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August 1, 2018

**VIA: ELECTRONIC FILING**

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

Re: Petition by Tampa Electric Company for a limited proceeding to approve Second SoBRA effective January 1, 2019; FPSC Docket No. 20180133-EI

Dear Ms. Stauffer:

Attached for filing in the above docket are Tampa Electric Company's responses to Staff's First Data Request Nos. 1-28, dated July18, 2018.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

**For the purpose of this question and sub-parts, please refer to the Direct Testimony and Exhibits of R. James Rocha, on behalf of Tampa Electric Company, as filed on June 29, 2018.**

**1.** Page 12, Line 11 and Document Number 3 of Exhibit RJR-1 reflect $46,045,000 as the amount of revenue requirements for the Second SoBRA with Sharing Mechanism. Please provide worksheets and/or schedules with formulas intact to demonstrate how:

A. The Capital RR and FOM amounts ($11,205,000, and $547,000, respectively) were calculated for Lithia.

B. The Capital RR and FOM amounts ($9,223,000, and $448,000, respectively) were calculated for Grange Hall.

C. The Capital RR and FOM amounts for ($8,155,000, and $407,000, respectively) were calculated for Peace Creek.

D. The Capital RR and FOM amounts ($5,848,000, and $275,000, respectively) were calculated for Bonnie Mine.

E. The Capital RR and FOM amounts ($4,786,000, and $233,000, respectively) were calculated for Lake Hancock.

F. The Land RR ($4,917,000) was calculated.

**A.** See the Excel file "20180133 Staff's 1st Data Request.xlsx" on tab "Q1" for responses to subsections (A) through (F).

A. See cells D45 and D47.

B. See cells H45 and H47.

C. See cells L45 and L47.

D. See cells P45 and P47.

E. See cells T45 and T47.

F. See the addition of cells D52, H52, L52, P52 and T52.

**For the purpose of this question and sub-parts, please refer to the Direct Testimony and Exhibits of Mark D. Ward, on behalf of Tampa Electric Company, as filed on June 29, 2018.**

**2.** Page 15, Line 8 through Page 16, Line 6. Please answer the following.

A. The witness asserts that recent steel tariffs could have a monetary impact of $20 to $30 per kilowatt-hour alternating current (kWac), and this will affect the project costs for Peace Creek. Does the estimated cost of $1,492/kWac for Peace Creek reflect the added cost of the steel tariffs? Please explain your response.

B. The witness asserts that recent steel tariffs could have a monetary impact of $20 to $30 per kilowatt-hour alternating current (kWac), and this will affect the project costs for Bonnie Mine. Does the estimated cost of $1,464/kWac for Bonnie Mine reflect the added cost of the steel tariffs? Please explain your response.

C. The witness asserts that recent steel tariffs could have a monetary impact of $20 to $30 per kilowatt-hour alternating current (kWac), and this will affect the project costs for Lake Hancock. Does the estimated cost of $1,494/kWac for Lake Hancock reflect the added cost of the steel tariffs? Please explain your response.

D. When will the Company be able to quantify the monetary impact of steel tariffs that could have the Peace Creek, Bonnie Mine, and Lake Hancock project costs?

**A.** A. The Peace Creek Solar project cost includes the impact of the steel import tariffs. The developer and Tampa Electric minimized cost increases by ordering steel equipment and material in advance. The Peace Creek Solar cost includes an estimate of $500k for steel tariffs.

B. The Bonnie Mine Solar project includes the impact of the steel import tariffs. The developer and Tampa Electric minimized cost increases by ordering steel equipment and material in advance. The Bonnie Mine Solar cost includes an estimate of $750k for steel tariffs.

C. The Lake Hancock Solar project cost includes the impact of the steel import tariffs. The developer and Tampa Electric minimized cost increases by ordering steel equipment and material in advance. The Lake Hancock cost includes an estimate of $750k for steel tariffs.

D. See the response to parts (A) through (C). Equipment containing significant amounts of steel (trackers and racking systems) and steel material (posts) will be delivered and fully invoiced in the fourth quarter of 2018. Tampa Electric can then determine the impacts of the tariffs with greater precision.

**For the purpose of questions 3-7 and sub-parts, please refer to Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, on behalf of Tampa Electric Company, as filed on June 29, 2018.**

**3.** Please answer the following questions regarding the Lithia property:

A. How many total acres are in the Lithia property?

B. How many acres in the Lithia property are planned for this solar installation?

C. How many acres in the Lithia property would be suitable for future development as a solar installation, or for other utility purposes?

D. How many acres in the Lithia property are not suitable for a solar installation, or for any other utility purpose?

E. How long has Tampa Electric Company owned the Lithia property?

F. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $2.4 million is planned for development of the Lithia property. Please describe the work activities that are needed to develop the Lithia property.

G. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $4 million is planned for developing the transmission interconnection for the Lithia property. Please describe the work needed to develop the transmission interconnection for the Lithia property.

H. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $900,000 is planned for owner costs for the Lithia property. Please describe the costs, citing examples.

**A.** A. The Lithia Solar project site is 596 acres.

B. The Lithia solar array will be on 438 acres.

C. Approximately 137 acres may be available for a future cost-effective battery storage project to be integrated with the solar project.

D. Approximately 21 acres are not compatible for PV solar or other utility purposes. This land has been identified as wetlands and will not be mitigated for any other use.

E. The site includes parcels purchased from 10 different owners. The first nine parcels were purchased February 13-15, 2018. The last parcel was purchased March 30, 2018.

F. The work activities necessary to develop the Lithia Solar site include developer due diligence to ensure the site can support a solar project and engineering required to complete county and state permit applications. Due diligence activities include detailed geotechnical studies, environmental studies, and wetlands delineation. Engineering and design activities include development and analysis of the civil plans, storm water analyses, and design of the project's solar array. Additional development work includes demolition of existing structures on the property and clearing and removing roots and stumps from the former orange groves.

G. The transmission interconnection required for Lithia Solar includes constructing a new 3-position 230-kV ring bus switchyard and loop into an existing 230-kV transmission line.

H. Owner's costs include costs of work performed by Tampa Electric employees that are assigned to the solar projects and were not employed prior to Tampa Electric's last rate case, as well as consultants that have been retained by the company to assist in development and project management activities. An example is the Director of Renewables, an employee hired by Tampa Electric at the end of 2016 who spends the majority of time working on Tampa Electric's utility scale solar projects.

The owner's costs also include site due diligence (preliminary geotechnical study and environmental studies), surveys, real estate due diligence, legal costs, wet lands delineation, the permitting and relocation of a large number of gopher tortoises, builder's risk insurance, engineering and management of the environmental permitting process.

**4.** Please answer the following questions regarding the Grange Hall property:

A. How many total acres are in the Grange Hall property?

B. How many acres in the Grange Hall property are planned for this solar installation?

C. How many acres in the Grange Hall property would be suitable for future development as a solar installation, or for other utility purposes?

D. How many acres in the Grange Hall property are not suitable for a solar installation, or for any other utility purpose?

E. How long has Tampa Electric Company owned the Grange Hall property?

F. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $1.8 million is planned for development of the Grange Hall property. Please describe the work activities that are needed to develop this property.

G. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $4.6 million is planned for developing the transmission interconnection for the Grange Hall property. Please describe the work needed to develop the transmission interconnection for this property.

H. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $500,000 is planned for owner costs for the Grange Hall property. Please describe the costs, citing examples.

**A.** A. The Grange Hall Solar project is 445 acres.

B. The Grange Hall solar array will be on 247 acres.

C. Approximately 10 acres may be available for a future cost-effective battery storage project to be integrated with the solar project.

D. Approximately 188 acres are not compatible for PV solar or other utility purposes. This land has been identified as wetlands and will not be mitigated for any other use.

E. The Grange Hall Solar site was purchased June 28, 2017.

F. The work activities necessary to develop the Grange Hall Solar site include developer due diligence to ensure the site can support a solar project and engineering required to complete county and state permit applications. Due diligence activities include detailed geotechnical studies, environmental studies, and wetlands delineation. Engineering and design activities include development and analysis of the civil plans, storm water analyses, and design of the project's solar array.

G. The transmission interconnection required for Grange Hall Solar facility includes constructing 4.75 miles of a 69-kV transmission radial line from the Grange Hall substation to interconnect the planned facility. In addition, there is estimated to be a need to upgrade relays at the existing Tampa Electric Mines Substation.

H. Owner's costs include costs of work performed by Tampa Electric employees that are assigned to the solar projects and were not employed prior to Tampa Electric's last rate case, as well as consultants that have been retained by the company to assist in development and project management activities. An example is the Director of Renewables, an employee hired by Tampa Electric at the end of 2016 who spends the majority of time working on Tampa Electric's utility scale solar projects.

The owner's costs also include site due diligence (preliminary geotechnical study and environmental studies), surveys, real estate due diligence, legal costs, wet lands delineation, builders risk insurance, engineering and management of the environmental permitting process.

