REVIEW OF THE

# 2018 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

FLORIDA PUBLIC SERVICE COMMISSION

NOVEMBER 2018

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# List of Ten-Year Site Plan Utilities

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

# Executive Summary

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

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

Pursuant to Section 186.801, Florida Statutes (F.S.), each generating electric utility must submit to the Commission a Ten-Year Site Plan which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a 10-year planning horizon. The Ten-Year Site Plans of Florida's electric utilities summarize the results of each utility's IRP process and identifies proposed power plants and transmission facilities. The Commission is required to perform a preliminary study of each plan and classify each one as either "suitable" or "unsuitable." This document represents the review of the 2018 Ten-Year Site Plans for Florida's electric utilities, filed by 11 reporting utilities.[1]

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

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[1]Investor-owned utilities filing 2018 TYSPs include Florida Power & Light Company (FPL), Duke Energy Florida, LLC. (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). Municipal utilities filing 2018 TYSPs include Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). Seminole Electric Cooperative (SEC) also filed a 2018 TYSP.

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

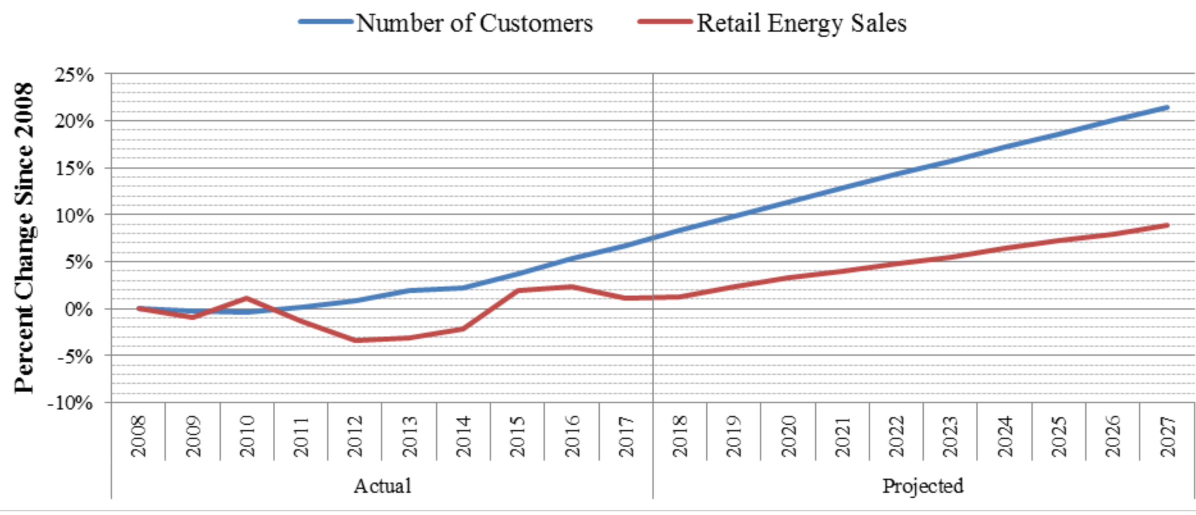
## *Review of the 2018 Ten-Year Site Plans*

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

### Load Forecasting

Forecasting load growth is an important component of system planning for Florida's electric utilities. Florida's electric utilities reduce the rate of growth in customer peak demand and annual energy consumption through demand-side management programs. The Commission, through its authority granted by Sections 366.80 through 366.83 and Section 403.519, F.S., otherwise known as the Florida Energy Efficiency and Conservation Act (FEECA), encourages demand-side management by establishing goals for the reduction of seasonal peak demand and annual energy consumption for those utilities under its jurisdiction. Based on current projections, Florida's electric utilities anticipate exceeding the historic 2010 peak by 2020. Figure 1 details these trends.

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




Source: 2018 FRCC Load and Resource Plan

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

### Renewable Generation

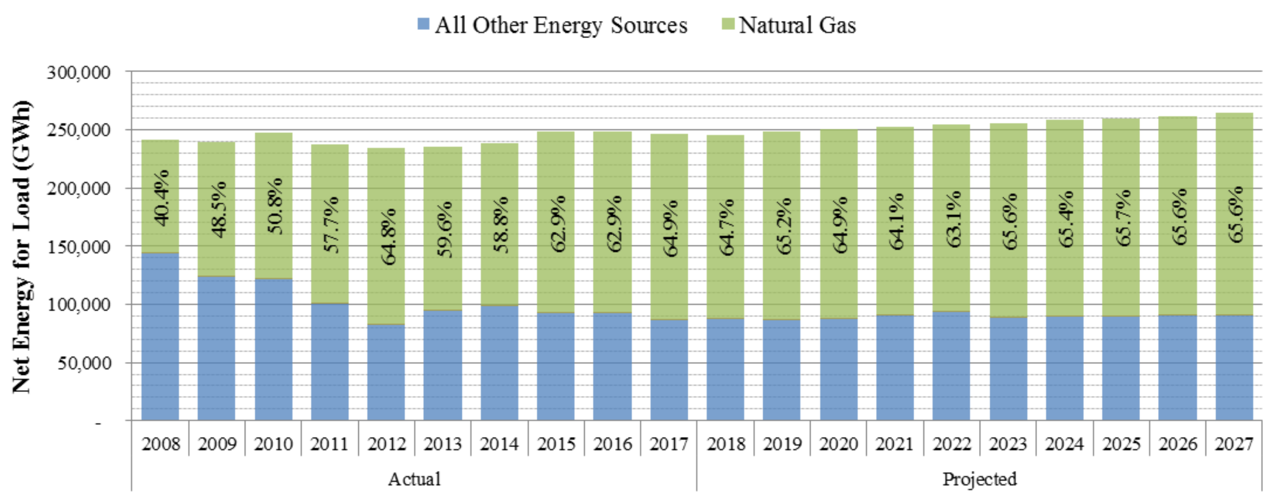
Renewable resources continue to expand in Florida, with approximately 2,583 MW of renewable generating capacity currently installed in Florida. The majority of installed renewable capacity is represented by biomass, solar, and municipal solid waste, making up approximately 73 percent of Florida's renewables. Other major renewable types, in order of capacity contribution, include waste heat, wind, landfill gas, and hydroelectric. Notably, Florida electric customers had installed 205 MW of demand-side renewable at the end of 2017, resulting in an increase in capacity of 45.4 percent from 2016.

Florida's total renewable resources are expected to increase by an estimated 7,049 MW over the 10-year planning period, excluding any potential demand-side renewable energy additions. Over three-quarters of the projected capacity additions are solar photovoltaic generation. Some utilities are including a portion of these solar resources as a firm resource for reliability considerations. Reasons given for these additions are a continued reduction in the price of solar facilities, availability of utility property with access to the grid, and actual performance data obtained during solar demonstration projects. If these conditions continue, cost-effective forms of renewable generation will continue to improve the state's fuel diversity and reduce dependence on fossil fuels.

### Traditional Generation

Generating capacity within Florida is anticipated to grow to meet the increase in customer demand, with approximately 8,190 MW of new utility-owned generation added over the planning horizon. This figure represents a decrease from the previous year, which estimated the need for about 8,850 MW new generation. While natural gas usage is expected to grow slowly, natural gas remains the dominant fuel over the planning horizon, with usage in 2017 at approximately 65 percent of the state's net energy for load (NEL). Figure 2 illustrates the use of natural gas as a generating fuel for electricity production in Florida.

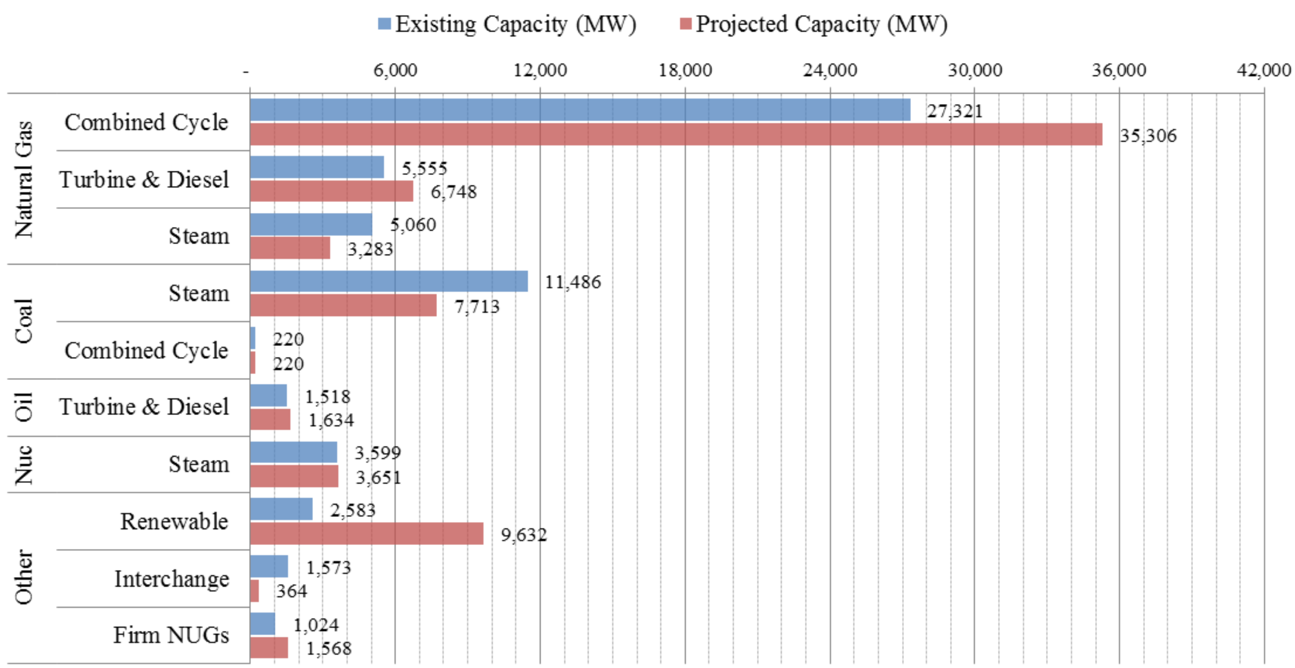
**Figure 2: State of Florida - Natural Gas Contribution to Energy Consumption**




Source: 2009-2018 FRCC Load and Resource Plan

Based on the 2018 Ten-Year Site Plans, Figure 3 illustrates the present and future aggregate capacity mix of Florida. The capacity values in Figure 3 incorporate all proposed additions, changes, and retirements planned during the 10-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 capacity within the state. However, this planning cycle differs from previous cycles in that renewable capacity is projected to surpass coal generation, becoming the second highest installed capacity source in the state.

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




Source: 2018 FRCC Load & Resource Plan and TYSP Data Responses

As noted previously, the primary purpose of this review is to provide information regarding proposed electric power plants for local and state agencies to assist in the certification process. Table 1 displays those planned generation facilities that have not yet received a determination of need from the Commission. A petition for a determination of need is generally anticipated four years in advance of the in-service date for a natural gas-fired combined cycle unit.

**Table 1: State of Florida - Planned Units Requiring a Determination of Need**

| Year | Utility Name | Unit Name | Fuel & Unit Type | Net Capacity (Sum MW) |
|---|---|---|---|---|
| 2024 | GPC | Unspecified CC | Natural Gas Combined Cycle | 595 |

Source: 2018 Ten-Year Site Plans

## Future Concerns

Florida's electric utilities must also consider environmental concerns associated with existing generators and planned generation to meet Florida's electric needs. The U.S. Environmental Protection Agency (EPA) has finalized several new rules that are expected to have a sizeable impact on Florida's existing generation fleet, as well as on its proposed new facilities.

The EPA published final rules in October 2015 associated with carbon pollution for existing power plants, also known as the Clean Power Plan. On the same date, the EPA also published final rules setting carbon emissions limits for new facilities. On October 10, 2017, the EPA proposed a repeal of the Clean Power Plan. On August 21, 2018, as part of its proposed Affordable Clean Energy Rule, the EPA proposed updates to the New Source Review permitting program that may impact utility decisions regarding power plant modifications and reconstruction. These recent regulatory developments will be addressed in a subsequent Ten-Year Site Plan review, and the potential effects on Florida's electric utilities are not considered as part of this review

## Conclusion

The Commission has reviewed the 2018 Ten-Year Site Plans and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. The Commission will continue to monitor the impact of current and proposed EPA Rules and the state's dependence on natural gas for electricity production.

Based on its review, the Commission finds the 2018 Ten-Year Site Plans to be suitable for planning purposes. Since the Plans are not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing.

# Introduction

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

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

## *Statutory Authority*

Section 186.801, F.S., requires all major generating electric utilities submit a Ten-Year Site Plan to the Commission at least every two years. Based on these filings, the Commission performs a preliminary study of each Plan and makes a non-binding determination as to whether it is suitable or unsuitable. The results of the Commission's study are contained in this report, the Review of the 2018 Ten-Year Site Plans, and are forwarded to the Florida Department of Environmental Protection for use in subsequent proceedings. In addition, Section 377.703(2)(e), F.S., requires the Commission to collect and analyze energy forecasts, specifically for electricity and natural gas, along with the Department of Agriculture and Consumer Services. The Commission has adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code (F.A.C.) in order to fulfill these statutory requirements and provide a solid framework for flexible, cost-effective utility resource planning. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving day-to-day planning and operations to utility management.

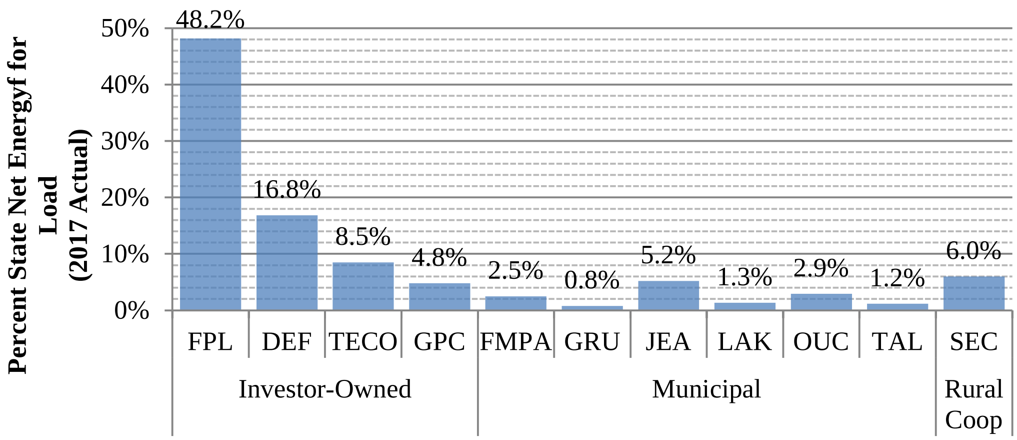
### Applicable Utilities

Florida is served by 57 electric utilities, including 5 investor-owned utilities, 35 municipal utilities, and 17 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 megawatts (MW) or a planned unit with a capacity of 75 MW or greater are required to file with the Commission a Ten-Year Site Plan every year.

In 2018, 11 utilities met these requirements and filed a Ten-Year Site Plan, including 4 investor-owned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company (FPL), Duke Energy Florida, LLC (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). The municipal utilities, in alphabetical order, are Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). The sole rural electric cooperative filing a 2018 Plan is Seminole Electric Cooperative (SEC). Collectively, these utilities are referred to as the Ten-Year Site Plan Utilities (TYSP Utilities).

Figure 4 illustrates the comparative size of the TYSP Utilities, in terms of each utility's percentage share of the state's retail energy sales in 2017. Combined, the reporting investor-owned utilities account for 78.3 percent of the state's retail energy sales. The reporting municipal and cooperative utilities make up approximately 19.9 percent of the state's retail energy sales.

**Figure 4: TYSP Utilities - Comparison of Reporting Electric Utility Size**




Source: 2018 Ten-Year Site Plans, 2018 FRCC Load & Resource Plan

## Required Content

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

## *Additional Resources*

The Commission's Rules also task the reporting electric utilities with collecting information on both a statewide basis and for Peninsular Florida, which excludes the area west of the Apalachicola River. The Florida Reliability Coordinating Council (FRCC) provides this aggregate data for the Commission's review. Each year, the FRCC publishes a Regional Load and Resource Plan, which contains historic and forecast data on demand and energy, capacity and reserves, and proposed new generating units and transmission line additions. In addition, the FRCC publishes an annual Reliability Report used for this review Certain comparisons additional data from various government agencies is relied upon, including the Energy Information Administration and the Florida Department of Highway Safety and Motor Vehicles.

Commission staff held a public workshop on October 29, 2018, (previously scheduled for October 11, 2018), to facilitate discussion of the annual planning process and allow for public comments. A presentation was conducted by the FRCC summarizing the 2018 Load and Resource Plan and other related matters, including fuel supply reliability, environmental regulations, and physical security of infrastructure. Presentations were also provided by FPL and DEF, on battery storage.

## *Structure of the Commission's Review*

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

## *Conclusion*

Based on its review, the Commission finds all 11 reporting utilities' 2018 Ten-Year Site Plans to be suitable for planning purposes. During its review, the Commission has determined that the projections for load growth appear reasonable and that the reporting utilities have identified sufficient generation facilities to maintain an adequate supply of electricity at a reasonable cost.

The Commission notes that, as the Ten-Year Site Plans are non-binding, the classification of suitable does not constitute a finding or determination in any docketed matter before the Commission, nor an approval of all planning assumptions contained within the Ten-Year Site Plans. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing.

# Statewide Perspective

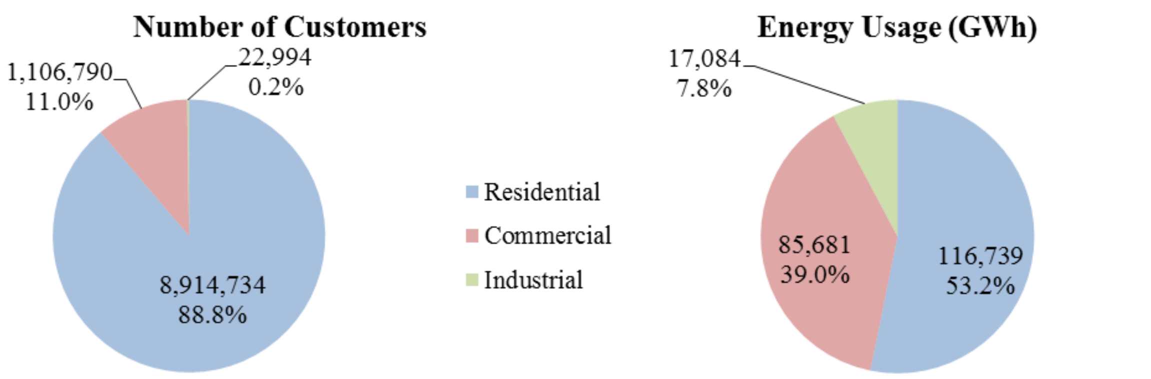
# Load Forecasting

Forecasting load growth is an important component of the IRP process for Florida's electric utilities. In order to maintain system reliability, utilities must be prepared for future changes in electricity consumption, including changes to the number of electric customers, customer usage patterns, building codes and appliance efficiency standards, new technologies such as electric vehicles, and the role of demand-side management.

## *Electric Customer Composition*

Utility companies categorize their customers by residential, commercial, and industrial classes. As of January 1, 2018, residential customers account for 88.8 percent of the total, followed by commercial (11.0 percent) and industrial (0.2 percent) customers, as illustrated in Figure 5 Commercial and industrial customers make up a sizeable percentage of energy sales, due to their higher energy usage per customer.

**Figure 5: State of Florida - Electric Customer Composition in 2017**



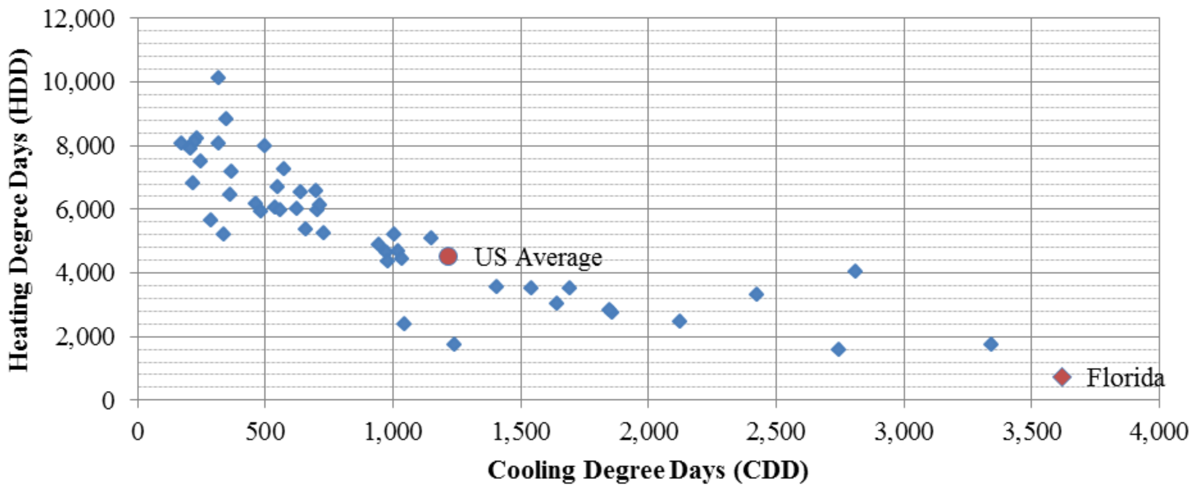

Source: FRCC 2018 Load & Resource Plan

Residential customers in Florida make up the largest portion of retail energy sales. Florida's residential customers accounted for 53.2 percent of retail energy sales in 2017, compared to a national average of 37.4 percent.[3] As a result, Florida's utilities are influenced more by trends in residential energy usage, which tend to be associated with weather conditions. In addition, Florida's residential customers rely more upon electricity for heating than the national average, with only a small portion using alternate fuels such as natural gas or oil for home heating needs.

[3]U.S. Energy Information Administration June 2018 Electric Power Monthly.

Florida's unique climate plays an important role in electric utility planning, with the highest number of cooling degree days and lowest number of heating degree days within the continental United States, as shown in Figure 6. Other states tend to rely upon alternative fuels for heating, but Florida's heavy use of electricity results in high winter peak demand.

**Figure 6: National - Climate Data by State (Continental US)**

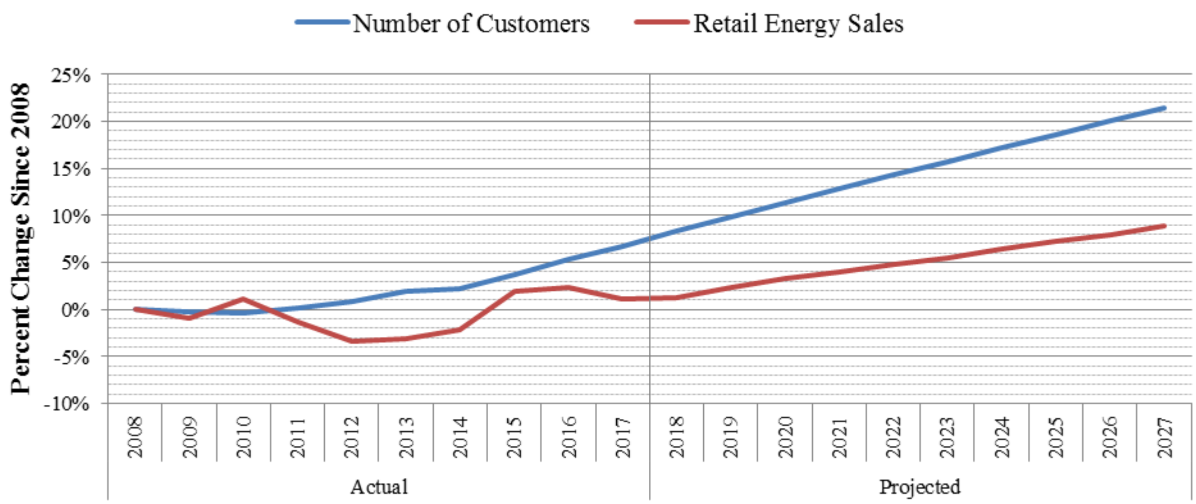



Source: National Oceanic & Atmospheric Administration, Historical Climatology Series 5-1 and 5-2

## *Growth Projections*

For the next 10-year period, Florida's retail sales are anticipated to grow at a faster pace than the last few years, breaking a trend of flattening retail sales. While this rate remains below that experienced before 2007, it would set Florida on track to exceed its 2007 retail sales peak by 2020. The current divide between customers and retail sales is anticipated to remain similar over the 10-year period, with customers growing at an average annual rate of about 1.28 percent, while retail sales increase by about 0.81 percent annually. Florida's electric utilities are projecting an increase in economic growth in the state, but at levels below those experienced before 2007. The trends are showcased in Figure 7 below.

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



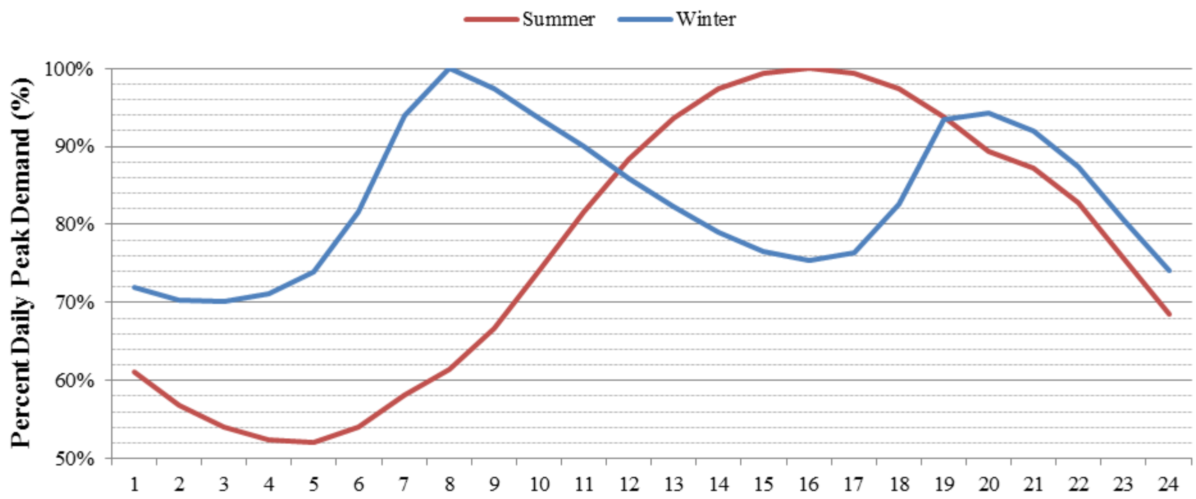

Source: FRCC 2018 Load & Resource Plan

## *Peak Demand*

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

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

**Figure 8: TYSP Utilities - Example Daily Load Curves**

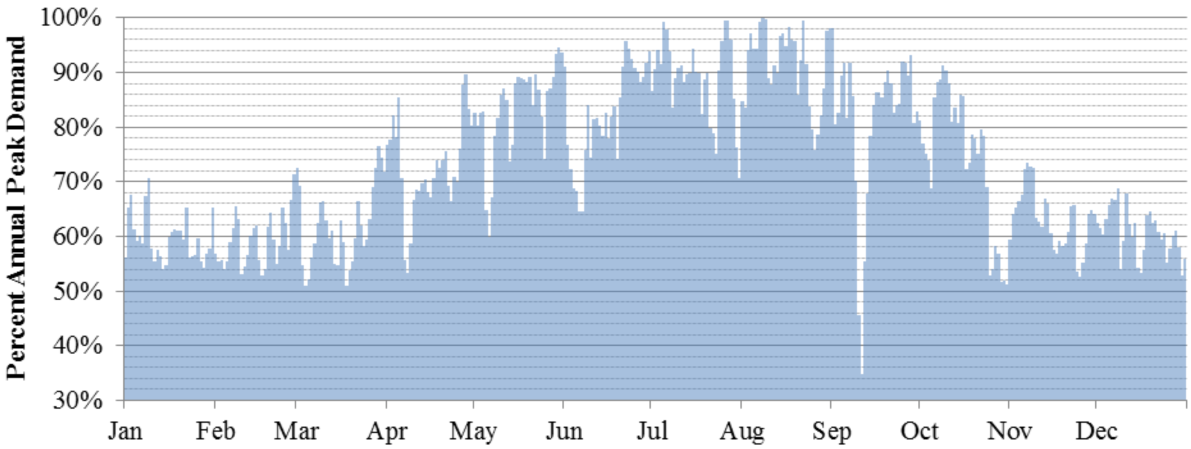



Source: TYSP Utilities Data Responses

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

As daily load varies, so do seasonal loads. Figure 9 shows the 2017 daily peak demand as a percentage of the annual peak demand for the reporting investor-owned utilities combined. Typically, winter peaks are short events while summer demand tends to stay at near peak levels for longer periods. The periods between seasonal peaks are referred to as shoulder months, in which the utilities take advantage of lower demand to perform maintenance without impacting their ability to meet daily peak demand.

**Figure 9: TYSP Utilities - Daily Peak Demand (2017 Actual)**




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

Unusual events such as natural disasters can also impact load, due to evacuations and potential damage to infrastructure. These impacts, however, tend to be temporary, with system load quickly returning to season norms as infrastructure is repaired and customers return. Figure 9 exemplifies this in the loss of load shown during the first half of September, when Hurricane Irma caused widespread damage thoughout much of Florida.

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

## *Electric Vehicles*

Utilities also examine other trends that may impact customer peak demand and energy consumption. These include new sources of energy consumption, such as electric vehicles, which can be considered analogous to home air conditioning systems in terms of system demand. At present, the reporting electric utilities estimate approximately 27,500 electric plug-in vehicles were operating in Florida at the end of 2017. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered automobiles, pickups, and buses in Florida, as of December 3, 2017, as 16.5 million vehicles, resulting in 0.17 percent penetration rate of electric vehicles.

Florida's electric utilities anticipate growth in the electric vehicle market, as illustrated in Table 2. Electric vehicle ownership is anticipated to grow rapidly throughout the planning period, resulting in approximately 420,000 electric vehicles operating within the electric service territories by the end of 2027.

**Table 2: TYSP Utilities - Estimated Number of Electric Vehicles by Service Territory (Five-Year Rolling Average)**

| Year | FPL | DEF | TECO | GULF | JEA | OUC | TAL | Total |
|---|---|---|---|---|---|---|---|---|
| 2017 | 17,753 | 4,945 | 2,008 | 449 | 968 | 485 | 1,365 | 27,488 |
| 2018 | 22,830 | 8,665 | 2,532 | 635 | 1,209 | 609 | 1,379 | 37,250 |
| 2019 | 29,076 | 12,327 | 2,866 | 809 | 1,527 | 757 | 1,392 | 47,997 |
| 2020 | 39,071 | 16,817 | 3,133 | 959 | 1,910 | 938 | 1,406 | 63,296 |
| 2021 | 52,564 | 22,573 | 3,385 | 1,094 | 2,351 | 1,160 | 1,420 | 83,387 |
| 2022 | 70,779 | 30,270 | 3,842 | 1,243 | 2,853 | 1,432 | 1,435 | 110,422 |
| 2023 | 95,370 | 40,096 | 4,490 | 1,412 | 3,412 | 1,767 | 1,449 | 146,229 |
| 2024 | 133,309 | 52,283 | 5,385 | 1,605 | 4,026 | 2,180 | 1,463 | 198,071 |
| 2025 | 179,786 | 67,271 | 6,899 | 1,861 | 4,698 | 2,690 | 1,478 | 261,993 |
| 2026 | 242,529 | 84,285 | 8,794 | 2,149 | 5,429 | 3,318 | 1,493 | 344,679 |
| 2027 | 290,930 | 103,071 | 11,170 | 2,498 | 6,219 | 4,093 | 1,508 | 419,489 |

Source: TYSP 2018 Data Responses

In terms of energy consumed by electric vehicles, Table 3 illustrates the estimates provided by the reporting utilities. The anticipated growth would result in an annual energy consumption of 1,697 GWh by 2027. Current estimates represent a less than 1 percent impact on net energy for load by 2027.

**Table 3: TYSP Utilities - Estimated Electric Vehicle Annual Energy Consumption (GWh)**

| Year | FPL | DEF | TECO | GULF | JEA | OUC | TAL* | Total |
|---|---|---|---|---|---|---|---|---|
| 2017 | - | - | 10.4 | 1.6 | 6.0 | 2.3 | - | 20.2 |
| 2018 | 30.0 | 4.6 | 13.7 | 2.2 | 7.2 | 2.9 | - | 60.6 |
| 2019 | 58.0 | 15.6 | 15.8 | 2.7 | 9.1 | 3.6 | - | 104.7 |
| 2020 | 103.0 | 29.7 | 17.5 | 3.2 | 11.4 | 4.4 | - | 169.2 |
| 2021 | 164.0 | 47.6 | 19.1 | 3.6 | 14.2 | 5.4 | - | 253.9 |
| 2022 | 246.0 | 71.4 | 22.0 | 4.0 | 17.6 | 6.7 | - | 367.7 |
| 2023 | 357.0 | 102.6 | 26.1 | 4.4 | 21.6 | 8.2 | - | 519.9 |
| 2024 | 528.0 | 142.8 | 31.7 | 4.9 | 26.1 | 10.1 | - | 743.7 |
| 2025 | 738.0 | 192.7 | 41.3 | 5.7 | 31.3 | 12.5 | - | 1,021.5 |
| 2026 | 1,021.0 | 252.6 | 53.2 | 6.6 | 37.2 | 15.4 | - | 1,386.0 |
| 2027 | 1,239.0 | 319.7 | 68.2 | 7.7 | 43.8 | 19.0 | - | 1,697.4 |

Source: TYSP 2018 Data Responses
*City of Tallahassee Utilities did not provide estimates of electric vehicle annual energy consumption.

The effect of increased electric vehicle ownership on peak demand is more difficult to determine. While comparable in electric demand to a home air conditioning system, the time of charging and whether charging would be shifted away from periods of peak demand are uncertainties. As electric vehicle ownership increases, the projected impacts of electric vehicles on system peak demand should become clearer and electric utilities will be better positioned to respond accordingly.

In order to investigate potential unknowns associated with the electric vehicle energy market in Florida, several utilities have initiated Commission-approved electric vehicle pilot programs. The nature of these pilot programs vary among utilities, but include investments in vehicle charging infrastructure, research partnerships, and electric vehicle rebate programs. Utilities will note key findings and track metrics of interest within these pilot programs to help inform the Commission regarding the future power needs of electric vehicles in Florida.

## *Demand-Side Management*

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

### Florida Energy Efficiency and Conservation Act (FEECA)

The Florida Legislature has directed the Commission to encourage utilities to decrease the growth rates in seasonal peak demand and annual energy consumption by FEECA, which consists of Sections 366.80 through 366.83 and Section 403.519, F.S. Under FEECA, the Commission is required to set goals for seasonal demand and annual energy reduction for seven electric utilities, known as the FEECA Utilities. These include the five investor-owned electric utilities (including Florida Public Utility Company, which is a non-generating utility and therefore does not file a Ten-Year Site Plan) and two municipal electric utilities (JEA and OUC). The FEECA utilities represented approximately 86 percent of 2017 retail sales in Florida.

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

The last FEECA goal-setting proceeding was completed in December 2014, establishing goals for the period 2015 through 2024. During 2015, the Commission reviewed the FEECA Utilities' proposed DSM Plans to comply with the established goals, approving the plans with some modifications in July 2015. The 2018 Ten-Year Site Plans incorporate the impacts of the DSM Plans established by the Commission for the planning period. The next FEECA goal-setting proceeding will occur in 2019, which will establish goals for the period 2020 through 2029.

## DSM Programs

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

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

Load management is similar to interruptible load, but focuses on smaller customers and targets individual appliances. The utility installs a device on an electric appliance, such as a water heater or air conditioner, which allows for remote deactivation for a short period of time. Load management activations tend to have less advanced notice than those for interruptible customers, but tend to be activated only for short periods and are cycled through groups of customers to reduce the impact to any single customer. Due to the focus on specific appliances, certain appliances would be more appropriate for addressing certain seasonal demands. For example, load management programs targeting air conditioning units would be more effective to reduce a summer peak, while water heaters are more effective for reducing a winter peak.

As of 2018, demand response available for reduction of peak load is 2,956 MW for summer peak and 2,762 MW for winter peak. Demand response is anticipated to increase to approximately 3,334 MW for summer peak and 3,124 MW for winter peak by the end of the planning period in 2027.[4]

Energy efficiency or conservation measures also have an impact on peak demand, and due to their passive nature do not require activation by the utility. Conservation measures include improvements in a home or business' building envelope to reduce heating or cooling needs, or the installation of more efficient appliances. By installing additional insulation, energy-efficient windows or window films, and more efficient appliances, customers can reduce both their peak demand and annual energy consumption, leading to reductions in customer bills. Demand-side management programs work in conjunction with building codes and appliance efficiency standards to increase energy savings above the minimum required by local, state, or federal regulations. As of 2018, energy efficiency is responsible for peak load reductions of 4,333 MW for summer peak and 3,830 MW for winter peak. Energy efficiency is anticipated to increase to approximately 4,981 MW for summer peak and 4,431 MW for winter peak by the end of the planning period in 2027.[5]

[4] TYSP Utilities Data Responses
[5] Id.

## *Forecast Load & Peak Demand*

The historic and forecasted seasonal peak demand and annual energy consumption values for Florida are illustrated in Figure 10. It should be noted, that the forecasts shown below are based upon normalized weather conditions, while the historic demand and energy values represent the actual impact of weather conditions on Florida's electric customers. Florida relies heavily upon both air conditioning in the summer and electric heating in the winter, so both seasons experience a great deal of variability due to severe weather conditions.

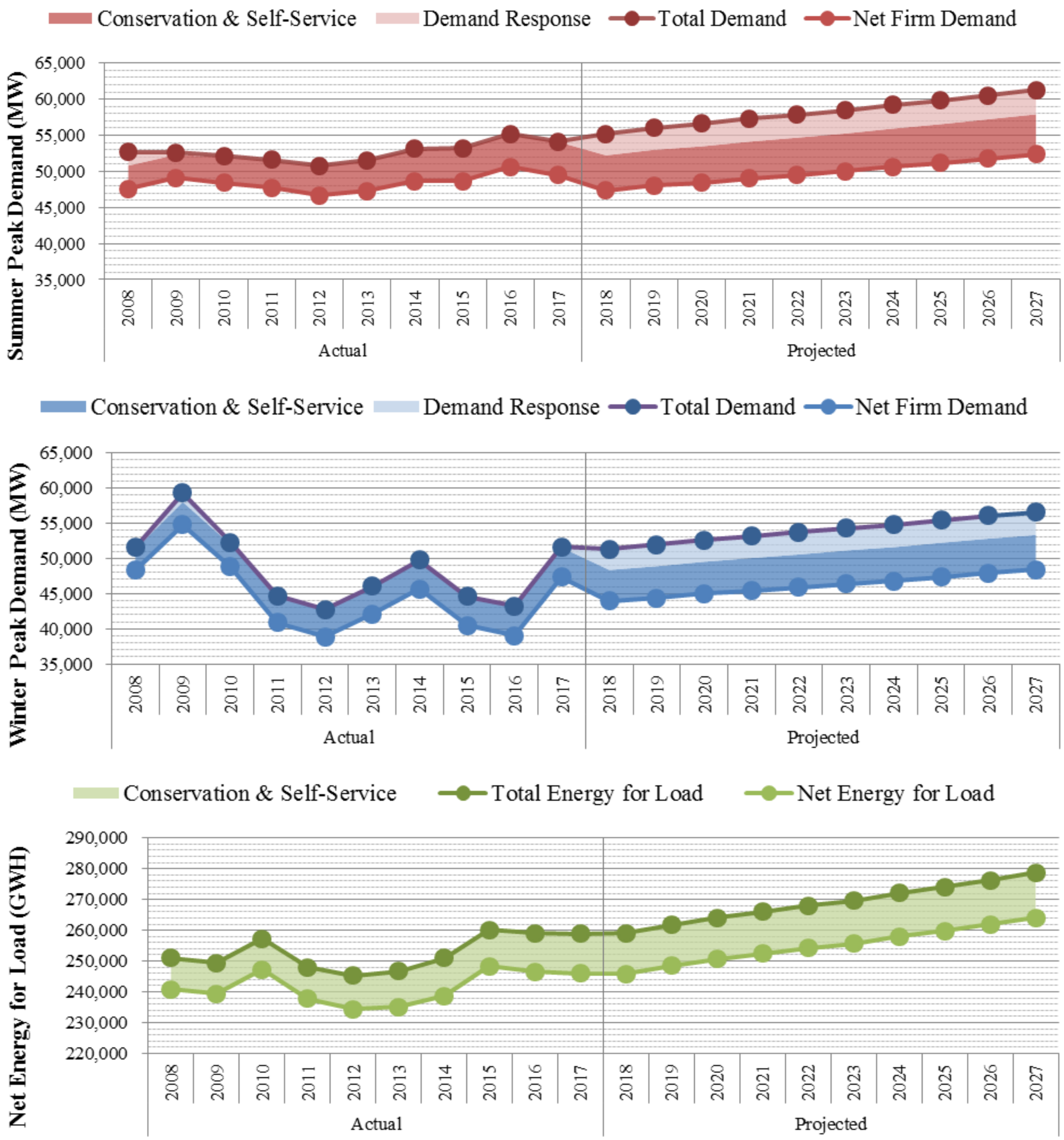
Demand-side management, including demand response and energy efficiency, along with self-service generation is included in each figure for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served if not for the impact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

Demand response is included in Figure 10, in two different ways based upon the time period considered. For historic values of seasonal demand, the actual rates of demand response activation are shown, not the full amount demand response that was available at the time. Overall, demand response has only been partially activated as sufficient generation assets were available during the annual peak. Residential load management has been called upon to a limited degree during peak periods, with a lesser amount of interruptible load activated. The primary exception to this trend was the summer of 2008 and winter of 2009, when a larger portion of the available demand response resources were called upon.

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

As previously discussed, Florida is normally a summer-peaking state. Only three of the past ten years have had higher winter net firm demand than summer, and all ten of the forecast years are anticipated to be summer peaking. Based upon current forecasts using normalized weather data, Florida's electric utilities do not anticipate exceeding the winter 2009 peak during the planning period.

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




Source: 2018 FRCC Load & Resource Plan

## Forecast Methodology

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

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

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

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

The various forecast models and techniques used by Florida's electric utilities are commonly used throughout the industry, and each utility has developed its own individualized approach to projecting load. The resulting forecasts allow each electric utility to evaluate its individual needs for new generation, transmission, and distribution resources to meet customers' current and future needs reliably and affordably.

For each reporting electric utility, the Commission reviewed the historic forecast accuracy of past retail energy sales forecasts. The review methodology, previously used by the Commission, involves comparing actual retail sales for a given year to energy sales forecasts made three, four, and five years prior. For example, the actual 2017 retail energy sales were compared to the forecasts made in 2012, 2013, and 2014. These differences, expressed as a percentage error rate, are used to determine each utility's historic forecast accuracy using a five-year rolling average. An average error with a negative value indicates an under-forecast, while a positive value represents an over-forecast. An absolute average error provides an indication of the total magnitude of error, regardless of the tendency to under or over forecast.

For the 2018 TYSPs, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2013 through 2017 to forecasts made between 2008 and 2014. As discussed previously, the period before the 2007 reccession, experienced a higher annual growth rate for retail energy sales than the post-crisis period. As most electric utilities and macroeconomic forecasters did not predict the financial crisis, the economic impact and its resulting effect on retail energy sales of Florida's electric utilities were not included in these projections. Therefore, the use of a metric that compares pre-recession forecasts with pre-recession actual data has a high rate of error.

Table 4 shows that the forecast errors (the difference between the actual data and the forecasts made five years prior) were increasing with time starting in 2012 due to the unexpected impact of the recession and its impact on retail energy sales in Florida. However, the forecast errors have started to return to lower levels as utility retail sales forecasts include more post-recession years. This was indicated by the actual sales data provided in the 2017 TYSPs. The forecasting error rates (five-year rolling average and/or absolute average) derived from 2018 TYSPs show continued decreases.

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

| Year | Five-Year Analysis Period | Forecast Years Analyzed | Forecast Error (%) | |
|---|---|---|---|---|
| | | | Average | Absolute Average |
| **2011** | 2010 - 2006 | 2007 - 2001 | 8.28% | 8.29% |
| **2012** | 2011 - 2007 | 2008 - 2002 | 11.93% | 11.93% |
| **2013** | 2012 - 2008 | 2009 - 2003 | 15.14% | 15.14% |
| **2014** | 2013 - 2009 | 2010 - 2004 | 16.16% | 16.16% |
| **2015** | 2014 - 2010 | 2011 - 2005 | 14.90% | 14.90% |
| **2016** | 2015 - 2011 | 2012 - 2006 | 12.48% | 12.48% |
| **2017** | 2016 - 2012 | 2013 - 2007 | 9.18% | 9.18% |
| **2018** | 2017 - 2013 | 2014 - 2008 | 6.08% | 6.08% |

Source: 2001-2018 Ten-Year Site Plans

To verify whether more recent forecasts lowered the error rates, an additional analysis was conducted to determine with more detail, the source of high error rates in terms of forecast timing. Table 5 provides the error rates for forecasts made between one to six years prior, along with the three-year average and absolute average error rates for the forecasting period of three- to five-year period used in the analysis in Table 4.

As displayed in Table 5 the utilities' retail energy sales forecasts show a consistent positive error rate beginning in 2007. The error rates reach a peak during the period 2009 through 2013. Starting in 2014, the error rates have declined considerably; and the error rates calculated based the recent years' TYSPs continue to show lower forecast error rates, compared to the peak value of the error rates related to 2009-2013 sales forecasts. Additionally, the last three years' one year ahead forecasts all bear negative error rates (under-forecast), with the current TYSPs showing an even smaller error rate.

**Table 5: TYSP Utilities – Accuracy of Retail Energy Sales Forcasts – Annual Analysis (Analysis of Annual and Three-Year Average of Three- to Five- Prior Years)**

| Year | Annual Forecast Error Rate (%) | | | | | | 3-5 Year Error (%) | |
|---|---|---|---|---|---|---|---|---|
| | Years Prior | | | | | | Average | Absolute Average |
| | 6 | 5 | 4 | 3 | 2 | 1 | | |
| **2006** | -3.29% | -0.03% | 1.03% | 2.30% | 2.43% | 2.37% | 1.10% | 1.12% |
| **2007** | 0.57% | 2.26% | 3.49% | 3.59% | 4.20% | 3.05% | 3.11% | 3.11% |
| **2008** | 7.02% | 8.40% | 8.56% | 9.97% | 9.24% | 8.34% | 8.98% | 8.98% |
| **2009** | 11.95% | 12.15% | 14.48% | 13.91% | 12.68% | 10.18% | 13.51% | 13.51% |
| **2010** | 12.93% | 15.57% | 14.89% | 13.70% | 10.55% | -0.73% | 14.72% | 14.72% |
| **2011** | 21.56% | 20.79% | 20.09% | 17.02% | 3.79% | 0.08% | 19.30% | 19.30% |
| **2012** | 26.31% | 25.97% | 23.04% | 8.47% | 3.90% | 3.71% | 19.16% | 19.16% |
| **2013** | 28.55% | 26.29% | 10.00% | 5.98% | 5.58% | 2.97% | 14.09% | 14.09% |
| **2014** | 27.28% | 9.80% | 6.10% | 5.73% | 2.84% | 2.21% | 7.21% | 7.21% |
| **2015** | 7.29% | 3.63% | 3.23% | 1.02% | 0.00% | -1.17% | 2.63% | 2.63% |
| **2016** | 4.49% | 4.54% | 2.44% | 1.40% | 0.35% | -0.82% | 2.79% | 2.79% |
| **2017** | 6.99% | 4.93% | 3.59% | 2.53% | 1.57% | -0.07% | 3.68% | 3.68% |

Source: 2001-2018 Ten-Year Site Plans

Barring any unforeseen economic crises or atypical weather patterns, average forecasted energy sales error rates in the next few years are likely to be more reflective of the error rates shown for 2015 through 2017 in Table 5 than the significantly higher error rates shown in earlier years associated with the recession. It is important to recognize that the dynamic nature of the economy and the weather continue to present a degree of uncertainty for Florida utilities' load forecasts, ultimately impacting the accuracy of energy sales forecasts.

# Renewable Generation

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

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

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

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

## *Existing Renewable Resources*

Currently, renewable energy facilities provide approximately 2,583 MW of firm and non-firm generation capacity, which represents 4.3 percent of Florida's overall generation capacity of 59,948 MW in 2017. Table 6 summarizes the contribution by renewable type of Florida's existing renewable energy sources.

**Table 6: State of Florida - Existing Renewable Resources**

| Renewable Type | MW | % Total |
|---|---|---|
| Solar | 804 | 31.1% |
| Biomass | 592 | 22.9% |
| Municipal Solid Waste | 484 | 18.7% |
| Waste Heat | 306 | 11.8% |
| Wind* | 272 | 10.5% |
| Landfill Gas | 75 | 2.9% |
| Hydro | 51 | 2.0% |
| **Renewable Total** | **2,583** | **100.00%** |
| *JEA's and Gulf's wind resources are not present in-state. | | |

Source: FRCC 2018 Load & Resource Plan and TYSP Utilities Data Responses

Of the total 2,583 MW of renewable generation, approximately 780 MW are considered firm, based on either operational characteristics or contractual agreement. Firm renewable generation can be relied on to serve customers and can contribute toward the deferral of new fossil fueled power plant construction. Solar generation contributes approximately 163 MW to this total, based upon the coincidence of solar generation and summer peak demand. Changes in timing of peak demand may influence the firm contributions of renewable resources such as solar and wind.

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

### *Non-Utility Renewable Generation*

The majority of Florida's existing renewable energy generation, approximately 71 percent, comes from non-utility generators. In 1978, the US Congress enacted the Public Utility Regulatory Policies Act (PURPA). PURPA requires utilities to purchase electricity from cogeneration facilities and renewable energy power plants with a capacity no greater than 80 MW (collectively referred to as Qualifying Facilities or QFs). PURPA required utilities to buy electricity from QFs at the utility's full avoided cost. These costs are defined in Section 366.051, F.S., which provides in part that:

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

If a renewable energy generator can meet certain deliverability requirements, it can be paid for its capacity and energy output under a firm contract. Rule 25-17.250, F.A.C., requires each IOU to establish a standard offer contract with timing and rate of payments based on each fossil-fueled generating unit type identified in the utility's TYSP. In order to promote renewable energy generation, the Commission requires the IOUs to offer multiple options for capacity payments, including the options to receive early (prior to the in-service date of the avoided-unit) or levelized payments. The different payment options allow renewable energy providers the option to select the payment option that best fits its financing requirements, and provides a basis from which negotiated contracts can be developed.

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

### *Customer-Owned Renewable Generation*

With respect to customer-owned renewable generation, Rule 25-6.065, F.A.C., requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer, with renewable generation capability, to offset their energy usage. In 2008, the effective year of Rule 25-6.065, F.A.C., customer-owned renewable generation accounted for 3 MW of renewable capacity. As of the end of 2017, approximately 205 MW of renewable capacity from over 24,000 systems has been installed statewide. Table 7 summarizes the growth of customer-owned renewable generation interconnections. Almost all installations are solar, with non-solar generation accounting for only 37 installations and 7.6 MW of installed capacity. The renewable generators in this category include wind turbines and anaerobic digesters.

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

| Year | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|
| **Number of Installations** | 2,833 | 3,994 | 5,302 | 6,697 | 8,581 | 11,626 | 15,994 | 24,166 |
| **Installed Capacity (MW)** | 19.9 | 28.4 | 42.2 | 63.0 | 79.8 | 107.5 | 141 | 205 |

Source: Annual Utility Reports

## *Utility-Owned Renewable Generation*

Utility-owned renewable generation also contributes to the state's total renewable capacity. The majority of this generation is from solar facilities. Due to the intermittent nature of solar resources, capacity from these facilities has previously been considered non-firm for planning purposes. However, several utilities are attributing firm capacity contributions to their solar installations based on the coincidence of solar generation and summer peak demand. Of the approximately 379 MW of existing utility-owned solar capacity, approximately 150 MW, or 40 percent, is considered firm.

In 2008, Section 366.92(4), F.S., was enacted and provides, in part, the following:

> In order to demonstrate the feasibility and viability of clean energy systems, the commission shall provide for full cost recovery under the environmental cost-recovery clause of all reasonable and prudent costs incurred by a provider for renewable energy projects that are zero greenhouse gas emitting at the point of the generation, up to a total of 110 MW statewide.

In 2008, the Commission approved a petition by FPL seeking installation of the full 110 MW across three solar energy facilities. The solar projects consisted of a pair of solar PV facilities and a single solar thermal facility. In response to staff interrogatories, FPL estimated that the three solar facilities would cost an additional $573 million above traditional generation costs over the life of the facilities. In 2012, Section 366.92, F.S., was revised and no longer includes the passage discussed.

In 2016, the Commission approved a settlement agreement entered into by FPL that included a provision for a Solar Base Rate Adjustment (SoBRA) mechanism.[6] The SoBRA mechanism

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

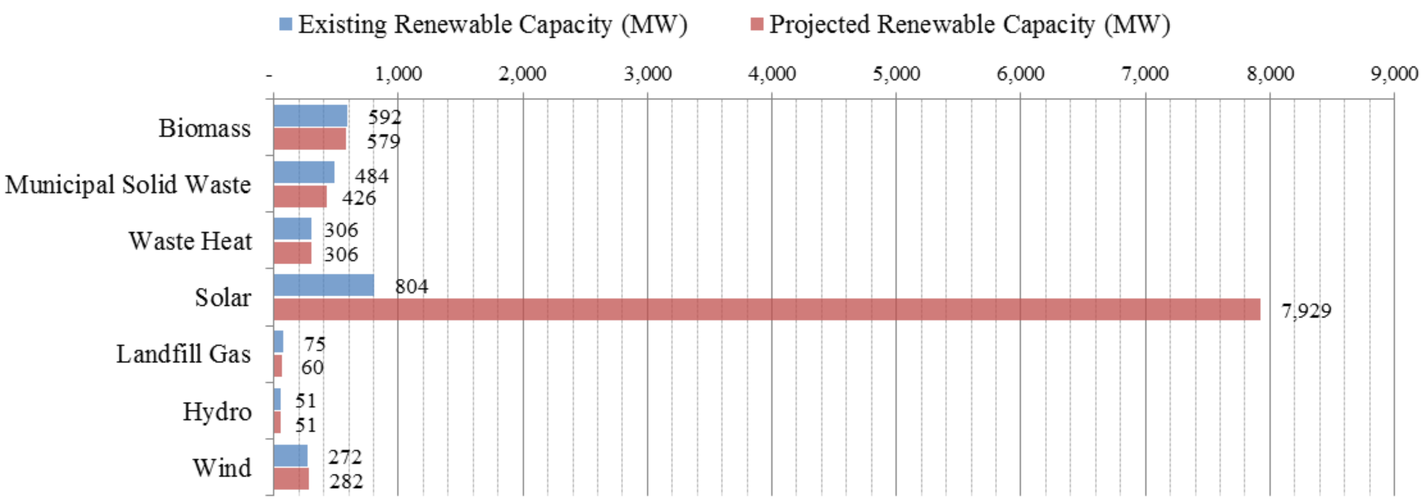
details a process by which FPL may seek approval from the Commission to recover costs for solar projects brought into service that meet certain project cost and operational criteria. In 2017, the Commission approved settlement agreements entered into by DEF and TECO that also included provisions for similar SoBRA mechanisms.[7,8] As of December 31, 2017, no solar capacity additions, through SoBRA mechanisms, have gone into commerical operation.

GPC has entered into purchase power agreements linked to 272 MW of wind energy produced by facilities located in Oklahoma. While the energy from the facilities may not actually be delivered to GPC's system, the renewable attributes for their output are retained by GPC for the benefit of its customers.

## *Planned Renewable Resources*

Florida's total renewable resources are expected to increase by an estimated 7,049 MW over the 10-year planning period, a significant increase from last year's estimated 4,204 MW projection. Figure 11 summarizes the existing and projected renewable capacity by generation type. Solar generation is projected to have the greatest increase over the planning horizon.

**Figure 11: State of Florida - Current and Projected Renewable Resources[9]**




Source: 2018 FRCC Load & Resource Plan, TYSP Utilities Data Responses

Of the 7,049 MW projected net increase in renewable capacity, firm resources contribute 3,155 MW, with 3,058 MW of that firm amount coming from solar generation. For some existing renewable facilities, contracts for firm capacity are projected to expire within the 10-year planning horizon. If new contracts are signed in the future to replace those that expire, these

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

[8] Order No. PSC-2017-0456-S-EI, issued November 27, 2017, in Docket No. 20170210-EI, *In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company.*

[9] JEA's and Gulf's wind resources are not present in-state.

resources will once again be included in the state's capacity mix to serve future demand. If these contracts are not extended, the renewable facilities could still deliver energy on an as-available basis.

As noted above, solar generation is anticipated to increase significantly over the 10-year period, with a total of 7,125 MW to be installed. This consists of 5,551 MW of utility-owned solar and 1,574 MW of contracted solar. As a result of their settlement agreements, FPL, DEF, and TECO are projecting solar capacity additions through SoBRA mechanisms totalling 1,200 MW, 700 MW, and 600 MW, respectively. The Commission has already approved 596 MW of FPL's SoBRA capacity and 145 MW of TECO's SoBRA capacity. FPL and DEF are also projecting solar capacity additions throughout the remainder of the planning period outside of their respective SoBRA mechanisms. Table 8 lists some of the utility-scale (greater than 10 MW) solar installations with in-service dates within the planning period.

**Table 8: TYSP Utilities - Planned Solar Installations**

| Year | Utility | Facility Name | Type | Capacity (MW) |
|---|---|---|---|---|
| 2018 | FPL | 2018 Solar Projects | Utility Owned | 597 |
| 2018 | JEA | 2018 Solar PPAs | Purchased | 84 |
| 2018 | TECO | Balm & Payne Creek | Utility Owned | 144 |
| | | | **2018 Subtotal** | **826** |
| 2019 | DEF | Hamilton Solar Power Plant | Utility Owned | 75 |
| 2019 | DEF | Solar 6, 7, & QF 3 | Combined | 270 |
| 2019 | FPL | 2019 Solar Projects | Utility Owned | 300 |
| 2019 | TAL | FL Solar 4 PPA | Purchased | 40 |
| 2019 | TECO | 2019 Solar Projects | Utility Owned | 279 |
| 2019 | RCI | FL Solar 5 PPA | Purchased | 50 |
| | | | **2019 Subtotal** | **1014** |
| 2020 | DEF | Solar 8, 9, 10, 11, & QF 4 | Combined | 445 |
| 2020 | FMPA | NextEra PPAs | Purchased | 149 |
| 2020 | FPL | Unsited Projects | Utility Owned | 522 |
| 2020 | OUC | Future Solar 1 & 2 | Purchased | 56 |
| 2020 | TECO | Wimauma & Alafia | Utility Owned | 125 |
| | | | **2020 Subtotal** | **1296** |
| 2021 | DEF | Solar 12, 13, 14, & QF 5 | Combined | 360 |
| 2021 | FPL | Unsited Projects | Utility Owned | 596 |
| 2021 | SECI | Tillman Solar Center | Purchased | 40 |
| 2021 | TECO | Lake Hancock | Utility Owned | 50 |
| | | | **2021 Subtotal** | **1045** |
| 2022 | DEF | Solar 15 & QF 6 | Combined | 150 |
| 2022 | FPL | Unsited Projects | Utility Owned | 298 |
| 2023 | DEF | Solar 16 & QF 7 | Combined | 150 |
| 2023 | FPL | Unsited Projects | Utility Owned | 298 |
| 2024 | DEF | Solar 17 & QF 8 | Combined | 150 |
| 2024 | FPL | Unsited Projects | Utility Owned | 298 |
| 2025 | DEF | Solar 18 & QF 9 | Combined | 150 |
| 2025 | FPL | Unsited Projects | Utility Owned | 298 |
| 2026 | DEF | Solar 19 & QF 10 | Combined | 150 |
| 2026 | FPL | Unsited Projects | Utility Owned | 298 |
| 2027 | DEF | Solar 20 & QF 11 | Combined | 150 |
| 2027 | FPL | Unsited Projects | Utility Owned | 298 |
| | | | **2022 - 2027 Subtotal** | **2687** |
| TBD | DEF | National Solar Projects | Purchased | 250 |
| | | | **TBD Subtotal** | **250** |
| | | | **Total Installations** | **7119** |

Source: 2018 FRCC Load & Resource Plan, TYSP Utilities Data Responses

## *Renewable Outlook*

Florida's renewable generation is projected to increase over the planning period. A significant portion of this increase can be attributed to growth in solar PV generation. As a result of the operational characteristics of these installations, namely the coincidence of solar generation and summer peak demand, some utilities are reporting a fraction of the nameplate capacity of these installations as firm resources for reliability considerations. However, emerging energy storage technologies have the potential to considerably increase not only the firm capacity contributions from solar PV installations, but their overall functionality as well.

A number of energy storage methodologies are currently being researched for utility-scale application. These include pumped hydropower, flywheels, compressed air, thermal storage, and electrochemical batteries. Among those listed, batteries are being extensively researched due to their declining costs, operational characteristics, scalability, and siting flexibility. A number of Florida utilities have developed pilot programs of varying sizes to explore where and how batteries can be incorporated into their systems. However, due to the infancy of the technology, firm capacity values are not being attributed to these programs. Nevertheless, these programs continue to explore the role battery storage can play in resource planning.

# Traditional Generation

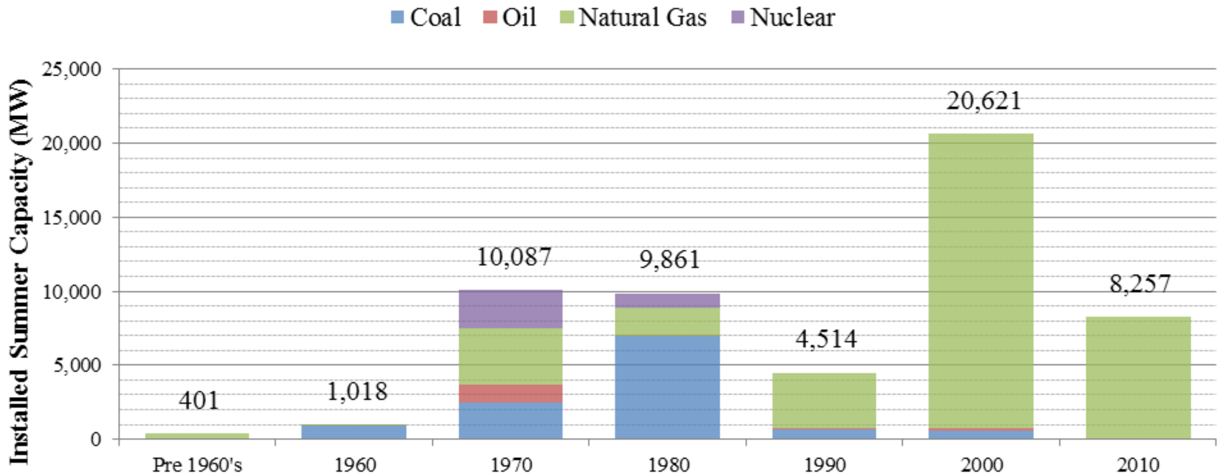
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and combustion turbine generators, that have been added to Florida's electric grid over the last several decades.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

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

## *Existing Generation*

Florida's generating fleet includes incremental new additions to a historic base fleet, with units retiring as they become uneconomical to operate or maintain. Currently, Florida's existing capacity ranges greatly in age and fuel type, and legacy investments continue. The weighted average age of Florida's generating units is 23 years. While the original commercial in-service date may be in excess of 60 years for some units, they are constantly maintained as necessary in order to ensure safe and reliable operation, including uprates from existing capacity, which may have been added after the original in-service date. Figure 12 illustrates the decade current operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

**Figure 12: State of Florida - Electric Utility Installed Capacity by Decade**




Source: 2018 FRCC Load & Resource Plan

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

## *Impact of EPA Rules*

In addition to maintaining a fuel efficient and diverse fleet, Florida's utilities must also comply with environmental requirements that impose incremental costs or operational constraints. During the planning period, six EPA rules were anticipated to affect electric generation in Florida:

- Carbon Pollution Emissions Standards for New, Modified and Reconstructed Secondary Sources: Electric Utility Generating Units - Sets carbon dioxide emissions limits for new, modified or reconstructed electric generators. These limits vary by type of fuel (coal or natural gas). New units are those built after January 18, 2014. Units that undergo modifications or reconstructions after June 18, 2014, that materially alter their air emissions are subject to the specified limits. This rule is currently under appeal. On August 21, 2018, as part of its proposed Affordable Clean Energy Rule, the EPA proposed updates to the New Source Review permitting program that may impact utility decisions regarding power plant modifications and reconstruction. These recent regulatory developments will be addressed in a subsequent Ten-Year Site Plan review.

- Carbon Pollution Emission Guideline for Existing Electric Generating Units (Clean Power Plan) - Requires each state to submit a plan to the EPA that outlines how the state's existing electric generation fleet over 25 megawatts will meet a series of goals, in terms of pounds of carbon dioxide emitted per generated megawatt-hour, to reduce the state's carbon dioxide emissions. The guidelines include increased use of renewable generation and decreased use of coal-fired generation by 2030. This rule has been stayed pending an appeal review. On October 10, 2017, the EPA proposed a repeal of the Clean Power Plan. On August 21, 2018, the EPA announced its Affordable Clean Energy Rule that replaces the Clean Power Plan. This recent regulatory development will be addressed in a subsequent Ten-Year Site Plan review.

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

- Cross-State Air Pollution Rule (CSAPR) - Requires certain states to reduce air emissions that contribute to ozone and/or fine particulate pollution in other states. The rule applies to all fossil-fueled (i.e., coal, oil, and natural gas) electric generators with a capacity over 25 megawatts within the upwind states. Originally, the Rule included Florida, however, the final Rule, issued September 7, 2016, removes North Carolina, South Carolina, and Florida from the program because modeling for the final Rule indicates that these states do not contribute significantly to ozone air quality problems in downwind states.

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

- Coal Combustion Residuals (CCR) - Requires liners and ground monitoring to be installed on new landfills in which coal ash is deposited.

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

### *Modernization and Efficiency Improvements*

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

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

Utilities also plan several efficiency improvements to existing generating units. For example, the conversion of existing simple cycle combustion turbines into a combined cycle unit, which captures the waste heat and uses it to generate additional electricity using a steam turbine. The Commission has granted a determination of need for the conversion of TECO's Polk Units 2 through 5 to a single combined cycle unit.[10] TECO is also modernizing its Big Bend Power Station through the conversion of Big Bend Unit 1, along with two planned combustion turbines, into a 2x1 combined cycle unit by 2023. Per the Florida Department of Environmental Protection, this conversion does not require a determination of need by the Commission. FPL plans on upgrading its existing combined cycle fleet by improving the performance of the integrated combustion turbines at many of its current and planned power plants. By 2018, DEF plans to increase the summer capacity rating at the Hines Energy Center through the installation of Inlet Chilling.

### *Planned Retirements*

Power plant retirements occur when the electric utility is unable to economically operate or maintain a generating unit due to environmental, economic, or technical concerns. Table 9 lists the 6,056 MW of existing generation that is scheduled to be retired during the planning period. While the number of natural gas units scheduled for retirement (17) is greater than that of coal units (8), only 2,849 MW of natural gas-fueled capacity is being retired, as compared to 3,183 MW of coal-fueled capacity.

[10]Order No. PSC-13-0014-FOF-EI, issued January 8, 2013, in Docket No. 20120234-EI, *In re: Petition to determine need for Polk 2-5 combined cycle conversion, by Tampa Electric Company.*

**Table 9: State of Florida - Electric Generating Units to be Retired**

| Year | Utility Name | Plant Name & Unit Number | Unit Type | Fuel Type | Net Capacity (MW) |
|---|---|---|---|---|---|
| | | | | | Summer |
| 2018 | DEF | Crystal River 1 & 2 | Steam Turbine | Coal | 766 |
| 2018 | FPL | SJRPP 1 & 2 | Steam Turbine | Coal | 254 |
| 2018 | FPL | Lauderdale 4 & 5 | Combustion Turbine | Natural Gas | 884 |
| 2018 | FPL | Martin 1 & 2 | Steam Turbine | Natural Gas | 1626 |
| 2018 | JEA | SJRPP 1 & 2 | Steam Turbine | Coal | 1002 |
| 2018 | TAL | Purdom 2 | Combustion Turbine | Natural Gas | 10 |
| 2018 | TAL | Hopkins 1 | Steam Turbine | Natural Gas | 76 |
| | | **2018 Subtotal** | | | **4,618** |
| 2020 | DEF | Avon Park 1 | Combustion Turbine | Natural Gas | 24 |
| 2020 | DEF | Avon Park 2 | Combustion Turbine | Distillate Fuel Oil | 24 |
| 2020 | DEF | Higgins 1 - 4 | Combustion Turbine | Natural Gas | 107 |
| | | **2020 Subtotal** | | | **155** |
| 2021 | TECO | Big Bend 2 | Steam Turbine | Coal | 385 |
| | | **2021 Subtotal** | | | **385** |
| 2022 | GRU | Deerhaven FS01 | Steam Turbine | Natural Gas | 75 |
| | | **2022 Subtotal** | | | **75** |
| 2023 | SECI | Seminole Generating Station 1 or 2* | Steam Turbine | Coal | 626 |
| | | **2023 Subtotal** | | | **626** |
| 2024 | GPC | Crist 4 | Steam Turbine | Coal | 75 |
| | | **2024 Subtotal** | | | **75** |
| 2025 | GPC | Pea Ridge 1 - 3 | Combustion Turbine | Natural Gas | 12 |
| | | **2025 Subtotal** | | | **12** |
| 2026 | GRU | Deerhaven GT01 & GT02 | Combustion Turbine | Natural Gas | 35 |
| 2026 | GPC | Crist 5 | Steam Turbine | Coal | 75 |
| | | **2026 Subtotal** | | | **110** |
| | | **Total Retirements** | | | **6,056** |

* SECI has not determined whether to retire SGS 1 (626 MW) or SGS 2 (634 MW) at this time.

Source: 2018 Ten-Year Site Plans

A notable retirement is DEF's Crystal River Units 1 and 2. Originally scheduled to retire in 2016, the retirement of these units has been delayed until 2018. This delay is due in part to a temporary averaging of emissions across the existing four units at the Crystal River site to meet environmental regulations, as Crystal River Units 4 and 5 have pollution controls installed. Another notable retirement is the St. Johns River Power Park (SJRPP) Units 1 and 2. The SJRPP is a large coal-fired generation facility that is jointly owned by both JEA and FPL and should be fully retired by 2019. Finally, TECO's retirement of its Big Bend Unit 2 in 2021 is part of the previously mentioned modernization of its Big Bend Power Station.

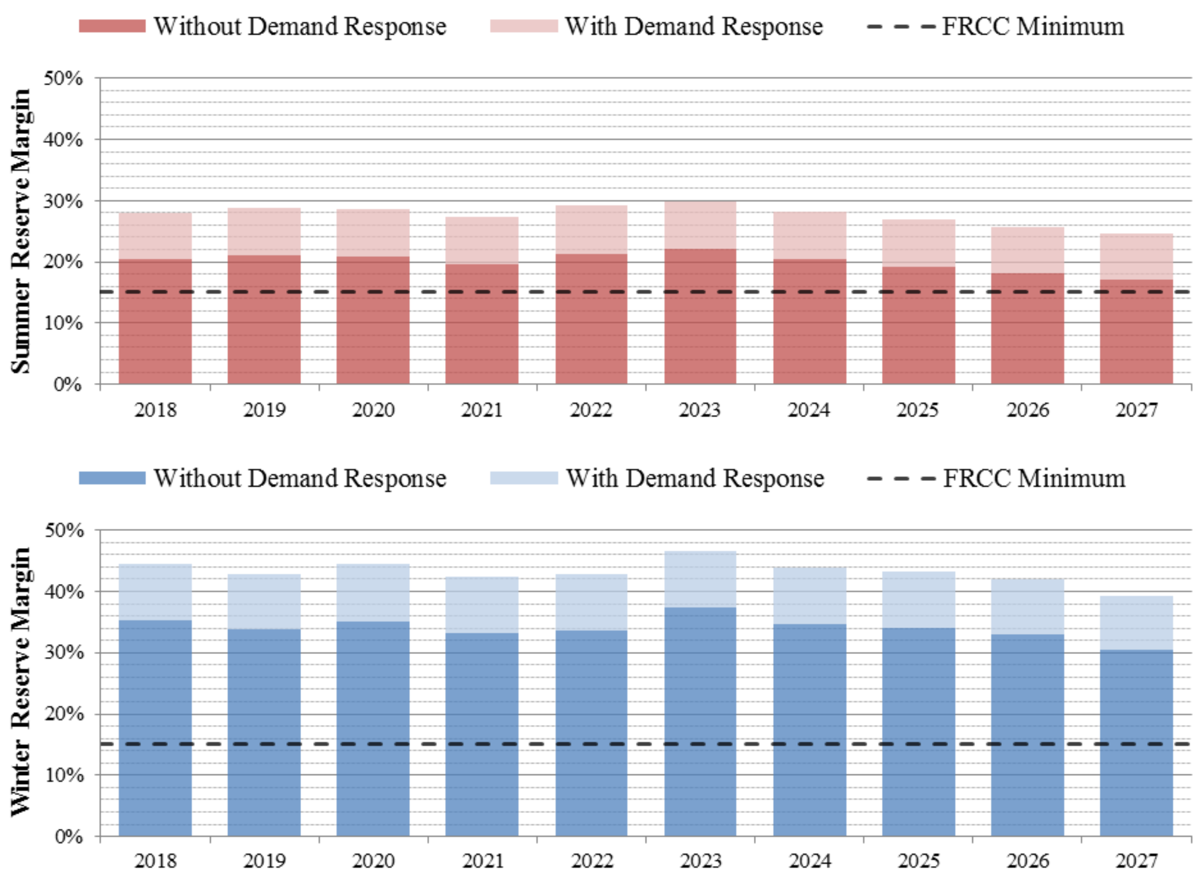
## *Reliability Requirements*

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

Electric utilities within the Florida Reliability Coordinating Council region, which consists of Peninsular Florida, must maintain a minimum of 15 percent reserve margin for planning purposes. Certain utilities have elected to have a higher reserve margin, either on an annual or seasonal basis. The three largest reporting electric utilities, FPL, DEF, and TECO, are party to a stipulation approved by the Commission that utilizes a 20 percent reserve margin for planning.

While Florida's electric utilities are separately responsible for maintaining an adequate planning reserve margin, a statewide view illustrates the degree to which capacity may be available for purchases during periods of high demand or unit outages. Figure 13 is a projection of the statewide seasonal reserve margin including all proposed power plants.

**Figure 13: State of Florida - Projected Reserve Margin by Season**




Source: 2018 FRCC Load & Resource Plan

## Role of Demand Response in Reserve Margin

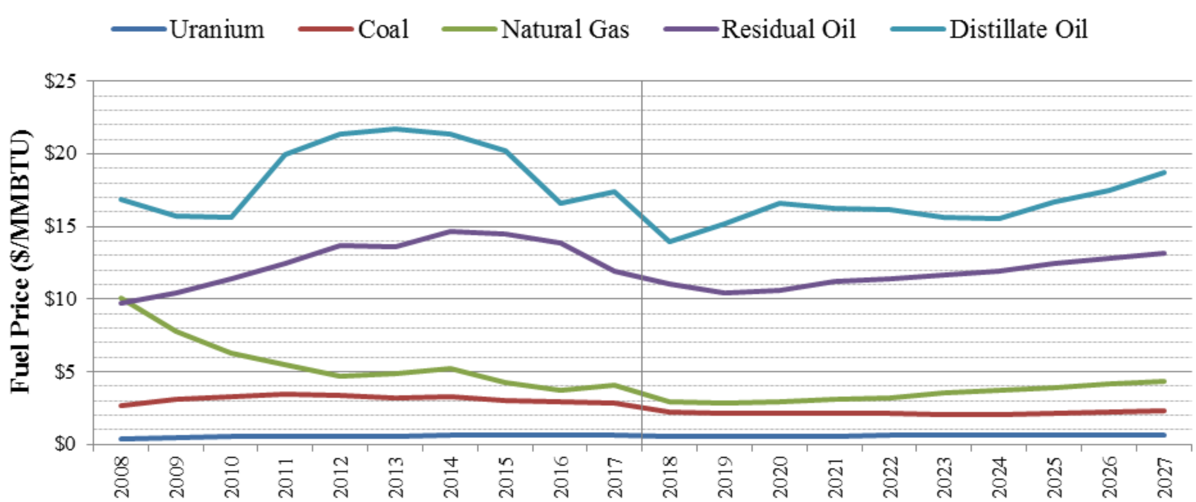
The Commission also considers the planning reserve margin without demand response. As illustrated above in Figure 13, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin without activation of demand response. Demand response activation increases the reserve margin in summer by 7.7 percent on average, and represents 28 percent of the planning reserve margin.

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

## *Fuel Price Forecast*

Fuel price is an important economic factor affecting the dispatch of the existing generating fleet and the selection of new generating units. In general, the capital cost of a power plant is inversely proportional to the cost of the fuel used to generate electricity from that unit. The major fuels consumed by Florida's electric utilities are natural gas, coal, uranium, and oil. Figure 14 illustrates the weighted average fuel price history and forecasts for the reporting electric utilities. While there has been a recent projected decrease in fuel oil prices, it remains the most expensive fuel and suitable primarily for backup and peaking purposes only.

**Figure 14: TYSP Utilities - Average Reporting Electric Utility Fuel Price**




Source: TYSP Utilities Data Responses

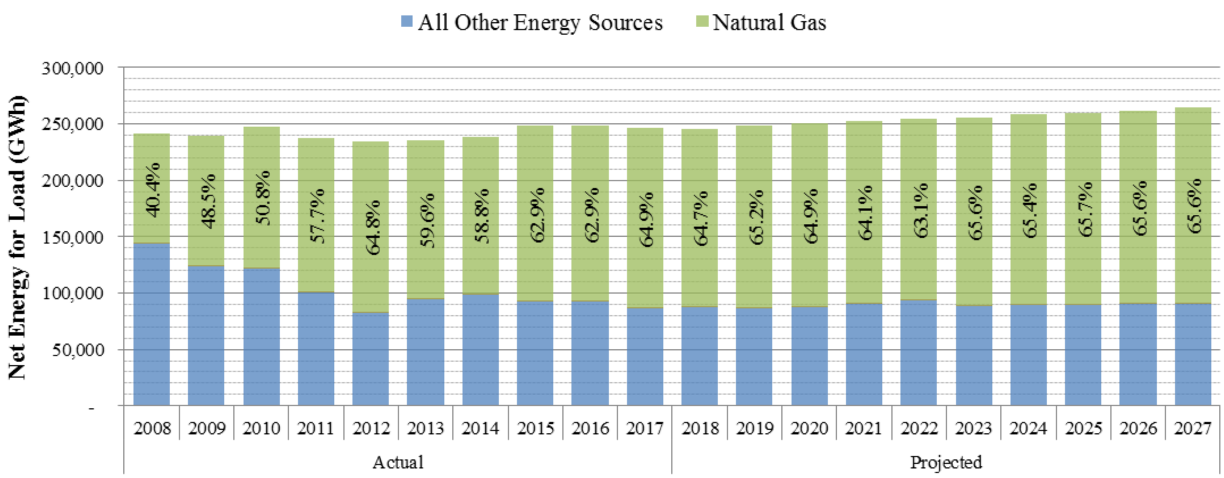
From 2003 to 2005, the price of natural gas was substantially higher than utilities had forecast. This natural gas price volatility led to concern regarding escalating customer bills and an expectation that natural gas prices would remain high. As a result, Florida's electric utilities began making plans to build coal-fired units rather than continuing to increase the reliance on natural gas. Concerns regarding potential environmental regulations, and other projected costs, lead to this coal-fired generation not to materialize. Traditionally, coal was the lowest cost fuel besides uranium and was dispatched before most natural gas-fired units. While natural gas-fired units have the advantage of a lower heat rate, and therefore consume less units of thermal energy per unit of electrical energy produced, the fuel price differential allowed coal to remain dominant until 2008.

The price of natural gas declined rapidly after 2008, and is forecasted to remain at historically low levels. The smaller differential and higher efficiency of natural gas has shifted the dispatch order, with natural gas units displacing some coal units. The trend has also encouraged utilities to modify existing units to be capable of burning natural gas, either as a starter fuel, supplemental fuel, or primary fuel.

## *Fuel Diversity*

Natural gas has risen to become the dominant fuel in Florida within the last 10 years, displacing coal, and since 2010 has generated more net energy for load than all other fuels combined. As Figure 15 illustrates, natural gas is the source of approximately 65 percent of electric energy consumed in Florida. Natural gas generation is anticipated to remain somewhat steady at its current level until the end of the planning period.

**Figure 15: State of Florida - Natural Gas Contribution to Energy Consumption**

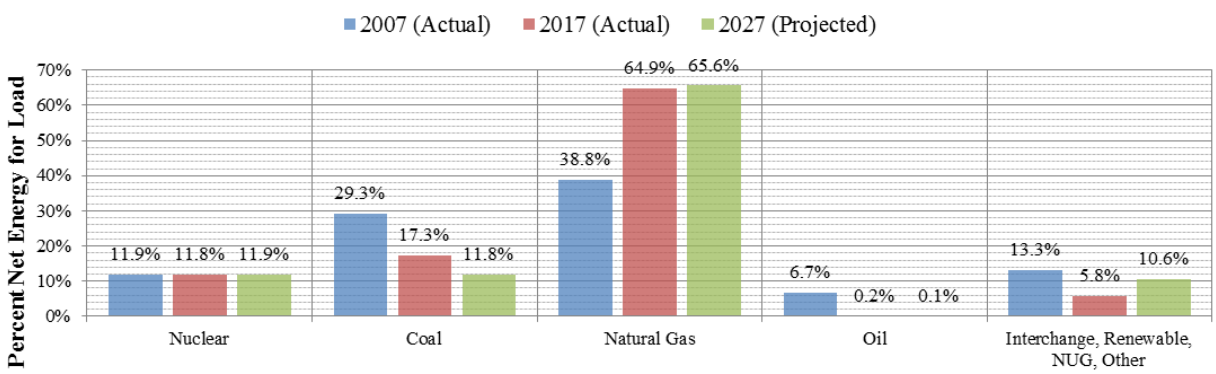



Source: 2008-2018 FRCC Load & Resource Plans

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

Figure 16 shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2007 and 2017, and forecast year 2027. Oil has declined significantly, with its uses reduced to start-up fuel, peaking, and back-up for dual-fuel units in case of a fuel outage. Nuclear generation was reduced beginning in 2010 by the outage and eventual retirement of Crystal River 3 and extended outages for uprates at FPL's St. Lucie and Turkey Point power plants. The resulting capacity leaves Florida's contribution from nuclear approximately the same even with the loss of one of five nuclear units. Coal generation is expected to continue its downward trend well into the planning period. Natural gas has been the primary fuel used to meet the growth of energy consumption, and this trend is anticipated to continue throughout the planning period.

**Figure 16: State of Florida - Historic and Forecast Fuel Consumption**




Source: 2008-2018 FRCC Load & Resource Plans

Based on 2014 Energy Information Administration (EIA) data, Florida ranks fourth place in terms of the total volume natural gas consumption compared to the rest of the United States. For volume of natural gas consumed for electric generation, Florida ranks second, behind Texas.

Florida's percentage of natural gas consumption for electric generation is the highest in the country, with 90 percent of all natural gas consumed in the state for electricity. However, these figures do not consider population. On a per capita basis, Florida's total consumption of natural gas ranks thirtieth, while natural gas consumption for electricity ranks sixth. Natural gas is not used as a heating fuel in most of Florida's homes and businesses, which rely instead upon electricity that is increasingly being generated by natural gas. This leads to Florida's per capita consumption of natural gas being 15 percent less than the national average, but twice the national average per capita consumption of natural gas for electricity. As Florida has very little natural gas production and no gas storage capacity, the state is reliant upon out-of-state production and storage to satisfy the growing electric demands of the state.

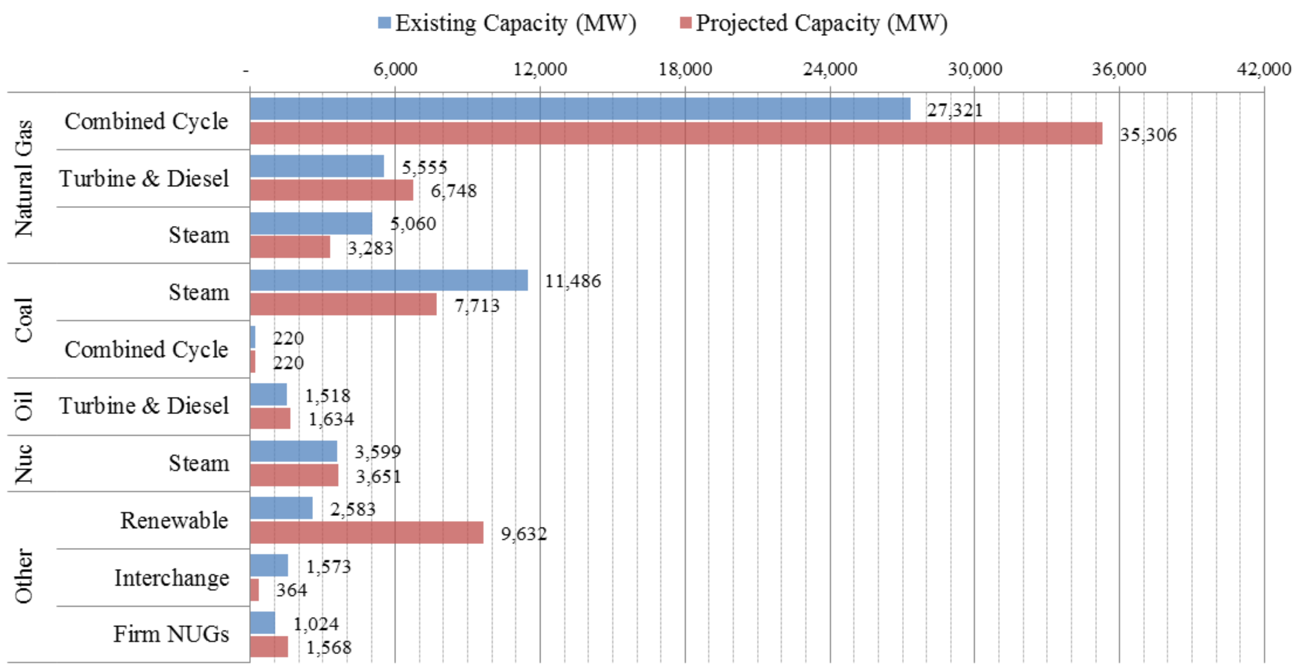
## *New Generation Planned*

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

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

Figure 17 illustrates the present and future aggregate capacity mix. The capacity values in Figure 17 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2018 Ten-Year Site Plans and the FRCC's 2018 Load and Resource Plan.

**Figure 17: State of Florida - Current and Projected Installed Capacity by Fuel**




Source: 2018 FRCC Load & Resource Plan and TYSP Utilities Data Responses

## *New Power Plants by Fuel Type*

### Nuclear

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. FPL has two nuclear projects at Turkey Point that have minimal uprates planned for 2018 and 2019. FPL had previously uprated its existing four nuclear generating units, with the last uprate completed in early 2013.

### Natural Gas

Excluding renewables and minor nuclear and coal generation uprates, all remaining new power plants are natural gas-fired combustion turbines, internal combustion units, or combined cycle units. Combustion turbines run in simple cycle mode as peaking units represent the third most abundant type of generating capacity, behind only coal-fired steam generation. As combustion turbines are not a form of steam generation, unless part of a combined cycle unit, they do not require siting under the Power Plant Siting Act. Table 10 summarizes the approximately 8,190 MW of proposed new natural gas-fired generation included in the 2018 Ten-Year Site Plans. Of this amount, approximately 6,441 MW are already under construction or have been previously certified.

**Table 10: State of Florida - Planned Natural Gas Units**

| In-Service Year | Utility Name | Plant Name & Unit Number | Net Capacity (MW) | Notes |
|---|---|---|---|---|
| **Previously Approved New Units** | | | | |
| 2018 | DEF | Citrus | 1,640 | Docket No. 20140110-EI |
| 2019 | FPL | Okeechobee Energy Center | 1,778 | Docket No. 20150196-EI |
| 2022 | FPL | Dania Beach Energy Center | 1,163 | Docket No. 20170225-EI |
| 2022 | SEC | Seminole CC Facility* | 1,108 | Docket No. 20170266-EI |
| | | | **Subtotal** | **5,689** |
| **New Units Requiring PPSA Approval** | | | | |
| 2024 | GPC | Unspecified CC | 595 | |
| | | | **Subtotal** | **595** |
| **New Units Not Requiring PPSA Approval** | | | | |
| 2018 | TAL | Sub 12 IC 1-2 | 18 | |
| 2018 | TAL | Hopkins IC 1-4 | 74 | |
| 2021 | TEC | Big Bend CT5 & CT6 | 660 | Convert to CC in 2023 |
| 2023 | TEC | Future CT 1 | 229 | Not under construction |
| 2025 | TAL | Hopkins IC 5 | 18 | |
| 2026 | TEC | Future CT 2 | 229 | |
| 2027 | DEF | Undesignated CT P1 | 226 | |
| 2027 | DEF | Undesignated CT P2 | 226 | |
| 2027 | DEF | Undesignated CT P3 | 226 | |
| | | | **Subtotal** | **1,906** |
| | | | **Total Planned Natural Gas Capacity** | **8,190** |
| * The Seminole CC Facility's Determination of Need is currently under appeal. | | | | |

Source: 2018 Ten-Year Site Plans

## *Commission's Authority Over Siting*

The Commission has been given exclusive jurisdiction to determine the need for new electric power plants by the Legislature, through the Electrical Power Plant Siting Act (PPSA), contained in Sections 403.501 through 403.518, F.S. Any proposed steam or solar generating unit greater than 75 MW requires a certification under the PPSA. Upon receipt of a determination of need, the electric utility would then seek approval from the Florida Department of Environmental Protection, which addresses land use and environmental concerns. Finally, the Governor and Cabinet, sitting as the Siting Board, ultimately must approve or deny the overall certification of a proposed power plant. As shown in Table 10 above, there is approximately 595 MW of generation that would require certification under the PPSA. Based on the unit type, GPC may be filing a need determination sometime in 2019.

## *Transmission*

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

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

Table 11 lists all proposed transmission lines in the 2018 Ten-Year Site Plans that require TLSA certification. All planned lines have already received the approval of the Commission, either independently or as part of a PPSA determination of need.

**Table 11: State of Florida - Planned Transmission Lines**

| **Utility** | **Transmission Line** | **Line Length** (Miles) | **Nominal Voltage** (kV) | **Date Need Approved** | **Date TLSA Certified** | **In-Service Date** |
|---|---|---|---|---|---|---|
| FPL | St Johns – Pringle | 25 | 230 | 05/13/2005 | 04/21/2006 | 12/01/2018 |
| FPL | Levee-Midway | 150 | 500 | 05/28/1988 | 04/20/1990 | 06/01/2019 |
| FPL | Duval - Raven | 45 | 230 | 02/25/2016 | 06/29/2016 | 12/01/2018 |
| TECO | Thonotosassa  Wheeler | 8 | 230 | 06/21/2007 | 08/07/2008 | TBD |
| TECO | Wheeler to Willow Oak | 17 | 230 | 06/21/2007 | 08/07/2008 | TBD |

Source: 2018 Ten-Year Site Plans

# Utility Perspectives

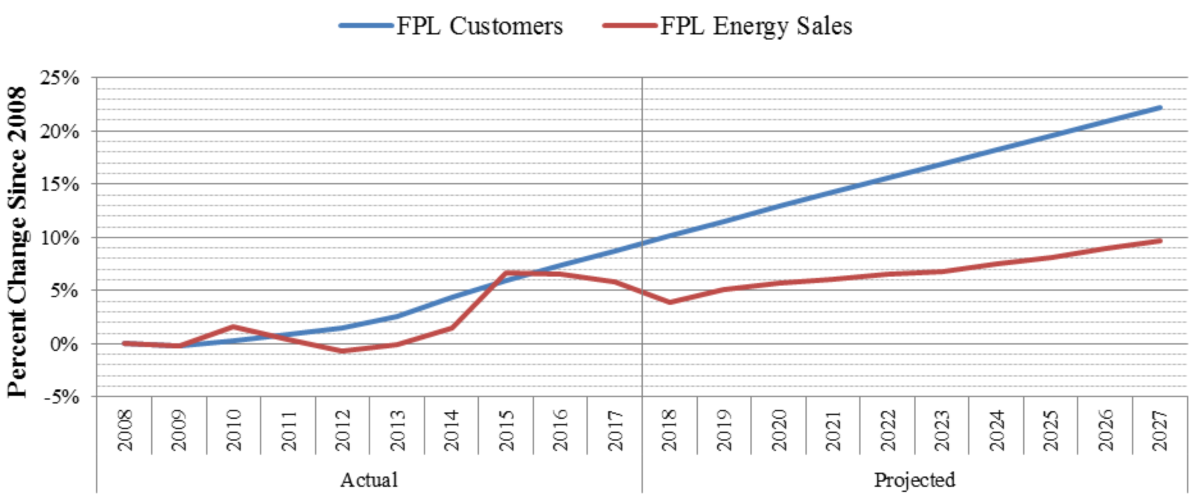
# Florida Power & Light Company (FPL)

FPL is an investor-owned utility and Florida's largest electric utility. The Utility's service territory is within the FRCC region and is primarily in south Florida and along the east coast. As an investor-owned utility, the Commission has regulatory authority over all aspects of FPL's operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds FPL's 2018 Ten-Year Site Plan suitable for planning purposes.

## Load and Energy Forecasts

In 2017, FPL had approximately 4,901,886 customers and annual retail energy sales of 108,871 GWh or approximately 48.2 percent of Florida's annual retail energy sales. Figure 18 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the past 10 years, FPL's customer base has increased by 8.70 percent, while retail sales have grown by 5.78 percent. As illustrated, FPL's retail energy sales are anticipated to exceed its historic 2015 peak in 2023. Since 2009, FPL has been outperforming the state average in retail energy sales growth, a trend it projects to continue into the future.

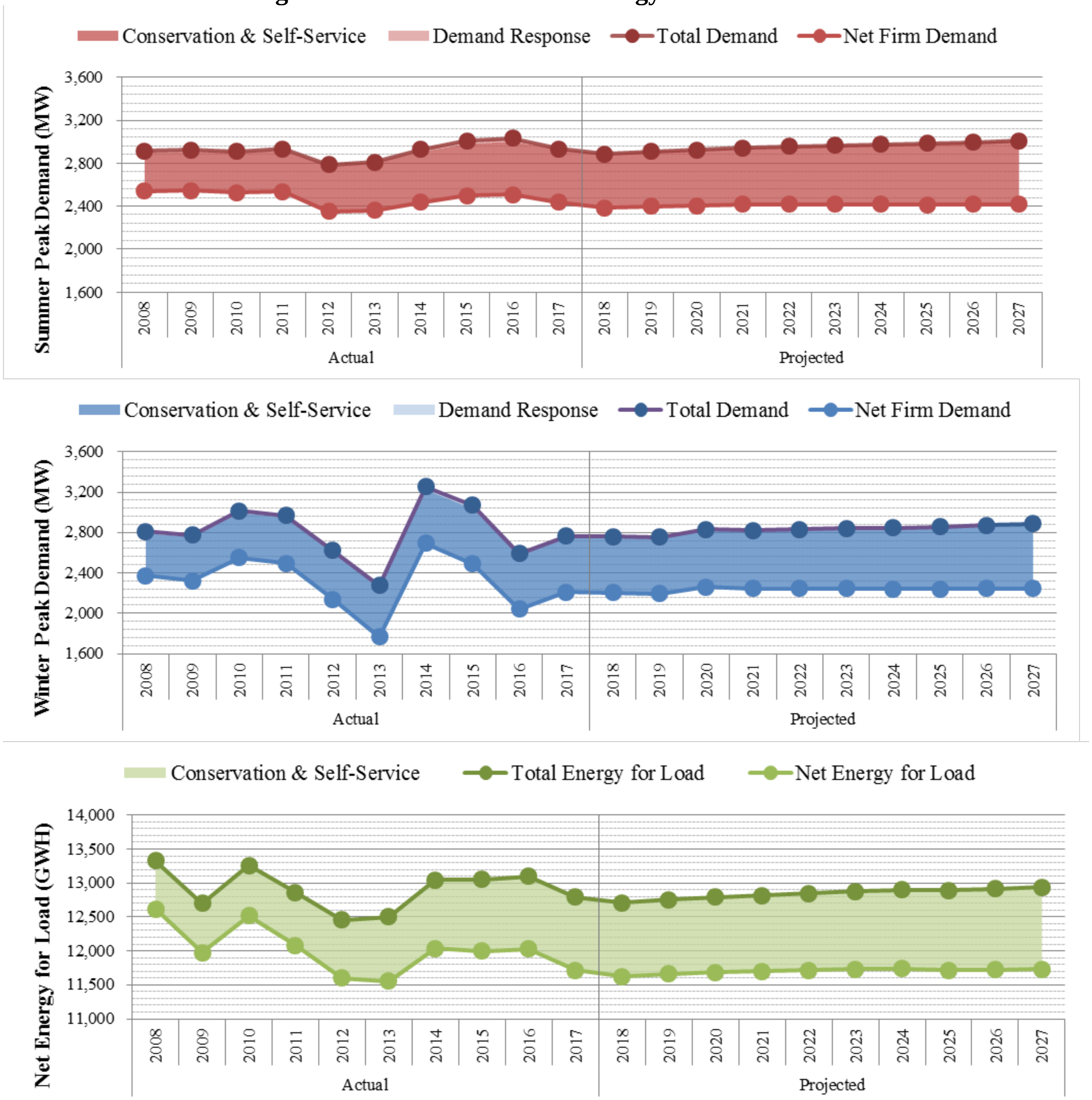
**Figure 18: FPL Growth Rate**




Source: 2018 Ten-Year Site Plan

The three graphs in Figure 19 show FPL's seasonal peak demand and net energy for load, for the historic years 2008 through 2017 and forecast years 2018 through 2027. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. Historically, demand response has not been activated during the seasonal peak demand, excluding the winters of 2010 and 2011. As an investor-owned utility, FPL is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2018 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

**Figure 19: FPL Demand and Energy Forecasts**




Source: 2018 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 12 shows FPL's actual net energy for load by fuel type for 2017, and the projected fuel mix for 2027. FPL relies primarily upon natural gas and nuclear for energy generation, making up 95 percent of net energy for load. Consistent with its previously discussed SoBRA, FPL projects that renewable energy will provide over 7 percent of generation by 2027.

**Table 12: FPL Energy Consumption by Fuel Type**

| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2017 | | 2027 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 86,706 | **71.8%** | 82,601 | **66.3%** |
| **Coal** | 4,057 | **3.4%** | 1,966 | **1.6%** |
| **Nuclear** | 27,971 | **23.2%** | 28,363 | **22.8%** |
| **Oil** | 400 | **0.3%** | 19 | **0.0%** |
| **Renewable** | 658 | **0.5%** | 9,391 | **7.5%** |
| **Interchange** | 1,598 | **1.3%** | 0 | **0.0%** |
| **Other** | -642 | **-0.5%** | 2,215 | **1.8%** |
| **Total** | **120,748** | | **124,555** | |

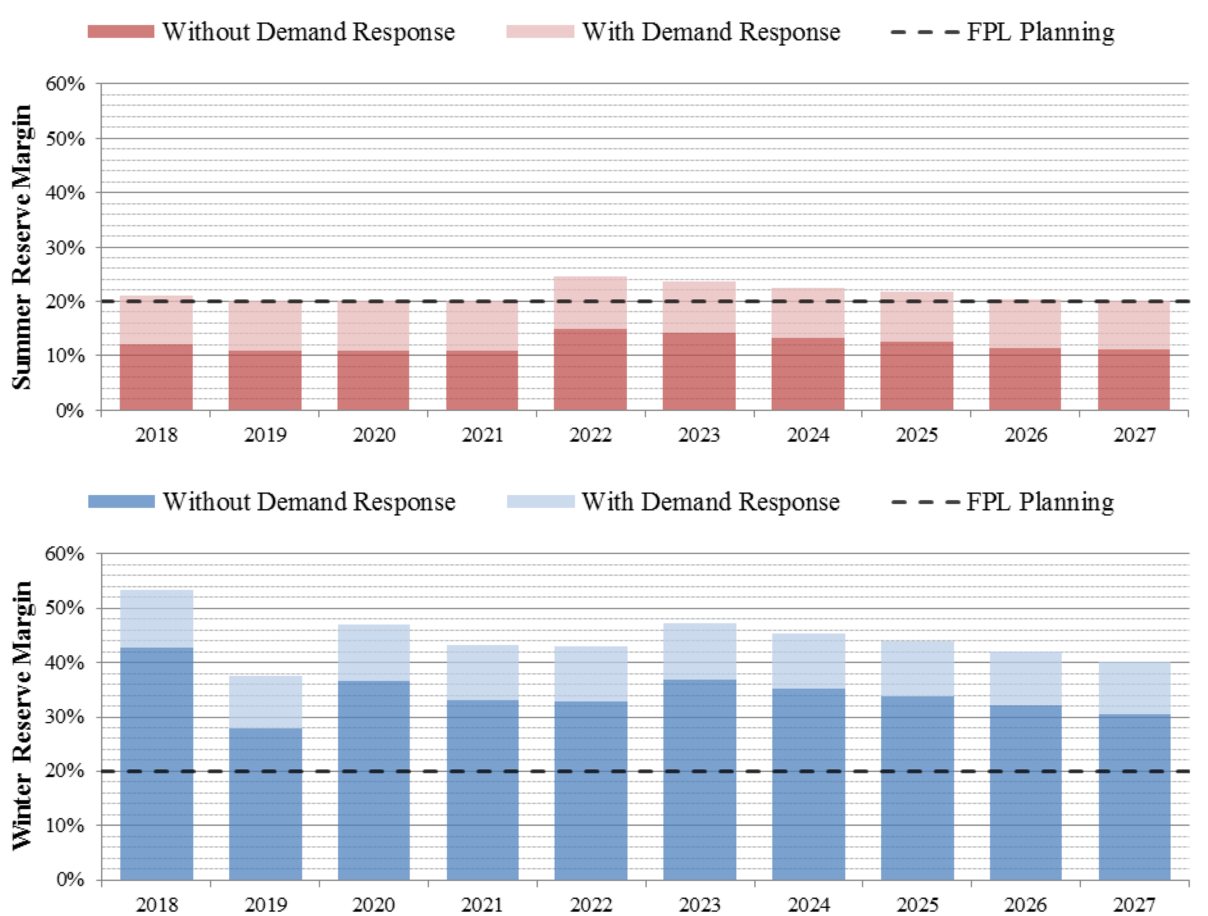
Source: 2018 Ten-Year Site Plan

## Reliability Requirements

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

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

**Figure 20: FPL Reserve Margin Forecast**




Source: 2018 Ten-Year Site Plan

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

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

Energy efficiency, which includes installation of equipment designed to reduce peak demand and annual energy consumption, is considered a passive resource. While demand response must be activated by the Utility, energy efficiency provides benefits consistently for the duration of the installation, reducing annual energy consumption, and if usage is coincident with system peak, peak demand. Customers do not remove building envelope improvements or newly installed equipment until the end of its service life for replacement.

As noted in the Statewide Perspective, the Commission does review the impact on reserve margin of demand response resources. At this time, FPL offers two types of demand response programs. The first type is interruptible and curtailable load programs, consisting of the Commercial/Industrial Load Control Program (CILC) and Commercial/Industrial Demand Reduction Rider (CDR) tariffs. The second type is load management programs, including the Residential On-Call and Business On-Call Programs. FPL utilizes load management programs on residential customers more often than commercial/industrial customers.

## Generation Resources

FPL plans multiple unit retirements and additions during the planning period, as described in Table 13. The projected in-service dates of FPL's new planned nuclear units are now outside the 10-year planning period. On September 3, 2015, FPL filed a need determination with the Commission for the Okeechobee Unit which was granted on January 19, 2016. The Okeechobee Unit is expected to be in-service by 2019. At the hearing on September 25, 2017, the Commission approved the Stipulation and Settlement Agreement which included FPL's proposal for early shutdown of SJRPP.[11] The SJRPP Units 1 & 2 are set to retire in 2018. FPL also plans to retire Martin Units 1 & 2 in 2018 due to the units' age and inefficiency in regards to converting natural gas or oil into electricity. Additionally, FPL is planning to retire Lauderdale Units 4 & 5 and replace them with the Dania Beach Clean Energy Center, a natural gas-fired combined cycle unit, consistent with the Commission approved need determination for the Dania Beach facility.[12] The Dania Beach Clean Energy Center is expected to be in-service by 2022.

FPL plans to increase the amount of planned solar projects by approximately 300 MW per calendar year, consistent with its last base rate case settlement.[13] FPL has included planned solar additions of 3,204 MW outside of the 596 MW of SoBRA additions approved in the fuel and purchased power cost recovery clause dockets.[14] FPL plans to conduct further economic analysis before reaching a decision to proceed with these additions. The planned solar additions make up approximately 56 percent of FPL's planned future units.

[11]Document No. 07922-2017, filed September 26, 2017, in Docket No. 20170123-EI, *In re: Petition for approval of arrangement to mitigate unfavorable impact of St. Johns River Power Park, by Florida Power & Light Company.*
[12]Order No. PSC-2018-0150-FOF-EI, issued March 19, 2018, in Docket No. 20170225-EI, *In re: Petition of determination of need for Dania Beach Clean Energy Center Unit 7, by Florida Power & Light Company.*
[13]Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 20160021-EI, *In re: Petition for rate increase by Florida Power & Light Company.*
[14]Order No. PSC-2018-0028-FOF-EI, issued January 8, 2018, in Docket No. 20180001-EI, I*n re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

**Table 13: FPL Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum | Solar Firm Capacity (Summer) Sum | Notes |
|---|---|---|---|---|---|
| **Retiring Units** | | | | | |
| 2018 | Lauderdale 4 & 5 | Natural Gas Combustion Turbine | 884 | | |
| 2018 | SJRPP 1 & 2 | Coal Steam Turbine | 254 | | |
| 2018 | Martin 1 & 2 | Natural Gas Steam Turbine | 1,626 | | |
| **Total Retirements** | | | **2,764** | | |
| **New Units** | | | | | |
| 2018 | Coral Farms | Photovoltaic | 75 | 40 | |
| 2018 | Horizon | Photovoltaic | 75 | 40 | |
| 2018 | Indian River | Photovoltaic | 75 | 40 | |
| 2018 | Wildflowerr | Photovoltaic | 75 | 40 | |
| 2018 | Barefoot Bay | Photovoltaic | 75 | 40 | |
| 2018 | Blue Cypressr | Photovoltaic | 75 | 40 | |
| 2018 | Hammock | Photovoltaic | 75 | 40 | |
| 2018 | Loggerhead | Photovoltaic | 75 | 40 | |
| 2019 | Interstate | Photovoltaic | 75 | 41 | |
| 2019 | Miami-Dade | Photovoltaic | 75 | 41 | |
| 2019 | Okeechobee | Natural Gas Combined Cycle | 1,778 | | Docket No. 20150196-EI |
| 2019 | Pioneer Trail | Photovoltaic | 75 | 41 | |
| 2019 | Sunshine Gateway | Photovoltaic | 75 | 41 | |
| 2020 | SoBRA PV Unsited | Photovoltaic | 298 | 165 | |
| 2020 | Unsited Solar | Photovoltaic | 224 | 124 | |
| 2021 | Unsited Solar | Photovoltaic | 596 | 330 | |
| 2022 | Dania Beach | Natural Gas Combined Cycle | 1,163 | | Docket No. 20170225-EI |
| 2022 | Unsited Solar | Photovoltaic | 298 | 165 | |
| 2023 | Unsited Solar | Photovoltaic | 298 | 165 | |
| 2024 | Unsited Solar | Photovoltaic | 298 | 165 | |
| 2025 | Unsited Solar | Photovoltaic | 298 | 155 | |
| 2026 | Unsited Solar | Photovoltaic | 298 | 131 | |
| 2027 | Unsited Solar | Photovoltaic | 298 | 116 | |
| **Total New Units** | | | **6,741** | **2,003** | |
| **Percentage of Solar Units Planned of Total New Units** | | | **56.4%** | | |
| **Net Additions** | | | **3,977** | | |

Source: 2018 Ten-Year Site Plan

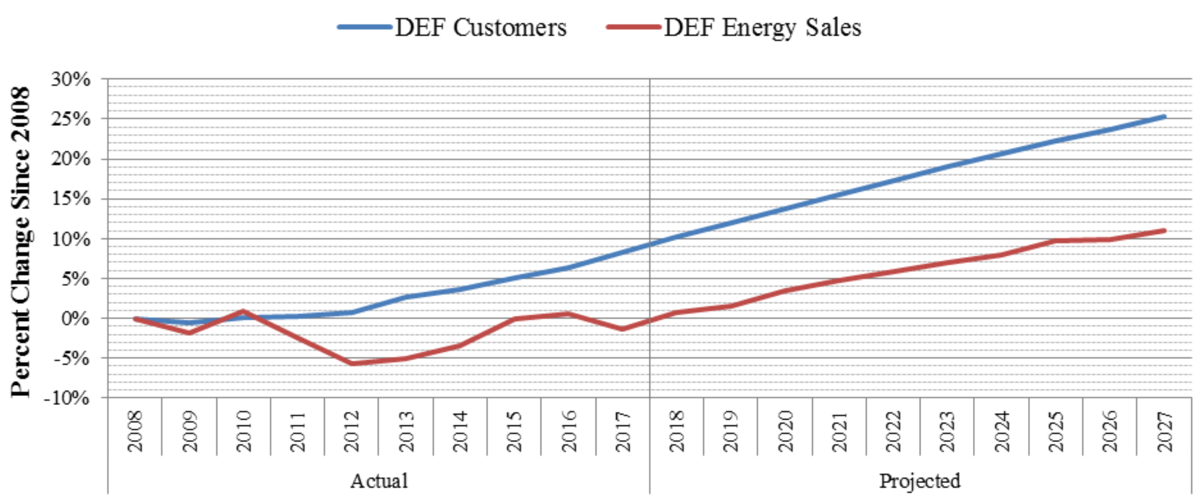
# Duke Energy Florida, LLC (DEF)

DEF is an investor-owned utility and Florida's second largest electric utility. The Utility's service territory is within the FRCC region and is primarily in central and west central Florida. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds DEF's 2018 Ten-Year Site Plan suitable for planning purposes.

