JANUARY 2026 — DECEMBER 2035

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines

TECO
TAMPA ELECTRIC

Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2026 to December 2035

April 1, 2026

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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
	HRSG	=	Heat Recovery Steam Generator
	IC	=	Internal Combustion
	PV	=	Photovoltaic
	ST	=	Steam Turbine
	RE	=	Reciprocating Engine
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
	FGD	=	Flue Gas Desulfurization
Transportation:	PL	=	Pipeline
	RR	=	Railroad
	TK	=	Truck
	WA	=	Water
Other:	EV	=	Electric Vehicle(s)
	NA	=	Not Applicable

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Executive Summary

The 2026 Ten-Year Site Plan (TYSP) developed by Tampa Electric Company (TEC) presents a comprehensive roadmap for enhancing the company's electric generating capacity. This plan addresses the projected incremental resource needs that are expected to arise between 2026 and 2035. By outlining the steps TEC will take to ensure adequate power supply, the TYSP reflects the company's commitment to meeting future demand.

In compliance with regulatory requirements, TEC submits its TYSP to the Florida Public Service Commission (FPSC). The purpose of this submission is to demonstrate TEC's ongoing dedication to delivering electricity to its customers in a manner that prioritizes safety, cost-effectiveness, and reliability. Through this plan, TEC reaffirms its focus on maintaining high standards of service and operational excellence for the communities it serves.

The portfolio of resource additions included in this TYSP are designed to work in concert to provide customers with cost savings, improved reliability and energy affordability. These enhancements also increase the system's operational flexibility, energy diversity, and resilience, ensuring TEC continues to meet its customers' needs effectively.

Tampa Electric Company is committed to ensuring that it can meet the evolving power needs of its customers throughout the planning horizon. To achieve this, TEC is focused on securing additional resources that are both cost-effective and reliable, with an emphasis on operational efficiency. The company's strategy is rooted in the belief that balancing these priorities is essential for delivering consistent, high-quality service to the communities it serves.

To guide the selection and implementation of resource additions, TEC employs an Integrated Resource Planning (IRP) process. This rigorous and ongoing evaluation considers a broad range of options from both the demand side (such as energy efficiency programs and demand response) and the supply side (including new generation and technological upgrades). By continually assessing these alternatives, TEC ensures that its approach is flexible and responsive to changing market conditions and customer needs.

The 2026 Ten-Year Site Plan was developed by Tampa Electric Company to ensure it meets the required minimum 20% reserve margin criteria. Through this comprehensive planning process, TEC can satisfy future energy requirements in a way that maintains the delicate balance between cost, resiliency and reliability. This approach underpins TEC's ongoing commitment to delivering safe, affordable, and dependable electric service now and in the years to come.

Tampa Electric Company continues to pursue prudent investments that support its commitment to operational efficiency across its electric system. By expanding its solar footprint, deploying battery storage solutions, and upgrading existing natural gas units, TEC is working to lower the system's overall heat rate which reduces fuel costs for customers, enabling more affordable electricity.

Investments in renewable generation also provide energy diversification, reducing 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 system's total solar installed capacity to nearly 2,400 MW by the end of the study horizon.

TEC plans to add approximately 115 megawatts (MW) of battery storage capacity to its system. Battery storage technology will allow TEC to optimize the dispatch of the generating fleet by capturing energy during periods of lower costs and dispatching it when demand and prices are higher. The next rollout of battery storage capacity addition includes a 20 MW project becoming operational at the start of 2026, followed by an additional 95 MW scheduled for service in 2027.

Additionally, TEC is pursuing cost-effective upgrades to its existing natural gas generating fleet. Planned improvements include enhancements to combustion turbines on the Polk Unit 2 combined cycle in 2026 and 2027. These upgrades will add generating capacity, boost efficiency, and increase the flexibility of TEC's operations, supporting the company's goal of delivering reliable and affordable electricity to customers.

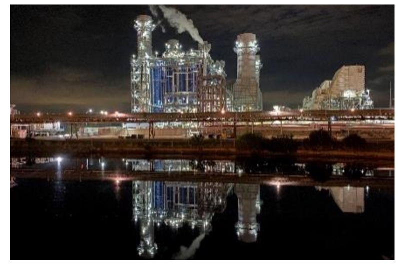
TEC's portfolio of both existing and planned resources has been structured to satisfy operating reserve requirements during periods of normal peak demand, ensuring operational flexibility in response to unforeseen outages or atypical weather patterns. Should temperatures diverge significantly from forecasted values, TEC may deploy mitigation strategies, including adjustments to unit dispatch, utilization of alternate fuel sources, expanded demand response initiatives, the pursuit of power purchase agreements, or, under extreme circumstances, managed customer interruptions to uphold grid stability. In 2025, dual fuel capability (Oil/Natural Gas) was introduced to Polk Unit 1; by 2027, all combustion turbines at the Polk Power Station will possess dual fuel capabilities. Additionally, TEC has reviewed and enhanced freeze protection protocols across all generation facilities and implemented measures to mitigate equipment failure risks during periods of extreme temperature.

Chapter I

DESCRIPTION OF EXISTING FACILITIES

TEC has four (4) central generating stations that include steam units, combined cycle units, reciprocating engines and combustion turbine peaking units. Additionally, TEC has numerous solar facilities and battery storage sites.

Big Bend Power Station



Big Bend Station is composed of one (1) combined cycle unit, Unit 1, which utilizes two (2) natural gas fueled 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 one (1) steam unit, Big Bend Unit 4. The steam unit is equipped with desulfurization scrubbers, electrostatic precipitators, and Selective Catalytic Reduction air pollution control systems. Big Bend Unit 4 can be fired with coal and natural gas. Big Bend CT 4 is a natural gas aero-derivative combustion turbine.

H.L. Culbreath "Bayside" Power Station

Bayside station consists of two (2) natural gas-fired combined cycle units and four (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 combustion turbine with the capability to burn two different fuels, natural gas and distillate oil. Polk 2 Combined Cycle utilizes four (4) natural gas-fired combustion turbines, four (4) HRSGs and one (1) steam turbine. Two (2) of the combustion turbines can also be fired with distillate oil.

MacDill Power Station

The MacDill Station consists of four (4) natural gas-fired reciprocating engines.

Solar and Battery

TEC's renewable energy fleet consists of a total of 1,424 MWAC of utility-scale solar across its service area. Most of these installations are single-axis tracking photovoltaic (PV) arrays, located throughout Hillsborough, Pasco, and Polk counties. In addition to these ground-mounted arrays, TEC also utilizes several large-scale fixed-tilt PV systems, which are installed on rooftops and carports, further diversifying their solar infrastructure.

Among TEC's innovative solar initiatives is a 1.0 MWAC floating solar project situated at the Big Bend Power Station. The company also operates an integrated renewable energy system that features solar PV carports designed to charge commercial-sized batteries. These batteries, in turn, are used to recharge TEC's expanding fleet of electric vehicles.

TEC has deployed a battery storage portfolio totaling 105 MW of capacity. It consists of 10.0 MW at the Big Bend Solar site, 15 MW at the Dover Solar site, 40 MW at the Lake Mabel solar site, and 40 MW at the Wimauma solar site.

Schedule 1
Existing Generating Facilities
As of December 31, 2025

(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		**Hillsborough Co.**											
	1		CC	NG	NA	PL	NA	NA	12/22	**	1,120,000	1,055	1,120
	4		ST	NG	BIT	PL	WA/RR	NA	02/85	01/40	380,000	380	380
	CT 4		GT	NG	NA	PL	NA	NA	08/09	**	61,000	56	61
Big Bend Total											**1,561,000**	**1,491**	**1,561**
Bayside		**Hillsborough Co.**											
	1		CC	NG	NA	PL	NA	NA	04/03	04/38	847,000	749	847
	2		CC	NG	NA	PL	NA	NA	01/04	01/39	1,121,000	1,001	1,121
	3		GT	NG	NA	PL	NA	NA	07/09	**	61,000	56	61
	4		GT	NG	NA	PL	NA	NA	07/09	**	61,000	56	61
	5		GT	NG	NA	PL	NA	NA	04/09	**	61,000	56	61
	6		GT	NG	NA	PL	NA	NA	04/09	**	61,000	56	61
Bayside Total											**2,212,000**	**1,974**	**2,212**
Polk		**Polk Co.**											
	1		CT	NG	DFO	PL	TK	*	09/96	9/36	206,000	177	206
	2		CC	NG	DFO	PL	TK	*	01/17	**	1,200,000	1,061	1,200
Polk Total											**1,406,000**	**1,238**	**1,406**
MacDill		**Hillsborough Co.**											
	1		IC	NG	NA	PL	NA	NA	2/25	**	18,200	18.2	18.2
	2		IC	NG	NA	PL	NA	NA	2/25	**	18,200	18.2	18.2
	3		IC	NG	NA	PL	NA	NA	12/25	**	18,200	18.2	18.2
	4		IC	NG	NA	PL	NA	NA	12/25	**	18,200	18.2	18.2
MacDill Total											**72,800**	**72.8**	**72.8**

Notes:
* Limited by environmental permit.
** Undetermined.
1 Big Bend Battery and Solar are co-located and restricted to a total output of 19.8 MW due to interconnection limits. This amount is used for reserve margin calculations.
2 Rating for Solar units are nameplate.
3 Utility owned solar/battery less than 1 MW not included.

Schedule 1 Cont'd
Existing Generating Facilities
As of December 31, 2025

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt	Commercial	Expected	Gen. Max.	Net Capability	
Plant	Unit		Unit	Fuel		Fuel Transport		Fuel	In-Service	Retirement	Nameplate	Summer	Winter
Name	No.	Location	Type	Pri	Alt	Pri	Alt	Days	Mo/Yr	Mo/Yr	kW	MW	MW
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 [1]	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 River 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	1	Hillsborough Co.	PV	SOLAR	NA	NA	NA	NA	01/22	**	45,800	45.8	45.8
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
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
Juniper Solar	1	Pasco Co.	PV	SOLAR	NA	NA	NA	NA	12/23	**	70,000	70.0	70.0
Alafia Solar	1	Polk Co.	PV	SOLAR	NA	NA	NA	NA	12/23	**	60,000	60.0	60.0
Lake Mabel Solar	1	Polk Co.	PV	SOLAR	NA	NA	NA	NA	12/23	**	74,500	74.5	74.5
Dover Solar	1	Hillsborough Co.	PV	SOLAR	NA	NA	NA	NA	12/23	**	25,000	25.0	25.0
English Creek Solar	1	Hillsborough Co.	PV	SOLAR	NA	NA	NA	NA	12/24	**	23,000	23.0	23.0
Bullfrog Creek Solar	1	Hillsborough Co.	PV	SOLAR	NA	NA	NA	NA	12/24	**	74,500	74.5	74.5
Cottonmouth Ranch Solar	1	Hillsborough Co.	PV	SOLAR	NA	NA	NA	NA	12/25	**	74,500	74.5	74.5
Solar Total [2,3]											1,424,100	1,424	1,424
Dover Battery Storage	1	Hillsborough Co.	BA	NA	NA	NA	NA	NA	12/24	**	15,000	15.0	15.0
Big Bend Battery Storage [1]	1	Hillsborough Co.	BA	NA	NA	NA	NA	NA	12/19	**	10,000	10.0	10.0
Lake Mabel Energy Storage	1	Polk Co.	BA	NA	NA	NA	NA	NA	3/25	**	40,000	40.0	40.0
Wimauma Energy Storage	1	Hillsborough Co.	BA	NA	NA	NA	NA	NA	4/25	**	40,000	40.0	40.0
Battery Total [3]											105,000	105	105
											TOTAL [1]	6,305	6,781

Notes:

* Limited by environmental permit.

