BEFORE THE PUBLIC SERVICE COMMISSION

ORIGINAL

In Re: Petition for approval of new environmental program for cost recovery through Environmental Cost Recovery Clause by Tampa Electric Company	))))))	DOCKET NO. 050958-EI FILED: January 24, 2007

PREFILED TESTIMONY

OF

JOHN B. STAMBERG

ON BEHALF OF

THE CITIZENS OF THE STATE OF FLORIDA

Harold McLean
Public Counsel

Patricia A. Christensen
Associate Public Counsel

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Attorneys for the Citizens
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BEFORE THE FLORIDA PUBLIC UTILITIES COMMISSION

Petition of Tampa Electric Company	**)**	
For approval of a new environmental	**)**	
program for cost recovery through	**)**	
the Environmental Cost Recovery Clause	**)**	**Docket No: 050958-EI**

PREFILED TESTIMONY OF JOHN B. STAMBERG

I. INTRODUCTION

Q: Please state your name.

A: My name is John B Stamberg, P.E.

Q: On whose behalf are you submitting testimony?

A: State of Florida's Office of Public Council (OPC).

Q: How are you currently employed?

A: Since 1981, I have been a Vice President at Energy Ventures Analysis, Inc (EVA), an energy consulting firm located at 1901 North Moore Street in Arlington, Virginia. Between 1974-1981, I had been employed as a Principal at Energy and Environmental Analysis Inc in Arlington, Virginia. During 1967 to 1974, I worked at the US Environmental Protection Agency in the Office of Air and Water Programs.

Q: What are your qualifications for providing your testimony?

A: I have a Bachelor of Science in Civil Engineering from the University of Maryland and a Master of Science Degree in Civil Engineering from Stanford University. I have been a licensed professional engineer since the mid 1990's.

I have conducted engineering and environmental analyses of numerous powerplants, industries and municipal systems. I have completed analyses of potential environmental control systems and cost at over 150 coal-fired powerplants and done engineering site visits of over 60 powerplants for various projects. My resume is attached as Exhibit JBS-1.

Q: Have you previously testified before the Florida Public Service Commission?

A: Yes, I have. I testified in Docket No: 031033-E1 as an engineer on behalf of CSX Transportation relating to potential rail car delivery versus the current barge delivery of coal to TECO's Big Bend and Polk County powerplants.

Q: Have you previously testified as an environmental expert before other regulatory bodies?

Yes, I have. I have testified in regulatory proceedings in Louisiana, New Jersey, Maryland, North Carolina, South Carolina and Virginia.

Q: Please describe the assignment you were given by the Office of Public Council.

A: EVA was asked to review the Tampa Electric Company (TECO) petition dated December 27, 2005 and revised March 16, 2006 that are part of Florida Public Service

Commission Docket No. 050958-EI and the materials that have been submitted by TECO as part of this docket. This petition requested approval for $21.651 million for 13 capital improvement projects associated with the Big Bend Flue Gas Desulfurization System (FGD) Reliability Program for cost recovery through the Environmental Cost Recovery Clause. TECO indicates in its petition that these 13 listed projects were required to improve the reliability of the FGD scrubbers servicing Big Bend Units #1, #2 and #3 and were necessary to comply with the February 2000 Consent Decree between the US Environmental Protection Agency (USEPA) and TECO. EVA was asked to provide an independent assessment on if these listed projects were required to comply with the Consent Decree requirements. I provided engineering assessments of the thirteen individual listed capital improvement projects.

Q: What is the purpose of your testimony?

A: To provide the results of an engineering assessment of the thirteen projects listed in the TECO petition and discuss their effect on FGD system operations and reliability. Secondly, to provide an opinion on if these projects were needed to comply with the future Consent Decree requirements.

II. Big Bend Units 1-4 Electrical Isolation Project

Q: What is the capital cost of the "Big Bend Units 1-4 Electrical Isolation" project that TECO has requested cost recovery through the Environmental Cost Recovery Clause (ECRC)?

A. TECO has requested that $6,600,000 in capital cost be recovered under the ECRC per TECO's December 27, 2005 petition entitled "Petition of Tampa Electric Company for Approval of a New Environmental Program for Cost Recovery Through the Environmental Cost Recovery Program." TECO supported their request in Exhibit D "Tampa Electric Company – Big Bend Desulfurization System Reliability Study".

