State of Florida

Public Service Commission

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COMMISSION CLERK

DATE: June 7, 2012

TO: Office of Commission Clerk (Cole)

FROM: Division of Regulatory Analysis (S. Brown) SBB TB AT ELT
Office of the General Counsel (Robinson) PER

RE: Docket No. 120074-EI – Petition for approval of revisions to standard offer contract and rate schedules COG-1 and COG-2, by Tampa Electric Company.

AGENDA: 06/19/12 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Edgar

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

FILE NAME AND LOCATION: S:\PSC\RAD\WP\120074.RCM.DOC

Case Background

Section 366.91(3), Florida Statutes (F.S.), requires that each investor-owned utility (IOU) continuously offer to purchase capacity and energy from renewable energy generators. Rules 25-17.200 through 25-17.310, Florida Administrative Code (F.A.C.), require each IOU to file with the Commission by April 1 of each year a standard offer contract based on the next avoidable generating unit or planned purchase. Tampa Electric Company (TECO) filed its petition for approval of an amended standard offer contract on April 2, 2012.

TECO's standard offer contract is based on its proposed 2012 Ten-Year Site Plan (TYSP). The company's TYSP includes generating capacity additions in 2017 and 2019. The 2017 addition is 463 megawatts (MW) of incremental capacity from the conversion of existing combustion turbines (CTs), Polk units 2 through 5, into a combined cycle (CC) unit. The 2019 addition is a 177 MW CT. Rule 25-17.250(2) requires that approved standard offer contracts remain open until a request for proposal (RFP) is issued for the utility's planned generating unit. Because the 2017 Polk conversion is the subject of an issued RFP, TECO is proposing a standard offer based on the 2019 CT.

On May 1, 2012, TECO submitted responses to Staff's First Data Request Nos. 1-10 relating to the company's proposed standard offer contract. On May 21, 2012, TECO submitted revised tariff sheets and revised responses to correct an error in the calculation of escalation of fixed and variable operation and maintenance (O&M).

The Commission has jurisdiction over this contract pursuant to Sections 366.04 and 366.91, F.S. and Rules 25-17.200 to 25-17.310, F.A.C.

Discussion of Issues

Issue 1: Should the Commission approve the standard offer contract filed by Tampa Electric Company?

Recommendation: Yes. The standard offer contract and related tariffs comply with Rules 25-17.200 through 25-17.310, F.A.C., and should be approved. (Brown)

Staff Analysis: Pursuant to Rule 25-17.250, F.A.C., an investor-owned utility must continuously make available a standard offer contract for the purchase of firm capacity and energy from renewable generating facilities and small qualifying facilities with a design capacity of 100 kW or less. Rule 25-17.250(1), F.A.C., specifies that the standard offer contract must be based on the next avoidable fossil fueled generating unit identified in the utility's Ten-Year Site Plan (TYSP). In addition, each investor-owned utility with no planned generating unit identified in its Ten-Year Site Plan, shall submit a standard offer based on avoiding or deferring a planned purchase.

TECO's proposed 2012 standard offer contract is based on its 2012 Ten-Year Site Plan. The company's TYSP includes generating capacity additions in 2017 and 2019. The 2017 addition is 463 megawatts (MW) of incremental capacity from the conversion of existing combustion turbines (CTs), Polk units 2 through 5, into a combined cycle (CC) unit. An RFP for the 463 MW of capacity was issued on March 23, 2012. The list of potential providers from the RFP will be screened, evaluated, and condensed to a short list of finalists that will be announced in June 2012. TECO's 2019 addition is a 177 MW CT.

Rule 25-17.250(2), F.A.C., requires that approved standard offer contracts remain open until an RFP is issued for the utility's planned generating unit. As previously mentioned, an RFP has been issued for the conversion of the Polk units, therefore exempting a need for a standard offer contract for the additional capacity. As such, TECO is proposing a standard offer based on the 2019 CT.

A renewable generator can elect to have no performance requirements and deliver energy on an as-available basis. If the renewable generator commits to certain performance requirements based on the avoided unit, including being online and delivering capacity by the in-service date, it can receive a capacity payment under the proposed standard offer contract or a separately negotiated contract. To promote renewable generation, the Commission requires multiple options for capacity payments, including the option to receive Normal, Levelized, Early, or Early Levelized payments.

If a renewable generator elects to receive Normal or Levelized capacity payments, it would receive those payments starting on the in-service date of the avoided unit (2019). If Early or Early Levelized capacity payments were selected, those payments would begin at an earlier date but tend to be less in the later years as the net present value of payments must remain the same. In addition, capacity payments greater than those made under the Normal option require additional performance security from the renewable generator. Table 1 below estimates the annual payments that would be made to a renewable facility of 50 MW running at a 90 percent capacity factor, with the avoided unit in-service date of 2019.

Table 1 - Estimated Annual Payments to a 50 MW Renewable Facility (90% Capacity Factor)

Year	Energy Payment	Capacity Payment Type			
		Normal	Levelized	Early	Early Levelized
	($000)	($000)	($000)	($000)	($000)
2013	18,078			2,320	2,837
2014	19,457			2,388	2,842
2015	21,004			2,458	2,848
2016	21,584			2,530	2,854
2017	19,356			2,605	2,860
2018	20,730			2,681	2,866
2019	21,103	4,787	5,577	2,760	2,873
2020	22,408	4,927	5,589	2,841	2,879
2021	24,162	5,072	5,601	2,925	2,886
2022	23,804	5,221	5,613	3,011	2,893
2023	25,283	5,375	5,626	3,099	2,900
2024	25,091	5,533	5,638	3,190	2,907
2025	26,822	5,696	5,651	3,284	2,914
2026	26,480	5,863	5,665	3,381	2,922
2027	27,954	6,036	5,678	3,480	2,930
2028	29,260	6,213	5,692	3,583	2,938
2029	29,552	6,396	5,707	3,688	2,946
2030	29,001	6,584	5,722	3,797	2,954
2031	30,027	6,778	5,737	3,909	2,963
2032	31,884	6,977	5,752	4,024	2,971
Tot.2013 NPV	493,040	28,402	28,402	28,402	28,402

