REVIEW OF THE

2012 TEN-YEAR SITE PLANS

FOR FLORIDA'S ELECTRIC UTILITIES

FLORIDA PUBLIC SERVICE COMMISSION

TALLAHASSEE, FL
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Investor-Owned Electric Utilities

FPL	Florida Power & Light
PEF	Progress Energy Florida
TECO	Tampa Electric Company
GULF	Gulf Power Company

Municipal Electric Utilities & Rural Electric Cooperatives

FMPA	Florida Municipal Power Agency
GRU	Gainesville Regional Utilities
JEA	JEA (formerly Jacksonville Electric Authority)
LAK	Lakeland Electric
OUC	Orlando Utilities Commission
SEC	Seminole Electric Cooperative
TAL	City of Tallahassee

LIST OF ACRONYMS

AB	Agricultural Byproducts (Biomass)
CC	Combined Cycle
CR3	Crystal River 3 Nuclear Unit
CT	Combustion Turbine
DACS	Department of Agriculture and Consumer Services
DEP	Department of Environmental Protection
DOE	Department of Energy
EIA	Energy Information Agency
EPA	Environmental Protection Agency
F.A.C.	Florida Administrative Code
F.S.	Florida Statutes
FEECA	Florida Energy Efficiency & Conservation Act
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
INT	Interruptible Load
IOU	Investor-Owned Utility
IPP	Independent Power Producer
LFG	Landfill Gas
LM	Load Management
MMBtu	Million British Thermal Units
MSW	Municipal Solid Waste
MW	Megawatts
MWh	Megawatt-hours
NEL	Net Energy for Load
NUG	Non-Utility Generators
NUG	Non-Utility Generator
OBG	Other Biogas (Biomass)
PPSA	Power Plant Siting Act
QF	Qualifying Facilities
REC	Renewable Energy Credits
RFP	Request for Proposals
RPS	Renewable Portfolio Standard
SUN	Solar
TLSA	Transmission Line Siting Act
TYSP	Ten-Year Site Plan
WAT	Hydro / Water
WDS	Wood Waste Solids (Biomass)
WH	Waste Heat

EXECUTIVE SUMMARY

Pursuant to Section 186.801(1), Florida Statutes (F.S.), each generating electric utility must submit to the Florida Public Service Commission (Commission) a Ten-Year Site Plan (TYSP or Plan) which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a ten-year planning horizon. The Commission is required to perform a preliminary study of each plan and classify each one as either "suitable" or "unsuitable." This document represents the study of the 2012 Ten-Year Site Plans for Florida's electric utilities. All findings of the Commission are made available to the Florida Department of Environmental Protection (DEP) for its consideration at any subsequent electrical power plant site certification proceedings pursuant to the Power Plant Siting Act (PPSA)[1]. In addition, this document is forwarded to the Department of Agriculture and Consumer Services (DACS) pursuant to Section 377.703(2)(e), F.S., which requires the Commission to provide a report on electricity and natural gas forecasts. A copy of this report is also posted on the Commission's website and is available to the public.

The Commission has reviewed the Ten-Year Site Plans filed by the eleven reporting utilities, as well as supplemental data provided through data requests, and finds that the projections of load growth appear reasonable.[2] The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. Therefore, the Commission finds the 2012 Ten-Year Site Plans filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes.

Since the TYSP is not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's TYSP at a public hearing.

Growth in Demand and Capacity

Customer growth remained positive in the last year, and is anticipated to continue at a somewhat slower pace than projected last year, but still below historic levels. Between 2012 and 2021, the annual average growth rate for residential customers is projected at 1.26 percent, slightly below last year's projection of 1.37 percent for 2011 through 2020, and down significantly from the 2.36 percent rate seen for the period 2002 through 2007. In contrast, commercial and industrial customers show a slightly increased rate of growth, but also remain below historic levels.

Generating capacity within the State of Florida is anticipated to grow to meet the increase in customer demand, with approximately 7,200 megawatts (MW) of new generation added over the planning horizon. This figure represents a decrease from last year's TYSPs, which estimated

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[1] The Power Plant Siting Act is Sections 403.501 through 403.518, Florida Statutes

[2] Investor-owned utilities (IOUs) filing 2012 Ten-Year Site Plans include Florida Power & Light Company (FPL) Progress Energy Florida, Inc. (PEF), Tampa Electric Company (TECO), and Gulf Power Company (Gulf). Municipal utilities filing 2012 Ten-Year Site Plans include Florida Municipal Power Agency (FMPA), Orlando Utilities Commission (OUC), City of Lakeland (LAK), City of Tallahassee (TAL), JEA (formerly Jacksonville Electric Authority), and Gainesville Regional Utilities (GRU). Seminole Electric Cooperative (SEC) also filed a 2012 Ten-Year Site Plan.

the need for about 10,300 MW new generation. This reduction in the estimated need for new capacity is primarily due to several units being constructed in 2012, and others being delayed beyond the ten year period due to slightly lower load forecasts. The 2012 Plans include retirements and uprates of existing units, along with new generating units to be added during the ten-year period. As in previous planning cycles, natural gas-fired generating units make up a majority of the generation additions and now represent a majority of energy produced within the state.

All TYSPs are subject to modification due to factors such as changes to fuel price forecast, energy demand forecasts, shifts in energy policy, or other factors. A notable change to the 2012 TYSPs is PEF's delay of the Levy 1 nuclear unit, which was originally planned to start commercial service in June 2021, but has been delayed until June 2024. PEF is anticipated to update their 2013 TYSP to reflect this change in projected installed capacity. While the delay is a significant impact on PEF's reserve margin in 2021, the statewide reserve margin is projected to be adequate to provide reliable service with the planned delay of the Levy nuclear units.

Demand-Side Management

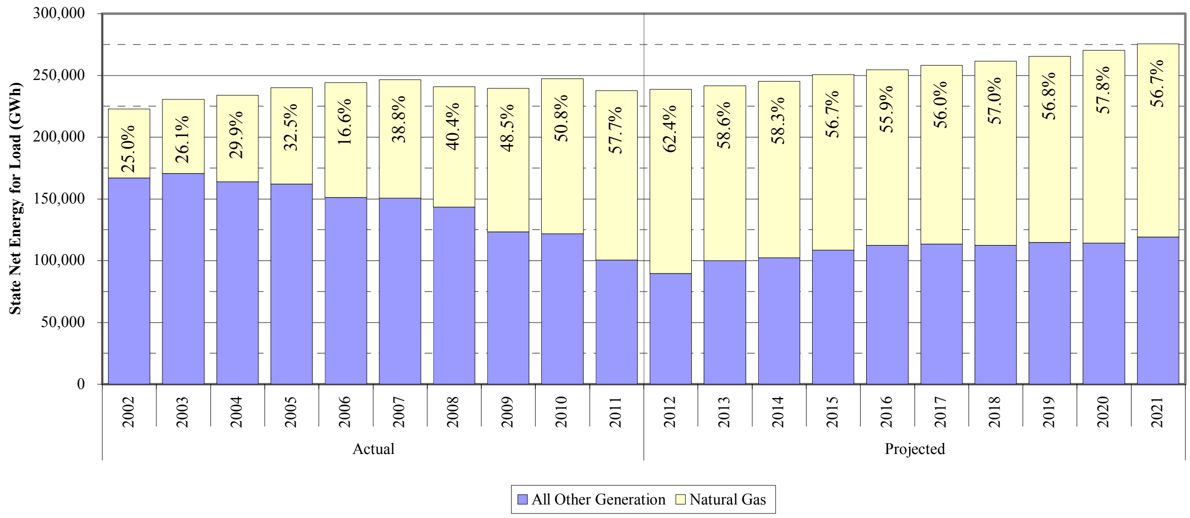
The first step in any resource planning process is to focus on the efficient use of electricity by consumers. Government mandates, such as building codes and appliance efficiency standards, provide the starting point for increasing energy efficiency. Customer choice is the next step in reducing the state's dependence upon expensive fuels and lowering greenhouse gas emissions. Consequently, educating consumers to make smart energy choices is particularly important. Finally, Florida's utilities can efficiently serve their customers by offering demand-side management (DSM) and conservation programs designed to use fewer resources at lower cost.

Florida's utilities project considerable demand and energy savings over the planning period, with conservation and load management programs by 2021 reducing the system's total seasonal peak demand by over 9,000 MW, or 15 percent for summer and winter, and reducing annual energy consumption by over 15,000 GWh or 5 percent.

Fuel Diversity

Natural gas is anticipated to remain the dominant fuel over the planning horizon, with usage in 2011 increasing to 57.7 percent of the state's net energy for load (NEL), up from 50.8 percent of NEL in 2010. Figure 1 below illustrates the increase in the role of natural gas in the state's electricity production during the last ten years, and the projected use during the next decade. Based on the Florida Reliability Coordinating Council (FRCC) 2012 Load and Resource Plan, state-wide natural gas usage is expected to peak in 2012, and then slowly decline throughout the planning period, to 56.7 percent in 2021.

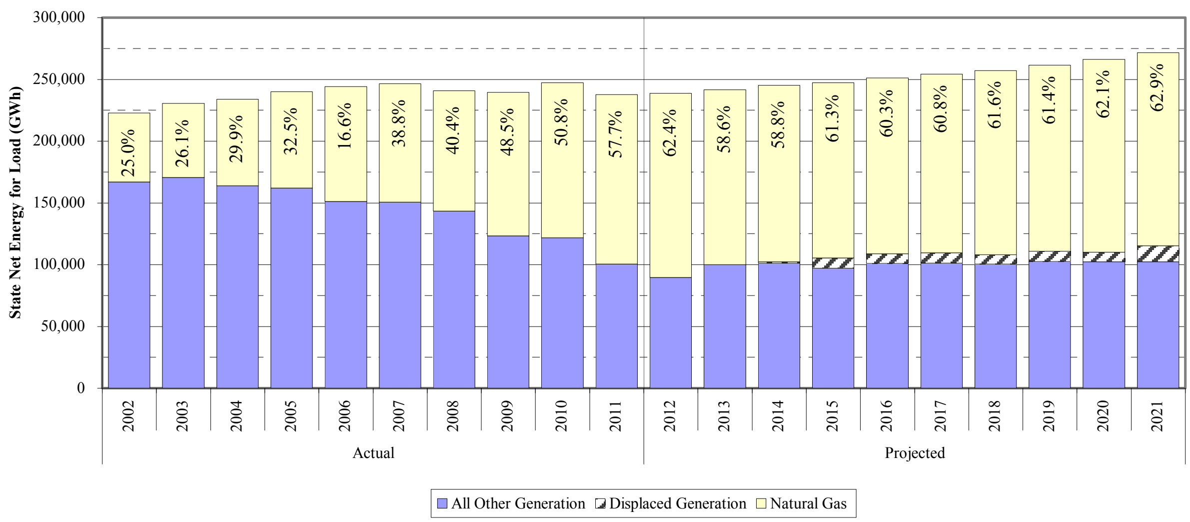
Figure 1. State of Florida: Natural Gas Usage (Total & Percent NEL)



Source: FRCC 2004 - 2012 Load and Resource Plans

While natural gas usage is projected to remain relatively level over the planning period, this situation is due to projected increases in nuclear generation, and a limited impact of new environmental compliance requirements. The FRCC 2012 Load and Resource Plan includes the addition of the Levy 1 nuclear unit in 2021, which has since been delayed until 2024. Also, this projection assumes the return to service in November 2014 of PEF's Crystal River 3 nuclear unit (CR3). However, no decision has been made regarding the repair or retirement of CR3. Furthermore, as discussed at the 2012 TYSP Workshop, PEF's Crystal River 1 & 2 coal units, along with GULF's Lansing Smith 1 & 2 coal units, may face challenges in economically meeting new environmental compliance requirements. If the facilities are unable to install sufficient emissions controls, they would face retirement as early as 2015. If the projected generation associated with these nuclear and coal units is displaced by natural gas, it would have the net effect of increasing natural gas' share of state electric generation to 62.9 percent by 2021, as shown in Figure 2 below.

Figure 2. State of Florida: Natural Gas Usage With Displaced Generation (Total & Percent NEL)



Source: FRCC 2004 - 2012 Load and Resource Plans, PEF 2012 TYSP, Responses to Staff Data Requests.

In an attempt to reduce natural gas consumption, Florida's utilities have encouraged other energy resources, including renewable energy and nuclear generation. Approximately 1,421 MW of renewable generation is currently operating in Florida, an increase of about 138 MW from the previous year. Presently, municipal solid waste (MSW) and biomass each represent roughly a third of renewable generation in Florida. Other major types of renewable generation operating in the state include waste heat, hydroelectric, landfill gas, and solar.

Over the planning horizon, approximately 957 MW of additional renewable generation is planned in Florida, an increase of 51 MW from last year. The majority of these additions are solar and biomass. While these new projects represent a significant increase from the existing total, renewable generation continues to provide a relatively small contribution towards the reduction of our state's reliance on fossil fuels.

While no new nuclear units are projected until 2022, uprates for all five existing nuclear units have been approved by the Commission, representing an increase of approximately 600 MW. Extended outages associated with unit uprates and other major maintenance work has reduced nuclear generation, and is projected to reduce nuclear's contribution to annual energy in the near future. One of the nuclear units, CR3, has been offline since 2009 due to a delamination of the concrete containment structure discovered during a steam generator replacement project. The unit, including the 154 MW of uprated capacity, is currently scheduled to return to service in the end of 2014. Currently four new nuclear units, Turkey Point 6 & 7, and Levy 1 & 2, totaling over 4,000 MW generation are planned outside of the ten-year horizon.

New and Proposed EPA Rules

Florida's electric utilities must also consider environmental concerns regarding existing and planned generation to meet Florida's electric needs. The Environmental Protection Agency

(EPA) has finalized or proposed several new rules in the last year that will have an impact on Florida's existing generation fleet, as well as on its proposed new facilities.

The new or proposed EPA rules limit emissions from existing power plants on a variety of pollutants, including mercury, other heavy metals, organic toxics, particulates, sulfur oxides, and nitrogen oxides. While many facilities within the state already have sufficient emissions control technologies to address these rules, some will require installation of new equipment to bring emissions into compliance. Other rules address concerns relating to cooling water's impact on aquatic life, and the disposal of coal ash. All of these activities will require investment and potential for extended outages of the relevant generating units, which will require careful planning to allow for a minimum impact on system reliability.

At this time, a final estimate of costs and units affected is not available, as some of the proposed rules are not yet final. Several of the TYSP utilities have provided preliminary estimates based upon known and proposed rule language, and are shown in Table 1 below.

Table 1. TYSP Utilities: Preliminary Estimates of EPA Rule Compliance Cost

Utility	Preliminary Total Cost Estimates* ($ Millions)
Florida Power & Light	$348 - $1,741
Progress Energy Florida	$165 - $1,330
Tampa Electric Company	$763
Gulf Power Company	$1,270 - $2,737
Florida Municipal Power Agency	$39
Gainesville Regional Utilities	Not Available
JEA	Not Available
Lakeland Electric	Not Available
Orlando Utilities Commission	$157
Seminole Electric Cooperative	Not Available
City of Tallahassee	$5
Total of All Utilities	**$2,747 - $6,772**

* These estimates are not final, and may not include all rules.
Source: Responses to Staff's Data Requests.

New Generation Facilities

The State of Florida has a total summer generating capacity of 56,973 MW installed as of January 1, 2012. A total of 7,200 MW of new generation units are planned in the ten-year period, all of which will be natural gas-fired units. Other impacts noted in the report reflect changes to existing units and/or purchased power agreements.

As noted previously, the primary purpose of this review of the utilities' TYSPs is to provide information regarding new electric power plants to the DEP for its use in the certification process. Table 2 displays those generation facilities included in the 2012 TYSPs that have not yet received a certification under the PPSA by the Commission. Certification is generally anticipated at four years in advance of the in-service date for a natural gas-fired combined cycle unit. TECO has recently filed a Request for Proposals (RFP) for their conversion to combined cycle configuration of their existing Polk Power Station units 2 through 5, and filed a petition for a determination of need on September 12, 2012.

Table 2. State of Florida: Proposed Generating Units Without PPSA Certification

Utility	Generating Unit Name	Unit Type	Fuel Type	Summer Capacity (MW)	In-Service Date
TECO	Polk 2-5 CC	CC	NG	1,063	Jan 2017
PEF	Unknown	CC	NG	767	Jun 2019
SEC	Unnamed CC1	CC	NG	196	Dec 2020
SEC	Unnamed CC2	CC	NG	196	Dec 2020
SEC	Unnamed CC3	CC	NG	196	Dec 2021

Source: Utilities 2012 TYSP

In addition to generating units, transmission lines that will require the Commission's certification under the Transmission Line Siting Act (TLSA) are projected during the planning period. Table 3 below details the only TLSA project included in the utility's plans, which is associated with TECO's combined cycle conversion at the Polk Power Station.

Table 3. State of Florida: Proposed Transmission Without TLSA Certification

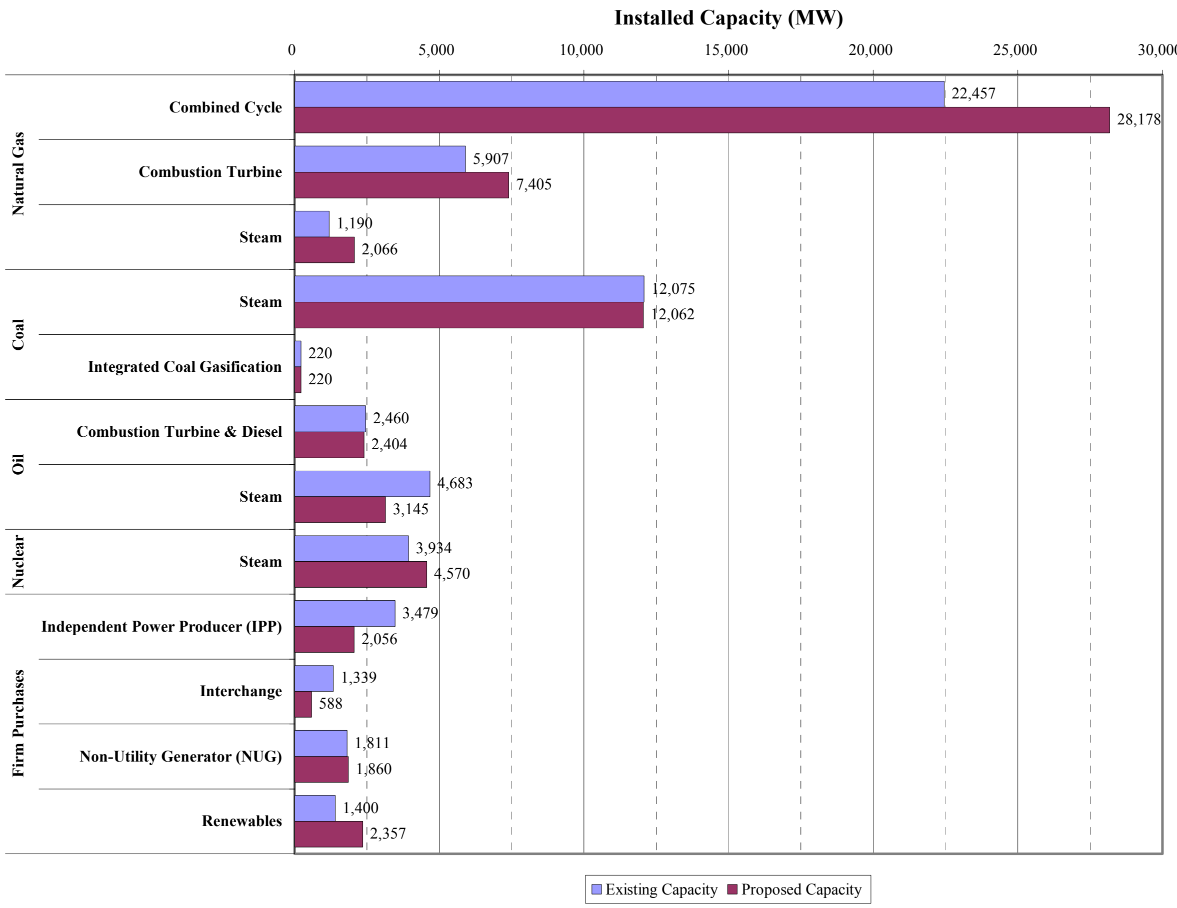
Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Commercial In-Service Date
TECO	Polk-Aspen-FishHawk	62.5	230	2017

Source: Utilities 2012 TYSP

Summary of the State of Florida

Figure 3 below illustrates the present and future aggregate capacity mix. The capacity values in Figure 3 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2012 Ten-Year Site Plans.

Figure 3. State of Florida: Existing and Projected Capacity



Source: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

INTRODUCTION

The Ten-Year Site Plans of Florida's electric utilities are designed to give state, regional, and local agencies advance notice of proposed power plants and transmission facilities. The Commission receives comments from these agencies regarding any issues with which they may have concerns. Because the TYSPs are considered to be planning documents and can contain tentative data, they may not necessarily contain sufficient information to allow regional planning councils, water management districts, and other reviewing agencies to evaluate site-specific issues within their respective jurisdictions. Each utility is responsible for providing detailed information based on individual assessments during certification proceedings under the Power Plant Siting Act (PPSA), Sections 403.501-403.518, F.S., or the Transmission Line Siting Act (TLSA), Sections 403.52-403.5365, F.S. In addition, other regulatory processes may require utilities to provide additional information as needed.

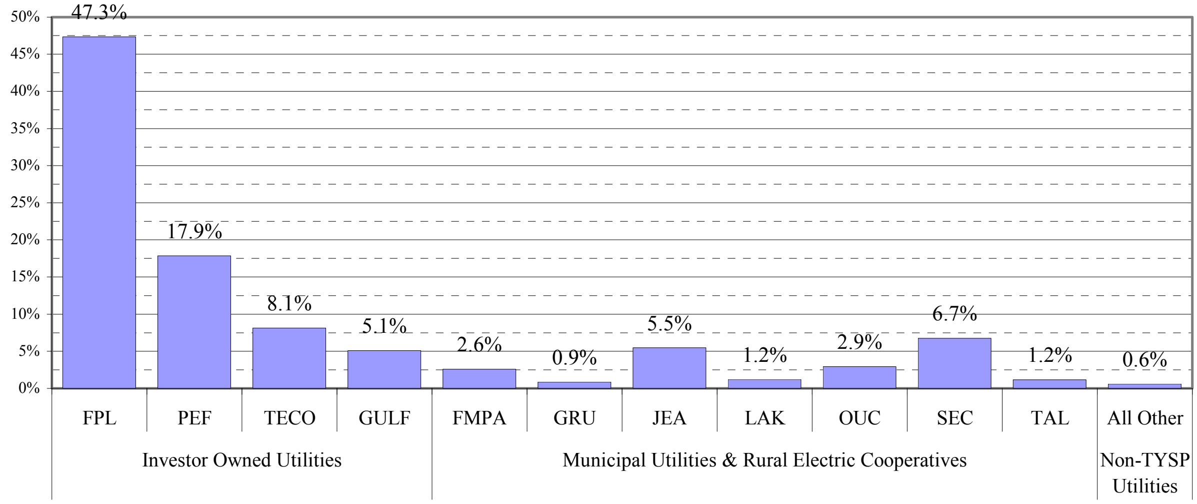
Statutory Authority

Section 186.801, F.S., requires that all major generating electric utilities submit a TYSP to the Commission for annual review. Section 377.703(2)(e), F.S., requires the Commission to analyze these plans and provide natural gas and electricity forecasts to the Department of Agriculture and Consumer Services (DACS). 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.

Florida is served by 58 electric utilities, including 5 investor-owned utilities (IOUs), 35 municipal utilities, and 18 rural electric cooperatives. Only generating electric utilities with an existing capacity above 250 megawatts or a planned unit with a capacity of 75 MW or greater are required to file with the Commission a TYSP, at least once every two years. In 2012, eleven utilities filed TYSPs, including 4 IOUs, 6 municipal utilities, and 1 rural electric cooperative.

Figure 4 below illustrates each TYSP utility's representative share of the state's net energy for load for 2011. In total, the investor-owned TYSP utilities represent 78 percent of net energy for load, with the remaining TYSP utilities contributing 21 percent. Those utilities which are not required to file a TYSP make up the remaining 1 percent.

Figure 4. State of Florida: Percent State Net Energy for Load by Electric Utility (2011 Actual)



Source: FRCC 2012 Load & Resource Plan, Utilities 2012 TYSPs

As outlined in the Commission's rules, each utility's TYSP contains projections of the utility's electric power needs, fuel requirements, and general location of proposed power plant sites and major transmission facilities. The utilities provide historic and projected information on existing generating capacity, customer base and energy usage, impact of demand-side management, fuel consumption, fuel diversity, anticipated reserve margin, and proposed new generating units and transmission.

In accordance with Section 186.801, F.S., the Commission performs a preliminary study of each TYSP and makes a determination as to whether it is suitable or unsuitable. This determination is non-binding, and is made in recognition that the information provided is tentative, and is subject to change by the utility upon written notice. The results of the Commission's study are contained in this report, Review of the 2012 Ten-Year Site Plans, and are forwarded to the DEP for use in subsequent power plant siting proceedings.

Information Sources for the Report

Contained in each utility's TYSP is a series of required tables which provide detailed information on a number of items. This information, supplemented by additional data requests, provides the basis of the Commission's review.

The Florida Reliability Coordinating Council (FRCC) is also an important source of information for the Commission's review. Each year, the FRCC publishes its Regional Load and Resource Plan which contains aggregate data on demand and energy, capacity and reserves, and proposed new generating units and transmission line additions, both for Peninsular Florida and for the state as a whole. In addition to its *2012 Regional Load and Resource Plan*, the Commission used the FRCC's *2012 Reliability Assessment* as a resource in the production of this review. The Commission held a public workshop on August 13, 2012, to facilitate discussion of the annual planning process and the Regional Load & Resource Plan and to allow for public comments on the TYSPs that were filed with the Commission.

Structure of the Report

This report is divided into multiple sections. The Statewide perspective provides a look at the impact of all planned unit additions to the State as a whole, and is intended as a resource for those seeking understanding of Florida's energy systems. Individual utility reports focus on the issues facing each electric utility and its unique situation. Lastly, Appendix A contains comments received from various review agencies, local governments, and others that have been collected and included in this report.

Conclusions

As discussed in each of the individual utility's reviews, the Commission's review of the eleven reporting utilities' 2012 TYSPs finds them all suitable for planning purposes. Through the review process, the Commission has determined that the projections of load growth appear reasonable, and that reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost.

Since the TYSP is not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in any docketed matters before the Commission. The Commission may address any concerns raised by a utility's TYSP at a public hearing.

Statewide Perspective

Forecasting load growth is the first component of system planning for Florida's electric utilities. In order to maintain a reliable system, utilities must stay abreast of changes in customer base as well as trends in demand and energy consumption. Utilities perform load and energy forecasts to estimate the amount and timing of future capacity needs.

Historical data forms the foundation for utility load and energy forecasts. These sets of data include energy usage patterns, trends in population growth, economic variables, and weather data for each utility's service territory. Econometric forecast models are then used to quantify the historical impact of population growth, economic conditions, and weather on energy usage patterns.

Finally, sets of forecast assumptions on future population growth, economic conditions, and weather are assembled and together with the forecast models, yield the final demand and energy forecasts. Each utility's peak demand and energy forecasts serve as a starting point for determining if and when new capacity additions are needed to reliably and efficiently serve the anticipated load.

Customer Growth Projections

The most basic starting point in the utility's forecast modeling is the projected number and type of electric customers. Florida is dominated by the residential class, which makes up a majority in both number of customers and energy sales, as shown in Table 4 below. As a result, Florida's electrical demands and energy requirements heavily focus on residential use patterns. While commercial and industrial customers may be lower in number, they typically consume far more per customer, and combined represent the other half of energy consumed in Florida. Compared to last year, Florida experienced a slight growth in the number of customers, but an overall decline in energy consumption.

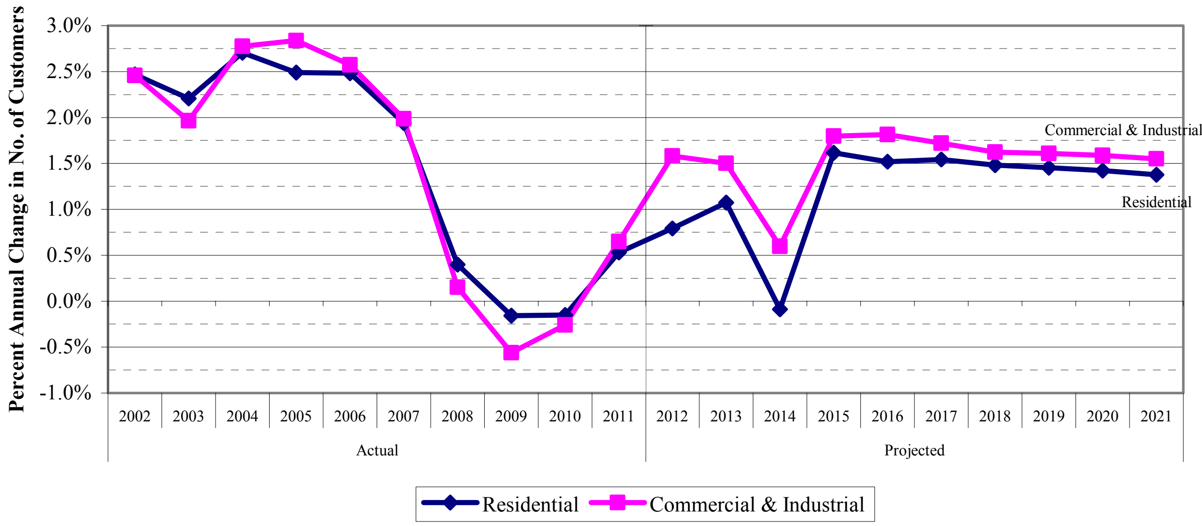
Table 4. State of Florida: Customer Numbers and Energy Usage (2011 Actual)

Customer Class	Number of Customers	% of Customers	Energy Sales (GWh)	% of Sales
Residential	8,369,607	88.71%	113,554	52.97%
Commercial	1,037,584	11.00%	80,284	37.45%
Industrial	27,202	0.29%	20,556	9.59%
Total	**9,434,393**		**214,394**	

Source: FRCC 2012 Load & Resource Plan

Florida's annual customer growth rate in 2011 was positive but significantly below historic norms for all customer classes, and is not anticipated to return to its previous rate during the planning period. Figure 5 shows the actual annual growth rate between 2002 and 2011, and the projected customer growth between 2012 and 2021. The historic data clearly shows the decline from high annual customer growth, resulting in significantly lower or even negative customer growth.

Figure 5. State of Florida: Annual Customer Growth Rate by Customer Class

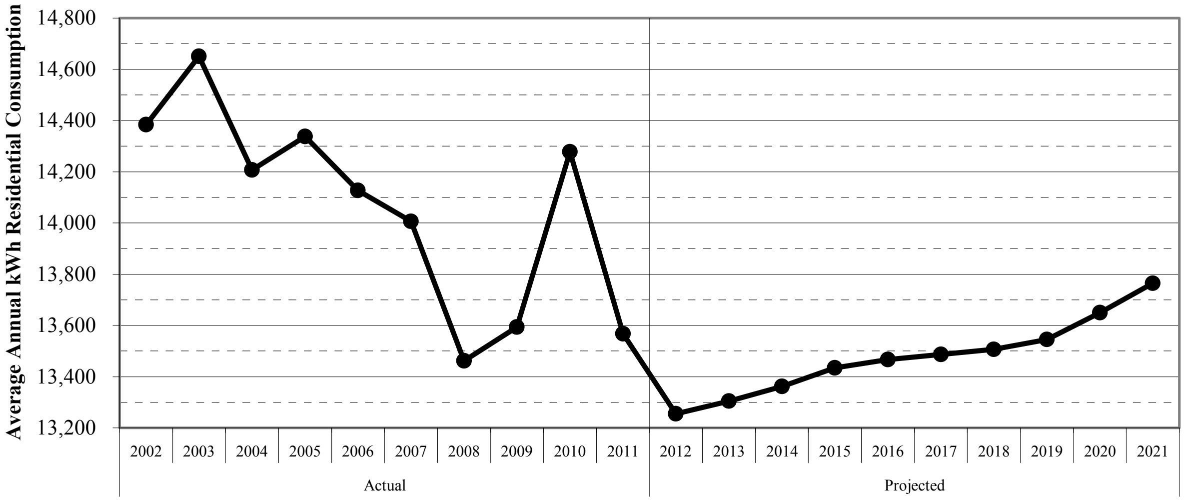


Source: FRCC 2012 Load & Resource Plan

Customer growth is projected to increase and remain higher throughout the planning period, with the exception of 2014. In 2014, both FMPA and SEC note that several member utilities are anticipated to change their service agreements, including the City of Lake Worth (which would leave FMPA's All Requirements Power Supply Project) and Lee County Electric Cooperative (which would no longer be served by SEC), resulting in the declining customer growth seen above in Figure 5.

Florida's energy requirements are heavily dependent on the energy consumption behaviors of residential customers. This relationship is a result of the fact that close to 90 percent of electric customers in Florida are residential accounts, with these customers purchasing more than half the energy sold in the state in 2011. Figure 6 shows the actual per-customer consumption from 2002 through 2011, as well as the projection for the period 2012 through 2021. Actual usage has generally decreased, excluding a spike in 2010 that is attributed to extreme winter weather. Per-customer residential sales are expected to decline in 2012, but then slowly rebound throughout the planning period.

