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March 24, 2014

HAND DELIVERED

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

Re: Petition to recovery capital costs of Big Bend fuel cost reduction project through the fuel cost recovery clause, by Tampa Electric Company;
FPSC Docket No. 140032-EI

Dear Ms. Stauffer:

Enclosed are the original and five copies of Tampa Electric Company's responses to Staff's First Data Request (Nos. 1-35) dated March 4, 2014.

Sincerely,

James D. Beasley

JDB/pp
Enclosure

cc: Ms. Martha Barrera (w/enc.)

COM ____
AFD 1
APA 1
ECO 1
ENG 1
GCL 1
IDM ____
TEL ____
CLK ____

1. In paragraph 4 of Tampa Electric's Petition, the Company asserts that it has looked at the price forecasts of distillate oil and natural gas into "the foreseeable future."

a. Please identify the forecasting models Tampa Electric relied on for natural gas, including in your response the forward curve date(s) and forecasting assumptions.

b. Please identify what forecasting model and forecasting assumptions Tampa Electric relies on for evaluating the future price of distillate oil.

A. The fuel price forecasts used in the economic analysis supporting Tampa Electric's petition are the same fuel price forecasts used for the company's 2014 Projected Fuel and Purchased Power Cost Recovery Clause Factor filing, submitted in August 2013, and for the 2014 Ten-Year Site Plan, to be submitted on April 1, 2014. The specifics of the natural gas price forecast and the distillate oil (No. 2 oil) price forecast are described below.

a. The average of the NYMEX natural gas futures contract closing prices for the five business days between August 6, 2013 and August 12, 2013 is the basis of the natural gas price forecast. The forward curve is escalated at the same escalation for natural gas commodity contained in the Energy Information Administration's Long-Term Energy Outlook.

b. The average of the NYMEX Heating Oil (also called No. 2 oil or distillate oil) futures contract closing prices for the five business days between May 17, 2013 and May 23, 2013 is the basis of the distillate oil price forecast. The forward curve is escalated at the same escalation for distillate oil commodity contained in the Energy Information Administration's Long-Term Energy Outlook.

2. What size is the existing natural gas main described in paragraph 5 of Tampa Electric's Petition? Does that main have the available capacity for supporting all four Big Bend units? Please explain your response.

A. The existing natural gas main described in paragraph 5 of Tampa Electric's Petition is a 12-inch line supplying gas to Big Bend Station. The operating pressure in the line will be increased to allow this existing line to supply the future gas needs of this igniter conversion project.

3. As stated on Page 21 of Exhibit BSB-2 (the estimated Planned Outage schedule for 2014, attached to the Direct Testimony of Brian S. Buckley, filed on August 30, 2013, in Docket No. 130001-EI), Big Bend Unit 3 is scheduled to have a 10-day planned outage in November. Assuming approval of this project, please answer the following:

a. The November planned outage at Big Bend Unit 3 is for "Fuel System Cleanup and FGD/SCR work." Will this planned outage be extended because of the fuel ignition conversion work? If so, please estimate the duration of the extension, and any incremental fuel costs attributable to the extension.

b. Please describe how, or if, the fuel ignition conversion work at Big Bend Unit 3 in November, 2014 will impact the planned outages at other units in the October-December, 2014 timeframe.

A. a. No. The November planned outage at Big Bend Unit 3 for "Fuel System Cleanup and FGD/SCR work" is unrelated to the fuel ignition conversion work. No planned outages in 2014 or 2015 are expected to be extended because of the fuel ignition conversion work. Tampa Electric will install a valve station and header pipeline to the individual units in 2014, but most of this work will occur while the units are operating. The new pipelines will be tied to each of the units during the currently scheduled planned outages during 2015 without impacting the critical paths of those outages.

b. The referenced outage is not for fuel ignition conversion work at Big Bend Unit 3. Also see the response to subpart (a).

4. Will the Average Net Operating Heat Rate (ANOHR or "heat rate") at the four Big Bend units be different post-conversion when using natural gas instead of distillate oil for start-up and flame stabilization? Please explain your response.

