting the dispatch of the existing generating fleet and the selection of new generating units. In general, the capital cost of a fuel-based power plant is inversely proportional to the cost of the fuel used to generate electricity from that unit. The major fuels consumed by Florida's electric utilities are natural gas, coal, and uranium. Distillate oil also factors into Florida utilities' fuel mix, albeit minimally, when compared to historical levels. Figure 17 illustrates the weighted average fuel price history and forecasts for the reporting electric utilities.

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



Source: TYSP Utilities' Data Responses

As shown on Figure 17, the forecasted weighted average price per million British Thermal Units (MMBTUs) for natural gas, uranium, coal, and distillate oil are all expected to increase in nominal terms over the next 10 years. Natural gas is expected to increase from $4.36 per MMBTU in 2026 to $5.91 per MMBTU by 2035, while coal prices are also expected to increase from $3.91 per MMBTU in 2026 to $5.42 per MMBTU by 2035. Meanwhile uranium, the lowest price fuel type per MMBTU, is projected to increase from $0.53 per MMBTU in 2026 to $0.77 per MMBTU by 2035. Distillate oil remains the most expensive fuel, with forecasted prices ranging between $17.53 and $23.51 per MMBTU from 2026 through 2035. Its relatively high cost compared to other fuel sources helps explain why it is used primarily for backup and peaking purposes only.

While the prices above are provided on a thermal energy basis, the efficiency of the generating units plays an important factor. This is referred to as the heat rate of the generating unit, with a lower value meaning the unit can produce the same amount of electricity with less fuel. As steam units have a higher heat rate than combined cycle generation, this disfavors steam generation even if the fuel price might be lower.

Modernizations and 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.

Within the current planning period, only OUC's conversion of Stanton Unit 2 is expected to be completed by April 2027.

Impact of State and Federal Regulations

Florida utilities continue to manage their generation portfolios amid changes in federal environmental regulations. The EPA proposed repealing GHG standards for fossil fuel-fired EGUs and, in February 2026, repealed the 2024 MATS amendments, reverting to the 2012 standards. The EPA also rescinded the 2009 GHG Endangerment Finding and repealed federal GHG emission standards for vehicles. In April 2026, revisions to oil and natural gas requirements provided additional flexibility related to methane emissions. These actions may reduce compliance burdens, although the evolving regulatory environment continues to create uncertainty regarding future GHG requirements and CO_2 compliance costs. Most utilities therefore are not currently including explicit CO_2 compliance costs in resource planning assumptions.

Impact on Existing Resources

Existing environmental requirements generally have not resulted in significant statewide reliability concerns, although certain generating units face site-specific compliance considerations. Most utilities expect to maintain their current generating resources through the planning period, with environmental requirements primarily resulting in targeted investments, operational changes, and ongoing monitoring rather than widespread curtailments or retirements. The most significant areas of regulatory activity involve air emissions, greenhouse gases, wastewater, cooling water systems, and coal ash management. Utilities are making facility specific upgrades and pursuing compliance measures where needed, while coal fired generation continues to decline through retirements, conversions, and reduced reliance on coal. The decline in coal generation has gradually reduced exposure to some environmental requirements.

Greenhouse gas regulation remains the largest area of uncertainty. Changes in federal requirements and ongoing regulatory and legal developments are making it difficult for utilities to determine the long-term costs and operational implications of future CO_2 compliance. As a result, most utilities are not currently including explicit CO_2 compliance costs in their resource planning assumptions. Overall, Florida's utilities are managing environmental requirements through incremental investments and changes to their generation portfolios, with no broad expectation that environmental regulations will materially affect electric reliability over the next decade.

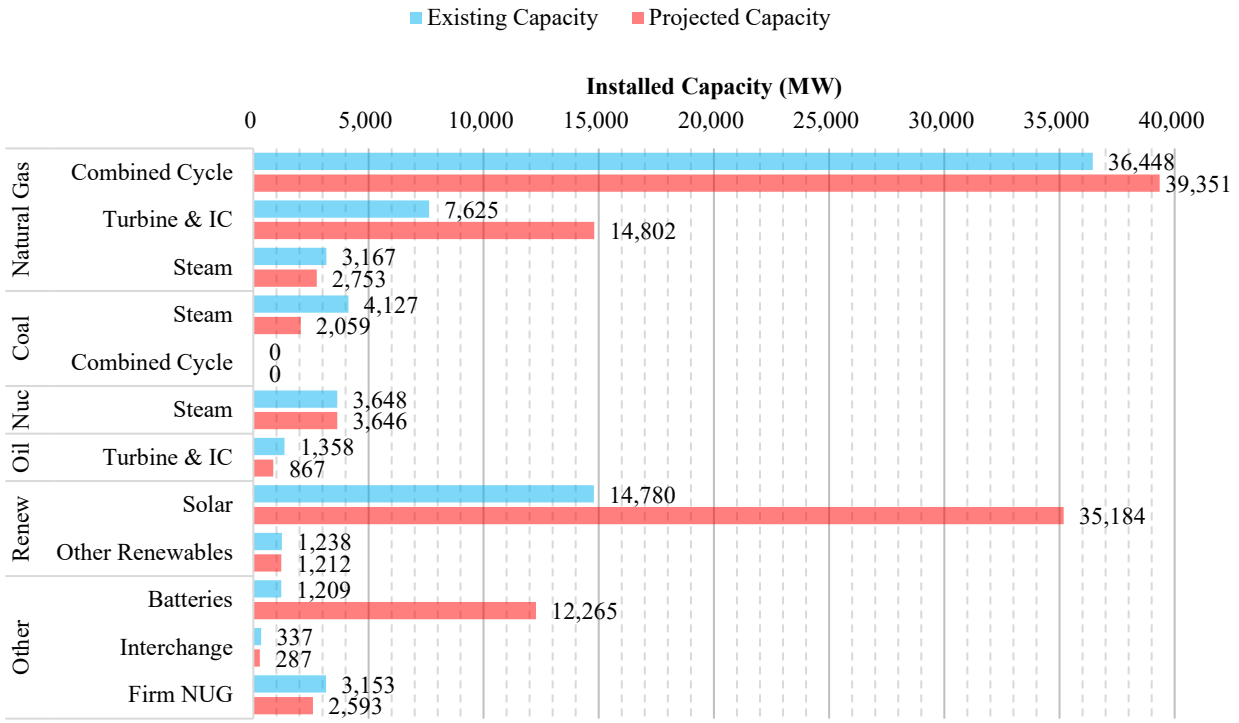
Projected Generation Resources

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

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

Figure 18 illustrates the present and future aggregate capacity mix, and incorporate all proposed additions, retirements, fuel switching, uprates and derates, and changes in operational or contract status contained in the reporting utilities' 2026 TYSPs and the FRCC's 2026 Regional Load and Resource Plan.

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



Source: FRCC 2026 Regional Load and Resource Plan and TYSP Utilities' Data Responses

Power Plant Siting Act

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 subject to the PPSA within the current planning period that have not yet received a determination of need. These units are a pair of 559 MW natural gas-fired combined cycles planned by SEC, with in-service dates in 2032 and 2035. The Commission would anticipate a petition for these units no later than 2028 and 2031, respectively. Table 7 summarizes all planned gas generating units proposed by the 2026 TYSP Utilities that have been approved or must be approved under the PPSA, as well as those other new generating units that do not require approval pursuant to the PPSA. All planned solar facilities are below the 75 MW threshold for PPSA consideration.

Table 7: TYSP Utilities - New Gas Generation and Power Plant Siting Act Requirements

In-Service Year	Utility Name	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Notes
New Units with PSC Determination of Need					
2026	SEC	Shady Hills Energy Center Unit 1	CC	546	Docket No. 20170267-EI
2031	JEA	Advanced-Class 1x1 CC	CC	582	Docket No. 20260087-EM
			Subtotal	**1,128**	
New Units Requiring PPSA Approval					
2032	SEC	Unnamed CC 1	CC	559	
2035	SEC	Unnamed CC 2	CC	559	
			Subtotal	**1,118**	
New Units Not Requiring PPSA Approval					
2031	DEF	Undesignated CT 1 & 2	CT	436	2 Units
2031	TECO	Future CT 1	CT	223	
2032	FPL	4x0 Martin CT	CT	930	
2032	SEC	Unnamed CT 1	CT	345	
2032	SEC	Unnamed CT 2	CT	345	
2033	FPL	4x0 Martin CT	CT	930	
2034	DEF	Undesignated CT 3 & 4	CT	799	2 Units
2034	FPL	4x0 Martin CT	CT	930	
2035	TECO	Future CT 2	CT	223	
2035	FPL	2x0 Martin CT	CT	465	
2035	JEA	Advanced Class 1x0 CT 1	CT	374	
2035	JEA	Advanced Class 1x0 CT 2	CT	374	
			Subtotal	**6,374**	
			Total	**8,620**	

Source: 2026 TYSPs

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 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.

Transmission Line Siting Act

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 [9]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.

Table 8 lists all proposed transmission lines in the 2026 TYSPs and the FRCC 2026 Regional Load and Resource Plan that require TLSA certification. In 2026, the Commission approved four TLSA projects for FPL, collectively referred to as the Andytown-Oasis Project. Only one utility, OUC, projected additional TLSA projects during the planning period in its TYSP, with petitions anticipated in 2030 and 2031. DEF filed notice of a TLSA project in September 2026, which will be addressed by the Commission in Docket No. 20260143-EI, *In re: Petition for determination of need for Avon Park to Vandolah transmission line in Highlands and Hardee Counties, by Duke Energy Florida, LLC.*

[9] The Commission's decision in this proceeding is currently under appeal.

Table 8: State of Florida - Planned Transmission Lines

Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
FPL	Sweatt to Whidden	79	230	05/2022	09/2022	06/2026
FPL	Oasis to Andytown	30	500	09/2026	Pending	12/2031
FPL	Oasis to Quarry	15	500	09/2026	Pending	12/2033
FPL	Quarry to Oasis	15	230	09/2026	Pending	12/2033
FPL	Levee to Oasis	15	230	09/2026	Pending	12/2033
DEF	DeLand West-Dona Vista	26.5	230	6/2025	1/2026	1/30/2026
DEF	Avon Park-Vandolah	33	230	TBD	Pending	TBD
TECO	TECO Lake Agnes to DEF Gifford	27.5	230	9/2007	2/2009	TBD
OUC	Source to St. Cloud West to Taft	>15	230	TBD	TBD	2033
OUC	Rocky Pond to Stanton	>15	230	TBD	TBD	2035

Source: 2026 TYSPs and FRCC 2026 Regional Load and Resource Plan

Reliability

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

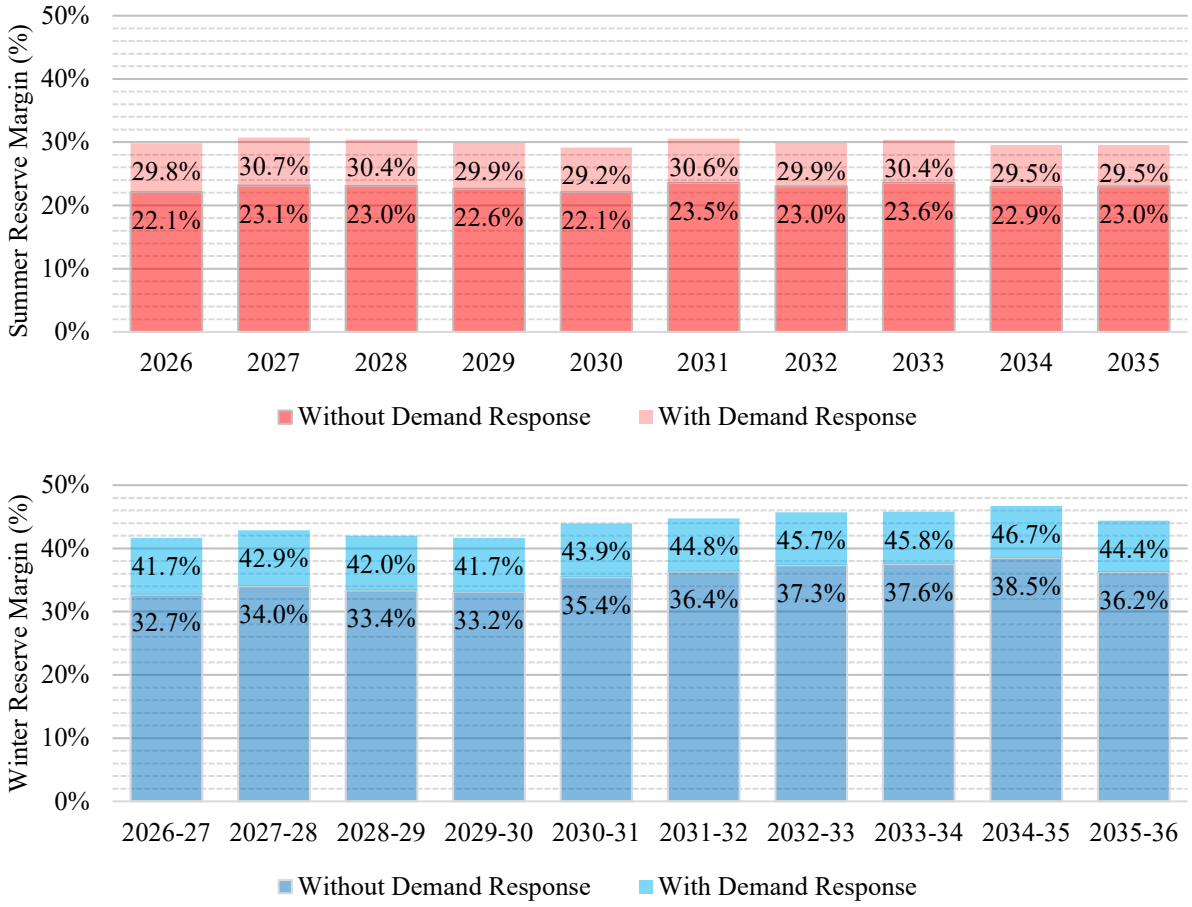
One reliability metric commonly used by the TYSP Utilities is a seasonal planning reserve margin. Each utility annually compares their forecasted seasonal peak demand after activation of demand response resources with the total amount of firm generation available at the seasonal peak hour. The difference 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.[10] 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 19, the

[10] 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*.

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 22.1 percent or above throughout the planning period. On average, demand response contributes 7.1 percent toward the summer reserve margin, and 8.5 percent toward the winter reserve margin.

Figure 19: State of Florida - Projected Reserve Margin by Season



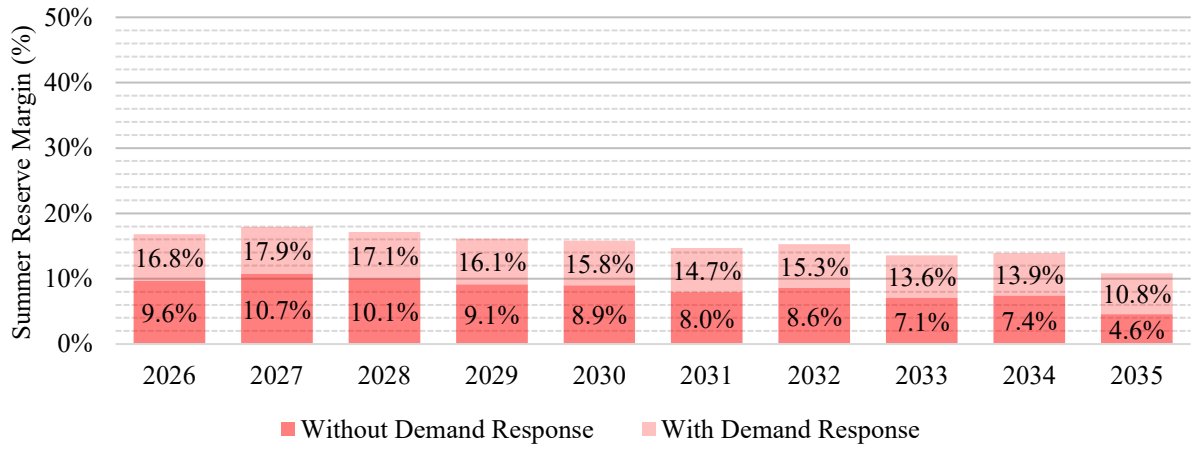
Source: FRCC 2026 Regional Load and Resource Plan - Form 10

Impact of Non-Firm Resources

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 12 percent towards the summer reserve margin over the planning period. As illustrated by Figure 20, even

without any contribution from solar at time of system peak, the statewide reserve margin would remain above the 15 percent threshold until 2031.

Figure 20: State of Florida - Projected Summer Reserve Margin without Solar



Source: FRCC 2026 Load & Resource Plan, 2026 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 2026 Load and Resource Reliability Assessment Report, the FRCC details how it conducted a statewide LOLP analysis for the period 2026 through 2030 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**
2026	0.0000299	0.0000524	0.0002835	0.0001320
2027	0.0000030	0.0000308	0.00001758	0.0001458
2028	0.0000615	0.0002506	0.0005417	0.0006854
2029	0.0000713	0.0000717	0.0005374	0.0008749
2030	0.0000885	0.0004383	0.0006053	0.0015899

Source: 2026 TYSP Workshop FRCC Studies and Reports

Utility Perspectives

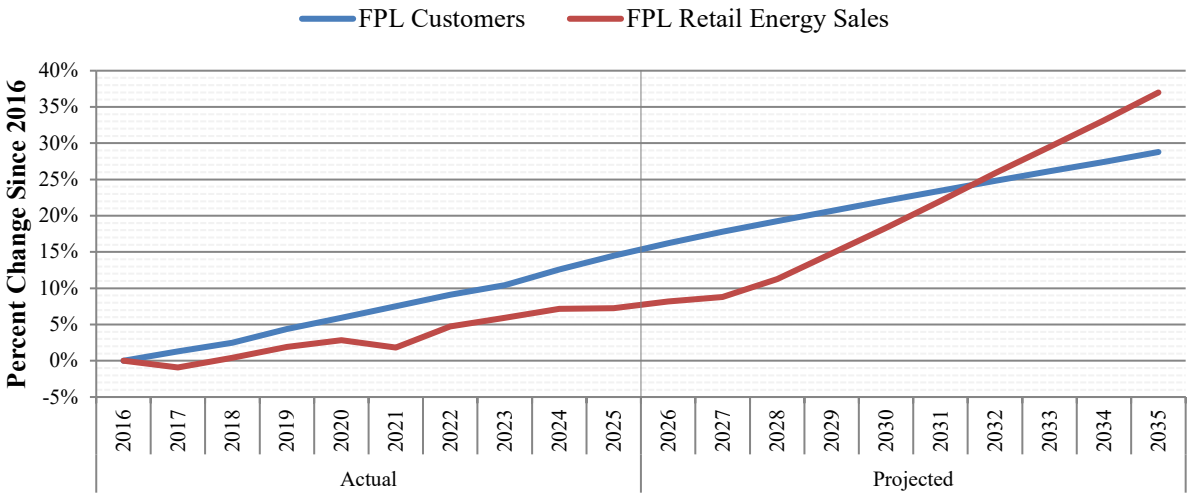
Florida Power & Light Company (FPL)

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 2026 TYSP suitable for planning purposes.

Load Forecasting

In 2025, FPL's service area had approximately 6,059,632 customers and annual retail energy sales of 129,471 GWh, accounting for approximately 53.2 percent of Florida's annual retail energy sales. The total number of customers and total retail energy sales grew by approximately 1.7 percent and 0.1 percent, respectively, in 2025. Figure 21 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that FPL filed in its 2026 TYSP.

Figure 21: FPL Growth



Source: 2026 TYSP

Over the past 10 years, FPL's customer base has increased by 14.5 percent, while retail energy sales have grown by approximately 7.2 percent. For the 2026 TYSP forecast horizon, customer growth is forecasted at 1.2 percent per year, with the residential and commercial classes accounting for most of the increase. Residential customers are expected to increase by approximately 1.2 percent annually, supported by continued but moderate growth and housing development trends. Commercial customers are projected to grow by approximately 0.9 percent per year, also reflecting steady but moderate economic activity. Industrial customer counts are forecasted to remain relatively flat, or 0.1 percent annually on average.