**5.** Please answer the following questions regarding the Peace Creek property:

A. How many total acres are in the Peace Creek property?

B. How many acres in the Peace Creek property are planned for this solar installation?

C. How many acres in the Peace Creek property would be suitable for future development as a solar installation, or for other utility purposes?

D. How many acres in the Peace Creek property are not suitable for a solar installation, or for any other utility purpose?

E. How long has Tampa Electric Company owned the Peace Creek property?

F. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $1.8 million is planned for development of the Peace Creek property. Please describe the work activities that are needed to develop this property.

G. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $4.7 million is planned for developing the transmission interconnection for the Peace Creek property. Please describe the work needed to develop the transmission interconnection for this property.

H. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $400,000 is planned for owner costs for the Peace Creek property. Please describe the costs, citing examples.

**A.** A. The Peace Creek Solar project site is 416 acres.

B. The Peace Creek Solar array will be on 228 acres.

C. Approximately 5 acres may be available for a future cost-effective battery storage project to be integrated with the solar project.

D. Approximately 183 acres are not compatible for PV solar or other utility purposes. This land has been identified as wetlands and will not be mitigated for any other use.

E. The Peace Creek project site was purchased February 23, 2018.

F. The work activities necessary to develop the Peace Creek Solar site include developer due diligence to ensure the site can support a solar project and engineering required to complete county and state permit applications. Due diligence activities include detailed geotechnical studies, environmental studies, and wetlands delineation. Engineering and design activities include development and analysis of the civil plans, storm water analyses, and design of the project's solar array.

G. The transmission interconnection required for the Peace Creek Solar facility includes constructing 2.78 miles of a 69-kV transmission radial line tap from the Peace Creek substation to interconnect the planned facility. This construction will include two new line switches and an upgrade to another line switch.

H. Owner's costs include costs of work performed by Tampa Electric employees that are assigned to the solar projects and were not employed prior to Tampa Electric's last rate case, as well as consultants that have been retained by the company to assist in development and project management activities. An example is the Director of Renewables, an employee hired by Tampa Electric at the end of 2016 who spends the majority of time working on Tampa Electric's utility scale solar projects.

The owner's costs also include site due diligence (preliminary geotechnical study and environmental studies), surveys, real estate due diligence, legal costs, wet lands delineation, builders risk insurance, engineering and management of required the environmental permitting process.

**6.** Please answer the following questions regarding the Bonnie Mine property:

A. How many total acres are in the Bonnie Mine property?

B. How many acres in the Bonnie Mine property are planned for this solar installation?

C. How many acres in the Bonnie Mine property would be suitable for future development as a solar installation, or for other utility purposes?

D. How many acres in the Bonnie Mine property are not suitable for a solar installation, or for any other utility purpose?

E. How long has Tampa Electric Company owned the Bonnie Mine property?

F. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $1.4 million is planned for development of the Bonnie Mine property. Please describe the work activities that are needed to develop this property.

G. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $900,000 is planned for developing the transmission interconnection for the Bonnie Mine property. Please describe the work needed to develop the transmission interconnection for this property.

H. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $300,000 is planned for owner costs for the Bonnie Mine property. Please describe the costs, citing examples.

**A.** A. The Bonnie Mine Solar project site is 352 acres.

B. The Bonnie Mine Solar array will be on 283 acres.

C. There will be no acreage available for a future cost-effective battery storage project to be integrated with the solar project.

D. Approximately 69 acres are not compatible for PV solar or other utility purposes. This land has been identified as wetlands and will not be mitigated for any other use.

E. The Bonnie Mine Solar project site was purchased April 28, 2018.

F. The work activities necessary to develop the Peace Creek Solar site include developer due diligence to ensure the site can support a solar project and engineering required to complete county and state permit applications. Due diligence activities include detailed geotechnical studies, environmental studies, and wetlands delineation. Engineering and design activities include development and analysis of the civil plans, storm water analyses, and design of the project's solar array.

G. The transmission interconnection required for the Bonnie Mine Solar facility includes constructing 0.1 miles of a 69-kV transmission radial line tap from the Bonnie Mine substation to interconnect the planned facility. This construction will include two new line switches.

H. Owner's costs include costs of work performed by Tampa Electric employees that are assigned to the solar projects and were not employed prior to Tampa Electric's last rate case, as well as consultants that have been retained by the company to assist in development and project management activities. An example is the Director of Renewables, an employee hired by Tampa Electric at the end of 2016 who spends the majority of time working on Tampa Electric's utility scale solar projects.

The owner's costs also include site due diligence (preliminary geotechnical study and environmental studies), surveys, real estate due diligence, legal costs, wet lands delineation, builders risk insurance, engineering and management of the environmental permitting process.

**7.** Please answer the following questions regarding the Lake Hancock property:

A. How many total acres are in the Lake Hancock property?

B. How many acres in the Lake Hancock property are planned for this solar installation?

C. How many acres in the Lake Hancock property would be suitable for future development as a solar installation, or for other utility purposes?

D. How many acres in the Lake Hancock property are not suitable for a solar installation, or for any other utility purpose?

E. How long has Tampa Electric Company owned the Lake Hancock property?

F. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $1.6 million is planned for development of the Lake Hancock property. Please describe the work activities that are needed to develop this property.

G. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $4.1 million is planned for developing the transmission interconnection for the Lake Hancock property. Please describe the work needed to develop the transmission interconnection for this property.

H. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $300,000 is planned for owner costs for the Lake Hancock property. Please describe the costs, citing examples.

**A.** A. The Lake Hancock Solar project site is 358 acres.

B. The Lake Hancock Solar array will be on 230 acres.

C. There are approximately 124 acres available for a future cost-effective battery storage project to be integrated with the solar project.

D. Approximately 4 acres are not compatible for PV solar or other utility purposes. This land has been identified as wetlands and will not be mitigated for any other use.

E. The Lake Hancock Solar project site was purchased June 29, 2018.

F. The work activities necessary to develop the Lake Hancock Solar site include developer due diligence to ensure the site can support a solar project and engineering required to complete county and state permit applications. Due diligence activities include detailed geotechnical studies, environmental studies, and wetlands delineation. Engineering and design activities include development and analysis of the civil plans, storm water analyses, and design of the project's solar array.

G. The transmission interconnection required for the Lake Hancock Solar facility includes constructing 1.35 miles of a 69-kV transmission radial line tap from the Lake Hancock substation to the 69-kV circuit between Sandhill and Crews Lake Substations. It is estimated that both the Sandhill and Crews Lakes Substations will require relay upgrades as a result of the interconnection of this planned facility.

H. Owner's costs include costs of work performed by Tampa Electric employees that are assigned to the solar projects and were not employed prior to Tampa Electric's last rate case, as well as consultants that have been retained by the company to assist in development and project management activities. An example is the Director of Renewables, an employee hired by Tampa Electric at the end of 2016 who spends the majority of time working on Tampa Electric's utility scale solar projects.

The owner's costs also include site due diligence (preliminary geotechnical study and environmental studies), surveys, real estate due diligence, legal costs, wet lands delineation, builders risk insurance, engineering and management of the environmental permitting process.

**8.** **Land.** Please refer to Page 13, Lines 10 – 20 , of the direct testimony of witness Ward. Please explain how existing sites were chosen as suitable for solar development.

**A.** Tampa Electric's land screening process includes evaluating each site for constructability, environmental compatibility, transmission access, acreage to support the solar project and land use compatibility. Tampa Electric has a land team that includes subject matter experts in renewable energy, real estate, environmental, legal and transmission planning.

When the land team identifies a potential site, it enters into an agreement with the land-owner that includes a price for the land and allows for a period of time for Tampa Electric's land team and developer to conduct site due diligence. The due diligence process includes but is not limited to geotechnical studies, environmental studies, cultural resource assessments, transmission interconnection cost estimates, indicative size and performance of the solar array, and cost estimates for the construction of solar project. An indicative all-in-cost is developed for the site, and that cost is evaluated for cost-effectiveness.

If the project site shows no environmental or constructability issues and the indicative cost and performance show the project is cost-effective, then Tampa Electric exercises its option to purchase the site.

**9.** **Cost Effectiveness.** Please refer to EXH MDW-1. Explain what transmission upgrades are necessary for completing each 2019 SoBRA Project and all associated costs. Provide this in electronic (Excel) format.

**A.** Preliminary estimates of the costs to interconnect and potential upgrades necessary are described for each project in the above responses to Data Requests 4(G) through 7(G). Additional transmission network upgrades may be required as identified through the pending System Impact and Facilities studies that have not yet been completed.

**10.** **Resource Planning.** Please refer to EXH RJR-1. Provide the reserve margin in percentage of net firm system peak for the years 2019 to 2048 (30-year period) in an Excel table comparing the reserve margin with only the 2018 Solar Tranche versus the reserve margin with the 2018 and 2019 Solar Tranches.