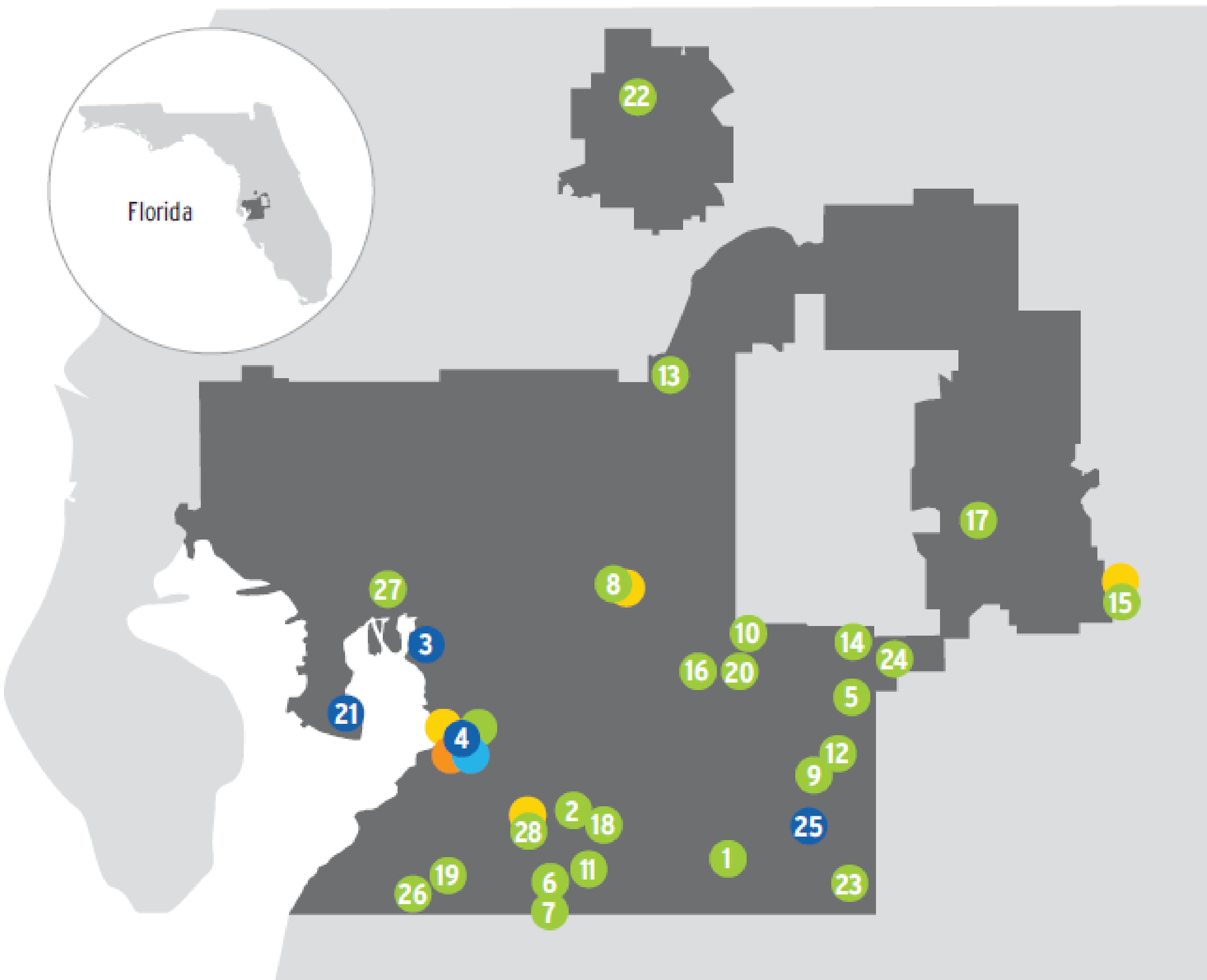
** Undetermined.

1 Big Bend Battery and Solar are co-located and restricted to a total output of 19.8 MW due to interconnection limits. This amount is used for reserve margin calculations.

2 Rating for Solar units are nameplate.

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

Figure I-I:
Tampa Electric Service Area Map



1 Alafia
2 Balm
3 Bayside
4 Big Bend
5 Bonnie Mine
6 Bullfrog Creek
7 Cottonmouth Ranch
8 Dover
9 Durrance
10 English Creek
11 Grange Hall
12 Jamison
13 Juniper
14 Lake Hancock
15 Lake Mabel
16 Laurel Oaks
17 Legoland Florida
18 Lithia
19 Little Manatee River
20 Magnolia
21 MacDill Station
22 Mountain View
23 Payne Creek
24 Peace Creek
25 Polk
26 Riverside
27 Tampa International Airport
28 Wimauma

Solar Generation
Floating Solar
Agrivoltaics
Power Station
Storage
Service Area

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 2026-2035 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the years 2026-2035.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2026-2035 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. Phosphate 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 lighting forecast energy and 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 recent trends.

    - The General Service Demand Customer Model ***(Equation #5)*** is a function of recent trends.

    - The General Service Large Demand Customer Model ***(Equation #6)*** is a function of recent 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 modeled individually for five rate classes. The General Service and General Service Demand rate classes are projected based on the recent growth trends in the governmental employment sector. The Residential Service, General Service Large Demand and Standby Large Demand rate classes are a function of recent trends. ***(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:

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

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:

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

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

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

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.

$$\textbf{HeatUse}_{\ y,m} =$$

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

$$\textbf{CoolUse}_{\ y,m} =$$

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

$$\textbf{OtherUse}_{\ y,m} =$$

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

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 cooling degree-days and seasonal trends.

  - The Standby Large Demand Energy Model ***(Equation #7)*** is based on cooling degree-days and 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 cooling degree-days.

  - 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, 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. Phosphate Demand and Energy Analysis

TEC phosphate customers are 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 phosphate customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecasts are based. Further input is provided by individual customer trend analysis and discussions with industry experts.

6. Customer-Owned Solar Photovoltaic

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 Charging

The electric vehicle charging forecast process begins with an estimate of the number of EVs operating in Tampa Electric's service area using vehicle registration data purchased from S&P Global. 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 EV charging load profiles by charging type (Level 1, Level 2, Fast DC, and whether at Home, Work, Public etc.) from NREL [National Renewable Energy Laboratory], now called NLR or National Lab of the Rockies.

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.

Tampa Electric's retail demand and energy forecasts are adjusted downward to reflect the incremental demand and energy savings of these DSM programs.

Tampa Electric 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 Florida Public Service Commission (FPSC) ten-year demand and energy 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 2025, Tampa Electric transitioned to the FPSC approved 2025-2034 Demand Side Management ("DSM") plan which consists of one renewable program, one research and development program, 14 residential and 15 commercial DSM Programs which support the approved FPSC goals which are reasonable, beneficial and cost-effective to all customers as required by the FEECA. The company completed its transition to the 2025-2034 DSM Plan on June 1st, after the company received approval of its plan and standards in Consummating Order PSC-2025-0137-CO-EG, issued on April 18th, 2025, in Docket No. 20240163-EG.

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

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

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

10. Prime Time Plus – a program that reduces weather-sensitive loads through direct load control of residential customers HVAC, water heating, Level 2 Electric Vehicle Chargers, and pool pumps. This program uses the company's advanced metering infrastructure ("AMI") system.

11. 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.

12. 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.

13. Custom Energy Efficiency - a rebate program that encourages commercial and industrial customers to invest in energy efficiency and conservation measures that are not sanctioned by other commercial programs.

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

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

16. 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.

17. 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.

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

19. 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.

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

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

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

23. 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. 20240014-EG, Order No. PSC-2024-0430-FOF-EU, Issued September 20, 2024. The 2025 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

Tampa Electric developed a Monitoring and Evaluation (M&E) plan in response to FPSC requirements filed in Docket No. 19941173-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 Tampa Electric 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
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	10.3	6.8	151.2%	12.5	2.9	429.5%	29.6	6.3	469.9%
2024	8.5	6.1	139.7%	9.8	2.5	393.4%	22.2	5.5	404.1%
2025	11.7	14.0	83.5%	7.0	7.9	88.4%	27.3	24.8	110.0%
2026		14.0			7.9			24.8	

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
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	7.2	1.8	398.1%	8.1	3.5	232.1%	30.3	9.9	305.6%
2024	9.2	1.7	542.5%	12.3	3.2	384.5%	86.5	9.6	900.9%
2025	4.6	5.4	84.9%	5.9	6.4	92.8%	38.0	22.2	171.2%
2026		5.4			6.4			22.2	

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
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	17.4	8.6	202.9%	20.6	6.4	321.6%	59.9	16.2	369.5%
2024	17.7	7.8	227.5%	22.1	5.7	388.4%	108.7	15.1	720.0%
2025	16.3	19.4	83.9%	12.9	14.3	90.3%	65.3	47.0	138.9%
2026		19.4			14.3			47.0	

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 points 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 2026-2035. Due to a delay in BEBR publishing its population projections, we used their prior year's forecast. The average annual population growth rate is expected to be 1.4%.

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 (2026-2035), employment is assumed to rise at a 1.1% 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 2.9% average annual rate from 2026-2035. 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 2026-2035, 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 FORECAST 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 2026-2035, 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

Schedules 3.1 and 3.2 provide historical and projected peak load forecasts for summer and winter under base, high, and low scenarios. For the period from 2026 to 2035, Tampa Electric Company's base retail firm peak demand is projected to grow at an average annual rate of 0.9% during the summer, and 1.1% during the winter.

Chapter III

INTEGRATED RESOURCE PLANNING PROCESSES

Tampa Electric Company's Integrated Resource Planning (IRP) process is structured to assess both demand-side and supply-side resources in a comparable and consistent manner. The objective is to meet future demand and energy requirements in a way that is cost-effective and reliable, while also considering the interests of utility customers and shareholders.

The IRP process includes a reliability analysis to establish the timing of future needs, as well as an economic analysis to determine which resource alternatives are best suited to meet future system demand and energy requirements. The process begins with the development of a demand and energy forecast that excludes incremental energy efficiency and conservation programs. This forecast sets the foundation for identifying the next potential avoided unit(s) and becomes the baseline for a comprehensive cost-effectiveness analysis of these programs. The analysis is carried out using Commission-approved methodologies, including the Rate Impact Measure (RIM) test, the Total Resource Cost (TRC) test, and the Participants Cost Test (PCT). Each measure is evaluated according to the Florida Public Service Commission's (FPSC) standard cost-effectiveness methodology, factoring in different marketing and incentive scenarios. Assumptions regarding utility plant avoidance for generation, transmission, and distribution are also included. Only those measures that pass the RIM and PCT tests in energy efficiency and demand response analysis are selected for potential adoption in utility programs.

Each adopted measure is quantified for its contribution to coincident summer and winter peak kilowatt (kW) reduction and its annual kilowatt-hour (kWh) savings. These results are then incorporated into the demand and energy forecast. TEC evaluates and reports on energy efficiency and demand response measures that comply with Rule 25-17.008, Florida Administrative Code (F.A.C.), as well as the FPSC's prescribed cost-effectiveness methodology.

Upon completion of this comprehensive analysis and determination of cost-effective energy efficiency and conservation programs, the system demand and energy requirements are revised to reflect the anticipated effects of these programs in reducing peak demand and overall energy requirements. The process is iterative, repeating to incorporate additional energy efficiency, conservation programs, and supply-side resources as needed.

Potential generating supply-side resources are identified through an alternative technology screening analysis, which is designed to assess the economic viability of a broad range of generating technologies for TEC's service area. Technologies that pass this screening are included in a supply-side analysis, examining various alternatives for meeting future system requirements.

TEC employs a long-term planning computer model developed by Energy Exemplar, known as PLEXOS, to evaluate supply-side resources. PLEXOS uses a mixed integer linear programming (MILP) approach to estimate the timing and types of generation additions required to meet system demand and energy requirements economically. The model's objective function is to compare all feasible combinations of generating unit additions, ensuring specified reliability criteria are satisfied, and to determine the schedule and addition plan with the lowest total system cost.

For each of the top-ranked resource plans, detailed cost analyses are performed using the PLEXOS production cost model. Capital expenditures including interconnection costs and incremental fuel transportation associated with each capacity addition are determined based on the generating unit type, fuel type, capital spending curve, and in-service year. Fixed charges from capital expenditures are expressed in present worth dollars for comparison. Fuel and operating and maintenance costs for each scenario are projected based on economic dispatch of all system energy resources. The total cumulative present value of revenue requirements for each alternative plan is calculated by combining projected operating expenses (in present worth dollars) with fixed charges.

The result of the IRP process is a plan that provides Tampa Electric's customers with cost-effective solutions, while maintaining flexibility and adaptability in a dynamic regulatory and competitive environment. This approach focuses on improving efficiency and energy affordability. To satisfy anticipated system demand and energy needs while maintaining reliability and cost-effectiveness, the company's expansion plan includes the following initiatives:

- Enhancements to capacity, efficiency, and dual fuel capability of existing combustion turbines at the Polk Power Station.
- Deployment of 115 megawatts (MW) of battery storage capacity.
- Addition of utility-scale solar resources.
- Installation of new combustion turbines.

