I. Meeting Packet

State of Florida
Public Service Commission
INTERNAL AFFAIRS AGENDA
Tuesday – October 25, 2022
9:30 AM
Room 148 - Betty Easley Conference Center

1. Draft Review of the 2022 Ten-Year Site Plans of Florida's Electric Utilities (Attachment 1)

2. Draft Report on Status of Utility Storm Protection Activities Pursuant to Section 366.96, Florida Statutes (Attachment 2)

3. Presentation on Prepaid Utility Service:
   - Jamie Wimberly, Senior Vice President at E Source
   - Sheila Pressley, Chief Customer Officer JEA
   - Emily Cowan, VP of Member Services and External Affairs at CHELCO

   (Attachment 3)

4. General Counsel's Report

5. Executive Director's report

6. Other Matters

BB/aml

OUTSIDE PERSONS WISHING TO ADDRESS THE COMMISSION ON ANY OF THE AGENDAED ITEMS SHOULD CONTACT THE OFFICE OF THE EXECUTIVE DIRECTOR AT (850) 413-6463.

Attachment 1

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: October 12, 2022

TO: Braulio L. Baez, Executive Director

FROM: Donald Phillips, Engineering Specialist II, Division of Engineering DP TB POE LK

RE: Review of the 2022 Ten-Year Site Plans of Florida Electric Utilities

CRITICAL INFORMATION: Place on October 25, 2022 Internal Affairs Agenda. Approval by the Commission is required by December 31, 2022.

Pursuant to Section 186.801, Florida Statues, electric utilities are required to submit to the Commission a Ten-Year Site Plan which shall estimate a utility's power-generating needs and the general location of its proposed power plant sites. The Commission is required to make a preliminary study of each plan and classify it as "suitable" or "unsuitable" within nine months after receipt of the proposed plan. Electric utility plans were filed on April 1, 2022. Staff seeks approval of the attached draft report that includes a statewide assessment, and an analysis and recommended classification of each plan.

Please contact me or Phillip Ellis if you have any questions or need additional information in reference to the attached document.

DP:pz

Attachment

cc: Keith Hetrick, General Counsel
Apryl Lynn, Deputy Executive Director – Administrative
Mark Futrell, Deputy Executive Director – Technical

REVIEW OF THE

2022 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

DRAFT 10-12-2022 at 11:00 a.m.

FLORIDA PUBLIC SERVICE COMMISSION

OCTOBER 2022

Table of Contents

List of Figures

List of Tables

List of Ten-Year Site Plan Utilities

Name	Abbreviation
Investor-Owned Electric Utilities	
Florida Power & Light Company	FPL
Duke Energy Florida, LLC	DEF
Tampa Electric Company	TECO
Municipal Electric Utilities	
Florida Municipal Power Agency	FMPA
Gainesville Regional Utilities	GRU
JEA	JEA
Lakeland Electric	LAK
Orlando Utilities Commission	OUC
City of Tallahassee Utilities	TAL
Rural Electric Cooperatives	
Seminole Electric Cooperative	SEC

Unit Type and Fuel Abbreviations

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

Executive Summary

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

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

Pursuant to Section 186.801, F.S., each generating electric utility must submit to the Commission a Ten-Year Site Plan which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a 10-year planning horizon. The Ten-Year Site Plans of Florida's electric utilities summarize the results of each utility's IRP process and identifies proposed power plants and transmission facilities. The Commission is required to perform a preliminary study of each plan and classify each one as either "suitable" or "unsuitable." This document represents the review of the 2022 Ten-Year Site Plans for Florida's electric utilities, filed by 10 reporting utilities.[1]

[1] Investor-owned utilities filing 2022 Ten-Year Site Plans include Florida Power & Light Company, Duke Energy Florida, LLC, and Tampa Electric Company. Municipal utilities filing 2022 Ten-Year Site Plans include Florida Municipal Power Agency, Gainesville Regional Utilities, JEA (formerly Jacksonville Electric Authority), Lakeland Electric, Orlando Utilities Commission, and City of Tallahassee Utilities. Seminole Electric Cooperative also filed a 2022 Ten-Year Site Plan. FPL initially submitted four versions of its Ten-Year Site Plan, consisting of a Business As Usual Plan using its traditional planning methodology, a Recommended Plan using a novel extreme winter planning methodology, and two additional plans based on potential federal legislation to be used for information purposes only. On July 11, 2022 FPL submitted a letter withdrawing its Recommended Plan. Only the Business As Usual Plan was utilized for this report.

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

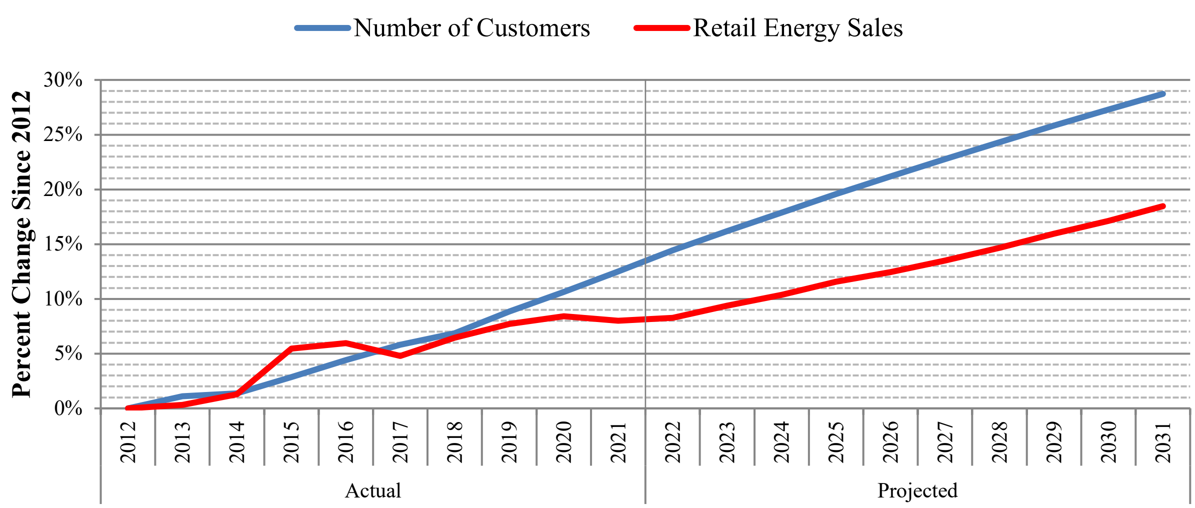
Review of the 2022 Ten-Year Site Plans

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

Load Forecasting

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

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



Source: FRCC 2022 Regional Load and Resource Plan

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

Renewable Generation

Renewable resources continue to expand in Florida, with approximately 7,584 megawatts (MW) of renewable generating capacity currently in Florida. The majority of installed renewable capacity is represented by solar photovoltaic (PV) generation which makes up approximately 80 percent of Florida's existing renewables. Notably, Florida electric customers had installed 1,177 MW of demand-side renewable capacity by the end of 2021, an increase of 41 percent from 2020.

Florida's total renewable resources are expected to increase by an estimated 15,894 MW over the 10-year planning period, excluding any potential demand-side renewable energy additions. Solar PV accounts for all of this increase. Some utilities are including a portion of these solar resources as a firm resource for reliability considerations. If these conditions continue, cost-effective forms of renewable generation will continue to improve the state's fuel diversity and reduce dependence on fossil fuels. Also, several utilities plan on adding battery storage totaling 2,462 MW which would increase firm capacity available during system peaks.

Table 1 provides a breakdown of each TYSP utility's actual 2021 and projected 2031 generation from renewables, in gigawatt-hours (GWh) and as a percentage of the net energy for load (NEL). Renewable energy as a percent of NEL is expected to increase from 5.2 percent in 2021 to 18.1 percent in 2031. Solar generation increases from approximately 67 percent of all renewable energy in 2021 to 95 percent of all renewable energy by 2031.

Table 1: State of Florida - Renewable Energy Generation

Utility	2021 Actual			2031 Projected		
	NEL	Renewables		NEL	Renewables	
	GWh	GWh	% NEL	GWh	GWh	% NEL
FPL[3]	136,757	7,187	5.26%	149,499	28,816	19.28%
DEF	45,065	1,551	3.44%	44,872	9,983	22.25%
TECO	21,033	1,252	5.95%	21,931	4,481	20.43%
FMPA	6,937	154	2.22%	6,823	757	11.09%
GRU	1,952	612	31.35%	1,967	586	29.79%
JEA	12,540	166	1.32%	13,734	82	0.60%
LAK	3,304	26	0.79%	3,516	153	4.35%
OUC	7,548	349	4.62%	8,515	4,764	55.95%
TAL	2,729	113	4.14%	2,985	116	3.90%
SEC	15,541	489	3.15%	17,711	766	4.32%
State of Florida	260,004	13,468	5.18%	279,454	50,647	18.12%

Source: FRCC 2022 Regional Load and Resource Plan & TYSP Utilities' Data Responses

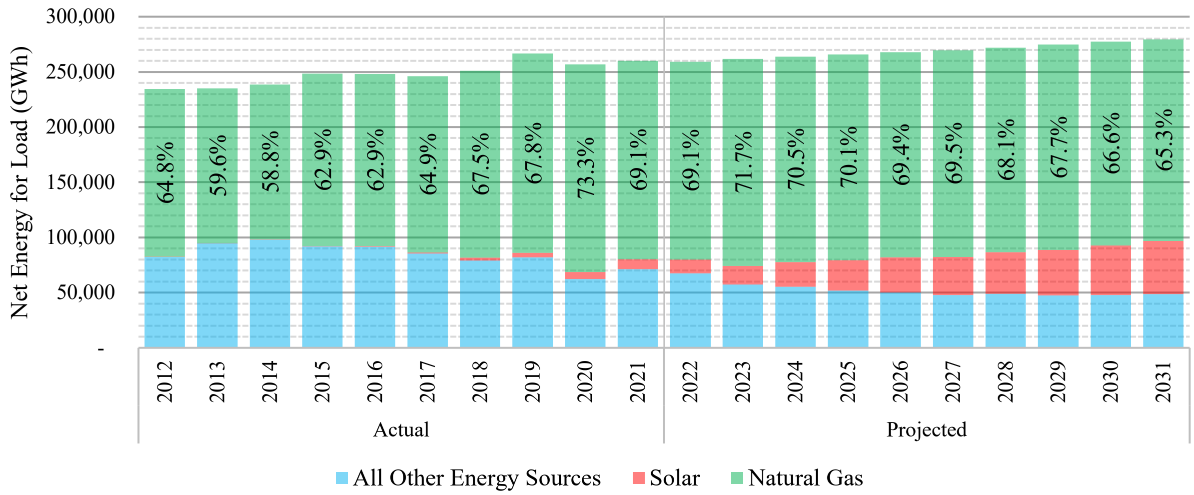
Traditional Generation

Generating capacity within Florida is anticipated to grow to meet the increase in customer demand, with an approximate net increase of 1,389 MW of traditional generation over the planning horizon, with natural gas plant additions offset by coal and oil retirements. Natural gas electric generation,

[3] FPL's values in 2021 include Gulf Power Company, which was a separate entity during 2021.

as a percent of NEL, is expected to decline from 69 percent in 2022 to 65 percent over the planning horizon. Figure 2 illustrates the use of natural gas as a generating fuel for electricity production in Florida compared to solar and all other energy sources combined. The total energy produced by solar generation is projected to exceed coal-fired generation by 2023, and nuclear based generation by 2026.

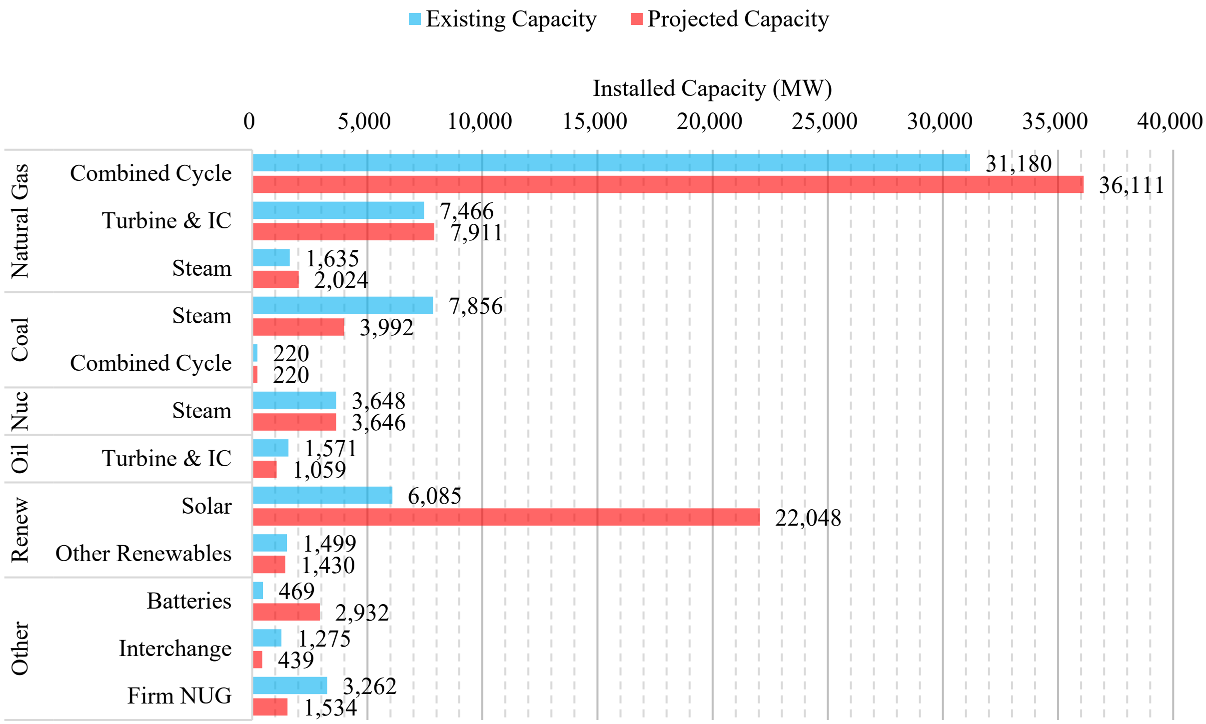
Figure 2: State of Florida - Electricity Generation Sources



Source: FRCC 2013-2022 Regional Load and Resource Plans

Figure 3 illustrates the present and future aggregate capacity mix of Florida based on the 2022 Ten-Year Site Plans. The capacity values in Figure 3 incorporate all proposed additions, changes, and retirements planned during the 10-year period. While natural gas-fired generating units represent a majority of capacity within the state, renewable capacity additions make up the majority of the projected net increase in generation capacity over the planning period. Solar generation is projected to be the second highest category of installed capacity by the end of the 10-year planning period.

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



Source: FRCC 2022 Regional Load and Resource Plan & TYSP Utilities' Data Responses

As noted previously, the primary purpose of this review is to provide information regarding proposed electric power plants for local, regional, and state agencies to assist in the certification process. During the next 10 years, there are no new units planned that require a determination of need from the Commission pursuant to Section 403.519, F.S.

Future Considerations

Florida's electric utilities must also consider changes in environmental regulations associated with existing generators and planned generation to meet Florida's electric needs. Developments in U.S. Environmental Protection Agency (EPA) regulations may impact Florida's existing generation fleet and proposed new facilities. For example, in January 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the Affordable Clean Energy (ACE) rule addressing greenhouse gas emissions from electric power plants and remanded it to the EPA. However, as the Court did not expressly reinstate the Clean Power Plan (CPP), the EPA understands the decision as leaving neither of those rules, and thus no Clean Air Act (CAA) section 111(d) regulation, in place with respect to greenhouse gas emissions from electric generating units. These and other relevant EPA actions are further discussed in the Traditional Generation Section.

In order to prepare for and to accommodate the inevitable increase in electric vehicle (EV) ownership, as well as investigate potential unknowns associated with EV charging, several utilities have initiated electric vehicle pilot programs, either as independent programs or as part of rate case settlement agreements. The nature of these pilot programs vary among utilities, but include investments in vehicle charging infrastructure, research partnerships, and electric vehicle rebate programs. Examples include: FPL's EVolution pilot program, DEF's Charge FL pilot program, and TECO's Drive Smart pilot program.

Some utilities, such as FPL and DEF, have begun to report key findings and metrics obtained through their respective EV pilot programs. This information includes: individual charging session data, peak EV charging hours, impacts to peak demand, as well as other metrics such as, revenue generated and port installation costs. Other utilities' EV pilot programs have not yet reached an age of maturity that will yield these same key findings. The Commission will continue to ask utilities to note key findings and track metrics of interest within these pilot programs in an effort to help inform the Commission about the future power needs of electric vehicles in Florida, which may require additional generating resources to meet their needs.

Conclusion

The Commission has reviewed the 2022 Ten-Year Site Plans of Florida's electric utilities and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity. The Commission will continue to monitor the impact of current and proposed EPA Rules, expansion of EV adoption, and the state's dependence on natural gas for electricity production.

Based on its review, the Commission finds the 2022 Ten-Year Site Plans to be suitable for planning purposes. Since the plans are not a binding plan of action for electric utilities, the Commission's classification of these plans as "suitable" or "unsuitable" does not constitute a finding or determination in docketed matters before the Commission.

Introduction

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

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

Statutory Authority

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

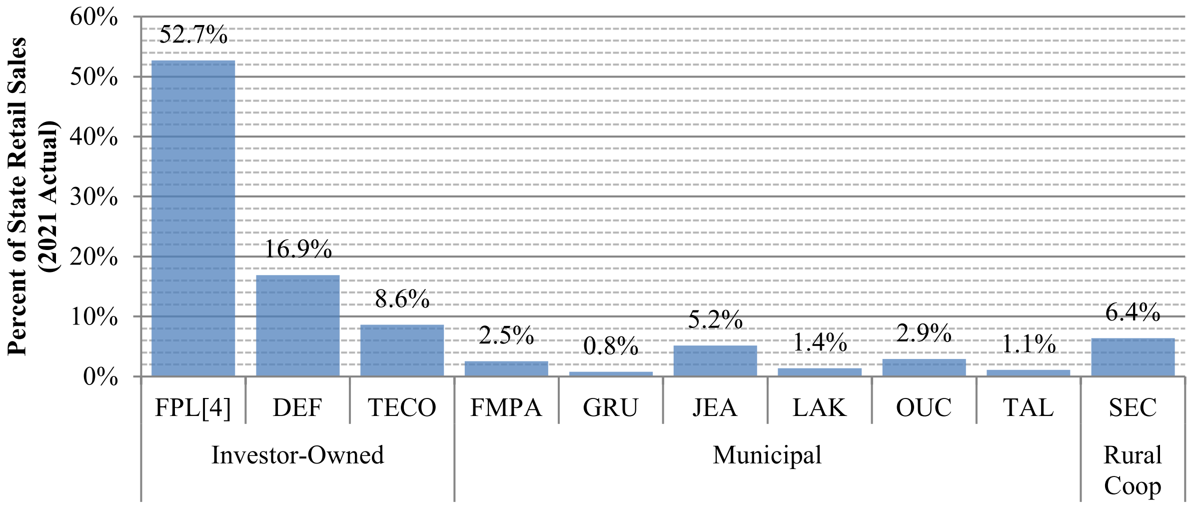
Applicable Utilities

Florida is served by 56 electric utilities, including 4 investor-owned utilities, 34 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 MW or a planned unit with a capacity of 75 MW or greater are required to file a Ten-Year Site Plan with the Commission every year.

In 2022, 10 utilities met these requirements and filed a Ten-Year Site Plan, including 3 investor-owned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company, Duke Energy Florida, LLC, and Tampa Electric Company. The municipal utilities, in alphabetical order, are Florida Municipal Power Agency, Gainesville Regional Utilities, JEA (formerly Jacksonville Electric Authority), Lakeland Electric, Orlando Utilities Commission, and City of Tallahassee Utilities. The sole rural electric cooperative filing a 2022 Ten-Year Site Plan is Seminole Electric Cooperative. Collectively, these utilities are referred to as the Ten-Year Site Plan Utilities (TYSP Utilities).

Figure 4 illustrates the comparative size of the TYSP Utilities, in terms of each utility's percentage share of the state's retail energy sales in 2021. Collectively, the reporting investor-owned utilities account for approximately 78 percent of the state's retail energy sales. The reporting municipal and cooperative utilities make up approximately 20 percent of the state's retail energy sales.

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



Source: FRCC 2022 Regional Load and Resource Plan & 2022 Ten-Year Site Plans

Required Content

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

Additional Resources

The Florida Reliability Coordinating Council (FRCC) compiles utility data on both a statewide basis and for Peninsular Florida, which excludes the area west of the Apalachicola River. This provides aggregate data for the Commission's review. Each year, the FRCC publishes a Regional Load and Resource Plan, which contains historic and forecast data on demand and energy, capacity

[4] FPL's value is the combined actual 2021 value of FPL and Gulf Power Company, which merged in 2022. Individually, FPL and Gulf Power Company represented 48.1 percent and 4.6 percent of the state's retail sales, respectively.

and reserves, and proposed new generating units and transmission line additions. For certain comparisons, the Commission employs additional data from various government agencies, including the Energy Information Administration and the Florida Department of Highway Safety and Motor Vehicles.

On June 1, 2022 the Commission held a workshop regarding the annual planning process and the planning methodology for extreme winter events. Representatives from TECO, DEF, FPL, the Office of Public Counsel, Southern Alliance for Clean Energy, and Florida Rising each gave presentations. On July 11, 2022, FPL withdrew its Recommended Plan based on a novel extreme winter planning methodology and requested review of its Business As Usual Plan based on its traditional planning methodology.

Structure of the Commission's Review

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

Conclusion

Based on its review, the Commission finds all 10 reporting utilities' 2022 Ten-Year Site Plans to be suitable for planning purposes. During its review, the Commission has determined that the projections for load growth appear reasonable and that the reporting utilities have identified sufficient generation facilities to maintain an adequate supply of electricity.

The Commission notes that the Ten-Year Site Plans are non-binding, and a classification of suitable does not constitute a finding or determination in any docketed matter before the Commission, nor an approval of all planning assumptions contained within the Ten-Year Site Plans.

Statewide Perspective

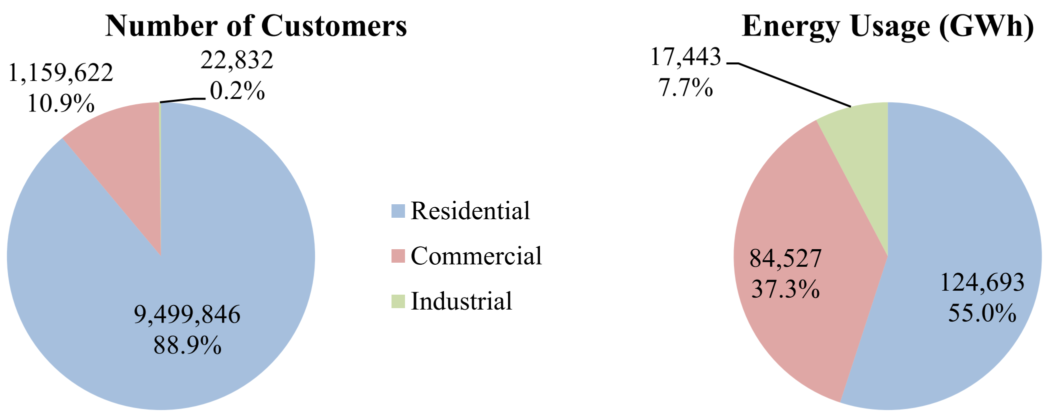
Load Forecasting

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

Electric Customer Composition

Utility companies categorize their customers by residential, commercial, and industrial classes. As of January 1, 2022, residential customers account for 88.9 percent of the total, followed by commercial (10.9 percent) and industrial (0.2 percent) customers, as illustrated in Figure 5. Commercial and industrial customers make up a sizeable percentage of energy sales due to their higher energy usage per customer.

Figure 5: State of Florida - Electric Customer Composition in 2021



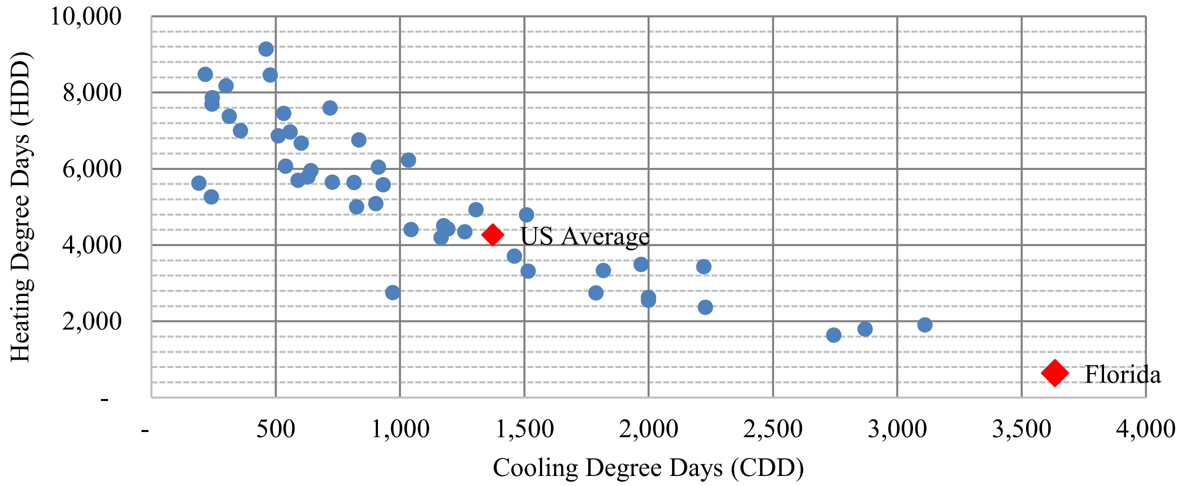
Source: FRCC 2022 Regional Load and Resource Plan

Residential customers in Florida make up the largest portion of retail energy sales. Florida's residential customers accounted for 55 percent of retail energy sales in 2021, compared to a national average of approximately 39 percent.[5] As a result, Florida's utilities are influenced more by trends in residential energy usage, which tend to be associated with weather conditions. Florida's unique climate plays an important role in electric utility planning, with the highest number of cooling degree days and lowest number of heating degree days within the continental United States, as shown in Figure 6. As such, most of Florida's utilities experience their peak demand during summer months. However, Florida's residential customers rely more upon electricity for heating than the national average, with only a small portion using alternate fuels

[5] U.S. Energy Information Administration July 2022 Electric Power Monthly.

such as natural gas or oil for home heating needs. Even with the low frequency of heating days required, such reliance can impact winter peak demand.

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

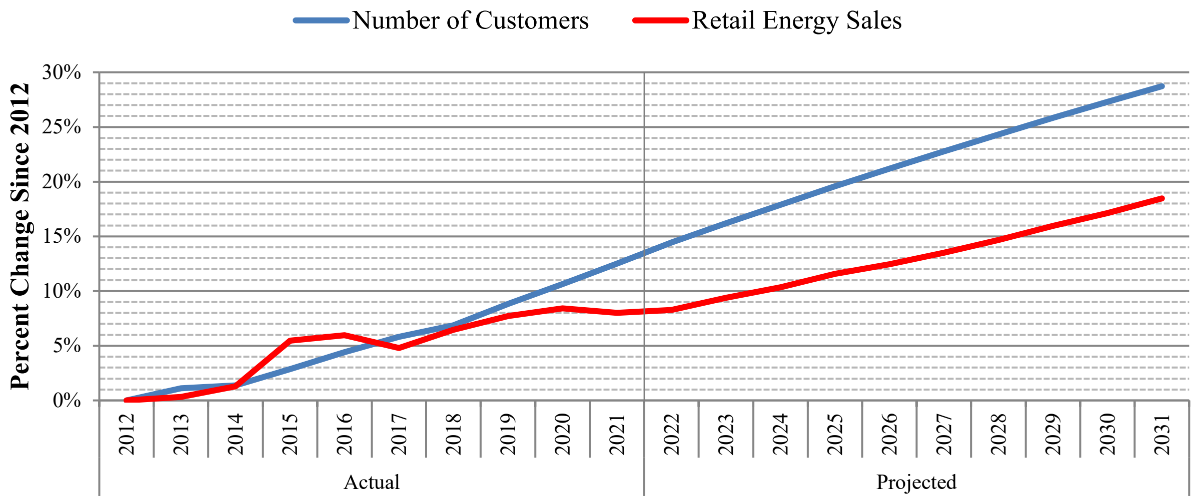


Source: National Oceanic and Atmospheric Administration Data

Growth Projections

For the next 10-year period, Florida's weather normalized retail energy sales are projected to grow at 1.01 percent per year, compared to the 0.86 percent actual annual increase experienced during the 2012-2021 period. The number of Florida's electric utility customers is anticipated to grow at an average annual rate of about 1.32 percent for the next 10-year period, the same as the actual annual increase experienced during the last decade. These trends are showcased in Figure 7.

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



Source: FRCC 2022 Regional Load and Resource Plan

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

With respect to the energy consumption per customer forecasts, FPL indicated that its residential use per customer will be flat or slightly decline through 2027 due to continued improvements in equipment efficiencies; then is expected to grow by 0.4 to 1 percent from 2028 due to economic growth and increased adoption of electric vehicles. The utility also expects that its commercial use per customer will decline by 0.3 to 0.6 percent per year over the forecast horizon due to continued improvements to equipment efficiencies. DEF reported that its per customer usage for both residential and commercial classes are primarily driven by fluctuations in electric price, end-use appliance saturation and efficiency improvement, building codes, and housing type/size. In addition, the utility is aware that more recently, the customer's ability to self-generate has begun to make an impact. A small percentage of industrial/commercial customers have chosen to install their own natural gas generators, reducing energy consumption from the power grid. Similarly, residential and some commercial accounts have reduced their utility requirements by installing solar panels behind the meter. However, the utility also noted that the penetration of electric vehicles has grown, leading to an increase in residential use per customer, all else being equal. Each of these stated items is directly or indirectly incorporated in DEF's sales forecast. TECO echoed that increases in appliance/lighting efficiencies, energy efficiency of new homes, conservation efforts and housing mix are also the primary drivers affecting the decrease in per customer usage. Other TYSP utilities likewise reported that the downward pressure to the growth trend in per customer energy consumption is due to advancements in efficient technologies, renewable generation, and alternative energy sources, with some utilities expecting that the increased electric vehicle charging will mitigate this downward pressure to some extent.

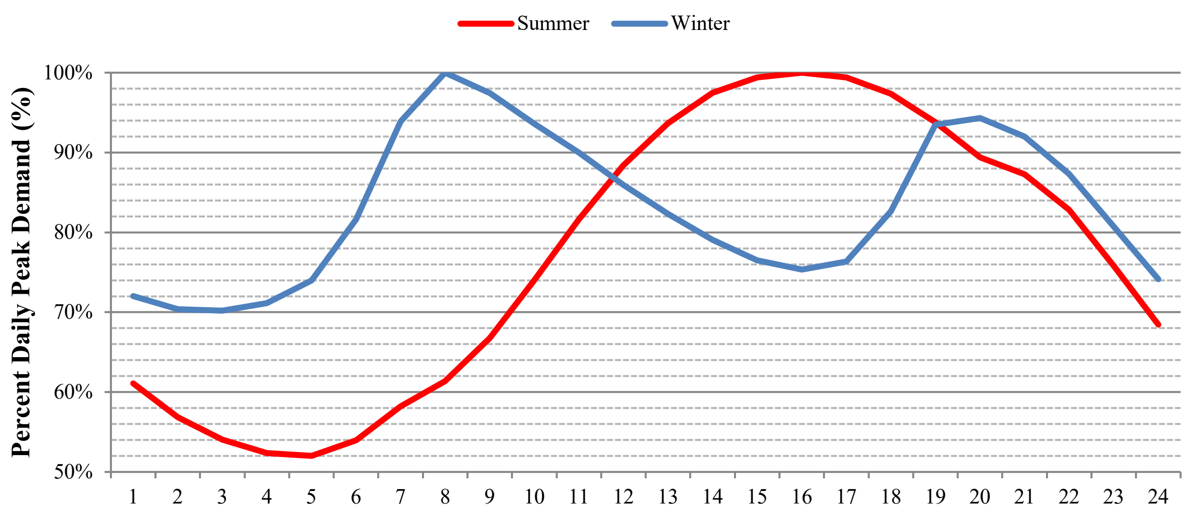
As shown in Figure 7, Florida utilities' total retail energy sales reached a historical peak in 2020. This is largely attributable to the significantly increased residential energy sales experienced by all of the utilities resulting from more people working and/or schooling from home due to the COVID-19 Pandemic. In 2021, the historical trend of Florida utilities' total retail energy sales experienced its second highest peak. As the aforementioned, Florida utilities' total retail energy sales are projected to grow at a higher annual average rate for the next 10 years than what was projected in the 2021 TYSPs. This sales growth is driven by growth in customers and business activity, as well as the expected increased level of adoption of electric vehicles.

Peak Demand

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

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

Figure 8: TYSP Utilities - Example Daily Load Curves

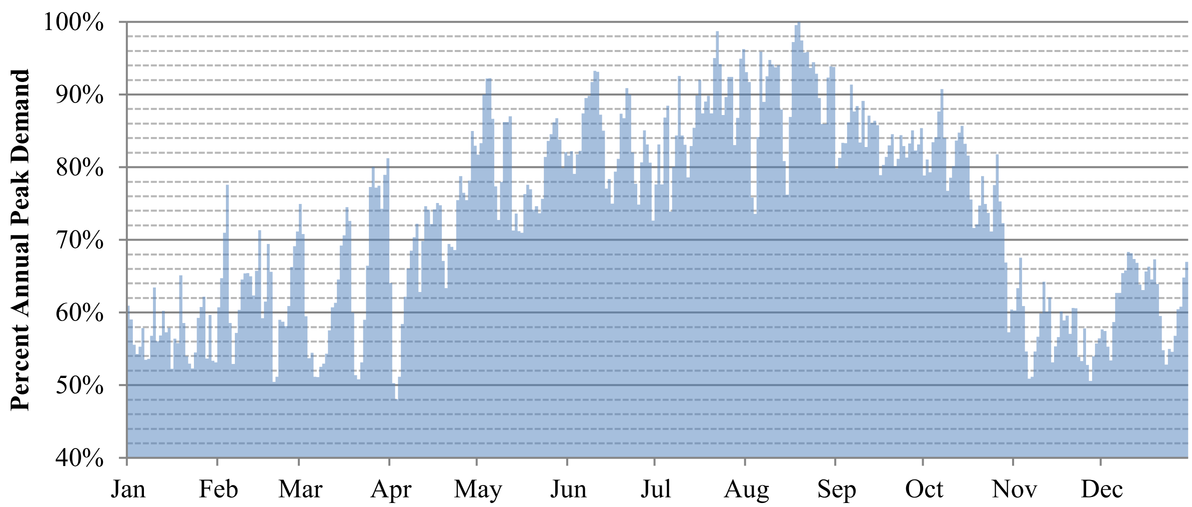


Source: TYSP Utilities' Data Responses

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

As daily load varies, so do seasonal loads. Figure 9 shows the 2021 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 (2021 Actual)



Source: 2022 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

Utilities also examine other trends that may impact customer peak demand and energy consumption. These include new sources of energy consumption, such as electric vehicles. The reporting electric utilities estimate approximately 168,722 EVs will be operating in Florida by the end of 2022. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered automobiles, heavy trucks, and buses in Florida, as of January 9, 2022 at 18.07 million vehicles, resulting in an approximate 0.93 percent penetration rate of electric vehicles. Each of the TYSP Utilities was sent a data request regarding estimates of electric vehicle ownership, public charging stations, and impacts to their electric grid. All responded and provided projections except for FMPA, LAK, OUC, and SEC. LAK was able to provide estimates for the number of vehicles and chargers in 2022, but did not have projections for the planning period and estimated EV impacts were insignificant to its grid. OUC did not provide a forecast, with OUC citing uncertainty in the EV market. FMPA and SEC do not have service territories; but, they do provide power to their member municipal utilities and rural electric cooperatives.

Florida's electric utilities anticipate continued growth in the electric vehicle market, as illustrated in Table 2. Electric vehicle ownership is anticipated to grow rapidly throughout the planning period, resulting in approximately 1,546,210 electric vehicles operating within the service territories of the TYSP Utilities by the end of 2031.

Table 2: TYSP Utilities - Estimated Number of Electric Vehicles

Year	FPL	DEF	TECO	JEA	GRU	LAK	TAL	Total
2022	116,202	33,325	12,218	4,220	1,065	534	1,158	168,722
2023	162,141	42,404	14,890	5,477	1,331	N/A	1,469	227,712
2024	220,697	52,918	17,742	6,939	1,664	N/A	1,832	301,792
2025	293,809	65,134	20,785	8,589	2,080	N/A	2,253	392,650
2026	391,240	79,267	24,119	10,419	2,600	N/A	2,736	510,381
2027	512,104	95,455	27,808	12,441	3,250	N/A	3,288	654,346
2028	657,776	114,021	31,977	14,689	4,063	N/A	3,921	826,447
2029	831,693	135,439	36,561	17,187	5,078	N/A	4,640	1,030,598
2030	1,037,328	160,059	41,599	19,951	6,348	N/A	5,459	1,270,744
2031	1,273,609	188,139	47,156	22,993	7,935	N/A	6,378	1,546,210

Source: TYSP Utilities' Data Responses

The major drivers of electric vehicle growth include a combination of the following: increased availability of charging infrastructure, lower fuel costs and emissions, increased commitment from auto manufacturers, broadened public outreach, expanded vehicle availability (makes and models), and strong government policy support at the local, state, and federal levels. Resulting from such policy support is the EV Infrastructure Master Plan, published in July 2021, in which the Florida Legislature required the Commission and the State Energy Office to assist the Florida Department of Transportation in developing, and recommending a master plan for the development of electric vehicle charging station infrastructure along the Florida State Highway System.[6] Government agencies, private entities, municipalities, and electric utilities continue to work together to expand charging infrastructure throughout the state to meet this expected growth in electric vehicles as well as to promote electric vehicle ownership.

Table 3 illustrates the reporting electric utilities' projections of public EV charging stations through 2031. While approximately 6,000 charging stations are estimated to be available across the state by the end of 2022, more than 32,000 charging stations are anticipated by 2031. The

[6] Florida Department of Transportation, *EV Infrastructure Master Plan,* published July 2021.

estimated public EV charging station counts listed in Table 3 include both normal and "quick-charge" public charging stations.[7]

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

Year	FPL	DEF	TECO	JEA	GRU	LAK	TAL	Total
2022	4,646	573	461	110	85	19	88	5,982
2023	6,292	926	512	124	94	N/A	90	8,038
2024	5,535	1,438	562	139	103	N/A	92	7,869
2025	10,431	2,128	613	155	113	N/A	94	13,534
2026	10,802	3,035	664	172	124	N/A	96	14,893
2027	12,678	4,170	714	190	137	N/A	98	17,987
2028	14,681	5,459	765	209	151	N/A	100	21,365
2029	17,063	6,867	815	229	166	N/A	103	25,243
2030	18,700	8,382	866	251	182	N/A	106	28,487
2031	20,908	10,018	917	274	200	N/A	109	32,426

Source: TYSP Utilities' Data Responses

Table 4 illustrates the TYSP Utilities' projections of energy consumed by electric vehicles through 2031. Across the TYSP Utilities, anticipated growth would result in an annual energy consumption of 5,977.1 GWh by 2031, which represents an impact of approximately 2.2 percent of the projected net energy for load.

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

Year	FPL	DEF	TECO	JEA	GRU	TAL	Total
2022	231.0	24.0	34.6	17.2	3.8	3.5	314.2
2023	401.0	54.1	45.5	24.1	4.8	4.5	534.0
2024	623.0	91.9	57.3	32.1	6.0	5.6	816.0
2025	908.0	138.9	70.3	41.2	7.5	6.9	1,172.7
2026	1,289.0	199.0	84.6	51.2	9.4	8.4	1,641.6
2027	1,771.0	274.5	100.8	62.3	11.7	10.1	2,230.5
2028	2,361.0	366.8	118.3	74.7	14.6	12.1	2,947.6
2029	3,075.0	470.4	137.9	88.5	18.3	14.4	3,804.4
2030	3,930.0	586.2	159.5	103.7	22.9	17.0	4,819.2
2031	4,913.0	712.2	183.0	120.5	28.6	19.9	5,977.1

Source: TYSP Utilities' Data Responses

Table 5 illustrates the TYSP Utilities' estimates of the effects of electric vehicle ownership on summer and winter peak demand through 2031. Across the TYSP Utilities, anticipated growth results in an impact to summer peak demand of approximately 1,395 MW and an impact to winter peak demand of approximately 610 MW by 2031. Current estimates represent a cumulative impact

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

of approximately 2.6 percent on summer peak demand and a 1.2 percent on winter peak demand by 2031.

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

Summer Peak Demand (MW)

Year	FPL	DEF	TECO	JEA	GRU	TAL	Total
2022	34	1.45	26.6	2.67	2.7	0.75	68
2023	76	3.6	31.7	3.73	3.3	0.95	119
2024	131	6.6	37.1	4.97	4.2	1.19	185
2025	202	10.5	42.8	6.37	5.2	1.46	268
2026	297	15.3	48.9	7.93	6.5	1.77	377
2027	418	21.2	55.6	9.65	8.1	2.13	515
2028	565	28.1	63.0	11.57	10.2	2.54	680
2029	744	71.0	71.0	18.33	12.7	3.00	920
2030	958	44.6	79.7	21.48	15.9	3.53	1,123
2031	1203	54.0	89.2	24.96	19.8	4.13	1,395

Winter Peak Demand (MW)

Year	FPL	DEF	TECO	JEA	GRU	TAL	Total
2022	15	0.5	11.5	0.24	4.0	0.44	32
2023	33	1.3	13.9	0.34	5.0	0.55	54
2024	57	1.9	16.4	0.45	6.2	0.69	83
2025	87	2.7	19.0	0.57	7.8	0.85	118
2026	129	3.8	21.9	0.71	9.8	1.03	166
2027	181	5.3	25.0	0.87	12.2	1.24	226
2028	244	7.2	28.5	1.04	15.2	1.48	297
2029	322	9.5	32.4	1.23	19.0	1.75	386
2030	414	12.1	36.5	1.45	23.8	2.05	490
2031	520	14.8	41.0	1.68	29.8	2.40	610

Source: TYSP Utilities' Data Responses

Some utilities, such as FPL and DEF, have begun to report key findings and metrics obtained through their respective EV pilot programs. This information includes: individual charging session data, peak EV charging hours, impacts to peak demand, as well as other metrics such as, revenue generated and port installation costs. Other utilities' EV pilot programs have not yet reached an age of maturity that will yield these same key findings. The Commission will continue to ask utilities to note key findings and track metrics of interest within these pilot programs in an effort to help inform the Commission about the future power needs of electric vehicles in Florida, which may require additional generating resources to meet their needs.

