TEN-YEAR SITE PLAN

For Electrical Generating Facilities
and Associated Transmission Lines

JANUARY 2020 - DECEMBER 2029

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TEC022420

Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2020 to December 2029

Submitted to: Florida Public Service Commission
April 1, 2020

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GLOSSARY OF TERMS

CODE IDENTIFICATION SHEET

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

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Executive Summary

Tampa Electric Company's (TEC) 2020 Ten-Year Site Plan (TYSP) features plans to enhance electric generating capability as part of our efforts to meet projected incremental resource needs for 2020 through 2029. The 2020 TYSP provides the Florida Public Service Commission (FPSC) with assurance that TEC will be able to supply cost-effective alternatives to ensure the delivery of adequate, safe, environmentally responsible, and reliable power to TEC's customers.

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 and reliable manner.

Investments in renewable generation enables fuel savings for customers, fuel diversification, and fortifies TEC's commitment towards decarbonization. The company has announced it plans to deploy more solar projects over the next several years, bringing the total solar capacity to 1,255 MW or approximately 21.7% of the total installed capacity by the end of 2023. As a result, TEC projects to produce more energy from solar than coal generation.

TEC is also committed to pursue cost-effective improvements on the existing generating fleet. The first phase of the Big Bend modernization project will commence with the deployment of two simple cycle CTs, and the retirement of Unit 2 in November 2021. These CTs will then be integrated into a repowered Big Bend Unit 1 steam turbine and converted into a natural gas combined cycle plant by 2023. In addition, the Bayside station plans to undergo advanced hardware upgrades to improve efficiency, generating capacity, and operational flexibility to its seven CTs during this ten-year period.

The remainder of the expansion plan will meet growing customer needs with the addition of distributed energy resources throughout our territory. Besides enhancements to the existing assets and the aforementioned solar, TEC plans to add approximately 220 MW of distributed battery storage capacity, and approximately 185 MW of capacity using reciprocating engines over the study horizon.

The portfolio of resource additions presented in this TYSP work in concert to provide cost savings, environmental and reliability benefits for customers, enhances operational flexibility, and improves system resiliency and reliability.

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Chapter I

DESCRIPTION OF EXISTING FACILITIES

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

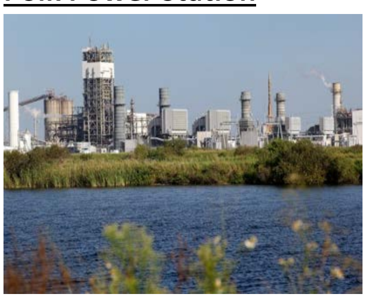
Big Bend Power Station

Big Bend Units 1-4 are four (4) pulverized coal-fired steam units equipped with desulfurization scrubbers, electrostatic precipitators, and Selective Catalytic Reduction (SCR) air pollution control systems. All four units can also be fired with natural gas. Natural gas is the primary fuel on 1 and 2. Big Bend CT 4 is one (1) aero-derivative combustion turbine that can be fired with natural gas or distillate oil.

H.L. Culbreath Bayside Power Station

The station operates two (2) natural gas-fired combined cycle units and (4) aero derivative combustion turbines. Bayside Unit 1 utilizes three (3) combustion turbines, three (3) heat recovery steam generators (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 IGCC / natural gas unit consisting of one (1) combustion turbine, one (1) HSRG, and one (1) steam turbine. Polk 2 Combined Cycle utilizes four (4) natural gas-fired combustion turbines, four (4) HRSGs and one (1) steam turbine. Two of the combustion turbines can also be fired with distillate oil.

Solar

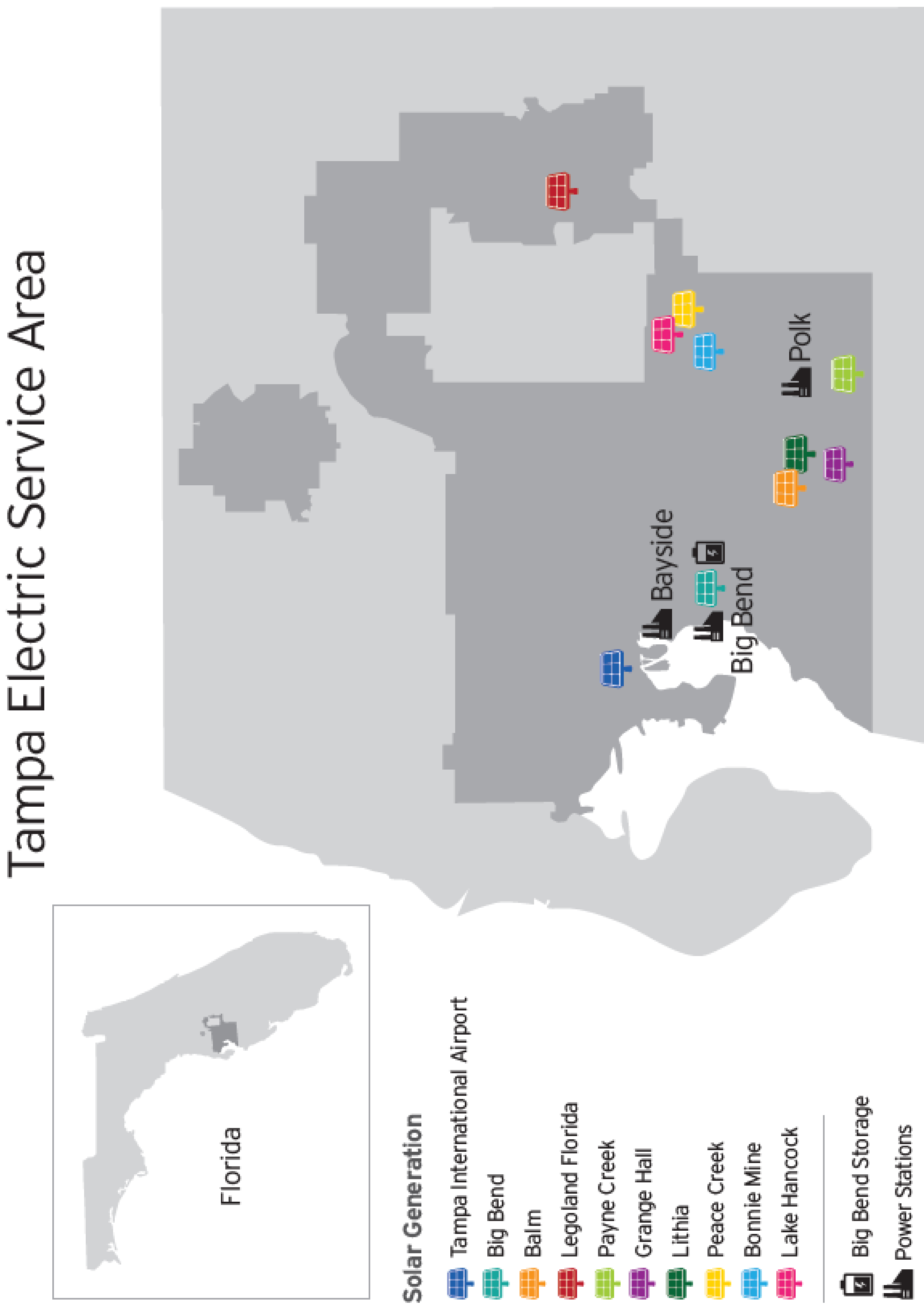
TEC owns 445 MW_{AC} of solar throughout our territory. It consists of a 1.6 MW_{AC} fixed tilt solar PV rooftop canopy array located atop the south parking garage at Tampa International Airport, a 1.4 MW_{AC} fixed tilt solar PV ground canopy array located at LEGOLAND® Florida, and a 19.8 MW_{AC} single axis tracking solar station coupled with a 12.6 MW battery storage unit located at Big Bend Power Station. Additionally, TEC has a total of 423 MW_{AC} of single axis tracking PV solar at several solar sites throughout Hillsborough and Polk counties.

Schedule 1
Existing Generating Facilities
As of December 31, 2019

(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
Big Bend***		Hillsborough Co.											
	1		ST	NG	NG	WA/RR	PL	NA	10/70	**	445,500	385	395
	2		ST	NG	NG	WA/RR	PL	NA	04/73	11/2021	445,500	385	395
	3		ST	BIT	NG	WA/RR	PL	NA	05/76	**	445,500	395	400
	4		ST	BIT	NG	WA/RR	PL	NA	02/85	**	486,000	437	442
	CT 4		GT	NG	DFO	PL	TK	*	08/09	**	69,900	56	61
Big Bend Total											**1,892,400**	**1,658**	**1,693**
Bayside		Hillsborough Co.											
	1		CC	NG	NA	PL	NA	NA	04/03	**	809,060	701	792
	2		CC	NG	NA	PL	NA	NA	01/04	**	1,205,100	929	1,047
	3		GT	NG	NA	PL	NA	NA	07/09	**	69,900	56	61
	4		GT	NG	NA	PL	NA	NA	07/09	**	69,900	56	61
	5		GT	NG	NA	PL	NA	NA	04/09	**	69,900	56	61
	6		GT	NG	NA	PL	NA	NA	04/09	**	69,900	56	61
Bayside Total											**2,293,759**	**1,854**	**2,083**
Polk		Polk Co.											
	1		IGCC	PC/BIT	NG	WA/TK	PL	*	09/96	**	326,299	220	220
	2		CC	NG	DFO	PL	TK	*	01/17	**	1,216,080	1,061	1,200
Polk Total											**1,542,379**	**1,281**	**1,420**
TIA	1	Hillsborough Co.	PV	SOLAR	NA	NA	NA	NA	12/15	**	1,600	1.6	1.6
LEGOLAND®	1	Polk Co.	PV	SOLAR	NA	NA	NA	NA	12/16	**	1,400	1.4	1.4
Big Bend Solar****	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	**	74,400	74.4	74.4
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
Solar Total											**445,400**	**445**	**445**
											TOTAL	**5,238**	**5,641**

Notes:
* Limited by environmental permit
** Undetermined
*** Plant firm net capability will be limited effective January 2023
**** The 12.6 MW Big Bend Battery was integrated into the solar site at Big Bend in December 2019.

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 the necessary 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 methods and the major assumptions utilized in developing the 2020-2029 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the 2020-2029 time period.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2020-2029 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 that is consistent with short-term statistical forecasts.

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

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

The MetrixND models are the company's most sophisticated and primary load forecasting models. The phosphate demand and energy are forecasted separately and then combined in the final forecast, as well as the effects of 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 nine-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.

1. *Residential Customer Model:* Customer projections are a function of regional population. Since a strong correlation exists between regional population and historical changes in service area customers, regional population estimates were used to forecast the future growth patterns in residential customers.

   Commercial Customer Model: Total commercial customers include commercial customers plus temporary service customers (construction sites); therefore, two models are used to forecast total commercial customers:

2. The <u>Commercial Customer Model</u> is a function of population. An increase in the number of households provides the need for additional services, restaurants, and retail establishments. The amount of residential activity also plays a part in the attractiveness of the Tampa Bay area as a place to relocate or start a new business.

3. Projections of permits in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the <u>Temporary Service Model</u> projects the number of customers as a function of new construction permits.

   Industrial Customer Model (Non-Phosphate): Non-phosphate industrial customers include two rate classes that have been modeled individually: General Service and General Service Demand.

