BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080317-EI

IN RE: TAMPA ELECTRIC COMPANY'S
PETITION FOR AN INCREASE IN BASE RATES
AND MISCELLANEOUS SERVICE CHARGES

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TAMPA ELECTRIC

DIRECT TESTIMONY AND EXHIBIT

OF

MARK J. HORNICK

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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 General Manager - Polk and Phillips Power Stations.

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 my current role of General Manager, Polk and Phillips Power Stations. I am 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". I am currently the Chairman of the Gasifier Users Association, an international group of users and potential users of gasification technology.

Q. What is the purpose of your direct testimony?

A. My direct testimony supports the company's budgeted construction capital and operations and maintenance ("O&M") expenses related to generation facilities included in the 2009 test year and the company's generation expansion plan. I show that the amounts budgeted for these items are reasonable and prudent. My direct testimony discusses the resource planning process used by Tampa Electric and the capital expenditures that are needed for generation expansion and continued operations of existing units. I also discuss the O&M activities and resources needed for continued operations of the company's generating assets. Finally, my direct testimony discusses the variance between the O&M benchmark and the test year for production.

Q. Have you prepared an exhibit for presentation in this proceeding?

A. Yes, Exhibit No. _____ (MJH-1) entitled "Exhibit of Mark J. Hornick" was prepared under my direction and supervision. It consists of the following five documents:

Document No. 1	List Of Minimum Filing Requirement Schedules Sponsored Or Co-Sponsored By Mark J. Hornick
Document No. 2	2009 Production Construction Budget
Document No. 3	2009 Production O&M Budget
Document No. 4	Total System Equivalent Availability Factor
Document No. 5	Total System Heat Rate

CHANGES TO GENERATING SYSTEMS

Q. Please describe the significant changes to the Tampa Electric generating system since the last rate case proceeding in 1992.

A. There have been several significant changes to the Tampa Electric generating system since 1992. In 2007, the company served a retail winter peak load of 4,123 megawatts ("MW") compared to 2,771 MW served in 1992, an increase of approximately 50 percent or 1,350 MW. To meet this growing demand, the company added new generation to its system beginning in 1996 at the Polk Power Station. Polk Unit 1 has been named the cleanest coal-fired power plant in North America, and the world leader in producing electricity from environmentally friendly, coal-derived synthesis gas. Polk Unit 1 is a 255 MW (net winter capability) coal and distillate oil fueled unit utilizing IGCC technology. Its combined cycle technology increases efficiency because it reuses exhaust heat to produce more electricity. Sulfur is removed from the gas prior to combustion. Polk Units 2 and 3 are 184 MW (net winter capability) dual fuel (natural gas and distillate oil) simple cycle combustion turbine ("CT") generating units that began commercial operation in 2000. Polk Units 4 and 5 are 184 MW (net winter capability) natural gas fired simple cycle CTs that began operation in 2007.

As the result of environmental agreements Tampa Electric made with the U.S. Environmental Protection Agency ("EPA") and Florida's Department of Environmental Protection ("FDEP") in late 1999 and 2000, the six coal fired units at Gannon Station totaling a nominal 1,200 MW were removed from service in 2003. The existing steam turbine generators from Gannon Units 5 and 6 were integrated into two new natural gas combined cycle units. The exhaust heat from three new CTs is used to generate steam to power the existing Gannon 5 steam turbine. This three-on-one configuration makes up Bayside Unit 1, which was put into service in April 2003. The exhaust heat from four new CTs is used to generate steam to power the existing Gannon Unit 6 steam turbine. This four-on-one configuration makes up Bayside Unit 2, which began operation in January 2004. These new highly efficient and reliable units comprise the H. L. Culbreath Bayside Power Station, a nominal 1,650 MW natural gas fired facility.

The changes at Bayside Power Station have resulted in significant reductions in sulfur dioxide ("SO_2"), nitrogen oxide ("NO_x"), particulate matter, mercury and carbon dioxide ("CO_2") emissions. Besides the significant emission reductions, the repowering was the most cost effective alternative based on 1) the need to satisfy customer demand for reliable electricity at reasonable costs; 2) the ability to use existing substation and transmission facilities; 3) the availability of natural gas supplied from existing and then-proposed natural gas pipelines in the area; and, 4) the opportunity to reuse existing plant equipment.

