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April 30, 2010

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

Re: Review of the Continuing Need and Cost Associated with Tampa Electric Company's Five Combustion Turbines and Big Bend Rail Facility; FPSC Docket No. 090368-EI

Dear Ms. Cole:

Enclosed for filing in the above docket on behalf of Tampa Electric Company are the original and fifteen (15) copies of each of the following:

1. Prepared Direct Testimony and Exhibit (WRA-1) of William R. Ashburn.

2. Prepared Direct Testimony and Exhibit (MJH-1) of Mark J. Hornick.

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

COM 5
APA 1
ECR 5
GCL 1
RAD 2
SSC
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CLK Ct Rep

JDB/pp
Enclosures

cc: All parties of record (w/encls.)

DOCUMENT NUMBER-DATE
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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing testimony and exhibits, filed on behalf of Tampa Electric Company, has been furnished by U. S. Mail or hand delivery (*) on this 30th day of April 2010 to the following:

Mr. Keino Young*
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Mr. John W. McWhirter, Jr.
Post Office Box 3350
Tampa, FL 33601-3350

ATTORNEY

TECO
TAMPA ELECTRIC

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 090368-EI
IN RE: REVIEW OF THE CONTINUING NEED AND COSTS ASSOCIATED WITH TAMPA ELECTRIC COMPANY'S FIVE COMBUSTION TURBINES AND BIG BEND RAIL FACILITY

TESTIMONY AND EXHIBIT
OF
MARK J. HORNICK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARK J. HORNICK

Q. Please state your name, business address, occupation and employer.

A. My name is Mark J. Hornick. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director of Planning, Engineering and Construction.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science Degree in Mechanical Engineering in 1981 from the University of South Florida. I am a registered professional engineer in the state of Florida. I began my career with Tampa Electric in 1981 as an Engineer Associate in the Production Department. I have held a number of engineering and management positions at Tampa Electric's power generating stations. From 1991 to 1998, I was a manager at Big Bend Power Station with various responsibilities including serving as Manager of Operations from 1995 to 1998. In July 1998, I was promoted to Director, Fuels where I was responsible for managing Tampa Electric's fuel procurement and transportation activities.

In March 2000, I was promoted to General Manager, Polk and Phillips Power Stations. I was responsible for the overall operations of these two generating facilities. I have broad experience in the engineering and operations of power generation equipment including Integrated Gasification Combined Cycle ("IGCC") technology. I have served on the Electric Power Research Institute's "IGCC Experts Panel".

In October 2008, I was promoted to Director of Engineering & Construction where I was responsible for managing all Energy Supply centralized engineering and construction related activities. This role was expanded in October 2009 to include the Resource Planning function which coordinates the daily commitment of our generating units and plans for future generation expansion to meet forecasted demand.

Q. Have you testified previously?

A. Yes. I testified before the Florida Public Service Commission ("FPSC" or "Commission") in Docket No. 080317-EI regarding Tampa Electric's request for an increase in base rates and miscellaneous service charges. The step increase being addressed in this docket was approved in the aforementioned docket.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to prove that Tampa Electric has satisfied the conditions relating to the addition of five combustion turbine ("CT") generating units and a solid fuel rail unloading facility ("rail facility") installed at Big Bend Power Station ("Big Bend") as set forth in Order No. PSC-09-0283-FOF-EI ("Order No. 09-0283") in Docket No. 080317-EI, issued April 30, 2009. Order No. 09-0283 approved a step increase designed to recover the costs of the five CTs and Big Bend rail facility put into service during 2009, to become effective on January 1, 2010, subject to certain conditions.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have. Exhibit No. ____(MJH-1), consisting of four documents was prepared by me or under my direction and supervision.

Q. *Has the step increase approved in Order No. 09-0283 been implemented?*

A. Yes. On December 1, 2009, the Commission voted to approve the implementation of the step increase effective January 1, 2010 in the amount of $25,742,209, subject to refund with interest, pending the outcome of an evidentiary hearing. Tampa Electric implemented the step increase rates subject to refund as approved in Order No. PSC-09-0842-PCO-EI ("Order No. 09-0842"). The step increase rates are discussed in detail in the direct testimony of Tampa Electric witness William R. Ashburn.

The Big Bend Rail Facility

Q. What was the condition set forth in Order No. 09-0283 related to the Big Bend rail facility?

A. The order stated that the portion of the step increase pertaining to the Big Bend rail facility was conditioned on the facility being completed and in commercial operation by December 31, 2009.

Q. Was the Big Bend rail facility completed and placed into commercial operation on or before December 31, 2009 as required in Order No. 09-0283?

A. Yes. Tampa Electric filed a Notice of Commercial Operation of the Big Bend Rail Unloading Facility on December 18, 2009 in this docket advising the Commission of the December 16, 2009 in-service commercial operation of the rail facility. A true copy of Commercial Operations Memorandum regarding the facility, which was provided as Exhibit "A" to the company's December 18, 2009 filing, is also provided as Document No. 1 of my Exhibit No. _____(MJH-1). In addition photographs of the rail facility are provided as Document No. 2 of my Exhibit No. _____(MJH-1).

Q. How much coal was received and unloaded at the Big Bend rail facility during calendar year 2009?

A. From December 5, 2009 through December 31, 2009, Tampa Electric received and unloaded 34,955 tons of coal delivered by three unit trains, which totaled 298 rail cars, at its Big Bend rail facility. Of those deliveries, two trains were received prior to declaration of commercial operation. The third train was received after the commercial operation date of December 16, 2009 and contained 11,739 tons of coal.

Q. How much coal has been received and unloaded at the Big Bend rail facility from January 1, 2010 through March 31, 2010?

A. From January 1, 2010 through March 31, 2010, the rail facility has received and unloaded 482,503 tons of coal delivered by 40 unit trains.

Q. What are Tampa Electric's expected coal delivery receipts at the Big Bend rail facility going forward?

A. Based on existing transportation contract terms, Tampa Electric expects to receive, at a minimum, 14 unit trains of coal per month through 2014, thereby supplying Tampa Electric with an average of 165,000 tons of coal per month going forward via rail transportation. The rail shipments are expected to vary throughout the year as customer electric usage varies by month, but will average 165,000 tons per month.

Cost of the Big Bend Rail Facility

Q. What is the actual total cost of the Big Bend rail facility project?

A. The total cost for the Big Bend rail facility project is forecasted to be $61,029,000, including AFUDC, as of March 31, 2010. This is $14,092,000 greater than the $46,937,000 used in the calculation of Tampa Electric's step increase rates as of January 2010.

Q. How were these costs derived?

A. They were derived from the books and records of the company as maintained in the normal course of business.

Q. What steps did Tampa Electric take to ensure that the costs it incurred with respect to the Big Bend rail facility were reasonable and prudent?

A. Tampa Electric evaluates the details of each project and selects the most appropriate contracting method to ensure that goals for cost, risk allocation, safety, performance, etc. are met. The rail project was originally bid as an Engineer Procure Construct ("EPC") contract. Evaluation of the responses indicated that the EPC contractors had placed significant contingency in their bids which increased the project costs. The decision was made to break the project into smaller elements and obtain lump sum pricing for each piece. This approach allocated project risk in a more prudent manner, which resulted in lower overall project costs.

In addition, the company routinely utilizes request for proposals ("RFPs") to ensure the selection of equipment, supplies and services are the most cost effective alternatives available. There were 21 RFPs issued during the construction of the Big Bend rail facility. Tampa Electric assigned a project manager and project team with accountability to oversee all contractor activity, achievement of project milestones, and management of project costs to ensure the costs incurred by the company were reasonable and prudent.

The Five CT Generating Units

Q. What were the conditions set forth in Order No. 09-0283 related to the five CTs?

A. The order stated that the portion of the step increase pertaining to the five CTs was conditioned on the units being completed and in commercial operation by December

31, 2009. Second, the five CTs must continue to be needed for load generation.

Q. *Were each of the five CTs completed and placed in commercial operation by December 31, 2009, as required in Order No. 09-0283?*

A. Yes. All of the CTs were completed and placed in commercial operation by December 31, 2009. Tampa Electric provided documentation, Appendix "B" - Commercial Operation Memorandums, regarding the commercial in service dates with its Petition for Approval of Rate Schedules filed October 12, 2009 in this docket. Achievement of the requirement for the five CTs actually being in service during 2009 is further confirmed in Order No. 09-0842, which states:

> Along with its Petition, TECO provided documentation that each of the five CTs has been placed in commercial operation on the dates indicated below:

Unit	In Service Date
Bayside CT 5	April 27, 2009
Bayside CT 6	April 20, 2009

Bayside CT 3	July 13, 2009
Bayside CT 4	July 13, 2009
Big Bend CT 4	August 26, 2009

Our staff verified the in-service dates of all five CTs by reviewing the Commercial Operation Memorandum for each CT attached to the Petition, as well as TECO's responses to our data requests in this docket and the May, July, and August A-Schedules filed by TECO with this Commission in the Fuel Docket. In addition, our staff from the Tampa District Office conducted a site visit and verified that all five CTs are fully completed and appear to be functional. Therefore, we find that TECO has met the condition of the Final order that all five CTs are actually in service during 2009.

In addition, a photograph of the four Bayside CTs is provided as Document No. 3 of my Exhibit No. ____(MJH-1).

The Five CTs are Needed for Load Generation

Q. Order No. 09-0283 states that, Tampa Electric's ability to recover the portion of the step increase pertaining to the five CTs is conditioned on there being a continued need of the CTs for load generation. Do they meet this condition?

A. Yes, they certainly do. The CTs are needed for load generation. Load generation is not simply meeting the minimum 20 percent reserve margin, but rather being able to select the best overall solution to meet customer demand for electricity, which involves having the right generating equipment and other resources available to support Tampa Electric's system under various conditions in a reliable, efficient and cost effective manner.

The continuing need for the CTs was confirmed during the company's winter peak period in January 2010, when they were used extensively to meet peak demand, respond to rapidly increasing customer demand and to avoid blackouts or interruptions to customers. This experience is consistent with the company's site planning projections as well as the *Commission Staff's* findings that all five CTs would be needed by January 2010 using monthly reserve margin information from Tampa *Electric's 2007 through 2009 Ten-Year Site Plans.*

Q. Have the five CTs been needed and beneficial during periods of peak demand?

A. Absolutely. The sustained cold weather period from January 6 through January 12, 2010 is an excellent example of the continuing need and value provided by the CTs. During this seven-day period, the CTs were started a total of 41 times and they operated at a 20 percent capacity factor, which is significantly higher than the typical peaking unit capacity factor of approximately five to ten percent. The CTs also operated more efficiently than the company's other peaking units, which resulted in fuel savings for customers.

Power purchases were limited and unavailable at times during this cold weather period. If the CTs were not in service, Tampa Electric would not have been able to meet record-breaking peak demands without interrupting customers as other state IOUs were forced to do in order to meet customer demand.

The supply of natural gas to the state was strained during this seven-day period of cold weather and high electricity demand. However, Tampa Electric was able to take advantage of the dual fuel capability of Big Bend CT 4, one of the five CTs installed during 2009, by operating it on distillate fuel oil. As a result, gas was freed up and available for use by other Tampa Electric generating units, which helped ensure that our customers had an adequate supply of electricity to meet their needs.

Additionally, the quick start and rapid loading capability of the CTs was used multiple times during this cold weather period. Winter peak demand increases rapidly on cold mornings as customers turn on heat, use hot water and operate other appliances. On January 11, 2010, Tampa Electric experienced a new instantaneous winter peak demand of 4,742 MW, which is 11 percent higher than the previous winter peak set in January 2009 and nine percent higher than the previous summer peak set in August 2007. The demand on Tampa Electric's system increased by 754 MW in the two hours leading up to the peak on January 11, 2010. The CTs were dispatched as the demand rapidly increased each morning, which allowed Tampa Electric to serve its customers in a reliable and efficient manner.

Q. Please describe the monthly utilization of each of these units.

A. Document No. 4 of my Exhibit No. ____(MJH-1) reflects the utilization of each CT placed into service during 2009 by providing the average number of start times for each unit by month since being placed into service. During the summer demand period of May through August, the 2009 CTs were started between 21 and 29 times on average each month. The 2009 average capacity factor for the five CTs since each unit went into commercial service is over 14 percent. As previously stated, the typical peaking unit capacity factor is approximately five to ten percent. Therefore, the use of the CTs has exceeded what is typically expected of peaking units.

Q. How did the actual system peak demand experienced in January 2010 compare to the winter peak demand projected in Tampa Electric's rate case load forecast?

A. The actual system peak demand was 4,742 MW versus the 4,605 MW forecast. In other words, the actual peak demand experienced for winter 2010 was three percent higher than the forecasted load in the company's rate case. This is one example of why the Commission has established that the minimum planning reserve margin should be 20 percent.

The winter peak period in January 2010 demonstrates this point and shows why having the five CTs available for load generation was important. Even though the company's forecasted reserve margin for January 2010 was 25 percent, the company's actual reserve margin during portions of the peak period was as low as six percent, which is very close to the point at which the company could have been required to begin shedding load or interrupting customers. The five CTs provided needed capacity and important operating flexibility during this critical period.

Customers rely heavily on electricity during extreme weather conditions and it is the company's responsibility to be prepared to serve their needs. Cold weather situations are particularly challenging and create significant peak demands. Many customers use heat pump based systems for home heating. These units run efficiently until the outside temperature drops into the 30's and below. In such cases, many heat pump systems must run continuously to keep indoor temperatures at acceptable levels. As a result, there is no system load diversity. In other words, a reduction in the overall system load demand does not occur as it typically would from the cycling on and off of customer heat pump units at different times. In very cold conditions the heat pump systems cannot maintain indoor temperatures and the emergency heat or resistance strip heaters are used to supplement the heat pump. These heaters consume three to four times the amount of energy as an efficiently running heat pump. The most recent January 11, 2010 peak demonstrated these facts and reinforces the value of the CTs in meeting the demands of our customers under all conditions.

Q. Was the need for the five CTs shown in previous Tampa Electric Ten-Year Site Plans?

A. Yes. In Tampa Electric's 2006 and 2007 Ten-Year Site Plans, the Aero CT technology was identified as a viable technology for the company's 2009 and 2010 generating need. In the 2008 and 2009 Tampa Electric Ten-Year Site Plans, the specific units and in-service dates were provided.

Q. Please explain the minimum 20 percent planning reserve margin requirement, its origin and its effect upon the reliability of Tampa Electric's system.

A. The purpose of a minimum 20 percent planning reserve margin requirement is to ensure the availability of adequate supply and demand side resources to meet firm peak demand during both the summer and winter system peak periods. This additional installed capacity ensures reliable service in the event an unplanned outage occurs on a generating unit, or higher than forecasted demands occur during the seasonal peak periods.

The minimum 20 percent reserve margin requirement was established due to the Commission's expressed concern about the adequacy of the planned reserve margin for Peninsular Florida, after reviewing the Ten-Year Site Plans filed in 1997 and 1998. In Docket No. 981890-EU, the Commission issued Order No. PSC-99-2507-S-EU ("Order No. 99-2507") on December 22, 1999, which approved the parties stipulation to voluntarily agree to meet a minimum 20 percent installed reserve requirement. The Stipulation approved in Order No. 99-2507 states:

> The twenty percent (20%) reserve margin planning criterion will be a minimum; no maximum or cap will be represented or implied by this criterion.

Furthermore, the Stipulation states:

> Neither the adoption by the IOUs of the minimum twenty percent (20%) planning criterion nor the approval of this Stipulation by the Commission shall be deemed to create any presumption that capacity additions must be through any particular mix of generation and/or demand-side resources. Nor shall said adoption or approval be deemed to create any presumption with respect to any proposals for adding generating capacity or create a presumption that a generating capacity addition proposed by any entity is not needed.

The minimum 20 percent planning reserve margin requirement has enabled Tampa Electric to ensure reliability of service at all times, and especially during planned outages and peak demand periods, with a cost effective mix of resources. By constructing and placing into service two of the Bayside units in April 2009, and the remaining two Bayside units and the Big Bend unit in July and August 2009, Tampa Electric was able to meet both the forecasted summer peak demand in 2009 and the winter peak demand in 2010.