FPL's billed UPC across the residential and commercial classes reflect the combined long-term effects of energy efficiency improvements, evolving customer consumption patterns, and weather variability. Residential UPC declined by 1.7 percent in 2025. Commercial UPC declined by 0.6 percent in 2025. Industrial UPC increased by 2.8 percent in 2025, primarily attributable to changes in small general service industrial customer counts and use compared to the remainder of customers within this class that is more heavily weighted toward larger, more energy intensive operations.

In the forecast period, residential billed UPC is forecasted to increase at an average annual rate of approximately 0.5 percent, with initial modest declines being largely offset by continued electric vehicle adoption. Commercial billed UPC is forecasted to decline at an average annual rate of 0.7 percent, driven by continued improvements associated with electric conservation efforts. Industrial UPC is expected to increase at an annual average rate of approximately 21 percent, supported by the addition of large load customers forecasted to enter the system beginning in 2028.

For the current TYSP forecast horizon, FPL's total billed retail energy sales are projected to grow at an average annual rate of approximately 2.6 percent, with overall growth driven by a combination of steady underlying demand, continued Plug-in Electric Vehicle adoption, and large loads entering the system beginning in 2028.

Data Centers

FPL reported that it has had multiple discussions with potential large power users inquiring about service under the Utility's recently approved Large Load Contract Service (LLCS) rate schedules and tariffs. Based on these inquiries and discussions, FPL indicated that the Utility reasonably believes that there is a high probability for customers with significant load requirements to be served under the LLCS tariffs beginning in 2028. Further, FPL indicated that it estimates the total load (annual maximum MW) associated with these customers to grow to approximately 3 GW by 2035. This projection was included in the forecast used to support FPL's 2026 TYSP, which is informed by large load customer interest, including engineering studies, customer engagement, and other indicators consistent with a progression toward executed service agreements. Table 10 shows FPL's planned data centers.

The Utility noted that adding large amounts of demand and energy to the Utility's load forecast will result in new generation resources being added to its system and increased usage of its existing generation fleet to meet the need for increased energy. The Utility currently projects that it will be able to add sufficient generation capacity to meet any increases in load from data centers and will continue to evaluate prospective large load additions to ensure the reliability requirements are met. FPL also indicated that, from a transmission interconnection perspective, the Utility evaluates large-load customers on a site-specific basis to identify any required upgrades needed to reliably serve the facilities. These upgrades are identified through established planning and interconnection study processes and are coordinated with the customer's anticipated in-service date.

Table 10: FPL's Projected Large Load Data Centers

Year	No. of Data Centers	Grid Impacts		
		Annual Energy	Summer Peak	Winter Peak
	(-)	(GWh)	(MW)	(MW)
2026	-	-	-	-
2027	-	-	-	-
2028	2	1,520	248	25
2029	2	4,311	620	320
2030	2	7,103	992	616
2031	2	9,895	1,364	911
2032	2	12,719	1,736	1,207
2033	2	15,480	2,108	1,502
2034	2	18,272	2,480	1,798
2035	2	21,064	2,852	2,093

Source: Utility's Response Data Requests

Forecasted Load and Peak Demand

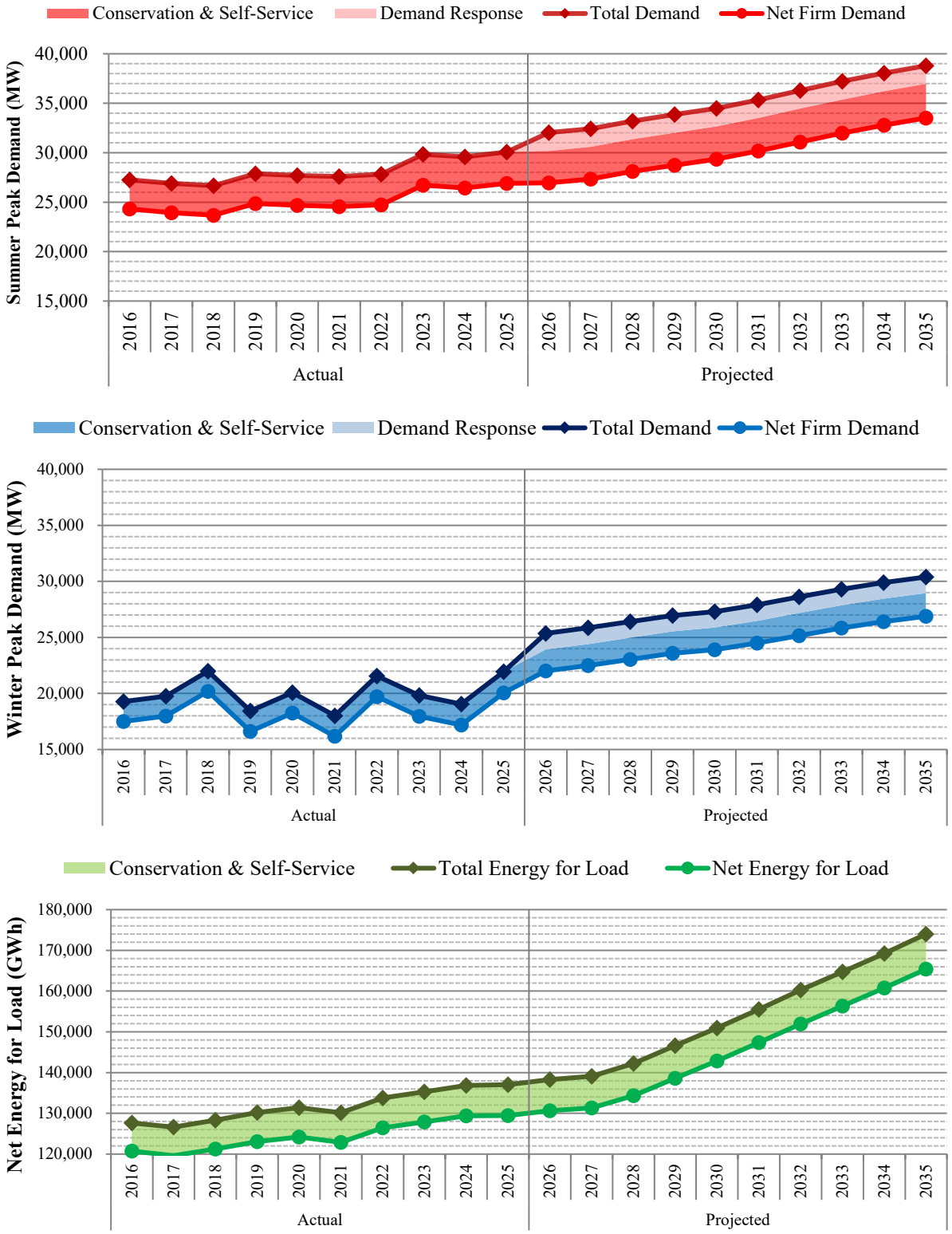
The three graphs in Figure 22 show FPL's seasonal peak demand and net energy for load for the historic years of 2016 through 2025 and forecast years 2026 through 2035. These graphs include the impact of DSM, and for future years assume that all available demand response resources will be activated during the seasonal peak. FPL also included the impact of expected data center-related large load customers in the development of its seasonal peak demand and energy forecasts.

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.[11]

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 2016 through 2021, and integrated FPL/GPC historical data for 2022 through 2025, and forecast data 2026 through 2035.

[11] See Order Nos. PSC-2024-0505-FOF-EG issued December 18, 2024, in Docket No. 20240012-EG, *In re: Commission review of numeric conservation goals (Florida Power & Light Company)* and PSC-2025-0292-PAA-EG issued July 29, 2025 in Docket No. 20250048-EG, *In re: Petition for approval of proposed demand-side management plan, by Florida Power & Light Company*.

Figure 22: FPL Demand and Energy Forecasts



Source: 2026 TYSP

Generation Resources

Currently, FPL generating facilities provide approximately 32,601 MW of summer capacity. This includes 24,519 MW from fossil generation, 3,502 MW from nuclear, 3 MW of landfill gas, and firm contributions of 3,588 MW from solar and 991 MW from energy storage. FPL has 7,932 MW of nameplate solar capacity installed, but only counts an average of 45 percent as firm towards summer peak. FPL considers its energy storage capacity as firm capacity for summer. FPL operates two of its 819 MW natural gas-fired steam units as winter peaking units only and are not included in this total.

In addition to the Utility's capacity, FPL has multiple long-term purchased power contracts. These include two wind contracts for approximately 270 MW of nameplate capacity, which FPL counts as contributing 30 percent towards summer peak.

Projected Generation Resources

FPL's unit retirements and additions during the planning period are described in Table 11. FPL plans multiple additions within the planning period, totaling an approximate 23,695 MW of additional generation capacity, most of this resulting from planned solar facilities with a combined capacity of approximately 12,293 MW. Other planned facilities include the installation of four natural gas combustion turbine units within Martin County with a combined capacity of 3,276 MW, the inclusion of the 672 MW Vandolah plant starting in 2027, and multiple upgrades to existing natural gas combined cycle units. Their energy storage portfolio is anticipated to expand by an approximate 7,545 MW of energy storage throughout the forecast period.

Over the planning period, FPL plans to retire the Lansing Smith Unit 3A by the end of 2027, the Gulf Clean Energy Center Units 4 and 5 and Perdido Units 1 and 2 by the end of 2029, and Pea Ridge Units 1 through 3 by the end of 2031. Purchased power agreements with the Palm Beach Solid Waste Authority for 40 MW and 70 MW end in April 2032 and June 2034 respectively, and a contract for 3.5 MW from the Broward South Landfill facility ends starting 2027.

Table 11: FPL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Firm Capacity (MW) Sum	Notes
Retiring Units					
2026	Lansing Smith Unit 3A	LO CT	32	32	
2030	Gulf Clean Energy Center 4 & 5	NG ST	150	150	
2030	Perdido 1 & 2	LFG IC	4	4	
2032	Pea Ridge 1-3	NG GT	12	12	
	Total Retirements		**198**	**198**	
New Units					
2026	Sited Solar Plants	PV	298	27	4 Sites
2026	Unsited Energy Storage	BA	1,420	1420	
2027	Sited Solar Plants	PV	1,192	53	16 Sites
2027	Unsited Energy Storage	BA	820	656	
2028	Sited Solar Plants	PV	1,490	79	20 Sites
2028	Unsited Solar Plant	PV	298	14	
2028	Unsited Energy Storage	BA	596	435	
2029	Sited Solar Plants	PV	596	34	
2029	Unsited Solar Plant	PV	1,788	92	
2029	Unsited Energy Storage	BA	596	370	
2030	Unsited Solar Plants	PV	2,980	152	
2030	Unsited Energy Storage	BA	596	310	
2031	Unsited Energy Storage	BA	1,192	620	
2032	4x0 Martin CT	NG CT	930	930	
2033	4x0 Martin CT	NG CT	930	930	
2033	Unsited Energy Storage	BA	596	250	
2034	4x0 Martin CT	NG CT	930	930	
2034	Unsited Solar Plants	PV	1,490	76	
2034	Unsited Energy Storage	BA	224	94	
2035	2x0 Martin CT	NG CT	465	465	
2035	Unsited Solar Plant	BA	1,565	80	
2035	Unsited Energy Storage	BA	820	316	
	Total New Units		**21,812**	**8,333**	
	Net Additions		**21,614**	**8,135**	

Source: 2026 TYSP and 2026 FRCC Load & Resource Plan

Fuel Diversity

Table 12 shows FPL's actual net energy for load by fuel type for 2025 and the projected fuel mix for 2035. FPL relies primarily upon natural gas for energy generation, making up 67.5 percent of net energy for load in 2025. FPL is projected to use natural gas for less than two thirds of its energy generation by 2035; however, natural gas will remain FPL's primary fuel source at approximately 57 percent, while renewables will account for 26.5 percent, followed by nuclear at 16.1 percent.

Table 12: FPL Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2025		2035	
	GWh	%	GWh	%
Natural Gas	99,427	**67.5%**	103,049	**57.0%**
Coal	479	**0.3%**	1,071	**0.6%**
Nuclear	29,384	**20.0%**	29,027	**16.1%**
Oil	56	**0.0%**	0	**0.0%**
Renewable	17,617	**12.0%**	47,798	**26.5%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	297	**0.2%**	(269)	**-0.1%**
Total	**147,260**		**180,677**	

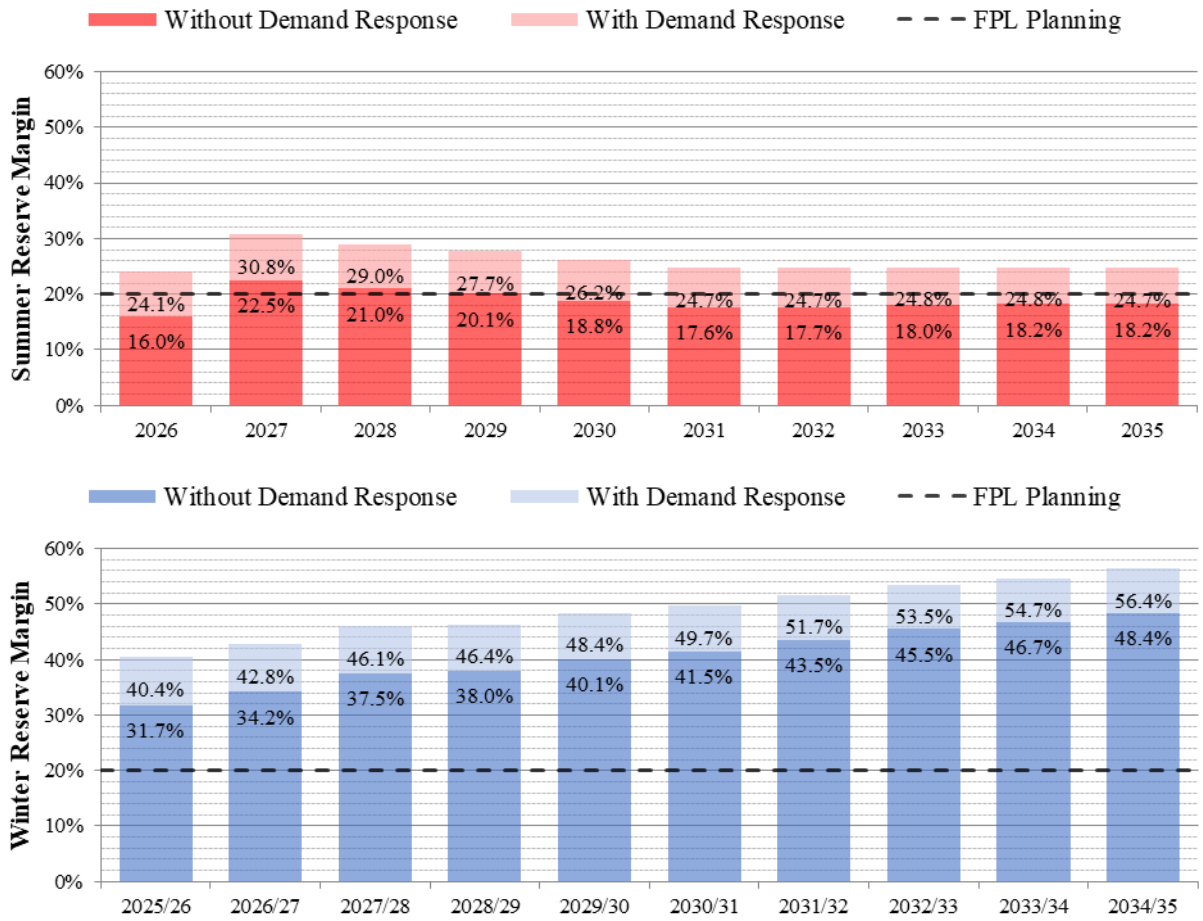
Source: 2026 TYSP

Reliability

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. 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, FPL's future 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 7,932 MW of existing utility-owned solar generation, it treats it as contributing 3,588 MW or 45 percent in summer, and 115 MW or 1.5 percent in winter. Planned solar generation additions of 18,265 MW are only considered firm for an additional 1,502 or 8.2 percent in summer, and 337 MW or 1.8 percent in winter.

Figure 23: FPL Reserve Margin Forecast



Source: 2026 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.

FPL has shifted 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 2026 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 Commission will have an opportunity to review this methodology during a future proceeding.

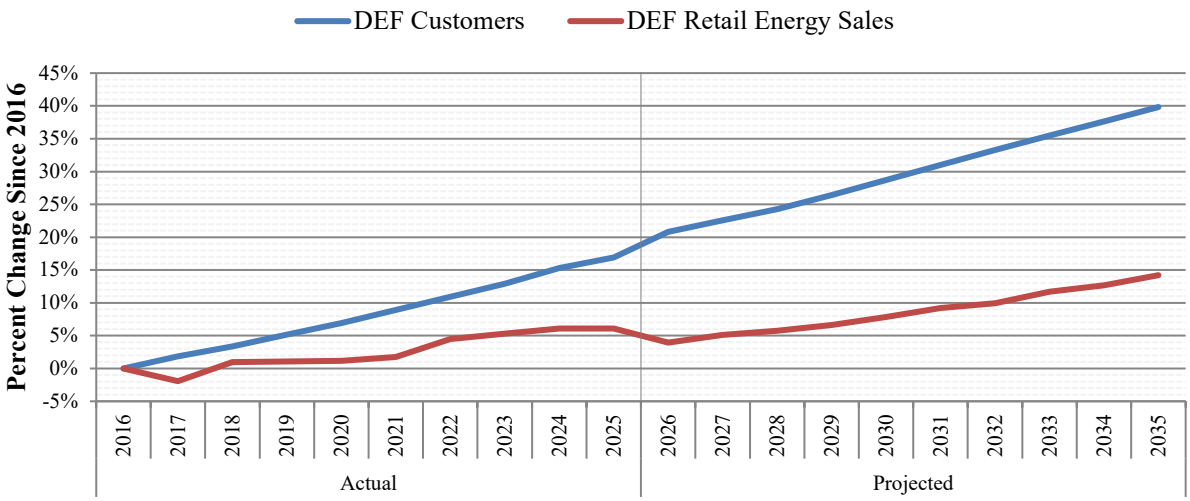
Duke Energy Florida, LLC (DEF)

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 2026 TYSP suitable for planning purposes.

Load Forecasting

In 2025, DEF had approximately 2,037,989 customers and annual retail energy sales of 41,140 GWh, accounting for approximately 16.9 percent of Florida's annual retail energy sales. DEF's total customers and total retail energy sales respectively grew approximately 1.4 percent and 0.02 percent in 2025. Over the past 10 years, DEF's customer base has increased by 16.9 percent, while retail energy sales have grown by 6.1 percent. Figure 24 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan DEF filed in its 2026 TYSP.

Figure 24: DEF Growth



Source: 2026 TYSP

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

DEF reported that the UPC of its residential and commercial accounts is driven primarily by fluctuations in price for electric service, end use appliance saturation, improved end use appliance efficiency, building codes, and changes in housing type/building size and space conditioning

equipment fuel type. Some residential and commercial accounts have reduced their utility requirements by installing solar panels behind their meter. The Utility indicated that more recently, the ability to self-generate also has begun to make an impact on UPC. A small percentage of industrial/commercial customers have chosen to install their own natural gas generation, reducing kWh consumption from the power grid. Not all recent trends in UPC are reflective of reductions to UPC. For example, DEF noted that the penetration of plug-in electric vehicles has grown, leading to an increase in residential use per customer, all else being equal.

For the 2026 TYSP forecast horizon, DEF's customer base is projected to grow at an average annual rate of approximately 1.6 percent, and its retail energy sales amount is projected to grow at an average annual rate of approximately 1.1 percent.

Data Centers

DEF has received inquiries from several potential new data center customers but stated that none of these inquiries have progressed to the level of commitment that would warrant inclusion in DEF's 2026 TYSP load forecast.