Figure 6. State of Florida: Average Annual Residential Customer Energy Consumption



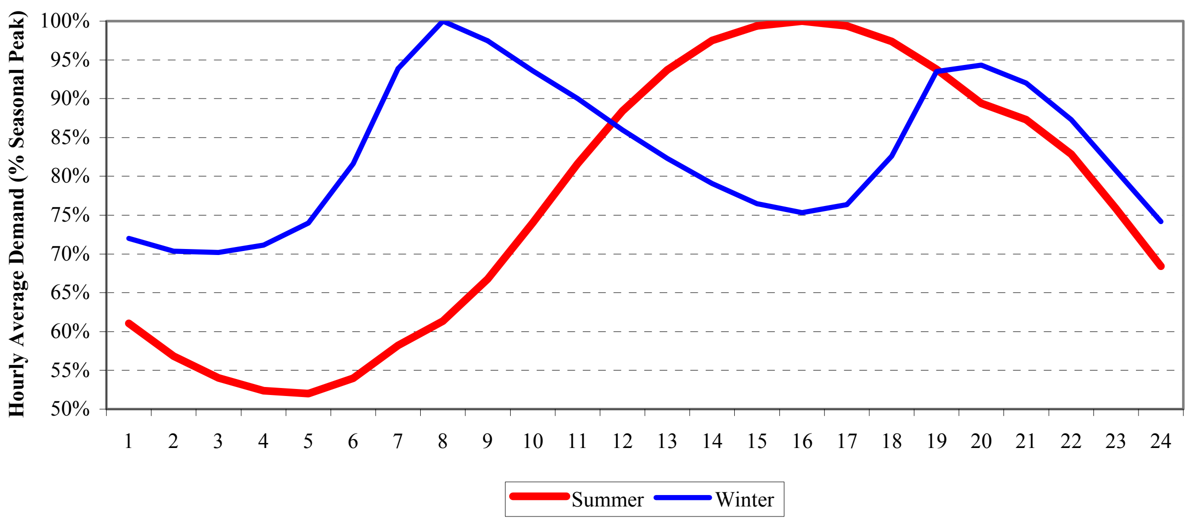
Source: FRCC 2012 Load & Resource Plan

Seasonal Peak Demand Forecast

Since there exists no economically feasible means to store electricity at the grid-scale, electric utilities must supply electricity near instantaneously to the time of its consumption. For a majority of the time, system demand is significantly less than the daily peak. However, system peak demand determines the timing of new generation needs, and is driven by seasonal weather patterns. With a growing customer base dominated by residential customers, both the rate of growth and usage patterns are important considerations in planning sufficient future generation to meet the state's projected customer load.

Figure 7 illustrates typical daily load curves for each season, which shows evidence of the influence of residential customers. In summer, air-conditioning demand causes a steady climb in the morning and a peak in early evening, before declining into the evening. In contrast, winter's demand curve is dominated by electric heating and water heating, causing a rapid peak in mid-morning and a second peak in the late evening.

Figure 7. TYSP Utilities: Example Daily Load Curve



Source: Responses to Staff Data Request (2011)

Florida is typically a summer-peaking state, meaning that the summer peak demand generally controls the amount of generation required. While winter peak demands tend to be greater than summer, the higher peak is offset by the increased winter rating of power plants, which can take advantage of lower ambient air and water temperatures to produce more electricity from the same generating unit. During summer peak demand, higher temperatures instead can decrease generation, as high water temperatures may reduce not only the quality, but quantity of cooling water available based on environmental permits.

As with daily load, there is a great variation in seasonal peak load. Generally speaking, Florida's summer season is significantly longer than its winter. The periods between the seasonal peaks are referred to as "shoulder months," and utilities take advantage of these periods of relatively low demand to perform maintenance without impacting their ability to meet the daily peak demand.

In general, a major controlling factor to seasonal peak demand is short-term weather conditions. While utilities forecast annual peak demand based upon historic factors, customer counts, and normalized weather patterns, utilities also continuously monitor weather conditions in their service territory and prepare for any increases (or decreases) in customer demand. By close monitoring of the weather situation, utilities can fine tune maintenance schedules to ensure the highest unit availability during time of the utility's peak demand.

Demand Side Management

The first step in any resource planning process is to focus on the efficient use of electricity by consumers. Government mandates, such as building codes and appliance efficiency standards, provide the starting point for increasing energy efficiency. Customer choice is the next step in reducing the state's dependence upon expensive fuels and lowering greenhouse gas emissions. Consequently, educating consumers to make smart energy choices is particularly important. Finally, Florida's utilities can efficiently serve their customers by offering DSM and conservation programs designed to use fewer resources at lower cost.

The Florida Legislature directed the Commission to encourage utilities to decrease the growth in seasonal peak demand and energy consumption in Sections 366.80 through 366.85 and Section 403.519, F.S., known as the Florida Energy Efficiency and Conservation Act (FEECA). Under FEECA, the Commission is required to set goals for demand and energy reduction for 7 electric utilities, namely the 5 investor-owned electric utilities (4 of which file TYSPs, the exception being Florida Public Utility Company, which is a non-generating utility) and 2 municipal electric utilities (JEA and OUC). These utilities represent 87 percent of sales in Florida.

DSM Programs generally fall into three categories: interruptible/curtailable load (INT), load management (LM), and conservation. The first two are generally considered dispatchable, meaning that the utility can call upon them during a period of peak demand, but otherwise they are not in active use. In contrast, conservation measures are considered passive and are always working to reduce customer demand.

Interruptible or curtailable load is achieved through the use of agreements with large customers to allow the utility to interrupt selected portions of the customer's load during periods of peak demand. Interrupted or curtailed customers could make up for this generation by reducing their own industrial processes or by activating back-up generation. In exchange for the ability to reduce their electrical load, the utility usually offers such customers a discounted rate for energy or other credits which are paid for by all customers.

Load management programs involve the installation of a device that can interrupt a customer's appliance(s) for a short duration during a period of peak demand. These interruptions tend to have less notice than those provided to interruptible customers, and generally do not fully disconnect customers, but interrupt an individual appliance. Normally, interruptions are kept to short periods and are cycled between groups of customers. Due to the nature of the program, certain devices would be more appropriate to handle different seasonal demands. For example, air conditioning units would be interrupted to reduce a summer peak, while water heaters being interrupted may contribute more towards reducing a winter peak. As of 2012, over 7,165 MW of interruptible load and load management is available for summer peak, and is anticipated to expand to 9,219 MW by 2021.

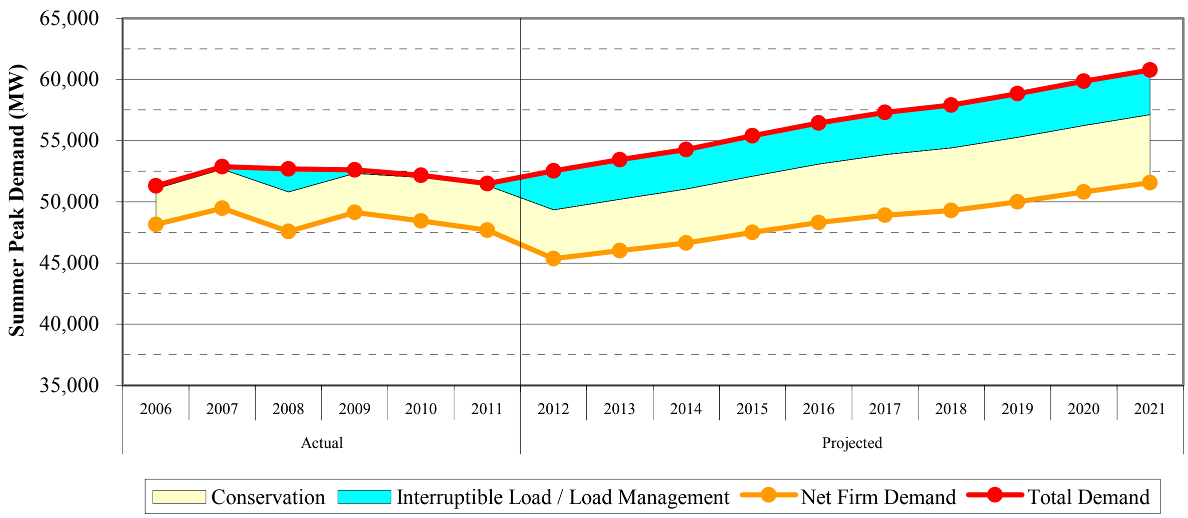
In addition to active measures, customer-based conservation measures can have an impact on peak demand without requiring activation by the utility. These passive conservation measures typically involve improving a home or business' building envelope, such as greater insulation and energy-efficient windows, or installing more efficient appliances. These energy efficiency improvements decrease the customer's load at all times without requiring an interruption or reduction in service, and also have an impact on annual energy consumption.

The seven FEECA utilities currently offer DSM programs to residential, commercial, and industrial programs. Energy audit programs provide a first step for utilities and customers to evaluate conservation opportunities and serve as the foundation for other programs.

Projected Peak Demands

Figure 8 below shows the historic and projected total summer peak demand, as well as demand side management impacts and the resulting net firm demand experienced by the utilities. While summer peak demand has been relatively steady in the past few years, demand is anticipated to increase steadily throughout the planning period. Interruptible load and load management programs have not been fully implemented in past years, with the primary impact shown below in 2008. When planning for future load, the electric utilities use net firm seasonal demand.

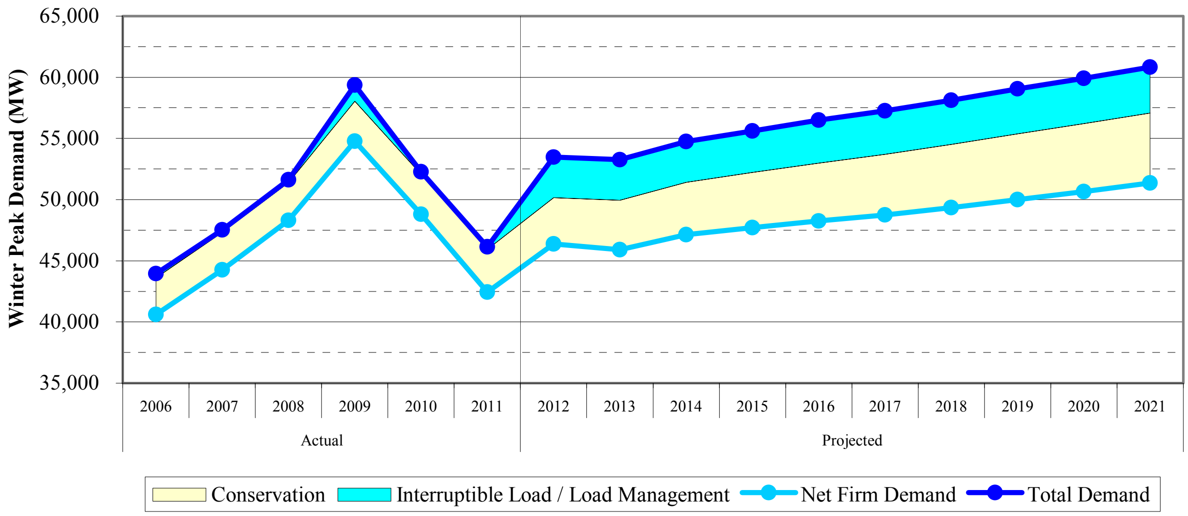
Figure 8. State of Florida: Historic & Projected Summer Peak Demand (With DSM Impacts)



Source: FRCC 2008 - 2012 Load and Resource Plans

Figure 9 below shows the historic and projected total winter peak demand, as well as DSM impacts and the resulting net firm demand experienced by the utilities. As with summer peak demand, demand response resources have not historically been fully utilized, as shown by the small reduction in the actual firm demand.

Figure 9. State of Florida: Historic & Projected Winter Peak Demand (With DSM Impacts)

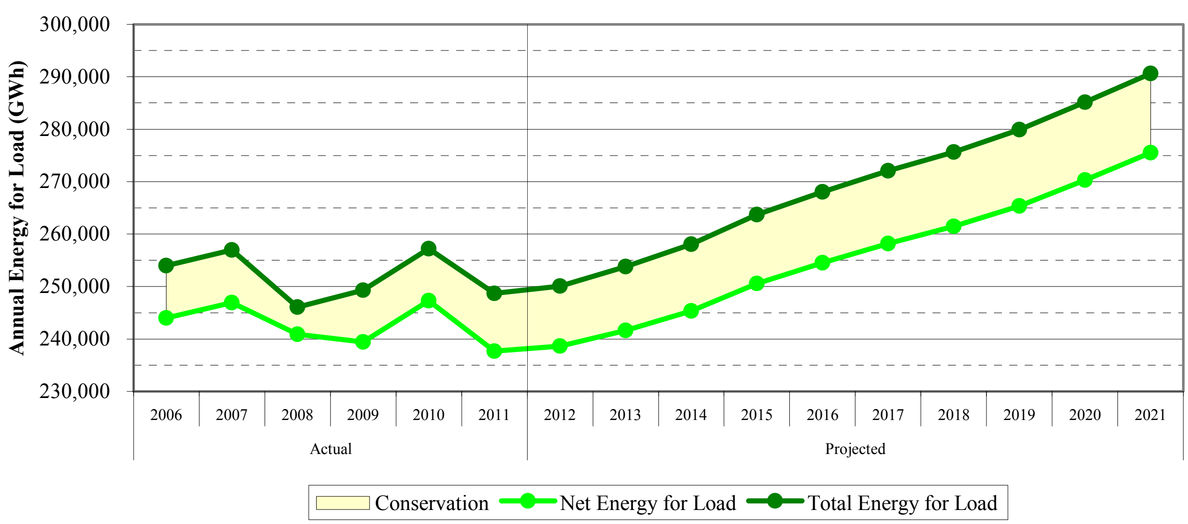


Source: FRCC 2008 - 2012 Load and Resource Plans

Annual Energy Consumption Forecasts

While peak demand is the instantaneous usage of a customer on the system, annual energy consumption addresses the total cumulative demand on the system over time, which determines the type of units required and the resulting amount of fuel consumed. Figure 10 below shows the historic and projected annual energy for load for the state of Florida. While energy consumption has been relatively steady for the past few years, it is anticipated to increase steadily through the end of the planning period.

Figure 10. State of Florida: Historic & Projected Annual Energy for Load (With DSM Impacts)



Source: FRCC 2008 - 2012 Load and Resource Plans

Historical Accuracy of Energy Forecasts

For each utility filing a TYSP, the Commission reviewed the historical forecast accuracy of total retail energy sales for the five-year period 2007 to 2011. The review compared actual energy sales for each year to energy sales forecasts made three, four, and five years prior. For example, the actual 2007 energy sales were compared to the projected 2007 forecasts made in 2002, 2003, and 2004. These differences, expressed as a percentage error rate, were used to calculate the utility's historical forecast accuracy.

Table 5 below illustrates the historical forecast error for 2012 and 2011, on an average error and average absolute error basis. The calculated average error is positive for all TYSP utilities, this shows a tendency to over-forecast, with the resulting average forecast error for all TYSP utilities combined at 11.38 percent in 2012, an increase from 8.45 percent in 2011.

Table 5. TYSP Utilities: Historical Accuracy of Net Energy for Load Forecasts

TYSP Utility	Forecast Error (%)			
	2012 (Years 2011 – 2007)		2011 (Years 2010 – 2006)	
	Average	Average Absolute	Average	Average Absolute
FPL	12.12%	12.12%	10.92%	10.97%
PEF	11.36%	11.90%	6.17%	7.05%
TECO	13.07%	13.07%	8.95%	8.95%
GULF	5.44%	7.37%	1.97%	5.62%
FMPA	11.81%	13.99%	6.09%	12.83%
GRU	11.40%	11.40%	8.32%	8.32%
JEA	12.72%	12.72%	9.78%	9.78%
LAK	7.89%	7.89%	5.69%	5.69%
OUC	5.83%	5.83%	5.87%	6.61%
SEC	11.41%	12.63%	4.41%	8.38%
TAL	8.77%	8.85%	7.04%	7.28%
Weighted Average	**11.38%**	**11.38%**	**8.45%**	**8.63%**

Source: Staff Calculation based on Utilities 2001 – 2012 TYSPs

The high error rate, increased from last year's, represents the impact of the recession on energy usage in Florida. This analysis primarily uses forecasts developed from between 2002 and 2008, a majority of which occurred before the recession. Due to the unexpected nature of the recent recession, it could not have been included in forecasts as far as 5 years preceding the event. As this analysis moves forward and begins to use forecasts developed after the beginning of the recession, the error rate should fall back to typical levels.

As indicated by this high error rate, utilities projected increased need for energy that has not materialized due to the recession. As discussed below, Florida currently has an excess of generation, in part due to these projections. The TYSP utilities have responded to changing circumstances by delaying or cancelling new generation, as discussed in previous annual reviews of the TYSPs.

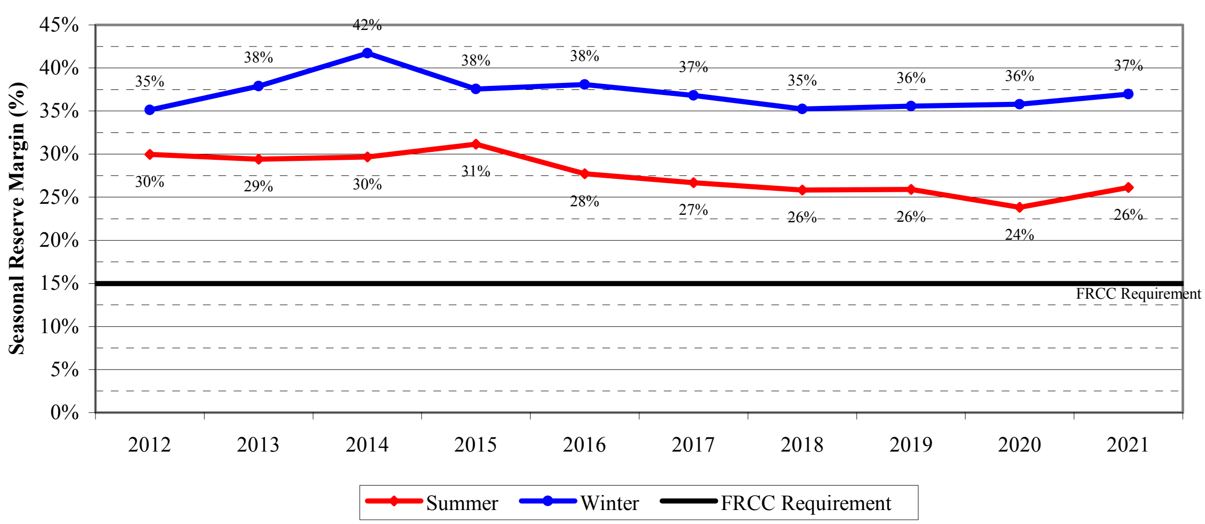
Reserve Margin Requirements

In order to maintain stability in the electric system, utilities must constantly adjust system output to match demand from moment to moment. As demand fluctuates, utilities must generate the precise amount of electrical power that will keep the system in balance while also performing periodic maintenance on its generating units. In addition, utilities must be prepared at any moment to meet unforeseen circumstances, such as extreme weather events or unit outages. Therefore, each utility must maintain a certain amount of "extra" or reserve capacity in the event that demand rises above or supply drops below forecasted levels. This additional amount of generating capacity is expressed as a percentage of firm demand and is referred to as the reserve margin.

Reserve margins in Florida typically remain well above the FRCC minimum of 15 percent for most of the year, and usually will only approach minimum levels in the summer peak season when air conditioning loads are at their highest levels. The higher margins during winter peak seasons are also due to the fact that generating units can operate at a higher capacity in colder temperatures. The three largest IOUs, FPL, PEF, and TECO, were party to a stipulation approved by the Commission setting a 20 percent reserve margin planning criterion.

The values in Figure 11 below include both supply-side and demand-side contributions, and shows that planning is mostly controlled by summer peak demand. It should be noted that the figure below is for the State of Florida, and therefore contains generating capacity outside of the FRCC region.

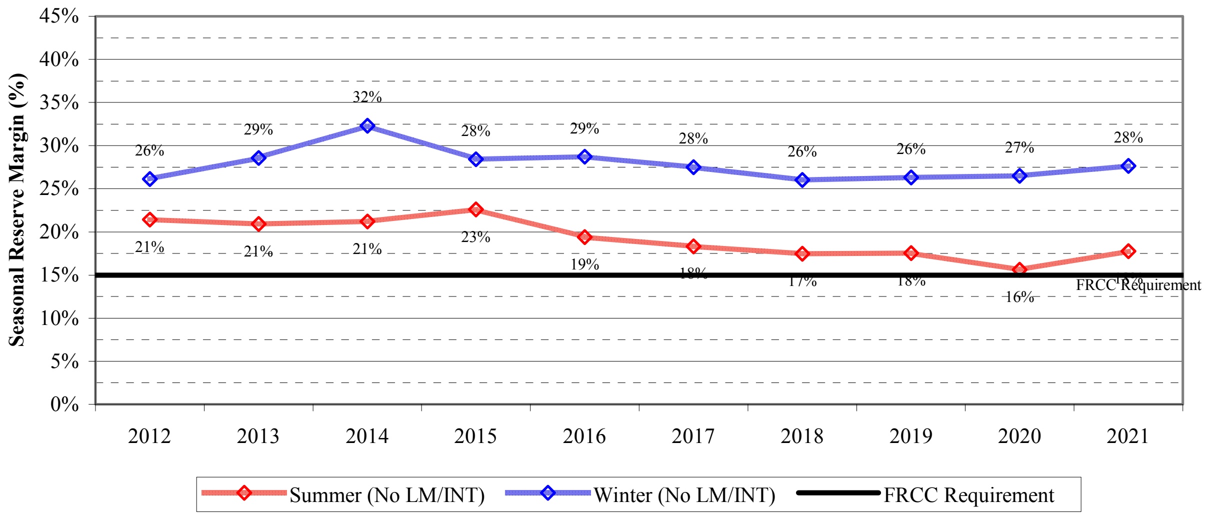
Figure 11. State of Florida: Seasonal Reserve Margin (With LM/INT)



Source: FRCC 2012 Load and Resource Plan

It should be noted that the reserve margin figures above are calculated using the net firm system demand, which assumes full use of interruptible load and load management devices to reduce peak demand. Participation in interruptible rates and load management programs are voluntary, for which incentives are provided in the form of lower rates or credits paid to the participant. As shown in Figure 12 below, the state as a whole has sufficient generation capacity planned throughout the period to meet the minimum reserve margin of 15 percent without relying on interruptible and load management customers.

Figure 12. State of Florida: Seasonal Reserve Margin (Without LM/INT)

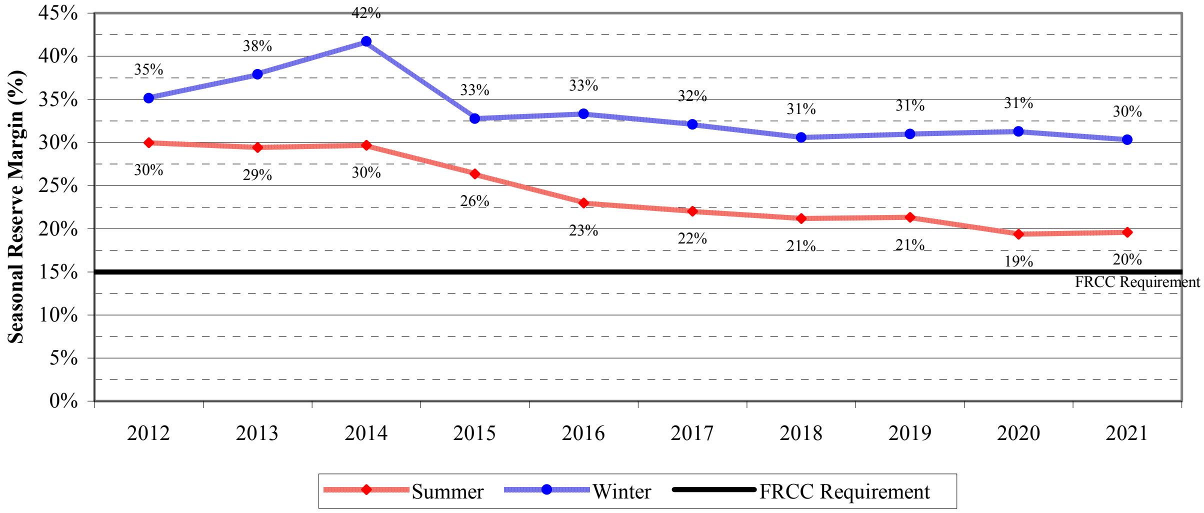


Source: FRCC 2012 Load and Resource Plan

The previous two figures have assumed that the expansion plans filed in the utilities TYSPs will continue as planned. Since the filing of the 2012 TYSPs, PEF has delayed the in-service date of the Levy 1 nuclear unit outside of the planning period. Staff is also aware of the long-term outage at PEF's CR3 nuclear unit, which is currently offline and scheduled to return to service in November 2014 if repaired. Retirement remains an open option for this unit in the event it is determined to be uneconomic to repair, which would have an impact on the statewide reserve margin. In addition, several coal-fired plants were identified at the Commission's Workshop on the 2012 Ten-Year Site Plans, which if retired would further decrease the state's reserve margin.[3] Figure 13 shows the total impact of the delay or potential retirement of all the units discussed above and that the state should still retain sufficient generating capacity. The potential impacts to PEF and GULF are discussed in the individual utility section of the report.

[3] Specifically, PEF's Crystal River 1 and 2 and GULF's Lansing Smith 1 and 2.

Figure 13. State of Florida: Seasonal Reserve Margin After Potential Unit Retirements (With LM/INT)



Source: FRCC 2012 Load and Resource Plan, Staff Calculation

Federal Legislation

In 1978, the U.S. Congress enacted the Public Utility Regulatory Policies Act (PURPA)[4]. PURPA endorsed three broad national purposes: (1) conservation of electric energy, (2) increased efficiency in the use of facilities and resources by electric utilities, and (3) equitable rates for electricity consumers. Section 210 of Title II, entitled "Cogeneration and Small Power Production," required electric utilities to interconnect and sell electric energy to qualifying cogeneration and small power production facilities, referred to as Qualifying Facilities, or QFs, and to purchase electric energy from these facilities at the utility's full avoided cost. The Federal Energy Regulatory Commission (FERC) subsequently adopted rules to implement PURPA. In addition, states were delegated authority to implement the FERC rules for electric utilities over which they have rate making authority.[5] In 1980, the FERC issued its rules establishing the criteria for determining the qualifying status of a facility and setting out regulations for electric utility interconnection with QFs, along with sales to and purchases from QFs.[6]

State Legislation

In 1981, the Florida Legislature authorized the Commission to establish guidelines for the purchase and sale of capacity and energy from cogenerators and small power producers, which includes renewable generators. In 1989, the statutes were broadened with the enactment of Section 366.051, F.S., which provides, in part, the following:

> Electricity produced by cogeneration and small power production is of benefit to the public when included as part of the total energy supply of the entire electric grid of the state or consumed by a cogenerator or small power producer. The electric utility in whose service area a cogenerator or small power producer is located shall purchase, in accordance with applicable law, all electricity offered for sale by such cogenerator or small power producer; or the cogenerator or small power producer may sell such electricity to any other electric utility in the state. The Commission shall establish guidelines relating to the purchase of power or energy by public utilities from cogenerators or small power producers and may set rates at which a public utility must purchase power or energy from a cogenerator or small power producer. In fixing rates for power purchased by public utilities from cogenerators or small power producers, the Commission shall authorize a rate equal to the purchasing utility's full avoided costs. 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.

[4] Public Law 95-617 (HR 4018) November 9, 1978.
[5] PURPA at Title II, section 210(f); In Florida, the Florida Public Service Commission has ratemaking jurisdiction over five investor-owned electric utilities: Florida Power & Light Company (FPL), Progress Energy Florida (PEF), Gulf Power Company (Gulf), Tampa Electric Company (TECO), and Florida Public Utilities Company (FPUC).
[6] 18 C.F.R. 292.101 through 18 CFR 292.602.

In 2005, the Legislature enacted Section 366.91, F.S., which requires IOUs to continuously offer purchase contracts to producers of renewable energy, and adopts the avoided cost standard as defined in Section 366.051, F.S. Section 366.91, F.S., also defines the term "renewable energy" as follows:

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

Commission Rules

Renewable facilities are permitted to enter into two types of contractual agreements for selling power: standard offer and negotiated contracts. Under these contracts, the energy can be sold as either "firm" or "as-available," depending on the characteristics of the output of the facility. When the output is continuous, except for occasional shutdowns for maintenance and repair, the utility also makes payments for the dependable capacity. These contract and payment options are outlined in Rules 25-17.0825 and 25-17.0832, F.A.C.

Standard Offer Contracts

Standard offer contracts are pre-approved contracts for the purchase of firm capacity and energy from any renewable generating facility or small QF. Rule 25-17.230, F.A.C., requires each investor-owned electric utility to establish a standard offer contract for each fossil-fueled generating unit type identified in the utility's TYSP. The renewable energy generator is allowed to select from a number of payment options that best fits its financing requirements as long as the total cumulative present value of such payments does not exceed full avoided cost, and adequate security for front-end loaded payments is provided. For example, the Commission rules allow for levelized payments over the life of the contract which may include both capacity and energy costs.

Negotiated Contracts

Renewable generating facilities are encouraged to negotiate purchased power contracts with IOUs pursuant to Rule 25-17.240, F.A.C. Payments made to a qualified renewable generator under a negotiated contract may be recovered from ratepayers by the purchasing utility as long as the cumulative present value of the payments does not exceed the utility's full avoided cost and adequate security for front-end loaded payments is provided.

Renewable Payment Types

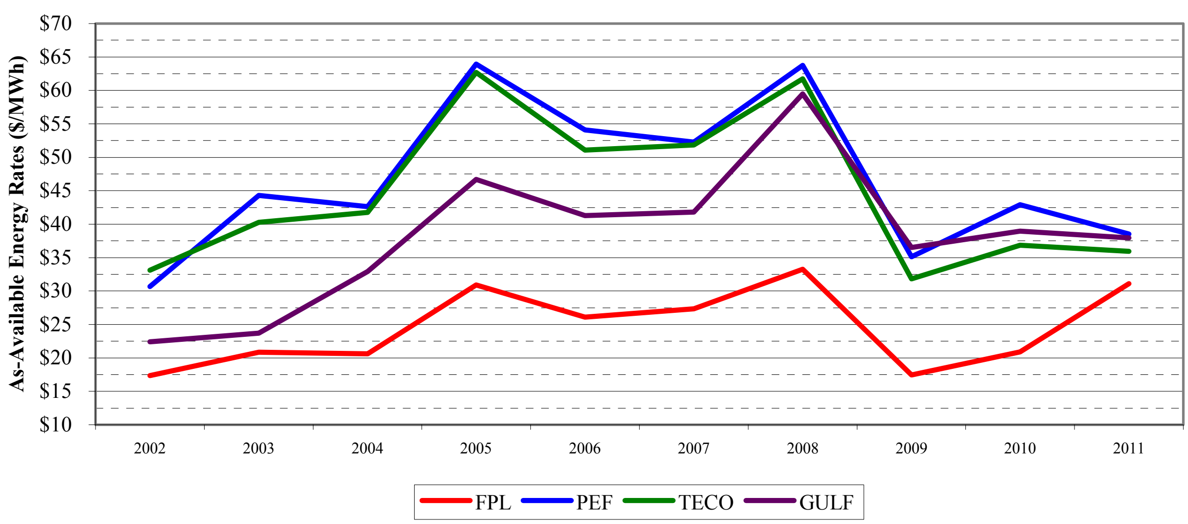
Pursuant to current state and federal law, payments made by utilities to generation facilities using renewable energy sources are capped at the utility's avoided cost for capacity and energy.

Firm capacity payments: Firm capacity is capacity (MW) produced and sold by a renewable energy generator pursuant to a standard offer contract or a negotiated contract subject to contractual commitments as to the quantity, time, and reliability of delivery. Firm capacity is purchased at a rate specified in a contract which is equal to the utility's avoided capacity cost or at a negotiated rate which may not exceed the utility's avoided capacity cost. Full avoided cost is calculated by determining the cumulative present value of a year-by-year value of deferring each avoided unit over the term of the contract.

Firm energy payments: Firm energy is energy (kWh) produced and sold by a renewable energy generator pursuant to a negotiated contract or a standard offer contract subject to contractual commitments as to the quantity, time, and reliability of delivery. Generally, the rate of payment for firm energy, in cents per kWh, is the lesser of the fuel cost associated with the avoided unit or the utility system's incremental fuel cost.

As-available energy payments: As-available energy is energy (kWh) produced and sold by a renewable energy generator on an hour-by-hour basis for which contractual commitments as to the quantity, time, or reliability of delivery are not required. As-available energy is purchased at a rate in cents per kilowatt hour (kWh) equal to the utility's hourly incremental system fuel cost, which reflects the highest fuel cost of generation dispatched each hour. No capacity payments are made for as-available energy because no reliability benefits are received. Figure 14 below illustrates historic as-available energy payments from the investor-owned TYSP utilities for the period 2002 through 2011. When natural gas prices spiked in 2008, averaging $10/MMBtu, as-available energy rates rose as well. As natural gas prices have declined since 2008, as-available energy rates have also decreased.

Figure 14. Investor Owned Utilities: Average Annual As-Available Energy Rates



Source: Responses to Staff Data Requests

Renewable Resource Outlook

In 2003, the Commission, in consultation with the DEP, completed the 2003 Renewable Energy Assessment Report to identify renewable energy viability in Florida. According to the report, the most feasible sources of renewable energy in Florida are from biomass materials, such as agricultural waste products or wood residues, and industrial waste heat. The 2003 report also stressed that technical feasibility does not ensure economic cost-effectiveness when determining energy resource production.

The Commission, in conjunction with the U.S. Department of Energy and the Lawrence Berkeley National Laboratory, retained Navigant Consulting, Inc. to prepare a detailed assessment of Florida's renewable potential. The 2008 Navigant Consulting Renewable Energy Potential Assessment (the 2008 Navigant Consulting Report) reported on the existing renewable conditions and the projected potential for renewable development in Florida through 2020, compared cost-effective differences, and considered the potential levels of economic impact future renewables may have. The 2008 Navigant Consulting Report substantiated the Commission's 2003 assessment by observing that the majority of Florida's existing renewables consist of solid biomass plants and municipal solid waste facilities. Although the 2008 Navigant Consulting Report considered solar technologies to have the largest technical potential of any renewable resource in Florida, only a portion of this potential can actually be economically achieved at this time.

