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August 7, 2014

HAND DELIVERED

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

Re: Tampa Electric Company's Petition to Modify Transmission Structure Inspection Cycle
FPSC Docket No.140122-EI

Dear Ms. Stauffer:

Enclosed for filing in the above docket are the original and five (5) copies of Tampa Electric Company's Responses to Staff's First Data Request (Nos. 1-6).

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/ne
Enclosure

1. In Paragraph 6, on Pages 2-3, TECO discusses its efforts to comply with the North American Reliability Corporation (NERC) inspection protocol.

a. Please describe the NERC inspection protocol.

b. When TECO conducted its assessment based on actual versus designed field conditions, what damage did TECO find and what repairs did TECO make?

c. Please provide an explanation and breakdown of the $9 million in projected costs to comply with the NERC protocol.

A. a. In October 2010, NERC issued a Recommendation to Industry requiring affected entities such as Tampa Electric to report on the status of those activities related to verifying current facility ratings were based on actual field conditions. The recommendation from NERC outlined the steps needed to report on the findings and any required remediation; however, it did not specify how this verification was to be done.

NERC provided a deadline for affected entities to submit a plan on how they would conduct the assessment and any necessary remediation of the issues identified. Tampa Electric submitted a plan to use airborne Light Detection and Ranging ("LiDAR") to collect actual field condition data for the affected transmission circuits. The data would be put into a transmission line design model for each circuit and analyzed to determine if any remediation would be required for possible clearance issues that may exist under maximum design load.

In January 2011, NERC issued a Compliance Application Notice detailing the completion schedule for an assessment on all facilities based on priority starting with December 2011 for high priority facilities and finishing with low priority facilities by December 2013. Any discrepancy between the design and actual field conditions required remediation to be completed within one year from the discrepancy being identified and confirmed. Tampa Electric began the assessment on the affected 72 circuits in late 2011, and completed it on schedule in December 2013. As required by NERC, Tampa Electric reported the status of the assessment, discrepancies and remediation required throughout the project duration.

b. Tampa Electric's focus for the assessment was to verify that proper clearances were maintained along the length of the circuit while operating under maximum design load. The company identified and remediated all possible clearance concerns with a number of strategies. These remediation strategies included lowering distribution facilities, replacing line insulators and replacing existing structures with taller concrete or steel structures. When a structure was replaced, all of the attachment hardware including the insulators was replaced simultaneously resulting in a complete new structure.

c. Starting with the first inspections done in 2011 and continuing through 2013, Tampa Electric confirmed points of interest that required remediation. Many of these remediation points were addressed by lowering the distribution lines, relocating the distribution lines or undergrounding distribution lines. In one case involving an elevated interstate light, the Department of Transportation was paid to shorten the pole height by 10 feet. In addition to these examples, 127 new transmission structures and insulator sets were installed through 2013, with an additional 42 projected for 2014.

In 2012 and 2013, remediation costs were $3.1 million and $2.5 million, respectively. For 2014, the remediation activity is projected to be $3.6 million.

2. In Paragraph 7 on Page 3, TECO asserts that since 2006 its transmission system performance had a consistent low impact on overall system reliability.

a. Has TECO's service area been affected by any hurricanes or other significant weather events since the 2004-2005 hurricane season?

b. If not, does TECO believe the improvements to its transmission system have been sufficiently tested to date? Please explain your response.

A. a. Tampa Electric has not experienced any hurricanes since the 2004-2005 hurricane seasons. However, from 2006-2013 the company experienced five tropical storms and one tornado. The company's system performed admirably during those events.

b. While Tampa Electric's system has not experienced a hurricane since the 2004–2005 hurricane seasons, the upgrades the company has performed will improve the overall performance of the transmission system during major storms. Tampa Electric has performed and installed many system wide upgrades. Since 2006, the company has installed over 5,200 non-wood structures raising the non-wood structure percentage to 63 percent of the entire transmission pole population. Tampa Electric has also replaced over 1,400 insulator sets resulting in further storm hardening. From a vegetation management perspective, the company has widened its 230 kv transmission Rights of Way to comply with NERC/FERC Standard FAC 003-3 which became effective on July 1, 2014. This has resulted in additional 230 kV vegetation clearances.