Q. Is it practical to build generation to exactly meet the minimum 20 percent planning reserve margin?

A. No, it is not practical to build generation to meet, but not exceed the minimum 20 percent planning reserve margin. Generating units are added in cost effective increments, which vary in size due to technology type, not in single MW increments to precisely match the forecasted system demand. Typically, when a generating unit is placed in service, the minimum 20 percent planning reserve margin is exceeded until customer load demand increases. Historically, the Commission has not viewed the minimum 20 percent planning reserve margin standard as a stand-alone, bright line test for recovering prudently incurred costs. In fact, the Commission has allowed recovery of the new generating units in base rates even when the minimum 20 percent reserve margin was exceeded. During this time, the customers receive operational benefits such as increased system reliability. To suggest that a utility must comply with a minimum 20 percent reserve criteria and never exceed that value as generating units are added to the system is impractical and uneconomic.

Q. Were there other benefits associated with the construction schedule of the five CTs?

A. Yes. The sequence of construction activities allowed the company to optimize the offsite fabrication of equipment and on-site construction activities. Substantial savings in project costs were achieved by planning an orderly sequence of activities from one unit to the next unit. Contractors staffed the job efficiently and avoided additional costs due to mobilization and demobilization charges associated with starting and stopping construction.

Q. What role have the CTs played in connection with the outage scheduled for the Big Bend Unit 1 Selective Catalytic Reduction ("SCR") installation?

A. Having the five CTs in service during the 2010 Big Bend Unit 1 SCR installation outage helped provide the capacity needed to maintain the minimum 20 percent reserve margin planning criterion. Tampa Electric does not typically schedule planned outages during summer or winter peak demand periods; however, the SCR installation outage on Big Bend Unit 1 and the earlier SCR installation outages on Big Bend Units 2, 3 and 4 were required to meet the conditions of the environmental agreements Tampa Electric entered into with the Florida Department of Environmental Protection on December 16, 1999 and the United States Environmental Protection Agency on February 29, 2000.

Q. What was the schedule for the Big Bend Unit 1 outage for the SCR installation?

A. The Big Bend Unit 1 outage for the SCR installation was scheduled from November 29, 2009 through April 8, 2010 to meet the requirements of the environmental agreements which mandate the SCR conversion and the applicable nitrogen oxides emissions rate by May 1, 2010.

Q. Was it necessary for Tampa Electric to perform the installation of the SCR on Big Bend Unit 1 during the November 2009 through April 2010 time frame?

A. Yes, the environmental agreements are legally binding and specified a completion date of no later than May 1, 2010. Attempting to schedule the Big Bend Unit 1 outage earlier in 2009 was not a viable option due to other planned outage requirements and the need to avoid outages during the summer period.

Q. Was the timing of the scheduled outages for Big Bend Unit 1 SCR installation flexible?

A. No, the timing of the scheduled outages for the Big Bend SCR installations was not flexible, discretionary or something that could be postponed easily due to the tightly scheduled completion deadlines detailed in the environmental agreements. In order to allow the continued use of coal as a fuel for Big Bend Units 1 through 4, the environmental agreements required Tampa Electric to sequentially install SCR technology on those units. Specifically, the installation requirements were staged as follows: 1) the first of the units on or before May 1, 2007; 2) the second of the units on or before May 1, 2008; 3) the third of the units on or before May 1, 2009; and 4) the fourth unit on or before May 1, 2010. For efficiency and cost effectiveness, the company agreed to complete the SCR installation on unit 4 first, followed by unit 3, then unit 2 and finally unit 1. Due to the large amount of work needed to complete the SCR installations and the extended length of these outages, the company scheduled these outages in the fall and winter periods immediately preceding the defined deadlines to minimize the overall costs to its customers.

Q. Would a purchased power arrangement to cover the Big Bend Unit 1 outage for the SCR installation have provided a reliable and cost effective alternative as opposed to the completion of the five CTs?

A. No. Two of the CTs were needed to meet the minimum 20 percent reserve margin planning criterion for summer 2009. The company viewed that the remaining three CTs provided a more reliable and cost effective alternative to a possible purchased power agreement to cover the Big Bend Unit 1 outage during the SCR installation. The new CTs are more efficient than many other peaking units which would be operated to provide the purchased power. Since the CTs are located within Tampa Electric's service area, they provide a higher quality of reserves than purchased power, which may be transmitted over longer distances from outside Tampa Electric's control area. Additionally, transmission service needed for delivery of the purchased power may be subject to curtailment; therefore, it may not be available during critical peak periods, as was the case during the cold weather in January 2010. Additionally, all five CTs provide beneficial operating characteristics such as black start and quick start capabilities, which improve reliability and reduce overall fuel costs for Tampa

Electric's customers.

Q. At the time of the rate case hearing in January 2009, did the company consider the possibility of deferring the construction of the five CTs?

A. Yes, however, the need for the units in terms of their capacity, economics, operating capabilities and role in the company's dispatch plans compelled moving forward. Moreover, deferring the construction of the CTs would not have been practical or cost effective.

Q. What circumstances led to these conclusions?

A. Bayside CTs 5 and 6 were nearing mechanical completion at the end of January 2009 and deferring the remaining three CTs would have resulted in additional costs due to construction inefficiencies as well as demobilization and remobilization costs.

By January 15, 2009, there were 29 separate contracts in place covering the civil, structural, mechanical, electrical, instrumentation, procurement and construction of the five CT units. This represented a total contract value of $149,079,666. At that point in time, 71 percent of the value for these contracts, or $106,433,780, was irrevocably committed, not including transmission construction costs, other owner's costs and Allowance for Funds Used During Construction ("AFUDC").

Construction of Bayside CTs 5 and 6 was in the final stages during the rate case hearing and was completed and in service before the Commission issued Order 09-0283 on April 30, 2009. In addition, Tampa Electric was able to meet its summer peak demand in 2009 with Bayside CTs 5 and 6 in service. The completion of Bayside CTs 5 and 6 was the only realistic and reliable option.

Additionally, postponement of Bayside CTs 3 and 4, which went into service July 13, 2009, was not a realistic or reliable alternative, nor would it have been consistent with Tampa Electric's Ten-Year Site Plan. As previously stated, the majority of funds for contracts on these CTs were committed and substantial construction had been completed at the time of the rate case hearing. Also, the postponement of Bayside CTs 3 and 4 would have eliminated the benefits of 120 MW of black start and quick start capability, thereby requiring additional spinning reserves and increasing fuel costs to customers. Therefore, postponement of Bayside CTs 3 and

4 was not a cost effective option.

Postponement of Big Bend CT 4 was not a realistic or reliable option because postponement would have left Big Bend Station without black start capability, which is the ability to start a unit independent of an energized connection to the bulk electric system such as in a blackout condition. The North American Electric Reliability Corporation ("NERC") requires Tampa Electric to maintain sufficient black start generator capability to initiate restoration of the power system or to make contractual arrangements with others to provide that restoration capability. Further, the postponement of Big Bend CT 4 would have caused the loss of 60 MW of quick start capability. Big Bend CT 4 also has the capability to operate either on natural gas or fuel oil. This dual fuel capability is beneficial in situations when the supply of natural gas is limited or where the price of natural gas is higher than distillate oil. The capability to use oil as a fuel was cost effectively applied to Big Bend CT 4 by using an existing oil tank and associated equipment that was already in service at the facility. As previously discussed, Tampa Electric was able to take advantage of Big Bend CT 4's dual fuel capability during the sustained cold weather period in

January 2010.

Q. Aside from supporting Tampa Electric's minimum 20 percent planning reserve margin criterion, please describe in greater detail the operating characteristics provided by the five CTs and their role in meeting load generation needs.

A. The five CTs are providing needed generating capacity and operating flexibility with a high level of efficient and environmentally beneficial performance. The heat rate of the CTs is approximately four to nine percent lower than the next peaking unit in Tampa Electric's dispatch order, making the CTs Tampa Electric's most efficient peaking units. These units have greater operating flexibility; they can start multiple times per day while requiring no minimum run time or off time between starts, thereby providing maximum dispatch flexibility and overall system optimization. In addition to meeting the peak demands of our customers, the five CTs will produce an estimated 2009 and 2010 fuel savings of $4 million through the displacement of other units that would otherwise be operated or more expensive and less reliable power purchases in lieu of the five CTs.

Q. Please describe the quick start operating characteristic of the CTs and associated benefits from a load generation perspective.

A. The five CTs have quick start capability, which enables these units to go from off-line to full load within 10 minutes. As a member of the Florida Reserve Sharing Group, Tampa Electric has an operating reserve requirement that the reserve megawatts must be fully available to support reliability of the bulk electric system within 10 minutes of being called upon. The quick start feature of the CTs provides a far more economical option to meet the company's operating reserve obligation than through the use of spinning reserves. Typically, spinning reserves are provided by keeping larger base and intermediate-load units running at less efficient load points. The use of quick start, peaking CTs to provide operating reserves in lieu of using spinning reserves benefits customers by enabling in-service generators to operate at higher average outputs, which improves efficiency. This lowers the overall system fuel and operating costs. In addition, the use of the quick start capable CTs for operating reserves rather than using demand-side load management curtailments is a less impactful alternative which limits the need to interrupt customer electrical service in such circumstances.

Q. Please describe the black start operating characteristic of the CTs and associated reliability benefits from a load generation perspective.

A. The CTs have black start capability which will allow each CT to start independent of an energized connection to the bulk electric system. A relatively small, on-site engine driven generator can provide the electric power required to start these units. Once the CT has been started, energy can be switched internally to power the auxiliaries required to start a larger generating unit at the station. This generation can be used to re-energize the electric grid to provide power to Tampa Electric customers without waiting for an external source from another electric utility. This black start capability allows for faster restoration of electric service to customers following hurricanes or other major system disturbances, especially in situations where the outage is so widespread that imported startup power is difficult to locate or even non-existent.

Cost of the Five CTs

Q. What is the actual total cost of the five CTs?

A. The total cost for the five CTs is projected to be $201,464,580 (system), of which over 99 percent are actual costs incurred through March 31, 2010. This is $13,286,156 (jurisdictional) greater than the $188,178,425 (jurisdictional) included in Tampa Electric's rates as of January 2010.

Q. How were these costs derived?

A. They were derived from the books and records of the company as maintained in the normal course of business.

Q. What steps did Tampa Electric take to ensure that the costs it incurred with respect to the five CTs were reasonable and prudent?

A. As previously discussed, Tampa Electric routinely utilizes RFPs to ensure the selection of equipment, supplies and services are the most cost effective alternatives available. Tampa Electric issued 30 RFPs during the construction of the CTs. In addition, a project manager and project team were formed to oversee all contractor activity, achievement of project milestones, and management of project costs to ensure the costs incurred by the company were reasonable and prudent. For example, major equipment deliveries were coordinated to coincide with the completion of equipment foundations to avoid double-handling of equipment. Also, construction schedules were developed to move from the installation of the first two Bayside CTs, to the second pair of Bayside CTs and finally to the last Big Bend CT. This minimized mobilization costs which Tampa Electric would have incurred if there were large gaps between the construction dates.

Q. Please summarize your testimony.

A. My testimony proves that Tampa Electric has satisfied the three conditions relating to the addition of the Big Bend rail facility and five CTs as required in Order No. 09-0283 in Docket No. 080317-EI. The Big Bend rail facility and five CTs were completed and placed into commercial operation on or before December 31, 2009 as required and the appropriate documentation has been provided by the company to confirm the commercial in-service date of each asset. As of March 31, 2010, 494,242 tons of coal have been received and unloaded at the rail facility since being declared commercially operational on December 16, 2009, further demonstrating commercial operation of the facility. In addition, the five CTs were placed into commercial operation between April 20, 2009 and August 26, 2009 and the Commission Staff verified the in-service dates of the units, thereby concluding in Order No. 09-0842 that Tampa Electric has met the condition of Order No. 09-0283 that the five CTs were actually in service during 2009.

The final condition in Order No. 09-0283 requires that there must be a continued need of the five CTs for load generation. My testimony demonstrates the ongoing need for and value of the CTs. As discussed extensively above, the continuing need for the CTs was reinforced during the company's winter peak period in January 2010, when they were used extensively to meet peak demand, respond to rapidly increasing customer demand and avoid blackouts or interruptions to customers. During the extended cold weather period, the CTs were started 41 times and they operated at a 20 percent capacity factor, which is significantly higher than the typical peaking unit capacity. In addition, the quick start and rapid loading capability of the CTs was used multiple times during the cold January weather. Without the CTs in service, Tampa Electric would not have been able to meet record-breaking peak demands without interrupting customers as other state IOUs were forced to do in order to meet customer demand.

Therefore, my testimony substantiates that the Big Bend rail facility and the five CTs were indeed complete and operational prior to December 31, 2009 and that there is a continuing need for the CTs. Based on the extensive details and facts provided above, Tampa Electric has met the conditions set forth in 09-0283 in Docket No. 080317-EI for the implementation of the $25,742,209 step increase approved in Order No. 09-0842 on a permanent basis.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

MARK J. HORNICK

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MEMORANDUM

DATE: December 16, 2009

TO: Big Bend Station Team Members/Support Groups

FROM: Jim Robertson

SUBJECT: Big Bend Rail Unloading Facility COMMERCIAL OPERATIONS

The Big Bend Station Rail Unloading Facility has commenced its commercial operation effective December 16, 2009 12:01 a.m. The Big Bend Station Coal Field team which has the responsibility for operating and maintaining Big Bend Solid Fuel Delivery Systems has accepted the project into the normal operations of the plant.

All costs associated with the operations of the Unloading Facility including costs relating to plant staff and operating personnel should now be charged to the proper operations and maintenance accounts.

For all costs associated with final construction activities such as punch list items, engineering, and processing of payments to close out the project, account "H29" will remain open to those charges through March 16, 2010. Any new capital qualifying projects will require approval under the standard capitalization criteria used within Tampa Electric.