The five oil-fired units at Hookers Point Station, totaling 220 MW, which were originally constructed in the 1940's and 1950's, were retired from service in 2002. The 12 MW oil and gas fired unit at the Dinner Lake Station was also retired from service in 2006.

Significant environmental retrofit projects have been completed at the Big Bend Power Station. Flue gas desulphurization ("FGD" or "scrubbers") equipment was added to Big Bend Units 1, 2 and 3. The scrubbers remove more than 95 percent of SO_2 from the four Big Bend units. Selective catalytic reduction ("SCR") equipment was added to Big Bend Units 3 and 4 and will be added to Big Bend Units 1 and 2 by 2010.

Q. Please describe the benefits of the environmental retrofit projects and environmental agreements with EPA and FDEP that have been undertaken since the last rate case in 1992.

A. Tampa Electric is now one of the cleanest utilities in the nation using coal and with no nuclear generation. This is the result of an industry-leading 10-year, $1.2 billion environmental improvement program that is currently in its final stages of implementation. As a result, by 2010, system wide NO_x emissions will be reduced by approximately 90 percent below 1998 levels. This significant reduction is possible due to the repowering of the Gannon Station to the natural gas fired Bayside Power Station and the installation of SCR systems on all four Big Bend units.

By 2010, system wide emissions of SO_2 will be reduced by approximately 90 percent below 1998 levels. This significant reduction was the result of several projects. In 1995, through the innovative efforts of Tampa Electric, a project was completed to integrate the flue gas from Big Bend Unit 3 with the exiting FGD system on Big Bend Unit 4. This provided the required level of sulfur removal at a very low cost. In 1999, an innovative single tower FGD system was completed to treat the flue gas from Big Bend Units 1 and 2, which also provided sulfur removal at a low cost. The scrubbers in service at Big Bend Power Station remove more than 95 percent of the SO_2 emissions from the flue gas streams. Sulfur emission reductions also resulted from the repowering of the Gannon Station to the natural gas fired Bayside Power Station.

By 2010, system wide emissions of mercury and particulate matter will both be reduced by approximately 72 percent from 1998 levels. These reductions are possible due to the combination of FGD and SCR system installations on the Big Bend units and the repowering of Gannon Station.

In addition to the reductions in regulated emissions listed above, since 1998, system-wide emissions of CO_2 have been reduced by over 20 percent bringing emissions below 1990 levels.

PLANNING PROCESS

Q. What process does Tampa Electric use to determine the need for additional generation facilities?

A. Tampa Electric uses an Integrated Resource Planning ("IRP") process. The IRP process determines the timing, type and amount of additional resources required to maintain system reliability in a cost-effective manner. The process considers expected growth in customer demand, existing and future demand side management ("DSM"), and renewable/supply-side resources needed to meet reliability requirements.

Q. Please describe the reliability criteria that Tampa Electric utilizes to determine the need for additional resources.

A. Tampa Electric utilizes a 20 percent planning reserve margin reliability criteria, as required by the Florida Public Service Commission ("FPSC" or "Commission") in Order No. PSC-99-2507-S-EU issued in December 1999. The total system firm peak is determined by including all firm wholesale agreements and excluding non-firm customer demand from the total system demand. Non-firm demand includes all interruptible service customers and DSM load reduction programs. Customers participating in these voluntary programs help defer the need for additional supply-side resources by reducing peak demands.

Q. How does the company plan and manage its generation projects?

A. The company utilizes long range planning tools to determine its future capital projects and generation plant additions. In very simplistic terms, once a need for future generating capacity is identified, a project team is assigned to begin project evaluations. The priorities in the evaluation process include the need to determine feasible alternatives, costs, schedules and participants in the project. After a specific project is identified as being the most cost-effective alternative, it must be approved by the company's management and Board of Directors. Once approved, the project team executes the project to design the plant, obtain permits, procure the equipment, construct, start-up and commission the plant until it achieves commercial operation. Throughout this process, the project is managed to meet the cost, schedule and performance goals.

