Pre-Filed Testimony

06 0155-EM

Florida Electrical Power Plant Siting Act Need for Power Application

Curtis H. Stanton Energy Center Unit B

Unit B IGCC Plant

B&V Project 142728

Submitted by:
Orlando Utilities Commission
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BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF NELSON F. REKOS

ON BEHALF OF

ORLANDO UTILITIES COMMISSION

DOCKET NO. __________

FEBRUARY 22, 2006

Q. Please state your name and business address.

A. My name is Nelson F. Rekos. My business mailing address is: National Energy Technology Laboratory, P.O. Box 880, Morgantown, WV 26507.

Q. By whom are you employed?

A. I am employed by the Department of Energy (DOE), National Energy Technology Laboratory (NETL) as the Advanced Energy Systems division director. I am responsible for the oversight of several Clean Coal Power Initiative (CCPI) demonstration projects, and, specifically, I serve as the DOE Project Manager for the Southern Company/Orlando Utilities Commission (OUC) IGCC Project at OUC's Stanton B Energy Center.

Q. Please state your educational background and professional experience.

A. I received Bachelor in Mechanical Engineering from the University of Maryland and a Masters in Business Administration from West Virginia University. I have worked on advanced coal-based power generating systems at NETL for the past 23 years.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to summarize the DOE's CCPI, the process involved with the selection of proposed CCPI projects and Stanton B in particular, and the benefits the DOE perceives will result from the construction and successful demonstration of the Stanton B project.

Q. Please briefly describe the structure and purpose of the Clean Coal Power Initiative.

A. The CCPI was initiated by President Bush in 2002 as a multi-year program to advance technologies that can help meet the Nation's growing demand for electricity while providing a secure and low-cost energy source and protecting the environment. The US DOE's Office of Fossil Energy through the National Energy Technology Laboratory is charged with implementation and management of the CCPI program. The CCPI is intended to leverage public and private investment, enhance teamwork, promote advanced coal technology, and provide the expertise and funding needed to ensure successful development and deployment of new clean coal technologies.

Q. What is the specific mission of the Clean Coal Power Initiative?

A. The specific missions of the CCPI are to develop promising, advanced clean coal power generation technologies; to accelerate these new coal power generation systems into the market by conducting successful full-scale technology demonstrations; and to generate substantial economic and environmental benefits to ensure a secure energy future as these technologies are commercialized by industry.

Q. How is the Clean Coal Power Initiative implemented?

A. The CCPI is implemented in successive solicitations, or rounds, that target priority areas of interest to meet the President's goals. Two rounds of solicitations resulting in applications and selections have occurred. Projects selected under these solicitations must promote advanced coal-based power generation technologies that have not been proven commercially, have fleet applicability, and provide substantial public benefit. Potential CCPI participants submit proposals during the selection process, which are evaluated by the DOE. Projects selected to receive DOE cost-sharing enter a negotiation phase where terms and conditions of the Cooperative Agreement and the Repayment Agreement are finalized. During these negotiations, host site availability, project teaming arrangements, and funding are confirmed.

Q. How was the proposed Stanton B project selected for an award of cost-sharing with the DOE?

A. The proposed Stanton B project was selected for an award of a cost-sharing cooperative agreement by the DOE in Round 2 of the CCPI. In October 2004, the DOE announced that four projects (including the Stanton B project) had been selected to receive the opportunity to partner with the DOE. The selection of these projects was a highly competitive process. The Stanton B project was one of the highest ranked projects and was selected to demonstrate a technology for the next generation of integrated gasification combined cycle (IGCC) power plants.

Q. How does the proposed Stanton B project address needs not currently met by the private sector?

A. The proposed Stanton B project will provide clean, low cost energy through the IGCC process. Existing IGCC plants in the US are less attractive for the commercial private sector, in part, due to their higher cost to build compared to conventional pulverized coal systems. Existing IGCC plants are oxygen-blown which results in higher capital cost due to the need for an oxygen plant and higher cost materials of construction to handle the increased temperatures. Stanton B is expected to be the first of many similar IGCC units. Commercial scale demonstration of the Transport Gasification process will allow the private sector to consider this type of IGCC as an alternative to conventional coal fired generation. In general, coal-based power generation is currently favored over natural gas generation whenever volatile, high natural gas prices exist. Further, commercial application of the Transport Gasification technology operating on lower cost subbituminous coals will increase the fuel diversity of the US as a whole.

Q. How does the proposed Stanton B promote technology that has not been commercially proven?

A. In the US there have been several research and commercial demonstration scale IGCC plants. Two were partially funded by the DOE. While the Stanton B project is based on the principal of gasifying coal and then combusting the coal gas in a gas turbine combined cycle power plant, the project is unique in several respects. Stanton B will be the first commercial scale US IGCC plant to use air blown technology in the gasification process eliminating the need for an oxygen plant thereby reducing cost and parasitic power consumption. Additionally, Stanton B will be designed to operate primarily on subbituminous Powder River Basin (PRB) coal. Most US IGCC projects have tested operation on a range of solid fuels, but do not primarily operate on 100 percent PRB coal. PRB coal has a lower cost per MBtu than other coals, a low sulfur content, and large proven reserves. Stanton B will be the first commercial scale electric generating unit to operate on 100 percent subbituminous coal in the State of Florida.

Stanton B will demonstrate the use of innovative ammonia removal technology, which is expected to produce marketable ammonia. The Transport Gasification process proposed for Stanton B will produce other potentially salable byproducts. The Stanton B project will also demonstrate selective catalytic reduction (SCR) for NO_x control, which has not been successfully demonstrated in a US IGCC plant.

Q. **In what ways does the Transport Gasification technology proposed for use in the Stanton B project have fleet applicability?**

A. One of DOE's criteria for selection is that, upon completion of a successful demonstration, the technology would be able to be ready for commercial licensing and wide spread deployment without additional DOE financial support. The commercialization and marketing plans developed for the Transport Gasification system and presented to the DOE fully satisfied the DOE's commercialization potential selection criteria.

Q. How does the Stanton B project provide substantial public benefit?

A. As I have outlined in my previous responses, Stanton B will provide OUC's customers with reliable energy from a clean coal technology at a lower cost than other generation technologies. Stanton B will diversify both OUC's fuel mix and the fuel mix for the State of Florida as it will be the first electric generating unit to operate on exclusively on subbituminous coal. The project will create jobs and promote the wide spread development of the Transport Gasification technology. Future IGCC units using this technology will provide similar benefits to other regions of the US, further satisfying the goals of the DOE under the CCPI.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF RANDALL RUSH

ON BEHALF OF

ORLANDO UTILITIES COMMISSION

DOCKET NO. _______

FEBRUARY 22, 2006

Q. Please state your name and business address.

A. My name is Randall Rush and my business address is Southern Company Generation & Energy Marketing, 30188 Highway 25 North, Wilsonville, Alabama 35186.

Q. By whom are you employed and in what position?

A. I am employed by Southern Company Services, Inc. as Director, Power Systems Development Facility, sometimes referred to as the PSDF. Southern Company Services is a service subsidiary of the Southern Company and provides engineering and construction services and research and environmental affairs among other services to all of the Southern Company subsidiaries.

Q. Please describe your duties as Director of the PSDF.

A. I am responsible for management of an advanced coal-based power generation research facility located near Wilsonville, Alabama. The facility is a joint project of the Department of Energy's (DOE's) National Energy Technology Laboratory (NETL), Southern Company, and other industrial participants currently including the Electric Power Research Institute, Siemens Westinghouse Power Corporation, Kellogg Brown and Root, Inc. (KBR), Peabody Energy, the Burlington Northern and Santa Fe Railway, and the Lignite Energy Council. My duties include management of the various relationships and contracts, and oversight of the engineering, operations, maintenance, and testing of the facility on behalf of the participants.

QUALIFICATIONS AND EXPERIENCE

Q. Please summarize your educational background.

A. I hold a Bachelor of Science degree in Chemical Engineering from Auburn University and a Juris Doctorate from the Birmingham School of Law.

Q. Please summarize your employment history and work experience.

A. I have 32 years of experience in the electric utility industry, all with Southern Company or one of its affiliates. Prior to joining Southern Company in 1973, I held positions as a process engineer with Fiber Industries (a subsidiary of Celanese Corporation) and for a short time I sold accounting systems in a family business. From 1973 through September 1986, I served as a project manager and then the manager of the Flue Gas Treatment & Water Quality Section in Southern Company Services. From October 1986 through February 1991, I served as manager and then director of Engineering Research with responsibility for program direction and management of Southern Company power plant related hardware research. From March 1991 through October 1993, I was the Director of Clean Air Compliance in Engineering and managed a multicompany organization that successfully developed the initial Clean Air Compliance strategy for Southern Company. Since 1993, I have been the Director of Power Systems Development as stated above.

SUMMARY AND PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Orlando Utilities Commission (OUC). My testimony supports the petition filed by OUC for a determination of need for the Stanton B Project, a combined cycle unit capable of burning either syngas from on-site gasification of coal using the Transport Gasification process or natural gas to be constructed at the Curtis H. Stanton Energy Center in Orlando, Florida. A Southern Company subsidiary will also be a joint applicant with OUC for site certification of the Project under the Florida Electrical Power Plant Siting Act (Siting Act).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the role of Southern Company and its subsidiaries in the Stanton B Project, to provide an overview of the Project, and discuss the gasification technology to be employed by the Project.

Q. What are your responsibilities with respect to the Project?

A. My responsibilities will include oversight of the DOE contract and overall project management, including engineering, procurement, construction, and operations and maintenance of Stanton B through the 4 years of the DOE demonstration phase of the project. My responsibilities for oversight at the PSDF will continue, but with less emphasis on day-to-day management of that facility.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring one exhibit, Exhibit ____ (RER-1), an organization chart of the various, relevant Southern Company subsidiaries that are involved in the Project.

Q. Does that exhibit accurately depict the corporate organization of the Southern Company subsidiaries that are involved in this Project?

A. Yes.

Q. Are you sponsoring any sections of Exhibit ____ (OUC-1), Stanton B Need for Power Application?

A. Yes. I am sponsoring Sections 6.1, 7.0, 7.2, 7.3, 7.4, 7.5 (excluding Table 7-4 and the description of OUC's additional costs and interest during construction), 7.6, 7.7, 7.8, 7.9, 7.10, 7.11, and 14.1. It is my understanding that OUC's consultant, Myron Rollins, will address the additional costs and Table 7-4 in his testimony.

Q. Are you adopting these sections as part of your testimony?

A. Yes.

OWNERSHIP AND PARTICIPANT ROLES FOR STANTON B

Q. Please describe the ownership of the Stanton B Project.

A. The Project will consist of a combined cycle unit wholly owned by OUC, and a gasification unit that will be owned 65 percent by Southern Power Company – Orlando Gasification LLC (SPC-OG) and 35 percent by OUC. SPC-OG will construct the combined cycle for OUC pursuant to a fixed price engineer, procure, and construct (EPC) contract. SPC-OG will also construct the gasification unit on behalf of OUC and SPC-OG.

Q. Please describe SPC-OG's relationship to Southern Company and its subsidiaries.

A. SPC-OG is a wholly owned subsidiary of Southern Power Company. Southern Power Company is the wholesale operating company of Southern Power, separate and distinct from the retail operating companies such as Gulf Power Company.

Q. Are the ratepayers of Gulf Power Company responsible for any of the costs associated with Stanton B?

A. No. The Project is being developed through SPC-OG to protect against any cross-subsidy by our other customers.

Q. Will OUC have exclusive use of SPC-OG's ownership interest in the gasification unit?

A. Yes. OUC and SPC-OG have entered into a 20-year gasification island capacity purchase agreement that gives OUC the right to utilize all of the output associated with SPC-OG's ownership interest in the project for a fixed monthly fee.

Q. Please describe Southern Company's experience in the development and operation of electrical power plant projects.

A. Southern Company is the one of the largest producers of electricity in the United States, and among the 10 largest in the world, with a proven record of designing, owning, and operating electric power plants. With over 70 plants, comprised of over 290 units, Southern Company has more than 40,000 MW of capacity in service or under construction. Southern Company also has more than 26,000 miles of transmission lines that interconnect with major utilities. Through its subsidiaries and affiliates, Southern Company develops, builds, owns, and operates power production and delivery facilities, conducts energy trading and marketing activities, and provides other energy services in the United States and in international markets. In 2005, Southern Company had operating revenues of $13.5 billion and net income of $1.6 billion.

Q. Are Southern Company's resources, expertise, and core competencies in power plant development available to SPC-OG?

A. Yes. SPC-OG is a subsidiary of Southern Power Company (SPC) which is a subsidiary of Southern Company and will have Southern Company's direct support in the areas of engineering, construction, operations, maintenance, accounting, financial services, and procurement. SPC-OG will acquire these services from Southern Company Services and pay the associated costs of these activities.

Q. Why is SPC-OG interested in constructing and participating in Stanton B?

A. Stanton B is a key component of Southern Company's long term strategy to develop, construct, own, and operate environmentally advanced, efficient, coal based generating units. The project will also be the first commercial scale application of the Transport Gasifier technology that was developed at the PSDF. This gasifier, jointly owned by Southern and KBR, is based on KBR's catalytic cracking technology that is used extensively in the petroleum refining industry. SPC-OG believes that there are cost efficiencies in having a partner in this first application of the Transport Gasifier technology and utilizing an existing site. Upon successful demonstration of Stanton B, Southern Company and KBR plan to license and market the Transport Gasifier technology. The Project also allows OUC the opportunity to diversify its fuel mix, participate in an environmentally advanced gasification project, while minimizing its cost exposure and thus ensuring a reliable and economical energy supply to meet its current and future needs.