Project Management — Jim Robertson

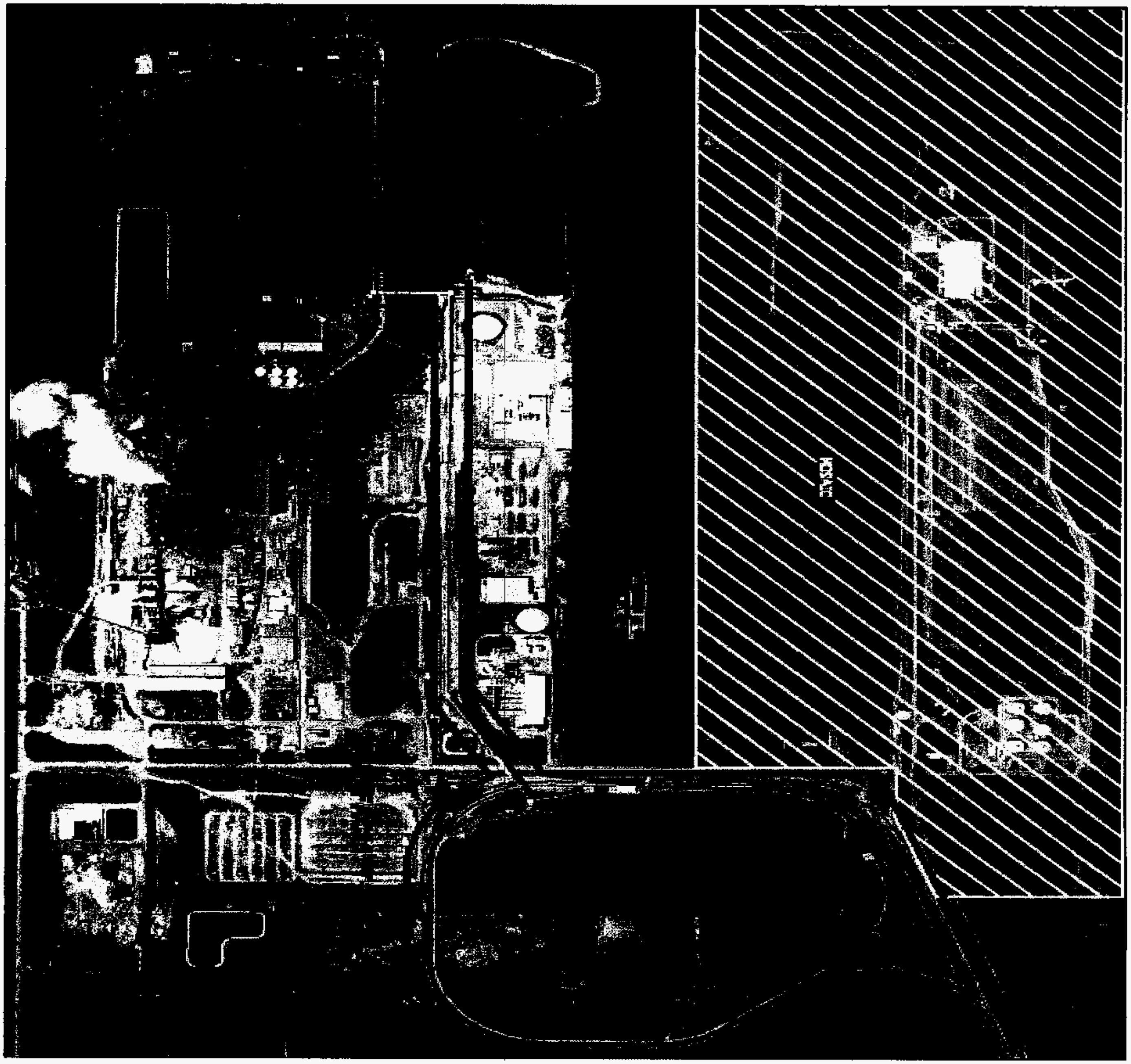
Plant Operations — Bill Smotherman

Fuels — Joann Wehle

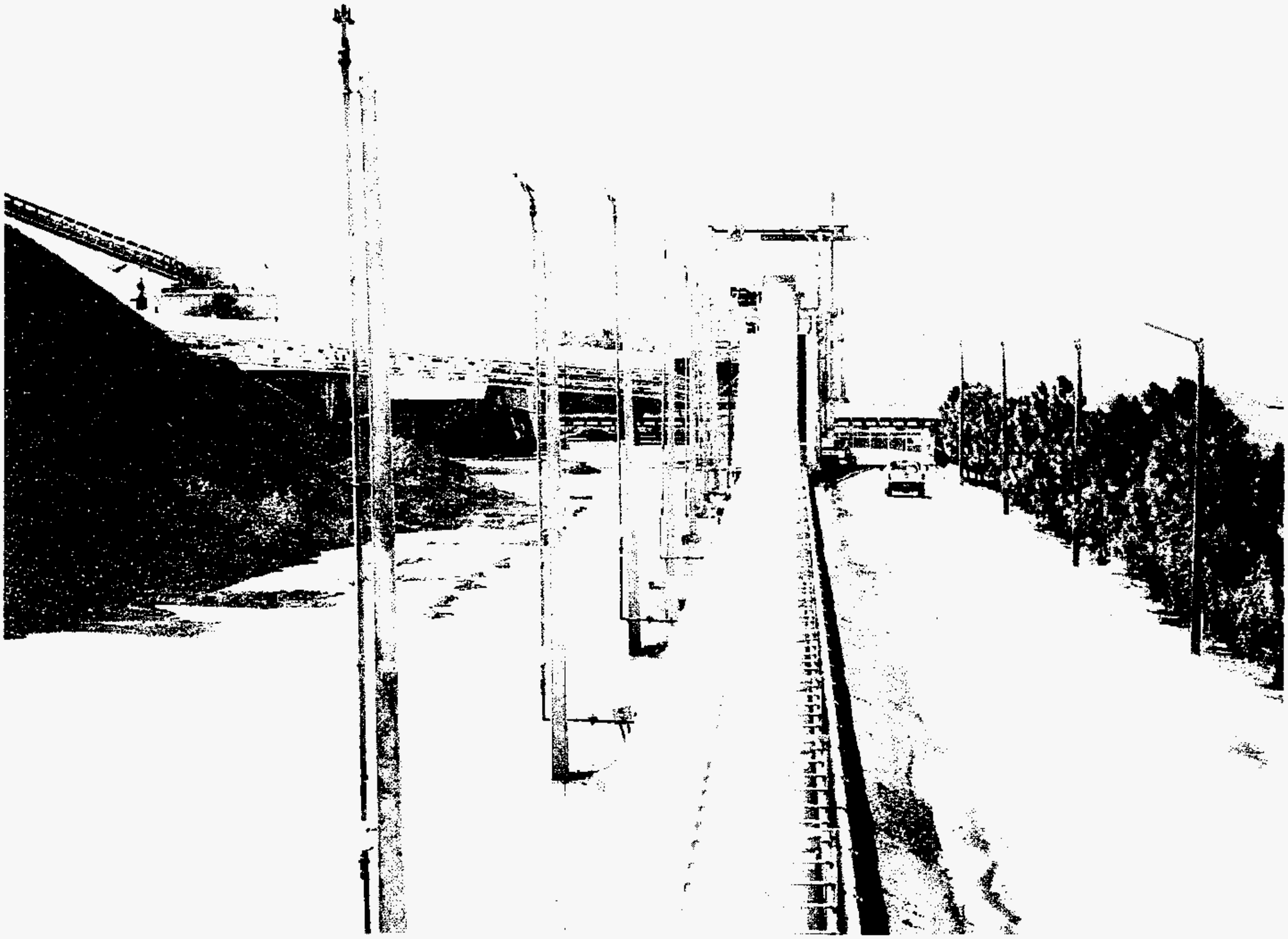
Cc: E.L. Carlson
J. S. Chronister
T. L Hernandez
M.J. Hornick
B.N. Narzissenfeld
V.C. Strickland
R.A. Walker

TAMPA ELECTRIC COMPANY
DOCKET NO. 090368-EI
EXHIBIT NO. ______ (MJH-1)
WITNESS: HORNICK
DOCUMENT NO. 2
PAGE 1 OF 5

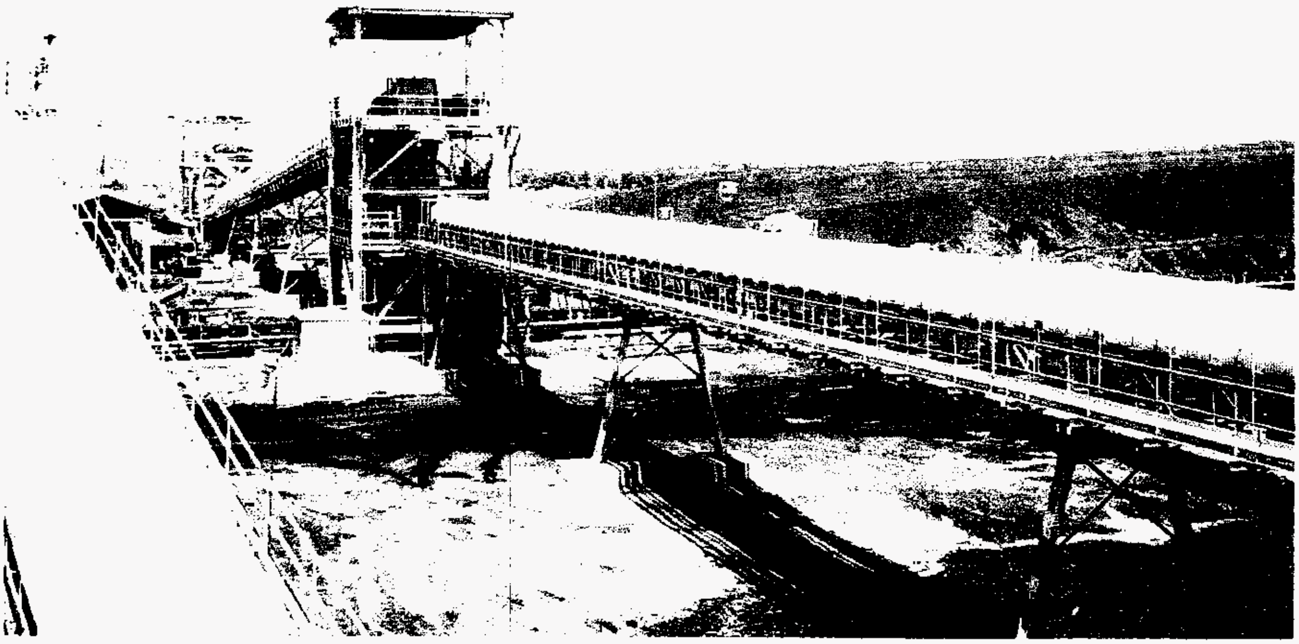
Aerial Photograph of Big Bend and Rail Facility Track Outline



Big Bend Rail Facility Conveyor 14 Looking West



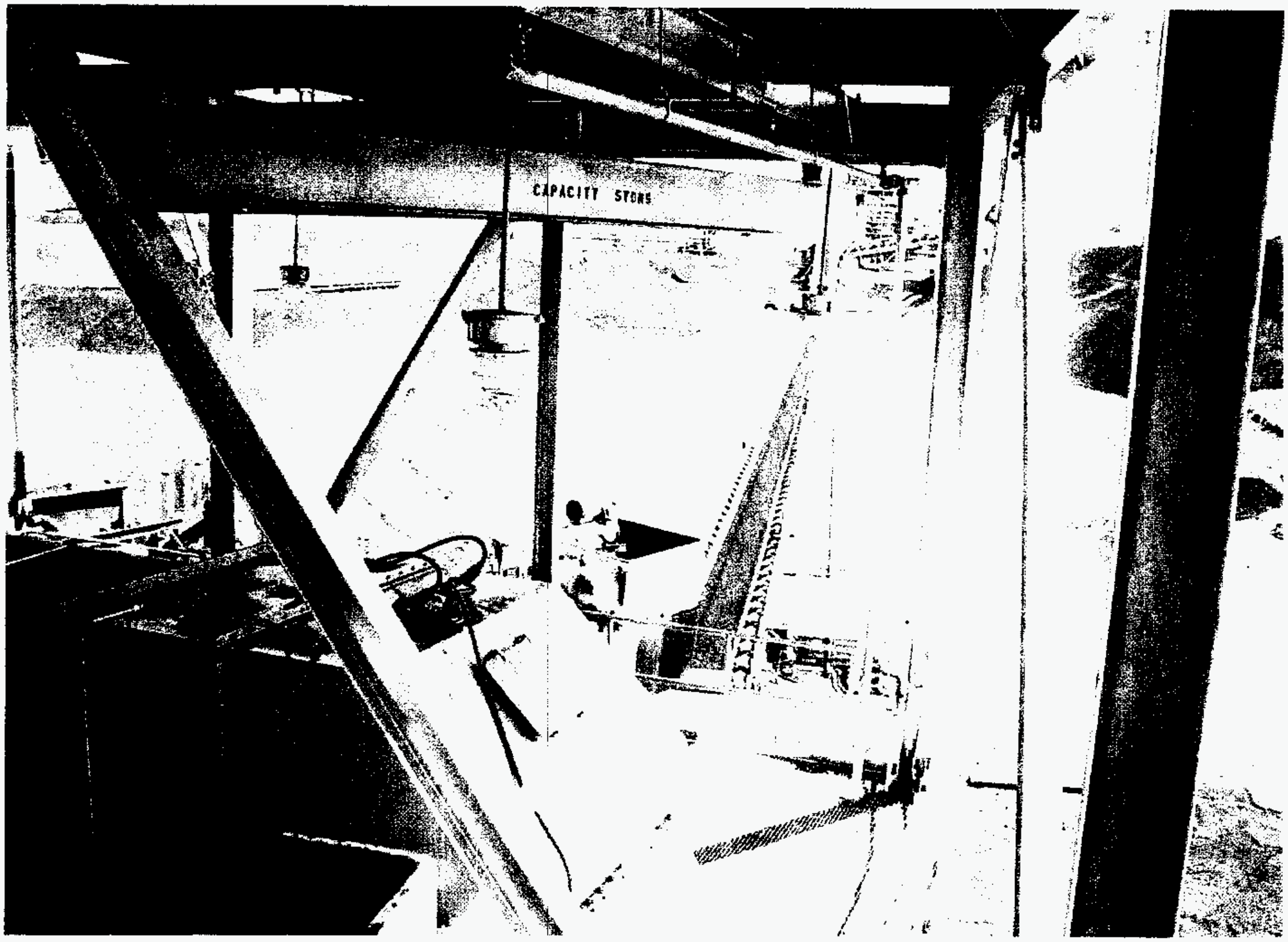
Big Bend Rail Facility Conveyors 15 and 16 Looking North



