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April 1, 2025

VIA: ELECTRONIC FILING

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

Re: Review of Tampa Electric Company's 2025 Ten-Year Site Plan
Staff's First Data Request (Nos. 1-2)
Undocketed 20250000-OT

Dear Mr. Teitzman:

Attached for filing are Tampa Electric Company's responses to Staff's First Data Request (Nos. 1-2) regarding the company's 2025 Ten-Year Site Plan, propounded on February 20, 2025.

Thank you for your assistance in connection with this matter.

Sincerely,

Malcolm N. Means

MNM/bml
Attachments
cc: Greg Davis (GDavis@psc.state.fl.us)
Phillip Ellis (PEllis@psc.state.fl.us)
TECO Regulatory Department

General Items

1. Please provide an electronic copy of the Company's Ten-Year Site Plan (TYSP) for the current planning period (2025-2034) in PDF format.

Answer:

An electronic PDF copy of Tampa Electric's 2025 Ten-Year Site Plan was provided to Staff on April 1, 2025.

Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2025 to December 2034

April 1, 2025

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GLOSSARY OF TERMS

CODE IDENTIFICATION SHEET

Unit Type:	BA	=	Battery Storage
	CC	=	Combined Cycle
	CT	=	Combustion Turbine
	D	=	Diesel
	FS	=	Fossil Steam
	GT	=	Gas Turbine (includes jet engine design)
	HRSG	=	Heat Recovery Steam Generator
	IC	=	Internal Combustion
	IGCC	=	Integrated Gasification Combined Cycle
	PV	=	Photovoltaic
	ST	=	Steam Turbine
	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
Transportation:	PL	=	Pipeline
	RR	=	Railroad
	TK	=	Truck
	WA	=	Water
Other:	EV	=	Electric Vehicle(s)
	NA	=	Not Applicable

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Executive Summary

Tampa Electric Company's (TEC) 2025 Ten-Year Site Plan (TYSP) features plans to enhance electric generating capability as part of our efforts to meet projected incremental resource needs for 2025 through 2034. The 2025 TYSP provides the Florida Public Service Commission (FPSC) with assurance that TEC will be able to supply cost-effective options to ensure the delivery of adequate, safe, environmentally responsible, and reliable power to TEC's customers.

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

Investments in renewable generation enable fuel savings for customers, provide energy diversification, and continue TEC's commitment toward a lower carbon future. The future solar in this expansion plan provides energy diversity by 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 total committed solar capacity to nearly 2,700 MW or approximately 33% of the total summer installed capacity by the end of the study horizon.

In addition to enhancements of the solar, TEC plans to add approximately 195 MW of battery storage capacity and approximately 75 MW of capacity using reciprocating engines over the study horizon. These distributed resources provide peaking capacity and fuel savings. Furthermore, these distributed energy resources have the potential to provide system operational benefits, avoid transmission and distribution investment, and reduce line losses.

Finally, TEC has two 10-year-term power purchase agreements with Pasco County and Hillsborough County starting this year. The Pasco County (Pasco) agreement is for 18 MW, while the Hillsborough agreement is for 16 MW. Both agreements are from waste-to-energy (WTE) facilities.

TEC is also committed to pursuing cost-effective improvements on the existing generating fleet. In 2025, Polk Unit 1 will have its combustion turbine upgraded. After this upgrade, Polk Unit 1 will operate in simple-cycle mode providing operational flexibility to the system and avoiding expensive ongoing maintenance of the heat recovery steam generator and steam turbine. In 2026 and 2027, TEC will upgrade the combustion turbines on the Polk 2 unit adding low cost capacity, improved efficiency, and operational flexibility.

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 extreme conditions. These mitigations could include changes to unit dispatch to enhance reliability, switching to alternate fuels, extensive use of demand response, pursuing purchase power agreements, and in a worst-case scenario, interrupting customers to maintain grid stability. The company has also reviewed and updated its freeze protection plans for each of its generation stations and has implemented measures to mitigate equipment failure during these extreme temperatures.

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

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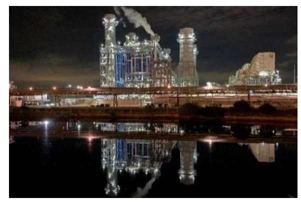
Chapter I

DESCRIPTION OF EXISTING FACILITIES

TEC has three (3) central generating stations that include steam units, combined cycle units and combustion turbine peaking units. Additionally, TEC has numerous solar facilities and growing 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

The 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 dual fuel natural gas / IGCC unit consisting of one (1) combustion turbine, one (1) HSRG, and one (1) steam turbine. The IGCC portion of this combined cycle was retired on December 31, 2024. 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.

Solar and Battery

As of December 31, 2024, TEC owns 1,350 MW_{AC} of solar throughout our territory. It consists of primarily single axis tracking PV solar array sites throughout Hillsborough, Pasco, and Polk counties, and several large-scale, fixed-tilt systems on rooftops, carports, and ground mount. Tampa Electric also has a 1.0 MW_{AC} floating solar project located at Big Bend Power Station, and an integrated renewable energy system, consisting of solar PV carports that charge commercial-sized batteries, which re-charge the company's growing EV fleet. TEC also has 27.6 MW of batteries with 12.6 MW at its Big Bend Solar site and 15 MW at its Dover Solar site.

Schedule 1
Existing Generating Facilities
As of December 31, 2024

(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	442,000	437	442
	CT 4		GT	NG	NA	PL	NA	NA	08/09	**	61,000	56	61
Big Bend Total											**1,623,000**	**1,548**	**1,623**
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		IGCC	NG	PC/BIT	PL	WA/TK	*	09/96	09/36	220,000	220	220
	2		CC	NG	DFO	PL	TK	*	01/17	**	1,200,000	1,061	1,200
Polk Total											**1,420,000**	**1,281**	**1,420**

Notes:
* Limited by environmental permit.
** Undetermined.
[1] Both assets (Battery and Solar) are co-located and restricted to a total output of 19.8 MW due to interconnection limits. For this reason, the battery capacity is not considered.
[2] Rating for Solar units are nameplate.
[3] Utility owned solar/battery less than 1 MW not included.

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Schedule 1 Cont'd
Existing Generating Facilities
As of December 31, 2024

(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
Solar Total [2,3]											1,349,600	1,350	1,350
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	**	12,600	12.6	12.6
Battery Total [3]											27,600	28	28
											TOTAL [1]	6,168	6,620

Notes:

* Limited by environmental permit.

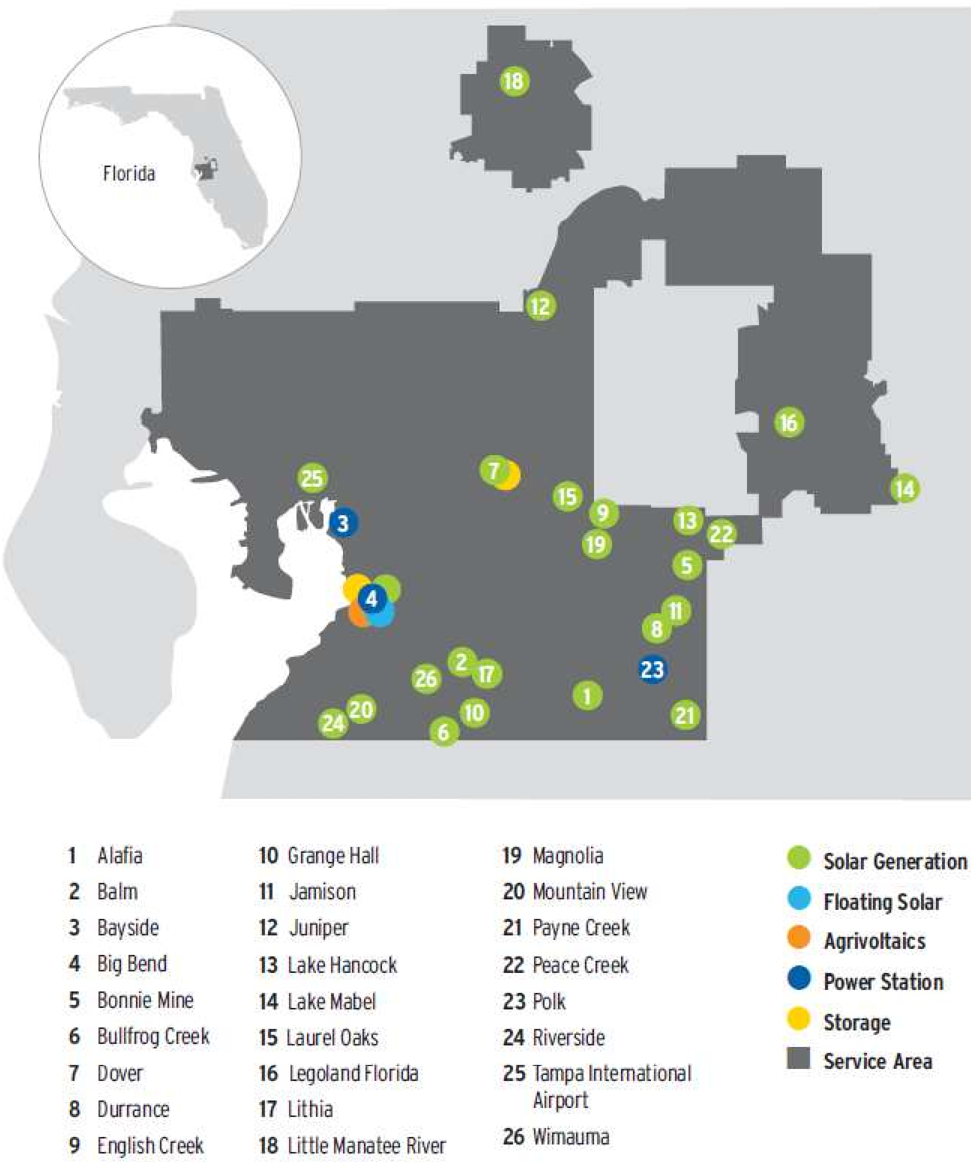
** Undetermined.

1 Both assets (Battery and Solar) are co-located and restricted to a total output of 19.8 MW due to interconnection limits. For this reason, the battery capacity is not considered.

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



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Chapter II

TAMPA ELECTRIC COMPANY FORECASTING METHODOLOGY

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

This chapter is devoted to describing TEC's forecasting methodologies and the major assumptions utilized in developing the 2025-2034 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the years 2025-2034.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2025-2034 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 Hillsborough County commercial employment.

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

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

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

3. Energy Multiregression Model

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

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

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

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

  Where:

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

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

Where:

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

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

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

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.

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

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

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

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

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

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

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 (PV)

Customer-owned solar forecasts are based on the historical number of PV installations and the average size of the PV systems installed in the service area. From this historical data, future penetration levels of PVs are based on assumptions used by the Energy Information Administration's (EIA) for the South Atlantic region; however, EIA did not prepare a forecast during 2024 due to a major revamping of their models, so we used their prior year's forecast. It is assumed Tampa Electric will no longer have to serve this portion of PV customers' load; therefore, the energy sales forecast is adjusted downward to incorporate the loss of this load.

7. Electric Vehicle (EV) Charging

The electric vehicle charging forecast process begins with an estimate of the number of EVs operating in Tampa Electric's service area. Future penetration levels of EVs are based on assumptions used by the Energy Information Administration's (EIA) for the South Atlantic region; however, EIA did not prepare a forecast during 2024 due to a revamping of their models, so we used a blend of the prior year's forecasts. The demand and energy consumption associated with EV charging is based on the National Renewable Energy Laboratory's [NREL] tool EVI-Pro Lite, using estimates for the Tampa-St.Pete-Clearwater MSA, reflecting diversity of charging at the system level..

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 2024, Tampa Electric continued operating within the FPSC approved 2020-2029 DSM Plan which consists of one renewable program, one research and development program, 15 residential and 20 commercial DSM Programs which support the approved FPSC goals which are reasonable, beneficial, and cost-effective to all customers as required by the FEECA. Also in 2024, the company filed its 2025-2034 DSM Plan. The following is a list that briefly describes the company's DSM programs:

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

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

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

4. Energy Education, Awareness and Agency Outreach - a program that provides opportunities for engaging and educating groups of customers, students on energy-efficiency and conservation in an organized setting and electric vehicles at participating high schools. Participants are provided with an energy savings kit which includes energy saving devices and supporting information appropriate for the audience.

5. Energy Star for New Multi-Family Residences - a rebate program that encourages the construction of new multi-family residences to meet the requirements to achieve the ENERGY STAR certified apartments and condominium label.

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

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

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

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

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

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

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

13. Residential Window Replacement – a rebate program that encourages existing residential customers to

install window upgrades in existing homes.

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

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

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

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

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

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

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

21. Street and Outdoor Lighting Conversion – A program that converts Tampa Electric's metal halide and high-pressure sodium street and outdoor lighting to energy efficient light emitting diode (LED) technology to reduce energy consumption and Tampa Electric's peak demand. Tampa Electric will recover the remaining unamortized costs in rate base with the eligible Non-LED luminaires. The company completed this conversion program in 2023.

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

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

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

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

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

27. Standby Generator – an incentive program designed to utilize the emergency generation capacity of

commercial/industrial facilities to reduce weather sensitive peak demand.