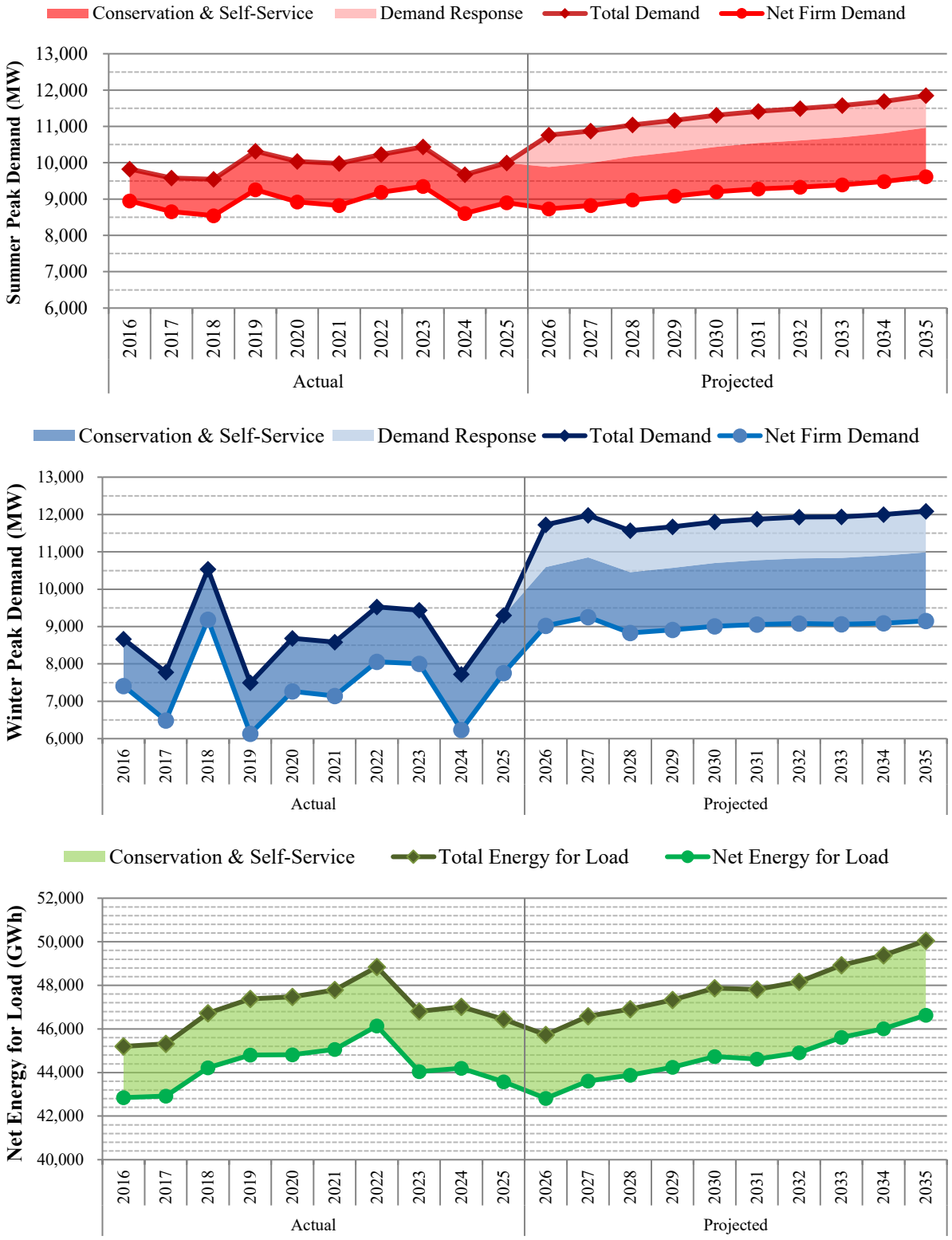
Forecasted Load and Peak Demand

The three graphs in Figure 25 show DEF's seasonal peak demand and net energy for load for the historic years of 2016 through 2025 and forecast years 2026 through 2035. 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. DEF did not include the impact of data center-related large load customers in the development of its seasonal peak demand and energy forecasts.

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.[12]

[12] See Order Nos. PSC-2024-0429-FOF-EG, issued September 20, 2024, in Docket No. 20240013-EG, *In re: Commission review of numeric conservation goals (Duke Energy Florida, LLC)* and 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: 2026 TYSP

Generation Resources

Currently, DEF generating facilities provide approximately 10,996 MW of summer capacity. This includes 10,132 MW from fossil generation and firm contribution of 864 MW from solar generation. DEF has 1,665 MW of nameplate solar capacity installed, but only counts an average of 52 percent as firm towards summer peak. In addition, DEF operates 50 MW of energy battery storage capacity.

Projected Generation Resources

DEF's unit retirements and additions during the planning period are described in Table 13. DEF plans a number of additions within the planning period including the installation of 67 new solar facilities totaling an approximate 5,017 MW of summer net capacity and 6 battery energy storage facilities with a combined total capacity of 1,400 MW.

A number of retirements are planned to begin with the retirement of the Bayboro Units 1, 2, and 4 by the end of 2026. Bartow Units P1 through P4, Debary Units P2 through P6, Intercession City Units P4 through P6, are also scheduled for retirement in 2034 alongside the coal-fired Crystal River Units 4 and 5.

Table 13: DEF Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Firm Capacity (MW) Sum	Notes
Retiring Units					
2026	Bayboro Units 1, 2, & 4	DFO CT	97	97	
2034	Bartow Units P1 & P3	DFO CT	82	82	
2034	Bartow Units P2 & P4	NG CT	86	86	
2034	Debary Units P2-P6	DFO CT	227	227	
2034	Intercession City P4-P6	DFO CT	138	138	
2034	Crystal River Units 4-5	BIT ST	1,422	1,422	
	Total Retirements		**2,052**	**2,052**	
New Units					
2026	Jumper Creek	PV	75	27	
2026	Bailey Mill	PV	75	26	
2027	Sited Solar	PV	374	131	5 Sites
2027	Powerline Energy Storage	BA	100	96	
2028	Bull Creek	PV	75	25	
2028	Wewahootee	PV	75	25	
2028	Unsited Solar	PV	375	113	5 Sites
2028	Bartow Energy Storage	BA	225	225	
2029	Unsited Solar	PV	449	117	6 Sites
2029	Co-located BESS	BA	100	96	
2030	Unsited Solar	PV	524	120	7 Sites
2030	Co-located BESS	BA	150	143	
2031	Unsited Solar	PV	599	120	8 Sites
2031	Undesignated CT P1-P2	NG GT	436	436	
2032	Unsited Solar	PV	599	100	8 Sites
2033	Unsited Solar	PV	599	95	8 Sites
2034	Unsited Solar	PV	599	93	8 Sites
2034	Co-located BESS	BA	525	469	
2034	Unsited Energy Storage	BA	300	255	
2034	Undesignated CT P3-P4	NG GT	799	799	
2035	Unsited Solar	PV	599	81	8 Sites
	Total New Units		**7,652**	**3,592**	
	Net Additions		**5,600**	**1,540**	

Source: 2026 TYSP and 2026 FRCC Load & Resource Plan

Fuel Diversity

Table 14 shows DEF's actual net energy for load by fuel type as of 2025 and the projected fuel mix for 2035. DEF relies primarily upon natural gas for energy generation, making up approximately 83.4 percent of net energy for load in 2025. 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 31.7 percent of its generation by 2035, which is the second highest percentage of renewable energy generation in 2035 of the TYSP Utilities. Natural gas would remain the primary fuel, at 68.3 percent in 2035.

Table 14: DEF Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2025		2035	
	GWh	%	GWh	%
Natural Gas	36,346	**83.4%**	31,850	**68.3%**
Coal	3,837	**8.8%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	34	**0.1%**	1	**0.0%**
Renewable	3,659	**8.4%**	14,780	**31.7%**
Interchange	(665)	**-1.5%**	0	**0.0%**
NUG & Other	369	**0.8%**	0	**0.0%**
Total	**43,580**		**46,632**	

Source: 2026 TYSP and Data Responses

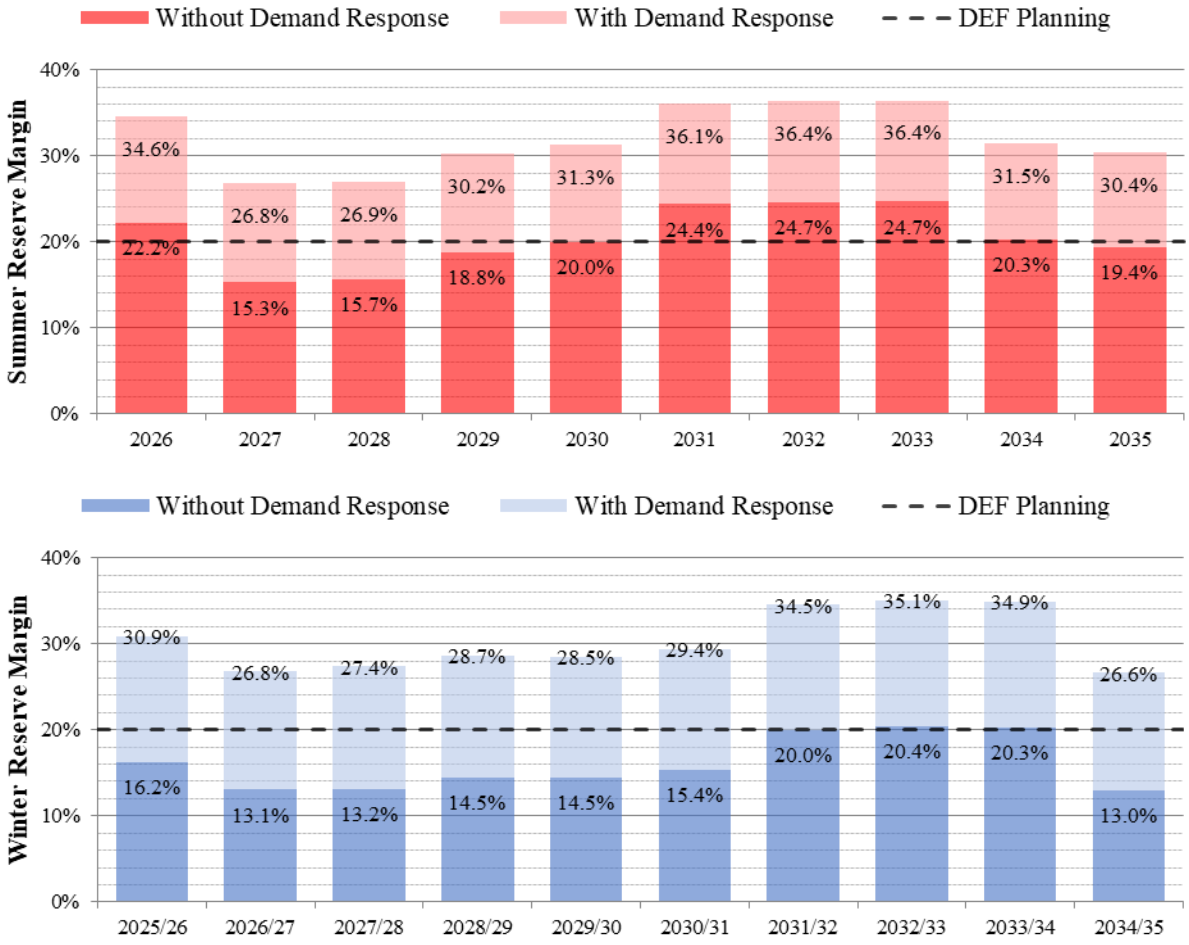
Reliability

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion based on a stipulation approved by the Commission.[13] 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.

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

Figure 26: DEF Reserve Margin Forecast



Source: 2026 TYSP

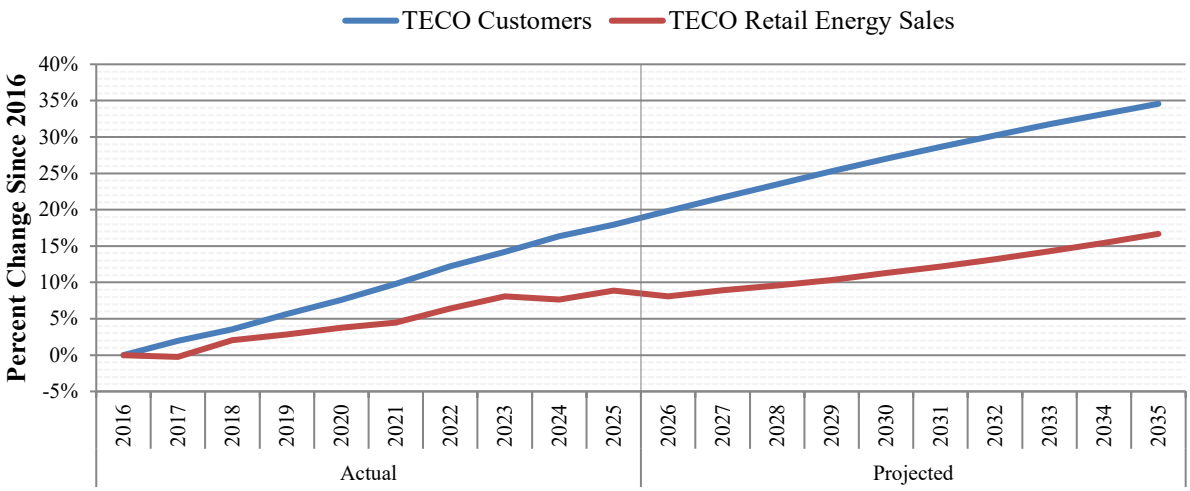
Tampa Electric Company (TECO)

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 2026 TYSP suitable for planning purposes.

Load Forecasting

In 2025, TECO had approximately 861,413 customers and annual retail energy sales of 20,943 GWh, accounting for approximately 8.6 percent of Florida's annual retail energy sales. Over the last 10 years, TECO's customer base has increased by approximately 17.9 percent, while retail energy sales have increased by approximately 8.9 percent. Figure 27 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan details that TECO filed as part of its 2026 TYSP.

Figure 27: TECO Growth



Source: 2026 TYSP

TECO's total customer growth in 2025 averaged approximately 1.4 percent with the residential class being the engine behind the growth. Over the next 10 years, total customer growth is expected to increase at an average rate of 1.3 percent annually.

TECO's residential UPC and commercial UPC growth rates were both slightly lower in 2025 than in 2024. The Utility's industrial UPC tends to be the most volatile primarily due to the phosphate sector, where mining activities and self-generation capabilities can vary significantly from month-to-month. Over the forecast horizon, TECO's residential UPC is expected to decline at an average annual rate of 0.4 percent. The primary drivers behind the decline in customer usage are increases in efficiencies for appliance, lighting, and new homes, conservation efforts, and changes in housing mix. The commercial UPC is expected to remain relatively flat, amounting to an annual average

reduction of about reducing 0.2 percent. The industrial UPC is expected to decrease slightly, by an annual average of 0.4 percent.

In 2025, TECO's retail energy sales were 1.2 percent higher than in 2024. 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 sales growth rate is below the projected customer growth rate of 1.3 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 the Utility's service territory.

Data Centers

TECO's 2026 TYSP does not include projections of data center loads because the Utility has not received firm end-use customer commitments.

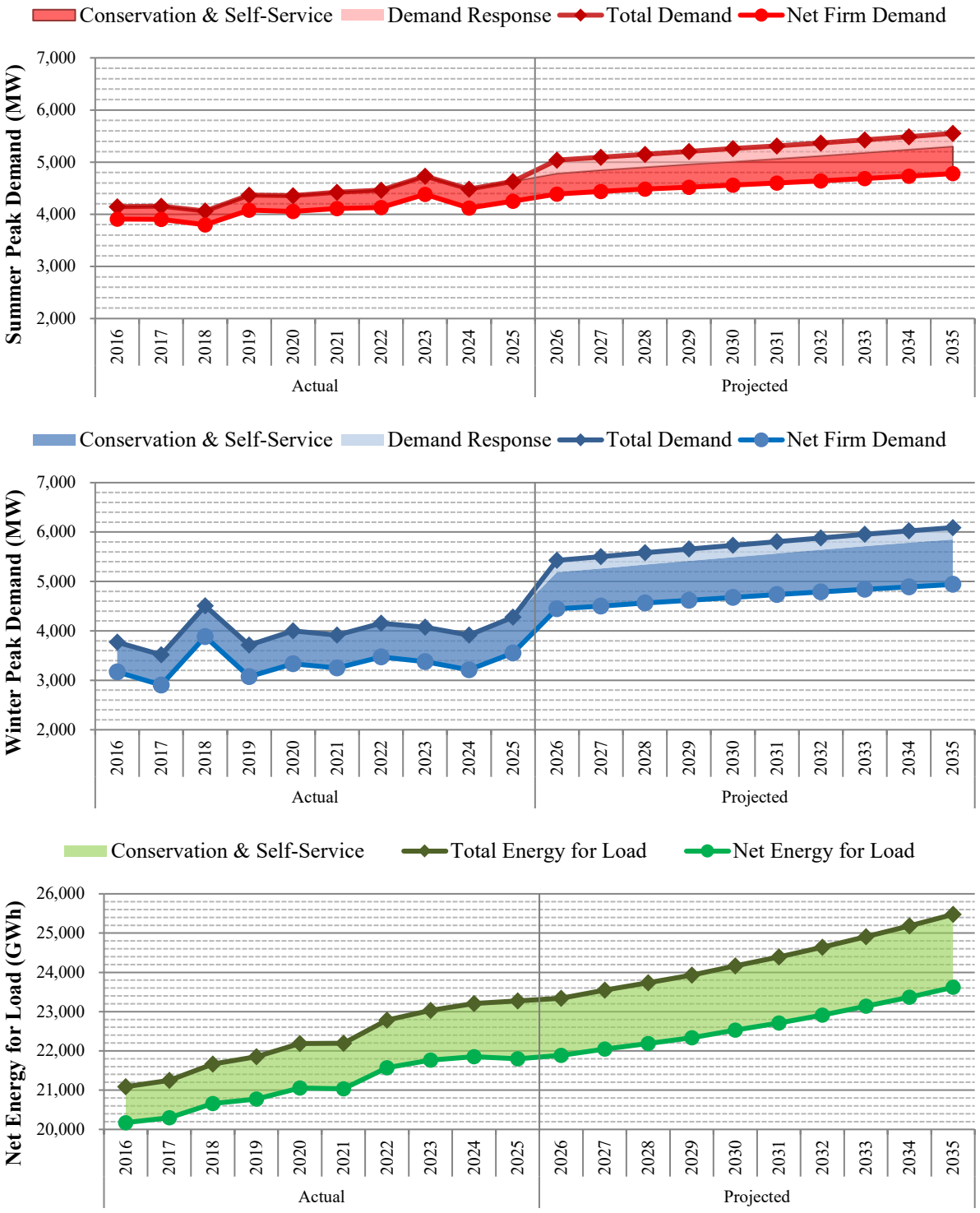
Forecasted Load and Peak Demand

The three graphs in Figure 28 show TECO's seasonal peak demand and net energy for load for the historic years of 2016 through 2025 and forecast years 2026 through 2035. 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. TECO did not include the impact of data center-related large load customers in the development of its seasonal peak demand and energy forecasts.

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.[14]

[14] See Order Nos. PSC-2024-0430-FOF-EG, issued September 20, 2024, in Docket No. 20240014-EG, *In re: Commission review of numeric conservation goals (Tampa Electric Company)* and 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: 2026 TYSP

Generation Resources

Currently, TECO generating facilities provide approximately 5,398 MW of summer capacity. This includes 4,779 MW from fossil generation and firm contributions of 514 MW firm from solar generation and 105 MW from energy storage. TECO has 1,424 MW of nameplate solar capacity solar installed, but only counts 36 percent towards summer peak. TECO considers its energy storage capacity as firm capacity for seasonal peak demand.

Projected Generation Resources

TECO's unit retirements and additions during the planning period are described in Table 15. TECO plans a number of additions within the planning period including the installation of approximately 1,424 MW additional solar generation as well as two natural gas combustion turbine facilities in early 2031 and 2035. TECO is not planning to retire any generating units and plans to upgrade Polk Unit 2 to be capable of being fueled by distillate oil by 2027. TECO anticipates the installation of an additional 115 MW of storage by the end of 2027.