## Load & Energy Forecasts

In 2017, DEF had approximately 1,775,340 customers and annual retail energy sales of 38,023 GWh or approximately 16.8 percent of Florida's annual retail energy sales. Figure 21 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, DEF's customer base has increased by 8.32 percent, while retail sales have declined by 1.38 percent. As illustrated, DEF's retail energy sales are anticipated to exceed its historic 2010 peak in 2019.

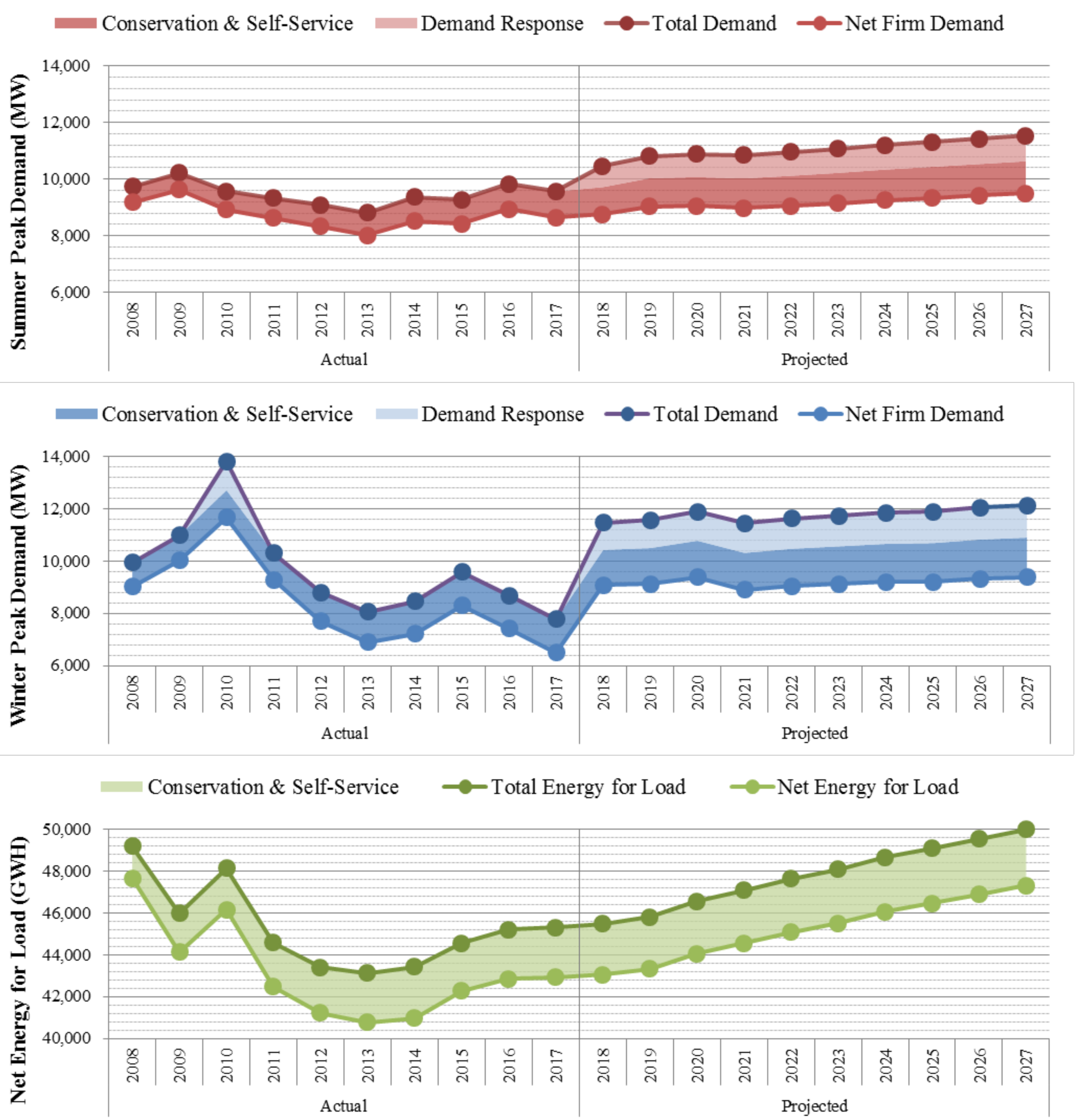
**Figure 21: DEF Growth Rate**




Source: 2018 Ten-Year Site Plan

The three graphs in Figure 22 show DEF's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. These graphs include the full impact of demand-side management and assume that all available demand response resources were or will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand, excluding extreme weather events. As an investor-owned utility, DEF is subject to FEECA, and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2018 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

**Figure 22: DEF Demand and Energy Forecasts**




Source: 2018 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 14 shows DEF's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. DEF relies primarily upon natural gas and coal for energy generation, making up approximately 84 percent of net energy for load. DEF plans to reduce coal usage over the planning period, and to increase renewable energy generation, making natural gas and renewable energy DEF's primary sources of generation by 2027. DEF projects the highest percentage of renewable energy generation in 2027 of the Ten-Year Site Plan utilities.

**Table 14: DEF Energy Consumption by Fuel Type**

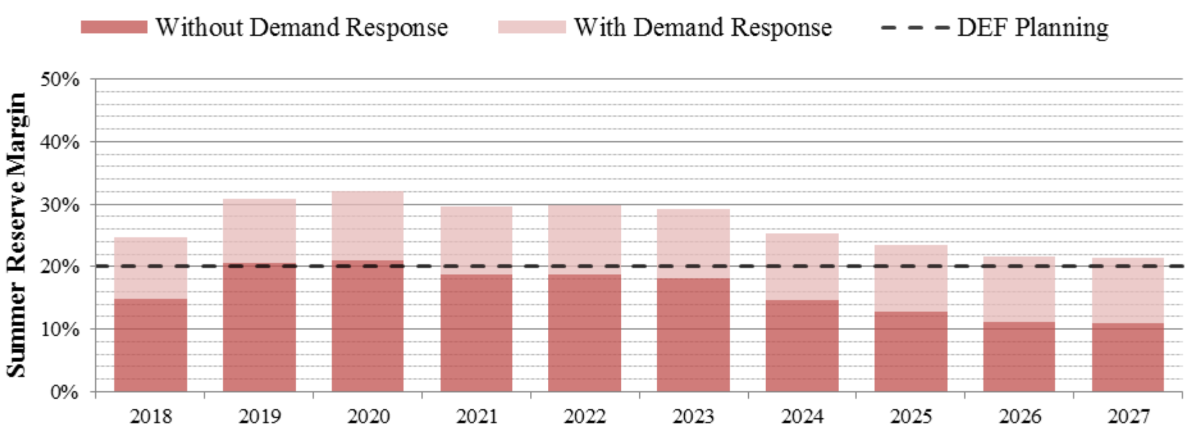
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2017 | | 2027 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 27,307 | **63.6%** | 36,552 | **77.3%** |
| **Coal** | 8,722 | **20.3%** | 3,908 | **8.3%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 62 | **0.1%** | 102 | **0.2%** |
| **Renewable** | 1,496 | **3.5%** | 6,504 | **13.7%** |
| **Interchange** | 2,037 | **4.7%** | 248 | **0.5%** |
| **NUG & Other** | 3,295 | **7.7%** | 2 | **0.0%** |
| **Total** | **42,919** | | **47,316** | |

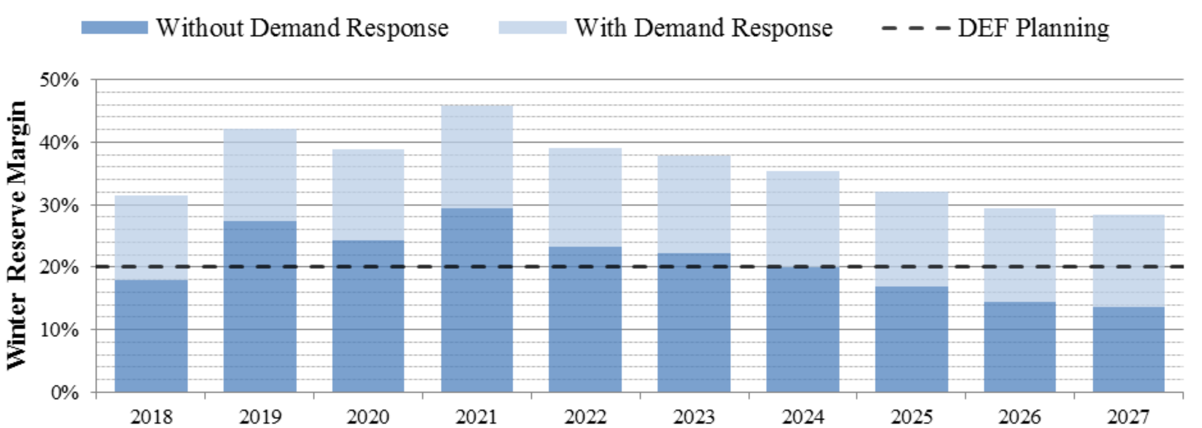
Source: 2018 Ten-Year Site Plan and Data Responses

## Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion. Figure 23 displays the forecast planning reserve margin for DEF through the planning period for both seasons, with and without the use of demand response. As shown in the figure, DEF's generation needs are controlled by its summer peaking throughout the planning period.

**Figure 23: DEF Reserve Margin Forecast**




Source: 2018 Ten-Year Site Plan

## Generation Resources

DEF plans multiple unit retirements and additions during the planning period, as described in Table 15. DEF's 2018 Ten-Year Site Plan includes the retirement of the coal-fired Crystal River Units 1 and 2, to be replaced by a pair of natural gas-fired combined cycle units. In addition to the units discussed above, DEF includes the retirement of five gas-fired units at multiple power plant sites. DEF's planned additions include a combined cycle facility in 2018 in Citrus County, and three planned Combustion Turbine Units at an undesignated site(s) in 2024, 2025, and 2026.

DEF also anticipates increasing the amount of planned solar projects by approximately 175 MW per calendar year, not to exceed 700 MW, consistent with its 2017 Second Revised and Restated Settlement Agreement.[15] DEF has included 450 MW of planned solar additions outside of the 700 MW cap. Currently, DEF is petitioning the Commission for approval of 149.8 MW of solar

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

additions as part of its first SoBRA.[16] As a result of forecasts that show the continued reduction in the price of solar PV technology, DEF has incorporated this energy source as a supply-side resource in both its near-term and long-term generation plans. The solar additions make up approximately 33 percent of DEF's planned future units.

**Table 15: DEF Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum | Solar Firm Capacity (Summer) Sum | Notes |
|---|---|---|---|---|---|
| **Retiring Units** | | | | | |
| 2018 | Crystal River 1 & 2 | Coal Steam Turbine | 766 | | |
| 2020 | Avon Park P1 | Natural Gas Combustion Turbine | 24 | | |
| 2020 | Avon Park P2 | Distillate Oil Gas Turbine | 24 | | |
| 2020 | Higgins P1-4 | Natural Gas Combustion Turbine | 107 | | |
| **Total Retirements** | | | **921** | | |
| **New Units** | | | | | |
| 2018 | Citrus CC | Natural Gas Combined Cycle | 1,640 | | Docket No. 20140110-EI |
| 2019 | Hamilton | Photovoltaic | 75 | 43 | |
| 2019 | Solar 6 & 7 | Photovoltaic | 120 | 68 | |
| 2020 | Solar 8, 9, 10, & 11 | Photovoltaic | 295 | 168 | |
| 2021 | Solar 12, 13, & 14 | Photovoltaic | 210 | 120 | |
| 2022 | Solar 15 | Photovoltaic | 75 | 43 | |
| 2023 | Solar 16 | Photovoltaic | 75 | 43 | |
| 2024 | Solar 17 | Photovoltaic | 75 | 43 | |
| 2025 | Solar 18 | Photovoltaic | 75 | 43 | |
| 2026 | Solar 19 | Photovoltaic | 75 | 43 | |
| 2027 | Unknown CT P1, P2, & P3 | Natural Gas Combustion Turbine | 678 | | |
| 2027 | Solar 20 | Photovoltaic | 75 | 43 | |
| **Total New Units** | | | **3,468** | **655** | |
| **Percentage of Solar Units Planned of Total New Units** | | | **33%** | | |
| **Net Additions** | | | **2,547** | | |

Source: 2018 Ten-Year Site Plan

[16]Document No. 049910-2018, filed July 31, 2018, in Docket No. 20180149-EI, *In re: Petition for a limited proceeding to approve first solar base rate adjustment, by Duke Energy Florida, LLC.*

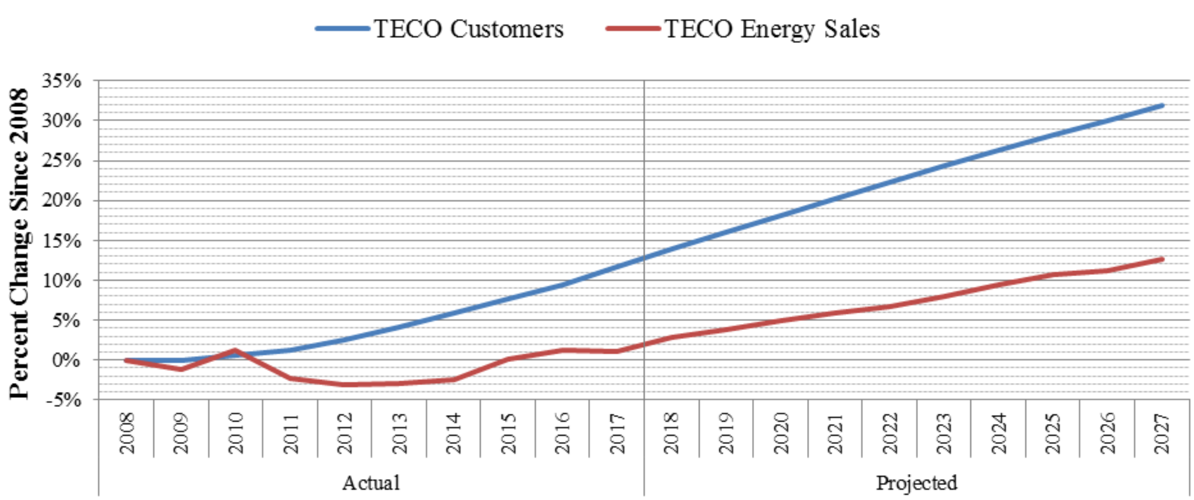
# Tampa Electric Company (TECO)

TECO is an investor-owned utility and Florida's third largest electric utility. The Utility's service territory is within the FRCC region and consists primarily of the Tampa metropolitan area. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds TECO's 2018 Ten-Year Site Plan suitable for planning purposes.

## Load & Energy Forecasts

In 2017, TECO had approximately 744,690 customers and annual retail energy sales of 19,186 GWh or approximately 8.5 percent of Florida's annual retail energy sales. Figure 24 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, TECO's customer base has increased by 11.6 percent, while retail sales have increased by 1.03 percent. As illustrated, TECO's retail energy sales are anticipated to exceed its historic 2016 peak in 2018.

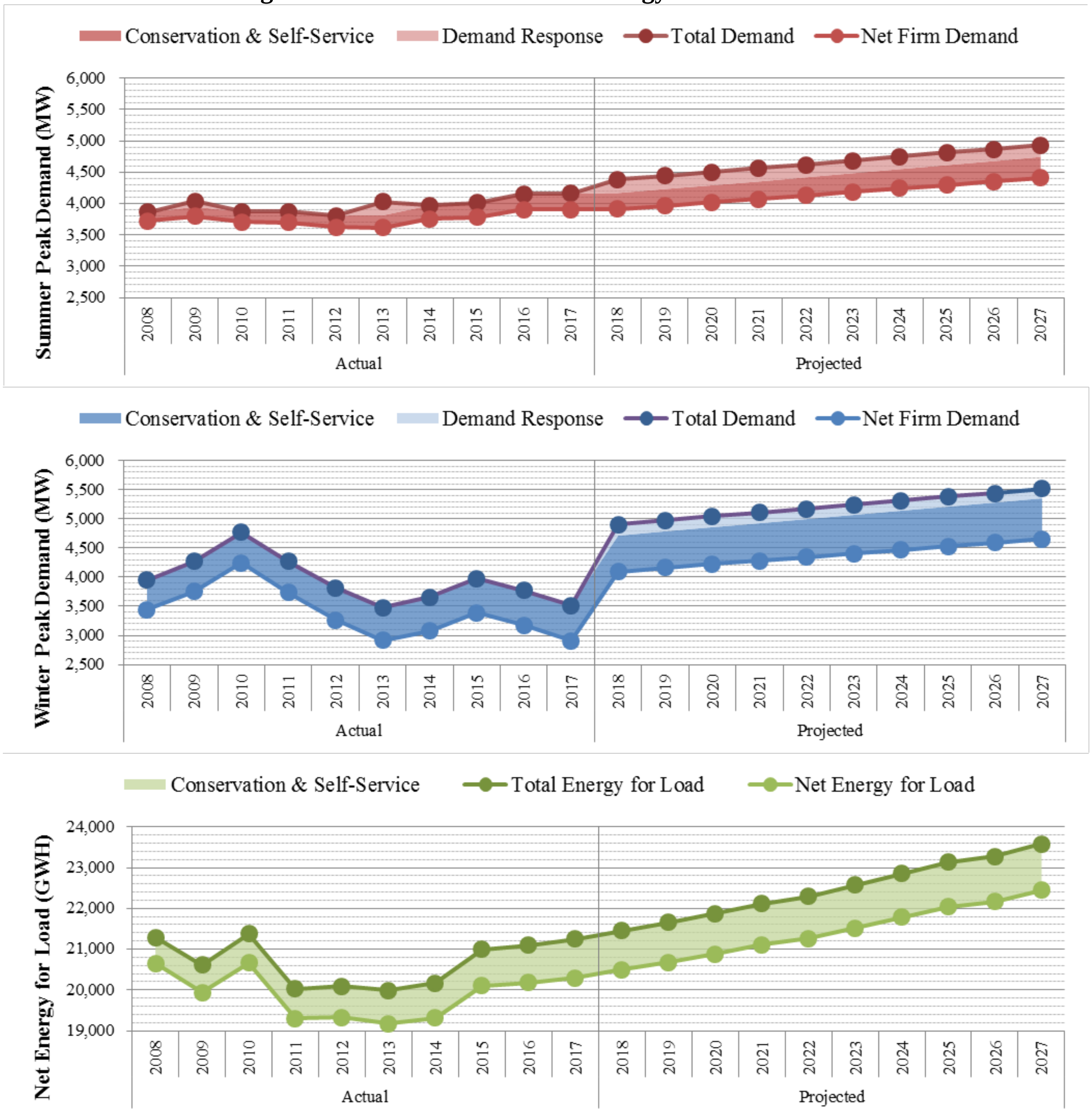
**Figure 24: TECO Growth Rate**




Source: 2018 Ten-Year Site Plan

The three graphs in Figure 25 show TECO's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. These graphs include the full impact of demand-side management, and assume that all available demand response resources were or will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand excluding extreme weather events.

**Figure 25: TECO Demand and Energy Forecasts**




Source: 2018 Ten-Year Site Plan and Data Responses

As an investor-owned utility, TECO is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2018 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

## Fuel Diversity

Table 16 shows TECO's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. Based on its 2018 Ten-Year Site Plan, natural gas is used for the majority of TECO's energy generation. Natural gas accounts for approximately 67 percent of net energy for load. In the future, TECO projects that energy from coal will slightly decrease and energy from natural gas will increase. TECO projects that renewable energy will increase from 0.2 percent to 6.2 percent of generation by 2027.

**Table 16: TECO Energy Consumption by Fuel Type**

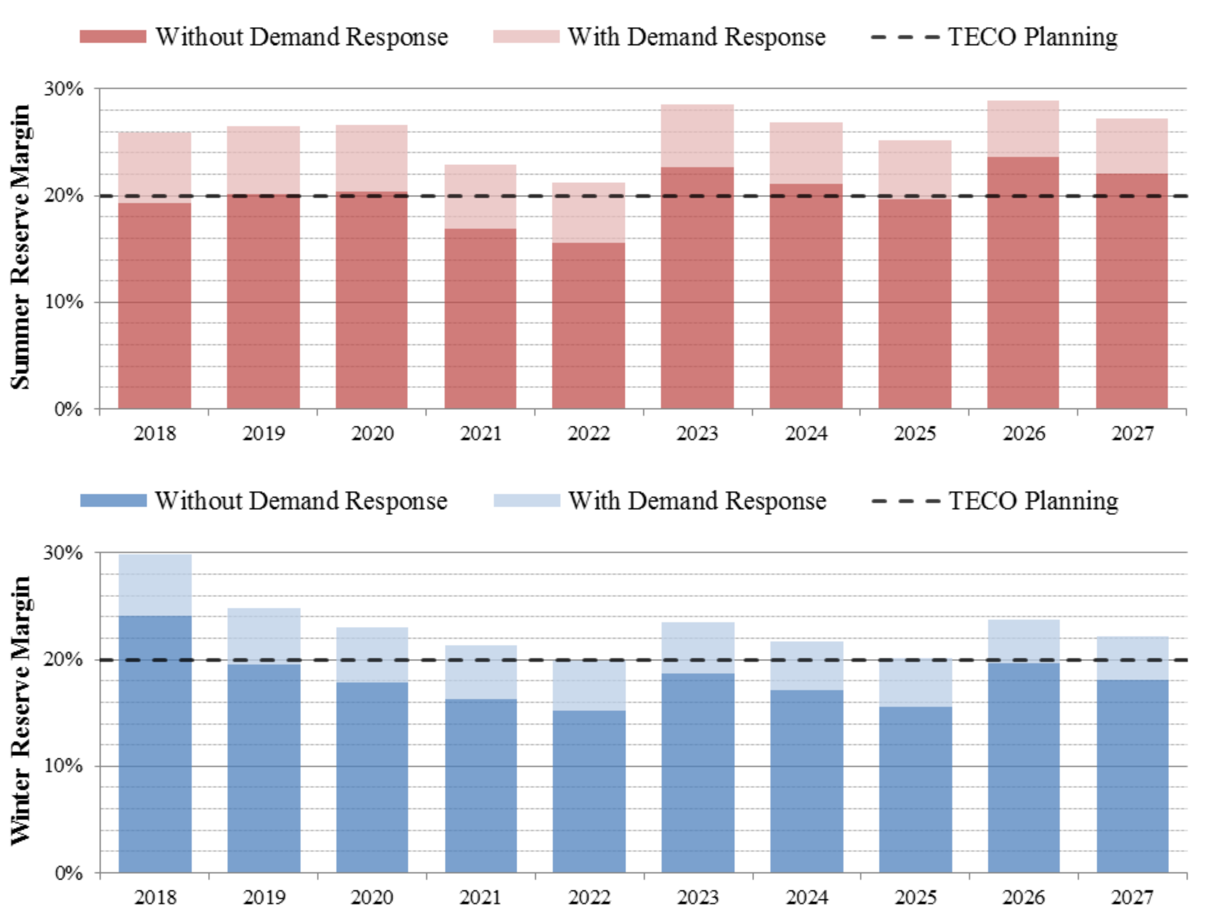
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2017 | | 2027 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 13,685 | **67.4%** | 16,379 | **73.0%** |
| **Coal** | 4,949 | **24.4%** | 3,430 | **15.3%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 0 | **0.0%** | 0 | **0.0%** |
| **Renewable** | 45 | **0.2%** | 1,387 | **6.2%** |
| **Interchange** | 122 | **0.6%** | 0 | **0.0%** |
| **NUG & Other** | 1,496 | **7.4%** | 1,256 | **5.6%** |
| **Total** | **20,298** | | **22,452** | |

Source: 2018 Ten-Year Site Plan and Data Responses

## Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion. TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 26 displays the forecast planning reserve margin for TECO through the planning period for both seasons, with and without the use of demand response. As shown in the figure, TECO's generation needs are controlled by its summer peak throughout the planning period. TECO's 7 percent supply-side only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20 percent reserve margin will be realized.

**Figure 26: TECO Reserve Margin Forecast**




Source: 2018 Ten-Year Site Plan

## Generation Resources

TECO plans a unit retirement and multiple unit additions during the planning period, as described in Table 17. TECO's 2018 Ten-Year Site Plan includes the retirement of the coal-fired Big Bend Unit 2 in 2021. TECO also plans to convert its coal-fired Big Bend Unit 1 steam turbine into a natural gas-fired combined cycle unit by 2023. The Florida Department of Environmental Protection has determined that a determination of need is not necessary for this conversion. TECO also plans the addition of two natural gas-fired combustion turbine peaking units in 2023 and 2026, and anticipates increasing the amount of planned solar projects over the planning period.

TECO's planned solar projects are consistent with its 600 MW cap, included in its 2017 Stipulation and Settlement Agreement.[17] In TECO's first SoBRA, 144.7 MW were approved.[18] Currently, TECO is petitioning the Commission for approval of 260.3 MW of solar additions as part of its second SoBRA.[19] The solar additions make up approximately 35 percent of TECO's planned future units.

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[17]Order No. PSC-2017-0456-S-EI, issued November 27, 2017, in Docket No. 20170210-EI, *In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company.*

[18]Order No. PSC-2018-0288-FOF-EI, issued July 5, 2018, in Docket No. 20170260-EI, *In re: Petition for limited proceeding to approve first solar base rate adjustment (SoBRA), effective September 1, 2018, by Tampa Electric Company.*

[19]Document No. 04469-2018, filed June 29, 2018, in Docket No. 20180133-EI, *In re: Petition for limited proceeding to approve second solar base rate adjustment (SoBRA), effective January 1, 2019, by Tampa Electric Company.*

**Table 17: TECO Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) | Solar Firm Capacity (Summer) |
|---|---|---|---|---|
| | | | Sum | Sum |
| **Retiring Units** | | | | |
| 2021 | Big Bend 2 | Coal Steam Turbine | 385 | |
| **Total Retirements** | | | **385** | |
| **New Units** | | | | |
| 2018 | Balm Solar | Photovoltaic | 74 | 38 |
| 2018 | Payne Creek Solar | Photovoltaic | 70 | 36 |
| 2019 | Bonnie Mine Solar | Photovoltaic | 35 | 18 |
| 2019 | Grange Hall Solar | Photovoltaic | 61 | 32 |
| 2019 | Lithia Solar | Photovoltaic | 75 | 39 |
| 2019 | Mountain View Solar | Photovoltaic | 55 | 28 |
| 2019 | Peace Creek Solar | Photovoltaic | 57 | 29 |
| 2020 | Alafia Solar | Photovoltaic | 50 | 26 |
| 2020 | Wimauma Solar | Photovoltaic | 75 | 38 |
| 2021 | Big Bend 5 & 6 | Natural Gas Combustion Turbine | 660 | |
| 2021 | Lake Hancock Solar | Photovoltaic | 50 | 26 |
| 2023 | Future CT 1 | Natural Gas Combustion Turbine | 229 | |
| 2026 | Future CT 2 | Natural Gas Combustion Turbine | 229 | |
| **Total New Units** | | | **1,719** | **311** |
| **Percentage of Solar Units Planned of Total New Units** | | | **35%** | |
| **Net Additions** | | | **1,334** | |

Source: 2018 Ten-Year Site Plan

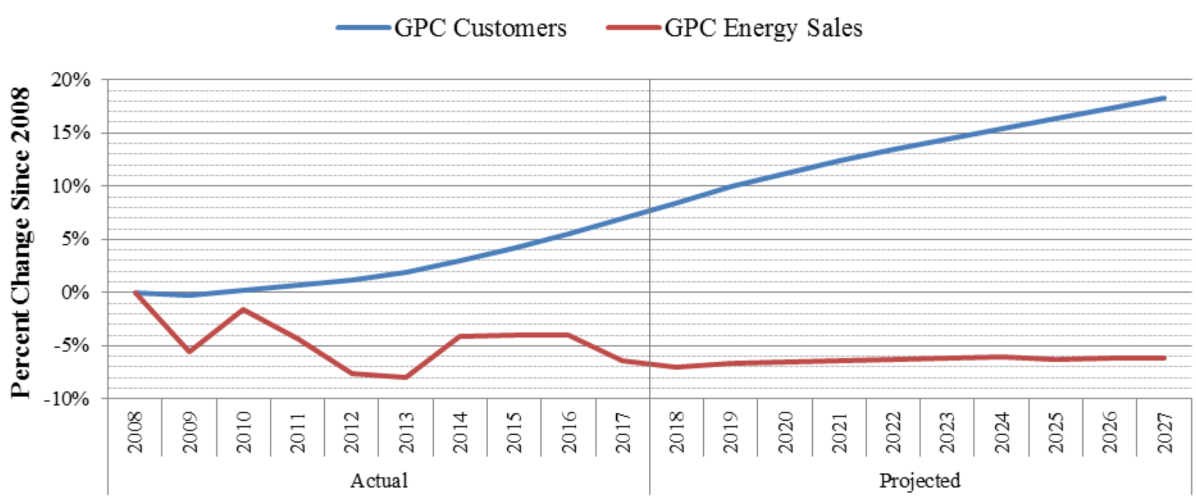
# Gulf Power Company (GPC)

GPC is an investor owned utility, and is Florida's sixth largest electric utility. It represents the smallest of the generating investor-owned utilities, and the only one inside the Southern Company electric system. As GPC plans and operates its system in conjunction with the other Southern Company utilities, not all of the energy generated by GPC is consumed within Florida. NextEra Energy Inc., FPL's parent company, plans to acquire GPC through a purchase, subject to federal approval, expected to close during the first half of 2019. The effects, if any, to future TYSP is unknown at this time. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds GPC's 2018 Ten-Year Site Plan suitable for planning purposes.

## Load & Energy Forecasts

In 2017, GPC had approximately 459,050 customers and annual retail energy sales of 10,809 GWh or approximately 4.8 percent of Florida's annual retail energy sales. Figure 27 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, GPC's customer base has increased by 6.93 percent, while retail sales have declined by 6.36 percent. As illustrated, GPC's retail energy sales are not anticipated to exceed its historic 2008 peak during the planning period.

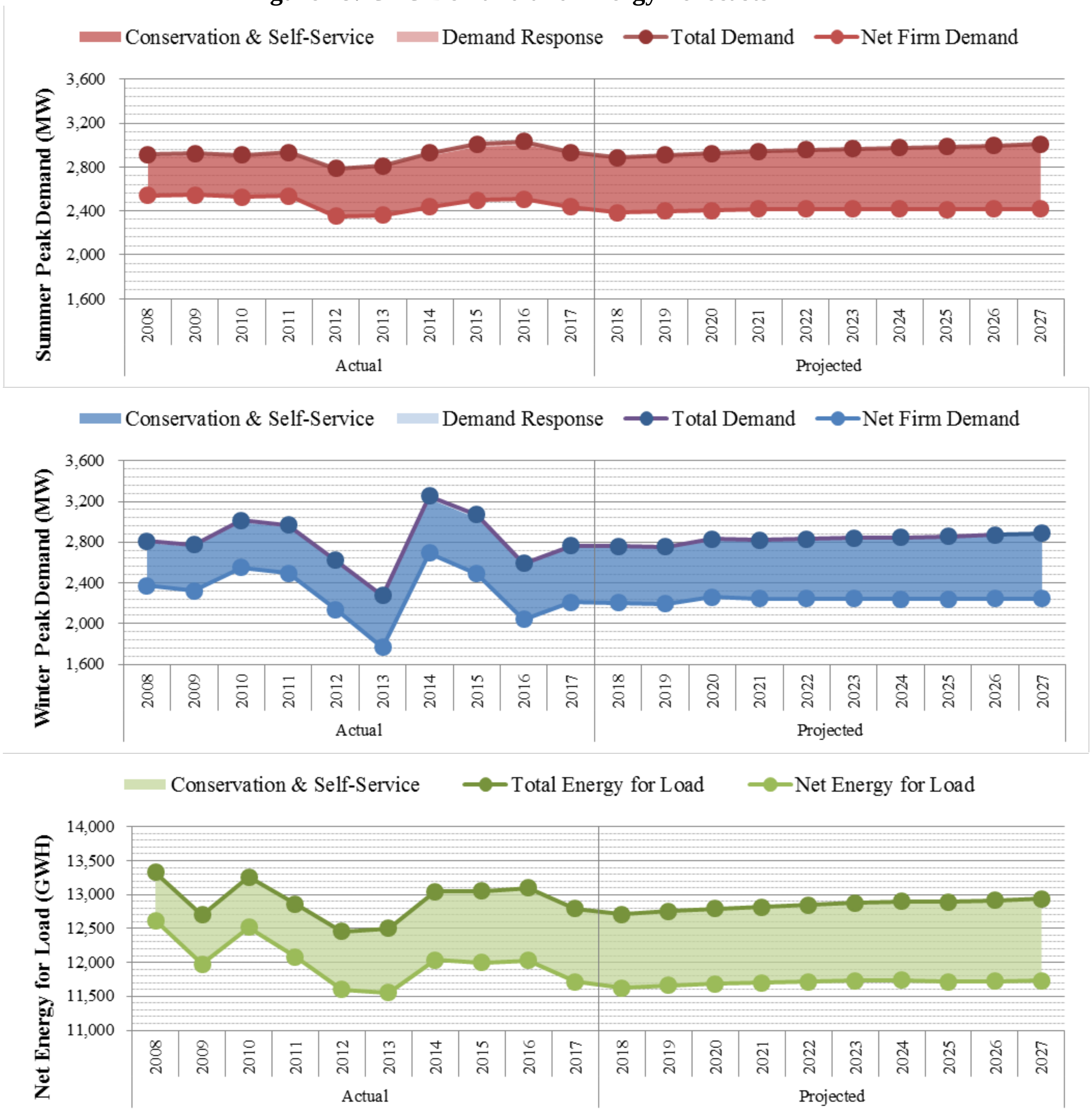
**Figure 27: GPC Growth Rate**




Source: 2018 Ten-Year Site Plan

As an investor-owned utility, GPC is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2018 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014. The three graphs in Figure 28 shows GPC's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. These graphs include the full impact of demand-side management.

**Figure 28: GPC Demand and Energy Forecasts**




Source: 2018 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 18 shows GPC's actual net energy for load by fuel type as of 2017, and the projected fuel mix for 2027. GPC is an energy exporter, producing approximately 31 percent more energy than it requires for native load. While natural gas was the dominant fuel source in 2017, coal was the second most utilized fuel source. By 2027, GPC's 2018 Ten-Year Site Plan projects a decrease in export to Southern Company Services that will be 29.7 percent of native load, with coal representing approximately 53 percent of system energy. GPC projects the second highest percentage of energy consumption from coal in 2027 of the Ten-Year Site Plan utilities.

**Table 18: GPC Energy Consumption by Fuel Type**

| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2017 | | 2027 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 8,983 | **76.6%** | 7,527 | **64.2%** |
| **Coal** | 4,973 | **42.4%** | 6,205 | **52.9%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 0 | **0.0%** | 1 | **0.0%** |
| **Renewable** | 1,214 | **10.4%** | 1,285 | **11.0%** |
| **Interchange** | -3,633 | **-31.0%** | -3,485 | **-29.7%** |
| **NUG & Other** | 188 | **1.6%** | 196 | **1.7%** |
| **Total** | **11,725** | | **11,729** | |

Source: 2018 Ten-Year Site Plan and Data Responses

## Reliability Requirements

As previously noted, GPC is the only Ten-Year Site Plan utility outside of the FRCC region. As part of Southern Company's electric system, GPC plans to maintain a 16.25 percent summer reserve margin beginning in 2021. Figure 29 displays the forecast planning reserve margin for GPC through the planning period for both seasons, including the impact of energy efficiency programs.

As shown in Figure 29, GPC is reporting a near-zero reserve margin for Summer 2023 and a 7.7 percent reserve margin for Winter 2023 through 2024. This is due to the expiration of a purchased power agreement with Shell Energy North America (Shell PPA) for 885 MW of firm capacity in May 2023. GPC currently anticipates replacing a portion of this lost capacity with a 595 MW 1x1 combined cycle unit in June 2024. GPC expects to manage its reserve margin requirements in the interim, between the expiration of the Shell PPA and the in-service date of its anticipated new combined cycle unit, with short-term arrangements that are available through the Intercompany Interchange Contract's reserve sharing mechanism or through capacity purchases from the market. The Intercompany Interchange Contract's reserve sharing mechanism is a benefit afforded to GPC from its association with the Southern electric system. However, while GPC expects that these purchases will serve to meet its reserve margin requirements, it has not included any contributed capacity from the purchases into its reserve margin projections due to their nature as market purchases. The FRCC's reserve margin is projected to be 30 percent in 2023 at the time of summer peak, and is projected to be 47 percent in 2023/24 at the time of winter peak. GPC will provide an update on its reserve margin for the specified timeframe in its next Ten-Year Site Plan. As shown below, GPC's generation needs are typically determined by its summer peak.

**Figure 29: GPC Reserve Margin Forecast**


Source: 2018 Ten-Year Site Plan

## Generation Resources

GPC plans unit retirements and additions during the planning period, as described in Table 19. Three natural gas-fired combustion turbines will be retired during the planning period. GPC has also indicated that the coal-fired units Crist 4 & 5 are tentatively scheduled for retirement in 2024 and 2026, respectively. GPC has indicated these retirement dates borrow from end-of-life depreciation calculations and do not represent results from an operational evaluation of the units.

Based on its 2018 Ten-Year Site Plan, GPC plans to add a natural gas-fired combined cycle unit in 2024, after the expiration of a purchased power agreement. The planned combined cycle addition will require a determination of need from the Commission.

**Table 19: GPC Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum |
|---|---|---|---|
| **Retiring Units** | | | |
| 2024 | Crist 4 | Coal Fossil Steam Turbine | 75 |
| 2025 | Pea Ridge 1 - 3 | Natural Gas Combustion Turbine | 12 |
| 2026 | Crist 5 | Coal Fossil Steam Turbine | 75 |
| **Total Retirements** | | | **162** |
| **New Units** | | | |
| 2024 | Combined Cycle 2 | Natural Gas Combined Cycle | 595 |
| **Total New Units** | | | **595** |
| **Net Additions** | | | **433** |

Source: 2018 Ten-Year Site Plan

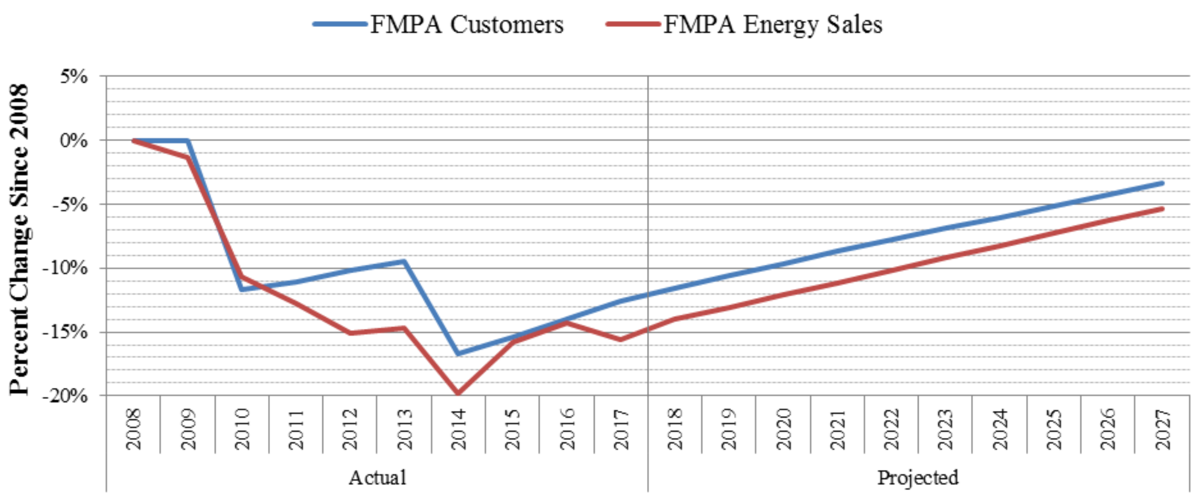
# Florida Municipal Power Agency (FMPA)

FMPA is a governmental wholesale power company owned by several Florida municipal utilities throughout Florida. Collectively, FMPA is Florida's eighth largest electric utility and third largest municipal electric utility. While FMPA has 31 member systems, only those members who are participants of the All-Requirements Power Supply Project (ARP) are addressed in the Utility's Ten-Year Site Plan. FMPA is responsible for planning activities associated with ARP member systems. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds FMPA's 2018 Ten-Year Site Plan suitable for planning purposes.

### Load & Energy Forecasts

In 2017, FMPA had approximately 257,698 customers and annual retail energy sales of 5,629 GWh or approximately 2.5 percent of Florida's annual retail energy sales. Figure 30 illustrates the Utility's historic and forecast number of customers and retail energy sales in terms of percentage growth from 2008. Over the last 10 years, FMPA's customer base has decreased by 12.59 percent, while retail sales have decreased by 15.66 percent. As illustrated, FMPA's retail energy sales are not anticipated to exceed its historic 2008 peak during the planning period. The reduction in sales is associated with several ARP member systems modifying their contractual agreements with FMPA, such that FMPA no longer provides for the system's capacity and energy needs. Those member systems modifying agreements include the City of Vero Beach in 2010, the City of Lake Worth in 2014, the City of Fort Meade in 2015, and the City of Green Cove Springs in 2019.

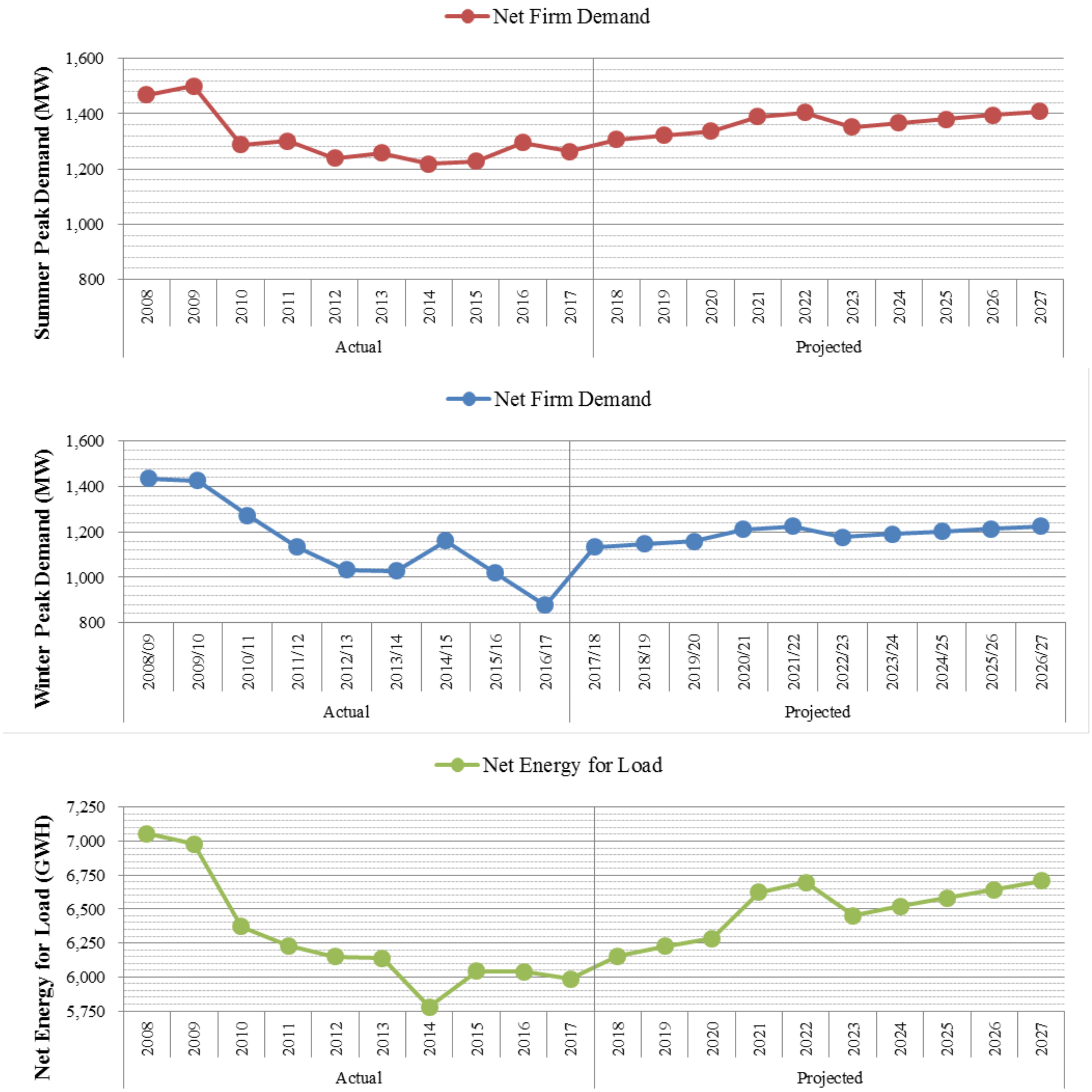
**Figure 30: FMPA Growth Rate**




Source: 2018 Ten-Year Site Plan

The three graphs in Figure 31 show FMPA's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer demand-side management programs, the impacts of which are included in the graphs.

**Figure 31: FMPA Demand and Energy Forecasts**




Source: 2018 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 20 shows FMPA's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects a decrease in energy generation from coal in 2027, but approximately 93 percent of energy would still be sourced from natural gas and nuclear.

**Table 20: FMPA Energy Consumption by Fuel Type**

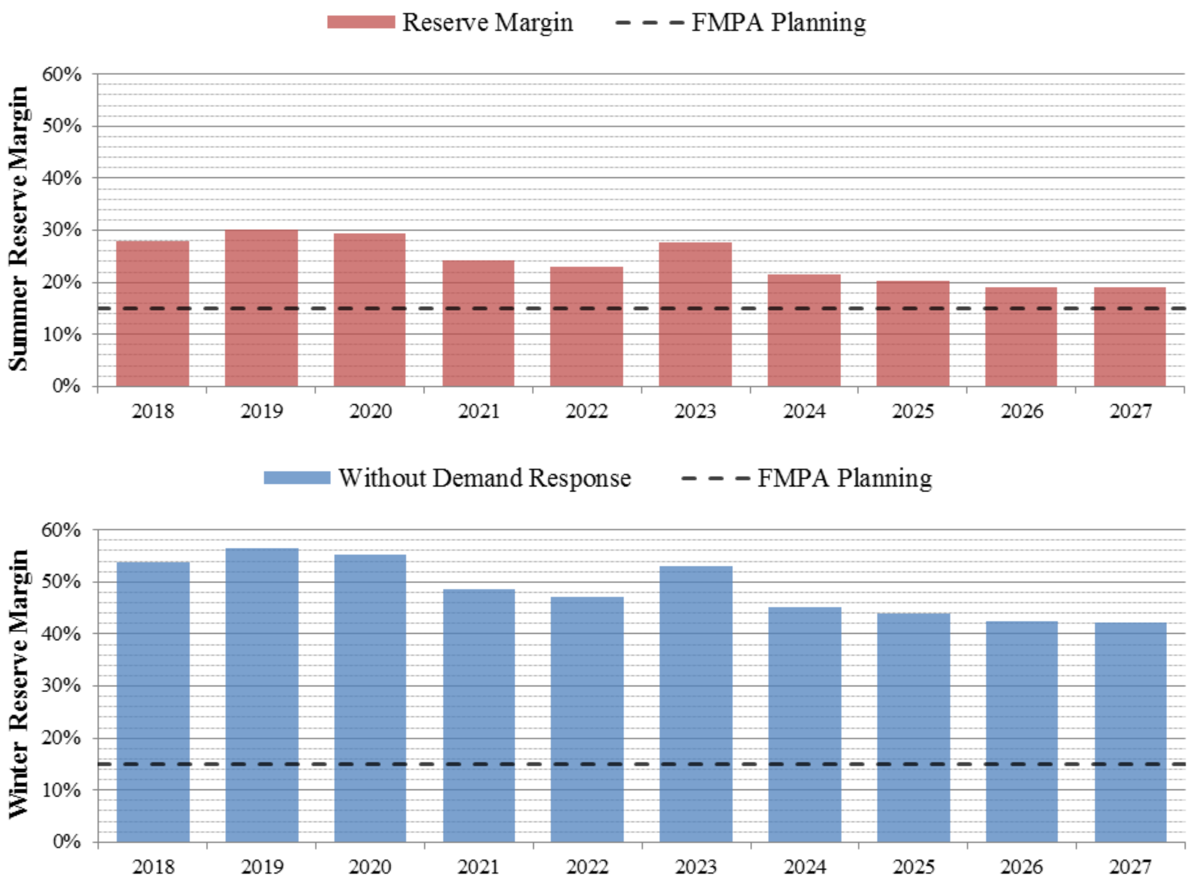
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2017 | | 2027 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 4,741 | **79.2%** | 5,828 | **86.9%** |
| **Coal** | 915 | **15.3%** | 472 | **7.0%** |
| **Nuclear** | 294 | **4.9%** | 376 | **5.6%** |
| **Oil** | 1 | **0.0%** | 1 | **0.0%** |
| **Renewable** | 33 | **0.6%** | 32 | **0.5%** |
| **Interchange** | 0 | **0.0%** | 0 | **0.0%** |
| **NUG & Other** | 0 | **0.0%** | 0 | **0.0%** |
| **Total** | **5,984** | | **6,708** | |

Source: 2018 Ten-Year Site Plan and Data Responses

## Reliability Requirements

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

**Figure 32: FMPA Reserve Margin Forecast**




Source: 2018 Ten-Year Site Plan

## Generation Resources

FMPA plans no unit additions or retirements during the planning period. However, as discussed above, several ARP member systems have elected to modify their contractual agreements with FMPA, such that FMPA no longer utilizes the member system's generation resources.

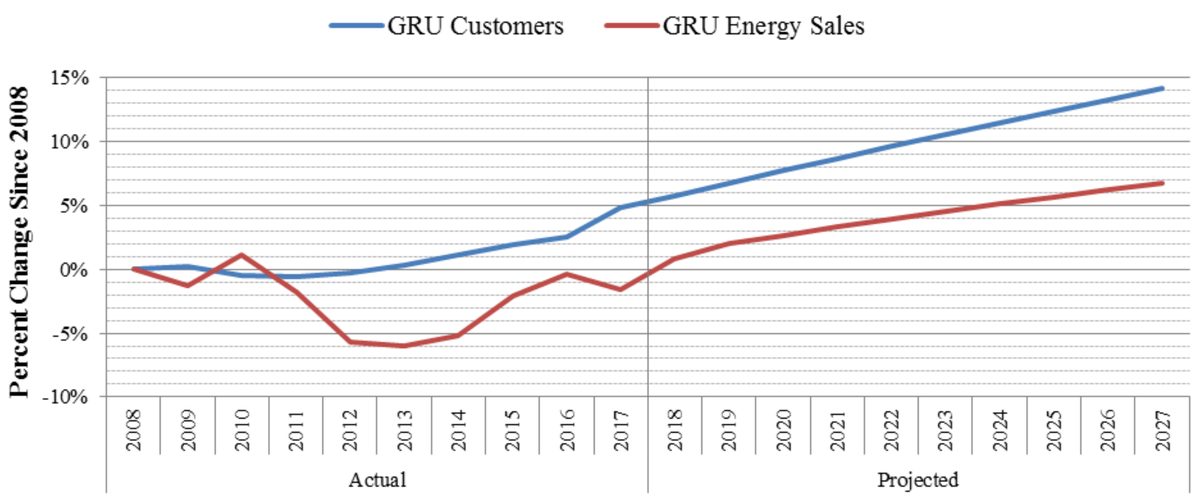
# Gainesville Regional Utilities (GRU)

GRU is a municipal utility and the smallest electric utility required to file a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and consists of the City of Gainesville and its surrounding area. GRU also provides wholesale power to the City of Alachua and Clay Electric Cooperative. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds GRU's 2018 Ten-Year Site Plan suitable for planning purposes.

## Load & Energy Forecasts

In 2017, GRU had approximately 97,245 customers and annual retail energy sales of 1,774 GWh or approximately 0.8 percent of Florida's annual retail energy sales. Figure 33 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, GRU's customer base has increased by 4.8 percent, while retail sales have decreased by 1.61 percent. As illustrated, GRU's retail energy sales are anticipated to exceed its historic 2010 peak in 2019.

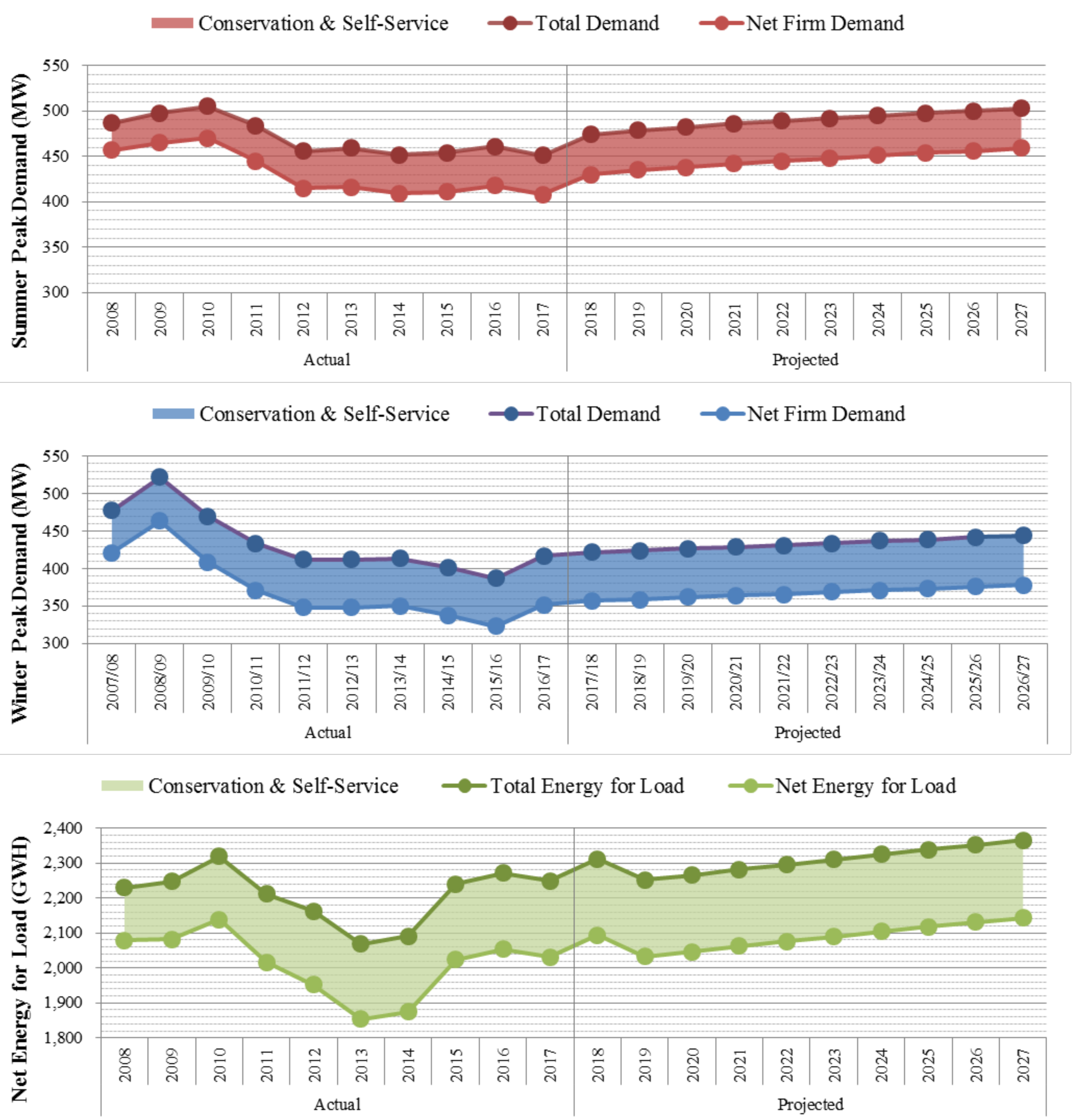
**Figure 33: GRU Growth Rate**




Source: 2018 Ten-Year Site Plan

The three graphs in Figure 34 show GRU's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 35 include the impact of these demand-side management programs.

**Figure 34: GRU Demand and Energy Forecasts**




Source: 2018 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 21 shows GRU's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. In 2014, coal was approximately two times natural gas in terms of contribution to net energy for load, with the remaining energy split between renewable generation and non-utility generators. In 2015, natural gas became GRU's primary fuel source which has continued into 2017. By 2027, GRU projects an increase in natural gas, approximately an increase from 25 percent to 33 percent in coal, and an approximate decrease from 18 percent to 15 percent in renewable energy.

**Table 21: GRU Energy Consumption by Fuel Type**

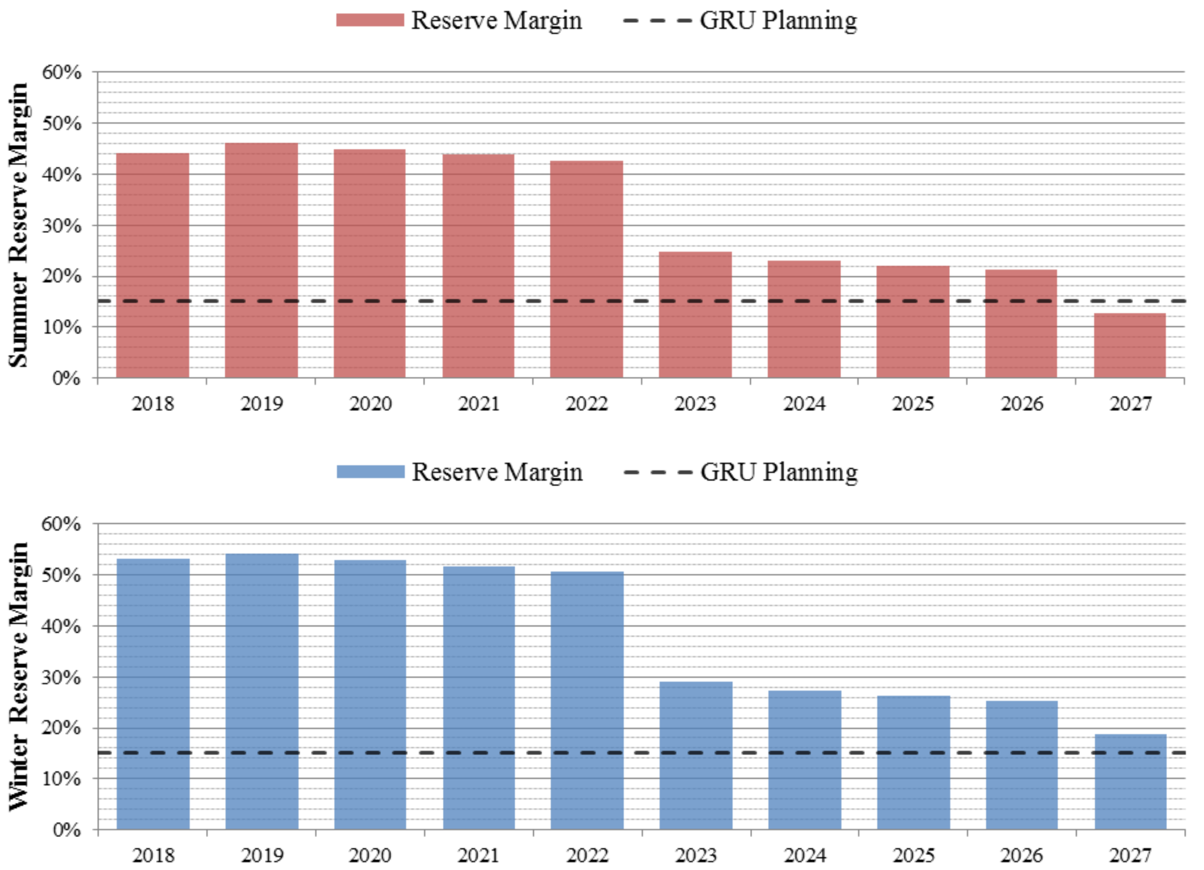
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2017 | | 2027 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 800 | **39.4%** | 980 | **45.7%** |
| **Coal** | 501 | **24.7%** | 696 | **32.5%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 2 | **0.1%** | 0 | **0.0%** |
| **Renewable** | 373 | **18.4%** | 315 | **14.7%** |
| **Interchange** | 0 | **0.0%** | 0 | **0.0%** |
| **NUG & Other** | 355 | **17.5%** | 153 | **7.1%** |
| **Total** | **2,031** | | **2,144** | |

Source: 2018 Ten-Year Site Plan and Data Responses

## Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 35 displays the forecast planning reserve margin for GRU through the planning period for both seasons, including the impacts of demand-side management. As shown in the figure, GRU's generation needs are controlled by its summer peak throughout the planning period. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, GRU's largest single unit, Deerhaven 2, a coal-fired steam unit, represented 36.4 percent of summer net firm peak demand in 2017, almost the entirety of the Utility's reserve margin.

**Figure 35: GRU Reserve Margin Forecast**




Source: 2018 Ten-Year Site Plan

## Generation Resources

GRU currently plans to retire a natural gas-fired steam unit in 2022, and a two natural gas-fired combustion turbines in 2026, as described in Table 22. As a smaller utility, single units can have a large impact upon reserve margin.

**Table 22: GRU Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum |
|---|---|---|---|
| **Retiring Units** | | | |
| 2022 | Deerhaven FS01 | Natural Gas Steam Turbine | 75 |
| 2026 | Deerhaven GT01 & GT02 | Natural Gas Combustion Turbine | 35 |
| **Total Retirements** | | | **110** |
| **Net Additions** | | | **(110)** |

Source: 2018 Ten-Year Site Plan

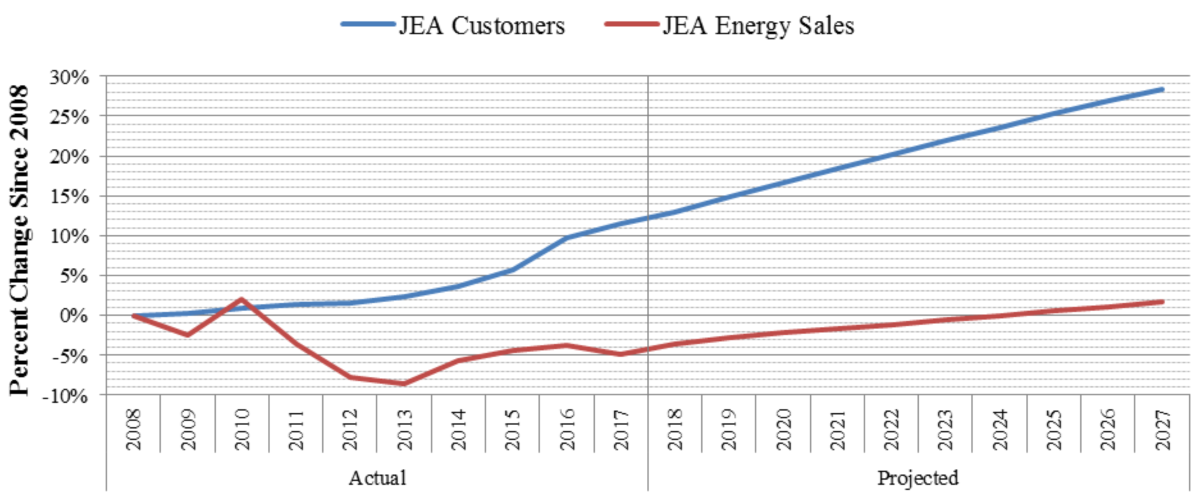
# JEA

JEA, formerly known as Jacksonville Electric Authority, is Florida's largest municipal utility and fifth largest electric utility. JEA's service territory is within the FRCC region, and includes all of Duval County as well as portions of Clay and St. Johns Counties. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds JEA's 2018 Ten-Year Site Plan suitable for planning purposes.

## Load & Energy Forecasts

In 2017, JEA had approximately 456,981 customers and annual retail energy sales of 11,805 GWh or approximately 5.2 percent of Florida's annual retail energy sales. Figure 36 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, JEA's customer base has increased by 11.44 percent, while retail sales have declined by 4.9 percent. As illustrated, JEA's retail energy sales are not anticipated to exceed its historic 2010 peak during the planning period.

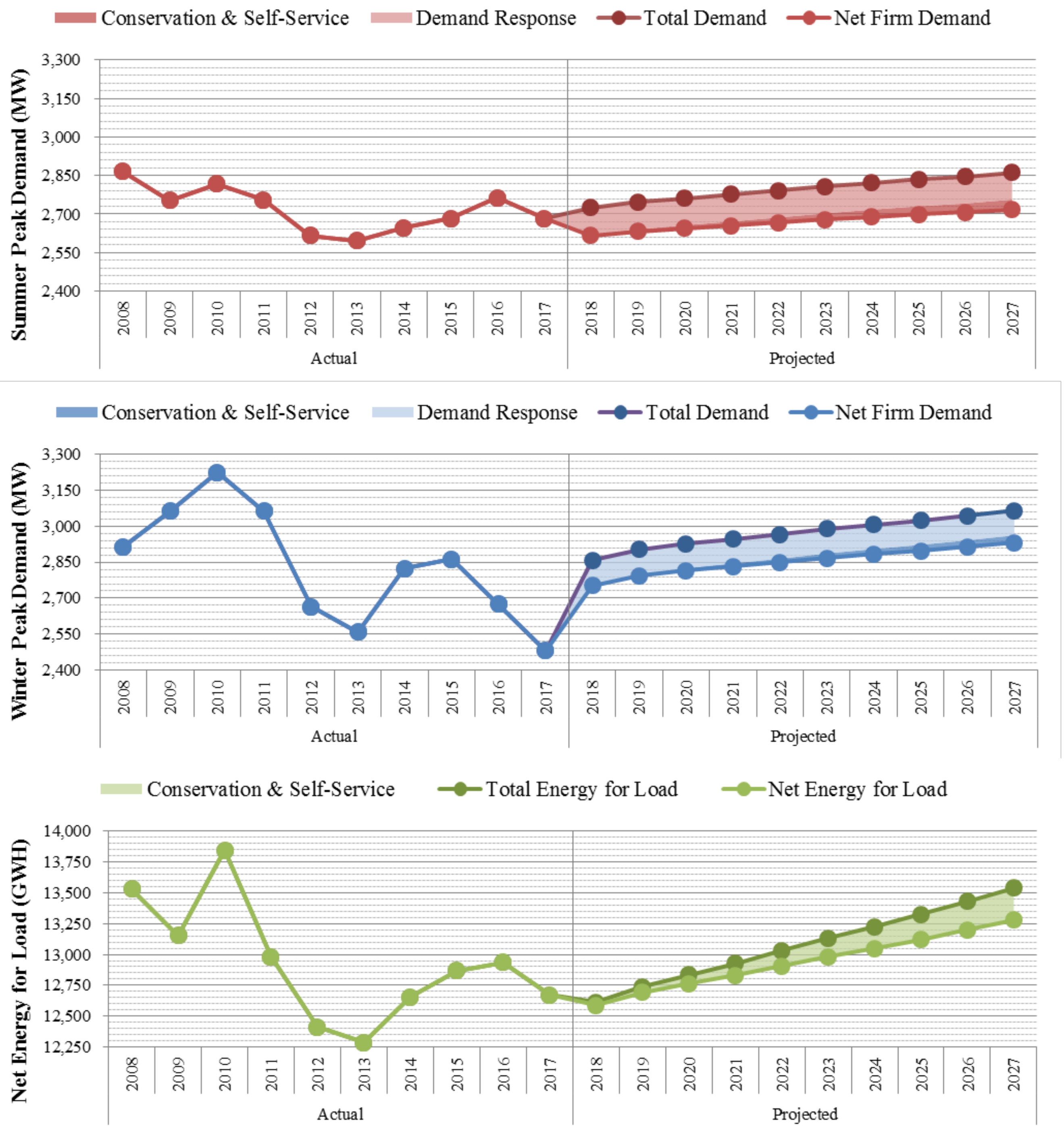
**Figure 36: JEA Growth Rate**




Source: 2018 Ten-Year Site Plan

The three graphs in Figure 37 show JEA's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. These graphs include the full impact of demand-side management, and assume that all available demand response resources were or will be activated during the seasonal peak.

**Figure 37: JEA Demand and Energy Forecasts**




Source: 2018 Ten-Year Site Plan and Data Responses

While a municipal utility, JEA is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2018 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

## Fuel Diversity

Table 23 shows JEA's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. While natural gas was the dominant fuel source in 2017, coal was JEA's second most utilized fuel source. JEA's 2018 Ten-Year Site plan projects a majority of its net energy for load will continue to come from natural gas and coal in 2027. JEA projects the third highest percentage of energy consumption from coal in 2027 of the Ten-Year Site Plan utilities.

**Table 23: JEA Energy Consumption by Fuel Type**

| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2017 | | 2027 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 5,697 | **45.0%** | 6,471 | **48.7%** |
| **Coal** | 5,416 | **42.7%** | 5,115 | **38.5%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 1 | **0.0%** | 5 | **0.0%** |
| **Renewable** | 111 | **0.9%** | 79 | **0.6%** |
| **Interchange** | 1,447 | **11.4%** | 1,611 | **12.1%** |
| **NUG & Other** | 0 | **0.0%** | 0 | **0.0%** |
| **Total** | **12,672** | | **13,281** | |

Source: 2018 Ten-Year Site Plan and Data Responses

## Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 38 displays the forecast planning reserve margin for JEA through the planning period for both seasons, with and without the use of demand response. As shown in the figure, JEA's generation needs are controlled by its summer peak throughout the planning period.

**Figure 38: JEA Reserve Margin Forecast**


Source: 2018 Ten-Year Site Plan

## Generation Resources

JEA plans to retire two units during the planning period, as described in Table 24. As discussed in FPL's section, the coal-fired steam SJRPP Units 1 & 2 are set to retire in 2018, based on the Utility's Ten-Year Site Plan.

**Table 24: JEA Generation Resource Changes**

| Year | Unit Name | Fuel & Unit Type | Net Capacity (MW) Sum |
|---|---|---|---|
| **Retiring Units** | | | |
| 2018 | SJRPP 1 & 2 | Coal Steam Turbine | 1,002 |
| **Total Retirements** | | | 1,002 |
| **Net Additions** | | | **(1,002)** |

Source: 2018 Ten-Year Site Plan

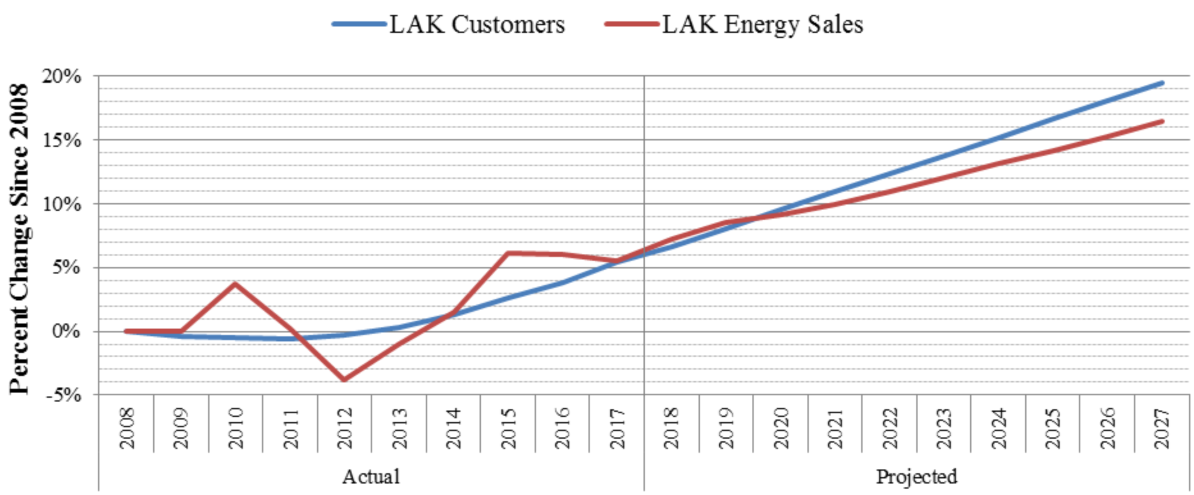
# Lakeland Electric (LAK)

LAK is a municipal utility and the state's third smallest electric utility required to file a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and consists of the City of Lakeland and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds LAK's 2018 Ten-Year Site Plan suitable for planning purposes.

### Load & Energy Forecasts

In 2017, LAK had approximately 129,113 customers and annual retail energy sales of 3,018 GWh or approximately 1.3 percent of Florida's annual retail energy sales. Figure 39 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, LAK's customer base has increased by 5.46 percent, while retail sales have grown by 5.56 percent. As illustrated, LAK's retail energy sales are anticipated to exceed its historic 2015 peak in 2018.

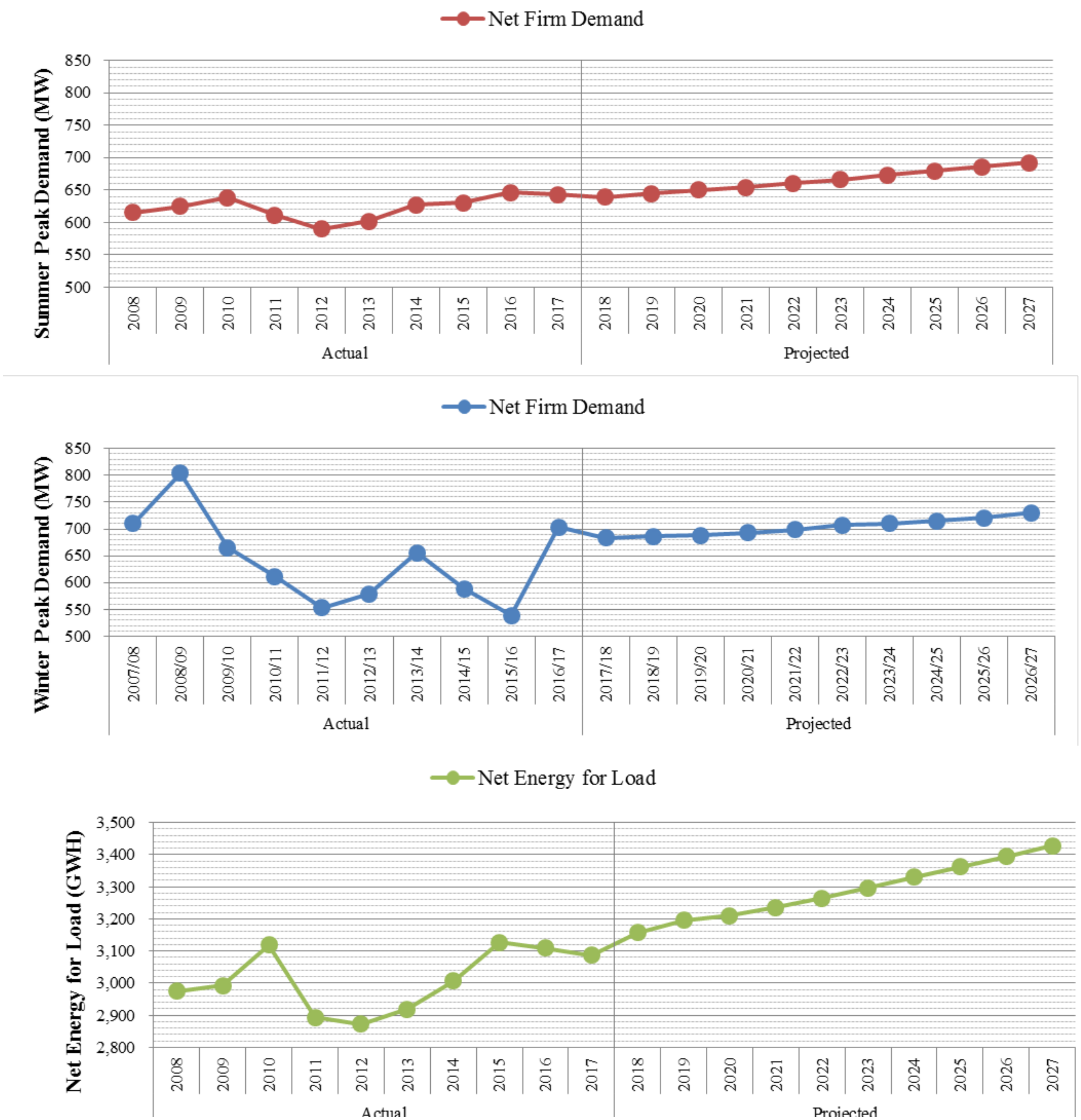
**Figure 39: LAK Growth Rate**




Source: 2018 Ten-Year Site Plan

The three graphs in Figure 40 show LAK's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. LAK offers energy efficiency programs, the impacts of which are included in the graphs.

**Figure 40: LAK Demand and Energy Forecasts**




Source: 2018 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 25 shows LAK's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. LAK uses natural gas as its primary fuel type for energy, with coal representing about 27 percent net energy for load. While natural gas usage is anticipated to increase as a percent of net energy for load, coal is projected to decrease by 2027.

**Table 25: LAK Energy Consumption by Fuel Type**

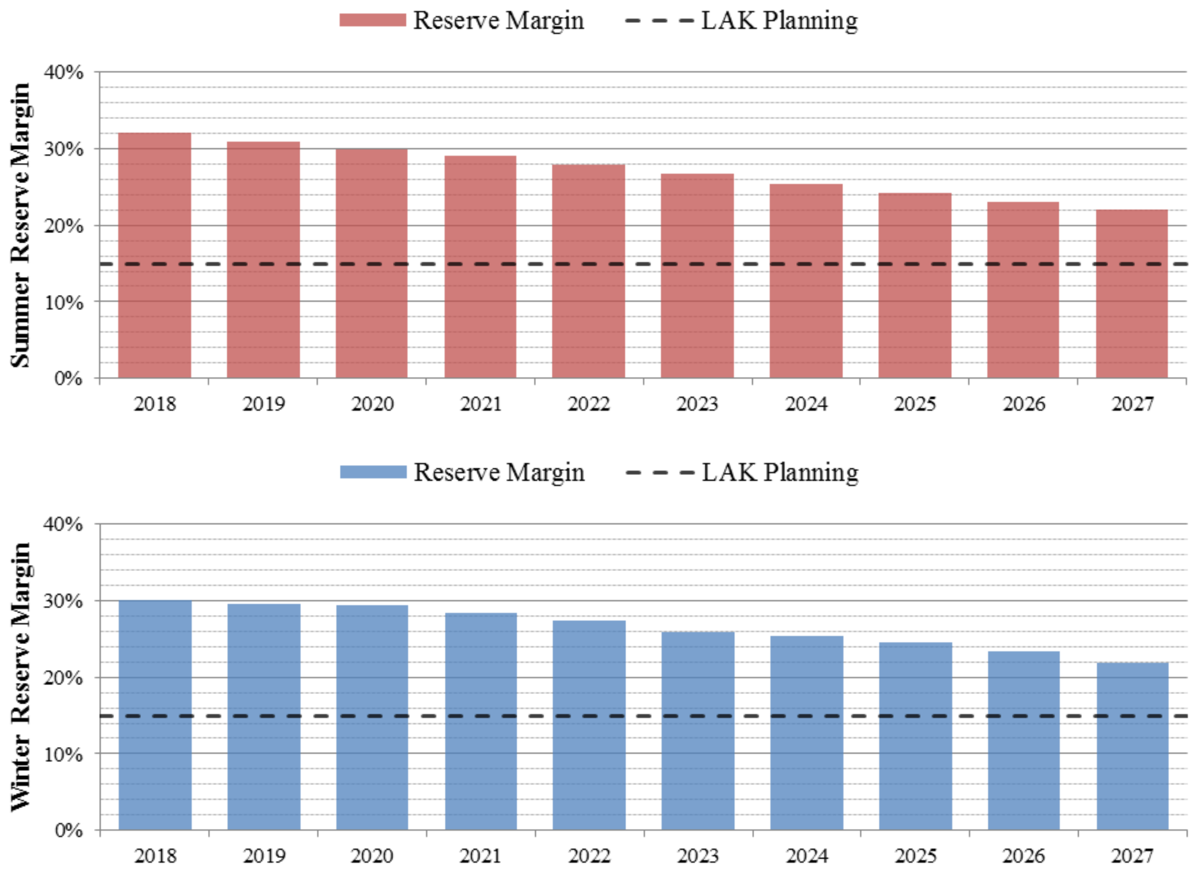
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2017 | | 2027 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 1,589 | **51.5%** | 2,667 | **77.8%** |
| **Coal** | 846 | **27.4%** | 474 | **13.8%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 0 | **0.0%** | 1 | **0.0%** |
| **Renewable** | 27 | **0.9%** | 37 | **1.1%** |
| **Interchange** | 0 | **0.0%** | 0 | **0.0%** |
| **NUG & Other** | 624 | **20.2%** | 248 | **7.2%** |
| **Total** | **3,086** | | **3,427** | |

Source: 2018 Ten-Year Site Plan and Data Responses

## Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 41 displays the forecast planning reserve margin for LAK through the planning period for both seasons, including the impacts of demand-side management. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, LAK's largest single unit, McIntosh 5, a natural gas-fired combined cycle unit, represents 25.2 percent of winter net firm peak demand in 2017, in excess of the Utility's reserve margin.

**Figure 41: LAK Reserve Margin Forecast**




Source: 2018 Ten-Year Site Plan

## Generation Resources

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

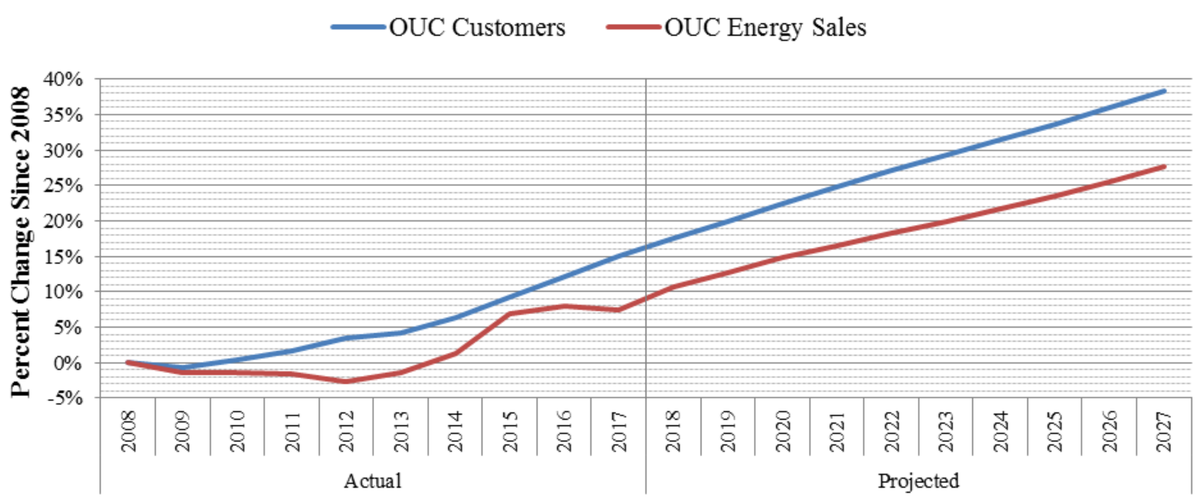
# Orlando Utilities Commission (OUC)

OUC is a municipal utility and Florida's seventh largest electric utility and second largest municipal utility. The Utility's service territory is within the FRCC region and primarily consists of the Orlando metropolitan area. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds OUC's 2018 Ten-Year Site Plan suitable for planning purposes.

## Load & Energy Forecasts

In 2017, OUC had approximately 237,121 customers and annual retail energy sales of 6,568 GWh or approximately 2.9 percent of Florida's annual retail energy sales. Figure 42 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, OUC's customer base has increased by 15 percent, while retail sales have grown by 7.41 percent. As illustrated, OUC's retail energy sales are anticipated to exceed its historic 2016 peak in 2018.

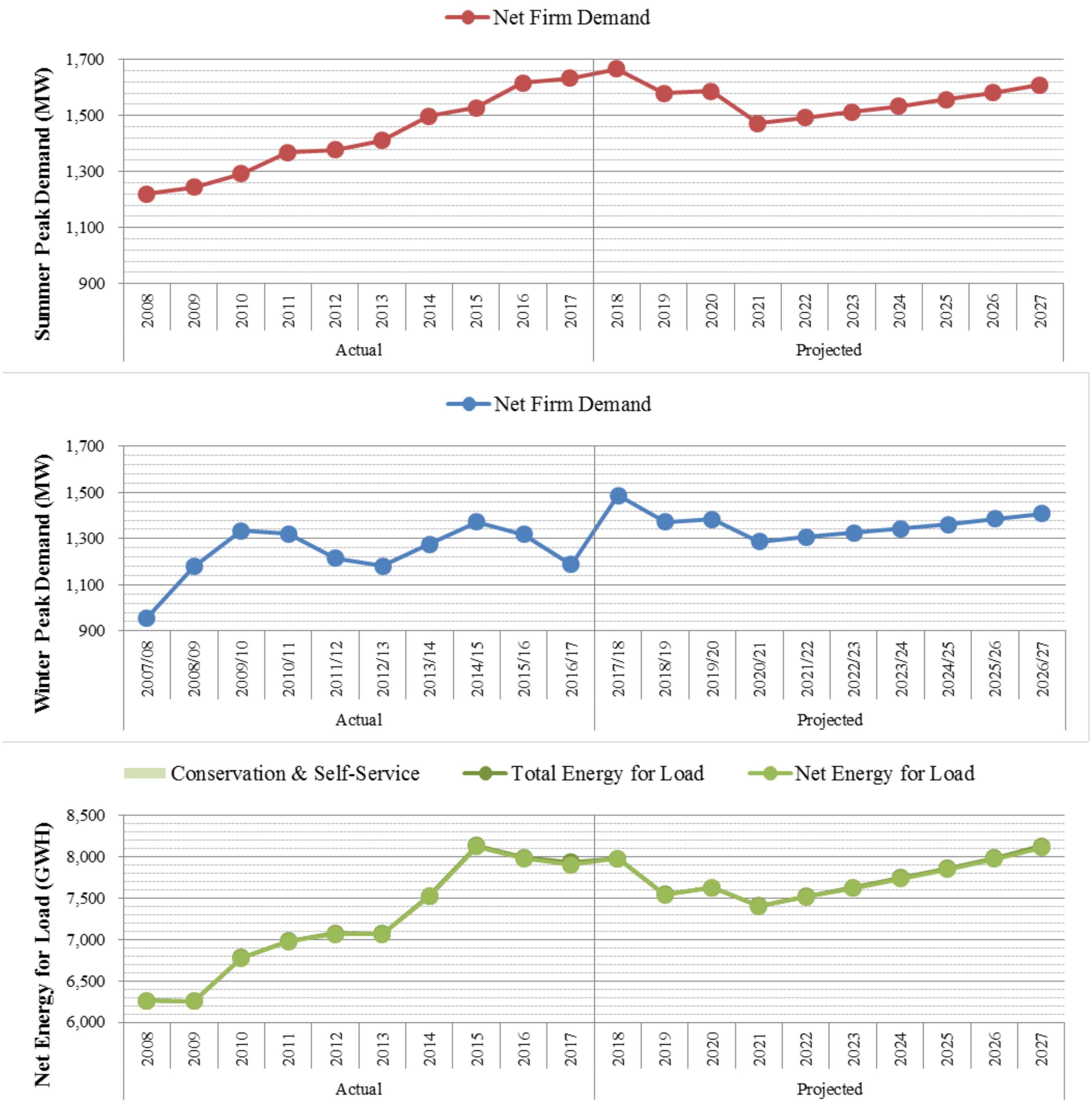
**Figure 42: OUC Growth Rate**




Source: 2018 Ten-Year Site Plan

The three graphs in Figure 43 show OUC's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. These graphs include the impact of the Utility's demand side management programs. While a municipal utility, OUC is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption.

**Figure 43: OUC Demand and Energy Forecasts**




Source: 2018 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 26 shows OUC's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. In 2017, OUC primarily used coal as fuel to meet its net energy for load at approximately 50 percent, with natural gas as the second most used fuel at approximately 42 percent. OUC projects an increase in the quantity of energy consumed from coal by 2027. Natural gas usage is planned to decrease to about 24 percent by 2027. Based upon this projection, OUC, as a percent of net energy for load, would be the largest user of coal of the Ten-Year Site Plan Utilities by 2027.

**Table 26: OUC Energy Consumption by Fuel Type**

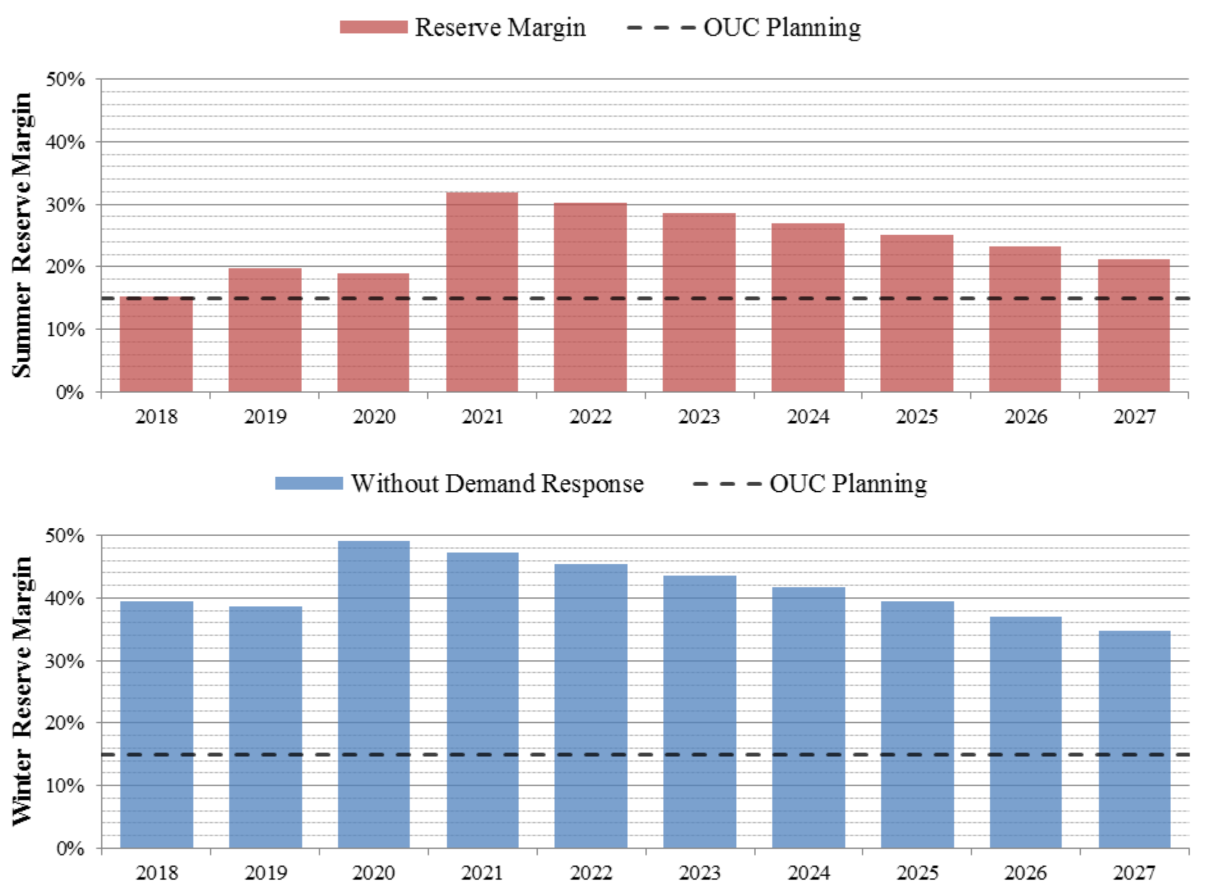
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2017 | | 2027 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 3,326 | **42.1%** | 1,944 | **24.0%** |
| **Coal** | 3,955 | **50.1%** | 4,920 | **60.6%** |
| **Nuclear** | 467 | **5.9%** | 560 | **6.9%** |
| **Oil** | 0 | **0.0%** | 0 | **0.0%** |
| **Renewable** | 154 | **1.9%** | 689 | **8.5%** |
| **Interchange** | 0 | **0.0%** | 0 | **0.0%** |
| **NUG & Other** | 0 | **0.0%** | 0 | **0.0%** |
| **Total** | **7,902** | | **8,113** | |

Source: 2018 Ten-Year Site Plan and Data Responses

## Reliability Requirements

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

**Figure 44: OUC Reserve Margin Forecast**




Source: 2018 Ten-Year Site Plan

## Generation Resources

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

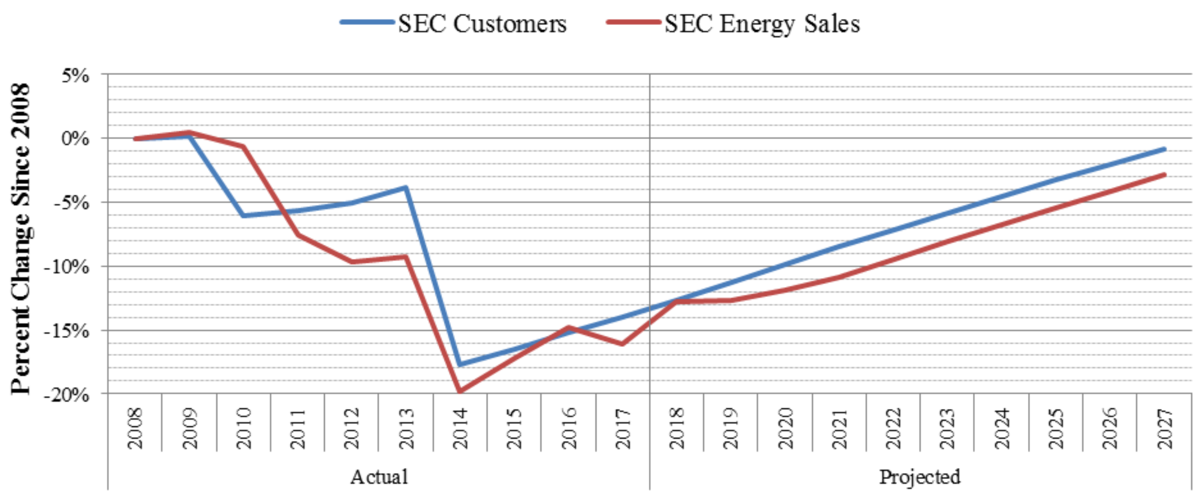
# Seminole Electric Cooperative (SEC)

SEC is a generation and transmission rural electric cooperative that serves its member cooperatives, and is collectively Florida's fourth largest utility. SEC's generation and member cooperatives are within the FRCC region, with member cooperatives located in central and north Florida. As a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds SEC's 2018 Ten-Year Site Plan suitable for planning purposes.

### Load & Energy Forecasts

In 2017, SEC had approximately 774,337 customers and annual retail energy sales of 13,563 GWh or approximately 6 percent of Florida's annual retail energy sales. Figure 45 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, SEC's customer base has decreased by 13.97 percent, and retail sales have decreased 16.08 percent. As illustrated, SEC's retail energy sales are not anticipated to exceed its historic 2009 peak during this planning period. The decline shown in 2014 is associated with one member cooperative, Lee County Electric Cooperative, electing to end its membership with SEC.

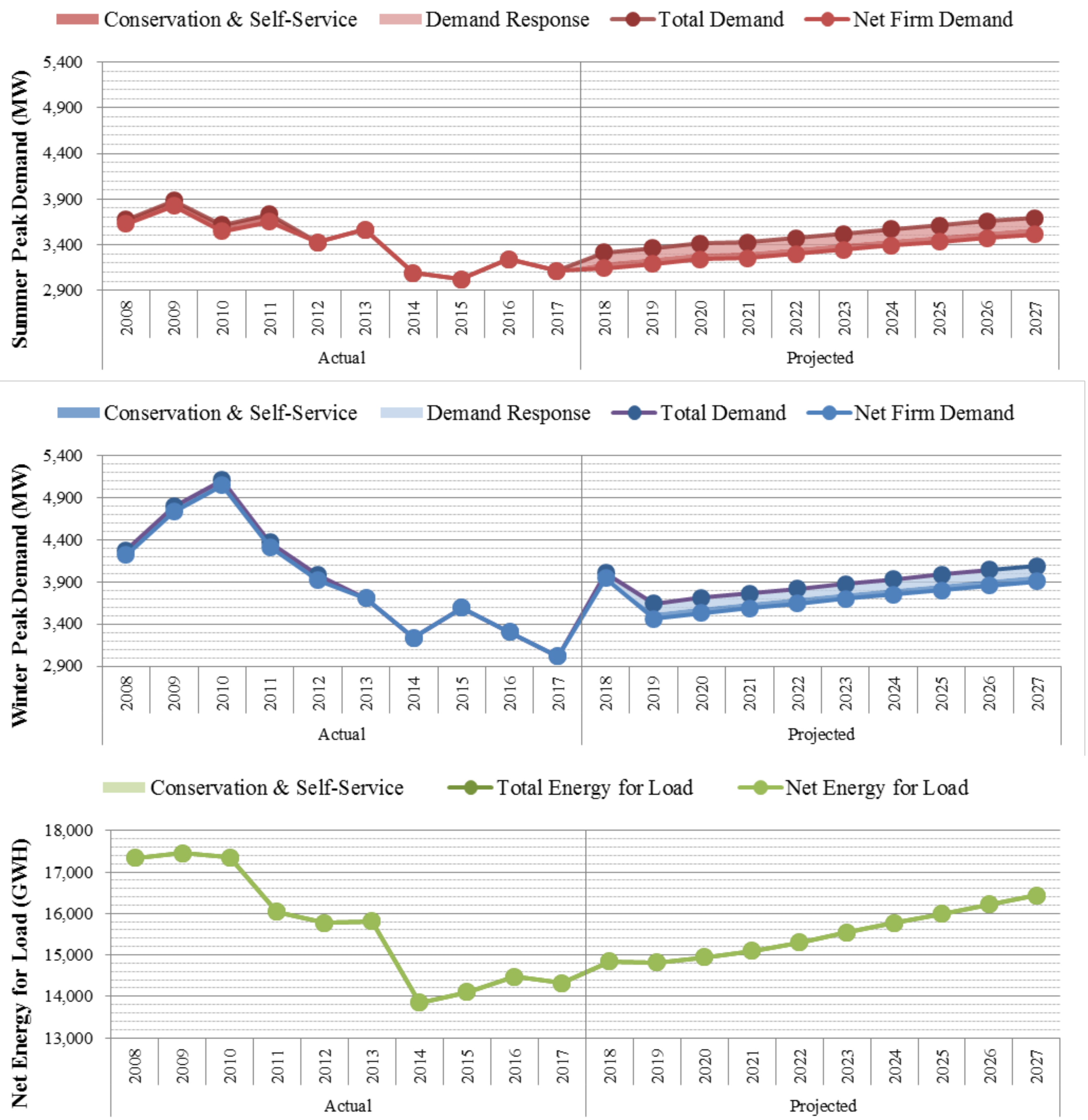
**Figure 45: SEC Growth Rate**




Source: 2018 Ten-Year Site Plan

The three graphs in Figure 46 show SEC's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. As SEC is a generation and transmission company, it does not directly engage in energy efficiency or demand response programs. Member cooperatives do offer demand-side management programs, the impacts of which are included in Figure 47.

**Figure 46: SEC Demand and Energy Forecasts**




Source: 2018 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 27 shows SEC's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. In 2017, SEC used a combination of coal and natural gas to meet its member cooperatives' net energy for load, with coal use exceeding all other combined sources. By 2027, SEC projects this to reverse, with natural gas usage higher than coal.

**Table 27: SEC Energy Consumption by Fuel Type**

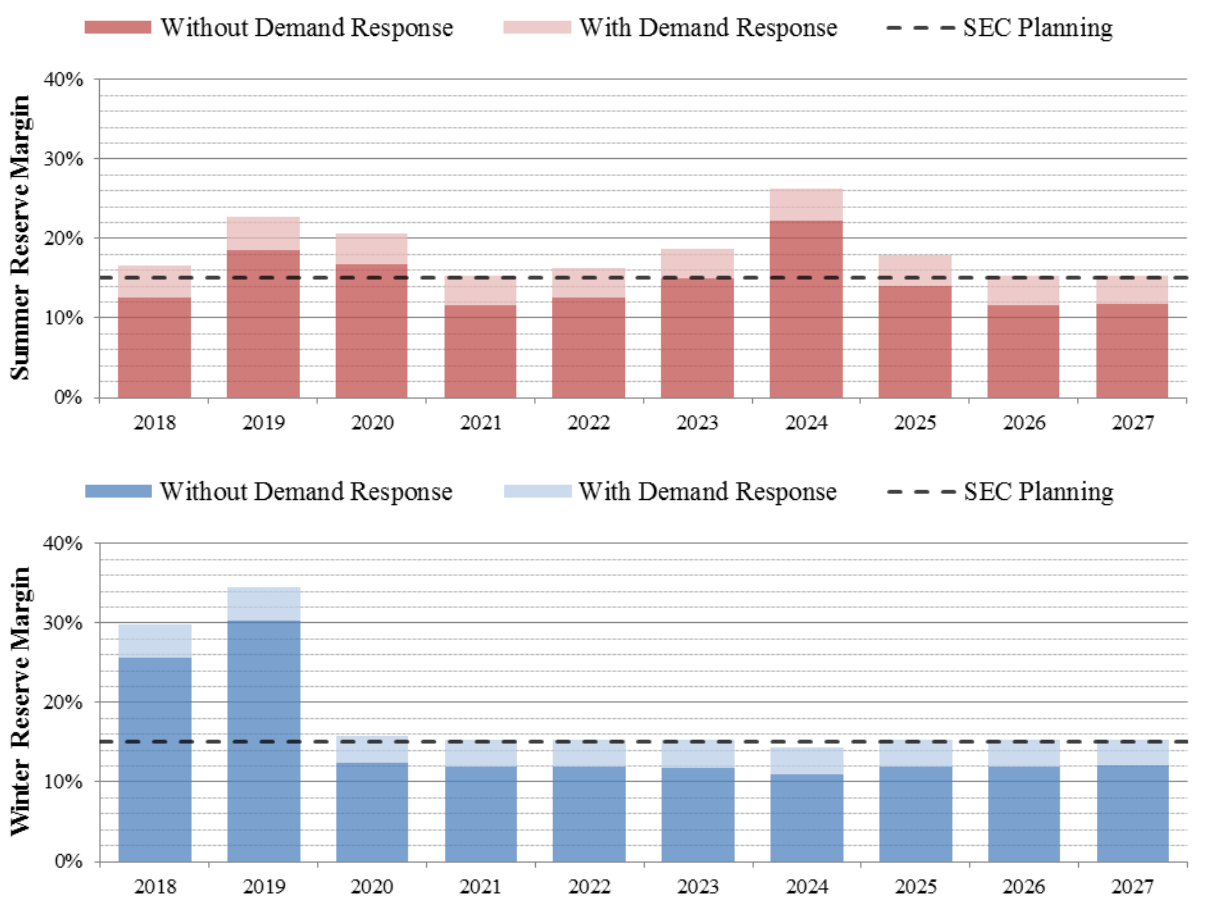
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2017 | | 2027 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 3,299 | **23.0%** | 9,863 | **60.0%** |
| **Coal** | 7,508 | **52.4%** | 3,040 | **18.5%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 17 | **0.1%** | 8 | **0.0%** |
| **Renewable** | 581 | **4.1%** | 113 | **0.7%** |
| **Interchange** | 0 | **0.0%** | 0 | **0.0%** |
| **NUG & Other** | 2,920 | **20.4%** | 3,413 | **20.8%** |
| **Total** | **14,325** | | **16,437** | |

Source: 2018 Ten-Year Site Plan and Data Responses

## Reliability Requirements

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

**Figure 47: SEC Reserve Margin Forecast**




Source: 2018 Ten-Year Site Plan

### Generation Resources

SEC plans to retire one unit and add one unit during the planning period, as described in Table 28. On December 21, 2017, SEC filed a need determination with the Commission for the Seminole CC Facility which was granted on May 25, 2018.[20] Consistent with its need determination filing, SEC plans to retire one of its coal-fired SGS units in 2023, and the Seminole CC Facility is expected to be in-service by 2022. However, this need determination is currently under appeal.

**Table 28: SEC Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum | Notes |
|---|---|---|---|---|
| **Retiring Units** | | | | |
| 2023 | SGS Unit | Coal Steam Turbine | 630 | |
| **Total Retirements** | | | **630** | |
| **New Units** | | | | |
| 2022 | Seminole CC Facility | Natural Gas Combined Cycle | 1,108 | Docket No. 20170266-EC |
| **Total New Units** | | | **1,108** | |
| **Net Additions** | | | **478** | |

Source: 2018 Ten-Year Site Plan

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

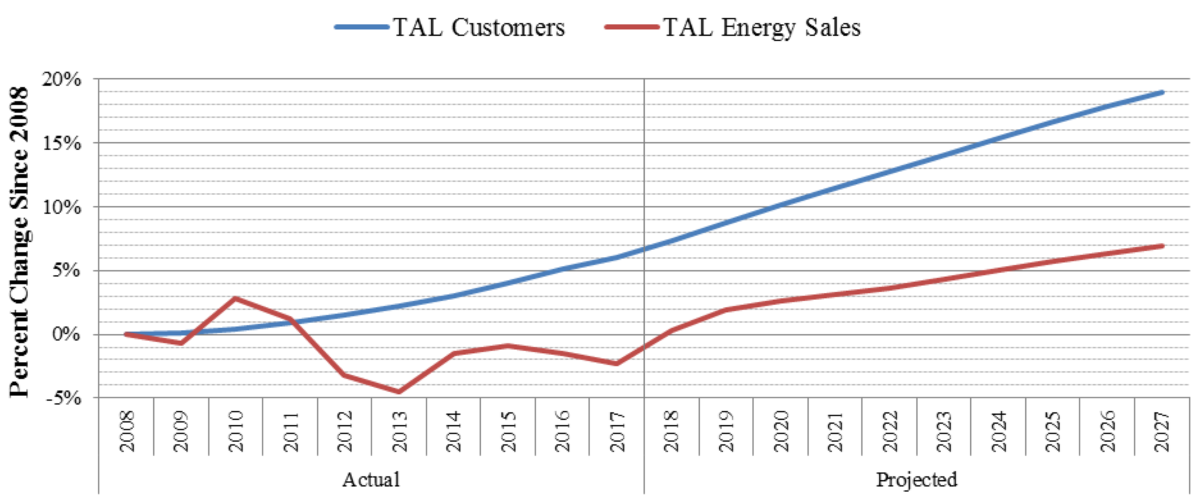
# City of Tallahassee Utilities (TAL)

TAL is a municipal utility and the second smallest electric utility which files a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and primarily consists of the City of Tallahassee and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds TAL's 2018 Ten-Year Site Plan suitable for planning purposes.

## Load & Energy Forecasts

In 2017, TAL had approximately 120,051 customers and annual retail energy sales of 2,617 GWh or approximately 1.2 percent of Florida's annual retail energy sales. Figure 48 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2008. Over the last 10 years, TAL's customer base has increased by 6.02 percent, while retail sales have declined by 2.31 percent. As illustrated, TAL's retail energy sales are not anticipated to exceed its historic 2010 peak until 2021.

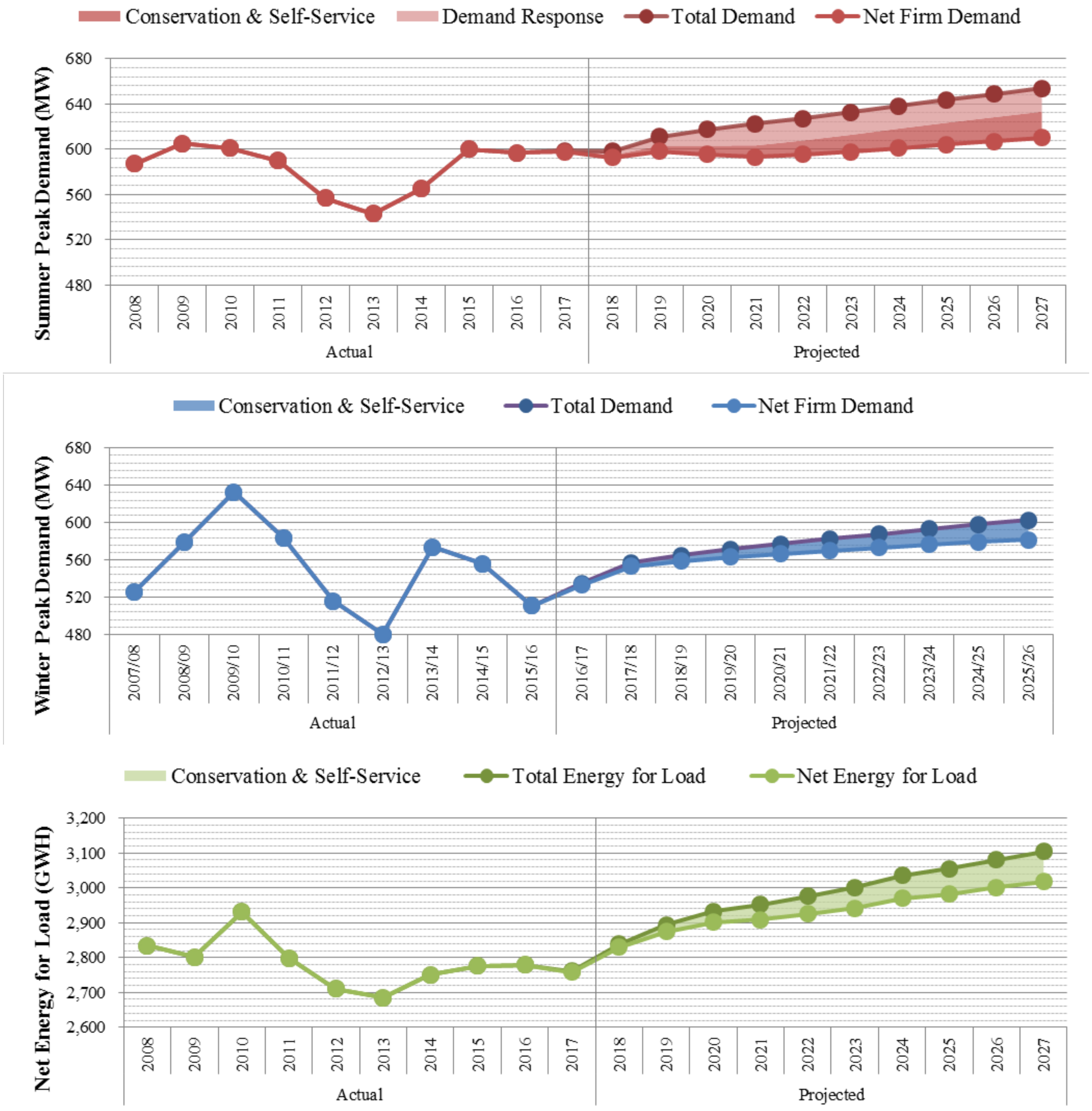
**Figure 48: TAL Growth Rate**




Source: 2018 Ten-Year Site Plan

The three graphs in Figure 49 shows TAL's seasonal peak demand and net energy for load for the historic years of 2008 through 2017 and forecast years 2018 through 2027. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. TAL offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. Currently TAL only offers demand response programs targeting appliances that contribute to summer peak, and therefore have no effect upon winter peak.