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

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

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

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

The programs listed above were developed to meet FPSC demand and energy goals established in Docket No. 20190021-EG, Order No. PSC-2019-0509-FOF-EU, Issued November 26, 2019. The 2024 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

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	12.3	2.6	473.1%	10.8	1.1	981.8%	21.2	1.8	1,177.8%
2016	7.7	4.1	187.8%	5.1	1.6	318.8%	13.2	3.5	377.1%
2017	6.9	5.2	132.7%	4.7	2.2	213.6%	14.9	4.8	310.4%
2018	8.0	6.5	123.0%	5.6	2.7	205.7%	17.1	6.1	280.3%
2019	8.3	7.6	108.8%	5.7	3.1	184.5%	16.8	6.9	243.2%
2020	3.5	7.6	45.5%	2.6	3.3	78.2%	8.9	7.4	120.3%
2021	4.5	8.0	55.8%	6.4	3.3	194.2%	16.4	7.7	213.1%
2022	9.5	7.4	127.8%	11.1	3.0	369.8%	30.4	6.9	441.0%
2023	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		14.0			7.9			24.8	

Commercial/ Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	8.1	1.2	675.0%	11.7	1.7	688.2%	12.5	3.9	320.5%
2016	2.9	1.3	223.1%	4.4	2.5	176.0%	17.8	6.0	296.7%
2017	9.2	1.6	575.0%	10.4	2.7	385.2%	30.2	8.0	377.5%
2018	13.0	1.7	767.1%	15.0	3.3	453.6%	33.7	9.2	365.9%
2019	22.4	1.6	1401.9%	29.2	3.3	885.9%	74.6	9.9	753.4%
2020	10.4	1.7	612.5%	11.8	3.5	336.0%	26.1	10.3	253.3%
2021	4.7	1.9	246.2%	5.6	3.6	156.8%	20.4	10.4	196.1%
2022	7.1	1.9	376.0%	12.3	3.3	372.2%	26.6	10.2	261.2%
2023	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		5.4			6.4			22.2	

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	20.4	3.8	536.8%	22.5	2.8	803.6%	33.7	5.7	591.2%
2016	10.6	5.4	196.3%	9.5	4.1	231.7%	31.0	9.5	326.3%
2017	16.1	6.8	236.8%	15.1	4.9	308.2%	45.1	12.8	352.3%
2018	21.0	8.2	256.5%	20.5	6.0	342.1%	50.8	15.3	331.8%
2019	30.7	9.2	333.7%	35.0	6.4	546.2%	91.4	16.8	543.9%
2020	13.9	9.3	149.1%	14.3	6.8	210.9%	35.0	17.7	197.7%
2021	9.1	9.9	92.3%	12.1	6.9	174.7%	36.8	18.1	203.3%
2022	16.6	9.3	178.5%	23.4	6.3	371.0%	57.1	17.1	333.8%
2023	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		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 point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Moody's Analytics supply population projections for Hillsborough County and Florida comparisons. BEBR's population growth for Hillsborough County was used to project future growth patterns in residential customers from 2025-2034. 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 (2025-2034), employment is assumed to rise at a 1.0% 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 2.8% average annual rate from 2025-2034. 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 2025-2034, real household income for Hillsborough County is expected to increase at a 1.2% 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 2025-2034, retail energy sales are projected to rise at a 0.9% annual rate. The primary contributor to growth is the residential class increasing at an annual rate of 1.2%.

2. Wholesale Energy

TEC has no scheduled firm wholesale power sales currently.

HISTORY AND FORECAST OF PEAK LOADS

Historical, base, high, and low scenario forecasts of peak loads for the summer and winter seasons are presented in Schedules 3.1 and 3.2, respectively. For the period of 2025-2034, TEC's base retail firm peak demand is expected to increase at an average annual rate of 1.0% in the summer and 1.1% in the winter.

Chapter III

INTEGRATED RESOURCE PLANNING PROCESSES

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

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

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

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

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

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

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

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

- Enhancements of existing assets at Polk and Bayside
- Completion of solar PV, reciprocating engines and batteries as presented in the 2024 rate case.
- Additional future utility-scale solar, batteries and combustion turbines over the study horizon.

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

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

FINANCIAL ASSUMPTIONS

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

- Per the Florida Administrative Code 25-6, an amount for AFUDC is recorded by the company during the construction phase of each capital project that meets the requirements. This rate is approved by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.
- The capitalization ratios represent the percentages of incremental long-term capital 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 1,350 MW_{AC} of solar PV generating capacity at 27 utility solar sites, which can produce enough electricity to power more than 223,000 homes. Over the next two years, the Company plans to expand with six new cost-effective, utility solar sites, adding 376 MW of additional solar capacity. By the end of 2026, Tampa Electric will have about 1,725 MW_{AC} of solar generating capacity – with the ability to produce enough energy to power more than 284,000 homes – or almost 18 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 2025 there is an additional 1,191 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 over 2,700 MW_{AC} of solar capacity by the end of the study horizon, which means approximately 25 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 2024, TEC's Renewable Energy Program has 1,009 customers purchasing over 1,754 blocks of renewable energy each month and there have been over 5,600 one-time blocks purchased since program inception.

The company's renewable generation portfolio is a mix of various technologies and renewable generation sources, including both large utility scale solar PV sites and smaller, company-owned community sited PV arrays that provide ample solar energy for the Renewable Energy Block Program. The smaller, community-sited PV arrays are currently installed at Middleton High School, the Manatee Viewing Center, Zoo Tampa at Lowry Park, LEGOLAND Florida's Imagination Zone, 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, 2024, there are 1466 customers interconnected with 13.995 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 nearly 30% 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 (ATC) Criteria

TEC adheres to the ATC calculation methodology described in the Attachment C of the Tampa Electric Company *Open Access Transmission Tariff FERC Electric Tariff*, Fourth Revised Volume No. 4 document, accessible at https://www.oasis.oati.com/woa/docs/TEC/TECdocs/Tariff___Fourth_Revised_Volume_No._4__effective_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:								
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
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
FORECAST:								
2025	1,586,736	2.5	10,351	768,577	13,467	6,386	82,749	77,173
2026	1,613,237	2.5	10,411	781,318	13,325	6,432	83,582	76,950
2027	1,639,557	2.5	10,470	793,972	13,187	6,469	84,414	76,637
2028	1,665,526	2.4	10,572	806,457	13,110	6,516	85,248	76,434
2029	1,690,680	2.4	10,712	818,551	13,087	6,572	86,088	76,337
2030	1,714,766	2.4	10,864	830,131	13,087	6,633	86,931	76,303
2031	1,737,855	2.4	11,022	841,231	13,102	6,699	87,778	76,319
2032	1,759,958	2.4	11,177	851,857	13,121	6,767	88,628	76,358
2033	1,781,051	2.4	11,327	861,998	13,140	6,832	89,483	76,353
2034	1,801,148	2.4	11,477	871,661	13,167	6,897	90,342	76,347

Notes:
December 31, 2024 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:								
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
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
FORECAST:								
2025	1,602,414	2.5	10,416	772,328	13,487	6,388	82,766	77,183
2026	1,637,189	2.5	10,543	788,965	13,363	6,436	83,618	76,965
2027	1,672,086	2.5	10,669	805,660	13,243	6,475	84,468	76,656
2028	1,706,930	2.5	10,842	822,330	13,185	6,524	85,321	76,460
2029	1,741,245	2.5	11,056	838,746	13,181	6,581	86,180	76,369
2030	1,774,757	2.5	11,284	854,779	13,201	6,645	87,044	76,340
2031	1,807,528	2.5	11,520	870,457	13,235	6,713	87,911	76,361
2032	1,839,554	2.5	11,756	885,778	13,272	6,784	88,782	76,406
2033	1,870,799	2.5	11,989	900,726	13,311	6,851	89,658	76,408
2034	1,901,263	2.5	12,226	915,301	13,357	6,918	90,541	76,406

Notes:
December 31, 2024 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:								
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
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
FORECAST:								
2025	1,571,135	2.5	10,285	764,826	13,448	6,384	82,731	77,164
2026	1,589,519	2.4	10,281	773,709	13,287	6,428	83,547	76,935
2027	1,607,505	2.4	10,273	782,398	13,130	6,463	84,360	76,617
2028	1,624,929	2.4	10,308	790,817	13,034	6,508	85,177	76,409
2029	1,641,345	2.4	10,378	798,749	12,992	6,562	85,997	76,306
2030	1,656,521	2.3	10,458	806,081	12,974	6,621	86,822	76,265
2031	1,670,544	2.3	10,543	812,856	12,970	6,686	87,649	76,276
2032	1,683,437	2.3	10,623	819,086	12,970	6,752	88,479	76,310
2033	1,695,196	2.3	10,697	824,768	12,970	6,815	89,314	76,300
2034	1,705,849	2.3	10,770	829,915	12,978	6,878	90,153	76,288

Notes:
December 31, 2024 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:							
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	2,024	1,608	1,259,094	0	0	1,771	19,186
2018	2,014	1,588	1,268,262	0	0	1,933	19,631
2019	2,021	1,516	1,332,913	0	0	1,939	19,783
2020	1,891	1,408	1,342,642	0	0	1,883	19,954
2021	2,122	1,382	1,535,835	0	0	1,886	20,093
2022	2,111	1,357	1,556,126	0	0	1,947	20,467
2023	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
FORECAST:							
2025	1,852	1,312	1,412,372	0	0	1,939	20,528
2026	1,846	1,309	1,409,579	0	0	1,948	20,636
2027	1,847	1,308	1,412,211	0	0	1,956	20,741
2028	1,848	1,306	1,415,060	0	0	1,965	20,901
2029	1,847	1,304	1,415,824	0	0	1,974	21,105
2030	1,844	1,303	1,415,374	0	0	1,983	21,325
2031	1,842	1,301	1,415,429	0	0	1,993	21,556
2032	1,840	1,300	1,415,806	0	0	2,002	21,786
2033	1,838	1,298	1,416,155	0	0	2,011	22,008
2034	1,836	1,296	1,416,588	0	0	2,021	22,231

Notes:
December 31, 2024 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:							
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	2,024	1,608	1,259,094	0	0	1,771	19,186
2018	2,014	1,588	1,268,262	0	0	1,933	19,631
2019	2,021	1,516	1,332,913	0	0	1,939	19,783
2020	1,891	1,408	1,342,642	0	0	1,883	19,954
2021	2,122	1,382	1,535,835	0	0	1,886	20,093
2022	2,111	1,357	1,556,126	0	0	1,947	20,467
2023	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
FORECAST:							
2025	1,852	1,310	1,414,031	0	0	1,939	20,596
2026	1,846	1,307	1,412,027	0	0	1,948	20,772
2027	1,847	1,304	1,416,108	0	0	1,956	20,947
2028	1,848	1,301	1,420,521	0	0	1,965	21,179
2029	1,847	1,298	1,422,842	0	0	1,974	21,458
2030	1,844	1,295	1,423,963	0	0	1,984	21,756
2031	1,842	1,292	1,425,578	0	0	1,993	22,068
2032	1,840	1,289	1,427,540	0	0	2,002	22,382
2033	1,838	1,286	1,429,486	0	0	2,012	22,690
2034	1,837	1,283	1,431,550	0	0	2,021	23,001

Notes:
December 31, 2024 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:							
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	2,024	1,608	1,259,094	0	0	1,771	19,186
2018	2,014	1,588	1,268,262	0	0	1,933	19,631
2019	2,021	1,516	1,332,913	0	0	1,939	19,783
2020	1,891	1,408	1,342,642	0	0	1,883	19,954
2021	2,122	1,382	1,535,835	0	0	1,886	20,093
2022	2,111	1,357	1,556,126	0	0	1,947	20,467
2023	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
FORECAST:							
2025	1,852	1,313	1,410,866	0	0	1,939	20,461
2026	1,846	1,312	1,406,697	0	0	1,947	20,501
2027	1,846	1,311	1,408,457	0	0	1,956	20,539
2028	1,848	1,311	1,409,517	0	0	1,965	20,629
2029	1,847	1,310	1,409,602	0	0	1,974	20,760
2030	1,844	1,310	1,407,409	0	0	1,983	20,906
2031	1,841	1,310	1,405,668	0	0	1,993	21,062
2032	1,840	1,309	1,405,318	0	0	2,002	21,216
2033	1,838	1,309	1,403,859	0	0	2,011	21,361
2034	1,836	1,309	1,402,489	0	0	2,020	21,504

Notes:
December 31, 2024 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:					
2015	0	1,098	20,105	8,168	718,713
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
FORECAST:					
2025	0	1,058	21,586	9,884	862,522
2026	0	1,063	21,699	9,955	876,165
2027	0	1,068	21,809	10,024	889,717
2028	0	1,075	21,977	10,092	903,104
2029	0	1,086	22,190	10,160	916,103
2030	0	1,097	22,421	10,228	928,592
2031	0	1,108	22,664	10,295	940,605
2032	0	1,120	22,906	10,362	952,147
2033	0	1,131	23,140	10,429	963,209
2034	0	1,142	23,374	10,497	973,796

Notes:
December 31, 2024 Status
*Includes sales to St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
RCID contract from 2016 to 2017.
**Utility Use and Losses include accrued sales.
***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
****Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.3

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

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
HISTORY:					
2015	0	1,098	20,105	8,168	718,713
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
FORECAST:					
2025	0	1,061	21,657	9,884	866,288
2026	0	1,070	21,842	9,955	883,845
2027	0	1,078	22,025	10,024	901,456
2028	0	1,090	22,269	10,092	919,044
2029	0	1,104	22,562	10,160	936,384
2030	0	1,119	22,875	10,228	953,346
2031	0	1,134	23,203	10,295	969,955
2032	0	1,150	23,532	10,362	986,211
2033	0	1,166	23,856	10,429	1,002,099
2034	0	1,182	24,183	10,497	1,017,622

Notes:
December 31, 2024 Status
*Includes sales to St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
RCID contract from 2016 to 2017.
**Utility Use and Losses include accrued sales.
***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
****Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Low 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:					
2015	0	1,098	20,105	8,168	718,713
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
FORECAST:					
2025	0	1,054	21,515	9,884	858,754
2026	0	1,056	21,557	9,955	868,523
2027	0	1,058	21,596	10,024	878,093
2028	0	1,061	21,690	10,092	887,397
2029	0	1,068	21,828	10,160	896,216
2030	0	1,075	21,982	10,228	904,441
2031	0	1,083	22,145	10,295	912,110
2032	0	1,090	22,307	10,362	919,236
2033	0	1,098	22,459	10,429	925,820
2034	0	1,105	22,609	10,497	931,874

Notes:
December 31, 2024 Status
*Includes sales to St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
RCID contract from 2016 to 2017.
**Utility Use and Losses include accrued sales.
***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
****Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 3.1

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

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation***	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
HISTORY:									
2015	4,248	0	4,248	111	21	142	102	88	3,784
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
FORECAST:									
2025	4,880	0	4,880	135	0	227	110	165	4,243
2026	4,943	0	4,943	135	0	248	110	172	4,278
2027	5,008	0	5,008	135	0	268	111	178	4,315
2028	5,081	0	5,081	134	0	289	111	185	4,362
2029	5,158	0	5,158	135	0	311	111	191	4,410
2030	5,235	0	5,235	135	0	332	111	197	4,460
2031	5,314	0	5,314	135	0	353	112	204	4,510
2032	5,390	0	5,390	134	0	374	112	210	4,560
2033	5,465	0	5,465	135	0	395	112	217	4,606
2034	5,537	0	5,537	135	0	416	113	223	4,650

