Report
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April 3, 2023

VIA: ELECTRONIC FILING

Mr. Adam J. Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Tampa Electric Company's 2023 Ten-Year Site Plan
Undocketed: 20230000-OT

Dear Mr. Teitzman:

Attached for filing on behalf of Tampa Electric Company is the company's January 2023 to December 2032 Ten-Year Site Plan.

Thank you for your assistance in connection with this matter.

Sincerely,

Malcolm N. Means

Malcolm N. Means

MNM/bml
Attachment
cc: Damian Kistner (DKistner@psc.state.fl.us)
Greg Davis (GDavis@psc.state.fl.us).
TECO Regulatory – (regdept@tecoenergy.com)

Ten-Year Site Plan

JANUARY 2023 – DECEMBER 2032

For Electrical Generating Facilities and Associated Transmission Lines

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2023 to December 2032

April 1, 2023

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TABLE OF CONTENTS

LIST OF SCHEDULES & TABLES

LIST OF FIGURES

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GLOSSARY OF TERMS

CODE IDENTIFICATION SHEET

Unit Type:	BA	=	Battery Storage
	CC	=	Combined Cycle
	CT	=	Combustion Turbine
	D	=	Diesel
	FS	=	Fossil Steam
	GT	=	Gas Turbine (includes jet engine design)
	HRSG	=	Heat Recovery Steam Generator
	IC	=	Internal Combustion
	IGCC	=	Integrated Gasification Combined Cycle
	PV	=	Photovoltaic
	ST	=	Steam Turbine
Unit Status:	LTRS	=	Long-Term Reserve Stand-By
	OP	=	Operating (In commercial operation)
	OT	=	Other
	P	=	Planned
	T	=	Regulatory Approval Received
	U	=	Under Construction, less than or equal to 50 percent complete
	V	=	Under Construction, more than 50 percent complete
	RT	=	Planned Retirement
Fuel Type:	BIT	=	Bituminous Coal
	RFO	=	Residual Fuel Oil (Heavy - #6 Oil)
	DFO	=	Distillate Fuel Oil (Light - #2 Oil)
	NG	=	Natural Gas
	PC	=	Petroleum Coke
	WH	=	Waste Heat
	BIO	=	Biomass
	SOLAR	=	Solar Energy
Environmental:	FQ	=	Fuel Quality
	LS	=	Low Sulfur
	SCR	=	Selective Catalytic Reduction
Transportation:	PL	=	Pipeline
	RR	=	Railroad
	TK	=	Truck
	WA	=	Water
Other:	EV	=	Electric Vehicle(s)
	NA	=	Not Applicable

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Executive Summary

Tampa Electric Company's (TEC) 2023 Ten-Year Site Plan (TYSP) features plans to enhance electric generating capability as part of our efforts to meet projected incremental resource needs for 2023 through 2032. The 2023 TYSP provides the Florida Public Service Commission (FPSC) with assurance that TEC will be able to supply cost-effective options to ensure the delivery of adequate, safe, environmentally responsible, and reliable power to TEC's customers.

The company plans to meet the power needs of its customers through additional resources and seeks to do so in the most cost-effective way possible while seeking cleaner and greener lower carbon emitting assets. The resource additions are based on TEC's Integrated Resource Planning (IRP) process, which incorporates an on-going evaluation of demand-side and supply-side resources on a comparable and consistent basis to satisfy future demand and energy requirements in a cost-effective, reliable, and environmentally responsible manner.

Investments in renewable generation enables fuel savings for customers, provides energy diversification, and continues TEC's commitment towards a lower carbon future. The future solar in this expansion plan provides energy diversity by reducing both reliance on natural gas and its associated price volatility risk for customers. The company has announced its plans to deploy more solar projects over the next several years, bringing the total committed solar capacity to nearly 2,000 MW or approximately 28% of the total summer installed capacity by the end of the study horizon.

In addition to enhancements of the aforementioned solar, TEC plans to add approximately 195 MW of battery storage capacity and approximately 74 MW of capacity using reciprocating engines over the study horizon. These distributed resources provide peaking capacity and fuel savings. Furthermore, these distributed energy resources have the potential to provide system operational benefits, avoided transmission and distribution investment, and reduced line losses.

TEC is also committed to pursuing cost-effective improvements on the existing generating fleet. Effective December of 2022, the modernized Big Bend combined cycle unit provides 1,120 MW of highly efficient natural gas fueled electricity generation. Moving forward, between 2023 and 2024, the Bayside station will undergo advanced hardware upgrades to improve efficiency, generating capacity, and operational flexibility to its seven (7) CTs.

Tampa Electric Company's current and expected resources meet operating reserve requirements under normal peak demand scenarios. The reserve margin provides operating flexibility in the case of unplanned outages and deviations to load from colder than normal (or hotter than normal) weather. However, temperatures that vary significantly from those used to prepare this plan would result in the need to employ operating mitigation under these extreme conditions. These mitigations could include changes to unit dispatch to enhance reliability, switching to alternate fuels, extensive use of demand response, pursuing purchase power agreements, and in a worst-case scenario, interrupting customers to maintain grid stability. The company has also reviewed and updated its freeze protection plans for each of its generation stations and has implemented measures to mitigate equipment failure during these extreme temperatures.

The portfolio of resource additions presented in this TYSP work in concert to provide cost savings, environmental, and reliability benefits for customers while also enhancing the system's operational flexibility, energy diversity, and resiliency.

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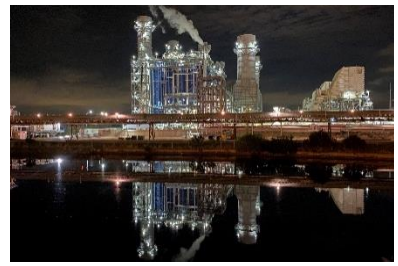
Chapter I

DESCRIPTION OF EXISTING FACILITIES

TEC has three (3) central generating stations that include steam units, combined cycle units, combustion turbine peaking units, and an integrated coal gasification combined cycle (IGCC) unit. Additionally, TEC has numerous solar facilities.

Big Bend Power Station



Big Bend Station is composed of one combined cycle unit, Unit 1, which utilizes two (2) combustion turbines that supply waste heat for reuse by the Unit 1 steam turbine via two (2) heat recovery steam generators (HRSGs). Big Bend also has two steam units, 3 and 4. Both steam units are equipped with desulfurization scrubbers, electrostatic precipitators, and Selective Catalytic Reduction air pollution control systems. Big Bend Unit 4 can be fired with natural gas or coal. Natural gas is the primary fuel on Unit 1 and Unit 3. Big Bend CT 4 is a natural gas aero-derivative combustion turbine.

H.L. Culbreath "Bayside" Power Station

The Bayside station consists of two (2) natural gas-fired combined cycle units and (4) aero derivative combustion turbines. Bayside Unit 1 utilizes three (3) combustion turbines, three (3) HRSGs and one (1) steam turbine. Bayside Unit 2 utilizes four (4) combustion turbines, four (4) HRSGs and one (1) steam turbine. Bayside 3, 4, 5, and 6 are four (4) natural gas fired aero-derivative combustion turbines.

Polk Power Station

Polk Unit 1 is a dual fuel natural gas / IGCC unit consisting of one (1) combustion turbine, one (1) HSRG, and one (1) steam turbine. Polk 2 Combined Cycle utilizes four (4) natural gas-fired combustion turbines, four (4) HRSGs and one (1) steam turbine. Two of the combustion turbines can also be fired with distillate oil.

Solar

As of December 31, 2022, TEC owns 1,023 MW_{AC} of solar throughout our territory. It consists of primarily single axis tracking PV solar array sites throughout Hillsborough, Pasco, and Polk counties, and several large-scale, fixed-tilt systems on rooftops, carports, and ground mount. Tampa Electric has a 1.0 MW_{AC} floating solar project located at Big Bend Power Station. Additionally, TEC has an integrated renewable energy system, consisting of solar PV carports that charge commercial-sized batteries, which re-charge the company's growing EV fleet.

Schedule 1
Existing Generating Facilities
As of December 31, 2022

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt Fuel Days	(10) Commercial In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen. Max. Nameplate kW	(13) Net Capability Summer MW	(14) Net Capability Winter MW
Big Bend [1]		**Hillsborough Co.**											
	1		CC	NG	NA	PL	NA	NA	12/22	**	1,241,100	1,055	1,120
	3		ST	NG	NA	PL	NA	NA	05/76	04/23	445,500	395	400
	4		ST	BIT	NG	WA/RR	PL	NA	02/85	01/45	486,000	437	442
	CT 4		GT	NG	NA	PL	NA	NA	08/09	**	69,900	56	61
Big Bend Total											**2,242,500**	**1,943**	**2,023**
Bayside		**Hillsborough Co.**											
	1		CC	NG	NA	PL	NA	NA	04/03	04/38	809,060	701	792
	2		CC	NG	NA	PL	NA	NA	01/04	01/39	1,205,100	929	1,047
	3		GT	NG	NA	PL	NA	NA	07/09	**	69,900	56	61
	4		GT	NG	NA	PL	NA	NA	07/09	**	69,900	56	61
	5		GT	NG	NA	PL	NA	NA	04/09	**	69,900	56	61
	6		GT	NG	NA	PL	NA	NA	04/09	**	69,900	56	61
Bayside Total											**2,293,759**	**1,854**	**2,083**
Polk		**Polk Co.**											
	1		IGCC	NG	PC/BIT	PL	WA/TK	*	09/96	09/36	326,299	220	220
	2		CC	NG	DFO	PL	TK	*	01/17	**	1,216,080	1,061	1,200
Polk Total											**1,542,379**	**1,281**	**1,420**
TIA	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	12/15	**	1,600	1.6	1.6
LEGOLAND®	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	12/16	**	1,400	1.4	1.4
Big Bend Solar [2]	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	02/17	**	19,800	19.8	19.8
Payne Creek Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	09/18	**	70,300	70.3	70.3
Balm Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	09/18	**	74,400	74.4	74.4
Lithia Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	01/19	**	74,500	74.5	74.5
Grange Hall Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	01/19	**	61,100	61.1	61.1
Bonnie Mine Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	01/19	**	37,500	37.5	37.5
Peace Creek Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	03/19	**	55,400	55.4	55.4
Lake Hancock Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	04/19	**	49,500	49.5	49.5
Little Manatee Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	02/20	**	74,500	74.5	74.5
Wimauma Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	04/20	**	74,800	74.8	74.8
Durrance Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	01/21	**	60,000	60.0	60.0
Magnolia Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	12/21	**	74,500	74.5	74.5
Big Bend II Solar (Phase I)	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	01/22	**	31,500	31.5	31.5
Big Bend Floating Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	03/22	**	1,000	1.0	1.0
Mountain View Solar	**1**	**Pasco Co.**	PV	SOLAR	NA	NA	NA	NA	04/22	**	54,600	54.6	54.6
Jamison Solar	**1**	**Polk Co.**	PV	SOLAR	NA	NA	NA	NA	04/22	**	74,500	74.5	74.5
Big Bend Agrivoltaic	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	06/22	**	1,000	1.0	1.0
Big Bend II Solar (Phase II)	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	11/22	**	14,300	14.3	14.3
Laurel Oaks Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	12/22	**	61,200	61.2	61.2
Riverside Solar	**1**	**Hillsborough Co.**	PV	SOLAR	NA	NA	NA	NA	12/22	**	55,200	55.2	55.2
Solar Total [3, 4]											**1,022,600**	**1,023**	**1,023**
											TOTAL	**6,101**	**6,549**

Notes:

* Limited by environmental permit.

** Undetermined.

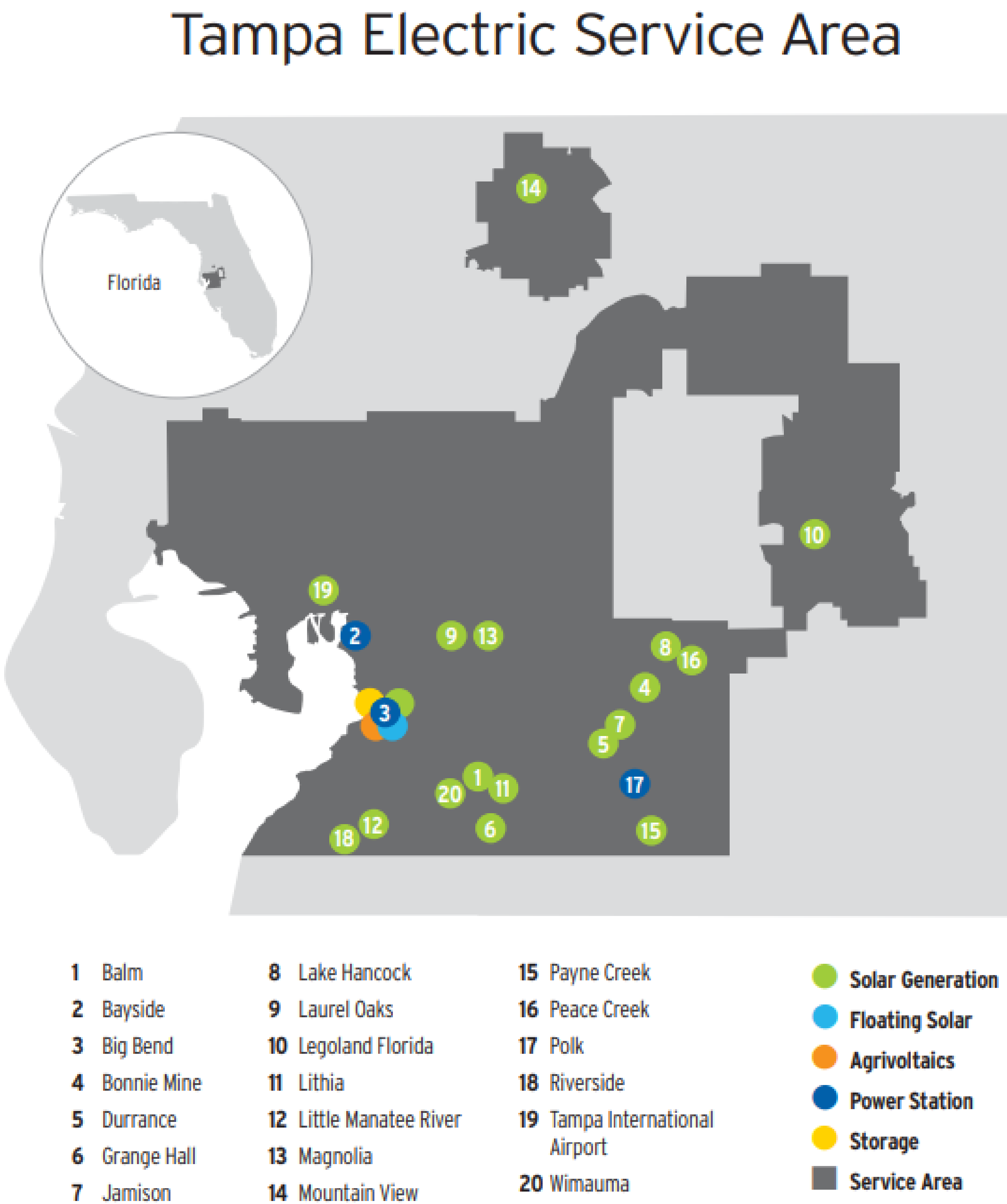
1 Plant firm net capability will be limited effective January 2023 due to site transmission constraints.

2 The 12.6 MW Big Bend Battery was integrated into the solar site at Big Bend in December 2019.

3 Approximately 54.1% of Solar generation is considered firm for Summer Reserve Margin and 0% is considered firm for Winter Reserve Margin calculation. Rating for Solar units are nameplate ratings.