**Figure 49: TAL Demand and Energy Forecasts**




Source: 2018 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 29 shows TAL's actual net energy for load by fuel type as of 2017 and the projected fuel mix for 2027. TAL relies almost exclusively on natural gas for its generation, excluding some purchases from other utilities and qualifying facilities and the use of oil as a backup fuel. Natural gas is anticipated to remain the primary fuel source on the system.

**Table 29: TAL Energy Consumption by Fuel Type**

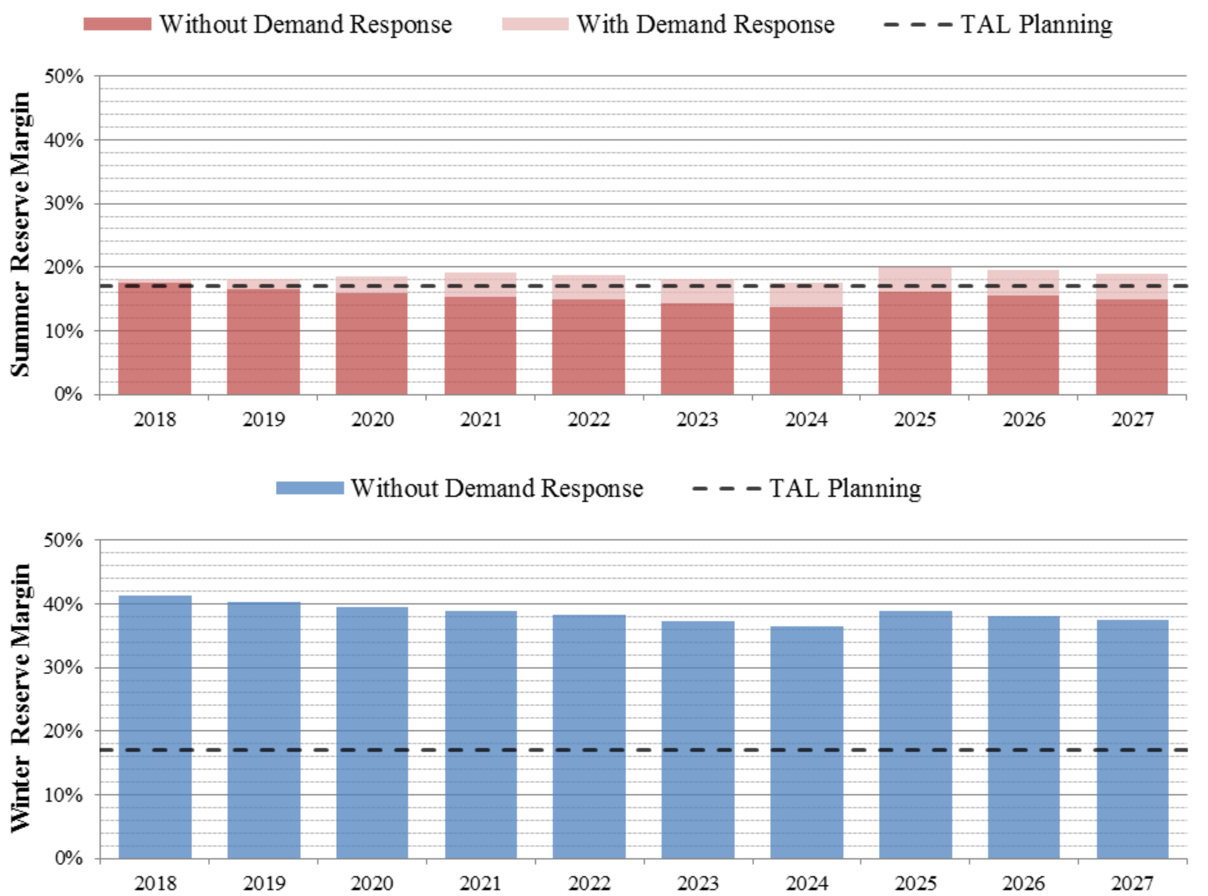
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2017 | | 2027 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 2,635 | **95.5%** | 2,907 | **96.3%** |
| **Coal** | 0 | **0.0%** | 0 | **0.0%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 0 | **0.0%** | 0 | **0.0%** |
| **Renewable** | 13 | **0.5%** | 132 | **4.4%** |
| **Interchange** | 110 | **4.0%** | -21 | **-0.7%** |
| **NUG & Other** | 0 | **0.0%** | 0 | **0.0%** |
| **Total** | **2,758** | | **3,018** | |

Source: 2018 Ten-Year Site Plan and Data Responses

## Reliability Requirements

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

**Figure 50: TAL Reserve Margin Forecast**




Source: 2018 Ten-Year Site Plan

## Generation Resources

TAL plans multiple unit retirements and additions during the planning period, as described in Table 30. A natural gas-fired steam unit and a natural gas-fired combustion turbine unit are anticipated to be retired during the planning period. Based upon its current planning, TAL intends to add several natural gas-fired internal combustion units.

**Table 30: TAL Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum |
|---|---|---|---|
| **Retiring Units** | | | |
| 2018 | Hopkins 1 | Natural Gas Steam Turbine | 76 |
| 2018 | Purdom CT-2 | Natural Gas Combustion Turbine | 10 |
| **Total Retirements** | | | **86** |
| **New Units** | | | |
| 2018 | Hopkins IC 1-4 | Natural Gas Internal Combustion | 74 |
| 2018 | Substation 12 IC 1 & 2 | Natural Gas Internal Combustion | 18 |
| 2025 | Hopkins IC 5 | Natural Gas Internal Combustion | 18 |
| **Total New Units** | | | **110** |
| **Net Additions** | | | **24** |

Source: 2018 Ten-Year Site Plan

# APPENDIX A

REVIEW OF THE

## 2018 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

FLORIDA
PUBLIC
SERVICE
COMMISSION

NOVEMBER 2018

## Ten-Year Site Plan Comments

### State Agencies



### Regional Planning Councils



### Water Management Districts



### Local Governments



### Environmental Groups

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State Agency

# Department of Economic Opportunity

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**Appendix A**

Rick Scott
GOVERNOR

FLORIDA DEPARTMENT of ECONOMIC OPPORTUNITY

Cissy Proctor
EXECUTIVE DIRECTOR

August 30, 2018

Ms. Takira Thompson
Engineering Specialist
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

RE: Review of the 2018 Ten-Year Site Plans for Florida's Electric Utilities

Dear Ms. Thompson:

At your request, we have reviewed the 2018 Ten-Year Site Plans of the electric utilities. The Department of Economic Opportunity's review focused on potential and preferred sites for future power generation, and the compatibility of those sites with the applicable local comprehensive plan, including the adopted future land use map. Please see our enclosed comments.

Should you have any questions regarding these comments, please contact Scott Rogers, Planning Analyst, at (850) 717-8510, or by email at scott.rogers@deo.myflorida.com.

Sincerely,

James D. Stansbury, Chief
Bureau of Community Planning and Growth

JDS/sr

Enclosure: DEO Review Comments

Florida Department of Economic Opportunity | Caldwell Building | 107 E. Madison Street | Tallahassee, FL 32399
850.245.7105 | www.floridajobs.org
www.twitter.com/FLDEO |www.facebook.com/FLDEO

**Florida Department of Economic Opportunity 2018 Ten-Year Site Plan Review Comments**

The Department's review focused on potential and preferred sites for future power generation, and the compatibility of those sites with the applicable local comprehensive plan, including the adopted future land use map. Nine utilities (Duke Energy Florida, Florida Municipal Power Agency, Florida Power and Light Company, Gainesville Regional Utilities, Gulf Power Company, Jacksonville Electric Authority, Seminole Electric Cooperative, City of Tallahassee, and Tampa Electric Company) have identified a total of 35 potential or preferred sites for future power generation in their Ten-Year Site Plan (TYSP). Potential sites are defined in Rule 25-22.070, Florida Administrative Code (F.A.C.), as "sites within the state that an electric utility is considering for possible location of a power plant, a power plant alteration, or an addition resulting in an increase in generating capacity." Preferred sites are defined in Rule 25-22.070, F.A.C., as "sites within the state on which an electric utility intends to construct a power plant, a power plant alteration, or an addition resulting in an increase in generating capacity."

**1. Duke Energy Florida**

The Duke Energy Florida TYSP identifies five preferred sites (Citrus County site; Suwannee River Energy Center site; Hamilton Solar Energy Center site; St. Petersburg Pier Solar Energy Center; and Debary Energy Center site) to increase power generating capacity.

A. <u>Citrus County Site:</u> The Citrus County site is located on 400 acres east of the existing Crystal River Energy Center. The site is designated as "Transportation, Communications and Utilities," which allows the electric generating facility. The 400 acre site has been certified by the State of Florida under the Power Plant Siting Act, and Duke Energy Florida has begun construction of the generating facility on the site.

B. <u>Suwannee River Energy Center Site:</u> The Suwannee River Energy Center site is located in Suwannee County, and the TYSP identifies the addition of a natural gas powered and/or solar generating facility on 68 acres within the Energy Center. The 68 acres is designated as "Agriculture" on the adopted Future Land Use Map of the Suwannee County Comprehensive Plan. Electric generating facilities may be allowed as a special exception in the Agriculture future land use category.

C. <u>Hamilton Solar Energy Center Site:</u> The Hamilton Solar Energy Center site is located on 550 acres in southwestern Hamilton County. The site is designated as "Agricultural-1" and "Agricultural-4" on the Hamilton County Comprehensive Plan Future Land Use Map. In January 2018, Hamilton County adopted a Comprehensive Plan amendment (Amendment 17-1ESR) to allow "solar electrical generating facilities and associated and related facilities" as a special exception use in the Agricultural future land use category. The Department has not yet received the adopted plan Amendment 17-1ESR from Hamilton County.

D. St. Petersburg Pier Solar Energy Center Site: The St. Petersburg Pier Solar Energy Center site is located on 2 acres of the existing pier in the City of St. Petersburg. The pier is being renovated, and the solar panels will be installed on canopies that cover parking spaces (solar carport). The City of St. Petersburg Comprehensive Plan Future Land Use Map designates the site as "Institutional" and the City has approved the solar carport as part of the renovation.

E. Debary Energy Center Site: The Debary Energy Center site is located on approximately 1,395 acres in the City of DeBary. The site contains existing power generating facilities. The City of DeBary Comprehensive Plan Future Land Use Map designates the site as "Industrial/Utilities", which allows electric power generation facilities.

**2. Florida Municipal Power Agency**

The Florida Municipal Power Agency TYSP identifies three potential sites for the increase in power generating capacity: (1) Cane Island Power Park; (2) Treasure Coast Energy Center; and (3) Stock Island.

A. Cane Island Power Park Site: The Cane Island Power Park (CIPP) site is located on 1,027 acres in rural northwest Osceola County, approximately one mile northwest of Intercession City. The site contains existing power generation facilities. The Osceola County Comprehensive Plan Future Land Use Map designates the site as "Rural/Agriculture", which allows electric utility facilities.

B. Treasure Coast Energy Center Site: The Treasure Coast Energy Center (TCEC) site is located on 69 acres in the Midway Industrial Park in the City of Fort Pierce. The site contains existing power generation facilities. The City of Fort Pierce Comprehensive Plan Future Land Use Map designates the site as "Institutional", which allows an electric generating plant.

C. Stock Island Power Plant Site: The Stock Island Power Plant site is located on Stock Island near Key West, and the site contains existing power generation facilities. The Monroe County Comprehensive Plan Future Land Use Map designates the Stock Island Power Plant site as "Public Facilities", which allows electric generation plants.

**3. Florida Power and Light Company**

The Florida Power and Light Company (FPL) TYSP identifies seven preferred sites for the increase in power generating capacity and various unspecified potential sites for the increase of power generating capacity.

A. The TYSP identifies the following as preferred sites:

1. Sunshine Gateway Solar Energy Center Site: The Sunshine Gateway Solar Energy Center site is located on 448 acres in Columbia County. The predominant existing use of the site is agriculture. The site is designated as "Agriculture-3" on the Columbia County Comprehensive Plan Future Land Use Map and "Agriculture-3" on the Columbia County Zoning Atlas. A solar power generation plant is allowed as a special exception use in the Agriculture-3 zoning district. In October 2017, Columbia County granted a special exception use approval for a solar power generation plant at the site, and Florida Power and Light Company has begun construction of the plant.

2. Miami-Dade Solar Energy Center Site: The Miami-Dade Solar Energy Center site is located on 432 acres in Miami-Dade County. The predominant existing use of the site is agriculture. The Miami-Dade County Comprehensive Plan Future Land Use Map designates the site as "Agriculture", which allows utility uses that are compatible with agriculture and rural residential character. The Miami-Dade County Zoning Map designates the site as "Agricultural", which allows an electric power plant to be approved upon public hearing.

3. Interstate Solar Energy Center Site: The Interstate Solar Energy Center site is located on 419 acres in St. Lucie County. The predominant existing use of the site is agriculture. The site is designated as "Towns, Villages & Countryside" on the St. Lucie County Comprehensive Plan Future Land Use Map and "Agricultural AG-1" on the St. Lucie County Zoning Atlas. A solar generation station/plant is allowed as a conditional use in the Agricultural AG-1 zoning district. In January 2018, St. Lucie County granted a conditional use permit approval for a 74.5 megawatt photovoltaic solar center at the site and determined that the permit is consistent with the Comprehensive Plan.

4. Pioneer Trail Solar Energy Center Site: The Pioneer Trail Solar Energy Center site is located on 473 acres in Volusia County. The predominant existing use of the site is agriculture. The Volusia County Comprehensive Plan Future Land Use Map designates the site as "Agricultural Resource" and "Environmental Systems Corridor." The site is designated as "Public Use" and "Resource Corridor" on the Volusia County Official Zoning Map. The Public Use zoning district allows publicly owned or regulated electric power plants and renewable energy production facilities as permitted principal uses. The Resource Corridor zoning district allows publicly owned or regulated electric power plants and renewable energy production facilities as special exception uses. The Comprehensive Plan allows publicly owned or regulated electrical power plants and renewable energy production facilities as: (1) a permitted principal use within the area zoned as Public Use; and (2) a special exception use within the area zoned as Resource Corridor.

5. Okeechobee Clean Energy Center Site: The Okeechobee Clean Energy Center site is located on 2,842 acres in Okeechobee County. The predominant existing use of the site is agriculture. The Okeechobee County Comprehensive Plan Future Land Use Map designates the site as

"Agriculture", which allows power generation. Construction has commenced and commercial operation of a natural gas-fired power generation facility is projected to begin in June 2019.

6. Dania Beach Clean Energy Center Site: The Dania Beach Clean Energy Center site is located on the existing Lauderdale Plant property (392 acres) in Broward County within the City of Dania Beach and the City of Hollywood. The site contains existing power generating facilities, and FPL intends to modernize the Lauderdale Plant by replacing two existing power generating units with a new single unit and rename the facility "Dania Beach Clean Energy Center." The Broward County Comprehensive Plan is applicable to both the unincorporated area of the County and the land within the incorporated municipalities of the County. The Broward County Comprehensive Plan Future Land Use Map designates the site as "Electrical Generating Facility", which allows electrical power plants. The City of Hollywood Comprehensive Plan Future Land Use Map designates the portion of the site within the City as "Utilities" and "Industrial", and the "Utilities" category allows electrical power plants and the "Industrial" category allows utility uses. The City of Dania Beach Comprehensive Plan Future Land Use Map designates the portion of the site within the City as "Electrical Generation Facilities", which allows electrical power plants.

7. Turkey Point Plant Site: The Turkey Point Plant site is located on approximately 3,300 acres in the southern portion of Miami-Dade County. The site contains existing power generating facilities. The Miami-Dade County Comprehensive Plan Future Land Use Map designates the site as "Institutions, Utilities, and Communications" which allows power generation and "Environmental Protection Area."

B. TYSP Potential Sites:

The TYSP states that FPL is currently evaluating potential sites for new photovoltaic facilities in fifteen counties (Baker, Charlotte, Clay, DeSoto, Hendry, Manatee, Martin, Miami-Dade, Nassau, Okeechobee, Palm Beach, Putnam, St. Johns, Suwannee, and Union Counties) and that FPL has not yet selected any specific locations for potential sites within these counties. The next TYSP should address any specific potential sites identified (selected) by FPL within these counties.

## 4. Gainesville Regional Utilities

The Gainesville Regional Utilities TYSP identifies one preferred site (Deerhaven Generating Station site) for the increase in power generating capacity.

A. Deerhaven Generating Station Site: The Deerhaven Generating Station site is located on 3,474 acres within the City of Gainesville, and the site contains an existing power generation facility. The City of Gainesville Comprehensive Plan Future Land Use Map designates the site as "Public and Institutional Facilities", which allows utilities.

**5. Gulf Power Company**

The Gulf Power Company TYSP identifies one preferred site (North Escambia site) for the increase in power generating capacity.

A. North Escambia Site: The North Escambia site is located on 2,728 acres in the northern part of Escambia County, approximately five miles southwest of Century, Florida. The existing use of the site is predominantly timber harvesting and agriculture. The Escambia County Comprehensive Plan Future Land Use Map designates the site as Agriculture, and electric power generating facilities may be allowed as a conditional use in Agriculture through the Land Development Code.

**6. Jacksonville Electric Authority**

The Jacksonville Electric Authority TYSP identifies one preferred site (Brady Branch Generating Station) for the increase in power generating capacity.

A. Brady Branch Generating Station Site: The Brady Branch Generating Station site is located on 153 acres in the City of Jacksonville, and the site contains an existing power generation facility. The City of Jacksonville Comprehensive Plan Future Land Use Map designates the site as "Public Buildings and Facilities", which allows the power generating facility.

**7. Seminole Electric Cooperative**

The Seminole Electric Cooperative TYSP identifies one potential site (Gilchrist site) and one preferred site (Seminole Generating Station site) for the increase in power generating capacity.

A. Gilchrist Site: The Gilchrist site is located on 520 acres in the central portion of Gilchrist County, approximately two miles northeast of the City of Bell. The site does not contain existing power generation facilities. Much of the site has been used for silviculture (pine plantation) and consists of large tracts of planted longleaf and slash pine community, and the site contains a limited amount of wetlands (10.1 acres). The site is designated Agriculture-2 on the adopted Future Land Use Map of the Gilchrist County Comprehensive Plan. Electric generating facilities are not identified as an allowable land use within the Agriculture-2 future land use category. Seminole Electric Cooperative should contact the Gilchrist County Community Development Department at (352) 463-3173 for information regarding consistency with the Gilchrist County Comprehensive Plan.

B. Seminole Generating Station Site: The Seminole Generating Station site is located on 1,996 acres in unincorporated Putnam County, approximately five miles north of the City of Palatka. The site contains existing power generation facilities. The site is designated as Public Facilities on the adopted Future Land Use Map of the Putnam County Comprehensive Plan. Power generation facilities are an allowable use within the Public Facilities future land use category.

**8. City of Tallahassee Utilities**

The City of Tallahassee Utilities TYSP identifies two preferred sites (Hopkins Plant; and Substation 12) for the increase in power generating capacity.

A. Hopkins Plant Site: The Hopkins Plant site is located in Leon County and contains existing power generation facilities. The Tallahassee-Leon County Comprehensive Plan Future Land Use Map designates the site as "Government Operational", which allows electric generating facilities.

B. Substation 12 Site: The Substation 12 site is located within the City of Tallahassee and contains existing substation facilities. The Tallahassee-Leon County Comprehensive Plan Future Land Use Map designates the site as "Government Operational", which allows electric generating facilities.

**9. Tampa Electric Company**

The Tampa Electric Company TYSP identifies ten preferred sites and three potential sites for the increase in power generating capacity.

A. TYSP Preferred Sites:
1. Alafia Solar Site: The Alafia Solar site is located on 477 acres in southwestern Polk County. The Polk County Comprehensive Plan Future Land Use Map designates the site as "Agricultural/Residential Rural", which allows solar electric power generation facilities as a conditional use.

2. Balm Solar Site: The Balm Solar site is located on 544 acres in southeastern Hillsborough County. The site is designated as "Agricultural/Rural" and "Residential Planned-2" on the Hillsborough County Comprehensive Plan Future Land Use Map and "Agricultural Rural" on the Hillsborough County Zoning Atlas. A solar energy production facility is allowed as a conditional use in the Agricultural Rural zoning district. The Comprehensive Plan does not expressly identify solar energy production facilities (or power generation facilities) as an allowable use within the "Agricultural/Rural" and "Residential Planned-2" future land use categories. Tampa Electric Company should contact the Hillsborough County City-County Planning Commission at (813) 273-3774 for information regarding consistency with the Hillsborough County Comprehensive Plan.

3. Bonnie Mine Solar Site: The Bonnie Mine Solar site is located on 352 acres in western Polk County. The site is designated as "Phosphate Mining" on the adopted Future Land Use Map of

the Polk County Comprehensive Plan, and electric power generation facilities are an allowable use within the Phosphate Mining future land use category.

4. Grange Hall Solar Site: The Grange Hall Solar site is located on 447 acres in southeastern Hillsborough County. The site is designated as "Agricultural/Mining" on the Hillsborough County Comprehensive Plan Future Land Use Map and "Agricultural Mining" on the Hillsborough County Zoning Atlas. A solar energy production facility is allowed as a conditional use in the Agricultural Mining zoning district. The Comprehensive Plan does not expressly identify solar energy production facilities (or power generation facilities) as an allowable use within the "Agricultural/Mining" future land use category. Tampa Electric Company should contact the Hillsborough County City-County Planning Commission at (813) 273-3774 for information regarding consistency with the Hillsborough County Comprehensive Plan.

5. Lake Hancock Solar Site: The Lake Hancock Solar site is located on 356 acres within the Silver Planned Development in the City of Bartow. The City of Bartow Comprehensive Plan Future Land Use Map designates the site with the following future land use categories: (1) Low Density Residential; (2) Medium Density Residential; (3) High Density Residential; and (4) Commercial. A "Utility-owned Renewable Generation System" (photovoltaic system as its fuel source) is allowed in the Low Density Residential and Medium Density Residential future land use categories within the Silver Planned Development.

6. Lithia Solar Site: The Lithia Solar site is located on 580 acres in southeastern Hillsborough County. The site is designated as "Agricultural" and "Agricultural/Rural" on the Hillsborough County Comprehensive Plan Future Land Use Map and "Agricultural" on the Hillsborough County Zoning Atlas. A solar energy production facility is allowed as a conditional use in the Agricultural zoning district. The Comprehensive Plan does not expressly identify solar energy production facilities (or power generation facilities) as an allowable use within the "Agricultural" and "Agricultural/Rural" future land use categories. Tampa Electric Company should contact the Hillsborough County City-County Planning Commission at (813) 273-3774 for information regarding consistency with the Hillsborough County Comprehensive Plan.

7. Mountain Solar Site: The Mountain Solar site is located on 345 acres in northeastern Pasco County. The Pasco County Comprehensive Plan Future Land Use Map designates the site with the following future land use categories: (1) Residential-1; (2) Residential-3; and (3) Agricultural/Rural. Private electric public utilities (includes power plants) may be permitted in these future land use categories.

8. Payne Creek Solar Site: The Payne Creek Solar site is located on 503 acres in southwestern Polk County. The site is designated as "Phosphate Mining" on the adopted Future Land Use Map of the Polk County Comprehensive Plan, and electric power generation facilities are an allowable use within the Phosphate Mining future land use category.

9. Peace Creek Solar Site: The Peace Creek Solar site is located on 422 acres within the Wilson Ranch Planned Development in the City of Bartow. The site is designated as "Mixed

Use/Neighborhood Development" on the adopted Future Land Use Map of the City of Bartow Comprehensive Plan. A "Utility-owned Renewable Generation System" (photovoltaic system as its fuel source) is allowed in the Mixed Use/Neighborhood Development future land use category within the Wilson Ranch Planned Development.

10. Wimauma Solar Site: The Wimauma Solar site is located on 500 acres in southeastern Hillsborough County. The site is designated as "Wimauma Village Residential-2" on the Hillsborough County Comprehensive Plan Future Land Use Map and "Agricultural Rural" on the Hillsborough County Zoning Atlas. A solar energy production facility is allowed as a conditional use in the Agricultural Rural zoning district. The Comprehensive Plan does not expressly identify solar energy production facilities (or power generation facilities) as an allowable use within the "Wimauma Village Residential-2" future land use category. Tampa Electric Company should contact the Hillsborough County City-County Planning Commission at (813) 273-3774 for information regarding consistency with the Hillsborough County Comprehensive Plan.

B. TYSP Potential Sites:

1. Polk Power Station Site: The Polk Power Station site is located in southwest Polk County and contains existing power generation facilities. The site is designated as "Phosphate Mining" on the adopted Future Land Use Map of the Polk County Comprehensive Plan, and electric power generation facilities are an allowable use within the Phosphate Mining future land use category.

2. H.L. Culbreath Bayside Power Station Site: The H.L. Culbreath Bayside Power Station site is located in unincorporated Hillsborough County and contains existing power generation facilities. The site is designated mostly as "Heavy Industrial" with a smaller area as "Light Industrial" on the adopted Future Land Use Map of the Hillsborough County Comprehensive Plan. Electric generation plants are an allowed use in the Heavy Industrial future land use category.

3. Big Bend Power Station Site: The Big Bend Power Station site is located in unincorporated Hillsborough County and contains existing power generation facilities. The site is designated as "Heavy Industrial," "Light Industrial," and "Environmentally Sensitive Areas" on the adopted Future Land Use Map of the Hillsborough County Comprehensive Plan. Electric generation plants are an allowed use only in the Heavy Industrial future land use category. The "Environmentally Sensitive Areas" protect wetlands and significant wildlife habitat along the southern portion of the site.

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State Agency

# Department of Environmental Protection

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| | |
|---|---|
| **From:** | Seiler, Ann |
| **To:** | Takira Thompson |
| **Cc:** | Mulkey, Cindy; Phillip Ellis; Charles Murphy |
| **Subject:** | FW: Request for Comments on the 2018 Ten-Year Site Plans of Florida's Electric Utilities |
| **Date:** | Friday, July 27, 2018 4:49:53 PM |
| **Attachments:** | image001.png |

Good afternoon,

The Department of Environmental Protection's Siting Coordination Office has reviewed the 2018 Ten-Year Site Plans for Florida's Electric Utilities and found the documents to be adequate for planning purposes.

Thank you for the opportunity to review and comment on the plans.

**Ann Seiler**
Florida Department of Environmental Protection
Siting Coordination Office
2600 Blair Stone Rd. MS 5500
Tallahassee, Florida 32399
ann.seiler@dep.state.fl.us
Office: 850.717.9113
Cell: 850.228.6237

**From:** Takira Thompson [mailto:tthompso@psc.state.fl.us]
**Sent:** Thursday, May 31, 2018 5:13 PM
**To:** Mulkey, Cindy <Cindy.Mulkey@dep.state.fl.us>
**Cc:** Phillip Ellis <PEllis@PSC.STATE.FL.US>; Charles Murphy <cmurphy@PSC.STATE.FL.US>
**Subject:** Request for Comments on the 2018 Ten-Year Site Plans of Florida's Electric Utilities

**Please see the attached file to see all relevant 2018 Ten Year Site Plans.**

Good afternoon,

Pursuant to Section 186.801, Florida Statutes, the Florida Public Service Commission (Commission) is responsible for reviewing and classifying each electric utility's Ten-Year Site Plan as "suitable" or "unsuitable." As part of the annual review in accordance with Rule 25-22.071, Florida Administrative Code, the Commission must provide a copy of the relevant Ten-Year Site Plans and solicit the views of the appropriate state, regional, and local agencies. To this end, the Commission has made available on its website electronic copies of the 2018 Ten-Year Site Plans for all the Florida electric utilities at the following link: http://www.psc.state.fl.us/ElectricNaturalGas/TenYearSitePlans

Please forward all comments by September 1, 2018, including an electronic copy to my email address below. If you have any questions or require additional time to file comments please feel free to contact me by phone at (850) 413-6592 or by email (tthompso@psc.state.fl.us) or Phillip Ellis by phone at (850) 413-6626 or by email (pellis@psc.state.fl.us). Thank you for your assistance.

*Takira T. Thompson*
ENGINEERING SPECIALIST
DIVISION OF ENGINEERING
FLORIDA PUBLIC SERVICE COMMISSION
TALLAHASSEE, FL 32311
PHONE: 850-413-6592

State Agency

# Fish and Wildlife Conservation Commission

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Florida Fish and Wildlife Conservation Commission



850-487-3796
850-921-5786 FAX

*Managing fish and wildlife resources for their long-term well-being and the benefit of people.*

620 South Meridian Street
Tallahassee, Florida
32399-1600
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Hearing/speech-impaired:
800-955-8771 (T)
800 955-8770 (V)

MyFWC.com

August 24, 2018

Takira Thompson
Division of Regulatory Analysis
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
tthompso@psc.state.fl.us

Re: Gulf Power 2018 10-Year Site Plan, Multi-County

Dear Ms. Thompson:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the Gulf Power 2018 10-Year Site Plan submitted to the Florida Public Service Commission (PSC) pursuant to Section 186.801, Florida Statutes, and provides the following comments and recommendations.

**Project Description**

Section 186.801, Florida Statutes, requires electric generating facilities to submit a 10-year site plan to the Florida Public Service Commission not less frequently than every two years. Gulf Power owns and operates four plants in Northwest Florida: Plant Crist (Escambia County); Plant Lansing Smith (Bay County); Pea Ridge (Santa Rosa County); and Perdido (Escambia County). Gulf Power has continued to evaluate the construction of generating facilities or the acquisition of equivalent capacity resources in coordination with other Southern Electric System (SES) operating companies. Gulf Power indicates that it has satisfied its need for firm capacity through the May 2023 time period. The 2018-2027 planning cycle defers all new facility construction to a later date. Gulf Power will consider future additional capacity at its existing sites at the Plant Crist, Plant Lansing Smith, or on the identified Gulf Power sites at the Shoal River property in Walton County, Caryville property in Holmes and Washington counties, or the North Escambia County property. Based on recent evaluations and analysis, Gulf Power has determined that the North Escambia site would provide the best long-term value.

FWC staff previously provided comments to Gulf Power on the potentially affected resources at proposed facility expansion sites during the 2012 and 2016 Plan Reviews, including the proposed North Escambia County site in 2016 (see enclosure). The 2018 plan provided additional information that was not available in the previous plans and indicated that approximately 4,800 gallons per minute (gpm) would be needed for cooling, industrial processing, and other water needs and the source would be a combination of groundwater from on-site wells and surface water from the Escambia River.

The undeveloped North Escambia County site is located approximately six miles southwest of Century, Florida, and approximately two miles west of U.S. Highway 29. The potential site is located in the Mitchell Creek watershed and in the Escambia River drainage basin. The dominant land covers onsite include pine plantation, freshwater forested wetlands, mixed hardwood-pine forest, row crops, sandhill, upland hardwood forest, roads, scrub-shrub wetlands, improved pasture, cypress wetlands, floodplain swamp, wet prairie, stream, and pond. The proposed project may also include intake and discharge pipelines from the site into Mitchell Creek and the Escambia River.

**Potentially Affected Resources**

Since the time of the previous letter (2016), the listing status of several species has changed, which affects the assessment of unique or significant environmental features that should be considered in an evaluation of the potential North Escambia project identified in the 10-Year Site Plan. Florida's Endangered and Threatened Species list was updated in May 2017. The revised list is available at http://myfwc.com/media/1515251/threatened-endangered-species.pdf.

FWC staff conducted a geographic information system (GIS) analysis of the project site and found that the project site contains, is adjacent to, or occurs near:

- U.S. Fish and Wildlife Service (USFWS) Designated Critical Habitat for:
    - Gulf sturgeon (*Acipenser oxyrinchus desotoi*, Federally Threatened [FT])
    - Southern sandshell mussel (*Hamiota australis*, FT)
    - Choctaw bean (*Villosa choctawensis*, Federally Endangered [FE])
    - Narrow pigtoe (*Fusconaia escambia*, FT)
    - Fuzzy pigtoe (*Pleurobema strodeanum*, FT)
    - Round ebonyshell (*Fusconaia rotulata*, FE)
    - Southern kidneyshell (*Ptychobranchus jonesi*, FE)
    - Tapered pigtoe (*Fusconaia burkei*, FT)

- Potential habitat for state- and federally listed species:
    - Red-cockaded woodpecker (*Picoides borealis*, FE)
    - Eastern indigo snake (*Drymarchon corais couperi*, FT)
    - Reticulated flatwoods salamander (*Ambystoma bishopii*, FE)
    - Gopher tortoise (*Gopherus polyphemus*, State Threatened [ST])
    - Alligator snapping turtle (*Macrochelys temminckii*, State Species of Special Concern [SSC])
    - Florida pine snake (*Pituophis melanoleucus mugitus*, ST)
    - Crystal darter (*Crystallaria asperalla*, ST)
    - Bluenose shiner (*Pteronotropis welaka*, ST)
    - Harlequin darter (*Etheostoma histrio*, SSC)

- Existing and proposed conservation lands:
    - Lower Escambia River Water Management Area (WMA)

**Comments and Recommendations**

Wildlife Assessments

Although the report indicates that proposed North Escambia County project is still in the planning stages and detailed studies to determine the exact size and position of the facility are ongoing, the current information provides an estimated peak water usage of 4,800 gpm which could be obtained as surface water from the Escambia River or its tributaries. The plan does not provide an anticipated process for discharge of industrial water, which potentially could include the Escambia River or adjacent tributaries. Depending on the location and process for withdrawal of surface water and discharge into the Escambia River or adjacent tributaries, federally or state-listed aquatic species could be affected by the project. The volume and rate of intake, volume and rate of discharge, temperature, dissolved oxygen levels, alterations of water quality, as well as other potential factors associated with discharge, could potentially affect essential behaviors of aquatic species, and should be included as part of any assessments of potential effects associated with the proposed project.

In the event that the planning for development of the North Escambia County project moves forward, FWC staff recommends that surveys and assessments for the species listed above should be completed prior to any phases of clearing or development. Species-specific wildlife surveys are time sensitive and FWC staff recommends that all wildlife surveys follow established survey protocols approved by the USFWS and the FWC and occur at the appropriate time of year. Surveys should also be conducted by qualified biologists with recent documented experience for each potential species. Basic guidance for conducting wildlife surveys may be found in the Florida Wildlife Conservation Guide (FWCG) at http://myfwc.com/conservation/value/fwcg/.

Federal Species and Designated Critical Habitat

The proposed project area may also contain habitat suitable for the federally listed species identified above, including the eastern indigo snake, reticulated flatwoods salamander, red-cockaded woodpecker, Gulf sturgeon, and seven freshwater mussel species. The potential project area now includes Designated Critical Habitat for Gulf sturgeon and the seven freshwater mussel species, which could be affected by the potential withdrawal and discharge of surface water. We recommend the applicant coordinate with the USFWS Panama City Ecological Services Office (ESO) as necessary for information regarding potential impacts to these species and Designated Critical Habitat. The USFWS Panama City ESO can be contacted at (850) 769-0552.

FWC staff finds that Gulf Power's 2018 10-Year Site Plan 2018-2027 document is suitable for planning purposes and recommends that Gulf Power provide the additional information described above prior to further project review of the North Escambia County facility. If you need any further assistance, please do not hesitate to contact our office by email at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions regarding the content of this letter, please contact Bryan Phillips at (850) 767-3646 or by email at Bryan.Phillips@MyFWC.com.

Sincerely,

Fritz Wettstein

Fritz Wettstein
Land Use Planning Program Administrator
Office of Conservation Planning Services

fw/bwp
ENV 2-11
Gulf Power 10-Year Site Plan 2018_36430_082418
Enclosure

cc: Lisa Roddy, Gulf Power, lroddy@southernco.com

Florida Fish
and Wildlife
Conservation
Commission

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*Key West*

Executive Staff
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**Eric Sutton**
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**Jennifer Fitzwater**
Chief of Staff

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**Nick Wiley**
Executive Director

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MyFWC.com

July 6, 2016

Moniaishi Mtenga
Division of Engineering
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
mmtenga@psc.state.fl.us

RE: Gulf Power 2016 10-Year Site Plan, Multi-County

Dear Mr. Mtenga:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the Gulf Power 2016 10-Year Site Plan and provides the following comments and recommendations.

## Project Description

Section 186.801, Florida Statutes, requires electric generating facilities to submit a ten-year site plan to the Florida Public Service Commission. Gulf Power owns and operates five plants in Northwest Florida: Plant Crist (Escambia County); Plant Lansing Smith (Bay County); Plant Scholz (Jackson County); Pea Ridge (Santa Rosa County); and Perdido (Escambia County). Gulf Power has continued to evaluate the construction of generating facilities or the acquisition of equivalent capacity resources in coordination with other Southern Electric System (SES) operating companies. Gulf Power indicates that it has satisfied its need for firm capacity through the May 2023 time period. Any new facility construction is deferred during the 2016-2025 planning cycle. Gulf Power will consider future additional capacity at its existing sites at the Plant Crist, Plant Lansing Smith, Plant Scholz, or on the identified Gulf Power sites at the Shoal River property in Walton County, Caryville property in Holmes and Washington counties, or the North Escambia County property.

## Potentially Affected Fish and Wildlife Resources

FWC staff previously provided comments to Gulf Power on the potentially affected resources at the proposed facility expansion sites during the 2010 and 2012 Plan Reviews, with the exception of the proposed North Escambia County Site (see enclosure). Since that time, the listing status of several species has changed which affects the discussion of unique or significant environmental features that are discussed under each site description in the Ten-Year Site Plan. We are providing the following information as technical assistance at the request of Gulf Power staff so that they may update these descriptions.

**Appendix A**

Plant Crist (Escambia County) is located adjacent to the Escambia River. FWC GIS analysis found that this site is located near, within, or adjacent to:

- U.S. Fish and Wildlife Service Critical Habitat for the:
  - Gulf sturgeon (*Acipenser oxyrinchus desotoi*, Federally Threatened (FT)

- Potential habitat for the:
  - Harlequin darter (*Etheostoma histrio*, State Species of Special Concern [SSC])

Plant Scholz (Jackson County) is located adjacent to the Apalachicola River. FWC GIS analysis found that this site is located near, within, or adjacent to:

- U.S. Fish and Wildlife Service Critical Habitat for the:
  - Gulf sturgeon (*Acipenser oxyrinchus desotoi*, FT)
  - Purple bankclimber (*Elliptoides sloatianus*, FT)
  - Fat three-ridge (*Amblema neislerii*, Federally Endangered [FE])

- Potential habitat for the:
  - Barbour's map turtle (*Graptemys barbouri*, SSC)

The undeveloped Shoal River Site (Walton County) is located on the Shoal River approximately 3 miles northwest of Mossy Head, Florida. The property is predominantly in pine plantation. FWC GIS analysis found that this site is located near, within, or adjacent to:

- U.S. Fish and Wildlife Service Consultation Area for the:
  - Red-cockaded woodpecker (*Picoides borealis*, FE)

- U.S. Fish and Wildlife Service Critical Habitat for the:
  - Southern sandshell mussel (*Hamiota australis*, FT)
  - Choctaw bean (*Villosa choctawensis*, FE)
  - Narrow pigtoe (*Fusconaia escambia*, FT)
  - Fuzzy pigtoe (*Pleurobema strodeanum*, FT)

- Potential habitat for the:
  - Gopher tortoise (*Gopherus polyphemus*, State Threatened [ST])
  - Blackmouth shiner (*Notropis melanostomus*, ST)
  - Bluenose shiner (*Pteronotropis welaka*, SSC)
  - Alligator snapping turtle (*Macrochelys temminckii*, SSC)
  - Eastern indigo snake (*Drymarchon couperi*, FT)
  - Pine barrens treefrog (*Hyla andersonii*, SSC)
  - Florida black bear (*Ursus americanus floridanus*)

The undeveloped Caryville Site (Holmes and Washington counties) is approximately 1.5 miles northeast of Caryville, Florida, and adjacent to the Choctawhatchee River. The property is predominantly in agriculture and pine plantation. FWC staff conducted a GIS analysis and found that this site is located near, within, or adjacent to:

- U.S. Fish and Wildlife Service Critical Habitat for the:
  - Gulf sturgeon (*Acipenser oxyrinchus desotoi*, FT)
  - Southern sandshell mussel (*Hamiota australis*, FT)
  - Choctaw bean (*Villosa choctawensis*, FE)

  - Southern kidneyshell (*Ptychobranchus jonesi*, FE)
  - Tapered pigtoe (*Fusconaia burki*, FT)
  - Fuzzy pigtoe (*Pleurobema strodeanum*, FT)

- Potential habitat for the:
  - Gopher tortoise (*Gopherus polyphemus*, ST)
  - Barbour's map turtle (*Graptemys barbouri*, SSC)
  - Bluenose shiner (*Pteronotropis welaka*, SSC)
  - Eastern indigo snake (*Drymarchon couperi*, FT)
  - Pine barrens treefrog (*Hyla andersonii*, SSC)
  - Alligator snapping turtle (*Macrochelys temminckii*, SSC)
  - Florida black bear (*Ursus americanus floridanus*)

The undeveloped North Escambia Property Site (Escambia County) is approximately 5 miles southwest of Century, Florida near County Road 4 and U.S. Highway 29. The site contains part of the Mitchell Creek drainage basin. FWC GIS analysis found that this site is located near, within, or adjacent to:

- Potential habitat for the:
  - Gopher tortoise (*Gopherus polyphemus*, State Threatened [ST])
  - Harlequin darter (*Etheostoma histrio*, SSC)
  - Sherman's fox squirrel (*Sciurus niger shermani*, SSC)

With the addition of the information provided above, FWC finds that Gulf Power's 2016 10-year Site Plan 2016-2025 document is suitable for planning purposes and the plan proposes no significant impacts to fish and wildlife resources as written. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions regarding the content of this letter, please contact Theodore Hoehn at (850) 488-8792 or by email at ted.hoehn@MyFWC.com.

Sincerely,

Jennifer D. Goff

Jennifer D. Goff
Land Use Planning Program Administrator
Office of Conservation Planning Services

jdg/th
ENV 2-11-4/3
Gulf Power Company 2016 Ten-Year Site Plan_ 30922_070616
Enclosure

cc: Robert McGee, Jr., Gulf Power, RLMMCGEE@southernco.com

Appendix A

Florida Fish and Wildlife Conservation Commission



Office of the Executive Director
**Nick Wiley**
Executive Director

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(850) 921-5786 FAX



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MyFWC.com

June 7, 2012

Mr. Phillip Ellis
Division of Regulatory Analysis
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
pellis@psc.statea.fl.us

RE: Gulf Power 2012 10-Year Site Plan, Multi-County

Dear Mr. Ellis:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the Gulf Power 2012 10-Year Site Plan and provides the following comments and recommendations for your consideration.

## Project Description

Section 186.801, Florida Statutes requires electric generating facilities to submit a ten-year site plan to the Florida Public Service Commission. Gulf Power owns and operates five plants in Northwest Florida: Plant Crist (Escambia County); Plant Lansing Smith (Bay County); Plant Sholtz (Jackson County); Pea Ridge (Santa Rosa County); and Perdido (Escambia County). Gulf Power has continued to evaluate the construction of generating facilities or the acquisition of equivalent capacity resources in coordination with other Southern Electric System (SES) operating companies. Gulf Power indicates that it has satisfied its need for firm capacity through the May 2023 time period. Any new facility construction is deferred during the 2012-2021 planning cycle. Gulf Power will consider additional capacity at its existing sites at the Plant Crist, Plant Lansing Smith, Plant Scholtz, or at the identified sites on the Shoal River property in Walton County or the Caryville property in Holmes and Washington Counties.

## Potentially Affected Resources

Plant Crist (Escambia County) is located adjacent to the Escambia River, which has been designated as Critical Habitat for the Gulf Sturgeon [*Acipenser oxyrinchus desotoi* – Federal Threatened (FT)]. The undeveloped portion of the site includes mixed hardwoods/pines and mixed scrub.

Plant Lansing Smith (Bay County) is located along North Bay of the St. Andrews Bay system. The undeveloped portion of the site is predominantly pine plantation with some wetland areas. The site is adjacent to areas identified for conservation under the Bay County Sector Plan.

Plant Scholtz (Jackson County) is located adjacent to the Apalachicola River. The site consists of a mixture of pine and hardwood forests. Plant Scholtz is adjacent to the Apalachicola River, which has designated critical habitat for the Gulf Sturgeon

[*Acipenser oxyrinchus desotoi* (FT)], and critical habitat for the purple bankclimber [*Elliptoides sloatianus* (FT)] and fat three-ridge [*Amblema neislerii* - Federal Endangered (FE)].

The undeveloped Shoal River Site (Walton County) is located on the Shoal River approximately 3 miles northwest of Mossy Head, Florida. The property is predominantly in pine plantation. The site falls within a federally designated red-cockaded woodpecker consultation area; and contains primary and secondary habitat for the Florida black bear [*Ursus americanus floridanus* – State Threatened (ST)]. This site is also within close proximity to known occurrences of southern sandshell mussel (*Hamiota australis* – Federal, Candidate Endangered), blackmouth shiner [*Notropis melanostomus* – State Endangered (SE)], bluenose shiner [*Pteronotropis welaka* – State Species of Special Concern (SSC)], Eastern indigo snake [*Drymarchon couperi* – (FT)], alligator snapping turtle [*Macrochelys temminckii* (State SSC)], gopher tortoise [*Gopherus polyphemus* – (ST)], and pine barrens treefrog [*Hyla andersonii* (State SSC)].

The undeveloped Caryville Site (Holmes/Washington County) is approximately 1.5 miles northeast of Caryville, Florida. The property is predominantly in agriculture and pine plantation. The site may contain gopher tortoise [*Gopherus polyphemus* (ST)], pine barrens treefrog [*Hyla andersonii* (State SSC)], and the Eastern indigo snake [*Drymarchon couperi* (FT)]. The site is also within close proximity to the Choctawhatchee River, which contains critical habitat for the Gulf Sturgeon [*Acipenser oxyrinchus desotoi* (FT)] and known occurrences of Barbour's Map Turtle [*Graptemys barbouri* (State SSC)], Fuzzy Pigtoe (*Pleurobema strodeanum* – Federal, Candidate Endangered), and bluenose shiner [*Pteronotropis welaka* (State SSC)].

FWC appreciates the opportunity to review Gulf Power's 2012 10-year Site Plan 2012-2021 document and extends an offer to assist Gulf Power in further identifying fish and wildlife resources within their planning area. Based on our review, we have determined that there are no development plans proposed in this Gulf Power Planning document that appear to pose significant fish and wildlife resource issues or potential conflicts for this planning period. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions regarding the content of this letter, please contact Theodore Hoehn at 850-488-8792 or by email at ted.hoehn@myfwc.com.

Sincerely,

for, Scott Sanders, Director
Office of Conservation Planning Services

ss/bg/th
ENV 2-11-4/3
Gulf Power Company 2012 10-year Site Plan_16170_060712
cc: Susan Ritenour, Gulf Power, SDRITENO@southernco.com

Regional Planning Council

# Apalachee Regional Planning Council

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# Apalachee Regional Planning Council

Serving Calhoun, Franklin, Gadsden, Gulf, Jackson, Jefferson,
Liberty, Leon and Wakulla counties and their municipalities


June 11, 2018

Takira Thompson
Division of Engineering
Florida Public Service Commission
Tallahassee, FL 32311

Dear Ms. Thompson:

Apalachee Regional Planning Council has received and reviewed the Florida Electric Utilities ten-year site plans for consistency with resources of regional significance and have no comments on the proposed plans.

Sincerely,

R Fetchick

Richard Fetchick, Regional Planner


**OFFICE**
2507 Callaway Rd, Ste 200
Tallahassee, Florida 32303

**CONTACT**
850.488.6211
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Regional Planning Council

# Central Florida Regional Planning Council

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August 31, 2018

Phillip Ellis
State of Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399

Dear Mr. Ellis,

**RE: Review of 2018 Ten-Year Site Plans for Florida's Electric Utilities**

The CFRPC reviewed ten-year site plans from Duke Energy Florida, Florida Municipal Power Agency, Florida Power and Light, Lakeland Electric, Orlando Utilities Commission, Seminole Electric Cooperative, and Tampa Electric Company as requested in the letter dated May 31, 2018, and included on the Public Service Commission's website. As requested, comments on the plans and a brief summary related to the suitability of the above-mentioned plans as planning documents is below.

**Duke Energy Florida:**

Duke Energy serves Polk, Hardee, and Highlands Counties. According to the plan, Duke Energy obtained full firm capacity if the Osprey Energy Center in 2017. They are planning for a new 50-mile long transmission line in June 2023.

This document is suitable for a planning document at a regional level because it provides information as to the proposed locations of planned new facilities. It is somewhat less suitable as a planning document at providing insight on the development through current demand and forecast demand because it cannot be extrapolated to a regional or county level because Duke Energy's boundaries cover so much of the State of Florida. It is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts are predicted to occur for the overall planning of the region's growth and development and protection.

**Florida Municipal Power Agency:**

Florida Municipal Power Agency (FMPA or the Agency) is a governmental wholesale power company owned by municipal electric utilities. FMPA provides economies of scale in power generation and related services to support community-owned electric utilities. The City of Fort Meade is a member. According to their plan, they do not require any additional resources from undesignated sources.

This document is suitable for a planning document at a regional level because it provides insight on the development of areas within a portion of the region through current demand and forecast demand. It also is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts are predicted to occur for the overall planning of the region's growth and development and protection.

**Florida Power and Light:**

According to the plan, Florida Power and Light will be adding a new CC generating unit at its Okeechobee site in mid-2019 to meet resource needs starting that year. This site requires no new transmittal lines. Construction has commenced and Commercial Operation is projected to begin by June 2019. In addition, FPL currently views the Okeechobee site as a potential location for future universal solar and gas-fueled generation facilities. FPL is currently evaluating potential sites in Okeechobee County for future PV facilities. No specific locations have been selected at this time. A site is also a potential site for new gas-fired generation.

The Wildflower Solar Energy Center in DeSoto County is a 74.5 MW PV facility that began commercial operation in the 1st Quarter of 2018. At the time this Site Plan is filed, DeSoto County produces more solar-generated electricity than any other county in Florida . FPL is currently evaluating potential sites in Desoto County for a future PV facility. No specific locations have been selected at this time.

This document is suitable for a planning document at a regional level because it provides information as to the proposed locations of planned new facilities. It includes great detail on the proposed locations that is easy to follow even for non-utility planners.

**Lakeland Electric:**

The plan states that there are no planned facilities for the 10-year planning reporting period. There are also no upgrades of existing facilities planned. As of December 2017, there are no long-term firm power sales or purchase contracts in place.

This document is suitable for a planning document at a regional level because it provides insight on the development of areas within a portion of the region through current demand and forecast demand. It also is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts are predicted to occur for the overall planning of the region's growth and development and protection.

This document is also written in a manner that makes it easy for non-utility planners to understand. However, due to the scanning or production process, the figures included in the document are blurry and very hard to read.

**Orlando Utilities Commission:**

According to the plan, no facilities are planned for development or retirement within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. OUC has a contract to provide power to Bartow through 2020. Bartow purchases the power from OUC, and then distributes it to its customers through its existing infrastructure. The plan discusses upgrades of existing facilities. Unfortunately, since there is not a map included to show where these facilities are located, it is not possible to determine which of them may be in the region.

This document is suitable for a planning document at a regional level because it provides information as to facilities located within the region. It is somewhat less suitable as a planning document at providing insight on the development through current demand and forecast demand because it cannot be extrapolated to a regional or county level the document does not provide clear information on the areas. This document would also be more helpful as a planning document with the inclusion of a service area map.

**Seminole Electric Cooperative:**

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. There are also no upgrades of existing facilities or retirement of existing facilities planned in these areas.

This document is suitable for a planning document at a regional level because it provides information as to facilities located within the region. It is somewhat less suitable as a planning document at providing insight on the development through current demand and forecast demand because it cannot be extrapolated to a regional or county level because Seminole Electric Cooperative services so much of the State of Florida.

**Tampa Electric Company:**

The Polk 2 Combined Cycle conversion project was completed in January 2017. The Polk Power Station site is located in southwest Polk County close to the Hillsborough and Hardee County lines. Tampa Electric Company anticipates planned and prospective generating facility additions at several of the Polk County solar plants, some of which require new right-of-way.

This document is suitable for a planning document at a regional level because it provides information as to the proposed locations of planned new expansions and because it provides insight on the development of areas within a portion of the region through current demand and forecast demand. It also is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts are predicted to occur for the overall planning of the region's growth and development and protection.

The proposed expansions/potential sitings as identified in the ten-year power plant site plans as submitted are consistent with the Central Florida Regional Planning Council Strategic Regional Policy Plan (SRPP). Thank you for the opportunity to review these electric utility ten-year site plans.

Sincerely,

Marisa M. Barmby, AICP
Senior Planner

cc: Takira T. Thompson, Florida Public Service commission (via email)

Water Management District

# St. Johns River Water Management District

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| | |
|---|---|
| **From:** | Steve Fitzgibbons |
| **To:** | Takira Thompson |
| **Cc:** | Phillip Ellis |
| **Subject:** | FW: Request for Comments on the 2018 Ten-Year Site Plans of Florida's Electric Utilities |
| **Date:** | Tuesday, July 17, 2018 1:59:37 PM |
| **Attachments:** | image001.gif<br>PSC Letter.pdf |

Ms. Thompson:

As requested in your letter dated May 31, 2018, the St. Johns River Water Management District (District) staff have reviewed the Ten-Year Site Plans (TYSPs) for Florida Power & Light Company (FPL), Duke Energy Florida (DEF), Gainesville Regional Utilities (GRU) and Seminole Electric Cooperative (SEC). Based on review of the submitted materials, District staff had no comments on the TYSPs and found them to be suitable as planning documents.

If you have any questions or need additional information, please contact me.

Sincerely,
Steve Fitzgibbons

Steven Fitzgibbons, AICP
Intergovernmental Planner
Governmental Affairs Program
St. Johns River Water Management District
7775 Baymeadows Way, Suite 102
Jacksonville, FL 32256
Office (386) 312-2369
E-mail: sfitzgibbons@sjrwmd.com
Website: www.sjrwmd.com
Connect with us: Newsletter, Facebook, Twitter, Instagram, YouTube, Pinterest
email-footer

---

**From:** Takira Thompson [mailto:tthompso@psc.state.fl.us]
**Sent:** Thursday, May 31, 2018 5:10 PM
**To:** Ann Shortelle <ashortelle@sjrwmd.com>
**Cc:** Phillip Ellis <PEllis@PSC.STATE.FL.US>; Charles Murphy <cmurphy@PSC.STATE.FL.US>
**Subject:** Request for Comments on the 2018 Ten-Year Site Plans of Florida's Electric Utilities

**Please see the attached file to see all relevant 2018 Ten Year Site Plans.**

Good afternoon,

Pursuant to Section 186.801, Florida Statutes, the Florida Public Service Commission (Commission) is responsible for reviewing and classifying each electric utility's Ten-Year Site Plan as "suitable" or "unsuitable." As part of the annual review in accordance with Rule 25-22.071, Florida Administrative Code, the Commission must provide a copy of the relevant Ten-Year Site Plans and solicit the views of the appropriate state, regional, and local agencies. To this end, the Commission has made available on its website electronic copies of the 2018 Ten-Year Site Plans for all the Florida electric utilities at the following link: http://www.psc.state.fl.us/ElectricNaturalGas/TenYearSitePlans

Please forward all comments by September 1, 2018, including an electronic copy to my email address below. If you have any questions or require additional time to file comments please feel free to contact me by phone at (850) 413-6592 or by email (tthompso@psc.state.fl.us) or Phillip Ellis by phone at (850) 413-6626 or by email (pellis@psc.state.fl.us). Thank you for your assistance.

*Takira T. Thompson*
ENGINEERING SPECIALIST
DIVISION OF ENGINEERING
FLORIDA PUBLIC SERVICE COMMISSION
TALLAHASSEE, FL 32311
PHONE: 850-413-6592

Water Management District

# Southwest Florida Water Management District

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Southwest Florida Water Management District

2379 Broad Street, Brooksville, Florida 34604-6899
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WaterMatters.org

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Bartow, Florida 33830-7700
(863) 534-1448 or
1-800-492-7862 (FL only)

**Sarasota Office**
6750 Fruitville Road
Sarasota, Florida 34240-9711
(941) 377-3722 or
1-800-320-3503 (FL only)

**Tampa Office**
7601 U.S. 301 North (Fort King Highway)
Tampa, Florida 33637-6759
(813) 985-7481 or
1-800-836-0797 (FL only)



August 21, 2018

Mr. Takira Thompson, Engineering Specialist
Florida Public Service Commission
Division of Engineering
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

**Subject: 2018 Electric Utility Ten-Year Site Plans**

Dear Mr. Thompson:

In response to your request, the Southwest Florida Water Management District (District) has completed its review of the 2017 Ten-Year Site Plans for Duke Energy Florida (DEF), Florida Power & Light Company (FPL) and Seminole Electric Cooperative (SEC). The District's review is being conducted pursuant to Section 186.801(2)(e), Florida Statutes, which requires the Public Service Commission to consider "the views of the appropriate water management district as to the availability of water and its recommendation as to the use by the proposed plant of salt water or fresh water for cooling purposes." Based on our review, DEF is planning to construct three new combustion turbine units in 2027 at undesignated sites which may or may not be located within the District's jurisdictional boundaries. It does not appear that FPL and SEC are proposing any new generating facilities within the District's jurisdictional boundaries, except for potential FPL solar generating facilities that do not require use of significant quantities of water.

The District offers the following technical assistance comments for consideration.

- The most water conserving practices must be used in all processes and components of the power plant's water use that are environmentally, technically and economically feasible for the activity, including reducing water losses, recycling, and reuse. If a lower quality water is available and is environmentally, technically and economically feasible for all or a portion of the proposed use, this lower quality water must be used.

- For new generating facilities proposed in the southern and much of the central portions of the District, there are additional water use constraints. These areas have been designated as Water Use Caution Areas. This designation has occurred in response to water resource impacts, such as saltwater intrusion, lowered water levels in lakes and wetlands, and reduced stream flows, which have been caused by excessive ground water withdrawals. Regional recovery strategies are being implemented to address these adverse water resource impacts. Consequently, the District has heightened concerns regarding potential impacts due to additional water withdrawals in these areas.

Early coordination with the District's Water Use Permit (WUP) staff is encouraged prior to submittal of any Site Certification or WUP applications. For assistance or additional information concerning the District's WUP program, or to schedule a preapplication conference, please contact April Breton, WUP manager, at (813) 985-7481, extension 2049, or april.breton@watermatters.org.

We appreciate this opportunity to participate in the review process. If you have any questions or require further assistance, please do not hesitate to contact me at (352) 796-7211, extension 4790, or james.golden@watermatters.org.

Sincerely,

James J. Golden, AICP
Senior Planner

JG
c: April Breton, SWFWMD

Water Management District

# Suwannee River Water Management District

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**Appendix A**

# SUWANNEE RIVER WATER MANAGEMENT DISTRICT



August 27, 2018

Ms. Takira Thompson
Engineering Specialist
Division of Engineering
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

RE: Review of the 2018 Ten-Year Site Plans for Florida's Electric Utilities

Dear. Ms. Thompson,

The Suwannee River Water Management District (District) appreciates the opportunity to review the relevant 2018 Ten-Year Sites Plans. District staff review the Ten-Year Site Plans for Duke Energy, Seminole Electric, Florida Power & Light Company, Gainesville Regional Utilities, and Florida Municipal Power Agency which have facilities or serve areas in the District. It is the District staff opinion that there does not appear to be any planning issues pertaining to water resources for the relevant Ten-Year Site Plans.

Sincerely,

Steve Minnis
Deputy Executive Director

cc/email: Phillip Ellis, Florida Public Service Commission

Water for Nature, Water for People

9225 CR 49 • LIVE OAK, FLORIDA 32060 • TELEPHONE 386/362-1001 • 800/226-1066 • FAX 386/362-1056
mysuwanneeriver.com

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Local Government

# Polk County

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| | |
|---|---|
| **From:** | Deardorff, Thomas |
| **To:** | Takira Thompson |
| **Cc:** | Freeman, Jim; Beasley, Bill |
| **Subject:** | 2018 Ten-Year Site Plans of Florida"s Electric Utilities - Polk County |
| **Date:** | Friday, August 24, 2018 2:09:55 PM |
| **Attachments:** | image001.png<br>image002.png |

Ms. Thompson:

We appreciate the opportunity to review the Ten-Year Site Plans for the electric utilities in Polk County. Our staff does not have any comments to offer.

Thanks.
Tom

**Tom Deardorff, AICP**
**Assistant County Manager - Planning and Development**
**Executive Director | Polk Transportation Planning Organization**
330 W. Church Street | 863-534-6467 | 863-534-6543 (fax)
P.O. Box 9005, Drawer GM01 | Bartow, FL 33831-9005

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Local Government

# St. Lucie County

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| | |
|---|---|
| **From:** | Mayte Santamaria |
| **To:** | Takira Thompson; Phillip Ellis |
| **Cc:** | Leslie Olson; Mayte Santamaria |
| **Subject:** | RE: Request for Comments on the 2018 Ten-Year Site Plans of Florida's Electric Utilities |
| **Date:** | Tuesday, July 03, 2018 9:53:35 AM |

Good morning,

St. Lucie County has reviewed the 2018 Ten-Year Site Plans for the Florida electric utilities, principally the Florida Power & Light Company's 2018 Ten-Year Power Plant Site Plan (Plan). The Plan identifies Interstate Solar Energy Center in St. Lucie County with an anticipated construction start date of 2018 and an anticipated commercial in-service date of 2019.

The County has reviewed this proposal and has processed FPL's development proposal requests related to the Interstate Solar Energy Center. The Board of County Commissioners of St. Lucie County adopted Resolution 2018-10 on January 23, 2018, granting a Conditional Use Permit approval for the construction and operation of a 74.5 MW photovoltaic solar center on +/-540 of agricultural land consisting of seven (7) parcels located West of Interstate 95, northeast of the Florida's Turnpike and north of Belcher Canal (C-25 Canal). The Board of County Commissioners of St. Lucie County adopted Resolution 2018-09 on January 23, 2018, granting major site plan approval for the construction and operation of a 74.5 mw photovoltaic solar energy center on +/-540 acres. The project includes approximately 300,000 solar panels that will cover approximately half the property, a substation, and stabilized access paths. The solar panels stand approx. 2 feet off the ground at their lowest point and are approx. 6 to 7 feet in height at their highest point.

Thank you for the opportunity to review and comment ten-year site plan.

Mayte

Mayte Santamaria
Planning and Development Services Assistant Director
2300 Virginia Avenue
Ft. Pierce, FL 34982
(772) 462-1589
www.stlucieco.org

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-------- Original message --------
From: Takira Thompson <tthompso@psc.state.fl.us>
Date: 5/31/18 4:46 PM (GMT-05:00)
To: Howard Tipton <TiptonH@stlucieco.org>
Cc: Phillip Ellis <PEllis@PSC.STATE.FL.US>, Charles Murphy <cmurphy@PSC.STATE.FL.US>
Subject: Request for Comments on the 2018 Ten-Year Site Plans of Florida's Electric Utilities

**Please see the attached file to see all relevant 2018 Ten Year Site Plans.**

Good afternoon,

Pursuant to Section 186.801, Florida Statutes, the Florida Public Service Commission (Commission) is responsible for reviewing and classifying each electric utility's Ten-Year Site Plan as "suitable" or "unsuitable." As part of the annual review in accordance with Rule 25-22.071, Florida Administrative Code, the Commission must provide a copy of the relevant Ten-Year Site Plans and solicit the views of the appropriate state, regional, and local agencies. To this end, the Commission has made available on its website electronic copies of the 2018 Ten-Year Site Plans for all the Florida electric utilities at the following link: http://www.psc.state.fl.us/ElectricNaturalGas/TenYearSitePlans

Please forward all comments by September 1, 2018, including an electronic copy to my email address below. If you have any questions or require additional time to file comments please feel free to contact me by phone at (850) 413-6592 or by email (tthompso@psc.state.fl.us) or Phillip Ellis by phone at (850) 413-6626 or by email (pellis@psc.state.fl.us). Thank you for your assistance.

*Takira T. Thompson*
ENGINEERING SPECIALIST
DIVISION OF ENGINEERING
FLORIDA PUBLIC SERVICE COMMISSION
TALLAHASSEE, FL 32311
PHONE: 850-413-6592

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Please Note: Florida has very broad public records laws. Most written communications to or from County officials regarding County business are public records available to the public and media upon request. It is the policy of St. Lucie County that all County records shall be open for personal inspection, examination and / or copying. Your e-mail communications will be subject to public disclosure unless an exemption applies to the communication. If you received this email in error, please notify the sender by reply e-mail and delete all materials from all computers.

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Please Note: Florida has very broad public records laws. Most written communications to or from County officials regarding County business are public records available to the public and media upon request. It is the policy of St. Lucie County that all County records shall be open for personal inspection, examination and / or copying. Your e-mail communications will be subject to public disclosure unless an exemption applies to the communication. If you received this email in error, please notify the sender by reply e-mail and delete all materials from all computers.

Environmental Group

# Sierra Club

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SIERRA CLUB

September 14, 2018

*Via electronic filing and electronic mail*

Chairman Graham, Comm'rs. Brown, Clark, Fay, Polmann
Florida Public Service Commission
2540 Shumard Oak Blvd
Tallahassee, Florida 32399-0850

**Re: Planning for least-cost electric service via 10-Year Site Plans**

Dear Commissioners:

On behalf of its more than 38,000 Florida members, Sierra Club urges you to reject the 10-Year Site Plans filed by Florida's electric utilities this year ("2018 Plans") because, contrary to Florida law, they fail to minimize the significant climate change costs arising from utilities' heavy reliance on fossil fuels and Florida's resulting vulnerability to catastrophic climate damages.[1] The law requires utilities to transition to abundant, affordable clean energy, as discussed in Sierra Club's past comments, incorporated herein by reference.[2] The utilities, however, plan to double-down on fossil fuels, especially gas imported from out of state, despite the overwhelming evidence that doing so hurts Floridians.

In fact, the utilities' planned expenditures on fossil fuel-burning power plants dwarfs their planned investments in clean energy. The Florida Public Service Commission (Commission) has no basis to approve such skewed plans because the utilities never reconciled their plans with the failing economics of fossil fuel-burning plants and their destructive environmental impacts. Nor have the utilities performed any basic side-by-side comparisons of such plants against clean energy alternatives. The 2018 Plans are clearly "unsuitable" for the purpose of ensuring least-cost electric service and therefore should be rejected.[3]

[1] "Increasing the concentration of carbon dioxide in the atmosphere increases the rate of climate change, which, in turn, accelerates sea level rise." *In Re: FPL Dania Beach Energy Center Project Power Plant Siting Act Application No. PA-89-26A2*, Florida Division of Administrative Hearings, Case No. 17-4388-EPP (July 30, 2018), Recommended Order on Certification at ¶ 181, available at: https://bit.ly/2QjLnqz. "Sea level rise causes substantial coastal hazards, including inundation of land, higher storm surges, higher king tides, increased flood height and frequency, coastal erosion and destruction of coastal mangroves and other ecosystems, erosion and destruction of coastal barrier islands, and saltwater intrusion into freshwater aquifers and ecosystems. These impacts will worsen or accelerate with sea level rise." Id. at ¶ 187.
[2] Sierra Club's past TYSP comments are available at the following: https://bit.ly/2oZBEt8.
[3] Section 186.801, Fla.Stat.

Sierra Club's comments recap the latest evidence that dirty power plants cannot keep up with the continuous cost and performance improvements of clean alternatives, such as solar, solar paired with storage, energy efficiency and other demand-side technologies. Based on this evidence and the Commission's charge to protect and serve the public interest, the Commission should reject the 2018 Plans or, at a minimum, defer any decision until the utilities fix their glaring omissions. In particular, the Commission should require the utilities to test the market and thereupon submit actual cost data on clean energy alternatives by the April 1, 2019, deadline for new plans. While we have advocated such commonsense enforcement of the laws in past comments, we now underscore the urgency of doing so in light of catastrophic climate damages threatening Florida under the utilities' business-as-usual, fossil-fuel intensive plans.

## DISCUSSION

The utilities fail to reconcile their 2018 Plans with abundant, money-saving, clean energy alternatives to fossil fuel-burning generation. Because market conditions overwhelmingly favor the alternatives, the Commission should reject the 2018 Plans.

### A. Planned gas-burning generation: When you're in a hole, stop digging.

The problem with gas is two-fold: Florida already burns too much gas for power, and every day that Florida continues to burn gas for power it becomes more vulnerable to catastrophic climate damages. Yet the utilities nonetheless plan to add more than 10,000 MW of gas-burning generation by 2027.[4] FPL plans to continue generating most of its power by burning gas at 65%.[5] DEF and TECO plan to increase their gas generation by 2023 from 58.6% to 77.3%[6]and from 73% to 81%, respectively.[7] As Florida Commission Chair Art Graham recently stated, Florida utilities are guilty of "moving all of our eggs to one basket."[8]

The costs to Floridians of gas over-reliance are well-documented: over $7 billion on hedging programs since 2002.[9] It also exposes Floridians to significant economic risk and enormous costs, as gas markets are prone to wild swings, as demonstrated by spiking prices in 2001, 2003, 2006 and 2008.[10] Even the Commission has recognized the problem with price volatility when it sought solutions to limit customers' exposure to volatile gas markets.[11] FPL, the state's largest

[4] Exhibit C: Planned Gas Burning Generation Additions.
[5] FPL 2018 10-Year Site Plan, Schedule 6.2.
[6] DEF 2018 10-Year Site Plan, Schedule 6.2.
[7] TECO 2018 10-Year Site Plan, Schedule 6.2.
[8] September 2018 Today's Public Utility Fortnightly, *Florida's PSC Chair Art Graham and Commissions Julie Brown,* available at: https://bit.ly/2N0Afkt.
[9] Direct testimony of Elizabeth A. Stanton On Behalf of Sierra Club, filed Aug. 10, 2017, Docket No. 20170057-EI. *See also* https://bit.ly/2kklfNc.
[10] U.S. Energy Info. Admin., *Henry Hub Natural Gas Spot Price*, (July 6, 2017), available at: https://bit.ly/2JDkfPn; *see also* Briefing by Public Counsel (July 15, 2016), Docket No. 160096-EI, *Joint Petition for approval of modifications to risk management plans by DEF, FPL,Gulf and Tampa Electric Co*., available at: https://bit.ly/2xerj0k.
[11] *See* Sierra Club, Comment Letter on Staff and IOU Proposed Natural Gas Hedging Strategies (Mar. 6, 2017), Docket No. 20170057 (Mar. 6, 2017), available at: https://bit.ly/2MsPk9f.

utility, has even acknowledged the risk that gas reliant units will be economically obsolete by 2020, raising stranded asset risks.[12]

In addition, because the costs of wind, solar, and batteries are dropping dramatically,[13] utilities throughout the country are skipping what was once termed the "natural gas bridge" (the bridge between coal and renewables) in favor of combinations of clean energy.[14] For example, Consumers Energy, in Michigan, submitted an Integrated Resource Plan (IRP) in June with 5000 MW solar and 550 MW wind in conjunction with storage and DSM.[15] In March, the Arizona Public Service Commission rejected an IRP because it relied on too much gas without an adequate price sensitivity analyses.It then placed a 9 month moratorium on new gas plants larger than 150 MW and required the utilities to model higher levels of renewable and storage.[16] These examples demonstrate that utilities and public service commissions around the country recognize that clean energy portfolios are becoming the norm.

This trend is occurring because, among other reasons, clean energy has zero fuel costs, unlike the highly volatile fuel costs from gas-burning power plants.[17] On a levelized cost basis, utility-scale solar PV (including the tax credit) is currently cost-competitive with combined-cycle gas plants,[18] and forecasts are "suggest[ing] that it may be cheaper to build new renewables+storage than to continue operating ***existing*** gas plants."[19] The National Renewable Energy Laboratory forecasts that the levelized cost of clean energy between 2020 and 2050 will fall dramatically while the levelized cost of fossil fuel generation will hold steady or even increase, as detailed in the table below.[20]

[12] Eric Wesoff, *NextEra on Storage: Post 202, There May Never Be Another Peaker Built in the US,* Greentech Media (Sept 30, 2015),available at: https://bit.ly/2x1sAIH.
[13] See below, Section C.
[14] *See* David Roberts, *Clean Energy is Catching Up to Natural Gas*, Vox (Aug 2018), available at: https://bit.ly/2MhDqza.
[15] *See id*.
[16] *See* Julian Spector, *Arizona Regulators Freeze New Gas Plants, Demand More Clean Energy Planning From Utilities*, Greentech Media (March 2018), available at: https://bit.ly/2MixyFB; *see also* https://bit.ly/2QrWw8U.
[17] *See id.* Some recent examples evidence that this forecast is becoming the new reality. Recently, the Colorado Public Utilities Commission (PUC) approved Xcel Energy's Colorado Energy Plan (CEP) to close coal-fired units 1 and 2 at the Comanche Generating Station in Pueblo ten years ahead of schedule. Colorado's largest utility will replace that coal generation with a $2.5 billion investment in mostly renewable energy and battery storage, estimated by Xcel to save customers as much as $374 million.
[18] U.S.Energy Information Administration, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2018* at 5, Tables 1a, 1b (March 2018), available at: https://bit.ly/2oslEy3.
[19] David Roberts, "Clean Energy is Catching Up to Natural Gas," Vox (Aug 2018), available at: https://bit.ly/2MhDqza.
[20] Silvio Marcacci , *Cheap Renewables Keep Pushing Fossil Fuels Further Away from Profitability - Despite Trumps Efforts*, Forbes (Jan. 23, 2018), available at: https://bit.ly/2NaID0U.

| Levelized Cost in MW/h | | | | | |
|---|---|---|---|---|---|
| | **Onshore Wind** | **Utility Scale Solar-PV** | **Combined-Cycle Gas** | **Coal** | **Nuclear** |
| **2020** | $39 | $51 | $43 | $71 | $79 |
| **2050** | $28 | $37 | $51 | $68 | $78 |

In the words of Tom Sanzillo, Director of Finance for the Institute for Energy Economics and Financial Analysis, "clean energy is now cheap energy."[21]

In summary, the utilities' 10 GW of new gas-burning generation is unjustified, risks leaving the customers holding the bag, and will become uncompetitive long before these new gas plants complete their life-cycle. This alone renders the 2018 Plans wholly unsuitable and requires their rejection.

### B. Building over 10,000 MW of gas-burning generation,[22] and its resulting potential 482,816,334 tons of GHG emissions, ignores the dire threat of climate change to Florida.

Carbon dioxide is a powerful greenhouse gas, and incremental emissions of carbon dioxide to the atmosphere will exacerbate climate change and the damage caused by climate change.[23] Climate change poses the greatest risk to Florida, of all states in the United States.[24] Under current projections, $15 billion to $23 billion of existing property in Florida will likely be underwater by 2050."[25]

The Florida Legislature even made it a state policy to consider the costs and risks of climate change: It is the policy of the State of Florida to:

> …[c]onsider, in its decision-making, the social, economic, and environmental impacts of energy-related activities, including the whole-life cycle impacts of any potential energy use choices, so that detrimental effects of these activities are understood and minimized.[26]

[21] *See* IEEFA Op-Ed: In 2018, *Expect Clean Energy to be Cheap Energy*, Tom Sanzillo (Jan.9, 2018), available at: https://bit.ly/2NEjlrA.
[22] *See* Exhibit C Planned Gas Burning Generation Additions 2018.
[23] *See* Intergovernmental Panel on Climate Change, *Climate Change 2013: The Physical Science Basis, Summary for Policymakers*, available at: https://bit.ly/1zekdFi.
[24] Trevor Houser, Solomon Hsiang, Robert Kopp, and Kate Larsen (2015), *Economic Risks of Climate Change: An American Perspective* (New York: Columbia University Press).
[25] Risky Business, The Economic Risks of Climate Change in the U.S., *A Climate Risk Assessment for the United States*, p.24 (June 2014), available at: https://bit.ly/2Lqhg24.
[26] Section 377.601(2)(j). Fla. Stat.

Climate change causes numerous coastal hazards including: sea level rise (SLR); higher storm surges; higher king tides; increased flooding and frequency of flooding; and saltwater intrusion displacing freshwater aquifers.[27] According to the U.S. government, "it is virtually certain that sea level rise this century and beyond will pose a growing challenge to coastal communities, infrastructure, and ecosystems from increased (permanent) inundation, more frequent and extreme coastal flooding, erosion of coastal landforms, and saltwater intrusion within coastal rivers and aquifers."[28]

Rising sea levels substantially increase the vulnerability of populations, specifically coastal populations, which are growing in the United States,[29] including Florida.[30] Researchers have predicted that 3 feet of sea level rise would permanently flood areas currently home to two million Americans.[31] Sea level rise is happening[32] and the major driver of sea level rise is climate change.[33]

Florida utilities are nonetheless proposing to build and expand gas plants in areas of great risk to climate change. FPL proposes to build Dania Beach Unit 7 in Southeast Florida, which is especially vulnerable to climate change.[34] Likewise, Hillsborough County, where TECO proposes to build another massive combined-cycle power plant is also at great risk of sea level rise impacts. Numerous studies estimate the projected sea level rise due to climate change. In particular, the Unified Sea Level Rise report prepared by the Tampa Bay Regional Planning Council, concludes that a reasonable high-end prediction of sea level rise by 2060, within the life-span of the Big Bend project, is approximately 3 feet in St. Petersburg, and by 2100, a reasonable high end prediction nears 7 feet.[35]

[27] Testimony of George Maul, May 16, 2018 (May 16 PM T.106:7 to 107:25, *In Re: FPL Dania Beach Energy Center Project Power Plant Siting Act Application No. PA-89-26A2*, Florida Division of Administrative Hearings Case No. 17-4388-EPP (July 30, 2018), attached as Exhibit H.
[28] U.S. Global Change Research Program, *Climate Science Special Report* 334 (2017); *see also* NOAA, *Global & Regional Sea Level Rise Scenarios for the U.S.* at 1 (2017) ("Long-term sea level rise driven by global climate change presents clear and highly consequential risks to the United States over the coming decades and centuries.").
[29] NOAA, *Global & Regional Sea Level Rise Scenarios for the U.S.* at 1 (2017), available at: https://bit.ly/2jgZnRb.
[30] Jeff Donn, *U.S. coast population continues to grow despite lessons of past storms,* Associated Press (Sept 16, 2017), available at: https://dpo.st/2xeZbdo.
[31] NOAA, *Global & Regional Sea Level Rise Scenarios for the U.S.* at 1 (2017), available at: https://bit.ly/2jgZnRb.
[32] *See* Maul May 16 PM T.101:17-19; Kennard F Kosky, May 16 AM T.111:14-25; SC-46, attached as Exhibit I; *see also* U.S. Nat'l Climate Assessment, *Climate Change Impacts in the U.S* p.44 (2014); SC-84, NOAA, *Global & Regional Sea Level Rise Scenarios for the U.S.* at 1 (2017).
[33] *See* Ex. H, Maul, May 16 PM T.103:22-24 & T.165:18-21.
[34] *See* Ex. H, Maul, May 16 PM T.109:12-24 & T.157:11-15; *see also* Wdowinski et al., Increasing Flooding Hazard in Coastal Communities Due to Rising Sea Level: Case Study of Miami Beach, 126 Ocean & Coastal Mgmt. 1, 1-2 (2016), available at: https://bit.ly/2p18LwE.
[35] *Recommendation for a Unified Projection of Sea Level Rise in the Tampa Bay Region*, Tampa Bay Climate Science Advisory Panel, available at: https://bit.ly/2oXcFH2.

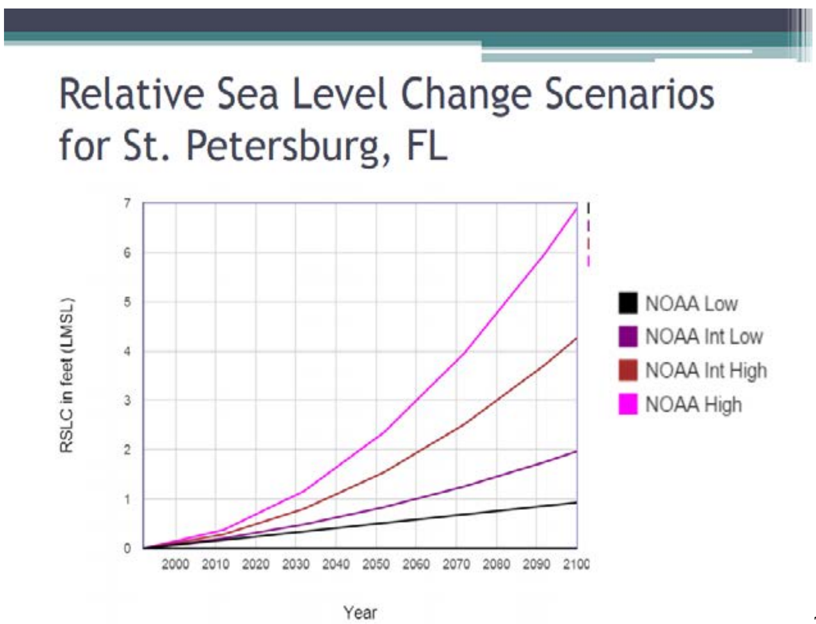
**Estimated Relative Sea Level Rise 1992 To 2100**

St. Petersburg, FL (Feet), NOAA Station #8726520

All values are expressed in **Feet** relative to LMSL

| Year | NOAA Low (Feet) | NOAA Int Low (Feet) | NOAA Int High (Feet) | NOAA High (Feet) |
|---|---|---|---|---|
| 1992 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2012 | 0.17 | 0.21 | 0.29 | 0.38 |
| 2032 | 0.34 | 0.49 | 0.80 | 1.16 |
| 2052 | 0.52 | 0.84 | 1.54 | 2.36 |
| 2072 | 0.69 | 1.26 | 2.52 | 3.96 |
| 2092 | 0.86 | 1.75 | 3.72 | 5.97 |
| 2100 | 0.93 | 1.97 | 4.26 | 6.89 |

[36]




[37]

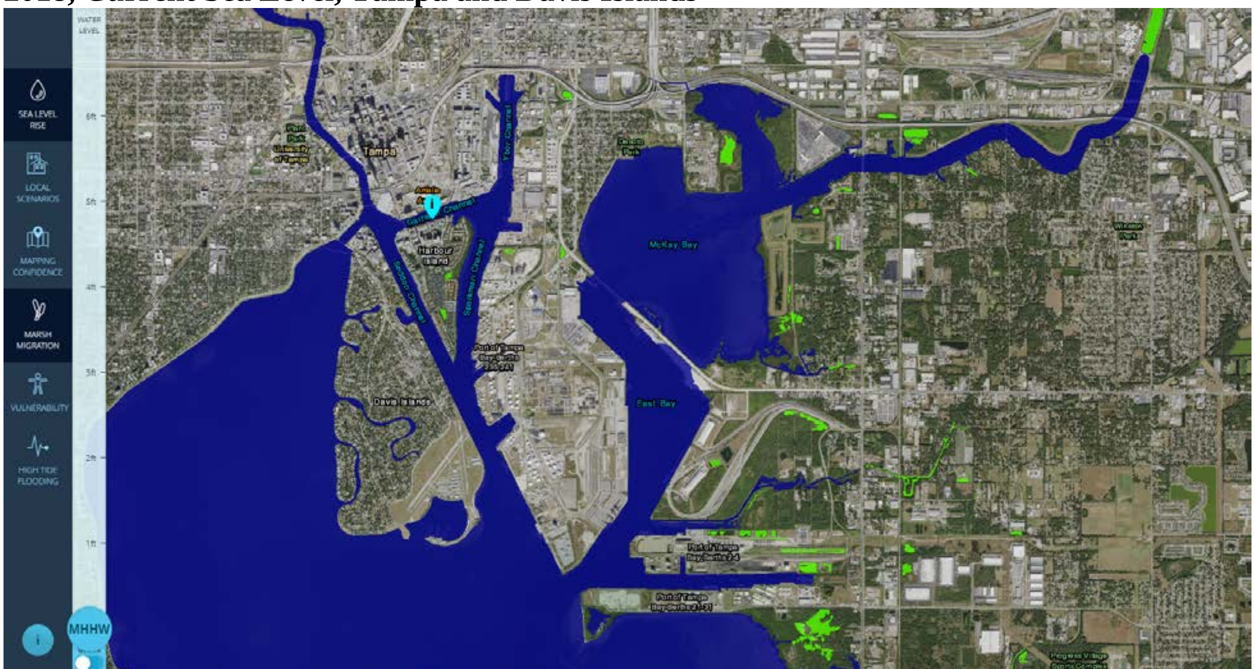
These predictions are based on data from the National Oceanic and Atmospheric Administration, ("NOAA"), and, as alarming as they are, understate the threats to Florida. Sea level rise is accelerating rapidly[38]—in Southeast Florida the average rate of sea level rise since 2006 has

[36] *Id*. at slide 16.
[37] *Id.* at slide 17.
[38] Climate Change Impacts in the United States, U.S. National Climate Assessment, 2014, Chapter 2 "Our Changing Climate" pp.44-45, available at: https://bit.ly/2OelMOx.

been 9 +/-4 mm per year.[39] These predictions do not include the possibility of rapid deterioration of land ice,[40] and they only consider mean sea level rise, not high tides or storm surges.

Nonetheless, the consequences for Tampa, MacDill Air Force Base, St Petersburg, and Hillsborough County are alarming. NOAA's Sea Level Rise Viewer tool displays the staggering amount of permanently inundated land by 2060 and 2090 under the NOAA high prediction.[41] Quite literally, as shown below, MacDill Air Force Base will cease to exist. So will much of Apollo Beach, including the Big Bend site, Hillsborough County, and Tampa. The Davis Islands will disappear, along with St. Pete's Beach and the islands to the north. Again, these images are only of mean sea level rise – they do not reflect king tides, or storm surges.

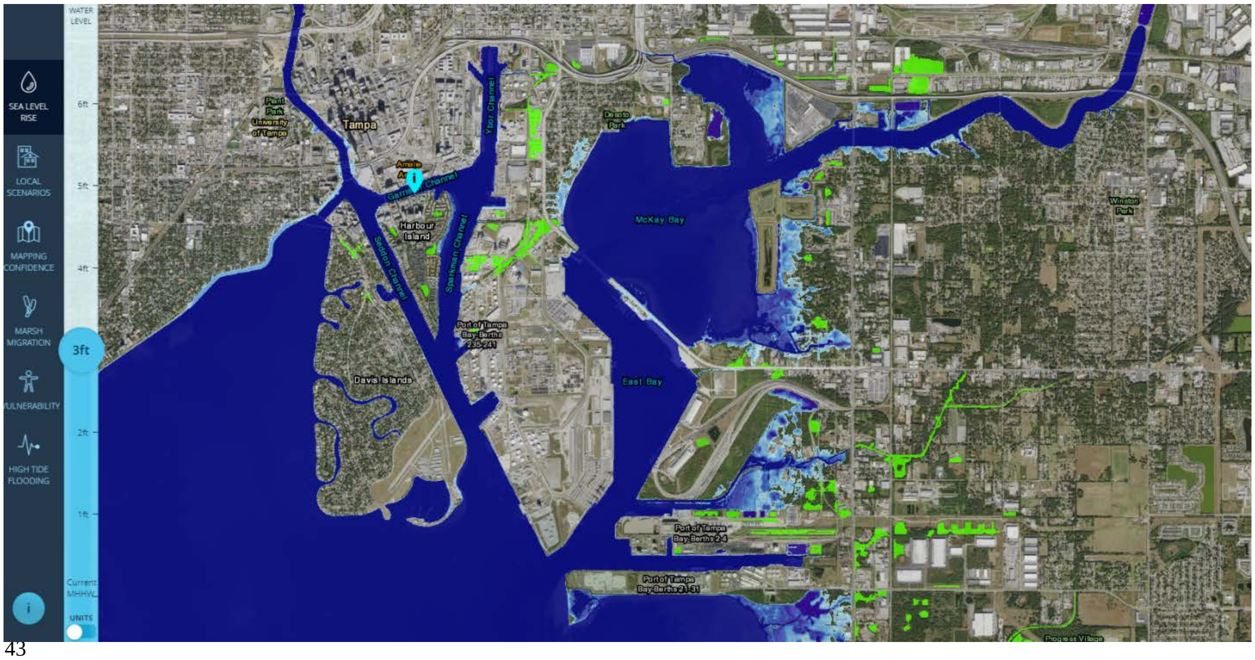
**2018, Current Sea Level, Tampa and Davis Islands**



[42]

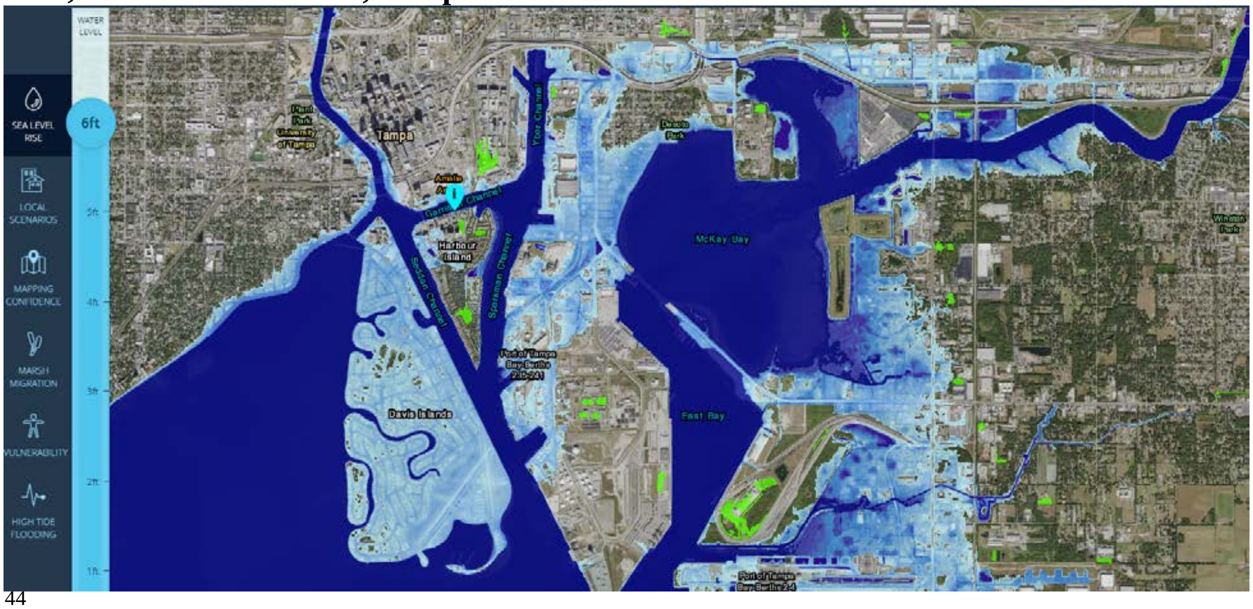
[39] Southeast Florida Regional Compact Climate Change. Unified Sea Level Rise Projection at 9 (Oct. 2015), available at: https://bit.ly/1LG66vc.
[40] Climate Change Impacts in the United States, U.S. National Climate Assessment, 2014, Chapter 2 at 44-45, available at: https://bit.ly/2OelMOx.
[41] According to NOAA's Sea Level Rise Viewer Legend Toggle, the green denotes "low lying areas," and the range of blue conveys water depth. Available at: https://bit.ly/2NDi3Nv.
[42] NOAA, Sea Level Rise Viewer, Florida, available at: https://bit.ly/2x0hW3X.

**2060, 3 feet of Sea Level Rise, Tampa and Davis Islands**




43

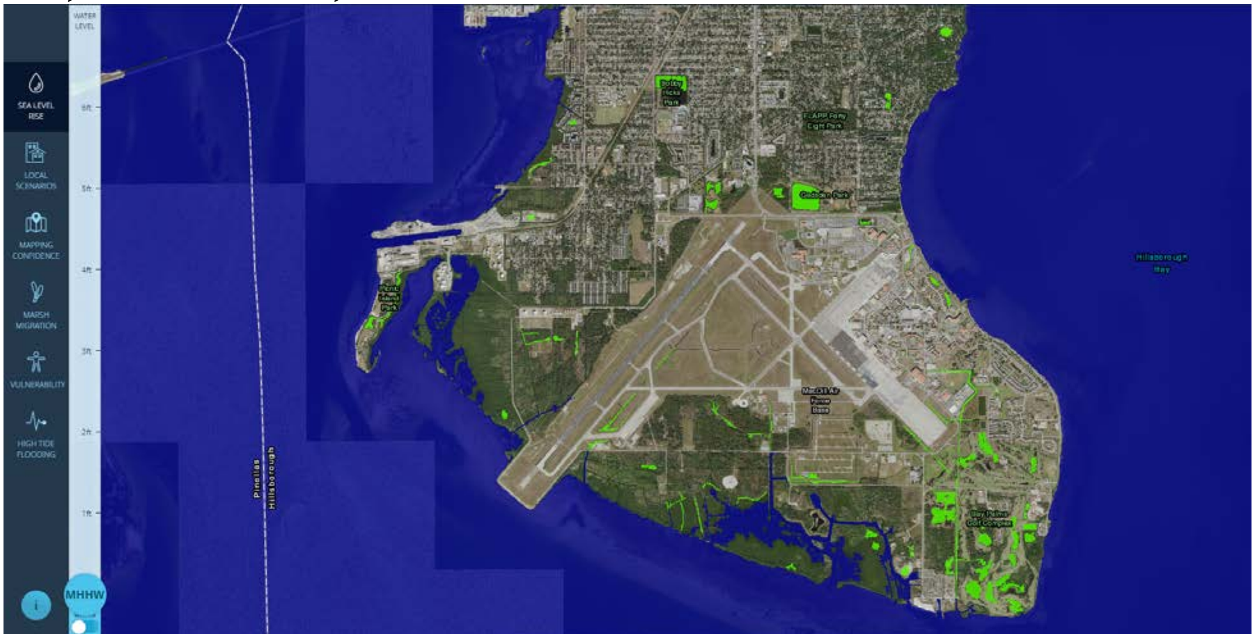
**2090, 6 feet Sea Level Rise, Tampa and Davis Islands**




44

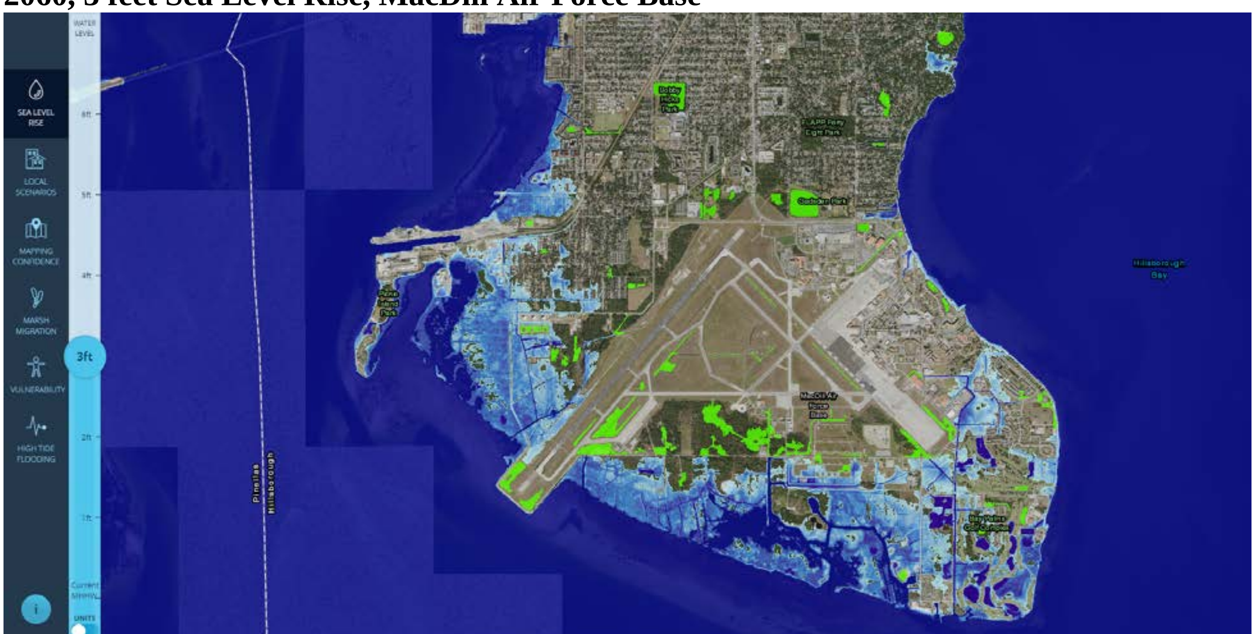
[43] *Id*.
[44] *Id*.

**2018, Current Sea Level, MacDill Air Force Base**




[45]

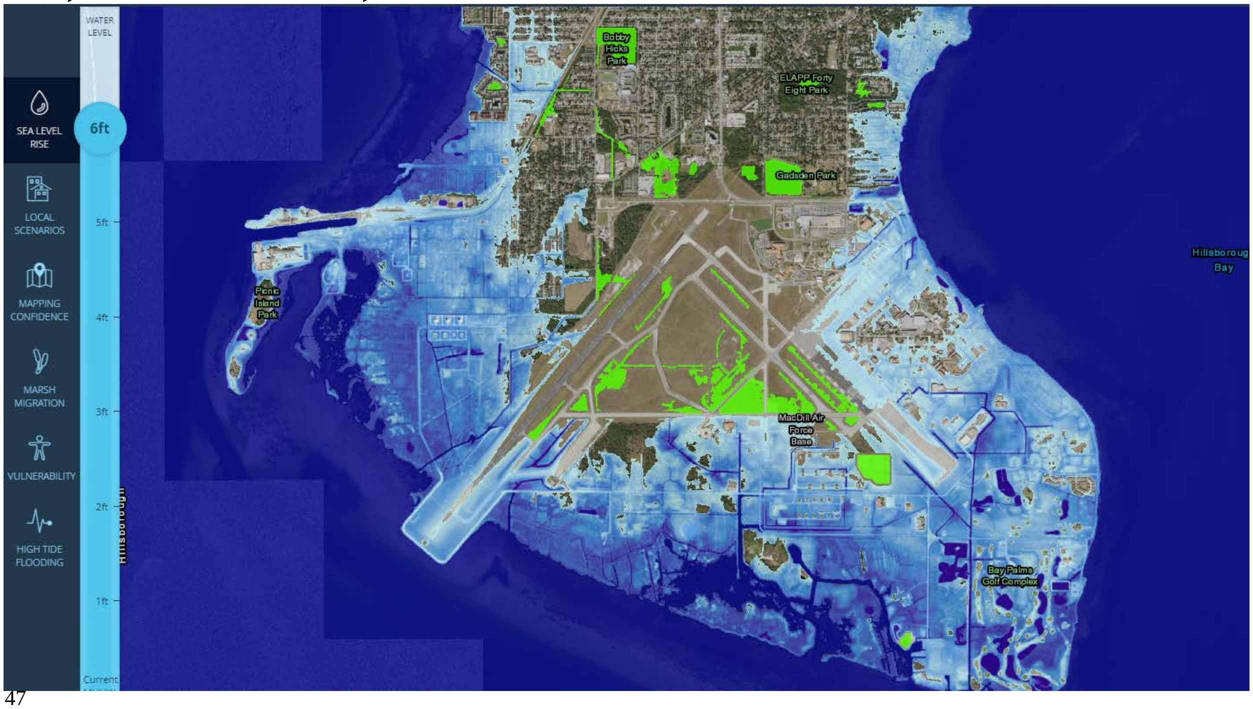
**2060, 3 feet Sea Level Rise, MacDill Air Force Base**




[46]

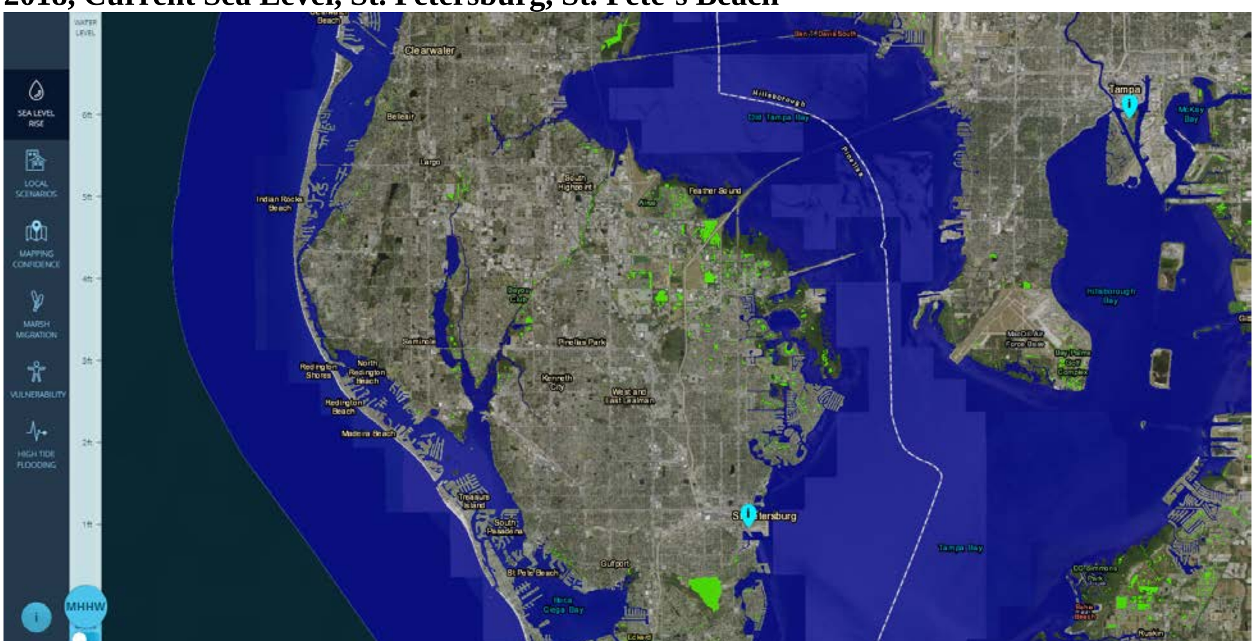
[45] *Id.*
[46] *Id.*

**2090, 6 feet Sea Level Rise, MacDill Air Force Base**



[47]

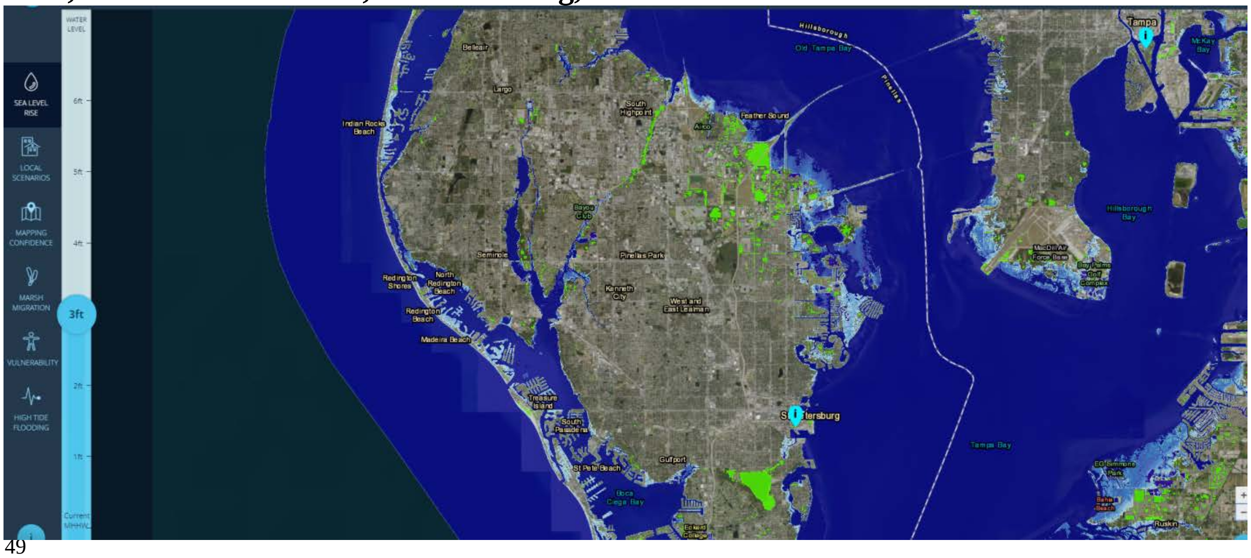
**2018, Current Sea Level, St. Petersburg, St. Pete's Beach**



[48]

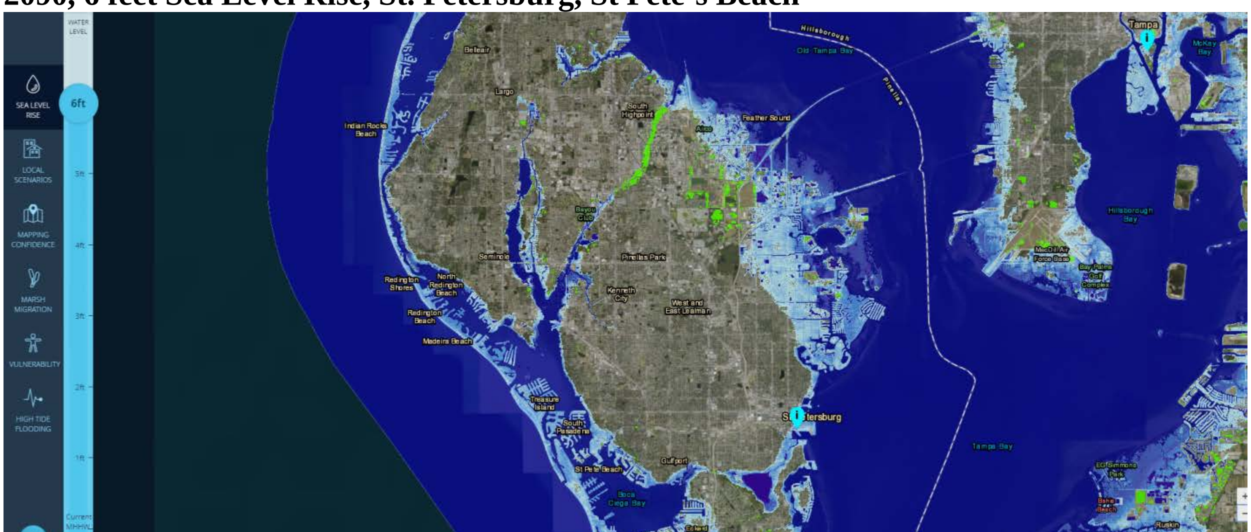
[47] *Id.*
[48] *Id.*

**2060, 3 feet Sea Level Rise, St. Petersburg, St. Pete’s Beach**




[49]

**2090, 6 feet Sea Level Rise, St. Petersburg, St Pete’s Beach**




[50]

[49] *Id.*
[50] *Id.*

**2018, Current Sea Level, Apollo Beach and Big Bend site**

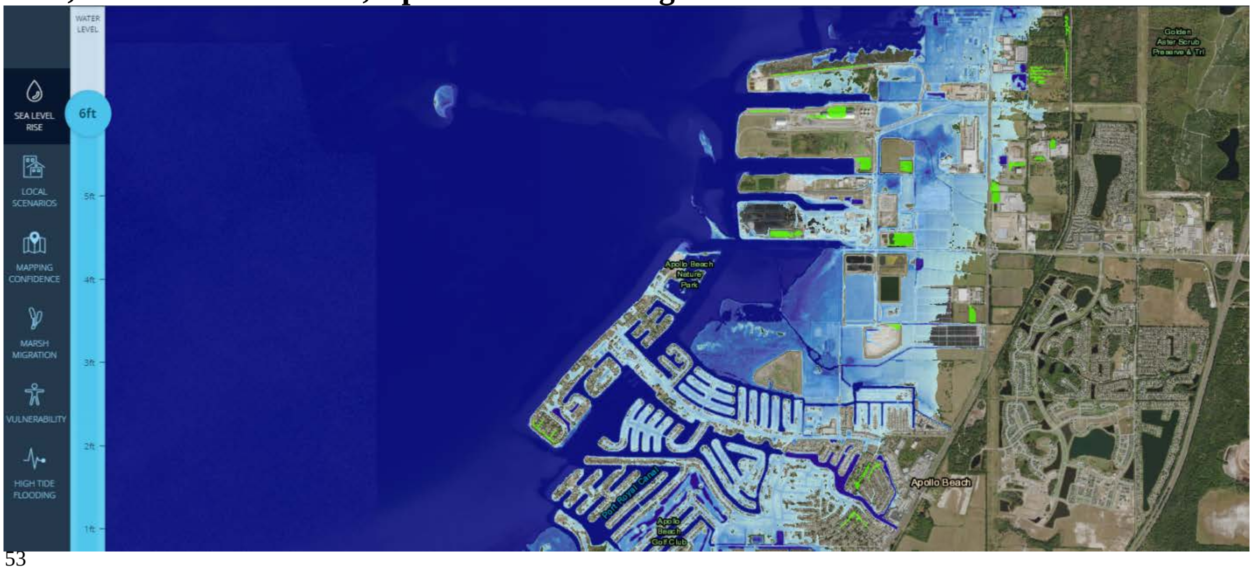

[51]

**2060, 3 feet Sea Level Rise, Apollo Beach and Big Bend site**


[52]

[51] *Id.*
[52] *Id.*

**2090, 6 feet Sea Level Rise, Apollo Beach and Big Bend site**



[53]

Sea level rise is just one aspect of climate damage that Florida will continue to suffer. Climate change also poses an acute threat to tourism,[54] beaches,[55] public health,[56] and wildlife,[57] among others. The economic harm caused by climate change can be quantified in a number of ways. One established conservative approach uses a federal government calculation for the Social Cost of Carbon (SCC). The latest federal SCC estimate is $49 for emissions in 2020, rising to $70 in 2040 and $81 in 2050 (converted to 2017 dollars per metric ton of $CO_2$).[58]

According to a recent in-depth study, Florida will suffer the worst climate damages of any of the 48 states covered, with a two-thirds probability that the cost impacts from climate change range between 10.1 and 24.0 percent of Florida's futures gross domestic product (GDP), largely due to heat-related mortality and coastal impacts.[59] There is a one in six chance that climate damages in

[53] *Id.*

[54] Robert Atzori and Alan Fyall (2018), "Climate change denial: vulnerability and costs for Florida's coastal destinations," *Journal of Hospitality and Tourism Insights* 1, pp. 137-149.

[55] Julie Harrington and Todd L. Walton, Jr. (2015), "Climate Change in Coastal Florida: Economic Impacts of Sea Level Rise," Florida State University.

[56] Risky Business Project (2015), "Come heat and high water: Climate risk in the southeastern U.S. and Texas," p.37, available at: https://bit.ly/2x25TTZ.

[57] Christopher P. Catano et al. (2014), "Using scenario planning to evaluate the impacts of climate change on wildlife populations and communities in the Florida Everglades," *Environmental Management* 55, pp. 807-823.