Another phase of long range planning is the development of a five-year construction budget, which identifies other near term projects required to provide reliable service. The capital projects in the five-year plan include maintenance projects to replace existing plant equipment that will affect the generating unit reliability, capacity or efficiency. It also includes additions of new equipment to meet new environmental requirements.

The plan is modified as new information is obtained. Each year the company must determine its capital plan for the following year. Information regarding the generating unit availability, operating conditions, new regulations and environmental needs are reviewed and considered for inclusion in the capital plan. Some projects are not discretionary but instead are required due to environmental or safety considerations, new regulations, etc. Other projects are prioritized based upon their relative benefits. Through a review process, the projects are selected for inclusion in the next year's budget. Similarly to how new generation projects are managed, these projects are also initiated and executed by a project team. Each project goes though an estimating and approval process to ensure its benefit and need. These projects are monitored for cost, schedule and desired performance throughout the process until they are completed and in service.

CONSTRUCTION PROGRAM AND CAPITAL BUDGET

Q. What are Tampa Electric's major generation construction requirements through 2009?

A. The company's forecasted capital additions and retirements are listed in MFR Schedule B-11. Tampa Electric's 2008 Ten Year Site Plan indicates the need for additional peaking capacity in the near term. Projects are underway to add five simple cycle CTs in 2009. These generating units will be aero-derivative CTs ("Aero CTs"), each with a nominal capacity of 60 MW. The term aero-derivative indicates that this technology was originally developed for aircraft engines. The Aero CTs provide good efficiency with net operating heat rates of 10,641 Btu/kWh (higher heating value), have low emissions and have quick start capability enabling the unit to start up and achieve off line to full load in 10 minutes. These machines offer a more economic option for meeting the company's operating reserve requirements than by spinning reserve, which requires keeping large units running. The use of quick start CTs in lieu of spinning reserve benefits customers by allowing the in-service generating units to operate at higher average outputs, which improves efficiency and reduces heat rate.

One 60 MW Aero CT, Big Bend CT Unit 4, will be placed in service in September 2009 at the Big Bend Power Station and will have the capability to use either natural gas or distillate oil as a fuel source. The electrical power required to start this unit is relatively small and can be provided by an on-site engine driven generator. The output of Big Bend CT Unit 4 may be used to provide power directly to the electric grid and provide the power required to start additional generating units at Big Bend Power Station. The Florida Reliability Coordinating Council defines the ability to energize portions of a blacked out region utilizing resources independent of an energized connection as "black start capability". This black start capability could allow for faster restoration of electric service to customers following events such as hurricanes that may cause widespread damage to the electric grid. The existing 10 MW Big Bend CT Unit 1, which provides black start capability, is at the end of its useful life and will be retired after Big Bend CT Unit 4 is placed into service in 2009.

Four 60 MW Aero natural gas fired CTs will be located at Bayside Power Station and will be designated Bayside Units 3, 4, 5 and 6. As with the Big Bend CT Unit 4, Bayside Units 3 through 6 can be started without requiring an energized connection from the electric grid by using on-site generators. This will provide black start capability at the Bayside Power Station. Two of the Bayside Aero CTs will be connected to the 69 kV system to allow power from these units to start the other Bayside units without an energized connection from the grid external to the station.

Bayside Units 5 and 6 will be placed in service in May 2009. Big Bend CT Unit 4 and Bayside Units 3 and 4 will be placed in service in September 2009. These five generating units will provide needed generating capacity and operating flexibility with a high level of efficiency and environmental performance.

Q. What other major generation-related capital projects are planned for 2009?

A. There are two major, non-expansion projects planned for 2009: the continuation of Big Bend Power Station's SCR installations and the construction of rail facilities at Big Bend Power Station to accommodate solid fuel transportation.