4 Utility owned solar/battery less than 1 MW not included.

Figure I-I: Tampa Electric Service Area Map



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Chapter II

TAMPA ELECTRIC COMPANY FORECASTING METHODOLOGY

The customer, demand and energy forecasts are the foundation from which the IRP is developed. Recognizing their importance, TEC employs proven methodologies for carrying out this function. The primary objective of this procedure is to blend proven statistical techniques with practical forecasting experience to provide a projection that represents the highest probability of occurrence.

This chapter is devoted to describing TEC's forecasting methodologies and the major assumptions utilized in developing the 2023-2032 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the 2023-2032 time period.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2023-2032 customer, demand and energy forecasts. This software allows a platform for the development of more dynamic and fully integrated models.

In addition, TEC uses MetrixLT, which integrates with MetrixND, to develop multiple-year forecasts of energy usage at the hourly level. This tool allows the annual or monthly forecasts in MetrixND to be combined with hourly load shape data to develop a long-term "bottom-up" forecast.

TEC's retail customer, demand and energy forecasts are the result of eight separate forecasting analyses:

1. Economic Analysis
2. Customer Multiregression Model
3. Energy Multiregression Model
4. Peak Demand Multiregression Model
5. Interruptible Demand and Energy Analysis
6. Customer-Owned Photovoltaic (PV)
7. Electric Vehicle Charging (EV)
8. Conservation, Load Management and Cogeneration Programs

The MetrixND models are the company's most sophisticated and primary load forecasting models. The phosphate demand and energy are forecasted separately and then combined in the final forecast, as well as the effects of customer-owned photovoltaic (PV) and electric vehicle (EV) related energy and demand. Likewise, the effects of TEC's conservation, load management, and cogeneration programs are incorporated into the process by subtracting the expected reduction in demand and energy from the forecast.

1. Economic Analysis

The economic assumptions used in the forecast models are derived from forecasts from Moody's Analytics and the University of Florida's Bureau of Economic and Business Research (BEBR).

See the "Base Case Forecast Assumptions" section of this chapter for an explanation of the most significant economic inputs to the MetrixND models.

2. Customer Multiregression Model

The customer multiregression forecasting model is a twelve-equation model. The primary economic drivers in the customer forecast models are population estimates, new construction, and employment growth. Below is a description of the models used for the five-customer classes.

- ***Residential Customer Model (Equation #1):*** Customer projections are a function of regional population due to the strong correlation that exists between regional population and historical changes in service area customers.

- ***Commercial Customer Model:*** Total commercial customers include commercial customers plus construction service customers; therefore, two models are used to forecast total commercial customers:

    - The Commercial Customer Model ***(Equation #2)*** is a function of commercial employment. An increase in employment signals growth in additional services, restaurants, and retail establishments.

    - Projections of permits in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the Construction Service Model ***(Equation #3)*** projects the number of customers as a function of new construction permits.

- ***Industrial Customer Model (Non-Phosphate):*** *Non-phosphate industrial customers include four rate classes modeled individually: General Service, General Service Demand, General Service Large Demand and Standby Large Demand.*

    - The General Service Customer Model ***(Equation #4)*** is a function of Hillsborough County commercial employment.

    - The General Service Demand Customer Model ***(Equation #5)*** is a function of Hillsborough County manufacturing employment.

    - The General Service Large Demand Customer Model ***(Equation #6)*** is a function of current trends.

    - The Standby Large Demand Customer Model ***(Equation #7)*** is a function of recent trends.

- ***Industrial Phosphate Customers:*** Customer counts seldom change within this industry; however, actual counts are tracked for any changes and phosphate accounts are individually surveyed annually to reflect any known future changes.

- ***Public Authority Customer Model:*** Customer projections are based on the recent growth trends in the governmental sector and are modeled individually for five rate classes: Residential Service, General Service, General Service Demand, General Service Large Demand and Standby Large Demand. ***(Equations #8 through #12)***

- ***Street & Highway Lighting Customers:*** Customer projections are based on recent growth trends in the sector and provided exogenously by the Lighting Growth department, subject matter experts who are familiar with industry dynamics and changing lighting technologies which can drive new customer growth.

3. Energy Multiregression Model

The energy multiregression forecasting model is also a twelve-equation model. All these equations represent average usage per customer (kWh/customer), except for the construction services which represent total energy (kWh) sales. The average usage models interact with the customer models to arrive at total sales for each class.

The energy models are based on a Statistically Adjusted End-Use (SAE) framework. SAE entails specifying end-use variables, such as heating, cooling, and base use appliance/equipment, and incorporating these variables into regression models. This approach allows the models to capture long-term structural changes that end-use models are known for, while also performing well in the short-term, as do econometric regression models.

- ***Residential Energy Model (Equation #1)****:* The residential forecast model is made up of three major components: (1) end-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements; (2) changes in the economy such as household income, household size, and the price of electricity; and (3) weather variables, which serve to allocate the seasonal impacts of weather throughout the year. The SAE model framework begins by defining energy use for an average customer in year (y) and month (m) as the sum of energy used by heating equipment (XHeat y,m), cooling equipment (XCool y,m), and other equipment (XOther y,m). The XHeat, XCool, and XOther variables are defined as a product of an annual equipment index and a monthly usage multiplier.

$$\text{Average Usage}_{y,m} = (\text{XHeat}_{y,m} + \text{XCool}_{y,m} + \text{XOther}_{y,m})$$

Where:

$$\text{XHeat}_{y,m} = \text{HeatEquipIndex}_{y} \times \text{HeatUse}_{y,m}$$
$$\text{XCool}_{y,m} = \text{CoolEquipIndex}_{y} \times \text{CoolUse}_{y,m}$$
$$\text{XOtherUse}_{y,m} = \text{OtherEquipIndex}_{y} \times \text{OtherUse}_{y,m}$$

The annual equipment variables (HeatEquipIndex, CoolEquipIndex, OtherEquipIndex) are defined as a weighted average across equipment types multiplied by equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations and operating efficiencies. The weights are defined by the estimated energy use per household for each equipment type in the base year.

Where:

$$\textbf{HeatEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_y \;/\; \text{Efficiency}_y}{\text{Saturation}_{\text{base } y} \;/\; \text{Efficiency}_{\text{base } y}} \right)$$

$$\textbf{CoolEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_y \;/\; \text{Efficiency}_y}{\text{Saturation}_{\text{base } y} \;/\; \text{Efficiency}_{\text{base } y}} \right)$$

$$\textbf{OtherEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_y \;/\; \text{Efficiency}_y}{\text{Saturation}_{\text{base } y} \;/\; \text{Efficiency}_{\text{base } y}} \right)$$

Next, the monthly usage multiplier or utilization variables (HeatUse, CoolUse, OtherUse) are defined using economic and weather variables. A customer's monthly usage level is impacted by several factors, including weather, household size, income levels, electricity prices and the number of days in the billing cycle. The degree-day variables allocate the seasonal impacts of weather throughout the year, while the remaining variables capture changes in the economy.

$$\textbf{HeatUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base } y,m}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base } y,m}} \right)^{.17} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base } y,m}} \right)^{.15} \times \left(\frac{\text{HDD}_{y,m}}{\text{Normal HDD}} \right)$$

$$\textbf{CoolUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base } y,m}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base } y,m}} \right)^{.17} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base } y,m}} \right)^{.15} \times \left(\frac{\text{CDD}_{y,m}}{\text{Normal CDD}} \right)$$

$$\textbf{OtherUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base } y,m}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base } y,m}} \right)^{.17} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base } y,m}} \right)^{.15} \times \left(\frac{\text{Billing Days}_{y,m}}{\text{Billing Days}_{\text{base } y,m}} \right)$$

The SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels and gives estimates of weather sensitivities that vary over time and trend adjustments.

- ***Commercial Energy Model:*** total commercial energy sales include commercial sales plus construction service sales; therefore, two equations are used to forecast total commercial energy sales.
  - Commercial Energy Model ***(Equation #2)***: The model framework for the commercial sector is the same as the residential model. It also has three major components and utilizes the SAE model framework. The differences lie in the type of end-use equipment and in the economic variables used. The end-use equipment variables are based on commercial appliance/equipment saturation and efficiency assumptions. The economic drivers in the commercial model are

commercial productivity measured in terms of dollar output and the price of electricity for the commercial sector. The third component, weather variables, is the same as in the residential model.

  - Construction Service Energy Model ***(Equation #3)***: This model is a subset of the total commercial sector and is a small percentage of the total commercial sector. Although small, it is still a component that must be included. A simple regression model is used with the drivers being construction service customer growth, projections of construction permits, along with the number of days billed, and cooling and heating degree-days.

- ***Industrial Energy Model (Non-Phosphate):*** *Non-phosphate industrial energy includes four rate classes modeled individually: General Service, General Service Demand, General Service Large Demand and Standby Large Demand.*

  - The General Service Energy Model ***(Equation #4)*** utilizes the same SAE model framework as the commercial energy model. The weather component is consistent with the residential and commercial models.

  - The General Service Demand Energy Model ***(Equation #5)*** is based on manufacturing output, the price of electricity in the industrial sector, cooling degree-days and number of days billed. Unlike the previous models discussed, heating load does not impact this sector.

  - The General Service Large Demand Energy Model ***(Equation #6)*** is based on seasonal trends.

  - The Standby Large Demand Energy Model ***(Equation #7)*** is based on seasonal trends.

- ***Public Authority Sector Energy Model:*** The governmental sector is modeled individually for five rate classes: Residential Service, General Service, General Service Demand, General Service Large Demand, and Standby Large Demand.

  - The Residential Service Energy Model ***(Equation #8)*** is based on the residential equipment saturation and efficiency assumptions used in the residential model.

  - The General Service Energy Model ***(Equation #9)*** is based on the same commercial equipment saturation and efficiency assumptions used in the commercial model. The economic component is based on government sector productivity and the price of electricity in this sector. Weather variables are consistent with the residential and commercial models.

  - The General Service Demand Energy Model ***(Equation #10)*** is a function of cooling and heating degree-days.

  - The General Service Large Demand Energy Model **(Equation #11)** is based on seasonal trends.

  - The Standby Large Demand Energy Model ***(Equation #12)*** is based on seasonal trends.

- ***Street & Highway Lighting Sector Energy:*** Street and highway lighting is not weather sensitive; therefore, it is a simple calculation. Street and highway lighting energy consumption is a function of energy (kWh) ratings by fixture type times the number of projected lighting fixtures. This information is provided exogenously by the Lighting Growth department, subject matter experts who are familiar with industry dynamics and changing lighting technologies which can drive changes in energy projections. The street and highway lighting forecast reflects the impacts of the company's LED lighting program.

The twelve energy models described above, plus the incremental effects of customer-owned rooftop solar [PV], electric vehicle [EV] charging and conservation related energy, along with an exogenous lighting, interruptible, and phosphate forecast, are added together to arrive at the total retail energy sales forecast. (See sections 5 – 8 below for details.) A line loss factor is applied to the energy sales forecast to produce the retail net energy for load forecast (RNEL).

In summary, the SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels, gives estimates of weather sensitivity that varies over time, and estimates trend adjustments.

4. *Peak Demand Multiregression Model*

After the retail net energy for load forecast is complete, it is integrated into the peak demand model as an independent variable along with weather variables. The energy variable represents the long-term economic and appliance trend impacts. To stabilize the peak demand data series and improve model accuracy, the volatility of the industrial phosphate load is removed. To further stabilize the data, the peak demand models project on a per customer basis.

The weather variables provide the monthly seasonality to the peaks. The weather variables used are heating and cooling degree-days based on the following: temperature at the time of the peak, 24-hour average on the day of the peak and the day prior to the peak. By incorporating the day prior to the peak, the model is accounting for the fact that cold/heat buildup contributes to determining the peak day.

The non-phosphate per customer kW forecast is multiplied by the final customer forecast. This result is then aggregated with a phosphate-coincident peak forecast and adjusted for the incremental effects of customer-owned PV, EV charging, and conservation related demand to arrive at the final projected peak demand.

5. *Interruptible Demand and Energy Analysis*

TEC interruptible customers are relatively few, which has allowed the company's Commercial and Industrial Business Development Department to obtain detailed knowledge of industry developments including:

- Knowledge of expansion and close-out plans
- Familiarity with historical and projected trends
- Personal contact with industry personnel
- Governmental legislation
- Familiarity with worldwide demand for phosphate products

This department's familiarity with industry dynamics and their close working relationship with phosphate and other company representatives were used to form the basis for a survey of the interruptible customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecast, and the commercial/industrial interruptible rate class forecasts are based. Further input is provided by individual customer trend analysis and discussions with industry experts.

6. Customer-Owned Solar (PV)

Customer-owned solar forecasts are based on the historical number of PV installations and the average size of the PV systems installed in the service area. From this historical data, future penetration levels of PVs are based on assumptions used by the Energy Information Administration's (EIA) for the South Atlantic region. It is assumed Tampa Electric will no longer have to serve this portion of PV customers' load; therefore, the energy sales forecast is adjusted downward to incorporate the loss of this load.

7. Electric Vehicle (EV) Charging

The electric vehicle charging forecast process begins with an estimate of the number of EVs operating in Tampa Electric's service area. Future penetration levels of EVs are based on assumptions used by the Energy Information Administration's (EIA) for the South Atlantic region. The demand and energy consumption associated with EV charging is based on several assumptions including the average number of miles driven in a year, the weighted average battery size of four common EV models sold within the service area and the number of charges per year.

8. Conservation, Load Management and Cogeneration Programs

Conservation and Load Management demand and energy savings are forecasted for each individual program. The savings are based on a forecast of the annual number of new participants, estimated annual average energy savings per participant and estimated summer and winter average demand savings per participant. The individual forecasts are aggregated and represent the cumulative amount of Demand Side Management (DSM) savings throughout the forecast horizon.

TEC retail demand and energy forecasts are adjusted downward to reflect the incremental demand and energy savings of these DSM programs.

TEC has developed conservation, load management and cogeneration programs to achieve five major objectives:

1. Defer expansion, particularly production plant construction.

2. Reduce marginal fuel cost by managing energy usage during higher fuel cost periods.

3. Provide customers with some ability to control energy usage and decrease energy costs.

4. Pursue the cost-effective accomplishment of the FPSC ten-year demand and energy conservation goals for the residential and commercial/industrial sectors.

5. Achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act (FEECA).

In 2022, Tampa Electric continued operating within the FPSC approved 2020-2029 DSM Plan which consists of one renewable program, one research and development program, 15 residential and 20 commercial DSM Programs which support the approved FPSC goals which are reasonable, beneficial, and cost-effective to all customers as required by the FEECA. Also in 2022, the company initiated the process with all the other FEECA utilities to start the development of the technical potential study which will support the 2025-2034 DSM Plan. The following is a list that briefly describes the company's DSM programs:

1. Energy Audits - a "how to" information and analysis guide for customers. Six types of audits are available to Tampa Electric customers; four types are for residential customers and two types are for commercial/industrial customers.

2. Residential Ceiling Insulation – a rebate program that encourages existing residential customers to install additional ceiling insulation in existing homes.

3. Residential Duct Repair – a rebate program that encourages residential customers to repair leaky duct work of central air conditioning systems in existing homes.

4. Energy and Renewable Education, Awareness and Agency Outreach - a program that provides opportunities for engaging and educating groups of customers, students on energy-efficiency and conservation in an organized setting and electric vehicles at participating high schools. Participants are provided with an energy savings kit which includes energy saving devices and supporting information appropriate for the audience.
5. Energy Star for New Multi-Family Residences - a rebate program that encourages the construction of new multi-family residences to meet the requirements to achieve the ENERGY STAR certified apartments and condominium label.

6. Energy Star for New Homes - a rebate program that encourages residential customers to construct residential dwellings that qualify for the Energy Star Award by achieving efficiency levels greater than current Florida building code baseline practices.

7. Energy Star Pool Pumps - a rebate program that encourages residential customers to install Energy Star rated pool pumps in existing homes.

