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May 1, 2012

HAND DELIVERED

Ms. Ann Cole, Director
Division of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

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

Dear Ms. Cole:

Pursuant to Staff's letter dated April 17, 2012, we enclose the original and five (5) copies of Tampa Electric Company's responses to Staff's First Data Requests Nos. 1-10 pertaining to Tampa Electric's 2011 standard offer contract.

Sincerely,

James D. Beasley

JDB/pp
Enclosure

cc: Pauline E. Robinson, Esq. (w/enc.)

COM ____
APA ____
ECR 1
GCL 1
RAD 3
SRC ____
ADM ____
OPC ____
CLK ____

1. TECO's 2011 standard offer contract (SOC) identified a 61 megawatt (MW) natural gas fired combustion turbine (CT), with an in-service date of May 2013, as its next avoidable unit. TECO's 2012 SOC, identifies a 177 MW CT with an in-service date of 2019 as its next avoidable unit. Will any new generation be built in 2013?

a. If yes, please provide the type of generation, in-service date, and amount of generation.

A. No. Tampa Electric took advantage of favorable market conditions and negotiated low cost purchased power agreements in lieu of constructing the 2013 avoided CT as well as the CTs that were planned in Year's 2014, 2015, and 2016. These purchases, along with an existing firm purchase, will extend through 2016. The in-service date of Tampa Electric's Polk Conversion Project has been pushed up from January 2019 to January 2017 coinciding with the expiration of the purchased power agreements.

2. Please explain how TECO determined the 2019 date for its next avoidable unit.

A. The 2013 avoided combustion turbine (CT) as well as the CTs present in the 2011 Ten Year Site Plan for the Years 2014, 2015 and 2016 have been replaced with low cost purchased power agreements (PPAs) through 2016 as explained in the response to Data Request No. 1.

The Polk Conversion Project (PCP) in-service date formerly scheduled for January 2019 has been accelerated to January 2017 which coincides with the expiration of the PPAs mentioned above. The incremental capacity of the PCP has been increased and is sufficient to meet the capacity requirements for both 2017, 2018, and the expiring purchase power agreements. The 2017 PCP is the subject of an issued RFP and therefore not considered an avoided unit.

The last remaining and only avoidable generating unit in Tampa Electric's 10-year planning horizon is a 177 MW GE 7F CT with an in-service date of May 1, 2019.

3. Please explain the increase in the amount of generation needed between the 2011 and 2012 SOCs.

A. The 2011 SOC was based on the operating parameters of a 61 MW (winter rating) aero-derivative CT with an in-service date of May 2013; however, the expansion plan in the company's 2011 Ten Year Site Plan indicated that three of these 61 MW units with the same May 2013 in-service date would need to be built for a total capacity of 183 MW (winter rating). All three of the 2013 CT units were considered avoidable in the 2011 SOC.

The 2012 SOC is based on the operating parameters of a 177 MW (winter rating) GE 7F CT with an in-service date of May 2019. The expansion plan in Tampa Electric's 2012 Ten Year Site Plan indicates that only one unit is needed to satisfy the generation capacity requirement.

If looking at the <u>total</u> amount of avoidable generation represented in the 2011 and 2012 SOCs, the amount of avoidable generation actually decreased in the 2012 SOC (from 183 MWs to 177 MWs). However, there is no connection between the two SOC's since they are based on avoided units planned in different years based on two very different expansion plans. The amount and type of avoidable generation and whether the need is achieved by one large or several smaller units depends on many variables including, but not limited to, executed PPA's, forecasted peak demands, forecasted energy consumption, construction costs, fuel costs, black-start requirements, and issued requests for proposals. As they change from year to year, these variables influence the expansion plan and the determination of the next avoidable unit.

4. Please refer to the legislative format of tariff sheet No. 8.422. Please explain why TECO's monthly avoided capacity, $/kW/month has decreased although the total cost of the avoided unit has increased from $757.10/kW to $878.11/kW.

A. Although construction cost for the 2019 avoided unit has increased, the monthly avoided capacity $/kW/month for the 2012 avoided unit has decreased due to the impact of other financial and cost parameters in the VACm equation that determines the monthly value of avoided capacity in year n, the in-service year. The combined impact lowers the $/kW/month by approximately $2.30. The impacts in isolation are provided below.

$$VACm = 1/12\ [K^* I_n * (1-R)/(1-R^L) + O_n]$$

K - The 2012 k-factor has decreased from 1.5964 to 1.4763 which results in lower carrying charges over the life of the project. The impact lowers the $/kW/month by $0.59.