Q. Please describe the Big Bend SCR installation project.

A. The EPA and FDEP agreements require that Big Bend Power Station achieve certain NO_x emission reductions by 2010. The company determined that the most cost-effective solution was the installation of SCRs on all four units. SCR technology was installed on Unit 4 in 2007; SCR for Unit 3 was placed in service during summer 2008; and Unit 2 and Unit 1 SCRs are scheduled to be placed in service in May 2009 and May 2010, respectively. The total cost for installation is expected to be $330 million, which will be recovered through the Environmental Cost Recovery Clause in accordance with past Commission orders.

Q. Please describe the rail facilities construction at Big Bend Power Station.

A. In 2007, Tampa Electric issued a request for proposal for solid fuel transportation to replace its existing contract that will expire on December 31, 2008. Based upon final contract negotiations, the company has contracted for bimodal transportation: water and rail. Bimodal transportation will afford the company more options to procure coal from additional sources resulting in customer benefits. Since there are no rail facilities for unloading coal at Big Bend Power Station, they must be constructed in 2008 and 2009 for deliveries to begin by January 1, 2010. Construction for this project is expected to begin in late 2008. The company expects to spend a total of $45,000,000 with $15,900,000 and $29,127,000 being invested in 2008 and 2009, respectively.

Q. What is Tampa Electric's construction capital budget for production facilities in 2009?

A. As shown on Document No. 2 of my exhibit, the construction capital budget for production facilities totals $369,593,000 for 2009. This includes $165,603,000 for recurring, non-expansion projects, $54,723,000 for the Big Bend SCR project and $29,127,000 of the total project cost of $45,000,000 for the rail facilities at Big Bend Power Station. The five Aero CTs are budgeted at $114,058,000 in 2009 of the $236,588,000 total project cost. The 2009 budget also includes $6,082,000 for transmission expansion associated with the addition of a natural gas combined cycle unit at Polk Power Station by 2013. Tampa Electric witness Jeffrey S. Chronister explains the company's proposed treatment of the Aero CTs and rail facilities in his direct testimony.

PRODUCTION O&M EXPENSES

Q. What is Tampa Electric's production O&M and non-recoverable fuel expense budgeted for 2009?

A. As shown on Document No. 3 of my exhibit, Tampa Electric's total production expense (excluding Environmental Cost Recovery Clause expense) budgeted in 2009 is $154,292,000. One item worth mentioning is the roughly $6.9 million the company plans to spend on channel dredging in 2009. Every five years, the channel adjacent to Big Bend Power Station must be dredged to allow vessels to deliver solid fuel to the plant efficiently. As discussed by witness Chronister, the company has made a pro forma adjustment to amortize the expense over five years.

Q. How does this compare with the FPSC O&M benchmark?

A. As described by witness Chronister in his direct testimony, the company's total 2009 O&M costs are expected to be under the benchmark by $7,693,000. This is despite the many challenges the company has faced since the last time O&M levels were reviewed by this Commission and it demonstrates cost control efforts have been able to offset increasing cost pressure over time. Witness Chronister notes that the company expects its 2009 budgeted expense for production to be below the benchmark. Specifically, the adjusted test year total production O&M per company books in 2009 is $142,429,000. The adjusted test year total production O&M benchmark in 1991 is $150,122,000. The production O&M benchmark calculation is shown in MFR Schedule C-37.

Q. How has the company managed to stay below the O&M benchmark for 2009 production expenses?

A. Tampa Electric is focused on controlling costs and ensuring that O&M dollars are spent in a prudent fashion. Generating technology is selected based on overall project economics that includes the expense needed for operations and maintenance. Recent generation additions such as the Bayside and Polk units have lower O&M expense than coal-fired units.

Q. Over the years, what are the major factors that have contributed to increase O&M needed to maintain Tampa Electric's fleet of generating units?

A. There are several factors contributing to increase production O&M expenses over time. The cost of materials, supplies and labor have all escalated significantly since the company's last rate proceeding and, in many cases, dramatically in recent years. For example, the cost of iron and steel has increased 88 percent and industrial chemicals have increased 85 percent over the past five years. Qualified construction labor has become more difficult to secure and labor costs are increasing. Labor costs have increased 31 percent from January 2003 to February 2008.

Changes in generating equipment technology and associated maintenance and outage costs have impacted O&M expenses as well. The additions of environmental control equipment to the generating units along with other environmental requirements have also increased the costs of O&M.