Table 15: TECO Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Firm Capacity (MW) Sum	Notes
Retiring Units					
	None				
	Total Retirements		**0**	**0**	
New Units					
2026	Sited Solar	PV	241	11	4 Sites
2026	Bayside Battery Storage	BA	20	20	
2027	Sited Solar	PV	191	2.9	4 Sites
2027	Sited Energy Storage	BA	95	95	2 Sites
2028	Rising Sun Solar	PV	75	1.1	
2028	Unsited Solar	PV	149	2.2	2 Sites
2029	Unsited Solar	PV	149	1.5	2 Sites
2030	Unsited Solar	PV	149	1.5	2 Sites
2031	Future CT 1	NG CT	223		
2035	Future CT 2	NG CT	223		
	Total New Units		**1,515**	**135**	
	Net Additions		**1,515**	**135**	

Source: 2026 TYSP and 2026 FRCC Load & Resource Plan

Fuel Diversity

Table 16 shows TECO's actual net energy for load by fuel type as of 2025 and the projected fuel mix for 2035. Natural gas is used for the majority of TECO's energy generation, and accounts for approximately 80.2 percent of net energy for load in 2025 and is projected to account for approximately 75.8 percent in 2035. Renewables, primarily solar, are anticipated to increase from 11.1 percent in 2025 to 23 percent in 2035.

Table 16: TECO Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2025		2035	
	GWh	%	GWh	%
Natural Gas	17,472	**80.2%**	17,897	**75.8%**
Coal	39	**0.2%**	193	**0.8%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	7	**0.0%**	0	**0.0%**
Renewable	2,419	**11.1%**	5,436	**23.0%**
Interchange	270	**1.2%**	74	**0.3%**
Other	1,592	**7.3%**	19	**0.1%**
Total	**21,798**		**23,619**	

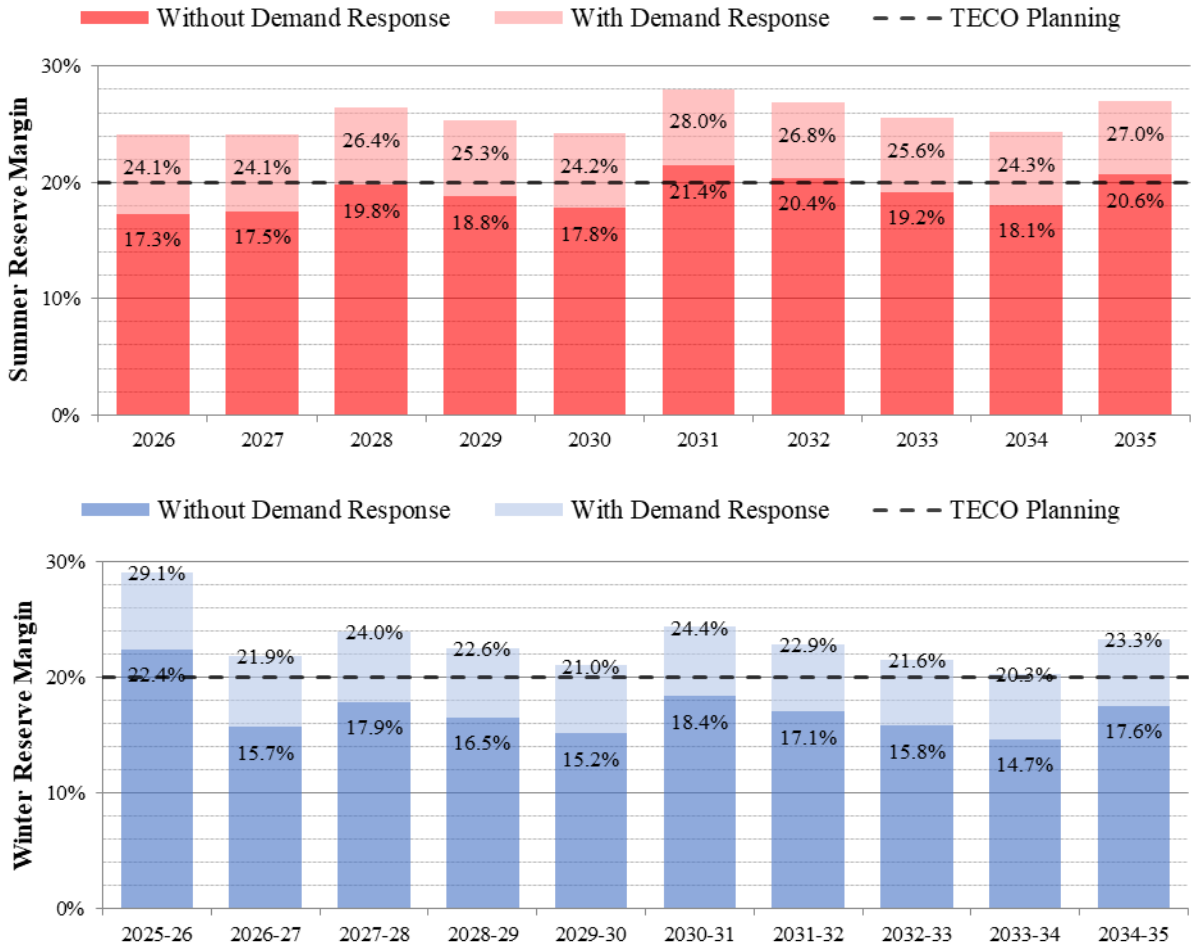
Source: 2026 TYSP and Data Responses

Reliability

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion based on a stipulation approved by the Commission.[15] 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 Figure 29, 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.

[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 29: TECO Reserve Margin Forecast



Source: 2026 TYSP

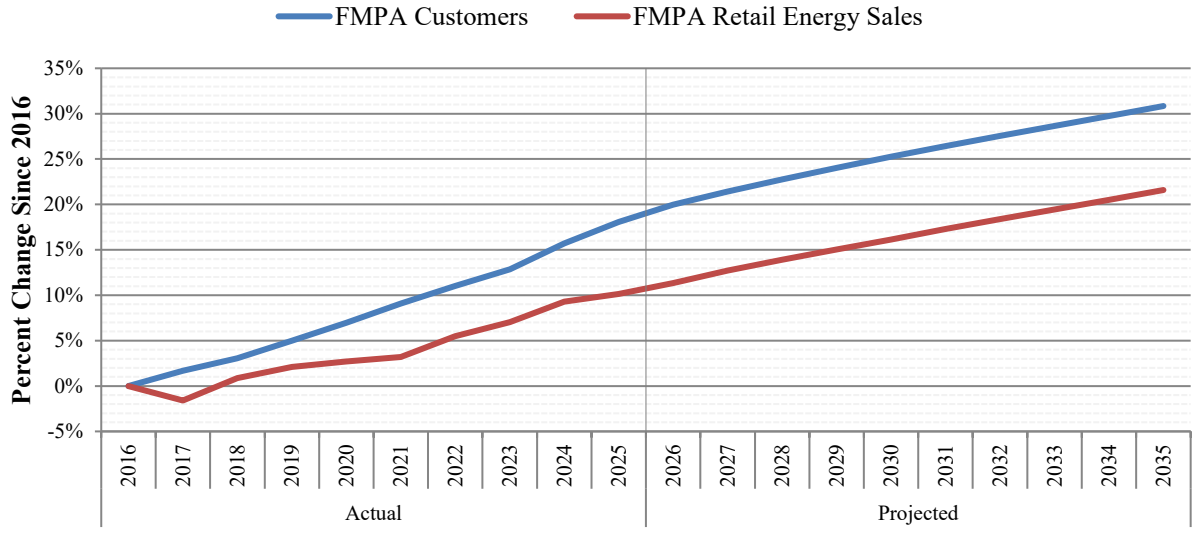
Florida Municipal Power Agency (FMPA)

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 33 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 2026 TYSP suitable for planning purposes.

Load Forecasting

In 2025, FMPA had approximately 299,269 customers and annual retail energy sales of 6,302 GWh, accounting for approximately 2.6 percent of Florida's annual retail energy sales. Over the last 10 years, FMPA's customer base has increased by 18.1 percent, while energy sales have increased by 10.2 percent. 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 approximately 1.0 percent average annual growth rate for energy sales as well. Figure 30 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that FMPA filed in its 2026 TYSP.

Figure 30: FMPA Growth



Source: 2026 TYSP

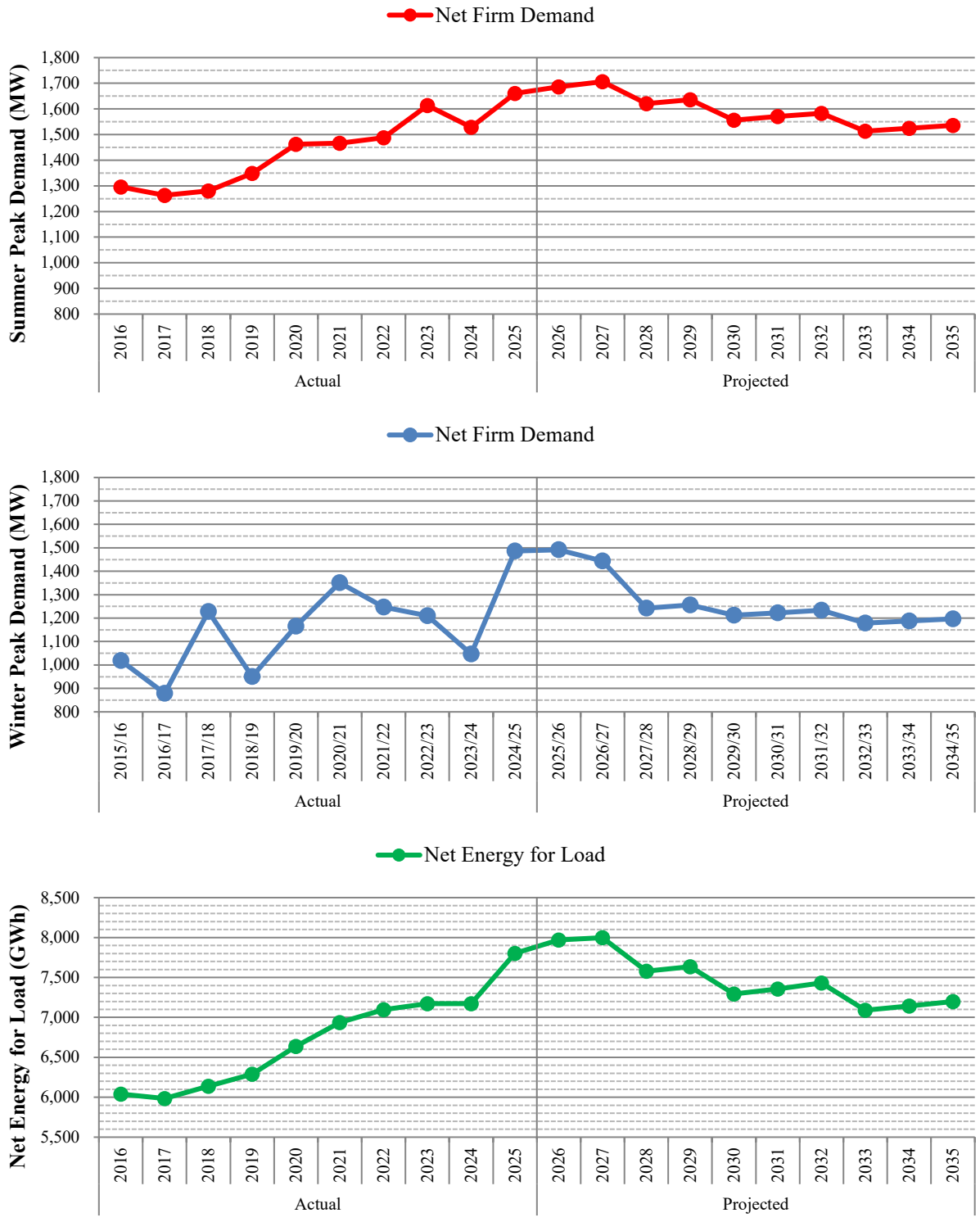
In 2025, FMPA's total customer growth averaged approximately 2.1 percent. It noticed strong customer count gains in certain areas of the ARP participant service territories where residential sector expansion is the primary driver.

FMPA's annual increase in energy sales was 0.8 percent in 2025, lower than the 2.1 percent increase recorded in 2024. The Utility explained that while total retail sales are significantly impacted by the growth in customer counts, they are also impacted by weather conditions, retail billing cycles and practices of the ARP Participants, among other factors. The calendar year 2025 exhibited lower cooling degree days than 2024 across much of the Florida peninsula, which reduced energy consumption for cooling load and therefore reduced the rate of growth in overall energy sales.

Forecasted Load and Peak Demand

The three graphs in Figure 31 show FMPA's seasonal peak demand and net energy for load for the historic years of 2016 through 2025 and forecast years 2026 through 2035. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer demand-side management programs, the impacts of which are included in the Utility's forecasts which use data provided by the ARP members. FMPA did not include the impact of data center-related large load customers in the development of its seasonal peak demand and energy forecasts.

Figure 31: FMPA Demand and Energy Forecasts



Source: 2026 TYSP

Generation Resources

Currently, FMPA generating facilities provide approximately 1,738 MW of summer capacity. This includes 1,689 MW from fossil generation and 49 MW from nuclear generation based on FMPA's full or partial ownership of units. The largest two units on FMPA's system are two natural gas-fired combined cycle units which provide 611 MW.

In addition to the Utility's capacity, FMPA has multiple long-term purchased power contracts. These include several solar contracts for 116 MW of nameplate capacity, which FMPA counts as contributing 40 percent towards summer peak.

Projected Generation Resources

FMPA has no plans for generating unit additions or retirements within the current planning period but anticipates upgrading the plant capacity of multiple existing units as well as decreased generation from the St. Lucie facility in 2027 and 2029 as a result of FMPA member purchased power contracts expiring.

Fuel Diversity

Table 17 shows FMPA's actual net energy for load by fuel type as of 2025 and the projected fuel mix for 2035. FMPA uses natural gas as its primary fuel, producing 80.5 percent of energy in 2025 and increasing to 89.9 percent of energy by 2035. 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 17: FMPA Energy Generation by Fuel Type

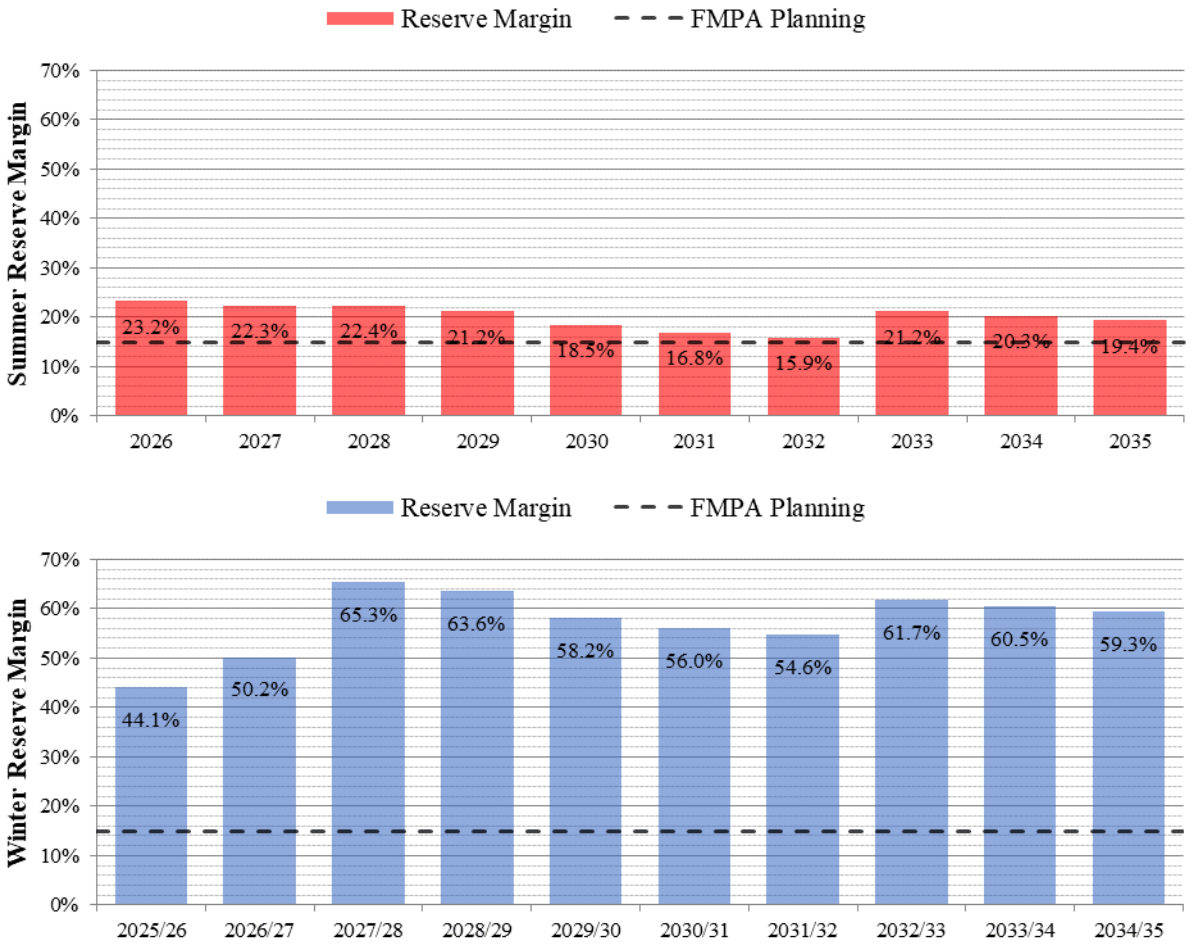
Fuel Type	Net Energy for Load			
	2025		2035	
	GWh	%	GWh	%
Natural Gas	6,281	**80.5%**	6,468	**89.9%**
Coal	814	**10.4%**	0	**0.0%**
Nuclear	411	**5.3%**	390	**5.4%**
Oil	7	**0.1%**	1	**0.0%**
Renewable	290	**3.7%**	339	**4.7%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**7,804**		**7,197**	

Source: 2026 TYSP and Data Responses

Reliability

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: 2026 TYSP

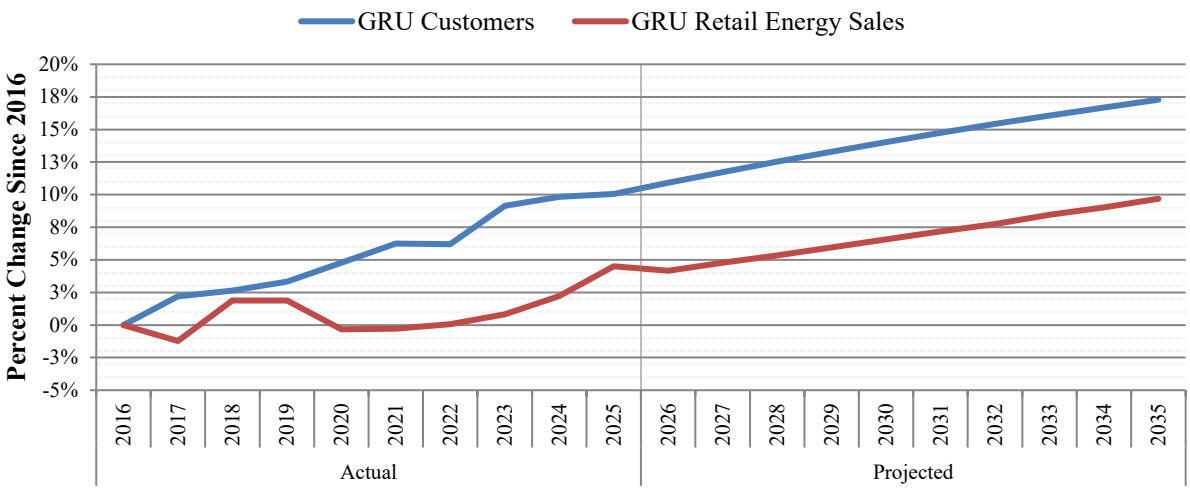
Gainesville Regional Utilities (GRU)

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 2026 TYSP suitable for planning purposes.

Load Forecasting

In 2025, GRU had approximately 104,730 customers and annual retail energy sales of 1,877 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 0.2 percent and 2.2 percent, respectively. Figure 33 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that GRU filed in its 2026 TYSP.