4. The <u>General Service Customer Model</u> is a function of Hillsborough County commercial employment.

5. The <u>General Service Demand Customer Model</u> is a function of employment in the manufacturing sector as well as recent trends.

Public Authority Customer Model: Customer projections are based on the recent growth trends in the governmental sector and are modeled individually for three rate classes: Residential Service, General Service and General Service Demand. Starting in 2017, street and highway lighting data was included as part of the public authority sector.

6. The Residential Service Customer Model is a function of recent trends.

7. The General Service Customer Model is a function of recent trends.

8. The General Service Demand Customer Model is a function of recent trends, as well.

9. *Street & Highway Lighting Customer Model:* Customer projections are based on recent growth trends in the sector.

3. Energy Multiregression Model

There are a total of nine energy models. All these models represent average usage per customer (kWh/customer), except for the temporary services and lighting models which represent total 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 an approach known as Statistically Adjusted Engineering (SAE). 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 time frame, as do econometric regression models.

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

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

   Where:

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

Commercial Energy Models: total commercial energy sales include commercial sales plus temporary service sales (construction sites); therefore, two models are used to forecast total commercial energy sales.

2. <u>Commercial Energy Model</u>: 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.

3. Temporary Service Energy Model: This model is a subset of the total commercial sector and is a rather small percentage of the total commercial sector. Although small in nature, it is still a component that needs to be included. A simple regression model is used with the primary driver being temporary service customer growth along with the number of days billed, cooling and heating degree-days.

Industrial Energy Model (Non-Phosphate): Non-phosphate industrial energy includes two rate classes that have been modeled individually: General Service and General Service Demand.

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

5. The General Service Demand Energy Model 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.

Public Authority Sector Energy Model: The governmental sector is modeled individually for three rate classes: Residential Service, General Service and General Service Demand.

6. The Residential Service Energy Model is based on the residential equipment saturation and efficiency assumptions used in the residential model.

7. The General Service Energy Model 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.

8. The General Service Demand Energy Model is a function of cooling and heating degree-days.

9. *Street & Highway Lighting Sector Energy Model:* The street and highway lighting sector is not weather sensitive; therefore; it is a rather simple model and the SAE modeling approach does not apply. The model is a linear regression model where street and highway lighting energy consumption is a function of the number of billing days in the cycle, the number of daylight hours in a day for each month and recent trends. Starting in 2017, street and highway lighting data was included as part of the public authority sector. The street and highway lighting forecast reflects the impacts of the company's LED lighting program.

The nine energy models described above, plus the effects of PV and EV related energy, and an exogenous interruptible and phosphate forecast, are added together to arrive at the total retail energy sales forecast. A line loss factor is applied to the energy sales forecast to produce the retail net energy for load forecast.

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, as well as 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 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 for both the temperature at the time of the peak and the 24-hour average on the day of the peak and day prior to the peak. By incorporating both temperatures, 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 to arrive at the final projected peak demand.

5. Interruptible Demand and Energy Analysis

TEC interruptible customers are relatively few in number, which has allowed the company's Sales and Marketing Department to obtain detailed knowledge of industry developments including:

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

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

6. Roof Top Solar (PV)

Roof top 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, assumptions on future incremental PV installations and the amount of generation they can produce are developed and accumulated to produce a forecast of PV generation. It is assumed that 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

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

8. Conservation, Load Management and Cogeneration Programs

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

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

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

1. Defer expansion, particularly production plant construction.
2. Reduce marginal fuel cost by managing energy usage during higher fuel cost periods.
3. Provide customers with some ability to control energy usage and decrease energy costs.
4. Pursue the cost-effective accomplishment of the FPSC ten-year demand and energy conservation goals for the residential and commercial/industrial sectors.
5. Achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act (FEECA).

In 2019, Tampa Electric continued operating within the 2015-2024 DSM Plan which supports the approved FPSC goals which are reasonable, beneficial and cost-effective to all customers as required by the FEECA. The company also completed the technical potential study through the achievable potential process that started in 2018 to develop and propose to the FSPC numerical DSM goals for the 2020-2029 period. On November 5, 2019, the FPSC decided to continue the DSM goals approved in the 2015 – 2024 goal setting dockets for the 2020-2024 period. 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 TEC 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. Residential Electronically Commutated Motor (ECM) – a rebate program that encourages residential customers to replace their existing HVAC air handler motor with an ECM.

5. Energy Education, Awareness and Agency Outreach - a program that provides opportunities for engaging and educating groups of customers and 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.

6. 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.

7. 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.

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

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

10. 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.

11. Residential Wall Insulation – a rebate program that encourages existing residential customers to install additional wall insulation in existing homes.

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

13. Commercial Ceiling Insulation – a rebate program that encourages commercial and industrial customers to install additional ceiling insulation in existing commercial structures.

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 that are not sanctioned by other commercial programs.

17. Cool Roof – a rebate program that encourages commercial and industrial customers to install a cool roof system above conditioned spaces.

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

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

20. Commercial Duct Repair – a rebate program that encourages existing commercial and industrial customers to repair leaky ductwork of central air-conditioning systems in existing commercial and industrial facilities.

21. Commercial Electronically Commutated Motors (ECM) - a rebate program that encourages commercial and industrial customers to replace their existing air handler motors or refrigeration fan motors with an ECM.

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

23. Street and Outdoor Lighting Conversion – a program that recovers the remaining net book value

for converting the company's existing metal halide and high-pressure sodium street and outdoor luminaires to light emitting diode technology.

24. 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.

25. 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.

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

27. 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.

28. Refrigeration Anti-Condensate Control – a rebate program that encourages commercial and industrial customers to install anti-condensate equipment sensors and control within refrigerated door systems.

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

30. Thermal Energy Storage - a rebate program that encourages commercial and industrial customers to install an off-peak air conditioning system.

31. Commercial Wall Insulation – a rebate program that encourages commercial and industrial customers to install wall insulation in existing commercial and industrial structures.

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

33. 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 TEC and its ratepayers.

The programs listed above were developed to meet FPSC demand and energy goals established in Docket No. 20130201-EI, Order No. PSC-14-0696-FOF-EU, Issued December 16, 2014. The 2019 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

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

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

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

Residential

	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		7.6			3.3			7.4	
2021		8.0			3.3			7.7	
2022		7.4			3.0			6.9	
2023		6.8			2.9			6.3	
2024		6.1			2.5			5.5	

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		1.7			3.5			10.3	
2021		1.9			3.6			10.4	
2022		1.9			3.3			10.2	
2023		1.8			3.5			9.9	
2024		1.7			3.2			9.6	

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		9.3			6.8			17.7	
2021		9.9			6.9			18.1	
2022		9.3			6.3			17.1	
2023		8.6			6.4			16.2	
2024		7.8			5.7			15.1	

BASE CASE FORECAST ASSUMPTIONS

RETAIL LOAD

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

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

1. Population and Households

Florida and Hillsborough County population forecasts are the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Moody's Analytics supply population projections for Hillsborough County and Florida comparisons. BEBR's population growth for Hillsborough County was used to project future growth patterns in residential customers for the period of 2020-2029. The average annual population growth rate is expected to be 1.6%.

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 (2020-2029), employment is assumed to rise at a 0.9% 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 2.3% average annual rate from 2020-2029. 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 2020-2029, real household income for Hillsborough County is expected to increase at a 2.1% 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. In addition, 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.

HIGH AND LOW SCENARIO FOCUS ASSUMPTIONS

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

HISTORY AND FORECAST OF ENERGY USE

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

1. Retail Energy

For 2020-2029, retail energy sales are projected to rise at a 1.1% annual rate. The major contributors to growth include the governmental and residential categories, increasing at an annual rate of 1.6% and 1.4%, respectively.

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 2020-2029, TEC's base retail firm peak demand is expected to increase at an average annual rate of 1.2% in the summer and 1.3% in the winter.

Chapter III

INTEGRATED RESOURCE PLANNING PROCESSES

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

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

Detailed cost analyses for each of the top ranked resource plans are performed using the Planning & Risk (PaR) production cost model, also developed by ABB. 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 TEC with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, the company's expansion plans include the remaining addition of solar PV through 2021 in accordance with the approved 2017 Solar Base Rate Adjustment (SoBRA) agreement. The company also plans to add an additional incremental 600 MW_{AC} of solar.

The first phase of the Big Bend modernization project will commence with the deployment of two simple cycle CTs, and the retirement of Unit 2 in November 2021. These CTs will then be integrated into a repowered Big Bend Unit 1 steam turbine and converted into a natural gas combined cycle by 2023. In addition, the Bayside station plans to undergo advanced hardware improvements to its seven CTs during this ten-year period. All these changes to the expansion plan are shown in Schedule 8.1.

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

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

FINANCIAL ASSUMPTIONS

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

- Per the Florida Administrative Code 25-6, an amount for AFUDC is recorded by the company during the construction phase of each capital project that meets the requirements. This rate is approved by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.

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

FUEL FORECAST

TEC forecasts base case natural gas, coal, and oil fuel commodity prices by analyzing current market prices and price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, PIRA Energy Group, U.S. Energy Information Administration, Coal Daily, Inside FERC, and Platt’s Oilgram. 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

Since being approved as a permanent Renewable Energy Program by the Commission in Docket No. 060678-EG, Order No. PSC-06-1063-TRF-EG, issued December 26, 2006, TEC has offered 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 portion to the program which allows residential, commercial and industrial customers the opportunity to purchase renewable energy 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 2019, TEC's Renewable Energy Program has 1,394 customers purchasing over 2,277 blocks of renewable energy each month.

The company's renewable-generation portfolio is a mix of various technologies and renewable generating sources, including smaller, company-owned photovoltaic (PV) arrays totaling 176 kW_{AC} and an increasing number of large-scale PV systems that provide ample solar kWh for the Renewable Energy Block Program. The smaller, community-sited PV arrays are installed at the Museum of Science and Industry, Walker Middle and Middleton High schools, Tampa Electric's Manatee Viewing Center, Tampa's Lowry Park Zoo, the Florida Aquarium, LEGOLAND Florida's Imagination Zone, and at the Florida Conservation and Technology Center (FCTC), an environmental and energy education facility located in Apollo Beach.

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.

In 2021, the Renewable Energy Program, marketed as Sun to Go, is projecting to install 30 solar powered streetlights in a newly built community. In addition to these lights, the company will install two small arrays that will provide solar powered charging stations for small electronics (cell phones, tablets) at the Museum of Science and Industry.

Looking forward, Super Bowl LV is scheduled to be played in Tampa, Florida on February 7^{th}, 2021. TEC is planning partnerships with Sports and Visitor Groups and Venues to engage customers and visitors. A presence to promote solar and sustainability at pop-up education stations is one activity planned.

In mid-2019, TEC launched a 17.5 MW_{AC} Shared Solar Program, called Sun Select, providing another choice for customers unable to install rooftop solar but prefer their energy generated from solar.

