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May 15, 2019

VIA: ELECTRONIC FILING

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

Re: Review of 2019 Ten-Year Site Plans - Supplemental Data Request #1 (Nos. 2-80)
Undocketed 20190000-OT

Dear Mr. Teitzman:

Pursuant to an email dated February 1, 2019 from Doug Wright, attached are Tampa Electric Company's responses to Staff's First Supplemental Data Request #1 (Nos. 2-80) regarding the company's 2019 Ten-Year Site Plan filed with the Commission on April 1, 2019.

Please note that Tampa Electric's response to Supplemental Data Request No. 55, Page 2 of 2 (Bates page 74) contains confidential information and will be filed under separate cover with the Clerk's Office.

Sincerely,

James D. Beasley

JDB/pp
Attachment

General Items

2. Please provide all data requested in the attached forms labeled "Appendix A." If any of the requested data is already included in the Company's 2019 Ten-Year Site Plan, state so on the appropriate form.

A. The requested data is provided in Excel, "2019 TYSP Data Request #1 Appendix A.xlsx", on the enclosed CD.

Load & Demand Forecasting

3. [Investor-owned Utilities Only] Please provide, on a system-wide basis, the hourly system load for the period January 1, 2018, through December 31, 2018, in Microsoft Excel format.

A. The requested data is provided in Excel, "2018 Tampa Electric Retail Load Served.xlsx", on the enclosed CD.

4. Please provide the monthly peak demand experienced in the period 2016–2018, including the actual peak demand experienced, the amount of demand response activated during the peak, and the estimated total peak if demand response had not been activated. Please also provide the day, hour, and system-average temperature at the time of each monthly peak.

Historic Peak Demand Timing & Temperature

Year	Month	Actual Peak Demand	Demand Response Activated	Estimated Peak Demand	Day	Hour	System-Average Temperature
		(MW)	(MW)	(MW)			(Degrees F)
2018	1						
	2						
	3						
	4						
	5						
	6						
	7						
	8						
	9						
	10						
	11						
	12						
2017	1						
	2						
	3						
	4						
	5						
	6						
	7						
	8						
	9						
	10						
	11						
	12						
2016	1						
	2						
	3						
	4						
	5						
	6						
	7						
	8						
	9						
	10						
	11						
	12						
Notes							
(Include Notes Here)							

A.

Historic Peak Demand Timing & Temperature

Year	Month	Actual Peak Demand	Demand Response Activated	Estimated Peak Demand	Date	Hour	System-Average Temperature
		(MW)	(MW)	(MW)			(Degrees F)
2018	1	4044	0	4044	18	800	29
	2	3120	0	3120	21	1700	86
	3	2881	0	2881	29	1800	78
	4	3267	0	3267	23	1800	80
	5	3607	0	3607	24	1700	86
	6	3956	0	3956	18	1700	90
	7	3955	0	3955	16	1600	89
	8	4037	0	4037	17	1800	91
	9	4021	0	4021	17	1700	92
	10	3877	0	3877	16	1700	92
	11	3272	0	3272	8	1600	84
	12	2890	0	2890	3	1900	75
2017	1	3138	0	3138	9	800	43
	2	2994	0	2994	28	1600	86
	3	3072	0	3072	29	1700	82
	4	3822	0	3822	28	1700	90
	5	3882	0	3882	31	1600	91
	6	3996	0	3996	22	1800	90
	7	4115	0	4115	26	1700	91
	8	4074	0	4074	31	1600	92
	9	3953	0	3953	1	1500	88
	10	3818	0	3818	9	1700	88
	11	2974	0	2974	7	1600	85
	12	2940	0	2940	11	800	46
2016	1	3339	0	3339	25	800	42
	2	3105	0	3105	11	800	47
	3	3169	0	3169	31	1800	79
	4	3604	0	3604	29	1700	86
	5	3624	0	3624	2	1700	85
	6	3955	0	3955	15	1700	89

	7	4130	0	4130	5	1700	91
	8	4101	0	4101	23	1700	86
	9	3812	0	3812	19	1700	88
	10	3557	0	3557	5	1700	88
	11	2887	0	2887	1	1700	84
	12	2996	0	2996	19	1600	83
Notes							
(Include Notes Here)							

5. Please identify the weather station(s) used for calculation of the system-wide temperature for the utility's service territory. If more than one weather station is utilized, please describe how a system-wide average is calculated.

A. Tampa Electric Company ("Tampa Electric", "company" or "TEC") is presently using Tampa International Airport weather station for calculation of the systemwide temperature for the utility's service territory.

6. Please explain how the Company's load and demand forecasting used in its 2019 TYSP was developed. In your response please include the following information: methodology, assumptions, data sources, third-party consultant(s) involved, and any difference/improvement made compared with the load and demand forecasting used in the Company's 2018 Ten-Year Site Plan.

A. The company's customer, demand and energy forecast methodology, as well as assumptions and sources, are explained in detail in Chapter 2 of the 2019 Ten-Year Site Plan (TYSP) on pages 7-20.

Appliance efficiencies are based on data provided by the U.S. Energy Information Administration (EIA). The economic assumptions used in the forecast models are derived from Moody's Analytics and the University of Florida's Bureau of Economic and Business Research (BEBR). A third-party consultant was not involved in the development of the forecasts reported in the 2019 TYSP. There were no significant differences or improvements made within the 2019 TYSP compared to the 2018 TYSP.

7. Please identify all closed and opened FPSC dockets and all non-docketed FPSC matters which were/are based on the same load forecast used in the Company's 2019 TYSP.

A. 20180001-EI
20180002-EG
20180007-EI
20180133-EI
20180204-EI
20180231-EI

8. **[Investor-Owned Utilities Only]** Does your Company review the accuracy of its customer, load, and demand forecasts presented in its TYSP by comparing the actual data for a given year to the data forecasted one, two, three, four, five, or six years prior?

a. If the response is affirmative, please explain the method used in such review.

b. If the response is affirmative, please provide the results of such review for each forecast presented in the TYSPs filed, or to be filed, to the Commission from 2001 to 2019 with supporting workpapers in Microsoft Excel format.

c. If the response is negative, please explain why not.

A. Yes, Tampa Electric does review the accuracy of customers, load and demand forecasts.

a. The method used to review the accuracy of forecasts throughout time is referred to as an error fan. This approach is also used by the Florida Reliability Coordinating Council (FRCC) in reviewing state forecast accuracy.

b. See Excel file Accuracy2019.xlsx.

c. Not applicable.

9. Please explain any recent and forecasted trends in customer growth, by customer type (residential, commercial, industrial) and as a whole.

A. **RESIDENTIAL:**
The residential sector's growth averaged 1.7 percent in 2018. Growth in 2019 is expected to be 1.6 percent. Customer growth is expected to increase at an annual average growth rate of 1.7 percent over the next ten years. The primary driver of customer growth will be new construction and increasing net in-migration to the service area.

COMMERCIAL:
Commercial customer growth has been increasing on average by approximately 1.0 percent. However, in 2018, growth was reported as being relatively flat due to the out-migration of customers to the Governmental sector. Customers are expected to increase at an annual average growth rate of 0.4 percent over the next ten years.

GOVERNMENTAL:
Governmental customer growth increased by 6.4 percent in 2018. A large portion of this increase is attributed to customer migration from the Commercial sector. Growth in the governmental sector is projected to increase at a rate of 1.0 percent over the next ten years.

INDUSTRIAL:
Industrial customer growth declined in 2018. The decline is primarily in the smaller manufacturing segment. The number of industrial accounts is anticipated to increase at an average annual rate of 0.5 percent over the next ten years.

TOTAL:
Total customer growth in 2018 averaged 1.6 percent with the residential class being the engine behind the growth. Over the next ten years customer growth is expected to increase at an average rate of 1.5 percent annually.

10. Please explain any recent and forecasted trends in electricity use per customer, by customer type (residential, commercial, industrial) and as a whole.

A. RESIDENTIAL:

Average consumption per customer increased in 2018 primarily due to a colder winter and a very hot fourth quarter. On a weather normalized basis, the downward trend seems to be stabilizing. This trend is expected to decline at an average annual decline of 0.2 percent over the next ten years. The primary drivers behind the declining per customer usage are increases in appliance/lighting efficiencies, energy efficiency of new homes, conservation efforts and housing mix.

COMMERCIAL:

Commercial consumption per customer decreased in 2018, primarily due to the out-migration of some larger accounts to the Governmental sector. Prior to that usage was relatively flat. It is projected to increase slightly over the ten-year forecast horizon.

GOVERNMENTAL:

Average per customer usage increased in 2018 due to the migration of commercial accounts to this sector. Usage in 2019 will also increase as there will be a full year of consumptions for these accounts that migrated. Over the forecast horizon, usage is expected to remain relatively flat over the short-term and then increase slightly.

INDUSTRIAL:

Industrial per customer usage, excluding Phosphate, increased again in 2018. The increase is primarily due to the trend in declining customer growth in the lower usage segment, making the average usage increase. Average per customer usage is expected to decline at an average of 0.6 percent over the forecast horizon.

The phosphate sector continues to decline over the forecast horizon due to the closure of plant/mine facilities and increased on-site transmission and generation capacity.

TOTAL:

Per customer usage increased slightly in 2018 primarily due to weather. Over the forecast horizon, the phosphate and residential sectors put downward pressure on average per customer consumption, while the other classes slightly offset the declines.

11. Please explain any recent and forecasted trends in peak demand by the sources of peak demand appearing in Schedule 3.1 of the 2019 TYSP.

A. RETAIL PEAKS:

Summer retail peak in 2018 was lower than 2017's peak, due primarily to milder temperatures on the peak day. The 2018 winter peak was higher than the prior year due to a colder winter. Total summer and winter retail peaks are projected to increase at an average annual rate of 1.2 and 1.3 percent, respectively, over the next ten years.

INTERRUPTIBLE LOAD:

Interruptible load has been declining due to the phosphate sector and is projected to decline by an average of 4.7 percent per year over the forecast horizon.

LOAD MANAGEMENT:

Load management is projected to increase by approximately 0.5 percent per year over the forecast horizon.

CONSERVATION:

Conservation at the time of the summer peak is projected to increase by 2.9 percent per year over the forecast horizon, and by 1.4 percent at the time of the winter peak.

NET FIRM DEMAND:

Net firm summer and winter peak demand is projected to increase at an average annual rate of 1.3 and 1.4 percent, respectively, over the next ten years.

12. **[Investor-Owned Utilities Only]** If not included in the Company's 2019 TYSP to be filed by April 1, 2019, please provide load forecast sensitivities (high band, low band) to account for the uncertainty inherent in the base case forecasts in the following TYSP schedules, as well as the methodology used to prepare each forecast:

a. Schedule 2.1 – History and Forecast of Energy Consumption and Number of Customers by Customer Class
b. Schedule 2.2 - History and Forecast of Energy Consumption and Number of Customers by Customer Class
c. Schedule 2.3 - History and Forecast of Energy Consumption and Number of Customers by Customer Class
d. Schedule 3.1 - History and Forecast of Summer Peak Demand
e. Schedule 3.2 - History and Forecast of Winter Peak Demand
f. Schedule 3.3 - History and Forecast of Annual Net Energy for Load
g. Schedule 4 - Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month.

A. The methodology used to prepare load forecast sensitivities (high band, low band) for Schedules 2.1, 2.2, 2.3, 3.1, 3.2, 3.3 and 4 is listed within the 2019 TSYP, Chapter 2, page 19, under "High and Low Scenario Focus Assumptions."

13. Please discuss whether the Company included plug-in electric vehicle (PEV) loads in its demand and energy forecasts for the 2019 TYSP. If so, how were these impacts accounted for in the modeling and forecasting process?

A. Tampa Electric developed estimates of the number of plug-in electric vehicles and their impacts on the demand and energy forecasts. These estimates were incorporated into the forecast results reported in the 2019 TYSP.

14. Please discuss the methodology and the assumptions (or, if applicable, the source(s) of the data) used to estimate the number of PEVs operating in the Company's service territory and the methodology used to estimate the cumulative impact on system demand and energy consumption.

A. The actual number of electric vehicles (EVs) operating in Tampa Electric's service territory through December 2018 was estimated using the most recent data provided by an independent third-party analyst.

The forecasted number of EVs operating in Tampa Electric's service territory through 2028 was created by estimating annual car sales and comparing the historic relationship of EVs in the company's service area with EIA's relationship of EV car sales to total car sales within the South Atlantic region.

Energy and demand impacts were developed using a weighted average of four common EV models sold within Tampa Electric's service territory.