R - The 2012 value for R has increased from 0.9433 to 0.9541. The impact lowers $/KW/month cost by $081.

$$R = (1+ i_p)/(1+ r)$$

where;

i_p = the annual escalation rate associated with plant cost which increased from 1.9% to 3.0% for 2012. (impact = $0.76)

r = the annual discount rate which has decreased from 8.02% to 7.95% in 2012. (impact = $0.05)

O_n - The annual Fixed O&M expense in $/kW/year for the avoided unit in year n. This value has decreased from $21.53/kW/year to $11.42/kW/year reflecting fixed O&M rate differences between the aero-derivative and 7F CTs. The impact lowers the monthly capacity cost by $0.85.

5. Please explain the increase in the total direct and indirect cost from $757.10/kW to $878.11/kW.

A. The $757.10/kW is the cost of an aero-derivative CT in 2013 dollars whereas the $878.11/kW is the cost of a 7F CT in 2019 dollars. When these costs are compared on an apples-to-apples basis (i.e., both costs in 2012 dollars) the difference between the $/kW costs of the two CTs is only $9/kW higher for the 7F CT (i.e., $689/kW compared to $680/kW). The real drivers for the cost increase between the 2013 avoided unit and the 2019 avoided unit are the escalation assumptions used to escalate the construction cost into the in-service year and the time difference between the in-service years. The escalation rate assumed for the 2019 avoided CT is 3% while the escalation rate assumed for the 2013 avoided CT was only 1.9%. Likewise, the construction costs for the 2019 avoided unit had to be escalated more years out in time than did the construction costs of the 2013 avoided CT.

6. Please explain the change in the total fixed operation and maintenance expense from $21.53/kW to $11.42/kW.

A. The $21.53/kW (in 2013 $) is the fixed operation and maintenance (FOM) expense of a 61 MW avoided CT with an in-service year of 2013 on which the 2011 SOC was based. The $11.42/kW (in 2019 $) is the FOM for a 177 MW avoided CT with an in-service year of 2019 on which the 2012 SOC is based. The dollars of fixed operation and maintenance expense are actually higher for the 2019 avoided CT primarily due to the escalation applied to bring the FOM dollars into 2019, the in-service year. However, this higher dollar amount, when divided by the much higher capacity of the 2019 avoided CT (i.e., 177,000 kWs compared to 61,000 kWs), yields a lower $/kW FOM value than that of the 2013 avoided CT on which the 2011 SOC was based.

7. Please explain why the annual escalation rate associated with the plant cost of the designated avoided unit increased from 1.9 percent to 3.0 percent.

A. The previous avoided unit had an in-service date of 2013; short term escalation rates are quite low. The current avoided unit has an in service of 2019; longer term escalation rates are around 3%.

8. Please refer to original tariff sheet No. 8.426, specifically the table titled "2013 combustion turbine monthly capacity payment rate." Please verify that the figures provided are case specific for the 2019 SOC. If the incorrect figures were used, please provide an updated chart using 2019 SOC figures.

A. Fourth Revised Tariff Sheet No. 8.426 in legislative format provided in Exhibit " C" of Tampa Electric's Petition does show a table titled "2013 Combustion Turbine Monthly Capacity Payment Rate"; however, albeit not very obvious, there is a horizontal line midway across this table that is Word's only indication under "track changes" that the entire table is being deleted. The updated replacement table titled "2019 Combustion Turbine Monthly Capacity Payment Rate" appears on the following overflow page of revisions for this same tariff sheet. Provided in Exhibit "B" is the standard format for this tariff sheet which reflects only the updated information for the 2019 avoided unit.

9. Please refer to revised tariff sheet No. 8.434. Please explain why a heat rate value of 11,983 Btu/kWh has been assigned to the proposed combustion turbine units. Has the company explored alternative CT units that would provide lower heat rates? Please explain and provide detail.

A. Yes. Based on the size of the need, and since the resulting capacity factor is so low, the less capital intensive technology was selected.

10. Please complete the tables below describing payments to a renewable provider based on the proposed tariffs included in the company's revised standard offer contract. Please assume the renewable generator is a 50 MW facility providing firm capacity at the minimum capacity factor required for full capacity payments. Additionally, please assume an in-service date of January 1, 2013 and a contract duration of 20 years. Please provide this information for the following scenarios:

- Normal Payments
- Levelized Payments
- Early Payments
- Early Levelized Payments

	Committed Capacity (MW)		50			
	Capacity Factor (%)					
	Payment Type:					
Year	Energy	Capacity Rates	Total Capacity Payments	Energy Rates	Total Energy Payments	Total Payments
	(MWh)	($/kW-mo)	($000)	($/MWh)	($000)	($000)
2012						
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						

A. The tables below contain estimated payments to a renewable generator ("RG") under the four payment options, normal, levelized, early, and early levelized, based on corrected avoided unit parameters included in Tampa Electric's revised standard offer contract that were filed on April 29, 2011. The estimated payments assume a 20-year contract term for a 50 megawatt renewable generating facility with an in-service date of January 1, 2013.