The expansion plan outlined in this Ten-Year Site Plan is designed to address growing customer needs through the addition of energy resources distributed across the service territory. Alongside enhancements to existing assets and increased utility-scale solar, new battery storage and combustion turbines will be integrated to meet customer demand growth, provide operational flexibility and system resiliency. The comprehensive details of the expansion plan can be found in Schedule 8.1.

TEC will continue to assess and incorporate competitive purchase power agreements and demand-side management (DSM) programs that have the potential to replace or defer the planned unit additions. Such optimizations are pursued only if they achieve the overarching objective of delivering 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 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, U.S. Energy Information Administration, 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

Since 2017, TEC has successfully completed the construction and commissioning of 1,424 MW_{AC} of solar PV generating capacity at 28 utility solar sites, which can produce enough electricity to power more than 230,000 homes. Over the next two years, the Company plans to expand with eight new cost-effective, utility solar sites, adding 433 MW of additional solar capacity. By the end of 2027, Tampa Electric will have about 1,857 MW_{AC} of solar generating capacity – with the ability to produce enough energy to power more than 305,700 homes – or almost 18.6 percent of TEC's energy produced by the sun by the following year.

The company's proposed solar expansion helps lower electricity costs. These cost-effective projects also help serve increased customer load while reducing the impact of fuel price fluctuations on the customers' bill due to the zero-fuel cost generation. The additional utility-scale solar will help moderate fuel price volatility, increase fuel diversity, reduce reliance on natural gas, and has little to no water requirements for operations. In addition, with the passage of the Inflation Reduction Act, the federal government is providing additional tax incentives which will also benefit customers.

Beyond 2027 there is an additional 522 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 would have around 2,400 MW_{AC} of solar capacity by the end of the study horizon, which means approximately 23 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 2025, TEC's Renewable Energy Program has 924 customers purchasing over 1,573 blocks of renewable energy each month and there have been over 5,935 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, LEGOLAND Florida's Imagination Zone, and the Museum of Science and Industry (MOSI). 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 TEC 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, a vanadium flow battery and a supercapacitor-based energy storage system. 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 show that floating solar can decrease water evaporation. 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 can 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.

2. *Storage Technology Initiatives*

Battery storage projects will help maintain the required winter capacity reserve margin as peak load grows with increased customers. Additionally, battery storage provides fuel savings for customers through energy arbitrage, where energy is stored during off-peak hours when electricity prices are cheapest and used during on-peak hours when electricity prices are highest. Other added benefits include the potential deferral or avoidance of future transmission and distribution investments by eliminating an otherwise necessary upgrade by locating an energy source close to a high load area.

In 2018, Tampa Electric began interconnecting customer-owned battery storage. As of December 31, 2025, there are 2,717 customers interconnected with 25.880 MW DC storage capacity.

3. *Electric Vehicle Initiatives*

The upward trajectory of customer adoption of Electric Vehicles (EV) continues, and this trend is expected to persist into the near future. Florida continually ranks second in the nation for the number of EVs sold, and TEC is forecasting a 20% average annual growth rate in the number of EVs within our service area through 2030. Given the ongoing enhancements in battery technology and cost efficiencies, increased access to public charging infrastructure, and greater consumer choice in the types of EVs offered by major automakers, forecasts show EV adoption will continue to grow.

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 nearly 750 ports being applied for. 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. To educate future Electric Vehicle (EV) drivers, TEC introduced a high school driver education program as an enhancement of the company's ongoing Energy Education and Awareness conservation program. TEC not only provided funding for the EVs, but also installed the necessary EV chargers and helped to develop curriculum used in the classrooms.

Through these activities, as well as increased customer engagement, TEC is learning valuable information to support the needs of specific market segments, particularly multi-family residential properties and commercial fleets. The high concentration of EVs at these locations requires extensive planning for both the customer and utility infrastructure needed to provide adequate charging while minimizing grid impacts. 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 is consistent with the agreement 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 potentially 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. Refer to schedule 7.2.1 to see how a 2-degree change in temperatures can impact winter reserve margins.

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, 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, but they are not absolute system expansion rules. 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 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 5-1-24.pdf as well as the principles contained in the NERC Reliability Standards relating to ATC calculations. FRCC members, including TEC, have formed the Florida Transmission Capability Determination Group 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 various 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 are 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 distinct 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
HISTORY:								
2016	1,352,797	2.6	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	1,541,531	2.6	10,307	742,575	13,880	6,462	80,622	80,154
2024	1,560,449	2.5	10,269	757,280	13,560	6,481	81,426	79,591
2025	1,575,637	2.6	10,309	768,806	13,409	6,536	81,376	80,320
FORECAST:								
2026	1,602,245	2.6	10,358	781,467	13,255	6,520	82,518	79,016
2027	1,628,386	2.6	10,468	794,110	13,182	6,602	83,384	79,176
2028	1,654,178	2.6	10,548	806,584	13,078	6,678	84,235	79,284
2029	1,679,161	2.6	10,608	818,666	12,957	6,749	85,080	79,329
2030	1,703,108	2.6	10,702	830,248	12,890	6,831	85,932	79,494
2031	1,726,130	2.6	10,781	841,382	12,814	6,919	86,790	79,716
2032	1,748,143	2.5	10,869	852,028	12,757	7,010	87,655	79,976
2033	1,769,075	2.5	10,981	862,151	12,737	7,103	88,524	80,238
2034	1,788,932	2.5	11,096	871,755	12,729	7,196	89,397	80,493
2035	1,807,956	2.5	11,226	880,956	12,743	7,294	90,274	80,804

Notes:
December 31, 2025 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
HISTORY:								
2016	1,352,797	2.6	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	1,541,531	2.6	10,307	742,575	13,880	6,462	80,622	80,154
2024	1,560,449	2.5	10,269	757,280	13,560	6,481	81,426	79,591
2025	1,575,637	2.6	10,309	768,806	13,409	6,536	81,376	80,320
FORECAST:								
2026	1,618,096	2.6	10,425	785,277	13,276	6,523	82,538	79,027
2027	1,652,586	2.6	10,603	801,876	13,222	6,607	83,425	79,192
2028	1,687,025	2.6	10,753	818,449	13,138	6,685	84,296	79,305
2029	1,720,939	2.6	10,883	834,770	13,037	6,758	85,164	79,352
2030	1,754,086	2.6	11,052	850,722	12,992	6,842	86,038	79,522
2031	1,786,568	2.6	11,209	866,354	12,938	6,932	86,920	79,747
2032	1,818,284	2.6	11,377	881,618	12,904	7,026	87,808	80,011
2033	1,849,147	2.7	11,571	896,471	12,907	7,121	88,702	80,277
2034	1,879,149	2.7	11,770	910,909	12,922	7,216	89,600	80,535
2035	1,908,528	2.7	11,987	925,047	12,959	7,317	90,502	80,850

Notes:
December 31, 2025 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
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
HISTORY:								
2016	1,352,797	2.6	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	1,541,531	2.6	10,307	742,575	13,880	6,462	80,622	80,154
2024	1,560,449	2.5	10,269	757,280	13,560	6,481	81,426	79,591
2025	1,575,637	2.6	10,309	768,806	13,409	6,536	81,376	80,320
FORECAST:								
2026	1,586,472	2.6	10,291	777,657	13,233	6,518	82,497	79,006
2027	1,604,423	2.6	10,334	786,382	13,141	6,598	83,343	79,161
2028	1,621,813	2.5	10,347	794,834	13,018	6,672	84,173	79,265
2029	1,638,199	2.5	10,338	802,798	12,877	6,741	84,998	79,305
2030	1,653,371	2.5	10,361	810,172	12,788	6,820	85,828	79,467
2031	1,667,454	2.5	10,367	817,017	12,689	6,906	86,665	79,684
2032	1,680,380	2.4	10,381	823,300	12,609	6,995	87,506	79,941
2033	1,692,099	2.4	10,418	828,996	12,567	7,086	88,352	80,200
2034	1,702,631	2.4	10,456	834,115	12,536	7,176	89,201	80,451
2035	1,712,225	2.4	10,507	838,778	12,527	7,273	90,054	80,759

Notes:
December 31, 2025 Status
*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
HISTORY:							
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	2,082	1,330	1,565,053	0	0	1,939	20,791
2024	2,019	1,310	1,540,708	0	0	1,933	20,702
2025	2,105	1,292	1,628,999	0	0	1,993	20,943
FORECAST:							
2026	1,925	1,301	1,479,587	0	0	1,987	20,791
2027	1,884	1,301	1,448,421	0	0	1,992	20,946
2028	1,855	1,301	1,425,806	0	0	1,997	21,079
2029	1,860	1,301	1,429,484	0	0	2,004	21,221
2030	1,858	1,301	1,427,863	0	0	2,013	21,404
2031	1,856	1,301	1,426,930	0	0	2,023	21,579
2032	1,856	1,301	1,426,875	0	0	2,033	21,769
2033	1,858	1,301	1,427,862	0	0	2,044	21,986
2034	1,859	1,301	1,428,907	0	0	2,053	22,204
2035	1,860	1,301	1,429,363	0	0	2,061	22,441

Notes:
December 31, 2025 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
HISTORY:							
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	2,082	1,330	1,565,053	0	0	1,939	20,791
2024	2,019	1,310	1,540,708	0	0	1,933	20,702
2025	2,105	1,292	1,628,999	0	0	1,993	20,943
FORECAST:							
2026	1,925	1,301	1,479,862	0	0	1,992	20,865
2027	1,886	1,301	1,449,317	0	0	2,000	21,095
2028	1,857	1,301	1,427,376	0	0	2,010	21,305
2029	1,863	1,301	1,431,733	0	0	2,021	21,525
2030	1,861	1,301	1,430,785	0	0	2,034	21,790
2031	1,861	1,301	1,430,557	0	0	2,049	22,051
2032	1,862	1,301	1,431,216	0	0	2,064	22,328
2033	1,864	1,301	1,432,927	0	0	2,079	22,635
2034	1,867	1,301	1,434,698	0	0	2,093	22,946
2035	1,868	1,301	1,435,883	0	0	2,106	23,278

Notes:
December 31, 2025 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
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
HISTORY:							
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	2,082	1,330	1,565,053	0	0	1,939	20,791
2024	2,019	1,310	1,540,708	0	0	1,933	20,702
2025	2,105	1,292	1,628,999	0	0	1,993	20,943
FORECAST:							
2026	1,925	1,301	1,479,309	0	0	1,983	20,716
2027	1,883	1,301	1,447,523	0	0	1,984	20,798
2028	1,853	1,301	1,424,234	0	0	1,985	20,857
2029	1,857	1,301	1,427,239	0	0	1,987	20,923
2030	1,854	1,301	1,424,950	0	0	1,992	21,027
2031	1,852	1,301	1,423,318	0	0	1,998	21,123
2032	1,851	1,301	1,422,558	0	0	2,004	21,231
2033	1,851	1,301	1,422,835	0	0	2,010	21,365
2034	1,852	1,301	1,423,169	0	0	2,015	21,499
2035	1,851	1,301	1,422,910	0	0	2,018	21,650

Notes:
December 31, 2025 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 2.3

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
HISTORY:					
2016	9	930	20,173	8,353	730,503
2017	2	1,110	20,298	8,698	744,690
2018	0	1,031	20,662	9,254	756,254
2019	0	986	20,770	9,283	771,960
2020	0	1,101	21,055	9,356	786,047
2021	0	940	21,033	9,418	802,049
2022	0	1,105	21,572	9,466	819,766
2023	0	976	21,767	9,616	834,144
2024	0	1,150	21,852	9,861	849,877
2025	0	854	21,797	9,939	861,413
FORECAST:					
2026	0	1,096	21,886	10,006	875,292
2027	0	1,103	22,049	10,037	888,832
2028	0	1,110	22,189	10,075	902,194
2029	0	1,116	22,337	10,122	915,169
2030	0	1,125	22,529	10,187	927,668
2031	0	1,134	22,713	10,257	939,731
2032	0	1,143	22,912	10,331	951,314
2033	0	1,154	23,140	10,405	962,381
2034	0	1,165	23,370	10,471	972,924
2035	0	1,177	23,619	10,526	983,056

Notes:
December 31, 2025 Status
*Includes sales to Reedy Creek (RCID)
**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
HISTORY:					
2016	9	930	20,173	8,353	730,503
2017	2	1,110	20,298	8,698	744,690
2018	0	1,031	20,662	9,254	756,254
2019	0	986	20,770	9,283	771,960
2020	0	1,101	21,055	9,356	786,047
2021	0	940	21,033	9,418	802,049
2022	0	1,105	21,572	9,466	819,766
2023	0	976	21,767	9,616	834,144
2024	0	1,150	21,852	9,861	849,877
2025	0	854	21,797	9,939	861,413
FORECAST:					
2026	0	1,100	21,965	10,037	879,153
2027	0	1,110	22,205	10,100	896,702
2028	0	1,121	22,426	10,170	914,216
2029	0	1,132	22,657	10,248	931,483
2030	0	1,145	22,935	10,346	948,407
2031	0	1,158	23,209	10,451	965,026
2032	0	1,172	23,500	10,559	981,286
2033	0	1,188	23,823	10,668	997,142
2034	0	1,204	24,150	10,770	1,012,580
2035	0	1,222	24,500	10,862	1,027,712

Notes:

December 31, 2025 Status

*Includes sales to Reedy Creek (RCID).