Demand-Side Management (DSM)

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

Florida Energy Efficiency and Conservation Act (FEECA)

In 1980, the Florida Legislature established FEECA, which consists of Sections 366.80 through 366.83 and Section 403.519, F.S. Under FEECA, the Commission is required to set appropriate goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems for electric utilities of a certain size, known as the FEECA Utilities.[8] Of the TYSP Utilities, these include the three investor-owned electric utilities, FPL, DEF, TECO, and two municipal electric utilities, JEA and OUC. The FEECA Utilities represented approximately 86 percent of 2021 retail electric sales in Florida.

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

The last FEECA goal-setting proceeding was completed in November 2019, establishing goals for the period 2020 through 2024. The Commission found that it was in the public interest to continue with the goals established in the 2014 FEECA goal-setting proceeding. Each FEECA electric utility was required to submit a proposed DSM Plan, designed to meet the goals within 90 days of the final order establishing the goals. In 2020, the Commission approved the DSM Plans proposed by the FEECA electric utilities. All FEECA Utilities that filed a 2022 Ten-Year Site Plan incorporated in their planning the impacts of the established DSM goals through 2024.

DSM Programs

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

[8] FEECA also applies to Florida Public Utilities Company, a non-generating investor-owned electric utility. As FPUC purchases power from other generating entities and does not own or operate its own generation resources, it is not required to file a Ten-Year Site Plan. Based on its 2022 Annual Report, FPUC accounted for 0.3 percent of the State's retail energy sales in 2021.

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

Load management is similar to interruptible load, but focuses on smaller customers and targets individual appliances. The utility installs a device on an electric appliance, such as a water heater or air conditioner, which allows for remote deactivation for a short period of time. Load management activations tend to have less advanced notice than those for interruptible customers, but tend to be activated only for short periods and are cycled through groups of customers to reduce the impact to any single customer. Due to the focus on specific appliances, certain appliances would be more appropriate for addressing certain seasonal demands. For example, load management programs targeting air conditioning units would be more effective to reduce a summer peak, while water heaters are more effective for reducing a winter peak. As of 2022, the total amount of demand response resources available for reduction of peak load is 3,097 MW for summer peak and 2,927 MW for winter peak. Demand response is anticipated to increase to approximately 3,401 MW for summer peak and 3,282 MW for winter peak by 2031.

Energy efficiency or conservation measures also have an impact on peak demand, and due to their passive nature do not require activation by the utility. Conservation measures include improvements in a home or business' building envelope to reduce heating or cooling needs, or the installation of more efficient appliances. By installing additional insulation, energy-efficient windows or window films, and more efficient appliances, customers can reduce both their peak demand and annual energy consumption, leading to reductions in customer bills. Demand-side management programs work in conjunction with building codes and appliance efficiency standards to increase energy savings above the minimum required by local, state, or federal regulations. As of December 31, 2021, energy efficiency is responsible for peak load reductions of 4,669 MW for summer peak and 4,920 MW for winter peak. Energy efficiency is anticipated to increase to approximately 5,378 MW for summer peak and 5,296 MW for winter peak by 2031.

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.

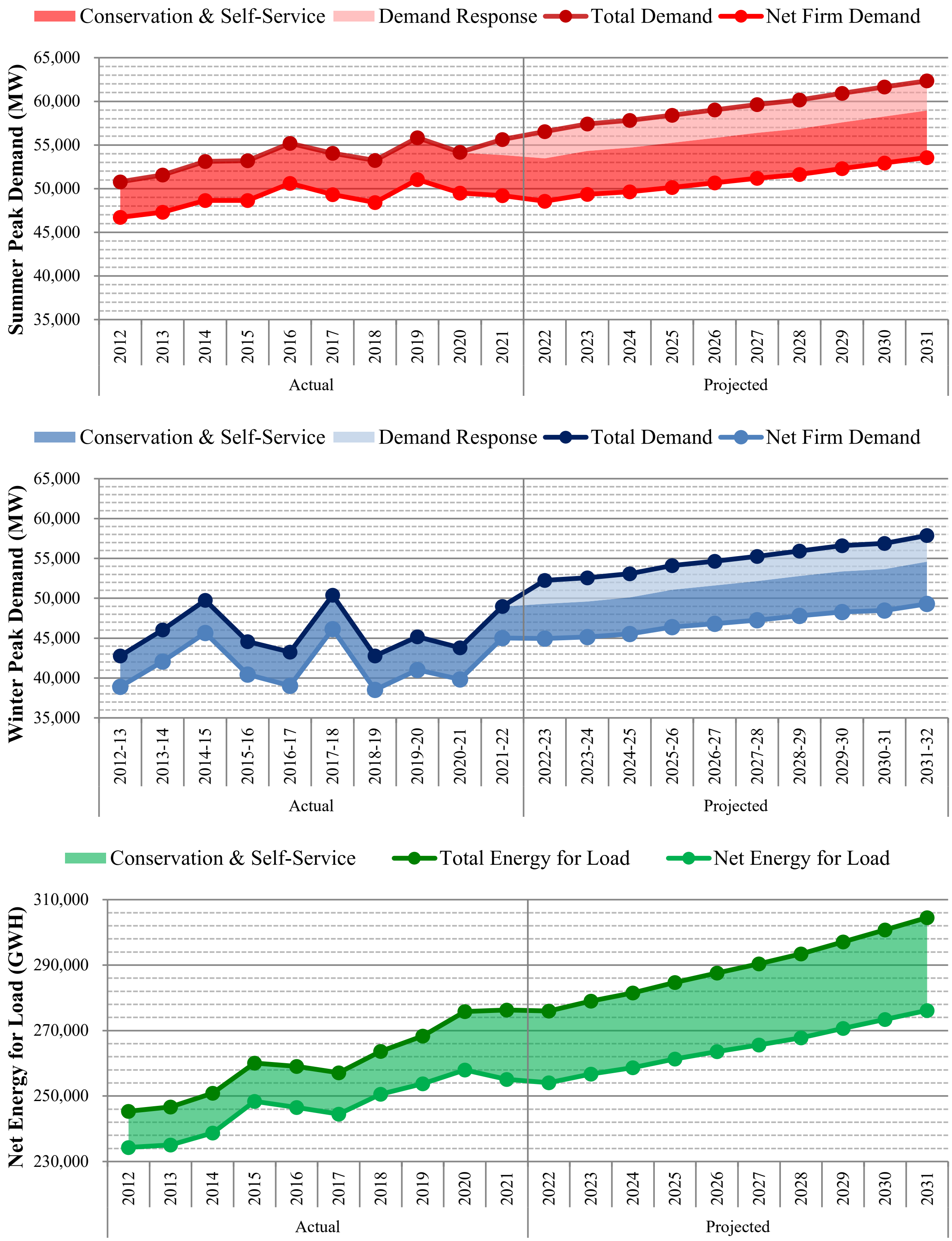
Demand-side management, including demand response and energy efficiency, along with self-service generation, is included in each graph appearing in Figure 10 for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served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

Demand response is included in Figure 10 in two different ways based upon the time period considered. For historic values of seasonal demand, the actual rates of demand response activation are shown, not the full amount of demand response that was available at the time. Overall, demand response has only been partially activated as sufficient generation assets were available during the annual peak. Residential load management has been called upon to a limited degree during peak periods, with a lesser amount of interruptible load activated.

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

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

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



Source: FRCC 2022 Regional Load and Resource Plan

Forecast Methodology

Load forecasting is an essential requirement of all electric utility companies for purposes of system planning. In order for utilities to reliably and cost-effectively serve their respective customers, they must be able to accurately determine their energy and demand requirements. Thus, the load forecast function facilitates the ongoing equilibrium between system demand and system supply. Load forecasting can be divided into three types depending on the forecasting horizon: short, medium and long-term. Short-term load forecasting denotes forecast horizons of up to one week ahead. Medium-term load forecasting ranges from one week to one year ahead. Long-term load forecasting typically targets forecast horizons of one to ten years, and sometimes up to several decades. Long-term load forecasting provides the essential load requirement data that a utility must have in order to effectively modify its system of generation, transmission, and distribution assets. Load forecasts directly impact the timing, type, and location of expansions, replacements, and retirements. Hence, the load forecast function plays a vital role in an electric utility's system planning and, in Florida, serves as the foundation of a utility's Ten-Year Site Plan.

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

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

End-use models are sometimes used to project energy use in conjunction with econometric models. 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 projecting load. The models have relied upon dependent and independent variable data to project energy 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 in 2022, 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 sales for a given year to energy sales forecasts made three, four, and five years prior. For example, the actual 2021 retail energy sales were compared to the forecasts made in 2016, 2017, and 2018. These 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 2022 TYSPs, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2017 through 2021 to forecasts made between 2012 and 2018. These are summarized in Table 6.

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

Year	Five-Year Analysis Period	Forecast Years Analyzed	Forecast Error (%)	
			Average	Absolute Average
2013	2013 - 2009	2010 - 2004	16.27%	16.27%
2014	2014 - 2010	2011 - 2005	14.99%	14.99%
2015	2015 - 2011	2012 - 2006	12.55%	12.55%
2016	2016 - 2012	2013 - 2007	9.19%	9.19%
2017	2017 - 2013	2014 - 2008	6.07%	6.07%
2018	2018 - 2014	2015 - 2009	3.58%	3.58%
2019	2019 - 2015	2016 - 2010	2.26%	2.42%
2020	2020 - 2016	2017 - 2011	1.68%	2.12%
2021	2021 - 2017	2018 - 2012	1.10%	1.67%

Source: 2004-2022 Ten-Year Site Plans

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

As displayed in Table 7, the utilities' retail energy sales forecasts show large positive error rates during the recession-impacted period 2010 through 2014. 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 2010-2014 sales forecasts. The last two years' four-year ahead forecasts and the last three years' three-year ahead forecasts all bear negative error rates (under-forecasts). Additionally, most of the last three years' two-year ahead forecasts and one-year ahead forecasts render negative error rates as well. The positive error rate exceptions are the 2020 one-year ahead forecasts and 2021 two-year ahead forecasts which reflect the unforeseen impacts of the COVID-19 Pandemic-related shelter-in-place orders in 2020. The current TYSP also shows a very small error rate with respect to both average and absolute average three to five year error percentages. Likewise, the one-year ahead forecast error associated with the 2022 TYSPs appears to be one of the lowest since 2010.

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

Year	Annual Forecast Error Rate (%)						3-5 Year Error (%)	
	Years Prior						Average	Absolute Average
	6	5	4	3	2	1		
2010	13.03%	15.68%	14.99%	13.81%	10.65%	-0.65%	14.83%	14.83%
2011	21.67%	20.91%	20.22%	17.14%	3.89%	0.18%	19.42%	19.42%
2012	26.43%	26.12%	23.16%	8.58%	4.01%	3.81%	19.29%	19.29%
2013	28.71%	26.42%	10.11%	6.09%	5.69%	3.08%	14.21%	14.21%
2014	27.28%	9.80%	6.10%	5.73%	2.84%	2.21%	7.21%	7.21%
2015	7.29%	3.63%	3.23%	1.02%	0.00%	-1.17%	2.63%	2.63%
2016	4.33%	4.38%	2.28%	1.25%	0.20%	-0.97%	2.64%	2.64%
2017	6.99%	4.93%	3.59%	2.53%	1.57%	-0.07%	3.68%	3.68%
2018	4.28%	2.76%	1.76%	0.75%	-1.13%	-1.08%	1.76%	1.76%
2019	2.95%	2.04%	0.92%	-1.23%	-1.25%	-1.87%	0.58%	1.40%
2020	2.44%	1.27%	-0.97%	-1.07%	-1.91%	2.73%	-0.25%	1.10%
2021	2.47%	0.24%	-0.09%	-0.91%	3.80%	-0.08%	-0.26%	0.41%

Source: 2004-2022 Ten-Year Site Plans

Barring any unforeseen economic crises or atypical weather patterns, average forecasted energy sales error rates in the next few years are likely to be more reflective of the error rates shown for 2015 through 2021 in Table 6. However, current major global and domestic events could, individually or collectively, inflict damage to the US economy. As such, there remains uncertainty as to when the economic impacts of these events will end. As a result, the actual retail energy sales of the next few years could be different from what Florida utilities projected in 2021 and prior years. Consequently, the average forecasted energy sales error rates in the next few years may deviate from the lower levels recently recorded. It is important to recognize that the dynamic nature of the economy, the weather, and now even global health, political and economic issues present a degree of uncertainty for Florida utilities' load forecasts, ultimately impacting the accuracy of energy sales forecasts.

Renewable Generation

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

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

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

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

Existing Renewable Resources

Currently, renewable energy facilities provide approximately 7,584 MW of firm and non-firm generation capacity, which represents 9.2 percent of Florida's overall generation capacity of 63,895 MW in 2021. Table 8 summarizes the contribution by renewable type of Florida's existing renewable energy sources.

Table 8: State of Florida - Existing Renewable Resources

Renewable Type	MW	% Total
Solar	6,085	80.2%
Municipal Solid Waste	451	5.9%
Biomass	380	5.0%
Waste Heat	276	3.6%
Wind	272	3.6%
Landfill Gas	70	0.9%
Hydroelectric	51	0.7%
Renewable Total	**7,584**	100.0%

Source: FRCC 2022 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Of the total 7,584 MW of renewable generation, approximately 2,790 MW are considered firm, based on either operational characteristics or contractual agreement. Firm renewable generation can be relied on to serve customers and can contribute toward the deferral of new fossil fuel power plants. Solar generation contributes approximately 2,458 MW to this total, based upon the coincidence of solar generation and summer peak demand, or about 40 percent of its installed capacity. Changes in timing of peak demand may influence the firm contributions of renewable resources such as solar and wind.

Of the 1,499 MW of non-solar generation, only 332 MW is treated as firm because of contractual commitments. The remaining renewable generation can generate energy on an as-available basis or for internal use (self-service). As-available energy is considered non-firm, and cannot be counted on for reliability purposes; however, it can contribute to the avoidance of burning fossil fuels in existing generators. Self-service generation reduces demand on Florida's utilities.

Utility-Owned Renewable Generation

Utility-owned renewable generation also contributes to the state's total renewable capacity. The majority of this generation is from solar facilities. Due to the intermittent nature of solar resources, capacity from these facilities has previously been considered non-firm for planning purposes. However, several utilities are attributing firm capacity contributions to their solar installations based on the coincidence of solar generation and summer peak demand. Of the approximately 4,490 MW of existing utility-owned solar capacity, approximately 2,347 MW, or about 52 percent, is considered firm.

Non-Utility Renewable Generation

Approximately 2938 MW, or 39 percent of Florida's existing renewable capacity is from non-utility owned sources. A majority, approximately 1,761 MW, or 23 percent, comes from mostly municipal solid waste and solar facilities. In 1978, the US Congress enacted the Public Utility Regulatory Policies Act (PURPA). PURPA requires utilities to purchase electricity from cogeneration facilities and renewable energy power plants with a capacity no greater than 80 MW (collectively referred to as Qualifying Facilities or QFs). PURPA required utilities to buy electricity from 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 renewable energy generator can meet certain deliverability requirements, its capacity and energy output can be paid for under a firm contract. Rule 25-17.250, F.A.C., requires each IOU to establish a standard offer contract with timing and rate of payments based on each fossil-fueled generating unit type identified in the utility's Ten-Year Site Plan. In order to promote renewable energy generation, the Commission requires the IOUs to offer multiple options for capacity payments, including the options to receive early (prior to the in-service date of the avoided-unit) or levelized payments. The different payment options allow renewable energy providers the option to select the payment option that best fits its financing requirements, and provides a basis from which negotiated contracts can be developed.

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

Demand-Side Renewable Generation

Approximately 1,177 MW, or 16 percent of existing non-utility owned renewable generation is from customer-owned systems, also referred to as demand-side renewable systems. Rule 25-6.065, F.A.C., requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer with renewable generation capability, to offset their energy usage. In 2008, the effective year of Rule 25-6.065, F.A.C., customer-owned renewable generation accounted for 3 MW of renewable capacity. As of the end of 2021, approximately 1,177 MW of renewable capacity from over 130,947 systems has been installed statewide. Table 9 summarizes the growth of customer-owned renewable generation interconnections. Almost all installations are solar, with non-solar generation accounting for only 34 installations and 7.1 MW of installed capacity. The renewable generators in this category include wind turbines and anaerobic digesters.

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

Year	2014	2015	2016	2017	2018	2019	2020	2021
Number of Installations	8,581	11,626	15,994	24,166	37,862	59,508	90,552	103,947
Installed Capacity (MW)	79.8	107.5	141	205	317	514	835	1,177

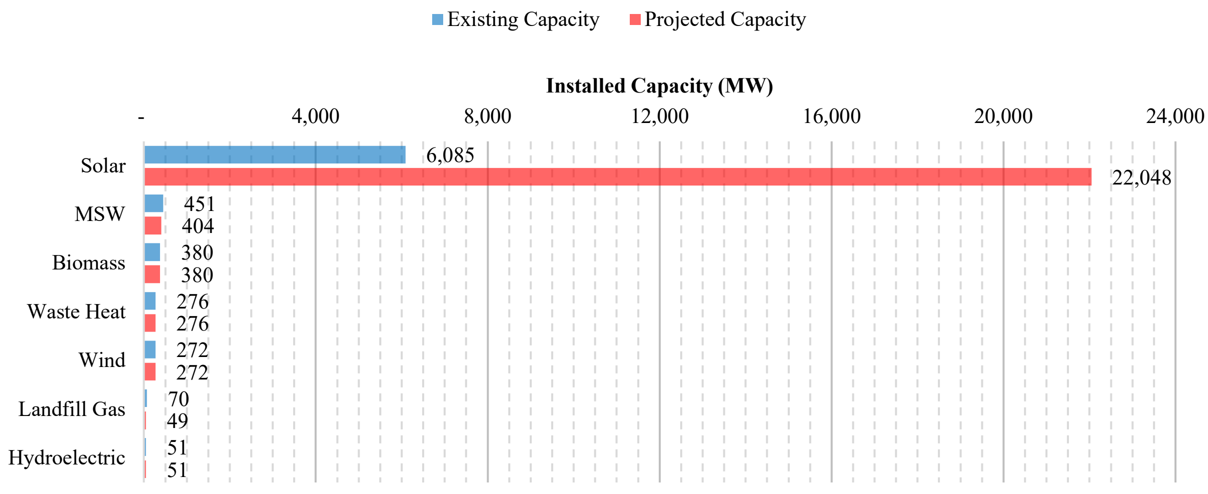
Source: 2015-2022 Net Metering Reports

Planned Renewable Resources

Florida's total renewable resources are expected to increase by an estimated 15,894 MW over the 10-year planning period, an increase from last year's estimated 15,055 MW projection. Figure 11 summarizes the existing and projected renewable capacity by generation type. Solar generation, primarily utility-owned, is projected to have the greatest increase over the planning horizon.

Of the 15,894 MW projected net increase in renewable capacity, firm resources contribute 5,279 MW, or about 33 percent, of the total. This net increase value takes into account that for some existing renewable facilities contracts for firm capacity are projected to expire within the 10-year planning horizon. If new contracts are signed in the future to replace those that expire, these resources will once again be included in the state's capacity mix to serve future demand. If these contracts are not extended, the renewable facilities could still deliver energy on an as-available basis.

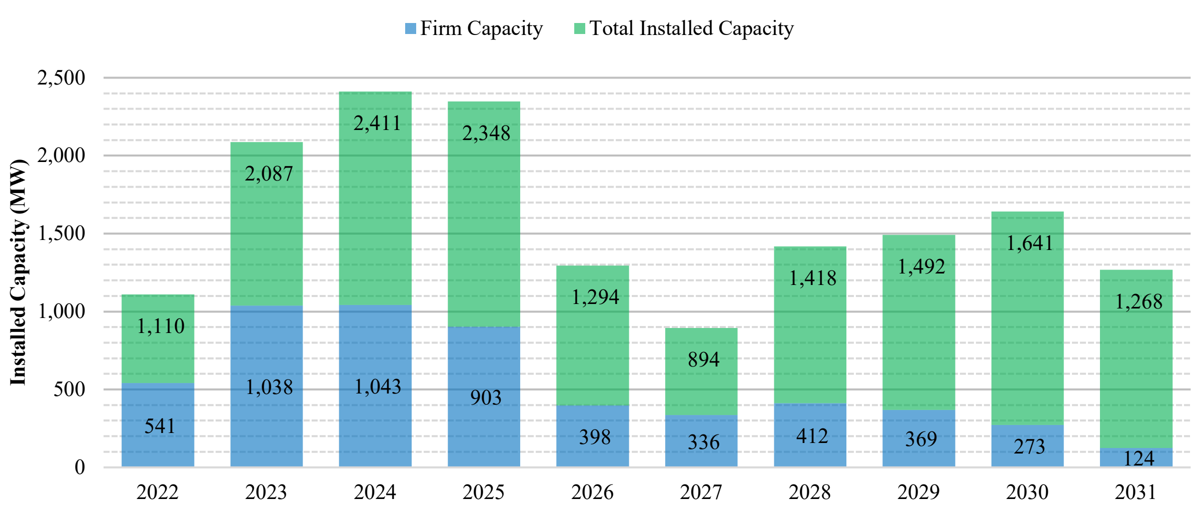
Figure 11: State of Florida - Current and Projected Renewable Resources



Source: FRCC 2022 Regional Load and Resource Plan & TYSP Utilities' Data Responses

As noted above, solar generation is anticipated to increase significantly over the 10-year period, with a net total of 15,963 MW to be installed. This consists of 13,650 MW of utility-owned solar and 2,313 MW of contracted solar. The firm contribution of solar varies by utility, with some having a set percentage value for all projects over the planning period, and others having a declining value as projects are added. Figure 12 provides an overview of the additional solar capacity generation planned within the next 10 years, as well as the amount considered firm for summer reserve margin planning.

Figure 12: TYSP Utilities - Planned Solar Installations



Source: FRCC 2022 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Energy Storage Outlook

In addition to a number of electric grid related applications, emerging energy storage technologies have the potential to considerably increase not only the firm capacity contributions from solar PV installations, but their overall functionality as well. Energy storage technologies currently being researched include pumped hydropower, flywheels, compressed air, thermal storage, and battery storage. Of these technologies, Lithium ion (Li-ion) battery storage is being extensively researched due to its declining costs, operational characteristics, scalability, and siting flexibility.

As part of its 2016 Settlement, FPL deployed approximately 50 MW of non-firm capacity through its Battery Storage Pilot Program, which examines the applications of combining battery storage with new and existing solar facilities.[9] In 2021, FPL added 409 MW of battery storage in Manatee County, which is charged by an existing PV facility. Additionally, two other 30 MW battery storage facilities were installed at two different locations and put into service in 2021. FPL's 2022 TYSP includes an additional 1,800 MW of unsited solar charged battery storage additions over the next 10 years.

DEF is expanding its battery storage with a 50 MW, non-firm capacity, Battery Storage Pilot Program as part of its 2017 Settlement.[10] The program includes six solar charged battery energy storage systems. Trenton and Lake Placid battery energy storage systems were placed in-service in late 2021 with the remaining four battery energy storage systems under construction and expected to be placed in-service in 2022. DEF stated these facilities will enhance grid operations, increase efficiencies, improve overall reliability, and provide backup generation during outages. DEF will use the data gathered from the operation of these systems to evaluate future opportunities with battery storage. DEF is planning an additional 111 MW of solar connected battery storage by the end of 2031.

TECO installed a 12.6 MW Li-ion storage system at its Big Bend Solar site in Hillsborough County in 2019. This facility is interconnected with the solar array and is expected to add 5.6 MW of firm capacity. In 2021 TECO completed its first integrated renewable energy system, consisting of solar PV carports that charge commercial-sized batteries which re-charge the Company's EV fleet. Over the next 10 years, TECO expects to deploy approximately 265 MW of energy storage systems to meet system reliability needs, maximize solar energy production, and to avoid transmission and distribution investments.

In addition to utility-owned battery storage, energy storage associated with purchased power agreements are also anticipated in the planning horizon. OUC also plans to enter into purchased power agreements with energy storage providers connected to future solar facilities, with an estimated 350 MW of capacity through 2031. Overall, whether utility-owned or contracted, a total of 2,819 MW of battery storage is projected to be installed by 2031.

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[9] Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 20160021-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

[10] Order No. PSC-2017-0451-AS-EU, issued November 20, 2017, in Docket No. 20170183-EI, *In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC.*

Traditional Generation

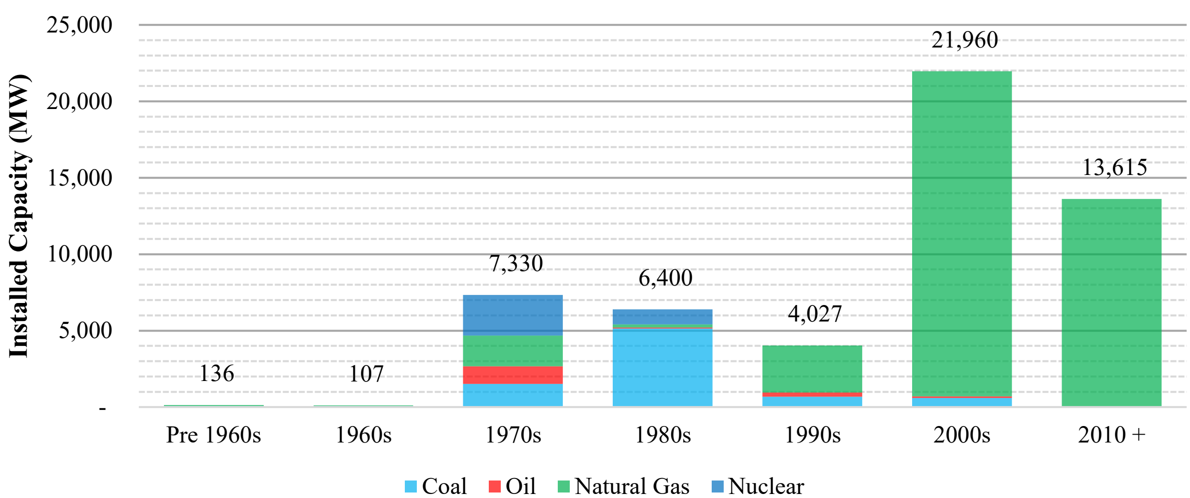
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and combustion turbine generators that have been added to Florida's electric grid over the last several decades.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

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

Existing Generation

Florida's generating fleet includes incremental new additions to a historic base fleet, with units retiring as they become uneconomical to operate or maintain. Currently, Florida's existing capacity ranges greatly in age and fuel type, and legacy investments continue. The weighted average age of Florida's generating units is 22 years. While the original commercial in-service date may be in excess of 50 years for some units, they are constantly maintained as necessary in order to ensure safe and reliable operation, including uprates from existing capacity, which may have been added after the original in-service date. Figure 13 illustrates the decade in which current operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

Figure 13: State of Florida - Electric Utility Installed Capacity by Decade



Source: FRCC 2022 Regional Load and Resource Plan

The existing generating fleet will be impacted by several events over the planning period. New and proposed environmental regulations may require changes in unit dispatch, fuel switching, or installation of pollution control equipment which may reduce net capacity. Modernizations will allow more efficient resources to replace older generation, while potentially reusing power plant assets such as transmission and other facilities, switching to more economic fuel types, or uprates at existing facilities to improve power output. Lastly, retirements of units which can no longer be economically operated and maintained or meet environmental requirements will reduce the existing generation.

Impact of EPA Rules

In addition to maintaining a fuel efficient and diverse fleet, Florida's utilities must also comply with environmental requirements that impose incremental costs or operational constraints. During the planning period, the six EPA rules identified below were anticipated to affect electric generation in Florida. The first five rules are currently under EPA review pursuant to Executive Order 13990. [11] Future developments will be addressed in a subsequent Ten-Year Site Plan review.

- Carbon Pollution Emissions Standards for New, Modified and Reconstructed Secondary Sources: Electric Utility Generating Units - Sets carbon dioxide emissions limits for new, modified or reconstructed electric generators. These limits vary by type of fuel (coal or natural gas). New units are those built after January 18, 2014. Units that undergo modifications or reconstructions after June 18, 2014, that materially alter their air emissions are subject to the specified limits. This rule is currently under appeal. On August 21, 2018, as part of its proposed Affordable Clean Energy Rule, the EPA proposed updates to the New Source Review permitting program that may impact utility decisions regarding power plant modifications and reconstruction. However, no final regulatory actions have been taken. Future developments will be addressed in a subsequent Ten-Year Site Plan review.

- Carbon Pollution Emission Guideline for Existing Electric Generating Units: On July 8, 2019, EPA finalized the ACE rule. ACE establishes carbon emission guidelines such that each state must perform site-specific reviews to determine the applicable standard of performance using the EPA's best system of emission reduction (BSER). The BSER identifies six technologies upgrades as well as operation and maintenance practices directed at improving the heat rate efficiency of coal-fired steam generating units greater than 25 MWs that began construction on or before January 8, 2014. No other type of existing fossil steam utility generators are subject to the requirements of ACE. However, on January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the ACE rule and remanded it to the EPA. As the Court did not expressly reinstate the CPP, the EPA understands the decision as leaving neither of those rules, and thus no CAA section 111(d) regulation, in place with respect to greenhouse gas emissions from electric generating units.

[11] See Executive Order 13990 Fact Sheet.

- Prevention of Significant Deterioration and Nonattachment New Source Review: On August 1, 2019, the EPA announced a proposed rule that would revise certain New Source Review (NSR) applicability regulation to clarify the requirements that apply to new sources, such as electric steam generators, proposing to undertake a physical or operational change (i.e., project) under the NSR preconstruction permitting program. EPA is proposing to clarify that both emission increases and decreases resulting from a given project are to be considered when determining whether the project by itself results in a significant emission increase.

- Mercury and Air Toxics Standards - Sets limits for air emissions from existing and new coal- and oil-fired electric generators with a capacity greater than 25 megawatts. Covered emissions include: mercury and other metals, acid gases, and organic air toxics for all generators, as well as particulate matter, sulfur dioxide, and nitrogen oxide from new and modified coal and oil units.

- Cooling Water Intake Structures - Sets impingement standards to reduce harm to aquatic wildlife pinned against cooling water intake structures at electric generating facilities. All electric generators that use state or federal waters for cooling with an intake velocity of at least two million gallons per day must meet impingement standards. Generating units with higher intake velocity may have additional requirements to reduce the damage to aquatic wildlife due to entrapment in the cooling water system.

- Coal Combustion Residuals (CCR) - Requires liners and ground monitoring to be installed on landfills in which coal ash is deposited. On July 29, 2020, the EPA issued for publication in the Federal Register, a final rule that will require among other things that unlined impoundments and CCR units that failed to meet ground water quality regulations must cease receipt of waste streams by April 11, 2021.

Each utility will need to evaluate whether these additional costs or operational limitations allow the continued economic operation of each affected unit, and whether installation of emissions control equipment, fuel switching, or retirement is the proper course of action.

Modernization and Efficiency Improvements

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

The Commission has previously granted determinations of need for several conversions of oil-fired steam units to natural gas-fired combined cycle units, including FPL's Cape Canaveral, Riviera, and Port Everglades power plants. DEF has also conducted a conversion of its Bartow power plant, but this did not require a determination of need from the Commission.

Utilities also plan several efficiency improvements to existing generating units. For example, the conversion of existing simple cycle combustion turbines into a combined cycle unit, which captures the waste heat and uses it to generate additional electricity using a steam turbine. TECO is modernizing its Big Bend Power Station through the conversion of Big Bend Unit 1, along with two planned combustion turbines, into a 2x1 combined cycle unit by the end of 2022. Per the Florida Department of Environmental Protection, this conversion does not require a determination of need by the Commission. FPL plans on upgrading its existing combined cycle fleet by improving the performance of the integrated combustion turbines at many of its current and planned power plants.

Planned Retirements

Power plant retirements occur when the electric utility is unable to economically operate or maintain a generating unit due to environmental, economic, or technical concerns. Table 10 lists the 4,003 MW of existing generation that is scheduled to be retired during the planning period. A majority of the retirements are coal-fired steam generators, with 10 units totaling 3,400 MW of capacity to be retired by 2031. Additional capacity reductions in coal occur due to fuel switching, such as the approximately 464 MW Stanton Unit 2, jointly owned by FMPA and OUC, which will be converted to natural gas in 2027.

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

Year	Utility Name	Plant Name & Unit Number	Net Capacity (MW) Summer
Coal Steam Retirements			
2022	FPL & JEA	Scherer Unit 4	832
2022	SEC	Seminole Generating Station Unit 1	626
2023	TEC	Big Bend Unit 3	395
2024	FPL	Daniel Units 1 & 2	502
2025	FPL	Gulf CEC Units 4 & 5	150
2025	FMPA & OUC	Stanton Unit 1	452
2029	FPL	Scherer Unit 3	215
2031	GRU	Deerhaven Unit FS02	228
		Coal Subtotal	**3,400**
Oil Combustion Turbine Retirements			
2025	FPL	Lansing Smith Unit A	32
2025	DEF	Bayboro Units P1-P4	171
2027	DEF	Debary Units P2-P6	227
2027	DEF	P.L. Bartow Units P1 & P3	82
		Oil Subtotal	**512**
Natural Gas Combustion Turbine Retirements			
2025	FPL	Pea Ridge Units 1-3	12
2026	GRU	Deerhaven Units GT01-02	35
2027	DEF	University of Florida Unit P1	44
		Gas Subtotal	**91**
		Total Retirements	**4,003**

Source: 2022 Ten-Year Site Plans

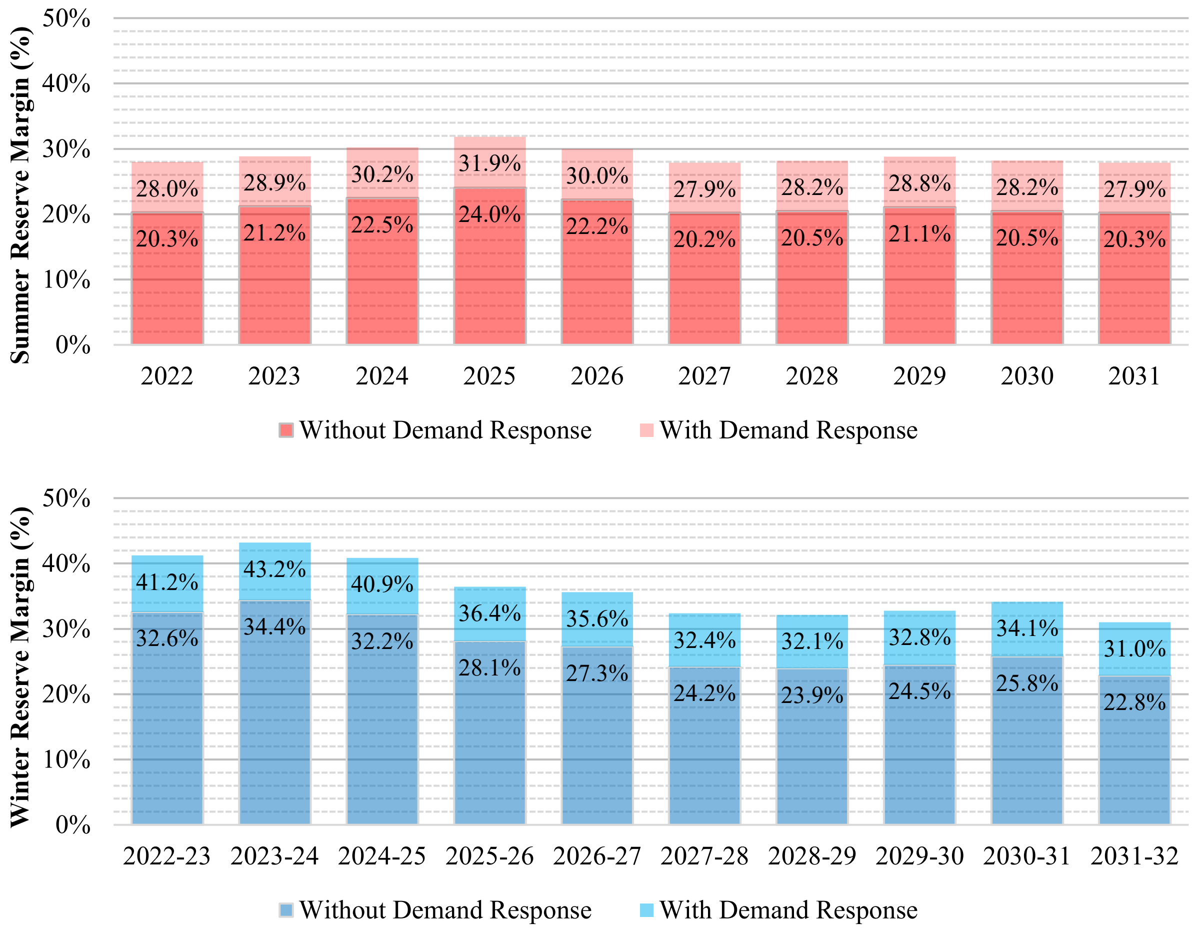
Reliability Requirements

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

On July 1, 2019, the SERC Reliability Corporation (formerly the Southeastern Electric Reliability Council) became the new Compliance Enforcement Authority for all electric utilities previously registered with the FRCC. Electric utilities within Florida must maintain a minimum reserve margin of 15 percent for planning purposes. Certain utilities have elected to have a higher reserve margin, either on an annual or seasonal basis. The three largest reporting electric utilities, FPL, DEF, and TECO, are party to a stipulation approved by the Commission that utilizes a 20 percent reserve margin for planning.

While Florida's electric utilities are separately responsible for maintaining an adequate planning reserve margin, a statewide view illustrates the degree to which capacity may be available for purchases during periods of high demand or unit outages. Figure 14 is a projection of the statewide seasonal reserve margin including all proposed power plants.

Figure 14: State of Florida - Projected Reserve Margin by Season



Source: FRCC 2022 Regional Load and Resource Plan - Revised Form 10

Role of Demand Response in Reserve Margin

The Commission also considers the planning reserve margin without demand response. As illustrated above in Figure 14, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin without activation of demand response. Demand response activation increases the reserve margin on average 7.7 percent in summer and 8.4 percent in winter.

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

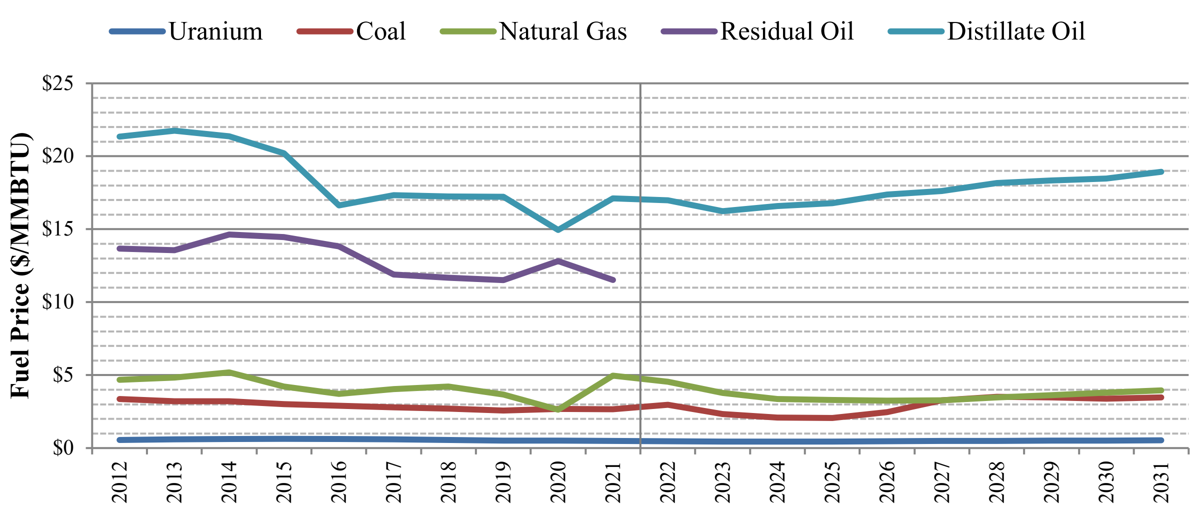
Fuel Price Forecast

Fuel price is an important economic factor affecting the dispatch of the existing generating fleet and the selection of new generating units. In general, the capital cost of a 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 15 illustrates the weighted average fuel price history and forecasts for the reporting electric utilities.

Natural gas remains the most intensively used fuel state-wide on a per GWh basis, accounting for 69.15 percent of electric generation in 2021.[12] As shown in Figure 15, the price of natural gas continued to decline from 2012 until 2020. However, there was an 89 percent increase, from a unit price in dollars per million British Thermal Units (BTUs) of $2.63 in 2020 to $4.97 in 2021. The price of natural gas is now forecast to decline from 2021 through 2026. Meanwhile, the price of coal has been stable from 2012 through 2021. However, forecasts show a slight decrease through 2025 at which time it is forecast to increase by roughly 68 percent from 2025 through 2031. It should be noted that the use of coal is projected to decrease substantially over the next 10 years.