TECO originally submitted the revised sheets of its renewable standard offer contract and revised tariff sheets corresponding to its COG-1 and COG-2 rate schedules. On May 21, 2012, TECO submitted revised tariff sheets and revised responses to correct an error in the calculation of escalation of fixed and variable O&M. Other than these corrections to the originally submitted material, the remainder of the revised tariff sheets reflect changes associated with the 2019 CT's new economic parameters. Beyond these revisions, all other terms, such as performance, payment, and security are retained from the previous 2011 standard offer contract and related tariffs. The proposed tariff sheets are attached to this recommendation in type and strike format as Attachment A.

The provisions of the 2012 standard offer contract and related tariffs submitted by TECO conform to all the requirements of Rules 25-17.200 through 25-17.310, F.A.C. TECO has filed tariff sheets that reflect the economic and technical assumptions of the 2019 avoided unit. The standard offer contract provides flexibility in the arrangements for payments so that a developer of renewable generation may select the payment stream best suited to its financial needs. Staff believes the standard offer contract and related tariffs comply with Rules 25-17.200 through 25-17.310, F.A.C., and therefore should be approved.

Issue 2: Should this docket be closed?

Recommendation: Yes. If the Commission approves staff's recommendation to approve the proposed standard offer contract and tariff filed by TECO, and no person whose substantial interests are affected requests a hearing to address this matter, then Docket No. 120074-EI should be closed upon issuance of a consummating order, and the standard offer contract and tariff filed by TECO should be effective as of the date of the Commission's vote. If a protest is filed within 21 days of the issuance of the Commission's Order, the tariff should remain in effect pending resolution of the protest. Potential signatories to the standard offer contract should be aware that TECO's tariff and standard offer contract may be subject to a request for hearing, and if a hearing is held, may subsequently be revised. (Robinson)

Staff Analysis: If the Commission approves staff's recommendation to approve the proposed standard offer contract and tariff filed by TECO, and no person whose substantial interests are affected requests a hearing to address this matter, then Docket No. 120074-EI should be closed upon issuance of a consummating order, and the standard offer contract and tariff filed by TECO should be effective as of the date of the Commission's vote. If a protest is filed within 21 days of the issuance of the Commission's Order, the tariff should remain in effect pending resolution of the protest. Potential signatories to the standard offer contract should be aware that TECO's tariff and standard offer contract may be subject to a request for hearing, and if a hearing is held, may subsequently be revised.

TAMPA ELECTRIC

STANDARD RATE FOR PURCHASE OF AS-AVAILABLE ENERGY FROM QUALIFYING COGENERATION AND SMALL POWER PRODUCTION FACILITIES (QUALIFYING FACILITIES)

SCHEDULE

COG-1, As-Available Energy

AVAILABLE

Tampa Electric Company will purchase energy offered by any Qualifying Facility irrespective of its location, which is directly or indirectly interconnected with the Company, under the provisions of this schedule or at contract negotiated rates. Tampa Electric Company will negotiate and may contract with a Qualifying Facility, irrespective of its location, which is directly or indirectly interconnected with the Company where such negotiated contracts are in the best interest of the Company's ratepayers.

APPLICABLE

To any cogeneration, renewable energy, or small power production Qualifying Facility producing energy for sale to the Company on an As-Available basis. As-Available Energy is described by the Florida Public Service Commission (FPSC) Rule 25-17.0825, Florida Administrative Code (F.A.C.), and is energy produced and sold by a Qualifying Facility on an hour-by-hour basis for which contractual commitments as to the time, quantity, or reliability of delivery are not required. Because of the lack of assurance as to the quantity, time, or reliability of delivery of As-Available Energy, no Capacity Payment shall be made to a Qualifying Facility for delivery of As-Available Energy. Criteria for achieving Qualifying Facility status shall be those set out in FPSC Rule 25-17.080.

CHARACTER OF SERVICE

Purchases within the territory served by the Company shall be, at the option of the Company, single or three phase, 60 hertz, alternating current at any available standard Company voltage. Purchases from outside the territory served by the Company shall be three phase, 60 Hertz, alternating current at the voltage level available at the interchange point between the Company and the entity delivering As-Available Energy from the Qualifying Facility.

Continued to Sheet No. 8.030

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**METHODOLOGY TO BE USED
IN THE CALCULATION OF
AVOIDED ENERGY COST
SCHEDULE COG-1
APPENDIX A**

The methodology Tampa Electric (TEC) has implemented in order to determine the appropriate avoided energy costs and any payments thereof to be rendered to qualifying facilities (QFs) is consistent with the provisions of Order No. 23625 in Docket No.891049-EU, issued on October 16, 1990, and with the Amendment of Rules 25-17.080 et seq, Florida Administrative Code.

The avoided energy costs methodology used to determine payments to Qualified Facilities (QFs) on an hourly basis is based on the incremental cost of fuel using the average price of replacement fuel purchased in excess of contract minimums~~ and is further described in Exhibit 1~~. Generally, avoided energy costs are defined to include incremental fuel, identifiable variable operation and maintenance expenses, identifiable variable purchase power cost, and an adjustment for line losses reflecting delivery voltage.

Under normal conditions the Company will have additional generation resources available which can carry its native load and firm interchange sales without the QF's contribution. When this is the case and the QF is present, the incremental fuel portion of the avoided energy cost is equal to the difference between TEC's production cost at two load levels, with and without the QFs' contribution.

