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April 2, 2018

VIA: ELECTRONIC FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Tampa Electric Company's 2018 Ten-Year Site Plan

Dear Ms. Stauffer:

Attached for filing on behalf of Tampa Electric Company is the company's January 2018 to December 2027 Ten-Year Site Plan.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

Tampa Electric Company

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines
January 2018 to December 2027

Submitted to: Florida Public Service Commission
April 2, 2018

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GLOSSARY OF TERMS

CODE IDENTIFICATION SHEET

Unit Type:	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
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) 2018 Ten Year Site Plan (TYSP) features plans to enhance electric generating capability as part of our efforts to meet projected incremental resource needs for 2018 through 2027. The 2018 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 and reliable power to TEC's customers.

The Polk 2 Combined Cycle conversion project was completed in January 2017, increasing incremental capacity by 480 MW winter and 461 MW summer. TEC also completed a 19.4 MW_{AC} PV solar array located at Big Bend Power Station with commercial operation in February 2017. In addition, TEC will add 144.7 MW_{AC} of solar PV across multiple sites in September 2018; that total will increase to over 400 MW_{AC} of solar PV by January 2019 and ultimately 600 MW_{AC} of solar PV by 2021. 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. Additionally, TEC will add peaking combustion turbines in 2023 and 2026 to meet reserve margin in future years.

TEC is committed to reliably serve the system's demand and energy requirements for the customers located in its service area as shown in Figure I-I. TEC will continue to meet resource requirements with the most economical combination of Demand Side Management (DSM), conservation, renewable energy, purchased power, and generation capacity additions. The resource additions in TEC's 2018 TYSP are projected to be needed based on our current Integrated Resource Planning (IRP) process. The IRP process incorporates an on-going evaluation of demand and supply resources and conservation measures to maintain system reliability. The IRP process is discussed further in Chapter III.

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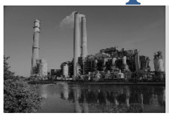
Chapter I



DESCRIPTION OF EXISTING FACILITIES

Tampa Electric has three (3) generating stations that include fossil steam units, combined cycle units, combustion turbine peaking units, an integrated coal gasification combined cycle unit and 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. Big Bend CT 4 is one (1) aero-derivative combustion turbine that entered into service in 2009 and 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 that were placed into service in 2009.

Polk Power Station

The station operates one (1) integrated coal gasification combined cycle (IGCC) unit and one (1) natural gas-fired combined cycle unit. Polk Unit 1 is an IGCC unit fired with synthetic gas produced from gasified coal and other carbonaceous fuels. This technology integrates state-of-the-art environmental processes to create a clean fuel gas from a variety of feedstock with the efficiency benefits of combined cycle generation equipment. Unit 1 can also be fired with natural gas. On January 16, 2017, Polk 2 Combined Cycle entered commercial operation. Polk 2 CC utilizes four (4) combustion turbines (formerly Polk 2-5 simple cycle CT’s), four (4) HRSGs and one (1) steam turbine.

Solar

TEC owns a 1.6 MW_{AC} fixed tilt solar PV array located atop the south parking garage of Tampa International Airport that was placed into service in 2015. The 1.4 MW_{AC} solar PV array located at LEGOLAND® Florida began operation on December 8, 2016. The 19.4 MW_{AC} Big Bend Solar Station located near Big Bend Power Station began operation on February 10, 2017. In addition, TEC will place in service over 400 MW_{AC} of single axis tracking PV solar by January 2019.

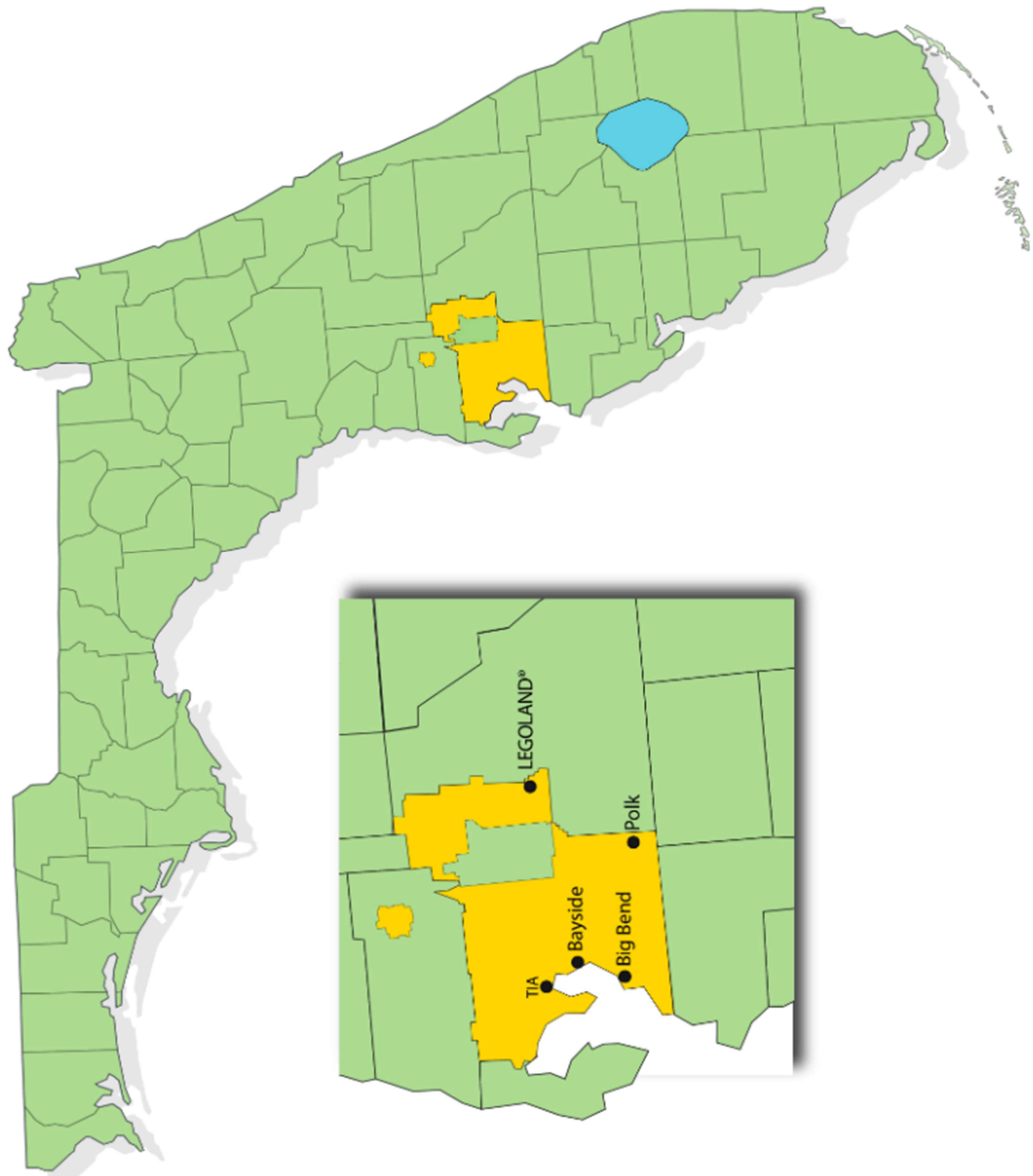
Schedule 1

Existing Generating Facilities
As of December 31, 2017

(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.**											
		14/31S/19E									**1,892,400**	**1,658**	**1,693**
	1		ST	BIT	NG	WA/RR	PL	NA	10/70	**	445,500	385	395
	2		ST	BIT	NG	WA/RR	PL	NA	04/73	06/2021	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
Bayside		**Hillsborough Co.**											
		4/30S/19E									**2,293,759**	**1,854**	**2,083**
	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
Polk		**Polk Co.**											
		2,3/32S/23E									**1,542,379**	**1,281**	**1,420**
	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
TIA		**Hillsborough Co.**											
	1	**31/28S/18E**	PV	SOLAR	NA	NA	NA	NA	12/15	**	1,600	1.6	1.6
LEGOLAND®		**Polk Co.**											
	1	**02/29S/26E**	PV	SOLAR	NA	NA	NA	NA	12/16	**	1,400	1.4	1.4
Big Bend Solar		**Hillsborough Co.**											
	1	**15/31S/19E**	PV	SOLAR	NA	NA	NA	NA	02/17	**	19,800	19.4	19.4
Solar Total											**22,800**	**22**	**22**
											TOTAL	**4,815**	**5,218**

Notes:
* Limited by environmental permit
** Undetermined
*** Combined net capability will be limited effective January 2023

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 its 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 2018-2027 forecasts. The data tables in Chapter IV outline the expected customer, demand, and energy values for the 2018-2027 time period.