Distillate oil remains the most expensive fuel, which explains why it is used for backup and peaking purposes only. Also of note is a phasing out of residual oil, with no forecast for purchasing residual oil after 2021. The truncated graph on Figure 15 reflects this phasing out of residual oil.

Figure 15: TYSP Utilities - Average Fuel Price of Reporting Electric Utilities



Source: TYSP Utilities' Data Responses

As shown in Figure 15, the price of natural gas continued to decline from 2012 until 2020. Even though current forecasts project the price of natural gas to remain relatively stable over the long term, there remains some degree of natural gas price volatility over the short and medium term.

[12] 2022 Florida Reliability Coordinating Council 2022 Regional Load and Resource Plan, p. S-19.

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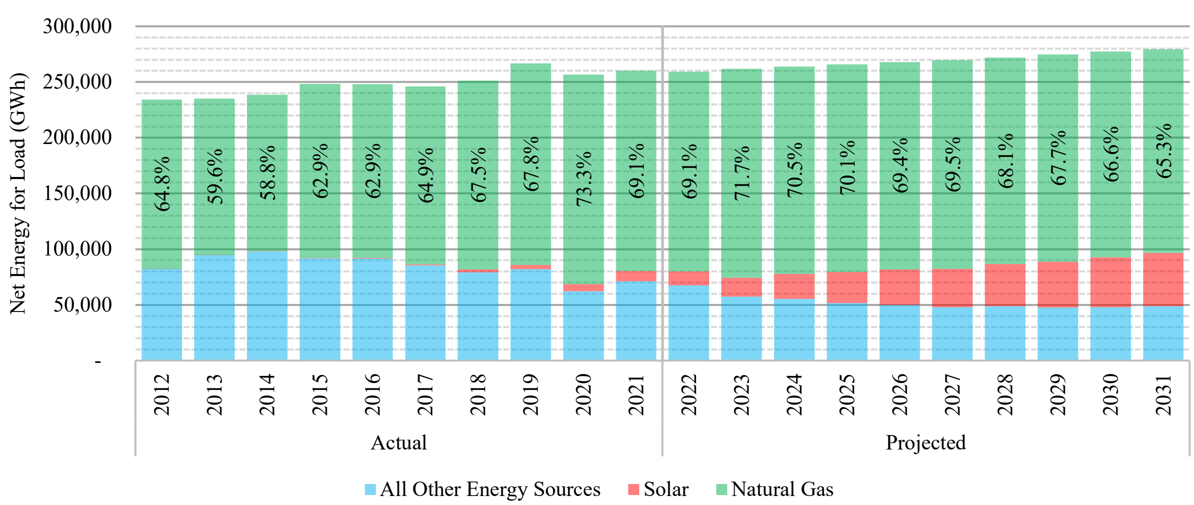
For instance, natural gas price volatility was reflected in the 2021 requests for fuel factor mid-course corrections (increases in customer fuel charges) filed by TECO and DEF, and approved by the Commission on August 30, 2021.[13]

The price of coal has been stable from 2012 through 2020. However, forecasts show a slight decrease through 2024 at which time coal prices are forecasted to nearly double by 2030. It should be noted that Florida utilities' reliance on coal for electric generation is projected to decrease substantially over the next 10 years.

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 16 illustrates, natural gas was the source of approximately 69 percent of electric energy consumed in Florida in 2021. Natural gas electric generation, as a percent of net energy for load, is anticipated to decline slightly throughout the remainder of the planning period.

Figure 16: State of Florida - Natural Gas Generation



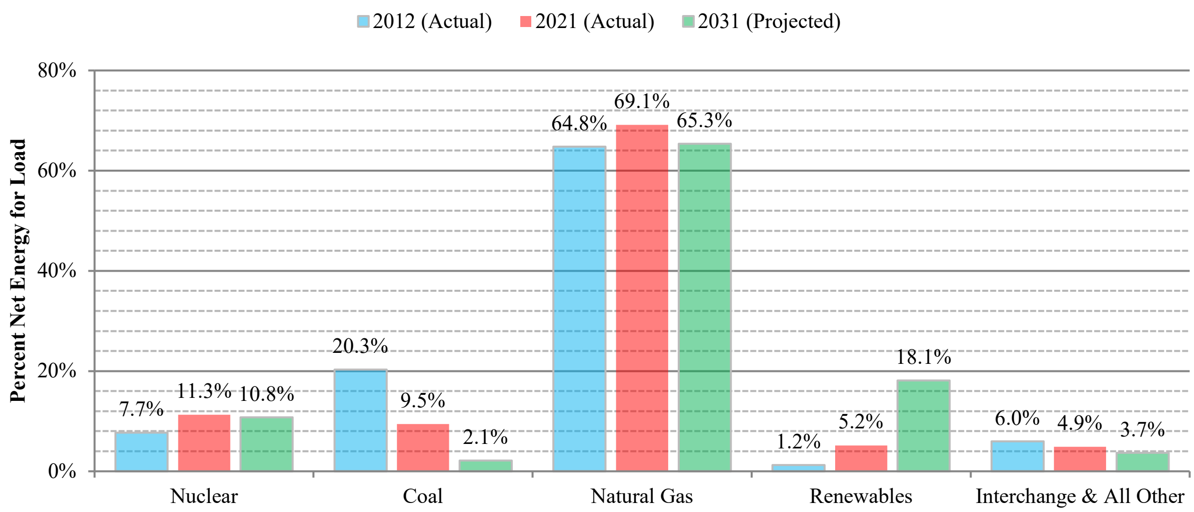
Source: FRCC 2013-2022 Regional Load and Resource Plans

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

[13] Docket No. 20210001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

Figure 17 shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2012 and 2021, and forecast year 2031. Nuclear generation is expected to remain steady throughout the planning period. Coal generation is expected to continue its downward trend well into the planning period. Natural gas has been the primary fuel used to meet the growth of energy consumption, and this trend is anticipated to continue throughout the planning period. Renewables are expected to exceed all other generation sources except for natural gas by 2031.

Figure 17: State of Florida - Historic and Forecast Generation by Fuel Type



Source: FRCC 2013-2022 Regional Load and Resource Plan

Based on 2020 Energy Information Administration data, Florida ranks fifth in terms of the total volume of natural gas consumed compared to the rest of the United States.[14] For volume of natural gas consumed for electric generation, Florida ranks second, behind Texas. Natural gas is not used as a heating fuel in most of Florida's homes and businesses, which rely instead upon electricity that is increasingly being generated by natural gas. As Florida has very little natural gas production and limited gas storage capacity, the state is reliant upon out-of-state production and storage to satisfy the growing electric demands of the state.

New Generation Planned

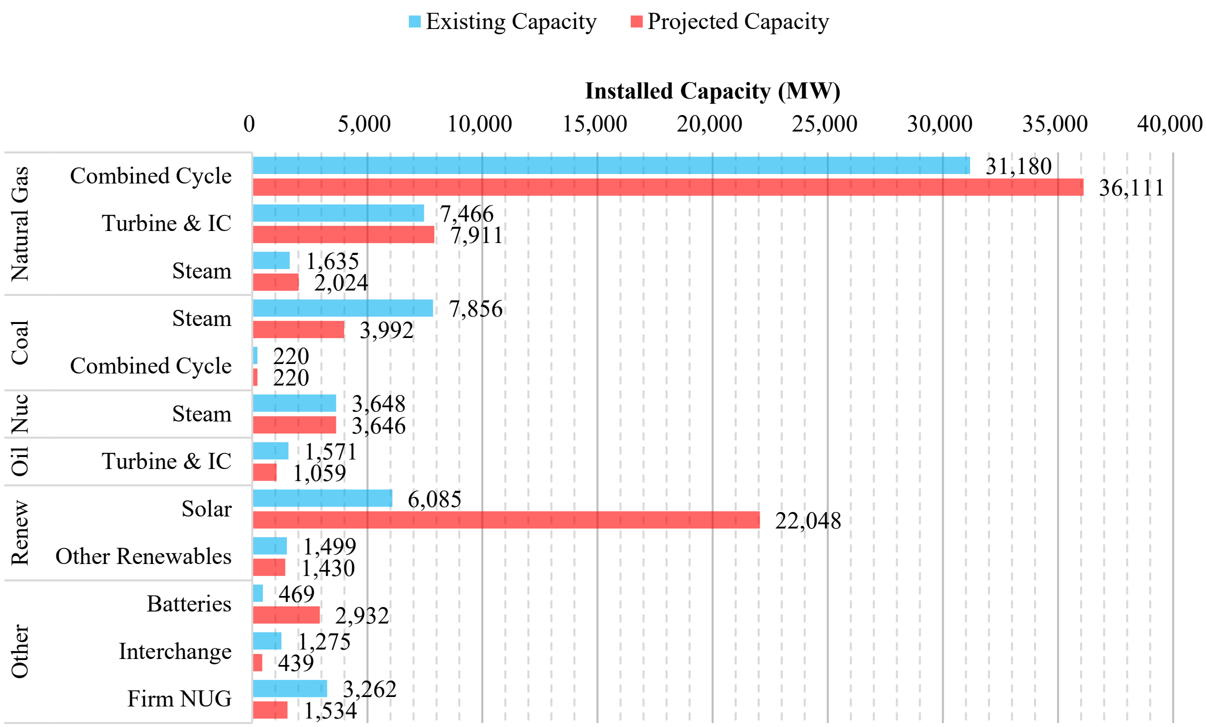
Current demand and energy forecasts continue to indicate that in spite of increased levels of conservation, energy efficiency, renewable generation, and existing traditional generation resources, the need for additional generating capacity still exists. While reductions in demand have been significant,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

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

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. The capacity values in Figure 18 incorporate all proposed additions, retirements, fuel switching, uprates and derates, and changes in operational or contract status contained in the reporting utilities' 2022 Ten-Year Site Plans and the FRCC's 2022 Regional Load and Resource Plan.

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



Source: FRCC 2022 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Commission's Authority Over Siting

Any proposed steam or solar generating unit greater than 75 MW requires a certification under the Electrical Power Plant Siting Act (PPSA), contained in Sections 403.501 through 403.518, F.S. The Commission has been given exclusive jurisdiction to determine the need for new electric power plants through Section 403.519, F.S. Upon receipt of a determination of need, the electric utility would then seek approval from the Florida Department of Environmental Protection, which addresses land use and environmental concerns. Finally, the Governor and Cabinet, sitting as the Siting Board, ultimately must approve or deny the overall certification of a proposed power plant. There are no new units in the 10 year horizon that require certification under the PPSA.

New Power Plants by Fuel Type

Nuclear

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

Natural Gas

Several new natural gas-fired combustion turbines, internal combustion units, and combined cycle units are planned over the next 10 years. While combined cycle systems are the dominant generating unit type, combustion turbines that run only in simple cycle mode and internal combustion units, taken together, will represent the third most abundant type of generating capacity by the end of 2031. As combustion turbines are not a form of steam generation, unless part of a combined cycle unit, they do not require siting under the Power Plant Siting Act. Table 11 summarizes the approximately 4,048 MW of additional capacity from new natural gas-fired generating units proposed by the 2022 Ten-Year Site Plan utilities.

Several utilities are exploring the use of natural gas internal combustion units (also called reciprocating engines) as a means of fast ramping peaking capacity. Such additions afford improved environmental and reliability benefits, enhanced operational flexibility, and improvements to system resiliency.

Table 11: TYSP Utilities - Planned Natural Gas Units

In-Service Year	Utility Name	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Notes
Previously Approved New PPSA Units					
2022	FPL	Dania Beach Energy Center	CC	1,258	Docket No. 20170225-EI
2022	SEC	Seminole CC Facility	CC	1,099	Docket No. 20170266-EI
2025	SEC	Unnamed CC	CC	571	Docket No. 20170266-EI
			Subtotal	**2,928**	
New Units Requiring PPSA Approval					
None					
			Subtotal	**0**	
New Units Not Requiring PPSA Approval					
2023	TECO	Big Bend CC Conversion	CC	395	Incremental Capacity
2024	LAK	C.D. McIntosh, Jr Units 01-06	IC	120	Six 20 MW Units
2025	TECO	Reciprocating Engine	IC	37	Pair of 18.5 MW Units
2027	SEC	Unnamed Combustion Turbine	CT	317	
2028	TECO	Reciprocating Engine	IC	37	Pair of 18.5 MW Units
2029	DEF	Unsited Combustion Turbine	CT	214	
			Subtotal	**1,120**	
			Total	**4,048**	

Source: 2022 Ten-Year Site Plans

Transmission

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

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

Table 12 lists all proposed transmission lines in the 2022 Ten-Year Site Plans and the FRCC 2022 Regional Load and Resource Plan that require TLSA certification. All planned lines have already received the approval of the Commission, either independently or as part of a PPSA determination of need.

Table 12: State of Florida - Planned Transmission Lines

Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
FPL	Levee to Midway	150	500	5/28/1988	4/20/1990	2030
FPL	Sweatt to Whidden	79	230	6/03/2022	TBD	2025
TECO	Thonotosassa to Wheeler	8	230	6/22/2007	8/8/2008	TBD
TECO	Wheeler to Willow Oak	17	230	6/23/2006	8/9/2008	TBD
TECO	Lake Agnes to Gifford	28	230	9/26/2007	2/18/2009	TBD

Source: 2022 Ten-Year Site Plans & FRCC 2022 Regional Load and Resource Plan

Utility Perspectives

Florida Power & Light Company (FPL)

FPL is an investor-owned utility and Florida's largest electric utility. FPL's service territory previously was solely in the FRCC Region and consisted of South Florida and the east coast. In 2019, FPL's parent company, NextEra Energy Inc., acquired Gulf Power Company (GPC). GPC's service territory was in the Florida Panhandle region. While the companies merged at the beginning of 2022, it was not until mid-2022 that the companies transitioned into operating as a single entity with the completion of an interconnecting transmission line project, the North Florida Resiliency Connection. As a result, the 2022 Ten-Year Site Plan for FPL contains actual distinct data for the FPL and GPC regions through 2022, and combined data for projections through 2031.

In its 2022 Ten-Year Site Plan filing, FPL submitted four Ten-Year Site Plans for the Commission's consideration. These included a Business As Usual Plan, which used the Company's traditional resource planning methodology, its Recommended Plan, which introduced a novel extreme winter planning methodology, and two additional plans for informational purposes only that projected the potential impact of possible federal legislation as variations of the Business As Usual and Recommended Plans. In its original filing, FPL sought approval of its Recommended Plan. On July 11, 2022, FPL submitted a letter withdrawing its Recommended Plan and requesting approval of the Business As Usual Plan. Therefore, the analysis contained within this section and the Statewide Perspective address only the Business As Usual Plan.

As an investor-owned utility, FPL, is subject to the regulatory authority of the Commission over all aspects of utility operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds FPL 2022 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2021, FPL legacy service area had approximately 5,214,263 customers and annual retail energy sales of 112,177 GWh, or approximately 47.9 percent of Florida's annual retail energy sales. GPC legacy service area had approximately 477,672 customers and annual retail energy sales of 10,731 GWh, or approximately 4.6 percent of Florida's 2021 annual retail energy sales. In both service areas, the total number of customers grew by approximately 1.5 percent in 2021 which was driven primarily by growth in the number of residential customers.

FPL's weather-normalized retail energy sales increased by 1.4 percent in 2021, driven by growth of the number of customers in the residential and commercial classes. Residential energy sales increased due to growth in the number of customers, even though the increase was partially offset by per customer usage declines. Commercial energy sales increased due to both customer numbers and per customer usage growth.

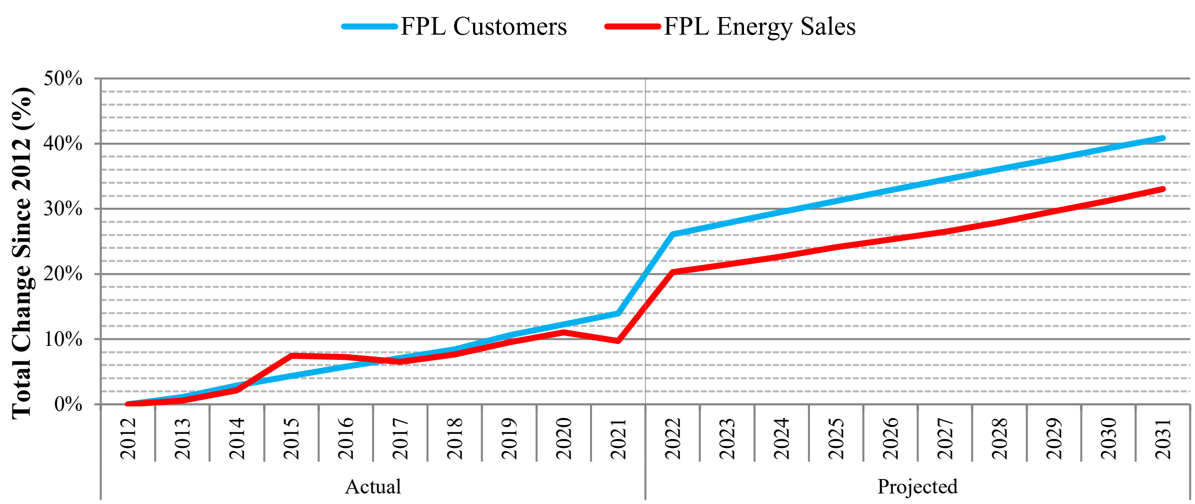
GPC's weather-normalized retail energy sales increased by 0.6 percent in 2021 due to higher commercial energy sales, partially offset by residential and industrial energy sales. Residential energy sales decreased due to usage declines, even though the increase was partially offset by growth in the number of customers. Industrial energy sales also decreased due to lower usage.

Over the past 10 years, FPL's customer base has increased by 13.9 percent, while retail sales have grown by approximately 9.7 percent. For the 2022 TYSP forecast horizon, the number of customers for the combined FPL and Gulf system are forecasted to grow by 1.1 to 1.4 percent per year. According to FPL, its total customer growth is being driven primarily by growth in residential customer numbers.

With respect to the average energy consumption per customer reflected in FPL's retail sales, residential use per customer for the combined system is forecasted to be flat or slightly decline through 2027 due to continued improvements in equipment efficiencies. For years 2028 and beyond, use per customer is forecasted to grow by 0.4 to 1.0 percent per year due to economic growth and increased adoption of electric vehicles. Commercial usage is forecasted to decline by 0.3 to 0.6 percent per year over the forecast horizon due to improvements to equipment efficiencies.

FPL's retail sales are forecasted to grow by 0.6 to 1.2 percent per year over the TYSP forecast horizon. This projected total retail sales growth is driven by sales growth in the residential class and commercial class, and these class-level energy sales increases are driven by growth in the number customers. Figure 19 illustrates historic and prospective forecasted growth rates in customers and retail energy sales for the two resource plans FPL filed in its 2022 TYSP.

Figure 19: FPL Growth
(Reflects post operational integration with GPC)



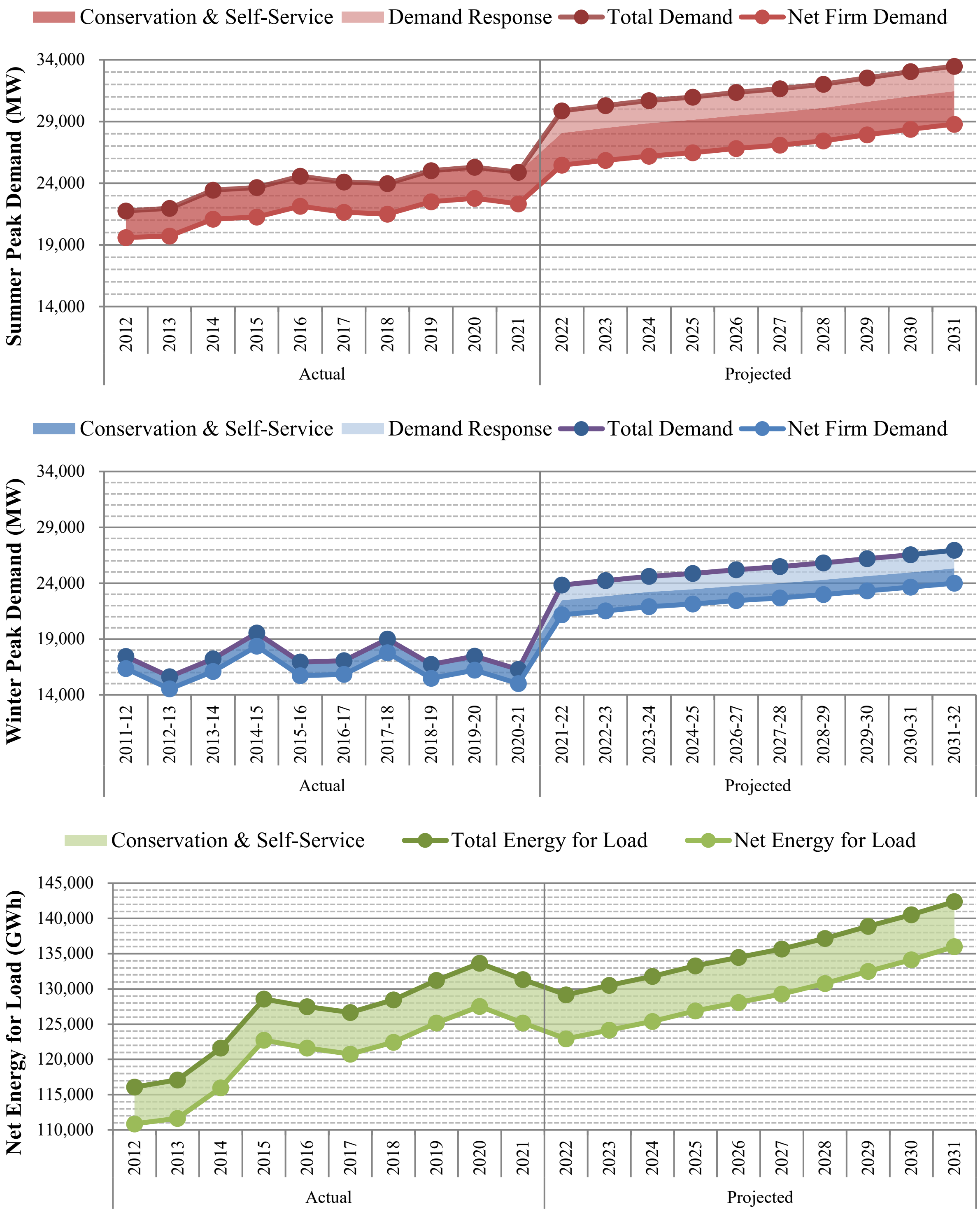
Source: 2022 Ten-Year Site Plan

As mentioned earlier, on January 1, 2019, GPC became a subsidiary of NextEra, FPL's parent company. FPL and GPC integrated the two systems into a single electric system, effective January 1, 2022. Despite the fact that the FPL and GPC systems were not be interconnected until mid-2022, the demand and energy forecasts for the years 2022 through 2031 are presented as a single integrated utility (FPL), as depicted in Figure 20. Consistent with last year's TYSP report, the demand and energy data for FPL and GPC continue to be presented separately through the year 2021.

The three graphs in Figure 20 show FPL's seasonal peak demand, summer and winter, and net energy for load, for the historic years 2012 through 2021, with the integrated FPL/GPC forecast for years 2022 through 2031. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. FPL expects a spike in all demand and energy forecasts in 2022 due to its planned integration with GPC's system. During the past 10 years, demand response has not been activated during seasonal peak demand.

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 last FEECA goal-setting proceeding was completed in November 2019, establishing goals for the period 2020 through 2024. In August 2020, the Commission approved separate FPL and GPC DSM plans designed to achieve the 2020-2024 DSM goals. In November 2021, the Commission approved an integrated FPL DSM plan designed to achieve FPL's and GPC's goals combined. In preparing its 2022 Ten-Year Site Plan seasonal peak demand and energy forecasts, FPL/GPC assume the trends in these goals will be extended through the forecast period (through 2031).

Figure 20: FPL Demand and Energy Forecasts
(Reflects post operational integration with GPC)



Source: 2022 Ten-Year Site Plan

Fuel Diversity

Table 13 shows FPL's and GPC's actual net energy for load by fuel type for 2021 and the projected fuel mix for the combined companies for 2031. FPL relies primarily upon natural gas and nuclear for energy generation, making up approximately 95 percent of net energy for load in 2021. GPC was an energy exporter in 2021, producing approximately 20 percent more energy than it required for native load. By 2031, the FPL system is projected to reduce natural gas usage from nearly 73 percent to approximately 61 percent. FPL projects that renewable energy will provide over 19 percent of its generation by 2031, which is the fifth highest percentage of renewable energy generation in 2031 of the TYSP Utilities.

Table 13: FPL and GPC Energy Generation by Fuel Type

Fuel Type	Net Energy for Load					
	FPL		GPC		FPL	
	2021		2021		2031	
	GWh	%	GWh	%	GWh	%
Natural Gas	90,903	**72.6%**	10,720	**92.5%**	90,484	**60.5%**
Coal	2,089	**1.7%**	1,765	**15.2%**	0	**0.0%**
Nuclear	28,342	**22.6%**	0	**0.0%**	28,919	**19.3%**
Oil	158	**0.1%**	0	**0.0%**	1	**0.0%**
Renewable	5,746	**4.6%**	1,441	**12.4%**	28,816	**19.3%**
Interchange	0	**0.0%**	-2,328	**-20.1%**	0	**0.0%**
Other	(2,071)	**-1.7%**	-8	**-0.1%**	1,279	**0.9%**
Total	**125,168**		**11,589**		**149,499**	

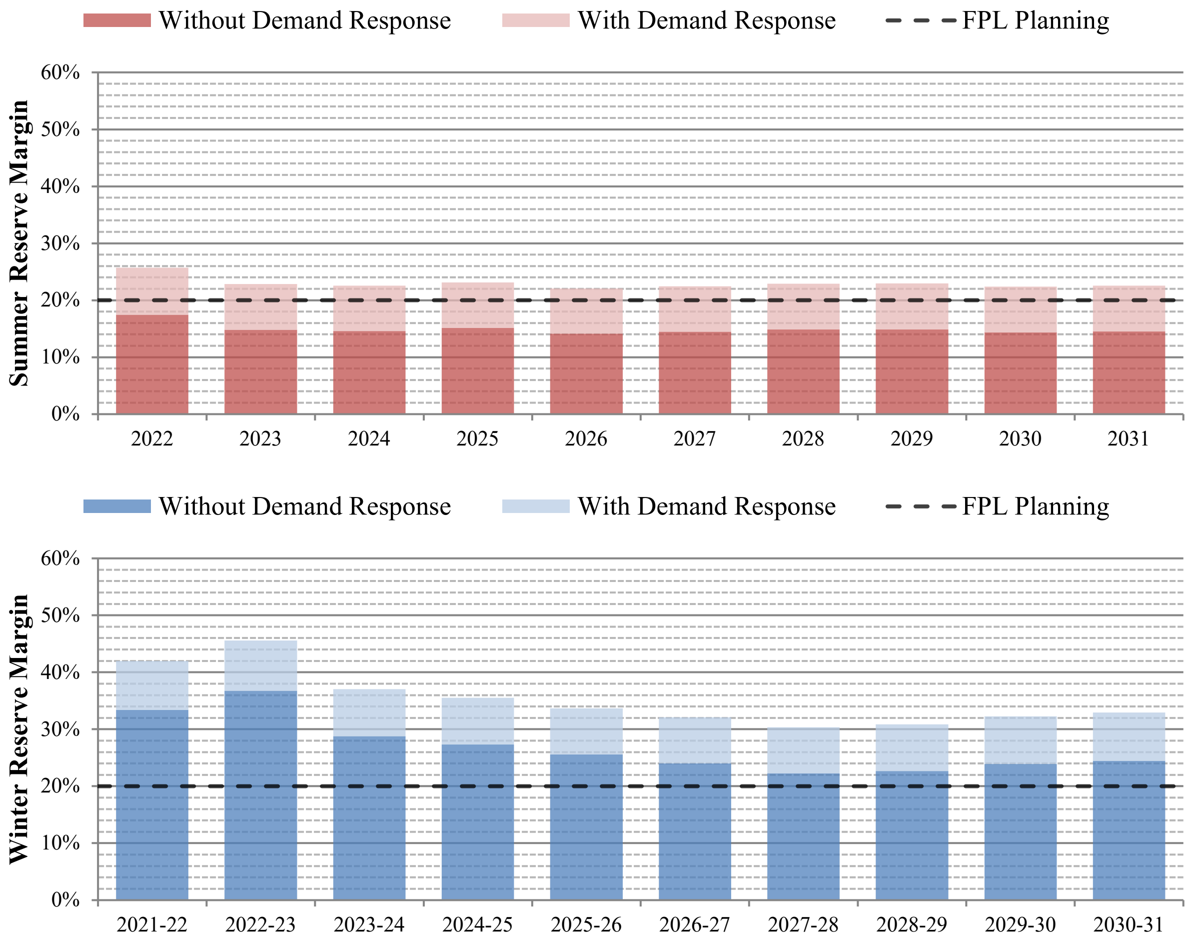
Source: 2022 Ten-Year Site Plan

Reliability Requirements

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

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

Figure 21: FPL Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

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

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

Generation Resources

FPL plans multiple unit retirements and additions during the planning period. These changes are described in Table 14. Six units totaling 1,501 MW of coal generation are being retired, including FPL's partial ownership of Scherer Units 3 & 4 and Daniel Units 1 & 2.

FPL is only constructing one new natural gas-fired unit, the Dania Beach Clean Energy Center, a combined cycle unit, which is expected to go into service by mid-2022. In addition, FPL plans upgrades to several of its natural gas combustion turbines totaling 370 MW in additional capacity over the planning period. However, the majority of changes on FPL's system are from solar photovoltaic plants, adding approximately 9,314 MW at approximately 130 sites. Also, FPL anticipates adding a total of 1,800 MW of battery storage in the latter years of the planning period.

Table 14: FPL Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW)	Solar Firm Capacity (MW)	Notes
			Sum	Sum	
Retiring Units					
2022	Scherer 4	BIT- ST	634		
2022	Lansing Smith	DFO - GT	32		
2024	Daniel 1 & 2	BIT- ST	502		
2025	Pea Ridge 1-3	NG - CT	12		
2025	Gulf Energy Center Units 4 &5	BIT - ST	150		
2029	Scherer	BIT- ST	215		
2029	Perdido	LFG - IC	3		
Total Retirements			**1,548**		
New Units					
2022	Dania Beach Clean Energy Center	NG - CC	1,258	N/A	Docket No. 20170225-EI
2022	Sited Solar Facilities	PV	447	155	6 Known Solar Sites
2023	Sited Solar Facilities	PV	1,118	528	16 Known Solar Sites
2024	Sited Solar Facilities	PV	1,416	617	19 Known Solar Sites
2024	Unknown Solar	PV	224	98	7 Solar Sites
2025	Unknown Solar	PV	1490	542	20 Solar Sites
2026	Unknown Solar	PV	596	178	8 Solar Sites
2027	Unknown Solar	PV	596	156	8 Solar Sites
2028	Unknown Solar	PV	745	195	10 Solar Sites
2029	Unknown Solar	PV	894	190	12 Solar Sites
2029	Unsited Battery Storage	BAT	500	N/A	Multiple Sites
2030	Unknown Solar	PV	894	58	12 Solar Sites
2030	Unsited Battery Storage	BAT	700	N/A	Multiple Sites
2031	Unknown Solar	PV	894	58	12 Solar Sites
2031	Unsited Battery Storage	BAT	600		Multiple Sites
Total New Units			**12,372**	**2,775**	
Net Additions			**10,824**		

Source: 2022 Ten-Year Site Plan

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 in central and west central Florida. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds DEF's 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

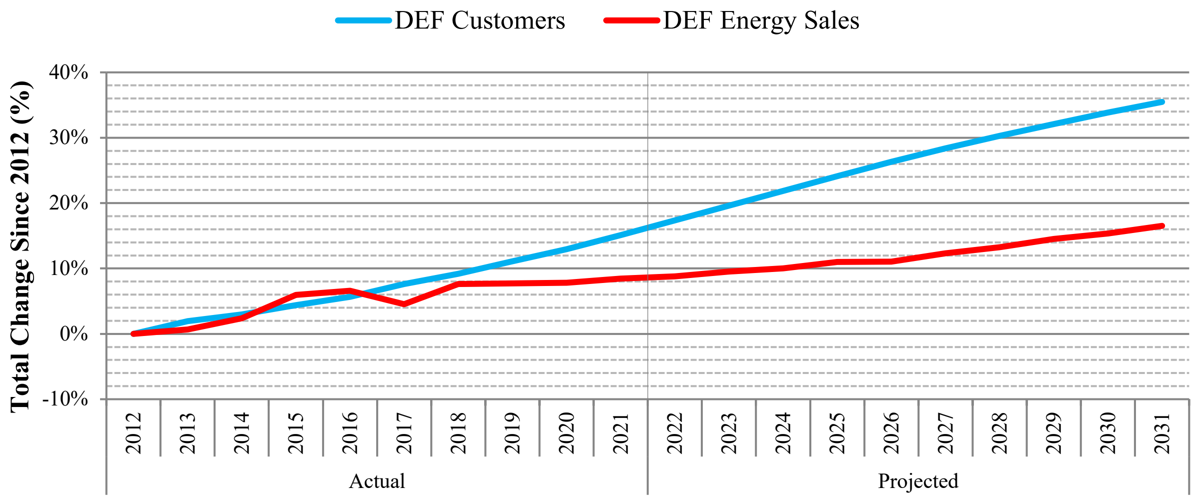
In 2021, DEF had approximately 1,898,726 customers and annual retail energy sales of 39,451 GWh or approximately 16.9 percent of Florida's annual retail energy sales. DEF's total customers grew approximately 1.87 percent in 2021. Figure 22 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012. Over the last 10 years, DEF's customer base has increased by 15.09 percent, while retail sales have grown by 8.44 percent.

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

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

For the 2022 TYSP forecast horizon, DEF's forecast results indicate that the utility's customer base is projected to grow at an average annual rate of 1.61 percent, and its retail energy sales are projected to grow at an average annual rate of 0.76 percent.

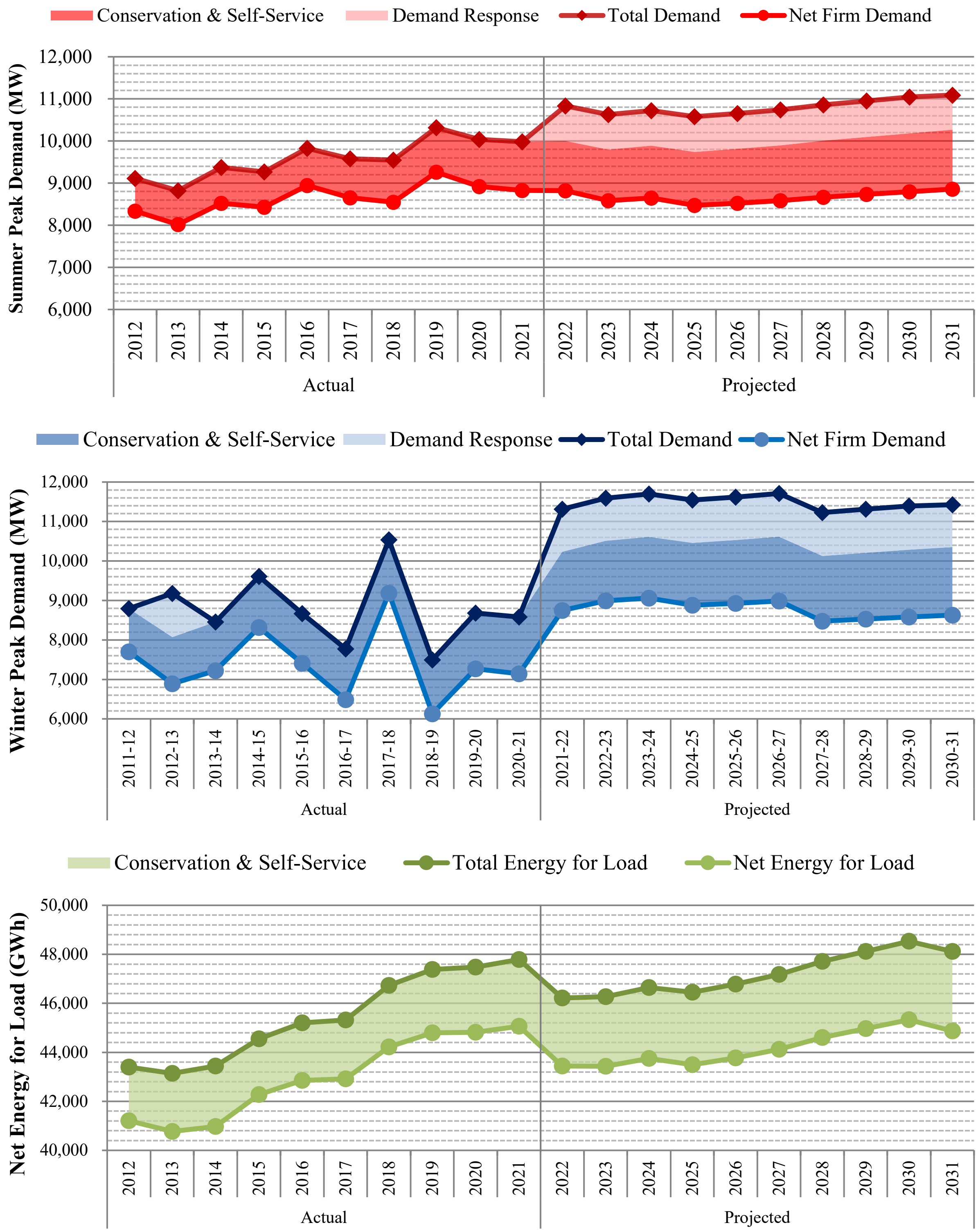
Figure 22: DEF Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 23 show DEF's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. These graphs include the full impact of demand-side management and assume that all available demand response resources will be activated during the seasonal peak. During the past 10 years, demand response has not been activated during seasonal peak demand. As an investor-owned utility, DEF is subject to FEECA, and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. In November 2019, the Commission established demand-side management goals for DEF for the years 2020 through 2024. In August 2020, the Commission approved DEF's plan designed to achieve the 2020-2024 DSM goals. In preparing its 2022 Ten-Year Site Plan seasonal peak demand and energy forecasts, DEF assumes trends in these goals will be extended through the forecast horizon (through 2031).

Figure 23: DEF Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 15 shows DEF's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. DEF relies primarily upon natural gas and coal for energy generation, making up approximately 84 percent of net energy for load. DEF plans to reduce coal usage over the planning period, and to increase renewable energy generation, making natural gas and renewable energy DEF's primary sources of generation in 2031. DEF projects the third highest percentage of renewable energy generation in 2031 of the TYSP Utilities.

Table 15: DEF Energy Generation by Fuel Type

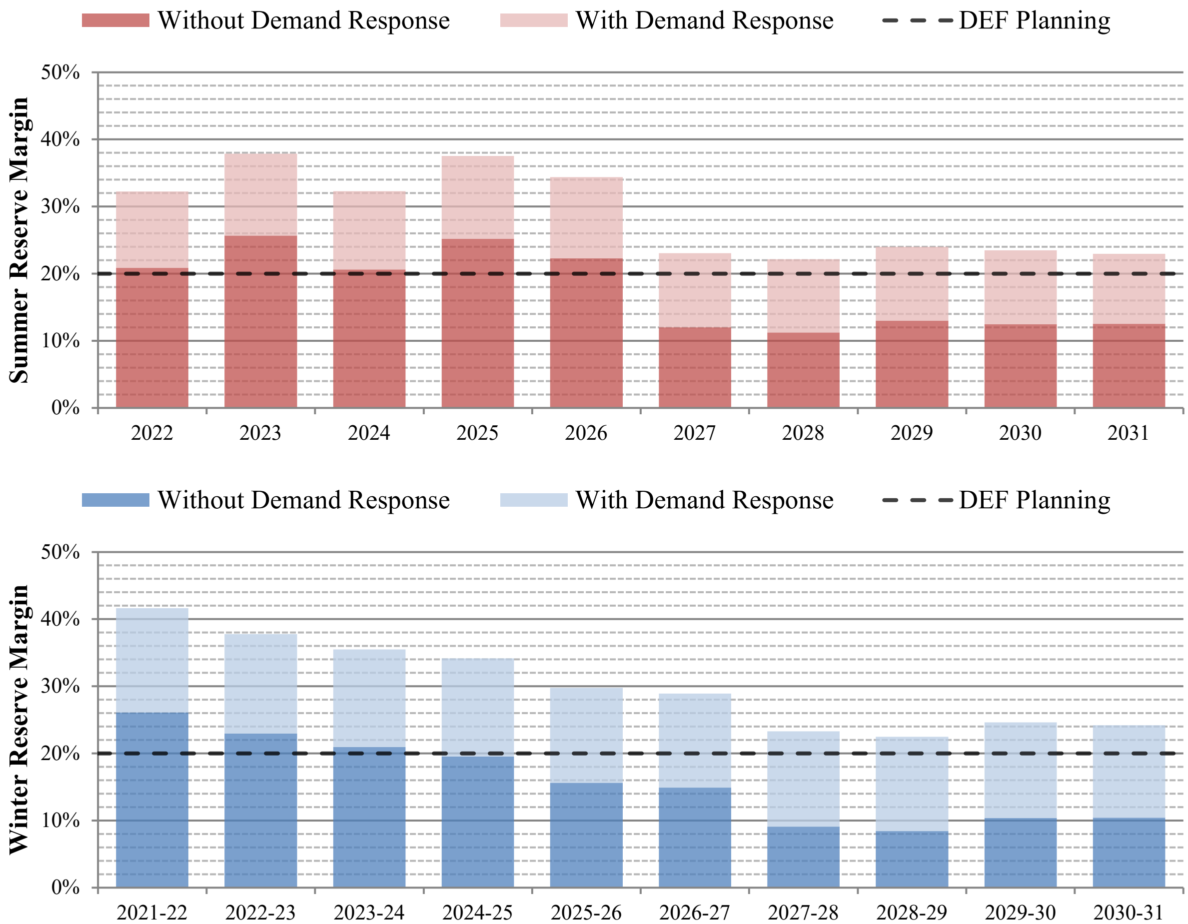
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	32,981	**73.2%**	33,318	**74.3%**
Coal	5,042	**11.2%**	1,548	**3.4%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	56	**0.1%**	4	**0.0%**
Renewable	1,551	**3.4%**	9,983	**22.2%**
Interchange	3,461	**7.7%**	17	**0.0%**
NUG & Other	1,974	**4.4%**	2	**0.0%**
Total	**45,065**		**44,872**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion. Figure 24 displays the forecast planning reserve margin for DEF through the planning period for both seasons, with and without the use of demand response. As shown in the figure, DEF's generation needs are mostly controlled by its summer peaking throughout the planning period.