Notes:
December 31, 2024 Status
2016, 2018, 2020, and 2022 Net Firm Demand is not coincident with system peak.
Notes prior to 2024
*Includes residential and commercial/industrial conservation.
**Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
***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) 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	4,248	0	4,248	111	21	142	102	88	3,784
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
FORECAST:									
2025	4,899	0	4,899	135	0	227	110	165	4,261
2026	4,980	0	4,980	135	0	248	110	172	4,315
2027	5,064	0	5,064	135	0	268	111	178	4,372
2028	5,157	0	5,157	134	0	289	111	185	4,438
2029	5,255	0	5,255	135	0	311	111	191	4,507
2030	5,354	0	5,354	135	0	332	111	197	4,578
2031	5,454	0	5,454	135	0	353	112	204	4,651
2032	5,552	0	5,552	134	0	374	112	210	4,722
2033	5,650	0	5,650	135	0	395	112	217	4,791
2034	5,748	0	5,748	135	0	416	113	223	4,861

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

Schedule 3.1

Forecast of Summer Peak Demand (MW)
Low Case

(1) 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	4,248	0	4,248	111	21	142	102	88	3,784
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
FORECAST:									
2025	4,863	0	4,863	135	0	227	110	165	4,225
2026	4,907	0	4,907	135	0	248	110	172	4,242
2027	4,953	0	4,953	135	0	268	111	178	4,261
2028	5,006	0	5,006	134	0	289	111	185	4,287
2029	5,063	0	5,063	135	0	311	111	191	4,315
2030	5,121	0	5,121	135	0	332	111	197	4,345
2031	5,178	0	5,178	135	0	353	112	204	4,375
2032	5,233	0	5,233	134	0	374	112	210	4,403
2033	5,287	0	5,287	135	0	395	112	217	4,428
2034	5,339	0	5,339	135	0	416	113	223	4,452

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

Schedule 3.2

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

(1) 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:									
2014/15	4,202	0	4,202	79	47	521	99	65	3390
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	3,213
FORECAST:									
2024/25	5,296	0	5,296	118	0	604	113	120	4,341
2025/26	5,374	0	5,374	118	0	621	113	126	4,396
2026/27	5,451	0	5,451	118	0	638	114	132	4,449
2027/28	5,531	0	5,531	118	0	657	114	137	4,505
2028/29	5,612	0	5,612	118	0	675	115	142	4,562
2029/30	5,693	0	5,693	118	0	693	115	148	4,619
2030/31	5,772	0	5,772	118	0	712	116	153	4,673
2031/32	5,849	0	5,849	118	0	730	116	159	4,726
2032/33	5,923	0	5,923	118	0	748	117	164	4,776
2033/34	5,996	0	5,996	118	0	767	117	170	4,825

Notes:

December 31, 2024 Status
2020/2021 and 2022/2023 Net Firm Demand is not coincident with system peak.

Notes prior to 2024

*Includes residential and commercial/industrial conservation.

**Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.

***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

all formulas except column 10

(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:									
2014/15	4,202	0	4,202	79	47	521	99	65	3,390
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
FORECAST:									
2024/25	5,315	0	5,315	118	0	604	113	120	4,361
2025/26	5,413	0	5,413	118	0	621	113	126	4,434
2026/27	5,510	0	5,510	118	0	638	114	132	4,508
2027/28	5,609	0	5,609	118	0	657	114	137	4,583
2028/29	5,712	0	5,712	118	0	675	115	142	4,662
2029/30	5,815	0	5,815	118	0	693	115	148	4,740
2030/31	5,915	0	5,915	118	0	712	116	153	4,817
2031/32	6,015	0	6,015	118	0	730	116	159	4,892
2032/33	6,114	0	6,114	118	0	748	117	164	4,967
2033/34	6,211	0	6,211	118	0	767	117	170	5,039

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

Schedule 3.2

Forecast of Winter Peak Demand (MW)
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
all formulas except column 10									
Year	Total *	Wholesale	Retail *	Interruptible	Residential Load Management	Residential Conservation**	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
HISTORY:									
2014/15	4,202	0	4,202	79	47	521	99	65	3,390
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
FORECAST:									
2024/25	5,278	0	5,278	118	0	604	113	120	4,324
2025/26	5,338	0	5,338	118	0	621	113	126	4,359
2026/27	5,396	0	5,396	118	0	638	114	132	4,394
2027/28	5,455	0	5,455	118	0	657	114	137	4,429
2028/29	5,516	0	5,516	118	0	675	115	142	4,466
2029/30	5,576	0	5,576	118	0	693	115	148	4,501
2030/31	5,633	0	5,633	118	0	712	116	153	4,535
2031/32	5,688	0	5,688	118	0	730	116	159	4,565
2032/33	5,741	0	5,741	118	0	748	117	164	4,594
2033/34	5,792	0	5,792	118	0	767	117	170	4,620

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

Schedule 3.3

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

(1) Year	(2) Total*	(3) Residential Conservation**	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale ***	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load **** Factor %
ACTUAL:								
2015	19,888	565	316	19,006	0	1,098	20,105	57.1
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	22,069	743	625	20,702	0	1,150	21,852	57.5
FORECAST:								
2025	21,932	778	626	20,528	0	1,058	21,586	53.9
2026	22,106	812	658	20,636	0	1,063	21,699	53.5
2027	22,274	844	688	20,741	0	1,068	21,809	53.2
2028	22,494	874	718	20,901	0	1,075	21,977	52.8
2029	22,757	905	748	21,105	0	1,086	22,190	52.8
2030	23,037	935	778	21,325	0	1,097	22,421	52.8
2031	23,329	965	808	21,556	0	1,108	22,664	52.7
2032	23,619	995	837	21,786	0	1,120	22,906	52.6
2033	23,901	1,026	867	22,008	0	1,131	23,140	52.7
2034	24,184	1,056	897	22,231	0	1,142	23,374	52.7

Notes:
December 31, 2024 Status
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
***Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
****Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

Schedule 3.3

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

(1) Year	(2) Total*	(3) Residential Conservation**	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load *** Factor %
HISTORY:								
2015	19,888	565	316	19,006	0	1,098	20,105	57.1
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	22,069	743	625	20,702	0	1,150	21,852	57.5
FORECAST:								
2025	22,000	778	626	20,596	0	1,061	21,657	53.8
2026	22,242	812	658	20,772	0	1,070	21,842	53.4
2027	22,480	844	688	20,947	0	1,078	22,025	53.0
2028	22,772	874	718	21,179	0	1,090	22,269	52.6
2029	23,111	905	748	21,458	0	1,104	22,562	52.6
2030	23,469	935	778	21,756	0	1,119	22,875	52.5
2031	23,841	965	808	22,068	0	1,134	23,203	52.4
2032	24,215	995	837	22,382	0	1,150	23,532	52.3
2033	24,583	1,026	867	22,690	0	1,166	23,856	52.4
2034	24,954	1,056	897	23,001	0	1,182	24,183	52.3

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

Schedule 3.3

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

(1) 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:								
2015	19,888	565	316	19,006	0	1,098	20,105	57.1
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	22,069	743	625	20,702	0	1,150	21,852	57.5
FORECAST:								
2025	21,865	778	626	20,461	0	1,054	21,515	53.9
2026	21,971	812	658	20,501	0	1,056	21,557	53.6
2027	22,071	844	688	20,539	0	1,058	21,596	53.3
2028	22,221	874	718	20,629	0	1,061	21,690	53.0
2029	22,413	905	748	20,760	0	1,068	21,828	53.0
2030	22,619	935	778	20,906	0	1,075	21,982	53.0
2031	22,835	965	808	21,062	0	1,083	22,145	53.0
2032	23,049	995	837	21,216	0	1,090	22,307	52.9
2033	23,254	1,026	867	21,361	0	1,098	22,459	53.1
2034	23,457	1,056	897	21,504	0	1,105	22,609	53.2

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

Schedule 4
Base Case

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST		FORECAST	
	2024		2025		2026	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,029	1,527	4,572	1,585	4,627	1,594
February	2,709	1,364	3,481	1,432	3,523	1,440
March	3,208	1,568	3,521	1,590	3,562	1,597
April	3,553	1,600	3,628	1,652	3,655	1,660
May	4,220	2,142	4,026	1,912	4,053	1,922
June	4,323	2,142	4,378	2,076	4,413	2,088
July	4,318	2,249	4,454	2,171	4,492	2,184
August	4,305	2,287	4,488	2,207	4,523	2,220
September	4,232	2,122	4,263	2,000	4,304	2,011
October	3,956	1,663	3,951	1,879	3,980	1,888
November	3,567	1,643	3,483	1,514	3,523	1,521
December	2,935	1,545	3,919	1,569	3,964	1,576
TOTAL		21,852		21,586		21,699

Notes:
December 31, 2024 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	
	2024		2025		2026	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,029	1,527	4,591	1,590	4,665	1,604
February	2,709	1,364	3,495	1,437	3,550	1,449
March	3,208	1,568	3,535	1,594	3,590	1,606
April	3,553	1,600	3,642	1,657	3,683	1,670
May	4,220	2,142	4,042	1,918	4,086	1,934
June	4,323	2,142	4,396	2,083	4,448	2,102
July	4,318	2,249	4,472	2,179	4,529	2,199
August	4,305	2,287	4,506	2,215	4,560	2,235
September	4,232	2,122	4,281	2,007	4,339	2,025
October	3,956	1,663	3,967	1,885	4,012	1,901
November	3,567	1,643	3,497	1,519	3,551	1,531
December	2,935	1,545	3,935	1,574	3,995	1,586
TOTAL		21,852		21,657		21,842

Notes:
December 31, 2024 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	
	2024		2025		2026	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,029	1,527	4,554	1,580	4,590	1,584
February	2,709	1,364	3,468	1,428	3,495	1,431
March	3,208	1,568	3,507	1,585	3,535	1,587
April	3,553	1,600	3,614	1,647	3,626	1,650
May	4,220	2,142	4,010	1,906	4,021	1,909
June	4,323	2,142	4,361	2,069	4,377	2,074
July	4,318	2,249	4,436	2,163	4,456	2,168
August	4,305	2,287	4,470	2,200	4,487	2,204
September	4,232	2,122	4,246	1,993	4,269	1,997
October	3,956	1,663	3,935	1,872	3,947	1,875
November	3,567	1,643	3,469	1,510	3,496	1,512
December	2,935	1,545	3,904	1,564	3,933	1,567
TOTAL		21,852		21,515		21,557

Notes:
December 31, 2024 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 2023	Actual 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	Nuclear	Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal	1000 Ton	367	26	220	277	272	226	272	193	252	226	243	171
(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	6	9	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	6	9	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	126,239	126,867	127,834	120,282	117,016	113,988	112,366	112,655	111,810	113,614	114,902	115,222
(16)	ST	1000 MCF	5,295	6,632	4,583	760	1,036	710	1,012	768	881	942	1,685	743
(17)	CC	1000 MCF	120,717	119,510	121,336	117,385	114,821	112,443	110,412	110,158	108,314	110,707	110,295	111,829
(18)	GT	1000 MCF	227	714	1,597	1,818	973	634	791	1,456	2,442	1,854	2,701	2,486
(20)	RE	1000 MCF	0	11	318	319	185	200	152	273	172	111	220	164
(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.

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 2023	Actual 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	Annual Firm Interchange	GWh	21	33	314	281	281	282	281	281	281	282	281	281
(2)	Nuclear	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal	GWh	769	58	419	526	516	429	516	367	477	429	461	323
(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	2	4	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	2	4	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	17,814	17,999	18,194	17,497	17,113	16,991	16,659	16,685	16,507	16,622	16,652	16,864
(17)	ST	GWh	473	582	401	61	89	59	86	65	73	81	145	63
(18)	CC	GWh	17,323	17,352	17,473	17,236	16,918	16,854	16,489	16,458	16,205	16,370	16,246	16,569
(19)	GT	GWh	18	64	277	157	81	51	64	125	206	156	231	210
(20)	RE	GWh	0	1	43	43	25	27	20	37	23	15	30	22
(21)	Renewable	GWh	1,748	2,235	2,540	3,340	3,848	4,237	4,699	5,042	5,368	5,540	5,711	5,870
(22)	Solar	GWh	1,748	2,235	2,540	3,340	3,848	4,237	4,699	5,042	5,368	5,540	5,711	5,870
(23)	Other (Specify)													
(24)	PC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(25)	Net Interchange	GWh	1,315	1,443	29	(32)	(34)	(39)	(40)	(27)	(40)	(40)	(36)	(36)
(26)	Purchased Energy from Non-Utility Generators	GWh	97	80	96	96	96	97	96	96	96	97	96	96
(27)	Other	GWh	0	0	(6)	(9)	(11)	(20)	(21)	(23)	(25)	(24)	(25)	(24)
(28)	Net Energy for Load	GWh	21,767	21,852	21,586	21,699	21,809	21,977	22,190	22,421	22,664	22,906	23,140	23,374

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 2023	Actual 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	Annual Firm Interchange	%	0.1	0.2	1.5	1.3	1.3	1.3	1.3	1.3	1.2	1.2	1.2	1.2
(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	%	3.5	0.3	1.9	2.4	2.4	2.0	2.3	1.6	2.1	1.9	2.0	1.4
(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	%	0.01	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	%	0.01	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	%	81.8	82.4	84.3	80.6	78.5	77.3	75.1	74.4	72.8	72.6	72.0	72.1
(17)	ST	%	2.2	2.7	1.9	0.3	0.4	0.3	0.4	0.3	0.3	0.4	0.6	0.3
(18)	CC	%	79.6	79.4	80.9	79.4	77.6	76.7	74.3	73.4	71.5	71.5	70.2	70.9
(19)	GT	%	0.1	0.3	1.3	0.7	0.4	0.2	0.3	0.6	0.9	0.7	1.0	0.9
(20)	RE	%	0.0	0.0	0.2	0.2	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1
(21)	Renewable	%	8.0	10.2	11.8	15.4	17.6	19.3	21.2	22.5	23.7	24.2	24.7	25.1
(22)	Solar	%	8.0	10.2	11.8	15.4	17.6	19.3	21.2	22.5	23.7	24.2	24.7	25.1
(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	%	6.0	6.6	0.1	(0.1)	(0.2)	(0.2)	(0.3)	(0.2)	(0.3)	(0.2)	(0.2)	(0.2)
(26)	Purchased Energy from Non-Utility Generators	%	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
(27)	Other	%	0.0	0.0	(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 capacity and is researching the viability of additional renewable technologies. The completion of the Big Bend Power Station modernization through the repowering of Unit 1 to a 2x1 combined cycle unit, the retirement of Unit 2 and Unit 3, and the advanced hardware upgrades on the CTs at Polk 2 provide low-cost, reliable, and grid-friendly options for customers. Additionally, distributed energy resources such as batteries and reciprocating engines provide reliability and resiliency to our system. The operating and cost parameters are shown in Schedule 9 for proposed generating facilities.