15. Please include the following information within the Utility's service territory: an estimate of the number of PEVs, an estimate of the number of public PEV charging stations, an estimate of the number of public "quick-charge" PEV charging stations (i.e., charging stations requiring a service drop greater than 240 volts and/or using three-phase power), and the estimated demand and energy impacts of the PEVs by year. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

Electric Vehicle Charging Impacts

Year	Number of PEVs	Number of Public PEV Charging Stations	Number of Public "Quick-charge" PEV Charging Stations	Cumulative Impact of PEVs		
				Summer Demand	Winter Demand	Annual Energy
				(MW)	(MW)	(GWh)
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
Notes						
(Include Notes Here)						

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Electric Vehicle Charging Impacts

Year	Number of PEVs	Number of Public PEV Charging Stations	Number of Public "Quick-charge" PEV Charging Stations	Cumulative Impact of PEVs		
				Summer Demand	Winter Demand	Annual Energy
				(MW)	(MW)	(GWh)
2018	3,666	251	45	9.0	3.5	27.1
2019	4,758	280	50	11.8	4.8	37.2
2020	5,896	322	58	14.2	5.9	46.1
2021	7,081	365	65	16.7	6.9	55.3
2022	8,309	407	73	19.2	8.1	64.9
2023	9,582	449	81	21.9	9.2	74.7
2024	11,057	491	88	24.8	10.5	86.2
2025	13,155	534	96	28.6	12.3	102.4
2026	15,638	576	103	33.1	14.3	121.6
2027	18,605	618	111	38.2	16.7	144.6
2028	22,033	661	118	44.1	19.5	171.0

Notes

Cumulative counts provided.
The number of public "quick-charge" PEV charging stations is a subset of the number of Public EV Charging Stations.
Home charging load estimated at 20% of residential EV demand at time of summer retail peak and at 10% of residential EV demand at time of winter retail peak.
Public charging station load estimated at 84% of commercial EV demand at time of summer retail peak and at 24% of commercial EV demand at time of winter retail peak.

16. Please describe any Company programs or tariffs currently offered to customers relating to PEVs, and describe whether any new or additional programs or tariffs relating to PEVs will be offered to customers within the 2019–2028 period.

a. Of these programs or tariffs, are any designed for or do they include educating customers on electricity as a transportation fuel?

b. Does the Company have any programs where customers can express their interest or expectations for electric vehicle infrastructure as provided for by the Utility, and if so, please describe in detail.

A. Tampa Electric continues to be active on several activities and potential offerings of future programs or tariffs with plug-in electric vehicles.

In May 2017, Tampa Electric received Commission approval to enhance the Energy Education, Awareness and Agency Outreach DSM Program by partnering with high schools' driver's education in the classroom. This portion of the program will focus on providing opportunities to encourage the conservation of energy and promote energy efficiency through local school systems by partnering with high schools' driver's education classes. All three selected high schools will begin offering the program in the 2019 school year.

Tampa Electric has also been working with The University of South Florida ("USF") and their Center for Urban Transportation Research ("CUTR") on a Research and Development ("R&D") Project. The project will be concluded by the summer of 2019 with the main R&D research objectives including:

a. Research benefits of electric vehicles to utility companies and the public.
b. Document the impacts of EV usage on energy conservation, energy security, emissions and cost of electricity production for the utility company.
c. Research cost-effectiveness of electric vehicle technologies.
d. If warranted, assist with the design of an effective vehicle rebate program to encourage EV purchases and higher EV usage in Tampa Bay.

In addition, Tampa Electric representatives continue exploring methods to eliminate or decrease the real or perceived barriers to electric vehicle adoption. These barriers could include consumer awareness and acceptance, rate options for different charging methods, workplace charging, range anxiety, retrofit of multi-family parking lots with charging stations, infrastructure concerns regarding the lack of charging stations or corridors in Florida and the potential contribution in aid of construction relief toward the large installation cost of a series of level II charging station or fast DC charging stations.

17. Please describe how the Company monitors the installation of public charging stations in its service area?

A. Although Tampa Electric does not have a specific process capable of monitoring the installation of third-party public charging stations, active participation in industry organizations such as the Tampa Bay Clean Cities Coalition, and relationships with equipment installers, provide reliable data on existing and planned public charging stations. Tampa Electric also leverages relationships with local developers for large projects where public charging may, or could be, included. For "quick-charge" electric vehicle stations requiring greater than 240-volt services, internal collaboration amongst various teams ensures that new installations are properly identified.

18. Please describe any instances since January 1, 2018, in which upgrades to the distribution system were made where PEVs were a contributing factor.

A. Tampa Electric is not aware of any instances since January 1, 2018, in which electric vehicles were a contributing factor to upgrades required on the company's distribution system.

19. Has the Company conducted or contracted any research to determine demographic and regional factors that influence the adoption of electric vehicles applicable to its service territory? If so, please describe in detail the methodology and findings.

A. Tampa Electric has not conducted or contracted any research to determine demographic and regional factors that influence EV adoption in the company's service territory.

20. What processes or technologies, if any, are in place that allow the Utility to be notified when a customer has established an electrical vehicle charging station in the home?

A. Tampa Electric does not have a process or technology in place that allows for company notification when a home EV charging stations has been installed.

21. **[FEECA Utilities Only]** For each source of demand response, use the table below to provide the customer participation information listed on an annual basis. Please also provide a summary of all sources of demand response using the chart below. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.].

[Demand Response Source or All Demand Response Sources]									
Year	**Beginning Year: Number of Customers**	**Available Capacity (MW)**		**New Customers Added**	**Added Capacity (MW)**		**Customers Lost**	**Lost Capacity (MW)**	
		Sum	Win		Sum	Win		Sum	Win
2009									
2010									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
Notes									
(Include Notes Here)									

A. The requested data is provided in the tables below and in Excel on the enclosed CD.

All Sources of Load Management and Demand Response Combined									
Year	Beginning Year: Number of Customers	Available Capacity (MW)		New Customers Added	Added Capacity (MW)		Customers Lost	Lost Capacity (MW)	
		Sum	Win		Sum	Win		Sum	Win
2009	50,906	251	340	14	7	7	2,614	21	32
2010	48,306	181	300	25	11	11	2,658	7	13
2011	45,673	235	306	7	3	3	2,544	11	15
2012	43,136	269	259	2	1	1	2,530	4	5
2013	40,608	262	287	14	9	9	2,896	16	18
2014	37,726	300	772	64	31	29	11,245	40	41
2015	26,545	234	225	17	9	9	12,740	32	42
2016	13,822	235	254	19	8	8	13,589	18	31
2017	252	205	231	6	3	3	6	3	3
2018	252	300	158	3	7	7	22	2	1

Commercial/Industrial Load Management									
Year	Beginning Year: Number of Customers	Available Capacity (MW)		New Customers Added	Added Capacity (MW)		Customers Lost	Lost Capacity (MW)	
		Sum	Win		Sum	Win		Sum	Win
2009	6	0.2	0.0	2	0.1	0.0	1	0.0	0.0
2010	7	0.2	0.0	0	0.0	0.0	1	0.0	0.0
2011	6	0.2	0.0	0	0.0	0.0	0	0.0	0.0
2012	6	0.3	0.0	0	0.0	0.0	0	0.0	0.0
2013	6	0.3	0.0	0	0.0	0.0	0	0.0	0.0
2014	6	0.3	0.0	0	0.0	0.0	0	0.0	0.0
2015	6	0.3	0.0	0	0.0	0.0	0	0.0	0.0
2016	6	0.3	0.0	0	0.0	0.0	0	0.0	0.0
2017	6	0.3	0.0	0	0.0	0.0	0	0.0	0.0
2018	6	0.3	0.0	0	0.0	0.0	0	0.0	0.0

Commercial/Industrial Standby Generator Program									
Year	Beginning Year: Number of Customers	Available Capacity (MW)		New Customers Added	Added Capacity (MW)		Customers Lost	Lost Capacity (MW)	
		Sum	Win		Sum	Win		Sum	Win
2009	79	40.2	18.0	5	2.5	1.1	0	0.0	0.0
2010	84	40.2	40.2	7	3.3	3.3	3	1.4	1.4
2011	88	40.2	40.2	6	2.7	2.7	0	0.0	0.0
2012	94	51.2	48.5	2	1.1	1.0	0	0.0	0.0
2013	96	50.7	51.4	6	3.2	3.2	4	2.1	2.1
2014	98	52.0	57.5	2	1.1	1.2	4	2.1	2.3
2015	96	58.5	56.5	4	2.4	2.4	4	2.4	2.4
2016	96	54.2	52.8	0	0.0	0.0	5	2.8	2.8
2017	91	52.0	51.0	6	3.4	3.4	3	1.7	1.7
2018	94	52.0	52.0	1	0.5	0.5	1	0.2	0.2

Interruptible Load									
Year	Beginning Year: Number of Customers	Available Capacity (MW)		New Customers Added	Added Capacity (MW)		Customers Lost	Lost Capacity (MW)	
		Sum	Win		Sum	Win		Sum	Win
2009	56	120.0	181.0	1	2.1	3.2	8	17.1	25.9
2010	49	73.0	117.0	0	0.0	0.0	2	3.0	4.8
2011	47	109.0	140.0	0	0.0	0.0	3	7.0	8.9
2012	44	133.0	103.0	0	0.0	0.0	0	0.0	0.0
2013	44	131.0	130.0	1	3.0	3.0	3	8.9	8.9
2014	42	170.0	610.0	1	4.0	1.5	3	12.1	4.4
2015	40	111.0	79.0	1	2.8	2.0	3	8.3	5.9
2016	38	138.0	145.0	0	0.0	0.0	4	14.5	15.3
2017	34	110.0	137.0	0	0.0	0.0	0	0.0	0.0
2018	34	208.0	66.0	1	4.8	4.5	1	0.3	0.08

Commercial Demand Response									
Year	Beginning Year: Number of Customers	Available Capacity (MW)		New Customers Added	Added Capacity (MW)		Customers Lost	Lost Capacity (MW)	
		Sum	Win		Sum	Win		Sum	Win
2009	82	36.4	36.4	6	2.7	2.7	2	0.9	0.9
2010	86	34.2	34.2	18	7.2	7.2	1	0.4	0.4
2011	103	37.5	37.5	1	0.4	0.4	4	1.5	1.5
2012	100	39.6	39.6	0	0.0	0.0	3	1.2	1.2
2013	97	40.7	40.7	7	2.9	2.9	6	2.5	2.5
2014	98	41.7	41.7	61	26.0	26.0	36	15.3	15.3
2015	123	42.8	42.8	12	4.2	4.2	32	11.1	11.1
2016	103	42.8	42.8	19	7.9	7.9	1	0.4	0.4
2017	121	42.8	42.8	0	0.0	0.0	3	1.1	1.1
2018	118	40.0	40.0	1	1.8	1.8	20	2.0	0.9

22. **[FEECA Utilities Only]** For each source of demand response, use the table below to provide the usage information listed on an annual basis. Please also provide a summary of all demand response using the chart below. As part of this response, please provide an electronic version of the table below in Microsoft Excel format. .

[Demand Response Source or All Demand Response Sources]										
Year	**Summer**					**Winter**				
	Number of Events	**Average Event Size**		**Maximum Event Size**		**Number of Events**	**Average Event Size**		**Maximum Event Size**	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009										
2010										
2011										
2012										
2013										
2014										
2015										
2016										
2017										
2018										
Notes										
(Include Notes Here)										

A. The requested data is provided in the tables below and in Excel on the enclosed CD.

All Sources of Load Management and Demand Response Combined										
Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	18	153.5	59,868	178.4	49,916	3	11	29,683	15	50,171
2010	2	18.2	46,213	18.2	46,213	2	196.9	45,683	196.9	45,683
2011	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0
2013	5	301.9	39,455	301.9	39,455	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0
2017	3	177.3	233	177.3	233	0	0	0	0	0
2018	1	44	34	44	34	3	139.2	189	166.4	243

Residential Load Management*										
Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	6	30.1	59,675	54.0	49,722	3	11.0	29,683	15.0	50,171
2010	1	18.0	46,207	18.0	46,207	1	69.0	45,661	69.0	45,661
2011	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2012	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2013	1	43.0	39,232	43.0	39,232	0	0.0	0	0.0	0
2014	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2015	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2016	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2017	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2018	0	0.0	0	0.0	0	0	0.0	0	0.0	0
Notes										
* Residential Load Management program ended during Summer 2016										

Commercial/Industrial Load Management										
Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	6	0.2	6	0.2	6	0	0.0	0	0.0	0
2010	1	0.2	6	0.2	6	0	0.0	0	0.0	0
2011	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2012	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2013	1	0.3	6	0.3	6	0	0.0	0	0.0	0
2014	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2015	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2016	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2017	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2018	0	0.0	0	0.0	0	0	0.0	0	0.0	0

Interruptible Load										
Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	1	69.2	24	69.2	24	0	0.0	0	0.0	0
2010	0	0.0	0	0.0	0	1	127.9	22	127.9	22
2011	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2012	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2013	1	166.6	22	166.6	22	0	0.0	0	0.0	0
2014	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2015	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2016	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2017	1	125.0	19	125.0	19	0	0.0	0	0.0	0
2018	1	44	34	44	34	1	74.4	31	74.4	31

Commercial/Industrial Standby Generator										
Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	2	24.0	80	25.0	81	0	0.0	0	0.0	0
2010	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2011	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2012	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2013	1	53.0	92	53.0	92	0	0.0	0	0.0	0
2014	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2015	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2016	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2017	1	9.6	94	9.6	94	0	0.0	0	0.0	0
2018	0	0.0	0	0.0	0	1	26.0	68	52.0	94

Commercial Demand Response										
Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	3	30.0	83	30.0	83	0	0.0	0	0.0	0
2010	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2011	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2012	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2013	1	39.0	103	39.0	103	0	0.0	0	0.0	0
2014	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2015	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2016	0	0.0	0	0.0	0	0	0.0	0	0.0	0
2017	1	42.7	120	42.7	120	0	0.0	0	0.0	0
2018	0	0	0	0	0	1	38.8	90	40.0	118

23. **[FEECA Utilities Only]** For each source of demand response, use the table below to provide the seasonal peak activation information listed on an annual basis. Please also provide a summary of all demand response using the chart below. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

[Demand Response Source or All Demand Response Sources]							
Year	**Average Number of Customers**	**Summer Peak**			**Winter Peak**		
		Activated During Peak? (Y/N)	**Number of Customers Activated**	**Capacity Activated** (MW)	**Activated During Peak?** (Y/N)	**Number of Customers Activated**	**Capacity Activated** (MW)
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
Notes							
(Include Notes Here)							

A. The requested data is provided in the table below and in Excel on the enclosed CD.

All Sources of Load Management and Demand Response Combined							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak?	Number of Customers Activated	Capacity Activated	Activated During Peak?	Number of Customers Activated	Capacity Activated
		(Y/N)		(MW)	(Y/N)		(MW)
2009	49,596	Yes	49,891	93	No	0	0
2010	46,267	No	0	0	No	0	0
2011	44,410	No	0	0	No	0	0
2012	41,876	No	0	0	No	0	0
2013	39,123	Yes	39,557	219	No	0	0
2014	33,198	No	0	0	No	0	0
2015	20,181	No	0	0	No	0	0
2016	3,659	No	0	0	No	0	0
2017	253	Yes	0	0	No	0	0
2018	246	No	0	0	Yes	212	65

Residential Load Management*							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak?	Number of Customers Activated	Capacity Activated	Activated During Peak?	Number of Customers Activated	Capacity Activated
		(Y/N)		(MW)	(Y/N)		(MW)
2009	49,370	Yes	49,722	54	No	0	0
2010	46,024	No	0	0	No	0	0
2011	44,161	No	0	0	No	0	0
2012	41,629	No	0	0	No	0	0
2013	38,880	Yes	39,323	45	No	0	0
2014	32,960	No	0	0	No	0	0
2015	19,930	No	0	0	No	0	0
2016	3,407	No	0	0	No	0	0
2017	0	No	0	0	No	0	0
2018	0	No	0	0	No	0	0

NOTES

*Residential Load Management program ended during Summer 2016.