Q. How did SPC and OUC decide to pursue development of Stanton B?

A. Stanton B is the result of an OUC and Southern Company (through Southern Company Services) response to a solicitation under the DOE's Clean Coal Power Initiative (CCPI). On June 15, 2004, this proposal was submitted for funding to support the demonstration of the Transport Gasifier as configured as an air blown integrated gasification combined cycle (IGCC) power plant. On October 21, 2004, the DOE officially announced that it had selected Southern Company Services for negotiation (on behalf of itself and the project partners) of a $235 million cost sharing cooperative agreement under Round 2 of the CCPI. This negotiation has been completed and all relevant contracts are circulating for signature. The CCPI was initiated in 2002 by President Bush with the ultimate goal of facilitating the development of more efficient clean coal technologies for use in both new and existing power plants throughout the world. It is important to note that the selection process was highly competitive with 13 proposals being submitted. The proposals were evaluated by DOE technical evaluators, with the DOE ultimately selecting four projects for federal cost sharing, including the proposed Stanton B project.

Q. How will the DOE cost sharing be utilized by the Stanton B project?

A. The $235 million cost sharing from DOE will be used to offset costs associated with design, construction, and demonstration of the gasification island. The total cost of the gasification island during design, construction, and demonstration is estimated to be $557 million. OUC and SPC-OG will fund

$322 million of this estimated cost. A portion of the DOE cost sharing is allocated to the gasification island cost. The cost of the combined cycle and some common facility costs will be funded directly by OUC. The combined cycle costs are not a part of the DOE project and are not subject to the DOE cost sharing. A portion of the DOE cost sharing is allocated to pay a portion of the costs incurred in operating the gasification plant during the 4 year demonstration phase. The DOE cost sharing is important to the Project as it will reduce the cost of the project including the capital cost of the gasifier unit, (including associated costs such as railcars) and operation and maintenance costs during the demonstration period. A detailed description of the DOE cost sharing distribution is discussed in Section 7.5 of the Stanton B Need for Power Application.

Q. Are there provisions for Southern Company to repay the DOE cost sharing?

A. Yes. Southern Company and KBR will repay the DOE cost sharing through royalties earned from future sales of Transport Gasifiers.

Q. Will OUC be required to repay any of the DOE cost sharing?

A. No.

GASIFICATION PROCESS OVERVIEW

Q. Please describe how the gasification process works.

A. Several systems comprise the gasification process including coal preparation and feeding, gasifier, high temperature syngas cooling, particulate collection, low temperature gas cooling and mercury removal, sulfur removal and recovery, sour water treatment and ammonia recovery, and the flare system. Coal preparation is a conventional system similar to other coal fired power plants, while the flare system is used to burn syngas during startup and upset conditions. Once the coal is crushed, it is fed into the gasifier with high pressure air. Within the gasifier, partial oxidation of the coal occurs to form synthesis gas (syngas) and gasification ash. The gasifier will operate at high temperature and will also generate steam for use in the combined cycle. Syngas will then flow through the remaining systems for further cleanup and before it is combusted in the combined cycle unit. During coal gasification sulfur, ammonia, and other constituents are removed from the syngas prior to combustion rather than during or after combustion as in other conventional coal fired technologies. Removal prior to combustion allows cleanup of a smaller volume of gas and for some of the constituents to be recovered in a marketable form. For example sulfur and ammonia will be recovered as by products from the process. Clean syngas is then combusted in a combined cycle power plant. The Transport Gasifier will have a heat rate estimated to be 8,461 Btu/kWh HHV - that is about 9 percent better than the most advanced supercritical pulverized coal fired power plant.

Q. What are some of the advantages and benefits of using the Transport Gasifier technology?

A. There are many advantages of the Transport Gasifier technology in comparison to other gasification technologies and conventional coal-fired technologies. First, the Transport Gasifier technology is especially well suited for low rank subbituminous coals such as Powder River Basin (PRB) coal. PRB coal is lower in sulfur and ash, and tends to be lower in cost than other coals. Other gasification technologies often require fuels with higher heating values to operate properly. Stanton B is planned to burn PRB coal. Testing of other subbituminous coals is planned during the demonstration phase. Also, since the Transport Gasifier uses air rather than oxygen to gasify the coal it does not require an expensive oxygen plant to function. Conventional air compressors will be used in place of an oxygen plant.

Due to its higher efficiency the Transport Gasifier generates smaller quantities of waste than in a comparably sized conventional coal fired plant. And, it uses about half the water needed by a conventional coal fired plant.

In summary, the Transport Gasifier technology provides the most efficient use of low rank coals for a power plant application while generating less waste, maintaining very low emissions, and using less water than conventional plants.

Q. Is the Transport Gasifier technology ready for commercial application?

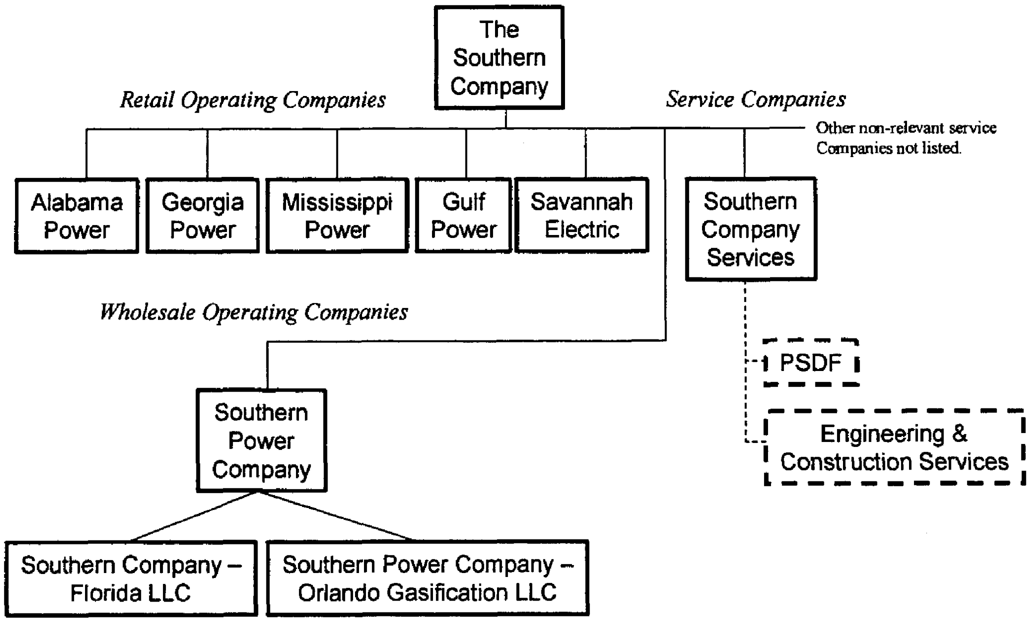
A. Yes. The previously mentioned Power Systems Development Facility (PSDF) near Wilsonville, Alabama is an engineering scale demonstration of Transport Gasifier technology designed at sufficient size to provide data for commercial scale-up. The PSDF facility has been in successful operation since 1996.

Q. What measures have been taken to ensure that Stanton B will have high availability?

A. First, pursuant to the gasification island capacity purchase agreement between SPC-OC and OUC, SPC-OG has provided an availability guarantee with penalties if the guarantee is not achieved. As a result, SPC-OG will have a significant financial incentive to maintain high availability of syngas. In addition, the combined cycle unit will be designed to operate on coal derived syngas as the primary fuel and natural gas as an alternate fuel. Therefore, if syngas is not available, the combined cycle plant will be capable of operating on natural gas similar to a conventional combined cycle unit. Finally, Southern Company has invested significant resources in the Transport Gasifier technology, and is committed to proving the technology successful. Indeed, the success of the Stanton B project is integral for Southern Company and KBR to achieve their long term business objective of constructing multiple plants that use Transport Gasifier technology.

Q. Does this conclude your testimony?

A. Yes.


The Southern Company
Retail Operating Companies
Service Companies
Other non-relevant service Companies not listed.
Alabama Power
Georgia Power
Mississippi Power
Gulf Power
Savannah Electric
Southern Company Services
Wholesale Operating Companies
PSDF
Southern Power Company
Engineering & Construction Services
Southern Company – Florida LLC
Southern Power Company – Orlando Gasification LLC

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF FREDERICK F. HADDAD, JR

ON BEHALF OF

ORLANDO UTILITIES COMMISSION

DOCKET NO. _______

FEBRUARY 22, 2006

Q. Please state your name and address.

A. My name is Frederick F. Haddad, Jr. My business address is 500 South Orange Avenue, Orlando, Florida 32802.

Q. By whom are you employed and in what capacity?

A. I am employed by Orlando Utilities Commission (OUC) as Vice President of the Power Resources Business Unit.

Q. Please describe your responsibilities in that position.

A. I am responsible for all of OUC's power resources including the planning, construction, and operation of OUC's generation portfolio. I also manage the fuel procurement and related financial hedging programs of OUC, and wholesale power marketing.

Q. Please state your educational background and professional experience.

A. I have a Bachelor's degree in Engineering from the University of Central Florida, as well as an MBA from Rollins College. I am a licensed professional engineer in the State of Florida.

I have worked for OUC since 1977 and my responsibilities included serving as a Results Engineer, Assistant Superintendent of Operations, Superintendent of Indian River Power Plant in Titusville, Director of Stanton Energy Center near Orlando, Managing Director of Generation, and my current position as Vice President of the Power Resources Business Unit.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to explain why Stanton B is a good business and strategic decision for OUC.

Q. Are you sponsoring any sections of Exhibit ____ (OUC-1), Stanton B Need for Power Application?

A. Yes. I am sponsoring Sections 1.0, 2.0, 6.3, 7.1, 7.12, and 14.2 through 14.10.

Q. Are you adopting these sections as part of your testimony?

A. Yes.

Q. Are there any corrections to these sections?

A. No.

Q. Please briefly describe OUC.

A. OUC provides electric energy service to residential and commercial customers in and around the City of Orlando, Florida (the City). OUC operates as a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City. OUC has full authority over the management and control of the electric and water works plants in the City and has been approved by the Florida legislature to offer these services in Osceola County as well as Orange County. OUC entered into an Interlocal Agreement with the City of St. Cloud in 1997 under which OUC assumed responsibility for supplying all of St. Cloud's loads for the term of the agreement, which is currently through 2032.

Through ownership shares in the Stanton Energy Center, Indian River Plant, Crystal River Unit 3, St. Lucie Unit 2, and McIntosh Unit 3 and St. Cloud's wholly owned diesel units, OUC and St. Cloud have a combined installed generating capability of 1,278 MW in the winter and 1,220 MW in the summer. OUC's capacity is comprised of nuclear, pulverized coal, combined cycle, simple cycle combustion turbine, and diesel units. OUC also purchases capacity under a power purchase agreement with Southern Company - Florida LLC (SCF) and St. Cloud has a power purchase agreement in place with Tampa Electric Company (TECO). OUC is in the final year of a unit power sale to the Florida Municipal Power Agency (FMPA).

OUC's transmission system consists of 28 substations interconnected through approximately 318 miles of 230 kV, 115 kV, and 69 kV lines and cables. OUC is fully integrated into the state transmission grid through its twenty-three 230 kV, one 115 kV, and three 69 kV metered interconnections with other generating utilities that are members of the Florida Reliability Coordinating Council (FRCC). Additionally, OUC is now responsible for St. Cloud's four substations as well as approximately 51 miles of 230 kV and 69 kV lines and cables. The St. Cloud transmission system includes three interconnections.

Q. Please describe OUC's resource planning strategy.

A. Our goal and competitive strategy is to neutralize our customers to increases in the commodity price of energy, conservatively plan for meeting loads, build in flexibility to attempt to stay neutral to the market, and make sure that our assets can generate net income to minimize the cost of retail electricity to our customers.

Q. Please describe what it means to neutralize your customers to increases in the commodity price of electricity.

A. At OUC, we try to deploy strategies that shield our customers from increases in prices of electricity. One strategy is to have a diverse fuel mix to avoid dependence on any single fuel. For example, when natural gas was inexpensive, a utility could have become very dependent upon natural gas and their customers would have lower costs; however, when natural gas prices increase, as in recent years, customer costs increase significantly for utilities that are highly dependent upon natural gas.

Q. What do you mean by conservatively plan for meeting customer loads?

A. At OUC, we plan to provide physical generation to supply our customers' loads. If we purchase power to meet our customers' loads, we ensure that the purchase power is based on physical generation that can be delivered to OUC's system in order to serve OUC's customers.

Q. Can you provide an example of conservatively planning for meeting customer loads?

A. Yes. Stanton A, a 633 MW combined cycle unit is a good example. OUC and our municipal partners own 35 percent of Stanton A and SCF owns the remaining 65 percent. The three municipal utilities purchase SCF's 65 percent ownership share. The purchase power is from a physical generating unit asset that is located on OUC's Stanton site.

Q. What do you mean by build in flexibility to stay neutral to the market?

A. We try to maintain the maximum amount of flexibility possible with generating resources to serve OUC's customers' loads. We use that flexibility to help reduce the impact to our customers from significant increases in the cost of electricity.

Q. Can you provide an example of using flexibility to stay neutral to the market?

A. Yes. As previously discussed, OUC has a purchase power agreement for a portion of SCF's ownership share of Stanton A. The purchase power agreement specifies a fixed capacity payment. OUC has the right to reduce the amount of capacity purchased from SCF. If market conditions change and Stanton A is no longer a competitive resource, OUC could back down the amount of capacity purchased.