8. Energy Star Thermostats - a rebate program that encourages residential customers to install Energy Star rated thermostats in existing homes.

9. Residential Heating and Cooling – a rebate program that encourages residential customers to install high-efficiency residential heating and cooling equipment in existing homes.

10. Neighborhood Weatherization – a program that provides for the installation of energy efficient measures for qualified low-income customers.

11. Prime Time Plus – a program that reduces weather-sensitive loads through direct load control of residential customers HVAC (Heating, Ventilating, and Air Conditioning), water heating and pool pumps. This program will use the company's advanced metering infrastructure ("AMI") system. The company added the first customer on this program in December 2022.

12. Residential Price Responsive Load Management (Energy Planner) – a program that reduces weather-sensitive loads through an innovative price responsive rate used to encourage residential customers to make behavioral or equipment usages changes by pre-programming HVAC, water heating and pool pumps.

13. Residential Window Replacement – a rebate program that encourages existing residential customers to install window upgrades in existing homes.

14. Commercial Chiller – a rebate program that encourages commercial and industrial customers to install high efficiency chiller equipment.

15. Cogeneration – an incentive program whereby large industrial customers with waste heat or fuel resources may install electric generating equipment, meet their own electrical requirements and/or sell their surplus to the company.

16. Conservation Value – a rebate program that encourages commercial and industrial customers to invest in energy efficiency and conservation measures not sanctioned by other commercial programs.

17. Commercial Cooling – a rebate program that encourages commercial and industrial customers to install high efficiency direct expansion commercial air conditioning cooling equipment.

18. Demand Response – a turn-key incentive program for commercial and industrial customers to reduce their demand for electricity in response to market signals.

19. Commercial Facility Energy Management System – a rebate program that encourages commercial and industrial customers to install high efficiency energy management systems.

20. Industrial Load Management – an incentive program whereby large industrial customers allow for the interruption of their facility or portions of their facility electrical load.

21. Street and Outdoor Lighting Conversion – A program that converts Tampa Electric's metal halide and high-pressure sodium street and outdoor lighting to energy efficient light emitting diode (LED) technology to reduce energy consumption and Tampa Electric's peak demand. Tampa Electric will recover the remaining unamortized costs in rate base with the eligible non-LED luminaires.

22. Lighting Conditioned Space – a rebate program that encourages commercial and industrial customers to invest in more efficient lighting technologies in existing conditioned areas of commercial and industrial facilities.

23. Lighting Non-Conditioned Space – a rebate program that encourages commercial and industrial customers to invest in more efficient lighting technologies in existing non-conditioned areas of commercial and industrial facilities.

24. Lighting Occupancy Sensors – a rebate program that encourages commercial and industrial customers to install occupancy sensors to control commercial lighting systems.

25. Commercial Load Management – an incentive program that encourages commercial and industrial customers to allow for the control of weather-sensitive heating, cooling, and water heating systems to reduce the associated weather sensitive peak.

26. Commercial Smart Thermostat - a rebate program that encourages commercial and industrial customers to install smart thermostats.

27. Standby Generator – an incentive program designed to utilize the emergency generation capacity of commercial/industrial facilities to reduce weather sensitive peak demand.

28. Variable Frequency Drive Control for Compressors - a rebate program that encourages commercial and industrial customers to install variable frequency drives on refrigerant or compressed air systems.

29. Commercial Water Heating – a rebate program that encourages commercial and industrial customers to install high efficiency water heating systems.

30. Integrated Renewable Energy System – a five-year pilot program to study and understand the potential opportunities and interactions of a fully integrated renewable energy system that contains a photovoltaic system, batteries, car charging and industrial truck charging.

31. Conservation Research and Development (R&D) – a program that allows for the exploration of DSM measures that have insufficient data on the cost-effectiveness of the measure and the potential impact to Tampa Electric and its ratepayers.

The programs listed above were developed to meet FPSC demand and energy goals established in Docket No. 20190021-EG, Order No. PSC-2019-0509-FOF-EU, Issued November 26, 2019. The 2022 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

TEC developed a Monitoring and Evaluation (M&E) plan in response to FPSC requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources.

The M&E plan has its focus on two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give TEC insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

TABLE III-1
Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals
Savings at the Generator

Residential

Year	Winter Peak MW Reduction Total Achieved	Winter Peak MW Reduction Commission Approved Goal	Winter Peak MW Reduction % Variance	Summer Peak MW Reduction Total Achieved	Summer Peak MW Reduction Commission Approved Goal	Summer Peak MW Reduction % Variance	GWh Energy Reduction Total Achieved	GWh Energy Reduction Commission Approved Goal	GWh Energy Reduction % Variance
2015	12.3	2.6	473.1%	10.8	1.1	981.8%	21.2	1.8	1,177.8%
2016	7.7	4.1	187.8%	5.1	1.6	318.8%	13.2	3.5	377.1%
2017	6.9	5.2	132.7%	4.7	2.2	213.6%	14.9	4.8	310.4%
2018	8.0	6.5	123.0%	5.6	2.7	205.7%	17.1	6.1	280.3%
2019	8.3	7.6	108.8%	5.7	3.1	184.5%	16.8	6.9	243.2%
2020	3.5	7.6	45.5%	2.6	3.3	78.2%	8.9	7.4	120.3%
2021	4.5	8.0	55.8%	6.4	3.3	194.2%	16.4	7.7	213.1%
2022	9.5	7.4	127.8%	11.1	3.0	369.8%	30.4	6.9	441.0%
2023		6.8			2.9			6.3	
2024		6.1			2.5			5.5	

Commercial/Industrial

Year	Winter Peak MW Reduction Total Achieved	Winter Peak MW Reduction Commission Approved Goal	Winter Peak MW Reduction % Variance	Summer Peak MW Reduction Total Achieved	Summer Peak MW Reduction Commission Approved Goal	Summer Peak MW Reduction % Variance	GWh Energy Reduction Total Achieved	GWh Energy Reduction Commission Approved Goal	GWh Energy Reduction % Variance
2015	8.1	1.2	675.0%	11.7	1.7	688.2%	12.5	3.9	320.5%
2016	2.9	1.3	223.1%	4.4	2.5	176.0%	17.8	6.0	296.7%
2017	9.2	1.6	575.0%	10.4	2.7	385.2%	30.2	8.0	377.5%
2018	13.0	1.7	767.1%	15.0	3.3	453.6%	33.7	9.2	365.9%
2019	22.4	1.6	1401.9%	29.2	3.3	885.9%	74.6	9.9	753.4%
2020	10.4	1.7	612.5%	11.8	3.5	336.0%	26.1	10.3	253.3%
2021	4.7	1.9	246.2%	5.6	3.6	156.8%	20.4	10.4	196.1%
2022	7.1	1.9	376.0%	12.3	3.3	372.2%	26.6	10.2	261.2%
2023		1.8			3.5			9.9	
2024		1.7			3.2			9.6	

Combined Total

Year	Winter Peak MW Reduction Total Achieved	Winter Peak MW Reduction Commission Approved Goal	Winter Peak MW Reduction % Variance	Summer Peak MW Reduction Total Achieved	Summer Peak MW Reduction Commission Approved Goal	Summer Peak MW Reduction % Variance	GWh Energy Reduction Total Achieved	GWh Energy Reduction Commission Approved Goal	GWh Energy Reduction % Variance
2015	20.4	3.8	536.8%	22.5	2.8	803.6%	33.7	5.7	591.2%
2016	10.6	5.4	196.3%	9.5	4.1	231.7%	31.0	9.5	326.3%
2017	16.1	6.8	236.8%	15.1	4.9	308.2%	45.1	12.8	352.3%
2018	21.0	8.2	256.5%	20.5	6.0	342.1%	50.8	15.3	331.8%
2019	30.7	9.2	333.7%	35.0	6.4	546.2%	91.4	16.8	543.9%
2020	13.9	9.3	149.1%	14.3	6.8	210.9%	35.0	17.7	197.7%
2021	9.1	9.9	92.3%	12.1	6.9	174.7%	36.8	18.1	203.3%
2022	16.6	9.3	178.5%	23.4	6.3	371.0%	57.1	17.1	333.8%
2023		8.6			6.4			16.2	
2024		7.8			5.7			15.1	

BASE CASE FORECAST ASSUMPTIONS

RETAIL LOAD

Numerous assumptions are inputs to the MetrixND models, of which the more significant ones are listed below.

1. Population and Households
2. Commercial, Industrial and Governmental Employment
3. Commercial, Industrial and Governmental Output
4. Real Household Income
5. Price of Electricity
6. Appliance Efficiency Standards
7. Weather

1. Population and Households

Florida and Hillsborough County population forecasts are the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Moody's Analytics supply population projections for Hillsborough County and Florida comparisons. BEBR's population growth for Hillsborough County was used to project future growth patterns in residential customers from 2023-2032. The average annual population growth rate is expected to be 1.3%.

2. Commercial, Industrial and Governmental Employment

Commercial, industrial, and governmental employment assumptions are utilized in computing the number of customers in their respective sectors. Over the next ten years (2023-2032), employment is assumed to rise at a 1.2% average annual rate within Hillsborough County. Moody's Analytics supplies employment projections for the non-residential models.

3. Commercial, Industrial and Governmental Output

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Output for the entire employment sector within Hillsborough County is assumed to rise at a 3.4% average annual rate from 2023-2032. Moody's Analytics supplies output projections.

4. Real Household Income

Moody's Analytics supplies the assumptions for Hillsborough County's real household income growth. During 2023-2032, real household income for Hillsborough County is expected to increase at a 1.5% average annual rate.

5. Price of Electricity

Forecasts for the price of electricity by customer class are supplied by TEC's Regulatory Affairs Department.

6. Appliance Efficiency Standards

Another factor influencing energy consumption is the movement toward more efficient appliances such as heat pumps, refrigerators, lighting, and other household appliances. The forces behind this development include market pressures for greater energy-saving devices, legislation, rules, and the appliance efficiency standards enacted by the state and federal governments. Also influencing energy consumption is the customer saturation levels of appliances. The saturation trend for heating appliances is increasing through time; however, overall electricity consumption declines over time as less efficient heating technologies (room heating and furnaces) are replaced with more efficient technologies (heat pumps). Similarly, cooling equipment saturation will continue to increase, but be offset by heat pump and central air conditioning efficiency gains.

Improvements in the efficiency of other non-weather-related appliances also help to lower electricity consumption. Although there is an increasing saturation trend of electronic equipment and appliances in households throughout the forecast period, it does not offset the efficiency gains from lighting and appliances.

7. Weather

The weather assumptions are the most difficult to project. Therefore, historical data is the major determinant in developing temperature profiles. For example, monthly profiles used in calculating energy consumption are based on twenty years of historical data. The temperature profiles used in projecting the winter and summer system peak are based on an examination of the minimum and maximum temperatures for the past twenty years plus the temperatures on peak days for the past twenty years. Monte Carlo simulations are performed to estimate weather probabilities.

HIGH AND LOW SCENARIO FOCUS ASSUMPTIONS

The base case scenario is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy scenarios represent alternatives to the company's base case outlook. Compared to the base case, the expected economic growth rates are 0.5 percent higher in the high scenario and 0.5 percent lower in the low scenario.

HISTORY AND FORECAST OF ENERGY USE

A history and forecast of energy consumption by customer classification are shown in Schedules 2.1 - 2.3 in Chapter IV.

1. Retail Energy

For 2023-2032, retail energy sales are projected to rise at a 0.9% annual rate. The primary contributor to growth is the residential class increasing at an annual rate of 1.2%.

2. Wholesale Energy

TEC has no scheduled firm wholesale power sales currently.

HISTORY AND FORECAST OF PEAK LOADS

Historical, base, high, and low scenario forecasts of peak loads for the summer and winter seasons are presented in Schedules 3.1 and 3.2, respectively. For the period of 2023-2032, TEC's base retail firm peak demand is expected to increase at an average annual rate of 0.7% in the summer and 0.9% in the winter.

Chapter III

INTEGRATED RESOURCE PLANNING PROCESSES

TEC's IRP process is designed to evaluate demand-side and supply-side resources on a comparable and consistent basis to satisfy future demand and energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders.

The process incorporates a reliability analysis to determine timing of future needs and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. Initially, a demand and energy forecast is developed which excludes incremental energy efficiency and conservation programs. This forecast is used to identify the basis for the next potential avoided unit(s), and becomes the baseline used to perform a comprehensive cost effectiveness analysis of these programs based on the following Commission approved tests: the Rate Impact Measure test (RIM), the Total Resource Cost test (TRC), and the Participants Cost test (PCT). Using the FPSC's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are also used in this analysis. All measures that pass the RIM and PCT tests in the energy efficiency and demand response analysis are considered for utility program adoption.

Each adopted measure is quantified into its coincident summer and winter peak kW reduction contribution and its annual kWh savings and is reflected in the demand and energy forecast. TEC evaluates and reports energy efficiency and demand response measures that comports with Rule 25-17.008, F.A.C., the FPSC's prescribed cost-effectiveness methodology.

Once this comprehensive analysis is complete and the cost-effective energy efficiency and conservation programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the energy efficiency and conservation programs and supply-side resources.

Generating supply side resources to be considered are determined through an alternative technology screening analysis, which is designed to determine the economic viability of a wide range of generating technologies for the TEC service area. The technologies that pass the screening are included in a supply-side analysis that examines various supply-side alternatives for meeting future system requirements.

TEC uses a computer model developed by Hitachi Energy, System Optimizer (SO), to evaluate supply-side resources. SO utilizes a mixed integer linear program (MILP) to develop an estimate of the timing and type of supply-side resources for generation additions that would economically meet the system demand and energy requirements. The objective function of the MILP is to compare all feasible combinations of generating unit additions, satisfy the specified reliability criteria, and determine the schedule and addition with the lowest total system cost.

Detailed cost analyses for each of the top ranked resource plans are performed using the Planning & Risk (PaR) production cost model, also developed by Hitachi. The capital expenditures, including interconnection costs and incremental fuel transportation associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources in our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total cumulative present value of revenue requirements for each alternative plan.

The result of the IRP process provides Tampa Electric's customers with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment, while positioning Tampa Electric for a lower carbon future. To meet the expected system demand and energy requirements and cost-effectively maintain system reliability, the company's expansion plan includes the following:

- Enhancements to and retirement of existing assets
- Completion of solar PV through 2023, in accordance with the 2021 Rate Case Settlement
- Additional future utility-scale solar, battery storage, and reciprocating engines beyond 2023 until the end of the study period

The modernization of Big Bend Unit 1 was completed and placed in service in December of 2022. The Bayside station Unit 1 and Unit 2 advanced hardware improvements to its existing CTs will be operational in 2023 and 2024, respectively. Big Bend Unit 3 will retire in April of 2023. All upcoming changes to the expansion plan are shown in Schedule 8.1.

The remainder of the expansion plan presented in this Ten-Year Site Plan will meet growing customer needs with the addition of energy resources distributed throughout our territory. In addition to enhancements to the existing assets and the utility-scale solar, battery storage and reciprocating engines will be added to meet customer demand growth and provide operational flexibility and system resiliency to better serve our customers. The detailed expansion plan is shown in Schedule 8.1.

TEC will continue to assess competitive purchase power agreements and DSM programs that may replace or delay the scheduled units. Such optimizations must achieve the overall objective of providing reliable power in a cost-effective manner.

FINANCIAL ASSUMPTIONS

TEC makes numerous financial assumptions as part of the preparation for its TYSP process. These assumptions are based on the current financial status of the company, the market for securities, and the best available forecast of future conditions. The primary financial assumptions include the FPSC-approved Allowance for Funds Used During Construction (AFUDC) rate, capitalization ratios, financing cost rates, tax rates, and FPSC-approved depreciation rates.