Source: Peak Report for MW capacity activated at time of retail summer and winter peak

Commercial/Industrial Load Management							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak?	Number of Customers Activated	Capacity Activated	Activated During Peak?	Number of Customers Activated	Capacity Activated
		(Y/N)		(MW)	(Y/N)		(MW)
2009	7	Yes	6	0.2	No	0	0.0
2010	7	No	0	0.0	No	0	0.0
2011	7	No	0	0.0	No	0	0.0
2012	7	No	0	0.0	No	0	0.0
2013	6	Yes	6	0.2	No	0	0.0
2014	6	No	0	0.0	No	0	0.0
2015	6	No	0	0.0	No	0	0.0
2016	6	No	0	0.0	No	0	0.0
2017	6	No	0	0.0	No	0	0.0
2018	6	No	0	0.0	No	0	0.0

Commercial/Industrial Standby Generator Program							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak?	Number of Customers Activated	Capacity Activated	Activated During Peak?	Number of Customers Activated	Capacity Activated
		(Y/N)		(MW)	(Y/N)		(MW)
2009	82	Yes	81	23.0	No	0	0.0
2010	91	No	0	0.0	No	0	0.0
2011	94	No	0	0.0	No	0	0.0
2012	96	No	0	0.0	No	0	0.0
2013	94	Yes	92	27.0	No	0	0.0
2014	96	No	0	0.0	No	0	0.0
2015	95	No	0	0.0	No	0	0.0
2016	93	No	0	0.0	No	0	0.0
2017	93	No	0	0.0	No	0	0.0
2018	94	No	0	0	Yes	94	26.0

Interruptible Load							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak?	Number of Customers Activated	Capacity Activated	Activated During Peak?	Number of Customers Activated	Capacity Activated
		(Y/N)		(MW)	(Y/N)		(MW)
2009	53	No	0	0	No	0	0
2010	49	No	0	0	No	0	0
2011	46	No	0	0	No	0	0
2012	44	No	0	0	No	0	0
2013	43	Yes	38	130	No	0	0
2014	41	No	0	0	No	0	0
2015	40	No	0	0	No	0	0
2016	36	No	0	0	No	0	0
2017	34	No	0	0	No	0	0
2018	34	No	0	0	No	0	0

Commercial Demand Response							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak?	Number of Customers Activated	Capacity Activated	Activated During Peak?	Number of Customers Activated	Capacity Activated
		(Y/N)		(MW)	(Y/N)		(MW)
2009	84	Yes	82	16.0	No	0	0.0
2010	96	No	0	0.0	No	0	0.0
2011	102	No	0	0.0	No	0	0.0
2012	100	No	0	0.0	No	0	0.0
2013	100	Yes	98	17.0	No	0	0.0
2014	95	No	0	0.0	No	0	0.0
2015	110	No	0	0.0	No	0	0.0
2016	117	No	0	0.0	No	0	0.0
2017	120	No	0	0.0	No	0	0.0
2018	112	No	0	0.0	Yes	118	38.8

Generation & Transmission

24. Please identify and describe each existing utility-owned renewable resource as of December 31, 2018, that delivered energy during the year. Please include the facility's name, unit type, fuel type, its installed capacity (AC-rating for photovoltaic (PV) systems), its net firm capacity or contribution during peak demand (if any), capacity factor for 2018 based off of the installed capacity, and its in-service date. For multiple small distributed renewable resources (<250 kW per installation), such as rooftop solar panels, please include a single combined entry for the resources that share the same unit & fuel type. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

Existing Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Net Firm Capacity (MW)		Capacity Factor	In-Service Date
-	-	-	Sum	Win	Sum	Win	(%)	(MM/YYYY)
Notes								
(Include Notes Here)								

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Existing Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Net Firm Capacity (MW)		Capacity Factor	In-Service Date
			Sum	Win	Sum	Win	(%)	(MM/YYYY)
Community-sited Solar (<250 kW)	PV	Solar	0.175	0.175	NA	NA	6.7	12/1999 – 12/2018
Tampa International Airport	PV	Solar	1.6	1.6	0.7	NA	22.0	12/2015
Legoland Parking Lot	PV	Solar	1.4	1.4	0.5	NA	18.3	12/2016
Big Bend Solar	PV	Solar	19.8	19.8	13.8	NA	23.5	02/2017
Payne Creek	PV	Solar	70.3	70.3	40.0	NA	18.3	09/2018
Balm	PV	Solar	74.4	74.4	41.3	NA	15.2	09/2018
Notes								
Net Firm Capacity in winter for solar is not assumed to contribute to winter peak. "Community-sited solar" includes eight sites less than 250 kW located throughout the community to support our voluntary renewable block program.								

25. Please identify and describe each planned utility-owned renewable resource for the period 2019–2028. Please include each proposed facility's name, unit type, fuel type, its installed capacity (AC-rating for PV systems), its net firm capacity or anticipated contribution during peak demand (if any), anticipated typical capacity factor, and projected in-service date. For multiple small distributed renewable resources (<250 kW per installation), such as rooftop solar panels, please include a single combined entry for the resources that share the same unit & fuel type. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

Planned Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Net Firm Capacity (MW)		Capacity Factor	In-Service Date
			Sum	Win	Sum	Win	(%)	(MM/YYYY)
Notes								
(Include Notes Here)								

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Planned Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Net Firm Capacity (MW)		Capacity Factor	In-Service Date
			Sum	Win	Sum	Win	(%)	(MM/YYYY)
Lithia	PV	Solar	74.5	74.5	38.5	NA	27	01/2019
Grange Hall	PV	Solar	61.1	61.1	33.3	NA	26	01/2019
Bonnie Mine	PV	Solar	37.5	37.5	17.7	NA	26	01/2019
Peace Creek	PV	Solar	55.4	55.4	30.5	NA	26	03/2019
Lake Hancock	PV	Solar	49.5	49.5	26.4	NA	27	04/2019
Epperson Ranch Solar Lights	PV	Solar	0.058	0.058	NA	NA	22	11/2019
Wimauma	PV	Solar	74.8	74.8	42.6	NA	27.3	01/2020
Little Manatee River	PV	Solar	74.5	74.5	38.5	NA	28.6	01/2020
Mountain View	PV	Solar	52.5	52.5	29.6	NA	27.3	01/2021

Notes

Net Firm Capacities included in chart are first year in-service values.
Net Firm Capacity in winter for solar is not assumed to contribute to winter peak.

26. Please refer to the list of planned utility-owned renewable resources for the period 2019 through 2028 above. Discuss the current status of each project.

A. Lithia Solar is a utility scale solar project with an output of 74.5 MWac. The project is located in Hillsborough County and was brought into service January 2019.

Grange Hall Solar is a utility scale solar project with an output of 61.1 MWac. The project is located in Hillsborough County and was brought into service January 2019.

Bonnie Mine is a utility scale solar project with an output of 34.5 MWac. The project is located in Polk County and was brought into service January 2019.

Peace Creek Solar is a utility scale solar project with an output of 55.4 MWac. The project is located in Polk County and was brought into service March 2019.

Lake Hancock Solar is a utility scale solar project with a planned output of 49.6 MWac. The project is located in Polk County was brought into service April 2019.

The Epperson Ranch Solar Light project is a collaboration between Withlacoochee River Electric Cooperative, Inc. and Tampa Electric to install 200 LED street lights with top of pole mounted solar collectors that will feed directly to the grid. In all, this project will add another .058 MWac to TEC's solar portfolio. TEC estimates this project will be live by year end 2019.

Wimauma Solar is a utility scale solar project with a planned output of 74.8 MWac. The project is located in Hillsborough County and is currently in its development and design phase with construction beginning early summer 2019. The project is planned to be brought into service January 2020.

Little Manatee River Solar is a utility scale solar project with a planned output of 74.5 MW. The project is located in Hillsborough County and is currently in its development and design phase with construction beginning during the summer of 2019. The project is planned to be brought into service January 2020.

Mountain View is a utility scale solar project with a planned output of 52.5 MWac. The project is located in Pasco County and is completing its permitting phase with construction in 2020. The project will be brought into service January 2021.

27. Please list and discuss any planned utility-owned renewable resources within the past year that were cancelled, delayed, or reduced in scope. What was the primary reason for the changes? What, if any, were the secondary reasons?

A. Mountain View Solar was delayed from a January 2019 in-service date to January 2021 in-service date due to a legal appeal.

Alafia Solar was delayed from a planned January 2020 in service date due to a legal appeal.

28. Please identify and describe each purchased power agreement with a renewable generator that delivered energy during 2018. Provide the name of the seller, the name of the generation facility associated with the contract, the unit type of the facility, the fuel type, the facility's installed capacity (AC-rating for PV systems), the amount of contracted firm capacity (if any), and the start and end dates of the purchased power agreement.

Existing Renewable Purchased Power Agreements

Seller Name	Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Contracted Firm Capacity (MW)		In-Service Date	Contract Term (MM/YY)	
				Sum	Win	Sum	Win	(MM/YY)	Start	End
Notes										
(Include Notes Here)										

A. Tampa Electric had no purchased power agreements with renewable generators during 2018.

Existing Renewable Purchased Power Agreements

Seller Name	Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Contracted Firm Capacity (MW)		In-Service Date	Contract Term (MM/YY)	
				Sum	Win	Sum	Win	(MM/YY)	Start	End
Notes										
(Include Notes Here)										

29. Please identify and describe each purchased power agreement with a renewable generator that is anticipated to begin delivering renewable energy to the Company during the period 2019–2028. Provide the name of the seller, the name of the generation facility associated with the contract, the unit type of the facility, the fuel type, the facility's installed capacity (AC-rating for PV systems), the amount of contracted firm capacity (if any), and the start and end dates of the purchased power agreement.

Renewable Purchased Power Agreements

Seller Name	Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Contracted Firm Capacity (MW)		In-Service Date	Contract Term (MM/YY)	
				Sum	Win	Sum	Win	(MM/YY)	Start	End
Notes										
(Include Notes Here)										

A. Tampa Electric has no purchased power agreements with renewable generators anticipated to begin delivering renewable energy to the company during the period 2019-2028.

Renewable Purchased Power Agreements

Seller Name	Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Contracted Firm Capacity (MW)		In-Service Date	Contract Term (MM/YY)	
				Sum	Win	Sum	Win	(MM/YY)	Start	End
Notes										
(Include Notes Here)										

30. Please refer to the list of renewable purchased power agreements that are anticipated to begin delivering capacity and/or energy to the Company during the period 2019–2028. Discuss the current status of each project.

A. As noted in the response to Request No. 29, Tampa Electric has no purchased power agreements with a renewable generator anticipated to begin delivering renewable capacity and/or energy to the company during the period 2019-2028.

31. Please list and discuss any renewable purchased power agreements within the past year that were cancelled, expired, delayed, or modified. What was the primary reason for the changes? What, if any, were the secondary reasons?

A. Tampa Electric did not have any renewable purchased power agreements that were canceled, expired, delayed, or modified within the past year.

32. Please provide the actual and projected annual output for all renewable resources on the Company's system, including utility-owned resources (firm, non-firm, and co-firing), purchases (firm, non-firm, and co-firing), and customer-owned generation, for the period 2019–2028.