Q. What do you mean by make sure that our assets can generate net income to minimize the cost of retail electricity to our customers?

A. OUC only adds capacity to meet system capacity requirements for retail load. However, when capacity is added, economies of scale dictate that generating units providing more capacity than OUC's capacity requirements are sometimes more economical to install. In some instances, it may be more appropriate to install a larger unit with higher capital cost and lower energy costs than to install a lower capital cost unit with high energy costs just meet OUC's capacity requirements. In any of these cases, OUC ensures that besides being economical to OUC, the unit would be economical in the broader Florida market. Thus, when any excess capacity is available from OUC's system, profitable sales can be made from that excess capacity. Profit from these sales goes directly to reduce the cost of retail electricity to OUC's customers.

Q. Please describe OUC's resource planning methodology.

A. OUC's planning methodology is initiated with a review of our annual Ten-Year Site Plan which identifies the lowest cost capacity expansion plan for OUC's stand alone system. Once this plan has been established OUC identifies competitive alternatives that may be more viable when both OUC's retail load and the Florida market as a whole are considered.

Q. What did OUC's most recent resource planning activities identify as the lowest cost capacity addition?

A. Previous OUC Ten-Year Site Plans indicated that the addition of simple cycle combustion turbines installed during various years in the near-term represented the lowest cost capacity expansion plan for OUC's stand alone system. Further analysis showed that a 1x1 natural gas fired combined cycle would provide savings over the installation of simple cycle combustion turbines to meet forecasted capacity requirements when OUC's retail loads and the Florida market as a whole were considered.

Q. Why did OUC decide to partner with Southern Company to construct Stanton B as part of the Department of Energy's (DOE's) Clean Coal Power Initiative (CCPI)?

A. The opportunity to partner with Southern Company in constructing Stanton B under the DOE's CCPI represented a consistent fit with OUC's competitive strategy. As I mentioned previously, installation of a natural gas fired 1x1 combined cycle was shown to be the lowest cost capacity addition for OUC's customers when the whole Florida market was considered. Participation in Stanton B, an integrated gasification combined cycle (IGCC) unit, captures the benefits of the 1x1 combined cycle while further enhancing OUC's ability to remain market neutral by also increasing the fuel diversity of OUC's generating resources and the State of Florida as a whole through the use of less volatile priced coal.

The opportunity to partner with Southern Power Company on Stanton B under the CCPI also offers OUC opportunities to obtain the benefits of the IGCC technology. First, the $235 million DOE cost-sharing significantly reduces the cost of Stanton B. Second, Southern Power Company's ability to fix OUC's price for the combined cycle and gasifier remove OUC's risk from the volatile construction market, and third Southern Power Company's ability to guarantee the performance of the gasifier minimized OUC's risk from first-of-a-kind technology.

Q. **How does Stanton B increase OUC's ability to remain market neutral?**

A. Stanton B will use Powder River Basin (PRB) coal. The delivered price of PRB coal to Stanton is less volatile than other coals because the coal commodity price represents a smaller percentage of the delivered price than for other coals. The use of coal in general reduces volatility significantly compared to natural gas. Furthermore, Stanton B will have the ability to either burn syngas derived from coal or natural gas.

Q. Does OUC intend to operate Stanton B primarily on syngas or natural gas?

A. Given the current fuel market, OUC is intending to operate Stanton B on coal-derived syngas. However, should a drastic change occur in the fuel market and the cost to operate on natural gas becomes more economical than operation on syngas, OUC could do so.

Q. How would Stanton B increase OUC's fuel diversity?

A. In addition to being capable of operating on either coal-derived syngas or natural gas, OUC's fuel diversity will be increased through the addition of Stanton B because Stanton B will use coal sourced from the Powder River Basin. OUC's coal fired Stanton Units 1 and 2 use Central Appalachian coal. PRB coal is less expensive than Central Appalachian coal on a $/MBtu basis, and there are much larger proven reserves of PRB coal than of Central Appalachian coal. Stanton B will be the first plant in Florida to burn Powder River Basin coal. The use of PRB coal will not only diversify OUC's fuel supply, but the fuel supply of the State of Florida as a whole.

Q. How will PRB coal be delivered to the Stanton Energy Center?

A. OUC has begun the early stages of negotiations for rail delivery of PRB coal for Stanton B. Final negotiations will clarify the routing used to deliver coal. At this time it is premature to enter into final negotiations for the purchase and transportation of PRB coal. The existing rail infrastructure is sufficient to accommodate delivery of PRB coal to the Stanton Energy Center.

Q. How does the efficiency of Stanton B compare with other coal and natural gas fired units?

A. Stanton B is considerably more efficient when burning coal-derived syngas than other coal fired generating units. When operating on natural gas, the efficiency of Stanton B is nearly equivalent to the efficiency of other natural gas fired 1x1 combined cycle units.

Q. What steps has OUC taken to address the risk of decreased reliability of Stanton B due to its first-of-a-kind technology?

A. Southern Power Company – Orlando Gasification LLC (SPC-OG) has provided availability guarantees for Stanton B. These guarantees provide financial incentive to SPC-OG to maximize the availability of Stanton B and limit OUC's financial exposure.

Q. Will Stanton B provide capacity to OUC in an environmentally responsible manner?

A. Yes. Stanton B will demonstrate both pre- and post-combustion environmental control technologies, thereby providing for efficient energy generation in an environmentally responsible manner consistent with OUC's commitment for environmental responsibility.

Q. In your opinion, is Stanton B OUC's optimum generation capacity addition?

A. Yes. Not only did the comprehensive, detailed economic analyses performed in the Stanton B Need for Power Application demonstrate the superior economics of Stanton B for OUC's system as compared to other generating capacity alternatives, the proposed project is consistent with OUC's goals and competitive strategy. Stanton B will provide OUC's customers with a low cost, reliable, environmentally responsible capacity resource.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF ERIC FOX

ON BEHALF OF

ORLANDO UTILITIES COMMISSION

DOCKET NO. _______

FEBRUARY 22, 2006

Q. Please state your name and business address.

A. My name is Eric Fox. My business address is 20 Park Plaza, Suite 910, Boston, Massachusetts, 02116.

Q. By whom are you employed and in what capacity?

A. I am employed by Itron Inc. My title is Director, Forecasting Solutions.

Q. Please describe your responsibilities in that position.

A. I am responsible for directing forecast and load analysis work to support electric, water, and gas utility operations and planning. I manage day-to-day work of Itron's Boston office. I also provide statistical modeling and forecast training through workshops sponsored by Itron and other organizations such as EPRI and the Institute of Business Forecasting. I am an active participant in forecasting and load analysis conferences and forums across the country.

Q. Please state your educational background and professional experience.

A. I received my M.A. in Economics from San Diego State University in 1984 and my B.A. in Economics from San Diego State University in 1981. While attending graduate school, I worked for Regional Economic Research, Inc. (RER) as a SAS programmer. After graduating, I worked as an Analyst in the Forecasting Department of San Diego Gas & Electric. I was later promoted to a Sr. Analyst in the Rate Department. I also taught statistics in the Economics department of San Diego State University on a part-time basis.

In 1986, I was employed by RER as Senior Analyst. I worked at RER for three years before moving to Boston and taking a position with New England Electric as a Sr. Analyst in the Forecasting Group. I was later promoted to Manager of Load Research. In 1994, I left New England Electric to open the Boston office for RER. RER was acquired by Itron in 2002.

Over the last 20 years, I have provided support for a wide-range of utility operations and planning requirements that include forecasting, load research, rate design, financial analysis, and conservation and load management program evaluation. Forecasting work has included developing econometric forecast models for short-term budget forecasts, implementation of EPRI long-term end-use forecast models for long-term capacity planning, and developing Artificial Neural Network models for daily gas sendout and hourly electric demand forecasting. Clients include traditional integrated utilities, distribution companies, Independent System Operators, generation and power trading companies, and energy retailers. Florida clients include Florida Power & Light (FP&L), Tampa Electric Company (TECO), and the City of Lakeland.

I have presented various forecasting and energy analysis topics at numerous forecasting conferences and forums. I also direct electric and gas forecast workshops that focus on estimating econometric models and using statistical-based models for monthly sales and customer forecasting, weather normalization, and calculation of billed and unbilled sales. Over the last few years, I have provided forecast training to several hundred utility analysts and analysts in other businesses.

I have also provided expert support in rate and regulatory related issues. This support has included developing forecasts for resource planning and rate filings, providing supporting testimony, and conducting forecast workshops with regulatory staff including the Florida Public Service Commission for the Stanton A Need for Power.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the load forecast prepared for Orlando Utilities Commission (OUC).

Q. Are you sponsoring any sections of Exhibit ____ (OUC-1), Stanton B Need for Power Application?

A. Yes. Section 3.0 and Appendix A.

Q. Are you adopting these sections as part of your testimony?

A. Yes.

Q. Please describe the methodology used in developing OUC's sales forecast.

A. The sales forecast is developed from a set of structured regression models that can be used for both forecasting monthly sales and customers for the OUC budget period and over the longer term, 20-year forecast horizon encompassing 2006 through 2025. Forecast models are estimated for each of the major rate classifications including: 1) residential, 2) general service non-demand (small commercial customers), 3) general service demand (large commercial and industrial customers), and 4) street lighting. Models are estimated using monthly sales data covering the period 1994 through 2004.

The baseline statistical forecast is adjusted for known large load additions that cannot be accounted for by the underlying regression model. These load additions are based on discussions with OUC key account representatives and engineering staff. Discussions included plans for OUC's largest existing customers and any known future developments. Finally, sales are adjusted for losses to yield a net energy for load forecast. A separate set of forecast models was prepared for the OUC and St. Cloud service territories.

Q. **How are long-term appliance saturation and efficiency trends captured by the forecast models?**

A. To capture long-term structural changes, end-use concepts are blended into the regression model specification. This approach, known as a statistically adjusted end-use (SAE) model, entails specifying end-use variables – Heating, Cooling, and OtherUse – and utilizing these variables in sales regression models. This approach allows us to capture the impact changes in technology saturation and efficiency gains have on long-term sales and demand.

Q. **How was peak demand projected?**

A. A set of hourly regression models is used to forecast hourly demand over the 20-year forecast period. System hourly demand is forecasted as a function of the retail energy forecast, expected weather conditions, hours of light, day of the week, and holidays. The winter and summer peak demand is then calculated as the maximum hourly demand occurring in the winter and summer period. A separate set of forecast models are developed for OUC and St. Cloud.

Q. **How is the impact of conservation reflected in the load forecast?**

A. The effects of existing conservation programs are implicitly included in the forecast. Program activity is captured both in the historical sales data and reflected in saturation and efficiency trends to the extent programs have impacted historical appliance purchase behavior. Future efficiency trends due to expected changes in appliance standards are embedded in the end-use model variables.

Largely as a result of expected efficiency gains in central air conditioning, heat pumps, refrigeration, and other major appliances, average use is projected to increase at a relatively low rate when compared with other regions in the country. For OUC, residential average use is expected to increase at an average annual rate of approximately 0.6 percent per year through 2025. Average use is growing somewhat faster in the St. Cloud service area, with residential average use projected to increase 1.0 percent per year through 2025. The nonresidential models also incorporate average efficiency projections as well as economic output projections and weather conditions into the constructed end-use variables. With expected efficiency gains projected to grow faster than end-use saturations, calculated nonresidential average use (sales divided by customers) is flat to negative.

Q. What are the results of OUC's demand and energy forecasts?

A. OUC and St. Cloud's net energy for load is expected to grow at a compound annual average growth rate of 2.8 percent over the 20-year forecast period. This is roughly the same growth rate as that experienced over the last 5 years. Peak demand is projected to track forecasted energy growth with summer peak demand increasing from 1,201 MW in 2006 to 2,042 MW in 2025. Winter peak demand is forecasted to grow from 1,203 MW in 2006 to 2,046 MW in 2025.

Regional economic growth will remain relatively strong over the forecast horizon with the number of households in the Orlando MSA expected to increase 2.8 percent per year. Regional output is projected to increase 4.3 percent annually through 2025 and employment is forecasted to grow 3.1 percent annually.

Q. Did you develop any alternative load forecasts to be used to perform sensitivity analyses?

A. Yes. In addition to the base case forecast, two long-term forecast scenarios were developed in order to bound potential long-term demand growth. We assume that over the long-term possible outcomes are largely driven by potential population growth paths. The high and low forecast scenarios are based on University of Florida's population projections for counties served by Orlando and St. Cloud. In the high case, population is forecast to increase 3.4 percent on a compounded basis between 2005 and 2025. This compares with the University of Florida's base case population projections of 2.3 percent. The high population growth scenario results in a forecasted long-term annual energy growth rate of 3.9 percent with system peak demand that is 486 MW higher than in the base case by 2025. In the low case energy increases 1.7 percent on a compounded basis through 2025. Peak demand is 396 MW lower than the base case by 2025. The low case assumes weak regional population growth with population growing just 1.2 percent over the forecast horizon. The high and low forecast scenarios are presented in Table A-11 of the Stanton B Need for Power Application Exhibit ____ (OUC-1).

Q. In your opinion are the assumptions in the load forecasts reasonable for planning purposes?

A. Given the uncertainty associated with long-term forecasting, the forecast assumptions are relatively conservative. In the base case, average use forecast projections are relatively flat with customer growth driving most of the sales forecast growth. The forecast is driven by economic projections based on Economy.com's economic outlook for Orlando and the State of Florida. These projections are consistent with economic and population projections from the University of Florida.