The 2008 Navigant Consulting Report described the comparison of the technical or physical potential versus the achievable potential for renewable energy development in Florida. For example, although the technical potential for solar power in Florida may be relatively high according to Navigant Consulting, cost-effectiveness and siting issues significantly reduce the achievable potential to commercially develop solar energy technology. The driving forces to the expansion and sustainability of the renewable market depend on the overall value of renewable energy, a basis that is determined by the financial environment as well as government regulation and support. As noted in the 2008 Navigant Consulting Report, a favorable scenario for the renewable market which has meaningful growth in Florida assumed the following:

1. High fossil fuel costs
2. Access to low cost capital and debt rates
3. Continual government rebate programs and tax incentives
4. Established pricing of CO_2 emissions
5. Formation of a Renewable Energy Certificate (REC) market

Since the 2008 Navigant Consulting Report was completed, economic and policy conditions have not been favorable for future renewable development. Specifically, Navigant Consulting assumed in their 2008 natural gas costs to be $11-$14/MMBtu in the favorable scenario. Natural gas is currently trading at approximately $2.95/MMBtu. Most forecasts project natural gas prices to gradually increase over the long term.

In the favorable scenario, Navigant assumed the estimated cost of debt to be approximately 6.5 percent, the cost of equity approximately 10 percent, and ready access to debt would make up 70 percent of renewable project financing. Currently credit markets are still tight for small businesses, and obtaining financing for renewable energy projects will be much more difficult for a smaller company than for a large utility.

In the favorable scenario, Navigant Consulting estimated that Florida's solar rebate program would expire in 2020, with a $10 million annual funding level. The Florida Energy and Climate Commission was authorized to provide $25.4 million in rebates for solar energy equipment between 2006 and 2009. Currently the authorized budget has been depleted. Also, the favorable scenario for carbon pricing assumes $2/ton initially, then scaling to $50/ton by 2020. Currently, there is no federal or state policy establishing carbon pricing. The favorable scenario also envisioned the creation of a Renewable Energy Credit (REC) market, with REC prices of approximately $18/MWh initially, decreasing to $11/MWh by 2020. At this time, no Renewable Energy Credit market has been established in Florida.

Table 6 below compares selected assumptions included in Navigant's favorable scenario and current market conditions. As detailed in the table, most current market conditions are not aligned with Navigant's favorable scenario for renewable generation development.

Table 6. State of Florida: Market Outlook for Renewable Energy

Market Area	2008 Navigant Consulting Report Favorable Scenario	Current Market Conditions
Natural Gas Prices ($/MMBTU)	$11 - $14	$3 - $4
Access to Capital & Debt	Available at Low Cost	Credit Markets Tight
Florida Solar Rebate Program	Expires in 2020, $10M/year	No Funds Allocated
CO2 Emissions Pricing ($/ton)	$2 (2009) to $50 (2020)	No pricing established
Renewable Energy Certificates ($/MWh)	$18 (2009) to $11 (2020)	No REC Market established

Source: 2008 Navigant Consulting Report, Responses to Staff Data Requests

Existing Renewable Resources

Currently, renewable energy facilities provide approximately 1,400 MW of gross electric generation capacity as reported by the FRCC. Compared to figures in the 2011 Ten-Year Site Plan Review, existing renewable generation facilities have increased by approximately 120 MW, or 9 percent. Table 7 summarizes Florida's existing renewable resources.

Table 7. State of Florida: Existing Renewable Generation Capacity

Renewable Type	Capacity (MW)
Solar	143.3
Wind	0.0
Biomass	401.5
Municipal Solid Waste	453.7
Waste Heat	297.1
Landfill Gas	58.4
Hydro	55.7
Total	**1,400**

Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

Firm Capacity Contracts

Roughly 28 percent of all renewable capacity in Florida is from renewable generators with firm capacity contracts, which are required to provide a particular amount of capacity for a specified period of time pursuant to contractual obligations. Approximately 78 percent of this renewable capacity consists of municipal solid waste (MSW) facilities. Although the majority of firm capacity is purchased by investor-owned utilities, a significant portion (137.8 MW) is purchased by Seminole Electric Company (SEC).

Table 8 lists the existing renewable generators that provide firm capacity. Significant changes in the firm contracts since 2011 include rerates from FPL's Palm Beach County Facility, SEC's Lee County Resource Recovery Facility, and a new contract agreement for firm energy between McKay Bay Waste to Energy Facility with SEC.

Table 8. State of Florida: Firm Renewable Resources

Purchasing Utility	Facility Name	Fuel Type	Gross Capacity* (MW)	Commercial In-Service Date
Investor-Owned Utilities				
FPL	(Wheelabrator) Broward-South	MSW	68	1987
FPL	(Wheelabrator) Broward-North	MSW	62	1992
FPL	Solid Waste Authority of Palm Beach	MSW	40	2005
PEF	Pinellas County Resource Recovery	MSW	61.7	1983
PEF	Lake County Resource Recovery	MSW	14.8	1990
PEF	Dade County Resource Recovery	MSW	43	1991
PEF	Pasco County Resource Recovery	MSW	26	1991
PEF	Ridge Generating Station	WDS	39.6	1994
	Subtotal of IOUs		**227.7**	
Municipal Utilities				
GRU	G2 Energy	LFG	4	2008
GRU	Solar FIT Program/Net Meter	SUN	26.8	2009
JEA	Trailridge	LFG	9	2008
	Subtotal of Municipals		**22.3**	
Cooperative Utilities				
SEC	Lee County Resource Recovery	MSW	50	1999
SEC	Telogia Power, LLC	WDS	13	2004
SEC	Seminole Landfill	LFG	6.2	2007
SEC	Brevard Energy	LFG	9	2008
SEC	Timberline Energy	LFG	1.6	2008
SEC	Hillsborough Waste to Energy	MSW	42.6	2010
SEC	McKay Bay Waste to Energy	MSW	22	2011
	Subtotal of Cooperatives		**137.8**	
	Total		**387.8**	

*The capacity listed here represents the gross capacity of the unit, which may be in excess of the contracted firm capacity of the generating unit.
Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

Non-Firm Renewable Energy Generators

In addition to the 387.8 MW of firm capacity described in Table 8 above, renewable energy facilities with a total capacity of 680.7 MW produce energy for sale to utilities on an as-available basis. Energy purchased on an as-available basis is considered non-firm capacity, and therefore cannot be counted on by Florida's utilities for reliability purposes. The energy produced by these providers, however, does contribute to the avoidance of burning fossil fuels in existing generators. Table 9 details the various non-firm energy contracts.

Table 9. State of Florida: Non-Firm Renewable Resources

Purchasing Utility	Facility Name	Fuel Type	Gross Capacity (MW)	Commercial In-Service Date
Investor-Owned Utilities				
FPL	New Hope / Okeelanta	AB	130	1991
FPL	Georgia Pacific	WDS	56.8	1995
FPL	Tomoka Farms	LFG	3.8	1998
FPL	MMA FLA LP	SUN	0.3	2007
FPL	WM Renewable Energy	LFG	8	2010
PEF	Potash Of Saskatchewan	WH	44.2	1986
PEF	Buckeye	WDS	52.3	1993
PEF	G2	LFG	3.5	2008
TECO	Mosaic: South Pierce	WH	30	1969
TECO	Mosaic: New Wales	WH	79	1984
TECO	CF Industries	WH	34.9	1988
TECO	City Of Tampa Sewage	OBG	1.5	1989
TECO	Mosaic: Ridgewood	WH	62	1992
TECO	Mosaic: Millpoint	WH	47	1995
GULF	Stone Container	AB	25	1960
GULF	International Paper Company	WDS	56	1983
GULF	Bay County Solid Waste	MSW	13.6	2008
	Subtotal of IOUs		**647.9**	
Municipal Utilities				
FMPA	US Sugar Corporation	AB	26.5	1984
LAK	Lakeland Center (Solar)	SUN	0.3	2010
OUC	Regenesis Stanton Energy Center	SUN	6	2011
	Subtotal of Municipals		**32.8**	
	Total		**680.7**	

Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

Utility-Owned Renewable Facilities

Several utilities also own renewable facilities, primarily solar generation, landfill gas, and hydroelectric technologies. Table 10 lists some of the larger utility-owned resources, which consist mostly of non-firm or intermittent resources.

Table 10. State of Florida: Utility Owned Renewable Generation

Purchasing Utility	Facility Name	Fuel Type	Gross Capacity (MW)	Commercial In-Service Date
Investor-Owned Utilities				
FPL	DeSoto	SUN	25	2009
FPL	Martin	SUN	75	2010
FPL	Space Coast Next Generation	SUN	10	2010
GULF	Perdido 1	LFG	1.8	2010
GULF	Perdido 2	LFG	1.8	2010
	Subtotal of IOUs		**113.6**	
Municipal Utilities				
JEA	North Landfill	LFG	1.5	1997
JEA	Girvin Landfill	LFG	1.2	1999
JEA	Buckman	OBG	0.8	2003
OUC	Co-Fired Stanton Energy Center	LFG	7	1998
TAL	Corn Hydro	WAT	12.2	1985
	Subtotal of Municipals		**22.7**	
Other Utilities				
UCEM	Jim Woodruff	WAT	43.5	1957
	Subtotal of Other		**43.5**	
	Total		**179.8**	

Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

Because most of the energy produced is non-firm, the majority of these renewable facilities serve more to reduce fossil fuel consumption than to provide system capacity. Among some of the recent notable additions to utility-owned renewables are the construction and operation of three solar generators by FPL in 2009 and 2010. The DeSoto, Martin, and Space Coast facilities are currently the largest solar facilities in Florida.[7] Also in 2010, GULF commissioned two landfill gas generation facilities, Perdido 1 and 2, to provide that utility with a total renewable gross capacity of 3.6 MW.

Existing Net Metering

Net metering is an arrangement between a utility and a customer with renewable generation capability whereby the customer's energy usage is offset, or credited, by the amount of energy generated. The customer will be billed for any net energy consumed that exceeds the energy generated.

In April 2008, the Commission amended Rule 25-6.065, F.A.C., on interconnection and net metering for customer-owned renewable generation. The rule 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. Customers benefit from

[7] The DeSoto and Space Coast facilities are direct energy-producing photovoltaic facilities, whereas the Martin facility uses thermal heat to create replacement steam for a pre-existing steam turbine usually supplied through fossil fuel generation.

such renewable systems by reducing their energy purchases from the utility and potentially selling excess energy to the utility.

The Commission's rule requires all electric utilities to annually report data associated with interconnection and net metering programs. Data submitted in April 2010 show that the number of customers owning renewable generation systems in Florida continues to grow. Statewide, a total of 29.3 MW of solar photovoltaic (PV) capacity from 3,994 systems have been installed, up from 2.8 MW produced by 537 systems in 2008. Table 11 displays the information on customer-owned renewable generation for 2011 reported by Florida's utilities.

Table 11. State of Florida: Customer Owned Renewable Generation

Utility Type	Connections	Non-Firm Capacity (MW)
Investor-Owned	2,826	20.4
Municipal	615	5.0
Rural Electric Cooperatives	553	3.9
Total	**3,994**	**29.3**

Sources: 2012 Interconnection and Net Metering of Customer-Owned Generation Report

Planned Renewables Additions

Florida's utilities plan to construct or purchase an additional 957 MW of renewable generation over the ten-year planning period. The expected major contributors to actual energy generation are planned biomass resources. Table 12 summarizes the overall proposed planned increases by generation type of all utilities. The largest source of planned renewable generation comes in the form of non-firm solar capacity built by a single vendor, National Solar. The company has as-available energy contracts with PEF, and as they have no capacity portion, are not considered for reliability purposes.

Table 12. State of Florida: Planned Renewable Resource Net Additions

Fuel Type	Capacity (MW)
Solar	**553.4**
Wind	**0**
Biomass	**321**
Municipal Solid Waste	**70**
Waste Heat	**0**
Landfill Gas	**13**
Hydro	**0**
Total	**957.4**

Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

As of January 2012, firm capacity contracts represent 39 percent of total planned renewable additions. Table 13 and Table 14, provide detailed lists of the renewable resources planned for construction in Florida over the ten-year planning horizon. Table 13 shows that, of the renewable firm capacity planned over the ten-year horizon, the majority is woody biomass that will be purchased by PEF and GRU.

Table 13. State of Florida: Planned Firm Renewable Resources

Purchasing Utility	Facility Name	Fuel Type	Gross Capacity* (MW)	Commercial In-Service Date
Investor-Owned Utilities				
PEF	FB Energy	AB	60	2013
PEF	Trans World Energy	WDS	40	2013
PEF	US EcoGen	WDS	60	2014
FPL	Solid Waste Authority of Palm Beach	MSW	70	2016
	Subtotal of IOUs		**230**	
Municipal Utilities				
JEA	Trailridge	LFG	9	2012
OUC	Port Charlotte	LFG	4	2012
OUC	Harmony	WDS	5	2012
GRU	American Renewables LLC	WDS	116	2013
GRU	Solar FIT Program	SUN	9.3	2021
	Subtotal of Municipals		**143.3**	
	Total		**373.3**	

Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

Table 14 shows that most of the non-firm capacity planned in Florida will be purchased by PEF, primarily from National Solar, discussed above.

Table 14. State of Florida: Planned Non-Firm Renewable Resources

Purchasing Utility	Facility Name	Fuel Type	Capacity (MW)	Commercial In-Service Date
Investor-Owned Utilities				
FPL	INEOS Bio	AB	2	2011
PEF	Eliho	WDS	8	2011
PEF	E2E2	WDS	30	2012
PEF	Blue Chip Energy #1	SUN	50	2013
PEF	National Solar #5-10	SUN	450	2021
All IOUs	Solar Installations (Aggregate)	SUN	0.1	2021
	Subtotal of IOUs		**540.1**	
Municipal Utilities				
OUC	CNL/City Hall	SUN	0.4	2012
OUC	GSLD Solar	SUN	0.8	2012
TAL	SDA	SUN	2	2012
TAL	SolarSink	SUN	0.5	2012
TAL	SunnyLand Solar	SUN	1	2012
LAK	Regenesis Power	SUN	15	2016
LAK	SunEdision	SUN	24	2017
All Munis	Solar Installations (Aggregate)	SUN	0.2	2021
	Subtotal of Municipals		**43.9**	
	Total		**584**	

Sources: FRCC 2012 Load and Resource Plan, Responses to Staff Data Requests

Updated Navigant Consulting Report

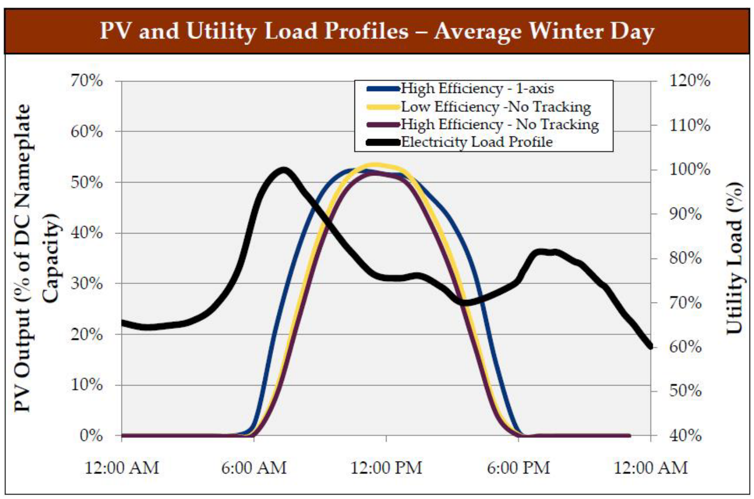
The Commission contracted with Navigant Consulting in early 2010 to update its 2008 analysis with current conditions. In June 2010, Navigant Consulting released new comparisons of cost estimates for different renewable generating facilities. Navigant Consulting also provided additional detail pertaining to Florida's renewable resource which it identified as having the most technical potential for growth, solar PV facilities. Findings from the report are summarized below.

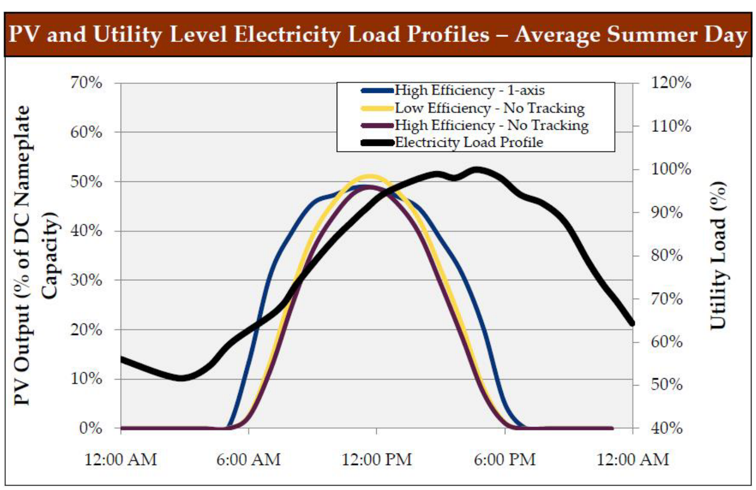
In the 2010 Navigant Consulting Report Update, the most meaningful findings include changes in prices of renewable technologies. PV module prices have fallen and commodity costs for PV units have decreased during the recession, but both are returning to near their pre-recession levels. Wind power prices have also decreased due to the recession, while utility turbine prices have risen as worldwide demand catches up with supply. According to the 2010 Navigant Consulting Report Update, no large performance breakthroughs occurred for any technology. Because Navigant Consulting found solar resources to hold the most potential in Florida, the remainder of the 2010 Navigant Consulting Report Update focuses on solar power.

The 2010 Navigant Consulting Report Update estimates that solar power systems have increased in efficiency while overall prices have decreased up to 40 percent since 2008. In spite of these changes, solar power systems continue to have some of the highest capital costs per kW of any renewable generating system. Varying the methods of using solar energy involving solar tracking technology and alternating solar film receptors produces a slight range of energy output and net capacity factors. In addition, the ability of solar PV systems to provide energy are limited to daytime hours. Supplemental battery storage units may alleviate this issue, but the costs of batteries are not included in Navigant Consulting's estimates.

Even with these advancements, capacity factors of solar panels are projected to remain below 25 percent. Such results indicate that solar PV facilities operate more like a conventional peaking unit and will not replace the need for base-load generating facilities. However, Navigant Consulting also reported that operating characteristics for these systems do not correlate with daily peak load hours. As shown in Figure 15, Navigant Consulting estimates that the peak output from solar PV facilities reaches a maximum of approximately 50 percent of the rated capacity, and occurs after the system's winter peak hour and before the system's summer peak hour. As a result, a solar PV facility's ability to provide reliability benefits appears limited.

Figure 15. Solar PV Output and Utility Seasonal Load Profiles





Sources: 2010 Navigant Consulting Report Update

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

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

Gas fired units have almost exclusively been selected in recent years due to higher thermal efficiencies, lower capital costs, short periods for permitting and construction, and sometimes the smaller land areas required. With the recent decrease in fuel prices due to unconventional natural gas production using hydraulic fracturing, natural gas is the favored fuel for all traditional generating units with the exception of new nuclear units.

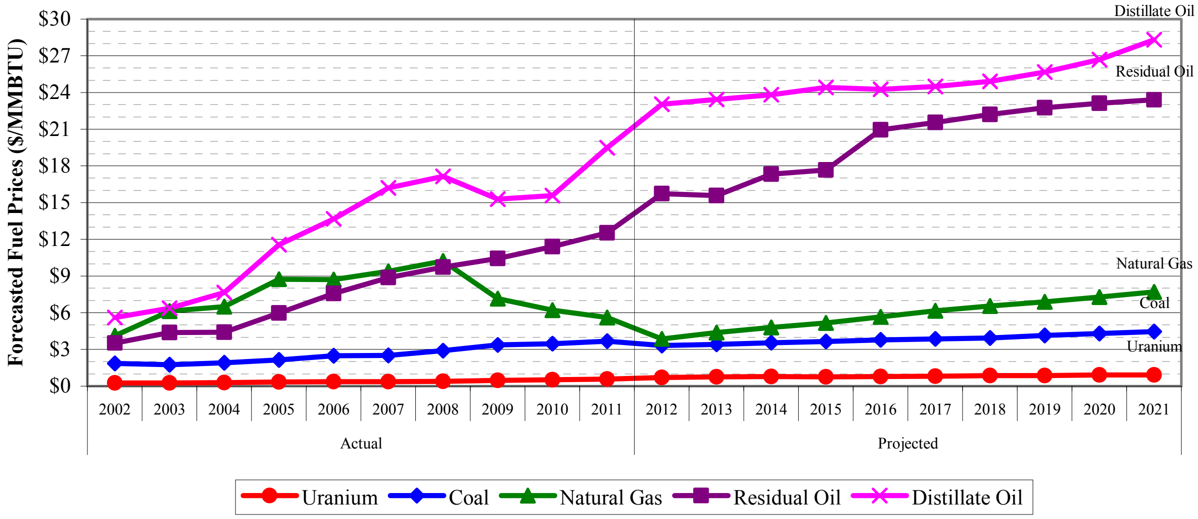
In the last ten years, almost 97 percent of all capacity additions to Florida's electric system use natural gas as the primary fuel. Coal units that were planned have been cancelled, and new nuclear units that have been approved have been delayed beyond the planning horizon. Currently, other than approximately 950 MW of renewable generation and 600 MW in uprates for existing nuclear units, all of the additional generation planned for the next ten years will use natural gas as a fuel source.

Fuel Price Forecasts

Fuel price forecast is the primary factor affecting the type of generating unit added by an electric utility. In general, the capital cost of a generating unit is inversely proportional to the cost of the fuel used to generate electricity from that unit. Historically, when the forecasted price difference between coal or nuclear and natural gas was small, the addition of a natural gas unit became the more attractive option. As the fuel price gap widened, a coal-fired or nuclear unit would normally be the more likely choice.

From 2003 to 2005, the price of natural gas was substantially higher than utilities had forecasted. This disparity led to concern regarding escalating customer bills and an expectation that natural gas prices would continue to be high and extremely volatile. As a result, Florida's utilities began making plans to build coal-fired units rather than continuing to increase the reliance on natural gas. However, as Figure 16 shows, the price of natural gas began to return to more historic levels after peaking in 2008, and has declined in the years since. Forecasts predict that gas prices will increase at a steady level throughout the planning horizon.

Figure 16. TYSP Utilities: Historic & Projected Weighted Average Fuel Prices ($/MMBtu)



Source: Responses to Staff Data Request

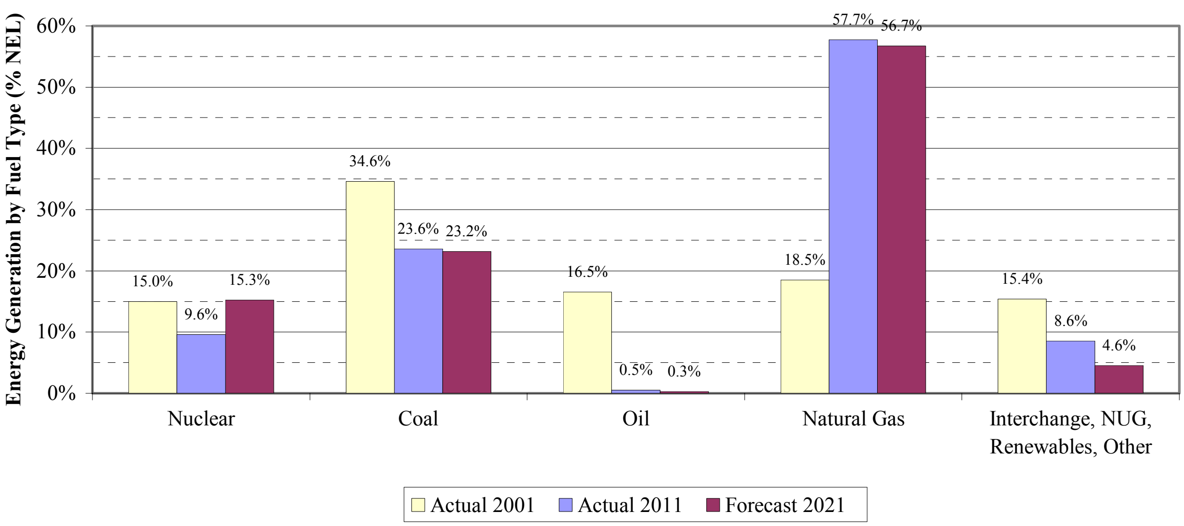
Previous TYSP reviews indicated that increases in gas prices may bring an end to the almost exclusive addition of natural gas-fired generation. As can be seen from Figure 16, the expectation of high prices for natural gas has not materialized and although it is forecasted to increase steadily, the rate of increase is more moderate than was previously contemplated.

Utility plans for a balanced fuel system have historically been highly dependent upon the accuracy of long-term fuel price forecasts, mostly due to the long lead times required for coal and especially nuclear generators. However, in recent years the options available to utilities for the addition of supply-side generation have been limited, and this situation seems unlikely to change at this time. Utilities will be faced with selecting technologies for new generation that will either continue to increase the already very high percentage of natural gas resources, or attempting to obtain approval for solid fuel resources that may have a negative near term rate impact.

Fuel Diversity

Natural gas has risen to become one of the dominant fuels in the state in the last ten years, displacing coal, and in 2011 generated more net energy for load than any two fuels combined in Florida. As Figure 17 shows, natural gas now makes up greater than 57.7 percent of electric energy consumed in Florida. Natural gas usage is anticipated to peak in 2012 at 62.4 percent, and then decline slightly to 56.7 percent by 2021.

Figure 17. State of Florida: Net Energy for Load by Fuel Type



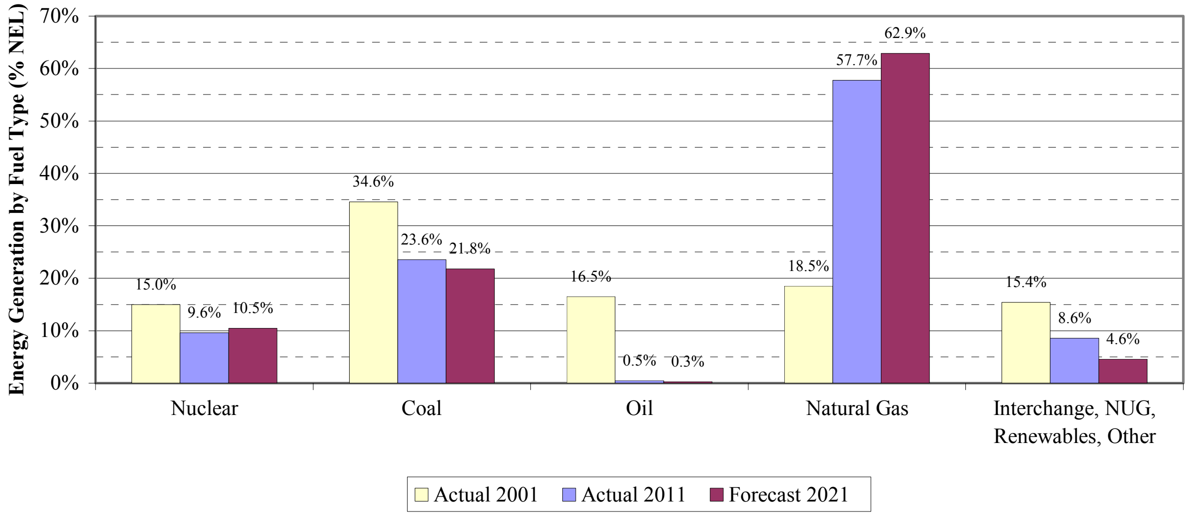
Source: FRCC 2002 and 2012 Load and Resource Plans

The anticipated decline in natural gas consumption by the end of the planning period is the result of increased nuclear generation and relatively stable contribution to NEL from coal-fired generation. Nuclear generation may decline from that projected in the FRCC 2012 Load and Resource Plan, primarily due to the delay of the Levy 1 nuclear unit, discussed below, and if the CR3 nuclear unit is retired instead of repaired. CR3 has been offline since 2009, following a delamination incident during a steam generator replacement project.

Coal generation, beyond the reduction in dispatch due to the cost-competitiveness of natural gas as a baseload fuel, faces challenges relating to new environmental compliance requirements. As discussed below, new EPA regulations will potentially require installation of new environmental controls, which could lead to the retirement of units if it is deemed uneconomic to upgrade its emission control equipment. During the 2012 TYSP Workshop, four coal units, PEF's Crystal River 1 & 2, and GULF's Lansing Smith 1 & 2, were identified by the Sierra Club/Earthjustice as potential units to consider retirement, though at this time all four are scheduled to remain in-service throughout the planning period.

If the projected generation associated with the nuclear and coal units discussed above is displaced by natural gas, it would have the net effect of increasing natural gas' share of state electric generation to 62.9 percent by 2021, as shown in Figure 18 below.

Figure 18. State of Florida: Net Energy for Load by Fuel Type After Generation Displacement



Source: FRCC 2002 and 2012 Load and Resource Plans, Utilities 2012 TYSPs, Responses to Staff Data Requests.

Because a balanced fuel supply can enhance system reliability and mitigate the effects of volatile fuel price fluctuations, it is important that utilities have the greatest possible level of flexibility in their generation fuel source mix. Although the Commission has cited the growing lack of fuel diversity within the State of Florida as a major strategic concern for the past several years, natural gas is anticipated to remain the dominant fuel over the planning horizon. Excluding renewables, all new generation facilities planned within the State of Florida over the ten-year period are natural gas-fired units.

Opportunities for Unit Modernization

Florida's generating fleet consists of incremental new additions to the 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.

While some units must be retired upon reaching the end of their economic life and cannot be refurbished, others have the potential for modernization. The modernization of existing generating units allows for significant improvement in both performance and emissions, typically at a price lower than new construction. Modernization typically involves the conversion of a generating unit from less efficient fossil steam generation to combined cycle operation. For some power plant sites, modernization does not involve using any of the existing generator units themselves, but rather the generation site's existing facilities such as transmission or fuel handling for an entirely new unit. For some steam units, generation output can be improved by installing more advanced equipment, such as the nuclear uprates discussed below. Other modernizations allow for changes in fuel type, or increased ability to use alternate fuels. Due to low natural gas price forecasts, the ability to run a unit on higher quantities of natural gas instead of fuel oil may be an economically viable option, even for an older generating unit.

Since the existing unit must be removed from service for a period of time, a utility's reliability is affected during the conversion process. As a result, scheduling modernizations during periods of temporary excess capacity is more desirable. With the forecasted decline in load, several of Florida's utilities may have sufficient reserve margins to allow some of their smaller units to be converted, and the upcoming ten-year planning horizon appears to be an ideal window for completing these types of projects. 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 investigated before considering new construction. Utilities should continue to explore potential conversion projects and report the feasibility and economic viability of each conversion in next year's TYSPs and before any need determination filing.

In response to a staff data request, the TYSP utilities identified the following facilities as potentially capable of conversion. Table 15 below summarizes their responses for conversion from fossil steam generation. Additional units were identified for conversion from simple cycle combustion turbines to combined cycle units.

Table 15. State of Florida: Potential Steam Units for Modernization

Utility	Generating Unit Name	Fuel Type	Summer Capacity (MW)	Original In-Service Date	Modernization Type
FPL	Manatee Units 1 & 2	Oil / NG	1624	1976 - 1977	CC
FPL	Martin Units 1 & 2	Oil / NG	1652	1980 - 1981	CC
FPL	Sanford Unit 3	Oil / NG	138	1959	CC
FPL	Turkey Point Units 1 & 2	Oil / NG	788	1967 - 1968	CC
FPL	Cutler Unit 5 & 6	NG	205	1954 - 1955	CC
PEF	Anclote Units 1 & 2	NG / Oil	1011	1974 - 1978	CC
PEF	Suwannee River Units 1 - 3	NG / Oil	129	1953 - 1956	CC/RF
PEF	Crystal River Units 1 & 2	Coal	873	1966 - 1969	CC/IGCC
PEF	Crystal River Units 4 & 5	Coal	1422	1982 - 1984	CC/IGCC
GULF	Crist Units 4 & 5	Coal	150	1959 - 1961	Natural Gas
GULF	Scholz Units 1 & 2	Coal	92	1953	Biomass
JEA	SJRPP Units 1 & 2	Coal / Petcoke	626	1987 - 1988	CC
JEA	Northside Unit 3	NG / Oil	524	1977	CC

Source: Responses to Staff Data Request

The Commission has previously granted determinations of need for three conversions from fossil steam to combined cycle units. The approved conversions, located at FPL's Cape Canaveral, Riviera, and Port Everglades sites, represent a significant increase in generating capacity while reusing the plant site and reducing fuel usage and emissions. PEF has also recently conducted a conversion of its Bartow plant from fossil steam to a combined cycle unit. This conversion did not require a PPSA determination of need.

Impact of EPA Regulations

In addition to maintaining a fuel efficient and diverse fleet, Florida's utilities must also comply with changing environmental requirements. Within the past several years, the EPA has finalized or proposed several rules which will impact both existing and planned units within the state. Potential environmental requirements and their associated costs must be considered to fully evaluate any new supply-side resources, as well as the maintenance and dispatch of existing generating units.

While at this time no units are anticipated to be retired as a result of any of these regulations, they do represent an increase cost of operations. Each utility should evaluate whether these additional costs or limitations allow the continued economic operation of each impacted unit, and whether installation of emissions control equipment, fuel switching, or retirement is the proper course of action to maintain the lowest cost to customers and meet environmental requirements. Several of the TYSP utilities have provided preliminary estimates based upon known and proposed rule language, and are shown in Table 16 below.

Table 16. TYSP Utilities: Preliminary Estimates of EPA Rule Compliance Cost

Utility	Preliminary Total Cost Estimates* ($ Millions)
Florida Power & Light	$348 - $1,741
Progress Energy Florida	$165 - $1,330
Tampa Electric Company	$763
Gulf Power Company	$1,270 - $2,737
Florida Municipal Power Agency	$39
Gainesville Regional Utilities	Not Available
JEA	Not Available
Lakeland Electric	Not Available
Orlando Utilities Commission	$157
Seminole Electric Cooperative	Not Available
City of Tallahassee	$5
Total of All Utilities	**$2,747 - $6,772**

* These estimates are not final, and may not include all rules.
Source: Responses to Staff Data Request

Table 17 is a partial listing of notable units and their anticipated unit costs for compliance. At this time, several of the proposed EPA Rules are the subject of litigation, or have not yet produced a final rule. More precise data associated with compliance costs for all units is anticipated in future filings by the utilities once rules are finalized and environmental compliance methods are determined.