A. Tampa Electric does not anticipate any changes to the ANOHR at the four Big Bend units when using natural gas instead of distillate oil for startup and flame stabilization since the amount of Btu required and burner efficiency are approximately the same.

5. Will the Net Output Factor (NOF or "output factor") at the four Big Bend units be different post-conversion when using natural gas instead of distillate oil for start-up and flame stabilization? Please explain your response.

A. The NOF at the four Big Bend units is not anticipated to be different post-conversion when using natural gas instead of distillate oil for startup and flame stabilization. NOF is almost entirely based on the operation and dispatch of the unit once committed. Therefore, startup and flame stabilization are negligible in comparison to the impact of the normal operating fuel and would not materially affect the calculation of NOF.

6. List any other performance-related metrics at the four Big Bend units that may be different post-conversion when using natural gas instead of distillate oil for start-up and flame stabilization? Please explain your response.

A. While not a quantifiable impact, the new natural gas igniters are expected to be more reliable than the existing equipment. Although this should result in more uniform heating of the boiler during startup activities, the units' startup cycle times will not change. The project also may provide a reliability enhancement in cases where unexpected wet coal would typically cause a deration of the unit with the existing igniters, and the natural gas igniters may be able to compensate for the impact of the wet coal.

7. Is Tampa Electric's dispatch projection for any of the Big Bend units for the next five years affected by the proposed conversion project? Please explain your response.

A. No. Tampa Electric does not anticipate any changes in the planned dispatch for the Big Bend Units for the next five years, due to the proposed igniter conversion project.

8. Please complete the table below describing Tampa Electric's revenue requirements assuming completion of the fuel conversion project.

Year	Capital CPVRR	Fuel CPVRR	Total
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			

A.

Year	Capital CPVRR ($)	Fuel CPVRR ($)	Total ($)
2014	0	0	0
2015	3,346,052	758,903,730	762,249,782
2016	5,290,000	768,058,570	773,348,570
2017	4,526,000	781,870,130	786,396,130
2018	5,444,156	828,177,990	833,622,146
2019	4,322,167	881,916,530	886,238,697
2020	1,750,725	936,966,680	938,717,405
2021	0	970,672,730	970,672,730
2022	0	1,018,967,440	1,018,967,440
2023	0	1,073,572,000	1,073,572,000
2024	0	1,124,320,290	1,124,320,290
2025	0	1,176,696,950	1,176,696,950

Note: All dollars are nominal dollars.

9. Please complete the table below describing Tampa Electric's revenue requirements without the fuel conversion project.

Year	Capital CPVRR	Fuel CPVRR	Total
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			

A.

Year	Capital CPVRR ($)	Fuel CPVRR ($)	Total ($)
2014	0	0	0
2015	0	762,375,730	762,375,730
2016	0	773,348,270	773,348,270
2017	0	786,395,620	786,395,620
2018	0	833,981,180	833,981,180
2019	0	886,770,810	886,770,810
2020	0	943,472,160	943,472,160
2021	0	976,596,110	976,596,110
2022	0	1,025,384,890	1,025,384,890
2023	0	1,080,081,340	1,080,081,340
2024	0	1,131,205,370	1,131,205,370
2025	0	1,183,731,980	1,183,731,980

Note: All dollars are nominal dollars.

10. Please complete the table below describing the estimated bill impact of the fuel reduction projects.

Year	Bill Impact ($/1,000 kWh)
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	

A. The estimated bill impact of the fuel reduction project is shown in the following table.

Year	Bill Impact ($/1,000 kWh)
2014	Not Applicable
2015	(0.01)
2016	0.00
2017	0.00
2018	(0.02)
2019	(0.03)
2020	(0.23)
2021	(0.28)
2022	(0.31)
2023	(0.31)
2024	(0.32)
2025	(0.32)

11. Please complete the table comparing the annual energy production of Big Bend Unit 1 with and without the reduction projects.