**A.** See the following table, which is also provided in Excel file "20180133 Staff's 1st Data Request.xlsx" on tab "Q10".

| | Reference w/ Tranche 1 | Reference w/ Tranche 1 & 2 | |
|---|---|---|---|
| **Year** | **Reserve Margin (W/S %)** | **Reserve Margin (W/S %)** | **RM Delta (W/S %)** |
| **2018** | 34% | 34% | 0.0% |
| | 24% | 24% | 0.0% |
| **2019** | 22% | 22% | 0.0% |
| | 21% | 24% | 3.4% |
| **2020** | 20% | 20% | 0.0% |
| | 23% | 23% | 0.2% |
| **2021** | 20% | 20% | 0.0% |
| | 22% | 22% | 0.2% |
| **2022** | 20% | 20% | 0.0% |
| | 20% | 20% | 0.2% |
| **2023** | 24% | 24% | 0.0% |
| | 27% | 27% | 0.0% |
| **2024** | 22% | 22% | 0.0% |
| | 26% | 26% | 0.0% |
| **2025** | 20% | 20% | 0.0% |
| | 24% | 24% | 0.0% |
| **2026** | 24% | 24% | 0.0% |
| | 28% | 28% | 0.0% |
| **2027** | 22% | 22% | 0.0% |
| | 26% | 26% | 0.0% |
| **2028** | 21% | 21% | 0.0% |
| | 25% | 25% | 0.0% |

| Year | Reference w/ Tranche 1 Reserve Margin (W/S %) | Reference w/ Tranche 1 & 2 Reserve Margin (W/S %) | RM Delta (W/S %) |
|---|---|---|---|
| 2029 | 24% | 24% | 0.0% |
| | 28% | 28% | 0.0% |
| 2030 | 23% | 23% | 0.0% |
| | 27% | 27% | 0.0% |
| 2031 | 22% | 22% | 0.0% |
| | 25% | 25% | 0.0% |
| 2032 | 20% | 20% | 0.0% |
| | 24% | 24% | 0.0% |
| 2033 | 24% | 24% | 0.0% |
| | 28% | 28% | 0.0% |
| 2034 | 23% | 23% | 0.0% |
| | 26% | 26% | 0.0% |
| 2035 | 21% | 21% | 0.0% |
| | 25% | 25% | 0.0% |
| 2036 | 20% | 20% | 0.0% |
| | 24% | 24% | 0.0% |
| 2037 | 24% | 24% | 0.0% |
| | 27% | 27% | 0.0% |
| 2038 | 24% | 24% | 0.0% |
| | 27% | 27% | 0.0% |
| 2039 | 24% | 24% | 0.0% |
| | 27% | 27% | 0.0% |
| 2040 | 24% | 24% | 0.0% |
| | 27% | 27% | 0.0% |
| 2041 | 24% | 24% | 0.0% |
| | 24% | 24% | 0.0% |
| 2042 | 23% | 23% | 0.0% |
| | 24% | 24% | 0.0% |
| 2043 | 23% | 23% | 0.0% |
| | 32% | 32% | 0.0% |
| 2044 | 20% | 20% | 0.0% |
| | 23% | 23% | 0.0% |

| Year | Reference w/ Tranche 1 Reserve Margin (W/S %) | Reference w/ Tranche 1 & 2 Reserve Margin (W/S %) | RM Delta (W/S %) |
|---|---|---|---|
| 2045 | 20% | 20% | 0.0% |
| | 23% | 23% | 0.0% |
| 2046 | 20% | 20% | 0.0% |
| | 23% | 23% | 0.0% |
| 2047 | 20% | 20% | 0.0% |
| | 23% | 23% | 0.0% |
| 2048 | 20% | 20% | 0.0% |
| | 23% | 23% | 0.0% |

**11.** **Resource Planning.** Please complete the table below based on your most recent planning for the life of the proposed solar tranche from 2019 to 2048 (30-year life) and provide in electronic format.

| Year | Installed Capacity (MW) | Firm Import Capacity (MW) | Firm Export Capacity (MW) | QF Capacity (MW) | Total Available Capacity (MW) | System Firm Summer Peak Demand (MW) | Reserve Margin Before Maintenance (MW) | Scheduled Maintenance (MW) | Reserve Margin After Maintenance (MW) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |

**A.** The requested information is provided in the Excel file titled "20180133 Staff's 1st Data Request.xlsx" on tab "Q11".

**12.** **Resource Planning.** Please refer to EXH RJR-1. Provide a table comparing TECO's resource plan with the 2019 Solar Tranche included and with the 2019 Solar Tranche excluded.

**A.** The following table describes the reference case with the 2019 Solar Tranche excluded.

**Reference w/ Tranche 1**

| Year | Portfolio Additions | Portfolio Retirement | Reserve Margin Winter and Summer % |
|---|---|---|---|
| **2018** | Solar 144.7 MW - S | – | 34%<br>24% |
| **2019** | – | – | 22%<br>21% |
| **2020** | PPA Placeholder 50 MW - S | – | 20%<br>23% |
| **2021** | (2) 7HA.02 CT (Converted to CC 2023) 393/360 MW - S<br>PPA Placeholder 50/100 MW - W/S | BB 1 Repower Feb 2021<br>BB 2 Retires June 2021 | 20%<br>22% |
| **2022** | PPA Placeholder 100/150 MW - W/s | – | 20%<br>20% |
| **2023** | (1) GE 7FA.05 CT 245/229 MW - W<br>(1) 2x1 CC (remaining portion) 335 MW - W | – | 24%<br>27% |
| **2024** | – | – | 22%<br>26% |
| **2025** | – | – | 20%<br>24% |
| **2026** | (1) GE 7FA.05 CT 245/229 MW - W | – | 24%<br>28% |

## Reference w/ Tranche 1

| Year | Portfolio Additions | Portfolio Retirement | Reserve Margin Winter and Summer % |
|---|---|---|---|
| 2027 | – | – | 22%<br>26% |
| 2028 | – | – | 21%<br>25% |
| 2029 | (1) GE 7FA.05 CT 245/229 MW - W | – | 24%<br>28% |
| 2030 | – | – | 23%<br>27% |
| 2031 | – | – | 22%<br>25% |
| 2032 | – | – | 20%<br>24% |
| 2033 | (1) GE 7FA.05 CT 245/229 MW - W | – | 24%<br>28% |
| 2034 | – | – | 23%<br>26% |
| 2035 | – | – | 21%<br>25% |
| 2036 | – | PK 1 Retires Sep 2036 | 20%<br>24% |
| 2037 | (2) GE 7FA.05 CT 489/459 MW - W | – | 24%<br>27% |
| 2038 | – | – | 24%<br>27% |
| 2039 | – | – | 24%<br>27% |
| 2040 | – | – | 24%<br>27% |

## Reference w/ Tranche 1

| Year | Portfolio Additions | Portfolio Retirement | Reserve Margin Winter and Summer % |
|---|---|---|---|
| **2041** | – | BB 3 Retires May 2041 | 24% |
| | | | 24% |
| **2042** | – | – | 23% |
| | | | 24% |
| **2043** | (1) GE 2x1 7HA.02 CC 1128/1064 MW - S | BAY 1 Retires Apr 2043 | 23% |
| | | | 32% |
| **2044** | (1) GE LM-2500 37/30 MW - W<br>(1) GE 1x1 7HA.02 CC 506/479 MW - W | BAY 2 Retires Jan 2044 | 20% |
| | | | 23% |
| **2045** | – | – | 20% |
| | | | 23% |
| **2046** | – | – | 20% |
| | | | 23% |
| **2047** | – | – | 20% |
| | | | 23% |

The following table describes the reference case plus 278 MW of solar generation.

**Reference w/ Tranche 1 & 2**

| Year | Portfolio Additions | Portfolio Retirement | Reserve Margin Winter and Summer % |
|---|---|---|---|
| **2018** | Solar 144.7 MW - S | – | 34%<br>24% |
| **2019** | Solar 278 MW - W | – | 22%<br>24% |
| **2020** | – | – | 20%<br>23% |
| **2021** | (2) 7HA.02 CT (Converted to CC 2023)<br>393/360 MW - S<br>PPA Placeholder 50 MW - W | BB 1 Repower<br>Feb 2021<br>BB 2 Retires<br>June 2021 | 20%<br>22% |
| **2022** | PPA Placeholder 100 MW - W | – | 20%<br>20% |
| **2023** | (1) GE 7FA.05 CT 245/229 MW - W<br>(1) 2x1 CC (remaining portion) 335 MW - W | – | 24%<br>27% |
| **2024** | – | – | 22%<br>26% |
| **2025** | – | – | 20%<br>24% |
| **2026** | (1) GE 7FA.05 CT 245/229 MW - W | – | 24%<br>28% |
| **2027** | – | – | 22%<br>26% |
| **2028** | – | – | 21%<br>25% |
| **2029** | (1) GE 7FA.05 CT 245/229 MW - W | – | 24%<br>28% |
| **2030** | – | – | 23% |