**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
HISTORY:					
2016	9	930	20,173	8,353	730,503
2017	2	1,110	20,298	8,698	744,690
2018	0	1,031	20,662	9,254	756,254
2019	0	986	20,770	9,283	771,960
2020	0	1,101	21,055	9,356	786,047
2021	0	940	21,033	9,418	802,049
2022	0	1,105	21,572	9,466	819,766
2023	0	976	21,767	9,616	834,144
2024	0	1,150	21,852	9,861	849,877
2025	0	854	21,797	9,939	861,413
FORECAST:					
2026	0	1,092	21,808	9,975	871,430
2027	0	1,095	21,893	9,975	881,001
2028	0	1,098	21,955	9,982	890,290
2029	0	1,100	22,023	9,997	899,094
2030	0	1,106	22,133	10,029	907,330
2031	0	1,110	22,233	10,068	915,051
2032	0	1,115	22,346	10,108	922,215
2033	0	1,121	22,486	10,148	928,797
2034	0	1,128	22,627	10,181	934,798
2035	0	1,136	22,786	10,202	940,335

Notes:

December 31, 2025 Status
*Includes sales to Reedy Creek (RCID).
**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)	(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
HISTORY:									
2016	4,401	15	4,386	138	0	149	101	92	3,907
2017	4,372	5	4,367	110	0	154	100	98	3,905
2018	4,289	0	4,289	125	0	159	101	106	3,798
2019	4,591	0	4,591	122	0	165	101	125	4,079
2020	4,573	0	4,573	113	0	169	104	135	4,053
2021	4,713	0	4,713	187	0	174	105	139	4,108
2022	4,772	0	4,772	204	0	183	106	148	4,131
2023	5,017	0	5,017	178	0	194	106	153	4,385
2024	4,687	0	4,687	92	0	204	108	160	4,122
2025	4,848	0	4,848	113	0	213	105	168	4,249
FORECAST:									
2026	5,037	0	5,037	143	0	220	112	173	4,389
2027	5,097	0	5,097	138	0	228	113	178	4,439
2028	5,151	0	5,151	135	0	237	113	184	4,482
2029	5,205	0	5,205	135	0	245	114	190	4,521
2030	5,261	0	5,261	135	0	255	114	195	4,562
2031	5,314	0	5,314	135	0	264	115	200	4,600
2032	5,369	0	5,369	134	0	273	116	205	4,641
2033	5,430	0	5,430	134	0	283	116	210	4,687
2034	5,490	0	5,490	134	0	292	117	214	4,732
2035	5,552	0	5,552	134	0	302	117	219	4,780

Notes:

December 31, 2025 Status

2016, 2018, 2020, and 2022 Net Firm Demand is not coincident with system peak.

*Includes residential and commercial/industrial conservation.

**Includes sales to RCID

***Includes Energy Planner and Prime Time Plus programs.

Values shown may be affected due to rounding.

Schedule 3.1

Forecast of Summer 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
HISTORY:									
2016	4,401	15	4,386	138	0	149	101	92	3,907
2017	4,372	5	4,367	110	0	154	100	98	3,905
2018	4,289	0	4,289	125	0	159	101	106	3,798
2019	4,591	0	4,591	122	0	165	101	125	4,079
2020	4,573	0	4,573	113	0	169	104	135	4,053
2021	4,713	0	4,713	187	0	174	105	139	4,108
2022	4,772	0	4,772	204	0	183	106	148	4,131
2023	5,017	0	5,017	178	0	194	106	153	4,385
2024	4,687	0	4,687	92	0	204	108	160	4,122
2025	4,848	0	4,848	113	0	213	105	168	4,249
FORECAST:									
2026	5,056	0	5,056	143	0	220	112	173	4,408
2027	5,136	0	5,136	138	0	228	113	178	4,479
2028	5,210	0	5,210	135	0	237	113	184	4,541
2029	5,286	0	5,286	135	0	245	114	190	4,602
2030	5,364	0	5,364	135	0	255	114	195	4,665
2031	5,440	0	5,440	135	0	264	115	200	4,726
2032	5,518	0	5,518	134	0	273	116	205	4,790
2033	5,602	0	5,602	134	0	283	116	210	4,859
2034	5,687	0	5,687	134	0	292	117	214	4,929
2035	5,775	0	5,775	134	0	302	117	219	5,003

Notes:

December 31, 2025 Status
2016, 2018, 2020, and 2022 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes sales to RCID
***Includes Energy Planner and Prime Time Plus programs.
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
HISTORY:									
2016	4,401	15	4,386	138	0	149	101	92	3,907
2017	4,372	5	4,367	110	0	154	100	98	3,905
2018	4,289	0	4,289	125	0	159	101	106	3,798
2019	4,591	0	4,591	122	0	165	101	125	4,079
2020	4,573	0	4,573	113	0	169	104	135	4,053
2021	4,713	0	4,713	187	0	174	105	139	4,108
2022	4,772	0	4,772	204	0	183	106	148	4,131
2023	5,017	0	5,017	178	0	194	106	153	4,385
2024	4,687	0	4,687	92	0	204	108	160	4,122
2025	4,848	0	4,848	113	0	213	105	168	4,249
FORECAST:									
2026	5,017	0	5,017	143	0	220	112	173	4,369
2027	5,057	0	5,057	138	0	228	113	178	4,400
2028	5,091	0	5,091	135	0	237	113	184	4,422
2029	5,125	0	5,125	135	0	245	114	190	4,441
2030	5,160	0	5,160	135	0	255	114	195	4,461
2031	5,192	0	5,192	135	0	264	115	200	4,478
2032	5,225	0	5,225	134	0	273	116	205	4,497
2033	5,262	0	5,262	134	0	283	116	210	4,519
2034	5,301	0	5,301	134	0	292	117	214	4,543
2035	5,340	0	5,340	134	0	302	117	219	4,568

Notes:

December 31, 2025 Status
2016, 2018, 2020, and 2022 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes sales to RCID
***Includes Energy Planner and Prime Time Plus programs.
Values shown may be affected due to rounding.

Schedule 3.2

History and Forecast of Winter 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
HISTORY:									
2015/16	4,034	0	4,034	145	21	533	98	67	3171
2016/17	3,748	0	3,748	137	0	541	95	70	2905
2017/18	4,670	0	4,670	66	0	548	96	77	3883
2018/19	3,913	0	3,913	104	0	556	95	88	3071
2019/20	4,238	0	4,238	140	0	564	98	99	3336
2020/21	4,151	0	4,151	132	0	568	102	103	3247
2021/22	4,414	0	4,414	158	0	572	104	108	3473
2022/23	4,396	0	4,396	217	0	582	105	113	3380
2023/24	4,142	0	4,142	164	0	588	64	114	3213
2024/25	4,542	0	4,542	156	0	601	109	122	3,554
FORECAST:									
2025/26	5,429	0	5,429	128	0	613	115	126	4,446
2026/27	5,501	0	5,501	124	0	627	116	131	4,503
2027/28	5,580	0	5,580	121	0	641	117	136	4,565
2028/29	5,654	0	5,654	121	0	655	117	141	4,620
2029/30	5,731	0	5,731	121	0	670	118	146	4,677
2030/31	5,806	0	5,806	121	0	684	118	150	4,733
2031/32	5,881	0	5,881	120	0	699	119	154	4,789
2032/33	5,952	0	5,952	120	0	714	119	158	4,842
2033/34	6,022	0	6,022	120	0	729	120	162	4,892
2034/35	6,090	0	6,090	120	0	743	120	166	4,941

Notes:
December 31, 2025 Status
2020/2021, 2022/2023 and 2024/2025 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner and Prime Time Plus programs.
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
HISTORY:									
2015/16	4,034	0	4,034	145	21	533	98	67	3,171
2016/17	3,748	0	3,748	137	0	541	95	70	2,905
2017/18	4,670	0	4,670	66	0	548	96	77	3,883
2018/19	3,913	0	3,913	104	0	556	95	88	3,071
2019/20	4,238	0	4,238	140	0	564	98	99	3,336
2020/21	4,151	0	4,151	132	0	568	102	103	3,247
2021/22	4,414	0	4,414	158	0	572	104	108	3,473
2022/23	4,396	0	4,396	217	0	582	105	113	3,380
2023/24	4,142	0	4,142	164	0	588	64	114	3,213
2024/25	4,542	0	4,542	156	0	601	109	122	3,554
FORECAST:									
2025/26	5,449	0	5,449	128	0	613	115	126	4,466
2026/27	5,540	0	5,540	124	0	627	116	131	4,542
2027/28	5,641	0	5,641	121	0	641	117	136	4,626
2028/29	5,737	0	5,737	121	0	655	117	141	4,702
2029/30	5,836	0	5,836	121	0	670	118	146	4,782
2030/31	5,934	0	5,934	121	0	684	118	150	4,861
2031/32	6,031	0	6,031	120	0	699	119	154	4,939
2032/33	6,127	0	6,127	120	0	714	119	158	5,016
2033/34	6,222	0	6,222	120	0	729	120	162	5,092
2034/35	6,315	0	6,315	120	0	743	120	166	5,165

Notes:
December 31, 2025 Status
2020/2021, 2022/2023 and 2024/2025 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner and Prime Time Plus programs.
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
HISTORY:									
2015/16	4,034	0	4,034	145	21	533	98	67	3,171
2016/17	3,748	0	3,748	137	0	541	95	70	2,905
2017/18	4,670	0	4,670	66	0	548	96	77	3,883
2018/19	3,913	0	3,913	104	0	556	95	88	3,071
2019/20	4,238	0	4,238	140	0	564	98	99	3,336
2020/21	4,151	0	4,151	132	0	568	102	103	3,247
2021/22	4,414	0	4,414	158	0	572	104	108	3,473
2022/23	4,396	0	4,396	217	0	582	105	113	3,380
2023/24	4,142	0	4,142	164	0	588	64	114	3,213
2024/25	4,542	0	4,542	156	0	601	109	122	3,554
FORECAST:									
2025/26	5,410	0	5,410	128	0	613	115	126	4,427
2026/27	5,462	0	5,462	124	0	627	116	131	4,464
2027/28	5,521	0	5,521	121	0	641	117	136	4,506
2028/29	5,574	0	5,574	121	0	655	117	141	4,539
2029/30	5,630	0	5,630	121	0	670	118	146	4,576
2030/31	5,684	0	5,684	121	0	684	118	150	4,611
2031/32	5,735	0	5,735	120	0	699	119	154	4,643
2032/33	5,784	0	5,784	120	0	714	119	158	4,673
2033/34	5,831	0	5,831	120	0	729	120	162	4,701
2034/35	5,877	0	5,877	120	0	743	120	166	4,727

Notes:
December 31, 2025 Status
2020/2021, 2022/2023 and 2024/2025 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner and Prime Time Plus programs.
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 %
ACTUAL:								
2016	20,149	584	330	19,234	9	930	20,173	55.2
2017	20,137	598	353	19,186	2	1,110	20,298	56.2
2018	20,634	614	388	19,631	0	1,031	20,662	58.3
2019	20,863	631	449	19,783	0	986	20,770	55.1
2020	21,085	644	487	19,954	0	1,101	21,055	56.1
2021	21,256	656	508	20,093	0	940	21,033	54.6
2022	21,676	679	530	20,467	0	1,105	21,572	55.5
2023	22,059	709	560	20,791	0	976	21,767	53.2
2024	22,058	737	620	20,702	0	1,150	21,852	57.5
2025	22,417	766	708	20,943	0	854	21,797	55.7
FORECAST:								
2026	22,243	787	665	20,791	0	1,096	21,886	53.3
2027	22,445	812	687	20,946	0	1,103	22,049	53.1
2028	22,625	837	709	21,079	0	1,110	22,189	52.6
2029	22,814	861	732	21,221	0	1,116	22,337	52.5
2030	23,042	886	752	21,404	0	1,125	22,529	52.3
2031	23,262	912	771	21,579	0	1,134	22,713	52.1
2032	23,495	937	789	21,769	0	1,143	22,912	51.9
2033	23,756	962	808	21,986	0	1,154	23,140	52.0
2034	24,018	987	826	22,204	0	1,165	23,370	52.0
2035	24,298	1,012	845	22,441	0	1,177	23,619	52.0