In order to be paid full capacity payments under Tampa Electric's SOC, the RG is required to meet a 90% "capacity factor". However, under Tampa Electric's SOC, "capacity factor" is defined as: the sum of 80% of the monthly average on-peak operating factor and 20% of the monthly off-peak operating factor in the summer months and 90% of the monthly average on-peak operating factor and 10% of the monthly off-peak operating factor in the winter months. By this definition, it is the capacity received from the RG during those hours that the RG is dispatched (i.e., the hours that the avoided unit would have been dispatched) by Tampa Electric that will determine if the RG is eligible for full capacity payments. It is difficult to select a minimum capacity factor for full payment based on the normal definition of capacity factor because the minimum capacity factor would vary from year-to-year consistent with the projected capacity factor of the avoided unit.

For purposes of this response, a 90% capacity factor has been assumed for the RG although this capacity factor neither represents a minimum capacity factor for receiving a full capacity payment nor necessarily guarantees a full capacity payment.

Committed Capacity (MW)	50
Capacity Factor % [1]	90%
Payment Type:	Normal

	Energy (MWh)	Capacity Rates [2] ($/kW-mo)	Total Capacity Payments ($000)	Energy Rates [3] ($/MWh)	Total Energy Payments ($000)	Total Payments to Renewable Provider ($000)
2013	394,200			45.86	18,078	18,078
2014	394,200	-	-	49.36	19,457	19,457
2015	394,200	-	-	53.28	21,004	21,004
2016	395,280	-	-	54.60	21,584	21,584
2017	394,200	-	-	49.10	19,356	19,356
2018	394,200	-	-	52.59	20,730	20,730
2019	394,200	8.12	4,874	53.54	21,104	25,978
2020	395,280	8.36	5,017	56.70	22,411	27,428
2021	394,200	8.61	5,164	61.30	24,166	29,330
2022	394,200	8.86	5,315	60.39	23,807	29,122
2023	394,200	9.12	5,471	64.15	25,287	30,758
2024	395,280	9.39	5,631	63.49	25,095	30,727
2025	394,200	9.66	5,796	68.06	26,831	32,627
2026	394,200	9.94	5,966	67.19	26,485	32,452
2027	394,200	10.24	6,141	70.93	27,960	34,101
2028	395,280	10.54	6,321	74.05	29,269	35,590
2029	394,200	10.84	6,507	75.00	29,565	36,072
2030	394,200	11.16	6,698	73.59	29,008	35,705
2031	394,200	11.49	6,894	76.20	30,037	36,931
2032	395,280	11.83	7,096	80.68	31,893	38,989

(1) The capacity factor used in this example is 90%. The minimum capacity factor required to obtain a full capacity payment would be approximately 90% of the average capacity factor of the avoided unit and other existing and future CTs of the same type in each year of the contract.

(2) The capacity payment under the Normal payment option begins May 1st of 2019 which is the in-service date of the avoided unit.

(3) The energy rate beginning in 2019 is a weighted blend based on the projected capacity factor or the avoided unit, the estimated avoided unit energy rate, and the estimated as-available energy rate.

Committed Capacity (MW)	50
Capacity Factor % [1]	90%
Payment Type:	Levelized

	Energy (MWh)	Capacity Rates [2] ($/kW-mo)	Total Capacity Payments ($000)	Energy Rates [3] ($/MWh)	Total Energy Payments ($000)	Total Payments to Renewable Provider ($000)
2013	394,200			45.86	18,078	18,078
2014	394,200	-	-	49.36	19,457	19,457
2015	394,200	-	-	53.28	21,004	21,004
2016	395,280	-	-	54.60	21,584	21,584
2017	394,200	-	-	49.10	19,356	19,356
2018	394,200	-	-	52.59	20,730	20,730
2019	394,200	9.44	5,664	53.54	21,104	26,768
2020	395,280	9.46	5,677	56.70	22,411	28,088
2021	394,200	9.49	5,691	61.30	24,166	29,858
2022	394,200	9.51	5,706	60.39	23,807	29,513
2023	394,200	9.53	5,721	64.15	25,287	31,008
2024	395,280	9.56	5,736	63.49	25,095	30,831
2025	394,200	9.59	5,751	68.06	26,831	32,582
2026	394,200	9.61	5,767	67.19	26,485	32,252
2027	394,200	9.64	5,783	70.93	27,960	33,743
2028	395,280	9.67	5,800	74.05	29,269	35,068
2029	394,200	9.69	5,817	75.00	29,565	35,382
2030	394,200	9.72	5,834	73.59	29,008	34,842
2031	394,200	9.75	5,852	76.20	30,037	35,889
2032	395,280	9.78	5,870	80.68	31,893	37,762

(1) The capacity factor used in this example is 90%. The minimum capacity factor required to obtain a full capacity payment would be approximately 90% of the average capacity factor of the avoided unit and other existing and future CTs of the same type in each year of the contract.