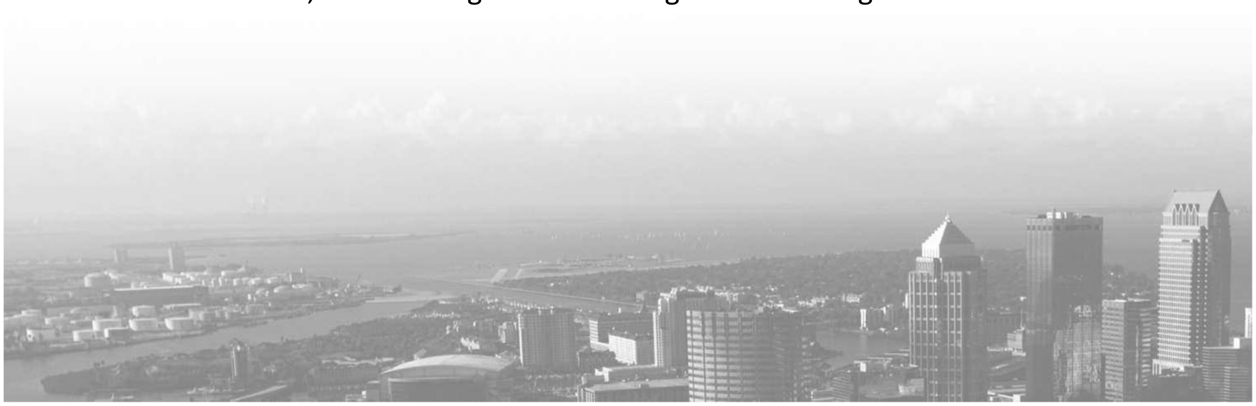
RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2018-2027 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 six 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. 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. 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 seven-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.

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

   a. 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.

   b. 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.

3. *Industrial Customer Model (Non-Phosphate):* Non-phosphate industrial customers include two rate classes that have been modeled individually: General Service and General Service Demand.
   a. The <u>General Service Customer Model</u> is a function of Hillsborough County commercial employment.

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

4. *Public Authority Customer Model:* Customer projections are based on the recent growth trend in the sector.

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

3. Energy Multiregression Model

There are a total of seven energy models. All of these models represent average usage per customer (kWh/customer), except for the temporary services model which represents 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:

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

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

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

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

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

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

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

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

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

    a. Commercial Energy Model: 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.

    b. 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.

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

    a. 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.

    b. 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.

4. *Public Authority Sector Model:* Within this model, the equipment index 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.

5. *Street & Highway Lighting Sector Model:* The street and highway lighting sector is not impacted by weather; 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, and the number of daylight hours in a day for each month. Starting in 2017, street and highway lighting data will be included as part of the public utility sector. The street and highway lighting forecast reflects the impacts of the company's LED lighting program.

The seven 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. 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 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 2017, TEC 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 received Commission approval of one new DSM program (ENERGY STAR Program for New Multi-Family Residences) and added a modification to include electric vehicle driver's education within the existing Energy Education, Awareness and Agency Outreach Program. Also in 2017, the company initiated the process with all the other FEECA utilities to start the development of the technical potential study, which will support the 2020-2029 DSM Plan. The following is a list that briefly describes the company's DSM programs:

1. Energy Audits - a "how to" information and analysis guide for customers. Six types of audits are available to 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 as well as electric vehicles (at participating high schools) in an organized setting. 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 encourage 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. 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.

24. 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.

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

26. 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.

27. 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.

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

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

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

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

32. 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. 130201-EI, Order No. PSC-14-0696-FOF-EU, Issued December 16, 2014. The 2017 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	1177.8%
2016	7.7	4.1	187.8%	5.1	1.6	318.8%	13.2	3.5	377.1%
2017	6.9	5.2	132.0%	4.7	2.2	212.0%	14.9	4.8	310.9%
2018		6.5			2.7			6.1	
2019		7.6			3.1			6.9	
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	578.1%	10.4	2.7	385.5%	30.2	8.0	377.9%
2018		1.7			3.3			9.2	
2019		1.6			3.3			9.9	
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	237.0%	15.1	4.9	307.6%	45.2	12.8	352.8%
2018		8.2			6.0			15.3	
2019		9.2			6.4			16.8	
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 2018-2027. The average annual population growth rate is expected to be 1.8%.

2. Commercial, Industrial and Governmental Employment

Commercial and industrial employment assumptions are utilized in computing the number of customers in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. Over the next ten years (2018-2027), employment is assumed to rise at a 1.2% average annual rate within Hillsborough County. Moody's Analytics supplies employment projections for the non-residential models.

3. Commercial, Industrial and Governmental Output

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Output for the entire employment sector within Hillsborough County is assumed to rise at a 3.8% average annual rate from 2018-2027. 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 2018-2027, 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 actually 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 2018-2027, retail energy sales are projected to rise at a 1.0% annual rate. The major contributors to growth include the residential and commercial categories, increasing at an annual rate of 1.5% and 0.9%, respectively.

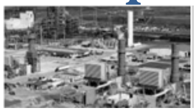
2. Wholesale Energy

TEC has no scheduled firm wholesale power sales at this time.

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 2018-2027, TEC's base retail firm peak demand is expected to increase at an average annual rate of 1.3% in the summer and 1.4% 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, which excludes incremental energy efficiency and conservation programs, is developed. Then, without any incremental energy efficiency and conservation, an interim supply plan based on the system requirements is developed based upon this new demand and energy forecast. This interim supply plan is used to identify the basis for the next potential avoided unit(s). The data from this interim supply plan provides the baseline data that is used to perform a comprehensive cost effectiveness analysis of the energy efficiency and conservation programs.

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.

The cost-effectiveness of energy efficiency and demand-response programs is 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 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.

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 capacity 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 capacity additions that would most 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 present worth revenue requirements.

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 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 present worth 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, TEC previously converted Polk Units 2-5 to Polk 2 CC, a natural gas combined cycle unit with the addition of a steam turbine that went into service in January 2017. The company's expansion plans include the addition of 600 MW_{AC} of solar PV through 2021 in accordance with the Solar Base Rate Adjustment (SoBRA) which was approved as part of the stipulation and settlement agreement in late 2017. TEC intends to modernize Big Bend by first installing simple cycle peaking combustion turbines and initiating the repowering of unit 1 and retirement of unit 2 by 2021. These combustion turbines will be integrated into a natural gas combined cycle unit by 2023 using the repowered unit 1 steam turbine. The company also plans to add a simple cycle combustion turbine in 2023 and another simple cycle combustion turbine in 2026. All these changes to the expansion plan are shown in Schedule 8.1.

TEC will continue to assess competitive purchase power agreements that may replace or delay the scheduled units. Such optimizations must achieve the overall objective of providing reliable power in the most 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.

EXPANSION PLAN ECONOMICS AND FUEL FORECAST

The overall economics and cost-effectiveness of the plan were analyzed using TEC’s IRP process. As part of this process, TEC evaluated various planning and operating alternatives against expected operations, with the objective to: meet compliance requirements in the most cost-effective and reliable manner, maximize operational flexibility and minimize total costs.

Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine the options that were the most feasible overall. Those alternatives that failed to meet the qualitative and quantitative considerations were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in more detailed economic analyses.

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, 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.

TAMPA ELECTRIC'S RENEWABLE ENERGY PROGRAMS

The Renewable Energy Program was signed into effect by the Commission in Docket No. 060678-EG, Order No. PSC-06-1063-TRF-EG, issued December 26, 2006. TEC's Renewable Energy Program 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 2017, TEC's Renewable Energy Program has approximately 1,600 customers purchasing over 2,500 blocks of renewable energy each month. In addition, there have been over 200 one-time blocks purchased for large, public and private events in Tampa in 2017. In 2018, TEC is refreshing the program marketing materials to focus on increasing one-time and recurring solar block purchases from all customer classes. TEC's solar portfolio has reached a level that the energy needed for the Renewable Energy Program is entirely generated from local solar sources.

In 2018, Tampa Electric's Renewable Energy Program is installing a 75 kW array at the Florida Conservation and Technology Center (FCTC). This community site is a collaborative effort between TEC, the Florida Fish & Wildlife Conservation Commission (FWC), and the Florida Aquarium, which will provide many more opportunities to educate Tampa Electric customers and visitors on the benefits of solar energy, in addition to the other seven local solar arrays the program has funded.

TEC continually analyzes renewable energy alternatives with the objective to integrate them into our resource portfolio. The company's renewable-generation portfolio is a mix of various solar technologies, including seven smaller, company-owned photovoltaic (PV) arrays totaling 116 KW_{AC} and three large-scale PV systems totaling 22.4 MW_{AC}.