Year	Energy Production with start-up fuel conversion (MWh)	Energy Production without start-up fuel conversion (MWh)
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		

A. The following table shows the estimated annual energy production of Big Bend Unit 1 with and without the fuel conversion project. Since there are no expected impacts to this unit's output rating, availability or dispatch, the estimated energy production does not change as a result of this project.

Year	Energy Production with start-up fuel conversion (MWh)	Energy Production without start-up fuel conversion (MWh)
2014	2,578,000	2,578,000
2015	2,169,100	2,169,100
2016	2,793,900	2,793,900
2017	2,711,000	2,711,000
2018	2,626,100	2,626,100
2019	2,376,690	2,376,690
2020	2,718,430	2,718,430
2021	2,651,380	2,651,380
2022	2,585,210	2,585,210
2023	2,376,400	2,376,400
2024	2,731,230	2,731,230
2025	2,729,020	2,729,020

12. Please complete the table comparing the annual energy production of Big Bend Unit 2 with and without the reduction projects.

Year	Energy Production with start-up fuel conversion (MWh)	Energy Production without start-up fuel conversion (MWh)
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		

A. The following table shows the estimated annual energy production of Big Bend Unit 2 with and without the fuel conversion project. Since there are no expected impacts to this unit's output rating, availability or dispatch, the estimated energy production does not change as a result of this project.

Year	Energy Production with start-up fuel conversion (MWh)	Energy Production without start-up fuel conversion (MWh)
2014	2,597,600	2,597,600
2015	2,623,270	2,623,270
2016	2,282,340	2,282,340
2017	2,702,560	2,702,560
2018	2,648,120	2,648,120
2019	2,581,360	2,581,360
2020	2,387,440	2,387,440
2021	2,713,080	2,713,080
2022	2,654,090	2,654,090
2023	2,585,050	2,585,050
2024	2,387,540	2,387,540
2025	2,726,900	2,726,900

13. Please complete the table comparing the annual energy production of Big Bend Unit 3 with and without the reduction projects.

Year	Energy Production with start-up fuel conversion (MWh)	Energy Production without start-up fuel conversion (MWh)
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		

A. The following table shows the estimated annual energy production of Big Bend Unit 3 with and without the fuel conversion project. Since there are no expected impacts to this unit's output rating, availability or dispatch, the estimated energy production does not change as a result of this project.

Year	Energy Production with start-up fuel conversion (MWh)	Energy Production without start-up fuel conversion (MWh)
2014	2,484,170	2,484,170
2015	2,430,060	2,430,060
2016	2,371,170	2,371,170
2017	2,161,040	2,161,040
2018	2,450,250	2,450,250
2019	2,388,040	2,388,040
2020	2,346,510	2,346,510
2021	2,157,110	2,157,110
2022	2,474,640	2,474,640
2023	2,425,770	2,425,770
2024	2,370,420	2,370,420
2025	2,077,860	2,077,860

14. Please complete the table comparing the annual energy production of Big Bend Unit 4 with and without the reduction projects.

Year	Energy Production with start-up fuel conversion (MWh)	Energy Production without start-up fuel conversion (MWh)
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		

A. The following table shows the estimated annual energy production of Big Bend Unit 4 with and without the fuel conversion project. Since there are no expected impacts to this unit's output rating, availability or dispatch, the estimated energy production does not change as a result of this project.

Year	Energy Production with start-up fuel conversion (MWh)	Energy Production without start-up fuel conversion (MWh)
2014	2,457,840	2,457,840
2015	2,872,030	2,872,030
2016	2,847,300	2,847,300
2017	2,792,120	2,792,120
2018	2,388,320	2,388,320
2019	2,908,670	2,908,670
2020	2,867,420	2,867,420
2021	2,807,390	2,807,390
2022	2,539,510	2,539,510
2023	2,914,120	2,914,120
2024	2,878,720	2,878,720
2025	2,880,440	2,880,440

15. Will this project reduce the fuel oil inventory or the need for fuel oil storage facilities for at the Big Bend station? Please explain your response, and include in your response information on what Tampa Electric plans to do with its current fuel oil inventory and fuel oil storage facilities.