## Reference w/ Tranche 1 & 2

| Year | Portfolio Additions | Portfolio Retirement | Reserve Margin Winter and Summer % |
|---|---|---|---|
| | | | 27% |
| 2031 | – | – | 22% |
| | | | 25% |
| 2032 | – | – | 20% |
| | | | 24% |
| 2033 | (1) GE 7FA.05 CT 245/229 MW - W | – | 24% |
| | | | 28% |
| 2034 | – | – | 23% |
| | | | 26% |
| 2035 | – | – | 21% |
| | | | 25% |
| 2036 | – | PK 1 Retires Sep 2036 | 20% |
| | | | 24% |
| 2037 | (2) GE 7FA.05 CT 489/459 MW - W | – | 24% |
| | | | 27% |
| 2038 | – | – | 24% |
| | | | 27% |
| 2039 | – | – | 24% |
| | | | 27% |
| 2040 | – | – | 24% |
| | | | 27% |
| 2041 | – | BB 3 Retires May 2041 | 24% |
| | | | 24% |
| 2042 | – | – | 23% |
| | | | 24% |
| 2043 | (1) GE 2x1 7HA.02 CC 1128/1064 MW - S | BAY 1 Retires Apr 2043 | 23% |
| | | | 32% |
| 2044 | | | 20% |

## Reference w/ Tranche 1 & 2

| Year | Portfolio Additions | Portfolio Retirement | Reserve Margin Winter and Summer % |
|---|---|---|---|
| | (1) GE LM-2500 37/30 MW - W<br>(1) GE 1x1 7HA.02 CC 506/479 MW - W | BAY 2 Retires Jan 2044 | 23% |
| **2045** | – | – | 20% |
| | | | 23% |
| **2046** | – | – | 20% |
| | | | 23% |
| **2047** | – | – | 20% |
| | | | 23% |

**13.** **Cost Effectiveness.** Please refer to Page 19, Lines 15 – 23, of the direct testimony of witness Ward. Provide a comparison of the 2019 Solar Plan to customer-owned residential rooftop installations with an equivalent installed capacity. Please assume a residential customer installs 5kW rooftop systems at each residence. Include any assumptions and how these assumptions were made.

**A.** Utility-scale solar makes cost-effective solar energy more available to all Tampa Electric customers regardless of roof condition, orientation, shade, or ownership. It allows customers to benefit from solar energy systems with no upfront out-of-pocket costs or financing fees, no long-term commitment and no maintenance or rooftop intrusion. With utility-scale solar, customers benefit from lower capital costs, due to economies of scale, and higher capacity factors, due to the ability to track the sun.

Page 19 of the direct testimony of witness Ward refers to the 2019 Solar Plan to build five single axis tracking solar PV projects with the total capacity of 278 MWac. The anticipated installed cost for each project ranges from $1,438/kWac to $1,494/kWac. Based on information gathered by local solar installers (and in line with what has been reported by the National Renewable Energy Laboratory), a 5 kWac residential rooftop system would cost on average about $2,805/kWac, almost twice the cost of utility-scale solar projects.

To achieve 278 MWac of rooftop solar capacity would require installing 5 kWac PV systems on 55,600 residential rooftops. To achieve the amount of energy that 278 MWac of utility-scale solar will produce, that number increases to 81,856 homes. This assumes the average capacity factor of 26.5% for utility-scale solar, which equates to 645,349 MWh/year. The average 5 kWac rooftop system with a capacity factor of 18% will produce approximately 7.9 MWh/year.

**14.** **Cost Effectiveness.** For all planned solar generation, please detail the depreciation life and actual life of each individual unit.

**A.** The company uses a thirty-year book life, with straight line depreciation for tracking photovoltaic solar facilities. This 30-year book life was selected because it is expected to be the actual life of the unit. All of the planned solar generation is tracking PV.

For tax depreciation, the federal Modified Accelerated Cost Recovery System ("MACRS"), establishes a set of class lives for various types of properties. Among the classes is solar energy to generate electricity which is denoted as a 5-year MACRS.

**15.** **Cost Effectiveness.** Please refer to EXH RJR-1, Document No. 5. For all planned solar generation, please provide the annual and cumulative values over a 30-year period (in nominal and net present value) for each of the following categories: Equipment and Installation, Incremental Fixed O&M, Fuel Savings, Emissions Savings, separated by type (CO2, etc.), Avoided Replacement Costs, Avoided Capacity Purchases, Avoided Fixed O&M, Avoided Variable O&M and Transmission Upgrades. Please provide this response in electronic (Excel) format.

a. Please explain in detail the assumptions, facts, and figures used to determine the value of each of the components evaluated in this analysis.

b. Please explain whether TECO's emissions savings include CO2 or CO2 equivalent emissions. If so, please provide a sensitivity of the analysis without these costs and provide the revised annual and cumulative values (in nominal and net present value) for each category in electronic (Excel) format.

c. Please explain whether TECO reviewed the cost-effectiveness of the generation upgrades using fuel price sensitivities. As part of this response, please provide a sensitivity of the fuel savings based upon a low fuel price forecast and a high fuel price forecast, with revised annual and cumulative values (in nominal and net present value) for each category in electronic (Excel) format.

**A.** The requested information is provided in the Excel file titled "20180133 Staff's 1st Data Reqest.xlsx" on tab "Q15". There are no avoided capacity purchases. Avoided replacement power costs are already included in the system fuel line. Avoided variable O&M is provided in the System VOM line. Transmission upgrade information is provided in the company's response to Data Request Nos. 3(g), 4(g), 5(g), 6(g), 7(g) and 9.

a. Detailed cost analyses are performed using System Optimizer and Planning & Risk (PaR) production costs models, developed by ABB. The capital and fixed expenditures are based on a compilation of technology costs from a third-party vendor. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch combined with the fixed charges to obtain the annual and total present values.

b. The Second SoBRA produces cost savings of $14.2 million, not including any emissions savings. $NO_X$ and $CO_2$ emission reductions produce an additional $24.8 million of savings for a total customer savings of $39.0 million. See the Excel file provided for the annual and cumulative values of $NO_X$ and $CO_2$ emission savings.

c. Yes, as stated in the prepared direct testimony of Tampa Electric witness Rocha on page 21, lines 9-13, the company reviewed the cost-effectiveness of the second tranche of solar generation using high and low fuel price sensitivities. The results of these sensitivities confirmed that customer savings would occur under the high fuel forecast.

The fuel forecast sensitivities used in the CPVRR analysis for the Second SoBRA are from the same fuel forecast used in preparing the 2019 projected costs and cost recovery factors to be submitted on August 24, 2018 in Docket No. 20180001-EI. The high and low fuel forecasts are shown in the company's response to the Staff's First Request for Production of Documents, No. 5.

See the Excel file provided, tabs "Q15c – High Fuel" and "Q15c – Low Fuel", for the annual and cumulative values for the high fuel and low fuel sensitivities.

**16.** **Cost Effectiveness.** Please refer to EXH RJR-1, Document No. 5. Provide the avoided fossil fuels (avoided oil barrels, avoided natural gas MMcf, avoided coal short tons) from the years 2019 to 2048 (30-year period). Please explain how calculations were made for each fuel and provide an example using 2020. Provide the response in tabular electronic format in Excel.

**A.** The production cost modeling performed for this analysis included 30 years of fuel and purchased power representing the period 2018 through 2047.

A base case model was prepared without the second tranche of solar generation. Next, starting from this base case, a change case model was prepared, and the base case and change case were run with the production cost modeling software for an economic dispatch. The generation times the heat rate divided by the fuel's heating value equals the fuel used. The change case fuels were then subtracted from the base case fuels to arrive at the avoided fuels.

The Excel file titled "20180133 Staff's 1st Data Reqest.xlsx" provides the avoided fossil fuels and example calculations for year 2020 on tabs "Q16", "Q16 – Coal Tons", "Q16 – NG MCF", and "Q16 – PetCoke Tons". Also see the company's response to Staff's 1st Request for Production of Documents, No. 5, for the base case and change case fuels.

**17.** **Cost Effectiveness**. Please refer to Page 22, Lines 4– 9, of the direct testimony of witness Ward. Provide the avoided air emissions (CO2, SO2, NOx) for the 30-year period. Show how each was calculated using the year 2020 as an example. Please provide the response in tabular electronic format in Excel.

**A.** Page 22, Lines 4–9, of the direct testimony of witness Rocha refers to avoided air emissions. The production cost modeling performed for this analysis included 30 years of fuel and purchased power representing the period of 2018 through 2046.

A base case model was prepared without the second tranche of solar generation. Next, starting from this base case, a change case model was prepared with the second tranche, 278 MW of solar generation in service on January 1, 2019. Both the base case and change case were run with the production cost modeling software for an economic dispatch. The fuel used times the fuel's emissions rate equals the emissions. The change case emissions were then subtracted from the base case emissions to arrive at the avoided emissions.

The Excel file titled "20180133 Staff's 1st Data Request.xlsx" provides the air emissions and example calculations for year 2020 on tabs "Q17", "Q17 – Avoided $CO_2$", "Q17 – Avoided $NO_X$", and "Q17 – Avoided $SO_2$".