Figure 33: GRU Growth



Source: 2026 TYSP

The annual growth in retail sales from 2024 to 2025 (2.2 percent) was primarily due to changes in weather-related heating and air conditioning loads. Weather-related factors that contributed to stronger-than-average energy sales in 2025 include a 3 percent increase in the heating degree days (from 2024) as well as a 5 percent increase in cooling degree days (from 2024). The Utility noted that year-to-year variation in energy sales due to varying weather conditions is not uncommon. Over the past 10 years, GRU has experienced changes in year-to-year energy sales from positive 3 percent to negative 2 percent.

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

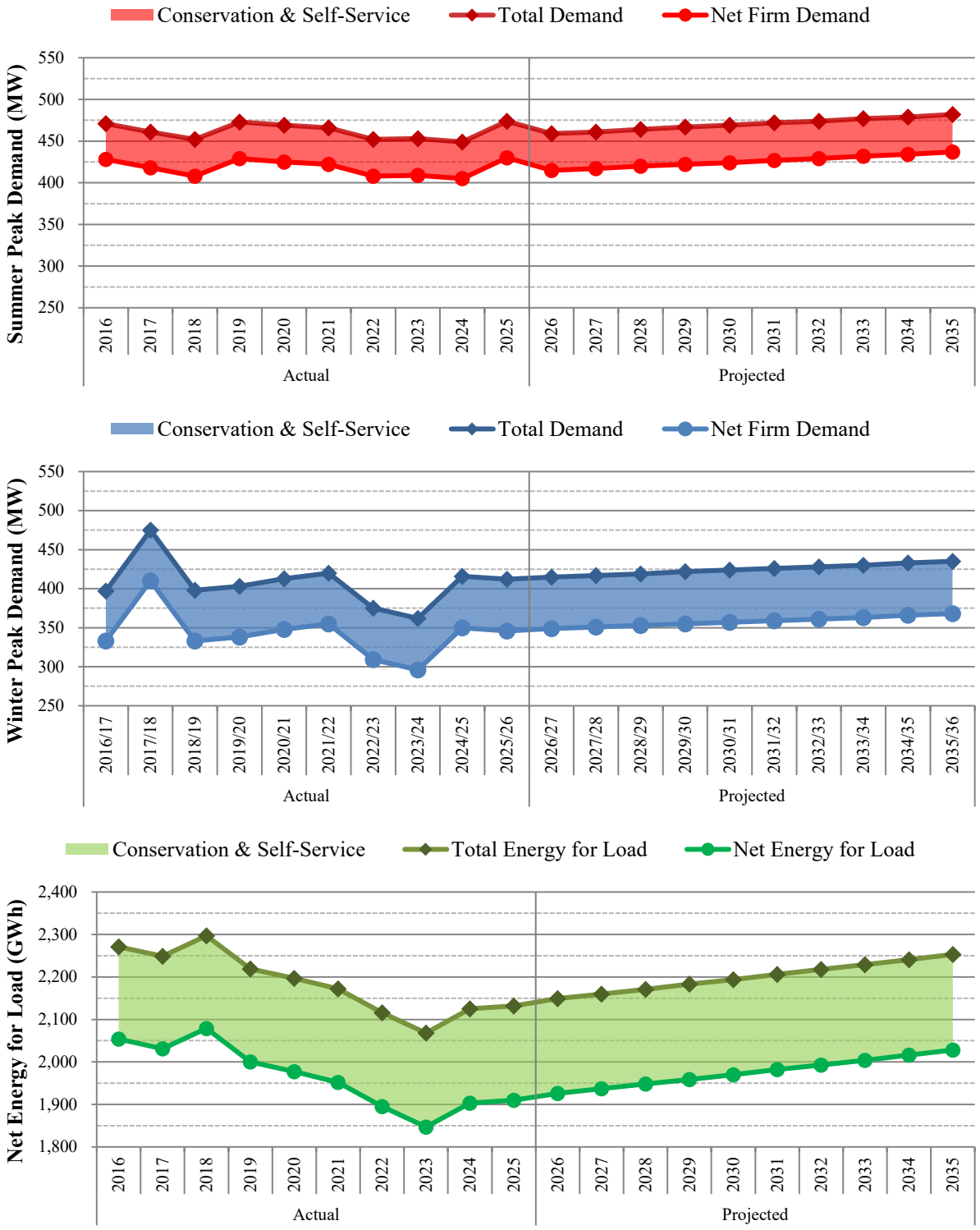
Over the last 10 years, GRU's customer base has increased by approximately 10.1 percent with an average annual growth rate of 1.1 percent, while retail energy sales have increased by approximately 4.5 percent with an average annual growth rate of 0.5 percent.

GRU's residential usage per customer declined by an average of 0.2 percent per year over the past 10 years. It is expected to increase by 0.1 percent per year over the next 10 years, driven by continued adoption of electric vehicles that charge at customer residences. The Utility's non-residential usage per customer declined by an average of 0.6 percent per year over the past 10 years. It is forecasted to decline more slowly at an average annual rate of 0.1 percent per year over the next 10 years.

Forecasted Load and Peak Demand

The three graphs in Figure 34 show GRU's seasonal peak demand and net energy for load for the historic years of 2016 through 2025 and forecast years 2026 through 2035. 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. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. GRU did not include the impact of data center-related large load customers in the development of its seasonal peak demand and energy forecasts.

Figure 34: GRU Demand and Energy Forecasts



Source: 2026 TYSP

Generation Resources

Currently, GRU generating facilities provide approximately 642 MW of summer capacity, including 105 MW of biomass-fired steam generation. GRU's largest generating unit is a natural gas-fired steam unit, with a capacity of 232 MW. GRU does not currently have any long-term purchased power contracts.

Projected Generation Resources

GRU's unit retirements and additions during the planning period are described in Table 18. GRU has no current plans to add any generation facilities and plans to retire the Deerhaven plant's combustion turbine Units GT01 and GT02 and the steam turbine Units FS01 and FS02. GRU notes that the remaining useful life of these units are currently being evaluated and the retirement dates may be deferred.

Table 18: GRU Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Firm Capacity (MW) Sum	Notes
Retiring Units					
2032	Deerhaven FS01	NG ST	76		
2036	Deerhaven FS02	NG ST	232		
2031	Deerhaven GT01	NG GT	18		
2031	Deerhaven GT02	NG GT	18		
Total Retirements			**344**		
New Units					
	None				
Total New Units			**0**	**0**	
Net Additions			**(344)**	**0**	

Source: 2026 TYSP and 2026 FRCC Load & Resource Plan

Fuel Diversity

Table 19 shows GRU's actual net energy for load by fuel type as of 2025 and the projected fuel mix for 2035. GRU relies primarily upon natural gas for energy generation, making up 72.6 percent of net energy for load in 2025. By 2035, natural gas will remain GRU's primary fuel source at 76.5 percent, while renewables will account for 17.3 percent. Coal generation is anticipated to end by 2035 with the planned retirement of Deerhaven Unit FS02, GRU's only remaining unit capable of burning coal.

Table 19: GRU Energy Generation by Fuel Type

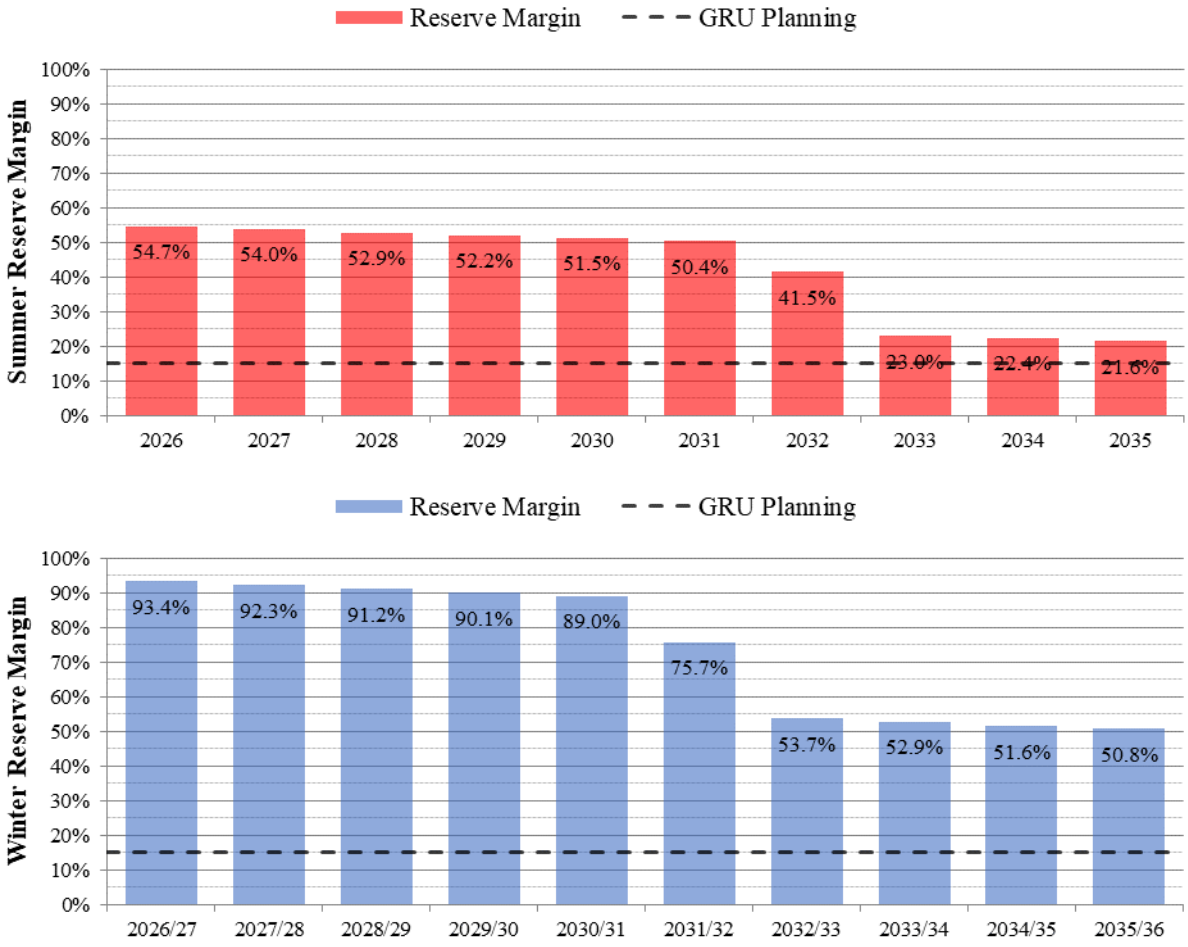
Fuel Type	Net Energy for Load			
	2025		2035	
	GWh	%	GWh	%
Natural Gas	1,387	**72.6%**	1,551	**76.5%**
Coal	13	**0.7%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	9	**0.5%**	0	**0.0%**
Renewable	453	**23.7%**	350	**17.3%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	48	**2.5%**	127	**6.3%**
Total	**1,910**		**2,028**	

Source: 2026 TYSP and Data Responses

Reliability

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 Figure 35, GRU's generation needs are controlled by its summer peak throughout the planning period.

Figure 35: GRU Reserve Margin Forecast



Source: 2026 TYSP

JEA

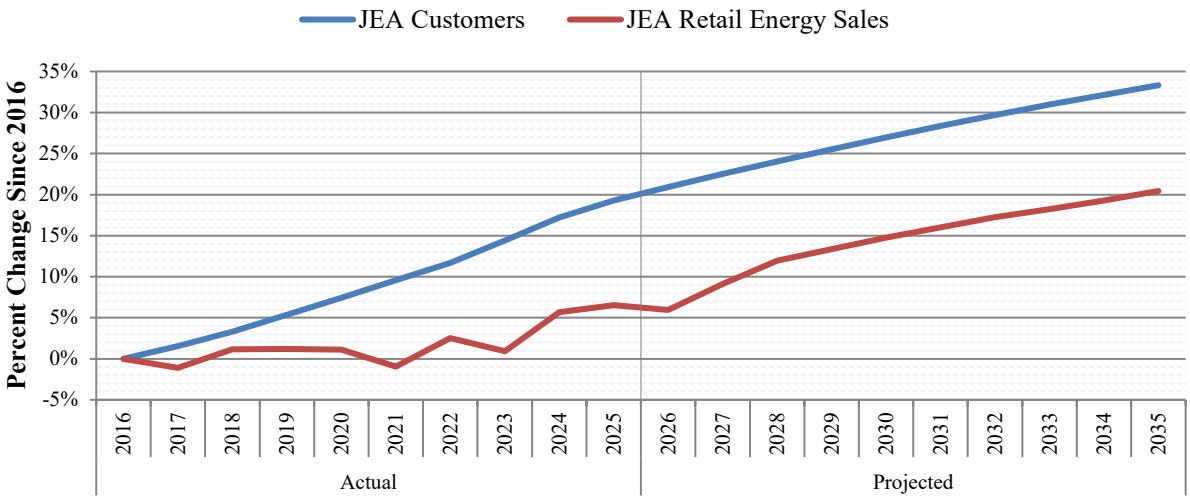
JEA, formerly known as Jacksonville Electric Authority, is Florida's largest municipal utility and fifth largest electric utility. JEA's service territory is within the FRCC region and includes all of Duval County as well as portions of Clay and St. Johns Counties. As a municipal utility, the Commission's 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 2026 TYSP suitable for planning purposes.

Load Forecasting

In 2025, JEA had approximately 536,862 customers and annual retail energy sales of 12,980 GWh, accounting for approximately 5.3 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.

For the next 10 years, JEA's customer forecast increases at an average annual rate of 1.1 percent; and its retail energy sales increases at an average annual rate of 1.4 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 2026 TYSP.

Figure 36: JEA Growth



Source: 2026 TYSP

From 2016-2025, JEA's residential UPC decreased by approximately 0.6 percent per year on average. The Utility indicated that the Utility-funded demand-side management 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 constructions, and the 2023 SEER rating standards that mandated more efficient new air conditioners.

For the 2026 TYSP forecast horizon, JEA expects that residential UPC will stay flat with an average annual growth rate of 0.2 percent, primarily driven by the forecasted increase in plug-in electric vehicle adoption. The Utility forecasts PEV total energy to grow at an average annual growth rate of 34.86 percent over the planning period. This upward pressure from PEV adoption outpaces the combined downward pressure from continued JEA funding of demand-side management programs, customer-sited renewables and distributed energy resources, shrinking household size, increased electric rates, and mandated more efficient new air conditioners. The Utility also projected its commercial UPC will decrease by 1.1 percent per year, and industrial UPC will decrease by 0.1 percent per year.

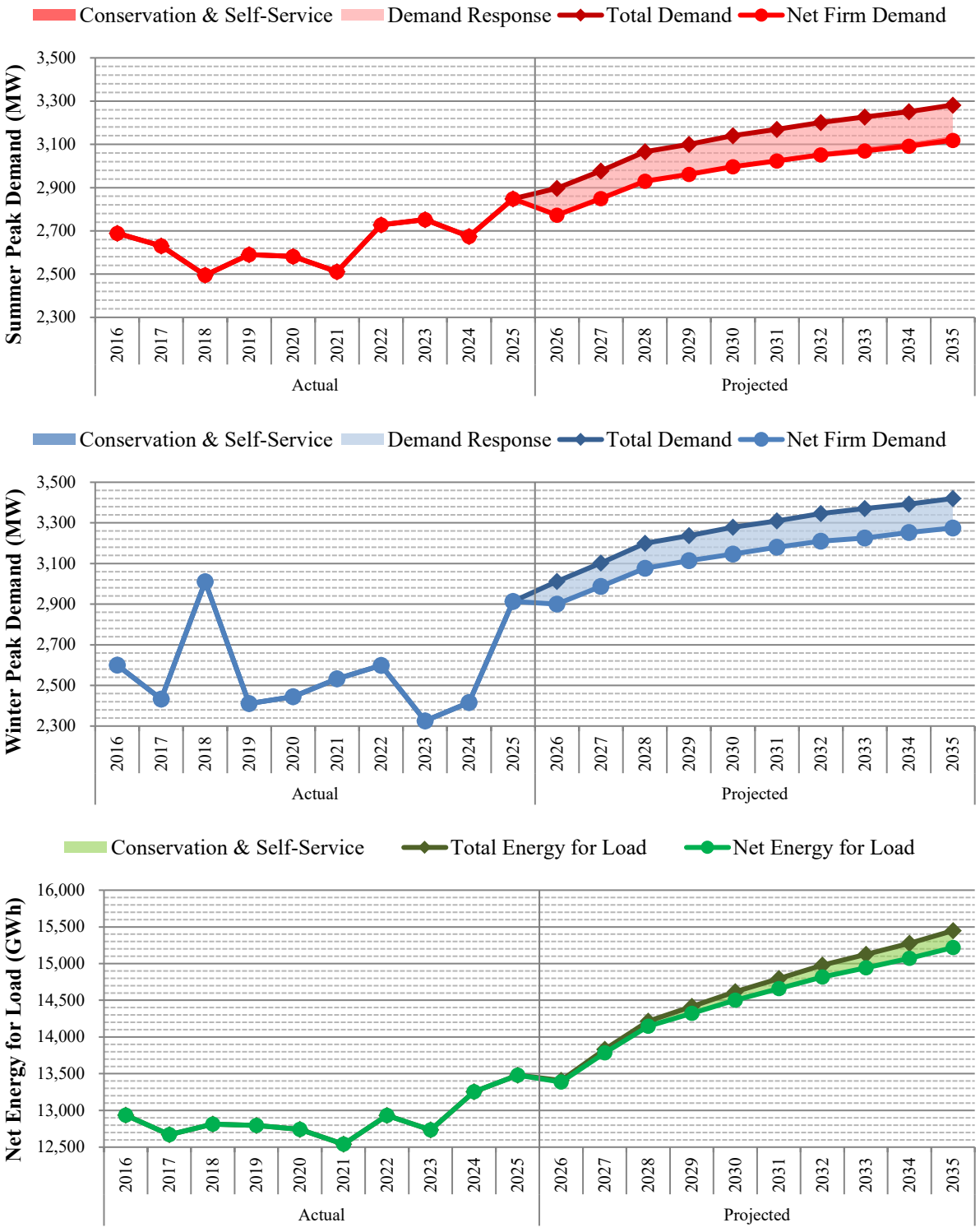
Forecasted Load and Peak Demand

The three graphs in Figure 37 show JEA's seasonal peak demand and net energy for load for the historic years of 2016 through 2025 and forecast years 2026 through 2035. 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. JEA included the impact of data center-related large load customers in the development of its seasonal peak demand and energy forecasts.

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. The Commission reviewed and established energy conservation goals for JEA and approved JEA's 2025-2034 DSM Plan.[16]

[16] See Order Nos. PSC-2024-0432-FOF-EG, issued September 20, 2024, in Docket No. 20240016-EG, *In re: Commission review of numeric conservation goals (JEA)* and 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: 2026 TYSP

Generation Resources

Currently, JEA generating facilities provide approximately 2,782 MW of summer capacity, exclusively from fossil generation. JEA's system includes approximately 1,110 MW of steam-fired generation associated with three generating units, including a pair of petcoke, coal, and biomass-fired units and a dual fuel gas/oil unit.

In addition to the Utility's capacity, JEA has multiple long-term purchased power contracts. The most notable is purchase from the Municipal Electric Authority of Georgia for 206 MW of nuclear capacity from Vogtle Units 3 and 4. This results in JEA having the second highest nuclear capacity in the state, only surpassed by FPL. Among its several fossil and renewable PPAs, JEA also has multiple solar contracts for a total of 389 MW of nameplate capacity, which JEA counts as contributing 20 percent towards summer peak.

Projected Generation Resources

JEA's unit retirements and additions during the planning period are described in Table 20. JEA plans for the addition of three facilities within the planning period, including a new natural gas-fired combined cycle unit in 2031 and a pair of two natural gas-fired combustion turbine units in 2035. JEA recently received a determination of need for the 2031 combined cycle unit in Docket No. 20260087-EM. JEA also plans to retire the Northside Unit 3 in early 2035 after commercial operation of the combined cycle unit.