- Per the Florida Administrative Code 25-6, an amount for AFUDC is recorded by the company during the construction phase of each capital project that meets the requirements. This rate is approved by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.
- The capitalization ratios represent the percentages of incremental long-term capital that are expected to be issued to finance the capital projects identified in the TYSP.

- The financing cost rates reflect the incremental cost of capital associated with each of the sources of long-term financing.
- Tax rates include federal income tax, state income tax, and miscellaneous taxes including property tax.
- Depreciation represents the annual cost to amortize the total original investment in a plant over its useful life less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the TYSP represents the average expected life for that type of asset.

FUEL FORECAST

TEC forecasts base case fuel commodity prices for natural gas, coal, and oil by analyzing current market prices and price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, S&P Global Future Energy Outlooks, U.S. Energy Information Administration, S&P Global Market Intelligence, Argus Coal and Petroleum Coke Publications, and Coaldesk, LLC Publications. For natural gas, coal and oil prices, the company produces both high and low fuel price projections, which represent alternative forecasts to the company’s base case outlook.

TEC RENEWABLE RESOURCES AND STORAGE TECHNOLOGY INITIATIVES

1. Renewable Energy Initiatives and Customer Programs

In September 2017, TEC announced plans to build 600 MW_{AC} of new solar PV generating capacity from 2018 through January 2021, which is enough electricity to power more than 100,000 homes. The actual design and completion of these projects resulted in 632 MW_{AC} and combined with 23 MW_{AC} from three smaller projects built prior to 2018, created a total of 655 MW_{AC} of solar capacity. In February 2020, the Company announced plans to build an additional 600 MW_{AC} of new cost-effective, utility-scale solar PV generating capacity from 2021 through the end of 2023. In 2023, Tampa Electric will have more than 1,250 MW_{AC} of solar power – enough energy to power more than 200,000 homes – or approximately 14 percent of TEC's energy produced by the sun.

The solar energy significantly reduces Tampa Electric's carbon emissions, reduces the use of potable water, reduces the utilities dependency on natural gas and our customers will benefit from zero-fuel cost solar energy for years to come. As part of its strategic transformation to become cleaner and greener, Tampa Electric is launching another significant expansion of solar power.

Beyond 2023 there is an additional 733 MW_{AC} of solar PV generating capacity shown in this TYSP that is in the planning and analysis phase and requires further development. In sum, TEC will have nearly 2,000 MW_{AC} of solar capacity by the end of the study horizon, which means approximately 20 percent of our energy will come from the sun.

Since 2006, TEC implemented the Renewable Energy Program which offers residential, commercial and industrial customers the opportunity to purchase 200 kWh renewable energy "blocks" for their home or business. In 2009, TEC added a new feature to the program which allows residential, commercial and industrial customers the opportunity to purchase renewable energy in one-time blocks to power a specific event. This enables a family, business or venue to make a statement about their commitment to the environment and to renewable energy. Through December 2022, TEC's Renewable Energy Program has 1,121 customers purchasing over 2,096 blocks of renewable energy each month and there have been over 5,600 one-time blocks purchased since program inception.

The company's renewable generation portfolio is a mix of various technologies and renewable generation sources, including both large utility scale solar PV sites and smaller, company-owned community sited PV arrays that provide ample solar energy for the Renewable Energy Block Program. The smaller, community-sited PV arrays are currently installed at Middleton High school, the Manatee Viewing Center, Zoo Tampa at Lowry Park, the Florida Aquarium, LEGOLAND Florida's Imagination Zone, the Museum of Science and Industry (MOSI), and Meachum Urban Farm. The newest array is located at an organic farm and store open to the public in downtown Tampa, featuring solar with battery storage and a charging station for visitor use. The Renewable Energy Program installations are strategically located throughout the community and are designed to educate students and the public on the benefits of renewable energy. Educational signage touts the advantages of solar energy and interactive displays provide hands-on experience to engage visitors' interest in clean, renewable technologies.

The Florida Conservation and Technology Center (FCTC) located south of Big Bend Station is a collaborative partnership with the Florida Aquarium and Florida Fish & Wildlife to develop and educate students and the public on water and energy conservation technologies, marine science development and clean energy demonstrations. The FCTC site includes the TEC Manatee Viewing Center, the Center for Conservation, and the Tom Hernandez Clean Energy Center (CEC). The CEC has a flexible rooftop adhesive PV array, a dual axis tracking

PV Smart Flower array, and a fixed tilt solar canopy array. The FCTC also includes a vertical axis Be-Wind wind turbine and a vanadium flow battery. A 1 MW_{AC} floating solar pilot project at FCTC began operations in 2022. It integrates solar panels onto floats and will analyze the benefits of bi-facial solar panels capabilities to increase the output created from reflected light onto the reverse side of the solar panels. The data collected and lessons learned will inform future applications over open water reservoirs and demonstrate that floating solar has the potential to decrease the evaporation of water. A 1 MW_{AC} agrivoltaics pilot project at FCTC was also completed in 2022. The project was designed to combine renewable energy with agriculture by positioning elevated solar panels in wider rows with plants or crops planted between the rows of solar panels. This will provide farmable acreage to balance the community attrition of acreage due to development. Agrivoltaics applications have the potential to lower the operating costs of large utility scale solar sites by sharing viable land with agricultural interests.

By Order No. PSC-2019-0215-TRF-EI, the Commission approved Tampa Electric Company's (TECO or utility) Shared Solar Tariff (SSR-1 tariff). The SSR-1 tariff provides residential and commercial customers with the option to purchase energy produced from a TECO-owned solar generation facility to replace all or a portion of their monthly energy consumption. Participants are charged a Shared Solar Charge of $0.063 per kilowatt-hour while the fuel kWh is removed for the subscribed portion. The SSR-1 tariff became effective on June 25, 2019, after TECO completed programming its billing system to administer the SSR-1 tariff. Tampa Electric Company launched the Sun Select program on June 26, 2019, making 17.5 MW_{AC} of solar generation available to its customers via the SSR-1 tariff. The program grew by another 14.3 MW_{AC} in 2021.

2. Storage Technology Initiatives

In December 2019, a 12.6 MW, 25 MWh lithium-ion energy storage system (ESS) was put in service at TEC's Big Bend Solar site. The ESS is integrated with the solar array and will charge via solar energy produced at the site and is discharged to the grid at times when our system is peaking or when solar production is reduced or unavailable. Expected benefits of battery storage projects include firming of the solar output during peak times and contribution to contingency reserves. TEC expects to develop and deploy approximately 195 MW of various types of energy storage systems from 2023 through 2032 to meet system reliability needs, maximize solar energy production by minimizing solar clipping during low system peak periods, and potentially avoid transmission and distribution investments.

In 2018, Tampa Electric began interconnecting customer-owned battery storage. As of December 31, 2022, there are 650 customers interconnected with 5.97 MW DC storage capacity.

3. Electric Vehicle Initiatives

Customer adoption of Electric Vehicles (EV) continues to increase, and this trend is expected to continue into the foreseeable future. Florida continually ranks second in the nation for the number of EVs sold, and TEC is forecasting a nearly 30% average annual growth rate in the number of EVs within our service area through 2030. With continued improvements in battery technology and cost, increased access to public charging infrastructure, and greater consumer choice in the types of EVs offered by major automakers, the upward trend in adoption is expected to accelerate.

Most recently, in 2021, the FPSC approved TEC's Drive Smart℠ EV charging pilot, which allows for the installation of up to 200 Level 2 (240V) and up to four Direct Current Fast Charging (DCFC) stations across the service territory. The 4-year pilot will help to increase driver confidence by expanding access to EV charging, while also providing valuable data to support proper grid planning. The pilot has seen significant interest from customers with approximately 600 ports being applied for. With 34 ports already serving EV drivers, the pilot is well underway to achieving its objectives. In 2020, TEC received FPSC approval for a variance to CIAC Rule No. 25-6.064, F.A.C. when primary line extensions are required to serve high-power DCFC locations. Through this variance, TEC can extend the revenue period used in determining customer CIAC, from 5-years to 10-years. By doing so, the economics for charging station developers should significantly improve, particularly as charging needs expand to more rural areas and underserved communities. Additionally, to help educate the next generation of EV drivers, TEC launched a high school driver education program as an enhancement to the company's existing Energy Education and Awareness conservation program. TEC has provided funding for the vehicles, and also installed the necessary EV chargers and helped to develop curriculum used in the classrooms.

As EV adoption continues to increase, smart grid enhancements, smart charging infrastructure and innovative customer programs will be necessary to help manage the potential effects of EV charging on our grid, in a way that benefits all TEC customers.

GENERATING UNIT PERFORMANCE ASSUMPTIONS

TEC's generating unit performance assumptions are used to evaluate long-range system operating costs associated with integrated resource plans. Generating units are characterized by several different performance parameters. These parameters include capacity, heat rate, unit derations, planned maintenance days, and unplanned outage rates.

The unit performance projections are based on historical data trends, engineering judgment, time since last planned outage, and recent equipment performance. The first five years of planned outages are based on a forecasted outage schedule, and the planned outages for the balance of the years are based on a repetitive pattern.

The forecasted outage schedule is based on unit-specific maintenance needs, material lead-time, labor availability, and the need to supply our customers with power in the most economical manner. Unplanned outage rates are projected based on an average of three years of historical data, future expectations, and any necessary adjustments to account for current unit conditions.

GENERATION RELIABILITY CRITERIA

1. Reserve Margin

TEC calculates reserve margin in two ways to measure reliability of the generating system. The company utilizes a minimum 20 percent firm reserve margin with a minimum contribution of 7 percent supply-side resources. TEC's approach to calculating percent reserves are consistent with the agreement that is outlined in the Commission approved Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, issued December 22, 1999. The calculation of the minimum 20 percent firm reserve margin employs an industry accepted method of using total available generating capacity and firm purchased power capacity (capacity less planned maintenance and solar capacity unavailable at the time of peak demand) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100. Capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from TEC's available capacity.

TEC's supply-side reserve margin is calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the firm peak demand and interruptible and load management loads.

2. *Winter Reliability Assessment*

Tampa Electric Company's current and expected resources meet operating reserve requirements under normal peak demand scenarios. The reserve margin provides operating flexibility in the case of unplanned outages and deviations to load from colder than normal (or hotter than normal) weather. However, temperatures that vary significantly from those used to prepare this plan would result in the need to employ operating mitigation under these extreme conditions. These mitigations could include changes to unit dispatch to enhance reliability, switching to alternate fuels, making full use of demand response, pursuing purchase power agreements, and in a worst-case scenario interrupting customers to maintain grid stability. The company has reviewed and updated its freeze protection plans for each of its generation stations and implemented measures to mitigate equipment failure during these extreme temperatures.

SUPPLY-SIDE RESOURCES PROCUREMENT PROCESS

TEC uses wholesale power market opportunities to enhance and optimize its system. Prospective suppliers of supply-side resources are identified in accordance with established policies and procedures. Competitive bid evaluations are used in developing award recommendations to management. Fuel, fuel transportation, transmission availability, transmission cost, environmental requirements, ancillary services, and balancing requirements are considered as part of evaluating future supply-side resources.

This process allows for future supply-side resources to be supplied from self-build, purchased power, or asset purchases. Consistent with company practice, bidders are encouraged to propose incentive arrangements that promote development and implementation of cost savings and process-improvement recommendations.

TRANSMISSION PLANNING - CONSTRAINTS AND IMPACTS

The TEC transmission system supports the reliable delivery of required capacity and energy to TEC's retail and wholesale customers. Transmission Planning studies are performed annually to evaluate the performance of the TEC transmission system with the results of the studies varying due to refinements in load projections, planning criteria, generation plans and operating flexibility. This involves the use of steady-state load flow, short circuit and transient stability programs to model various contingency situations, 3-Phase Fault and Single Line-Ground Fault analysis that may occur to determine if the TEC transmission system meets the reliability criteria. Simulations of normal system conditions, as well as single and select multiple contingency events, are performed during system peak and off-peak load levels, and summer and/or winter conditions.

Based on existing studies (ex: internal expansion, joint utility, operating, Florida Reliability Coordinating Council (FRCC) Long Range Study, FRCC Planning and Extreme Events Stability Analysis, FRCC Summer Assessment, FRCC Winter Assessment and other miscellaneous studies) and TEC's current transmission construction program, TEC anticipates no transmission constraints that violate the criteria as described in the Transmission Planning Reliability Criteria section of this document.

TRANSMISSION PLANNING RELIABILITY CRITERIA

1. *Transmission*

TEC developed the transmission planning reliability criteria, as described in the FERC Form 715 filing, to assess and test the strength and limits of the transmission system, while meeting the load responsibility and being able to move bulk power between and among other electric systems. TEC has adopted the transmission planning criteria outlined in the FRCC's *FRCC Regional Transmission Planning Process*. The FRCC's transmission planning criteria are consistent with the North American Electric Reliability Corporation (NERC) Reliability Standards.

In general, the NERC Reliability Standards state the transmission system will remain stable, within the applicable thermal and voltage rating limits, without cascading outages, under normal, single and select multiple contingency conditions. In addition to the FRCC criteria, TEC utilizes company-specific planning criteria for normal system operation and contingency operation, along with a Facility Rating Methodology and Facility Interconnection Requirements document available at https://www.oasis.oati.com/TEC/index.html.

The transmission planning reliability criteria are used as guidelines for proposing transmission system expansion and/or improvement projects, however they are not absolute rules for system expansion. These criteria are used to alert planners of potential transmission system capacity limitations. Engineering analysis is used in all stages of the planning process to weigh the impact of system deficiencies, the likelihood of the triggering contingency, and the viability of any operating options. Only by carefully researching each potential planning criteria violation can a final evaluation of available transmission capacity be made.

2. Available Transmission Transfer Capability (ATC) Criteria

TEC adheres to the ATC calculation methodology described in the Attachment C of the Tampa Electric Company *Open Access Transmission Tariff FERC Electric Tariff*, Fourth Revised Volume No. 4 document, accessible at https://www.oasis.oati.com/woa/docs/TEC/TECdocs/Tariff___Fourth_Revised_Volume_No._4_effective_1-1-23.pdf as well as the principles contained in the NERC Reliability Standards relating to ATC calculations. Members of the FRCC, including TEC, have formed the Florida Transmission Capability Determination Group in an effort to provide ATC values to the regional electric market that are transparent, coordinated, timely and accurate.

TRANSMISSION SYSTEM PLANNING ASSESSMENT PRACTICES

TEC's transmission system planning assessment practices are developed according to the TEC and NERC Reliability Standards to ensure a reliable system is planned that demonstrates adequacy within TEC's footprint to meet present and future system needs. The Reliability Standards require that the TEC transmission system be planned such that it will remain stable within the applicable facility ratings and voltage rating limits and without cascading outages under normal system conditions, as well as single and select multiple contingency events.

TEC performs transmission studies independently, collaboratively with other utilities, and as part of the FRCC to determine if the system meets the criteria. The studies involve the use of steady-state power flows, transient stability analyses, short circuit assessments and various other assessments to ensure adequate system performance.

1. Base Case Operating Conditions

The TEC transmission system can support peak and off-peak system load levels while meeting the criteria as described in the Transmission Planning Reliability Criteria section of this document.

2. Single Contingency Planning Criteria

The TEC transmission system is designed to support any single event outage of a transmission circuit, autotransformer, generator, or shunt device (including FRCC studies of Category P1 and P2-1 events) at a variety of load levels while meeting the criteria as described in the Transmission Planning Reliability Criteria section of this document.

3. Multiple Contingency Planning Criteria

Select double contingencies (including FRCC studies of Category P2-2 through P7 events) involving two or more Bulk Electric System (BES) transmission system elements out of service are analyzed at a variety of load levels. The TEC transmission system is designed such that double contingencies meet the criteria as described in the Transmission Planning Reliability Standards Criteria section of this document.