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

COGENERATION

In 2025, TEC plans for 206 MW of cogeneration capacity operating in its service area.

Table IV-I **2025 Cogeneration Capacity Forecast**	**Capacity (MW)**
Self-service [1]	145
Firm to Tampa Electric	0
As-available to Tampa Electric	6
Export to other systems	55
Total	206

[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 as well but is still pending Commission approval. If approved by the Commission, the purchase would begin as early as March 2025 and continue through February 2035. The company also has three (3) short-term agreements that provide firm capacity during the winter of 2025. The short-term purchases are (i) 100 MW from the Florida Municipal Power Agency (FMPA), December 2024 through February 2025; (ii) 150 MW from Orlando Utilities Commission, January through February 2025; and (iii) 200 MW from Seminole Electric Cooperative (SEC), December 2024 through February 2025. These winter purchases, along with Pasco, provide firm capacity for the winter 2025 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 2025 with 84.3% natural gas, 11.8% solar, 1.9% 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

Air Quality

TEC continually strives to reduce emissions from its generating facilities, and since 2000, has reduced sulfur dioxide, nitrogen oxide, particulate matter, and mercury emissions by 96% or more. Carbon emissions have also been reduced by more than 50%.

The installation of 1,350 megawatts of solar power by the end of 2024 enabled the company to continue to reduce its dependence on carbon-based fuels. 10% of TEC's energy was fueled by the sun.

TEC's emission reduction activities also include:

1. Completed the modernization of Big Bend Unit 1 combined cycle unit and retired Unit 2.
2. The retirement of Big Bend Unit 3 in April of 2023.
3. The Polk Power Station combined-cycle project improved system reliability and efficiency, and reduced emissions system-wide.

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

5. Energy storage capacity that will capture low-cost generation and discharge when it's needed most.

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.

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

The final Effluent Limitations Guidelines (ELG) were published on November 3, 2015. The ELGs establish limits for wastewater discharges from flue gas desulfurization (FGD) processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals, gasification processes, and flue gas mercury controls. Big Bend 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.

Solid Waste

The Coal Combustion Residuals Rule (CCR) became effective on October 19, 2015. The former Big Bend Unit #4 Economizer Ash & Pyrites Pond System (EAPPS), converted Units 1-3 West Slag Disposal Pond (WSDP) and North Gypsum Stackout Area (NGSA) were covered by this rule. Three ECRC projects were proposed and approved by the Commission for these operating units to comply with the CCR Rule requirements, as follows. The WSDP was remediated and lined in 2020 to allow for continued storm water storage and the EAPPS

Closure Project was completed in 2021 by removing and disposing of the CCRs offsite and restoring the site. Phase III of the NGSA Drainage Enhancements Project were 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 will perform the required evaluations in 2025 and 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)
Year	Total Installed Firm Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2025	5,364	34	0	0	5,398	4,243	1,155	27%	0	1,155	27%
2026	5,427	34	0	0	5,461	4,278	1,183	28%	0	1,183	28%
2027	5,493	34	0	0	5,527	4,315	1,211	28%	0	1,211	28%
2028	5,648	34	0	0	5,682	4,362	1,319	30%	0	1,319	30%
2029	5,649	34	0	0	5,683	4,410	1,273	29%	0	1,273	29%
2030	5,648	34	0	0	5,682	4,460	1,223	27%	0	1,223	27%
2031	5,869	34	0	0	5,903	4,510	1,393	31%	0	1,393	31%
2032	5,868	34	0	0	5,902	4,560	1,342	29%	0	1,342	29%
2033	5,867	34	0	0	5,901	4,606	1,295	28%	0	1,295	28%
2034	5,866	34	0	0	5,900	4,650	1,249	27%	0	1,249	27%

Values shown may be affected due to rounding.

Schedule 7.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Firm Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2024-25	5,283	468	0	0	5,751	4,341	1,409	32%	337	1,072	25%
2025-26	5,379	34	0	0	5,413	4,396	1,017	23%	0	1,017	23%
2026-27	5,422	34	0	0	5,456	4,449	1,007	23%	0	1,007	23%
2027-28	5,560	34	0	0	5,594	4,505	1,089	24%	0	1,089	24%
2028-29	5,560	34	0	0	5,594	4,562	1,032	23%	0	1,032	23%
2029-30	5,560	34	0	0	5,594	4,619	975	21%	0	975	21%
2030-31	5,807	34	0	0	5,841	4,673	1,168	25%	0	1,168	25%
2031-32	5,807	34	0	0	5,841	4,726	1,115	24%	0	1,115	24%
2032-33	5,807	34	0	0	5,841	4,776	1,065	22%	0	1,065	22%
2033-34	5,807	34	0	0	5,841	4,825	1,016	21%	0	1,016	21%

Values shown may be affected due to rounding.

Schedule 7.2.1*

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Firm Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2024-25	5,283	468	0	0	5,751	4,540	1,210	27%	337	873	19%
2025-26	5,379	34	0	0	5,413	4,599	814	18%	0	814	18%
2026-27	5,422	34	0	0	5,456	4,655	801	17%	0	801	17%
2027-28	5,560	34	0	0	5,594	4,714	880	19%	0	880	19%
2028-29	5,560	34	0	0	5,594	4,774	820	17%	0	820	17%
2029-30	5,560	34	0	0	5,594	4,834	760	16%	0	760	16%
2030-31	5,807	34	0	0	5,841	4,891	950	19%	0	950	19%
2031-32	5,807	34	0	0	5,841	4,946	895	18%	0	895	18%
2032-33	5,807	34	0	0	5,841	4,999	842	17%	0	842	17%
2033-34	5,807	34	0	0	5,841	5,050	791	16%	0	791	16%

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)
				Fuel		Fuel Trans.		Const.	Commercial	Expected	Gen. Max.	Firm Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate kW	Summer MW	Winter MW	Status
2025														
South Tampa Resilience Project Phase I	1	Hillsborough	IC	NG	NA	PL	N/A	-	2/25	*	37,600	37.6	37.6	OP
Lake Mabel Energy Storage Capacity	1	Polk	BA	N/A	NA	N/A	N/A	-	3/25	*	40,000	40.0	40.0	V
Wimauma Energy Storage Capacity	1	Hillsborough	BA	N/A	N/A	N/A	N/A	-	3/25	*	40,000	40.0	40.0	V
Big Bend	4	Hillsborough	ST	NG	BIT	PL	WA/RR	-	4/25	*	442,000	(57.0)	(62.0)	OT
Polk Unit 1 Simple Cycle Conversion	1	Polk	CT	NG	N/A	PL	N/A	-	6/25	*	203,000	(30.0)	(17.0)	P
South Tampa Resilience Project Phase II	1	Hillsborough	IC	NG	NA	PL	N/A	-	12/25	*	37,600	37.6	37.6	V
Bayside Energy Storage Capacity	1	Hillsborough	BA	N/A	N/A	N/A	N/A	-	12/25	*	20,000	20.0	20.0	P
Long Branch Solar [1]	1	Manatee	PV	SOLAR	NA	NA	NA	-	12/25	*	74,500	3.7	-	U
Cottonmouth Ranch Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/25	*	74,500	3.7	-	U
Solar Degradation [2]	N/A											(2.0)	-	
											2025 Changes and Additions:	93.7	96.2	
2026														
Polk 2 Enhancement Phase I	2	Polk	CC	NG	NA	PL	NA	-	11/26	*	43,000	59.5	43.0	P
Keene Branch Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/26	*	74,500	3.7	-	P
Curiosity Creek Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/26	*	54,300	2.7	-	P
Brewster Solar [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	12/26	*	42,700	0.6	-	P
Mattaniah Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/26	*	55,000	0.8	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2026 Changes and Additions:	65.4	43.0	
2027														
Polk 2 Enhancement Phase II	2	Polk	CC	NG	NA	PL	NA	-	6/27	*	43,000	59.5	43.0	P
Future Battery Storage 1	1	Unknown	BA	N/A	N/A	N/A	N/A	-	10/27	*	20,000	20.0	20.0	P
Brewster Solar Phase II	1	Polk	PV	SOLAR	NA	NA	NA	-	12/27	*	15,600	0.2	-	P
Future Solar 1 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/27	*	74,500	1.1	-	P
Future Solar 2 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/27	*	74,500	1.1	-	P
Future Battery Storage 2	1	Unknown	BA	N/A	N/A	N/A	N/A	-	12/27	*	75,000	75.0	75.0	P
Solar Degradation [2]	N/A											(2.0)	-	
											2027 Changes and Additions:	155.0	138.0	

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 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)
					Fuel		Fuel Trans.		Const.	Commercial	Expected	Gen. Max.	Firm Net Capability		
	Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate kW	Summer MW	Winter MW	Status
2028															
	Future Solar 3 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/28	*	74,500	1.1	-	P
	Future Solar 4 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/28	*	55,000	0.8	-	P
	Future Solar 5 [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:	1.1	-	
2029															
	Future Solar 6 [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)	-	
2030															
	Future Solar 7 [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	Unknown	CT	NG	NA	PL	N/A	-	1/31	*	247,000	222.0	247.0	P
	Future Solar 8 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/31	*	74,500	0.7	-	P
	Solar Degradation [2]	N/A											(2.0)	-	
												2031 Changes and Additions:	220.8	247.0	
2032															
	Future Solar 9 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/32	*	74,500	0.7	-	P
	Solar Degradation [2]	N/A											(2.0)	-	
												2032 Changes and Additions:	(1.2)	-	

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
2033														
Future Solar 10 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/33	*	74,500	0.7	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2033 Changes and Additions:	(1.2)	-	
2034														
Future Solar 11 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/34	*	74,500	0.7	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2034 Changes and Additions:	(1.2)	-	

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
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	South Tampa Resilience Project Phase I	
(2)	Net Capability		
	A. Summer	37.6	MW
	B. Winter	37.6	MW
(3)	Technology Type	Engine	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Dec-22	
	B. Commercial In-Service Date	Feb-25	
(5)	Fuel		
	A. Primary Fuel	Natural Gas	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	Selective Catalytic Reduction (SCR)	
(7)	Cooling Method	Close Loop cooling	
(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)	2%	
	Forced Outage Factor (FOF)	2%	
	Equivalent Availability Factor (EAF)	96%	
	Resulting Capacity Factor	8%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	8,300	Btu/kWh
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost (In-Service Year $/kW) [1]	2,224	
	Direct Construction Cost ($/kW)	2,056	
	AFUDC Amount ($/kW)	168.30	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	19.63	
	Variable O&M (In-Service Year $/MWh)	2.36	
	K-Factor	1.32	

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

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Lake Mabel Energy Storage Capacity	
(2)	Net Capability		
	A. Summer	40	MW-ac
	B. Winter	40	MW-ac
(3)	Technology Type	Battery	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Jan-24	
	B. Commercial In-Service Date	Mar-25	
(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 $/kW) [1]	1,281	
	Direct Construction Cost ($/kW)	1,215	
	AFUDC Amount ($/kW)	65.57	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	4.11	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	1.05	

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

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Wimauma Energy Storage Capacity	
(2)	Net Capability		
	A. Summer	40	MW-ac
	B. Winter	40	MW-ac
(3)	Technology Type	Battery	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Feb-24	
	B. Commercial In-Service Date	Mar-25	
(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 $/kW) [1]	1,108	
	Direct Construction Cost ($/kW)	1,067	
	AFUDC Amount ($/kW)	40.64	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	4.11	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	1.05	

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

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Polk Unit 1 Simple Cycle Conversion
(2)	Net Capability	
	A. Summer	190 MW
	B. Winter	203 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date [2]	Mar-25
	B. Commercial In-Service Date	Jun-25
(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	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	5%
	Forced Outage Factor (FOF)	2%
	Equivalent Availability Factor (EAF)	93%
	Resulting Capacity Factor	5%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	10,643 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	11
	Total Installed Cost (In-Service Year $/kW) [1]	397
	Direct Construction Cost ($/kW)	383
	AFUDC Amount ($/kW)	13.79
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	-
	Variable O&M (In-Service Year $/MWh)	5.6
	K-Factor	-

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

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	South Tampa Resilience Project Phase II	
(2)	Net Capability		
	A. Summer	37.6	MW
	B. Winter	37.6	MW
(3)	Technology Type	Engine	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Dec-22	
	B. Commercial In-Service Date	Dec-25	
(5)	Fuel		
	A. Primary Fuel	Natural Gas	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	Selective Catalytic Reduction (SCR)	
(7)	Cooling Method	Close Loop cooling	
(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)	2%	
	Forced Outage Factor (FOF)	2%	
	Equivalent Availability Factor (EAF)	96%	
	Resulting Capacity Factor	8%	
	Average Net Operating Heat Rate (In-Service Year ANOHR)	8,300	Btu/kWh
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost (In-Service Year $/kW) [1]	2,224	
	Direct Construction Cost ($/kW)	2,056	
	AFUDC Amount ($/kW)	168.30	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	19.63	
	Variable O&M (In-Service Year $/MWh)	2.36	
	K-Factor	1.23	

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

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Bayside Energy Storage Capacity	
(2)	Net Capability		
	A. Summer	20	MW-ac
	B. Winter	20	MW-ac
(3)	Technology Type	Battery	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Dec-24	
	B. Commercial In-Service Date	Dec-25	
(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	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 $/kW) [1]	1,799	
	Direct Construction Cost ($/kW)	1,735	
	AFUDC Amount ($/kW)	-	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	4.09	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.93	

[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	Long 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-24
	B. Commercial In-Service Date	Dec-25
(5)	Fuel	
	A. Primary Fuel Solar	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+690 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 $/kW) [1,3]	1,601
	Direct Construction Cost ($/kW)	1,534
	AFUDC Amount ($/kW)	67.54
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	18.55
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.65

[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	Cottonmouth Ranch 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-24	
	B. Commercial In-Service Date	Dec-25	
(5)	Fuel		
	A. Primary Fuel Solar	Solar	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	N/A	
(7)	Cooling Method	N/A	
(8)	Total Site Area	+530 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 $/kW) [1,3]	1,574	
	Direct Construction Cost ($/kW)	1,491	
	AFUDC Amount ($/kW)	83.08	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	18.55	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.79	