[58] Interagency Working Group (August 2016), "Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, available at: https://bit.ly/2o10VBB. Experts have identified that the calculations in this document underestimate the most serious climate risks, such that the actual costs should be much higher than those resulting from this approach. *See* Expert Report of Dr. Frank Ackerman at 1, filed as Sierra Club Exhibit 88 in *In Re: FPL Dania Beach Energy Center Project Power Plant Siting Act Application No. PA-89-26A2,* Florida Division of Administrative Hearings, Case No. 17-4388-EPP, attached as Exhibit J.

[59] Trevor Houser, Solomon Hsiang, Robert Kopp, and Kate Larsen (2015), *Economic Risks of Climate Change: An American Perspective* (New York: Columbia University Press). *See also* Ex. J, Expert Report of Dr. Ackerman pp. 9-11.

Florida will be even greater than a loss of 24 percent of GDP by the last two decades of this century.[60]

Translating these impacts into dollars shows staggering economic losses. In 2017, Florida's GDP was $967.3 billion.[61] Assuming Florida's economy continues to grow at the same rate that it has between 1997 and 2017,[62] a 2.24 percent real growth rate, Florida's GDP in 2090 would be $4,874 billion (in 2017 dollars). Climate losses of 10.1 to 24.0 percent of that amount would mean $492 to $1,170 billion per year, again in 2017 dollars.[63]

Florida is experiencing a massive rush to build out fracked gas plants and it is imperative that both the utilities and the Commission recognize the cumulative impacts this massive build-out will have across the State. Currently pending are five projects totaling 4,033MW: Dania Beach (1200 MW), Big Bend (1,090 MW), Seminole (1,050 MW), Shady Hills (573 MW) and McIntosh (120 MW). In addition, in the past four years, 4,050 MWs of gas at Riviera (1,250 MW), Port Everglades (1,200 MW) and Okeechobee (1,600 MW) have all been authorized. This brings the total amount of new fracked gas projects to 8,083MW,[64] none of which have taken into account the cumulative impacts of GHG emissions from permitting so many fracked gas plants—though that is itself an understatement as the Florida Department of Environmental Protection and the Commission ideally should consider all existing and reasonably foreseeable sources because "once carbon dioxide is emitted it persists in the atmosphere for approximately 4,000 years."[65]

The business-as-usual $CO_2$ emissions have severe consequences, such as increasing global mean temperatures by 3.2-5.4 degrees Celsius by 2100.[66] This approach of rubber-stamping fracked gas plants will cause loss of property, extreme heat, and agriculture losses.[67] "If we continue on our current emissions path, the average Southeast resident will likely experience an additional 17-53 extremely hot days per year by mid-century…that translates to 11,000 to 35,000 additional deaths per year" due to heat-related mortality.[68]

Setting aside the GHG emissions from the three approved projects in the last four years, and other existing fracked gas plants, the table below demonstrates that if all five new fracked gas projects are approved and come online between 2020-2023, the State of Florida is looking at

[60] *Id.*
[61] Downloaded from Bureau of Economic Analysis, May 4, 2018.
[62] Federal Reserve Bank of St. Louis, available at: https://bit.ly/2NbuJLX.
[63] These calculations were presented by the Sierra Club in the context of Dania Beach Energy Center, in the Expert Report of Dr. Frank Ackerman *See* Exhibit J.
[64] The 8,083 MW of new fracked gas projects only encompasses projects that have been approved or are pending approval as compared to the over 10,000MW of new fracked gas plants that the utilities have "planned" for in their respective 10-Year Site Plans (*see* Ex. C).
[65] *In Re: FPL Dania Beach Energy Center Project Power Plant Siting Act Application No. PA-89-26A2*, Florida Division of Administrative Hearings, Case No. 17-4388-EPP (July 30, 2018), Recommended Order on Certification at ¶178, available at: https://bit.ly/2QjLnqz.
[66] NOAA, *Global & Regional Sea Level Rise Scenarios for the U.S.* at 11 (2017), available at: https://bit.ly/2jgZnRb.
[67] Risky Business Project, *Risky Business Climate Assessment*, p. 4-5, available at: https://bit.ly/2Lqhg24
[68] Risky Business Project, *Risky Business Climate Assessment*, p. 26, available at: https://bit.ly/2Lqhg24

increasing the lifetime emissions over the next 30-40 years by up to 482,816,334 tons of greenhouse gas, resulting in adverse economic environmental impacts to the state of Florida of over $23,658,000,170.

| New Fracked Gas Project | Potential to Emit GHGs (tpy) | Lifetime GHGs (tons) | Monetary Impact per year ($49/ton) | Total Adverse Economic Impact by end of projects lifecycle |
|---|---|---|---|---|
| Seminole (online 2022) | 3,868,991 | 116,069,730 | $189,580,559 | $5,687,416,770 (2052) |
| Dania Beach (online 2022) | 4,550,233 | 182,009,316 | $222,961,417 | $8,918,456,680 (2062) |
| Shady Hills CC (online 2021) | 1,885,471 | 75,418,848 | $92,388,079 | $3,695,523,160 (2061) |
| Big Bend CC (online 2023) | 3,563,633 | 106,908,990 | $174,618,017 | $5,238,540,510 (2053) |
| McIntosh CT[69] (online 2020) | 80,315 | 2,409,450 | $3,935,435 | $118,063,050 (2050s) |
| **TOTALS** | **13,948,643** | **482,816,334** | **$683,483,507** | **$23,658,000,170** |

Moreover, the harms would be even greater, as these do not include the full scope of life-cycle emissions arising from these plants. As noted above, it is Florida policy to consider the costs and risks of climate change, including the whole life-cycle impacts of energy use choices.[70] In fact, it is not uncommon for a life-cycle analysis to be used, even by Florida Power & Light, to evaluate the emissions caused by power plants.[71] In order to truly grasp the impacts that this massive fracked gas build-out will have on Florida, Floridians, and its economy, this life-cycle analysis, consistent with Florida policy, should have been included in the 2018 Plans.

### C. In addition to avoiding harmful climate change impacts, renewables, storage, and demand-side resources are more cost effective than investing in gas generation.

The 2018 Plans propose to invest in twice the amount of gas-burning generation as compared to clean energy resources. Combined, the utilities propose 10,000 MW of new gas generation by 2027 versus less than 5,000 MW of solar, 209 MW in new solar PPAs and 282 MW wind PPA and at most 52 MW in storage by 2027.[72] More shocking is that by 2027, renewables will represent only 7.4% of FPL's generation mix, 9.7% of DEF's generation mix, and 6.2% of

[69] Lakeland fails to include this new 120 MW CT in its 10-Year Site Plan (Schedule 8) or in their response to Staff supplemental question 46. They claimed "no new gas projects". However, Lakeland was issued a final air construction permit on July 23, 2018 to simultaneously install a new 120 MW CT and retire McIntosh Unit 2 (115 MW) sometime before December 2021, attached as Exhibit K.
[70] Section 377.601(2)(j) Fla. Stat.
[71] *See e.g.*, Order No. PSC-08-0237 at 17 (Fla. PSC 2008)(reviewing evidence by interevenors on life-cycle GHG emissions from FPLs Turkey Point 6 & 7 as compared to other fuels), available at: https://bit.ly/2CUN8YE; *see also* Ex. I: *In Re: Florida Power & Light Company, Dania Beach Energy Center Project, Plant Siting Application*, DOAH Case No. 17-4388 EPP, Transcript, Kosky, May 16 AM T.109:18-20 (acknowledging previous life-cycle analysis on at least two other projects).
[72] *See* Exhibits A-C.

TECO's generation mix,[73] despite the fact that over the past eight years, wind and solar have become more cost-competitive. Wind has seen a 67% decrease in price in the last eight years and solar has seen an 86% decrease.[74] Thereby making the "cost of producing one megawatt-hour of electricity...around $50 for solar power," compared to coal at $102.[75]

The roughly 5,000 MW of clean energy is a drop in the bucket as compared to both the massive gas-burning build-out and to the vast, untapped potential for clean energy resources in Florida. The utilities even acknowledge the interest and outreach from renewable energy providers: DEF recorded over 33 requests in 2017 and TECO estimated between 20-30 requests from potential renewable energy providers.[76] DEF admitted that "[a]s the cost of solar PV technology continues to drop, there has been more interest from developers utilizing this technology."[77]

Prior requests for proposals by Florida municipal utilities confirm that Florida faces no shortage of opportunities for cost-effective solar PV.[78] For example, a 2017 RFP for solar PPAs in Florida produced bids as low as $22.15 per MWh.[79] In addition, RFPs in other Southeastern States, such as Georgia, have had winning solar procurement PPAs signed at an average price of $36/MWh.[80]Even the CEO of NextEra Energy, who is in the process of acquiring Gulf Power, predicted that "he would be selling energy from solar farms with four hours of energy storage for 3.5 cents/kWh within a few years," which is "lower than the operating costs of existing coal and nuclear."[81]

The 2018 Plans fail to include a side-by-side comparison of adding more renewables, storage and demand-side resources versus new, planned gas-burning generation. Abundant renewables, energy storage, and demand-side resources are available to meet peak demand and save costs across the grid's generation, transmission and distribution functions. Moreover, investing in these resources helps to divorce electricity production from the unpredictable gas market. Important considerations mandating performing this indispensable comparison include:

- Solar is cheap, plentiful and flexible. Florida has abundant solar resources, was ranked the third best state in the country for solar generation potential,[82] and is seeing pricing as low as $22.15 per MWh for a 15 year PPA.[83] As utilities are well aware, solar costs have "plunged" in recent years. Nationwide, the unsubsidized levelized cost of solar has

[73] FPL 2018 10-Year Site Plan, Schedule 6.2.
[74] Lazard Levelized Cost of Energy Analysis, Version 11 (2017) at 10, available at: https://bit.ly/2AxsqYT, *see also* "Solar Industry Research Data, SEIA, available at: https://bit.ly/2qhg5p0.
[75] Business Insider, "One simple chart shows why an energy revolution is coming — and who is likely to come out on top," Jeremy Berke (May 8, 2018), available at: https://read.bi/2NEEMsp.
[76] *See* Exhibit G: Developer Interest in New Renewable Energy Projects.
[77] *See* Exhibit G.
[78] *See* Exhibit E: Examples of Florida RFPs for renewables.
[79] *See* Exhibit E; *see also* Exhibit L: Gulf Renewable Energy RFI Proposals (Feb. 12, 2018).
[80] PV Magazine "510 MW of Solar Contracts Awarded in Georgia," Christian Roselund (Nov. 16, 2017), available at: https://bit.ly/2yPHCA2; *see also* Exhibit F: Examples of Recent Southeast RFP & PPA for Renewables.
[81] David Roberts "Clean Energy is Catching Up to Natural Gas," Vox (Aug 2018), available at: https://bit.ly/2KU1Z9h *citing* Will Wadea and Brian Eckhouse , "NextEra CEO: Cheap, Disruptive Batteries Coming to Kill Coal," Bloomberg News(June 2018), available at: https://bloom.bg/2I5QRzW.
[82] AEE, Advanced Energy in Florida (June 11, 2015), available at: https://bit.ly/2NHiR3S.
[83] *See* Exhibit E.

dropped to as low as $43 per MWh, versus $156 per MWh for gas peaking plants.[84] In Florida, the levelized cost of solar is estimated as low as $33 per MWh,[85] a decline of $5.63/MWh from 2016, with costs expected to continue to decline.[86] More specifically, JEA stated in an October 2017 memo that "the price of utility scale solar PPAs has declined from $75/MWh on average in 2016 to $32.50/MWh today."[87] In fact, FPL even admitted that solar can now work "cost-effectively at large-scale" and "save customers money."[88] Florida is not taking advantage of these solar opportunities, as evidenced by a 2018 ranking comparing all 50 states and D.C. from best to worst on their solar friendliess (pricing, Renewable Portfolio Standards, tax credits, rebates, net metering, etc..); Florida, the "sunshine state," ranked among the worst at 28.[89]

- <u>Florida utilities have access to low-cost wind generation.</u> In 2015, Gulf Power's 178 MW and 94 MW wind purchases from Oklahoma were priced below avoided cost. In addition, Florida has the potential to generate 84,000GWh of wind power by 2020, yet currently generates none.[90] This is an untapped market.

- <u>Energy storage can save money and help meet peak demand</u>. Energy storage technologies allow utilities to reduce or avoid expensive peak generation by re-deploying surplus energy from lower cost, off-peak hours. Investments in storage can save states hundreds of millions, if not billions of dollars in generation, transmission and distribution costs.[91] Storage is projected to become even more cost competitive in coming years, with costs continuing to drop dramatically: median prices for battery storage are projected by Lazard to be between approximately $800 and $1,100 per KW by 2021.[92] PPAs for combined solar and storage are already beating gas plants, dropping to as low as 31¢[93] and 36¢ per kWh.[94]

[84] Lazard Levelized Cost of Energy Analysis, Version 11 (2017), pp. 2, 8, available at: https://bit.ly/2AxsqYT.
[85] For solar (tracking) subsidized. Bloomberg New Energy Finance, 2018 Amer. Levelized Cost of Electricity (DATE) (providing estimates of LCOE for solar by state), available at: https://bnef.turtl.co/story/neo2018?teaser=true.
[86] Bloomberg New Energy Finance, 2016 Amer. Levelized Cost of Electricity (Update 9 Oct. 2016), 2018 Amer. Levelized Cost of Electricity 2018, available at: https://bnef.turtl.co/story/neo2018?teaser=true.
[87] *See* Direct Testimony of Ezra Hausman, Exhibit EDH-3, filed Dec. 8, 2017, Docket No. 20170225-EI, *Petition for Determination of Need Regarding Dania Beach Clean Energy Center Unit 7*, available at: https://bit.ly/2QhNueu.
[88] *See* Transcript of Prudence Hearing, Vol. 2, 302, Vol. 12, 1514, *In re Petition for Rate Increase by Florida Power & Light*, Docket Nos. 160021-EI, 160061-EI, 160062-EI, 160088-EI, available at: https://bit.ly/2CU16dh and https://bit.ly/2OjicTj.
[89] *See* 2018 State Solar Power Rankings Report, available at: https://bit.ly/2MY1LPF.
[90] *See* WINDExchange, U.S. Dept of Energy, available at: https://windexchange.energy.gov/states/fl.
[91] State of Charge: Massachusetts Energy Storage Initiative Study (2017), available at https://bit.ly/2NxCWt9.
[92] Energy Storage Association, *Advanced Energy Storage in Integrated Resource Planning*, 2018 Update (June 19, 2018), available at: https://bit.ly/2QkegTO.
[93] 2018 Joint IRP of Nevada Power Co. and Sierra Pacific Power Co., Public Utility Commission of Nevada, Docket No. 18-06, Direct Testimony of Dave Ulozas at 21-22 (overall pages 153-154), available at: https://bit.ly/2NnnYWR.
[94] Public Service Co. of Colorado, CPUC Proceeding No. 16A-0396E, "2017 All Source Solicitation 30 Day Report," Att. A (Dec. 28, 2017), available at: https://bit.ly/2wQmbQE.

- Demand side management is cost-effective and increases grid reliability. Energy efficiency is the lowest cost energy resource available[95] and is essential to providing least cost, low risk electric service and meeting seasonal peak demand.[96] Utilities report saving billions of dollars from targeted efficiency programs, especially those that defer or avoid large transmission and distribution expenditures.[97] Demand side resources, such as peak shaving demand response programs, reduce total system demand and help protect customers against price volatility.[98]

- Investing in clean energy creates jobs for Floridians. Florida's clean energy industry employs four times more workers than the fossil fuel sector. A recent study showed that energy efficiency programs alone "could create 10,000 new jobs in Florida's energy efficiency sector."[99] Other states have experienced similar benefits: North Carolina's renewable energy policy "contributed to the creation of over 4,000 jobs and $2 billion in direct investment across the state."[100] Energy Efficiency employs 2 million more people, which is nearly twice as many as the oil and gas industry.[101]

## D. Burning coal for power is not the least cost choice.

Florida's utilities maintain over 9.6 GW of aging coal-burning generation.[102] This generation includes several units well past their book lives, including Gulf Power's Crist Units 4 & 5, which are 58 and 56 years old, respectively. Yet Gulf and other utilities have submitted no evidence to support that their customers should shoulder the costs of these aging units for another year, let alone indefinitely, as the 2018 Plans fail to identify any retirements dates for these units.

By contrast, coal plants across the country are closing. Since 2010, more than 273 coal plants have retired or announced their retirement.[103] The reasons cited for the retirements are numerous (exorbitant operation and maintenance costs, cleanup and environmental compliance costs) but

[95] *See e.g.*, ACEEE, *The Best Value for America's Energy Dollar – A National Review of the Cost of Utility Energy Efficiency Programs*; (March 2014); ACEEE, *New Data, Same Results -- Saving Energy Is Still Cheaper than Making Energy* (December 1, 2017), available at: https://bit.ly/2Mt5HCY.
[96] Regulatory Assistance Project, *Recognizing the Full Value of Energy Efficiency* (2013) at 41; Electric Power Research Institute, *U.S. Energy Efficiency Potential Through 2035* (April 2014), available at: https://bit.ly/2FmMUtn.
[97] *See e.g.*, NEEP Northeast Energy Efficiency Partnerships, *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts To Use Geographically Targeted Efficiency Programs to defer T & D Investments* (Jan. 2015), p.12; available at: https://bit.ly/2M7JtGv.
[98] *See e.g.*, Steven Nadel, *Demand Response Programs Can Reduce Utilities' Peak Demand and Average of 10%, Complementing Savings from Energy Efficiency Programs*, AM. COUNCIL FOR AN ENERGY-EFFICIENT ECON. (Feb 9. 2017), available at https://bit.ly/2kQMY8e.
[99] Clean Jobs Florida, *Sizing Up Florida's Clean Energy Jobs Base and its Potential* (2014), at 5, available at: https://bit.ly/2CDsQTk.
[100] Community and Economic Development Program at UNC School of Government, *Solar Powers Economic Development in NC* (Mar. 3, 2016), available at: https://unc.live/2oXhjVu.
[101] *See* U.S. Energy and Employment Report, Jan 2017, available at: https://bit.ly/2jPIalG.
[102] Exhibit D: Existing Coal Burning Generation & Retirement Dates.
[103] *See* Sierra Club, Victories, available at: https://content.sierraclub.org/coal/victories.

more recently include utilities choosing clean energy because phasing out coal saves customers money,[104]improves their bottom line, and boosts grid flexibility.[105]

In the current market, a prudent utility would look hard at alternatives to the continued operation of aging coal units. But Florida utilities instead offer only conclusory assertions that they will continue to operate their units, without any actual account of how they will manage the costs and risks of doing so, or whether it even makes sense to bear such costs and risks in light of the available alternatives.[106] Of the roughly 3.3 GW of old coal generation slated for retirement, the utilities plan to operate 58% of this capacity past 2026.[107] But the utilities present no evidence that doing so makes economic sense for customers.

Two utilities have commissioned economic studies, comparing coal unit retrofit and retirement scenarios; unfortunately only one, Lakeland Electric, made that information public.[108] The second utility, Gulf Power, submitted its retirement study of the Crist Plant to the Commission,[109] but claimed the information was confidential, so the results of that study are not discloseable.[110] Unsurprisingly, even in 2015, Lakeland concluded that renewables and energy efficiency could meet load growth more cost-effectively than any of the scenarios where its C.D. McIntosh coal plant would continue to operate.[111] Regardless of this conclusion, and the Institute for Energy Economics and Financial Analysis' recommendation to retire C.D. McIntosh Unit 3,[112] Lakeland continues to operate C.D. McIntosh Unit 3 without even bothering to provide a projected retirement date.[113] Similarly, without any discussion of the results of its 2018 Crist Retirement Study, let alone mention its existence, Gulf continues to decline to commit to retiring Crist Units 4 & 5 in its 10-Year Site Plan.[114]

[104] *See* Forbes, *Embracing the Coal Closure Trend: Economic Solutions for Utilities Facing A Crossroads*, available at: https://bit.ly/2x5C70K.
[105] *See* Forbes, *Utilities Closed Dozens of Coal Plants in 2017. Here Are the 6 Most Important*, available at: https://bit.ly/2Qh1aqe.
[106] Exhibit D.
[107] Exhibit D.
[108] *See* Exhibit M : nFront Consulting LLC, "Strategic Resource Plan, Lakeland Electric" (Mar. 2015).
[109] Environmental Cost Recovery, Docket No. 20180007-EI, available at: https://bit.ly/2xk93lY.
[110] In its Crist Retirement Study, Gulf assessed the following: continued operation of Crist Units 4 & 5 and the entire plant, retirement and replacement with combustion turbines, conversion to 100% natural gas, retirement and replacement with solar capacity, retirement and replacement with a combination of solar and natural gas capacity and retirement and replacement with a combination of solar, natural gas capacity and battery storage. *See* Environmental Compliance Program Update, filed April 2, 2018, Docket No. 20180007-EI, available at: https://bit.ly/2O4f5hV.
[111] *See* Ex. M at 3-13, 3-24.
[112] *See* Institute for Energy Economics and Financial Analysis (IEEFA), *The Time is Right to Retire C.D. McIntosh Unit 3*" (Oct. 2015), available at: https://bit.ly/2Qk70Y4. The IEEFA concluded that the retirement of McIntosh Unit 3 would benefit the utilities, their customers and the environment since the average cost to produce power has risen by 33% from 2009-2013; its performance has dropped drastically from 2.5 million MWh in 2008 to roughly 0.5 million MWh in 2014 making it no longer necessary for grid reliability.
[113] *See* Lakeland 10-Year Site Plan 2018, Schedule 1. Interestingly, Lakeland was issued a final air construction permit on July 23, 2018 to simultaneously install a new 120 MW CT and retire McIntosh Unit 2 (115 MW) sometime before December 2021, but failed to include that projected retirement date in its 10-Year Site Plan. *See* Exhibit K.
[114] *See* Gulf 10-Year Site Plan 2018, Schedule 8.

Duke Energy Florida also needs to assess the continued economic viability of Crystal River Units 4 & 5 in light of clean energy alternatives. The 2018 Plans must demonstrate that the utilities have considered the risks and relative costs of retirement of existing coal-burning generation versus continued operation and maintenance of aging dirty coal plants. Without such a demonstration, the utilities' plans to continue to operate their dirty aging coal units indefinitely are unjustified.

## CONCLUSION

The utilities' plans are deficient in several fundamental ways. The plans' proposed continued over reliance on gas and old coal ignores the dire climate change costs imposed on Florida from GHG emitting fossil fuels, when Florida itself is on the front line of climate change, and already suffering devastating damages from it. That failure to consider the costs of climate change precludes the Commission from fulfilling its oversight duties -- to comply with the explicit regulatory requirement that the Commission "shall review"… "the anticipated environmental impact" of the new gas plants."[115] Likewise, the continued over reliance is deficient because it continues to short change "fuel diversity in the state,"[116] imposing greater risks on Floridians. Additionally, the absence of proper consideration and valuation of clean energy alternatives risks locking Floridians into paying for expensive, risky and polluting energy sources. The utilities fail to present the Commission with options to allow for least-cost comparison between the proposed new gas generation and clean energy options. Similarly, the plans fail to evaluate whether continued operation of aging coal plants is uneconomic and detrimental to customers' financial interests. These omissions violate the explicit regulatory requirement that the Commission "shall review"…"possible alternatives to the proposed plan[s]" and preclude a Commission determination that the utilities are meeting their obligation to provide least-cost service to Florida customers. Without this detailed information on assumptions and alternatives, the Commission cannot fulfill its oversight duties. Every year that passes without a full and fair identification of (1) the devastating environmental costs of continued reliance on fracked gas and (2) the least-cost electric service further jeopardizes the competitiveness of Florida's economy, the well-being of Floridians, and the opportunity to arrest the already dire climate change impacts in Florida. Thank you for considering Sierra Club's comments.

Sincerely,

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[115] *See* Section 186.801(2), Fla.Stat.
[116] *Id.*

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**List of Exhibits**
Exhibit A: Planned Solar & Wind Generation
Exhibit B: Existing & Planned Battery Storage Projects
Exhibit C: Planned Gas Burning Generation Additions
Exhibit D: Existing Coal Burning Generation & Retirement Dates
Exhibit E: Examples of Florida RFPs & PPAs for Renewables
Exhibit F: Examples of Southeast RFPs & PPAs for Renewables
Exhibit G: Developer Interest in New Renewable Energy Projects
Exhibit H: Excerpts from the Testimony of George Maul, May 16, 2018, PM, *In Re: FPL Dania Beach Energy Center Project Power Plant Siting Act Application No. PA-89-26A2*, Florida Division of Administrative Hearings Case No. 17-4388-EPP (July 30, 2018)
Exhibit I: Excerpts from the Testimony of Kennard F Kosky May 16, 2018, AM, *In Re: FPL Dania Beach Energy Center Project Power Plant Siting Act Application No. PA-89-26A2*, Florida Division of Administrative Hearings Case No. 17-4388-EPP (July 30, 2018)
Exhibit J: Expert Report of Dr. Frank Ackerman (May 6, 2018)
Exhibit K: Final Minor Air Construction Permit 1050004-48-AC C.D. McIntosh Jr. Power Plant, Lakeland Electric (July 23, 2018)
Exhibit L: Gulf Renewable Energy RFI Proposals (Feb. 12, 2018)
Exhibit M: nFront Consulting LLC, “Strategic Resource Plan, Lakeland Electric (Mar. 2015)

# Exhibit A

**Exhibit A: Planned Solar & Wind Generation Additions**



The table below reflects utility responses to Commission Staff's First Supplemental Data Request regarding planned solar and wind generation additions. The text of the relevant requests (nos. 24, 25, 27, 28, and 33) are reproduced below the table.

| | DEF | FMPA | FPL | GRU | GULF | JEA | LAK | OUC | SEC | TAL | TECO |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Planned Solar** | 1150 MW (2018-2027) | None | 1.4 MW (2018); 2 MW (2019); 298 (2019)[1]; 2905.5 MW unsited (2020-2027) | None | 1 MW (in-service date TBD) | None | None | Not submitted | None | None | 600 MW (2017-2021) |
| **Planned Wind** | None | None | None | None | None | None | None | Not submitted | None | None | None |
| **Ongoing Solar PPAs** | None | None | None | 18.6 MW (2032) | 30 MW (2017-2042); 40 MW (2017-2042); 50 MW (2017-2042) | 12 MW (2040); 7 MW (2042); 3 MW(2037); 5 MW(2037); 2 MW(2038); 4 MW(2038) | 0.25 MW (2030); 2.3 MW (2037); 3.0 MW (2027); 6.0 MW (2040); 0.553 MW (2029); 3.15 MW (2041) | Not submitted | 2.2 MW (2017-2027) | 20 MW (2017-2037) | None |
| **Ongoing Wind PPAs** | None | None | None | None | 178 MW (2016-2035); 94 MW (2017-2035) | 10 MW (2019) | None | Not submitted | None | None | None |
| **Planned Solar PPAs** | 5 non-firm agreements of 50 MW each | 58 MW (2020-2040) | None | None | 120 MW (2017-2043)[2] | 5 MW (2018-2038); 1 MW (2018-2038) | None | Not submitted | 40 MW (2021-2041) | 40 MW (2019-2039) | None |
| **Planned Wind PPAs** | None | None | None | None | None | None | None | Not submitted | None | None | None |

Sources: 2018 TYSP Plans from each utility. MW data describes "Installed Capacity."

[1] Four sites of 74.5 MW each.

[2] 3 different contracts of varying MW.

**Question #24:** Please identify and describe each planned utility-owned renewable resource for the period 2018 through 2027. Please include each proposed facility's name, unit type, fuel type, its installed capacity (AC-rating for PV systems), its net firm capacity or anticipated contribution during peak demand (if any), anticipated typical capacity factor, and projected in-service date. For multiple small distributed renewable resources (< 250 kW per installation), such as rooftop solar panels, please include a combined entry for the resources that share the same unit & fuel type.

**Question #25:** Please refer to the list of planned utility-owned renewable resources for the period 2018 through 2027 above. Discuss the current status of each project.

**Question #27:** Please identify and describe each purchased power agreement with a renewable generator that delivered energy during 2017. Provide the name of the seller, the name of the generation facility associated with the contract, the unit type of the facility, the fuel type, the facility's installed capacity (AC-rating for PV systems), the amount of contracted firm capacity (if any), and the start and end dates of the purchased power agreement.

**Question #28:** Please identify and describe each purchased power agreement with a renewable generator that is anticipated to begin delivering renewable energy to the Company during the period 2018 and 2027. Provide the name of the seller, the name of the generation facility associated with the contract, the unit type of the facility, the fuel type, the facility's installed capacity (AC-rating for PV systems), the amount of contracted firm capacity (if any), and the start and end dates of the purchased power agreement.

**Question #33**: Please complete the table below, providing a list of all of the Company's plant sites that are potential candidates for utility-scale wind installations. As part of this response, please provide the plant site's name, approximate land area available for wind installations, potential installed capacity rating of a wind farm installation, and a description of any major obstacles that could affect utility-scale wind installations at any of these sites, such as land devoted to other uses or other requirements

# Exhibit B

## Exhibit B: Existing & Planned Battery Storage Projects

Mentions of battery storage projects in the 2018 10-Year Site Plans and in Responses to Commission Staff's Supplemental Data Requests are compiled below.

### DEF

"DEF has a general interest in the future of energy in the state and how energy storage will play a part in this future. The Company has addressed this interest at public meetings when sharing news on DEF's 50 MW Battery Pilot Program as well as engaging local customers on potential sites and uses for these energy storage projects."[1]

### FMPA

FMPA does not currently include energy storage technologies as part of the ARP system portfolio.

### FPL

At the time of this response, FPL has begun two solar-plus-storage projects totaling 14 MW of capacity and approved an additional 10 MW project under the Large Scale Storage Pilot, representing a combined 24 MW out of the 50 MW approved in the Settlement Agreement. Included below is an outline of the projects and the targeted learnings for them:

- A 10 MW solar-plus-storage battery was recently installed at FPL's Babcock Ranch Solar Energy Center, targeted at understanding how to best design AC-coupled batteries for FPL's system and demonstrating several storage applications, including: 1) solar shifting – charging solar energy in non-peak times and discharging it during peak times; and 2) solar smoothing – using the battery to smooth out a solar plant's intermittent output, which can ramp up or down quickly due to cloud cover. Preliminary results appear favorable regarding both of these applications.
- A 4 MW solar-plus-storage battery was recently installed at FPL's Citrus Solar Energy Center, targeted at understanding how to best design DC-coupled batteries for FPL's system and demonstrating recovery of clipped (curtailed) solar energy that would otherwise be lost behind the solar inverters. Additional testing will also be performed on how to best coordinate recovery of clipped energy with other applications such as solar
- An additional 10 MW project was recently approved for development which is a distribution-connected battery system that will demonstrate potential deferral of distribution upgrades, mitigate outages by being coordinated with smart grid devices, and explore how to best operate the battery to balance generation needs versus distribution needs. This project will be located in Miami, and FPL expects the battery to be installed in 2019. [2]

---

[1] Question #39 of DEF response.

[2] 2018 Ten-Year Site Plan - Staff's Supplemental Data Request # 1 Question No. 41

**GRU**

GRU does not have any energy storage technology.

**GULF**

Gulf Power is demonstrating the following projects:

> **McCrary Battery Energy Storage Demonstration** – A 250-kW/1-MWh Tesla Powerpack lithium-ion system is interconnected at Gulf Power's McCrary Training and Storm Center in Pensacola, Florida. This system is the basic unit building block of the Tesla technology and can be used at both the commercial/industrial and utility scale. The project will enable a better understanding of the siting, installation and operational requirements of distribution-scale energy storage systems, as well as the value storage applications can offer customers and the energy provider through peak shaving, demand management, ancillary services, energy arbitrage and backup power.
>
> **Residential Energy Storage Demonstration** – Gulf Power is demonstrating the Tesla Powerwall residential battery system in two different applications:
>
> 1. Photovoltaics with battery storage to evaluate pairing rooftop solar with energy storage.
> 2. Demand response with battery storage to identify impacts on peak reduction and time-of-use rates.[3]

**JEA**

"JEA currently has no energy storage technologies in its system portfolio."

**LAK**

The storage project under study in Lakeland Electric is smaller than 1 MW.

**OUC**

Not submitted.

**SEC**

"Seminole currently has no energy storage technology as part of its system portfolio, but keeps abreast of industry trends for potential evaluation."

**TAL**

TAL does not currently have any energy storage technologies that are part of its system portfolio.

[3] Response to Question 41

**TECO**

TECO does not currently have any energy storage technologies that are part of its system portfolio.

"Yes, a declining trend [of energy storage technologies cost] has been observed through observation of trade journals and vendor presentations. Tampa Electric has not yet purchased any battery storage systems so the Company has not observed this trend in actual practice."

"Battery storage, while not constrained by time of day or seasonal constraints on its ability to operate during peak, is constrained by the capacity of the battery system as to how long it can provide power. One of the intriguing synergistic opportunities being explored is the combination of battery capacity with solar, which can extend the period and reset the time when solar generated power can be dispatched to meet system capacity needs (e.g., in the winter, store solar generated energy during the day for availability during the next morning when the sun is not out but the temperatures are cold and electric demand is high). Cost is one of the main considerations being evaluated and the cost of such battery systems going down over time will have a major impact on this."

"Tampa Electric is actively evaluating a large, utility scale battery storage pilot associated with its Big Bend Solar unit."

# Exhibit C

**Exhibit C: Planned Gas Burning Generation Additions**

Per the 10-Year Site Plans filed in April 2018, Florida utilities plan to add electric generating units that primarily burn gas, as shown in the table below.[1]

| Utility Owner/Operator | Unit | Unit Type | Capacity (MW)[2] | Projected service date |
|---|---|---|---|---|
| FPL | Okeechobee Energy Center | CC | 1,748 | 2019 (Q2) |
| | Dania Beach (a.k.a., Lauderdale Modernization) | CC | 1,163 | 2022 (Q2) |
| DEF | Location Unknown | CT | 226 | 2027 (Q2) |
| | Location Unknown | CT | 226 | 2027 (Q2) |
| | Location Unknown | CT | 226 | 2027 (Q2) |
| | Citrus | CC | 1640 | 2018 (Q4) |
| GULF | Location Unknown | CC | 595 | 2024 (Q2) |
| TECO | Big Bend CT 5 | CT | 360 | 2021 (Q2) |
| | Big Bend CT 6 | CT | 360 | 2021 (Q2) |
| | Big Bend ST 1 | ST | 335 | 2023 (Q1) |
| | Location Unknown | CT | 229 | 2023 (Q2) |
| | Location Unknown | CT | 229 | 2026 (Q2) |
| JEA | None | None | None | None |
| LAK | None[3] | None | None | None |
| OUC | Not submitted | Not submitted | Not submitted | Not submitted |
| FMPA | None | None | None | None |
| TAL | Sub 12 DG No. 1 | IC | 9.2 | 2018 (Q3) |
| | Sub 12 DG No. 2 | IC | 9.2 | 2018 (Q3) |
| | Hopkins IC No. 1 | IC | 18.4 | 2018(Q4) |
| | Hopkins IC No. 2 | IC | 18.4 | 2018(Q4) |
| | Hopkins IC No. 3 | IC | 18.4 | 2018(Q4) |
| | Hopkins IC No. 4 | IC | 18.4 | 2018 (Q4) |
| | Hopkins IC No. 5 | IC | 18.4 | 2025 (Q2) |
| GRU | None | None | None | None |
| SEC | Seminole | CC | 1108 | 2022 (Q4) |
| | Shady Hills | CC | 546 | 2021 (Q4) |
| | Location Unknown | CC | 593 | 2022 (Q4) |
| | Location Unknown | CT | 215 | 2024 (Q4) |

[1] The data in the table above reflects information submitted to the Commission in question 46 of Staff's Supplemental Data Request.
[2] Capacity reflects summer MW capacity as reported by the utilities.
[3] In response to Staff Supplemental Question 46 and in Schedule 8 of its 10-Year Site Plan, Lakeland claims that it has no plans for any new gas-burning units. However, Lakeland was issued a final air construction permit on July 23, 2018 to simultaneously install a new 120 MW CT at McIntosh and retire McIntosh Unit 2 (115 MW) sometime before December 2021. Therefore, it appears that Lakeland does have plans to construct a new CT and this information should have been included in its 10-Year Site Plan. *See* https://fldep.dep.state.fl.us/air/emission/apds/listpermits.asp.

| | | | | |
|---|---|---|---|---|
| | Location Unknown | CT | 215 | 2027 (Q4) |
| | Location Unknown | CT | 215 | 2027 (Q4) |
| **TOTAL** | | | **10,029.5** | |

# Exhibit D

**Exhibit D: Existing Coal Burning Generation & Retirement Dates**

Per the plans filed in April 2018, Florida utilities own or operate coal-burning electric generating units and project retirement dates for those units as shown in the table below.[1]

| Utility Owner/Operator | Unit | Capacity (MW)[2] | Projected retirement date |
|---|---|---|---|
| **FPL-JEA** | St. Johns No. 1 (a) | 136 | 2019 (Q1) |
| | St. Johns No. 2 (a) | 136 | 2019 (Q1) |
| **DEF** | Crystal River No. 1 | 441 | 2018 (Q3) |
| | Crystal River No. 2 | 524 | 2018 (Q3) |
| | Crystal River No. 4 | 739 | N/A |
| | Crystal River No. 5 | 739 | N/A |
| **GULF** | Crist No. 4 | 94 | 2024 (Q4) |
| | Crist No. 5 | 94 | 2026 (Q4) |
| | Crist No. 6 | 370 | 2035 (Q4) |
| | Crist No. 7 | 578 | 2038 (Q4) |
| | Daniel No. 1 (b) | 274 | 2042 (Q4) |
| | Daniel No. 2 (b) | 274 | 2046 (Q4) |
| | Scherer No. 3 (c) | 223 | 2052 (Q4) |
| **TECO** | Big Bend No. 1 | 446 | N/A |
| | Big Bend No. 2 | 446 | 2021 (Q2) |
| | Big Bend No. 3 | 446 | N/A |
| | Big Bend No. 4 | 486 | N/A |
| | Polk No. 1 | 326 | N/A |
| **JEA** | St. Johns No. 1 (d) | 680 | 2018 (Q1)(retired) |
| | St. Johns No. 2 (d) | 680 | 2018 (Q1)(retired) |
| | Scherer No. 4 (e) | 846 | N/A |
| **LAK-OUC** | C.D. McIntosh, Jr. No. 3 (f) | 219 | N/A |
| **OUC-FMPA** | Stanton No. 1 (g) | 465 | N/A |
| | Stanton No. 2 (h) | 465 | N/A |
| **GRU** | Deerhaven No. FS02 | 251 (i) | 2031 |
| **SEC** | Seminole No. 1 | 736 | N/A |
| | Seminole No. 2 | 736 | N/A |

(a) FPL owns 20% of St. Johns No. 1 & 2.
(b) Gulf Power owns 50% of Daniel No. 1 & 2 (located in Mississippi).
(c) Gulf Power owns 25% of Scherer No. 3 (located in Georgia).
(d) JEA owns 80% of St. Johns No. 1 & 2.
(e) JEA owns 23.64% of Scherer No. 4
(f) LAK owns 60% and OUC owns 40% of C.D. McIntosh, Jr. No. 3.

[1] The data in the table above reflects information submitted to the Commission in Schedule 1 of the 2018 Plans.
[2] Capability reflects "Gen. Max. Nameplate" as reported by the utilities.

(g) OUC owns 68.6% of Stanton No. 1
(h) OUC owns 71.6% of Stanton No. 2.
(i) Net summer capability.

# Exhibit E

**Exhibit E: Examples of Florida RFPs & PPAs for Renewables**

| Utility | Project | Energy Source | Cost | Capacity | Date |
|---|---|---|---|---|---|
| **Seminole** | Market Alternative Solicitation[1] | Solar PV | 127 offers, with 650 MW offered at prices less than $50/MWh[2] | More than 3,000 MW offered into the solicitation | Sept. 2016 |
| | Coronal Tillman (selected through above Market Alternative Solicitation) | Solar PV | Redacted[3] | 50 MW | Sept. 2016, awarded Oct. 2017 |
| **Gulf**[4] | 15 Yr PPA #1 (Fixed Price) | Solar PV | $28.10 | 50 MW | Feb. 2018 |
| | 15 Yr PPA #2 (Fixed Price) | Solar PV | $26.72 | 50 MW | |
| | 15 Yr PPA #3 (Fixed Price) | Solar PV | $24.35 | 50 MW | |
| | 15 Yr PPA #4 (Fixed Price) | Solar PV | $24.00 | 50 MW | |
| | 15 Yr PPA #5 (Fixed Price) | Solar PV | $29.45 | 50 MW | |
| | 15 Yr PPA #6 (Escalating Price) | Solar PV | $22.15 | 50 MW | |

[1] http://www.psc.state.fl.us/library/filings/2018/02559-2018/02559-2018.pdf
[2] http://www.psc.state.fl.us/library/filings/2018/02737-2018/02737-2018.pdf
[3] Table A-8, http://www.psc.state.fl.us/library/filings/2018/02559-2018/02559-2018.pdf
[4] *See* Ex L, "Gulf Renewable Energy RFI Proposals - PSC Version - 02.12.18.xlsx"

| | | | | | |
|---|---|---|---|---|---|
| | 15 Yr PPA #7 (Escalating Price) | Solar PV | $22.15 | 50 MW | |
| | 15 Yr PPA #8 (Escalating Price) | Solar PV | $22.15 | 50 MW | |
| | 15 Yr PPA #9 (Escalating Price) | Solar PV | $22.15 | 50 MW | |
| | 15 Yr PPA #10 (Escalating Price) | Solar PV | $22.15 | 50 MW | |
| | 15 Yr PPA #11 (Fixed Price) | Solar PV | $41.25 | 50 MW | |
| | 15 Yr PPA #12 (Fixed Price) | Solar PV | $31.45 | 50 MW | |
| | 15 Yr PPA #13 (Fixed Price) | Solar PV | $35.81 | 50 MW | |
| | 15 Yr PPA #14 (Escalating Price) | Solar PV | $31.41 | 50 MW | |
| | 15 Yr PPA #15 (Escalating Price) | Solar PV | $32.06 | 50 MW | |
| | 15 Yr PPA #16 (Escalating Price) | Solar PV | $32.61 | 50 MW | |
| | 15 Yr PPA #17 (Fixed Price) | Solar PV | $40.10 | 50 MW | |
| | 15 Yr PPA #18 (Fixed Price) | Solar PV | $27.50 | 50 MW | |

| | | | | | |
|---|---|---|---|---|---|
| | 15 Yr PPA #19 (Escalating Price) | Solar PV | $24.80 | 50 MW | |
| | 15 Yr PPA #20 (Fixed Price) | Solar PV | $39.80 | 49.5 MW | |
| **JEA**[5] | COX Radio: Old Plank Road, Solar Farm | Solar PV | $59.00/MWh | 3 | June 2015 |
| | National Solar: Imeson Solar Farm | Solar PV | $79.00/MWh | 5 | June 2015 |
| | Inman Solar: Simmons Road Solar | Solar PV | $83.43/MWh | 2 | June 2015 |
| | Inman Solar: Starratt Solar | Solar PV | $86.50/MWh | 5 | June 2015 |
| | SunEdison: SunE Salisbury Road Solar | Solar PV | $87.50/MWh | 4.5 | June 2015 |
| | Mirasol Fafco Solar: Pipit | Solar PV | $64.00/MWh | 0.5 | June 2015 |
| | Mirasol Fafco Solar: JTA Phillips Lot Solar Array | Solar PV | $64.00/MWh | 0.5 | June 2015 |
| | groSolar: Montgomery Solar Farm | Solar PV | $69.30/MWh | 7 | June 2015 |
| | Hecate Energy: Blair Site | Solar PV | $62.41/MWh | 4 | June 2015 |
| | Hecate Energy: Forest Road | Solar PV | $63.88/MWh | 0.5 | June 2015 |
| | Hecate Energy: UNF | Solar PV | $64.27/MWh | 0.5 | June 2015 |
| | COX Radio: Old Plank Road, Solar Farm | Solar PV | $59.00/MWh | 3 | June 2015 |
| | National Solar: Imeson Solar Farm | Solar PV | $79.00/MWh | 5 | June 2015 |

[5] goo.gl/iSZiRD

| | | | | | |
|---|---|---|---|---|---|
| | Inman Solar: Simmons Road Solar | Solar PV | $83.43/MWh | 2 | June 2015 |
| | Inman Solar: Starratt Solar | Solar PV | $86.50/MWh | 5 | June 2015 |
| | SunEdison: SunE Salisbury Road Solar | Solar PV | $87.50/MWh | 4.5 | June 2015 |
| | Mirasol Fafco Solar: Pipit | Solar PV | $64.00/MWh | 0.5 | June 2015 |
| | Mirasol Fafco Solar: JTA Phillips Lot Solar Array | Solar PV | $64.00/MWh | 0.5 | June 2015 |

# Exhibit F

**Exhibit F: Examples of Recent Southeast RFPs & PPAs for Renewables**

| State | Utility | Project | Energy Source | Cost | Capacity | Date |
|---|---|---|---|---|---|---|
| **Alabama** | Alabama Power | Alabama Power plans to procure up to 500 MW of renewable energy from 80 MW or smaller facilities[1] and received over 200 bids.[2] | Solar, hydro, biomass | | 500 MW | Mar. 2019 |
| | | Anniston Army Depot[3] | Solar | $23 Million | 7 MW | Apr. 2017 |
| | | Fort Rucker[4] | Solar | $25 Million | 10 MW | Apr. 2017 |
| | | Redstone Arsenal[5] | Solar | | 10 MW | Late 2017 |
| | | LaFayette[6] | Solar | $140 million | 72 MW | Dec. 2017 |
| **Arkansas** | Entergy Arkansas | 2016 EAI RFP for Long-Term Renewable Generation Resources[7] | Solar PV, wind, hydro, biomass | | 100 MW | 2018 |

[1] goo.gl/uf5Ffm.
[2] goo.gl/icxhHV.
[3] goo.gl/CPGLZK; goo.gl/EbwCRv.
[4] goo.gl/CPGLZK; goo.gl/Buf4h9.
[5] goo.gl/CPGLZK; goo.gl/xba7ZP.
[6] goo.gl/BfX1vi; goo.gl/IMi0G2.
[7] goo.gl/kRTM8z.

| | | | | | | |
|---|---|---|---|---|---|---|
| | | The 2014 EAI RFP[8] received 28 proposals and resulted in a 20-year PPA for the Stuttgart Solar Project[9] | Solar, wind | | 81 MW | 2018 |
| **Georgia** | Georgia Power | 2013 Advanced Solar Initiative[10] | Solar | <8.5 cents/kWh | 50 MW | 2016 |
| | | 2014 Advanced Solar Initiative and IRP[11] | Solar | <6.5 cents/kWh | 515 MW | 2016 |
| | | Advanced Solar Initiative Distribution Generation Program[12] | Solar | | 190 MW | Late 2017 |
| | | Renewable Energy Development Initiative (REDI)[13] | Solar, wind, biomass, biogas | | 1,050 MW utility-scale, 100 MW DG | Georgia Power will conduct two 525 MW utility-scale RFPs in 2017 and 2019 |
| **Kentucky** | KyMEA | 2017 Renewable Capacity and Energy Procurement, 10- to 20-year PPA[14] | Solar PV, wind | | 50 MW | 2019 – 2022 |

[8] goo.gl/1EjszM.
[9] goo.gl/o6T2iA.
[10] goo.gl/ZBrDfc.
[11] *Id.*
[12] *Id.*
[13] *Id.*
[14] goo.gl/DEvfkq.

| | | | | | | |
|---|---|---|---|---|---|---|
| **Louisiana** | Entergy Louisiana | 2016 Request for Proposals for Long-Term Renewable Generation Resources[15] | Solar PV, solar thermal, wind, biomass, hydro | | 200 MW | 20-year PPA starting by 2020 |
| **Mississippi** | South Mississippi Electric Power Association | 2015 RFP for a 20-year PPA and up to 250 MW of capacity from wind resources[16] | Wind | | 250 MW | |
| **North Carolina** | Duke Energy Carolinas | Duke Energy 2017 Wind RFP[17] | Wind | | 500 MW | 2022 |
| | | DEC 2016 Renewables RFP[18] | Solar, wind, biomass, landfill gas | | 750,000 MWh | Dec. 2018 |
| | City of Raleigh | RFP sought proposals to own, install, operate, and maintain solar systems on 53 acres of city-owned land[19] | Solar PV | Land is being leased for $87,500/ year | 13 MW | 2018 |
| | Avangrids Renewables | Amazon Wind Farm US East [20] | Wind | $400 million | 208 MW | 2016 |

[15] goo.gl/1jTkyt.
[16] goo.gl/ds51gU.
[17] goo.gl/xNLLcg.
[18] goo.gl/STfN6C.
[19] goo.gl/qLi1no.
[20] goo.gl/xzFmsW; goo.gl/1xgYym.

| | | | | | | |
|---|---|---|---|---|---|---|
| | NC Green Power | Dec. 2015 RFP,[21] seeking contracts for a one- to two-year term | Solar PV, wind, small hydro (<10 MW), biomass | | 70,000 MWh | |
| | | Oct. 2014 RFP,[22] seeking contracts for a one- to two-year term | Solar PV, wind, small hydro (<10 MW), biomass | | 40,000 MWh | |
| **South Carolina** | Duke Energy | Duke Energy 2015 Solar RFP[23] | Solar PV | | 53 MW utility-scale, 5 MW Shared Solar Program | 2016 |
| | South Carolina Electric & Gas Company | SCE&G 2015 Solar RFP[24] | Solar PV | | 30 MW | Late 2016 |
| | | SCE&G 2014 Solar RFP[25] | Solar PV | | 3-4 MW | 2015 |
| **Tennessee** | Tennessee Valley Authority | TVA Request for Pricing for Solar Power Agreements[26] | Solar PV | | 80 MW | 2018 |
| | EPB | Solar Share Pilot Project[27] | Solar PV | | 1.35 MW | 2017 |

[21] goo.gl/QevrwT.
[22] goo.gl/MrxUU2.
[23] goo.gl/19pkRA.
[24] goo.gl/fiwnWP.
[25] goo.gl/LEmyJD.
[26] goo.gl/RXJPzv.

[27] goo.gl/kthBka; goo.gl/R1R597.

| | | | | | | |
|---|---|---|---|---|---|---|
| **Virginia** | Appalachian Power Company | 2015 Solar RFP[28] | Solar PV | | 10 MW | Dec. 2017 |
| | Dominion Energy | Community Solar Pilot Program[29] | Solar PV | | 10 MW | 2018 |
| **Multiple States** | Appalachian Power Company | 2017 RFP for Virginia or West Virginia[30] | Solar PV | | 25 MW | Dec. 2019 |
| | | Bluff Point Wind Energy Center,[31] for Virginia, West Virginia, and Tennessee | Wind | $200 million | 120 MW | 2018 |
| | SWEPCO | 2016 Wind RFP[32] for Arkansas, Louisiana, and Texas | Wind | | Up to 100 MW | Dec. 2018 |

[28] goo.gl/vGg2EW.
[29] https://tinyurl.com/y72ar8ba.
[30] goo.gl/3a97fn.
[31] goo.gl/9G2oPz; goo.gl/MiK8Y3.
[32] goo.gl/gcwdNv.

# Exhibit G

## Exhibit G: Developer Interest in New Renewable Energy Projects

The below quotes describe each utility's interactions with renewable energy contractors. The text is from responses to question No. 36 of the Commission Staff's First Supplemental Data Request.

**Question #36:** Please discuss whether the Company has been approached by renewable energy generators during 2017 regarding constructing new renewable energy resources. If so, please provide a description of the number and type of renewable generation represented.

**DEF**

"DEF has officially recorded over 33 requests in 2017 from potential renewable energy providers through DEF's Request for Renewables program and DEF has undertaken many more phone conversations. As the cost of solar PV technology continues to drop, there has been more interest from developers utilizing this technology. This interest can be seen in the dramatic increase in interconnection requests that DEF has received from solar PV projects. DEF currently has over 4,600 MW in its interconnection queues. DEF continues to educate renewable energy generators on the potential QF structure and pricing of a renewable power purchase agreement. Most of the inquiries during 2017 were for solar photovoltaic projects, but there was also an inquiry about a hydroelectric facility."

**FMPA**

"During 2017, FMPA had numerous conversations with renewable energy generators through the development of the recently announced Florida Municipal Solar Project. FMPA evaluated a number of firms on their ability to develop solar facilities and negotiated with a power purchase agreement with a short-list of proposers. FMPA is routinely approached by renewable energy generators and we view discussions with these entities as a way to stay on top of market developments. "

**FPL**

"FPL was approached multiple times in 2017 by potential renewable developers with a wide range of potential projects. While most projects suggested are solar photovoltaic, developers have also proposed landfill gas generators, small biomass generators and small waste generators. Proposed projects total over 600 MW. "

**GRU**

"GRU was not approached by renewable energy generators in 2016."

**GULF**
"Gulf routinely fields inquiries from outside entities regarding the potential development of renewable projects in the area served by Gulf. Throughout 2017, Gulf has been in contact with 25+ renewable generators/developers, primarily focusing on PV solar."

**JEA**
"Through the Large Scale Solar PV PPA solicitation process discussed in question 35, JEA received RFQ submittals from 38 companies. Of the 7 companies shortlisted, 6 provided responses to the RFP, with a total of 50 conforming proposals. In addition to these, JEA received a total of 3 unsolicited solar PV proposals from 3 separate entities."

**LAK**
"Renewable developers occasionally contact the utility in attempts to enter into renewable energy contracts, usually in the form of a long term PPA for electricity generated by solar or a biofuel. There is no tracking system in place to measure the frequency or quantity of these callers."

**OUC**
Not submitted

**SEC**
"Seminole has reviewed a few indicative proposals sent by solar developers in 2017. Generally, these proposals followed the types of responses Seminole received to the RFP issued in March 2016. As indicated above, Seminole executed an agreement with Tillman Solar Center for 40 MW of solar PV capacity and energy starting in June 1, 2021 as a result of its RFP process. "

**TAL**
"TAL was approached by four renewable energy developers during 2017 regarding constructing new renewable energy resources, specifically solar PV of a capacity 74.9 MW each."

**TECO**
"Tampa Electric estimates that 20-30 renewable energy developers contacted the Company about renewable energy opportunities in 2017. Most of the contact was with respect to Tampa Electric's process for selecting developers and equipment suppliers for its utility scale PV solar projects. Other developers contacted Tampa Electric about the integration of battery storage and wind energy that would be generated in Oklahoma and delivered to Tampa Electric by HVDC and AC transmission."

# Exhibit H

STATE OF FLORIDA

DIVISION OF ADMINISTRATIVE HEARINGS

IN RE: FLORIDA POWER AND . VOLUME #1
LIGHT COMPANY; DANIA . Case No. 2017-4388-EPP
BEACH ENERGY CENTER .
PROJECT POWER PLANT .
SITING APPLICATION NO. .
PA89-26A2 .
. . . . . . . . . . . . . . ..

Transcript of Administrative Hearing Proceedings and Testimony in the above-entitled cause held before the Honorable Cathy M. Sellers, Administrative Law Judge, located in Broward County, on Wednesday, May 16, 2018 at 9:00 a.m.

(2:47 p.m. to 8:08 p.m.)

Old Davie Schoolhouse
Cafetorium
6650 Griffin Road
Davie, Florida 33314

REPORTED BY:
PRISCILLA GARCIA, COURT REPORTER
NOTARY PUBLIC, STATE OF FLORIDA

I believe this is correct.

Q. Sir, if you could turn to the end of the deposition, you will see a page that says errata. Do you see that, sir?

A. Yes.

Q. Is that your signature there, sir?

A. Yes.

Q. Did you have a chance to review this deposition transcript?

A. Yes. Yes. I read it.

Q. Did you make corrections to it?

A. This is the errata sheet.

Q. That errata sheet accurately identifies your corrections to the transcript?

A. Yes.

Q. Thank you, sir.

You testified that sea level rise is happening in Florida, correct?

A. Yes.

Q. And you reviewed the elements in response to your counselor's question that are leading to sea level rise, correct?

A. Yes.

Q. And you identified vertical land motion; is that correct?

deposition transcript.

If you look at -- sorry, sir.

A. Let me get the page you're talking about.

Q. All right.

A. Yes. I have it. Page 18.

Q. I'm going to begin reading at line 22. When I complete reading I'm going to ask you if I read everything correctly.

"Question: So your testimony is that sea level is rising in Florida?

"Answer: Yes.

"Question: Do you know what is causing that sea level rise in Florida?

"Answer: Yes.

"Question: And what is causing that sea level rise in Florida?

"Answer: The primary cause of the sea level rise in Florida is the global rise associated with long-term climate change."

Did I read that correctly?

A. Yes.

Q. Is it your opinion today that the primary cause of sea level rise in Florida is the global rise associated with long-term climate change?

A. Yes.

Q. And sea level rise, correct?
A. Yes.
Q. And coastal hazards?
A. Yes.
Q. And currents?
A. Yes.
Q. Are you aware of what coastal hazards are caused by sea level rise?
A. If the water level is higher than the possibility of inundation, meaning flooding or so on would be higher from a storm surge for example or from a higher. Yes.
Q. Have you ever heard of saltwater infusion?
A. Infusion? You mean intrusion?
Q. Yes. I misread my notes. Yes.
A. Yeah. Yeah. Yes, I have.
Q. Thank you.
What does that refer to?
A. It usually refers to the water -- saltwater moving into where fresh water would have been in the coastal aquifer.
Q. You mean aquifers?
A. Yes.
Q. So is saltwater intrusion displacing fresh water aquifers?

A. That's my understanding. Yes.

Q. Thank you.

And you testified that the sea level rise is ongoing, correct?

A. Yes.

Q. As it continues, would you expect it to continue to advance saltwater intrusion into aquifers?

A. That's not my area of expertise but if I were to venture a guess, it would be yes.

Q. Thank you.

And you mention, I believe, that sea level rise will cause an increase in flooding; is that right?

A. The potential is there, yes.

Q. Excuse me?

A. Yes. The potential is there, yes. Yes.

Q. Thank you.

Will sea level rise cause an increase in the frequency of flooding?

A. Again, that's not my area of expertise but I would expect, yes.

Q. Sir, can you define what the scope of coastal hazards consist of?

A. Coastal hazards include things such as sea level rise, tsunamis, storm surge, king tides and flooding, so on. Yes.

Sir, I'd like to shift the line of questioning for just a minute. You mentioned that the effects of climate change are not uniform around the globe, correct?

A. Yes.

Q. There are certain areas that are more vulnerable to climate change?

A. Yes. I think so.

Q. Are there certain areas that are more vulnerable to the effects of sea level rise?

A. Yes.

Q. Turning to Florida now.

Is Florida particularly vulnerable to sea level rise?

A. Yes.

Q. Is Southeast Florida vulnerable to sea level rise?

A. Yes.

Q. Is Miami an area vulnerable to sea level rise?

A. Yes.

Q. Is South Miami vulnerable to sea level rise?

A. Yes.

Q. So is Miami an area at greater risk to sea level rise than most other parts of the United States?

A. I believe that to be true. Yes.

Q. Thank you.

Southeast Florida is considered highly vulnerable to SLR sea level rise. Recently the City of Miami has been identified as economically most vulnerable city to SLR sea level rise in the world open paren U.S. National Climate Assessment open paren 2014 close paren close paren, heretofore the effect of sea level rise is felt mostly in lower lying coastal communities such as the City of Miami Beach and some sections of Fort Lauderdale.

Did I read that correctly?

A. Yes.

Q. Okay. Do you agree with the statement made in that article that the low elevation in this highly populated area of Southeast Florida makes it considered highly vulnerable to sea level rise?

A. Yes.

Q. Thank you.

I'm going to now turn to the second section of highlighted language.

These additional analyses indicate that the post 2006 increased flooding frequency in Miami Beach correlates well with rapid acceleration of sea level rise in Southeast Florida, which may have been introduced by a weakening of the entire gulfstream system as proposed previously open paren EG et cetera 2013, close paren.

Did I read that correctly?

the -- to the datum, the record from Miami Beach and Virginia Key we continued a continuous record there. We compared that with Key West and asked, was the rate similar to Key West and the answer was, yes.

Q. Thank you.

And do you have an opinion as to what the most likely rate of sea level rise will be over the next 50 or hundred years?

A. No.

Q. Thank you.

Give me just a minute to review my notes.

So would you agree with the -- Exhibit 7 of your deposition, which is the University of Florida sea level rise -- that the future sea level rise depends what happens on a global scale?

A. Yes. I think that's probably correct.

Q. Okay.

A. Or in part probably correct.

Q. Okay. But you testified that climate change was a predominant reason for sea level rise?

A. I believe that's correct.

Q. Okay. And is it your understanding that carbon dioxide and methane are some of the predominant drivers of climate change?

A. The most important driver of global climate

# Exhibit I

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARING

IN RE: FLORIDA POWER AND LIGHT COMPANY; DANIA BEACH ENERGY CENTER PROJECT POWER PLANT SITING APPLICATION NO. PA89-26A2

CASE NO: 17-4388EPP

Old Davie Schoolhouse
6650 Griffin Road
Davie, Florida
May 16, 2018

AMENDED NOTICE OF HEARING

The above-entitled matter came on for hearing before the Honorable, CATHY SELLERS, Administrative Law Judge, pursuant to Notice.

BY MS. CSANK:

Q. Sir you have not performed any calculations regarding the actual units 4 and 5 emissions version the projections --

THE COURT REPORTER: Can you repeat that please?

BY MS. CSANK:

Q. Sir, you have not performed any calculations regarding the actual unit 4 and 4 emission versus the projection with Units 7 emission of greenhouse gases emission over time, correct?

A. I have not.

Q. And can we agree the definition of life cycle analysis as analysis that determines the emissions of a particular source from start to finish so as relevant here from gas extraction through gas burn?

A. I can agree for that description.

Q. You have performed life cycle analysis on at least two projects before, correct?

A. Yes.

Q. But you didn't perform life cycle analysis for this project, for Unit 7, correct?

A. No.

Q. You didn't consider performing life cycle analysis for Unit 7 because you did not see a need,

BY MS. CSANK:

Q. Sir, do you dispute that the construction and operation of Unit 7 will lead to offsite environmental impasse?

A. I don't dispute it.

Q. And you cannot dispute that methane leaks in upstream gas infrastructure such as valves, pipe lines, drip piles, et cetera?

A. I don't dispute that.

Q. Have you not performed any original analysis to quantify methane leakage rates or mass construction, correct?

A. I have not.

Q. And sir, the environmental impacts of climate change includes sea level rise, more storm, wild fires, draughts, among others, correct?

A. Those that are concerns that have been expressed, yes.

Q. And those are such impact and danger you may held the natural environment and the ecology on land and in water in Florida, correct?

A. That concern has been expressed.

Q. So you do not dispute such endangerment?

A. I do not.

Q. Sir, are you familiar with the term, in the air

# Exhibit J

# DBEC and climate impacts in Florida: An economic analysis

**Prepared for Sierra Club**

Frank Ackerman, PhD

EXHIBIT
2
Ackerman 5/6/18
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# CONTENTS

# 1. INTRODUCTION AND SUMMARY

This report has been prepared for the Sierra Club in the docket on Florida Power & Light Company's (FPL) Dania Beach Energy Center (DBEC) Siting Certification Application. Florida statute 403.519(3) sets forth criteria for approval of power plants; the impacts of DBEC's projected greenhouse gas emissions would raise serious questions about several of these criteria.

The principal sections of the report address

- Selected recent studies of the impacts of climate change in Florida
- Quantification of climate impacts: the social cost of carbon
- DBEC's projected share of global $CO_2$ emissions
- Quantitative estimates of climate damages in Florida, and DBEC's share of those damages
- Summary evaluation of DBEC.

The principal conclusions of these sections are

- Numerous researchers have identified multiple categories of climate damages expected in Florida, including harms to human health, to native wildlife and ecosystems, to the tourism industry, and effects of sea-level rise including increases in flooding, property damage, and displacement of people living in low-lying areas. Florida will be, by some measures, the hardest-hit state in the country as temperatures and sea levels continue to rise.
- The social cost of carbon (SCC), defined as the present value of the incremental damages from an additional ton of $CO_2$ emissions, is a common measure of the monetary value of climate damages. Federal government estimates, developed in 2010-2016, will reach $49 as of 2020, and $70 in 2040 (in 2017 dollars per metric ton of emissions), and will continue to climb beyond that level. Other research, including my own, has identified reasons why this calculation underestimates the most serious climate risks. For this reason, I believe that the true value of the SCC should be much higher.
- To create a perspective on DBEC's role in causation of climate change, it is helpful to compare its emissions to expected global emissions. DBEC's projected annual emissions are either 4.13 or 3.04 million metric tons, of $CO_2$, depending on which of two estimates is used. Using the federal SCC for 2040, approximating the midpoint of DBEC's projected lifetime, the value of the damage done by DBEC's emissions would be either $289 or $213 million per year, in 2017 dollars. DBEC's projected emissions represent either 64 or 47 parts per million (roughly 1/15,000, or 1/20,000) of projected global emissions during 2020-2060. In this sense, DBEC will be responsible for either 64 or 47 parts per million of the climate crisis.

- A detailed recent study estimated state-level impacts of six major categories of climate damages. For Florida, the most likely levels of projected losses were 10.1 – 24.0 percent of state GDP by 2080-2099, the highest of any of the contiguous 48 states. Florida's GDP could reach almost $5 trillion (in 2017 dollars) by 2090; the projected climate losses in these six categories would then be equal to $492 – $1,170 billion. The DBEC share (47 parts per million) of these losses would be $19.3 - $46.5 million per year. Because these estimates are based on only six categories of damages, and address damages only within the state of Florida, I believe that they are significant underestimates of the true value of climate damages attributable to DBEC emissions.

- FPL projects a cumulative present value savings to ratepayers of $337 million from DBEC, or $8.4 million per year. The DBEC share of the Florida damages discussed in the last section has a present value of $8.4 - $27.1 million per year. Thus the DBEC share of just these six categories of damages, just in Florida, has an annual present value ranging from comparable to, up to more than three times the projected benefit of the plant to ratepayers. (The much larger SCC valuation of DBEC emissions swamps the savings to ratepayers.) As a result, even partial measures of DBEC's climate damages equal or exceed its benefits to ratepayers.

- In my opinion, FPL should find a way to reduce greenhouse gas emissions, at the DBEC site or elsewhere, by an amount equal to the projected DBEC emissions, for as long as DBEC continues to operate.

# 2. CLIMATE IMPACTS ON FLORIDA: SELECTED RESEARCH STUDIES

Climate change will have impacts on every state. Florida, facing the combination of rising temperatures and sea levels, will be hit hard – by some measures, it will be hit the hardest of the 48 contiguous states.[1] It would be impossible to present a complete survey of all recent research related to climate impacts on Florida. This section presents selected research findings, highlighting a broad range of impact categories.

## 2.1. Tourism

Tourism is the number one industry in Florida. The state's beautiful beaches and attractive climate, among other attractions, draw visitors from around the country, and from abroad. Yet the natural assets that attract tourists to Florida are vulnerable to rising sea levels and increasing storm activity. If Florida becomes hotter and stormier, storm surges and rising sea levels will erode or submerge beaches. A recent survey found that protecting coastal destinations will require expensive adaptation measures.[2]

## 2.2. Human health

Higher temperatures will be harmful to health in many respects. On a business-as-usual scenario, Florida is projected to have 18 to 32 days per year over 95°F by 2020-2039, and 30 to 76 days per year at that temperature by 2040-2059. Additional annual temperature-related deaths could reach 1,737 to 5,083 in the latter time period.[3]

Higher temperatures also increase vulnerability to several tropical diseases. To cite just one of these diseases, which has been studied in recent research, transmission of dengue fever is impossible in most of the United States, due to temperature, but is currently possible in southern Florida in the summer months. With projected increases in temperature, dengue fever will be able to spread in Florida for most or all of the year.[4]

## 2.3. Ecological health

By 2060, a recent study found, climate change is expected to cause temperature and precipitation changes that will reduce the reproductive capacity of populations of native wildlife in the Everglades,

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[1] Many interstate comparisons exclude Alaska and Hawaii, focusing only on the remaining 48 states.

[2] Robert Atzori and Alan Fyall (2018), "Climate change denial: vulnerability and costs for Florida's coastal destinations", *Journal of Hospitality and Tourism Insights* 1, pp. 137-149.

[3] Risky Business Project (2015), "Come heat and high water: Climate risk in the southeastern U.S. and Texas", p.37, https://riskybusiness.org/site/assets/uploads/2015/09/Climate-Risk-in-Southeast-and-Texas.pdf.

[4] Melinda K. Butterworth, Cory W. Morin, and Andrew C. Comrie (2017), "An analysis of the potential impact of climate change on dengue transmission in the southeastern United States", *Environmental Health Perspectives* 125, pp.579-585.

including wading birds, fish, alligators, native apple snails, and amphibians. Climate change, and the resulting decline of native species, will increase the likelihood of the intrusion and expansion of invasive species.[5]

## 2.4. Impacts of sea level rise and storm surges

Multiple researchers have investigated damaging impacts of sea level rise (SLR) on Florida's environment and economy. The studies are not all based on the same projection of the extent of SLR, and no attempt is being made here to support any specific SLR projection. Rather, the point is that many scientists have identified reasons why some amount of SLR would prove harmful.

Meteorologists have found that on moderate projections of SLR, rising to 0.5 – 1.2m (20 inches – 4 feet) by 2100, the "sunny day flooding" that southeastern Florida experienced in September 2015 will happen more than twice a year by 2030, and about once a month in the 2040s.[6]

Researchers at Florida State University have projected that by 2080, 7-foot storm surges in Miami-Dade County (comparable to Hurricane Wilma) will occur once every 21 years (with one foot of SLR) to once every 5 years (with two feet of SLR). Property losses in such a storm, at today's property values, could reach $12 billion in Miami-Dade County alone.[7]

On a business-as-usual climate trajectory, SLR is likely to mean that $34 to $69 billion of existing property in Florida is below mean high tide by 2030, and $127 to $152 billion by 2050.[8]

By 2100, SLR of 0.9m (3 feet) would displace 1.2 million people in Florida, or 28% of the total displaced nationwide. SLR of 1.8m (6 feet) would displace 6.1 million people in Florida, or 46% of the national total. At 6 feet of SLR, one-fourth of the U.S. population displaced by SLR would be in Miami-Dade and Broward Counties alone.[9]

It is worth emphasizing again that these studies are based on differing, inconsistent projections of SLR. This report is not seeking to settle their disagreements about the expected pace of SLR. However, the range of impacts cited here, as well as in the previous subsections, emphasizes the extent to which

[5] Christopher P. Catano et al. (2014), "Using scenario planning to evaluate the impacts of climate change on wildlife populations and communities in the Florida Everglades", *Environmental Management* 55, pp. 807-823.

[6] William V. Sweet et al. (2016), "In tide's way: Southeast Florida's September 2015 sunny-day flood", *Bulletin of the American Meteorological Society* 97, pp. S25-S30.

[7] Julie Harrington and Todd L. Walton, Jr. (2015), "Climate Change in Coastal Florida: Economic Impacts of Sea Level Rise", Florida State University.

[8] "Come heat and high water" (footnote 3), p.37.

[9] Matthew E. Hauer, Jason M. Evans and Deepak R. Mishra (2016), "Millions projected to be at risk from sea-level rise in the continental United States", *Nature Climate Change* 6, pp.691-695.

Florida faces many varieties of climate damages – by many measures, it will face more severe damages than any other state in the nation.

# 3. QUANTIFYING CLIMATE DAMAGES: THE SOCIAL COST OF CARBON

The complex, multi-dimensional portrait of climate damages presented in the last section leads naturally the question of whether damages can be measured by a single number. The most widely used measure is the social cost of carbon (SCC), defined as the present value of the incremental damages done by an additional ton of $CO_2$ emissions.

The logic of the SCC calculation is illustrated in Exhibit 63. Start with a scenario for projected carbon emissions (left graph, blue dotted line); create a second scenario that differs from the first only in one year's emissions (left graph, solid orange line). Calculate the climate damages expected from each scenario over time (right graph, top two lines); then calculate the difference between the damages from the two scenarios (right graph, bottom line). The present value of the difference, divided by the number of tons of $CO_2$ in the emissions "spike" (left graph), is the SCC.

While the logic of the SCC calculation appears straightforward, there is an obstacle lurking in the movement from the left graph to the right one in Exhibit 63 – that is, in the translation from emission scenarios to monetary estimates of damages. Some climate damages, such as extinction of endangered species, or loss of unique, irreplaceable environments, are difficult or impossible to monetize. And even if damages can be monetized, it remains necessary to project the pace at which damages increase with temperatures or other climate indicators. These issues have given rise to a wide range of SCC estimates, as illustrated in Exhibit 64 and explained here.

From 2010 to 2016 the federal government's Interagency Working Group on the Social Cost of Greenhouse Gases developed and refined estimates of the SCC, for use in cost-benefit analyses of federal programs and regulations. In the final, August 2016 iteration, the federal SCC estimate was $49 for emissions in 2020, rising to $70 in 2040 and $81 in 2050 (all SCC values in this section have been converted to 2017 dollars per metric ton of $CO_2$.)[10]

The Interagency Working Group relied on an average of results from three simple models of climate economics, all of which minimized or ignored some of the most serious climate risks. In particular, these models ignored or minimized the risks of tipping points and abrupt, irreversible losses, one of the most

[10] Interagency Working Group (August 2016), "Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf. Figures cited in the text are the so-called "central estimate" at a 3 percent discount rate and a mid-range estimate of climate sensitivity (a measure of the expected pace of future warming). The Interagency Working Group also calculated estimates at discount rates of 5 percent and 2.5 percent, and another using a much higher estimate of climate sensitivity (and a 3 percent discount rate). In practice, the "central estimate" is the only one commonly cited or used.

damaging features of future climate projections. This and other criticisms of the methodology are spelled out in an extensive evaluation of the federal SCC by the National Academy of Sciences.[11]

Concerns about limitations of the Interagency Working Group methodology have led to research by many economists on risks and uncertainties, producing alternative SCC values that are often higher than the Working Group estimates. A review of the effect of climate risks on the SCC found that, in order to reflect well-known major risks, the SCC needs to be at least $131.[12]

A major study by the well-known British climate economists Simon Dietz and Nicholas Stern found a range of optimal carbon prices (i.e. SCC values), depending on key climate uncertainties, ranging from $41 to $192 for emissions in 2025, and from $100 to $383 for emissions in 2055.[13]

In my own research, with a colleague, Dr. Stanton, we found that a small number of major uncertainties – concerning low-temperature damages, high-temperature damages, climate sensitivity (roughly, the speed of warming), and the discount rate – led to an extremely wide range of possible values, from $33 to $1,048 for emissions in 2010, and from $75 to $1,821 in 2050.[14]

The high but widely varying estimated values for the SCC lead to a quandary for valuation of emissions. There are good reasons to think that damages are very large, but we are not sure exactly how large. The Interagency Working Group numbers are a useful conventional standard, because they are so widely cited and recognized. They are almost certainly an underestimate of the true value of climate damages and should be interpreted as a floor under the true value, not an accurate estimate.

The following sections explore valuation of DBEC emissions using the Interagency Working Group SCC estimates, and also develop a narrower, even more limited focus on DBEC's potential impact on selected categories of climate damages felt in Florida.

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[11] National Academy of Sciences, Engineering, and Medicine (2017). *Valuing Climate Damages: Updating Estimates of the Social Cost of Carbon Dioxide* (Washington, DC: The National Academies Press), https://www.nap.edu/catalog/24651/valuing-climate-damages-updating-estimation-of-the-social-cost-of

[12] J.C.J.M. van den Bergh and W.J.W. Botzen (2014), "A lower bound to the social cost of $CO_2$ emissions", *Nature Climate Change* 4, pp. 253-258.

[13] Simon Dietz and Nicholas Stern (2015), "Endogenous growth, convexity of damage and climate risk: how Nordhaus' framework supports deep cuts in carbon emissions", *Economic Journal* 125, pp. 574-620, Table 4.

[14] Frank Ackerman and Elizabeth A. Stanton (2012), "Climate risks and carbon prices: revising the social cost of carbon", *Economics E-Journal* 6, article 2012-10.

# 4. DBEC's SHARE OF GLOBAL EMISSIONS

In order to frame DBEC's role in causation of climate change, it is helpful to estimate its share of worldwide carbon emissions.

As shown in Exhibit 65, a Florida DEP report on DBEC estimates its annual emissions at 4,550,233 tons of $CO_2$.[15] This is equivalent to **4,129,068** metric tons.

An alternative estimate is based on

- 1168 MW of average year-round capacity (average of winter and summer capacity)
- 90 percent capacity factor
- 727 lbs $CO_2$ per MWh from DBEC gas consumption, from company sources[16]

This leads to an estimate of: 3,347,294 short tons of $CO_2$ per year, or equivalently **3,037,472** metric tons.

FPL's total emissions, during the projected lifetime of DBEC, are projected to average 44,259,444 tons per year.[17] Thus DBEC is projected to represent either 10.3 or 7.6 percent of FPL total emissions, depending on which DBEC emissions estimate is used.

Global emissions, on a business-as-usual trajectory (i.e. with no success in major emission reduction initiatives), are projected to average 64.97 *billion* metric tons of CO2 during 2020-2060, approximating DBEC's lifetime.[18]

Therefore, DBEC's projected share of global emissions is equal to either 64/1,000,000 or 47/1,000,000, of global damages. Roughly speaking, this is either 1/15,000 or 1/20,000 of the global total. One could say that DBEC will be responsible for either "64 parts per million" or "47 parts per million" of global climate damages.

These ratios are used in an alternate approach to Florida climate damages, developed below.

[15] Florida DEP, Electrical Power Plant Site Certification and Project Analysis Report for DBEC, p.9.

[16] From DBEC Unit 7 Plant Specifications, Exhibit JKK-8, p.4.

[17] Docket 20170255-EI, FPL response to Staff's First Set of Interrogatories, #8, emissions for "Plan 2 – With DBEC", annual average 2020-2060.

[18] Data from Intergovernmental Panel on Climate Change (IPCC), Fifth Assessment Report, Working Group I report, Annex II, Table AII.2.1c (for emissions under RCP8.5, the IPCC's high-emission scenario).

# 5. MEASURING FLORIDA CLIMATE DAMAGES

An alternate approach to valuation of Florida climate damages, and DBEC's responsibility for those damages, rests on a detailed recent study that estimates values, by state, for six categories of climate impacts.[19] The study has been cited dozens of times, and the authors have published highly regarded articles in leading scientific journals drawing on the same database. I am not aware of other studies that provide similar state-level detail on expected climate studies.

The six impacts highlighted in the study are not an exhaustive list of all important climate impacts; rather, they are six categories for which it was possible to develop meaningful monetary estimates by state.

The six categories are:

1. **Agriculture:** economic impacts of changes in corn, wheat, oilseeds (soybeans) and cotton yields caused by projected temperature and precipitation changes. Earlier research, from the 1990s, projected that the first few degrees of warming might be good for U.S. agriculture. A newer research paradigm, reflected in this study, observes that there are temperature thresholds above which many crop yields drop precipitously; climate change leads to an increase in the number of summer days above those thresholds, and hence to a decline in yields.
2. **Labor:** changes in labor supply and productivity caused by rising temperatures. It is well known that people work more slowly, and work shorter hours, as temperatures rise above a comfortable level, particularly for outdoor occupations.
3. **Health:** changes in mortality caused by rising temperatures (fewer cold-related deaths, more heat-related deaths). An extensive research literature has documented the close relationship between temperatures and death rates.
4. **Crime:** increases in crime rates associated with rising temperatures. There is a well-known, strong correlation between temperatures and crime.
5. **Energy costs:** rising temperatures lead to reduction in heating costs and increase in air conditioning costs, and also make electric systems less efficient. These trends cause a net increase in required generation capacity and costs as temperatures rise.
6. **Coastal impacts:** Mean sea level rise alone leads to inundation of valuable coastal property, including beaches as well as structures. Losses are much greater when sea level rise amplifies the effects of storm surges, as it increasingly does. The best projections of storm activity imply that future storms will become more intense and damaging.

Impacts are measured as percentage losses in state GDP in 2080-2099, assuming the world follows a high-emission, business-as-usual scenario (the IPCC's so-called "RCP8.5" scenario). Florida has the largest climate impacts of any of the 48 states covered in the study, with a likely cost range between

[19] Trevor Houser, Solomon Hsiang, Robert Kopp, and Kate Larsen (2015), *Economic Risks of Climate Change: An American Perspective* (New York: Columbia University Press).

10.1 and 24.0 percent of state GDP, most of it due to heat-related mortality and coastal impacts.[20] "Likely", in this context, means that the researchers estimate there is a two-thirds probability that impacts will fall in this range (following an approach adopted in other climate analyses). The wide gap between 10.1 and 24 percent losses reflects the fact that we are uncertain about exactly how fast the climate will worsen. In effect, the researchers have estimated a probability distribution for damages, in which 10.1 percent is the 17$^{th}$ percentile and 24 percent is the 83$^{rd}$ percentile. Notice that this implies a one in six chance that climate damages in Florida will be even greater than a loss of 24 percent of GDP, by the last two decades of this century.

Florida's GDP was $967.3 billion in 2017.[21] Assuming a 2.24 percent real growth rate for the long term (matching the average from 1997 to 2017[22]), Florida's GDP in 2090 (the midpoint of the 2080-2099 range cited in the paragraph above) would be $4,874 billion in 2017 dollars. Climate losses of 10.1 to 24.0 percent of that amount would mean $492 to $1,170 billion per year, again in 2017 dollars.

Recalling the calculation from the previous section, which found that DBEC represented either 64 or 47 parts per million of global emissions, the DBEC share of projected Florida climate losses in 2090 would be $31.5 to $74.9 million per year on the high emissions estimate, or $23.1 to $55.0 million per year on the low estimate. Discounted to 2017 present values, the DBEC share of these projected losses would be $11.4 to $27.1 million per year with higher emissions, or $8.4 to $19.9 million with lower emissions.[23]

This is not a precise calculation of DBEC's contribution to Florida climate losses in 2080-2099. DBEC, projected to be on line from 2022 to 2061, will also cause damages both before and after 2080-2099, while other, newer sources of emissions will contribute more to damages at the end of this century. Nonetheless, it may be a reasonable approximation of the share of projected Florida climate losses in 2080-2099, as calculated above.

It is also important to remember that this estimate of damages caused by DBEC's emissions is sure to be an underestimate of the true value, for at least two reasons. First, it looks only at damages in Florida, ignoring damages in other states, let alone other countries. DBEC's share of nationwide U.S. climate damages would be much larger than its share of Florida damages alone. Its share of global damages, consistent with SCC calculations, would be larger still.

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[20] *Ibid.*, p. 141, 148. Numbers in the text refer to costs using the "value of a statistical life" (VSL) valuation of mortality, which has become common in cost-benefit analysis of environmental policy, and projected levels of future hurricane activity.

[21] Downloaded from Bureau of Economic Analysis, May 4, 2018.

[22] Federal Reserve Bank of St. Louis, https://fred.stlouisfed.org/series/FLRGSP.

[23] Since this calculation involves intergenerational climate impacts, it is appropriate to use a low discount rate. In this case, the calculation employs the Stern Review's recommended long-run climate discount rate of 1.4 percent per year. For the source of this discount rate, and economic and philosophical arguments for very low discount rates in intergenerational climate calculations, see Nicholas Stern, *The Stern Review on the Economics of Climate Change* (London: HM Treasury, 2006; Cambridge, UK: Cambridge University Press, 2007).

Second, the Florida damages considered here are not an exhaustive list of all climate damages. Ecosystem damages and losses in the tourism industry, two categories discussed in Section 2 above, are excluded. Rather, the estimates considered here are projected Florida damages from just six categories of climate impacts.

Thus the full extent of climate damages attributable to DBEC emissions is sure to be greater than the numbers discussed in this section, probably much greater. The federal SCC is $70 per metric ton of emissions in 2040, approximating the midpoint of DBEC's expected lifetime. Since DBEC is projected to have about either 4.13 or 3.04 million metric tons of $CO_2$ emissions per year, the SCC value of the damage from DBEC emissions would be $289 or $213 million per year, again in 2017 dollars. As noted above, this is a floor under the true value of climate damages, not an accurate estimate.

# 6. EVALUATION OF DBEC

FPL's assessment of DBEC projects a cumulative present value savings for ratepayers of $337 million, or $8.4 million per year for the 40 years of expected operation.[24] This amount is dwarfed by the SCC valuation of damages attributable to DBEC emissions, $289 or $213 million per year. The projected savings for ratepayers amounts to less than $3 per ton of $CO_2$ emissions, while the federal SCC reaches $70 per ton around the midpoint of DBEC's lifetime.

Even the much smaller estimate of the DBEC share of Florida damages – ignoring all damages outside the state boundaries, and all damages other than six specific categories – has a present value of $8.4 to $27.1 billion per year. In other words, the likely values of the DBEC share of selected in-state Florida damages range from comparable to the ratepayer benefit, up to more than three times the ratepayer benefit. The true value of DBEC-caused climate damages, including a broader geographical scope and more damage categories, would be even larger.

In summary, FPL has failed to show that the benefits of DBEC outweigh the climate costs which it will impose on Florida, let alone broader jurisdictions. I have identified two ways to quantify some of the impacts of DBEC's greenhouse gas emissions. As explained above, I view both of these methods as underestimates of the true damages; they are floors under the actual value, not a best guess at the true value. Yet even with these values, the quantified damages from DBEC's emissions are comparable to, if not larger than, the projected benefits to ratepayers. (The benefits from construction, meanwhile, can be achieved by building anything: a new headquarters, or new generation facilities relying on any fuel and technology, would achieve the same construction benefits; thus they are not specific to the proposed DBEC gas plant.)

The conclusion that even a partial evaluation of climate damages outweighs the ratepayer benefits is of utmost importance for the evaluation of DBEC in this hearing. Construction of DBEC will lock in a 40-year commitment to a large absolute quantity of emissions, millions of tons of $CO_2$ per year, much too high for the rapid reduction that is required to stabilize the climate and mitigate future damages. In my opinion, FPL should find a way to reduce its emissions, either at the DBEC site or elsewhere, by an amount equal to its projected emissions from DBEC.

[24] FPL website, http://fpl.com/daniabeachenergy.

CERTIFICATE OF SERVICE

I hereby certify this 11th day of May, 2018 that a true and correct copy of the foregoing has been served by electronic mail upon the following:

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*/s/ Julie Kaplan*

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*Qualified representative for Sierra Club*

# Exhibit K

**PERMITTEE**

Lakeland Electric
3030 East Lake Parker Drive
Lakeland, FL 33805

Authorized Representative:
Michael Lunday, Plant Manager

Air Permit No. 1050004-048-AC
Permit Expires: 12/31/2021
Minor Air Construction Permit
C.D. McIntosh, Jr. Power Plant
Simple Cycle Combustion Turbine Installation

**PROJECT**

This is the final air construction permit, which authorizes the installation of a 120 Megawatts (MW) Siemens Westinghouse 501D5A simple cycle combustion turbine. The facility is also proposing to retire McIntosh Unit 2, a nominal 115 MW fossil-fueled fired steam electric generating unit as part of this project. The proposed work will be conducted at the existing C.D. McIntosh, Jr. Power Plant, which is a power plant categorized under Standard Industrial Classification No. 4911. The existing facility is in Polk County at 3030 East Lake Parker Drive in Lakeland, Florida. The UTM coordinates are Zone 17, 409.0 kilometers (km) East and 3,106.2 km North.

This final permit is organized into the following sections: Section 1 (General Information); Section 2 (Administrative Requirements); Section 3 (Emissions Unit Specific Conditions); and Section 4 (Appendices). Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of Section 4 of this permit.

**STATEMENT OF BASIS**

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. and is not subject to the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Upon issuance of this final permit, any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

*For:*
Syed Arif, P.E., Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management

## CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Air Construction Permit package was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on the date indicated below to the following persons.

Mr. Michael Lunday, Lakeland Electric: michael.lunday@lakelandelectric.com
Mr. Nedin Bahtic, P.E., Lakeland Electric: nedin.bahtic@lakelandelectric.com
Mr. Kennard F. Kosky, P.E., Golder Associates Inc.: kkosky@golder.com
DEP Southwest District Office: SWD_Air@dep.state.fl.us
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Ms. Lynn Scearce, DEP OPC: lynn.scearce@dep.state.fl.us

Clerk Stamp

**FILING AND ACKNOWLEDGMENT FILED**, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

## FACILITY DESCRIPTION

This facility consists of: a 20 MW simple-cycle combustion turbine peaking unit (Unit 1); two fossil fuel fired electric generating units, 114.7 MW (Unit 2) and 364 MW (Unit 3); a 370 MW combined-cycle combustion turbine (Unit 5); and, three stationary diesel fuel-fired reciprocating internal combustion engines.

Simple cycle combustion turbine peaking Unit 1 is fired with natural gas with a maximum heat input rate of 330 million Btu per hour (MMBtu/hour) or No. 2 fuel oil with a maximum sulfur content of 0.5 percent by weight and a maximum heat input rate of 320 MMBtu/hr. Fossil fuel fired steam electric generator Unit 2 is fired with natural gas with a maximum heat input rate of 1,184.5 million Btu per hour (MMBtu/hour), No. 2 fuel oil or No. 6 fuel oil, both with a maximum heat input rate of 1,115 MMBtu/hr. Fossil fuel fired steam electric generator Unit 3 is fired with coal and natural gas, both with a maximum heat input rate of 3,640 MMBtu/hr. McIntosh Unit 5, a combined-cycle combustion turbine, is fired with natural gas with a maximum heat input rate of 2,407 MMBtu/hour or No. 2 or superior grade fuel oil with a maximum sulfur content of 0.05 percent by weight and a maximum heat input rate of 2,236 MMBtu/hr. The three diesel engines are: a 25-horsepower non-emergency diesel engine-driven sump pump manufactured by Lister and used at the coal tunnel; a 300-horsepower diesel engine-driven emergency fire water pump designated as UPS Diesel No. 32; and, a 500-horsepower diesel engine-driven black-start generator used to start up the combustion turbines.

The facility consists of the following existing emissions units (EU).

| EU No. | Emission Unit Description |
|---|---|
| 004 | Gas Turbine Peaking Unit 1 |
| 005 | McIntosh Unit 2 – Fossil Fuel Fired Steam Generator |
| 006 | McIntosh Unit 3 – Fossil Fuel Fired Steam Generator |
| 008 | Diesel Drive Coal Tunnel Sump Engine |
| 010 | Fire water UPS diesel No. 32 |
| 011 | CT Startup Diesel |
| 028 | McIntosh Unit 5 – 370 MW Combined Cycle Stationary Combustion Turbine |

## PROPOSED PROJECT

On May 3, 2018, Lakeland Electric (LE) submitted an application (Link to Application) seeking authorization to install a new Siemens Westinghouse 501D5A simple cycle combustion turbine (CT) at the C.D. McIntosh Jr. Power Plant (McIntosh Power Plant). This CT is a nominal 120 MW simple cycle combustion turbine-electrical generator set. LE is also proposing to retire McIntosh Unit 2, a nominal 115 MW fossil-fueled fired steam electric generating unit as part of this project.

The following new EU will be added by this project.

| EU No. | Description |
|---|---|
| 034 | Gas Turbine Peaking Unit 2 |

The following existing EU will be deleted by this project.

| EU No. | Description |
|---|---|
| 005 | McIntosh Unit 2 - Fossil Fuel Fired Steam Generator |

## FACILITY REGULATORY CLASSIFICATION

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates units subject to the acid rain provisions of the Clean Air Act (CAA).

- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400(PSD), F.A.C.
- The facility does operate units subject to the New Source Performance Standards (NSPS) of Title 40 Part 60 of the Code of Federal Regulations (40 CFR 60).
- The facility does operate units subject to the National Emissions Standards of Hazardous Air Pollutants (NESHAP) of 40 CFR 63.

1. Permitting Authority: The permitting authority for this project is the Office of Permitting and Compliance in the Division of Air Resource Management of the Department of Environmental Protection (Department). The Office of Permitting and Compliance mailing address is 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400.
2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Southwest District Office at: 13051 N Telecom Parkway, Suite 101, Temple Terrace, Florida 33637-0926.
3. Appendices: The following Appendices are attached as a part of this permit: Appendix A (Citation Formats and Glossary of Common Terms); Appendix B (General Conditions); Appendix C (Common Conditions); Appendix D (Common Testing Requirements); Appendix E (NSPS Subpart A); and Appendix F (NSPS Subpart GG).
4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296 and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. No new emissions unit shall be constructed and no existing emissions unit shall be modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]
7. Construction and Expiration: The expiration date shown on the first page of this permit provides time to complete the physical construction activities authorized by this permit, complete any necessary compliance testing, and obtain an operation permit. Notwithstanding this expiration date, all specific emissions limitations and operating requirements established by this permit shall remain in effect until the facility or emissions unit is permanently shut down. For good cause, the permittee may request that a permit be extended. Pursuant to Rule 62-4.080(3), F.A.C., such a request shall be submitted to the Permitting Authority in writing before the permit expires. [Rules 62-4.070(3) & (4), 62-4.080 & 62-210.300(1), F.A.C.]
8. Source Obligation:
    a. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.
    b. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

    [Rule 62-212.400(12), F.A.C.]

9. Application for Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V air operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V air operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the appropriate Permitting Authority with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050 and Chapter 62-213, F.A.C.]

10. Shutdown of McIntosh Unit 2: Upon completion of commissioning and testing of the new CT (EU 034), the existing McIntosh Unit 2 (EU 005) shall be permanently shut down. The Title V permit revision required by **Specific Condition 9** of this section shall reflect the shutdown of McIntosh Unit 2. The turbine "becomes operational" for the purposes of Rule 62-210.200(166), F.A.C., when the combustion turbine is first ready for normal dispatch to deliver power to the electric grid. [Rule 62-210.200(PTE), F.A.C. and Application No. 1050004-048-AC]

This section of the permit addresses the following emissions unit.

| EU No. | Emission Unit Description |
|---|---|
| 034 | Gas Turbine Peaking Unit 2 |

This EU is a nominal 120 MW simple cycle combustion turbine-electrical generator set consisting of a Siemens Westinghouse Model No. 501D5A unit. The primary fuel is natural gas and distillate fuel oil is fired as a backup fuel. Stack height is 50 feet, stack exit dimensions are 33.5 feet by 12 feet, resulting in an equivalent diameter of 22.6 feet, volumetric flow rate is 1,887,100 actual cubic feet per minute (acfm) and exit temperature is 1,000 degrees Fahrenheit (ºF).

*{Permitting Note: The combustion turbine is subject to: Phase II of the federal Acid Rain Program; 40 CFR 60, Subpart A (General Provisions); and 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines).}*

**EQUIPMENT**

1. Combustion Turbine: The permittee is authorized to install a new 120 MW Siemens Westinghouse Model 501D5A simple cycle combustion turbine-electrical generator set. [Application No. 1050004-048-AC]

**PERFORMANCE RESTRICTIONS**

2. Permitted Capacity: Based on 100% base load, a higher heating value (HHV) and a compressor inlet air temperature of 32° F, the maximum allowable heat input rates are as follows
   a. Natural Gas: 1,776 MMBtu/hr.
   b. Distillate Fuel Oil: 1,726 MMBtu/hr.

   [Rule 62-210.200(PTE), F.A.C. and Application No. 1050004-048-AC]
3. Authorized Fuels:
   a. The combustion turbine shall fire only natural gas with maximum sulfur content of 2 grains of sulfur per 100 dry standard cubic feet of gas (monthly average) or distillate oil with a maximum sulfur content of 0.0015% by weight.
   b. The combustion turbine shall fire no more than 1,350,084 MMBtu of natural gas during any consecutive 12-month period (equivalent to approximately 812 hours/year at base load and 59℉ turbine inlet). The combustion turbine shall fire no more than 565,550 MMBtu of distillate oil during any consecutive 12-month period (equivalent to approximately 350 hours/year at base load and 59℉ turbine inlet). If distillate oil is fired in any 12-month period, the amount of total natural gas that can be fired is reduced by 1.8 times the heat input used for distillate oil firing. The permittee shall install, calibrate, operate and maintain a monitoring system to measure and accumulate the following for each fuel fired: quantity, heat input rate and hours of operation.

   [Rule 62-210.200(PTE), F.A.C. and Application No. 1050004-048-AC]

**EMISSIONS STANDARDS**

4. Nitrogen Oxides (NOx) Emissions: NOx emissions shall not exceed: 25.0 parts per million by volume, dry (ppmvd) corrected to 15% oxygen based on a 24-hour block average when firing natural gas; 42.0 ppmvd corrected to 15% oxygen based on a 24-hour block average when firing distillate oil; and 56 tons/year based on a 12-month rolling sum total. [Application No. 1050004-048-AC]
5. Carbon Monoxide (CO) Emissions: CO emissions shall not exceed 10 ppmvd corrected to 15% oxygen at base load, based on a 24-hour block average. [Application No. 1050004-048-AC]

## CONTROL TECHNOLOGY

6. Water Injection: The permittee shall install, calibrate, operate, and maintain a water injection system to reduce $NO_X$ emissions from this CT. The system shall be designed and operated so as to meet the $NO_X$ limits of this permit. [Rule 62-210.200(PTE), F.A.C. and Application No. 1050004-048-AC]

## EXCESS EMISSIONS

*{Permitting Note: The following condition applies only to the emissions standards in **Specific Conditions. 4** **and 5** of this subsection. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}*

7. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted provided:

   a. Best practices to minimize emissions are adhered to; and

   b. The duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for longer duration.

   Excess emissions that are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.

   [Rule 62-210.700(1), F.A.C.]

## TESTING REQUIREMENTS

8. Continuous compliance Demonstration: Continuous compliance with the emissions standard for emissions of NOx and CO shall be demonstrated using continuous emissions monitoring systems (CEMS). [Rule 62-4.070(3), F.A.C., and Application No. 1050004-048-AC]

9. Annual Compliance Tests: An annual emissions test is not required for NOx and CO as long as they are measured by CEMS and, the CEMS meet the performance specifications, quality assurance, and quality control measures of 40 CFR part 60 or 40 CFR. part 75, adopted and incorporated in Rule 62-204.800, F.A.C. [Rule 62-297.310(8)(a)5b, F.A.C.]

10. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix D (Common Testing Requirements) of this permit. [Rule 62-297.310(9), F.A.C.]

11. Test Methods: Required tests shall be performed in accordance with the following reference methods.

| Method | Description of Method and Comments |
|---|---|
| 1-4 | Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content |
| 7E | Determination of Nitrogen Oxide Emissions from Stationary Sources |
| 10 | Determination of Carbon Monoxide Emissions from Stationary Sources<br>*{Note: The method shall be based on a continuous sampling train.}* |
| 20 | Determination of $NO_X$, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines |

The above methods are described in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; and Appendix A of 40 CFR 60]

## MONITORING REQUIREMENTS

12. CO, NOx and $O_2$ CEMS: The permittee shall install, calibrate, operate, and maintain in the exhaust stack of this emissions unit to measure and record the emissions of NOx and CO from the CT, and the oxygen (O2) content of the flue gas at the location where NOx and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of this permit.

    a. The NOx and $O_2$ monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. Record keeping, and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. Relative Accuracy Test Audit (RATA) tests required for the NOx monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. The RATA tests required for the oxygen monitor shall be performed using EPA Method 3, 3A or 3B, of Appendix A of 40 CFR 60. The span for the oxygen monitor shall not be greater than 21%. For each CEMS, the permittee shall conduct RATAs in accordance with the regulations of 40 CFR 75 for NOx and Performance Specification 4 or 4A for CO.

    b. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of section 7 shall be made each calendar quarter and reported semi-annually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The span for the CO monitor shall not be greater than 100 ppmvd corrected to 15% $O_2$.

    c. For purposes of determining compliance with the NOx emission limits based on a 24-hour block average, missing data shall not be substituted pursuant to 40 CFR 75. Instead the block average shall be determined using the remaining hourly data in the 24-hour block. However, the permittee's record keeping for the EU-034 NOx emissions cap (tons/year) shall be in full agreement with data submitted for inclusion on EPA's Acid Rain website which includes all documented exclusions reported to the Department in a quarterly report. The permittee may exclude start up, shutdown, and Part 75 missing data from the ppmvd calculations. However, this data will need to be recorded for the tons/year calculations for netting purposes and as required by the Acid Rain website.

    d. The CO, NOx and $O_2$ data shall be recorded by the CEMS during episodes of startup, shutdown and malfunction. No valid monitoring data shall be excluded from the mass-based (tons/year) NOx emissions limits. Monitoring data collected during startup, shutdown and malfunctions may be excluded in accordance with the following conditions when determining compliance with concentration-based (ppmvd) CO and NOx emissions limits. CO and NOx emissions data recorded during these episodes may be excluded from the 24-hour block average calculated to demonstrate compliance with the emission limits of this permit as provided in this paragraph. Periods of data excluded for startup and shutdown shall not exceed two hours (120 minutes) in any operating day. Periods of data excluded for malfunctions shall not exceed two hours (120 minutes) in any operating day. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. Periods of data excluded for all startup, shutdown or malfunction episodes shall not exceed four hours (240 minutes) in any operating day. An operating day is defined as a day (midnight to midnight) that contains operation of this emissions unit. The owner or operator shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented.

e. The 24-hour block averages are calculated as follows: starting at midnight of each operating day, a 24-hour block average shall be calculated from 24 valid hourly average emission rate values. Each hourly value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). A valid hourly emission rate shall be calculated for each hour in which at least two measurements are obtained at least 15 minutes apart. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. Monitoring data shall be excluded from the 24-hour block average for the following periods: startup, shutdown, or malfunction as defined in Rules 62-210.200 and 62-210.700, F.A.C.; when fuel is not fired in the unit; CEMS quality assurance checks; or when the CEMS is out of control.

f. For the annual (tons/year) emissions limit for NOx, measurements shall be in pounds (converted to tons) and be based on a 12-month rolling total starting at the first day of each calendar month. Each monthly total shall be calculated by adding the pounds per day for each valid operating day (all fuels) within the calendar month. This monthly total shall be combined with the emissions from the previous valid 11 calendar months and shall comprise a 12-month rolling total.

g. CEMS data collected during seasonal or other major combustor tuning sessions shall be excluded from the CEMS compliance demonstration for short term emission standards provided the tuning session is performed in accordance with the manufacturer's specifications. All valid emissions data shall be used to demonstrate compliance with annual emissions caps. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. "Seasonal tuning", where minor adjustments are performed, is also required to compensate for changes in average ambient conditions. Prior to performing any major or seasonal tuning session, the permittee shall provide the Compliance Authority with advance notice that details the activity and proposed tuning schedule. The notice shall be by telephone, facsimile transmittal, or electronic mail.

h. Note that the twelve month rolling emissions totals required to be reported for NOx do not exclude any data.

[Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subparts A & GG; 40 CFR 60, Appendices A, B & F; 40 CFR 75, Subparts B, C, F & G]

**RECORDS AND REPORTS**

13. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix D (Common Testing Requirements) of this permit. [Rule 62-297.310(10), F.A.C.]

14. Periodic Emissions Monitoring:

    a. *Malfunction Notification*: If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within one working day of the following: the nature, extent, and duration of the excess emissions; the cause of the excess emissions;

and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *Semi-Annual Report*: Within 30 days following the end of each semi-annual period, the permittee shall submit a report to the Compliance Authority summarizing periods of emissions in excess of the limits in this permit limit or the limits in 40 CFR 60, Subpart GG limit, following the NSPS format in 40 CFR 60.7(c), Subpart A. In addition, the report shall summarize the $NO_X$ and CO CEMS system monitor availability for the previous semi-annual period.

[Rules 62-4.130 & 62-210.700(5), F.A.C.; and 40 CFR 60.7 & 60.334(j)(5)]

15. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

a. *Natural Gas Sulfur Limit*: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

b. *Fuel Oil Sulfur Limit*: Compliance with the fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to the Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D.

[Rule 62-210.200(PTE), F.A.C.]

**OTHER REQUIREMENTS**

16. NSPS Provisions: The combustion turbine is subject to applicable requirements in Subpart A (General Provisions) and Subpart GG (Stationary Gas Turbines) of 40 CFR 60 (see attached appendices). [Rule 62-4.070(3), F.A.C., and Application No. 1050004-048-AC]

# Exhibit L

**Exhibit L: GULF RENEWABLE ENERGY RFI PROPOSALS - PSC VERSION 2-12-18**

| Project Name | Resource Type | Name Plate Capacity (MW) | Expected COD | Term of Contract (yrs) | Price Structure | Escalator | PPA Price ($/MWh) |
|---|---|---|---|---|---|---|---|
| 15 Yr PPA #1 | Solar PV | 50.0 | Dec-20 | 15 | Fixed Price PPA | | $ 28.10 |
| 15 Yr PPA #2 | Solar PV | 50.0 | Dec-21 | 15 | Fixed Price PPA | | $ 26.72 |
| 15 Yr PPA #3 | Solar PV | 50.0 | Sep-22 | 15 | Fixed Price PPA | | $ 24.35 |
| 15 Yr PPA #4 | Solar PV | 50.0 | Sep-22 | 15 | Fixed Price PPA | | $ 24.00 |
| 15 Yr PPA #5 | Solar PV | 10.0 | Sep-22 | 15 | Fixed Price PPA | | $ 29.45 |
| 15 Yr PPA #6 | Solar PV | 50.0 | Dec-20 | 15 | Escalating Price PPA | 3.0% | $ 22.15 |
| 15 Yr PPA #7 | Solar PV | 50.0 | Dec-20 | 15 | Escalating Price PPA | 3.0% | $ 22.15 |
| 15 Yr PPA #8 | Solar PV | 50.0 | Dec-20 | 15 | Escalating Price PPA | 3.0% | $ 22.15 |
| 15 Yr PPA #9 | Solar PV | 50.0 | Dec-20 | 15 | Escalating Price PPA | 3.0% | $ 22.15 |
| 15 Yr PPA #10 | Solar PV | 50.0 | Dec-20 | 15 | Escalating Price PPA | 3.0% | $ 22.15 |
| 15 Yr PPA #11 | Solar PV | 50.0 | Dec-20 | 15 | Fixed Price PPA | | $ 41.25 |
| 15 Yr PPA #12 | Solar PV | 50.0 | Dec-21 | 15 | Fixed Price PPA | | $ 31.45 |
| 15 Yr PPA #13 | Solar PV | 50.0 | Dec-21 | 15 | Fixed Price PPA | | $ 35.81 |
| 15 Yr PPA #14 | Solar PV | 50.0 | Jun-20 | 15 | Escalating PPA | 2.9% | $ 31.41 |
| 15 Yr PPA #15 | Solar PV | 50.0 | Jun-21 | 15 | Escalating PPA | 2.9% | $ 32.06 |
| 15 Yr PPA #16 | Solar PV | 50.0 | Jun-22 | 15 | Escalating PPA | 2.9% | $ 32.61 |
| 15 Yr PPA #17 | Solar PV | 50.0 | Dec-21 | 15 | Fixed Price PPA | | $ 40.10 |
| 15 Yr PPA #18 | Solar PV | 50.0 | Nov-20 | 15 | Fixed Price PPA | | $ 27.50 |
| 15 Yr PPA #19 | Solar PV | 50.0 | Nov-20 | 15 | Escalating PPA | 3.1% | $ 24.80 |
| 15 Yr PPA #20 | Solar PV | 49.5 | Dec-20 | 15 | Fixed Price PPA | | $ 39.80 |

**Exhibit L: GULF RENEWABLE ENERGY RFI PROPOSALS - PSC VERSION 2-12-18**

| Project Name | Resource Type | Name Plate Capacity (MW) | Expected COD | Term of Contract (yrs) | Price Structure | Escalator | PPA Price ($/MWh) | Storage Cost ($/kW-mo) |
|---|---|---|---|---|---|---|---|---|
| Project #1 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 37.60 | |
| Project #2 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 37.30 | |
| Project #3 | Solar PV | 50.0 | Dec-20 | 25 | Fixed Price PPA | | $ 26.39 | |
| Project #4 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 24.36 | |
| Project #5 | Solar PV | 50.0 | Sep-22 | 25 | Fixed Price PPA | | $ 21.13 | |
| Project #6 | Solar PV | 50.0 | May-20 | 25 | Escalating Price PPA | 2.0% | $ 29.75 | |
| Project #7* | Solar PV + Battery | 50.0 | May-20 | 25 | Fixed Price PPA | | $ 46.00 | |
| Project #8* | Solar PV + Battery | 50.0 | May-20 | 25 | Escalating Price PPA | 2.3% | $ 39.75 | |
| Project #9 | Solar PV | 50.0 | Sep-22 | 25 | Fixed Price PPA | | $ 32.25 | |
| Project #10 | Solar PV | 10.0 | Sep-22 | 25 | Fixed Price PPA | | $ 37.15 | |
| Project #11 | Solar PV | 50.0 | Dec-20 | 25 | Escalating Price PPA | 3.0% | $ 22.15 | |
| Project #12 | Solar PV | 50.0 | Dec-20 | 25 | Escalating Price PPA | 3.0% | $ 22.15 | |
| Project #13 | Solar PV | 50.0 | Dec-20 | 25 | Escalating Price PPA | 3.0% | $ 22.15 | |
| Project #14 | Solar PV | 50.0 | Dec-20 | 25 | Escalating Price PPA | 3.0% | $ 22.15 | |
| Project #15 | Solar PV | 50.0 | Dec-20 | 25 | Escalating Price PPA | 3.0% | $ 22.15 | |
| Project #16 | Solar PV | 50.0 | Dec-20 | 25 | Fixed Price PPA | | $ 33.00 | |
| Project #17 | Solar PV | 50.0 | Dec-20 | 25 | Escalating Price PPA | 3% | $ 25.50 | |
| Project #18 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 32.00 | |
| Project #19 | Solar PV | 50.0 | Dec-21 | 25 | Escalating Price PPA | 3% | $ 24.70 | |
| Project #20 | Solar PV | 40.0 | Dec-20 | 25 | Fixed Price PPA | | $ 32.80 | |
| Project #21 | Solar PV | 40.0 | Dec-20 | 25 | Escalating Price PPA | 3% | $ 25.30 | |
| Project #22 | Solar PV | 40.0 | Dec-21 | 25 | Fixed Price PPA | | $ 31.80 | |
| Project #23 | Solar PV | 40.0 | Dec-21 | 25 | Escalating Price PPA | 3% | $ 24.50 | |
| Project #24 | Solar PV | 50.0 | Dec-20 | 25 | Fixed Price PPA | | $ 45.00 | |
| Project #25 | Solar PV | 50.0 | Dec-22 | 25 | Fixed Price PPA | | $ 37.90 | |
| Project #26 | Solar PV | 50.0 | Dec-22 | 25 | Escalating Price PPA | 2.50% | $ 30.15 | |
| Project #27 | Solar PV | 50.0 | Dec-22 | 25 | Fixed Price PPA | | $ 39.25 | |
| Project #28 | Solar PV | 50.0 | Dec-22 | 25 | Escalating Price PPA | 2.50% | $ 31.25 | |
| Project #29 | Solar PV | 10.0 | Dec-19 | 25 | Fixed Price PPA | | $ 40.80 | |
| Project #30 | Solar PV | 10.0 | Dec-19 | 25 | Fixed Price PPA | | $ 41.05 | |
| Project #31 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 34.39 | |
| Project #32 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 36.84 | |
| Project #33 | Solar PV | 50.0 | Jun-20 | 25 | Escalating PPA | 2.9% | $ 28.06 | |
| Project #34 | Solar PV | 50.0 | Jun-21 | 25 | Escalating PPA | 2.9% | $ 28.56 | |
| Project #35 | Solar PV | 50.0 | Jun-22 | 25 | Escalating PPA | 2.9% | $ 28.96 | |
| Project #36 | Solar PV | 50.0 | Jun-20 | 25 | Escalating Price PPA | 2% | $ 29.94 | |
| Project #37 | Solar PV | 50.0 | Sep-19 | 25 | Fixed Price PPA | | $ 32.46 | |
| Project #38 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 42.50 | |
| Project #39 | Solar PV | 50.0 | Dec-20 | 25 | Fixed Price PPA | | $ 39.70 | |
| Project #40 | Solar PV | 50.0 | Dec-20 | 25 | Escalating Price PPA | 2.5% | $ 31.80 | |
| Project #41 | Solar PV | 35.0 | Dec-20 | 25 | Fixed Price PPA | | $ 43.20 | |
| Project #42 | Solar PV | 35.0 | Dec-20 | 25 | Escalating Price PPA | 2.5% | $ 34.70 | |
| Project #43 | Solar PV | 50.0 | Dec-20 | 25 | Fixed Price PPA | | $ 41.63 | |
| Project #44 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 36.68 | |
| Project #45 | Solar PV | 50.0 | Sep-22 | 25 | Fixed Price PPA | | $ 35.10 | |
| Project #46 | Solar PV | 50.0 | Dec-20 | 25 | Fixed Price PPA | | $ 38.15 | |
| Project #47 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 32.50 | |
| Project #48 | Solar PV | 50.0 | Sep-22 | 25 | Fixed Price PPA | | $ 31.52 | |
| Project #49 | Solar PV | 50.0 | Dec-20 | 25 | Fixed Price PPA | | $ 38.59 | |
| Project #50 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 33.31 | |
| Project #51 | Solar PV | 50.0 | Sep-22 | 25 | Fixed Price PPA | | $ 32.83 | |
| Project #52** | Solar PV + Battery | 50.0 | Dec-20 | 25 | Fixed Price PPA | | $ 38.59 | $ 6.53 |
| Project #53 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 30.50 | |
| Project #54 | Solar PV | 50.0 | Dec-21 | 25 | Escalating Price PPA | 2% | $ 25.35 | |
| Project #55 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 29.65 | |
| Project #56 | Solar PV | 50.0 | Dec-21 | 25 | Escalating Price PPA | 2% | $ 24.65 | |
| Project #57 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 29.80 | |
| Project #58 | Solar PV | 50.0 | Dec-21 | 25 | Escalating Price PPA | 2% | $ 24.75 | |
| Project #59 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 29.43 | |
| Project #60 | Solar PV | 50.0 | Dec-21 | 25 | Escalating Price PPA | 2% | $ 24.45 | |
| Project #61 | Solar PV | 50.0 | Dec-21 | 25 | Fixed Price PPA | | $ 29.65 | |
| Project #62 | Solar PV | 50.0 | Dec-21 | 25 | Escalating Price PPA | 2% | $ 24.65 | |
| Project #63 | Solar PV | 20.0 | Jun-20 | 25 | Escalating Price PPA | 2% | $ 43.20 | |
| Project #64 | Solar PV | 50.0 | Dec-19 | 25 | Escalating Price PPA | 2% | $ 35.98 | |
| Project #65 | Solar PV | 50.0 | Dec-20 | 25 | Escalating Price PPA | 2% | $ 34.98 | |
| Project #66 | Solar PV | 50.0 | Dec-20 | 25 | Escalating Price PPA | 1.5% | $ 29.45 | |
| Project #67 | Solar PV | 50.0 | Jun-20 | 25 | Escalating Price PPA | 2% | $ 34.30 | |
| Project #68 | Solar PV | 50.0 | Jun-21 | 25 | Escalating Price PPA | 2% | $ 32.00 | |
| Project #69 | Solar PV | 20.0 | Sep-22 | 25 | Fixed Price PPA | | $ 43.65 | |
| Project #70 | Solar PV | 50.0 | Sep-22 | 25 | Fixed Price PPA | | $ 39.09 | |
| Project #71 | Solar PV | 50.0 | Jan-21 | 25 | Escalating Price PPA | 3% | $ 29.30 | |
| Project #72 | Solar PV | 49.5 | Dec-20 | 25 | Fixed Price PPA | | $ 41.10 | |

*PV+Storage Project PPA Price does include the Storage Cost

**PV+Storage Project PPA Price does not include the Storage Cost

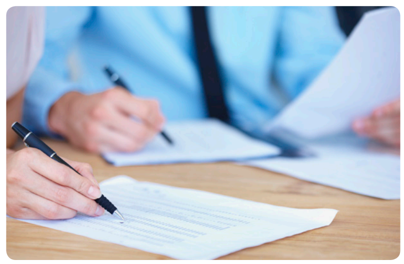
# Exhibit M

# STRATEGIC RESOURCE PLAN

## Lakeland Electric

March 2015

LAKELAND ELECTRIC
POWERED FOR LIFE



PREPARED BY:

NewGen Strategies & Solutions

nFRONT CONSULTING LLC
Power Industry Planners • Analysts • Advisors

March 9, 2015

Ms. Farzie Shelton
Associate General Manager, Technical Support
Lakeland Electric
501 East Lemon Street
Lakeland, Florida 33801

Subject: **Strategic Resource Plan Final Report**

Dear Ms. Shelton,

Attached is the final report for the Lakeland Electric Strategic Resource Plan (SRP) which reflects the collective efforts and participation of an External Advisory Panel of Lakeland community leaders, an SRP Team comprised of senior Lakeland Electric staff, and the consulting services of Luminate, NewGen Strategies and Solutions, and nFront Consulting.