4. Transmission Construction and Upgrade Plans

A specific list of the proposed directly associated transmission construction projects corresponding with the proposed generating facilities can be found in Chapter V, Schedule 10. This list represents the latest BES transmission construction related to the generation expansion on Schedule 8.1 and 9. However, due to the timing of this document in relationship to the company's internal planning schedule, this plan may change in the future. The current transmission construction and upgrade plan for the planning horizon does not require any electric utility system lines to be certified under the Transmission Line Siting Act (403.52-403.536, F.S.).

ENERGY EFFICIENCY, CONSERVATION, AND ENERGY SAVINGS DURABILITY

TEC ensures that DSM programs the company offers are directly monitorable and yield measurable results. The achievements and durability of energy savings from the company's conservation and load management programs is validated by several methods. First, TEC has established a monitoring and evaluation process where historical analysis validates the energy savings. These include:

- Periodic system load reduction analysis for price responsive load management (Energy Planner), Commercial industrial load management and Commercial demand response to confirm and verify the accuracy of TEC's load reduction estimation formulas.

- Billing energy usage and demand analysis of participants in certain energy efficiency and conservation programs as compared to control groups.

- Analysis of DOE2 modeling of various program participants.

- End-use monitoring and evaluation of projects and programs.

- Specific metering of loads under control to determine the actual demand and energy savings in commercial programs such as Standby Generator and Commercial Load Management and Commercial Demand Response.

Second, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Specifically, those programs that promote the installation of energy-efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, wall insulation, window replacements, air distribution system repairs, DX commercial cooling units, chiller replacements, and water heating replacements) have program standards that require the new equipment to be installed in a permanent manner thus ensuring their durability.

Chapter IV

FORECAST OF ELECTRIC POWER, DEMAND AND ENERGY CONSUMPTION

Tables in Schedules 2 through 4 reflect three different levels of load forecasting: base case, high case, and low case. The expansion plan is developed using the base case load forecast and is reflected on Schedules 5 through 9. This forecast band best represents the current economic conditions and the long-term impacts to TEC's service territory.

Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.3: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 3.1: History and Forecast of Summer Peak Demand (Base, High & Low)

Schedule 3.2: History and Forecast of Winter Peak Demand (Base, High & Low)

Schedule 3.3: History and Forecast of Annual Net Energy for Load (Base, High & Low)

Schedule 4: Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month (Base, High & Low)

Schedule 5: History and Forecast of Fuel Requirements

Schedule 6.1: History and Forecast of Net Energy for Load by Fuel Source in GWh

Schedule 6.2: History and Forecast of Net Energy for Load by Fuel Source as a Percent

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2013	1,276,410	2.6	8,470	613,206	13,812	6,090	71,966	84,619
2014	1,301,887	2.6	8,656	623,846	13,875	6,142	72,647	84,548
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
2016	1,352,797	2.5	9,187	646,221	14,217	6,310	74,313	84,911
2017	1,379,302	2.6	9,029	659,387	13,693	6,362	74,998	84,830
2018	1,408,864	2.6	9,418	670,517	14,046	6,266	74,895	83,664
2019	1,444,870	2.6	9,584	685,122	13,989	6,239	76,038	82,057
2020	1,459,762	2.6	10,122	698,493	14,491	6,058	76,790	78,890
2021	1,490,374	2.6	9,941	713,135	13,940	6,144	78,115	78,653
2022	1,520,529	2.6	10,109	729,334	13,861	6,300	79,610	79,131
2023	1,546,681	2.5	9,997	743,743	13,441	6,209	80,918	76,731
2024	1,571,885	2.5	10,099	756,662	13,347	6,274	81,384	77,091
2025	1,595,797	2.5	10,238	768,927	13,314	6,349	81,824	77,597
2026	1,618,751	2.5	10,367	780,711	13,279	6,406	82,229	77,904
2027	1,640,792	2.5	10,494	792,033	13,249	6,459	82,594	78,207
2028	1,661,951	2.5	10,627	802,909	13,236	6,518	83,068	78,463
2029	1,682,219	2.4	10,764	813,334	13,235	6,576	83,603	78,663
2030	1,701,496	2.4	10,896	823,255	13,235	6,636	84,171	78,835
2031	1,719,612	2.4	11,028	832,584	13,245	6,695	84,776	78,969
2032	1,736,939	2.4	11,162	841,511	13,264	6,755	85,417	79,086

Notes:
December 31, 2022 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2023	1,560,479	2.6	10,064	747,638	13,461	6,211	80,945	76,731
2024	1,593,711	2.6	10,236	764,610	13,387	6,278	81,444	77,088
2025	1,625,923	2.5	10,448	781,079	13,376	6,356	81,916	77,592
2026	1,657,440	2.5	10,652	797,207	13,362	6,415	82,348	77,901
2027	1,688,296	2.5	10,857	813,012	13,354	6,471	82,740	78,208
2028	1,718,508	2.5	11,070	828,502	13,361	6,532	83,239	78,469
2029	1,748,058	2.5	11,290	843,665	13,382	6,593	83,799	78,675
2030	1,776,830	2.5	11,506	858,441	13,403	6,655	84,394	78,852
2031	1,804,632	2.5	11,724	872,730	13,433	6,716	85,026	78,991
2032	1,831,839	2.5	11,946	886,725	13,472	6,780	85,693	79,116

Notes:
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2023	1,530,128	2.5	9,930	739,848	13,421	6,207	80,891	76,730
2024	1,547,412	2.5	9,963	748,756	13,306	6,270	81,324	77,095
2025	1,563,214	2.4	10,031	756,904	13,252	6,343	81,734	77,602
2026	1,577,883	2.4	10,088	764,472	13,196	6,397	82,111	77,906
2027	1,591,479	2.4	10,141	771,489	13,145	6,448	82,452	78,205
2028	1,604,044	2.4	10,200	777,977	13,110	6,504	82,901	78,456
2029	1,615,585	2.3	10,261	783,938	13,088	6,560	83,413	78,648
2030	1,626,021	2.3	10,315	789,330	13,068	6,617	83,956	78,815
2031	1,635,203	2.3	10,369	794,076	13,058	6,673	84,537	78,941
2032	1,643,504	2.3	10,425	798,368	13,057	6,731	85,152	79,052

Notes:
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.2

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH **	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2013	2,027	1,564	1,295,916	0	75	1,756	18,418
2014	1,901	1,572	1,208,831	0	75	1,752	18,526
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	2,024	1,608	1,259,094	0	0	1,771	19,186
2018	2,014	1,588	1,268,262	0	0	1,933	19,631
2019	2,021	1,516	1,332,913	0	0	1,939	19,783
2020	1,891	1,408	1,342,642	0	0	1,883	19,954
2021	2,122	1,382	1,535,835	0	0	1,886	20,093
2022	2,111	1,357	1,556,126	0	0	1,947	20,467
2023	1,826	1,354	1,348,866	0	0	1,943	19,975
2024	1,800	1,354	1,328,750	0	0	1,954	20,126
2025	1,794	1,355	1,324,062	0	0	1,964	20,346
2026	1,793	1,356	1,322,477	0	0	1,974	20,540
2027	1,793	1,356	1,322,311	0	0	1,984	20,731
2028	1,779	1,356	1,311,531	0	0	1,994	20,918
2029	1,779	1,356	1,312,006	0	0	2,004	21,124
2030	1,780	1,356	1,312,883	0	0	2,014	21,325
2031	1,781	1,355	1,313,936	0	0	2,024	21,527
2032	1,782	1,355	1,315,022	0	0	2,033	21,733

Notes:
December 31, 2022 Status
*Average of end-of-month customers for the calendar year.
**Sales shown for Street and Highway Lighting from 2017 forward are now included with Other Sales to Public Authorities.
Values shown may be affected due to rounding.

Schedule 2.2

History and Forecast of Energy Consumption and Number of Customers by Customer Class
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH **	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2023	1,826	1,354	1,348,962	0	0	1,943	20,045
2024	1,801	1,354	1,330,188	0	0	1,954	20,269
2025	1,796	1,355	1,325,799	0	0	1,964	20,565
2026	1,796	1,356	1,324,306	0	0	1,974	20,837
2027	1,797	1,356	1,324,965	0	0	1,984	21,108
2028	1,783	1,356	1,314,760	0	0	1,994	21,379
2029	1,784	1,356	1,315,651	0	0	2,004	21,671
2030	1,786	1,356	1,316,861	0	0	2,014	21,960
2031	1,787	1,355	1,319,163	0	0	2,024	22,251
2032	1,789	1,355	1,320,503	0	0	2,034	22,549

Notes:
*Average of end-of-month customers for the calendar year.
**Sales for Street and Highway Lighting from 2017 forward are now included with Other Sales to Public Authorities.
Values shown may be affected due to rounding.

Schedule 2.2

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH **	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2023	1,825	1,354	1,347,963	0	0	1,943	19,905
2024	1,798	1,354	1,328,188	0	0	1,954	19,984
2025	1,792	1,355	1,322,771	0	0	1,964	20,130
2026	1,790	1,356	1,320,240	0	0	1,974	20,249
2027	1,790	1,356	1,319,844	0	0	1,984	20,363
2028	1,774	1,356	1,308,569	0	0	1,994	20,472
2029	1,774	1,356	1,308,376	0	0	2,004	20,599
2030	1,774	1,356	1,308,488	0	0	2,014	20,720
2031	1,775	1,355	1,309,667	0	0	2,023	20,840
2032	1,775	1,355	1,309,874	0	0	2,033	20,964

Notes:
*Average of end-of-month customers for the calendar year.
**Sales for Street and Highway Lighting from 2017 forward are now included with Other Sales to Public Authorities.
Values shown may be affected due to rounding.

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class Base Case

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
2013	0	760	19,177	7,962	694,698
2014	0	789	19,315	7,999	706,065
2015	0	1,098	20,105	8,095	718,640
2016	9	930	20,173	8,168	730,318
2017	2	1,110	20,298	8,353	744,346
2018	0	1,031	20,662	8,698	755,698
2019	0	986	20,770	9,254	771,931
2020	0	1,101	21,055	9,283	785,974
2021	0	940	21,033	9,356	801,987
2022	0	1,105	21,572	9,418	819,718
2023	0	1,002	20,977	9,570	835,584
2024	0	1,008	21,134	9,644	849,045
2025	0	1,020	21,365	9,716	861,823
2026	0	1,029	21,569	9,785	874,080
2027	0	1,039	21,769	9,853	885,837
2028	0	1,048	21,966	9,921	897,255
2029	0	1,059	22,183	9,989	908,282
2030	0	1,069	22,394	10,056	918,839
2031	0	1,079	22,606	10,124	928,839
2032	0	1,089	22,822	10,191	938,474

Notes:
December 31, 2022 Status
*Includes sales to St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
RCID contract from 2016 to 2017.
**Utility Use and Losses include accrued sales.
***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
****Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class
High Case

(1) Year	(2) Sales for Resale GWH	(3) Utility Use * & Losses GWH	(4) Net Energy ** for Load GWH	(5) Other *** Customers	(6) Total *** Customers
2023	0	1,005	21,050	9,570	839,507
2024	0	1,015	21,284	9,644	857,052
2025	0	1,030	21,595	9,716	874,066
2026	0	1,044	21,881	9,785	890,696
2027	0	1,058	22,166	9,853	906,961
2028	0	1,071	22,450	9,921	923,018
2029	0	1,086	22,757	9,989	938,809
2030	0	1,100	23,060	10,056	954,247
2031	0	1,115	23,366	10,124	969,235
2032	0	1,129	23,678	10,191	983,964

Notes:

*Utility Use and Losses include accrued sales.

**Net Energy for Load includes output to line including energy supplied by purchased cogeneration.

***Average of end-of-month customers for the calendar year.

Values shown may be affected due to rounding.

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWH	Utility Use * & Losses GWH	Net Energy ** for Load GWH	Other *** Customers	Total *** Customers
2023	0	998	20,903	9,570	831,663
2024	0	1,002	20,986	9,644	841,078
2025	0	1,009	21,139	9,716	849,709
2026	0	1,015	21,264	9,785	857,724
2027	0	1,021	21,384	9,853	865,150
2028	0	1,026	21,498	9,921	872,155
2029	0	1,032	21,631	9,989	878,696
2030	0	1,038	21,758	10,056	884,698
2031	0	1,045	21,885	10,124	890,092
2032	0	1,051	22,015	10,191	895,066

Notes:
*Utility Use and Losses include accrued sales.
**Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
***Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 3.1

History and Forecast of Summer Peak Demand (MW)
Base Case

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation***	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2013	4,072	0	4,072	131	39	122	89	77	3,614
2014	4,270	0	4,270	170	36	132	91	83	3,757
2015	4,245	0	4,245	111	21	143	98	87	3,784
2016	4,403	15	4,388	138	0	150	101	92	3,907
2017	4,373	5	4,368	110	0	155	100	98	3,905
2018	4,287	0	4,287	125	0	160	98	106	3,798
2019	4,591	0	4,591	122	0	166	98	126	4,079
2020	4,568	0	4,568	113	0	169	98	135	4,053
2021	4,706	0	4,706	187	0	174	98	139	4,108
2022	4,716	0	4,716	204	0	183	104	148	4,077
2023	4,642	0	4,642	129	1	194	106	148	4,064
2024	4,704	0	4,704	126	4	206	107	152	4,108
2025	4,767	0	4,767	126	8	219	107	156	4,151
2026	4,825	0	4,825	126	13	232	107	161	4,185
2027	4,880	0	4,880	126	20	246	108	165	4,216
2028	4,935	0	4,935	125	27	261	108	169	4,245
2029	4,989	0	4,989	125	35	275	108	173	4,273
2030	5,041	0	5,041	125	43	289	109	178	4,298
2031	5,093	0	5,093	125	52	303	109	182	4,322
2032	5,142	0	5,142	125	60	317	109	186	4,345

Notes:
December 31, 2022 Status
2016, 2018 and 2020 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
***Includes Energy Planner program.
Values shown may be affected due to rounding.

Schedule 3.1

Forecast of Summer Peak Demand (MW)
High Case

(1) Year	(2) Total *	(3) Wholesale	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation**	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2023	4,659	0	4,659	129	1	194	106	148	4,081
2024	4,739	0	4,739	126	4	206	107	152	4,143
2025	4,821	0	4,821	126	8	219	107	156	4,205
2026	4,898	0	4,898	126	13	232	107	161	4,258
2027	4,974	0	4,974	126	20	246	108	165	4,310
2028	5,049	0	5,049	125	27	261	108	169	4,360
2029	5,125	0	5,125	125	35	275	108	173	4,408
2030	5,199	0	5,199	125	43	289	109	178	4,456
2031	5,272	0	5,272	125	52	303	109	182	4,502
2032	5,345	0	5,345	125	60	317	109	186	4,548

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
Values shown may be affected due to rounding.

Schedule 3.1

Forecast of Summer Peak Demand (MW)
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale	Retail *	Interruptible	Residential Load Management	Residential Conservation**	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2023	4,625	0	4,625	129	1	194	106	148	4,047
2024	4,669	0	4,669	126	4	206	107	152	4,073
2025	4,714	0	4,714	126	8	219	107	156	4,098
2026	4,753	0	4,753	126	13	232	107	161	4,113
2027	4,789	0	4,789	126	20	246	108	165	4,125
2028	4,824	0	4,824	125	27	261	108	169	4,135
2029	4,860	0	4,860	125	35	275	108	173	4,143
2030	4,892	0	4,892	125	43	289	109	178	4,149
2031	4,922	0	4,922	125	52	303	109	182	4,152
2032	4,952	0	4,952	125	60	317	109	186	4,155

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
Values shown may be affected due to rounding.