Table 20: JEA Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Firm Capacity (MW)	Notes
			Sum	Sum	
Retiring Units					
2035	Northside Unit 3	NG ST	524		
		Total Retirements	**524**	**0**	
New Units					
2031	Advanced 1x1 CC	NG CC	582		Docket No. 20260086-EM
2035	Advanced 1x0 CT	NG GT	374		
2035	Advanced 1x0 CT	NG GT	374		
		Total New Units	**1,330**	**0**	
		Net Additions	**806**	**0**	

Source: 2026 TYSP and 2026 FRCC Load & Resource Plan

Fuel Diversity

Table 21 shows JEA's actual net energy for load by fuel type as of 2025 and the projected fuel mix for 2035. Natural gas is the dominant fuel source for JEA in 2025 and is projected to remain so in 2035 with purchases from other utilities, through the Interchange, being JEA's second most utilized energy source. The nuclear energy generation is also sourced through interchange, associated with JEA's contract for a portion of Vogtle Units 3 and 4. JEA anticipates reducing its

reliance on non-nuclear interchange, reducing from 18.7 percent in 2025 to 6.7 percent in 2035, primarily offset by an increase in natural gas.

Table 21: JEA Energy Generation by Fuel Type

Fuel Type	Net Energy for Load			
	2025		2035	
	GWh	%	GWh	%
Natural Gas	7,427	**55.1%**	10,433	**68.6%**
Coal	1,334	**9.9%**	1,413	**9.3%**
Nuclear	1,613	**12.0%**	1,765	**11.6%**
Oil	20	**0.1%**	0	**0.0%**
Renewable	564	**4.2%**	594	**3.9%**
Interchange	2,521	**18.7%**	1,014	**6.7%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**13,479**		**15,219**	

Source: 2026 TYSP and Data Responses

Reliability

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.

Figure 38: JEA Reserve Margin Forecast



Source: 2026 TYSP

Lakeland Electric (LAK)

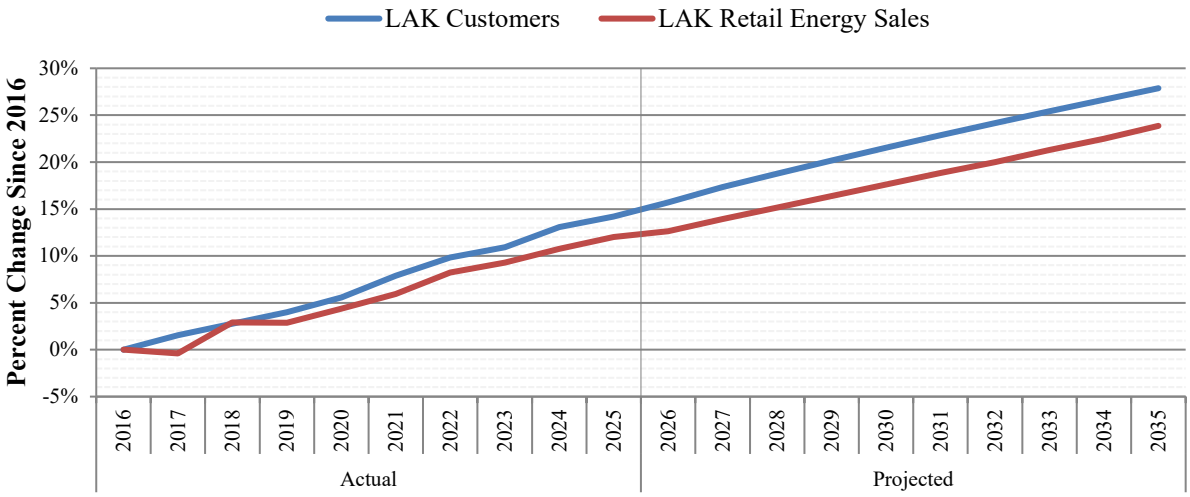
LAK is a municipal utility and the state's third smallest electric utility required to file a TYSP. The Utility's service territory is within the FRCC region and consists of the City of Lakeland and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds LAK's 2026 TYSP suitable for planning purposes.

Load Forecasting

In 2025, LAK had approximately 145,224 customers and annual retail energy sales of 3,394 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 1.1 percent and 1.0 percent, respectively. Over the last 10 years, LAK's customer base has increased by 14.2 percent, while retail energy sales have grown by 12.0 percent approximately.

For the next 10 years, LAK's customer forecast increases at an average annual rate of 1.2 percent; and its retail energy sales increases at an average annual rate of 1.1 percent. Figure 39 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that LAK filed in its 2026 TYSP.

Figure 39: LAK Growth



Source: 2026 TYSP

LAK's residential and commercial customer growth has been driven primarily by sustained population increases and continued economic development within the service territory. The City of Lakeland has been recognized as one of the fastest-growing areas in the nation, contributing to steady residential expansion and corresponding commercial development. The Utility's industrial customer growth has been more moderate, reflecting the stability of existing facilities and measured industrial expansion within the region.

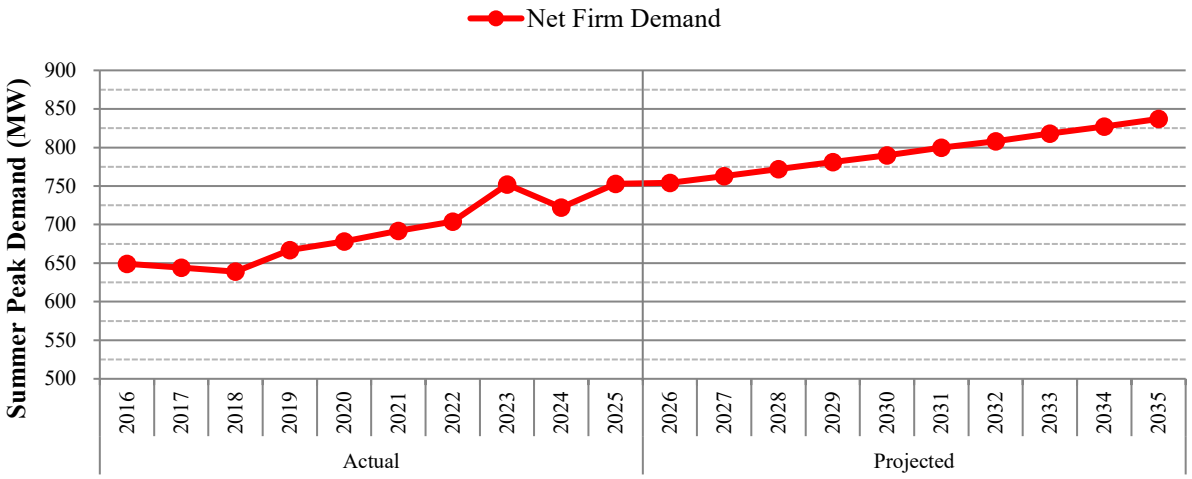
LAK noted that its residential UPC has remained relatively stable over the last 10 years, with modest variation attributable primarily to weather conditions and customer usage patterns. Commercial and industrial UPC has shown slight moderate reduction compared to the 10-year average, reflecting operational efficiencies, economic conditions, and energy management improvements within those sectors.

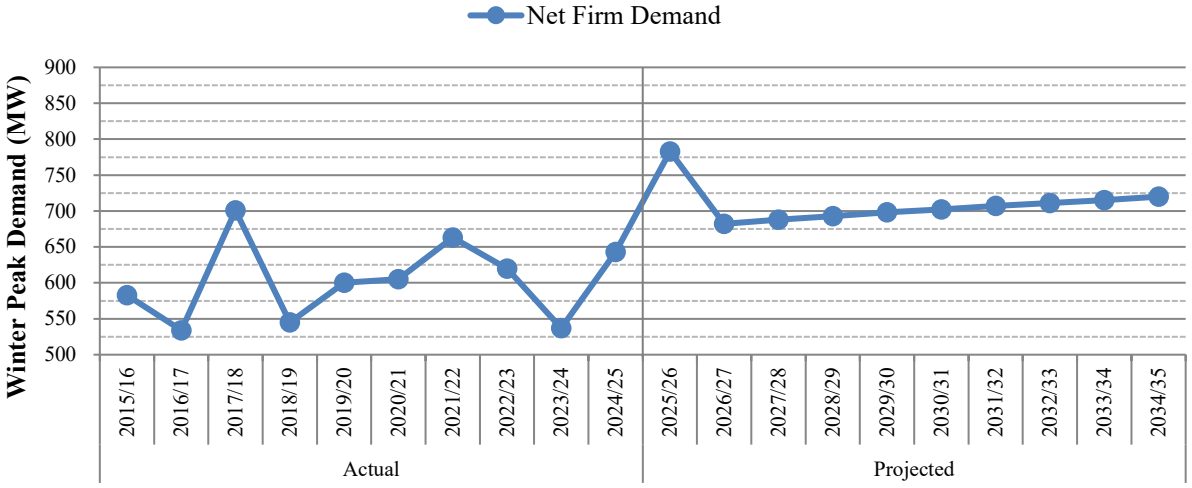
For the forecast horizon, residential UPC is projected to remain relatively stable, as incremental electrification (e.g., electric vehicles or electric heating) is largely offset by continued improvements in appliance efficiency and building standards. Commercial UPC reflects stable business activity and operating patterns. Industrial UPC remains high due to the energy-intensive nature of industrial operations. However, growth of industrial UPC is assumed to be stable, consistent with production forecasts and the absence of major process changes.

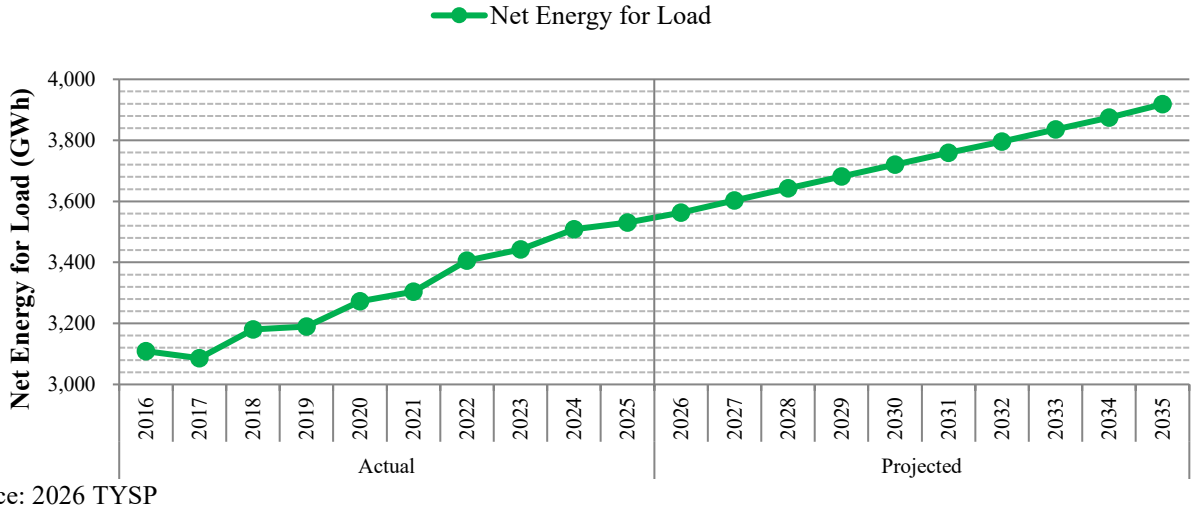
Forecasted Load and Peak Demand

The three graphs in Figure 40 show LAK's seasonal peak demand and net energy for load for the historic years of 2016 through 2025 and forecast years 2026 through 2035. 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. LAK is not subject to FEECA but offers energy efficiency programs that reduce seasonal peak and annual energy consumption. LAK included the impact of data center-related large load customers in the development of its seasonal peak demand and energy forecasts.

Figure 40: LAK Demand and Energy Forecasts







Source: 2026 TYSP

Generation Resources

Currently, LAK generating facilities provide approximately 778 MW of summer capacity, exclusively from fossil generation. Approximately half of LAK's capacity is from a single natural gas-fired combined cycle unit, with a capacity of 352 MW.

In addition to the Utility's capacity, LAK has multiple long-term purchased power contracts. These include five solar contracts for a total of 14.4 MW of nameplate capacity, which LAK counts as contributing 50 percent towards summer peak.

Projected Generation Resources

LAK plans no unit additions or retirements during the planning period. However, LAK has recently entered into a purchased power agreement for a 74.8 MW solar facility and assumes a 50 percent contribution to summer peak.

Fuel Diversity

Table 22 shows LAK's actual net energy for load by fuel type as of 2025 and the projected fuel mix for 2035. LAK uses natural gas as its primary fuel type for energy, 68.3 percent in 2025, with purchases (listed in the NUG & Other category) representing 30.8 percent net energy for load, and the remaining 0.8 percent from renewables. By 2035, natural gas is expected to be reduced to 66.3 percent, offset by purchases and renewables, which would represent 28.5 and 5.2 percent, respectively. LAK, in the actual and projected period, is the utility most reliant upon energy purchases.

Table 22: LAK Energy Generation by Fuel Type

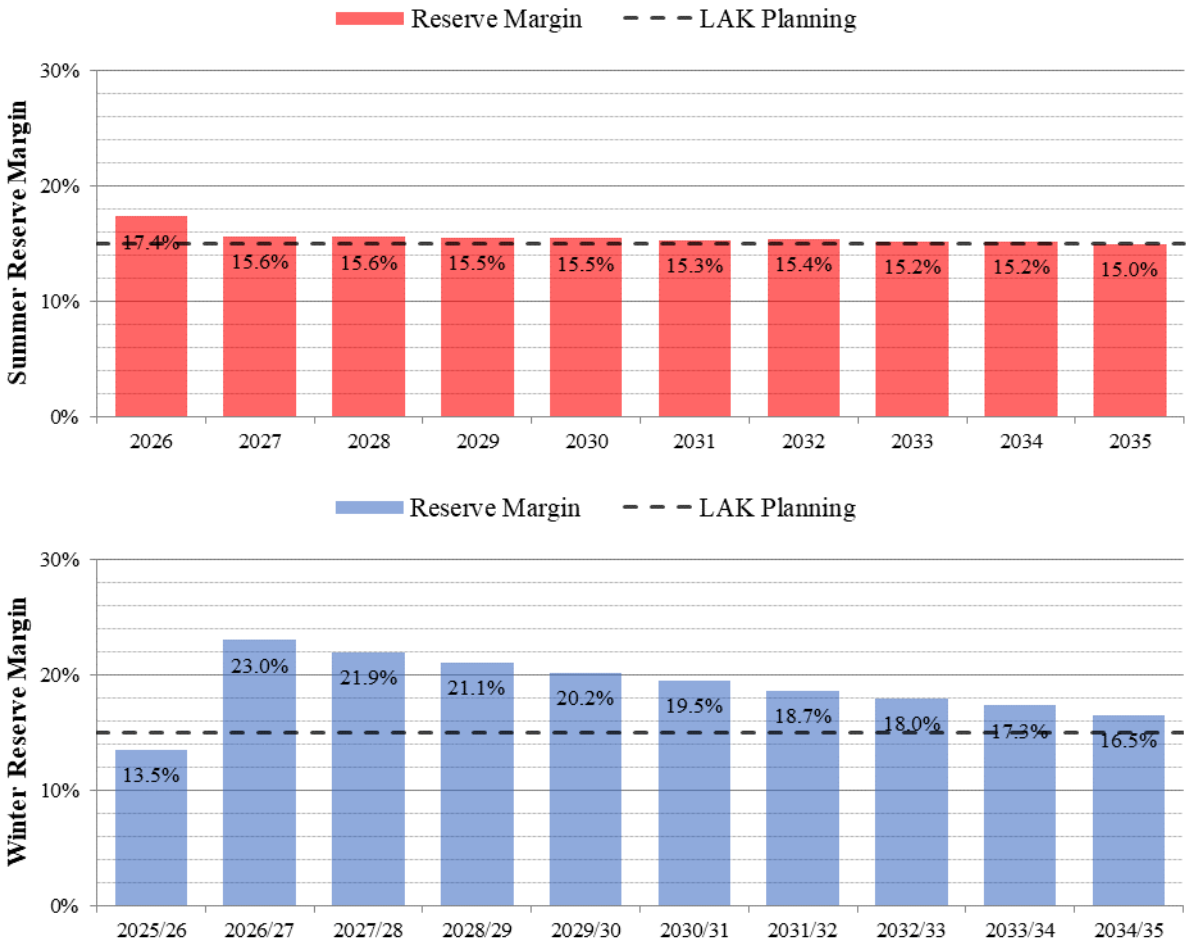
Fuel Type	Net Energy for Load			
	2025		2035	
	GWh	%	GWh	%
Natural Gas	2,413	**68.3%**	2,596	**66.3%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	30	**0.8%**	204	**5.2%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	1,087	**30.8%**	1,118	**28.5%**
Total	**3,531**		**3,918**	

Source: 2026 TYSP and Data Responses

Reliability

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 currently. 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: 2026 TYSP

Orlando Utilities Commission (OUC)

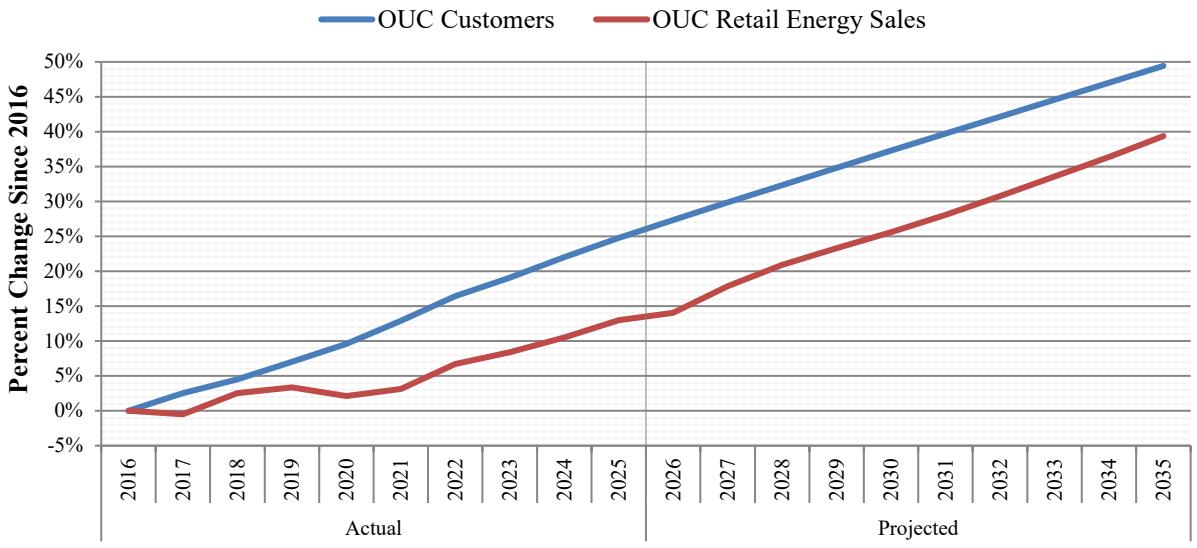
OUC is a municipal utility and Florida's sixth largest electric utility and second largest municipal utility. The Utility's service territory is within the FRCC region and primarily consists of the Orlando metropolitan area. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds OUC's 2026 TYSP suitable for planning purposes.

Load Forecasting

In 2025, OUC had approximately 288,492 customers and annual retail energy sales of 7,459 GWh, accounting for approximately 3.1 percent of Florida's annual retail energy sales. Over the last 10 years, OUC's customer base has increased by 24.8 percent, while its retail energy sales have increased by approximately 13.0 percent.

Figure 42 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that OUC filed in its 2026 TYSP.

Figure 42: OUC Growth



Source: 2026 TYSP

OUC acknowledged that over the past 10 years, its UPC has declined at a negative 0.6 percent average annual rate, for the residential customer segment, increased at an average annual growth rate of 1 percent for the commercial customer segment, and increased at an average annual growth rate of 2.1 percent for the industrial customer segment. For the next 10 years, OUC's residential UPC is expected to grow 1.3 percent annually. The main driver of this increase is the projected adoption of electric vehicles. The Utility's commercial UPC is expected to grow 0.5 percent annually. This growth is primarily due to the addition of larger commercial customers than

historically. The Utility's industrial UPC is forecast to increase at an average annual growth rate of 0.9 percent.