In September 2017, TEC announced the Company's plans to install an additional 600 MW_{AC} at ten new sites by January 2021, which is enough electricity to power more than 100,000 homes. When the projects are complete, TEC will have 827 watts per customer of solar capacity and over 7 percent of TEC's generation will come from the sun. The first two project sites, Payne Creek Solar and Balm Solar, went in service in September 2018 with the ability to generate 144.7 MW_{AC} of clean, renewable energy for more than 22,000 homes. An additional 277.8 MW_{AC} went into service at five more project sites that year, including 17.5 MW_{AC} specifically built for Tampa Electric's new shared solar program, Sun Select. With the completion of two more 75 MW_{AC} projects, which are well underway, and one more being constructed in 2020, the most recent solar additions, totaling more than 600 MW_{AC}, will significantly reduce Tampa Electric's carbon dioxide emissions and give customers the benefit of zero fuel-cost solar generation for years to come.

As market conditions continue to change and technology improves in this sector, renewable alternatives, such as solar, become more cost-effective to our customers. Rooftop solar is currently cost-effective for some of our customers. Between December 2018 and December 2019, with tax incentives and the incentive provided by the FPSC's net metering rule, over 2,000 customers installed solar panels on their homes or businesses, indicating the increasing acceptance of customer owned renewable generation. Through December 2019, more than 5,000 customers installed PV systems on their homes or businesses, accounting for more than 46 MW_{AC} of net metered, distributed solar generation interconnected on TEC's grid.

2. Storage Technology Initiatives

Battery storage costs have declined over the last few years and are projected to continue to decline in the future. In December 2019, a 12.6 MW lithium-ion energy storage system (ESS) was put in service at TEC's Big Bend Solar site. The ESS is AC coupled with the solar array and will charge via solar. Several of the expected benefits of battery storage projects include firming of the solar output during peak times, energy arbitrage, and contribution to contingency reserves.

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

TEC calculates reserve margin in two ways to measure reliability of the generating system. The company utilizes a minimum 20 percent firm reserve margin with a minimum contribution of 7 percent supply-side resources. TEC's approach to calculating percent reserves are consistent with the agreement that is outlined in the Commission approved Docket No. 981890-EU, Order No. PSC-99-

2507-S-EU, issued December 22, 1999. The calculation of the minimum 20 percent firm reserve margin employs an industry accepted method of using total available generating capacity and firm purchased power capacity (capacity less planned maintenance and solar capacity unavailable at the time of peak demand, and contracted unit sales) 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.

SUPPLY-SIDE RESOURCES PROCUREMENT PROCESS

TEC will manage the procurement process in accordance with established policies and procedures. Prospective suppliers of supply-side resources, as well as suppliers of equipment and services, will be identified using various database resources and competitive bid evaluations, and will be used in developing award recommendations to management.

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

TRANSMISSION PLANNING - CONSTRAINTS AND IMPACTS

The TEC transmission system supports the reliable delivery of required capacity and energy to TEC's retail and wholesale customers. Transmission Planning studies are performed annually to evaluate the performance of the TEC transmission system with the results of the studies varying due to refinements in load projections, planning criteria, generation plans and operating flexibility. This involves the use of steady-state load flow, short circuit and transient stability programs to model various contingency situations, 3-Phase Fault and Single Line-Ground Fault analysis that may occur to determine if the TEC transmission system meets the reliability criteria. Simulations of normal system conditions, as well as single and select multiple contingency events, are performed during system peak and off-peak load levels, and summer and/or winter conditions. Based on existing studies (ex: internal expansion, joint utility, operating, Florida Reliability Coordinating Council (FRCC) Long Range Study, FRCC Planning and Extreme Events Stability Analysis, FRCC Summer Assessment, FRCC Winter Assessment and other miscellaneous studies) and TEC's current transmission construction program, TEC anticipates no transmission constraints that violate the criteria as described in the Transmission Planning Reliability Criteria section of this document.

TRANSMISSION PLANNING RELIABILITY CRITERIA

1. Transmission

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

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

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

2. Available Transmission Transfer Capability (ATC) Criteria

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

TRANSMISSION SYSTEM PLANNING ASSESSMENT PRACTICES

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

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

1. Base Case Operating Conditions

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

2. Single Contingency Planning Criteria

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

3. Multiple Contingency Planning Criteria

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

4. Transmission Construction and Upgrade Plans

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

ENERGY EFFICIENCY, CONSERVATION, AND ENERGY SAVINGS DURABILITY

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

1. 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.

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

3. Analysis of DOE2 modeling of various program participants.

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

5. 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, water heating replacements, and ECM motor upgrades) have program standards that require the new equipment to be installed in a permanent manner thus ensuring their durability.

Chapter IV

FORECAST OF ELECTRIC POWER, DEMAND AND ENERGY CONSUMPTION

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

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

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

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

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

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

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

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

Schedule 5: History and Forecast of Fuel Requirements

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

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

Schedule 2.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2010	1,229,226	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,238,951	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,256,118	2.6	8,395	603,594	13,909	6,185	71,143	86,937
2013	1,276,410	2.6	8,470	613,206	13,812	6,090	71,966	84,619
2014	1,301,887	2.6	8,656	623,846	13,875	6,142	72,647	84,548
2015	1,325,563	2.6	9,045	635,403	14,235	6,301	73,556	85,658
2016	1,352,797	2.5	9,187	646,221	14,217	6,310	74,313	84,911
2017	1,379,302	2.6	9,029	659,387	13,693	6,362	74,998	84,830
2018	1,408,864	2.6	9,418	670,517	14,046	6,266	74,895	83,664
2019	1,444,870	2.6	9,584	685,122	13,989	6,239	76,038	82,057
2020	1,468,762	2.6	9,600	698,024	13,753	6,302	76,922	81,929
2021	1,496,002	2.6	9,696	711,081	13,635	6,358	77,381	82,159
2022	1,522,909	2.6	9,844	723,831	13,599	6,417	78,168	82,088
2023	1,549,085	2.6	9,982	736,236	13,558	6,474	79,071	81,871
2024	1,574,425	2.5	10,131	748,247	13,540	6,525	79,660	81,906
2025	1,598,843	2.5	10,269	759,820	13,515	6,565	79,932	82,137
2026	1,622,162	2.5	10,409	770,874	13,503	6,600	80,121	82,378
2027	1,644,706	2.5	10,556	781,561	13,507	6,635	80,381	82,543
2028	1,666,516	2.5	10,717	791,900	13,533	6,673	80,762	82,627
2029	1,687,616	2.5	10,889	801,903	13,579	6,716	81,181	82,733

Notes:

December 31, 2019 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**
2020	1,479,071	2.6	9,663	701,436	13,775	6,315	77,075	81,938
2021	1,513,897	2.6	9,823	718,056	13,680	6,385	77,694	82,176
2022	1,548,696	2.6	10,039	734,513	13,667	6,458	78,648	82,115
2023	1,583,058	2.6	10,247	750,766	13,649	6,530	79,724	81,910
2024	1,616,870	2.6	10,469	766,759	13,654	6,597	80,491	81,957
2025	1,651,404	2.6	10,682	782,444	13,653	6,654	80,948	82,198
2026	1,685,272	2.6	10,900	797,732	13,664	6,705	81,326	82,448
2027	1,718,278	2.6	11,127	812,772	13,691	6,757	81,783	82,621
2028	1,750,750	2.6	11,371	827,580	13,740	6,813	82,364	82,717
2029	1,782,720	2.6	11,630	842,164	13,810	6,874	82,988	82,836

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

Schedule 2.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2020	1,450,341	2.6	9,538	694,611	13,731	6,289	76,769	81,921
2021	1,469,987	2.5	9,570	704,141	13,591	6,331	77,069	82,143
2022	1,489,077	2.5	9,651	713,254	13,531	6,376	77,693	82,062
2023	1,507,226	2.5	9,722	721,919	13,467	6,418	78,429	81,830
2024	1,507,226	2.4	9,802	730,094	13,426	6,454	78,845	81,854
2025	1,523,064	2.4	9,870	737,745	13,378	6,479	78,941	82,076
2026	1,537,664	2.4	9,938	744,796	13,343	6,498	78,950	82,309
2027	1,551,345	2.4	10,012	751,405	13,324	6,517	79,028	82,464
2028	1,564,160	2.4	10,097	757,596	13,327	6,539	79,222	82,537
2029	1,576,143	2.3	10,192	763,386	13,351	6,565	79,452	82,630

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

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				Street &	Other Sales	Total Sales
			Average KWH	Railroads	Highway	to Public	to Ultimate
			Consumption	and Railways	Lighting	Authorities	Consumers
Year	GWH	Customers*	Per Customer	GWH	GWH **	GWH	GWH
2010	2,010	1,434	1,401,767	0	73	1,724	19,213
2011	1,804	1,494	1,207,299	0	74	1,761	18,564
2012	2,001	1,537	1,302,171	0	75	1,756	18,412
2013	2,027	1,564	1,295,916	0	75	1,756	18,418
2014	1,901	1,572	1,208,831	0	75	1,752	18,526
2015	1,870	1,586	1,179,087	0	77	1,714	19,006
2016	1,928	1,616	1,193,504	0	78	1,730	19,234
2017	2,024	1,608	1,259,094	0	0	1,771	19,186
2018	2,014	1,588	1,268,262	0	0	1,933	19,631
2019	2,021	1,516	1,332,913	0	0	1,939	19,783
2020	1,662	1,576	1,054,424	0	0	2,007	19,571
2021	1,675	1,577	1,062,157	0	0	2,028	19,757
2022	1,661	1,581	1,050,891	0	0	2,048	19,969
2023	1,667	1,584	1,052,375	0	0	2,072	20,194
2024	1,673	1,587	1,054,054	0	0	2,105	20,433
2025	1,677	1,590	1,055,040	0	0	2,143	20,654
2026	1,669	1,593	1,047,881	0	0	2,181	20,860
2027	1,674	1,596	1,048,892	0	0	2,222	21,088
2028	1,680	1,599	1,050,318	0	0	2,264	21,334
2029	1,686	1,603	1,052,285	0	0	2,307	21,599

Notes:
December 31, 2019 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				Street &	Other Sales	Total Sales
			Average KWH	Railroads	Highway	to Public	to Ultimate
			Consumption	and Railways	Lighting	Authorities	Consumers
Year	GWH	Customers*	Per Customer	GWH	GWH **	GWH	GWH
2020	1,664	1,578	1,054,691	0	0	1,957	19,599
2021	1,680	1,580	1,063,134	0	0	1,962	19,849
2022	1,668	1,585	1,052,160	0	0	1,968	20,132
2023	1,676	1,589	1,054,672	0	0	1,980	20,432
2024	1,684	1,594	1,056,419	0	0	1,995	20,745
2025	1,691	1,598	1,058,098	0	0	2,010	21,037
2026	1,685	1,602	1,051,628	0	0	2,025	21,315
2027	1,692	1,606	1,053,434	0	0	2,041	21,617
2028	1,700	1,611	1,055,128	0	0	2,056	21,940
2029	1,709	1,615	1,058,003	0	0	2,071	22,284

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

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH **	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2020	1,660	1,575	1,053,842	0	0	1,957	19,444
2021	1,671	1,575	1,060,823	0	0	1,962	19,533
2022	1,654	1,576	1,049,667	0	0	1,967	19,649
2023	1,658	1,579	1,050,080	0	0	1,979	19,777
2024	1,662	1,580	1,051,756	0	0	1,995	19,912
2025	1,664	1,582	1,052,080	0	0	2,010	20,023
2026	1,654	1,584	1,044,212	0	0	2,025	20,115
2027	1,657	1,586	1,044,709	0	0	2,040	20,226
2028	1,661	1,588	1,045,750	0	0	2,055	20,351
2029	1,665	1,591	1,046,678	0	0	2,070	20,492