As the results of the SRP study show, Lakeland Electric is well positioned to address many of the potential scenarios that can develop as the electric power industry continues to evolve. Although uncertainties such as workforce availability and regulatory changes will affect virtually all electric utilities going forward, refinement of the SRP Sustainability and Technology Roadmap over time will help to assure LE can address these issues with finite and measurable action plans that can achieve a balance between competitive energy supply and remaining both environmentally responsible and a solid contributor to the community it serves.

We thank you for the opportunity to participate with Lakeland Electric on this endeavor and hope that you have found the effort and its results a beneficial tool as you move forward. It has been a pleasure to work with you and your capable staff, coworkers, and community leaders as we have propagated this work effort to its completion. If we can be of any additional assistance with further development of your SRP alternatives, tactical development plans, or any other services within our scope of expertise that can bring value to LE, please do not hesitate to contact us at your convenience.

With Best Regards,

Frederick F. Haddad Jr.
Executive Consultant
nFront Consulting LLC

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# EXECUTIVE SUMMARY

The energy and power market is changing like at no other time in the past 50 years. Advancements and developments in renewable energy, distributed generation, regulations, smart appliances, energy efficiency, smart grid, electric vehicles, power generation, and utility programs are all beginning to converge and drive significant change in the electric grid, utilities and consumer consumption. While Lakeland Electric (LE) faces this evolving market and changing customer demands, they are also approaching significant decision points regarding its current fleet of power generation resources and the development of the portfolio of generation resources for the future. To navigate this convergence of market, technology and asset related issues, and understand the impacts to its customers, LE developed the Strategic Resource Plan (SRP).

The key goals of the SRP included identification of a path forward integrating generation asset decisions with customer involvement under uncertain market conditions. A Sustainability and Technology Roadmap (Roadmap) was developed to integrate and leverage technology, engage stakeholders, and to develop a plan to improve LE's triple bottom line performance. The Roadmap identified a future state where LE will leverage diverse, sustainable resources to deliver competitive, innovative solutions that support a vibrant LE community. From that future state, LE looked back to identify the key steps or destinations they must reach to realize their strategic direction. Figure ES-1 illustrates the completed LE Roadmap.

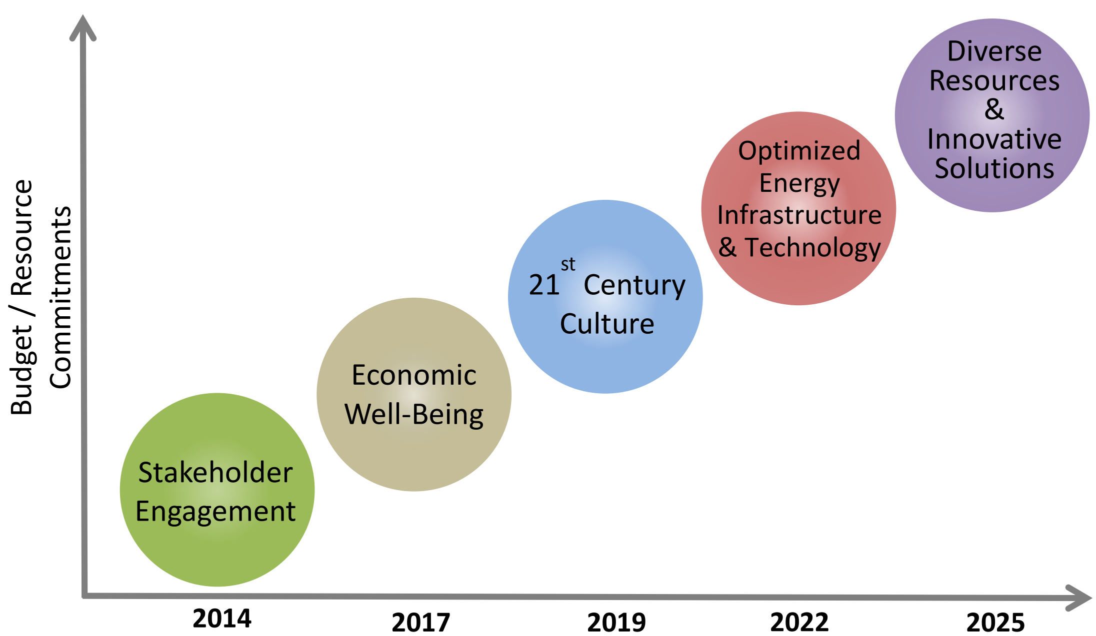



**Figure ES-1: Lakeland Electric Sustainability and Technology Roadmap**

As the Roadmap sets the strategic direction for LE over the next 10 years, detailed analytics and resource simulation was required to evaluate specific generation technology alternatives and existing asset related decisions. One of the outcomes of the Roadmap process was the creation of four Business Cases to reflect current generation technology planning options and external market conditions.

- Business Case 1: Build New Resources – repower existing LE generation units.
- Business Case 2: Purchase Future Resources – purchase capacity and energy from the market as needed.
- Business Case 3: Customer Demand Technology – elimination of load growth through high customer adoption of energy conservation and distributed generation (e.g., solar photovoltaic).
- Business Case 4: Greenhouse Gas Regulation – developing generation and demand-side resources to meet EPA proposed regulations.

The economic resource simulation modeling allowed for a comparison of the four Business Cases over the 20-year study period by contrasting system average rate projections, resource mix, and risks between scenarios. The results of the economic and resource modeling for the four Business Cases are shown below in Figure ES-2 as the system average rate for LE customers.

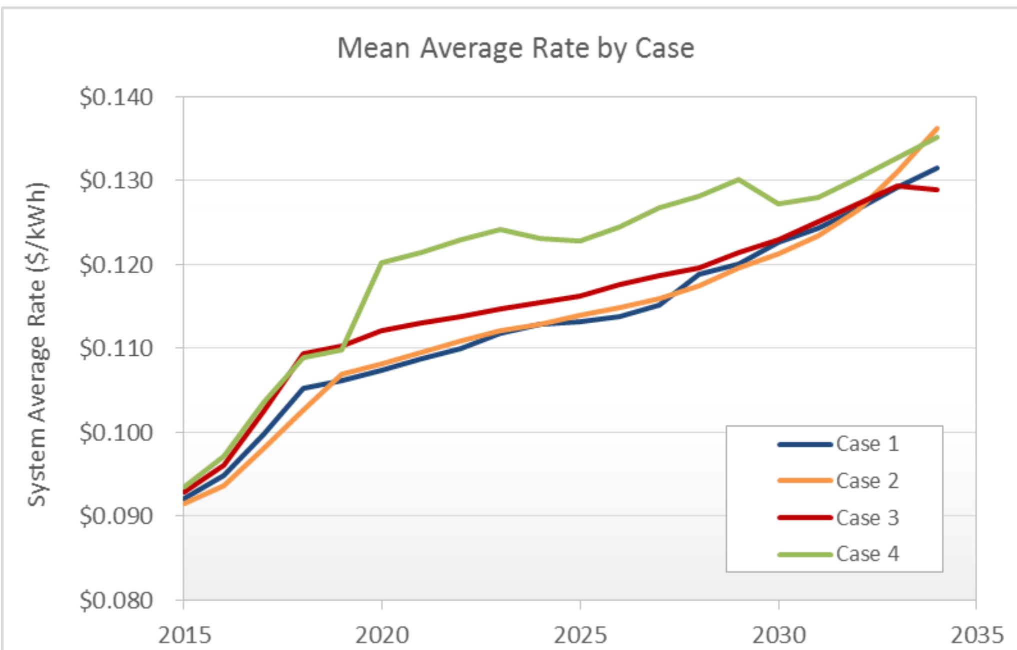



**Figure ES-2: Business Case System Average Rate Results**

Although LE's aging generation fleet was of particular strategic concern across the organization and its stakeholder base, the economic evaluations and risk assessments of the four Business Cases show that LE has a significant amount of flexibility to address future resource needs while also remaining competitive from a rate perspective under the expected conditions. The results also demonstrate LE can reasonably and cost effectively address carbon related issues even if regulations remain as currently proposed. In addition, LE has the potential to effectively address issues where demand destruction takes hold in the market, if or when it begins to become widespread.

Business Case 1 and 2 each provide reasonable and cost effective options for LE to restructure its approach to the development of its generation resource plan. The level of uncertainty LE anticipates for regulatory and market conditions will likely drive the final resource and Business Case selections. Depending on the level of uncertainty, LE may choose to adopt a more traditional approach of building resources or a more flexible approach involving purchases in the market until critical regulatory and market factors become clearer.

As environmental conditions and regulatory policies continue to escalate in scope and magnitude to LE and other electric utilities, the SRP included a review of the regulatory landscape, sustainability performance and potential impacts and risks to LE's asset mix and operations. A baseline assessment for environmental, labor and societal performance was completed to assess the current LE operating state. This baseline assessment was aligned with the Roadmap to help identify gaps or critical needs in achieving the strategic direction of diverse resources and innovative solutions. This broader approach to utility performance prepares LE for the new reality in the electric utility industry of increased stakeholder engagement, customer needs, and regulatory constraints.

While the Business Case analysis showed LE has the ability to meet changing marketing and regulatory conditions while remaining competitive, the sustainability assessment identified areas or gaps to address in meeting the challenges of the future stakeholder and customer demands. One of the more significant issues facing LE, and most utilities, is the current and potential future attrition of the workforce. The potential retirement of staff and loss of expertise is an issue common to each of the Business Cases and an issue that may present significant hurdles to achieving the goals of the Roadmap. It does, however, also represent an opportunity for the utility to restructure its approach to workforce development, management practices / procedures, and a shifting of the corporate culture as the organization may deem appropriate.

As the SRP and Roadmap are now developed, the next challenge facing LE is effectively integrating the Roadmap into LE's day-to-day operations in a programmatic way and using the economic modeling data and analysis to identify and support near term generation resource decisions. While LE is facing several strategic and important decisions over the next 10 years, LE is positioned well for implementation and supported internally and externally as seen in the response of the staff survey and successful participation and contribution of the external Advisory Panel.

# Section 1
# INTRODUCTION

The energy and power market is changing like at no other time in the past 50 years. Advancements and developments in renewable energy, distributed generation, regulations, smart appliances, energy efficiency, smart grid, electric vehicles, power generation, and utility programs are all beginning to converge and drive significant change in the electric grid, utilities, and consumer consumption. In addition, many municipal utilities not only face these market demands but additional societal and community related demands on their operations. In response to these uncertain times and a need to plan for imminent generation resource decisions, Lakeland Electric (LE) developed a Strategic Resource Plan (SRP).

## Lakeland Electric Preparing for the Future

LE is approaching significant decisions regarding the future of its current fleet of power generation resources. Market and regulatory forces are converging with aging resources at LE to accelerate decision making regarding future capital investments, technology, and customer services. LE is also planning to leverage its recently completed deployment of advanced metering infrastructure (AMI) or "smart meters" to offer new services and benefits to customers.

Awareness of these key market trends, a desire to leverage technology investments, and a need to understand the potential impacts to LE and its customers was the purpose behind the development of the SRP. The key goals or desired outcomes for the SRP included identification of a path forward with generation asset related decisions in these uncertain conditions, a roadmap to integrate and leverage technology, stakeholder engagement, and a plan to improve LE's triple bottom line performance.

The core elements of the SRP included five project modules:

- Sustainability and Technology Roadmap (Roadmap)
- Economic modeling of resource planning options
- Environmental assessment and gap analysis
- Labor assessment and gap analysis
- Societal assessment and gap analysis

## Sustainability and Technology Roadmap

The Roadmap aligns with LE's overall vision and mission while providing a more actionable strategic plan linked to tactical operating, customer, and capital decisions. The Roadmap identifies where the organization should be positioned in 10 years to best serve customers and remain competitive in the market. Ideally, the Roadmap is a living document allowing the organization to simultaneously screen activities and provide direction in planning and execution.

LE's Roadmap identified a future state where they will ***leverage diverse, sustainable resources to deliver competitive, innovative solutions that support our vibrant community.*** From that future state, LE looked back to identify the key steps or destinations they must reach to realize their strategic direction. Figure 1-1 illustrates the completed LE Roadmap.

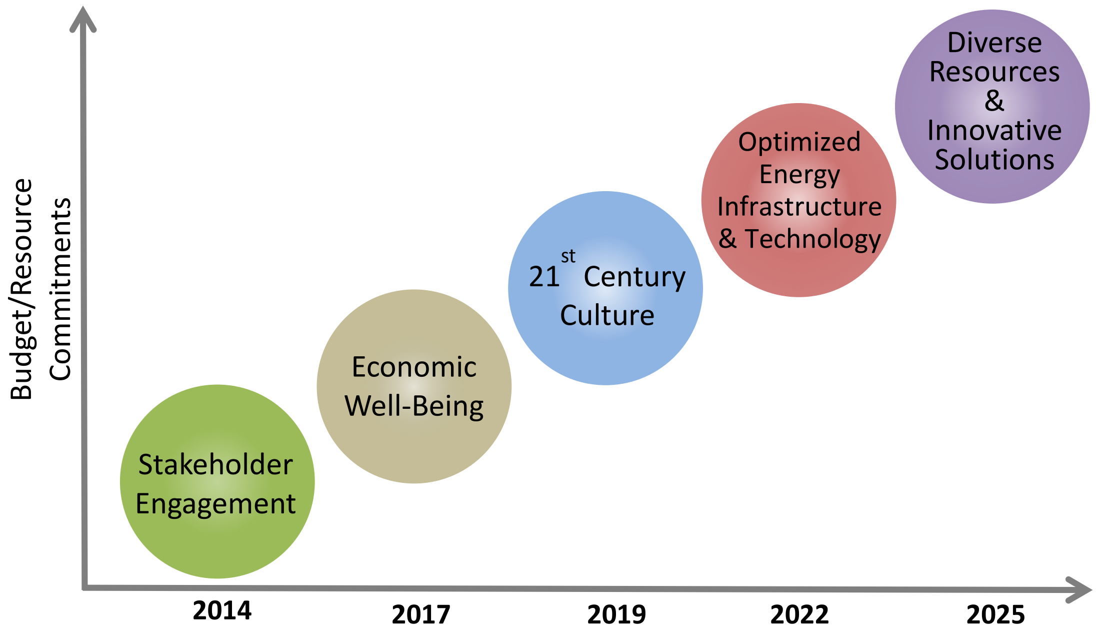



**Figure 1-1: Lakeland Electric Sustainability and Technology Roadmap**

The Roadmap development relied on a comprehensive stakeholder engagement process including the following:

- Strategic Resource Plan Team (SRP Team)

  The internal LE SRP Team included each of the Assistant General Managers and key LE and City of Lakeland (the City) staff. The SRP Team held five workshops in support of developing the Roadmap.

- External Advisory Panel (AP)

  The AP provided a vital external stakeholder view and feedback on the Roadmap through the course of three workshops. The AP included members of the business community, customers, City representatives, and other community leaders.

- LE Staff Survey and Interviews

  The staff survey and more in-depth interviews helped inform the development of the Roadmap with critical insight from staff on market and customer trends, organizational performance, and the LE culture.

The completion of the Roadmap also framed and guided the subsequent economic and triple bottom line analysis. The Roadmap identified the four representative generation planning scenarios for detailed economic analysis and helped frame the environmental, labor, and social assessments.

## Economic Modeling

Utilizing the four market and LE generation resource scenarios or Business Cases derived from the Roadmap process, the economic analysis evaluated and compared the projected rates, generation asset mix, and risks to LE and their customers. The project team of nFront Consulting, LLC and NewGen Strategies and Solutions, LLC (the Project Team) worked closely with the SRP Team and LE staff in performing the generation dispatch analysis and discussing the results of the financial forecast of system rates. The four Business Cases included:

- Business Case 1: Build Future Resources – repower existing LE generation units.
- Business Case 2: Purchase Future Resources – purchasing capacity and energy from the market as needed.
- Business Case 3: Customer Demand Technology – elimination of load growth through high customer adoption of energy conservation and distributed generation (e.g., solar photovoltaic (PV)).
- Business Case 4: Greenhouse Gas (GHG) Regulation – developing generation and demand-side resources to meet United States (U.S.) Environmental Protection Agency (EPA) proposed GHG goals.

The economic modeling allowed for a comparison of the four Business Cases over the 20-year forecasted study period (Study Period) by contrasting system average rate projections, resource mix, and risks between scenarios. The economic analysis provides LE managers, Utility Board, and community stakeholders with the quantitative results necessary to make the strategic generation asset related decisions to support a sustainable and competitive future.

## Environmental, Labor and Societal Performance

In support of improved triple bottom line performance, the SRP included a baseline assessment and evaluation of environmental, labor, and societal performance. By applying an environmental, labor, and societal lens to LE's performance and the Roadmap, the Project Team identified gaps in current LE conditions and the desired destinations defined in the Roadmap. Assessing the environmental, labor, and societal performance ensures a more robust Roadmap and comprehensive implementation of strategic direction.

As environmental conditions and regulatory policies continue to escalate in scope and impact to LE and other electric utilities, the SRP included a detailed review of the regulatory landscape and potential impacts and risks to LE's asset mix and operations. A baseline assessment for environmental, labor, and societal performance was completed to assess the current LE operating state. This baseline assessment was aligned with the Roadmap to help identify gaps or critical needs in achieving the strategic direction of diverse resources and innovative solutions.

The environmental, labor, and societal modules also help LE prepare for sustainability performance reporting. Assessing the current state, identifying gaps, bridging gaps, and identifying metrics for future sustainability reporting helps LE manage and improve triple bottom line (e.g., economic, environmental, and social) performance. This broader approach to utility performance prepares LE for the new reality in the electric utility industry of increased stakeholder engagement, customer needs, and regulatory constraints.

## Conclusion

The underlying challenge in the SRP effort is to effectively integrate the Roadmap into the day-to-day operations of LE in a programmatic way and use the economic modeling data and analysis to better inform the generation resource decisions. The response of the staff survey and interest and success of the stakeholder AP in the process bode well for LE and the successful implementation of the SRP and Roadmap. In the subsequent sections of this report, each module of the SRP and the related process and analysis is described in detail.

# Section 2
# SUSTAINABILITY AND TECHNOLOGY ROADMAP

The Roadmap allows organizations to step back from their day-to-day activities, look to the future and identify where the organization should be positioned in 10 years to best serve customers and remain competitive in the market. By focusing on the 10-year time frame, the Roadmap is a more actionable strategic plan linking and aligning the desired future state and strategic goals with more tactical operating, capital, and customer service plans. In the end, the Roadmap provides a guide for LE to ***leverage diverse, sustainable resources to deliver competitive, innovative solutions that support the vibrant community***.

The key benefits of the Roadmap include:

- Providing a guide for LE to navigate the multiple sustainability, technology, and resource related issues and facilitate decision making.
- Aligning LE's overall strategic plan with resource decisions over the next 10 years.
- Addressing and integrating key sustainability and technology related elements that will shape LE's future.
- Connecting the long-term desired state with interim destinations to provide a clear path to achieving LE's goals.

## The Sustainability and Technology Roadmap

The Roadmap first identifies the desired future state in 10 years, then looks back to identify the key steps or destinations LE must achieve to realize their goals. Figure 2-1 shows the completed LE Roadmap.

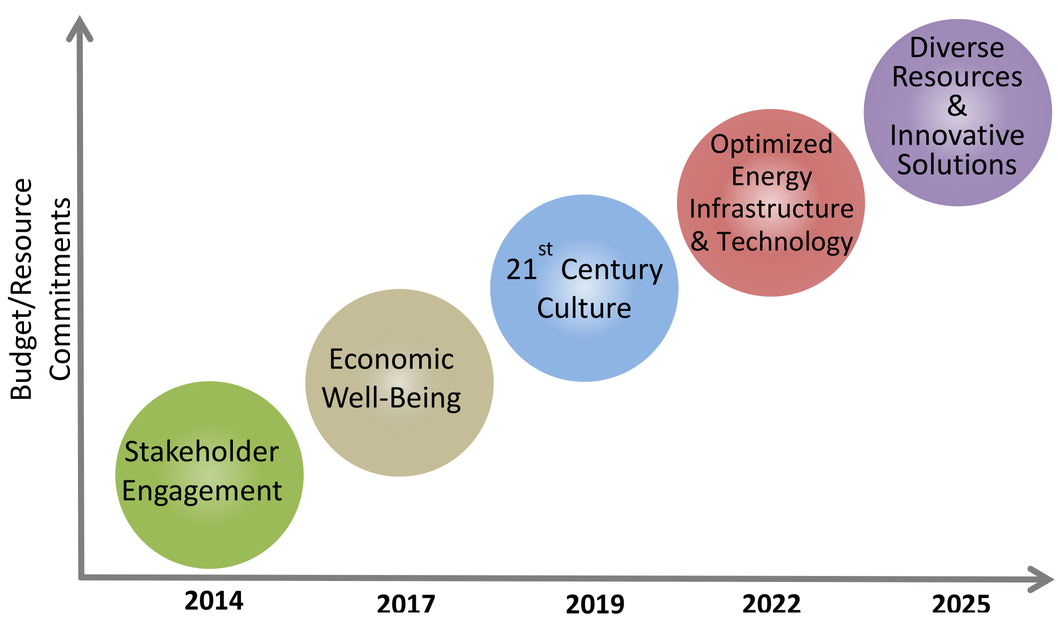



**Figure 2-1: LE Sustainability and Technology Roadmap**

LE's final destination for the Roadmap, diverse resources and innovative solutions, is defined in the Roadmap purpose statement:

*Lakeland Electric will leverage **diverse, sustainable resources** to deliver **competitive, innovative** solutions that support our **vibrant community.***

There are key elements of the purpose statement that encompass broader concepts. These key elements include:

- Diverse, Sustainable Resources: Includes fuels for power generation, employees, generation technologies, and customer "virtual" resources.
- Competitive, Innovative Solutions: Includes managing and containing costs, while providing valuable, flexible, and dynamic services.
- Vibrant Community: Includes facilitating the economic health of the City, improving community status, attracting new employers, and community well-being (e.g., environment, social, economic aspects).

## Interim Destinations

After defining the future desired state with the purpose statement, the SRP Team then identified the interim destinations or steps needed to achieve this strategic direction. This process of identifying and creating steps along a roadmap allows an organization to align its existing projects and initiatives with these steps, identify gaps that exist and develop a path forward.

The destinations shown in Figure 2-1 are not discrete points in time, but a continuum, with each destination building on the previous step in the Roadmap. While these destinations will begin in different years, they evolve over time based on customers', the market, and LE's needs. The four interim destinations include:

1. **Stakeholder Engagement**

   LE must effectively engage employees, customers, and the community to deliver our services.

2. **Economic Well-Being**

   LE will support community well-being by optimizing financial performance, delivering competitive services, and promoting economic development.

3. **21st Century Culture**

   LE must have a 21st Century workforce with a culture of innovation to power a dynamic organization.

4. **Optimized Energy Infrastructure and Technology**

   LE must embrace technology to enhance performance, optimize infrastructure, and provide innovative services.

The purpose statement and destinations were initially developed by the SRP Team, then refined and finalized with significant feedback and input from the AP and other staff at LE. For example, the AP feedback on the purpose statement included a focus on LE's diverse resources and competitive services as key differentiators for the utility. This feedback was directly included in the language for the final purpose statement. In addition, LE staff and the AP's feedback led to refinements of the destinations as illustrated with the 21st Century Culture destination. The original destination description included focusing on developing a 21st century workforce. However, the AP and LE staff felt workforce was too limiting, and LE needed an underlying culture to drive innovation. The LE staff and AP's insight led to refining the destinations and a broadening of the eventual tactical elements supporting the destination.

### Tactical Action Plan

In support of implementing and realizing the destinations and strategic elements of the Roadmap, a Tactical Action Plan (TAP) was created to align operational, capital and organizational activities and projects. To develop the TAP, the Project Team facilitated the development of an inventory of strategic initiatives, projects, and programs to align with the Roadmap. Once aligned with the Roadmap, the SRP Team performed a gap analysis to identify any gaps between the existing programs and the strategic direction of the Roadmap. Where gaps were identified, projects or programs were developed to bridge the gaps and address key issues for implementation. Through a prioritization and consolidation process, the TAP was refined to a manageable set of projects grouped into four categories:

- Communications
- Financial
- Power and Virtual Resources
- Operations

See Appendix A TAP and related project descriptions.

## Roadmap Development Process

The Roadmap development used a comprehensive internal and external stakeholder engagement process to augment market research. The core elements of the process included the following:

- **Conditions Assessment:** Market research, internal LE staff survey, key staff interviews, and inventory of LE initiatives, operations, programs, and plans.
- **Strategic Resource Planning Team:** Internal LE team made up of Assistant General Managers responsible for developing the Roadmap through a series of workshops.
- **Advisory Panel:** External stakeholder panel comprised of community, business, customer, and City leaders.

The Roadmap was developed during a series of workshops with the SRP Team using input from the conditions assessment and feedback from the AP. The conditions assessment informed the development of the strategic elements of the Roadmap including the purpose statement and destinations. These draft strategic elements were then presented to the AP for targeted community insight and feedback. Over the course of the workshops, the AP feedback was synthesized and integrated into the final Roadmap.

Ideally, the Roadmap, like any strategic planning document, is a living document. In the future, LE should review the Roadmap on a periodic basis, as necessary, to adapt to new realities and reflect changes in the market, shifts in customer trends, or significant adjustments in the organization. Typically, organizations update strategic planning documents on a one to three year cycle depending on the market and organizational conditions.

## Strategic Resource Plan Team

The SRP Team was integral to the development of the Roadmap. The Roadmap Team was comprised of Assistant General Managers and targeted City communications staff. The Roadmap Team included representation from power generation, distribution, transmission, regulatory and environmental, finance, and communications.

The SRP Team members participated in five facilitated workshops from January through April to develop the draft Roadmap and TAP. Table 2-1 shows the members of the SRP Team.

**Table 2-1: SRP Team**

| Participants | |
|---|---|
| Farzie Shelton | Tony Candales |
| Don Eckert | Phuong Tran |
| Alan Shaffer | Kevin Cook |
| John McMurray | Melissa Lee |

## Advisory Panel

The external AP provided targeted, balanced feedback from community leaders on the SRP and specifically the Roadmap. The AP met for three workshops and included 23 participants from across business interests, residential representatives, community leaders, local businesses, and City representatives. By creating a targeted and representative AP, the SRP was assured a balanced representation of community interests and an open/collaborative environment for feedback. Stakeholder or APs are becoming a best practice in soliciting balanced and open stakeholder engagement on key utility issues or strategic plans. Table 2-2 below shows the AP participants.

**Table 2-2: SRP Team**

| AP Participants | | |
|---|---|---|
| Chuck McDanal | Robert Loftin | Jarvis Kendrick |
| Keith Merritt | Doug Wimberly | Larry Mitchell |
| Sandy Estep | Alice Hunt | Matt Ruthven |
| Bill Mutz | Veronica Rountree | Terry Worthington |
| Alice O'Reilly | Kurt Smith | Terry Simmers |
| Dean Boring | Tony Delgado | Ron Tomlin |
| Trudy Block | Patricia Jackson | Stacy Campbell-Domineck |
| Myra Bryant | David Carr | |

To keep AP participants engaged and up-to-date of all changes to the Roadmap, a workshop summary was provided after each meeting. Appendix B includes each of the three workshop summaries.

# Conditions Assessment

The first step in the Roadmap development was the conditions assessment, which included gathering comprehensive industry, staff, and organizational insight. This input was critical to developing a Roadmap direction that was then vetted and calibrated with community leaders and customers in the AP workshops. The AP feedback and market research informed the development process and delivered invaluable insight that was otherwise difficult to obtain. The conditions assessment process utilized two internal market research tools: an online survey and one-on-one interviews. The themes gathered from the research were integral to developing the strategic and tactical elements of the Roadmap.

## Online Survey

In order to develop a comprehensive view of the market and gather perspectives of staff, the Project Team conducted an online survey of staff. Survey results were confidential and topics included issues such as what types of services customers may need from LE in 2024, technology adoption within LE and with customers, and the critical success factors for LE in the future. Overall survey response was strong, as illustrated in the response rates:

**Table 2-3: Survey Response Rates**

| Survey | Total Recipients | Responses | Response Rate |
|---|---|---|---|
| Staff Survey | 552 | 336 | 61% |

This market research provided valuable insight into the planning process and enabled LE to integrate customer, staff, and stakeholder perspectives with the Roadmap. A summary of the key survey themes and results is included below with full results in Appendix C.

- LE is delivering value to customers and the community.
- Strong desire for a long-term plan and strategy (especially generation); need to communicate strategy within LE.
- Organization is willing and even seeking change.
- Overall, staff is uncertain if the organization is nimble, with the responses equal between agreement, disagreement, and neutral.
- Overall, there was alignment in survey responses across roles or positions in LE (minor exceptions below):
    - Operators and linemen see a need for greater investment in generation facilities.
    - Customer Service perceives LE as more nimble than other departments.

- Need for internal and external stakeholder engagement.
- LE and perceived customer views are closely aligned; AP will confirm or identify gaps.
- Few envision LE divesting of any utility functions (e.g., generation, transmission, or distribution) in the future.
- Strong desire for customer choices (strong desire for choice in Residential class and very strong in Commercial and Industrial class).
  - High priority: smart meter options, time of use rates, demand response, distributed generation (primarily Commercial class).
  - Medium priority: distributed generation (Residential).
  - Economics will drive many market or service decisions.
- Everything is important and key to LE's success:
  - Aging infrastructure, competitive, regulatory impacts, technology adoption, big data, knowledge management, workforce, stakeholder engagement, partnerships, and generation flexibility.

## Interviews

In early January 2014, the Project Team conducted 17 one-hour formal staff interviews with the individuals representing a cross section of LE's organization. The interviews were conducted by the Project Team onsite at LE's offices. These interviews acted as an in-depth discussion of LE's organizational capabilities, customer trends, adoption of technology, and where the utility should be in 10 years. Table 2-4 lists the LE staff that were interviewed.

**Table 2-4: Staff Interviews**

| Lakeland Electric Staff | |
|---|---|
| John Adkinson | Betsy Levingston |
| David Kus | Nedin Bahtic |
| Mark Meeks | Tory Bombard |
| David Miller | Joel Ivy |
| Brian Butler | Randy Dotson |
| Jeff Sprague | Tranice Carmichael |
| Joey Curry | Bruce Walker |
| Ron Kremann | Steve Marshall |

Staff interviews were kept confidential, with the Project Team providing only summarized responses and themes from interviews not attributable to specific individuals. Each interview included the same questions soliciting feedback on:

1. Most significant challenges for LE;
2. What is working well with customers/needs improvement;
3. Future of LE in 2025;
4. Use/adoption of technology; and

5. Change three aspects of the organization.

A summary of the key outcomes and common themes from staff interviews is included below by question asked.

1. Most significant challenges facing LE:
    - Uncertainty in regulatory decisions, fuel markets, and electric markets,
    - Governance, collaboration/integration with City, and strategic direction in uncertain business environment;
    - Smart grid and managing technology;
    - Workforce; and
    - Aging infrastructure and asset gaps.
2. What is working well or needs significant improvement with customers:
    - Customer satisfaction is high overall;
    - Communication and stakeholder engagement needs to increase and improve; and
    - Smart grid integration, energy efficiency (EE) programs need to improve for customers.
3. What is the future of LE and customer demands in 2025:
    - LE will remain an economic engine for the City;
    - EE and demand response (DR) will likely mute the impact of growth;
    - Greater technology options/adoption and increasing customer choice;
    - Stakeholder engagement is the new reality and becoming mandatory; and
    - Increased use of and leverage of partnerships (e.g., Power Pool).
4. LE and customers' current versus future use/adoption of technology:
    - LE's use/adoption of technology is currently fragmented, the future will be integrated;
    - Need to optimize current partnership with City for all technology needs; and
    - Future is dynamic, portable, accessible, and distributed.
5. If you could change three aspects of the organization:
    - Greater flexibility and less risk averse;
    - Need for "line of sight" with staff connected to a clear strategic direction; and
    - Technology and stakeholder capabilities/capacity in parallel within LE.

One of the clear outcomes from the interviews and survey was a clear need to bridge the issues LE is currently experiencing. These issues are in key areas that market trends show and staff believe will increase in importance in the future. Some of these issues include:

- Communications and engagement needs increasing → Limited capacity at City

- City manages all information technology (IT) → Large and growing IT needs at LE
- Maintain LE control → Clear need for partnerships and likely outsourcing
- Need to empower staff → staff stays because they feel they can make a difference
- Low cost/competitive → Drive for energy efficiency, distributed generation customer options
- Aging infrastructure → Inland utility; resiliency service opportunity
- Aging "snowbird" population → customer interest in web applications

## Business Cases

As the Roadmap was completed in Module 1, it also guided subsequent analytics in the SRP to further analyze and evaluate the strategic options and resources related decisions facing LE. Near the completion of the Roadmap, the SRP Team identified four Business Cases to evaluate and model to better inform near-term generation resource decision making. These four Business Cases represented both specific asset mix options for LE and potential market conditions, such as demand destruction and GHG regulations.

General descriptions for the identified business cases are as follows.

- **Business Case 1: Build Future Resources**

  Build or repower LE generation units to meet future resource needs. Promote customer demand-side programs consistent with current levels.

- **Business Case 2: Purchase Future Resources**

  Purchase capacity and energy from others as needed to meet future resource needs. Promote customer demand-side programs consistent with current levels.

- **Business Case 3: Customer Demand Technology**

  High customer adoption of conservation, demand response, and distributed generation (e.g., solar PV), eliminating load growth for LE.

- **Business Case 4: GHG Regulation**

  Develop generation and demand-side portfolio to meet EPA proposed GHG goals.

# Section 3
# ECONOMIC ANALYSIS

Subsequent to the Roadmap process – which established a strategic direction for LE over the next 10 years and identified concepts for resource planning business cases that LE should consider when establishing strategic goals – detailed economic and financial analyses were performed to evaluate the potential cost of various strategic decisions. Analyses included resource simulation and utility financial modeling to investigate how market conditions, environmental regulations, and resource planning decisions could impact LE operating costs and rates. The results of these analyses provided key metrics such as total power supply costs and system average rates for each business case to assist LE with making decisions regarding its future resource plans.

There were two primary phases to the economic analysis: resource planning and dispatch simulation, and financial forecasting and risk modeling. Each phase analyzed all four business cases. The first phase defined and developed power supply and demand-side resource plans for each business case, simulated the future dispatch and operation of LE resources, and developed projections of LE power supply production costs for each business case. The second phase calculated total electric system costs and developed projections of system average rates, and evaluated risks or uncertainties associated with each business case.

The economic analysis entailed a collaborative process with the LE staff, though which the Project Team worked with LE resource planning staff to develop resource plans and simulate generation dispatch for each of the Business Case. The Project Team also worked with LE staff in the rates and financial departments to develop projections of LE electric system costs and rates. The following describes the methodology, major assumptions, and results of these evaluations.

## Business Case Resource Plans

The following section discusses the development of LE resource plans for each Business Case, including: a technical description of each Business Case, a discussion of major assumptions used to develop resource plans for each Business Case, and a presentation of detailed load and resource plans for each Business Case.

### Business Case Descriptions

Each Business Case defined through the roadmapping process describes a distinct power supply plan depicting different resource expansion strategies and/or market and regulatory conditions that could affect future LE resource plans. For Business Cases 1 and 2, the SRP assumes that LE will adopt two different approaches to meet future resource expansion needs; build LE-owned resources versus buy from others (Business Case 1 and Business Case 2, respectively). For these Business Cases, market and regulatory conditions are not assumed to vary significantly from current conditions. For Business Case 3, the SRP assumes that a significant marketplace transformation will occur in the electric utility industry, causing or promoting customers to significantly alter energy consumption patterns and/or install distributed generating (DG) resources (owned and operated by customers). These market transformations would significantly reduce future growth of retail load, changing the way that electric utilities plan for and operate resources. For Business Case 4, the SRP assumes that GHG regulations recently proposed by the U.S. EPA will be implemented, which will require LE to alter its existing resources and resource plans to meet the new GHG emission targets. A comprehensive discussion of the proposed EPA GHG regulations can be found in Section 4 of the Report.

The Business Case resource plans can generally be described as follows.

### Business Case 1: Build Future Resources

Business Case 1 represents a traditional utility approach to build new generating resources as needed to meet future load growth and planning reserve criteria. This case incorporates assumptions for market and economic conditions, including future LE load growth, that are consistent with current industry trends and forecasts. Environmental regulations modeled for Business Case 1 are consistent with currently adopted laws and rules, and do not include newly proposed rules governing GHG.

For Business Case 1, the SRP assumes the installation of a new combustion-turbine (CT) and heat recovery steam generator (HRSG) at the LE McIntosh Plant. These facilities will permit the repowering of the McIntosh Unit 2 steam turbine as a combined-cycle (CC) unit. As described more fully below, Business Case 1 assumes the mothballing or retirement of several LE generating resources that are reaching the end of their useful lives. Business Case 1 also assumes that LE will continue to provides demand-side programs consistent with current implementation rates and plans. Demand-side programs include energy efficiency, conservation, renewable, load management, and DR programs, collectively demand-side management (DSM) programs. Business Case 1 also assumes that LE will add utility solar PV resources consistent with current contractual arrangements.

### Business Case 2: Purchase Future Resources

For Business Case 2, instead of installing new CT and HRSG facilities, the SRP assumes that LE will meet future resource capacity needs through purchases of power from other electric utilities or merchant generation facility owners. Business Case 2 assumes that LE will enter into consecutive purchased power agreements (PPA) lasting five years each at capacity levels needed to meet a 15 percent capacity reserve margin criteria over each five-year period. Other resource planning assumptions for Business Case 2 are generally consistent with those for Business Case 1. Market and economic conditions and load growth trends are consistent with current industry forecasts. Environmental regulations are consistent with currently adopted laws and rules and do not include newly proposed rules governing GHG.

As described more fully below, Business Case 2 assumes the mothballing or retirement of several LE generating resources that are reaching the end of their useful lives. Business Case 2 also assumes LE will continue promoting existing customer demand-side programs and will add utility solar PV resources consistent with current contractual arrangements.

### Business Case 3: Customer Demand Technology

Business Case 3 addresses potential trends in the electric utility industry toward greater customer adoption of utility DSM programs, DG resources (e.g., solar PV), and other general EE and equipment practices. If customer adoptions rates were to occur at sufficiently high levels, such trends could erode utility retail sales and modify utility load shapes, thus necessitating a change in the way electric utilities operate and plan for resources.

For Business Case 3, the SRP assumes that LE customers will adopt DSM, DG, and EE resources in sufficient quantity to eliminate growth in LE retail energy sales over the Study Period. Furthermore, because EE and solar PV resources tend to impact peak load periods more than off-peak periods, the LE net peak demand is projected to decline over the Study Period under Business Case 3. As such, for Business Case 3, the SRP assumes that LE will not need to add any new generating resources nor enter into any PPAs over the Study Period.

### Business Case 4: Greenhouse Gas Regulation

Business Case 4 assumes that GHG regulations recently proposed by the EPA for new and existing electric utility generating resources will result in new environmental regulations being implemented in Florida. These regulations will require LE to not exceed certain $CO_2$ emission targets beginning in 2020 (described more fully below and in Section 4 of the Report).

LE resource dispatch simulations performed for the SRP (described below) indicate that LE can meet the proposed $CO_2$ targets by implementing the following: convert McIntosh Unit 3 from coal-fired to natural gas (NG)-fired operation by 2020; add utility solar PV resources consistent with current contractual arrangements; expand DSM programs to offset approximately seven percent of customer energy by 2034; and install or purchase power from carbon-neutral generating resources beginning in 2030.

## Resource Planning Assumptions

The following major assumptions were used when developing resource expansion plans.

### Peak Demand Forecast

The 2014 official load forecast for LE was adopted for use for the SRP. LE develops its customer, sales, and peak demand forecasts using a combination of econometric and end-use modeling techniques. LE is forecast to remain a winter peaking electric utility over the Study Period; normal weather conditions were assumed when forecasting peak demand. Peak winter demand is forecast to grow from 688.5 megawatt (MW) in 2015 to 821.4 MW in 2034, representing an average compound growth rate of approximately 0.9 percent over the Study Period.

### Planning Reserve Margin

LE utilizes a 15 percent reserve margin when planning for power supply additions. As such, LE plans to meet its forecast annual peak demand plus an additional 15 percent reserves (15 percent of peak demand) through owned and operating generating resources plus delivered capacity from any firm purchased power resources.

### Fossil Generating Resources

LE currently maintains three fossil fuel-fired power plants: Larsen, McIntosh, and Winston. Generating resources include one coal-fired steam unit (jointly owned with

Orlando Utilities Commission (OUC)), two NG-fired steam units, two CC units, three CT units, and 22 internal combustion units. Winter capacity for these resources totals 975 MW.

Five of the LE generating units are nearing the end of their useful lives and were assumed to be retired in January 2015 for purposes of the projections and simulations modeled for the SRP. The units assumed to be retired include: Larsen CT Units 2 and 3, McIntosh Diesel Units 1 and 2, and McIntosh Steam Unit 1.

Additionally, for Business Cases 2, 3, and 4, McIntosh Steam Unit 2 is assumed to be retired by November 2020. For Business Case 1, the boiler for McIntosh Unit 2 is assumed to be retired by November 2020, while the steam turbine and electric generator is assumed to be retained for repowering as a CC resource. For Business Case 1, a new F-class CT is planned for installation at the McIntosh Plant to coincide with the retirement of the McIntosh Unit 2 boiler. A new HRSG is assumed to be installed between November 2020 and November 2022, and paired with the new CT to supply steam to the McIntosh Unit 2 steam turbine and electric generator, creating a repowered CC resource operating by November 2022.

It is important to note that official decisions to retire and/or repower existing LE generating units have not been made at this time. Likewise, no official decisions have been made to construct new resources or enter into any PPA. Following consideration of the results of the SRP, LE administration and staff may decide to conduct additional studies to evaluate and establish potential retirement and repowering plans for the LE generating resources and develop plans to add or purchase new resources.

Resource capacity ratings, retirement dates for existing resources, and on-line dates for new resources assumed for the SRP are summarized below in Tables 3-1 through 3-4.

**Table 3-1: LE Supply Resources**
**Business Case 1**

| Resource Name | Type | Net Capacity (MW) Summer | Net Capacity (MW) Winter | On-line Date | Retire Date |
|---|---|---|---|---|---|
| **Existing Resources:** | | | | | |
| Larsen 2 | NG CT | 10.0 | 14.0 | | Jan-2015 |
| Larsen 3 | NG CT | 9.0 | 13.0 | | Jan-2015 |
| Larsen 8 | NG CC | 105.0 | 124.0 | | |
| Winston 1-20 | IC | 50.0 | 50.0 | | |
| McIntosh D1&2 | IC | 5.0 | 5.0 | | Jan-2015 |
| McIntosh GT | NG CT | 16.0 | 19.0 | | |
| McIntosh 1 | NG ST | 85.0 | 85.0 | | Jan-2015 |
| McIntosh 2 | NG ST | 106.0 | 106.0 | | Nov-2020 |
| McIntosh 3 | Coal ST | 205.0 | 205.0 | | |
| McIntosh 5 | NG CC | 338.0 | 354.0 | | |
| **New Resources:** | | | | | |
| New CT Unit | NG CT | 168.3 | 187.0 | Nov-2020 | Nov-2022 |
| McIntosh 2 CC | NG CC | 252.5 | 280.5 | Nov-2022 | |

## Table 3-2: LE Supply Resources
## Business Case 2

| Resource Name | Type | Net Capacity (MW) Summer | Winter | On-line Date | Retire Date |
|---|---|---|---|---|---|
| **Existing Resources:** | | | | | |
| Larsen 2 | NG CT | 10.0 | 14.0 | | Jan-2015 |
| Larsen 3 | NG CT | 9.0 | 13.0 | | Jan-2015 |
| Larsen 8 | NG CC | 105.0 | 124.0 | | |
| Winston 1-20 | IC | 50.0 | 50.0 | | |
| McIntosh D1&2 | IC | 5.0 | 5.0 | | Jan-2015 |
| McIntosh GT | NG CT | 16.0 | 19.0 | | |
| McIntosh 1 | NG ST | 85.0 | 85.0 | | Jan-2015 |
| McIntosh 2 | NG ST | 106.0 | 106.0 | | Nov-2020 |
| McIntosh 3 | Coal ST | 205.0 | 205.0 | | |
| McIntosh 5 | NG CC | 338.0 | 354.0 | | |
| **New Resources:** | | | | | |
| PPA 2020-2025 | Peaking | 72.0 | 80.0 | Nov-2020 | Nov-2025 |
| PPA 2025-2030 | Peaking | 102.6 | 114.0 | Nov-2025 | Nov-2030 |
| PPA 2030-2035 | Peaking | 127.8 | 142.0 | Nov-2030 | Nov-2035 |

## Table 3-3: LE Supply Resources
## Business Case 3

| Resource Name | Type | Net Capacity (MW) Summer | Winter | On-line Date | Retire Date |
|---|---|---|---|---|---|
| **Existing Resources:** | | | | | |
| Larsen 2 | NG CT | 10.0 | 14.0 | | Jan-2015 |
| Larsen 3 | NG CT | 9.0 | 13.0 | | Jan-2015 |
| Larsen 8 | NG CC | 105.0 | 124.0 | | |
| Winston 1-20 | IC | 50.0 | 50.0 | | |
| McIntosh D1&2 | IC | 5.0 | 5.0 | | Jan-2015 |
| McIntosh GT | NG CT | 16.0 | 19.0 | | |
| McIntosh 1 | NG ST | 85.0 | 85.0 | | Jan-2015 |
| McIntosh 2 | NG ST | 106.0 | 106.0 | | Nov-2020 |
| McIntosh 3 | Coal ST | 205.0 | 205.0 | | |
| McIntosh 5 | NG CC | 338.0 | 354.0 | | |

**Table 3-4: LE Supply Resources**
**Business Case 4**

| Resource Name | Type | Net Capacity (MW) Summer | Winter | On-line Date | Retire Date |
|---|---|---|---|---|---|
| **Existing Resources:** | | | | | |
| Larsen 2 | NG CT | 10.0 | 14.0 | | Jan-2015 |
| Larsen 3 | NG CT | 9.0 | 13.0 | | Jan-2015 |
| Larsen 8 | NG CC | 105.0 | 124.0 | | |
| Winston 1-20 | IC | 50.0 | 50.0 | | |
| McIntosh D1&2 | IC | 5.0 | 5.0 | | Jan-2015 |
| McIntosh GT | NG CT | 16.0 | 19.0 | | |
| McIntosh 1 | NG ST | 85.0 | 85.0 | | Jan-2015 |
| McIntosh 2 | NG ST | 106.0 | 106.0 | | Nov-2020 |
| McIntosh 3 | Coal ST | 205.0 | 205.0 | | Jan-2020 |
| McIntosh 5 | NG CC | 338.0 | 354.0 | | |
| **New Resources:** | | | | | |
| McIntosh 3 NG | NG ST | 155.4 | 155.4 | Jan-2020 | |
| PPA 2030-2035 | Peaking | 127.8 | 142.0 | | |
| PPA 2020-2029 | Peaking | 53.1 | 59.0 | Nov-2020 | Jan-2030 |
| PPA 2030-3035 | Peaking | 13.5 | 15.0 | Jan-2030 | |
| Renewable 2030 | Renew | 44.7 | 44.7 | Jan-2030 | |

### Utility Solar PV Resources

In 2008, LE executed a contract with a developer to install up to 24 MW of solar PV resources in the LE service territory from which LE would purchase the electricity produced by the PV facilities at negotiated prices and retain environmental attributes. To date, 5.6 MW have been installed through three projects; the remaining capacity is currently scheduled or assumed to be installed through three additional projects planned in each of the next three years. Peak dependable capacity ratings for the solar PV resources were estimated by reviewing hourly PV production data for peak weather days during summer and winter seasons and determining coincidence with the peak hour of the LE forecasted system peak demand. Hourly PV production and weather data used for this analysis was obtained from the National Renewable Energy Laboratory (NREL), using the NREL PVWatts model and database.

Solar PV resource capacity ratings and on-line dates assumed for the SRP study are summarized in Tables 3-5. Tabulated capacity ratings represent AC ratings, adjusted for transmission and distribution system losses, and are provided for annual maximum facility output and for summer and winter dependable capacity coincident with the LE system peak.

**Table 3-5: Utility Solar PV Resources**

| Resource Name | Type | Installed Capacity (MW) | Dependable Capacity (MW) Summer | Winter | On-line Date |
|---|---|---|---|---|---|
| Solar PV LCC | Fixed | 0.3 | 0.2 | 0.0 | Apr-2010 |
| Solar PV Phase I | 1-Axis | 2.3 | 1.8 | 0.5 | Jan-2012 |
| Solar PV Phase II | 1-Axis | 3.0 | 2.4 | 0.7 | Sep-2012 |
| Solar PV Phase III | 1-Axis | 6.0 | 4.8 | 1.3 | Jan-2015 |
| Solar PV Phase IV | 1-Axis | 5.0 | 4.0 | 1.1 | Nov-2016 |
| Solar PV Phase V | 1-Axis | 7.5 | 5.9 | 1.7 | Apr-2017 |

### Demand-side Resources

LE provides a number of utility DSM programs, including promotion of solar water heating; rebates and low-interest loans for various high-efficiency equipment and products; various high-efficiency equipment giveaway programs; and EE information programs. Additionally, LE offers a retail rate net metering program for customers installing solar PV resources and offers an interruptible retail rate for large commercial customers. LE is planning to continue offering existing DSM programs as permitted by budgetary considerations or until customer participation levels reach saturation limits.

LE has also recently installed an AMI system throughout the LE electric system that permits remote customer meter reading and data collection on customer usage. The AMI system also provides for real-time, two-way communication with customers regarding electricity consumption. AMI systems provide the framework for implementation of DR programs that allow customers to more precisely control their electricity use in response to retail pricing programs offered by the utility or utility requests for load shedding or modification.

DR programs can include innovative rate structures such as real-time and critical peak pricing, traditional and advanced time-of-use rates, load management notification and controls, and integration with smart appliances and smart-home systems. LE has begun investigating the potential to provide DR programs, but has not yet developed any official programs for long-term implementation. Nonetheless, the installed AMI system represents a significant potential for future DSM load reductions through DR programs for the LE system, which have been modeled at various levels for each of the Business Cases.

A general discussion of assumptions used to model demand-side resources is provided below for each Business Case.

#### *Demand-side Resources – Business Cases 1 and 2*

For Business Cases 1 and 2, implementation of DSM programs are assumed to continue based on near-term program plans and projections developed by LE, and continue longer-term based on several factors, including assumed annual implementation rates, targeted customer saturation levels, and growth relative to projected growth of customer loads.

- Residential and commercial conservation load impacts and implementation rates were modeled as fixed annual quantities estimated by LE, with consideration of historical LE program performance and impacts, and implementation rates for similar programs developed by other electric utilities. Additionally, load reductions were modeled to degrade with time.
- Near-term impacts for solar PV and solar water heating were modeled based on current implementation levels and plans, and assumptions for customer participation over the next five years. Long-term impacts from solar PV and solar water heating were tied to customer load growth, with solar PV implementation modeled to grow at multiples of load growth. Additionally, load reductions were modeled to degrade with time.

- Interruptible load impacts were modeled based on historical and forecast loads for the existing large commercial customers purchasing electricity through interruptible rates, with growth tied to projected load growth for large commercial customers.
- DR impacts from smart grid programs were modeled based on expansion of the current LE pilot programs. Estimated load impacts were developed through LE's studies of its DR programs and performance of similar programs developed by other Florida utilities. Long-term growth of DR impacts were tied to growth of customer loads.

Appendix D, Table D-1 provides a summary of projected demand-side annual energy and peak demand reductions modeled for Business Cases 1 and 2. Tabulated values depict incremental load reductions beyond 2014 for all demand-side programs other than the interruptible rates, since impacts for existing LE DSM programs are already incorporated in the LE load forecast. Values have been adjusted for transmission and distribution system losses and reflect demand reductions coincident with forecast LE system peaks.

*Demand-side Resources – Business Case 3*

For Business Case 3, the SRP has assumed reductions in retail customer loads at levels generally consistent with scenarios developed by the U.S. Department of Energy, Energy Information Administration (EIA) in their published 2014 Annual Energy Outlook (AEO). The 2014 AEO includes a scenario entitled *Best Available Demand Technology* that depicts exceptionally high levels of adoption for efficient appliances and equipment, efficient construction and building retrofit practices, and high implementation of renewable technologies. Projections developed for the 2014 AEO *Best Available Demand Technology* scenario indicate that load reductions will reach 20 percent in the Florida market by the end of the Study Period.

To simulate the higher levels of load reduction assumed for this Business Case, LE demand-side resources were increased from levels modeled for Business Cases 1 and 2. Solar PV installations were increased approximately five-fold (consistent with AEO forecast) and solar water heating installations were doubled (limited by practical saturation of this technology). DR programs were modeled to provide approximately 11 times the levels modeled for Business Cases 1 and 2, reaching levels generally consistent with conservative estimates prepared by other utilities and industry groups on the max potential for this technology. Residential and commercial conservation programs were modeled to provide the remainder of the 20 percent load reduction depicted for this Business Case, resulting in an approximate 26-fold increase in conservation-related energy reductions and an 11-fold increase in conservation-related demand reductions by the end of the Study Period, as compared to assumptions used for Business Cases 1 and 2.

Appendix D, Table D-2 provides a summary of projected demand-side annual energy and peak demand reductions modeled for Business Case 3. Tabulated values depict incremental load reductions beyond 2014 for all demand-side programs other than the interruptible rates, since impacts for existing LE DSM programs are already incorporated in the LE load forecast. Values have been adjusted for transmission and distribution system losses and reflect demand reductions coincident with forecast LE system peaks.

*Demand-side Resources – Business Case 4*

For Business Case 4, the SRP has assumed reductions in retail customer loads at levels generally consistent with GHG scenarios published in the 2014 AEO. GHG scenarios in the 2014 AEO depict load levels for the Florida market that are seven percent lower than the Reference Case published for the AEO. Additionally, the AEO GHG scenarios depict higher levels of solar PV.

To simulate the higher levels of load reduction assumed for Business Case 4, LE demand-side resources were increased from levels modeled for Business Cases 1 and 2. Solar PV and water heating installations were approximately doubled. DR programs were modeled at the same max potential levels modeled for Business Case 3. Residential and commercial conservation programs were modeled to provide the remainder of the seven percent load reduction depicted for this Business Case, resulting in an approximate eight-fold increase in conservation-related energy reductions and a five-fold increase in conservation-related demand reductions by the end of the Study Period.

Appendix D, Table D-3 provides a summary of projected demand-side annual energy and peak demand reductions modeled for Business Case 3. Tabulated values depict incremental load reductions beyond 2014 for all demand-side programs other than the interruptible rates, since impacts for existing LE DSM programs are already incorporated in the LE load forecast. Values have been adjusted for transmission and distribution system losses and reflect demand reductions coincident with forecast LE system peaks.

Figures 3-1 and 3-2 provides a comparison of net energy and peak demand modeled for each Business Case following reductions for demand-side resources, as described above.

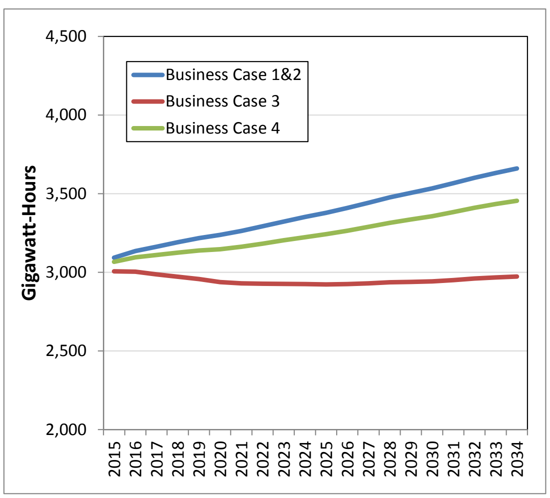



**Figure 3-1: Forecast Energy Net of DSM**

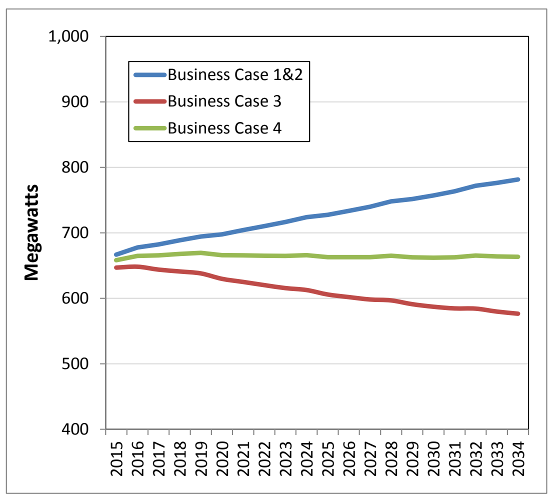



**Figure 3-2: Forecast Peak Demand Net of DSM**

## Resource Expansion Plans

With consideration of the Business Case descriptions and assumptions discussed above, resource expansion plans were developed for each case. Figure 3-3 provides a general summary of future resource retirements and additions modeled for the Business Cases. More detailed discussions are provided below.

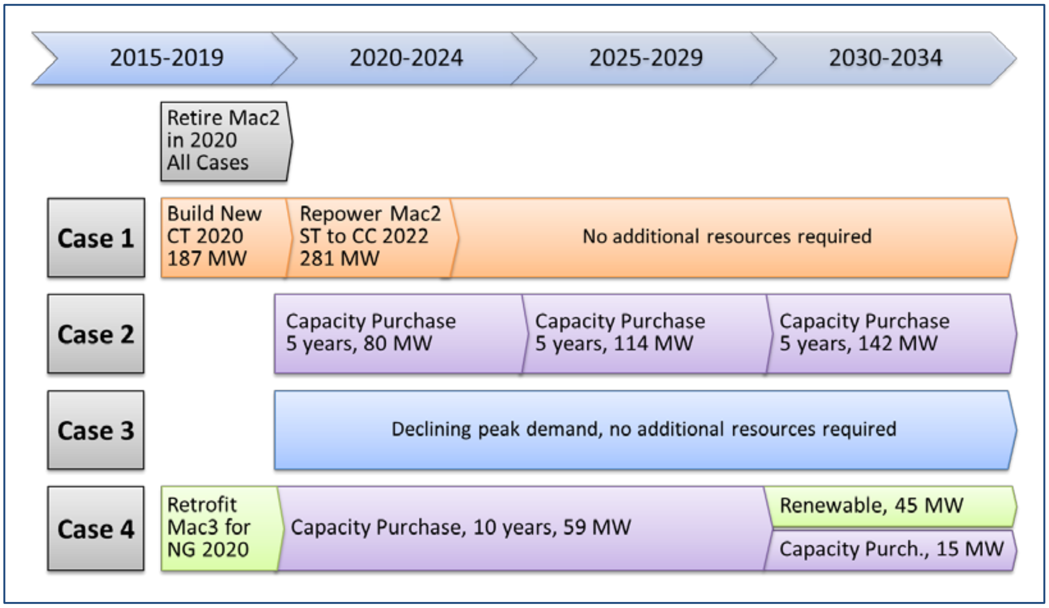



**Figure 3-3: Summary of SRP Resource Expansion Plans**

### Business Case 1

Under Business Case 1 assumptions, LE is assumed to have sufficient existing generating resources to serve the forecast winter peak plus capacity reserves through 2020. However, with the retirement of McIntosh Unit 2, LE will need to add new resources to meet it capacity obligations. For Business Case 2, the SRP assumes that LE will add a new 187 MW CT in 2020 (winter rating), coincident with the McIntosh Unit 2 retirement in November 2020. The CT will operate through 2022 as a standalone resource, at which time the CT will be paired with a new HRSG and integrated with the McIntosh steam turbine and generator to produce a 280.5 MW CC resource (winter rating), with a planned online date of November 2022. Following the addition of the repowered McIntosh Unit 2 CC resource, LE would own 1,038 MW of installed capacity (winter rating), sufficient to meet the forecast winter peak demand plus reserves obligation of 824 MW in 2023 and 899 MW in 2034 (end of the Study Period).

It should be noted that the repowered McIntosh Unit 2 CC is projected to produce significant surplus capacity for the LE system following its installation. With the resource, LE is projected to have 214 MW of surplus capacity in 2023 (producing a 45 percent reserve margin), decreasing with load growth to 139 MW of surplus capacity by 2034 (producing a 33 percent reserve margin). Higher than expected load growth could utilize the projected surplus capacity, however, load would need to grow at a rate of over twice the current forecast levels to fully utilize the surplus capacity by the end of the Study Period. Moreover, if LE load growth is less than currently forecast, LE could be burdened with additional surplus capacity and potential cost exposure.

Simulation of LE resource dispatch performed for the SRP, described below, indicates that a portion of the energy produced by the McIntosh Unit 2 repowered CC resource can be sold in the Florida Municipal Power Pool (FMPP). However, the surplus capacity created by the McIntosh Unit 2 CC repowering creates an investment by LE that may not be warranted. Since LE can meet future capacity obligations with the addition of the proposed CT (without the HRSG and steam turbine repowering), LE should consider performing additional analyses to determine whether the incremental cost of the HRSG and steam turbine integration and refurbishment can be justified by projected LE fuel cost savings and FMPP sales revenue.

Figure 3-4 depicts the projected winter load and resources for Business Case 1, and Appendix D, Table D-4 provides a tabulation of the supply and demand balance for the summer and winter periods over the Study Period.

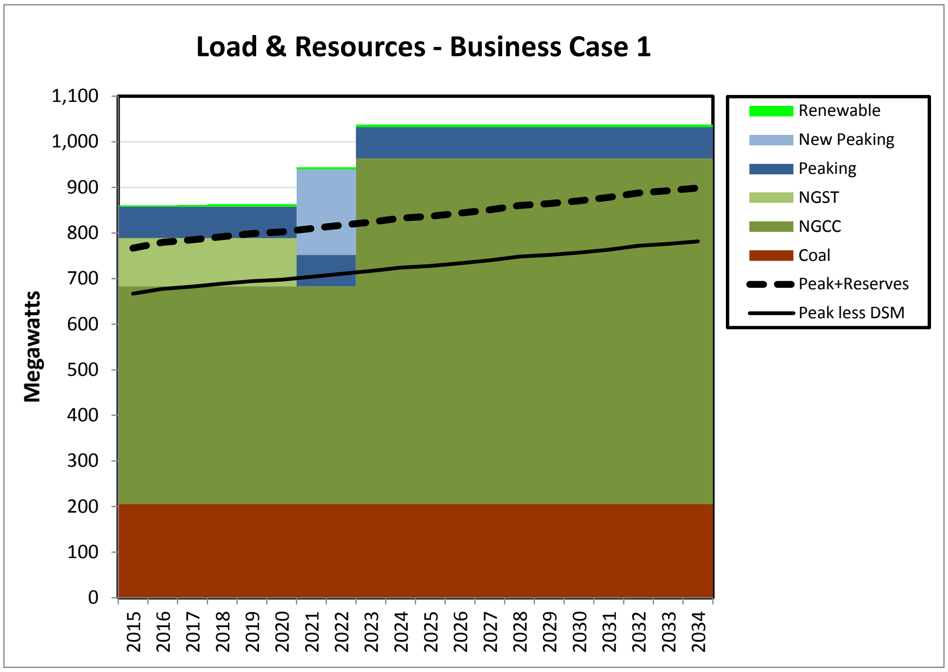



**Figure 3-4: Load & Resources – Business Case 1**

### Business Case 2

Under the Business Case 2 assumptions, LE is assumed to have sufficient existing generating resources to serve the forecast winter peak demand plus capacity reserves through the 2020 winter and summer peak periods. However, with the retirement of McIntosh Unit 2 in November 2020, LE will need to add new resources to meet its capacity obligations. For Business Case 2, LE is assumed to purchase peaking capacity through consecutive PPAs, lasting five-years each, beginning with the retirement of McIntosh Unit 2. Delivered PPA capacity is assumed to just meet the LE capacity obligation at the end of each five-year period, providing 80 MW for 2021 through 2025, 114 MW for 2026 through 2030, and 142 MW for 2031 through the end of the Study Period. Under these assumptions, capacity is projected to closely match capacity obligations, with annual capacity surpluses projected to be not larger than 28 MW during any of the five-year periods.

The purchase power scenario described for Business Case 2 represents a flexible method to meet future LE capacity obligations (as compared to Business Case 1). Should LE experience higher or lower load growth than is currently forecast, LE can adjust its plans for the timing and/or size of the future PPAs as needed (subject to market availability and contractual limits of any executed PPA). Conversely, the resource expansion plan developed for Business Case 2 may not produce energy as efficiently as the resource plan developed for Business Case 1. Business Case 1 has the potential to meet portions of LE's load with relatively low-cost CC energy from the repowered McIntosh Unit 2, whereas Business Case 2 would secure capacity from less efficient peaking resources, supplemented by energy purchases through the FMPP.

Figure 3-5 depicts the projected winter load and resources for Business Case 2, and Appendix D, Table D-5 provides a tabulation of the supply and demand balance for the summer and winter periods over the Study Period.

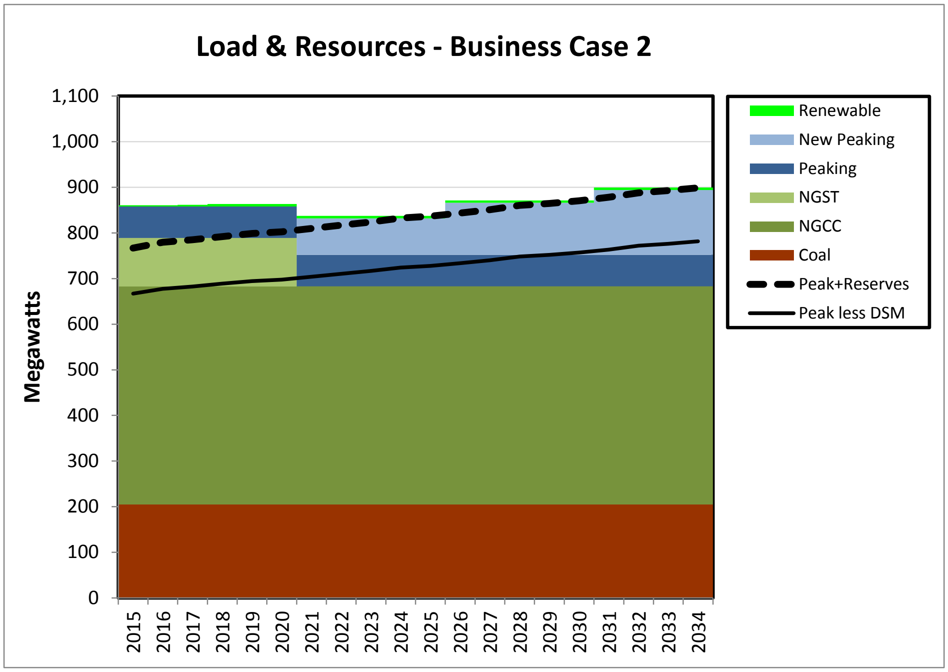



**Figure 3-5: Load & Resources – Business Case 2**

## Business Case 3

Business Case 3 depicts a scenario reflecting transformation of the electric utility market, under which retail customers are projected to adopt DG and EE at high levels, thus significantly reducing future growth of LE loads. Specific quantities of DG and EE modeled for Business Case 3 are documented above in the discussions on assumptions. With adjustments to the forecast LE peak demand for projected DG and EE implementations, LE peak demand is projected to decline at an annual rate of approximately one percent under Business Case 3, resulting in LE not needing to add any new resources over the Study Period.

Figure 3-6 depicts the projected winter load and resources for Business Case 3, and Appendix D, Table D-6 provides a tabulation of the supply and demand balance for the summer and winter periods over the Study Period.

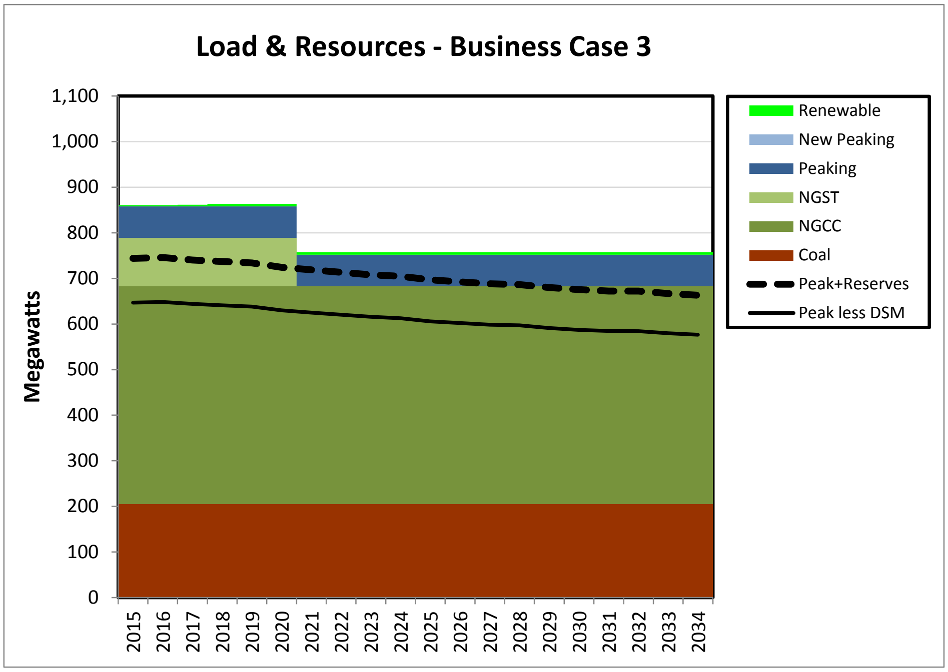



**Figure 3-6: Load & Resources – Business Case 3**

## Business Case 4

Business Case 4 depicts a scenario reflecting adoption of GHG regulations that will impact the operation and planning LE resources. For the SRP, LE is assumed to meet $CO_2$ emission limits by converting the existing McIntosh Unit 3 coal-fired steam unit to operate on NG, expand customer EE and solar PV programs, purchase power from planned solar PV facilities, and add carbon-neutral, renewable generating resources beginning in 2030. LE will also need to add peaking capacity PPA purchases to meet forecast peak demand plus capacity reserves.

Specific quantities of EE and solar PV programs modeled for Business Case 4 are documented above in the discussions on assumptions. Following adjustments for EE and solar PV programs projected for Business Case 4, LE's peak demand is projected to remain essentially flat over the Study Period. With regard to McIntosh Unit 3, because the unit is designed to optimally operate on coal not NG, conversion to NG will results in an approximate 24 percent degradation of capacity from the unit (from 341.7 MW to 259.1 MW, of which LE owns 60 percent). With the degradation of McIntosh Unit 3 and the retirement of McIntosh Unit 2, LE would need to add approximately 59 MW through a peaking PPA through 2029.

Beginning in 2030, LE will need to add base-load (high capacity factor), carbon-neutral, renewable resources to its power supply mix to meet the $CO_2$ emission targets modeled for Business Case 4. Likely options for base-load, renewable resources include the purchase or part ownership of a new nuclear resource, a biomass-fired steam resource, or a landfill gas-fired internal combustion engine and generator. For the SRP, the carbon-neutral resource had been modeled as a 45 MW renewable resource operating at an 85 percent capacity factor. This resource was shown to provide sufficient renewable energy to allow LE to conservatively meet the proposed $CO_2$ emission targets for 2030 and beyond. Additionally, a 15 MW peaking PPA purchase was modeled beginning in 2030 to meet LE's capacity planning requirements.

Figure 3-7 depicts the projected winter load and resources for Business Case 4, and Appendix D, Table D-7 provides a tabulation of the supply and demand balance for the summer and winter periods over the Study Period.

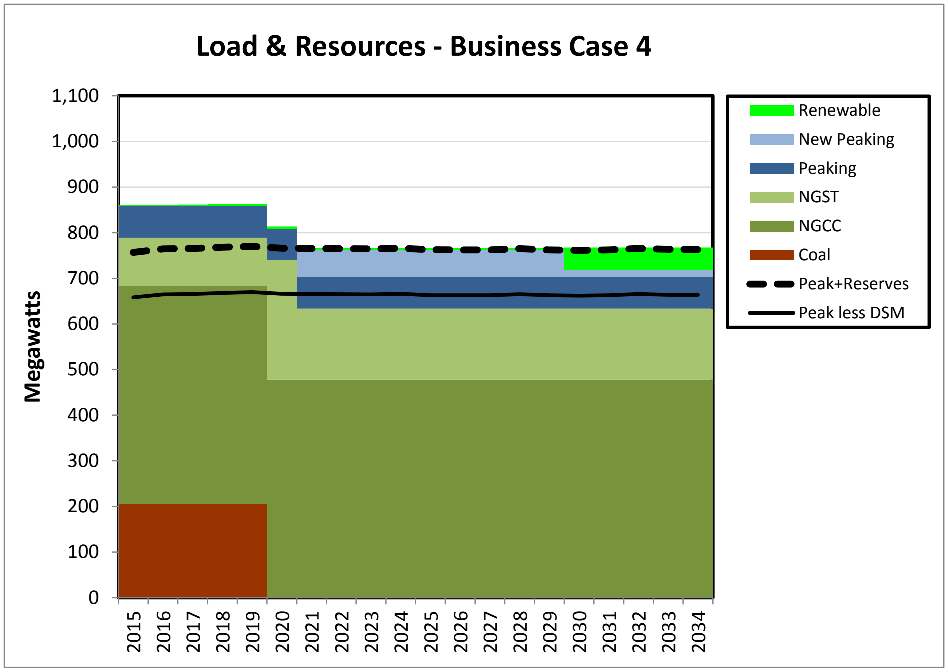



**Figure 3-7: Load & Resources – Business Case 4**

# Projected Production Costs

Following the development of resource expansion plans for each Business Case, simulations of future resource operation were performed for each case to estimate future power supply costs. Through this process, projections of total LE costs for power were developed for use in the financial and risk models, described below, and to permit comparisons between the SRP Business Cases with respect to operating results of each power supply plan, as presented below. The following section of the Report documents the methodology, assumptions, and results of the production cost simulation and modeling.

## Dispatch Simulations

A crucial aspect of assessing the Business Cases (and associated power supply plans) was an evaluation of how the supply and demand-side resources would be used to serve the load requirements of the LE system. To perform this analysis, the Project Team worked closely with the LE staff to develop and perform generation dispatch simulations of the planned generating and purchased power resources identified for each Business Case. Generation simulation models and other software tools currently maintained by LE were utilized to perform the dispatch simulation conducted for the SRP.

LE utilizes a robust system to simulate the dispatch of its generating resources and wholesale transaction within FMPP. Dispatch simulations are performed using the generation simulation model PowerSym, which is used to simulate hourly resource commitment and dispatch of multiple resources for multiple years. LE utilizes PowerSym databases and models to simulate the entire FMPP, which, besides LE, includes the OUC and the Florida Municipal Power Agency (FMPA). In total, these utilities currently possess approximately 4,400 MW of resources (summer rating) to serve peak demand and reserve obligations of approximately 3,700 MW.

In addition to the PowerSym model, LE has developed models to interrogate the hourly results of the PowerSym simulation to compute transaction quantities, marginal pricing, and simulate revenue and charges for transactions between the FMPP members. These models are collectively referred to as the CHP model, based on the FMPP process used to compute a clearinghouse price used to financially settle pool transactions.

For purposes of the SRP, the Project Team members worked with LE staff to review the LE PowerSym models and develop assumptions for simulating the SRP Business Case resource plans in PowerSym and the CHP models. LE managed the editing and operation of the PowerSym and CHP models, and provided output of the models to the Project Team for further analysis, summary, and reporting. Output from the dispatch simulation and pool transaction models were summarized by the Project Team and were combined with projections of other production-related costs and assumptions to develop projections of production operating results, power supply costs, average rates, and risks, as presented within this Report.

## Major Assumptions

The following assumptions were used to conduct the dispatch simulation and prepare projections of power supply costs. These assumptions were used in addition to the assumptions previously discussed above for the development of the Business Case resource plans. Except as described herein, modeling assumptions for OUC and FMPA were adopted from their official 2014 Ten-Year Site Plans (TYSP) filed with the Florida Public Service Commission.

### Cost Escalation

A constant general inflation rate of 2.1 percent was assumed where appropriate for purposes of modeling general cost escalation. Utility operation and maintenance (O&M) costs are assumed to escalate at a constant 3.0 percent over the Study Period.

### Load

Load forecasts and hourly load shapes cover the entire Study Period and were provided by LE, OUC, and FMPA. OUC and FMPA are forecasting average load growth rates of approximately 1.1 percent over the Study Period. Near-term wholesale obligations of OUC and FMPA have been included in the modeled loads. Adjustments were made to the load shapes provided by the LE, OUC, and FMPA to correct for inconsistencies in underlying load and weather patterns used by the three utilities.

### Demand-side Resources

LE demand-side resources modeled for each Business Case are described above in the discussion of resource plans. For OUC and FMPA, demand-side resources forecast in each utility's TYSP were modeled for Business Cases 1 and 2. Modeled demand-side impacts beyond the initial 10-year period contained in the TYSP were assumed to escalate at trends observed for the initial 10-year period. For Business Cases 3 and 4, demand-side technologies and load impacts for OUC and FMPA were assumed to occur at levels proportional to the elevated demand-side load reductions being modeled for LE, less any planned quantities already assumed for the utilities.

Algorithms were developed to estimate hourly load shape impacts for demand-side resources forecast for each Business Case. Demand-side resources were simulated as either peak shavings, energy conservation, or solar PV load shapes. Load impacts were modeled to achieve seasonal load factors projected for each demand-side resource, thus accurately simulating forecast peak load reductions and allocating proportionally larger quantities of energy reductions during seasonal and monthly peak periods, as appropriate.

### Solar PV Resources

Solar PV load shapes were developed from simulated hourly production obtained from the NREL PVWatts model. Load shapes representing an average of normal weather conditions for Lakeland and Orlando were used to develop an average shape for the dispatch simulations. Production patterns were developed separately for fixed plate and single-axis tracking PV configurations. Typical hourly solar PV production patterns were developed for each month and were scaled to reflect the quantities of solar PV energy projected for each Business Case, with appropriate adjustments for transmission and distribution losses when appropriate. The solar PV load shapes were used to model both large-scale utility PV projects and customer PV installations.

### Fuel Prices

Fuel prices modeled in PowerSym for Business Cases 1 and 2 were based on current long-term price forecasts prepared by LE. For Business Cases 3 and 4, fuel commodity prices were adjusted to reflect price variation depicted in the 2014 AEO for the *Best Available Demand Technology* and GHG scenarios described above. These variations reflect changes in fuel prices in response to lower or higher market demand for individual fuels as projected under these scenarios. Figures 3-8 and 3-9 depict the variance in NG and coal fuel prices modeled for the Business Cases. Average annual fuel prices modeled for each Business Case are provided in Tables D-7 through D- 9 included in Appendix D.

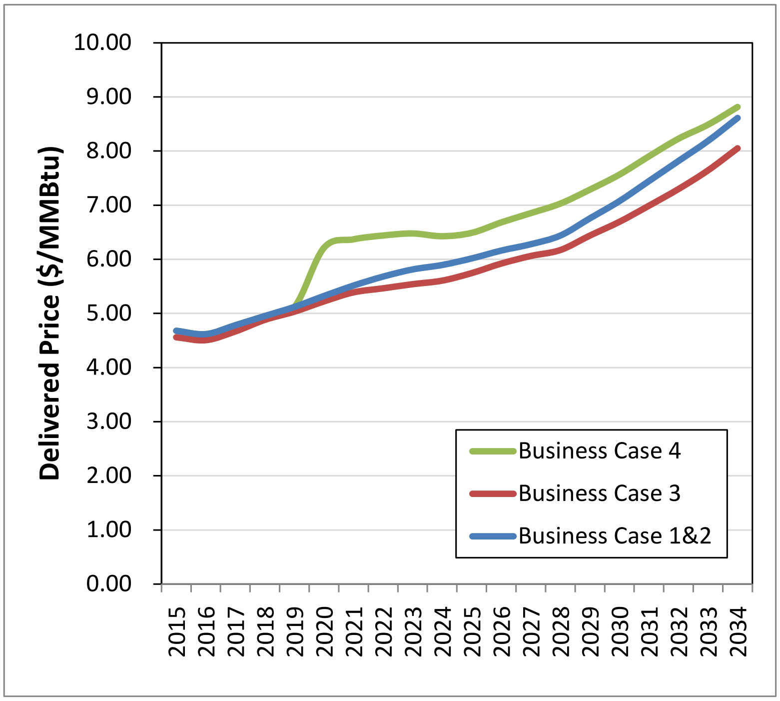



**Figure 3-8: Modeled Natural Gas Fuel Prices**

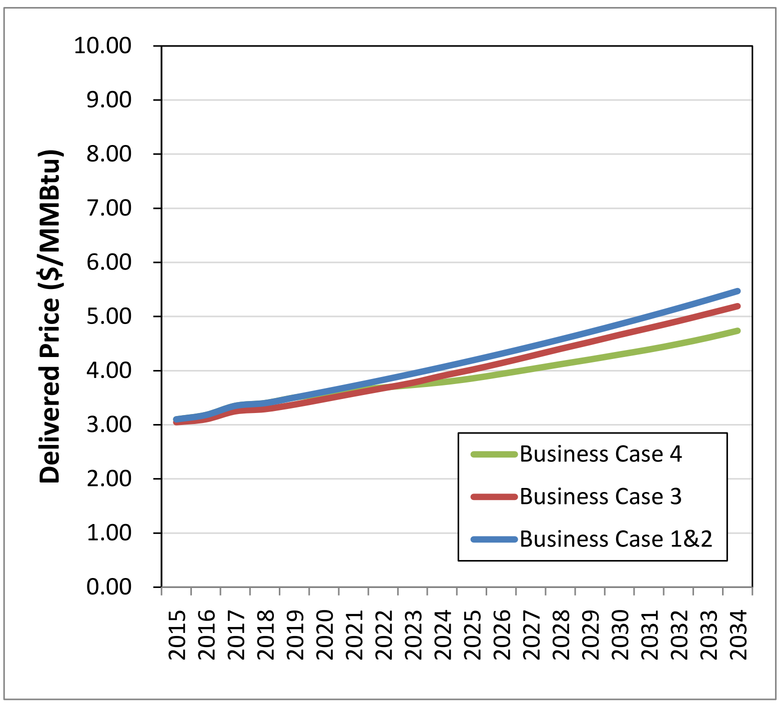



**Figure 3-9: Modeled LE Coal Fuel Prices**

### Existing Resources Operating Characteristics

Operating characteristics modeled by LE in PowerSym for existing LE, OUC, and FMPA generating resources are based on data and assumptions used for real-time dispatch operations of the FMPP. Use of consistent data provides for simulation of resource dispatch and costs that are typical of actual FMPP operations. Operating characteristics for exiting resources is considered confidential, market-sensitive data and is not documented in this Report.

### LE Generation Expansion Resources

The SRP assumes several resources for expansion by LE under Business Cases 1, 2, and 4. These include a new F-class CT, retrofit of McIntosh Unit 2 to CC operation, retrofit of McIntosh Unit 3 to NG operation, ownership or purchase of carbon-neutral renewable power, and PPA purchases corresponding to a new F-class CT.

With regard to the McIntosh 2 repowering modeled for Business Case 1, the Project Team relied on capital cost estimates for the F-class CT provided by LE. Additional costs for the HRSG, integration of the steam turbine, engineering and contingency, and O&M costs were estimated by the Project Team. Operating characteristics were assumed to be consistent with a standard F-class 1x1 CC.

To model the retrofit of McIntosh Unit 3 for Business Case 4, the Project Team relied on equipment and cost estimates provided by LE. Because McIntosh Unit 3 is designed to optimally operate on coal not NG, LE estimates that the conversion to NG will results in an approximate 24 percent degradation of capacity and 4 percent higher heat rate. These estimates include adjustments for both suboptimal boiler performance but lower auxiliary plant loads.

Additional information on assumptions and the methodology used to model financing of the McIntosh Unit 2 repowering and McIntosh Unit 3 retrofit are described below in the section on financial modeling.

Future PPA purchases modeled for Business Cases 2 and 4 were modeled as capacity purchases from new F-class equivalent CT resources built and sold by an investor-owned utility (IOU) or merchant plant developer. As such, modeled financing costs were assumed to be consistent with costs for private debt and equity, and were assumed to escalate over the Study Period at the rate of inflation. Firm transmission costs were also added to the modeled cost of the peaking PPA.

For Business Case 4, LE is modeled to add 45 MW of base-load, carbon-neutral, renewable resources in 2030. Likely options for base-load, renewable resources include the purchase or part ownership of new nuclear, biomass, or landfill gas-fired resources. Because an official carbon-neutral plan for LE has not yet been defined, the costs and characteristics for this resource were assumed to represent the highest-cost of the available options, depicted as an average of the fixed and variable costs of purchasing nuclear and biomass power from a private owner. Firm transmission costs were also added to the modeled cost of the renewable resource.

Assumptions for costs and operating characteristics for the expansion resources are provided in the Tables D-10 and D-11 in Appendix D.

### OUC and FMPA Expansion Resources

For purposes of simulating dispatch of the FMPP, resources and plans for OUC and FMPA contained in their respective TYSP were modeled. Beyond the 10-year period referenced in the TYSP's, OUC and FMPA were assumed to continue operation of their owned resources and purchased power arrangements through the end of the Study Period. When OUC and FMPA load growth plus capacity reserves was forecast to exceed available capacity, the utilities were assumed to install peaking resources as needed. Both F-class CT and aero derivative LM6000 were assumed to be added to meet capacity need. Assumptions for variable operating characteristics for these resources are provided in Table 3-6 and 3-7.

**Table 3-6: McIntosh Repowering and Retrofit Resource Assumptions**

| | Repower McIntosh 2 | | |
|---|---|---|---|
| | F-Class CT | HRSG & ST Integration | Retrofit McIntosh 3 |
| COD | Nov-2020 | Nov-2022 | Jan-2020 |
| Maximum Capacity (Winter MW) | 187.0 | 93.5 [1] | [2] |
| Construction Cost (2014 $Millions) | $ 136.5 | $ 87.9 | $ 8.4 |
| Spending Curve (Yrs. before COD): | | | |
| 3 | 10% | | |
| 2 | 50% | 60% | |
| 1 | 40% | 40% | 100% |
| Capital Costs: | | | |
| Cost of Debt | 5.0% | 5.0% | [3] |
| Financing Period (years) | 20 | 20 | n/a |
| Fixed O&M (2014 $/kW-yr.) | $ 7.61 | $ 13.65 [4] | [6] |
| Variable O&M (2014 $/MWh) | $ 2.11 | $1.50 [4] | [6] |
| Avg. Operating Heat Rate (Btu/kWh) [5] | 10,500 | 6,970 [4] | [6] |
| Modeled Emission Rates (lb/MMBtu): | | | |
| $NO_x$ | 0.007 | 0.018 | 0.165 |
| $SO_2$ | 0.0005 | 0.0005 | 0.0005 |
| $CO_2$ | 110.0 | 110.0 | 110.0 |

1. Incremental capacity.
2. Approximately 24% capacity reduction.
3. Assumed to be funded from cash.
4. Value for full CC resource.
5. Approximate.
6. Confidential.

**Table 3-7: Peaking and Renewable Resource Assumptions**

| | F-Class CT | LM6000 | Biomass | Nuclear |
|---|---|---|---|---|
| Construction Cost (2014 $/kW) | $ 730 | [1] | $ 4,061 | $ 5,701 |
| Capital Costs: | | | | |
| Cost of Debt | 9.6% | [1] | 9.6% | 9.6% |
| Financing Period (years) | 30 | [1] | 30 | 30 |
| Fixed O&M (2014 $/kW-yr.) | $ 7.61 | [1] | $ 109.48 | $ 96.67 |
| Firm Transmission (2014 $/kW-yr.) | $ 19.79 | [1] | $ 19.79 | $ 19.79 |
| Variable O&M (2014 $/MWh) | $ 2.11 | $ 2.54 | $ 5.45 | $ 2.22 |
| Fuel Price (2014 $/MMBtu) | [2] | [2] | 2.00 | 0.50 |
| Avg. Operating Heat Rate (Btu/kWh) [3] | 10,500 | 9,160 | 13,500 | 10,500 |

1. Fixed costs not modeled for OUC and FMPA resources.
2. Modeled NG fuel price.
3. Approximate.

## Emissions

Emissions for LE resources projected by the PowerSym dispatch simulations were developed for the following effluents: nitrogen oxide ($NO_x$), sulfur dioxide ($SO_2$ or $SO_x$), $CO_2$, carbon monoxide (CO), volatile organic compounds, particulate matter, and lead. Emissions were computed by summarizing annual fuel consumption simulated for LE generating units (and by the summer ozone season for $NO_x$) and applying unit emission rates in pounds per million British thermal units (MMBtu) developed by the environmental consultant, Luminate. Additional information can be found in Section 4 of the Report.

Emission allowance costs were modeled for annual $SO_2$ and seasonal $NO_x$ emissions over the Study Period. Modeled $SO_2$ and $NO_x$ emission prices are provided in Table 3-18. Additionally, under Business Case 4, an effective price of $CO_2$ emissions was added to the modeled price of fuels relative to the quantity of $CO_2$ emissions that would be expected to be produced by consuming each fuel type. These $CO_2$ price adders provide appropriate price signals for dispatching resources under the GHG regulatory scenario modeled for Business Case 4 — generating units with fuel types that produce more $CO_2$ emissions are curtailed to avoid the cost of $CO_2$. However, because GHG regulations modeled for the SRP do not assume transactions of allowances, the modeled cost of $CO_2$ was removed from the reported costs of fuel and emissions prior to reporting costs for production. The $CO_2$ price used to develop the fuel price adders in included in Table 3-8.

For Business Case 4, $CO_2$ emissions produced by LE generating resources were summarized and compared to emission goals established for Florida in the recently proposed GHG emissions regulation for existing generating units. These emission goals are expressed in terms of the maximum pounds per megawatt-hour of $CO_2$ that a utility can generate from existing generating units and are established for two time periods: an Interim Period from 2020 through 2029, and a Final Period for 2030 and beyond. The proposed Interim Goal for Florida is 794 pounds per megawatt-hour, and the proposed Final Goal is 740 pounds per megawatt-hour. As the rules are currently proposed by the EPA, generation from future renewable and carbon-neutral resources and load reductions from incremental utility DSM programs can be applied to the denominator when computing $CO_2$ emission rates.

For the SRP, $CO_2$ emissions from LE generating resources were modeled and incremental renewable generation and demand-side energy reductions were summarized to compute the effective pounds per megawatt-hours produced over each year of the Study Period. The LE resource expansion plan modeled for Business Case 4 was designed to meet or exceed the goals on average for the Interim Period and exceed the goal for the Final Period.

**Table 3-8: Projected Emission Prices**
**Nominal $/ton**

| | $NO_x$ | $SO_2$ | $CO_2$ |
|---|---|---|---|
| 2015 | 50 | 1.00 | - |
| 2016 | 800 | 1.03 | - |
| 2017 | 816 | 1.05 | - |
| 2018 | 832 | 1.08 | - |
| 2019 | 849 | 1.10 | - |
| 2020 | 866 | 1.13 | 20.42 |
| 2021 | 883 | 1.16 | 21.44 |
| 2022 | 901 | 1.19 | 22.51 |
| 2023 | 919 | 1.22 | 23.64 |
| 2024 | 937 | 1.25 | 24.82 |
| 2025 | 956 | 1.28 | 26.06 |
| 2026 | 975 | 1.31 | 27.37 |
| 2027 | 995 | 1.34 | 28.73 |
| 2028 | 1015 | 1.38 | 30.17 |
| 2029 | 1035 | 1.41 | 31.68 |
| 2030 | 1056 | 1.45 | 33.26 |
| 2031 | 1077 | 1.48 | 34.93 |
| 2032 | 1098 | 1.52 | 36.67 |
| 2033 | 1120 | 1.56 | 38.51 |
| 2034 | 1143 | 1.60 | 40.43 |

## Projected Operating Results

Projected LE resource dispatch for each Business Case is described below and depicted in the following figures and tables.

### Operating Results – Business Case 1

Business Case 1 represents a traditional utility approach to build new generating resources as needed to meet future load growth and planning reserve criteria. Market and economic conditions, including future LE load growth, are consistent with current industry trends and forecasts. Environmental regulations represent currently adopted laws and rules, and do not include newly proposed rules governing GHG. Demand-side and renewable resources remain at fairly low levels.

As depicted by Figure 3-10, under these conditions and assumptions, the proportions of LE load served by various fuel types is expected to remain fairly static over the Study Period. Coal-fired resources are projected to supply between 28 and 33 percent of LE's load over the Study Period, increasing slightly through time as base-load coal resources are more fully utilized with load growth. NG-fired resources are projected to supply between 71 and 64 percent of LE's load over the Study Period, declining slightly in relative terms in response to the slight increase in the proportion of load served by coal, renewable, and demand-side resources. Renewable and demand-side resources are projected to grow slightly over the Study Period from approximately one percent to three percent of load. Supply from economy energy purchases is projected to decline from approximately eight percent of load in 2015 to three percent of load in 2034.

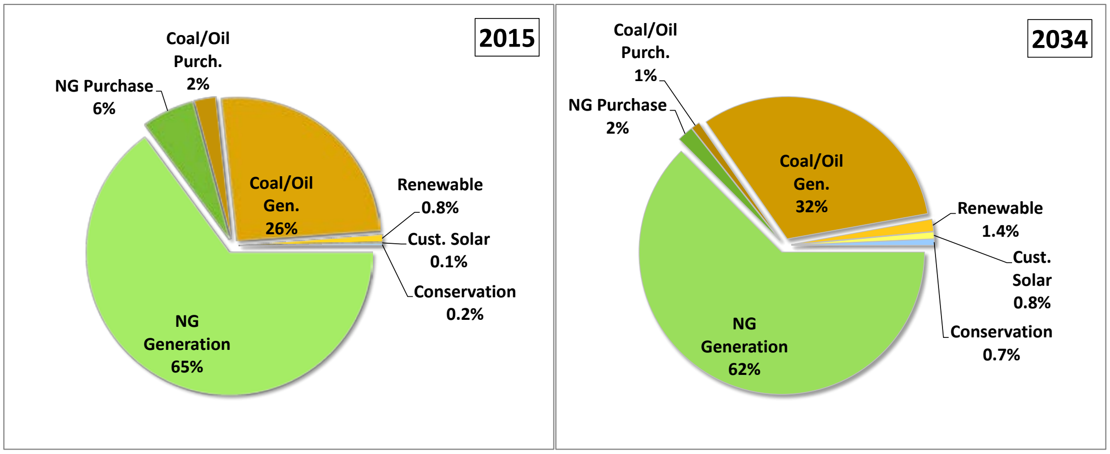



**Figure 3-10: Energy Supply 2015 and 2034, Business Case 1**

A review of projected operating results (projected generation and fuel use) for Business Case 1, as presented in Appendix D, Table D-12, reveals that LE is projected to significantly increase economy energy sales to other utilities (modeled as economy energy sales to FMPP members) with the modeled CC repowering of McIntosh Unit 2 in late 2022. Economy energy sales are projected to increase approximately 2.5 times following the installation of the repowered resource, as compared to modeled energy transactions prior to the start of the McIntosh Unit 2 repowering project. Similarly, economy energy purchases from other suppliers (modeled as economy energy purchases from FMPP members) are projected to decline by approximately one-half following the installation of the McIntosh Unit 2 repowering project.

### Operating Results – Business Case 2

Business Case 2 represents a resource planning scenario under which LE meets all future resource capacity needs through short-term (five-year) purchase power arrangements. Other economic, market, and regulatory assumptions are generally consistent with those for Business Case 1. As might be expected, the proportions of LE load served by various fuel types follows closely with what was modeled for Business Case 1. As depicted by Figure 3-11, the primary difference between Business Case 2 and Business Case 1 is the proportion of the LE load that is served from purchases instead of LE generating resources. For Business Case 2, supply from economy energy purchases is projected to increase slightly over the Study Period from eight percent in 2015 to 10 percent in 2034.

A review of projected operating results for Business Case 2, as presented in Appendix D, Table D-12, reveals that LE is projected to increase economy energy purchases slightly over the Study Period (an approximately 50 percent increase), while economy energy sales are projected to remain fairly constant (less than a 10 percent change).

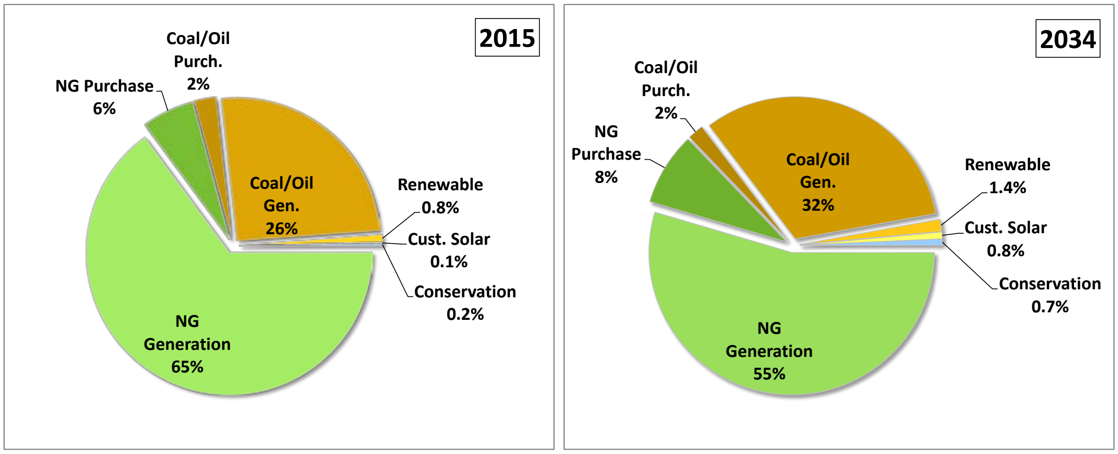



**Figure 3-11: Energy Supply 2015 and 2034, Business Case 2**

## Operating Results – Business Case 3

Business Case 3 depicts a significant marketplace transformation of the electric utility industry, causing high levels of customer adoption of utility DSM programs, DG resources, and other general EE equipment and practices. These market transformations are projected to eliminate future LE load growth. As depicted by Figure 3-12, demand-side and renewable resources are projected to meet approximately 21 percent of future LE loads (resulting in lower loads being served from LE traditional resources and transactions). Base-load coal generation is projected to remain at levels similar to Business Cases 1 and 2, but energy from NG resources is projected to decline as it is displaced by load reductions from demand-side resources.

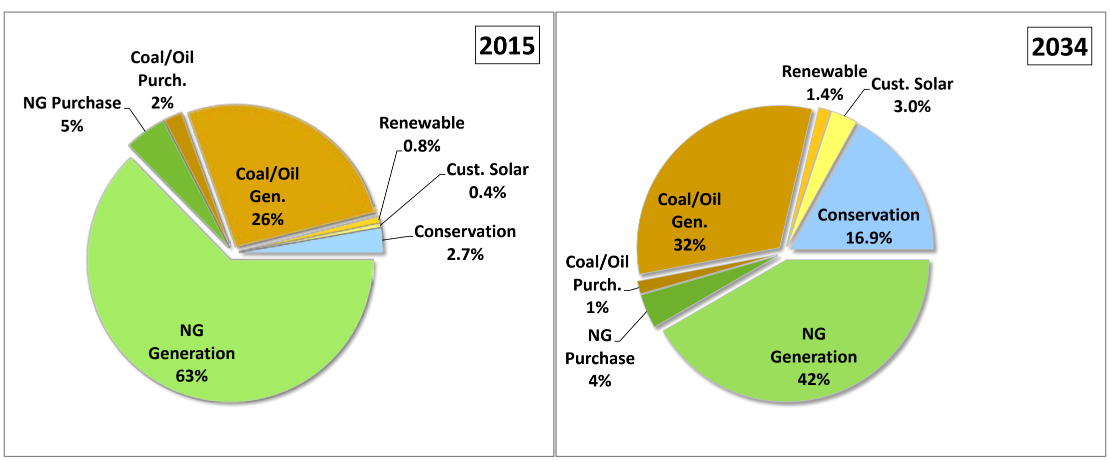



**Figure 3-12: Energy Supply 2015 and 2034, Business Case 3**

A review of projected operating results for Business Case 3, as presented in Appendix D, Table D-13, indicates that LE generation and economy energy transactions are projected to remain relatively constant over the Study Period, as would be expected for a case with no LE load growth.

## Operating Results – Business Case 4

Business Case 4 depicts a scenario under which GHG regulations recently proposed by the EPA will cause LE to modify the planning and operation of generating resources to meet $CO_2$ emission goals beginning in 2020. To meet the proposed $CO_2$ goals, LE is modeled to convert its existing coal unit, McIntosh Unit 3, to NG operation by 2020. Additionally, LE is modeled to significant increase utility DSM programs and install or purchase power from new base-load, carbon-neutral resources by 2030.

As depicted by Figure 3-13, with the conversion of McIntosh Unit 3 to operate on NG, LE coal-fired generation is projected to be eliminated by the end of the Study Period, although a small amount of coal-fired generation is still projected to be purchased from the FMPP. Over the same period, NG-fired generation is projected to increase from 67 to 79 percent, and renewable generation is projected to meet 10 percent of the LE load by the end of the Study Period. Demand-side resources are projected to offset 7 percent of LE loads by the end of the Study Period.

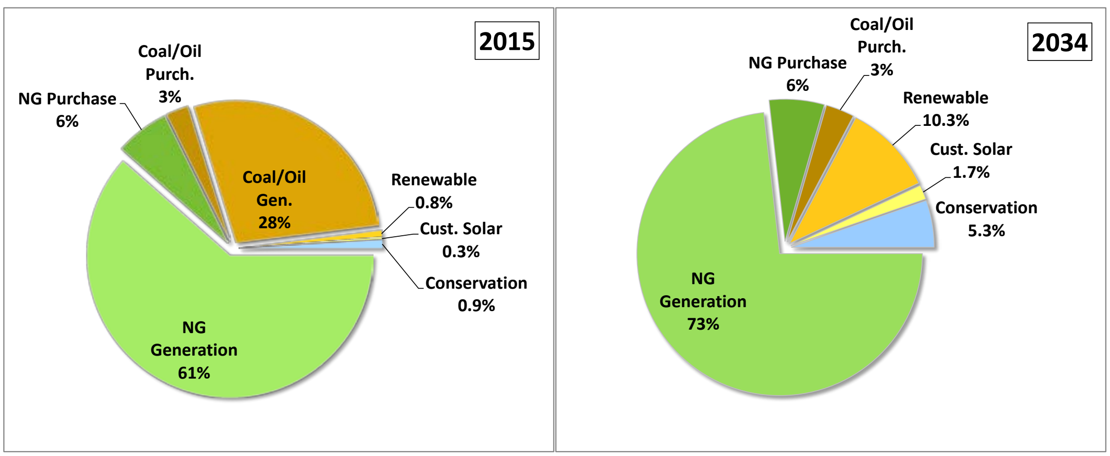



**Figure 3-13: Energy Supply 2015 and 2034, Business Case 4**

Figure 3-14 provides a comparison of $CO_2$ emission rates for existing LE generating units under Business Cases 1 and 4 to identify how $CO_2$ emission goals are met under Business Case 4. For each case, $CO_2$ emissions are computed consistent with the methodology proposed by the EPA. As can be seen in the chart, emissions rates under Business Case 1 are projected to be approximately 1,200 pounds per megawatt-hour. While under Business Case 4, emission rates are lower than the Interim Goal of 794 pounds per megawatt-hour, on average, for 2020 through 2029, and lower than the Final Goal of 740 pounds per megawatt-hour for 2030 and beyond.

The majority of $CO_2$ emission reductions are achieved by converting McIntosh Unit 3 to NG. These reductions are achieved by reducing the overall operation of McIntosh Unit 3, replacing a portion of McIntosh Unit 3 coal-fired generation with NG-fired generation from McIntosh Unit 3, and replacing McIntosh Unit 3 generation with generation from other LE NG-fired resources and with purchases from the FMPP (or other suppliers). Additionally, by the end of the Study Period, approximately one-fourth of the $CO_2$ emissions reduction are provided by offsets from renewable resources and utility DSM programs.