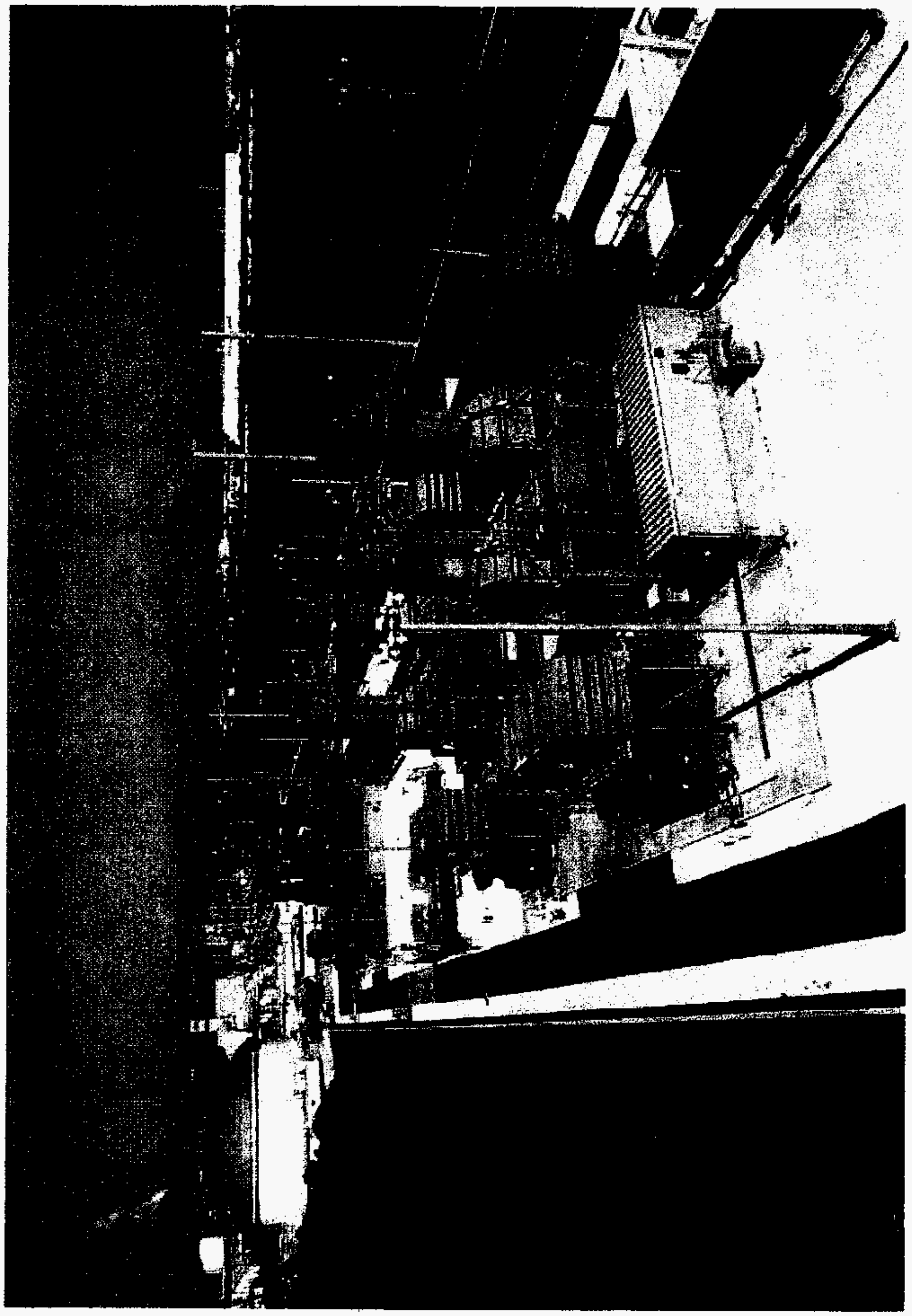
Big Bend Rail Facility Conveyor 13

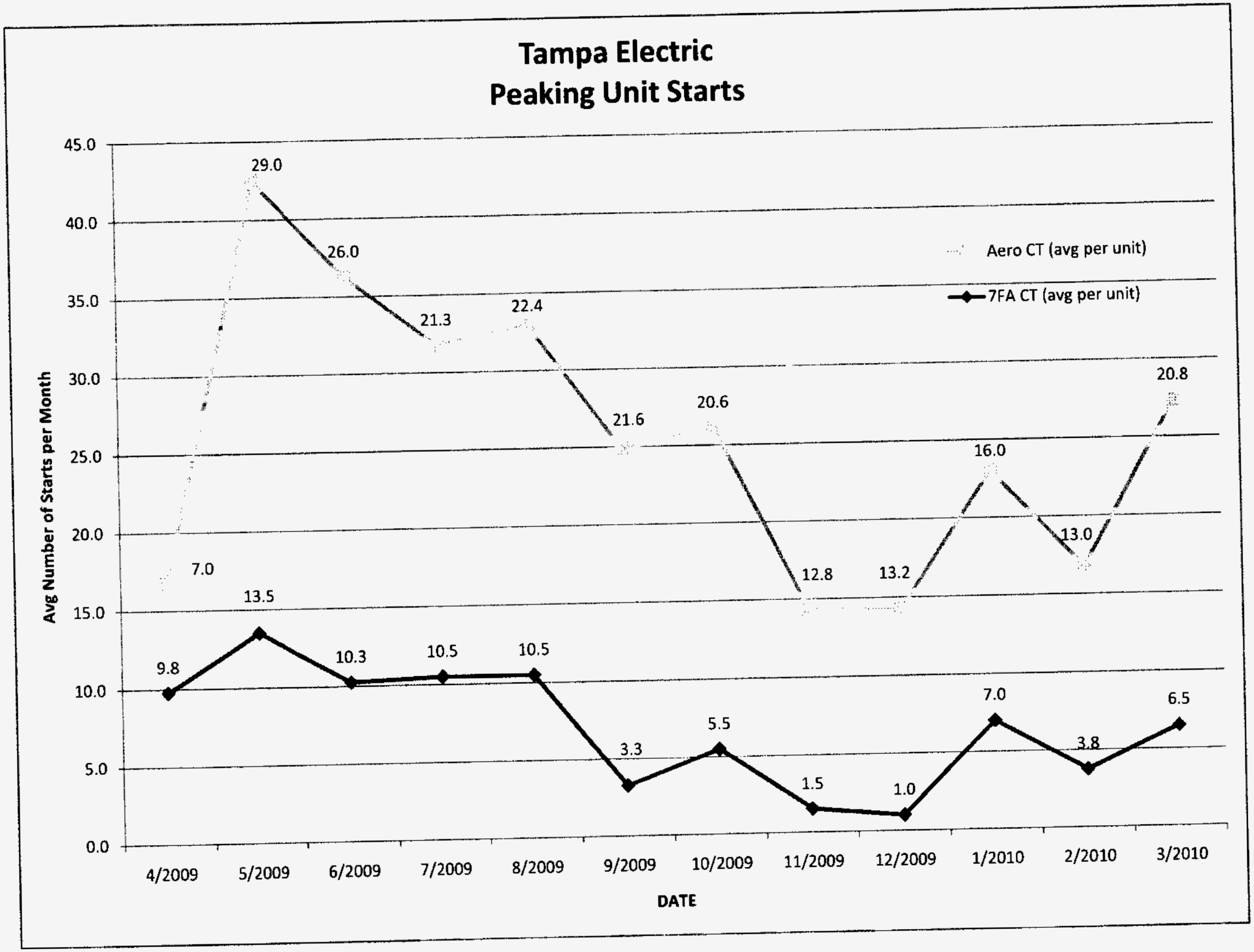
Enclosed Conveyor Over Inlet Canal

Big Bend Rail Facility Discharge of New Conveyor 16



Bayside Aero CTs Three through Six





TAMPA ELECTRIC COMPANY
DOCKET NO. 090368-EI
EXHIBIT NO. ___ (MJH-1)
WITNESS: HORNICK
DOCUMENT NO. 4
PAGE 1 OF 1
FILED: 04/30/2010

TECO
TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 090368-EI

IN RE: REVIEW OF THE CONTINUING NEED AND COSTS ASSOCIATED WITH TAMPA ELECTRIC COMPANY'S FIVE COMBUSTION TURBINES AND BIG BEND RAIL FACILITY

TESTIMONY AND EXHIBIT
OF
WILLIAM R. ASHBURN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM R. ASHBURN

Q. Please state your name, business address, occupation and employer.

A. My name is William R. Ashburn. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am the Director, Pricing and Financial Analysis for Tampa Electric Company ("Tampa Electric" or "the company").

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from Creighton University with a Bachelor of Science degree in Business Administration. Upon graduation, I joined Ebasco Business Consulting Company; my consulting assignments included the areas of cost allocation, computer software development, electric system inventory and mapping, cost of service filings and property record development. I joined Tampa Electric in 1983 as a Senior Cost Consultant in the Rates and Customer Accounting Department. At Tampa

Electric, I have held a series of management positions with responsibility for embedded and marginal cost of service studies, rate filings, rate design, implementation of new conservation and marketing programs, customer surveys and various state and federal regulatory filings. In March 2001, I was promoted to my current position of Director, Pricing and Financial Analysis in Tampa Electric's Regulatory Affairs Department. I am a member of the Rate and Regulatory Affairs Committee of the Edison Electric Institute and the Rate Committee of the Southeastern Electric Exchange.

Q. Have you testified previously?

A. Yes. I have testified or filed testimony before the Florida Public Service Commission ("FPSC" or "Commission") in several dockets. I testified for Tampa Electric in Docket No. 000061-EI regarding the company's Commercial/Industrial Service Rider tariff and in Docket No. 020898-EI regarding a self-service wheeling experiment. In Docket Nos. 000824-EI, 001148-EI, 010577-EI and 020898-EI, I testified for Tampa Electric and as a joint witness representing Tampa Electric, Florida Power & Light Company and Progress Energy

Florida Inc. regarding rate and cost support matters related to the GridFlorida proposals. Most recently, I testified in Docket No. 080317-EI supporting Tampa Electric's cost of service methodology and rate design in the company's base rate proceeding. In addition, I have testified or presented for Tampa Electric numerous times at workshops and in other proceedings regarding rate, cost of service and related matters. I have also provided testimony and represented Tampa Electric before the Federal Energy Regulatory Commission in rate and cost of service matters.

Q. Please state the purpose of your direct testimony?

A. The purpose of my testimony is to present the revenue allocation and resulting rates designed to recover the step increase approved in Order No. PSC-09-0283-FOF-EI ("Order No. 09-0283") in Docket No. 080317-EI, issued April 30, 2009. The step increase revenue requirement approved in Order No. PSC-09-0842-PCO-EI ("Order No. 09-0842"), issued on December 22, 2009, is associated with the costs incurred by Tampa Electric to construct five combustion turbine ("CT") generating units and a solid fuel rail unloading facility ("rail facility") at Big Bend Power Station. Additionally, I support the final approval of the step increase tariff sheets on a permanent basis.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have. My Exhibit No.__ (WRA-1), consisting of five documents, was prepared by me or under my direction and supervision.

Q. Has the step increase approved in Order No. 09-0283 been implemented?

A. Yes. Following the issuance of Order No. 09-0283 and Order No.PSC-09-0571-FOF-EI, disposing of motions for reconsideration of Order No. 09-0283, the Commission opened this docket as a means of implementing the step increase as approved in Order No. 09-0283. Tampa Electric filed a petition in this docket on October 12, 2009 for approval of the step increase tariff sheets and resulting rates. On December 1, 2009, the Commission voted to approve the implementation of the step increase effective January 1, 2010 in the amount of $25,742,209, subject to refund with interest pending the outcome of an evidentiary hearing. Tampa Electric implemented the step increase rates subject to refund as approved in Order No. 09-0842.

Revenue Requirement

Q. How was the revenue requirement for the CTs to be recovered in the step increase determined?

A. In its rate case proceeding, Tampa Electric proposed making a pro forma adjustment for the impact on operating expenses as well as impact on net plant in service to bring the company's total cost profile to an amount that reflects a full year of operation for the CTs. That proposed pro forma adjustment included jurisdictional net operating income adjustments of decreases of $2,352,000 for the May units and $4,864,000 for the September units. The proposed jurisdictional rate base adjustments were increases of $36,125,000 for the May units and $94,562,000 for the September units.

In Order No. 09-0283, rather than make the proposed pro forma adjustment as part of the initial rate increase, the Commission decided to reflect the increased revenue requirements for the CTs, $26,554,650, in a step increase to become effective January 1, 2010, if the CTs were in service by December 31, 2009 and needed for load generation. These conditions and proof that they have been met are discussed and provided in the direct testimony of Tampa Electric witness Mark J. Hornick.

In the reconsideration order, the revenue requirement for the CTs in the step increase was revised upward to $26,938,806. This revised value was subsequently changed to $18,603,935 in Order No. 09-0842 to reflect reduced projected final costs for the CTs and was used to develop the step increase rates now in effect.

Q. How was the revenue requirement for the rail facility to be recovered in the step increase determined?

A. In its rate case proceeding, Tampa Electric proposed a pro forma adjustment for the impact on operating expenses as well as impact on net plant in service to bring the company's total cost profile to an amount that reflects a full year of operation for the rail facility. The proposed pro forma adjustment included an impact on operating expenses as well as an impact on net plant in service to bring the company's total cost profile to an amount that reflects a full year of operation for the facility. The jurisdictional net operating income adjustment was a decrease of $1,195,000. The jurisdictional rate base adjustment was an increase of $44,754,000.

In Order No. 09-0283, rather than make the proposed pro forma adjustment as part of the initial rate increase, the Commission decided to reflect the increased revenue requirements for the rail facility, $7,006,720, in a step increase to become effective January 1, 2010, if the rail facility was in service by December 31, 2009. In the reconsideration order, the revenue requirement for the rail facility in the step increase was revised upward to $7,138,274. This revised value was not changed in Order No. 09-0842 and was used to develop the step increase rates now in effect.

The $7,138,274 for the rail facility, together with the $18,603,935 for the five CTs, totals $25,742,209, which is the approved amount for the step increase.

Q. How was the total step increase annual operating revenue increase resulting from the inclusion of the rail facility and CTs in rate base derived?

A. As shown in Document No. 1 of my Exhibit No.__ (WRA-1), the total annual operating revenue increase of

$25,742,209 associated with the CTs and rail facility was derived in the same manner as it was derived by the Commission in Order No. 09-0842. The authorized overall rate of return of 8.29 percent resulting from Order No. 09-0283 was applied to the net plant in service values for the CTs and rail facility. The resulting required return amount was added to the approved and tax effected O&M expense, depreciation and taxes other than income associated with the CTs and rail facility. The income tax effect of interest was added to all the above, which derived the total net operating income ("NOI") requirement. The company then applied the approved NOI multiplier to the NOI requirement as the final step in the calculation of the revenue requirement for the CTs and rail facility. The reasonableness of the costs of the CTs and rail facility described above is described in the direct testimony of Tampa Electric witness Mark J. Hornick.

Q. What is the appropriate total annual revenue requirement for the rail facility?

A. As shown in Document No. 1 of my Exhibit No.__ (WRA-1), the appropriate total annual revenue requirement for the rail facility is $7,230,216, which reflects the combined revenue requirement of the initial rate increase and step increase.

Q. What is the appropriate total annual revenue requirement for the CTs?

A. As shown in Document No. 1 of my Exhibit No.__ (WRA-1), the appropriate total annual revenue requirement for the May CTs is $17,546,357 and for the September CTs is $18,507,502 for a total of $36,053,859, which reflects the combined revenue requirement of the initial rate increase and step increase.

Revenue Allocation

Q. Did the Commission provide guidance on how the step increase revenue requirement was to be allocated to rate classes?

A. Yes. Order No. 09-0283, at pages 6 and 9, prescribes the following parameters for revenue allocation of the step increase:

> We authorize an increase in base rates . . . consistent with the cost allocation methodology we approved in this order . . .

On page 127 of Order No. 09-0283, it states:

> In order to retain the relative class relationships developed in the current cost of service study, the incremental costs shall first be allocated to each rate class, consistent with the 12 CP and 25 percent AD cost methodology approved herein.

Q. Did Tampa Electric follow these guidelines when it allocated revenues for the step increase?

A. Yes. The revenue allocation for the step increase was derived consistent with the Commission's direction. The CTs and rail facility are production or production-related facilities. Consistent with the cost allocation methodology approved in Order No. 09-0283, the step increase revenue requirement was allocated based on the 12 CP and 25 percent allocation factor utilized for such facilities. This approach results in a fair allocation of the increase revenues to all rate classes that are benefiting from these facilities.

Q. Does the Interruptible Service ("IS") class of customers particularly benefit from these facilities?

A. Yes. The company's IS customers take service under a demand-side management program and are subject to interruption or allocation of purchased power costs when generation is not sufficient to meet their load requirements. The addition of the five CTs during 2009 provided additional peaking generating resources which reduced the likelihood of such interruption as soon as the units went into service and will continue to reduce the likelihood of interruption in the future. Thus, the five CTs provide a real benefit to IS customers through continuation of service at peak times. Tampa Electric witness Mark J. Hornick discusses the extensive use of the five CTs during the record-breaking winter demand days in January 2010 to help prevent interruptions and curtailment of firm load in his direct testimony.

Additionally, the rail facility provides a second mode of fuel delivery, which will not only improve the reliability of fuel delivery to Big Bend, but also adds competition for sources of coal and downward pressure on coal prices. IS customers are generally higher load factor customers who will benefit particularly from this improvement in two ways: improved fuel delivery reliability will reduce the risk of interruption in all hours and higher load factor customer are taking service more hours of the year, and the higher energy use of the higher load factor IS customers will reduce their overall cost per kWh because the expected lower fuel costs resulting from this investment represents a higher percentage of their overall bill. Thus, the addition of the CTs and rail facility provides significant benefits to the IS customers which is why their class of service is appropriately allocated a share of the revenue requirement associated with these facilities going into service.

Q. Did you prepare an exhibit that demonstrates how the step increase revenues were allocated to rate classes as required by the Commission?

A. Yes. Document No. 2 of my Exhibit No.__ (WRA-1) shows how the increased revenues were allocated to the rate classes and the derivation of the target total revenues which were utilized for rate design.

Q. Does the allocation of the step increase to rate classes take into account the customer group transfers and combinations as approved in Order No. 09-0283?

A. Yes. As approved in Order No. 09-0283, certain customer groups were transferred between rate classes or combined into a single rate class. Because these transfers occurred in May 2009 and the rates resulting from the step increase became effective in January 2010, Tampa Electric factored in the transfers and combinations before revenue allocation occurred to clearly demonstrate the final revenue and rate impacts on the MFRs utilized to confirm the final results. A schedule showing how the transfers and combinations were factored into the revenue allocation is included as Document No. 3 of my Exhibit No._ (WRA-1).

Q. Do the tariffs currently in effect generate sufficient revenues to permit Tampa Electric to recover all of its costs associated with the five CTs and rail facility?

A. No. Following the opening of this docket as a vehicle for implementing the step increase, the Commission Staff completed an audit to verify the capital costs for the five CTs and rail facility. Based on that audit, the Commission Staff recommended a lower step increase amount to reflect the lower actual/estimated cost of the CTs than originally projected. However, the Commission Staff did not recommend an offset to that reduction to reflect the actual cost of the rail facility, which was higher than the estimate used by the Commission in establishing the step increase. That revised revenue amount, $25,742,209, was approved by the Commission, as reflected in Order No. 09-0842 and is the amount Tampa Electric allocated and used for rate design. It is also the basis for the tariffs sheets for which Tampa Electric is requesting approval.

Rate Design

Q. How were the resulting rates derived after the allocation of revenues to each rate class?

A. Order No. 09-0283, at page 127, includes the following requirement regarding the resulting rate design:

> Once the dollar increase per class is established, the base rate energy, or energy and demand charges, shall be increased by the percentage increase in class revenues. In addition, non-clause recoverable credits shall also be increased by a similar amount to retain the relationship between the charges and credits approved in the current cost study.