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

Schedule 2.3

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

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	Total **** Customers
2010	305	1,149	20,667	7,827	670,991
2011	93	642	19,298	7,869	675,799
2012	69	839	19,320	7,962	684,236
2013	0	760	19,177	7,999	694,735
2014	0	789	19,315	8,095	706,161
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	926	20,497	9,486	786,008
2021	0	918	20,674	9,577	799,616
2022	0	912	20,882	9,668	813,247
2023	0	911	21,105	9,759	826,650
2024	0	905	21,338	9,851	839,345
2025	0	892	21,547	9,942	851,284
2026	0	878	21,738	10,034	862,622
2027	0	863	21,950	10,126	873,664
2028	0	847	22,181	10,218	884,479
2029	0	831	22,430	10,309	894,996

Notes:

December 31, 2019 Status

*Includes sales to Duke Energy Florida (DEF), Wauchula (WAU), Ft. Meade (FTM), St. Cloud (STC), Reedy Creek (RCID) and Florida Power & Light (FPL). Contract ended with DEF on 2/31/11, WAU on 9/31/11, STC on 12/31/2012, FPL on 12/31/12, and RCID on 12/31/10. 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
2020	0	980	20,579	9,486	789,575
2021	0	991	20,841	9,577	806,907
2022	0	1,005	21,137	9,668	824,414
2023	0	1,020	21,453	9,759	841,838
2024	0	1,036	21,781	9,851	858,695
2025	0	1,051	22,088	9,942	874,932
2026	0	1,065	22,380	10,034	890,694
2027	0	1,080	22,697	10,126	906,287
2028	0	1,096	23,036	10,218	921,773
2029	0	1,113	23,397	10,309	937,076

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

Schedule 2.3

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

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWH	Utility Use * & Losses GWH	Net Energy ** for Load GWH	Other *** Customers	Total *** Customers
2020	0	972	20,416	9,486	782,441
2021	0	975	20,509	9,577	792,362
2022	0	981	20,630	9,668	802,191
2023	0	988	20,765	9,759	811,686
2024	0	994	20,907	9,851	820,370
2025	0	1,000	21,023	9,942	828,210
2026	0	1,005	21,120	10,034	835,364
2027	0	1,011	21,236	10,126	842,145
2028	0	1,017	21,368	10,218	848,624
2029	0	1,024	21,516	10,309	854,738

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

Schedule 3.1

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

(1)	(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
2010	4,171	118	4,053	73	33	97	75	65	3,710
2011	4,130	28	4,102	109	48	103	75	68	3,699
2012	4,089	15	4,073	133	45	111	86	71	3,627
2013	4,072	0	4,072	131	39	122	89	77	3,614
2014	4,270	0	4,270	170	36	132	91	83	3,757
2015	4,245	0	4,245	111	21	143	98	87	3,784
2016	4,403	15	4,388	138	0	150	101	92	3,907
2017	4,373	5	4,368	110	0	155	100	98	3,905
2018	4,287	0	4,287	125	0	160	98	106	3,798
2019	4,591	0	4,591	122	0	166	98	126	4,079
2020	4,434	0	4,434	87	0	172	101	115	3,960
2021	4,488	0	4,488	89	0	178	102	118	4,002
2022	4,547	0	4,547	86	0	183	102	121	4,054
2023	4,608	0	4,608	86	0	189	103	124	4,105
2024	4,667	0	4,667	86	0	195	103	127	4,155
2025	4,723	0	4,723	86	0	201	104	131	4,201
2026	4,776	0	4,776	85	0	207	104	134	4,246
2027	4,831	0	4,831	85	0	213	105	137	4,291
2028	4,889	0	4,889	85	0	219	105	140	4,340
2029	4,948	0	4,948	85	0	225	106	144	4,389

Notes:

December 31, 2019 Status
2010, 2016 and 2018 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. Contract with RCID from 2016 to 2017.
***Includes Energy Planner program.
Values shown may be affected due to rounding.

Schedule 3.1

Forecast of Summer Peak Demand (MW)
High Case

(1) Year	(2) Total *	(3) Wholesale	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation**	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2020	4,451	0	4,451	87	0	172	101	115	3,977
2021	4,524	0	4,524	89	0	178	102	118	4,038
2022	4,602	0	4,602	86	0	183	102	121	4,109
2023	4,682	0	4,682	86	0	189	103	124	4,179
2024	4,762	0	4,762	86	0	195	103	127	4,250
2025	4,839	0	4,839	86	0	201	104	131	4,317
2026	4,913	0	4,913	85	0	207	104	134	4,383
2027	4,991	0	4,991	85	0	213	105	137	4,451
2028	5,072	0	5,072	85	0	219	105	140	4,523
2029	5,154	0	5,154	85	0	225	106	144	4,595

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

Schedule 3.1

Forecast of Summer Peak Demand (MW)
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale	Retail *	Interruptible	Residential Load Management	Residential Conservation**	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2020	4,416	0	4,416	87	0	172	101	115	3,942
2021	4,453	0	4,453	89	0	178	102	118	3,967
2022	4,493	0	4,493	86	0	183	102	121	4,000
2023	4,535	0	4,535	86	0	189	103	124	4,032
2024	4,575	0	4,575	86	0	195	103	127	4,063
2025	4,611	0	4,611	86	0	201	104	131	4,089
2026	4,643	0	4,643	85	0	207	104	134	4,113
2027	4,678	0	4,678	85	0	213	105	137	4,138
2028	4,714	0	4,714	85	0	219	105	140	4,165
2029	4,751	0	4,751	85	0	225	106	144	4,192

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
2009/10	5,140	67	5,073	117	109	470	75	56	4,246
2010/11	4,697	122	4,575	140	88	480	75	58	3,735
2011/12	4,186	120	4,066	103	68	487	83	58	3,267
2012/13	3,780	15	3,764	130	65	501	90	61	2,918
2013/14	3,876	0	3,876	61	63	512	97	64	3,079
2014/15	4,195	0	4,195	79	44	521	96	65	3,390
2015/16	4,025	0	4,025	145	13	533	96	67	3,171
2016/17	3,749	0	3,749	137	0	541	96	70	2,905
2017/18	4,670	0	4,670	66	0	548	96	77	3,883
2018/19	3,921	0	3,921	104	0	556	98	92	3,071
2019/20	5,042	0	5,042	62	0	564	97	94	4,225
2020/21	5,121	0	5,121	63	0	573	97	102	4,287
2021/22	5,195	0	5,195	61	0	581	98	109	4,346
2022/23	5,272	0	5,272	61	0	589	98	116	4,408
2023/24	5,343	0	5,343	61	0	597	99	118	4,468
2024/25	5,410	0	5,410	61	0	605	100	119	4,525
2025/26	5,472	0	5,472	60	0	614	100	120	4,578
2026/27	5,534	0	5,534	60	0	622	101	121	4,630
2027/28	5,596	0	5,596	59	0	630	101	122	4,684
2028/29	5,660	0	5,660	61	0	638	102	123	4,735

Notes:

December 31, 2019 Status
2011/2012 and 2015/2016 Net Firm Demand is not coincident with system peak.
*Includes residential and commercial/industrial conservation.
**Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. Contract with RCID from 2016 to 2017.
***Includes energy planner program.
Values shown may be affected due to rounding.

Schedule 3.2

Forecast of Winter Peak Demand (MW)
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	**Total ***	**Wholesale**	**Retail ***	**Interruptible**	**Residential Load Management**	**Residential Conservation****	**Comm./Ind. Load Management**	**Comm./Ind. Conservation**	**Net Firm Demand**
2019/20	5,061	0	5,061	62	0	564	97	94	4,244
2020/21	5,160	0	5,160	63	0	573	97	102	4,326
2021/22	5,253	0	5,253	61	0	581	98	109	4,404
2022/23	5,352	0	5,352	61	0	589	98	116	4,488
2023/24	5,444	0	5,444	61	0	597	99	118	4,569
2024/25	5,534	0	5,534	61	0	605	100	119	4,649
2025/26	5,619	0	5,619	60	0	614	100	120	4,725
2026/27	5,705	0	5,705	60	0	622	101	121	4,801
2027/28	5,791	0	5,791	59	0	630	101	122	4,879
2028/29	5,881	0	5,881	61	0	638	102	123	4,956

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) 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
2019/20	5,023	0	5,023	62	0	564	97	94	4,206
2020/21	5,083	0	5,083	63	0	573	97	102	4,249
2021/22	5,137	0	5,137	61	0	581	98	109	4,288
2022/23	5,194	0	5,194	61	0	589	98	116	4,330
2023/24	5,244	0	5,244	61	0	597	99	118	4,369
2024/25	5,289	0	5,289	61	0	605	100	119	4,404
2025/26	5,329	0	5,329	60	0	614	100	120	4,435
2026/27	5,369	0	5,369	60	0	622	101	121	4,465
2027/28	5,409	0	5,409	59	0	630	101	122	4,497
2028/29	5,450	0	5,450	61	0	638	102	123	4,525

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 %
2010	19,923	458	251	19,213	305	1,149	20,667	51.1
2011	19,296	474	259	18,564	93	642	19,298	53.0
2012	19,178	493	273	18,412	69	839	19,320	60.4
2013	19,225	513	294	18,418	0	760	19,177	68.0
2014	19,377	546	305	18,526	0	789	19,315	66.8
2015	19,890	568	315	19,006	0	1,098	20,105	57.2
2016	20,153	588	331	19,234	9	930	20,173	55.2
2017	20,141	602	353	19,186	2	1,110	20,298	56.2
2018	20,647	618	399	19,631	0	1,031	20,662	58.7
2019	20,896	635	478	19,783	0	986	20,770	55.2
2020	20,695	647	477	19,571	0	926	20,497	53.2
2021	20,930	661	512	19,757	0	918	20,674	53.1
2022	21,192	675	547	19,969	0	912	20,882	52.9
2023	21,452	690	569	20,194	0	911	21,105	52.8
2024	21,713	704	577	20,433	0	905	21,338	52.5
2025	21,957	718	585	20,654	0	892	21,547	52.5
2026	22,184	732	593	20,860	0	878	21,738	52.4
2027	22,434	746	601	21,088	0	863	21,950	52.3
2028	22,703	760	609	21,334	0	847	22,181	52.1
2029	22,990	774	617	21,599	0	831	22,430	52.3

Notes:

December 31, 2019 Status
*Includes residential and commercial/industrial conservation.
**Includes Energy Planner program.
***Includes sales to FTM, RCID, DEF, WAU, STC and FP&L. Contract ended with DEF on 2/28/11, WAU on 9/30/11, STC on 12/31/12, FP&L on 12/31/12, and RCID on 12/31/10. 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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total*	Residential Conservation**	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load *** Factor %
2020	20,724	647	477	19,599	0	980	20,579	53.2
2021	21,023	661	512	19,849	0	991	20,841	53.0
2022	21,354	675	547	20,132	0	1,005	21,137	52.9
2023	21,690	690	569	20,432	0	1,020	21,453	52.7
2024	22,025	704	577	20,745	0	1,036	21,781	52.4
2025	22,340	718	585	21,037	0	1,051	22,088	52.4
2026	22,640	732	593	21,315	0	1,065	22,380	52.3
2027	22,964	746	601	21,617	0	1,080	22,697	52.2
2028	23,309	760	609	21,940	0	1,096	23,036	52.0
2029	23,675	774	617	22,284	0	1,113	23,397	52.2