Schedule 3.2

History and Forecast of Winter Peak Demand (MW)
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale **	Retail *	Interruptible	Residential Load Management	Residential Conservation***	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2012/13	3,780	15	3,764	130	65	501	90	61	2,918
2013/14	3,876	0	3,876	61	63	512	97	64	3,079
2014/15	4,195	0	4,195	79	44	521	96	65	3,390
2015/16	4,025	0	4,025	145	13	533	96	67	3,171
2016/17	3,749	0	3,749	137	0	541	96	70	2,905
2017/18	4,670	0	4,670	66	0	548	96	77	3,883
2018/19	3,921	0	3,921	104	0	556	98	92	3,071
2019/20	4,237	0	4,237	140	0	564	97	99	3,336
2020/21	4,147	0	4,147	132	0	568	98	103	3,247
2021/22	4,415	0	4,415	158	0	572	104	108	3,473
2022/23	5,184	0	5,184	115	0	583	104	109	4,273
2023/24	5,249	0	5,249	112	2	594	105	112	4,324
2024/25	5,321	0	5,321	111	6	605	106	115	4,378
2025/26	5,387	0	5,387	111	10	616	106	118	4,426
2026/27	5,449	0	5,449	111	16	627	107	121	4,467
2027/28	5,507	0	5,507	109	22	638	107	124	4,506
2028/29	5,567	0	5,567	109	30	649	108	127	4,544
2029/30	5,627	0	5,627	109	38	661	109	130	4,580
2030/31	5,682	0	5,682	109	47	672	109	133	4,612
2031/32	5,735	0	5,735	109	55	683	110	136	4,643

Notes:
December 31, 2022 Status
2015/2016 and 2020/2021 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
***Includes energy planner program.
Values shown may be affected due to rounding.

Schedule 3.2

Forecast of Winter Peak Demand (MW)
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale	Retail *	Interruptible	Residential Load Management	Residential Conservation**	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2022/23	5,204	0	5,204	115	0	583	104	109	4,293
2023/24	5,288	0	5,288	112	2	594	105	112	4,363
2024/25	5,379	0	5,379	111	6	605	106	115	4,436
2025/26	5,466	0	5,466	111	10	616	106	118	4,505
2026/27	5,549	0	5,549	111	16	627	107	121	4,567
2027/28	5,629	0	5,629	109	22	638	107	124	4,628
2028/29	5,711	0	5,711	109	30	649	108	127	4,687
2029/30	5,792	0	5,792	109	38	661	109	130	4,745
2030/31	5,871	0	5,871	109	47	672	109	133	4,802
2031/32	5,949	0	5,949	109	55	683	110	136	4,856

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
Values shown may be affected due to rounding.

Schedule 3.2

Forecast of Winter Peak Demand (MW)
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	**Total ***	**Wholesale**	**Retail ***	**Interruptible**	**Residential Load Management**	**Residential Conservation****	**Comm./Ind. Load Management**	**Comm./Ind. Conservation**	**Net Firm Demand**
2022/23	5,165	0	5,165	115	0	583	104	109	4,254
2023/24	5,212	0	5,212	112	2	594	105	112	4,287
2024/25	5,263	0	5,263	111	6	605	106	115	4,320
2025/26	5,310	0	5,310	111	10	616	106	118	4,349
2026/27	5,351	0	5,351	111	16	627	107	121	4,369
2027/28	5,389	0	5,389	109	22	638	107	124	4,388
2028/29	5,429	0	5,429	109	30	649	108	127	4,405
2029/30	5,465	0	5,465	109	38	661	109	130	4,418
2030/31	5,499	0	5,499	109	47	672	109	133	4,430
2031/32	5,532	0	5,532	109	55	683	110	136	4,439

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
Values shown may be affected due to rounding.

Schedule 3.3

History and Forecast of Annual Net Energy for Load (GWh)
Base Case

(1) Year	(2) Total*	(3) Residential Conservation**	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale ***	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load **** Factor %
2013	19,225	513	294	18,418	0	760	19,177	56.5
2014	19,377	546	305	18,526	0	789	19,315	54.4
2015	19,890	568	315	19,006	0	1,098	20,105	57.2
2016	20,153	588	331	19,234	9	930	20,173	55.2
2017	20,141	602	353	19,186	2	1,110	20,298	56.2
2018	20,647	618	399	19,631	0	1,031	20,662	58.1
2019	20,896	635	478	19,783	0	986	20,770	55.2
2020	21,085	644	487	19,954	0	1,101	21,055	56.2
2021	21,256	656	508	20,093	0	940	21,033	54.7
2022	21,676	679	530	20,467	0	1,105	21,572	56.2
2023	21,230	707	548	19,975	0	1,002	20,977	53.3
2024	21,430	736	568	20,126	0	1,008	21,134	53.0
2025	21,700	767	588	20,346	0	1,020	21,365	53.0
2026	21,947	799	608	20,540	0	1,029	21,569	52.9
2027	22,191	833	628	20,731	0	1,039	21,769	52.9
2028	22,432	867	648	20,918	0	1,048	21,966	52.7
2029	22,693	901	668	21,124	0	1,059	22,183	52.9
2030	22,948	935	688	21,325	0	1,069	22,394	52.9
2031	23,204	969	708	21,527	0	1,079	22,606	52.9
2032	23,463	1003	727	21,733	0	1,089	22,822	52.8

Notes:
December 31, 2022 Status
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
***Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
****Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

Schedule 3.3

Forecast of Annual Net Energy for Load (GWh)
High Case

(1) Year	(2) Total*	(3) Residential Conservation**	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load *** Factor %
2023	21,299	707	548	20,045	0	1,005	21,050	53.3
2024	21,573	736	568	20,269	0	1,015	21,284	52.9
2025	21,919	767	588	20,565	0	1,030	21,595	52.9
2026	22,244	799	608	20,837	0	1,044	21,881	52.8
2027	22,569	833	628	21,108	0	1,058	22,166	52.7
2028	22,893	867	648	21,379	0	1,071	22,450	52.5
2029	23,240	901	668	21,671	0	1,086	22,757	52.6
2030	23,583	935	688	21,960	0	1,100	23,060	52.6
2031	23,928	969	708	22,251	0	1,115	23,366	52.6
2032	24,279	1003	727	22,549	0	1,129	23,678	52.6

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

Schedule 3.3

Forecast of Annual Net Energy for Load (GWh)
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total*	Residential Conservation**	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load *** Factor %
2023	21,160	707	548	19,905	0	998	20,903	53.3
2024	21,288	736	568	19,984	0	1,002	20,986	53.0
2025	21,484	767	588	20,130	0	1,009	21,139	53.1
2026	21,656	799	608	20,249	0	1,015	21,264	53.0
2027	21,824	833	628	20,363	0	1,021	21,384	53.0
2028	21,987	867	648	20,472	0	1,026	21,498	52.9
2029	22,167	901	668	20,599	0	1,032	21,631	53.1
2030	22,343	935	688	20,720	0	1,038	21,758	53.1
2031	22,517	969	708	20,840	0	1,045	21,885	53.2
2032	22,695	1,003	727	20,964	0	1,051	22,015	53.2

Notes:
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program
***Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

Schedule 4
Base Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2022 Actual		2023 Forecast		2024 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,735	1,572	4,492	1,543	4,543	1,548
February	3,042	1,399	3,503	1,386	3,540	1,392
March	3,242	1,605	3,478	1,522	3,514	1,526
April	3,571	1,660	3,716	1,592	3,751	1,599
May	4,006	1,992	4,073	1,881	4,113	1,893
June	4,385	2,099	4,261	1,999	4,304	2,016
July	4,355	2,226	4,254	2,095	4,298	2,115
August	4,378	2,213	4,300	2,139	4,345	2,160
September	4,225	1,897	4,166	1,967	4,211	1,987
October	3,624	1,734	3,878	1,856	3,919	1,875
November	3,666	1,578	3,310	1,461	3,348	1,474
December	3,526	1,598	4,144	1,536	4,194	1,549
TOTAL		21,572		20,977		21,134

Notes:
December 31, 2022 Status
*Peak demand represents total retail and wholesale demand, excluding conservation impacts.
**Values shown may be affected due to rounding.

Schedule 4
High Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2022 Actual		2023 Forecast		2024 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,735	1,572	4,512	1,548	4,581	1,559
February	3,042	1,399	3,517	1,390	3,569	1,402
March	3,242	1,605	3,493	1,527	3,542	1,536
April	3,571	1,660	3,731	1,597	3,781	1,609
May	4,006	1,992	4,090	1,888	4,147	1,906
June	4,385	2,099	4,279	2,006	4,340	2,030
July	4,355	2,226	4,271	2,103	4,333	2,130
August	4,378	2,213	4,317	2,147	4,380	2,176
September	4,225	1,897	4,182	1,974	4,245	2,002
October	3,624	1,734	3,893	1,863	3,949	1,889
November	3,666	1,578	3,321	1,466	3,373	1,484
December	3,526	1,598	4,159	1,541	4,227	1,560
TOTAL		21,572		21,050		21,284

Notes:
December 31, 2022 Status
*Peak demand represents total retail and wholesale demand, excluding conservation impacts.
**Values shown may be affected due to rounding.

Schedule 4
Low Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2022 Actual		2023 Forecast		2024 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,735	1,572	4,473	1,538	4,505	1,538
February	3,042	1,399	3,488	1,381	3,512	1,383
March	3,242	1,605	3,464	1,517	3,486	1,516
April	3,571	1,660	3,701	1,586	3,721	1,588
May	4,006	1,992	4,057	1,875	4,080	1,880
June	4,385	2,099	4,244	1,992	4,269	2,001
July	4,355	2,226	4,237	2,088	4,263	2,099
August	4,378	2,213	4,283	2,132	4,310	2,144
September	4,225	1,897	4,149	1,959	4,177	1,973
October	3,624	1,734	3,863	1,849	3,888	1,861
November	3,666	1,578	3,298	1,456	3,323	1,464
December	3,526	1,598	4,128	1,531	4,161	1,539
TOTAL		21,572		20,904		20,986

Notes:
December 31, 2022 Status
*Peak demand represents total retail and wholesale demand, excluding conservation impacts.
**Values shown may be affected due to rounding.

Schedule 5

History and Forecast of Fuel Requirements
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements	**Unit**	**Actual 2021**	**Actual 2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
(1)	**Nuclear**	**Trillion BTU**	0	0	0	0	0	0	0	0	0	0	0	0
(2)	**Coal**	**1000 Ton**	638	652	524	451	95	121	119	119	114	81	94	124
(3)	**Residual**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(4)	**ST**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(5)	**CC**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(6)	**GT**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(7)	**D**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(8)	**Distillate**	**1000 BBL**	6	19	0	0	0	0	0	0	0	0	0	0
(9)	**ST**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(10)	**CC**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(11)	**GT**	**1000 BBL**	6	19	0	0	0	0	0	0	0	0	0	0
(12)	**D**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(13)	**Natural Gas**	**1000 MCF**	124,017	124,914	118,695	117,691	121,381	120,328	120,214	120,044	120,414	120,111	120,583	122,129
(14)	**ST**	**1000 MCF**	20,466	6,892	1,778	1,831	4,973	6,272	6,192	6,207	5,947	4,219	4,876	6,411
(15)	**CC**	**1000 MCF**	99,954	105,985	115,249	114,670	115,810	113,000	112,915	113,234	113,547	114,845	115,174	114,412
(16)	**GT**	**1000 MCF**	3,596	12,036	1,668	1,190	598	1,056	1,107	603	920	1,047	533	1,306
(17)	**Other (Specify)**													
(18)	**PC**	**1000 Ton**	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
Values shown may be affected due to rounding.
Actual values exclude ignition.
Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.
Dual fuel capabilities will be maintained on applicable units.

Schedule 6.1

History and Forecast of Net Energy for Load by Fuel Source
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources	Unit	Actual 2021	Actual 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
(1)	**Annual Firm Interchange**	GWh	77	23	57	0	169	169	169	170	169	169	169	170
(2)	**Nuclear**	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	**Coal**	GWh	1,358	1,337	1,030	885	187	237	234	234	224	159	183	243
(4)	**Residual**	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(5)	ST	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)	CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)	GT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)	D	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	**Distillate**	GWh	2	6	0	0	0	0	0	0	0	0	0	0
(10)	ST	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)	CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(12)	GT	GWh	2	6	0	0	0	0	0	0	0	0	0	0
(13)	D	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	**Natural Gas**	GWh	16,124	17,066	17,368	17,275	17,742	17,373	17,416	17,460	17,534	17,637	17,687	17,826
(15)	ST	GWh	1,743	831	148	156	436	553	546	546	523	370	428	566
(16)	CC	GWh	13,992	14,907	17,101	17,034	17,261	16,738	16,782	16,867	16,938	17,181	17,216	17,145
(17)	GT	GWh	389	1,327	119	85	45	82	88	47	73	86	43	115
(18)	**Renewable**	GWh	1,252	1,492	2,478	2,932	3,242	3,764	3,924	4,088	4,234	4,401	4,549	4,535
(19)	Solar	GWh	1,252	1,492	2,478	2,932	3,242	3,764	3,924	4,088	4,234	4,401	4,549	4,535
(20)	**Other (Specify)**													
(21)	PC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(22)	Net Interchange	GWh	2,157	1,600	(21)	(23)	(37)	(35)	(35)	(47)	(38)	(32)	(40)	(8)
(23)	Purchased Energy from Non-Utility Generators	GWh	63	49	65	65	65	65	65	65	65	65	65	65
(24)	Other	GWh	0.0	0.0	0.0	0.0	(3)	(4)	(4)	(4)	(5)	(5)	(7)	(9)
(25)	**Net Energy for Load**	GWh	21,033	21,572	20,977	21,134	21,365	21,569	21,769	21,966	22,183	22,394	22,606	22,822

Notes:

Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.
Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.
Dual fuel capabilities will be maintained on applicable units.
Generation quantities do not reflect periodic testing of distillate fuel oil capability.
Batteries are represented in row (24).

Schedule 6.2

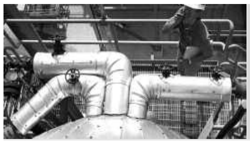
History and Forecast of Net Energy for Load by Fuel Source
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources	Unit	Actual 2021	Actual 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
(1)	Annual Firm Interchange	%	0.4	0.1	0.3	0.0	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.7
(2)	Nuclear	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(3)	Coal	%	6.5	6.2	4.9	4.2	0.9	1.1	1.1	1.1	1.0	0.7	0.8	1.1
(4)	Residual	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)	ST	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)	CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	GT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	D	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Distillate	%	0.0	0.03	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	ST	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)	CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)	GT	%	0.0	0.03	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)	D	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	%	76.7	79.1	82.8	81.7	83.0	80.5	80.0	79.5	79.0	78.8	78.2	78.1
(15)	ST	%	8.3	3.9	0.7	0.7	2.0	2.6	2.5	2.5	2.4	1.7	1.9	2.5
(16)	CC	%	66.5	69.1	81.5	80.6	80.8	77.6	77.1	76.8	76.4	76.7	76.2	75.1
(17)	GT	%	1.8	6.2	0.6	0.4	0.2	0.4	0.4	0.2	0.3	0.4	0.2	0.5
(18)	Renewable	%	6.0	6.9	11.8	13.9	15.2	17.5	18.0	18.6	19.1	19.7	20.1	19.9
(19)	Solar	%	6.0	6.9	11.8	13.9	15.2	17.5	18.0	18.6	19.1	19.7	20.1	19.9
(20)	Other (Specify)													
(21)	PC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(22)	Net Interchange	%	10.3	7.4	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)	(0.2)	(0.0)
(23)	Purchased Energy from Non-Utility Generators	%	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
(24)	Other	%	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
(25)	Net Energy for Load	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Notes:

Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.
Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.
Dual fuel capabilities will be maintained on applicable units.
Generation quantities do not reflect periodic testing of distillate fuel oil capability.
Batteries are represented in row (24).