Q: How was the $6,600,000 estimate prepared?

A. Per Bates Stamp page 5755 of Tampa Electric Company Response to OPC Production of Documents #5, the cost components for this project were:

Direct Cost	$3,822,723
Indirect Cost	181,238
Administrative Cost	134,203
Adjustments/Escalation	375,837
Total	$4,514,000

According to page 5732 of this same Tampa Electric Company response, this estimate was first rounded upward to $5,000,000 and then added a $1.6 million contingency (32% of $5 million or alternatively 47.9% of the $4.514 million original project cost estimate).

Q: What equipment would be served by the new electric isolation project transformer 3B?

A: Per Tampa Electric Company Response to OPC Interrogatory No. 38 (1/12/07), this transformer with about 20,522 KVA would serve 6 downstream smaller transformers (B3003A, B3003B, B3004A, B3004B, B3005A, and B3005B). Four of these downstream transformers are small and two are large (B3004A and B3004B).

The two large downstream transformers on the circuit created by this project would serve variable frequency induced draft (I.D.) fans 3A and 3B that are part of the boiler system (not directly part of environmental control equipment). The I.D. fans would comprise 92.6 percent of the load that would be serviced by the project's new proposed transformer 3B (see Exhibit JBS-2). The variable frequency I.D. fans drive system has a high capital cost and is a deluxe I.D. fan feature that allows improved I.D. fan speed control that can reduce onsite electrical use.

Q: What is the load would be served by the proposed new transformer from pollution control equipment and from other miscellaneous onsite uses?

A: In comparison to the variable speed I.D. fans, the electricity load from pollution specific equipment served through the proposed new transformer 3B is trivial at 0.4% of the total projects load for FGD specific equipment and 0.6% for SCR specific equipment. Unidentified "motors and lights and other equipment" accounts for an additional 6.4% of the load. Without the two large I.D. fans, these smaller loads alone would not justify use of a 20,522 KVA transformer.

Q: What are the existing I.D. fans 3A and 3B electrical loads? Will the transformer capacity that services these fans be considered surplus capacity and could be available for other use?

A. The existing loads for I.D. fans 3A and 3B are approximately 19,000 KVA but are fixed frequency loads. Thus, if the proposed electric isolation project with a new transformer 3B is built, approximately 19,000 KVA from existing transformers elsewhere onsite will be freed up for other large electricity loads from other large onsite equipment loads.

Q: What was the frequency of forced outages caused by the existing I.D. fans 3A and 3B failures due to transformer failure in the last 5 years?

A. There were no recorded FGD related forced outages that have occurred within the past 5 years because of failure of transformer(s) servicing I.D. fans 3A and 3B.

Q: What was the extent of forced derates caused by I.D. fans 3A and 3B failures due to transformer failure in the last 5 years?

A. There were no recorded forced derates over the last 5 years because of transformer failure or lack of transformer capacity of I.D. fans 3A and 3B.

Q: In your opinion, is the $6,600,000 electrical isolation project reasonable and prudent under the ECRC clause?

A. No, it is neither reasonable nor prudent under the ECRC clause. Given the electrical systems demonstrated high availability and that it is designed to service primarily the large I.D. fan load that is not part of the pollution control system, the electrical isolation system project with its proposed new transformer is not necessary to achieve compliance with the consent decree or any other known environmental law or regulation. As discussed in Mr. Hewson's testimony, TECO concurs with this assessment by including the first phase of this project in their Quarterly Report listing of capital projects not required by the Consent Decree.

Q: Are there other potential reasons outside of the environmental requirements to justify the proposed electric isolation project?

A. The variable frequency (variable speed) driven 3A and 3B I.D. fan motors should provide energy efficiency benefits (lower onsite power consumption) and improved operational control. By placing them on a separate circuit with a new transformer, TECO would reduce the electrical loadings on other circuits and reduce the effect of any planned maintenance events on other parts of the plant.

Given the TECO material submitted on this project, it is difficult to determine if there may be other operational reasons outside environmental requirements to justify this project.

III. Group A--Big Bend Units 3-4 (Split Inlet Duct and Split Outlet Duct)

Q: What is the capital cost of the "Group A Big Bend Units 3-4 Split Inlet and Outlet Ducts" project that TECO has requested cost recovery through the Environmental Cost Recovery Clause (ECRC)?