Over the forecast horizon, OUC is projecting growth in the number of customers at an average annual rate of 1.8 percent, and growth in retail energy sales at an average annual rate of approximately 2.2 percent. The Utility indicates that this projected increase is driven by large commercial expansions and residential electric vehicle adoption.

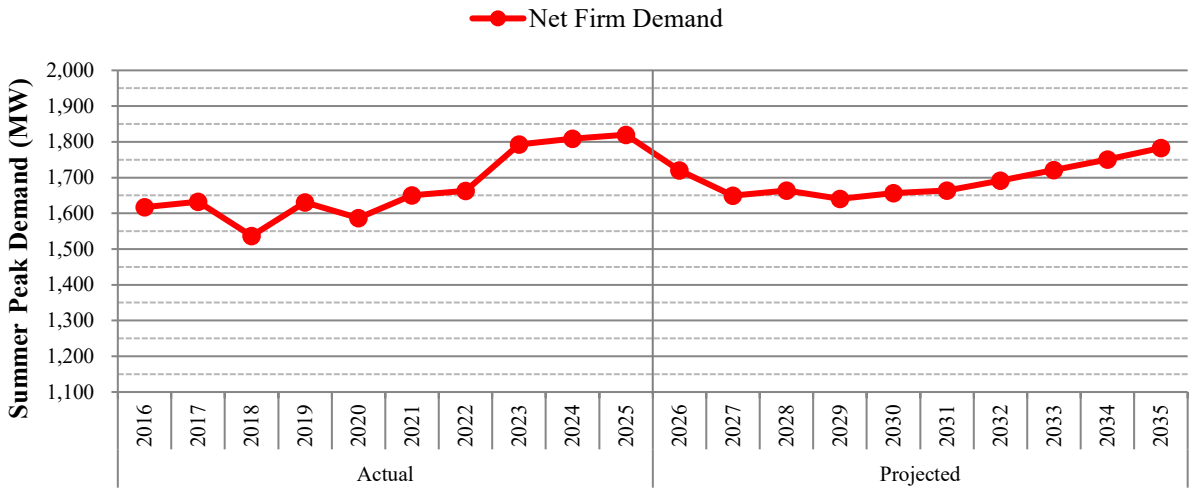
Forecasted Load and Peak Demand

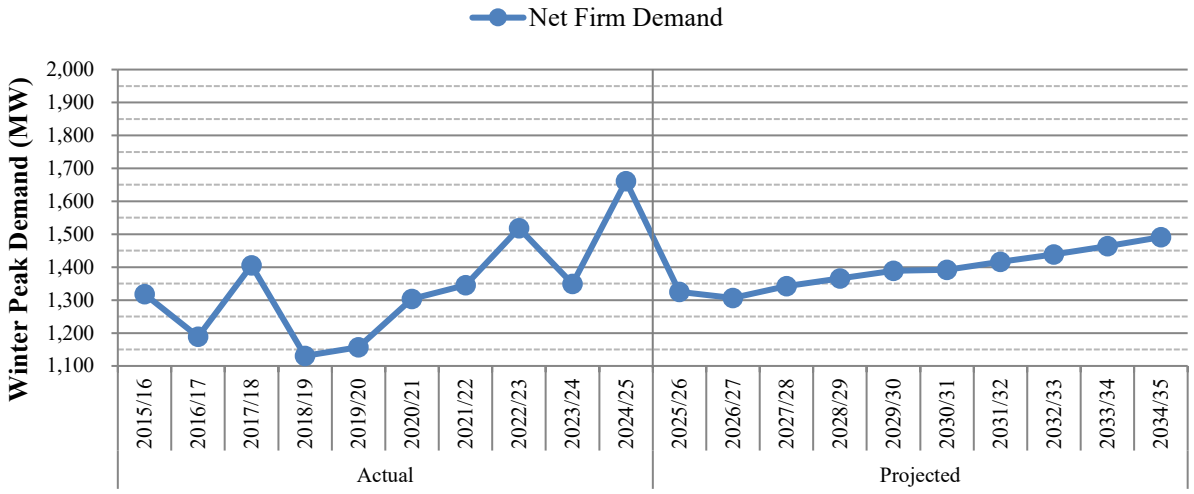
The three graphs in Figure 43 show OUC's seasonal peak demand and net energy for load for the historic years of 2016 through 2025 and forecast years 2026 through 2035. These graphs include the impact of DSM, and for future years assume that all available demand response resources will be activated during the seasonal peak. OUC did not include the impact of data center-related large load customers in the development of its seasonal peak demand and energy forecasts.

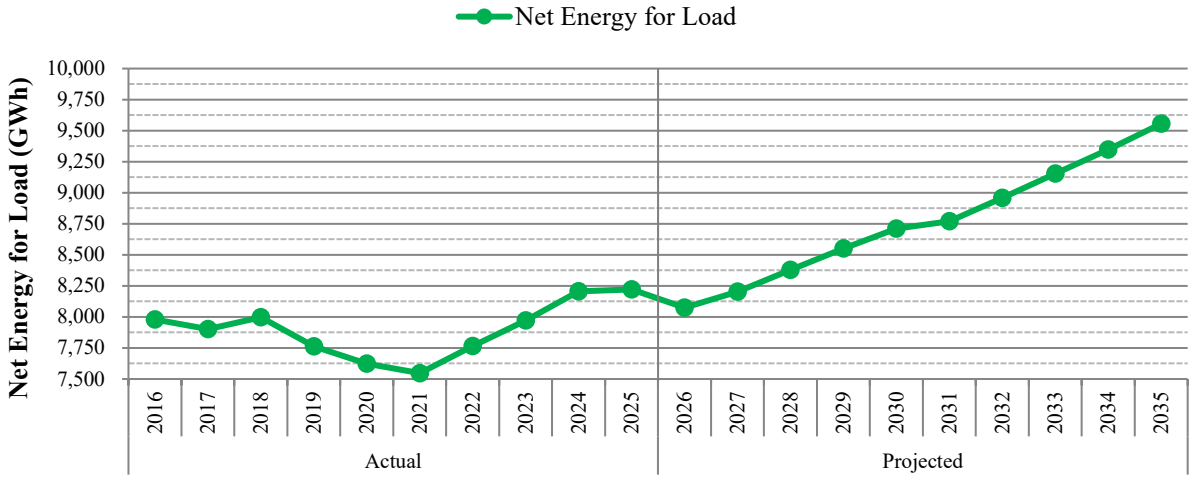
While a municipal utility, OUC is subject to FEECA and currently offers energy efficiency programs to customers to reduce peak demand and annual energy consumption. The Commission reviewed and approved OUC's 2025-2034 DSM plans.[17]

[17] See Order Nos. PSC-2024-0433A-FOF-EG, issued September 24, 2024, in Docket No. 20240017-EG, *In re: Commission review of numeric conservation goals (Orlando Utilities Commission)* and PSC-2025-0086-PAA-EG, issued March 24, 2025, in Docket No. 20240166, *In re: Petition for approval of 2025 demand-side management plan, by Orlando Utilities Commission.*

Figure 43: OUC Demand and Energy Forecasts







Source: 2026 TYSP

Generation Resources

Currently, OUC's generating facilities provide approximately 1,868 MW of summer capacity. This includes 1,808 MW from fossil generation and 60 MW from nuclear generation based on OUC's full or partial ownership of the units. This includes a pair of coal-fired steam units providing 663 MW and a pair of natural gas-fired combined cycle units providing 476 MW. OUC also operates 4 MW of energy storage.

In addition to the Utility's capacity, OUC has multiple long-term purchased power contracts. These include six solar contracts for a total of 272 MW of nameplate capacity, which OUC counts as contributing 50 percent towards summer peak, and three LFG contracts for 19 MW, which are treated as firm resources.

Projected Generation Resources

OUC plans no unit additions or retirements during the planning period. However, OUC plans several modifications to its system which impact its firm capacity. OUC plans on system upgrades to allow Osceola Generating Station Unit 2, a 157 MW natural gas-fired combustion turbine, to provide its full capacity during system peaks. OUC also plans on converting Stanton Unit 2 from coal-fired to natural gas-fired in 2027. Last, OUC include in its TYSP placing Stanton Unit 1 into an extended cold shutdown beginning in 2026, which would remove its 453 MW of capacity from OUC's planning.

Fuel Diversity

Table 23 shows OUC's actual net energy for load by fuel type as of 2025 and the projected fuel mix for 2035. In 2025, approximately 61.5 percent of OUC's net energy for load was met with natural gas, while coal, the second most-used fuel, met approximately 25.6 percent of the demand. By 2035, OUC anticipates reducing natural gas use to 49.1 percent, making it the only utility to use natural gas for less than half of its energy generation.

Table 23: OUC Energy Generation by Fuel Type

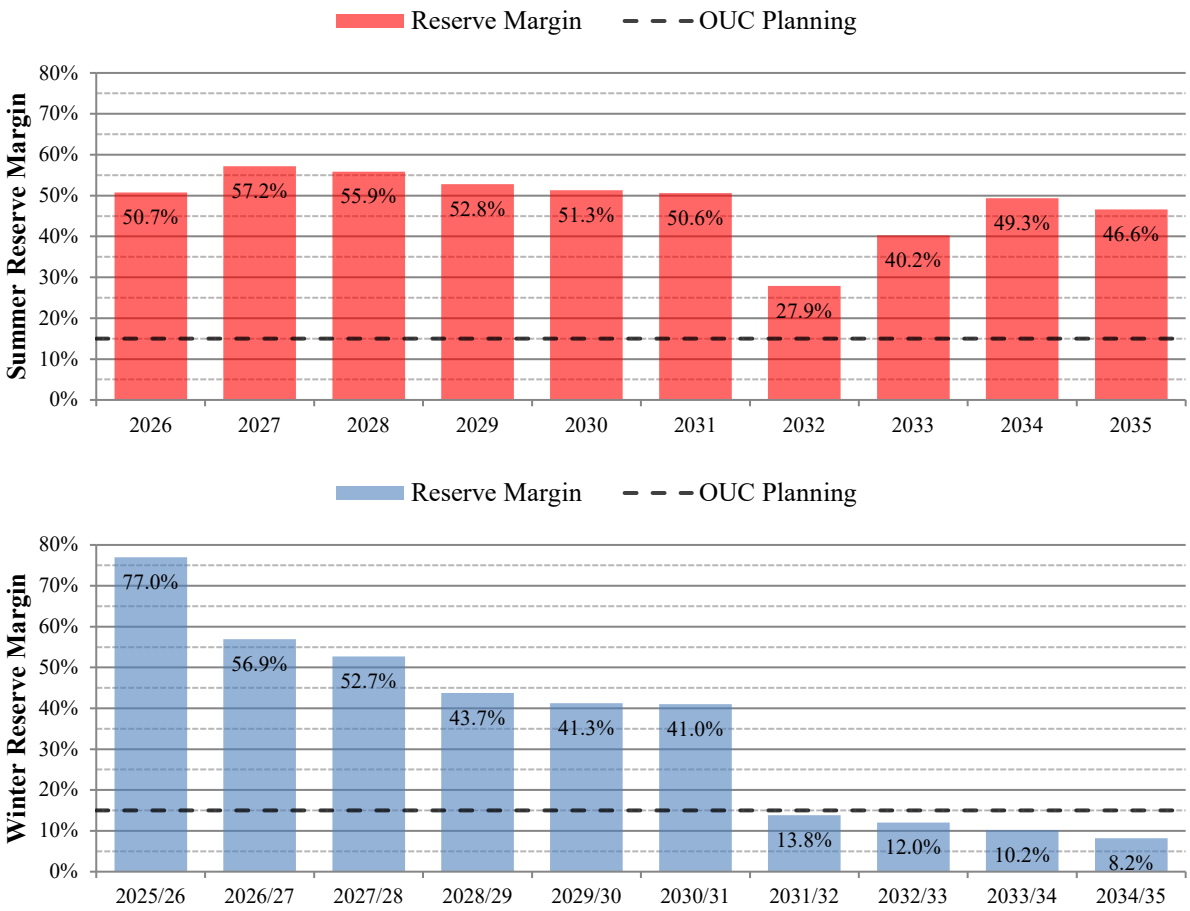
Fuel Type	Net Energy for Load			
	2025		2035	
	GWh	%	GWh	%
Natural Gas	5,059	**61.5%**	4,696	**49.1%**
Coal	2,105	**25.6%**	0	**0.0%**
Nuclear	469	**5.7%**	503	**5.3%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	588	**7.2%**	4,356	**45.6%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**8,222**		**9,556**	

Source: 2026 TYSP and Data Responses

Reliability

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 Figure 44, OUC's generation needs are controlled by its summer peak demand.

Figure 44: OUC Reserve Margin Forecast



Source: 2026 TYSP

Seminole Electric Cooperative (SEC)

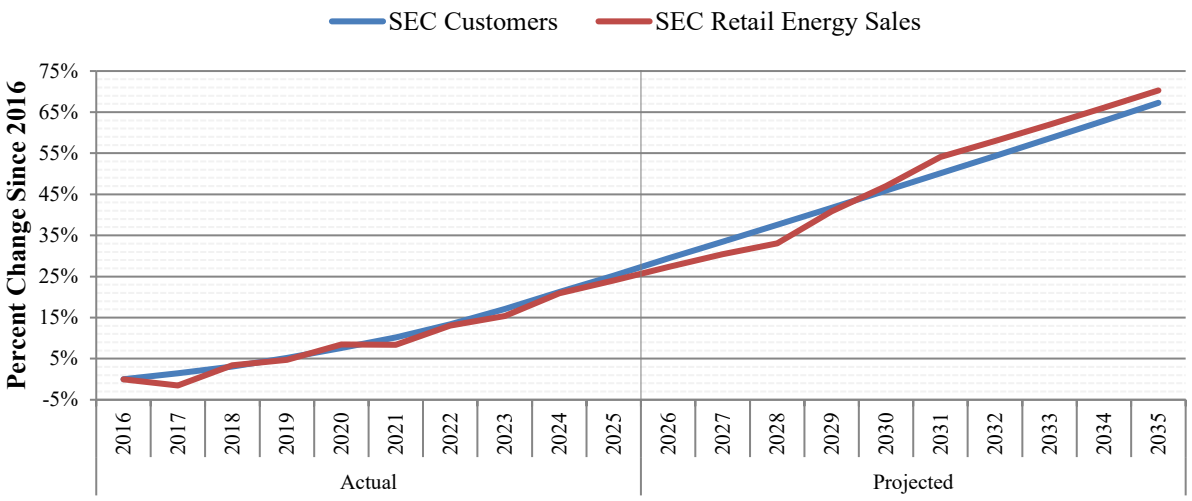
SEC is a generation and transmission rural electric cooperative that serves its member distribution cooperatives and is collectively Florida's fourth largest utility. SEC's generation and member cooperatives are within the FRCC region, with member cooperatives located in central and north Florida. As 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 2026 TYSP suitable for planning purposes.

Load Forecasting

In 2025, SEC member cooperatives had approximately 956,128 customers and annual retail energy sales of 17,078 GWh, accounting for approximately 7.0 percent of Florida's annual retail energy sales. Over the last 10 years, SEC's customer base has increased by 25.2 percent, while its retail energy sales have increased by approximately 24.0 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 2026 TYSP.

Figure 45: SEC Growth



Source: 2026 TYSP

SEC's average UPC has remained constant over the past 10 years, with the residential sector increasing by 0.04 percent and the commercial sector decreasing by 0.6 percent annually on average. For the next 10 years, the Utility is expected its residential customer UPC showing a flat to decreasing trend with an annual growth rate of negative 0.7 percent in average; and its commercial customer UPC showing an increasing trend with an annual growth rate of 2.3 percent on average.

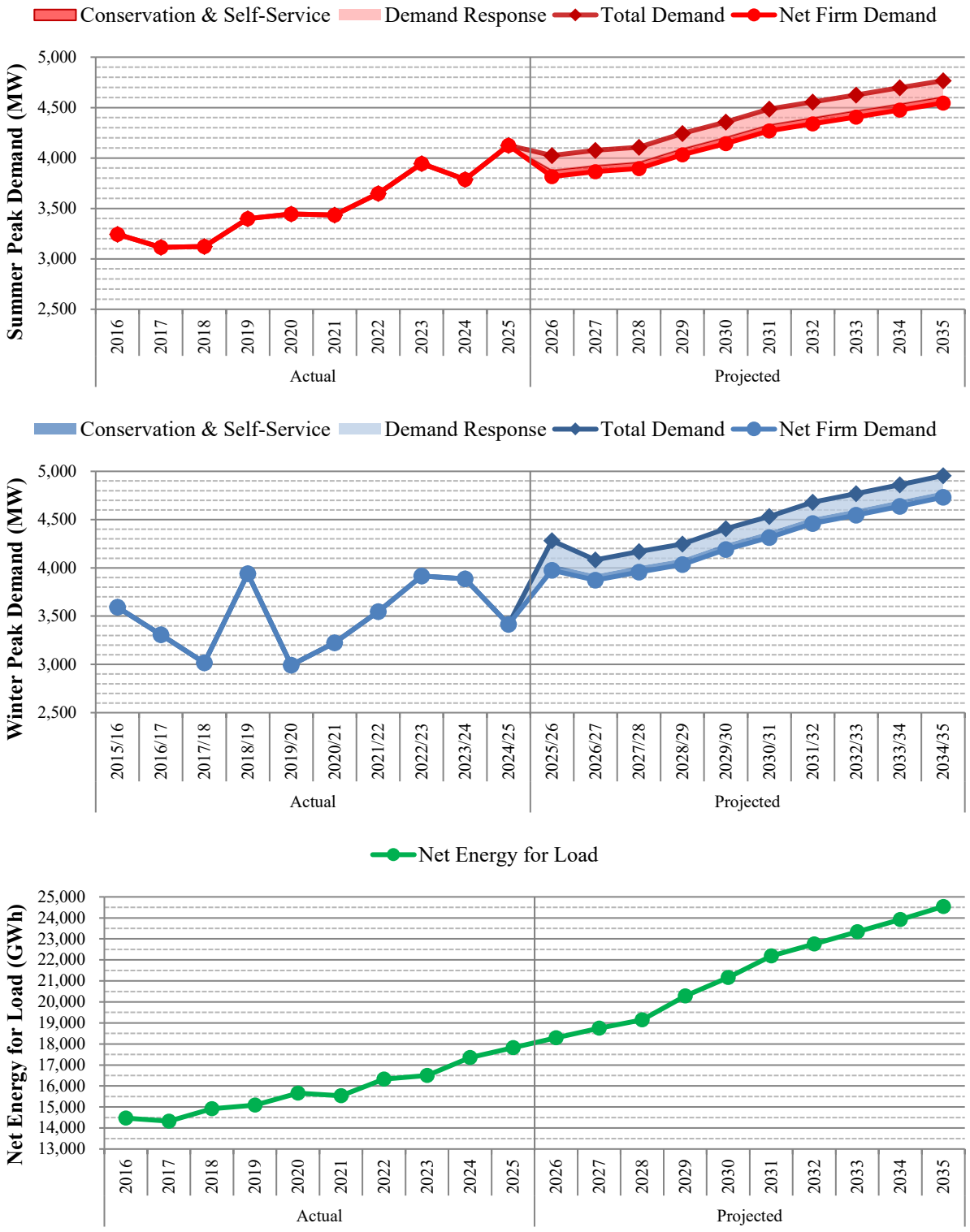
Over the current 10-year forecast horizon, SEC is projecting an average annual growth rate in its customer base of 2.9 percent. The Utility indicated that population growth in SEC's territory is sensitive to national economic and demographic factors that influence population migration from other states and metropolitan areas within Florida. Historically, consumer growth in the Member systems has grown at a faster rate than the State of Florida as a whole and this trend is expected to continue. The leading indicators for load growth are Florida's expanding economy and net migration prospects into the state. SEC's projected average annual growth rate in retail energy sales is 3.3 percent.

Forecasted Load and Peak Demand

The three graphs in Figure 46 show SEC's seasonal peak demand and net energy for load for the historic years of 2016 through 2025 and forecast years 2026 through 2035. 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 the Utility's load forecasts which are the aggregate of SEC member provided forecasts.

SEC included the impact of one expected large load customer in the development of its seasonal peak demand and energy forecasts, with an anticipated impact of 75 MW and 657 GWh beginning in 2029, increasing to 162 MW and 1,419 GWh by 2031. However, recently SEC stated that this one large load customer addition was part of a project that has since been canceled. SEC will make an adjustment to its 2027 TYSP filing to reflect this cancellation.