The forecast scenarios provide a means to help bound forecast uncertainty. High and low growth scenarios yield a reasonable bound around the base case forecast with energy demand increasing 1.1 percent faster in the high case and 1.1 percent slower in the low case.

Q. Does this complete your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF SETH SCHWARTZ

ON BEHALF OF

ORLANDO UTILITIES COMMISSION

DOCKET NO. _______

FEBRUARY 22, 2006

INTRODUCTION

Q. Please state your name and business address.

A. My name is Seth Schwartz. My business address is 1901 North Moore Street, Suite 1200, Arlington, Virginia 22209-1706.

Q. By whom are you employed and in what capacity?

A. I am employed by Energy Ventures Analysis, Inc. (EVA), where I am a principal.

Q. Please describe EVA.

A. EVA is a consulting firm that engages in a variety of projects for private and public sector clients. These consulting projects are related to energy and environmental issues. In the energy area, much of our work is related to analysis of the electric utility industry and fuel markets, particularly oil, natural gas, and coal. Our clients in these areas include coal, oil and natural gas producers, electric utility and industrial energy consumers, and gas pipelines and railroads. We also work for a number of public agencies, such as state regulatory commissions, the U.S. Environmental Protection Agency, and the U.S. Department of Energy, as well as intervenors in utility rate proceedings, such as consumer counsels and municipalities. Another group of clients include trade and industry associations, such as the Electric Power Research Institute, the Gas Research Institute, and the Center for Energy and Economic Development. EVA has provided testimony to numerous state public utility commissions, including the Florida Public Service Commission. Furthermore, the firm has filed testimony in a number of cases in both state and federal courts, as well as before the Federal Energy Regulatory Commission.

QUALIFICATIONS AND BACKGROUND

Q. Please describe your educational background and experience.

A. I received a BSE in Geological Engineering from Princeton University in 1977. I was a founder of EVA in 1981, and have been a principal in the company since then. I perform and manage a variety of fuels-related consulting work for the electric utility industry, including fuel supply strategy studies, market analyses, and price forecasts. I also audit the management and performance of electric utility fuel supply departments and provide testimony to public service commissions. My resume is attached as Exhibit ___ (SS-1).

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports portions of the Need for Power Application (NPA) filed in this proceeding by Orlando Utilities Commission (OUC). Specifically, my testimony describes how the fuel forecasts for this project were developed and provides EVA's expert opinion that the fuel forecasts used by Black & Veatch to evaluate whether the Stanton IGCC unit is the most cost-effective alternative available to meet the capacity needs of OUC were reasonable.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit ____ (SS-1) is a copy of my resume. Exhibit ____ (SS-2) is EVA's forecast of delivered prices for coal and petroleum coke. Exhibit ____ (SS-3) is EVA's forecast of delivered natural gas prices. Exhibit ____ (SS-4) is EVA's forecast of oil prices.

Q. Are you sponsoring any sections of the NPA?

A. No. I am only providing testimony as to the preparation and reasonableness of the fuel forecasts used in the NPA.

Q. Please summarize your testimony.

A. EVA, as a normal part of its practice, routinely prepares fossil fuel price forecasts. For the evaluation of the Stanton IGCC project, EVA prepared a base case price forecast for natural gas, coal, petroleum coke, and crude oil. EVA evaluated the cost of transportation for coal, natural gas, and petroleum coke to Stanton and prepared delivered price forecasts in both constant and nominal dollars.

THE FUELS FORECAST

Q. How did EVA become involved in this proceeding?

A. OUC retained EVA to provide a reasonable forecast of prices for various fuels that potentially could be used for a new generation plant at the Stanton site. This forecast, in turn, was used by OUC's consultant, Black & Veatch, to evaluate whether the Stanton IGCC unit is the most cost-effective generating alternative available to OUC.

Q. What function does a fuels forecast serve in a utility's evaluation of future generating alternatives?

A. Fuel prices, and their differentials, represent one of the economic factors used in evaluating the types of new generation that could be added to a utility's system when a need for new capacity exists. Fuel prices are also relevant to the determination of the most efficient method of operating a utility's existing and proposed generating units in compliance with environmental and system requirements.

Q. What information did EVA develop for OUC?

A. EVA prepared the following price forecasts for the period 2005 through 2030: (a) delivered coal prices to the Stanton site; (b) delivered petroleum coke prices to the Stanton site; (c) natural gas prices at the Henry Hub, and delivered to the Stanton site; and (d) oil prices, including crude oil prices and No. 2 fuel oil prices.

COAL PRICE FORECAST

Q. How did EVA prepare its coal price forecast?

A. As part of its normal practice, EVA regularly analyzes coal markets, including coal supply and demand, and projects coal prices. EVA's coal price forecasts are relied upon by a variety of clients in the energy industry for long-term planning. EVA provided Black & Veatch with its current long-term price forecasts in December 2005. This forecast is for coal prices at the mine or origin point, known as FOB (free on board).

Q. What coal types did EVA consider and forecast for OUC?

A. EVA considered a wide variety of coals and coal types, including coals from every major commercial region in the U.S., plus imported coals. The coals considered were:

1. Central Appalachia; including qualities ranging from very low sulfur to mid-sulfur content.
2. Northern Appalachia; including high-sulfur and mid-sulfur coals from the Pittsburgh seam, as well as low-sulfur coal.
3. Illinois Basin; including high-sulfur coals from Illinois, Indiana, and West Kentucky.
4. Powder River Basin; including very low sulfur coals from Wyoming with both higher and lower heat content.
5. Imported coal; including very low sulfur coals from Colombia and Venezuela.

Q. Did you forecast the delivered coal prices to the Stanton Energy Center?

A. Yes. For each coal source, the likely transportation modes and routes were identified. Transportation rates were calculated and forecast using, in part, OUC's long-term rail contract, which specifies rates from most origins. Imported coal was projected to be shipped through a dock in Tampa, and delivered by rail. Colombia and Venezuela are the likely origins for imported coals, and will set the market price even if coals from other countries are competitive.

Q. Recently, coal prices have increased well above historical levels. What caused this change in prices?

A. Eastern U.S. coal prices experienced a sharp increase in early 2004, which has generally continued through the end of 2005. The principal causes of this price increase are:

1. A sharp rise in international coal prices, beginning in late 2003. This was driven in large part by rapid economic growth in China and India, causing increased demand for steel and raw materials, including coal. As world prices rose, Appalachian supply was diverted into the export market, creating a shortage domestically.
2. Eastern coal production capacity had been steadily declining through years of low market prices. As a result, there was little capacity available to respond to increased demand.
3. Barriers to entry in the Eastern coal mining industry have increased. Reserve depletion has reduced available reserves, permitting times are

much longer, and shortages of equipment and labor have delayed mine development.

4. Mining costs have increased. Reserve depletion, lower productivity, increased cost of supplies and equipment, and higher wages and benefits have all affected operating costs.

Powder River Basin (PRB) coal prices jumped in 2005, due to the following factors:

1. Rail transportation disruptions. A major maintenance outage on the Joint Line in Wyoming reduced deliveries, causing customer stocks to drop and increasing demand for 2006 delivery.
2. Increased demand in eastern markets. Utilities in the East were switching to PRB coal in response to high costs for SO_2 emission allowances and higher eastern coal prices.
3. Reduced excess capacity. Capacity reductions in 1999 and 2000 combined with increased demand to create a supply shortage in 2005 and 2006.

Q. How have these events affected EVA's coal price forecast?

A. EVA had already been projecting increasing coal prices before the change in the markets. EVA further increased its price forecasts to reflect the increases in production costs, much of which will persist. However, EVA projects that the current capacity shortage will be overcome by increased supply, and that prices will fall from the current elevated levels.

Q. Did you consider petroleum coke in the coal price forecast?

A. Yes. As a solid fuel which can substitute for, or blend with, coal, petroleum coke (pet coke) was considered as an alternate fuel.

Q. How did EVA prepare its petroleum coke price forecast?

A. Petroleum coke represents a niche market for fuels that tend to be regionally specific. On occasion, in the past, EVA has analyzed the supply and demand fundamentals for this niche market in order to prepare a petroleum coke price forecast for other clients. There are two types of petroleum coke: (1) a higher value petroleum coke, which is used for aluminum and steel production; and (2) a lower value petroleum coke, which is used as a fuel. EVA prepares a regular forecast for fuel grade petroleum coke. While supply is, in general, increasing as a result of refinery upgrades and greater use of heavier grades of crude, this is a thinly traded commodity that can be subject to rapid price escalation whenever demand increases. In general, production costs of petroleum coke prices are related to crude oil prices but the prices of fuel grade petroleum coke are capped by delivered coal prices.

Q. Where is EVA's coal and pet coke price forecast presented?

A. A summary of EVA's forecast for delivered coal and pet coke prices is provided in Exhibit ____ (SS-2). Prices are displayed for each solid fuel option in delivered $/MBtu.

NATURAL GAS PRICE FORECAST

Q. How did EVA prepare its natural gas price forecast?

A. As part of its normal practice, EVA tracks both the short-term and long-term supply and demand fundamentals for natural gas in order to prepare natural gas price forecasts for a variety of clients. These natural gas price forecasts have been developed both at specified hubs and on a delivered basis. The natural gas price forecast prepared for OUC represents EVA's latest long-term gas price forecast.

Q. Explain the basis for EVA's long-term outlook for natural gas prices.

A. EVA's long-term price forecast for natural gas prices is based upon an analysis of the supply and demand fundamentals for natural gas. The U.S. gas market currently is in a supply limited environment, with gas prices set by the marginal customer rather than the cost of supply. The key factor behind this limited supply environment has been the decline in U.S. and Canadian production, which at present appears to be rebounding, albeit moderately. The sectors most heavily affected by the resulting high prices are the industrial sector, where a second wave of demand destruction appears to have begun, and the electric sector, where high gas prices have forced fuel switching. The current outlook is that this supply limited environment and the associated high gas prices will continue into 2007.

After 2007, supply is expected to fill this widening gap between supply and demand from a series of emerging resource areas, with the net result being a decline in gas prices. The largest of these emerging resource areas and the one with the greatest intermediate-term impact is liquefied natural gas (LNG). Increased LNG imports will come from the combination of scheduled first and second phase capacity expansions at several of the four existing LNG terminals and a series of new LNG terminals.

With respect to demand, the power sector will account for about 62 percent of the projected increased demand over the forecast period. This increase in the power sector is the net result of two factors, namely projected economic growth, which drives electricity demand growth rates, and the recent dominance of gas-fired units for new capacity additions over the next two decades. For example, between 1998 and 2007 the industry likely will add 247 GW of new gas-fired capacity (i.e., 68 percent combined cycle capacity and 32 percent simple cycle capacity). However, going forward gas will have to compete with coal, nuclear, and renewables for new capacity additions. Growth in demand in other sectors should be modest, primarily as a result of conservation in response to high prices. This is particularly true for the industrial sector, where demand is expected not to return to 2000 levels until post-2015.

Q. How will gas prices in Florida be affected by the outlook for gas prices?

A. With the exception of transportation, gas prices within Florida are affected by the same factors that impact gas prices throughout the nation. This is the net result of the integrated nature of the North American gas infrastructure.

Q. How did EVA prepare its delivered price forecast for natural gas?

A. EVA used its standard market price forecast for natural gas at Henry Hub, Louisiana. The cost of transportation to Stanton was based upon the transportation tariffs for Florida Gas Transmission and the basis differential compared to Henry Hub.

Q. Where is EVA's natural gas price forecast presented?

A. EVA's natural gas price forecast delivered to Stanton is presented in Exhibit ____ (SS-3).

OIL PRICE FORECAST

Q. Has EVA prepared a forecast of oil prices?

A. Yes, EVA has provided OUC with a forecast of crude oil prices, as well as prices for high-sulfur (0.2%) and low-sulfur (0.05%) fuel oil.

Q. What are the factors behind EVA's long-term forecast for oil prices?

A. World oil supplies are forecast to increase approximately 11.5 million barrels per day (MMBD) between now and the end of the decade. This projected increase in supplies, which should be greater than increases in demand over the same period, is based upon announced development projects and is a fairly conservative assessment, as other analysts foresee the increase in supplies being 5 MMBD higher. In addition, this increase in supplies should enable the market to restore spare capacity levels to the more acceptable 3 MMBD level.

With respect to the outlook for demand, price-induced conservation has caused world wide demand growth rates to decline from the record 3.2 percent, or 2.5 MMBD, in 2004. The net result is that the 2005 world wide demand growth rate will be a more modest 1.9 percent, or 1.6 MMBD. For the entire forecast period demand is expected to grow at an average annual rate of 1.7 MMBD. A key attribute of this outlook for demand is that China, India and the U.S. will account for about 44 percent of the projected growth.

After 2015, Non-OPEC production likely will begin to decline. At this point the world will be 100 percent dependent upon OPEC for the incremental barrel. In addition, all but six countries (i.e., Saudi Arabia, Iran, Iraq, Venezuela, the UAE and Canada) will be at, or past, their peak production levels based upon the current understanding of the world's reserve potential and industry technology. Furthermore, at that point in time seven countries will account for 50 percent of the world's production, whereas the current 11 members of OPEC account for 41 percent of worldwide production. Based upon the market's reaction to the recent tight supply conditions, the $15 to $20 per barrel scarcity premium will likely reemerge in the later years of this forecast.