Figure 24: DEF Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

DEF projects multiple unit retirements and additions during the planning period, as described in Table 16. DEF plans on retiring one gas and several oil-fired units at multiple power plant sites totaling 524 MW. DEF is adding a combustion turbine in 2029, at an undesignated site. Transmission upgrades are expected to be completed in 2024 that will allow DEF to fully utilize its existing Osprey facility, with the incremental available firm capacity listed in Table 16.

DEF has included 2,700 MW of planned solar additions, which make up approximately 73 percent of DEF's planned total new capacity. DEF also plans on adding 111 MW of storage capacity to be connected to its solar facilities. In July 2020, DEF petitioned the Commission to implement a Clean Energy Connection program (CEC), which is designed to be a community solar program through which participating customers can voluntarily subscribe to a share of new solar energy centers.[15] The Order approving the CEC program was appealed to the Supreme Court of Florida. The Supreme Court remanded the decision back to the Commission, requesting a revised final

[15] See Docket No. 20200176-EI, *In re: Petition for a limited proceeding to approve clean energy connection program and tariff and stipulation, by Duke Energy Florida, LLC.*

order to explain the Commissions finding and reasoning.[16] In addition to its utility-owned solar additions, DEF is also entering into several purchased power agreements with solar qualifying facilities for approximately 285 MW of capacity.

Table 16: DEF Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Solar Firm Capacity (Summer) Sum	Notes
Retiring Units					
2025	Bayboro P1-4	DFO – CT	171	N/A	
2027	Debary P2-6	DFO – CT	227	N/A	
2027	Bartow P1 & 3	DFO – CT	82	N/A	
2027	University of Florida P1	NG – CT	44	N/A	
Total Retired MW			**524**	N/A	
New Units					
2022	Sited Solar Facilities	PV	300	172	4 Known Solar Sites
2023	Sited Solar Facilities	PV	300	172	4 Known Solar Sites
2024	Osprey	NG – CC	338	N/A	Transmission Upgrades
2024	Unknown Solar	PV	450	208	Multiple Sites
2025	Unknown Solar	PV	300	75	Multiple Sites
2026	Unknown Solar	PV	300	75	Multiple Sites
2027	Unknown Solar	PV	300	75	Multiple Sites
2028	Unknown Solar	PV	300	75	Multiple Sites
2029	Unknown Solar	PV	300	38	Multiple Sites
2029	Unknown CT	NG – CT	214	N/A	
2029	Unknown Solar Storage	BAT	37	N/A	Connected to Solar
2030	Unknown Solar	PV	300	38	Multiple Sites
2030	Unknown Solar Storage	BAT	37	N/A	Connected to Solar
2031	Unknown Solar Storage	BAT	37	N/A	Connected to Solar
2031	Unknown Solar	PV	300	38	Multiple Sites
Total New MW			**3,715**	**1,180**	

Net Additions	**3,172**	

Source: 2022 Ten-Year Site Plan

[16] Order No. PSC-2021-0059A-S-EI, issued September 23, 2022, in Docket No. 20200176-EI, *In re: Petition for a limited proceeding to approve clean energy connection program and tariff and stipulation, by Duke Energy Florida, LLC.*

Tampa Electric Company (TECO)

TECO is an investor-owned utility and Florida's third largest electric utility. The utility's service territory is within the FRCC region and consists primarily of the Tampa metropolitan area. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds TECO's 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

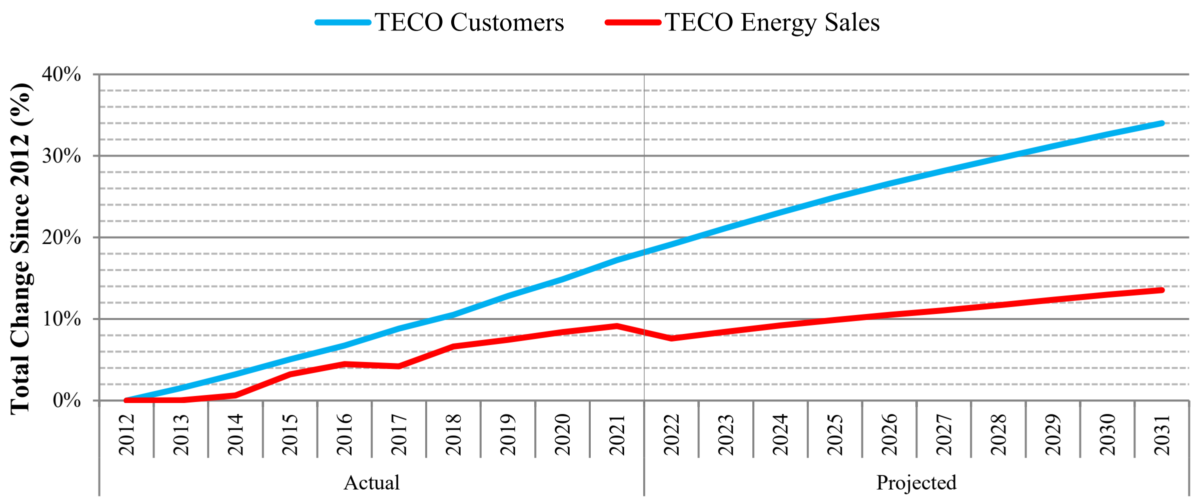
In 2021, TECO had approximately 802,050 customers and annual retail energy sales of 20,093 GWh or approximately 8.6 percent of Florida's annual retail energy sales. Figure 25 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012. Over the last 10 years, TECO's customer base has increased by 17.2 percent, while retail sales have increased by 9.1 percent.

TECO's total customer growth in 2021 averaged 2.0 percent with the residential class being the engine behind the growth. Over the next 10 years customer growth is expected to increase at an average rate of 1.3 percent annually. The primary driver of customer growth will be new construction and increasing net in-migration to the utility's service area.

TECO's average annual energy consumption per residential customer decreased in 2021, primarily due to milder weather than in the prior year. In addition, the effects of COVID-19 are not as prevailing as in 2020, evidenced by people returning to work places/schools which results in a reduced residential energy consumption compared to what was experienced during the pandemic-triggered stay-at-home period. Over the next 10 years, the utility expects average energy consumption per residential customer to decline at an average annual rate of 0.4 percent. The primary drivers behind the decline are increases in appliance efficiencies, lighting efficiencies, energy efficiency in new homes, conservation efforts, and changes in housing mix. TECO's commercial per customer usage in 2021 was 0.3 percent lower than in 2020, and such usage is projected to remain relatively flat over the current TYSP forecast horizon. The utility's industrial per customer usage in 2021 was 0.1 percent higher than what was achieved in 2020. This is mainly attributable to the industrial phosphate sector having less self-serving generation and more purchases from TECO. Over the forecast horizon, the average usage per industrial customer is expected to decrease slightly by an average of 0.1 percent per year.

For the next 10 years, TECO's retail energy sales are projected to grow at an annual average rate of 0.6 percent. This is below the customer growth rate of 1.3 percent primarily due to continued per customer energy consumption declines in the residential sector, as well as declines in the phosphate sector as the mining industry continues to move south and out of the utility's service territory.

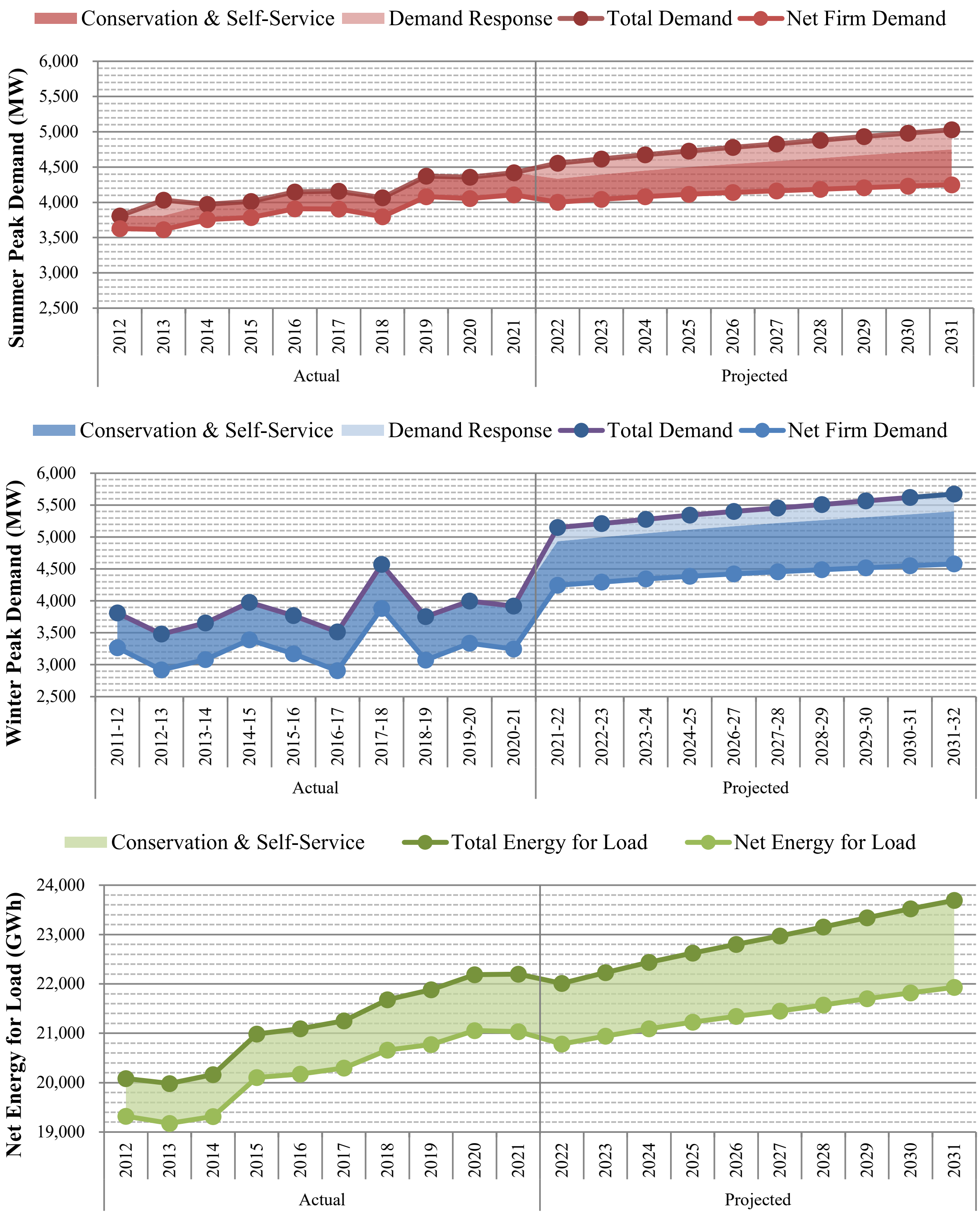
Figure 25: TECO Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 26 show TECO's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. These graphs include the full impact of demand-side management, and assume that all available demand response resources will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand, excluding the summer of 2013 and winters of 2017-2018 and 2018-2019. As an investor-owned utility, TECO is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. In November 2019, the Commission established demand-side management goals for TECO for the years 2020 through 2024. In August 2020, the Commission approved TECO's plan designed to achieve the 2020-2024 DSM goals. In preparing its 2022 Ten-Year Site Plan seasonal peak demand and energy forecasts, TECO assumes the trends in these goals will be extended through the forecast period (through 2031).

Figure 26: TECO Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 17 shows TECO's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. Based on its 2022 Ten-Year Site Plan, natural gas is used for the majority of TECO's energy generation. Natural gas accounts for approximately 77 percent of net energy for load. In the future, TECO projects that energy from coal will decrease and energy from renewables will increase. TECO projects that renewable energy will increase from 6.0 percent to 20.4 percent by 2031. TECO projects the fourth highest percentage of renewable energy generation in 2031 of the TYSP Utilities.

Table 17: TECO Energy Generation by Fuel Type

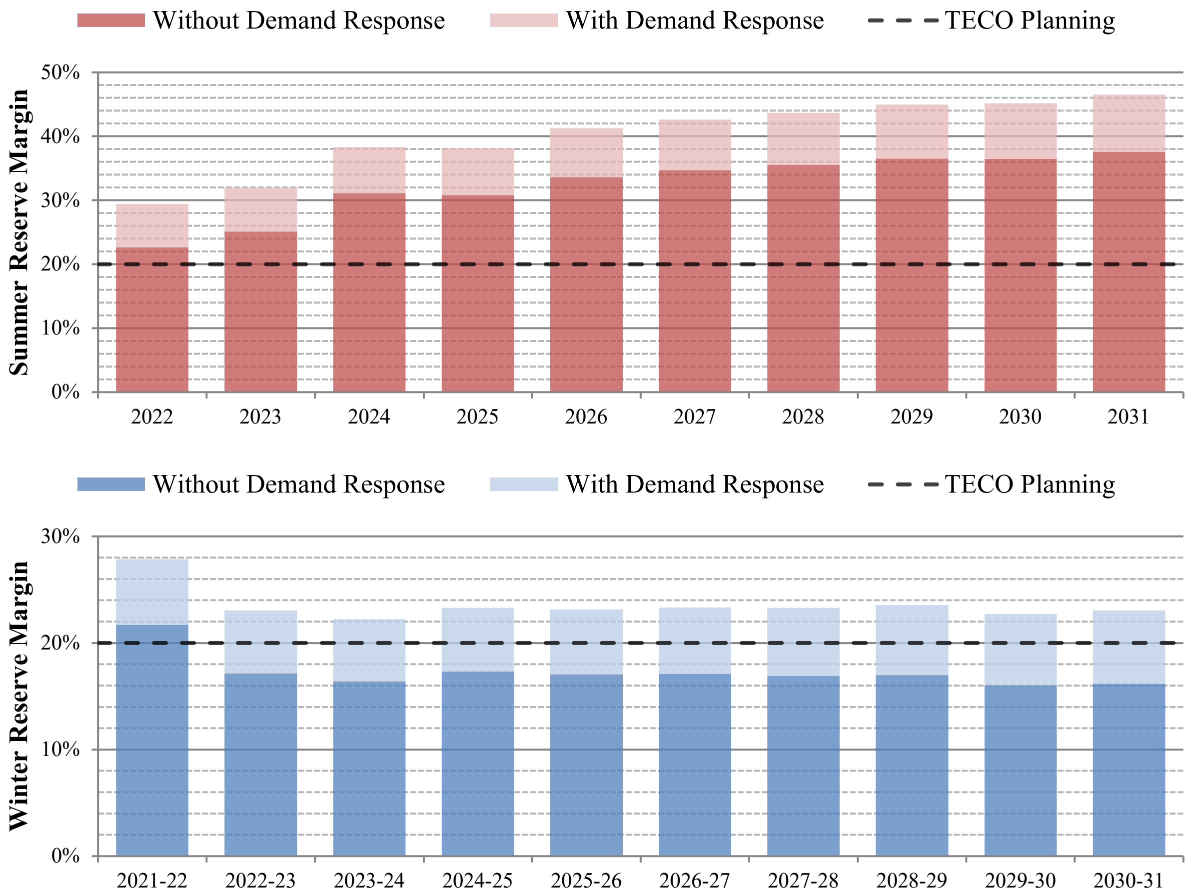
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	16,124	**76.7%**	17,278	**78.8%**
Coal	1,358	**6.5%**	160	**0.7%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	2	**0.0%**	0	**0.0%**
Renewable	1,252	**6.0%**	4,481	**20.4%**
Interchange	77	**0.4%**	0	**0.0%**
NUG & Other	2,220	**10.6%**	12	**0.1%**
Total	**21,033**		**21,931**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion. TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 27 displays the forecast planning reserve margin for TECO through the planning period for both seasons, with and without the use of demand response. As shown in the figure, TECO's generation needs are being controlled by its winter peak. TECO's current and planned investments in solar generation contribute to this shift in planning because solar resources provide coincident capacity during the summer peak but not the winter peak. TECO's 7 percent supply-side only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20 percent reserve margin will be realized.

Figure 27: TECO Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

TECO plans one unit retirement and multiple unit additions during the planning period, as described in Table 18. TECO anticipates retiring its natural gas-fired Big Bend Unit 3. For natural gas-fired units, TECO plans to add two internal combustion units and convert Big Bend Unit 1, a former coal unit, along with Big Bend Units CT5 and CT6 into a combined cycle configuration, providing an incremental 395 MW of generation. TECO also anticipates adding several solar projects over the planning period totaling 1,342 MW, supplemented by the addition of 275 MW of battery storage.

Table 18: TECO Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Solar Firm Capacity (Summer) Sum	Notes
				Retiring Units	
2023	Big Bend 3	NG – ST	395	N/A	
Total Retirements			**395**	N/A	
				New Units	
2022	Sited Solar Facilities	PV	361	202	6 Known Sites
2022	Big Bend Conversion	NG – CC	395	N/A	
2023	Sited Solar Facilities	PV	135	75	2 Known Sites
2023	Dover Solar + Storage 1	PV – BAT	25.0	15	15 MW of Batteries
2023	Unknown Solar	PV	74.5	41.6	
2024	Battery Storage 1	BAT	100	N/A	
2025	Unknown Solar	PV	300	167	Multiple Sites
2025	Reciprocating Engine 1	NG – IC	37	N/A	
2026	Unknown Solar	PV	74.5	41.6	
2027	Battery Storage 2	BAT	50	N/A	
2027	Unknown Solar	PV	74.5	41.6	
2028	Reciprocating Engine 2	NG – IC	37	N/A	
2028	Unknown Solar	PV	74.5	41.6	
2029	Battery Storage 3	BAT	50	N/A	
2029	Unknown Solar	PV	74.5	41.6	
2030	Unknown Solar	PV	74.5	41.6	
2031	Battery Storage 4	BAT	50	N/A	
2031	Unknown Solar	PV	74.5	41.6	
Total New Units			**2,179**	**760.2**	
Net Additions			**1,784**		

Source: 2022 Ten-Year Site Plan

Florida Municipal Power Agency (FMPA)

FMPA is a governmental wholesale power company owned by several Florida municipal utilities throughout the state. Collectively, FMPA is Florida's eighth largest electric utility and third largest municipal electric utility. While FMPA has 31 member systems, only those members that are participants in the All-Requirements Power Supply Project (ARP) are addressed in the utility's Ten-Year Site Plan. FMPA is responsible for planning activities associated with ARP member systems. For a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds FMPA's 2022 Ten-Year Site Plan suitable for planning purposes.

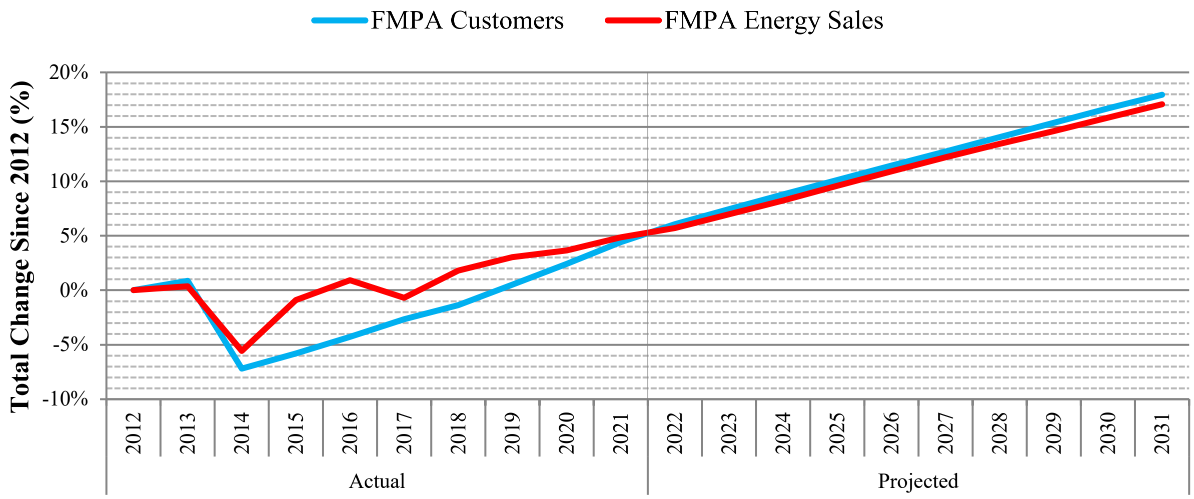
Load & Energy Forecasts

In 2021, FMPA had approximately 276,418 customers and annual retail energy sales of 5,944 GWh or approximately 2.5 percent of Florida's annual energy sales. Figure 28 illustrates the utility's historic and forecasted growth rates in customers and energy sales beginning in 2012. Over the last 10 years, FMPA's customer base has increased by 4.41 percent, while energy sales have increased by 4.85 percent.

FMPA's per-customer energy usage has been flat to declining in both the residential and non-residential sectors in recent years. In response to staff data requests, FMPA noted that there were countervailing factors that influence usage. In general, declines in electricity prices, improvements in the employment situation, increased average income, and reductions in vacancy rates and under-occupied accounts have a small upward impact on usage. Concurrently, the lingering effects of the recent recession in terms of reduced propensity to spend, a continued orientation to conservation, and continued improvement in energy efficiency, driven primarily from technological advances, equipment standards, and building codes, place downward pressure on average usage. These impacts have been offset by strong customer count gains in certain areas of the utility's service territories, which has resulted in continued recovery in net energy for load since the Great Recession. FMPA expects that an explicit projection of the impact of increased EV adoption will be infused into the forecast in the future.

For the current 10-year forecast horizon, the utility is projecting a 1.19 percent average annual growth rate for its customer base, and a 1.14 percent average annual growth rate for energy sales.

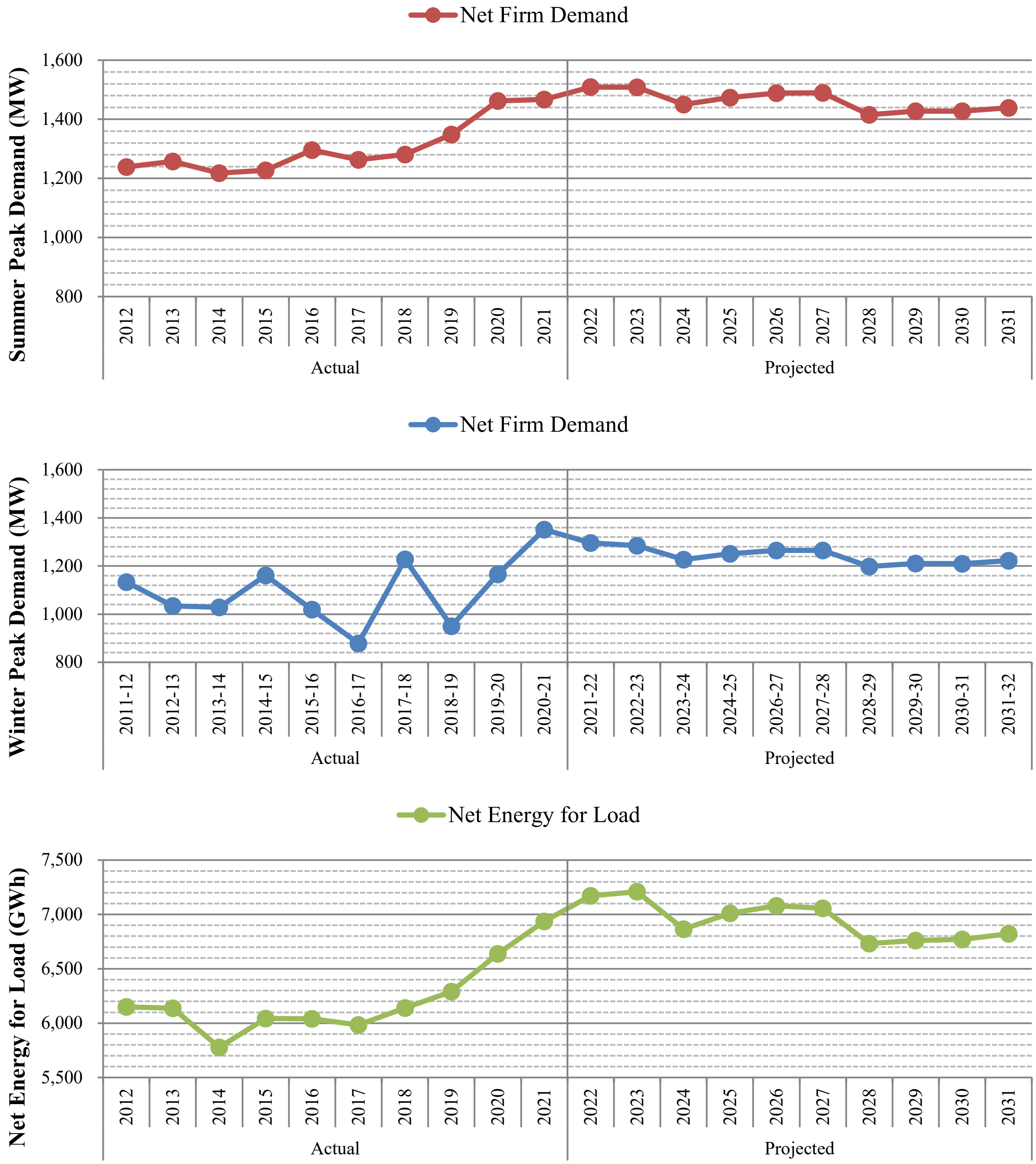
Figure 28: FMPA Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 29 show FMPA's seasonal peak demand and net energy for load for the historic years 2012 through 2021 and forecast years 2022 through 2031. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer demand-side management programs, the impacts of which are included in the graphs.

Figure 29: FMPA Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 19 shows FMPA's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects to end energy generation from coal by 2026, but approximately 89 percent of energy would still be sourced from natural gas and nuclear. FMPA projects serving 11 percent of its net energy for load with renewable resources by the end of the planning period.

Table 19: FMPA Energy Generation by Fuel Type

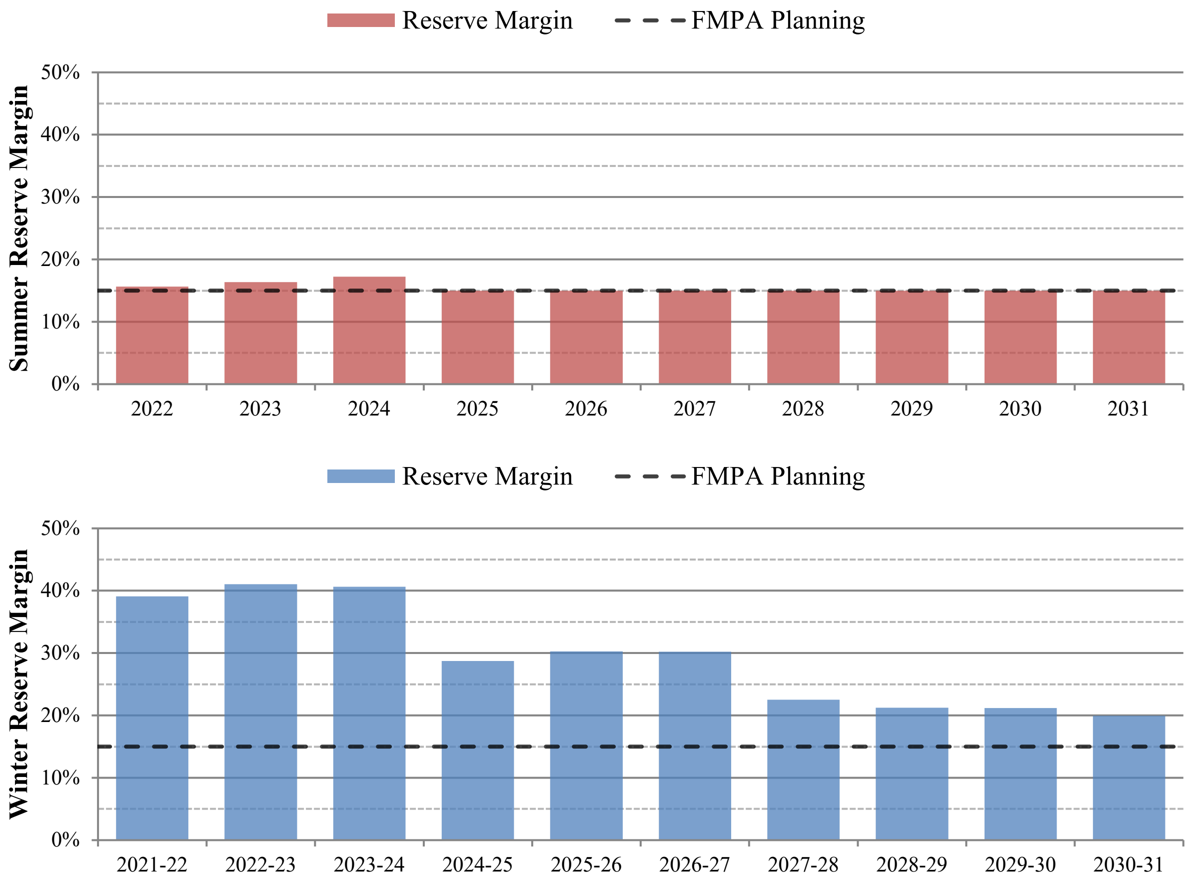
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	5,271	**76.0%**	5,675	**83.2%**
Coal	1,126	**16.2%**	0	**0.0%**
Nuclear	383	**5.5%**	390	**5.7%**
Oil	3	**0.0%**	1	**0.0%**
Renewable	154	**2.2%**	757	**11.1%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**6,937**		**6,823**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

FMPA utilizes a 15 percent planning reserve margin criterion. Figure 30 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 30: FMPA Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

FMPA plans on retiring Stanton Unit 1, a coal unit, in 2025 as described in Table 20. The utility also plans the conversion of Stanton Unit 2 from coal-fired to natural gas-fired in 2027. FMPA also has entered in two purchased power agreements (PPAs) that will add a total of 154 MW of solar capacity by the end of 2024. FMPA anticipates entering into additional PPAs that will add another 100 MW of solar capacity within the planning period.

Table 20: FMPA Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2025	Stanton Unit 1	BIT – ST	118	Jointly Owned with OUC
Total Retirements			**118**	
Net Additions			**(118)**	

Gainesville Regional Utilities (GRU)

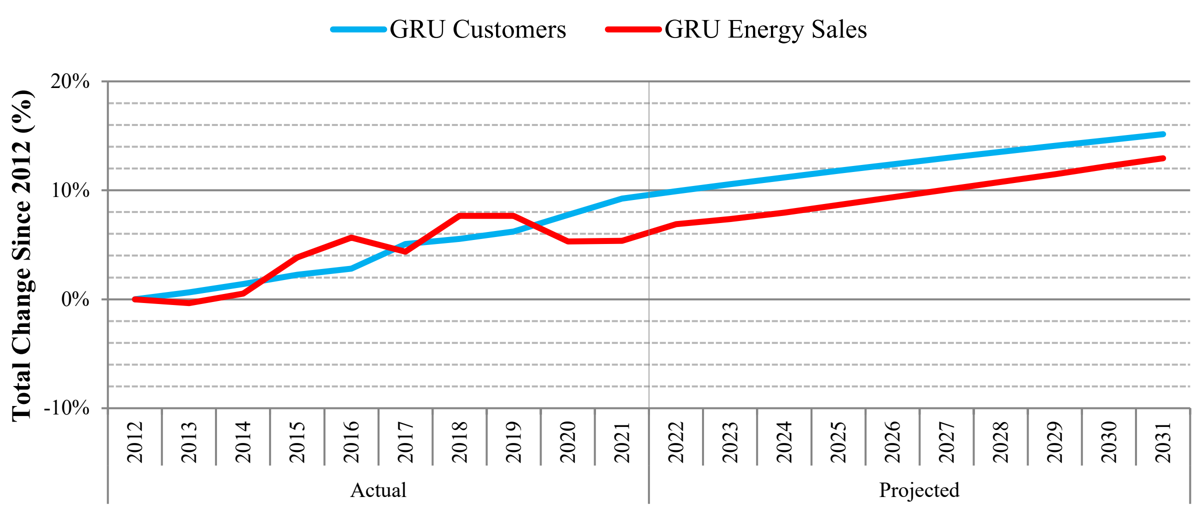
GRU is a municipal utility and the smallest electric utility required to file a Ten-Year Site Plan. The utility's service territory is within the FRCC region and consists of the City of Gainesville and its surrounding area. GRU also provides wholesale power to the City of Alachua and Clay Electric Cooperative. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds GRU's 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2021, GRU had approximately 101,117 customers and annual retail energy sales of 1,791 GWh, or approximately 0.8 percent of Florida's annual retail energy sales. Over the last 10 years, GRU's customer base has increased by 9.25 percent, while retail sales have increased by 5.35 percent. Figure 31 illustrates GRU's historic and forecasted growth rates in customers and retail energy sales beginning in 2012.

GRU noted that over the past 10 years, its residential energy consumption per customer increased 0.15 percent per year, while its non-residential consumption per customer declined 0.84 percent per year. For the next 10 years, the utility projects that both residential and non- residential energy consumption per customer will stay constant. For the current 10-year forecast horizon, GRU's number of customers is projected to grow at an annual average rate of 0.52 percent, and its retail energy sales are projected to grow at an annual average rate of 0.61 percent. The utility indicated that its projected growth of retail energy sales is supported by its projected increase in the number of customers and, to a small degree, offset by flat or declining energy consumption per customer. The utility also noted that load associated with electric vehicle charging is anticipated to support energy sales more in this forecast than in past forecasts.

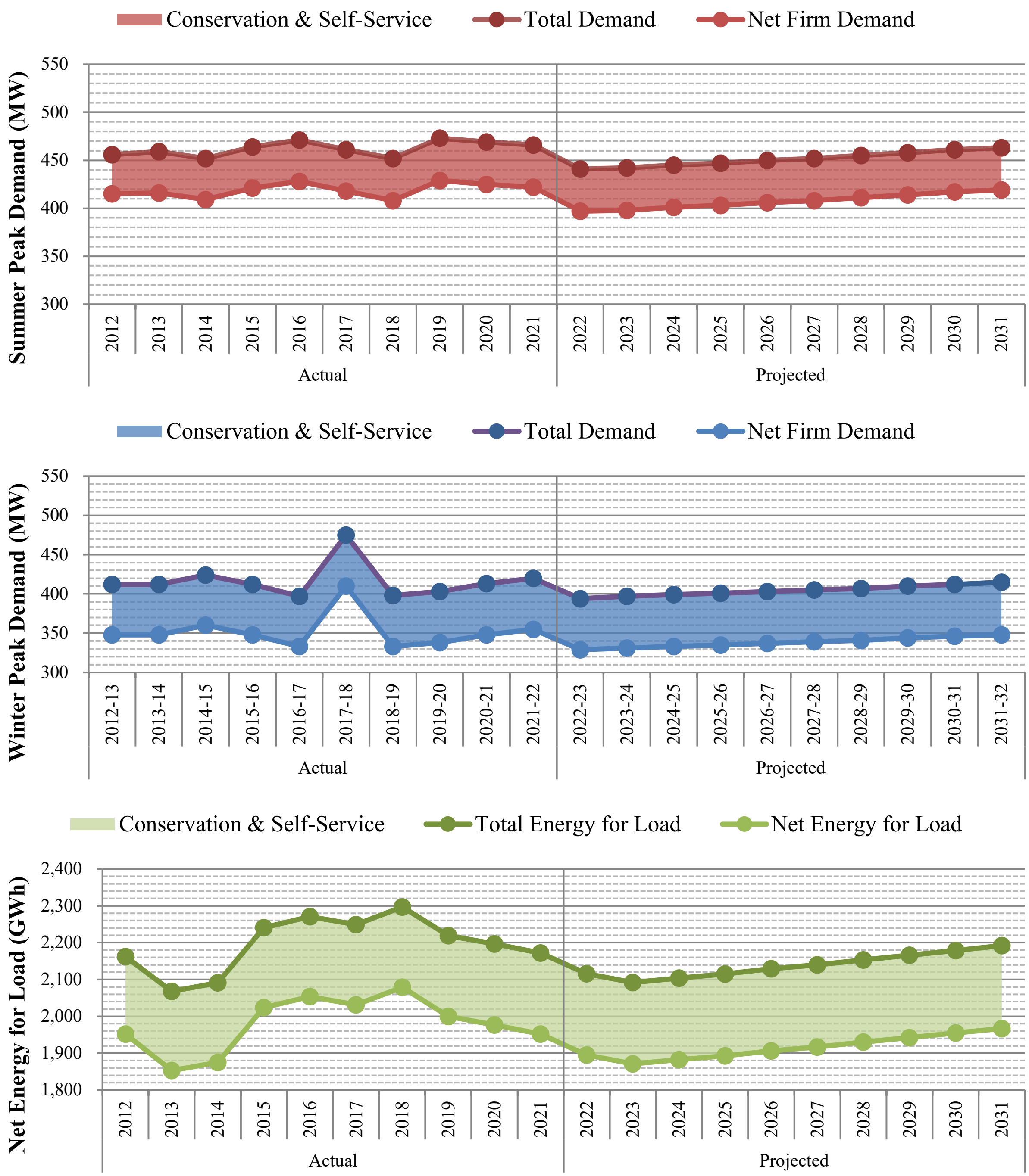
Figure 31: GRU Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 32 show GRU's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 32 include the impact of these demand-side management programs.

Figure 32: GRU Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 21 shows GRU's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. In 2021, natural gas was the primary fuel followed by renewables and coal respectively. GRU currently has the highest percentage contribution of renewables in Florida for net energy for load. By 2031 natural gas and renewables are expected to be the only generation, with coal-fired generation eliminated. GRU is forecasted to drop to the second highest percent contribution from renewables for net energy for load by 2031.

Table 21: GRU Energy Generation by Fuel Type

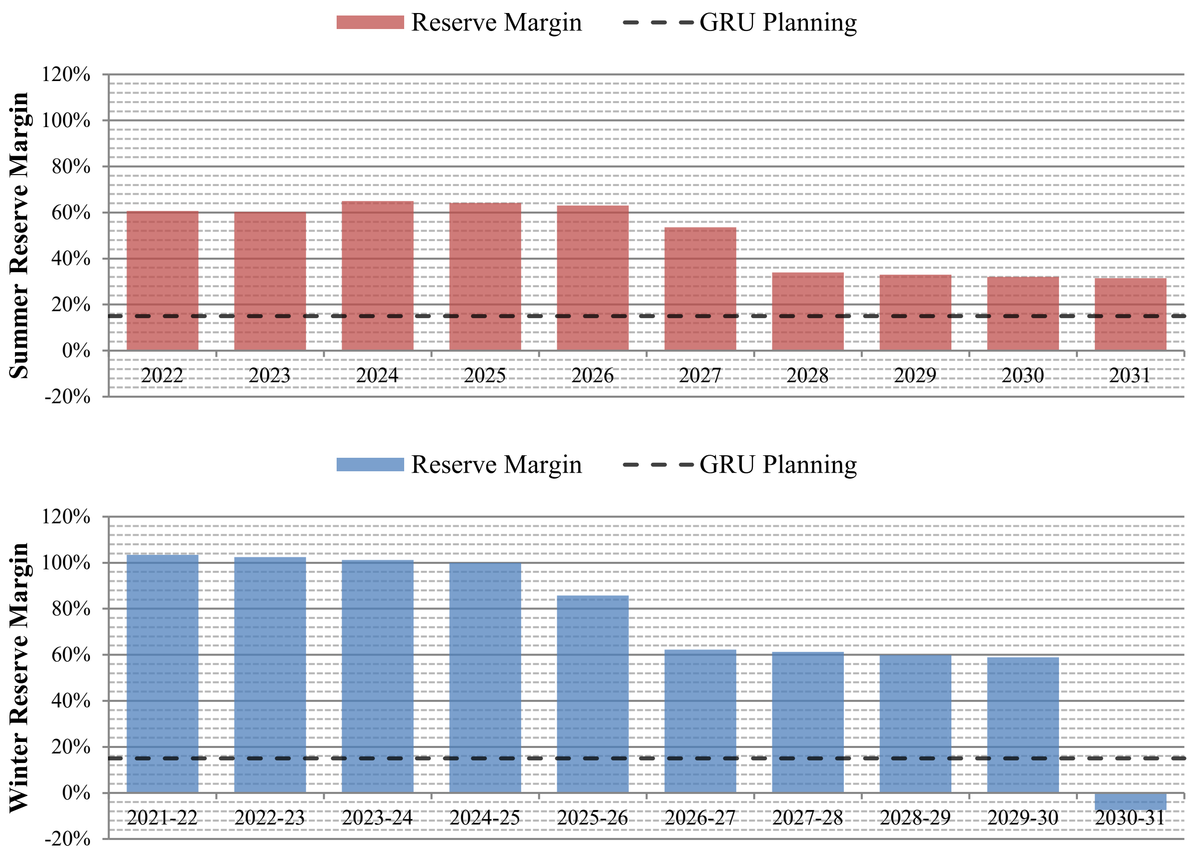
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	1,004	**51.4%**	1,389	**70.6%**
Coal	320	**16.4%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	6	**0.3%**	0	**0.0%**
Renewable	612	**31.4%**	586	**29.8%**
Interchange	10	**0.5%**	-8	**-0.4%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**1,952**		**1,967**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 33 displays the forecast planning reserve margin for GRU through the planning period for both seasons, including the impacts of demand-side management. As shown in the figure, GRU's generation needs are controlled by its summer peak throughout the planning period. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. GRU's reserve margin, is projected to be negative in the Winter of 2030/31 due to a unit retiring in 2031. As GRU approaches this date, the utility will continue to evaluate how to meet its 15 percent reserve margin criterion. Staff believes this to be acceptable for planning purposes this year. Staff will evaluate future plans to ensure reserve margin is maintained.