A. TECO has requested that $4,945,000 in capital cost be recovered under the ECRC per TECO's December 27, 2005 petition entitled "Petition of Tampa Electric Company for Approval of a New Environmental Program for Cost Recovery Through the Environmental Cost Recovery Program" imported with Exhibit D "Tampa Electric Company – Big Bend Desulfurization System Reliability Study".

Q: What are the cost of each split duct project in Group A?

A. The individual projects in TECO's petition are:

- Big Bend Units 3-4 Split Inlet Duct $116,000
- Big Bend Units 3-4 Split Outlet Duct $4,829,000

Q: Would you agree with TECO's conclusion that the split duct projects will significantly improve the reliability of the environmental equipment?

A: No, I do not.

Q: Has there ever been a forced outage, forced derate or FGD bypass event(s) (a.k.a. de-integration events) of Big Bend Unit 3 or Unit 4 or both Units 3 and 4 attributed to failures or problems with existing common inlet duct or outlet duct for the FGD?

A. Yes, according to TECO quarterly reports, there have been two bypass events cited in the disintegration reports being attributable to duct work.

(1) First Quarter 2005: "1.33 hours for inspection and repair of duct work" with FGD bypass (de-integration)."

(2) First Quarter 2006: "8.55 hours for FGD system and duct work maintenance" with FGD bypass (de-integration).

Q: Had TECO no longer been allowed to bypass (future limitation), would these events have required a forced outage?

A. Given the limited descriptions provided, one cannot definitively determine if the two events under the future limitations would have triggered a forced outage or could have been delayed to the next scheduled maintenance period and therefore I am forced to speculate. Based upon the little description provided, I would guess that the first quarter 2005, 1.33-hour event would appear to cause an outage, while the first quarter 2006, 8.55-hour event appears to be a FGD system problem in which the duct maintenance may have been discretionary and coordinated with other FGD system maintenance during the event. If the duct maintenance was discretionary, it alone would likely have not triggered a forced outage.

Q: Based on the above history, what would the range of forced or maintenance outages be for the five year period?

A. Based upon the five-year outage history provided by TECO, the lower range of the forced or maintenance outage rate would be 1.33 hours per 5 years or 0.266 hours per year, or 0.011 days per year for one unit (No. 3). The upper forced or maintenance outage rate would be a combined 9.88 hours (8.55 hours plus 1.33 hours) per 5 years or 1.976 hours per year or 0.082 days per year for one unit (No. 3).

Q: What rate of force or maintenance outages were assumed in the "Tampa Electric Company Big Bend Station Flue Gas Desulfurization System Reliability Study for Group A Splitting of the Inlet and Outlet Ducts"?

A. The TECO study assumptions were not developed based on historical record but instead were "based on experience" for which no supporting documentation was provided. The TECO study assumptions were:

- Forced Outages: 2.0 days/year per unit
- Maintenance Outages: 2.0 days/year per unit

Q: Can you compare the assumptions for Group A used in the reliability study and the 5-year history rates for Group A outages?

A: As is shown in Exhibit JBS-3, the TECO study's assumed avoided forced rate for the split duct Group A projects would total 192 hours per year. This is far higher that the documented 5 year historic rate that would be between 0.266 hours and 1.976 hours/year. The TECO assumption is between 97 and 722 times higher than the historic outage rate used for Group A projects.

Q: Can you compare the project cost, net present value (NPV) of capital expenditures, NPV of savings, net savings and cost benefit ratio of TECO's assumptions in the reliability study to historic rates you presented earlier?

A. Yes. This comparison is provided in Exhibit JBS-4. For the NPV estimate based upon the historical forced outage rate range, I have simply multiplied the TECO NPV estimate ($7.131 million) by the ratio of the 5-year historic outage rate (0.266 hr/year (low) to 1.976 hr/year (high)) to the TECO study outage rate (192 hr/year). By applying the 5-year historic outage rate range, the split duct projects would have a net present value of savings of only $10,000 to $73,500.

Q: Based on historic performance rate, would you consider the Group A Split Duct projects reasonable and prudent under the ECRC?

A. No, I would not. In my opinion, a NPV of savings of only $10,000 to $73,500 would not justify a nearly $5 million capital project.

Q: Would you consider that the Group A projects are required to comply with the Consent Decree?