The rate design for the rates currently in effect followed the direction provided in Order No. 09-0283, as described above. The base rate energy and demand charges as well as all associated credits and charges in each rate class were increased based on the percentage increase of that class's allocated revenue, resulting in revised charges and credits. The resulting revised charges and credits are shown in Document No. 4 of my Exhibit No.__ (WRA-1) and in the tariff sheets.

Q. Was this procedure followed for all charges and credits?

A. In general yes. Certain of the charges or credits did not change under the methodology as the percentage increase in class revenues was not sufficient to change the rate by as much as a penny. In such cases, the existing rate was retained.

Tariff Sheets

Q. What tariff sheets are you requesting Commission approval of in this proceeding?

A. I am requesting that the Commission approve the continuation of the tariff sheets currently in effect, copies of which are contained in Document No. 5 of my

Exhibit No.__ (WRA-1).

Q. When were these tariff sheets filed and approved?

A. The tariff sheets were filed by the company on December 2, 2009 and administratively approved by the Commission Staff, as provided for in Order No. 09-0842, on December 7, 2009. The tariff sheets went into effect for the first billing cycle in January 2010 subject to refund.

Q. What revenue requirement amount is being recovered in the tariff sheet currently in effect?

A. As previously stated, the rates contained in the tariff sheets are designed to recover the $25.74 million step increase revenue requirement as approved in Order No. 09-0842.

Q. Do the tariff sheets comply with Order No. 09-0283, which requires that the costs of the five CTs and Big Bend rail facility be allocated to rate classes consistent with the approved cost of service methodology?

A. As previously discussed, yes they do comply with Order

No. 09-0283.

Q. Are the rates contained in the tariff sheets the same rates you describe above in your direct testimony?

A. Yes. They reflect the appropriate revenue allocation and rate design per Order No. 09-0283, at page 127.

Mechanism for Refund

Q. Does Tampa Electric request any specific mechanism to address refunds, if any, that may be ordered by the Commission?

A. Tampa Electric does not believe that any refunds are appropriate as a result of this proceeding, especially given that the company's actual cost incurred for the CTs and rail facility is greater than the amount approved for recovery in retail rates. However, should the Commission determine that refunds are called for, Tampa Electric does recommend certain specifications associated with refunding that will facilitate appropriate refunding while minimizing the cost and avoid the need for substantial programming work to accomplish the task.

First, the company proposes that all refunds made, if any, should be applied only to active bills at the time the refunds are being made. Second, since the step increase was implemented with Cycle 1 billing for January 2010, the company proposes that any refund also commence on Cycle 1 billing one month following the date of the order regarding such refund. If that date is within the time period when another rate change is to be made, for example when the annual adjustment clauses are going into effect, it would facilitate the programming to make the change at that time. Third, the refund mechanism should be based on an energy rate (cents/kWh) basis for all applicable customers. An energy rate based refund mechanism is currently programmed into the company's billing system and is an appropriate manner to apply the refund comparable to how the charges were first applied.

Summary

Q. Please summarize your testimony?

A. My direct testimony describes Tampa Electric's implementation of the step increase associated with the company's addition of the five CTs and Big Bend rail facility. The step increase, effective January 1, 2010, was approved in Order No. 09-0842 and is subject to refund with interest pending the outcome of the evidentiary hearing. I explain that 1) the $25,742,209 total annual operating revenue increase was derived in the same manner as it was by the Commission in Order No. 09-0842; and, 2) the step increase revenue was allocated to rate classes in a manner consistent with the cost allocation methodology prescribed by the Commission in Order No. 09-0283, which was the final order in the company's most recent rate proceeding. I then describe the benefits that flow to interruptible customers as a result of the addition of the five CTs and rail facility.

I sponsor an exhibit showing how the step increase revenues were allocated to rate classes as required by the Commission, taking into account customer group transfers and combinations approved in Order No. 09-0283. I further describe the shortfall in approved revenues because of the additional costs of the CTs and rail facility not included in the step increase.

With respect to rate design, I describe the company's derivation of rates in a manner that complies with the directions set forth in Order No. 09-0283. I sponsor tariff sheets that were approved in Order No. 09-0842, explain their compliance with Order No. 09-0283 and request that the tariff sheets be approved for continuing application at the conclusion of this proceeding. Finally, although Tampa Electric believes that no refunds are appropriate as a result of this proceeding, I describe the most appropriate method for making refunds, if any, in the event they are required by the Commission.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

OF

WILLIAM R. ASHBURN

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TAMPA ELECTRIC COMPANY
DOCKET NO. 080317-EI
CALCULATION OF REVENUE REQUIREMENTS
TOTAL ANNUAL REVENUE REQUIREMENTS

Line No.		MAY 2009 CTs (2 Units) Jurisdictional Approved Total Annual Revenue Requirement	Jurisdictional Revised Total Annual Revenue Requirement	Jurisdictional Difference
1	Net Plant in Service	$ 94,758,291	$ 92,068,272	$ (2,690,019)
2	Rate of Return	8.29%	8.29%	8.29%
3	Required Return (1x2)	$ 7,855,462	$ 7,632,460	$ (223,003)
4	O&M Expense	636,000	636,000	-
5	Depreciation	4,173,000	4,055,020	(117,980)
6	Taxes Other Than Income	2,226,000	2,159,621	(66,379)
7	Income Taxes (4+5+6)x.38575	(2,713,751)	(2,642,635)	(71,116)
8	Income Tax Effect of Interest [(1)x3.12%x-.38575]	(1,140,469)	(1,108,093)	32,375
9	Total NOI Requirement (3+4+5+6+7+8)	11,036,242	10,732,373	(303,870)
10	NOI Multiplier	1.6349	1.6349	1.6349
11	Revenue Requirement (9x10)	$ 18,043,152	$ 17,546,357	$ (496,796)

Line No.		SEPTEMBER 2009 CTs (3 Units) Jurisdictional Approved Total Annual Revenue Requirement	Jurisdictional Revised Total Annual Revenue Requirement	Jurisdictional Difference
12	Net Plant in Service	$ 137,373,373	$ 96,110,153	$ (41,263,220)
13	Rate of Return	8.29%	8.29%	8.29%
14	Required Return (12x13)	$ 11,388,253	$ 7,967,532	$ (3,420,721)
15	O&M Expense	987,000	987,000	-
16	Depreciation	6,051,000	4,142,195	(1,908,805)
17	Taxes Other Than Income	3,348,000	2,212,234	(1,135,766)
18	Income Taxes (15+16+17)x.38575	(4,006,400)	(2,831,956)	(1,174,443)
19	Income Tax Effect of Interest [(12)x3.12%x-.38575]	(1,653,365)	(1,156,739)	496,626
20	Total NOI Requirement (14+15+16+17+18+19)	16,114,488	11,320,265	(4,794,222)
21	NOI Multiplier	1.6349	1.6349	1.6349
22	Revenue Requirement (20x21)	$ 26,345,577	$ 18,507,502	$ (7,838,075)

Line No.		Big Bend Rail Jurisdictional Approved Total Annual Revenue Requirement	Jurisdictional Revised Total Annual Revenue Requirement	Jurisdictional Difference
23	Net Plant in Service	$ 44,712,909	$ 44,712,909	-
24	Rate of Return	8.29%	8.29%	8.29%
25	Required Return (23x24)	$ 3,706,700	$ 3,706,700	-
26	O&M Expense	-	-	-
27	Depreciation	988,364	988,364	-
28	Taxes Other Than Income	1,133,455	1,133,455	-
29	Income Taxes (26+27+28)x.38575	(818,491)	(818,491)	-
30	Income Tax Effect of Interest [(23)x3.12%x-.38575]	(587,606)	(587,606)	-
31	Total NOI Requirement (25+26+27+28+29+30)	4,422,420	4,422,420	-
32	NOI Multiplier	1.6349	1.6349	1.6349
33	Revenue Requirement (31x32)	$ 7,230,216	$ 7,230,216	$ -

Line No.		Amount	Ratio	Cost Rate	Weighted Cost
34	Common Equity	$ 1,632,611,907	53.96%	N/A	N/A
35	Long Term Debt	1,384,998,776	45.78%	6.80%	3.11%
36	Short Term Debt	7,904,810	0.26%	2.75%	0.01%
37	Total	$ 3,025,515,493	100.00%		3.12%

TAMPA ELECTRIC COMPANY
DOCKET NO. 080317-EI
CALCULATION OF REVENUE REQUIREMENTS
CALCULATION OF STEP INCREASE REVENUE REQUIREMENTS

Line No.		APPROVED ORDER NO. 09-00571	PSC ADJUSTMENT	APPROVED ORDER NO. 09-00842
1	Big Bend Rail Facility	$ 7,138,274	$ -	$ 7,138,274
2	May 2009 CTs	8,030,533	(496,796)	7,533,737
3	September 2009 CTs	18,908,273	(7,838,075)	11,070,198
4	Total Step Increase	$ 34,077,080	$ (8,334,871)	$ 25,742,209

Line No.		Big Bend Rail Facility	Bayside 5&6 May CTs (2 Units)	Bayside 3&4/CT 4 September CTs (3 Units)	Staff Adjusted	Aproved Step Increase
5	Net Plant in Service	$ 44,754,000	$ 36,125,000	$ 94,563,000	$ (43,953,239)	$ 131,488,761
6	Approved Rate of Return	8.29%	8.29%	8.29%	8.29%	8.29%
7	Required Return (5x6)	$ 3,710,107	$ 2,994,763	$ 7,839,273	$ (3,643,724)	$ 10,900,418
8	O&M Expense	-	212,000	658,000	-	870,000
9	Depreciation	906,000	1,391,000	4,034,000	(2,026,785)	4,304,215
10	Taxes Other Than Income	1,039,000	2,226,000	3,227,000	(1,202,145)	5,289,855
11	Income Taxes (8+9+10)x.38575	(750,284)	(1,477,037)	(3,054,754)	1,245,559	(4,036,516)
12	Income Tax Effect of Interest [(5)X3.12%X-.38575]	(538,639)	(434,784)	(1,138,118)	529,002	(1,582,539)
13	Total NOI Requirement (7+8+9+10+11+12)	4,366,184	4,911,941	11,565,400	(5,098,092)	15,745,433
14	Approved NOI Multiplier	1.6349	1.6349	1.6349	1.6349	1.6349
15	Revenue Requirement (13x14)	$ 7,138,274	$ 8,030,533	$ 18,908,273	$ (8,334,871)	$ 25,742,209

Line No.		Amount	Ratio	Cost Rate	Weighted Cost
16	Common Equity	$ 1,632,611,907	53.96%	N/A	N/A
17	Long Term Debt	1,384,998,776	45.78%	6.80%	3.11%
18	Short Term Debt	7,904,810	0.26%	2.75%	0.01%
19	Total	$ 3,025,515,493	100.00%		3.12%

TAMPA ELECTRIC COMPANY
TEST PERIOD: PROJECTED CALENDAR YEAR 2009
DEVELOPMENT OF TARGET 2010 STEP INCREASE CLASS SALES REVENUES
IN $(000)

Line No.	Rate Class	(A) Class Sales Revenue Prior to Rate Case	(B) Incremental Revenue Under Rates Effective May-09	(C) Incremental Revenue Under Rates Effective Aug-09	(D) Class Revenue Based on 2009 Increase (A)+(B)+(C)	(E) Class Revenue Based on 2009 Increase Adjusted for Customer Transfers	(F) Production Capacity Allocation Factor 12 CP & 25% AD	(G) Allocated Revenue Step Increase (F) x $25,742	(H) Target Step Increase Class Sales Revenues (E) + (G)	(I) Step Increase Revenue Under Proposed Rates	% Increase
1											
2											
3	I. Residential (RS)	454,812					52.488%				
4											
5	II. General Service -										
6	Non-Demand (GS)	53,970					6.019%				
7											
8	Total: I + II	508,782	46,901	5,991	561,674	559,126	58.507%	15,061	574,187	574,206	2.7%
9											
10	III. General Service -										
11	Demand (GSD)	266,206	27,017	3,260	296,483	299,031	36.117%	9,297	308,329	308,303	3.1%
12											
13	IV. Interruptible										
14	General Service (IS)	21,915	21,571	61	43,547	43,547	4.996%	1,286	44,833	44,827	2.9%
15											
16	V. Lighting Service (LS)										
17	A. Energy	4,683	714	77	5,474	5,474	0.380%	98	5,572	5,571	1.8%
18	B. Facilities	36,265	1,022	-	37,287	37,287	0.000%	-	37,287	37,287	0.0%
19	Total: V.	40,948	1,736	77	42,761	42,761	0.380%	98	42,859	42,858	0.2%
20											
21											
22	Total	837,851	97,225 (1)	9,389 (2)	944,464	944,465	100.000%	25,742	970,207	970,194	2.7%

Notes:

1. This total, $97,225 K, represents the achieved revenue increase in May-09 under rates approved in Order No. PSC-09-0283-FOF-EI. The approved target increase, per that order, was a $104,269 K total revenue increase less $7,117 K in service charge revenue increase less -$132 K in additional unbilled revenues for a total of $97,284 K in base rate revenues.
2. This total, $9,389 K, represents the achieved revenue increase in Aug-09 under rates approved in Order No. PSC-09-0571-FOF-EI, which was the difference between the $97,225 K achieved in May-09 and the $106,614 K achieved in Aug-09. The approved target increase, per that order, was a $113,604 K total revenue increase less $7,117 K in service charge revenue increase less -$145 K in additional unbilled revenues for a total of $106,632 K in base rate revenues.
3. Differences between RS and GSD totals in Columns D and E reflect net customer transfers between the two classes based on 2009 rate changes.
4. The derivation of class revenue under present rates after customer transfers provided on following page.
5. The increase of $25,742 K is derived by subtracting $8,335 K related to audit findings (i.e., CT installation costs) from the total step increase of $34,077 K identified in Order No. 09-0283-FOF-EI.

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CLASS REVENUE UNDER PRESENT RATES BEFORE AND AFTER CUSTOMER TRANSFERS

Class Revenue Before Transfers [1]		Customer Transfers [2]		Class Revenue After Transfers			
		RS, RSVP-1 Excluding Transfers from RST to RSVP-1	501,238	501,285	RS, RSVP-1		
RS, RST	$ 501,285	RST Transfers to RSVP-1	47				
		GS, GST Excluding Transfers to GSD Standard and GSD Optional	54,143				
GS, GST	$ 59,951	GS Transfers to GSD Standard	3,387	57,403	GS, GST		
		GS Transfers to GSD Optional	2,420				
TS	$ 437	TS	437	437	TS		
		GSD, GSDT Standard Excluding Transfers to GS and GSD Optional	195,391			559,126	RS/GS
GSD, GSDT	$ 203,851	GSD Standard Transfers to GS	2,367				
		GSD Standard Transfers to GSD Optional	6,093	274,432	GSD, GSDT		
GSD Optional	$ 12,358	GSD Optional Excluding Transfers to GS	11,465				
		GSD Optional Transfers to GS	893	20,486	GSD Optional		
GSLD, GSLDT	$ 76,161	GSLD, GSLDT Transfers to GSD Standard	75,653				
		GSLD, GSLDT Transfers to GSD Optional	508				
SBF, SBFT	$ 4,114	SBF, SBFT	4,114	4,114	SBF, SBFT		
IS1, IST1	$ 27,340	IS-1, IST-1 Transfers to IS, IST	27,340			299,031	GSD/SBF
IS3, IST3	$ 6,556	IS-3, IST-3 Transfers to IS, IST	6,556	33,895	IS, IST		
SBI1	$ 4,918	SBI-1Transfers to SBI, SBIT	4,918				
SBI3	$ 4,733	SBI-3 Transfers to SBI, SBIT	4,733	9,651	SBI		
SL-2 (Energy)	$ 1,787	SL-2 (Energy Service) Transfers to LS-1	1,787			43,547	IS/SBI
OL-1 (Energy)	$ 1,780	OL-1 (Energy Service) Transfers to LS-1	1,780				
OL-3 (Energy)	$ 1,907	OL-3 (Energy Service) Transfers to LS-1	1,907	5,474	LS-1 (Energy Service)	5,474	
SL-2 (Facilities)	$ 11,356	SL-2 (Facilities) Transfers to LS-1	11,356				
OL-1 (Facilities)	$ 9,786	OL-1 (Facilities) Transfers to LS-1	9,786	37,287	LS-1 (Facilities)	37,287	
OL-31 (Facilities)	$ 16,145	OL-3 (Facilities) Transfers to LS-1	16,145				
TOTAL	$ 944,465		$ 944,465	$ 944,465	TOTAL	944,465	