Figure 33: GRU Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

GRU currently plans on retiring two natural gas-fired combustion turbines in 2026, a natural gas-fired steam unit in 2027, and a coal unit in 2031 as described in Table 22. GRU entered into a 20 year contact that is expected to deliver an additional 50 MW of solar capacity, 27.5 MW of which are considered firm, through a PPA with an expected in-service year of 2024.

Table 22: GRU Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum
Retiring Units			
2026	Deerhaven GT01 & GT02	NG – CT	35
2027	Deerhaven FS01	NG – ST	75
2031	Deerhaven FS02	BIT – ST	228
Total Retirements			**338**
Net Additions			**(338)**

Source: 2022 Ten-Year Site Plan

JEA

JEA, formerly known as Jacksonville Electric Authority, is Florida's largest municipal utility and fifth largest electric utility. JEA's service territory is within the FRCC region, and includes all of Duval County as well as portions of Clay and St. Johns Counties. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds JEA's 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

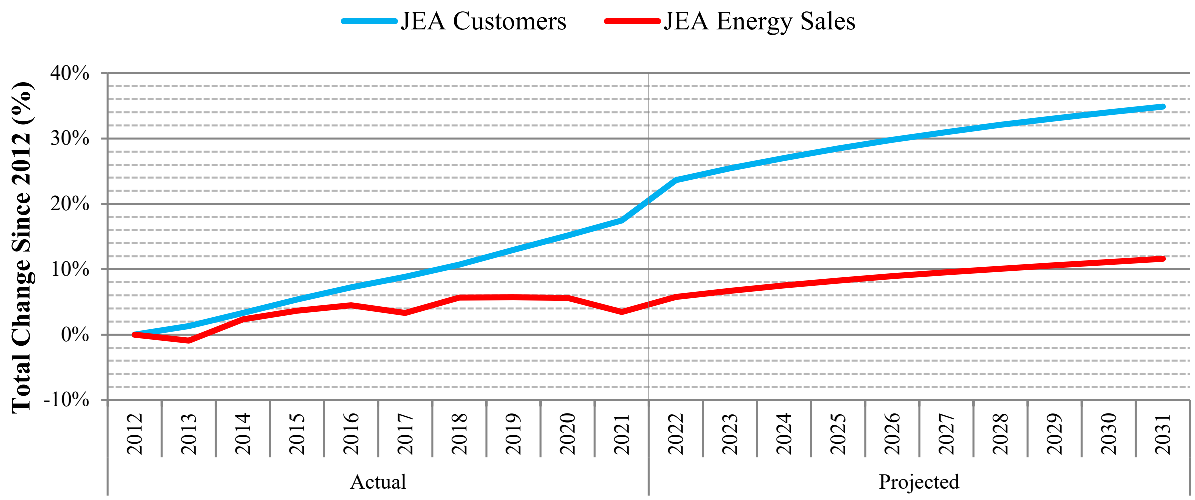
In 2021, JEA had approximately 493,039 customers and annual retail energy sales of 12,066 GWh or approximately 5.2 percent of Florida's annual retail energy sales. Figure 34 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012. Over the last 10 years, JEA's customer base has increased by 17.45 percent, while retail sales have increased by 3.45 percent.

JEA indicated that, overall, Moody's Analytics forecast for all parameters used in the utility's 2022 TYSP forecast of customer growth are lower as compared to the previous forecasts. As a result, JEA noted a lower forecast for customers as compared to its 2021 forecast.

JEA projected that the average annual energy consumption per customer will decrease by 0.3 percent and 1.1 percent, respectively, for residential and commercial classes over the forecasted 10-year period. The utility noted that demand-side management programs, customer behavioral change, the increase in electric rates, as well as housing type and federal central air conditioner-related requirements are contributors to these declines in per-customer energy consumption. However, JEA expects a small growth of 0.1 percent in average annual industrial energy consumption for the next 10 years.

For the next 10 years, the JEA's forecast results indicate that the customer numbers are projected to grow at an average annual rate of 0.97 percent; and the retail energy sales are projected to grow at an average annual rate of 0.81 percent.

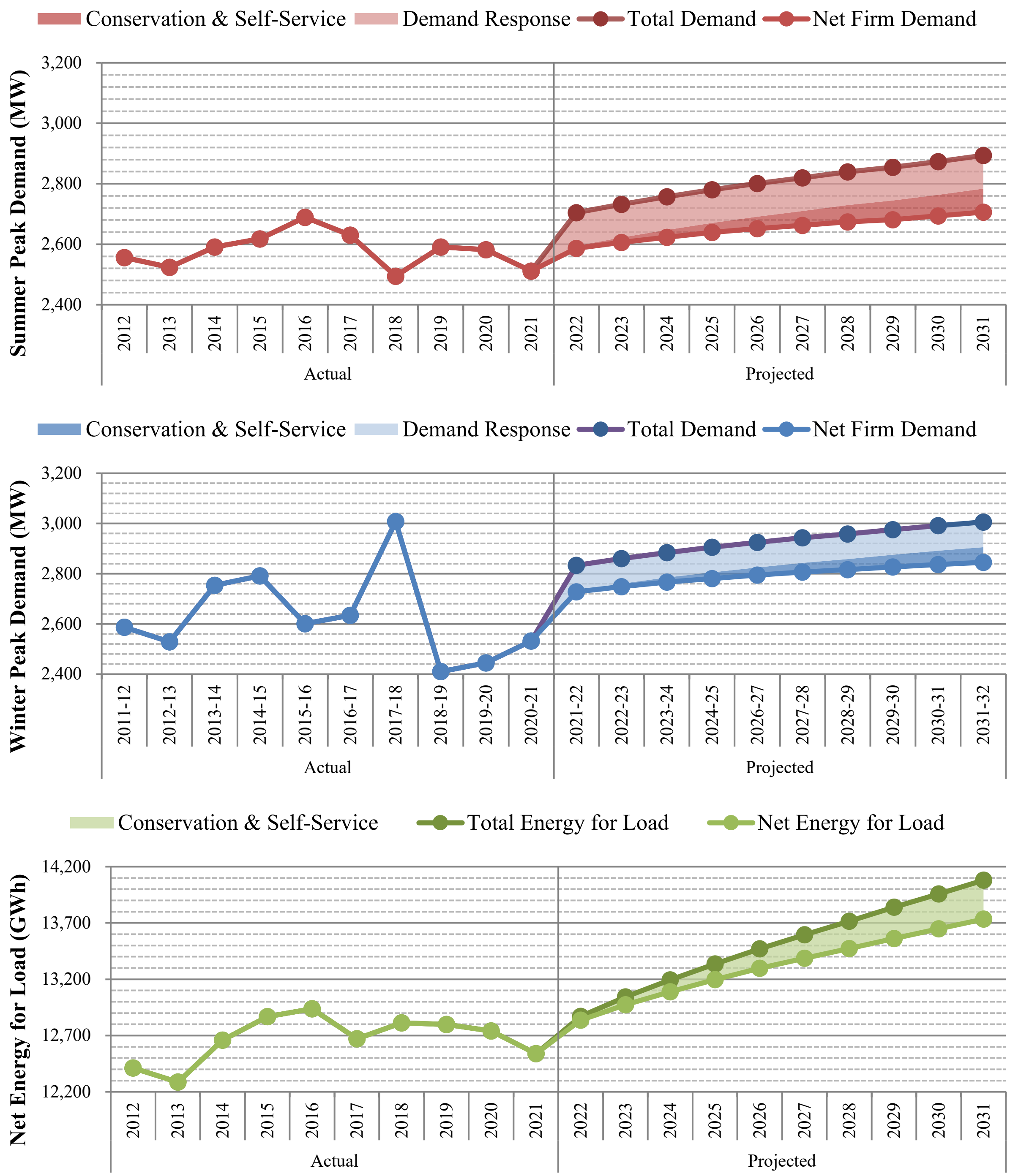
Figure 34: JEA Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 35 show JEA's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. While a municipal utility, JEA is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. These graphs include the full impact of demand-side management, and assume that all available demand response resources will be activated during the seasonal peak. In November 2019, the Commission established demand side management goals for JEA for the years 2020 through 2024. In July 2020, the Commission approved JEA's plan designed to achieve the 2020-2024 DSM goals. In preparing its 2022 Ten-Year Site Plan seasonal peak demand and energy forecasts, JEA assumes the trends in these goals will be extended through the forecast period (through 2031).

Figure 35: JEA Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 23 shows JEA's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. While natural gas was the dominant fuel source in 2021, coal was JEA's second most utilized fuel source. JEA's 2022 Ten-Year Site plan projects that a JEA will reduce its use of coal while increasing purchases. JEA has the highest percentage of energy from interchange, primarily from a contract with the Municipal Electric Authority of Georgia for 200 MW from the nuclear Vogtle Units 3 and 4.

Table 23: JEA Energy Generation by Fuel Type

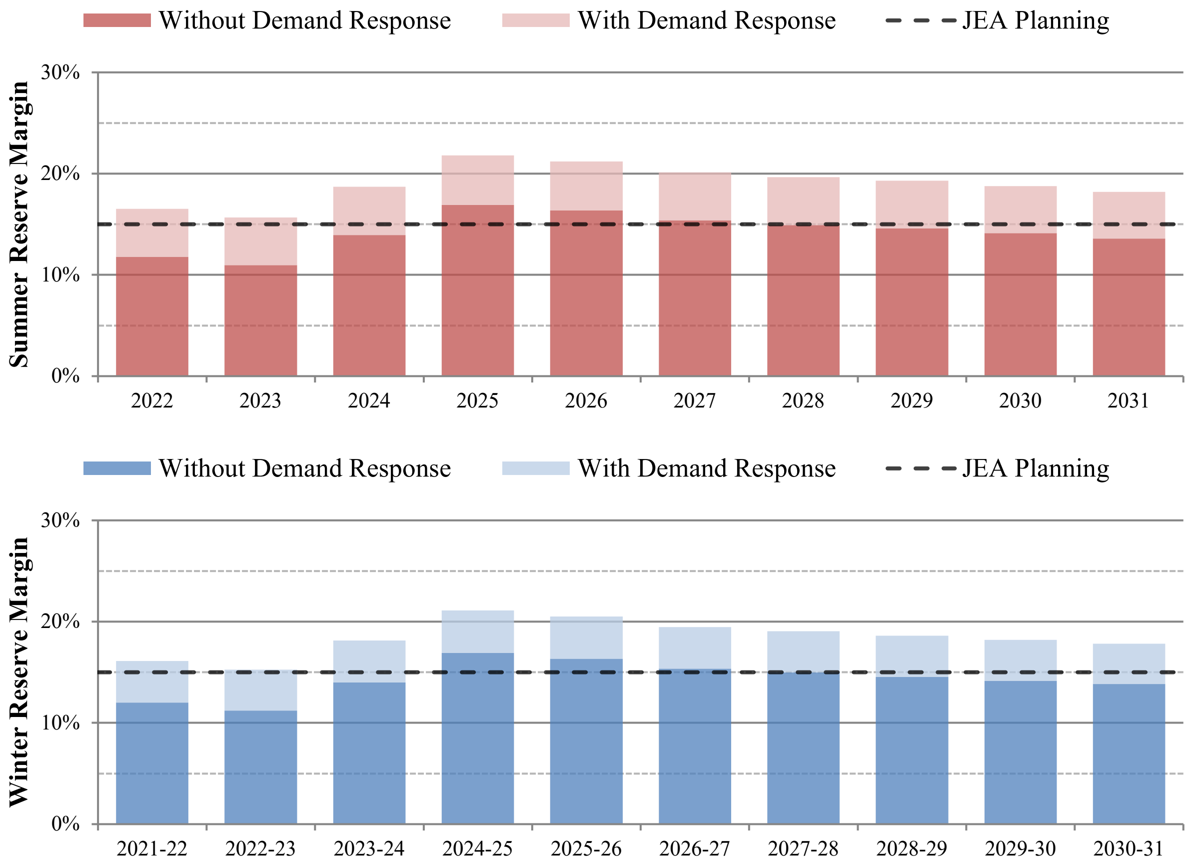
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	7,673	**61.2%**	7,617	**55.5%**
Coal	2,742	**21.9%**	2,570	**18.7%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	16	**0.1%**	28	**0.2%**
Renewable	166	**1.3%**	82	**0.6%**
Interchange	1,943	**15.5%**	3,437	**25.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**12,540**		**13,734**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 36 displays the forecast planning reserve margin for JEA through the planning period for both seasons, with and without the use of demand response. JEA's current and planned purchased power agreements with solar generators contribute to this shift in planning because solar resources provide coincident capacity during the summer peak but not the winter peak.

Figure 36: JEA Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

JEA retired its share of Scherer Unit 4 on January 1, 2022, as detailed in Table 24. JEA plans no unit additions during the planning period.

Table 24: JEA Energy Generation by Fuel Type

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2022	Scherer Unit 4	BIT - ST	198	Jointly Owned with FPL
Net Additions			**(198)**	

Source: 2022 Ten-Year Site Plan

Lakeland Electric (LAK)

LAK is a municipal utility and the state's third smallest electric utility required to file a Ten-Year Site Plan. The utility's service territory is within the FRCC region and consists of the City of Lakeland and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds LAK's 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

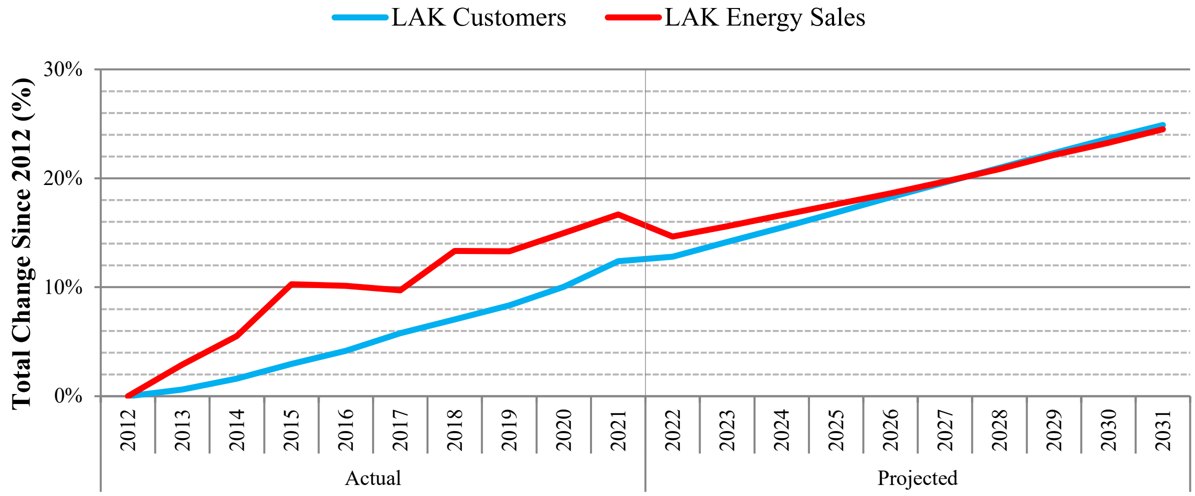
In 2021, LAK had approximately 137,162 customers and annual retail energy sales of 3,210 GWh or approximately 1.4 percent of Florida's annual retail energy sales. Figure 37 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012. Over the last 10 years, LAK's customer base has increased by 12.68 percent, while retail sales have grown by 16.48 percent.

In recent years, LAK's service area in Polk County has seen a boom in e-commerce warehouse development. Particularly, LAK has benefited from the relocation of Amazon's air-hub to the utility's service area in 2020 and the continuing trend of work from home. As a result, LAK experienced 2.2 percent total customer growth in 2021, the highest growth rate for the utility in the past 10 years.

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

LAK noted that, although the average energy consumption per customer is declining or flat for all three main rate classes, positive customer growth rates are expected to compensate for average use declines. The utility assumed the impact of conservation programs are already in the energy sales history and made no additional assumptions regarding their impact. For the next 10 years, the utility's forecast results indicated that its number of customers are projected to grow at an average annual rate of 1.14 percent, and its retail energy sales are projected to grow at an average annual rate of 0.92 percent.

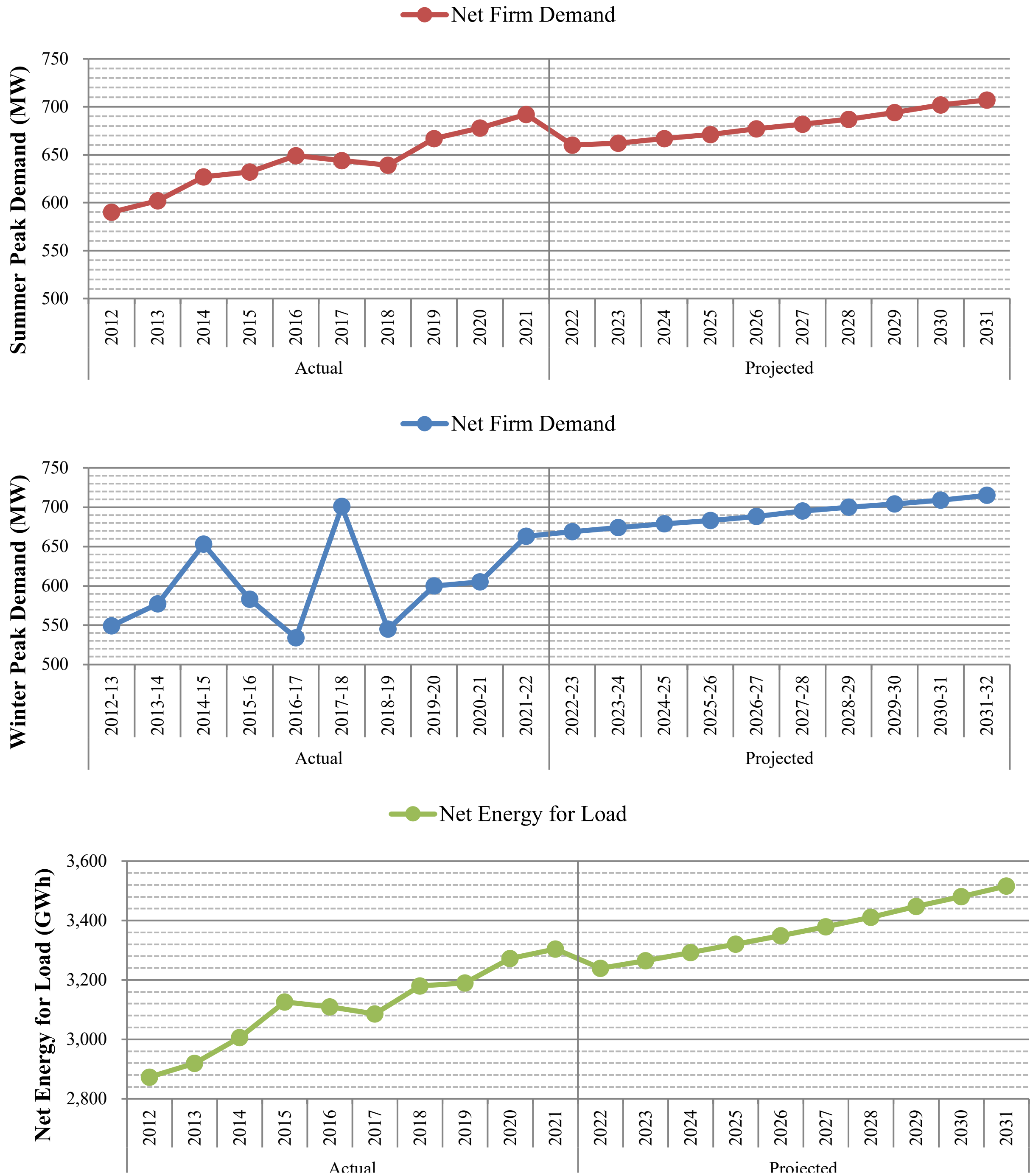
Figure 37: LAK Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 38 show LAK's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. LAK offers energy efficiency programs, the impacts of which are included in the graphs.

Figure 38: LAK Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 25 shows LAK's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. LAK uses natural gas as its primary fuel type for energy, with coal representing about 13 percent net energy for load. While natural gas generation is anticipated to increase over the next 10 years; generation by coal is projected to be phased out by 2031.

Table 25: LAK Energy Generation by Fuel Type

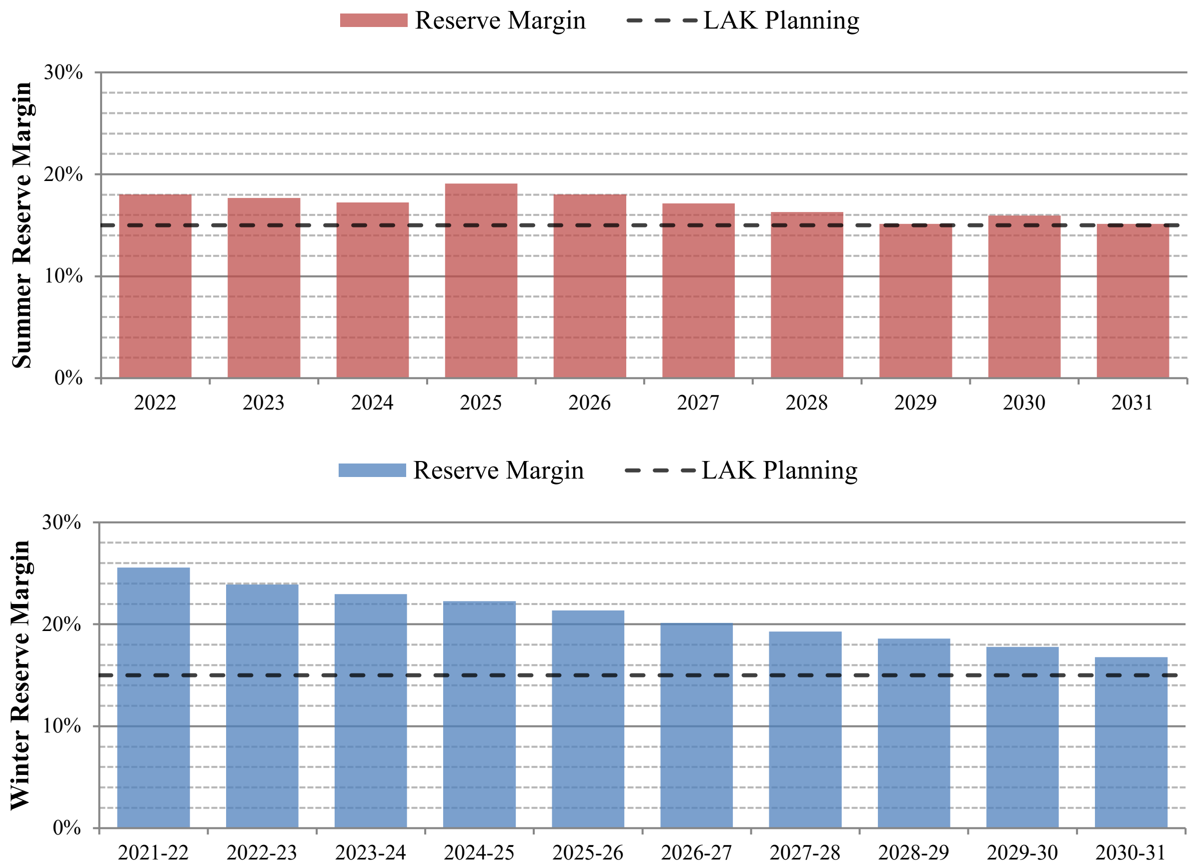
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	2,208	**66.8%**	3,071	**87.3%**
Coal	434	**13.1%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	26	**0.8%**	153	**4.4%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	636	**19.2%**	292	**8.3%**
Total	**3,304**		**3,516**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 39 displays the forecast planning reserve margin for LAK through the planning period for both seasons. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, LAK's largest single unit, McIntosh 5, a natural gas-fired combined cycle unit, represented 50 percent of summer net firm peak demand in 2019.

Figure 39: LAK Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

LAK is adding a set of solar sites and natural gas internal combustion engines during the planning period, as detailed in Table 26. LAK is also adding approximately 50 MW of additional capacity through PPAs during the planning period.

Table 26: LAK Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Solar Firm Capacity (MW) Sum	Notes
New Units					
2024	McIntosh	PV	16	8	
2024	Mcintosh Units ME1-ME-6	NG-IC	120	N/A	6 Reciprocating Engines
2025	McIntosh	PV	34	17	
Net Additions			**170**	**25**	

Source: 2022 Ten-Year Site Plan and Data Responses

Orlando Utilities Commission (OUC)

OUC is a municipal utility and Florida's sixth largest electric utility and second largest municipal utility. The utility's service territory is within the FRCC region and primarily consists of the Orlando metropolitan area. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds OUC's 2022 Ten-Year Site Plan suitable for planning purposes.

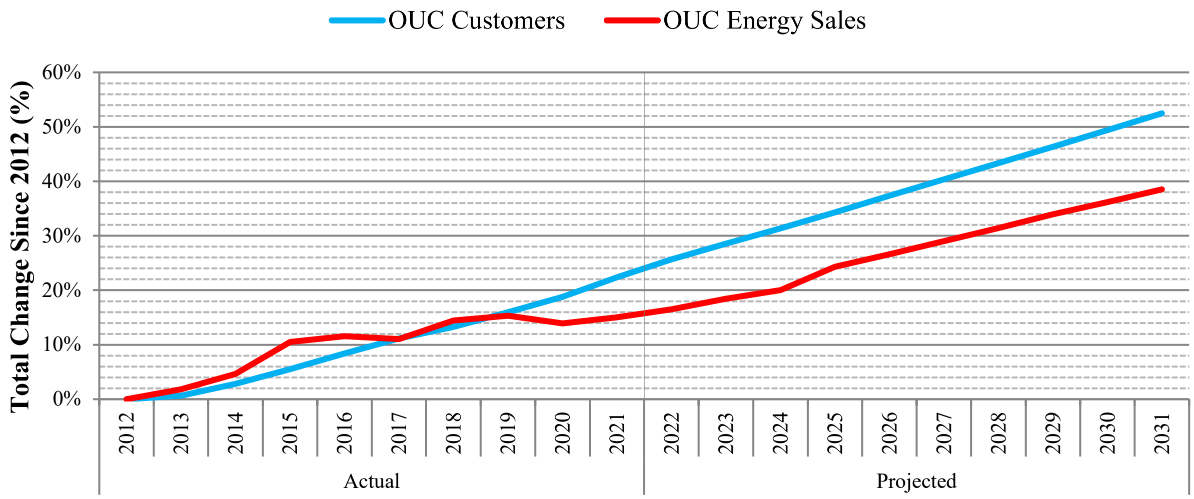
Load & Energy Forecasts

In 2021, OUC had approximately 261,045 customers and annual retail energy sales of 6,807 GWh or approximately 2.9 percent of Florida's annual retail energy sales. Over the last 10 years, OUC's customer base has increased by 22.37 percent, while its retail energy sales have increased by 15.06 percent, approximately. Figure 40 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012.

OUC experienced a continued decline in average use per residential customer in 2021. The utility noted that such decline has tapered dramatically since the beginning of the 10-year historic period due to the increased saturation of more efficient HVAC equipment and other electrical devices, as well as customer conservation efforts. OUC's forecasted residential average per-customer usage is expected to remain relatively flat as increased electric vehicle charging mitigates further saturation of more efficient electrical equipment and conservation efforts. The utility's average use per commercial customer also experienced a slight, long-term decline, which was greatly exacerbated by the impacts of COVID-19, but is expected to return to pre-COVID levels.

Over the forecast horizon, OUC is projecting growth in the number of customers at a slightly increased average annual rate of 2.17 percent, and retail sales at a moderately increased average annual rate of 1.94 percent. OUC noted that the main contributors to the projected higher customer growth rate include the increased population and household numbers in its service area. The main drivers for the projected higher growth rate of the energy sales than what was projected in the past include the recovery from COVID-19 effects, the projected growth in electric vehicle charging load, and major commercial expansions by Universal Studios and the Orlando International Airport.

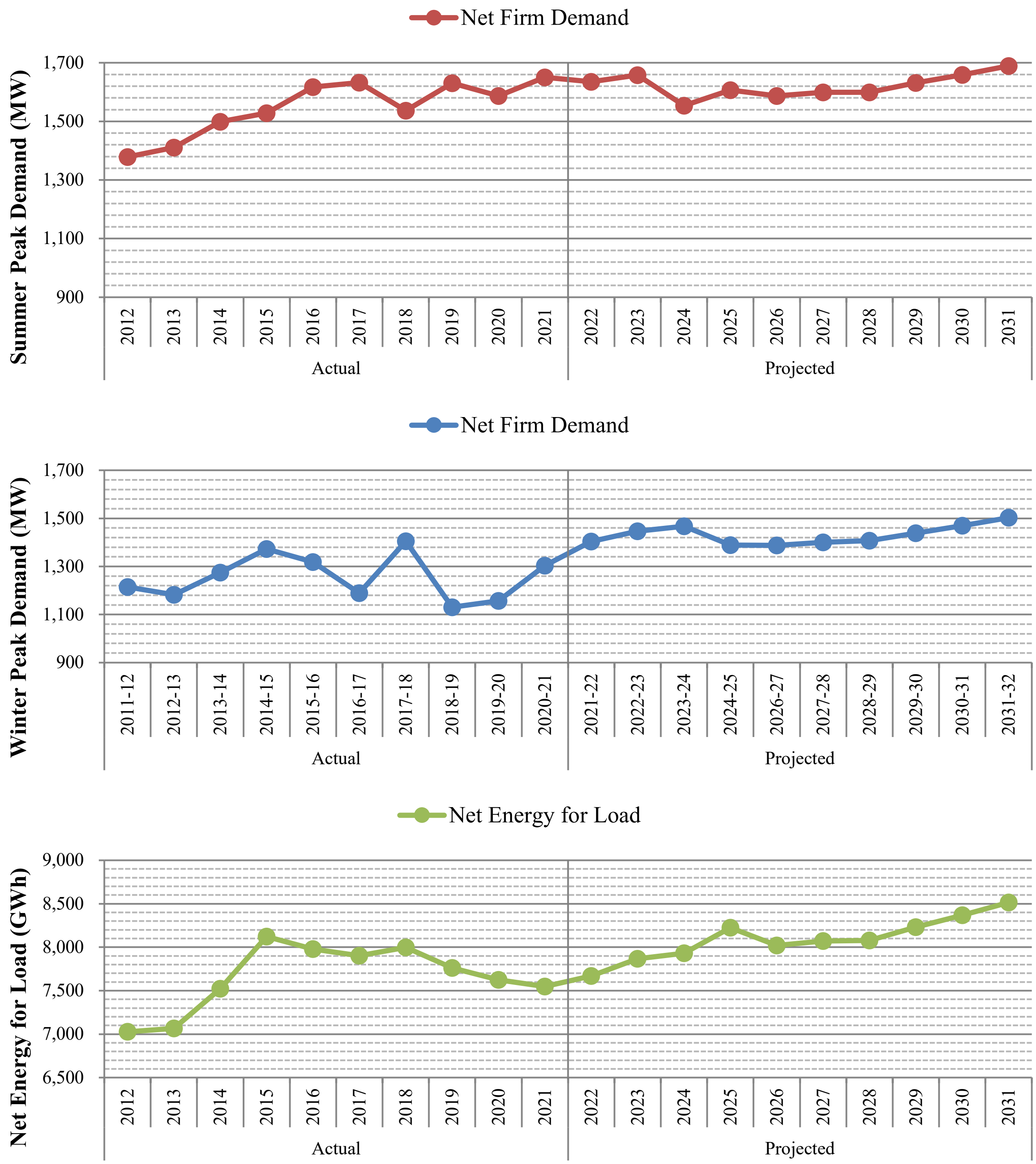
Figure 40: OUC Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 41 show OUC's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. These graphs include the impact of the utility's demand-side management programs. While a municipal utility, OUC is subject to FEECA and currently offers energy efficiency programs to customers to reduce peak demand and annual energy consumption. In November 2019, the Commission established demand-side management goals for OUC for the years 2020 through 2024. In June 2020, the Commission approved OUC's plan designed to achieve the 2020-2024 DSM goals. In preparing its 2022 Ten-Year Site Plan seasonal peak demand and energy forecasts, OUC assumes the trends in these goals will be extended through the forecast period (through 2031).

Figure 41: OUC Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 27 shows OUC's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. In 2021, approximately 48 percent of OUC's net energy for load was met with natural gas, while coal, the second most-used fuel, met 42 percent of the demand. By 2031, OUC projects an increase in renewable energy generation from 5 percent to 55.9 percent, the highest in the state and the only utility projected to meet a majority of its net energy for load through renewables. The remainder of energy primarily comes from natural gas and nuclear, with coal generation completely eliminated.

Table 27: OUC Energy Generation by Fuel Type

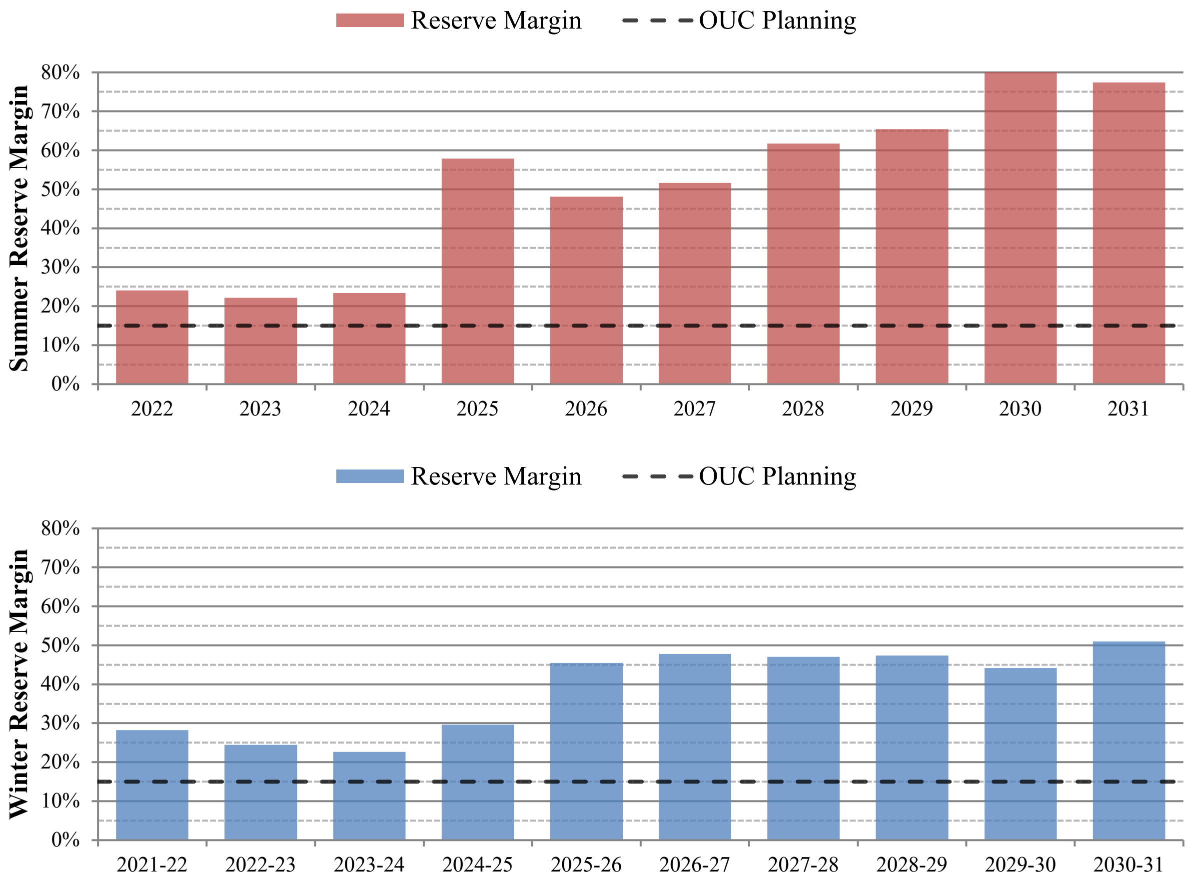
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	3,583	**47.5%**	3,173	**37.3%**
Coal	3,152	**41.8%**	0	**0.0%**
Nuclear	464	**6.1%**	578	**6.8%**
Oil	0	**0.0%**	0	**0.0%**
Renewable	349	**4.6%**	4,764	**55.9%**
Interchange	0	**0.0%**	0	**0.0%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**7,548**		**8,515**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

OUC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 42 displays the forecast planning reserve margin for OUC through the planning period for both seasons, including the impact of demand-side management programs. As shown in the figure, OUC's generation needs are controlled by its summer peak demand until 2024.

Figure 42: OUC Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

As detailed in Table 28, OUC plans on retiring one coal-fired unit and adding three natural gas-fired units. OUC plans on retiring Stanton Unit 1, OUC's oldest coal-fired unit, no later than 2025. OUC also plans on converting Stanton Unit 2 from a coal unit to a natural gas unit in 2027. After the conversion in 2027, OUC plans to no longer burn coal as a fuel source. OUC is purchasing the existing Osceola Generating Station Units 1 through 3, natural gas-fired combustion turbines; but, will not be able to fully utilize their capacity during peak periods until 2025. Portions of their capacity will be available before that for summer peaks beginning in 2022.

OUC anticipates entering into PPAs for a total of 1,417 MW of solar capacity and 350 MW of storage. OUC has already signed two of these PPA with NextEra for a total of 149 MW of solar capacity and 40 MW of storage with a planned in-service year of 2023. The additional solar capacity produced by these PPAs will help OUC achieve their pledge of reducing carbon emissions 50 percent by the year 2030.

Table 28: OUC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2025	Stanton Unit 1	BIT – ST	312	Jointly Owned with FMPA
Total Retirements			**312**	
New Units				
2025	Osceola Generating Station Units 1-3	NG – GT	471	Purchase of existing units.
Total New Units			**471**	
Net Additions			**159**	

Source: 2022 Ten-Year Site Plan

Seminole Electric Cooperative (SEC)

SEC is a generation and transmission rural electric cooperative that serves its member cooperatives, and is collectively Florida's fourth largest utility. SEC's generation and member cooperatives are within the FRCC region, with member cooperatives located in central and north Florida. As a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds SEC's 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

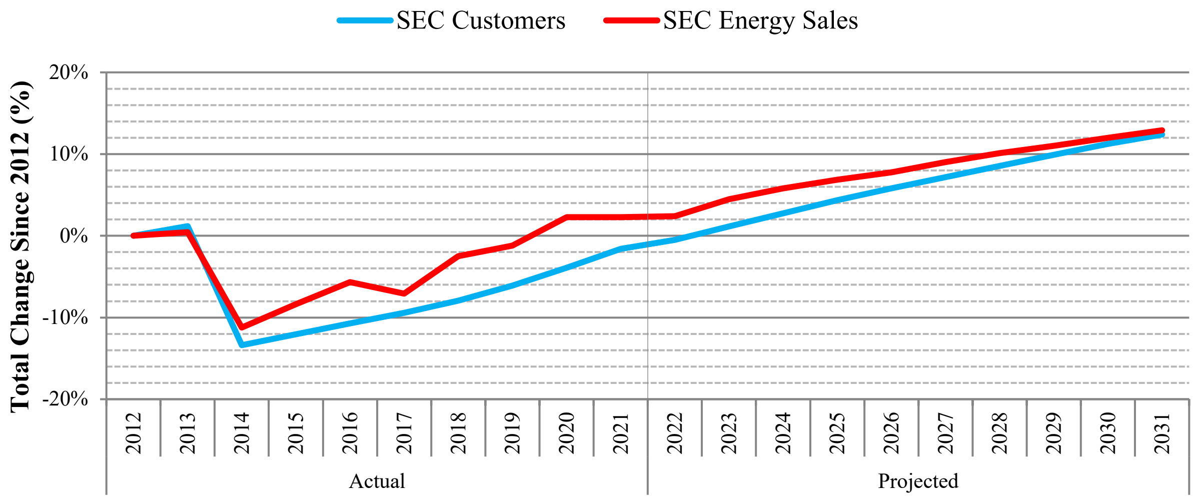
In 2021, SEC member cooperatives had approximately 841,276 customers and annual retail energy sales of 14,930 GWh or approximately 6.4 percent of Florida's annual retail energy sales. Figure 43 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012.

SEC's current TYSP indicated that over the last 10 years, 2012-2021, the utility members' aggregate customer base has decreased by 1.61 percent, compared to a 3.22 percent decrease shown in SEC's 2021 TYSP for the 2011-2020 period. The negative 10-year customer growth rate is attributed to a substantial growth decline in 2014 when one member cooperative, Lee County Electric Cooperative, elected to end its membership with SEC. In the current TYSP, the utility reported that its retail sales have increased by 2.27 percent over the historical period 2012-2021, compared to 0.03 percent decrease indicated in its 2021 TYSP for 2011-2020.

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

Over the current 10-year forecast horizon, SEC is projecting an average annual growth rate in its customer base of 1.36 percent, and an average annual growth rate in its retail energy sales of 1.09 percent.