The smaller, community-sited PV arrays are installed at the Museum of Science and Industry, Walker Middle and Middleton High schools, TEC's Manatee Viewing Center, Tampa's Lowry Park Zoo, the Florida Aquarium and LEGOLAND® Florida's Imagination Zone. To further educate the public on the benefits of renewable energy, the installations at these facilities include signage and interactive displays that were built to provide a hands-on experience to engage visitors' interest and provide education in solar technology.

The company completed the installation of its first large-scale solar facility at Tampa International Airport in 2015. The solar PV array, sized at 1.6 MW_{AC}, can produce enough electricity to power more than 250 homes. In 2016, TEC completed its second large-scale PV system – a 1.4 MW_{AC} array at LEGOLAND® Florida in Winter Haven. This array was constructed on a shade canopy in the park's preferred parking lot and generates enough energy to power more than 200 homes. TEC owns both large-scale solar PV facilities and the electricity they produce goes to the grid to benefit TEC's renewable energy program customers. In February 2017, TEC placed in operation a 19.4 MW_{AC} array which is located at the company's Big Bend Station and has the capacity to power nearly 3,300 homes.

As market conditions continue to change and technology improves in this sector, renewable alternatives, such as solar, become more cost effective to our customers. Through December 2017, more than 1,744 residential customers installed PV systems on their homes and another 123 commercial or industrial customers installed PV systems on their businesses. The number of home solar arrays in 2017 is 150% of what they were in 2016. At the end of 2017, 1867 TEC customers with PV arrays on their home or business had a total connected capacity of almost 19 MW_{DC}.

In addition, TEC has announced plans to install up to an additional 600 MW_{AC} of utility scale solar PV distributed across multiple sites by 2021 as part of the SoBRA approved in 2017.

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 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 reserve margin employs an industry accepted method of using total available generating 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, under 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 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
2008	1,206,084	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,215,216	2.5	8,666	587,396	14,754	6,274	70,182	89,395
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	1,408,464	2.6	9,263	673,808	13,747	6,545	76,005	86,110
2019	1,436,883	2.5	9,419	687,116	13,708	6,597	76,726	85,987
2020	1,465,951	2.5	9,560	700,815	13,641	6,636	77,261	85,888
2021	1,493,987	2.5	9,695	714,059	13,577	6,679	77,726	85,936
2022	1,521,576	2.5	9,864	727,119	13,566	6,736	78,339	85,988
2023	1,548,669	2.5	10,004	739,964	13,520	6,803	79,010	86,103
2024	1,575,078	2.5	10,146	752,501	13,483	6,878	79,567	86,438
2025	1,600,735	2.5	10,293	764,692	13,461	6,952	80,002	86,895
2026	1,625,683	2.5	10,448	776,555	13,455	7,032	80,405	87,459
2027	1,649,944	2.5	10,601	788,098	13,452	7,114	80,830	88,017

Notes:
December 31, 2017 Status
*Average of end-of-month customers for the calendar year.
Values shown may be affected due to rounding.

Schedule 2.1

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
2018	1,415,360	2.6	9,322	677,099	13,768	6,558	76,152	86,117
2019	1,450,996	2.6	9,541	693,848	13,751	6,624	77,026	86,001
2020	1,487,604	2.6	9,747	711,143	13,706	6,677	77,721	85,911
2021	1,523,492	2.6	9,950	728,132	13,664	6,736	78,353	85,966
2022	1,559,244	2.6	10,189	745,084	13,675	6,808	79,140	86,027
2023	1,594,803	2.6	10,402	761,967	13,652	6,891	79,991	86,153
2024	1,631,173	2.6	10,619	778,681	13,638	6,983	80,733	86,498
2025	1,667,145	2.6	10,844	795,185	13,637	7,076	81,360	86,966
2026	1,702,638	2.6	11,080	811,492	13,654	7,175	81,962	87,539
2027	1,737,687	2.6	11,316	827,607	13,674	7,277	82,591	88,107

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

Schedule 2.1

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
2018	1,401,567	2.5	9,203	670,516	13,725	6,532	75,859	86,103
2019	1,422,840	2.5	9,298	680,416	13,665	6,571	76,427	85,973
2020	1,444,509	2.5	9,375	690,587	13,576	6,595	76,805	85,867
2021	1,464,913	2.5	9,446	700,192	13,490	6,624	77,108	85,906
2022	1,484,640	2.5	9,548	709,503	13,457	6,666	77,554	85,949
2023	1,503,652	2.4	9,620	718,495	13,389	6,717	78,054	86,053
2024	1,521,775	2.4	9,692	727,081	13,330	6,775	78,434	86,377
2025	1,538,955	2.4	9,768	735,229	13,285	6,832	78,689	86,825
2026	1,555,245	2.4	9,849	742,964	13,257	6,895	78,908	87,380
2027	1,570,679	2.4	9,927	750,297	13,231	6,959	79,146	87,926

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**
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	1,995	1,424	1,401,219	0	68	1,771	18,774
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	1,964	1,633	1,202,128	0	0	1,773	19,544
2019	1,927	1,646	1,170,773	0	0	1,769	19,713
2020	1,947	1,657	1,174,953	0	0	1,769	19,911
2021	1,970	1,666	1,182,386	0	0	1,775	20,119
2022	1,890	1,676	1,127,708	0	0	1,784	20,274
2023	1,914	1,685	1,135,787	0	0	1,797	20,518
2024	1,934	1,693	1,142,162	0	0	1,812	20,769
2025	1,944	1,700	1,143,372	0	0	1,827	21,016
2026	1,808	1,708	1,058,765	0	0	1,842	21,131
2027	1,831	1,715	1,067,633	0	0	1,858	21,404

Notes:
December 31, 2017 Status
*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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting** GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2018	1,967	1,634	1,203,747	0	0	1,773	19,620
2019	1,934	1,647	1,174,149	0	0	1,769	19,869
2020	1,957	1,659	1,179,663	0	0	1,769	20,150
2021	1,984	1,669	1,188,932	0	0	1,774	20,444
2022	1,908	1,679	1,136,438	0	0	1,784	20,689
2023	1,936	1,689	1,146,458	0	0	1,796	21,026
2024	1,961	1,698	1,154,732	0	0	1,811	21,374
2025	1,976	1,706	1,158,210	0	0	1,826	21,722
2026	1,844	1,714	1,076,109	0	0	1,841	21,941
2027	1,872	1,721	1,087,752	0	0	1,857	22,322

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

Schedule 2.2

Forecast of Energy Consumption and Number of Customers by Customer Class Low 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
2018	1,960	1,633	1,200,402	0	0	1,773	19,468
2019	1,920	1,645	1,167,258	0	0	1,770	19,558
2020	1,936	1,655	1,169,825	0	0	1,770	19,676
2021	1,956	1,663	1,175,988	0	0	1,775	19,801
2022	1,871	1,672	1,119,243	0	0	1,785	19,869
2023	1,891	1,681	1,125,101	0	0	1,798	20,025
2024	1,907	1,688	1,129,861	0	0	1,812	20,187
2025	1,914	1,695	1,128,989	0	0	1,828	20,341
2026	1,773	1,702	1,041,766	0	0	1,843	20,361
2027	1,791	1,708	1,048,743	0	0	1,859	20,537

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

Schedule 2.3

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

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
2008	752	909	20,650	7,473	667,266
2009	191	978	19,943	7,748	666,750
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	956	20,500	8,612	760,058
2019	0	964	20,677	8,672	774,160
2020	0	973	20,885	8,734	788,467
2021	0	984	21,103	8,795	802,246
2022	0	991	21,266	8,852	815,986
2023	0	1,004	21,521	8,912	829,571
2024	0	1,016	21,785	8,976	842,736
2025	0	1,028	22,044	9,041	855,435
2026	0	1,034	22,165	9,106	867,774
2027	0	1,048	22,452	9,171	879,814

Notes:
December 31, 2017 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 FTM on 12/31/08, 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

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
2018	0	959	20,580	8,625	763,510
2019	0	971	20,840	8,698	781,219
2020	0	985	21,135	8,773	799,296
2021	0	1,000	21,443	8,848	817,002
2022	0	1,012	21,701	8,919	834,822
2023	0	1,028	22,054	8,993	852,640
2024	0	1,046	22,420	9,071	870,183
2025	0	1,063	22,784	9,150	887,401
2026	0	1,074	23,014	9,230	904,398
2027	0	1,092	23,414	9,310	921,229