Q. Where is EVA's oil price forecast presented?

A. EVA's oil price forecast is contained in Exhibit ____ (SS-4).

Q. Does this conclude your testimony?

A. Yes.

RESUME OF

SETH SCHWARTZ

EDUCATIONAL BACKGROUND

B.S.E. Geological Engineering, Princeton University, 1977

PROFESSIONAL EXPERIENCE

Current Position

Seth Schwartz is a co-founder of Energy Ventures Analysis. Mr. Schwartz directs EVA's coal and utility, practice and manages the COALCAST Report Service. The types of projects in which he is involved are described below:

Fuel Procurement

Assists utilities, industries and independent power producers in developing fuel procurement strategies, analyzing coal and gas markets, and in negotiating long-term fuel contracts.

Fuel Procurement Audits

Audits utility fuel procurement practices, system dispatch, and off-system sales on behalf of all three sides of the regulatory triangle, i.e., public utility commissions, rate case intervenors, and utility management.

Coal Analyses

Directs EVA analyses of coal supply and demand, including studies of utility, industrial, export, and metallurgical markets and evaluations of coal production, productivity and mining costs.

Natural Gas Analyses

Evaluates natural gas markets, especially in the utility and industrial sectors, and analyzes gas supply and transportation by pipeline companies.

Expert Testimony

Testifies in fuel contract disputes, including arbitration and litigation proceedings, regarding prevailing market prices, industry practice in the use of contract terms and conditions, market conditions surrounding the initial contracts, and damages resulting from contract breach.

Acquisitions and Divestitures

Assists companies in acquisitions and sales of reserves and producing properties, both in consulting and brokering activities. Prepares independent assessments of property values for financing institutions.

Prior Experience

Before founding Energy Ventures Analysis, Mr. Schwartz was a Project Manager at Energy and Environmental Analysis, Inc. Mr. Schwartz directed several sizable quick-response support contracts for the Department of Energy and the Environmental Protection Agency. These included environmental and financial analyses for DOE's Coal Loan Guarantee Program, analyses of air pollution control costs for electric utilities for EPA's Office of Environmental Engineering and Technology, Energy Processes Division, and technical and economic analysis of coal production and consumptions for DOE's Advanced Environmental Control Technology Program.

Publications

Crerar, D.A., Susak, N.J., Borcsik, M., and Schwartz, S., "Solubility of the Buffer Assemblage Pyrite + Pyrrhotite + Magnetite in NaCl Solutions from 200° to 350°", Geochimica et Cosmochimica Acta (42)1427-1437, 1978.

EVA FORECAST OF DELIVERED COAL PRICES TO STANTON ENERGY CENTER

Origin	FOB Point	Btu/lb	#SO2/ MMBtu	% Ash	Real 2005 Dollars per MMBtu 2005	2010	2015	2020	2025	2030
Northern Appalachia										
Pitt Seam	MGA	13,000	4.0	8.0	$2.680	$2.319	$2.366	$2.518	$2.586	$2.634
Pitt Seam	MGA	13,000	3.0	8.0	$2.912	$2.421	$2.453	$2.572	$2.641	$2.690
NWV	Fairmont	13,000	1.8	8.0	$3.394	$2.652	$2.712	$2.853	$2.951	$3.033
Central Appalachia										
Compliance	Big Sandy	12,500	1.2	10.0	$3.419	$2.727	$2.737	$2.801	$2.886	$2.979
Low-Sulfur	Big Sandy	12,500	1.8	10.0	$3.142	$2.492	$2.574	$2.747	$2.851	$2.939
Mid-Sulfur	Big Sandy	12,500	2.5	10.0	$2.957	$2.377	$2.500	$2.719	$2.823	$2.911
Illinois Basin										
Illinois	ICG origin	11,500	5.0	10.0	$2.474	$2.400	$2.438	$2.563	$2.563	$2.535
Indiana	Princeton	11,000	5.0	10.0	$2.410	$2.342	$2.381	$2.505	$2.506	$2.477
West Kentucky	West Kentucky	11,500	6.0	10.0	$2.289	$2.268	$2.314	$2.435	$2.437	$2.411
Powder River Basin										
Low-Btu Gillette	BN	8,400	0.8	5.0	$2.379	$2.459	$2.486	$2.695	$2.705	$2.677
High-Btu Gillette	BN	8,800	0.8	5.0	$2.387	$2.442	$2.469	$2.669	$2.678	$2.652
Foreign Coal (Rail from Tampa)										
Colombia	Tampa	11,700	1.2	6.0	$3.414	$2.551	$2.530	$2.522	$2.582	$2.668
Venezuela	Tampa	12,900	1.0	5.5	$3.355	$2.514	$2.492	$2.479	$2.539	$2.625
Pet Coke (Rail from Tampa)				HGI						
U.S. Gulf Coast	Tampa	14,300	7.0	70.0	$1.757	$1.583	$1.680	$1.756	$1.799	$1.837
Venezuela	Tampa	14,300	7.0	45.0	$1.731	$1.579	$1.680	$1.759	$1.805	$1.846

EVA FORECAST OF DELIVERED NATURAL GAS PRICES TO STANTON

	Prices in Real 2005 Dollars						
	2000	2005	2010	2015	2020	2025	2030
Wellhead Prices in Real 2005 Dollars							
Henry Hub	$4.69	$8.84	$5.29	$5.63	$5.70	$6.14	$6.58
U.S. Spot Wellhead	$4.52	$8.64	$5.16	$5.51	$5.59	$6.04	$6.49
Canadian-Alberta	$3.87	$7.73	$4.80	$5.18	$5.29	$5.77	$6.24
Gas Pipeline Transportation Cost in Real 2005 Dollars							
FGT Z3 Basis to HH	$ (0.030)	$ 0.450	$ 0.224	$ 0.123	$ 0.075	$ 0.034	$ 0.031
FGT Fuel Loss	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
FGT FTS2 Usage	$ 0.028	$ 0.045	$ 0.040	$ 0.037	$ 0.034	$ 0.031	$ 0.028
Delivered Cost to SEC using OUC FTS2 Capacity							
Real 2005 Dollars	$ 4.831	$ 9.626	$ 5.725	$ 5.966	$ 5.987	$ 6.396	$ 6.848

EVA OIL PRICE FORECAST

	2000	2005	2010	2015	2020	2025	2030
Real 2005 Dollars per Barrel							
West Texas Intermediate	$33.57	$57.93	$46.00	$50.50	$53.00	$55.50	$58.00
North Sea Brent	$32.14	$55.84	$43.31	$48.05	$50.76	$53.45	$55.86
OPEC Basket	$31.63	$56.18	$41.51	$46.42	$49.27	$52.09	$54.44
Real 2005 Cents per Gallon							
No. 2 Fuel Oil/Diesel (0.2%)	97.3	165.6	131.4	144.3	151.4	158.6	165.7
No. 2 Fuel Oil/Diesel (0.05%)	97.6	169.1	134.3	146.9	153.8	160.8	168.0

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF CHRIS J. KLAUSNER

ON BEHALF OF

ORLANDO UTILITIES COMMISSION

DOCKET NO. ___________

FEBRUARY 22, 2006

Q. Please state your name and business address.

A. My name is Chris Klausner. My business address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Corporation. My current position is Senior Consultant/Project Manager.

Q. Please describe your responsibilities in that position.

A. As a senior consultant and project manager, I am responsible for the management of various projects for utility and non-utility clients. These projects encompass a wide variety of services for the power industry. The services include development of generating unit addition alternatives, screening evaluations, analysis of production cost simulations and optimal generation expansion modeling, economic and financial evaluation, sensitivity analysis, risk analysis, power purchase and sales evaluation, feasibility studies, qualifying facility and independent power producer evaluations, independent engineering assessments for lenders, and power plant financing evaluations.

Q. Please state your educational background and experience.

A. I received a Bachelor of Science degree in Mechanical Engineering from the University of Kansas. I have a Master of Business Administration with concentration in finance from the University of Kansas. I am also a licensed professional engineer.

I have over 15 years of experience in the power industry specializing in generation design, feasibility analysis, planning, due diligence, independent engineering, and project development. In the past few years, I have been the project manager for six projects. In addition, I have participated in the development of two Need for Power applications that have been filed on behalf of Florida utilities. I also have been engaged in integrated resource planning for electric utilities. Florida utilities for which I have worked include Florida Municipal Power Agency, Orlando Utilities Commission (OUC), and JEA. I have participated in more than 30 feasibility study and independent engineering assignments that have required assessment of simple cycle, combined cycle, circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), wind, biomass, and other power generation technologies. These assignments have involved development, review, and analysis of generating technology performance characteristics, O&M cost, capital cost, reliability, and emissions rates.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide an overview and summary of the conventional, advanced, emerging, energy storage, and distributed generation supply-side alternatives. I will discuss the numerous supply side alternatives that were considered in the economic analyses conducted in determining that Stanton B is part of OUC's least-cost capacity expansion plan.

Q. Are you sponsoring any sections of Exhibit ____ (OUC-1), Stanton B Need for Power Application?

A. Yes. I am sponsoring Sections 8.2, 8.3, 8.4, 8.5, and 8.6, all of which were prepared by me or under my direct supervision.

Q. Are you adopting these sections as part of your testimony?

A. Yes.

Q. What conventional supply-side alternatives were considered in the Stanton B Need for Power Application?

A. Several conventional supply-side alternatives were considered including simple cycle combustion turbines (General Electric LM6000, 7EA, and 7FA), a General Electric 1x1 7FA combined cycle, a CFB boiler plant, and a pulverized coal unit. The conventional supply side alternatives represent a wide range of technologies and fuel types, and thus provide a good mix of potential peaking, intermediate, and baseload type alternatives.

Q. What fuel types were considered for the conventional alternatives?

A. Depending on the alternative, various fuel types were considered. The simple cycle combustion turbine alternatives were assumed to burn ultra-low sulfur fuel oil as the primary fuel with natural gas as a backup fuel. Fuel oil was assumed as the primary fuel because it is cost prohibitive to obtain firm natural gas transportation for simple cycle units and because of the potential supply disruptions related to interruptible gas transportation. The combined cycle alternative was assumed to fire natural gas as its primary fuel with ultra-low sulfur fuel oil as backup. The cost for firm natural gas transportation was included in the evaluation of the combined cycle alternative.

The CFB option was assumed to burn high sulfur Northern Appalachian coal, and the pulverized coal option was assumed to burn low sulfur Central Appalachian coal (identical to the coal burned by the existing Stanton Units 1 and 2).

Q. Please describe the range of capacity sizes considered.

A. The simple cycle combustion turbines range in capacity from approximately 47 MW to approximately 167 MW. The combined cycle was assumed to be approximately 299 MW. The CFB was assumed to be approximately 302 MW, and the pulverized coal unit was assumed to be approximately 447 MW, which is identical in size to the existing Stanton Unit 2. While a larger coal fired unit may have provided increased economies of scale, a larger unit would be too large for OUC's capacity requirements.

Q. Are the capital costs for these alternatives inclusive of all expected costs?

A. Yes. The capital costs include the engineer, procure, and construction (EPC) costs plus an allowance for owner's costs, or costs that are not included in the EPC capital cost estimates. Although in Black & Veatch's experience owner's costs can vary significantly from project to project, a representative amount was added to the capital costs for each alternative. The capital costs are exclusive of escalation, financing fees, and interest during construction. These costs were calculated separately during the economic modeling process.

Q. Were any new greenfield alternatives considered?

A. No. In order to have the capital costs for the generating alternatives be as competitive as possible, all alternatives were assumed to be installed at the Stanton Energy Center so that, similar to Stanton B, each alternative could benefit from existing infrastructure. Greenfield alternatives would be more expensive in comparison to building at an existing site.

Q. Please describe the methodology used to determine the cost and performance characteristics of the conventional supply-side alternatives?

A. In developing the cost and performance estimates, a specific manufacturer (General Electric) and specific models were analyzed. These alternatives were evaluated not to indicate a preference to a specific manufacturer, but rather to generalize the properties of similar generating technologies with similar attributes. Capital costs were developed using direct and indirect costs, with an allowance for owners' costs.

Performance estimates for output and heat rate were also developed taking into account performance degradation. Fixed and variable operating and maintenance (O&M) cost estimates were developed for each of the conventional alternatives. Availability estimates were derived from estimated scheduled maintenance requirements and forced outage rates for each alternative. The construction period for each of the conventional alternatives also was estimated.

For the coal fired options in particular, estimates were developed for the capital cost of the additional railcars that OUC would need to purchase. Additionally, estimates were developed for the variable operating expenses associated with the railcars.

Q. Were any other supply-side alternatives considered in addition to the conventional technologies?

A. Yes. Cost and performance estimates were developed for renewable, emerging, advanced, energy storage, and distributed generation technologies. Renewable energy technologies will be addressed by Myron Rollins in his testimony.

Q. Please describe the emerging technologies considered.

A. Emerging technologies are technologies that would likely only be considered by a utility such as OUC after successful demonstration of commercial operation. These technologies are generally either just starting or are about to start commercial operation. The technologies presented in Exhibit ____ (OUC-1) that fall into this category include the LMS100 which I mentioned previously in my testimony and a nuclear alternative.

The LMS100 is considered an emerging technology because it is a new unit offered by General Electric which has not been commercially proven. From a timing perspective, it has been assumed that commercial operation of the LMS100 will have been proven by the time OUC is forecasted to require additional capacity (2010).