A. Although plans have not been finalized, this project may allow Tampa Electric to reduce fuel oil inventory and decommission the Main Fuel Tank, a 4,188,324 gallon tank.

16. Please describe any structures or equipment at the Big Bend station that will be retired post-conversion. For each item, state the approximate salvage value.

A. Although there will be material and structures retired as a result of this conversion, the salvage value of that equipment will only partially offset the cost of remediation and disposal. The equipment to be retired is oil piping and regulating equipment on and near the boilers. The equipment has no value beyond its scrap metal value, which is estimated at approximately $1,000 per unit.

17. In paragraph 12 of Tampa Electric's Petition, the Company discusses its proposed methodology for recovering project costs. Please answer the following:

a) Is salvage value a component of the cost recovery projections? Why or why not? Please explain your answer.

b) Assuming that project costs are amortized over a five-year period (as Tampa Electric proposes), will the recoverable costs in each year of the five year period be capped at the actual fuel savings achieved in each respective year, or will a final true up analysis occur at the end of the fifth year? Please explain why Tampa Electric believes this is reasonable.

c) Please discuss Tampa Electric's proposed regulatory treatment of project costs including capital investment, and/or other associated costs such as fuel oil tank removal, taxes, allowance for funds used during construction (AFUDC), interest, and return on investment if actual fuel savings are less that project costs in one year of the five years.

d) Please discuss Tampa Electric's proposed regulatory treatment of any unrecovered regulatory asset balance that may exist after the five-year term, if any.

A.

a. Salvage value is not included in the Petition cost recovery projections. The cost of removal typically exceeds salvage value. Any net salvage value would be accounted for in Tampa Electric's next depreciation and dismantlement study.

b. Yes, the company proposed that recoverable costs in each year of the five-year period would be limited to the amount of actual fuel savings for that year. In the event that there is a remaining balance of un-recovered project costs at the end of the five-year period, Tampa Electric proposes to recover that amount in a subsequent year. The company would request approval for any such proposal in Tampa Electric's fuel cost recovery petition and testimony relating to the cost recovery period in which the costs are sought to be recovered.

The proposed amortization period is based on the expectation of full recovery of the project costs during that five-year period. However, the five-year period is not designed as a limit on the amount of time the

company has to recover the costs. This cost recovery method provides the benefits of the project to customers with a lower or net-zero bill in each period, and subsequently provides additional fuel savings, and lower bills, after the project cost recovery period ends.

c. Tampa Electric proposes that this project be treated in the same manner as the Polk Unit 1 conversion project, and Tampa Electric would defer recovery of the annual amortized project costs if the annual actual fuel savings are less than those costs. As proposed, cost recovery would be deferred to a subsequent annual period in which the fuel savings would equal or exceed the project costs. Also see the company's response to subpart (b) above.

d. Tampa Electric does not expect any remaining asset balance, but if there is some small amount, the company proposes that it be included in a subsequent year fuel cost recovery factor. Also see the company's response to subparts (b) and (c) above.

18. Are there any operating and maintenance (O&M) expenses included in the revenue requirement calculations? If yes, please describe.

A. No.

19. Please list all non-fuel fixed and variable operating and maintenance (O&M) expenses that Tampa Electric typically identifies as base rate expenses (or currently credits against base rate revenues), if any, that will be reduced due to the conversion project and the expected reductions during the five-year period.

A. This project may result in a minimal O&M expense reduction at Big Bend Station, since costs are occasionally incurred to address igniter tip fouling of the current oil igniters.

20. For each non-zero amount Tampa Electric includes in its response to Question 19, please state if Tampa Electric excluded the expense from its calculation of the proposed annual fuel clause recovery amount and explain why.

A. Tampa Electric did not include or exclude the potential O&M expense reduction referenced in the company's response to Data Request No. 19 from its proposed project fuel clause cost recovery amount. The Petition addresses cost recovery of the project depreciation and return, not O&M expenses.