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 3.3

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total*	Residential Conservation**	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load *** Factor %
2020	20,568	647	477	19,444	0	972	20,416	53.2
2021	20,706	661	512	19,533	0	975	20,509	53.1
2022	20,871	675	547	19,649	0	981	20,630	53.0
2023	21,035	690	569	19,777	0	988	20,765	52.8
2024	21,192	704	577	19,912	0	994	20,907	52.6
2025	21,325	718	585	20,023	0	1,000	21,023	52.6
2026	21,440	732	593	20,115	0	1,005	21,120	52.5
2027	21,572	746	601	20,226	0	1,011	21,236	52.4
2028	21,720	760	609	20,351	0	1,017	21,368	52.2
2029	21,883	774	617	20,492	0	1,024	21,516	52.4

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)
	2019 Actual		2020 Forecast		2021 Forecast	
Month	**Peak Demand * MW**	**NEL ** GWH**	**Peak Demand * MW**	**NEL ** GWH**	**Peak Demand * MW**	**NEL ** GWH**
January	3,091	1,493	4,384	1,528	4,447	1,535
February	3,094	1,351	3,610	1,328	3,657	1,335
March	3,129	1,477	3,456	1,448	3,493	1,462
April	3,505	1,589	3,547	1,570	3,583	1,587
May	4,153	1,978	3,790	1,808	3,828	1,819
June	4,298	2,014	4,071	1,970	4,113	1,994
July	4,073	2,013	4,089	2,046	4,134	2,067
August	4,111	2,090	4,148	2,106	4,193	2,094
September	4,101	1,991	3,867	1,925	3,912	1,967
October	3,672	1,892	3,627	1,780	3,665	1,798
November	3,309	1,428	3,085	1,449	3,122	1,450
December	2,765	1,453	3,954	1,541	4,006	1,567
TOTAL		20,770		20,497		20,674

Notes:
December 31, 2019 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)
	2019 Actual		2020 Forecast		2021 Forecast	
Month	**Peak Demand * MW**	**NEL ** GWH**	**Peak Demand * MW**	**NEL ** GWH**	**Peak Demand * MW**	**NEL ** GWH**
January	3,091	1,493	4,403	1,521	4,486	1,526
February	3,094	1,351	3,626	1,336	3,688	1,342
March	3,129	1,477	3,471	1,473	3,523	1,476
April	3,505	1,589	3,562	1,572	3,614	1,579
May	4,153	1,978	3,806	1,819	3,861	1,829
June	4,298	2,014	4,088	1,960	4,148	1,993
July	4,073	2,013	4,106	2,050	4,169	2,085
August	4,111	2,090	4,165	2,071	4,229	2,107
September	4,101	1,991	3,883	1,941	3,945	1,975
October	3,672	1,892	3,642	1,769	3,695	1,799
November	3,309	1,428	3,097	1,449	3,147	1,472
December	2,765	1,453	3,970	1,566	4,039	1,590
TOTAL		20,770		20,529		20,774

Notes:
December 31, 2019 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)
	2019 Actual		2020 Forecast		2021 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,091	1,493	4,365	1,509	4,409	1,501
February	3,094	1,351	3,595	1,326	3,626	1,321
March	3,129	1,477	3,441	1,462	3,464	1,453
April	3,505	1,589	3,532	1,560	3,553	1,554
May	4,153	1,978	3,774	1,805	3,796	1,800
June	4,298	2,014	4,054	1,943	4,078	1,959
July	4,073	2,013	4,071	2,033	4,099	2,050
August	4,111	2,090	4,130	2,054	4,158	2,071
September	4,101	1,991	3,851	1,925	3,879	1,941
October	3,672	1,892	3,612	1,754	3,634	1,769
November	3,309	1,428	3,073	1,437	3,096	1,449
December	2,765	1,453	3,938	1,554	3,972	1,565
TOTAL		20,770		20,362		20,431

Notes:
December 31, 2019 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 2018	Actual 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
(1)	Nuclear	Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal	1000 Ton	1,426	570	527	566	591	201	210	196	204	224	227	242
(3)	Residual	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)	ST	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)	CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)	GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)	D	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	1000 BBL	0	1	0	0	0	0	0	0	0	0	0	0
(9)	ST	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)	CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)	GT	1000 BBL	0	1	0	0	0	0	0	0	0	0	0	0
(12)	D	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	1000 MCF	121,662	137,874	134,383	135,021	129,948	125,052	124,446	126,451	127,027	127,724	129,345	131,011
(14)	ST	1000 MCF	19,777	31,564	14,874	14,308	5,022	3,418	4,214	4,461	4,485	3,997	4,654	4,130
(15)	CC	1000 MCF	101,372	106,021	115,886	115,116	123,351	120,975	119,729	121,081	122,001	123,127	123,987	126,243
(16)	GT	1000 MCF	513	289	3,623	5,597	1,575	659	503	909	541	600	704	638
(17)	Other (Specify)													
(18)	PC	1000 Ton	197	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 2018**	**Actual 2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
(1)	**Annual Firm Interchange**	GWh	89	0	84	87	0	0	0	0	0	0	0	0
(2)	**Nuclear**	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	**Coal**	GWh	2,982	1,214	925	995	1,033	345	362	346	359	401	413	444
(4)	**Residual**	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(5)	ST	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)	CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)	GT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)	D	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	**Distillate**	GWh	0	1	0	0	0	0	0	0	0	0	0	0
(10)	ST	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)	CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(12)	GT	GWh	0	1	0	0	0	0	0	0	0	0	0	0
(13)	D	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	**Natural Gas**	GWh	16,097	17,493	17,923	17,861	17,784	18,170	17,883	18,128	18,321	18,503	18,736	18,981
(15)	ST	GWh	1,754	2,632	1,228	1,189	401	272	335	354	355	314	374	326
(16)	CC	GWh	14,297	14,836	16,403	16,204	17,241	17,847	17,507	17,698	17,919	18,136	18,299	18,600
(17)	GT	GWh	45	25	292	468	142	51	41	76	47	53	63	55
(18)	**Renewable**	GWh	118	756	1,414	1,588	1,944	2,466	2,964	2,949	2,937	2,925	2,918	2,902
(19)	Solar	GWh	118	756	1,414	1,588	1,944	2,466	2,964	2,949	2,937	2,925	2,918	2,902
(20)	**Other (Specify)**													
(21)	PC	GWh	551	0	0	0	0	0	0	0	0	0	0	0
(22)	Net Interchange	GWh	633	1,085	29	13	(2)	1	8	(1)	3	2	(0)	(7)
(23)	Purchased Energy from Non-Utility Generators	GWh	192	220	122	130	124	124	122	126	123	124	123	122
(24)	Other	GWh	0	0	0	0	(1)	(1)	(1)	(1)	(4)	(4)	(9)	(12)
(25)	**Net Energy for Load**	GWh	20,662	20,770	20,497	20,674	20,882	21,105	21,338	21,547	21,738	21,950	22,181	22,430

Notes:

Line (22) includes energy purchased from Non-Renewable and Renewable resources.

Values shown may be affected due to rounding.

Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.

Dual fuel capabilities will be maintained on applicable units.

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 2018	Actual 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
(1)	Annual Firm Interchange	%	0.4	0.0	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(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	%	14.4	5.8	4.5	4.8	4.9	1.6	1.7	1.6	1.7	1.8	1.9	2.0
(4)	Residual	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)	ST	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)	CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)	GT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)	D	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Distillate	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	ST	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)	CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)	GT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)	D	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	%	77.9	84.2	87.4	86.4	85.2	86.1	83.8	84.1	84.3	84.3	84.5	84.6
(15)	ST	%	8.5	12.7	6.0	5.8	1.9	1.3	1.6	1.6	1.6	1.4	1.7	1.5
(16)	CC	%	69.2	71.4	80.0	78.4	82.6	84.6	82.0	82.1	82.4	82.6	82.5	82.9
(17)	GT	%	0.2	0.1	1.4	2.3	0.7	0.2	0.2	0.4	0.2	0.2	0.3	0.2
(18)	Renewable	%	0.6	3.6	6.9	7.7	9.3	11.7	13.9	13.7	13.5	13.3	13.2	12.9
(19)	Solar	%	0.6	3.6	6.9	7.7	9.3	11.7	13.9	13.7	13.5	13.3	13.2	12.9
(20)	Other (Specify)													
(21)	PC	%	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(22)	Net Interchange	%	3.1	5.2	0.1	0.1	(0.0)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	(0.0)
(23)	Purchased Energy from Non-Utility Generators	%	0.9	1.1	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5
(24)	Other	%	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)
(25)	Net Energy for Load	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Notes:
Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.
Values are based on the economic dispatch of TEC's planned portfolio using the most recent fuel price projections and are subject to change.
Dual fuel capabilities will be maintained on applicable units.

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Chapter V

FORECAST OF FACILITIES REQUIREMENTS

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

The results of the IRP process provide TEC with a cost-effective plan that maintains system reliability and environmental requirements while considering technology, availability, dispatch ability, and lead times for construction. To cost-effectively meet the expected system demand and energy requirements over the next ten years, solar PV, intermediate, and distributed energy resources are needed. By the end of 2023, TEC will add an additional incremental 600 MW_{AC} of solar PV capacity. The modernization of the Big Bend Power Station through the repowering of Unit 1 to a 2x1 combined cycle unit and retirement of Unit 2, and the advanced hardware upgrades on the CTs at Bayside provide low cost 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.

TEC will compare viable 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 2020, TEC plans for 300 MW of cogeneration capacity operating in its service area.

Table IV-I 2020 Cogeneration Capacity Forecast	Capacity (MW)
Self-service [1]	227
Firm to Tampa Electric	0
As-available to Tampa Electric	18
Export to other systems	55
Total	300

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

FIRM INTERCHANGE SALES AND PURCHASES

Currently, TEC has no long-term firm purchase power agreements. The company does have five short-term firm peaking purchases that cover three seasons: winter 2020, summer 2020, and winter 2021. The seasonal purchases are (i) 112 MW from the Florida Municipal Power Agency (FMPA) for December 2019 through February 2020, (ii) 74 MW from FMPA for July through September 2020, and (iii) for December 2020 through February 2021, 100 MW from the Orlando Utilities Commission, 150 MW from FMPA, and 160 MW from Florida Power & Light for a total of 410 MW.

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 solid fuels and natural gas for its energy requirements. TEC has firm transportation contracts with the Florida Gas Transmission Company, Gulfstream Natural Gas System LLC, and Sabal Trail for delivery of natural gas to Big Bend, Bayside, and Polk. As shown in Schedule 6.2, in 2020, coal will fuel 4.5% of the net energy for load, natural gas will fuel 87.5%, and solar will provide 6.9% . The remaining net energy for load is served by firm, non-firm, and non-utility generator purchases. Some of the company's generating units have dual-fuel (i.e., natural gas or oil) capability, which enhances system reliability and provides fuel cost reduction opportunities.