Notes:

December 31, 2025 Status
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner and Prime Time Plus programs.
***Includes sales to RCID.
****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)	(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 %**
HISTORY:								
2016	20,149	584	330	19,234	9	930	20,173	55.2
2017	20,137	598	353	19,186	2	1,110	20,298	56.2
2018	20,634	614	388	19,631	0	1,031	20,662	58.3
2019	20,863	631	449	19,783	0	986	20,770	55.1
2020	21,085	644	487	19,954	0	1,101	21,055	56.1
2021	21,256	656	508	20,093	0	940	21,033	54.6
2022	21,676	679	530	20,467	0	1,105	21,572	55.5
2023	22,059	709	560	20,791	0	976	21,767	53.2
2024	22,058	737	620	20,702	0	1,150	21,852	57.5
2025	22,417	766	708	20,943	0	854	21,797	55.7
FORECAST:								
2026	22,317	787	665	20,865	0	1,100	21,965	53.2
2027	22,594	812	687	21,095	0	1,110	22,205	53.0
2028	22,851	837	709	21,305	0	1,121	22,426	52.5
2029	23,117	861	732	21,525	0	1,132	22,657	52.4
2030	23,428	886	752	21,790	0	1,145	22,935	52.1
2031	23,733	912	771	22,051	0	1,158	23,209	52.0
2032	24,054	937	789	22,328	0	1,172	23,500	51.7
2033	24,405	962	808	22,635	0	1,188	23,823	51.7
2034	24,759	987	826	22,946	0	1,204	24,150	51.7
2035	25,135	1,012	845	23,278	0	1,222	24,500	51.7

Notes:

December 31, 2025 Status
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner and Prime Time Plus programs.
***Includes sales to RCID.
****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) 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 %
HISTORY:								
2016	20,149	584	330	19,234	9	930	20,173	55.2
2017	20,137	598	353	19,186	2	1,110	20,298	56.2
2018	20,634	614	388	19,631	0	1,031	20,662	58.3
2019	20,863	631	449	19,783	0	986	20,770	55.1
2020	21,085	644	487	19,954	0	1,101	21,055	56.1
2021	21,256	656	508	20,093	0	940	21,033	54.6
2022	21,676	679	530	20,467	0	1,105	21,572	55.5
2023	22,059	709	560	20,791	0	976	21,767	53.2
2024	22,058	737	620	20,702	0	1,150	21,852	57.5
2025	22,417	766	708	20,943	0	854	21,797	55.7
FORECAST:								
2026	22,168	787	665	20,716	0	1,092	21,808	53.3
2027	22,297	812	687	20,798	0	1,095	21,893	53.1
2028	22,403	837	709	20,857	0	1,098	21,955	52.7
2029	22,516	861	732	20,923	0	1,100	22,023	52.6
2030	22,665	886	752	21,027	0	1,106	22,133	52.5
2031	22,805	912	771	21,123	0	1,110	22,233	52.3
2032	22,957	937	789	21,231	0	1,115	22,346	52.1
2033	23,134	962	808	21,365	0	1,121	22,486	52.3
2034	23,312	987	826	21,499	0	1,128	22,627	52.3
2035	23,507	1,012	845	21,650	0	1,136	22,786	52.4

Notes:

December 31, 2025 Status

*Includes residential and commercial/industrial conservation.

**Includes Energy Planner and Prime Time Plus programs.

***Includes sales to RCID.

****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)
	ACTUAL		FORECAST		FORECAST	
	2025		2026		2027	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,787	1,692	4,689	1,598	4,743	1,605
February	3,209	1,401	3,657	1,461	3,699	1,468
March	3,437	1,517	3,675	1,616	3,718	1,623
April	3,852	1,743	3,660	1,664	3,683	1,667
May	4,270	2,089	4,149	1,961	4,184	1,977
June	4,183	2,061	4,498	2,094	4,534	2,110
July	4,467	2,264	4,582	2,198	4,620	2,216
August	4,350	2,248	4,644	2,234	4,690	2,255
September	4,020	2,036	4,394	2,032	4,433	2,053
October	3,755	1,801	4,060	1,882	4,100	1,899
November	3,124	1,465	3,554	1,555	3,601	1,574
December	2,765	1,480	3,860	1,591	3,904	1,602
TOTAL		21,797		21,886		22,049

Notes:
December 31, 2025 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)
	ACTUAL		FORECAST		FORECAST	
	2025		2026		2027	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,787	1,692	4,709	1,604	4,782	1,616
February	3,209	1,401	3,672	1,466	3,730	1,478
March	3,437	1,517	3,690	1,622	3,748	1,634
April	3,852	1,743	3,675	1,669	3,713	1,678
May	4,270	2,089	4,166	1,968	4,219	1,990
June	4,183	2,061	4,516	2,102	4,572	2,126
July	4,467	2,264	4,601	2,207	4,659	2,233
August	4,350	2,248	4,663	2,242	4,730	2,272
September	4,020	2,036	4,412	2,040	4,471	2,068
October	3,755	1,801	4,077	1,889	4,134	1,913
November	3,124	1,465	3,568	1,561	3,630	1,585
December	2,765	1,480	3,875	1,596	3,935	1,613
TOTAL		21,797		21,965		22,205

Notes:
December 31, 2025 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)
	ACTUAL		FORECAST		FORECAST	
	2025		2026		2027	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,787	1,692	4,670	1,593	4,704	1,594
February	3,209	1,401	3,642	1,456	3,669	1,458
March	3,437	1,517	3,660	1,611	3,688	1,613
April	3,852	1,743	3,645	1,658	3,654	1,656
May	4,270	2,089	4,133	1,954	4,150	1,963
June	4,183	2,061	4,479	2,086	4,497	2,095
July	4,467	2,264	4,563	2,190	4,582	2,200
August	4,350	2,248	4,624	2,225	4,651	2,238
September	4,020	2,036	4,375	2,025	4,396	2,037
October	3,755	1,801	4,043	1,875	4,066	1,885
November	3,124	1,465	3,539	1,550	3,571	1,563
December	2,765	1,480	3,844	1,586	3,872	1,591
TOTAL		21,797		21,808		21,893

Notes:
December 31, 2025 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 2024**	**Actual 2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
(1)	**Nuclear**	**Trillion BTU**	0	0	0	0	0	0	0	0	0	0	0	0
(2)	**Coal**	**1000 Ton**	26	20	113	135	118	101	100	104	101	100	100	101
(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)	**RE**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(9)	**Distillate**	**1000 BBL**	9	22	0	0	0	0	0	0	0	0	0	0
(10)	**ST**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(11)	**CC**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(12)	**GT**	**1000 BBL**	9	22	0	0	0	0	0	0	0	0	0	0
(13)	**D**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(14)	**RE**	**1000 BBL**	0	0	0	0	0	0	0	0	0	0	0	0
(15)	**Natural Gas**	**1000 MCF**	126,867	123,428	129,226	123,955	120,426	119,603	118,501	117,702	120,142	120,416	122,469	124,547
(16)	**ST**	**1000 MCF**	6,632	7,922	7,072	4,346	5,300	7,154	6,761	5,567	7,162	7,100	9,235	5,482
(17)	**CC**	**1000 MCF**	119,510	113,230	121,408	118,108	114,007	110,934	109,997	108,529	109,179	110,305	110,301	114,336
(18)	**GT**	**1000 MCF**	714	2,078	503	1,433	1,052	1,427	1,628	3,526	3,701	2,960	2,848	4,694
(20)	**RE**	**1000 MCF**	11	198	243	68	67	88	115	79	101	51	86	35
(21)	**Other (Specify)**													
(22)	**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.
Generation quantities do not reflect periodic testing of distillate fuel oil capability.

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 2024**	**Actual 2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
(1)	**Annual Firm Interchange**	GWh	33	270	379	281	282	281	281	281	282	281	281	74
(2)	**Nuclear**	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	**Coal**	GWh	58	39	216	260	224	196	195	200	194	193	193	193
(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)	RE	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(10)	**Distillate**	GWh	4	7	0	0	0	0	0	0	0	0	0	0
(11)	ST	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(12)	CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(13)	GT	GWh	4	7	0	0	0	0	0	0	0	0	0	0
(14)	D	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(15)	RE	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)	**Natural Gas**	GWh	17,999	17,472	18,136	17,743	17,529	17,189	17,019	16,859	16,990	17,234	17,449	17,897
(17)	ST	GWh	582	675	599	366	446	604	571	469	604	599	781	462
(18)	CC	GWh	17,352	16,608	17,243	17,248	16,987	16,452	16,295	16,071	16,045	16,369	16,405	17,021
(19)	GT	GWh	64	166	261	120	87	121	137	308	327	259	251	409
(20)	RE	GWh	1	23	33	9	9	12	16	11	14	7	12	5
(21)	**Renewable**	GWh	2,235	2,419	3,103	3,732	4,133	4,652	5,011	5,356	5,405	5,414	5,428	5,436
(22)	Solar	GWh	2,235	2,419	3,103	3,732	4,133	4,652	5,011	5,356	5,405	5,414	5,428	5,436
(23)	**Other (Specify)**													
(24)	PC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(25)	Net Interchange	GWh	1,443	1,498	(9)	(28)	(34)	(34)	(30)	(34)	(10)	(34)	(32)	(33)
(26)	Purchased Energy from Non-Utility Generators	GWh	80	108	70	70	70	70	70	70	70	70	70	70
(27)	Other	GWh	0	(14)	(9)	(9)	(15)	(17)	(17)	(19)	(19)	(18)	(19)	(18)
(28)	**Net Energy for Load**	GWh	21,852	21,797	21,886	22,049	22,189	22,337	22,529	22,713	22,912	23,140	23,370	23,619

Notes:
Line (25) 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 (27).

Schedule 6.2

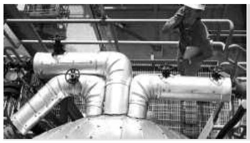
History and Forecast of Net Energy for Load by Fuel Source
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources	Unit	Actual 2024	Actual 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
(1)	Annual Firm Interchange	%	0.2	1.2	1.7	1.3	1.3	1.3	1.2	1.2	1.2	1.2	1.2	0.3
(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	%	0.3	0.2	1.0	1.2	1.0	0.9	0.9	0.9	0.8	0.8	0.8	0.8
(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)	RE	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	Distillate	%	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)	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
(12)	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
(13)	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
(14)	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
(15)	RE	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(16)	Natural Gas	%	82.4	80.2	82.9	80.5	79.0	76.9	75.5	74.2	74.2	74.5	74.7	75.8
(17)	ST	%	2.7	3.1	2.7	1.7	2.0	2.7	2.5	2.1	2.6	2.6	3.3	2.0
(18)	CC	%	79.4	76.2	78.8	78.2	76.6	73.7	72.3	70.8	70.0	70.7	70.2	72.1
(19)	GT	%	0.3	0.8	1.2	0.5	0.4	0.5	0.6	1.4	1.4	1.1	1.1	1.7
(20)	RE	%	0.0	0.1	0.1	0.0	0.0	0.1	0.1	0.0	0.1	0.0	0.0	0.0
(21)	Renewable	%	10.2	11.1	14.2	16.9	18.6	20.8	22.2	23.6	23.6	23.4	23.2	23.0
(22)	Solar	%	10.2	11.1	14.2	16.9	18.6	20.8	22.2	23.6	23.6	23.4	23.2	23.0
(23)	Other (Specify)													
(24)	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
(25)	Net Interchange	%	6.6	6.9	(0.0)	(0.1)	(0.2)	(0.2)	(0.1)	(0.1)	(0.0)	(0.1)	(0.1)	(0.1)
(26)	Purchased Energy from Non-Utility Generators	%	0.4	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
(27)	Other	%	0.0	(0.1)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
(28)	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 (25) 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 (27).