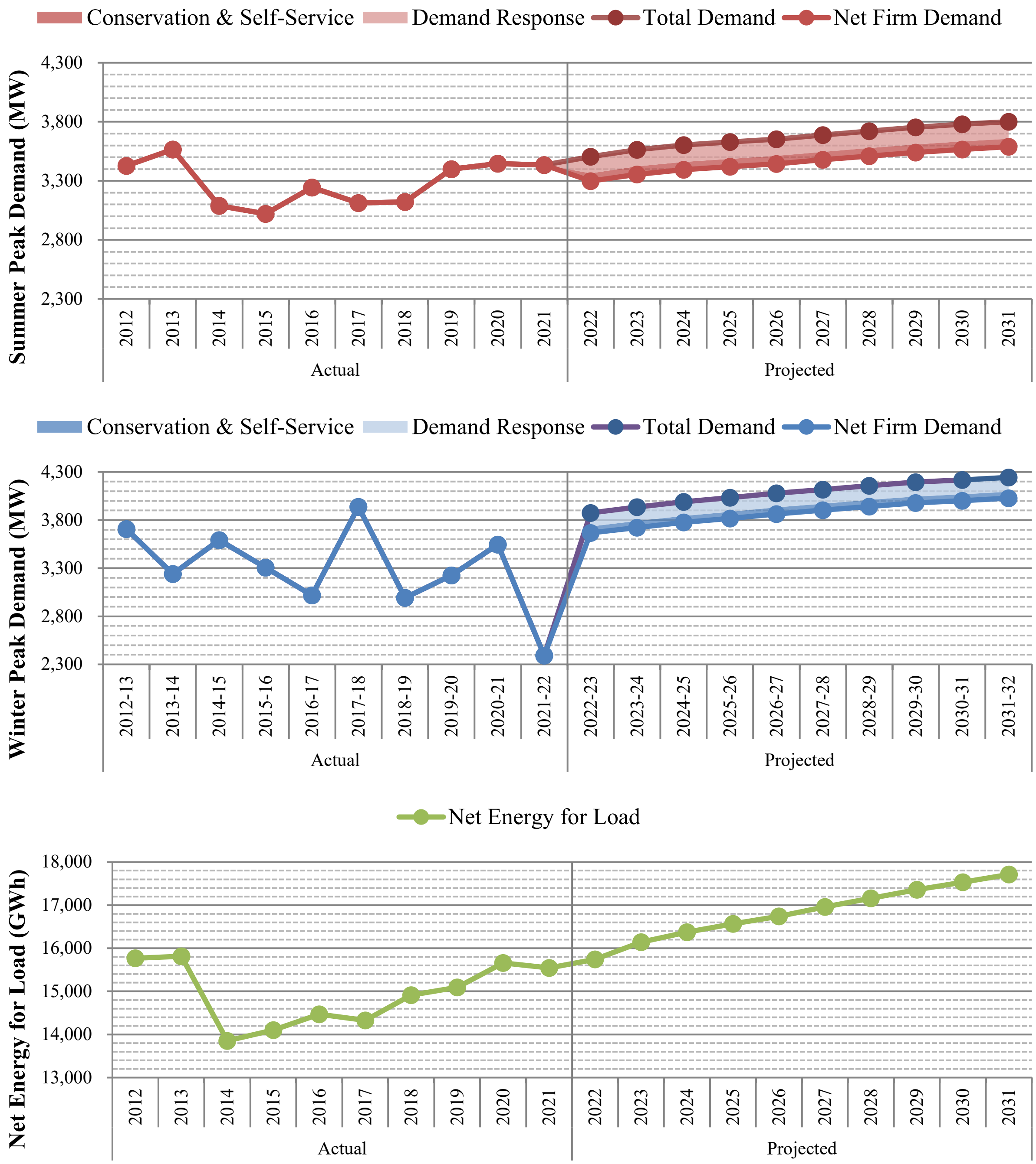
Figure 43: SEC Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 44 show SEC's seasonal peak demand and net energy for load for the historic years 2012 through 2021 and forecast years 2022 through 2031. As SEC is a generation and transmission company, it does not directly engage in energy efficiency or demand response programs. Member cooperatives do offer demand-side management programs, the impacts of which are included in Figure 44.

Figure 44: SEC Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 29 shows SEC's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. In 2021 SEC used coal as its primary source of fuel. By 2031 natural gas usage is expected to become the primary fuel source.

Table 29: SEC Energy Generation by Fuel Type

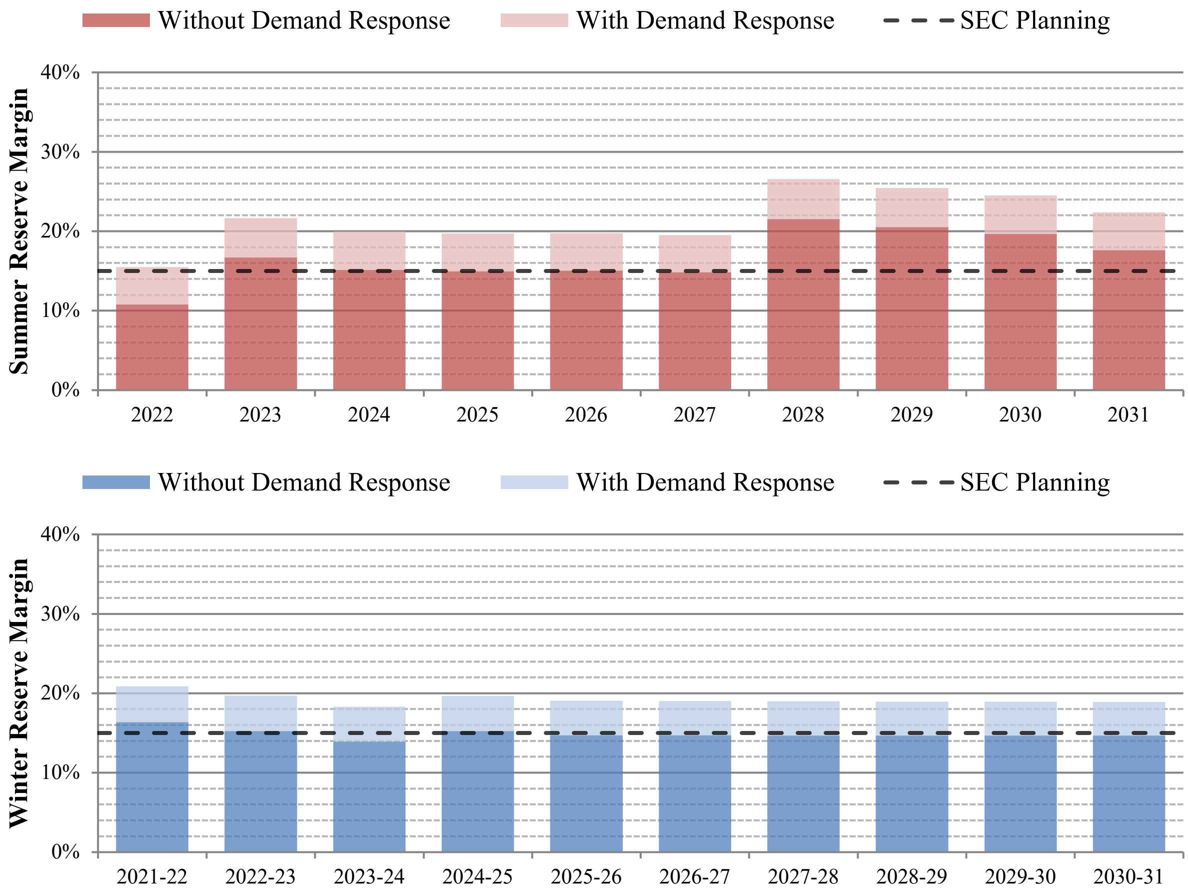
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	4,180	**26.9%**	14,673	**82.8%**
Coal	6,508	**41.9%**	1,637	**9.2%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	21	**0.1%**	4	**0.0%**
Renewable	489	**3.1%**	766	**4.3%**
Interchange	4,343	**27.9%**	631	**3.6%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**15,541**		**17,711**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

SEC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 45 displays the forecast planning reserve margin for SEC through the planning period for both seasons, with and without the use of demand response. Member cooperatives allow SEC to coordinate demand response resources to maintain reliability. As shown in the figure, SEC's generation needs are determined by winter peak demand more often than summer peak demand during the planning period.

Figure 45: SEC Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

SEC plans to retire one unit and add two units during the planning period, as described in Table 30. On December 21, 2017, SEC filed a need determination with the Commission for the Seminole CC Facility which was granted on May 25, 2018.[17] SEC plans on retiring one of its coal-fired SGS units at the end of 2022; but, has not yet selected the generator. In addition, SEC plans to add two natural gas-fired generating resources, a combined cycle and combustion turbine, during the planning period. SEC considers these as proxy units to meet its reliability criteria due to ending PPA contracts. SEC anticipates an additional 300 MW of solar generation through PPAs to become commercially operational by the end of 2023.

[17] Order No. PSC-2018-0262-FOF-EC, issued May 25, 2018, in Docket No. 20170266-EC, *In re: Petition to determine need for Seminole combined cycle facility, by Seminole Electric Cooperative, Inc.*

Table 30: SEC Generation Resource Changes

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes
Retiring Units				
2022	SGS Unit 1 or 2	BIT – ST	626	Unit choice for retirement pending.
Total Retirements			**626**	
New Units				
2022	Seminole CC Facility	NG – CC	1,099	Docket No. 20170266-EC
2025	Unnamed CC	NG – CC	571	
2027	Unnamed CT	NG – CT	317	
Total New Units			**1,987**	
Net Additions			**1,361**	

Source: 2022 Ten-Year Site Plan

City of Tallahassee Utilities (TAL)

TAL is a municipal utility and the second smallest electric utility that files a Ten-Year Site Plan. The utility's service territory is within the FRCC region and primarily consists of the City of Tallahassee and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds TAL's 2022 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2021, TAL had approximately 125,901 customers and annual retail energy sales of 2,590 GWh or approximately 1.1 percent of Florida's annual retail energy sales. Figure 46 illustrates the utility's historic and forecasted growth rates in customers and retail energy sales beginning in 2012. Over the last 10 years, TAL's customer base has increased by 9.55 percent, while retail sales have increased by 0.13 percent.

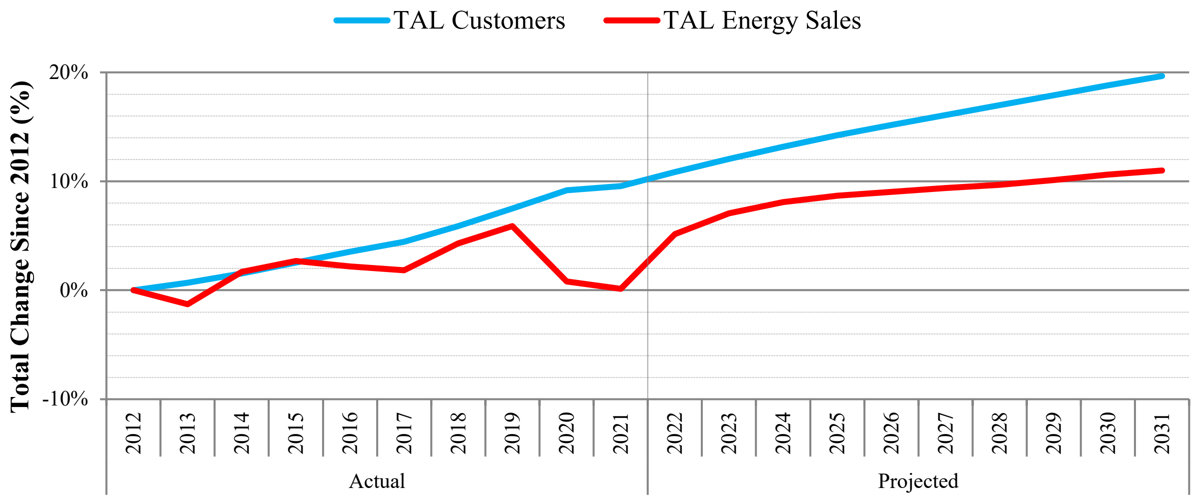
TAL's customer base consists of residential and commercial classes; and, the total energy consumption associated with the commercial class is higher than that associated with the residential class. Over the last decade, the utility's customer count growth has been robust. This growth correlates well to the rate of change in Leon County's population, household formation, and economic activity; such as, the increased rates of household counts, total employment and average real income per household. As a result of the expected continuation of favorable economic conditions in Leon County, TAL expects a continued strong growth in its customer counts.

The utility's residential electricity use per customer has been flattening after several years of decline. This is believed to be driven primarily from end-use efficiency standards that have been filtering into the stock of equipment through replacements and new builds. These end-use efficiency standards are believed to be nearly fully diffused into the current residential stock. Commercial energy use per customer has continued to decline it has been particularly impacted since early 2020 by COVID-19, from which certain large loads are still recovering.

TAL's load forecast reflects the continued impacts of energy efficiency standards and codes, as well as the utility's DSM and conservation/energy efficiency programs. These impacts are slightly offset by upward pressure on total residential consumption from increasing incomes, electric vehicle adoption, and other factors, resulting in essentially flat residential sales growth over the forecast horizon.

Over the current forecast horizon, TAL is projecting an average annual growth of 0.85 percent in its total customer counts, and a growth rate of 0.60 percent in its annual retail energy sales.

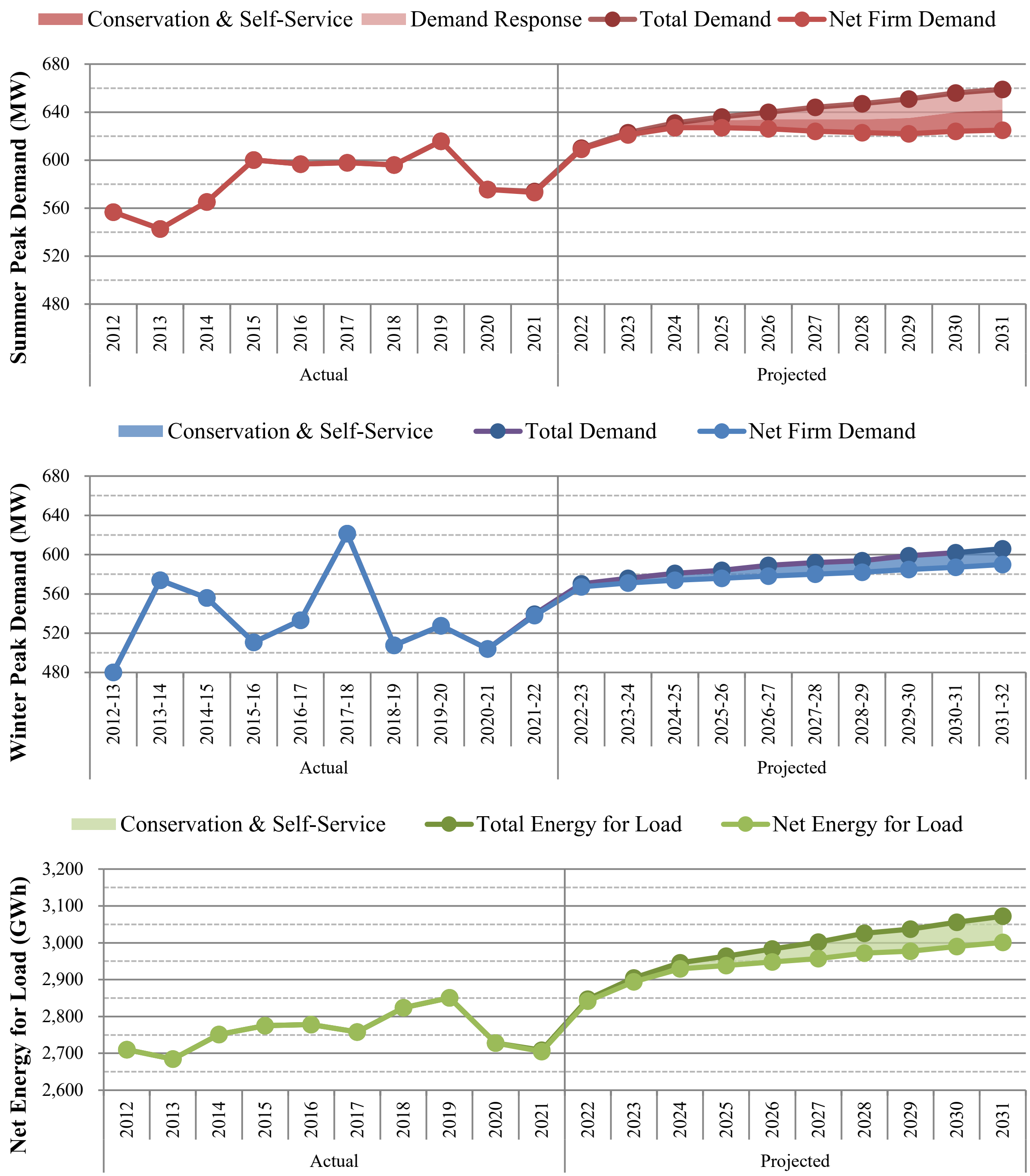
Figure 46: TAL Growth



Source: 2022 Ten-Year Site Plan

The three graphs in Figure 47 shows TAL's seasonal peak demand and net energy for load for the historic years of 2012 through 2021 and forecast years 2022 through 2031. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. TAL offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. Currently, TAL only offers demand response programs targeting appliances that contribute to summer peak, and therefore have no effect upon winter peak.

Figure 47: TAL Demand and Energy Forecasts



Source: 2022 Ten-Year Site Plan and Data Responses

Fuel Diversity

Table 31 shows TAL's actual net energy for load by fuel type as of 2021 and the projected fuel mix for 2031. TAL relies almost exclusively on natural gas for its generation, excluding some purchases from other utilities and qualifying facilities. Natural gas is anticipated to remain the primary fuel source on the system. TAL projects it will continue to be a net exporter of energy, primarily of off-peak power during shoulder months due to its generation's operating characteristics.

Table 31: TAL Energy Generation by Fuel Type

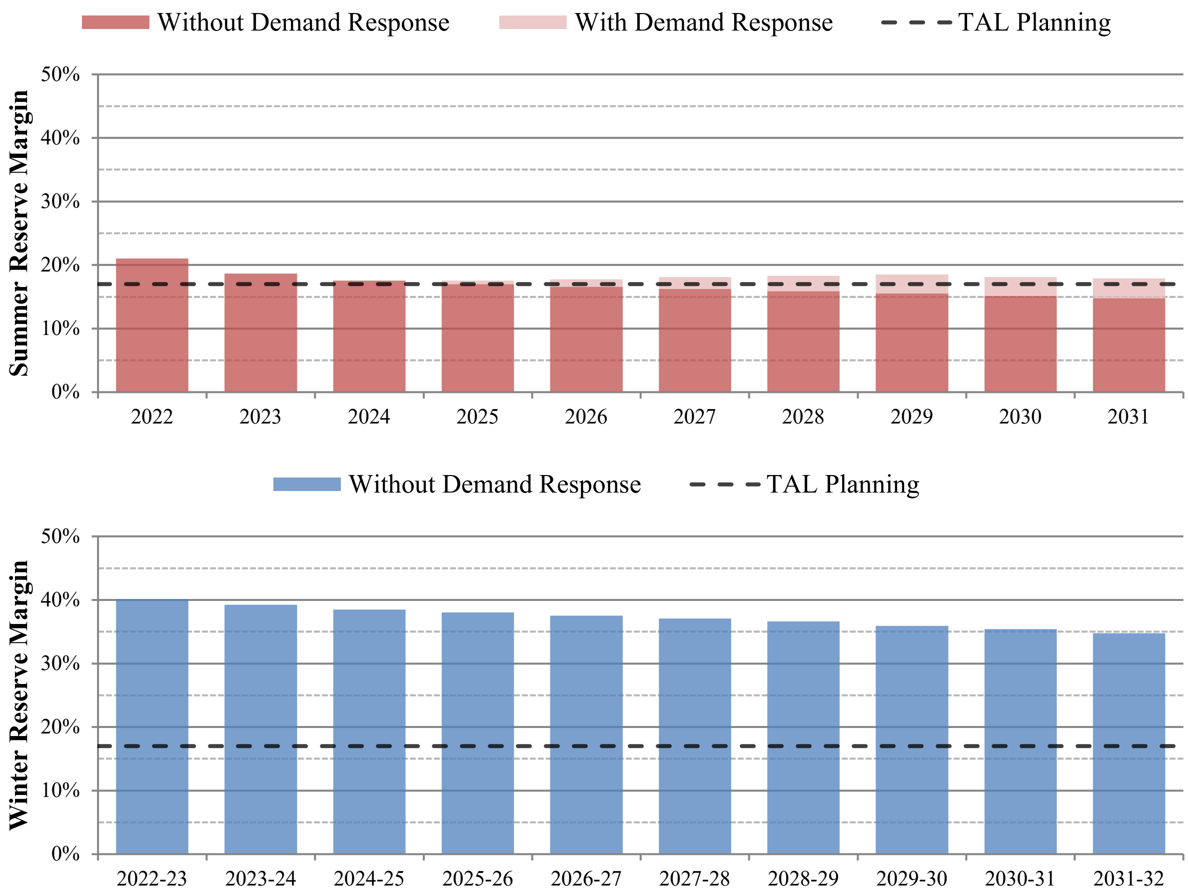
Fuel Type	Net Energy for Load			
	2021		2031	
	GWh	%	GWh	%
Natural Gas	2666	**97.7%**	3,021	**101.2%**
Coal	0	**0.0%**	0	**0.0%**
Nuclear	0	**0.0%**	0	**0.0%**
Oil	1	**0.0%**	0	**0.0%**
Renewable	113	**4.1%**	116	**3.9%**
Interchange	-51	**-1.9%**	(153)	**-5.1%**
NUG & Other	0	**0.0%**	0	**0.0%**
Total	**2,729**		**2,985**	

Source: 2022 Ten-Year Site Plan and Data Responses

Reliability Requirements

TAL utilizes a 17 percent planning reserve margin criterion for seasonal peak demand. Figure 48 displays the forecast planning reserve margin for TAL through the planning period for both seasons, with and without the use of demand response. As discussed above, TAL only offers demand response programs applicable to the summer peak. As shown in the figure, TAL's generation needs are controlled by its summer peak throughout the planning period.

Figure 48: TAL Reserve Margin Forecast



Source: 2022 Ten-Year Site Plan

Generation Resources

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

Attachment 2

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: October 13, 2022

TO: Braulio L. Baez, Executive Director

FROM: Penelope Buys, Engineering Specialist IV, Division of Engineering PB TB MR LK

RE: Annual Status Report on Storm Protection Plan Activities of Florida Investor-Owned Utilities

CRITICAL INFORMATION: Place on October 25, 2022 Internal Affairs Agenda. Commission approval is sought, due to the Governor and Legislature by December 1, 2022.

Pursuant to Section 366.96(10), F.S., the Commission is required to submit to the Governor, the President of the Senate, and the Speaker of the House of Representatives a status report of the utilities' storm protection activities. The attached draft satisfies the requirement of the Statute and its approval by the Commission is sought. The report is due by December 1, 2022.

Please let me or Marissa Ramos know if you have any questions or need additional information in reference to the attached document.

PB:jp

Attachment

cc: Keith Hetrick, General Counsel
Apryl Lynn, Deputy Executive Director, Administrative
Mark Futrell, Deputy Executive Director, Technical

FLORIDA
PUBLIC
SERVICE
COMMISSION

DRAFT 10/13/22

Annual Status Report on Storm Protection Plan Activities of Florida Investor-Owned Utilities

As Required by Section 366.96(10), Florida Statutes

OCTOBER 2022

Table of Contents

List of Tables

Acronyms

DEF	Duke Energy Florida, LLC
EWL	Extreme Wind Loading
F.A.C.	Florida Administrative Code
FPL	Florida Power & Light Company
FPUC	Florida Public Utilities Company
F.S.	Florida Statutes
GULF	Gulf Power Company
IOU	Investor-Owned Electric Utility
NESC	National Electric Safety Code
OPC	Office of Public Counsel
SPP	Storm Protection Plan
SPPCRC	Storm Protection Plan Cost Recovery Clause
TECO	Tampa Electric Company

Executive Summary

In 2019, the Florida Legislature passed Senate Bill 796 to enact Section 366.96, F.S., entitled "Storm Protection Plan Cost Recovery." Section 366.96, F.S., requires each investor-owned electric utility (IOU) to file a transmission and distribution Storm Protection Plan (SPP) that covers the immediate 10-year planning period. The plans are required to be filed with the Commission at least every three years and must explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability. Pursuant to Section 366.96(7), F.S., the Commission shall conduct an annual proceeding to determine the utility's prudently incurred SPP costs. In addition, Section 366.96(10), F.S., requires that the Commission submit an annual report to the Governor, President of the Senate, and Speaker of the House, on the status of the utilities' storm protection activities and costs which is the purpose of this report. The Commission's rules implementing this new statute became effective on February 18, 2020.

This report is a summary of information provided pursuant to Rule 25-6.030(4), F.A.C., which includes:

- Planned and completed SPP programs and projects in the previous year.
- Actual costs and rate impacts associated with completed SPP programs compared to the estimated costs and rate impacts for the same activities.
- Estimated costs and rate impacts associated with SPP programs planned for the next year.

Sections 3 through 5 of this report summarize the information required pursuant to Section 366.96(10) F.S. for Duke Energy Florida, LLC (DEF), Florida Power & Light Company (FPL)/Gulf Power Company (Gulf), and Tampa Electric Company (TECO). A majority of these SPP programs are a continuation of the utility's previously approved Storm Hardening Plan[1] and SPP.[2] This report does not include any data from Florida Public Utilities Company (FPUC), as the Commission granted a motion to defer its 2020 SPP filing and refrain from participating in the Storm Protection Plan Cost Recovery Clause (SPPCRC) proceeding due to circumstances affecting the utility as a result of Hurricane Michael in 2020. FPUC's first SPP was approved, with modifications, at the October 4, 2022 Commission Conference. NextEra Energy Inc., FPL's parent company acquired Gulf Power Company through a purchase that closed during the first half of 2019. The companies continued to exist as separate entities under the Commission's jurisdiction and submitted separate SPPs which were approved by the Commission in 2020. The Commission approved the unification of FPL and Gulf's systems for ratemaking purposes, effective January 1, 2022. Accordingly, FPL's SPP will, going forward, address the combined territory and customers of the unified company.

Table A provides a summary of each utility's reported estimated and actual total storm protection expenditures.[3] While most of these expenditures are being recovered through the SPPCRC, some costs

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[1] Docket No. 20180144-EI (FPL), Docket No. 2018045-EI (TECO), Docket No. 20180146-EI (DEF), Docket No. 20180147-EI (Gulf) and Docket No. 20180148-EI (FPUC), *In re: Review of 2019-2021 storm hardening plan.*

[2] Docket No. 20200067-EI (TECO), Docket No. 20200069-EI (DEF), Docket No. 2020070-EI (Gulf), and Docket No. 20200071-EI (FPL), *In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C.*

[3] The Commission is not drawing any conclusions or making any findings in this report. Any findings about current or future storm protection program cost recovery will be considered as part of a docketed proceeding and subsequent Commission order.

continue to be recovered through the utility's base rates. Table B is a summary of each utility's reported estimated and actual bill impacts for a typical residential customer. For reference purposes, the values initially reported for 2020 are also included in both tables.

Table A
Summary of SPP Costs

Utility	2020* Actual (Millions)	2021 Estimated (Millions)	2021 Actual (Millions)	2022** Estimated (Millions)
Duke Energy Florida, LLC	$239.3	$409.3	$343.5	$651.2
Florida Power & Light/	$1,037.2	$1,090.6	$1,149.5	$1,360.0
Gulf Power Company	$36.6	$100.8	$96.3	
Tampa Electric Company***	$36.9	$137.7	$115.1	$181.4
Totals	**$1,350.0**	**$1,738.4**	**$1,704.4**	**$2,192.6**

*Note: The 2020 Actual amounts are from the Companies' 2020 SPP Annual reports.
**Note: Consists of consolidated amounts for FPL and Gulf.
***Note: TECO's SPP costs reflect only the actual/estimated SPPCRC costs.

Table B
Summary of SPP Bill Impacts (in dollars)

Utility	2020* Actual Residential Bill Impact ($/1,000 kWh)	2021 Estimated Residential Bill Impact ($/1,000 kWh)	2021 Actual Residential Bill Impact ($/1,000 kWh)	2022** Estimated Residential Bill Impact ($/1,000 kWh)
Duke Energy Florida, LLC	$2.05	$2.65	$2.40	$3.15
Florida Power & Light/	$1.29	$1.36	$1.39	$1.48
Gulf Power Company	$0.98	$1.44	$1.38	
Tampa Electric Company	$1.03	$1.90	$2.09	$3.26

*Note: The 2020 Actual amounts are from the Companies' 2020 SPP Annual reports.
**Note: Consists of consolidated amounts for FPL and Gulf.

Section 1 – Background

In order to implement the new statute, the Commission staff held two rule development workshops, on June 25, 2019, and August 20, 2019, to obtain stakeholder comments on the draft rules. Representatives from each IOU, Florida Retail Federation, Florida Industrial Power Users Group, and the Office of Public Counsel (OPC) participated at the workshops and submitted post-workshop comments. Additionally, representatives from Florida Electric Cooperatives Association, Inc., and Florida Municipal Electric Association submitted post-workshop comments.

The Commission proposed the adoption of Rules 25-6.030, F.A.C, Storm Protection Plan, and 25-6.031, F.A.C., Storm Protection Plan Cost Recovery Clause, at its October 3, 2019 Commission Conference.[4] However, the rules were challenged and an administrative hearing was held on December 20, 2019, at the Department of Administrative Hearings.[5] The Administrative Law Judge issued a final order on January 21, 2020, deeming the rules as valid and the rules became effective on February 18, 2020.

On April 11, 2022, DEF, FPL, and TECO each filed their second SPP for Commission approval.[6] These plans are largely a continuation of the IOUs' initial Commission-approved SPPs with the addition of some newly proposed programs.[7] The initial SPPs were approved by the Commission through individual settlement agreements. In addition, FPUC filed its first SPP for Commission approval on April 11, 2022.[8]

The Commission held a technical hearing on August 2-4, 2022, to address all four dockets. On October 4, 2022, the Commission voted to approve the plans with modifications. The modified plans are to be filed within 30 days of the final order for administrative approval.

Pursuant to Section 366.96(8), F.S., and Rule 25-6.031, F.A.C., SPP costs that are being recovered through the SPPCRC cannot be recovered through base rates or any other cost recovery method. SPP costs that are being recovered through the SPPCRC are evaluated by the Commission on an annual basis via the SPPCRC docket. The most recent SPPCRC docket was opened on January 3, 2022, and the Commission is scheduled to make a final decision on this docket by the end of the year.[9]

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[4] Docket No. 20190131-EU, *In re: Proposed adoption of Rule 25-6.030, F.A.C., Storm Protection Plan and Rule 25-6.031, F.A.C., Storm Protection Plan Cost Recovery Clause.*

[5] Case No. 19-006137RP, *In re: Petitioner and Intervenor had standing to challenge the proposed rules, but the evidence showed that the proposed rules are not invalid exercises of delegated legislative authority.*

[6] Docket No. 20220048-EI (TECO), Docket No. 20220050-EI (DEF), and Docket No. 20220051-EI (FPL), *In re: Review of Storm Protection Plan pursuant to Rule 25-6.030, F.A.C.*

[7] TECO and FPUC's SPPs are for 2022 through 2031. DEF and FPL's SPPs are for 2023 through 2032.

[8] Docket No. 20220049-EI, *In re: Review of Storm Protection Plan pursuant to Rule 25-6.030, F.A.C.*

[9] Docket No. 20220010-EI, *In re: Storm Protection Plan Cost Recovery Clause.*

Section 2 - Summary of Filings

On June 1, 2022, DEF, FPL, and TECO filed their annual status reports regarding their SPP programs.[10] As required by Section 366.96(10), F.S., these status reports include:

- A description of all planned and completed SPP programs and projects in 2021.
- Actual costs and rate impacts associated with completed SPP programs compared to the estimated costs and rate impacts for the same activities.
- Estimated costs and rate impacts associated with SPP programs planned for 2022.

Each section below contains a brief description of each utility's SPP programs. A majority of these programs are a continuation of the utility's SPP previously approved by the Commission. The tables contained within each section summarize the information required pursuant to Section 366.96(10), F.S. Additional details of the programs are also contained in each utility's annual status report and its filings in the annual SPPCRC proceeding.

[10] http://www.floridapsc.com/ElectricNaturalGas/StormProtectionPlans Annual Status Reports

Section 3 - Duke Energy Florida, LLC

Program Descriptions
Below are the programs that DEF implemented in 2021 or will implement in 2022. Further details of the programs are in DEF's SPP[11] or its annual SPP report.[12]

Distribution Self-Optimizing Grid
This program utilizes automated switching which allows most circuits to be restored from alternate sources. The program has connectivity projects that create tie points between circuits and adds segmentation such that the distribution circuits have much smaller line segments, thus reducing the number of customers that are affected by outages.

Distribution Targeted Underground
Existing overhead distribution lines are converted to underground in accessible locations to reduce tree and debris-related outages in heavily vegetated neighborhoods. DEF selects and prioritizes locations based on a 10-year reliability assessment of protective devices and outage history.

Distribution Deteriorated Conductor
The primary purpose of this program is to replace over-dutied overhead conductors that are prone to outages due to brittle composition, small load capacity, and reduced connection quality. The selected areas will have all of the copper and smaller aluminum conductors brought up to the current aluminum equivalent. In addition, poles, transformers, other primary equipment, and vegetation will be brought up to DEF's current standards.

Distribution Pole Replacements and Inspections
DEF inspects wood poles on an average eight-year cycle to determine the extent of pole decay and any associated loss of strength. The information gathered from the inspections is used to determine if the pole needs to be replaced or if treatment and reinforcement will extend the life of the pole. DEF completes a loading analysis on poles with joint-use attachments on its system on an average eight-year cycle.

Distribution Feeder Hardening
This program will enable the feeder backbone to better withstand extreme weather events. This includes strengthening or replacing structures, updating basic insulation levels and conductors to current standards, relocating difficult to access facilities, and incorporates the Company's pole inspection and replacement activities. All new structures will meet the National Electric Safety Code (NESC) 250C extreme wind load standard.

Distribution Lateral Hardening
This program will enable branch lines to better withstand extreme weather events. The Lateral Hardening Program includes undergrounding of the laterals that are most prone to damage during

[11] Docket No. 20220050-EI, *In re: Review of Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.*
[12] http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/StormProtectionPlans/2020/2020%20Duke%20Energy%20Florida,%20Inc.%20SPP%20Annual%20Status%20Report.pdf

extreme weather events and are in inaccessible locations, and overhead hardening of those laterals less prone to damage. Laterals will also be relocated to accessible locations, where practical.

Distribution Underground Flood Mitigation

This program will harden existing underground facilities that are prone to storm surge during extreme weather events. This involves the installation of specialized stainless steel equipment, submersible connections, and concrete pads with increased mass.

Distribution Vegetation Management

The program consists of routine maintenance trimming, hazard tree removal, herbicide applications, vine removal, customer requested work, and right-of-way brush mowing where applicable. DEF trims its feeders on an average three-year cycle and trims its laterals on an average five-year cycle.

Transmission Structure and Drone Inspections

The transmission system's inspection activities include all types of structures, line hardware, guying, and anchoring systems. Ground-line inspections determine the extent of pole decay and any associated loss of strength. The transmission wood poles are inspected on a four-year cycle and the transmission non-wooden poles and towers are inspected on a six-year cycle. Drone inspections provide high resolution imagery for structure, hardware and insulation vulnerabilities that otherwise would be difficult to see.

Transmission Pole Replacements

This program's activities are based on the results of the inspections of transmission wood poles. This activity upgrades wood poles to non-wood material such as steel or concrete. Other related hardware upgrades will occur simultaneously, such as insulators, crossarms, switches, and guys.

Transmission Tower Upgrades

This program focuses on the replacement of tower types that failed during extreme weather events as well as lattice towers identified during inspection results and cathodic protection data. It will prioritize towers based on inspection data and enhanced weather modeling.

Transmission Overhead Ground Wire

This program targets lines to improve lightning protection. The program prioritizes the replacement of deteriorated overhead ground wires by targeting lines with frequent lightning events, outage histories, structure design types, overhead ground wire materials, and inspection results.

Transmission GOAB Automation

The Gang Operated Air Break (GOAB) line switch automation project is a 20-year initiative that will upgrade 160 switch locations with modern switches enabled with remote-control capabilities. The GOAB upgrades increase the number of remote-control switches to support faster isolation of trouble spots on the transmission system and more rapid restoration following line faults.

Transmission Cathodic Protection

This program mitigates active ground level corrosion on the steel lattice tower system. The Cathodic Protection program includes the installation of passive cathodic protection systems comprised of anodes on each leg of the lattice towers. The anodes serve as sacrificial assets that corrode in place of the structural steel, preventing loss of structure strength due to corrosion.

Transmission Substation Hardening

The replacement of oil circuit breakers with state-of-the-art breakers will result in the transmission system being able to more effectively and consistently isolate faults, reclose after momentary interruptions, and improve the customer experience through fewer interruptions. The replacement of electro-mechanical relays with electronic relays is designed to provide rapid communication capabilities and microprocessor technology, which enables a quicker recovery from events. Relay upgrades will be matched with breaker replacements.

Transmission Vegetation Management

DEF’s Transmission vegetation management program focuses on ensuring the safe and reliable operation of the transmission system by minimizing vegetation-related interruptions and adequate conductor-to-vegetation clearances. The program consists of planned threat and condition-based work, hazard tree mitigation, and floor management (herbicide, mowing, and hand cutting).

Table 3-1 provides a list of the projects and activities planned and completed for 2021 and the projects and activities planned for 2022. In addition, the table includes a comparison of the estimated and actual costs of the projects and activities for 2021 and the estimated costs for 2022.

Table 3-1
DEF's SPP Projects and Activities Planned and Completed for 2021 - 2022

Program name	Projects/ Activities Planned for 2021	Estimated Cost for 2021 (Millions)	Projects/ Activities Completed in 2021	Actual Cost for 2021 (Millions)	Projects/ Activities Planned for 2022	Estimated Cost for 2022 (Millions)
Dist. Self-Optimizing Grid	741	$ 75.3	378	$ 58.2	715	$ 79.6
Dist. Targeted Underground	204	$ 65.2	344	$ 57.7	157	$ 36.6
Dist. Deteriorated Conductor	17	$ 28.2	31	$ 17.4	21	$ 7.5
Dist. Pole Inspections (poles)	153,573	$ 6.3	121,244	$ 4.9	0	$ 0.0
Dist. Pole Inspections (poles) – Feeder Hardening	0	$ 0.0	0	$ 0.0	31,857	$ 1.5
Dist. Pole Inspections (poles) – Lateral Hardening	0	$ 0.0	0	$ 0.0	90,567	$ 4.2
Dist. Pole Replacements (poles)	3,433	$ 25.1	2,251	$ 19.8	2,651	$ 23.5
Dist. Pole Replacements (poles) – Feeder Hardening	0	$ 0.0	0	$ 0.0	1,826	$14.5
Dist. Pole Replacements (poles) – Lateral Hardening	0	$ 0.0	0	$ 0.0	5,143	$40.7
Dist. Feeder Hardening	17	$ 59.5	17	$ 35.7	42	$ 79.4
Dist. Lateral Hardening - Overhead	0	$ 0.0	0	$ 2.0	28	$64.0
Dist. Lateral Hardening - Underground	0	$ 0.0	0	$ 2.9	25	$99.5
Dist. Underground Flood Mitigation	0	$ 0.0	0	$ 0.0	3	$ 0.8
Dist. Vegetation Management (miles)	4,361	$ 46.5	4,517	$ 44.3	4,227	$ 46.2
Trans. Pole/Tower Inspections/Drone Inspections	13,900	$ 0.5	14,329	$ 0.4	12,747	$ 0.5
Trans. Pole Replacements (poles)	1,495	$ 69.7	1,271	$ 66.0	2,180	$111.5
Trans. Tower Upgrades	3	$ 1.8	1	$ 1.4	2	$ 4.3
Trans. Overhead Ground Wire	2	$ 1.5	7	$ 1.4	4	$ 4.2
Trans. GOAB Automation	0	$ 0.0	0	$ 0.0	2	$ 1.0
Trans. Cathodic Protection	3	$ 1.2	3	$ 2.5	2	$ 0.9
Trans. Substation Hardening	15	$ 5.5	5	$ 5.6	9	$ 7.8
Trans. Vegetation Management (miles)	335	$ 23.0	394	$ 23.5	426	$ 23.0
Totals		**$409.3**		**$343.5**		**$651.2**

Source: DEF's 2021 SPP Annual Report and responses to staff's data requests.

Note: Trans. = Transmission, Dist. = Distribution.

Table 3-2 provides the typical residential customer's bill impact for the implementation of DEF's SPP programs. These values represent the total costs of DEF's SPP activities, some of which are recovered through base rates and others through the SPPCRC.

Table 3-2
DEF's Actual and Projected Bill Impacts (in dollars)

2020* Actual		2021 Estimated		2021 Actual		2022 Estimated	
Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)
$239.3	$2.05	$409.3	$2.65	$343.5	$2.40	$651.2	$3.15

Source: DEF's 2021 SPP Annual Report and responses to staff's data requests.

*Note: The 2020 Actual amounts are from the Company's 2020 SPP Annual Report.

Section 4 - Florida Power & Light/Gulf Power Company

Program Descriptions
Gulf was merged with FPL in 2021, however, the utilities remained separate ratemaking entities. As such, the utilities separately administered their SPP programs and projects during 2021. In 2022, the utilities were consolidated for ratemaking purposes. Below are the programs that FPL and Gulf implemented in 2021. Further details of the programs are in FPL's SPP[13] or in its annual SPP report.[14]

Distribution Inspection Program
This program includes an eight-year pole inspection cycle for all distribution poles. FPL established nine inspection zones to ensure inspection coverage throughout its service area. In addition, joint-use audits are conducted at the same time as the Distribution Inspection Program.

Transmission Inspection Program
This program ensures that transmission wood, steel, and concrete structures are visually inspected on an annual basis. Transmission circuits and substations will be inspected on a six-year cycle. Climbing or bucket truck inspections on wood structures will be on a six-year cycle and climbing or bucket truck inspections on steel and concrete structures will be on a ten-year cycle.