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

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
2018	0	952	20,420	8,599	756,607
2019	0	956	20,514	8,645	767,133
2020	0	962	20,638	8,694	777,741
2021	0	968	20,769	8,741	787,704
2022	0	972	20,841	8,784	797,513
2023	0	980	21,005	8,829	807,059
2024	0	988	21,174	8,878	816,081
2025	0	995	21,336	8,928	824,541
2026	0	996	21,357	8,977	832,551
2027	0	1,005	21,542	9,026	840,177

Notes:

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

Schedule 3.1

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

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation***	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2008	4,276	148	4,128	143	69	84	53	55	3,723
2009	4,316	136	4,180	120	54	90	58	59	3,799
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	4,383	0	4,383	115	0	160	100	98	3,910
2019	4,441	0	4,441	109	0	165	100	101	3,966
2020	4,502	0	4,502	109	0	170	100	105	4,018
2021	4,564	0	4,564	110	0	176	101	108	4,069
2022	4,619	0	4,619	98	0	181	101	111	4,128
2023	4,685	0	4,685	98	0	187	102	114	4,184
2024	4,750	0	4,750	98	0	192	102	117	4,241
2025	4,814	0	4,814	97	0	197	103	120	4,296
2026	4,862	0	4,862	81	0	203	103	124	4,352
2027	4,929	0	4,929	81	0	208	103	127	4,410

Notes:

December 31, 2017 Status

2010 and 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 FTM on 12/31/08, 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)	(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
2018	4,400	0	4,400	115	0	160	100	98	3,927
2019	4,476	0	4,476	109	0	165	100	101	4,001
2020	4,556	0	4,556	109	0	170	100	105	4,072
2021	4,637	0	4,637	110	0	176	101	108	4,142
2022	4,713	0	4,713	98	0	181	101	111	4,222
2023	4,800	0	4,800	98	0	187	102	114	4,299
2024	4,886	0	4,886	98	0	192	102	117	4,377
2025	4,973	0	4,973	97	0	197	103	120	4,455
2026	5,044	0	5,044	81	0	203	103	124	4,534
2027	5,135	0	5,135	81	0	208	103	127	4,616

Notes:

*Includes residential and commercial/industrial conservation.

**Includes Energy Planner program.

Values shown may be affected due to rounding.

Schedule 3.1

Forecast of Summer Peak Demand (MW)
Low Case

(1) Year	(2) Total *	(3) Wholesale	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation**	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2018	4,366	0	4,366	115	0	160	100	98	3,893
2019	4,406	0	4,406	109	0	165	100	101	3,931
2020	4,449	0	4,449	109	0	170	100	105	3,965
2021	4,493	0	4,493	110	0	176	101	108	3,998
2022	4,528	0	4,528	98	0	181	101	111	4,037
2023	4,574	0	4,574	98	0	187	102	114	4,073
2024	4,618	0	4,618	98	0	192	102	117	4,109
2025	4,662	0	4,662	97	0	197	103	120	4,144
2026	4,688	0	4,688	81	0	203	103	124	4,178
2027	4,733	0	4,733	81	0	208	103	127	4,214

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
2007/08	4,405	152	4,253	120	130	456	53	52	3,443
2008/09	4,696	67	4,629	181	105	462	75	52	3,754
2009/10	5,195	122	5,073	117	109	470	75	56	4,246
2010/11	4,695	120	4,575	140	88	480	75	58	3,735
2011/12	4,081	15	4,066	103	68	487	83	58	3,267
2012/13	3,764	0	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	4,903	0	4,903	94	0	548	95	70	4,096
2018/19	4,972	0	4,972	88	0	555	96	71	4,162
2019/20	5,043	0	5,043	88	0	563	97	72	4,223
2020/21	5,111	0	5,111	88	0	571	97	73	4,282
2021/22	5,172	0	5,172	77	0	579	98	74	4,344
2022/23	5,245	0	5,245	77	0	587	98	75	4,408
2023/24	5,318	0	5,318	78	0	595	99	76	4,470
2024/25	5,388	0	5,388	77	0	603	100	77	4,531
2025/26	5,443	0	5,443	60	0	611	100	78	4,594
2026/27	5,515	0	5,515	60	0	619	101	79	4,656

Notes:

December 31, 2017 Status

2011/2012 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 FTM on 12/31/08, 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) 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
2017/18	4,921	0	4,921	94	0	548	95	70	4,114
2018/19	5,010	0	5,010	88	0	555	96	71	4,200
2019/20	5,100	0	5,100	88	0	563	97	72	4,280
2020/21	5,188	0	5,188	88	0	571	97	73	4,359
2021/22	5,270	0	5,270	77	0	579	98	74	4,442
2022/23	5,365	0	5,365	77	0	587	98	75	4,528
2023/24	5,461	0	5,461	78	0	595	99	76	4,613
2024/25	5,555	0	5,555	77	0	603	100	77	4,698
2025/26	5,634	0	5,634	60	0	611	100	78	4,785
2026/27	5,731	0	5,731	60	0	619	101	79	4,872

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
2017/18	4,884	0	4,884	94	0	548	95	70	4,077
2018/19	4,935	0	4,935	88	0	555	96	71	4,125
2019/20	4,987	0	4,987	88	0	563	97	72	4,167
2020/21	5,036	0	5,036	88	0	571	97	73	4,207
2021/22	5,076	0	5,076	77	0	579	98	74	4,248
2022/23	5,128	0	5,128	77	0	587	98	75	4,291
2023/24	5,179	0	5,179	78	0	595	99	76	4,331
2024/25	5,228	0	5,228	77	0	603	100	77	4,371
2025/26	5,260	0	5,260	60	0	611	100	78	4,411
2026/27	5,309	0	5,309	60	0	619	101	79	4,450

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 %
2008	19,632	431	212	18,990	752	909	20,650	56.8
2009	19,449	444	231	18,774	191	978	19,943	54.4
2010	19,923	458	251	19,213	305	1,149	20,667	50.5
2011	19,296	474	259	18,564	93	642	19,298	55.6
2012	19,178	493	273	18,412	69	839	19,320	56.3
2013	19,225	513	294	18,418	0	760	19,177	56.5
2014	19,377	546	305	18,526	0	789	19,315	54.4
2015	19,890	568	315	19,006	0	1,098	20,105	57.2
2016	20,153	588	331	19,234	9	930	20,173	55.2
2017	20,141	602	353	19,186	2	1,110	20,298	56.2
2018	20,502	611	346	19,544	0	956	20,500	54.6
2019	20,688	624	352	19,713	0	964	20,677	54.3
2020	20,905	636	358	19,911	0	973	20,885	53.9
2021	21,132	649	364	20,119	0	984	21,103	53.9
2022	21,306	662	370	20,274	0	991	21,266	53.7
2023	21,568	674	376	20,518	0	1,004	21,521	53.6
2024	21,838	687	382	20,769	0	1,016	21,785	53.4
2025	22,104	699	388	21,016	0	1,028	22,044	53.5
2026	22,237	712	394	21,131	0	1,034	22,165	53.2
2027	22,529	724	400	21,404	0	1,048	22,452	53.2

Notes:

December 31, 2017 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 FTM on 12/31/08, 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) 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 %
2018	20,578	611	346	19,620	0	959	20,580	54.6
2019	20,844	624	352	19,869	0	971	20,840	54.3
2020	21,144	636	358	20,150	0	985	21,135	53.9
2021	21,456	649	364	20,444	0	1,000	21,443	53.9
2022	21,721	662	370	20,689	0	1,012	21,701	53.7
2023	22,076	674	376	21,026	0	1,028	22,054	53.5
2024	22,443	687	382	21,374	0	1,046	22,420	53.3
2025	22,809	699	388	21,722	0	1,063	22,784	53.4
2026	23,047	712	394	21,941	0	1,074	23,014	53.1
2027	23,447	724	400	22,322	0	1,092	23,414	53.1

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 %
2018	20,426	611	346	19,468	0	952	20,420	54.6
2019	20,534	624	352	19,558	0	956	20,514	54.3
2020	20,670	636	358	19,676	0	962	20,638	54.0
2021	20,813	649	364	19,801	0	968	20,769	54.0
2022	20,901	662	370	19,869	0	972	20,841	53.8
2023	21,076	674	376	20,025	0	980	21,005	53.7
2024	21,255	687	382	20,187	0	988	21,174	53.5
2025	21,429	699	388	20,341	0	995	21,336	53.6
2026	21,467	712	394	20,361	0	996	21,357	53.3
2027	21,662	724	400	20,537	0	1,005	21,542	53.3