In those situations where the Company's available maximum generation resources not including its minimum operating reserves are insufficient to carry its native load and firm interchange sales, in the absence of the QF contribution, TEC's incremental fuel component of the avoided energy cost will be determined by:

1) system lambda - if "off-system purchases" are not being made and all available generation has been dispatched; or
2) the highest incremental cost of any "off-system purchases" that are being made for native load.

Examples of these situations are found in Exhibits ~~2-5~~1-4.

Continued to Sheet No. 8.102

ISSUED BY: G. L. Gillette, President **DATE EFFECTIVE:** ~~June 14, 2011~~

Continued from Sheet No. 8.103

AVOIDED ENERGY COST CALCULATIONS

Example 1: No Off-System Purchases, TEC's Generation Is Capable Of Carrying Its Native Load and Firm Sales.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an ~~hour-by-hour~~hour-by-hour basis when no off-system purchases are taking place is as follows:

In these instances, the price per megawatt hour ($/MWH) that Tampa Electric will pay the QFs is determined by calculating the production cost at two load levels.

This first calculation determines TEC's production cost "without" the benefit of cogeneration.

The second calculation determines TEC's production cost "with" the benefit of cogeneration.

After each of the two calculations are made, the avoided energy cost rate is calculated by dividing the difference in production cost between the two calculations described above by the "Standard Tariff Block." [The "Standard Tariff Block" is defined to be an x-megawatt (XMW) block equivalent to the combined actual hourly generation delivered to TEC from all QFs making as-available energy sales to Tampa Electric. In the absence of metered information on exports from a QF making as-available energy sales to Tampa Electric an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MWs and then added to the sum of the other as-available purchases for that hour. Prior to the in-service date of the appropriate designated avoided unit, firm energy sales will be equivalent to as-available sales. Beginning with the in-service date of the appropriate designated avoided unit, firm energy purchases from QFs shall be treated as "as-available" energy for the purposes of determining the XMW block size only during the periods that the appropriate designated avoided unit would not be operated.] The difference in production costs divided by the XMW block determines the As-Available Energy Payment Rate (AEPR) for the hour. The AEPR will be applied to the "Actual" QF megawatts purchased during the hour to determine payment to each QF supplying as-available energy, and each QF supplying firm energy in those instances where the avoided unit would not have been operated during the hour. See Exhibit ~~2~~1.

Continued to Sheet No. 8.105

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Continued from Sheet No. 8.104

Example 2: Off-System Purchases Are Not Being Made. TEC's Generation Can Only Carry Its Native Load and Firm Sales With The QF Contribution.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever Tampa Electric is not purchasing off-system interchange is as follows:

In this instance, the avoided energy cost that Tampa Electric will pay the QFs will be determined by calculating the production cost at the last MW load level. The avoided energy cost is the production cost at system lambda. See Exhibit ~~3~~2.

In the situation where TEC's generation is not fully dispatched, and additional generation capability is available to price a portion of the QF block, then the QF block will be priced at a combination of the difference between TEC's production cost at two load levels as previously defined and at system lambda. See Exhibit ~~4~~3.

Example 3: Off-System Purchases Are Being Made To Serve Native Load.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever Tampa Electric is making off-system purchases for native load is as follows:

In this instance, the price per MWH that Tampa Electric will pay is determined by applying the highest incremental cost of the off-system purchases to the QF block. See Exhibit ~~5~~4.

DELIVERY VOLTAGE ADJUSTMENT

A credit for avoided line losses reflecting the voltage at which generation by the QFs is received is included in Tampa Electric's procedure for the determination of incremental avoided energy cost associated with as-available energy. Tampa Electric uses the adjustment factors shown on Sheet No. 8.050 for calculating the compensation for avoided line losses at the transmission and distribution system voltage levels based on the appropriate classification of service.

Continued to Sheet No. 8.106

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Continued from Sheet No. 8.107

EXHIBIT ~~2~~1

Example: No Off-System Purchases, TEC's Generation Is Capable Of Carrying Its Native Load and Firm Sales.

Given:
Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1560 MWs
Native Load = 1550 MWs
Firm Sales = 10 MWs

First Calculation ("WITHOUT" QF):
Production Cost at 1560 MWs = $20,275/Hour

Second Calculation ("WITH" QF):
Production Cost at 1510 MWs = $19,500/Hour

Third Calculation (QF Rate $/MWH):
Actual Hourly Avoided Energy Cost =
($20,275/Hour - $19,500/Hour) / (50MW)
or
As-Available Energy Payment Rate (AEPR) = $15.50/MWH

Continued to Sheet No. 8.110

TAMPA ELECTRIC

Continued from Sheet No. 8.109

EXHIBIT ~~3~~2

Example: Off-System Purchases Are Not Being Made. TEC's Generation Can Carry Its Native Load and Firm Sales Only With The QF Contribution.

Given:
- Actual QF Energy = 50 MWs
- TEC's Maximum Available Generation = 1460 MWs
- Native Load = 1500 MWs
- Firm Sale = 10 MWs

First Calculation:
- Production Cost at 1460 MWs = $18,900/Hour

Second Calculation:
- Production Cost at 1459 MWs = $18,882.50/Hour

Third Calculation (QF Rate $/MWH):
- Actual Hourly Avoided Energy Cost at 1 MW (System Lambda1) =
  ($18,900/Hour - $18,882.50/Hour) / (1 MW)

or
- As-Available Energy Payment Rate (AEPR) = $17.50/MWH

NOTE:
1 In this example, System Lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

Continued to Sheet No. 8.111

ISSUED BY: ~~W. N. Cantrell~~ G. L. Gillette, President

DATE EFFECTIVE: ~~March 9, 2004~~

Docket No. 120074-EI
Date: June 7, 2012

Attachment A

~~THIRD~~ FOURTH REVISED SHEET NO. 8.111
CANCELS ~~SECOND~~ THIRD REVISED SHEET NO. 8.111

TAMPA ELECTRIC

Continued from Sheet No. 8.110

EXHIBIT 43

Example: **Off-System Purchases Are Not Being Made to Serve Native Load and Firm Sales. Available Generation Capacity Is Not Fully Dispatched. Without the QF's Contribution, TEC's Native Load and Firm Sales Can Be Carried Only With Additional Power Purchases.**