Renewable Generation by Source

Renewable Source	Annual Renewable Generation (GWh)										
	Actual	Projected									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Utility - Firm											
Utility - Non-Firm											
Utility - Co-Firing											
Purchase - Firm											
Purchase - Non-Firm											
Purchase - Co-Firing											
Customer - Owned											
Total											
Notes											
(Include Notes Here)											

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Renewable Generation by Source

Renewable Source	Annual Renewable Generation (GWh)										
	Actual	Projected									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Utility - Firm	0	0	0	0	0	0	0	0	0	0	0
Utility - Non-Firm[1]	118.4	1,004.7	1,412.8	1,528.6	1,522.9	1,516.8	1,514.7	1,505.8	1,499.6	1,493.5	1,491.1
Utility - Co-Firing	0	0	0	0	0	0	0	0	0	0	0
Purchase - Firm	0	0	0	0	0	0	0	0	0	0	0
Purchase - Non-Firm	0.005	0	0	0	0	0	0	0	0	0	0
Purchase - Co-Firing	0	0	0	0	0	0	0	0	0	0	0
Customer – Owned[2]	42.9	70.0	102.1	138.3	178.2	220.4	265.1	312.4	362.4	415.3	471.2
Total	161.305	1,074.7	1,514.9	1,666.9	1,701.1	1,737.2	1,779.8	1,818.2	1,862.0	1,908.8	1,962.3
Notes											

[1]Utility Non-Firm GWh includes energy generated from existing company-owned PV systems funded by the company's voluntary renewable program as well as the company's utility scale sites shown in Schedule 1 & 8.1 of the 2019 TYSP.
[2]For customer-owned solar, growth remains strong, but is expected to grow at a diminishing rate during the phasing out of residential community solar tax credits (30% until 12/31/2019, 26% until 01/01/2021, and 22% until 01/01/2022; with a 10% commercial tax credit remaining indefinitely).

33. Please complete the table below, providing a list of all of the Company's plant sites that are potential candidates for utility-scale (>2 MW) solar installations. As part of this response, please provide the plant site's name, approximate land area available for solar installations, potential installed capacity rating of a PV installation, and a description of any major obstacles that could affect utility-scale solar installations at any of these sites, such as land devoted to other uses or other requirements.

Candidate Sites - Solar

Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Candidate Sites - Solar

Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues
English Creek	218	30	
BB Solar II	130	25	
Little Manatee	190	25	
Alafia	477	55	Appeal

34. Please complete the table below, providing a list of all of the Company's plant sites that are potential candidates for utility-scale wind installations. As part of this response, please provide the plant site's name, approximate land area available, potential installed capacity rating of a wind farm installation, and a description of any major obstacles that could affect utility-scale wind installations at any of these sites, such as land devoted to other uses or other requirements.

Candidate Sites - Wind

Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues

A. Tampa Electric has no potential sites for utility scale wind installations.

Candidate Sites - Wind

Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues

35. Please describe any actions the Company engages in to encourage production of renewable energy within its service territory.

A. As market conditions continue to change and technology improves, renewable alternatives, such as solar, become more attractive to our customers. Through December, more than 3,000 customers installed PV systems on their homes or businesses, accounting for more than 26.86 MWAC of net metered, distributed solar generation interconnected on Tampa Electric's grid. In October 2018, the company streamlined the interconnection application process for the customer/contractor from a manual process to an easy to use online application system.

For over twelve (12) years, Tampa Electric'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, Tampa Electric 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. The funds from this program build small, community-sited PV arrays at highly visible locations. These demonstration arrays are designed to educate students and the public on the benefits of renewable energy.

36. **[Investor-Owned Utilities Only]** Please discuss whether the Company has been approached by renewable energy generators during 2018 regarding constructing new renewable energy resources. If so, please provide the number and a description of the type of renewable generation represented.

A. Tampa Electric received offers from seven companies in 2018 proposing to construct new renewable energy resources. All were solar facilities. The range of potential sizes was 40 MW_{AC} up to 160 MW_{AC}.

37. Does the Company consider solar PV to contribute to one or both seasonal peaks for reliability purposes? If so, please provide the percentage contribution and explain how the Company developed the value.

A. For the 2019 TYSP, Tampa Electric used 38 percent for summer reserve margin at the fixed PV sites at Legoland and TIA and 56 percent for summer reserve margin at the single axis tracking sites at Big Bend Solar and approved SoBRA sites and 0.0 percent during the winter. For future tracking PV, the company estimates 56 percent as firm generating capacity for Tampa Electric's summer reserve margin and 0.0 percent during the winter. These capacity values are calculated using hourly projections from vendor data and will be updated once Tampa Electric has gathered enough historical data.

38. Please identify whether a declining trend in costs of energy storage technologies has been observed by the Company.

A. Yes, multiple industry forecasts show a declining trend through 2030.

39. Briefly discuss any progress in the development and commercialization of non-lithium battery storage technology the Company has observed in recent years.

A. Tampa Electric continuously monitors and evaluates developing technologies including various battery storage technologies. While lithium batteries remain the most mature and widely adopted battery technology, other battery technologies such as flow batteries show great potential. Their ability to accommodate repeated cycles with minimal degradation is appealing. However, their higher round trip efficiency losses and initial capital installation costs remain a challenge.

40. Briefly discuss any considerations reviewed in determining the optimal positioning of energy storage technology in the Company's system. (e.g. Closer to/further from sources of load, generation, or transmission/distribution capabilities.)

A. There are a variety of factors that can influence the optimal positioning of an energy storage facility within Tampa Electric's system. Placing energy storage closer to the load can improve customer resiliency, effectively shave the peak, and defer or avoid transmission and/or distribution system upgrades. Energy storage systems can also be used to address possible voltage support and frequency regulation issues. Placing energy storage systems at an existing generating facility can provide black start capability. In addition, the availability of land to place energy storage in densely developed areas remains a consideration.

41. Please provide whether ratepayers have expressed interest in energy storage technologies. If so, how have their interests been addressed?

A. Account Managers have on-going technology and distributed generation discussions with customers during regular customer interactions. Several large customers are very interested in learning about battery storage and have asked about Tampa Electric plans for using battery storage in the future. A few large, assigned accounts have expressed interest in potential partnership opportunities, if a battery storage pilot or program were to emerge.

Tampa Electric, under its DSM Research and Development conservation program, is looking at battery storage for peak shifting at small commercial application.

42. Please complete the table below, identifying all energy storage technologies that are currently either part of the Company's system portfolio or are part of a pilot program sponsored by the Company. As part of this response, please identify the project to which the energy storage technology is associated with, whether this project is a pilot program or not, the in-service date or pilot start date associated with the energy storage technology, and the maximum capacity output and maximum energy stored of/by the energy storage technology under normal operating conditions.

Project Name	Pilot Program (Y/N)	In-Service/ Pilot Start Date	Max Capacity Output (MW)	Max Energy Stored (MHh)
Notes				
(Include Notes Here)				

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Project Name	Pilot Program (Y/N)	In-Service/ Pilot Start Date	Max Capacity Output (MW)	Max Energy Stored (MHh)
Big Bend Battery Energy Storage System	N	9/30/19	12.6	26.1
Notes				
(Include Notes Here)				

43. Please identify and describe the objectives and methodologies of all energy storage pilot programs currently running or in development with an anticipated launch date within the next 10 years. If the Company is not currently participating in or developing energy storage pilot programs, has it considered doing so? If not, please explain.

a. Please discuss any pilot program results, addressing all anticipated benefits, risks, and operational limitations when such energy storage technology is applied on a utility scale (> 2 MW) to provide for either firm or non-firm capacity and energy.
b. Please provide a brief assessment of how these benefits, risks, and operational limitations may change over the next 10 years.
c. Please identify and describe any plans to periodically update the Commission on the status of your energy storage pilot programs.

A. Tampa Electric's objective is to identify the most promising applications for batteries within our system and to gain experience with battery installation and operation. This enables the company to take advantage of battery storage for the benefit of our customers as the economics of the technology continue to improve.

a. Although not a PSC approved pilot program, the Big Bend Battery Energy Storage facility is currently under development. The anticipated benefits of this project will be the experience gained with battery installation, operation, degradation, economic life, and various grid support cases. The battery could be utilized to shift energy generation to off-peak times (energy arbitrage), for voltage support and frequency regulation, and to contribute to contingency reserves. Operational limitations include the energy capacity of the battery as well as considering the number of cycles on the battery to limit degradation.

b. Energy storage technology is expected to continue its advances over the next 10 years. Declining costs and improving technology may enable more and larger batteries to deployed and reduce the operating costs associated with cycling of the batteries. As intermittent renewables become a larger part of our portfolios, batteries can play a larger role in balancing our system.

c. Large utility scale battery storage projects will be reported to the Commission through the 10-Year Site Plan process, however additional reporting desired by the Commission would be provided as requested.

44. If the Company utilizes non-firm generation sources in its system portfolio, please detail whether it currently utilizes or has considered utilizing energy storage technologies to provide firm capacity. If not, please explain.

A. Certain generating resources, such as solar, provide a capacity benefit to serve system peak but are intermittent during the day. Battery storage offers the opportunity to complement solar generation. This will be one of the key benefits of the Big Bend Energy Storage facility at the Big Bend Solar site.

45. Please identify and describe any programs you offer that allow your customers to contribute towards the funding of specific renewable projects, such as community solar programs.

a. Please describe any such programs in development with an anticipated launch date within the next 10 years.

A. For twelve years, Tampa Electric has offered a Renewable Energy Program option to customers where they can purchase blocks of renewable energy produced at or purchased from clean renewable energy sources. This tariffed program includes an additional bill cost of $5.00 per 200 kWh block purchased. The money collected under this program, in major part, goes towards the development of new photovoltaic resources at either schools or in public places, which serves to both increase solar generation within the Tampa Electric system and educate the public on the benefits and operations of solar power generation.

a. Tampa Electric filed for a shared solar program in late 2018. Once approved, the Sun Select program will offer customers the opportunity to have a portion or all of their electric purchase from Tampa Electric to be directly served from a Tampa Electric owned and operated solar generating unit with different pricing for any such energy supplied to them. This program is slated to go live mid-2019. Tampa Electric will build more solar to accommodate the popularity of the Sun Select Program.

46. Please identify and discuss the Company's role in the research and development of utility power technologies. As part of this response, please describe any plans to implement the results of research and development into the Company's system portfolio and discuss how any anticipated benefits will affect your customers.

A. Tampa Electric does not currently have any dedicated R&D programs. Outside of the Conservation R&D program, the company does not actively pursue R&D projects.

47. **[Investor-Owned Utilities Only]** Provide, on a system-wide basis, the historical annual average as-available energy rate in the Company's service territory for the period 2009–2018. If the Company uses multiple areas for as-available energy rates, please provide a system-average rate as well. Also, provide the projected annual average as-available energy rate in the Company's service territory for the period 2019–2028.

As-Available Energy Rates

Year		As-Available Energy ($/MWh)	On-Peak Average ($/MWh)	Off-Peak Average ($/MWh)
Actual	2009			
	2010			
	2011			
	2012			
	2013			
	2014			
	2015			
	2016			
	2017			
	2018			
Projected	2019			
	2020			
	2021			
	2022			
	2023			
	2024			
	2025			
	2026			
	2027			
	2028			
Notes				
(Include Notes Here)				

A. The requested data is provided in the table below and in Excel on the enclosed CD.

As-Available Energy Rates

Year		As-Available Energy ($/MWh)	On-Peak Average ($/MWh)	Off-Peak Average ($/MWh)
Actual	2009	31.85	35.71	29.93
	2010	36.83	42.94	34.82
	2011	35.94	38.29	35.16
	2012	28.40	29.36	28.08
	2013	28.39	29.67	27.96
	2014	30.67	33.23	29.83
	2015	24.81	26.36	24.29
	2016	20.99	23.17	20.28
	2017	21.73	23.71	21.08
	2018	24.04	26.18	23.33
Projected	2019	28.12	30.30	27.36
	2020	25.90	28.02	25.18
	2021	26.35	28.87	25.49
	2022	27.72	30.43	26.79
	2023	27.57	27.39	27.64
	2024	29.60	28.78	29.88
	2025	31.05	31.17	31.01
	2026	32.68	32.58	32.71
	2027	35.45	34.59	35.74
	2028	38.19	38.20	38.19
Notes				
Includes variable O&M				

48. Please complete the following table detailing planned unit additions, including information on capacity and in-service dates. Please include only planned conventional units with an in-service date past January 1, 2018. For each planned unit, provide the date of the Commission's Determination of Need and Power Plant Siting Act certification (if applicable), and the anticipated in-service date.

Planned Unit Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions				
Combustion Turbine Unit Additions				
Combined Cycle Unit Additions				
Steam Turbine Unit Additions				
Notes				
(Include Notes Here)				

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Planned Unit Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions				
N/A	N/A	N/A	N/A	N/A
Combustion Turbine Unit Additions				
Big Bend CT 5	360*	N/A	N/A	06/2021
Big Bend CT 6	360*	N/A	N/A	06/2021
Future CT 1	229	N/A	N/A	01/2023
Future CT 2	229	N/A	N/A	01/2026
Combined Cycle Unit Additions				
N/A	N/A	N/A	N/A	N/A
Steam Turbine Unit Additions				
Big Bend ST 1**	335	N/A	N/A	01/2023
Notes				
*Net capability will be restricted to 330 MW summer until being placed into combined cycle mode in 2023. **Big Bend CT 5 & 6 will be converted to a combined cycle unit in 2023 when Big Bend ST 1 is placed into service.				