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

Schedule 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)
	2017 Actual		2018 Forecast		2019 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,138	1,479	4,285	1,516	4,346	1,526
February	2,994	1,297	3,550	1,338	3,598	1,346
March	3,077	1,486	3,368	1,478	3,411	1,487
April	3,837	1,639	3,548	1,575	3,595	1,587
May	3,890	1,889	3,761	1,834	3,810	1,850
June	4,005	1,849	4,046	1,990	4,098	2,009
July	4,120	2,023	4,079	2,057	4,128	2,078
August	4,074	2,103	4,125	2,086	4,175	2,107
September	3,953	1,867	3,852	1,940	3,897	1,960
October	3,818	1,773	3,640	1,736	3,681	1,753
November	2,974	1,420	3,042	1,411	3,075	1,423
December	2,940	1,472	3,878	1,537	3,925	1,549
TOTAL		20,298		20,500		20,677

Notes:

December 31, 2017 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)
	2017 Actual		2018 Forecast		2019 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,138	1,479	4,303	1,522	4,384	1,538
February	2,994	1,297	3,565	1,343	3,628	1,356
March	3,077	1,486	3,382	1,484	3,440	1,499
April	3,837	1,639	3,563	1,581	3,625	1,599
May	3,890	1,889	3,777	1,841	3,842	1,864
June	4,005	1,849	4,063	1,998	4,133	2,025
July	4,120	2,023	4,096	2,066	4,162	2,095
August	4,074	2,103	4,142	2,094	4,210	2,124
September	3,953	1,867	3,868	1,948	3,929	1,977
October	3,818	1,773	3,655	1,743	3,711	1,767
November	2,974	1,420	3,054	1,417	3,099	1,434
December	2,940	1,472	3,894	1,543	3,958	1,561
TOTAL		20,298		20,580		20,840

Notes:

December 31, 2017 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)
	2017 Actual		2018 Forecast		2019 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,138	1,479	4,266	1,510	4,309	1,514
February	2,994	1,297	3,535	1,333	3,568	1,336
March	3,077	1,486	3,354	1,473	3,383	1,476
April	3,837	1,639	3,534	1,570	3,565	1,575
May	3,890	1,889	3,745	1,827	3,778	1,836
June	4,005	1,849	4,030	1,982	4,064	1,993
July	4,120	2,023	4,062	2,049	4,093	2,061
August	4,074	2,103	4,108	2,077	4,140	2,090
September	3,953	1,867	3,836	1,932	3,865	1,944
October	3,818	1,773	3,626	1,729	3,651	1,739
November	2,974	1,420	3,030	1,406	3,050	1,413
December	2,940	1,472	3,863	1,532	3,893	1,537
TOTAL		20,298		20,421		20,514

Notes:

December 31, 2017 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)
			Actual	Actual										
	Fuel Requirements	**Unit**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
(1)	Nuclear	Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal	1000 Ton	3,005	2,279	1,762	1,552	1,474	1,249	1,347	566	1,148	1,314	1,224	1,533
(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	1	0	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	1	0	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	77,896	100,445	108,691	106,754	107,664	111,478	110,013	115,546	109,203	108,473	110,590	109,127
(14)	ST	1000 MCF	8,736	8,445	9,587	8,701	8,169	2,652	1,707	812	1,490	1,687	1,568	1,853
(15)	CC	1000 MCF	59,525	91,202	95,032	95,467	97,064	105,083	102,021	112,393	105,831	104,725	106,526	104,611
(16)	GT	1000 MCF	9,635	798	4,072	2,586	2,431	3,743	6,285	2,341	1,882	2,061	2,496	2,663
(17)	Other (Specify)													
(18)	PC	1000 Ton	393	380	366	432	433	396	432	423	396	432	432	395

Notes:

Values shown may be affected due to rounding.
All values exclude ignition.

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 2016**	**Actual 2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
(1)	Annual Firm Interchange	GWh	193	122	161	0	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	7,667	4,949	3,950	3,463	3,256	2,705	2,997	1,283	2,574	2,944	2,752	3,430
(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	0	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	0	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	10,129	13,685	14,911	14,756	14,876	15,756	15,503	17,457	16,536	16,334	16,668	16,379
(15)	ST	GWh	899	744	817	742	677	212	141	51	120	139	128	165
(16)	CC	GWh	8,381	12,871	13,733	13,787	13,986	15,162	14,714	17,198	16,249	16,012	16,317	15,976
(17)	GT	GWh	849	70	361	227	213	382	648	208	167	183	223	238
(18)	Renewable	GWh	3	45	139	976	1272	1422	1416	1410	1408	1399	1393	1387
(19)	Solar	GWh	3	45	139	976	1272	1422	1416	1410	1408	1399	1393	1387
(20)	Other (Specify)													
(21)	PC	GWh	1,100	1,064	1,033	1,220	1,224	1,118	1,220	1,195	1,119	1,220	1,220	1,115
(22)	Net Interchange	GWh	842	244	216	172	167	12	40	86	58	57	41	50
(23)	Purchased Energy from Non-Utility Generators	GWh	237	188	90	90	90	90	90	90	90	90	90	90
(24)	Net Energy for Load	GWh	20,173	20,298	20,500	20,677	20,885	21,103	21,266	21,521	21,785	22,044	22,165	22,452

Notes:

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

Values shown may be affected due to rounding.

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 2016**	**Actual 2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
(1)	Annual Firm Interchange	%	1.0	0.6	0.8	0.0	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	%	38.0	24.4	19.3	16.7	15.6	12.8	14.1	6.0	11.8	13.4	12.4	15.3
(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	%	50.2	67.4	72.7	71.4	71.2	74.7	72.9	81.1	75.9	74.1	75.2	73.0
(15)	ST	%	4.5	3.7	4.0	3.6	3.2	1.0	0.7	0.2	0.6	0.6	0.6	0.7
(16)	CC	%	41.5	63.4	67.0	66.7	67.0	71.8	69.2	79.9	74.6	72.6	73.6	71.2
(17)	GT	%	4.2	0.3	1.8	1.1	1.0	1.8	3.0	1.0	0.8	0.8	1.0	1.1
(18)	Renewable	%	0.0	0.2	0.7	4.7	6.1	6.7	6.7	6.6	6.5	6.3	6.3	6.2
(19)	Solar	%	0.0	0.2	0.7	4.7	6.1	6.7	6.7	6.6	6.5	6.3	6.3	6.2
(20)	Other (Specify)													
(21)	PC	%	5.5	5.2	5.0	5.9	5.9	5.3	5.7	5.6	5.1	5.5	5.5	5.0
(22)	Net Interchange	%	4.2	1.2	1.1	0.8	0.8	0.1	0.2	0.4	0.3	0.3	0.2	0.2
(23)	Purchased Energy from													
(24)	Non-Utility Generators	%	1.2	0.9	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
(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.

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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 peaking resources are needed. In September 2018, TEC will add 144.7 MW_{AC} of solar PV generation. In subsequent years, the company will install over 450 MW_{AC} of additional solar PV, intermediate resources by modernizing Big Bend Power Station through the repowering of unit 1 to a 2x1 combined cycle unit and retiring unit 2, and peaking capacity from simple cycle combustion turbines. These peaking units will be installed in 2023 and 2026, respectively. The operating and cost parameters are shown in Schedule 9.

TEC will compare viable purchased power options as an alternative and/or enhancements 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 2018, TEC plans for 331 MW of cogeneration capacity operating in its service area.

Table IV-I 2018 Cogeneration Capacity Forecast	Capacity (MW)
Self-service [1]	268
Firm to Tampa Electric	0
As-available to Tampa Electric	7
Export to other systems	56
Total	331

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

FIRM INTERCHANGE SALES AND PURCHASES

Currently, TEC has one long-term firm purchase power agreement. Below is the contract for capacity and energy:

- 121 MW purchase from Quantum Pasco Power through December 2018

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 and Gulfstream Natural Gas System LLC for delivery of natural gas to Big Bend, Bayside, and Polk. As shown in Schedule 6.2, in 2018, coal and petcoke will fuel 24.3% of the net energy for load and natural gas will fuel 72.7%. The remaining net energy for load is served by solar PV as well as firm, non-firm, and non-utility generator purchases. Some of the company's generating units also have dual-fuel (i.e., natural gas or oil) capability, which enhances system reliability.

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 and mercury emissions as a result of the agreement with the Florida Department of Environmental Protection and the agreement with the U.S. Environmental Protection Agency in a Consent Decree. TEC fulfilled all commitments of the agreements and the motion to terminate the Consent Decree was granted on November 22, 2013. TEC's major addition of solar generation through 2021 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:

- Improvement of the Big Bend electrostatic precipitators

- The installation of natural gas-fired igniters at Big Bend Station will continue to provide opportunities to augment coal-fired operation and further reduce emissions during startup and normal operation.

- The Polk Power Station combined-cycle project. This improved system reliability and further reduced emissions system-wide.

- The SoBRA agreement enables the company to significantly reduce its carbon emissions profile and its dependence on carbon-based fuels by installing 600 MW_{AC} of photovoltaic single axis tracking solar generation.