**18. Resource Planning.** Please refer to Schedule 8.1 of TECO's 2018 Ten-Year Site Plan, provided in response to POD No. 1, and EXH MDW-1, Document No. 1, Page 1 of 3 to the direct testimony of witness Ward. Why was the in-service date of the Lake Hancock Solar Project changed from January 2021 to January 2019? If this change is related to the status of the Mountain View Solar Project, please state so, and provide an explanation of the circumstances leading to the decision.

**A.** Tampa Electric originally believed the Lake Hancock Solar project would require additional time to receive its land use approvals. Mountain View Solar was selected as a Tranche 2 project because its interconnection approvals were in advanced stages.

In May 2018, Tampa Electric received Pasco County Planning Commission's approval that the Mountain View Solar site could be used for a PV solar project. One month later an appeal was filed challenging the Planning Commission's approval. The appeal is expected to be heard on August 7, 2018. The appeal process delayed the company's environmental resource permit filing for this project, thus delaying its completion.

In June 2018, Lake Hancock received approval from the City of Bartow to construct a PV solar project on the site. The remaining approval needed to begin construction is the FDEP Environmental Resource Permit ("ERP"). The ERP application for Lake Hancock was filed with the FDEP at the end of June 2018.

Tampa Electric decided to move Lake Hancock Solar to a Tranche 2 project and replace Mountain View Solar because of the Mountain View appeal. The two projects are similar in size, and each is expected to produce 50-55 MWac. This change enables First Solar, the developer, to effectively use its workforce of more than 1,000 workers to construct three of the five Tranche 2 projects while the Mountain View project goes through its appeal process.

**19. Customer Bills.** Please refer to EXH WRA-1, Document No. 4, Page 1 of 4 to the direct testimony of witness Ashburn. Provide a breakdown of a residential customer's 1000 kWh bill, identifying what portion of the proposed rate increase and bill total are attributable to the additional revenue requirements from the sharing mechanism. Please provide all calculations in Excel format, with formulas intact.

**A.** The requested information is provided in the following table and in the Excel file "20180133 Staff 1st DR No. 19.xlsx."

| **Revenue Requirements (RR)** | **Source** | | **(000)** | **% of Total** | **Calculation** |
|---|---|---|---|---|---|
| **Tranche 2 RR with Incentive** | 1 | | $46,045 | | |
| **Tranche 2 RR without Incentive** | 2 | | 45,886 | | |
| **Difference (Incentive)** | | | $159 | 0.3453% | +D7/D5 |
| | | | | | |
| **RR by Class** | 3 | RS | $26,145 | 56.7814% | +D9/D14 |
| | | GS | 2,272 | 4.9343% | +D10/D14 |
| | | GSD | 16,417 | 35.6543% | +D11/D14 |
| | | IS | 1,184 | 2.5714% | +D12/D14 |
| | | LTG | 27 | 0.0586% | +D13/D14 |
| | | Total | $46,045 | 100.0000% | |
| | | | | | |
| **RS Portion of Incentive** | | | $90 | | +D7*E9 |
| **RS Incentive as Percent of RS Total** | | | | 0.3453% | +D16/D9 |

| **Residential Customer Bill Impact** | 4 | | | | |
|---|---|---|---|---|---|
| **1,000 kWh RS Bill** | **Present Rates** | **Proposed Rates** | **Difference** | **Incentive Difference** | |
| **Base Rate** | $64.08 | $66.55 | $2.47 | $0.01 | +D23*E17 |
| **Fuel Charge *** | 28.18 | 26.96 | -1.22 | 0.00 | |
| **ECCR Charge** | 2.46 | 2.46 | 0 | 0.00 | |
| **Capacity Charge** | 0.66 | 0.66 | 0 | 0.00 | |
| **ECRC Charge** | 3.43 | 3.43 | 0 | 0.00 | |
| **GRT Charge** | 2.53 | 2.57 | 0.04 | 0.00 | +D28*E17 |
| **Total** | $101.35 | $102.63 | $1.28 | $0.01 | |

***** Incentive Does Not Affect Fuel Charge Difference

1 Direct Testimony of witness Rocha, page 29
2 Direct Testimony of witness Rocha, page 28
3 Direct Testimony of witness Ashburn, page 15, column D
4 Direct Testimony of witness Ashburn, Exhibit WRA-1, Document No. 4, page 1 of 4

**20.** **Land.** Please refer to Page 12, Lines 12-16, of the direct testimony of witness Ward.

a. When is the permitting process for the Bonnie Mine Solar and Lake Hancock Solar Projects expected to be complete?

b. Does TECO anticipate any delays in the permitting process for either project?

**A.** a. The Bonnie Mine project ERP was approved by the FDEP in July 2018. The company is awaiting the formal letter from FDEP to be issued, and then the county is expected to issue the county conditional use permit.

The ERP application for the Lake Hancock project was submitted at the end of June 2018. The FDEP is expected to issue the ERP in August, at which time construction may begin.

b. No.

**21.** **Cost-effectiveness.** Please refer to Page 11, Lines 17-18, of the direct testimony of witness Ward. Explain what the phrase "because they originated their respective project sites" means.

**A.** Invenergy and Swinerton originated their respective project sites. Invenergy originated the Lithia Solar site and proposed a competitive price to construct the 74.5 MWac project. Swinerton, along with Pacific Northwest Solar, originated the Bonnie Mine Solar site and proposed a competitive price to construct the 37.5 MWac project.

The land parcels for both projects were assigned to Tampa Electric, and Tampa Electric purchased the sites.

**22. Cost-effectiveness.** Please refer to POD No. 3. Identify those costs in the "other traditionally allowed rate base costs" category.

**A.** With respect to SoBRA cost recovery, paragraph 6(d) of the company's 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Settlement Agreement") states the following:

> The types of costs of solar projects that traditionally have been allowed in rate base (including Engineering, Procurement and Construction ("EPC") costs; development costs including third party development fees, if any; permitting fees and costs; actual land costs and land acquisition costs; taxes; utility costs to support or complete development; transmission interconnection costs; installation labor and equipment costs; costs associated with electrical balance of system, structural balance of system, inverters, and modules; AFUDC at the weighted average cost of capital from Exhibit B of this 2017 Agreement; and other traditionally allowed rate base costs) shall be eligible for SoBRA cost recovery.

All of the costs listed in the company's response to POD No. 3 are one of the more specific types of costs listed in the 2017 Settlement Agreement, as opposed to "other traditionally allowed rate base costs."

**23.** Please refer to the Direct Testimony of Tampa Electric Company (TECO or Company) witness R. James Rocha, page 21, lines 15-25.

a. Please fully explain how the Company developed the $324.9 million projected value of fuel savings presented in this section of testimony.

b. Please identify the source and date of TECO's fuel price forecast used in developing the Current Present Value of Revenue Requirements (CPVRR) analysis of the proposed Second Solar Base Rate Adjustment (SoBRA) Transaction.

c. Please identify the date, if known, of TECO's next/updated fuel price forecast that will be used for Company/business planning purposes.

d. Please discuss TECO's fuel forecast methodology. Please also remark on approximate the length of time TECO has employed this same or very similar fuel forecasting methodology for Company planning purposes.

e. Please fully explain how TECO developed the $24.8 million projected value of reduced emissions presented in this section of testimony.

f. Please identify the sources and dates of all environmental compliance cost related forecasts TECO used in developing its CPVRR analysis of the proposed Second SoBRA Transaction.

g. Please discuss TECO's environmental compliance cost related forecast methodology. Please also remark on approximate the length of a time TECO has employed this same or very similar methodology.

h. Please provide a detailed explanation (with specificity) of the sensitivity analyses TECO performed with regard to forecasted fuel prices and forecasted market prices for carbon dioxide (CO2) in testing the robustness of the projected cost savings.

**A.** a. Using the company's Integrated Resource Planning process, a long-term base case model was prepared without the second tranche of solar generation. Next, starting from this base case, a change case model was prepared with the second tranche 260.3 MW of solar generation in-service January 2019. Both the base case and change

case were run with the production cost modeling software to determine fuel costs for both cases. The change case system fuel cost was then subtracted from the base case system fuel cost equating to $324.9 million in savings to customers.

b. The fuel forecast used in the CPVRR analysis for the second tranche of solar is the company's most recent fuel forecast updated in Summer 2018 and is the same fuel forecast used in preparing the 2019 projected costs and cost recovery factors to be submitted in Docket No. 20180001-EI on August 24, 2018.

c. The fuel price forecast will next be updated in Summer 2019 to prepare the 2020 projected costs and cost recovery factors.

d. Tampa Electric has used the same methodology to forecast fuel commodity prices for approximately ten years. The methodology is consistent across commodities. It uses market indicators (e.g., NYMEX futures contracts) to estimate near-term prices (one to three years). The methodology then uses a commercially available, published fuel commodity price forecast from an independent energy consulting firm (e.g., PIRA, Wood MacKenzie) for the mid-term (two to 20 years). The final long-term portion of the fuel price forecast ~~is~~ then transitions to using an independent, longer term source for the annual price changes (e.g., EIA Long Term Energy Outlook). The source data is blended to transition between time periods. The forecast is produced early each summer to support the late-summer fuel clause actual-estimate and projection filings and is used for one year until the next official forecast is produced.