A. No, I would not. First, the projects would not appreciably improve the reliability of the FGD system. Second, at the time the consent decree was negotiated and signed, the parties did not believe that splitting the ducts would be necessary to comply with the Consent Decree and therefore did not include them on their list of needed projects to optimize FGD performance (see Hewson testimony). Finally, TECO is not alone in electing to combine multiple units into a single FGD system in order to capture the economies of scale capital savings. Many utilities have considered combined systems to meet their facility reliability needs without splitting the ducts between units.

Q: What has been the history of Group A projects in the 21 quarterly reports prepared by TECO as work pursuant to paragraph 44.B (2) of the Consent Decree of Civil Action No. 99-2524-CIV-T-23F?

A. Only a few inlet duct related projects that have been included in the TECO Quarterly Compliance reports to USEPA. These projects were on the list of Section 44.B (2) projects that were not being required by the consent decree include:

- <u>Unit #3-4 common inlet duct replacement</u>- TECO reports that the common inlet duct replacements occurred during the 2nd quarter of 2003, 4th quarter of 2004 and the 2nd Quarter of 2006.

- Unit #3-4 split inlet duct — TECO reports that this project was started during the 3rd quarter 2006 with an estimated project cost of \$4.8 million. This project estimate is far greater than the petition split inlet duct request for \$0.116 million.

Q: Why would TECO list the split inlet duct project as \$4,800,000 during the 3rd quarter 2006 and as \$116,000 in the December 2005/March 2006 petition?

A. I do not know the answer. However, it appears that even in its petition TECO considers only a small portion of the split inlet duct project as being associated with the Consent Decree. As I discussed earlier above, I do not believe that any of this project is associated with the Consent Decree requirements.

IV. Group C Big Bend Gypsum Projects

Q: What is the capital cost of the "Group C Projects for Gypsum Processing" project that TECO has requested cost recovery through the Environmental Cost Recovery Clause (ECRC)?

A. TECO has requested that \$3,489,000 in 2006 dollars in capital cost be recovered under the ECRC per TECO's December 27, 2005 petition entitled "Petition of Tampa Electric Company for Approval of a New Environmental Program for Cost Recovery Through the Environmental Cost Recovery Program" imported with Exhibit D "Tampa Electric Company – Big Bend Desulfurization System Reliability Study".

Q: What are the cost of each project in Group C?

A. Per the above petition the individual projects are:

- Gypsum Fines Filter ($3,179,000)- $1,566,000 in 2008 and $1,613,000 in 2009.
- Gypsum Filter Vacuum Pump Upgrades ($691,000)- $340,000 in 2008 and $351,000 in 2009.

Q: Has there ever been a forced outage or forced derate of any of the Big Bend units caused by the failure of the gypsum dewatering system?

A. No forced outage or forced derate has been reported with the root cause being gypsum processing in the 5 years of quarterly reports to the U.S. EPA submitted by TECO under the Consent Decree for Civil Action No. 99-2524-T-23F.

Q: In the TECO FGD Optimization Plan specifically identify any modifications to the gypsum dewatering system as being required to comply with the Consent Decree?

A: As discussed in Mr. Hewson's testimony, the plan did not specifically list any specific elements of the gypsum dewatering as part of its needs to comply with the Consent Decree requirements. The plan had generally identified that a study would be conducted to determine what spare parts were needed for the full range of the station's process elements, including the gypsum dewatering system, would be needed to improve the system reliability. However, the results of this work were not included in the plan, nor did the subsequent quarterly compliance reports mention that a gypsum fine filter was a needed spare part.

Q: Did the vendor of the gypsum vacuum filter provide a performance guarantee with the existing system?

A: Yes. Raytheon Engineers and Constructors, Inc. provided a performance guarantee with item 1c that states "feed solids must have a minimum average size of 41 microns with no more than 5% of the particles having a size less than 5 microns . . ."

Q: Does it appear that the gypsum solids are substantially finer or have a particle size distribution below the guarantee level?

A. The one particle size distribution supplied by TECO (Results: Analysis Report, Run 17, Record Number 332, Analyzed Friday, December 22, 2006, 1:30 p.m.) showed particle size distribution similar to the criteria in the guarantee.

Q: Are the problems identified as failures by TECO in its response to Citizen's Interrogatory No. 24, a result of bad engineering or a result of poor operation?