[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	Polk 2 Enhancement Phase I
(2)	Net Capability	
	A. Summer	59.5 MW
	B. Winter	43.0 MW
(3)	Technology Type	Combined Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date [2]	Sep-26
	B. Commercial In-Service Date	Nov-26
(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	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)	30
	Total Installed Cost (In-Service Year $/kW) [1]	905
	Direct Construction Cost ($/kW)	820
	AFUDC Amount ($/kW)	-
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	-
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	1.34

[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	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 MethodN/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	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 $/kW) [1,3]	1,567	
	Direct Construction Cost ($/kW)	1,493	
	AFUDC Amount ($/kW)	73.44	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	18.96	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.86	

[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	Curiosity Creek Solar
(2)	Net Capability	
	A. Summer	54.3 MW-ac
	B. Winter	54.3 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	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	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 $/kW) [1,3]	1,858
	Direct Construction Cost ($/kW)	1,763
	AFUDC Amount ($/kW)	94.82
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	18.96
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.73

[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	Brewster Solar
(2)	Net Capability	
	A. Summer	42.7 MW-ac
	B. Winter	42.7 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	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	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 $/kW) [1,3]	1,541
	Direct Construction Cost ($/kW)	1,482
	AFUDC Amount ($/kW)	59.35
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	18.96
	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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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Mattaniah Solar
(2)	Net Capability	
	A. Summer	55.0 MW-ac
	B. Winter	55.0 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	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	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 $/kW) [1,3]	1,609
	Direct Construction Cost ($/kW)	1,517
	AFUDC Amount ($/kW)	91.17
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	18.96
	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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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Polk 2 Enhancement Phase II	
(2)	Net Capability		
	A. Summer	59.5	MW
	B. Winter	43.0	MW
(3)	Technology Type	Combustion Turbine	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Apr-27	
	B. Commercial In-Service Date	Jun-27	
(5)	Fuel		
	A. Primary Fuel Natural Gas	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	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)	30	
	Total Installed Cost (In-Service Year $/kW) [1]	905	
	Direct Construction Cost ($/kW)	820	
	AFUDC Amount ($/kW)	-	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	-	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	1.34	

[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	Future Battery Storage 1	
(2)	Net Capability		
	A. Summer	20	MW-ac
	B. Winter	20	MW-ac
(3)	Technology Type	Battery	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Oct-26	
	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	N/A	
(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 $/kW) [1]	2,330	
	Direct Construction Cost ($/kW)	2,083	
	AFUDC Amount ($/kW)	247.04	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	4.20	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.93	

[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	Brewster Solar Phase II
(2)	Net Capability	
	A. Summer	15.6 MW-ac
	B. Winter	15.6 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	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	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 $/kW) [1,3]	1,748
	Direct Construction Cost ($/kW)	1,607
	AFUDC Amount ($/kW)	140.85
	Escalation ($/kW)	-
	Fixed O&M (In-Service Year $/kW – Yr)	19.38
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	0.73

[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 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-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	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	TBD
	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 $/kW) [1]	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

[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	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-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	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	TBD	
	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 $/kW) [1]	TBD	
	Direct Construction Cost ($/kW)	TBD	
	AFUDC Amount ($/kW)	TBD	
	Escalation ($/kW)	TBD	
	Fixed O&M (In-Service Year $/kW – Yr)	TBD	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	TBD	

[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	Future Battery Storage 2	
(2)	Net Capability		
	A. Summer	75	MW-ac
	B. Winter	75	MW-ac
(3)	Technology Type	Battery	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date [2]	Dec-26	
	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	N/A	
(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 $/kW) [1]	2,080	
	Direct Construction Cost ($/kW)	1,869	
	AFUDC Amount ($/kW)	211.65	
	Escalation ($/kW)	-	
	Fixed O&M (In-Service Year $/kW – Yr)	6.42	
	Variable O&M (In-Service Year $/MWh)	-	
	K-Factor	0.93	

[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 Solar 3
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date [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	TBD
	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 $/kW) [1]	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

[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	Future Solar 4
(2)	Net Capability	
	A. Summer	55.0 MW-ac
	B. Winter	55.0 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	TBD
	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 $/kW) [1]	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

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

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 5
(2)	Net Capability	
	A. Summer	74.5 MW-ac
	B. Winter	74.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date [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	TBD
	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 $/kW) [1]	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

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

Schedule 9
(Page 23 of 29)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 6 (Multiple Sites, each not to exceed 74.5MW)
(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	TBD
	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 $/kW) [1]	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

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

Schedule 9
(Page 24 of 29)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 7 (Multiple Sites, each not to exceed 74.5MW)
(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	TBD
	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 $/kW) [1]	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

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

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future CT
(2)	Net Capability	
	A. Summer	222 MW
	B. Winter	247 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)	4%
	Forced Outage Factor (FOF)	2%
	Equivalent Availability Factor (EAF)	94%
	Resulting Capacity Factor	8%
	Average Net Operating Heat Rate (In-Service Year ANOHR)	10,867 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	40
	Total Installed Cost (In-Service Year $/kW) [1]	1,497
	Direct Construction Cost ($/kW)	1,300
	AFUDC Amount ($/kW)	106.11
	Escalation ($/kW)	90.54
	Fixed O&M (In-Service Year $/kW – Yr)	12.96
	Variable O&M (In-Service Year $/MWh)	327.72
	K-Factor	1.33

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

Schedule 9
(Page 26 of 29)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 8
(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-30
	B. Commercial In-Service Date	Dec-31
(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	TBD
	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 $/kW) [1]	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

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

Schedule 9
(Page 27 of 29)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 9
(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-31
	B. Commercial In-Service Date	Dec-32
(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	TBD
	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 $/kW) [1]	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

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

Schedule 9
(Page 28 of 29)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 10
(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-32
	B. Commercial In-Service Date	Dec-33
(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	TBD
	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 $/kW) [1]	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

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

Schedule 9
(Page 29 of 29)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar 11
(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-33
	B. Commercial In-Service Date	Dec-34
(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	TBD
	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 $/kW) [1]	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	-
	K-Factor	TBD

[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, 2024

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
Big Bend ST 4	Big Bend ST 4 does not require any new transmission line	-	-	-	230 kV	April 2025	-	Big Bend	None
Polk CT 1****	Polk CT 1 does not require any new transmission lines****	-	-	-	230 kV	June 2025	-	Polk	None
Polk CC 2 Phase I	Polk CC 2	-	-	-	230 kV	November 2026	-	Polk	None
Curiosity Creek Solar***	Curiosity Creek Solar - Curiosity Creek 230kV	1	Not Determined	0.01	230 kV	December 2026	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

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

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

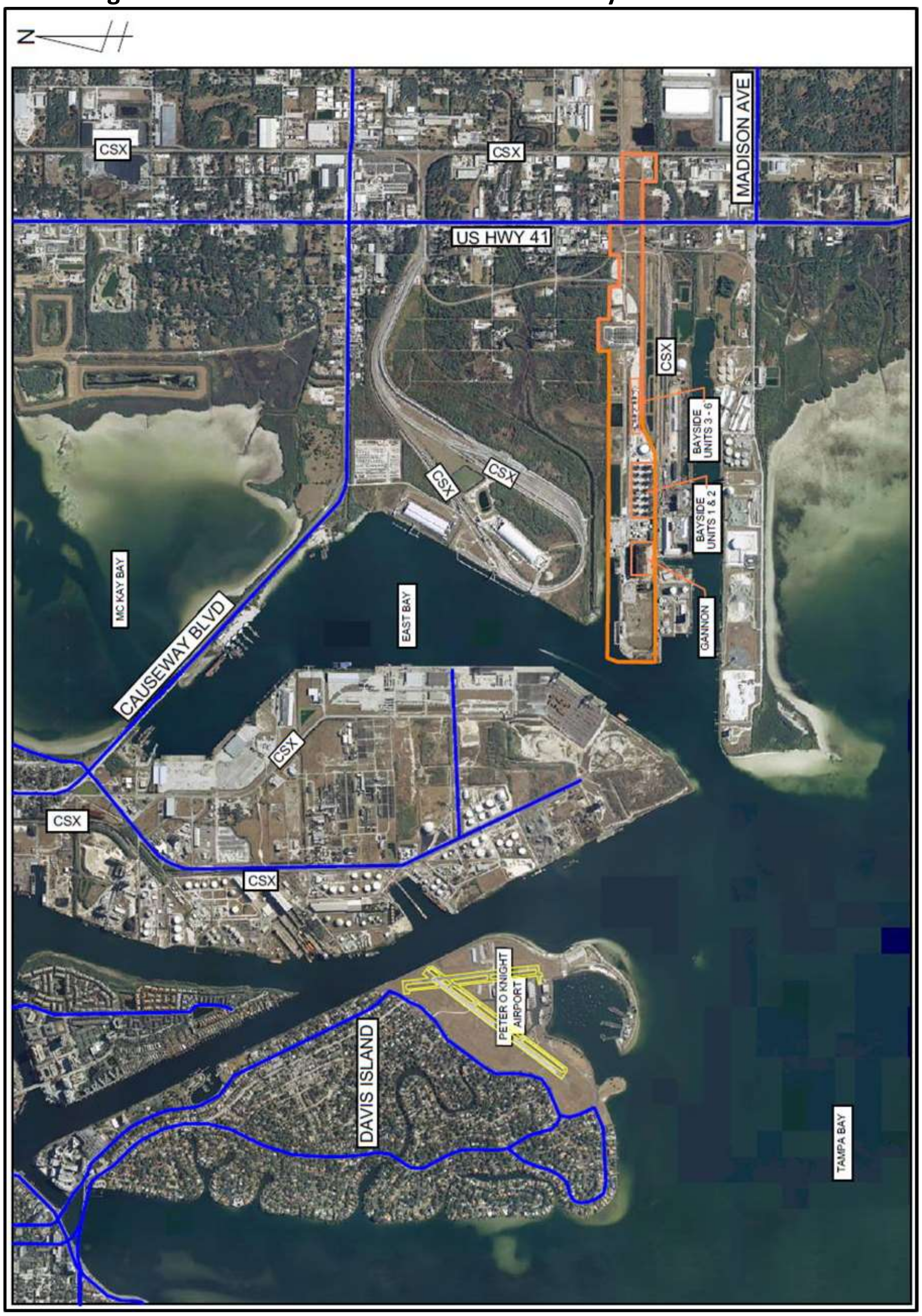


Figure VI-II: Site Location of Polk Power Station

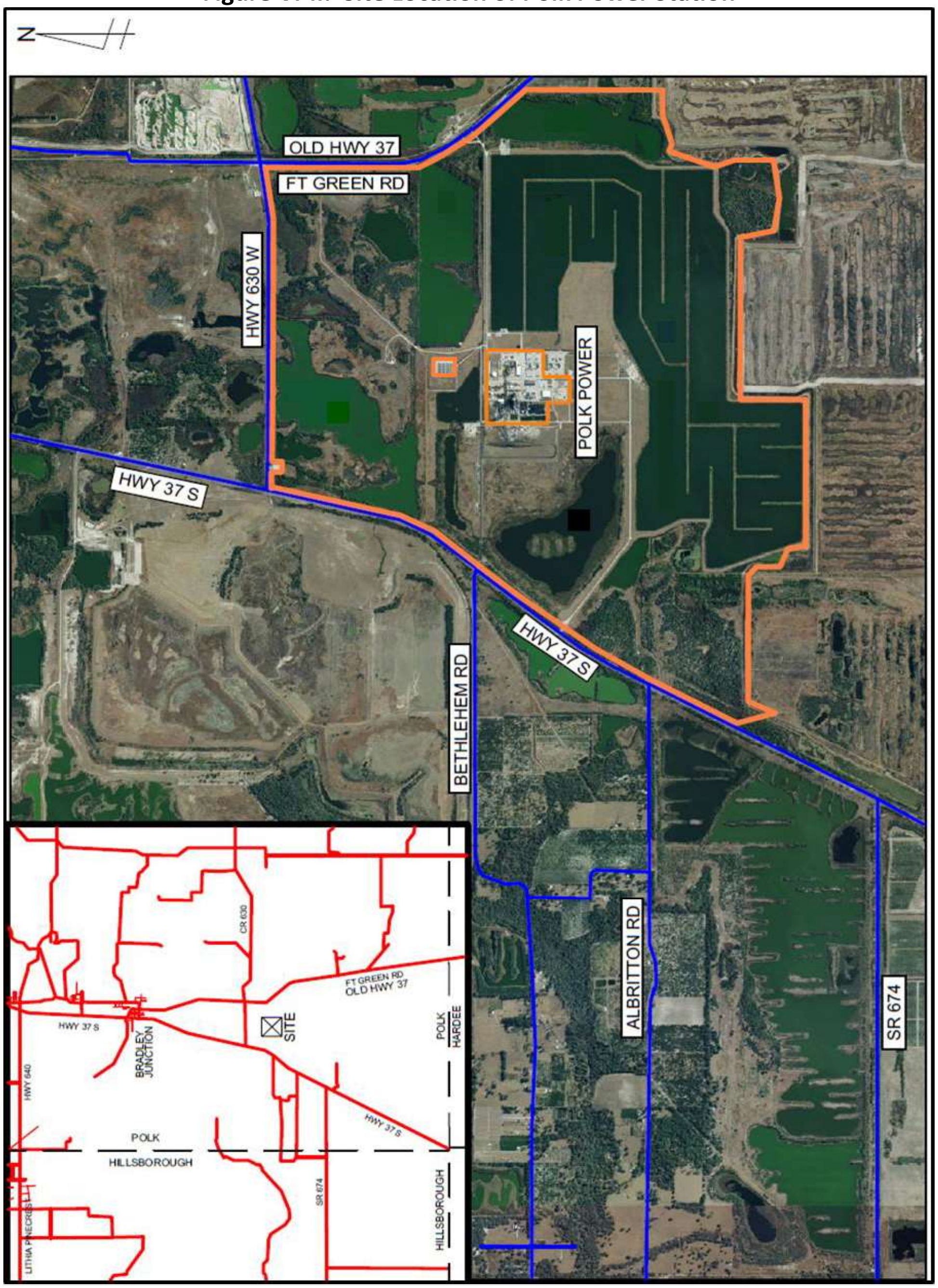
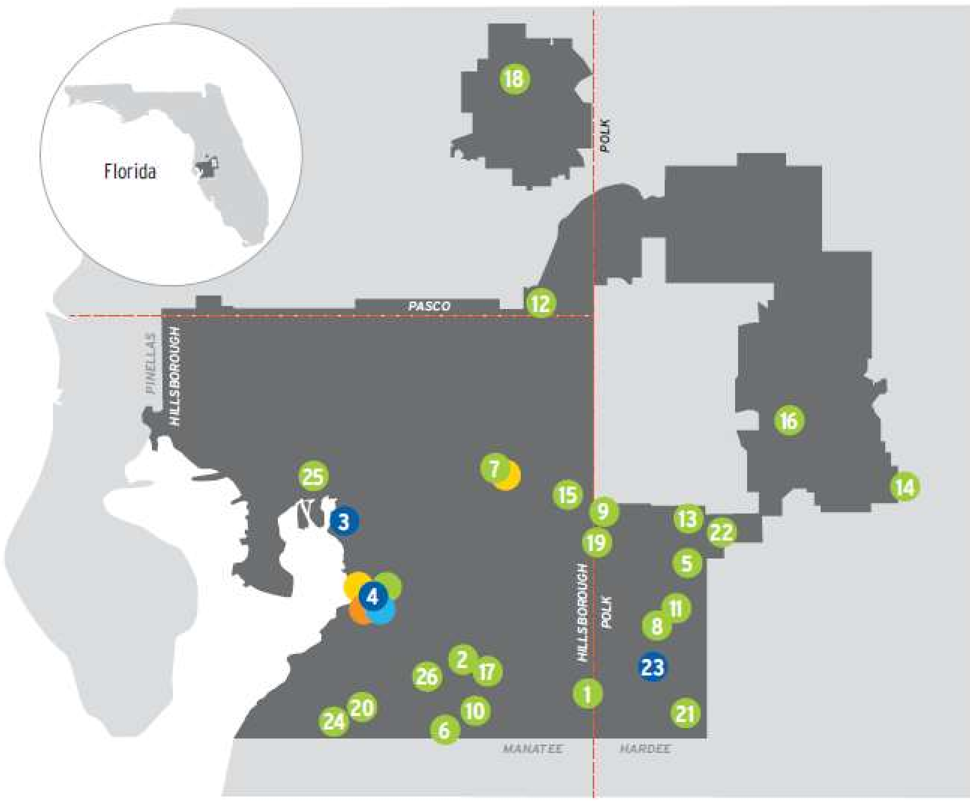