Although there are currently many nuclear units operating throughout the United States, a new domestic nuclear unit has not been constructed in more than 25 years. In addition to the new designs and technologies that would have to be demonstrated in a new nuclear option, there are uncertainties related to the duration of the proposed new licensing process which makes it difficult to estimate an in-service date. These schedule uncertainties as well as public perception, capital costs, and disposal of spent fuel from an environmental perspective preclude nuclear technology from being considered a viable conventional alternative at this time.

Q. Please describe the advanced technologies considered.

A. Advanced technologies include technologies that are still in developmental stages or are nearing commercial status that offer the potential for cost and efficiency improvements over conventional technologies. The advanced technologies considered included three different combustion turbine technologies, fuel cells, and two advanced coal technologies. For each of the advanced technologies, representative cost and performance estimates were developed. Myron Rollins discusses the screening analysis performed on each of these technologies in his testimony.

Q. Please describe the energy storage technologies considered.

A. Energy storage technologies convert and store electricity, increasing the value of power by allowing better utilization of off-peak baseload generation and helping to reduce instantaneous power fluctuations. Depending on the technology considered, various durations of energy storage are available. The energy storage technologies considered included pumped hydroelectric, batteries, and compressed air. For each of these technologies, representative cost and performance estimates were developed. Myron Rollins discusses the screening analysis performed on each of these technologies in his testimony.

Q. Please describe the distributed generation technologies considered.

A. Distributed generation is used to describe capacity resources that are generally relatively small and have high reliability, and are used to meet peak demands. Two different distributed generation technologies were considered, including reciprocating engines and microturbines. Representative cost and performance estimates were developed for each of these technologies. Myron Rollins discusses the screening analysis performed on each of these technologies in his testimony.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF BRADLEY E. KUSHNER

ON BEHALF OF

ORLANDO UTILITIES COMMISSION

DOCKET NO. _________

FEBRUARY 22, 2006

Q. Please state your name and business address.

A. My name is Bradley E. Kushner. My business mailing address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

Q. By whom are you employed?

A. I am employed by Black & Veatch.

Q. Please describe your responsibilities in that position.

A. I am responsible for production cost modeling associated with utility system expansion planning, as well as feasibility studies and demand-side management (DSM) evaluation. I also have involvement in the issuance and evaluation of requests for proposals (RFPs).

Q. Please state your educational background and professional experience.

A. I received my Bachelors of Science in Mechanical Engineering from the University of Missouri – Columbia in 2000. I have more than 5 years of experience in the engineering and consulting industry. I have experience in the development of integrated resource plans, ten-year-site plans, demand-side management plans, and other capacity planning studies for clients throughout the United States. Utilities in Florida for which I have worked include Florida Municipal Power Agency (FMPA), JEA, Kissimmee Utility Authority (KUA), OUC, Lakeland Electric, Reedy Creek Improvement District, and the City of Tallahassee. I have performed production cost modeling and economic analysis and otherwise participated in three Need for Power Applications that have been filed on behalf of Florida utilities. I have testified before the Florida Public Service Commission (FPSC) in a previous Need for Power filing.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the economic evaluation of supply-side resources performed in determining that Stanton B represents the least-cost alternative to OUC. I will also discuss OUC's existing demand-side management (DSM) and conservation measures as well as the evaluation of demand-side management measures performed in the Stanton B Need for Power Application.

Q. Are you sponsoring any sections of Exhibit ____ (OUC-1), Stanton B Need for Power Application?

A. Yes. I am sponsoring Sections 10.0, 11.0, 12.0, and Appendix C. These sections were prepared by me or under my direct supervision.

Q. Are you adopting these sections as part of your testimony?

A. Yes.

Q. How was the detailed system economic evaluation conducted?

A. The detailed system economic evaluation was conducted using an optimum generation expansion model (POWROPT) and a detailed chronological production costing model (POWRPRO). POWROPT and POWRPRO are proprietary expansion planning and production costing models that have both been used in numerous Need for Power Applications filed with the Florida Public Service Commission, as well as for other clients throughout the United States.

Both POWROPT and POWRPRO operate on an hourly chronological basis using the same set of input files related to OUC's existing generating resources, load projections, and fuel price projections. POWROPT is used to identify the timing of capacity additions comprising the least-cost capacity expansion plan from among the alternatives which passed the screening process described in the testimony of Myron Rollins. Once the least-cost capacity expansion plan is identified in POWROPT, the selected units are integrated with OUC's existing capacity resources and POWRPRO is used to obtain the annual production costs for the capacity expansion plan.

The POWRPRO results are used to generate a cumulative present worth cost (CPWC) of the expansion plan being considered, which accounts for all system fuel costs, non-fuel variable O&M costs, fixed O&M costs for new capacity additions, startup costs, and levelized capital costs. The CPWC for various capacity expansion plans can be compared to one another to identify the least-cost capacity expansion plan.

Q. What supply-side alternatives were included in the detailed economic analysis?

A. The detailed economic analysis included all of the technologies which passed the supply-side screening as Myron Rollins described in his testimony. These included the simple cycle combustion turbines, the combined cycle, the circulating fluidized bed (CFB), and the pulverized coal options. All alternatives were assumed to be available to meet OUC's initial forecast capacity requirements, and there were no restrictions placed on the number of each option that could be selected by POWROPT.

Q. How was the least-cost capacity expansion plan identified?

A. The least-cost expansion plan was identified by using POWROPT to develop two unique capacity expansion plans. The first plan developed considered Stanton B a committed resource as of June 1, 2010, and POWROPT was used to select the optimum capacity additions beyond Stanton B. The second plan did not include Stanton B as a committed resource, nor was it included among the capacity expansion alternatives. This approach identified the least-cost capacity expansion plan including Stanton B as well as the least-cost capacity expansion plan not including Stanton B, and allowed for consideration of the unique aspects of Stanton B.

Q. Identify the unique aspects of Stanton B that needed to be accounted for in the economic analysis.

A. There were a number of unique aspects that needed to be considered in order for Stanton B to be accurately evaluated, including:

- Department of Energy (DOE) cost-sharing for the capital cost associated with the gasifier.
- DOE cost-sharing during the 4 year demonstration phase.
- The guaranteed capital cost of the combined cycle and OUC's ownership share of the gasifier.
- Monthly demand payments for use of Southern Power Company-Orlando Gasification LLC's (SPC-OG's) ownership share of the gasifier.
- Facility lease payments OUC will receive from SPC-OG.
- Project completion costs required by the DOE.
- Stanton B availability guarantees.
- Sale of energy generated during the startup of Stanton B.

These aspects are described in detail of Section 10.0 of Exhibit ____ (OUC-1) and in part by the testimony of Fred Haddad.

Q. Describe how the economic analysis considered emissions costs?

A. The costs of SO_2 and NO_x allowances were estimated for each of OUC's existing capacity resources, Stanton B, and the supply-side alternatives considered in the analysis. These costs were developed on a $/MBtu basis, and were added to the fuel price projections for each unit. As a result, each unit was modeled using different prices for fuel because of the differences in the emission rates of each unit. By including the costs of SO_2 and NO_x allowances in the fuel price projections they were factored into the unit dispatch and commitment in POWROPT and POWRPRO. The value of allowances allocated to OUC's existing units was not included in the economic analysis since it would be the same for each capacity expansion plan.

Q. **What were the results of the economic analysis?**

A. As mentioned previously in my testimony, two unique capacity expansion plans were identified, one including Stanton B with commercial operation in June 2010 and one which did not include Stanton B. The plan with Stanton B included the addition of a 7FA simple cycle combustion turbine in 2015, a second 7FA simple cycle combustion turbine in 2018, a pulverized coal unit in 2021, an LM6000 simple cycle combustion turbine in 2029, and a 7EA simple cycle combustion turbine in 2030. The plan not including Stanton B consisted of a 7FA simple cycle combustion turbine in 2010, a pulverized coal unit in 2013, a 7EA simple cycle combustion turbine in 2021, a 7FA simple cycle combustion turbine in 2023, and a 1x1 7FA combined cycle in 2026.

The cumulative present worth cost of the capacity expansion plan including commercial operation of Stanton B in June 2010 was approximately $12.9 million less than the plan not including Stanton B.

Q. Is Stanton B the most cost-effective alternative available to OUC?

A. Yes. Stanton B is the most cost-effective alternative available to OUC.

Q. Will Stanton B provide adequate electricity at a reasonable cost?

A. Yes. Stanton B meets OUC's electric generation needs at the lowest cost of all the alternatives evaluated

Q. Will Stanton B meet OUC's need for electric system reliability and integrity?

A. Yes.

Q. Did you conduct any sensitivity analyses relative to Stanton B?

A. Yes. Several sensitivity analyses were conducted to identify the least-cost capacity expansion plans with and without Stanton B under a variety of different scenarios. Sensitivity analyses were performed for high and low fuel price scenarios, high and low load and energy growth scenarios, a high capital cost scenario, utilization of the gasification ash produced by Stanton B, high and low emissions allowance price scenarios, a scenario in which emission allowance prices were not considered in the optimum unit commitment and dispatch, a scenario in which no coal fired capacity additions were allowed except for Stanton B, and a scenario in which commercial operation of Stanton B was delayed by 1 year to June 2011.

Q. What were the results of the sensitivity analyses?

A. For all but two of the sensitivity analyses performed, the capacity expansion plan including Stanton B in 2010 was the least-cost plan. Overall, the results of the sensitivity analyses coupled with the results of the base case analysis indicate that the capacity expansion plan involving Stanton B is a robust plan and is sufficiently flexible to overcome variations and deviations from the base case assumptions.

Q. Does OUC have any numeric DSM or conservation goals that are required to be met by the Florida Public Service Commission?

A. No. On September 1, 2004 the Florida Public Service Commission established and approved zero DSM and conservation goals for OUC's residential and commercial/industrial sectors after reviewing OUC's 2005 Demand-Side Management Plan (Docket No. 040035-EG). However, OUC continues to offer numerous DSM and conservation programs to its customers.

Q. If OUC is not required to offer DSM and conservation programs to their customers, why are they offered?

A. OUC's existing DSM and conservation programs promote efficient use of energy and provide other general benefits to OUC's customers such as consumer education.

Q. Please list the DSM and conservation programs offered by OUC.

A. During 2005, OUC offered its customers the following DSM and conservation programs:

- Residential Energy Survey Program
- Residential Energy Efficiency Rebate Program
- Residential Low-Income Home Energy Fix-Up Program
- Residential Insulation Billed Solution Program
- Residential Efficient Electric Heat Pump Program
- Residential Gold Ring Program
- Commercial Energy Survey Program
- Commercial Indoor Lighting Retrofit Program
- Residential Energy Conservation Rate
- Commercial OUConsumption Online Program
- Commercial OUConvenient Lighting Program
- Commercial Power Quality Analysis Program
- Commercial Infrared Inspections Program
- OUCooling
- Green Pricing Initiative Program
- Photovoltaic Generation Pilot Program

Q. Are DSM and conservation separately accounted for in OUC's load forecast?

A. No, they are embedded in OUC's load forecast.

Q. How was DSM and conservation evaluated in the Stanton B Need for Power Application?

A. The approach used to evaluate DSM and conservation in the Stanton B Need for Power Application was similar to that performed in OUC's 2005 Numeric Conservation Goal filing (Docket No. 040035-EG, discussed previously in my testimony). The DSM and conservation measures evaluated in Docket No. 040035-EG were reviewed, and assumptions specific to each measure were updated as necessary. In all, approximately 180 DSM and conservation measures were developed. Next, the DSM and conservation measures were evaluated using the Florida Integrated Resource Evaluator (FIRE) model. The FIRE model has been used extensively in DSM and conservation filings before the FPSC and has been found to be an appropriate means of evaluating conservation and DSM.

The FIRE model requires three main sources of input. The first is the characterization of the DSM and conservation measures as discussed above. The second is the cost and characteristics of the unit to be avoided with the DSM and conservation, which in this case is Stanton B. Finally, utility system specific information such as rates are required with separate rates used depending on the customer class each measure pertains to.

The FIRE model provides three tests designed to measure the cost-effectiveness of DSM and conservation from different perspectives:

- The *Total Resource Test* measures the benefit-to-cost ratio of a specific measure by comparing the total benefits (both the participant's and the utility's) to the total costs (equipment costs, utility costs, participant costs, etc.).
- The *Participant Test* measures the impact of the DSM measure on the participating customer. Benefits to the participant may include bill reductions, incentives, and tax credits. Participants' costs may include equipment costs, O&M expenses, equipment removal, etc. The Participant Test is important because customers will not participate in a program if it is not cost-effective from their perspective.
- The *Rate Impact Test* is an indicator of the expected impact on customer rates resulting from a DSM measure. The test statistic is the ratio of the utility's benefits (avoided supply costs and increased revenues) compared to the utility's costs (implementation costs, incentives paid, increased supply costs, and revenue losses). A value of less than 1.0 indicates an upward pressure on electricity rates as a result of the DSM program.

If the benefits to costs ratio of these tests is greater than 1.0, then the DSM and conservation measures are cost-effective under the test. OUC believes that the Rate Impact (RIM) Test is the appropriate test for determining cost-effectiveness. The FPSC has also consistently found the RIM Test to be appropriate for determining cost-effectiveness.

Q. Did any of the conservation and DSM measures pass the RIM test?

A. No. Of the approximately 180 DSM and conservation measures considered none had a RIM test score greater than 1.0. Thus, none of the DSM or conservation measures were found to be cost-effective.

Q. Do you agree with OUC that the RIM test is appropriate for determining cost-effectiveness for DSM and conservation measures?