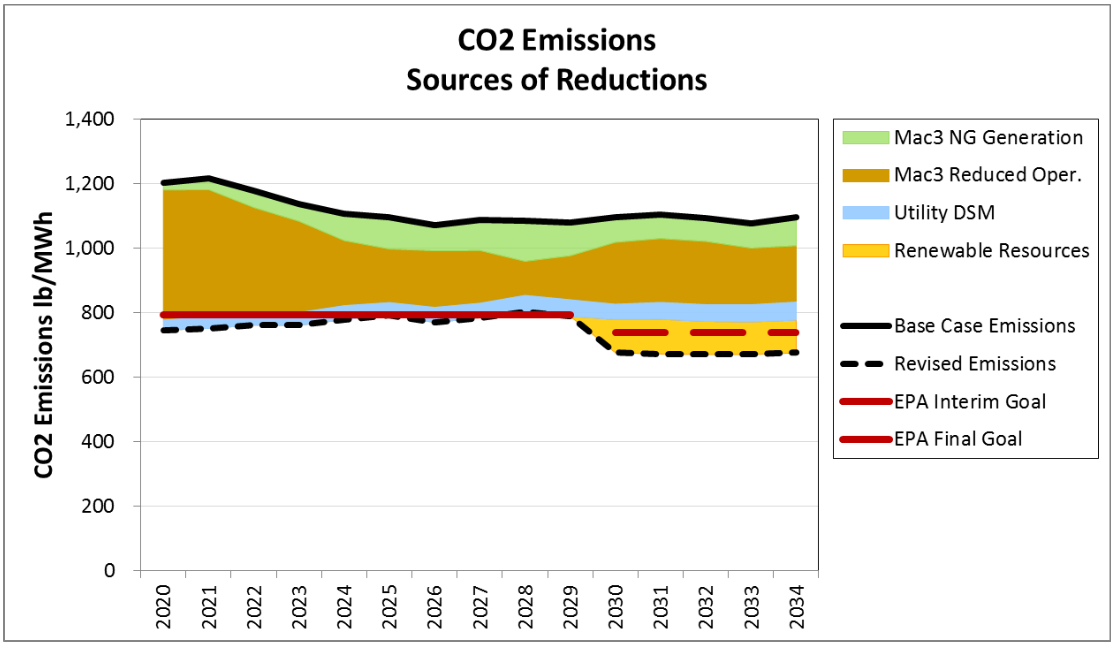



**Figure 3-14: Sources of $CO_2$ Emissions Reductions**

A review of projected operating results for Business Case 4, as presented in Appendix D, Table D-14, indicates that economy energy purchases are anticipated to be approximately 2.5 times higher after the implementation of the GHG rules in 2020, while economy energy sales are anticipated to drop by almost two-thirds after the implementation of the GHG rules in 2020.

## Projected Power Supply Costs

Projected annual power supply costs for each Business Case are presented below in Tables D-15 through D-18 included in Appendix D. Projected costs are based on the dispatch simulated for each case and calculations of other fixed and variable costs for PPA purchases and LE resource additions. The projected power supply costs were utilized in the financial and risk modeling described below.

The projected power supply costs include the following items:

- Simulated variable costs for LE generating resources (including fuel costs, variable O&M and start costs, and costs for emissions);
- Revenue and costs for simulated FMPP sales and purchases;
- Projected fixed O&M costs for LE generating resources;
- Fixed costs for modeled PPA purchases (including capital, fixed O&M, and transmission related costs);
- Fixed costs for modeled renewable purchases (including capital, fixed O&M, and transmission related costs);
- Costs for utility solar PV purchases; and

- Fixed capital expenditures for repowering and retrofit projects for McIntosh Units 1 and 2.

Table 3-9, below, provides a comparison of average levelized power supply costs for the Business Cases, including estimated costs for financing the new McIntosh Unit 2 and Unit 3 projects.

**Table 3-9: Average Levelized Power Supply Costs 2015-2034**

| | Levelized $/MWh |
|---|---|
| Business Case 1 | 55.07 |
| Business Case 2 | 54.89 |
| Business Case 3 | 50.48 |
| Business Case 4 | 59.61 |

Excludes debt service-related costs for existing generating resources.

While comparison of power supply costs across the Business Cases can be difficult given the significantly different assumptions for future market conditions assumed for some of the Business Cases, certain conclusions can be drawn from this comparison, as follows.

- Levelized costs for Business Cases 1 and 2 are similar. This result indicates that LE can expect to achieve similar total costs for power irrespective of whether it adopts a more traditional resource building strategy or decides to procure power from others. Instead, other factors such as flexibility and exposure to market risks are likely to influence the LE decision to proceed with one strategy or the other.
- As might be expected, power supply costs are projected to be lower for Business Case 3. Even though load is lower for Business Case 3, which would tend to drive up average costs, higher utilization of low energy cost resources and no new capital and fixed costs for future resource additions are projected to cause average costs for this case to be lower than for Business Cases 1 and 2. It is important to note that while average power supply costs may be lower under Business Case 3, the result does not necessarily indicate retail rates under this scenario would be lower. Fixed costs for debt service related to existing generating facilities and other costs for other utility facilities and services do not typically decline with declining load. As such, total average costs and rates for the total LE system are likely to be higher under Business Case 3.
- Average levelized costs for Business Case 4 are projected to be approximately 8.5 percent higher than for Business Cases 1 and 2. This result is to be expected given the higher utilization of NG to serve LE loads (versus lower priced coal) and greater reliance on relatively expensive renewable and carbon-neutral resources. Based on preliminary industry studies being performed to determine the impact of the proposed EPA GHG rules, the average levelized cost increase projected for LE

for Business Case 4 is expected to similar or possibly lower than cost impacts that could be experienced by other utilities.

# Financial Forecast

The financial forecast model provides a comprehensive and dynamic 20-year forecast to translate the four Business Cases into long-term revenue requirement forecasts with supporting retail rate levels expressed on a system average basis. The model allows users to optimize the use of debt, rates, and reserves to meet revenue requirements on an annual basis and project the system average rate impacts. One of the key inputs to the financial forecast is the outcomes and results of the resource planning simulation described previously. Once completed for each Business Case, the financial model allows for a comparison on key financial metrics such as debt service coverage ratios (DSCR), reserve levels, average rates, and days cash on hand to help inform the generation resource related decisions.

The financial model was designed on a cash flow basis to align with municipal utility financial practices and incorporated common economic evaluation metrics such as discounted cash flow (DCF) or net present value (NPV). As the initial financial forecast and comparisons on a system average rate for the four Business Cases are completed, the model will transition to evaluating the risk or uncertainty associated with each Business Case.

The financial risk for LE in each case is represented as the uncertainty or range of potential outcomes associated with each case's system average rate results. For example, by completing the risk analysis, LE not only evaluates the system average rate results over 20 years for each case, but also begins quantifying the risks in each case. This risk is quantified in the model by identifying the boundaries of potential system average rates under uncertain inputs such as fuel price forecasts and municipal bond interest rates. The risk results are quantified using a 95 percent confidence interval (i.e., 95 percent of the potential results for system average rates are within the range of values calculated in that particular year). The data gathered from LE and related assumptions used in the financial is discussed below.

## Inputs, Data Sources and Assumptions

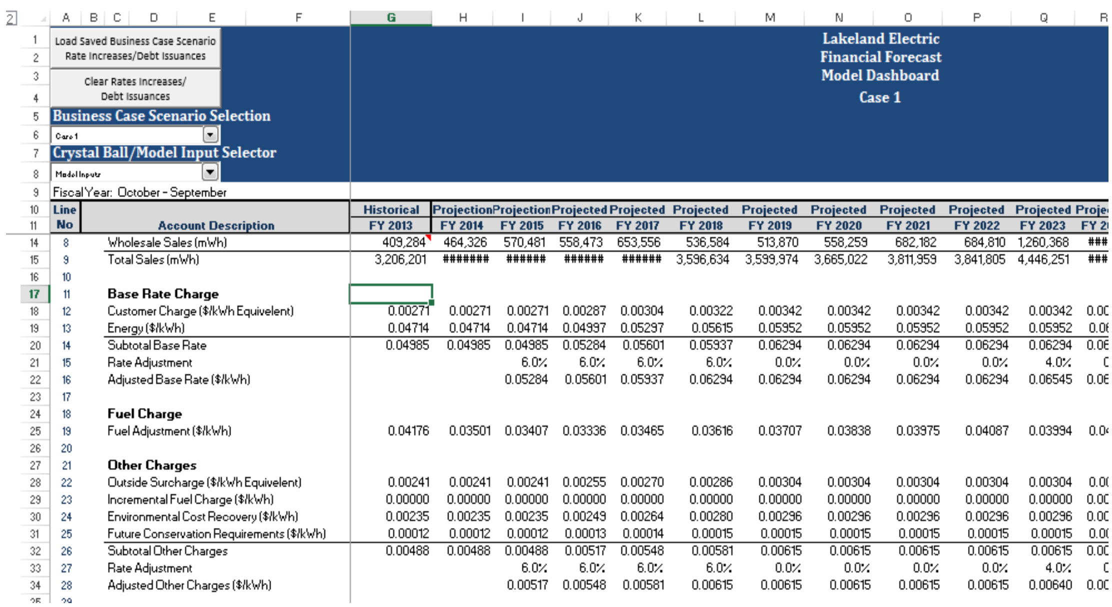
The financial forecast model was developed using budget, operational, and financial performance data from LE and the output from the PowerSym simulation. The data used in the financial forecast model included:

- PowerSym related data:
  - Results from LE's production cost modeling tool
  - Projected market sales and other wholesale power transactions
  - Asset retirement/repowering/re-investment schedules
  - Generation operating unit characteristics (e.g., heat rates, availability, capacities)
  - Load forecast
  - Fuel purchases

  - Load destruction from EE and DR programs
- LE budgeting and/or operating data:
  - LE annual operating budget
  - System revenues
  - System losses
  - Capital improvements plans
  - Labor and related benefits costs
  - Revenue bond amortization schedules
  - Cost of capital
  - Reserve fund requirements
  - Payments to the City
  - Other financial obligations of the City
- Financial Model escalation rates and assumptions (applied to each Business Case)
  - Inflation rate based on the consumer price index (CPI) of 1.9 percent in the early years, increasing to 2.4 percent through the remainder of the Study Period.
  - Long term capital cost escalation rates tied to CPI.
  - Long term municipal debt financing interest rates of five percent based on current Bloomberg municipal bond rates with an adjustment to represent longer term market conditions; debt issuance costs were estimated at two percent of the total bond issue.
  - Debt service coverage ratios reflect current LE requirements with a minimum coverage ratio of 1.5 and goal / practice of maintaining 2.0.
  - Reserve levels were modeled on days cash on hand and maintain 120 days of cash needs.
  - Interest earnings accrue on cash balances at three percent per year over the Study Period.

## Financial Forecast Results and Business Case Comparisons

The financial forecast model creates a 20-year forecast of revenue requirements on a cash basis for each Business Case. Based on the revenue requirements each year, the user selects and optimizes rate changes, debt issuances, and use of reserves to fully recover the revenue requirements while maintaining the key financial performance metrics. The financial forecast output includes a summary dashboard similar to a LE operating statement and a visual dashboard with graphs illustrating system average rates, DSCR, operating expenses, operating reserves, and revenues. Figure 3-15 and 3-16 illustrate the operating statement and visual dashboards generated by the model for each Business Case. The figures are intended as an illustration of the model functionality, results and related graphs illustrated in the figures are explained in greater detail within this Section.



Load Saved Business Case Scenario Rate Increases/Debt Issuances

Clear Rates Increases/ Debt Issuances

Business Case Scenario Selection

Case 1

Crystal Ball/Model Input Selector

Model Inputs

Lakeland Electric
Financial Forecast
Model Dashboard
Case 1

Fiscal Year: October - September

| Line No | Account Description | Historical FY 2013 | Projection FY 2014 | Projection FY 2015 | Projected FY 2016 | Projected FY 2017 | Projected FY 2018 | Projected FY 2019 | Projected FY 2020 | Projected FY 2021 | Projected FY 2022 | Projected FY 2023 | Proje FY 2 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | Wholesale Sales (mWh) | 409,284 | 464,326 | 570,481 | 558,473 | 653,556 | 536,584 | 513,870 | 558,259 | 682,182 | 684,810 | 1,260,368 | ### |
| 9 | Total Sales (mWh) | 3,206,201 | ####### | ###### | ###### | ###### | 3,596,634 | 3,599,974 | 3,665,022 | 3,811,959 | 3,841,805 | 4,446,251 | ### |
| 10 | | | | | | | | | | | | | |
| 11 | **Base Rate Charge** | | | | | | | | | | | | |
| 12 | Customer Charge ($/kWh Equivelent) | 0.00271 | 0.00271 | 0.00271 | 0.00287 | 0.00304 | 0.00322 | 0.00342 | 0.00342 | 0.00342 | 0.00342 | 0.00342 | 0.0C |
| 13 | Energy ($/kWh) | 0.04714 | 0.04714 | 0.04714 | 0.04997 | 0.05297 | 0.05615 | 0.05952 | 0.05952 | 0.05952 | 0.05952 | 0.05952 | 0.0 |
| 14 | Subtotal Base Rate | 0.04985 | 0.04985 | 0.04985 | 0.05284 | 0.05601 | 0.05937 | 0.06294 | 0.06294 | 0.06294 | 0.06294 | 0.06294 | 0.06 |
| 15 | Rate Adjustment | | | 6.0% | 6.0% | 6.0% | 6.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.0% | C |
| 16 | Adjusted Base Rate ($/kWh) | | | 0.05284 | 0.05601 | 0.05937 | 0.06294 | 0.06294 | 0.06294 | 0.06294 | 0.06294 | 0.06545 | 0.06 |
| 17 | | | | | | | | | | | | | |
| 18 | **Fuel Charge** | | | | | | | | | | | | |
| 19 | Fuel Adjustment ($/kWh) | 0.04176 | 0.03501 | 0.03407 | 0.03336 | 0.03465 | 0.03616 | 0.03707 | 0.03838 | 0.03975 | 0.04087 | 0.03994 | 0.0 |
| 20 | | | | | | | | | | | | | |
| 21 | **Other Charges** | | | | | | | | | | | | |
| 22 | Outside Surcharge ($/kWh Equivelent) | 0.00241 | 0.00241 | 0.00241 | 0.00255 | 0.00270 | 0.00286 | 0.00304 | 0.00304 | 0.00304 | 0.00304 | 0.00304 | 0.0 |
| 23 | Incremental Fuel Charge ($/kWh) | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.0C |
| 24 | Environmental Cost Recovery ($/kWh) | 0.00235 | 0.00235 | 0.00235 | 0.00249 | 0.00264 | 0.00280 | 0.00296 | 0.00296 | 0.00296 | 0.00296 | 0.00296 | 0.0C |
| 25 | Future Conservation Requirements ($/kWh) | 0.00012 | 0.00012 | 0.00012 | 0.00013 | 0.00014 | 0.00015 | 0.00015 | 0.00015 | 0.00015 | 0.00015 | 0.00015 | 0.0 |
| 26 | Subtotal Other Charges | 0.00488 | 0.00488 | 0.00488 | 0.00517 | 0.00548 | 0.00581 | 0.00615 | 0.00615 | 0.00615 | 0.00615 | 0.00615 | 0.0C |
| 27 | Rate Adjustment | | | 6.0% | 6.0% | 6.0% | 6.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.0% | C |
| 28 | Adjusted Other Charges ($/kWh) | | | 0.00517 | 0.00548 | 0.00581 | 0.00615 | 0.00615 | 0.00615 | 0.00615 | 0.00615 | 0.00640 | 0.0C |

Figure 3-15: Example Financial Forecast Model Operating Statement


Figure 3-16: Example Visual Dashboard Results for Business Case

In addition to the resource planning simulation output, key inputs will impact or contribute to the system average rate results calculated by the financial model. These include inputs such as projected capital costs, debt issuances, and DSM program costs. The key financial forecast related assumptions and inputs that vary between each Business Case are described below.

- Business Case 1: Build Future Resource (Base Case)

  - Uses 100 percent debt financing for generation plant upgrades.
  - $258 Million total capital plan over five years is fully debt funded from 2018 through 2023 with 20-year bonds.
  - Capital costs are escalated from current year dollars (2014) to nominal year dollars in the year the project(s) are implemented.
  - DSM funding remains at existing levels escalated at inflation plus additional labor cost escalation each year of the forecast period.
  - Potential GHG regulations and limits on GHG related emissions are not applied.
- Business Case 2: Purchase Future Resources
  - No capital costs for construction or upgrades of existing generation plant(s).
  - No new debt is issued to support capital investment in generation plan.
  - DSM funding remains at existing levels escalated at inflation plus additional labor cost escalation each year of the forecast period.
  - Potential GHG regulations and limits on GHG related emissions are not applied.
- Business Case 3: Customer Demand Technology
  - No capital costs for construction or upgrades of existing generation plant(s) and no new debt issuances for capital spending.
  - Potential GHG regulations and limits on GHG related emissions are not applied.
  - DSM funding (e.g., staff, rebates and program costs) increases on average 135 percent from business as usual DSM funding levels. The DSM funding increase is approximately 40 to 75 percent in the earlier years of the forecast escalating to more than 200 percent of business as usual funding late in the forecast period. This equates to approximately $300,000 per year in the earlier years and up to $2,000,000 in the later years.
- Business Case 4: GHG Regulation
  - No capital costs for construction or upgrades of existing generation plant(s), and no new debt issuances for capital spending.
  - DSM funding remains at existing levels escalated at inflation, plus additional labor cost escalation each year of the forecast period.
  - GHG emission limits are applied and LE adjusts resource portfolio accordingly, including the purchase of renewable energy resources.

## Financial Forecast Outcomes

Based on the inputs and assumptions above and the generation resource dispatching results from the PowerSym model, the financial forecast produced an average system rate required for each Business Case to recover revenue requirements and meet the key financial metrics. Figure 3-17 shows and compares the system average rates calculated using the financial forecast model. The system average rate is calculated by dividing the total LE revenue for a specific year by the related total load (kilowatt-hours (kWh)). In general, LE's total costs are approximately 60 percent related to LE specific costs for operating and capital needs, while approximately 40 percent are related to fuel costs to operate the generating plants.

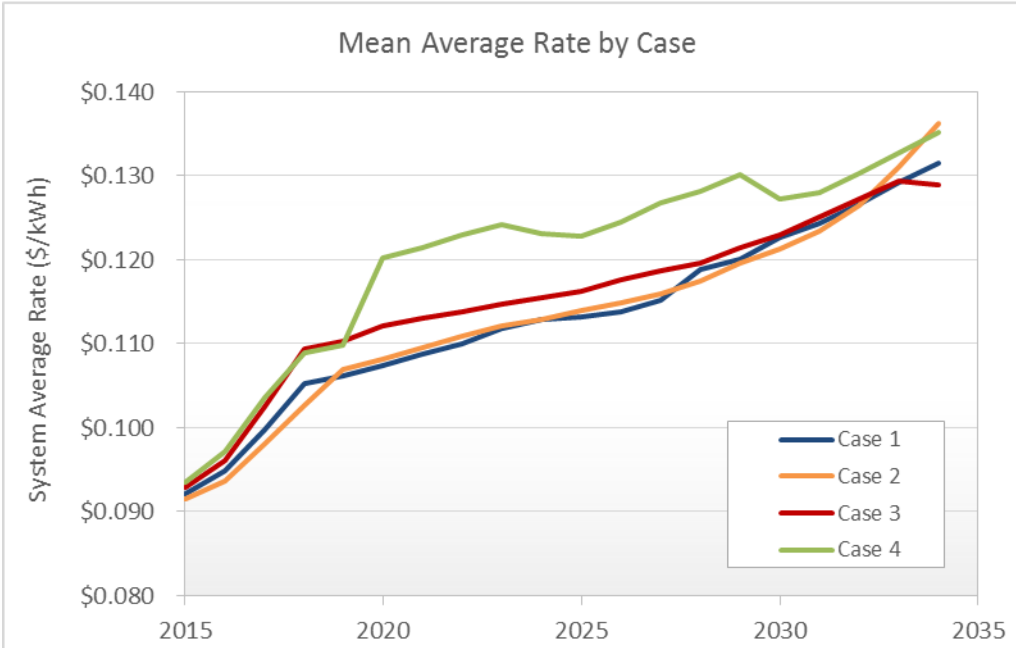



**Figure 3-17: Average System Rate Results for each Business Case**

All of the Business Cases begin at the same average rate in 2015 at $0.092 per kWh as expected due to each Business Case having similar operating costs and profiles. The system average rates for Business Case 1 and Business Case 2 are very similar over the course of the Study Period. This is expected as both Business Case1 and 2 are driven by either LE generating their own power or purchasing market power from a NG CC plant. The major differences between Business Cases 1 and 2 are the risks related to market price fluctuations and the potential for stranded costs in the reinvestment of LE plants. These risks are evaluated in more detail later in this section.

Business Cases 3 and 4's system average rate increases at a higher rates than Business Cases 1 and 2 due to increased costs associated with meeting regulatory GHG emission levels in Business Case 4 and increasing costs for DSM programs and lower overall sales (e.g., kWh) in Business Case 3. The Business Case 4 system average rate begins to increase at an even greater rate in 2020 as GHG regulatory constraints begin to increase.

The system average rates for Business Case 3 begin to stabilize in 2020 and track the year over year increases of Business Cases 1 and 2. It is important to note that while the system average rate (dollars per kWh) increases the overall system load (kWh) and demand (kilowatts (kW)) are flat to declining. Therefore, the overall bill for many customers under Business Case 3 may remain unchanged and/or decline. This is due to the widespread adoption of DSM measures such as efficient light bulbs, air conditioning, appliances, and smart meter related programs. This demand destruction and decline in system load is unique to Business Case 3. In the other Business Cases, LE's system load is growing and costs are increasing. In Business Cases 1, 2, and 4, it is likely the system average rate increases, as well as the overall monthly bills for customers.

At the end of the Study Period, each of the four Business Cases reaches a similar average rate of approximately $0.130 to $0.135 per kWh. While the financial model projects average rates over the 20-year period under a set of conditions and assumptions, additional risk analysis is required to fully understand how each Case is impacted by the key variables such as fuel prices, interest rates, and regulatory costs.

## Risk Analysis

Performing a quantitative risk analysis of the financial model provides for a deeper understanding of the underlying drivers for and the sensitivities of the system average rate results in the financial model. Due to the number of inputs and assumptions used to generate the financial model results and the inherent volatility or uncertainty in these inputs, risk analysis provides risk-adjusted results. These risk-adjusted results calculate the range of system average rates within a certain probability (e.g., confidence interval).

One example of the uncertainty and volatility inherent in the initial financial model results is the fuel price forecast for 2015 through 2034. The fuel price forecast includes projected costs for coal and NG fuels, which are key drivers of the overall cost of electricity. The NG price forecast shown previously in Figure 3-8 is an initial projection; however, actual prices will vary from the initial forecast. To account for the uncertainty in the forecasted prices, a probability distribution (e.g., normal, log normal, etc.) are selected to simulate the uncertainty and price variance in the NG markets. Figure 3-18 illustrates the initial forecast for NG prices and the related uncertainty in the forecast.

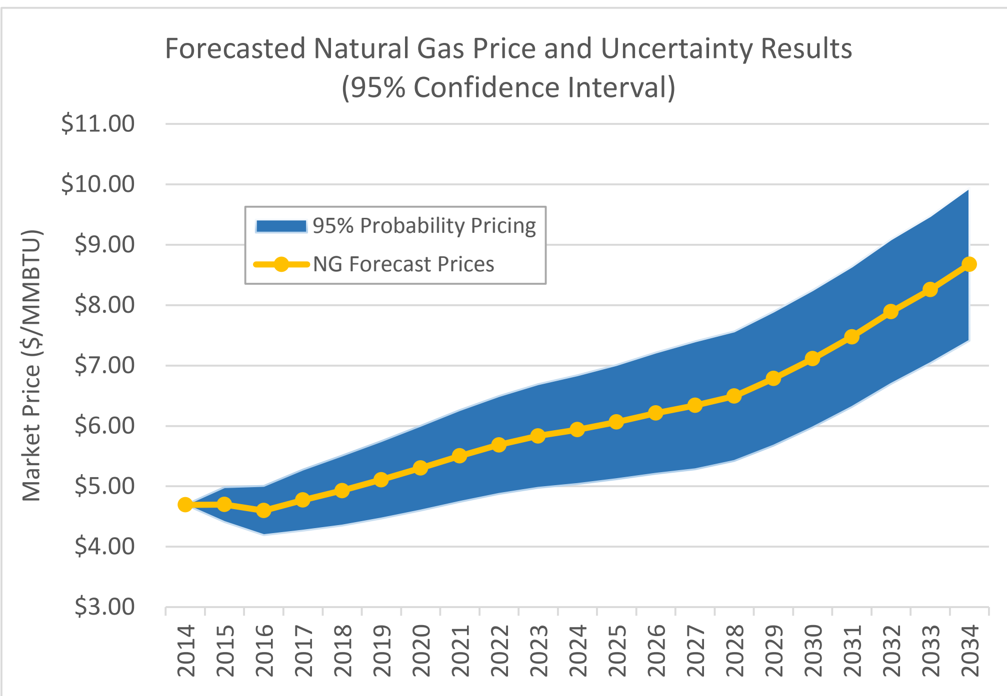



**Figure 3-18: Natural Gas Price Forecast and Uncertainty**

The Project Team used Oracle Crystal Ball (Crystal Ball) to perform the risk analysis on the financial forecast and facilitate greater insight on the risks associated with each Business Case. Crystal Ball calculated the range of potential system average rate outcomes and the related sensitivities to the key inputs and assumptions for each

Business Case. This analysis and insight allows for the comparison of the Business Cases based on the projected system average rates and amount of risk embedded in the projected results. Crystal Ball also provides insight and analysis into the sensitivities of each Business Case to the key inputs and variables. Identifying sensitivities allows LE to potentially mitigate risk by hedging against the input driving the volatility in the results.

For example, the financial model and forecasted average rates may show one Business Case to be the lowest cost; however, it also carries the highest level of uncertainty or risk. Further evaluation of the results may show the low cost Business Case is highly dependent on a single volatile market price or input. Once the driver for the uncertainty or risk is identified, LE could mitigate that specific risk to reduce the risk and increase the probability that the Business Case will remain the lower cost option.

### Key Inputs and Assumptions Selected for Risk Analysis

In performing the risk analysis, the Project Team identified several key inputs and assumptions that have a material effect on the system average rate results. Additional analysis of the historical behavior of each input led to the selection of the probability distribution for the uncertainty associated with the data. The key inputs with associated probability distributions used to evaluate the risks associated with Business Cases are summarized in the following table.

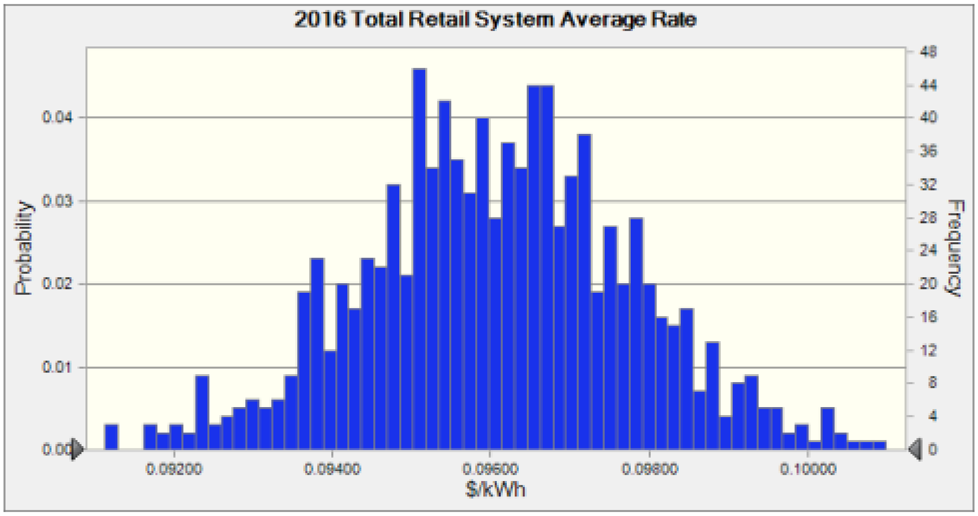
**Table 3-10: Key Inputs with Associated Probability Distributions**

| Input Variable | Distribution |
|---|---|
| Inflation | Lognormal |
| Natural Gas Price | Gamma |
| Coal Price | Maximum |
| Fuel Oil Price | Gamma |
| $NO_x$ emission allowance costs | Lognormal |
| $SO_2$ emission allowance costs | Lognormal |
| $CO_2$ emission allowance costs | Lognormal |
| Municipal Bond Interest Rates | Beta |
| Fixed Production Operating Costs | Normal |

Detailed information pertaining to each of these can be found in Appendix D

## Risk Analysis Results and Comparisons

Crystal Ball runs a simulation for each Business Case using the inputs and probabilities listed above to calculate the potential outcomes for the system average rate. In addition to calculating for the system average rate, the simulation also tracks the results for a number of other key metrics such as DSCR, reserve levels, and wholesale rate revenues. Below is a representative histogram for the system average rate simulation for Business Case 1 in 2016.




| Statistics: | Forecast values |
|---|---|
| Trials | 1,000 |
| Base Case | 0.09087 |
| Mean | 0.09249 |
| Median | 0.09162 |
| Mode | --- |
| Standard Deviation | 0.01204 |
| Variance | 0.00015 |
| Skewness | 0.4136 |
| Kurtosis | 3.22 |
| Coeff. of Variation | 0.1302 |
| Minimum | 0.06285 |
| Maximum | 0.14622 |
| Range Width | 0.08336 |
| Mean Std. Error | 0.00038 |

**Figure 3-19: Example Crystal Ball Histogram Output, Business Case 1, 2016 System Average Rate Results**

In 2016, the expected mean system rate is $0.09249 per kWh; the mean rate is 1.8 percent higher than the Base Case average system rate of $0.09087 per kWh as described earlier in this Report. In general, the simulation analysis yields average system rates that are slightly higher than the Base Case for each of the four business cases analyzed. This result is due to the aggregate influence of the various distribution parameters on each variable in the simulation analysis. Further, in 2016, the expected mean system rate can vary by ± $0.01204 per kWh (one standard deviation from the mean) depending upon the deviation of the various assumptions from the base value. Therefore, the 2016 average system rate may vary from $0.08044 to $0.10453 per kWh with a confidence level of approximately 68 percent. A higher confidence level, at 95 percent would include two standard deviations from the mean or $0.06840 to $0.11657 per kWh.

With each year, Crystal Ball simulates possible outcomes and develops an overall mean and standard deviation or uncertainty associated with each Business Case. Figures 3-20 through 3-23 illustrate the mean system average retail rate for electricity and the uncertainty with each Business Case over the Study Period. The following graphs shows the mean system rate with an uncertainty band equivalent to two standard deviations yielding a confidence level of approximately 95 percent. As the projection of average system rates moves farther into the future, uncertainty related to the various assumptions used in the forecast grows. Therefore, the uncertainty surrounding mean system rates in 2016 is $0.02408 (two standard deviations from the mean) per kWh as previously discussed and is $0.04793 per kWh in 2034. Uncertainty nearly doubles over the Study Period.

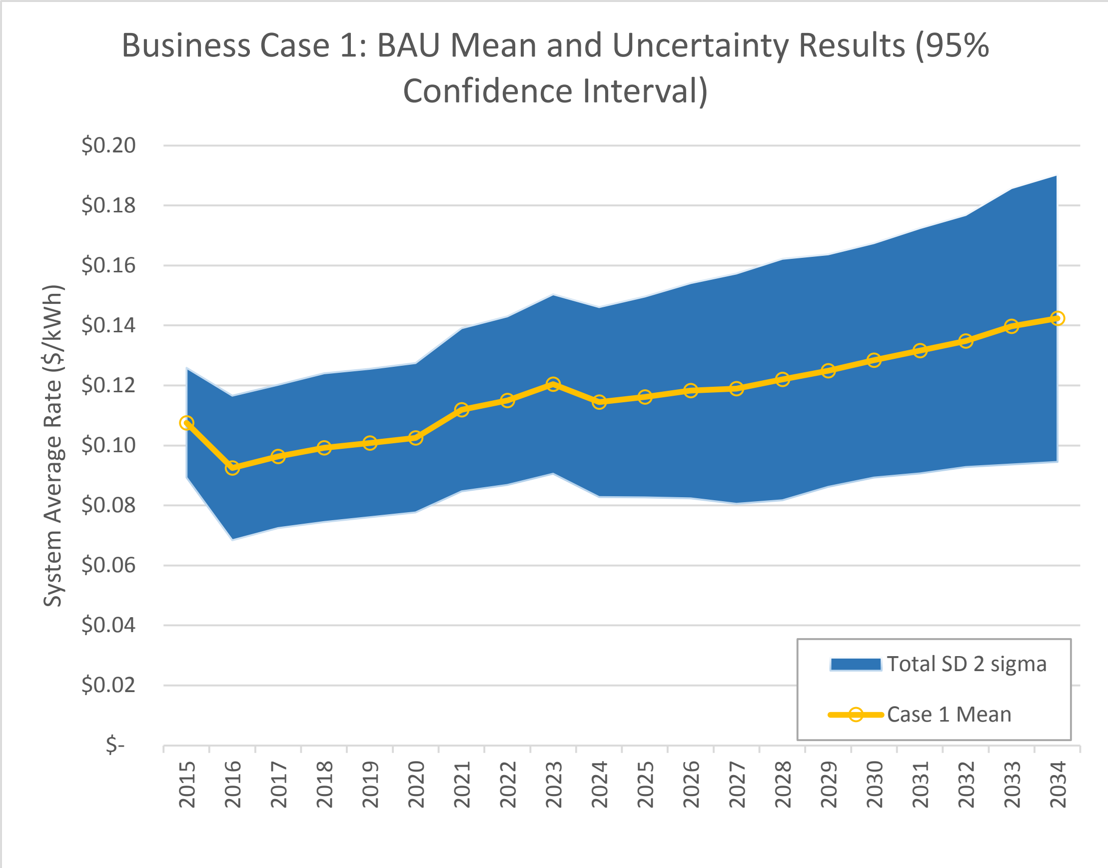



**Figure 3-20: Business Case 1 System Average Rate and Uncertainty Results**

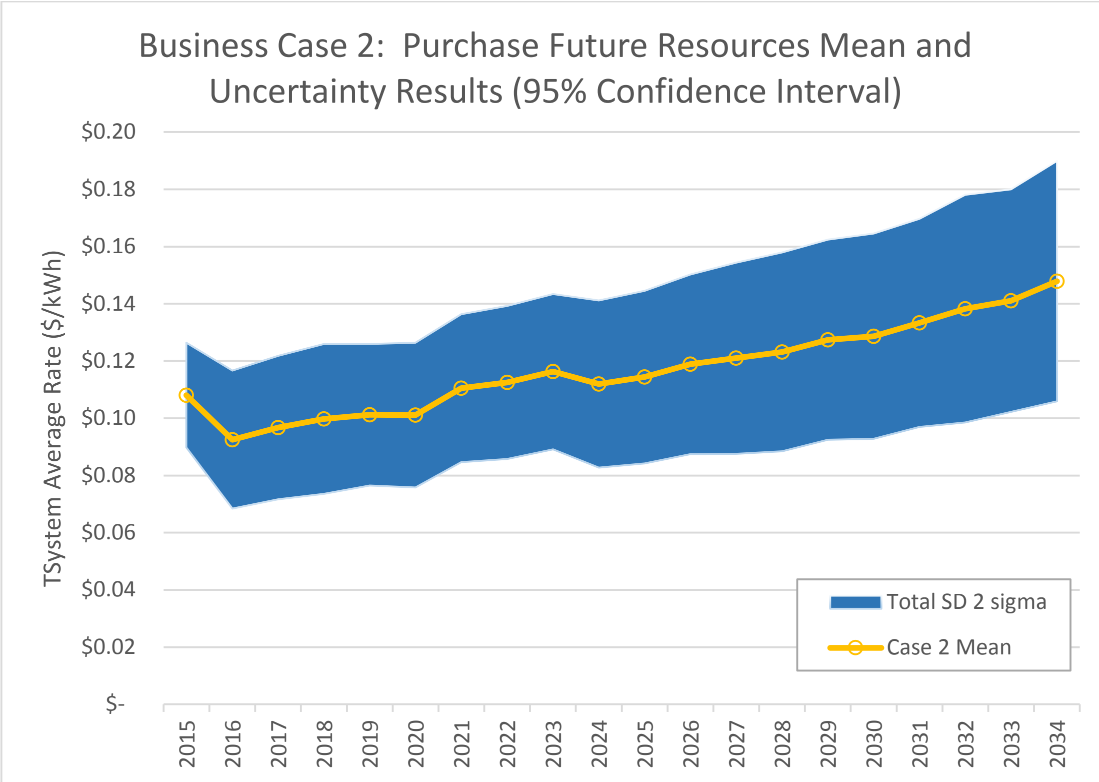



**Figure 3-21: Business Case 2 System Average Rate and Uncertainty Results**

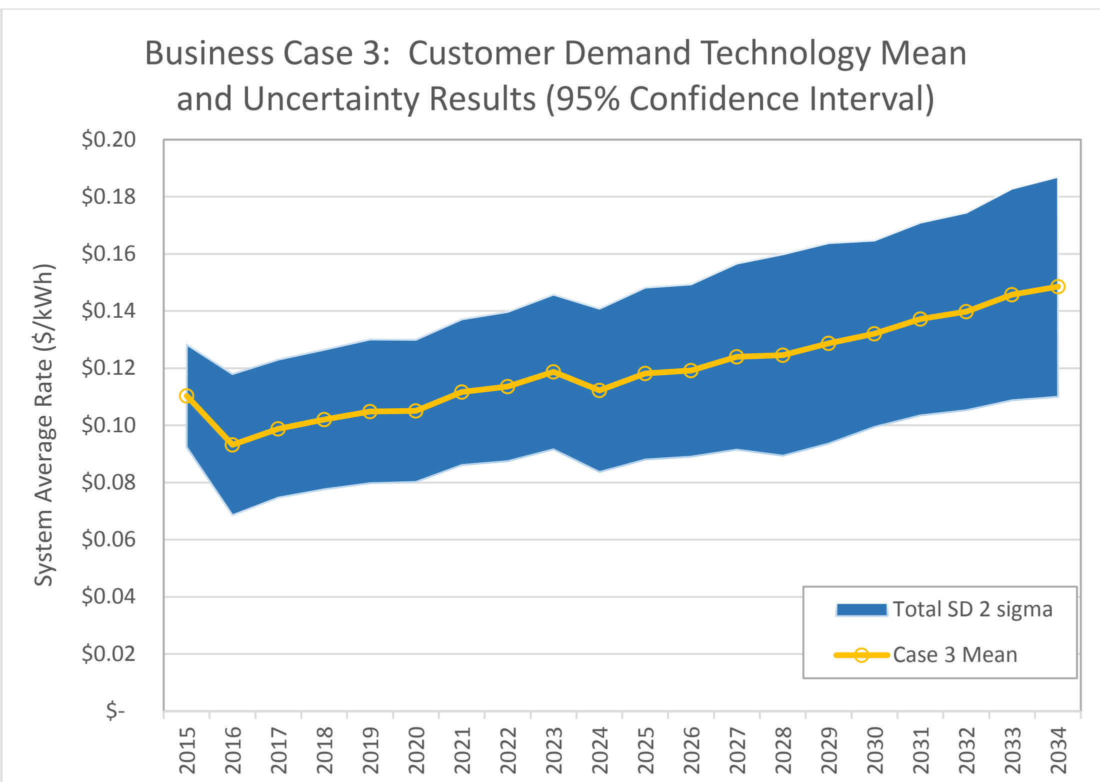



**Figure 3-22: Business Case 3 System Average Rate and Uncertainty Results**

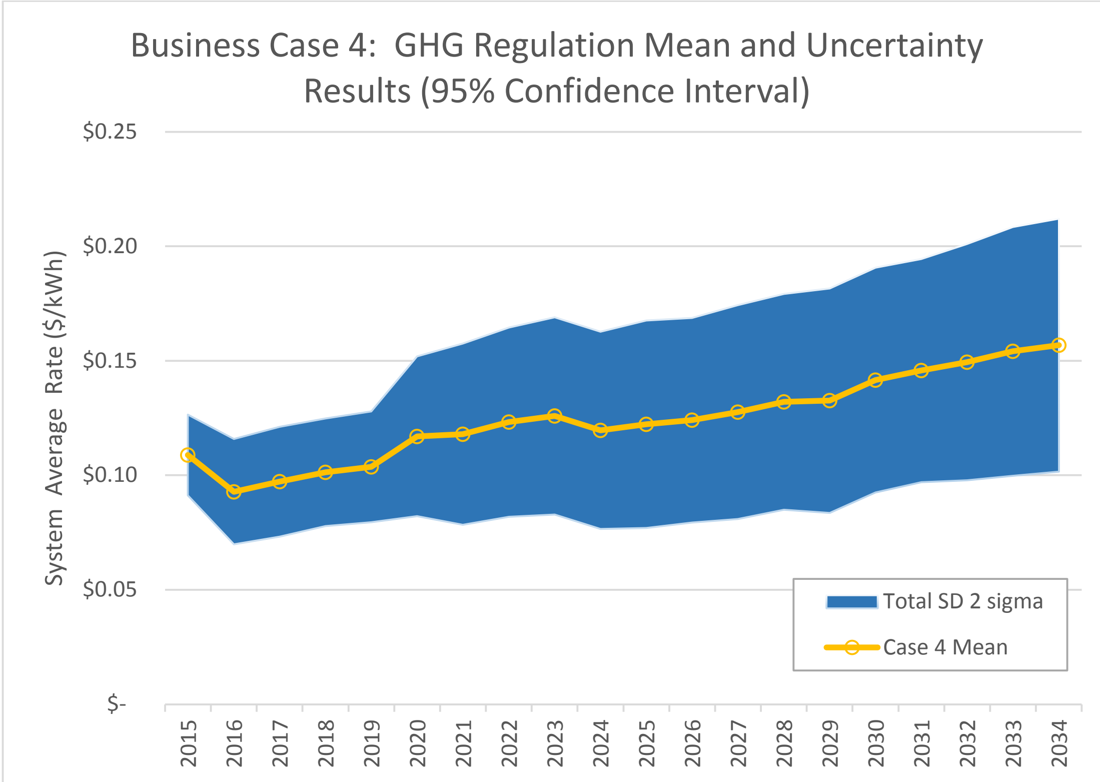



**Figure 3-23: Business Case 4 System Average Rate and Uncertainty Results**

A comparison of the expected mean average rate for each case is as follows:

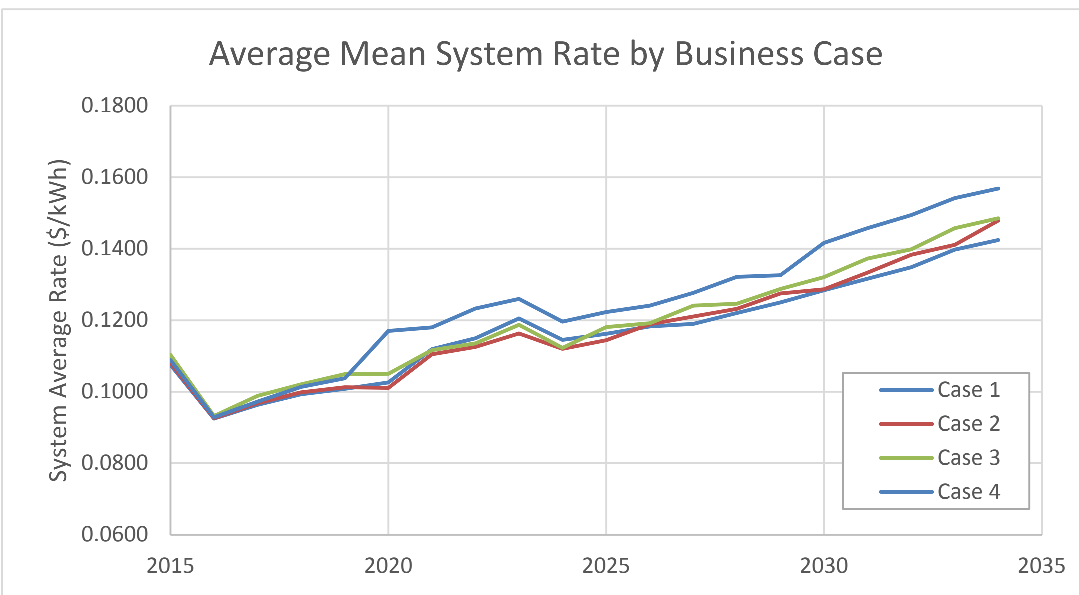



**Figure 3-24: Average Mean System Rate by Business Case**

Simulation results indicate the Business Case 1 and 2 yield similar results with Business Case 1 resulting in slightly lower average system rates over the period, Business Case 4 yields the highest average system rate with Business Case 3 being in the middle of the cases analyzed. Note that all cases are similar through 2019. After 2019, assumptions related to load growth, carbon emission taxes and generation expansion alternatives manifest themselves in the financial forecast.

As described earlier in this Section, standard deviation is a measure of risk associated with each business case. The following graph compares the standard deviation of each business case.

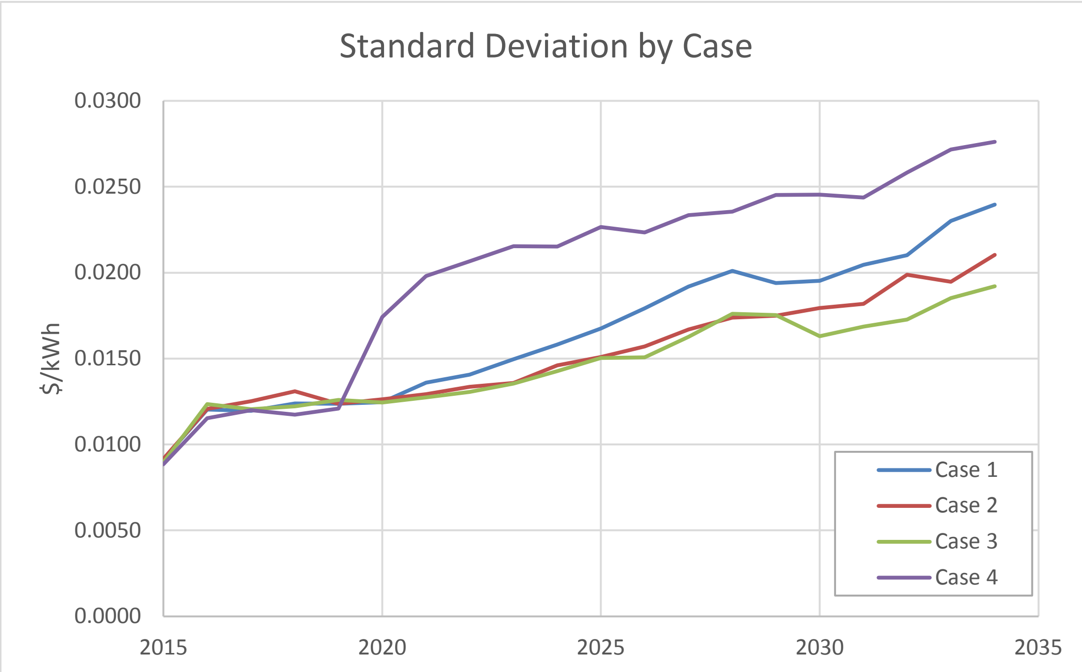



**Figure 3-25: Standard Deviation by Business Case**

A risk analysis indicates that the projected average system rates associated with Business Cases 2 and 3 are more certain than Cases 1 and 4. This result is due to the following factors:

- Volatility associated with carbon emission tax add significant uncertainty to Business Case 4.
- The capital cost associated with a new CT and repowering Mac 2, add uncertainty to Business Case 1 compared to Business Case 2.
- Lower uncertainty associated with Business Case 3 can be attributed in part to lower system demand and energy requirements thereby reducing exposure to power market volatility compared to Cases 1 and 2.

As the Crystal Ball simulation is completed for the full Study Period, the simulation creates summary calculations and data to compare the results for each Business Case. The NPV of the system average rate revenues is an easy and accurate way to compare the results for each Business Case. The NPV summary data provided calculates a 2014 present value of the 20 years of system retail revenues for each case in addition to related probability and risk metrics. These additional metrics provide insight into the average NPV, standard deviation (e.g., uncertainty), and probability of results (e.g., 90 percent of results within a range). Table 3-11 and Figure 3-26 compares the key metrics outcomes of the NPV calculation for each case.

The NPV of the system average rate revenues is an effective way to compare the system average revenues for each Business Case. The lowest NPV among the Business Cases will identify the lowest overall system rate revenues for the full 20-year Study Period. Similarly, the highest standard deviation among the Business Cases will identify the highest risk alternative for the Study Period.

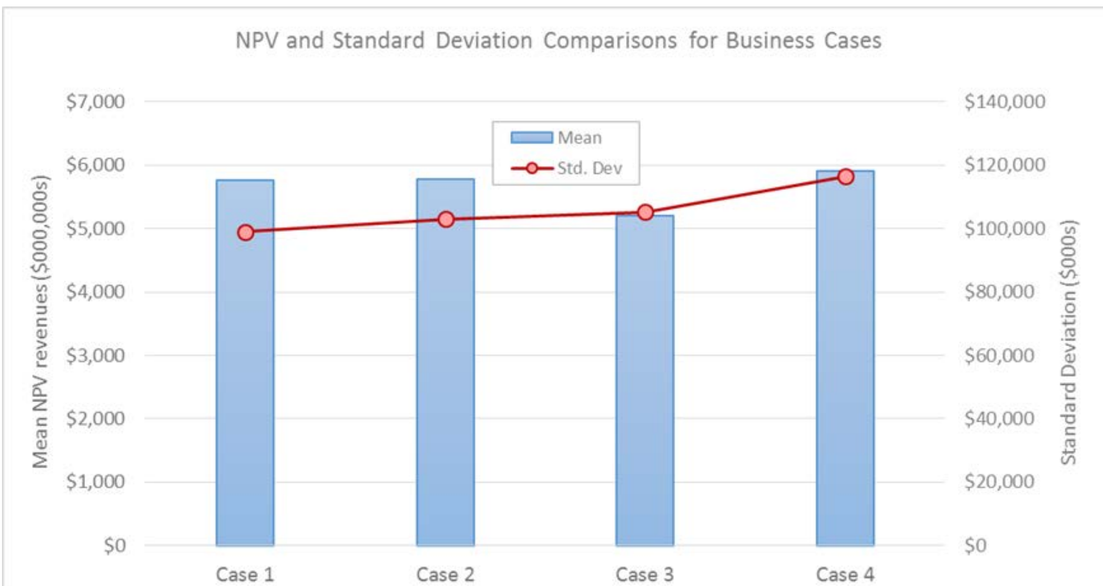



**Figure 3-26: NPV and Standard Deviation Comparisons**

**Table 3-11: NPV and Probability Results for Business Cases**

| Business Case | NPV Effective Average System Rate ($/kWh) | Mean NPV of Retail Revenues ($000) | Standard Deviation ($000) | 2X Standard Deviation Approximate 95% Confidence Interval Range of Values ($000) |
|---|---|---|---|---|
| 1. Build New Resource | $0.1139 | $5,766,466 | $98,980 | $5,568,486 to $5,964,406 |
| 2. Purchase New Resources | $0.1140 | $5,776,578 | $103,099 | $5,570,381 to $ 5,982,775 |
| 3. Customer Demand Technology | $0.1152 | $5,198,528 | $105,214 | $4,988,099 to $5,408,956 |
| 4. GHG Regulations | $0.1204 | $5,901,586 | $116,498 | $5,668,590 to $6,134,581 |

Based on the NPV results, Business Case 3 has the lowest NPV for the 20 years of retail revenues while Business Case 4 has the highest NPV. The lowest NPV does not directly translate to the lowest rate of the four Business Cases. As discussed previously with Figure 3-18 Business Case 3 had the second highest system average rates; however, it also has the lowest NPV of annual retail revenues. Business Case 3's slightly higher average rates and lowest overall NPV of revenues is driven by the reduction in overall load and consumption in the case. Under Case 3, customers have higher rates but lower power bills.

Comparing the standard deviation of the Business Cases also sheds insight on which case has higher volatility or risk in the revenue results. For example, the higher the standard deviation, the higher the potential uncertainty or range of forecasted values. Business Case 4 has the highest standard deviation at $116,498,000. Standard deviations associated with Business Cases 1, 2 and 3 are similar but vary slightly compared to the risk comparison shown in Figure 3-25 above. This difference is attributable to the NPV calculation, which weights variations in the early years of the analyses greater than in the later years. For example in Figure 3-25, Business Case 3 has the lowest standard deviation over the period with measurable lower standard deviation from 2029 and beyond. However, in review of NPV's for each business case, Business Case 1 is less volatile. This result is due to lower volatility in the early years of the forecast compared to volatility in the later years.

Business Cases 1 and 2 are directly comparable as many variables or inputs were equal in both Business Cases such as load and regulatory requirements. These two Business Cases focused on different approaches to serving LE's load. Business Case 1 builds new resources, while Business Case 2 purchases power in the market. Both Cases result in similar mean system rates over the Study Period. Each case has a different risk profile as Case 1 has more volatility beyond 2022 when new the generation projects are completed. Compared to Case 2, this volatility is associated with the cost of capital. Case 2 has more NPV volatility over the Study Period due primarily to greater exposure to power market prices compared to Case 1.

## Financial and Risk Analysis Conclusions

Of the two market condition Business Cases, Business Case 4 results in the highest system average prices and NPV. Also, Business Case 4 has the highest degree of uncertainty in projected costs. This uncertainty is attributable to assumptions surrounding future carbon emission taxes. Under this case, average system rates can range from as low as $0.10 per kWh to over $0.21 per kWh by the end of the Study Period. At the high end of the range, average system rates could be 10 percent greater than the other three cases. While rates at 10 percent higher than other scenarios is not desirable, under conditions where carbon emission taxes are high, this incremental cost appears to be manageable and is not significantly higher than the other Business Cases as initially expected. This illustrates LE may be positioned well and can address coming GHG regulations while remaining competitive in the market and serving customers.

The results for Business Case 3 illustrate how overall revenues, and likely the bills of customers, will decrease slightly with a dramatic increase in the adoption of demand side technologies. While revenues decline for LE, the combined effect of added costs for demand side technology programs with demand destruction results in a modest increase in rates. Upward pressure on rates is somewhat mitigated as LE meets future power supply needs with market purchases without the need for new significant capital investments. The reductions in customer demand and energy are driven by modest investments in DSM programs. In short, under Case 3, LE keeps fixed costs in check, thereby relieving much of the upward rate pressure. However, in pursuit of this strategy, LE must closely manage fixed costs and ensure that rate structures align with the underlying nature of fixed and variable costs.

If customer loads (demand and energy) decrease significantly, as depicted for Business Case 3, revenue from energy-based rates will decline. If LE's customer rates are not structured properly, this reduction could lead to a significant under-recovery of costs. Because of the modest investment required to achieve reduced load growth, this case yields the most certain projection of average system rates. LE reduces exposure to market prices, carbon emission taxes and the cost of large capital projects in Business Case 3. In addition, LE has slightly more control over the impacts of Case 3 versus Case 4. The management of fixed costs associated with exiting utility operations is under the control of LE staff unlike the price of commodities such as natural gas or the adverse cost impact of environmental regulation in Case 4.

Both of the generation resource focused Business Cases (Case 1 and 2) result in similar projected system average rates over the Study Period. However, as mentioned earlier, uncertainty surrounding the impact on retail rates differs between these two cases. In Case 1, LE makes a significant investment in new and repowered generation assets. Uncertainty surrounding the capital cost associated with these investments combined with exposure to market prices adds risk to this Business Case. In Case 1, market price exposure is weighted more heavily to market power sales associated with the new generation assets.

Conversely, in Case 2, LE meets its future power supply needs with market purchases. Without new generation assets, LE's ability to hedge volatility in market purchases with self-generation is diluted over the Study Period resulting in greater exposure to market price volatility. If LE should pursue Case 1, risk management strategies that would minimize investment and borrowing costs would mitigate upward rate pressure compared to Case 2. In both cases, the ability to buy and sell power under bilateral agreements with firm price provisions will greatly reduce uncertainty surrounding each case. However, such a strategy will yield average system rate levels that will either be above or below the market at any given time. Thus a tradeoff exists between mitigating price risk and uncertainty but potentially increasing political risk associated with customer perceptions of rates. An example of this dilemma may arise when LE rates are above other Florida utilities when market prices are unforeseen and favorable compared to exiting bilateral contracts.

# Section 4
# ENVIRONMENTAL

## Introduction

From an environmental perspective, sustainable resource plans for LE will include the monitoring of emissions, water supply management, energy and water conservation, and other environmental measures and impacts related to electric utility operations. One of the industry standard tools in monitoring and tracking environmental performance is the Global Reporting Initiative (GRI) indicators. The GRI provides LE the framework necessary to measure, track, and report on environmental performance while also benchmarking to other utilities.

The environmental performance of the SRP will be driven by decisions related to the selection of the generation resource technologies from which LE will provide the energy needs of the community. Environmental regulatory compliance, such as air and water emissions will continue to grow in importance both from a physical and financial perspective. The environmental section of this study concentrates on the key environmental regulatory issues that may affect potential generation resource additions/modifications contemplated in the four Business Cases being evaluated.

LE's generating units are subject to federal, state, and local laws, regulations, and policies, some of which are currently uncertain, as they are in the process of development and promulgation. The following regulatory assessment provides an overview of the major regulatory trends and environmental policies being pursued at the federal level with corresponding observations as they may be relevant to the LE generation resources and assets and similar units that may be considered for LE's future generation resource portfolio.

In support of the SRP and Roadmap, the Project Team gathered data and performed an initial assessment of LE's potential to report on environmental performance based on the GRI indicators. The Project Team requested key environmental data that facilitates broader sustainability reporting, benchmarking performance with other utilities, and will allow LE to monitor and track performance over time. The GRI was used as an initial framework to identify potential environmental performance indicators. The GRI is widely considered an industry leading and best practice sustainability reporting tool. These initially recommended environmental reporting indicators include:

- Emissions (GHG related, $NO_x$, and $SO_2$)
- Vegetation management
- Material used (weight/volume)
- Energy consumption within the organization
- Efforts to provide EE and renewable energy based products
- Water use and source

- Waste/disposal
- Habitat restoration/environmental protection

Utilizing these categories, LE can assess current and track future performance to better track, manage, report, and optimize environmental performance. For each category, multiple indicators and a discussion of the data required to generate annual metrics for each indicator have been provided.

Appendix E includes a detailed summary of the above GRI environmental indicators and their related metrics for reporting on performance. Where possible, the Project Team provided current fiscal year (FY) 2014 data and performance. In addition to performing a baseline assessment with the GRI indicators, a more detailed environmental compliance assessment was included to support the evaluation of current LE generation assets, future options and potential compliance costs or issues.

## Existing Resource Characteristics

The LE generation fleet is currently comprised of three fossil fuel-fired power plants: Larsen, McIntosh and Winston. Generating resources include one coal-fired steam unit (jointly owned with OUC), two natural gas-fired steam units, two CC units, three CT units, and 22 internal combustion units. Five of the LE generating units are nearing the end of their useful lives and for the purposes of this SRP, were assumed to be retired by the start of the Study Period. These units are the Larsen CT Units 2 and 3, McIntosh Diesel Units 1 and 2, and McIntosh Steam Unit 1. Additionally, for Business Cases 2, 3 and 4, McIntosh Steam Unit 2 is assumed to be retired by November 2020. For Case 1, the boiler for McIntosh Unit 2 is assumed to be retired by November 2020, while the steam turbine and electric generator is assumed to be retained for repowering as a CC resource by November 2022.

Based on study information provided by LE, those units of the LE generation fleet that are not modeled as being retired and available to meet LE generation resource needs can generally be described as follows:

- Larson Unit 8: this nominal 120 MW natural gas or distillate fuel-fired one-by-one combustion turbine combined cycle facility comprised of a GE Model PG7111 Frame 7EA combustion turbine and unfired HRSG installed in 1992 providing steam to a preexisting steam turbine electric generator. The CT is equipped with low-NOx burners and water injection to reduce $NO_x$;
- McIntosh Unit 2: this nominal 115 MW natural gas and oil-fired steam unit commenced operation in 1976. McIntosh Unit 2 utilizes exhaust gas recirculation to help control for $NO_x$, and uses sewage plant effluent to meet cooling tower makeup demands;
- McIntosh Unit 3: this nominal 365 MW pulverized bituminous coal-fired unit commenced operation in 1982. McIntosh Unit 3 is equipped with a selective catalytic reduction (SCR) system (installed in 2009), low $NO_x$ burners, overfire air, a wet flue gas desulfurization (FGD) system, an electrostatic precipitator (ESP), and uses sewage plant effluent to meet cooling tower makeup demands.

- McIntosh Unit 5: this nominal 360 MW unit consists of a one-by-one, NG-fired Westinghouse 501G CT CC facility equipped with an SCR system, CO catalysts, and a wet cooling tower. McIntosh Unit 5 commenced commercial operations as a CC facility in 2002.
- The Winston Peaking Station: this station consists of 20 EMD reciprocating engines fueled by #2 distillate fuel oil, each driving a 2.5 MW generator for a total installed capacity of 50 MW. The plant is equipped with an SCR system and commenced commercial operations as a peaking facility in 2002.

# Regulatory Assessment

## Proposed Greenhouse Gas Rulemaking

As directed under the Climate Action Plan, on September 20, 2013 the EPA released proposed New Source Performance Standards (NSPS) for new coal-fired power plants and stationary combustion turbines that will effectively require carbon capture and storage (CCS) technology on new coal-fired generation. As this rulemaking is directed towards newly-constructed electrical generators, it will not have an impact on LE's existing units. As resource modeling does not contemplate any new coal-fired generation, this rulemaking is not anticipated to have a future effect for the plans LE is currently considering.

On June 2, 2014, the EPA released its proposed guidelines for $CO_2$ emissions from existing power plants, titled the Clean Power Plan (CPP) Proposal, effectively requiring a 30 percent reduction in annual $CO_2$ emissions from fossil fuel-fired power plants from 2005 levels by the year 2030. Under the proposed rulemaking, individual states are required to prepare and submit implementation plans outlining how they intend to achieve the required levels of emissions reductions. These are due to the EPA for review and approval by June 30, 2016 (with provisions for up to two years of extension provided). The goals, in the form of adjusted output-weighted average pounds of $CO_2$ per net MWh emission rates, are state specific and Florida was generally within an average range of projected $CO_2$ intensity, with a Final Goal of 740 pounds of $CO_2$ per net MWh. This is an approximate 40 percent reduction from Florida's 2012 fossil fuel-fired carbon intensity rate of 1,238 pounds of $CO_2$ per MWh.

The following four basic areas were identified by the EPA as viable means to achieve the mandated $CO_2$ reductions: i) improving power plant efficiency and heat rates (i.e., inside-the-fence improvements); ii) reducing dispatch of carbon-intensive coal units; iii) adding low and zero $CO_2$ generation capacity (i.e., renewable energy sources); and iv) reducing energy demand by increasing demand-side energy efficiency. Each state's adjusted emissions factor is to be based on the degree of emissions limitations achievable through the application of the "best system of emission reduction" (BSER) (as defined under the Clean Air Act), using the four "building blocks" discussed above. According to the proposed guidelines, states maintain the discretion to either burden existing generators or develop other programs, such as renewable energy or DSM, to decrease state-wide $CO_2$ intensity. Examples of other alternative measures include cap-and-trade, renewable portfolio standards, NG-fired CC units, nuclear, and carbon capture and sequestration. The EPA's four proposed building blocks are broad and expansive relative to past BSER determinations, which are typically facility specific and pertain to "inside-the-fence" controls.

States can also endeavor to adopt a "mass-based" $CO_2$ target, which would be needed to support a market- based trading scheme. Market based cap-and-trade, whether limited to a single state or combined in a multi-state program, is one approach that can be proposed, although some sources indicate that past court precedent does not interpret cap-and-trade programs to satisfy BSER.

The CPP affords significant discretion at the state level to address the required emissions reductions. The EPA plans to finalize the proposed rule by June 2015, with state plans due to the EPA during the 2016 to 2018 period. Interim Goal compliance obligations commence in 2020, as proposed.

While it is reasonable to assume appeals and legal challenges will ensue to oppose the EPA's latest GHG proposals, a recent U.S. Supreme Court ruling in June 2014 upheld the EPA's statutory authority to regulate GHG under the federal Clean Air Act; however, the ruling placed limits on this authority, redefined some of the EPA's prior legal interpretations relevant to GHG policy, and involved stationary source permitting, not NSPS or Clean Air Act Section 111(d) (relevant to the CPP), which are regulated under separate Clean Air Act framework.

## Mercury and Air Toxic Standards

The technology-based Mercury and Air Toxic Standards (MATS) Rule published in February 2012 is intended to control emissions of hazardous air pollutants (HAPs) from coal- and oil-fired power plants with a capacity of 25 MW or greater by setting limits on mercury, along with particulate matter and hydrochloric acid as "surrogates" of HAPs. The EPA issued an updated final rule on March 28, 2013 that did not change requirements for existing power plants. The MATS rule generated concern from the power industry due to the stringency of control technology requirements, the absence of emissions trading as a compliance option, and a statutorily constrained compliance deadline of up to four years (ending in 2015). The MATS rule was recently upheld by the U.S. Court of Appeals in April 2014.

Under a worst-case scenario, wet or dry FGD and sophisticated baghouse systems may be required, while under different circumstances less costly dry sorbent injection (DSI), activated carbon injection (ACI), or dry scrubbing options combined with existing downstream particulate matter control (e.g., ESPs or fabric filters) can achieve the required levels of HAPs reduction. FGD requires greater initial capital investments, whereas DSI requires greater operating expenditures resulting from sorbents supply and increased waste disposal.

## Cross State Air Pollution Rule

As a total replacement of the existing Clean Air Interstate Rule (CAIR), the Cross State Air Pollution Rule (CSAPR) was promulgated to further limit emissions of $NO_x$ and $SO_2$ in Midwestern and Eastern states through market-based emission allowance trading. On August 21, 2012, the D.C. Circuit Court vacated CSAPR implementation whereby policies under CAIR temporarily remained in effect while the EPA develops an acceptable replacement. On April 29, 2014, the U.S. Supreme Court overturned this ruling, and on October 23, 2014 the D.C. Circuit Court lifted the stay on CSAPR and Phase 1 implementation of CSAPR began January 1, 2015. Under CSAPR, facilities are required to either install additional pollution control equipment or purchase allowances to meet the required levels of $NO_x$ and $SO_2$ emission reductions.

The above-mentioned HAPs abatement systems significantly aid in $SO_2$ reductions and will therefore improve a facility's ability to comply with the proposed CSAPR or other ozone cap-and-trade programs.

## Coal Combustion Residuals Rule

Historically coal ash has been classified as exempt waste under the Resource Conservation and Recovery Act (RCRA). The Coal Combustion Residuals Rule (CCR Rule) is to create for the first time, requirements under RCRA for the disposal of coal ash generated by power plants. Two options are currently being contemplated: 1) regulate coal ash as "special hazardous waste" under RCRA Subtitle C; or 2) regulate coal ash as "non-hazardous waste" under RCRA Subtitle D. Regulating coal ash as special hazardous waste would effectively require closure of wet ash surface impoundments and force facilities using wet ash handling systems to close, or convert to dry ash handling and disposal. If regulated as non- hazardous waste, wet ash impoundments would likely require stringent design standards and monitoring protocol. Although the EPA has not announced a date on which it intends to issue the final CCR Rule, it is under pressure to do so expeditiously as many environmental groups have filed suit.

The CCR Rule proposes the elimination of wet coal-ash handling systems and the closure and decommissioning of wet ash impoundments. The proposed facility and operational modifications include bottom ash conversion, fly ash conversion, wastewater treatment upgrades, and impoundment remediation and closure. After such changes, ash disposal operating costs are largely contingent upon land availability, disposal fees, transportation, and existing equipment.

Based on topical industry opinion, coal ash waste is not expected to be regulated as hazardous waste; however, the rule could impose additional operating requirements and capital upgrades.

## Clean Water Act 316(b) Thermal Power Plant Cooling Water Intake Structure Rule

The Clean Water Act 316(b) Thermal Power Plant Cooling Water Intake Structure Rule (the "316(b) Rule"), which was issued by the EPA as final on May 19, 2014, was developed to reduce impingement (trapping) and entrainment of aquatic organisms in cooling water intake structures and reduce the thermal heating of natural water bodies from facilities utilizing "once-through" cooling technology that have a design intake flow greater than two million gallons per day (mgd) of water (and use at least 25 percent of this water for cooling purposes). Affected existing facilities are required to conduct studies to assess Best Technology Available options on a site-specific basis.

Compliance with the 316(b) Rule could require relatively low-cost cooling water intake structure retrofits such as wedge wire screens, low-velocity caps, and variable-speed pumps or more capital-intensive options including traveling screens and complete cooling tower installations. As the authority to regulate technology requirements under the 316(b) Rule resides with state permitting agencies, compliance costs will vary depending on location and unique site characteristics.

### Revised Power Plant Effluent Limitation Guidelines

Revised Power Plant Effluent Limitation Guidelines (ELGs) are national standards, based on the performance of wastewater treatment and control technologies for wastewater discharges to surface waters or municipal sewage treatment plants, which are enforced through National Pollutant Discharge Elimination System permits. Revised ELGs for steam-electric power generation facilities are currently in draft proposal form and were to be finalized in May 2014; however, this deadline was missed and it is understood that the EPA is in the process of negotiating a new timeframe for promulgation. The ELGs are to regulate wastewater, wet FGD discharges, CCR leachate, and discharges from coal waste storage sites, among other waste streams.

### National Ambient Air Quality Standards

The EPA is required under the Clean Air Act to set National Ambient Air Quality Standards (NAAQS) for six pollutants that endanger public health ("primary" NAAQS) or welfare ("secondary" NAAQS). While NAAQS does not directly regulate emissions, the primary NAAQS does identify ambient pollutant concentration levels that must be achieved to protect public health and secondary NAAQS are established to protect broadly-defined public welfare. Upon finalization, the EPA, using monitoring data and other information submitted by local and states agencies, identifies areas that exceed NAAQS (i.e., non- attainment areas). State and local governments generally have three years to prepare State Implementation Plans to outline their proposed methodology to reduce emissions and ultimately achieve "attainment" status. The timing for NAAQS compliance deadlines vary depending on location and level of pollutant concentrations.

### Reciprocating Internal Combustion Engine National Emissions Standards for Hazardous Air Pollutants

The Reciprocating Internal Combustion Engine National Emissions Standards for Hazardous Air Pollutants (RICE NESHAP) rule targeted emissions of CO as surrogates of HAPs and required augmentation/installation of CO catalysts, in addition to other engine retrofit and maintenance requirements.

## Baseline Assessment

To evaluate the potential impacts and risks to LE's generation resources, it was assumed that the SRP production simulation modeling plans for the retirement of the following units in all four of the Business Cases as of January 2015: Larsen Unit 2; Larsen Unit 3; McIntosh Diesels Units 1 and 2; and McIntosh Unit 1. Additionally, McIntosh Unit 2 is modeled as retired in November 2020 in all Business Cases.

With the exception of new NG combustion turbines in Business Case 1 and fuel switching in Business Case 4, all new generation forecast to meet LE capacity demand is to come from purchases. For purchased capacity, it is assumed that responsibility for all environmental requirements, including compliance obligations and credit purchases, are to reside with the plant owners, although costs for these items will presumably be reflected in the energy or capacity purchase pricing incurred by LE.

Based on these assumptions, the following represents the current assessment of LE's position in relation to the regulatory issues addressed above.

## Mercury and Air Toxic Standards

McIntosh Unit 3 is equipped with a wet FGD system and ESP, which is a positive sign relative to MATS compliance; an engineering evaluation was reportedly completed in January 2014 for particulate matter, metals, and mercury. This evaluation, in addition to stack testing performed in 2013, indicated particulate matter emissions to be below the MATS limit. LE reported that the January 2014 evaluation tested mercury emissions were at 0.018 pounds per gigawatt hour (GWh), above the 0.013 pounds per GWh MATS limit. To meet future compliance obligations, LE plans to introduce a mercury oxidation coal additive and an FGD system additive to reduce mercury re-emission. Optimization and performance testing of the additives will be required to achieve the desired mercury reductions. $SO_2$ emissions were similarly above the MATS threshold, and LE expects an FGD upgrade planned in the spring 2015. McIntosh Unit 3 outage is to bring levels below the MATS limit.

## Cross State Air Pollution Rule

We note that McIntosh Units 3 and 5 both have SCR systems, which significantly reduce NOx emissions, and McIntosh Unit 3's FGD reduces $SO_2$ output. Fuel sourcing $SO_2$ content consideration is another compliance option for McIntosh Unit 3 to the extent future $SO_2$ reductions are required. Market-based trading for ozone related pollutants will ultimately increase the operating costs of higher-emitting coal sources, such as McIntosh Unit 3, relative to NG-fired generators.

## Coal Combustion Residuals Rule

We understand that McIntosh Unit 3 coal ash is either sold for beneficial re-use or stored. Additional consideration of McIntosh Unit 3's coal ash handling, storage, and disposal methodology will be needed when the EPA's regulation intent is further defined in the future.

## Clean Water Act 316(b) Thermal Power Plant Cooling Water Intake Structure Rule

While we understand certain LE generating units utilize once-through cooling systems in conjunction with surface water bodies, which would require "closed-loop" or U.S. jurisdictional water agency determinations, McIntosh Units 2, 3 and 5 have cooling towers and would therefore not be materially affected by the 316(b) rulemaking. Larsen Unit 8, which utilizes once-through cooling technology, is currently permitted under the NPDES Program with the State of Florida.

## Revised Power Plant Effluent Limitation Guidelines

While we understand that the McIntosh Plant has "zero discharge" wastewater treatment capabilities, wastewater and CCR disposal practices will need to be analyzed for compliance with the new ELG standards once they are finalized.

## National Ambient Air Quality Standards

The City of Lakeland, Florida is located in Polk County, which is currently designated as an attainment area with all current NAAQS. In recent years the EPA has promulgated a number of revised NAAQS including primary $NO_x$ and $SO_2$, particulate matter (2.5 microns), and ground-level ozone, among others, that could potentially impact certain generators in Polk County if this attainment status is compromised.

## Reciprocating Internal Combustion Engine National Emissions Standards for Hazardous Air Pollutants

Compliance deadlines have passed, and we understand that the CO catalysts at the Winston Peaking Station were recently replaced. While LE has reportedly completed some internal engineering evaluation and testing with positive results relative to the RICE NESHAP, initial emissions testing on some of the Winston Peaking Station units is scheduled during the fall of 2014. To the extent non-compliance is demonstrated, further CO catalyst improvements or augmentation could be required.

## Regulatory Impacts and Risk Exposure to Lakeland Electric Generation

Based on the study's current understanding of McIntosh Unit 3's configuration, its principal distinguishing factors for non-GHG initiatives include a wet FGD system and planned MATS compliance upgrades, an SCR system, ESP, cooling tower, and zero discharge wastewater capabilities. While any future market based carbon or ozone cap-and-trade schemes would certainly increase McIntosh Unit 3's operating costs and make it less competitive relative to lower emitting NG-fired generators, it is still reasonably well positioned compared against other coal-fired power plants with lesser equipped pollution controls. In determining the state specific $CO_2$ reduction goals under the CPP, each state's total generation from coal was reduced by six percent, which brings the potential for McIntosh Unit 3 curtailment in the future; however, discretion of the methods to achieve the CPP goals reside at the state level in forthcoming compliance plan, as discussed in the *Proposed Greenhouse Gas Rulemakings* outlined in the *Regulatory Assessment* section. The potential for coal curtailment in Florida to meet future GHG obligations is further exacerbated by the state's currently limited utility-scale renewable energy initiatives (i.e., solar and wind). Although modeling results indicate little dispatch from Larsen Unit 8, the 316(b) Rule poses potential material impact to this facility due to its use of once-through cooling.

While a detailed compliance evaluation of LE's generation units was not within the scope of the study, based on publicly available databases and compliance information provided by LE, from a technical and environmental perspective it appears that McIntosh Units 3 and 5, and the Winston Peaking Station should be capable of continuing operations in compliance with reasonably-foreseeable environmental obligations, with the following exceptions: i) the CCR rule has the potential to materially impact the means and methods of McIntosh Unit 3's current coal ash disposal; and ii) Florida could potentially elect to curtail or limit McIntosh Unit 3 operations in future State Implementation Plan revisions to achieve the GHG reduction standards imposed by the recently-promulgated CPP.

Relative to the new or augmented generation resources contemplated in the SRP Business Cases, the following discusses the potential regulatory impact for each of the four Business Cases.

### Business Case 1: Build Future Resource (Base Case)

The SRP modeling is considering a repowered 252.5 MW (assumed summer net) CT CC facility in November 2022. This CC unit is to be a re-powering of the existing McIntosh Unit 2, which is to be performed in stages. A 168 MW (assumed summer net) F-class CT is to be installed in November 2020, followed by the installation of a HRSG to be installed by November 2022. The HRSG is to be connected to the new CT and is to supply steam to the existing McIntosh Unit 2 steam turbine. While it is speculative to forecast the future emissions capabilities of evolving utility-scale gas turbines and associated pollution control equipment, CC generation is the most efficient means of base-load fossil fuel-fired electrical generation available at this time and major gas turbine technology providers endeavor to maintain compliance with new air pollution policies, such as NSPS, Best Available Control Technology, and New Source Review permitting requirements, among others. It is therefore reasonable to assume that deployment of new combustion turbines will be capable of fulfilling future environmental obligations.

### Business Case 2: Purchase Future Resources

This case assumes three staggered peaking capacity CT purchases in five year increments with the first purchase commencing in November 2020 and the last purchase ending in November 2035. The MW capacities (assumed summer net) during these five year purchases are 72 MW, 102.6 MW, and 127.8 MW. As discussed above, it is assumed that responsibility for environmental requirements from purchased capacity is to reside with respective plant owners and will not be a compliance obligation of LE.

### Business Case 3: Customer Demand Technology

Business Case 3 assumes no new generation capacity additions, which is assumed to result from modeled demand side energy efficiency. As discussed in *Proposed Greenhouse Gas Rulemakings*, demand side EE measures are one of the BSER options available to achieve compliance with the proposed CPP $CO_2$ goals. Other impacts from demand side energy reductions are inconsequential from an environmental compliance perspective.

### Business Case 4: GHG Regulation

Under Business Case 4, LE is assumed to purchase or acquire one or more non-solar, carbon-neutral resources. These carbon-neutral resources have been modeled to operate at relatively high capacity factors and, therefore, are likely to include ownership, joint-ownership, or purchase of capacity and energy from nuclear, biomass, and/or landfill gas (LFG) resources. LFG and biomass fired resources may be considered viable base-load renewable energy resources for LE to meet the CPP $CO_2$ reduction goals. Despite the recent expiration and vacatur of the biogenic source deferral under federal Prevention of Significant Deterioration permitting requirements, the CPP recognizes that LFG and biomass-derived fuels can be utilized to reach state-level $CO_2$ reduction goals. It should be noted, however, that the EPA is in the process of revising the framework under which emissions from LFG and biomass feedstock are assessed. It is therefore reasonable to assume this federal framework, in addition to state-level carbon reduction proposals, will outline the detailed guidelines for how $CO_2$ emissions from biomass fuel sources are considered with respect to $CO_2$ offsetting. As such, $CO_2$ offsets from LFG and biomass may not be on a 1:1 reduction ratio as is the case with wind, solar, and other renewable energy sources. The exact ratio specific to LE's purchased capacity will likely be contingent upon details of the fuel source (i.e., location, transportation, forestry management, etc.). Business Case 4 assumes a 44.7 MW (assumed summer net) zero-$CO_2$ capacity purchase commencing in January 2030.

Business Case 4 also assumes retirement of McIntosh Unit 3 coal operations in January 2020, with fuel switching to NG occurring in the same year. It should be noted that there may likely be an approximate three to six month period, or longer, required to install the retrofits and modifications to accommodate the fuel switch, which may be accounted for in the low generation forecast in 2020 for McIntosh Unit 3. While this conversion will significantly reduce $CO_2$ emissions relative to the existing coal-fired McIntosh Unit 3, the retrofitted NG-fired McIntosh Unit 3 will not reach the same heat rate efficiencies as new CC units, and will therefore be commensurately less efficient when compared to new CC generators in regards to $CO_2$ emissions on a per MWh basis.

Business Case 4 also assumes two peaking capacity CT purchases, one 59.0 MW (assumed summer net) commencing in November 2020 and ending in January 2030 and one 13.5 MW (assumed summer net) commencing in January 2030. Emissions related assumptions for these anticipated additions are identical to those in assumptions utilized for Business Case 1.

## Conclusion and Assessment of Future Needs

As discussed in the specific context of individual environmental requirements above, LE's McIntosh Units 3 and 5, and the Winston Peaking Station are generally well-suited for the EPA's current regulatory agenda relative to other aging coal units, with the exception of proposed GHG regulations where McIntosh Unit 3 does not likely have any material strategic advantages.

From an industry perspective, carbon related regulatory concerns will likely have the most significant effect on decisions relating to the use of both the existing generation resource base and future generation resources contemplated as well. As the modeling results for Business Case 4 demonstrate, LE is reasonably positioned to address these issues so long as they remain proactive in monitoring the development of future regulations and the timing of their decisions for future resource additions with reduced or carbon neutral impact.

The maintenance of proactive relationships with permitting agencies, as well as the advance planning and timely implementation of required permitting initiatives, should allow LE to both meet its future compliance requirements while maintaining its competitive business position going forward.

# Section 5
# LABOR

## Introduction

One of the few areas where an organization can clearly distinguish itself from other competitors is with their workforce, its composition, work ethic, and interaction with external and internal customers. Simply put, the people that comprise an organization's workforce should be considered critical and valuable resources.

The most critical labor issue facing LE is the current and future potential for a loss of a significant portion of the workforce. In fact, succession planning was rated in the staff survey as the most important critical success factor facing LE over the next 10 years. This issue is particularly acute in the technical areas of LE as turnover, lag time to refill vacancies, and most importantly retirement eligibility, can decimate the employee ranks in areas that are critical to the talent base required for all four Business Cases.

In addition to potential losses in the technical areas, a significant percentage of LE's internal management resources are subject to the same attrition exposure. This section addresses the current state of the workforce, characteristics of the workforce of the future under sustainable resource plan options, and suggestions for proactive approaches to address the needs and exposures identified. In support of the SRP and labor issues evaluation, the Project Team gathered data and performed an initial assessment of LE's potential report on labor related performance. The Project Team requested key labor related data that facilitates broader sustainability reporting, benchmarking performance with other utilities, and will allow LE to monitor and track performance over time. The GRI was used as an initial framework to identify potential labor related performance indicators. These initially recommended indicators include:

- Employment
- Labor and management relations
- Occupational health and safety
- Training and education

Utilizing these broad indicators and related metrics, LE can gain insight into performance through an understanding of the efforts to provide a fair, rewarding, productive, and complete employment environment. Appendix F includes a detailed summary of the above GRI labor indicators and their related metrics for reporting on performance. Where possible, the Project Team provided current FY 2014 data and performance, and guidance on future data gathering.

## Evaluation of Current Situation

The current situation for LE was developed subsequent to a detailed review of labor tracking reports, training documents, and the collective bargaining agreement with LE Workers of America union.

The following highlights primary observations related to the current labor situation. Each topic on its own can be the basis for future studies and program development. These observations are summarized below in labor agreements, training, and staffing.

## Labor Relationship

The labor relationship currently in place allows reasonable management controls over the primary labor functions and incorporates provisions that allow LE to modify, change, or adapt the labor force and its associated work practices to meet changing needs of the LE. It allows for performance-based compensation, skill development as a responsibility of the employee, and educational reimbursement provisions for accredited skill development. In addition, the contract reasonably reflects LE's societal responsibilities, particularly as it relates to employee conduct on and off the job, and storm response requirements that require work processes outside of normal operating procedures.

## Training

Current training functions concentrate on aspects of foundational and supervisory training. Foundational training concentrates on public service expectations, values, and ethics. Safety training is included in the foundational description as well. Supervisory training utilizes a multi-stage format.

It is clear that documentation exists that demonstrates the internal understanding of the type of training that would be valuable to the organization in the future. What is uncertain is the constraints that prevent implementation at this time. Typical limiting factors relate to budget constraints and the lack of the availability of time away from the normal job requirements to dedicate to the training function. Lower staffing levels and associated vacancies make the implementation of additional training programs difficult at best.

## Staffing

The most acute concern relating to the existing situation is in the staffing area. Taking into account only the professional, skilled craft, and technician classifications, the single biggest challenge LE will face in preparation for any of the Business Cases is the potential reduction in available technical resources going forward. The situation can best be described as follows:

- Over 40 percent of the technical employee base is eligible to retire at the current time
- Over 62 percent of the technical workforce will be eligible to retire in the next five years
- Over 68 percent of the technical workforce will be eligible to retire in the next 10 years

For the overall organization, there are currently 73 employees enrolled in the DROP program. Of the 73 individuals, 19 are currently in a management or supervisory position. Of the 19 individuals in management positions, 2 are at the AGM level.

In short, the potential technical resource drain will not only erode LE's technical base critical to its future, a significant percentage of LE's management core is at risk as well. These two effects, the technical drain and the management drain, affect not only the ability to meet and embrace the technical changes the future will require, but could also significantly impact the continuity of the organization at the same time.

Compounding this exposure is the lag that exists between when individuals either retire or terminate and when a new hire is brought on board. Even when excluding the amount of time a new employee requires to get up to a level of full productivity, the hiring process appears to lag the attrition by approximately 20 percent.

As turnover and retirements put pressure on all of the business units involved, it will be important for LE to address its infrastructure support services to streamline the hiring process and mitigate any unsustainable levels of vacancies that can occur.

# Gap Analysis and Assessment of Future Needs

## Lakeland Electric Workforce of the Future

Through interviews with external and internal team members, as well as key employees across a spectrum of business divisions and skill sets, the team has developed a solid understanding of the organization and its labor related functions for its current business acumen.

Recognizing that the GRI indicators selected and assessed provided a foundation for the critical activities that should be monitored in the future, the following sections are to provide LE with potential programs and processes to help to bridge the most critical gaps from a labor perspective.

From the four Business Cases analyzed during the course of this study, all four will require similar skill sets to meet LE's future needs. All four will require sophisticated IT capability, advanced electronic and instrumentation skills, computer (including mobile device) literacy, and strong oral and written communication skills. Although strong communication skills are an important requirement in any Business Case, the need becomes especially acute for Business Case 3 where there is a high level of distributed resources, more business is conducted at off-site locations, and customer and third party communications occur at a higher level than the other Business Cases potentially require.

## Employee Characteristics

LE workforce of the future will likely require the following employee characteristics:

- Flexibility
- Multi skill set orientation
- Advanced technical skill sets
- Strong oral and written communication skills

As the nature of the business and associated competitive changes that are inevitable to occur, the workforce of the future must be able to adapt to a continually changing environment and feel comfortable effectively addressing a wide and diverse range of tasks.

As it is often difficult to attract and retain a group of individual employees with this broad base of talent, particular attention will have to be paid to staffing each department/division with a combination of individuals that collectively as a group can provide the critical characteristics required.

## Infrastructure Support Requirements

## Competitive Compensation

For LE to have the ability to hire and retain a highly skilled workforce, foundational infrastructure elements must be assessed and addressed. A competitive wage package combined with a competitive and flexible benefits package are generic basics that are necessary if there is any hope of successfully competing for these individuals.

As important as these elements are, two additional elements must be considered. The first is a determination of what wage comparators should be utilized. As is often the case with City based utilities, there is tremendous pressure to manage LE wage and benefit packages to the comparators used for the City's own wage scales for municipal services.

Although this approach may provide for more convenient internal consistency, and there may be some positions that have reasonable comparators, the actual competitors for LE's labor pool often operate using a very different set of wage and benefit comparators.

With a competitive compensation achieved, the promotional policies should be structured to allow an employee to move through the structure over a reasonable period of time based on the development of critical skill sets and performance. The policies should be well defined by the company and its management team and well understood by the employee so that the benefits of the compensation program design can be best achieved.

## Responsiveness to Implementation Needs

For the future of LE, implementation needs are likely to center on two primary areas; personnel management and IT support. With a greater level of customer interaction and additional service offerings, effective achievement of these functions will require people on the ground in sufficient quantities to respond in a timely manner to customer and company needs, backed by a reliable and user friendly technology infrastructure.

From a personnel staffing perspective, the staffing and skill levels that must be maintained in this type of working environment must be both stable in numbers and balance skill sets required. Dilution of the workforce can be reduced by monitoring and managing turnover, attrition rates, and reasonably predictable attrition timing. Although the typical approach tends to center on filling vacancies when they occur, the resultant lag time can leave gaps resulting in lower responsiveness and potential gaps in expertise required to support the organizations critical functions. To the point that the lag time between vacancies occurring and new hire starts is not acceptable, it requires higher staffing levels than might be required of a pro-active approach to staffing management. With staffing costs representing a significant component of a business' cost of operation, significant economies can potentially be achieved for the long-term even though a pro-active approach may require some additional head count during transition periods.

Infrastructure support from a technology perspective includes the ability to provide the advanced technology available across the range of businesses that LE supports going forward. Examples of this support technology include; advanced diagnostic and monitoring equipment, computer hardware and software, customized IT software and systems where required, and ongoing and responsive IT support. These activities will require timely and effective support from both the procurement and IT functions of the organization. As these activities are critical to the nature of LE's future operations, these two business areas will require significant management attention from not only the policies and procedures utilized, but also the organization of these two groups and the delineation of where in the organization accountability lies.

## Communication

Communication, while typically a task utilities struggle with, is critically important to managing the workforce for the future. The communication process and its associated messages set both the culture of the organization and the effective response to changing business needs or customer requirements. The need is particularly acute considering the likely nature of the future organization to be decentralized rather than a nested group in a corporate headquarters environment. Top down and bottom up communication is critical to a nimble organization's success as it is the vehicle that instills the corporate vision in individuals that face the customers and community, and provides the necessary reconnaissance from the field to facilitate responsiveness and changes in the competitive situation.

## Decisions Related to Labor Management

If LE is to be competitive in the marketplace, it must realize that the relative size of the organization is a competitive disadvantage in relation to economies of scale. To effectively compete, it must identify and maintain the critical skill sets required, and determine how best this can be achieved. Decisions will have to be made to determine from where these skill sets will be provided. Options include self-providing through internal staff, use of third party resources, or a combination of the two. Each option carries its own risk profile requiring that this process and strategy be monitored and modified if necessary on as ongoing basis. Regardless of the methods utilized to fulfill the need, a decision on what core competencies must be maintained internal to the organization is the critical starting point and the basis for the balance of any strategy implemented.

# Bridging Gaps

## Organizational Approaches to Bridge Gaps

Mitigation of gaps in Roadmap alternatives primarily relate to addressing dilution of the workforce both in physical numbers and the critical skillsets associated with the loss of these individuals. Primary contributors to this situation are DROP program participants, employees otherwise eligible to retire, the rate and location of turnover of existing staff, and the rate of rehire to replace these individuals.

In preparing the Roadmap for the future, regardless of which Business Case (or combination of Business Cases) is selected, some fundamental organizational decisions must be addressed. These include the organizations approach to managing its core competencies, its approach to managing its ancillary competencies, and the methods by which these management plans are achieved. Methods could include developing these competencies internally, contracting to third parties, or a combination of the two approaches.

Corporate cultural issues to be addressed include how to address LE's historical self-perform preference, internal and external effectiveness of communication, and the reliance on the City for critical infrastructure related functions. The following sections will address a sampling of these critical issues and potential considerations from an overview perspective. Any or all of these suggested approaches can be studied in more detail at a later date, consistent with the preferences and priorities of the organization going forward.

## Workforce Hiring Practices for Turnover Reduction

### Organizational Responsibility for Hiring

Of the critical decisions that have to be addressed related to the hiring function, organizational placement is one of the foundational decisions required to put an effective process in place. Although the hiring function currently rests with the City, this may not be the optimal approach for the future. Although consolidation with other City functions has some advantages, a number of disadvantages potentially exist as well. These include, differing priorities within the two organizations, more customary comparators are often not applicable, and accountability for performance and responsiveness may be lacking from LE's perspective. Regardless of where it is determined that the function should ultimately reside, acceptable pre-qualification standards for employee eligibility and acceptable turnaround parameters must be established and ingrained within the hiring organization. Establishment and periodic refreshment of these standards will allow for performance monitoring and accountability regardless of where the function lies. In the case where the City retains this function, specific assignments of dedicated staff to support LE's specific needs can be a reasonably effective approach to serve LE's hiring needs.

### Approach to Staffing

A classic approach to staffing is to initiate the hiring process once a vacancy is established. As the hiring process typically takes longer than the notice period for a departing employee, gaps occur in the organization resulting in either a reduction in responsiveness/productivity of the affected business area or the generation of overtime in various proportions to the workload of the affect group. Once overtime reaches levels that approach and exceed 20 percent over extended periods of time, productivity declines and opportunity for safety related incidents increase.

A more proactive approach to staffing involves taking predictive steps to first anticipate where vacancies will occur going forward and either make provisions to build the replacement skill sets internally, develop a pool of pre-qualified employee candidates to streamline the hiring process, or use third party resources to fill in the gaps.

Two vehicles can be utilized to develop a proactive and predictive staffing program. The first is to periodically create a workforce profile starting with the current workforce, with additional forecasts of profiles at three, five, and ten-year increments. The look ahead timeframe allows the incorporation of academic and vocational programs and incentives within the community as well as sufficient time for the existing workforce to gain necessary skills if vacancies represent advancement alternatives to outside hires. On the shorter horizon, the hiring entity can begin to pre-qualify outside candidates to create a labor pool to draw from when vacancies do develop. Although the physical hiring of these prequalified outside candidates may not eliminate the lag time in hiring, the amount of lag can be significantly reduced.

A second vehicle for predictive hiring involves use of the DROP program. For the 73 employees currently enrolled in the program, each has a specific date of departure that will occur either during or at the end of the DROP period. This program basically pre-establishes where vacancies will exist and the relative timeframe within which the vacancy will actually occur. This information allows the opportunity for a well-defined, manageable, and economic succession planning function. Using the budget for a few existing staff vacancies to fund an internal pool of employees with the necessary skill sets to replace departing individuals, employees can fill vacancies faster and with less impacts on productivity than other alternative methods available to the organization.

### Workforce Related Program and Approach

#### *Compensation*

Attracting and retaining a skilled and competitive workforce will require a compensation plan consistent with plans that are designed to attract similar skill sets both in the industry and within the geographic reach of LE. As is common with many municipally based utilities, there is significant internal pressure to use comparators to other City functions. Although a few comparators may be applicable, the majority of technical positions now, and more so in the future, will likely make these internal comparators less appropriate over time.

In addition to a competitive wage structure, progression mechanisms based on fundamentals such as attainment of additional skills, performance, productivity, availability for new and more difficult assignments, and overtime when required are as important as the ultimate wage potential of the job category.

*Benefits*

At a minimum, the employee benefit package will have to remain competitive with competing employment alternatives in the marketplace. Where an entity can achieve competitive advantage is with the introduction of unique programs to fill any economic gaps in the benefit packages themselves as compared to competitive alternatives. The introduction of workplace flexibility to include enhanced training opportunities, advanced academic educational pursuits, and flexible work hours to accommodate these opportunities can often provide qualitative benefits that employees may find of equal or greater value than the specific economics of competing benefit packages.

*Safe Work Practices*

In LE's environment, education and training begins with comprehensive safe work practices. Considering the nature of the work, materials utilized in LE processes, and the extended work hours necessary to respond to emergency situations, a heightened awareness to safe work practices is a fundamental building block to establishing work procedures, specific maintenance plans, and effective outage productivity. In addition to day-to-day work practice training, strict isolation and tagging programs, as well as incipient fire and medical training can pay dividends. A well-designed program transcends the specific work environment to provide benefits both at home and in the surrounding community where employees are active. Metrics such as incident, frequency, and severity rates are well established and can provide precursors to avoiding major loss through effective implementation of the safe work practices program.

*Development of Company Required Skill Sets*

Although the responsibility for attaining necessary skill sets should continue to rest with employees, LE's ability to maintain a balance of critical skill sets can be enhanced through company sponsored training programs. This training can be accomplished through the use of nationally recognized and certified programs and can be integrated into the employee's progression through the compensation program as an additional incentive for pursuing a career path deemed critical to the company's needs. The specific skill sets can be established using the profiles developed from the predictive staffing analyses recommended above. The programs can be implemented over a term consistent with the expected attrition within the skill category. The "on company time" component of the training can be tailored to accelerate the process if necessary.

*Development of Employee Desired Skill Sets*

The approach to development of employee desired skill sets when different from the company required skill sets can be addressed with a somewhat different approach. With an initial requirement that any company sponsored or facilitated training program be for a skill set used somewhere within the company's current and/or anticipated operation, the program can be developed targeting established outside educational programs for both academic and vocational pursuits. Monetary compensation of successful completion, minimum retention requirements, and potential work hour flexibility to address time restrictions for specific course offerings are all tools that can be used to provide incentives for employee participation.

### *Onsite Training Facilitation*

Onsite training access can be an effective tool to facilitate the accelerated development of critical core competencies. This aspect of training would be to primarily provide facilities and potentially provide instructors to run an accredited skill development program convenient to the day-to-day work environment. Courses conducted at convenient company locations immediately after working hours can be both highly productive and minimally disruptive to family life when compared to pursuing similar opportunities at outside educational institutions. Convenience combined with incentives for accelerated advancement have proven to be a highly effective approach to putting skill sets in place in the company's required timeframes.

### *Use of Third Party Resources*

Third party contracting is a vehicle that should be considered in the development and implementation of any organizational staffing plan. Although it tends to be controversial in organizations when a strong self-perform mentality exists, if appropriately utilized, it can bring a number of advantages to an organization that has also put in place the necessary management controls to not only utilize these resources effectively, but also to effectively mitigate the associated risk as well.

The use of third party resources is one area where a smaller entity can achieve greater economies of scale, reduce the impact of internal labor performance/productivity concerns, potentially mitigate some of the more troublesome wage comparators that might exist for permanent staff, and most importantly fill the gaps between attrition and the hiring of new employees where applicable.

Risks that must be considered and addressed include potential loss of core competencies, loss or diminishment of customer interaction, and the business risk associated with the contracting organization. Prequalification and management control contract provisions are critical requirements for managing contracting risk.

Hybrid use of third party contracts can carry with it a number of advantages. For example, the partial use of third party resources allows LE to maintain its critical core competencies internally while allowing ancillary functions to be contracted. Supplementing internal staff with outside resources allows exposure to competitive work practices, can reduce the impact of labor related internal process inefficiencies, and can actually provide a greater level of internal job security. As third party labor contractors typically have a broader reach for employee resources, critical functions can be maintained through temporary gaps in employee hiring, particularly when considering the potential attrition rates for internal employees eligible to retire at LE.

### *Organizational Infrastructure Support Considerations*

Critical functions for the future LE organization under any of the four Business Cases include IT, Human Resources hiring and training functions, and communications. IT support is critical to the advanced technologies and distributed services that the future LE organization will be obligated to provide. HR functions will be critical to addressing the acute attrition exposure the organization must address over the next five years. Communications will be critical to any initiative that must address competitive forces and any adaptation of the culture of the organization to changing times.

Communications will be critical to create a depth of vision for the organization. It will require continual reemphasis as the organization embraces change from what may have been the status quo to the new vision under the various Roadmap scenarios from which LE can select. Communication will be necessary not only within the management ranks but also through the entire workforce down to the ground level. At the end of the day, the communication to customers, regardless of where the interaction occurs, must be a constant message consistent with the vision of the organization going forward.

Communication within the organization as it relates to the workforce must include updates to the current status of the organization, creative problem solving vehicles to address future competition and related uncertainties, and clear expectations for employee roles, commitment to the organization, and the performance parameters by which they will be gauged.

## Conclusion and Assessment of Future Needs

The current actual and potential future attrition of the workforce represent a significant liability to LE under any of the Business Case scenarios included in this study. It does, however, also represent an opportunity for the utility to restructure its approach to workforce development, management practices and procedures, and a shifting of the corporate culture, as the organization may deem appropriate.

All of the proactive approaches suggested in this section have been proven through actual experience. Although outside the scope of this particular study, any or all of these suggested approaches and associated implementation plans can be developed in more detail based on the needs of the organization and the desired approach to its management.

# Section 6
# SOCIAL

## Introduction

Similar to the processes described in the Environmental and Labor sections, the Project Team applied a societal lens in evaluating LE's social performance and identifying potential opportunities in support of the Roadmap. Societal performance for utilities and most organizations is the most difficult area of sustainability and the triple bottom line to measure. While it is difficult to measure societal performance, municipal utilities often have a significant impact in their community.

To perform an initial evaluation of LE's social performance, the Project Team performed a high-level baseline assessment, gap analysis, and prioritization of existing and/or new initiatives and policies to support the Roadmap goals. The results of Module 5 could also be used by LE to monitor, track, and report on societal performance and progress towards goals. The Project Team requested key social related data that facilitates broader sustainability reporting, benchmarking performance with other utilities. The baseline assessment will also allow LE to monitor, track, and improve performance over time. As with the environmental and labor data, the GRI was used as an initial framework to identify potential environmental performance indicators. These initial environmental reporting indicators recommended for LE include:

- Stakeholder engagement
- Low income programs
- Contingency planning

## Baseline Assessment

Three areas, or indicators, were identified and recommended for LE's sustainability and social performance reporting. LE is currently providing programs or offering services in each of the three indicator areas recommended. In addition, the SRP included significant stakeholder engagement efforts as a part of the Roadmap development process. LE has had a long history in providing low income and support programs, as well as contingency planning. Being located in Central Florida requires a significant amount of contingency planning due to hurricanes and other weather events. In fact, contingency planning and resiliency was identified as a potential competitive advantage in the staff survey responses and Roadmap development process.

In the past few years, LE has significantly increased and focused efforts on stakeholder engagement activities. LE's Customer Academies and partnerships with local trade schools have significantly benefited the utility. In fact, the partnership with a local trade school has led to placement of multiple graduates at LE in distribution maintenance and operations. Furthermore, while the SRP AP was initially developed in support of the Roadmap process, LE has begun transitioning the stakeholder panel to a more permanent and period strategic feedback role. As the Roadmap work concluded, LE began incorporating the AP in the subsequent rate study, which began in the summer of 2014.

Low income programs are common at electric utilities across the country. Supporting low income or disabled customers is often viewed as a community responsibility with many customers participating to help with additional contributions to a support fund. LE currently provides low income senior and disabled customer support with a customer "round up" program called Round Up for Project Care. Round up programs are popular with municipal utilities and provide an easy way for all customers to provide community support. The round up program simply rounds up a customer's bill to the next dollar with the round up portion donated to support low income seniors and disabled customers. The program also offers customers alternative contribution amounts in addition to rounding up their bill. The last FY the round up program generated more than $38,000 of support.

## Gap Analysis and Assessment of Future Needs

After completing the high-level assessment of social performance, the current programs and performance were aligned with the Roadmap to identify potential gaps or opportunities to leverage existing programs. This gap analysis identified stakeholder engagement as an area to expand LE's current programs and pursue additional programs and tactics to increase overall customer and stakeholder engagement. As the electric utility industry continues to evolve and customer needs transition to more technology based with increased services, the need to engage, educate, and involve stakeholders will also increase.

The LE SRP Team recognized the need to expand stakeholder engagement programs early in the Roadmap process. One of the initial recommendations and TAP items was formalizing the AP developed during the Roadmap process. The Roadmap and SRP Team also identified key gaps or needs for expanded capabilities and capacity for customer and stakeholder communications. To address the growing engagement needs, a Communications category was included in the TAP. This includes programs to leverage existing efforts such as the Customer Academy and development of a communications plan and new tools. To support the growing need and customer services, communications also includes an expansion of staff capacity in communications and engagement. Finally, in an effort to further educate customers on LE's services, a bill redesign project was included to more effectively communicate LE's costs, rates, responsibilities, and services to customers.

While LE currently has an existing low income support program, less than 2 percent of customers participate in the Round Up for Project Care program. The added communications capabilities and capacity planned in the TAP will also provide additional support for and likely enhance the current low income program. This increased capacity should lead to an increase interest, participation, and funding in the Round Up for Project Care program.

Initial data collected and a summary of the GRI social indicators and their related metrics for reporting on sustainability performance is included in Appendix G. Where possible, the Project Team provided current FY 2014 data and performance and recommendations on future data gathering and reporting.

# Section 7
# CONCLUSIONS AND RECOMMENDATIONS

The underlying challenge in the SRP effort is to effectively integrate the Roadmap into LE's day-to-day operations in a programmatic way and use the economic modeling data and analysis to better inform the generation resource decisions.

Based on the survey, interviews, and stakeholder participation results obtained during the Roadmap development process, LE's external stakeholders and internal employee resources appear willing and receptive to the changes both organizationally and in processes that an SRP Roadmap implementation plan may require. It is recommended that the types of interactive communication processes utilized for this study be maintained for the implementation phase of any roadmap plan.

## Section 3 – Economic Analysis

Although LE's aging generation fleet was of particular strategic concern across the organization and its stakeholder base, the economic evaluations and risk assessments of the four Business Cases addressed in this study show that LE has a significant amount of flexibility to address future resource needs. In addition to demonstrating the capability to reasonably address carbon related issues even if regulations remain as originally proposed, LE has a competitive opportunity to restructure its approach to the development of its generation resource base for the future either through Business Cases 1 or 2, or ideally a hybrid of the two alternatives until the regulatory arena becomes more certain.

The study also shows that LE can weather a business scenario where demand destruction takes place. To help mitigate the risks of a demand destruction case and to avoid the potential for significant under-recovery of cost exposure, it is very important to assure that fixed and variable costs of operation are accurately allocated in any new rate structure developed, particularly where new capital investments are contemplated.

Considering that the four Business Case scenarios address the primary concerns of external stakeholders as well as those of the internal organization, the study shows that LE is in a reasonable position to address any of the scenarios of concern so long as detailed planning and deliberate implementation of the Business Case SRP's or associated hybrids becomes a primary focus of the organization going forward.

## Section 4 - Environmental

As discussed in the Environmental Section of this report, LE's McIntosh Units 3 and 5, and the Winston Peaking Station are generally well-suited for the EPA's current regulatory agenda relative to other aging coal units, with the exception of proposed GHG regulations where McIntosh Unit 3 does not likely have any material strategic advantages.

From an industry perspective, carbon related regulatory concerns will likely have the most significant effect on decisions relating to the use of both the existing generation resource base and future generation resources contemplated. LE is reasonably positioned to address these issues so long as they remain proactive in monitoring the development of future regulations and the timing of their decisions for future resource additions with reduced or carbon neutral impact.

As scenarios that demonstrate LE can reasonably address proposed carbon based regulatory requirements require a modest addition of a carbon neutral future resource, it is recommended that LE begin a deliberate process for familiarization with the current and developing carbon neutral technologies to better facilitate resource decisions that will be required for the 2020 timeframe. A portfolio approach that reduces exposure to any individual technology and can remain market neutral through the selection of both owned and purchased assets may carry the day.

The maintenance of proactive relationships with permitting agencies as well as the advance planning and timely implementation of required permitting initiatives should allow LE to both meet its future compliance requirements while maintaining its competitive business position going forward.

## Section 5 - Labor

The current actual and potential future attrition of the workforce represent a significant liability to LE under any of the Business Case scenarios included in this study. It does, however, also represent an opportunity for the utility to restructure its approach to workforce development, management practices and procedures, and a shifting of the corporate culture, as the organization may deem appropriate.

Creation of a proactive and predictive hiring process can be accomplished using any or all of the suggested approaches included in this study. Using these suggested approaches as a guideline, it is recommended that LE select, and then prioritize those functions that would address their most acute needs. The associated implementation plans can be developed in more detail based on the needs of the organization and the desired approach to its management.

Of particular importance is the need to characterize the demographics of the workforce eligible for retirement primarily from a technical skill perspective and potential timing when this attrition will occur. This type of review should also be conducted specific to the management ranks of the organization targeting both the business area and level in the management structure. It will be especially important to maintain a reasonably stable and collectively focused management group, as they will be the foundation for an effective mobilization and integration of new individuals into the workforce with minimal negative impact to business operations.

With the level of potential attrition within the LE organization, the use of a hiring system that only addresses vacancies from a reactive perspective will fall far short when considering the magnitude of the exodus from both the technical and management ranks.

## Section 6 - Social

As the electric utility industry continues to evolve and customer needs transition to more technology based with increased services, the need to engage, educate, and involve stakeholders will also increase. It is therefore recommended that the stakeholder engagement programs implemented for the SRP be continued going forward as these groups will be an invaluable resource to assist with and ideally aligned with the critical business decisions required as LE moves forward with their selected SRP.

Stakeholder communication can be enhanced by leveraging both existing efforts such as the Customer Academy and development of a communications plan, along with additional new tools. To support the growing need and customer service, communications enhancement also includes an expansion of staff capacity in communications and engagement.

In an effort to further educate customers on LE's services, a bill redesign project should be considered to more effectively communicate LE's costs, rates, responsibilities, and services to customers.

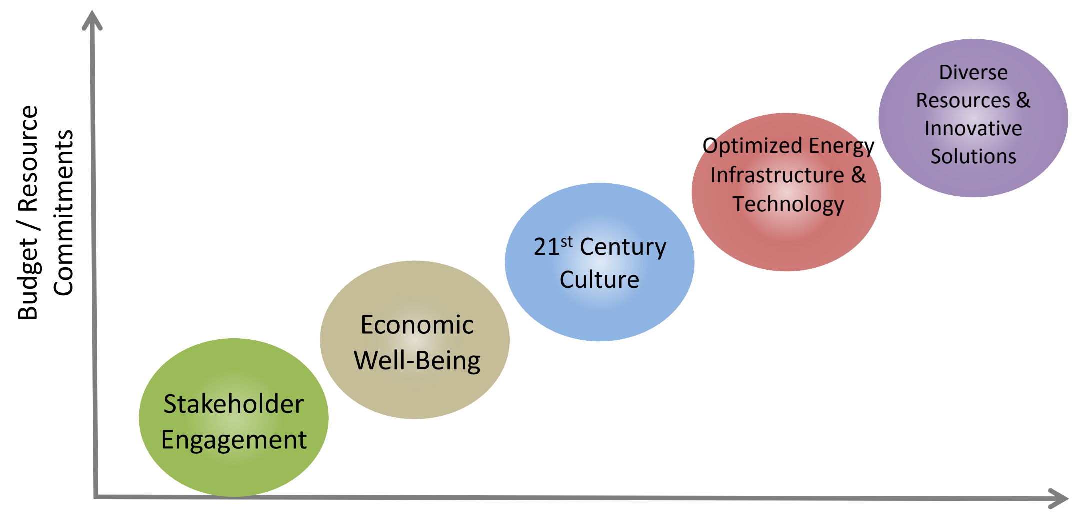
While LE currently has an existing low income support program, less than two percent of customers participate in the Round Up for Project Care program. Added communications capabilities and capacity should be considered to provide additional support for and likely enhance the current low income program. This increased capacity should lead to an increased interest, participation, and funding in the Round Up for Project Care program.

Competitive threats routinely challenge the cost competitiveness of a municipal utility without due consideration for the qualitative contribution a municipal makes to its community outside of the direct services the utility provides. It is recommended that enhancement of the communication process include the tracking and communication of the indirect contributions of LE as an organization, as well as individual volunteers within its workforce.