3. In Paragraph 7 on Page 3, TECO indicates service interruptions were minimal from 2006 through 2013 and Exhibit B shows a total of 65 transmission service interruptions during the period. Please describe the cause of each transmission service interruption, the effected repair, and the duration of the service interruption from 2006 to 2013?

A. The following data identifies the date, outage duration, outage description and repair associated with each of the 65 transmission service interruptions from 2006-2013.

Please see attached table.

Date	Outage Duration (Minutes)	Discussion
2/27/2006	0.05	A pole top switch (918) bound up while attempting to close, tripping the circuit. Crew performed maintenance on switch.
3/2/2006	0.17	Patrolman found broken brace on crossarm and static wire down in two places. Crew replaced failed crossarm assembly with horizontal line post insulators and replaced static wire.
5/4/2006	0.07	Patrolman found a crossarm failed due to contamination/tracking. Crew replaced failed crossarm assembly with horizontal line post insulators.
6/10/2006	0.61	Patrolman found broken crossarm braces. Crew replaced failed crossarm assembly with horizontal line post insulators
6/26/2006	0.66	Patrolman found broken crossarm. Crew replaced failed crossarm assembly with horizontal line post insulators
7/26/2006	0.70	Patrolman found broken crossarm. Crew replaced failed crossarm assembly with horizontal line post insulators
8/2/2006	0.99	Patrolman found broken crossarm. Crew replaced failed crossarm assembly with horizontal line post insulators
8/9/2006	0.03	Patrolman found 4 spans of static and 1 span of conductor down. Crews replaced static and conductor.
10/4/2006	0.04	Insulator shank rusted in two. Crew replaced failed cross-arm assembly with horizontal line post insulators.
10/25/2006	1.70	Patrolman found static wire down. Crew replaced static wire.
11/23/2006	1.35	Eyebolt burned through crossarm. Crew replaced failed crossarm assembly with horizontal line post insulators.
11/26/2006	1.30	Patrolman found static wire down. Crew replaced static wire.
12/5/2006	0.21	Insulator shank rusted in two. Crew replaced failed insulators with horizontal line post insulators.
1/20/2007	0.41	Patrolman found a crossarm failed due to contamination/tracking. Crew replaced failed crossarm assembly with horizontal line post insulators.
1/29/2007	0.04	Patrolman found a string of bell-type insulators failed due to corrosion. Crew replaced failed insulators and crossarms with horizontal line post insulators.
2/15/2007	0.31	The jumper conductor on a deadend structure failed at the connector. This caused a single phase condition that resulted in the relaying taking the line out of service. Crew repaired jumper.
7/23/2007	0.02	Patrolman found static wire down. Failure believed to be due to vibration. Crew cleared the static wire.
9/13/2007	0.04	Patrolman found a string of bell-type insulators failed due to corrosion. Crew replaced failed insulators and crossarms with horizontal line post insulators.
9/24/2007	0.14	Patrolman found a string of bell-type insulators failed due to corrosion. Crew replaced failed insulators and crossarms with horizontal line post insulators.
10/31/2007	0.08	Patrolman found static wire down. Crew cleared the static wire.
10/31/2007	0.07	Patrolman found a string of bell-type insulators failed due to corrosion. Crew replaced failed insulators and crossarms with horizontal line post insulators.
11/1/2007	0.03	Patrolman found a string of bell-type insulators failed due to corrosion. Crew replaced failed insulators and crossarms with horizontal line post insulators.
12/11/2007	0.04	Patrolman found static wire down. Crew cleared the static wire.