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 meet 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 and Battery Storage capacity and is researching the viability of additional renewable technologies. Additionally, the integration of conventional energy resources such as high technology combustion turbines, and the advanced hardware upgrades on the CTs at Polk 2 provide low-cost, reliable, and grid-friendly options for customers. 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 2026, TEC plans for 162 MW of cogeneration capacity operating in its service area.

Table IV-I

2026 Cogeneration Capacity Forecast	Capacity (MW)
Self-service [1]	101
Firm to Tampa Electric	0
As-Available to Tampa Electric	8
Export to other systems	53
Total	162

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

FIRM INTERCHANGE SALES AND PURCHASES

TEC has two (2) long-term firm purchase power agreements. The long-term agreements are with Pasco and Hillsborough Counties, and both are from waste-to-energy (WTE) facilities. The Pasco County (Pasco) agreement is for 18 MW and has a 10-year term, beginning January 2025 and continuing through December 2034. The Hillsborough County (Hillsborough) agreement is for 16 MW and has a 10-year term from August 2025 through July 2035. The company also has two (2) short-term agreements that provide firm capacity during the winter of 2026. The short-term purchases are (i) 150 MW from the Florida Municipal Power Agency (FMPA), mid-December 2025 through February 2026; and (ii) 200 MW from Orlando Utilities Commission, January through February 2026. These winter purchases, along with Pasco and Hillsborough, provide firm capacity for the winter 2026 period.

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 solar for its energy requirements. TEC has long-term 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 2026 with 82.9% natural gas, 14.2% solar, 1.0% coal, and around two (2) percent of other resources, such as non-firm purchases from the market, non-utility generators and Firm Interchange. 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 60%.

The installation of 1,424 megawatts of solar power by the end of 2025 enabled the company to continue to reduce its dependence on carbon-based fuels. About 11% of TEC's energy was fueled by the sun.

TEC's emission reduction activities also include:

1. The modernization of Big Bend Unit 1 to a combined cycle unit.
2. The retirements of Big Bend Unit 2 and Big Bend Unit 3.
3. The Polk Power Station combined-cycle project improved system reliability, efficiency, and reduced emissions system-wide.
4. The upgrade of gas path components on Bayside and Polk Power Station's combustion turbines increase output, efficiency and reliability while reducing fuel consumption.
5. Battery energy storage capacity that will capture low-cost generation and discharge when it's needed most.

2. Water Conservation

TEC is sensitive to water constraints in its service territory and works to minimize impacts, especially to groundwater, on all its properties. Solar generation requires no water. Approximately 98 percent of the water use in TEC power stations is to cool steam. The Big Bend and Bayside stations circulate large amounts of seawater from Tampa Bay for this cooling water; however, this water is simply returned to the bay, rather than consumed by the power stations. At Polk Power Station, an on-site freshwater reservoir provides a closed-loop system for cooling water. TEC has extensive diversion and collection systems at each of its power stations to collect rainwater and process water to maximize water reuse. TEC's Big Bend and Polk Power Station also receive reclaimed water from local municipalities to further reduce the use of potable water and groundwater for plant processes.

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. Bayside Power Station replaced the circulator pumps on Units 1 and 2 in 2023 and 2024 respectively, which included fish friendly screens and a fish return system. 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 remaining compliance requirements for Big Bend Station are to be determined and completed later.

FDEP's numeric nutrient regulations are ineffective 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 completed construction of a deep injection well system in December 2023 for disposal of FGD wastewater, bottom ash transport water, stormwater, and other process wastewaters, which means ELG are no longer applicable.

4. Solid Waste

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 was initiated in 2023 and the final phase of the project will be completed in 2025. The South Gypsum Storage Area Closure Project was completed as a component of the Big Bend Modernization in January 2020. On May 8, 2024, EPA finalized revisions to the 2015 rule, commonly referred to as the Legacy Impoundments and CCR Management Units (CCRMUs) Rule. The new rule regulates Impoundments that were still in existence at facilities no longer producing power as of October 2015 (not applicable to Tampa Electric) and requires utilities to evaluate their facilities beginning in 2025 to identify any past placements of CCRs in the environment, which are defined by the rule as CCRMUs. Tampa Electric began the required evaluations in 2025, which will be completed in 2026, after which groundwater monitoring and corrective actions could be required based on the results. There are no CCR units at the Polk or Bayside Power Stations regulated under the CCR 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)	(13)	(14)	(15)	(16)
	Total Installed Firm Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Winter Peak Demand	DSM	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance		Generation Only Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak	MW	% of Peak
2026	5,412	34	0	0	5,446	4,644	255	4,389	1,057	24%	0	1,057	24%	802	17%
2027	5,476	34	0	0	5,510	4,690	251	4,439	1,071	24%	0	1,071	24%	820	17%
2028	5,632	34	0	0	5,666	4,730	248	4,482	1,184	26%	0	1,184	26%	936	20%
2029	5,633	34	0	0	5,667	4,770	249	4,521	1,146	25%	0	1,146	25%	897	19%
2030	5,632	34	0	0	5,666	4,811	249	4,562	1,105	24%	0	1,105	24%	855	18%
2031	5,855	34	0	0	5,889	4,850	250	4,600	1,289	28%	0	1,289	28%	1,039	21%
2032	5,853	34	0	0	5,887	4,891	250	4,641	1,245	27%	0	1,245	27%	996	20%
2033	5,851	34	0	0	5,885	4,937	250	4,687	1,198	26%	0	1,198	26%	948	19%
2034	5,849	34	0	0	5,883	4,983	251	4,732	1,151	24%	0	1,151	24%	900	18%
2035	6,070	0	0	0	6,070	5,031	251	4,780	1,290	27%	0	1,290	27%	1,039	21%

Notes:
TEC utilizes a minimum 20 percent firm reserve margin criteria for the development of its Ten-Year Site Plans as shown on Column (14).
Values shown may be affected due to rounding.
93° F at time of Peak.

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)	(13)	(14)	(15)	(16)
	Total Installed Firm Capacity	Firm Capacity Import	Firm Capacity Export		Total Capacity Available	System Winter Peak Demand		System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance		Generation Only Reserve Margin After Maintenance	
Year	MW	MW	MW	QF MW	MW	MW	DSM MW	MW	MW	% of Peak	MW	MW	% of Peak	MW	% of Peak
2025-26	5,357	384	0	0	5,741	4,689	243	4,446	1,295	29%	0	1,295	29%	1,052	22%
2026-27	5,455	34	0	0	5,489	4,743	240	4,503	986	22%	0	986	22%	746	16%
2027-28	5,628	34	0	0	5,662	4,803	238	4,565	1,096	24%	0	1,096	24%	859	18%
2028-29	5,628	34	0	0	5,662	4,858	238	4,620	1,042	23%	0	1,042	23%	804	17%
2029-30	5,628	34	0	0	5,662	4,916	239	4,677	984	21%	0	984	21%	746	15%
2030-31	5,852	34	0	0	5,886	4,972	239	4,733	1,153	24%	0	1,153	24%	914	18%
2031-32	5,852	34	0	0	5,886	5,028	239	4,789	1,097	23%	0	1,097	23%	858	17%
2032-33	5,852	34	0	0	5,886	5,081	239	4,842	1,044	22%	0	1,044	22%	805	16%
2033-34	5,852	34	0	0	5,886	5,132	240	4,892	994	20%	0	994	20%	754	15%
2034-35	6,076	16	0	0	6,092	5,181	240	4,941	1,151	23%	0	1,151	23%	911	18%

Notes:
TEC utilizes a minimum 20 percent firm reserve margin criteria for the development of its Ten-Year Site Plans as shown on Column (14).
Values shown may be affected due to rounding.
31° F at time of Peak.

Schedule 7.2.1 *

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak (Weather Sensitivity)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Total Installed Firm Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Winter Peak Demand	DSM	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance		Generation Only Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak	MW	% of Peak
2025-26	5,357	384	0	0	5,741	4,896	243	4,653	1,088	23%	0	1,088	23%	845	17%
2026-27	5,455	34	0	0	5,489	4,952	240	4,712	777	16%	0	777	16%	537	11%
2027-28	5,628	34	0	0	5,662	5,016	238	4,778	883	18%	0	883	18%	646	13%
2028-29	5,628	34	0	0	5,662	5,074	238	4,836	826	17%	0	826	17%	588	12%
2029-30	5,628	34	0	0	5,662	5,135	239	4,896	765	16%	0	765	16%	527	10%
2030-31	5,852	34	0	0	5,886	5,194	239	4,955	931	19%	0	931	19%	692	13%
2031-32	5,852	34	0	0	5,886	5,252	239	5,013	873	17%	0	873	17%	634	12%
2032-33	5,852	34	0	0	5,886	5,308	239	5,069	817	16%	0	817	16%	578	11%
2033-34	5,852	34	0	0	5,886	5,361	240	5,121	765	15%	0	765	15%	525	10%
2034-35	6,076	16	0	0	6,092	5,413	240	5,173	919	18%	0	919	18%	679	13%

Notes:
Values shown may be affected due to rounding.
* For information purposes only
* 29° F at time of Peak.

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)
								Const.	Commercial	Expected	Gen. Max.	Firm Net Capability		
Plant	Unit		Unit	Fuel		Fuel Trans.		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Name	No.	Location	Type	Primary	Alternate	Primary	Alternate	Mo/Yr	Mo/Yr	Mo/Yr	kW	MW	MW	Status
2026														
Long Branch Solar [1]	1	Manatee	PV	SOLAR	NA	NA	NA	-	2/26	*	74,900	3.7	-	OP
Bayside Energy Storage Capacity	1	Hillsborough	BA	N/A	N/A	N/A	N/A	-	3/26	*	20,000	20.0	20.0	V
Polk 2 Enhancement Phase I	2	Polk	CC	NG	NA	PL	NA	-	12/26	*	78,000	59.5	78.0	P
Keene Branch Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/26	*	74,500	3.7	-	U
Mattaniah Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/26	*	52,000	2.6	-	U
Brewster Solar [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	12/26	*	40,000	0.6	-	U
Solar Degradation [2]	N/A											(2.0)	-	
									2026 Changes and Additions:			88.2	98.0	
2027														
Polk 2 Enhancement Phase II	2	Polk	CC	NG	NA	PL	NA	-	6/27	*	78,000	59.5	78.0	P
Future Battery Storage Capacity 1	1	Unknown	BA	N/A	N/A	N/A	N/A	-	10/27	*	20,000	20.0	20.0	P
Future Battery Storage Capacity 2	1	Unknown	BA	N/A	N/A	N/A	N/A	-	12/27	*	75,000	75.0	75.0	P
Curiosity Creek Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/27	*	38,800	0.6	-	P
Brewster Solar Phase II [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	12/27	*	34,500	0.5	-	P
Riverside II Solar [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/27	*	43,400	0.7	-	P
Harvest Sun Solar [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/27	*	74,500	1.1	-	P
Solar Degradation [2]	N/A											(2.0)	-	
									2027 Changes and Additions:			155.4	173.0	
2028														
Rising Sun Solar [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/28	*	74,500	1.1	-	P
Future Solar 1 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/28	*	74,500	1.1	-	P
Future Solar 2 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/28	*	74,500	1.1	-	P
Solar Degradation [2]	N/A											(2.0)	-	
									2028 Changes and Additions:			1.3	-	
2029														
Future Solar 3 [1,3]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/29	*	149,000	1.5	-	P
Solar Degradation [2]	N/A											(2.0)	-	
									2029 Changes and Additions:			(0.5)	-	

Notes:

* Undetermined

1 Solar MW values reflect capacity at time of peak. The firm capacity shows expected capacity values for the projected incremental solar additions.