Considering the demographics of those within the organization eligible to retire, educational programs that can be accomplished under the training venue can be offered to not only assist individuals with the transitions that will occur when they leave the active workforce but to help integrate them into potential community service active participation opportunities. These programs can have the potential to not only mitigate some of the effects of the transition from full employment to full retirement, but also further enhance recognition of LE's qualitative contribution to the community.

# Appendix A
# Tactical Action Plan Project Summaries

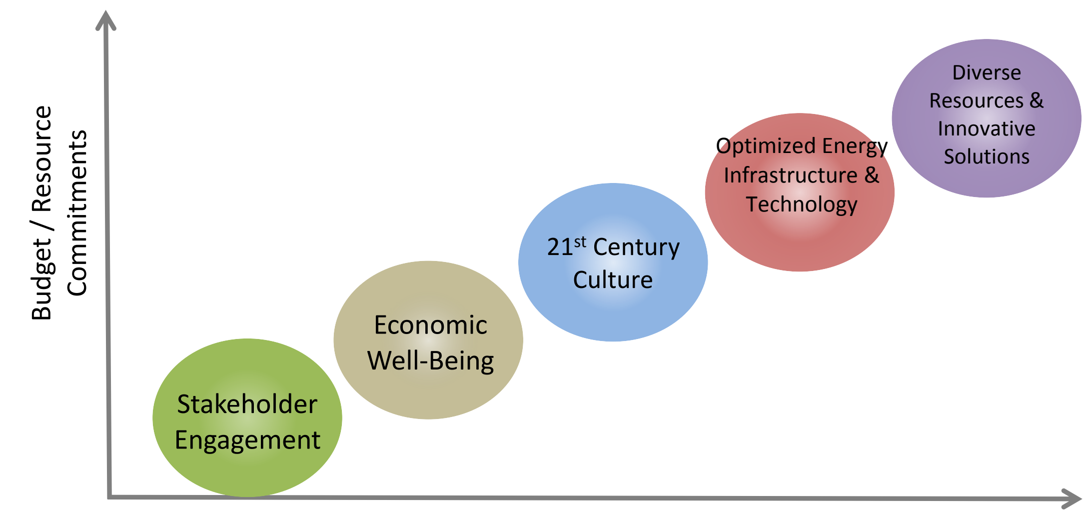
## Lakeland Electric - Strategic Roadmap and Tactical Action Plan




Budget Impact
- Small <$100k
- Medium ~$500k
- Large >$1M

| | | 2014 2017 2019 2022 2025 | Budget Impact (note if existing, or marginal / new budget dollars) |
|---|---|---|---|
| | **Communications - David Kus - AGM Customer Serv./Kevin Cook - Director of Communications** | | |
| 1 | **Comprehensive Customer Engagement Plan** | | |
| 1.1 | Communications Plan and Tools | By 2nd Quarter FY 2015 | $250K/ Yr |
| 1.2 | Key Accounts | Ongoing | Existing |
| 1.3 | Formalize Advisory Panel | 2015-2025 | $8,000/Yr |
| 1.4 | Monthly Customer Statement | By 3rd Quarter of FY 2015 | $50K |
| 2 | **Internal Engagement Plan** | Ongoing | Low |
| | **Financial - Mark Mead** | | |
| 1 | **Dynamic Financial Modeling / Rate Support** | | |
| 1.1 | New Rates and Rebates | 2014-2015; 2020-2021 | Existing ($150K per study) |
| 1.2 | Develop Dashboard Program to Monitor and Report Progress and Impact of Key Success Metrics (Economic, Social, Regulatory, and Financial) | 2015-2016 | $125K |
| 2 | **Economic Partnerships** | | |
| 2.1 | Partnership with Agencies that Already Offer Incentives | FY 20104 | Existing (~$150K) |
| 2.2 | Partner with City office of Economic Development (Objectives, Incentives and Responsibilities) | Ongoing into FY 2015 | Include in FY 2016 Budget (est. $200K) |
| 3 | **Funding Strategy** | | <$200K |
| 4.1 | Assign LE Project Mangers to Pursuing Grant Funding, Public Moneys or Commercial Banking Partnership | Ongoing | Existing (Marketing Manager proposed for FY 2015) |
| 4.2 | LE Fiscal Operations - Alternative Funding | FY 2015 Forward | Existing |
| 4 | **Risk Oversight Committee (ROC)** | Ongoing | Existing |
| 5 | **Dividend - Contribution to City** | | Formula Approved by Commission |
| | **Power and Virtual Resources - (NEED CATEGORY LEAD)** | | |
| 1 | **Generation Reinvestment** | | |
| 1.1 | Retire McIntosh 1 | 2014 | $100K |
| 1.2 | McIntosh 2 (CC Conversion) | 2020 | $50K |
| 1.3 | Retire Larsen Unit 2 &3 | 2014-2018 | $500K |
| 1.4 | Retire McIntosh Diesels | 2022 | $80M |
| 1.5 | Add New Generation as necessary | >2022 | $1M/ MW |
| 2 | **Optimized Power Pool** | 2018-2025 | 500K |
| 3 | **Partnerships** - | | |
| 3.1 | Renewable (Distributed and Utility Scale) | Ongoing | Sun Edison = $0.11/kWh Existing |
| | A.Utility-scale Solar Production | Ongoing | |
| | B. Customer Net Metering (small DG) | Ongoing | |
| | C. Residential Solar Hot Water (thermal DG) | Ongoing | |
| 3.2 | PPA or Partner with Another Utility to Jointly Own Generation Units | Ongoing | Existing |
| 4 | **Customer (DSM, DR, EE, RE)** - | | |
| 4.1 | Smart Grid Measures and Interface | | Medium to Large = $500K - $1M+ |
| 4.2 | Innovative Rates (TOU, Green options) | | |
| 4.3 | Solar / PV | Ongoing | |
| 4.4 | DSM Programs Energy Efficiency Upgrades, Contractor Partners(Existing and new) David Kus - | | $370K |
| | **Operations - (NEED CATEGORY LEAD)** | | |

## Lakeland Electric - Strategic Roadmap and Tactical Action Plan




Budget Impact
- Small <$100k
- Medium ~$500k
- Large >$1M

| # | Item | 2014 | 2017 | 2019 | 2022 | 2025 | Budget Impact (note if existing, or marginal / new budget dollars) |
|---|---|---|---|---|---|---|---|
| **1** | **2020 Technology Vision** | | | | | | |
| 1.1 | Elements, Tools and Task - TBD | Unknown | | | | | Existing |
| 1.2 | SG measure functionality | Ongoing | | | | | Existing |
| **2** | **Asset Management** | | | | | | |
| 2.1 | Technology - Maximo, Preventative Maintenance, Life Cycle Management of Assets | Ongoing | | | | | Existing |
| 2.2 | Field Inventory Survey of Existing Facilities | FY2015 - FY2017 | | | | | Existing |
| **3** | **Optimize Organizational Capabilities** | | | | | | |
| 3.1 | Develop LE Technology Capacity and Staff | 1st Quarter FY2015 | | | | | Unknown |
| 3.2 | Organizational Assessment incl. Work Process Mapping / Improvement | 1st Quarter FY2015 | | | | | $500K |
| 3.3 | Formalize Existing Cross Functional Rotational Program | Ongoing | | | | | Existing |
| 3.4 | Cultural Assessment and Change Management for Innovation - | 2014-2015 | | | | | $500K |
| **4** | **Workforce Plan -** | | | | | | |
| 4.1 | Retention, Attraction, Succession Plans | Ongoing | | | | | Large >$1M (Incl. is existing budget) |
| 4.2 | Regional academy/college/tech programs | Ongoing | | | | | included in existing budget |
| 4.3 | Knowledge Management / Sharing Program | Ongoing | | | | | included in existing budget |
| 4.4 | Staff Performance Plans, KPIs, Metrics aligned with Roadmap | Ongoing | | | | | included in existing budget |
| 4.5 | Department and Division targets/ Metrics established | Ongoing | | | | | included in existing budget |
| 4.6 | PPR's (performance plans) Note: Due 9/30/14 | | | | | | included in existing budget |
| **5** | **Training and Safety -** | | | | | | |
| 5.1 | Technology Training | Ongoing | | | | | $100K - $500K |
| 5.2 | General Training | Ongoing | | | | | $10K - $25K |
| **6** | **Compliance and Regulatory** | | | | | | |
| 6.1 | EPA and FERC | Ongoing | | | | | Existing |
| 6.2 | Physical and Cyber Security | 2015 | | | | | $250K -$400K |
| **7** | **Internal Sustainability Effort - "walk the talk"** | 2014 - 2025 | | | | | None |

# Tactical Plan Worksheet

## Program or Tactic and Point of Contact

Communications –
1) Comprehensive Customer Engagement Plan
POC: New Marketing Manager (TBD)

## Description (note if it is an existing program with budget and staff):

Plan that outlines short-term then long-term communication strategy that includes methods and tools used to reach internal and external publics. The benefits of establishing a planned, comprehensive and consistent program are immediate and far-reaching. The utility will benefit directly through improved communication and feedback from all target audiences – both internal and external. At the same time far-reaching and intangible benefits include an improved public image, the ability to measure results and track performance, increased trust and a greater sense of community.

In order to create a Comprehensive Customer Engagement Plan LE will need to fund and staff a professional utility marketing department, and then charter that department to "oversee and direct all functions related to marketing and communications with the various customer segments of Lakeland Electric." The department will compliment and integrate with the marketing and communications plan established by the City of Lakeland's Communications department.

## Supporting Elements, Tools, or Tasks:

1.1 Communications Plan and Tools – establish Action Plan with goals, performance measures, key milestones, and expected deliverables, detailed by products, services, and market segments.
1.2 Key Accounts – maintain and complement existing Key Accounts quarterly meetings with customers as well as direct contact practices with designated account representatives.
1.3 Formalize Advisory Panel - Formalize existing SRP Advisory Panel to include periodic meetings (e.g. quarterly). The Panel will be chartered to provide "strategic" as opposed to "operational" direction to the marketing department.
1.4 Monthly Customer Statement – Develop a statement (monthly bill design) that segments each billing entity with a graphical element so customers have a better understanding of their service charges. Work includes graphic design/redesign, focus groups and back office compatibility. Create a statement that segments the utility cost, services, and message.

## Schedule (years) or Ongoing:

1.1 By 2nd quarter of FY2015.
1.2 Ongoing.
1.3 2015 – 2025 (or, duration of SRP effort).
1.4 By 3rd quarter of FY2015.

| |
|---|
| Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):<br><br>1.1 $250,000 / Yr<br>1.2 Incl. in existing budget; existing key accounts staff can manage expanded program responsibilities.<br>1.3 $8,000 / Yr<br>1.4 $50,000 |
| Notes: |

# Tactical Plan Worksheet

| |
|---|
| Program or Tactic and Point of Contact<br><br>Communications –<br>2) Internal Engagement Plan<br>POC: Betsy Livingston, Kevin Cook |
| Description (note if it is an existing program with budget and staff):<br><br>• Internal Communication and Engagement – outreach to include, inform and engage employees. Specific tactics and programs include employee meetings, surveys, VIP Program, intranet, social media, web and through appreciation programs. Develop consistent, focused key messages built on strong themes. Internal Communications should support, reinforce and reflect the goals established through LE's strategic planning initiatives. Some initiatives currently exist, others need to be expanded and added. |
| Supporting Elements, Tools, or Tasks:<br><br>▪ Annual employee meeting (discontinued)<br>▪ Surveys<br>▪ Divisional quarterly meetings<br>▪ Intranet<br>▪ Social Media<br>▪ Web<br>▪ Employee appreciation programs<br>▪ Onboarding new employees to include SRP Engagement Tools and Plan |
| Schedule (years) or Ongoing:<br><br>Ongoing |
| Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):<br><br>Low |
| Notes: |

# Tactical Plan Worksheet

| |
|---|
| Program or Tactic and Point of Contact<br>Financial –<br>1) Dynamic Financial Modeling/Rate Support<br>POC: Jeff Sprague |
| Description (note if it is an existing program with budget and staff):<br><br>Ability to fund strategic initiatives is linked to retail rates that generate the target level of revenue. Generating the desired revenue is a combination of projected program needs, forecasted sales, and the general health of the local economy. Evaluating select financial indicators against forecasts will expose divergence in the indicators leading LE to anticipate changes in revenue. Key elements are proper rate design and tracking of key performance indicators. |
| Supporting Elements, Tools, or Tasks:<br><br>1.1. New Rates and Rebates - Rates proceedings begin to incorporate smart grid technology/data, develop new customer rate options, and support the development and funding of rebates and other customer programs. Rates will maintain competitive position.<br>1.2. Develop dashboard program to monitor and report progress and impact of key success metrics including economic, social, regulatory and financial goals. Additional software needs such as MCR forecasting, Hyperion. Existing revenue and expense forecasts should be expanded to at least a five year forward view. Overall assessment of metrics will be used to initiate changes in rate design and marketing objectives. |
| Schedule (years) or Ongoing:<br>1.1. 2014-2015; 2020-2021<br>1.2. 2015-2016 |
| Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):<br><br>1.1. Incl. in existing budget. ($150,000 per study)<br>1.2. $125,000 |
| Notes: |

# Tactical Plan Worksheet

Program or Tactic and Point of Contact

Financial –

2) Economic Partnerships

POC: Joel Ivy, Jeff Sprague

Description (note if it is an existing program with budget and staff):

Continued enhancement of economic partnerships, including collaboration with City office of Economic Development and LEDC, supporting policy developments, and developing appropriate economic development incentives for the purposes of maintaining and recruiting businesses into LE's service territory.

Supporting Elements, Tools, or Tasks:

2.1. Enter into a supportive partnership with those agencies that already offer incentives.

2.2. Partner with City office of Economic Development in formulating a policy of objectives, incentives, and responsibilities.

Schedule (years) or Ongoing:

2.1. FY14

2.2. Ongoing into FY15

Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):

2.1. Existing budget for memberships & high skills initiative (~$150,000)

2.2. Include in FY16 Budget, est. $200,000

Notes:

- Currently pay dues for LEDC, Chamber of Commerce, Tampa Bay Partnership.
- High skills initiative ~$150k

# Tactical Plan Worksheet

| |
|---|
| Program or Tactic and Point of Contact<br>Financial –<br>3) Funding Strategy (external)<br>POC: Mark Meeks |
| Description (note if it is an existing program with budget and staff):<br><br>Explore funding options from third parties that complement the program objectives of LE. When available COL/LE can serve as a conduit for Federal and State funds for such things as energy efficiency, infrastructure development, and social program advancement. Other financial instruments shall be considered as alternatives to internally generated capital. |
| Supporting Elements, Tools, or Tasks:<br>3.1. Assign LE project managers to pursing grant funding, public moneys, or commercial banking partnerships for programs that are already a strategic fit for LE.<br>3.2. LE Fiscal Operations to pair major capital expenditures with alternative funding such as joint ventures, capital lease, and power purchase agreements. |
| Schedule (years) or Ongoing:<br><br>3.1. Ongoing<br>3.2. FY15 and forward |
| Budget (Note: include financial and number of FTEs, if applicable):<br>3.1. Existing budget. Marketing Manager proposed for FY15.<br>3.2. Existing budget and FTE.<br><br>Noted as less than $200,000 as a whole |
| Notes: |

# Tactical Plan Worksheet

| |
|---|
| Program or Tactic and Point of Contact<br>Financial –<br>4) Risk Oversight Committee (ROC)<br>POC: Joel Ivy |
| Description (note if it is an existing program with budget and staff):<br><br>Utilize / expand existing ROC as needed to review risks regarding natural gas hedging and other operations, decisions or capital investments. Collaborative effort between City Hall and LE officials. |
| Supporting Elements, Tools, or Tasks:<br><br>▪ Hedge consultant<br>▪ Other consultants as needed |
| Schedule (years) or Ongoing:<br><br>Ongoing |
| Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):<br><br>Incl. in existing budget and FTE |
| Notes: |

Program or Tactic and Point of Contact
Power & Virtual Resources –
1) Generation Reinvestment
POC: Tony Candales, Farzie Shelton, Phuong Tran

Description (note if it is an existing program with budget and staff):

LE determined that several generating units within its fleet will need to be retired or reinvested to ensure sufficient and reliable resources to accommodate load growth for the entire planning (ten year) horizon. These units are Larsen units 2 and 3, McIntosh units 1 &2 and McIntosh Diesel units. Parts of Larsen unit 2 could be used to replace bad parts of Larsen unit 3 to extend its life to 2018. Decommissioning of McIntosh unit 1 will create necessary (physical) space for the conversion of McIntosh unit 2 to a combine cycled unit. The program is staffed but not yet budgeted. Marginal budget costs are indicated below.

Supporting Elements, Tools, or Tasks:

| Item | MW | Cost | Fuel | Yr | Category |
|---|---|---|---|---|---|
| 1.1 Retire McIntosh 1 | -90 | 0 | Gas | 2014 | High |
| 1.2 McIntosh 2 (CC Conversion) | +170 | $80 M | Gas | 2020 | High |
| 1.3 Retire Larsen Unit 2 & 3 | -20 | 0 | Gas | 2014 & 2018 | High |
| 1.4 Retire McIntosh Diesels | -5 | 0 | Diesel | 2022 | High |
| 1.5 Add New Generation as necessary | | $1M/MW | | >2022 | High |

Schedule (years) or Ongoing:
1.1 2014
1.2 2020
1.3 2014 and 2018
1.4 2022
1.5 >2022

Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):

1.1 $100K
1.2 $50K
1.3 $500K
1.4 $80M
1.5 $1M/MW

Notes:

## TACTICAL PLAN WORKSHEET

# Tactical Plan Worksheet

| |
|---|
| Program or Tactic and Point of Contact<br><br>Power & Virtual Resource –<br>2) Optimized Power Pool<br>POC: Alan Shaffer, Tony Candales |
| Description (note if it is an existing program with budget and staff):<br><br>To form a Capacity pool with the FMPP members between 2018 and 2025. This possible partnership is currently an intention and is being discussed at a very high level as an opportunity to expand the current Pool's functions. Cost to benefit analysis and risk analyses with possible independent consultant study will and a mutual agreement will need to take place prior to forming a Capacity Pool. This partnership may include jointly fuel, transportation, short and long-term capacity planning, and compliance, etc., which may lead to decreased operational costs and increased efficiencies. |
| Supporting Elements, Tools, or Tasks:<br>Preliminary cost-to-benefit analyses are to be performed by Pool members' personnel. Joint activities in areas that could lead to obvious benefits to all Pool members and do not require contract bindings, such fuel planning, may start earlier than other areas. |
| Schedule (years) or Ongoing:<br><br>May start sometime between 2018 and 2025 |
| Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):<br><br>$500,000 (High) Estimated $1.5M total Consultant Study ($500k to each utility). |
| Notes: |

# Tactical Plan Worksheet

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## Program or Tactic and Point of Contact

Power & Virtual Resources –<br>
3) Partnerships<br>
POC: Joel Ivy, Alan Shaffer, Farzie Shelton, Jeff Curry

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## Description (note if it is an existing program with budget and staff):

This program addresses consideration of potential generating partnership opportunities to accommodate growth and replace generation lost due to scheduled generation retirements.<br>
Renewable program is intended to 1) satisfy customers' growing demand for renewable energy and 2) offset legislative pressures to include clean energy sources in the generation mix. In two situations, alliances with private sector developers were made using the PPA business mechanism, thus freeing COL from any capital budget commitments. Supporting vendors were recruited based on their ability to optimize income tax incentives (and pass lower costs through to LE) as well as having appropriate renewable energy expertise.

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## Supporting Elements, Tools, or Tasks:

3.1 – Renewables (distributed and utility scale)<br>
LE participates in two areas of solar PV generation and one solar thermal initiative:

A. <u>Utility-scale Solar Production</u><br>
Wary of a legislative mandate and in concert with FL's utilities, LE has been pro-active with its development of central grid-dedicated solar generation. PPA mechanism in use, 5.5MW total installed thus far and expecting to grow to 24MW by 2017.

B. <u>Customer Net Metering (small DG)</u><br>
FL requires all utilities to allow the interconnection of small renewable devices for those customers who wish to self-generate. LE is in basic compliance with FL PSC RULE <u>25-6.065</u> Interconnection and Net Metering of Customer-Owned Renewable Generation.

C. <u>Residential Solar Hot Water (thermal DG)</u><br>
Responding to customer surveys that the utility should encourage clean solar energy, LE has contracted with a private sector provider for the installation of residential solar water heaters. PPA mechanism in use.

3.2 – PPA or partner with another utility to jointly own generation units<br>
When LE indicates capacity need within the ten year timeframe, PPA and generating partnership opportunities should be considered to replace generation lost from retirements of existing fleet. Program requires no additional budget or staff until a feasible partnership opportunity arises.

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## Schedule (years) or Ongoing:

3.1 Ongoing<br>
3.2 Ongoing

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| |
|---|
| Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):<br><br>3.1 Sun Edison = $0.11/kWh (Incl. in existing budget)<br>3.2 include in existing budget |
| Notes: |

# Tactical Plan Worksheet

| |
|---|
| Program or Tactic and Point of Contact<br>Operations<br>1) 2020 Technology Vision<br>POC: LE Technology Steering Committee (LETSC), Rick Fitz-Gordon, John McMurray, John McAuliffe |
| Description (note if it is an existing program with budget and staff):<br><br>Inventory current and anticipated technologies and methodologies and capabilities employed by the Utility, to determine **s**trengths, **w**eaknesses, **o**pportunities, and **t**hreats. Document gaps, determine requirements, determine implementation strategy (upgrade, replace or build in-house), coordinate disbursement and review of requests for Information, determine preferred implementation priority and timeline, present options and alternatives to LETSC for approval and prioritization and prepare requests for proposals, including implementation plan, based on LETSC approval. |
| Supporting Elements, Tools, or Tasks:<br>1.1 Elements, tools and tasks will be determined after the inventory and assessment identifies options and alternatives. In the interim the one project listed below has been funded and should be completed within one to three years of initiation. It is anticipated that additional projects will be added after the inventory.<br><br>1.2 Integrated Dist. Mgmt. System / SG Measure functionality / Oracle DataRaker<br>DataRaker provides a robust dashboard system with preset queries that enable Lakeland Electric staff to pinpoint and investigate theft, equipment loading and alarm management which all should provide significant improvement in the usage of the Smart Meter data. These activities will provide operational savings to Lakeland Electric. |
| Schedule (years) or Ongoing:<br>1.1 Unknown<br>1.2 Ongoing |
| Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):<br>1.1 Incl. in existing budget<br>1.2 Incl. in existing budget |
| Notes: |

# Tactical Plan Worksheet

| |
|---|
| **Program or Tactic and Point of Contact**<br>Operations<br>2) Asset Management<br>POC: John McMurray |
| **Description (note if it is an existing program with budget and staff):**<br>Develop a Strategic Asset Management (SAM) system that enables staff to better utilize resources (field inventory assessment, preventive equipment replacement /asset life cycle mgt., just-in-time ordering, with the advantage of increased accuracy in operational and planning models). |
| **Supporting Elements, Tools, or Tasks:**<br>2.1 Technology – Maximo, Preventative Maintenance, Life Cycle Management of Assets: tagging and storing information on equipment installation dates with asset attributes (manufacturer details) to assist in identifying life cycles/failure rates for each equipment piece. Eventually, a reliability model with equipment failure rates can be utilized to calculate circuit reliability.<br>2.2 Field inventory survey of existing transmission and distribution facilities – assessment will provide detail level information about system that will be tied into ArcGIS, Advanced Distribution Management System, Schneider Designer, SynerGEE and other systems. The inventory will provide the asset data for the Strategic Asset Mgt. system for equipment utilization and life cycle replacement and schedules and costs. |
| **Schedule (years) or Ongoing:**<br><br>2.1 Ongoing<br>2.2 2015 - 2017 |
| **Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):**<br>2.1 Incl. in existing budget<br>2.2 Incl. in existing budget |
| **Notes:** |

# Tactical Plan Worksheet

## Program or Tactic and Point of Contact

Operations:
3) Optimize Organizational Capabilities
POC: Farzie Shelton, Rick Fitz-Gordon, John McMurray, Kathy McNelis

## Description (note if it is an existing program with budget and staff):

Lakeland Electric will review its organizational structure in comparison to its business needs. The organization will be assessed for its capacity to handle advanced normal business and technology challenges along with the need to cross-train and develop internal talent. The previously conducted internal survey will be used to determine the required level of employee engagement for a successful culture change with respect to creating the 21st Century workforce (diverse, agile, multi-dimensional, etc.). Technology capacity and staff will be facilitated through a SWOT matrix, evaluate the strengths, weaknesses, opportunities, and threats in the Utility's Organizational Capabilities. Document the objectives for mission critical business functions identifying the internal and external factors that are favorable and unfavorable to achieve those objectives.

## Supporting Elements, Tools, or Tasks:

3.1. Develop LE technology capacity and staff - This will be facilitated after the SWOT has been performed so as to ensure setting achievable goals and/or objectives for the Utility.
   a. Strengths: characteristics of the business or project that give it an advantage over others.
   b. Weaknesses: characteristics that place the business or project at a disadvantage relative to others
   c. Opportunities: elements that the project could exploit to its advantage
   d. Threats: elements in the environment that could cause trouble for the business or project

3.2. New Organizational Assessment including existing work process mapping and improvement –
   a. Corporate Performance will continue to compare divisional improvement opportunities through business process mapping (Rapid Process Improvement – RPI).
   b. Conduct a holistic and systematic assessment of the alignment of organizational structure, major work processes and human resources needed to successfully perform the work. This will encompass both existing skill sets and future competencies needed to improve the cost effectiveness and efficiency of work flows, productivity and the customer service experience. -

3.3. Formalize existing cross functional rotational program – The AGM's will collaborate to develop a plan to develop high potential employee through cross-functional rotations.

3.4. Cultural assessment and change management for innovation – Workforce Performance will assess the readiness of the organization for change. This effort will determine the flexibility of groups and employees to handle change.

## Schedule (years) or Ongoing:

3.1. 1st quarter 2015
3.2. Ongoing process improvement; Organizational Assessment will be new project (1st quarter 2015)
3.3. Ongoing

2014 – 2015 (Aligned with Organizational Assessment)

| |
|---|
| Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):<br>3.1. Unknown (Current city IT transfer ~$6M/Yr)<br>3.2. $500,000<br>3.3. Incl. in existing budget<br>3.4. $500,000 |
| Notes: |

# Tactical Plan Worksheet

## Program or Tactic and Point of Contact

Operations – Workforce Plan (1)
POC: Betsy Levingston

## Description (note if it is an existing program with budget and staff):

1.1 – Implement feasible components of the 2008 workforce planning and development plan and request that City management review and approve remaining initiatives.

1.2 – Continue existing academic partnerships (Tenoroc, USF, etc.), internships and apprenticeships.

1.3 – LE needs to develop a knowledge sharing program for contingency planning, cross-training, document standards and manuals for business continuity purposes.

1.4 – Establish employee development plans with concrete metrics.

1.5 – Targets

1.6 – PPR's

## Supporting Elements, Tools, or Tasks:

1.1 – See 2008 workforce planning and development plan.

1.2 – Workforce development and training plans encompass this area.

1.3 – Utilize programs and create manuals for standards.

1.4 – Align employee development plans linked to higher level performance metrics.

1.5 – Department and Division targets / metrics established

1.6 – PPR's (performance plans) Note: due 9/30/14

## Schedule (years) or Ongoing:

All employee metrics should be established by 9/30/14. All subelement programs are ongoing schedules.

## Budget (Note: include financial and number of FTEs, if applicable):

Included in existing budget.

## Notes:

1.5 – Department and division targets/metrics are established.

1.6 – PPR's (performance plans) are due 9/30/14.

# Tactical Plan Worksheet

## Program or Tactic and Point of Contact

Operations:
5) Training and Safety
POC: Betsy Levingston, Rick Fitz-Gordon

## Description (note if it is an existing program with budget and staff):

LE's training will address the human resource challenges which have been exacerbated by the high number of persons in the "DROP" program or nearing retirement. It will put forward recommendations for key education and training activities to advance the provision of adequate human capital and to assist the development of the necessary cooperation frameworks among Training and Safety, available technology and the needs of the business.

## Supporting Elements, Tools, or Tasks:

5.1 Technology Training will be accommodated by aligning strategy, intellectual capital, delivery systems and cost:

- Strategy – testing the alignment of the learning organization's vision, strategy and goals with those of the business they are meant to support
- Intellectual Capital – comparing the quality of training staff, partners and programs to best-in-class
- Delivery Systems – measuring the capability of training structure, operations and technology for efficiency and effectiveness
- Cost – determining the return on investment in learning services, staff and technology.

5.2 General Training will align training with the organization's strategies and goals. Training will target key knowledge, skills and abilities gaps. Learning opportunities will be identified and/or developed to address the gaps required to sustain a workforce that is productive, efficient and safe now and into the future.

Elements and Tools include strategically aligned IDPs for all employees; CityU Training, and Technical and Developmental opportunities identified to target specific performance gaps. Tools will include OJT, job rotations and other identified resources. Additional budget for Skill Assessment tools may be required.

## Schedule (years) or Ongoing:

Ongoing schedules for each supporting element

## Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):

2.1 $100,000 to $500,000
2.2 $10,000-$25,000

Notes:

# Tactical Plan Worksheet

## Program or Tactic and Point of Contact

Operations
6) Compliance and Regulatory
POC: Phuong Tran, Jim Howard, Farzie Shelton

## Description (note if it is an existing program with budget and staff):

Compliance to regulatory agencies such as EPA, FERC, NERC, etc. are an ongoing process and LE is committed to be fully compliant with all current and future enforceable standards. It is not possible to predict budgetary and staffing impact of all future regulatory standards/requirements; the (foreseeable) possible affects due to new requirements that are on the utility radar and are being discussed at EPA, FERC, NERC, etc. are listed below.

## Supporting Elements, Tools, or Tasks:

6.1 EPA and FERC – LE does not expect to see increase in number of staff required to comply with environmental regulation. However, the future regulations may force LE to limit its generation to gas powered units and renewables which would require a lot less staff than present time. LE's FRCC membership cost may be permanently increased (~$3K) due to required changes in the FRCC Planning Criteria per FERC Order 1000.

6.2 Physical and Cyber Security – LE expects to see increased staffing requirements to meet upcoming NERC/FERC Standards and Requirements, including but not limited to the Critical Infrastructure Protection(CIPS ) Version 5 Standards. This will include both Physical and Cyber Security.

## Schedule (years) or Ongoing:

6.1 Ongoing
6.2 2015

## Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):

6.1 No more capital budget should be allocated to retrofit generating units such as Unit No. 3 for compliance with GHG. Additionally, the environmental costs are pass through a billing item on our customer's bill

6.2 $250K-$400K (Depending on CIP Security Future Requirements)

## Notes:

# Tactical Plan Worksheet

Program or Tactic and Point of Contact
Operations:
7) Internal Sustainability Effort – “walk the talk”
POC: Farzie Shelton

Description (note if it is an existing program with budget and staff):

This project includes LE’s efforts, in collaboration with the City as necessary, to carry out actions/programs identified in the roadmap as per the SRP study to ensure LE’s continued success.

Supporting Elements, Tools, or Tasks:

- nFront consultants will communicate the SRP results/findings to the internal and external stakeholders.
- The overall Internal Sustainability Effort is responsibility of the AGM of Technical Support
- SRP team members will assist their appropriate LE personnel l in identifying their role(s) and provide necessary tools for them to carry out their tasks as identified in the SRP roadmap.
- Program Leader - The identified program category leaders will keep track of the progress of each program within their program category.
- Parts of the SRP roadmap may become a KSI to be incorporated into the LE Annual Strategic Plan. Each KSI progress will be reported quarterly.
- Certain elements resulted from the SRP will be incorporated to the annual Integrated Resource Plan (IRP) report.
- The LE SRP team will meet biannually to review programs progresses and modify the programs as necessary to ensure that the SRP is carried out successfully.
- All SRP status report will be posted on Insite and communicated to all employees.

Schedule (years) or Ongoing:

From completion of the SRP study (expected July 2014) to 2025

Budget (Note: include financial and number of FTEs, if applicable; marginal budget costs associated with SRP, should note include existing budgeted funds or ongoing expenses):
None currently however progress will be reviewed annually and if external help is needed, funding will be provided as necessary.

Notes:

# Appendix B
# Advisory Panel Workshop Summaries

# Strategic Resource Plan

## Advisory Panel Workshop #1

February 12, 2014

Advancements and developments in technology, renewable energy, distributed generation, regulations, energy efficiency, smart grid, electric vehicles, power generation, and utility programs are all beginning to converge and drive significant change in the electric grid, utilities, and consumer consumption. In addition, many municipal utilities not only face these broader market demands but other community related demands on their operations. *To address these issues, Lakeland Electric (LE) is developing a Sustainability and Technology Roadmap (Roadmap) to navigate these market demands, remain competitive, and assure a forward-looking enterprise aligned with LE's and our customer's goals.*

The Roadmap will provide a path for LE to achieve our desired resource related goals for the next 10 years as well as a tool to facilitate decision making and manage key sustainability and resource related changes. A key component to the Roadmap development is stakeholder engagement and the Advisory Panel. The Advisory Panel provides broad and representative community input, feedback, and insight that will be integral to the development of the Roadmap and supporting elements.

---

The first Advisory Panel Workshop focused on providing a general background on market trends affecting LE, soliciting feedback on how customers would characterize LE, and identifying what services customers may need in the future. The Advisory Panel also participated in an exercise to identify the supporting elements of a Roadmap purpose statement.

### Advisory Panel Workshops

Workshop #1:
February 12, 2014

Workshop #2:
March 5, 2014

Workshop #3:
April 2, 2014

******

All workshops to be held at the Lakeland Center. Please review emails prior to meetings for conference room assignment.

Below are the results that the Advisory Panel agreed, or strongly agreed with regarding customer trends and how participants would characterize LE.

**Characterize LE:**

- Forward thinking
- Provides good value for the money
- Valuable asset to the community

**Customer Issues or Services Growing in Importance:**

- Pricing signals for energy efficiency and demand response
- Choice on renewable energy options
- Increasing technology demands by customers
- Growth in Smart Grid "Apps" or services
- Customer choice in rates, programs, services, etc.

The purpose statement defines the "stake in the ground" for LE to achieve over the next 10 years and acts as a filter for resource related decision making. The following questions were asked of the Advisory Panel to provide initial feedback:

PASSION:
What LE is deeply passionate about?

UNDERSTANDING:
What LE can be the best in the world at?

ECONOMIC ENGINE:
What drives LE's value to customers/economic engine?

Advisory Panel input from purpose statement exercise:

**Passion**

- Efficiency of operations (corporate)
- Customer choice / customer service centric
- Reliability
- Bettering culture of customer understanding

**Understanding: Best at**

- Communication
- Most efficient and reliable at economical cost
- Future vision/planning (workforce, technology, regulatory)
- Power generation understanding

**Economic Engine**

- Efficiency of generation
- Diversity of fuel supply
- Provide competitive value to attract businesses to grow local community
- Make Lakeland an inviting community
- Progressive

LE Draft Purpose Statement*:*

***Lakeland Electric will leverage sustainable resources to deliver competitive and innovative energy solutions that support our vibrant community***

# Strategic Resource Plan

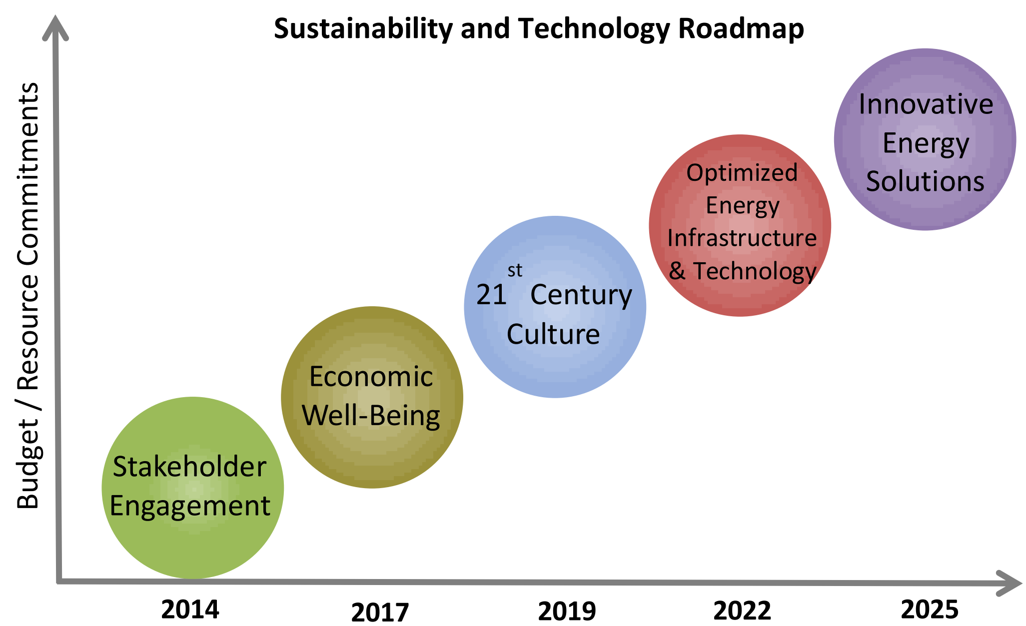
## Advisory Panel Workshop #2

March 5, 2014

*To address the multiple energy industry challenges, opportunities, and uncertainties related to resources, regulatory, technology, and customer demands Lakeland Electric (LE) is developing a Sustainability and Technology Roadmap (Roadmap) to navigate these demands, remain competitive, and assure a forward-looking enterprise aligned with LE's and our customer's goals. To support the Roadmap development, LE is holding three Advisory Panel meetings to facilitate feedback on the draft Roadmap elements.*

The second Advisory Panel Workshop focused on gathering feedback on LE's draft purpose statement. The purpose statement will act to define LE's "stake in the ground" by envisioning what LE must look like and where it must be positioned in 10 years to continue delivering value to its customers. Feedback was also solicited on the interim "Destinations" that LE must address or achieve in order to realize the purpose statement. The draft Roadmap is shown below.

**Sustainability and Technology Roadmap**




### Advisory Panel Workshops

Workshop #1:
February 12, 2014

Workshop #2:
March 5, 2014

Workshop #3:
April 2, 2014

******

All workshops to be held at the Lakeland Center. Please review emails prior to meetings for conference room assignment.

Once the purpose statement is developed, the interim steps or "Destinations" must be identified that lead LE to the desired end state in 2025. The Destinations define the key issues for LE to address in achieving the purpose statement.

The Advisory Panel was asked for input regarding their expectations, resource planning outcomes anticipated, and / or tactical programs desired for each Destination. The responses are shown on the right.

Advisory Panel feedback on the Draft Purpose Statement:

*Lakeland Electric will leverage sustainable resources to deliver competitive and innovative energy solutions that support our vibrant community.*

**Feedback and Input:**

- Too close to current LE Mission
- Sustainable could be limiting (i.e. only sustain) or too green (e.g. environmental sustainability)
- Diversity is an important LE attribute
- Use of 'Vibrant' community was supported
- Resources viewed as multi-faceted (e.g. human, power generation, services, etc.)
- Competitive may not encompass economical and cost-effective
- Potential confusion with "energy" going beyond electric services

---

Advisory Panel feedback is listed in bullet form below each Destination and its related definition:

**STAKEHOLDER ENGAGEMENT:** engage employees, customers and the community to deliver our services

- Independent Board to reduce political influence
- Expand alliances or partnerships beyond the current community or region
- Effective messaging and consistent delivery

**ECONOMIC WELL-BEING:** optimize financial performance, deliver competitive services, and promote economic development

- Leverage local expertise, best practices for operational efficiencies
- Consider sale of generation assets (not a consensus opinion of the group)

**21ST CENTURY CULTURE:** a 21st Century Culture with a culture of innovation to power a dynamic organization

- Proactively train and recruit, expand educational partnerships
- Foster a culture of innovation
- Identify the organizational needs of a 21$^{st}$ Century Culture

**OPTIMIZED ENERGY INFRASTRUCTURE & TECHNOLOGY:** embrace technology to enhance performance, optimize infrastructure, and provide innovative services

- Optimize and leverage web portal
- Continue / expand on research and development
- Staff must stay ahead of the curve, up to date on power technology applications

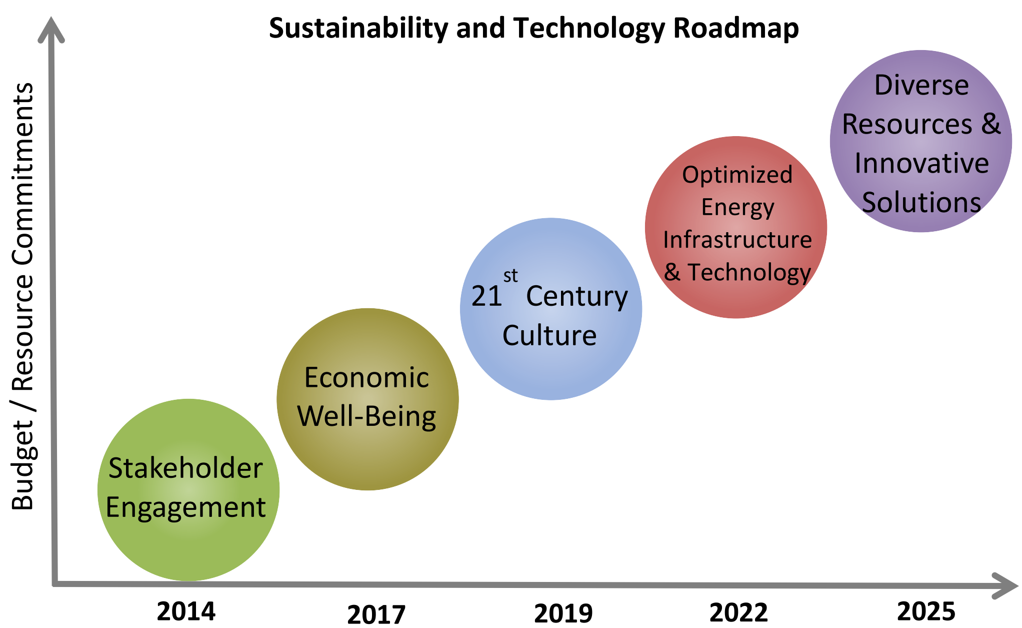
# Strategic Resource Plan

## Advisory Panel Workshop #3

April 2, 2014

*To address the multiple energy industry challenges, opportunities, and uncertainties related to resources, regulatory, technology, and customer demands, Lakeland Electric (LE) is developing a Sustainability and Technology Roadmap (Roadmap) to navigate these demands, remain competitive, and assure a forward-looking enterprise aligned with LE's and our customer's goals. To support the Roadmap development, LE held three Advisory Panel meetings to facilitate feedback on the draft Roadmap elements.*

The third and final Advisory Panel Workshop summarized the final Roadmap and strategic elements in addition to discussing the four business cases or generation resource modeling scenarios. The final Roadmap included refinements and input suggested in the previous Advisory Panel Workshops. A detailed summary of the four business cases or generation resource modeling scenarios is included on the following page. The final Roadmap is illustrated below.




The purpose statement (shown as the final destination in the illustration to the left) represents LE's desired end state in 2025 – *e.g. diverse, sustainable resources and competitive, innovative solutions*. The interim steps or "destinations" define the key issues for LE to address or steps to take in achieving the purpose statement.

Roadmap Purpose Statement:

***Lakeland Electric will leverage diverse, sustainable resources to deliver competitive, innovative energy solutions that support our vibrant community.***

**Diverse, sustainable resources:** fuels, employees, generation technologies, and customer "virtual" resources

**Competitive, innovative solutions:** managing / containing costs, valuable / flexible / dynamic services – "kW and beyond"

**Vibrant community:** facilitating economic health, improving community status, attracting new employers, and encompassing community well-being (environment, social, economic)

The final Workshop also included a discussion of transitioning from the strategic to the analytical or modeling phase of the resource plan. The key element guiding the analytics is the identification and definition of four business cases or scenarios to evaluate. The four business cases are summarized to the right.

Four business cases will be evaluated and modeled to inform generation asset and plant related investment decisions such as which new power technologies or plants to invest in to meet LE's power needs. The four business cases and feedback are summarized below.

1. **BASE CASE:** Retrofit / upgrade existing LE generation units to provide added fuel diversity. No new units will be constructed.
2. **IDENTIFY NEW RESOURCES:** Identify the lowest cost new generation alternative(s) instead of upgrading existing units
3. **VIRTUAL CUSTOMER RESOURCES:** Utilizing the base case, include high adoption rates for distributed generation (e.g. rooftop PV), energy efficiency, and 'virtual' customer smart grid resources to eliminate system growth and reduce peak demand
4. **MODEST GREEN CASE:** Utilizing the base case, include renewable energy resources to meet 10% of LE's system load (e.g. kWh). This case also represents increased federal regulatory impacts.

**Advisory Panel Feedback:**

- The cases are easy to understand, align with Advisory Panel insights or views of the market trends
- Cases 1 and 2 were thought to be the lowest cost
- Case 1, the Base Case, was somewhat perceived as a short term fix rather than a long term option
- Case 4, renewable energy was consistently viewed as high cost
- In general, a mixture of Case 2 and 3 was believed to be the likely reality of the future, and potentially most accurate representation for costs and highest value to community

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# Appendix C
# Lakeland Electric Internal Survey Results

# Strategic Resource Planning: Staff Survey Results

February 13, 2014

## Strategic Resource Planning Project (SRP)

- SRP is the development of a Sustainability and Technology Roadmap (Roadmap) to guide resource planning related decision making
- Roadmap is developed with significant collaboration from:
  - LE staff (internal stakeholders)
  - external stakeholders/customers (Advisory Panel)
- The Roadmap will provide:
  - a tool to facilitate decision making and manage key sustainability and resource related changes.
  - a path for LE to achieve our desired resource goals for the next 10 years

2

# Staff Survey Results

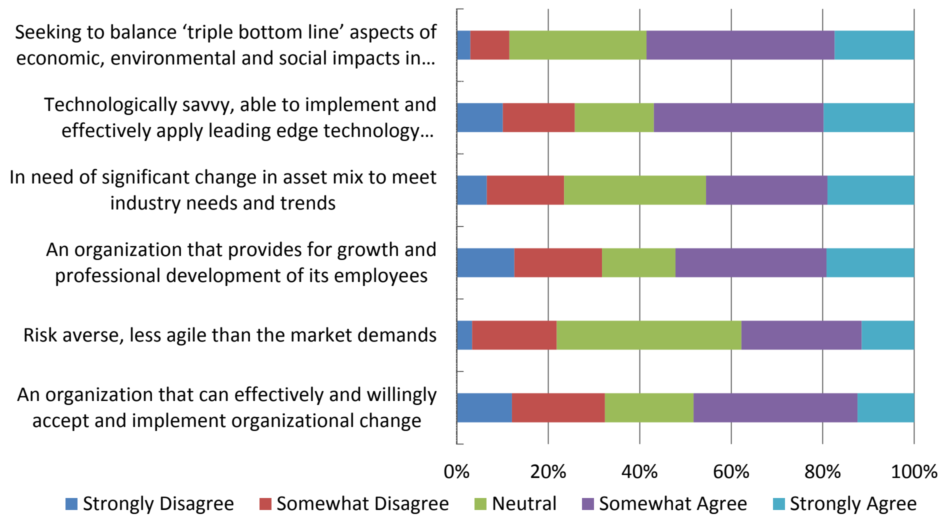
- Response Rate:
  - 321 Total Responses (~75% of Lakeland Electric Staff)
  - Excellent response rate, supports statistically valid survey

3

# Q1. Currently, I would characterize Lakeland Electric as:


n = 321

# Q1. Currently, I would characterize Lakeland Electric as:




n = 321

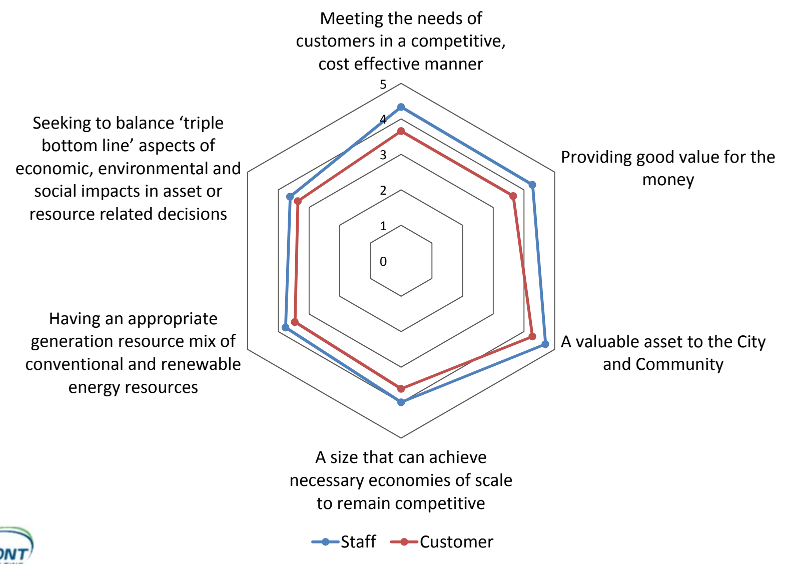
# Comparing Questions 1 and 2

- Questions 1 and 2 asked the same series of questions
- Question 1 solicited feedback from Lakeland Electric staff perspective
- Question 2 solicited feedback from a customer perspective
- The following slides and 'spider web' graphs compare how staff characterize Lakeland Electric to how customers are perceived to characterize Lakeland Electric

6

# Comparison of Q1 (Staff View) and Q2 (Perceived Customer View) Responses

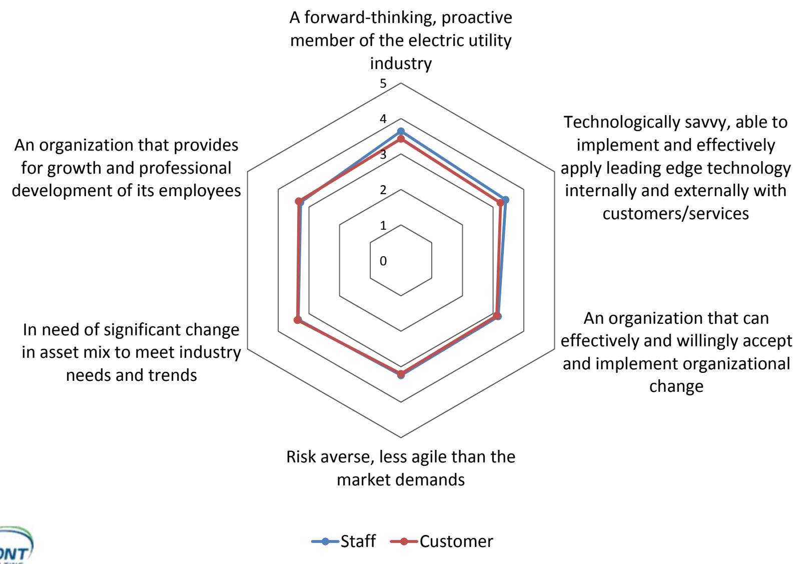
Based on Average Score (1=Strongly Disagree to 5=Strongly Agree)




n = 320

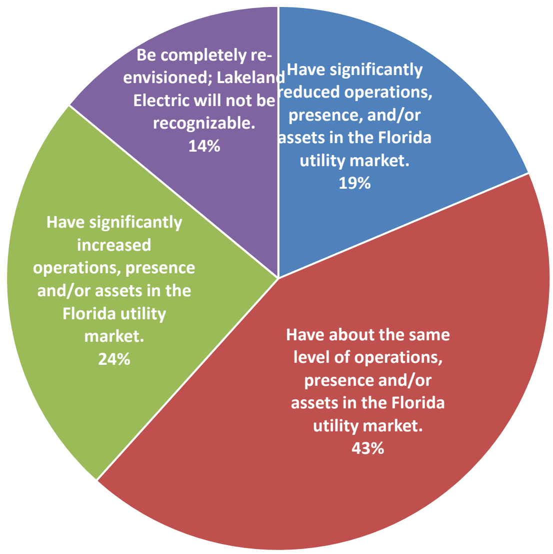
# Comparison of Q1 and Q2 responses

Based on Average Score (1=Strongly Disagree to 5=Strongly Agree)



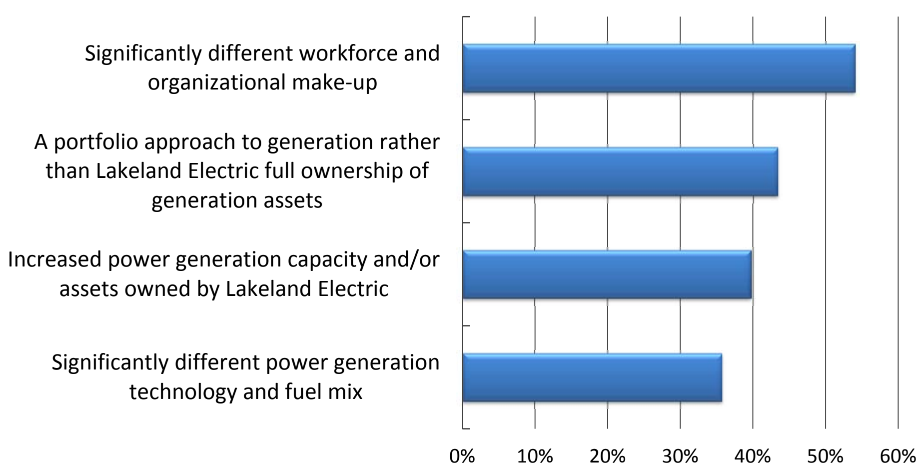

n = 320

# Q3. In 2025 Lakeland Electric will:



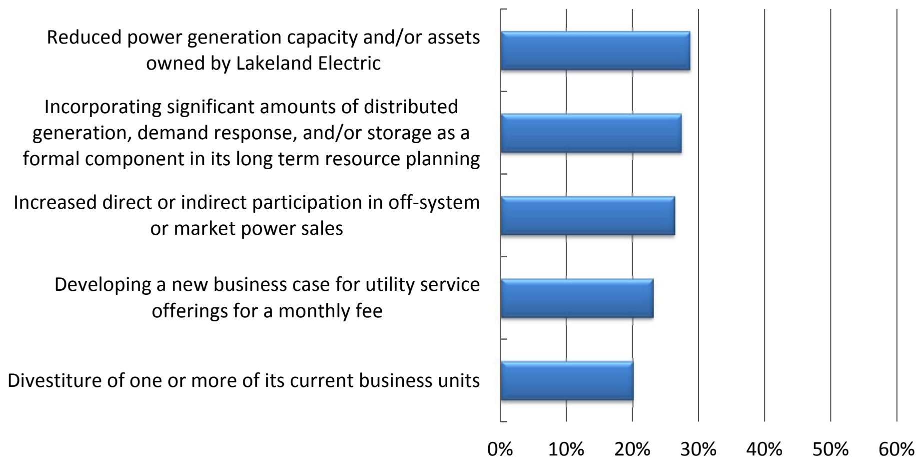

n = 300

# Q4. If Lakeland Electric were to look different in 2025, it may include:




n = 300

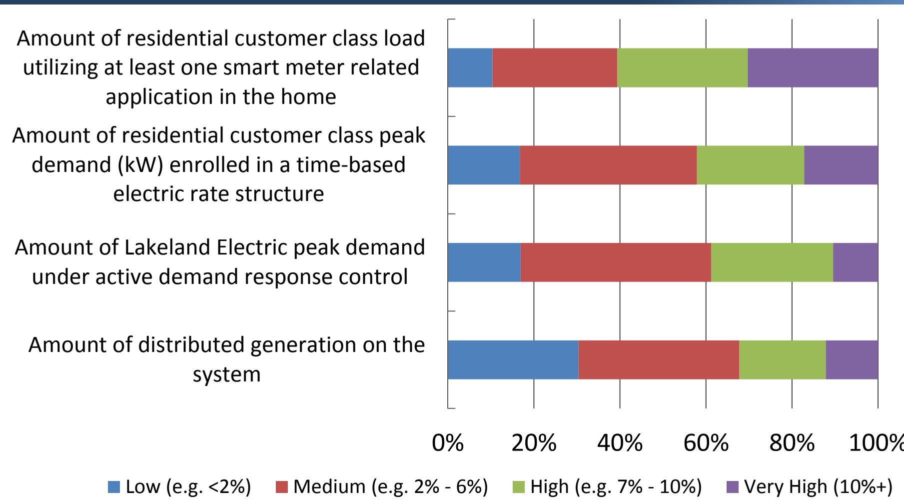
# Q4. If Lakeland Electric were to look different in 2025, it may include:




nFRONT CONSULTING

n = 300

# Q5. Please indicate your expectation at the level of customer adoption and/or integration with Lakeland Electric by 2025 for each of the following:




Note: "Don't Know" was selected on 27% of responses

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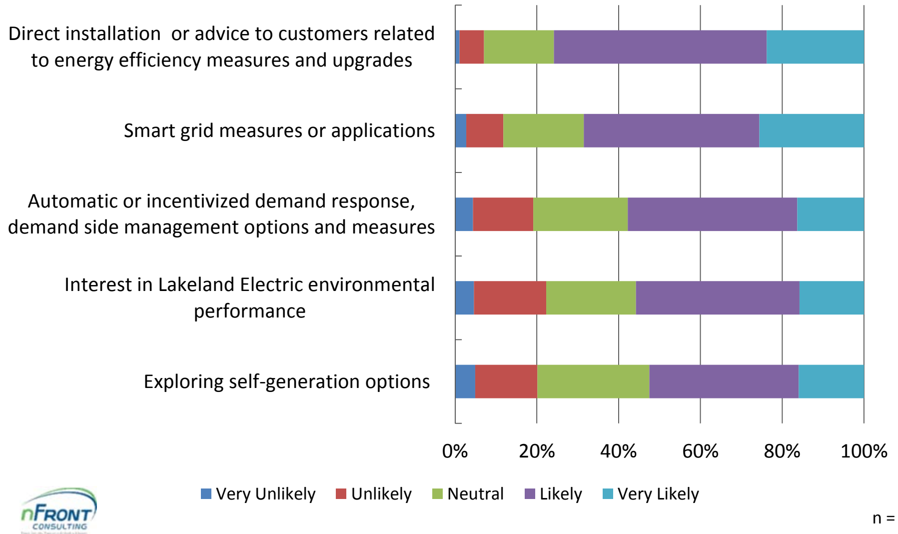
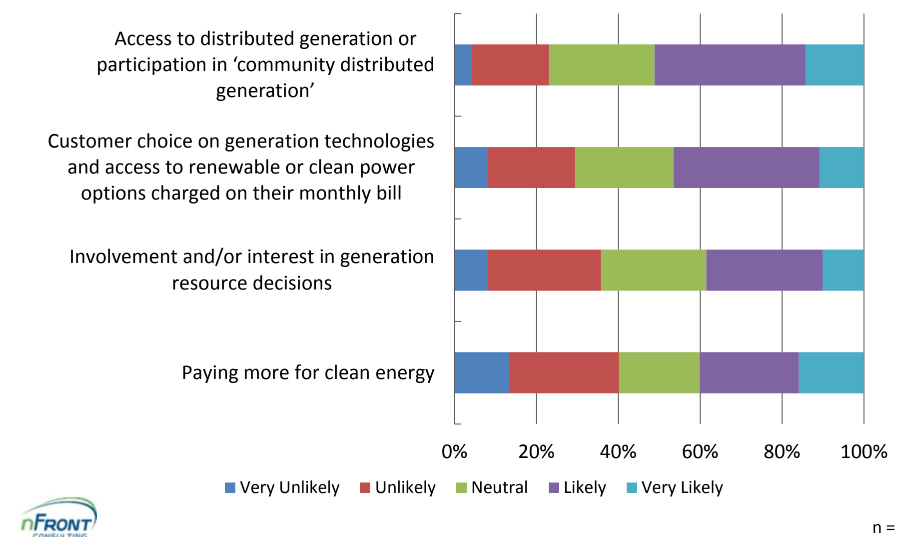
n = 296

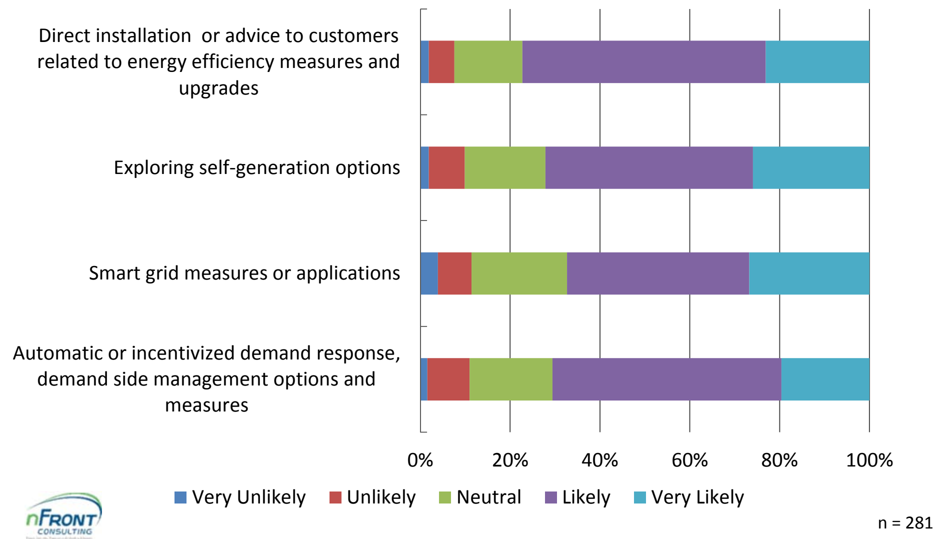
## Q6. Will the following issues or services grow in importance to our residential customers between now and 2025?



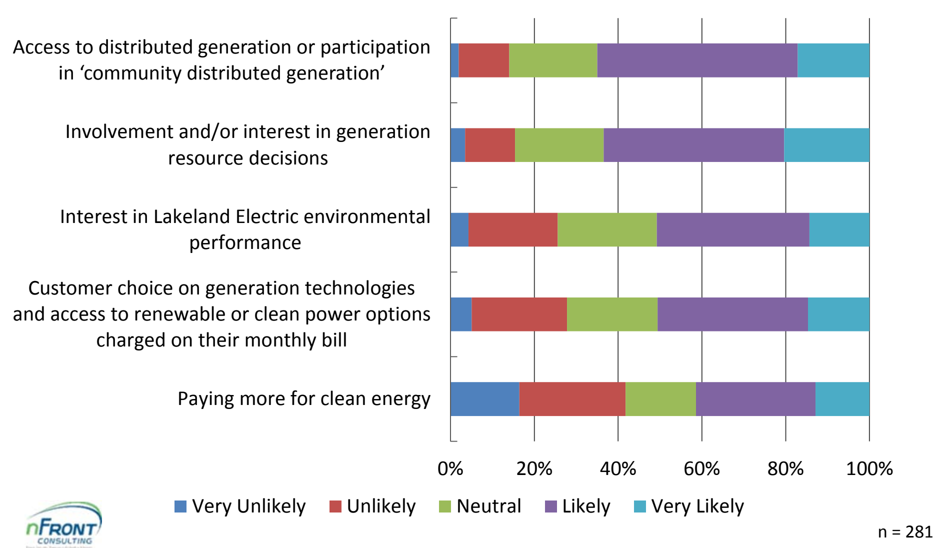

## Q6. Will the following issues or services grow in importance to our residential customers between now and 2025?



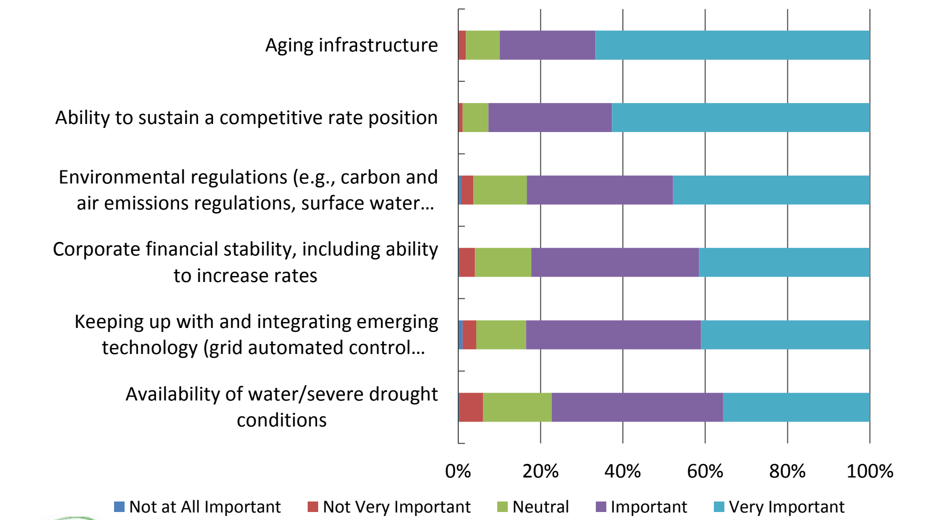
## Q7. Will the following issues or services grow in importance for our commercial and industrial customers between now and 2025?




## Q7. Will the following issues or services grow in importance for our commercial and industrial customers between now and 2025?

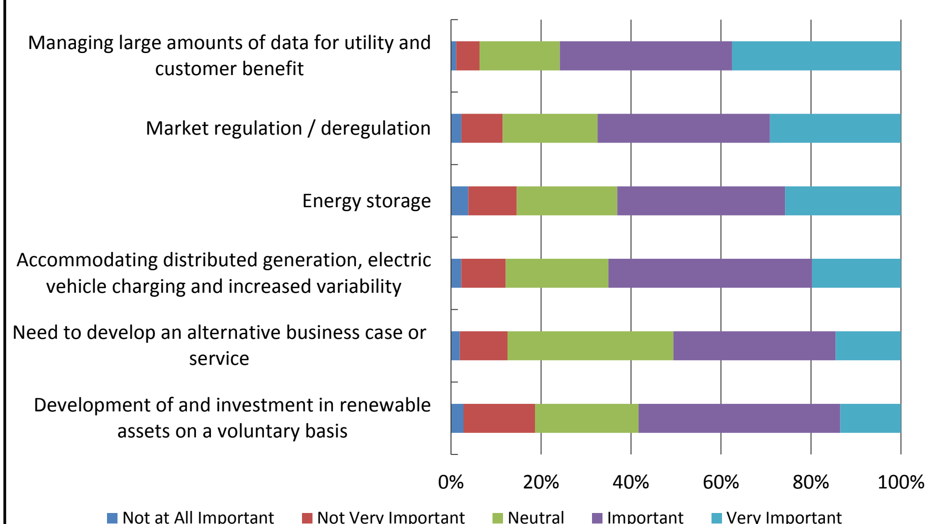


## Q8. Please rate the importance of the following issues for Lakeland Electric in 2017:



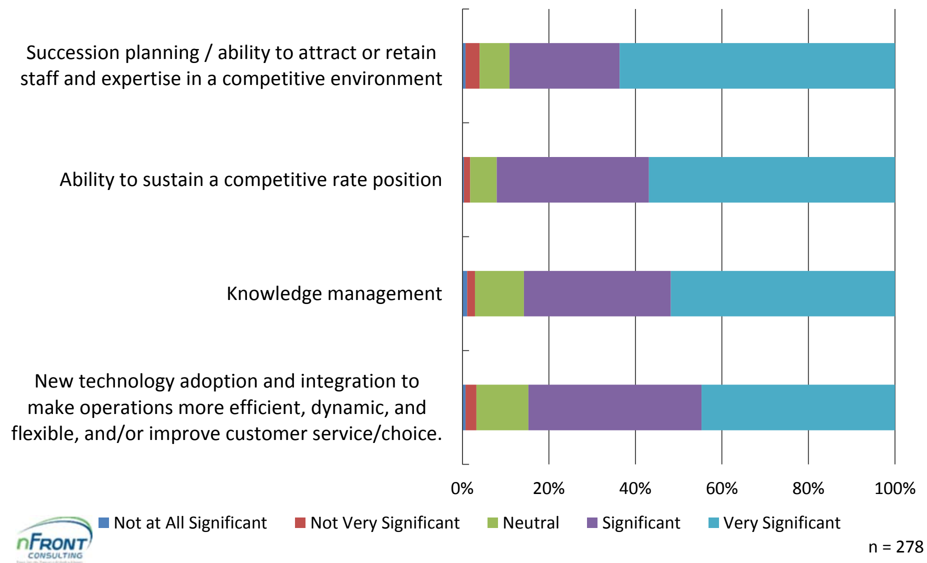

n = 277

## Q8. Please rate the importance of the following issues for Lakeland Electric in 2017:

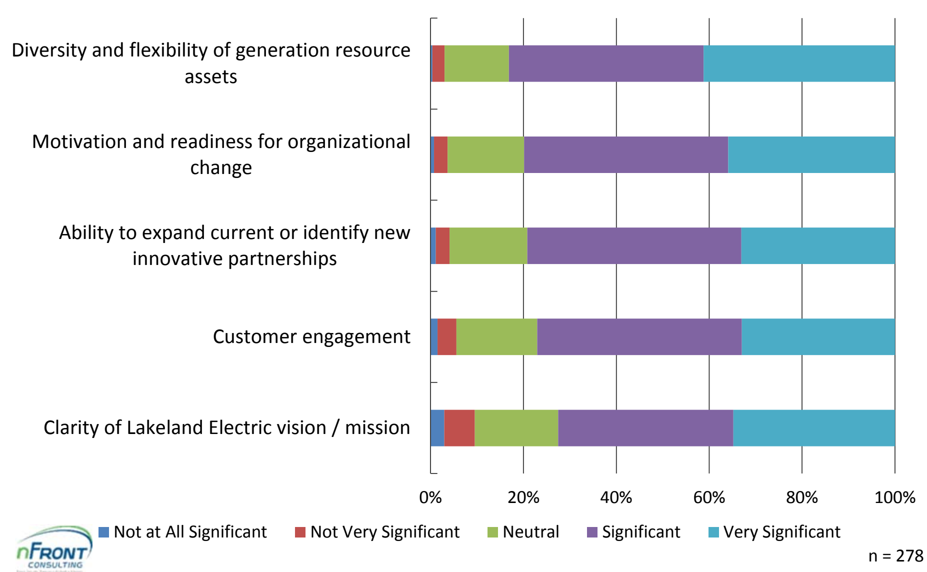



n = 277

## Q9. Rate the critical success factors for Lakeland Electric as it meets the challenges of the industry over the next ten years:




## Q9. Rate the critical success factors for Lakeland Electric as it meets the challenges of the industry over the next ten years:



## Q10. Open Responses - Please tell us more regarding your views about Lakeland Electric now and in the future, and/or what elements the Strategic Resource Plan should address or include.

### General Themes

- Address Aging Infrastructure / Asset Management
  - Existing generation plant decisions
  - Generation portfolio diversity
- Attracting / Retaining Employees
  - Competitive Compensation
  - Development and Training
- Support for developing a long term strategy
- Governance Structure
  - How to maintain operating excellence through political changes?
  - Ensure stakeholders and decision makers are educated on LE and utility issues

84 Total Responses

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21

## Q10. Open Responses - Please tell us more regarding your views about Lakeland Electric now and in the future, and/or what elements the Strategic Resource Plan should address or include.

### General Themes Continued

- Organizational
  - Perceived gap between management and staff
  - Enhance communication
- Leverage AMI to Provide Customer Technology Options
- Prepare for Renewable Energy
  - Distributed Generation (prepare rate structures now, ensure LE stability)
  - Meet customers needs, comply at state/national level, don't pursue voluntary renewables
  - Use business case justification for owned / larger scale renewable energy
- LE has a Great Opportunity / Upside
  - Talented staff, willing to work hard
  - 'put us to work' on the strategy

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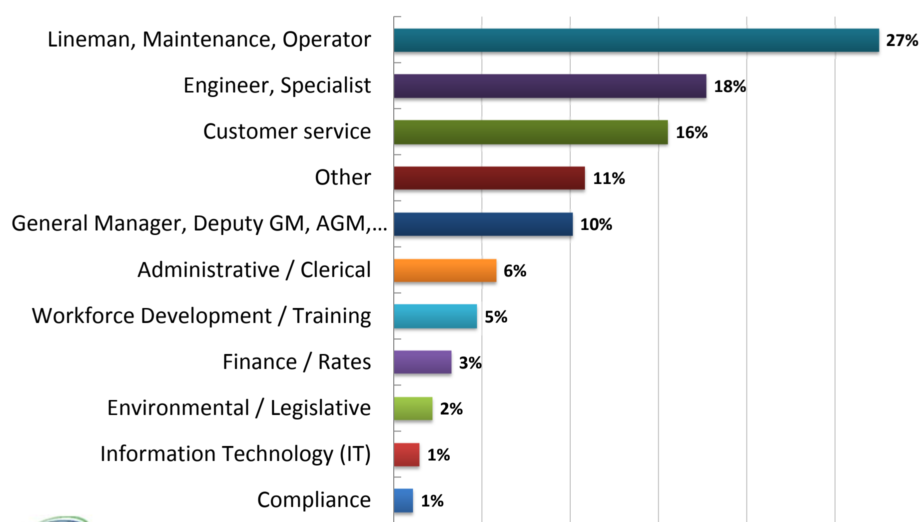
84 Total Responses

22

## Survey Demographics

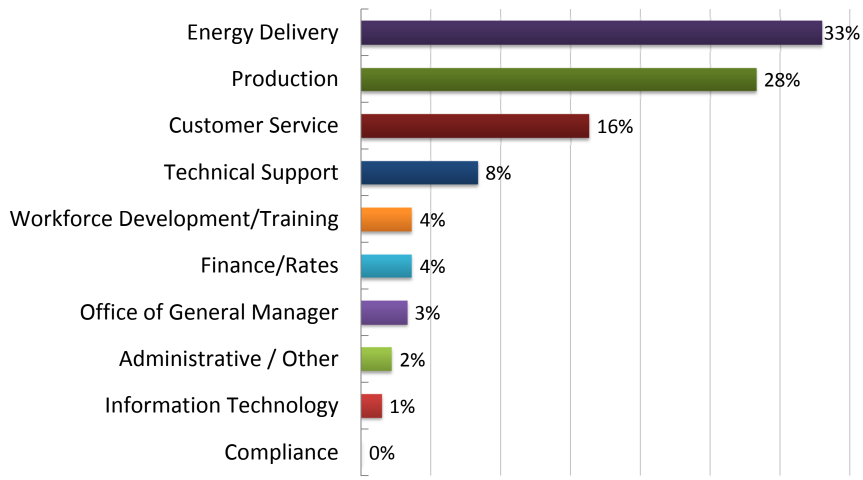
23

# Job function / role in organization:



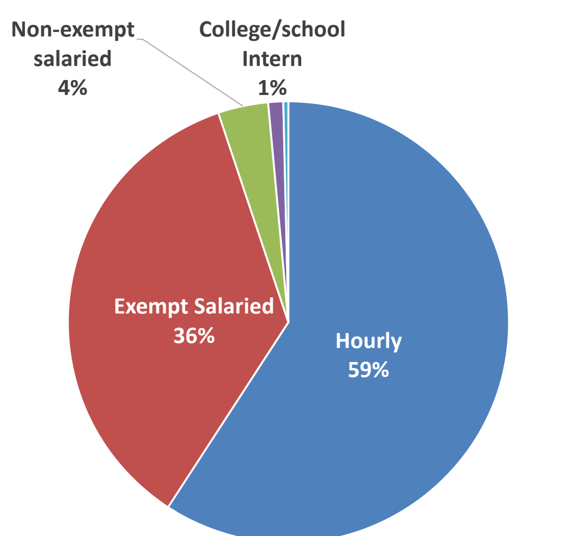

n = 277

# Utility department or functional area:



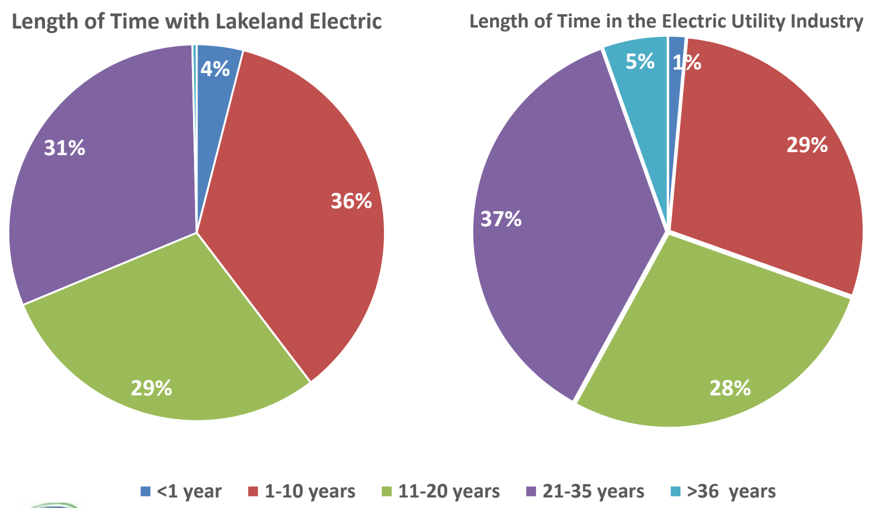

n = 276

# Method of Compensation:




n = 275

## Length of Time with Lakeland Electric / Electric Utility Industry




For questions or additional information regarding the staff survey in support of the Strategic Resource Plan, please contact:

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Farzie.Shelton@lakelandelectric.com

# Appendix D
# Resource Planning Results and Risk Modeling Inputs

## Table D-1: Projected DSM – Business Cases 1 & 2

| DSM Load Reduction | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Conservation | | | | | | | | | | | | | | | | | | | | |
| Annual Energy (GWh) | 3.8 | 6.2 | 8.6 | 10.8 | 13.1 | 14.3 | 15.5 | 16.6 | 17.7 | 18.8 | 19.8 | 20.8 | 21.8 | 22.8 | 23.7 | 24.5 | 25.4 | 26.2 | 27.1 | 27.8 |
| Summer Peak (MW) | 1.9 | 2.9 | 3.9 | 4.8 | 5.7 | 6.5 | 7.2 | 7.8 | 8.5 | 9.1 | 9.8 | 10.4 | 10.9 | 11.5 | 12.0 | 12.6 | 13.1 | 13.6 | 14.0 | 14.5 |
| Winter Peak (MW) | 2.1 | 3.2 | 4.3 | 5.4 | 6.5 | 7.2 | 7.9 | 8.6 | 9.3 | 9.9 | 10.5 | 11.1 | 11.7 | 12.3 | 12.8 | 13.4 | 13.9 | 14.4 | 14.8 | 15.3 |
| DR & Interruptible | | | | | | | | | | | | | | | | | | | | |
| Annual Energy (GWh) | 0.1 | 0.1 | 0.2 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Summer Peak (MW) | 20.7 | 21.4 | 22.1 | 22.8 | 23.5 | 23.6 | 23.6 | 23.7 | 23.7 | 23.8 | 23.9 | 23.9 | 24.0 | 24.1 | 24.1 | 24.2 | 24.2 | 24.3 | 24.4 | 24.4 |
| Winter Peak (MW) | 19.7 | 20.7 | 21.7 | 22.7 | 23.7 | 23.8 | 23.8 | 23.9 | 23.9 | 24.0 | 24.0 | 24.1 | 24.2 | 24.2 | 24.3 | 24.3 | 24.4 | 24.5 | 24.5 | 24.6 |
| Customer Solar PV | | | | | | | | | | | | | | | | | | | | |
| Annual Energy (GWh) | 2.1 | 4.3 | 6.4 | 8.5 | 10.5 | 12.6 | 13.0 | 13.5 | 14.1 | 14.7 | 15.2 | 15.8 | 16.5 | 17.3 | 17.9 | 18.6 | 19.4 | 20.2 | 21.0 | 21.7 |
| Summer Peak (MW) | 0.9 | 1.7 | 2.6 | 3.4 | 4.3 | 5.1 | 5.3 | 5.6 | 5.9 | 6.1 | 6.4 | 6.7 | 7.0 | 7.4 | 7.7 | 8.0 | 8.4 | 8.8 | 9.1 | 9.5 |
| Winter Peak (MW) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |

## Table D-2: Projected DSM – Business Case 3

| DSM Load Reduction | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Conservation | | | | | | | | | | | | | | | | | | | | |
| Annual Energy (GWh) | 82.1 | 122.2 | 161.0 | 198.7 | 235.1 | 268.4 | 300.5 | 331.7 | 361.8 | 390.9 | 419.0 | 446.2 | 472.5 | 497.9 | 522.5 | 546.3 | 569.2 | 591.5 | 612.9 | 633.7 |
| Summer Peak (MW) | 21.5 | 31.9 | 41.9 | 51.7 | 61.1 | 69.9 | 78.4 | 86.6 | 94.6 | 102.2 | 109.7 | 116.8 | 123.8 | 130.5 | 137.0 | 143.3 | 149.3 | 155.2 | 160.9 | 166.3 |
| Winter Peak (MW) | 21.8 | 32.5 | 42.8 | 52.8 | 62.5 | 71.3 | 79.9 | 88.1 | 96.0 | 103.8 | 111.2 | 118.4 | 125.3 | 132.1 | 138.5 | 144.8 | 150.9 | 156.8 | 162.5 | 167.9 |
| DR & Interruptible | | | | | | | | | | | | | | | | | | | | |
| Annual Energy (GWh) | 0.1 | 0.1 | 0.2 | 0.3 | 0.3 | 0.6 | 0.8 | 1.1 | 1.3 | 1.6 | 1.8 | 2.1 | 2.3 | 2.6 | 2.8 | 3.0 | 3.3 | 3.5 | 3.8 | 4.0 |
| Summer Peak (MW) | 20.7 | 21.4 | 22.1 | 22.8 | 23.5 | 26.8 | 30.2 | 33.5 | 36.8 | 40.1 | 43.5 | 46.8 | 50.1 | 53.5 | 56.8 | 60.1 | 63.4 | 66.8 | 70.1 | 73.4 |
| Winter Peak (MW) | 19.7 | 20.7 | 21.7 | 22.7 | 23.7 | 27.2 | 30.8 | 34.3 | 37.8 | 41.3 | 44.8 | 48.3 | 51.9 | 55.4 | 58.9 | 62.4 | 65.9 | 69.5 | 73.0 | 76.5 |
| Customer Solar PV | | | | | | | | | | | | | | | | | | | | |
| Annual Energy (GWh) | 10.0 | 19.9 | 29.7 | 39.4 | 49.0 | 58.6 | 60.5 | 62.9 | 65.5 | 68.0 | 70.4 | 73.2 | 76.3 | 79.7 | 82.5 | 85.5 | 89.0 | 92.8 | 96.3 | 99.4 |
| Summer Peak (MW) | 4.1 | 8.1 | 12.1 | 16.0 | 19.9 | 23.8 | 24.8 | 26.0 | 27.1 | 28.4 | 29.5 | 30.8 | 32.3 | 34.0 | 35.2 | 36.7 | 38.3 | 40.3 | 41.8 | 43.3 |
| Winter Peak (MW) | 0.0 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 |

## Table D-3: Projected DSM – Business Case 4

| DSM Load Reduction | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Conservation | | | | | | | | | | | | | | | | | | | | |
| Annual Energy (GWh) | 26.6 | 40.3 | 53.7 | 66.6 | 79.2 | 89.5 | 99.4 | 109.0 | 118.3 | 127.3 | 136.0 | 144.4 | 152.5 | 160.4 | 168.0 | 175.3 | 182.4 | 189.3 | 196.0 | 202.4 |
| Summer Peak (MW) | 10.3 | 15.4 | 20.3 | 25.1 | 29.7 | 33.9 | 37.9 | 41.8 | 45.6 | 49.2 | 52.7 | 56.1 | 59.4 | 62.6 | 65.6 | 68.6 | 71.5 | 74.3 | 76.9 | 79.5 |
| Winter Peak (MW) | 10.6 | 16.0 | 21.2 | 26.3 | 31.2 | 35.3 | 39.4 | 43.3 | 47.0 | 50.7 | 54.2 | 57.6 | 60.9 | 64.1 | 67.2 | 70.2 | 73.1 | 75.9 | 78.5 | 81.1 |
| DR & Interruptible | | | | | | | | | | | | | | | | | | | | |
| Annual Energy (GWh) | 0.1 | 0.1 | 0.2 | 0.3 | 0.3 | 0.6 | 0.8 | 1.1 | 1.3 | 1.6 | 1.8 | 2.1 | 2.3 | 2.6 | 2.8 | 3.0 | 3.3 | 3.5 | 3.8 | 4.0 |
| Summer Peak (MW) | 20.7 | 21.4 | 22.1 | 22.8 | 23.5 | 26.8 | 30.2 | 33.5 | 36.8 | 40.1 | 43.5 | 46.8 | 50.1 | 53.5 | 56.8 | 60.1 | 63.4 | 66.8 | 70.1 | 73.4 |
| Winter Peak (MW) | 19.7 | 20.7 | 21.7 | 22.7 | 23.7 | 27.2 | 30.8 | 34.3 | 37.8 | 41.3 | 44.8 | 48.3 | 51.9 | 55.4 | 58.9 | 62.4 | 65.9 | 69.5 | 73.0 | 76.5 |
| Customer Solar PV | | | | | | | | | | | | | | | | | | | | |
| Annual Energy (GWh) | 4.8 | 9.6 | 14.4 | 19.1 | 23.7 | 28.3 | 29.3 | 30.5 | 31.7 | 32.9 | 34.1 | 35.5 | 37.0 | 38.7 | 40.1 | 41.5 | 43.2 | 45.1 | 46.8 | 48.3 |
| Summer Peak (MW) | 2.0 | 3.9 | 5.8 | 7.7 | 9.6 | 11.5 | 12.0 | 12.6 | 13.1 | 13.8 | 14.3 | 15.0 | 15.7 | 16.5 | 17.1 | 17.8 | 18.6 | 19.6 | 20.3 | 21.0 |
| Winter Peak (MW) | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |

## Table D-4: Supply & Demand Balance
## Business Case 1

| SUMMER | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak less DSM | 608 | 616 | 620 | 624 | 628 | 633 | 639 | 645 | 652 | 658 | 663 | 670 | 677 | 684 | 690 | 696 | 702 | 710 | 716 | 722 |
| Peak+Reserves | 699 | 708 | 713 | 718 | 723 | 728 | 735 | 742 | 749 | 757 | 763 | 770 | 778 | 787 | 793 | 800 | 808 | 816 | 823 | 830 |
| Resources: | | | | | | | | | | | | | | | | | | | | |
| Coal | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 |
| NGCC | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 695 | 695 | 695 | 695 | 695 | 695 | 695 | 695 | 695 | 695 | 695 | 695 |
| NGST | 106 | 106 | 106 | 106 | 106 | 106 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Peaking | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 |
| Renewable | 9 | 9 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| New Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 168 | 168 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Resources | 829 | 829 | 839 | 839 | 839 | 839 | 901 | 901 | 985 | 985 | 985 | 985 | 985 | 985 | 985 | 985 | 985 | 985 | 985 | 985 |
| Capacity Need/(Surplus) | -130 | -121 | -126 | -121 | -116 | -111 | -166 | -159 | -236 | -229 | -223 | -215 | -207 | -199 | -193 | -186 | -178 | -169 | -162 | -156 |

| WINTER | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak less DSM | 667 | 678 | 682 | 689 | 694 | 698 | 704 | 710 | 717 | 724 | 728 | 734 | 740 | 748 | 752 | 757 | 764 | 772 | 776 | 781 |
| Peak+Reserves | 767 | 779 | 785 | 792 | 799 | 802 | 810 | 817 | 824 | 833 | 837 | 844 | 851 | 860 | 864 | 871 | 878 | 888 | 893 | 899 |
| Resources: | | | | | | | | | | | | | | | | | | | | |
| Coal | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 |
| NGCC | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 759 | 759 | 759 | 759 | 759 | 759 | 759 | 759 | 759 | 759 | 759 | 759 |
| NGST | 106 | 106 | 106 | 106 | 106 | 106 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Peaking | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 |
| Renewable | 3 | 3 | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| New Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 187 | 187 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Resources | 861 | 861 | 862 | 863 | 863 | 863 | 944 | 944 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 | 1,038 |
| Capacity Need/(Surplus) | -94 | -81 | -77 | -71 | -65 | -61 | -135 | -127 | -214 | -205 | -201 | -194 | -187 | -178 | -173 | -167 | -160 | -150 | -145 | -139 |

## Table D-5: Supply & Demand Balance
## Business Case 2

| SUMMER | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak less DSM | 608 | 616 | 620 | 624 | 628 | 633 | 639 | 645 | 652 | 658 | 663 | 670 | 677 | 684 | 690 | 696 | 702 | 710 | 716 | 722 |
| Peak+Reserves | 699 | 708 | 713 | 718 | 723 | 728 | 735 | 742 | 749 | 757 | 763 | 770 | 778 | 787 | 793 | 800 | 808 | 816 | 823 | 830 |
| Resources: | | | | | | | | | | | | | | | | | | | | |
| Coal | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 |
| NGCC | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 |
| NGST | 106 | 106 | 106 | 106 | 106 | 106 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Peaking | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 |
| Renewable | 9 | 9 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| New Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 72 | 72 | 72 | 72 | 72 | 103 | 103 | 103 | 103 | 103 | 128 | 128 | 128 | 128 |
| Total Resources | 829 | 829 | 839 | 839 | 839 | 839 | 805 | 805 | 805 | 805 | 805 | 836 | 836 | 836 | 836 | 836 | 861 | 861 | 861 | 861 |
| Capacity Need/(Surplus) | -130 | -121 | -126 | -121 | -116 | -111 | -70 | -63 | -56 | -48 | -42 | -65 | -58 | -49 | -43 | -36 | -53 | -44 | -37 | -31 |

| WINTER | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak less DSM | 667 | 678 | 682 | 689 | 694 | 698 | 704 | 710 | 717 | 724 | 728 | 734 | 740 | 748 | 752 | 757 | 764 | 772 | 776 | 781 |
| Peak+Reserves | 767 | 779 | 785 | 792 | 799 | 802 | 810 | 817 | 824 | 833 | 837 | 844 | 851 | 860 | 864 | 871 | 878 | 888 | 893 | 899 |
| Resources: | | | | | | | | | | | | | | | | | | | | |
| Coal | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 |
| NGCC | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 |
| NGST | 106 | 106 | 106 | 106 | 106 | 106 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Peaking | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 |
| Renewable | 3 | 3 | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| New Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 80 | 80 | 80 | 80 | 80 | 114 | 114 | 114 | 114 | 114 | 142 | 142 | 142 | 142 |
| Total Resources | 861 | 861 | 862 | 863 | 863 | 863 | 837 | 837 | 837 | 837 | 837 | 871 | 871 | 871 | 871 | 871 | 899 | 899 | 899 | 899 |
| Capacity Need/(Surplus) | -94 | -81 | -77 | -71 | -65 | -61 | -28 | -20 | -13 | -5 | -1 | -28 | -20 | -11 | -7 | -1 | -21 | -11 | -7 | -1 |

## Table D-6: Supply & Demand Balance
## Business Case 3

| SUMMER | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak less DSM | 585 | 580 | 572 | 565 | 557 | 548 | 542 | 536 | 531 | 526 | 521 | 516 | 512 | 509 | 504 | 500 | 497 | 494 | 491 | 487 |
| Peak+Reserves | 673 | 668 | 658 | 650 | 641 | 630 | 623 | 617 | 611 | 605 | 599 | 594 | 589 | 585 | 580 | 575 | 572 | 569 | 564 | 560 |
| Resources: | | | | | | | | | | | | | | | | | | | | |
| Coal | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 |
| NGCC | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 |
| NGST | 106 | 106 | 106 | 106 | 106 | 106 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Peaking | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 |
| Renewable | 9 | 9 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| New Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Resources | 829 | 829 | 839 | 839 | 839 | 839 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 | 733 |
| Capacity Need/(Surplus) | -156 | -162 | -181 | -189 | -198 | -209 | -110 | -116 | -122 | -128 | -134 | -139 | -144 | -148 | -153 | -158 | -161 | -164 | -169 | -173 |

| WINTER | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak less DSM | 647 | 648 | 644 | 641 | 638 | 630 | 625 | 620 | 616 | 613 | 606 | 602 | 598 | 597 | 591 | 587 | 585 | 584 | 580 | 577 |
| Peak+Reserves | 744 | 746 | 740 | 737 | 734 | 724 | 719 | 713 | 708 | 705 | 697 | 692 | 688 | 686 | 680 | 675 | 672 | 672 | 667 | 663 |
| Resources: | | | | | | | | | | | | | | | | | | | | |
| Coal | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 | 205 |
| NGCC | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 |
| NGST | 106 | 106 | 106 | 106 | 106 | 106 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Peaking | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 |
| Renewable | 3 | 3 | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| New Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Resources | 861 | 861 | 862 | 863 | 863 | 863 | 757 | 757 | 757 | 757 | 757 | 757 | 757 | 757 | 757 | 757 | 757 | 757 | 757 | 757 |
| Capacity Need/(Surplus) | -117 | -115 | -121 | -126 | -129 | -139 | -38 | -44 | -49 | -53 | -61 | -65 | -69 | -71 | -78 | -82 | -85 | -85 | -90 | -94 |

## Table D-7: Supply & Demand Balance
## Business Case 4

| SUMMER | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak less DSM | 599 | 601 | 600 | 600 | 599 | 596 | 595 | 595 | 594 | 594 | 593 | 593 | 593 | 594 | 594 | 594 | 595 | 596 | 596 | 596 |
| Peak+Reserves | 688 | 691 | 690 | 690 | 689 | 686 | 684 | 684 | 683 | 683 | 682 | 682 | 682 | 684 | 683 | 683 | 684 | 685 | 686 | 685 |
| Resources: | | | | | | | | | | | | | | | | | | | | |
| Coal | 205 | 205 | 205 | 205 | 205 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NGCC | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 |
| NGST | 106 | 106 | 106 | 106 | 106 | 261 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 |
| Peaking | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 | 66 |
| Renewable | 9 | 9 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 64 | 64 | 64 | 64 | 64 |
| New Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 14 | 14 | 14 | 14 | 14 |
| Total Resources | 829 | 829 | 839 | 839 | 839 | 789 | 737 | 737 | 737 | 737 | 737 | 737 | 737 | 737 | 737 | 742 | 742 | 742 | 742 | 742 |
| Capacity Need/(Surplus) | -141 | -138 | -149 | -149 | -150 | -104 | -52 | -53 | -53 | -54 | -55 | -55 | -54 | -53 | -54 | -59 | -58 | -56 | -56 | -56 |

| WINTER | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak less DSM | 658 | 665 | 666 | 668 | 670 | 666 | 666 | 665 | 665 | 666 | 663 | 663 | 663 | 665 | 663 | 662 | 663 | 665 | 664 | 664 |
| Peak+Reserves | 757 | 765 | 765 | 768 | 770 | 766 | 766 | 765 | 765 | 766 | 762 | 762 | 762 | 765 | 762 | 761 | 762 | 765 | 764 | 763 |
| Resources: | | | | | | | | | | | | | | | | | | | | |
| Coal | 205 | 205 | 205 | 205 | 205 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NGCC | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 | 478 |
| NGST | 106 | 106 | 106 | 106 | 106 | 261 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 | 155 |
| Peaking | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 | 69 |
| Renewable | 3 | 3 | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 50 | 50 | 50 | 50 | 50 |
| New Peaking | 0 | 0 | 0 | 0 | 0 | 0 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 15 | 15 | 15 | 15 | 15 |
| Total Resources | 861 | 861 | 862 | 863 | 863 | 814 | 767 | 767 | 767 | 767 | 767 | 767 | 767 | 767 | 767 | 767 | 767 | 767 | 767 | 767 |
| Capacity Need/(Surplus) | -104 | -96 | -96 | -95 | -93 | -48 | -1 | -2 | -2 | -1 | -4 | -5 | -4 | -2 | -5 | -6 | -5 | -2 | -4 | -4 |

**Table D-8: Projected Fuel Prices – Business Cases 1 &2**
**Nominal $/MMBtu**

| | Natural Gas | | | Coal | |
|---|---|---|---|---|---|
| | H. Hub | Delivered | #2 Oil | LE | OUC |
| 2015 | 4.39 | 4.68 | 22.67 | 3.10 | 3.30 |
| 2016 | 4.34 | 4.62 | 23.22 | 3.18 | 3.39 |
| 2017 | 4.49 | 4.78 | 23.79 | 3.35 | 3.43 |
| 2018 | 4.65 | 4.95 | 24.37 | 3.40 | 3.54 |
| 2019 | 4.81 | 5.12 | 24.96 | 3.50 | 3.65 |
| 2020 | 5.00 | 5.32 | 25.57 | 3.61 | 3.76 |
| 2021 | 5.18 | 5.51 | 26.20 | 3.72 | 3.87 |
| 2022 | 5.34 | 5.68 | 26.84 | 3.83 | 3.99 |
| 2023 | 5.46 | 5.81 | 27.49 | 3.94 | 4.11 |
| 2024 | 5.54 | 5.89 | 28.16 | 4.06 | 4.23 |
| 2025 | 5.65 | 6.02 | 28.85 | 4.19 | 4.36 |
| 2026 | 5.79 | 6.16 | 29.56 | 4.31 | 4.49 |
| 2027 | 5.90 | 6.28 | 30.28 | 4.44 | 4.63 |
| 2028 | 6.05 | 6.44 | 31.02 | 4.58 | 4.77 |
| 2029 | 6.35 | 6.76 | 31.77 | 4.71 | 4.91 |
| 2030 | 6.65 | 7.07 | 32.55 | 4.86 | 5.06 |
| 2031 | 7.00 | 7.45 | 33.34 | 5.00 | 5.21 |
| 2032 | 7.35 | 7.82 | 34.16 | 5.15 | 5.37 |
| 2033 | 7.70 | 8.19 | 34.99 | 5.31 | 5.53 |
| 2034 | 8.10 | 8.61 | 35.84 | 5.47 | 5.70 |

**Table D-9: Projected Fuel Prices – Business Case 3**
**Nominal $/MMBtu**

| | Natural Gas | | | Coal | |
|---|---|---|---|---|---|
| | H. Hub | Delivered | #2 Oil | LE | OUC |
| 2015 | 4.28 | 4.56 | 22.67 | 3.05 | 3.24 |
| 2016 | 4.18 | 4.46 | 23.22 | 3.10 | 3.31 |
| 2017 | 4.38 | 4.67 | 23.79 | 3.25 | 3.33 |
| 2018 | 4.58 | 4.88 | 24.37 | 3.29 | 3.42 |
| 2019 | 4.72 | 5.03 | 24.96 | 3.37 | 3.51 |
| 2020 | 4.90 | 5.22 | 25.57 | 3.47 | 3.62 |
| 2021 | 5.06 | 5.39 | 26.20 | 3.58 | 3.72 |
| 2022 | 5.13 | 5.46 | 26.84 | 3.68 | 3.83 |
| 2023 | 5.20 | 5.54 | 27.49 | 3.78 | 3.93 |
| 2024 | 5.26 | 5.61 | 28.16 | 3.90 | 4.06 |
| 2025 | 5.39 | 5.74 | 28.85 | 4.02 | 4.18 |
| 2026 | 5.56 | 5.92 | 29.56 | 4.14 | 4.31 |
| 2027 | 5.69 | 6.06 | 30.28 | 4.27 | 4.45 |
| 2028 | 5.79 | 6.17 | 31.02 | 4.40 | 4.58 |
| 2029 | 6.04 | 6.44 | 31.77 | 4.53 | 4.72 |
| 2030 | 6.28 | 6.69 | 32.55 | 4.66 | 4.85 |
| 2031 | 6.56 | 6.99 | 33.34 | 4.79 | 4.98 |
| 2032 | 6.85 | 7.30 | 34.16 | 4.92 | 5.12 |
| 2033 | 7.18 | 7.64 | 34.99 | 5.05 | 5.26 |
| 2034 | 7.56 | 8.05 | 35.84 | 5.19 | 5.40 |

**Table D-10: Projected Fuel Prices – Business Case 4**
**Nominal $/MMBtu**

| | Natural Gas | | | Coal | |
|---|---|---|---|---|---|
| | H. Hub | Delivered | #2 Oil | LE | OUC |
| 2015 | 4.39 | 4.68 | 22.67 | 3.10 | 3.30 |
| 2016 | 4.34 | 4.62 | 23.22 | 3.18 | 3.39 |
| 2017 | 4.49 | 4.78 | 23.79 | 3.35 | 3.43 |
| 2018 | 4.65 | 4.95 | 24.37 | 3.40 | 3.54 |
| 2019 | 4.81 | 5.12 | 24.96 | 3.50 | 3.65 |
| 2020 | 5.80 | 6.17 | 25.44 | 3.57 | 3.72 |
| 2021 | 5.86 | 6.23 | 25.97 | 3.64 | 3.79 |
| 2022 | 5.99 | 6.37 | 26.50 | 3.69 | 3.84 |
| 2023 | 6.09 | 6.48 | 27.04 | 3.74 | 3.89 |
| 2024 | 5.92 | 6.30 | 27.60 | 3.79 | 3.94 |
| 2025 | 5.91 | 6.29 | 28.20 | 3.85 | 4.01 |
| 2026 | 6.20 | 6.59 | 28.85 | 3.94 | 4.10 |
| 2027 | 6.35 | 6.76 | 29.52 | 4.03 | 4.19 |
| 2028 | 6.47 | 6.88 | 30.20 | 4.12 | 4.29 |
| 2029 | 6.75 | 7.19 | 30.91 | 4.21 | 4.38 |
| 2030 | 7.01 | 7.46 | 31.65 | 4.30 | 4.47 |
| 2031 | 7.33 | 7.79 | 32.38 | 4.39 | 4.57 |
| 2032 | 7.63 | 8.11 | 33.13 | 4.49 | 4.68 |
| 2033 | 7.87 | 8.36 | 33.95 | 4.61 | 4.80 |
| 2034 | 8.17 | 8.69 | 34.80 | 4.74 | 4.93 |

## Table D-11: Projected Operating Results
## Business Case 1

| | PROJECTED PRODUCTION OPERATION | | Calendar Year 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Energy Balance** | | | | | | | | | | | | | | | | | | | | | |
| | Generation: | | | | | | | | | | | | | | | | | | | | | |
| 1. | Natural Gas | GWh | 2,343 | 2,448 | 2,456 | 2,245 | 2,343 | 2,344 | 2,503 | 2,660 | 3,104 | 3,399 | 3,523 | 3,693 | 3,672 | 3,487 | 3,633 | 3,699 | 3,519 | 3,718 | 3,772 | 3,693 |
| 2. | Coal | GWh | 935 | 1,182 | 1,086 | 1,092 | 1,183 | 1,118 | 1,215 | 1,125 | 1,203 | 1,169 | 1,159 | 1,100 | 1,178 | 1,086 | 1,122 | 1,231 | 1,232 | 1,236 | 1,177 | 1,242 |
| 3. | #2 Oil | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 | - | - | - | - | - |
| 4. | #6 Oil | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5. | Power Purchase (NG) | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6. | Renewable Resource | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7. | Utility PV | GWh | 24 | 26 | 47 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| 8. | Total Gross Generation & Purchases | GWh | 3,303 | 3,656 | 3,589 | 3,388 | 3,576 | 3,514 | 3,769 | 3,835 | 4,357 | 4,619 | 4,733 | 4,844 | 4,901 | 4,624 | 4,806 | 4,981 | 4,802 | 5,005 | 5,001 | 4,987 |
| | FMPP Transactions: | | | | | | | | | | | | | | | | | | | | | |
| 9. | Purchases | GWh | 258 | 155 | 169 | 298 | 237 | 261 | 206 | 202 | 189 | 104 | 103 | 67 | 51 | 133 | 118 | 82 | 173 | 69 | 75 | 104 |
| 10. | Sales | GWh | (468) | (676) | (596) | (495) | (595) | (537) | (711) | (745) | (1,224) | (1,371) | (1,457) | (1,502) | (1,510) | (1,281) | (1,419) | (1,529) | (1,409) | (1,473) | (1,444) | (1,430) |
| 11. | Net FMPP Transactions | GWh | (210) | (521) | (427) | (197) | (358) | (276) | (506) | (543) | (1,035) | (1,267) | (1,354) | (1,434) | (1,459) | (1,148) | (1,301) | (1,447) | (1,236) | (1,404) | (1,369) | (1,326) |
| 12. | Net Load | GWh | 3,093 | 3,135 | 3,163 | 3,191 | 3,218 | 3,238 | 3,263 | 3,293 | 3,323 | 3,352 | 3,379 | 3,410 | 3,442 | 3,476 | 3,505 | 3,534 | 3,567 | 3,601 | 3,632 | 3,660 |
| | **Fuel Use** | | | | | | | | | | | | | | | | | | | | | |
| | Generation: | | | | | | | | | | | | | | | | | | | | | |
| 13. | Natural Gas | GBtu | 16,666 | 17,380 | 17,398 | 15,997 | 16,555 | 16,676 | 18,164 | 19,212 | 21,764 | 23,789 | 24,605 | 25,793 | 25,610 | 24,366 | 25,414 | 25,838 | 24,536 | 25,987 | 26,406 | 25,870 |
| 14. | Coal | GBtu | 9,648 | 12,221 | 11,305 | 11,333 | 12,222 | 11,534 | 12,500 | 11,573 | 12,394 | 12,072 | 11,966 | 11,365 | 12,177 | 11,295 | 11,562 | 12,645 | 12,623 | 12,630 | 12,015 | 12,663 |
| 15. | #2 Oil | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16. | #6 Oil | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 17. | PPA (NG) | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 18. | Renewable Resource | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 19. | Utility PV | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 20. | Total Fuel Use | GBtu | 26,314 | 29,602 | 28,703 | 27,330 | 28,777 | 28,209 | 30,665 | 30,785 | 34,158 | 35,861 | 36,571 | 37,158 | 37,787 | 35,661 | 36,976 | 38,483 | 37,158 | 38,617 | 38,422 | 38,533 |

## Table D-12: Projected Operating Results
## Business Case 2

| | PROJECTED PRODUCTION OPERATION | | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Calendar Year | | | | | | | | | | | | | | | | | | | |
| | **Energy Balance** | | | | | | | | | | | | | | | | | | | | | |
| | Generation: | | | | | | | | | | | | | | | | | | | | | |
| 1. | Natural Gas | GWh | 2,343 | 2,448 | 2,456 | 2,245 | 2,343 | 2,305 | 2,305 | 2,304 | 2,208 | 2,428 | 2,375 | 2,507 | 2,591 | 2,445 | 2,459 | 2,515 | 2,319 | 2,604 | 2,476 | 2,424 |
| 2. | Coal | GWh | 935 | 1,182 | 1,086 | 1,092 | 1,183 | 1,117 | 1,205 | 1,113 | 1,199 | 1,175 | 1,163 | 1,106 | 1,183 | 1,107 | 1,128 | 1,234 | 1,234 | 1,228 | 1,170 | 1,235 |
| 3. | #2 Oil | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4. | #6 Oil | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5. | Power Purchase (NG) | GWh | - | - | - | - | - | 0 | 14 | 12 | 16 | 19 | 19 | 38 | 37 | 42 | 61 | 39 | 31 | 29 | 35 | 35 |
| 6. | Renewable Resource | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7. | Utility PV | GWh | 24 | 26 | 47 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| 8. | Total Gross Generation & Purchases | GWh | 3,303 | 3,656 | 3,589 | 3,388 | 3,576 | 3,474 | 3,575 | 3,480 | 3,475 | 3,673 | 3,608 | 3,702 | 3,862 | 3,645 | 3,699 | 3,839 | 3,635 | 3,912 | 3,732 | 3,745 |
| | FMPP Transactions: | | | | | | | | | | | | | | | | | | | | | |
| 9. | Purchases | GWh | 258 | 155 | 169 | 298 | 237 | 271 | 262 | 291 | 360 | 252 | 283 | 228 | 183 | 299 | 314 | 263 | 417 | 217 | 353 | 375 |
| 10. | Sales | GWh | (468) | (676) | (596) | (495) | (595) | (507) | (574) | (478) | (512) | (573) | (512) | (520) | (604) | (468) | (508) | (569) | (486) | (528) | (453) | (459) |
| 11. | Net FMPP Transactions | GWh | (210) | (521) | (427) | (197) | (358) | (236) | (312) | (187) | (152) | (321) | (229) | (292) | (420) | (169) | (194) | (305) | (69) | (311) | (100) | (84) |
| 12. | Net Load | GWh | 3,093 | 3,135 | 3,163 | 3,191 | 3,218 | 3,238 | 3,263 | 3,293 | 3,323 | 3,352 | 3,379 | 3,410 | 3,442 | 3,476 | 3,505 | 3,534 | 3,567 | 3,601 | 3,632 | 3,660 |
| | **Fuel Use** | | | | | | | | | | | | | | | | | | | | | |
| | Generation: | | | | | | | | | | | | | | | | | | | | | |
| 13. | Natural Gas | GBtu | 16,666 | 17,380 | 17,398 | 15,997 | 16,555 | 16,304 | 16,229 | 16,257 | 15,571 | 17,101 | 16,684 | 17,593 | 18,166 | 17,207 | 17,314 | 17,657 | 16,284 | 18,291 | 17,368 | 17,041 |
| 14. | Coal | GBtu | 9,648 | 12,221 | 11,305 | 11,333 | 12,222 | 11,523 | 12,416 | 11,473 | 12,365 | 12,123 | 12,006 | 11,418 | 12,226 | 11,481 | 11,610 | 12,669 | 12,639 | 12,562 | 11,954 | 12,597 |
| 15. | #2 Oil | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16. | #6 Oil | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 17. | PPA (NG) | GBtu | - | - | - | - | - | 3 | 150 | 128 | 174 | 206 | 198 | 403 | 388 | 446 | 647 | 416 | 327 | 308 | 376 | 370 |
| 18. | Renewable Resource | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 19. | Utility PV | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 20. | Total Fuel Use | GBtu | 26,314 | 29,602 | 28,703 | 27,330 | 28,777 | 27,830 | 28,796 | 27,858 | 28,110 | 29,430 | 28,888 | 29,414 | 30,780 | 29,135 | 29,571 | 30,742 | 29,250 | 31,162 | 29,698 | 30,007 |