Date	Outage Duration (Minutes)	Discussion
3/5/2008	0.09	Crossarm failed due to tracking. Crew replaced failed crossarm and insulators with horizontal line post insulators.
5/9/2008	0.78	Patrolman found static wire down. Crew cleared the static wire.
6/9/2008	1.00	Patrolman found static wire down. Crew cleared the static wire
6/13/2008	0.04	Patrolman found broken crossarm. Crew replaced failed crossarm and insulators with horizontal line post insulators.
6/18/2008	0.04	Patrolman found broken crossarm. Crew replaced failed crossarm and insulators with horizontal line post insulators.
7/6/2008	2.26	Patrolman found static wire down. Crew cleared the static wire.
7/9/2008	1.63	Patrolman found static wire down. Bad weather was reported in the area. Crew cleared the static wire.
8/12/2008	0.60	Lightning arrester at Clearview Substation failed causing outage. Crew replaced lightning arrester.
8/19/2008	0.09	Patrolman found broken crossarm. Crew replaced failed crossarm and insulators with horizontal line post insulators.
8/19/2008	0.08	Patrolman found broken crossarm. Crew replaced failed crossarm and insulators with horizontal line post insulators.
8/25/2008	0.08	A problem with the pole top switch that would not close completely caused the outage. Crew performed maintenance on switch.
11/30/2008	0.05	Insulator flashed over causing outage. Flash was possibly due to a vine being displaced by high winds. Crew trimmed vine.
12/16/2008	0.09	Patrolman found broken insulator. Crew replaced failed insulators with horizontal line post insulators.
4/2/2009	3.72	A span of static wire failed and fell into the circuit. The static was cleared from the circuit by a crew.
4/7/2009	0.48	A set of porcelain insulator bells failed. A crew replaced the insulators on the pole.
4/11/2009	0.70	Suspension insulator failed on a tangent structure. A crew replaced the insulators on the pole.
4/14/2009	1.65	A span of static wire failed and fell into the circuit. A crew cleared out the circuit.
6/18/2009	1.48	A span of static wire failed and fell into the circuit. Crews cleared the static wire from the circuit.
7/12/2009	0.08	A span of static wire failed and fell into the circuit. Crews cleared the static wire from the circuit.
8/10/2009	2.45	A span of conductor fell after a splice in the line came apart. Crews spliced the conductor and replaced the insulators on an adjacent structure.
8/11/2009	0.96	A jumper splice on deadend pole opened up. Crews replaced all three jumpers on that pole.
11/8/2009	0.80	A suspension insulator failed in the company's right-of-way. Crews replaced the insulators with polymer HLPs.
1/4/2010	0.05	A horizontal line post insulator failed and dropped the phase conductor. The pole was reframed and returned to service.
5/28/2010	0.42	A suspension insulator failed. A crew replaced the insulator and returned the circuit to service.
7/9/2010	0.52	A span of static wire failed and fell into the circuit. Crews cleared the static wire from the circuit.
8/18/2010	0.98	A crossarm on a tangent pole failed, causing one of the phases to contact the pole. Crews reframed the pole and returned the circuit to service.