Figure 46: SEC Demand and Energy Forecasts



Source: 2026 TYSP

Generation Resources

Currently, SEC generating facilities provide approximately 2,989 MW of summer capacity. This includes 2,988 MW from fossil generation and 1 MW partial contribution from solar. SEC currently has 2 MW nameplate solar generation installed, but only counts 40 percent as contributing towards summer peak. A majority of SEC capacity is associated with two natural gas-fired combined cycle units, which provide 1,631 MW. SEC also has 634 MW of coal-fired steam generation.

In addition to the Utility's capacity, SEC has multiple long-term purchased power contracts. These include approximately four solar contracts for a total of 300 MW of nameplate capacity, which SEC counts as contributing 40 percent towards summer peak.

Projected Generation Resources

SEC's unit retirements and additions during the planning period are described in Table 24. SEC plans for the completion of the Shady Hills Energy Center, a 547 MW natural gas-fired combined cycle facility in 2026. SEC also plans for the addition of two combustion turbine units and two combined cycle units, totaling approximately 2,006 MW of capacity, and two energy storage units 150 MW, to meet reserve requirement obligations. However, SEC states it has not yet determined if this requirement will be met by construction of the unnamed facilities, future acquisitions, or purchased power agreements.

Table 24: SEC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Firm Capacity (MW) Sum	Notes
Retiring Units					
	None				
	Total Retirements		**0**	**0**	
New Units					
2026	Shady Hills Energy Center Unit 1	NG CC	547		
2032	Unnamed CC	NG CC	559		
2032	Unnamed CT	NG CT	345		
2032	Unnamed CT	NG CT	345		
2033	Unnamed Battery	BA	75		
2035	Unnamed Battery	BA	75		
2035	Unnamed CC	NG CC	559		
	Total New Units		**2,505**	**0**	
	Net Additions		**2,505**	**0**	

Source: 2026 TYSP and 2026 FRCC Load & Resource Plan

Fuel Diversity

Table 25 shows SEC's actual net energy for load by fuel type as of 2025 and the projected fuel mix for 2035. In 2025, natural gas was SEC's primary fuel, at 61.2 percent, with purchases making

up approximately 15 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 2035, natural gas will represent approximately 90.3 percent of SEC's fuel usage while purchases decrease to an approximate 0.9 percent.

Table 25: SEC Energy Generation by Fuel Type

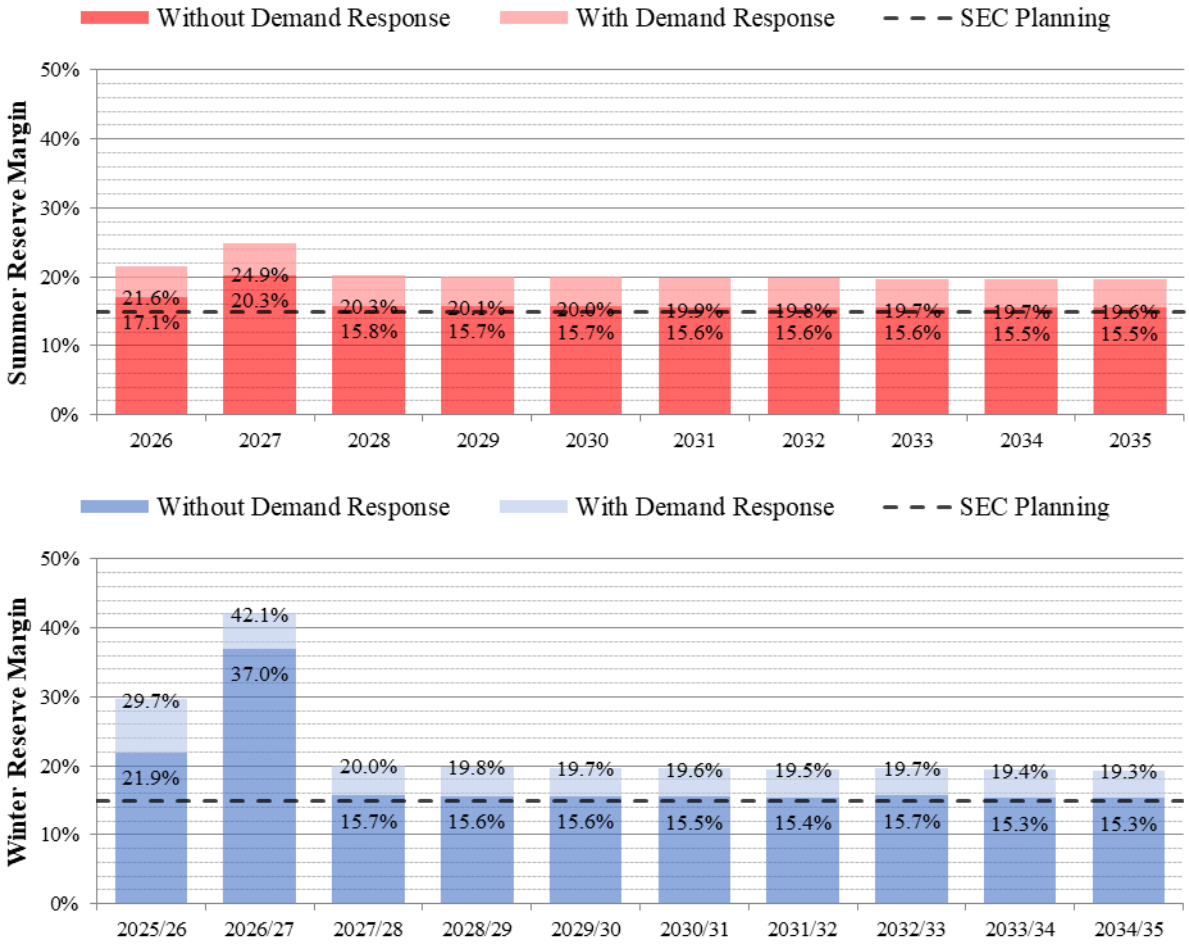
Fuel Type	Net Energy for Load			
	2025		2035	
		%	GWh	%
Natural Gas	10,889	**61.2%**	22,164	**90.3%**
Coal	2,918	**16.4%**	1,448	**5.9%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	12	**0.1%**	6	**0.0%**
Renewable	932	**5.2%**	700	**2.9%**
Interchange	366	**2.1%**	0	**0.0%**
NUG & Other	2,661	**15.0%**	225	**0.9%**
Total	**17,778**		**24,543**	

Source: 2026 TYSP and Data Responses

Reliability

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 Figure 47, 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: 2026 TYSP

City of Tallahassee Utilities (TAL)

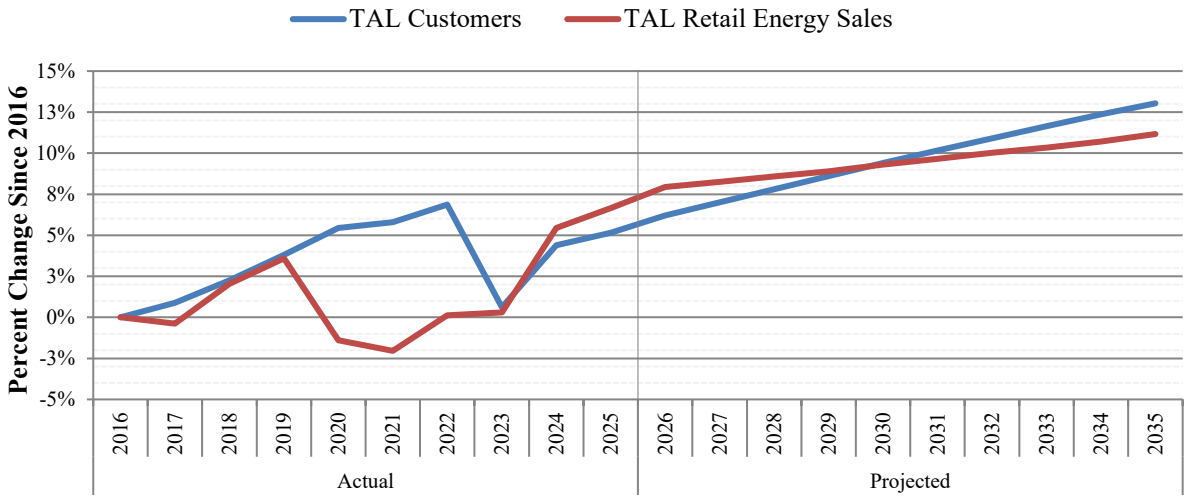
TAL is a municipal utility and the second smallest electric utility by sales that files a TYSP. The Utility's service territory is within the FRCC region and primarily consists of the City of Tallahassee and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds TAL's 2026 TYSP suitable for planning purposes.

Load Forecasting

In 2025, TAL had approximately 125,146 customers and annual retail energy sales of 2,820 GWh, or approximately 1.2 percent of Florida's annual retail energy sales. Over the last 10 years, TAL's customer base has increased by approximately 5.2 percent, while retail energy sales have increased by approximately 6.7 percent.

For the next 10 years, TAL projected an average annual growth rate in its customer base of approximately 0.7 percent. The Utility continues to see new growth in single-family and multi-family housing in its service territory. TAL's total sales are projected to increase approximately 0.3 percent per year, in line with the average growth of the previous decade. Figure 48 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the resource plan that TAL filed in its 2026 TYSP.

Figure 48: TAL Growth



Source: 2026 TYSP

TAL implemented new customer billing software in 2023 which changed the methodology of accounting for customer types and consolidated some service points. The resulting data anomaly shows an increase in average residential consumption and a decrease in average commercial consumption as well as an overall reduction in service points. TAL noted that the calculation of the Utility's customer number growth is complicated by the software system change in 2022-2023

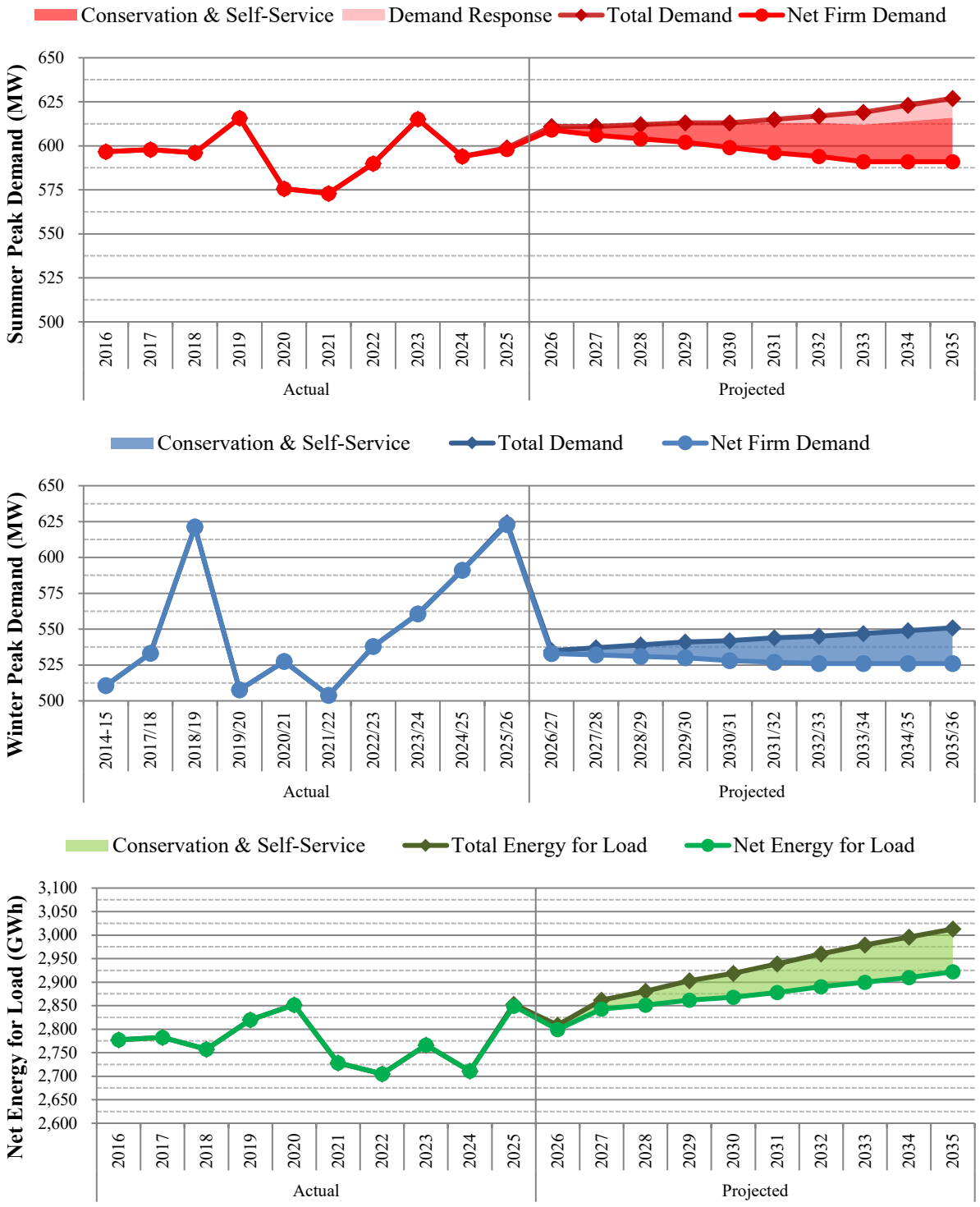
that altered the customer count methodology and reset the service points lower based on synthesizing accounts with multiple meters for the same address, for all service types. Excluding the software changeover from the data results in a 1.2 percent annual growth average for residential customers and 0.8 percent for commercial customers, though the past two years of commercial growth have been stronger than the COVID influenced period.

TAL reported that its residential UPC in the historic period only had minor year-over-year fluctuations, likely due to weather. As with customer counts, the software change and resulting customer count consolidation created an anomalous impact to the UPC data. In the 2022-2023 software changeover period, UPC increased due to having a smaller customer count for the same sales area, but the average consumption for the pre- and post- 2022-2023 changeover period show no changes. However, the Utility also noted that its measurement of commercial UPC in the historic period was impacted by the software change raising the average UPC by approximately 8 percent in a single reporting year. This created an anomaly in the UPC trend as measured before and after the changeover period. The period 2016-2022 shows decreasing average commercial consumption, declining at 1.5 percent per year; however, in recent years (2024-2025), the commercial UPC is growing about 1.5 percent per year. The software changeout and weather alone do not explain these trends; higher-use customers added to the system are impacting the UPC metric. TAL cited several key accounts in the past few years impacting the trend, including the new FSU Business School, DC Fast Charging stations, and Amazon fulfillment centers.

Forecasted Load and Peak Demand

The three graphs in Figure 49 show TAL's seasonal peak demand and net energy for load for the historic years of 2016 through 2025 and forecast years 2026 through 2035. 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. While not a FEECA Utility, 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. TAL did not include the impact of data center-related large load customers in the development of its seasonal peak demand and energy forecasts.

Figure 49: TAL Demand and Energy Forecasts



Source: 2026 TYSP

Generation Resources

Currently, TAL generating facilities provide approximately 737 MW of summer capacity. This includes 725 MW from fossil generation and 12 MW partial contribution from solar. While TAL reports its solar generation as native, these are the result of long term purchased power contracts. TAL currently has 62 MW nameplate solar capacity installed, but only counts 20 percent as contributing towards summer peak. A majority of TAL generation capacity is associated with two natural gas-fired combined cycle units, which provide 522 MW.

Projected Generation Resources

TAL has no planned unit additions or retirements during the planning period.

Fuel Diversity

Table 26 shows TAL's actual net energy for load by fuel type as of 2025 and the projected fuel mix for 2035. TAL relies almost exclusively on natural gas for its generation, excluding some purchases from other utilities and qualifying facilities. In 2025, TAL produced more energy than required for its native load and was a net exporter by approximately 9.7 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 26: TAL Energy Generation by Fuel Type

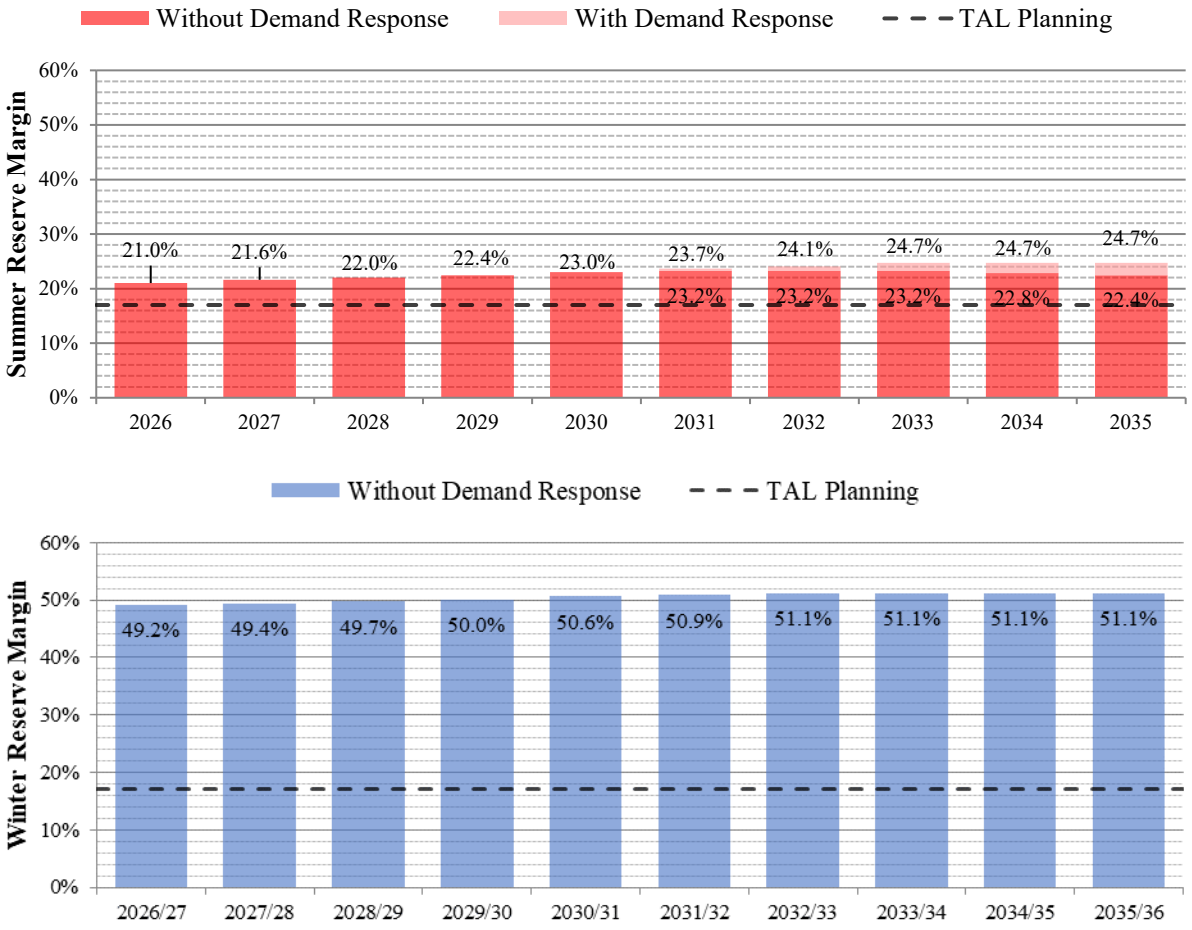
Fuel Type	Net Energy for Load			
	2025		2035	
	GWh	%	GWh	%
Natural Gas	3045	**105.8%**	3,036	**101.3%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	4	**0.1%**	0	**0.0%**
Renewable	108	**3.8%**	103	**3.4%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	(280)	**-9.7%**	(141)	**-4.7%**
Total	**2,877**		**2,998**	

Source: 2026 TYSP and Data Responses

Reliability

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, which it begins including in its resource planning beginning in 2031. As shown in Figure 50, TAL's generation needs are controlled by its summer peak throughout the planning period.

Figure 50: TAL Reserve Margin Forecast



Source: 2026 TYSP