ENVIRONMENTAL CONSIDERATIONS

Air Quality

TEC continually strives to reduce emissions from its generating facilities. Since 1998, TEC greatly reduced annual sulfur dioxides, nitrogen oxides, particulate matter, carbon dioxide and mercury emissions. TEC's major addition of solar generation will continue the company's transformation into a cleaner, more sustainable energy company. TEC's major activities to increase pollution control and decrease emissions include:

- TEC will phase in a modernization of Big Bend through the repowering of Unit 1 by 2023 into a highly efficient combined cycle unit and retiring Unit 2.
- The Polk Power Station combined-cycle project, which was completed in January 2017, improved system reliability and further reduced emissions system-wide.

The installation of 1200 megawatts of solar power by 2023 enables the company to significantly reduce its carbon emissions profile and its dependence on carbon-based fuels. Once complete, approximately 14% of TEC's energy will be fueled by the sun, reducing carbon dioxide (CO_2) emissions by more than a million tons each year. These projects, as well as best operation and maintenance work practices have reduced CO_2 emissions by more than half compared to 1998 levels.

TEC will see additional emission reductions through its compliance with the Affordable Clean Energy (ACE) rule. Issued in June 2019, the ACE rule establishes guidelines for states to develop greenhouse gas reduction standards for existing coal-fired electric utility generating units (EGUs). ACE establishes heat rate improvements as the best system of emissions reduction for greenhouse gases from coal-fired EGUs. By employing a broad range of heat rate improvement technologies and techniques, EGUs can more efficiently generate electricity with less carbon intensity. Based on the rule applicability criteria, TEC has at least one unit subject to the rule and compliance will likely be expected beginning in 2024.

Water Conservation

Most of the properties purchased by TEC for solar generation are former agricultural lands with existing water use permits. When land is sold to new owners, Southwest Florida Water Management District (SWFWMD) rules require that these water permits are transferred as well. Since solar generation requires no water, TEC conserves this groundwater, which otherwise would have pumped and used for agricultural needs. To date, TEC's development of solar power has saved more than 1.4 billion gallons of water, which significantly helps an area of the state that has critical concerns over water use.

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.

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. New limits will require new technology at Big Bend Station. Since Polk Power Station discharges gasification wastewater to the onsite deep injection well rather than to surface water, the limits are not applicable.

Solid Waste

The Coal Combustion Residuals Rule (CCR) became effective on October 19, 2015. The Big Bend Unit #4 Economizer Ash Ponds and the converted Units 1-3 slag fines pond are covered by this rule. The slag pond will be cleaned out and lined in 2020 to allow for continued storm water storage. The Economizer Ponds Closure Project is in progress and will be completed in 2021 by removing and disposing of the CCRs offsite and restoring the site to natural grade. The South Gypsum Storage Area Closure Project was completed as a component of the Big Bend Modernization in January 2020. There are no regulated CCR units at Polk or Bayside Power Stations.

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)
		Firm	Firm		Total	System Firm	Reserve Margin Before Maintenance		Scheduled*	Reserve Margin After Maintenance	
	Installed	Capacity	Capacity		Capacity	Summer Peak			Maintenance		
	Capacity	Import	Export	QF	Available	Demand					
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2019	5,238	0	0	0	5,238	3,926	1,312	33%	327	984	25%
2020	5,387	0	0	0	5,387	3,980	1,407	35%	391	1,017	26%
2021	5,330	0	0	0	5,330	4,032	1,298	32%	290	1,008	25%
2022	5,330	0	0	0	5,330	4,087	1,243	30%	291	952	23%
2023	5,704	0	0	0	5,704	4,143	1,562	38%	293	1,269	31%
2024	5,704	0	0	0	5,704	4,199	1,506	36%	294	1,212	29%
2025	5,704	0	0	0	5,704	4,253	1,451	34%	295	1,156	27%
2026	5,933	0	0	0	5,933	4,309	1,625	38%	297	1,328	31%
2027	5,933	0	0	0	5,933	4,363	1,570	36%	298	1,272	29%
2028	5,933	0	0	0	5,933	4,420	1,513	34%	299	1,214	27%

Notes:

* Includes capacity unavailable at time of peak.

Values shown may be affected due to rounding.

Schedule 7.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
							Reserve Margin Before Maintenance			Reserve Margin After Maintenance	
Year	Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Winter Peak Demand MW	MW	% of Peak	Scheduled* Maintenance MW	MW	% of Peak
2018-19	5,536	0	0	0	5,536	4,151	1,385	33%	465	920	22%
2019-20	5,790	0	0	0	5,790	4,215	1,576	37%	707	869	21%
2020-21	5,843	50	0	0	5,893	4,274	1,619	38%	759	859	20%
2021-22	5,753	100	0	0	5,853	4,336	1,517	35%	634	883	20%
2022-23	6,088	0	0	0	6,088	4,398	1,690	38%	634	1,055	24%
2023-24	6,088	0	0	0	6,088	4,460	1,628	37%	634	994	22%
2024-25	6,088	0	0	0	6,088	4,521	1,567	35%	634	932	21%
2025-26	6,332	0	0	0	6,332	4,582	1,751	38%	634	1,116	24%
2026-27	6,332	0	0	0	6,332	4,643	1,689	36%	634	1,055	23%
2027-28	6,332	0	0	0	6,332	4,703	1,629	35%	634	995	21%

Notes:

* Includes capacity unavailable at time of peak.

Values shown may be affected due to rounding.

Schedule 8.1
Planned and Prospective Generating Facility Additions and Changes

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Primary	(6) Fuel Alternate	(7) Fuel Trans. Primary	(8) Fuel Trans. Alternate	(9) Const. Start Mo/Yr	(10) Commercial In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen. Max. Nameplate kW	(13) Net Capability Summer MW	(14) Net Capability Winter MW	(15) Status
2020														
Little Manatee River Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	2/20	*	74,500	74.5	74.5	V
Wimauma Solar [1]	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	4/20	*	74,800	74.8	74.8	V
Big Bend ST1 Modernization Outage	1	Big Bend	ST	BIT	NG	WA/RR	PL	**	1/23	*	445,500	(385.0)	(395.0)	OT
											2020 Changes and Additions:	(235.7)	(245.7)	
2021														
Durrance [1]	1	Polk	PV	SOLAR	NA	NA	NA	-	01/21	*	60,000	60.0	60.0	P
Mountain View Solar	1	Pasco	PV	SOLAR	NA	NA	NA	-	12/21	*	52,500	52.5	52.5	P
Future Solar 1	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/21	*	25,000	25.0	25.0	P
Future Solar 2	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/21	*	70,000	72.0	72.0	P
Big Bend CT 5 [2]	5M	Big Bend	GT	NG	NA	PL	NA	08/19	11/21	*	397,800	360.0	392.0	P
Big Bend CT 6 [2]	6M	Big Bend	GT	NG	NA	PL	NA	08/19	11/21	*	397,800	360.0	392.0	P
Reciprocating Engine	1	Unknown	IC	NG	NA	PL	NA	-	12/21	*	18,500	18.5	18.5	P
Reciprocating Engine	2	Unknown	IC	NG	NA	PL	NA	-	12/21	*	18,500	18.5	18.5	P
Reciprocating Engine	3	Unknown	IC	NG	NA	PL	NA	-	12/21	*	18,500	18.5	18.5	P
Reciprocating Engine	4	Unknown	IC	NG	NA	PL	NA	-	12/21	*	18,500	18.5	18.5	P
Reciprocating Engine	5	Unknown	IC	NG	NA	PL	NA	-	12/21	*	18,500	18.5	18.5	P
Big Bend 2 Retirement	2	Big Bend	ST	BIT	NG	WA/RR	PL	-	04/73	11/21	445,500	(385.0)	(395.0)	RT
											2021 Changes and Additions:	637.0	1,086.0	
2022														
Battery Storage	1	Unknown	BA	N/A	N/A	N/A	N/A	-	01/22	*	10,000	10.0	10.0	P
Battery Storage	2	Unknown	BA	N/A	N/A	N/A	N/A	-	01/22	*	10,000	10.0	10.0	P
Battery Storage	3	Unknown	BA	N/A	N/A	N/A	N/A	-	01/22	*	10,000	10.0	10.0	P
Future Solar 3	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/22	*	74,500	74.5	74.5	P
Future Solar 4	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/22	*	74,500	74.5	74.5	P
Future Solar 5	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/22	*	74,500	74.5	74.5	P
											2022 Changes and Additions:	253.5	253.5	
2023														
Big Bend ST 1	1M	Big Bend	ST	NG	NA	PL	NA	04/20	01/23	*	445,500	335.0	335.0	P
Bayside 1 Enhancement	1	Bayside	CC	NG	NA	PL	NA	-	01/23	*	50,000	47.0	50.0	P
Future Solar 6	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/23	*	74,500	74.5	74.5	P
Future Solar 7	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/23	*	74,500	74.5	74.5	P
Future Solar 8	1	Unknown	PV	SOLAR	NA	NA	NA	-	12/23	*	74,500	74.5	74.5	P
											2023 Changes and Additions:	605.5	608.5	
2024														
Bayside 2 Enhancement	2	Bayside	CC	NG	NA	PL	NA	-	01/24	*	66,000	62.0	66.0	P
											2024 Changes and Additions:	62.0	66.0	

2025															
	Reciprocating Engine	6	Unknown	IC	NG	NA	PL	NA	-	1/25	*	18,500	18.5	18.5	P
	Battery Storage	4	Unknown	BA	N/A	N/A	N/A	N/A	-	1/25	*	10,000	10.0	10.0	P
										2025 Changes and Additions:			28.5	28.5	
2026															
	Battery Storage	5	Unknown	BA	N/A	N/A	N/A	N/A	-	1/26	*	10,000	10.0	10.0	P
	Battery Storage	6	Unknown	BA	N/A	N/A	N/A	N/A	-	1/26	*	10,000	10.0	10.0	P
	Battery Storage	7	Unknown	BA	N/A	N/A	N/A	N/A	-	1/26	*	10,000	10.0	10.0	P
	Battery Storage	8	Unknown	BA	N/A	N/A	N/A	N/A	-	1/26	*	10,000	10.0	10.0	P
	Battery Storage	9	Unknown	BA	N/A	N/A	N/A	N/A	-	1/26	*	10,000	10.0	10.0	P
	Battery Storage	10	Unknown	BA	N/A	N/A	N/A	N/A	-	1/26	*	10,000	10.0	10.0	P
										2026 Changes and Additions:			60.0	60.0	
2027															
	Reciprocating Engine	7	Unknown	IC	NG	NA	PL	NA	-	1/27	*	18,500	18.5	18.5	P
	Reciprocating Engine	8	Unknown	IC	NG	NA	PL	NA	-	1/27	*	18,500	18.5	18.5	P
	Reciprocating Engine	9	Unknown	IC	NG	NA	PL	NA	-	1/27	*	18,500	18.5	18.5	P
	Reciprocating Engine	10	Unknown	IC	NG	NA	PL	NA	-	1/27	*	18,500	18.5	18.5	P
										2027 Changes and Additions:			74.0	74.0	
2028															
	Battery Storage	11	Unknown	BA	N/A	N/A	N/A	N/A	-	1/28	*	10,000	10.0	10.0	P
	Battery Storage	12	Unknown	BA	N/A	N/A	N/A	N/A	-	1/28	*	10,000	10.0	10.0	P
	Battery Storage	13	Unknown	BA	N/A	N/A	N/A	N/A	-	1/28	*	10,000	10.0	10.0	P
	Battery Storage	14	Unknown	BA	N/A	N/A	N/A	N/A	-	1/28	*	10,000	10.0	10.0	P
	Battery Storage	15	Unknown	BA	N/A	N/A	N/A	N/A	-	1/28	*	10,000	10.0	10.0	P
	Battery Storage	16	Unknown	BA	N/A	N/A	N/A	N/A	-	1/28	*	10,000	10.0	10.0	P
										2028 Changes and Additions:			60.0	60.0	
2029															
	Battery Storage	17	Unknown	BA	N/A	N/A	N/A	N/A	-	1/29	*	10,000	10.0	10.0	P
	Battery Storage	18	Unknown	BA	N/A	N/A	N/A	N/A	-	1/29	*	10,000	10.0	10.0	P
	Battery Storage	19	Unknown	BA	N/A	N/A	N/A	N/A	-	1/29	*	10,000	10.0	10.0	P
	Battery Storage	20	Unknown	BA	N/A	N/A	N/A	N/A	-	1/29	*	10,000	10.0	10.0	P
	Battery Storage	21	Unknown	BA	N/A	N/A	N/A	N/A	-	1/29	*	10,000	10.0	10.0	P
	Battery Storage	22	Unknown	BA	N/A	N/A	N/A	N/A	-	1/29	*	10,000	10.0	10.0	P
										2029 Changes and Additions:			60.0	60.0	

Notes:

* Undetermined
** Big Bend ST1 Modernization outage planned to start 06/20
1 Solar MW values reflect seasonal capacity values, not available capacity at time of peak.
2 Net capability will be restricted to 330 MW summer / 350 MW winter until being placed into combined cycle mode in 2023.