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 Cont'd
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Const.	Commercial	Expected	Gen. Max.	Firm Net Capability		
Plant	Unit		Unit	Fuel		Fuel Trans.		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Name	No.	Location	Type	Primary	Alternate	Primary	Alternate	Mo/Yr	Mo/Yr	Mo/Yr	kW	MW	MW	Status
2030														
Future Solar 4 [1 3]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/30	*	149,000	1.5	-	P
Solar Degradation [2]	N/A											(2.0)	-	
									2030 Changes and Additions:			(0.5)	-	
2031														
Future CT 1	1	Unknown	CT	NG	NA	PL	N/A		1/31	*	224,000	223.0	224.0	P
Solar Degradation [2]	N/A											(2.0)	-	
									2031 Changes and Additions:			221.0	224.0	
2032														
Solar Degradation [2]	N/A											(2.0)	-	
									2032 Changes and Additions:			(2.0)	-	
2033														
Solar Degradation [2]	N/A											(2.0)	-	
									2033 Changes and Additions:			(2.0)	-	
2034														
Solar Degradation [2]	N/A											(2.0)	-	
									2034 Changes and Additions:			(2.0)	-	
2035														
Future CT 2	1	Unknown	CT	NG	NA	PL	N/A		1/35	*	224,000	223.0	224.0	P
Solar Degradation [2]	N/A											(2.0)	-	
									2035 Changes and Additions:			221.0	224.0	

Notes:

* Undetermined
1 Solar MW values reflect capacity at time of peak. The firm capacity shows expected capacity values for the projected incremental solar additions.
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 20)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Long Branch Solar	
(2)	Net Capability		
	A. Summer	74.9	MW-ac
	B. Winter	74.9	MW-ac
(3)	Technology Type	Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Jan-24	
	B. Commercial In-Service Date	Feb-26	
(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	659 Acres	
(9)	Construction Status	Operating	
(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	26%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW) [1,3]	1,650	
	Direct Construction Cost ($/kW)	1,557	
	AFUDC Amount ($/kW)	93.15	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	17.31	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.85	

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

Schedule 9
(Page 2 of 20)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Bayside Energy Storage Capacity	
(2)	Net Capability		
	A. Summer	20.0	MW-ac
	B. Winter	20.0	MW-ac
(3)	Technology Type	Battery	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Dec-24	
	B. Commercial In-Service Date	Mar-26	
(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	2 Acres	
(9)	Construction Status	Under Construction	
(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	N/A	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	20	
	Total Installed Cost (In-Service Year $/kW) [1]	2,056	
	Direct Construction Cost ($/kW)	1,957	
	AFUDC Amount ($/kW)	98.60	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	4.16	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	1.04	

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

Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Polk 2 Enhancement Phase 1	
(2)	Net Capability		
	A. Summer	59.5	MW
	B. Winter	78.0	MW
(3)	Technology Type	Combustion Turbine	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	May-26	
	B. Commercial In-Service Date	Dec-26	
(5)	Fuel		
	A. Primary Fuel	Natural Gas	
	B. Alternate Fuel	Distillate Fuel Oil	
(6)	Air Pollution Control Strategy	Dry-Low NOx, Water Injection	
(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	N/A	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	N/A	
	Total Installed Cost (In-Service Year $/kW) [1]	712	
	Direct Construction Cost ($/kW)	679	
	AFUDC Amount ($/kW)	32.06	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	-	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	1.23	

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

Schedule 9
(Page 4 of 20)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Keene Branch 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 [2]	Jan-25	
	B. Commercial In-Service Date	Dec-26	
(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	576 Acres	
(9)	Construction Status	Under Construction	
(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	26%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW) [1,3]	1,705	
	Direct Construction Cost ($/kW)	1,590	
	AFUDC Amount ($/kW)	114.40	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	17.31	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.75	

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land Lease costs not included

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Mattaniah Solar	
(2)	Net Capability		
	A. Summer	52.0	MW-ac
	B. Winter	52.0	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Jan-25	
	B. Commercial In-Service Date	Dec-26	
(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	322 Acres	
(9)	Construction Status	Under Construction	
(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	26%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW) [1,3]	1,647	
	Direct Construction Cost ($/kW)	1,574	
	AFUDC Amount ($/kW)	72.95	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	17.31	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.75	

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

Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Brewster Solar	
(2)	Net Capability		
	A. Summer	40.0	MW-ac
	B. Winter	40.0	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[2]	Jan-25	
	B. Commercial In-Service Date	Dec-26	
(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	174 Acres	
(9)	Construction Status	Under Construction	
(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	26%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW)[1,3]	1,810	
	Direct Construction Cost ($/kW)	1,730	
	AFUDC Amount ($/kW)	79.77	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	17.31	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.74	

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

Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Polk 2 Enhancement Phase 2	
(2)	Net Capability		
	A. Summer	59.5	MW
	B. Winter	78.0	MW
(3)	Technology Type	Combustion Turbine	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[2]	Oct-26	
	B. Commercial In-Service Date	Jun-27	
(5)	Fuel		
	A. Primary Fuel	Natural Gas	
	B. Alternate Fuel	Distillate Fuel Oil	
(6)	Air Pollution Control Strategy	Dry-Low NOx, Water Injection	
(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	N/A	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	N/A	
	Total Installed Cost (In-Service Year $/kW)[1]	712	
	Direct Construction Cost ($/kW)	679	
	AFUDC Amount ($/kW)	32.06	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	-	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	1.23	

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

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(1)	Plant Name and Unit Number	Future Battery Storage Capacity 1	
(2)	Net Capability		
	A. Summer	20.0	MW-ac
	B. Winter	20.0	MW-ac
(3)	Technology Type	Battery	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Dec-25	
	B. Commercial In-Service Date	Oct-27	
(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	3.7 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	N/A	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	20	
	Total Installed Cost (In-Service Year $/kW) [1]	2,068	
	Direct Construction Cost ($/kW)	1,963	
	AFUDC Amount ($/kW)	104.52	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	4.24	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	1.00	

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

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(1)	Plant Name and Unit Number	Future Battery Storage Capacity 2	
(2)	Net Capability		
	A. Summer	75.0	MW-ac
	B. Winter	75.0	MW-ac
(3)	Technology Type	Battery	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[2]	Dec-25	
	B. Commercial In-Service Date	Dec-27	
(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	12 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	N/A	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	20	
	Total Installed Cost (In-Service Year $/kW)[1]	1,513	
	Direct Construction Cost ($/kW)	1,433	
	AFUDC Amount ($/kW)	79.73	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	4.24	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.94	

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

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Curiosity Creek Solar	
(2)	Net Capability		
	A. Summer	38.8	MW-ac
	B. Winter	38.8	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Jan-26	
	B. Commercial In-Service Date	Dec-27	
(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	290 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	26%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW) [1,3]	2,168	
	Direct Construction Cost ($/kW)	1,962	
	AFUDC Amount ($/kW)	205.81	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	17.66	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.85	

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

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(1)	Plant Name and Unit Number	Brewster Ph. II Solar	
(2)	Net Capability		
	A. Summer	34.5	MW-ac
	B. Winter	34.5	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Jan-26	
	B. Commercial In-Service Date	Dec-27	
(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	218 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	26%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW) [1,3]	1,433	
	Direct Construction Cost ($/kW)	1,357	
	AFUDC Amount ($/kW)	75.64	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	17.68	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.63	

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

Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Riverside II Solar	
(2)	Net Capability		
	A. Summer	43.4	MW-ac
	B. Winter	43.4	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Jan-26	
	B. Commercial In-Service Date	Dec-27	
(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	216 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	26%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW) [1,3]	1,507	
	Direct Construction Cost ($/kW)	1,420	
	AFUDC Amount ($/kW)	86.76	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	17.68	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.69	

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

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(1)	Plant Name and Unit Number	Harvest Sun 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 [2]	Jan-26	
	B. Commercial In-Service Date	Dec-27	
(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	411 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	27%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW) [1, 3]	1,649	
	Direct Construction Cost ($/kW)	1,558	
	AFUDC Amount ($/kW)	91.35	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	17.66	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.71	

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land Lease costs not included

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(1)	Plant Name and Unit Number	Rising Sun 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 [2]	Jan-27	
	B. Commercial In-Service Date	Dec-28	
(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	551 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	27%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW) [1,3]	1,677	
	Direct Construction Cost ($/kW)	1,564	
	AFUDC Amount ($/kW)	113.62	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	18.01	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.70	

[1] Total installed cost includes transmission interconnection
[2] Construction schedule includes engineering design and permitting
[3] Land Lease costs not included

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 1	
(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 [2]	Jan-27	
	B. Commercial In-Service Date	Dec-28	
(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	27%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW) [1,3]	1,826	
	Direct Construction Cost ($/kW)	1,716	
	AFUDC Amount ($/kW)	110.45	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	18.01	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.74	

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

Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 2	
(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 [2]	Jan-27	
	B. Commercial In-Service Date	Dec-28	
(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	27%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW) [1,3]	1,796	
	Direct Construction Cost ($/kW)	1,702	
	AFUDC Amount ($/kW)	93.65	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	18.01	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.74	

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

Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 3 (Multiple Sites, each not to exceed 74.5 MW)	
(2)	Net Capability		
	A. Summer	149.0	MW-ac
	B. Winter	149.0	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Jan-28	
	B. Commercial In-Service Date	Dec-29	
(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	29%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW) [1,3]	1,807	
	Direct Construction Cost ($/kW)	1,660	
	AFUDC Amount ($/kW)	147.14	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	18.37	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.72	

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

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 4 (Multiple Sites, each not to exceed 74.5 MW)	
(2)	Net Capability		
	A. Summer	149.0	MW-ac
	B. Winter	149.0	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Jan-29	
	B. Commercial In-Service Date	Dec-30	
(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	29%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A	
(13)	Projected Unit Financial Data		
	Book Life (Years)	35	
	Total Installed Cost (In-Service Year $/kW) [1, 3]	1,827	
	Direct Construction Cost ($/kW)	1,639	
	AFUDC Amount ($/kW)	188.13	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	18.74	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.72	

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

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(1)	Plant Name and Unit Number	Future CT 1	
(2)	Net Capability		
	A. Summer	223.0	MW
	B. Winter	224.0	MW
(3)	Technology Type	Combustion Turbine	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	TBD	
	B. Commercial In-Service Date	Jan-31	
(5)	Fuel		
	A. Primary Fuel	Natural Gas	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	Dry-Low NOx	
(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)	6%	
	Forced Outage Factor (FOF)	2%	
	Equivalent Availability Factor (EAF)	92%	
	Resulting Capacity Factor	8%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	10,711	Btu/kWh
(13)	Projected Unit Financial Data		
	Book Life (Years)	40	
	Total Installed Cost (In-Service Year $/kW) [1]	1,851	
	Direct Construction Cost ($/kW) [1]	1,430	
	AFUDC Amount ($/kW)	300.57	
	Escalation ($/kW)	120.30	
	Fixed O&M (In-Service Year $/kW – Yr)	12.82	
	Variable O&M (In-Service Year $/MWh)	1.37	
	K-Factor	1.35	

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

Schedule 9
(Page 20 of 20)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future CT 2	
(2)	Net Capability		
	A. Summer	223.0	MW
	B. Winter	224.0	MW
(3)	Technology Type	Combustion Turbine	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	TBD	
	B. Commercial In-Service Date	Jan-35	
(5)	Fuel		
	A. Primary Fuel	Natural Gas	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	Dry-Low NOx	
(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)	6%	
	Forced Outage Factor (FOF)	2%	
	Equivalent Availability Factor (EAF)	92%	
	Resulting Capacity Factor	8%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	10,711	Btu/kWh
(13)	Projected Unit Financial Data		
	Book Life (Years)	40	
	Total Installed Cost (In-Service Year $/kW) [1]	2,099	
	Direct Construction Cost ($/kW)	1,430	
	AFUDC Amount ($/kW)	340.93	
	Escalation ($/kW)	328.43	
	Fixed O&M (In-Service Year $/kW – Yr)	13.87	
	Variable O&M (In-Service Year $/MWh)	1.48	
	K-Factor	1.35	

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

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines
As of December 31, 2025

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
Polk CC 2 Phase I****	Polk CC 2	-	-	-	230 kV	December 2026	-	Polk	None
Curiosity Creek Solar***	Curiosity Creek Solar - Curiosity Creek 230kV	1	Not Determined	0.01	230 kV	December 2027	Included in total installed cost on Schedule 9	Curiosity Creek Solar Station; Curiosity Creek Substation	None
Polk CC 2 Phase II****	Polk CC 2	-	-	-	230 kV	June 2027	-	Polk	None
Future CT 1	Unsited*	-	-	-	-	Jan 2031	-	-	-
Future CT 2	Unsited*	-	-	-	-	Jan 2035	-	-	-

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.
***** Interconnection Requests pertaining to a Large Generating Facility have been submitted for these units. Pending completion of the Interconnection Request studies, the information provided on Schedule 10 may change.