(1) MFR E-13C - Base Revenue at Final Rates Col. 2 - Summary by Old Classification (July 2009)

(2) MFR E-13C - Base Revenue at Final Rates Col. 2 (July 2009)

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PROPOSED STEP INCREASE BASE RATES
EFFECTIVE WITH CYCLE 1 BILLS FOR JANUARY 2010

Schedule/Code	Charge Descripton	Current Rate	Units	Proposed Rates	Units
RS/RST/RSVP1					
	Customer Charge:				
RS, RSVP	Standard	10.50	$/Bill	10.50	$/Bill
	Energy Charge:				
RSVP	Standard	4.696	¢/kWh	4.845	¢/kWh
RS	Tier 1	4.346	¢/kWh	4.495	¢/kWh
RS	Tier 2	5.346	¢/kWh	5.495	¢/kWh
GS/GSVP/GST					
	Customer Charge:				
GS, GSVP	Standard Metered	10.50	$/Bill	10.50	$/Bill
GS	Standard Unmetered	9.00	$/Bill	9.00	$/Bill
GST	Time-of-Day	12.00	$/Bill	12.00	$/Bill
GST	Time-of-Day (Meter CIAC paid)	10.50	$/Bill	10.50	$/Bill
	Energy Charge:				
GS, GSVP	Standard	4.696	¢/kWh	4.845	¢/kWh
GST	Time-of-Day On-Peak	12.655	¢/kWh	13.057	¢/kWh
GST	Time-of-Day Off-Peak	1.014	¢/kWh	1.046	¢/kWh
	Emergency Relay Charge:				
GS, GSVP	Standard	0.146	¢/kWh	0.151	¢/kWh
GST	Time-of-Day	0.146	¢/kWh	0.151	¢/kWh
TS					
	Customer Charge:	10.50	$/Bill	10.50	$/Bill
	Base Energy Charge:	4.696	¢/kWh	4.845	¢/kWh
GSD/GSDT					
Rate Code	**Customer Charge:**				
360, 365	Standard - Secondary	57.00	$/Bill	57.00	$/Bill
360, 365	Standard - Primary	130.00	$/Bill	130.00	$/Bill
360, 365	Standard - Subtrans	930.00	$/Bill	930.00	$/Bill
362	Time-of-Day - Secondary	57.00	$/Bill	57.00	$/Bill
362	Time-of-Day - Primary	130.00	$/Bill	130.00	$/Bill
362	Time-of-Day - Subtrans	930.00	$/Bill	930.00	$/Bill
362	T-O-D (Meter CIAC) - Secondary	57.00	$/Bill	57.00	$/Bill
362	T-O-D (Meter CIAC) - Primary	130.00	$/Bill	130.00	$/Bill
362	T-O-D (Meter CIAC) - Subtrans	930.00	$/Bill	930.00	$/Bill
364	Optional - Secondary	57.00	$/Bill	57.00	$/Bill
364	Optional - Primary	130.00	$/Bill	130.00	$/Bill
364	Optional -Subtrans	930.00	$/Bill	930.00	$/Bill
	Energy Charge:				
360, 365	Standard - Secondary	1.533	¢/kWh	1.583	¢/kWh
360, 365	Standard - Primary	1.533	¢/kWh	1.583	¢/kWh
360, 365	Standard - Subtrans	1.533	¢/kWh	1.583	¢/kWh
362	Time-of-Day Secondary - On-Peak	2.804	¢/kWh	2.898	¢/kWh
362	Time-of-Day Primary - On-Peak	2.804	¢/kWh	2.898	¢/kWh
362	Time-of-Day Subtrans - On-Peak	2.804	¢/kWh	2.898	¢/kWh
362	Time-of-Day Secondary - Off-Peak	1.014	¢/kWh	1.046	¢/kWh
362	Time-of-Day Primary - Off-Peak	1.014	¢/kWh	1.046	¢/kWh
362	Time-of-Day Subtrans - Off Peak	1.014	¢/kWh	1.046	¢/kWh
364	Optional - Secondary	5.635	¢/kWh	5.814	¢/kWh
364	Optional - Primary	5.635	¢/kWh	5.814	¢/kWh
364	Optional -Subtrans	5.635	¢/kWh	5.814	¢/kWh

Schedule/Code	Charge Descripton	Current Rate	Units	Proposed Rates	Units
	Demand Charge:				
360, 365	Standard - Secondary	8.15	$/kW	8.41	$/kW
360, 365	Standard - Primary	8.15	$/kW	8.41	$/kW
360, 365	Standard - Subtrans	8.15	$/kW	8.41	$/kW
362	T-O-D Billing - Secondary	2.75	$/kW	2.84	$/kW
362	T-O-D Billing - Primary	2.75	$/kW	2.84	$/kW
362	T-O-D Billing - Subtrans	2.75	$/kW	2.84	$/kW
362	T-O-D Peak - Secondary	5.40	$/kW	5.57	$/kW
362	T-O-D Peak - Primary	5.40	$/kW	5.57	$/kW
362	T-O-D Peak - Subtrans	5.40	$/kW	5.57	$/kW
364	Optional - Secondary	-	$/kW	-	$/kW
364	Optional - Primary	-	$/kW	-	$/kW
364	Optional -Subtrans	-	$/kW	-	$/kW
	Power Factor Charge:				
360, 362, 364	Secondary	0.002	$/ kVARh	0.002	$/ kVARh
360, 362, 364	Primary	0.002	$/ kVARh	0.002	$/ kVARh
360, 362, 364	Subtransmission	0.002	$/ kVARh	0.002	$/ kVARh
	Power Factor Credit:				
360, 362, 364	Secondary	(0.001)	$/ kVARh	(0.001)	$/ kVARh
360, 362, 364	Primary	(0.001)	$/ kVARh	(0.001)	$/ kVARh
360, 362, 364	Subtransmission	(0.001)	$/ kVARh	(0.001)	$/ kVARh
	Meter Level Discount:				
360, 365	Standard Primary	(1.0)	%	(1.0)	%
360, 365	Standard - Subtrans	(2.0)	%	(2.0)	%
362	Time-of-Day Primary	(1.0)	%	(1.0)	%
362	Time-of-Day - Subtrans	(2.0)	%	(2.0)	%
364	Optional Primary	(1.0)	%	(1.0)	%
364	Optional -Subtrans	(2.0)	%	(2.0)	%
	Transformer Ownership Discount:				
360, 365	Standard Primary	(0.71)	$/kW	(0.73)	$/kW
360, 365	Standard - Subtrans	(1.12)	$/kW	(1.16)	$/kW
362	Time-of-Day Primary	(0.71)	$/kW	(0.73)	$/kW
362	Time-of-Day - Subtrans	(1.12)	$/kW	(1.16)	$/kW
364	Optional Primary	(0.187)	¢/kWh	(0.193)	¢/kWh
364	Optional -Subtrans	(0.290)	¢/kWh	(0.299)	¢/kWh
	Emergency Relay Charge:				
360, 365	Standard Secondary	0.58	$/kW	0.60	$/kW
360, 365	Standard Primary	0.58	$/kW	0.60	$/kW
360, 365	Standard - Subtrans	0.58	$/kW	0.60	$/kW
362	Time-of-Day Secondary	0.58	$/kW	0.60	$/kW
362	Time-of-Day Primary	0.58	$/kW	0.60	$/kW
362	Time-of-Day - Subtrans	0.58	$/kW	0.60	$/kW
364	Optional Secondary	0.146	¢/kWh	0.151	¢/kWh
364	Optional Primary	0.146	¢/kWh	0.151	¢/kWh
364	Optional -Subtrans	0.146	¢/kWh	0.151	¢/kWh
SBF/SBFT					
	Customer Charge:				
359	Standard - Secondary	82.00	$/Bill	82.00	$/Bill
359	Standard - Primary	155.00	$/Bill	155.00	$/Bill
359	Standard - Subtransmission	955.00	$/Bill	955.00	$/Bill
358	Time-of-Day Secondary	82.00	$/Bill	82.00	$/Bill
358	Time-of-Day Primary	155.00	$/Bill	155.00	$/Bill
358	Time-of-Day Subtrans.	955.00	$/Bill	955.00	$/Bill
	Energy Charge - Supplemental:				
359	Standard - Secondary	1.533	¢/kWh	1.583	¢/kWh

Schedule/Code	Charge Descripton	Current Rate	Units	Proposed Rates	Units
359	Standard - Primary	1.533	¢/kWh	1.583	¢/kWh
359	Standard - Subtransmission	1.533	¢/kWh	1.583	¢/kWh
358	TOD Secondary - On-Peak	2.804	¢/kWh	2.898	¢/kWh
358	TOD Primary - On-peak	2.804	¢/kWh	2.898	¢/kWh
358	TOD Subtransmission - On-peak	2.804	¢/kWh	2.898	¢/kWh
358	TOD Secondary - Off-Peak	1.014	¢/kWh	1.046	¢/kWh
358	TOD Primary - Off-peak	1.014	¢/kWh	1.046	¢/kWh
358	TOD Subtransmission - Off-peak	1.014	¢/kWh	1.046	¢/kWh
	Energy Charge - Standby:				
359, 358	TOD Secondary - On-Peak	1.016	¢/kWh	1.049	¢/kWh
359, 358	TOD Primary - On-peak	1.016	¢/kWh	1.049	¢/kWh
359, 358	TOD Subtransmission - On-peak	1.016	¢/kWh	1.049	¢/kWh
359, 358	TOD Secondary - Off-Peak	1.016	¢/kWh	1.049	¢/kWh
359, 358	TOD Primary - Off-peak	1.016	¢/kWh	1.049	¢/kWh
359, 358	TOD Subtransmission - Off-peak	1.016	¢/kWh	1.049	¢/kWh
	Demand Charge - Supplemental:				
359	Standard - Secondary	8.15	$/kW	8.41	$/kW
359	Standard - Primary	8.15	$/kW	8.41	$/kW
359	Standard - Subtransmission	8.15	$/kW	8.41	$/kW
358	Time-of-Day Secondary - Billing	2.75	$/kW	2.84	$/kW
358	Time-of-Day Primary - Billing	2.75	$/kW	2.84	$/kW
358	Time-of-Day Subtransmission - Billing	2.75	$/kW	2.84	$/kW
358	Time-of-Day Secondary - Peak	5.40	$/kW	5.57	$/kW
358	Time-of-Day Primary - Peak	5.40	$/kW	5.57	$/kW
358	Time-of-Day Subtransmission - Peak	5.40	$/kW	5.57	$/kW
	Demand Charge - Standby:				
359, 358	TOD Secondary - Facilities Reservation	2.26	$/kW	2.33	$/kW
359, 358	TOD Primary - Facilities Reservation	2.26	$/kW	2.33	$/kW
359, 358	TOD Subtrans. - Facilities Reservation	2.26	$/kW	2.33	$/kW
359, 358	TOD Secondary - Power Supply Reservation	1.22	$/kW	1.26	$/kW
359, 358	TOD Primary - Power Supply Reservation	1.22	$/kW	1.26	$/kW
359, 358	TOD Subtrans. - Power Supply Reservation	1.22	$/kW	1.26	$/kW
359, 358	TOD Secondary - Power Supply Demand	0.48	$/kW	0.50	$/kW
359, 358	TOD Primary - Power Supply Demand	0.48	$/kW	0.50	$/kW
359, 358	TOD Subtrans. - Power Supply Demand	0.48	$/kW	0.50	$/kW
	Power Factor Charge Supplemental :				
359, 358	Secondary	0.002	$/ kVARh	0.002	$/ kVARh
359, 358	Primary	0.002	$/ kVARh	0.002	$/ kVARh
359, 358	Subtransmission	0.002	$/ kVARh	0.002	$/ kVARh
	Power Factor Charge Standby :				
359, 358	Secondary	0.002	$/ kVARh	0.002	$/ kVARh
359, 358	Primary	0.002	$/ kVARh	0.002	$/ kVARh
359, 358	Subtransmission	0.002	$/ kVARh	0.002	$/ kVARh
	Power Factor Credit Supplemental :				
359, 358	Secondary	(0.001)	$/ kVARh	(0.001)	$/ kVARh
359, 358	Primary	(0.001)	$/ kVARh	(0.001)	$/ kVARh
359, 358	Subtransmission	(0.001)	$/ kVARh	(0.001)	$/ kVARh
	Power Factor Credit Standby :				
359, 358	Secondary	(0.001)	$/ kVARh	(0.001)	$/ kVARh
359, 358	Primary	(0.001)	$/ kVARh	(0.001)	$/ kVARh
359, 358	Subtransmission	(0.001)	$/ kVARh	(0.001)	$/ kVARh
	Meter Level Discount - Supplemental:				
359	Standard - Primary	-1%		-1%	
359	Standard - Subtransmission	-2%		-2%	
358	Time-of-Day Primary	-1%		-1%	
358	Time-of-Day Subtrans.	-2%		-2%	
	Meter Level Discount - Standby:				
359, 358	Time-of-Day Primary	-1%		-1%	

Schedule/Code	Charge Descripton	Current Rate	Units	Proposed Rates	Units
359, 358	Time-of-Day Subtrans.	-2%		-2%	
	Transformer Ownership Discount - Supplemental:				
359	Standard - Primary	(0.71)	$/kW	(0.73)	$/kW
359	Standard - Subtransmission	(1.12)	$/kW	(1.16)	$/kW
358	Time-of-Day Primary	(0.71)	$/kW	(0.73)	$/kW
358	Time-of-Day Subtrans.	(1.12)	$/kW	(1.16)	$/kW
	Transformer Ownership Discount - Standby:				
359, 358	Time-of-Day Primary	(0.58)	$/kW	(0.60)	$/kW
359, 358	Time-of-Day Subtrans.	(1.13)	$/kW	(1.17)	$/kW
	Emergency Power Relay Charge - Supplemental:				
359	Standard - Secondary	0.58	$/kW	0.60	$/kW
359	Standard - Primary	0.58	$/kW	0.60	$/kW
359	Standard - Subtransmission	0.58	$/kW	0.60	$/kW
358	Time-of-Day Secondary	0.58	$/kW	0.60	$/kW
358	Time-of-Day Primary	0.58	$/kW	0.60	$/kW
358	Time-of-Day Subtrans.	0.58	$/kW	0.60	$/kW
	Emergency Power Relay Charge - Standby:				
359, 358	Secondary	0.58	$/kW	0.60	$/kW
359, 358	Primary	0.58	$/kW	0.60	$/kW
359, 358	Subtrans.	0.58	$/kW	0.60	$/kW
IS/IST					
Rate Code	**Customer Charge:**				
340	Standard - Primary	622.00	$/Bill	622.00	$/Bill
340	Standard - Subtrans	2,372.00	$/Bill	2,372.00	$/Bill
342	Time-of-Day - Primary	622.00	$/Bill	622.00	$/Bill
342	Time-of-Day - Subtrans	2,372.00	$/Bill	2,372.00	$/Bill
	Energy Charge:				
340	Standard - Primary	2.504	¢/kWh	2.577	¢/kWh
340	Standard - Subtrans	2.504	¢/kWh	2.577	¢/kWh
342	Time-of-Day Primary - On-Peak	2.504	¢/kWh	2.577	¢/kWh
342	Time-of-Day Subtrans - On-Peak	2.504	¢/kWh	2.577	¢/kWh
342	Time-of-Day Primary - Off-Peak	2.504	¢/kWh	2.577	¢/kWh
342	Time-of-Day Subtrans - Off Peak	2.504	¢/kWh	2.577	¢/kWh
	Demand Charge:				
340	Standard - Primary	1.45	$/kW	1.49	$/kW
340	Standard - Subtrans	1.45	$/kW	1.49	$/kW
342	T-O-D Billing - Primary	1.45	$/kW	1.49	$/kW
342	T-O-D Billing - Subtrans	1.45	$/kW	1.49	$/kW
342	T-O-D Peak - Primary	-	$/kW	-	$/kW
342	T-O-D Peak - Subtrans	-	$/kW	-	$/kW
	Power Factor Charge:				
340	Standard - Primary	0.002	$/ kVARh	0.002	$/ kVARh
340	Standard - Subtransmission	0.002	$/ kVARh	0.002	$/ kVARh
342	T-O-D Billing - Primary	0.002	$/ kVARh	0.002	$/ kVARh
342	T-O-D Billing - Subtrans	0.002	$/ kVARh	0.002	$/ kVARh
	Power Factor Credit:				
340	Standard - Primary	(0.001)	$/ kVARh	(0.001)	$/ kVARh
340	Standard - Subtransmission	(0.001)	$/ kVARh	(0.001)	$/ kVARh
342	T-O-D Billing - Primary	(0.001)	$/ kVARh	(0.001)	$/ kVARh
342	T-O-D Billing - Subtrans	(0.001)	$/ kVARh	(0.001)	$/ kVARh
	Meter Level Discount:				
340	Standard - Subtrans	(1.0)	%	(1.0)	%
342	Time-of-Day - Subtrans	(1.0)	%	(1.0)	%
	Transformer Ownership Discount:				