Date	Outage Duration (Minutes)	Discussion
10/23/2010	0.99	A crossarm failed and dropped a Transmission conductor into the Distribution circuit below. Crews made the necessary repairs and the circuit was returned to service.
10/27/2010	1.43	A suspension insulator failed and dropped a conductor on to the Distribution circuit below. Crews made the necessary repairs and returned the circuit to service.
12/12/2010	0.03	A tree fell into the circuit. Crews removed the tree and the circuit was returned to service.
1/6/2011	1.31	A static wire failed causing one span to fall into then energized conductor. The damage section of static wire was replaced and the circuit was returned to service.
1/13/2011	0.05	A line post insulator broke and caused an interruption in service. The damaged insulator was replaced and the circuit was returned to service.
1/18/2011	0.52	A broken wood pole interrupted service. The damaged pole was replaced and the circuit was returned to service.
2/4/2011	0.02	A faulty line arrestor was the cause of the interruption of service. A crew replaced the arrestor and returned the circuit to service.
3/14/2011	0.05	One suspension insulator failed causing an interruption in service. The insulator was replaced and the circuit was returned to service.
11/28/2011	0.05	Service was interrupted when an insulator failed. The damaged insulator was replaced and the circuit was returned to service.
12/7/2011	0.07	This interruption of service was caused by the failure of a lightning arrestor inside of a substation. The lightning arrestor was replaced and the circuit was returned to service.
8/10/2012	2.92	A span of static wire broke and fell into the energized lines which caused an interruption in service. The static wire was repaired and the circuit was returned to service.
10/20/2012	0.04	Service was interrupted due to a planned outage to perform switch maintenance on an inoperable switch. The switch was repaired and the circuit was returned to service.
11/19/2012	0.41	Service was interrupted when a wood pole broke. The pole was replaced and the circuit was returned to service.
2/7/2013	0.05	Service was interrupted when insulators broke. The damaged insulators were replaced and the circuit was returned to service.
4/18/2013	0.07	A cross arm broke and the conductor fell causing an interruption in service. The structure was repaired and the circuit was returned to service.
6/6/2013	0.00	The circuit tripped when insulators flashed. The insulators were replaced and the circuit was returned to service.

4. In Paragraph 8 on Page 3, TECO states that its strong reliability performance during the previous six-year cycle is due to the multi-pronged inspection the company applied to the system.

a. Is TECO's multi-pronged inspection an ongoing process?

b. Does the multi-pronged inspection approach include all of the Ten Initiatives reflected in Order No. PSC-06-0781-PAS-EI?

c. Does the multi-pronged inspection approach include any initiatives not reflected in Order No. PSC-06-0781-PAS-EI? If so, please describe the additional initiatives.

d. Exhibit B indicates a significant drop in outages caused by equipment failures from 2006 through 2013. If TECO modifies its inspection cycle to eight years, does TECO expect to maintain its SAIDI performance? Please explain your response.

e. In addition to a decreased SAIDI, what was the overall effect on MAIFI for 2006 through 2013?

f. Under the current inspection cycle, how many transmission inspections are performed annually? If an eight-year cycle is granted, how many transmission inspections would be performed annually?

A. a. Yes.

b. The multi-pronged approach describes Tampa Electric's successful implementation of not only the company's Ten Point Storm Implementation Plan, but also its approach to transmission structure inspections – one of the vital components of the Ten Point Implementation Plan.

c. Yes. In 2011, the LiDAR initiative discussed in Tampa Electric's response to Staff's First Data Request, No.1, was added to the transmission inspection protocols. The other inspection activities include groundline inspections, ground patrol, aerial infrared patrol, above ground inspections, substation inspections and pre-climb inspections.

d. Yes. Tampa Electric expects the transmission portion of SAIDI to remain consistently low. Due to the company's substantial transmission pole replacement and maintenance program, customers will continue to experience a decrease in outages related to transmission equipment issues.

e. The MAIFI reliability index is independent of transmission outages.

f. Under the current six-year above ground transmission inspection protocol, Tampa Electric has inspected an average of 4,287 transmission structures per year. With the proposed eight-year inspection cycle, the company projects an average of 3,216 transmission structure inspections per year. All other transmission inspection protocols, which include annual ground patrol, aerial infrared patrol and substation inspections, system wide groundline inspections on an eight-year cycle (Order No. PSC-06-0144-PAA-EI), as well as pre-climb inspections will continue to be performed on their respective current cycles.

5. In Paragraph 11 on Page 4, TECO states the adoption of an eight-year transmission structure inspection cycle will save $108,000 annually and these savings will be used to optimize the State Estimator model in TECO's Energy Management system.

a. Please describe the State Estimator model and how the "optimized" model will be used?

b. How did TECO calculate the $108,000 annual savings? Please provide any work papers that support the calculation.

c. If the modification of the six-year cycle is granted, please identify the benefits to TECO's customers.