A. Yes. Cost-effective conservation and DSM should reduce rates, not increase them.

Q. Does it surprise you that none of the DSM and conservation measures were found to be cost-effective?

A. No. The same conclusion was reached for JEA's 2004 Numeric Conservation Goals filing before the FPSC (Docket No. 040030-EG) and FMPA's recently filed Treasure Coast Energy Center Unit 1 Need for Power Application (Docket No. 050256-EM). It is also the same conclusion that has been reached in the integrated resource planning work that I have done for a number of municipal utilities in the State of Florida.

Q. In your opinion, are there conservation measures available to OUC that could mitigate the need for Stanton B?

A. No.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF THOMAS E. WASHBURN

ON BEHALF OF

ORLANDO UTILITIES COMMISSION

DOCKET NO. _________

FEBRUARY 22, 2006

Q. Please state your name and business address.

A. My name is Thomas Washburn and my business address is 6003 Pershing Avenue, Orlando, Florida, 32822.

Q. By whom are you employed and in what position?

A. I am employed by the Orlando Utilities Commission (OUC) as Chief Information Officer and Vice President of the Transmission Business Unit.

Q. Please describe your duties in this position with OUC.

A. As the Chief Information Officer for OUC, I am responsible for the computer software and hardware, microcomputer support, and communication systems. As the Vice President of the Transmission Business Unit, I am responsible for the operation of the transmission system, the Energy Control Center (ECC), transmission planning, and the operation of the Florida Municipal Power Pool. I represent OUC on the Florida Reliability Coordinating Council (FRCC) Engineering Committee. I have been the chair of the FRCC Engineering Committee and FRCC's representative on the North American Electric

Reliability Council (NERC) Planning Committee since 2001. I am also a Trustee for the OUC pension fund.

Q. Please summarize your educational background.

A. I hold a Masters of Science degree in Electrical Engineering from University of Central Florida and a Bachelor of Science degree in Mathematics from Georgia Institute of Technology. In addition, I have attended numerous seminars on topics pertaining to the electric utility industry.

Q. Please summarize your employment history and work experience.

A. I have 33 years of experience in the electric utility industry, all with OUC. From July 1972 through June 1984, I served in various positions in system planning for OUC. During this time I was responsible for production costing, load flows, rate making, and financial modeling. From June 1984 through June 1995 I served as the Director of System Operations for OUC. I was responsible for OUC's Energy Control Center including the EMS/SCADA system and also for OUC's power marketing. Beginning in January 1992 my responsibilities also included the role of the Director of System Planning for OUC. This entailed transmission, supply-side, and demand-side planning. From June 1995 through September 2000 I served as the Vice President of the Transmission Business Unit for OUC. I was responsible for the maintenance and operation of OUC's transmission system, OUC's Energy Control Center, transmission planning, engineering and constructing of OUC's transmission system, OUC's bulk communications systems, and operating the Florida Municipal Power Pool.

I have served in my current position, as described above, as the Chief Information Officer and Vice President of the Transmission Business Unit since October 2000.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the impacts of Stanton B to OUC's transmission system and the Central Florida transmission system as a whole.

Q. Are you sponsoring any sections of Exhibit ____ (OUC-1), Stanton B Need for Power Application?

A. Yes. I am sponsoring Section 13.0.

Q. Are you adopting this section as part of your testimony?

A. Yes.

Q. Have there been any studies conducted to determine the impact of Stanton B to the transmission system?

A. Yes. OUC conducted an initial study in 2004. That study indicated that the direct impact of Stanton B to the transmission system was the need to reconductor the Stanton West-Curry Ford 230 kV transmission line.

Q. In that study were there any other system improvements identified?

A. Yes, there were several system improvements identified that were related to load growth in the Orlando service area.

Q. Please summarize the study conducted by OUC in 2004 as well as its findings?

A. OUC's 2004 study addressed the potential impact of a capacity addition in 2008 at the Stanton Energy Center on the Central Florida transmission system. The study results indicated that various overloads would exist under contingency conditions by the summer of 2008. However, many of the overloads identified in the study were due to load, generation, and transmission conditions not related to the installation of additional capacity at Stanton Energy Center. A preliminary list of upgrades was identified to address the overload conditions, and only one of the upgrades, the reconductoring of the Stanton West-Curry Ford 230 kV transmission line, is directly connected to the Stanton Substation.

Q. Please describe the actions that have been taken in response to the results of OUC's 2004 study.

A. None of the proposed upgrades have been installed to date. However, the two additional regional studies have been undertaken to develop alternatives that reduce cost and increase reliability of the Central Florida transmission system. These regional studies address load growth and generation in the entire Central Florida region, not just the addition of Stanton B and OUC's load.

Q. Please describe these additional studies.

A. There are currently two regional studies underway to address possible overloads on the Central Florida transmission system during contingency conditions and to plan for future growth in the region. One study focuses on the area north and east of Orlando and includes Florida Power & Light (FPL), OUC, and Progress Energy Florida (PEF). The second study focuses on the area south and west of Orlando including Polk County and includes PEF, Tampa Electric Company (TECO), OUC, Reedy Creek Improvement District, Seminole Electric Cooperative, Florida Municipal Power Agency (FMPA), Lakeland Electric, FPL, and Kissimmee Utility Authority (KUA). These studies are all in addition to the studies that OUC (and most of the other utilities) continue to perform independently, such as the study that OUC is currently conducting on its 115 kV system, which serves most of OUC's load.

Q. **Based on the transmission studies performed to date, what impact will Stanton B have on the OUC and Central Florida transmission systems?**

A. Independently OUC has determined that the addition of Stanton B will require the reconductoring of the Stanton West-Curry Ford 230 kV transmission line. OUC is actively participating with other utilities in the region to develop regional transmission solutions to meet the needs of all the loads in the Central Florida region. If a regional solution that is beneficial to all parties is identified, OUC will participate in the regional solution in lieu of OUC's independent solution.

Q. Please discuss the contingency results in Table 13-1, Exhibit ___ (OUC-1), Stanton B Need for Power Application.

A. Table 13-1 shows the contingency in the first column that causes an overload of a transmission element in the second column and the last two columns show the loading as a percentage of the continuous line rating. As you can see from the loadings in Table 13-1, with or without Stanton B, OUC has some overloads in the 115 kV system and this is why OUC is studying the 115 kV system as mentioned above. The addition of Stanton B has minimal to no impact on the 115 kV system.

Q. Were the costs of transmission system upgrades included in the economic evaluation of the Need for Power Application of Stanton B?

A. No, only costs for upgrades in the Stanton Substation that were a direct result of the installation of Stanton B were included in the economic evaluation of Stanton B. These costs are included in the additional OUC common facility costs shown in Table 7-4 of Exhibit ___ (OUC-1), Stanton B Need for Power Application. All of the supply-side alternatives evaluated were assumed to be installed at Stanton Energy Center. As such, any impact to the transmission system would be similar in all plans. Other than the Stanton Substation upgrades, no transmissions system upgrade costs have been included for Stanton B nor for any of the other supply-side alternatives considered in the Stanton B Need for Power Application.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JOHN E. HEARN

ON BEHALF OF

ORLANDO UTILITIES COMMISSION

DOCKET NO. _________

FEBRUARY 22, 2006

Q. Please state your name and address.

A. My name is John E. Hearn. My business address is 500 South Orange Avenue, Orlando, Florida, 32802.

Q. By whom are you employed and in what capacity?

A. I am employed by Orlando Utilities Commission (OUC) as Vice President and Chief Financial Officer.

Q. Please describe your responsibilities in that position.

A. I am responsible for the financial operations of OUC. Among my duties are financial planning and project financing.

Q. Please state your educational background and professional experience.

A. I am a graduate of the University of Central Florida with a bachelor's degree in accounting. I am also a certified public accountant in the State of Florida. I previously served as finance director for the City of Kissimmee. I have been with OUC for 19 years.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss OUC's ability to finance Stanton B.

Q. Are you sponsoring any sections of Exhibit ____ (OUC-1), Stanton B Need for Power Application?

A. Yes. I am sponsoring Section 16.0.

Q. Are you adopting this section as part of your testimony?

A. Yes.

Q. How does OUC intend to finance its ownership share of Stanton B?

A. No final decision has been made as to the method of financing. As with other recent projects, OUC will assess whether the project should be financed with long-term debt, short-term debt, internally generated funds, or a combination of these sources. As a municipal utility, OUC could finance the project in whole or in part with tax-exempt debt.

Q. Does OUC have the capability to finance the project with long-term debt if required?

A. Yes. OUC is financially very healthy. Our debt service coverage ratio for fiscal year 2005 was 2.26X. We have strong credit ratings on all of our debt consisting of AA by Fitch, Aa1 by Moody's, and AA by Standard & Poor's. In fact, OUC is one of the most highly rated municipal utilities in the United States.

In light of this financial health, OUC has the capacity to finance the project entirely through long-term debt if that proves to be the most appropriate option.

Q. In general, how does OUC recover costs in rates?

A. Rates are developed on a cost of service basis. Base rates are set to recover capital costs including the amortization of debt and a return on equity, operating and maintenance (O&M) costs, capacity charges, administrative, and general costs. Fuel and purchase power costs are recovered through a fuel charge.

Q. How will the costs for Stanton B be recovered by OUC?

A. The capital and O&M costs for Stanton B will be recovered through base rates. As mentioned above, a portion of the capital costs may be paid from internally generated funds. The fuel cost will be recovered through the fuel charge.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MYRON R. ROLLINS

ON BEHALF OF

ORLANDO UTILITIES COMMISSION

DOCKET NO. ___________

FEBRUARY 22, 2006

Q. Please state your name and business address.

A. My name is Myron Rollins. My business address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Corporation. My current position is Project Manager.

Q. Please describe your responsibilities in that position.

A. As a project manager, I am responsible for the management of various projects for utility and non-utility clients. These projects encompass a wide variety of services for the power industry. The services include load forecasts, conservation and demand-side management, reliability criteria and evaluation, development of generating unit addition alternatives, fuel forecasts, screening evaluations, production cost simulations, optimal generation expansion modeling, economic and financial evaluation, sensitivity analysis, risk analysis, power purchase and sales evaluation, strategic considerations, analyses of the effects of the 1990 Clean Air Act Amendments, feasibility studies, qualifying facility and independent power producer evaluations, power market studies, and power plant financing.

Q. Please state your educational background and experience.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Missouri - Columbia. I also have two years of graduate study in nuclear engineering at the University of Missouri – Columbia. I am a licensed professional engineer and a Senior Member of the Institute of Electrical and Electronic Engineers.

I have over 29 years of experience in the power industry specializing in generation planning and project development. In the past 10 years, I have been the project manager for over 100 projects, the vast majority of which are for Florida utilities. Florida utilities for which I have worked include the City of Lakeland, Kissimmee Utility Authority, Florida Municipal Power Agency, Orlando Utilities Commission, JEA, City of St. Cloud, City of Tallahassee, Utilities Commission of New Smyrna Beach, Sebring Utilities Commission, City of Homestead, Florida Power Corporation, and Seminole Electric Cooperative.

I was responsible for the development of Black & Veatch's POWRPRO chronological production costing program and RECOM unit commitment program, and POWROPT optimal generation expansion program. I am also responsible for power market analysis and project feasibility studies. I have been responsible for need for power certification on a number of power plants in Florida including Treasure Coast Energy Center 1, Stanton 1, 2, and A, Cedar Bay, Cane Island 3, McIntosh 5, and the Brandy Branch Combined Cycle Conversion. I also participated in the need for power certification for the Hardee and Hines projects. I have presented expert testimony on several occasions before the Alaska, Indiana, Missouri, and Florida public service commissions and have presented numerous papers on strategic planning and cogeneration.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide an overview and summary of the economic evaluation criteria and methodology used in the detailed economic analysis which is described in the testimony of Bradley E. Kushner. These criteria include the economic parameters and the fuel prices used in the detailed economic analyses. I will describe the renewable technologies evaluated as supply-side alternatives to meet OUC's capacity needs, and the supply-side screening used to evaluate all supply-side technologies considered. I will discuss the environmental considerations of future regulatory programs, and their relevance to the Stanton B economic analysis. Finally, I will summarize the consequences of delaying the commercial operation of Stanton B, and peninsular Florida's need for the project.

Q. Are you sponsoring any sections of Exhibit ___ (OUC-1), Stanton B Need for Power Application?

A. Yes. I am sponsoring Sections 4.0, 5.0, 6.2, 8.1, 8.6, 9.0, 15.0, 17.0, and Appendix B. These sections were all prepared by me or under my direct supervision.

Q. Are you adopting these sections as part of your testimony?

A. Yes.

Forecast of Facilities Requirements

Q. Please describe the reliability criteria used by OUC.

A. OUC uses 15 percent minimum reserve margin criteria.

Q. Is the 15 percent minimum reserve margin criteria used by OUC reasonable?

A. Yes, many utilities use a 15 percent minimum reserve margin criteria.

Q. Are higher reserve margins also considered reasonable?

A. Yes, the Commission has approved the investor-owned utilities current use of a 20 percent minimum reserve margin.

Q. Based on OUC's reserve margin criteria, when is additional capacity required?

A. OUC is forecasted to require additional capacity beginning in the summer of 2010.

Economic Parameters

Q. Please describe the economic parameters used in the evaluation of alternatives to meet OUC's capacity need.

A. A 2.5 percent annual general inflation rate was used. Escalation rates of 2.5 percent annually were used for capital and operating and maintenance (O&M) costs. The weighted average cost of capital was assumed to be 7.0 percent which was based on an embedded rate of 5.25 percent for new debt and a return on equity of 10.3 percent. The rate for interest during construction was assumed to be 5.25 percent. The present worth discount rate was assumed to be 7.0 percent. A single levelized fixed charge rate was developed which incorporates all of the fixed charges for the project including property insurance as a percent of initial investment cost. The resulting levelized fixed charge rate assuming a 30 year financing term is 8.159 percent.