Figure VI-III: Site Location of Big Bend Power Station

Figure VI-IV: Site Location of Solar Power Stations



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

2. Please provide an electronic copy of all schedules and tables in the Company's current planning period TYSP in Excel format.

Answer:

An electronic Excel copy of Tampa Electric's Ten-Year Site Plan schedules and tables were provided to Staff on April 1, 2025.

Schedule 1
Existing Generating Facilities
As of December 31, 2024

(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	442,000	437	442
	CT 4		GT	NG	NA	PL	NA	NA	08/09	**	61,000	56	61
Big Bend Total											**1,623,000**	**1,548**	**1,623**
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		IGCC	NG	PC/BIT	PL	WA/TK	*	09/96	09/36	220,000	220	220
	2		CC	NG	DFO	PL	TK	*	01/17	**	1,200,000	1,061	1,200
Polk Total											**1,420,000**	**1,281**	**1,420**

Notes:
* Limited by environmental permit.
** Undetermined.
1 Both assets (Battery and Solar) are co-located and restricted to a total output of 19.8 MW due to interconnection limits. For this reason, the battery capacity is not considered.
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, 2024

(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
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
Solar Total 2,3											**1,349,600**	**1,350**	**1,350**
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	**	12,600	12.6	12.6
Battery Total 3											**27,600**	**28**	**28**
											TOTAL 1	**6,168**	**6,620**

Notes:
* Limited by environmental permit.
** Undetermined.
1 Both assets (Battery and Solar) are co-located and restricted to a total output of 19.8 MW due to interconnection limits. For this reason, the battery capacity is not considered.
2 Rating for Solar units are nameplate.
3 Utility owned solar/battery less than 1 MW not included.

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:								
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
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
FORECAST:								
2025	1,586,736	2.5	10,351	768,577	13,467	6,386	82,749	77,173
2026	1,613,237	2.5	10,411	781,318	13,325	6,432	83,582	76,950
2027	1,639,557	2.5	10,470	793,972	13,187	6,469	84,414	76,637
2028	1,665,526	2.4	10,572	806,457	13,110	6,516	85,248	76,434
2029	1,690,680	2.4	10,712	818,551	13,087	6,572	86,088	76,337
2030	1,714,766	2.4	10,864	830,131	13,087	6,633	86,931	76,303
2031	1,737,855	2.4	11,022	841,231	13,102	6,699	87,778	76,319
2032	1,759,958	2.4	11,177	851,857	13,121	6,767	88,628	76,358
2033	1,781,051	2.4	11,327	861,998	13,140	6,832	89,483	76,353
2034	1,801,148	2.4	11,477	871,661	13,167	6,897	90,342	76,347

Notes:
December 31, 2024 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:								
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
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
FORECAST:								
2025	1,602,414	2.5	10,416	772,328	13,487	6,388	82,766	77,183
2026	1,637,189	2.5	10,543	788,965	13,363	6,436	83,618	76,965
2027	1,672,086	2.5	10,669	805,660	13,243	6,475	84,468	76,656
2028	1,706,930	2.5	10,842	822,330	13,185	6,524	85,321	76,460
2029	1,741,245	2.5	11,056	838,746	13,181	6,581	86,180	76,369
2030	1,774,757	2.5	11,284	854,779	13,201	6,645	87,044	76,340
2031	1,807,528	2.5	11,520	870,457	13,235	6,713	87,911	76,361
2032	1,839,554	2.5	11,756	885,778	13,272	6,784	88,782	76,406
2033	1,870,799	2.5	11,989	900,726	13,311	6,851	89,658	76,408
2034	1,901,263	2.5	12,226	915,301	13,357	6,918	90,541	76,406

Notes:
December 31, 2024 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:								
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
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
FORECAST:								
2025	1,571,135	2.5	10,285	764,826	13,448	6,384	82,731	77,164
2026	1,589,519	2.4	10,281	773,709	13,287	6,428	83,547	76,935
2027	1,607,505	2.4	10,273	782,398	13,130	6,463	84,360	76,617
2028	1,624,929	2.4	10,308	790,817	13,034	6,508	85,177	76,409
2029	1,641,345	2.4	10,378	798,749	12,992	6,562	85,997	76,306
2030	1,656,521	2.3	10,458	806,081	12,974	6,621	86,822	76,265
2031	1,670,544	2.3	10,543	812,856	12,970	6,686	87,649	76,276
2032	1,683,437	2.3	10,623	819,086	12,970	6,752	88,479	76,310
2033	1,695,196	2.3	10,697	824,768	12,970	6,815	89,314	76,300
2034	1,705,849	2.3	10,770	829,915	12,978	6,878	90,153	76,288

Notes:
December 31, 2024 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:							
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	2,024	1,608	1,259,094	0	0	1,771	19,186
2018	2,014	1,588	1,268,262	0	0	1,933	19,631
2019	2,021	1,516	1,332,913	0	0	1,939	19,783
2020	1,891	1,408	1,342,642	0	0	1,883	19,954
2021	2,122	1,382	1,535,835	0	0	1,886	20,093
2022	2,111	1,357	1,556,126	0	0	1,947	20,467
2023	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
FORECAST:							
2025	1,852	1,312	1,412,372	0	0	1,939	20,528
2026	1,846	1,309	1,409,579	0	0	1,948	20,636
2027	1,847	1,308	1,412,211	0	0	1,956	20,741
2028	1,848	1,306	1,415,060	0	0	1,965	20,901
2029	1,847	1,304	1,415,824	0	0	1,974	21,105
2030	1,844	1,303	1,415,374	0	0	1,983	21,325
2031	1,842	1,301	1,415,429	0	0	1,993	21,556
2032	1,840	1,300	1,415,806	0	0	2,002	21,786
2033	1,838	1,298	1,416,155	0	0	2,011	22,008
2034	1,836	1,296	1,416,588	0	0	2,021	22,231

Notes:
December 31, 2024 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:							
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	2,024	1,608	1,259,094	0	0	1,771	19,186
2018	2,014	1,588	1,268,262	0	0	1,933	19,631
2019	2,021	1,516	1,332,913	0	0	1,939	19,783
2020	1,891	1,408	1,342,642	0	0	1,883	19,954
2021	2,122	1,382	1,535,835	0	0	1,886	20,093
2022	2,111	1,357	1,556,126	0	0	1,947	20,467
2023	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
FORECAST:							
2025	1,852	1,310	1,414,031	0	0	1,939	20,596
2026	1,846	1,307	1,412,027	0	0	1,948	20,772
2027	1,847	1,304	1,416,108	0	0	1,956	20,947
2028	1,848	1,301	1,420,521	0	0	1,965	21,179
2029	1,847	1,298	1,422,842	0	0	1,974	21,458
2030	1,844	1,295	1,423,963	0	0	1,984	21,756
2031	1,842	1,292	1,425,578	0	0	1,993	22,068
2032	1,840	1,289	1,427,540	0	0	2,002	22,382
2033	1,838	1,286	1,429,486	0	0	2,012	22,690
2034	1,837	1,283	1,431,550	0	0	2,021	23,001

Notes:
December 31, 2024 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:							
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	2,024	1,608	1,259,094	0	0	1,771	19,186
2018	2,014	1,588	1,268,262	0	0	1,933	19,631
2019	2,021	1,516	1,332,913	0	0	1,939	19,783
2020	1,891	1,408	1,342,642	0	0	1,883	19,954
2021	2,122	1,382	1,535,835	0	0	1,886	20,093
2022	2,111	1,357	1,556,126	0	0	1,947	20,467
2023	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
FORECAST:							
2025	1,852	1,313	1,410,866	0	0	1,939	20,461
2026	1,846	1,312	1,406,697	0	0	1,947	20,501
2027	1,846	1,311	1,408,457	0	0	1,956	20,539
2028	1,848	1,311	1,409,517	0	0	1,965	20,629
2029	1,847	1,310	1,409,602	0	0	1,974	20,760
2030	1,844	1,310	1,407,409	0	0	1,983	20,906
2031	1,841	1,310	1,405,668	0	0	1,993	21,062
2032	1,840	1,309	1,405,318	0	0	2,002	21,216
2033	1,838	1,309	1,403,859	0	0	2,011	21,361
2034	1,836	1,309	1,402,489	0	0	2,020	21,504

Notes:
December 31, 2024 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:					
2015	0	1,098	20,105	8,168	718,713
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
FORECAST:					
2025	0	1,058	21,586	9,884	862,522
2026	0	1,063	21,699	9,955	876,165
2027	0	1,068	21,809	10,024	889,717
2028	0	1,075	21,977	10,092	903,104
2029	0	1,086	22,190	10,160	916,103
2030	0	1,097	22,421	10,228	928,592
2031	0	1,108	22,664	10,295	940,605
2032	0	1,120	22,906	10,362	952,147
2033	0	1,131	23,140	10,429	963,209
2034	0	1,142	23,374	10,497	973,796

Notes:
December 31, 2024 Status
*Includes sales to St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
RCID contract from 2016 to 2017.
**Utility Use and Losses include accrued sales.
***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
****Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.3

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

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
HISTORY:					
2015	0	1,098	20,105	8,168	718,713
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
FORECAST:					
2025	0	1,061	21,657	9,884	866,288
2026	0	1,070	21,842	9,955	883,845
2027	0	1,078	22,025	10,024	901,456
2028	0	1,090	22,269	10,092	919,044
2029	0	1,104	22,562	10,160	936,384
2030	0	1,119	22,875	10,228	953,346
2031	0	1,134	23,203	10,295	969,955
2032	0	1,150	23,532	10,362	986,211
2033	0	1,166	23,856	10,429	1,002,099
2034	0	1,182	24,183	10,497	1,017,622

Notes:
December 31, 2024 Status
*Includes sales to St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
RCID contract from 2016 to 2017.
**Utility Use and Losses include accrued sales.
***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
****Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Low 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:					
2015	0	1,098	20,105	8,168	718,713
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
FORECAST:					
2025	0	1,054	21,515	9,884	858,754
2026	0	1,056	21,557	9,955	868,523
2027	0	1,058	21,596	10,024	878,093
2028	0	1,061	21,690	10,092	887,397
2029	0	1,068	21,828	10,160	896,216
2030	0	1,075	21,982	10,228	904,441
2031	0	1,083	22,145	10,295	912,110
2032	0	1,090	22,307	10,362	919,236
2033	0	1,098	22,459	10,429	925,820
2034	0	1,105	22,609	10,497	931,874

Notes:
December 31, 2024 Status
*Includes sales to St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL).
RCID contract from 2016 to 2017.
**Utility Use and Losses include accrued sales.
***Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
****Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 3.1

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

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation***	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
HISTORY:									
2015	4,248	0	4,248	111	21	142	102	88	3,784
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
FORECAST:									
2025	4,880	0	4,880	135	0	227	110	165	4,243
2026	4,943	0	4,943	135	0	248	110	172	4,278
2027	5,008	0	5,008	135	0	268	111	178	4,315
2028	5,081	0	5,081	134	0	289	111	185	4,362
2029	5,158	0	5,158	135	0	311	111	191	4,410
2030	5,235	0	5,235	135	0	332	111	197	4,460
2031	5,314	0	5,314	135	0	353	112	204	4,510
2032	5,390	0	5,390	134	0	374	112	210	4,560
2033	5,465	0	5,465	135	0	395	112	217	4,606
2034	5,537	0	5,537	135	0	416	113	223	4,650

Notes:
December 31, 2024 Status
2016, 2018, 2020, and 2022 Net Firm Demand is not coincident with system peak.
Notes prior to 2024
*Includes residential and commercial/industrial conservation.
**Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
***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) 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	4,248	0	4,248	111	21	142	102	88	3,784
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
FORECAST:									
2025	4,899	0	4,899	135	0	227	110	165	4,261
2026	4,980	0	4,980	135	0	248	110	172	4,315
2027	5,064	0	5,064	135	0	268	111	178	4,372
2028	5,157	0	5,157	134	0	289	111	185	4,438
2029	5,255	0	5,255	135	0	311	111	191	4,507
2030	5,354	0	5,354	135	0	332	111	197	4,578
2031	5,454	0	5,454	135	0	353	112	204	4,651
2032	5,552	0	5,552	134	0	374	112	210	4,722
2033	5,650	0	5,650	135	0	395	112	217	4,791
2034	5,748	0	5,748	135	0	416	113	223	4,861