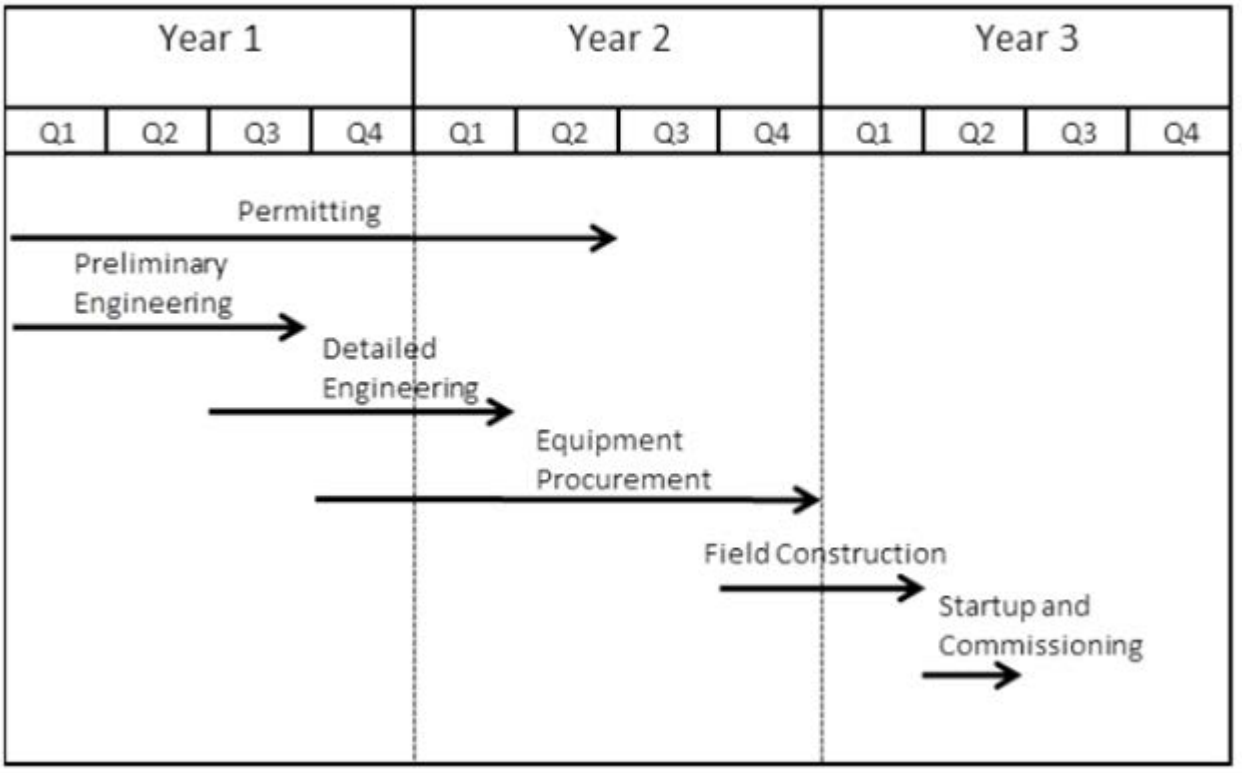
49. For each of the planned generating units contained in the Company's 2019 TYSP, please discuss the "drop dead" date for a decision on whether or not to construct each unit. Provide a time line for the construction of each unit, including regulatory approval, and final decision point.

A. Tampa Electric estimates a final decision point for procuring and constructing a typical combustion turbine (CT) to be approximately 30 months prior to the expected in-service date. The 30 months is comprised of 24 months for engineering, procurement, and permitting, which could vary depending on whether the unit is placed at a green field site or an existing site, and 9 months for construction. The 30-month time estimate may be improved or extended based upon major equipment availability and site permitting.

The 600 MWAC of solar being installed through 2021 identified in TEC's Ten-Year Site Plan has already procured major pieces of equipment and several of the sites are already under construction in accordance with the Solar Base Rate Adjustment (SoBRA) which was approved as part of the stipulation and settlement agreement in late 2017.

The Big Bend Unit 1 modernization includes Big Bend CT 5, Big Bend CT 6, and Big Bend ST 1 and is already significantly underway including certain major equipment procurement as well as engineering and permitting.

Future CT Project Execution Plan



50. Please provide an estimate of the revenue requirements of the Company based upon the 2019 TYSP's planned generating units.

A. The estimated cumulative present worth revenue requirements for Tampa Electric's future units are $2,259,792,000.

CPWRR - Combined Future Units (2019 $)	
Capital Revenue Requirements	1,952,118
Variable O&M	94,265
Fixed O&M	213,410
Total - CPWRR	2,259,792

51. For each of the planned generating units contained in the Company's 2019 TYSP, please identify the next best alternative that was rejected for each unit. Provide information similar to Schedule 9 regarding each of the next best alternative unit(s). As part of this response, please also provide the additional revenue requirement that would have been associated with the next best alternative compared to the planned unit.

A. The next best alternative to Tampa Electric's current planned generating units would have been a simple cycle aero derivative in 2023. The estimated cumulative present revenue requirements for this unit would have been $67,149,000 more than Tampa Electric's current plan.

Incremental RR from 2019 TYSP Base Case	
Capital Revenue Requirements	57,913
Variable O&M	1,376
Fixed O&M	7,860
CPWRR (2019 $000)	67,149

Next best alternative: GE Simple Cycle LM6000
Net Capability:
A. Summer: 43.9 MW
B. Winter: 52.0 MW
Technology Type: Simple Cycle
Estimated construction timing: 24+ from start date
Fuel: NG
Planned Outage Factor: 3.0%
Forced Outage Rate: 2.0%
Equivalent Availability Factor: 95.0%
Average Net Operating Heat Rate: 10,500 Btu/kWh
Book Life: 30
Total Installed Cost (In-Service Year $/kW): 1,353.49
Direct Construction Cost ($/kW): 1,065.77
AFUDC Amount ($/kW): 110.62
Escalation ($/kW): 177.10
Fixed O&M (In-Service year $/kW-yr.): 16.27
Variable O&M (In-Service year $/MWh): 8.60
K-Factor: 1.5433

52. For each existing and planned unit on the Company's system, provide the following data based upon historic data from 2018 and projected capacity factor values for the period 2019–2028. Please complete the tables below and provide an electronic copy in Microsoft Excel format.

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Notes														
(Include Notes Here)														

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Big Bend	1	ST	BIT/NG	14.2	3.7	6.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Big Bend	2	ST	BIT/NG	17.4	29.1	28.2	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Big Bend	3	ST	BIT/NG	47.2	13.1	26.3	24.7	31.1	5.0	8.3	14.1	10.4	18.5	31.4
Big Bend	4	ST	BIT/NG	54.6	55.3	50.8	57.3	54.5	8.3	11.7	21.9	22.2	32.1	46.1
Big Bend	CT4	GT	NG/DFO	1.9	2.2	2.5	1.5	1.0	1.5	1.4	0.8	0.7	1.0	2.4
Bayside	1	CC	NG	50.5	57.2	61.3	62.8	55.3	37.0	37.6	39.3	36.7	33.9	33.4
Bayside	2	CC	NG	39.8	43.1	42.8	45.5	47.2	20.0	23.9	25.2	22.7	25.0	15.0
Bayside	3	GT	NG	2.6	0.9	1.1	0.3	0.3	0.6	0.6	0.3	0.4	0.3	1.8
Bayside	4	GT	NG	2.5	0.5	0.7	0.2	0.2	0.4	0.3	0.2	0.2	0.1	0.9
Bayside	5	GT	NG	1.2	1.7	1.8	0.8	0.6	1.2	1.1	0.7	0.8	0.9	2.9
Bayside	6	GT	NG	0.8	1.3	1.4	0.5	0.4	0.9	0.9	0.5	0.7	0.6	2.3
Polk	1	IGCC	BIT/NG	45.9	12.8	16.5	26.0	26.6	11.1	9.2	9.6	7.2	6.5	41.1
Polk	2[1]	GT	NG/DFO	N/A	1.1	0.5	1.6	0.3	0.4	0.3	0.7	0.2	0.1	0.8
Polk	3[1]	GT	NG/DFO	N/A	0.8	0.2	1.1	0.2	0.3	0.2	0.4	0.5	0.2	0.7
Polk	4[1]	GT	NG	N/A	0.4	0.1	0.5	0.0	0.1	0.1	0.2	0.4	0.1	0.0
Polk	5[1]	GT	NG	N/A	0.2	0.1	0.2	0.0	0.1	0.0	0.2	0.3	0.1	0.6
Polk 2 CC	2	CC	NG/DFO	75.3	72.2	70.5	64.7	74.2	59.1	56.7	50.6	58.8	59.0	49.8
Big Bend	CT 5[2]	GT	NG	N/A	0.0	0.0	7.8	6.4	0.0	0.0	0.0	0.0	0.0	0.0
Big Bend	CT 6[2]	GT	NG	N/A	0.0	0.0	4.4	2.4	0.0	0.0	0.0	0.0	0.0	0.0
Big Bend	ST 1[2]	CC	NG	N/A	0.0	0.0	0.0	0.0	89.0	87.2	88.2	88.7	84.7	87.7
Fut CT 1	1	GT	NG	N/A	0.0	0.0	0.0	0.0	0.5	0.6	0.3	0.3	0.5	1.7
Fut CT 2	2	GT	NG	N/A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	1.1
Notes														
1. Data listed for Polk 2-5 GT's is for simple cycle operation only; historical capacity factors for simple cycle operation only are not available														
2. Big Bend ST 1 capacity factor represents the capacity factor for the combined cycle unit which consists of Big Bend ST 1, CT 5, and CT 6.														

53. For each existing unit on the Company's system, please provide the planned retirement date. If the Company does not have a planned retirement date for a unit, please provide an estimated lifespan for units of that type and a non-binding estimate of the retirement date for the unit.

A. Refer to 2019 TYSP, Chapter 1 Schedule 1. Currently the company is depreciating its existing units in accordance with the remaining depreciable life approved in its most recent depreciation study.

54. Please complete the table below, providing a list of all of the Company's steam units that are potential candidates for repowering to operation as Combined Cycle units. As part of this response, please provide the unit's current fuel type, summer capacity rating, in-service date, and what potential conversion, fuel-switching, or repowering would be most applicable. Also include a description of any potential issues that could affect repowering efforts at any of these sites, related to such things as unit age, land availability, or other requirements.

Repowering Candidate Units - Steam

Plant Name	Fuel Type	Summer Capacity (MW)	In-Service Date	Potential Conversion	Potential Issues
Notes					
(Include Notes Here)					

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Repowering Candidate Units - Steam

Plant Name	Fuel Type	Summer Capacity (MW)	In-Service Date	Potential Conversion	Potential Issues
Big Bend 3	Bit/NG	395	05/1976	NGCC	Economics & Reduced Fuel Diversity
Big Bend 4	Bit/NG	437	02/1985	NGCC	Economics & Reduced Fuel Diversity
Notes					
(Include Notes Here)					

55. Please identify each of the Company's existing (as of December 31, 2018) and planned (between 2019–2028) power purchase contracts, including firm capacity imports reflected in Schedule 7 of the Company's 2019 TYSP. Provide the seller, the term of the contract, amount of seasonal capacity purchased, the primary fuel (if applicable, such as with a unit purchase), whether it is included in the Utility's firm peak capacity, and a description of the source of the purchase (such as the name of the unit in a unit purchase).

Existing Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Capacity	Description
	Begins	Ends	Summer	Winter	%			
Notes								
(Include Notes Here)								

Planned Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Capacity	Description
	Begins	Ends	Summer	Winter	%			
Notes								
(Include Notes Here)								

A. As of December 31, 2018, Tampa Electric had no purchased power contracts but had entered negotiations with Duke Energy Florida for a non-firm economy purchase. The companies reached agreement and executed a contract for the term February 2019 through February 2020. Tampa Electric does not include the purchase as part of its firm capacity.

Also, in 2019 Tampa Electric negotiated an addition purchase from the Florida Municipal Power Agency (FMPA). The purchase is 120 MW and is a non-firm economy purchase. The term of the FMPA purchase is May through October of 2019.

Tampa Electric Company's power purchases include those listed in the following tables.

REDACTED

TAMPA ELECTRIC COMPANY
UNDOCKETED: REVIEW OF TYSP'S
SUPPLEMENTAL DATA REQUEST
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Existing Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Capacity	Description
	Begins	Ends	Summer	Winter	%			
Pasco Cogen	Jan 2009	Dec 2018	121	121	Call-option (dispatchable)	NG	Yes	Intermediate
Notes								

Planned Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Capacity	Description
	Begins	Ends	Summer	Winter	%			
Duke Energy Florida	Feb 2019	Feb 2020	360	160	7x16	System	---	Non-firm
FMPA	May 2019	Oct 2019	120	0	7x8	NG	---	Non-firm
TBD	Dec 2020	March 2021	0	50	Call-option (dispatchable)	TBD	Yes	Peaking
TBD	Dec 2021	March 2022	0	100	Call-option (dispatchable)	TBD	Yes	Peaking
Notes								
[redacted]								

56. Please identify each of the Company's existing (as of December 31, 2018) and planned (between 2019–2028) power sales, including firm capacity exports reflected in Schedule 7 of the Company's 2019 TYSP. Provide the purchaser, the term of the contract, amount of seasonal capacity sold, the primary fuel (if applicable, such as with a unit purchase), whether it is included in the Utility's firm peak demand, and a description of the sale (such as the name of the unit in a unit purchase).

Existing Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter	%			
Notes								
(Include Notes Here)								

Planned Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter	%			
Notes								
(Include Notes Here)								

A. As of December 31, 2018, Tampa Electric had one sale, and it is a sale of non-firm energy to Seminole Electric Cooperative. That is also Tampa Electric's only planned sale for the period 2019 through 2028.

Existing Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter	%			
Seminole Electric Cooperative	Dec 1991	(see notes)	18	18	Varies	System	0	Non-firm
Notes								
The agreement continues indefinitely unless terminated by either party with three years' prior notice.								