A. It is likely neither bad engineering or poor operation. Gypsum, which is created in the FGD system, is a gritty material (same as in drywall when dry) is tough on equipment and requires operator attention. The gypsum transitions from a pumpable slurry, to a thick/pasty consistency and eventually to a cake in gypsum processing. It is this difficulty of operation that resulted in the original design to have 100% redundancy.

Q: It is reasonable and prudent to pursue the Group C as an environmental project under the ECRC clause?

A. For the most part, the answer is no. The additional funds for gypsum filter system and vacuum filter appear to make an improved gypsum suitable for sale into the gypsum market as a more economical choice than making gypsum suitable for disposal. The system was originally designed and was operated in the past to make gypsum suitable for disposal. While upgrading the gypsum to salable grades may be laudable and maybe economical, it would not be considered as necessary to comply with the requirements of the Consent Decree. Since this project is also not required to meet a new environmental requirement, it should not be eligible for recovery under the ECRC clause.

However, the gypsum filter pump upgrade project may be appropriate to include in the ECRC. When TECO started to use recycled water beginning in 2002, the vacuum seal water became more corrosive and required the use of more corrosion resistant material for the pump casing. In addition, the equipment supplier currently suggests more air-flow capacity based upon their experience with newer FGD installations. EVA concluded that these vacuum pump upgrades would likely improve future FGD operation and reliability and thereby would be an appropriate maintenance item to include in the ECRC.

V. Big Bend Units 3-4 FGD Booster Fan Capacity Expansion

Q: What is the capital cost of the "Big Bend Units 3-4 FGD Booster Fan Capacity Expansion" project that TECO has requested cost recovery?

A. TECO has petitioned that $1,849,000 in capital cost be recovered through the base rates and not through the ECRC per TECO's March 2006 petition.

Q: Has TECO already completed the 3-4 FGD booster capacity project?

A. Yes. The project to boost unit #3 and #4 FGD capacity has been completed for the existing combined Units 3 and 4 duct configuration. Per the Fourth Quarter 2004, TECO reported completion of one portion of the project at a cost of $923,000 and in the Second Quarter 2005 TECO reported completion of a $400,000 additional cost for another portion of the project. Thus, TECO has already completed this project at a cost of $1,323,000 for the existing combined Unit 3 and Unit 4 duct.

Q: Why is the newly proposed "Big Bend Units 3-4 FGD Booster Fan Capacity Expansion" needed if the problem has already been reported as complete?

A. This new project is needed only if the Units 3 and 4 existing combined duct is split into two ducts. The split duct will require more booster fan capacity than the existing combined duct.

Q: If the Group A Big Bend Units 3-4 (Split Inlet Duct and Split Outlet Duct), is not reasonable and prudent under the ECRC as you earlier have stated, is this new Units 3-4 FGD Booster Fan Capacity Expansion also not reasonable or prudent under ECRC?

A. Yes. This $1,849,000 project is not reasonable or prudent for recovery under the ECRC since it is not associated with compliance with a new environmental law or regulation. As a result, the determination about the prudence of this equipment should be part of a base rate determination as requested by TECO.

Q: In summary, if the Group A duct split projects are built at $4,945,000, does it require another $1,849,000 investment in booster fans?

A. Yes. The splitting of the ducts for Units 3 and 4 requires an investment of $6,788,000 and must include both projects.

VI. Group B Mist Eliminator Projects

Q: What is the capital cost of the "Group B Mist Eliminator Projects" that TECO has requested cost recovery through the Environmental Cost Recovery Clause (ECRC)?

A. TECO has requested that $3,617,000 in capital cost be recovered under the ECRC per TECO's December 27, 2005 petition entitled "Petition of Tampa Electric Company for Approval of a New Environmental Program for Cost Recovery Through the Environmental Cost Recovery Program" imported with Exhibit D "Tampa Electric Company – Big Bend Desulfurization System Reliability Study".

Q: What are the cost of each project in Group B?

A. Per the above petition the individual projects are:

- Big Bend Units 1-4 Mist Eliminator Upgrades at $834,000 in 2006, $789,000 in 2007, $66,000 in 2008 and $870,000 in 2009.
- Big Bend On Line Mist Eliminator Wash System at $753,000 in 2009.