TEC will continue to reduce emissions through project enhancements and best operation and maintenance work practices. However, the company recognizes that environmental regulations continue to change. As these regulations evolve, they will impact both cost and operations.

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 treatment technology at Big Bend Station and potentially require new treatment at Polk Power Station.

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 2018 -2019 to allow for continued storm water storage. Planning is underway to close the Economizer Ponds by removing and disposing of the CCRs offsite and restoring the site to natural grade. TEC is also planning to retire the South Gypsum Storage Area in 2018-2019 by removing and processing the CCRs for beneficial in 2018-2019.   This CCR unit is not regulated by the CCR Rule. 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)
							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 Summer Peak Demand MW	MW	% of Peak	Scheduled** Maintenance MW	MW	% of Peak
2018	4,815	121	0	0	4,936	3,911	1,025	26%	13	1,012	26%
2019	5,227	0	0	0	5,227	3,966	1,261	32%	211	1,049	26%
2020	5,367	0	0	0	5,367	4,018	1,349	34%	279	1,070	27%
2021	5,306	0	0	0	5,306	4,070	1,236	30%	303	933	23%
2022	5,306	0	0	0	5,306	4,129	1,177	29%	303	875	21%
2023	5,681	0	0	0	5,681	4,184	1,496	36%	303	1,193	29%
2024	5,681	0	0	0	5,681	4,241	1,440	34%	303	1,137	27%
2025	5,681	0	0	0	5,681	4,297	1,383	32%	303	1,080	25%
2026	5,910	0	0	0	5,910	4,352	1,558	36%	303	1,255	29%
2027	5,910	0	0	0	5,910	4,410	1,500	34%	303	1,197	27%

Notes:

* Includes purchase power agreement (PPA) with Quantum Pasco Power of 121 MW through 2018.

** Includes solar 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)
	Installed Capacity	Firm * Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled** Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2017-18	5,218	121	0	0	5,339	4,096	1,244	30%	22	1,221	30%
2018-19	5,630	0	0	0	5,630	4,163	1,467	35%	434	1,033	25%
2019-20	5,770	0	0	0	5,770	4,223	1,546	37%	574	973	23%
2020-21	5,819	0	0	0	5,819	4,283	1,536	36%	623	913	21%
2021-22	5,729	100	0	0	5,829	4,344	1,485	34%	623	862	20%
2022-23	6,064	0	0	0	6,064	4,408	1,656	38%	623	1,033	23%
2023-24	6,064	0	0	0	6,064	4,470	1,594	36%	623	971	22%
2024-25	6,064	0	0	0	6,064	4,531	1,533	34%	623	909	20%
2025-26	6,309	0	0	0	6,309	4,594	1,715	37%	623	1,092	24%
2026-27	6,309	0	0	0	6,309	4,656	1,653	35%	623	1,029	22%

Notes:

* Includes purchase power agreement (PPA) with Quantum Pasco Power of 121 MW through 2018.

** Includes solar capacity unavailable at time of peak.

Values shown may be affected due to rounding.

Schedule 8.1

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.		Const. Start	Commercial In-Service	Expected Retirement	Gen. Max. Nameplate	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Mo/Yr	Mo/Yr	Mo/Yr	kW	Summer MW	Winter MW	Status
Balm Solar**	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	09/18	*	74,400	74.4	74.4	P
Payne Creek Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	09/18	*	70,300	70.3	70.3	P
Lithia Solar**	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	1/19	*	74,500	74.5	74.5	P
Grange Hall Solar**	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	1/19	*	61,000	61.1	61.1	P
Peace Creek Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	1/19	*	57,000	56.6	56.6	P
Bonnie Mine Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	1/19	*	34,000	34.5	34.5	P
Mountain View Solar**	1	Pasco County	PV	SOLAR	NA	NA	NA	-	1/19	*	55,000	55.1	55.1	P
Wimauma Solar**	1	Hillsborough	PV	SOLAR	NA	NA	NA	-	1/20	*	74,500	74.5	74.5	P
Alafia Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	1/20	*	50,000	50.3	50.3	P
Lake Hancock Solar**	1	Polk County	PV	SOLAR	NA	NA	NA	-	1/21	*	50,000	49.6	49.6	P
Big Bend CT 5***	5M	Big Bend	GT	NG	NA	PL	NA	08/19	06/21	*	*	360	392	P
Big Bend CT 6***	6M	Big Bend	GT	NG	NA	PL	NA	08/19	06/21	*	*	360	392	P
Big Bend ST 1	1M	Big Bend	ST	NG	NA	PL	NA	06/20	01/23	*	*	335	335	P
Future CT 1	1	*	GT	NG	NA	PL	NA	01/20	01/23	*	*	229	245	P
Future CT 2	2	*	GT	NG	NA	PL	NA	01/23	01/26	*	*	229	245	P

Notes:

* Undetermined

** Solar MW values reflect seasonal capacity values, not available capacity at time of peak.

*** 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.

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Balm Solar	
(2)	Net Capability		
	A. Summer	74.4	MW-ac
	B. Winter	74.4	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	June 2017	
	B. Commercial In-Service Date	September 2018	
(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	+544 Acres	
(9)	Construction Status	In progress	
(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 (2019)	26 % (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[3] (In-Service Year $/kW)	1,479.54	
	Direct Construction Cost ($/kW)	1,450.13	
	AFUDC[2] Amount ($/kW)	29.41	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.17	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.11	

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

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Payne Creek Solar	
(2)	Net Capability		
	A. Summer	70.3	MW-ac
	B. Winter	70.3	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	June 2017	
	B. Commercial In-Service Date	September 2018	
(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	+503 Acres	
(9)	Construction Status	In progress	
(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 (2019)	27 % (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[3] (In-Service Year $/kW)	1,324.18	
	Direct Construction Cost ($/kW)	1,292.95	
	AFUDC[2] Amount ($/kW)	31.23	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.17	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.10	

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

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Lithia 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[4]	June 2017	
	B. Commercial In-Service Date	January 2019	
(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	+580 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 (2019)	27 % (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[3] (In-Service Year $/kW)	1,467.15	
	Direct Construction Cost ($/kW)	1,436.66	
	AFUDC[2] Amount ($/kW)	30.49	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.34	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.11	

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

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Grange Hall Solar	
(2)	Net Capability		
	A. Summer	61.1	MW-ac
	B. Winter	61.1	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	June 2017	
	B. Commercial In-Service Date	January 2019	
(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	+447 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 (2019)	26 % (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[3] (In-Service Year $/kW)	1,392.90	
	Direct Construction Cost ($/kW)	1,363.83	
	AFUDC[2] Amount ($/kW)	29.07	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.34	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.12	

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

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Peace Creek Solar	
(2)	Net Capability		
	A. Summer	56.6	MW-ac
	B. Winter	56.6	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	September 2017	
	B. Commercial In-Service Date	January 2019	
(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	+422 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 (2019)	26 % (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[3] (In-Service Year $/kW)	1,478.05	
	Direct Construction Cost ($/kW)	1,448.26	
	AFUDC[2] Amount ($/kW)	29.79	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.34	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.11	

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

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Bonnie Mine Solar	
(2)	Net Capability		
	A. Summer	34.5	MW-ac
	B. Winter	34.5	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	November 2017	
	B. Commercial In-Service Date	January 2019	
(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	+352 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 (2019)	26 % (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[3] (In-Service Year $/kW)	1,467.27	
	Direct Construction Cost ($/kW)	1,435.78	
	AFUDC[2] Amount ($/kW)	31.49	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.52	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.12	

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

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Mountain View Solar	
(2)	Net Capability		
	A. Summer	55.1	MW-ac
	B. Winter	55.1	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	June 2017	
	B. Commercial In-Service Date	January 2019	
(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 (2019)	26 % (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[3] (In-Service Year $/kW)	1,388.68	
	Direct Construction Cost ($/kW)	1,359.53	
	AFUDC[2] Amount ($/kW)	29.15	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.52	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.12	

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

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Wimauma 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[4]	October 2017	
	B. Commercial In-Service Date	January 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 % (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[3] (In-Service Year $/kW)	1,485.02	
	Direct Construction Cost ($/kW)	1,454.38	
	AFUDC[2] Amount ($/kW)	30.64	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.34	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.11	

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

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Alafia Solar	
(2)	Net Capability		
	A. Summer	50.3	MW-ac
	B. Winter	50.3	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	November 2017	
	B. Commercial In-Service Date	January 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	+477 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 % (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[3] (In-Service Year $/kW)	1,470.97	
	Direct Construction Cost ($/kW)	1,439.52	
	AFUDC[2] Amount ($/kW)	31.44	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.52	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.12	