Schedule/Code	Charge Descripton	Current Rate	Units	Proposed Rates	Units
340	Standard - Subtrans	(0.40)	$/kW	(0.41)	$/kW
342	Time-of-Day - Subtrans	(0.40)	$/kW	(0.41)	$/kW
	Emergency Relay Charge:				
340	Standard Primary	0.57	$/kW	0.59	$/kW
340	Standard - Subtrans	0.57	$/kW	0.59	$/kW
342	Time-of-Day Primary	0.57	$/kW	0.59	$/kW
342	Time-of-Day - Subtrans	0.57	$/kW	0.59	$/kW
SBI					
	Customer Charge:				
349	Standard - Primary	647.00	$/Bill	647.00	$/Bill
349	Standard - Subtransmission	2,397.00	$/Bill	2,397.00	$/Bill
348	Time-of-Day Primary	647.00	$/Bill	647.00	$/Bill
348	Time-of-Day Subtrans.	2,397.00	$/Bill	2,397.00	$/Bill
	Energy Charge - Supplemental:				
349	Standard - Primary	2.504	¢/kWh	2.577	¢/kWh
349	Standard - Subtransmission	2.504	¢/kWh	2.577	¢/kWh
348	TOD Primary - On-peak	2.504	¢/kWh	2.577	¢/kWh
348	TOD Subtransmission - On-peak	2.504	¢/kWh	2.577	¢/kWh
348	TOD Primary - Off-peak	2.504	¢/kWh	2.577	¢/kWh
348	TOD Subtransmission - Off-peak	2.504	¢/kWh	2.577	¢/kWh
	Energy Charge - Standby:				
348 , 349	Primary - On-peak	1.006	¢/kWh	1.035	¢/kWh
348 , 349	Subtransmission - On-peak	1.006	¢/kWh	1.035	¢/kWh
348 , 349	Primary - Off-peak	1.006	¢/kWh	1.035	¢/kWh
348 , 349	Subtransmission - Off-peak	1.006	¢/kWh	1.035	¢/kWh
	Demand Charge - Supplemental:				
349	Standard - Primary	1.45	$/kW	1.49	$/kW
349	Standard - Subtransmission	1.45	$/kW	1.49	$/kW
348	Time-of-Day Primary - Billing	1.45	$/kW	1.49	$/kW
348	Time-of-Day Subtransmission - Billing	1.45	$/kW	1.49	$/kW
348	Time-of-Day Primary - Peak	-	$/kW	-	$/kW
348	Time-of-Day Subtransmission - Peak	-	$/kW	-	$/kW
	Demand Charge - Standby:				
348 , 349	Primary - Facilities Reservation	1.45	$/kW	1.49	$/kW
348 , 349	Subtrans. - Facilities Reservation	1.45	$/kW	1.49	$/kW
348 , 349	Primary - Power Supply Reservation	1.20	$/kW	1.25	$/kW
348 , 349	Subtrans. - Power Supply Reservation	1.20	$/kW	1.25	$/kW
348 , 349	Primary - Power Supply Demand	0.48	$/kW	0.50	$/kW
348 , 349	Subtrans. - Power Supply Demand	0.48	$/kW	0.50	$/kW
	Power Factor Charge Supplemental :				
348 , 349	Primary	0.002	$/ kVARh	0.002	$/ kVARh
348 , 349	Subtransmission	0.002	$/ kVARh	0.002	$/ kVARh
	Power Factor Charge Standby :				
348 , 349	Primary	0.002	$/ kVARh	0.002	$/ kVARh
348 , 349	Subtransmission	0.002	$/ kVARh	0.002	$/ kVARh
	Power Factor Credit Supplemental :				
348 , 349	Primary	(0.001)	$/ kVARh	(0.001)	$/ kVARh
348 , 349	Subtransmission	(0.001)	$/ kVARh	(0.001)	$/ kVARh
	Power Factor Credit Standby :				
348 , 349	Primary	(0.001)	$/ kVARh	(0.001)	$/ kVARh
348 , 349	Subtransmission	(0.001)	$/ kVARh	(0.001)	$/ kVARh
	Meter Level Discount - Supplemental:				
348 , 349	Subtransmission	(1.0)	%	(1.0)	%
	Meter Level Discount - Standby:				
348 , 349	Subtransmission	(1.0)	%	(1.0)	%

Schedule/Code	Charge Descripton	Current Rate	Units	Proposed Rates	Units
	Transformer Ownership Discount - Supplemental:				
348 , 349	Subtransmission	(0.40)	$/kW	(0.41)	$/kW
	Transformer Ownership Discount - Standby:				
348 , 349	Subtransmission	(0.33)	$/kW	(0.34)	$/kW
	Emergency Power Relay Charge - Supplemental:				
348 , 349	Primary	0.57	$/kW	0.59	$/kW
348 , 349	Subtransmission	0.57	$/kW	0.59	$/kW
	Emergency Power Relay Charge - Standby:				
348 , 349	Primary	0.57	$/kW	0.59	$/kW
348 , 349	Subtransmission	0.57	$/kW	0.59	$/kW
LS1					
	Customer Charge (Metered Street Lights)	10.50	$/Bill	10.50	$/Bill
	Energy Charge	2.419	¢/kWh	2.462	¢/kWh

SEVENTEENTH REVISED SHEET NO. 6.030
CANCELS SIXTEENTH REVISED SHEET NO. 6.030

TECO
TAMPA ELECTRIC

RESIDENTIAL SERVICE

SCHEDULE: RS

RATE CODE: 110, 111, 120, 121, 130, 131, 170, 171, 180, 181.

AVAILABLE: Entire service area.

APPLICABLE: To residential consumers in individually metered private residences, apartment units, and duplex units. All energy must be for domestic purposes and should not be shared with or sold to others. In addition, energy used in commonly-owned facilities in condominium and cooperative apartment buildings will qualify for this rate schedule, subject to the following criteria:

1. 100% of the energy is used exclusively for the co-owners' benefit.
2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each point of delivery will be separately metered and billed.
4. A responsible legal entity is established as the customer to whom the Company can render its bills for said service.

Resale not permitted.

LIMITATION OF SERVICE: This schedule includes service to single phase motors rated up to 7.5 HP. Three phase service may be provided where available for motors rated 7.5 HP and over.

MONTHLY RATE:

Customer Facilities Charge:
$10.50

Energy and Demand Charge:

First 1,000 kWh	4.495¢ per kWh
All additional kWh	5.495¢ per kWh

MINIMUM CHARGE: The Customer Facilities Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.031

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

NINTEENTH REVISED SHEET NO. 6.050
CANCELS EIGHTEENTH REVISED SHEET NO. 6.050

TECO
TAMPA ELECTRIC

GENERAL SERVICE - NON DEMAND

SCHEDULE: GS

RATE CODE: 200, 201, 920.

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted on Schedule GST only.

MONTHLY RATE:
Customer Facilities Charge:

Metered accounts	$10.50
Un-metered accounts	$ 9.00

Energy and Demand Charge:
4.845¢ per kWh

MINIMUM CHARGE: The Customer Facilities Charge.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.151¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.051

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

EIGHTEENTH REVISED SHEET NO. 6.080
CANCELS SEVENTEENTH REVISED SHEET NO. 6.080

TECO
TAMPA ELECTRIC

GENERAL SERVICE - DEMAND

SCHEDULE: GSD

RATE CODE: 360, 364, 365.

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

	STANDARD		OPTIONAL
Customer Facilities Charge:		Customer Facilities Charge:	
Secondary Metering Voltage	$ 57.00	Secondary Metering Voltage	$ 57.00
Primary Metering Voltage	$130.00	Primary Metering Voltage	$130.00
Subtransmission Metering Voltage	$930.00	Subtransmission Metering Voltage	$930.00
Demand Charge:		Demand Charge:	
$8.41 per kW of billing demand		$0.00 per kW of billing demand	
Energy Charge:		Energy Charge:	
1.583¢ per kWh		5.814¢ per kWh	

The customer may select either standard or optional. Once an option is selected, the customer must remain on that option for twelve (12) consecutive months.

Continued to Sheet No. 6.081

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:
JAN 0 1 2010

SIXTEENTH REVISED SHEET NO. 6.081
CANCELS FIFTEENTH REVISED SHEET NO. 6.081

TAMPA ELECTRIC

Continued from Sheet No. 6.080

BILLING DEMAND: The highest measured 30-minute interval kW demand during the billing period.

MINIMUM CHARGE: The Customer Facilities Charge and any Minimum Charge associated with optional riders.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR
Power factor will be calculated for customers with measured demands of 1,000 kW or more in any one billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased $0.002 for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased $0.001 for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING LEVEL DISCOUNT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Transformer Ownership Discount, Power Factor billing, Emergency Relay Power Supply Charge, and any credits from optional riders.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Transformer Ownership Discount, Power Factor billing, Emergency Relay Power Supply Charge, and any credits from optional riders.

TRANSFORMER OWNERSHIP DISCOUNT: When a customer under the standard rate takes service at primary voltage, a discount of 73¢ per kW of billing demand will apply. A discount of $1.16 per kW of billing demand will apply when a customer under the standard rate takes service at subtransmission or higher voltage.

Continued to Sheet No. 6.082

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

TECO
TAMPA ELECTRIC

THIRD REVISED SHEET NO. 6.082
CANCELS SECOND REVISED SHEET NO. 6.082

Continued from Sheet No. 6.081

When a customer under the optional rate takes service at primary voltage, a discount of 0.193¢ per kWh will apply. A discount of 0.299¢ per kWh will apply when a customer under the optional rate takes service at subtransmission or higher voltage.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 60¢ per kW of billing demand for customers taking service under the standard rate and 0.151¢/kWh for customer taking service under the optional rate. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:

JAN 0 1 2010

TECO
TAMPA ELECTRIC

SEVENTEENTH REVISED SHEET NO. 6.085
CANCELS SIXTEENTH REVISED SHEET NO. 6.085

INTERRUPTIBLE SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: IS

RATE CODE: 340

AVAILABLE: Entire Service Area.

APPLICABLE: To be eligible for service under Rate Schedule IS, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Agreement for the Purchase of Industrial Load Management Service under Rate Schedule GSLM-2. When electric service is desired at more than one location, each such location or point of delivery shall be considered as a separate customer. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

Customer Facilities Charge:

Primary Metering Voltage	$622.00
Subtransmission Metering Voltage	$2,372.00

Demand Charge:
$1.49 per KW of billing demand

Energy Charge:
2.577¢ per KWH

Continued to Sheet No. 6.086

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

FIFTEENTH REVISED SHEET NO. 6.086
CANCELS FOURTEENTH REVISED SHEET NO. 6.086

TAMPA ELECTRIC

Continued from Sheet No. 6.085

BILLING DEMAND: The highest measured 30-minute interval KW demand during the month.

MINIMUM CHARGE: The Customer Facilities Charge and any Minimum Charge associated with optional riders.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased $0.002 for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased $0.001 for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING LEVEL DISCOUNT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% of the energy and demand charge will apply to the Demand Charge, Energy Charge, Transformer Ownership Discount, Power Factor billing, Emergency Relay Power Supply Charge, and any credit associated with optional riders.

TRANSFORMER OWNERSHIP DISCOUNT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 41¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 59¢ per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

VOLTAGE ADJUSTMENT FOR CONTRACT CREDIT VALUE
The Contract Credit Value (CCV) under Rate Rider GLSM-2 will be reduced by 1% to reflect service at primary voltage, the lowest voltage service provided under this schedule. Additionally, a Metering Level Discount may apply under this schedule.

Continued to Sheet No. 6.087

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

TWENTY-THIRD REVISED SHEET NO. 6.290
CANCELS TWENTY-SECOND REVISED SHEET NO. 6.290

TECO
TAMPA ELECTRIC

TEMPORARY SERVICE

SCHEDULE: TS

RATE CODE: 050.

AVAILABLE: Entire service area.

APPLICABLE: Single phase temporary service.

LIMITATION OF SERVICE: Service is limited to a maximum of 70 amperes at 240 volts. Larger services and three phase service entrances must be served under the appropriate rate schedule, plus the cost of installing and removing the temporary facilities is required.

MONTHLY RATE:
Customer Facilities Charge:
$10.50
Energy and Demand Charge:
4.845¢ per kWh.

MINIMUM CHARGE: *The Customer Facilities Charge*

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

MISCELLANEOUS: A Temporary Service Charge of $235.00 shall be paid upon application for the recovery of costs associated with providing, installing, and removing the company's temporary service facilities. Where the Company is required to provide additional facilities other than a service drop or connection point to the Company's existing distribution system, the customer shall also pay, in advance, for the estimated cost of providing, installing and removing such additional facilities, excluding the cost of any portion of these facilities which will remain as a part of the permanent service.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:
JAN 01 2010

EIGHTEENTH REVISED SHEET NO. 6.320
CANCELS SEVENTEENTH REVISED SHEET NO. 6.320

TECO
TAMPA ELECTRIC

TIME-OF-DAY
GENERAL SERVICE - NON DEMAND
(OPTIONAL)

SCHEDULE: GST

RATE CODE: 202.

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. All of the electric load requirements on the customer's premises must be metered at one (1) point of delivery. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted.

MONTHLY RATE:
Customer Facilities Charge:
$12.00

Energy and Demand Charge:
13.057¢ per kWh during peak hours
1.046¢ per kWh during off-peak hours

Continued to Sheet No. 6.321

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:
JAN 01 2010

SIXTEENTH REVISED SHEET NO. 6.321
CANCELS FIFTEENTH REVISED SHEET NO. 6.321

TECO
TAMPA ELECTRIC

Continued from Sheet No. 6.320

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

MINIMUM CHARGE: The Customer Facilities Charge.

CUSTOMER FACILITIES CHARGE CREDIT: Any customer who makes a one time contribution in aid of construction of $70.00 (lump-sum meter payment), shall receive a credit of $1.50 per month. This contribution in aid of construction will be subject to a partial refund if the customer terminates service on this optional time-of-day rate.

TERMS OF SERVICE: A customer electing this optional rate shall have the right to transfer to the standard applicable rate at any time without additional charge for such transaction, except that any customer who requests this optional rate for the second time on the same premises will be required to sign a contract to remain on this rate for at least one (1) year.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.151¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.322

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

TAMPA ELECTRIC

NINTEENTH REVISED SHEET NO. 6.330
CANCELS EIGHTEENTH REVISED SHEET NO. 6.330

TIME-OF-DAY
GENERAL SERVICE - DEMAND
(OPTIONAL)

SCHEDULE: GSDT

RATE CODE: 362.

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

Customer Facilities Charge:

Secondary Metering Voltage	$ 57.00
Primary Metering Voltage	$130.00
Subtransmission Metering Voltage	$930.00

Demand Charge:
$2.84 per kW of billing demand, plus
$5.57 per kW of peak billing demand

Energy Charge:
2.898¢ per kWh during peak hours
1.046¢ per kWh during off-peak hours

Continued to Sheet No. 6.331

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

TECO
TAMPA ELECTRIC

FIFTEENTH REVISED SHEET NO. 6.332
CANCELS FOURTEENTH REVISED SHEET NO. 6.332

Continued from Sheet No. 6.331

POWER FACTOR
Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased $0.002 for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased $0.001 for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING LEVEL DISCOUNT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Transformer Ownership Discount, Power Factor billing, Emergency Relay Power Supply Charge, and any credits from optional riders.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Transformer Ownership Discount, Power Factor billing, Emergency Relay Power Supply Charge, and any credits from optional riders.