e. A long-term base case model was prepared without the second tranche of solar. Next, starting from this base case, a change case model was prepared with the second tranche, 260.3 MW of solar in-service January 2019. Both the base case and the change case were run with the production cost modeling software to determine $CO_2$ and $NO_X$ output for both cases using the company's emission factors. Tampa Electric then calculated the avoided emissions between these two cases and multiplied them by a $CO_2$ price forecast from a global consulting services company, ICF International, Inc., and an estimated $NO_X$ cost estimated using a previous sale of Tampa Electric's $NO_X$ Ozone Season allowances. These calculations resulted in $24.8 million in projected value of reduced emissions from

$NO_X$ and $CO_2$, approximately $23.8 million of $CO_2$ and $1.0 million of $NO_X$ forecasted. Several policies and regulations relating to emissions valuation are in various stages of development and/or litigation and the anticipated value of emission reductions is captured in the forecast.

f. The $CO_2$ price forecast used in the cost-effectiveness analysis for the second tranche of solar was purchased from a global consulting services company, ICF International, Inc., and developed in the third quarter of 2017. The $NO_X$ price forecast is estimated using an actual sale of Tampa Electric's $NO_X$ Ozone Season allowances in 2016 and escalated by one percent a year after 2017.

g. Tampa Electric has been tracking $CO_2$ impacts since the initial Clean Power Plan talks began around June 2014. Since that time, the company has assessed carbon emissions for each project.

h. The fuel forecast sensitivities used in the CPVRR analysis for the second tranche of solar are from the same fuel forecast used in preparing the 2019 projected costs and cost recovery factors to be submitted on August 24, 2018 in Docket No. 20180001-EI. The high and low fuel forecasts are shown in the company's response to Staff's First POD No. 5. The results of the high and low fuel forecast sensitivities are shown in the following tables:

| Delta CPWRR Revenue Requirements - **Base Fuel** | Cost/(Savings) (2018 US $ millions) |
|---|---|
| Capital RR - Other New Units | ($78.8) |
| Capital RR - Solar New Arrays (w/Interconnect) | $326.7 |
| RR of Land for Solar | $61.2 |
| System VOM | ($19.2) |
| FOM - Other Future Units | $0.0 |
| FOM - Solar Future Arrays | $29.9 |
| System Fuel | ($324.9) |
| System Capacity | ($9.1) |
| Sub Total w/o NOX or CO2 Cost | ($14.2) |
| Plus Emissions Costs | |
| CO2 - Base | ($23.8) |
| CO2 - High | ($86.7) |
| CO2 - Low | $0.0 |
| NOX - Base | ($1.0) |
| Total w/ CO2 (Base) & NOX Cost | ($39.0) |
| Total w/ CO2 (High) & NOX Cost | ($101.9) |
| Total w/ CO2 (Low) & NOX Cost | ($15.2) |

| Delta CPWRR Revenue Requirements - **High Fuel Sensitivity** | Cost/(Savings) (2018 US $ millions) |
|---|---|
| Capital RR - Other New Units | ($78.8) |
| Capital RR - Solar New Arrays (w/Interconnect) | $326.7 |
| RR of Land for Solar | $61.2 |
| System VOM | ($15.1) |
| FOM - Other Future Units | $0.0 |
| FOM - Solar Future Arrays | $29.9 |
| System Fuel | ($458.0) |
| System Capacity | ($9.1) |
| Sub Total w/o NOX or CO2 Cost | ($143.1) |
| Plus Emissions Costs | |
| CO2 - Base | ($23.3) |
| CO2 - High | ($82.3) |
| CO2 - Low | $0.0 |
| NOX - Base | ($0.9) |
| Total w/ CO2 (Base) & NOX Cost | ($167.4) |
| Total w/ CO2 (High) & NOX Cost | ($226.3) |
| Total w/ CO2 (Low) & NOX Cost | ($144.0) |

| Delta CPWRR Revenue Requirements - **Low Fuel Sensitivity** | Cost/(Savings) (2018 US $ millions) |
|---|---|
| Capital RR - Other New Units | ($78.8) |
| Capital RR - Solar New Arrays (w/Interconnect) | $326.7 |
| RR of Land for Solar | $61.2 |
| System VOM | ($20.5) |
| FOM - Other Future Units | $0.0 |
| FOM - Solar Future Arrays | $29.9 |
| System Fuel | ($233.8) |
| System Capacity | ($9.1) |
| Sub Total w/o NOX or CO2 Cost | $75.6 |
| Plus Emissions Costs | |
| CO2 - Base | ($24.6) |
| CO2 - High | ($88.9) |
| CO2 - Low | $0.0 |
| NOX - Base | ($1.2) |
| Total w/ CO2 (Base) & NOX Cost | $49.8 |
| Total w/ CO2 (High) & NOX Cost | ($14.5) |
| Total w/ CO2 (Low) & NOX Cost | $74.4 |

**24.** Please provide a summary of all the existing federal, state, and local government policies and rules regarding the regulation of CO2 emissions. Please also discuss the economic impacts of any such policies or rules.

**A.** The following is a summary of the potentially relevant existing federal policies and rules regarding the regulation of $CO_2$ emissions and economic impacts if applicable. There are currently no state or local policies or rules relevant to the subject testimony.

***Greenhouse Gas Mandatory Reporting Rule – 40 CFR 98:*** In 2009, the Environmental Protection Agency ("EPA") promulgated a regulation to require reporting of greenhouse gas emissions from multiple sectors of the economy. The final rule applies to fossil fuel suppliers and industrial gas suppliers, direct greenhouse gas emitters and manufacturers of heavy-duty and off-road vehicles and engines. The rule does not require control of greenhouse gases, rather it requires only that sources above certain threshold levels monitor and report emissions. Tampa Electric's Greenhouse Gas ("GHG") Reporting program was approved by the Commission in Docket No. 090508-EI, Order No. PSC-10-0157-PAA-EI, issued March 22, 2010, and is a result of the EPA's Mandatory reporting rule requiring annual reporting of greenhouse gas emissions. Tampa Electric was required to report greenhouse gas emissions for the first time in 2011. Reporting for the EPA's Greenhouse Gas Mandatory Reporting rule will continue in 2018. For 2018, this activity is projected to result in approximately $93,149 of O&M expenditures.

***Prevention of Significant Deterioration - 40 CFR 52:*** This EPA rule became effective January 2, 2011. It addresses the GHG emission threshold triggers that would require permitting review of new and/or major modifications to existing stationary sources of GHG emissions. A subsequent U. S. Supreme Court ruling narrowed the EPA's authority to implement this rule, but the key provisions remain applicable to Tampa Electric. While this rule does not have an immediate impact on Tampa Electric's operations, GHG permitting was completed for Tampa Electric's most recent base load unit, the Polk Unit 2 – 5 conversion to combined cycle. These standards do not directly pertain to the scope of the subject testimony; however, the standards are not expected to have any significant economic impact to Tampa Electric's current plans to meet load demand.

***New Source Performance Standards (NSPS) – 40 CFR 60 Subpart TTTT:*** The New Source Performance Standards (NSPS) for $CO_2$ emissions from new electric generating units were promulgated on October 23, 2015. The rule is applicable to any steam generating unit, integrated gasification combined cycle, or stationary CTG that commenced construction after January 8, 2014, or commenced modification or reconstruction after June 18, 2014. This rule is being challenged in the D.C. Circuit, and the case is currently in temporary abeyance. These standards do not directly pertain to the scope of the subject testimony; however, the standards are not expected to have any significant economic impact to Tampa Electric's current plans to meet load demand.

***Standards for Modified/Reconstructed Sources - 40 CFR 60 Subpart TTTT:*** On October 23, 2015, EPA published final standards for existing units that are modified or reconstructed. This rule is being challenged in the D.C. Circuit. These standards do not directly pertain to the scope of the subject testimony; however, the standards are not expected to have any significant economic impact to Tampa Electric's current plans to meet load demand.

***Emission Guidelines and State Standards for Existing Sources (Clean Power Plan) - 40 CFR 60 Subpart UUUU:*** On October 23, 2015, EPA published final Emission Guidelines for existing utility units, setting individual statewide emission rate goals, and directing states to submit initial plans to achieve the goal by September 6, 2016. On Feb. 9, 2016 the Supreme Court stayed implementation of the rule. Florida Department of Environmental Protection ("FDEP") is not actively working on any state plan due to the Supreme Court's stay. These standards were designed to incentivize renewable energy development that is in the scope of the proposed projects. However, on October 16, 2017, EPA published a notice of its intent to repeal the Clean Power Plan rules for existing units. On December 28, 2017, EPA published an Advance Notice of Proposed Rulemaking to solicit comments on EPA's consideration of a new rule to limit GHGs from existing electric generating units. Since the Clean Power Plan replacement rule is in the early stages of development, Tampa Electric utilized the ICF International, Inc. study developed in the third quarter of 2017 to provide a forecasted cost of $CO_2$ emissions.