Given:

Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1530 MWs
TEC's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sale = 1 0 MWs

Step 1 (Calculations for First 30 MWs)

First Calculation ("WITHOUT" QF):
Production Cost at 1530 MWs = $20,590/Hour
Second Calculation ("With" QF):
Production Cost at 1500 MWs = $20,050/Hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 30 MWs =
($20,590/Hour) - ($20,050/Hour) = $540/Hour

Step 2 (Calculations for Remaining 20 MWs)

First Calculation:
Production Cost at 1530 MWs = $20,590/Hour
Second Calculation:
Production Cost at 1529 MWs = $20,571.50/Hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 1 MW (System Lambda [1]) for 20 MWs=
($20,590/Hour- $20,571.50/Hour) X (20 MWs) = $370/Hour

Step 3 (Calculation of Composite Rate for Total 50 MW Block)

Composite Actual Hourly Avoided Energy Cost of 50 MW Block =
($540 + $370)/ 50 MW

or

As-Available Energy Payment Rate (AEPR) = $18.20/MWH

Note: [1] In this example, System Lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

Continued to Sheet No. 8.112

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~June 14, 2011~~

TAMPA ELECTRIC

Continued from Sheet No. 8.111

EXHIBIT ~~5~~4

Example: Off-System Purchases Are Being Made, TEC's Native Load and Firm Sales Can Be Carried Only With Additional Purchase Power.

Given:

Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1500 MWs
TEC's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sales = 20 MWs
Off-System Purchases1 = 10 MWs Costing $400/Hour

Actual Incremental Hourly Avoided Energy Cost = $400 / 10 MW

or

AEPR = $40/Hour

NOTE:

1 Off-System Purchase shall be the highest cost purchased energy block bought during the hour for native load.

Continued from Sheet No. 8.234

Contracted Capacity payment made to the CEP and the "normal" Contracted Capacity payment calculated pursuant to Contracted Capacity payment option 1 (Value of Deferral Payments) in COG-2 will also be added each month to the Repayment Account, so long as the payment made to the CEP is greater than the monthly payment the CEP would have received if it had selected Contracted Capacity Payment Option 1 in Section 6.b.iii. The annual balance in the Repayment Account shall accrue interest at an annual rate of ~~8.02~~7.95%.

Also beginning on _______________, at such time that the Monthly Contracted Capacity Payment made to the CEP, pursuant to the Contracted Capacity Payment Option selected, is less than the "normal" Monthly Contracted Capacity Payment in Capacity Payment Option 1 in COG-2, there shall be debited from the Repayment Account an Early Payment Offset Amount to reduce the balance in the Repayment Account. Such Early Payment Offset Amount shall be equal to the amount which the Company would have paid for capacity in that month if Contracted Capacity payments had been calculated pursuant to Contracted Capacity Payment Option 1 in COG-2 and the CEP had elected to begin receiving Contracted Capacity payments on __________________, minus the Monthly Contracted Capacity Payment the Company makes to the CEP (assuming the MPS are met or exceeded), pursuant to the Contracted Capacity Payment Option chosen by the CEP in Section 6.b.ii.

The CEP shall owe the Company and be liable for the current balance in the Repayment Account. The Company agrees to notify the CEP monthly as to the current Repayment Account balance.

In the event of default by the CEP, the total Repayment Account balance shall become due and payable within twenty (20) business days of receipt of written notice, as reimbursement for the Early Contracted Capacity Payments made to the CEP by the Company. The CEP's obligation to reimburse the Company in the amount of the balance in the Repayment Account shall survive the termination of the CEP's Contract with the Company. Such reimbursement shall not be construed to constitute liquidated damages and shall in no way limit the right of the Company to pursue all its remedies at law or in equity against the CEP.

Continued to Sheet No. 8.238

TAMPA ELECTRIC

RATE SCHEDULE COG-2
TABLE OF APPENDICIES

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 13, 2010~~

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~~FIRST~~ SECOND REVISED SHEET NO. 8.344
CANCELS ~~ORIGINAL~~ FIRST REVISED SHEET NO. 8.344

RATE SCHEDULE COG-2
APPENDIX B
METHODOLOGY TO BE USED IN THE CALCULATION OF AVOIDED ENERGY COST

The methodology the Company has implemented in order to determine the appropriate avoided energy costs and any payments thereof to be rendered to CEPs is consistent with the provisions of Order No. 23625 in Docket No. 891049-EU, issued on October 16, 1990; the Amendment of FPSC Rules 25-17.080 et seq, F.A.C.

The avoided energy costs methodology used to determine payments to CEPs on an hourly basis is based on the incremental cost of fuel using the average price of replacement fuel purchased in excess of contract minimums ~~and is further described in Exhibit 1~~. Generally, avoided energy costs are defined to include incremental fuel, identifiable variable operation and maintenance expenses, identifiable variable purchased power costs and an adjustment for line losses reflecting delivery voltage.

Under normal conditions the Company will have additional generation resources available which can carry its native load and firm interchange sales without the CEP's contribution. When this is the case and the CEP is present, the incremental fuel portion of the avoided energy cost is equal to the difference between the Company's production cost at 2 load levels, with and without the CEP's contribution.

In those situations where the Company's maximum available generation (not including its minimum operating reserves) ~~are~~ is insufficient to carry its native load and firm interchange sales, in the absence of the CEP contribution, the Company's incremental fuel component of the avoided energy cost will be determined by:

1. system lambda - if "off-system purchases" are not being made and all available generation has been dispatched; or

2. the highest incremental cost of any "off-system purchases" that are being made for native load.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~June 14, 2011~~

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Examples of these situations are found in Exhibits ~~2-5~~1 - 4.