## Table D-13: Projected Operating Results
## Business Case 3

| | PROJECTED PRODUCTION OPERATION | | Calendar Year 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Energy Balance** | | | | | | | | | | | | | | | | | | | | | |
| | Generation: | | | | | | | | | | | | | | | | | | | | | |
| 1. | Natural Gas | GWh | 2,366 | 2,536 | 2,410 | 2,299 | 2,260 | 2,152 | 2,191 | 2,223 | 2,294 | 2,349 | 2,248 | 2,288 | 2,340 | 2,470 | 2,200 | 2,489 | 2,262 | 2,129 | 2,219 | 2,181 |
| 2. | Coal | GWh | 934 | 1,168 | 1,072 | 1,139 | 1,208 | 1,164 | 1,156 | 1,155 | 1,098 | 1,042 | 1,164 | 1,102 | 1,058 | 1,153 | 1,043 | 1,188 | 1,127 | 1,226 | 1,214 | 1,219 |
| 3. | #2 Oil | GWh | - | - | - | - | - | - | - | - | 0 | - | - | - | 0 | - | - | - | - | - | - | 0 |
| 4. | #6 Oil | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5. | Power Purchase (NG) | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6. | Renewable Resource | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7. | Utility PV | GWh | 24 | 26 | 47 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| 8. | Total Gross Generation & Purchases | GWh | 3,325 | 3,731 | 3,529 | 3,490 | 3,520 | 3,367 | 3,398 | 3,429 | 3,444 | 3,441 | 3,463 | 3,441 | 3,449 | 3,674 | 3,294 | 3,728 | 3,440 | 3,406 | 3,484 | 3,452 |
| | FMPP Transactions: | | | | | | | | | | | | | | | | | | | | | |
| 9. | Purchases | GWh | 211 | 94 | 135 | 178 | 174 | 212 | 191 | 210 | 168 | 191 | 205 | 190 | 176 | 116 | 276 | 60 | 208 | 231 | 207 | 199 |
| 10. | Sales | GWh | (529) | (821) | (677) | (695) | (736) | (641) | (659) | (712) | (686) | (708) | (745) | (706) | (696) | (854) | (631) | (846) | (697) | (676) | (723) | (678) |
| 11. | Net FMPP Transactions | GWh | (318) | (727) | (542) | (517) | (562) | (429) | (468) | (502) | (517) | (516) | (540) | (516) | (520) | (738) | (355) | (786) | (490) | (445) | (516) | (479) |
| 12. | Net Load | GWh | 3,007 | 3,004 | 2,987 | 2,973 | 2,958 | 2,937 | 2,930 | 2,927 | 2,926 | 2,925 | 2,923 | 2,925 | 2,930 | 2,936 | 2,939 | 2,942 | 2,950 | 2,960 | 2,968 | 2,973 |
| | **Fuel Use** | | | | | | | | | | | | | | | | | | | | | |
| | Generation: | | | | | | | | | | | | | | | | | | | | | |
| 13. | Natural Gas | GBtu | 16,796 | 17,883 | 17,012 | 16,245 | 15,943 | 15,204 | 15,484 | 15,637 | 16,138 | 16,440 | 15,734 | 16,010 | 16,349 | 17,240 | 15,365 | 17,384 | 15,858 | 14,960 | 15,628 | 15,428 |
| 14. | Coal | GBtu | 9,634 | 12,099 | 11,184 | 11,760 | 12,445 | 11,999 | 11,918 | 11,893 | 11,382 | 10,796 | 12,053 | 11,418 | 10,948 | 11,961 | 10,805 | 12,267 | 11,587 | 12,583 | 12,410 | 12,445 |
| 15. | #2 Oil | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16. | #6 Oil | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 17. | PPA (NG) | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 18. | Renewable Resource | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 19. | Utility PV | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 20. | Total Fuel Use | GBtu | 26,430 | 29,982 | 28,197 | 28,005 | 28,388 | 27,203 | 27,403 | 27,530 | 27,520 | 27,235 | 27,787 | 27,429 | 27,296 | 29,202 | 26,171 | 29,651 | 27,445 | 27,543 | 28,038 | 27,872 |

## Table D-14: Projected Operating Results
## Business Case 4

| | PROJECTED PRODUCTION OPERATION | | Calendar Year 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Energy Balance** | | | | | | | | | | | | | | | | | | | | | |
| | Generation: | | | | | | | | | | | | | | | | | | | | | |
| 1. | Natural Gas | GWh | 2,298 | 2,384 | 2,435 | 2,272 | 2,362 | 2,579 | 2,593 | 2,613 | 2,641 | 2,560 | 2,976 | 2,629 | 2,906 | 2,795 | 2,840 | 2,964 | 2,828 | 2,941 | 2,934 | 2,965 |
| 2. | Coal | GWh | 944 | 1,176 | 1,075 | 1,113 | 1,118 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3. | #2 Oil | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 | - | - | - | - | - |
| 4. | #6 Oil | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5. | Power Purchase (NG) | GWh | - | - | - | - | - | 4 | 8 | 10 | 8 | 11 | 14 | 11 | 10 | 13 | 17 | 3 | 4 | 3 | 4 | 4 |
| 6. | Renewable Resource | GWh | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 333 | 333 | 334 | 333 | 333 |
| 7. | Utility PV | GWh | 24 | 26 | 47 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| 8. | Total Gross Generation & Purchases | GWh | 3,267 | 3,587 | 3,556 | 3,436 | 3,531 | 2,635 | 2,651 | 2,674 | 2,700 | 2,623 | 3,041 | 2,691 | 2,967 | 2,859 | 2,908 | 3,351 | 3,216 | 3,329 | 3,321 | 3,353 |
| | FMPP Transactions: | | | | | | | | | | | | | | | | | | | | | |
| 9. | Purchases | GWh | 270 | 159 | 156 | 263 | 212 | 622 | 636 | 659 | 636 | 788 | 449 | 753 | 541 | 705 | 647 | 286 | 440 | 332 | 360 | 352 |
| 10. | Sales | GWh | (469) | (650) | (603) | (574) | (603) | (110) | (125) | (150) | (133) | (187) | (249) | (179) | (219) | (249) | (218) | (280) | (273) | (251) | (247) | (249) |
| 11. | Net FMPP Transactions | GWh | (199) | (491) | (447) | (311) | (392) | 512 | 511 | 508 | 504 | 601 | 201 | 574 | 322 | 456 | 428 | 6 | 167 | 81 | 113 | 103 |
| 12. | Net Load | GWh | 3,068 | 3,096 | 3,110 | 3,125 | 3,139 | 3,147 | 3,162 | 3,182 | 3,204 | 3,224 | 3,242 | 3,265 | 3,289 | 3,315 | 3,336 | 3,357 | 3,383 | 3,410 | 3,434 | 3,455 |
| | **Fuel Use** | | | | | | | | | | | | | | | | | | | | | |
| | Generation: | | | | | | | | | | | | | | | | | | | | | |
| 13. | Natural Gas | GBtu | 16,409 | 16,944 | 17,223 | 16,089 | 16,684 | 18,464 | 18,756 | 19,212 | 19,472 | 19,427 | 22,823 | 19,834 | 22,240 | 22,061 | 22,021 | 21,777 | 20,874 | 21,560 | 21,564 | 21,977 |
| 14. | Coal | GBtu | 9,724 | 12,167 | 11,207 | 11,512 | 11,556 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 15. | #2 Oil | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16. | #6 Oil | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 17. | PPA (NG) | GBtu | - | - | - | - | - | 43 | 82 | 107 | 87 | 120 | 147 | 111 | 107 | 138 | 176 | 31 | 38 | 33 | 38 | 41 |
| 18. | Renewable Resource | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 4,055 | 4,054 | 4,062 | 4,051 | 4,051 |
| 19. | Utility PV | GBtu | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 20. | Total Fuel Use | GBtu | 26,133 | 29,111 | 28,431 | 27,601 | 28,240 | 18,507 | 18,837 | 19,319 | 19,560 | 19,547 | 22,970 | 19,945 | 22,347 | 22,199 | 22,198 | 25,864 | 24,966 | 25,655 | 25,653 | 26,070 |

## Table D-15: Projected Power Supply Costs
## Business Case 1

| Line | Category | Units | Calendar Year 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **PROJECTED PRODUCTION OPERATING COSTS** | | | | | | | | | | | | | | | | | | | | | |
| | **Variable Production Costs** | | | | | | | | | | | | | | | | | | | | | |
| | **Fuel Cost:** | | | | | | | | | | | | | | | | | | | | | |
| | Generation | | | | | | | | | | | | | | | | | | | | | |
| 1. | Natural Gas | $000 | 76,826 | 80,290 | 83,493 | 79,582 | 85,267 | 89,332 | 100,880 | 110,097 | 127,698 | 141,639 | 149,874 | 160,923 | 163,051 | 159,240 | 174,514 | 185,749 | 185,800 | 207,046 | 220,557 | 227,381 |
| 2. | Coal | $000 | 29,970 | 38,981 | 38,023 | 38,723 | 43,031 | 41,808 | 46,743 | 44,485 | 49,189 | 49,302 | 50,369 | 49,268 | 54,321 | 51,926 | 54,732 | 61,715 | 63,466 | 65,365 | 64,086 | 69,676 |
| 3. | #2 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 10 | - | - | - | - | - |
| 4. | #6 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5. | Power Purchase (NG) | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6. | Renewable Resource | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7. | Utility PV | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8. | Total Fuel Cost | $000 | 106,795 | 119,271 | 121,516 | 118,305 | 128,298 | 131,140 | 147,623 | 154,582 | 176,886 | 190,941 | 200,243 | 210,190 | 217,373 | 211,167 | 229,256 | 247,464 | 249,267 | 272,412 | 284,643 | 297,057 |
| | **Variable O&M and Start Costs:** | | | | | | | | | | | | | | | | | | | | | |
| | Generation | | | | | | | | | | | | | | | | | | | | | |
| 9. | Natural Gas | $000 | 4,002 | 4,255 | 4,098 | 4,321 | 3,972 | 4,450 | 6,110 | 6,789 | 8,590 | 7,909 | 8,786 | 9,359 | 9,325 | 8,728 | 10,227 | 10,276 | 10,370 | 10,659 | 11,170 | 11,135 |
| 10. | Coal | $000 | 2,541 | 3,395 | 3,407 | 3,454 | 3,521 | 3,327 | 3,624 | 3,407 | 3,694 | 3,563 | 3,467 | 3,740 | 3,799 | 4,085 | 3,772 | 3,998 | 3,941 | 4,024 | 4,211 | 4,316 |
| 11. | #2 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1 | - | - | - | - | - |
| 12. | #6 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 13. | Power Purchase (NG) | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 14. | Renewable Resource | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 15. | Utility PV | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16. | Total Variable O&M and Start Costs | $000 | 6,543 | 7,650 | 7,505 | 7,775 | 7,493 | 7,777 | 9,734 | 10,196 | 12,284 | 11,471 | 12,253 | 13,099 | 13,124 | 12,813 | 14,000 | 14,274 | 14,311 | 14,683 | 15,381 | 15,452 |
| | **Emissions Allowance Costs:** | | | | | | | | | | | | | | | | | | | | | |
| 17. | NOx | $000 | 35 | 562 | 572 | 597 | 610 | 627 | 646 | 660 | 696 | 699 | 719 | 737 | 749 | 749 | 802 | 825 | 856 | 887 | 913 | 937 |
| 18. | SO2 | $000 | 5 | 6 | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 8 | 7 | 8 | 9 | 9 | 9 | 9 | 10 |
| 19. | CO2 | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 20. | Total Cost of Emission Allowances | $000 | 40 | 567 | 577 | 602 | 616 | 633 | 653 | 666 | 704 | 706 | 726 | 744 | 757 | 757 | 810 | 834 | 865 | 896 | 922 | 946 |
| 21. | **Total Variable Production Cost** | $000 | 113,378 | 127,489 | 129,599 | 126,683 | 136,407 | 139,550 | 158,010 | 165,445 | 189,874 | 203,118 | 213,222 | 224,034 | 231,253 | 224,737 | 244,065 | 262,572 | 264,442 | 287,990 | 300,945 | 313,456 |
| | **FMPP Transactions** | | | | | | | | | | | | | | | | | | | | | |
| 22. | Total Cost of Pool Purchases | $000 | 9,658 | 5,852 | 6,800 | 12,027 | 9,771 | 10,968 | 9,398 | 9,337 | 8,209 | 4,580 | 4,449 | 3,096 | 2,538 | 6,500 | 5,948 | 4,455 | 9,581 | 4,028 | 4,777 | 6,986 |
| 23. | Total Sales Revenue | $000 | (16,522) | (25,092) | (21,696) | (18,536) | (23,176) | (21,558) | (31,415) | (34,347) | (56,423) | (62,587) | (70,405) | (75,273) | (76,179) | (66,300) | (78,676) | (85,963) | (84,950) | (91,979) | (95,187) | (99,103) |
| 24. | **Net Cost/(Revenue) of FMPP Transactions** | $000 | (6,865) | (19,240) | (14,896) | (6,509) | (13,406) | (10,590) | (22,018) | (25,010) | (48,214) | (58,007) | (65,957) | (72,177) | (73,641) | (59,800) | (72,728) | (81,508) | (75,368) | (87,951) | (90,410) | (92,117) |
| | **Fixed Costs** | | | | | | | | | | | | | | | | | | | | | |
| 25. | Generation Fixed O&M (Incl Common Plant | $000 | 15,220 | 14,760 | 15,432 | 16,077 | 16,841 | 17,454 | 17,722 | 18,594 | 19,364 | 21,042 | 21,281 | 21,597 | 22,404 | 23,781 | 23,773 | 24,591 | 26,051 | 26,504 | 27,141 | 28,243 |
| 26. | Capacity Purchases (Incl Transmission) | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 27. | Renewable Purchase Fixed Cost (Incl Trans) | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 28. | Existing Utility PV | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 29. | Incremental Utility PV | $000 | 1,840 | 2,107 | 5,262 | 5,888 | 5,899 | 5,910 | 5,922 | 5,934 | 5,946 | 5,958 | 5,971 | 5,984 | 5,997 | 6,011 | 6,025 | 6,039 | 6,053 | 6,068 | 6,083 | 6,098 |
| 30. | Total Fixed Production Costs | $000 | 17,061 | 16,867 | 20,693 | 21,965 | 22,739 | 23,364 | 23,644 | 24,528 | 25,310 | 27,000 | 27,252 | 27,581 | 28,401 | 29,792 | 29,798 | 30,630 | 32,104 | 32,572 | 33,224 | 34,342 |
| 31. | **Total Costs before Financing Costs** | $000 | 123,574 | 125,115 | 135,396 | 142,138 | 145,741 | 152,325 | 159,636 | 164,963 | 166,970 | 172,111 | 174,517 | 179,438 | 186,014 | 194,728 | 201,135 | 211,694 | 221,178 | 232,611 | 243,759 | 255,680 |
| | **Annual Capital Expenditures (Pre-Financing)** | | | | | | | | | | | | | | | | | | | | | |
| | Annual Construction Expend. (Excl. IDC) | | | | | | | | | | | | | | | | | | | | | |
| 32. | Repower McIntosh 2 | $000 | - | - | 2,472 | 25,241 | 74,737 | 62,791 | 58,820 | 35,326 | - | - | - | - | - | - | - | - | - | - | - | - |
| 33. | Retrofit McIntosh 3 | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

## Table D-16: Projected Power Supply Costs
## Business Case 2

| Line | Category | Units | Calendar Year 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **PROJECTED PRODUCTION OPERATING COSTS** | | | | | | | | | | | | | | | | | | | | | |
| | **Variable Production Costs** | | | | | | | | | | | | | | | | | | | | | |
| | **Fuel Cost:** | | | | | | | | | | | | | | | | | | | | | |
| | Generation | | | | | | | | | | | | | | | | | | | | | |
| 1. | Natural Gas | $000 | 76,826 | 80,290 | 83,493 | 79,582 | 85,267 | 87,337 | 90,131 | 93,164 | 91,363 | 101,824 | 101,630 | 109,767 | 115,663 | 112,460 | 118,898 | 126,937 | 123,317 | 145,741 | 145,073 | 149,790 |
| 2. | Coal | $000 | 29,970 | 38,981 | 38,023 | 38,723 | 43,031 | 41,770 | 46,428 | 44,101 | 49,075 | 49,509 | 50,540 | 49,498 | 54,542 | 52,784 | 54,962 | 61,838 | 63,549 | 65,017 | 63,759 | 69,309 |
| 3. | #2 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4. | #6 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5. | Power Purchase (NG) | $000 | - | - | - | - | - | 18 | 834 | 734 | 1,020 | 1,227 | 1,207 | 2,512 | 2,471 | 2,915 | 4,441 | 2,993 | 2,479 | 2,455 | 3,137 | 3,248 |
| 6. | Renewable Resource | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7. | Utility PV | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8. | Total Fuel Cost | $000 | 106,795 | 119,271 | 121,516 | 118,305 | 128,298 | 129,126 | 137,394 | 137,998 | 141,459 | 152,560 | 153,377 | 161,777 | 172,675 | 168,159 | 178,301 | 191,767 | 189,345 | 213,213 | 211,969 | 222,348 |
| | **Variable O&M and Start Costs:** | | | | | | | | | | | | | | | | | | | | | |
| | Generation | | | | | | | | | | | | | | | | | | | | | |
| 9. | Natural Gas | $000 | 4,002 | 4,255 | 4,098 | 4,321 | 3,972 | 4,030 | 3,717 | 3,899 | 3,898 | 4,351 | 4,316 | 4,649 | 4,955 | 5,015 | 5,257 | 5,346 | 5,071 | 5,673 | 5,583 | 5,719 |
| 10. | Coal | $000 | 2,541 | 3,395 | 3,407 | 3,454 | 3,521 | 3,327 | 3,622 | 3,404 | 3,710 | 3,629 | 3,535 | 3,682 | 3,872 | 3,905 | 3,846 | 4,080 | 4,025 | 4,108 | 4,294 | 4,406 |
| 11. | #2 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12. | #6 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 13. | Power Purchase (NG) | $000 | - | - | - | - | - | 49 | 2,109 | 1,839 | 2,571 | 3,128 | 3,107 | 6,007 | 5,939 | 6,932 | 10,433 | 6,915 | 5,473 | 5,333 | 6,670 | 6,753 |
| 14. | Renewable Resource | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 15. | Utility PV | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16. | Total Variable O&M and Start Costs | $000 | 6,543 | 7,650 | 7,505 | 7,775 | 7,493 | 7,406 | 9,448 | 9,143 | 10,179 | 11,108 | 10,958 | 14,338 | 14,765 | 15,853 | 19,535 | 16,341 | 14,569 | 15,114 | 16,547 | 16,878 |
| | **Emissions Allowance Costs:** | | | | | | | | | | | | | | | | | | | | | |
| 17. | NOx | $000 | 35 | 562 | 572 | 597 | 610 | 627 | 639 | 652 | 666 | 680 | 691 | 709 | 720 | 732 | 768 | 796 | 823 | 845 | 869 | 894 |
| 18. | SO2 | $000 | 5 | 6 | 6 | 6 | 6 | 6 | 7 | 6 | 7 | 7 | 7 | 7 | 8 | 8 | 8 | 9 | 9 | 9 | 9 | 10 |
| 19. | CO2 | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 20. | Total Cost of Emission Allowances | $000 | 40 | 567 | 577 | 602 | 616 | 633 | 646 | 659 | 673 | 687 | 698 | 716 | 728 | 740 | 776 | 805 | 832 | 854 | 878 | 903 |
| 21. | **Total Variable Production Cost** | $000 | 113,378 | 127,489 | 129,599 | 126,683 | 136,407 | 137,164 | 147,487 | 147,800 | 152,311 | 164,356 | 165,033 | 176,832 | 188,169 | 184,752 | 198,612 | 208,913 | 204,745 | 229,181 | 229,394 | 240,129 |
| | **FMPP Transactions** | | | | | | | | | | | | | | | | | | | | | |
| 22. | Total Cost of Pool Purchases | $000 | 9,658 | 5,852 | 6,800 | 12,027 | 9,771 | 11,405 | 11,983 | 13,485 | 17,086 | 12,778 | 14,278 | 11,462 | 9,864 | 16,444 | 18,413 | 16,243 | 26,837 | 15,033 | 25,895 | 28,899 |
| 23. | Total Sales Revenue | $000 | (16,522) | (25,092) | (21,696) | (18,536) | (23,176) | (20,049) | (24,058) | (20,226) | (22,505) | (26,052) | (23,809) | (25,445) | (29,915) | (24,135) | (27,926) | (32,456) | (29,078) | (31,683) | (29,046) | (30,361) |
| 24. | **Net Cost/(Revenue) of FMPP Transactions** | $000 | (6,865) | (19,240) | (14,896) | (6,509) | (13,406) | (8,645) | (12,074) | (6,741) | (5,419) | (13,274) | (9,530) | (13,983) | (20,052) | (7,691) | (9,512) | (16,213) | (2,241) | (16,650) | (3,151) | (1,462) |
| | **Fixed Costs** | | | | | | | | | | | | | | | | | | | | | |
| 25. | Generation Fixed O&M (Incl Common Plant | $000 | 15,220 | 14,760 | 15,432 | 16,077 | 16,841 | 17,583 | 17,707 | 18,493 | 18,963 | 19,387 | 20,338 | 20,703 | 21,079 | 21,882 | 22,624 | 23,252 | 24,563 | 24,888 | 25,832 | 26,655 |
| 26. | Capacity Purchases (Incl Transmission) | $000 | - | - | - | - | - | 1,549 | 9,473 | 9,654 | 9,838 | 10,026 | 10,942 | 14,839 | 15,124 | 15,414 | 15,710 | 16,667 | 20,328 | 20,719 | 21,118 | 21,525 |
| 27. | Renewable Purchase Fixed Cost (Incl Trans) | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 28. | Existing Utility PV | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 29. | Incremental Utility PV | $000 | 1,840 | 2,107 | 5,262 | 5,888 | 5,899 | 5,910 | 5,922 | 5,934 | 5,946 | 5,958 | 5,971 | 5,984 | 5,997 | 6,011 | 6,025 | 6,039 | 6,053 | 6,068 | 6,083 | 6,098 |
| 30. | Total Fixed Production Costs | $000 | 17,061 | 16,867 | 20,693 | 21,965 | 22,739 | 25,042 | 33,101 | 34,080 | 34,747 | 35,372 | 37,251 | 41,527 | 42,200 | 43,307 | 44,359 | 45,958 | 50,943 | 51,674 | 53,032 | 54,278 |
| 31. | **Total Costs before Financing Costs** | $000 | 123,574 | 125,115 | 135,396 | 142,138 | 145,741 | 153,562 | 168,514 | 175,140 | 181,638 | 186,454 | 192,753 | 204,376 | 210,317 | 220,368 | 233,458 | 238,658 | 253,448 | 264,205 | 279,275 | 292,945 |
| | **Annual Capital Expenditures (Pre-Financing)** | | | | | | | | | | | | | | | | | | | | | |
| | Annual Construction Expend. (Excl. IDC) | | | | | | | | | | | | | | | | | | | | | |
| 32. | Repower McIntosh 2 | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 33. | Retrofit McIntosh 3 | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

## Table D-17: Projected Power Supply Costs
## Business Case 3

| Line | Category | Units | Calendar Year 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **PROJECTED PRODUCTION OPERATING COSTS** | | | | | | | | | | | | | | | | | | | | | |
| | **Variable Production Costs** | | | | | | | | | | | | | | | | | | | | | |
| | **Fuel Cost:** | | | | | | | | | | | | | | | | | | | | | |
| | Generation | | | | | | | | | | | | | | | | | | | | | |
| 1. | Natural Gas | $000 | 76,152 | 79,974 | 79,764 | 79,671 | 80,669 | 79,914 | 84,121 | 86,136 | 90,283 | 93,229 | 91,384 | 95,999 | 100,442 | 107,949 | 100,517 | 118,253 | 112,822 | 111,265 | 121,765 | 126,779 |
| 2. | Coal | $000 | 29,442 | 37,620 | 36,493 | 38,882 | 42,189 | 41,924 | 42,884 | 43,916 | 43,218 | 42,342 | 48,662 | 47,533 | 46,950 | 52,926 | 49,175 | 57,504 | 55,782 | 62,176 | 63,027 | 64,916 |
| 3. | #2 Oil | $000 | - | - | - | - | - | - | - | - | 19 | - | - | - | 10 | - | - | - | - | - | - | 9 |
| 4. | #6 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5. | Power Purchase (NG) | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6. | Renewable Resource | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7. | Utility PV | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8. | Total Fuel Cost | $000 | 105,595 | 117,594 | 116,257 | 118,553 | 122,858 | 121,838 | 127,005 | 130,053 | 133,519 | 135,571 | 140,045 | 143,532 | 147,402 | 160,874 | 149,692 | 175,756 | 168,605 | 173,442 | 184,791 | 191,704 |
| | **Variable O&M and Start Costs:** | | | | | | | | | | | | | | | | | | | | | |
| | Generation | | | | | | | | | | | | | | | | | | | | | |
| 9. | Natural Gas | $000 | 3,722 | 3,995 | 3,749 | 3,582 | 3,545 | 3,310 | 3,359 | 3,447 | 3,718 | 3,818 | 3,826 | 3,984 | 4,233 | 4,612 | 4,161 | 4,760 | 4,535 | 4,397 | 4,715 | 4,835 |
| 10. | Coal | $000 | 2,534 | 3,373 | 3,391 | 3,457 | 3,516 | 3,328 | 3,477 | 3,628 | 3,768 | 3,800 | 3,745 | 3,899 | 3,930 | 3,886 | 4,033 | 4,015 | 4,194 | 4,176 | 4,238 | 4,465 |
| 11. | #2 Oil | $000 | - | - | - | - | - | - | - | - | 2 | - | - | - | 1 | - | - | - | - | - | - | 1 |
| 12. | #6 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 13. | Power Purchase (NG) | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 14. | Renewable Resource | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 15. | Utility PV | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16. | Total Variable O&M and Start Costs | $000 | 6,256 | 7,369 | 7,140 | 7,039 | 7,061 | 6,638 | 6,836 | 7,075 | 7,488 | 7,618 | 7,571 | 7,883 | 8,165 | 8,498 | 8,194 | 8,775 | 8,729 | 8,573 | 8,953 | 9,301 |
| | **Emissions Allowance Costs:** | | | | | | | | | | | | | | | | | | | | | |
| 17. | NOx | $000 | 35 | 547 | 565 | 592 | 612 | 612 | 632 | 646 | 587 | 582 | 671 | 619 | 634 | 708 | 660 | 753 | 709 | 814 | 843 | 790 |
| 18. | SO2 | $000 | 5 | 6 | 6 | 6 | 7 | 6 | 7 | 7 | 7 | 6 | 7 | 7 | 7 | 8 | 7 | 9 | 8 | 9 | 9 | 10 |
| 19. | CO2 | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 20. | Total Cost of Emission Allowances | $000 | 40 | 553 | 570 | 598 | 618 | 618 | 638 | 653 | 593 | 588 | 678 | 627 | 641 | 716 | 667 | 762 | 717 | 823 | 853 | 800 |
| 21. | **Total Variable Production Cost** | $000 | 111,890 | 125,516 | 123,967 | 126,190 | 130,537 | 129,094 | 134,479 | 137,780 | 141,601 | 143,777 | 148,294 | 152,041 | 156,208 | 170,089 | 158,553 | 185,293 | 178,051 | 182,838 | 194,597 | 201,806 |
| | **FMPP Transactions** | | | | | | | | | | | | | | | | | | | | | |
| 22. | Total Cost of Pool Purchases | $000 | 7,630 | 3,464 | 5,080 | 6,602 | 6,449 | 8,444 | 7,605 | 8,543 | 7,184 | 8,301 | 9,059 | 8,715 | 8,136 | 5,560 | 13,436 | 2,945 | 10,882 | 12,328 | 11,366 | 11,415 |
| 23. | Total Sales Revenue | $000 | (18,106) | (28,021) | (23,559) | (24,746) | (26,594) | (23,446) | (25,027) | (27,373) | (27,032) | (28,225) | (31,301) | (29,835) | (30,575) | (38,444) | (29,038) | (40,574) | (34,683) | (34,569) | (38,219) | (37,226) |
| 24. | **Net Cost/(Revenue) of FMPP Transactions** | $000 | (10,476) | (24,557) | (18,480) | (18,144) | (20,145) | (15,002) | (17,422) | (18,830) | (19,848) | (19,924) | (22,242) | (21,121) | (22,439) | (32,885) | (15,602) | (37,629) | (23,801) | (22,241) | (26,853) | (25,812) |
| | **Fixed Costs** | | | | | | | | | | | | | | | | | | | | | |
| 25. | Generation Fixed O&M (Incl Common Plant | $000 | 15,364 | 14,900 | 15,797 | 16,586 | 17,273 | 18,301 | 18,210 | 18,722 | 19,082 | 19,750 | 20,618 | 21,151 | 21,741 | 22,305 | 23,533 | 23,904 | 24,930 | 26,095 | 26,756 | 27,479 |
| 26. | Capacity Purchases (Incl Transmission) | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 27. | Renewable Purchase Fixed Cost (Incl Trans) | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 28. | Existing Utility PV | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 29. | Incremental Utility PV | $000 | 1,840 | 2,107 | 5,262 | 5,888 | 5,899 | 5,910 | 5,922 | 5,934 | 5,946 | 5,958 | 5,971 | 5,984 | 5,997 | 6,011 | 6,025 | 6,039 | 6,053 | 6,068 | 6,083 | 6,098 |
| 30. | Total Fixed Production Costs | $000 | 17,205 | 17,007 | 21,059 | 22,474 | 23,171 | 24,211 | 24,132 | 24,656 | 25,028 | 25,709 | 26,589 | 27,135 | 27,738 | 28,315 | 29,557 | 29,942 | 30,983 | 32,163 | 32,839 | 33,577 |
| 31. | **Total Costs before Financing Costs** | $000 | 118,619 | 117,965 | 126,546 | 130,519 | 133,563 | 138,303 | 141,189 | 143,606 | 146,781 | 149,561 | 152,642 | 158,056 | 161,507 | 165,520 | 172,508 | 177,606 | 185,232 | 192,760 | 200,582 | 209,571 |
| | **Annual Capital Expenditures (Pre-Financing)** | | | | | | | | | | | | | | | | | | | | | |
| | Annual Construction Expend. (Excl. IDC) | | | | | | | | | | | | | | | | | | | | | |
| 32. | Repower McIntosh 2 | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 33. | Retrofit McIntosh 3 | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

## Table D-18: Projected Power Supply Costs
## Business Case 4

| | | | Calendar Year | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | Category | Units | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| | **PROJECTED PRODUCTION OPERATING COSTS** | | | | | | | | | | | | | | | | | | | | | |
| | **Variable Production Costs** | | | | | | | | | | | | | | | | | | | | | |
| | **Fuel Cost:** | | | | | | | | | | | | | | | | | | | | | |
| | Generation | | | | | | | | | | | | | | | | | | | | | |
| 1. | Natural Gas | $000 | 76,446 | 78,488 | 82,654 | 80,039 | 85,929 | 115,776 | 119,112 | 124,865 | 129,006 | 125,199 | 147,035 | 134,296 | 154,452 | 156,291 | 163,031 | 167,424 | 167,828 | 180,629 | 186,541 | 197,798 |
| 2. | Coal | $000 | 30,206 | 38,657 | 37,695 | 39,333 | 40,687 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3. | #2 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 10 | - | - | - | - | - |
| 4. | #6 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5. | Power Purchase (NG) | $000 | - | - | - | - | - | 271 | 519 | 698 | 579 | 771 | 946 | 753 | 741 | 975 | 1,304 | 241 | 305 | 277 | 328 | 371 |
| 6. | Renewable Resource | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 7,599 | 7,757 | 7,934 | 8,079 | 8,250 |
| 7. | Utility PV | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8. | Total Fuel Cost | $000 | 106,652 | 117,145 | 120,348 | 119,372 | 126,616 | 116,047 | 119,632 | 125,562 | 129,585 | 125,971 | 147,980 | 135,048 | 155,193 | 157,267 | 164,346 | 175,264 | 175,890 | 188,841 | 194,948 | 206,420 |
| | **Variable O&M and Start Costs:** | | | | | | | | | | | | | | | | | | | | | |
| | Generation | | | | | | | | | | | | | | | | | | | | | |
| 9. | Natural Gas | $000 | 3,981 | 4,181 | 3,933 | 3,849 | 3,963 | 4,356 | 4,014 | 4,232 | 4,319 | 4,316 | 5,205 | 4,645 | 5,287 | 5,369 | 5,824 | 5,884 | 6,117 | 6,312 | 6,405 | 6,697 |
| 10. | Coal | $000 | 2,547 | 3,396 | 3,405 | 3,459 | 3,506 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 11. | #2 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1 | - | - | - | - | - |
| 12. | #6 Oil | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 13. | Power Purchase (NG) | $000 | - | - | - | - | - | 675 | 1,273 | 1,704 | 1,436 | 1,995 | 2,484 | 1,953 | 1,876 | 2,467 | 3,326 | 971 | 1,174 | 1,025 | 1,181 | 1,343 |
| 14. | Renewable Resource | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,807 | 1,845 | 1,887 | 1,921 | 1,962 |
| 15. | Utility PV | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16. | Total Variable O&M and Start Costs | $000 | 6,528 | 7,577 | 7,338 | 7,308 | 7,469 | 5,031 | 5,287 | 5,936 | 5,755 | 6,311 | 7,689 | 6,598 | 7,162 | 7,836 | 9,151 | 8,662 | 9,135 | 9,224 | 9,508 | 10,002 |
| | **Emissions Allowance Costs:** | | | | | | | | | | | | | | | | | | | | | |
| 17. | NOx | $000 | 35 | 562 | 568 | 596 | 608 | 120 | 132 | 145 | 178 | 214 | 311 | 243 | 287 | 340 | 356 | 280 | 271 | 275 | 309 | 340 |
| 18. | SO2 | $000 | 5 | 6 | 6 | 6 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19. | CO2 | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | 468 | - | - | - | - | - | - |
| 20. | Total Cost of Emission Allowances | $000 | 40 | 568 | 573 | 601 | 614 | 120 | 132 | 145 | 178 | 214 | 311 | 243 | 287 | 808 | 356 | 280 | 271 | 275 | 309 | 340 |
| 21. | **Total Variable Production Cost** | $000 | 113,220 | 125,290 | 128,260 | 127,282 | 134,700 | 121,197 | 125,050 | 131,643 | 135,518 | 132,496 | 155,980 | 141,889 | 162,643 | 165,911 | 173,853 | 184,205 | 185,297 | 198,340 | 204,765 | 216,761 |
| | **FMPP Transactions** | | | | | | | | | | | | | | | | | | | | | |
| 22. | Total Cost of Pool Purchases | $000 | 9,876 | 5,830 | 6,245 | 10,387 | 8,586 | 34,749 | 35,939 | 37,241 | 36,485 | 44,889 | 22,019 | 45,482 | 30,678 | 41,031 | 40,552 | 22,836 | 35,567 | 28,678 | 32,207 | 32,541 |
| 23. | Total Sales Revenue | $000 | (17,005) | (23,849) | (21,739) | (21,372) | (23,316) | (6,198) | (7,741) | (9,741) | (8,491) | (13,721) | (18,963) | (13,819) | (17,523) | (20,583) | (19,951) | (21,498) | (23,011) | (21,128) | (21,441) | (22,630) |
| 24. | **Net Cost/(Revenue) of FMPP Transactions** | $000 | (7,130) | (18,019) | (15,494) | (10,985) | (14,729) | 28,551 | 28,197 | 27,500 | 27,994 | 31,169 | 3,056 | 31,663 | 13,155 | 20,449 | 20,601 | 1,339 | 12,555 | 7,550 | 10,766 | 9,911 |
| | **Fixed Costs** | | | | | | | | | | | | | | | | | | | | | |
| 25. | Generation Fixed O&M (Incl Common Plant | $000 | 15,182 | 14,838 | 15,599 | 16,317 | 16,865 | 20,583 | 21,032 | 21,565 | 22,251 | 23,052 | 22,983 | 24,389 | 24,619 | 25,434 | 25,902 | 26,794 | 27,542 | 28,357 | 29,303 | 30,083 |
| 26. | Capacity Purchases (Incl Transmission) | $000 | - | - | - | - | - | 6,856 | 6,986 | 7,120 | 7,256 | 7,394 | 7,536 | 7,680 | 7,827 | 7,977 | 8,130 | 2,107 | 2,147 | 2,189 | 2,231 | 2,274 |
| 27. | Renewable Purchase Fixed Cost (Incl Trans) | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 39,251 | 39,399 | 39,550 | 39,704 | 39,861 |
| 28. | Existing Utility PV | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 29. | Incremental Utility PV | $000 | 1,840 | 2,107 | 5,262 | 5,888 | 5,899 | 5,910 | 5,922 | 5,934 | 5,946 | 5,958 | 5,971 | 5,984 | 5,997 | 6,011 | 6,025 | 6,039 | 6,053 | 6,068 | 6,083 | 6,098 |
| 30. | Total Fixed Production Costs | $000 | 17,023 | 16,944 | 20,861 | 22,204 | 22,764 | 33,349 | 33,940 | 34,618 | 35,453 | 36,405 | 36,490 | 38,053 | 38,443 | 39,422 | 40,057 | 74,191 | 75,141 | 76,163 | 77,321 | 78,316 |
| 31. | **Total Costs before Financing Costs** | $000 | 123,113 | 124,215 | 133,627 | 138,501 | 142,734 | 183,098 | 187,188 | 193,761 | 198,965 | 200,069 | 195,526 | 211,606 | 214,242 | 225,782 | 234,511 | 259,735 | 272,993 | 282,054 | 292,852 | 304,988 |
| | **Annual Capital Expenditures (Pre-Financing)** | | | | | | | | | | | | | | | | | | | | | |
| | Annual Construction Expend. (Excl. IDC) | | | | | | | | | | | | | | | | | | | | | |
| 32. | Repower McIntosh 2 | $000 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 33. | Retrofit McIntosh 3 | $000 | - | - | - | - | 9,516 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

## Mean and Probability Distributions for Key Inputs

**Lakeland Electric Utility**
**Financial Forecast**
**Key Inputs with Associated Probability Distributions**

**Case 1 - Inflation**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 3.96% | 2.79% |
| 2016 | 0.00% | 3.93% | 2.74% |
| 2017 | 0.00% | 4.07% | 2.81% |
| 2018 | 0.00% | 4.01% | 2.68% |
| 2019 | 0.00% | 4.21% | 2.93% |
| 2020 | 0.00% | 4.00% | 2.78% |
| 2021 | 0.00% | 4.18% | 2.79% |
| 2022 | 0.00% | 4.14% | 2.98% |
| 2023 | 0.00% | 4.15% | 2.86% |
| 2024 | 0.00% | 3.86% | 2.67% |
| 2025 | 0.00% | 3.98% | 2.66% |
| 2026 | 0.00% | 4.03% | 2.68% |
| 2027 | 0.00% | 4.02% | 2.91% |
| 2028 | 0.00% | 3.99% | 2.68% |
| 2029 | 0.00% | 3.96% | 2.67% |
| 2030 | 0.00% | 4.19% | 3.10% |
| 2031 | 0.00% | 4.02% | 2.65% |
| 2032 | 0.00% | 4.01% | 2.90% |
| 2033 | 0.00% | 4.10% | 2.85% |
| 2034 | 0.00% | 3.93% | 2.77% |

**Case 1 - Natural Gas Adjustment Factor**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 3.95% | 28.28% |
| 2016 | 0.00% | 4.19% | 28.44% |
| 2017 | 0.00% | 3.27% | 27.46% |
| 2018 | 0.00% | 2.91% | 27.22% |
| 2019 | 0.00% | 4.28% | 28.35% |
| 2020 | 0.00% | 3.45% | 27.39% |
| 2021 | 0.00% | 4.24% | 28.32% |
| 2022 | 0.00% | 4.64% | 28.69% |
| 2023 | 0.00% | 3.40% | 26.64% |
| 2024 | 0.00% | 3.42% | 26.75% |
| 2025 | 0.00% | 3.02% | 26.44% |
| 2026 | 0.00% | 4.01% | 27.86% |
| 2027 | 0.00% | 3.12% | 27.51% |
| 2028 | 0.00% | 3.17% | 27.43% |
| 2029 | 0.00% | 4.11% | 26.87% |
| 2030 | 0.00% | 4.85% | 28.77% |
| 2031 | 0.00% | 4.68% | 27.66% |
| 2032 | 0.00% | 4.69% | 28.37% |
| 2033 | 0.00% | 5.64% | 28.43% |
| 2034 | 0.00% | 5.73% | 28.80% |

## Lakeland Electric Utility
## Financial Forecast
## Key Inputs with Associated Probability Distributions

### Case 1 - Coal Fuel Adjustment Factor

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 1.47% | 5.60% |
| 2016 | 0.00% | 1.18% | 5.79% |
| 2017 | 0.00% | 1.54% | 5.62% |
| 2018 | 0.00% | 1.56% | 5.72% |
| 2019 | 0.00% | 1.31% | 5.31% |
| 2020 | 0.00% | 1.42% | 5.58% |
| 2021 | 0.00% | 1.49% | 5.60% |
| 2022 | 0.00% | 1.44% | 5.70% |
| 2023 | 0.00% | 1.34% | 5.62% |
| 2024 | 0.00% | 1.30% | 5.55% |
| 2025 | 0.00% | 1.24% | 5.89% |
| 2026 | 0.00% | 1.33% | 5.59% |
| 2027 | 0.00% | 1.40% | 5.54% |
| 2028 | 0.00% | 1.22% | 5.40% |
| 2029 | 0.00% | 1.75% | 5.92% |
| 2030 | 0.00% | 2.01% | 5.92% |
| 2031 | 0.00% | 1.30% | 5.50% |
| 2032 | 0.00% | 1.06% | 5.41% |
| 2033 | 0.00% | 1.19% | 5.44% |
| 2034 | 0.00% | 1.21% | 5.42% |

### Case 1 - #2 Oil Fuel Adjustment Factor

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 10.01% | 26.05% |
| 2016 | 0.00% | 8.97% | 25.71% |
| 2017 | 0.00% | 10.56% | 25.81% |
| 2018 | 0.00% | 10.58% | 25.88% |
| 2019 | 0.00% | 10.96% | 26.01% |
| 2020 | 0.00% | 10.53% | 25.67% |
| 2021 | 0.00% | 11.38% | 26.49% |
| 2022 | 0.00% | 11.56% | 27.42% |
| 2023 | 0.00% | 9.98% | 25.08% |
| 2024 | 0.00% | 10.04% | 26.16% |
| 2025 | 0.00% | 9.79% | 25.83% |
| 2026 | 0.00% | 10.44% | 26.78% |
| 2027 | 0.00% | 10.49% | 26.55% |
| 2028 | 0.00% | 11.46% | 26.94% |
| 2029 | 0.00% | 11.35% | 25.65% |
| 2030 | 0.00% | 10.26% | 25.85% |
| 2031 | 0.00% | 12.07% | 25.69% |
| 2032 | 0.00% | 12.14% | 25.35% |
| 2033 | 0.00% | 12.17% | 26.41% |
| 2034 | 0.00% | 11.41% | 26.60% |

**Lakeland Electric Utility**
**Financial Forecast**
**Key Inputs with Associated Probability Distributions**

**Case 1 - Nox**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2014 | $27.04 | $26.36 | $14.46 |
| 2015 | $24.61 | $24.35 | $14.40 |
| 2016 | $310.70 | $308.54 | $52.21 |
| 2017 | $373.31 | $356.37 | $137.12 |
| 2018 | $405.10 | $404.70 | $244.56 |
| 2019 | $415.44 | $414.82 | $256.87 |
| 2020 | $411.04 | $413.78 | $276.97 |
| 2021 | $427.08 | $440.57 | $484.81 |
| 2022 | $432.11 | $428.86 | $359.17 |
| 2023 | $449.37 | $463.05 | $354.82 |
| 2024 | $440.57 | $438.04 | $394.55 |
| 2025 | $456.88 | $446.77 | $276.41 |
| 2026 | $470.12 | $474.47 | $382.76 |
| 2027 | $480.92 | $462.59 | $286.25 |
| 2028 | $493.57 | $498.22 | $495.34 |
| 2029 | $502.50 | $530.13 | $502.25 |
| 2030 | $520.08 | $511.98 | $336.90 |
| 2031 | $517.38 | $508.66 | $293.85 |
| 2032 | $534.93 | $529.28 | $334.23 |
| 2033 | $550.67 | $551.92 | $404.42 |
| 2034 | $561.80 | $577.91 | $405.50 |

**Case 1 - SO2**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2014 | $1.00 | $0.96 | $1.03 |
| 2015 | $1.00 | $0.99 | $1.00 |
| 2016 | $1.02 | $1.00 | $0.99 |
| 2017 | $1.05 | $1.06 | $1.06 |
| 2018 | $1.08 | $1.05 | $0.90 |
| 2019 | $1.10 | $1.09 | $0.94 |
| 2020 | $1.13 | $1.06 | $0.88 |
| 2021 | $1.16 | $1.10 | $0.94 |
| 2022 | $1.19 | $1.17 | $0.92 |
| 2023 | $1.22 | $1.20 | $0.96 |
| 2024 | $1.25 | $1.20 | $0.93 |
| 2025 | $1.29 | $1.29 | $1.04 |
| 2026 | $1.32 | $1.35 | $1.01 |
| 2027 | $1.36 | $1.35 | $0.97 |
| 2028 | $1.39 | $1.40 | $0.96 |
| 2029 | $1.43 | $1.46 | $1.00 |
| 2030 | $1.46 | $1.46 | $1.00 |
| 2031 | $1.50 | $1.47 | $0.93 |
| 2032 | $1.54 | $1.61 | $1.14 |
| 2033 | $1.58 | $1.55 | $0.89 |
| 2034 | $1.62 | $1.63 | $0.97 |

**Lakeland Electric Utility**
**Financial Forecast**
**Key Inputs with Associated Probability Distributions**

**Case 1 - CO2**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2014 | $0.00 | $0.00 | $0.00 |
| 2015 | $0.00 | $0.00 | $0.00 |
| 2016 | $0.00 | $0.00 | $0.00 |
| 2017 | $0.00 | $0.00 | $0.00 |
| 2018 | $0.00 | $0.00 | $0.00 |
| 2019 | $0.00 | $0.00 | $0.00 |
| 2020 | $15.42 | $14.87 | $3.94 |
| 2021 | $0.01 | $15.13 | $4.24 |
| 2022 | $0.01 | $14.89 | $3.99 |
| 2023 | $0.01 | $15.28 | $4.23 |
| 2024 | $0.01 | $15.03 | $4.07 |
| 2025 | $0.01 | $14.87 | $3.93 |
| 2026 | $0.01 | $14.95 | $4.08 |
| 2027 | $0.01 | $14.97 | $4.04 |
| 2028 | $0.01 | $14.86 | $3.97 |
| 2029 | $0.01 | $14.91 | $3.97 |
| 2030 | $0.01 | $14.84 | $3.90 |
| 2031 | $0.01 | $15.08 | $3.90 |
| 2032 | $0.01 | $15.09 | $4.06 |
| 2033 | $0.01 | $14.89 | $4.04 |
| 2034 | $0.01 | $15.04 | $4.06 |

**Case 1 - Mid-Term Interest Rate**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 0.05% | 1.26% |
| 2016 | 0.00% | -0.01% | 1.26% |
| 2017 | 0.00% | -0.01% | 1.26% |
| 2018 | 0.00% | 0.05% | 1.25% |
| 2019 | 0.00% | -0.02% | 1.23% |
| 2020 | 0.00% | 0.01% | 1.23% |
| 2021 | 0.00% | 0.02% | 1.21% |
| 2022 | 0.00% | -0.04% | 1.23% |
| 2023 | 0.00% | -0.01% | 1.24% |
| 2024 | 0.00% | -0.05% | 1.26% |
| 2025 | 0.00% | 0.02% | 1.24% |
| 2026 | 0.00% | -0.04% | 1.26% |
| 2027 | 0.00% | -0.02% | 1.25% |
| 2028 | 0.00% | -0.03% | 1.26% |
| 2029 | 0.00% | 0.02% | 1.23% |
| 2030 | 0.00% | -0.06% | 1.26% |
| 2031 | 0.00% | 0.02% | 1.25% |
| 2032 | 0.00% | -0.03% | 1.26% |
| 2033 | 0.00% | 0.06% | 1.24% |
| 2034 | 0.00% | -0.09% | 1.26% |

**Lakeland Electric Utility**
**Financial Forecast**
**Key Inputs with Associated Probability Distributions**

**Case 1 - Fixed Production Operating Costs-Capacity Purchases**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 2.12% | 30.95% |
| 2016 | 0.00% | -1.19% | 29.90% |
| 2017 | 0.00% | -0.53% | 30.64% |
| 2018 | 0.00% | -0.22% | 29.79% |
| 2019 | 0.00% | -1.70% | 30.21% |
| 2020 | 0.00% | 0.05% | 30.16% |
| 2021 | 0.00% | -1.18% | 29.91% |
| 2022 | 0.00% | -0.53% | 30.45% |
| 2023 | 0.00% | -0.73% | 29.50% |
| 2024 | 0.00% | -0.08% | 29.29% |
| 2025 | 0.00% | 0.94% | 28.60% |
| 2026 | 0.00% | -0.59% | 31.53% |
| 2027 | 0.00% | 0.37% | 31.16% |
| 2028 | 0.00% | -1.51% | 30.13% |
| 2029 | 0.00% | 1.20% | 30.41% |
| 2030 | 0.00% | 1.46% | 29.71% |
| 2031 | 0.00% | 1.06% | 29.97% |
| 2032 | 0.00% | 0.67% | 29.96% |
| 2033 | 0.00% | 0.31% | 29.91% |
| 2034 | 0.00% | -1.33% | 31.17% |

**Lakeland Electric Utility**
**Financial Forecast**
**Key Inputs with Associated Probability Distributions**

**Case 2 - Inflation**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 4.21% | 3.33% |
| 2016 | 0.00% | 4.13% | 2.92% |
| 2017 | 0.00% | 4.07% | 3.25% |
| 2018 | 0.00% | 4.27% | 3.10% |
| 2019 | 0.00% | 4.09% | 2.69% |
| 2020 | 0.00% | 4.01% | 2.79% |
| 2021 | 0.00% | 4.23% | 3.17% |
| 2022 | 0.00% | 4.08% | 2.71% |
| 2023 | 0.00% | 3.99% | 2.91% |
| 2024 | 0.00% | 4.13% | 3.01% |
| 2025 | 0.00% | 3.95% | 2.67% |
| 2026 | 0.00% | 4.08% | 2.82% |
| 2027 | 0.00% | 4.32% | 3.10% |
| 2028 | 0.00% | 4.11% | 3.03% |
| 2029 | 0.00% | 4.15% | 2.89% |
| 2030 | 0.00% | 4.09% | 2.86% |
| 2031 | 0.00% | 4.12% | 2.86% |
| 2032 | 0.00% | 4.10% | 2.72% |
| 2033 | 0.00% | 3.95% | 2.59% |
| 2034 | 0.00% | 4.03% | 2.69% |

**Case 2 - Natural Gas Adjustment Factor**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 5.56% | 28.03% |
| 2016 | 0.00% | 5.21% | 29.25% |
| 2017 | 0.00% | 4.11% | 27.60% |
| 2018 | 0.00% | 4.10% | 28.37% |
| 2019 | 0.00% | 4.55% | 28.46% |
| 2020 | 0.00% | 4.00% | 27.58% |
| 2021 | 0.00% | 2.83% | 26.61% |
| 2022 | 0.00% | 3.03% | 26.78% |
| 2023 | 0.00% | 4.20% | 26.91% |
| 2024 | 0.00% | 4.75% | 26.68% |
| 2025 | 0.00% | 5.35% | 27.71% |
| 2026 | 0.00% | 4.04% | 27.34% |
| 2027 | 0.00% | 5.30% | 28.18% |
| 2028 | 0.00% | 4.97% | 27.34% |
| 2029 | 0.00% | 4.37% | 27.32% |
| 2030 | 0.00% | 3.30% | 27.94% |
| 2031 | 0.00% | 2.88% | 28.21% |
| 2032 | 0.00% | 4.87% | 27.39% |
| 2033 | 0.00% | 2.78% | 26.34% |
| 2034 | 0.00% | 5.11% | 27.83% |

**Lakeland Electric Utility**
**Financial Forecast**
**Key Inputs with Associated Probability Distributions**

**Case 2 - Coal Fuel Adjustment Factor**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 1.34% | 5.52% |
| 2016 | 0.00% | 1.65% | 5.75% |
| 2017 | 0.00% | 1.64% | 5.80% |
| 2018 | 0.00% | 1.41% | 5.73% |
| 2019 | 0.00% | 1.59% | 5.89% |
| 2020 | 0.00% | 1.21% | 5.67% |
| 2021 | 0.00% | 1.24% | 5.68% |
| 2022 | 0.00% | 1.50% | 5.76% |
| 2023 | 0.00% | 1.25% | 5.56% |
| 2024 | 0.00% | 1.46% | 6.00% |
| 2025 | 0.00% | 1.66% | 5.80% |
| 2026 | 0.00% | 1.54% | 6.04% |
| 2027 | 0.00% | 1.48% | 5.61% |
| 2028 | 0.00% | 1.45% | 5.79% |
| 2029 | 0.00% | 1.61% | 5.83% |
| 2030 | 0.00% | 1.17% | 5.40% |
| 2031 | 0.00% | 1.43% | 5.83% |
| 2032 | 0.00% | 1.43% | 5.62% |
| 2033 | 0.00% | 1.66% | 5.60% |
| 2034 | 0.00% | 1.46% | 5.78% |

**Case 2 - #2 Oil Fuel Adjustment Factor**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 11.64% | 26.77% |
| 2016 | 0.00% | 11.89% | 27.39% |
| 2017 | 0.00% | 10.98% | 27.29% |
| 2018 | 0.00% | 10.44% | 27.50% |
| 2019 | 0.00% | 12.38% | 26.56% |
| 2020 | 0.00% | 10.61% | 25.91% |
| 2021 | 0.00% | 9.10% | 25.11% |
| 2022 | 0.00% | 10.22% | 26.12% |
| 2023 | 0.00% | 10.71% | 26.67% |
| 2024 | 0.00% | 11.19% | 25.78% |
| 2025 | 0.00% | 10.83% | 26.86% |
| 2026 | 0.00% | 9.20% | 25.26% |
| 2027 | 0.00% | 11.08% | 26.77% |
| 2028 | 0.00% | 11.02% | 25.70% |
| 2029 | 0.00% | 9.98% | 24.88% |
| 2030 | 0.00% | 10.70% | 26.00% |
| 2031 | 0.00% | 10.34% | 27.05% |
| 2032 | 0.00% | 11.06% | 27.52% |
| 2033 | 0.00% | 10.73% | 25.63% |
| 2034 | 0.00% | 10.92% | 25.57% |

**Lakeland Electric Utility**
**Financial Forecast**
**Key Inputs with Associated Probability Distributions**

**Case 2 - Nox**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2014 | $27.04 | $27.20 | $15.77 |
| 2015 | $24.61 | $24.29 | $14.79 |
| 2016 | $310.70 | $306.46 | $41.27 |
| 2017 | $373.31 | $354.44 | $155.20 |
| 2018 | $405.10 | $440.20 | $836.89 |
| 2019 | $415.44 | $412.29 | $278.73 |
| 2020 | $411.04 | $414.91 | $387.02 |
| 2021 | $427.08 | $416.54 | $294.03 |
| 2022 | $432.11 | $426.72 | $239.31 |
| 2023 | $449.37 | $455.45 | $349.16 |
| 2024 | $440.57 | $440.56 | $319.16 |
| 2025 | $456.88 | $473.87 | $504.49 |
| 2026 | $470.12 | $479.47 | $319.52 |
| 2027 | $480.92 | $489.04 | $399.04 |
| 2028 | $493.57 | $477.34 | $275.45 |
| 2029 | $502.50 | $510.29 | $335.72 |
| 2030 | $520.08 | $516.31 | $308.36 |
| 2031 | $517.38 | $500.77 | $269.64 |
| 2032 | $534.93 | $524.06 | $394.34 |
| 2033 | $550.67 | $541.21 | $356.44 |
| 2034 | $561.80 | $566.15 | $345.73 |

**Case 2 - SO2**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2014 | $1.00 | $0.99 | $0.88 |
| 2015 | $1.00 | $1.03 | $1.02 |
| 2016 | $1.02 | $1.04 | $0.99 |
| 2017 | $1.05 | $1.07 | $1.01 |
| 2018 | $1.08 | $1.06 | $1.01 |
| 2019 | $1.10 | $1.08 | $0.92 |
| 2020 | $1.13 | $1.10 | $0.96 |
| 2021 | $1.16 | $1.17 | $0.96 |
| 2022 | $1.19 | $1.25 | $1.07 |
| 2023 | $1.22 | $1.23 | $1.00 |
| 2024 | $1.25 | $1.24 | $0.90 |
| 2025 | $1.29 | $1.29 | $1.01 |
| 2026 | $1.32 | $1.37 | $1.16 |
| 2027 | $1.36 | $1.36 | $1.00 |
| 2028 | $1.39 | $1.38 | $0.95 |
| 2029 | $1.43 | $1.38 | $0.90 |
| 2030 | $1.46 | $1.42 | $0.93 |
| 2031 | $1.50 | $1.51 | $0.99 |
| 2032 | $1.54 | $1.57 | $1.03 |
| 2033 | $1.58 | $1.58 | $0.97 |
| 2034 | $1.62 | $1.68 | $1.07 |

**Lakeland Electric Utility**
**Financial Forecast**
**Key Inputs with Associated Probability Distributions**

**Case 2 - CO2**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2014 | $0.00 | $0.00 | $0.00 |
| 2015 | $0.00 | $0.00 | $0.00 |
| 2016 | $0.00 | $0.00 | $0.00 |
| 2017 | $0.00 | $0.00 | $0.00 |
| 2018 | $0.00 | $0.00 | $0.00 |
| 2019 | $0.00 | $0.00 | $0.00 |
| 2020 | $15.42 | $15.00 | $3.91 |
| 2021 | $0.01 | $15.07 | $3.98 |
| 2022 | $0.01 | $15.04 | $3.98 |
| 2023 | $0.01 | $15.07 | $4.15 |
| 2024 | $0.01 | $15.09 | $4.02 |
| 2025 | $0.01 | $15.20 | $4.33 |
| 2026 | $0.01 | $15.06 | $3.83 |
| 2027 | $0.01 | $15.18 | $4.12 |
| 2028 | $0.01 | $14.95 | $3.95 |
| 2029 | $0.01 | $14.91 | $3.82 |
| 2030 | $0.01 | $15.24 | $4.14 |
| 2031 | $0.01 | $14.88 | $4.14 |
| 2032 | $0.01 | $14.97 | $3.91 |
| 2033 | $0.01 | $14.88 | $4.08 |
| 2034 | $0.01 | $14.98 | $4.10 |

**Case 2 - Mid-Term Interest Rate**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 0.08% | 1.17% |
| 2016 | 0.00% | 0.05% | 1.22% |
| 2017 | 0.00% | -0.03% | 1.27% |
| 2018 | 0.00% | -0.11% | 1.30% |
| 2019 | 0.00% | -0.02% | 1.27% |
| 2020 | 0.00% | -0.02% | 1.28% |
| 2021 | 0.00% | -0.04% | 1.25% |
| 2022 | 0.00% | -0.04% | 1.25% |
| 2023 | 0.00% | -0.07% | 1.26% |
| 2024 | 0.00% | -0.07% | 1.35% |
| 2025 | 0.00% | -0.05% | 1.26% |
| 2026 | 0.00% | 0.00% | 1.21% |
| 2027 | 0.00% | -0.01% | 1.27% |
| 2028 | 0.00% | -0.06% | 1.26% |
| 2029 | 0.00% | -0.04% | 1.30% |
| 2030 | 0.00% | -0.06% | 1.27% |
| 2031 | 0.00% | -0.07% | 1.28% |
| 2032 | 0.00% | -0.06% | 1.29% |
| 2033 | 0.00% | -0.05% | 1.22% |
| 2034 | 0.00% | -0.02% | 1.22% |

**Lakeland Electric Utility**
**Financial Forecast**
**Key Inputs with Associated Probability Distributions**

**Case 2 - Fixed Production Operating Costs-Capacity Purchases**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | -0.68% | 30.62% |
| 2016 | 0.00% | -0.70% | 30.75% |
| 2017 | 0.00% | 0.46% | 29.69% |
| 2018 | 0.00% | 0.29% | 30.08% |
| 2019 | 0.00% | 1.25% | 29.46% |
| 2020 | 0.00% | 0.24% | 28.75% |
| 2021 | 0.00% | -0.02% | 30.25% |
| 2022 | 0.00% | -0.78% | 29.76% |
| 2023 | 0.00% | -0.15% | 30.17% |
| 2024 | 0.00% | -2.13% | 30.10% |
| 2025 | 0.00% | 0.02% | 29.02% |
| 2026 | 0.00% | -0.50% | 30.28% |
| 2027 | 0.00% | -0.49% | 29.91% |
| 2028 | 0.00% | -1.22% | 30.26% |
| 2029 | 0.00% | 0.56% | 28.76% |
| 2030 | 0.00% | -0.23% | 28.49% |
| 2031 | 0.00% | -0.06% | 28.48% |
| 2032 | 0.00% | 0.07% | 29.88% |
| 2033 | 0.00% | 1.39% | 30.16% |
| 2034 | 0.00% | 0.92% | 29.74% |

**Lakeland Electric Utility**
**Financial Forecast**
**Key Inputs with Associated Probability Distributions**

**Case 3 - Inflation**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 4.03% | 2.83% |
| 2016 | 0.00% | 3.96% | 2.93% |
| 2017 | 0.00% | 4.10% | 2.95% |
| 2018 | 0.00% | 3.91% | 2.72% |
| 2019 | 0.00% | 3.98% | 2.84% |
| 2020 | 0.00% | 4.17% | 2.97% |
| 2021 | 0.00% | 4.17% | 2.88% |
| 2022 | 0.00% | 3.99% | 2.70% |
| 2023 | 0.00% | 4.01% | 2.80% |
| 2024 | 0.00% | 4.02% | 2.71% |
| 2025 | 0.00% | 4.05% | 2.83% |
| 2026 | 0.00% | 4.12% | 2.93% |
| 2027 | 0.00% | 4.03% | 2.93% |
| 2028 | 0.00% | 4.17% | 2.97% |
| 2029 | 0.00% | 4.09% | 2.90% |
| 2030 | 0.00% | 4.00% | 2.84% |
| 2031 | 0.00% | 4.10% | 2.91% |
| 2032 | 0.00% | 4.10% | 3.07% |
| 2033 | 0.00% | 4.00% | 2.69% |
| 2034 | 0.00% | 4.01% | 2.88% |

**Case 3 - Natural Gas Adjustment Factor**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 6.15% | 28.60% |
| 2016 | 0.00% | 4.40% | 28.14% |
| 2017 | 0.00% | 4.54% | 27.93% |
| 2018 | 0.00% | 3.98% | 27.79% |
| 2019 | 0.00% | 4.91% | 28.46% |
| 2020 | 0.00% | 4.08% | 26.97% |
| 2021 | 0.00% | 4.70% | 27.84% |
| 2022 | 0.00% | 3.43% | 27.36% |
| 2023 | 0.00% | 5.85% | 26.27% |
| 2024 | 0.00% | 3.07% | 27.99% |
| 2025 | 0.00% | 6.42% | 27.38% |
| 2026 | 0.00% | 3.55% | 27.11% |
| 2027 | 0.00% | 5.44% | 28.43% |
| 2028 | 0.00% | 3.61% | 26.93% |
| 2029 | 0.00% | 3.29% | 27.79% |
| 2030 | 0.00% | 4.02% | 25.57% |
| 2031 | 0.00% | 5.67% | 27.83% |
| 2032 | 0.00% | 3.55% | 26.99% |
| 2033 | 0.00% | 4.66% | 28.84% |
| 2034 | 0.00% | 3.23% | 27.80% |

**Lakeland Electric Utility**
**Financial Forecast**
**Key Inputs with Associated Probability Distributions**

**Case 3 - Coal Fuel Adjustment Factor**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 1.60% | 5.90% |
| 2016 | 0.00% | 1.56% | 5.96% |
| 2017 | 0.00% | 1.68% | 5.84% |
| 2018 | 0.00% | 1.98% | 5.90% |
| 2019 | 0.00% | 1.48% | 5.74% |
| 2020 | 0.00% | 1.45% | 5.63% |
| 2021 | 0.00% | 1.17% | 5.64% |
| 2022 | 0.00% | 1.52% | 5.70% |
| 2023 | 0.00% | 1.22% | 5.41% |
| 2024 | 0.00% | 1.30% | 5.77% |
| 2025 | 0.00% | 1.50% | 5.83% |
| 2026 | 0.00% | 1.01% | 5.39% |
| 2027 | 0.00% | 1.22% | 5.57% |
| 2028 | 0.00% | 1.32% | 5.58% |
| 2029 | 0.00% | 1.22% | 5.51% |
| 2030 | 0.00% | 1.68% | 5.88% |
| 2031 | 0.00% | 1.52% | 5.83% |
| 2032 | 0.00% | 1.33% | 5.84% |
| 2033 | 0.00% | 1.12% | 5.21% |
| 2034 | 0.00% | 1.42% | 5.78% |

**Case 3 - #2 Oil Fuel Adjustment Factor**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 12.27% | 25.61% |
| 2016 | 0.00% | 10.97% | 27.65% |
| 2017 | 0.00% | 10.60% | 26.28% |
| 2018 | 0.00% | 10.57% | 27.35% |
| 2019 | 0.00% | 10.93% | 25.99% |
| 2020 | 0.00% | 11.06% | 26.46% |
| 2021 | 0.00% | 11.95% | 26.28% |
| 2022 | 0.00% | 9.53% | 25.30% |
| 2023 | 0.00% | 12.16% | 26.34% |
| 2024 | 0.00% | 9.32% | 25.87% |
| 2025 | 0.00% | 13.20% | 26.84% |
| 2026 | 0.00% | 10.82% | 25.94% |
| 2027 | 0.00% | 11.97% | 26.02% |
| 2028 | 0.00% | 10.12% | 25.98% |
| 2029 | 0.00% | 10.03% | 27.41% |
| 2030 | 0.00% | 10.29% | 25.80% |
| 2031 | 0.00% | 11.12% | 26.42% |
| 2032 | 0.00% | 10.76% | 26.14% |
| 2033 | 0.00% | 11.65% | 26.30% |
| 2034 | 0.00% | 10.32% | 27.27% |

## Lakeland Electric Utility
## Financial Forecast
## Key Inputs with Associated Probability Distributions

### Case 3 - Nox

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2014 | $27.04 | $26.62 | $14.80 |
| 2015 | $24.61 | $24.45 | $14.47 |
| 2016 | $310.70 | $308.58 | $51.22 |
| 2017 | $373.31 | $406.50 | $1,104.95 |
| 2018 | $405.10 | $392.15 | $227.35 |
| 2019 | $415.44 | $409.54 | $235.96 |
| 2020 | $411.04 | $406.37 | $269.84 |
| 2021 | $427.08 | $443.40 | $364.01 |
| 2022 | $432.11 | $419.79 | $246.52 |
| 2023 | $449.37 | $436.84 | $280.21 |
| 2024 | $440.57 | $443.96 | $352.05 |
| 2025 | $456.88 | $466.19 | $376.02 |
| 2026 | $470.12 | $457.63 | $270.51 |
| 2027 | $480.92 | $478.87 | $331.41 |
| 2028 | $493.57 | $501.05 | $349.24 |
| 2029 | $502.50 | $500.08 | $372.31 |
| 2030 | $520.08 | $530.19 | $333.01 |
| 2031 | $517.38 | $516.05 | $370.45 |
| 2032 | $534.93 | $535.39 | $378.88 |
| 2033 | $550.67 | $551.38 | $424.10 |
| 2034 | $561.80 | $548.23 | $330.20 |

### Case 3 - SO2

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2014 | $1.00 | $1.05 | $1.11 |
| 2015 | $1.00 | $0.98 | $0.97 |
| 2016 | $1.02 | $1.02 | $0.92 |
| 2017 | $1.05 | $1.06 | $1.10 |
| 2018 | $1.08 | $0.99 | $0.83 |
| 2019 | $1.10 | $1.09 | $0.99 |
| 2020 | $1.13 | $1.12 | $0.92 |
| 2021 | $1.16 | $1.11 | $0.91 |
| 2022 | $1.19 | $1.19 | $1.23 |
| 2023 | $1.22 | $1.21 | $0.99 |
| 2024 | $1.25 | $1.24 | $1.01 |
| 2025 | $1.29 | $1.19 | $0.80 |
| 2026 | $1.32 | $1.34 | $1.02 |
| 2027 | $1.36 | $1.38 | $0.99 |
| 2028 | $1.39 | $1.34 | $0.89 |
| 2029 | $1.43 | $1.42 | $0.95 |
| 2030 | $1.46 | $1.41 | $0.96 |
| 2031 | $1.50 | $1.44 | $0.93 |
| 2032 | $1.54 | $1.56 | $1.01 |
| 2033 | $1.58 | $1.62 | $0.97 |
| 2034 | $1.62 | $1.59 | $0.97 |

**Lakeland Electric Utility**
**Financial Forecast**
**Key Inputs with Associated Probability Distributions**

**Case 3 - CO2**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2014 | $0.00 | $0.00 | $0.00 |
| 2015 | $0.00 | $0.00 | $0.00 |
| 2016 | $0.00 | $0.00 | $0.00 |
| 2017 | $0.00 | $0.00 | $0.00 |
| 2018 | $0.00 | $0.00 | $0.00 |
| 2019 | $0.00 | $0.00 | $0.00 |
| 2020 | $15.42 | $14.92 | $3.92 |
| 2021 | $0.01 | $14.95 | $4.08 |
| 2022 | $0.01 | $15.03 | $3.99 |
| 2023 | $0.01 | $14.78 | $3.94 |
| 2024 | $0.01 | $14.87 | $3.84 |
| 2025 | $0.01 | $15.15 | $3.94 |
| 2026 | $0.01 | $14.86 | $4.11 |
| 2027 | $0.01 | $15.08 | $4.21 |
| 2028 | $0.01 | $14.95 | $4.01 |
| 2029 | $0.01 | $15.12 | $4.00 |
| 2030 | $0.01 | $15.08 | $3.92 |
| 2031 | $0.01 | $14.95 | $4.10 |
| 2032 | $0.01 | $14.99 | $4.09 |
| 2033 | $0.01 | $14.87 | $3.86 |
| 2034 | $0.01 | $15.14 | $3.97 |

**Case 3 - Mid-Term Interest Rate**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | -0.07% | 1.20% |
| 2016 | 0.00% | -0.03% | 1.24% |
| 2017 | 0.00% | 0.03% | 1.25% |
| 2018 | 0.00% | 0.08% | 1.23% |
| 2019 | 0.00% | -0.07% | 1.27% |
| 2020 | 0.00% | -0.05% | 1.29% |
| 2021 | 0.00% | -0.04% | 1.28% |
| 2022 | 0.00% | 0.03% | 1.23% |
| 2023 | 0.00% | -0.04% | 1.24% |
| 2024 | 0.00% | -0.03% | 1.25% |
| 2025 | 0.00% | -0.01% | 1.29% |
| 2026 | 0.00% | 0.07% | 1.25% |
| 2027 | 0.00% | -0.02% | 1.25% |
| 2028 | 0.00% | 0.05% | 1.22% |
| 2029 | 0.00% | 0.04% | 1.26% |
| 2030 | 0.00% | -0.06% | 1.24% |
| 2031 | 0.00% | -0.09% | 1.23% |
| 2032 | 0.00% | 0.00% | 1.25% |
| 2033 | 0.00% | -0.03% | 1.29% |
| 2034 | 0.00% | -0.01% | 1.30% |

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### Case 3 - Fixed Production Operating Costs-Capacity Purchases

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 0.11% | 29.92% |
| 2016 | 0.00% | 0.59% | 29.31% |
| 2017 | 0.00% | -1.37% | 30.83% |
| 2018 | 0.00% | 1.05% | 29.33% |
| 2019 | 0.00% | 0.41% | 30.18% |
| 2020 | 0.00% | 0.24% | 30.39% |
| 2021 | 0.00% | -0.54% | 30.46% |
| 2022 | 0.00% | 1.15% | 29.83% |
| 2023 | 0.00% | 0.86% | 30.03% |
| 2024 | 0.00% | -0.35% | 30.90% |
| 2025 | 0.00% | 1.18% | 29.61% |
| 2026 | 0.00% | -0.47% | 29.78% |
| 2027 | 0.00% | -1.41% | 30.97% |
| 2028 | 0.00% | 1.78% | 30.08% |
| 2029 | 0.00% | -0.30% | 29.62% |
| 2030 | 0.00% | 1.26% | 29.38% |
| 2031 | 0.00% | -0.93% | 29.08% |
| 2032 | 0.00% | -0.38% | 30.18% |
| 2033 | 0.00% | 0.91% | 30.36% |
| 2034 | 0.00% | -1.30% | 29.79% |

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**Case 4 - Inflation**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 4.10% | 2.78% |
| 2016 | 0.00% | 4.10% | 2.87% |
| 2017 | 0.00% | 3.99% | 2.64% |
| 2018 | 0.00% | 3.99% | 2.79% |
| 2019 | 0.00% | 4.11% | 2.79% |
| 2020 | 0.00% | 4.17% | 2.98% |
| 2021 | 0.00% | 4.10% | 2.79% |
| 2022 | 0.00% | 3.96% | 2.72% |
| 2023 | 0.00% | 4.08% | 2.79% |
| 2024 | 0.00% | 4.04% | 2.85% |
| 2025 | 0.00% | 4.12% | 2.86% |
| 2026 | 0.00% | 4.08% | 2.94% |
| 2027 | 0.00% | 4.10% | 2.82% |
| 2028 | 0.00% | 3.98% | 2.91% |
| 2029 | 0.00% | 4.06% | 2.70% |
| 2030 | 0.00% | 4.09% | 2.94% |
| 2031 | 0.00% | 4.12% | 2.71% |
| 2032 | 0.00% | 4.18% | 2.76% |
| 2033 | 0.00% | 3.95% | 2.75% |
| 2034 | 0.00% | 4.03% | 2.83% |

**Case 4 - Natural Gas Adjustment Factor**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 4.30% | 28.07% |
| 2016 | 0.00% | 3.96% | 28.45% |
| 2017 | 0.00% | 2.64% | 25.84% |
| 2018 | 0.00% | 5.88% | 27.32% |
| 2019 | 0.00% | 3.80% | 27.42% |
| 2020 | 0.00% | 5.12% | 28.43% |
| 2021 | 0.00% | 2.80% | 27.39% |
| 2022 | 0.00% | 3.66% | 27.70% |
| 2023 | 0.00% | 3.73% | 27.18% |
| 2024 | 0.00% | 4.19% | 27.23% |
| 2025 | 0.00% | 5.27% | 27.79% |
| 2026 | 0.00% | 4.58% | 27.14% |
| 2027 | 0.00% | 3.88% | 28.81% |
| 2028 | 0.00% | 5.93% | 27.10% |
| 2029 | 0.00% | 4.33% | 26.88% |
| 2030 | 0.00% | 3.45% | 28.09% |
| 2031 | 0.00% | 2.67% | 26.94% |
| 2032 | 0.00% | 2.98% | 28.41% |
| 2033 | 0.00% | 4.02% | 27.44% |
| 2034 | 0.00% | 3.02% | 26.28% |

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**Case 4 - Coal Fuel Adjustment Factor**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 1.43% | 5.64% |
| 2016 | 0.00% | 1.59% | 5.62% |
| 2017 | 0.00% | 1.25% | 5.59% |
| 2018 | 0.00% | 1.52% | 6.09% |
| 2019 | 0.00% | 1.34% | 5.53% |
| 2020 | 0.00% | 1.66% | 5.72% |
| 2021 | 0.00% | 1.65% | 5.86% |
| 2022 | 0.00% | 1.55% | 5.72% |
| 2023 | 0.00% | 1.22% | 5.54% |
| 2024 | 0.00% | 1.34% | 5.61% |
| 2025 | 0.00% | 1.48% | 5.54% |
| 2026 | 0.00% | 1.00% | 5.84% |
| 2027 | 0.00% | 1.14% | 5.69% |
| 2028 | 0.00% | 1.40% | 5.97% |
| 2029 | 0.00% | 1.18% | 5.49% |
| 2030 | 0.00% | 1.13% | 5.56% |
| 2031 | 0.00% | 1.38% | 5.37% |
| 2032 | 0.00% | 1.33% | 5.61% |
| 2033 | 0.00% | 1.44% | 5.64% |
| 2034 | 0.00% | 1.67% | 5.92% |

**Case 4 - #2 Oil Fuel Adjustment Factor**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | 11.00% | 26.81% |
| 2016 | 0.00% | 11.08% | 25.97% |
| 2017 | 0.00% | 9.82% | 25.28% |
| 2018 | 0.00% | 11.64% | 25.75% |
| 2019 | 0.00% | 10.62% | 26.24% |
| 2020 | 0.00% | 11.36% | 27.09% |
| 2021 | 0.00% | 9.63% | 25.89% |
| 2022 | 0.00% | 9.60% | 26.43% |
| 2023 | 0.00% | 10.38% | 26.57% |
| 2024 | 0.00% | 11.04% | 26.15% |
| 2025 | 0.00% | 10.26% | 25.33% |
| 2026 | 0.00% | 11.25% | 25.47% |
| 2027 | 0.00% | 10.10% | 25.72% |
| 2028 | 0.00% | 11.43% | 24.76% |
| 2029 | 0.00% | 9.56% | 25.06% |
| 2030 | 0.00% | 9.88% | 25.65% |
| 2031 | 0.00% | 9.02% | 25.93% |
| 2032 | 0.00% | 9.92% | 26.45% |
| 2033 | 0.00% | 10.41% | 25.67% |
| 2034 | 0.00% | 8.80% | 25.44% |

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**Case 4 - Nox**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2014 | $27.04 | $26.89 | $14.68 |
| 2015 | $24.61 | $24.90 | $15.31 |
| 2016 | $310.70 | $318.96 | $191.79 |
| 2017 | $373.31 | $380.75 | $508.15 |
| 2018 | $405.10 | $403.16 | $243.63 |
| 2019 | $415.44 | $413.80 | $317.57 |
| 2020 | $411.04 | $394.30 | $265.77 |
| 2021 | $427.08 | $424.34 | $287.67 |
| 2022 | $432.11 | $435.73 | $292.68 |
| 2023 | $449.37 | $460.49 | $515.76 |
| 2024 | $440.57 | $436.46 | $261.30 |
| 2025 | $456.88 | $459.34 | $342.70 |
| 2026 | $470.12 | $449.36 | $276.28 |
| 2027 | $480.92 | $496.95 | $383.54 |
| 2028 | $493.57 | $490.70 | $380.50 |
| 2029 | $502.50 | $506.76 | $429.54 |
| 2030 | $520.08 | $515.19 | $350.60 |
| 2031 | $517.38 | $512.19 | $346.34 |
| 2032 | $534.93 | $529.90 | $312.96 |
| 2033 | $550.67 | $553.59 | $333.39 |
| 2034 | $561.80 | $572.25 | $428.48 |

**Case 4 - SO2**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2014 | $1.00 | $1.01 | $1.10 |
| 2015 | $1.00 | $0.97 | $0.90 |
| 2016 | $1.02 | $0.96 | $0.86 |
| 2017 | $1.05 | $1.05 | $1.04 |
| 2018 | $1.08 | $1.09 | $0.94 |
| 2019 | $1.10 | $1.10 | $0.93 |
| 2020 | $1.13 | $1.15 | $0.98 |
| 2021 | $1.16 | $1.12 | $0.95 |
| 2022 | $1.19 | $1.15 | $0.88 |
| 2023 | $1.22 | $1.23 | $0.94 |
| 2024 | $1.25 | $1.28 | $1.10 |
| 2025 | $1.29 | $1.28 | $0.94 |
| 2026 | $1.32 | $1.28 | $0.97 |
| 2027 | $1.36 | $1.34 | $0.94 |
| 2028 | $1.39 | $1.43 | $1.04 |
| 2029 | $1.43 | $1.41 | $0.98 |
| 2030 | $1.46 | $1.47 | $1.01 |
| 2031 | $1.50 | $1.48 | $1.00 |
| 2032 | $1.54 | $1.56 | $1.02 |
| 2033 | $1.58 | $1.57 | $0.97 |
| 2034 | $1.62 | $1.64 | $1.00 |

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### Case 4 - CO2

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2014 | $0.00 | $0.00 | $0.00 |
| 2015 | $0.00 | $0.00 | $0.00 |
| 2016 | $0.00 | $0.00 | $0.00 |
| 2017 | $0.00 | $0.00 | $0.00 |
| 2018 | $0.00 | $0.00 | $0.00 |
| 2019 | $0.00 | $0.00 | $0.00 |
| 2020 | $15.42 | $14.95 | $4.03 |
| 2021 | $0.01 | $15.01 | $3.99 |
| 2022 | $0.01 | $15.18 | $4.15 |
| 2023 | $0.01 | $15.03 | $4.06 |
| 2024 | $0.01 | $15.07 | $3.98 |
| 2025 | $0.01 | $14.85 | $3.91 |
| 2026 | $0.01 | $14.76 | $3.88 |
| 2027 | $0.01 | $15.05 | $4.24 |
| 2028 | $0.01 | $15.03 | $4.03 |
| 2029 | $0.01 | $15.12 | $4.16 |
| 2030 | $0.01 | $15.08 | $4.07 |
| 2031 | $0.01 | $14.74 | $4.03 |
| 2032 | $0.01 | $14.78 | $4.06 |
| 2033 | $0.01 | $15.09 | $4.03 |
| 2034 | $0.01 | $14.86 | $3.95 |

### Case 4 - Mid-Term Interest Rate

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | -0.11% | 1.32% |
| 2016 | 0.00% | -0.02% | 1.27% |
| 2017 | 0.00% | -0.05% | 1.24% |
| 2018 | 0.00% | -0.06% | 1.27% |
| 2019 | 0.00% | 0.01% | 1.23% |
| 2020 | 0.00% | -0.03% | 1.25% |
| 2021 | 0.00% | -0.04% | 1.23% |
| 2022 | 0.00% | 0.00% | 1.23% |
| 2023 | 0.00% | -0.02% | 1.25% |
| 2024 | 0.00% | 0.02% | 1.24% |
| 2025 | 0.00% | 0.00% | 1.23% |
| 2026 | 0.00% | 0.06% | 1.26% |
| 2027 | 0.00% | -0.02% | 1.24% |
| 2028 | 0.00% | -0.04% | 1.26% |
| 2029 | 0.00% | 0.04% | 1.22% |
| 2030 | 0.00% | -0.01% | 1.27% |
| 2031 | 0.00% | 0.01% | 1.24% |
| 2032 | 0.00% | -0.01% | 1.26% |
| 2033 | 0.00% | -0.02% | 1.24% |
| 2034 | 0.00% | 0.01% | 1.28% |

**Lakeland Electric Utility**
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**Case 4 - Fixed Production Operating Costs-Capacity Purchases**

| Year | Base Case | Mean | Standard Deviation |
|---|---|---|---|
| 2015 | 0.00% | -1.03% | 30.28% |
| 2016 | 0.00% | 0.07% | 29.81% |
| 2017 | 0.00% | 0.06% | 29.21% |
| 2018 | 0.00% | -0.03% | 28.84% |
| 2019 | 0.00% | 0.82% | 29.33% |
| 2020 | 0.00% | -1.98% | 29.28% |
| 2021 | 0.00% | -2.25% | 30.19% |
| 2022 | 0.00% | 1.46% | 30.26% |
| 2023 | 0.00% | -0.72% | 30.84% |
| 2024 | 0.00% | 1.43% | 30.32% |
| 2025 | 0.00% | -0.03% | 30.13% |
| 2026 | 0.00% | -2.72% | 29.44% |
| 2027 | 0.00% | -1.81% | 29.91% |
| 2028 | 0.00% | -0.15% | 29.68% |
| 2029 | 0.00% | -0.73% | 28.78% |
| 2030 | 0.00% | 0.37% | 29.26% |
| 2031 | 0.00% | -0.83% | 30.71% |
| 2032 | 0.00% | 1.38% | 30.18% |
| 2033 | 0.00% | 0.45% | 29.76% |
| 2034 | 0.00% | -1.42% | 30.54% |

# Appendix E
# Environmental GRI Indicators

As discussed in Section 4: Environmental, the GRI and subsequent industry sector supplements for the electric utility industry were used as a framework to report on triple bottom line performance. Several GRI Environmental Indicators were selected by the Project Team as the basis for LE to begin reporting on environmental performance. The tables below summarize each of the recommended indicators (e.g. emissions, material used), the related metrics, data required to report on performance and LE provided data or recommendations for gathering data.

# Emissions

All Electric Utilities must annually report certain power generation related emissions to the state and federal government. This reporting should be leveraged to generate emission related metrics and track annual performance. The appropriate emissions related metrics, data required to report and the information provided by LE are summarized below. Data shown is for FY 2014.

**Table E-1: GHG Emissions Indicators and Data Collection**

| Metric | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Net generation from owned fossil or owned renewable and purchased power resources. | • Annual generation by unit.<br>• Unit generation type (e.g. coal, NG, wind, etc.). | 1. Net Generation from NG: 1,752,778 MWh<br>2. Net Generation from Coal: 735,323 MWh<br>3. Net Generation from Other Fuel (Incl Util PV): 11,721 MWh<br>4. Net Generation from Purchased Power Unavailable |
| 2. $CO_2$ emission in aggregate (MTCO2e) and by intensity (MTCO2e/MWh) by unit/plants. | • Annual $CO_2$ emission for total from LE generation.<br>• $CO_2$ emission intensity by unit. | See table E-1A below. |
| 3. $CO_2$ emissions in aggregate (MTCO2e) by intensity (MTCO2e/MWh) for all purchased power; including any off system sales or allocation of off system sales from the Pool | • Annual $CO_2$ emissions from purchased power.<br>• $CO_2$ emission intensity for all purchased power. | Existing data being refined to align with GRI reporting. Coordinate with FMPP to gather fuel mix and related aggregate and intensity level emissions |
| 4. NOx and SOx emissions in aggregate and by intensity by unit/plant and purchased power. | • Annual NOx and SOx emissions and intensity from LE generation.<br>• Annual NOx and SOx emissions and intensity from purchased power. | LE Generation:<br>• NOx: 1,187 tons<br>• SOx: 2,916 tons<br>Coordinate with FMPP to estimate NOx and SOx emissions based on average FMPP rates and LE purchased power. |
| 5. Initiatives taken to reduce, or planned to reduce, GHG/NOx/SOx emissions (e.g. retrofits to coal units) | • List of planned initiative(s) to reduce emissions. | Current efforts provided in 2013 IRP |
| 6. GHG/NOx/SOx reduction strategies currently under consideration. | • List of planned strategies to achieve an emission reduction. | • Installed ammonia injection system, selective catalytic reduction (SCR) on Unit 3 (2009)<br>• 2014+: upgrades based on Resource Planning and Roadmap decisions. |

**Table E-1A: Carbon Dioxide Emissions and Emission Rates**

| Unit | Plant | Metric Tons CO2e | MWh (Net) | Metric Tons CO2e per Net MWh |
|---|---|---|---|---|
| Unit 1 | McIntosh | 208.77 | -4,585.10 | N/A |
| Unit 2 | McIntosh | 18,848.16 | 18,659.70 | 1.01 |
| Unit 3 | McIntosh | 778,091.21 | 716,663.70 | 1.09 |
| Unit 5 | McIntosh | 638,247.74 | 1,752,721.90 | 0.36 |
| MD1 | McIntosh | 7.25 | 9.30 | 0.78 |
| MD2 | McIntosh | 33.58 | 40.60 | 0.83 |
| MGT1 | McIntosh | 27.22 | 6.50 | 4.19 |
| Unit 8 | Larsen | 0.00 | -2,003.30 | N/A |
| LGT2 | Larsen | 23.59 | -3.10 | N/A |
| LGT3 | Larsen | 1.84 | -15.70 | N/A |
| 20 engines | Winston | 266.63 | -1,453.30 | N/A |

## Vegetation Management

The vegetation management involved in maintaining Electric LE infrastructure can generate a large volume of organic material and waste on an annual basis. By choosing to direct this material towards a sustainable disposal method, LE has an opportunity to minimize its contribution to the waste stream. The appropriate vegetation management related metrics, data required to report and the information provided by LE are summarized below.

### Table E-2: Vegetation Management Indicators and Data Collection

| Metric | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Self-performed or under contract with a third party. | • Internal department or contracted provider for vegetation management? | • Currently contracted out. |
| 2. Does LE own the trimmings and sell, or pay, for the disposal? | • What is the cost of disposing, or revenue generated from, the organic material collected? | • Review Contract Parameters for Ownership and Potential for Monetization |

Based on the data provide by LE, it is the Project Team's understanding that LE utilizes contractors for vegetation management activities. It is recommended that LE monitor the cost, or revenue generated from the organics generated from this operation. If LE currently pays for disposal, there may be opportunities to sell or recycle the organic waste resource locally at no cost for a beneficial use such as feedstock for a biomass plant or mulching operations.

## Material Used

Identifying the amount of raw materials LE uses on an annual basis, will allow the LE to track the growth of raw materials and the corresponding by-products generated. Table E-3 below, summarizes the appropriate materials related metrics, data required to report and the information provided by LE. The reporting period for the data provided in the tables is fiscal FY 2014.

**Table E-3: Material Used Indicators and Data Collection**

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Annual coal consumed. | • Volume of coal used by LE annually. | • Annual volume of coal used by unit provided in EIA report: 704,289 tons (2011) |
| 2. Annual NG consumed. | • Volume of NG used by LE annually. | • Annual volume of NG used by unit provided in EIA report: 16,766,205 MMBtu (2011) |
| 3. Byproducts generated. | • Byproducts generated from generation activities. | • Ash byproduct amounts provided in EIA report. 314 tons (2011)<br>• Sulfur byproduct amounts provided in EIA report: 49 tons (2011) |
| 4. Energy sold by LE (e.g. kWhs) | • Energy sold per year. | • Annual energy sold provided in the EIA report: 249,204 KWh. (2011) |

## Energy Consumption within the Organization

Managing LE's internal use of energy is a valuable metric, which reflects LE's internal practices towards conservation. The energy consumption indicator is summarized below with the appropriate metrics, data required to report and the information provided by LE. The reporting period for the data provided in the tables is fiscal FY 2014.

**Table E-4: Internal Energy Consumption Indicators and Data Collection**

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Electricity consumed by LE's facilities. (kWh) | • LE's annual electricity consumption. | • Total for all buildings: 4,238,461kWh |
| 2. Fuel consumed by LE's vehicles. (gallons) | • LE's annual fuel (gasoline, diesel, CNG, etc.) used by vehicles. | • Unleaded: 42,906 gal<br>• E85: 38,399 gal<br>• Diesel: 92,007 gal<br>• Total: 173,312 gal |

Based on the data provided by LE, The Project Team was unable to develop a baseline for these indicators. However, going forward, the Project Team recommends LE track these metrics, to ensure internal operations are following and adopting the same conservation practices customers are encouraged to implement.

# Efforts to Provide Energy Efficiency and Renewable Energy Based Products

Consistent with the basis of tracking Energy Consumption within the Organization, it is important for LE to track the success of EE and conservation programs. By understanding the success, or lack of success with certain programs, LE can focus resources on programs that are working and begin trouble shooting for programs with limited successes. The table below shows the two applicable metrics for reporting EE and renewable based products.

**Table E-5: Energy Efficiency and Renewable Energy Products Indicators and Data Collection**

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. EE results (kWh) for LE's DSM program. | • Annual energy demand before DSM program implementation.<br>• Annual energy demand, each year since DSM program implementation. | • FY 2013 LE DSM programs resulted in 2,390,688kWh of energy savings and 1,439kW of demand savings<br>• In FY 2013, LE spent $443,155 in rebate expense for the DSM program |
| 2. Results of EE implementation for LE and/or City buildings (kWh). | • Annual energy used by LE and/or City buildings before EE implementation, by building.<br>• Annual energy used by LE and/or City buildings after EE implementation, by building. | • While no EE and savings projects were implemented in 2014, in 2012 an energy savings project was implemented at the T&D City Warehouse at the LE Administration building and in 2011 the LE Administration building upgraded the HVAC system. |
| 3. Amount of renewable energy included in LE generation mix to serve load | • Amount of renewable energy in LE generation portfolio<br>• Amount of renewable distributed generation by customers | • 10,894 MWh renewable energy included in LE's portfolio<br>• Existing data for distributed generation being refined to align with GRI reporting. |

Based on the data provided by LE, The Project Team was unable to develop a baseline for these metrics. The Project Team recommends LE begin tracking these indicators going forward to better understand what level of EE the utility is achieving and the aggregate and relative adoption of renewable energy technologies.

# Water Use and Source

With increased water scarcity and increasing water prices, it is important to properly measure and manage the use of water in electricity production. Metrics to benchmark and track LE's operational performance related to water consumption are outlined below. The Project Team included all metrics with the indicator; however, it is recommended to further tailor the metrics based on data available.

**Table E-6: Water Use and Source Indicators and Data Collection**

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Total water withdraw by source. | • Volume of water annually used by LE to generate electricity. | • Lake Parker: 1.8Million Gallons 2014 YTD (Sept.) for Larsen Plant.<br>• Groundwater wells: 105.3 Million Gallons 2014 YTD for McIntosh Plant. |
| 2. Surface, well, reuse water consumed by source (e.g. lake, river, watershed). | • Annual volume and source of water used by generation plants. | • Surface water from Lake Parker: 1.8 Million Gallons 2014 YTD<br>• Groundwater: 105.3 Million Gallons 2014 YTD |
| 3. Collaborative approaches with the City Water LE. (e.g. reuse, collaborative approach to water resources). | • List any collaboration efforts with City Water LE. | • City of Lakeland wastewater utility supplies cooling tower make-up water for units 2,3 &5. |
| 4. Percentage of total water recycled and reused. | • Volume of water recycled and reused annually.<br>• Volume of water annually used by LE to generate electricity. | • Existing data being refined to align with GRI reporting.<br>• No current water recycling programs in place with exception of storm water reuse. |
| 5. Total water, annually discharged by plant/location. | • Volume of water discharged annually, by plant/location. | • McIntosh plant has permitted water discharge that is metered and effluent is treated at the Glendale WWRTF.<br>• The Larsen plant has once through cooling supplied by the lake and process water from the Process Water Ponds at McIntosh.<br>• Stormwater is collected onsite for reuse. |
| 6. Identify size, location and protected biodiversity value of water bodies impacted (if any). | • List of any protected biodiversity, including size and location, in area or proximity to LE and/or LE's water source. | • The City of Lakeland Wetlands and Lake Parker receive water / effluent from LE. These are not protected biodiversity areas. |

Understanding the water resources that LE depends on, and their natural restrictions, will help LE in long-term planning for any needed water resources. Additionally, tracking effort to recycle water resources and collaborate with the City's Water Utility will safeguard the current water resources for future use.

# Waste and Disposal

Electricity generation can produce byproducts, which must be properly disposed of to mitigate environmental impacts. The Project Team has summarized the appropriate metrics to track LE's progress on managing the disposal of these byproducts. The metrics outlined in table below will allow LE to benchmark and track the current volume of waste being produced by LE's generation operation, and manage its level of waste generation and disposal.

**Table E-7: Water and Disposal Indicators and Data Collection**

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Total weight of waste byproduct discharge. | • Annual weight of waste byproduct, by byproduct material. | • Existing data being refined to align with GRI reporting and account for reuse/recycle and disposal; refer to Table E-3 for initial byproducts. |
| 2. Volume of ash waste disposed and reused. (e.g. fly ash recycling for concrete). | • Annual volume of ash waste disposed.<br>• Annual volume of ash waste recycled. | • Existing data being refined to align with GRI reporting and account for reuse/recycle and disposal; refer to Table E-3 for initial generation of byproducts. |
| 3. Sludge conditioning byproducts generated. | • Annual volume of sludge conditioning byproducts. | • Existing data being refined to align with GRI reporting; refer to Table E-3 for initial generation of byproducts. |
| 4. Disposal method(s). | • List of disposal methods used. | • Existing data being refined to align with GRI reporting; refer to Table E-3 for initial generation of byproducts. |

## Habitat Restoration and Environmental Protection

Power generation plants and electric utility operations can unintentionally place strain on their surrounding ecosystems. It is not unusual for utilities to establish programs to maintain or restore local habitats and protect the local environment. This table outlines metrics that will allow LE to track any efforts to protect the local environment and restore local habitats. This indicator and related metrics will likely be focused on environmental compliance activities unless LE is involved with restoring sensitive habitat near its plants.

**Table E-8: Habitat Restoration and Environmental Protection Indicators and Data Collection**

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Habitat restoration activities (if any). | • List of any habitat restoration activities by LE. | • Existing data being refined to align with GRI reporting. |
| 2. Summary of environmental protection expenditures and investments by type. | • Annual investment in environmental protection projects, by project. | • Existing data being refined to align with GRI reporting. |
| 3. Waste disposal emissions treatment, remediation. | • List of disposal emission treatment programs. | • Existing data being refined to align with GRI reporting. Refer to table E-7 and E-3 for waste/byproduct generation. |
| 4. Prevention and environmental management costs (e.g. annual compliance and regular cots, outreach). | • Annual expense related to prevention and environmental management. | • Existing data being refined to align with GRI reporting. |
| 5. Number of full time equivalents (FTE) directly/solely supporting environmental efforts. | • Number of FTE dedicated to environmental efforts. | • Existing data being refined to align with GRI reporting. |

# Appendix F
# Labor GRI Indicators

# Employment

Basic metrics such as number of new hires and employee turnover can provide an organization with a high understanding of the changing dynamics of the organization. Understanding and tracking the number of employees that are eligible for retirement is also important for the organization to monitor, to ensure the Utility is prepared for potentially replacing these employees and managing the turnover of organizational knowledge. In the table below, the Project Team has summarized the appropriate labor related metrics, data required to report performance and the information provided by LE. The reporting period for the data provided in the tables is fiscal FY 2013.

**Table F-1: Employment Indicators and Data Collection**

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Total number and rate of new employee hires and employee turnover by age, group, gender, and region. | • Number of new employees by age, group, gender, and region for current year and previous year.<br>• Number of employee turnover by age, group, gender, and region for current year and previous year. | • Number of new hires, retirements, and terminations over previous year. See Table F-1A below. |
| 2. Percentage of employees eligible to retire in the next 5 – 10 years broken down by job category and by region. | • Number of employees eligible to retire currently, in the next 5 years and 10 years, by job category and region.<br>• Number of total employees by job category and region. | • Number of employees eligible for retirement by job category. See Table F-1B Below. |
| 3. Days worked by contractor and subcontractor employees involved in construction, operations, and maintenance actives. | • Number of days worked by contractor and subcontractor employees in operations outlined. | • Existing data being refined to align with GRI reporting. |
| 4. Percentage of contractor and subcontractor employees that have undergone relevant health and safety training. | • Number of contractors and subcontractor employees that have completed health and safety training.<br>• Total number of contractors and subcontractor employees. | • Existing data being refined to align with GRI reporting. |

### Table F-1A: Employee Hire and Turnover Rate – Indicator 1

| Gender | Hire (HIR) | Retire (RWP) | Terminated (TWR) |
|---|---|---|---|
| Female | 16 | 5 | 7 |
| Male | 23 | 15 | 22 |
| Total | 39 | 20 | 29 |

| Age Bracket | Hire (HIR) | Retire (RWP) | Terminated (TWR) |
|---|---|---|---|
| <20 | 7 | 1 | 1 |
| 20 | 14 | 4 | 14 |
| 30 | 8 | 10 | 4 |
| 40 | 6 | 5 | 7 |
| 50 | 3 | 0 | 3 |
| 60 | 1 | 0 | 0 |
| Total | 39 | 20 | 29 |

### Table F-1B: Employees Eligible for Retirement – Indicator 2

| Job Category | Eligible in 5 years | Eligible in 10 years | Eligible Now |
|---|---|---|---|
| Office/Clerical | 0.0% | 0.0% | 0.0% |
| Office/Clerical - Financial Admin | 2.3% | 3.3% | 0.0% |
| Office & Clerical - Utilities & Trans | 10.0% | 21.3% | 10.0% |
| Officials and Admin- Utilities & Trans | 2.7% | 0.0% | 0.0% |
| Professionals | 2.3% | 1.6% | 3.3% |
| Professionals - Utilities & Trans | 22.6% | 21.3% | 20.0% |
| Service Management - Utilities & Trans | 1.4% | 0.0% | 3.3% |
| Skilled Craft | 0.9% | 2.5% | 0.0% |
| Skilled Craft - Utilities & Trans | 24.4% | 26.2% | 33.3% |
| Technicians | 0.5% | 0.0% | 0.0% |
| Technicians - Utilities & Tech | 33.0% | 23.8% | 30.0% |
| Total | 40.3% | 22.2% | 5.5% |

As shown in Table F-1A, it can be concluded that LE has not filled all of the positions that have been vacated from either retirement or termination. LE has also hired a variety of ages over the past year. Table F-1B illustrates the level of employees that are eligible to retire.

Based on the information provided in Table F-1B, there are a considerable amount of employees in Skilled Craft – Utilities & Trans and Professionals – Utilities & Trans, which are eligible for retirement. With a sizeable number of employees that are eligible for retirement, suggest the Utility may benefit from ensuring that these departments are cross-training newer employees and guaranteeing organizational knowledge is being recorded or passed-on.

## Labor/Management Relations

The Project Team has reviewed potential initiatives that reflect LE's labor and management relations. In the table below, the Project Team has summarized the appropriate labor/management relations related metrics, data required to report and the information provided by LE.

**Table F-2: Employment Indicators and Data Collection**

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Minimum notice periods regarding operational changes, including whether these are specified in collective bargaining agreements. | • Organization's policy regarding operational changes.<br>• Collective bargaining agreements. | • Based on staff communication - No notice period. |

The Utility does not currently have a notice period for operational changes. Although this policy does not appear to be causing a disruption among the organization's labor and management, LE may consider implementing a policy outlining an appropriate notice period for any operation change that will effect employees.

# Occupational Health and Safety

A central aspect of employee satisfaction is their occupational health and safety. It is important to track and understand the frequency of injuries, diseases, and lost days related for each activity type of department/function. This will allow the Utility to identify occupational hazards and respond accordingly. In the table below, the Project Team has summarized the appropriate occupational health and safety related metrics, data required to report, and the information provided by LE.

**Table F-3: Occupational Health and Safety Indicators and Data Collection**

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Type of injury and rates of injury, occupational disease, lost days, absenteeism, and total number of work related fatalities, by region and by gender. | • Types and frequency of injury and occupational disease by region and gender<br>• Number of lost days, absenteeism and work related fatalities by region and gender | • Existing data being refined to align with GRI reporting. |

**Table F-3A: Occupational Health and Safety – Injury Reporting**

| Fiscal Year | 2011 | 2012 | 2013 |
|---|---|---|---|
| Lost Day Cases | 4 | 8 | 1 |
| Total Lost Days | 128 | 258 | 15 |
| Restricted Day Cases | 8 | 16 | 4 |
| Total Restricted Days | 50 | 449 | 26 |
| Fatalities | 0 | 0 | 0 |
| Incident Rate | 4.23 | 4.87 | 1.02 |

The information provided in Table F-3A illustrates LE experienced a spike in lost days and restricted days in 2012; however, based on the data, these incidents have drastically decreased in 2013. The Utility has also achieved a substantial decrease in its incident rate since 2012. It is important to understand the underlying drivers for the dramatic decrease in lost days and restricted days to either identify key efforts or programs to leverage and grow these successes or the potential for changed calculation process/incorrect data. These metrics are important to track and review, enabling the Utility to identify the cause of increased occupational injuries and develop safeguards to prevent work related injuries.

# Training and Education

Providing training and education for employees empowers employees to excel in their field, provide improved service to customers and typically improves employee satisfaction. Benchmarking the level of the organization's training across employees, departments and positions is valuable to ensure training opportunities are being provided to all employees. In the table below, the Project Team has summarized the appropriate training and education related metrics, data required to report, and the information provided by LE.

### Table F-4: Training and Education Indicators and Data Collection

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Average hours of training per year per employee by gender and employment category. | • Number of training hours per year per employee.<br>• Gender of employee.<br>• Employee employment category. | • Training report – gender of employee is currently not included in this report<br>• See table F-4A for training details.<br>• See Training Report for source data |
| 2. Programs for skills management and lifelong learning that supports the continued employability of employees and assist them in managing career endings. | • List of programs designed for skills management and lifelong learning.<br>• Programs to assist employees in planning retirement. | • Workforce Planning Executive Summary<br>• Talent Management Succession Proposal<br>• See table F-4B |
| 3. Percentage of employees receiving regular performance and career development reviews by gender and employee category. | • Number of employees receiving regular performance reviews.<br>• Gender of employee.<br>• Employee employment category. | • Workforce Planning Executive Summary |

**Table F-4A: Training and Education – Average Training Hours**

| Department | Number of Employees | Total Training Hours | Hours per Employee |
|---|---|---|---|
| 2011 - Technician | 173 | 11,983 | 69.3 |
| 2017 - Skilled Craft/Service Maintenance | 198 | 10,461 | 52.8 |
| 2031 - Officials and Admin | 22 | 957 | 43.5 |
| 2071 - Office Clerical | 104 | 4,286 | 41.2 |
| 2091 - Professionals | 13 | 447 | 34.4 |
| 2098 - Professionals | 27 | 968 | 35.9 |
| **Total** | **537**[1] | **29,102** | **54.2**[2] |

Notes:

1. Total LE employees as of 4/30/13 was 570. Total employees receiving training was 537.
2. Average hours per employee represents Total Training Hours divided by total LE employees receiving training (29,102 / 537). Using total LE employees (570), the hours of training for all employees is 51.1hrs per employee.

As shown in Table F-4B, the Utility currently provides a varying level of training to different departments. It is not unusual for the level of training to vary by department due to need, availability of training opportunities, job requirements, and availability of staff to participate. The programs provided for sills management and lifelong learning by the Utility are listed in Table F-4B.

## Table F-4B: Training and Education – Programs for Skill Development and Learning

| Program Name/Organizational Focus | Purpose of Program |
|---|---|
| 1. Leadership and developmental opportunities. | • Training staff will play a larger role in facilitating the professional development of employees. |
| 2. Mechanisms in place to implement phased retirement strategies. | • Encourage attrition to occur over time, ensuring proper transitions to new employees. |
| 3. Revise current guidelines on the payment of "retention bonuses" | • Retain highly skilled employees. |
| 4. Increase recognition and awards. | • Encourage high-performing employees. |
| 5. Integrate the Performance Plan and Workforce Plans with Training and Development Plans. | • Encouraging employees to participate in workforce and training opportunities as part of their performance plan. |
| 6. Require Individual Development Plans (IDPs) for all employees. | • Encourages all employees to develop and attain goals annually. |
| 7. Recognize employees who have become licensed, certified, or credentialed. | • Encourage employees to attain licenses, certifications, and/or credentials. |
| 8. Lakeland Electric Power Academy | • Development of a pipeline of qualified applicants for positions in the organization |
| 9. Mentoring of Lakeland Electric Power Academy students by employees. | • Mentoring programs to encourage and train qualified applicants and develop potential employee pool. |
| 10. Support and fund the formation and use of “communities of practice.” | • Encourages collaboration and employee comradery. |
| 11. Encourage the movement of personnel between divisions. | • Enhancing professional development. |
| 12. Invest a minimum of three percent of salaries and benefits | • Increase training budget. |
| 13. Increase collaboration with Polk Manufacturing Association, Polk Community College, and the Polk County Schools. | • Providing training for current and potential future employees. |
| 14. Expand the training program to include additional technical and non-technical programs | • Providing training for technical and non-technical subjects. |
| 15. Lineman Apprentice Program | • Provides specific equipment training, Electrician training in Generation, Supervisory training, Office specific skills training. |
| 16. Workshops are held every year by our Retirement Department on investing, deferred compensation plans. Retirement Fund Administrators come on site and meet with individuals as well as have financial planning seminars. | • Aid employees in planning for retirement. |

# Appendix G
# Social GRI Indicators

# Stakeholder Engagement

By involving LE stakeholders in the decision making processes and encouraging feedback throughout program changes ensures enhanced customer programs and services. In the table below, the Project Team has summarized the appropriate stakeholder engagement related metrics, data required to report and the information provided by LE. The reporting period for the data provided in the tables is fiscal FY 2014 where applicable.

**Table G-1: Stakeholder Engagement Indicators and Data Collection**

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
| --- | --- | --- |
| Stakeholder Engagement and participation in decision making process, energy planning and infrastructure development (in addition to City Council/public meetings) | List of outreach efforts to encourage stakeholder involvement and participation | • LE has formalized a community AP in 2014 to provide strategic insight on a key projects and LE plans<br>• Dixieland HOA meetings regarding transmission upgrade project<br>• The Key Accounts program and Customer Service representatives meet quarterly with the 100 largest customers in addition to 100 individual surveys each year of the same group.<br>• Summarize Customer Service Academy information and partnerships with local technical colleges<br>• Coordinate program summary with all Center Manager (Karen Thompson) or the Director of Communication Department Kevin Cooks). |

# Low Income Programs

As utility services are a basic need in our society, it is important to consider all customers when recovering a utility's cost of service, including those customers on a lower or fixed income. By having a low income program, LE is able to aid these customers, and provide a valuable service to the local community. The appropriate low income related metrics are summarized in the table below with the data required to report and the information provided by LE. The reporting period for the data provided in the tables is fiscal FY 2014.

**Table G-2: Low Income Programs Indicators and Data Collection**

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Low income programs and annual amount of support | • Annual budget for low income programs.<br>• Description of low income programs. | • LE uses a voluntary contribution low income support program called Project Care, which allows customers to round up their bill and support low income customers.<br>• Round up for Project Care; $38,570 of support; data located on LE website |
| 2. Low income customers as a percent of total customers. | • Number of low income customers.<br>• Total number of customers. | • 253 customers participated; data located on LE website |

# Contingency Planning

Maintaining system reliability through natural disasters and adverse conditions is important to the safety of LE staff and customers. Due to the City's in-land geographic location, it is in a unique position to maintain or quickly regain system reliability in the event of natural disasters (e.g. hurricanes) and aid neighboring utilities less fortunate with the reenergizing of service. Maintaining a detailed and thorough contingency plan is vital to customer service, through ensuring timely reconnections for critical customers (i.e. life support reliant customers, hospitals, etc.), minimizing outage time and occurrences, and ensuring the safety of LE resources and staff. Table G-3 outlines the metrics the Project Team has developed to measure the success of LE's Contingency Planning.

**Table G-3: Contingency Planning Indicators and Data Collection**

| Indicator | Data Required | LE Information Provided or Recommended Data Collection |
|---|---|---|
| 1. Summary of contingency planning, disaster/emergency management planed and training programs, and recovery/restoration plans. | • Contingency plan or summary of contingency plan, including training programs and recovery/restoration plans. | • Existing data being refined to align with GRI reporting. However, plans exist and LE is well positioned to provide broader and regional support for hurricane or weather events |
| 2. How does the Utility communicate with customers during storm or other emergency events? | • Process for emergency communication management. | • LE utilizes multiple communication tools such as the newspaper, Twitter, Facebook, IVR, web site, local cable station and email/text messages in emergency management events. |
| 3. Number of residential disconnections for non-payment | • Annual number of residential customer disconnections from non-payment. | • LE averages 33,000 actual monthly disconnections per year; this represents a sum of each month's disconnections, not the number of customers disconnected each year, which is lower. |
| 4. Power outage frequency/durations (e.g. SAIDI/SAIFI) | • SADI/SAIFI numbers reflecting outage frequency and duration. | • FY 2013 SAIDI: 76.63 (e.g. average outage minutes for each customer in LE territory)<br>• FY 2013 SAIFI: 1.22 (e.g. number of service interruptions per customer)<br>• FY 2013 CAIDI: 62.84 (average outage/interruption minutes for each customer outage). |