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

Linked to Sch3.1
all formulas except column 10

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:									
2015	4,248	0	4,248	111	21	142	102	88	3,784
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
FORECAST:									
2025	4,863	0	4,863	135	0	227	110	165	4,225
2026	4,907	0	4,907	135	0	248	110	172	4,242
2027	4,953	0	4,953	135	0	268	111	178	4,261
2028	5,006	0	5,006	134	0	289	111	185	4,287
2029	5,063	0	5,063	135	0	311	111	191	4,315
2030	5,121	0	5,121	135	0	332	111	197	4,345
2031	5,178	0	5,178	135	0	353	112	204	4,375
2032	5,233	0	5,233	134	0	374	112	210	4,403
2033	5,287	0	5,287	135	0	395	112	217	4,428
2034	5,339	0	5,339	135	0	416	113	223	4,452

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

Schedule 3.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale **	Retail *	Interruptible	Residential Load Management	Residential Conservation***	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
HISTORY:									
2014/15	4,202	0	4,202	79	47	521	99	65	3390
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	3,213
FORECAST:									
2024/25	5,296	0	5,296	118	0	604	113	120	4,341
2025/26	5,374	0	5,374	118	0	621	113	126	4,396
2026/27	5,451	0	5,451	118	0	638	114	132	4,449
2027/28	5,531	0	5,531	118	0	657	114	137	4,505
2028/29	5,612	0	5,612	118	0	675	115	142	4,562
2029/30	5,693	0	5,693	118	0	693	115	148	4,619
2030/31	5,772	0	5,772	118	0	712	116	153	4,673
2031/32	5,849	0	5,849	118	0	730	116	159	4,726
2032/33	5,923	0	5,923	118	0	748	117	164	4,776
2033/34	5,996	0	5,996	118	0	767	117	170	4,825

Notes:
December 31, 2024 Status
2020/2021 and 2022/2023 Net Firm Demand is not coincident with system peak.
Notes prior to 2024
*Includes residential and commercial/industrial conservation.
**Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
***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)
all formulas except column 10									
Year	Total *	Wholesale	Retail *	Interruptible	Residential Load Management	Residential Conservation**	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
HISTORY:									
2014/15	4,202	0	4,202	79	47	521	99	65	3,390
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
FORECAST:									
2024/25	5,315	0	5,315	118	0	604	113	120	4,361
2025/26	5,413	0	5,413	118	0	621	113	126	4,434
2026/27	5,510	0	5,510	118	0	638	114	132	4,508
2027/28	5,609	0	5,609	118	0	657	114	137	4,583
2028/29	5,712	0	5,712	118	0	675	115	142	4,662
2029/30	5,815	0	5,815	118	0	693	115	148	4,740
2030/31	5,915	0	5,915	118	0	712	116	153	4,817
2031/32	6,015	0	6,015	118	0	730	116	159	4,892
2032/33	6,114	0	6,114	118	0	748	117	164	4,967
2033/34	6,211	0	6,211	118	0	767	117	170	5,039

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

Schedule 3.2

Forecast of Winter Peak Demand (MW)
Low Case

all formulas except column 10

(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:									
2014/15	4,202	0	4,202	79	47	521	99	65	3,390
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
FORECAST:									
2024/25	5,278	0	5,278	118	0	604	113	120	4,324
2025/26	5,338	0	5,338	118	0	621	113	126	4,359
2026/27	5,396	0	5,396	118	0	638	114	132	4,394
2027/28	5,455	0	5,455	118	0	657	114	137	4,429
2028/29	5,516	0	5,516	118	0	675	115	142	4,466
2029/30	5,576	0	5,576	118	0	693	115	148	4,501
2030/31	5,633	0	5,633	118	0	712	116	153	4,535
2031/32	5,688	0	5,688	118	0	730	116	159	4,565
2032/33	5,741	0	5,741	118	0	748	117	164	4,594
2033/34	5,792	0	5,792	118	0	767	117	170	4,620

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

Schedule 3.3

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

(1) Year	(2) Total*	(3) Residential Conservation**	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale ***	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load **** Factor %
ACTUAL:								
2015	19,888	565	316	19,006	0	1,098	20,105	57.1
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	22,069	743	625	20,702	0	1,150	21,852	57.5
FORECAST:								
2025	21,932	778	626	20,528	0	1,058	21,586	53.9
2026	22,106	812	658	20,636	0	1,063	21,699	53.5
2027	22,274	844	688	20,741	0	1,068	21,809	53.2
2028	22,494	874	718	20,901	0	1,075	21,977	52.8
2029	22,757	905	748	21,105	0	1,086	22,190	52.8
2030	23,037	935	778	21,325	0	1,097	22,421	52.8
2031	23,329	965	808	21,556	0	1,108	22,664	52.7
2032	23,619	995	837	21,786	0	1,120	22,906	52.6
2033	23,901	1,026	867	22,008	0	1,131	23,140	52.7
2034	24,184	1,056	897	22,231	0	1,142	23,374	52.7

Notes:

December 31, 2024 Status
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
***Includes sales to RCID, STC and FP&L.
Contract with RCID from 2016 to 2017.
****Load Factor is the ratio of total system average load to peak demand.
Values shown may be affected due to rounding.

Schedule 3.3

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

(1) Year	(2) Total*	(3) Residential Conservation**	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load *** Factor %
HISTORY:								
2015	19,888	565	316	19,006	0	1,098	20,105	57.1
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	22,069	743	625	20,702	0	1,150	21,852	57.5
FORECAST:								
2025	22,000	778	626	20,596	0	1,061	21,657	53.8
2026	22,242	812	658	20,772	0	1,070	21,842	53.4
2027	22,480	844	688	20,947	0	1,078	22,025	53.0
2028	22,772	874	718	21,179	0	1,090	22,269	52.6
2029	23,111	905	748	21,458	0	1,104	22,562	52.6
2030	23,469	935	778	21,756	0	1,119	22,875	52.5
2031	23,841	965	808	22,068	0	1,134	23,203	52.4
2032	24,215	995	837	22,382	0	1,150	23,532	52.3
2033	24,583	1,026	867	22,690	0	1,166	23,856	52.4
2034	24,954	1,056	897	23,001	0	1,182	24,183	52.3

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

Schedule 3.3

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

(1) 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:								
2015	19,888	565	316	19,006	0	1,098	20,105	57.1
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	22,069	743	625	20,702	0	1,150	21,852	57.5
FORECAST:								
2025	21,865	778	626	20,461	0	1,054	21,515	53.9
2026	21,971	812	658	20,501	0	1,056	21,557	53.6
2027	22,071	844	688	20,539	0	1,058	21,596	53.3
2028	22,221	874	718	20,629	0	1,061	21,690	53.0
2029	22,413	905	748	20,760	0	1,068	21,828	53.0
2030	22,619	935	778	20,906	0	1,075	21,982	53.0
2031	22,835	965	808	21,062	0	1,083	22,145	53.0
2032	23,049	995	837	21,216	0	1,090	22,307	52.9
2033	23,254	1,026	867	21,361	0	1,098	22,459	53.1
2034	23,457	1,056	897	21,504	0	1,105	22,609	53.2

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

Schedule 4
Base Case

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST		FORECAST	
	2024		2025		2026	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,029	1,527	4,572	1,585	4,627	1,594
February	2,709	1,364	3,481	1,432	3,523	1,440
March	3,208	1,568	3,521	1,590	3,562	1,597
April	3,553	1,600	3,628	1,652	3,655	1,660
May	4,220	2,142	4,026	1,912	4,053	1,922
June	4,323	2,142	4,378	2,076	4,413	2,088
July	4,318	2,249	4,454	2,171	4,492	2,184
August	4,305	2,287	4,488	2,207	4,523	2,220
September	4,232	2,122	4,263	2,000	4,304	2,011
October	3,956	1,663	3,951	1,879	3,980	1,888
November	3,567	1,643	3,483	1,514	3,523	1,521
December	2,935	1,545	3,919	1,569	3,964	1,576
TOTAL		21,852		21,586		21,699

Notes:
December 31, 2024 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	
	2024		2025		2026	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,029	1,527	4,591	1,590	4,665	1,604
February	2,709	1,364	3,495	1,437	3,550	1,449
March	3,208	1,568	3,535	1,594	3,590	1,606
April	3,553	1,600	3,642	1,657	3,683	1,670
May	4,220	2,142	4,042	1,918	4,086	1,934
June	4,323	2,142	4,396	2,083	4,448	2,102
July	4,318	2,249	4,472	2,179	4,529	2,199
August	4,305	2,287	4,506	2,215	4,560	2,235
September	4,232	2,122	4,281	2,007	4,339	2,025
October	3,956	1,663	3,967	1,885	4,012	1,901
November	3,567	1,643	3,497	1,519	3,551	1,531
December	2,935	1,545	3,935	1,574	3,995	1,586
TOTAL		21,852		21,657		21,842

Notes:
December 31, 2024 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	
	2024		2025		2026	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,029	1,527	4,554	1,580	4,590	1,584
February	2,709	1,364	3,468	1,428	3,495	1,431
March	3,208	1,568	3,507	1,585	3,535	1,587
April	3,553	1,600	3,614	1,647	3,626	1,650
May	4,220	2,142	4,010	1,906	4,021	1,909
June	4,323	2,142	4,361	2,069	4,377	2,074
July	4,318	2,249	4,436	2,163	4,456	2,168
August	4,305	2,287	4,470	2,200	4,487	2,204
September	4,232	2,122	4,246	1,993	4,269	1,997
October	3,956	1,663	3,935	1,872	3,947	1,875
November	3,567	1,643	3,469	1,510	3,496	1,512
December	2,935	1,545	3,904	1,564	3,933	1,567
TOTAL		21,852		21,515		21,557

Notes:
December 31, 2024 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 2023	Actual 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	Nuclear	Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal	1000 Ton	367	26	220	277	272	226	272	193	252	226	243	171
(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	6	9	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	6	9	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	126,239	126,867	127,834	120,282	117,016	113,988	112,366	112,655	111,810	113,614	114,902	115,222
(16)	ST	1000 MCF	5,295	6,632	4,583	760	1,036	710	1,012	768	881	942	1,685	743
(17)	CC	1000 MCF	120,717	119,510	121,336	117,385	114,821	112,443	110,412	110,158	108,314	110,707	110,295	111,829
(18)	GT	1000 MCF	227	714	1,597	1,818	973	634	791	1,456	2,442	1,854	2,701	2,486
(20)	RE	1000 MCF	0	11	318	319	185	200	152	273	172	111	220	164
(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.

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 2023	Actual 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	Annual Firm Interchange	GWh	21	33	314	281	281	282	281	281	281	282	281	281
(2)	Nuclear	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal	GWh	769	58	419	526	516	429	516	367	477	429	461	323
(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	2	4	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	2	4	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	17,814	17,999	18,194	17,497	17,113	16,991	16,659	16,685	16,507	16,622	16,652	16,864
(17)	ST	GWh	473	582	401	61	89	59	86	65	73	81	145	63
(18)	CC	GWh	17,323	17,352	17,473	17,236	16,918	16,854	16,489	16,458	16,205	16,370	16,246	16,569
(19)	GT	GWh	18	64	277	157	81	51	64	125	206	156	231	210
(20)	RE	GWh	0	1	43	43	25	27	20	37	23	15	30	22
(21)	Renewable	GWh	1,748	2,235	2,540	3,340	3,848	4,237	4,699	5,042	5,368	5,540	5,711	5,870
(22)	Solar	GWh	1,748	2,235	2,540	3,340	3,848	4,237	4,699	5,042	5,368	5,540	5,711	5,870
(23)	Other (Specify)													
(24)	PC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(25)	Net Interchange	GWh	1,315	1,443	29	(32)	(34)	(39)	(40)	(27)	(40)	(40)	(36)	(36)
(26)	Purchased Energy from Non-Utility Generators	GWh	97	80	96	96	96	97	96	96	96	97	96	96
(27)	Other	GWh	0	0	(6)	(9)	(11)	(20)	(21)	(23)	(25)	(24)	(25)	(24)
(28)	Net Energy for Load	GWh	21,767	21,852	21,586	21,699	21,809	21,977	22,190	22,421	22,664	22,906	23,140	23,374

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 2023	Actual 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	Annual Firm Interchange	%	0.1	0.2	1.5	1.3	1.3	1.3	1.3	1.3	1.2	1.2	1.2	1.2
(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	%	3.5	0.3	1.9	2.4	2.4	2.0	2.3	1.6	2.1	1.9	2.0	1.4
(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	%	0.01	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	%	0.01	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	%	81.8	82.4	84.3	80.6	78.5	77.3	75.1	74.4	72.8	72.6	72.0	72.1
(17)	ST	%	2.2	2.7	1.9	0.3	0.4	0.3	0.4	0.3	0.3	0.4	0.6	0.3
(18)	CC	%	79.6	79.4	80.9	79.4	77.6	76.7	74.3	73.4	71.5	71.5	70.2	70.9
(19)	GT	%	0.1	0.3	1.3	0.7	0.4	0.2	0.3	0.6	0.9	0.7	1.0	0.9
(20)	RE	%	0.0	0.0	0.2	0.2	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1
(21)	Renewable	%	8.0	10.2	11.8	15.4	17.6	19.3	21.2	22.5	23.7	24.2	24.7	25.1
(22)	Solar	%	8.0	10.2	11.8	15.4	17.6	19.3	21.2	22.5	23.7	24.2	24.7	25.1
(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	%	6.0	6.6	0.1	(0.1)	(0.2)	(0.2)	(0.3)	(0.2)	(0.3)	(0.2)	(0.2)	(0.2)
(26)	Purchased Energy from Non-Utility Generators	%	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
(27)	Other	%	0.0	0.0	(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).