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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), Big Bend Power Station is located in Hillsborough County on Big Bend Road (See Figure VI-III) and MacDill Power station is located on the grounds of the MacDill Air Force Base (See Figure VI-IV) . The solar sites identified in Schedule 1 are spread across Hillsborough, Polk, and Pasco counties (See Figure VI-V). 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

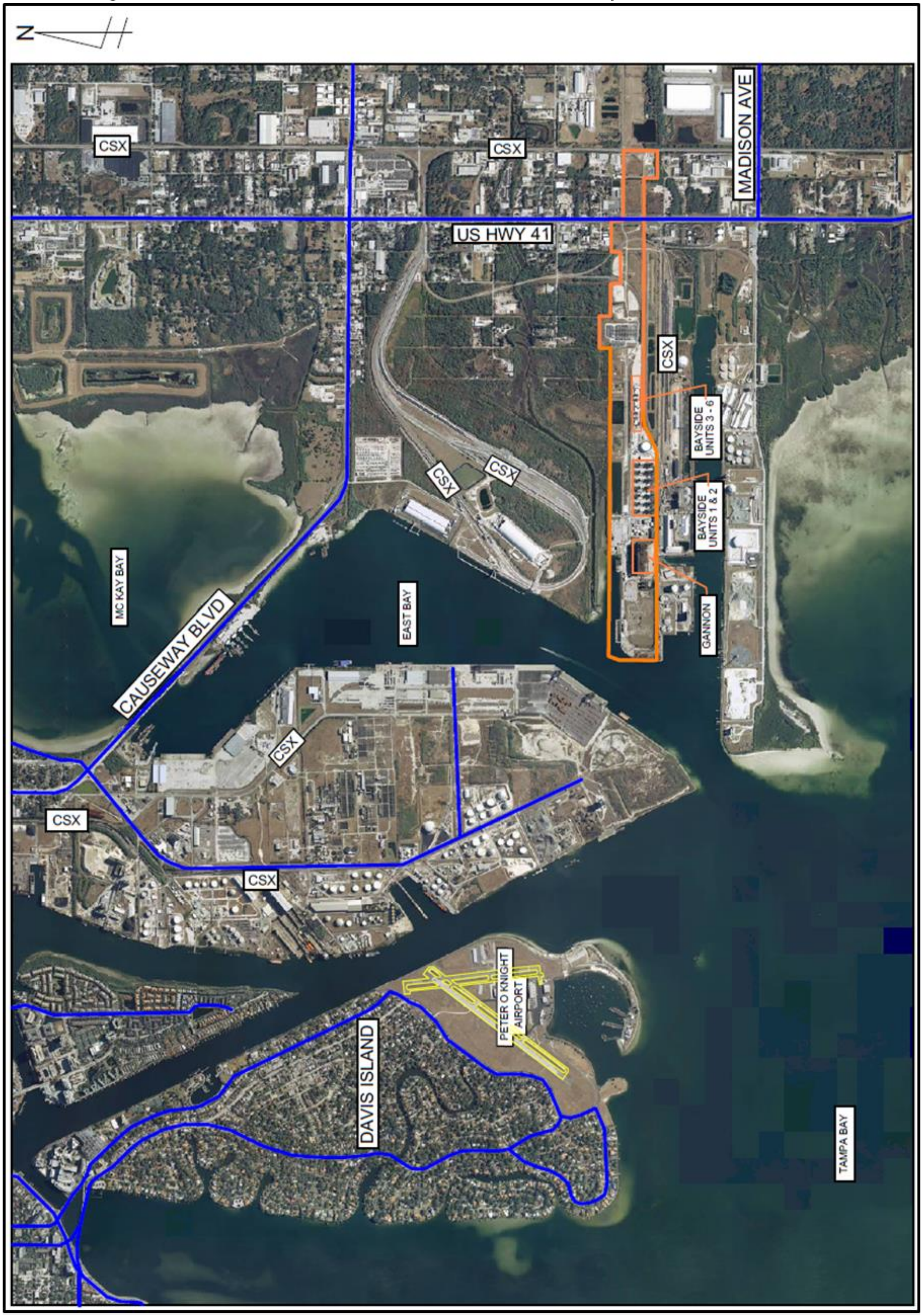


Figure VI-II: Site Location of Polk Power Station

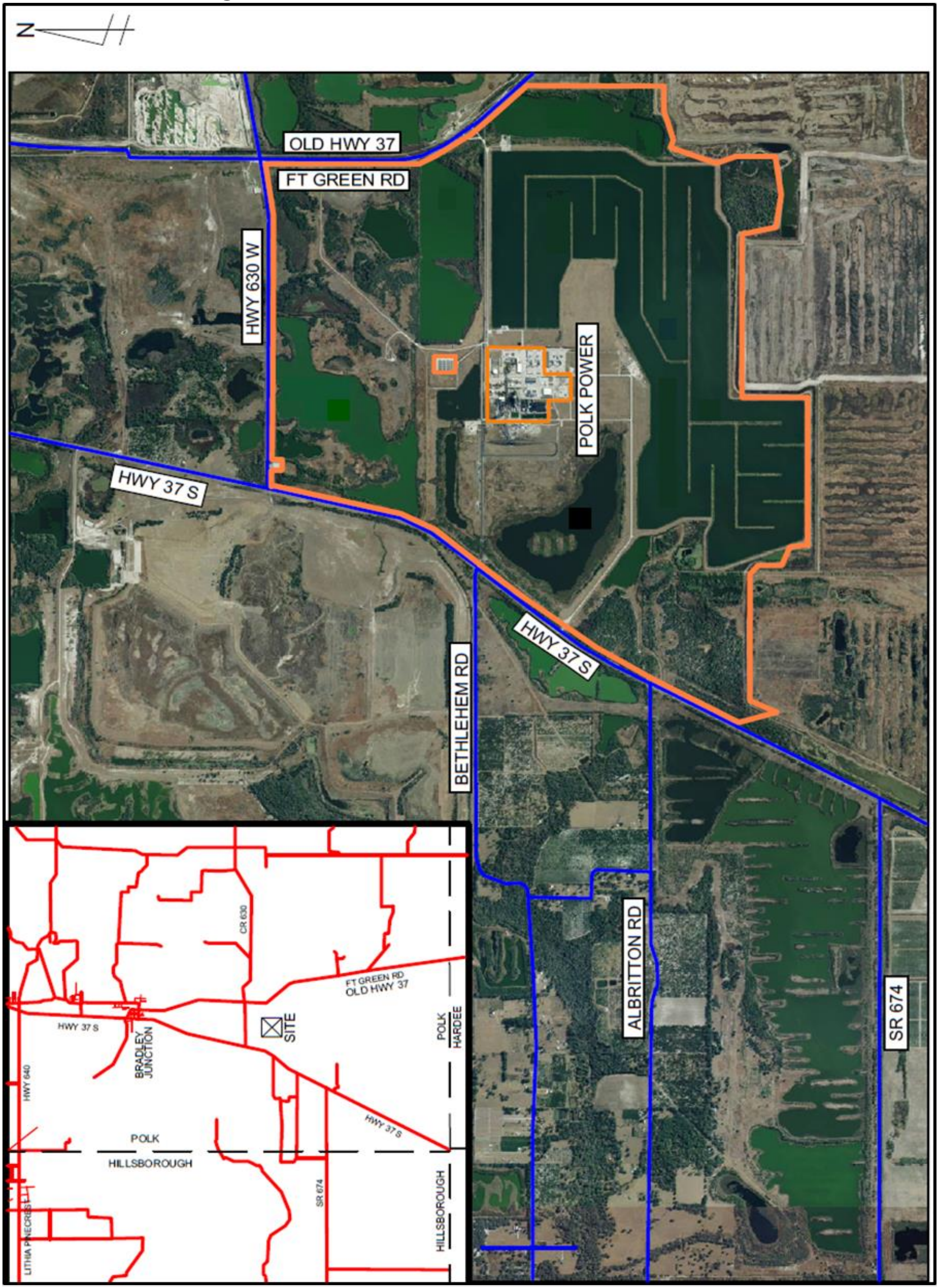
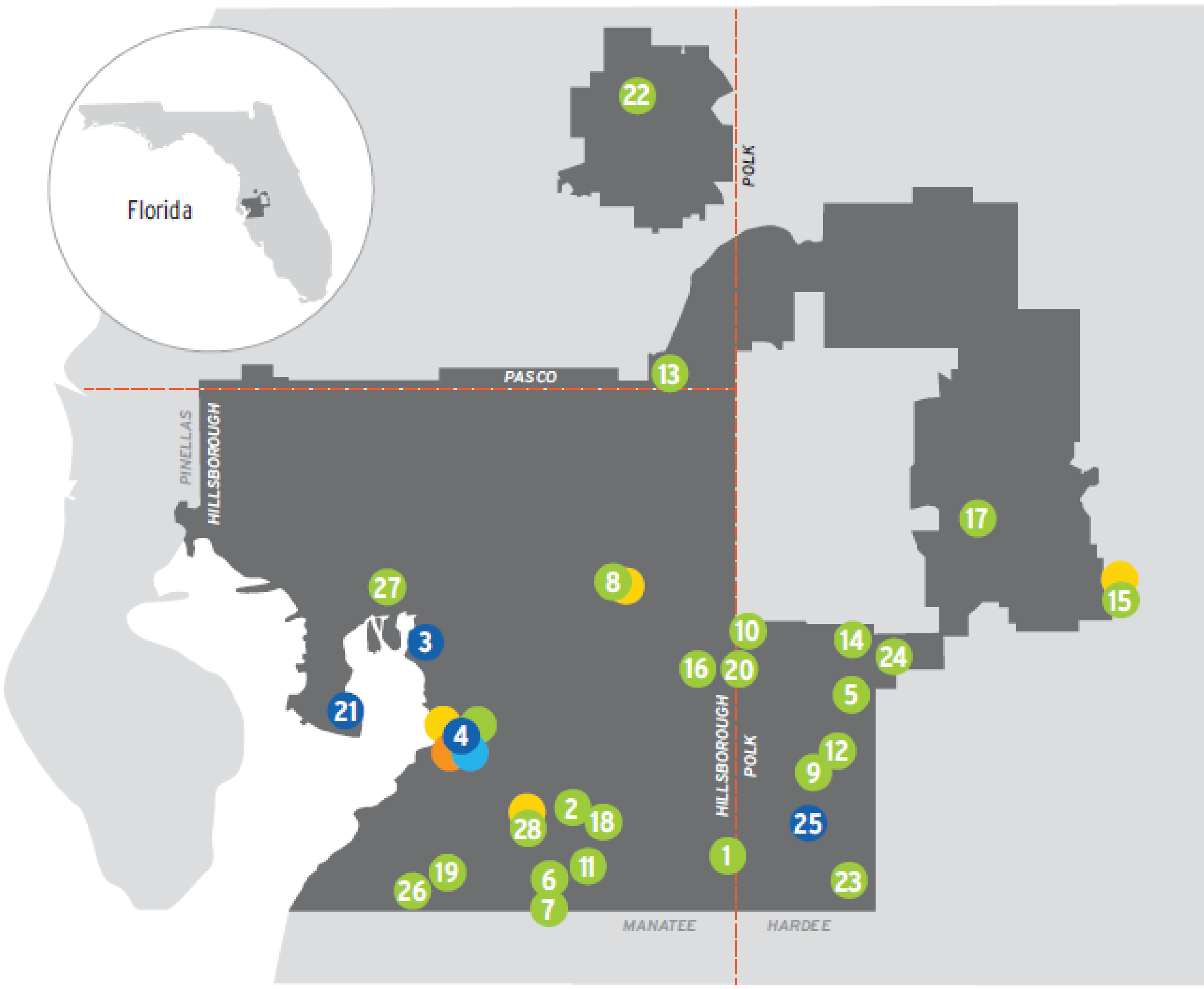


Figure VI-III: Site Location of Big Bend Power Station

Figure VI-IV: Site Location of MacDill Power Stations

Figure VI-V: Site Location of Solar Power Stations



1 Alafia	**8** Dover	**16** Laurel Oaks	**24** Peace Creek	Solar Generation
2 Balm	**9** Durrance	**17** Legoland Florida	**25** Polk	Floating Solar
3 Bayside	**10** English Creek	**18** Lithia	**26** Riverside	Agrivoltaics
4 Big Bend	**11** Grange Hall	**19** Little Manatee River	**27** Tampa International Airport	Power Station
5 Bonnie Mine	**12** Jamison	**20** Magnolia	**28** Wimauma	Storage
6 Bullfrog Creek	**13** Juniper	**21** MacDill Station		Service Area
7 Cottonmouth Ranch	**14** Lake Hancock	**22** Mountain View		
	15 Lake Mabel	**23** Payne Creek		