Q. Please define planned outages versus other types of outages.

A. Planned outages, as the name suggests, are defined as those outage periods that are anticipated and planned for well in advance of the actual outage period (typically at least one year in advance). Forced outages, on the other hand, are not planned and scheduled in advance of the outage period and can be the result of an in service failure or imminent failure of some generating unit component. In addition, forced outages are typically short in duration and have greatly reduced scope of work versus planned outages. Maintenance conducted during planned outages consists of large tasks that are performed infrequently and have a long duration. Typical examples are steam turbine inspections and repairs, replacement of large heat transfer surfaces in the boiler, and refurbishment of large motors and pumps. The maintenance performed during these outages is required to ensure the safe and reliable operation of the generating units.

Q. What is the impact of planned outages on Tampa Electric's generating units in the test year?

A. The 2009 planned unit maintenance durations are shown for each unit in MFR Schedule F-8 page 10 of 21. There are 13 generating units with planned maintenance outages scheduled in 2009. A total of 54 planned outage weeks are scheduled across the 13 units. The planned outage schedule varies from year to year based on the maintenance requirements of each generating unit and the need for adequate generating capacity in service to meet demand throughout the year. The planned maintenance forecasted for 2009 is typical of the past and expected future planned outage requirements.

Q. What has been the reliability of Tampa Electric's generating units over time?

A. The overall generating unit equivalent availability factor ("EAF") has increased from approximately 75 percent in 1997 to the 80 percent range now. This improvement was due in large part to the installation of new, highly reliable units at the Polk and Bayside Power Stations. Document No. 4 of my exhibit shows the total system EAF from 1997 to 2007.

Q. What has been the efficiency of Tampa Electric's generating units over time?

A. The heat rate of Tampa Electric's units has improved from approximately 10,500 Btu/kWh in 1997 to approximately 9,500 Btu/kWh. Document No. 6 of my exhibit shows the total system heat rate from 1997 to 2007.

Q. How do the maintenance needs of newer generation using CT technology compare with those of a conventional steam unit?

A. CT technology, when used in simple cycle or in combined cycle applications, provides a high level of performance and low emissions but has unique maintenance challenges. CTs operate at very high firing temperatures, which results in high efficiency, but also places high stress and thermal fatigue on the turbine components. Turbine suppliers have prescribed maintenance intervals for most key components in the machines that are dictated by the amount of use each turbine experiences. Maintenance of turbines in peaking service is typically dictated by the number of accumulated starts. Maintenance of turbines in intermediate or base load service is typically dictated by the number of accumulated operating hours. Each turbine must have the recommended maintenance performed at the intervals prescribed by the equipment manufacturer to ensure safe and reliable service.

Gas turbine components such as turbine blades, nozzles and combustion hardware are highly engineered with specialized designs and often are only available from the original equipment supplier or in some limited cases, a few aftermarket suppliers. Parts availability, particularly on new model machines can be very limited and if not managed properly, can have a detrimental impact on turbine reliability and availability.

Q. How has Tampa Electric addressed the maintenance needs of its CTs?

A. The CTs used by Tampa Electric at Polk and Bayside Power Stations are General Electric ("GE") 7F frames and they have a high level of performance and low emissions. The availability of parts and technical support services for these machines is very limited; therefore, Tampa Electric entered into contractual services agreements ("CSAs") with GE to perform ongoing maintenance of these turbines. Under these agreements, GE is responsible for supplying maintenance services and parts necessary to perform all planned and unplanned maintenance on the covered units in order to keep them in good working condition and in an effort to maintain availability and reliability while operating in a cost-effective and safe manner.

Q. What are the benefits of using CSAs for the ongoing maintenance needs of Tampa Electric's CTs?

A. Under CSAs, the availability of spare parts is improved and the inventory requirements for these parts are reduced. The risks of cost increases due to reduced maintenance interval requirements, parts life risk and fallout from inspection are borne by GE. Unplanned maintenance expense and the management of maintenance services including subcontracting qualified craft labor and providing technical support are also GE's responsibility. Maintenance costs are levelized and escalation rates are pre-negotiated.