Table 17. TYSP Utilities: Preliminary Estimates of EPA Rule Compliance Costs by Unit

Primary Owner	Facility Name	Fuel	Net Summer Capacity	EPA Rule Impact ($ Million)				
				MATS[8]	CSPAR[9]	CWIS[10]	CCR[11]	Total
PEF	Anclote 1&2	Oil	1011	80	-	15-130	-	95-210
PEF	Bartow 4	NG	1,133	-	-	10-170	-	10-170
PEF	Crystal River 1&2	Coal	873	TBD	-	45-780	TBD	45-780
PEF	Crystal River 4&5	Coal	1422	5-50	-	2-5	TBD	7-55
PEF	Suwannee 1-3	Oil	129	-	-	5-75	-	5-75
TECO	Big Bend 1-4	Coal	1552	10	-	400	3-6	413-416
TECO	Polk 1	Coal	220	-	-	-	1-2.5	1-2.5
TECO	Bayside 1&2	NG	1,630	-	-	400	-	400
GULF	Daniel 1-2	Coal	510	310-617		1-2	110-210	421-829
GULF	Crist 4-5	Coal	150	40-305		26-47	170-450	236-802
GULF	Crist 6-7	Coal	756					
GULF	Smith 1-2	Coal	357	60-288		1-65	30-260	91-613
GULF	Scholz 1-2	Coal	92	6-97		1-50	160-180	167-327
OUC	Stanton 1&2	Coal	886	2	118	-	13	133
Total Impact			**10,721**	**631-1,557**		**904-2,124**	**487-1,122**	**2,024-4,813**

Source: Responses to Staff Data Request

Power Plant Siting Act

The Florida PSC is given exclusive jurisdiction by the Legislature, through the PPSA, to be the forum for determining the need for new electric power plants. Any proposed steam or solar generating unit of at least 75 MW requires certification under the Power Plant Siting Act.

Approximately 7,200 MW of new generating units are planned to enter service over the next 10-year period, consisting solely of natural gas-fired combustion turbines and combined cycle units. A majority of this capacity has already received a determination of need from the Commission or is exempted from the statutory requirements of the PPSA. Only 2,418 MW still requires certification, as shown in Table 18. TECO has recently issued a Request for Proposals (RFP) for its planned unit, a combined cycle conversion of several existing simple cycle combustion turbines at the Polk Power Station, and filed for a need determination on September 12, 2012.

[8] Mercury and Air Toxics Standards (MATS) Rule.
[9] Cross-State Air Pollution Rule (CSAPR)
[10] Cooling Water Intake Structures (CWIS) Rule
[11] Coal Combustion Residuals (CCR) Rule.

Table 18. State of Florida: Projected Units Requiring Power Plant Siting Act Certification

Utility	Generating Unit Name	Summer Capacity (MW)	Certification Dates		In-Service Date
			Need Approved (Commission)	PPSA Certified	
FPL	St. Lucie Unit 1 Uprate	129	01/2008	09/2008	05/2012
FPL	Turkey Point Unit 3 Uprate	123	01/2008	10/2008	06/2012
FPL	St. Lucie Unit 2 Uprate	84	01/2008	09/2008	10/2012
FPL	Turkey Point Unit 4 Uprate	123	01/2008	10/2008	02/2013
FPL	Cape Canaveral	1,210	09/2008	10/2009	06/2013
FPL	Riviera Beach	1,212	09/2008	11/2009	06/2014
PEF	Crystal River Unit 3 Uprate	154	02/2007	08/2008	11/2014
FPL	Port Everglades	1,277	04/2012	02/2013*	06/2016
TECO	Polk 2-5 CC	1,063	-	-	01/2017
PEF	Unknown	767	-	-	06/2019
SEC	Unnamed CC1	196	-	-	12/2020
SEC	Unnamed CC2	196	-	-	12/2020
SEC	Unnamed CC3	196	-	-	12/2021

*Estimated Date for Siting Board Hearing on Site Certification.
Source: Utilities 2012 TYSPs

Nuclear

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. Florida's utilities project an expansion of nuclear power in the state through uprates at existing nuclear power plants, and the construction of four new nuclear units. FPL's and PEF's TYSPs anticipate approximately 600 MW of capacity to be added by uprates.

While PEF's 2012 TYSP originally projected the in-service date for Levy Unit 1 in 2021, PEF's filing in Docket No. 120009-EI indicates that it will be delayed until 2024. Table 19 below provides a summary of nuclear capacity additions planned in the State.

Table 19. State of Florida: Projected Nuclear Uprates & New Units

Utility	Generating Unit Name	Summer Capacity (MW)	In-Service Date
Existing Nuclear Unit Uprates			
FPL	St. Lucie Unit 1	129	05/2012
FPL	Turkey Point Unit 3	123	06/2012
FPL	St. Lucie Unit 2	84	10/2012
FPL	Turkey Point Unit 4	123	02/2013
PEF	Crystal River Unit 3	154	11/2014
New Nuclear Units			
FPL	Turkey Point 6	1100	06/2022
FPL	Turkey Point 7	1100	06/2023
PEF	Levy 1	1092	06/2024
PEF	Levy 2	1092	06/2025

Source: Utilities 2012 TYSPs, Utilities filings in Docket 120009-EI

Natural Gas

With the exception of the aforementioned renewable and nuclear capacity, all remaining new generation comes in the form of natural gas fired combustion turbines or combined cycle units. The 2012 TYSPs include approximately 7,200 MW of natural gas-fired generation.

A total of 1,571 MW of natural gas-fired combustion turbine capacity is expected to enter service by 2021. Because these units are not steam-fired capacity, they do not require siting under the PPSA. A list of all combustion turbine units entering service is included in Table 20.

Table 20. State of Florida: Projected New Combustion Turbines

Utility	Generating Unit Name	Summer Capacity (MW)	In-Service Date
SEC	Unnamed CT1	158	12/2018
TECO	Future CT 1	149	05/2019
SEC	Unnamed CT2	158	12/2019
SEC	Unnamed CT3	158	12/2020
SEC	Unnamed CT4	158	12/2020
SEC	Unnamed CT5	158	12/2020
SEC	Unnamed CT6	158	05/2021
SEC	Unnamed CT7	158	12/2021
SEC	Unnamed CT8	158	12/2021
SEC	Unnamed CT9	158	12/2021

Source: Utilities 2012 TYSPs

The remainder of the natural gas-fired additions come from combined cycle units, which currently represent the most abundant type of generating capacity in the State of Florida, making up approximately a third of installed capacity in 2012. As combined cycles utilize steam generated from the waste heat of combustion turbines, they fall under the PPSA when they have greater than 75 MW of steam capacity. Table 21 below includes all combined cycle units planned to enter service by 2021. With these new additions (6,117 MW in total), natural gas-fired combined cycles will represent approximately half of all generation within the state.

Table 21. State of Florida: Projected New Combined Cycle Units

Utility	Generating Unit Name	Summer Capacity (MW)	In-Service Date
FPL	Cape Canaveral	1,210	06/2013
FPL	Riviera Beach	1,212	06/2014
FPL	Port Everglades	1,277	06/2016
TECO	Polk 2-5 CC	1,063	01/2017
PEF	Unknown	767	06/2019
SEC	Unnamed CC1	196	12/2020
SEC	Unnamed CC2	196	12/2020
SEC	Unnamed CC3	196	12/2021

Source: Utilities 2012 TYSPs

Transmission Capacity

As generation capacities increase, the transmission system must grow accordingly to maintain the capability of delivering the energy to the end user. 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 Transmission Line Siting Act (TLSA). 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 for and the proposed starting and ending points for lines requiring TLSA certification. The Commission must issue a final order granting or denying a determination of need within 90 days of the petition filing. The proposed corridor route is determined by the DEP during the certification process. Much like the PPSA, the Governor and Cabinet sitting as the Siting Board ultimately must approve or deny the overall certification of the proposed line.

Table 22 below lists all proposed transmission lines in the 2012 TYSPs that require TLSA certification. The Polk-Aspen-FishHawk line is directly associated with the combined cycle conversion at the Polk Power Station, and is anticipated to be reviewed concurrently.

Table 22. State of Florida: Proposed Transmission Requiring Transmission Line Siting Act Certification

Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Certification Dates		Commercial In-Service Date
				Need Approved (Commission)	TLSA Certified	
PEF	Intercession City - Gifford	13	230	09/2007	01/2009	05/2013
FPL	Manatee – Bobwhite	30	230	08/2006	11/2008	12/2014
FPL	St Johns – Pringle	25	230	05/2005	04/2006	12/2016
TECO	Polk-Aspen-FishHawk	62.5	230	-	-	01/2017

Source: FRCC 2012 Load & Resource Plan, Utilities 2012 TYSPs

Utility Perspectives

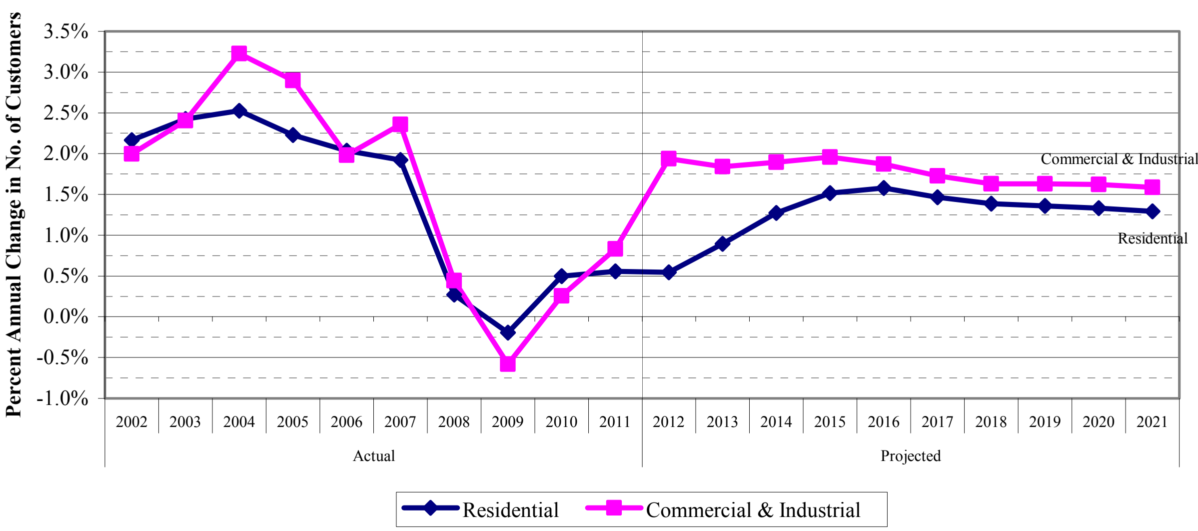
FPL is the state's largest electric utility. The utility's service territory is within the FRCC region, and is primarily in southern Florida and along the east coast. As FPL is an IOU, the Commission has regulatory authority over all aspects of operations, including rates and safety.

In 2011, FPL had an average of 4,547,051 customers, and had a total net energy for load of 103,327 GWh, approximately 47.3 percent of the NEL generated in the entire state last year.

Peak Demand and Energy Forecasts

FPL Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. Positive growth is anticipated over the entire planning period, with an average annual growth rate (AAGR) of 1.39 percent. This compares to the actual AAGR of 2.27 for the period 2002 through 2007.

FPL Figure 1: Annual Customer Growth Rate by Customer Class



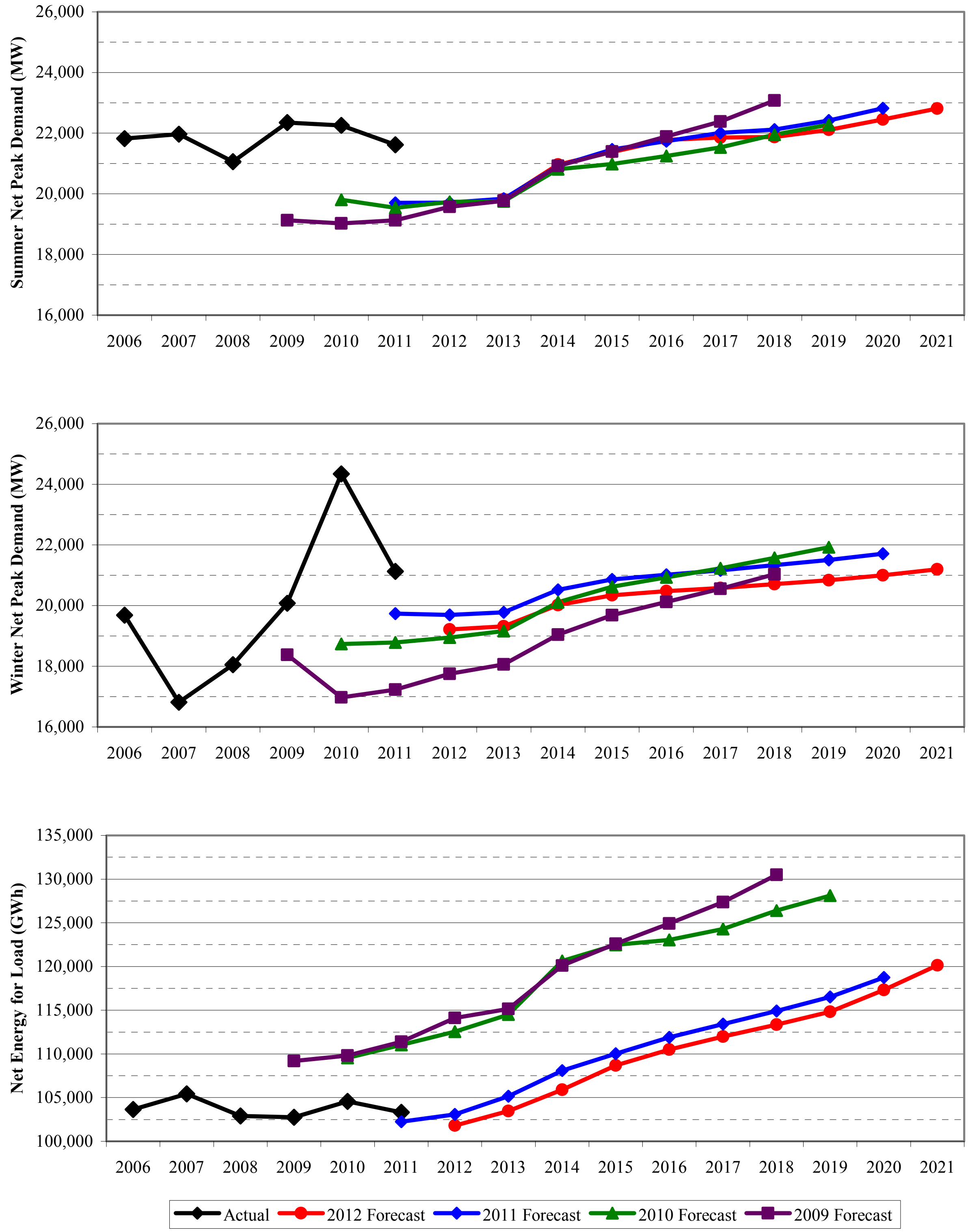
Source: FPL 2012 TYSP

The following three graphs in FPL Figure 2 show FPL's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is similar but slightly lower than the 2011 values for both seasons of peak demand and NEL.

Analysis of FPL's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that FPL's average forecast error is 12.12 percent. This value indicates that the company tends to over-forecast its retail energy sales by 12.12 percent, which is unfavorable when compared to the average forecast error for all eleven of the TYSP utilities, which was

11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

FPL Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

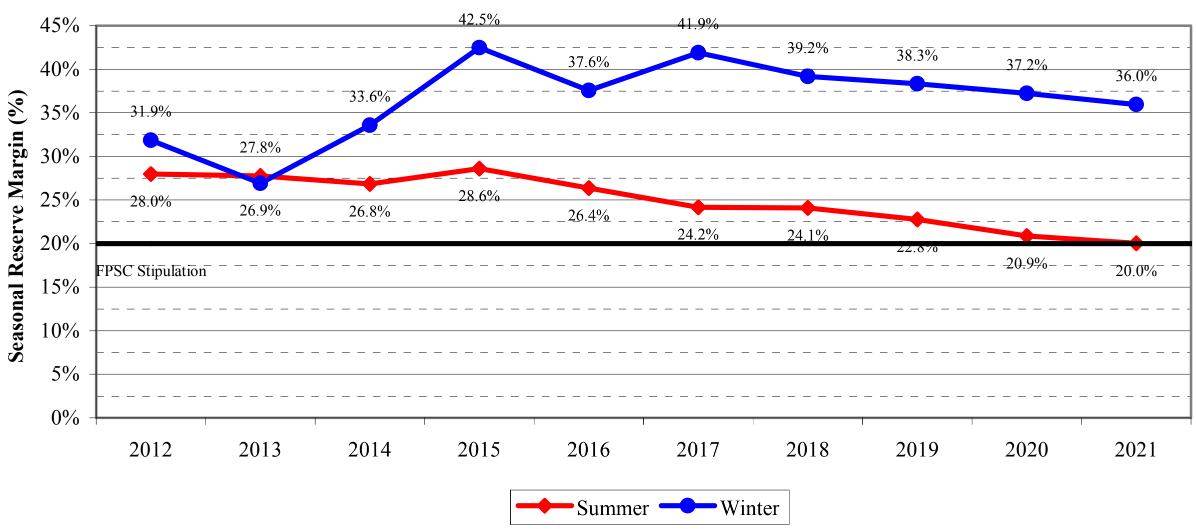


Source: FPL 2009 -2012 TYSPs

Reserve Margin Requirements

As mentioned in the Statewide Perspective, FPL maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. FPL Figure 3 displays the projected reserve margin for FPL through the planning period for both seasonal peaks. As shown in the figure, summer peak demand would be the driving force for generation additions. The reserve margin shown below includes the cumulative impact of conservation and demand response on FPL's system demand.

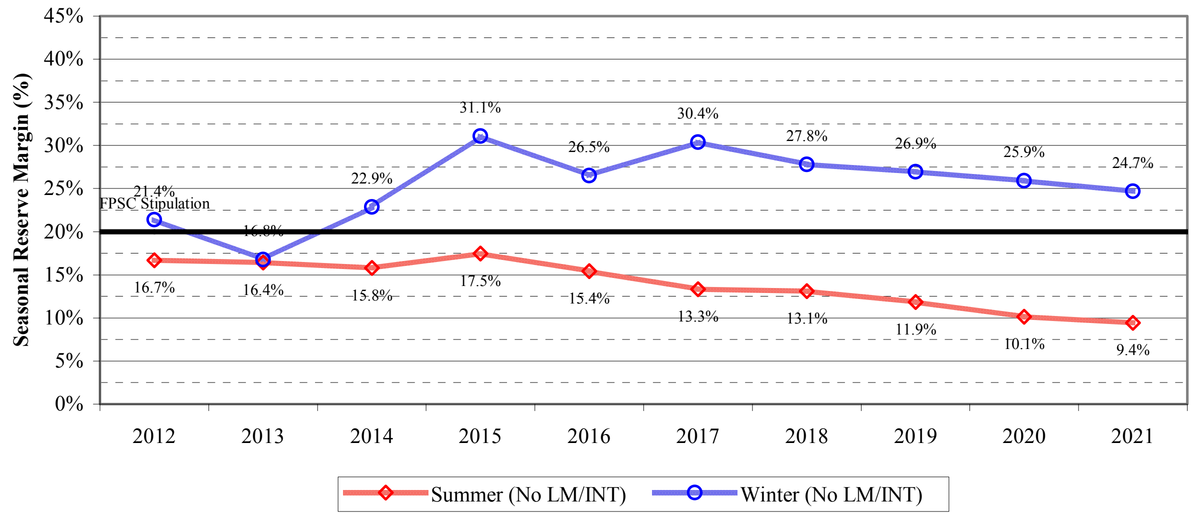
FPL Figure 3. Seasonal Reserve Margin (With LM/INT)



Source: FPL 2012 TYSP

Some concerns have been expressed regarding increased dependence upon demand response to meet customer peak demand. The concern is that interruptible load and load management programs are voluntary, and that customers may elect to opt-out of an existing program if the utility interrupted service too frequently. FPL Figure 4 shows the impact of excluding demand response programs from meeting customer demand, which causes the reserve margin to fall below both the company's stipulated 20 percent reserve margin and the FRCC Region's 15 percent planning margin for the summer only. FPL has indicated that it is continuing to study the possibility of instituting a generation-only minimum reserve.

FPL Figure 4. Seasonal Reserve Margin (Without LM/INT)

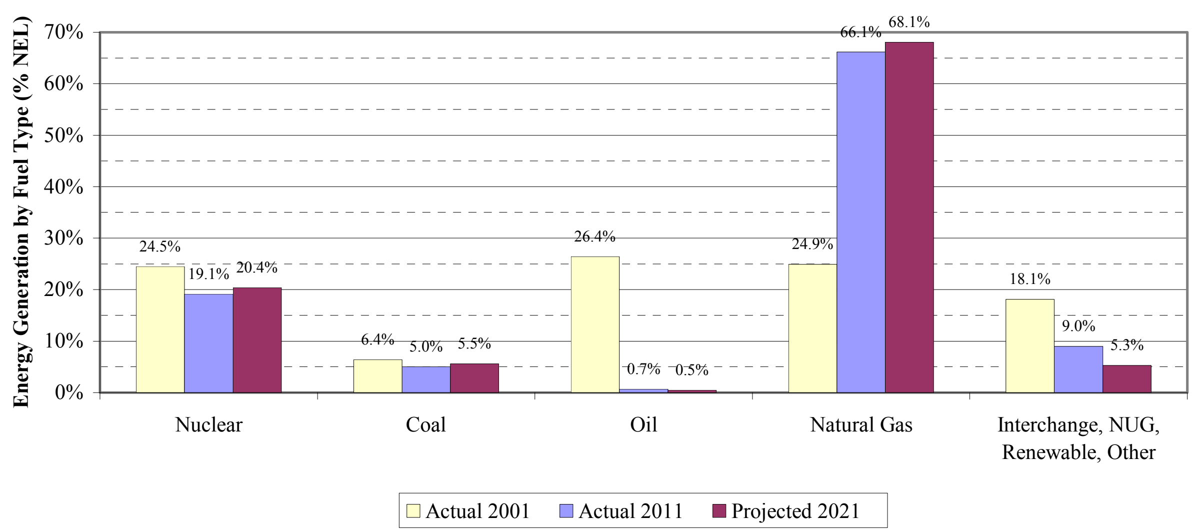


Source: FPL 2012 TYSP

Fuel Diversity

FPL Figure 5 shows FPL's historic fuel mix for 2001 and 2011, and the projected fuel mix for 2021. FPL's primary generation fuel is natural gas, which has increased from about a quarter of system energy in 2001, to approximately two-thirds by 2011. Natural gas is projected to remain the main system fuel, with 68.1 percent of net energy for load generated by natural gas.

FPL Figure 5. Net Energy for Load by Fuel Type



Source: FPL 2002 and 2012 TYSPs

Generation Additions

FPL's 2012 TYSP includes 3 new generating units, all of which are natural gas-fired combined cycles. FPL also anticipates uprates at all its nuclear generation units by 2013, and two new nuclear units, Turkey Point 6 & 7, which are planned beyond the planning horizon. All of the new generation units that FPL is planning to add to its system are shown in FPL Table 1.

FPL Table 1. Planned Generation Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Uprates				
St. Lucie Unit #1 Uprates	129	09/2008	09/2008	5/2012
St. Lucie Unit #2 Uprates *	84	09/2008	09/2008	10/2012
Turkey Point Unit # 3 Uprates	123	09/2008	10/2008	6/2012
Turkey Point Unit # 4 Uprates	123	09/2008	10/2008	2/2013
Combined Cycle Unit Additions				
Cape Canaveral Next Generation Clean Energy Center	1,210	09/2008	10/2009	6/2013
Riviera Beach Next Generation Clean Energy Center	1,212	09/2008	11/2009	6/2014
Port Everglades Next Generation Clean Energy Center	1,277	4/2012	02/2013***	6/2016
Nuclear Unit Additions				
Turkey Point Unit #6**	1,100	3/2008	12/2013***	6/2022
Turkey Point Unit #7**	1,100	3/2008	12/2013***	6/2023

*31 MW of St. Lucie Unit #2 uprates have already been achieved in 2011.
** These units are outside of the 2012-2021 planning period
*** This is the anticipated date of the Siting Board Hearing on Site Certification.
Source: FPL 2012 TYSP

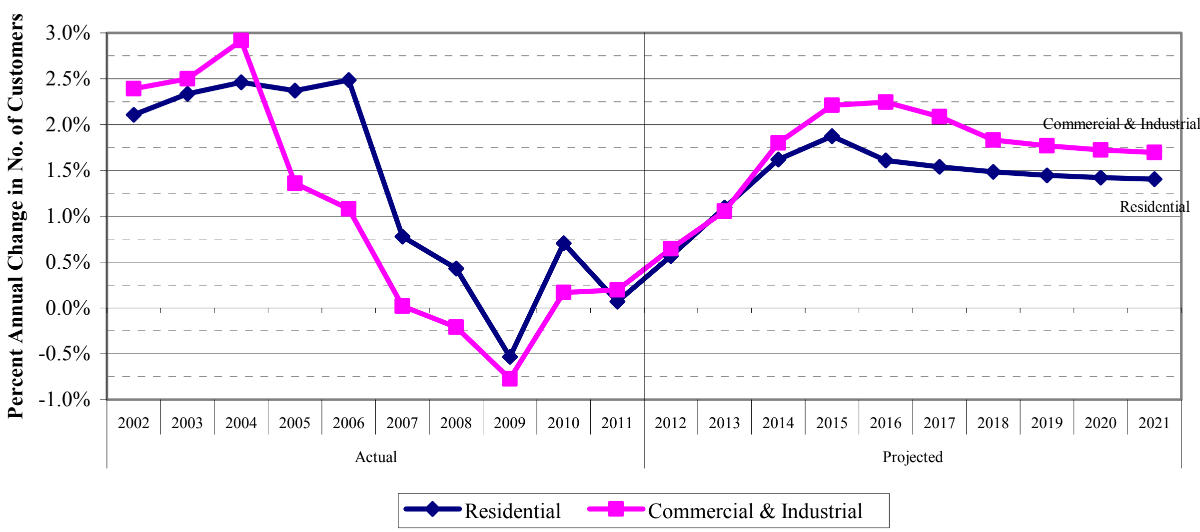
PEF is an investor-owned utility, and Florida's second largest TYSP utility. The utility's service territory is within the FRCC region, and is primarily located in central and west central Florida. As PEF is an IOU, the Commission has regulatory authority over all aspects of operations, including rates and safety.

In 2011, PEF had an average of 1,642,161 customers, and had a total net energy for load of 42,490 GWh, approximately 17.9 percent of the NEL generated in the entire state last year.

Peak Demand and Energy Forecasts

PEF Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. Customer growth is anticipated to increase from the period of the economic downturn until approximately 2015, and then remain steady or decline somewhat while remaining positive until the end of the period, yielding an average annual growth rate of 1.53 percent. This compares with the actual rate of 2.03 for the period 2002 through 2007.

PEF Figure 1. Annual Customer Growth Rate by Customer Class

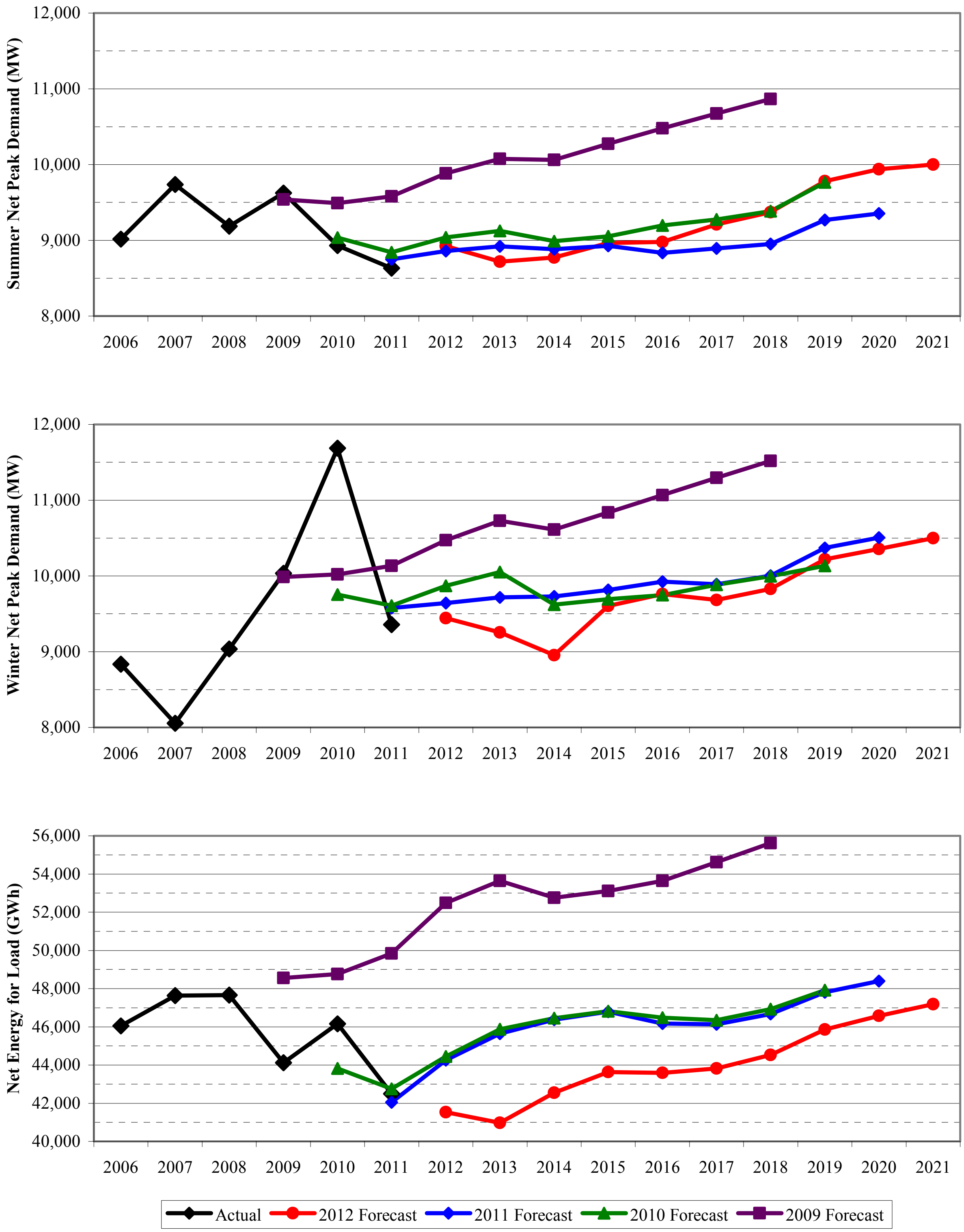


Source: PEF 2012 TYSP

The following three graphs in PEF Figure 2 show PEF's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is significantly above last year's in summer peak demand, but below the 2011 forecast for winter peak demand and NEL.

Analysis of PEF’s historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that PEF’s average forecast error is 11.36 percent. This value indicates that the company tends to over-forecast its retail energy sales by 11.36 percent, which is approximately equivalent to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

PEF Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

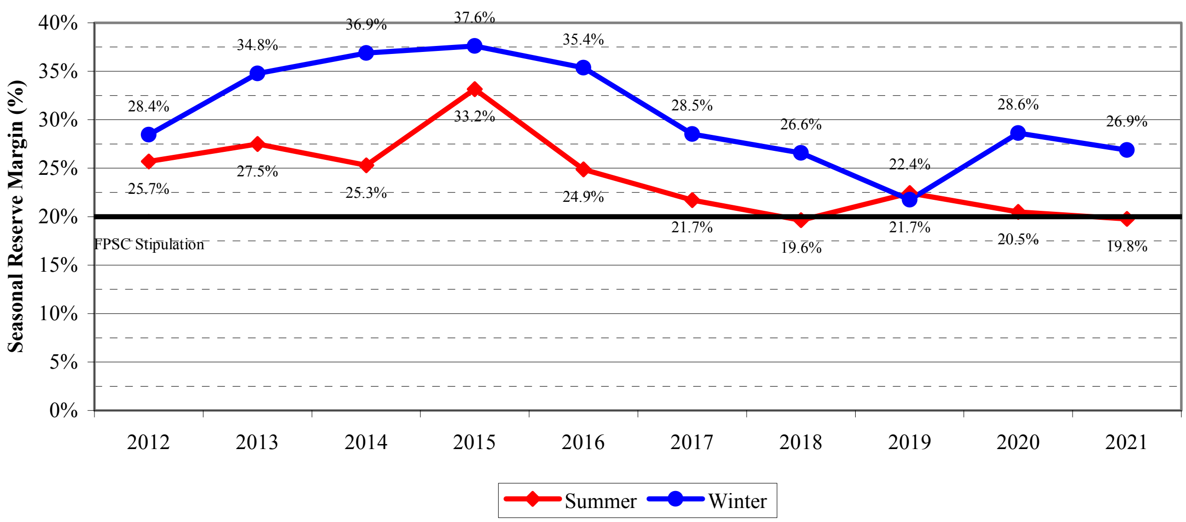


Source: PEF 2009 - 2012 TYSPs

Reserve Margin Requirement

As mentioned in the Statewide Perspective, PEF maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. PEF Figure 3 displays the projected reserve margin for PEF through the planning period for both seasonal peaks. As shown in the figure, summer peak demand would be the driving force for generation additions. The reserve margin shown below includes the cumulative impact of conservation and demand response on PEF's system demand. The delay of the Levy 1 nuclear unit and its decrease of the company's reserve margin in 2021 is included in the graph.