It is not appropriate to consider this potential O&M expense reduction, since there may be offsetting increases in O&M expenses related to future work on the replacement equipment or in other areas of the station. There are typically variances in O&M expenses once base rate recovery amounts are set and the utility manages those in between base rate cases, sometimes having to spend more than planned for O&M expenses, and sometimes less.

21. Please list all non-fuel fixed and variable O&M expenses that Tampa Electric typically identifies as an Environmental Clause expense, if any, that will be reduced due to the conversion project and the expected reductions for the five-year period.

A. The project will not cause any non-fuel fixed or variable O&M expenses that Tampa Electric typically identifies as an environmental cost recovery clause expense to be reduced.

22. For each non-zero amount Tampa Electric includes in its response to Question 21, please state if Tampa Electric includes the expense in its calculation of the proposed annual fuel clause recovery amount and explain why.

A. Not applicable. See the company's response to Staff's First Data Request No. 21.

23. Please provide an example of the schedule that Tampa Electric will submit to the Commission as described in paragraph 12 of the Company's petition. Additionally, please provide sample calculations.

A. The first year in which the project costs would be included in the company's fuel cost recovery factor is 2015. The schedule provided as Exhibit B, Page 1 of 6, attached to Tampa Electric's Petition, is the schedule that would be included in the company's 2015 fuel cost recovery projection filing to be submitted to the Commission in Docket No. 140001-EI on August 22, 2014. The aforementioned Exhibit B contains sample calculations, which Tampa Electric will update with any new estimates prior to filing it with the 2015 projection filing.

24. When did Tampa Electric begin the engineering and financial analysis of this project?

A. Tampa Electric began preliminary analysis of project feasibility and rough project cost engineering in Fall 2013. The final project design and engineering work was awarded in February 2014.

25. Please explain how this project will be charged to the Fuel Clause, and when the project costs will appear in the company's fuel factor as proposed by the company.

A. The project costs will be charged as each unit begins post-conversion operations during 2015 and will be recovered through the Fuel Clause beginning in 2015. The estimated costs will be included in the company's 2015 fuel factor and shown in the fuel and purchased power cost recovery projection filing, which will be submitted to the Commission in Docket No. 140001-EI on August 22, 2014.

26. Paragraph 7 of the petition addresses fuel savings. Will the fuel savings be calculated using actual delivered fuel prices?

A. Yes.

27. Please summarize the environmental benefits, if any, that would result from the proposed Big Bend Fuel Cost Reduction Project.

A. This project is not expected to provide significant environmental benefits as it affects only the startup and flame stabilization of the units, both small components of the fuel burned compared to normal operation of the units. However, the igniter conversions will result in a reduction in the amount of distillate oil that is burned at Big Bend Station. This is a benefit since natural gas, the replacement fuel, is a cleaner burning fuel than distillate oil.

28. Please list the potential O&M cost saving factors, such as avoiding oil tank repairs during outages, that would result from the proposed project. Please specify whether each of these factors has been included in the fuel saving projections presented in Tampa Electric's Petition.

A. Other than Tampa Electric's response to Data Request No. 19, there are currently no potential O&M cost savings factors that result from the proposed project. With respect to avoiding oil tank repairs during outages, if the Main Fuel Tank is decommissioned in the future, then future upgrades or repairs to this tank would be avoided. The decision as to whether to decommission the Main Fuel Tank has not yet been made.

29. Given the volatile nature of the fuel pricing,

a. Will the proposed project still be cost-effective if natural gas prices are increased significantly in the near future?

b. What is the break-even point for the proposed project, in terms of the natural gas prices, above which the capital cost of the proposed project would not be able to fully be recovered within the cost recovery period petitioned by Tampa Electric?