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

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Little Manatee River 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[1]	December 2017
	B. Commercial In-Service Date	February 2020
(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	+572 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 (2020)	28.6 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	1,410.24
	Direct Construction Cost ($/kW)	1,410.24
	AFUDC[3] Amount ($/kW)	N/A
	Escalation ($/kW)	N/A
	Fixed O&M[4] (In-Service Year $/kW – Yr)	11.63
	Variable O&M (In-Service Year $/MWh)	0.0
	K-Factor [5]	1.17

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection and excludes land costs
[3] Based on the current AFUDC rate of 6.46%
[4] Fixed O&M cost includes land lease
[5] w/o land

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Wimauma Solar
(2)	Net Capability	
	A. Summer	74.8 MW-ac
	B. Winter	74.8 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[1]	October 2017
	B. Commercial In-Service Date	April 2020
(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	+500 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 (2020)	27.3 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	1,478.59
	Direct Construction Cost ($/kW)	1,446.32
	AFUDC[3] Amount ($/kW)	32.27
	Escalation ($/kW)	N/A
	Fixed O&M (In-Service Year $/kW – Yr)	5.46
	Variable O&M (In-Service Year $/MWh)	0.0
	K-Factor [4]	1.10

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection
[3] Based on the current AFUDC rate of 6.46%
[4] w/o land

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Durrance Solar
(2)	Net Capability	
	A. Summer	60 MW-ac
	B. Winter	60 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[1]	April 2020
	B. Commercial In-Service Date	January 2021
(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	+473 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 (2020)	27.3 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	1,527.39
	Direct Construction Cost ($/kW)	1,475.27
	AFUDC[3] Amount ($/kW)	52.12
	Escalation ($/kW)	N/A
	Fixed O&M (In-Service Year $/kW – Yr)	5.46
	Variable O&M (In-Service Year $/MWh)	0.0
	K-Factor [4]	1.10

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection
[3] Based on the current AFUDC rate of 6.46%
[4] w/o land

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Bend CT 5
(2)	Net Capability	
	A. Summer	360 MW[1]
	B. Winter	392 MW[1]
(3)	Technology Type	Combustion Turbine[2]
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	August 2019
	B. Commercial In-Service Date	November 2021
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	In Progress
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.05
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.93
	Resulting Capacity Factor (2022)	4.4 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	9,557 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	533.17
	Direct Construction Cost ($/kW)	351.04
	AFUDC[3] Amount ($/kW)	36.37
	Escalation ($/kW)	145.76
	Fixed O&M (In-Service Year $/kW – Yr)	7.32
	Variable O&M (In-Service Year $/MWh)	2.68
	K-Factor	1.5613

[1] Net capability will be restricted to 330 MW S / 350 MW W until being placed into combined cycle mode in 2023
[2] Converts to 2x1 Combined Cycle with a HRSG & Big Bend ST 1 in 2023
[3] Based on the current AFUDC rate of 6.46%

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Bend CT 6
(2)	Net Capability	
	A. Summer	360 MW[1]
	B. Winter	392 MW[1]
(3)	Technology Type	Combustion Turbine[2]
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	August 2019
	B. Commercial In-Service Date	November 2021
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	In Progress
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.05
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.93
	Resulting Capacity Factor (2022)	4.4 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	9,557 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	533.17
	Direct Construction Cost ($/kW)	351.04
	AFUDC[3] Amount ($/kW)	36.37
	Escalation ($/kW)	145.76
	Fixed O&M (In-Service Year $/kW – Yr)	7.32
	Variable O&M (In-Service Year $/MWh)	2.68
	K-Factor	1.5613

[1] Net capability will be restricted to 330 MW S / 350 MW W until being placed into combined cycle mode in 2023
[2] Converts to 2x1 Combined Cycle with a HRSG & Big Bend ST 1 in 2023
[3] Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 6 of 18)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Mountain View Solar
(2)	Net Capability	
	A. Summer	52.5 MW-ac
	B. Winter	52.5 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[1]	2020
	B. Commercial In-Service Date	December 2021
(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	+345 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 (2021)	27.3 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	1,453.34
	Direct Construction Cost ($/kW)	1,403.61
	AFUDC[3] Amount ($/kW)	49.73
	Escalation ($/kW)	N/A
	Fixed O&M (In-Service Year $/kW – Yr)	5.58
	Variable O&M (In-Service Year $/MWh)	0.0
	K-Factor [4]	1.10

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection
[3] Based on the current AFUDC rate of 6.46%
[4] w/o land

Schedule 9
(Page 7 of 18)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar (Multiple Sites, each not to exceed 74.5 MW)
(2)	Net Capability	
	A. Summer	97.0 MW-ac
	B. Winter	97.0 MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date[1]	2020
	B. Commercial In-Service Date	December 2021
(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	TBD
(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)	30
	Total Installed Cost[2] (In-Service Year $/kW)	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC[3] Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M[4] (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	TBD
	K-Factor [5]	TBD

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection and excludes land costs
[3] Based on the current AFUDC rate of 6.46%
[4] Fixed O&M cost includes land lease
[5] w/o land

Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Reciprocating Engine
(2)	Net Capability	
	A. Summer	92.5 MW (Consisting of 5 engines)
	B. Winter	92.5 MW (Consisting of 5 engines)
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	December 2020
	B. Commercial In-Service Date	December 2021
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.02
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.96
	Resulting Capacity Factor (2023)	4.8 %
	Average Net Operating Heat Rate (In-Service Year ANOHR)	8,099 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	1,169.89
	Direct Construction Cost ($/kW)	1,033.86
	AFUDC[1] Amount ($/kW)	73.99
	Escalation ($/kW)	62.04
	Fixed O&M (In-Service Year $/kW – Yr)	21.57
	Variable O&M (In-Service Year $/MWh)	8.92
	K-Factor	1.250

[1] Based on the current AFUDC rate of 6.46%

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

(1)	Plant Name and Unit Number	Battery Storage
(2)	Net Capability	
	A. Summer	30 MW
	B. Winter	30 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	December 2020
	B. Commercial In-Service Date	December 2021
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	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 (2026)	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost (In-Service Year $/kW)	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC[1] Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	TBD
	K-Factor	TBD

[1] Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 10 of 18)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar (Multiple Sites, each not to exceed 74.5 MW)	
(2)	Net Capability		
	A. Summer	223.5	MW-ac
	B. Winter	223.5	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[1]	2021	
	B. Commercial In-Service Date	December 2022	
(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	TBD	
(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)	30	
	Total Installed Cost[2] (In-Service Year $/kW)	TBD	
	Direct Construction Cost ($/kW)	TBD	
	AFUDC[3] Amount ($/kW)	TBD	
	Escalation ($/kW)	TBD	
	Fixed O&M[4] (In-Service Year $/kW – Yr)	TBD	
	Variable O&M (In-Service Year $/MWh)	TBD	
	K-Factor [5]	TBD	

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection and excludes land costs
[3] Based on the current AFUDC rate of 6.46%
[4] Fixed O&M cost includes land lease
[5] w/o land

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Bend ST 1
(2)	Net Capability	
	A. Summer	335 MW
	B. Winter	335 MW
(3)	Technology Type	Combined Cycle[1]
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	June 2020
	B. Commercial In-Service Date	January 2023
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	SCR, DLN Burners
(7)	Cooling Method	Once Through Cooling
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	In Progress
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.05
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.93
	Resulting Capacity Factor (2023)	89.0 %
	Average Net Operating Heat Rate (In-Service Year ANOHR)	6,263 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW)	1,266.28
	Direct Construction Cost ($/kW)	1,037.75
	AFUDC[2] Amount ($/kW)	143.43
	Escalation ($/kW)	85.11
	Fixed O&M (In-Service Year $/kW – Yr)	6.44
	Variable O&M (In-Service Year $/MWh)	2.81
	K-Factor	1.4634

[1] Converts Big Bend CT 5 & 6 and HRSG's to 2x1 Combined Cycle
[2] Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 12 of 18)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future Solar (Multiple Sites, each not to exceed 74.5 MW)	
(2)	Net Capability		
	A. Summer	223.5	MW-ac
	B. Winter	223.5	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[1]	2022	
	B. Commercial In-Service Date	December 2023	
(5)	Fuel		
	A. Primary Fuel	Solar	
	B. Alternate Fuel	N/A	
(6)	Air Pollution Control Strategy	N/A	
(7)	Cooling Method	N/A	
(8)	Total Site Area	TBD	
(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)	30	
	Total Installed Cost[2] (In-Service Year $/kW)	TBD	
	Direct Construction Cost ($/kW)	TBD	
	AFUDC[3] Amount ($/kW)	TBD	
	Escalation ($/kW)	TBD	
	Fixed O&M[4] (In-Service Year $/kW – Yr)	TBD	
	Variable O&M (In-Service Year $/MWh)	TBD	
	K-Factor [5]	TBD	

[1] Construction schedule includes engineering design and permitting
[2] Total installed cost includes transmission interconnection and excludes land costs
[3] Based on the current AFUDC rate of 6.46%
[4] Fixed O&M cost includes land lease
[5] w/o land

Schedule 9
(Page 13 of 18)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Reciprocating Engine
(2)	Net Capability	
	A. Summer	18.5 MW
	B. Winter	18.5 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	January 2024
	B. Commercial In-Service Date	January 2025
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	TBD
	Forced Outage Factor (FOF)	TBD
	Equivalent Availability Factor (EAF)	TBD
	Resulting Capacity Factor (2023)	TBD
	Average Net Operating Heat Rate (In-Service Year ANOHR)	8,100 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC[3] Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M[4] (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	TBD
	K-Factor [5]	TBD