Planned Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter	%			
(None)								
Notes								
(Include Notes Here)								

57. Please list and discuss any long-term power sale or purchase agreements within the past year that were cancelled, expired, or modified.

A. As of the end of 2018, Tampa Electric's 121 MW firm purchase from the Pasco Cogen facility expired.

58. Please provide a list of all proposed transmission lines in the planning period that require certification under the Transmission Line Siting Act. Please also include those that have been approved, but are not yet in-service, when completing the table below.

Transmission Projects Requiring TLSA Approval

Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
Notes					
(Include Notes Here)					

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Transmission Projects Requiring TLSA Approval

Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
Thonotosassa to Wheeler	8.0	230	6/21/2007	8/7/2008	TBD
Wheeler to Willow Oak	17.0	230	6/21/2007	8/7/2008	TBD
Notes					

Environmental

59. Provide a narrative explaining the impact of any existing environmental regulations relating to air emissions and water quality or waste issues on the Company's system during the 2018 period. As part of your narrative, please discuss the potential for existing environmental regulations to impact unit dispatch, curtailments, or retirements during the 2019–2028 period.

A. Air Emissions

In 2018, Tampa Electric (TEC) did not experience significant impacts from environmental restrictions. For the 2019 through 2028 period, TEC does not anticipate impacts to its generating resources as a result of the current Cross State Air Pollution Rule (CSAPR) or Mercury and Air Toxics Standards (MATS). However, due to grid connectivity, it is possible that the CSAPR or MATS may impact the operational characteristics of neighboring generating resources to the point of impacting the reliability of the company's system.

In 2017, EPA implemented an update to CSAPR that removed Florida from the CSAPR program based on updated modeling and emission reduction commitments. However, Florida (including TEC power plants) could be subject to a future version of CSAPR as a result of an expected update triggered by compliance with the more stringent 2015 ozone standard or ongoing litigation relating to current rule applicability. Courts have completed their evaluation and allowed CSAPR implementation in lieu of CAIR. No modifications to TEC's generating system are anticipated to be necessary to comply with the current CSAPR or MATS. Beyond 2019, it is uncertain if additional requirements will result due to the pending court action of these rules.

On June 2, 2014, EPA proposed rules described as the Clean Power Plan (CPP) to regulate existing, new, modified, and reconstructed power plants and a final rule was issued on August 3, 2015. On February 9, 2016, the U.S. Supreme Court granted a stay of the rule, which stopped its implementation. On August 21, 2018, EPA released a proposed rule to replace the CPP, named the Affordable Clean Energy (ACE) rule, to establish emission guidelines for states to address GHG emissions from existing fossil fuel-fired electric generating units (EGUs). In the guidelines, EPA is proposing to determine that heat rate improvement measures are the best system of emission reduction for existing coal-fired EGUs. TEC is expected to have emission units that are subject to this rule, and is evaluating several potential compliance scenarios.

Florida has not begun any CPP rulemaking process and is currently awaiting final resolution of the legal challenges and EPA efforts before proceeding with state rulemaking. The outcome of this litigation and the rule-making process and its impact on TEC's EGU's is therefore uncertain at this time; however, it may impact unit dispatch, curtailments, or retirements during the 2019–2028.

Water Quality

Tampa Electric discharges cooling water and low volume industrial wastewater at Big Bend, Bayside and Polk Power Stations. These discharges are required to meet water quality effluent limits for both chemical and thermal components.

For chemical constituents at all three stations, Tampa Electric implements a combination of control measures, including internal treatment technologies, waste-stream discharge restrictions and recycling of internal waste-streams. At Big Bend Power Station, the only low volume wastewater discharge is the blowdown from the FGD System. All other internal waste-streams are recycled continuously in a zero liquid discharge system which provides makeup water for plant processes.

For compliance with thermal permit limitations at Big Bend and Bayside Power Stations, both of which employ once-through cooling technology, the only method of discharge control available is limiting unit output (derating) to reduce thermal loading. Ambient temperature conditions requiring such measures typically occur only in the hottest months (July-September) of the year.

Polk Power Station employs a recirculating Cooling Reservoir for thermal control.

Waste

There were no waste issues related to existing environmental regulations affecting dispatch, curtailments or retirements during 2018. However, the Company continued to comply with specific operating requirements of the federal CCR Rule throughout the year, as further described in DR Response 64 below.

60. Please complete the table below, providing actual and projected amounts of regulated air pollutants and carbon dioxide emitted, on an annual and per megawatt-hour basis, by the Company's generation fleet. Please also provide an electronic copy of the completed table in Microsoft Excel format.

Emissions of Registered Air Pollutants & CO2

Year		SOX		NOX		Mercury		Particulates		CO2	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2009										
	2010										
	2011										
	2012										
	2013										
	2014										
	2015										
	2016										
	2017										
	2018										
Projected	2019										
	2020										
	2021										
	2022										
	2023										
	2024										
	2025										
	2026										
	2027										
	2028										
Notes											
(Include Notes Here)											

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Emissions of Registered Air Pollutants & CO2

Year		SOX		NOX		Mercury		Particulates		CO2	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	**2009**	1.2	10,000	1.9	10,700	0.000012	0.12	0.14	1,330	1,590	15,200,000
	2010	1.0	10,800	1.1	5,900	0.00001	0.1	0.097	948	1,560	16,500,000
	2011	1.1	10,200	0.58	5,400	0.0000096	0.1	0.069	705	1,620	16,000,000
	2012	1.0	10,100	0.55	5,500	0.0000034	0.033	0.055	540	1,640	16,000,000
	2013	1.0	11,900	0.56	5,600	0.0000026	0.025	0.046	450	1,640	15,700,000
	2014	1.3	12,300	0.61	5,700	0.0000032	0.032	0.045	435	1,620	16,200,000
	2015	0.8	8,000	0.64	6,100	0.0000036	0.033	0.039	367	1,730	15,300,000
	2016	0.8	7,200	0.5	4,400	0.000002	0.019	0.031	298	1,540	13,600,000
	2017	0.6	5,600	0.36	3,500	0.0000013	0.013	0.03	296	1,340	13,300,000
	2018	0.4	3,700	0.33	3,200	0.0000013	0.013	0.021	203	1,200	11,800,000
Projected	**2019**	0.2	1,900	0.22	2,100	0.00000029	0.0028	0.022	215	960	9,400,000
	2020	0.3	2,700	0.25	2,500	0.00000042	0.0043	0.034	349	980	10,100,000
	2021	0.3	3,200	0.24	2,500	0.00000048	0.0050	0.035	361	990	10,300,000
	2022	0.3	3,300	0.23	2,400	0.00000050	0.0052	0.037	388	980	10,300,000
	2023	0.1	600	0.21	2,200	0.00000008	0.0008	0.016	168	770	8,100,000
	2024	0.1	800	0.22	2,300	0.00000012	0.0013	0.018	193	790	8,400,000
	2025	0.1	1,400	0.24	2,700	0.00000020	0.0022	0.022	242	830	8,900,000
	2026	0.1	1,300	0.24	2,600	0.00000018	0.0020	0.021	225	820	9,000,000
	2027	0.2	2,000	0.26	2,900	0.00000028	0.0031	0.026	285	860	9,500,000
	2028	0.3	3,400	0.33	3,700	0.00000084	0.0095	0.036	409	950	10,700,000
Notes											

61. For the U.S. Environmental Protection Agency's (EPA's) Mercury and Air Toxics Standards (MATS) Rule:

a. Will your Company be materially affected by the rule?

b. What compliance strategy does the Company anticipate employing for the rule?

c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?

d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?

e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding MATS-related costs:

Year	Estimated Cost of Mercury and Air Toxics Standards (MATS) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

If the answer to any of the above questions is not available, please explain why.

A. a. Tampa Electric is materially affected by the MATS Rule. This rule has impacted the solid fuel matrix, natural gas usage and system operations.

b. Tampa Electric will comply with the MATS standards, as required, at both Polk Power Station and Big Bend Station. In 2018, Polk Power Station maintained its Low Emitting Electric Generating Unit (LEE) status. To achieve LEE status, Polk Power Station demonstrated compliance with emission rates by testing mercury annually, and particulate matter (PM) and hydrogen chloride (HCl) quarterly for three years. Now that LEE status has been obtained at Polk Power Station, testing for PM and HCl is only required every three years, if continued compliance is demonstrated.

At Big Bend Power Station, the compliance plan is to continue to demonstrate LEE status for mercury. This requires a 30-day annual testing requirement using a sorbent trap system. For compliance with the non-mercury metals standard, PM is used as the surrogate compliance indicator. PM continuous emissions monitoring systems (PM CEMS) are utilized for compliance and annual certification testing is conducted on each stack. Compliance with the acid gas standards are being achieved using the SO2 surrogate compliance indicator. It is possible that impacts to the company's system may occur as a result of environmental regulations affecting other companies on the local electric grid.

c. The MATS compliance strategy has been implemented. This strategy will continue in order to meet the rule requirements.

d. Regulatory approvals for cost recovery of expenses will continue in order to maintain compliance with the MATS rule.

e. As mentioned above, cost recovery of expenses will continue in order to maintain compliance with the Rule. The current compliance strategy completed under the recovery clause (Docket No. 120302-EI) is expected to be sufficient to meet the requirements. A summary of the projected expenses for years 2019 through 2028 are shown in the table below.

Year	Estimated Cost of Mercury and Air Toxics Standards (MATS) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	0.03	0.01	0	0.03
2020	0.15	0.03	0	0.18
2021	0.15	0.03	0	0.18
2022	0.03	0.03	0	0.05
2023	0.00	0.03	0	0.03
2024	0.00	0.03	0	0.03
2025	0.03	0.03	0	0.05
2026	0.00	0.03	0	0.03
2027	0.00	0.03	0	0.03
2028	0.03	0.03	0	0.05
Notes				

62. For the U.S. EPA's Cross-State Air Pollution Rule (CSAPR):

a. Will your Company be materially affected by the rule?

b. What compliance strategy does the Company anticipate employing for the rule?

c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?

d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?

e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding CSAPR-related costs:

Year	Estimated Cross-State Air Pollution Rule (CSAPR) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

If the answer to any of the above questions is not available, please explain why.

A. a. No. Tampa Electric is no longer materially affected by the rule. Bayside Power Station, Big Bend Power Station, and Polk Power Station were previously required to demonstrate compliance with CSAPR. For 2018, TEC is no longer subject to CSAPR ozone season program (or any CSAPR program). EPA finalized an update to CSAPR on October 26, 2016 removing Florida from the CSAPR program based on updated modeling and emission reduction commitments. The updated rule was implemented in 2017 for applicable units. However, Florida (including TEC power plants) could be subject to a future version of CSAPR as a result of an expected update triggered by compliance with the more stringent 2015 ozone standard or ongoing litigation relating to current rule applicability.

b. No compliance strategy is required based on the status of the current rule.

c. Not Applicable

d. Not Applicable

e. Not Applicable

Year	Estimated Cross-State Air Pollution Rule (CSAPR) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
Notes				

63. For the U.S. EPA's Cooling Water Intake Structures (CWIS) Rule:

a. Will your Company be materially affected by the rule?

b. What compliance strategy does the Company anticipate employing for the rule?

c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?

d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?

e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding CWIS-related costs:

Year	Estimated Cost of Cooling Water Intake Structures Rule (CWIS) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

If the answer to any of the above questions is not available, please explain why.

A. a. Tampa Electric may be materially affected by this rule. The costs associated with compliance with this rule could be significant, as shown in the table.

b. Tampa Electric has submitted the 316(b) compliance study element required by the rule for Bayside in conjunction with the National Pollutant Discharge Elimination System (NPDES) Permit renewal and recommends modified traveling screens and a fish return for impingement reduction compliance. Development of the compliance strategy for Big Bend continues. Modified traveling screens and a fish return for impingement will be installed on Unit 1 as a part of the Big Bend Modernization Project. Entrainment compliance will be at the discretion of the FDEP Director.

c. Tampa Electric completed the strategy for Bayside, including the study element required for submittal with the NPDES permit application for renewal. For Big Bend, a plan of study required by the NPDES permit (when finalized) will establish the compliance schedule, including the submittal of the 316(b) compliance study elements.

d. Regulatory approvals of the selected impingement and entrainment strategy will be provided by the Florida Department of Environmental Protection (FDEP) and USEPA through the NPDES permit renewals for both Bayside and Big Bend Power Stations, which will most likely include a compliance schedule.

e. The costs included in the table are as estimated will be revised as we proceed through the compliance timeline.

Year	Estimated Cost of Cooling Water Intake Structures Rule (CWIS) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	4.0	0	0	4.0
2020	12.5	0	0	12.5
2021	13.0	1.3	0.1	14.4
2022	8.0	0.3	0.1	8.4
2023	5.0	0.6	0.2	5.8
2024	7.0	0.6	0.2	7.8
2025	7.0	1.2	0.2	8.4
2026	0.0	1.2	0.2	1.4
2027	0.0	1.2	0.2	1.4
2028	0.0	1.2	0.2	1.4
Notes				
(Include Notes Here)				

64. For the U.S. EPA's Coal Combustion Residuals Rule (CCR), both for classification of coal ash as a "Non-Hazardous Waste" and as a "Special Waste."

a. Will your Company be materially affected by the rule?
b. What compliance strategy does the Company anticipate employing for the rule?
c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?
d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?
e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding CCR-related costs:

Year	Estimated Coal Combustion Residuals Rule (CCR) Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

If the answer to any of the above questions is not available, please explain why.