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

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Lake Hancock Solar	
(2)	Net Capability		
	A. Summer	49.6	MW-ac
	B. Winter	49.6	MW-ac
(3)	Technology Type	Single Axis Tracking PV Solar	
(4)	Anticipated Construction Timing		
	A. Field Construction Start Date[4]	January 2018	
	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	+356 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 % (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[3] (In-Service Year $/kW)	1,470.03	
	Direct Construction Cost ($/kW)	1,439.91	
	AFUDC[2] Amount ($/kW)	30.11	
	Escalation ($/kW)	N/A	
	Fixed O&M (In-Service Year $/kW – Yr)	7.70	
	Variable O&M (In-Service Year $/MWh)	0.0	
	K-Factor [1]	1.14	

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

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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Big Bend CT 5
(2)	Net Capability	
	A. Summer	360 MW[4]
	B. Winter	392 MW[4]
(3)	Technology Type	Combustion Turbine[3]
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	August 2019
	B. Commercial In-Service Date	June 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	Undetermined
(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)	9.2 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	9,367 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	533.17
	Direct Construction Cost ($/kW)	351.04
	AFUDC[1] 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] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection
[3] Converts to 2x1 Combined Cycle with a HRSG & Big Bend ST 1 in 2023
[4] Net capability will be restricted to 330 MW S / 350 MW W until being placed into combined cycle mode in 2023

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[4]
	B. Winter	392 MW[4]
(3)	Technology Type	Combustion Turbine[3]
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	August 2019
	B. Commercial In-Service Date	June 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	Undetermined
(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)	9.2 % (1st Full Yr Operation)
	Average Net Operating Heat Rate (In-Service Year ANOHR)	9,367 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	533.17
	Direct Construction Cost ($/kW)	351.04
	AFUDC[1] 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] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection
[3] Converts to 2x1 Combined Cycle with a HRSG & Big Bend ST 1 in 2023
[4] Net capability will be restricted to 330 MW S / 350 MW W until being placed into combined cycle mode in 2023

Schedule 9
(Page 13 of 15)
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[3]
(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	Undetermined
(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)	87.8 %
	Average Net Operating Heat Rate (In-Service Year ANOHR)	6,258 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	1,266.28
	Direct Construction Cost ($/kW)	1,037.75
	AFUDC[1] 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] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection
[3] Converts Big Bend CT 5 & 6 and HRSG's to 2x1 Combined Cycle

Schedule 9
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Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future CT 1
(2)	Net Capability	
	A. Summer	229 MW
	B. Winter	245 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	January 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	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.04
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.94
	Resulting Capacity Factor (2023)	4.1 %
	Average Net Operating Heat Rate (In-Service Year ANOHR)	11,110 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	616.14
	Direct Construction Cost ($/kW)	471.31
	AFUDC[1] Amount ($/kW)	52.76
	Escalation ($/kW)	92.01
	Fixed O&M (In-Service Year $/kW – Yr)	6.33
	Variable O&M (In-Service Year $/MWh)	2.25
	K-Factor	1.5213

[1] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection

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

(1)	Plant Name and Unit Number	Future CT 2
(2)	Net Capability	
	A. Summer	229 MW
	B. Winter	245 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	January 2023
	B. Commercial In-Service Date	January 2026
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-Low NO_x
(7)	Cooling Method	N/A
(8)	Total Site Area	Undetermined
(9)	Construction Status	Proposed
(10)	Certification Status	Undetermined
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.04
	Forced Outage Factor (FOF)	0.02
	Equivalent Availability Factor (EAF)	0.94
	Resulting Capacity Factor (2026)	2.5 %
	Average Net Operating Heat Rate (In-Service Year ANOHR)	11,123 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost[2] (In-Service Year $/kW)	661.58
	Direct Construction Cost ($/kW)	467.48
	AFUDC[1] Amount ($/kW)	56.65
	Escalation ($/kW)	137.45
	Fixed O&M (In-Service Year $/kW – Yr)	6.80
	Variable O&M (In-Service Year $/MWh)	2.42
	K-Factor	1.5213

[1] Based on the current AFUDC rate of 6.46%
[2] Total installed cost includes transmission interconnection

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines

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
Balm Solar ****	Balm - Aspen	1	ROW-TEC Owned	1	230 kV	September 2018	$2.5 Million	Balm Metering Station & Aspen Substation	None
Lithia Solar ****	Mines - Lithia - Aspen	1	ROW-TEC Owned	1	230 kV	December 2018	$3.8 Million	Lithia Metering Station, Mines & Aspen Substation	None
Alafia Solar ****	Alafia - Polk	1	New ROW required	2	230 kV	December 2019	$4.7 Million	Alafia Metering Station & Polk Substation	None
Lake Hancock Solar ****	Recker - Lake Hancock - Crews Lake	1	Not Determined	1	230 kV	December 2020	$3.4 Million	Lake Hancock Metering Station, Recker & Crews Lake Substation	None
Big Bend CT 5 ****	Big Bend CT 5 does not require any new transmission lines	-	-	-	230 kV	June 2021	****	Big Bend	None
Big Bend CT 6 ****	Big Bend CT 6 does not require any new transmission lines	-	-	-	230 kV	June 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
Future CT 1	Unsited *	-	-	-	-	January 2023	-	-	-
Future CT 2	Unsited *	-	-	-	-	January 2026	-	-	-

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

Chapter VI

ENVIRONMENTAL AND LAND USE INFORMATION

The future generating capacity additions identified in Chapter V could occur at H.L. Culbreath Bayside Power Station, Polk Power Station, or Big Bend Power Station. 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 new solar sites identified in Schedule 8.1 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.