The As-Available Avoided Energy Cost, as determined by this methodology, is priced at a level not to exceed the Company's incremental fuel and identifiable variable operating and maintenance (O&M) expenses including the cost of any off-system purchases for native load.

PARAMETERS FOR DETERMINING AS-AVAILABLE AVOIDED ENERGY COSTS: The Company uses production costing methods for determining avoided energy cost payments to CEPs. Computerized production costing is accomplished on an hourly basis. The parameters used are as follows:

1. The system load is the actual system load at the Hour Ending with the clock hour (HE).
2. The first allocation of load for production costing is to those units that are base loaded at a certain level for operating reasons. The remainder of the load is allocated to units available for economic dispatch through the use of incremental cost curves.
3. The fuel costs associated with each of the Company's units operating at its allocated level of generation is determined by using the individual units input/output equation, its heat rate performance factor and the composite price of supplemental fuel.
4. The Company's own production cost for each hour of operation at a particular generation level equals the sum of the individual units' fuel cost for that hour. The production cost, thus determined, consists of the composite price of replacement fuel based on supplemental purchases and the incremental heat rate for the generating system.
5. The Company's total cost equals its own production cost (paragraph 4 above), identified variable O&M, plus the cost of any off-system purchases to serve native load.
6. Native load includes all firm and non-firm retail load.
7. The cost of off-system firm and non-firm variable purchases is defined as the highest energy cost energy block purchased for native load during the hour.
8. Firm interchange sales are included in production cost calculations.

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In these instances, the \$/MWH price that the Company will pay the CEPs is determined by calculating the production cost at 2 load levels.

The 2nd calculation determines the Company's production cost with the benefit of cogeneration.

After each of the 2 calculations are made, the avoided energy cost rate is calculated by dividing the difference in production cost between the 2 calculations described above by the "Standard Tariff Block." [The "Standard Tariff Block" is defined to be an XMW block equivalent to the combined actual hourly generation delivered to the Company from all CEPs making As-Available Energy sales to the Company. In the absence of metered information on exports from the CEP making As-Available Energy sales to the Company, an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MWs and then added to the sum of the other as-available purchases for that hour. Prior to the in-service date of the appropriate Designated Avoided Unit, firm energy sales will be equivalent to as-available sales. Beginning with the in-service date of the appropriate Designated Avoided Unit(s), firm energy purchases from CEPs shall be treated as as-available energy for the purposes of determining the XMW block size only during the periods that the appropriate Designated Avoided Unit would not be operated.] The difference in production costs divided by the XMW block determines the As-Available Energy Payment Rate (AEPR) for the hour. The AEPR will be applied to the "Actual" CEP MWs purchased during the hour to determine payment to each CEP supplying As-Available Energy, and each CEP supplying firm energy in those instances where the avoided unit would not have been operated during the hour. See Exhibit ~~2~~1.

Example 2 Off-system purchases are not being made. The Company's generation can only carry its native load and firm sales with the CEP contribution.

The procedure used to deterministically calculate the incremental avoided energy cost associated with As-Available Energy on an hour by hour basis whenever the Company is not purchasing off-system interchange is as follows:

In this instance, the avoided energy cost that the Company will pay the CEPs will be determined by calculating the production cost at the last MW load level. The avoided energy cost is the production cost at system lambda. See Exhibit ~~3~~2.

In the situation where the Company's generation is not fully dispatched, and additional generation capability is available to price a portion of the CEP block, then the CEP block will be priced at a combination of the difference between the Company's production cost at 2 load levels as previously defined and at system lambda. See Exhibit 4~~3~~.

ISSUED BY: ~~C. R. Black~~G. L. Gillette, President

DATE EFFECTIVE: ~~May 22, 2007~~

TAMPA ELECTRIC

Example 3 Off-system purchases are being made to serve native load.

The procedure used to deterministically calculate the incremental avoided energy cost associated with As-Available Energy on an hour by hour basis whenever the Company is making off-system purchases for native load is as follows:

In this instance, the $/MWH price that the Company will pay is determined by applying the highest incremental cost of the off-system purchases to the CEP block. See Exhibit ~~5~~4.

DELIVERY VOLTAGE ADJUSTMENT: A credit for avoided line losses reflecting the voltage at which generation by the CEPs is received is included in the Company's procedure for the determination of incremental avoided energy cost associated with As-Available Energy. Tampa Electric uses the adjustment factors shown on Sheet No. 8.306 for calculating the compensation for avoided line losses at the transmission and distribution system voltage levels based on the appropriate classification of service.

Example: (Firm Standby Time-of-Day)

Actual Incremental Hourly Avoided Energy Cost is:
$14.80/MWH

Adjustment Factor for Line Losses:
1.0561

The Actual Incremental Hourly Avoided Energy Cost adjusted for avoided line losses associated with As-Available Energy provided to the Company would then become, in this example, $15.63/MWH.

"IDENTIFIABLE" INCREMENTAL VARIABLE O&M: Tampa Electric's methodology for determining incremental avoided energy costs associated with As-Available Energy includes a procedure for calculating "identifiable" incremental variable O&M (VOM) expense.

A VOM rate ($/MWH) is calculated annually for each Tampa Electric generating group. A generating group comprises units of the same type with similar size and operating characteristics (e.g., Big Bend coal units, Bayside CCs, Polk IGCC, all 180 MW CTs, etc.). The VOM rate for a generating group is calculated by dividing the previous year's identifiable VOM expenses for the group by the previous year's generation in megawatt-hours for the group.

ISSUED BY: ~~C. R. Black~~G. L. Gillette, President

DATE EFFECTIVE: ~~May 22, 2007~~

EXHIBIT ~~2~~1

Example: Off-system purchases are not being made. The Company's generation is capable of carrying its native load and firm sales.