TRANSFORMER OWNERSHIP DISCOUNT: When the customer takes service at primary voltage a discount of 73¢ per kW of billing demand will apply. When the customer takes service at subtransmission or higher voltage, a discount of $1.16 per kW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 60¢ per kW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:
JAN 01 2010

TAMPA ELECTRIC

SEVENTEENTH REVISED SHEET NO. 6.340
CANCELS SIXTEENTH REVISED SHEET NO. 6.340

TIME OF DAY
INTERRUPTIBLE SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: IST

RATE CODE: 342.

AVAILABLE: Entire Service Area.

APPLICABLE: To be eligible for service under Rate Schedule IST, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Agreement for the Purchase of Industrial Load Management Service under Rate Schedule GSLM-2. When electric service is desired at more than one location, each such location or point of delivery shall be considered as a separate customer. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

Customer Facilities Charge:

Primary Metering Voltage	$622.00
Subtransmission Metering Voltage	$2,372.00

Demand Charge:
$1.49 per KW of billing demand

Energy Charge:
2.577¢ per KWH

Continued to Sheet No. 6.345

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:
JAN 01 2010

TECO
TAMPA ELECTRIC

TWENTY-FIRST REVISED SHEET NO. 6.350
CANCELS TWENTIETH REVISED SHEET NO. 6.350

Continued from Sheet No. 6.345

METERING LEVEL DISCOUNT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% of the energy and demand charge will apply to the Demand Charge, Energy Charge, Transformer Ownership Discount, Power Factor billing, Emergency Relay Power Supply Charge, and any credit associated with optional riders.

TRANSFORMER OWNERSHIP DISCOUNT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 41¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 59¢ per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

VOLTAGE ADJUSTMENT FOR CONTRACT CREDIT VALUE
The Contract Credit Value (CCV) under Rate Rider GLSM-2 will be reduced by 1% to reflect service at primary voltage, the lowest voltage service provided under this schedule. Additionally, a Metering Level Discount may apply under this schedule.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.025.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

FOURTH REVISED SHEET NO. 6.565
CANCELS THIRD REVISED SHEET NO. 6.565

TAMPA ELECTRIC

Continued from Sheet No. 6.560

MONTHLY RATES:
Customer Facilities Charge: $10.50

Energy and Demand Charges: 4.845¢ per kWh (for all pricing periods)

MINIMUM CHARGE: The Customer Facilities Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

DETERMINATION OF PRICING PERIODS: Pricing periods are established by season for weekdays and weekends. The pricing periods for price levels P_1 (Low Cost Hours), P_2 (Moderate Cost Hours) and P_3 (High Cost Hours) are as follows:

May through October	P_1	P_2	P_3
Weekdays	11 P.M. to 6 A.M.	6 A.M. to 1 P.M. 6 P.M. to 11 P.M.	1 P.M. to 6 P.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

November through April	P_1	P_2	P_3
Weekdays	11 P.M. to 5 A.M.	5 A.M. to 6 A.M. 10 A.M. to 11 P.M.	6 A.M. to 10 A.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

The pricing periods for price level P_4 (Critical Cost Hours) shall be determined at the sole discretion of the Company. Level P_4 hours shall not exceed 134 hours per year.

Continued to Sheet No. 6.570

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

SECOND REVISED SHEET NO. 6.585
CANCELS FIRST REVISED SHEET NO. 6.585

TECO
TAMPA ELECTRIC

Continued from Sheet No. 6.580

MONTHLY RATES:
Customer Facilities Charge: $10.50

Energy and Demand Charges: 4.845¢ per KWH (for all pricing periods)

MINIMUM CHARGE: The customer facilities charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

DETERMINATION OF PRICING PERIODS: Pricing periods are established by season for weekdays and weekends. The pricing periods for price levels P_1 (Low Cost Hours), P_2 (Moderate Cost Hours) and P_3 (High Cost Hours) are as follows:

May through October	P_1	P_2	P_3
Weekdays	11 P.M. to 6 A.M.	6 A.M. to 1 P.M. 6 P.M. to 11 P.M.	1 P.M. to 6 P.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

November through April	P_1	P_2	P_3
Weekdays	11 P.M. to 5 A.M.	5 A.M. to 6 A.M. 10 A.M. to 11 P.M.	6 A.M. to 10 A.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

The pricing periods for price level P_4 (Critical Cost Hours) shall be determined at the sole discretion of the Company. Level P_4 hours shall not exceed 134 hours per year.

Continued to Sheet No. 6.590

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

SECOND REVISED SHEET NO. 6.590
CANCELS FIRST REVISED SHEET NO. 6.590

TAMPA ELECTRIC

Continued from Sheet No. 6.585

The pricing period for the following observed holidays will be the same as the weekend hour price levels for the month in which the holiday occurs: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.151¢ per KWH of billing energy. This charge is in addition to the compensation the customer must make to the Company as contribution-in-aid of construction.

TERM OF SERVICE: The initial term of service under this rate shall be for a period of one year to be continued thereafter unless terminated by the customer with thirty days written notice.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:
JAN 01 2010

TECO
TAMPA ELECTRIC

NINTH REVISED SHEET NO. 6.600
CANCELS EIGHTH REVISED SHEET NO. 6.600

FIRM STANDBY AND SUPPLEMENTAL SERVICE

SCHEDULE: SBF

RATE CODE: 359

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard company voltage.

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

MONTHLY RATE:

Customer Facilities Charge:

Secondary Metering Voltage	$ 82.00
Primary Metering Voltage	$155.00
Subtransmission Metering Voltage	$955.00

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ 2.33 per kW-Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$ 1.26 per kW-Month of Standby Demand
(Power Supply Reservation Charge) or

$ 0.50 per kW-Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

1.049¢ per Standby kWh

Continued to Sheet No. 6.601

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

NINTH REVISED SHEET NO. 6.601
CANCELS EIGHTH REVISED SHEET NO. 6.601

TECO
TAMPA ELECTRIC

Continued from Sheet No. 6.600

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$8.41 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
1.583¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.602

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

TENTH REVISED SHEET NO. 6.603
CANCELS NINTH REVISED SHEET NO. 6.603

TECO
TAMPA ELECTRIC

Continued from Sheet No. 6.602

METERING LEVEL DISCOUNT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Transformer Ownership Discount, Power Factor billing, Emergency Relay Power Supply Charge, and any credits from optional riders.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Transformer Ownership Discount, Power Factor billing, Emergency Relay Power Supply Charge, and any credits from optional riders.

TRANSFORMER OWNERSHIP DISCOUNT: When the customer takes service at primary voltage, a discount of 73¢ per kW of Supplemental Demand and 60¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $1.16 per kW of Supplemental Demand and $1.17 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 60¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021. Note: Standby fuel charges shall be based on the time of use (i.e., peak and off-peak) fuel rates for Rate Schedule SBF. Supplemental fuel charges shall be based on the standard fuel rate for Rate Schedule SBF.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:

JAN 01 2010

SIXTH REVISED SHEET NO. 6.605
CANCELS FIFTH REVISED SHEET NO. 6.605

TECO
TAMPA ELECTRIC

TIME-OF-DAY
FIRM STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

SCHEDULE: SBFT

RATE CODE: 358

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard company voltage.

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

MONTHLY RATE:

Customer Facilities Charge:

Secondary Metering Voltage	$ 82.00
Primary Metering Voltage	$155.00
Subtransmission Metering Voltage	$955.00

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ 2.33 per kW-Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$ 1.26 per kW-Month of Standby Demand
(Power Supply Reservation Charge) or

$ 0.50 per kW-Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

1.049¢ per Standby kWh

Continued to Sheet No. 6.606

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

SIXTH REVISED SHEET NO. 6.606
CANCELS FIFTH REVISED SHEET NO. 6.606

TAMPA ELECTRIC

Continued from Sheet No. 6.605

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$2.84	per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$5.57	per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

2.898¢	per Supplemental kWh during peak hours
1.046¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest measured 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Continued to Sheet No. 6.607

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

SEVENTH REVISED SHEET NO. 6.608
CANCELS SIXTH REVISED SHEET NO. 6.608

TECO
TAMPA ELECTRIC

Continued from Sheet No. 6.607

TERM OF SERVICE: Any customer receiving service under this schedule will be required to give the Company written notice at least 60 months prior to transferring to a firm non-standby schedule. Such notice shall be irrevocable unless the Company and the customer should mutually agree to void the notice.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased $0.002 for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased $0.001 for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING LEVEL DISCOUNT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charges, Energy Charges, Transformer Ownership Discounts, Power Factor billing, Emergency Relay Power Supply Charge, and any credits from optional riders.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charges, Energy Charges, Transformer Ownership Discounts, Power Factor billing, Emergency Relay Power Supply Charge, and any credits from optional riders.

TRANSFORMER OWNERSHIP DISCOUNT: When the customer takes service at primary voltage, a discount of 73¢ per kW of Supplemental Demand and 60¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $1.16 per kW of Supplemental Demand and $1.17 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 60¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.609

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:

JAN 0 1 2010

TECO
TAMPA ELECTRIC

FOURTH REVISED SHEET NO. 6.700
CANCELS THIRD REVISED SHEET NO. 6.700

INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: SBI

RATE CODES: 348, 349

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating customers eligible for service under rate schedules IS or IST whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to self-generating customers eligible for service under rate schedules IS or IST whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. To be eligible for service under this rate schedule, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Supplemental Tariff Agreement for the Purchase of Industrial Standby and Supplemental Load Management Rider Service. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher

LIMITATION OF SERVICE: A customer taking service under this tariff must sign the Tariff Agreement for the Purchase of Standby and Supplemental Service

MONTHLY RATE:
Customer Facilities Charge:

Primary Metering Voltage	$647.00
Subtransmission Metering Voltage	$2,397.00

Demand Charge:
$1.49 per KW-Month of Supplemental Demand (Supplemental Demand Charge)
$1.49 per KW-Month of Standby Demand (Local Facilities Reservation Charge)

plus the greater of:
$1.25 per KW-Month of Standby Demand (Bulk Transmission Reservation Charge); or
$0.50 per KW-Day of Actual Standby Billing Demand (Bulk Transmission Demand Charge)

Continued to Sheet No. 6.705

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

TECO
TAMPA ELECTRIC

SECOND REVISED SHEET NO. 6.705
CANCELS FIRST REVISED SHEET NO. 6.705

Continued from Sheet No. 6.700

Energy Charge:
2.577¢ per Supplemental KWH
1.035¢ per Standby KWH

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval KW demand served by the company during the month.

Site Load - The highest KW total of Customer generation plus deliveries by the Company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.710

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 0 1 2010

SECOND REVISED SHEET NO. 6.715
CANCELS FIRST REVISED SHEET NO. 6.715

TECO
TAMPA ELECTRIC

Continued from Sheet No. 6.710

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased $0.002 for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased $0.001 for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING LEVEL DISCOUNT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% will apply to the standby and supplemental demand charges, energy charges, Transformer Ownership Discounts, Power Factor billing, Emergency Relay Power Supply Charges, and any credits associated with optional riders.

TRANSFORMER OWNERSHIP DISCOUNT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 41¢ per KW of Supplemental Demand and 34¢ per KW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 59¢ per KW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

VOLTAGE ADJUSTMENT FOR CONTRACT CREDIT VALUE
The Contract Credit Value (CCV) under Rate Rider GLSM-3 will be reduced by 1% to reflect service at primary voltage, the lowest voltage service provided under this schedule. Additionally, a Metering Level Discount may apply under this schedule.

FUEL CHARGE: Supplemental energy may be billed at either standard or time-of-day fuel rates at the option of the customer. See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: JAN 01 2010

TECO
TAMPA ELECTRIC

SECOND REVISED SHEET NO. 6.805
CANCELS FIRST REVISED SHEET NO. 6.805

Continued from Sheet No. 6.800

MONTHLY RATE:

Fixture and Fixture Maintenance Charges:

Rate Code			Lamp Size				Charges per Unit ($)			
					kWh				Non-Fuel Energy	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[3]	Lamp Wattage[4]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
		High Pressure Sodium								
800	860	Cobra[1]	4,000	50	20	10	2.85	2.24	0.49	0.25
802	862	Cobra/Nema[1]	6,300	70	29	14	2.89	1.90	0.71	0.34
803	863	Cobra/Nema[2]	9,500	100	44	22	3.28	2.10	1.08	0.54
804	864	Cobra	16,000	150	66	33	3.77	1.82	1.62	0.81
805	865	Cobra	28,500	250	105	52	4.40	2.35	2.59	1.28
806	866	Cobra	50,000	400	163	81	4.59	2.70	4.01	1.99
468	454	Flood[1]	28,500	250	105	52	4.85	2.35	2.59	1.28
478	484	Flood	50,000	400	163	81	5.15	2.71	4.01	1.99
809	869	Mongoose	50,000	400	163	81	5.87	2.73	4.01	1.99
509	508	Post Top (PT)[1]	4,000	50	20	10	3.59	2.24	0.49	0.25
570	530	Classic PT	9,500	100	44	22	10.70	1.71	1.08	0.54
810	870	Coach PT[1]	6,300	70	29	14	4.25	1.90	0.71	0.34
572	532	Colonial PT	9,500	100	44	22	10.61	1.71	1.08	0.54
571	531	Contemporary PT[1]	9,500	100	44	22	7.48	1.93	1.08	0.54
573	533	Salem PT	9,500	100	44	22	8.15	1.71	1.08	0.54
550	534	Shoebox	9,500	100	44	22	7.23	1.71	1.08	0.54
566	536	Shoebox	28,500	250	105	52	7.84	2.87	2.59	1.28
552	538	Shoebox	50,000	400	163	81	8.59	2.20	4.01	1.99
		Metal Halide								
520	522	Cobra[1]	32,000	400	159	79	5.44	3.62	3.91	1.94
556	541	Flood[1]	32,000	400	159	79	7.55	3.63	3.91	1.94
558	578	Flood	107,800	1,000	383	191	9.48	7.37	9.43	4.70
574	548	General PT[1]	14,400	175	74	37	9.83	3.37	1.82	0.91
575	568	Salem PT[1]	14,400	175	74	37	8.47	3.38	1.82	0.91
564	549	Shoebox[1]	12,800	175	74	37	7.18	3.34	1.82	0.91
554	540	Shoebox[1]	32,000	400	159	79	9.04	3.58	3.91	1.94
576	577	Shoebox	107,800	1,000	383	191	14.89	7.37	9.43	4.70

[1] Closed to new business
[2] Nema fixture is closed to new business. 100 Watt Cobra fixture is still available.
[3] Lumen output may vary by lamp configuration and age.
[4] Wattage ratings do not include ballast losses.

Continued to Sheet No. 6.810

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:
JAN 0 1 2010

TECO
TAMPA ELECTRIC

SECOND REVISED SHEET NO. 6.815
CANCELS FIRST REVISED SHEET NO. 6.815

Continued from Sheet No. 6.810

Miscellaneous Facilities Charges:

Rate Code	Description	Monthly Facility Charge	Monthly Maintenance Charge
563	Timer	$6.81	$1.29
569	PT Bracket (accommodates two post top fixtures)	$3.85	$0.05

NON-STANDARD FACILITIES AND SERVICES:

The customer shall pay all costs associated with additional company facilities and services that are not considered standard for providing lighting service, including but not limited to, the following:

1. relays;
2. distribution transformers installed solely for lighting service;
3. protective shields;
4. bird deterrent devices;
5. light trespass shields;
6. light rotations;
7. light pole relocations;
8. devices required by local regulations to control the levels or duration of illumination including associated planning and engineering costs;
9. removal and replacement of pavement required to install underground lighting cable; and
10. directional boring.

MINIMUM CHARGE: The monthly charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021

FRANCHISE FEE: See Sheet No. 6.021

PAYMENT OF BILLS: See Sheet No. 6.022

SPECIAL CONDITIONS:
On customer-owned public street and highway lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be 2.462¢ per kWh of metered usage, plus a customer charge of $10.50 per month and the applicable additional charges as specified on Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.820

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:
JAN 0 1 2010