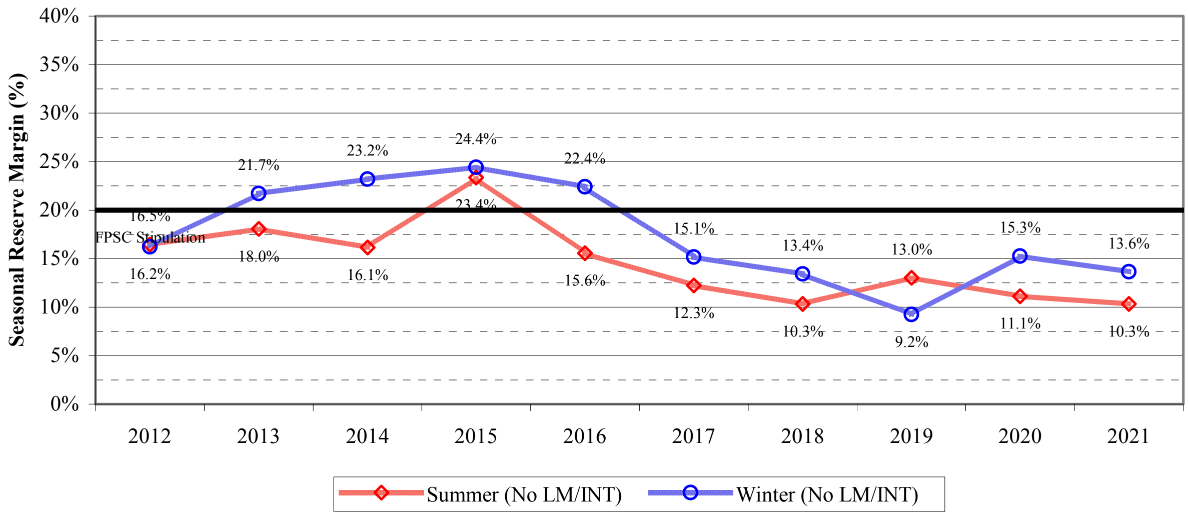
PEF Figure 3. Seasonal Reserve Margin (With LM/INT)



Source: PEF 2012 TYSP

Some concerns have been expressed regarding increased dependence upon demand response to meet customer peak demand. The concern is that interruptible load and load management programs are voluntary, and that customers may elect to opt-out of an existing program if the utility interrupted service too frequently. PEF Figure 4 shows the impact of excluding demand response programs from meeting customer demand, which causes the reserve margin to fall below both the company's stipulated 20 percent reserve margin and the FRCC Region's 15 percent planning margin.

PEF Figure 4. Seasonal Reserve Margin (Without LM/INT)

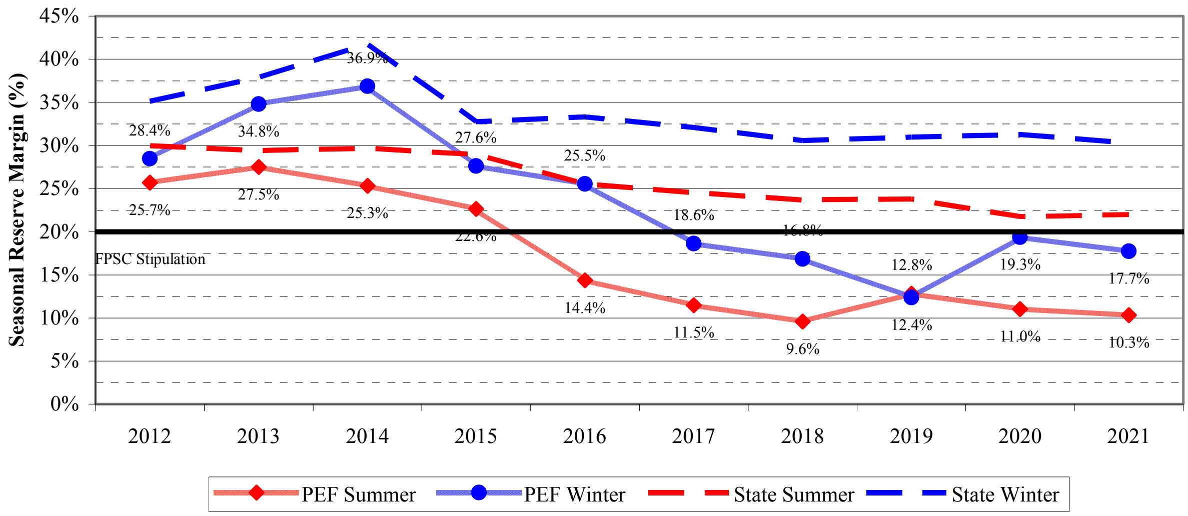


Source: PEF 2012 TYSP

Crystal River 3 Outage

The CR3 nuclear unit has been offline since 2009 due to a concrete delamination experience during a steam generator replacement project. Currently PEF anticipates CR3 returning to service in November 2014, but at this time the decision to repair or retire the unit has not been decided. PEF Figure 5 illustrates the reliability impact of not returning CR3 to service in 2014 and assuming no other changes to PEF's available generation. As shown, PEF would fall below its 20 percent reserve requirement as early as the summer of 2016, and falling to a minimum reserve margin of 9.6 percent for the 2018 summer peak. In the event CR3 is retired or its return to service delayed past 2014, PEF must seek additional firm capacity to meet its reserve requirements, which may be from purchased power contracts, acceleration of currently planned units, and/or new generating units. While the loss of capacity associated with CR3 has a significant impact on PEF's system, the statewide reserve margin appears adequate for possible purchased power agreements.

PEF Figure 5. Seasonal Reserve Margin With Potential Unit Retirements / Delays (With LM/INT)

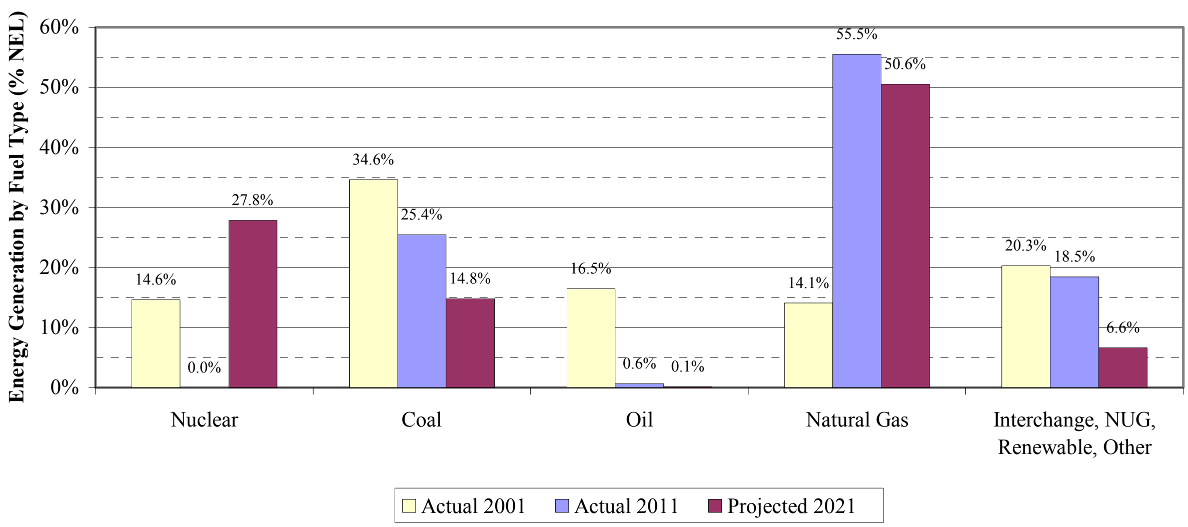


Source: PEF 2012 TYSP, Responses to Staff Data Request

Fuel Diversity

PEF Figure 6 shows PEF's historic fuel mix for 2001 and 2011, and the projected fuel mix for 2021. PEF's primary generation fuel is natural gas, which has increased from approximately 14 percent in 2001, to over 55 percent in 2011. Natural gas is projected to remain the main system fuel, but decline somewhat to 50.6 percent of net energy for load by 2021.

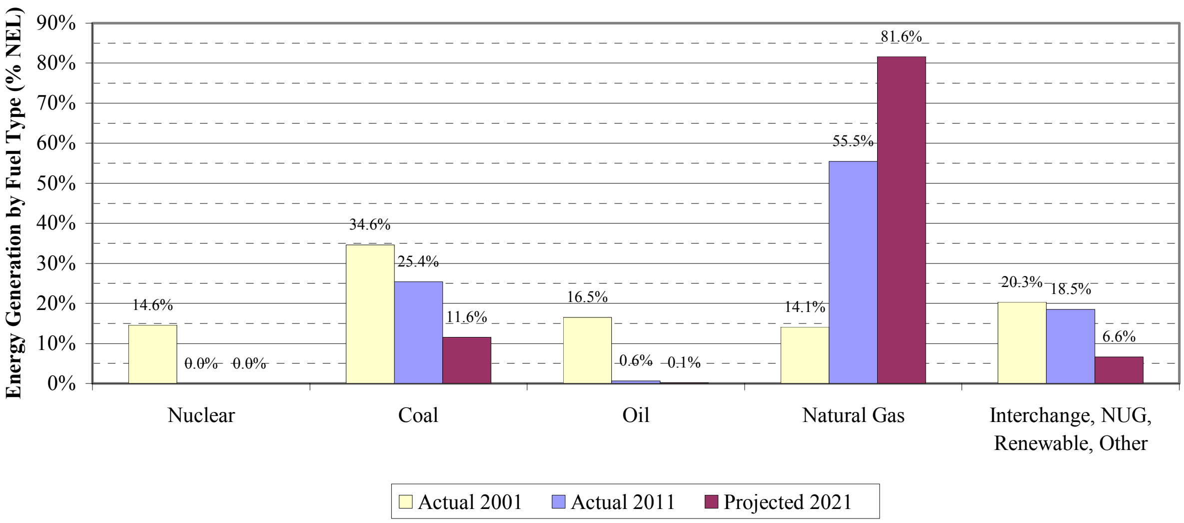
PEF Figure 6. Net Energy for Load by Fuel Type



Source: PEF 2002 and 2012 TYSPs

The decline in natural gas usage is primarily the result of an increase in nuclear generation from the inclusion of the now delayed Levy 1 nuclear unit and the return to service of CR3. While usage of coal for generation is expected to decline, this does not take into account the potential impact of retirements due to new environmental compliance requirements. During the 2012 TYSP workshop, PEF's Crystal River 1 and 2, both coal-fired units, were identified by the Sierra Club/Earthjustice as facing challenges if new emissions control equipment was required. If the projected generation from these nuclear and coal units is displaced by natural gas, it would have the net effect of increasing natural gas' share of PEF's electric generation to 81.6 percent by 2021, as shown in PEF Figure 7 below.

PEF Figure 7. Net Energy for Load by Fuel Type with Displaced Generation



Source: PEF 2002 and 2012 TYSPs, Responses to Staff Data Requests

Generation Additions

PEF's 2012 TYSP includes three generation additions, one of which has been delayed. The first is the uprate of the CR3 nuclear unit, which is subject to the uncertainties discussed above. The second is an unsited 767 MW combined cycle unit, scheduled to begin commercial operation in 2019. The last unit, the Levy 1 nuclear unit, has been delayed outside of the TYSP planning horizon. These are summarized in PEF Table 1.

PEF Table 1. Planned Generation Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Uprates				
Crystal River 3 Uprate	154	2/2007	8/2008	11/2014
Combined Cycle Unit Additions				
Unknown	767	-	-	6/2019
Nuclear Unit Additions				
Levy 1*	1092	5/2008	8/2009	6/2024
Levy 2*	1092	5/2008	8/2009	6/2025

* These units are outside of the 2012-2021 planning period
Source: PEF 2012 TYSP

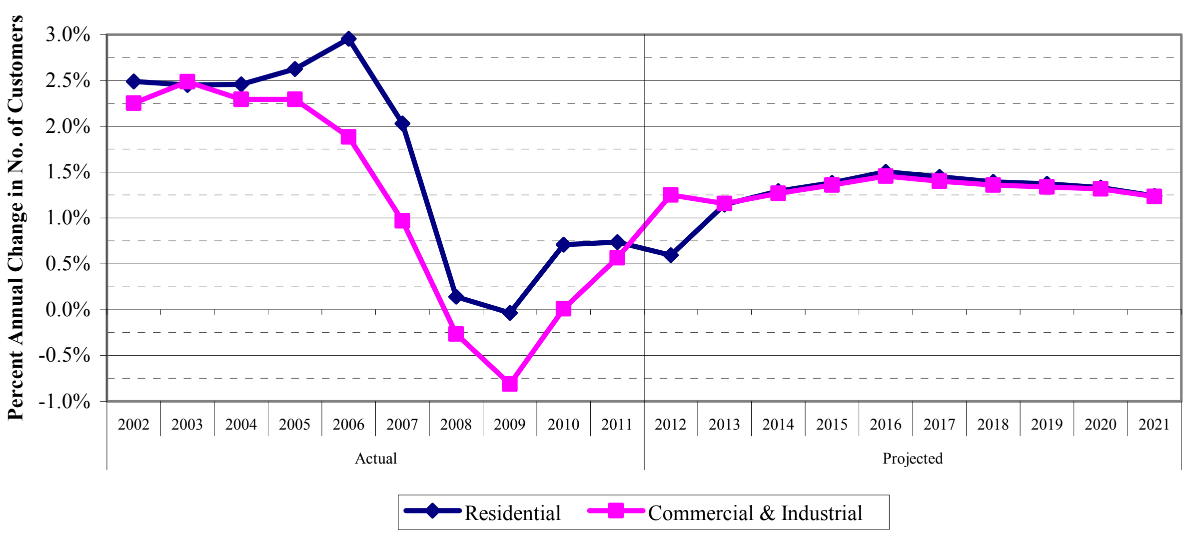
TECO is an investor-owned electric utility, and Florida's third largest TYSP utility. The utility's service territory is within the FRCC region, and consists primarily of the Tampa metropolitan area. As TECO is an IOU, the Commission has regulatory authority over all aspects of operations, including rates and safety.

In 2011, TECO had an average of 675,799 customers, and had a total net energy for load of 19,325 GWh, approximately 8.1 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

TECO Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. Customer growth is anticipated to stay relatively stable over the planning period, with an average annual growth rate of 1.34 percent. This compares with the actual rate of 2.45 percent for the period 2002 through 2007.

TECO Figure 1. Annual Customer Growth Rate by Customer Class

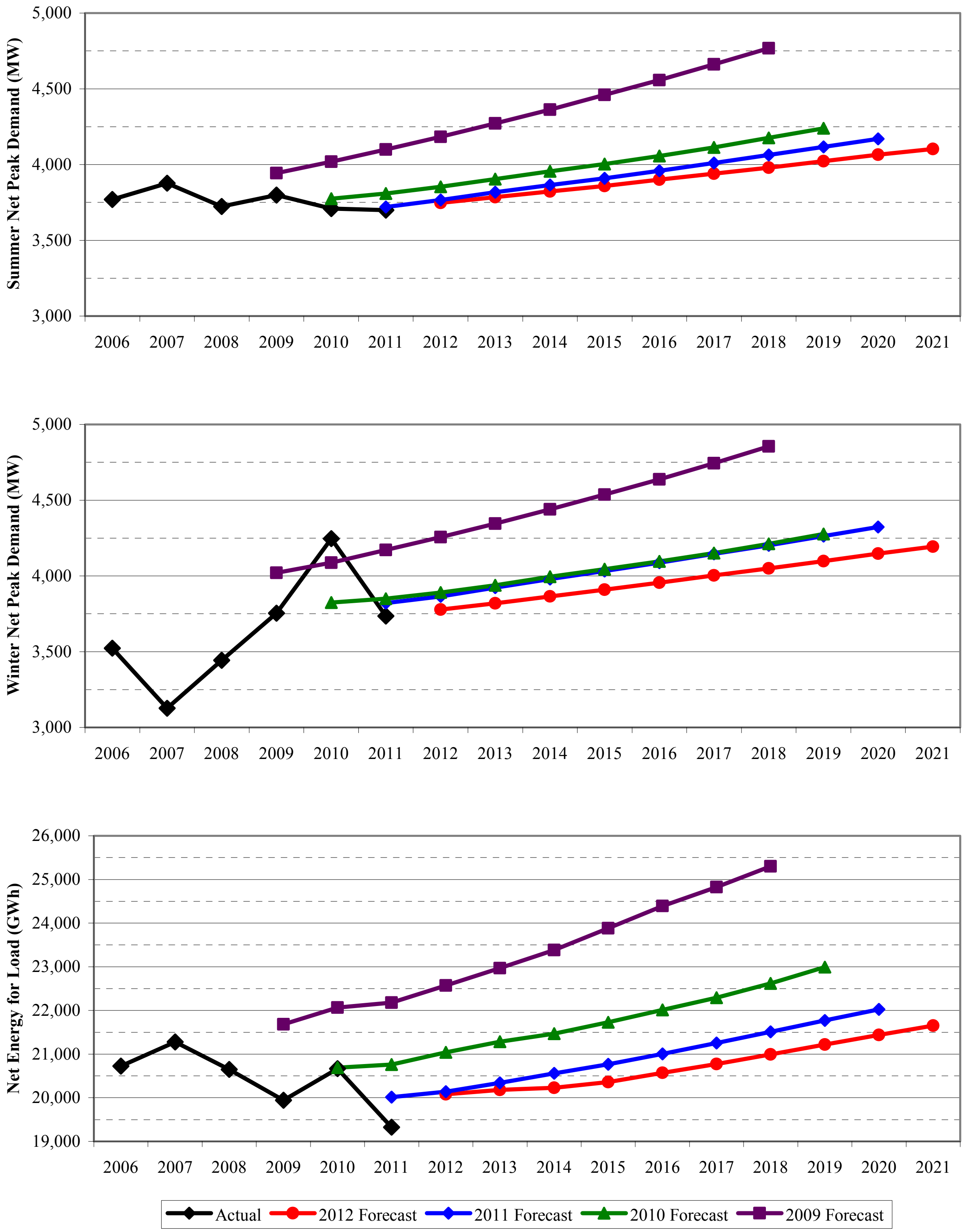


Source: TECO 2012 TYSP

The following three graphs in TECO Figure 2 show TECO's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is lower than the 2011 forecast values for both seasons of peak demand and NEL.

Analysis of TECO's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that TECO's average forecast error is 13.07 percent. This value indicates that the company tends to over-forecast its retail energy sales by 13.07 percent, which is unfavorable when compared to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

TECO Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

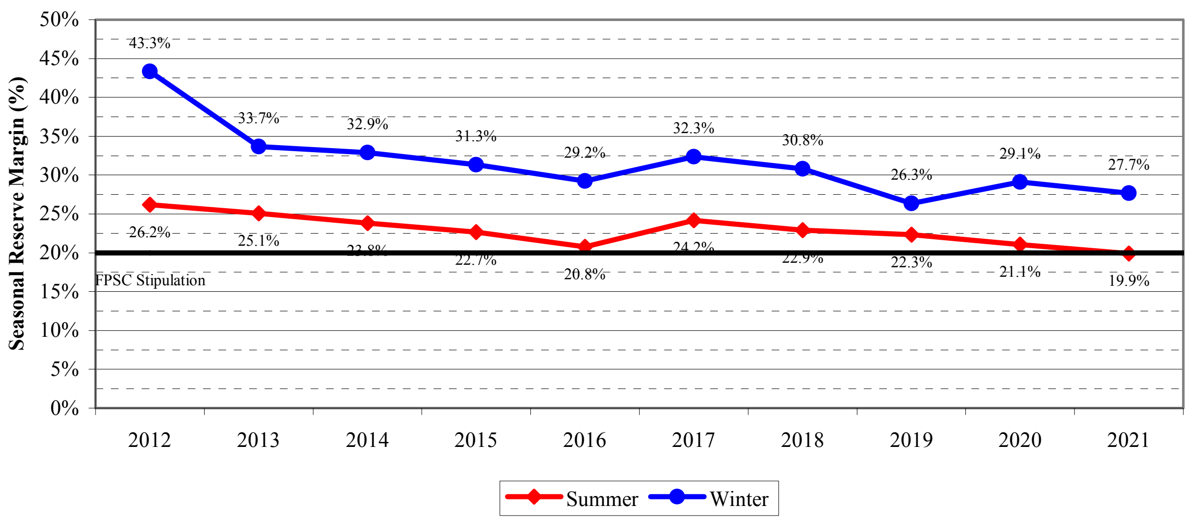


Source: TECO 2009 - 2012 TYSPs

Reserve Margin Requirement

As mentioned in the Statewide Perspective, TECO maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. TECO Figure 3 displays the projected reserve margin for TECO through the planning period for both seasonal peaks. As shown in the figure, summer peak demand would be the driving force for generation additions. The reserve margin shown below includes the cumulative impact of conservation and demand response on TECO's system demand.

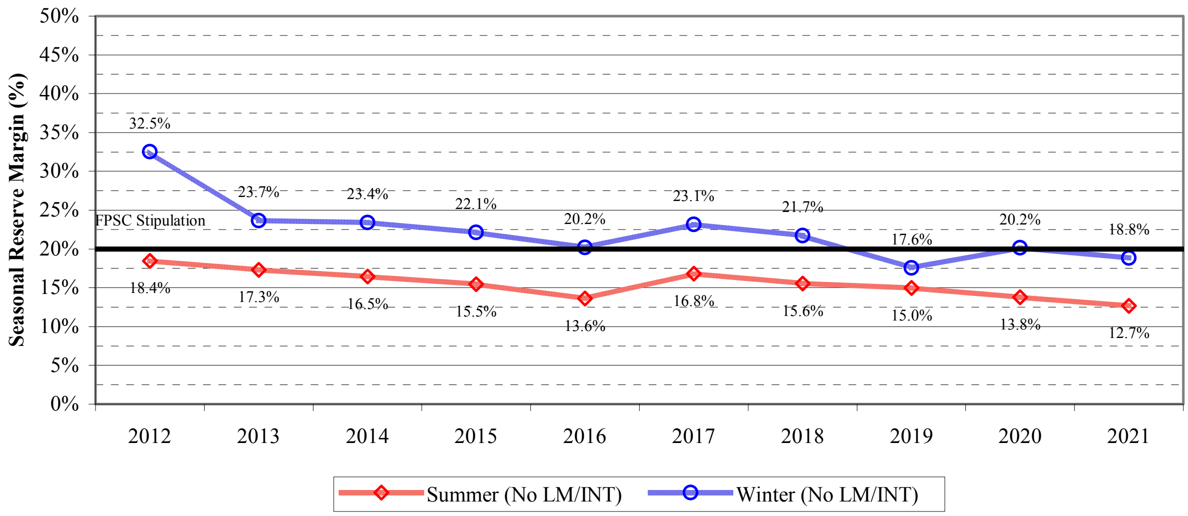
TECO Figure 3. Seasonal Reserve Margin (With LM/INT)



Source: TECO 2012 TYSP

TECO is the only IOU that currently maintains a minimum supply-side contribution to reserve margin, set at 7 percent. As with other utilities, the concern is that interruptible load and load management programs are voluntary, and that customers may elect to opt-out of an existing program if the utility interrupted service too frequently. TECO Figure 4 shows the impact of excluding demand response programs from meeting customer demand, which causes the reserve margin to fall below the company's stipulated 20 percent reserve margin. Even without demand response, TECO exceeds its own supply-side requirements, and generally maintains the FRCC Region's 15 percent planning margin, excluding three summer periods where it falls as low as 12.7 percent in 2021.

TECO Figure 4. Seasonal Reserve Margin (Without LM/INT)

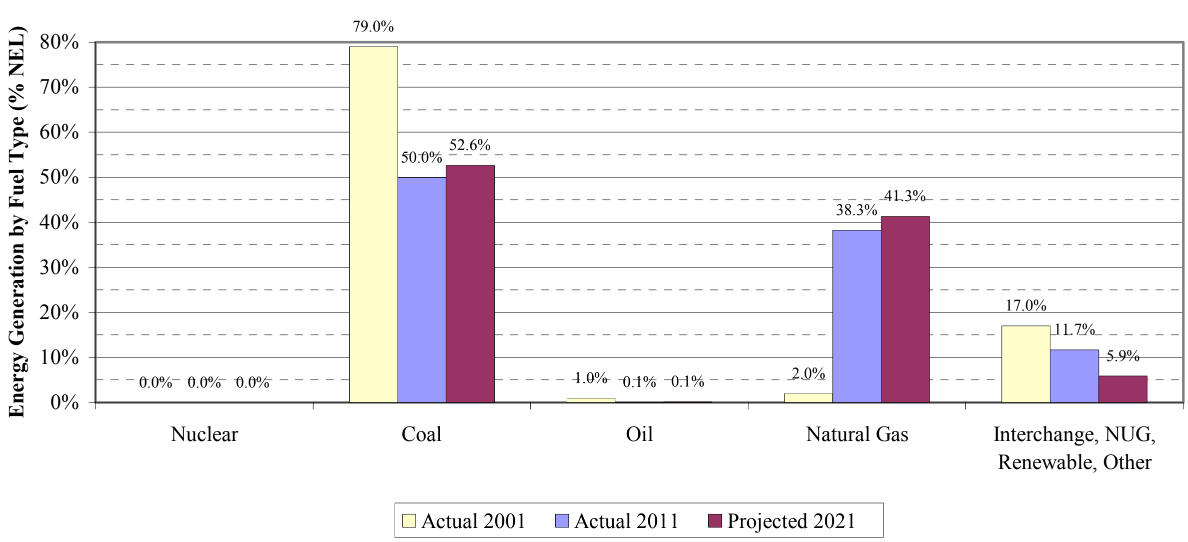


Source: TECO 2012 TYSP

Fuel Diversity

TECO Figure 5 shows TECO's historic fuel mix for 2001 and 2011, and the projected fuel mix for 2021. TECO's primary generation fuel is coal, although this has decreased from nearly 80 percent of system energy in 2001, to only 50 percent in 2011. A slight rebound is anticipated by the end of the planning period, with 52.6 percent of energy from coal-fired generation. Natural gas has increased from a minor fuel on the system, at 2.0 percent in 2001, to the secondary fuel at 38.3 percent in 2011, is also expected to make gains, increasing to 41.3 percent by the end of the planning period.

TECO Figure 5. Net Energy for Load by Fuel Type



Source: TECO 2002 and 2012 TYSPs

Generation Additions

TECO's 2012 TYSP includes two unit additions, including a conversion of its existing Polk facility to combined cycle operation in 2017, and the addition of a single 149 MW combustion turbine in 2019. This represents a reduction from the 2011 TYSP, where TECO included 8 smaller combustion turbines in addition to the Polk CC conversion. TECO's planned additions are summarized in TECO Table 1 below. TECO has recently issued a Request for Proposals (RFP) for its planned combined cycle conversion of several existing simple cycle combustion turbines at the Polk Power Station, and filed for a need determination on September 12, 2012.

TECO Table 1. Planned Generation Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Combined Cycle Unit Additions				
Polk 2-5 CC	1,063	-	-	01/2017
Combustion Turbine Unit Additions				
Future CT 1	149	N/A	N/A	05/2019

Source: TECO 2012 TYSP

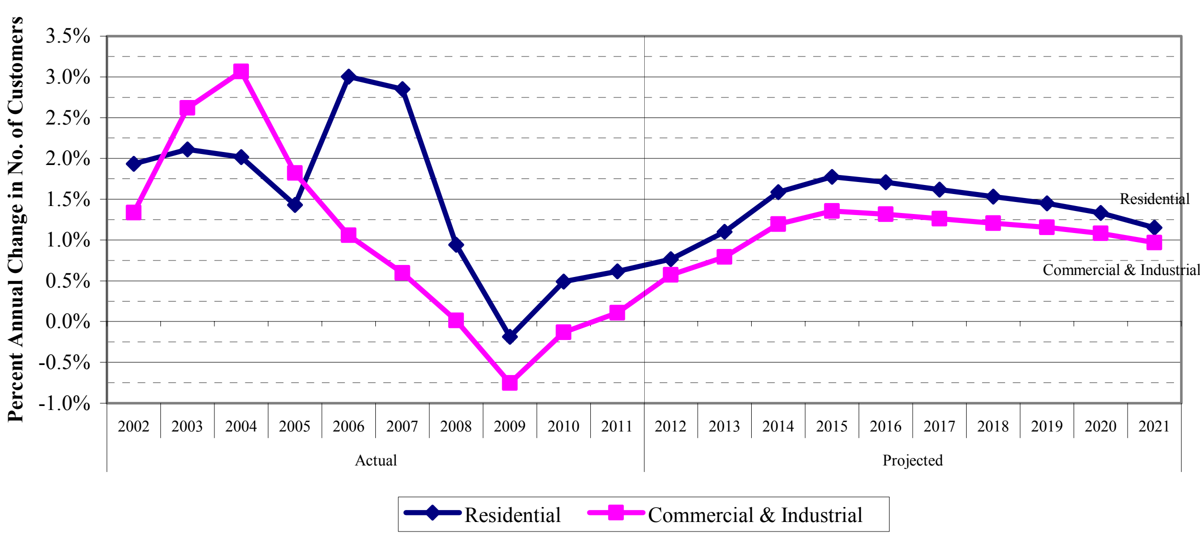
GULF is the smallest investor-owned generating utility, and the sixth largest TYSP utility. The utility's service territory includes western Florida, and is the only TYSP utility outside of the FRCC region. Gulf Power, along with Alabama Power, Georgia Power, and Mississippi Power, are members of the Southern Company electric system. GULF therefore has SERC as its regional reliability entity. Because GULF plans and operates its system in conjunction with the other Southern Company utilities, not all of the energy generated by the GULF units is consumed in Florida. As GULF is an IOU, the Commission has regulatory authority over all aspects of operations, including rates and safety.

In 2011, GULF had an average of 432,403 customers, and had a total net energy for load of 12,086 GWh, approximately 5.1 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

GULF Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. As shown below, GULF anticipates annual customer growth rates to climb until approximately 2015, and then begin to decline slightly but remain positive till the end of the planning period, with an average annual growth rate of 1.43 percent. This compares to the actual rate of 2.22 percent for the period 2002 through 2007.

GULF Figure 1. Annual Customer Growth Rate by Customer Class

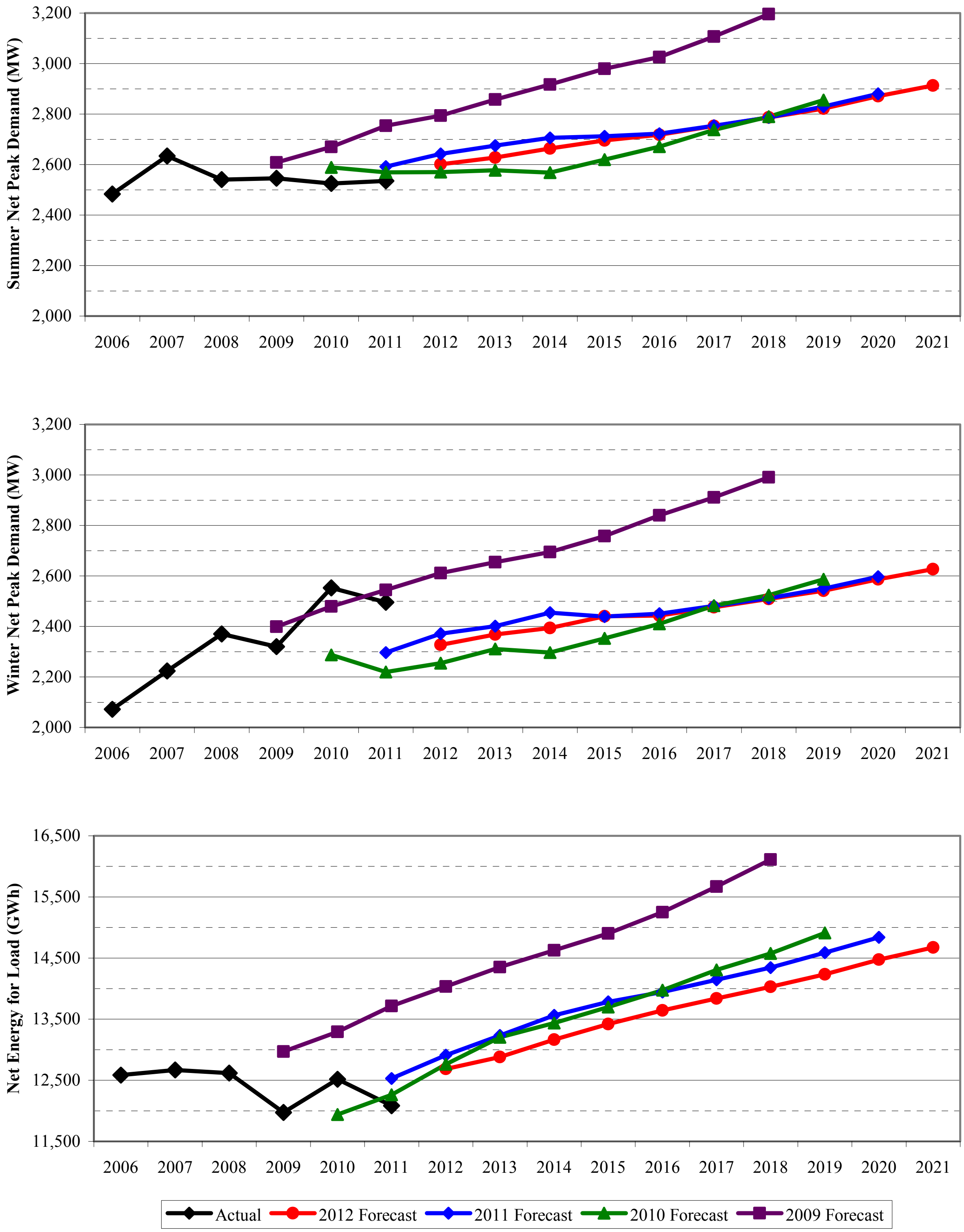


Source: GULF 2012 TYSP

The following three graphs in GULF Figure 2 show GULF's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is similar but slightly below last year's forecast in both seasonal peak demand and NEL.