A. a. Yes.

b. Tampa Electric's strategy includes both its ongoing beneficial use program for CCR's generated at Big Bend Station and continued compliance with the applicable operating requirements of the CCR Rule for the existing regulated CCR units at Big Bend Station until closure of these units is complete The units for which closure activities are continuing in 2019 are the West Slag Disposal Pond (WSDP), the Economizer Ash and Pyrites Pond System (EAPPS) Closure, the North Gypsum Stackout Area (NGSA) Drainage Improvements and the South Gypsum Storage Area (SGSA) closure. The CCR Rule's operational requirements which will continue until the final closure or retrofit of all the regulated units at the site include

berm inspections, fugitive dust emissions control and groundwater monitoring.

c. Not applicable.

d. The rule remains a self-implementing federal rule in Florida, with no direct agency permitting requirements. However, Tampa Electric complies with all applicable requirements of the rule for posting of compliance documentation on the company's website and notifications to FDEP. FDEP is also provided the opportunity to review the engineering plans for TEC's closure projects prior to initiation. No project delays are anticipated.

e. Yes. Tampa Electric's expected recovery of environmental expenses related to this rule are detailed in the following table:

Year	Estimated Coal Combustion Residuals Rule (CCR) Impacts (2019 $ millions)			
	Capital Costs	O&M Costs[1]	Fuel Costs	Total Costs
2019	1.695	16.325	0.000	18.020
2020	0.500	10.478	0.000	11.978
2021	1.010	6.128	0.000	7.138
2022	0.000	0.156	0.000	0.156
2023	0.000	0.167	0.000	0.167
2024	0.000	0.128	0.000	0.128
2025	0.000	0.128	0.000	0.128
2026	0.000	0.110	0.000	0.110
2027	0.000	0.110	0.000	0.110
2028	0.000	0.100	0.000	0.100
Notes				
1-Includes currently anticipated CCR disposal costs and post-closure monitoring for all closure projects through 2025. Routine (operational) off-spec CCR disposal costs related to Big Bend Unit 4 will continue after 2025.				

65. For the U.S. EPA's Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units Rule:

a. Will your Company be materially affected by the rule?

b. What compliance strategy does the Company anticipate employing for the rule?

c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?

d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?

e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding costs:

Year	Estimated Cost of Standards of Performance for Greenhouse Gas Emissions Rule for New Sources Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

If the answer to any of the above questions is not available, please explain why.

A. a. Yes.

b. The Big Bend Unit 1 modernization project will involve the repowering of Unit 1 with a highly efficient, state of the art, natural gas-fired, combined cycle generating unit. The new units will be designed to comply with the referenced standards.

c. The new units are planned to be in commercial operation in 2023.

d. Yes. Approvals are currently being pursued pursuant to the Florida Electrical Power Plant Siting Act (PPSA), Chapter 403, Part II, Florida Statutes. These approvals will not affect the completion of the compliance

strategy relating to the referenced rule.

e. Tampa Electric does not anticipate asking for cost recovery for any expenses relating to this rule.

Year	Estimated Cost of Standards of Performance for Greenhouse Gas Emissions Rule for New Sources Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
Notes				

66. Please identify, for each unit affected by one or more of EPA's rules, what the impact is for each rule, including; unit retirement, curtailment, installation of additional emissions controls, fuel switching, or other impacts identified by the Company. As part of this response, please also indicate the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy in Microsoft Excel format.

Estimated Impacts of EPA's Rules on Generating Units

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Type of EPA Rule Impacts					Anticipated Impacts
				MATS	CSAPR/ CAIR	CWIS	CCR		
							Non-Hazardous Waste	Special Waste	
Notes									
(Include Notes Here)									

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Estimated Impacts of EPA's Rules on Generating Units

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Type of EPA Rule Impacts					Anticipated Impacts
				MATS	CSAPR/ CAIR	CWIS	CCR		
							Non-Hazardous Waste	Special Waste	
BB1	Boiler	Coal/Natural Gas	385	No Additional Enhancements Required	No Additional Enhancements Required	Cooling Towers/Intake Modifications	Slag Pond Closure/ Retrofit, NGSA Drainage Improvements, SGSA Closure	N/A	See DR Responses 59- 65 Above.
BB2	Boiler	Coal/Natural Gas	385	No Additional Enhancements Required	No Additional Enhancements Required	Cooling Towers/Intake Modifications	Slag Pond Closure/ Retrofit, NGSA Drainage Improvements, SGSA Closure	N/A	See DR Responses 59- 65 Above.
BB3	Boiler	Coal/Natural Gas	365	No Additional Enhancements Required	No Additional Enhancements Required	Cooling Towers/Intake Modifications	Slag Pond Closure/ Retrofit, NGSA Drainage Improvements, SGSA Closure	N/A	See DR Responses 59- 65 Above.
BB4	Boiler	Coal/Natural Gas	407	No Additional Enhancements Required	No Additional Enhancements Required	Cooling Towers/Intake Modifications	Economizer Ash Ponds Closure, SGSA Closure, NGSA Drainage Improvements	N/A	See DR Responses 59- 65 Above.
BBCT4A	Simple Cycle CT	Natural Gas	56	Not Impacted	Not Impacted	Not Impacted	N/A	N/A	Not Impacted
PPS1	Integrated Gasification Combined Cycle	Coal/Natural Gas	220	No Additional Enhancements Required	Not Impacted	Not Impacted	N/A	N/A	Not Impacted
PPS2	Combined Cycle CT	Natural Gas	165	Not Impacted	Not Impacted	Not Impacted	N/A	N/A	Not Impacted
PPS3	Combined Cycle CT	Natural Gas	165	Not Impacted	Not Impacted	Not Impacted	N/A	N/A	Not Impacted
PPS4	Combined Cycle CT	Natural Gas	165	Not Impacted	Not Impacted	Not Impacted	N/A	N/A	Not Impacted
PPS5	Combined Cycle CT	Natural Gas	165	Not Impacted	Not Impacted	Not Impacted	N/A	N/A	Not Impacted
BPS1	Combined Cycle CT	Natural Gas	701	Not Impacted	Not Impacted	Cooling Towers/Intake Modifications	N/A	N/A	See DR Responses 59- 65 Above.
BPS2	Combined Cycle CT	Natural Gas	929	Not Impacted	Not Impacted	Cooling Towers/Intake Modifications	N/A	N/A	See DR Responses 59- 65 Above.
BPS3	Simple Cycle CT	Natural Gas	56	Not Impacted	Not Impacted	Not Impacted	N/A	N/A	Not Impacted
BPS4	Simple Cycle CT	Natural Gas	56	Not Impacted	Not Impacted	Not Impacted	N/A	N/A	Not Impacted
BPS5	Simple Cycle CT	Natural Gas	56	Not Impacted	Not Impacted	Not Impacted	N/A	N/A	Not Impacted
BPS6	Simple Cycle CT	Natural Gas	56	Not Impacted	Not Impacted	Not Impacted	N/A	N/A	Not Impacted
Notes									
(Include Notes Here)									

67. Please identify, for each unit impacted by one or more of the EPA's rules, what the estimated cost is for implementing each rule over the course of the planning period. As part of this response, please indicate the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy in Microsoft Excel format.

Estimated Unit Cost of EPA's Rules

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Cost of EPA Rules Impacts (2019 $ millions)						
				MATS	CSAPR/ CAIR	CWIS	CCR		Anticipated Impacts	Total Cost
							Non-Hazardous Waste	Special Waste		
Notes										
(Include Notes Here)										

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Estimated Unit Cost of EPA's Rules

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Cost of EPA Rules Impacts (2019 $ millions)						
				MATS	CSAPR/ CAIR	CWIS	CCR		Anticipated Impacts	Total Cost
							Non-Hazardous Waste	Special Waste		
BB1	Boiler	Coal/Natural Gas	385	0	0	21.10	4.014	0	See DR Responses 59- 65 Above.	25.114
BB2	Boiler	Coal/Natural Gas	385	0	0	21.10	4.014	0	See DR Responses 59- 65 Above.	25.114
BB3	Boiler	Coal/Natural Gas	365	0.028	0	7.5	4.014	0	See DR Responses 59- 65 Above.	11.542
BB4	Boiler	Coal/Natural Gas	407	0.003	0	7.5	26.102	0	See DR Responses 59- 65 Above.	33.605
BBCT4A	Simple Cycle CT	Natural Gas	56	0	0	0	0	0	See DR Responses 59- 65 Above.	0
PPS1	Integrated Gasification Combined Cycle	Coal/Natural Gas	220	0.003	0	0	0	0	See DR Responses 59- 65 Above.	0.003
PPS2	Combined Cycle CT	Natural Gas	165	0	0	0	0	0	See DR Responses 59- 65 Above.	0
PPS3	Combined Cycle CT	Natural Gas	165	0	0	0	0	0	See DR Responses 59- 65 Above.	0
PPS4	Combined Cycle CT	Natural Gas	165	0	0	0	0	0	See DR Responses 59- 65 Above.	0
PPS5	Combined Cycle CT	Natural Gas	165	0	0	0	0	0	See DR Responses 59- 65 Above.	0
BPS1	Combined Cycle CT	Natural Gas	701	0	0	14.1	0	0	See DR Responses 59- 65 Above.	14.1
BPS2	Combined Cycle CT	Natural Gas	929	0	0	14.1	0	0	See DR Responses 59- 65 Above.	14.1

BPS3	Simple Cycle CT	Natural Gas	56	0	0	0	0	0	See DR Responses 59- 65 Above.	0
BPS4	Simple Cycle CT	Natural Gas	56	0	0	0	0	0	See DR Responses 59- 65 Above.	0
BPS5	Simple Cycle CT	Natural Gas	56	0	0	0	0	0	See DR Responses 59- 65 Above.	0
BPS6	Simple Cycle CT	Natural Gas	56	0	0	0	0	0	See DR Responses 59- 65 Above.	0
Notes										
(Include Notes Here)										

68. Please identify, for each unit impacted by one or more of EPA's rules, when and for what duration units would be required to be offline due to retirements, curtailments, installation of additional controls, or additional maintenance related to emission controls. Include important dates relating to each rule. Please complete the table below and provide an electronic copy in Microsoft Excel format.

Estimated Timing of Unit Impacts of EPA's Rules

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Timing of EPA Rule Impacts (Month/Year - Duration)				
				MATS	CSAPR/ CAIR	CWIS	CCR	
							Non-Hazardous Waste	Special Waste
Notes								
(Include Notes Here)								

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Estimated Timing of Unit Impacts of EPA's Rules

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Timing of EPA Rule Impacts (Month/Year - Duration)				
				MATS	CSAPR/ CAIR	CWIS	CCR	
							Non-Hazardous Waste	Special Waste
BB1	Boiler	Coal/Natural Gas	385	None	N/A	11/2021 – 5 month outage (BB Mod Project)	None	None
BB2	Boiler	Coal/Natural Gas	385	None	N/A	11/2021 – 5 month outage (BB Mod Project)	None	None
BB3	Boiler	Coal/Natural Gas	365	None	N/A	03/2025 – 1 year outage	None	None
BB4	Boiler	Coal/Natural Gas	407	None	N/A	03/2025 – 1 year outage	None	None
BBCT4A	Simple Cycle CT	Natural Gas	56	N/A	N/A	N/A	None	None
PPS1	Integrated Gasification Combined Cycle	Coal/Natural Gas	220	None	N/A	N/A	None	None
PPS2	Combined Cycle CT	Natural Gas	165	N/A	N/A	N/A	None	None
PPS3	Combined Cycle CT	Natural Gas	165	N/A	N/A	N/A	None	None
PPS4	Combined Cycle CT	Natural Gas	165	N/A	N/A	N/A	None	None
PPS5	Combined Cycle CT	Natural Gas	165	N/A	N/A	N/A	None	None
BPS1	Combined Cycle CT	Natural Gas	701	N/A	N/A	03/2021 – 1 year outage	None	None
BPS2	Combined Cycle CT	Natural Gas	929	N/A	N/A	03/2021 – 1 year outage	None	None
BPS3	Simple Cycle CT	Natural Gas	56	N/A	N/A	N/A	None	None
BPS4	Simple Cycle CT	Natural Gas	56	N/A	N/A	N/A	None	None
BPS5	Simple Cycle CT	Natural Gas	56	N/A	N/A	N/A	None	None
BPS6	Simple Cycle CT	Natural Gas	56	N/A	N/A	N/A	None	None
Notes								
(Include Notes Here)								

69. Explain any expected reliability impacts resulting from each of the EPA rules listed below. As part of your explanation, please discuss the impacts of transmission constraints and units not modified by the rule, that may be required to maintain reliability if unit retirements, curtailments, additional emissions control upgrades, or longer outage times due to each of these EPA rules.

a. Mercury and Air Toxics Standards (MATS) Rule.
b. Cross-State Air Pollution Rule (CSAPR).
c. Cooling Water Intake Structures (CWIS) Rule.
d. Coal Combustion Residuals (CCR) Rule.
e. Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units.