Given:
Actual CEP Energy = 50 MWs
The Company's Maximum Available Generation = 1560 MWs
Native Load = 1550 MWs
Firm Sales = 10 MWs

First Calculation (WITHOUT CEP):
Production Cost at 1560 MWs = $20,275/hour

Second Calculation (WITH CEP):
Production Cost at 1510 MWs = $19,500/hour

Third Calculation (CEP Rate $/MWH):
Actual Hourly Avoided Energy Cost = ($20,275/hour - $19,500/hour) / (50 MW)

or

As-Available Energy Payment Rate (AEPR) = $15.50/MWH

TAMPA ELECTRIC

EXHIBIT ~~3~~2

Example: Off-system purchases are not being made. The Company's generation can carry its native load and firm sales only with the CEP contribution.

Given:

Actual CEP Energy = 50 MWs
The Company's Maximum Available Generation = 1460 MWs
Native Load = 1500 MWs
Firm Sale = 10 MWs

First Calculation:

Production Cost at 1460 MWs = $18,900/hour

Second Calculation:

Production Cost at 1459 MWs = $18,882.50/hour

Third Calculation (CEP Rate $/MWH):

Actual Hourly Avoided Energy Cost at 1 MW (system lambda[1]) =
($18,900/hour - $18,882.50/hour) / (1 MW)

or

As-Available Energy Payment Rate (AEPR) = $17.50/MWH

[1] In this example, system lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

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Date: June 7, 2012

Attachment A

TAMPA ELECTRIC

~~FIRST~~ SECOND REVISED SHEET NO. 8.402
CANCELS ~~ORIGINAL~~ FIRST REVISED SHEET NO. 8.402

EXHIBIT ~~4~~3

Example: **Off-system purchases are not being made to serve native load and firm sales. Available generation capacity is not fully dispatched. Without the CEP's contribution, the Company's native load and firm sales can be carried only with additional power purchases.**

Given:
Actual CEP Energy = 50 MWs
The Company's Maximum Available Generation = 1530 MWs
The Company's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sale = 10 MWs

Step 1 (Calculations for First 30 MWs)
First Calculation (Without CEP):
Production Cost at 1530 MWs = $20,590/hour
Second Calculation (With CEP):
Production Cost at 1500 MWs = $20,050/hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 30 MWs =
($20,590/hour) - ($20,050/hour) = $540/hour

Step 2 (Calculations for Remaining 20 MWs)
First Calculation:
Production Cost at 1530 MWs = $20,590/hour
Second Calculation:
Production Cost at 1529 MWs = $20,571.50/hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 1 MW (system lambda[1]) for 20 MWs =
($20,590/hour - $20,571.50/hour) X (20 MWs) = $370/hour

Step 3 (Calculation of Composite Rate for Total 50 MW Block)

Composite Actual Hourly Avoided Energy Cost of 50 MW Block = ($540 + $370) / 50 MW
or
As-Available Energy Payment Rate (AEPR) = $18.20/MWH

[1] In this example, system lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~June 14, 2011~~

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TAMPA ELECTRIC

EXHIBIT ~~6~~4

Example: **Off-system purchases are being made. The Company's native load and firm sales can be carried only with additional purchase power.**

Given:

Actual CEP Energy = 50 MWs
The Company's Maximum Available Generation = 1500 MWs
The Company's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sales = 20 MWs
Off-System Purchase[1] = 10 MWs Costing $400/hour

Actual Incremental Hourly Avoided Energy Cost = $400 / 10 MW

Or

As-Available Energy Payment Rate (AEPR) = $40/hour

[1] Off-System Purchase shall be the highest cost purchased energy block bought during the hour for native load.

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~~THIRD~~ FOURTH REVISED SHEET NO. 8.406
CANCELS ~~SECOND~~ THIRD REVISED SHEET NO. 8.406

TAMPA ELECTRIC

RATE SCHEDULE COG-2
APPENDIX C

~~2013~~ 2019 COMBUSTION TURBINE

This Designated Avoided Unit is a ~~61~~177 MW (winter rating) natural gas-fired combustion turbine with a May 1, ~~2013~~2019, in-service date.

MINIMUM PERFORMANCE STANDARDS

In order to receive a Monthly Capacity Payment, all Contracted Capacity and Associated Energy provided by CEPs shall meet or exceed the following MPS on a monthly basis. The MPS are based on the anticipated peak and off-peak dispatchability, unit availability, and operating factor of the Designated Avoided Unit over the term of this Standard Offer Contract. The CEP's proposed generating facility ("the Facility") as defined in the Standard Offer Contract will be evaluated against the anticipated performance of a combustion turbine, starting with the first Monthly Period following the date selected in Paragraph 6.b.ii of the Company's Standard Offer Contract.

1. **Dispatch Requirements:** The CEP shall provide peaking capacity to the Company on a firm commitment, first-call, on-call, as-needed basis. In order to receive a Contracted Capacity Payment for each calendar month that the Facility is to be dispatched, the CEP must meet or exceed both the minimum Monthly Availability and Monthly Capacity Factor requirements.