- Big Bend On Line Nozzle Wash System at $30,000 in 2006 and $564,000 in 2007.

Q: Was the "Group B Projects" included in the "Flue Gas Desulfurization System Optimization Plan – Phase I" presented to the U.S. EPA, Region IV in TECO's May 31, 2000 plan prepared pursuant to the Consent Decree; Civil Action No. 99-2524-CIV-T-23F?

A. Yes. A, B, C and D tower demister changes were included in the Plan for Units 3 and 4.

Q: Was the "Group B Projects" included in the "Flue Gas Desulfurization System Optimization Plan – Phase II" presented to the U.S. EPA, Region IV in TECO's February 20, 2001 plan prepared pursuant to the Consent Decree; Civil Action No. 99-2524-CIV-T-23F?

A. Yes, as stated above.

Q: Was the "Group B Mist Eliminators for Units 1 and 2" included in any of the quarterly reports that presents scope of work pursuant to Paragraph 44.3(2) of the Consent Decree; Civil Action No. 99-2524-CIV-T-23F?

A. Yes. The must eliminator upgrades for Units 1 and 2 were included in the First Quarter 2006 (4/27/06). By including this project on a listing of projects not specifically required under the consent decree, TECO acknowledges that they may not be specifically associated with the Consent Decree compliance.

Q: Have the plugging of Mist Eliminators caused or could cause forced outages or forced derates of Big Bend Units 1-4?

A. Yes, it has according to data supplied by TECO.

Q: Are the Group B Mist Eliminator Projects reasonable and prudent environmental projects from an engineering perspective?

A. Yes, I believe that they are. The plugging of the must eliminators have caused historic derates that could be reduced through Group B project implementation. Once by-pass (de-integration) is phased out under the consent decree, TECO will need to clean the must eliminators "on the run". Thus, I consider that these projects are necessary upgrades to improve the FGD system reliability.

VII. Big Bend Other Upgrade and Maintenance Projects

Q: What other projects capital costs were requested by TECO to be recovered under the ECRC clause per TECO's December 27, 2005 petition?

A. There were four "Other Projects" not previously discussed:

- Big Bend Units 1-2 Gypsum Blow Down Line at $284,000.
- Big Bend Units 1-2 Recycle Pump Discharge Isolation Bladders at $227,000.
- Big Bend Units 1-2 Inlet Duct C-276 Wallpaper at $234,000.
- Control Additions at $406,000.

Q: Are these projects reasonable and prudent projects to comply with environmental requirements and eligible for cost recovery under the ECRC?

A. Yes. The TECO reliability study justifies these maintenance upgrades for reliability of Unit 1 and 2 FGD systems to meet the terms of the Consent Decree without unreasonable forced outages or forced derates of these units. Also, control system failures and malfunctions of the control systems have been historically documented and improvements are needed to prevent unreasonable forced outages or derates cause by control system failures.

Q: Does this conclude your testimony?

A: Yes it does.

RESUME OF
JOHN B. STAMBERG, P.E.

Educational Background
1967 M.S. (Sanitary Civil Engineering), Stanford University
1966 B.S. (Civil Engineering), University of Maryland

Professional Experience
1981-Present Energy Ventures Analysis, Inc.
Vice President

Responsible for Energy Ventures Analysis, Inc. (EVA) engineering studies of coal, gas and oil boilers, gas turbines, pipelines and compressors, and air and water pollution controls. Conducts building and demolition inspections for environmental hazards such as asbestos and lead and the clean up or removal of contaminated soils. Performs engineering cost and performance analysis of new construction and major modifications to coal-fired power plants and combined cycle gas turbines as well as other power generation and related facilities.

Provides engineering analysis of utility and industrial boiler facilities for fuel choice, efficiency, performance, and environmental control. Assesses a broad range of combustion, cogeneration, and environmental control systems. Worked for EPRI on various power generation projects including cost estimation of pollution controls for coal boilers and deratings caused by switching pulverized coal boilers from Illinois Basin coal to low-sulfur coals.

Develops capital and O&M costs for a variety of natural gas compression options for gas pipelines, utilities and EPRI, including fixed vs. variable speed electrical compression, combustion turbine compression, and reciprocating compression, as well as conversion of existing reciprocating units to electric drive. Examines pipeline delivery capacity and cost of looping or adding compression to existing interstate and intrastate pipelines as well as on-site evaluations of booster compression needed to supply new combustion turbines. Served as process engineer on coal-fired ethanol plant and City of West Monroe wastewater plant. Also, conducted demolition and renovation projects for a major developer in numerous malls and office buildings.