A.

a. None
b. None
c. Effects on reliability related to compliance with this rule will depend on the compliance option implemented at each facility. Installation of closed cycle cooling towers to meet the requirements would not affect reliability directly. However, the parasitic load associated with the operation of such units would reduce the net output by the facility, requiring replacement power to be generated elsewhere. Also, any malfunction of cooling tower components or related equipment could require unit derating or shutdown, depending on the specific compliance conditions in the NDPES Permit. Likewise, if unit operation is contingent on the function of intake structure modifications, then malfunction of screens or pumps could limit or prevent operation of associated generating units.
d. None
e. None

70. If applicable, identify any currently approved costs for environmental compliance investments made by your Company, including but not limited to renewable energy or energy efficiency measures, which would mitigate the need for future investments to comply with recently finalized or proposed EPA regulations. Briefly describe the nature of these investments and identify which rule(s) they are intended to address.

A. MATS

The MATS rule compliance strategy utilizes the control devices installed as part of Tampa Electric's 10-year, $1.2 billion environmental initiative completed in 2010. Further optimization of these existing control devices were necessary to ensure compliance with the standards. Tampa Electric's Big Bend and Polk Power Station started showing compliance with the MATS rule beginning on April 16, 2015. The current compliance strategy completed under the recovery clause (Docket No. 120302-EI) is sufficient to meet the requirements.

CCR

As described in DR Response 64 above, Tampa Electric is either closing or retrofitting all CCR Units currently regulated under the CCR Rule so that the rule will eventually no longer be applicable to any of these management units. This will eliminate the necessity to continue to comply with the rule's operating requirements in the future. It is expected that there will be no continued costs for compliance with this rule past 2025. However, it should be noted that ongoing litigation or revisions to the rules technical requirements or applicability provisions could result in unanticipated future compliance costs.

71. What steps has your Company taken, is currently taking, or is planning to take to address curbing carbon dioxide emissions for existing sources? How has your Company addressed the ruling by the U.S. Supreme Court that carbon dioxide is a pollutant under the Clean Air Act? How does your Company plan on addressing carbon dioxide emissions from existing sources during the 10-year site planning period?

A. In 2005, Tampa Electric completed the first part of a $1.2 billion initiative that reduced carbon dioxide (CO2) emissions by 20 percent from 1998 levels. By repowering the coal-fired units to a Natural Gas Combined Cycle system, CO2 was reduced approximately 5 million tons per year.

Recently, the Polk Power Station Unit 1 oil-to-natural gas Ignition Conversion project (Docket No. 120153-EI), Big Bend Station Ignition Conversion project Docket No. 140032-EI and the Polk Unit 2 natural gas combined cycle project Docket No. 120234-EI will further minimize CO2 emission intensity and mitigate the need for future investment in carbon reduction.

In addition to multiple small-scale solar installations throughout the service territory, Tampa Electric recently completed a 1.4 MW photovoltaic solar array located at LEGOLAND®, a 1.6 MW photovoltaic solar array at Tampa International Airport, and a 19.4 MW photovoltaic solar array at Big Bend Station in Apollo Beach, Florida. The 600 MWAC of solar being installed through the SoBRA agreement also enables the company to significantly reduce its carbon emissions profile and its dependence on carbon-based fuels.

The Big Bend Unit 1 modernization project will involve the repowering of BB Unit 1 with a highly efficient, state-of-the-art, natural gas-fired, combined-cycle generating unit and Unit 2 will be shut down. This project, expected to commence commercial operation in 2023, will significantly reduce carbon dioxide emissions from Big Bend Station. Further CO2 reduction opportunities during the ten-year site planning period are currently being evaluated. The Supreme Court ruling that CO2 is a pollutant is addressed in routine permitting activities similar to permitting for other pollutants.

Fuel Supply & Transportation

72. Please provide, on a system-wide basis, the actual annual fuel usage (in GWh) and average fuel price (in nominal $/MMBTU) for each fuel type utilized by the Company in the period 2009–2018. Also, provide the forecasted annual fuel usage (in GWh) and forecasted annual average fuel price (in nominal $/MMBTU) for each fuel type forecasted to be used by the Company in the period 2019–2028. As part of this response, please complete the table below and provide the completed table in Microsoft Excel format.

Average Fuel Price Comparison

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	2009										
	2010										
	2011										
	2012										
	2013										
	2014										
	2015										
	2016										
	2017										
	2018										
Projected	2019										
	2020										
	2021										
	2022										
	2023										
	2024										
	2025										
	2026										
	2027										
	2028										
Notes											
(Include Notes Here)											

A. The requested data is provided in the table below and in Excel on the enclosed CD.

Average Fuel Price Comparison

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	**GWh**	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	**2009**	NA	NA	9619	3.02	**8660**	10.6	24	15.24	33	22.21
	2010	NA	NA	10613	3.09	**8375**	7.99	0	12.12	49	17.61
	2011	NA	NA	10888	3.38	**7392**	6.19	0	0	13	19.97
	2012	NA	NA	10691	3.52	**7568**	5.33	0	0	20	23.56
	2013	NA	NA	10821	3.35	**7601**	5.23	0	0	8	24.72
	2014	NA	NA	11595	3.44	**7116**	5.68	0	0	0	0
	2015	NA	NA	9119	3.29	**9919**	4.33	0	0	0	22.34
	2016	NA	NA	7754	3.32	**9865**	3.8	0	0	0	615.14
	2017	NA	NA	6013	3.06	**13685**	4.01	0	0	0	21.87
	2018	NA	NA	3533	3.24	**16097**	4.07	0	0	0	38.24
Projected	**2019**	NA	NA	1725	2.82	**16734**	4.21	0	0	0	0
	2020	NA	NA	2467	2.57	**16618**	3.87	0	0	0	0
	2021	NA	NA	2929	2.59	**16274**	4.15	0	0	0	0
	2022	NA	NA	3039	2.71	**16328**	4.37	0	0	0	0
	2023	NA	NA	469	4.67	**19156**	4.59	0	0	0	0
	2024	NA	NA	711	3.96	**19175**	4.78	0	0	0	0
	2025	NA	NA	1276	3.45	**18893**	5.09	0	0	0	0
	2026	NA	NA	1163	3.71	**19279**	5.37	0	0	0	0
	2027	NA	NA	1799	3.47	**18931**	5.66	0	0	0	0
	2028	NA	NA	3295	3.27	**17729**	6.00	0	0	0	0

Notes

The average fuel price for Distillate Oil in 2016 is skewed by the dismantlement of the oil tank at Big Bend and the associated disposal of oil. Petroleum coke is included with coal.

73. Please discuss how the Company compares its fuel price forecasts to recognized, authoritative independent forecasts.

A. Fuel commodity price forecasting is derived through analysis of historical and current prices combined with price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, Energy Information Administration, PIRA Energy Group, Coal Daily, Inside FERC Gas Market Report, and Platt's Oilgram. The company carefully examines its final fuel forecasts for trending relationships among fuels and anomalies (e.g., an unexplainable spike in natural gas prices) to eliminate elements that could impact the validity of long-term energy pricing and planning. The resulting fuel price forecasts are compared to independent sources such as NYMEX, EIA and PIRA (now owned by Platts) for reasonableness.

74. Please identify and discuss expected industry trends and factors for each fuel type (coal, natural gas, nuclear fuel, oil, etc.) that may affect the Company during the period 2019–2028.

a. Coal
b. Natural Gas
c. Nuclear (if applicable)
d. Fuel Oil
e. Other (please specify each, if any)

A. Coal

The coal industry is expected to continue in a state of much uncertainty and reduced production during the period 2019 through 2028. The demand for coal is declining due to coal unit retirements and shifts in generation to natural gas or renewables, low natural gas prices and evolving environmental regulations. The availability and cost of coal is also uncertain due to resource constraints in labor, land access, land use, and production costs. The reduced demand and rising production cost are causing financial stress for many participants in the coal industry. Domestic production is consolidating under a few, large producers who are primarily targeting the international market where short-term demand has been strong from developing countries. This adds uncertainty and upward pressure on the price of coal. The International Maritime Organization will enforce a new sulfur cap on fuel content which will impact the global fuel market in 2020.

Natural Gas

The natural gas industry will continue to be influenced by the growth in unconventional gas production (shale gas) in North America, associated gas from shale oil production, changes in pipeline flows and projects to connect new supply to changing load centers, exports to Mexico and the international market for LNG. Expectations for continued production growth keeps the forecasted price for natural gas relatively low in the foreseeable future. This low price is also encouraging exports of LNG from the U.S. and is virtually the only fuel being selected for future electric generation in the U.S. However, there are some upside price risks to consider including restrictions on fracking and infrastructure, slowed growth in mid to long term shale production and increased global LNG demand. Tampa Electric is affected by the evolving gas market since production is coming from Appalachia, Mid-continent and Permian instead of the Gulf of Mexico. Tampa Electric's pipeline contracts must access this changing supply location.

Nuclear Fuel
Tampa Electric does not have nuclear fueled generation facilities.

Oil
Crude oil, heavy oil and distillate fuel oil have all historically shown levels of pricing volatility and are expected to continue in the foreseeable future. Global tensions, global economics, weather related supply disruptions, and aging refining capacity may cause the price of crude and its related products to change dramatically. These risk factors will continue in the future, so continued price volatility is likely. Other supply and demand drivers are electric vehicle penetration, petrochemical growth, shale oil production and cost reductions in non-shale non-OPEC production. Since Tampa Electric has a small quantity of oil-capable units and uses oil solely as a back-up fuel, oil price volatility will have limited impact on the company.

75. Please identify and discuss steps that the Company has taken to ensure natural gas supply availability and transportation over the 2019–2028 planning period.

A. Tampa Electric has taken four primary steps to ensure gas supply availability for the period 2019 through 2028. The company has 1) contracted for and utilizes underground storage, 2) participated in the Southeast Supply Header and the Transco 4A South Lateral projects to increase access to onshore supply, 3) developed natural gas supplier relationships with vendors who own natural gas production in growing supply regions, and 4) monitors opportunities for long-term, firm interstate pipeline capacity. In particular, Tampa Electric participated in an "open season" on Gulfstream Natural Gas System (Phase VI) which is expected to be filed at FERC in spring 2019.

76. Please identify and discuss any existing or planned natural gas pipeline expansion project(s), including new pipelines and those occurring or planned to occur outside of Florida that would affect the Company for the period 2019–2028.

A. Numerous natural gas pipeline projects have been completed, are in the works, or are proposed to move natural gas from the Mid-continent Appalachia, and Permian production areas, to markets across the United States. These are the primary projects that directly impact the Florida market and Tampa Electric Company:

- Southeast Supply Header and Transco's 4a South lateral (completed)

- Sabal Trail and Florida Southeast Connector (completed)

- Southern Natural's expansion (Dalton and Fairburn) to bring Marcellus Shale gas into the southeast (completed)

- Gulfstream Natural Gas Pipeline System Phase VI expansion (announced)

- Transco's Phase 2/3 of the Hillabee expansion project; part of the Southeast Market Pipelines project (announced)

- Multiple gulf coast pipeline projects feeding LNG export demand (announced)

77. Please identify and discuss expected liquefied natural gas (LNG) industry factors and trends that will impact the Company, including the potential impact on the price and availability of natural gas, for the period 2019–2028.

A. The recently increased production of shale gas in the United States has reduced the demand in the United States for any LNG imports. Instead, a number of LNG export facilities have been proposed and several are operational. The projects that have been approved and constructed, have had little impact on Tampa Electric's natural gas supply portfolio. However, an upward pressure on natural gas prices could materialize if LNG export volumes increase, and more projects are approved and constructed. Global demand for LNG in Asia and Europe could boost US LNG exports increasing the risk that the company experiences higher natural gas prices.

78. Please identify and discuss the Company's plans for the use of firm natural gas storage for the period 2019–2028.

A. Tampa Electric currently maintains 2,000,000 MMBtu of underground natural gas storage capacity at two facilities. High-deliverable salt dome storage is a key component of Tampa Electric's natural gas supply portfolio. The storage serves both as a reliable supply source and a key component of balancing supply and demand on a daily basis. Tampa Electric attempts to keep storage close to full. Maintaining this volume allows the storage to be a reliable source of supply that provides risk mitigation against various events, such as production freeze-offs during the winter and production shut-ins due to storms in the Gulf of Mexico that impact Mobile Bay, Destin and other off shore facilities.

79. Please identify and discuss expected coal transportation industry trends and factors, for transportation by both rail and water that will impact the Company during the period 2019–2028. Please include a discussion of actions taken by the Company to promote competition among coal transportation modes, as well as expected changes to terminals and port facilities that could affect coal transportation.

A. Rail transportation and inland river barge transportation are evolving rapidly as retirements of coal-fired generation units, coal-fired generation units switching source basins, and surges in sand for shale fracturing and crude from shale production change the flow of energy commodities by rail and river barge. Ocean transportation is experiencing similar dynamics while burdened by an aging Jones Act fleet.

The coal supply chain continues to experience significant financial stress as reflected in several industry bankruptcy filings. Although global demand was strong over much of 2018, the domestic and global coal supply markets continue to be over-supplied due to low natural gas prices, increased governmental regulations, renewables growth and limited electric load growth. These factors affect all legs of the transportation chain. The demands for inland barging, terminals and ocean transportation have all decreased rather significantly causing inordinate financial stress for these companies. Tampa Electric strives to maintain bi-modal transportation agreements to encourage market liquidity and increased reliability of supply should one source experience interruption. However, due to a reduction in the amount of generation fueled by coal, Tampa Electric is evaluating delivered coal as an option as well as utilizing its own transportation agreements.

80. Please identify and discuss any expected changes in coal handling, blending, unloading, and storage for any planned changes and construction projects at coal generating units for the period 2019–2028.

A. There are no expected changes in coal handling, blending, unloading or storage facilities for the period 2019 through 2028.