2. **Dispatch Procedure:** Commencing on the calendar day prior to the Facility In-Service Date or the Extended Facility In-Service Date, as applicable, and continuing each calendar day thereafter during the Term, by 7:00 A.M. EPT, the CEP shall electronically transmit a schedule ("Available Schedule") of the hour-by-hour amounts of Contracted Capacity expected to be available from the Facility the next day ("Committed Capacity"). Commencing on the calendar day prior to the Facility In-Service Date or the Extended Facility In-Service Date, as applicable, and continuing each calendar day thereafter during the Term, by 3:00 P.M. EPT, the Company shall electronically transmit the hour-by-hour amounts of Contracted Capacity that the Company desires the CEP to dispatch from the Facility the next day based on the Available Schedule supplied at 7:00 A.M. EPT by the CEP ("Dispatch Schedule"). The CEP's Available Schedule and the Company's Dispatch

Continued to Sheet No. 8.408

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~July 13, 2010~~

FIFTH REVISED SHEET NO. 8.422
CANCELS FOURTH REVISED SHEET NO. 8.422

TAMPA ELECTRIC

Continued from Sheet No. 8.418

PARAMETERS FOR AVOIDED CAPACITY COSTS

Beginning with the in-service date (5/12019) of the Company's Designated Avoided Unit, a 177 MW (Winter Rating) natural gas-fired Combustion Turbine, for a 1 year deferral:

			VALUE
VAC_m	=	Company's monthly value of avoided capacity, $/kW/month, for each month of year n	8.12
K	=	present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present value to the middle of the first year	1.4763
I_n	=	total direct and indirect cost, in mid-year $/kW including AFUDC but excluding CWIP, of the Designated Avoided Unit(s) with an in-service date of year n, including all identifiable and quantifiable costs relating to the construction of the Designated Avoided Unit that would have been paid had the Designated Avoided Unit(s) been constructed	878.11
O_n	=	total fixed operation and maintenance expense for the year n, in mid-year $/kW/year, of the Designated Avoided Unit(s);	9.67
i_p	=	annual escalation rate associated with the plant cost of the Designated Avoided Unit(s)	3.0%
i_o	=	annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s);	2.4%
r	=	discount rate, defined as the Company's incremental after tax cost of capital;	7.95%

Continued to Sheet No. 4.424

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:

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~~FOURTH~~ FIFTH REVISED SHEET NO. 8.424
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Continue from Sheet No. 8.122

L	=	expected life of the Designated Avoided Unit(s); and	25
n	=	year for which the Designated Avoided Unit is deferred starting with its original anticipated in-service date and ending with the termination of the contract for the purchase of firm capacity and energy.	~~2013~~2019
A_m	=	monthly early capacity payments to be made to the CEP for each month of the contract year n, in $/kW/month, if payments start in ~~2011~~2012;	~~6.95~~3.25
m	=	Earliest year in which early capacity payments to the CEP may begin;	~~2011~~2012*
F	=	the cumulative present value, in the year contractual payments will begin, of the avoided capital cost component of capacity payments over the term of the contract which would have been made had capacity payments commenced with the anticipated in-service date of the Designated Avoided Unit(s);	~~596.55~~411.58*
t	=	the term, in years, of the contract for the purchase of firm capacity if early capacity payments commence in year m;	~~12~~17*

** Actual values will be determined based on the capacity payment start date and contract term selected by the CEP.*

Continued to Sheet No. 8.426

ISSUED BY: G. L. Gillette, President **DATE EFFECTIVE:** ~~June 14, 2011~~

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FIFTH REVISED SHEET NO. 8.426
CANCELS FOURTH REVISED SHEET NO. 8.426

Continued from Sheet No. 8.424

2019 COMBUSTION TURBINE - AVOIDED UNIT
MONTHLY CAPACITY PAYMENT RATE ($/KW-MONTH)
NON-LEVELIZED PAYMENT OPTIONS

		OPTION 1	OPTION 2							
		NORMAL PAYMENT	EARLY PAYMENT							
CONTRACT YEAR		Starting 5/1/19	Starting 5/1/18	Starting 5/1/17	Starting 5/1/16	Starting 5/1/15	Starting 5/1/14	Starting 5/1/13	Starting 5/1/12
FROM	TO	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo
5/1/12	4/30/13								3.19
5/1/13	4/30/14							3.58	3.28
5/1/14	4/30/15						4.04	3.69	3.38
5/1/15	4/30/16					4.57	4.16	3.79	3.48
5/1/16	4/30/17				5.20	4.71	4.28	3.91	3.58
5/1/17	4/30/18			5.96	5.36	4.85	4.40	4.02	3.68
5/1/18	4/30/19		6.87	6.13	5.52	4.99	4.53	4.14	3.79
5/1/19	4/30/20	7.98	7.07	6.31	5.68	5.14	4.67	4.26	3.90
5/1/20	4/30/21	8.21	7.28	6.50	5.84	5.29	4.80	4.39	4.02
5/1/21	4/30/22	8.45	7.49	6.69	6.02	5.44	4.95	4.52	4.14
5/1/22	4/30/23	8.70	7.71	6.89	6.19	5.60	5.09	4.65	4.26
5/1/23	4/30/24	8.96	7.94	7.09	6.38	5.77	5.24	4.78	4.38
5/1/24	4/30/25	9.22	8.17	7.30	6.56	5.94	5.40	4.93	4.51
5/1/25	4/30/26	9.49	8.41	7.51	6.76	6.11	5.55	5.07	4.65
5/1/26	4/30/27	9.77	8.66	7.73	6.95	6.29	5.72	5.22	4.78
5/1/27	4/30/28	10.06	8.91	7.96	7.16	6.48	5.89	5.37	4.92
5/1/28	4/30/29	10.36	9.17	8.20	7.37	6.67	6.06	5.53	5.07

Continued to Sheet No. 8.427

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:

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Continued to Sheet No. ~~8.428~~8.427

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Attachment A

ORIGINAL SHEET NO. 8.427

TECO
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Continued from Sheet No. 8.426