Chapter V



FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility changes and additions shown in Schedule 8.1 integrate energy efficiency and conservation programs and generating resources to provide economical, reliable service to TEC's customers. Various energy resource plan alternatives, comprised of a mixture of generating technologies, purchased power, and cost-effective energy efficiency and conservation programs, are developed to determine this plan. These alternatives are combined with existing resources and analyzed to determine the resource options which best meets TEC's future system demand and energy requirements. A detailed discussion of TEC's integrated resource planning process is included in Chapter III.

The results of the IRP process provide TEC with a cost-effective plan that maintains system reliability and environmental requirements while considering technology, availability, dispatchability, resiliency, and lead times for construction. To cost-effectively meet the expected system demand and energy requirements over the next ten years, solar PV, base load, intermediate, and distributed energy resources are needed. TEC will add incremental utility-scale solar PV capacity and is researching the viability of additional renewable technologies. The completion of the Big Bend Power Station modernization through the repowering of Unit 1 to a 2x1 combined cycle unit, the retirement of Unit 2 and Unit 3, and the advanced hardware upgrades on the CTs at Bayside provide low-cost, reliable, and grid-friendly options for customers. Additionally, distributed energy resources such as batteries and reciprocating engines provide reliability and resiliency to our system. The operating and cost parameters are shown in Schedule 9 for proposed generating facilities.

TEC will continue to compare purchased power options as an alternative and/or enhancement to planned unit additions, conservation, and load management. At a minimum, the purchased power must have firm transmission service and firm fuel transportation to support firm reserve margin criteria for reliability. Assumptions and information that impact the plan are discussed in the following sections and in Chapter III.

COGENERATION

In 2023, TEC plans for 261 MW of cogeneration capacity operating in its service area.

Table IV-I **2023 Cogeneration Capacity Forecast**	**Capacity** **(MW)**
Self-service [1]	182
Firm to Tampa Electric	0
As-available to Tampa Electric	24
Export to other systems	55
Total	261

[1] Capacity and energy that cogenerators produce to serve their own internal load requirements.

FIRM INTERCHANGE SALES AND PURCHASES

TEC has one (1) long-term firm purchase power agreement. That agreement is with Pasco County (Pasco) for TEC to purchase up to 25 MW from Pasco's waste-to-energy (WTE) facility and, if approved by the Florida Public Service Commission, begins in 2025. The agreement has an initial capacity of 21 MW and increases to 25 MW if Pasco expands the facility's generating capacity. The term is 10 years, beginning January 2025 and continuing through December 2034. The company also has three (3) short-term agreements that provide firm capacity during the winter of 2023. The short-term purchases are (i) 50 MW from the Florida Municipal Power Agency (FMPA), (ii) 100 MW from Orlando Utilities Commission and (iii) 250 MW from Duke Energy Florida (DEF). These winter purchases provide firm capacity for the period January through February 2023.

FUEL REQUIREMENTS

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2. TEC currently uses a generation portfolio consisting mainly of natural gas and solid fuels for its energy requirements. TEC has firm transportation contracts with the Florida Gas Transmission Company and Gulfstream Natural Gas System LLC for delivery of natural gas to Big Bend, Bayside, and Polk. As shown in Schedule 6.2, TEC forecasts serving net energy for load in 2023 with 82.8% natural gas, 11.8% solar, 4.9% coal, and less than one (1) percent of other resources, such as non-firm purchases from the market and non-utility generators. Some of the company's generating units have dual-fuel (i.e., natural gas or oil) capability, which enhances system reliability, increases resiliency, and provides fuel cost reduction opportunities.

ENVIRONMENTAL CONSIDERATIONS

1. Air Quality

TEC continually strives to reduce emissions from its generating facilities, and since 2000, has reduced sulfur dioxide, nitrogen oxide, particulate matter and mercury emissions by 96% or more. Carbon emissions have also been reduced by more than 50%, and TEC has committed to a 60% reduction of carbon emissions by 2025, 80% by 2040, and has a vision to achieve net zero carbon emissions by 2050.

The installation of over 1,250 megawatts of solar power by 2023 will enable the company to continue to reduce its dependence on carbon-based fuels. Once complete, approximately 14% of TEC's energy will be fueled by the sun.

In addition to solar, TEC's emission reduction activities include:

1. The modernization of Big Bend Unit 1 combined cycle unit and the retirement Big Bend Unit 2.

2. The retirement of Big Bend Unit 3 in April of 2023.

3. The Polk Power Station combined-cycle project improved system reliability and efficiency, and reduced emissions system-wide.

4. The upgrade of gas path components on Bayside Power Station's Unit 1 and Unit 2 combustion turbines will increase output, efficiency and reliability while reducing fuel consumption.

2. Water Conservation

TEC's Big Bend and Polk Power Station use reclaimed water from local municipalities to minimize the use of potable water and groundwater for plant processes. Most of the properties purchased by TEC for solar generation are former agricultural lands with existing water use permits. When land is sold to new owners, Southwest Florida Water Management District (SWFWMD) rules require that these water permits are transferred as well. Since solar generation requires no water, TEC conserves this groundwater, which otherwise would have pumped and used for agricultural needs. To date, TEC's acquisition of land for the development of solar power has saved an estimated 5.1 billion gallons of water, which significantly helps an area of the state that has critical concerns over water use.

3. Water Quality

The final 316(b) rule became effective in October 2014 and seeks to reduce impingement and entrainment at cooling water intakes. This rule affects both Big Bend and Bayside Power Stations, since both withdraw cooling water from waters of the U.S. The full impact of the new regulations will be determined by the results of the study elements performed to comply with the rule as well as the actual requirements of the state regulatory agencies. Tampa Electric began a multi-year construction project to install new fish-friendly modified traveling screens and a fish return in 2022. Tampa Electric is negotiating an alternative schedule for Big Bend (as allowed by the rule) but completed a portion of the compliance requirements with the Big Bend modernization project with the installation of fish-friendly modified traveling screens and a fish return on modernized Unit 1. The remainder of the compliance requirements are to be determined and completed at a later date.

FDEP's numeric nutrient regulations are effective and may potentially impact the discharge from the Polk Power Station cooling water reservoir in the future. The established nitrogen allocations by Tampa Bay Nitrogen Management Consortium for both Bayside and Big Bend Power Stations are expected to meet the numeric nutrient criteria in Tampa Bay.

The final Effluent Limitations Guidelines (ELG) were published on November 3, 2015. The ELGs establish limits for wastewater discharges from flue gas desulfurization (FGD) processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals, gasification processes, and flue gas mercury controls. . Big Bend will complete construction of a deep injection well system in December 2023 for disposal of FGD wastewater, bottom ash transport water, stormwater and other process wastewaters.

4. Solid Waste

The Coal Combustion Residuals Rule (CCR) became effective on October 19, 2015. The former Big Bend Unit #4 Economizer Ash & Pyrites Pond System (EAPPS), converted Units 1-3 West Slag Disposal Pond (WSDP) and North Gypsum Stackout Area (NGSA) were covered by this rule. Three ECRC projects were proposed and approved by the Commission for these operating units to comply with the CCR Rule requirements, as follows. The WSDP was remediated and lined in 2020 to allow for continued storm water storage and the EAPPS Closure Project was completed in 2021 by removing and disposing of the CCRs offsite and restoring the site. Phase III of the NGSA Drainage Enhancements Project will be initiated in 2023 and completed not later than 2024. The South Gypsum Storage Area Closure Project was completed as a component of the Big Bend Modernization in January 2020. There are no other CCR units at the Big Bend, Polk or Bayside Power Stations currently regulated under the rule.

Schedule 7.1

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Firm Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Firm Capacity Available	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2023	5,337	0	0	0	5,337	4,064	1,273	31%	0	1,273	31%
2024	5,509	0	0	0	5,509	4,108	1,400	34%	0	1,400	34%
2025	5,720	21	0	0	5,741	4,151	1,590	38%	0	1,590	38%
2026	5,842	21	0	0	5,863	4,185	1,678	40%	0	1,678	40%
2027	5,881	21	0	0	5,902	4,216	1,686	40%	0	1,686	40%
2028	5,919	21	0	0	5,940	4,245	1,695	40%	0	1,695	40%
2029	5,958	21	0	0	5,979	4,273	1,706	40%	0	1,706	40%
2030	6,034	21	0	0	6,055	4,298	1,757	41%	0	1,757	41%
2031	6,112	21	0	0	6,133	4,322	1,810	42%	0	1,810	42%
2032	6,148	21	0	0	6,169	4,345	1,825	42%	0	1,825	42%

Values shown may be affected due to rounding.

Schedule 7.2

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
							Reserve Margin Before Maintenance			Reserve Margin After Maintenance	
Year	Total Firm Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Firm Capacity Available MW	System Firm Winter Peak Demand MW	MW	% of Peak	Scheduled Maintenance MW	MW	% of Peak
2022-23	5,274	400	0	0	5,674	4,273	1,401	33%	0	1,401	33%
2023-24	5,299	0	0	0	5,299	4,324	975	23%	0	975	23%
2024-25	5,399	21	0	0	5,420	4,378	1,041	24%	0	1,041	24%
2025-26	5,436	21	0	0	5,457	4,426	1,031	23%	0	1,031	23%
2026-27	5,436	21	0	0	5,457	4,467	990	22%	0	990	22%
2027-28	5,436	21	0	0	5,457	4,506	951	21%	0	951	21%
2028-29	5,436	21	0	0	5,457	4,544	913	20%	0	913	20%
2029-30	5,473	21	0	0	5,494	4,580	914	20%	0	914	20%
2030-31	5,513	21	0	0	5,534	4,612	922	20%	0	922	20%
2031-32	5,553	21	0	0	5,574	4,643	932	20%	0	932	20%

Values shown may be affected due to rounding.

Schedule 8.1
Planned and Prospective Generating Facility Additions and Changes

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Primary	(6) Fuel Alternate	(7) Fuel Trans. Primary	(8) Fuel Trans. Alternate	(9) Const. Start Mo/Yr	(10) Commercial In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen. Max. Nameplate kW	(13) Firm Net Capability Summer MW	(14) Firm Net Capability Winter MW	(15) Status
2023														
Bayside 1 Enhancement	1	Hillsborough	CC	NG	NA	PL	NA	-	1/23	*	65,000	48.0	65.0	P
Big Bend 3 Retirement	3	Hillsborough	ST	NG	NA	PL	NA	-	05/76	4/23	445,500	(395.0)	(400.0)	RT
Juniper Solar [1]	1	Pasco	PV	SOLAR	NA	NA	NA	-	8/23	*	70,000	39.1	-	P
Alafia Solar [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	12/23	*	60,000	33.5	-	P
Lake Mabel Solar [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	12/23	*	74,500	41.6	-	P
Dover Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/23	*	25,000	14.0	-	P
Solar Degradation [2]	N/A											(1.5)	-	
											2023 Changes and Additions:	(274.3)	(335.0)	
2024														
Bayside 2 Enhancement	2	Bayside	CC	NG	NA	PL	NA	-	1/24	*	80,000	70.0	80.0	P
Dover Storage	1	Hillsborough	BA	N/A	N/A	N/A	N/A	-	1/24	*	15,000	15.0	15.0	P
Solar Degradation [2]	N/A											(2.3)	-	
											2024 Changes and Additions:	82.7	95.0	
2025														
Future Solar 1 [1,3]	1	Unknown	PV	SOLAR	NA	NA	NA	-	1/25	*	137,500	76.9	-	P
Battery Storage 1	1	Unknown	BA	N/A	N/A	N/A	N/A		1/25	*	100,000	100.0	100.0	P
Reciprocating Engine 1	1	Unknown	IC	NG	NA	PL	NA	-	4/25	*	37,000	37.0	37.0	P
Solar Degradation [2]	N/A											(2.7)	-	
											2025 Changes and Additions:	211.2	137.0	
2026														
Future Solar 2 [1, 3]	1	Unknown	PV	SOLAR	NA	NA	NA	-	1/26	*	223,500	124.9	-	P
Solar Degradation [2]	N/A											(2.8)	-	
											2026 Changes and Additions:	122.1	-	

Notes:

* Undetermined

1 Solar MW values reflect capacity at time of peak.

2 Solar capacity degrades at approximately 0.4% every year.

Tampa Electric Company continually analyzes renewable energy and distributed generation alternatives with the objective to integrate them into its resource portfolio.

3 Muliple Sites, each not to exceed 74.5MW

Schedule 8.1
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel Primary	Fuel Alternate	Fuel Trans. Primary	Fuel Trans. Alternate	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Firm Net Capability Summer MW	Firm Net Capability Winter MW	Status
2027														
Future Solar 3 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	1/27	*	74,500	41.6	-	P
Solar Degradation [2]	N/A											(3.1)	-	
									2027 Changes and Additions:			38.6	-	
2028														
Future Solar 4 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	1/28	*	74,500	41.6	-	P
Solar Degradation [2]	N/A											(3.1)	-	
									2028 Changes and Additions:			38.5	-	
2029														
Future Solar 5 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	1/29	*	74,500	41.6	-	P
Solar Degradation [2]	N/A											(3.2)	-	
									2029 Changes and Additions:			38.4	-	
2030														
Future Solar 6 [1]	1	Unknown	PV	SOLAR	N/A	N/A	N/A	-	1/30	*	74,500	41.6	-	P
Reciprocating Engine 2	1	Unknown	IC	NG	NA	PL	NA	-	1/30	*	37,000	37.0	37.0	P
Solar Degradation [2]	N/A											(3.3)	-	
									2030 Changes and Additions:			75.4	37.0	
2031														
Future Solar 7 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	1/31	*	74,500	41.6	-	P
Battery Storage 2	1	Unknown	BA	N/A	N/A	N/A	N/A	-	1/31	*	40,000	40.0	40.0	P
Solar Degradation [2]	N/A											(3.4)	-	
									2031 Changes and Additions:			78.3	40.0	
2032														
Battery Storage 3	1	Unknown	BA	N/A	N/A	N/A	N/A	-	1/32	*	40,000	40.0	40.0	P
Solar Degradation [2]	N/A											(3.4)	-	
									2032 Changes and Additions:			36.6	40.0	

Notes:

* Undetermined
1 Solar MW values reflect capacity at time of peak.
2 Solar capacity degrades at approximately 0.4% every year.
Tampa Electric Company continually analyzes renewable energy and distributed generation alternatives with the objective to integrate them into its resource portfolio.
3 Muliple Sites, each not to exceed 74.5MW

Schedule 9
(Page 1 of 19)
Status Report and SPECIFICATIONS of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Bayside 1 Enhancement
(2)	Net Capability	
	A. Summer	48 MW
	B. Winter	65 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	2022
	B. Commercial In-Service Date	January 2023
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Planned
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2023)	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	15
	Total Installed Cost[1] (In-Service Year $/kW)	375
	Direct Construction Cost ($/kW)	367
	AFUDC[1] Amount ($/kW)	-
	Escalation ($/kW)	8.10
	Fixed O&M (In-Service Year $/kW – Yr)	-
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	1.21

[1] Total installed cost includes transmission interconnection

Schedule 9
(Page 2 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Juniper Solar
(2)	Net Capability	
	A. Summer	70.0 MW-ac
	B. Winter	70.0 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	December 2020
	B. Commercial In-Service Date	August 2023
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+695 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2024)	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,426
	Direct Construction Cost ($/kW)	1,419
	AFUDC Amount ($/kW)	7.23
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.15
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.81

[1] Land price included
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 3 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Alafia Solar
(2)	Net Capability	
	A. Summer	60 MW-ac
	B. Winter	60 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	December 2017
	B. Commercial In-Service Date	December 2023
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+408 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2024)	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,538
	Direct Construction Cost ($/kW)	1,458
	AFUDC Amount ($/kW)	79.48
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.39
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.82

