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TECO’s response to Staff's Fifth Set of Interrogatories Nos. 15-17

TAMPA ELECTRIC COMPANY
DOCKET NO: 20210007-EI
STAFF'S FIFTH SET OF INTERROGATORIES
INTERROGATORY NO. 15
BATES PAGES: 1-2
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15. Please refer to witness Sizemore's actual-estimated testimony filed on July 30, 2021, page 6, lines 9 through 12, for the following questions (SO2 Emissions Allowances).

a. Please explain why there were more cogeneration purchases than originally projected.

b. Please explain how cogeneration purchases impact the SO2 emission costs TECO is responsible for.

c. Please identify both the SO2 emission allowance rate used in the original projection and the rate used in the actual-estimated filing.

A. a. Cogen purchases projected for 2021 were based on the monthly average of the actual cogeneration purchased during the first half of 2020, annualized for a full year. Cogeneration purchases in the 2021 Act-Est were based on six months of actual 2021 cogeneration purchases, and six months reforecasted using the average of the first six months of actual data. Cogeneration purchases during the first half of 2021 were higher than in the first half of 2020, resulting in a higher reforecast than originally projected.

b. The acid rain control title of the CAAA sets forth a comprehensive regulatory mechanism designed to control acid rain by limiting sulfur dioxide (SO_2) emissions by electric utilities. For each ton of SO_2 emitted, utilities consume one allowance. EPA issues allowances to utilities at no cost, or they can be purchased in the allowance marketplace. The weighted value of these allowances consumed is passed through the ECRC. Additionally, payments made to cogenerators at the marketplace value for allowances are expensed through this project because the cogeneration purchases avoid company use of additional allowances.

c. As can be seen on Form 42 – 4E, SO_2 Emissions Allowances in columns (1) and (2) are made up of Tampa Electric generating unit SO_2 Allowance consumption less Cogen SO_2 Allowances (related to purchases from cogenerators). The $15 projected for 2021 shown in column (2) was based on 6 months of prior year actual Tampa Electric generation unit SO_2 Allowance consumption less Cogen Purchases, annualized for a full year. The $41 reforecast for the 2021 Actual / Estimate shown in column (1) was based on actual Tampa Electric generation unit SO_2 Allowance consumption and Cogen purchases booked the first six months of 2021,

annualized for the remainder of the year. Cogenerator purchases for the first half of 2021 were higher than in the first half of 2020, resulting in a higher reforecast than originally projected.

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INTERROGATORY NO. 16
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16. Please refer to witness Sizemore's actual-estimated testimony filed on July 30, 2021, page 6, lines 16 through 19, and TECO's response to Staff's Third Set of Interrogatories, No. 3, for the following questions (Big Bend Units 1 & 2 FGD).

a. Please explain if there are any regulations that require flue gas desulfurization (FGD) for the combustion of natural gas.

i. If no, please explain if it is technically possible to bypass the FGD system while combusting natural gas.

b. Please explain why TECO assumed it would not be necessary to operate the FGD system while combusting natural gas.

c. Please explain how the "system ductwork" is connected to the FGD system (e.g., upstream, downstream, self-contained, separate system, etc.).

d. Please explain how and why the FGD system is needed to protect system ductwork, when "virtually no particulate matter is generated when combusting natural gas."

e. Please provide both the estimated annual cost of operating the FGD system when generating by natural gas and when the units had previously generated by coal.

f. Please explain why only Unit 2 is required to operate the FGD system, when Big Bend Units 1 and 3 were generating by natural gas as well.

A. a. No. There are not any regulations that require flue gas desulfurization ("FGD") while combusting natural gas; however, it is necessary to operate the FGD system to allow the flue gas to exit the system.

i. Please see Tampa Electric's response to Interrogatory No. 16(a), above.

b. Tampa Electric assumed that the FGD system would still be operating; however, the company assumed minimal costs as the unit would not be combusting coal.

c. The system ductwork connects the boiler to the selective catalytic reduction ("SCR") and electrostatic precipitator and then connects to the scrubber

tower. The scrubber is the last piece of pollution control equipment prior to the stack.

d. When combusting natural gas, which has virtually no SO_2, FGD operating expenses are significantly lower than when combusting coal. Because the flue gases flow through the scrubber system regardless of combustion fuel type, the infrastructure will continue to require maintenance to protect the duct work and stacks.

e. The average FGD costs while running Big Bend Station units primarily on coal was approximately $1.25 million per year, based on the period 2015 through 2017. The average FGD costs for operating Big Bend Station units on primarily natural gas is approximately $25,000 per year, based on the period 2020 through 2021. For years 2018 and 2019, the Big Bend Station units generated energy using a mix of both coal and gas.

f. Tampa Electric's response to Staff's Third Set of Interrogatories, No. 3(b) pertained to the Big Bend Units 1 & 2 FGD system. Units 1 & 2 use one FGD system, and Units 3 & 4 share a second FGD system. The Unit 3 & 4 FGD system was used when Unit 3 burned natural gas.

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INTERROGATORY NO. 17
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17. Please refer to witness Sizemore's actual-estimated testimony filed on July 30, 2021, page 9, lines 17 through 20. For each Big Bend unit, please identify both the date when TECO first anticipated operating the unit on natural gas, and the date when the unit actually began operating on natural gas.

A. Tampa Electric added natural gas capability to Big Bend Units 1-4 through the initial igniter conversions in 2015 and then, in 2017, increased the units' natural gas capacities by adding more natural gas burners to Big Bend Units 1, 2, and 3 so that those units could operate close to the maximum dependable capacity (MDC) on natural gas. They operated as dual fuel units based on economics. In April 2018, as part of the Big Bend Modernization project, Tampa Electric applied for a permit to modernize Unit 1, and retire Unit 2. In its Florida Department of Environmental Protection (FDEP) Air Construction Permit application, Tampa Electric stated its intention to cease coal combustion operations at Big Bend Unit 1 once the Modernization project construction began, and to retire Big Bend Unit 2. Big Bend Units 1 and 2 have operated on natural gas for economic reasons since 2017. Big Bend Unit 3 has been operating on natural gas based on economics and operational efficiency since 2018, and will be retired in 2023. Big Bend Unit 4 can operate on natural gas or coal and currently burns coal for economic and operational reasons.