Analysis of GULF's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that GULF's average forecast error is 5.44 percent. This value indicates that the company tends to over-forecast its retail energy sales by 5.44 percent, the lowest of the TYSP Utilities. GULF's forecast error is favorable when compared to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

GULF Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

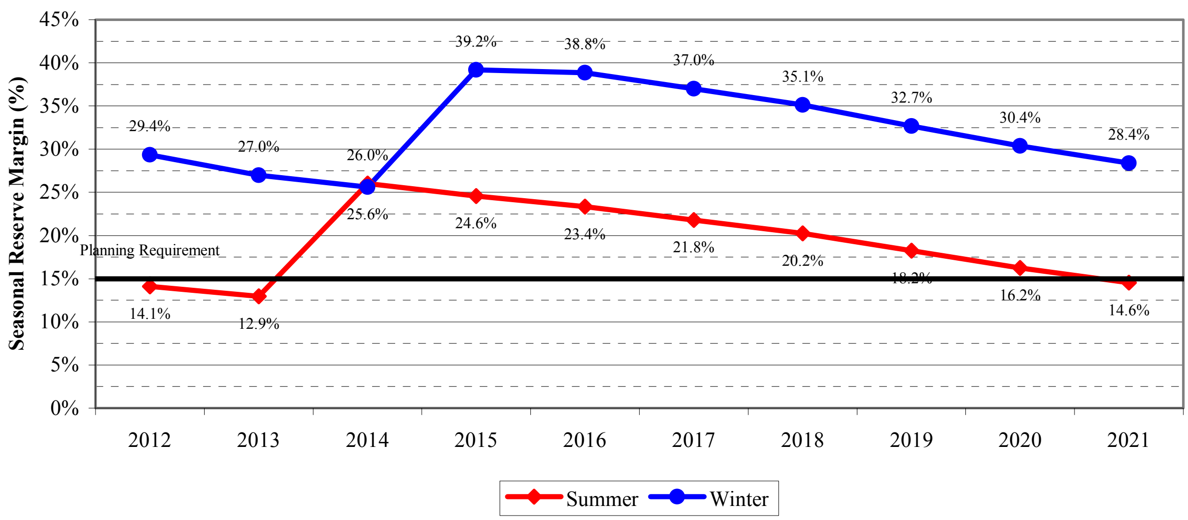


Source: GULF 2009 - 2012 TYSPs

Reserve Margin Requirement

GULF is not within the FRCC region, and therefore not subject to its minimum reserve margin requirements. GULF operates within SERC, and as part of the Southern Power Pool has a planning reserve margin of 15 percent after 2015. The company's projected reserve margin for summer and winter peak demand is shown below in GULF Figure 3. The reserve margin shown below includes the cumulative impact of conservation, but as GULF does not administer any active demand response programs, there are no non-firm load components in its reserve margin.

GULF Figure 3. Seasonal Reserve Margin

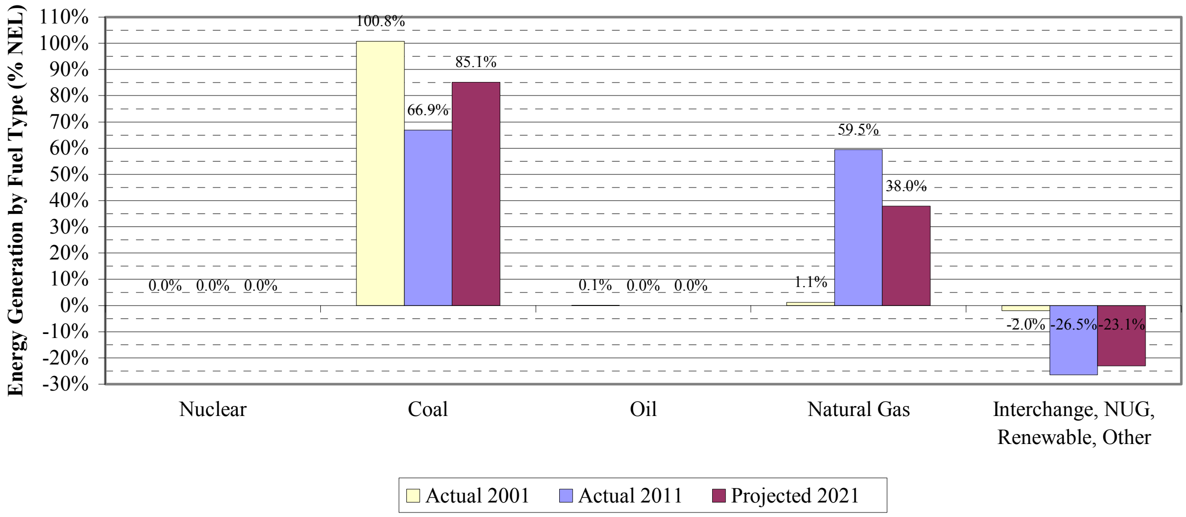


Source: GULF 2012 TYSP

Fuel Diversity

GULF Figure 4 shows GULF's historic fuel mix for 2001 and 2011, and the projected fuel mix for 2021. The negative value for interchange/other category of generation represents power sales, as GULF generates more energy than its native customers consume. GULF's primary generation fuel has been coal, with 66.9 percent of native load served by it in 2011, down from 100.8 percent in 2001. This is anticipated to rebound by the end of the planning period, with a projected 85.1 percent of native NEL from coal in 2021. The main source of reduction in coal generation comes from natural gas, which was used to produce 59.5 of native NEL in 2011, and is projected to decline to 38.0 percent by 2021.

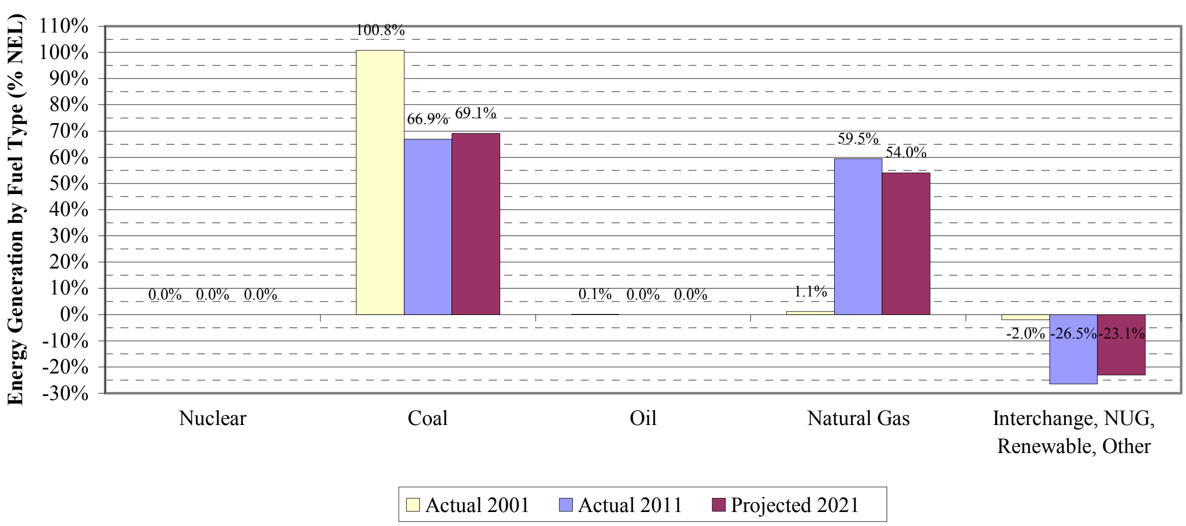
GULF Figure 4. Net Energy for Load by Fuel Type



Source: GULF 2002 and 2012 TYSPs

While usage of coal for generation is expected to increase, this does not take into account the potential impact of retirements due to new environmental compliance requirements. During the 2012 TYSP workshop, GULF's Lansing Smith 1 and 2, both coal-fired units, were identified by the Sierra Club/Earthjustice as facing challenges if new emissions control equipment was required. If the projected generation from these coal units is displaced by natural gas, it would have the net effect of increasing natural gas' share of GULF's electric generation to 54 percent by 2021, while reducing the increase in coal generation to only 69.1 percent, as illustrated in GULF Figure 5 below.

GULF Figure 5. Net Energy for Load by Fuel Type with Displaced Generation



Source: GULF 2002 and 2012 TYSPs, Responses to Staff Data Requests

Generation Additions

GULF has no planned generation additions over the planning horizon. This is consistent with the company's 2011 TYSP, which also included no new generating units through 2020.

FLORIDA MUNICIPAL POWER AGENCY (FMPA)

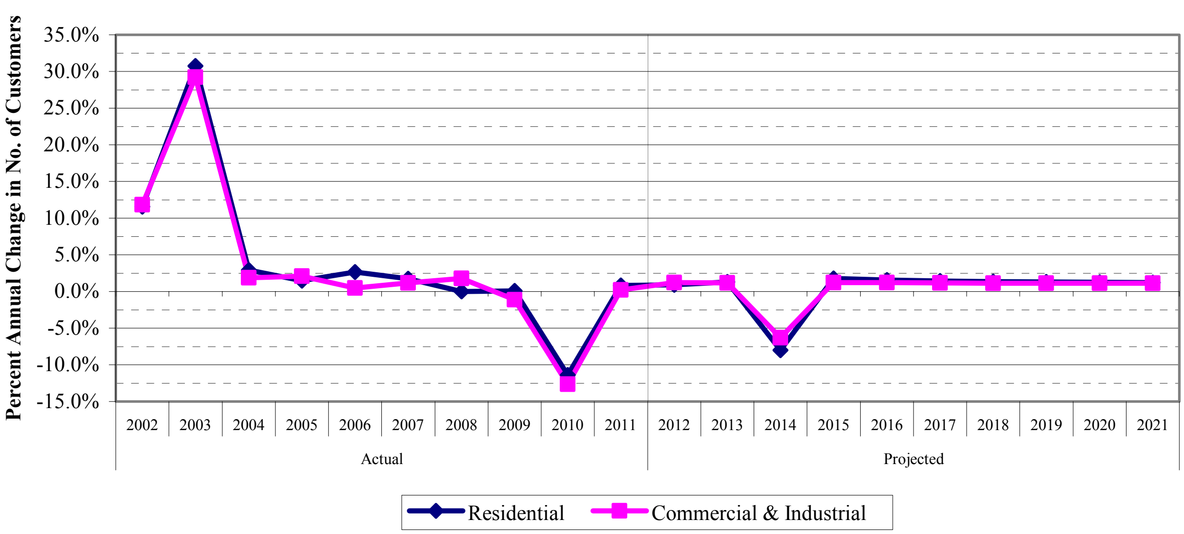
FMPA is a governmental wholesale power company owned by 30 municipal electric utilities located throughout the State of Florida. It is collectively the state's eighth largest TYSP utility. FMPA facilitates opportunities for its members to participate in power supply projects developed by Florida utilities and other producers, and provides economies of scale in power generation and related services. As FMPA is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. FMPA's direct responsibility for power supply is with the All-Requirements Power Supply Project (ARP), where FMPA plans and supplies all of the power requirements for 14 of its participating utilities. The values for capacity in the following figures corresponds to the ARP.

In 2011, FMPA had an average of 262,659 customers, and had a total net energy for load of 6,209 GWh, approximately 2.6 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

FMPA Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth during for 2012 through 2021. The drop in the rate of growth for 2010 is due to the City of Vero Beach leaving the ARP, and the smaller drop in 2014 is the expected result of the departure of the City of Lake Worth from the ARP. These utilities will remain as members of FMPA, but are exercising an option to modify their memberships from a full requirements basis to a partial requirements basis. These changes in membership status means that the ARP will no longer utilize these participants' generating resources, if any exist.

FMPA Figure 1. Annual Customer Growth Rate by Customer Class

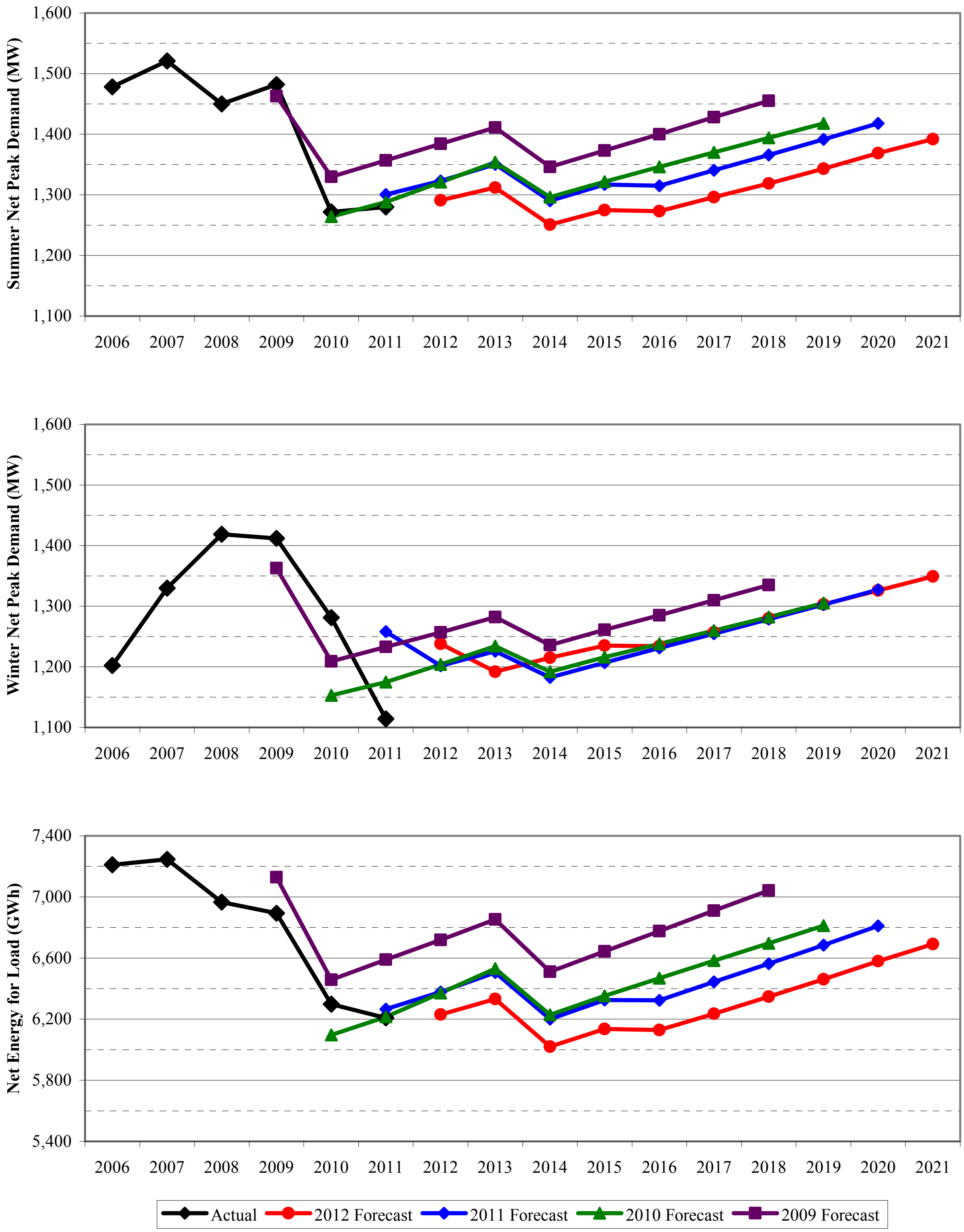


Source: FMPA 2012 TYSP

The following three graphs in FMPA Figure 2 show FMPA's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is below last year's in terms of summer peak demand and NEL, but winter peak demand is similar.

Analysis of FMPA's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that FMPA's average forecast error is 11.81 percent. This value indicates that the company tends to over-forecast its retail energy sales by 11.81 percent, which is somewhat higher than the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

FMPA Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

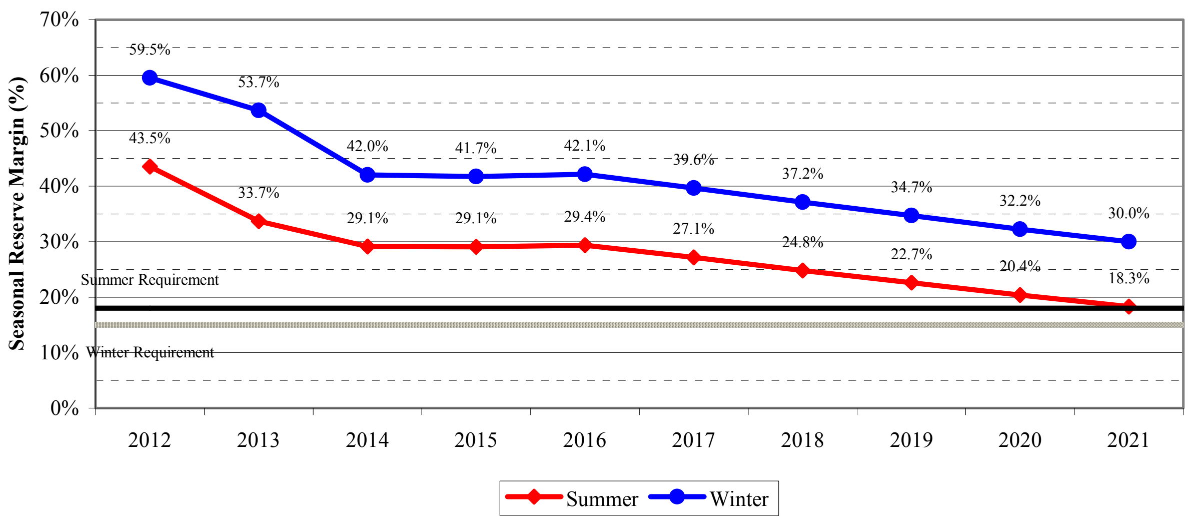


Source: FMPA 2009 - 2012 TYSPs

Reserve Margin Requirement

FMPA is required to maintain a minimum 15 percent reserve margin, pursuant to FRCC requirements. In addition, the utility uses a planning reserve margin of 18 percent for summer peak reserve margin planning. As can be seen in FMPA Figure 3 below, FMPA has ample reserves and its margin only begins to approach the 15 percent minimum in the last few years of the horizon. FMPA does not administer load management or interruptible load programs, and therefore has no non-firm load component in its reserve margin.

FMPA Figure 3. Seasonal Reserve Margin

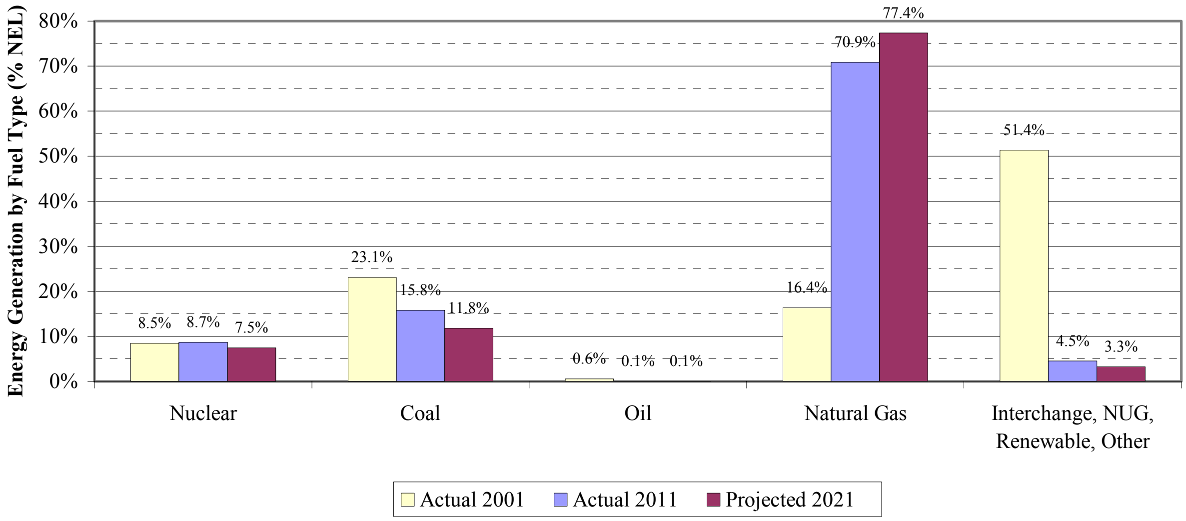


Source: FMPA 2012 TYSP

Fuel Diversity

FMPA Figure 4 displays the composition of FMPA's system in terms of energy generated. Again, natural gas has risen to become the system's primary fuel, increasing over 50 percent, from 16.4 percent in 2001 up to 70.9 percent in 2011. Natural gas is anticipated to increase somewhat to 77.4 percent in 2021, with further decreases in purchased power and coal generation.

FMPA Figure 4. Net Energy for Load by Fuel Type



Source: FMPA 2002 and 2012 TYSPs

Generation Additions

FMPA has no planned generation additions over the planning horizon. This is consistent with the company's 2011 TYSP, which also included no new generating units through 2020.

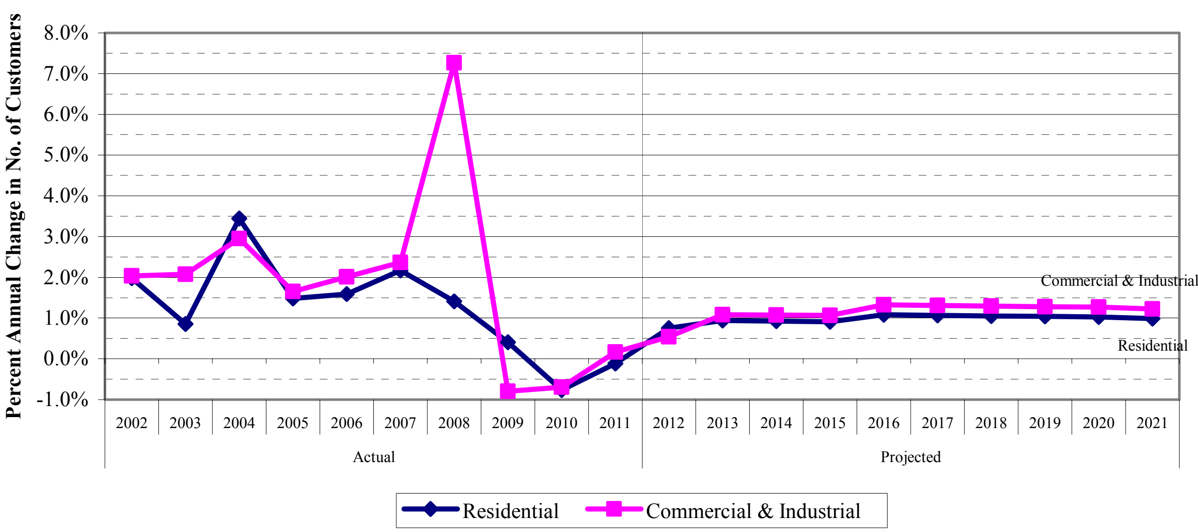
GRU is a municipal utility and the state's smallest TYSP utility. The company's service area is within the FRCC region, and includes the City of Gainesville and its surrounding urban area. GRU also provides wholesale power to the City of Alachua and Clay Electric Cooperative. As GRU is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning

In 2011, GRU had an average of 92,265 customers, and had a total net energy for load of 2,024 GWh, approximately 0.9 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

GRU Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth during for 2012 through 2021. GRU anticipates customer growth to remain steady through the end of the planning period, with an average annual growth rate of 1.03 percent. This compares with the actual rate of 1.94 percent for the period 2002 through 2007.

GRU Figure 1. Annual Customer Growth Rate by Customer Class

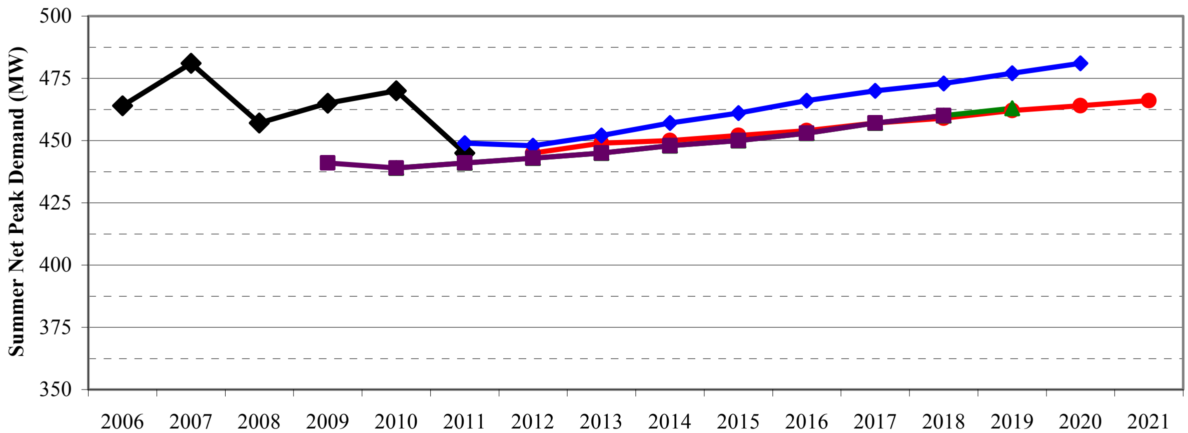


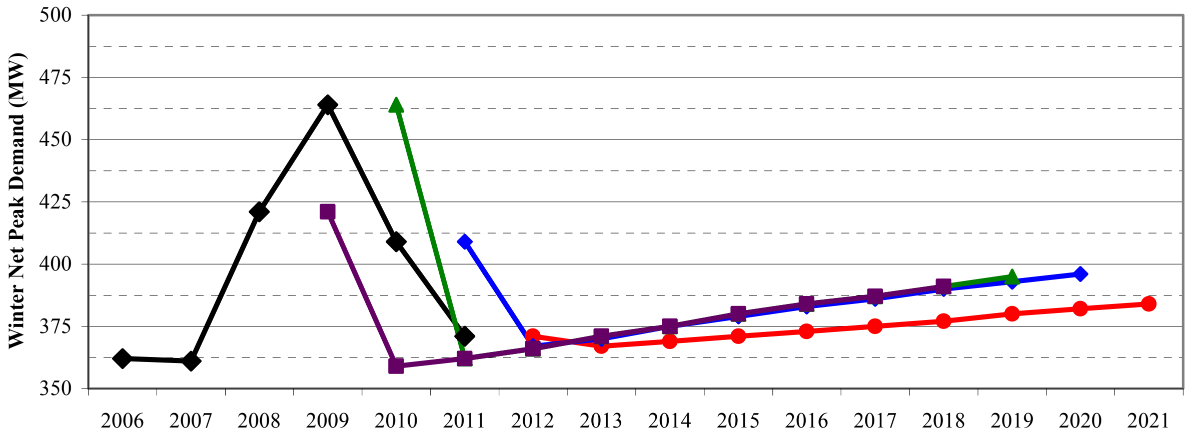
Source: GRU 2012 TYSP

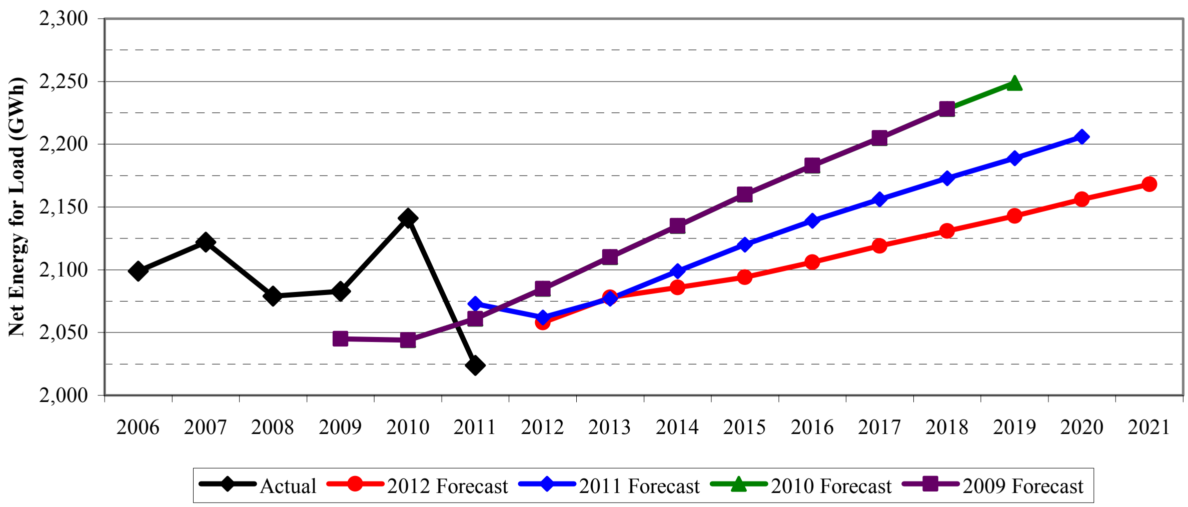
The following three graphs in GRU Figure 2 show GRU's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is below last year's in both seasonal peak demand and NEL.

Analysis of GRU's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that GRU's average forecast error is 11.40 percent. This value indicates that the company tends to over-forecast its retail energy sales by 11.40 percent, which is approximately equivalent to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

GRU Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts





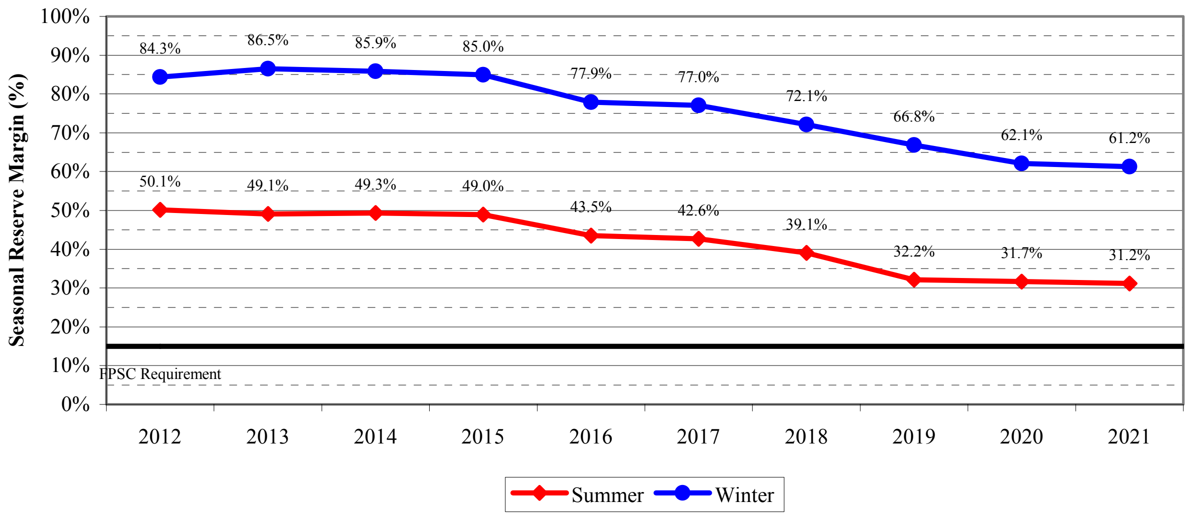


Source: GRU 2009 - 2012 TYSPs

Reserve Margin Requirement

Pursuant to FRCC requirements, GRU maintains a 15 percent reserve margin. As GRU Figure 3 clearly shows, GRU's reserve margin is forecasted to remain well above the minimum level throughout the planning horizon for the summer and winter peak seasons. GRU does not have any active load management or interruptible load programs and therefore has no non-firm load component to its reserve margin.

GRU Figure 3. Seasonal Reserve Margin

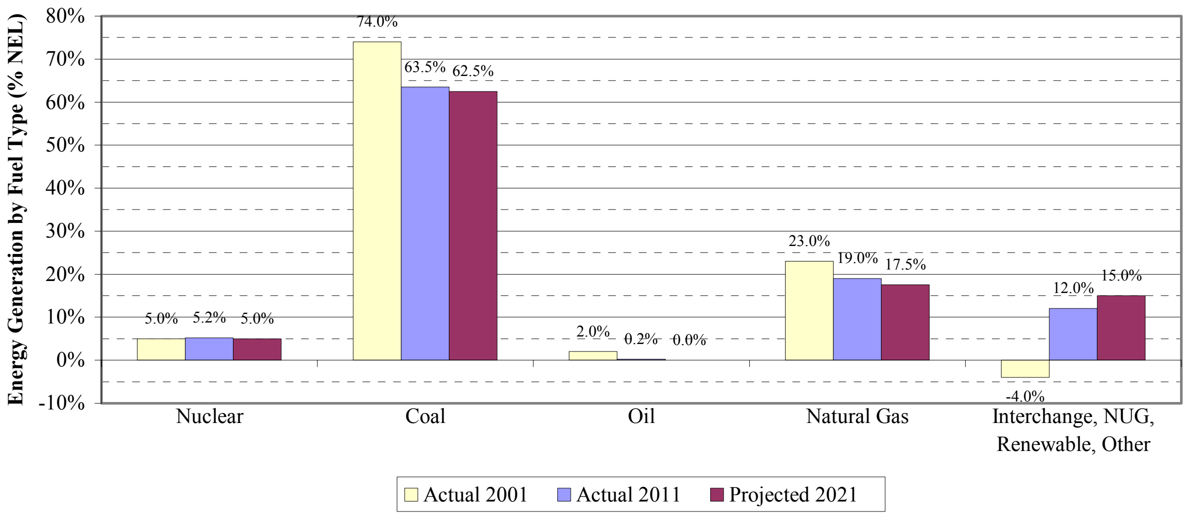


Source: GRU 2012 TYSP

Fuel Diversity

GRU Figure 4 displays the composition of GRU's system in terms of energy generated. The company has historically relied upon coal generation, and it is projected to produce a majority of energy for load through the end of the planning period. Other energy sources include natural gas, nuclear, purchased power, and renewables. GRU anticipates a decline in both coal-fired and natural gas-fired generation, made up for by renewable purchased power contracts, especially a large biomass unit that the Commission authorized recently.

GRU Figure 4. Net Energy for Load by Fuel Type



Source: GRU 2012 TYSP

Generation Additions

GRU has no planned generation additions over the planning horizon. This is consistent with the company's 2011 TYSP, which also included no new generating units through 2020.