[1] Land price included
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 4 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Lake Mabel Solar
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	December 2020
	B. Commercial In-Service Date	December 2023
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+575 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2024)	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,397
	Direct Construction Cost ($/kW)	1,332
	AFUDC Amount ($/kW)	64.57
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.39
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.78

[1] Land price included
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 5 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Dover Solar
(2)	Net Capability	
	A. Summer	25 MW-ac
	B. Winter	25 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	March 2022
	B. Commercial In-Service Date	December 2023
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+177 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2024)	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,814
	Direct Construction Cost ($/kW)	1,735
	AFUDC Amount ($/kW)	79.67
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.17
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.83

[1] Land Price Included
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 6 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Dover Storage
(2)	Net Capability	
	A. Summer	15 MW-ac
	B. Winter	15 MW-ac
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	March 2022
	B. Commercial In-Service Date	January 2024
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2024)	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,312
	Direct Construction Cost ($/kW)	1,233
	AFUDC Amount ($/kW)	78.83
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	4.08
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.88

[1] Land price included
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 7 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Bayside 2 Enhancement
(2)	Net Capability	
	A. Summer	70 MW
	B. Winter	80 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	2023
	B. Commercial In-Service Date	January 2024
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Planned
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2024)	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	15
	Total Installed Cost[1] (In-Service Year $/kW)	407
	Direct Construction Cost ($/kW)	398
	AFUDC Amount ($/kW)	-
	Escalation ($/kW)	8.77
	Fixed O&M (In-Service Year $/kW – Yr)	-
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	1.21

[1] Total installed cost includes transmission interconnection

Schedule 9
(Page 8 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 1 (Multiple Sites, each not to exceed 74.5MW)
(2)	Net Capability	
	A. Summer	137.5 MW-ac
	B. Winter	137.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2024
	B. Commercial In-Service Date	January 2025
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2025)	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,430
	Direct Construction Cost ($/kW)	1,335
	AFUDC Amount ($/kW)	94.62
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.24
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.85

[1] w/o Land
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 9 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage 1
(2)	Net Capability	
	A. Summer	100 MW
	B. Winter	100 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	2024
	B. Commercial In-Service Date	January 2025
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2024)	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,452
	Direct Construction Cost ($/kW)	1,330
	AFUDC Amount ($/kW)	121.87
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	4.16
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.93

[1] w/o Land
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 10 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Reciprocating Engine 1
(2)	Net Capability	
	A. Summer	37 MW (Consisting of 2 Units)
	B. Winter	37 MW (Consisting of 2 Units)
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	December 2022
	B. Commercial In-Service Date	April 2025
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	2%
	Forced Outage Factor (FOF)	2%
	Equivalent Availability Factor (EAF)	96%
	Resulting Capacity Factor (2026)	0.64%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	8,117 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[1] (In-Service Year $/kW)	1,279
	Direct Construction Cost ($/kW)	1,176
	AFUDC Amount ($/kW)	65.41
	Escalation ($/kW)	37.43
	Fixed O&M (In-Service Year $/kW – Yr)	22.69
	Variable O&M (In-Service Year $/MWh)	2.51
	K-Factor	1.32

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

Schedule 9
(Page 11 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 2 (Multiple Sites, each not to exceed 74.5MW)
(2)	Net Capability	
	A. Summer	223.5 MW-ac
	B. Winter	223.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2025
	B. Commercial In-Service Date	January 2026
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2026)	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,417
	Direct Construction Cost ($/kW)	1,335
	AFUDC Amount ($/kW)	82.16
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.46
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.85

[1] w/o Land
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 12 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 3
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2026
	B. Commercial In-Service Date	January 2027
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2025)	26 %
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,305
	Direct Construction Cost ($/kW)	1,177
	AFUDC Amount ($/kW)	128.47
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	11.88
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.82

[1] w/o Land
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 13 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 4
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2027
	B. Commercial In-Service Date	January 2028
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2026)	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,305
	Direct Construction Cost ($/kW)	1,177
	AFUDC Amount ($/kW)	128.47
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	12.12
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.83

[1] w/o Land
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 14 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 5
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2028
	B. Commercial In-Service Date	January 2029
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2028)	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,305
	Direct Construction Cost ($/kW)	1,177
	AFUDC Amount ($/kW)	128.47
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	12.36
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.83

[1] w/o Land
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 15 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 6
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2029
	B. Commercial In-Service Date	January 2030
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2029)	26%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,305
	Direct Construction Cost ($/kW)	1,177
	AFUDC Amount ($/kW)	128.47
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	12.61
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.84

[1] w/o Land
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 16 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Reciprocating Engine 2
(2)	Net Capability	
	A. Summer	37 MW (Consisting of 2 Units)
	B. Winter	37 MW (Consisting of 2 Units)
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	2028
	B. Commercial In-Service Date	January 2030
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	2%
	Forced Outage Factor (FOF)	2%
	Equivalent Availability Factor (EAF)	96%
	Resulting Capacity Factor (2028)	0.64%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	8,117 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[1] (In-Service Year $/kW)	1,505
	Direct Construction Cost ($/kW)	1,279
	AFUDC Amount ($/kW)	77.00
	Escalation ($/kW)	149.49
	Fixed O&M (In-Service Year $/kW – Yr)	33.74
	Variable O&M (In-Service Year $/MWh)	2.77
	K-Factor	1.34

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting

Schedule 9
(Page 17 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 7
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[3]	2030
	B. Commercial In-Service Date	January 2031
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2031)	26% (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	35
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,305
	Direct Construction Cost ($/kW)	1,177
	AFUDC Amount ($/kW)	128.47
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	13.92
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.84

[1] w/o Land
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 18 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage 2
(2)	Net Capability	
	A. Summer	40 MW
	B. Winter	40 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	2030
	B. Commercial In-Service Date	January 2031
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2029)	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,931
	Direct Construction Cost ($/kW)	1,770
	AFUDC Amount ($/kW)	161.55
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	7.03
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.93

[1] w/o Land
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 9
(Page 19 of 19)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage 3
(2)	Net Capability	
	A. Summer	40 MW
	B. Winter	40 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[2]	2031
	B. Commercial In-Service Date	January 2032
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	N/A
	Forced Outage Factor (FOF)	N/A
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2031)	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost[1,2] (In-Service Year $/kW)	1,853
	Direct Construction Cost ($/kW)	1,770
	AFUDC Amount ($/kW)	161.55
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	7.17
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.93

[1] w/o Land
[2] Total installed cost includes transmission interconnection
[3] Construction schedule includes engineering design and permitting

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines
As of December 31, 2022

Units	Point of Origin and Termination	Number of Circuits	Right-of-Way (ROW)	Circuit Length **	Voltage	Anticipated In-Service Date	Anticipated Capital Investment ***	Substations	Participation with Other Utilities
Bayside CC 1	Bayside CC 1 does not require any new transmission lines ****	-	-	-	230 kV	January 2023	-	Gannon	None
Alafia Solar	Polk - Alafia	1	New ROW required	2	230 kV	December 2023	Included in total installed cost on Schedule 9	Alafia Solar Station; Polk Substation	None
Bayside CC 2	Bayside CC 2 does not require any new transmission lines ****	-	-	-	230 kV	January 2024	-	Gannon	None

Note:

* Specific information related to "Unsited" units unknown at this time.

** Approximate mileage listed is based on construction activity, not overall circuit length.

*** Cumulative capital investment at the in-service date. Cost included in total installed cost on Schedule 9.

**** Interconnection request studies pertaining to a Large Generating Facility have been completed and the unit does not require any new transmission lines.

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Chapter VI

ENVIRONMENTAL AND LAND USE INFORMATION

The H.L. Culbreath Bayside Power Station site is located in Hillsborough County on Port Sutton Road (See Figure VI-I), Polk Power Station site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-II) and Big Bend Power Station is located in Hillsborough County on Big Bend Road (See Figure VI-III). The solar sites identified in Schedule 1 are spread across Hillsborough, Polk, and Pasco counties (See Figure VI-IV). Additional land use requirements and/or alternative site locations are currently under consideration to accommodate the addition of future solar PV generation facilities and distributed energy resources.

Figure VI-I: Site Location of H.L. Culbreath Bayside Power Station

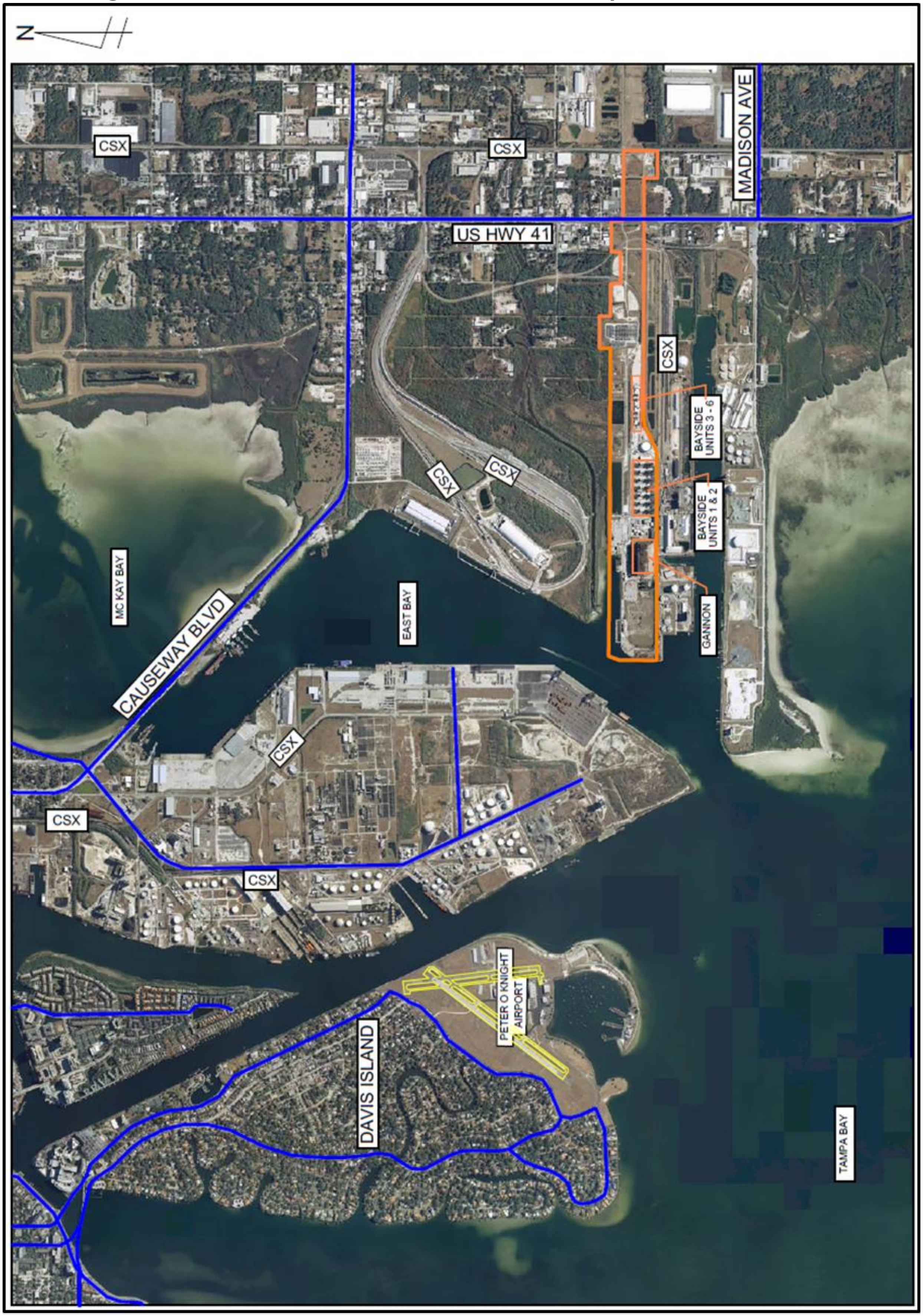

Figure VI-II: Site Location of Polk Power Station

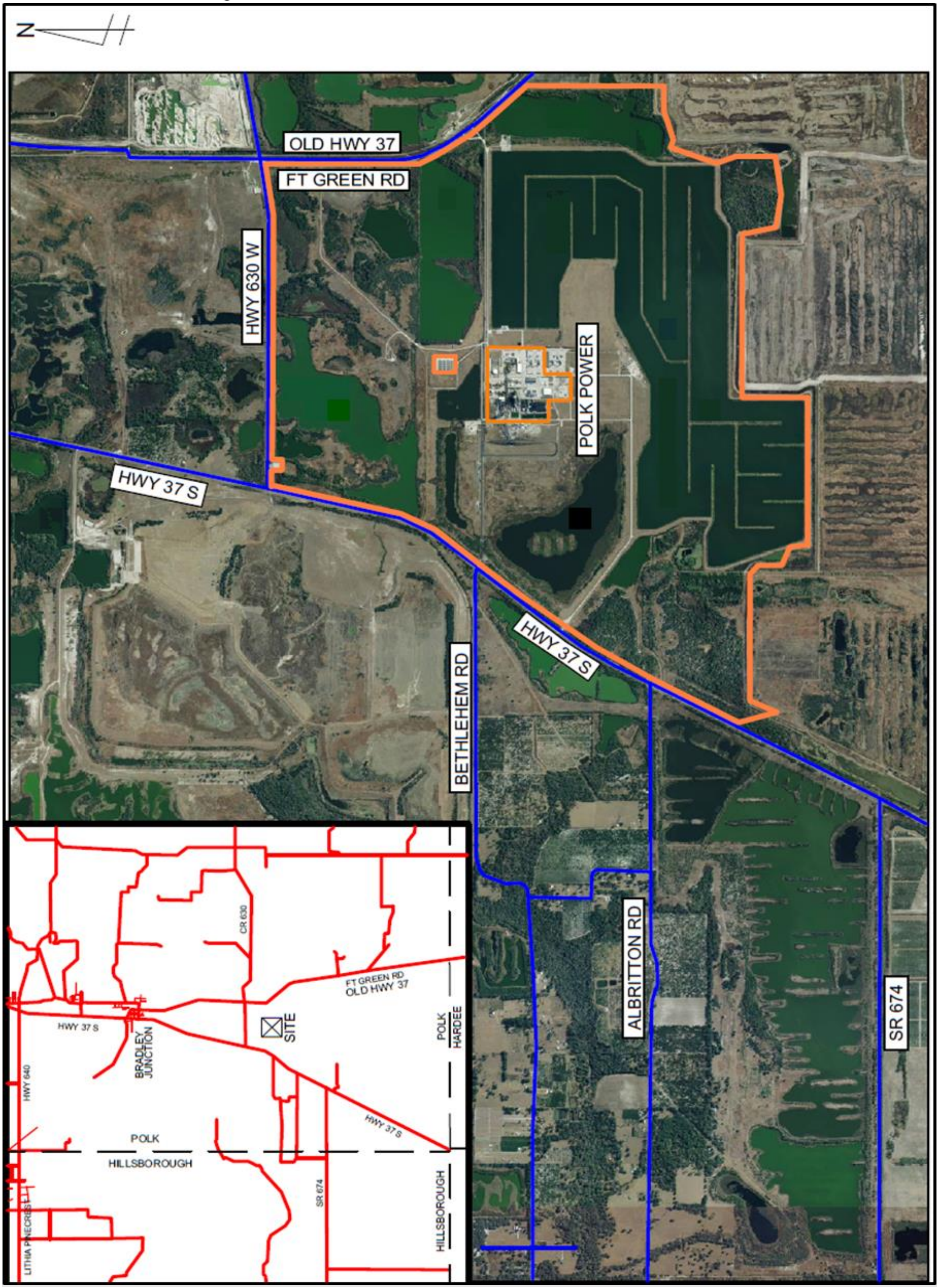

Figure VI-III: Site Location of Big Bend Power Station

Figure VI-IV: Site Location of Solar Power Stations