Q. Are contractual services agreements an accepted industry practice for the maintenance of CTs?

A. Yes. It is a common practice for CT operators to enter into CSAs with the original equipment supplier. According to GE, 504 of the 590 operating 7F class CTs in North America are covered by CSAs. In the southern region of the United States, 307 of the 334 units are covered by CSAs.

Q. Has Tampa Electric taken other measures to control generation O&M costs over this same period?

A. Yes. Tampa Electric has taken a number of steps to ensure that its team members are safe, productive and focused on the right priorities while managing costs. Some of the key measures are in the areas of safety, staffing and productivity, and operating goals and priorities.

Tampa Electric emphasizes safety over all other considerations. Considerable effort has been placed on safety improvements across the entire company, including in Energy Supply, which implemented programs to deal with hazard elimination and personal safety behavior improvement. The company investigates safety incidents and near miss events to determine the root cause and appropriate corrective actions. The company observes team members while performing tasks to reinforce positive safety behaviors and coach them on opportunities to improve. These efforts have reduced the Occupational Safety and Health Administration recordable injury rates, which represents the annual number of recordable incidents per 100 employees, in the Energy Supply area from 3.80 in 2003 to 1.43 in 2007, which is a 68 percent reduction.

Staffing levels in Energy Supply have been reduced from over 1,000 in 1991 to an estimated 807 in 2009. This reduction took place during a period when net generation increased by nearly 1,000 MW and was accomplished through efficiency improvements and by the installation of less O&M intensive generating technologies such as the conversion from Gannon Station's coal-fired generation to Bayside Power Station's gas-fired generation. Front line craftsmen are trained and encouraged to perform tasks outside of traditional boundaries safely. In cooperation with the collective bargaining unit at the Big Bend and Bayside Power Stations, team members now perform maintenance and operation tasks as needs dictate without barriers from prior strict work rules. A pay-for-skills system encourages team members to learn and apply key skills in addition to their primary maintenance craft at the Polk and Phillips Power Stations. For example, a team member who has a core skill in mechanical maintenance may learn certain skills traditionally limited to electricians. When a task involves both mechanical and electrical work elements, one team member is able to complete the work, which improves overall workforce efficiency and productivity and allows for reduced staffing levels.

Tampa Electric ensures team members' priorities are aligned with business goals by setting business goals at the company level, which are in turn supported by goals at the department and business unit level. Team members can receive incentive pay known as Success Sharing if certain goals are met. Progress on goal achievement is regularly reviewed with team members. All of these actions have contributed to the company's ability to control costs while still providing reliable service to customers.

Q. Please summarize your direct testimony.

A. Tampa Electric serves a retail peak load of 4,123 MW compared to almost 2,800 MW served in 1992. To meet this growing demand, the company added new generation to the system beginning in 1996 at the Polk Power Station. The company has also made significant investments in environmental projects including the repowering from coal to natural gas at Bayside Power Station and the installation of scrubbers and SCRs at Big Bend Power Station. The production capital construction and O&M expenses projected for 2009 are reasonable, prudent and below the FPSC O&M benchmark. The budgets were developed and include expenditures that will improve heat rate, prevent forced outages and help ensure the availability of efficient, reasonably priced generation for customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