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

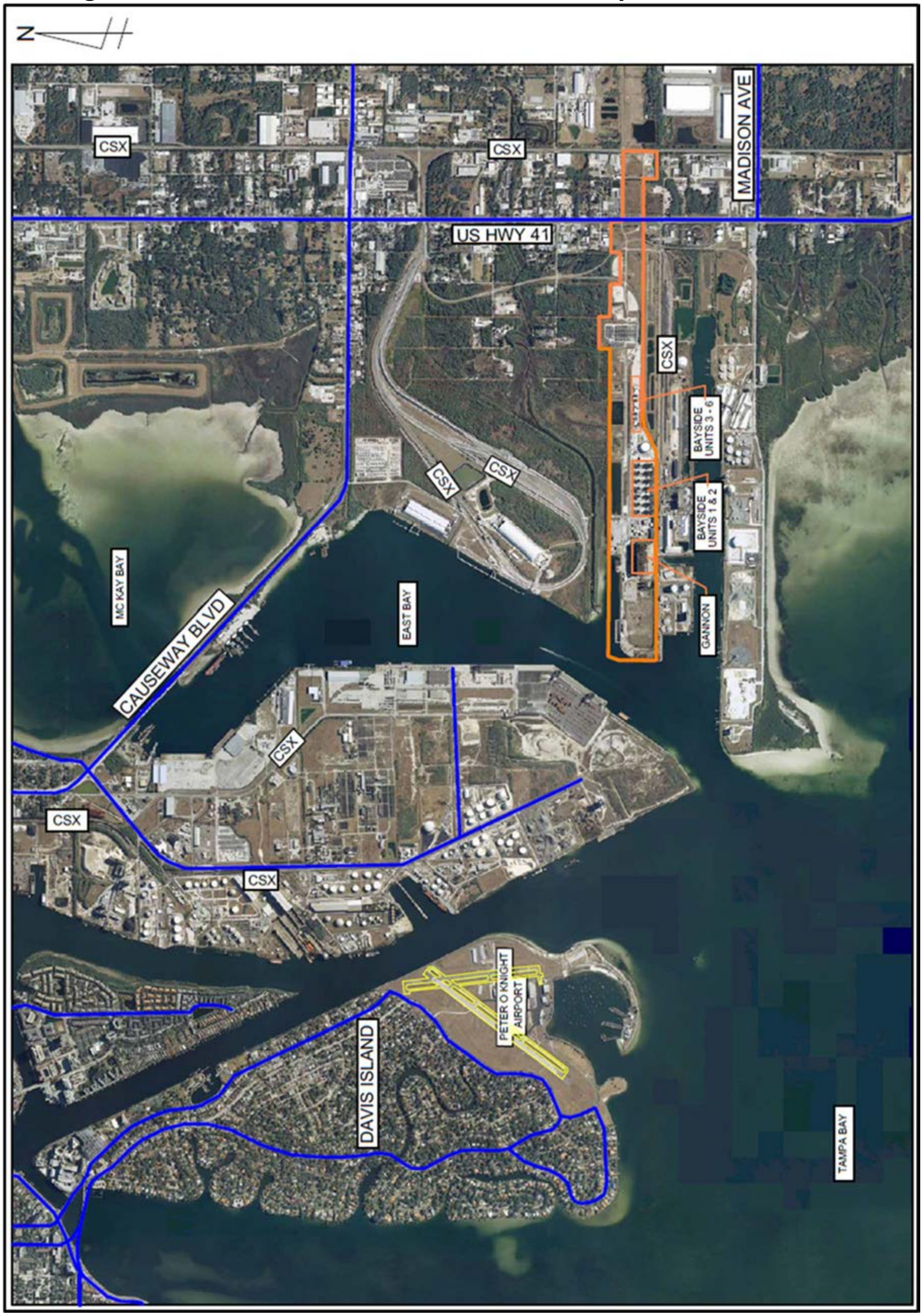

Figure VI-II: Site Location of Polk Power Station

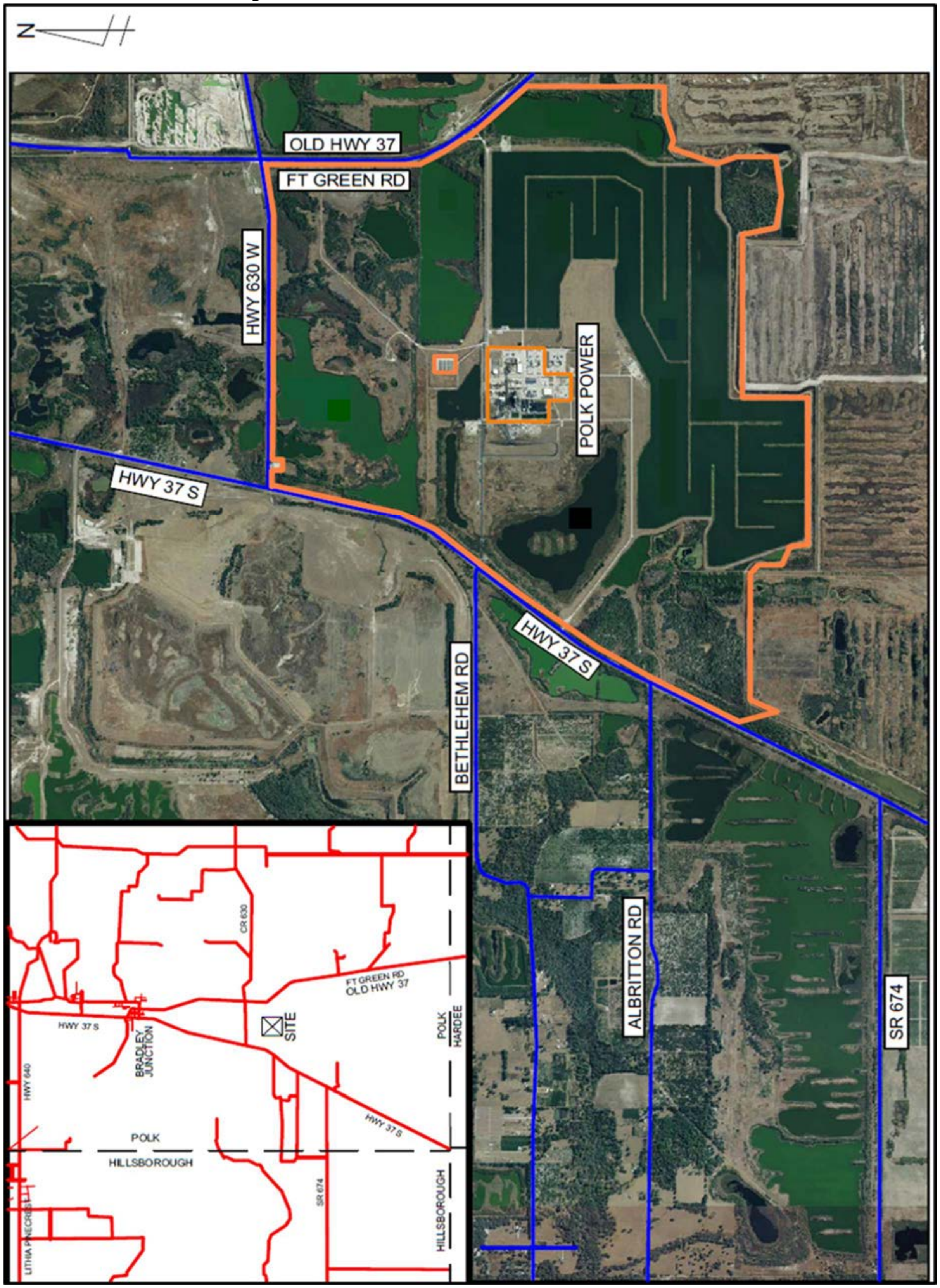

Figure VI-III: Site Location of Big Bend Power Station

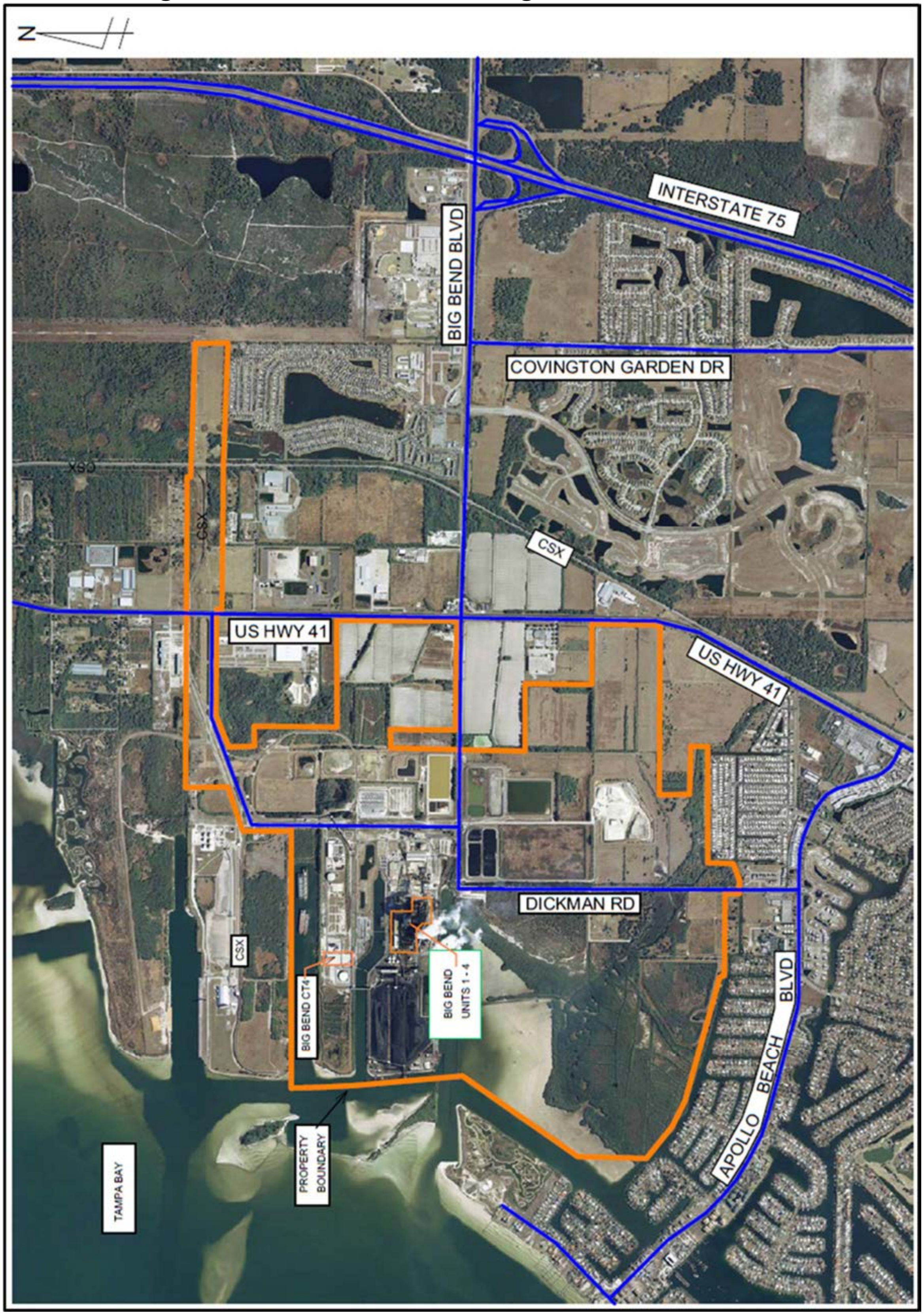

Figure VI-IV: Site Location of Future Solar Power Stations