Distribution Feeder Hardening Program
FPL hardens feeder throughout its service area, considering historical reliability performance, restoration difficulties, ongoing/upcoming projects and geographic locations. This includes FPL's initiative of design and construction practices to meet the NESC EWL criteria.

Distribution Lateral Hardening Program
FPL originally started this program as a pilot program in 2018 and has continued the program as part of its SPP. This program targets certain overhead laterals, which were impacted by recent storms and have a history of vegetation-related outages and other reliability issues, for conversion from overhead to underground.

Transmission Hardening Program
This program replaces all wood transmission structures with steel or concrete structures. As of year-end 2019, FPL reported that 96 percent of its transmission system is steel or concrete; therefore, less than 2,900 (4 percent) wood transmission structures need to be replaced. As of year-end 2019, 62 percent of Gulf's transmission structures were steel or concrete with 38 percent (approximately 4,600) wood transmission structures remaining.

Distribution Vegetation Management Program
To maintain current cycles, FPL plans to inspect and maintain, on average, approximately 12,177 miles of feeders and 5,057 miles of laterals, which is consistent with historically recorded miles.

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[13] Docket No. 20220051-EI, *In re: Review of Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Florida Power & Light Company.*
[14] http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/StormProtectionPlans/2020/2020%20Florida%20Power%20and%20Light%20Company%20SPP%20Annual%20Status%20Report.pdf

This program includes a three-year average vegetation maintenance cycle for feeders, mid-cycle targeted vegetation maintenance cycle for certain feeders, six-year average vegetation maintenance cycle for laterals, and continued customer education through FPL's "Right Tree, Right Place" initiative.

Transmission Vegetation Management Program

FPL plans to inspect and maintain, on average, approximately 9,000 miles of its transmission lines annually, which is comparable to the historically maintained miles. This program includes inspecting the rights-of-way of transmission infrastructure, documenting vegetation inspection results and findings, and prescribing and executing a work plan.

Substation Storm Surge/Flood Mitigation Program

The Substation Storm Surge/Flood Mitigation program is a continuing program, first established in FPL's 2020 SPP. Damage to substations that are susceptible to storm surge and flooding during extreme weather events can be prevented and/or mitigated by raising the equipment at certain substations above flood level and constructing flood protection walls around other substations.

Table 4-1 provides a list of the projects and activities planned and completed by FPL and Gulf for 2021 and the projects and activities planned by FPL for 2022. In addition, the table includes a comparison of the estimated and actual costs of the projects and activities for 2021 and the estimated costs for 2022.

Table 4-1
FPL/Gulf's SPP Projects & Activities Planned & Completed for 2021 - 2022

Program Name	Projects/ Activities Planned for 2021	Estimated Cost for 2021 (Millions)	Projects/ Activities Completed in 2021	Actual Cost for 2021 (Millions)	Projects/ Activities Planned for 2022	Estimated Cost for 2022 (Millions)
Dist. Inspection (poles)- FPL	150,000	$ 57.9	151,114	$ 62.3	180,000	$ 60.9
Dist. Inspection (poles)- Gulf	26,000	$ 3.0	27,283	$ 4.6		
Trans. Inspections - FPL	69,000	$ 32.2	69,158	$ 34.4	81,000	$ 32.8
Trans. Inspections - Gulf	2,400	$ 3.6	1,798	$ 2.0		
Dist. Feeder Hardening -FPL	350	$664.9	300	$ 675.2	347	$ 728.2
Dist. Feeder Hardening -Gulf	21	$ 35.9	11	$ 39.4		
Dist. Lateral Hardening -FPL	350	$212.5	440	$ 245.6	630	$ 368.2
Dist. Lateral Hardening -Gulf	8	$ 5.2	1	$ 2.5		
Trans. Hardening - FPL	822	$ 42.9	587	$ 52.9	1,271	$ 81.1
Trans. Hardening - Gulf	384	$ 45.5	278	$ 40.6		
Dist. Vegetation Management (miles)-FPL	15,200	$ 61.3	15,369	$ 62.6	16,690	$ 67.0
Dist. Vegetation Management (miles)-Gulf	2,000	$ 4.7	1,318	$ 5.0		
Trans. Vegetation Management (miles)-FPL	7,000	$ 8.9	7,385	$ 8.7	9,062	$ 11.8
Trans. Vegetation Management (miles)-Gulf	1,675	$ 2.9	1,677	$ 2.2		
Substation Storm Surge/Flood Mitigation	2	$ 10.0	3	$ 7.8	3	$ 10.0
Totals		**$1,191.4**		**$1,245.8**		**$1,360.0**

Source: FPL's 2021 SPP Annual Report and responses to staff's data requests.

Note: Trans. = Transmission, Dist. = Distribution.

Table 4-2 provides the typical residential customer's bill impact for the implementation of FPL and Gulf's SPP programs. These values represent the total costs of FPL's SPP activities, some of which are recovered through base rates and others through the SPPCRC.

Table 4-2
FPL/Gulf's Actual and Projected Bill Impacts (in dollars)

	2020* Actual		2021 Estimated		2021 Actual		2022 Estimated**	
	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)
FPL	$1,037.2	$1.29	$1,090.6	$1.36	$1,149.5	$1.39	$1,360.0	$1.48
Gulf	$36.6	$0.98	$100.8	$1.44	$96.3	$1.38		

Source: FPL's 2021 SPP Annual Report and responses to staff's data requests.

*Note: The 2020 Actual amounts are from the Companies' 2020 SPP Annual Reports.

**Note: Consists of consolidated amounts for FPL and Gulf.

Section 5 - Tampa Electric Company

Program Descriptions

Below are the programs that TECO implemented in its initial 2020-2029 SPP. The first full year of implementation of this SPP was 2021. Further details of the programs are in TECO's SPP[15] or in its annual SPP report.[16]

Distribution Lateral Undergrounding

TECO's Distribution Lateral Undergrounding program is a program that strategically undergrounds existing overhead laterals. The primary factor in prioritizing laterals to be underground is based on reliability performance during extreme weather events.

Vegetation Management

TECO's distribution and transmission vegetation management activities are both addressed in this program. TECO's distribution tree trimming program includes circuit tree trimming activities, mid-cycle trimming activities, customer requested work, and work orders associated with circuit improvement processes. TECO's distribution system is on a four-year cycle and the transmission system is on three-year cycle.

Transmission Asset Upgrades

TECO plans to replace its remaining transmission wood poles with non-wood material by the end of its initial 2020-2029 SPP. This is a continuation of TECO's existing storm hardening pole replacement program, which includes replacing poles based on preventative, corrective or project-driven assessments.

Substation Extreme Weather Hardening

Hardening existing substations to minimize outages, reduce restoration times and enhance emergency response during extreme weather events is a new program included in TECO's SPP. No projects were planned or completed for 2021 under this program as TECO finished its studies on the substations. Nine substations are recommended for hardening; however, the projects are projected to start in 2023.

Distribution Overhead Feeder Hardening

TECO's distribution system will be hardened to withstand increased wind-loading and harsh environmental conditions associated with extreme weather events by increasing the resiliency and sectionalizing capabilities of the system.

Transmission Access Enhancements

In order to have continuous access to its transmission facilities for restoration, TECO implemented this program in its SPP to maintain the access roads and bridges leading to its facilities. TECO did not plan or complete any projects in 2021 as the Utility continued to focus on the program's

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[15] Docket No. 20220048-EI, *In re: Review of Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company.*

[16] http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/StormProtectionPlans/2020/2020%20Tampa%20Electric%20Company%20SPP%20Annual%20Status%20Report.pdf

specifications, contracts, and plans. However, the utility plans to complete 25 road projects and 19 bridge projects during the 2020-2029 time frame.

Infrastructure Inspections

TECO's distribution wood pole inspections and transmission structure inspections, and the joint use pole attachment audit are combined into one program. The distribution wood pole inspections are on an eight-year cycle program consisting of visual inspections, sound and bore inspections, and excavations at least 18 inches below ground line. The transmission structure inspections include a range of inspections from ground to aerial infrared patrols with a range of cycles from annual to eight years. The joint use pole attachment audit is a comprehensive loading analysis to ensure TECO's poles with joint use attachments are not overloaded and meet the NESC standards. This audit will be performed every four to five years.

Table 5-1 provides a list of the projects and activities planned and completed for 2021 and the projects and activities planned for 2022. In addition, the table includes a comparison of the estimated and actual costs of the projects and activities for 2021 and the estimated costs for 2022.

Table 5-1
TECO's SPP Projects and Activities Planned and Completed for 2021 - 2022

Program name**	Projects/ Activities Planned for 2021	Estimated Cost for 2021 (Millions)	Projects/ Activities Completed in 2021	Actual Cost for 2021 (Millions)	Projects/ Activities Planned for 2022	Estimated Cost for 2022 (Millions)
Dist. Lateral Undergrounding	520	$ 79.5	169	$ 53.7	698	$108.1
Dist. Vegetation Management (miles)	2,317	$ 19.8	2,348	$ 19.4	2,448	$ 21.2
Trans. Vegetation Management (miles)	523	$ 3.5	523	$ 3.0	557	$ 3.6
Trans. Asset Upgrades (poles)	577	$ 15.5	637	$ 18.5	474	$ 15.3
Substation Extreme Weather Hardening*	0	$ 0.3	Hi0	$ 0.1	0	$ 0.0
Dist. Overhead Feeder Hardening	1,291	$ 15.8	1,222	$ 17.4	47	$ 30.0
Trans. Access Enhancements	18	$ 1.4	0	$ 0.7	26	$ 1.5
Dist. Infrastructure Inspections (pole and structures)	19,650	$ 1.0	19,861	$ 0.6	35,625	$ 1.0
Trans. Infrastructure Inspections (poles and structures)	4,110	$ 0.5	4,170	$ 0.5	4,049	$ 0.5
SPP Planning & Common	N/A	$ 0.4	N/A	$ 1.2	N/A	$ 0.2
Totals		**$137.7**		**$115.1**		**$181.4**

Source: TECO's 2021 SPP Annual Report and responses to staff's data requests.

*Note: TECO performed a study to evaluate hardening options for 24 existing transmission and distribution substations. The projects are projected to begin 2023 and estimates are given for engineering, permitting, project management, testing, and commissioning.

**Note: This table represents the programs and costs that TECO is requesting cost recovery through the SPPCRC.

Note: Trans. = Transmission, Dist. = Distribution.

Table 5-2 provides the typical residential customer's bill impact for the implementation of TECO's SPP programs. These values represent the total costs of TECO's SPP activities, some of which are recovered through base rates and others through the SPPCRC.

Table 5-2
TECO's Actual and Projected Bill Impacts (in dollars)

2020* Actual		2021 Estimated		2021 Actual		2022 Estimated	
Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)	Total Costs (Millions)	Residential Bill Impact ($/1,000 kWh)
$36.9	$1.03	$142.9	$1.90	$115.1	$2.09	$186.1	$3.26

Source: TECO's 2021 SPP Annual Report and responses to staff's data requests.

*Note: The 2020 Actual amounts are from the Company's 2020 SPP Annual Reports.

Attachment 3

E Source

Why Every Utility Should Be Offering Prepay Energy

Florida Public Service Commission

Presentation by Jamie Wimberly
Senior Vice President, E Source

Why Prepay, Why Now?

The utility sector faces a growing debt crisis.

Prepay has proven to be an extremely effective tool to help customers stay current on their bills, save money by saving energy, pay down any debt *and remain highly satisfied.*

For this reason, we expect 2023 to be a banner year for expanding existing prepay programs and implementing new ones.

And by the way, consumer interest in prepay energy, regardless of income, is at an all-time high. Younger customers in particular love prepay energy.

Prepay Energy Working Group Overview

In 2022, DEFG's Prepay Energy Working Group (PEWG) will mark its 13th year as the industry's leading forum for the exploration of prepaid energy service offerings and other enhanced transactions enabled by smart grid.

The PEWG continues to grow because its members value the extensive and actionable research agenda and the record of accomplishments.

- Participants include energy utilities and suppliers, metering and software vendors, and other public stakeholders. Together they cover a broad spectrum of perspectives and experiences
- The PEWG conducts research across *7 tracks*:
  1. **Regulatory Issues**
  2. **Consumer / Market Research**
  3. **Energy Conservation Impact Assessment**
  4. **Business / Operational Applications**
  5. **PEWG Creative and Communications**
  6. **Enhanced Transaction Research**
  7. **Payment Arrangements and Customer Arrearages**

- Prepaid energy service is a catalyst for a discussion about the need for innovative and “smart” consumer offerings and the need to bring the rulebook into the 21st century

Baltimore Gas & Electric
Summary of Program Results

Total Addressable Market
47% of customers income >4X poverty level and only 44% had arrearages before entering program

Control
78% of currently enrolled customers report improved control.

Customer Satisfaction
96% of currently enrolled customers somewhat or very satisfied with the program.

Debt Management
78% reported program helped them pay off arrearages; average balances declined $159 to $196 based on use of gas or electric heat

Energy Efficiency
Customers reduced their energy usage by 2.6% to 4%, based on use of gas or electric heat.

Service Disconnection
68% of customers with arrearages report the program helped them avoid or reduce the length of disconnection

Customer Savings
Customers saved between $106 and $120 based on use of gas or electric heat.

Payment Arrangements
Customers entering into payment arrangements declined from 24% the year before the program to 3% after joining

Who Is Adopting Prepay Energy?

Prepay energy requires a segmented view of the utility customer base.
As such, prepay is not for everyone.

The customer segments that are most likely to enroll in prepay energy are:

1) **Wealthy customers** using prepay to manage remote assets, e.g., rental property, or people, e.g., kids at school

2) **Millennials** looking for a payment option that allows for “pay as you go” and is aligned with mobile payments

3) **Credit-challenged customers** who adopt prepay energy as an alternative to cash security deposits

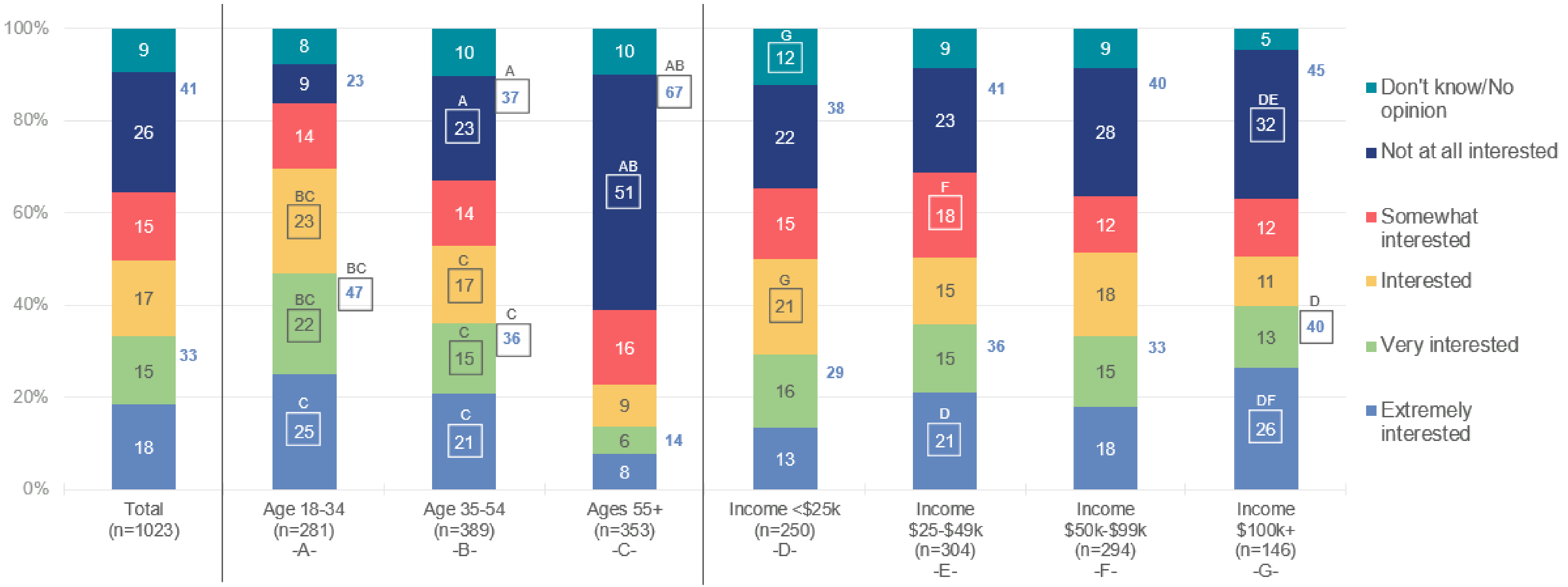
4) **Immigrants** who have come from unbanked or underbanked countries who are very used to prepay

5) **Customers with debt** who are looking for an alternative to allow for a small portion of payments to go towards debt while keeping the lights on

Why Are Customers Adopting Prepay?

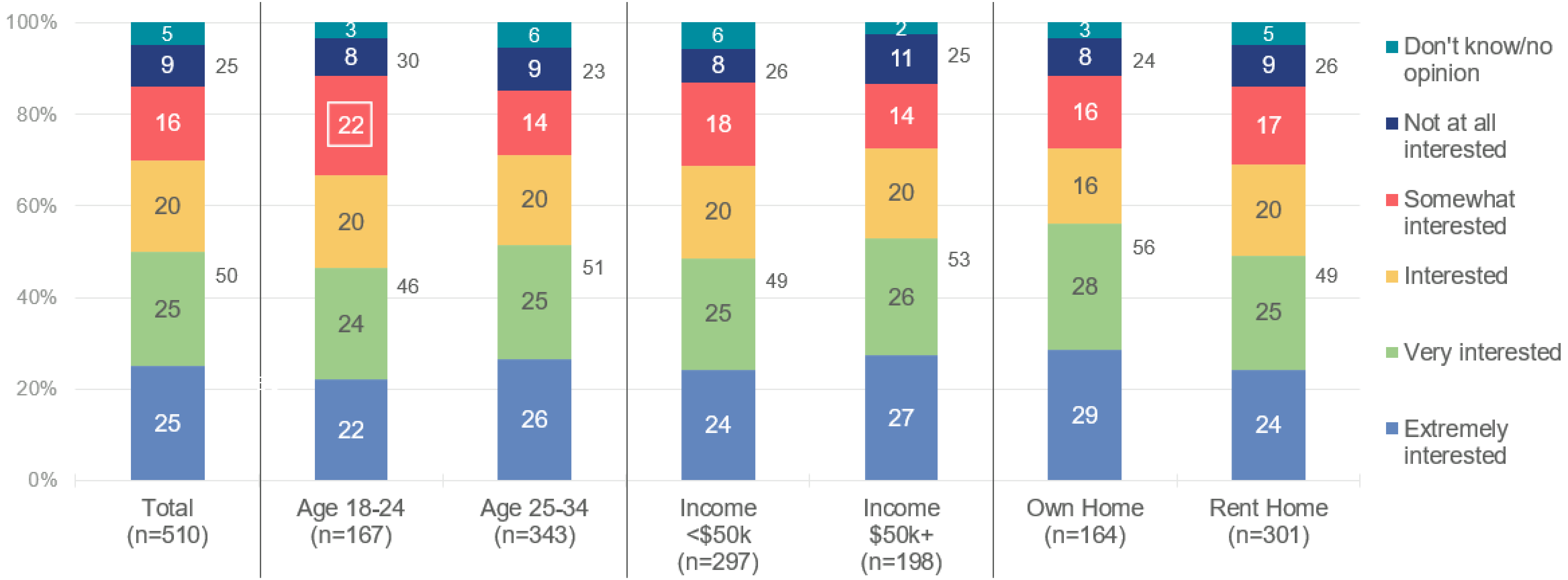
In addition to specific needs and applications aligned with segments, **convenience** and **control** are major customer drivers.

Customer Interest in Prepay Energy at All-Time High



Base: Total Respondents. Q.9. A growing number of local utilities (electric and gas) or service providers are offering voluntary prepaid energy service to consumers. Under this option, you would choose to pay upfront anytime you wanted before you used the energy rather than paying your bill at the end of the month after you used the service. Reasons for possibly using prepaid energy would include to help manage your utility bill or avoiding unexpected high bills. You would always be able to check the balance remaining in your prepaid account. If your local utility or provider were to offer a voluntary prepaid option for consumers, how interested would you be?

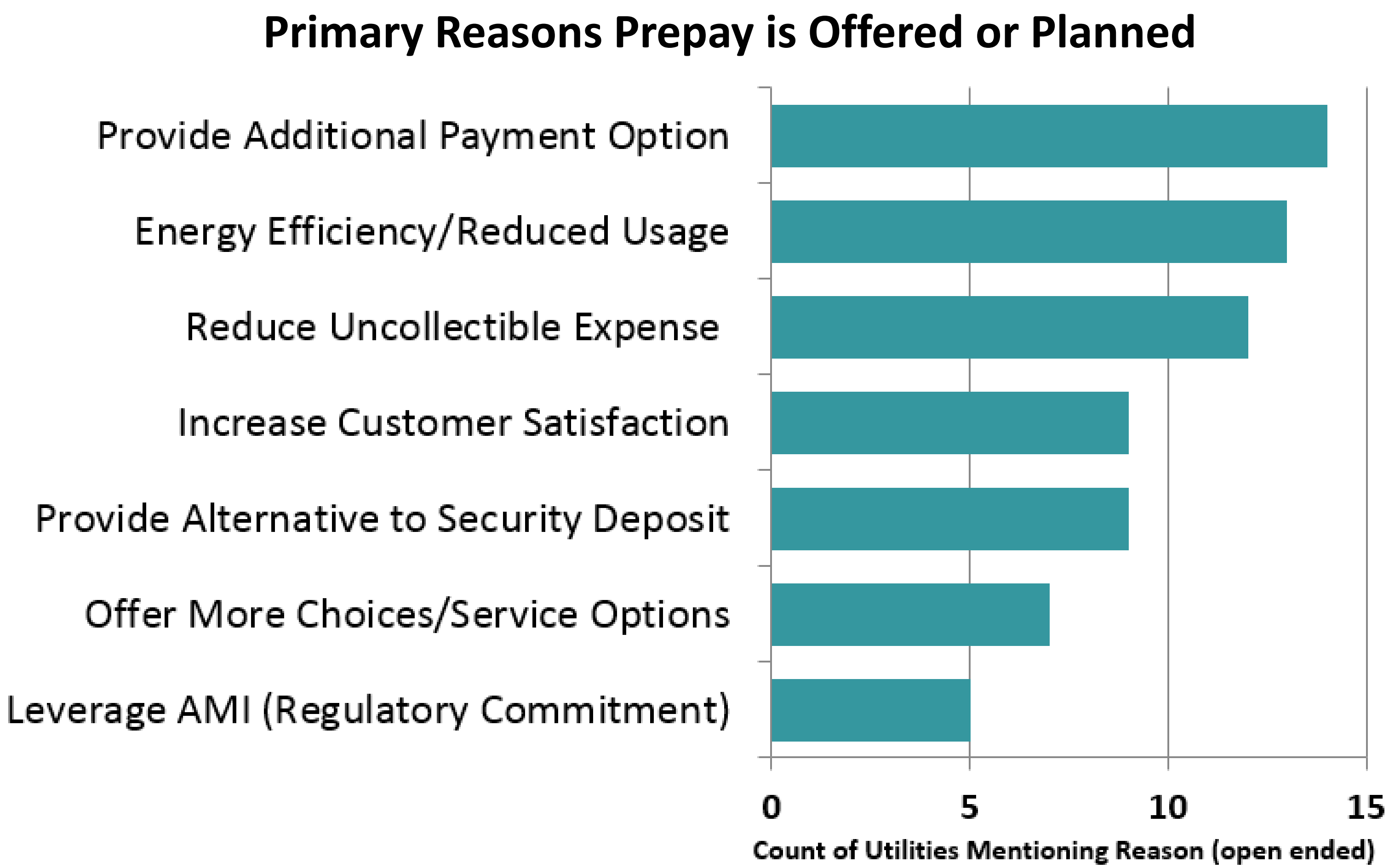
Half of People Ages 18 to 34 Are Very or Extremely Interest in Voluntary Prepaid Energy Service



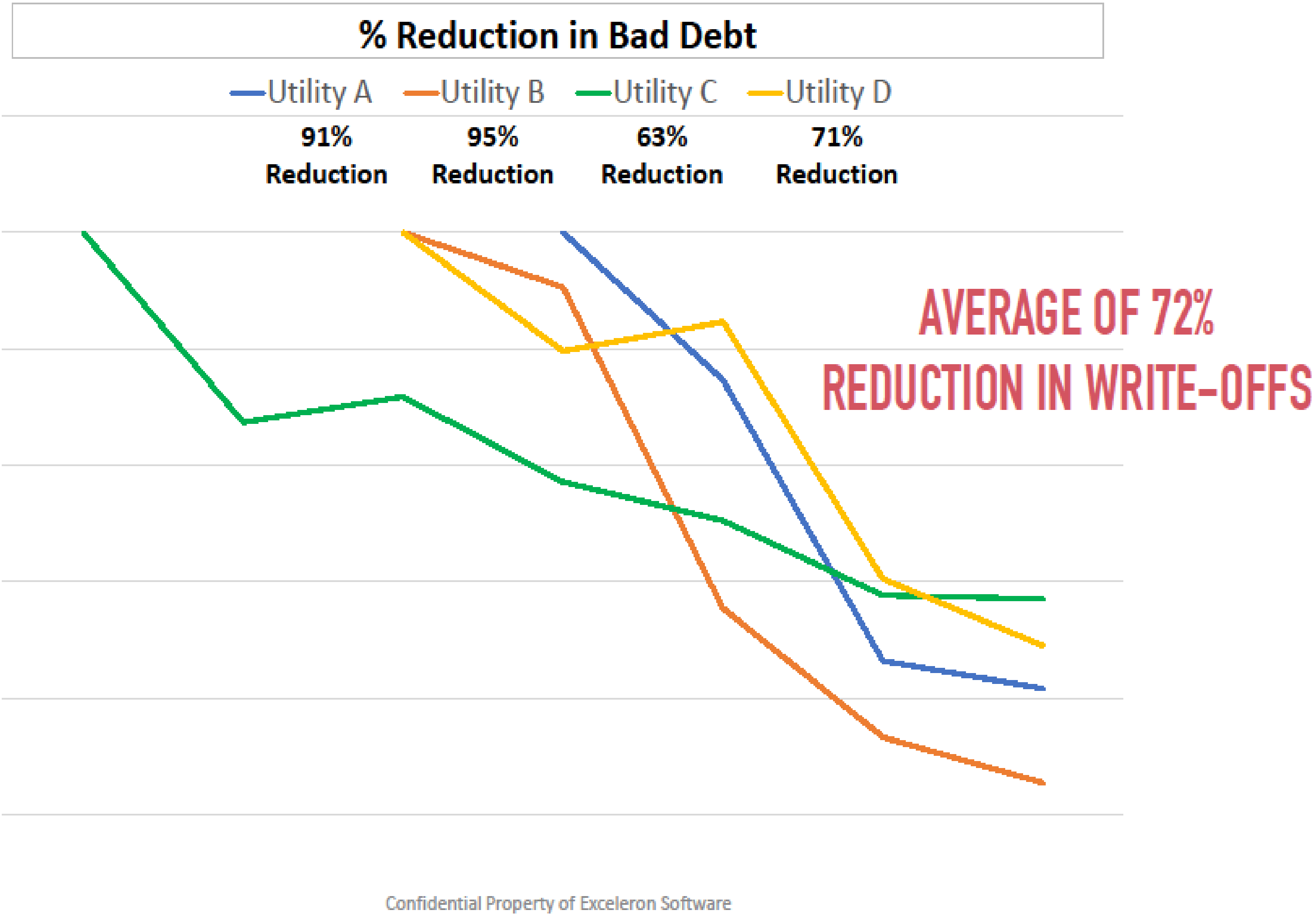
Base: Total Respondents. F6. A growing number of local electric utilities or service providers are offering voluntary prepaid energy service to consumers. Under this option, you would choose to pay upfront anytime you wanted before you used the energy rather than paying your bill at the end of the month after you used the service. Reasons for possibly using prepaid energy would include to help manage your utility bill or managing property that you may own or understanding roommate electric usage. You would always be able to check the balance remaining in your prepaid account. If your local utility or provider were to offer a voluntary prepaid option for consumers, how interested would you be?

Primary Reasons for Utility to Offer Prepay

Prepay addresses many business objectives (hybrid business case)

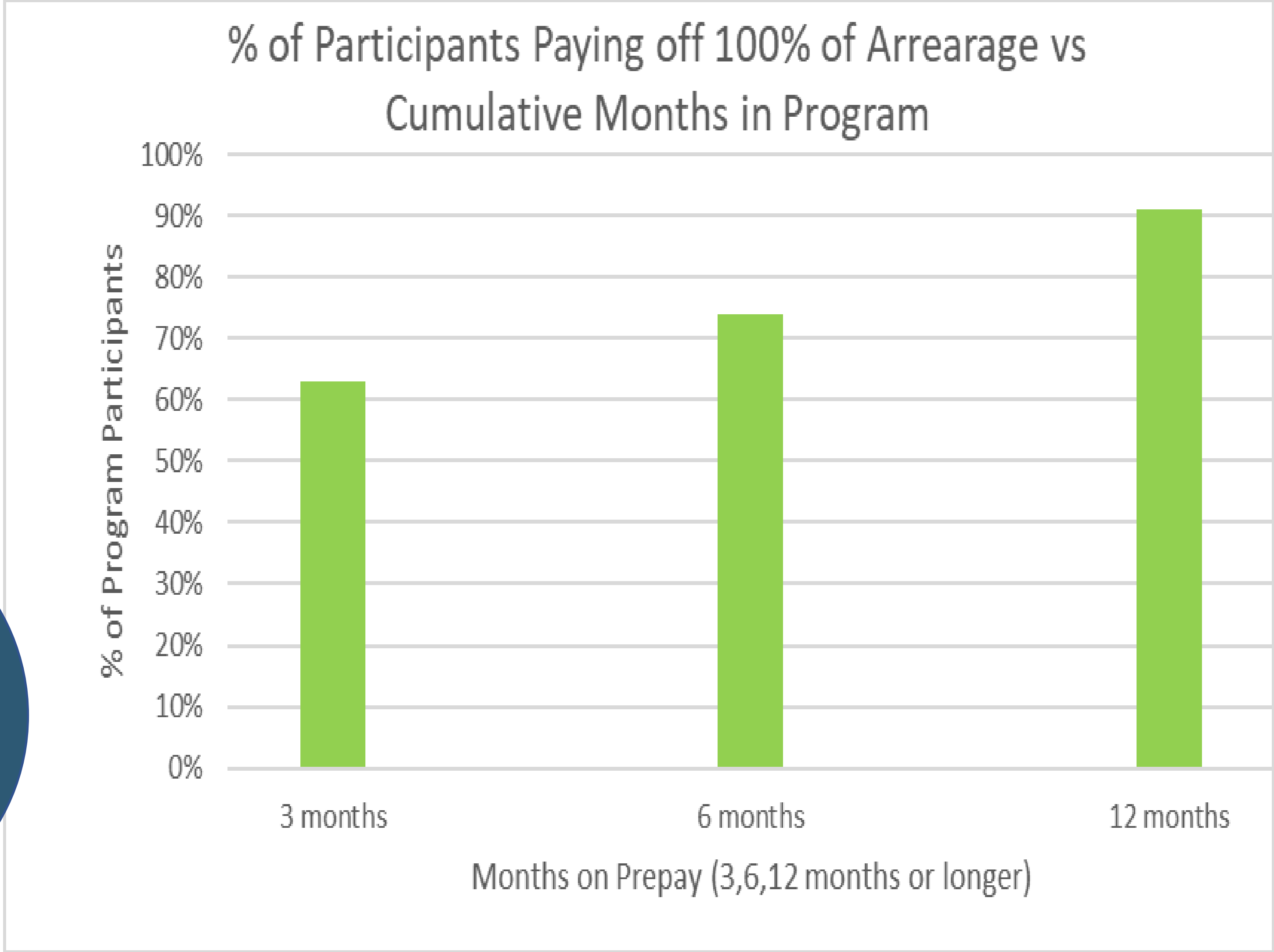


Prepay a Proven Solution to Reduce Write-Offs



Example from Exceleron, a prepay vendor

Prepay Leads to High Percent Paying Off Arrears



Example from PayGo, a prepay vendor

Contact:

Jamie Wimberly
SVP, Customer Strategy
Jamie_Wimberly@esource.com

III. Supplemental Materials for Internal Affairs

Note: The records reflect that there were no supplemental materials provided to the Commission during this Internal Affairs meeting.

IV. Transcript

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

PROCEEDINGS: INTERNAL AFFAIRS

COMMISSIONERS PARTICIPATING:
CHAIRMAN ANDREW GILES FAY
COMMISSIONER ART GRAHAM
COMMISSIONER GARY R. CLARK
COMMISSIONER MIKE LA ROSA
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Tuesday, October 25, 2022

TIME: Commenced: 9:30 a.m.
Concluded: 10:47 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter and
Notary Public in and for
the State of Florida at Large

PREMIER REPORTING
112 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
(850) 894-0828

P R O C E E D I N G S

CHAIRMAN FAY: All right. We will start this morning with our Employee of the Month, and as some you have, we used to have offices down in Miami and in Tampa, and so we wanted to recognize somebody from our Miami office even as we transition to a different structure.

So for this month, we are recognizing Gabriela Leon, she goes by Gabby. Gabby joined our Bureau of Auditing in 1987 as a staff auditor in the Miami district. She has worked on a wide array of audits during her tenure at the Commission. However, it isn't Gabby's tenure that makes her so exceptional, it's the quality of work that she provides. Gabby's dedication to her audits, attention to detail play a significant role in both our timely release of professional quality of the Commission's audit reports.

And I had the pleasure in speaking with Gabby just to ask her if things are very similar now as they were in 1987 when she started at the Commission, and they are slightly different in both Miami and our Commission operation.

So with that, we will just give Gabby a round of applause and recognize her for this month.

(Applause from the audience.)

CHAIRMAN FAY: All right. And next, Commissioners, we will move on to our draft review of the 2022 10-year site plans for Florida Electric Utilities.

With that, we will recognize our staff.

MR. PHILLIPS: Good morning, Commissioners. Donald Phillips with Commission staff.

Item No. 1 is the Draft Review of the 2022 10-Year Site Plans of Florida Electric Utilities. This year's review is in the same format and contains similar content as last year's review. Staff reviewed each of the utility's site plans and the state as a whole.

Overall, natural gas continues to provide the majority of net energy for load with its contribution forecasted to decrease from 69 percent in 2021 to 65 percent by 2031. Coal is forecasted to decrease from nine percent in 2021 to only two percent in 2031.

These declines are offset by an increase in renewables. Primarily solar, which will increase from five percent of the state's net energy for load in 2021 to 18 percent in 2031. The state is projected to add approximately 20,000 megawatts of net generation with renewable generation, all solar PV, making up approximately 16,000 megawatts.

At this time, staff seeks the Commission's approval of the draft review of the 2022 10-year site plans which would find each utility's plan suitable for planning purposes. If the Commission approves the draft as suitable, the review and any comments received will be provided to the Department of Environmental Protection for consideration in future need determination proceedings, and the Department of Agriculture and Consumer Services regarding fuel and load forecasts.

Staff also seeks administrative authority to make minor edits if needed.

Staff is available for any questions.

CHAIRMAN FAY: Great. Thank you, Mr. Phillips.

Commissioners, I will start if we've got any questions for our staff, and if no questions, any comments on the report before we take up a motion for suitable or unsuitable.

Commissioner Clark, you are recognized.

COMMISSIONER CLARK: I would -- excuse me. I would make just one very brief comment. I want to just continue to wave the flag for my concern about fuel diversity. I realize we are taking a reduction in the plan forecast.

And I want to thank the staff and utilities for the work that they did in putting the report together. Staff, thank you for the outstanding culmination of all of the reports together in one very well done. I appreciate the effort that's put in. But I just want to continue to raise that fuel diversity issue.

We continue to -- we are seeing a little bit of reduction in the natural gas usage for fuel production -- or for energy production over the 10-year forecast, but we are just shifting from one fuel source moving into another, and continuing to load that one up as well.

We need to be -- continue to seek diversity. Just to raise the flag that as we continue to see this type of fuel use for energy production, we are going to continue to see the volatility in pricing that we've seen over the last number of years, and also in the security concerns that I have over our natural gas supply system.

So I just wanted to continue to raise that flag, Mr. Chairman. I don't want it to be said that we are not at least thinking about and considering these as we look at the plans going in the future. But with that said, I certainly see, for planning purposes, the forecast to be suitable for planning purposes, Mr. Chairman.

CHAIRMAN FAY: Okay. Great. Thank you. And valid point on the diversity, Commissioner Clark.

With that, we have a motion for suitable. Do we have a second?

COMMISSIONER GRAHAM: Second.

CHAIRMAN FAY: We have a motion and a second finding these plans suitable.

Any opposed?

(None opposed.)

CHAIRMAN FAY: None opposed. With that, we accept the 10-year site plans as suitable.

Thank you, Mr. Phillips.

Commissioners, next we will move to the draft report on the status of utility storm protection activities. Give our staff a minute to go ahead and present.

You are recognized, Ms. Buys.

MS. BUYS: Good morning. I am Penelope Buys with the Division of Engineering.

Item No. 2 is the draft annual report on the storm protection activities of the Florida investor-owned utilities.

In 2019, the Florida Legislature passed Senate Bill 796 to enact Section 366.96 of the Florida Statutes, entitled the Storm Protection Plan Cost Recovery. Pursuant to subsection (10) of to the statute, the Commission is required by December 1st each year to submit to the Governor, the President of the Senate and the Speaker of the House of Representatives an annual status report of the IOU storm protection activities.

Rule 25-6.030(4), Florida Administrative Code, requires that each utility submit an annual status report that identifies all storm protection plan programs and projects completed in the prior calendars year or planned for completions actual costs and rate impact compared to the estimated costs and rate impact for those activities, and the estimated costs and rate impacts associated with the program's plan for completion during the next calendar year. The IOUs submitted their status report to the Commission on June 1st, 2022.

Staff notes that the Commission is not drawing any conclusions or making any findings in this report. Any findings about current or future storm protection program cost recovery will be considered as part of a docketed proceeding or subsequent Commission order.

Staff is seeking your approval on the report, as well as administrative authority to make minor edits if needed.

Staff is available for questions. Thank you.

CHAIRMAN FAY: Great. Thank you, Ms. Buys.

With that, Commissioners, we will take any questions for our staff.

Commissioner La Rosa, you are recognized.

COMMISSIONER LA ROSA: Great. Thank you, Chairman.

This is obviously to staff. If what we approved back in earlier this month, in October, if that was added to this report, how different would this report look as far as for planning purposes?

MS. BUYS: This report is for the years 2021 and 2022. So what we approved was before that. I think maybe two companies would have a different projection for the 2022, but the -- but two other ones were for the 2023.

COMMISSIONER LA ROSA: Okay. Thank you.

So the reason I am asking the question is being in the Legislature before, looking at what's coming before you, this report lands on their desk, I am saying maybe my concern is, is that that's not taken into consideration as far as what we just approved as this coming legislative session is before us.

Knowing that a hurricane has -- a major hurricane has just hit us, I would expect that that would be top of conversation, and I think I would like to see either an updated summary or something that could include what we've just passed into a report like this, and maybe it doesn't necessarily have to happen in this draft, because I know there are time deadlines, but maybe before session starts that, if any member of the Legislature does pick this up is reminded, and there is at least a summary or a lead of what we've just done so they are not kind of working off old information.

CHAIRMAN FAY: Great. We will -- Tom, you want to add something to that?

MR. BALLINGER: Well, I want to make sure -- I think I understand.

This report is more of a historic what has happened, and, yes, a look-forward for the next year. What you just approved back in October is a plan for 10-year going forward. I don't know that the two necessarily go together. But I understand it what you are wanting to say to the Legislature.

Maybe it would be more appropriate that when the orders come out for what you just approved to the plans, the Legislature is notified of those, that this is what's going forward.

COMMISSIONER LA ROSA: Correct. That seems like that's something kind of in between. And my idea is for them not to pick up this report come February -- of course, what we just passed has, you know, gone through the process and, you know, becomes official at that time. I know it's not today -- and then they are looking at the most updated information as far as what the PSC is doing and what we've approved.

MR. BALLINGER: Right. And that's -- there are two different ones. This is more of a historic look-back of what has accomplished and what the rate impacts are. That's what this summary report is. And as Penny said, this is not any decision that you are making going forward. This is simply a summary reporting of activities that utilities are doing. What you just approved, the plans going forward, is an action by the Commission of what you approved. And that's an order for the next 10 years going forward.

So it's -- I am -- I am -- I understand where you are wanting to make a clear message to the Legislature. I am not quite sure how to do it, or to attach it to this report. This is an Internal Affairs, not a decision-making. And then you -- you are going to a more formal proceeding with the plans. So I am struggling a little with -- I understand what you want to do --

COMMISSIONER LA ROSA: And I know I am just kind of throwing this out of the blue. I guess what I am looking for is some type of summary before the legislative session starts. And it's not necessarily attached -- doesn't have to be attached to this report, understanding that there are deadlines to it and it does have to fall on their desk, according to statute, by a certain time, but something beforehand so that there is kind of a clear understanding of what we've done so that as this report is picked up, there is a follow-up to it that we could ultimately point to.

CHAIRMAN FAY: Yeah. And I agree with you, Commissioner La Rosa. I mean, I think it's relevant to what hits their desk and what data is up to date as far as what they are saying.

Mr. Baez, do you have any thoughts on how we could to present?

MR. BAEZ: I merely wanted to mention, not a solution at this time, but I just wanted to mention to the Commission that, internally, the staff has recognized that there is a disconnect between the freshness of the report that's required and the information, the most up-to-date information as that takes place later in the year.