MARK J. HORNICK

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LIST OF MINIMUM FILING REQUIREMENT SCHEDULES

SPONSORED OR CO-SPONSORED BY MARK J. HORNICK

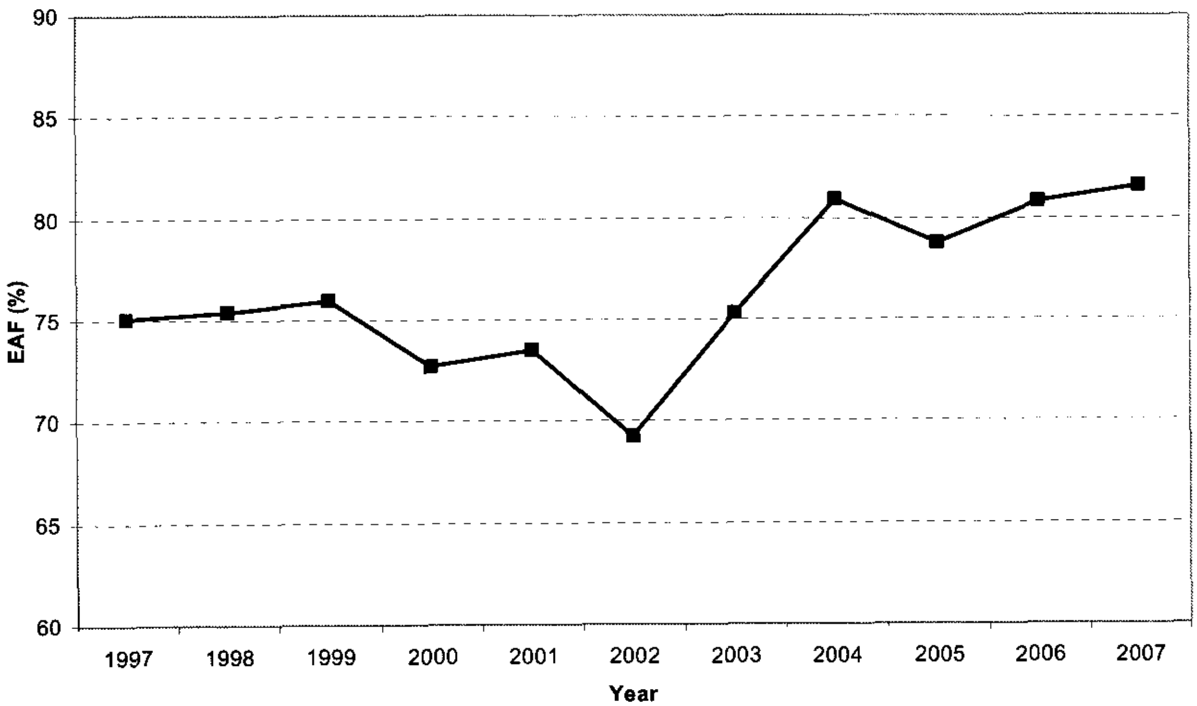
MFR Schedule	Title
B-11	Capital Additions And Retirements
B-12	Production Plant Additions
B-13	Construction Work In Progress
C-8	Detail Of Changes In Expenses
C-9	Five Year Analysis - Change In Cost
C-33	Performance Indices
C-34	Statistical Information
C-36	Non-Fuel Operations And Maintenance Expense Compared To CPI
C-37	O&M Benchmark Comparison By Function
C-39	Benchmark Year Recoverable O&M Expenses By Function
C-41	O&M Benchmark Variance By Function
F-8	Assumptions

2009 Production Construction Budget ($000)		
Big Bend Power Station	95,707	
Bayside Power Station	13,353	
Polk Power Station	9,667	
CSA Capital - Bayside & Polk	32,329	
Environmental & Other	14,547	
Recurring Capital	**$165,603**	
		Total Project
Aero-Derivative CT Expansion	114,058	236,588
Total SCR Project w/o AFUDC	54,723	---
Rail Expansion Big Bend	29,127	45,000
Transmission for NGCC	6,082	---
Non-Recurring Capital	**$203,990**	
Total Energy Supply Capital - 2009	**$369,593**	

2009 Production O&M Budget
($000)

Big Bend Power Station	87,975
Bayside Power Station	15,650
Polk Power Station	22,976
Phillips Power Station	1,821
CSA O&M - Bayside & Polk	2,426
Environmental, Health & Safety	5,329
Non-Recoverable Fuel	6,889
Fuels, Sales & Engg. & Construction	5,925
Support Services	5,301
Environmental Cost Recovery Clause	18,038
Total Energy Supply O&M Including ECRC	**$172,330**
Environmental Cost Recovery Clause	(18,038)
Total Energy Supply O&M Excluding ECRC	**$154,292**

Total System Equivalent Availability Factor (EAF) 1997 through 2007



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Total System Heat Rate
1997 through 2007