**25.** To date, has TECO incurred any costs related to emissions of CO2? If so, please discuss the economic details as well as the method of cost recovery.

a. If the response is negative, when does TECO believe it will be affected by CO2 emissions regulation/costs for emitting?

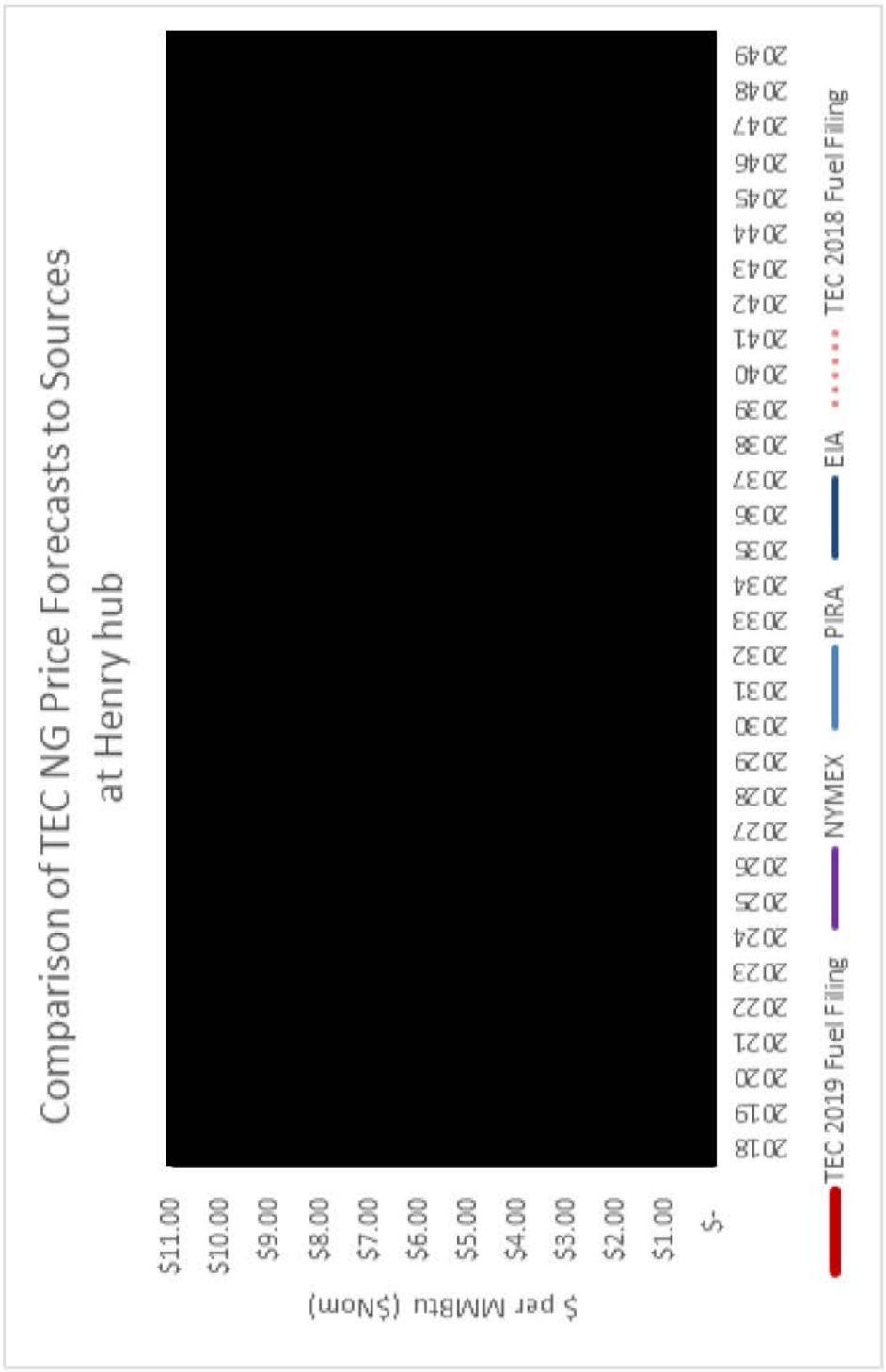
**A.** a. As described in the response to Data Request No. 24, Tampa Electric's GHG Reporting program is the only program for which Tampa Electric has incurred costs related to $CO_2$ emissions, to date. Cost recovery through the Environmental Cost Recovery Clause was approved by the Commission in Docket No. 090508-EI, Order No. PSC-10-0157-PAA-EI, issued March 22, 2010, to comply with the EPA's Mandatory Reporting Rule requiring annual reporting of greenhouse gas emissions. Tampa Electric was required to report greenhouse gas emissions for the first time in 2011. Reporting for the EPA's Greenhouse Gas Mandatory Reporting Rule will continue in 2018 at an estimated cost of $95,974.

**26.** Please refer to the Direct Testimony of TECO witness Rocha, Exhibit RJR-1, Document No. 2, Page 1 of 1. Has TECO compared the fuel price forecast shown on Document No. 2 to any other publically available source of forecasted fuel prices, such as the Energy Information Administration? If so, please discuss the results of any analysis performed.

**A.** Yes, Tampa Electric compares its fuel price forecasts for natural gas and coal to other sources. The first graph below shows Tampa Electric's forecasted price of natural gas at Henry Hub compared to other sources, both publicly available and as a subscribed service. The second graph shows Tampa Electric's price forecast for "standard" coal at the mine mouth in the Illinois Basin (source of most coal for Tampa Electric) compared to both public and subscriber service sources. The comparison is not as direct as for natural gas due to the quality and locational differences for different types of coal. Nonetheless, the relative price compared to near-term spot prices, *e.g.*, in *Coal Daily*) and longer term modeled prices (EIA average mine-mouth) show that Tampa Electric's coal price forecast is consistent with both near term market prices and longer-term comparative sources. Tampa Electric's fuel price forecasts for natural gas and coal are reasonable for planning purposes and consistent with other sources.

**REDACTED**




Comparison of TEC NG Price Forecasts to Sources at Henry hub
$ per MMBtu ($Nom)
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$-
2018
2019
2020
2021
2022
2023
2024
2025
2026
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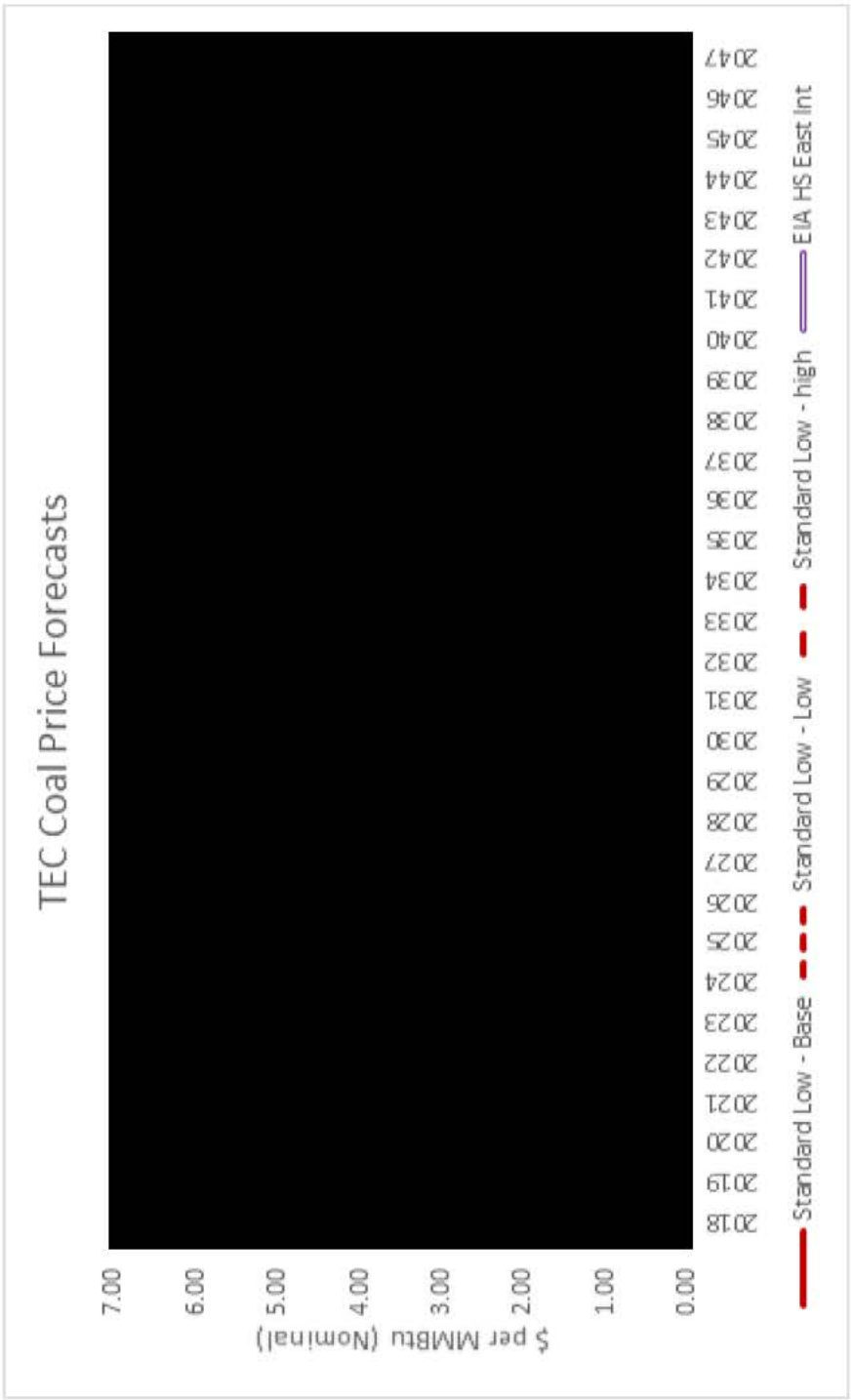
2047
2048
2049
TEC 2019 Fuel Filing
NYMEX
PIRA
EIA
TEC 2018 Fuel Filing