A.

a. Yes. Even if gas prices increase significantly, the proposed project is still cost-effective as long as natural gas remains at a lower cost than oil and the long term price differential results in fuel savings that are greater than the project costs. In the current forecast, distillate oil is nearly five times the cost of natural gas.

b. The spread between natural gas and distillate oil prices would need to be reduced by at least 20 percent in order for the capital cost of the proposed project not to be recovered within the cost recovery period proposed by Tampa Electric. In the company's analysis, the price differential between distillate oil and natural gas is $19.16, based upon forecast average oil and natural gas prices of $24.00 and $4.85, respectively, over the proposed recovery period. A 20 percent reduction in the price differential, from $19.16 to $15.33, where the differential is multiplied by the projected number of unit starts and the MMBtu used per start to calculate the fuel savings, would result in the project costs not being recovered within the five-year cost recovery period proposed by Tampa Electric. However, the project would still be cost-effective over a longer cost recovery period.

30. Referring to Polk Fuel Cost Reduction Project that the Commission approved in Docket 120153-EI, does that project generate more, or less, fuel savings than the total expenditures (capital plus O&M costs) associated with the project up to the present day?

A. The Polk Fuel Cost Reduction Project was placed in service in June 2013 and it has generated greater fuel savings through February 2014 than the amortized project costs for the same period.

31. Refer to paragraph 4 of the Petition, please explain:

a. Why does Tampa Electric need to "stabilize Big Bend (BB) Units 1 through 4"?

b. How are BB Units 1 through 4 are currently stabilized?

c. What fuel does Tampa Electric use to stabilize BB Units 1 though 4 currently?

A.

a. Flame stabilization is required for Big Bend Units 1 through 4 during periods of low load, unexpected wet coal, when bringing a coal mill in or out of service, or due to equipment failure such as a coal pipe plug. Utilizing a fluid, high heat content source such as distillate oil or natural gas, guards against the flame being extinguished in those situations.

b. Tampa Electric currently stabilizes Big Bend Units 1 through 4 by placing the distillate oil igniters into service over the affected burners.

c. Tampa Electric currently uses No. 2 fuel oil to stabilize Big Bend Units 1 through 4.

32. How many oil tanks are currently at the BB facility? How many oil tank(s) will remain in service at the BB facility after the completion of the proposed project?

A. Currently Big Bend Station has two large oil tanks and many smaller remote tanks. The Main Fuel Tank may be decommissioned after the completion of this project; however, that decision has not yet been made.

33. After the completion of the proposed project, how will the Company start BB Units 1 through 4 up in case of natural gas supply disruption?

A. The project design allows for natural gas tanker trucks to connect and supply the necessary gas to start Big Bend Units 1 through 4 in case of a natural gas supply disruption.

The design includes tie-in points to the main gas supply header to allow gas trucks to unload natural gas into the header.

34. In terms of depreciation accounting, please provide estimates of the following that are resulted from the proposed project:

a. Retirement expense
b. Gross salvage
c. Cost of removal

A. For this project, Tampa Electric estimated cost of removal to encompass only the tasks necessary to allow access for installation of the new equipment. Following removal of the oil igniters, piping and wiring will be removed in areas directly affecting locations where the new gas igniters are to be installed. Existing piping systems will be "abandoned in place".

a. Retirement expense, defined as the cost of removal less gross salvage value, is estimated to be $239,700 per unit, or a total of $958,800 for all four units.

b. Gross salvage is estimated to be approximately $1,000 per unit, or a total of $4,000 for all four units.

c. Cost of removal is estimated to be $240,700 per unit, or a total of $962,800 for all four units.

35.

a. Can BB Units 1 through 4 be fired by natural gas at this time without further conversion?

b. If the response to the above is affirmative, what will be the efficiency of each generating unit when being fired by natural gas?

c. What is the current heat rate of each BB unit?

A.

a. No.

b. Not applicable.

c. The net annual heat rate for each unit is shown in the following table.

	Heat Rate (Btu/kWh)
Big Bend Unit 1	10,530
Big Bend Unit 2	10,324
Big Bend Unit 3	10,508
Big Bend Unit 4	10,454