2019 COMBUSTION TURBINE - AVOIDED UNIT
MONTHLY CAPACITY PAYMENT RATE ($/KW-MONTH)
LEVELIZED PAYMENT OPTIONS

		OPTION 3	OPTION 4						
		LEVELIZED NORMAL PAYMENT	LEVELIZED EARLY PAYMENT						
CONTRACT YEAR		Starting 5/1/19	Starting 5/1/18	Starting 5/1/17	Starting 5/1/16	Starting 5/1/15	Starting 5/1/14	Starting 5/1/13	Starting 5/1/12
FROM	TO	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo	$/kw-mo
5/1/12	4/30/13								3.80
5/1/13	4/30/14							4.23	3.81
5/1/14	4/30/15						4.72'	4.24	3.81
5/1/15	4/30/18					5.30	4.73	4.25	3.82
5/1/16	4/30/17				5.97	5.31	4.74	4.26	3.83
5/1/17	4/30/18			6.77	5.99	5.32	4.76	4.27	3.84
5/1/18	4/30/19		7.72	6.78	6.00	5.33	4.77	4.27	3.85
5/1/19	4/30/20	8.88	7.74	6.80	6.01	5.35	4.76	4.28	3.86
5/1/20	4/30/21	8.90	7.75	6.81	6.03	5.36	4.79	4.29	3.87
5/1/21	4/30/22	8.92	7.77	6.83	6.04	5.37	4.80	4.31	3.88
5/1/22	4/30/23	8.94	7.79	6.84	6.05	5.38	4.81	4.32	3.69
5/1/23	4/30/24	8.96	7.81	6.86	6.07	5.40	4.82	4.33	3.90
5/1/24	4/30/25	8.98	7.83	6.88	6.08	5.41	4.83	4.34	3.91
5/1/25	4/30/26	9.00	7.85	6.90	6.10	5.42	4.85	4.35	3.92
5/1/26	4/30/27	9.02	7.87	6.91	6.11	5.44	4.86	4.36	3.93
5/1/27	4/30/28	9.04	7.89	6.93	6.13	5.45	4.87	4.37	3.94
5/1/28	4/30/29	9.07	7.91	6.95	6.15	5.47	4.89	4.39	3.95

Continued to Sheet No. 8.428

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:

TECO
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Continued from Sheet No. ~~8.426~~8.427

BASIS FOR MONTHLY ENERGY PAYMENT CALCULATION:

1. **Energy Payment Rate:** Prior to the in-service date of the avoided unit, the CEP's Energy Payment Rate shall be the Company's As-Available Energy Payment Rate (AEPR), as described in Appendix B. Starting the in-service date of the avoided unit, the basis for determining the Energy Payment Rate will be whether:

   a. The Company has dispatched the CEP's unit on AGC; or

   b. The Company has dispatched the CEP's unit off AGC and the CEP is operating its unit at or below the dispatched level; or

   c. The Company has dispatched the CEP's unit off AGC but the CEP is operating its unit above the dispatched level; or

   d. The Company has not dispatched the CEP's unit but the CEP is providing capacity and energy.

   Note: For any given hour the CEP unit must be operating on AGC a minimum of 30 minutes to qualify under case (a).

   The CEP's total monthly energy payment shall equal; (1) the sum of the hourly energy at the Unit Energy Payment Rate (UEPR), when the CEP's unit was dispatched by the Company, plus (2) the sum of the hourly energy at the corresponding hourly AEPR when the CEP's unit was operating at times other than when the Company dispatched the unit.

2. **Unit Energy Payment Rate:** Starting the in-service date of the avoided unit, the CEP will be paid at the UEPR for energy provided in Paragraph 1.a, Paragraph 1.b and that portion of the energy provided up to the dispatched level in Paragraph 1.c as defined above. The UEPR, which is based on the Company's Designated Avoided Unit and Heat Rate value of 10,798 Btu/kWh, will be calculated monthly by the following formula:

$$UEPR = FC + O_v$$

   where;

   O_v = Unit Variable Operation & Maintenance Expense in $/MWH.

   ~~FC = Fuel Component of the Energy Payment in $/MWH as defined~~

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~~by:~~

$$\cancel{FC = \frac{10{,}798 \text{ Btu/kWh} \times FP}{1{,}000}}$$

~~where;~~

~~FP = Fuel Price in $/MMBTU determined by:~~

~~FP = GC/(1-FRP) + TC~~

Continued to Sheet No. 8.434

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~June 14, 2011~~

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Continued from Sheet No. 8.428

FC = Fuel Component of the Energy Payment in $/MWH as defined by:

$$FC = \frac{11{,}983 \text{ Btu/kWh} \times FP}{1{,}000}$$

where;

FP = Fuel Price in $/MMBTU determined by:

$$FP = GC/(1-FRP) + TC$$

where;

GC = Fuel Price in $/MMBTU determined by taking the first publication of each month of Inside FERC's Gas Market Report low price quotation under the column titled "Index" for "Florida Gas Transmission Co., "Zone 2", listings.

TC = then currently approved Florida Gas Transmission (FGT) Company tariff rate in $/MMBTU for forward haul Interruptible Market Area Transportation (ITS-1), including usage and surcharges.

FRP= then currently approved FGT Company tariff Fuel Reimbursement Charge Percentage in percent applicable to forward hauls for recovery of costs associated with the natural gas used to operate FGT's pipeline system.

3. **As-Available Energy Payment Rate (AEPR):** For energy provided and not covered under Paragraph 2 above, the AEPR will be applicable and will be based on the system avoided energy cost as defined in Appendix B.

ISSUED BY: ~~C. R. Black~~G. L. Gillette, President **DATE EFFECTIVE:** ~~June 30, 2009~~

TAMPA ELECTRIC

Continued to Sheet No. 8.436

ISSUED BY: ~~C. R. Black~~G. L. Gillette, President

DATE EFFECTIVE: ~~June 30, 2009~~

Continued from Sheet No. 8.428

PARAMETERS FOR AVOIDED UNIT ENERGY AND VARIABLE OPERATION AND MAINTENANCE COSTS

Beginning on May 1, 2019, to the extent that the Designated Avoided Unit(s) would have been operated had it been installed by the Company:

			VALUE
O_V	=	total variable operating and maintenance expense, in \$/MWH, of the Designated Avoided Unit(s), in year n	4.87
H	=	The average annual heat rate, in British Thermal Units (Btus) per kilowatt-hour (Btu/kWh), of the Designated Avoided Unit(s)	11,983