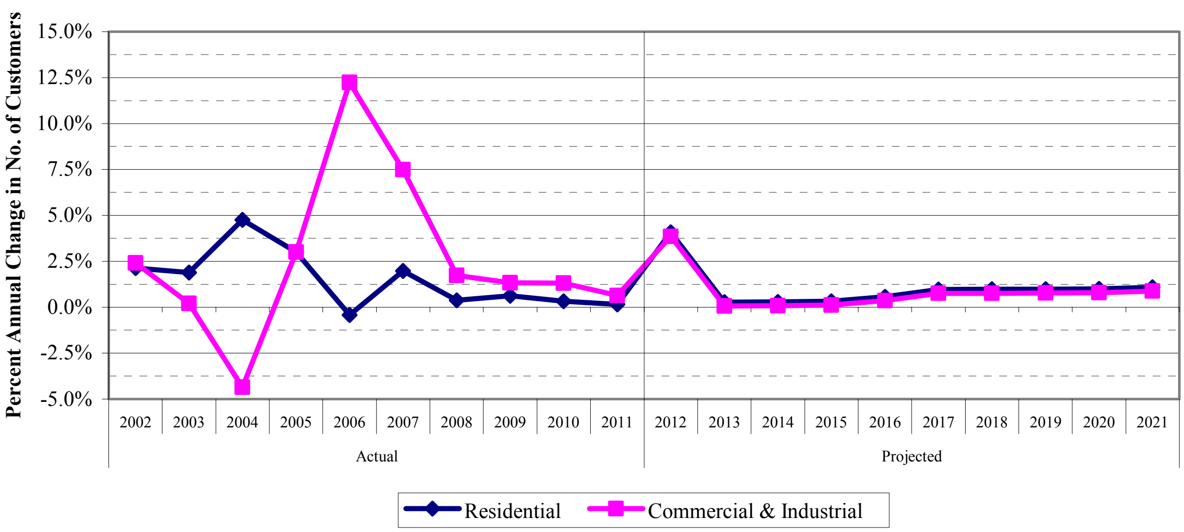
JEA is a municipal electric utility, and the state's fifth largest TYSP utility, and is the largest generating municipal utility. JEA's service territory is within the FRCC region, and includes all of Duval County as well as portions of Clay and St. Johns Counties. As JEA is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning

In 2011, JEA had an average of 416,278 customers, and had a total net energy for load of 12,980 GWh, approximately 5.5 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

JEA Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. Positive growth is anticipated over the entire planning period, with an average annual growth rate of 0.69 percent. This compares with the actual rate of 2.36 percent for the period 2002 through 2007.

JEA Figure 1. Annual Customer Growth Rate by Customer Class

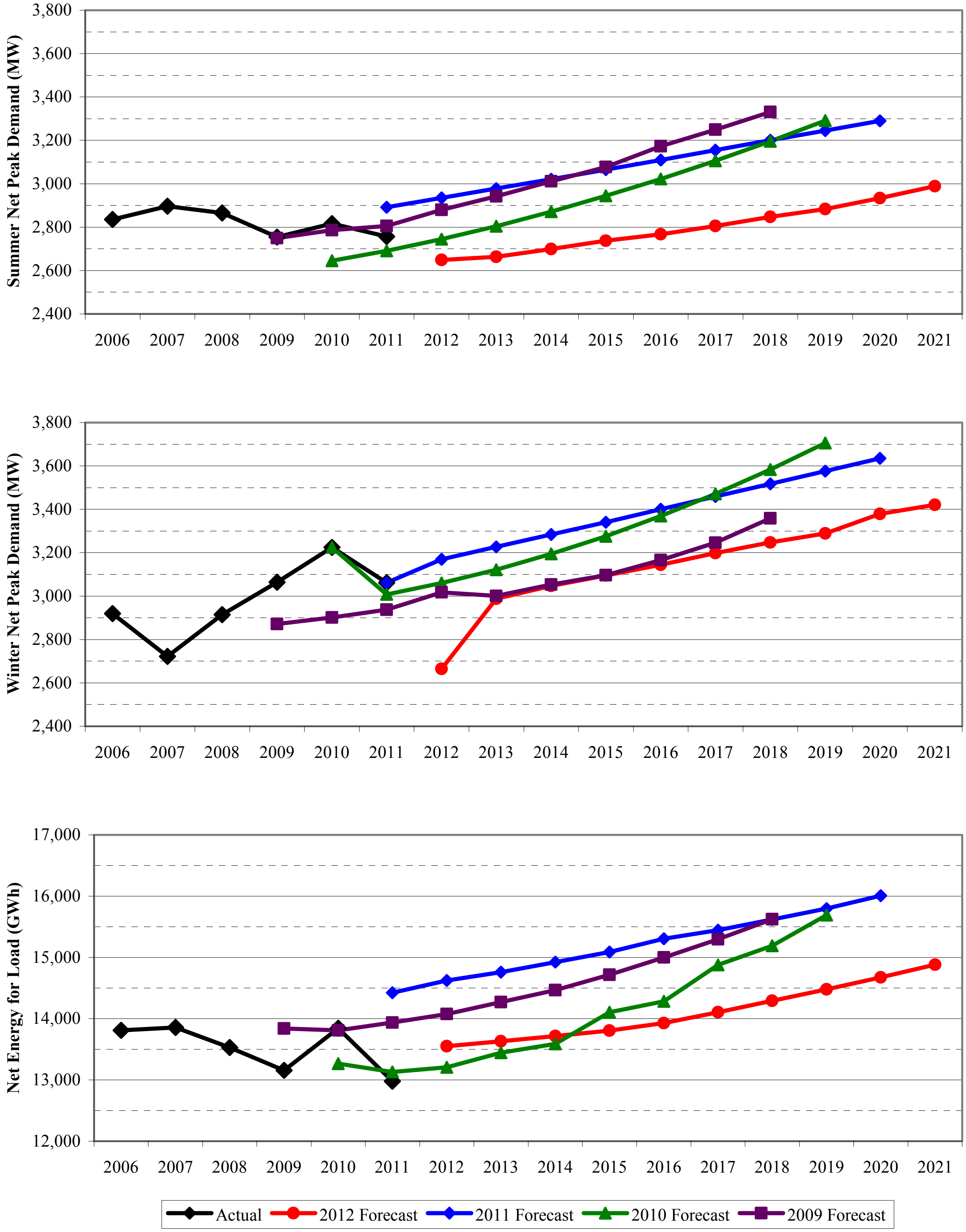


Source: JEA 2012 TYSP

The following three graphs in JEA Figure 2 show JEA's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is below last year's in both seasonal peak demand and NEL.

Analysis of JEA's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that JEA's average forecast error is 12.72 percent. This value indicates that the company tends to over-forecast its retail energy sales by 12.72 percent, which is unfavorable when compared to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

JEA Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

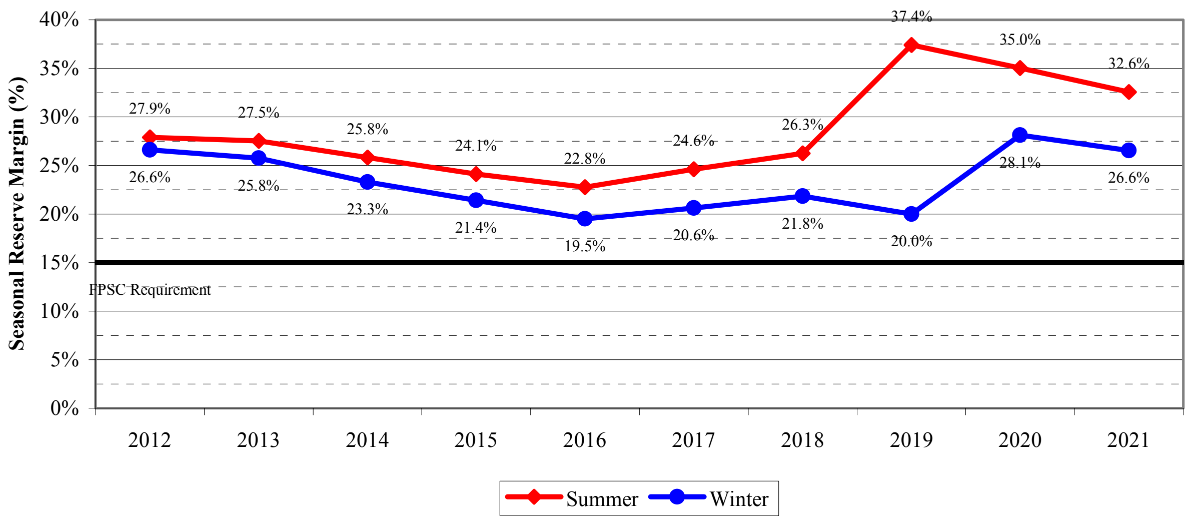


Source: JEA 2009 - 2012 TYSPs

Reserve Margin Requirement

JEA maintains a 15 percent reserve margin pursuant to FRCC requirements. JEA Figure 3 shows their projected reserve margin, which is sufficient for both summer and winter seasonal peaks.

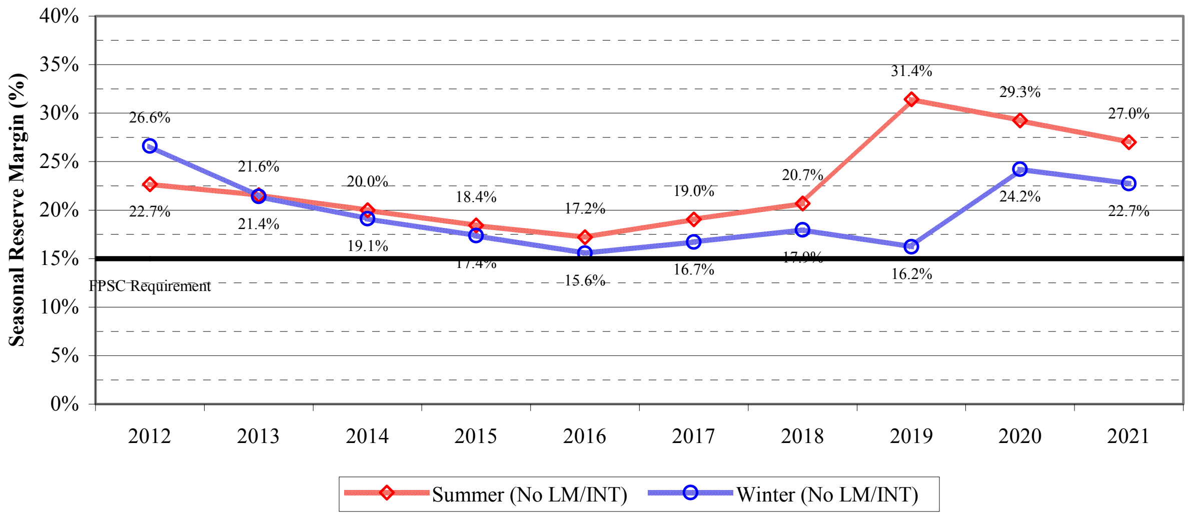
JEA Figure 3. Seasonal Reserve Margin (With LM/INT)



Source: JEA 2012 TYSP

Because JEA does have active load management and interruptible load programs in place, a portion of its reserve margin can be attributed to non-firm load. The measure of reserve margin without any contribution from demand-side programs is shown in JEA Figure 4. JEA's reserve margin exceeds its planning requirement for both summer and winter peak demand throughout the ten year horizon without activating demand response programs.

JEA Figure 4. Seasonal Reserve Margin (Without LM/INT)

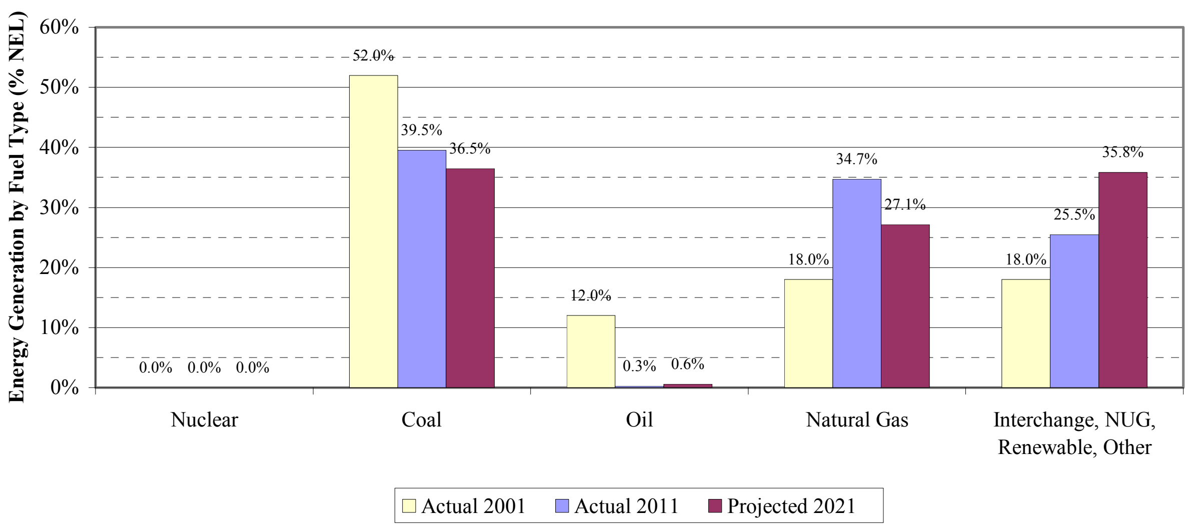


Source: JEA 2012 TYSP

Fuel Diversity

JEA Figure 5 displays the composition of JEA's system in terms of energy generated. Coal, natural gas, and purchased power are the primary sources, with coal overall declining since 2001 while natural gas and purchased power have increased by 2011. Coal is expected to further decline, along with natural gas, in favor of purchased power by 2021.

JEA Figure 5. Net Energy for Load by Fuel Type



Source: JEA 2002 and 2012 TYSPs

Generation Additions

JEA has no planned generation additions over the planning horizon. This is consistent with the company's 2011 TYSP, which also included no new generating units through 2020.

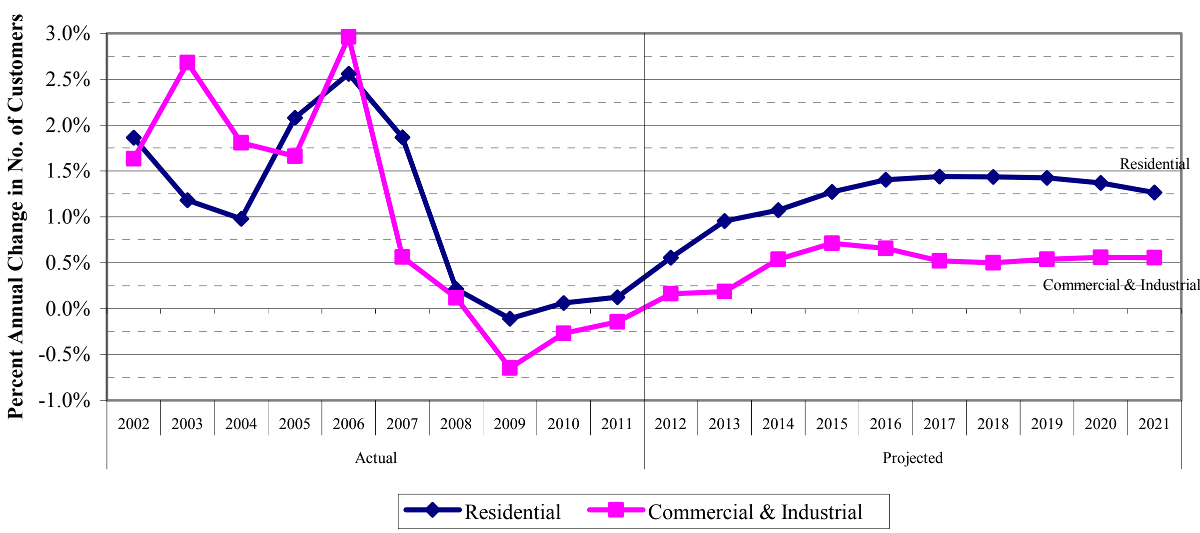
LAK is the municipal utility, and is the state's ninth largest TYSP utility. LAK is owned and operated by the City of Lakeland. LAK is a member of the Florida Municipal Power Pool (FMPP), along with OUC and FMPA's All-Requirements Project (ARP). The FMPP operates as an hourly energy pool with all FMPP capacity from its members committed and dispatched together. Each member of the FMPP retains the responsibility of adequately planning it own system to meet native load and FRCC reserve requirements. As LAK is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning

In 2011, LAK had an average of 121,763 customers, and had a total net energy for load of 2,893 GWh, approximately 1.2 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

LAK Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth during for 2012 through 2021. Customer growth is anticipated to increase slowly throughout the planning period, with an average annual growth rate of 1.21 percent. This compares with the actual rate of 1.75 percent for the period 2002 through 2007.

LAK Figure 1. Annual Customer Growth Rate by Customer Class

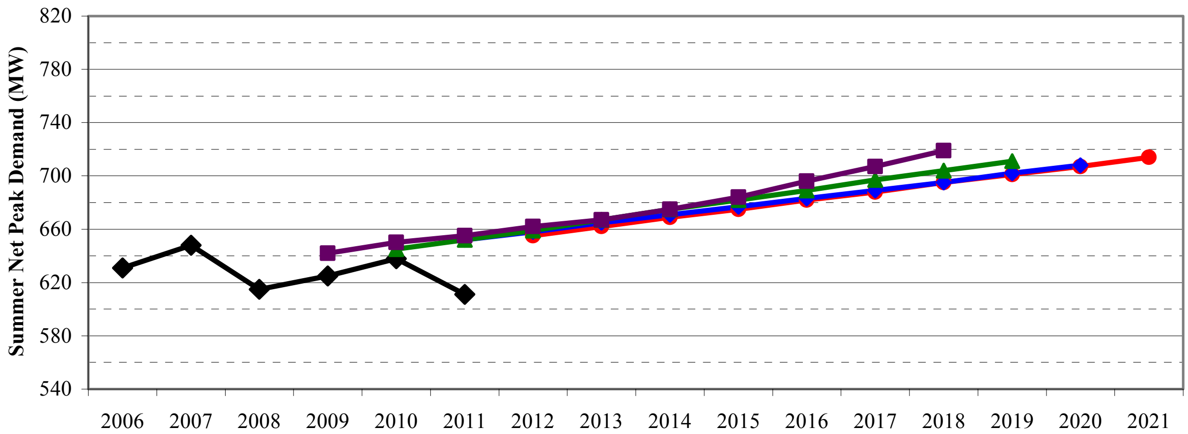


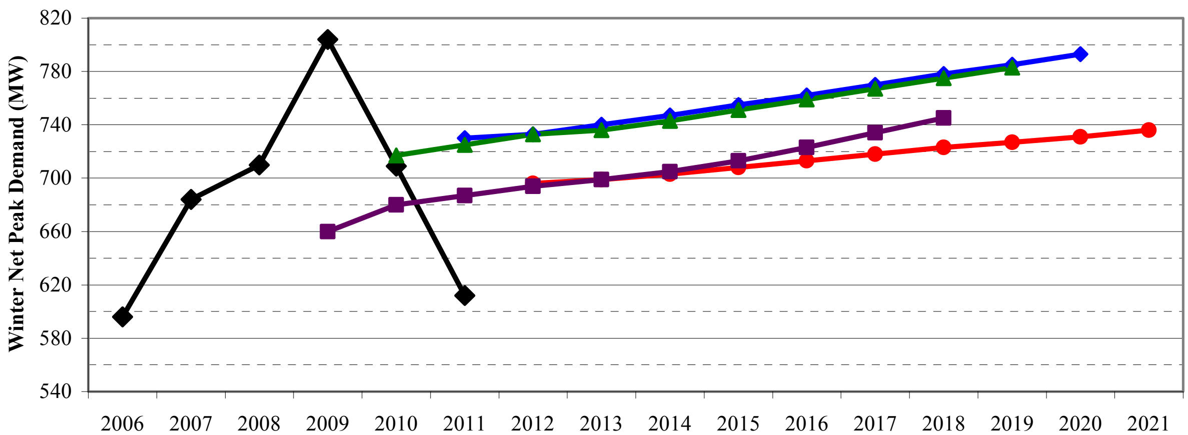
Source: LAK 2012 TYSP

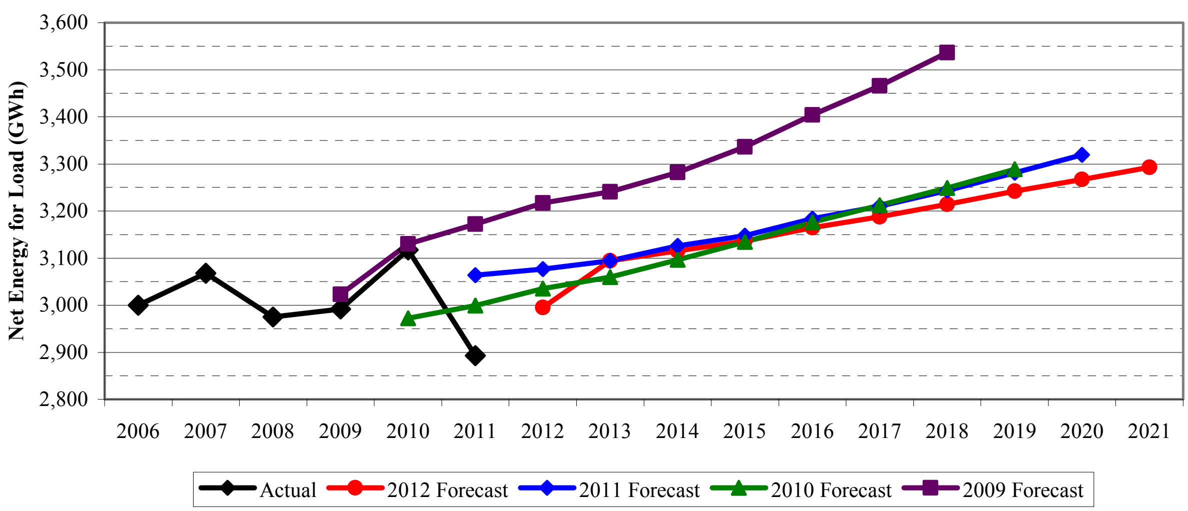
The following three graphs in LAK Figure 2 show LAK's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is equivalent to last year's for summer peak demand and NEL, but notably below for winter peak demand.

Analysis of LAK's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that LAK's average forecast error is 7.89 percent. This value indicates that the company tends to over-forecast its retail energy sales by 7.89 percent, which is favorable when compared to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

LAK Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts





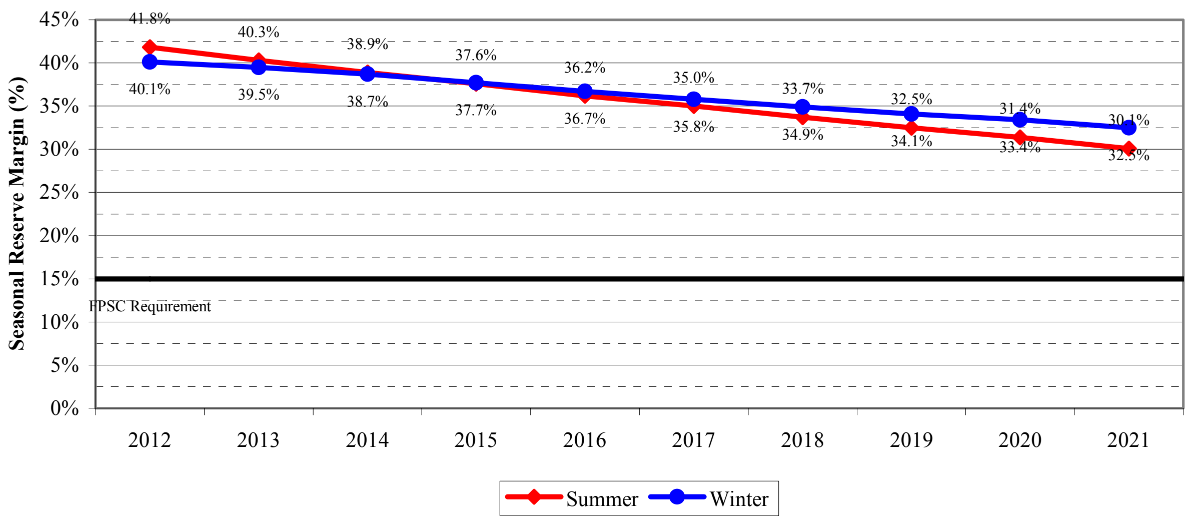


Source: LAK 2009 - 2012 TYSPs

Reserve Margin Requirement

As an FRCC utility, LAK maintains a 15 percent minimum reserve margin. As LAK Figure 3 shows, although LAK's reserve margin decreases steadily over the planning horizon, it remains well above the minimum level of 15 percent.

LAK Figure 3. Seasonal Reserve Margin

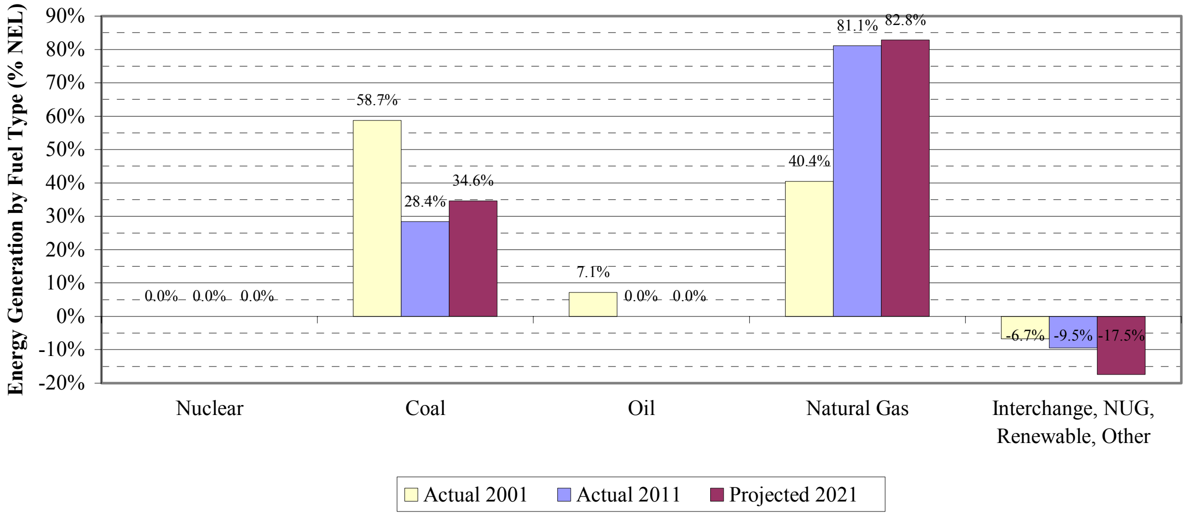


Source: LAK 2012 TYSP

Fuel Diversity

LAK Figure 4 displays the composition of LAK's system in terms of energy generated. Natural gas has increased its share of the company's energy from 40.4 percent in 2001 to 81.1 percent in 2011. While coal and oil made a significant portion of generation historically, oil usage has been drastically reduced, and coal's portion of generation has declined to approximately a third of system energy. LAK also makes significant energy sales, which cause its total energy produced to exceed 100 percent of its native load.

LAK Figure 4. Net Energy for Load by Fuel Type



Source: LAK 2012 TYSP

Generation Additions

LAK has no planned generation additions over the planning horizon. This is consistent with the company's 2011 TYSP, which also included no new generating units through 2020.

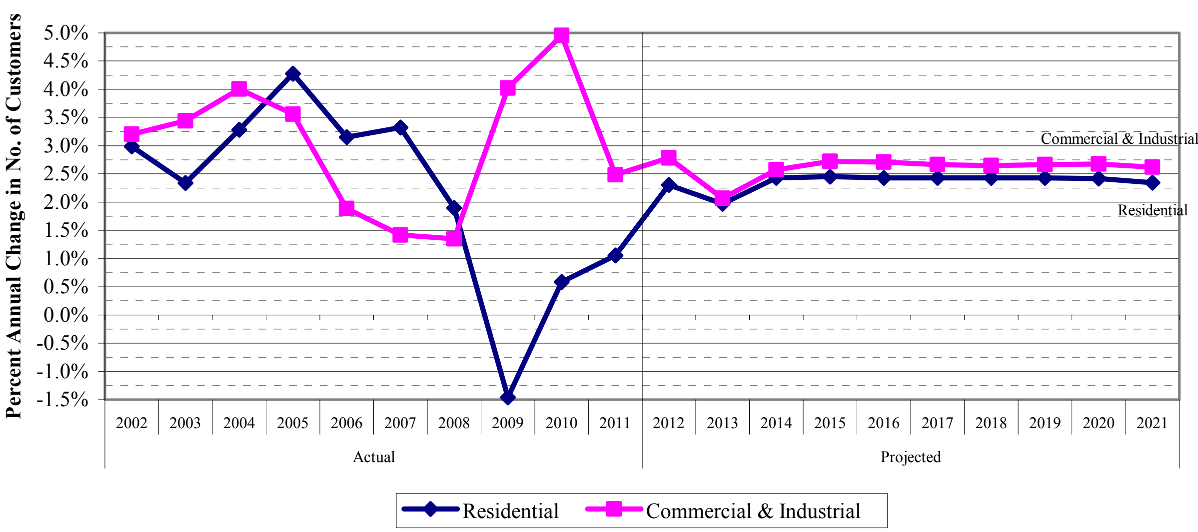
OUC is a municipal utility, and the state's seventh largest TYSP utility. The utility's service territory is within the FRCC region, and serves the Orlando metropolitan area. OUC is a member of the FMPP, along with LAK and FMPA's All-Requirements Project (ARP). As OUC is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning.

In 2011, OUC had an average 209,638 customers, and had a total net energy for load of 6,977 GWh, approximately 2.9 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

OUC Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. Overall, OUC projected a steady growth throughout the planning period, with an average annual growth rate of 2.40 percent through 2021. This compares with the actual rate of 3.22 percent for the period 2002 through 2007.

OUC Figure 1. Annual Customer Growth Rate by Customer Class

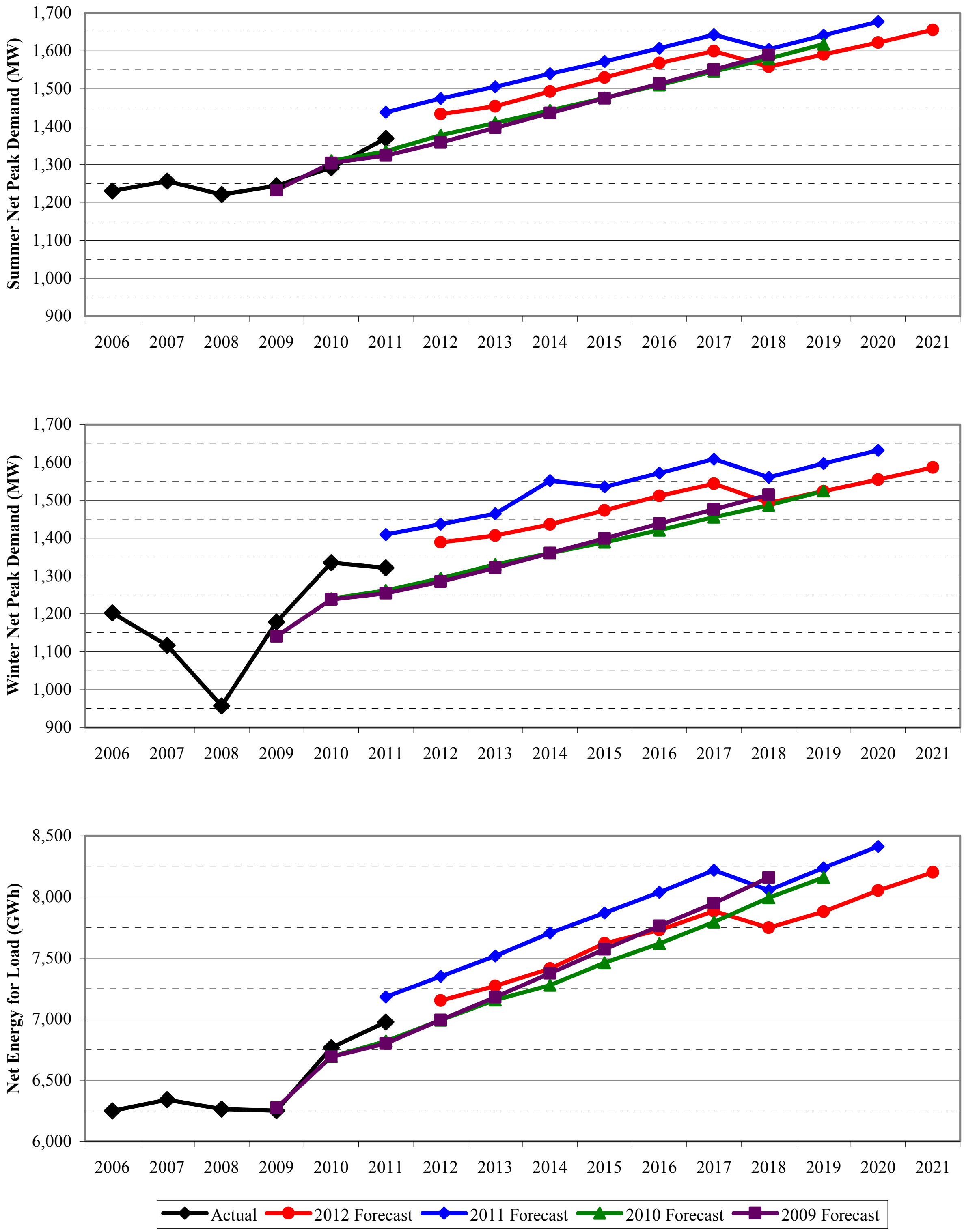


Source: OUC 2012 TYSP

The following three graphs in OUC Figure 2 show OUC's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is below last year's for both seasonal peaks and NEL.

Analysis of OUC's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that OUC's average forecast error is 5.83 percent, the second lowest error rate in 2012. This value indicates that the company tends to over-forecast its retail energy sales by 5.83 percent, which is favorable when compared to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

OUC Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

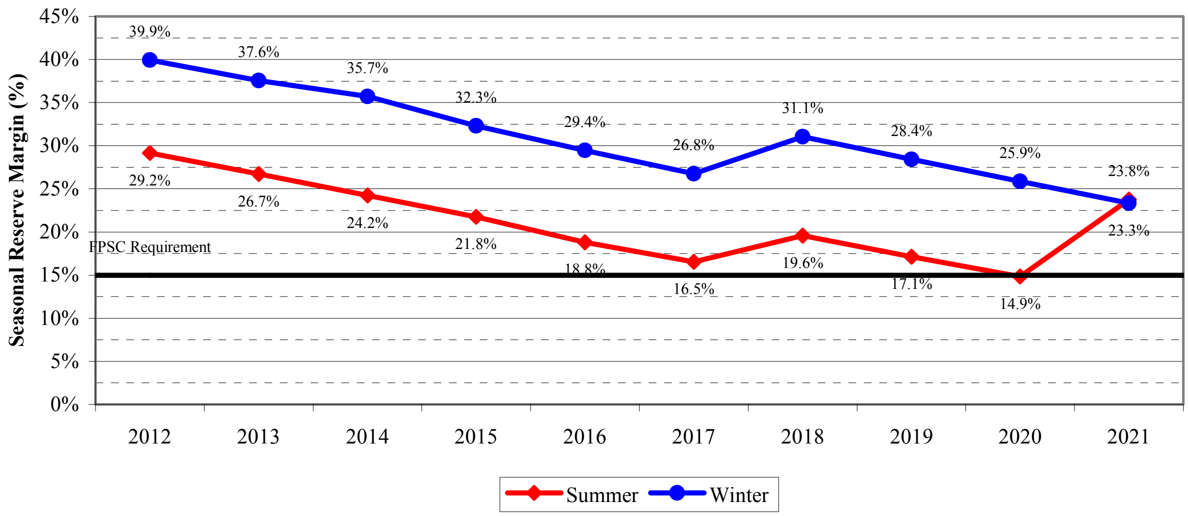


Source: OUC 2009 - 2012 TYSPs

Reserve Margin Requirement

OUC maintains a 15 percent reserve margin pursuant to FRCC requirements. OUC Figure 3 shows their projected reserve margin, which is sufficient for both summer and winter seasonal peaks. OUC does not have active load management and interruptible load programs as part of its DSM program, and therefore has no energy efficiency component included in its reserve margin.