A. a. The State Estimator model provides the Energy Management System and Energy System Operators ("ESO") with load flow and generation status data based upon the real time configuration of the bulk electric system. The real time data is received from numerous points across the state wide grid. The data received is set as the initial conditions for a snapshot model of the system and is then used to analyze the impact of various simulated outages on the state transmission system in a Real Time Contingency Analysis ("RTCA"). This RTCA runs every four minutes and assists the ESO to maintain situational awareness along with developing and reviewing mitigation plans for potential outages before they occur. The RTCA in the State Estimator is crucial to ensuring the continued safe and reliable operation of the bulk electric system. Tampa Electric will refine and improve the accuracy of State Estimator model using the cost savings from the requested cycle change to the above ground inspection protocol.

b. The average annual cost savings will be approximately $108,000 over the next ten years, beginning in year 2015. The cost savings breakdown on an annual basis as well as the average annual cost savings over the next ten years is provided on the attached table.

c. Reallocating the $108,000 average annual savings into refining and enhancing the accuracy of the State Estimator model will result in additional reliability benefits to Tampa Electric's transmission system by providing the ability to identify potential outages before they occur. As previously stated, the strong reliability performance of Tampa Electric's transmission system is due to the multi-pronged inspection approach the company has applied to the system. Through the enhancement of the State Estimator model and the alignment of the above ground transmission inspection protocol with the eight-year ground line inspection protocol, improvements to system reliability at no additional cost will further provide reliable power to customers. In essence, Tampa Electric's customers will benefit from improved reliability with zero additional cost.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Current Inspection Plan (6 Year Cycle)										
Poles to Be Inspected	4,600	4,600	4,600	4,287	4,287	4,287	4,287	4,287	4,287	4,287
Annual Cost Per Pole	$71.10	$77.22	$81.10	$87.65	$93.22	$96.16	$100.88	$105.88	$111.10	$117.22
Total Above Ground Cost	$327,060	$355,212	$373,060	$375,756	$399,634	$412,238	$432,473	$453,908	$476,286	$502,522
Proposed Inspection Plan (8 Year Cycle)										
Poles to be Inspected	3,216	3,216	3,216	3,216	3,216	3,216	3,216	3,216	3,216	3,216
Annual Cost Per Pole	$71.10	$77.22	$81.10	$87.65	$93.22	$96.16	$100.88	$105.88	$111.10	$117.22
Total Above Ground Cost	$228,658	$248,340	$260,818	$281,882	$299,796	$309,251	$324,430	$340,510	$357,298	$376,980
Annual Cost Savings	$98,402	$106,872	$112,242	$93,873	$99,839	$102,987	$108,042	$113,397	$118,988	$125,543

Ten-Year (2015-2024) Average Cost Savings per Year: $108,019

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6. In Paragraph 14 on Page 5, TECO asserts that aligning the above ground transmission structure and ground line inspections to the same eight-year inspection cycle will provide efficiency gains in the overall inspection scheduling process as well as data integration. Please identify specifically the efficiencies that would be gained.

A. By aligning the above ground transmission inspections with the eight-year ground line inspection cycle, Tampa Electric will be able to schedule the same circuits for both inspection protocols during the same year. This will reduce the time needed to determine which circuits are due for which type of inspection on an annual basis. The coordination efforts between the inspection subcontractors would also be reduced since the company would be able to provide consistent work packages regardless of inspection subcontractor. In addition to the efficiency gains in the scheduling and coordination processes, the company will also improve the data integration process by comparing the inspection data per circuit from both types of inspections from the same year. This process will eliminate dual entries of any failures and will improve the accuracy of the Transmission Maintenance Database. This accuracy improvement will allow for a more accurate backlog of work to be performed and will improve Tampa Electric's budgeting process for the Transmission Pole Replacement and Maintenance Program.