Schedule 7.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Firm Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2025	5,364	34	0	0	5,398	4,243	1,155	27%	0	1,155	27%
2026	5,427	34	0	0	5,461	4,278	1,183	28%	0	1,183	28%
2027	5,493	34	0	0	5,527	4,315	1,211	28%	0	1,211	28%
2028	5,648	34	0	0	5,682	4,362	1,319	30%	0	1,319	30%
2029	5,649	34	0	0	5,683	4,410	1,273	29%	0	1,273	29%
2030	5,648	34	0	0	5,682	4,460	1,223	27%	0	1,223	27%
2031	5,869	34	0	0	5,903	4,510	1,393	31%	0	1,393	31%
2032	5,868	34	0	0	5,902	4,560	1,342	29%	0	1,342	29%
2033	5,867	34	0	0	5,901	4,606	1,295	28%	0	1,295	28%
2034	5,866	34	0	0	5,900	4,650	1,249	27%	0	1,249	27%

Values shown may be affected due to rounding.

Schedule 7.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Firm Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2024-25	5,283	468	0	0	5,751	4,341	1,409	32%	337	1,072	25%
2025-26	5,379	34	0	0	5,413	4,396	1,017	23%	0	1,017	23%
2026-27	5,422	34	0	0	5,456	4,449	1,007	23%	0	1,007	23%
2027-28	5,560	34	0	0	5,594	4,505	1,089	24%	0	1,089	24%
2028-29	5,560	34	0	0	5,594	4,562	1,032	23%	0	1,032	23%
2029-30	5,560	34	0	0	5,594	4,619	975	21%	0	975	21%
2030-31	5,807	34	0	0	5,841	4,673	1,168	25%	0	1,168	25%
2031-32	5,807	34	0	0	5,841	4,726	1,115	24%	0	1,115	24%
2032-33	5,807	34	0	0	5,841	4,776	1,065	22%	0	1,065	22%
2033-34	5,807	34	0	0	5,841	4,825	1,016	21%	0	1,016	21%

Values shown may be affected due to rounding.

Schedule 7.2.1*

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Firm Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2024-25	5,283	468	0	0	5,751	4,540	1,210	27%	337	873	19%
2025-26	5,379	34	0	0	5,413	4,599	814	18%	0	814	18%
2026-27	5,422	34	0	0	5,456	4,655	801	17%	0	801	17%
2027-28	5,560	34	0	0	5,594	4,714	880	19%	0	880	19%
2028-29	5,560	34	0	0	5,594	4,774	820	17%	0	820	17%
2029-30	5,560	34	0	0	5,594	4,834	760	16%	0	760	16%
2030-31	5,807	34	0	0	5,841	4,891	950	19%	0	950	19%
2031-32	5,807	34	0	0	5,841	4,946	895	18%	0	895	18%
2032-33	5,807	34	0	0	5,841	4,999	842	17%	0	842	17%
2033-34	5,807	34	0	0	5,841	5,050	791	16%	0	791	16%

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

TAMPA ELECTRIC COMPANY
UNDOCKETED: REVIEW OF TYSP'S
STAFF'S FIRST DATA REQUEST
REQUEST NO. 2
BATES PAGE(S): 113- 147
FILED: APRIL 1, 2025

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
2025														
South Tampa Resilience Project Phase I	1	Hillsborough	IC	NG	NA	PL	N/A	-	2/25	*	37,600	37.6	37.6	OP
Lake Mabel Energy Storage Capacity	1	Polk	BA	N/A	NA	N/A	N/A	-	3/25	*	40,000	40.0	40.0	V
Wimauma Energy Storage Capacity	1	Hillsborough	BA	N/A	N/A	N/A	N/A	-	3/25	*	40,000	40.0	40.0	V
Big Bend	4	Hillsborough	ST	NG	BIT	PL	WA/RR	-	4/25	*	442,000	(57.0)	(62.0)	OT
Polk Unit 1 Simple Cycle Conversion	1	Polk	CT	NG	N/A	PL	N/A	-	6/25	*	203,000	(30.0)	(17.0)	P
South Tampa Resilience Project Phase II	1	Hillsborough	IC	NG	NA	PL	N/A	-	12/25	*	37,600	37.6	37.6	V
Bayside Energy Storage Capacity	1	Hillsborough	BA	N/A	N/A	N/A	N/A	-	12/25	*	20,000	20.0	20.0	P
Long Branch Solar [1]	1	Manatee	PV	SOLAR	NA	NA	NA	-	12/25	*	74,500	3.7	-	U
Cottonmouth Ranch Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/25	*	74,500	3.7	-	U
Solar Degradation [2]	N/A											(2.0)	-	
											2025 Changes and Additions:	93.7	96.2	
2026														
Polk 2 Enhancement Phase I	2	Polk	CC	NG	NA	PL	NA	-	11/26	*	43,000	59.5	43.0	P
Keene Branch Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/26	*	74,500	3.7	-	P
Curiosity Creek Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/26	*	54,300	2.7	-	P
Brewster Solar [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	12/26	*	42,700	0.6	-	P
Mattaniah Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	12/26	*	55,000	0.8	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2026 Changes and Additions:	65.4	43.0	
2027														
Polk 2 Enhancement Phase II	2	Polk	CC	NG	NA	PL	NA	-	6/27	*	43,000	59.5	43.0	P
Future Battery Storage 1	1	Unknown	BA	N/A	N/A	N/A	N/A	-	10/27	*	20,000	20.0	20.0	P
Brewster Solar Phase II	1	Polk	PV	SOLAR	NA	NA	NA	-	12/27	*	15,600	0.2	-	P
Future Solar 1 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/27	*	74,500	1.1	-	P
Future Solar 2 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/27	*	74,500	1.1	-	P
Future Battery Storage 2	1	Unknown	BA	N/A	N/A	N/A	N/A	-	12/27	*	75,000	75.0	75.0	P
Solar Degradation [2]	N/A											(2.0)	-	
											2027 Changes and Additions:	155.0	138.0	

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 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
2028														
Future Solar 3 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/28	*	74,500	1.1	-	P
Future Solar 4 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/28	*	55,000	0.8	-	P
Future Solar 5 [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:	1.1	-	
2029														
Future Solar 6 [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)	-	
2030														
Future Solar 7 [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	Unknown	CT	NG	NA	PL	N/A	-	1/31	*	247,000	222.0	247.0	P
Future Solar 8 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/31	*	74,500	0.7	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2031 Changes and Additions:	220.8	247.0	
2032														
Future Solar 9 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/32	*	74,500	0.7	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2032 Changes and Additions:	(1.2)	-	

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
2033														
Future Solar 10 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/33	*	74,500	0.7	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2033 Changes and Additions:	(1.2)	-	
2034														
Future Solar 11 [1]	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/34	*	74,500	0.7	-	P
Solar Degradation [2]	N/A											(2.0)	-	
											2034 Changes and Additions:	(1.2)	-	

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

TAMPA ELECTRIC COMPANY
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Schedule 9
Status Report and Specifications of Proposed Generating Facilities

18	19	20	21	22	23	24	25	26	27	28	29
Future Solar 2	Future Battery Storage 2	Future Solar 3	Future Solar 4	Future Solar 5	Future Solar 6	Future Solar 7	Future CT	Future Solar 8	Future Solar 9	Future Solar 10	Future Solar 11
					(Multiple Sites, each not to exceed 74.5MW)	(Multiple Sites, each not to exceed 74.5MW)					
74.5 MW-ac	75 MW-ac	74.5 MW-ac	55 MW-ac	74.5 MW-ac	149 MW-ac	149 MW-ac	222 MW	74.5 MW-ac	74.5 MW-ac	74.5 MW-ac	74.5 MW-ac
74.5 MW-ac	75 MW-ac	74.5 MW-ac	55 MW-ac	74.5 MW-ac	149 MW-ac	149 MW-ac	247 MW	74.5 MW-ac	74.5 MW-ac	74.5 MW-ac	74.5 MW-ac
Single Axis Tracking PV Solar	Battery	Single Axis Tracking PV Solar	Single Axis Tracking PV Solar	Single Axis Tracking PV Solar	Single Axis Tracking PV Solar	Single Axis Tracking PV Solar	Combustion Turbine	Single Axis Tracking PV Solar	Single Axis Tracking PV Solar	Single Axis Tracking PV Solar	Single Axis Tracking PV Solar
Jan-26	Dec-26	Jan-27	Jan-27	Jan-27	Jan-28	Jan-29	TBD	Jan-30	Jan-31	Jan-32	Jan-33
Dec-27	Dec-27	Dec-28	Dec-28	Dec-28	Dec-29	Dec-30	Jan-31	Dec-31	Dec-32	Dec-33	Dec-34
Solar	N/A	Solar	Solar	Solar	Solar	Solar	Natural Gas	Solar	Solar	Solar	Solar
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A	N/A	Dry Low Nox	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Undetermined	N/A	Undetermined	Undetermined	Undetermined	Undetermined	Undetermined	Undetermined	Undetermined	Undetermined	Undetermined	Undetermined
Planned	Planned	Planned	Planned	Planned	Planned	Planned	Planned	Planned	Planned	Planned	Planned
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A	N/A	4%	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A	N/A	2%	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A	N/A	94%	N/A	N/A	N/A	N/A
TBD	N/A	TBD	TBD	TBD	TBD	TBD	6%	TBD	TBD	TBD	TBD
N/A	N/A	N/A	N/A	N/A	N/A	N/A	10,687 Btu/kWh	N/A	N/A	N/A	
35	10	35	35	35	35	35	40	35	35	35	35
TBD	2,080	TBD	TBD	TBD	TBD	TBD	1,497	TBD	TBD	TBD	TBD
TBD	1,669	TBD	TBD	TBD	TBD	TBD	1,300	TBD	TBD	TBD	TBD
TBD	211.65	TBD	TBD	TBD	TBD	TBD	106.11	TBD	TBD	TBD	TBD
TBD	-	TBD	TBD	TBD	TBD	TBD	90.54	TBD	TBD	TBD	TBD
TBD	6.42	TBD	TBD	TBD	TBD	TBD	12.96	TBD	TBD	TBD	TBD
-	-	-	-	-	-	-	337.72	-	-	-	-
TBD	0.00	TBD	TBD	TBD	TBD	TBD	1.33	TBD	TBD	TBD	TBD
1 Total installed cost includes transmission interconnection	1 Total installed cost includes transmission interconnection	1 Total installed cost includes transmission interconnection	1 Total installed cost includes transmission interconnection	1 Total installed cost includes transmission interconnection	1 Total installed cost includes transmission interconnection	1 Total installed cost includes transmission interconnection	1 Total installed cost includes transmission interconnection	1 Total installed cost includes transmission interconnection	1 Total installed cost includes transmission interconnection	1 Total installed cost includes transmission interconnection	1 Total installed cost includes transmission interconnection
2 Construction schedule includes engineering design and permitting	2 Construction schedule includes engineering design and permitting	2 Construction schedule includes engineering design and permitting	2 Construction schedule includes engineering design and permitting	2 Construction schedule includes engineering design and permitting	2 Construction schedule includes engineering design and permitting	2 Construction schedule includes engineering design and permitting	2 Construction schedule includes engineering design and permitting	2 Construction schedule includes engineering design and permitting	2 Construction schedule includes engineering design and permitting	2 Construction schedule includes engineering design and permitting	2 Construction schedule includes engineering design and permitting

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines
As of December 31, 2024

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
Big Bend ST 4	Big Bend ST 4 does not require any new transmission line	-	-	-	230 kV	April 2025	-	Big Bend	None
Polk CT 1** **	Polk CT 1 does not require any new transmission lines****	-	-	-	230 kV	June 2025	-	Polk	None
Polk CC 2 Phase I	Polk CC 2	-	-	-	230 kV	November 2026	-	Polk	None
Curiosity Creek Solar* **	Curiosity Creek Solar - Farmland	1	Not Determined	0.7	230 kV	December 2026	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

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.

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

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	12.3	2.6	473.1%	10.8	1.1	981.8%	21.2	1.8	1,177.8%
2016	7.7	4.1	187.8%	5.1	1.6	318.8%	13.2	3.5	377.1%
2017	6.9	5.2	132.7%	4.7	2.2	213.6%	14.9	4.8	310.4%
2018	8.0	6.5	123.0%	5.6	2.7	205.7%	17.1	6.1	280.3%
2019	8.3	7.6	108.8%	5.7	3.1	184.5%	16.8	6.9	243.2%
2020	3.5	7.6	45.5%	2.6	3.3	78.2%	8.9	7.4	120.3%
2021	4.5	8.0	55.8%	6.4	3.3	194.2%	16.4	7.7	213.1%
2022	9.5	7.4	127.8%	11.1	3.0	369.8%	30.4	6.9	441.0%
2023	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		14.0			7.9			24.8	

Commercial/ Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	8.1	1.2	675.0%	11.7	1.7	688.2%	12.5	3.9	320.5%
2016	2.9	1.3	223.1%	4.4	2.5	176.0%	17.8	6.0	296.7%
2017	9.2	1.6	575.0%	10.4	2.7	385.2%	30.2	8.0	377.5%
2018	13.0	1.7	767.1%	15.0	3.3	453.6%	33.7	9.2	365.9%
2019	22.4	1.6	1401.9%	29.2	3.3	885.9%	74.6	9.9	753.4%
2020	10.4	1.7	612.5%	11.8	3.5	336.0%	26.1	10.3	253.3%
2021	4.7	1.9	246.2%	5.6	3.6	156.8%	20.4	10.4	196.1%
2022	7.1	1.9	376.0%	12.3	3.3	372.2%	26.6	10.2	261.2%
2023	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		5.4			6.4			22.2	

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2015	20.4	3.8	536.8%	22.5	2.8	803.6%	33.7	5.7	591.2%
2016	10.6	5.4	196.3%	9.5	4.1	231.7%	31.0	9.5	326.3%
2017	16.1	6.8	236.8%	15.1	4.9	308.2%	45.1	12.8	352.3%
2018	21.0	8.2	256.5%	20.5	6.0	342.1%	50.8	15.3	331.8%
2019	30.7	9.2	333.7%	35.0	6.4	546.2%	91.4	16.8	543.9%
2020	13.9	9.3	149.1%	14.3	6.8	210.9%	35.0	17.7	197.7%
2021	9.1	9.9	92.3%	12.1	6.9	174.7%	36.8	18.1	203.3%
2022	16.6	9.3	178.5%	23.4	6.3	371.0%	57.1	17.1	333.8%
2023	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		19.4			14.3			47.0	

Table IV-I **2025 Cogeneration Capacity Forecast**	**Capacity** **(MW)**
Self-service [1]	145
Firm to Tampa Electric	0
As-available to Tampa Electric	6
Export to other systems	55
Total	206

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