(2) The capacity payment under the Levelized payment option begins May 1st of 2019 which is the in-service date of the avoided unit.

(3) The energy rate beginning in 2019 is a weighted blend based on the projected capacity factor or the avoided unit, the estimated avoided unit energy rate, and the estimated as-available energy rate.

Committed Capacity (MW)	50
Capacity Factor % [1]	90%
Payment Type:	Early

	Energy (MWh)	Capacity Rates ($/kW-mo)	Total Capacity Payments ($000)	Energy Rates[2] ($/MWh)	Total Energy Payments ($000)	Total Payments to Renewable Provider ($000)
2013	394,200	3.94	2,362	45.86	18,078	20,441
2014	394,200	4.05	2,432	49.36	19,457	21,888
2015	394,200	4.17	2,503	53.28	21,004	23,507
2016	395,280	4.29	2,576	54.60	21,584	24,160
2017	394,200	4.42	2,652	49.10	19,356	22,007
2018	394,200	4.55	2,729	52.59	20,730	23,459
2019	394,200	4.68	2,809	53.54	21,104	23,913
2020	395,280	4.82	2,892	56.70	22,411	25,303
2021	394,200	4.96	2,976	61.30	24,166	27,143
2022	394,200	5.11	3,064	60.39	23,807	26,871
2023	394,200	5.26	3,154	64.15	25,287	28,441
2024	395,280	5.41	3,246	63.49	25,095	28,341
2025	394,200	5.57	3,341	68.06	26,831	30,172
2026	394,200	5.73	3,439	67.19	26,485	29,924
2027	394,200	5.90	3,540	70.93	27,960	31,500
2028	395,280	6.07	3,644	74.05	29,269	32,913
2029	394,200	6.25	3,751	75.00	29,565	33,316
2030	394,200	6.43	3,861	73.59	29,008	32,869
2031	394,200	6.62	3,974	76.20	30,037	34,011
2032	395,280	6.82	4,091	80.68	31,893	35,983

(1) The capacity factor used in this example is 90%. The minimum capacity factor required to obtain a full capacity payment would be approximately 90% of the average capacity factor of the avoided unit and other existing and future CTs of the same type in each year of the contract.

(2) The energy rate beginning in 2019 is a weighted blend based on the projected capacity factor or the avoided unit, the estimated avoided unit energy rate, and the estimated as-available energy rate.

Committed Capacity (MW)	50
Capacity Factor % [1]	90%
Payment Type:	Early Levelized

	Energy (MWh)	Capacity Rates ($/kW-mo)	Total Capacity Payments ($000)	Energy Rates[2] ($/MWh)	Total Energy Payments ($000)	Total Payments to Renewable Provider ($000)
2013	394,200	4.80	2,879	45.86	18,078	20,958
2014	394,200	4.81	2,886	49.36	19,457	22,343
2015	394,200	4.82	2,893	53.28	21,004	23,897
2016	395,280	4.83	2,900	54.60	21,584	24,484
2017	394,200	4.85	2,907	49.10	19,356	22,263
2018	394,200	4.86	2,915	52.59	20,730	23,645
2019	394,200	4.87	2,922	53.54	21,104	24,026
2020	395,280	4.88	2,930	56.70	22,411	25,341
2021	394,200	4.90	2,938	61.30	24,166	27,104
2022	394,200	4.91	2,946	60.39	23,807	26,753
2023	394,200	4.92	2,954	64.15	25,287	28,241
2024	395,280	4.94	2,963	63.49	25,095	28,058
2025	394,200	4.95	2,971	68.06	26,831	29,802
2026	394,200	4.97	2,980	67.19	26,485	29,466
2027	394,200	4.98	2,989	70.93	27,960	30,949
2028	395,280	5.00	2,999	74.05	29,269	32,268
2029	394,200	5.01	3,008	75.00	29,565	32,574
2030	394,200	5.03	3,018	73.59	29,008	32,026
2031	394,200	5.05	3,028	76.20	30,037	33,065
2032	395,280	5.06	3,039	80.68	31,893	34,931

(1) The capacity factor used in this example is 90%. The minimum capacity factor required to obtain a full capacity payment would be approximately 90% of the average capacity factor of the avoided unit and other existing and future CTs of the same type in each year of the contract.

(2) The energy rate beginning in 2019 is a weighted blend based on the projected capacity factor or the avoided unit, the estimated avoided unit energy rate, and the estimated as-available energy rate.