[1] Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 14 of 18)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage
(2)	Net Capability	
	A. Summer	10 MW
	B. Winter	10 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	January 2024
	B. Commercial In-Service Date	January 2025
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	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 (2026)	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost (In-Service Year $/kW)	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC[1] Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	TBD
	K-Factor	TBD

[1] Based on the current AFUDC rate of 6.46%

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage
(2)	Net Capability	
	A. Summer	60 MW
	B. Winter	60 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	January 2025
	B. Commercial In-Service Date	January 2026
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	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 (2026)	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost (In-Service Year $/kW)	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC[1] Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	TBD
	K-Factor	TBD

[1] Based on the current AFUDC rate of 6.46%

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Reciprocating Engine
(2)	Net Capability	
	A. Summer	74 MW (Consisting of 4 engines)
	B. Winter	74 MW (Consisting of 4 engines)
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	January 2026
	B. Commercial In-Service Date	January 2027
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	TBD
	Forced Outage Factor (FOF)	TBD
	Equivalent Availability Factor (EAF)	TBD
	Resulting Capacity Factor (2023)	TBD
	Average Net Operating Heat Rate (In-Service Year ANOHR)	8,100 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC[3] Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M[4] (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	TBD
	K-Factor [5]	TBD

[1] Based on the current AFUDC rate of 6.46%

Schedule 9
(Page 17 of 18)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Battery Storage
(2)	Net Capability	
	A. Summer	60 MW
	B. Winter	60 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	January 2027
	B. Commercial In-Service Date	January 2028
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	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 (2026)	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost (In-Service Year $/kW)	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC[1] Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	TBD
	K-Factor	TBD

[1] Based on the current AFUDC rate of 6.46%

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

(1)	Plant Name and Unit Number	Battery Storage
(2)	Net Capability	
	A. Summer	60 MW
	B. Winter	60 MW
(3)	Technology Type	Battery
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	January 2028
	B. Commercial In-Service Date	January 2029
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	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 (2026)	N/A
	Average Net Operating Heat Rate (In-Service Year ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	10
	Total Installed Cost (In-Service Year $/kW)	TBD
	Direct Construction Cost ($/kW)	TBD
	AFUDC[1] Amount ($/kW)	TBD
	Escalation ($/kW)	TBD
	Fixed O&M (In-Service Year $/kW – Yr)	TBD
	Variable O&M (In-Service Year $/MWh)	TBD
	K-Factor	TBD

[1] Based on the current AFUDC rate of 6.46%

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines
As of December 31, 2019

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
Little Manatee River Solar	Big Bend-Ruskin-Manatee 230 kV line section to Little Manatee River Metering Station	1	No ROW required	0.36	230 kV	February 2020	Included in total installed cost on Schedule 9	Little Manatee River Metering Station; Big Bend, Manatee & Ruskin Substations	Yes
Durrance Solar	Polk-Aspen 230 kV line section to Durance Metering Station	1	No ROW required	0.06	230 kV	January 2021	Included in total installed cost on Schedule 9	Durrance Metering Station; Polk & Aspen Substations	None
Big Bend CT 5	Big Bend CT 5 does not require any new transmission lines ****	-	-	-	230 kV	November 2021	-	Big Bend	None
Big Bend CT 6	Big Bend CT 6 does not require any new transmission lines ****	-	-	-	230 kV	November 2021	-	Big Bend	None
Big Bend ST 1	Big Bend ST 1 does not require any new transmission lines ****	-	-	-	230 kV	January 2023	-	Big Bend	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.

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). All existing facilities are currently permitted as existing power plant sites. 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

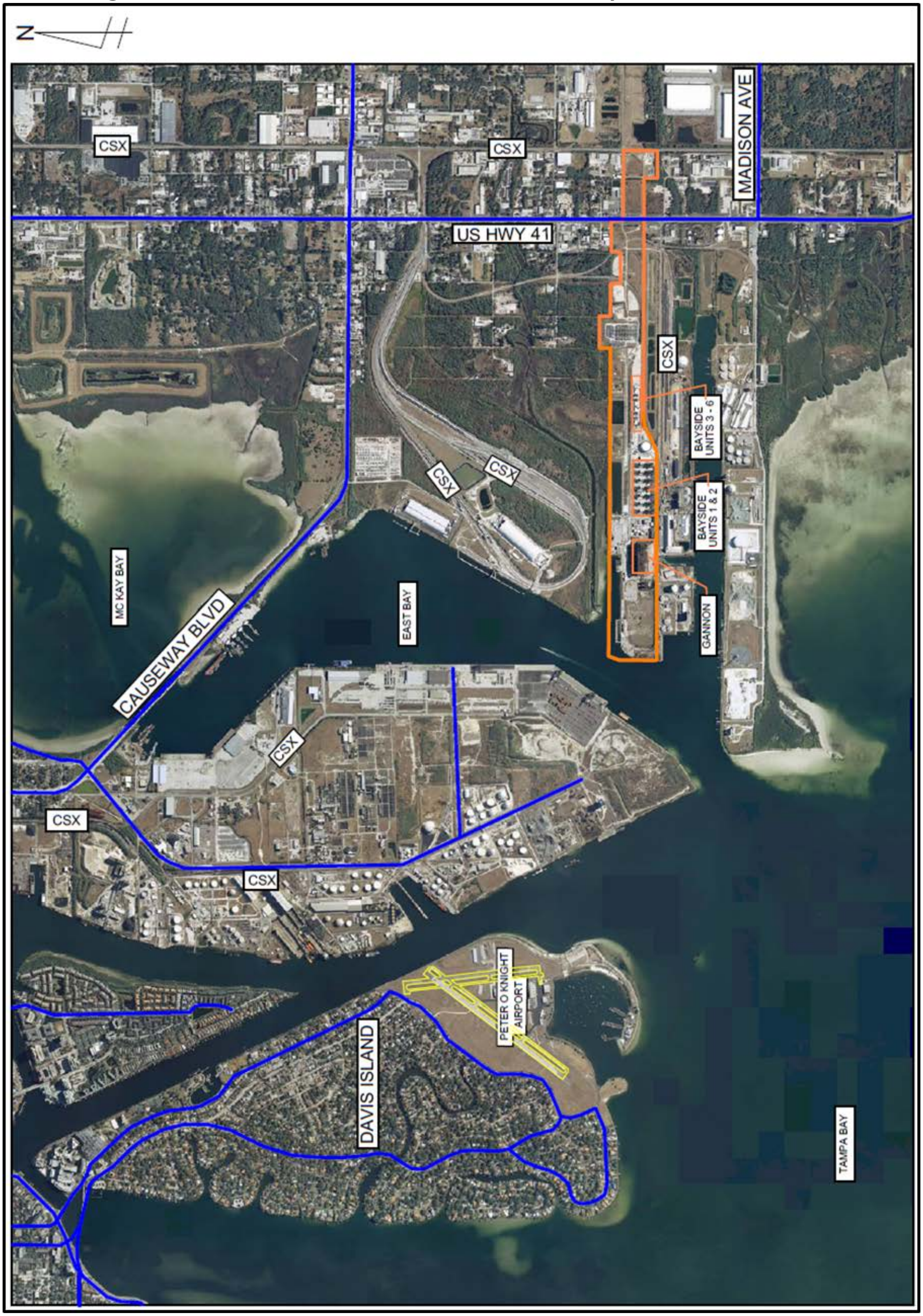

Figure VI-II: Site Location of Polk Power Station

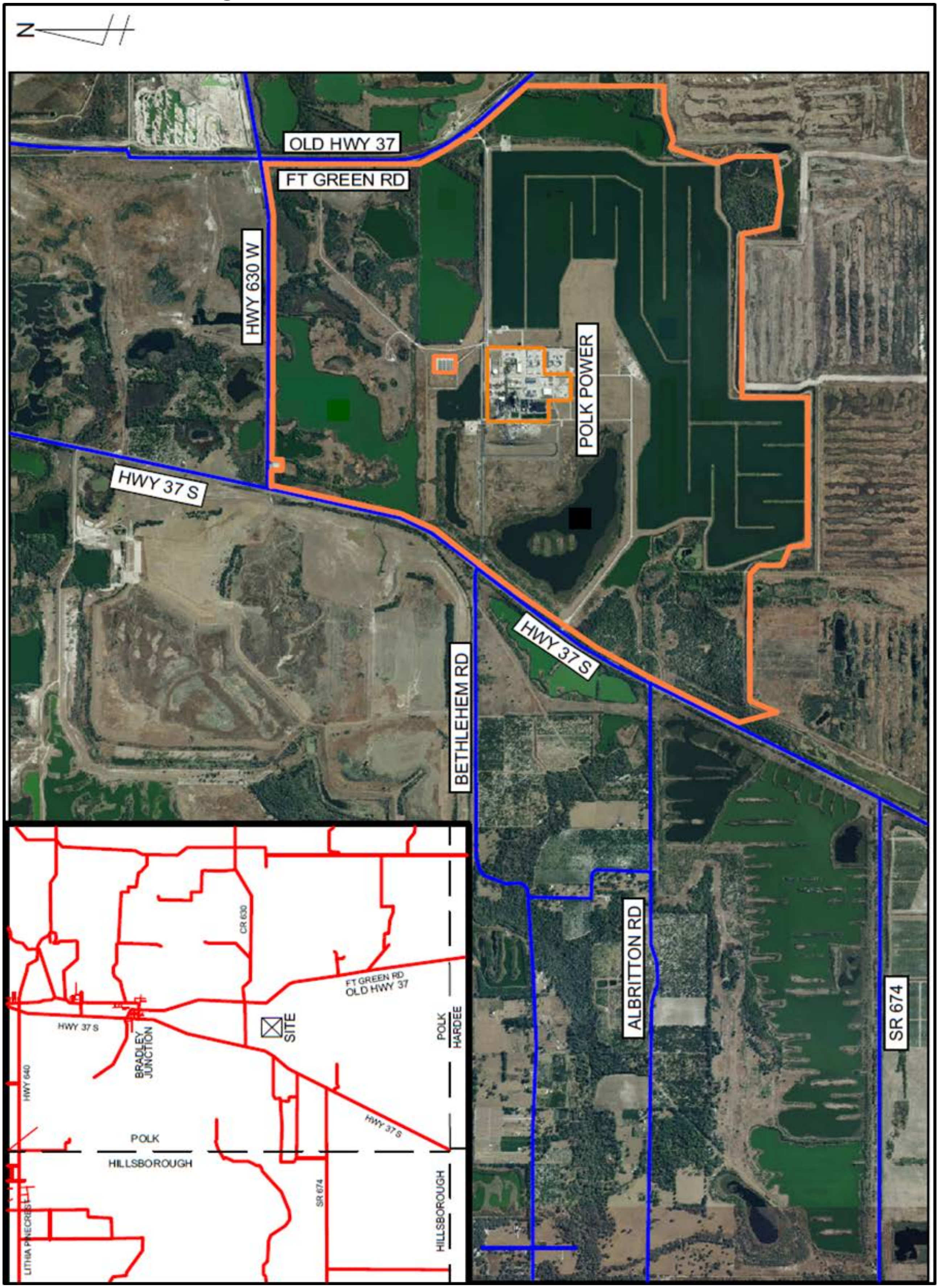

Figure VI-III: Site Location of Big Bend Power Station

Figure VI-IV: Site Location of Solar Power Stations