Q. Are these economic parameters appropriate for use in this Need for Power Application?

A. Yes. They are consistent with economic parameters that have been used in similar evaluations presented before the Commission.

Fuel Forecast

Q. Please describe the development of the fuel price forecast used in the economic analysis.

A. Fuel price projections for coal, natural gas, and No. 2 fuel oil were developed for the Stanton B Need for Power Application economic analyses by Energy Ventures Analysis, Inc. (EVA). These price projections and their methodology are described in the testimony of Seth Schwartz. Black & Veatch reviewed the fuel forecasts provided to OUC by EVA and found them to be reasonable and appropriate for use.

Q. Describe the specifics of the fuel forecast.

A. EVA provided delivered prices for coal to Stanton Energy Center which did not include the cost associated with railcars. For Stanton B and the other coal alternatives, the cost of railcars was added as a capital cost. EVA provided the commodity price for 0.05 percent sulfur No. 2 fuel oil to which a cost of delivery to Stanton was added as well as a premium for ultra-low sulfur (0.0015 percent). EVA provided the Henry Hub-based commodity price and included the Florida Gas Transmission (FGT) Zone 3 adder, as well as fuel loss and usage charges. Firm natural gas transportation charges were added as described in Section 10.2 of the Need for Power Application.

Q. Was the price of nuclear fuel considered in the economic analysis?

A. Yes. Nuclear fuel price projections were required for OUC's ownership shares of St. Lucie Unit 2 and Crystal River Unit 3. EVA did not provide fuel price forecasts for nuclear fuel. OUC provided historical prices for nuclear fuel which were used as the basis for future nuclear fuel prices. An average delivered nuclear fuel price was determined on a $/MBtu basis in 2004. The nuclear fuel forecast was developed by escalating this price at the general inflation rate for the economic analysis period.

Renewable Technology Alternatives and Supply-Side Screening

Q. Were there any renewable technologies considered as alternatives to Stanton B?

A. Yes. There were several renewable technologies analyzed to determine whether renewable energy was a viable alternative to Stanton B. The renewable technologies considered include solid biomass (direct-firing and co-firing), biogas (anaerobic digestion and landfill gas), waste to energy (mass burn and refuse derived fuel), wind, solar (solar thermal and solar photovoltaic), geothermal, hydroelectric (new and incremental addition), and ocean energy (ocean thermal energy conversion, wave, and tidal) technologies.

Q. Please describe how the costs and performance of the renewable technologies were developed.

A. Cost and performance were estimated based on prior project experience and industry knowledge to develop the most promising applications of each technology to meet OUC's need for capacity. When appropriate, ranges of costs and performance for each renewable technology application were developed to create best and worst case scenarios for capital cost, net plant output, net plant heat rate, fixed and variable O&M, and operating capacity factor. These ranges of costs and performance create a band which helps to provide more reasonable analyses due to the many uncertainties associated with renewable technologies.

Q. How were supply-side alternatives selected for detailed economic analysis?

A. A supply-side screening was performed for the following technology categories: renewable, conventional, emerging, advanced, energy storage, and distributed generation. The most promising technologies were selected for further economic analyses.

Q. Please describe the methodology used in the supply-side screening.

A. The supply-side screening considered both economic and non-economic aspects of each type of technology. The non-economic aspects considered included the technology's developmental status, fuel availability or availability of means to generate electric energy, reliability, feasibility, and the technology's overall ability to meet OUC's forecast capacity needs. Economics for the technologies were captured in the development of a levelized cost, or range of levelized costs, for each type of technology.

Q. How were the levelized costs for each supply-side alternative developed?

A. Levelized costs are representative of an all-in cost for each type of technology. The levelized costs are calculated at an assumed capacity factor and consider the costs of capital, fixed and variable O&M costs, and fuel cost for each alternative. Once determined, the levelized cost reflects the overall cost for energy for a given alternative on a $/MWh basis. Levelized cost comparison of supply-side alternatives provides a good method for screening a large number of alternatives into a smaller number of supply-side alternatives which are the most capable of providing low cost energy.

Q. Please describe the results of the supply-side screening.

A. Before alternatives were screened on a levelized cost basis, they were screened on the non-economic basis previously described. Many of the renewable and advanced technologies analyzed are still in the developmental stages and have not been commercially proven. As a result of a being in the early stages of development, parabolic dish, central receiver, solar chimney, ocean thermal, advanced combustion, fuel cell, and advanced coal technologies were eliminated from further economic evaluation.

Renewable technologies are highly dependent on the availability and sufficiency of the various resources required for electric power generation. The geographical range for renewable supply-side alternatives to meet its capacity needs was limited to the Central Florida area. Several of the renewable technologies are dependent upon resources not readily available in Central Florida and were therefore eliminated from further economic analysis. These include wind, solar parabolic trough, geothermal, and hydroelectric technologies. Landfill gas is available and is currently co-fired in Stanton Units 1 and 2.

The remaining non-conventional supply-side technologies were examined on a levelized cost basis, and were evaluated against the levelized costs of the conventional technologies. As a result of this comparison, municipal solid waste mass burn, refuse-derived fuel, direct-fired biomass, solar photovoltaic, pumped hydroelectric energy storage, lead-acid battery energy storage, and compressed air energy storage, reciprocating engine, and microturbine technologies were eliminated from further economic analyses.

A few non-conventional supply-side technologies appeared favorable when compared to conventional alternatives on a levelized cost basis, but were eliminated from further analyses for various non-economic reasons. These technologies include co-fired biomass, anaerobic digestion, and nuclear fission. The co-fired biomass and anaerobic digestion alternatives considered would not provide sufficient capacity to OUC to defer the need for Stanton B. The nuclear alternatives considered were competitive with the conventional alternatives on a levelized cost basis; however, OUC's possible future participation in a nuclear unit is dependent on too many uncertainties at this time to consider it as a supply-side alternative to meet OUC's capacity needs.

The overall result of the supply-side screening was that there were no renewable, advanced, energy storage, or distributed generation technologies that passed all of the criteria of the supply-side screening to merit further economic analysis. The technologies considered in the detailed economic included all conventional technologies and the General Electric LMS100 combustion turbine which is considered an emerging technology.

Q. In general, how did the renewable technologies compare to the conventional technologies in the levelized cost comparison?

A. Although renewable technologies are not available to meet OUC's capacity needs in Central Florida, they are competitive with conventional alternatives in other areas of the country. Alternatives that can be competitive in other areas of the country include wind, parabolic trough, hydroelectric, geothermal, landfill gas, and biomass.

Consideration of Environmental Regulations

Q. Please describe the pending environmental regulations considered in Exhibit ____ (OUC-1), Stanton B Need for Power Application.

A. There were two future environmental regulatory programs considered. These programs are the EPA's Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). CAIR and CAMR are regulatory programs designed to reduce emissions in 28 states (including Florida) and the entire US, respectively. The former will reduce NO_x and SO_2 emissions, while the latter will reduce mercury (Hg) emissions. Both programs are structured to reduce emissions by imposing statewide limits or caps on the amount of pollutants that can be emitted in tons per year. It is up to each affected state to develop a method for meeting these caps, which is subject to the EPA's approval. The programs will be implemented in phases with the first phase for NO_x emission reductions under CAIR and Hg starting in 2009. The first phase for SO_2 emission reductions under CAIR and Hg emission reductions under CAMR will begin in 2010. The second phase for NO_x and SO_2 emission reductions under CAIR and Hg emission reductions under CAMR will start in 2015.

Q. Does the EPA provide any model or suggested means of meeting the statewide emission caps?

A. Yes. The EPA has developed a recommended model cap-and-trade program for meeting the emission caps for each state, which is similar to the program currently in use for meeting emission reductions in the EPA's Acid Rain Program. Under the proposed cap-and-trade program, states will receive allowances corresponding to each state's cap or emission limit. States will decide which emission sources to regulate, and distribute allowances accordingly on an annual basis. An allowance represents the ability to emit a given amount of NO_x, SO_2, or Hg. Regulated sources within the state, which are expected to primarily consist of electric generating units, will then be required to possess enough allowances to equal the amount of pollutants emitted by each regulated source every year. Under the proposed cap-and-trade program, allowances will be fully transferable and can be bought, sold, traded, or saved for future use. A utility with more than one regulated generating unit can distribute their allowances in any manner to ensure that each unit has enough allowances to cover its emissions for the year.

Q. Will the State of Florida participate in the EPA's recommended cap-and-trade program?

A. It cannot be known for certain whether the State of Florida will participate in the EPA's model cap-and-trade program until the EPA approves Florida's State Implementation Plan (SIP), which all states are required to submit to the EPA by September 11, 2006. However, initial information provided by the Florida Department of Environmental Protection (FDEP) indicates that Florida will likely participate in a cap-and-trade program similar to the EPA's recommended model program under CAIR. The information provided by the FDEP also indicates that Florida is not likely to participate in the EPA's recommended cap-and-trade program under CAMR, but will meet statewide Hg caps by imposing limiting standards and compliance schedules for coal fired electric generating units. As such, there is not expected to be any market for Hg allowances in the State of Florida.

Q. How were the effects of CAIR and CAMR incorporated into the detailed economic analysis?

A. Forecasts for emission allowances were developed by Black & Veatch to reflect the cost to reduce emissions of SO_2 and NO_x by one ton per year. Forecasts were not developed for Hg due to Florida's indication that it will not participate in a cap-and-trade program under CAMR. These costs were incorporated into the fuel prices for both existing and candidate units in the economic analysis based on the emission rates of the units. Emission rates for units in OUC's existing system were provided by OUC. Emission rates for candidate units were developed by Black & Veatch based on each unit's fuel, emission control equipment, and best available control technology (BACT) emission permit limits. An individual fuel price adder was calculated and applied to existing and candidate units based on this information.

Q. How were the prices for allowances determined?

A. The prices for NO_x and SO_2 allowances were determined by examining all of the affected utility boilers in the CAIR region. For NO_x, each affected steam generator is analyzed to determine whether it is feasible for additional emission control equipment to be added and the costs associated with the addition of various emission control technologies are determined. The least cost emission control strategy for each boiler is determined on a $/ton removed basis. After the least cost emission control strategy for each boiler is determined, the costs for removal are ranked from least cost to highest cost. The marginal price to remove a ton of NO_x when the total amount of tons removed is equal to the CAIR regional cap is assumed to be the price of an allowance to remove one ton of NO_x. The SO_2 evaluation is similar to the NO_x evaluation, except that it moves down the ranking of emission removal costs in blocks of units, rather than a single unit. The SO_2 evaluation categorizes boilers into size and coal type. The evaluation indicates that scrubbers should be installed on all bituminous coal fired units down to 250 MW, and a portion of bituminous coal fired units sized between 100 MW and 250 MW. Section 9.3 of Exhibit ____ (OUC-1), the Stanton B Need for Power Application, presents the details of the evaluations.

Q. Were allowance allocations for OUC's existing units considered in the economic analyses?

A. No. As stated above the cost of allowances for all existing and candidate units were included in the economic analyses. Similar to the capital cost and fixed O&M costs for OUC's existing units, the value of the allowance allocations for OUC's existing units would be the same for all plans and was therefore not included in the economic analyses.

Consequences of Delay

Q. Please describe the consequences associated with the delay of installation of Stanton B.

A. If there is a delay in the installation of Stanton B, Stanton B is no longer an alternative because the agreements with Southern Company and the DOE cost-sharing may no longer be available to OUC.

Q. Is there also a reliability concern with a delay of Stanton B?

A. Yes, OUC's reserve margin would drop below the 15 percent minimum criteria and would increase the risk of interruptions of reliable service to OUC's customers.

Q. Are there economic consequences related to the delay of Stanton B?

A. Yes, a 1 year delay in commercial operation of Stanton B would result in $9.4 million in additional cumulative present worth costs.

Peninsular Florida Needs

Q. Please describe how OUC's need for capacity associated with Stanton B is consistent with the State of Florida's needs.

A. The weighted average minimum reserve margin requirements of the peninsular Florida utilities are 18.9 percent in the summer and 18.8 percent in the winter. Based on the Florida Reliability Coordinating Council (FRCC) 2005 Load and Resource Database (LRDB), peninsular Florida is projected to drop below these minimum reserve margins in the winter of 2008/09 and summer of 2009 without the addition of yet to be certified new generating units such as Stanton B. Stanton B will contribute to maintaining the minimum peninsular Florida reserve margins and help maintain the reliability and integrity of peninsular Florida's system.

Q. Does Stanton B contribute to fuel diversity in Florida?

A. Yes. The percentage of energy generated by natural gas is projected to increase from 29.9 percent in 2004 to 44.4 percent in 2014 based on the Florida Public Service Commission's December 2005 *Review of Florida Electric Utility 2005 Ten-Year Site Plans.* Stanton B's use of coal-derived syngas will further reduce dependence on natural gas generation in the state and protect customers from high prices and potential supply risks associated with natural gas. In addition, Stanton B's use of subbituminous coal diversifies coal use at the Stanton site and in the state.

Q. Does this conclude your testimony?

A. Yes.