And part of the postmortem, after all of this is said and done going forward, is to figure out the best way to address that disconnect. Clearly, timing is going to get discussed, or what the contents -- this is an evolving process. I know you all appreciate that. Our second time out, and really our only first that was truly, you know, litigated, if you will. So we are still filling in blanks and addressing bugs for it, of which that is one and probably the most prominent.

So we did -- we do have that in mind. How we wind up addressing it, or suggesting for the Commission to address it, I can't really say at the moment, but it is top of our list. So thanks for pointing it out. I think we have good direction, and knowing that you guys are worried about it as well gives us comfort.

CHAIRMAN FAY: Yeah, and I think for just, Mr. Baez, for the benefit of the Commission, maybe, I know we have the plan side, the cost component. As Commissioner La Rosa mentioned, we will have the final orders come out at some point. Assuming those orders come out, and there is no sort of further litigation involved in those, we would be able to provide those to these various parties?

MR. BAEZ: We will make sure -- we will make sure that the order is, once they are finalized and, again, assuming that, as you mentioned, that they aren't -- that there is no continuation process to them, we will make sure that they get transmitted to the substantive committees in the Legislature at a minimum, and any -- anyone else that you might suggest certainly to the leadership on down the line as you might like, we will make sure that the report is supplemented --

CHAIRMAN FAY: Okay.

MR. BAEZ: -- with the orders.

CHAIRMAN FAY: Perfect. Does that work, Commissioner La Rosa?

COMMISSIONER LA ROSA: It does. And, you know, the order in the way it's formatted is going to say a lot -- and I know this wasn't what you were indicating -- is a very judicial type document, right? So if that landed on my desk, I would probably read through a few pages and say, wow, this is pretty technical.

When I am reading through a summary -- and the reason I said -- I said planning, is as they plan for the legislative session, as I read through a summary, I start to see, oh, wow, these are the highlights, right? You know, these are the points that have been changed. These are the things they are going to be doing. These are the projected projects. So something of that nature, that gives a better scope and understanding that you don't have to do a super deep dive and have a legal background to understand.

MR. BAEZ: We would be happy to work with your office to come you with, say, a document that summarizes it in the way that someone that -- I know you have -- you are more in touch with those feelings, if you will --

COMMISSIONER LA ROSA: Yeah, I am pretty layman.

MR. BAEZ: -- we would be happy to work -- happy to work with your office to get a document that kind of summarizes that on.

COMMISSIONER LA ROSA: Okay. Thank you.

MR. BAEZ: Thank you, Commissioner.

CHAIRMAN FAY: Great. Yep. Thank you, Mr. Baez.

Commissioner Clark.

COMMISSIONER CLARK: I had a full page of notes that said basically the same thing Commissioner La Rosa said, so I am going to forego going back through it. I agree 100 percent. I think it's a very valid point.

My conclusion was that I wanted to ask staff here today to bring us back a recommendation on how we could improve the timing of this report and include the necessary information.

Looking back at the statute, the initial report was due December 1, and I believe it said, and then annually thereafter. If it's a simple statutory change that we need to say, okay, let's produce this report in January instead of December, based on the information, the timing of the Storm Protection Plan, I think that might solve part of our problem. It's just we could actually -- and have this report submitted in December. We can turn right around in January and do a look-forward report that may solve some of the same issues.

I felt the same way. There is nothing that we approved a couple of weeks ago that's really taken into consideration here that someone could look at and say, okay, here's where our Storm Protection Plan dollars are going.

MR. BAEZ: Part of the -- part the language of the statute, as I am reading it, gives us a little bit of wiggle room in terms of addressing -- addressing the timing on our -- on our own -- on our own clock. I don't know that we might even need a statutory modification. But again, I think we are trying to pair up all of the interests and all the target dates to find where the sweet spot is, but that's certainly on our mind.

MR. BALLINGER: And if I may add, we may not get in this problem the next time because we are thinking and contemplating moving the Storm Protection Plan hearings earlier, because we found we are also bumping up against the Cost Recovery Clause, so we've got some internal scheduling. So hopefully the next time around, the plans will be approved well in advance of this report coming, and we can do it. So, yeah, we are learning as we are going.

CHAIRMAN FAY: Great. Thank you, Mr. Ballinger and Mr. Baez. In addition to the updates this year, there will be some consideration as to the future how we line up the timing of these, so then maybe we can satisfy the point that Commissioner Clark made.

Commissioner Clark, do you have any other follow-up or you're good?

COMMISSIONER CLARK: No.

CHAIRMAN FAY: All right. With that, Commissioners, we will submit this report for publication, so we don't need a formal motion on it, but so seeing no objections for publication of the report, see that satisfied. Thank you, Ms. Buys. Appreciate it.

All right. With that, next we will move into our IA presentation, which includes prepaid utility services. We have Jamie Wimberly, Senior Vice-President at E Source, Sheila Pressley, the Chief Customer Officer at JEA, and Emily Cowan, the VP of Member Services and External Affairs at CHELCO. I pronounce that CHELCO, Commissioner Clark, is that right?

Okay. So with that, what I would like to do -- Commissioner Clark, I know this has been an issue of yours. I think since you have been on the Commission you have mentioned this a few times. So with that, I would like to give you some deference this morning to go ahead and provide some context maybe to our presenters, or any other introductions you would like to provide for the Commission.

COMMISSIONER CLARK: Thank you, Mr. Chairman.

Yes. This is -- this program has been something that's very near and dear to me. I personally, firsthand, worked on prepaid energy about 15 years ago helping to launch a new program at the utility I worked with at the time. We saw tremendous success with the program in helping our customers be able to manage their energy consumption; to be able to budget for their energy expenditures, and basically to be able to take control of their own budgeting process. And the success that came out of that also had tremendous benefits to the utility as well, being able to help manage bad debt.

Bad debt is something that is spread not just to the people that leave the debt, but to every customer that pays a bill to that utility. And so the more of that that we can eliminate, the lower the price is going to be for the utility services that are provided.

So prepaid energy is one way of achieving several of the goals that I have, that I like to see for utility customers. And we've asked a couple of companies today to talk about the programs that they have implemented, and specifically to share some of the successes that they have seen with the programs. And I am very appreciative for all of our partners here today that are going to be making this presentation, especially Mr. Wimberly, who represents a bigger picture provider of prepaid services. And they recently were planning to hold a prepaid conference in Tampa a couple of weeks ago that a storm interrupted. We were looking forward to being a part of that program as well, but I appreciate the opportunity for being able to have this presentation today, Mr. Chairman, and look forward to hearing what our presenters have to say.

CHAIRMAN FAY: Great. And thank you for bringing it forward.

Mr. Wimberly, we've got your presentation up here. Make sure we can -- we can hear you all right. Feel free to provide an introduction of your background and then begin your presentation.

MR. WIMBERLY: Thank you, Commissioners. Good morning.

Yeah, a little bit of feedback, but we will get through it.

So my name is Jamie Wimberly. I am the Senior VP for E Source. I have been in this space for 25 plus years, and many of those years as an executive.

As Commissioner Clark said -- if we can go to the next slide, please -- we have been running the prepaid energy working group for almost 15 years, but it still seems new. And I think, as Commissioner Clark said, I think it's an important voluntary option for you to consider in Florida, not the least of which because your customers are looking for options to manage bills and also debt.

And so, again, as we are going to see, prepay offers an opportunity to not only pay down and stay current, but also to get out of any debt. And I think the proof in the pudding is that the fact that they are very satisfied with this option.

So we expect this year to be a big year nationally for both the expansion of prepaid programs, but also a number of utilities kicking off a new option around prepay.

If we can go to the next slide, please.

So the prepaid energy working group pretty much brings together every large utility across the country that has a prepaid program. As I said, we are actually going into 2023, our 14th year. I think we continue to grow, again, because the successes that are occurring in the marketplace with customer adoption and satisfaction around prepay.

There is a number of different issues that we consider around regulatory. We look at consumer market research. There is a big energy conservation impact, business, and so on. So a very good group, a very active group.

If we can go to the next one.

This just gives you a taste of some of the benefits that Commissioner Clark was talking about. So this is a Baltimore Gas & Electric. We had a pilot in Maryland. This is part of a commission report.

As you will note, it just mirrors some of the things that I said. So they had 96 of their customers with, you know, somewhat are very satisfied with the program. It, again, produced energy efficiency, or energy conservation impacts.

There was customer savings between $106 and $120 based on use of gas or electric heat. You know, again, it's very much around control and convenience.

And one of the things that you will see at the bottom here, around payment arrangements, the nice thing about prepay is that it offers your customers an opportunity to forego a security deposit and/or if they are in debt, you know, an alternative to a payment arrangement.

As we all know, payment arrangements in this space default at very high rates, which means basically that that utility is extending credit into the future. And if that customer cannot pay, that means that that debt is getting bigger and bigger. So this is an alternative to that that, again, customers like.

So if we can go to the next one.

So prepaid is not for everybody. It's a very segmented offering. And it's a little bit counterintuitive, because most people think of prepaid as something around low-income or credit challenged. And it certainly is that in the sense that it helps low-income customers manage their bills, stay out of debt. It gives them alternatives to cash deposits, and so on.

But actually, our research shows that wealthy customers, so those customers that may have rental property, Airbnb, vacation homes, kids in college, they really appreciate the opportunity to manage their bills and energy consumption remotely.

Millennials are very much part of this generation that likes to pay as they go. They like to have mobile payment options. They like daily bills rather than, you know, getting a 30-day bill and so on.

And then, again, you have, in Florida, obviously, a big immigrant population. I can almost guarantee that regardless of income, if they come from countries that they were under banked or unbanked, they are very, very comfortable and familiar with prepay. And most of them are using prepay here anyways in terms of prepaid telephone and other things.

So if we can go to the next slide, please.

So as I said before, I mean, customers really love this option, mainly because it's convenient for them. And again, that convenient means a lot of different things, as we just went over the segment. Each one of those has a different reason for why they like prepay, but generally speaking, it's convenient.

So if we can go to the next slide, please.

You know, as I said before, we have been at this for a long time. We have been tracking -- every year we do an annual customer survey. And what's interesting is that the interest in prepaid energy as a voluntary option just continues to grow. And there is a lot of boxes here and colors, but basically what you are seeing here is one-third of customers that we surveyed have -- are either extremely interested or very interested. Really what that means is that that's an addressable market. That means one-third without too much marketing or education would at least consider a prepay option.

As I said before, it's not for every customer. But for those customers that are looking for some the things that I talked about in terms of value benefit, you know, they are very much looking for this.

And what's interesting about, again, looking at prepay and the fact that it's segmented, you can see here just comparing younger customers, so 18 to 34-year-olds, compared to older customers, I mean, it's a huge gap. So 47 percent of younger customers said they would be really interested in a prepay offering, and only 14 percent of older customers basically said that they would be interested in prepay.

And you know what, that's okay. Again, I think we need to figure out a service model that accommodates preferences, especially around the generational gap that we are seeing, and prepay is one of those ways to fill that gap.

If we can go to the next slide, please.

And as I just said here, I mean, this is just basically making the point that I just made. But, you know, again, prepay is not just for low-income, but actually it's for a lot of different customers, including younger customers.

If we can go to the next slide, please.

So utilities are basically offering prepay for a variety of reasons. It's not -- these are not mutually exclusive. You know, many are just looking to add to their service model some additional payment options. Some utilities are looking at this as a way to get -- drive energy efficiency and hit DSM targets. Basically let me take a second and explain what's going on.

So people get a daily bill, or daily communication. They can do something about it because they see, you know, what they owe, what's left on their prepay account, and then they take actions in order to manage that energy consumption and they can see the results the next day. So there is a behavioral component to this. It results in persistent and fairly significant savings. Meaning, on average, we are seeing anywhere from eight to 10 percent of energy consumption drops. Which, from a customer perspective, what that directly means is that they -- their bills are lower. So essentially through their own efforts, you know, they are able to reduce their consumption and actually pay less. So this is a nice way, again, as I said before, to provide some other options to customers.

If we can go to the next slide, please.

As Commissioner Clark said, I mean, you know, one of the things that my firm is getting very concerned about is what I would -- I don't think it's too much of a stress to start to say that we are on the cusp of potentially an affordability crisis in this space. Part of that is also growing amounts of customer debt.

And so when you look at the subprime market, when you look at where people are in terms of the interest rates and inn inflation, and everything else, and realizing that they have pretty much burned through all their savings -- and I am not saying everybody, but a good chunk of our population -- we need to look at different options in helping them manage, you know, whatever debt situation. I mean, oftentimes in this space we kind of are looking at income and income qualified program. I think that this is as much of a credit issue as anything else, and so these folks don't really have credit, or have limited credit.

And so one of the things that prepay is able to do is say, hey, you know what, I am going to give you an option. A portion of your bill is going to be paid towards you staying current, keeping the lights on, but a portion your bill, let's say 25 percent of whatever you put on a prepay account, is going to go to paying off whatever debt you have. And so this is a way for cuss a customer to stay current, to get out of that debt trap, and they can do so usually within 18 months. And so -- and I am talking about some significant amounts of arrearage. So, you know,

$500, $1,000, what have you, customers can, through their own efforts, you know, get out of that debt.

And so if we can go to the next one.

This is just, you know, again, another reason, again, showing there is a lot of proof points here. So within 12 months, PayGo, which is a prepaid vendor, shows that their clients have gotten 90 percent of over outstanding debt covered within that period.

So, you know, again from -- both in terms of a prudency, from watching out for the entire rate base, but also for these customers that are in debt, you know, prepay is a nice voluntary option.

So if we can go to the next one.

Okay. So that's my presentation. Thank you, again, Commissioners. I would be glad to answer questions. I know you have some other great panelists, so I will stay on.

CHAIRMAN FAY: Great. Thank you, Mr. Wimberly.

And I just -- I have one or two quick questions for you, then make sure -- my colleagues might have some for you too before moving on.

You mentioned the energy efficiency part for the reduction on your Slide 4 there. Is that

something you base on the psychology of the
customer? I mean, why would prepaid translate to
reduced usage?

MR. WIMBERLY: Yeah, I think, Commissioner, you are right. It is something do with behavioral efficiency. So, I mean, if you think about it, you know, people essentially, again, are getting something that they get in a realtime perspective that they can have some control over, unlike their bill, which is oftentimes a surprise. So it goes 30 days -- let's say, 30 days in the hot summer, you really don't know what that bill is going to actually end up being. From a day-to-day perspective, prepay, I mean, you know exactly where you stand. So again, and you can control it.

Even low-income folks, we have found in our own research, have a variety of ways of controlling their costs to reduce their, you know, consumption by, you know, at least a few percentage points.

So I think you are right. It's mostly a behavioral efficiency response, but it is a proven one. So there is a ton of studies out there that have confirmed this across the country, and I can guarantee you in Florida, that, you know, there is energy conservation going on through prepay even if they don't call it out. I know Sheila is going to be presenting, so I know JEA is seeing some of this.

CHAIRMAN FAY: Okay. Great. And then just one more question for you.

I am not familiar with how the shutoff process would work for prepaid. So obviously, normal customers, they have a line of communication with the utility and there is an understanding as to their arrears and how that works, and notifications of shutoff. Is prepaid done the same way? How would that be structured? At what point would the customer still have proper notice that they are, you know, in risk of being shut off?

MR. WIMBERLY: So prepay -- I mean, one of the misconceptions out there is that prepay is somehow lessening consumer protections. None of our utility clients are doing anything in terms of lessening the notification or other things leading up to a disconnect. In fact, I would argue that there is way more communication than you would typically find with a post-pay customer, because you are getting a communication through your preferred channel every day if you so desire.

Secondly, the disconnect happens the same way the post-pay happens. Meaning, you know, you are using remote connect and disconnect from the AMI. And I think the real important thing to look for is not disconnects as far as the number of disconnects, but to look at the frequency of disconnects. So how many times does a customer over the course of a year get disconnected, and for how long they get disconnected.

So most customers are basically getting disconnected for whatever reason, and if they do get disconnected, they get reconnected within usually 15 minutes. And that means that they post a payment on their prepay account. It's almost, you know, realtime reconciliation. So they -- and then their power gets turned on. And there is -- and the nice thing about AMI and prepay is that usually it's done without any penalty or timeline.

So, again, part of the issue I think we have, and a broader issue that we have in this space is how we look at disconnect. I see it as a mechanical act. I see it as not deprivation necessarily, but, again, it matters how long you are disconnected and how many times you are disconnected, and that's where we should be putting our analysis.

CHAIRMAN FAY: Okay. Great. Thank you.

And I am going to go to Commissioner Clark next. I did want to just if, Commissioner Clark, you didn't have a specific slide to refer to on, our IT folks were going to pull up JEA's presentation. Does that work for you? Okay.

Well, go ahead, Commissioner Clark, you are recognized.

COMMISSIONER CLARK: Just a quick observation. I am going to talk in a few minutes about some of the statistics that I saw, but one that is a little surprising to me, Mr. Wimberly, is the kilowatt hour consumption reduction that you are seeing.

Now, you mentioned that you -- most utilities are seeing a four- to six-percent reduction in kilowatt hour consumption for people who are on prepay. That number seems to be decreasing over time. I can recall in 2007, 2008, we were seeing an average -- I saw an average of about 17 percent reduction in individuals who were using prepay. Historically, back through the early stages of the program, those numbers were in the 10, 15 percent range. But I have seen that, as time has moved forward, the potential impacts for energy consumption reduction have been reduced. Is that an accurate trend?

MR. WIMBERLY: You know, Commissioner, I actually was being fairly conservative. I don't -- you know, again, I don't think it's been reduced that much. I mean, again, you are -- I mean, our studies point to, on average, you know, eight to 12 percent. I was just pointing, because Baltimore Gas & Electric has lower. But some of that is methodology. It's looking at, you know, how you do that measurement and verification. Some of it is around, you know, using tests around persistence and things like that.

But your average DSM portfolio, your straight energy efficiency, trying to get -- can you imagine trying to get an additional eight percent out of your lightbulb in terms of efficiency? That just is not going to happen.

So this is -- you know, behavioral efficiency is a very important way to hit efficiency targets that, again, are combining with things like payment or other measures that I think are going go to be very important.

To date, though, most states, because of how they do the cost test, and so on, you know, really haven't said, okay, we are going to allow prepay to be part of that DSM portfolio. But, you know, again, I think there is a lot of research that it's pointing to, you know, why it should be considered.

COMMISSIONER CLARK: Good point. Thank you.

CHAIRMAN FAY: All right. Commissioner La Rosa, you are recognized.

COMMISSIONER LA ROSA: Thank you, Chairman.

Just a quick question. You mentioned they can kind of control their communication as far as how much they are using almost on a daily basis. What about payment scheduling? Is -- can they choose how frequent they pay per month, or how does that work?

MR. WIMBERLY: Yes. Frankly, Commissioner, you know, it's interesting, because the people on prepay tend to pay more down on their prepay account than they would getting a monthly bill.

So there is this -- again, it's not just prepay. There is a broad movement in terms of payment trends and consumer finance of moving away kind of these scheduled 30-day, or whatever that structure is, into something much more fluid.

So conceivably, like with post-pay, I mean, they could pay every day if they wanted to. Nobody really does, but, you know, more frequently; or they could just -- you know, if you are wealthier and you have thousands of dollars that you can just sit into -- you know, stick into an account, you can do that too.

So again, we have noted that there are more frequent payments made when people are on prepay, but that's not necessarily, you know, meaning that precluding the fact that you could, like, put a chunk of change down and not pay for it more frequently.

COMMISSIONER LA ROSA: Great. Thank you.

CHAIRMAN FAY: Great. Thank you.

With that, any other questions for Mr. Wimberly?

With that, we will move on to Ms. Pressley from JEA.

Ms. Pressley, you are recognized. I believe our folks are going to get a small presentation up on our end through IT. Just give us a minute to make sure we are able to pull that up for you. And if you want to, you could give us a quick brief of your background before your presentation gets pulled up.

MS. PRESSLEY: Fantastic.

I am Sheila Pressley, JEA's Chief Customer

Officer. And in January, will celebrate 20 years with the municipal utility, and I am honored to be here today.

I have the honor and distinction of being JEA's first prepay customer. As the program sponsor, I wanted to experience what our customers would experience. So when I talk to groups of people like you, I can talk to you from my personal experience.

So Jamie gave you the global view of prepay programs, and I am going to share the view of prepay from a JEA's customer perspective.

10 years after the program began, we have about 22,000 customers, or five percent of our customer base, that's enjoying the program. They pay the same rate as all residential customers. There is no security deposit required, which averages about $200 for customers that are not part of this program, and they are not assessed a late fee.

The daily account balances that you asked about are communicated via text, phone or email. They have access to their daily balance. They know if they continue to consume at the same rate about how long that credit on their account about last, and they are notified well in advance of a disconnection. And these customers, like every other customer, they are eligible for payment arrangements.

During COVID, we suspended disconnections for six months, like most utilities. And then at the conclusion of the COVID period, the moratorium, we gave every customer an opportunity to pay back their balances over a period of time. That included prepay customers. And as Jamie mentioned, those balances were cleared in about 18 months. With our customers, most of those balances were cleared within a year.

So how does it work? The cost of a day of service becomes the new normal. Every day there is a reconcilement of their balance. We multiply their consumption times the rate, and that gives them their daily charge, and that daily charge is deducted from their credit balance.

This graph shows you what the daily charge was for a particular customer. And if you look around the first of March, you will see the bar graph is below zero. That means that the consum-- the customer consumed more than their account balance. And because they were notified, they paid and you see the following day they -- well, they paid in the following day, they were back in a positive balance.

The graph also shows the high and low temps for the day, because we know that there is a correlation between weather and consumption, and this graph provides that for them.

We are one of the few multiservice utilities in the nation that offer prepay. We provide electric, water and sewer services, and all of those services are wrapped in the account, and the customer uses the service to maintain -- maintain their account.

So we started talking about the decrease in consumption at JEA, and this is over a 10-year period. But the decrease in consumption is about eight percent, and that's weather normalized, and excluding disconnection periods, about eight percent.

Five percent of our customers choose -- choose to participate in the program. And of that five percent, 60 percent are categorized as low and moderate income.

The average account balance is about $36, and that has not changed this 10 years.

So we talked about payment frequency a moment ago. One of my favorite stories is of a young man that was a barista at a Starbucks and came in every day and used his tips to apply to his account, and that's how he maintained his service. And he mentioned that absent of a program like this he probably wouldn't have service, because the charge that arrives at the end of the month for a traditional customer was too much for him to satisfy all at once; but making payments every day with his tips, meant that he could keep his service active, and he did for a very long time.

For those customers that experience disconnection, 60 percent are reconnected within three hours. Most within 15 minutes. And almost 100 percent within 24 hours. But here's the important part, 45 percent are never disconnected because they are able to manage the service without interruption.

Now, you might wonder would a frequent disconnection be of concern to customers? At the end of this presentation, I have videos from a focus group that we conducted with these customers very recently, and you will find that their perception of disconnection may differ from what you expect.

So what's in it for the customer? Well, energy conservation, we talked about that, about eight percent less. And they can control their household budget. Many of them know how much they spend in utilities each day, and they plan accordingly. There are no penalties, no deposits, and they spend less time interacting with the utility.

But I think the biggest, the greatest benefit for these customers is they are not having to deal with a bill at the end of the month that comes as a surprise, because they know every day what they are consuming, so it causes less stress. And because of their interaction daily, knowing what they are consuming, they have an increased knowledge of the behavior and how that connects with the charges.

So now let's hear from a few of our customers. We asked them have they been disconnected within the last year?

(Video presentation.)

MS. PRESSLEY: So what did we learn? We learned that they are highly engaged and aware of their behavior and how that affects their charges. They don't see the disconnection as a negative.

They realize that, oh, gee, I just maybe forgot to pay the bill. And they also know how long a balance of $20 or $25 will last, and they plan accordingly. They are highly engaged and very satisfied customers.

So let's look at the next. So the next is a net promoter question. Would you recommend the program to a friend or family?

(Video presentation.)

MS. PRESSLEY: So that was one of eight groups interviewed. And every one of the folks in every group answered the question the same way. Asked if they would recommend the program to a friend, they all raised their hand. And you heard the young woman say, I don't know why everybody isn't on this program.

What questions do you have for me?

CHAIRMAN FAY: Great. Thank you.

Commissioners, any questions for Ms. Pressley?

All right. Commissioner Clark.

COMMISSIONER CLARK: I would like to ask one quick question.

In terms of the number of transactions that occur in a month, we saw on average of about 4.2 transactions per customer per month. Do you have that calculation?

MS. PRESSLEY: Yeah. Ours is about the same. Most customers pay every week. Some, like the Starbucks barista, pay every day, but the majority pay every week, so four, four per month.

COMMISSIONER CLARK: And the options they have to pay with your system, is it via their phone, via some sort of interchange with their credit card, or something like that, that they can make their payment?

MS. PRESSLEY: Yes. They can pay in-person at any one of 400 locations. They could pay over the phone. They can go to the web. All options are available.

COMMISSIONER CLARK: It's interesting that the transaction numbers are remaining pretty consistent among most of the companies that engage prepay. Early on, when we first implemented the program, we actually used the card swipe program. The customer had to come to the office, have a prepaid card loaded, go back and swipe that card in a power line carrier device inside the house that was talking directly to the meter, and we still saw an average of about four transactions. They were still driving to those offices basically on a weekly basis to reload their card, so that's interesting.

Thank you, Mr. Chairman.

CHAIRMAN FAY: Yeah. Great. Thank you Ms. Pressley. We appreciate your time.

MS. PRESSLEY: Thank you.

CHAIRMAN FAY: Commissioner Graham, you are recognized.

COMMISSIONER GRAHAM: Thank you.

You know, when I -- when I -- I have heard Gary talk about this since he has been here, and I have always scratched my head, I don't see the point. And it's funny, I was looking at Mr. Wimberly's graph. If you look at 55 plus category, it says about, you know, 50 to 60 percent of the people say the same thing, I don't see the point. So the graph is very appropriate.

MS. PRESSLEY: Yes.

COMMISSIONER GRAHAM: But I see it as being a means to an end, and I understand and I respect that means to the end. I have always said, when I got here, when they started talking about smart meters, and how that's the newest best thing. And I always thought that was fantastic because I always believed that knowledge is power. And I have always -- I have always told people, if we had a big meter that sat on the refrigerator door and showed how much electricity you are using, people, talking about energy efficiency, would use so much less because they can see immediately how much, you know, how much it's pulling.

And so I think that works -- that's why this works so well, and that's why I think this sort of thing works well for everybody because you are constantly aware of what you are using. You know, you don't ever think about the temperature of that beer in your refrigerator until you drink it and it's warm, but you constantly always turn it down, turn it down, turn it down a little bit until you hit per efficiency.

But I think it all comes down to that information, and I think that information makes this absolutely fantastic. But if there is just away for us to incentivize everybody to readily look at this information, because I know it's there. I know they can download your app, and I know they can use your smart meters, but it's just how do we -- how do we motivate them to do it? And that's kind of the question, you know, for us as a whole, and for you as a utility.

MS. PRESSLEY: Well, what we've learned is people live -- they have very busy lives. And while the information is helpful, they don't want to go to the site and try to access it. But for these folks, the information is presented to them every day.

So the way for every customer to take advantage of that information, that knowledge, would be for us, and the utility industry, to push it to customers every day, and be armed with that information, then they can make behavioral changes if they choose to do so.

COMMISSIONER GRAHAM: It's this something that we sell to the customers when they come in, or is this just after they get into trouble, this is something that we allow them to get into?

MS. PRESSLEY: Both. Both. We present it as an offering to new customers. The customers that want to avoid a deposit are most likely to adopt the program.

We also offer it to customers that have been disconnected and don't have the full balance to reconnect. It's available. It's voluntary, and customers are gravitated to it if it addresses a need.

You know, we've learned something recently, Commissioner Graham, and that is that because it's addressing a need, it is not a long-term adoption. So there is a bit of turn in the program. As soon as the need is met, the crisis is averted, they may migrate back to traditional service, but absent of this program, they wouldn't have electricity, water or water service.

COMMISSIONER GRAHAM: Doesn't JEA, after a couple of years of good service, return security deposits?

MS. PRESSLEY: Well, yes, we have recently escalated that. After a year now the deposit is returned.

COMMISSIONER GRAHAM: Okay. Thank you.

CHAIRMAN FAY: Any other questions?

All right. Thank you, Ms. Pressley. We appreciate your time.

With that, we will move next to Ms. Cowan the VP of Member Services and External Affairs at CHELCO. I don't believe you have a slide presentation, correct?

MS. COWAN: No, I do not.

CHAIRMAN FAY: Okay. Great. No problem. You are recognized whenever you are ready.

MS. COWAN: Okay. Great. Thank you for

having me.

I am Emily Cowan, Vice-President of Member Services and External Affairs at CHELCO. CHELCO is an electric cooperative in the Florida Panhandle. We serve Walton, Okaloosa, parts of Santa Rosa and Holmes Counties. We have 58,000 meters, and we have the utility privatization contract on Eglin Air Force Base. We were also the first electric cooperative to have a prepaid tariff in the state of Florida.

So I have been at CHELCO for four years, and prepay -- running -- managing the prepay program is part of my responsibility, but prior to that -- excuse me -- I was at a co-op in Indiana, and part of my responsibilities was running a prepay program there as well. So I have a few years of history. I, as well, was a prepay customer, the first one at my co-op in Indiana, so I also have some firsthand experience with it.

So thank you for inviting me here today, Commissioners, to talk about it. I am a very big proponent of the program and really happy to be here.

So, CHELCO is a member-owned, not-for-profit, electric cooperative. So our business is different than an investor-owned utility. Our goal is to safely provide quality services and products at a competitive value. Our goal is not to maximize shareholder profit. In fact, we use our -- we return our unused margins to our members in the form of capital credits.

So we currently have about 1,500 members on our prepay program. And that doesn't maybe seem like a lot, but we've kind of talked about this a little bit here this morning. CHELCO uses it as a tool. It's never really our goal to get as many people on prepay and keep them on prepay, but to have people on prepay that is appropriate for them to be -- to be there.

And we've talked about this too. Prepay is generally marketed as a way to self-manage your electricity. And that's true, because account holders will start to notice and you will see behavioral changes, as we've also discussed prior to my presentation. But in our experience at CHELCO, prepay is mostly a reactive program.

And there is generally two groups of people that we've seen that use prepay. The first is existing members who have pending disconnects, or in jeopardy of disconnection for nonpayment, and the second is credit-challenged applicants. And this can be people with poor credit or no credit.

So we found that low-income applicants who struggle to pay even the most basic bills are also a lot of the most credit-challenged. So huge deposits are really daunting for them.

So how it works at CHELCO is a member comes in and applies for service. We run an on-line utility exchange credit report on them, and then that score comes back. And depending on what score that person gets, you could have an unfavorable result, and that -- those are the accounts that require a deposit, because they are high credit risk according to their credit report. So if they are unable to pay their report -- or pay their deposit, prepay is a really good option. But an average bill at CHELCO is about $140, and two months at our location is a typical deposit for us for a high risk credit customer. And a person is able to get on our prepay program for $70, 50 of that which goes right on their energy account. So $15 application fee, $5 membership fee, and then $50 and they are off and running with their service.

So one of our success stories was some employees got together and they had heard about a school system that the teachers were going together to raise money for a family who had some trouble getting on their feet, and they were faced with a large deposit.

Well, it turns out that the mom didn't have any credit, and the dad was a soldier that was killed in the line of duty. And so we were able to get them on prepay for just $70, as opposed to the large deposit that we would have required prior to that just because she didn't have any credit. So we consider that to be a big success story.

So the second group of members that are our post-pay members who are in jeopardy of disconnection, or have already been disconnected. Those few members are subject to disconnection are likely almost three months behind. So four -- 400, $450, even more than that. As I mentioned, that is an insurmountable amount to some people, and so it's overwhelming to them to pay. But it also, as we talk about bad debt, it also adds to our collection efforts.

When members leave a location, they don't leave a forwarding address if they don't intend to pay us, so it's hard -- it's hard for us to find them, and that money goes back to our collection efforts.

So in addition to post-pay accounts, also charge a $75 reconnect fee. So they have to pay what's due on their account plus a $75 redirect fee. For prepay, there is no reconnect fee, and there is no late fees. All they need to do is bring their account balance back above zero.

So our prepay program has a debt recovery component where you have split payments. So we can move a high bill into debt recovery, and for every dollar that a member pays, 70 cents goings to their energy and 30 cents goes to their debt account. And as both of my colleagues have said, we collect. People pay. We don't have problems with people leaving large balances. It's my experience if they get to remain in their home, then they are going to pay off that debt. They are almost always, always satisfied.

We don't have accurate data going back to 2010, when we started the program, because we changed customer information systems. But from 2010 to 2022, we collected $154,000 through the debt recovery program. So a significant amount that probably would have gone, or a portion of it gone toward our bad debt.

The other option that we have is post-pay members who are disconnected often already have a deposit on their account. So if they want to switch over to prepay, we can apply their deposit to their account. It reduces their debt by that certain amount, and either they have a credit balance on their account, or they have a small balance that's more -- easier for them to get their minds around.

And prepay was a huge tool for us during COVID. We serve 30A, and we surround Destin, so we have a lot of gig workers in our area, and everyone, a lot of those people lost jobs and were -- lost hours. And we, like other cooperatives, did a four-month moratorium. So when we came out of that, we had some hefty balances and people weren't back on their feet yet, because they weren't -- restaurants and tourism wasn't back open. So prepay was a perfect option for those members, and we only, out of all of the people that were carrying hefty balances, we only disconnected two people. And that is, in large part, because of prepay.

So -- and we talked about the beforehand here, but our writeoffs actually went down from 2019 to

2020, was the worst of the moratorium for the -- during the pandemic, and our numbers actually were lower in 2020 than 2019. So we also see a decline in bad debt as a result of prepay.

At CHELCO, because we are a member-owned cooperative, we are very conscious about our controllable costs. And some people would argue that bad debt isn't a controllable cost, but having high risk customers minimizes the amount of bad debt that they can accrue. So in the end, it is a great opportunity for the co-op and for the member. And for us, because we are a co-op, our bad debts are eventually covered by our other members, so we take a hard look at all of that.

And I think you guys talked about this a little bit already, but the account management is different. There is no monthly statement, but they receive daily text messages. They can sign up for low balance alerts. They are alerted before they get disconnected. And firsthand experience, being a prepay customer, sometimes it's actually more information than you want. So you can pick and choose how you want to sign up for and what kind of notices that work for you. It's all tailored to you.

The other couple of small extra benefits that I think are important to mention is that, as my colleague mentioned, the smaller, more palatable payments. The other portion -- excuse me, I apologize. For people that receive one check a month. If your bill is due on the 17th and you don't get your Social Security check until the first, you would like to think that people can manage their money along the way, but again, that's a large surprise bill that they get later in the month. So if they are paying two weeks after they get their Social Security check, they are incurring a late fee. With prepay they can pay along as they go, and they don't incur any late fees or penalties and -- thank you.

We handle our prepay accounts the same as we handle our post-paid accounts. We don't disconnect on the weekends. We don't do holidays, and we also treat them the same as if there is -- if there is a weather related event that we are holding other accounts.

And so the last thing I will mention is I worry about the mental health of my team sometimes. I am sure that you are familiar with it takes a special person to be a member service rep. And for them to be able to offer this option to a member that is upset and scared and afraid is really a wonderful tool.

So I mentioned that the option of bringing prepay is an option for those that are struggling, but we found that this is such a successful way to do business and really fits well with the cooperative model. So thank you.

CHAIRMAN FAY: Great. Thank you, Ms. Cowan, for your presentation and your time.

I will go to our colleagues for questions. I just have one quick one.

You mentioned a $15 application fee. That's just -- is that just for activation of service, or is for that enrollment in the prepaid program?

MS. COWAN: That's activation for service. Everyone pays that, post-pay or prepay members.

CHAIRMAN FAY: Okay. Great. Thank you.

Commissioner Clark.

COMMISSIONER CLARK: Just a couple of final observations. I think one of the -- just one area that nobody mentioned, I know it's an important part of everyone's program, is landlords, and how people with rental properties, especially right now, as we are seeing rental prices on houses increase, housing affordability becoming a bigger issue. One of the barriers to getting into a new rental unit is often security deposits -- excuse me -- utility deposits, and utilization of this program by the landlords makes it very, very easy for new tenants moving into properties. Most utilities can leave the account in one name. This person just picks up and begins to make the payment for it. There is no risk of bad debt. There is no risk of someone running off and leaving an old bill, or anything like that. So it's also a really, really good management tool for the rental business.

But I wanted to share -- I wanted to just echo a comment you made. If you have never been in a situation where you are the one put in the position to have to make a decision on pulling a meter for nonpayment, and whether it be, you know, a family, a mother with multiple children there, that's one of the hardest things that anyone is going to ever have to do. And if you haven't been there, you certainly can't appreciate the possibility of having a tool that you can utilize to help that family get electricity back in their house. As we all know, the point in time, tough decisions have to be made.

And everyone has mentioned their average bill and $148 average bill, and how that really mounts up by the time you get to a disconnect point. I think you are underselling that. The ones that -- the way the system works, by the time the customer gets the bill and by the time it gets disconnected, if they had a $300 a month utility bill, which is possibility of why they are not going to be able to pay it to begin with, by the time you get to disconnect and reconnect, that customer owes you about 1,200 bucks. They are going to have to come up with about $1,200 to be able to reconnect their service, not the 300 they owed. They owed 300 for about two months service, plus sometimes a security upgrade, deposit upgrade, or putting up a new deposit if it's after their first year, and they had had a successful first year, there is also disconnect and reconnect fees that are associated with post-pay systems.

So you actually get to a $1,200 charge that that customer is going to have to pay in order to have their service reestablished. And if you can do that on a system where, you know, here's a prepaid meter, just start paying your bill now and we will do 50-50 split, or 70-30 split, it is a phenomenal management tool for those customer service reps to be able to utilize.

And that's one of the things that I am so passionate about, being able to help customers manage their own, you know, manage their own bills and be able to afford the energy they are using. I think it's an incredible tool for awareness of how you are using electricity.

It's not the folks who have average bills that we need to have the concern about. It's folks who have the abnormal bills that are dealing with a much, much more difficult situation than everyone else. This is a great tool.

Thank you all for being a part of this. I really appreciate the information. I hope that what we are doing here today raises awareness, and that some the other utility companies in the state will take heed, take note, and see that this is a wonderful opportunity to serve their customers even better as well. So thank you for the opportunity I have had, Mr. Chairman.

CHAIRMAN FAY: Great. No. Thank you, Commissioner Clark. I have learned a great deal, even the no reconnect fee for some of these folks who are on the programs is probably very enticing for them to sign up for it.

So with that, I think we might still have Mr. Wimberly, we don't have him on the screen, but I wanted to thank him and our other participants, Ms. Pressley and Ms. Cowan, for being here.

And we do sometimes, as Commissioners, have our offices follow up with questions about specific information, and so you may hear from us in the next few weeks if there is something else that we need, but really do appreciate your time and thank you being here today.

MR. WIMBERLY: Thank you, Commissioner.

CHAIRMAN FAY: He is still here.

All right. Next we will move on to our General Counsel's report.

MR. HETRICK: Mr. Chair, just real quick. I would like to take this moment, an opportunity to introduce our newest attorney who had joined us yesterday, Tim Sparks. Tim, if you do stand. Tim comes to us from AHCA. He is eight years experienced lawyer, and he is going to add a lot of depth to the regulatory analysis section of Adria Harper. So we are really excited to have Tim join us, really excited, so welcome, Tim.

CHAIRMAN FAY: Great. Thank you, Tim. Excited to have you. That' it?

MR. HETRICK: That's my report.

CHAIRMAN FAY: All right. Great. Thank you for introducing.

Mr. Baez, Executive Director's report.

MR. BAEZ: Thank you, Mr. Chairman.

You all know by now how much I enjoy giving you bad news, and the only thing I enjoy more than that is giving you bad good news, and so on that note, I -- as most of you know by now, our legislative affairs director, Kaley Slattery, is leaving us at the end of the month for greener pastures. And though I am loath to embarrass anyone publicly, sometimes a little light embarrassment is due all for the cause.

She's been here with us doing great work just short of three years, which time flies. I can't get my head around how quickly. But for her, I just have a humble thank you. And I want to thank her for her curiosity and her willingness to act on it by asking questions, which I am sure most of you around the building have experienced at one point or another. I also wanted to thank her for her attention to detail, and a commitment to follow up, which is almost maniacal at times.

And along those lines, personally, I want to thank her for the subtlety of her reminders, because it didn't feel like she's tapping on the shoulder when she is, and that really worked for me.

I know her decision was a difficult one, and I think that that speaks well of -- as well of her as it does about this agency. It's always a difficult point to lose a valued member of the staff, and this time is no different. But, you know, she ought to be proud of the work that she did here, as proud as we are. And I know that we wish her well and continued success.

So thanks again, Kaley, and good luck on your greener pastures. I know you are moving -- you get to move back home, which is -- I don't know, somebody says you can never go home. I forget what author said, but I hopefully that's not the case. Congratulations.

CHAIRMAN FAY: Great .thank you.

And I will just -- I will echo thank you. I know while you have been here, we've had a lot of legislative direction, not blaming anyone, just we've had a lot of that challenges that required some implementation, and so we do appreciate all the work that you have done.

And just speaking real quick from someone else who worked legislative affairs in the agency, sometimes I think the most rewarding projects are the ones that aren't seen as complex policy changes. And I know you worked on some lifeline improvements, and those bills can also be some of the most challenging because they don't necessarily have a lot of drive behind them, and so I think your work on those things, as Braulio put it, was subtle at times, but also important for those customers and the people who engage with lifeline. And I appreciate your work here, and know you will do great in your next role. And I know I speak for the Commission we wish you the best for your next journey.

With that, Commissioners, anything else?

All right, with that, we will adjourn our Internal Affairs. What I would like to do is take a quick 10-minute break, and at 11:00 we will start back for the beginning of the FPUC hearing to do some introductory information and then break for lunch. Thanks.

(Proceedings concluded.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 8th day of November, 2022.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024