OUC Figure 3. Seasonal Reserve Margin

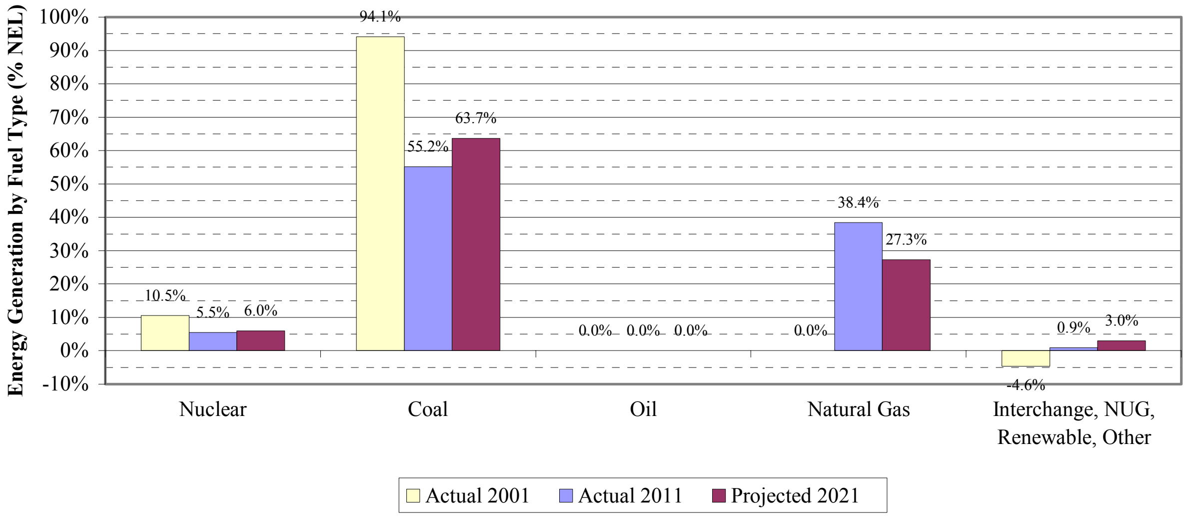


Source: OUC 2012 TYSP

Fuel Diversity

OUC Figure 4 displays the composition of OUC's system in terms of energy generated. As seen in the figure, OUC is historically a coal dependent utility, and as of 2001 did not use natural gas for generation, and was a net exporter of energy. However, by 2011, natural gas had assumed a significant role in OUC's system, with 38.4 percent of generation, as compared to 55.2 percent for coal. The utility's projected fuel mix shows an increase in coal over the planning period, which would result in a reduction of natural gas from its current level.

OUC Figure 4. Net Energy for Load by Fuel Type



Source: OUC 2002 and 2012 TYSPs

Generation Additions

OUC's 2012 TYSP includes a single new generating unit, an sited 185 MW natural gas-fired combustion turbine with an in-service date in 2021, as detailed in OUC Table 1 below.

OUC Table 1. Planned Generation Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Combustion Turbine Unit Additions				
Unknown CT1	185	N/A	N/A	05/2021

Source: OUC 2012 TYSP

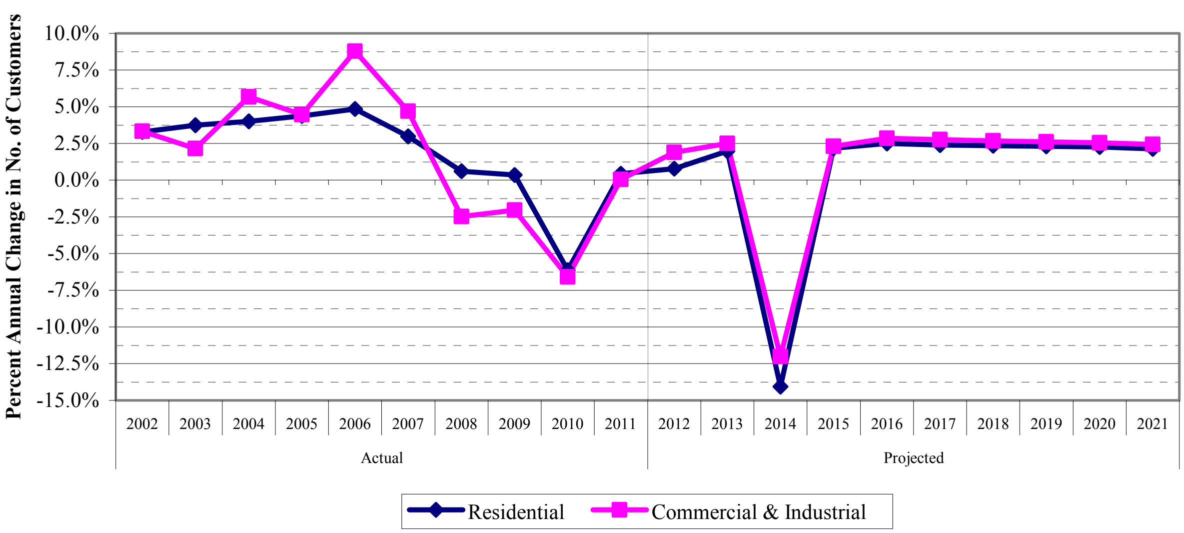
SEC is a corporation that provides electric power to its distribution members' systems, and is collectively the state's fourth largest TYSP utility. SEC is a generation and transmission rural electric cooperative that serves only wholesale customers that purchase power from SEC under long-term wholesale power contracts. SEC is within the FRCC Region, with load serviced throughout the State of Florida. Its generation assets are primarily within the central region. As SEC is a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning

In 2011, SEC had an average 849,059 customers, and had a total net energy for load of 16,037 GWh, approximately 6.7 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

SEC Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. Generally the utility expects level growth throughout the planning period, with the exception of 2014. As SEC is composed of multiple members, the overall growth of the utility is heavily impacted by their departure. The projected drop in customers in 2014 is due to the Lee County Electric Cooperative load no longer being served by SEC beginning January 1, 2014.

SEC Figure 1. Annual Customer Growth Rate by Customer Class

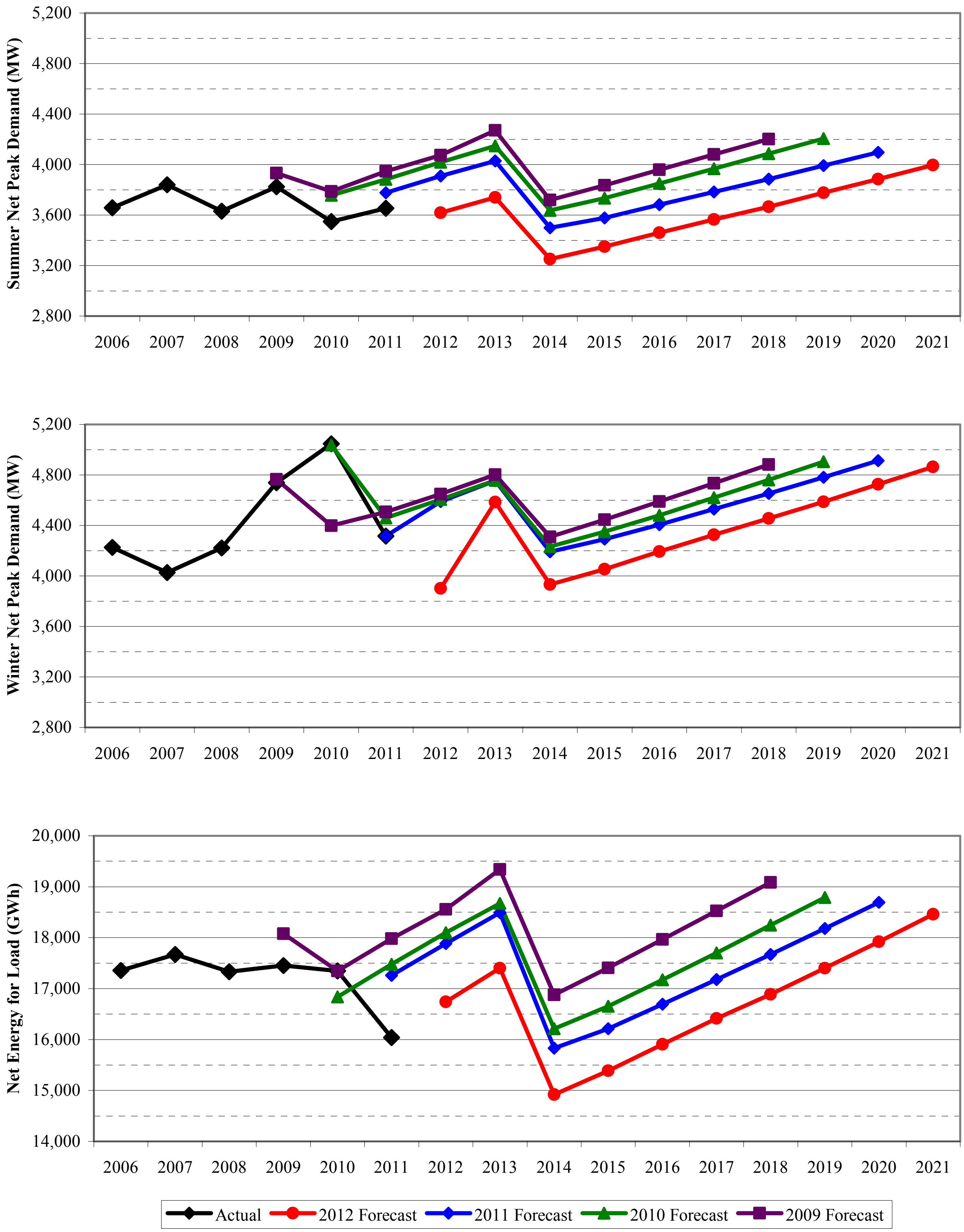


Source: SEC 2012 TYSP

The following three graphs in SEC Figure 2 show SEC's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is below last year's for both seasonal peaks and NEL. The forecasts show a significant drop in 2014, associated with the reduction in customers discussed above.

Analysis of SEC's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that SEC's average forecast error is 11.41 percent. This value indicates that the company tends to over-forecast its retail energy sales by 11.41 percent, which is approximately equivalent to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

SEC Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

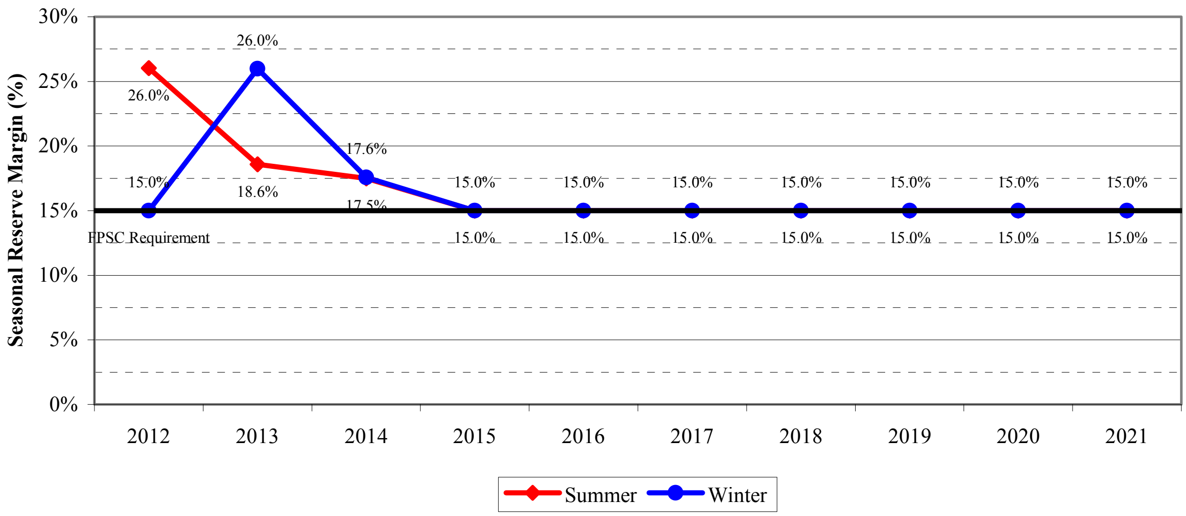


Source: SEC 2009 - 2012 TYSPs

Reserve Margin Requirement

As SEC is within the FRCC region, it is required to meet a 15 percent reserve margin requirement. SEC projects its reserve margin to remain at or above this requirement for both summer and winter seasonal peaks, as shown in SEC Figure 3.

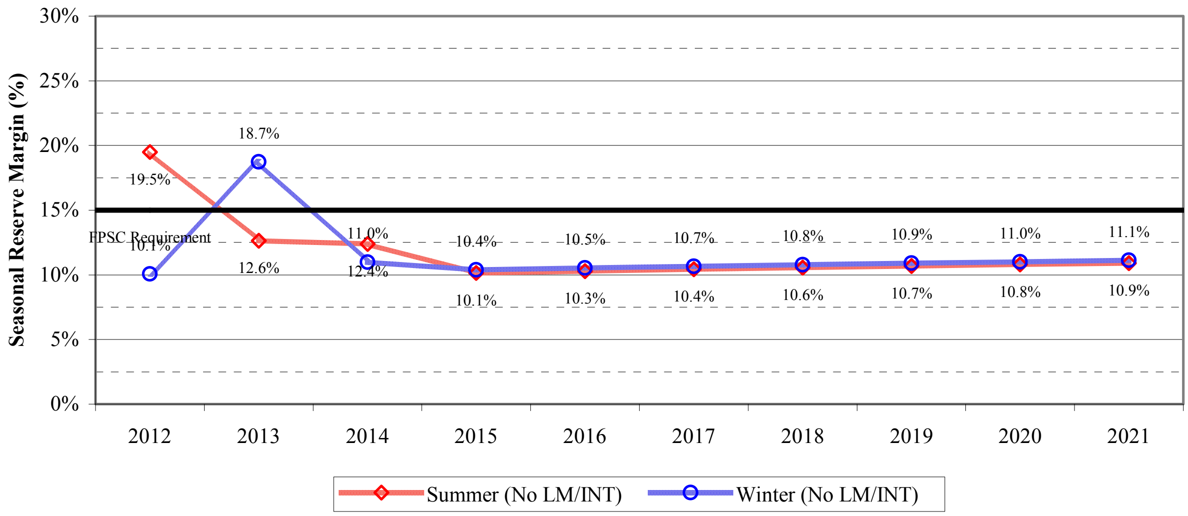
SEC Figure 3. Seasonal Reserve Margin (With LM/INT)



Source: SEC 2012 TYSP

Because SEC does offer load management programs, a portion of its reserve margin can be attributed to non-firm load. The measure of reserve margin without any contribution from demand-side programs is shown in SEC Figure 4. As the figure shows, SEC's reserve margin is projected to remain at approximately 10 percent without activating demand response programs.

SEC Figure 4. Seasonal Reserve Margin (Without LM/INT)

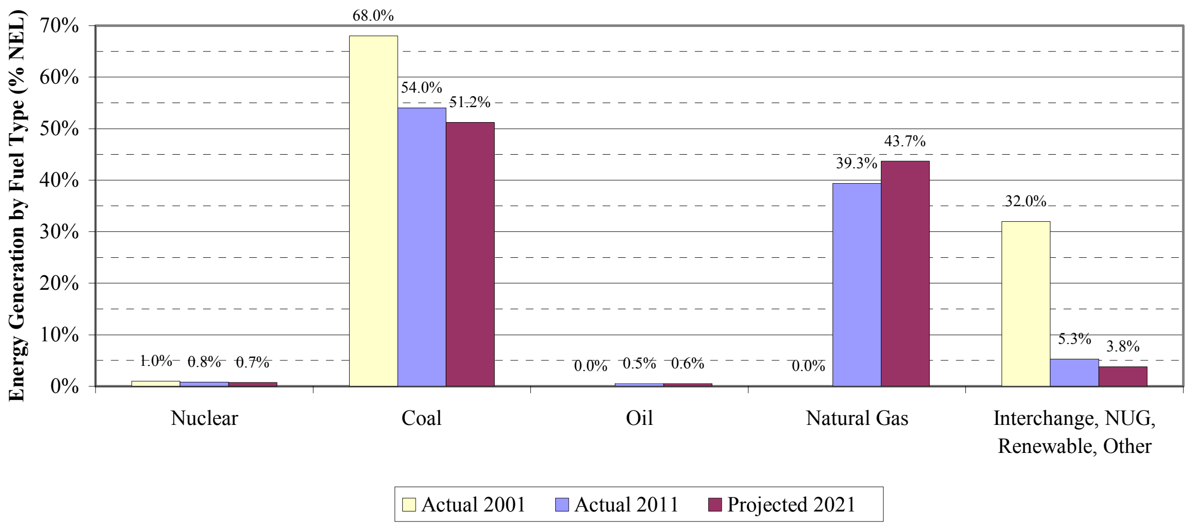


Source: SEC 2012 TYSP

Fuel Diversity

SEC Figure 5 displays the composition of SEC's system in terms of energy generated. As the figure shows, SEC is historically a coal dependent utility, though this portion has decreased from 68 percent in 2001 to 54 percent in 2011. SEC did not have any generation from natural gas in 2001, but now a significant portion of its generation comes from natural gas units. While purchased power made up a significant portion of system reserves, this has decreased dramatically, from 32 percent to 5.3 percent last year. Generally, SEC's projected fuel mix is unchanged, except for a slight shift from coal and purchased power towards natural gas generation.

SEC Figure 5. Net Energy for Load by Fuel Type



Source: SEC 2002 and 2012 TYSPs

Generation Additions

SEC's 2012 TYSP includes the addition of nine natural gas combustion turbine units, and three combined cycle units by the end of the planning period. SEC Table 1 details the generation additions below.

SEC Table 1. Planned Generation Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Combustion Turbine Unit Additions				
Unnamed CT1	158	N/A	N/A	12/2018
Unnamed CT2	158	N/A	N/A	12/2019
Unnamed CT3	158	N/A	N/A	12/2020
Unnamed CT4	158	N/A	N/A	12/2020
Unnamed CT5	158	N/A	N/A	12/2020
Unnamed CT6	158	N/A	N/A	05/2021
Unnamed CT7	158	N/A	N/A	12/2021
Unnamed CT8	158	N/A	N/A	12/2021
Unnamed CT9	158	N/A	N/A	12/2021
Combined Cycle Unit Additions				
Unnamed CC1	196	-	-	Dec-20
Unnamed CC2	196	-	-	Dec-20
Unnamed CC3	196	-	-	Dec-21

Source: SEC 2012 TYSP

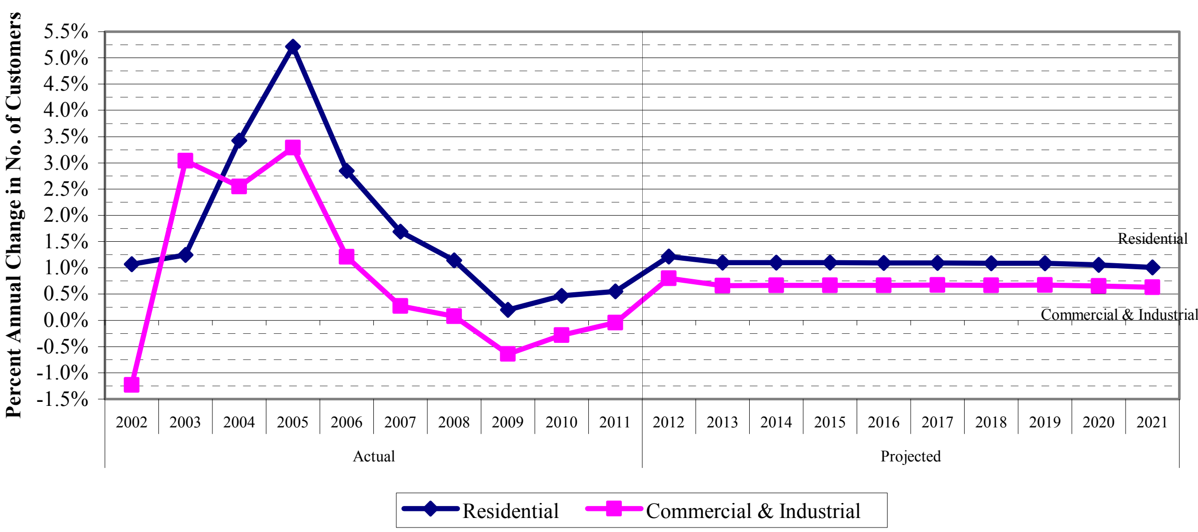
TAL is a municipal utility, and the state's second smallest TYSP utility. The utility's service territory is within the FRCC region, in Leon County, and primarily serves the City of Tallahassee. As TAL is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning.

In 2011, TAL had an average 114,212 customers, and had a total net energy for load of 2,799 GWh, approximately 1.2 percent of the NEL generated in the state last year.

Peak Demand and Energy Forecasts

TAL Figure 1 illustrates the company's actual customer growth trends for the period 2002 through 2011, and the 2012 TYSP projections for growth for 2012 through 2021. A level, but positive growth is anticipated over the entire planning period, with an average annual growth rate of 1.01 percent. This compares to the actual average growth rate of 2.74 percent for the period 2002 through 2007, before the economic downturn.

TAL Figure 1. Annual Customer Growth Rate by Customer Class

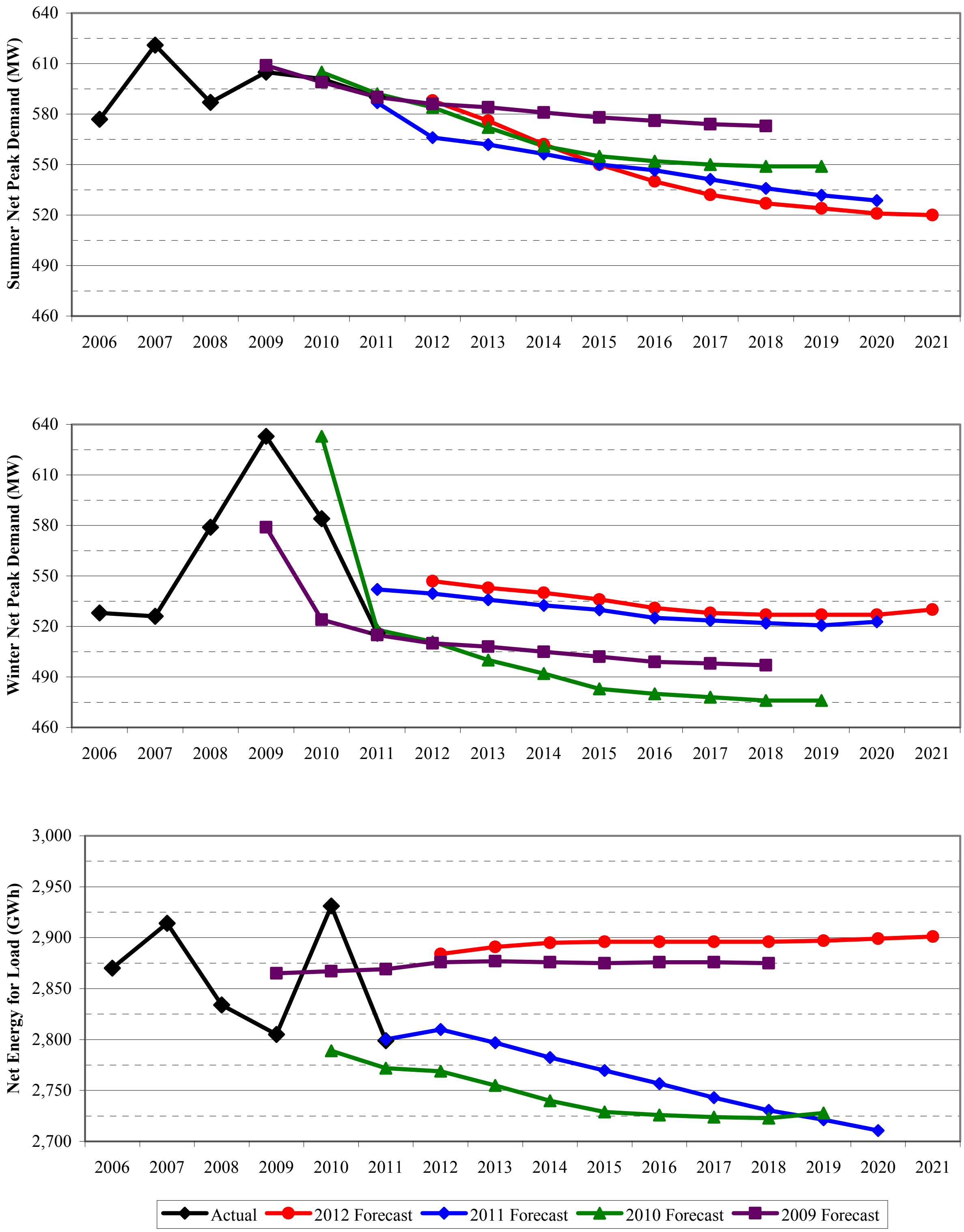


Source: TAL 2012 TYSP

The following three graphs in TAL Figure 2 show TAL's historic peak demand for both the summer and winter seasons, and NEL for the years since 2006. The forecasted values are also shown through the current planning horizon, including the effect of DSM, for the current year and three previous forecast years. These figures show that the current forecast is similar for seasonal peak demand, but higher for NEL.

Analysis of TAL's historic forecast accuracy for total retail energy sales from 2007 through 2011 shows that TAL's average forecast error is 8.77 percent. This value indicates that the company tends to over-forecast its retail energy sales by 8.77 percent, which is favorable when compared to the average forecast error for all eleven of the TYSP utilities, which was 11.38 percent in 2012. This forecasting error is associated with the decline in forecasted customer growth experienced in the period analyzed, 2007 through 2011.

TAL Figure 2. Seasonal Peak Demand and Annual Energy Consumption Forecasts

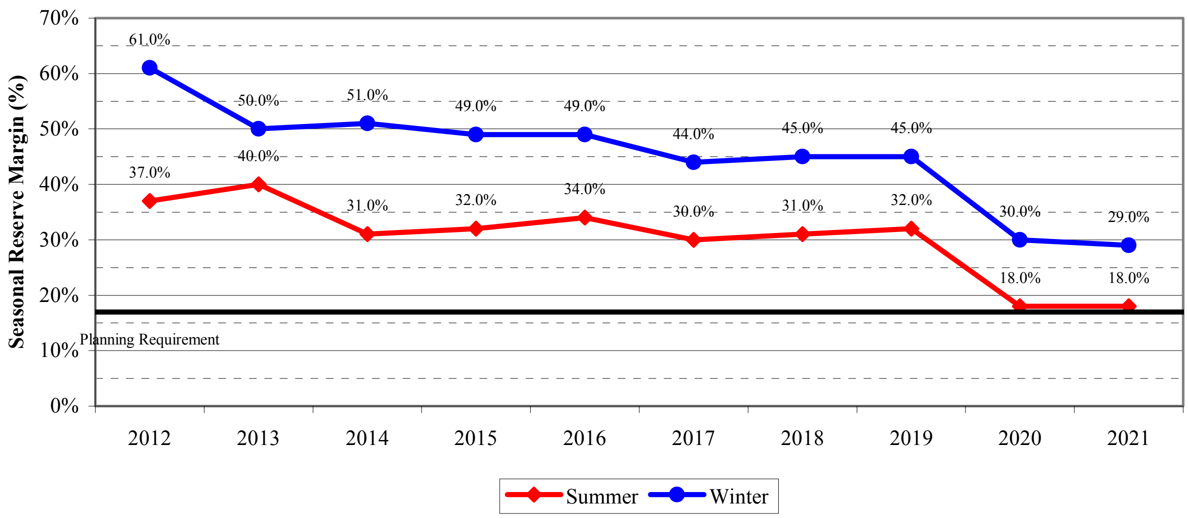


Source: TAL 2009 - 2012 TYSPs

Reserve Margin Requirement

As TAL is within the FRCC region, it is required to meet a 15 percent reserve margin requirement. However, TAL has adopted an 18 percent planning reserve margin requirement, as reflected in TAL Figure 3 below. TAL has sufficient reserve margin including the impact of demand response.

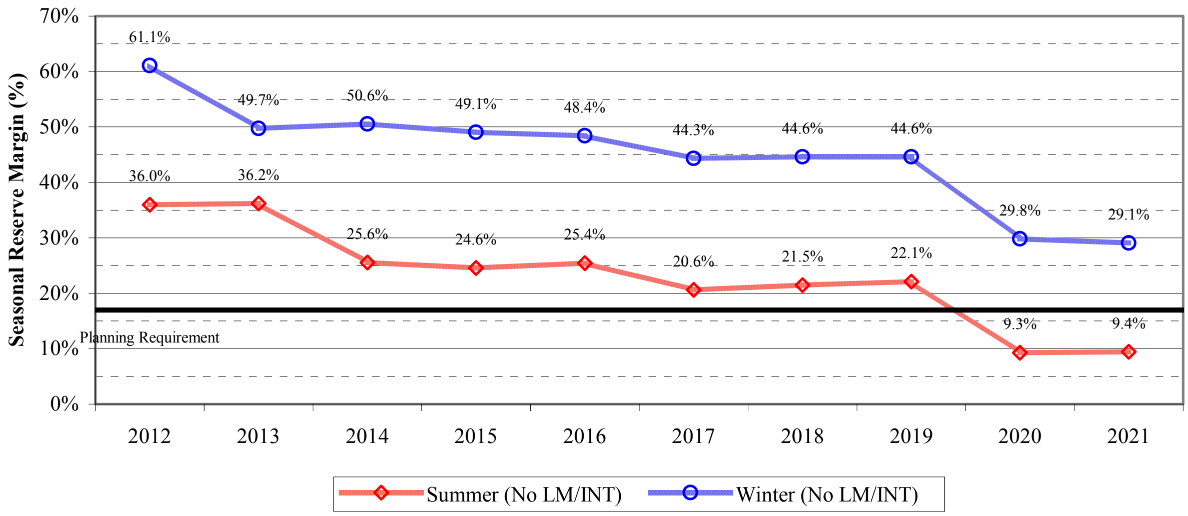
TAL Figure 3. Seasonal Reserve Margin (With LM/INT)



Source: TAL 2012 TYSP

In addition to supply-side resources, TAL has interruptible load and load management programs, which assist the utility in meeting reserve margin requirements. TAL Figure 4 below illustrates the impact on reserve margin of excluding demand response programs. As seen below, the summer peak demand period would fall below the planning reserve margin without the use of demand response programs to reduce peak demand in the outer years.

TAL Figure 4. Seasonal Reserve Margin (Without LM/INT)

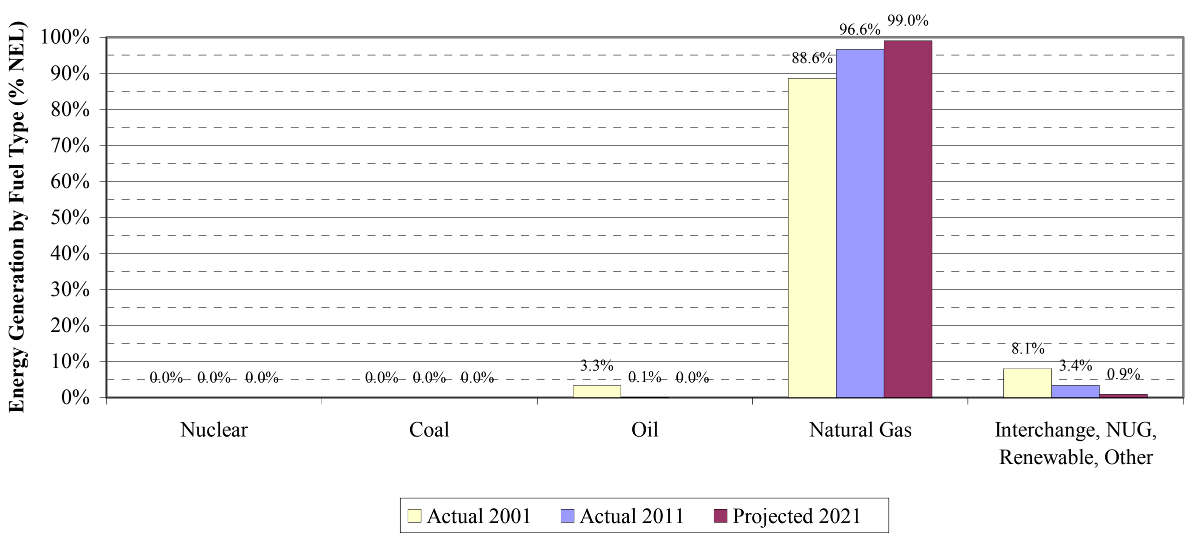


Source: TAL 2012 TYSP

Fuel Diversity

TAL Figure 5 displays the composition of Tallahassee's system in terms of energy generated. As seen below, TAL has an almost exclusive dependence on natural gas, and by the end of the planning period almost 100 percent of energy for load will be from natural gas. The only other sources of energy on TAL's system are oil, purchased power, and renewable energy.

TAL Figure 5. Net Energy for Load by Fuel Type



Source: TAL 2002 and 2012 TYSPs

Generation Additions

TAL has no planned generation additions over the planning horizon. This represents a decline from the company's 2011 TYSP, which anticipated the addition of a 46 MW combustion turbine unit in 2020.