**REDACTED**




TEC Coal Price Forecasts
$ per MMBtu (Nominal)
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
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2043
2044
2045
2046
2047
Standard Low - Base
Standard Low - Low
Standard Low - high
EIA HS East Int

**27.** Please refer to the Direct Testimony of TECO witness Rocha, Exhibit RJR-1, Document No. 5, Page 1 of 1. Please discuss how the CO2 and nitrogen oxide (NOx) reduction amounts presented in this exhibit were formulated.

a. Please provide the percent error in TECO's delivered natural gas price forecasts 3 to 5 years out using data which supported TECO's 2010 through 2014 Ten Year Site Plans, per the following tables. Please provide an explanation for any forecast error rate in excess of 20 percent.

**Accuracy of Natural Gas Price Forecasts**

| ear | Natural Gas Price Annual Forecast Error Rate (%) | | |
|---|---|---|---|
| | Years Prior | | |
| | 5 | 4 | 3 |
| 2015 | | | |
| 2016 | | | |
| 2017 | | | |
| Average | | | |

**Natural Gas Price Forecasts**

| Year | Natural Gas Price Annual Forecast ($/MMbtu) | | |
|---|---|---|---|
| | Years Prior | | |
| | 5 | 4 | 3 |
| 2015 | | | |
| 2016 | | | |
| 2017 | | | |
| Average | | | |

**Natural Gas Price**

| Year | Natural Gas Price Annual Actuals ($/MMbtu) | | |
|---|---|---|---|
| | Years Prior | | |
| | 5 | 4 | 3 |
| 2015 | | | |
| 2016 | | | |
| 2017 | | | |
| Average | | | |

**A.** Regarding emissions, Tampa Electric has been monitoring forecasted carbon prices since the draft Clean Power Plan was issued. The company reviewed forecasts that other IOUs included with their Commission filings,

as well as public forecasts found on the internet, such as those of Synapse Energy. Tampa Electric contracted with a global consulting services company, ICF International, Inc., to obtain a $CO_2$ forecast that utilized the most current assumptions and market conditions. The consultant compared projections for various regions of the country and included low, medium, and high forecasts. Tampa Electric estimated the $NO_X$ cost using a recent, very small sale of Tampa Electric's $NO_X$ Ozone Season allowances.

a. Tampa Electric recommends caution in drawing conclusions from the requested window of information. These forecasts were produced in 2010 to 2012 for the years 2015 – 2017. The requested information is provided in the following tables.

**Accuracy of Natural Gas Price Forecasts**

| Year | Natural Gas Price Annual Forecast Error Rate (%) | | |
|---|---|---|---|
| | Years Prior | | |
| | 5 | 4 | 3 |
| **2015** | -52% | -51% | -41% |
| **2016** | -54% | -54% | -46% |
| **2017** | -55% | -56% | -48% |
| **Average** | -53% | -54% | -45% |

**Natural Gas Price Forecasts**

| Year | Natural Gas Price Annual Forecast ($/MMbtu) | | |
|---|---|---|---|
| | Years Prior | | |
| | 5[A] | 4[B] | 3[C] |
| **2015** | 8.66 | 8.64 | 7.14 |
| **2016** | 8.76 | 8.83 | 7.39 |
| **2017** | 8.88 | 9.01 | 7.65 |
| **Average** | 8.76 | 8.83 | 7.39 |

**Notes:**

**A.** Forecasted prices 2015 - 2017 from 2010 TYSP
**B**. Forecasted prices 2015 - 2017 from 2011 TYSP
**C.** Forecasted prices 2015 - 2017 from 2012 TYSP

**Natural Gas Price**

| Year | Natural Gas Price Annual Actuals ($/MMbtu) | | |
|---|---|---|---|
| | Years Prior | | |
| | 5[D] | 4 | 3 |
| **2015** | 4.20 | | |
| **2016** | 4.02 | | |
| **2017** | 4.01 | | |
| **Average** | 4.08 | | |
| **Notes:** | | | |
| **D.** Actual Fuel Prices | | | |

Actual natural gas prices often vary from forecasted prices by more than 20 percent. This occurs despite the forecasted prices being based on independent, industry-recognized sources. The variance derives from an ongoing revolution in the production of natural gas from shale rock that began around 2009. That revolution has accelerated through technology and expanded into crude oil production. The price of natural gas in recent years (2015 through 2017) has been depressed compared to projected prices based on typical supply-demand-cost relationships because the associated natural gas produced from crude oil production has flooded the natural gas market. It is being produced based on crude oil production margins, not natural gas fundamentals. Industry experts are recognizing this phenomenon and factoring it into their future forecasts.

**28.** Please provide the percent error in TECO's delivered coal price forecasts 3 to 5 years out using data which supported TECO's 2010 through 2014 Ten Year Site Plans, per the following tables. Please provide an explanation for any forecast error rate in excess of 15 percent.

**Accuracy of Coal Price Forecasts**

| Year | Coal Price Annual Forecast Error Rate (%) | | |
|---|---|---|---|
| | Years Prior | | |
| | 5 | 4 | 3 |
| 2015 | | | |
| 2016 | | | |
| 2017 | | | |
| Average | | | |

**Coal Price Forecasts**

| Year | Coal Price Annual Forecast ($/MMbtu) | | |
|---|---|---|---|
| | Years Prior | | |
| | 5 | 4 | 3 |
| 2015 | | | |
| 2016 | | | |
| 2017 | | | |
| Average | | | |

**Coal Price**

| Year | Coal Price Annual Actuals ($/MMbtu) | | |
|---|---|---|---|
| | Years Prior | | |
| | 5 | 4 | 3 |
| 2015 | | | |
| 2016 | | | |
| 2017 | | | |
| Average | | | |

**A.** Tampa Electric recommends caution in drawing conclusions from the requested window of information. The forecasts are from 2010 through 2012, 5 to 10 years prior to the forecasted period. The requested information is provided in the following tables.

Several things have changed dramatically in the coal industry over the past decade. Beginning with the spike in coal prices led by international coal in 2008 and 2012, the price of U.S. domestic coal in the east is shifting from a

cost-based supply to a pricing model based on the value of delivered solid fuel to China/India/South Africa. This evolution has been exacerbated by the closure of numerous mines and the consolidation of producers as the result of higher costs to produce, lower projected domestic coal consumption, and numerous bankruptcy proceedings. This evolution means that the surviving mines are mostly those with access to international markets via export. These facilities will be pricing their product based on the higher of the net from the international market or the domestic alternative. Thus, the actual price of coal has increased compared to the forecasts that were produced during the early 2010's.

**Accuracy of Coal Price Forecasts**

| Year | Coal Price Annual Forecast Error Rate (%) | | |
|---|---|---|---|
| | Years Prior | | |
| | 5 | 4 | 3 |
| **2015** | 17% | -23% | -19% |
| **2016** | 17% | -19% | -13% |
| **2017** | 1% | -28% | -23% |
| **Average** | 12% | -23% | -18% |

**Coal Price Forecasts**

| Year | Coal Price Annual Forecast ($/MMbtu) | | |
|---|---|---|---|
| | Years Prior | | |
| | 5[A] | 4[B] | 3[C] |
| **2015** | 2.86 | 4.34 | 4.13 |
| **2016** | 3.01 | 4.37 | 4.04 |
| **2017** | 3.11 | 4.40 | 4.08 |
| **Average** | 2.99 | 4.37 | 4.08 |

**Notes:**

**A.** Forecasted prices 2015 - 2017 from 2010 TYSP
**B**. Forecasted prices 2015 - 2017 from 2011 TYSP
**C.** Forecasted prices 2015 - 2017 from 2012 TYSP

## Coal Price

| Year | Coal Price Annual Actuals ($/MMbtu) | | |
|---|---|---|---|
| | Years Prior | | |
| | 5[D] | 4 | 3 |
| **2015** | 3.35 | | |
| **2016** | 3.52 | | |
| **2017** | 3.15 | | |
| **Average** | 3.34 | | |
| **Notes:** | | | |
| **D.** Actual Fuel Prices | | | |