1974-81 Energy and Environmental Analysis, Inc.
Director
Provided engineering analysis for the reactivation and the conversion from oil and natural gas to coal of industrial and utility boilers. Responsible for structural inspections and analysis of the boiler buildings, coal silos, and duct and stack supports. Evaluated second generation fluidized bed combustors (CFBC's) using petroleum coke and coal as fuels.

1967-74 **U.S. Environmental Protection Agency**
1972-1974 **Chief, Municipal Technology Branch, Office of Air and Water Programs**
1967-1971 **Chief, Biological Treatment, National Environmental Research Center**

Formulated policies and regulations required to implement PL92-500. Responsible for area-wide planning, facilities planning, effluent guidelines for municipal pollution control, operation and maintenance of advanced waste treatment facilities, combined sewer control, urban run-off, and cost-effectiveness analysis. Developed research objectives; designed and operated pilot- to full-scale plants to achieve various effluent objectives using a variety of biological or biological/chemical treatment techniques. Did engineering development work which was the basis for design for the District of Columbia's 309 MGD advanced waste treatment at Blue Plains and numerous other advanced waste treatment plants.

Expert Testimony
Mr. Stamberg testifies as an expert witness before courts, public utility commissions, and arbitra¬tions. Recent testimony before the Florida Public Service Commission addressed the engineering and cost of options to deliver solid fuel to TECO's Big Bend station. Just completed testimony before an arbitration in Michigan addressed the engineering, construction and repair cost at a complex power generation site that includes two gas turbines/HRSG's, one CT, and three 500,000 lb/hr blast furnace gas steam boilers, and a 250 MW steam turbine.

Honors
Chi Epsilon National Civil Engineering Honor Fraternity
Pi Mu Epsilon Honorary Mathematical Fraternity
Phi Kappa Phi Honor Society
Phi Theta Kappa National Honorary Scholastic Society
U.S. EPA Bronze Medal for Commendable Service

Professional Registration And Memberships
Registered Professional Engineer, Louisiana
Water Pollution Control Federation
Federal Water Quality Association

Patents And Publications
Holder of Wastewater Treatment Systems and Mineral Processing Patents Pending and has 17 technical publications.

Tampa Electric Company
Load Descriptions of New Electric Isolation Project
Transformer 3B

Transformers	Specific FGD Equipment	Lights and Other Non-Motor Loads 268 KVA	Specific SCR Equipment	Variable Frequency ID Fans
B3003A	94	268	0	0
B3003B	0	379	0	0
B3004A	0	0	0	9,500
B3004B	0	0	0	9,500
B3005A	0	418	126	0
B3005B	0	237	0	0
Totals 20,522 KVA	**94 KVA (0.4%)**	**1,302 KVA (6.4%)**	**126 KVA (0.6%)**	**19,000 KVA (92.6%)**

Tampa Electric Company
Comparative Group A Outage Rates

TECO Assumption for Group A Related Outages

Unit	Forced Outage	Maintenance Outage	Total Outage
Unit 3	48 hours/year	48 hours/year	96 hours/year
Unit 4	48 hours/year	48 hours/year	96 hours/year
Total	**96 hours/year**	**96 hours/year**	**192 hours/year**

Big Bend 5 Year History For Possible Group A Outages

Risk	Forced Outage	Maintenance Outage	Total Outage
Low	-	-	0.266 hours/year
High	-	-	1.976 hours/year

Tampa Electric Company
Comparison Of The Project Cost, Net Present Value Of Capital Expenditures, NPV Of Savings, Net Savings And Cost Benefit Ratio Of TECO's Assumptions

	TECO's Assumption in the Reliability Study	Historic Low Rate	Historic High Rate
Project	$4,945,000	$4,945,000	$4,945,000
NPV of Capital	$4,463,000	$4,463,000	$4,463,000
NPV of	$7,131,000	$10,000	$73,500
Net Savings	**$2,668,000**	**None**	**None**
Cost Benefit	1.6	0.0022	0.0165

DOCKET NO. 050958-EI
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail and U.S. Mail on this 24th day of January, 2007, to the following:

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